Policy analysis of electricity demand flexibility

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Policy analysis of electricity demand flexibility
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Preface

This thesis has been submitted to the Department of Management Engineering at the Technical University of Denmark [DTU], in partial fulfilment of the requirements for a PhD degree. The work has been supervised by Professor Poul Erik Morthorst (DTU) and Chief Economist Stine Grenaa Jensen (Energinet.dk). Funding was provided by the Danish Council for Strategic Research as part of the research project INCAP (*Inducing Consumer Adoption of Automated Reaction Technology for Dynamic Power Pricing Tariffs*).

The thesis consists of two major parts. The first part introduces the background and defines the scope of the study. It gives a brief overview of the methods applied and a summary and discussion of the results achieved. The second part consists of five scientific articles that form the major contribution of the study. Two of the articles have been published in peer-reviewed journals and another two have been submitted for review. One paper has been presented at an international conference and is published in the conference proceedings.

Kgs. Lyngby, November 2016
Jonas Katz

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Many other people have supported, taught and inspired me earlier and have contributed to this work in their own way. I am also grateful for the funding by the Danish Council for Strategic Research. A special thank has to go to Anders N. Andersen, who introduced me to the importance of flexibility during an internship; he has been a great mentor to me ever since.

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Summary

The large-scale development of variable renewable energy sources, like wind and solar power, increases the demand for flexibility in power systems. At the same time, their electricity production replaces that of conventional power plants – the traditional suppliers of flexibility, and consequently, a new flexible infrastructure needs to be established. This thesis addresses the policy dimension of the flexibility challenge with a focus on Denmark, a country committed politically in two ways that make it particularly interesting: first, a commitment to renewable energy formulated as a long-term vision of becoming independent of fossil fuels; and second, a commitment to liberalised energy sectors with a notably progressive approach to market-based operations.

The crucial question of how it will be possible to balance the Danish electricity system with large amounts of variable renewable production, primarily wind power, is still under debate. To maintain reliability in the most cost-efficient way, a policy strategy aiming at flexibility needs to be developed. Technologically, several different options are available to fulfil the requirement. A part of the solution may be to make use of idle flexibility on the demand side. Its potential could be substantial and technical solutions are available. Still, demand flexibility is largely unutilised and establishing an enabling policy and regulatory framework has been identified as one of the major challenges. While the latest Danish energy policies include a clear commitment to develop an "intelligent" energy system that utilises the flexibility potential of the demand side, a coherent policy strategy covering all aspects of the flexibility challenge has not yet been defined.

By use of economic models and concepts of policy analysis, this thesis considers several policy options aiming at demand flexibility in terms of their effectiveness to induce adoption and their efficiency in creating system value while accounting for the specific characteristics of the demand side. The thesis suggests barriers relevant to be addressed due to either market failures in the classic economic sense or systemic failures founded in market design, rules and regulations. The analysis covers impacts of failures stemming from incomplete markets for flexibility and inappropriate regulation that distort the observed value or risks of demand flexibility. Furthermore, it considers various types of transaction costs related to adopting a demand response contract (switching costs) and to activation (monitoring and decision costs). The thesis develops methods to quantify the impacts of these failures and applies them in relation to the Danish case.

Switching costs are estimated and found to be a major barrier to the adoption of dynamic pricing schemes in spite of the benefits that could be achieved. As the cost of adoption may be difficult to influence directly, policies may aim at increasing the benefits

of flexible demand. One suggested option is to address the issue of incomplete markets and expand market access of flexible demand in the spatial and time dimensions. The value of improving the access of the demand side to intra-hourly reserve markets is found to be substantial. Quantitative findings of the thesis suggest that the reserve value of flexible demand may be significantly higher than the value in hourly spot markets. Another improvement might be achieved by adjusting distortional electricity price elements. It can be shown that value-based taxation, even if applied to smaller portions of the electricity taxes and levies, generates benefits sufficient to exceed switching cost estimates.

Monitoring and decision costs can be caused by the complexity of pricing schemes and hamper efficient response. Even though real-time pricing generates the highest benefits in theory, results of the thesis suggest that simplified schemes with minimal monitoring and decision costs would generate around half of the ideal gains and could be deemed sufficiently beneficial during an initial phase. After consumers gained experience with dynamic pricing, they should be transferred to the more complex and efficient schemes, though. Focussing on the installation of automation equipment could be another way to improve the efficiency of response. As this would require investments, the question of risk involved in generating benefits from demand response becomes more relevant. Using a stochastic price model the thesis shows that risk-averse investors might require a significant cost reduction, resulting in lower levels of investment in automation than what could be expected based on average prices. A policy intervention could be considered to initialise adoption, depending on the further technology cost development.

Overall, the thesis improves the understanding of the specific challenges that policy-making faces when aiming at better utilisation of demand-side flexibility. It includes aspects that often would remain unaddressed in the evaluation of policies. On that basis, it provides support to the development of a coherent policy strategy for flexibility that is required for the successful transition to a fossil-free energy system.

Dansk sammenfatning

Udbygningen med fluktuerende elproduktion fra vedvarende energi, såsom vindmøller og solceller, medfører et øget fleksibilitetsbehov. Samtidig fortrænges den termiske produktion, der traditionelt har leveret fleksibiliteten, hvilket nødvendiggør opbygningen af nye former for fleksibilitet. I denne afhandling behandles den danske fleksibilitetsudfordring med henblik på de politiske konsekvenser. Danmark udgør en særlig interessant case pga. to centrale energipolitiske valg: For det første, er der lagt en strategi om at udbygge vedvarende energi med baggrund i en langsigtet vision om at blive uafhængig af fossile brændsler; for det andet, er der en stærk opbakning omkring liberaliseringen af energimarkederne og en positiv indstilling til markedsbaserede løsninger.

Spørgsmålet om hvordan balanceringen af det danske elsystem fremover skal håndteres, er endnu ikke afklaret. For at opretholde driftssikkerheden på den mest omkostningseffektive måde, er det nødvendigt fra politisk side at definere en strategi med fokus på fleksibilitetsudfordringen. Teknologisk set, står der en række forskellige tiltag til rådighed for at opfylde behovet. En del af løsningen kunne være at gøre brug af uudnyttet fleksibilitet på forbrugssiden, da der allerede eksisterer et betragteligt potentiale, samtidig med at de nødvendige tekniske løsninger er til rådighed. Alligevel har fleksibiliteten på forbrugssiden stort set ikke været anvendt, og i forhold hertil er de politiske og regulatoriske rammer blevet udpeget som en væsentlig forhindring. Der er endnu ikke lagt en strategi, der sammenholder alle forskellige aspekter i fleksibilitetsudfordringen, selvom de seneste danske energipolitiske målsætninger indeholder en klar beslutning om at udvikle et "intelligent"energisystem, der udnytter elforbrugernes fleksibilitetspotentiale.

I denne afhandling analyseres forskellige tiltag, som sigter mod at øge forbrugsfleksibiliteten. Tiltagene vurderes med henblik på deres evne til at fremme udbredelsen af fleksibelt forbrug og deres økonomiske effektivitet. Dette sker ved brug af økonomiske modeller og politikanalyse under hensyntagen til de specifikke karakteristika på forbrugssiden. I afhandlingen afdækkes relevante barrier med udgangspunkt i enten markedssvigt i klassisk økonomisk forstand eller institutionel svigt grundet markedsdesign, regler eller regulering, da disse forhold kan medføre forvrængninger af værdi og risici ved det fleksible forbrug. Herudover betragtes transaktionsomkostninger relateret til indgåelsen af fleksibilitetsaftaler (*switching costs*) samt omkostninger ved løbende aktivering af fleksibilitet (monitorerings- og beslutningsomkostninger). Der udvikles metoder for at kvantificere forvrængningseffekterne i en dansk sammenhæng.

Transaktionsomkostninger ved kontraktindgåelse anses for at være en væsentlig barriere for udbredelsen af dynamiske priser, også selvom forbrugerne kunne opnå en økonomisk besparelse. I og med at omkostningerne vil være svære at reducere, kunne politiske tiltag sigte efter at øge den økonomiske besparelse ved fleksibelt forbrug. En mulighed vil være at udvide markedsadgangen for fleksibelt forbrug geografisk og tidsmæssigt. Værdien ved at forbedre forbrugssidens adgang til reservemarkeder inden for driftstimen vil være betydelig. Resultaterne i denne afhandling tyder på, at værdien af fleksibelt forbrug som reserve kunne være væsentlig højere end spotmarkedsværdien. En yderligere forbedring kunne opnås ved at rette op på de forvrængende elementer i elprisen. En værdibaseret afgift vil kunne generere besparelser hos forbrugerne, der overstiger transaktionsomkostningerne ved at skifte, også selvom den kun anvendes på en mindre del af elafgiftene.

Komplekse prismodeller kan være årsag til høje monitorerings- og beslutningsomkostninger og på den måde hæmme en effektiv respons. Selvom spotpriser giver de højeste teoretiske gevinster, så tyder resultaterne i denne afhandling på, at simple modeller med mindst mulige monitorerings- og beslutningsomkostninger vil kunne give omtrent halvdelen af de optimale gevinster. I en introduktionsfase vil de simple modeller derfor kunne betragtes som tilstrækkelige. På et tidspunkt, når forbrugerne har samlet erfaring med den dynamiske prissætning, bør man dog gå over til de mere komplekse og effektive modeller. Et øget fokus på installering af automatik på forbrugsstederne kunne være en anden tilgang til at opnå en mere effektiv respons. Eftersom dette vil kræve investeringer, bliver det relevant at analysere, hvilke risici der er forbundet med at agere fleksibelt. Ved brug af en stokastisk prismodel illustreres det, at risikoaverse investorer ville kræve en betydelig omkostningsreduktion for at installere automatik, hvilket vil medføre færre investeringer end der kunne forventes på baggrund af gennemsnitlige priser. Dette kan modvirkes politisk, hvis den videre udvikling af teknologi og omkostninger gør det nødvendig.

Alt i alt bidrager denne afhandling ved at fremme forståelsen for de specifikke politiske udfordringer, der følger med en målsætning om at fremme udnyttelsen af fleksibelt forbrug. Afhandlingen behandler forhold, der sjældent belyses i forbindelse med de analyser, der ligger til grund for politiske beslutninger. Konklusionerne kan bruges til at understøtte udviklingen af en politisk strategi for fleksibilitet, som er nødvendig for en vellykket overgang til et fossilfrit energisystem.

Publications included in thesis

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Articles under review

Katz, J., Balyk, O. & Hevia-Koch, P. (2016). The impact of residential demand response on the costs of a fossil-free system reserve. *UNDER REVIEW*.

Katz, J., Kitzing, L., Schröder, S. T., Andersen, F. M., Morthorst, P. E. & Stryg, M. (2016). Dynamic pricing and electricity taxation from a household customer perspective. *UNDER REVIEW*.

Conference papers

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List of other publications

Hethey, J., Kofoed-Wiuff, A., Bornak, L., Lindboe, H., Sawatzki, S., Vestarchi, M., Skytte, K., Katz, J., Egerer, J., Zerrahn, A. & von Hirschhausen, C. (2015). *Increased integration of the Nordic and German electricity systems: Modelling and assessment of economic and climate effects of enhanced electrical interconnection and the additional deployment of renewable energies*. Berlin: Agora Energiewende. Retrieved from http://orbit.dtu.dk/files/110948746/Agora_Increased_Integration_Nordics_Germany_LONG_WEB.pdf

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Contents

Chapter 1

Introduction

1.1 Scope

An increasing number of countries have set national renewable energy targets, and energy systems are undergoing a transition towards larger shares of renewable energies (International Energy Agency [IEA], 2016). Environmental concerns and the mitigation of climate change play an important role. In addition, for regions like Europe utilising domestic renewable potentials shall help to reduce the import-dependency and exposure to volatile prices of fossil fuels (European Commission, 2011a). Reductions in technology costs, in particular for wind and solar power, make investments attractive in economic terms as well, and, consequently, these technologies are installed at increasing rates (REN21, 2016). One of the resulting challenges is handling variations in production due to the intermittent nature of the renewable resources; this requires a flexible system. Although renewable energies will have an important role to play in other sectors as well, the focus of this thesis is on the electricity system that faces a very specific challenge in that it lacks access to inexpensive sources of flexibility.

In power systems, flexibility is a fundamental and technical challenge to start with. The most important, and traditionally largest source of flexibility, is dispatchable generation capacity (IEA, 2011). As larger shares of generation will be taken over by variable renewable sources, dispatchable plants become less available. At the same time the level of flexibility needed to operate a stable and reliable system is increasing. Technically, a wide range of options to provide flexibility exists, and it has been argued that even fully supplying an electricity system by renewable energies is possible, when employing the available technologies (Hohmeyer & Bohm, 2015). The portfolio of options has been described in a number of comprehensive international studies (e.g. Gül & Stenzel, 2005; Papaefthymiou et al., 2014). Besides the conventional power plants, renewable energies themselves can be used as a flexibility option (P. E. Sørensen, 2009). For instance, Danish wind turbines are already participating in the regulating power market as of today (Sorknæs et al., 2013). Under certain conditions wind turbines could also provide additional ancillary services, such as inertia (Muljadi et al., 2012),voltage control or secondary reserves (Ela et al., 2014; Red Eléctrica de Espana et al., 2013). Other categories of flexibility resources include storages and grid infrastructure.

A particular option that has attracted interest throughout several decades now is the flexibility of the demand side. It seems attractive, because it constitutes a large technical potential that could be relatively inexpensive to utilise and, most importantly, it is already present as part of the existing system. Thus, it may require only minor technical changes (e.g. new metering equipment); at the same time though, utilising the potential poses new challenges induced by the adoption and consumption behaviour of electricity consumers. From an economic point of view, one should expect that demand is responsive to changes in price, and exposure to cost-reflective prices would result in efficient behaviour. Due to fundamental flaws in the structure of the electricity sector, however, proper interaction of demand and supply is prevented (Stoft, 2002). In particular, the lack of real-time metering and settlement on the basis of actual consumption prevents demand from being responsive to price in practice. If this issue was resolved, according to the theoretical argument, substantial welfare gains would be achieved. Field research of the past more than 30 years has worked towards confirming and quantifying the theory of price-responsive consumers. Although evidence has been presented within different settings (see Conchado & Linares, 2012), many countries, including Denmark, have continued to serve a passive demand side (Danish Energy Agency, 2009), and practical implications of the theoretical economic argument have been limited.

With recent developments in the electricity production from intermittent renewable sources the demand side is once again regarded as a potential solution. The theoretical argument that enabling demand response would result in welfare gains, will still be valid. The motivation of addressing cost reductions of integrating renewable energies in particular, could be even more important, though. Besides creating a need for flexibility, renewable generation, as opposed to the traditional electricity production in big centralised units, occurs to a larger extent in smaller decentralised units. Moreover, electrification of heating and transport may lead to additional loads connected to distribution grids, hence, resulting in additional challenges at these lower voltage levels. In such a system a decentralised source of flexibility, like demand response, becomes important.

The term *flexibility* is widely used and often applied very broadly to cover different aspects. In the most general sense, flexibility denotes the *"capacity to adapt"* (Golden & Powell, 2000). In an energy system context, most widely, flexibility can be defined as the capacity to contribute to reliable energy supply. Reliability has different dimensions, one of which is the time horizon. The capacity to adapt to long-term changes affecting reliability considers, mostly, the primary energy supply of fuels. A flexible energy system would, therefore, be able to change the use of fuel or technology in response to changes in price or availability (Pérez-Arriaga, 2007). In Denmark this ability had high priority in the aftermath of the 1970s energy crises (Danish Ministry of Energy, 1981; Hvelplund et al., 1983), and therefore this period showed a prevalent use of the term flexibility for the long-term horizon.

More recently, *flexibility* has primarily been used to denote the capacity to adapt to changes in a shorter time frame. In this perspective flexibility relates to reliability as defined by electricity system operators: a measure to determine how well customer load is served (ENTSO-E, 2004). It covers two aspects. The first one is the adequacy of the system, which is the ability of the system to cover the electrical demand at all times. Adequacy is a measure reflecting the requirement for sufficient capacity to be installed. The other aspect is system security, which is the ability to react to sudden disturbances. At any point in time the system needs to maintain a certain reserve margin to handle such conditions. Flexibility is the prerequisite to maintain a reliable system both in terms of adequacy and security. In this sense, it may be defined as *"the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons"* (Danish Energy Agency et al., 2015).

In the following the term flexibility is used to describe the ability of the electricity system to change the loading of its components in order to ensure reliable operation covering both adequacy and security aspects. Consumers that hold a *capacity to adapt* will be able to provide flexibility akin to flexible generators. Different terms are being used to describe the flexible capabilities of demand. Besides *demand flexibility*, commonly used terms are *demand response* and *elasticity*. The following definitions may be helpful in distinguishing these concepts and will be used as such in this thesis:

Demand flexibility describes the ability of a demand-side unit to actively change its level of consumption or production.

Demand response is the active change in reaction to any kind of control signal (usually price or volume, but also environmental incentives etc.).

Demand elasticity is short for price elasticity of demand and describes the economic concept of how consumers react to a change in price.

In summary, demand flexibility is used as a more technical term describing the potential, while demand response denotes utilised potential (this definition is similar to that of THEMA Consulting Group, 2014); as often potential will be utilised through price signals on a market, such response is based on the elasticity of demand. In a wider behavioural understanding of elasticity, the term could as well cover the response to other kinds of incentive signals that include environmental or social benefits (as proposed by, e.g. Stoll et al., 2014).

1.2 Research interest

The described conditions lead to an overall policy challenge that this thesis seeks to address. The policy focus is on Denmark; the country is committed politically in two ways that make it particularly interesting. First of all, a commitment to green energy creates an unresolved long-term challenge for electricity system planning and operation (Energinet.dk, 2015a). Danish Government (2011a) formulated a long-term vision of becoming independent of fossil fuels by 2050. Regardless of whether this ambition will be exactly fulfilled in the targeted year, a high share of renewable electricity, in particular from wind power, will be part of Denmark's energy supply in a foreseeable future. Already today Denmark has a high share of wind power corresponding to around 42% of electricity consumption (Energinet.dk, 2016d)

The second commitment is related to the liberalisation of the electricity sector. Amongst the countries of the European Union aiming at a common electricity market, Denmark and its electricity sector institutions have demonstrated a notably progressive approach to market-based operations. Electricity sector liberalisation, although controversial (see Meyer, 2004), was largely backed up politically. One reason might have been that in Denmark state-owned industries play a far less significant role than in other European countries (Petersen, 2009). Market principles are also sought implemented to support the integration of wind power by both industry stakeholders (e.g. Energinet.dk, 2015b; Energinet.dk & Dansk Energi, 2012) as well as policy-makers (e.g. Danish Ministry of Climate, Energy and Building, 2013).

The role of the demand side in the ongoing transition has been acknowledged by policy-makers.[1] Technical challenges remain, but become less of a barrier (Schleicher-Tappeser, 2012b), in particular, as large-scale smart metering is being installed – Denmark opted for a full roll-out by the year 2020 (Danish Energy Agency, 2014b). In the context of the future development of renewable energies and the focus on a liberalised market model, an unresolved challenge in Denmark lies in defining a supportive regulatory framework. Consumers need to be integrated into the market mechanisms so as to utilise their flexibility potential. The utilisation of demand flexibility to a large extent depends on the willingness of electricity consumers to adopt enabling technologies and pricing schemes. Policy-makers can significantly influence the conditions that enable this to happen. Consequently, the overarching research question of this thesis is:

> *How can policies enable cost-efficient utilisation of demand-side flexibility to support the integration of large shares of variable renewable energy sources in a liberalised electricity market?*

1.3 Contributions

The dissertation is based on a series of articles appended to the thesis. In the text the articles will be referred to as Papers A–E. The papers provide contributions to the above research question by addressing different aspects of the policy challenge.

Paper A performs a policy analysis to establish a framework that also serves to organise the further research within this study. The framework is illustrated in Figure 1.1, and the basis for deriving it is described in more detail in Section 3.2. It aims at answering the question:

> *Which are the major issues that policies aiming at demand flexibility should focus on?*

Figure 1.1 is constructed around the concept of *system diagrams* (van der Lei et al., 2011), though in a simplified form, with the system to be influenced restricted to *demand flexibility*, the theme of this thesis. The overall policy objective, shown on the right-hand side, is defined as an *efficient utilisation of demand flexibility*. External factors are given by the *market structure* that may be difficult to influence by policy. Policy influences are summarised under the heading of *market design & regulation*. The upper part of the diagram shows how the papers relate to different aspects of demand flexibility. Their specific contributions are briefly described in the following and in more detail in Section 4.

[1] As stated by the European Commissioner for Climate Action and Energy: *"[...] we also need to improve demand-response. We need to look at the barriers – both regulatory or in terms of market design – to allow consumers to provide flexibility in the market. Changes to the overall market design are needed, both to allow the market to respond but also to provide the right investment signals for flexible capacity and demand services."* (European Commission, 2015b)

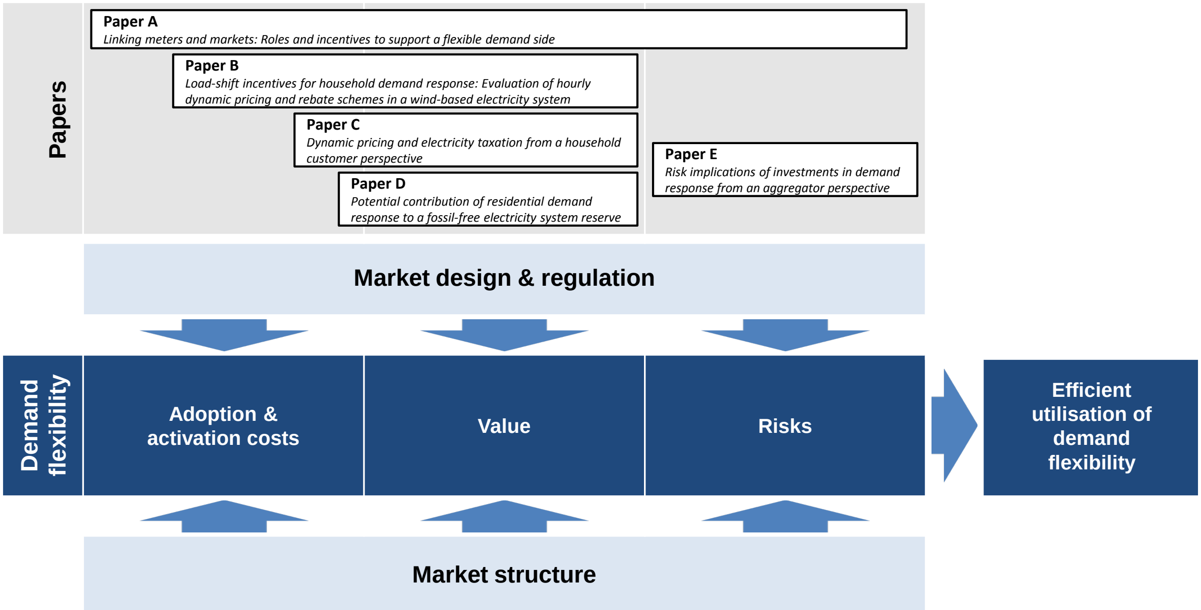


Figure 1.1: Contributions of papers in relation to addressed policy areas

An essential policy objective in support of demand flexibility is to align the observed market value and the underlying system value of flexibility. This is dealt with in Paper D; more specifically the following question is addressed:

What is the value of expanding the scope of demand-side market access?

Paper D considers valuation at an intra-hourly time frame to include the potential contribution of demand-side flexibility to system reserves. It may be seen as an attempt to establish a more complete market value of demand flexibility with the reserve element as a potential addition to the value generated in the hourly market.

Papers B, C and E address different aspects of value. Their focus lies on the alignment of flexibility policies with the specific capabilities of the demand side. Paper B focusses on value in relation to risks and transaction costs of different retail product designs. It acts on the assumption that complex products might not result in efficient demand response or that they will not even be adopted by consumers. Simplifying products, though, results in a lower value of the response from a system perspective. This poses the question:

How valuable are simplified products for flexibility?

Paper C, similar to Paper B, investigates the impact of different pricing schemes, but focusses more on the value from an individual households perspective, and how it would be influenced by redesigning electricity taxation. It acknowledges that consumer adoption of dynamic pricing is subject to transaction costs of switching to a new contract and potentially even a new supplier. It therefore considers the question:

Can consumers be expected to adopt dynamic pricing in the light of their transaction costs of switching?

The last Paper E addresses the aspect of uncertainty regarding the value of demand response, which may become relevant in particular in those cases that require additional up-front investment in automation equipment. This analysis aims to provide insight into the following question:

> *Is risk a major issue for demand response adoption and does it need to be addressed by policy-makers?*

The remainder of the thesis is structured as follows. Section 2 introduces the flexibility challenge in more detail. It describes the role the demand side might be able to play and focusses furthermore on the policy response to the issue. Section 3 summarises the methodological approach. Where necessary, descriptions are expanded, in comparison to those in the papers, to provide appropriate background. Section 4 discusses the contributions of the thesis and possible policy implications. General conclusions and recommendation for further research are presented in Section 5.

Chapter 2

Background: Flexibility, policy and the demand-side

2.1 Demand flexibility in Danish energy policy

2.1.1 Energy conservation and load management

The overall aim of Danish energy policy is to provide secure, cost-efficient and environmentally friendly energy. Since the energy crises of the 1970s a key driving force of energy policy has been to reduce the dependency from imported fuels (Moe, 2007). This was primarily sought achieved by implementing energy efficiency measures and developing domestic resources (Danish Ministry of Commerce, 1976). Moreover, in 1985 plans to develop nuclear power had been abandoned (Folketinget, 1985). This first and foremost left natural gas and renewable energies as domestic resources for further development.

The focus on energy efficiency increased the focus on the demand side. With the development of a more diverse electricity production infrastructure based on coal and gas-fired plants, to a larger extent cogenerating heat, and slowly increasing production from wind power, the time dimension of savings became more relevant (see also Edvinsson, 1986). This meant that besides emphasising mere energy conservation, a more efficient utilisation of resources became possible by load shifting (Ilic et al., 2007). A more even distribution of load to better utilise coal power plants and avoid costly oil-based peak production was an early motivation for demand-side management in Denmark (Danish Ministry of Energy, 1981). Such measures had already been implemented in other European countries, like France, Great Britain and Germany (Mitchell & Acton, 1977). In the US the first load control programs fall into this period as well (see Hurley et al., 2013). A programme aiming at controlling air condition units was implemented in California in 1983; larger units had been targeted already during the 1970s (Zarnikau, 2008).

The focus on cost efficiency resulted in a first significant wave of demand response research internationally. Economists became more involved in the debate on electricity rates, and whether they should be based on marginal cost principles instead of accounting costs (Malko & Swensen, 1989). The discussion about implementing time-of-use pricing go back to the beginning of the electricity industry (Hausman & Neufeld, 1984), but now even more detailed concepts of real-time pricing were proposed building upon the very same arguments about demand response[1] (Schweppe, 1978; Schweppe et al., 1980). Such pricing schemes were expected to reflect costs more precisely onto consumers, potentially, facilitating savings in operation but also in the requirement for new capacity (Räsänen et al., 1997). To find out about the responsiveness of consumers, also a range of pricing experiments based on time-of-use principles were conducted (e.g. Faruqui & Malko, 1983; Lifson & Miedema, 1981).

In Denmark time-of-use tariffs for large customers were not introduced before the late 1980s (Togeby et al., 2001). Also proposals of dynamic pricing had been put forward, for instance, in order to provide incentives for electric heating customers to shift their consumption (Mikkelsen et al., 1994). This was even before, in 2000, Denmark had fully become part of the common Nordic electricity exchange Nordpool and its hourly spot market (Grønli, 2003). The active management of electric heating installations had not been put into practice, however. One reason might have been the ban Danish legislation put onto the installation of electric heating when introducing decentralised combined heat and power plants across the country (Danish Energy Agency, 2005).

2.1.2 Liberalised markets and smart grids

New interest had been generated in the topic of demand response after the liberalisation of the electricity sector during the late 1990s and early 2000s. In the early days of liberalisation there had been a focus on efficient market operation and the potential market power of incumbent utilities. Some of the still immature electricity spot markets settled at extremely high prices in some of the traded hours (e.g. Sweeney, 2006; von der Fehr et al., 2005). While in a pure market-based system, with the spot market as the main source of generator revenues, such scarcity prices are necessary to recover fixed costs, frequent price spikes might as well be interpreted as a sign of market power. Better integration of the demand side into the market was seen as a promising instrument to mitigate the exercise of market power (IEA, 2003).

As wholesale markets began to attract more liquidity giving less cause for concerns about market power, the demand response debate shifted somewhat from the wholesale level to lower grid levels. The liberalisation in most countries had been phased-in first on wholesale level affecting generation and large consumers (IEA, 1999). Europe opted for a development towards full retail competition, while for instance parts of the US contained liberalisation to wholesale level (Faruqui et al., 2010). Efficient retail competition required the unbundling of grid operation and electricity supply business. The isolation of distribution grid operations entailed a focus on cost efficiency in this part of the industry as well (Danish Electricity Regulation Committee, 2014b). In particular, a question appeared on the agenda of whether it could be preferable to invest into smarter distribution grids instead of investing into capacity expansion. Accordingly, an effort was made in both Europe and the US towards increasingly including intelligent control to avoid capacity investments, fostering the now ubiquitous term of a *smart grid* (Amin & Wollenberg, 2005; Coll-Mayor et al., 2007).

[1]One of the first records in economic literature regarding the importance of the timing of demand has been made by Clark (1911): *"If consumers can make extra demands on the utility without paying as much as the extra expense they are causing, they are likely to make wastefully large demands on it."* (p. 475)

2.1.3 Renewable energy integration

The flexibility challenge of an energy system largely based on renewable and combined heat and power production had been acknowledged early on (B. Sørensen, 1975). While the very first energy policy plan merely considered the impact of wind power on the physical landscape (Danish Ministry of Commerce, 1976), the integration with the existing power system had been identified as a potential issue already in the earliest phases of its development (Danish Ministry of Energy, 1981). Up until the mid 1980s the technical maximum for the integration of wind power production into the electricity system was claimed by the utilities to lie at around 10% (H. Lund, 2000). Consequently, policies were cautious in their assumptions about future developments. The first official plans started out with negligible amounts of variable production from renewable energies at 3% of electricity production in the target year of 1995 (Danish Ministry of Commerce, 1976). At the same time, however, alternative plans were developed that included shares of 10% and were based on the premise of avoiding the introduction of nuclear energy into the Danish system (Blegaa et al., 1976, 1977). A target of 10% of wind in electricity production for the year 1995 has later been set in the official plans as well (Danish Ministry of Energy, 1981). Beyond such levels it was expected that additional flexibility measures would become necessary or that wind production would need to be curtailed (see B. Sørensen, 1978). Already, it had been expected that the increase of electricity cogenerated with heat would introduce the risk of excess production (ELSAM, 1984).

With experience gained and technologies maturing, scenarios and policies became more optimistic regarding wind power in the 1990s. On a local scale concepts were developed that combined flexible electricity production and consumption in decentralised district heating with wind power to allow for wind shares in electricity above 25% (Jørgensen et al., 1986). Also the emergence of the climate policy agenda was a driver for more ambitious renewable energy targets. The official 1990-plan was based on a scenario with a level of 20% of wind power in 2030 (Danish Ministry of Energy, 1990). Measures to handle variability were explicitly addressed, and integration issues were defined as a focus area for research. This path was further pursued, and the Danish Energy Agency (1995) developed a scenario with 37% of variable renewables. From that point and onwards, system flexibility became an important element of energy policy. The important role of the district heating sector in balancing the system was emphasised and measures like building heat storages and increasing the flexibility of power plants were included in the policies (Danish Ministry of Environment and Energy, 1996).

The political push towards renewable energies during the 1990s was expected to put the electricity system under stress. In particular, the issue of excess wind and combined heat and power production was sought addressed in a range of studies. Various stakeholders were involved in an analysis prepared for the Danish Energy Agency (2001) that foresaw the possibility to handle excess production in a 2020 scenario at reasonable costs and on the basis of readily available technologies, e.g. industrial demand response as well as the use of heat storages and electric boilers in the district heatings system. In a subsequent political agreement in 2002 it was decided to improve the possibility of the system operator to regulate decentralised and renewable production in cases of oversupply (Danish Government, 2002). Subsequently, the potential of domestic resources to balance the increasing wind power production was further emphasised in several studies (H. Lund & Münster, 2003, 2006). Integrating 50% wind shares or even more were deemed possible without compromising system security if balancing and ancillary service provision were decentralised as well (Østergaard, 2006).

In 2006 the Danish Government announced the long-term goal of a self-sufficient energy supply independent of fossil fuels (Danish Prime Minister's Office, 2006). A strategy paper specifying the target was published the following year – without, however, setting a more precise time horizon for the attainment of the formulated goal (Danish Ministry of Transportation and Energy, 2007). The target year of 2050 to achieve the goal was set four years later (Danish Government, 2011a, 2011b). Ever since, and in particular after the energy agreement of 2012 between all major Danish parties (Danish Government, 2012), this target has been a guiding principle of Danish energy policy. At the same time, it is an important element in the overall climate policy target of reducing greenhouse gas emission by 40% in 2020[2] and contributing to the common European reduction target by 2050 (Danish Government, 2013).

The formulation of the Danish long-term target of a fossil-free energy system once more stepped up the need to define a feasible solution to the flexibility challenge. Extensive scenario analyses with large shares of wind production were initialised that also included evaluations of different flexibility options. Besides the district heating system, scenarios increasingly included storage and demand-side options (e.g Karlsson & Meibom, 2008; H. Lund, 2007; H. Lund & Mathiesen, 2009). The most important demand-side options included electric vehicles, individual heat pumps and flexible industrial demand (Danish Commission on Climate Change Policy, 2010).

Danish Government had taken up demand-side flexibility again in 2007 as one of the initiatives regarding energy efficiency (Danish Ministry of Transportation and Energy, 2007). In governmental strategies following in 2011 flexible demand and the smart-grid concept have been emphasised as a precondition to reach the formulated targets of a fossil-free energy system (Danish Government, 2011a, 2011b). Resulting from these strategies and the following agreement of the political parties in 2012 was the decision about a full smart-meter roll-out by 2020 and the first definition of an official smart grid strategy (Danish Ministry of Climate, Energy and Building, 2013), the most comprehensive Danish policy document regarding flexible demand thus far.

2.2 The flexibility challenge

2.2.1 System balancing with large shares of renewable production

As a consequence of the political agreements the Danish energy system will primarily be based on wind, solar and biomass as energy source in the long run. On the supply side two major scenario paths have been pursued in recent years (see Danish Energy Agency, 2014c). One with a focus on mainly wind power, and one with a maximum utilisation of electricity production from biomass complemented by wind. Of these two approaches the wind path seems to be the least controversial, due to the fact that the biomass path would to a large extent rely on imports and create new dependencies (see Energinet.dk, 2015a). As mentioned, Danish energy policy has aimed at becoming less dependent on imports for some time. Full self-sufficiency had been finally achieved by

[2] as compared to 1990-levels

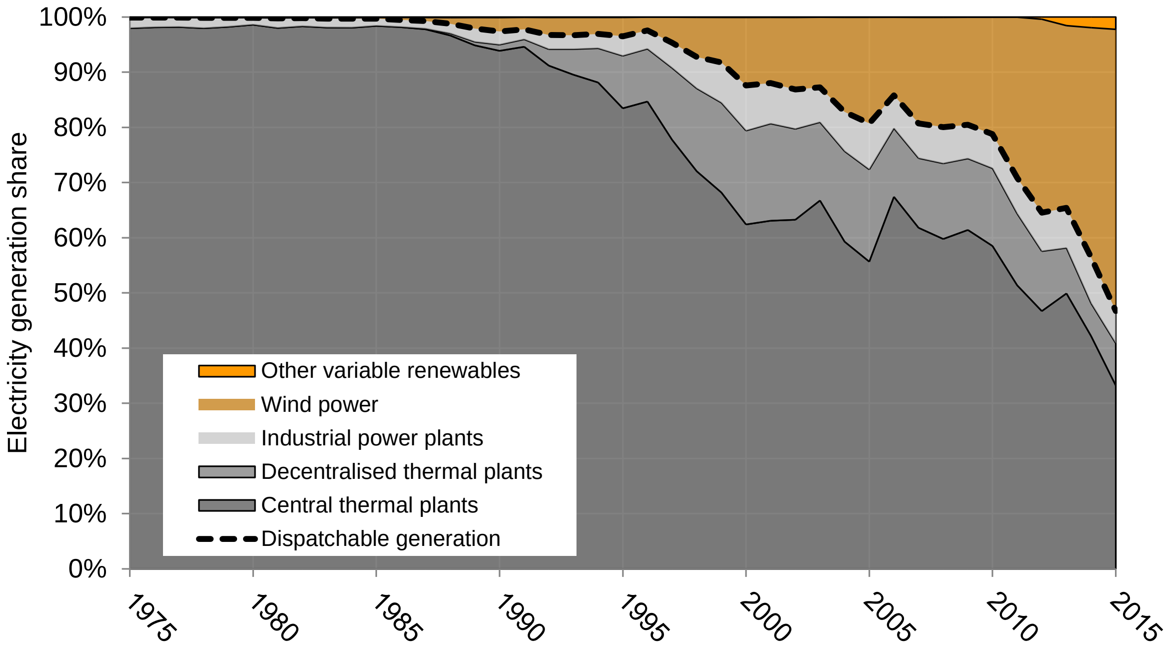


Figure 2.1: Shares of generation from variable sources and dispatchable plants in Denmark (based on data from Danish Energy Agency, 2016b)

1997 by developing own resources of fossil fuels, highly efficient use of energy through insulation of buildings and using combined heat and power production, as well as developing domestic renewable energy resources, in particular wind (Sovacool, 2013). On the other hand, the cost of wind developments, especially offshore, have recently been subject to some debate and could be argued to justify a certain level of imported biomass (Danish Economic Councils, 2014).

According to the scenario calculations of the Danish Energy Agency (2014c) a wind share in the range of 60% to 90% of total electricity consumption is to be expected. The share will eventually depend not only on the use of biomass, but also on the strategy regarding the transport sector. In any case, though, wind power development will be a major driver for future flexibility demand. The challenge may become even more severe as Denmark's largest neighbour Germany is pursuing a similar path and foresees a substantial need for flexibility as well (German Ministry for the Environment, Nature Conservation and Nuclear Safety, 2012, sketches and categorises the demand for flexibility in the German system). Moreover, it can be expected that conventional sources of flexibility will become less available. The downward trend in the development of production from dispatchable supply from both central and decentralised power producers in Denmark is illustrated in Figure 2.1.

Specific challenges for the Danish system have been summarised in several reports (Dansk Energi & Energinet.dk, 2012; Energinet.dk et al., 2015; Energinet.dk & Dansk Energi, 2012; Togeby, Werling, Hethey et al., 2009). Also the Danish transmission system operator [TSO] addresses challenges within their Nordic (Statnett et al., 2016) and wider European cooperation (ENTSO-E, 2010). In the light of closing thermal power plants, increasing shares of wind power and developments in neighbouring regions, challenges at system level have been identified under the headings of *flexibility*, *functionality* and *capacity* (Energinet.dk et al., 2015). More specifically, system operators need to maintain a certain degree of controllable elements (flexibility), ensure that adequate transmission and generation capacity is available to serve load (capacity) and that the stability of the system is maintained by means of frequency quality as well as sufficient inertia (functionality).

Often the system balancing challenge is illustrated with the residual demand to be covered when non-dispatchable production is subtracted from total demand. Challenges already arise in the present system. As political targets set the ambition of a fully renewable system, analyses of residual demand in such a future system are helpful in understanding the flexibility challenge related to balancing. A number of such analyses have been carried out for, e.g. Denmark (Dansk Energi & Energinet.dk, 2015; Hedegaard & Meibom, 2012), Germany (Droste-Franke et al., 2012; Schill, 2014) or the whole of Europe (Bertsch et al., 2016; Huber et al., 2014).

Figure 2.2 provides an illustration of Danish residual demand in the form of a duration curve. The example simply takes the total Danish electricity consumption of 2015 and subtracts the corresponding wind profile as well as the same profile scaled to cover 80% of the demand. Although of course neither consumption nor the wind profile exactly resemble a future situation, it gives an impression of the challenge ahead. In addition to the duration curves, Figure 2.4 shows curves with the maximum consecutive duration of the respective residual demand. For clarity, only the positive and negative extremes are shown. It can be seen that while a certain residual demand may occur in a large number of hours, the maximum number of consecutive hours that such capacity would have to be supplied, is much lower. The latter curve, therefore, provides a good indication of the needed flexibility in terms of volume, i.e. the capacity and the duration it needs to be available. Some of it will be provided by dispatchable generation, and a certain share will be covered by imports and exports. In terms of demand response, the left-hand side of the curve (Figure 2.4a) represents a need for capacity to be curtailed, while the right-hand side (Figure 2.4b) represents additional need for consumption. Ideally, some of the load would be shifted between those periods.

Another important aspect to consider is the change in residual load from one hour to the next, as this defines the ramping requirement of the system. Figure 2.3 illustrates the rise in ramping requirement with larger shares of wind. It is based on hourly values – intra-hourly ramp rates may be less severe (Holttinen et al., 2011). The extreme ends show a clear rise in the demand for flexibility in the form of almost doubled ramping requirements from hour to hour. In combination with the reduction in dispatchable capacity this will create a flexibility gap that in parts could be filled by the demand side (Papaefthymiou et al., 2014).

2.2.2 Distribution grid challenges

Not only will the Danish transition towards a fossil-free energy system result in challenges to balance the electricity system as a whole, it will most likely also affect conditions at the distribution level (Energinet.dk & Dansk Energi, 2012). In contrast to the centralised production of most fossil power plants, more and more production units will be connected to lower voltage grids, resulting in power flows that have not been foreseen when the grids were originally planned. Challenges may occur, in particular, when production is fed into the lowest levels, which increasingly is the case with con-

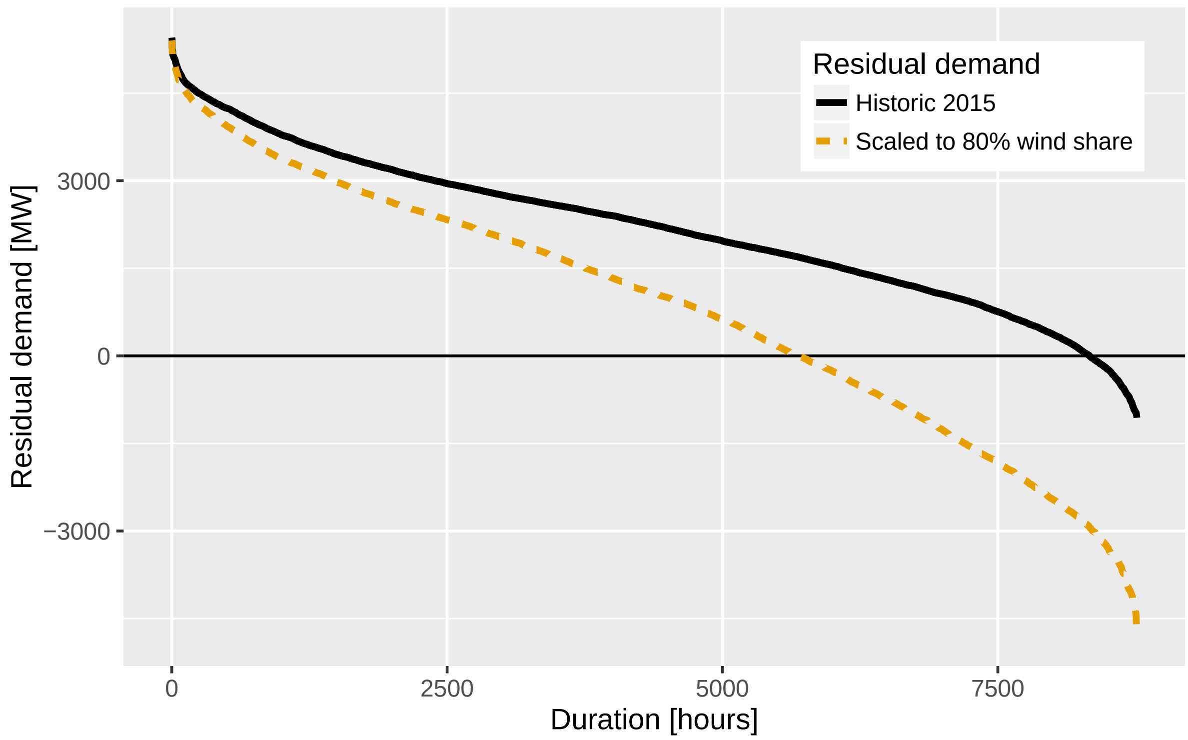


Figure 2.2: Residual demand duration curve (based on data for consumption and wind power in Denmark from Nord Pool, 2016)

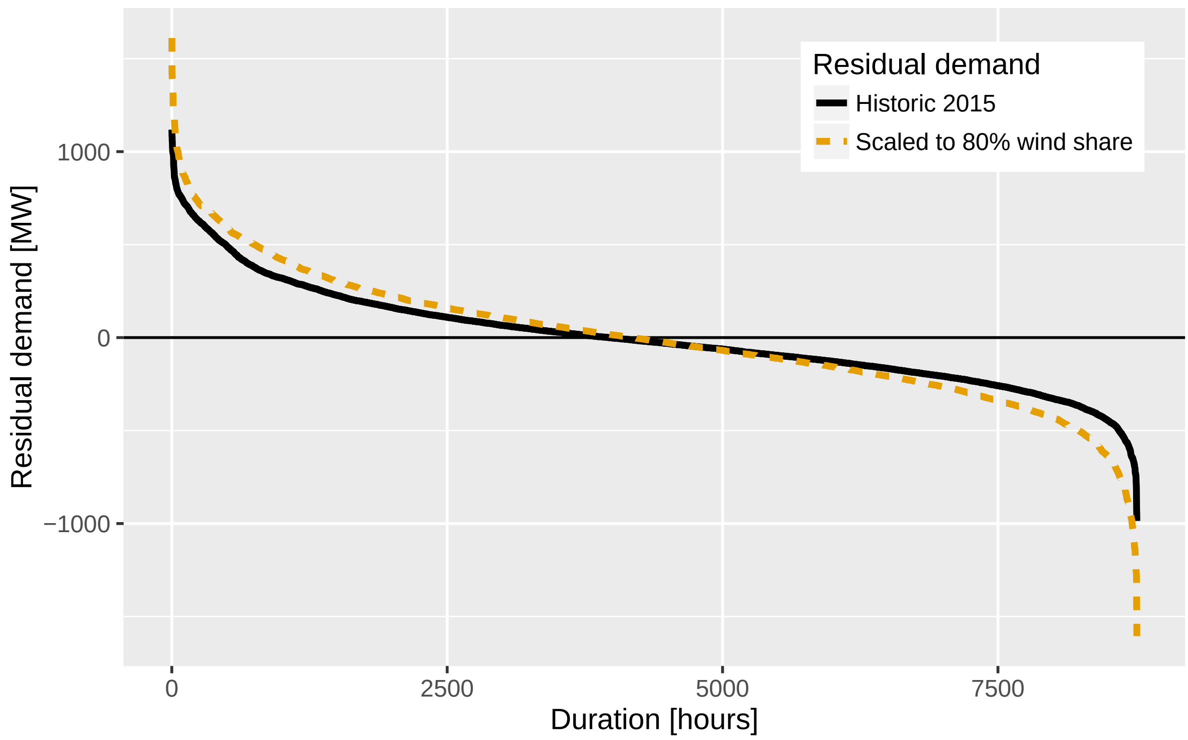
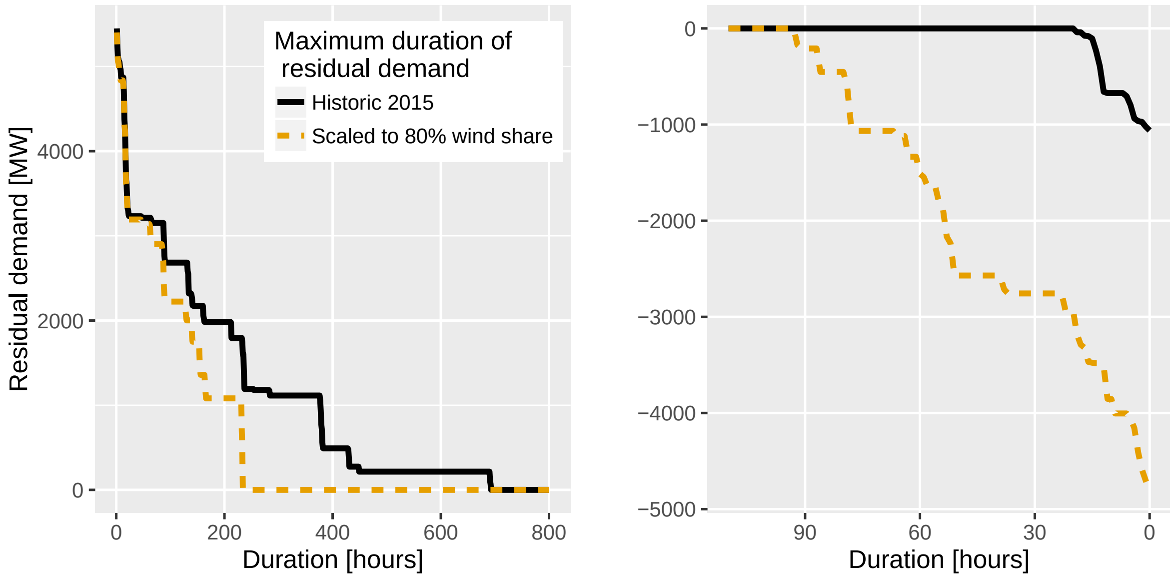


Figure 2.3: Duration curve of hourly changes in residual demand (based on data for consumption and wind power in Denmark from Nord Pool, 2016)



(a) Positive

(b) Negative

Figure 2.4: Maximum continuous duration of residual demand (based on data for consumption and wind power in Denmark from Nord Pool, 2016)

sumers installing roof-top photovoltaic. As the production from such units may avoid consumption of electricity from the grid, with declining technology costs they become attractive without any additional support measures at some point in time. At what cost level that would be the case depends on the exact regulation regarding the metering and settlement of the end consumers' own production. With current net-metering schemes, the Danish TSO foresees a rapid growth in photovoltaic installations over the coming decades (Energinet.dk, 2016e). Increasing decentralised production may lead to voltage fluctuations and risks of reversing the power flow (Passey et al., 2011). Already now this seems to create issues for some distribution companies in Denmark (e.g. Johansen, 2016).

Another development that might put stress on distribution grids in the future is the connection of new electric loads for transport and heating, as they will have a significant effect on the load profiles (Andersen et al., 2013). Such new loads would primarily be electric vehicles and in some areas potentially individual electric heat pumps. If such elements are operated in a random fashion, they will have a severe impact on peak demand and thus on the required capacity, such that an increased use of the grid is to be expected (Dansk Energi & Energinet.dk, 2012). In Denmark the impact from such new loads is expected by some to become more severe than that of new generation (Rasmussen et al., 2012).

This development occurs at a time of ageing infrastructure providing an opportunity to reconsider grid operation (Veldman et al., 2009). In a future system with increasing variable activity at the distribution level, instead of building or replacing grid capacity, distribution system operators may ask for flexibility services and seek to establish a more active management of such resources (Energinet.dk & Dansk Energi, 2012). In certain case studies, such measures are found to contribute with significant savings due to avoided grid capacity (Veldman et al., 2013). Some of the use cases that flexible demand is supposed to address will make sense in any environment irrespective of the development of new loads and production. The installation of new loads and generation, however, adds significantly to the value of smart grid operation, and flexibility placed in the distribution grids, like demand-side resources, might be well suited to address the introduced challenges directly at the source (Biegel et al., 2014).

The exact impacts are always subject to the individual configuration of a specific grid. Thus distribution grid impacts are more difficult to assess than aggregated system impacts. Moreover, they are very much subject to the future development of distributed generation and load. For now, at least in Denmark, industry organisations do not yet see an urgent need to act (Danish Intelligent Energy Alliance, 2013). Also, most Danish scenario studies still have a focus on the system level, and distribution grid challenges are often not included. As distribution grid issues have been emphasised more and more in connection with recent developments of solar power, however, these are coming more into focus also in scenario analyses (Energinet.dk, 2016e), and some attempts have been made also in a Danish context. E.g. Dansk Energi and Energinet.dk (2015) address the future demand for capacity in distribution grids to asses the potential for local flexibility within the framework of a system study. This has been done as an expansion of earlier studies with a focus on the value of avoided distribution grid expansion (Dansk Energi & Energinet.dk, 2010). From the results it becomes clear that distribution grid impacts are subject to considerable uncertainty. While the early analysis (Dansk Energi & Energinet.dk, 2010) reports a reduction of costs for grid expansions of around €215 million, the figure is more than halved in the updated analysis (Dansk Energi & Energinet.dk, 2015).

2.3 The demand side as flexibility option

2.3.1 Specific characteristics

The development of balancing requirements at system level creates a demand for additional flexibility. In combination with the challenges at distribution level this could provide an interesting option for flexible consumption. To assess the potential response that can be expected from different customer groups, one has to take into account the composition of their loads, technical restrictions, comfort requirements, alternative sources of supply, and the involved costs. Figure 2.5 shows a classification of loads based on technical characteristics. As illustrated, self-generation behind customer meters may sometimes be included. Subject to the right incentives, it may provide similar services to the system as all other generation. Loads, however, are subject to different constraints as described below.

A first distinction is made between loads with and without access to storage. Obvious examples for storable loads are battery systems that are about to gain some popularity in connection with on-site solar electricity production. Another example involving storage are electric vehicles that are equipped with batteries as well. Equipment used for heat production from electricity often has access to thermal stores, thus, providing the possibility to shift electricity consumption. Many times a building has a certain thermal storage capacity of its own enabling load shift even without additional heat buffer tanks (Hedegaard & Balyk, 2013). All of these options do not store electricity

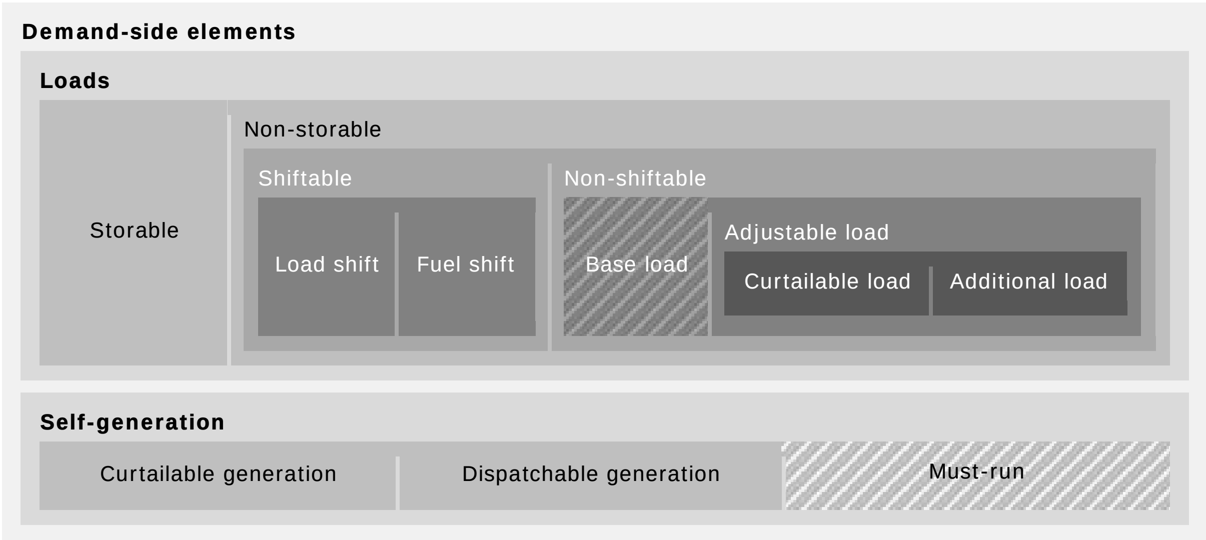


Figure 2.5: Categories of demand-side resources (own illustration based on Ea Energianalyse, 2011; Gellings, 1985; He et al., 2013)

directly and are therefore categorised as shiftable loads rather than storage options.

A wide range of other loads might be considered shiftable. A characteristic for such loads is that, while there is a fixed demand for a certain service, the timing is flexible within limits. For industrial and other large commercial consumers this might be electricity used for pumping, cooling, ventilation or pressurised air. In the residential sector electric heating may provide a large contribution if widely applied (e.g. Klobasa, 2007). Moreover, circulation pumps in heating systems, refrigerators and freezers, as well as washing machines and dishwashers hold a certain load-shift potential. Industrial processes may hold a large potential for fuel shift as well. This means that either electricity driving certain processes may be substituted by other fuels or vice versa (see Ea Energianalyse, 2011). In particular this could be applied in installations providing process heat for steam production, heating, drying, distillation, vitrification, melting etc. A precondition is to establish dual lines of process heat production.

The remaining load will not be shiftable. The base load category covers all loads that will have the highest priority to run. This is the case for most of residential lighting, cooking and consumer electronic appliances. Some loads, however, may still be curtailed at times if required. Depending on the time of day and location lighting could be curtailable, e.g. street lights, advertisements, shop windows and the like. Also in the residential sector lighting for purposes not strictly necessary (e.g. outdoor, garden and pool lights) might add to the potential. Sometimes it may be possible to use additional electricity for some purposes. Additional loads could, for instance, be switched on to produce extra hot water or space heat. This type of response will probably be applied more rarely in comparison to the others, though.

A special case of flexible electricity demand is represented by other energy sectors that may be coupled to electricity. Short-term flexibility is particularly relevant for the electricity system, while most other types of energy supply have inexpensive sources of flexibility, often in the form of storage. This includes grid-bound systems like gas and district heating. Sector coupling has gained increased attention with more ambitious policy targets and the development of 100% renewable energy scenarios (H. Lund et al., 2014; H. Lund & Mathiesen, 2009; Mathiesen et al., 2015). But the importance of considering the coupling of energy sectors has been emphasised already in the early Danish energy plans. For instance, Hvelplund et al. (1983) refer to research on the electrification of transport and how electric vehicles could be used for storage. In the Danish context, the extensive district heating system is often proposed as a good supplement to the variable wind production (Morthorst et al., 2009). In the future, the coupling of power and gas systems may play a role in providing flexibility (Anderson & Leach, 2004).

2.3.2 Theoretical and technical potential of demand response

The Danish demand response potential has been assessed by several studies over the years. A theoretical estimate is given by Kwon and Østergaard (2014) in a bottom-up calculation. Here the maximum hourly potential of flexible demand is estimated to around 2.4 GW, which assumes a load factor of the underlying demand of 50%. Another estimate of the Danish potential is given as part of a larger European study of the theoretical demand response potential divided by types of consumption (Gils, 2014). On average Danish consumption may be reduced by 920 MW for the duration of one hour. Figure 2.6 shows the average Danish potentials by sector as well as the possible duration of a response action according to the study. The hourly distribution of the potential is part of the study as well, but data is only available on an aggregate basis. Across the whole of Europe, demand response would be able to curtail or delay around 93 GW on average, while in certain hours the potential could become as much as 172 GW and down to 61 GW based on the underlying consumption patterns.

Boundaries for the Danish potential are given in relation to the peak load. Approximate values, can thus be derived such that the maximum load reduction lies at 1.6 GW, while the minimum lies at around 500 MW. Based on these figures, and depending on the timing, demand response might be able to reduce the residual demand (Figure 2.4a) with up to one third in extreme situations, and even more at other times. Also the theoretical potential of increasing load could make up a high share of the excess production illustrated in Figure 2.4b.

In an extensive survey, an estimate of shiftable and curtailable volumes of large industrial and commercial consumers has been determined (Ea Energianalyse, 2011). The total volume that could be shifted on a yearly basis is estimated to be 6372 TJ from industry and 6847 TJ in the trades and services sector. Moreover, the household potential is estimated to be 13,195 TJ. No number is provided in terms of capacity. If conservatively assuming a flat annual profile for all consumers, these potentials would add up to 664 MW and would thus be very close to the earlier findings.

The technical potential, in contrast to the theoretical potential, accounts for the technical feasibility of measures (Grein & Pehnt, 2011). This distinction is not easily verifiable, as different studies put different emphasis on technical constraints. Estimates by utilities and grid operators tend to be more of a technical potential. Early assessments by Danish utilities focussed mostly on savings – although the possibility of peak-load reduction had been acknowledged as well (Mikkelsen et al., 1994). A review of the flexibility potential in the Eastern Danish transmission zone estimated that about 142

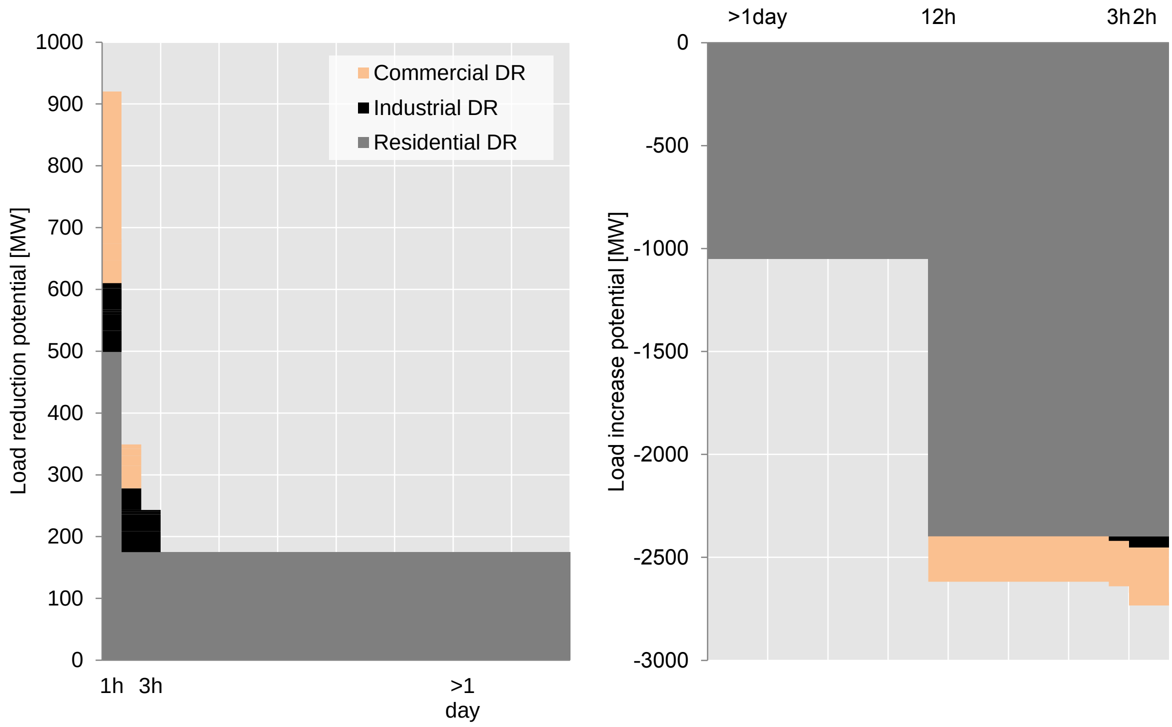


Figure 2.6: Average theoretical potentials of demand response in Denmark by sector (based on data from Gils, 2014)

MW of load from large customers could be shifted for at least one hour (Togeby et al., 2001). In a follow up report (Elkraft System & Eltra, 2005) the scope has been extended to cover the whole of Denmark. A potential of 660 MW had been identified, which included a contribution of 187 MW from household electric heating. This is actually close to the minimum hourly theoretical potential as found by Gils (2014). Recent estimates by the Danish TSO are slightly lower (Energinet.dk et al., 2015): the potential is expected to lie around 150 MW, while in addition emergency supply units (e.g. at hospital and water plants) could contribute another 300 MW. These numbers are called a "practical" potential and clearly consider more strict constraints than mere technical feasibility.

The potential for new loads that may provide flexibility in the future could be substantial as well. A scenario analysis of the Danish Energy Agency (2014a) includes estimates of shiftable or curtailable electricity demand. Residential heat pumps account for 800 MW in the study. Electric vehicles, although not considered flexible, are assumed to use 1100 MW on average. Moreover, large flexible consumption is assumed to be present in the form of hydrogen production (4600 MW), large heat pumps (500 MW), as well as electric boilers (2300 MW). The same scenario analysis, however, does not apply any of the theoretical potential in the existing demand as identified by the above studies.

2.3.3 Barriers to utilisation

In practice one seldom sees much of the potential realised, and sometimes demand response is viewed as too limited in providing the required flexibility at all (H. Lund et al., 2012). As Olsthoorn et al. (2015) conclude, policy-makers should not solely rely on reports on the technical potentials. One concern is that demand response for large parts would require enabling technologies. A row of experiments conclude that automatic control is required in order to get a relevant response (Clastres, 2011), for example, from household customers with electric heating (Togeby & Hay, 2009). Manual response, on the other hand, shows almost no effect (P. Lund et al., 2015). For larger consumers such automation will be even more relevant to avoid expenses for additional manual labour (Togeby et al., 2001).

Often the lack of adoption is attributed to a lack of economic attractiveness (Alcázar-Ortega et al., 2015), and the economic potential can therefore be considered significantly smaller than the technical potential. A range of studies identify only very limited benefits when breaking them down onto individual customers. Togeby and Hay (2009) find that electric heating customers could achieve savings of around €13 per year[3] under hourly dynamic pricing. Danish Energy Agency (2009) finds savings in the same order of magnitude based on the theoretical potential in Danish spot prices. Customer expectations regarding benefits on the other hand tend to be in the order of several hundred Euro (see Groothuis & McDaniel Mohr, 2014; Torstensson & Wallin, 2015). A factor closely related to benefits is risk He et al. (2013). Insights into the barriers to demand response from an industrial customer perspective are provided by Olsthoorn et al. (2015) using a framework developed in relation to energy efficiency. One of the conclusions is that energy intensive industries are very risk averse. The risk of disruption during the production process plays an important role. Also companies do not in any way want to compromise product quality.

Other obstacles to the success of demand response lie in regulation and behavioural constraints (Kim & Shcherbakova, 2011). Regulatory barriers include issues of market rules, organisation and product structure. Some of these conditions directly inhibit market access of demand-side resources, while others affect the achievable value and the level of risks. As soon as, especially, individual households or smaller businesses are expected to react, behavioural issues may come into play as well (Allcott & Mullainathan, 2010). Some studies have shown that not only the economics play a role in adopting responsive behaviour. While in most cases these issues represent an additional barrier, if addressed properly, they might also be used to work in favour of demand response (Rathi & Chunekar, 2015).

2.4 Policy options

2.4.1 Key policy objectives

The development of large amounts of wind power on the supply side is not contested in principle. Details of the implementations are discussed, e.g. in relation to the timing and

[3] 100 DKK/year

shares of onshore, near-shore and offshore wind developments.[4] The crucial question of how it will be possible to balance the electricity system with such large amounts of wind power, on the other hand, is still under rigorous debate. A range of measures have been proposed – amongst them demand-side flexibility that is strongly encouraged by EU legislation as well (EU, 2009a, 2009b). The present focus, though, is still on defining technically feasible solutions, and many solutions require further research before they can be reliably implemented (Energinet.dk, 2015a). A policy strategy covering all aspects of the flexibility challenge therefore has not yet been settled.

Nonetheless, based on the published policies on national and European level a set of key principles related to the electricity demand side and its flexibility can be compiled. First of all, demand-side participation shall be organised around market-based principles (European Commission, 2011b). European legislation contains some regulations in support of demand response. The Electricity Market Directive states that the potential for demand-side flexibility must be taken into account in grid planning (EU, 2009b). Furthermore, the Energy Efficiency Directive states that grid regulation should allow for demand response measures, and tariffs should reflect potential cost-savings from demand response (EU, 2012). At the same time, consumer protection principles shall be maintained such that consumers will be free to choose whether they offer flexibility (European Commission, 2015a). Also, inflexible consumers should not be penalised. The Danish Smart Grid Strategy formulates the general aim that cost-efficient demand-side measures shall contribute to the integration of renewable energies (Danish Ministry of Climate, Energy and Building, 2013). In more practical terms all consumers shall be equipped with smart meters (Danish Government, 2012; EU, 2009b) and have the possibility to be settled on an hourly basis (Danish Energy Agency, 2014b). Initiatives have been taken for further development of wholesale markets (Energinet.dk, 2015b), retail markets (NordREG, 2014) and the regulatory framework (Danish Electricity Regulation Committee, 2014a) in support of an enhanced contribution of demand flexibility.

2.4.2 Strategic considerations

The way in which responsibility for the development of demand flexibility is shared between the regulated or the liberalised part of the industry is one of the fundamental policy questions that need to be addressed (Brandstätt et al., 2012). Policies targeting the demand side of electricity for its flexibility may be centred around different approaches. In terms of the instruments, they may make use of the approaches are not mutually exclusive, but they differ in responsibilities assigned. Choosing one particular direction defines which types of instruments primarily should be taken into use. Earlier publications on the smart grid distinguish three concepts: a more technical grid oriented one, a market oriented concept and one focussing on direct consumer engagement (Slootweg et al., 2011).[5] Although the smart grid concept aims broader, activation of

[4]The Danish Economic Councils (2014), e.g., have been critical about Danish over-achievement of European energy policy targets due to the support and fast introduction of renewable energies.

[5]Slootweg et al. (2011) distinguish a system and a market oriented smart grid concept, the first focussing on system balancing and the latter on market integration of consumers; as in the Danish context system optimisation is closely related to the market (see also Jenle, 2015), here, a slightly different terminology is used for the concepts.

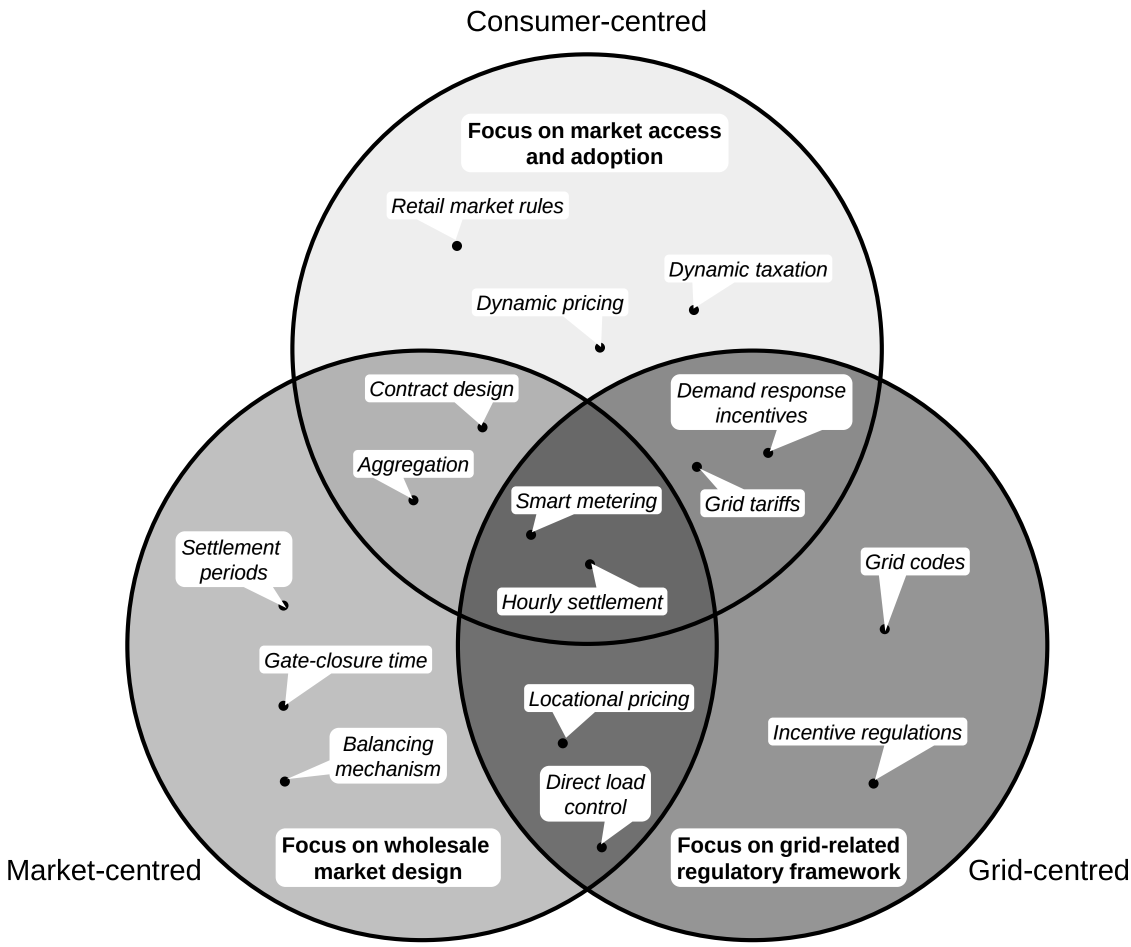


Figure 2.7: Overview of policy approaches for demand flexibility

demand flexibility is an important element and the concepts are roughly transferable. Therefore a similar distinction will be applied here to describe the overall implied policy options. Figure 2.7 shows the three distinct policy approaches to demand flexibility in combination with relevant instruments.

The grid-centred approach is based on the idea that grid operators should become the initial responsible actors to ensure that flexible demand is utilised. Flexibility would thus be subject to a centralised control structure as a starting point (Friedrichsen, 2015). From a policy point of view this necessitates a focus on the grid-related regulatory framework. A particular challenge related to this approach is that benefits from demand response would probably be distributed onto various actors. If investments should be driven by grid operators, therefore, this requires appropriate incentive regulation (Clastres, 2011). In comparison to cost-based regulation, the incentive-based schemes are able to induce higher levels of investment (Cambini et al., 2016). Also the terms under which grids may be accessed by the user, i.e. grid codes or other standardised connection agreements, may have to be adjusted in order to create a more standardised interface between grid operators and flexibility resources. In such a context, even the implementation of obligations for demand flexibility, similar to those established for energy efficiency measures (Togeby, 2009), would be a possibility.

Although grid operators may be expected to play a significant role in the utilisation of demand flexibility, a purely grid-centred model is unlikely to be implemented within the guidelines formulated by the European Union. At the same time the Smart Grid Strategy at the European level has an explicit focus on market mechanisms (European Commission, 2011b). The principle of a market-driven development of demand flexibility is also propagated by European regulators (Council of European Energy Regulators, 2014). As stated above, EU policies have a strong focus on market mechanisms and Danish policies point into a similar direction. A recent Danish reform has introduced a supplier-centric approach in the retail market that is intended to serve as a common Nordic model (Pöyry, 2015) and is favoured on the European level as well (Eurelectric, 2011). The model establishes the supplier as the single point of contact to the end-user with the intention to encourage commercial actors to provide innovative products that at some point may include demand response (Danish Ministry of Climate, Energy and Building, 2013). The grid operator, in this model, could only interact with the demand side via market mechanisms for flexibility that are not yet defined and established.

Danish policies at present point towards an approach focussing on the commercial actors as the major drivers of demand-flexibility development. The primary role of the regulated actors is to define products and market mechanism that enable commercial actors to deliver the required flexibility. Grid operators are still the ultimate responsible parties for maintaining reliability. As they have been unbundled from the production and demand side, though, they do not have the resources to balance the system just by themselves. Therefore flexibility is mostly procured through market arrangements,[6] and focus should be on well-functioning wholesale markets that accommodate for the utilisation of the demand side. The Danish system operator has significant influence on the design of such mechanisms (Lockwood, 2015) and takes a leading roles in the practical development of market design and regulation (e.g. Energinet.dk, 2014). In a process involving many relevant stakeholders several issues have been identified (Energinet.dk, 2015b), e.g. settlement periods, gate-closure times and balancing mechanisms, and adjustments are about to be implemented (Energinet.dk, 2016c).

It is still an open question in how far the development should be solely driven by wholesale actors or to a larger extent should directly involve the consumer level. While such a development could as well run in parallel to a market-driven approach, policy-makers have a role in directing the process and may have the possibility to encourage it or slow it down. Following this approach will provide consumers with a high level of freedom. While evoking consumer activity, therefore, it is important to ensure incentive structures that contribute to an overall optimisation of the system. To describe the behaviour by consumers of co-creating system value the term *prosumption* has constructed (Ritzer & Jurgenson, 2010). Prosumers interact with the system not merely as off-takers of energy, but are able and willing to contribute themselves. Consumers with own generation capacity are obvious examples (Rickerson et al., 2014), but the term may be used more widely to describe consumers that provide services to the grid including demand response (Shandurkova et al., 2012).

Consumer-centred policies will focus on providing access to the market for small decentralised units and could aim at encouraging adoption of flexible behaviour by consumers. A key element is the design of retail markets including regulations regarding

[6]Exceptions to the market-based approach may be observed in some segments of the ancillary services that plant operators are obliged to supply.

contracts, pricing and aggregation. Electricity taxation and grid tariff regulation could play a role as well. Thus far, Danish policies and in particular the Danish smart grid strategy have not yet put much emphasis on the involvement of consumers (Schick & Gad, 2015). The most mature initiatives, moreover, focus on the wholesale level. A wholesale market focus implies a rather hierarchical model, whereas the emergence of advanced IT infrastructure and increasing consumer engagement in self-generation could necessitate a more distributed approach to activate flexibility (Schleicher-Tappeser, 2012a). Even though there is some uncertainty to the extent of such developments, their potential impact has been acknowledged (Energinet.dk, 2016b).

Chapter 3

Methods

3.1 Overall approach

The starting point for all analyses of the thesis is the seemingly paradoxical difference between a substantial theoretical value of demand flexibility derived in many studies, and its apparently low practical value at present. This discrepancy has a considerable parallel to the so-called "efficiency gap" observed in the lack of implemented energy saving measures (see Hirst & Brown, 1990). While implementing energy efficiency often is a question of investment and requires limited action afterwards, benefits from demand flexibility are generated in a more continuous effort (Goldman et al., 2007). The decision of adopting new technology or behaviour is quite similar, however, and thus studies of barriers to energy efficiency are helpful in the further analysis of demand flexibility as well.

Market barriers to demand response are frequently addressed in the literature (see Nolan & O'Malley, 2015, for a recent review). As the major technical barrier, installing suitable metering equipment, has been overcome in many places, the focus is increasingly on the regulatory framework and consumer behaviour. While overall economic benefits are mostly undisputed, the incentives to those responsible for adopting demand response activities, i.e. consumers, but also intermediaries and utilities, are commonly regarded as too small. Policy-makers should therefore remove barriers in regulation and ensure to engage the relevant actors. Two obvious approaches would be either to address individual benefits or costs by policy intervention. Even subsidising demand response has been regarded a valid policy to achieve its activation in some cases (Muench et al., 2014; Walawalkar et al., 2008).

It should be clear that demand response is no end in itself, but rather it may provide a contribution to the overall energy policy objectives. Hence, demand flexibility should only become utilised if it is competitive with alternative flexibility options. A balance must be struck between breaking down barriers and inducing excessive, and potentially inefficient, demand response. Economists underline that policies should only address a subset of market barriers that constitute market failures (Jaffe & Stavins, 1994). Such failures would violate the underlying assumptions of fully competitive markets (Brown, 2001): rationality, perfect information, lack of transaction costs. While market failures are an essential concept in deciding on policy interventions, it may be too narrow to address the full range of obstacles that exist in the real world (Sorrell, 2004). Studies

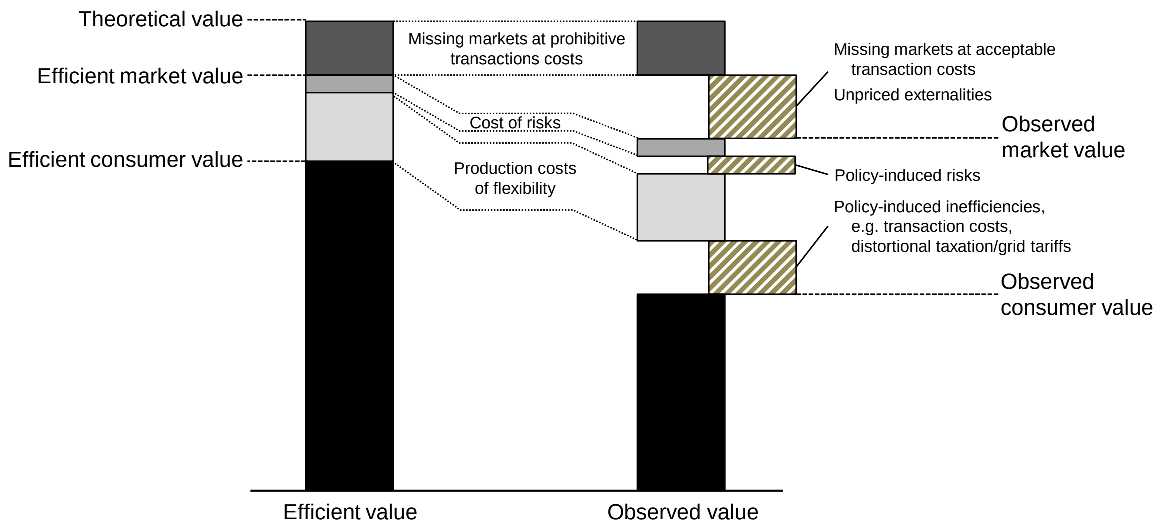


Figure 3.1: Difference between efficient and observed value of flexibility

within the framework of innovation systems argue that policy interventions should be based on *systemic* failures in addition to market failures (Wieczorek & Hekkert, 2012). As from the outset the electricity market is subject to a substantial amount of regulation, institutional failures, a special case of systemic failures, may have to be addressed as well (Klein Woolthuis et al., 2005).

This thesis focusses on such policies that reduce the gap between the efficient and the observed value of demand flexibility. A central argument is that a gap exists due to conditions that may be affected by policy-makers, either by directly addressing market failures or by correcting for inadequate framework conditions. Figure 3.1 is an attempt to illustrate the targeted gaps in value. The left bar shows the ideal situation. The theoretical value of demand flexibility can only be achieved in a world of perfectly competitive markets with full information and no transaction costs. In reality organising a market to cover for all aspects of flexibility would be costly in terms of transaction costs. In that case, the losses due to a missing market are lower than these transaction costs, and therefore the achievable market value will be lower than the theoretical value. The market value can be interpreted as the wholesale-level value. Benefits at the consumer level will be lower due to the costs involved in providing the flexibility – a part of these related to risks. Disregarding such costs will lead to an overestimation of benefits to the consumer and potentially wrongful policy decision.

There is some evidence that the currently observed value of demand flexibility is not fully reflective of the efficient value. Some conditions directly affect the observed wholesale market value. Markets may be incomplete leading to a lack of information about the supply and demand of flexibility (Newbery, 2016). Added reliability by demand response may thus be an unpriced externality to the market (Droste-Franke et al., 2012). There may also be issues of information asymmetry and split incentives resulting in benefits accruing to stakeholders not carrying the costs (Römer et al., 2012). The achievable retail value could be further reduced by a range of policy induced conditions: the regulatory framework may expose certain market participants to additional risks; transaction costs may be increased by complex market rules; and regulations regarding taxes and grid tariffs may introduce further distortions (Brown, 2001).

On the basis of these overall considerations on the value of demand flexibility the remainder of the thesis will analyse, in how far it will be possible to close the gap between the observed and efficient wholesale market value of flexibility, and in how far it will be possible to close the gap between the observed and efficient consumer value of flexibility. Another concern that should guide demand-side policy is the difference between efficient market and efficient consumer value. The initial part consists of a qualitative policy analysis (Paper A) that indicates sensible policy measures. This is followed up by a set of quantitative studies that seek to elaborate on related aspects to provide further input to policy recommendations. Hidden value due to missing markets is addressed in Paper D. Impacts of transaction costs are analysed in Papers B and C. In addition, Paper C analyses the impact of the electricity tax regime. Costs of risks are quantified in Paper E. In the cases of risks and transaction costs, the analyses concern both real costs and artificial policy-induced costs as depicted in Figure 3.1. In relation to the formulation of policies, the real cost elements are important to get a realistic expectation of the demand response potential. While transaction costs should be considered real costs and thus part of the production costs of demand flexibility (Joskow & Marron, 1992), it should also be taken into account in how far policy-makers may affect them (Sorrell, 2004). Implementing efficient regulation that acknowledges transaction costs may increase benefits, while inefficient regulation may as well be the cause for additional costs.

3.2 Policy analysis

A first concern of this thesis addressed in Paper A is to diagnose the policy problem related to the activation of demand-side flexibility. This is required in order to be able to define proper areas for policy intervention. The framework laid out in this way also serves as a basis for the remaining analyses of the thesis that select different policy aspects and point out specific issues that need to be taken into account regarding their implementation. The problem diagnosis builds on general concepts of policy analysis that are combined with elements from the fields of industrial organisation (V. J. Tremblay & Tremblay, 2012) and transaction cost economics (Williamson, 2008). The basic underlying idea is a system analytical approach (Thissen, 2013).

The focus of Paper A lies in distinguishing between system elements that can and should be influenced by policy and those that are part of the underlying structure. This distinction has been inspired by the *structure-conduct-performance* paradigm of industrial organisation (V. J. Tremblay & Tremblay, 2012). The theory builds upon the presumption that the market outcome (*performance*) is a result of the behaviour of market participants (*conduct*), which may be explained by the *market structure* and *basic conditions* such as the characteristics of demand and technology. Policy may intervene in order to achieve a socially more desirable market outcome if market failures exist.

Basic conditions can only be affected by policy to a limited extent; for example by support of research and development. They will barely be affected by such policies that are the focus of this thesis and that target market rules and regulation. Research in the field of industrial organisation is mainly concerned with issues of market power, and market structure describes relevant parameters like the number of firms and concentration. In this thesis these are not the subject of analysis; rather, a competitive

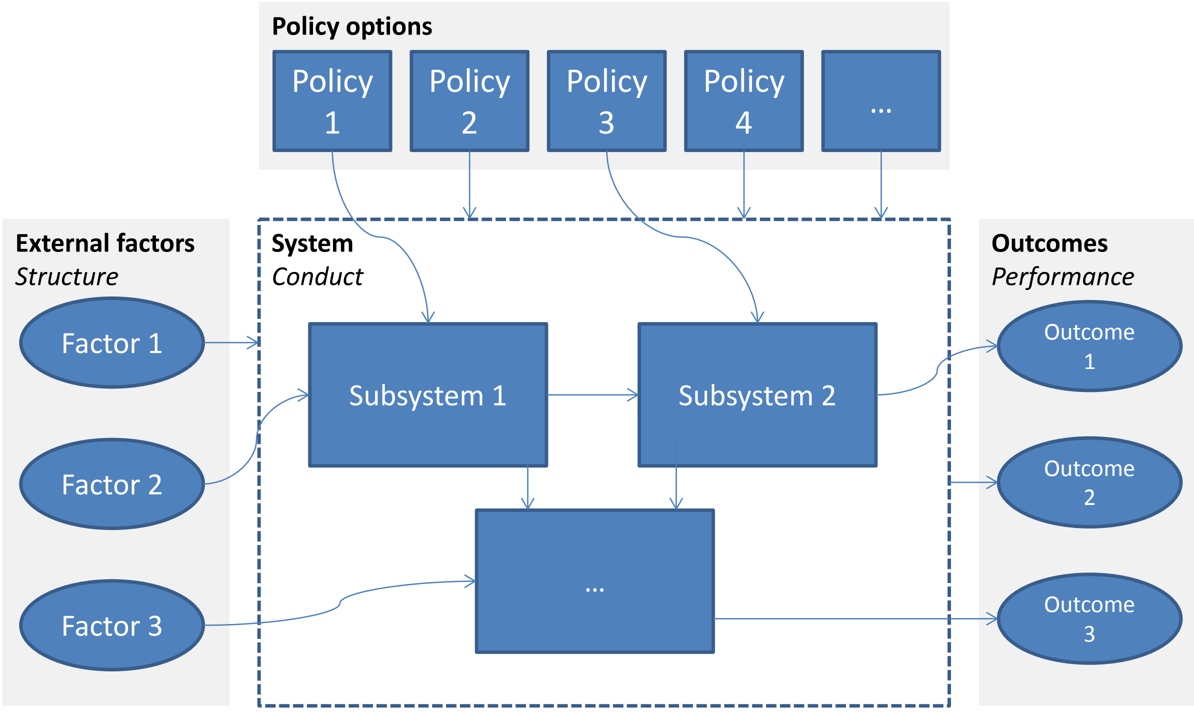


Figure 3.2: Example of a system diagram (based on Thissen & Walker, 2013) with additional labels according to the *structure-conduct-performance* paradigm

market outcome is assumed as a starting point. The issues identified in this thesis deal with other elements that may prevent the market from approaching the best possible outcome. These are related to imperfect information and the definition of market rules and regulation. Market structure is here used as a term to describe the fundamental conditions that policy-makers have to deal with (in accordance with Stoft, 2002, p. 74).

An informative tool to develop and work with a system analytical approach is the *system diagram* as presented in Figure 3.2 (Thissen & Walker, 2013). In the system analytical approach a system of interest is influenced by external factors. Policy-makers will not be able to affect them or at least they will be difficult to affect in the short term. At the same time the system may be influenced by different measures (*policy options*). External factors and policies in combination generate a set of outcomes that are of relevance to the policy-maker. In terms of the framework developed in Paper A market structure represents these external factors. The mix of developed policy options will be referred to as market design, using the term market in a broader sense than the mere place of transactions and trades.

A set of methods exists to identify the different elements of a System Diagram (van der Lei et al., 2011). External factors have been presented in the Background Section 2. The presented demand-side policy objective may be broken down from the overall targets by the use of *objective trees*. Potential measures may be defined by the use of a *means-ends diagram*. Those tools are helpful in visualising the aspects that this thesis focusses on. Paper A does not make explicit use of these tools. Nonetheless, they are applied in Section 4 for a better illustration of the results. The format of the diagrams is shown in Figures 3.3 and 3.4.

The basic structure of the objectives tree and the means-ends diagram are similar.

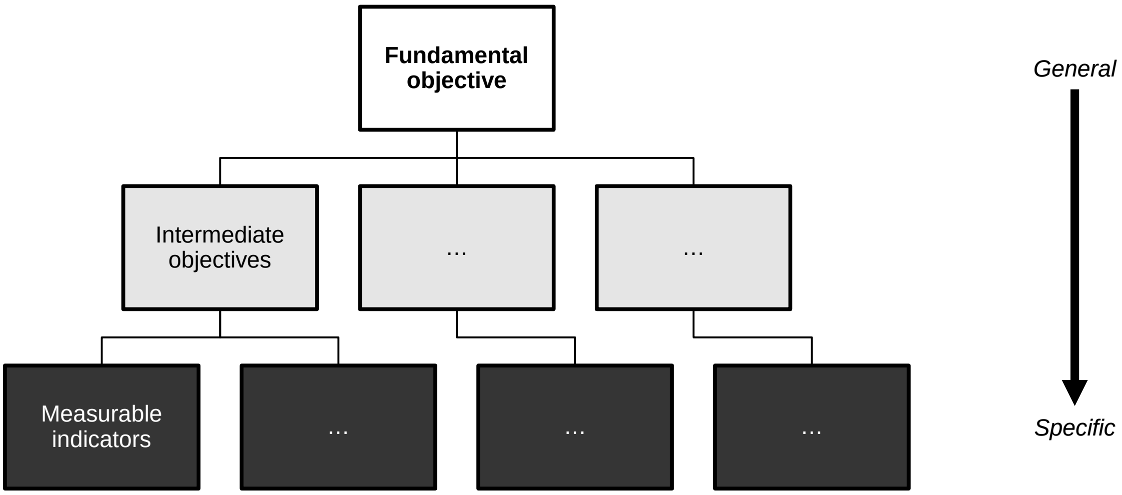


Figure 3.3: Structure of an objectives-tree diagram (based on Thissen & Walker, 2013)

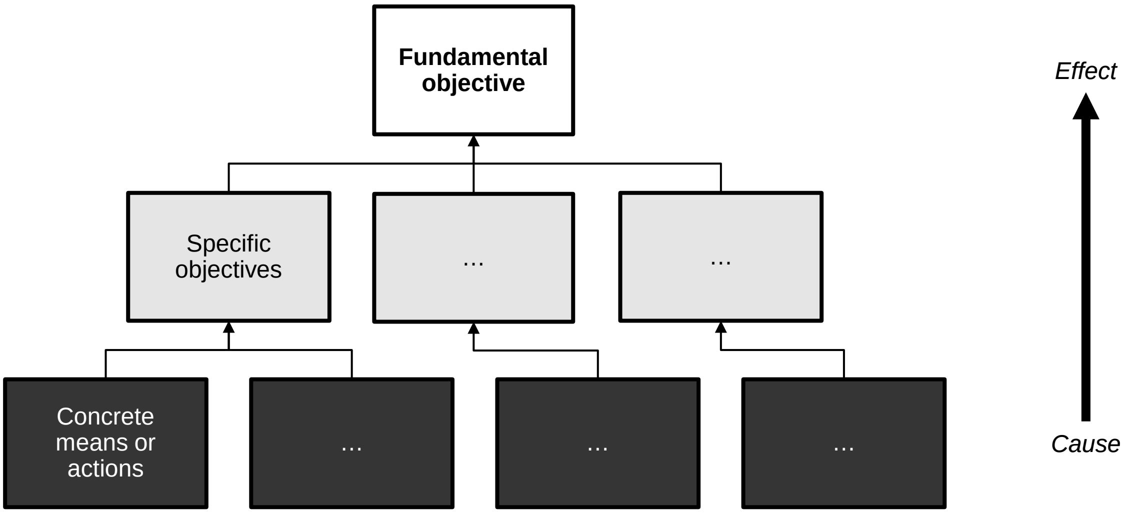


Figure 3.4: Structure of a means-ends diagram (based on Thissen & Walker, 2013)

Both start with an overarching fundamental objective. The purpose of the objectives tree is to determine measurable indicators that specify in how far the objective has been achieved. This is done be finding specific attributes describing the general objective. The indicators may be used on the right side of the system diagram as more specific outcomes of interest. The means-ends diagram also works from the general towards the specific. It establishes a causal relationship, however. Rather than defining specific attributes, its aim is to define concrete means that contribute to the objective. These means can be interpreted as policy options that enter the top of the system diagram.

3.3 Economic valuation of demand flexibility

On the basis of the current overall policy objectives demand flexibility would have to be developed in a liberalised market framework. Thus, the development would be value-driven and to a large extent the analyses of the thesis are concerned with the valuation of flexibility. They are not, however, aiming at determining an absolute value, but rather deal with gaps in value to point out elements that might be missed out in the current framework. Those elements are sought quantified in order to determine their relevance, as they might be part of the explanation of why there is a lack of demand response adoption and could form a further foundation for policy decisions. The general valuation methods used to quantify various gaps are not always the same. A common approach, though, is to use a particular valuation in a version with and without the element of interest to identify the gap between those two cases. This section provides an overview of the models used; approaches to deal with the specific gaps are described separately in the following section.

In the literature several ways have been used to assess the value of demand flexibility. The evaluation of demand response benefits has been subject to a vast amount of analysis ever since the concept has been proposed to enhance system efficiency. The choice of model for demand response has a significant impact (as illustated by Neves et al., 2015). The analyses of this thesis address the value of demand response from different angles. A brief review of valuation methods has been presented by Katz et al. (2015) and in Paper B (for a more extensive review of methodologies used in recent demand response modelling studies see also Boßmann & Eser, 2016).

Table 3.1 gives an overview of the most common approaches within different dimensions in model-based demand response evaluation relevant for the analyses of the papers. Some of the dimensions are similar to those proposed by Boßmann and Eser (2016). In addition, to illustrate differences in the approaches used in the papers, the modelling of demand flexibility and the type of market model have been included as properties too. The table also indicates how the aspects are dealt with in the quantitative analyses of Papers B–E. The analyses of this thesis deviate from one another in the following aspects: the underlying model of demand and its flexibility; the underlying assumptions about the market framework, the interactions between flexible demand and the rest of the system and how the market outcome is calculated; the perspective of evaluation; the spatial scope; and the time resolution. The chosen approaches are marked in Table 3.1. When a model mixes approaches, then the secondary one is marked in parentheses. A more detailed discussion follows below.

Beginning with the *modelling of demand flexibility* itself a range of approaches exist that originate from the theoretical background of the model. Models founded in economic theory will typically use an elasticity-based approach, while the more technical models tend to model flexible appliances directly or use generic representations as an approximation. Both types have their merits and disadvantages. The price elasticity of demand is an integral part of microeconomic theory and may therefore be helpful in the formulation of more formalised models of demand response – from an economic point of view. It is however a somewhat theoretical construct that needs to be confirmed by empirical evidence in order to be helpful in policy analysis. Many studies have tried to estimate values for demand elasticity. Such estimates, however, seem to be very much subject to the framework conditions under which data has been collected. The climate plays a role (Darby & McKenna, 2012), details of pricing schemes do as well (Batlle & Rodilla, 2009), and it may be hard to transfer results from one environment to the other.

Appliance-based bottom-up models may have a bit of an advantage in this regard. Such models take offset in the technical potential and constraints of response. These technical aspects might be more straight-forward to measure. National or even regional

Table 3.1: Properties of demand response models and applications in Papers B–E

	Approach	Paper			
		B	*C*	*D*	*E*
Demand model	Elasticity-based	×			
	Appliance-based			(×)	
	Generic		×	×	×
	Agent-based				
Calculation method	Optimisation	×		×	
	Simulation (ex-post/ex-ante)		×		×
	Empirical estimates				
Market model	Static		×		×
	Static equilibrium	×			
	Dynamic equilibrium	×		×	
Perspective	System	×		×	
	End-user	(×)	×		
	Utility				×
Spatial scope	Local				
	National	×	×	×	
	International			(×)	×
Sectoral scope	Electricity (sub-sectors)	×	×	×	×
	Coupled energy sectors			(×)	
Time resolutions	Peak/off-peak				
	Hour	×	×	×	×
	Intra-hour			(×)	

statistics might help in determining differences in usage, installation rates and flexibility potential if models should be transferred to other settings. If some of the consumption is controlled automatically anyway, such methods could be more exact. If the control algorithms are known, then the response to different kinds of pricing schemes are easier to model as well. One issue that these models might fail to capture is the behaviour of consumers and their potential impact on flexibility available for control. More and more of such elements are taken into account in another category of models using an agent-based approach, or at least incorporating aspects of behaviour in other types of models.

The demand model used is very closely related to the *calculation method* applied and the underlying market model that is assumed. For the calculation method a distinction is made between optimisation, simulation and empirical estimates. In optimisation models the best possible outcome under a set of given constraints is determined for the whole system (Fleiter et al., 2011). Simulation studies may apply optimisation methods as well. They do however focus on results within a static framework. The same is valid for valuations based on empirical data that estimate benefits on the basis of actual behaviour.

The close relation to the *market model* is obvious. As in simulation studies demand response does not affect the market, they act within a static framework. This may be thought of as a price-taker approach. Such a method may seem wrong to start with. Often, however, analyses have a limited scope and it may be valid to assume that the market is not influenced by flexibility within the scope of the study. The Danish market, for example, is strongly interconnected with both Nordic and the continental power markets. Analyses limited to Denmark could therefore be thought of as having a very limited impact on prices. Nevertheless, from a theoretical point of view using an equilibrium approach is more complete. Here, supply and demand is brought into balance resulting in prices that clear the market. In a static equilibrium new capacity investments are neglected and the supply-demand structure is kept constant. A dynamic equilibrium takes such long-term changes of capacity into account. Calculations will then have to be based on an optimisation approach. An elasticity-based demand model only makes sense in an equilibrium framework, while the other types of demand models my be applied within different market settings.

Demand response evaluation can take various *perspectives*. Most importantly there is the system perspective and the individual customer value. These largely correspond to the concepts of socio-economic and private cost-benefits. A third perspective is added in Table 3.1 to also include an intermediary like the utility – or another type of aggregator. Here we also take an individual actor's private perspective. The socio-economic value tells us whether demand flexibility is valuable taking into account the economy as a whole. If it is beneficial it may be an indication for policy-makers to work towards framework conditions in support of demand flexibility utilisation.

The private-economic value tells us something about the individual incentives to adopt flexible technology and behaviour. Although an individual benefit does not equal a societal benefit, the private value indicates whether an existing potential would be utilised and to which extent. Often private and social value would be different, due to, e.g. externalities or distortive effects of subsidies and taxes, potentially requiring policy intervention. Such intervention could go into either the direction of supporting further development or the opposite of preventing a development based on adverse incentives. For example, we may want to support flexible behaviour of consumers to help the system as a whole; on the other hand, we may want to prevent flexibility that only serves individual purposes and may counteract system needs. An example for such a case are net-metering arrangements for decentralised power producers that could create incentives for local battery storages. These will then be optimised with regard to local needs and may even create additional system stress (Eid et al., 2014).

Other important dimensions of valuation are the *spatial, sectoral and temporal scope*. The characteristics of demand flexibility often mean that they are not fully suited for the scope of existing markets. For all sources of flexibility to be utilised, thus, the scope may have to be adjusted in time or space (see also Henriot & Glachant, 2013). A typical spatial scope is the national energy system. Modelling of interconnected markets would provide more correct results, though. This is both the case for including neighbouring systems as well as other coupled energy sectors, like heating and transport. On the opposite side of the spectre the scope may be extended as well to include smaller units, like distribution grids, that have specific flexibility needs, and thus might contribute to the value of demand flexibility. In terms of time, higher resolution enables a more accurate determination of flexibility value. If a certain time horizon is left out of scope, the value it might contribute with cannot be captured. Many models use an hourly resolution, as intra-hourly modelling may be difficult to do due to lack of available data and higher computational effort. It may be possible to take short-cuts approximating activities within shorter time-frames by limiting details in other model dimensions.

As indicated in Table 3.1 the papers take different perspectives and use different approaches. Papers B and D take primarily a system perspective, while Papers C and E take a private perspective. For the private analyses we assume static market conditions, i.e. demand flexibility does not affect prices. These can be regarded as simulation studies with Paper C taking an ex-post approach based on historical data, and Paper E taking an ex-ante approach based on simulated future prices. Both use a simplified generic demand response model. Paper D uses a similar model of flexibility, but defines the potential more specifically on an appliance basis. Paper B uses a price elasticity of demand to determine demand response.

The most thorough valuation approach is used in Paper D that applies a detailed energy system model with an international scope and includes the flexibility of the heating sector. All other models have a limited scope that, nonetheless, allows for a more detailed analysis of the policy aspects in focus of the different papers. The gap analysis of Paper D is concerned with the time resolution and explores the value of extending the model to include intra-hourly contributions. Papers B, C and E keep their respective model structures throughout the analysis and only change economic incentives to the consumers.

3.4 Gap analyses

3.4.1 Intra-hourly market value

The value creation from flexibility sources should be properly reflected in the market, in order to get supply and demand of flexibility to meet. To be able to discover the value and create incentives to establish and utilise flexible capacity, the reliability requirements need be translated into marketable products (Helman et al., 2008). Maintaining system reliability requires a wide range of activities and therefore a wide range of flexibility tools. Besides the plain delivery of energy, the ability to adjust the level of loading at certain rates and lead-times, will usually be defined as a separate regulation product (Baritaud, 2012). Moreover, electricity network constraints add a locational dimension that may be reflected in products as well. Defining the right set of products to ensure reliability in the most efficient way is an important task in designing electricity markets. In this way, ideally, all potential flexibility suppliers may provide their bids to the system and a least-cost solution may be found (Gül & Stenzel, 2005). In practice, though, market products will often not cover the full system demand, and some services will be delivered under out-of-market arrangements that may distort markets for existing products (Baritaud, 2012). As a result some of the underlying value will be missing in the observed market value.

System needs are only one side of products. The design should as well consider constraints to those delivering a product. For demand response it could become attractive to offer intra-hourly services, as the value that can be captured by shifting between hours often will be limited for many types of demand flexibility due to technical restrictions. Therefore, although the volume of intra-hourly markets in general is smaller than the hourly market, the provision of such reserves could make up a larger share in the revenues of demand response in comparison to the smaller relevance this market has in revenues of participants on the supply side. As at the wholesale level of electricity markets, traditionally, large power plant operators had been the primary counterparties, product design in some cases favours such units in comparison to decentralised resources and the demand side (e.g. Cappers et al., 2012; Neuhoff et al., 2016). This could be another reason for missing market value.

Paper D sheds some light on the foregone value of not enabling the demand side to contribute to intra-hourly flexibility. As indicated in Paper A, market access of demand flexibility could be expanded in the dimensions of space and time. While the locational dimension has been addressed in several recent studies (e.g. Babonneau et al., 2016; Conchado et al., 2013; Dansk Energi & Energinet.dk, 2015; Mathieu, 2015), Paper D focusses on the time aspect. It evaluates the capacity available for regulation tasks within the hour by implementing a reserve requirement in an energy system model. Reserves have to be provided by costly supply-side measures in a reference case. The contribution of demand flexibility is determined as the difference in total system costs between this reference case and a case that allows for demand-side contributions to the reserve.

3.4.2 Transaction costs of adoption

If demand response activities are to take place at the level of the private consumer then, on top of pure economic and regulatory considerations, behavioural restrictions need to be taken into account. At the consumer end such non-tangible costs may play a significant role; and the smaller the consumer, the higher the impact of such costs. But even large industrial and commercial consumers will face additional costs, although these may be more easily quantified in terms of used resources. Not accounting for such costs in implementing policies aimed at consumers may lead to wrong expectations about participation and response.

As introduced above, these parts of the analysis rely on the theoretical framework of transaction costs economics. While originally this framework has considered mostly firms and their decisions to make or buy, the idea behind the concept is applicable more widely. A useful classification of transaction costs has been proposed in the area of energy efficiency (Sorrell, 2004). While efficiency measures are different in certain aspects from utilising demand flexibility, they are closely related and have traditionally been addressed under the common headline of demand-side management (see Gellings, 1985). Many cost categories defined for energy efficiency do clearly matter in the case of demand response adoption and activation as well. Transaction costs can be divided into market transaction costs and organisational transactions costs. Market costs cover all kinds of costs that come with a transaction, or potential transaction, via the market place. This includes search costs for collecting and understanding information regarding relevant products, determining the right supplier, negotiating contractual terms and, potentially, even legal counsel. Organisational costs are internal costs to the consumer related to monitoring, control and, decision-making. This thesis deals with both market and organisational costs, but in slightly different ways.

The adoption of contracts based on dynamic pricing and enabling technology are a precondition for demand response and a major obstacle at the same time (Goldman et al., 2007). Market transaction costs are considered an important barrier to adoption. In electricity markets with retail competition market transaction costs are not only an issue related to flexibility. A common phenomenon of liberalised retail markets for electricity are low switching rates of consumers as compared to other industries like telecommunication, for instance (Defeuilley, 2009). According to the key policy objectives formulated at EU and national level (see also Section 2.4.1) consumers should be free to choose their supplier and whether they want to participate in demand response activities. They would therefore have to make an active choice incurring search costs very similar to switching retail supplier. Probably, the effort to understand the contractual terms are even higher as compared to the standard supply contract in the present market.

The transaction costs related to switching contract or supplier are sometimes termed *switching costs* (Klemperer, 1995). To be more precise, transaction costs may be a substantial part of the costs involved in switching that may also include more tangible elements, like e.g. discount and bonus schemes. For the most part though the elements of switching costs conform to the broad definition of transaction costs used in the analyses of this thesis. Usually a quantification is challenging. While some empirical attempts have been made to estimate the impact of switching costs (e.g. Ek & Söderholm, 2008; Patterson & Smith, 2003), simplified concepts relying on aggregated market data have been developed as well (Shy, 2002).

In Paper C such a method is applied to estimate the cost of switching in the Danish electricity retail market. As noted in Table 3.1, the paper addresses the question of value by focussing on the individual customers' perspective. In this way it has been possible to derive conclusions on the incentive to adopt demand response activities and appropriate contract structures. Moreover, the paper analyses how policy-makers may influence the attractiveness of demand response by changing the way electricity is taxed. Instead of using an equilibrium setting to determine the impact of demand response on the rest of the market, the analysis is done in a static setting with fixed prices not affected by consumers. Consumers are thus price-takers, which might not be a correct assumption if analysing large-scale impacts, but is deemed valid here, as the analysis takes an individual perspective.

3.4.3 Transaction costs of response actions

After adoption, the second step in utilising demand flexibility is the actual response to the market or other kinds of control signals. At this stage monitoring and decision costs will begin to play a role. Based on the framework presented above, system value translates into market prices and products, which eventually will be reflected in contractual terms at the end-consumer level. In order to cover real-time value, contract prices would need to reflect real-time system conditions. Real-time prices, however, may be difficult to monitor and interpret from a consumer perspective. Most likely, it will not be possible to make any reasonable decisions different from what could be done under simpler averaging schemes, like time-of-use pricing, because monitoring and decision costs would become too high (Slootweg & Ackermann, 2012). There is some evidence of such costs and that routines play a role in substituting active monitoring of prices such that the exact price profile has less impact (Klaassen et al., 2016). Similar effects can be shown in customers' response to non-linear block rates, where the monthly bills are often used by consumers as a proxy instead of the actual marginal price of consumption (Ito, 2014).

Transaction costs may be brought down by simplifying contract structures such that beneficial decisions are more obvious and frequent monitoring is reduced by simple provision of information. Demand response on a manual basis requires a simple price signal for significant effects to occur (Darby & McKenna, 2012). For some purposes, like peak shaving, such simple schemes may be sufficient (Bergaentzlé et al., 2014). They could also provide a good option to gather experience and prepare for more complex schemes (Kintner-Meyer et al., 2003). The signal should preferably be rather stable and foreseeable. In practical terms this means that if some consumption may be shifted, it should be clear from the price signal at which alternative point in time consumption is favourable; and when that time comes, the shift should still be beneficial. A phenomenon termed *response fatigue* has been observed in dynamic pricing pilots, i.e. consumers at some point lose interest (Goldman et al., 2007). It is likely that such fatigue will increase if active participation does not pay out as expected due to frequent changes in the underlying price of the product.

Several simplified pricing schemes have been proposed for demand response. A popular one is critical peak pricing, which is meant to reflect real-time conditions only at critical points in time (Hu et al., 2015). Of course the more simple the product, the less real-time information will be carried by the price (Brandstätt & Friedrichsen, 2012). Therefore response to the price will be imprecise and of less value to the overall system compared to an exact (automated) response to a real-time signal. So while these structures address the issue of transaction costs, some value is lost in translation by reducing the amount of information in the product. Paper B analyses a simple rebate structure for such losses from a system perspective. It applies a partial equilibrium model of the electricity market in order to derive the impact on the surplus of different groups of consumers and suppliers. Focussing on simpler instruments to achieve flexible behaviour at the demand side the analysis informs policy-makers about the loss in efficiency, when transaction costs are taken into account. Moreover, focus is on the difference between short-term and long-term effects. Solutions that work in the short-term might not be suited in the longer run or vice versa. The case study calculations for Denmark provide specific insights into how benefits are affected and distributed in systems with large amounts of wind power.

An alternative to simplifying products and a common response to behavioural concerns is the automation of response activities (Di Giorgio & Pimpinella, 2012). The behaviour of loads would thus be optimised by algorithms with the aim to extract the highest possible value. A complex pricing scheme may be implemented if monitoring and decision-making is automated in this way. However, automation devices need to be accepted by consumers. So even in such a case we face a private adoption decision that does not necessarily have to be fully rational (see also Brewer et al., 2015). The issue of adopting automation equipment is taken up in Paper E addressing it from a risk perspective.

3.4.4 Distortional taxation

Taxes and levies on electricity are a substantial part of the electricity bill in countries of the European Union, especially of household customers (European Commission, 2014b). Together with increasing grid costs these are the main cause of rising prices amongst these customers (European Commission, 2014a). In Denmark taxes are particularly high, accounting for around 60% of the household end-consumer price (Kitzing et al., 2016). From the vantage point of demand flexibility, excessive taxation has distortive effects and creates a gap between the efficient and the observed value of flexibility. Paper C takes up this issue and discusses whether there could be a more efficient way to tax electricity than the present approach.

The first Danish tax on electricity had been put into force in 1977 (Danish Energy Agency, 2016a). It was primarily introduced as a measure to induce energy savings, but like other energy taxes it also served a fiscal, i.e., revenue generating purpose (Danish Environmental Protection Agency, 2000). Over time the rate was raised and additional levies and taxes on electricity were introduced for different purposes. In 1992 Denmark introduced a tax to reflect a shadow price of CO_2 onto electricity consumption. After market liberalisation in 1999 a set of additional levies were introduced, partly with a mere fiscal purpose and partly to pay for special purposes, like energy efficiency measures (Danish Ministry of Taxation, 2010). When Denmark became part of the European emission trading scheme for CO_2 allowances, the CO_2 tax became obsolete for other than fiscal purposes. It was, however, maintained under a different name until, beginning in 2014, electricity taxation was greatly simplified, and all elements were adjusted and gathered into a single tax.

In 1998 an additional levy for public-service obligations [PSO] collected by the transmission system operator had been introduced. This levy still is a separate part of the electricity bill in addition to the general electricity tax, although the removal of the PSO element from the bill to transfer it onto the general state budget is currently being discussed (Danish Ministry of Taxation, 2016b).[1] The payment covers for costs of prioritised electricity production from renewable sources and decentralised CHP as well as research activities mandated to the electricity industry by the Danish state. As it is purely meant for cost recovery, EU law treats it as a para-fiscal levy.

Danish electricity taxation thus fulfils a set of different aims. At first, it should contribute to the political targets of energy efficiency and renewable electricity production. The taxes are, however, not directly related to the damage costs of environmental impacts from electricity production. Such costs should already be part of the electricity price, due to environmental taxes on SO_2 and NO_x related to the fuel input as well as a price on CO_2 determined by the European emission trading scheme. Although it could be questioned whether the full damage costs are being internalised via the politically implemented cap on CO_2 (Lehmann & Gawel, 2013), such external costs should clearly not be the primary objective of electricity taxation. Nonetheless, the support of renewable energies may have positive consequences beyond reducing emissions that may justify the target and the related levy. Also the energy savings argument may still be somewhat relevant, but less so with increasing shares of renewable production. Otherwise the main objective of electricity taxes seems to be fiscal.

Taxing parts of consumption will always to some extent distort the economy and generate so-called deadweight losses. In combination with dynamic pricing schemes, the current tax system will also lead to a weakening of the market price signal. In relative terms, price differences between different time periods decline because of the tax. If generating government revenues was the only purpose, then fully removing the tax payments from electricity and instead increasing income tax may be a less distorting option (Danish Ministry of Taxation, 2016a). This does not seem like a realistic scenario, though, as the tax on electricity could be used for other purposes than for mere revenue.

[1]The outcome of this discussion is still uncertain, but there seems to be a majority in support of this proposition.

Moreover, European legislation requires Member States to put a minimum tax on electricity (EU, 2003), so a certain level of tax is likely to be maintained.

There are different views on how a revenue-generating electricity tax should be designed ideally. Stoft (2002) points at Ramsey taxation as the most efficient way to raise revenues.[2] The approach involves the so called inverse elasticity rule that requires ad-valorem tax rates, i.e. percentage rates based on price, proportional to the inverse of demand elasticities. Effectively, demand with low elasticity should be taxed higher than demand with high elasticity (see also Myles, 1995). Stoft (2002), however, advocates a simple unit rate on all electricity use, as this would minimise the administrative burden and avoid discrimination between customers.

The great advantage of an ad-valorem rate over a unit-tax would surface, though, when end-consumer prices are variable and reflect marginal costs. The inverse elasticity rule also implies that if elasticities are equal then the percentage tax rate should be the same. This is clearly not the case with unit taxation, as at high prices the unit rate decreases relative to prices and vice versa. So in the case of constant price elasticity over time, one common ad-valorem rate would disturb consumption the least (Togeby et al., 2001). Although the price elasticity is not exactly constant across hours (see Knaut & Paulus, 2016), the ad-valorem tax is still likely to be a more accurate instrument than unit taxation.

Besides revenue generation an electricity tax could contribute to fulfil the target of renewable energy use. For that purpose it could make sense to specifically tax the use of fossil electricity on a per-unit basis (Danish Ministry of Taxation, 2016a). One of the issues here is that the production of electricity is dynamic, and the exact amount of fossil production would not be the same for each unit consumed. A unit-tax on consumption would thus only contribute to the target on average. At the same time, the share of wind power does have a significant impact on price (Jónsson et al., 2010) providing another argument for value-based taxation. The PSO levy could be particularly relevant to consider in this context, because it directly supports renewable energies. If high prices largely correspond to low renewable energy penetrations, then a dynamic PSO levy could contribute to shifting demand towards times with more renewable resources available.

The positive impact of dynamic ad-valorem taxation on the demand reponse incentive has been emphasised from time to time (e.g. Østrup, 2013; Singh & Østergaard, 2010; Togeby et al., 2001; Togeby, Werling & Hethey, 2009). Paper C quantifies the difference in benefits to flexible consumers. Revenue-neutrality of the change in taxation is ensured. As the analysis uses a simulation approach, it disregards dynamic effects. It thus applies a price-taker approach to estimate in how far a changed tax regime might contribute to the adoption of demand response accounting for transaction costs of switching as described above. It does so analysing the effects of a dynamic tax as well as a dynamic PSO levy for different groups of residential consumers and different levels of flexibility.

3.4.5 Risk analysis

The previous sections used the term value as though it could be determined with certainty. This is not the case; rather the value of flexibility is strongly driven by

[2]as initially proposed by Ramsey (1927)

uncertainty: the higher the uncertainty, the higher the value of flexibility. At the same time, the realisation of value is subject to various risks.[3] Demand response contains elements of volume and price risk that affect value and thus the willingness to adopt tariffs and technologies. Price risk stems from uncertainty about the timing and level of prices in the future. It is therefore difficult to foresee when, and if, the expected revenues will be generated. Volume risk relates to uncertainty about the availability of the capacity. These remain to be dealt with through market design, and thus to some extent it is a political question, who should deal with the risk.

Uncertainty has an impact on the valuation of flexibility. In fact, flexibility value is not easily determined on the basis of market conditions in a specific point in time. The value of flexibility is contingent on future market developments similar to option contracts in finance. Just as the value of an option contract will depend on the market outcome, so will the value of demand flexibility. The challenge is to set a price on the option before the market outcome is known. Valuation is further complicated by the employment of variable production. While it could make demand response activities more attractive, revenues will become even more uncertain. An additional uncertainty is the indirect dependence on political decisions related to the development of renewables.

Issues of uncertain revenues are particularly relevant if upfront investments are required to become flexible. The traditional cost-benefit approach would be to determine an expected value of the investment under an assumed price scenario. Instead, stochastic approaches have been developed that provide insights into a possible distribution of resulting revenues. A technique based on Monte Carlo analysis is applied in Paper E to evaluate the opportunity to invest into demand response equipment from the perspective of an aggregator. Based on a stochastic price model, a number of possible future price outcomes are simulated and the value of demand response is determined in each of the scenarios. The paper thus only deals with price risk. It still provides an idea of the impact of risk on the adoption decision for demand response and may deliver insights into the potential upside and downside of such investments. Using a value-at-risk approach a threshold value depending on the risk appetite of an investor may be established. This threshold may represent an additional barrier to be taken into account when considering demand response adoption on the basis of costly automation equipment.

[3] as e.g. in the case of storage (Sioshansi et al., 2012)

Chapter 4

Main results and discussion

This section summarises the main results of the papers of this thesis and responds to the research questions stated in Section 1.3. It concludes by evaluating the results in relation to the overall research question of Section 1.1.

4.1 Elements of a sound demand-side policy

The overall policy analysis of Paper A addressed the following question:

> *Which are the major issues that policies aiming at demand flexibility should focus on?*

Major areas of concern for policy-makers have been defined in Paper A. By use of the tools described in Section 3.2, these findings are first put into a greater policy context that relates them to the background described in 2. A recommended policy focus is presented as a basis for the further analysis. This is done in two steps: first, suitable objectives are defined; second, based on suggestions of Paper A, a selection of instruments is proposed and related to the defined objectives.

4.1.1 Measurable objectives

Policies regarding demand flexibility should support one or more of the overall energy policy objectives, and should preferably not compromise any of them. Figure 4.1 shows an objectives tree that relates demand-side flexibility to the overall objectives. Starting at the top, Danish energy policy aims at a fossil-free system in the long run resulting in a high penetration of variable renewable electricity production. The variability in production has an impact on reliability, another essential policy objective, resulting in a need for additional provision of flexibility to the power system. A sub-target for flexibility or renewable-integration has been stated, in mostly general ways, in many of the Danish Government energy policy plans (see also Section 2.1). Demand flexibility is more specifically addressed in the government's Smart Grid Strategy (Danish Ministry of Climate, Energy and Building, 2013).

The third major objective of energy policy, cost efficiency, should be the guiding principle in selecting the sources of flexibility. Clearly, demand flexibility is only one of the building blocks in the overall picture, and it needs to be utilised in competition

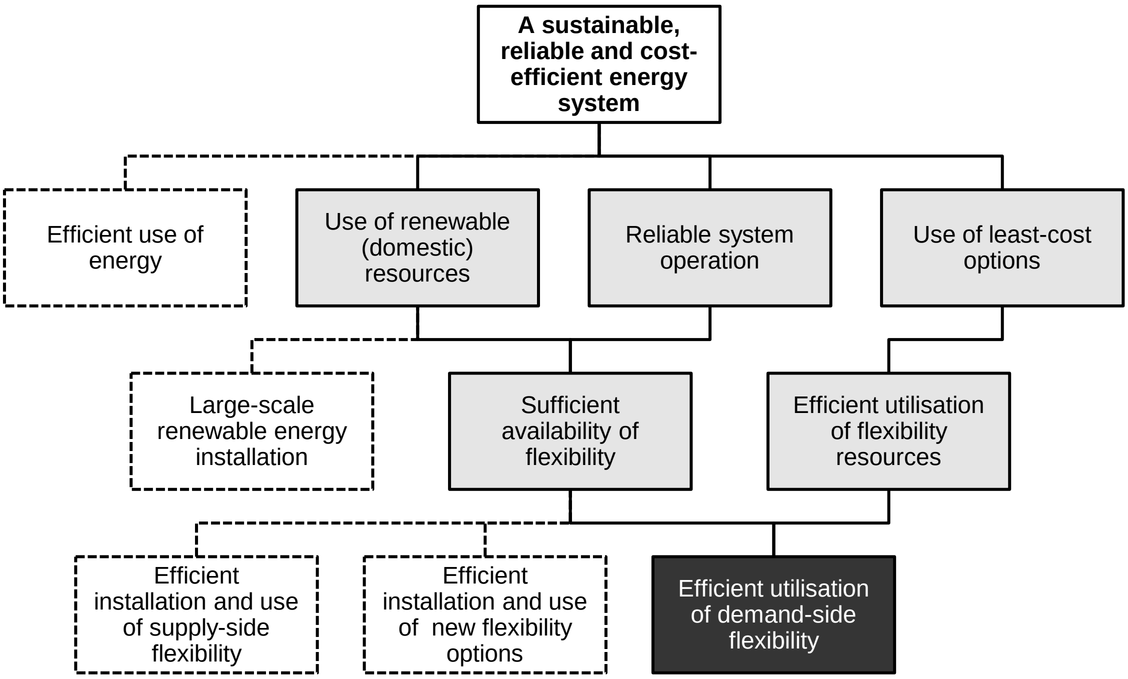


Figure 4.1: Policy objectives and relation to demand flexibility

with other options. Implementation at any cost would counteract the goal of cost efficiency. Therefore, in economic terms policies should aim at removing barriers to efficient utilisation of demand flexibility. In Danish policy, and also in a wider European context, this objective translates into a wide application of market mechanisms. This has been the point of departure in Paper A.

The objective of *efficient utilisation of demand-side flexibility* serves as the main policy goal. Its fulfilment would certainly contribute to the general energy policy targets. It is not directly measurable, though. As this is a requirement in order to evaluate the success of policies, it will be necessary to define attributes of the objective that can be tracked by policy-makers and regulators. Paper A argues that interest in market participation of demand flexibility is low even in segments that should face relatively low barriers. Consequently, information that could enable efficient demand response is not passed through to the demand side. Achieving higher participation and providing information for efficient response may be defined as sub-objectives of demand flexibility policy and could potentially serve as measurable indicators. Participation rates should be straight-forward to quantify. Information for efficient response is still a more abstract objective. It could become operational by setting a target for the share of load to be activated through market mechanisms.

4.1.2 Targeted policy instruments

On the basis of the intermediate objectives of participation and efficiency, Paper A identifies three areas of concern for policy. The first area addresses the *market value* of demand flexibility in order to ensure that the economic incentive is appropriate. The second area focusses on *risks* involved in utilising demand flexibility, as high risks will prevent participation. The last area is termed *responsibility*; in a broad sense it addresses

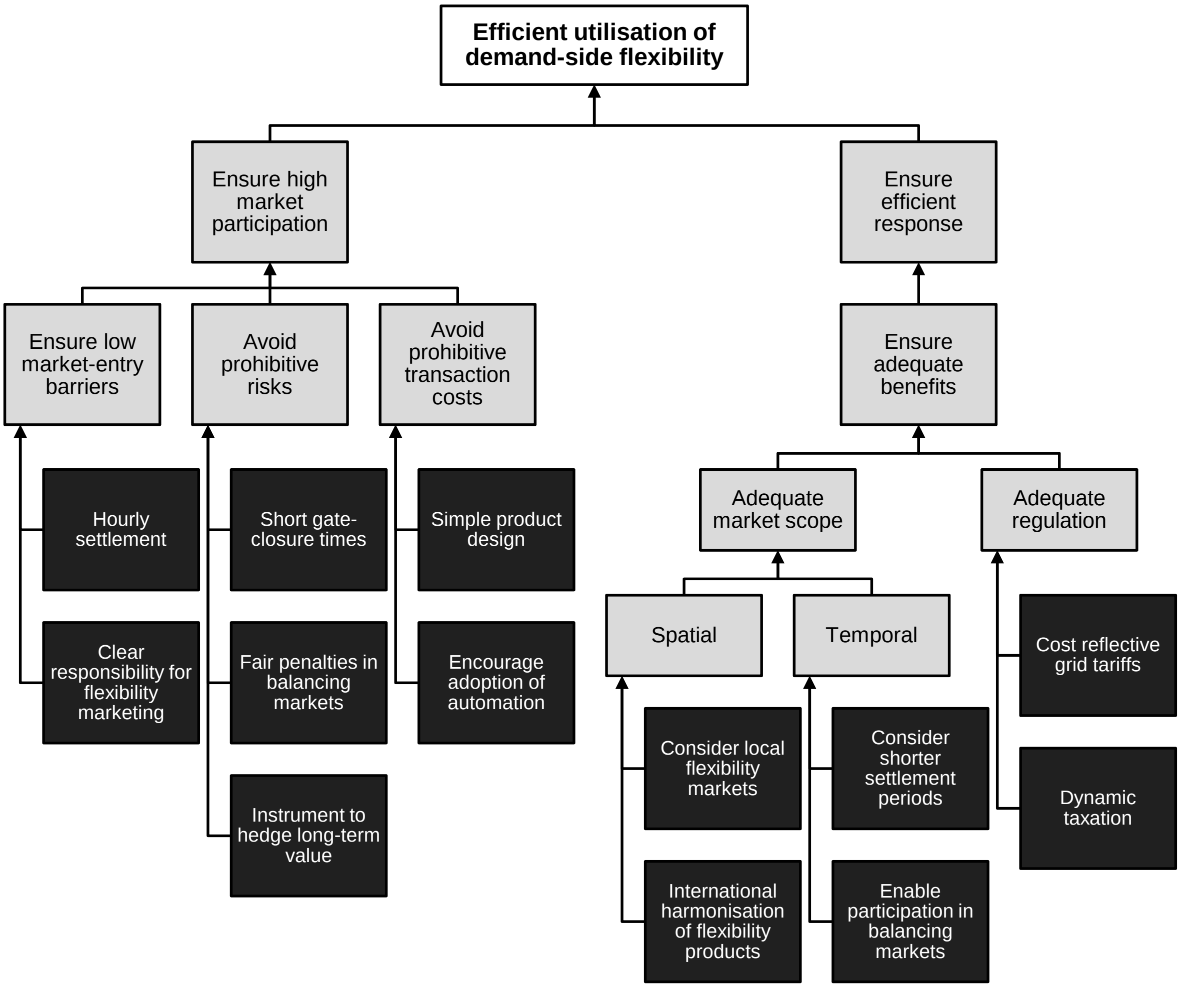


Figure 4.2: Means-ends diagram illustrating policy focus for demand flexibility

the market access of demand-side participants. These areas are preconditions to activate the demand side for flexibility and are critical in determining the value that may be achieved. In order to determine relevant measures, however, it is necessary to define whether conditions affecting value, risk or market access should be considered a market failure or not. Policy interventions aiming at conditions that cannot be considered a failure could lead to even less efficient outcomes. Using the distinction between market structure and market design, i.e. rules and regulation, a number of relevant measures are pointed out.

The exact choice of means should ultimately depend on strategic considerations, as described in Section 2.4, taking either a grid, market or consumer-centred approach. As argued in that section, many of the developments on the demand side will be consumer-driven and a successful activation of demand flexibility would probably require a somewhat consumer-centred approach. At the same time, this has to be based on sound wholesale market mechanisms. The proposed instruments therefore cover both wholesale and retail elements. Figure 4.2 illustrates how different means may contribute to the overall objective using a means-ends diagram. The black boxes indicate specific measures that have been proposed in Paper A. These have been complemented with additional initiatives, some of which have been more specifically addressed in the

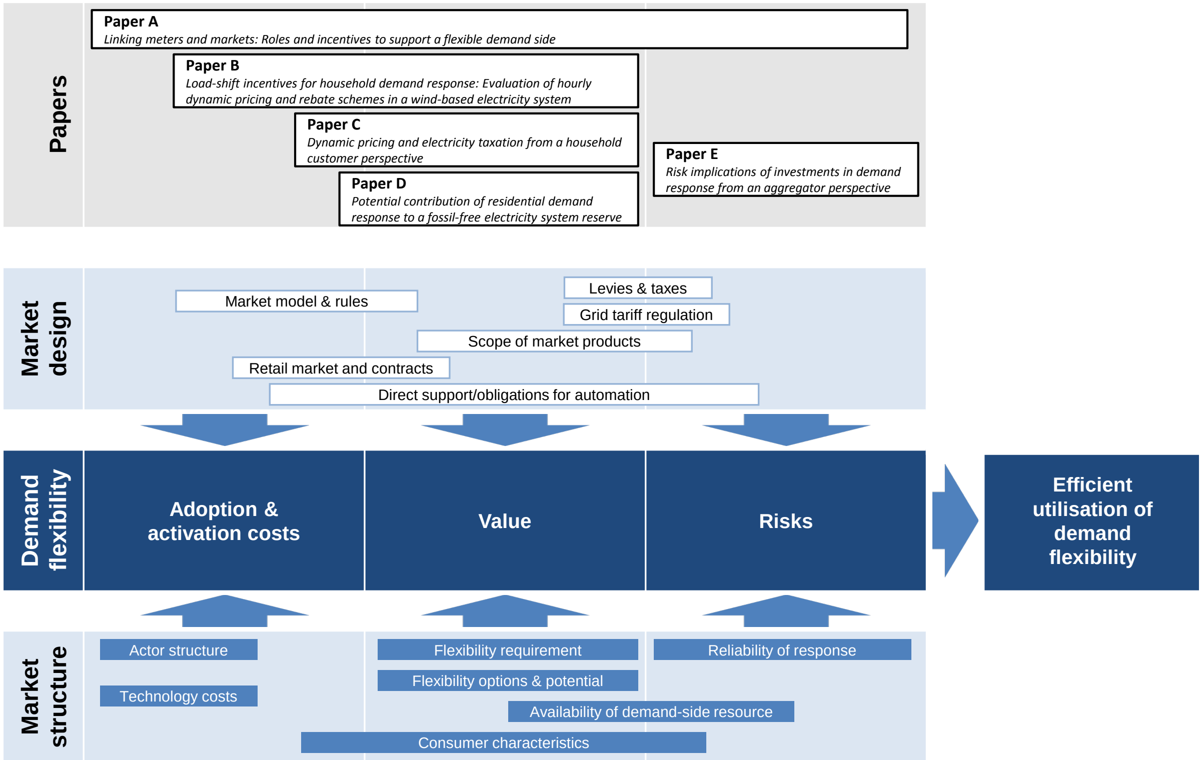


Figure 4.3: Simplified system diagram indicating paper contributions

quantitative analyses of the thesis.

The efficient utilisation of demand flexibility requires participation on the one hand, and efficient response on the other. A basic precondition for participating is market access and a better integration of wholesale and retail markets. Measures in support of market access are an hourly settlement of demand in accordance to the wholesale market settlement periods and a distribution of market roles and responsibilities that ensures proper information transfer from wholesale to retail. Further, to extend market participation it should be taken into account that the arrangements do not introduce prohibitive transaction costs in terms of monitoring, control and decision-making. This requires accounting for demand-side characteristics in the design of products, keeping them simple or enabling automation. Also risks should be appropriately shared accounting for specific characteristics of demand flexibility, such as shorter forecasting horizons and changes in availability at short notice. Short gate-closure times may be helpful. The design of the balancing mechanism could be an issue if it penalises flexible demand stronger than other participants. A general risk issue is the lack of products to hedge the long-term value of demand flexibility.

To ensure efficient response the demand side should not only become able to participate in the market on equal terms. Benefits achievable on the market should reflect the real system value. Therefore markets may have to be aligned to the spatial and temporal characteristics of the demand side. If value can be created in the local grid it should be possible to offer a service. At the same time international harmonisation might open up opportunities across borders. Regarding the timing, shorter settlement periods and the participation in real-time markets could be relevant for the demand side. In addition, grid tariffs and taxation should be aligned to reflect actual underlying costs.

Some of the identified aspects of the framework and their impact on expected value, risks and responsibilities are further addressed in the following results. The value aspect is taken up by considering the market scope in Paper D and different aspects of transaction costs in Papers B and C. The risk aspect is addressed in E. Figure 4.3 illustrates the paper contributions in a simplified system diagram denoting external conditions as *market structure* and policy options as *market design & regulation*. In addition to the illustration in Section 1.3, it provides an overview of how aspects of demand flexibility may be addressed by policy instruments. Moreover, the figure shows external factors inherent in the structure of the electricity system that influence the demand side.

4.2 Missing market value of flexibility

One of the central policy measures as defined above is to align the observed market value with the efficient system value of flexibility. The question addressed in Paper D is consequently:

What is the value of expanding the scope of demand-side market access?

As shown in Figure 4.2, an expansion may be carried out in spatial or temporal dimensions. Paper D carries out an analysis of increasing demand-side participation in markets with higher granularity in the time dimension.

The central conclusion from Paper D is that the intra-hourly value of demand flexibility may be even higher than the value obtainable in the hourly spot market. In the model calculations, system costs are reduced by around €60 million per year, when the full flexibility potential of residential loads for cooling and freezing as well as for cleaning are utilised. The same loads achieve savings of below €30 million per year in pure spot market optimisation. Although of course these values are subject to a considerable amount of uncertainty, their relative sizes point into an interesting direction for the further development of demand flexibility.

It can be concluded that a significant value potential lies within the hourly balancing tasks, and using demand-side resources will have a positive impact on the reserve capacity needed from generation. For some flexibility providers, revenues generated in these markets may even exceed those generated in spot markets. Therefore it will be crucial to provide adequate market access to such units. It cannot be finally concluded, in how far the value potential may be captured by small-scale demand response, even if markets would be redesigned in full consideration of their characteristics. It may simply be more efficient and require fewer adjustments to integrate flexibility from other sources.

Although some market re-designs may be considered no-regret options (Baritaud, 2012), defining new market arrangements to exchange information and trade flexibility is a complex task that comes at a cost. It is not possible at this point to provide a complete estimation of such costs. It is clear, however, that they need to be outweighed by the benefits in a proper assessment. Costs to be considered include the cost of market operation, metering and settlement of volumes. Additional costs will occur in the retail part in particular for customer care and billing. It should also be expected that disputes occur more often due to disagreement about, e.g. prices, timing and frequency of requests to respond or customer bills in general. Some changes in market design, however, seem to be recommendable in any case. These could concern the reduction of minimum bid sizes, allowing to define upper limits on volumes and less strict technical requirements regarding the monitoring and metering of participating units (see Energinet.dk et al., 2015).

4.3 Transaction cost assessment

The transaction costs of demand response activities depend on a range of factors. The organisation of market access and the definition of information flows between the parties is one fundamental element as considered in Paper A. The benefits that may be achieved from a reduction in transaction cost are somewhat intangible. Therefore a cost-benefit analysis of measures will have to rely on approximations, as those presented below.

4.3.1 Adoption costs

One cost element that has been addressed is switching costs, i.e. costs related to search and hassle of finding a new supplier and understanding contractual terms etc. The existence of such costs poses the following question that has been analysed in Paper C:

> *Can consumers be expected to adopt dynamic pricing in the light of their transaction costs of switching?*

Besides the detailed design of products analysed in Paper B, the overall economic benefit plays a great role in the adoption decision. As Paper C argues, though, a contract will not necessarily be adopted on the basis of just any economic benefit. Using observations from Danish retail competition, first, an estimate of the cost of switching is made and, second, it is compared to possible benefits. This reveals that dynamic pricing as such could be insufficient.

The switching cost estimates are not an accurate measure, but provide an indication of the level of benefits required to incentivise large-scale adoption of new pricing schemes. In Paper C two different estimates have been derived that differ in what they assume to be the incumbent market share. As most customers still have a contract with the former monopoly supplier in their area (84% on average according to data provided in Energinet.dk, 2016a), a switching cost estimate based on the market share of the largest local suppliers becomes rather high. As in relation to dynamic pricing the contract structure is more relevant than the actual supplier, an alternative switching costs has been derived based on the market share of traditional fixed price contracts (55% according to Danish Energy Regulatory Authority, 2016). These two estimates span a range from €78 to €114.

The analysis of benefits has been performed using disaggregated consumption data to account for the diversity of household consumers. A first observation as a consequence of using such detailed profiles is that, even within the same customer categories, e.g. apartments or single-family homes, the costs of electricity may be quite different. Therefore the benefits of dynamic pricing and, thus, the incentive to adopt such schemes cover a wide range. In relation to the switching costs estimates, only a minority of consumers would be able to generate benefits exceeding them, even if load could be shifted optimally within time windows of up to six hours. Switching costs would only be exceeded on average at load shifts within 12 hours or more. Taking into account the practical limitations of residential loads, it is very uncertain whether such flexibility may be provided by many consumers.

The limited incentive in the light of switching costs to adopt dynamic pricing and demand response activities could be addressed by easing the switching process. From a policy stand, possibilities beyond the tools of supportive web interfaces and information campaigns seem to be limited, though. It might make sense, rather, to address inefficiencies in the end-consumer price, related to grid tariffs and taxes. Such other price components could be made variable, as a supplement. Based on the arguments given in Section 3.4.4, Paper C therefore also analyses the impact of dynamic taxation.

The analysis shows that introducing dynamic taxation would allow benefits to exceed switching costs at realistic levels of consumer flexibility. Furthermore, it can be shown that, even restricting dynamics to certain elements, like the PSO payment, could yield sufficient incentives to switch for large shares of consumers. Of course the positive effects of suches switches should not be seen in isolation. As Paper C also points out, welfare and distributional effects should be analysed in more detail. Still, both theoretical arguments and practical implications seem to be in favour of a more dynamic approach to electricity taxation. As the value of flexibility may be expected to rise in the future, a dynamic tax could as well be introduced with the long-term target of phasing it out again, when market price variations suffice as an incentive to shift.

4.3.2 Activation costs

As argued in Paper B reducing product complexity or enabling automation could reduce transaction costs of customers. The underlying reasoning is that instead of (hourly) real-time pricing schemes, dynamic price information may be provided to consumers in the form of tariffs that are less volatile. Paper B takes a rebate scheme as an example to address the question:

How valuable are simplified products for flexibility?

It is based on a design that offers a fixed percentage reduction in the electricity price for volumes increased or reduced relative to a baseline. This reduces the signal to the customer to a simple request asking for either to increase or reduce consumption during a critical time period. Customers would always be able to save the same amount on the adjusted volumes. Transaction costs for monitoring and decision-making should thus be minimal. Moreover, customers would not have to be concerned with potential losses.

Based on the rebate-product example, Paper B finds that simplified products may be of significantly lower value if compared to the ideal pricing schemes. In a new long term equilibrium the rebate only captures around 18% of the system value as compared to an hourly pricing scheme. Taking into account that even in the case of full adoption of hourly pricing the long-term benefits amount to around 4% of system costs of serving load, the rebate result is rather limited. In the short term, though, i.e.

without accounting for capacity adjustments on the supply side, even simple products may generate benefits of around 50% compared to hourly pricing.

The inputs to the analysis of Paper B are not sufficiently certain to conclude on the absolute level of benefits from demand response. Moreover, as discussed in the paper, the developed model neglects some of the conditions that might have a crucial impact on the absolute value of flexibility, e.g. competition from other domestic and international flexibility resources. That said, the paper confirms the positive effect of responsive demand under dynamic pricing and shows that the value increases (in absolute terms) with higher shares of wind power. The results of Paper B are mostly relevant for strategic considerations if the benefits are deemed sufficient, and the introduction of mass-market dynamic pricing is considered. In view of current Danish and European policy initiatives that facilitate large-scale smart metering and encourage dynamic pricing, this seems to be the case.

Although the exact timing of the dynamic effects are uncertain, the adjustments of the system in the long run have a severe impact on the value of demand flexibility. To some extent the long-term development will be subject to large investment decisions and could thus be expected to be somewhat sluggish. This sluggishness could be leveraged in support of the introduction of dynamic pricing. As the paper shows, it is possible to generate a large share of the short-term benefits under simple schemes as well. Therefore, it might be a good idea to introduce simple products to start with and go over to more complex schemes only in the long run, when the benefits of simple schemes vanish. With minimal transaction costs of responding, higher adoption rates should be expected. At the same time consumers gain valuable experience that lower the learning costs of adopting complex schemes and may even increase the resulting response (as found by Taylor et al., 2005).

4.4 Risks of demand flexibility

The final element considered as potentially leading to unnecessarily high costs at the demand side is risk. Paper E allows for drawing preliminary conclusions regarding the question:

> *Is risk a major issue for demand response adoption and does it need to be addressed by policy-makers?*

Paper E answers this question in relation to the price risk. Price variations represent the major source of income for flexibility providers, which makes it essential to address related risks. The paper strictly analyses hourly spot prices, as in the Nordic market they serve as a reference point for both forward and real-time markets. In the analysis the difference in the willingness to invest is determined between a risky and a rather certain outcome. More specifically, the comparison is between the expected value that is subject to risk, and the Value-at-Risk at the 5% level, that is, a value that will be exceeded with 95% probability. In the paper this gap is illustrated in terms of a potential downside in the gross margin of an aggregator.

The risk assessment confirms some general and immediately intuitive mechanisms: increasing flexibility gives rise to higher benefits; at the same time, those are subject

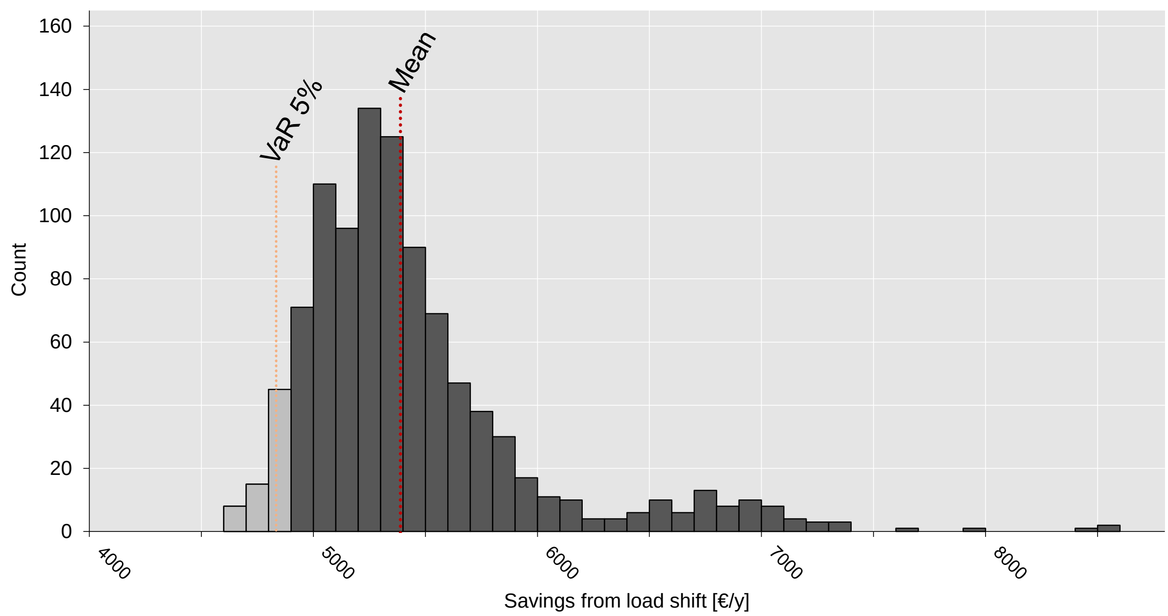


Figure 4.4: Example of a distribution of savings from demand response

to increased uncertainty. Moreover, the results show an upside potential that is larger than the downside. An example of the pronounced right hand tail in the distribution of demand response benefits can be observed in Figure 4.4. If one assumes, as in the optimisation model of Paper E, that volumes will only be shifted when it is beneficial, then a benefit of zero is the natural lower bound. The upside, on the other hand, is in principle unbounded. Still, it will still be possible to end up with a net negative outcome, if a commitment to provide flexibility is associated with costs, as for instance due to investments in appropriate equipment. The risk of negative outcomes may create a reluctance to invest, and either investment costs would be required to become relatively lower or the potential benefits higher.

Paper E argues that the price risk should have a low impact, as the aggregator is assumed to be the supplier at the same time. In this case the demand response benefits make up only a small share in the operating gross margin, and so does the risk. Seen in isolation, however, the impact of price risk on investments may be substantial. The difference between the mean value that has a downside risk of around 50%, and the value with a downside risk of only 5% represents a reduction in value according to around 10% of the investment threshold. This could be interpreted as the premium equivalent to being able to almost fully remove the price risk. A risk-averse investor would, thus, require lower costs than what would be optimal on average. Investments in demand flexibility might, therefore, be underprovided in the existence of risk. As discussed in Paper A, a further issue in this regard is the lack of instruments to properly hedge the risk.

Policy interventions could counterbalance the risk of flexible demand to some extent. It might be worth considering if this risk should be borne solely by flexible consumers, or whether some of it could be shared amongst all consumers to support the introduction of demand response. The capacity to bear risk, in general, could be higher if it is distributed more widely (Arrow & Lind, 1970). This principle could be applicable to demand response as well. An option that has been proposed for this purpose is integrating the demand-side into capacity remuneration mechanisms (e.g. Rious et al., 2015).

The question of risk sharing may become even more relevant when other risks than price volatility are taken into account, in particular, volume risk. Depending on the market rules, demand flexibility could also become subject to harsh penalties when committed capacity in spot or regulating markets are not available for some reason. Such payments could in the worst case not just reduce benefits, but generate losses. The design of market rules should, therefore, ensure that penalties reflect proper costs. It could be considered as well whether all of these costs should be borne by the flexibility provider, or if some of it could be shared.

4.5 Revisiting the policy implications

This thesis set out to answer the question:

> *How can policies enable cost-efficient utilisation of demand-side flexibility to support the integration of large shares of variable renewable energy sources in a liberalised electricity market?*

A set of detailed policy options has been presented above, followed by a range of quantitative analyses of missing value elements and hidden costs of demand flexibility. The results and answers to the sub-questions allow for the formulation of policy implications given in the form of overall guiding principles:

Commit to a strategy for consumer involvement: Clearly defining the intended role of the consumers enables a more targeted choice of instruments. In the light of the developments of on-site generation and advanced digital solutions, consumers should become an integral part of the strategy for demand flexibility.

Choose policies to support the strategy: Targeted instruments can be chosen on the basis of a clearly stated strategy. The proposed strategy entails a focus on strengthening the link between wholesale and retail markets.

Set targets for demand-side market participation: The evaluation of policies requires the definition of clear and measurable targets. Therefore, a target should be set for the level of flexible demand adoption. The share of consumers on dynamic pricing schemes could be considered as another indicator. Defined targets for demand flexibility establish a commitment that is expected to encourage further adoption.

Consider initial measures to support adoption: To overcome adoption barriers, such as transaction costs of switching, monitoring and learning, supportive regulations could initialise the development of demand response, through e.g.:

- adjustment of distortional electricity price elements;
- encouraging simplified dynamic pricing;
- risk sharing mechanisms.

Widen the scope of markets to cover missing value: Large-scale adoption is crucially dependent on market mechanisms to discover the full value of flexibility. Where market operation costs outweigh the estimated benefits, regulatory arrangements should seek to utilise a broad range of options on a least-cost basis. For mass-market demand response, though, an integration into the market mechanism seems inevitable.

Chapter 5

Concluding remarks

This thesis started out by identifying the flexibility challenge as one of the essential issues in building a sustainable and reliable energy system. The focus of this study has been Denmark, but many other countries will face similar issues in the future. With increasing efforts to bring down CO_2 emissions and lessen import dependency of fuels, a strong development towards renewable energy sources can be observed. With the least costly and most widely available types of renewable resources, wind and solar energy, come fluctuations and the need for balancing. The Danish case has shown throughout more than three decades that the need may be fulfilled by a combination of flexible power production and exchange with neighbouring countries. With larger shares from variable sources, however, flexible producers become fewer. Although interconnections are an instrument to smooth out variations across larger areas, not all balancing tasks can be exported.

Technologically, several different flexibility options are available and scenario analyses of an energy system with large shares of variable renewable production show that feasible solutions may be found at reasonable costs. One contribution to solve the flexibility challenge may come from the demand side, supposedly through the electrification of transport and heating, but also through more active management of existing demand. Another strong driver that may play a role in the future is the development at the distribution-grid level. Both the installation of renewable production as well as the expected new loads from electric vehicles and heating systems will to a large extent occur at the distribution level. This will create a need for investments in new or additional distribution grid capacities. Activating the demand side to avoid some of the investments could supplement the ability to support the system as a whole and reduce overall costs.

A review of Danish energy policies since the mid 1970s has shown that the interest in developing renewable energies has always been accompanied with the question of how to integrate them with the rest of the system. Related policy initiatives started out with a focus on research. Ideas of using heating and transport for flexibility in the electricity system had been developed early on. With more ambitious policies regarding the development of wind power, came more detailed analyses of the effects, often including proposals for solutions as well. The latest Danish energy policies include a clear commitment to develop an "intelligent" energy system and refers extensively to a flexible demand side as part of the solution.

The demand-side focus has been followed up by a Smart Grid Strategy defining initiatives more specifically. Besides the need to roll out smart metering and establish the basis for hourly settlement of all consumption, the strategy mostly points at further research that needs be done in order to address the flexibility challenge as a whole. This development work is, thus, at present delegated to system operators, industry stakeholders and research institutions. Although the results are still open, the role of the demand side has been clearly acknowledged. At the same time current regulation has been identified as one of the major challenges and focus areas in the development of smart energy solutions and utilisation of demand flexibility (Smart Energy Networks, 2015).

In view of this background of technical challenges and regulatory gaps, this thesis aimed at providing insights into some of the aspects that affect the utilisation and efficient activation of demand flexibility from a policy point of view. Instead of viewing the lack of incentives to demand response as a regulatory issue in general, the first contribution of the thesis was to distinguish between those barriers that should and those that should not be addressed by public policy. Only barriers due to either market failures in the classic economic sense or systemic failures founded in market design, rules and regulations are deemed relevant to be addressed. A range of such failures have been identified in the Danish framework, and options to address them have been proposed. Although the focus has been on Danish regulation, similar issues will be present in other countries. In that sense, the conclusions are of general concern for systems aiming at the utilisation of demand flexibility.

A frequently mentioned barrier to becoming responsive is the economic incentive. As analyses of the thesis have shown, achievable benefits seem to be outweighed, currently, by transaction costs that arise from initial adoption and continuous activity of flexible demand. Simply put, policies may aim at either increasing benefits or reducing costs in order to ensure participation and adequate response. Measures to add value to flexibility are limited, especially, if no particular market failures can be identified. This thesis points out, however, that potential failures may also be found in the design of markets and regulation. The current definition of market scope in the dimensions space and time are not optimal for the demand side, and higher granularity in both dimensions could increase benefits. Moreover, taxation and grid tariff regimes could be argued to unnecessarily stabilise prices, working as a disincentive to flexible behaviour. In this thesis, value lying in a higher time granularity of relevant markets for demand and a change in the taxation regime have been quantified. It has been found that the demand side could generate significant value serving as intra-hourly reserves, if automated and reliable response is available. A change in taxation regime towards a value-based electricity taxation has been found to hold a significant value potential as well. Such value gains, however, always need to be held up against the costs involved in establishing the measures.

The costs of demand response are another crucial issue. These need not be a market failure if they reflect the real production costs of demand flexibility. The study has been most concerned with the more intangible cost elements like transaction costs and risks, and less so with costs for technology. Some of these intangible elements are significantly influenced by the design of markets, rules and contracts, and should therefore be included in the assessment of policy options. Transaction costs addressed are costs related to adopting a demand response contract (switching costs) and costs of activation (monitoring and decision costs). The first have been estimated indirectly from available market data and used as a benchmark to evaluate potential benefits. The latter have not been estimated directly; rather, the foregone benefits of a simple contract structure have been estimated to provide insights into the potential effect of such costs. This could provide a benchmark for the value of automation as well.

Apart from transaction cost analyses the thesis also addressed the question of risks involved in activating demand response. For some parts, risks may be due to design, but much of the price and volume risk is a fundamental characteristic of flexibility. Price risk has been dealt with in a quantitative way, and has been found to further increase the threshold to adoption when investment costs are involved. It might be relevant to consider from a policy perspective whether such risks should be borne alone by those that provide flexibility.

5.1 Further research

Some of the suggested issues may be directly addressed by policy-makers. On the other hand, there are many open questions that provide possibilities for further research. A refinement of the evaluations that have been part of this thesis is one option. Besides that, there are a set of relevant issues that have not been addressed. In terms of missing markets, the spatial dimension could become more relevant in the future, and market mechanisms at the distribution-grid level are intensely debated. An analysis of the costs and benefits of such markets, including their impact on a system-wide scale, would be highly relevant. The thesis touched upon the question of electricity taxation – an issue that is addressed from time to time by government agencies, but rarely in academic literature. More detailed analysis of the dynamic effects of different taxation techniques is clearly recommendable. As a final issue, the role of risks in the development of demand response holds various opportunities for further research and may become increasingly relevant in the future. New risk sharing agreements based on the experience with renewable energy deployment, for instance, could be interesting to further investigate, as they could additionally contribute to enhanced market participation.

5.2 Outlook

How much the demand side will contribute to solving the challenges of future energy systems, depends very much on the vision that is pursued. Two relevant alternatives have been suggested that differ in the involvement of consumers in the green transition towards a renewable system. A consumer-centred vision would seek to engage the consumer as much as possible to contribute with flexibility, potentially in combination with decentralised renewable production. A wholesale-centred vision builds on an energy system that just works – with minimal consumer involvement – much like the traditional system. Demand-side contribution under this vision would likely not exceed that of today.

The increase that can be seen in roof-top solar electricity installations, the use of electric vehicles and heat pumps, may make it difficult to pursue the latter vision and isolate the consumer fully from the system. At the least, the green transition requires informed consumers that are somewhat familiar with the effects of their installations, and on that basis accept possible interventions as well as technical or financial obligations. A consumer-centred vision with active and engaged consumers on the other side, may only be achieved on the basis of a firm political commitment, targeted market rules and regulation as well as supportive industry stakeholders. Only if the role of consumers is made explicit, they can be expected to try to work towards the political goal. Inspiration may be drawn from the development in renewable installations: a clear political commitment, combined with risk sharing arrangements, has led to a broad engagement also by households. A similar development is possible for demand flexibility.

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Papers

Paper A

Linking meters and markets: Roles and incentives to support a flexible demand side

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Abstract

Present trends in the development of electricity systems are expected to generate a growing need for flexibility in decentralised resources, including demand response. In order to enable decentralised actors to create value, the organisation of markets and incentives should incorporate these new participants. The roll-out of smart metering to electricity consumers is an important precondition to establishing a flexible demand side and will provide essential information flows. On the basis of current incentive structures and related risks, however, the pass-through of information and value from wholesale market participants to the demand side is mostly infeasible, resulting in flexibility tasks being aggregated and delegated to balancing responsible wholesale traders. This analysis focuses on whether current incentives and roles are appropriate and where the design could be improved to establish a flexible demand side with a particular focus on the Danish case. Design-related barriers are identified that affect expected value, associated risks, and the distribution of responsibilities. This serves as a basis to define policy options in the context of Nordic electricity markets.

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A.1 Introduction

Policy-makers intend to cure the missing information transfer between the demand side and wholesale markets by rolling out smart metering to all or most customers. Arguments for establishing this kind of infrastructure are based on socio-economic calculations that show substantial benefits induced by flexible demand-side resources (e.g., Danish Energy Agency, 2013; Energinet.dk, 2013, for Denmark). However, such findings also rely on significant adoption rates.

At the moment many barriers, mainly regulatory and institutional, still exclude decentralised resources from the informational flows about flexibility supply and demand (e.g., Greening, 2010).

Currently, with market products generating only weak incentives, combined with their risk profiles it remains an open question whether adoption will take place at expected rates and if economic projections are justified. The present distribution of responsibilities for handling flexibility suggests the need for some adjustment.

Considering the Danish situation, the existing market places for flexibility are reviewed from the perspective of decentralised resources, including both demand response and distributed generation.

The analysis focuses not so much on the economic value of flexibility and the underlying incentive to bring it to the market. Instead, the focus lies on how flexibility trades and whether the form of products and the organisation of markets fit with the characteristics of demand-side flexibility. The reasoning is that while the demand for flexibility and its value can be expected to increase with growing shares of intermittent production, it is of central importance that information about the rise in value is in a form that creates demand-side incentives.

The next section lays out the scope and research interest in more detail. It points out trends that suggest a growing importance of flexibility from decentralised resources and describes the approach taken towards barriers to demand-side flexibility. A clear distinction is drawn between barriers caused by the underlying market structure and additional barriers introduced by regulation and design. Hereafter the major design-related barriers as well as options to address them in favour of small-scale demand-side actors are presented and discussed.

A.2 Drivers for decentralised flexibility

A.2.1 A growing demand for flexible resources

The necessity of providing flexibility to the system originates from reliability requirements. Securing system balance and power quality at all times are basic preconditions to the operation of electricity systems. In a liberalised electricity market these requirements establish the demand side in a market for flexibility.

As reliability is both a long-term and a short-term task, so is the provision of flexibility. In the long-term the reliability or system adequacy requirement traditionally meant providing sufficient production and transmission capacity to serve demand at all times (ENTSO-E, 2004). Here flexibility is seen as the ability to handle fluctuations in demand (see also Nicolosi, 2010). With recent developments in intermittent production, adequacy increasingly must to take into account variability of production.

In the short term reliability translates into security requirements within an otherwise adequate system. In particular, reserve requirements for outages and stochastic deviations are determining factors. Although electricity demand is subject to forecasting errors, these are comparatively small on an aggregated basis. Flexibility in the short term, therefore, is almost completely driven by the supply side of the system (Gül & Stenzel, 2005).

The demand for flexibility due to adequacy and security requirements thus depends very much on supply-side developments. In a broader sense, therefore, flexibility can be defined as changes in the behaviour of connected parties to accommodate system needs (Dansk Energi & Energinet.dk, 2012). As the supply side of electricity changes, so will the value of and the demand for flexibility. The development of variable renewable electricity production, accordingly, is expected to increase the demand for flexible capacity (Grohnheit et al., 2011).

A.2.2 Declining availability of traditional flexibility providers

Centralised thermal power plants are the most common providers of operational flexibility to the system at present. Due to low marginal costs of most renewable energies, conventional production technologies may experience lower utilisation rates. Combined with the overall price depressing effect (cp. Munksgaard & Morthorst, 2008), this reduces the feasibility of these traditional suppliers of flexibility.

Therefore, it can be expected that conventional sources of flexibility will become less available or, at least, more costly (cp. e.g., Droste-Franke et al., 2012, p. 63ff., for an analysis of German scenarios). Although there is an option of keeping them on-line to provide reliability services, this may result in substantial costs. Adding new flexibility resources should be considered.

Several flexibility options have been identified, ranging from grid extension to establishing storage and demand response (cp. Energinet.dk & Dansk Energi, 2012; German Ministry for the Environment, Nature Conservation and Nuclear Safety, 2012; Gül & Stenzel, 2005). Some of those are centralised options and others are more decentralised, that is, smaller in size and typically connected to lower voltage grids. A cost-efficient system should take advantage of and optimise among all available resources.

A.2.3 Decentralisation of reliability management

Building an electricity system with large shares of intermittent renewable production typically implies that the supply structure becomes more decentralised. Therefore regional and local grids may become challenged. As a result, reliability management requires either more grid capacity or more decentralised solutions (CIRED, 2013).

Currently, flexibility services are primarily managed by transmission-system operators. At the distribution level, reliability requirements traditionally have been covered by investments in new grid capacity. In a future system with increasing variable activity at the distribution level, building sufficient grid capacity may come at a significant cost and distribution system operators may instead ask for flexibility services and seek to establish a more active management of such resources (Energinet.dk & Dansk Energi, 2012).

In addition to the specific challenges in distribution grids, various benefits have been identified and are expected to become effective when activating the flexibility of the demand side (see e.g., Albadi & El-Saadany, 2008; Andersen et al., 2006). Active demand response is expected to improve general market performance by reducing variability of prices and preventing market power (Hirst, 2001; Kirschen, 2003). It reduces the usage and investments in peak capacity and supports reliability (Earle & Faruqui, 2006; Strbac, 2008). At the same time, improved monitoring may lead to operational benefits to suppliers and grid companies (Faruqui, 2010).

Although developing a smart and flexible demand side is supported by research and acknowledged by policy-makers in countries with growing shares of renewable resources, including Denmark and Germany, the scale is an ongoing debate (see Lund et al., 2012). In particular the demand-response potential from most household appliances may be limited. If individual transport and heating systems become electrified, however, the flexibility of such devices should be utilised actively in order to prevent severe reliability issues (Slootweg et al., 2011).

A.2.4 Market structure and impacts of market design

Many options already exist to activate flexible capacities on the demand side. In principle demand response and other decentralised resources also are able to participate in most if not all of the relevant markets (Hirst, 2002). The lack of smart metering installations is sometimes considered a major barrier to the utilisation of demand response (e.g., Kim & Shcherbakova, 2011). While this clearly is an important technical precondition, metering by itself is not sufficient to induce flexible demand.

In order to enable decentralised actors to create value, informational links between markets and customer meters should be established. The current information asymmetry in electricity markets to a great extent explains the inelasticity of demand (Stoft, 2002). It has been shown that customers respond to dynamic price information (Faruqui & Sergici, 2010), but even in the case of large-volume market participants (such as industrial customers) with advanced metering already installed, timely information about market conditions is only rarely passed-through.

Customers often prefer fixed rates to variable ones (for a survey amongst large Danish consumers, see Dansk Energi Analyse & Norenergi, 2005), and household customers may prefer stable prices as well (Costello, 2004). An astonishing finding is that only a small number of customers with real-time metering is actually bringing flexibility to the market (see Faruqui et al., 2014).

From a commercial point of view, three major reasons contribute to this situation. First, the expected value from response actions on existing markets is low. Second, even though studies claim to identify value created from demand response, it will always be subject to substantial risks. Third, demand-side actors are mostly not held responsible for their behaviour toward the system.

All of these three barriers may be perfectly good reasons, economically speaking, to refrain from implementing demand response in spite of smart metering installations. It would be clearly inefficient to employ demand response if the related costs for enabling automation equipment and information management are not competitive. Prevailing market risks add to the cost of demand response as well. Delegation of responsibility also makes economic sense due to economies of scale and benefits from portfolio aggregation.

These conditions are built into the basic structure of the market. They are based on the underlying economics of flexibility, on technological restrictions and costs, which are difficult to affect by policy-makers. While these structural barriers exist, they are most certainly not the only reasons for weak incentives and missing information flows (see Sorrell, 2004, for an analysis of barriers in the context of energy efficiency). There is a difference between the value that demand-side flexibility could add to the electricity system and the value reflected in market conditions and perceived on the demand side. Essentially, this difference can be attributed to imperfect information not addressed by market design. As shown below, the small size of the potential new flexibility resources and their location at the distribution-grid level play an important role in this regard.

Another distinct characteristic of decentralised flexibility resources is that their primary function is not to provide services to the electricity system. Therefore the planning horizon and availability for these services is different from traditional options. Market organisation and product design perfectly suited for centralised actors may imply additional uncertainties for small-scale actors (e.g., Cappers et al., 2012), although, they would not necessarily pose an additional risk to the system.

Accordingly, the distribution of responsibilities across the whole model of market roles is designed around a passive demand side. If predefined by legislation or market rules, however, delegation of responsibility may become a barrier to utilising decentralised resources in spite of potentially favourable economic incentives.

The market should take the structural characteristics of the demand side into account if its flexibility is to be developed as a resource option. In the following framework, to distinguish it from basic structural factors, market design refers to features founded in policy, market organisation and product design. It is analysed with regard to impacts on expected value, risks, and on the distribution of responsibilities. Table A.1 provides an overview of these distinctions.

Due to the developments described above, the value of flexible demand can be expected to increase and structural barriers should decline. To improve incentives on the demand side, the primary policy focus should be directed to the design-related barriers. With regard to regulatory intervention it is important to acknowledge that the design of incentives and the resulting informational flows contribute to the missing activation of demand-side flexibility potential. By looking into market rules and product definitions it can be shown for the Danish case how market design aspects and barriers relate.

The following sections at first evaluate design-based risks related to demand-side participation in existing flexibility markets. Subsequently, the design issue of imperfect information about the underlying value of flexibility is discussed. A third section deals with the distribution of market responsibilities and how the established market organisation may impede development of demand-side flexibility. All sections conclude with policy measures to address the identified barriers.

Table A.1: Market structure and market-design impacts on flexible demand

	Basic market structure	Market-design impacts
Expected value	Value based on: – Supply/demand balance – Price-elasticity – Technology – Costs	Low perceived value due to: – Imperfect information about location of supply/demand – Imperfect information about timing of demand
Risks	Risks due to: – Price-dependent revenue – Timing of response (availability) – Greater technical risks (reliability)	High perceived risks due to: – Difference between planning horizon and trading lead times – Penalties for non-availability – Unsuitable hedging instruments
Responsibility	Delegation due to: – Economies of scale – Efficiency gains from aggregation – Specialisation	Limited responsibility due to: – Pooling requirements – Defined information flows in market model

A.3 Risks related to product design

The underlying flexibility incentive of electricity market products relates to the supply and demand balance of flexible capacity within the respective time frames of the products. This is reflected in price differences encouraging a load shift, or price spikes (both upwards and downwards) encouraging a change in instantaneous consumption. An exception is a capacity market, like the one for reserves, that remunerates the potential for adjustments in production or consumption.

As the exact supply and demand situation for flexibility is uncertain the exact value of flexible capacity cannot be known in advance. This is a basic market risk that also will be reflected in the prices of the products; but as such it is not caused by the design of the products. In this section only design-related risks shall be discussed.

Table A.2 sums up the characteristics of different flexibility products traded publicly in the Nordic system. It shows basic market design aspects as well as the related barriers to demand-side flexibility due to product design. Many of the barriers can be associated with an increased risk in relation to the value of flexibility.

A.3.1 Trading lead times

The demand side is usually forecast on a day-ahead basis, sometimes merely based on fixed standard profiles. While providing active and reliable response requires precise forecasts, these also become more challenging to generate. Long lead times in traded markets will result in a higher risk of deviating from a promised response, although smart metering certainly would make better forecasting possible over a shorter time horizon.

As of now, traded markets require lead times and determine prices based on bids

Table A.2: Design-based barriers in flexibility products

	Market design	Design-based barriers
Forwards	– Continuous trading – Peak/base contracts – Price differences provide incentive for load shift – Value locked-in immediately – Quantity risk due to uncertainty about volumes and load pattern	– Timing structure does not reflect flexibility supply/demand – Minimum bid size of 1 MW
Day-ahead	– Daily auction with hourly resolution – Prices provide basis for optimal dispatch decision – Close to actual value based on marginal costs – Risk/opportunities from price spikes – Risk due to unplanned imbalances	– Trading lead times do not fit planning horizon – Minimum bid size of 0.1 MW
Intraday	– Continuous trading with hourly resolution – Adjustment market with limited liquidity – Reflects (firm) expectations about the state of the physical system close to delivery	– No auction to determine clearing price and gather liquidity – Automation may be required – Minimum bid size of 1 MW
Real time	– Physical deviations create demand for regulation – Available capacities submit hourly bids – Intra-hourly activation – Reflects immediate system costs of flexibility – Substantial price risk/opportunities	– Short activation lead time requires automation – Penalties for non-availability – Minimum bid size of 10 MW

from market participants. Ideally, the demand side would respond to prices reflecting real-time system conditions. Although the system operator publishes real-time balancing prices, under the current market rules they do not provide an incentive to utilise short-term flexibility. By definition, to encourage bidding into existing markets, passive regulation (without submitting regulation bids) cannot surpass spot market value. All relevant flexibility products are traded with specified lead times.

Daily unit commitment has been organised around big and centralised production units. The lead time required for their dispatch is very different from that of small-scale demand-side activities. Nevertheless, the hourly day-ahead price for most actors determines volumes planned to produce and to consume, respectively.

In the Nordic system, the day-ahead market forms the benchmark for the settlement of forward financial contracts (NASDAQ OMX, 2013). Also the day-ahead prices are used as a baseline for the real-time market (Energinet.dk, 2008). These structural facts make it a central market place for the trade of flexibility.

It has therefore been a prominent market place for the pass through of price signals to the demand side (e.g., Hirst, 2002). Day-ahead prices come close to the actual value of electricity in a specific hour and at times provide substantial incentives for demand response due to spikes or even negative prices in some hours.

Most demand-side actors, however, will not be able to schedule their response actions in advance with the necessary lead times. They will therefore not be able to recover the full day-ahead value. If their characteristics require shorter lead times, flexibility could instead be offered closer to real time on the intraday or regulating markets.

The intraday market is a short-term hourly market mainly used to react to new information and unforeseen events. Some design features of the intraday market make direct utilisation of the demand side a bit more challenging. It is based on continuous trading; the delivery for a particular hour may be traded at several different, potentially quite volatile, prices only valid for the two involved parties. Thus, it may be the case that the individual price and a resulting reaction are not based on the average value of flexibility.

The real-time or regulating market is organised by the transmission-system operator to ensure that no physical deviations occur. Available flexibility may bid into the regulating market while the flexibility demand arises from physical deviations from scheduled transactions resulting in an obligation to trade at the real-time system price. This market reflects the immediate system costs of flexibility and thus provides substantial value potential.

Activation of real-time resources happens in a cascade of automatic reaction of units within seconds and manual regulation within the time frame of minutes. The bidding lead time for regulation is 45 minutes. The activation lead time, however, will be a maximum of 15 minutes only. In most cases, additional investments in automation equipment are required if decentralised resources are to participate at all.

A.3.2 Penalties

Harsh penalties may be prohibitive to small and new market participants. In the traditional markets participants commit firm volumes. The day-ahead market conveniently determines prices before actual delivery, allowing them to be easily communicated to all relevant parties. But they will be the result of an auction requiring commitment of firm volumes. Deviations from committed volumes will usually have a value that is different from the discovered prices.

Closer to delivery, market prices approach the actual value of electricity at a particular point in time. Market trading still occurs after the day-ahead market has closed. This means that deviations incur costs, while the providers of flexibility generate additional income for providing the service.

Availability of committed capacity therefore is subject to risk. The risk may be increased by market design features, for example the above mentioned lead times. The cost should be determined by the basic market structure and reflect system costs to replace the capacity at short notice. This cost, however, may be further increased by the design of penalties forming an additional barrier for small market participants. Penalties can be included in balancing prices and in the rules for regulating power.

The risk of imbalances can hardly be avoided. The market-design aspect lies in the definition of balancing rules and price mechanisms. A penalty in imbalance prices can have the form of a simple premium. But it may also be the result of an inefficient regulating power market resulting in higher costs for balancing.

The regulating market, typically backed up by reserve markets, organises the forward trading of reliability provision. Flexible capacities may participate in these markets and receive payments for availability. The system operator commits these capacities to remain available for regulation within a specific time frame.

A risk for providers of flexibility lies in potential penalties from not providing the announced regulation. A particularly harsh penalty is the threat of disqualification from further market participation.

Clearly, the system operator requires reliable forecasts and resources to balance the system. However, even if aggregated in larger portfolios, decentralised resources will have difficulty marketing their flexibility through the traditional products if the risks of imbalances and penalties in the regulating markets are too high.

A.3.3 Hedging instruments

The participation of demand-side flexibility in electricity markets will most likely require upfront investments in additional communication infrastructure, automation equipment, and in-house displays (e.g., Strbac, 2008). As the long-term revenue from such investments will be uncertain to some extent, market participants may want to be able to hedge some of the involved risks.

At present, forwards are the only long-term contracts that may be used to lock-in the value of a load-shift potential, thus forming a basis for investments in necessary equipment. In the forward market, buyers and sellers commit to certain quantities before actual delivery, for example for the upcoming month over several years. Usually contracts are traded as peak or base load deliveries. Price differences between the two will provide incentives for flexible capacities to shift production or consumption from one period to the other.

Forward contracts for electricity deliveries are the basis for pricing most traditional end-customer contracts (see also Burger et al., 2007, p. 220ff.). Therefore expected price differences between peak and off-peak periods are passed through to the demand side. Accordingly, a customer who is able to influence his load shape may be able to achieve favourable prices in contracts based on the forward market.

A design issue with forwards is that as they represent expected averages over longer periods, incentive effects will be dampened. This is partially due to the fact that future load is unknown and it may not make sense to trade in more precise volumes, such as hourly profiles.

Large shares of demand-side flexibility potential do not fit with the design of forwards, limiting their usefulness as an instrument to hedge such activities. To support investments in responsive technologies different products or tariffs will be required.

A.3.4 Policy measures: Consideration of risks

Providing flexibility is a completely new function for most of the demand side. It may be a valuable service for the system but its value is very volatile and to a large extent uncertain. Precise timing and forecasting is crucial.

The availability of flexible demand-side resources is more uncertain than that of centralised units. In a system with large shares of intermittent production, the demand for flexibility also is uncertain. It may therefore become increasingly necessary to commit capacities closer to delivery and more frequent than is the case today. At the moment this need is met via intraday trading platforms. However, auctions may be a more suitable way to market small capacities. They would make pricing more transparent while also gathering the existing liquidity in the market and lowering the risk of failing to find a counterparty for an intraday trade. Having several auctions a day would be an option.

The Nordic regulating power market already provides a market place for short-term flexibility. The rules can be regarded as rather accommodating and generally suited for participation by decentralised actors. In particular, short lead times in the bidding process allow for small participants to gain a sufficient amount of information before submitting bids.

Still, the submission of bids and commitment of capacities may prove to be difficult with demand-side resources. For that reason, the concepts of bidless real-time markets (as proposed by Ding et al., 2012) would make it possible to provide prices ahead of the actual delivery and communicate respective signals (volume or price) to customers.

The risk of penalties in the Danish case is limited at present. A deviation from the schedule may, however, have a significant effect. Costs are incurred through the balancing mechanism. Its design should therefore consider whether a risk imposed through balancing costs is appropriate and not prohibitive for active demand-side participation. This to a large extent depends on competitive regulating markets that do not exclude any capacities from participating.

If investments are a prerequisite to participate in flexibility markets, uncertainty related to the long-term value of flexibility may become an issue. As described above, existing forward products seem to provide only limited help in this regard. As the forward market is organised by commercial actors, it is unlikely that new products will emerge in the short run. Complementary policies and pricing schemes that help demand-side actors to plan for longer time frames could be a temporary solution (see also Alexander, 2010).

A good example of investments based on long-term price incentives is the installation of large thermal stores at Danish decentralised combined-heat-and-power plants. They have mostly been based on a three-level tariff, which is only slightly more variable than the two levels of Nordic forward markets (cp. Togeby et al., 2009). Similar tariff schemes backed by legislation could be imagined for demand response as well.

A.4 Barriers to discovering the value of flexibility

Information about supply and demand for flexibility contained in the prices of existing products (Table A.2) is limited to the scope of the products. Any demand or potential supply that does not fit with the predefined timing or location will not be allowed to participate. Besides indicating a possibly low value of flexibility due to the basic market structure, the imperfect information may be one of the reasons why incentives from traded products are often found to be too weak to establish demand response (see Chao, 2010; Singh & Østergaard, 2010; Strbac, 2008).

The discussion in this section suggests that existing products and markets do not reveal the full value of flexibility. The decentralised part of the demand for flexibility is hidden. If flexibility remuneration mechanisms can be designed to reflect needs at higher resolutions in time and location, then it will become more attractive to activate decentralised resources.

A.4.1 Locational information

At some level of penetration with variable renewable production connected to regional and local grids, signs indicate a demand by the system that cannot be suitably addressed with existing products. If not coordinated, the use of some products at system level may even increase localised demands.

Local regulation and re-dispatch is already taking place on a bilateral basis to ensure power-system stability. The extent of such flexibility actions without public price signals may become significant with increasing shares of distributed production. One example is the extensive regulation of wind power in North-Eastern Germany (cp. Bömer, 2011). In 2012, the amount paid to regulate German renewable energy plants in this way was almost half of the amount spent on the comparable service of tertiary reserves the same year (cp. Bundesnetzagentur, 2013).

In the future, regulation in the opposite direction may become a growing issue. Such sub-market regulation is not reflected in current prices, raising questions about the possibility of including a larger share of the actual value of decentralised flexibility resources in existing or new market products.

According to the expectations about future challenges in distribution grids, it is likely that some value is hidden from the current markets at the regional and local levels. Challenges for distribution system operators will originate from increased installation of distributed generation and potentially from new electrical loads associated with electric vehicles and heat pumps.

If regulation services must be provided at lower voltage levels, demand-side resources would be very well suited to provide those (cp. e.g., Csetvei et al., 2011; Shaw et al., 2009). This will eventually help reduce the need for capacity investments (Dansk Energi & Energinet.dk, 2012). Value created in this way should be reflected back onto the actors creating it, which may allow some demand-side resources to become competitive with conventional measures (CIRED, 2013).

A.4.2 Timing prerequisites

Market-design barriers regarding the time frame for providing existing products are closely related to the characteristics and technical capabilities at the demand side. Decentralised flexibility resources will differ in the services they are able to provide (cp. Hirst & Kirby, 2001). Some may have limits regarding the duration of their response; others may not be able to return to previous load levels fast enough. Such resources have limited value within the current framework, although they could be well suited for new or slightly adjusted services.

In the Nordic system, both the day-ahead and the intraday markets are settled on an hourly basis. Any provider of flexibility on these markets, therefore, must be able to react for at least one hour. If load shifting is involved, both the increase and the decrease of load is required to have a duration of at least one hour. For many residential appliances this will be prohibitive unless they are pooled and controlled in an aggregated way to fulfil the market requirements.

The timing requirements of products on the regulating power market may be a challenge as well. Although Denmark provides rather flexible conditions in support of decentralised production units, integrating the demand side into this market remains a big step.

A.4.3 Policy measures: Product definitions to reveal full value

A market for flexibility services on a more local level is being widely discussed. On the one hand, such markets could help to solve regulation tasks at the distribution level. On the other hand, they may become necessary as a coordinating mechanism if increasingly transmission-system services are supplied by demand-side resources, thus putting more pressure on distribution grids (cp. Medina et al., 2010).

It is still somewhat open what kind of products should be traded on such markets (proposals for the Danish case can be found in Ding et al., 2013; Energinet.dk & Dansk Energi, 2012). One of the challenges is to design them in a way that does not conflict with the existing set-up at system level. Continuous coordination mechanisms between system and local levels will most likely be required (Friedrichsen, 2012).

In general, the demand for flexibility at the distribution-grid level is not easily addressed through market-based arrangements. At low-voltage levels, the need very much depends on the layout of the local grid infrastructure (DENA, 2012). Therefore, tendering standardised products may sometimes be difficult, as demand can be very specific. The grid operator should avoid paying for resources not actually required. Yet knowing when to upgrade the grid and socialise costs among all users instead of applying local incentives is also a critical policy issue (cp. Csetvei et al., 2011).

From a timing perspective conclusions on changes in market design seem less clear than from a locational perspective. To achieve full efficiency prices should reflect real-time conditions of the power system. However, it is not certain that such volatile price information would lead to the most efficient response from the demand side. Frequent price changes to prompt changes in consumption behaviour may result in consumers getting tired of reacting and, eventually, becoming less responsive (Kim & Shcherbakova, 2011). Of course, for automated load control this will not be an issue. Automated and manual demand response should therefore be targeted at different time scales.

A.5 Barriers in the design of roles and responsibility

Defining clear incentives and adequate risks towards the demand side is an important foundation for activating flexibility potential. Moreover, the incentive structures in the market also require a suitable division of roles and responsibilities. Adoption of demand response contracts and flexible technologies only makes sense in a model that can communicate the right information and make use of the responsive behaviour of small units.

Market-structural factors, such as costs and risks of participating in flexibility markets, naturally lead to an aggregation of capacities and centralisation of responsibility for such portfolios. However, various design elements contribute to predefining roles and responsibilities as well and these may impede the development of an active demand side.

Product definitions are important in this respect too as they implicitly or explicitly contain pooling requirements for participating capacities. But delegation may also be built into policies and market regulations, leaving no choice but to actively take responsibility.

Here the focus will be on information flows within the Danish model. Essential information on the demand for flexibility is contained in short-term price signals. Initially, the market-role model determines who receives such signals, defining the type of actors allowed in the market and how communication must take place amongst them.

On the other hand, communicating demand-side activities back to the market without significant delay is just as important. Besides the definition of market roles, balancing and settlement rules for demand-side volumes are important in predefining how potential flexibility is aggregated and whether it can be utilised in the market places.

A.5.1 Pooling requirements

To some extent, some of the market-design issues mentioned in Sections A.3 and A.4 are currently mitigated by the pooling of smaller capacities. If one unit cannot fulfil the requirements, then perhaps another portfolio of units will do so.

Minimum bid-sizes in the markets represent an explicit pooling requirement if small capacities are to participate. While the Nordic spot market enables trading of relatively small lots of 100 kW, long-term forward and intraday trades have to cover at least 1 MW. The regulating power market has a minimum bid-size of 10 MW.

Besides the mere volume requirements, timing also plays a role. The day-ahead and intraday markets cover settlement periods of one hour. Forward products cover far longer periods. The underlying physical capacities must match these time patterns as deviations will have to be settled in the balancing market at an additional cost. Portfolio aggregation is the only practical solution.

The attractive market for regulating power features a few more implicit pooling requirements besides the explicit minimum bid size. While committed capacity will have to stay available for at least one full hour, activation is scheduled only in 5-minute intervals. At the same time, complying with a potential activation of one whole hour or only five minutes may be very difficult without aggregation of many small units. Moreover, to mitigate the risk of a unit not being available for regulation it may become necessary to hold reserve capacity within the portfolio, depending on what level of penalties to expect.

The result is that the only practical access to flexibility markets is through centralised aggregation. Direct market participants will have to translate market products into products for the demand side. Pooling then can become complex and, inevitably, pooling providers will add risk premiums to cover any differences in value between wholesale and demand-side products.

This creates additional design-related costs for demand-side flexibility. Moreover the pooling of smaller capacities limits taking into account individual preferences. Unless it is possible to pool units with like preferences, this would reduce the efficiency of demand-side flexibility.

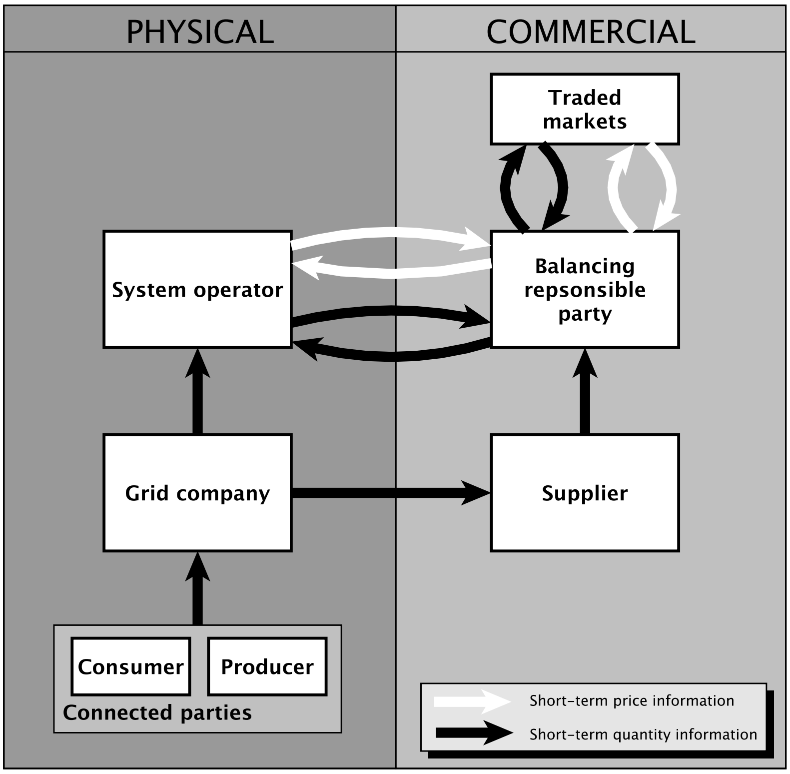

Figure A.1: Market-roles and short-term informational links in the present model

A.5.2 Information flows in the market-role model

All incentives must work along given lines of communication, determined to a great extent by the model of market-roles. In liberalised markets, the model assigns responsibilities to different actors and defines indispensable information flows. In this way, the market-role model enables efficient handling of the processes required to run functioning wholesale and retail markets while continuously maintaining system reliability.

The following observations are organised around the current Danish model of market roles (Energinet.dk, 2007). As the Danish model reflects the harmonised European electricity market-role model (ENTSO-E, 2011) the observations to some extent apply for other European markets as well.

The model of roles as shown in Figure A.1 describes informational flows between different actors related to price and quantities on a short-term basis (at least daily exchange of information). These flows are most relevant to the provision of flexibility.

The grid and system operators as well as grid-connected parties, both consumers and producers, make up the physical side of the system. The commercial actors are shown on the right side and consist of suppliers and balancing responsible parties [BRP].

Grid and system operators may set the terms and incentives to ensure reliability in the physical system entering into contractual relations with the commercial actors. Consumers as well as generating plants are obliged to enter agreements with a supplier that assumes the obligation to supply certain loads and to off-take produced electricity. The supplier then has to make sure that all production and consumption is part of a

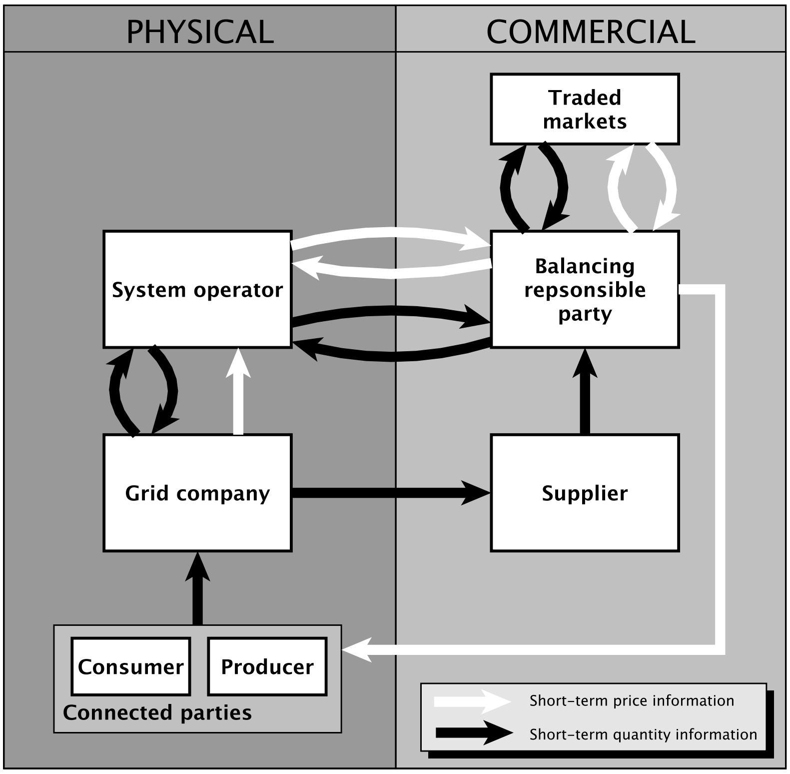

Figure A.2: Market-roles including DSO price information links

BRP's account.

Such contractual links often include some form of information exchange regarding volume and price. Those long-term links are omitted in Figure A.1 as they only contain limited information on the actual value of flexibility. Some degree of information may be transferred by implementing time-of-use pricing within a contract; the flexibility incentive, however, will be weaker.

Due to explicit and implicit pooling requirements, aggregation takes place on the commercial side as to make portfolios fit with wholesale products and system services. The only commercial party receiving initial short-term price information is the BRP. It is thus the only role that is obliged and incentivised towards the system operator to maintain a balanced portfolio in the short-term. This way, it has become the central role on the commercial side to communicate demand for reliability in the system by trading with other BRPs and by distributing control signals to connected parties possibly through their respective suppliers.

In principle the preconditions to market flexibility from demand-side actors are given, also under the present conditions and by the use of existing products. Most of the activities related to bringing new demand-side flexibility to the market would have to be organised around the role of the BRP. Either existing BRPs in the market would take that role, or alternatively other actors would have to assume the role of a BRP.

As the market model in its present form does not distribute price information to the demand side, this would have to be done by commercial actors as well. In that case, to establish the required informational links between demand side and flexibility markets, suitable commercial agreements would have to be negotiated (see also He et al., 2013).

In Figure A.2 communication between the BRP and connected parties is indicated by an additional price link. Signals to the demand side may instead contain quantity information or quantity-related information, such as temperature set-points see also, Ikäheimo et al. (2010, for examples of different signals).

New informational flows would also have to be established if flexibility products are to address a local demand. Figure A.2 also provides an example of how the informational flow from local grid companies could be extended to include signals about flexibility and its potential value. In this first, step it is not important to whom these signals are sent as long as they are received by one of the commercial actors.

A.5.3 Aggregation and settlement of demand-side volumes

At this point in time, it is still somewhat unclear which market role should be expected to initiate the development of decentralised flexibility resources. Internationally, countries are following diverse approaches (cp. Brandstätt et al., 2012).

Denmark is pursuing a market-based approach that puts responsibility for developing suitable products with the commercial actors to the greatest extent possible. Although some degree of direct regulation by grid operators may still be necessary (cp. Energinet.dk & Dansk Energi, 2012), this might conflict with the evolving retail market model (Danish Energy Agency, 2012). This new model is aimed at establishing the supplier as the single point-of-contact for end customers. This commercial role would clearly have to be included in the facilitation and operation of demand-side flexibility.

The challenges of pooling in order to participate in the market were described above. In addition, pooling only makes sense if balancing and settlement rules for the demand side are consistent with the requirements of market products.

As indicated by the black arrows from the connected parties and further upwards in Figures A.1 and A.2, short-term changes in demand-side volumes must be reflected back to the commercial side and onto the respective wholesale balancing accounts. At present, in Denmark as in many other markets, this only happens for large customers (annual consumption of at least 100 MWh).

Unless they accept a significant increase in their metering tariff, smaller customers will be settled based on the same hourly profiles valid for all customers in the distribution grid area. Even if hourly metering is installed, the actual consumption will not have an immediate effect on the market portfolio of the balancing responsible party. Thus, it will not be possible to earn a profit from potential response actions, which presents a severe design-related barrier to demand-side flexibility.

A.5.4 Policy measures: Ensure adequate aggregation

Enforced centralisation should be viewed as an important policy issue regarding the aggregation of demand-side flexibility. Aggregation should be an active choice based on fundamental economics and not a requirement in market regulations.

In the case of product definitions in the regulating power market the issue of bid sizes and demand-side participation is already being discussed by regulatory policy-makers (Bang et al., 2012). A change in the timing of products, however, does not seem to be on the way. The neighbouring German market, by comparison, has 15-minute settlement periods and is preparing to introduce 15-minute day-ahead contracts. For some decentralised resources this could be an attractive option.

Substantial changes to the model of market roles are unlikely in the near future, and activation of flexible resources has to primarily rely on commercial initiatives within the defined framework of roles. As long as reliability is maintained, it makes sense from the perspective of the system operator to keep this set-up. Adjustments could still be achieved by introducing new flexibility products.

Concepts of flexibility products at distribution-grid level are being developed. A model in which the system operator then would coordinate both local and system-wide flexibility demand and exchange information with the BRPs has been proposed by the Danish system operator (cp. Energinet.dk & Dansk Energi, 2012). Alternatively, grid companies could also enter into agreements with the commercial side directly.

At present, on the commercial side, BRPs are the central hub for flexibility information, while at the same time their connection to the demand side is still rather weak. This unbalanced constellation could impede the creation of a more active demand side.

The adoption of demand flexibility by commercial actors could be supported by establishing a more direct link to the relevant markets. With BRP aggregation there will be a chain of communication and contractual links between consumer and markets. While it may be possible to break up this chain or shorten some of the links by integration of roles or by commercial agreements within the present model, another option is to create a link by re-designing the market communication model.

This could imply introducing new roles or requiring different communication flows. With regard to local flexibility products, defining new responsibilities for demand-side aggregation might be considered, such that the provision of flexibility may be handled separately.

The introduction of a new aggregator role is frequently brought up in discussions about demand response, but it may be interpreted very differently (e.g., Ding et al., 2013; Energinet.dk & Dansk Energi, 2012; Ikäheimo et al., 2010). In principle, the role contains elements of both suppliers and BRPs in that it involves gathering a portfolio of customers like a supplier, while at the same time, at least to some extent, it includes responsibility for marketing flexibility (similar to a BRP).

How to treat this role within the market-role model is unresolved as it is somewhat unclear where it would fit into the picture. Some argue that although it would be necessary to establish such actors, they would still have to refer to a BRP that takes final responsibility for marketing and balancing of flexible capacities (as in Figure A.3). The Danish system operator favours such a set-up (cp. Energinet.dk & Dansk Energi, 2012). It does not necessarily add anything new, as it would essentially still be a BRP aggregation model.

It would mean a substantial change, however, if the new role represented self-contained flexibility aggregators. Such actors would have to be able to market flexibility independent of the supply of electricity. One aggregator presumably would have to refer to several BRPs, which would be somewhat contradictory to their aggregation role. It might be more obvious to let such aggregators refer to the system or grid operators directly to market their flexibility in a truly aggregated manner (see Figure A.4).

Some see such an aggregator role as new pivotal point for the marketing of flexibility services separate from existing roles (cp. Ding et al., 2013). However, as this model for some parts separates flexibility from the energy delivery, a flexible customer would have to be affiliated with both a supplier and an aggregator. While the supplier would

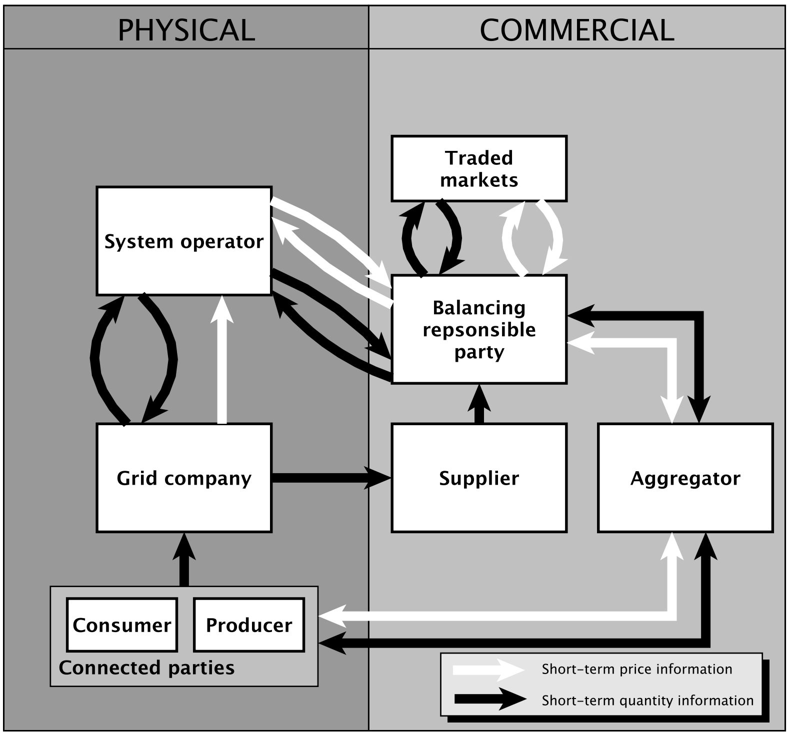

Figure A.3: Market-role model including aggregator

have to procure energy for the customer, the aggregator would need to manage the flexibility.

The advantage of a set-up with separate flexibility aggregation would be that it creates an open market with competition among aggregators over flexibility capabilities of the demand side. It would however, require substantial adjustments to settlement rules in order to not affect the balancing responsible of the energy deliveries. It may also open up the possibility of managing different appliances behind the same meter by different aggregators. For household customers, in particular, this may create more transaction costs than actual benefit.

While separating flexibility marketing may be a workable idea, the most practical model to implement it is probably to integrate the flexibility aggregation role with the supply task. In this model, retailers would also be able to aggregate and market the flexibility of their customers (Ikäheimo et al., 2010). This would ensure that although flexibility could be marketed directly (with for instance the grid company) all adjustments would happen within the same balancing account and settled volumes at the BRP level could be more easily corrected for flexibility actions.

Under a supplier aggregation model the coordination requirements for the system operator and potentially also the BRP will inevitably increase. The model may be attractive to the suppliers and in particular to the customers maintaining a single point-of-contact to the electricity market (cp. Scheer & Strömbäck, 2010). As acceptance and adoption is one of the major issues for demand-side flexibility, this may prove to be valuable.

Table A.3 provides an overview of consequences to the different market roles of the discussed approaches for allocating the demand-side flexibility aggregation task. Aggregation by BRP, supplier, or a new aggregator role is compared to the current

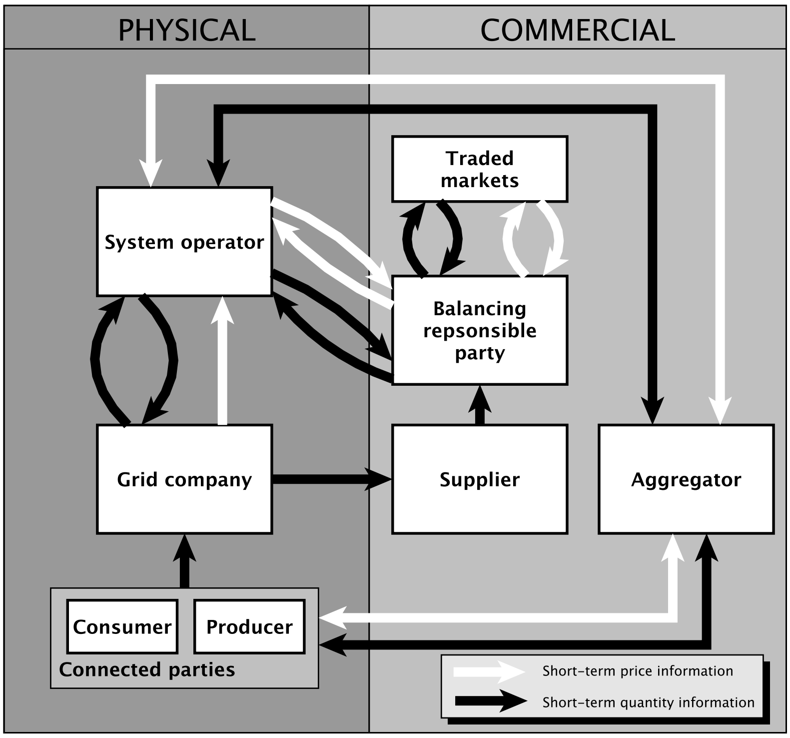

Figure A.4: Market-role model including aggregator with direct market access

status. Coordination requirements increase as soon as flexibility aggregation happens around the BRP. At the same time the opportunities for the provision of demand-side participation and new services will improve.

In any case it would first be necessary to establish adequate settlement rules. Real-time metering and frequent settlement is costly and not yet feasible for small consumer. The usual tariff for hourly metering with daily settlement lies at almost 700 EUR per year and will only be borne by larger customers.

For now, only proposals for intermediate solutions exist that aim at a compromise between efficient informational flows and cost by introducing hourly metering with monthly settlement (Danish Energy Regulatory Authority, 2012). This way the flexibility potential can only be utilised to a limited extent, as response actions would not have direct influence on the market portfolios. To communicate price signals towards the demand side, however, this is a good starting point that should be further developed.

A.6 Conclusion

As Section A.2 suggests, flexible capacities on the demand side may become valuable to the electricity system if enabled to take over reliability tasks. The level of adoption of this new function is critical for a policy strategy aiming at utilising demand-side flexibility potential.

Establishing informational links is a fundamental precondition for having the demand side actively participate in the market. While the smart meter roll-out is firmly seated on the political agenda, it is questionable whether the relevant actors can be

Table A.3: Implications of different aggregation models on market roles

Market roles	Continued BRP aggregation	Supplier aggregation	Separate aggregation role
System operator	– Additional coordination with distribution level	⟵ Potentially increasing coordination with new counterparties ⟶	
Grid company	⟵	Potential access to new services	⟶
BRP	– Dependence on cooperation with suppliers – Potentially increasing competition from new BRPs	⟵ Potential for cooperation ⟶ Potentially increased coordination	
Supplier	– Dependence on cooperation with BRP	– New business opportunities – New competencies required	– Potentially increased coordination – Increasing competition
Demand side	– New options offered by (potentially unknown) specialists	– Comfortable access through single-point-of-contact	– New options offered by (unknown) specialists – Potentially several new contractual counterparties
Aggregator	– Dependence on cooperation with BRP	– Dependence on cooperation with suppliers	– New business opportunities

forced to implement dynamic pricing or other incentive-based schemes and whether consumers can be motivated to adopt such schemes.

From a policy perspective, it will be important to establish economically efficient solutions that also work in an international context, especially within the common European electricity market. Emphasis has to be placed on the right issues. As Section A.2.4 points out, some barriers have their background in the fundamental characteristics of the electricity market structure such that intervention may create inadvertent inefficiencies.

The policy priority should thus be on addressing barriers in market rules, products, and existing regulation. This analysis identifies the design of incentives, their expected value and related risks as well as the distribution of roles and responsibilities, as key elements for successful activation of demand-side flexibility.

Important design-related barriers due to the implicit risks of applying existing market products to flexible demand were examined in Section A.3. They include short trading lead times, penalties and inappropriate hedging instruments. Regulatory options to consider include short gate-closure times and more frequent auctions. Moreover, pricing schemes with a high degree of certainty about price levels could improve investment incentives.

Imperfect information about the timing and location of physical demand for flexibility were described in Section A.4. A first step towards improving imperfect information about locational flexibility needs would be to implement coordinating mechanisms between the system operator and local grid operators regarding the demand and availability of flexibility. This would also be a precondition for efficiently utilising demand-side resources for system services. Such mechanisms may eventually develop into market platforms at the distribution-grid level. Information about timing may be improved by refining the rules of regulating power markets and possibly by shorter settlement periods.

Section A.5 looked into the delegation of responsibility from many decentralised actors to a few wholesale market participants as well as the route of information between markets and the demand side. An important precondition is to establish a settlement system that reflects response actions back onto market portfolios.

Regarding aggregation, the model of continued BRP aggregation has some clear advantages. It would keep flows simple and utilise established processes. However, it is dependent on cooperation between BRPs and suppliers and may favour incumbent market participants.

Separating responsibility for demand-side flexibility from the usual BRP tasks would indeed be another option, but it would require extending the current model with a new aggregator role. To avoid the risk of designing new barriers and additional transaction costs, it seems recommendable, to initially let existing roles (that is, suppliers) handle the aggregation task for demand flexibility, with only minor adjustments to the current market-role set-up.

A big challenge following the roll-out of smart metering lies in activating the potential for demand response by inducing the adoption of smart technologies and matching electricity market products. Future research should consider incentives and barriers faced by different kinds of demand-side actors, including the potential transaction costs. The expected increase in the demand for flexibility will be the major driver for new capacities. Market-design barriers should stay in the focus of researchers and policy-makers to not impede the development of beneficial flexibility.

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Paper B

Load-shift incentives for household demand response: Evaluation of hourly dynamic pricing and rebate schemes in a wind-based electricity system

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Abstract

Applying a partial equilibrium model of the electricity market we analyse effects of exposing household electricity customers to retail products with variable pricing. Both short-term and long-term effects of exposing customers to hourly spot market prices and a simpler rebate scheme are analysed under scenarios with large shares of wind power in a Danish case study. Our results indicate strategies that could be favourable in ensuring high adoption of products and efficient response by households. We find that simple pricing schemes, though economically less efficient, could become important in an early phase to initialise the development of household demand response. At a later point, when long-term dynamics take effect, a larger effort should be made to shift consumers onto real-time rates, and an increased focus on overall adoption of variable pricing will be required. Another finding is that demand response under variable pricing makes wind power more valuable. These gains in value reduce the need for support, and could be redistributed in further support of demand response.

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B.1 Introduction

Incentives for household electricity consumers to provide flexibility are increasingly being discussed to support the integration of intermittent renewable energies (Torriti et al., 2010). To do so, incentives need to be highly dynamic, and real-time pricing is frequently mentioned as providing highest economic benefits. Households may perceive dynamic pricing as complex and as potentially colliding with their preference for stability, predictability and low risk (Curtius et al., 2012; S. J. Darby, 2013). Because individual behaviour shapes household consumption (Rathi & Chunekar, 2015), it will barely be planned ahead of time and will most often not be automated or remote controlled. Demand response in this segment may therefore face a dilemma in that the economically most efficient pricing schemes will be too complex for the majority of customers to become interested in or react upon. If schemes are simplified, on the other hand, they will generate far less economic benefits, especially in systems with large shares of renewable generation. In this paper we contribute to evaluating this trade-off between economic efficiency and product simplicity by determining the effect of a simple rebate scheme as compared to dynamic hourly pricing.

While our analysis builds on general economic principles, we derive results in a stylised Danish setting, to illustrate the interplay of demand response with large-scale development of intermittent production. With Danish energy policy aiming at a fossil-free electricity supply in 2035 (Danish Government, 2011), wind energy is going to play a major role in the future (Kwon & Østergaard, 2012). In 2020 electricity generation from wind energy should make up close to 50% of annual consumption (Danish Government, 2012). The increasing volumes of wind power require sufficient flexible capacity to maintain a stable system, and with conventional power plants replaced by renewable generators, the Danish electricity system operator, amongst several other initiatives, aims at a better utilisation of demand-side flexibility (Energinet.dk, 2013); though this still is subject to removing various barriers within the regulatory framework (Katz, 2014).

We focus on household consumption, because in this segment we expect the trade-off between efficiency and effectiveness of incentives to be most significant. It has been established that household consumers hold a technical potential to provide flexibility (Gils, 2014). Several studies show that, when provided with economic incentives, they will utilise their potential and thus reveal some extent of elasticity towards short-term electricity prices (see Faruqui & Sergici, 2010, for an overview). For competitive retail markets it should be acknowledged, though, that consumers cannot be forced into specific schemes. They rather choose their pricing plans themselves and determine which products for demand response are going to be adopted.

Possible products have been discussed thoroughly (Albadi & El-Saadany, 2008) and may be categorised into price-based and volume-based schemes, depending on whether customers receive varying prices or are subject to direct constraints on their level of consumption (X. He et al., 2013). Demand response of households without the use of automation will typically have to occur under price-based schemes. Here we can distinguish three major types of rate designs (Cappers et al., 2012): 1) time-of-use pricing, 2) critical event pricing, 3) real-time pricing. The first type consists of a mostly static pattern of prices that make it less efficient in a system based on wind power like the Danish one. The latter two are more dynamic schemes. In critical event pricing

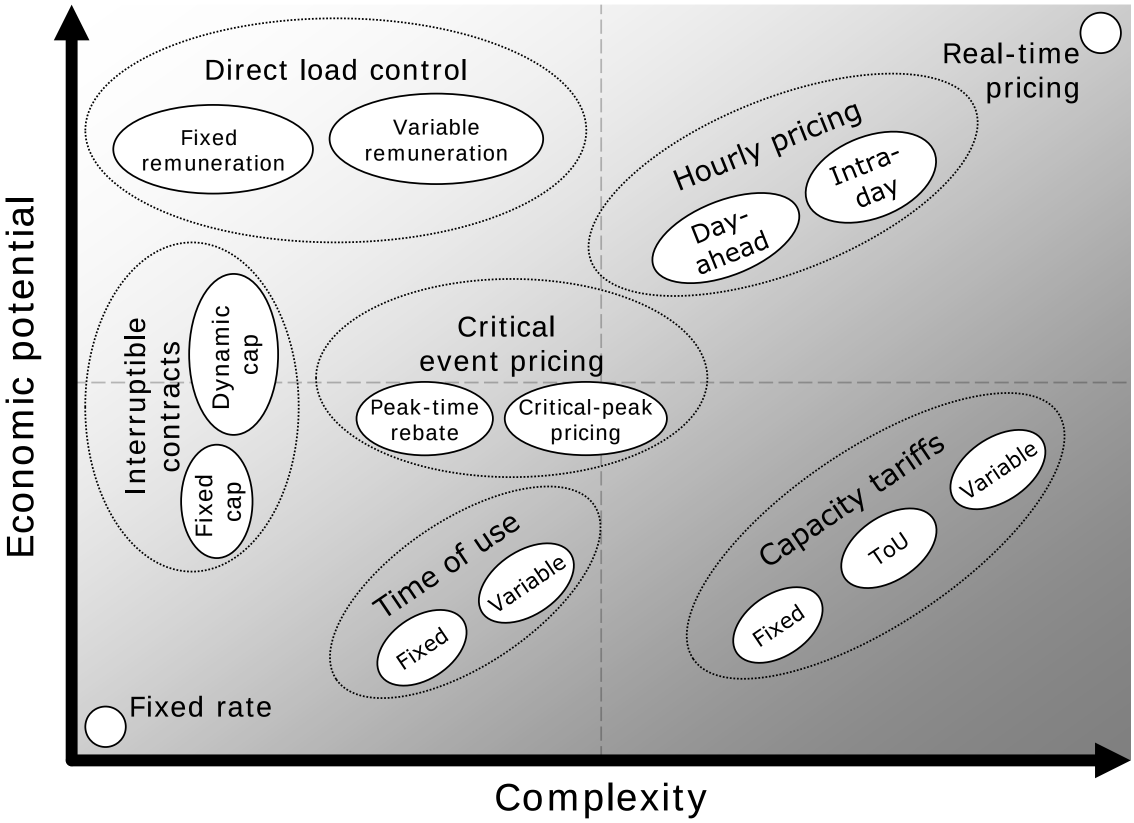

Figure B.1: Complexity and economic potential of different pricing schemes

customers are subject to a significant price increase or rebate at specific times considered critical. With real-time pricing customers receive frequently updated price signals reflecting system cost. While all of these schemes provide an incentive for demand response, they differ in their theoretical economic potential and in how effective they will be in practice.

Real-time pricing is the ideal scheme from an economic point of view (Vickrey, 1992) and should be well suited in a dynamic environment with large fluctuations from wind power. Recent experience shows, however, that real-time prices work best with automated control and may be less applicable to manual response (Lund et al., 2015; Vanthournout et al., 2015). Comparisons of dynamic pricing studies also reveal that higher elasticities are achieved under critical event pricing or time-of-use schemes than under real-time pricing (Conchado & Linares, 2012). Schemes with higher economic potential tend to be more complex from a customer point of view (Sarah J. Darby & McKenna, 2012) resulting in higher transaction costs (Faruqui et al., 2010), which in turn may reduce effectiveness by lowering adoption and response potential. Figure B.1 is an attempt to illustrate this trade-off by putting different types of pricing schemes into the two mentioned dimensions. So although real-time pricing in theory should be the best solution, it might not be in practice, when taking into account behavioural aspects of households like: response fatigue (Kim & Shcherbakova, 2011), risk aversion (Costello, 2004) and resistance to increasing transaction cost (Broberg & Persson, 2016).

In this paper we evaluate the economic benefits of an electricity retail product for demand response that is less complex than real-time pricing. We therefore compare economic gains of switching customers from a flat rate to hourly pricing to those of switching customers to a rebate product that customers should be better able to foresee the implications of. For that purpose we set up a partial equilibrium model of the electricity market based on hourly values (Section 2) and derive results for two different scenarios of wind production in a Danish setting (Section 3 presents the underlying case study assumptions). We then compare outcomes for the different retail price regimes (Sections 4 and 5).

As we will show in the following brief review of related work, elements of our study have been addressed in the literature previously. Economic analyses of demand response have been conducted in various studies and within different market and regulatory contexts (for an overview see Conchado & Linares, 2012). Where we identify a gap and contribute with this paper is in economic benefit analyses of different retail pricing schemes including long-term dynamics in a setting with intermittent renewables. Based on such analyses we will be better able to evaluate the gap in economic benefit that we might have to accept in order to achieve effective incentives in terms of adoption and response levels.

A number of studies conduct their analysis in a static setting assuming the response has no impact on prices. Many of these works consider real-time or hourly pricing: e.g. analysing heating and cooling in Texas (Yoon et al., 2014), household appliances in Ireland (Finn et al., 2011) and Germany (Gottwalt et al., 2011; Stötzer et al., 2015) or storage-like loads under German (Schreiber et al., 2015) and Danish (Biegel et al., 2014) conditions. Static prices simplify the analysis of different retail pricing structures, which might be the reason that besides real-time pricing also many analyses of simpler rate structures have been performed. Some of them study critical event pricing (Park et al., 2015; Schare, 2008), but most works look into the effects of time-of-use rates from the perspective of utilities (Y. He et al., 2012; Vera et al., 2013; Xu et al., 2015) or customers (Gudi et al., 2012; Zhao et al., 2013).

We choose an approach based on economic equilibrium modelling in order to account for the dynamic market impacts of demand response. After all the impact on prices and generation capacities has been one of the main arguments in favour of demand response. Even though many studies use a similar equilibrium approach, they do not necessarily take long-term dynamics into account. Such works acknowledge the price impact of the response, but keep supply capacities static. Analyses with a short-term focus have been carried out examining real-time or day-ahead pricing (e.g. in the US (Hirst, 2002; Sioshansi & Short, 2009; Spees & Lave, 2008), the UK (Green & Vasilakos, 2010; Roscoe & Ault, 2010), Slovenia (Kladnik et al., 2013) or Denmark (Andersen et al., 2006)), time-of-use and critical peak pricing (Faruqui et al., 2009; Moghaddam et al., 2011) as well as incentive-based response schemes (Aalami et al., 2010; Walawalkar et al., 2008). A short-term equilibrium approach provides a bit more insight into the market dynamics of demand response. To fully evaluate the impact of policies, however, the short-term approach should be accompanied by an analysis of the long-term equilibrium (Cepeda & Saguan, 2016). One particular formal equilibrium framework developed for demand response by Borenstein and Holland (2005) has been applied several times in different variations, showing how real-time pricing and resulting response of elastic demand generates significant benefits even with limited elasticities, for example, for US electricity markets (Allcott, 2012; Borenstein, 2005) and Norway (Kopsakangas-Savolainen & Svento, 2012). A related approach has been developed and applied to four weeks of Danish wind and demand data (De Jonghe et al., 2012).

Long-term models result in the construction of an electricity system with optimal generation capacities. Usually this neglects existing capacity in a market, assuming divestment from overcapacity. As long as the state of the system is not taken into account, the long-term equilibrium found remains somewhat theoretical. Energy system models take a step further. They require a high level of detail in representing the energy system often resulting in extensive computation requirements. Analyses have been carried out, for example, with a focus on demand response from residential appliances (Göransson et al., 2014; Pina et al., 2012; Rodrigues & Linares, 2015), heat pumps (Fehrenbach et al., 2014; Hedegaard & Balyk, 2013; Hedegaard & Münster, 2013) or electric vehicles (Hedegaard, Ravn et al., 2012; Juul & Meibom, 2011; Kiviluoma & Meibom, 2010).

Besides one analysis quantifying the impact of time-of-use pricing (Borenstein, 2005), the above long-term equilibrium studies do not take into account retail products that are less complex than hourly pricing. While hourly pricing may be the efficient and a realistic option, one has to take into account the restrictions of individual consumers in reacting to hourly prices and their potential reluctance in adopting such schemes (Dütschke & Paetz, 2013). The impact of rebate pricing or other critical event pricing has only been analysed in short-term modelling frameworks (Faruqui et al., 2009; Moghaddam et al., 2011) or estimated on the basis of empirical data (Fenrick et al., 2014; Herter, 2007).

Increasingly renewable energies have become an argument in favour of demand response and benefits are expected to become even more distinct. The economic impacts of large shares of renewables have been studied in equilibrium settings, without including demand response (e.g. for Southern (Mendes & Soares, 2014; Sáenz de Miera et al., 2008) and Central European markets (Obersteiner & Saguan, 2011; Rosen et al., 2007)). Some studies take into account demand response and renewables but limit analysis to a local grid (Zareen et al., 2015), apply a static market setting (Batas Bjelić et al., 2013; Hedegaard, Mathiesen et al., 2012; Kwon & Østergaard, 2014), or derive short-term equilibria (Green & Vasilakos, 2010; Roscoe & Ault, 2010; Sioshansi & Short, 2009). The long-term interaction of renewable energies with demand flexibility is most thoroughly analysed in the energy system studies mentioned above. These studies however assume optimal response to real-time system prices and do not consider specific retail product structures. This is where we set in with this paper.

B.2 Method

B.2.1 Market model

The model developed is a closed-market model without interconnections to other systems. To find a short-term equilibrium requires a specification of demand and supply curves based on the characteristics of generators and consumers and their respective marginal cost and benefit functions.

The demand side is characterised by a price elasticity of demand that may be defined in several ways depending on the underlying model of individual utility (Ramskov &

Munksgaard, 2001). Moreover one has to distinguish between elasticity of demand due to price changes of the good itself (own-price elasticity) and of other goods (cross-price elasticity). Here we focus on own-price elasticity. We use constant elasticities defined as the percentage change of quantity Q given a percentage change of the price P (Wetzstein, 2013):

$$\varepsilon = \frac{dQ}{dP}\frac{P}{Q} \tag{B.1}$$

Our focus lies on the short-term elasticity of electricity demand, which is expressed in adjustments along a demand curve that is static within the analysed time horizon. Sometimes this is referred to as the real-time price elasticity (Lijesen, 2007). We do not consider structural changes in electricity demand due to investments in appliances on the basis of the long-term price level (Genc, 2016). Moreover, potential effects from changes in income are not included (Jamil & Ahmad, 2011). This is a simplification we consider acceptable, as individual changes in income based on savings from variable pricing will be relatively small.

Our constant-elasticity demand curves have the form:

$$D_t = D_{0,t}\left(\frac{P_t}{P_0}\right)^{\varepsilon} \tag{B.2}$$

With:

D_t: Demand in hour t
$D_{0,t}$: Baseline demand in hour t
P_t: Price in hour t
P_0: Anchor price
ε: Price elasticity

The model requires a baseline demand $D_{0,t}$ and an anchor price P_0 as a starting point for any response. While P_0 is a fixed anchor price, $D_{0,t}$ changes on an hourly basis. P_0 is set such that it reflects the efficient level of the flat-rate tariff in the reference case.

The marginal benefit function is derived from the demand function incorporating both the demand from consumers on a flat-rate tariff and consumers on a variable tariff such that:

$$D_t = D_{0,t}\left(\alpha\left(\frac{P_t}{P_0}\right)^{\varepsilon} + (1-\alpha)\left(\frac{P_f}{P_0}\right)^{\varepsilon}\right) \tag{B.3}$$

With additional parameters:

α: Share of consumers on variable prices
P_f: Flat-rate price

Rearranging for the price P_t to find the inverse demand function (Kirschen & Strbac, 2004), provides us with the aggregate marginal benefit function:

$$MB_t = P_0\left(\frac{1}{\alpha}\left(\frac{D_t}{D_{0,t}} - (1-\alpha)\left(\frac{P_f}{P_0}\right)^{\varepsilon}\right)\right)^{\frac{1}{\varepsilon}} \tag{B.4}$$

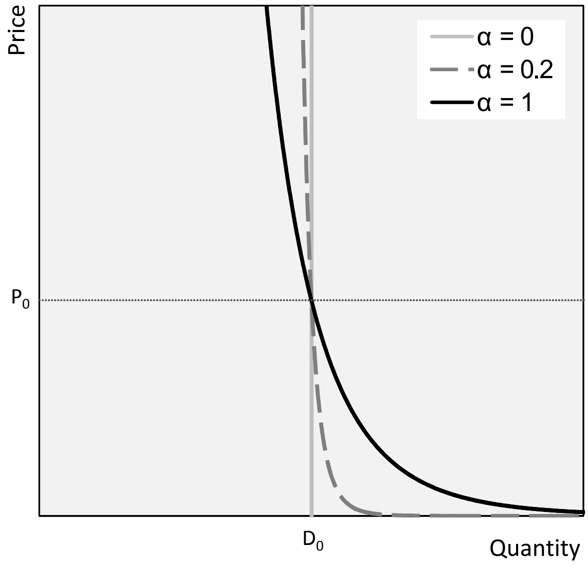

Figure B.2: Aggregate demand curve for different shares of variable price customers

Here we have to ensure that $D_t > D_{0,t}(1-\alpha)(P_f/P_0)^{\varepsilon}$, i.e. total demand will never be less than the demand of flat-rate customers.

With a flat rate P_f equal to P_0 and a 100% share of flat-rate customers the model simply yields the load curve $D_{0,t}$. If a share of customers is exposed to spot prices, total demand follows the curve described by equations (B.3) and (B.4). For increased elasticity ε and increased share of customers on variable prices α market demand becomes more elastic. For a given price elasticity ε, Figure B.2 illustrates the shape of the demand curves at different adoption levels of the variable pricing scheme.

To model generation we use a step-wise supply curve. Supply is based on wind power and three generic thermal technologies: base load, mid-merit and peak load capacity. The short-term marginal cost function is a piecewise linear function as illustrated in Figure B.3 and described by:

$$MC_t = \begin{cases} c_{var,wind} & \text{for} \quad D_t \leq Q_{wind,t} \\ c_{var,base} & \text{for} \quad Q_{wind,t} < D_t \leq Q_{wind,t} + K_{base} \\ c_{var,mid} & \text{for} \quad Q_{wind,t} + K_{base} < D_t \leq Q_{wind,t} + K_{base} + K_{mid} \\ c_{var,peak} & \text{for} \quad Q_{wind,t} + K_{base} + K_{mid} < D_t \leq \\ & \qquad\qquad Q_{wind,t} + K_{base} + K_{mid} + K_{peak} \end{cases} \tag{B.5}$$

With:

$Q_{wind,t}$: Quantity supplied by wind in hour t
$K_{base/mid/peak}$: Installed capacities of respective technology
$c_{var,wind/base/mid/peak}$: Variable costs of respective technology

A computational difficulty occurs at the shift of one technology to the next, as well as when demand exceeds supply capacity. We therefore insert steep slopes at these positions of the supply curve to avoid vertical curve sections. These enable us

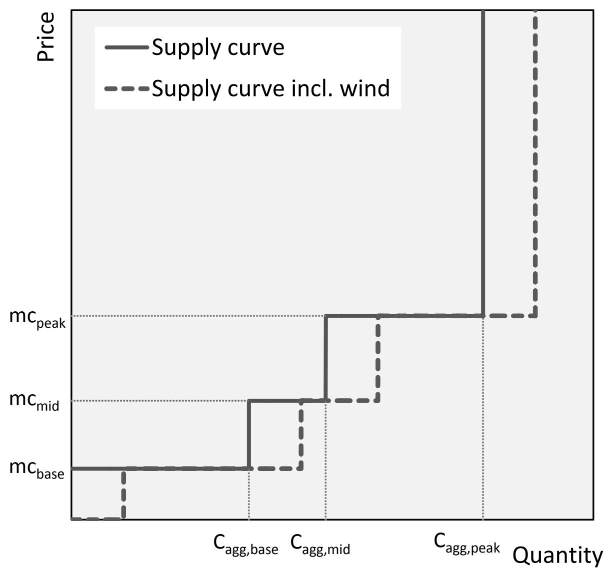

Figure B.3: Stylised supply curves with and without wind production

to determine equilibrium prices at any point and ensure market clearing in every case. Most importantly, we may approximate finite price spikes without having to set a price cap. The sloping sections are defined such that:

$$MC_t = c_{margin,t} + k\left(D_t - Q_{sum,infra,t}\right) \quad \text{for} \quad K_{sum,infra} < D_t < \frac{c_{var,extra} - c_{margin,t}}{k} \tag{B.6}$$

With:

$c_{margin,t}$: Variable costs of the marginal technology in hour t
$Q_{sum,infra,t}$: Sum of inframarginal production incl. wind in hour t
$c_{var,extra}$: Variable costs of next extramarginal technology
k: Emergency slope

In theory the factor k, representing the slope between steps, has an infinite value. Using a sufficiently large number will result in practically vertical slopes. We can interpret the minor additional capacity as emergency generation only utilised during short periods of time (Stoft, 2002). We use a constant value for k of 10^6.

B.2.2 Determining equilibrium

The above supply and demand curves enable us to calculate a short-term equilibrium by setting marginal cost equal to marginal benefits in every time step. We derive a set of hourly prices that, in combination with the respective technologies' cost structures, determines generator revenues. Profits are then determined as:

$$\Pi_{gen} = \sum_{t=1}^{T} \left(Q_{gen,t}\left(P_t - c_{var,gen}\right)\right) - K_{gen}\, c_{fix,gen} \tag{B.7}$$

With:

$Q_{gen,t}$: Quantity supplied by generation technology in hour t
K_{gen}: Installed capacity of generation technology
$c_{var,gen}$: Variable cost of generation technology
$c_{fix,gen}$: Fixed cost of generation technology

In the long run generators have the possibility to adjust their capacities. New entrants may join the market, or plants may be shut down. This process continues until capacity reaches a new long-term equilibrium, where adding additional capacity would result in overall losses, while reducing capacity would result in profits attracting new entrants and a capacity increase.

Retailers will have to buy volumes supplied to their customers at the equilibrium wholesale prices. The retail market will reach equilibrium, when retailer profits become zero. Eventually, consumers will therefore pay a price exactly covering whole-sale procurement costs of their suppliers, and retailer profits would be determined as:

$$\Pi_{retail} = \sum_{t=1}^{T} \left((P_f - P_t)\, D_{0,t}\, (1-\alpha) \left(\frac{P_f}{P_0} \right)^{\varepsilon} \right) \tag{B.8}$$

Equation (B.8) is valid as long as variable pricing customers exactly pay the wholesale market price, thus, not affecting retailer profits. Below we define a slightly different version of the retailer profit function if the variable retail price and the wholesale price are not necessarily equal (as in the analysed rebate pricing schemes).

Figure B.4 illustrates the steps to take in determining short-term and long-term equilibria. As a reference we first establish an equilibrium without any variable retail rates largely resembling the situation of today ($\alpha = 0$). We determine a set of generation capacities that results in a profit of zero for all generators. This is done by: 1) setting peak generator capacity to supply all of demand at zero profits, 2) substituting peak generator capacity with mid-merit capacity until both produce at zero profits, and 3) substituting mid-merit capacity with base-load generation until all generators, except for wind, produce at zero profits. We then find the flat retail rate that exactly covers wholesale market procurement cost of the retailer if consumption equals D_0 (which will be the case at $P_0 = P_f$).

When customers switch to variable prices ($\alpha > 0$), consumption and price in all of the hours changes according to the price elasticity of demand. To compensate for the retailer profits generated by a change in wholesale prices a new flat rate has to be determined. A change in consumption also affects producer revenues. In order to fulfil the equilibrium condition of zero profits will therefore require adjusting capacities until we reach a new long-term equilibrium state with both generator and retailer profits at zero.

B.2.3 Determining the economic benefits

Overall economic benefits are determined as the net-change in consumer and producer surplus. Due to retail market competition retailer profits will be at zero. Producer surplus, defined by the difference between costs and revenues, will also be at zero in long-term equilibrium as revenues exactly cover fixed costs. This does not, however, apply to wind power producers; here we allow for the exception of non-zero profits.

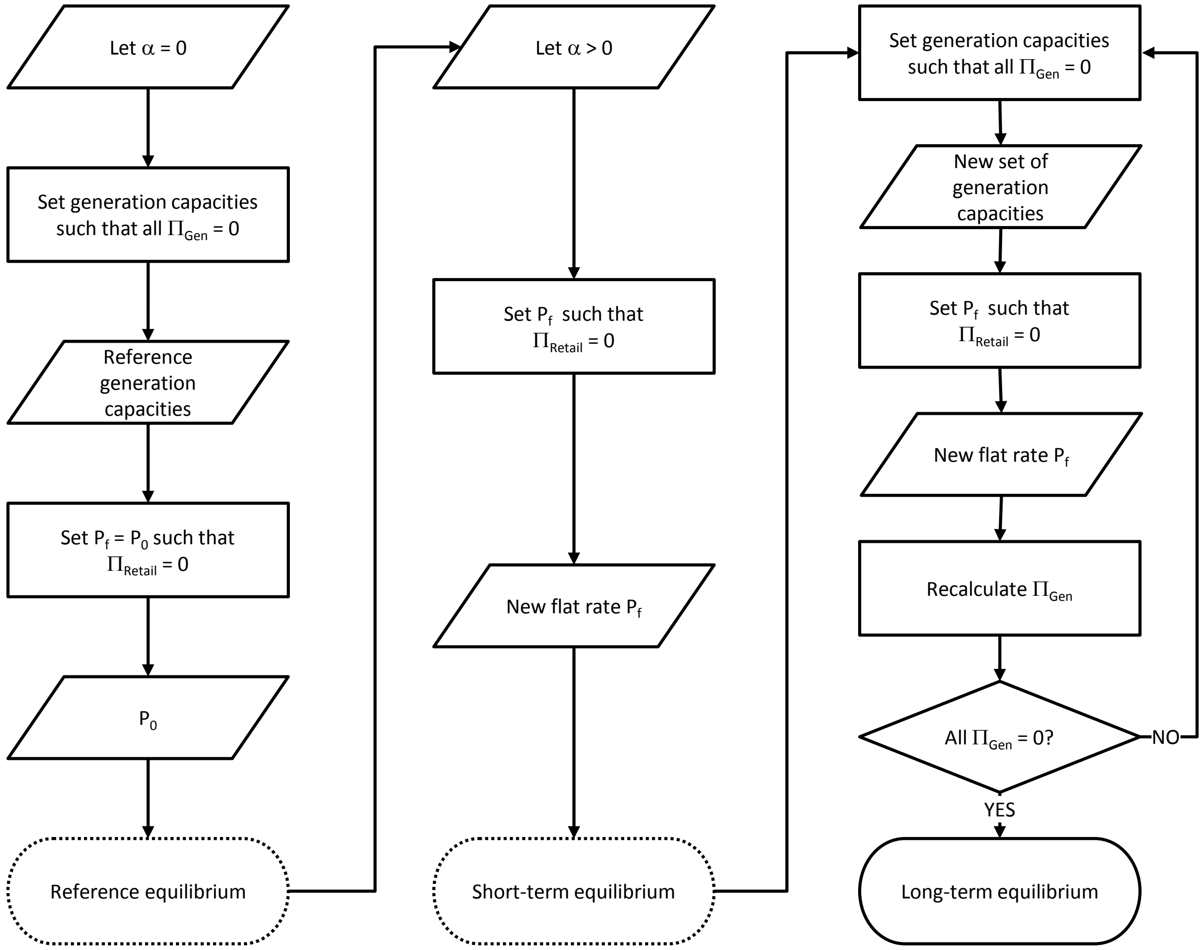

Figure B.4: Algorithm to determine short and long-term equilibria

The relatively high investment cost of wind power would usually result in losses that we assume support payments to compensate for. We can then account for a change in support payments caused by the introduction of variable pricing in the overall net benefits.

The change in consumer surplus, from a situation with all costumers on fixed prices to a new option with variable pricing, can be measured using the demand curve and the new set of prices. Figure B.5 illustrates the change during one time step t as an area to the left of the marginal benefit curve in equation (B.4). As the marginal benefit curve is the inverse of the demand curve the area in Figure B.5a corresponds to the area under the demand function shown in Figure B.5b. We can thus take the integral of equation (B.3) over the price difference to determine the following expression for a change in consumer surplus per time step t:

$$\Delta CS_t = \alpha D_{0,t} \frac{P_0 - P_t \left(\frac{P_t}{P_0}\right)^{\varepsilon}}{\varepsilon + 1} + (\alpha - 1)\, D_{0,t} \frac{P_0 - P_f \left(\frac{P_f}{P_0}\right)^{\varepsilon}}{\varepsilon + 1} \tag{B.9}$$

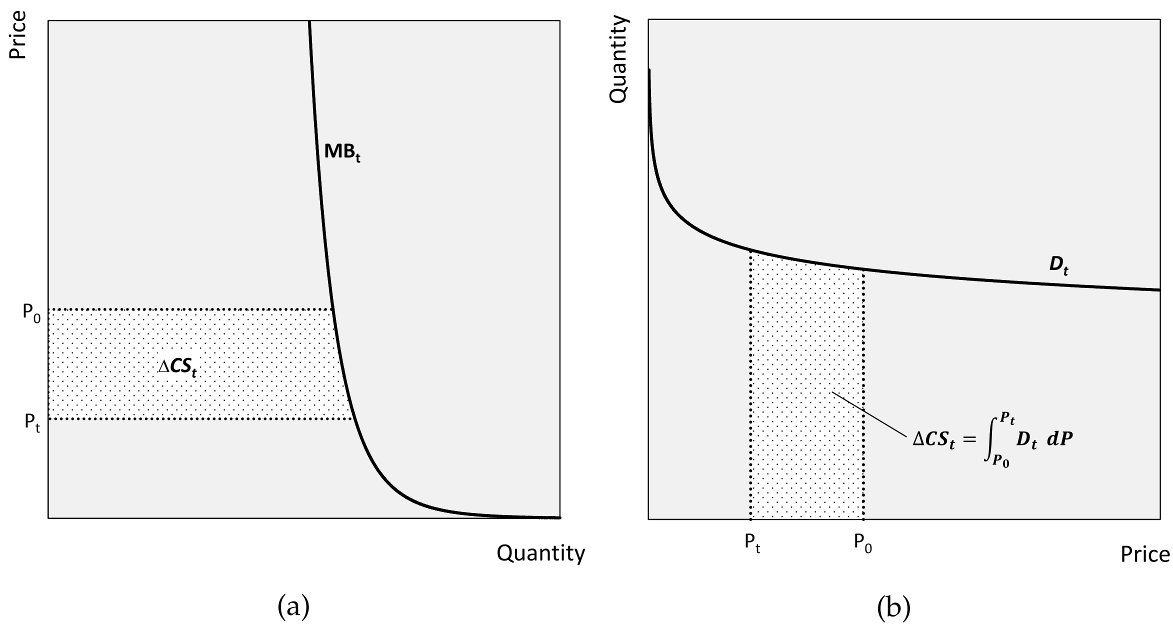

Figure B.5: Change in consumer surplus to the left of the marginal benefit curve (a) and equivalent area under the demand curve (b)

B.2.4 Modelling of rebate pricing schemes

In modelling the load-shift rebate we want to reward only volumes shifted – payments for all other volumes stay the same as for flat rate customers. Although the rebate is not applied to the full volume, customers will have a marginal benefit on their consumption of the full rebate. Demand of rebate customers can thus be determined in line with equation (B.3) as:

$$D_{reb,t} = \alpha D_{0,t} \left(\frac{(1+r)\, P_f}{P_0} \right)^{\varepsilon} \tag{B.10}$$

To settle such a product we need to establish a baseline in order to measure the load shift. The base-line consumption $D_{BL,t}$ is determined as the expected consumption of rebate customers at a rebate of zero:

$$D_{BL,t} = \alpha D_{0,t} \left(\frac{P_f}{P_0} \right)^{\varepsilon} \tag{B.11}$$

The aim of the product is to react upon system conditions. Therefore the rebate will depend on the difference between the average flat rate price and the price during a predefined critical period. If during a particular rebate period T_{reb} spot prices on average show a price difference to the flat rate, then the rebate gets triggered. A threshold value r_{thr} may be added to avoid the provision of large rebates for relatively small deviations. During every single rebate period the rebate r is thus based on a predefined percentage rebate level r_{level} and determined as:

$$r = \begin{cases} r_{level} & \text{for} \quad \overline{P}_{t\in T_{reb}} > (1 + r_{thr})\, P_f \\ -r_{level} & \text{for} \quad \overline{P}_{t\in T_{reb}} < (1 - r_{thr})\, P_f \\ 0 & \text{otherwise} \end{cases} \tag{B.12}$$

Depending on whether customers are expected to increase or reduce consumption in a given period the rebate r will now be either negative or positive. With the rebate determined by equation (B.12) during critical periods the electricity cost of a customer is calculated as:

$$C_{rebate,t} = P_f \left(D_{BL,t} + (1 + r) \left(D_{reb,t} - D_{BL,t} \right) \right) \tag{B.13}$$

Equation (B.13) should result in savings only if $D_{reb,t}$ deviates from $D_{BL,t}$ in the requested direction. Otherwise r should equal zero and costs will simply be based on the consumed volume times the flat rate P_f. This is important in contractual terms, but we do not add this condition here, because with demand determined by equations (B.10) and (B.11) this will always be the case due to the sign of the rebate.

Dividing equation (B.13) with the consumption of rebate customers $D_{reb,t}$ yields the average price a rebate customer pays for the full consumed volume during a rebate period – again provided the customer reacts as requested. The result may be simplified to:

$$P_{rebate,t} = P_f \left(1 + r - r \frac{D_{BL,t}}{D_{reb,t}} \right) \tag{B.14}$$

Figures 6 and 7 illustrate the changed marginal price level, which is the flat rate adjusted for the rebate, and the resulting relative average price ($P_{rebate,t}/P_f$) during critical periods for a rebate of 50%. While customers never pay more than the original flat rate, the marginal values under this scheme always create an incentive to shift demand in the required direction.

A long-term equilibrium is not easily established for the rebate pricing scheme. As for other averaging variable pricing schemes, like for example time-of-use pricing, convergence is not guaranteed (Borenstein, 2005). In our case, rebates should ideally be based on the actual price outcome, which in turn is affected by the behaviour of rebate customers. We avoid such feedback loops by setting rebates once for all based on prices in the reference case. Price changes in the variable pricing case are not allowed to further affect rebate levels.

As for the hourly pricing cases we establish a retail market equilibrium by requiring zero retailer profits. The rebate customers do not pay the wholesale price, though, and thus affect retailer profits. We therefore need to adjust equation (B.8) accordingly:

$$\Pi_{retail} = \sum_{t=1}^{T} \left(\left(P_f - P_t \right) D_{0,t} \left(1 - \alpha \right) \left(\frac{P_f}{P_0} \right)^{\varepsilon} + \left(P_{rebate,t} - P_t \right) D_{reb,t} \right) \tag{B.15}$$

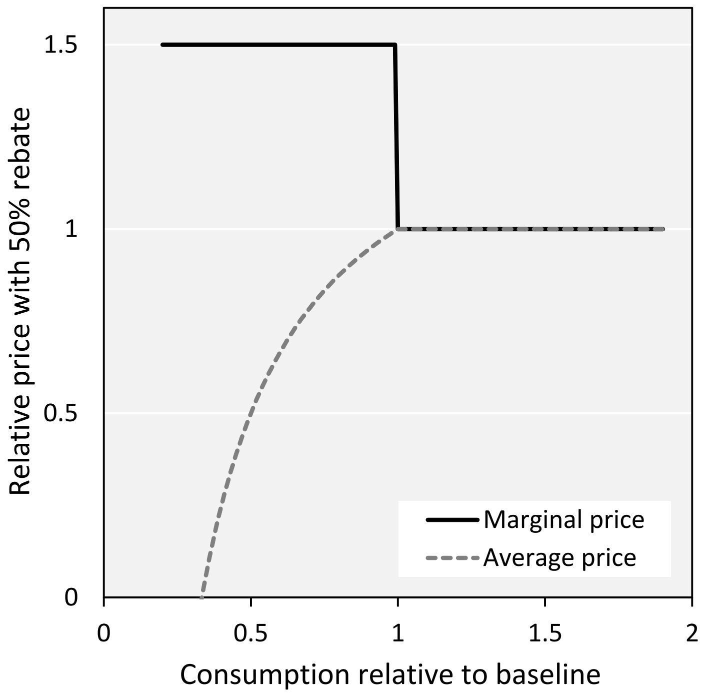

Figure B.6: Rebate for reduced consumption

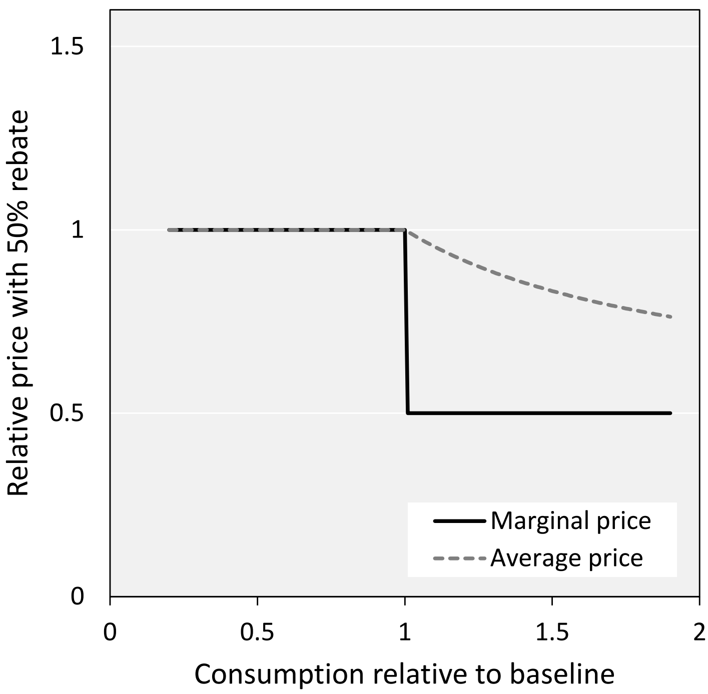

Figure B.7: Rebate for increased consumption

B.3 Case study assumptions

B.3.1 Demand side

Consumption profiles

A fundamental input to the model is the baseline demand D_0. We use the aggregate Danish consumption profile of 2012, however, only of consumers not settled on an hourly basis (Energinet.dk, 2015a); that is, consumers with an annual consumption of less than 100 MWh. We focus on this particular group of customers, because we want to isolate the impact of a shift to variable pricing for customers without access to variable pricing schemes in the current regime.

The price elasticity of demand is another crucial input. Although the exact elasticity will affect the overall absolute results, for our purpose it is most important that customers are price elastic at all. We therefore assume a fixed elasticity value and use -0.1 in line with various previous publications (Conchado & Linares, 2012; Lijesen, 2007; U.S. Department of Energy, 2006). Table B.1 summarises the main features of the demand assumptions.

Table B.1: Main features of demand input data

		Demand input
Total consumption	GWh	15,729.40
Max. consumption	MW	3700.8
Min. consumption	MW	824.6
Elasticity	-	-0.1

Retail pricing schemes

We analyse four different retail pricing schemes. The first one is an hourly real-time pricing scheme reflecting wholesale market prices. The three remaining cases are variations of the rebate pricing scheme as described in section B.2.4.

The parameters of the rebate scheme should be kept simple from a customer point of view. Therefore customers will only be asked to shift volumes relative to a time window of three hours. The difference between the analysed cases lies in the time of day defined as rebate periods. In two of the cases periods are fixed, while the third case operates with a dynamic time window. As the response potential of household customers, in particular, is expected to be highest in the evening hours we analyse cases covering the early evening hours (16.00-19.00) as well as later hours (20.00-23.00). In the following we refer to these products as *"Rebate Evening"* and *"Rebate Night"*. In the dynamic case (*"Rebate Dynamic"*) we determine the daily rebate period such that it covers the three-hour period with the largest price deviation, in any direction.

The input parameters for the rebate cases are summarised in Table B.2. In all cases shifted volumes generate a rebate of 50% of the retail price. A signal to customers is triggered, whenever the average hourly price level within the defined time window differs from the flat rate price with more than 10%. This built-in threshold is to ensure that the response generates sufficient value at wholesale level.

To not further complicate social benefit calculations all levies and taxes are left out of the picture. This is important to keep in mind, when interpreting the results. The consumers thus respond to prices as if taxed on an ad valorem basis instead of the usual unit tax.

Table B.2: Input data for rebate pricing cases

			Rebate	
		Evening	*Night*	*Dynamic*
Rebate	% of flat rate	50%	50%	50%
Rebate period	Hours of day	17-19	21-23	3 hours with largest Δ
Rebate threshold	% of flat rate	10%	10%	10%

Adoption scenarios

We calculate results for different adoption rates of variable pricing, and a reference case with all customers on a flat retail rate. For all of the different retail pricing cases, we calculate the effects of 20% of customers under the scheme and of all customers adopting the scheme. The 20% scenario should reflect a realistically achievable potential, while the 100% is calculated as a reference showing the maximum potential under the different schemes.

B.3.2 Supply side

Generation

We use fixed and variable costs for three stylised thermal generation technologies and wind power as shown in Table 3. Cost and technology data are based on the Technology Catalogue of the Danish Energy Agency (Danish Energy Agency & Energinet.dk, 2015). All costs are adjusted for inflation to the price level of 2016. Prices of fuels and CO_2 are based on a simple average of forecasts over the lifetime of the respective technologies (Danish Energy Agency, 2016).

Wind power scenarios

Two wind power scenarios are defined to determine the impact of an increase of variable production. The first scenario ("Base wind") applies an hourly profile of the wind share in consumption in 2012. Using shares instead of the actual production values allows us to scale the wind profile to the share of consumption that we analyse. The annual share of wind power in consumption for this case is around 31%. In the second scenario ("High wind") we increase the share to 50% of consumption.

To estimate the costs of wind power we weight the assumptions in Table B.3 to reflect the relative shares of onshore and offshore wind installations. In the base wind scenario we use a share of 25% offshore wind installations approximately reflecting current levels, while in the high wind scenario we assume an increase of offshore installations to 35% of installed wind power in line with scenarios by the Danish TSO (Energinet.dk, 2015b). The installed wind power capacity is determined based on the maximum annual wind production assuming that the production peak will lie at 92% of installed capacity.

Table B.3: Input costs of stylised generation technologies

		Base	**Mid**	**Peak**	**Wind (onshore)**	**Wind (offshore)**
Fixed costs						
Specific investment	M EUR/MW	2.19	0.93	0.7	1.29	3.61
Lifetime	years	40	25	25	20	25
Discount rate	%	4%	4%	4%	4%	4%
Equivalent annual cost	EUR/MW	110,764	59,849	44,715	94,891	231,140
Fixed O&M cost	EUR/MW	61,471	32,240	0	0	0
Total fixed costs	**EUR/MW**	**172,235**	**92,089**	**44,715**	**94,891**	**231,140**
Variable costs						
Plant efficiency	%	46.00%	56.50%	39.50%	-	-
Fuel	-	Coal	Gas	Gas	-	-
Emission	ton/GJ-fuel	0.094	0.056	0.056	-	-
Fuel price	EUR/GJ-fuel	3.05	7.14	7.14	-	-
CO_2 price	EUR/t-CO_2	14.47	12.97	12.97	-	-
Fuel cost	EUR/MWh	23.9	45.48	65.06	0	0
CO_2 cost	EUR/MWh	2.96	1.29	1.84	0	0
Variable O&M cost	EUR/MWh	2.15	2.69	3.44	10.75	20.42
Total variable cost	**EUR/MWh**	**29.00**	**49.46**	**70.34**	**10.75**	**20.42**

B.4 Results

B.4.1 Base wind scenario

Hourly pricing

Table B.4 provides a summary of the results for the hourly retail pricing scheme under the base wind scenario showing the different cases horizontally and the results within several categories vertically. We will present results in similarly structured tables for all cases throughout this section.

The first vertical section of the Table B.4 provides an overview of consumption and generation. For the consumption total annual volumes and the annual peak level is shown. On the supply side the installed capacities are shown together with the full load hours for each of the three dispatchable generation types: base load, mid-merit and peak load. Wind volumes are not shown as they are constant throughout all the cases within the same wind scenario.

In all simulated cases total consumption increases as compared to the reference case. A part of the increase will again rebound towards the reference level in the long-term, however. The usual expectation is that the peak consumption decreases due to the customers' response to high peak prices. This is the case for all but one of the simulations. Quite contrary to intuition, we do notice an increase in peak consumption in the short-term simulation results for 20% of customers on hourly pricing. This is due to a reduction of the flat rate in combination with the variable production profile of wind power (see also the discussion in Section 5).

The generation capacities in the short-term simulations are kept at the reference case levels. In the long term they are adjusted by the model as expected, such that peak and mid-merit capacities are reduced, and base load capacity increased. These adjustments are due to the respective generator profits provided in the third vertical section of Table B.4. In the short-term they become negative, because of the changes in wholesale prices caused by demand response. In particular, the peak prices are clearly reduced, but also the average is lower than in the reference case. The wholesale price is shown in the second vertical section of the results table. The capacity adjustments increase peak as well as average prices from their short-term levels, and generator profits return to zero. The long-term price peaks are lower than in the reference scenario, while the outcome for the average price level in both adoption scenarios is a slight increase.

Besides wholesale prices the second vertical section of Table B.4 also shows the cost of serving total load, reflecting the wholesale procurement cost of retailers, and the average prices paid by retail customer on either flat rate or variable rate. In all cases the cost of serving load is reduced compared to the reference. The described changes in wholesale market prices are reflected onto the flat retail rate that is reduced by more than 9 €/MWh as compared to the reference case in the short term. In the long run, however, the rate may as well increase. So while consumers immediately gain from responding to variable prices, not all customers will necessarily profit after generation capacity has been adjusted.

The overall costs and benefits are presented in the lower sections of Table B.4, where we show the change in consumer surplus for different customer groups in absolute terms and relative to total reference cost of serving load. Here we can observe that it is not even required for all of the consumers to switch to variable rates in order to find short-term gains of around 16%. The short-term result in the 100% adoption case is not much higher. The effect of capacity adjustments in the long run is evident in the results and reduces the change in consumer surplus to about 4.2% for 100% adoption and down to 1.18% for 20% adoption.

We already mentioned thermal generator profits; besides those the total profit of wind generators is shown. The figures are negative due to high investment costs and reflect their need for support payments. The line showing total change in generator profits is the difference in profit compared to the reference case, which we consider as the relevant benefits on the supply side. It is worth noting that for wind generators the change in profits is positive and their losses are reduced in all of the cases. The heightened value of wind power will result in reductions in the need for support payments and thus may also have a positive impact on consumers.

Netting the effects in the lowest two lines of Table B.4 provides us with the ideal economic gains of hourly pricing under given assumptions. These are 3.95% relative to total costs for serving load including the support to finance wind power in the reference case. With a more realistic adoption level of 20% the long-term results point at a relative annual improvement of 1.12%.

Table B.4: Simulation results for hourly pricing in base wind scenario

Case		**Reference**	**Hourly pricing**			
Adoption rate	%	0%	20%		100%	
Equilibrium		long-term	short-term	long-term	short-term	long-term
Consumption						
Total	GWh/y	15,729	16,033	15,815	16,134	16,106
Max	MW	3701	3737	3658	3622	3613
Generation capacities						
Base	MW	1302	1302	1316	1302	1372
Mid	MW	284	284	268	284	205
Peak	MW	1864	1864	1572	1864	856
Full load hours						
Base	h/y	7045	7200	7091	7406	7256
Mid	h/y	3116	3294	3114	3262	3093
Peak	h/y	488	516	565	430	882
Wholesale price						
Avg.	€/MWh	48.54	44.39	48.61	44.36	48.61
Max.	€/MWh	44,785.07	117.64	12,328.52	70.34	1749.17
Cost of serving load						
Total	T€/y	891,570	761,060	882,073	756,461	857,867
Specific	€/MWh	56.68	47.47	55.77	46.89	53.26
Average retail rate						
Flat rate	€/MWh	56.68	47.61	56.73	-	-
Variable	€/MWh	-	46.89	52.06	46.89	53.26
Consumer surplus change						
Flat rate	T€/y	0	115,096	-571	0	0
Variable rate	T€/y	0	29,915	11,123	150,121	37,447
Total	T€/y	0	145,011	10,552	150,121	37,447
Relative[a]	%	0%	16.26%	1.18%	16.84%	4.20%
Generator profits						
Thermal	T€/y	0	-143,304	0	-144,988	0
Wind	T€/y	-236,276	-235,494	-234,239	-234,556	-229,135
Total change	T€/y	0	-142,522	2037	-143,268	7141
Net effect						
Total	T€/y	0	2489	12,589	6853	44,588
Relative[b]	%	0%	0.22%	1.12%	0.61%	3.95%

[a] *Relative to total reference cost of serving load*
[b] *Relative to total reference cost of serving load and wind support*

Rebate pricing schemes

Results for the rebate pricing schemes are presented in Table B.5 showing the different rebate schemes horizontally. We only present the final long-term equilibrium results here. The relation between short-term and long-term results is similar to the previous calculations of the hourly scheme. Note also, that we have not repeated the reference case results, so the presented numbers should be held up against the first column in Table B.4.

The rebate pricing scheme as defined for this analysis only covers a daily three-hour period. Therefore effects are limited as compared to the hourly pricing scheme. The most significant impact comes from a rebate during the early evening hours (Rebate "Evening"), because this is the time of the wholesale price peak in the reference case, given the used hourly data. Having a rebate during later hours (Rebate "Night") is not very effective if using the same elasticity. The net effect of the "Night" rebate is only around 25% of the "Evening" rebate.

A dynamic rebate turns out slightly better. But although this scheme catches the highest daily differences between flat rate and hourly prices, it could not improve on the result of the evening rebate. The major reason for the weak performance of the dynamic rebate is that the level of the flat rate lies above the simple average of wholesale prices, and thus the difference to peak prices is usually less than the difference to base prices, resulting in rebates to increase consumption during off-peak hours on many days. Only during very high price spikes will the dynamic rebate be triggered at peak times. At off-peak times, however, the rebate is often not sufficient to affect prices, and this is also a reason for the negative impact on wind power profits under the dynamic scheme.

Similar to the hourly scheme two of the rebates may result in an increase in total consumption. But while the hourly scheme reduces total cost of serving load in spite of increased consumption, this is not the case for all of the rebate simulations. On the other hand the rebate products are able to consistently increase the consumer surplus and the net effects including the change in generator profits are positive as well. Just as in the hourly case, we also note that passive flat rate customers in the 20% scenario may be affected negatively. However, this only happens in the "Night" rebate case which has a very limited impact anyway.

B.4.2 High wind scenario

Hourly pricing

Results for hourly pricing under the high wind scenario are summarised in Table B.6. At first it is important to note the difference in the results of the reference case with 100% flat rate pricing as compared to the base wind scenario. In the reference case of the high wind scenario total costs of supply are reduced by around 40 million EUR. At the same time the net support to wind power is increased by 160 million EUR, mostly because we require higher capacities to be installed and a larger share of them will be offshore and thus more expensive. Moreover, base load capacity is lower compared to the base wind scenario, while required peak capacity rises. Full load hours are decreased for all dispatchable generation technologies, most significantly, though, for the base load capacity. We can also observe higher price peaks than in the base wind scenario.

Table B.5: Simulation results for rebate pricing schemes in base wind scenario

Case		**Rebate "Evening"**		**Rebate "Night"**		**Rebate "Dynamic"**	
Adoption rate	%	20%	100%	20%	100%	20%	100%
Equilibrium		long-term	long-term	long-term	long-term	long-term	long-term
Consumption							
Total	GWh/y	15,728	15,726	15,745	15,804	15,749	15,819
Max	MW	3671	3709	3701	3700	3701	3701
Generation capacities							
Base	MW	1305	1317	1306	1321	1305	1309
Mid	MW	282	273	283	275	282	276
Peak	MW	1836	1721	1862	1853	1858	1858
Full load hours							
Base	h/y	7045	7035	7047	7045	7054	7096
Mid	h/y	3121	3128	3118	3118	3111	3109
Peak	h/y	488	492	484	473	489	488
Wholesale price							
Avg.	€/MWh	48.60	48.61	48.54	48.54	48.61	48.61
Max.	€/MWh	44,784.86	44,784.80	44,784.92	44,784.86	44,784.84	44,784.67
Cost of serving load							
Total	T€/y	890,706	885,791	892,022	894,177	890,658	892,423
Specific	€/MWh	56.63	56.33	56.66	56.58	56.55	56.41
Average retail rate							
Flat rate	€/MWh	56.68	56.56	56.70	56.80	56.59	56.58
Variable	€/MWh	56.45	56.33	56.48	56.58	56.42	56.41
Consumer surplus change							
Flat rate	T€/y	0	0	-244	0	1211	0
Variable rate	T€/y	712	5537	618	1496	802	4051
Total	T€/y	712	5537	374	1496	2013	4051
Relative[a]	%	0.08%	0.62%	0.04%	0.17%	0.23%	0.45%
Generator profits							
Thermal	T€/y	0	0	0	0	0	0
Wind	T€/y	-235,401	-233,818	-236,242	-235,936	-237,513	-237,708
Total change	T€/y	875	2458	34	340	-1237	-1432
Net effect							
Total	T€/y	1587	7995	408	1836	775	2619
Relative[b]	%	0.14%	0.71%	0.04%	0.16%	0.07%	0.23%

[a] *Relative to total reference cost of serving load*
[b] *Relative to total reference cost of serving load and wind support*

Consumption on the other hand is at a similar level for all cases in both wind scenarios, with a less pronounced increase under hourly pricing in the high wind scenario.

Again we see the expected relation between short-term and long-term effects. A more surprising result is the extent of the negative impact on passive flat rate customers in the 20% adoption case in the long run. While in the short term all customers gain as expected, the flat rate is required to rise significantly above the reference level in the long-term in order for the retailers to break even. The result in this case is that the 80% flat rate customers loose three times as much as the 20% variable pricing customers gain.

The net effect is still positive for all of the cases. In absolute terms the net effect is higher than in the lower wind scenario, while relative to the reference cost the gains are slightly lower. This is because, even in the case affecting flat rate customers the worst, the effect on revenues of wind power producers is positive. Their increased income on the wholesale market more than compensates for the losses of flat rate consumers. If these gains are evenly distributed amongst customers then the 80% flat rate consumers will be compensated, because 80% of the gains for wind producers exceed the reductions in the 20% adoption case.

Overall we observe the net effect to be similar to the base wind scenario. But while in the base wind scenario gains primarily come from an increase in consumer surplus, they will to a larger extent result from the increase in the value of wind power in the high wind case.

Rebate pricing schemes

Table B.7 provides an overview of the simulation results for the rebate pricing schemes. A striking result is that for all of the partial adoption cases the consumer surplus gains of rebate customers are insufficient to compensate for losses of remaining customers due to a rise in the flat rate. In order to maintain the same flat rate across all customers, pure flat rate customers will contribute to compensate a reduction in revenues to the retailer caused by rebates. This will not necessarily be the case in practice, where rebate customers may have to compensate for inefficient response on their own.

The short-term results, not shown in the table, are very positive in all the rebate cases. In the long-term, though, one might see an increase in prices and thus cost as compared to the reference level. Although we are observing these effects in the high wind scenario, the rebate schemes still provide a positive contribution to wind power producers. Therefore the overall net results in all of the cases stay positive.

The 100% cases for the “Night” and the “Dynamic” rebate schemes show that a poorly designed scheme would result in long-term losses for the participants. As compared to the base wind scenario, however, the dynamic rebate has a much more positive effect on the value of wind power. In the reference case for the high wind scenario, wind is the marginal technology in more than 1000 hours of the year as compared to 40 hours in the base wind case. The dynamic rebate reduces the number of hours by 365 in the high wind scenario, which is much more than what could be achieved in the base wind case. This stresses the importance of dynamic instruments in a setting with high wind production.

Table B.6: Simulation results for hourly pricing in high wind scenario

Case		**Reference**	**Hourly pricing**			
Adoption rate	%	0%	20%		100%	
Equilibrium		long-term	short-term	long-term	short-term	long-term
Consumption						
Total	GWh/y	15,729	16,001	15,770	16,110	16,069
Max	MW	3701	3727	3646	3682	3682
Generation capacities						
Base	MW	1029	1029	1036	1029	1086
Mid	MW	385	385	369	385	309
Peak	MW	2007	2007	1690	2007	909
Full load hours						
Base	h/y	6050	6238	6113	6514	6394
Mid	h/y	3097	3204	3094	3165	3082
Peak	h/y	460	478	534	398	857
Wholesale price						
Avg.	€/MWh	46.88	44.06	48.61	43.90	48.61
Max.	€/MWh	44,785.07	102.65	23,692.33	70.34	2589.32
Cost of serving load						
Total	T€/y	850,818	739,813	863,535	733,354	838,582
Specific	€/MWh	54.09	46.24	54.76	45.52	52.19
Average retail rate						
Flat rate	€/MWh	54.09	46.38	55.78	54.09	54.09
Variable	€/MWh	NA	45.66	50.81	45.52	52.19
Consumer surplus change						
Flat rate	T€/y	0	97,761	-21158	0	0
Variable rate	T€/y	0	25,577	7028	130,515	13,596
Total	T€/y	0	123,339	-14130	130,515	13,596
Relative[a]	%	0%	14.50%	-1.66%	15.34%	1.60%
Generator profits						
Thermal	T€/y	0	-147,308	0	-150,238	0
Wind	T€/y	-398,437	-372,343	-370,650	-372,172	-363,524
Total change	T€/y	0	-121,214	27,787	-123,974	34,913
Net effect						
Total	T€/y	0	2124	13,656	6542	48,509
Relative[b]	%	0%	0.17%	1.09%	0.52%	3.88%

[a] *Relative to total reference cost of serving load*
[b] *Relative to total reference cost of serving load and wind support*

Table B.7: Simulation results for rebate pricing schemes in high wind scenario

Case		**Rebate "Evening"**		**Rebate "Night"**		**Rebate "Dynamic"**	
Adoption rate	%	20%	100%	20%	100%	20%	100%
Equilibrium		long-term	long-term	long-term	long-term	long-term	long-term
Consumption							
Total	GWh/y	15,729	15,741	15,734	15,777	15,728	15,799
Max	MW	3671	3782	3699	3699	3696	3696
Generation capacities							
Base	MW	1030	1039	1031	1039	1028	1036
Mid	MW	382	371	382	371	383	373
Peak	MW	1981	1872	2006	2008	1984	1986
Full load hours							
Base	h/y	6057	6081	6056	6088	6062	6115
Mid	h/y	3100	3104	3095	3104	3097	3090
Peak	h/y	462	471	457	451	465	464
Wholesale price							
Avg.	€/MWh	47.00	47.00	47.09	47.09	47.50	47.50
Max.	€/MWh	44,784.89	44,785.04	44,784.83	44,784.89	44,784.85	44,784.80
Cost of serving load							
Total	T€/y	851,736	846,711	854,366	855,504	860,503	862,217
Specific	€/MWh	54.15	53.79	54.30	54.23	54.71	54.58
Average retail rate							
Flat rate	€/MWh	54.19	54.09	54.34	54.42	54.75	54.75
Variable	€/MWh	53.98	53.88	54.15	54.23	54.57	54.58
Consumer surplus change							
Flat rate	T€/y	-1292	0	-3137	0	-8237	0
Variable rate	T€/y	329	3254	-210	-2227	-1542	-7761
Total	T€/y	-963	3254	-3347	-2227	-9780	-7761
Relative[a]	%	-0.11%	0.38%	-0.39%	-0.26%	-1.15%	-0.91%
Generator profits							
Thermal	T€/y	0	0	0	0	0	0
Wind	T€/y	-395,782	-394,794	-394,676	-394,246	-387,201	-387,397
Total change	T€/y	2655	3644	3761	4191	11,237	11,040
Net effect							
Total	T€/y	1692	6898	414	1965	1457	3279
Relative[b]	%	0.14%	0.55%	0.03%	0.16%	0.12%	0.26%

[a] *Relative to total reference cost of serving load*
[b] *Relative to total reference cost of serving load and wind support*

B.5 Discussion

The results of our case study illustrate some general effects of variable pricing in line with findings in other studies on real-time pricing. As we used the case of Denmark applying two scenarios of wind power production, we are able to observe some additional effects specific to systems with high shares of fluctuating, non-dispatchable generation. We also used alternative rebate pricing schemes to investigate whether the economic effects under such schemes may justify their implementation, assuming they could reach higher levels of adoption and response than hourly pricing.

Some generally expected effects of variable pricing can be observed in our simulation results. Maximum price peaks are significantly reduced under hourly pricing. In the short term reduction will be quite strong, while in the long-term prices return to a higher level due to adjustments in generation capacity. Another observation confirming previous findings (Caves et al., 2000) is that low adoption rates, with hourly pricing in particular, are sufficient to generate very attractive results from a consumer point of view in the short term, while increasing adoption does not change results significantly. In the long term, however, we find adoption to be more important in generating economic benefits, underlining the importance of analysing these effects.

The impact of wind power is reflected in some effects we found to be different from results in other studies. Usually peak consumption would be decreased with variable pricing, however, the irregular pattern of wind production allows for increasing peak consumption without increasing costs in some of the analysed cases as well. The reason for that is a significant decrease in the flat retail rate with flat rate customers increasing their consumption in response. This is only possible, because due to the wind production during the consumption peak, this is not the hour determining demand for dispatchable capacity.

Variable pricing will on average lead to price reductions in the short term that affect other customers on fixed rates positively as well. In the long run this is not necessarily the case and the immediate cost of flat rate customers may even rise in specific cases. It has been stated in previous analyses that a switch of customers to real-time pricing makes all customers better off (Borenstein & Holland, 2005). The intuitive explanation of such a result is that the efficient retail rate is equal to the volume-weighted average wholesale prices. Customers on variable pricing schemes reduce peak prices, at times when demand is usually high. In contrast, our results show that in a system with high shares of variable production it is possible to observe an increase in the flat rate. While demand response customers still reduce price peaks, these peaks, because they also depend on the wind power production, must not in any case coincide with the highest consumption of flat-rate customers. Therefore, depending on the profiles of wind and consumption, retailer costs to supply flat-rate customers are not necessarily reduced as it should be expected without the effect of wind. This effect seems to become more pronounced with larger shares of wind power in the system.

Besides the impacts on consumers we note direct implications for wind producers. The value of wind production increases in all but one of the rebate cases under the base wind scenario. For the high wind scenario we find a consistent positive effect in all of the pricing schemes. This effect reduces the requirement for support payments to wind producers. On the other hand the positive effect of variable pricing on consumer surplus is reduced in the high wind scenario due to increasing prices for flat rate customers.

The gains from savings in the support should therefore be returned to the consumers via lower electricity bills or taxes.

The analyses of the rebate schemes have shown that simple rebate structures are necessarily less effective from an economic point of view than customers responding directly to wholesale price signals. Under rebate pricing the long-term peak prices are almost at the same level as in the reference case. Only in the short term significant peak price reductions can be attained under such schemes. If we compare the effect of the rebates to the ideal schemes we see that we can still achieve up to about 18% of the hourly pricing long-term effect with a much simpler rebate scheme as well. It should be kept in mind that this level is achieved by only sending a simple signal regarding three consecutive hours to the customers per day. The signal will only contain the information of whether increased or reduced consumption will generate savings, and the benefit to the consumers will always be the same. This is much to the contrary of conditions under a real-time pricing scheme. Moreover, in the short-term the relative effect of a rebate can be shown to be up to around 50% of gains under real-time pricing.

In the rebate pricing schemes the timing of rebate periods is critical. A problem of fixed rebate periods, as applied in two of the cases, will be that in the long-term price peaks are likely to occur at times outside of the rebate time window. The integration of higher shares of wind will require more dynamic schemes (Mills & Wiser, 2013). Accordingly we find the dynamic rebate to have the most positive impact on wind power revenues in the high wind scenario. The design of the applied rebate structure, however, could certainly be improved. Due to simplification in the modelling of the dynamic rebate scheme in particular, it does not improve results as much as it should be expected.

The model presented and applied above provides indications of how demand response affects consumer and producer surplus in a system with high shares of wind power. To keep the model versatile and enable testing of different pricing structures we limited its complexity and left out a couple of conditions. In the following we briefly discuss how these may affect results.

The most substantial concern may be that we look at a closed economy and do not allow for other sources of flexibility to react upon prices. This would clearly reduce the economic benefit of these kinds of pricing schemes, because the flat-rate benchmark will not have such extreme price spikes as we see them in the model. It could still be argued that for political reasons, from a national perspective, production capacities should be held available for security reasons, even though peak demand is covered by interconnection capacities with neighbouring countries. This approach has been used previously (Batas Bjelić et al., 2013; Hedegaard, Mathiesen et al., 2012; Pillai et al., 2011) and ensures that isolated system operation will be possible. The capacity will then be idle at peak times and would not gain scarcity rents as in the model. They would still have to be financed, though, so consumers would have to cover this cost. In that case however, demand response could not directly contribute to avoiding the costs, as payments for such capacity most likely will be independent of the timing of consumption.

The model uses a simplified representation of production capacities, only incorporating the major categories of plants. Using a more detailed model of plants may provide more accurate numerical results. The general conclusions, however, would stay the same. In practice generators would have more technical restrictions limiting their flexibility. In Denmark, for example, combined heat and power production is an important factor. Such restrictions of plant flexibility could be expected to add to the value of demand response.

B.6 Conclusion

Using a partial equilibrium model of the electricity market we were able to derive a couple of new insights regarding the economic benefits of different retail pricing schemes for household customers. Applying case study data for Denmark we were able to analyse the interplay of demand response with different levels of wind power. Our results indicate favourable strategies in such a setting to ensure high adoption and efficient response to load shifting incentives for households.

Simple pricing schemes could become important in an early phase to initialise the development of household demand response. Our results confirm that variable pricing, whether in the form of real-time pricing or less complex structures, will have an overall positive economic impact. As expected, real-time pricing is clearly superior to the analysed rebate pricing schemes in a long-term equilibrium producing significant benefits of around 4% of total costs. Although the effects of the rebate structures may be limited in the long term, it can also be observed that the simple schemes could provide quite sizable gains in a short-term equilibrium. This result suggests that it could be recommendable to implement simplified pricing schemes in building up a base of demand response to begin with.

At a later point in time when the long-term dynamics begin to take effect, a larger effort should be made to shift consumers onto real-time rates. As households would have gathered experience with variable pricing schemes, the barriers to adoption should be expected to be lower. Moreover, automation equipment should be more widely available enabling a more active response. Such an approach would also accommodate the point that with higher shares of variable production, more dynamic schemes are preferable.

Benefits are not evenly distributed among customers on different rates. With increasing shares of variable production passive customers may even become negatively affected. While initially this should be evaluated as a welfare reduction, it could also increase the incentive for such customers to switch to variable rates and become more responsive.

Demand response under variable pricing can also be found to make wind power more valuable. The resulting reduction in the need for support should be returned to consumers in a way that preserves incentives for demand response, and could maybe even reward flexible customers specifically. Such compensations could become recommendable due to the diminishing long-term benefits for responsive customers; but also because customer gains may be far lower in the high wind settings, even though in absolute terms total economic benefits from demand response increase with more wind.

Our findings also suggest that an increased focus on adoption rates will be required in the long term. While harvesting the short-term gains could become an incentive for first-movers, the decrease in benefits over time could have an adverse effect and result in customers moving back to flat rates. As flexibility will be required even more in the long run this situation should be avoided. The more exact timing of long-term over short-term effects is an important aspect that requires further research.

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Paper C

Dynamic pricing and electricity taxation from a household customer perspective

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Abstract

Dynamic pricing of retail electricity, as opposed to the widely applied average pricing, has often been proposed to enhance economic efficiency through demand response. The development of variable production from renewable energies and expectations about the installation of heat pumps and electric vehicles have now reinforced interest in flexible demand and dynamic pricing in Denmark. With a roll-out of smart metering one important technical hurdle is going to be cleared, and dynamic retail pricing may soon become an eligible option for Danish households. Limited activity of household consumers on the retail market indicates, however, that switching supplier or contract is perceived costly. We apply the concept of switching costs to explain this hesitant behaviour, and use it to estimate a threshold level based on recent observations in the Danish market. We calculate potential savings from dynamic pricing and show how the choice of electricity taxation technique may hamper or enhance potential benefits. In the light of switching costs, our results suggest that a combination of smart meter roll-out and offering of dynamic pricing schemes might be insufficient to convince the average household consumers to switch contracts and become active in response to prices, unless they hold a substantial flexibility potential. Dynamic taxation, even if applied to smaller parts of the levies, is shown to exceed switching costs at moderate levels of flexibility.

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C.1 Introduction

Dynamic pricing of retail electricity has become a recurring item on the energy policy agenda. If introduced instead of the ubiquitous average pricing, it generates economic efficiency gains – assuming retail demand is price responsive. So far, however, technical and administrative requirements as well as uncertainty about potential gains have prevented implementation in many markets. Large-scale development of variable production from renewable energies in Denmark has now reestablished an interest in flexible demand and dynamic pricing (Danish Ministry of Climate, Energy and Building, 2013; Energinet.dk & Dansk Energi, 2012). As the effectiveness of new pricing schemes depends largely on individual decisions of households, this paper explores implications of dynamic electricity pricing in Denmark from a household consumer perspective. While theoretical gains are mostly undisputed (Borenstein & Holland, 2005; Kopsakangas-Savolainen & Svento, 2012), it remains an open question whether electricity retail customers find it attractive to adopt dynamic pricing schemes and responsive behaviour (He et al., 2013).

A certain flexibility potential is assumed to be present also in Danish households (Ea Energianalyse, 2011; Kwon & Østergaard, 2014), and consumers are continuously equipped with smart meters (Jørgensen, 2014). Some regulatory issues regarding data access and settlement have thus far hindered the development of dynamic price products (Danish Energy Regulatory Authority, 2012). With the implementation of a data hub and new retail market rules, though, all consumers in a foreseeable future should have the possibility to switch to an hourly-varying price contract, both technically and in terms of access to competitive products. This leaves us with the question of consumers' potential financial benefits, providing an incentive to switch to dynamic rates and become responsive to varying prices.

To date the Danish retail price is dominated by fixed per-unit elements (Kitzing et al., 2016): payments for grid use, fiscal levies and the para-fiscal public-service-obligation (PSO) levy that mainly finances renewable energy support (see Figure C.1). Even with dynamic pricing of the purely market related part, relative variability becomes almost invisible to the consumer. Analyses of retail electricity prices in Denmark thus must consider taxes. In order to sustain the relative variations in the underlying market price and increase the incentive for demand response under dynamic pricing, a changed dynamic approach to levies and taxes could become relevant (Røpke & Nyborg, 2011; Singh & Østergaard, 2010). A few studies already assess the possibility of dynamically linking the para-fiscal levy that finances renewable support in Germany to spot market prices (Ecofys, 2014; Jansen et al., 2015). In Denmark dynamic taxes and levies have gained some attention in the debate as well (Togeby, Werling & Hethey, 2009; Togeby, Werling, Hethey et al., 2009). But while some new dynamic electricity tax structures based on market indicators, such as the amount of wind power in the system, have been assessed (Danish Ministry of Taxation, 2010), we did not find any work exploring the details of *ad-valorem* taxation based on the underlying electricity price.

The overall aim of our paper is to provide an indication of whether dynamic pricing could be competitive as a product on the Danish retail electricity market taking into account the possibility of consumers to respond to hourly prices in order to generate benefits. Therefore we estimate potential benefits of consumers switching to a dynamic pricing scheme under different assumptions of their ability to respond to prices. To gain

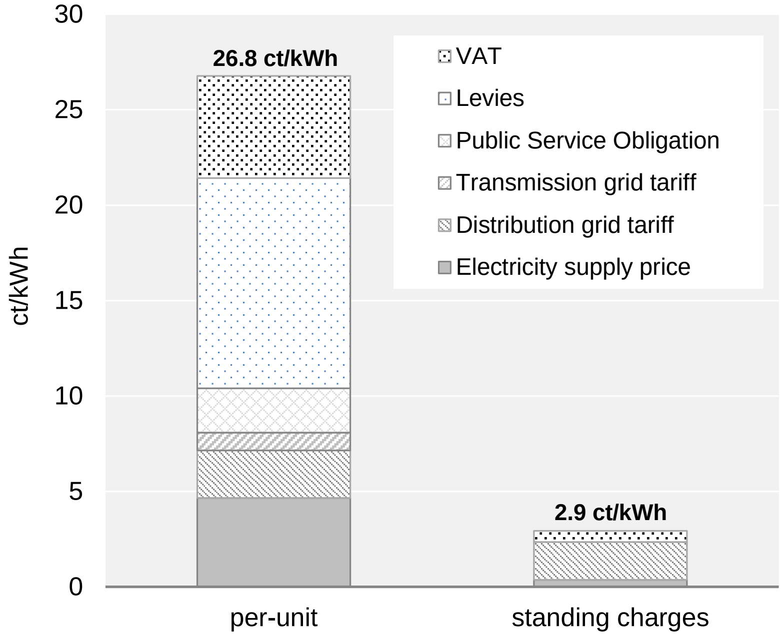

Figure C.1: Danish household electricity price (4000 kWh/year) in 2013 (Danish Energy Regulatory Authority, 2014)

insight into the distribution of benefits among households we use disaggregated load profiles for different types of homes. In our evaluation we take into account all elements of the retail price including taxation. We also determine the gains of converting fixed per-unit adders to the electricity price into dynamic elements and evaluate the impact on the attractiveness of dynamic rates. This is done for both the fiscal levies (*dynamic tax*) and for the public-service-obligation levy (*dynamic PSO*).

While any demand response optimisation would result in financial benefits, it is unclear what level of benefits would actually be required to trigger adoption of dynamic pricing and responsive behaviour. We do have information, though, about the behaviour of household consumers on the Danish retail market. Based on this information we propose threshold levels and evaluate the attractiveness of dynamic pricing schemes as a viable option to customers under retail competition.

C.2 Determining the attractiveness of dynamic pricing

C.2.1 Disaggregated hourly consumption data set

To account for heterogeneity of consumers we evaluate benefits on a disaggregated basis. Actual hourly metering data has been acquired for Danish consumers in the period of 2007–2012. Information on electric heating is available as well. Measurements are obtained by various network companies that report to the Danish Energy Association (*Dansk Energi*) and the Danish transmission system operator (*Energinet.dk*) on a regular basis. Information on the used data set is shown in Table C.1. It covers a total of 652 meters, many on a sub-station level. On average a metering point covers around 14 individual households. In total the data set covers 9215 household customers with an average consumption of 3941 kWh per year. Where necessary the metering data for a connection point is scaled down according to the number of households connected. Therefore the load-shift potential of individual households in some cases is estimated by using the respective sub-station profile.

Table C.1: Used hourly consumption data set

	Meters	Consumers		Consumption		
	total	total	per meter	average [kWh/y]	share in used data	share in 2013
Apartments	86	5,691	66.2	3,464	11.6%	24.4%
Semi-/detached houses	566	3,524	6.2	4,013	88.4%	75.6%
without electric heating	557	3,057	5.5	3,999	86.7%	62.5%
with electric heating	9	467	51.9	4,858	1.7%	13.1%
Total	**652**	**9,215**	**14.1**	**3,941**	**100.0%**	**100.0%**

In Denmark residential consumption of electricity accounts for about 30% of total electricity consumption, the major share consumed in detached or semi-detached homes (Dansk Energi, 2015). Most commonly no electric heating is installed. The share of consumption per category in the used data are shown in Table C.1 together with the actual share in Denmark of 2013. Every metered profile is just used once and scaled down to the size of one household. Consequently the apartment category, where limited individual metering is available, weigh somewhat less in the analysis.

C.2.2 Benefits from dynamic pricing

The incentive to adopt a new contract is approximated by simulating potential response activities and resulting savings on individual customers' electricity bills. Based on the actual metering data the total annual electricity bill of a household is determined, at first, by applying a traditional flat price per kWh that is adjusted every quarter of a year. This is then compared to hourly pricing. All end-user prices include relevant levies and taxes within the analysed time period and have been deflated to the level of 2012, the last year in the used data set. In addition to applying the current per-unit taxation scheme we also derive results adding dynamic, *ad-valorem* levies for both the fiscal and para-fiscal elements. In all cases these are defined as a percentage such that they result in the same annual revenues if consumers would not respond to prices.

For simplicity we use a stylised demand response model rather than estimates of price-elasticity or models of specific appliances. Load shift occurs to the lowest priced hours within predefined time slices. We restrict the shifting by assuming that consumers will not reduce their demand below the lowest hourly consumption measured during one full year. Moreover, we assume that the measured peak during one year represents the connected load of household appliances reduced by a coincidence factor (CF):

$$\mathrm{CF} = \frac{\text{Peak load}}{\text{Total connected load}} \tag{C.1}$$

Applying the factor to the peak load therefore gives us a theoretical maximum load per household. A common approximation of the coincidence factor for different numbers n of connected loads is given by Bayliss and Hardy (2007):

$$\mathrm{CF} = 0.5\left(1 + \frac{5}{2n+3}\right) \tag{C.2}$$

For large numbers of connected loads of around 250 this approximation approaches 0.5. We use this number for the apartment category. Although a single apartment might not have 250 loads connected, we want to account for that the used profiles actually cover larger blocks of apartments. In this way, when scaled down to a single apartment, we avoid underestimating the individual peak loads. For detached homes we use a slightly higher factor of 0.55 assuming that fewer electrical loads are covered by the profiles (using equation (C.2) the value corresponds to around 23 loads). For customers with electric heating we use a factor of 0.8 (Kasikci, 2004).

In mathematical terms our approach is equivalent to the following simple optimisation problem:

$$\begin{array}{llcll}
\min\limits_{d \geq 0} & \sum\limits_{t=1}^{T} d_t P_t & & & \\
\text{s.t.} & d_t & \geq & \min_t D_t^0 & \forall\, t \in T \\
& \frac{1}{\mathrm{CF}} \max_t D_t^0 & \geq & d_t & \forall\, t \in T \\
& \sum\limits_{s=t}^{t+L-1} d_s & = & \sum\limits_{s=t}^{t+L-1} D_s^0 & \forall\, \{\, t \in T \mid t = L(m-1)+1, m \in \mathbb{Z}^+ \,\}
\end{array} \tag{C.3}$$

We minimise costs given by multiplying the chosen demand level d with the end user price P. The original metered consumption D_0 determines upper and lower bounds of d applying the principles described above. The last constraint ensures that load is shifted and not just curtailed: within given time windows of length L the sum of load after shifting (d) needs to be equal to the sum of loads in the original profile (D_0). We use windows of 3, 6, 12, 24 and 168 hours to represent the potential load shift horizons. These time slices cover the most important short-term patterns in hourly electricity prices. Moreover, it may be assumed that the load-shift potential of a household customer is somewhat limited and would not exceed the maximum period of one whole week (i.e. 168 hours).

In order to estimate a savings potential we apply rather optimistic constraints. Deriving results for this kind of best-case scenario helps us to determine, whether a sufficient economic incentive to adopt dynamic pricing can be expected, and consequently, whether such options can be attractive on a liberalised retail market.

C.2.3 Threshold benefit levels of consumers

Several studies have investigated benefits of demand response under dynamic pricing (Albadi & El-Saadany, 2008; Conchado & Linares, 2012; Strbac, 2008). A number of these also estimate financial impacts on household consumers (Faruqui & Sergici, 2010; Zarnikau, 2008). We argue, though, that consumer benefits of demand response should not be seen in isolation. Rather, they should be analysed with consumers' adoption decisions in mind. Making consumers actively participate will become one of the critical issues in the further development of demand response under retail competition

(Faruqui et al., 2010; Gyamfi et al., 2013). We therefore analyse our results in the context of observed behaviour in the liberalised Danish retail market.

Switching rates of 3–7% indicate that consumers in Denmark are mostly comfortable with their suppliers and the prices they offer (NordREG, 2012, 2014). For the largest share of consumers this means they are buying electricity at traditional flat rate conditions (Lyndrup, 2016). Potential savings of switching from the traditional rate to competitive offers can be observed to be around 5–10% – on average not more than €50 per year; for many customers this does not provide a sufficient incentive. An offer that in addition would ask for the consumer to change behaviour as a precondition to obtain savings (as in the case of load-shifting) would likely require larger savings. For example, research in Germany has shown that consumers on average expected savings of €54 per year (more than 5% of their total bill) from giving access to automatic control of their fridges alone (Pfeifroth et al., 2012). A Swedish survey resulted in even higher figures (Torstensson & Wallin, 2015).

With homogeneous goods like electricity one should expect that small price differences would be sufficient to induce switching. In practice, we can see that this is not the case. For households in particular, factors beyond the financial incentive do play a role as previous research has found (Darby & McKenna, 2012). A Dutch survey, for example, has shown that autonomy, privacy and comfort are highly valued and that households may be very reluctant towards participating if these factors are compromised (Pepermans, 2014). The findings seem to be supported by a Swiss experiment characterising only 20% of a sample of household consumers as "price sensitive", whereas the remaining share focussed more on rate stability, home automation and security (Kaufmann et al., 2013). Furthermore, in a German study 69% of respondents preferred a fixed rate to dynamic pricing as well (Dütschke & Paetz, 2013).

The observed switching behaviour as well as the above findings regarding household consumer preferences suggest that potential benefits would need to outweigh a range of intangible costs associated with switching to another supplier or pricing scheme (Jones et al., 2002). If we could determine the cost of switching and compare it with the benefits of a dynamic rate, then we would have an estimate of the required level of benefits from a consumer point of view in order to switch to such new schemes. This is not easily measured, but fortunately a simplified method to determine the cost of switching has already been developed (Shy, 2002). It simply uses market shares and price differences observed for a homogeneous product in the market, and has been applied previously, for example, in the context of electricity (Defeuilley & Mollard, 2008), internet providers (Krafft & Salies, 2008) or the airline industry (Carlsson & Löfgren, 2006).

A dominant market position with deviating prices in this framework is explained by switching costs. Switching cost S_{AB} of supplier A's customers switching to supplier B with respective market shares M and prices p is defined as:

$$S_{AB} = p_A - \frac{M_B\, p_B}{M_A + M_B} \tag{C.4}$$

This expression results from the assumption that the observed prices of A and B are chosen such that it is unattractive for any of the two suppliers – costs of switching taken into account – to offer their product to the other supplier's customers at sufficiently low prices to switch. Supplier B would have to offer a price of p_A minus S_{AB} in order to convince A's customers to switch. Switching costs may then be determined by observing that the actual revenue of supplier B, $p_B M_B$, has to be more or at least equally attractive to the revenue resulting from getting supplier A's customers to switch, which is: $(p_A - S_{AB})(M_A + M_B)$. Setting these two expressions equal and rearranging results in equation (C.4).

The data on market shares of suppliers in Denmark that is required to determine the above switching cost is not readily available. We therefore use the *Herfindahl-Hirschman Index* (HHI) for market concentration regularly published by the Danish transmission system operator (Energinet.dk, 2016). The index is defined as:

$$\mathrm{HHI} = \sum_{i=1}^{N} {M_i}^2 \tag{C.5}$$

As the number of market participants is made public, we can approximate the market share of the largest supplier M_1 assuming that the remaining share is divided equally amongst all other suppliers:

$$\mathrm{HHI} = M_1^2 + (N-1)\left(\frac{1-M_1}{N-1}\right)^2 \tag{C.6}$$

While 70 suppliers are active in Denmark in total, only a part of them supply customers in the whole country. For the calculation of market shares we therefore define the market to consist of 44 suppliers, which is the maximum number active in any distribution area. As traditionally consumers have been supplied by their local utility company, we take into account the concentration index within local distribution areas, where the weighted average HHI value lies at 0.7, resulting in an average 84% market share of the largest supplier. Being with the largest supplier does not necessarily mean that customers have not been active on the market by comparing prices or choosing new contracts. This could be taken into account by using the share of consumers on a traditional fixed price product as the incumbent market share instead of the one derived from the HHI. This alternative value is around 55% (Lyndrup, 2016).

Switching costs are estimated by applying equation (C.4). We use the above incumbent market shares as M_A and the combined share of all competitors as M_B. As the incumbent price we use average supply costs based on a traditional flat rate price, whereas for the competitors we use the most attractive offers in the retail market: products with prices fixed at the most for 6 months ahead. Resulting switching cost estimates are given in Table C.2. We use these benchmark levels below to evaluate estimated savings generated by a switch to dynamic pricing under different tax regimes.

Table C.2: Switching cost estimates

	Incumbent share [-]	**Switching cost [€]**
Local HHI	84%	114
Fixed price share	55%	78

C.3 Results

C.3.1 Consumer benefits of dynamic pricing under different taxation schemes

Figure C.2 shows resulting costs subdivided by price element. The top panel shows results in the reference case of flat pricing. The other two panels show results for dynamic pricing with and without a dynamic tax under different assumptions about the load-shifting time window. As expected, larger windows reduce the supply cost for customers under dynamic pricing, and the effect becomes even more pronounced with a dynamic tax replacing the unit tax. Individual costs span a wide range from as low as €100 and up to far above €2000 per year. To provide an indication of the distribution of costs among households and consumer categories we use boxplots. In these, 50% of the results lie within the boxes, and the bars are set to cover 95% of the results. The means are indicated by different shapes per category and deviate from the median line, due to asymmetric distributions in some of the results.

The average benefits of switching to another pricing scheme are summarised in Table C.3 for different customer categories and in total. Horizontally the table shows potential benefits from shifting load within the analysed time windows. The first section represents a switch from flat to dynamic pricing maintaining per-unit levies on electricity. The remaining sections of Table C.3 show the effects of introducing dynamic PSO payments and taxes. There is an advantage to be gained by switching from the default product to an hourly-price product even without load shifting (column *'no resp.'*). This has to be kept in mind when looking into the potential of demand response actions. Although significant benefits may be achieved in total, some of those will have to be attributed to the mere effect of hourly pricing that for some part covers the implicit insurance premium in a fixed price. As competition increases one may expect this gap to become smaller, though. Therefore the last line in each section of Table C.3 shows the net load-shift benefit that would be achievable even if the average level of flat and dynamic pricing would be exactly the same.

It does not seem to play a large role in the average benefits whether the consumers live in apartments or detached homes. Additional consumption from electric heating is an advantage when it comes to load shifting. What cannot be seen from the presented average figures is that the benefits are not equal in all years of the data set and electricity bills may become more volatile with hourly pricing schemes. Electric heating customers are particularly vulnerable to high prices during the heating season. Therefore dynamic pricing holds a certain risk for these customers. If the dynamics are further increased through taxation this may have adverse effects if customers with electric heating do not react to prices properly.

Switching from static unit taxation to dynamic ad-valorem taxation would support the incentive for demand response. Even when correcting for savings that result from the mere switch between a flat and a dynamic electricity price, demand response generates significant savings under dynamic taxation. In all of the simulated cases the load-shift benefits under dynamic taxation are more than three times the amount achieved under dynamic pricing with traditional taxation. Admittedly, a dynamic tax would be a rather substantial intervention. Therefore we also analysed the option of a dynamic PSO payment, both as a separate instrument and in combination with a

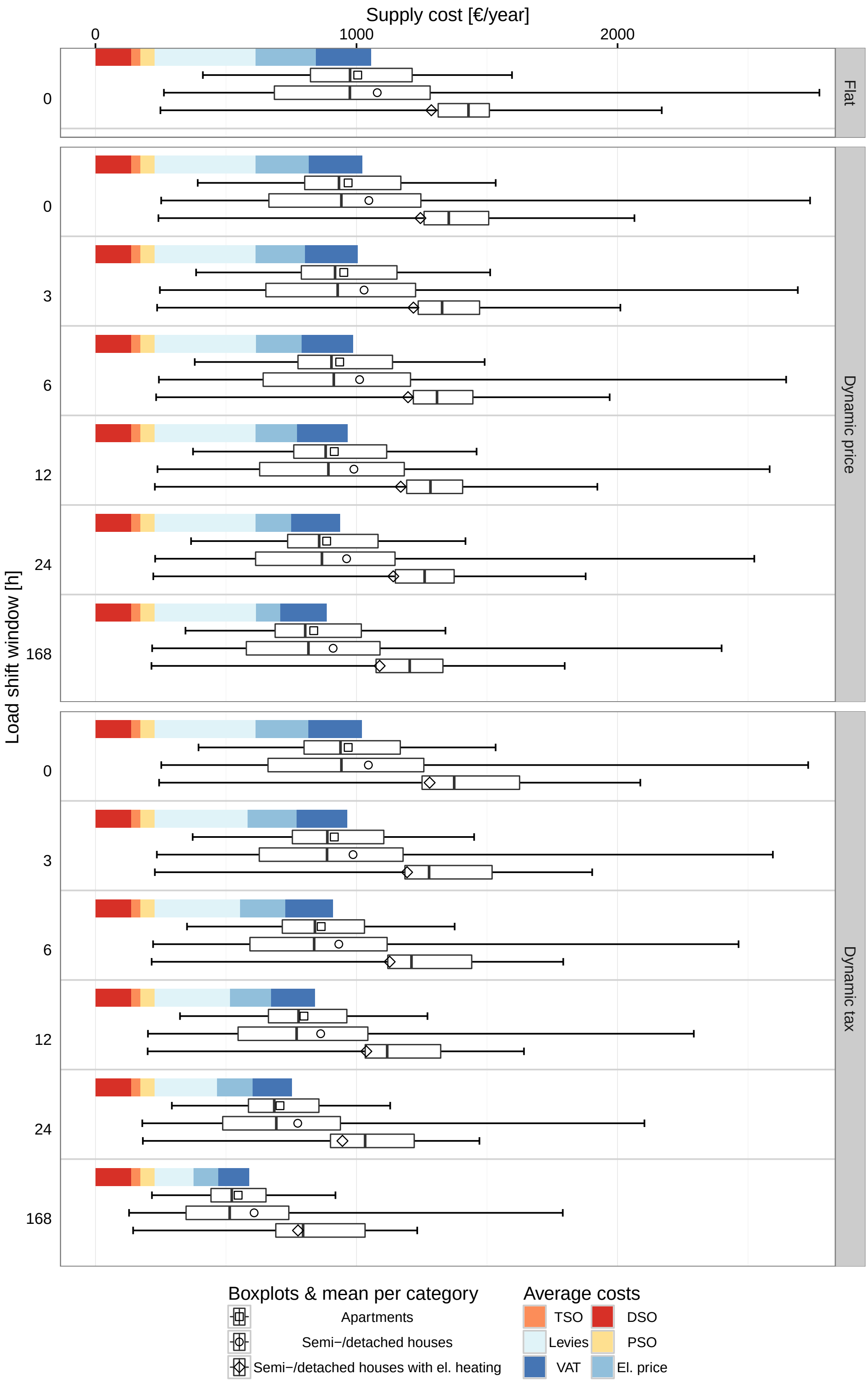

Figure C.2: Supply cost results of load shift simulations under different pricing and tax regimes

Table C.3: Average benefits of switching to dynamic pricing under different taxation schemes by load shift window

	Load shift horizon					
	no resp. [€/y]	3 hours [€/y]	6 hours [€/y]	12 hours [€/y]	24 hours [€/y]	168 hours [€/y]
Dynamic price						
Apartments	36.8	53.3	69.0	89.8	118.9	168.5
Semi-/detached homes	32.4	51.0	68.2	90.3	118.3	169.9
without electric heating	32.1	50.5	67.6	89.5	117.4	169.0
with electric heating	41.9	68.7	89.4	117.3	145.8	198.1
All categories	34.1	51.9	68.5	90.1	118.5	169.4
net load-shift benefit	-	*17.8*	*34.5*	*56.1*	*84.5*	*135.3*
Dynamic price and PSO						
Apartments	36.9	58.8	79.5	106.6	144.4	210.0
Semi-/detached homes	32.4	57.1	79.9	109.0	145.6	215.0
without electric heating	32.4	56.7	79.4	108.3	144.8	214.1
with electric heating	32.7	68.6	96.1	133.0	170.8	242.4
All categories	34.1	57.8	79.7	108.1	145.2	213.1
net load-shift benefit	-	*23.7*	*45.7*	*74.0*	*111.1*	*179.0*
Dynamic price and tax						
Apartments	36.5	89.8	140.0	206.0	297.7	458.1
Semi-/detached homes	33.2	92.8	147.7	217.8	305.7	472.9
without electric heating	34.0	92.8	147.3	216.7	304.6	471.6
with electric heating	6.6	93.0	159.7	249.2	340.6	510.8
All categories	34.5	91.6	144.7	213.3	302.7	467.2
net load-shift benefit	-	*57.2*	*110.3*	*178.8*	*268.2*	*432.8*
Dynamic price, PSO and tax						
Apartments	36.6	95.3	150.4	222.8	323.2	499.7
Semi-/detached homes	33.1	98.8	159.3	236.4	333.0	517.9
without electric heating	34.3	99.0	159.1	235.5	332.0	516.8
with electric heating	-2.6	92.9	166.5	264.9	365.6	554.0
All categories	34.5	97.5	155.9	231.3	329.3	511.0
net load-shift benefit	-	*63.0*	*121.5*	*196.8*	*294.8*	*476.6*

dynamic tax (see Table C.3). Similar effects can be achieved by a dynamic PSO, though to a lesser degree. Benefits would increase by more than 30% as compared to a fixed PSO payment under dynamic pricing. Combining dynamic tax and PSO would yield the maximum incentive for load-shifting with savings around 3.5 times those of dynamic pricing with fixed levies.

C.3.2 Attractiveness of pricing schemes

Considering the total average electricity bill of more than €1000 under flat pricing (see Figure C.2), demand response alone (after switching from a flat to a dynamic price) generates savings in a range of 2–10% of total costs. This is comparable to price differences we have seen under retail competition in the past (Lyndrup, 2016), but may still seem somewhat limited considering the rather optimistic assumptions of our demand response simulation. Dynamic taxation could increase results by a factor three, and such savings should make it far more likely to motivate customers to switch contracts if we use today's switching behaviour as an indicator. We will have to return to our switching cost benchmarks, however, to further conclude whether such savings are sufficiently attractive or not.

Figure C.3 shows distributions of cost savings under dynamic pricing for unit and dynamic tax regimes subject to optimal load shifting under the given constraints. The mean levels for the three different residential consumer categories are indicated by vertical lines of the same colour as the distribution. As benchmarks we show the two levels of switching costs from Table C.2 as grey vertical bars. Moreover, we indicate gains that may be obtained by a simple switch of supplier under current retail market conditions by a third bar. A first thing to note is how differently an hourly pricing regime may affect customers. Due to the different individual profiles some households are only able to achieve savings in the low end. It may even be the case that certain customers lose on dynamic pricing. Another small group of customers will profit substantially from variable pricing regimes.

The light blue distributions show savings under the present unit taxation. Without any response, the level will lie at or around the observed savings from switching supplier in the market. Although dynamic pricing provides benefits even without becoming flexible, it is unlikely that residential consumers would choose it with similarly attractive, but more stable, options at hand. Adding flexibility, switching may become attractive; the lower switching cost benchmark is exceeded at windows of 12 hours for all three consumer categories. The higher switching cost level is exceeded with full flexibility within 24 hours. For most consumers such levels of flexibility can only be achieved for parts of their consumption, so the simulated savings will be difficult to achieve in practice. With dynamic taxation (dark blue lines and distributions) the lower switching cost benchmark will be exceeded already by being flexible within 3-hour windows, while the high benchmark is exceeded at the 6-hour window for all categories. Taking into account the various behavioural constraints of households this seems more realistic. At the same time, though, benefits are distributed throughout a wider range with both winners and losers among the individual households.

Although the switching cost levels are somewhat hypothetical and very uncertain, they indicate that pure dynamic pricing might be insufficient to convince customers of, firstly, choosing a dynamically priced product and, subsequently, become active in response to the variable prices. Introducing dynamic taxation on the other hand could help to counteract the inertia of consumers and make them switch to dynamic pricing. But also a less intrusive option like the dynamic PSO payment might be helpful. In Figure C.4 we show the isolated effect of the dynamic PSO on the distribution of savings (note the shortened horizontal scale). Although effects are smaller than for dynamic taxes, this instrument would exceed the lower switching cost benchmark with 6-hour load shifting windows as well, and could thus be a real alternative to the wide ranging dynamic tax. The option seems particularly relevant with rising levels of the PSO payment to be expected as renewable capacity is further increased.

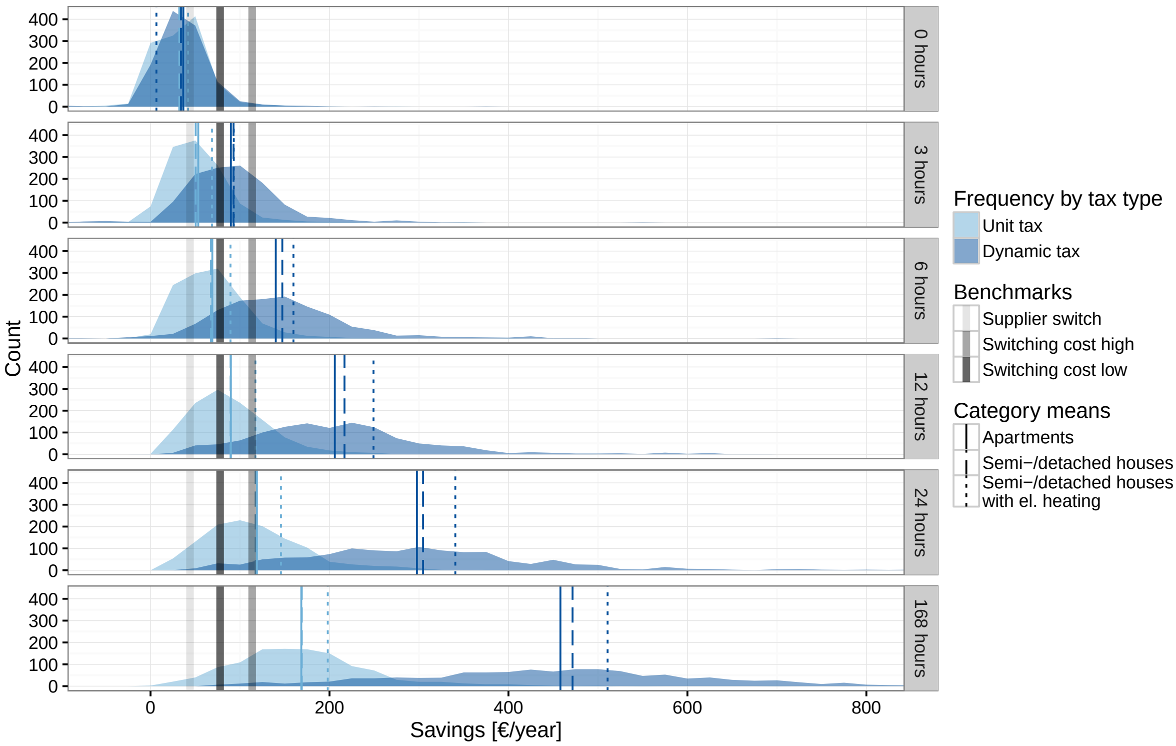

Figure C.3: Simulated savings of different load shift simulations with unit and dynamic taxation (total frequency distributions and consumer category means) comparing with switching threshold values

C.4 Discussion

On liberalised electricity retail markets dynamic pricing offers have to compete against other types of retail products. Despite of the high uncertainty in determining a level of benefits that would be sufficient for consumers to switch to dynamic pricing, our simulations show that substantial flexibility will be required from consumers to make savings from dynamic pricing more attractive than other retail market options. Benefits compensating for switching costs suggested by the applied model will be difficult to achieve with simple dynamic pricing. Dynamic taxation, or even just a dynamic PSO payment, has been shown to create an incentive exceeding switching costs at moderate levels of flexibility.

The rationale behind the retail electricity tax system in Denmark to date is primarily to generate an incentive to save energy and so reduce import dependency. This reaches back to the energy crises of the 1970s (Moe, 2007). At that time the largest share of electricity was produced from imported fossil fuels; so any unit of electricity saved had an immediate impact on imports. A per-kWh tax thus was well suited to provide the right incentives. Add to that the relatively limited elasticity of electricity demand in the short term, and the tax makes for a reliable and efficient source of government income. With the introduction of more and more low-carbon electricity production largely independent from fuel imports, the energy savings argument might not be as straightforward anymore. In addition timing of savings becomes more crucial in a wind-based system. Thus a dynamic electricity tax seems like an elegant solution to

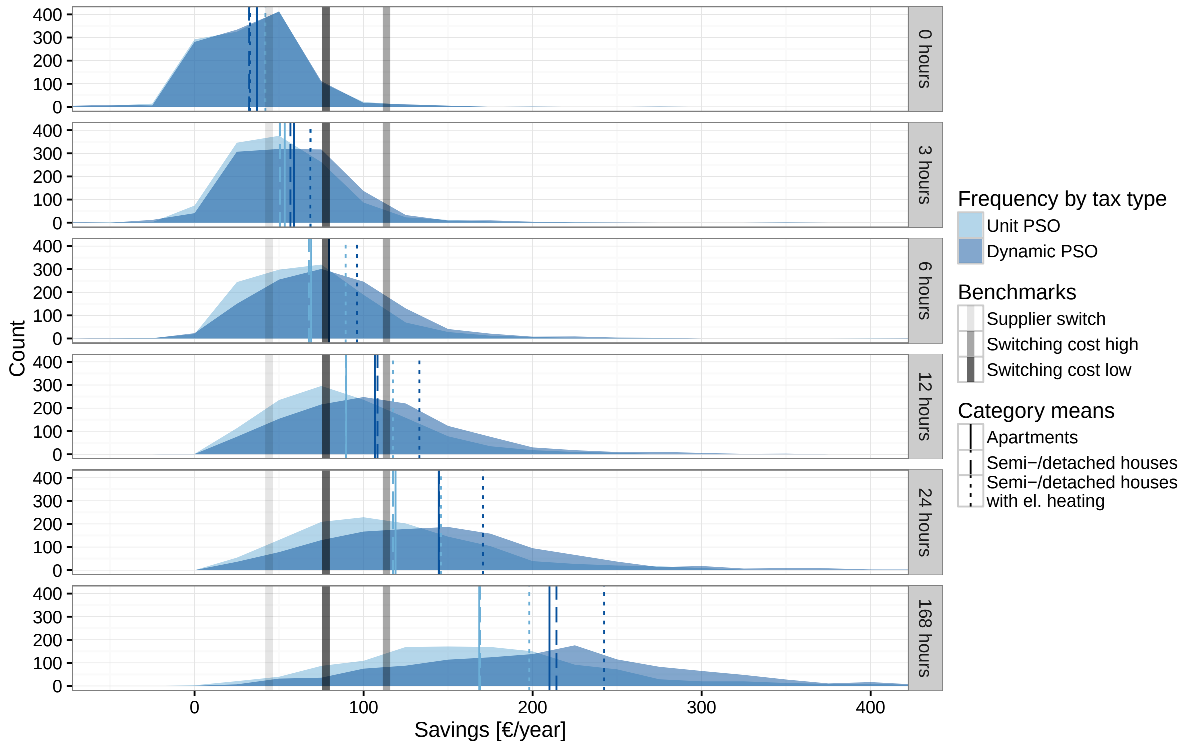

Figure C.4: Simulated savings of different load shift simulations with unit and dynamic PSO (total frequency distributions and consumer category means) comparing with switching threshold values

increase the incentive for demand response. It does, however, introduce a couple of questions as we will discuss in the following.

A fiscal issue of potentially more unstable state revenues with dynamic taxes arises from the fact that the tax income in a particular year is subject to uncertainty about both market price and resulting customer responses. It will become necessary to implement frequent adjustments of the tax rate to stabilise revenues. While technically the problem seems manageable, politically this may pose a substantial issue (Østrup, 2013). Regarding the PSO levy similar issues in determining future revenues are prevalent in the current system as well: neither production volume, nor market price can be predicted exactly. Currently the levy is adjusted on a quarterly basis; so a frequent adjustment of rates is common practice. If a dynamic tax rate would be kept stable or is adjusted less frequently, we estimate annual variations in the range of 20-30%. By rate adjustments it will be possible to keep revenue variations to a minimum.

From a welfare point of view it is essential to determine whether ad-valorem taxes introduce higher or lower distortions as compared to unit taxes. It is well-established theoretically that, in the case of fully competitive markets, unit and ad-valorem taxation that generate the same revenue are equivalent in terms of distortions (Kay & Keen, 1983). In oligopolistic settings ad-valorem taxation may even have the advantage of lower consumer prices than specific taxation raising the same amount of tax revenue (M. Keen, 1998). For electricity such conclusions would only hold on average while in the extreme situations of peak and off-peak consumption revenues will differ between the two techniques of taxation. Eventually, the distortive effect depends on the shape of demand

and supply curves, and we cannot at this point conclude which one of the taxation techniques would result in fewer dead-weight losses in the Danish retail market. As long as market mechanisms are missing that adequately address the flexibility potential of small-scale actors, a dynamic tax could as well be justified, if flexible household consumers enable the integration of intermittent production from renewable energies and thus provide environmental benefits.

A more political question is the distributional effect: if the total amount of tax income is to remain stable, then benefits for active customers will become a burden for passive customers. Moreover, distributions of results among individual consumers show that some will have better opportunities than others for participating in demand response activities. It would be worth investigating if certain characteristics beyond the categories we apply determine achievable benefits. This could provide the possibility of more targeted measures. Potentially, high income households that do have the resources to invest in, e.g., automation equipment would be likely to benefit more than others (Alexander, 2010). On the other hand even if low-income customers remain passive, they could benefit from an overall price reduction as a result of demand response from active customers (Borenstein, 2005).

The competitiveness of dynamic pricing will change over time, as price patterns develop more in favour of flexible loads with increasing shares of intermittent generation. In the future with even higher shares of production from wind energy we expect to see a significant increase in potential savings if price volatility increases accordingly. The impact of wind on prices in scenarios up to 2035 is noticeable (Capion & Meibom, 2016), and should lead to an increased interest in demand response. In order to prepare for a future situation with a high demand for flexibility, however, it could still be useful to implement additional incentives early on. Our analysis shows that dynamic taxation of electricity certainly is an instrument that adds to the incentive of adopting demand response. Savings could increase by a factor three or more for those customers that respond to prices. In combination with a smart meter roll-out and hourly pricing schemes dynamic taxation should be a feasible option to initiate the development of active demand response at household level; especially if substantial adoption of dynamic pricing is to be established before we see noteworthy market price impacts from large-scale renewable generation. If desired, an incentive structure like this could even be gradually phased out again in later years, with variations in energy prices increasing.

C.5 Conclusions

We have analysed the incentives for household demand response under hourly pricing schemes by calculating potential savings of individual households on their overall electricity bill. The reluctant switching behaviour of household consumers in the Danish retail market indicates that switching supplier or contract is perceived costly. We apply switching costs as a concept to explain the lack of switching, and calculate an estimate using recent observations in Danish retail competition. Accounting for such intangible costs, our results suggest that a combination of smart meter roll-out and the offering of dynamic pricing schemes might be insufficient to convince the average household consumers to switch contracts and become active in response to prices unless they hold a substantial flexibility potential. Distributions of benefits among individual customers, however, show that even if on average the results are only moderately attractive, a dynamic pricing scheme could still have success amongst a smaller group of customers.

Furthermore, our results show that dynamic taxation can help to activate flexible demand on a larger scale. Maintaining the relative effect of hourly price variations after taxes, increases the incentive to respond by a factor three in a Danish setting. Such a change in taxation technique, thus, makes it more likely that customers will switch their supplier and enter into demand-response activities. The issue of varying state revenues could be solved by annual or even quarterly rate adjustments. Distributional and welfare effects remain to be analysed in detail.

It could be an option to introduce an ad-valorem rate only for parts of the electricity levies and taxes. Keeping in mind the positive effect of the expected demand response on the integration of renewable production, it may be appropriate to apply dynamic rates only to those elements related to renewable sources (i.e. the so called PSO levy). Although effects are smaller, our results suggest that a dynamic PSO payment might be just sufficient to surmount an optimistic estimate of switching costs.

From a policy perspective a gradual approach to encourage dynamic retail pricing seems recommendable. As soon as settlement based on dynamic pricing becomes practically possible in the market, contract offers by suppliers and their respective adoption by consumers should be examined. If adoption lags behind expectation, it should be considered to introduce dynamics within a share of the electricity levies. As of now, the PSO payment seems to be an obvious starting point, but that could change at a later point. As all stakeholders gain experience, further adoption may be induced by introducing the full dynamic tax. During the time such a dynamic system is in place, the market development should be closely monitored. If at some point market prices would provide sufficient signals in support of demand response, commencing a gradual phase-out of the dynamic tax would be possible.

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Paper D

The impact of residential demand response on the costs of a fossil-free electricity system reserve

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Abstract

In order to achieve a better understanding of the system value of residential demand response, we study the potential impact of flexible demand on the costs of system reserves in a fossil-free electricity supply. Comparing these costs with traditional means of regulation, our analysis aims to contribute to the identification of the least-cost options for reserves in a fossil-free power system. To do so, we extend an existing energy system model with demand response and reserve modelling and analyse the impact for the case of Denmark in 2035 to reflect a system based on renewable resources for electricity and heating. The reserve requirement is determined subject to the installed wind power capacity. To reflect a realistic demand response potential, we base it on hourly distributions of suitable household appliances. Our results show that residential demand flexibility could provide significant value if used for intra-hourly reserves. The reserve value of flexible demand might even be higher than the value attainable in the hourly spot market.

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D.1 Introduction

The flexibility potential of the demand side has received increased attention in recent years from policy makers in countries developing large shares of variable renewable electricity generation (European Commission, 2015). System operators and regulators frequently mention the potential contribution of demand response to reliability in a system with large shares of renewable energies (Council of European Energy Regulators, 2016). Technically, load following production, could provide a partial solution to the arising intermittency problem. Such potential contributions of demand response to the efficient operation of power systems have been studied extensively in many different settings (Conchado & Linares, 2012) confirming that properly timed load adjustments generate benefits by avoiding or deferring investments in new generation or grid assets (Strbac, 2008).

One limitation of many types of demand response is the restriction to a short duration (Chassin & Rondeau, 2016). An evaluation of contributions to system operation must therefore be sufficiently detailed on the time scale. Many analyses focus on the hourly scale, and often the economic potential found is limited (e.g. Gottwalt et al., 2011; Prüggler, 2013). Flexibility of the demand side may, however, be better suited for short-term response. For instance, the Danish Energy Agency (2009) argues that new flexibility products are required to utilise demand-side resources; pure hourly spot price products would not suffice. In order to grasp the full potential one should include contributions within the hour (see also Welsch et al., 2014). Such flexibility could then be interpreted as a reserve to the power system.

In the future, reserve markets will become increasingly important. As wind power production rises, its fluctuations add to the reserve requirement of the system, as has been analysed in previous studies (see Brouwer et al., 2014, for a review). At the same time, the increased reserve demand has to be met by fewer dispatchable plants, because power from renewable sources displaces conventional generation. As a result, new providers of ancillary services will be needed (Douglass et al., 2011). Technically, demand response is capable of providing reserves if automation equipment is installed (Kirby, 2006). Such regulation is not just restricted to large industrial loads, but could also be provided by aggregation of many small residential loads (Molina-Garcia et al., 2011; Short et al., 2007). The available capacity could be used for reserves of different qualities (Kirby, 2003). It may even react faster than generation capacity, and some loads might be able to comply with the conditions for fast frequency control (Lakshmanan et al., 2016).

From a consumer's perspective, revenues in the reserve and balancing markets could significantly improve the business case of demand response (see Alcázar-Ortega et al., 2012; Bessa & Matos, 2014; Biegel et al., 2014; Hao et al., 2015; Hovgaard et al., 2012; Huang et al., 2015; Lakić et al., 2015; Valencia-Salazar et al., 2011). The precondition to install automation equipment could pose a barrier; but at the same time, participation in demand response by automation may be the more comfortable and effective option as opposed to manual response. Pilots and field experiments have shown that the interest in manual activities may be rather low (for experiences in Denmark see e.g. Lund et al., 2015; Togeby & Hay, 2009), and that large groups of, in particular, residential consumers stay unresponsive to price signals (Gyamfi et al., 2013). This is even more pronounced for complex schemes based on real-time pricing (Vanthournout et al., 2015). Another positive side-effect of automation may be that it prevents *response fatigue*, that is, a declining willingness to react over longer times or upon many events within a short time frame (Goldman et al., 2007). Ultimately, to conclude on the attractiveness of demand response as a reserve it is necessary to evaluate it from a system perspective. This has been done to some extent within different settings and by applying different modelling approaches in previous works. We briefly review these to point out the contribution of this paper.

In partial models of reserve markets, Shayesteh et al. (2010) and Artač et al. (2016) conclude that demand response may reduce the cost of reserves and increase reliability. Babonneau et al. (2016) present a linear model that explicitly includes the contribution of decentralised generation and demand in distribution grids to secondary reserves and reactive power. They demonstrate how the developed module can be directly applied within large energy system models. Keane et al. (2011) use a stochastic unit-commitment model of the electricity system to evaluate operational benefits of demand-side resources, including the impact of providing system reserves. The study concludes that demand flexibility may significantly improve adequacy. It does not consider, though, how this would affect investments in new capacities. Brouwer et al. (2016) also use a unit-commitment model and include requirements for spinning and standing reserves to model the impact of different flexibility options (amongst them demand response) on system costs including investments in new capacities. Demand response is not allowed to provide reserves, though, as the capabilities of demand response regarding reserve provision are considered uncertain. Zerrahn and Schill (2015a) present a linear energy system model that explicitly models reserve provision of different qualities. While the model is calibrated to German conditions, it does not include existing generation, interconnections to neighbouring countries or other energy sectors.

We want to contribute with a study of residential demand response in Denmark using *Balmorel*, a partial equilibrium model of the electricity and district heating systems formulated as a linear program (see Hindsberger, 2003; Ravn et al., 2001, for a detailed description). In this paper, we (1) implement a residential demand response model in *Balmorel*; (2) implement a reserve requirement in the model based on statistical characteristics of forecasting errors and contingencies; (3) estimate the cost of reserves without demand response; (4) estimate the potential savings in costs of reserves with contributions from demand response. In comparison to most of the studies mentioned above, the model has a larger sectoral and geographical scope. Our focus, though, lies on Denmark and the cost of reserve provision in the electricity system. We use a strictly linear model resulting in formulations regarding the reserve provision that differ from previously published models. The flexibility potential we use is defined per hour and based on a bottom-up analysis of residential appliances. To determine the reserve requirement, we use a static probabilistic approach to construct a reserve demand curve dependent on the share of installed wind power.

D.2 Method

D.2.1 Demand response modelling

As a first step, we extend the existing system model *Balmorel* by incorporating responsive electricity demand from households. Implementations of demand-side flexibility in *Balmorel* and similar models have been done in previous works. Some of these have focussed on single applications like electric vehicles (Hedegaard et al., 2012; Juul, 2012; Kiviluoma & Meibom, 2010) or residential heat pumps (Hedegaard & Balyk, 2013; Hedegaard & Münster, 2013). Early versions of the model already included the possibility of adding demand response in the form of elastic demand curves (see Grohnheit & Klavs, 2000). Certainly good arguments exist to represent residential electricity consumers' ability to be flexible using price elasticities. On the other hand, due to the limited manual response under real-time pricing, automation of response could become a crucial factor. The automation algorithms may be better represented by generic storage-like models instead of elasticities (as implemeted by e.g. Biegel et al., 2014; Göransson et al., 2014; Tveten et al., 2016; Zerrahn & Schill, 2015b). Moreover, the technical potential can be more directly assessed looking at the usage of different appliances, as opposed to assessing the more abstract concept of price elasticity.

We implement a generic demand response model that is based on assumptions about the flexibility of different categories of household appliances. We then use hourly consumption profiles per appliance category to define the distribution of the flexibility potential throughout the year. The consumption data set and its construction has been described by Jacobsen and Juul (2015). It builds on data from several sources. First, average daily load curves for individual appliances on working days and weekends have been adopted from a large European study (Grinden & Feilberg, 2008). These have been adjusted to Danish conditions using information about annual profiles of Danish household consumption (Energinet.dk & Dansk Energi Net, 2016) as well as ownership rates (Danish Energy Agency, 2016b). The daily profiles have been rolled out accounting for seasonality in appliance use (as observed by Bennich et al., 2011). Appliances covered make up around 25% of total Danish electricity demand.

The appliance profiles have been divided into four categories with different load-shifting capabilities. Time windows for load shifting have been assigned to each of the categories based on literature values as shown in Table D.1 (Bertsch et al., 2012; Franz et al., 2006; Gils, 2014). We restrict shifting to major appliances for cleaning, cooling and freezing. Appliances for cooking, lighting as well as smaller devices such as consumer electronics are not considered available for automated control. Figure D.1 shows the hourly appliance profiles for one week coloured according to the assigned categories.

The consumption of the relevant appliances is included in the model as a flexibility potential. Our extensions to the model are described below with a list of symbols at the end of the paper. For every hour h, geographic area a and appliance category j, we define a flexibility potential $D_{a,h,j}^{flex\text{-}pot}$ defined by the hourly end-use profiles per appliance. The time windows defined in Table D.1 are termed S_j. Within these windows the changes in demand due to load shifting $D_{a,h,j}^{flex}$ are determined such that:

$$\sum_{h}^{h+S_j} D_{a,h,j}^{flex} = 0 \quad \forall\, j, \{\, h \in T \mid (h-1) \bmod S_j = 0 \,\} \tag{D.1}$$

Table D.1: Load-shift potential per category

Appliances	**Time window**
Cleaning	**24 hours**
Washing machine	
Dishwasher	
Tumble dryer	
Freezing	**4 hours**
Freezer	
Cooling	**2 hours**
Refrigerator	
Refrigerator with freezer	
Inflexible	**0 hours**
Lighting	
Cooker	
Microwave oven	
Electric kettle	
Vacuum cleaner	
Audio/Video	
Mobile phone charger	
Computer	

The sum of $D^{flex}_{a,h,j}$ over all categories j thus represents the hourly load-shift delta in MW relative to the baseline demand of the hour. It will also be used in the overall system balance equation to adjust the load to be served by the system. As the system model we use is defined with an hourly resolution, this representation reflects participation of flexible demand in the hourly spot market. We could as well reserve the flexibility for activation within the hour reflecting participation of demand flexibility in the system reserve. We will therefore include unused flexibility in our reserve modelling in section D.2.3, equations (D.10) and (D.11).

Equation (D.1) could have been applied to all hours $h \in T$, i.e. a rolling time window

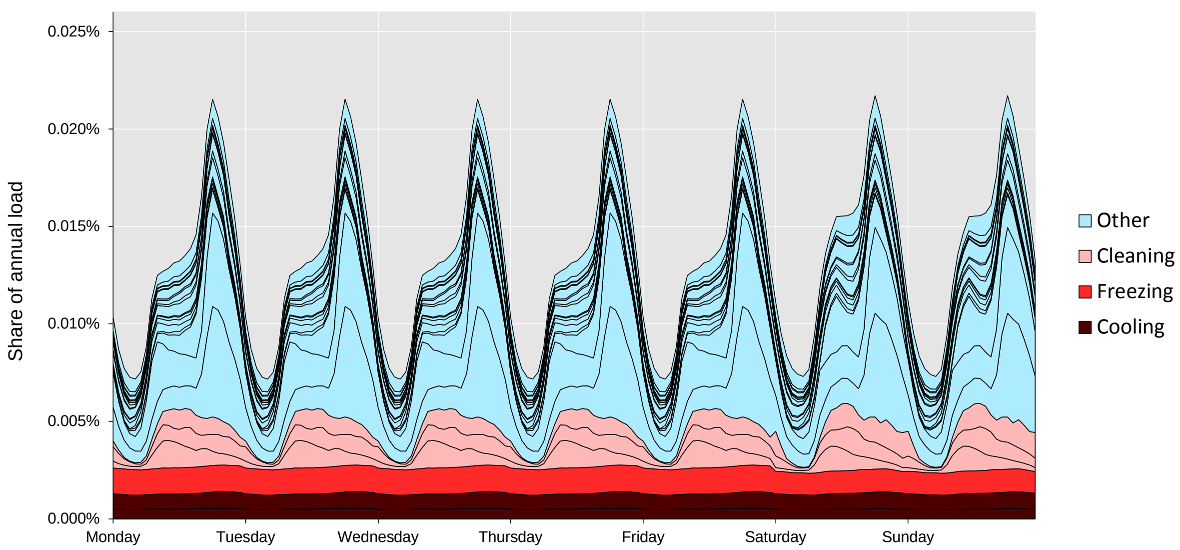

Figure D.1: Hourly appliance load profiles for one week

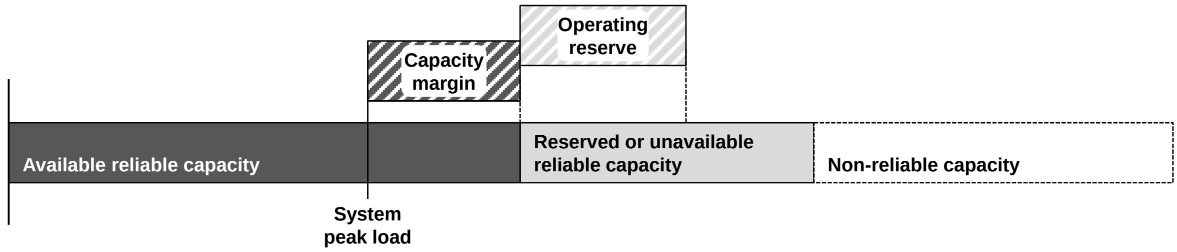

Figure D.2: Division of installed capacity

across all hours. Because we only consider demand flexibility actions that do not add or remove demand, but just shift it across time, such a rolling constraint would create interdependencies, even for hours that lie far apart from one another. In order to avoid this, we use fixed time windows defined by the capabilities of relevant flexible appliances. Therefore every window starts only in an hour h that is a multiple of the window length S_j determined by use of the mod-operator that provides us with the remainder of the division $(h-1)/S_j$.

To always cover inflexible conventional demand, flexibility is restricted in the following way:

$$D^{flex}_{a,h,j} \geq -D^{flex\text{-}pot}_{a,h,j} \quad \forall\, h, a \tag{D.2}$$

We allow $D^{flex}_{a,h,j}$ to reduce demand (i.e. the variable may become negative), but it is always limited by the potential. On the other hand we do not include an upward limit, so that the model is free to choose the optimal time of consumption within the time windows S_j.

D.2.2 Reserve dimensioning

A reliable system requires a certain reserve margin to ensure that sufficient capacity is available at any point in time to serve load. Figure D.2 illustrates how installed capacity may contribute to the margin. The most simple approach to define an adequate capacity compares the system peak load with the available generation capacity. A distinction has to be made between reliable and non-reliable capacity. Plants with limitations in the fuel supply or primary energy source, such as wind and solar power, would traditionally not be counted as a reliable source (ENTSO-E, 2012). In Europe at present, the whole definition of adequate capacity is subject to revisions that aim to include probabilistic analyses due to the development of renewable production (ENTSO-E, 2015). As a result, certain shares of the variable production could be considered reliable in the future. Capacity from dispatchable plants counts as reliable, unless it is out for maintenance, mothballed or reserved for system services. The remaining available reliable capacity should add up to exceed peak demand by a minimum spare capacity margin. Recommendations for such a margin range from defining it deterministically, i.e. as a percentage of total generation capacity, to using a probabilistic approach that ensures a shortage risk of, e.g., less than 1% accounting for the risk of outages.

In a linear programming model, like the one used for our analysis, a system balance equation warrants that production and load match in all time steps. Based on this constraint, costs would be minimised by investing in production capacity that is exactly able to cover demand up to the system peak load. As illustrated by Figure D.2, this would exclude the capacity margin. Accounting for a reserve margin thus requires the definition of additional constraints. To implement the deterministic version of the above adequacy requirement, average availability factors may be used. Plant availabilities between 90% and 95% depending on the technology have been suggested (Kiviluoma & Meibom, 2010). With such an approach alone, installed capacity would always have to be slightly higher than the load served. This would fulfil the adequacy requirement if the modelling period includes the system peak. Capacity defined as unavailable for adequacy, such as intermittent production, and non-domestic sources, i.e. imports, may have been included to cover for the required capacity, though.

To ensure sufficient reliable capacity from domestic sources a capacity balance equation may be included to define technologies allowed to contribute to the margin. Random non-availabilities during system peak may be accounted for by limiting the contribution of a technology through a capacity credit (Doherty et al., 2006). Applying this approach, appropriately determines a capacity margin both excluding unavailable reliable capacity as well as non-reliable capacity. Depending on the underlying assumptions on capacity credits one could even argue that the capacity margin implies the system need of operating reserves as well. From the studies that apply the approach, however, it cannot be told whether this had been the intention or not. In determining an adequate capacity in accordance with ENTSO-E (2015), the capacity required for operating reserves needs to be taken into account, and in our analysis we aim to include it explicitly. In contrast to the capacity margin, the operating reserve only covers short-term imbalances with a duration of less than one hour.

The main purpose of including the reserve in our analysis is to determine the potential contribution from demand flexibility. The approach using a capacity balance equation with capacity credits allows for an extension to account for flexible demand, as it has been demonstrated for electric vehicles (Hedegaard et al., 2012; Juul, 2011) and heat pumps (Hedegaard & Balyk, 2013). These extensions allow for peak shaving to reduce the capacity margin. An advantage of including an operating reserve requirement is that it provides us with the possibility of assigning an additional capacity value to demand response that goes beyond the hourly peak-shaving contribution analysed in the mentioned studies.

There is no absolute set of rules for the calculation of the requirement for reserves, and different types of methodologies are available (Ibanez et al., 2014). For continental Europe, rules are provided by ENTSO-E (2004). Furthermore, a new grid code on load-frequency control and reserves is under development (ENTSO-E, 2013). Nordic rules are defined by Nordel (2006). All of these arrangements, however, leave some degree of freedom to the individual system operators. Traditionally, deterministic methods have been used to determine reserves relying solely on variations in the system load. The ENTSO-E Operation Handbook still proposes a deterministic formula to size control reserves for predictable load and generation variations (ENTSO-E, 2009). Methods relying on the probabilistic characteristics of variability and contingencies, however, are becoming more common (Ela et al., 2010; Jost, Speckmann et al., 2015).

For Denmark, criteria for measuring security of supply have been set forth (Danish Energy Agency, 2015b). The Danish Energy Agency uses a probabilistic model to determine the level of security of supply in Denmark (Danish Energy Agency, 2015a). A procedure to explicitly determine a reserve requirement, however, is not included.

For the future Danish system the impact of fluctuations and forecast errors in relation to renewable energies on the demand for reserves will be a central issue. The influence of wind power on the reserve requirement is analysed in several studies (for reviews see Ela et al., 2010, 2011; Hamon & Söder, 2011; Holttinen et al., 2012; Milligan et al., 2010). A general finding is that wind power only influences the operating reserve requirement and not the contingency reserves (Holttinen et al., 2012). This would mostly affect slower types of reserves. With higher levels of penetration and the development of large offshore wind farms, however, fast frequency response may also be affected (Das et al., 2015).

Our approach to determine the reserve margin is based on static probabilistic criteria. It combines the need for a capacity margin due to contingencies on plants and lines with deviations due to forecast errors. The requirement will not be dynamically updated and may therefore overestimate the actual costs of reserves slightly. Due to the focus of this paper on the change of costs from demand response contributions, we find this to be acceptable.

Following the findings by Holttinen et al. (2012) as well as Gül and Stenzel (2005), forecasting errors reflect the most important balancing issue introduced by wind power, which will make up a large share of the system we analyse. Holttinen et al. (2009) use the standard deviation to characterise the increase in operational reserve requirements from wind. Hodge et al. (2012), however, find that normal distributions are not good at approximating the distribution of wind forecast errors due to their narrow tails and a low peak. They propose to use the hyperbolic or the Cauchy distributions instead (see also Hodge & Milligan, 2011). Similar findings are presented by Bludszuweit et al. (2008) proposing the beta distribution for a better fit, their main argument being pronounced kurtosis of the error distribution. Hodge et al. (2012) compare distributions of wind forecast errors across different countries. For Denmark the distribution is found to be fairly symmetric and its skewness not very distinct. We circumvent the question of the exact distribution of errors by using a probability density estimate based on the relative frequency count within 1 MW bins.

Danish day-ahead forecast errors on an hourly basis are available from for the years 2013 to 2015 from Nord Pool (2016). We use these data in combination with information on the installed wind capacities throughout the period (Danish Energy Agency, 2016a) to determine a probability distribution of wind forecast errors relative to capacity. The day-ahead errors will to some extent be corrected in the intraday market by balance responsible traders. For the dimensioning of reserves capacities a more critical dimension is the hour-ahead error (Das et al., 2015). Dragging on Danish experience, the normalised wind forecast error can be reduced from 5.2% at day-ahead to 3.0% at hour-ahead (ENTSO-E, 2010). Nitsch et al. (2012) provide even more optimistic figures in a German study and expect further improvements in the future. We therefore find it appropriate to use 50% of the observed day-ahead forecast errors as an approximation for the hour-ahead forecast (see the second panel in Figure D.3 for the resulting distribution).

Gül and Stenzel (2005) underline that the role of the demand side as a driver for reserve capacity is limited due to low forecasting errors of 1–5%. In the future, therefore, operational reserve capacity may be dispatched mainly for reasons related to the supply side. Load forecasting errors will, however, still have a role to play in reserve dimensioning. We therefore apply a distribution of load forecast errors also using data

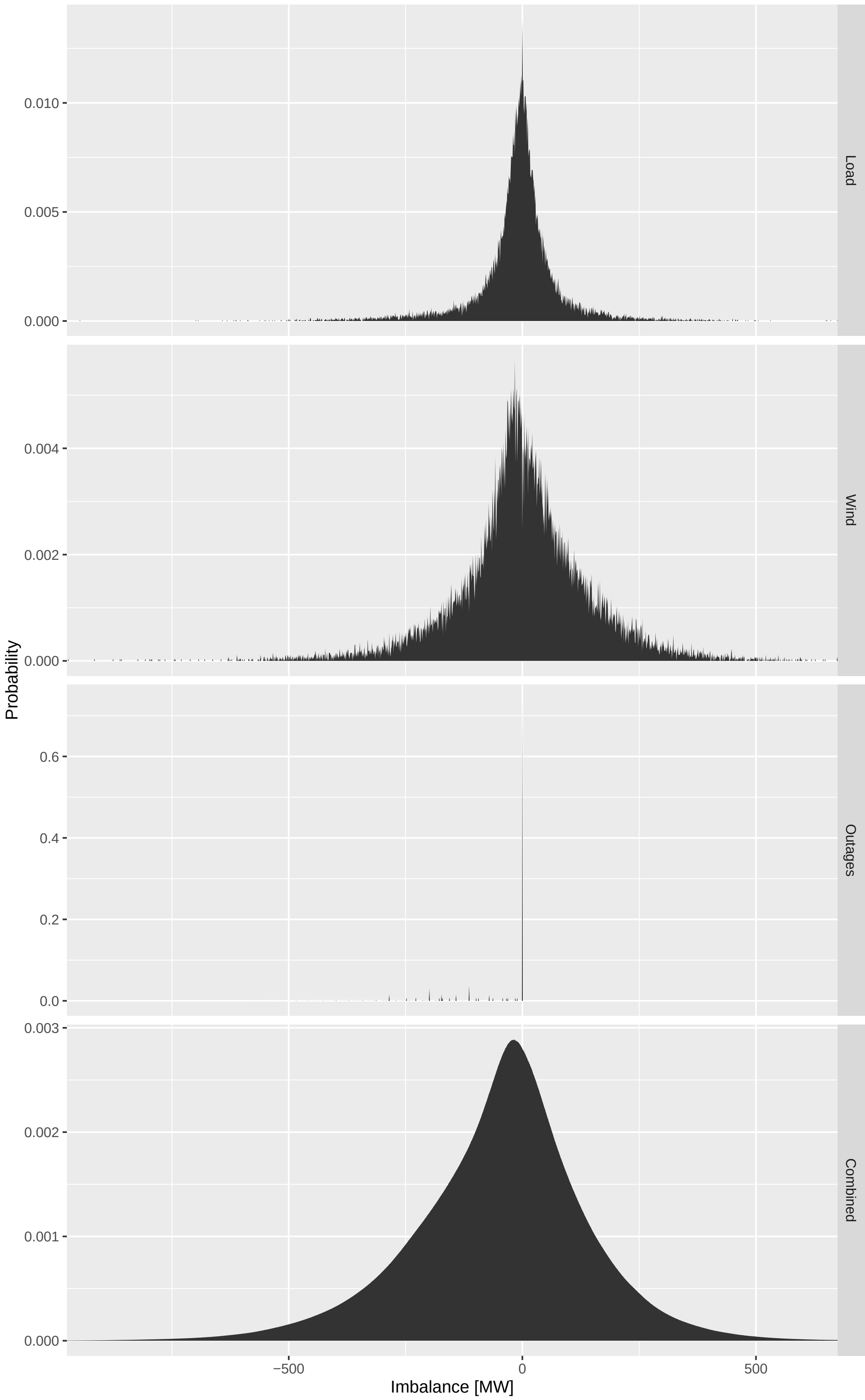

Figure D.3: Distributions of load, wind, outages and combined distribution of imbalances from Nord Pool (2016). It is shown in the upper panel of Figure D.3.

Besides operating reserves to cover forecast errors in load and wind, we take into account capacity to cover for contingencies, as critical outages may occur on power stations or transmission capacity. For the Danish system we take into account capacities in Table D.2 (data based on CESI et al., 2005; Energinet.dk, 2015). We only consider full outages and disregard the possibility of partial outages in this analysis. To calculate probability distributions for outages we use 4000 full load hours for power plant blocks, which corresponds to the number used by Danish Energy Agency (2014a). For transmission lines we use 2500 full load hours corresponding to an average of data on imports over the different lines in 2015 (based on data retrieved from Energinet.dk, 2016b). We use a common outage risk on all lines and plants of 1% in any given hour. This number is close to the outage risks considered in a comprehensive German study (Jansen et al., 2005). Figure D.3 shows the resulting probability distribution for outages

Table D.2: Capacities included for contingency estimation (estimations based on CESI et al., 2005; Energinet.dk, 2015)

	Capacity [MW]
Power plants	
Fynsværket Block 7	380
Fynsværket Block 8	35
Nordjyllandsværket Block 3	380
Skærbækværket Block 3	390
Amagerværket Block 1	70
Amagerværket Block 3	250
Asnæsværket Block 2	140
Avedøreværket Block 1	250
Avedøreværket Block 2	545
HC Ørstedværket Block 7	75
HC Ørstedværket Block 8	25
Transmission lines	
Sweden - Eastern Denmark	800
	500
Germany - Eastern Denmark	600
	400
Norway - Western Denmark	250
	250
	500
	700
Sweden - Western Denmark	350
	330
Germany - Western Denmark	150
	550
	400
	400
	1000
	1000
UK - Western Denmark	700
	700
Netherlands - Western Denmark	700

in the third panel, obtained by convolution of the individual outage risk probabilities. The probability of no failures occurring at all is thus around 70%.

With these 3 major sources of imbalance risk: wind forecast errors, load forecast errors and outages, we estimate a joint distribution of imbalances for the whole system by convolution (as commonly applied in, e.g., Jansen et al., 2005; Jost, Braun et al., 2015; Jost, Speckmann et al., 2015; Molly et al., 2010). In order to do so, we have to assume that the events are independent. For plant and line failures versus forecasting errors this should be the case. A correlation of wind and load forecasting errors should not be ruled out in general. For the sake of this analysis, however, we ignore any potential correlations. As we have normalised the wind forecast errors to the installed capacity, we are able to scale them to the a relevant capacity in a future scenario. Figure D.3 shows the resulting distribution applying the currently installed capacity of around 5 GW.

In order to determine reserve capacity we need to define the level of deviations required to be covered. The exact criteria used in practice is not publicly available. A security margin of 99.9% corresponding to a loss of load probability (LOLP) of 0.1% or 8.76 hours per year is sometimes used (ENTSO-E, 2009). In the light of numbers for actual outages this seems high in a Danish context. We calculate a reserve according to a requirement of a LOLP of 1 hour per year. We use the cumulative probabilities to find positive and negative reserve requirements. For the reserve modeling we only use the positive reserve assuming that negative capacity would always be available by means of reducing production. For different levels of installed wind capacity the resulting reserve requirement is shown in Figure D.4. We divide the reserve requirement

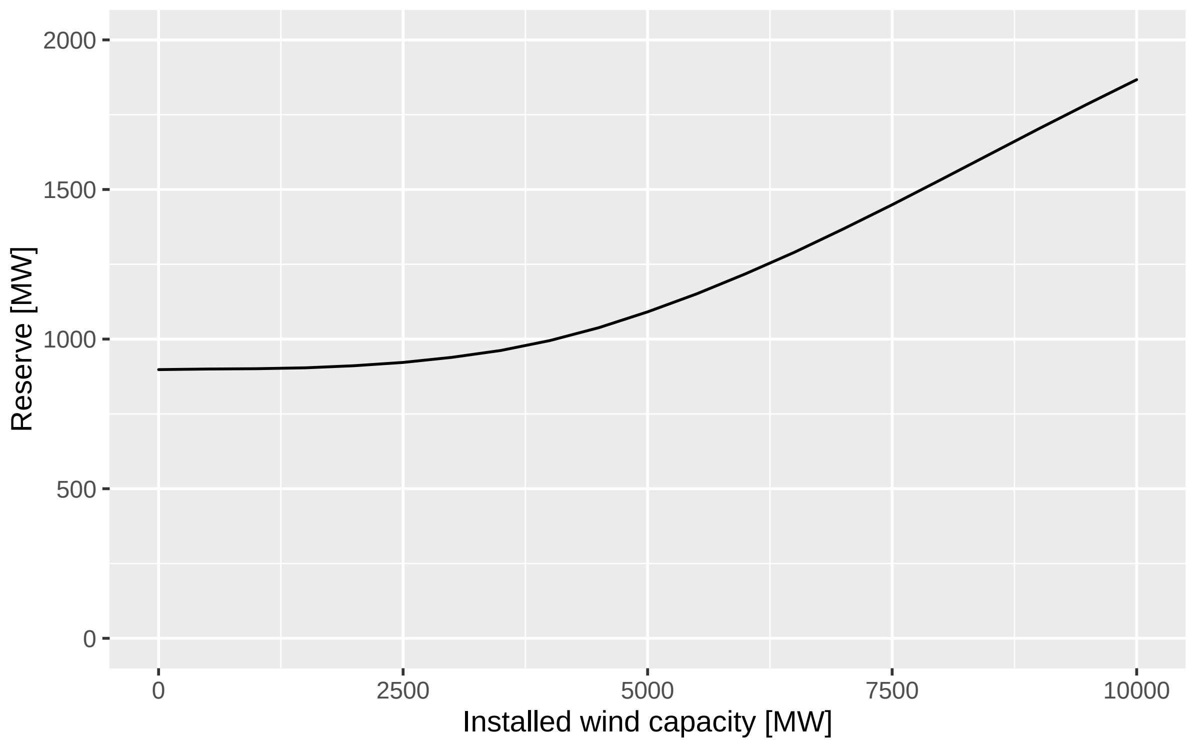

Figure D.4: Reserve requirement dependent on the installed wind capacity assuming a LOLP of 1 h/a into two qualities, fast and slow, representing two categories of response time largely corresponding to secondary and tertiary control. On the basis of the yearly maximum of historically activated capacity of secondary and tertiary reserves (as of data retrieved from Energinet.dk, 2016b) we use a division of 10% for fast and 90% for slow reserves.

D.2.3 Reserve modelling

In order to determine the cost of a reserve capacity margin in a fossil-free scenario for Denmark in 2035, besides the reserve requirement of the system, we need to define the capacity available to cover for the reserves. We require total capacity to be able to fulfil demand in any given hour. The hourly flexible demand variable as introduced in equations (D.1) and (D.2) enables peak shaving in order to save costs of installing peak capacity. Moreover, we want to ensure that in any given hour we are able to cover for an additional reserve requirement as determined in the previous section D.2.2. In order to take into account the capability of different types of generation technologies in regard to ramping, we define subsets of technologies that are able to provide the system with fast (FR) and with slow reserves (SR). Fast reserves include capacities for regulating and ramping reserves corresponding to secondary reserve in ENTSO-E terms that are immediately activated (Milligan et al., 2010). Slow reserves include capacities for load-following reserve and supplemental reserves corresponding to tertiary reserves. Depending on the technology used, a share of capacity may be required to be spinning. This way we make sure that a technology with long start-up times or slow ramping capability is actually available in the required hour. Technology types used for reserves are shown in Table D.3.

Table D.3: Generation technologies providing reserve

	Slow	**Fast**
spinning required	Steam turbines	Steam turbines
	CCGT	CCGT
		Gas turbines
no spinning required	Gas turbines	
	Combustion engines	

Technologies capable of providing fast reserve capacity should reserve a share of capacity in any given hour such that, after planned generation, the sum of available capacity covers the reserve requirement. We define a variable for such reserved capacity per technology g, area a and time step h for both slow and fast reserves respectively ($K^{FR/SR}_{a,g,h}$). To fulfil the reserve requirement in every country c we define:

$$\sum_{a \in A_c} \sum_{g \in FR} K^{FR}_{a,g,h} \geq R^{FR}_c \quad \forall\, h, c \tag{D.3}$$

Similarly for the slow reserve capacity:

$$\sum_{a \in A_c} \sum_{g \in SR} K^{SR}_{a,g,h} \geq R^{SR}_c \quad \forall\, h, c \tag{D.4}$$

The installed capacity of any individual technology capable of providing reserves constrains hourly reserve provision such that:

$$K_{a,g} - G_{a,g,h} \geq K^{FR}_{a,g,h} + K^{SR}_{a,g,h} \quad \forall\, h, a, g \tag{D.5}$$

For the technologies providing fast reserve capacity we also want to ensure that sufficient capacity is spinning:

$$G_{a,g,h} \geq k^{spin} \cdot K^{FR}_{a,g,h} \quad \forall\, h, a, g \tag{D.6}$$

where k^{spin} defines the proportion of capacity available for reserves. A similar constraint is added for the slow reserve technologies required to be spinning.

This ensures that no reserves may be provided if a technology is not running. At the same time the constraint forces capacities to be running at higher levels to be able to provide sufficient capacity. This formulation is only an approximation in order to avoid unit commitment. We do ensure on a technology basis that capacity will be spinning. We do not, however, exactly ensure in this way that a particular unit considered for up-regulation will be spinning. What we do know is that some capacity of a technology that would be capable of fast up-regulation is spinning. As usually several units of the same technology type would be present in the system, we may risk that all spinning units are fully utilised and we rely on a different non-spinning unit for the fast reserve. We do consider this inaccuracy to be acceptable in the context of our analysis.

The constraint we use to force spinning capacities in equation (D.6) allows for increasing levels of reserve provision as generation of a technology increases. To reflect the ramping capability of generation technologies more realistically we introduce an additional constraint to limit the reserve provision of a technology to a certain percentage of installed capacity.

$$K_{a,g} \cdot k^{ramp} \geq K^{FR}_{a,g,h} \quad \forall\, h, a, g \tag{D.7}$$

We use approximate ramp rates; moreover, we define the spinning factor k^{spin} such that it stays active only until a minimum load level of 20% is reached.[1] Therefore, as far as reserve provision is concerned, the full ramping capability is only utilised at levels above the minimum load. Again we avoid unit commitment modelling and do not model minimum load requirements explicitly. We do, however, substantially restrict reserve provision at generation levels below the technical minimum using this kind of non-integer linear approximation. Table D.4 shows the technology characteristics used (based on Papaefthymiou et al., 2014). The potential for reserve provision subject to the level of generation of the different technologies is indicated by the dark grey areas in Figures D.5–D.7.

To determine the overall required capacity we apply an approach incorporating demand flexibility in a way similar to that of Hedegaard and Balyk (2013). To determine the capacity margin (as illustrated in Figure D.2) we use technology specific capacity credits to account for availability constraints at system peak. In addition we have defined an operating reserve requirement by equations (D.3) and (D.4). This far, demand flexibility only explicitly affects the hourly energy balance of the system, and demand flexibility is able to reduce required peak capacity to serve hourly load. We would like

[1] This will be the case for $k^{spin} = \frac{load^{min}}{k^{ramp}}$

Table D.4: Technology characteristics used in reserve constraints

Technology	**Min. load** [%]	**Ramp rate** [%/5 min.]	k_{spin} [-]
Steam turbines	20%	20%	1
CCGT	20%	20%	1
Gas turbines	20%	40%	0.5
Combustion engines	0%	100%	-

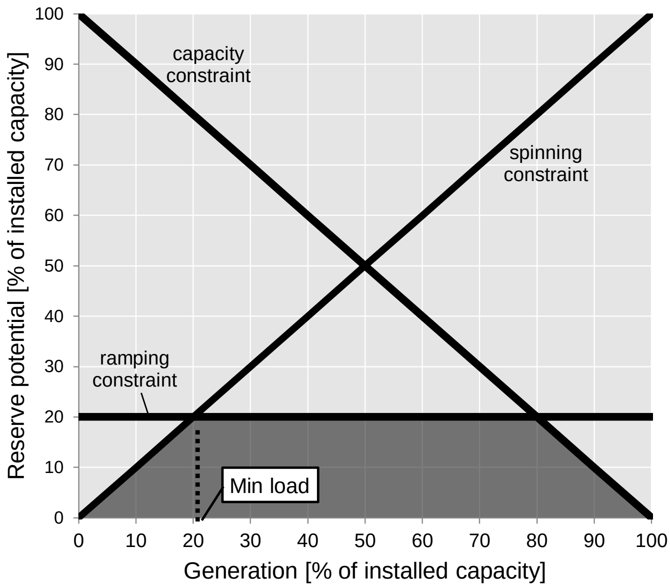

Figure D.5: Potential reserve provision from steam turbines and CCGT

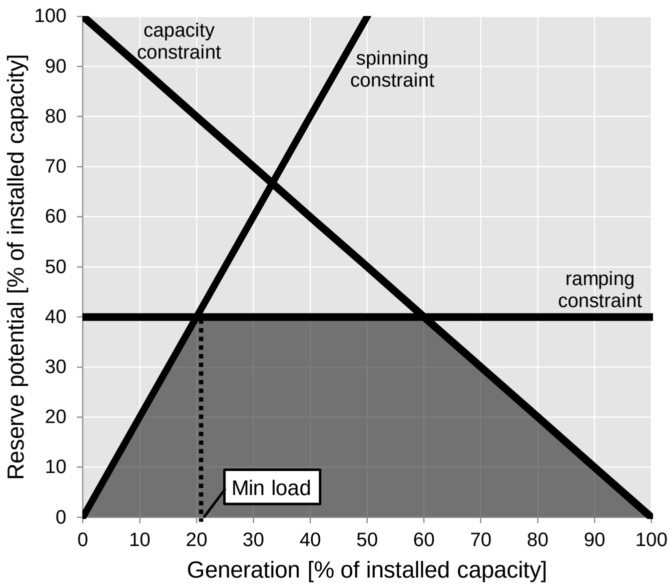

Figure D.6: Potential reserve provision from gas turbines

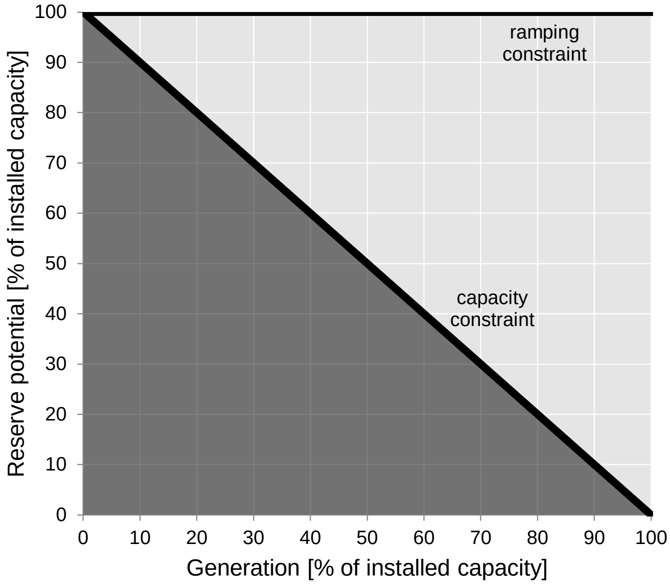

Figure D.7: Potential reserve provision from combustion engines

to extend this approach, though, to also allow for provision of reserves from demand flexibility. To analyse this case we extend the reserve capacity equations (D.3) and (D.4) with variables reflecting reserve contribution from demand response $R_j^{Dflex,SR/FR}$:

$$\sum_{a \in A_c} \sum_{g \in FR} K_{a,g,h}^{FR} \geq R_c^{FR} - \sum_j \sum_{a \in A_c} R_{a,h,j}^{Dflex,FR} \quad \forall\, h, c \tag{D.8}$$

$$\sum_{a \in A_c} \sum_{g \in SR} K_{a,g,h}^{SR} \geq R_c^{SR} - \sum_j \sum_{a \in A_c} R_{a,h,j}^{Dflex,SR} \quad \forall\, h, c \tag{D.9}$$

The flexibility potential of the demand side may only contribute to reserves if it is not utilised in the spot market. As we only consider positive reserves, we have to be able to reduce consumption in order to contribute:

$$D_{a,h,j}^{flex\text{-}pot} + D_{a,h,j}^{flex} \geq R_{a,h,j}^{Dflex,FR} + R_{a,h,j}^{Dflex,SR} \quad \forall\, h, a, j \tag{D.10}$$

We want to avoid, however, that a planned increase in consumption due to postponed demand in earlier hours will be postponed even further as this would violate the assumptions used in the demand response modelling of a limited time window for any response. Therefore additional demand due to activated flexibility is not allowed to be curtailed and used for reserves. Consequently, any contribution of demand flexibility to reserves is restricted to the original flexibility potential:

$$D_{a,h,j}^{flex\text{-}pot} \geq R_{a,h,j}^{Dflex,FR} + R_{a,h,j}^{Dflex,SR} \quad \forall\, h, a, j \tag{D.11}$$

In principle, the model would be free to choose whether the demand side would provide fast or slow reserves. We find it relevant to restrict this due to two reasons: 1) we lack information on the reaction times of the controlled appliances, but assume that some devices would be restricted to deliver slow reserves; 2) we consider it unlikely that the system operator would solely rely on fast reserve provision by demand-side resource – a result that could easily occur without further restrictions. For those reasons, we limit the provision of fast reserves from the demand side to 10%.

As opposed to reserves from generation capacity, the shifting of consumption in time implies that it has to be recovered at some point. We do take this into account as long as demand is shifted in the hourly simulation. As we do not explicitly model activation of reserves within the hour, we lack the need for recovery. Thus reserve provision from demand response would not take into account the potential costs of an activation. Therefore we assume an average activation of demand response and distribute recovery equally over the following hours corresponding to the time window of the response. The overall system balance equation is extended by adding the following term:

$$\cdots + D^{flex}_{a,h,j} + \alpha \sum_j \left(\sum_{t=h-S_j}^{h} \frac{R^{Dflex,FR}_{a,j}(t) + R^{Dflex,SR}_{a,j}(t)}{S_j} - R^{Dflex,FR}_{a,j}(h) - R^{Dflex,SR}_{a,j}(h) \right) \tag{D.12}$$

The factor α represents the fraction of reserve capacity expected to be activated. Based on historical observations (Energinet.dk, 2016b) we use a factor of $\alpha = 0.15$.

D.2.4 Scenario set-up

Denmark pursues a strategy of decarbonising its energy system. Although not undisputed, the long-term target of a fossil-free energy system in 2050 is widely supported. An important contribution is supposed to come from the electricity and heating sectors, both of which should become fully renewable by 2035 according to a strategy set forth by the Danish Government (2011). We reflect this strategy in our model using framework conditions in line with the Danish Energy Agency (2014b) "wind scenario" (see Salvucci & Münster, 2015, for further details regarding the scenario implementation). Although the model formulations in sections D.2.1 and D.2.3 are applicable to cover any country that is part of the model, we focus on Denmark only for this case study. Both the reserve requirements and the demand response model are therefore only applied in the two Danish regions East and West in order to isolate the effects.

We set up the following model runs for the year 2035 in order to evaluate the system contribution of demand response with high shares of renewable energies:

1. Reference case: including neither reserve requirement nor flexible demand;

2. Reference with flexibility: including flexible demand, but no reserve requirement;

3. Reserves with hourly flexibility: including reserve requirement, and flexible demand in the hourly energy balance equation;

4. Reserves with demand flexibility reserve: including reserve requirement, with flexible demand included in the energy and reserve balance equations.

The difference in costs between the reference and the base case reflects the costs of the reserve requirement if no flexible demand is available. We want to determine the potential contribution of flexible demand to a reduction of these costs. Therefore we need to isolate the effect on reserves from general savings in the spot market. We

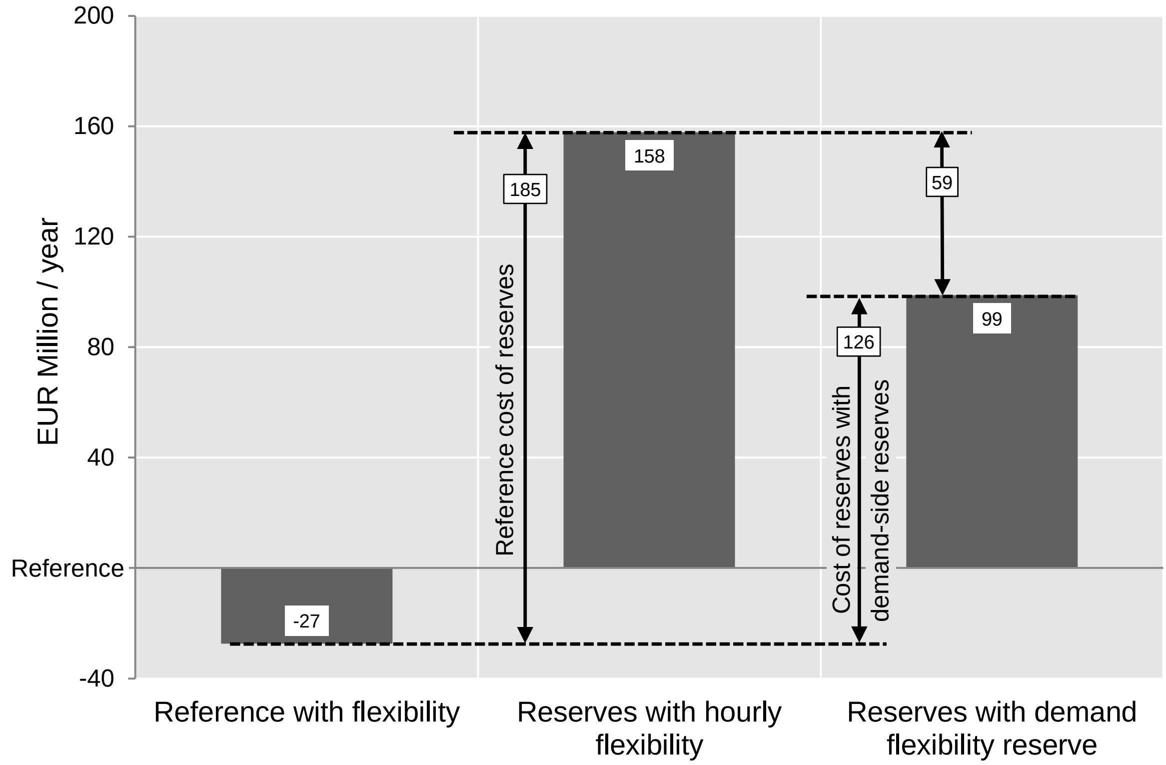

Figure D.8: Reserve costs derived from case results 2–4 relative to the reference case 1

can calculate the benefit that demand flexibility generates in the hourly spot market as the difference between the total system costs of cases 1 and 2, the reference cases without and with demand flexibility. To determine the net effect of a direct contribution of demand flexibility to reserves, we first find the reference costs of reserve without demand flexibility (case 2 minus case 3) and compare it to the new reduced costs (case 2 minus case 4).

D.3 Results

The reference case results provide us with a benchmark to compare results of the remaining cases. We derive total costs of maintaining a certain capacity in excess of demand to provide balancing services covering the imbalances introduced by wind power and load forecasting errors as well as potential plant and line outages as shown in Figure D.8. We derive annual benchmark costs of €185 million to provide sufficient reserve capacity to the Danish system in the year 2035. We use the full flexibility of the supply side of the power system, including flexibility in the district heating sector for as far as it may affect the electricity balance. It should be mentioned that this cost only covers the availability of capacity and not the potential activations due to actual deviations.

Including demand response as a resource that may be used just as any supply-side resource to provide flexibility in order to minimise total system costs, will in the first instance be equivalent to optimising available capacity in the hourly spot market.

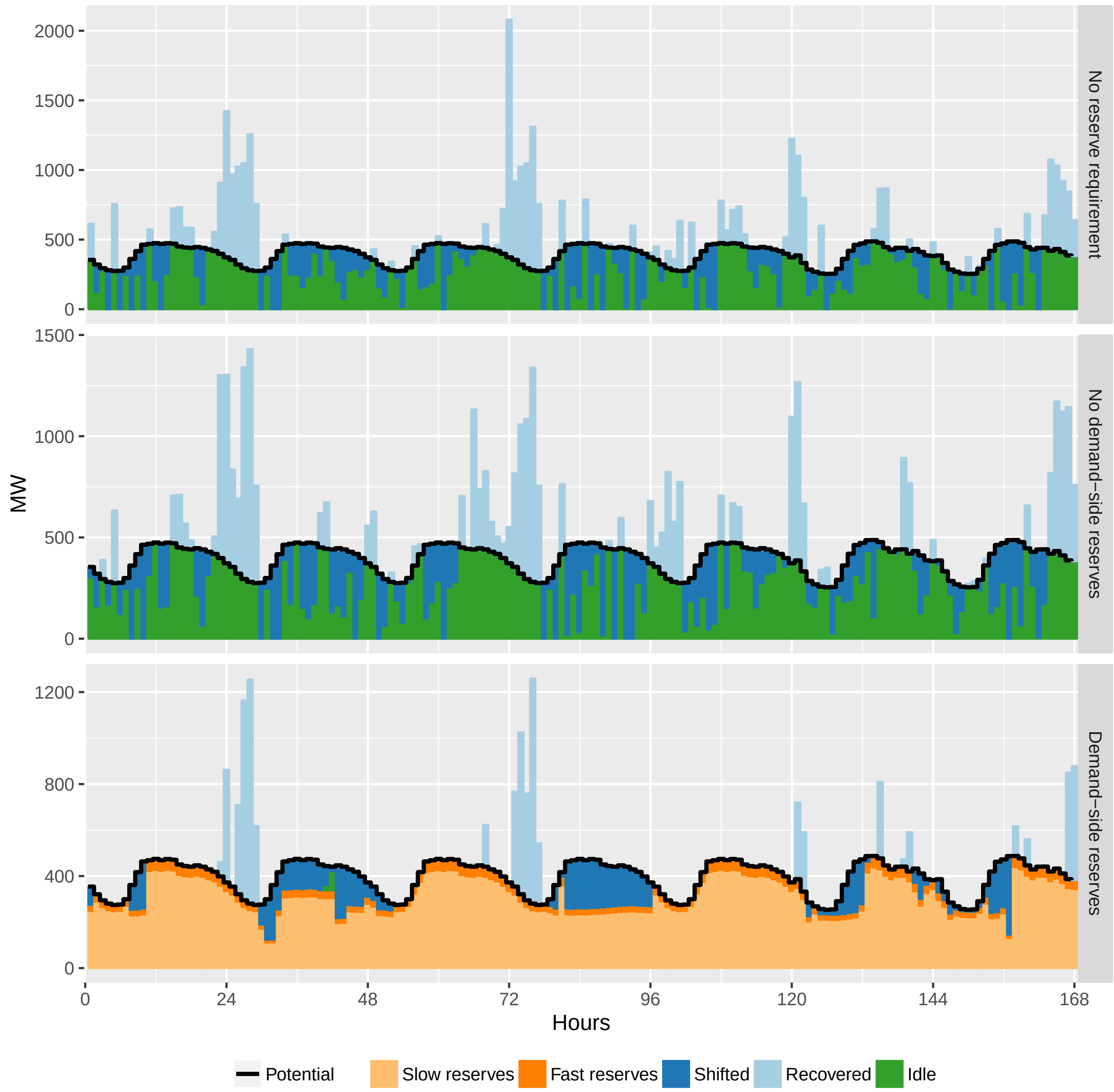

Figure D.9: Utilisation of flexible demand during one week by case

As we run the model on an hourly basis, any contribution can only be on an hourly level. Moreover, the deterministic nature of the model within a year means that we do not deal with uncertainties in the first place. The participation in the spot market yields a positive effect on the total system of €27 million. As should be expected from the formulation of the demand response model, within the given assumptions on the flexibility of consumers, load may be served in a cheaper way. The resulting demand profile for one of the modelled weeks is shown in comparison to the original profile in the top panel of Figure D.9.

Another effect we observe is whether and to what extent the optimisation in the spot market relieves capacity and makes it available for the use as system reserve capacity. In particular, if investments in new capacity that should stay available as peak and reserve capacity could be avoided or reduced, this could be expected to generate significant

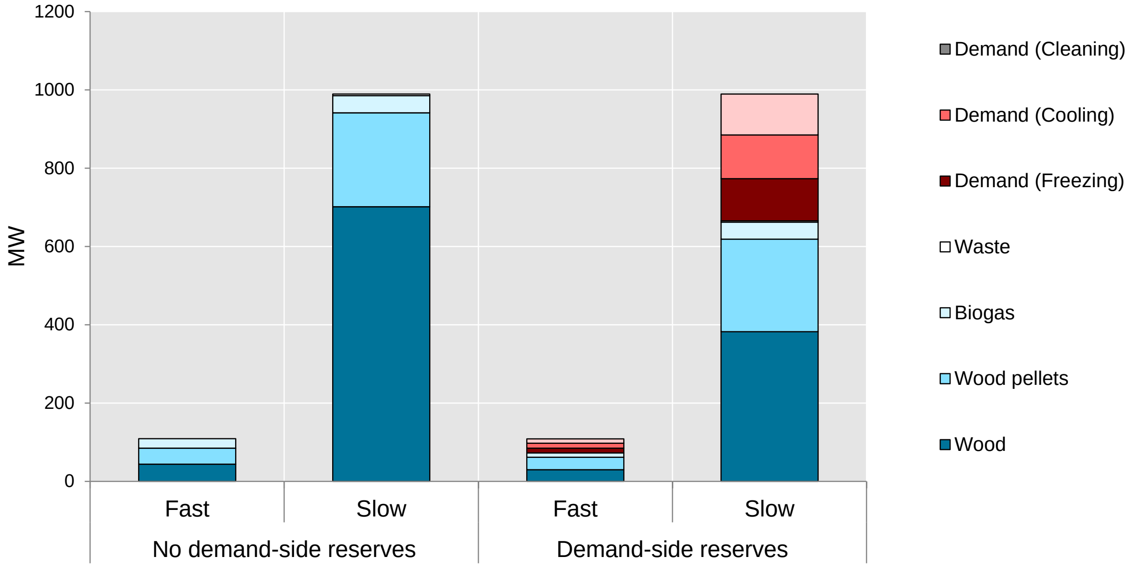

Figure D.10: Annual average reserve provision by technology

benefits attributable to the utilisation of demand response – although only participating in the spot market. We do observe a change in the demand response pattern (see mid panel of Figure D.9), however, the cost of reserves is hardly affected by the hourly demand flexibility.

We assume idle demand response capacity to be available as reserve, as it implicitly contains a potential for curtailment or load increase. The ability of the demand side to leave idle capacity for system reserves results in a reduction of costs for providing reserves. Comparing the reference cost with the demand response case (right bar in Figure D.8) we find that contributions from the demand side could reduce the costs of reserves provided by generating units by €59 million. The resulting costs lie at €126 million corresponding to a reduction of around 30%. One has to mention here that this result does not take into account other costs than the opportunity costs of withholding capacity from the hourly market and the cost of recovering activated reserve at later points in time.

A notable result is that the types of demand flexibility that we included in our calculations are more valuable as a system reserve than in the hourly spot market. Based on our assumption the savings of €59 million generated in reserves are more than double the savings of €27 million generated in the hourly market. Accordingly, idle flexible demand is utilised as reserve to a large extent when allowed to, as it can be seen in the lower panel of Figure D.9. At the same time, hourly benefits may be maintained at the same level as in the case without demand-side reserve provision.

The composition of capacities available for reserves change slightly under the different scenarios. In Figure D.10 we show the composition in cases with and without demand participation in reserves. We can see that demand is mostly substituting reserves provided by large-scale biomass plants based on wood chips. In the case of fast reserves, the demand side also reduces the relative high share of biogas.

As we use a linear optimisation model we interpret the marginal values of the electricity balance equation in the model as the electricity production cost that provide us with the marginal spot prices. As the costs of the system changes with the different demand flexibility scenarios we apply, so do the electricity prices. Results are presented in Table D.5. We allow the model to invest in new generation capacity, therefore, the hours triggering investments due to capacity bottlenecks will have significantly higher marginal values. Such spikes may be interpreted as scarcity prices required in order to finance new investments. We find that the utilisation of demand response reduces these scarcity prices due to a lower demand for new capacity. However, if demand flexibility is utilised in the reserve instead of the spot markets the reduction in the price peak is clearly lower.

Table D.5: Electricity prices in reserve scenarios

	Eastern Denmark [€/MWh]			**Western Denmark [€/MWh]**		
	Min.	*Max.*	*Avg.*	*Min.*	*Max.*	*Avg.*
Without demand flexibility	40.28	3456.31	60.13	41.84	3456.31	60.35
With hourly load-shift	43.33	3419.14	60.10	43.37	3419.14	60.30
With demand-side reserves	40.33	3451.52	60.35	43.37	3451.52	60.58

D.4 Discussion

Our case study results show that intra-hourly flexibility holds a significant value potential for demand response. To the extent that the control of residential appliances, for e.g. cooling, freezing or cleaning, may be automated, even household customers could be able to capture some of this value. The benefits of providing reserves clearly exceed those of hourly load shifting. In our calculations demand response reduces system costs by around three times as much when providing reserves as compared to when it is utilised only in the hourly market. Thus, the value of participating in reserve markets could potentially contribute to two thirds of the total value. The provision of reserves could also be attractive for another reason: in the spot market revenues may only be generated when load is actively shifted, whereas in reserve markets only parts of the offers will be activated and result in actual load shifts. Therefore it may be an option for the demand side to participate primarily in the reserve markets, despite of the trade-off present in the model results between utilising response potential in the spot market and leaving it to stay available for intra-hour demand response.

It should be noted, though, that the absolute level of the reserve costs and the corresponding savings are somewhat uncertain. A crucial model input is the reserve requirement and its forward projection based on installed wind power. Although the resulting curve of the reserve requirement resembles findings of similar analyses (e.g. Hirth & Ziegenhagen, 2015), it cannot be fully verified. We are able, however, to validate the order of magnitude of the resulting reserve costs on the basis of costs published by the Danish system operator. In 2015 the costs for reserves have been stated as close to €79 million (Energinet.dk, 2016a), but costs have been as high as €142 million in 2008 (Energinet.dk, 2009). Our estimations are slightly higher, which should be expected as we scale wind forecast errors with the expected capacity in 2035 and, accordingly, assume a higher reserve requirement. A couple of conditions make it difficult to directly compare the model results with actual costs, though. The modelled costs reflect the need for building additional capacity, while it is unclear in how far plant operators actually rely on reserve markets to drive investments. Moreover, we do not reflect, in our reserve dimensioning and modelling, the Nordic cooperation that enables cross-border provision of reserves subject to available transmission capacities. We also exclude some potential providers of reserve, like heat pumps, from the market. A slight overestimation of costs, thus, seems to be inherent in our assumptions. Considering the substantial simplifications in the dimensioning and modelling of reserves, however, we regard our cost estimates as rather close to actual costs.

In relation to the demand-side contributions to reserves, we need to add some qualifications. An important precondition for using demand response as reserve capacity, in general, would be automatic control. Devices could be controlled in a centralised way or even in a more autonomous decentralised manner. It is unlikely, however, that a system operator would rely on price-based manual control to ensure system reliability. Our analysis relies on studies that identified certain potentials, some of which may not be fully automated. Moreover, automation will come at a cost that has not been considered in our model runs. An additional uncertainty is added by the adoption behaviour of households and a limited willingness to accept automation equipment (Fell et al., 2015; Murtagh et al., 2014). The total cost savings should therefore be considered as an upper bound. Household consumers with a high flexibility potential and the willingness to accept automated control would still be able to benefit considerably. It should also be noted that other appliances, like heat pumps and electric vehicles with a possibly even higher potential in the future, would be able to contribute in a similar way and compensate for a lack of potential in the appliances used for this analysis.

A general challenge for load-shifting demand is that a response will have to be made up at a different point in time such that the overall consumption does not change. In an hourly market this could be planned ahead of time, although one may have to rely on price-independent bidding. In a regulation market, if capacity is provided as reserve within an hour and it is activated, then activation will only occur in one direction. The recovery will require changing consumption in the opposite direction. At present this could not occur within the regulating market, as it would not be possible to place a bid for the recovery beforehand. A compensation has to occur at a later point in time, potentially through intra-day activities or through placement of adjusted bids in the following periods for regulation. Alternatively it might be helpful to integrate load recovery directly into the bidding mechanism (as proposed by O'Connell et al., 2016). The challenge could also be decreased if settlement periods were shortened and the regulating market would be re-organised around such periods. With any bid placed in this market, one would only commit capacities during a comparatively shorter time frame, and recovery could happen through short-term market transactions in subsequent periods. If none such options are established, recovery would have to be settled through the imbalance mechanism, potentially recreating the problem it was meant to solve in the first place. Demand participation as reserves in the form of load shifting may therefore be limited until products are re-designed.

Another issue that may have an influence on the value of demand flexibility is the timing of its introduction. Early availability of demand flexibility will reduce or delay the investment needs in new flexible capacities. We have in our analysis restricted demand response to the Danish market. The potential value that could be achieved in the ordinary spot market, thus, reflects either early adoption in Denmark, or delayed adoption in surrounding countries. With neighbouring regions pursuing similar plans for demand-side flexibility, the value in the internationally coupled hourly markets would become lower than estimated. The value of reserve provision should not be affected in the same way, as the reserve requirement will be provided by domestic resources to a larger extent. Efforts towards an improved international integration of reserve and balancing markets, however, could have an impact on the intra-hourly value in the future as well.

D.5 Conclusion

Keeping in mind the limitations discussed above, we were able to determine a first estimate of the system value that demand flexibility could contribute with by participating in hourly spot and reserve markets. While attractiveness of the price differences in hourly spot markets may be limited also in future systems with large shares of variable renewable production, participation in reserve markets could provide an interesting additional source of income to providers of flexibility on the demand side. We focussed on the Danish case, but analysed the feasibility taking an energy system approach. In this way, we were able to reflect the dynamic interactions with neighbouring systems and the heating sector as well as, to a certain extent, competition with other sources of flexibility.

An important conclusion is that the value of shifting load intra-hourly may exceed the value of doing so on an hourly basis. Thus, it might be an attractive market segment for the demand side to participate in, and our results suggest that the short-term value of demand response should be analysed in greater detail. The addressed short-term flexibility, however, is complex to handle and its utilisation is subject to several preconditions. It seems recommendable to further explore the value potential through system studies based on refined modelling of reserves and demand flexibility. A more detailed assessment of the input parameters regarding the reserve requirement and specific load characteristics may be required in order to draw more robust conclusions. Also, the potential of increased competition from other flexibility measures both domestic and in neighbouring regions should be considered.

From a more practical point of view, technical and regulatory limitations need to be addressed. First of all, the processes of bidding and activation need to be largely automated. But besides such technical constraints, large-scale participation of demand-side units requires some of the market mechanisms to be adjusted accounting for the specific characteristics of load shifting. If no measures are taken, demand-side reserve provision would stay restricted to mere load curtailment or load shifts with a longer time horizon; these conditions would probably exclude many residential loads. To utilise the full value potential that lies within the intra-hourly time frame, therefore, the reserve market design should provide for a better integration of residential demand flexibility.

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Nomenclature

h: index for hours
c: index for countries
g: index for generation technology
j: index for consumer appliance
a: index for areas
A_c: set of areas belonging to country c
FR: set of generation technologies capable of providing fast reserves
SR: set of generation technologies capable of providing slow reserves
$D_{a,h,j}^{flex\text{-}pot}$: hourly demand flexibility potential of appliances j in area a [MWh]
$D_{a,h,j}^{flex}$: shift from flexible demand in area a [MWh]
S_j: load shift horizon of appliances j [h]
$K_{a,g,h}^{FR}$: hourly capacity of technology g in area a reserved for fast reserves [MW]
$K_{a,g,h}^{SR}$: hourly capacity of technology g in area a reserved for slow reserves [MW]
$G_{a,g,h}$: hourly generation by technology g in area a [MWh]
R_c^{FR}: fast reserve requirement in country c [MW]
R_c^{SR}: slow reserve requirement in country c [MW]
$R_{a,h,j}^{Dflex,FR}$: hourly demand flexibility from appliances j reserved for fast reserves in area a [MW]
$R_{a,h,j}^{Dflex,SR}$: hourly demand flexibility from appliances j reserved for slow reserves in area a [MW]
$K_{a,g}$: installed capacities of generation technology g in area a [MW]
k^{spin}: factor for spinning requirement [-]
k^{ramp}: factor for ramping limitation [-]
α: average share of activated reserve capacity [-]

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Paper E

Risk implications of investments in demand response from an aggregator perspective

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Abstract

Aggregators are expected to play an important role in making households provide flexibility to the electricity system. We investigate the business case of aggregators offering a demand response product in a competitive retail market, then directly accessing their customers' flexibility through remotely controlled demand response devices and marketing it on the electricity markets. As the value of flexibility largely relies on price variations, we use a stochastic electricity price model, which we combine with a linear optimisation program and a cash-flow model to determine expected operating gross margins and their probability distributions. We find that, for a case of Danish residential customers with optimistic assumptions on the available flexibility in terms of flexible volumes and load-shift time horizons, the benefits may be in the range of current investment cost for automation equipment. Furthermore, a Value-at-Risk analysis shows that income expectations are rather stable with more upside than downside potential. With foreseeable cost reductions for smart devices the aggregator business case might soon become attractive, particularly in markets with high shares of renewable production.

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E.1 Introduction

In electricity systems with large shares of intermittent renewable production, a growing challenge arises to provide sufficient flexibility. This has reinforced interest in utilising the flexibility potential of the demand side. From a technical perspective, this is certainly a feasible option. Some practical issues, however, prevail in actually exploiting demand-side flexibility. These issues include how to organise market access for the demand side and how to activate consumers who are used to receiving electricity as an unconditional service and often do not attach much significance to contract structure and pricing of electricity. To cope with such organisational and motivational issues it has often been proposed that end user flexibility should be marketed by an entity aggregating many consumers' flexible units (see Katz, 2014). Moreover, it has been found that automatic control will be far more effective than relying on an active manual response by customers (e.g. P. Lund et al., 2015).

We investigate in this paper the business model of such aggregators with remotely controlled demand response devices added to appliances of end customers. The aggregators' operative conditions will be highly dependent on variable market prices and their capability to profit from these variations. It is therefore crucial to understand the inherent risks of their business model. In our analysis we also explore risk implications of aggregated demand-side response regarding the exposure to uncertain future market prices and how it influences the decision of aggregators to invest in demand response equipment.

In the business model that we propose, aggregators market end user flexibility in the electricity wholesale market, while remunerating their customers in the form of a reduction in their contracted electricity price. In order to be able to access certain customer devices for flexibility purposes, the aggregators equip their customers with remotely controllable switches that should be installed with the relevant flexible appliances. Such switches require additional upfront investment by the aggregators.

In this paper we investigate whether such a business model is feasible for an aggregator, i.e. whether the additional revenue from marketing demand-side flexibility is sufficient to justify the required investment. For this, we develop an investment appraisal model consisting of a price module, a demand response module and a cash-flow module. For the stochastic electricity price model we choose to apply a framework proposed by Lucia and Schwartz (2002). We see this model fit as it provides the possibility to incorporate seasonality into the price process and therefore is helpful in the context of electricity. We calibrate the stochastic process to the Danish electricity market. The realistic results from the specific case application shall help to strengthen our point. The demand response model is an optimisation model based on load shifting, calibrated to historical profiles of Danish residential customers. We explore three different scenarios of the share of consumption available for flexibility and four different scenarios for the load-shift horizon. The cash-flow model is based on a single-period operational gross margin indicator.

Using Monte Carlo simulations we calculate the aggregator's income as well as the threshold levels that indicate the maximum allowable investments to ensure a certain expected gross margin for the aggregator. Doing this, we can identify not only the expected average benefits for the aggregator (and the customers), but can also explore the related risks by analysing the probability distribution of the outcomes. Applying a Value-at-Risk approach we quantify the risk of adverse outcome, i.e. when prices develop in a direction where demand-side flexibility is not valuable enough so that the installation of equipment leads to a loss for the aggregator. Having determined the maximum allowable investment levels under different flexibility assumptions, we compare this to currently available technology and assess whether the business model of an aggregator is viable in the current market environment.

E.2 Methods

E.2.1 Model concept

We build a model that determines the operational gross margin for the aggregator based on several different input factors. First of all, it depends on the contractual relation that the aggregator has with the electricity customers: The aggregator may be their supplier, i.e. delivering the full volumes consumed, or may only be a third party optimising the load profile of a customer portfolio on behalf of the actual supplier. In the latter case, the added value must be shared amongst all parties subject to the contractual arrangements. For simplicity, we assume that the aggregator is also the supplier. We further assume that the aggregator offers an annual fixed price contract to their customers, with the price being determined by the expectation on the annual cost of procuring electricity for the customer portfolio from the spot market plus a margin. We assume that the aggregator then undertakes the required investment in demand response equipment and generates additional revenue by being able to optimise procurement of electricity on the spot market using the obtained flexibility from load-shifting. The aggregator may pass through some of this additional revenue to the customers in form of a reduced price.

As we focus on the aggregator role and the marketing of demand flexibility we do not directly analyse the risks involved in the supply business case. That is, depending on the price development, the supply business may be subject to higher than expected cost of procuring electricity on the spot market and thus the risk to achieve lower margins than expected. This part of the business risk is not in scope of the analysis here, so in the risk analysis we focus on the margin added by utilising the flexibility potential only.

The margin contribution from demand flexibility depends on the demand profile, the flexibility potential and characteristics of the underlying appliances as well as the market price for electricity. We take into account all of these elements in different modules. Figure E.1 provides an overview of the model set-up.

The demand profile depends on the customer portfolio. In planning the business case an aggregator will face uncertainty about the characteristics of potential customers. Using average and standard profiles may be a good first approximation. It might be the case, though, that aggregators will attract and maybe even target a type of customer different from the average. Our focus will be on a small portfolio of residential customers. As limited data is available on the portfolio level it might for some application cases be necessary to scale down consumption data of a larger data set, e.g. of a country or region. We are able to avoid that by having access to a consistent set of historical individual profiles of Danish residential customers aggregated to a joint portfolio (Dansk

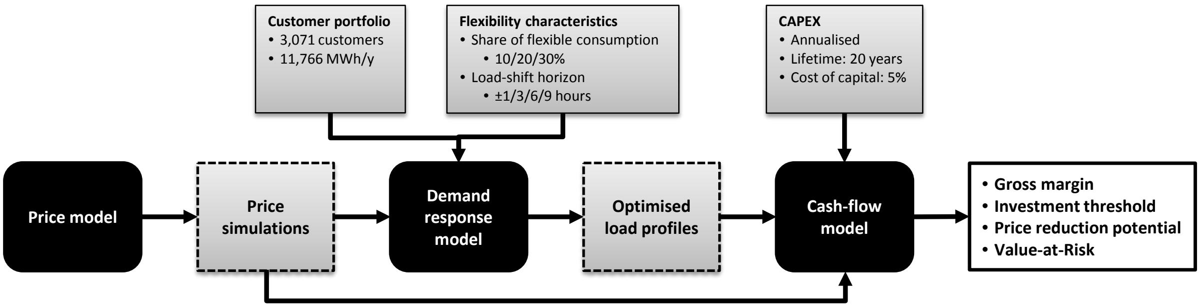

Figure E.1: Overall model concept

Energi, 2013). The portfolio consists of 3,071 residential customers with a total annual consumption of 10,766 MWh.

We generate electricity price developments using a stochastic price model. The price paths are then fed into a demand response model together with the aforementioned load profile. The model optimises available flexibility using a linear programming approach utilising the solver *LPSolve*. Finally, the results of the optimal demand response in form of savings achieved in the procurement price of electricity are used together with the assumed investment costs for the demand response equipment to determine the profitability of the aggregator business in an annualised cash-flow model. Each part of the model is described in more detail in the following sections.

E.2.2 Stochastic price model

To simulate electricity prices for our analysis we define a stochastic price model including a deterministic seasonal component. We use a one-factor model based on the log spot price as defined by Lucia and Schwartz (2002):

$$\ln(P_t) = f(t) + X_t \tag{E.1}$$

where P_t denotes the spot price, $f(t)$ is a function defining the seasonality and X_t is a variable that follows a mean-reverting stochastic process reverting to a mean of zero such that the increments are determined as:

$$dX_t = -\kappa X_t dt + \sigma dZ \tag{E.2}$$

Here κ defines the speed of mean reversion and σ represents the volatility. The term dZ stands for the random increments of a Brownian motion.

Adding the stochastic and deterministic components of the model, we get a mean-reverting price process around a fixed seasonal pattern.

The seasonal pattern should capture observable patterns within a year. In order to do so we use a harmonic model (as described in Hannan et al., 1970; Sørensen, 2002). As electricity prices are very different on working days as compared to holidays and weekends, we include a factor for the type of day as well. Moreover, we include a linear trend. The resulting seasonal model is defined as:

$$f(t) = \alpha + \beta t + \gamma D_t + \sum_{k=1}^{K} \left(a\cos(2\pi kt) + b\cos(2\pi kt)\right) \tag{E.3}$$

with D_t representing a dummy variable for whether a day is a working day or non-working day (i.e. holidays and weekends), and the integer value K defining the number of annual cycles. α, β and γ as well as a and b are parameters that need to be estimated.

E.2.3 Price model calibration

To calibrate the model we follow a stepwise approach similar to the one applied by Lucia and Schwartz (2002). We use hourly Nordpool spot price data for the Western Danish price zone for ten historic years (2006–2015). As a first step we calibrate the deterministic seasonal component using ordinary least squares. This provides us with a fitted model and we can derive the observed residuals. The stochastic component is then fitted to the series of residuals according to, Iacus (2008, p. 113ff.).

The first two steps are based on daily average spot prices. For the demand response optimisation, however, we require more detailed price simulations. We therefore extend the approach by applying normalised hourly profiles to the daily averages in order to achieve hourly prices.

The simplest approach to normalising an hourly price series would be to divide by the daily average. This approach, however, cannot be applied with a series including negative prices. There is the option of neglecting negative values and set those prices to zero. As far as possible we would like to reflect the full price variation in our model, because it determines the value of demand response, in particular for small residential customers with limited load-shift horizons. Moreover, we want to keep extreme cases like spikes or negative prices, because they hold a significant share of the value potential. We therefore choose to calculate the hourly deviations from the daily average and normalise by the annual average like this:

$$P_{t,nrm} = \frac{P_t - \overline{P}_{t,d}}{\overline{P}_{t,y}} \tag{E.4}$$

with $\overline{P}_{t,d}$ and $\overline{P}_{t,y}$ representing the average price over a time period of the day and year that the hour t is a part of. This approach would thus result in the same absolute hourly deviations from the daily average as long as the yearly average is the same. With increasing annual average, we would assume the hourly profile to become more pronounced as well. A negative hourly price would be represented by a large negative absolute deviation from the daily average, which would likely produce a new negative price based on a different daily average in the stochastic model as well.

We apply the normalised hourly profiles to the simulation results by random sampling of daily 24-hour-sets depending on the type of day. We thus randomly apply observed hourly profiles of working days and non-working days to the daily averages in our simulation:

$$P_{t,sim} = \overline{P}_{t,y} P_{t,nrm} + \overline{P}_{t,d} \tag{E.5}$$

This way we are able to preserve the extreme prices that can be observed in electricity price series with a probability reflecting the frequency of occurrence in the sample series.

E.2.4 Demand response model

We use a generic demand response model that implements only load shifting. Demand is based on historical profiles of residential consumers, and a certain percentage of the profile is assumed to be flexible, while the remaining load cannot be shifted.

Assuming the aggregator uses demand response to minimise spot market procurement costs, we need to solve a minimisation problem for all sets of modelled prices, such that:

$$\min_{d \geq 0} \sum_{t \in T} d_t P_t \tag{E.6}$$

where d_t denotes consumption in hour t at a price of P_t.

We ensure that the resulting consumption d_t in any given hour will at least cover the inflexible base demand determined as a share of $1 - k^{flex}$ of the the total demand D_t^0 before demand response with k^{flex} as consumption share assumed to be flexible:

$$d_t \geq D_t^0 \cdot \left(1 - k^{flex}\right) \quad \forall\, t \in T \tag{E.7}$$

Moreover, we need to take into account restrictions keeping flexibility within a technical bound of the underlying appliances. We use a rolling time horizon of S to contain volumes shifted in the short-term within a predefined time span. In every hour volumes may be shifted back or forward in time resulting in an interdependence of load shifts also beyond the defined horizon. We contain such interdependencies within a second larger time horizon L.

$$\sum_{t-S}^{t+S} d_t \geq \sum_{t-S}^{t+S} D_t^0 \quad \forall \left\{\, t \in T \mid S < (t \bmod L) < L - S \,\right\} \tag{E.8}$$

The long-term horizon is furthermore governed by the following contraint:

$$\sum_{t}^{t+L} d_t = \sum_{t}^{t+L} D_t^0 \quad \forall \left\{\, t \in T \mid (t-1) \bmod L = 0 \,\right\} \tag{E.9}$$

In both equations (E.8) and (E.9) the modulo operator produces the remainder of dividing the two values providing a way to refer to individual hours within the longer time horizon. The two constraints may be interpreted as the possibility to shift volumes, but at the same time shifted consumption in total over a certain time needs to equal consumption before load shifting. An example of a resulting profile is shown in Figure E.2. It is based on parameters $S = 3$ and $L = 24$ with a flexible share of $k^{flex} = 10\%$. The lower panel shows a corresponding price scenario generated by the stochastic model that is used as the basis for cost minimisation.

E.2.5 Cash-flow model

We determine the profitability of the aggregator business using a single-period operational gross margin as indicator. The demand response module aggregates the demand response effect into annual values, so that we can keep the cash-flow model on the same basis.

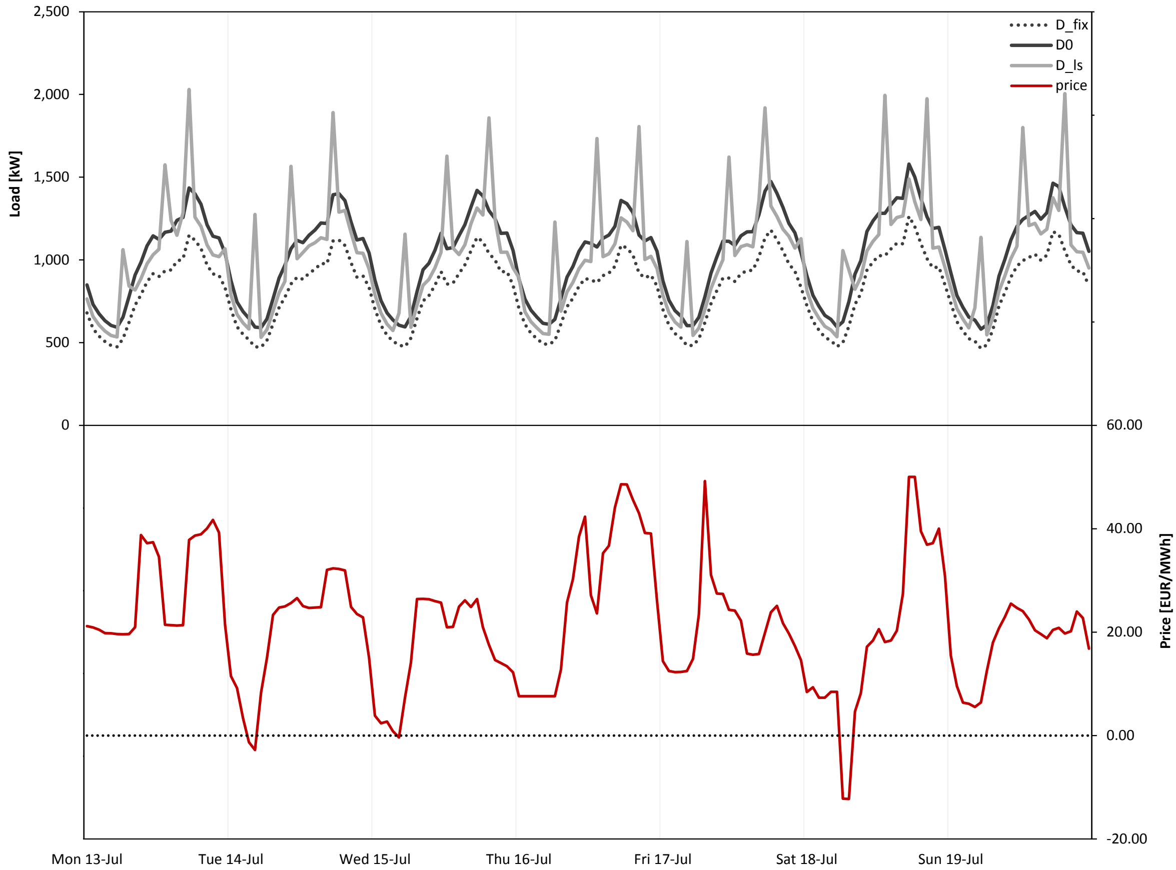

Figure E.2: One week example of simulated load and price profiles (10%-flex scenario, ±3 hours load shift)

We determine the operational gross margin in a simplified way by approximating net profits based on Earnings before Interests, Depreciation and Amortisation (EBITDA) (thus neglecting taxes and several other elements) and then dividing this by the total revenues. We thus calculate the operational gross margin (OGM) as:

$$OGM = \frac{R_{sales} + R_{DR} - O_{power} - O_{other} - I_{DR}}{R_{sales} + R_{DR}} \tag{E.10}$$

where R_{sales} is the annual revenue of power sales to customers, R_{DR} is the annual revenue from demand response activity, O_{power} is the annual cost of procuring power from the spot market, O_{other} is additional operating cost of the aggregator, and I_{DR} is the annuity of the investment cost for demand response equipment. In the base case without demand response, R_{DR} and I_{DR} are zero.

We exogenously set the operational gross margin. The gross margin of Danish suppliers varies between years and products offered. It has been found to lie between 50–100 DKK/MWh in the past years under retail competition (Okholm et al., 2015). Assuming competition to rather increase than decrease in the coming years we use the lower value of 50 DKK/MWh, which transforms to a margin of 18.025% to be used as our baseline. The corresponding electricity sales price to customers in the base case is 37.23 EUR/MWh excl. any levies, taxes and network charges. By then ensuring that the aggregator achieves the same expected profitability in either case, we re-estimate the possible sales price to customers after demand response. If the demand response activity as a whole is good business, the aggregator will be able to offer a discount to their customers.

By choosing the approach of keeping the expected profitability of the aggregator constant, we calculate the maximum potential reduction in sales price to customers that can be achieved by the aggregator through demand response activities. In reality, one could expect that the aggregator will not pass all of the effect through to the customers but that the savings are shared between the two. For our purpose of analysing the business case of an aggregator as such and to enhance transparency between the scenarios we find it appropriate not to split the effect further.

In the same way, we can also find the threshold of maximum allowable investment cost at which the aggregator would start to be interested in entering into the business. Here again, we assume that the aggregator should at least be able to achieve the same expected profitability and to offer at least the same sales price to customers.

E.2.6 Value-at-risk estimation

Exploiting the information on probability distributions of the demand response effect that the stochastic price modelling generates, we can further analyse the risk that the aggregator assumes when investing into demand response equipment. For this, we use the Value-at-risk measure.

In the Value-at-risk measure, a quantile $\alpha \in (0, 1)$ is specified that represents the risk tolerance of an investor. From the specified α and the mean profit, a value η is calculated, so that the probability of obtaining a profit less than η is lower than $(1 - \alpha)$:

$$\mathrm{VaR}(\alpha, x) = \max\left\{\eta : P(\omega \mid f(x,\omega) < \eta) \leq 1 - \alpha\right\}, \quad \forall\, \alpha \in (0, 1). \tag{E.11}$$

Commonly used values for α are derived from the standard deviation σ. When using one standard deviation, the profit will lie above the calculated value η with a probability of 68.27%. Using 2σ corresponds to 95.45% probability. In financial analysis, a rounded value of $\alpha = 5\%$ is commonly used, and we apply this here as well. Thus, using the VaR to our operational gross margin as the measure for profitability, we determine the level of the margin that the aggregator can expect to at least obtain with a probability of 95%.

E.2.7 Scenarios

We calculate results for a set of scenarios to account for the uncertainty about the volume of flexible consumption as well as the technical load-shift capabilities of specific appliances. These scenario parameters only affect the demand response optimisation.

The literature on flexibility potentials of Danish households is rather sparse. Ea Energianalyse (2011) provides one of the few estimates: A share of 35% of residential consumption is considered to become flexible if fully equipped with automation units. A similar figure has been used by Kwon and Østergaard (2014) in their analysis of flexible demand in Denmark. Such estimations are in line with international findings as well (e.g. Faruqui et al., 2007; Klobasa & Obersteiner, 2009). Most of the flexibility comes from shifting loads. Only a few categories of lighting as well as some electrical heating could be considered for curtailment or additional load during extreme periods.

The estimated potential of 35% flexible load share on the national level defines an upper bound that is subject to how many customers actually adopt demand response technology and behave flexibly. In our analysis, however, the aggregator creates a dedicated portfolio with flexible customers, so the adoption uncertainty is not relevant here (other than for a potential limit of the possible number of customers in the portfolio itself). At the same time we may assume that those customers that are part of the portfolio utilise a large share of their individual flexibility potential. Still, a full utilisation of the estimated 35% load share potential might be too optimistic, as it e.g. might not be feasible to attach devices to all potentially flexible appliances so that not all of the flexible load can be included in the business case of an aggregator. Furthermore, one should account for some variation in the customer base. We therefore use the following scenarios for the flexibility share k^{flex}: 10%, 20%, 30%.

Regarding the load-shift horizon, Gils (2014) points out that most demand response options are limited to a relatively short time horizon. Other assessments of the flexible potential in residential appliances with regard to timing are available from, e.g., Klobasa (2007) or Paatero and Lund (2006). They find that some load-shifting options provided by fridges and freezers are restricted to one hour, while appliances like washing machines and dishwashers are assumed to be flexible within a whole day. As we use aggregated profiles we do not explicitly account for individual appliances. Instead we use a set of values for the load-shift horizon S that should cover the possible range of shifting potentials from the overall load of residential customers. We choose to set these at: ± 1 hour, ± 3 hours, ± 6 hours, ± 9 hours. At the same time we fix the longer load-shift horizon L to 24 hours.

E.3 Results

E.3.1 Results for the expected value of load-shifting

In this section we present results based on the expectation of savings generated by load-shifts across all simulated scenarios. All numbers in this section are thus based on the mean value over 1,000 simulations.

As described in Section E.2.1, we have calculated for each set of scenarios the operational gross margin and then analysed it from different perspectives. Here the investment cost threshold is one of the crucial elements in the analysis. Note that the investment thresholds of the different scenarios are calculated so that both the margin for the aggregator and the sales price for the customers are kept constant in comparison to the base case without demand response. The investment thresholds presented here are thus the maximum allowable cost which have in reality to be undercut for the aggregator business model to become attractive.

Table E.1 provides an overview of the investment thresholds subject to the load shift and flexibility scenarios. With longer time horizons and larger flexible volumes we observe a substantial increase in the investment cost that may be covered by load-shifting returns.

In addition to determining the feasibility of investment it is relevant to establish by how much customer prices could potentially be reduced. As customers in competitive retail markets like the Danish one will have to be convinced of participating in demand

Table E.1: Investment threshold [EUR/customer]

	Load-shift horizon			
Flexible share	±1 hour	±3 hours	±6 hours	±9 hours
10%	2.65	8.88	15.97	32.88
20%	5.31	17.76	31.94	65.76
30%	7.96	26.64	47.91	98.64

response activities, a benefit to the customer will be essential. Table E.2 provides an overview on the leeway that would exist regarding the sales prices based on the full load-shift effect. The values are therefore equivalent to zero investment costs and, in practice, any benefit would have to be shared between the customer and the aggregator: The aggregator needs to cover the investment cost and may want to achieve some additional margin, while the customer must be provided with an incentive to switch to the demand-response product.

Table E.2: Maximum price reduction potential [EUR/MWh]

	Load shift horizon			
Flexible share	±1 hour	±3 hours	±6 hours	±9 hours
10%	0.07	0.25	0.45	0.92
20%	0.15	0.50	0.89	1.84
30%	0.22	0.74	1.34	2.75

Although the absolute price reduction may seem low in comparison to the average sales price of around 37 EUR/MWh, one can conclude that some of the scenarios hold a rather attractive relative reduction potential. It has to be noted, though, that we disregard taxes and network tariffs in our price. Considering these elements, which make up around 80% of the total residential electricity bill in Denmark (cp. Kitzing et al., 2016), one could suspect that the potential reductions resulting from our scenarios may not be sufficient to attract much participation of residential customers.

E.3.2 Results for a distribution of load-shift effects

In addition to analysing the investment thresholds and potential sales price reductions based on scenario mean values, we assess the probability of achieving a certain benefit. For this, we determine the probability distributions of the demand response effects in each scenario. In Figure E.3 we show the distributions for all simulated load-shift horizons under the scenario with a 20% share of flexible consumption. As the load-shift horizon is extended, the results become more favourable and move along the x-axis. At the same time it becomes clear how the distributions get wider and thus the return becomes more uncertain. Another observation is that all the distributions have a pronounced upside represented by a thicker tail.

The shapes for other simulated shares of flexibility (10% and 30%) are similar to those presented in the graph. The 10%-scenario results are slightly narrower and shifted further towards the left of the x-axis, while the 30%-scenarios are wider and further towards the right end.

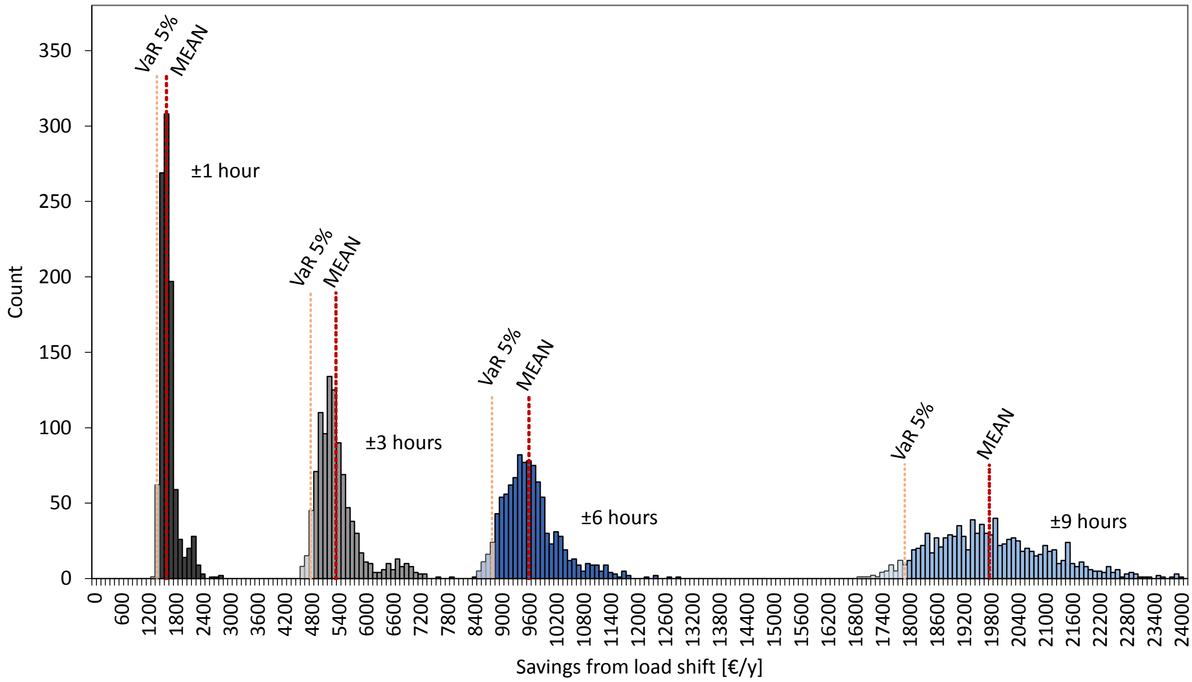

Figure E.3: Distribution and Value-at-Risk (5%) for different load-shift horizons in the 20%-flex scenario

Assuming that the aggregator decides to invest as soon as the investment cost undercuts the threshold in the mean outcome, we estimate the Value-at-Risk (VaR) in case of lower than expected demand response potential. The VaR for the different scenarios are summarised in Table E.3. For the scenario with a load-shift horizon of 6 hours and a flexibility potential of 20%, for instance, the profitability for the aggregator would decrease from 18.025% to 17.861% for a 5% VaR, corresponding to a 0.9% decrease in gross margin. Overall, the margin reductions lie in a range of 0.1–3%. These relatively small deviations are due to the small share of the load shift benefits in the gross margin as defined in equation (E.10).

Table E.3: Gross margin at the 5% VaR level [%]

	Load-shift horizon			
Flexible share	± 1 hour	± 3 hours	± 6 hours	± 9 hours
10%	18.004%	17.969%	17.942%	17.838%
20%	17.983%	17.913%	17.861%	17.659%
30%	17.962%	17.858%	17.782%	17.487%

E.4 Discussion

The maximum allowable investment costs lie between 2.65 and 98.64 EUR per customer in our scenarios, depending on the flexible share and the load-shift horizon. Comparing these results to the current market conditions is rather difficult as no established market exists for neither aggregator businesses nor demand response equipment. Remote controllable smart plugs are offered in the Danish market for around 50 EUR (cp. Develco Products, 2016). Such devices have been applied to control single appliances (see Lakshmanan et al., 2016), but require additional equipment to be installed for automatic remote control not included in the price. Reverting to other studies, Jötten et al. (2011) present the cost of automation equipment for three demand response business cases. One of the cases is similar to the aggregator case in our analysis. In this case, the required device was provided at a cost of 100 EUR/customer. None of our scenarios reach above that level. If actual investment cost for automation equipment will be in this range, we must conclude that in our investigated scenarios for the Danish market and under current market conditions, the business case for an aggregator will be rather difficult. Investment cost in the range of 50 EUR/customer can, however, already provide an interesting business case for aggregators today, depending on the customer portfolio that they are able to attract.

It may be discussed if our assumptions on the flexibility share and the load-shift horizon are realistic. We can see that especially the load-shift horizon becomes interesting as soon as it involves the opportunity to benefit from day-to-night differences, i.e. at ±9 hours and above. But ±6–9 hours load-shifting are already rather optimistic assumptions for many home appliances, and could certainly not be expected from all of them. As mentioned freezers will probably have a much shorter time frame for load shifting. Even heat pump systems might run into problems with such horizons if storages are not large enough. One could thus expect that the longer the load-shift horizon the lower the flexible share of the load and vice versa. On the other hand, for the very short horizon, one could potentially achieve higher flexible shares.

We have made many simplifications in the analysis. One of these is that we operate with constant investment cost in all scenarios. In reality, one should expect higher investment cost for getting access to higher flexible shares, because then probably more appliances have to be equipped with remote control devices at a customer.

Due to the scope of the analysis, it was not possible to consider all kinds of risks in the aggregator business model. One major risk for an aggregator is not being able to access flexibility despite of having invested into the demand response equipment. This risk arises from unforseeable actions by the customers, e.g. if they remove the remote control device from the appliance, or they remove respective appliances on the whole. Customers might also unexpectedly shut down appliances, e.g. when going on holidays and forgetting to inform the aggregator. All such issues pose potential threats to the business case of an aggregator and will in practice have to be factored into the calculation of potential sales prices, thus further diminishing potential benefits for customers.

E.5 Conclusion

Aggregators are expected to become important providers of flexibility in a system that relies on decentralised demand response. The analysis of a robust business case for such aggregators should not only take into account average values, but also consider risks and their implications for income variability and attractiveness of investments. We have developed a model that is capable of analysing the operational gross margin of an aggregator, related investment thresholds and potential sales price reductions. At the same time, it provides the opportunity to determine probability distributions and thus enables us to do a Value-at-Risk assessment.

Applying the model to the Danish market, we find that aggregators have a difficult business case under current market conditions unless they can find a portfolio of customers with a very high flexibility share of their load and very long load-shifting horizons. In the residential segment such opportunities are limited at present. On the other hand, we do see smart devices emerging in the market with investment cost in a range that could make the business model of an aggregator attractive already today. Furthermore, we find that the income expectations are rather stable and there is more upside than downside related to uncertain electricity market price developments and their exploitation for demand response.

Overall we can conclude that there is still some way to go for aggregators to assume a significant role as providers of flexibility in the future. In terms of analysis, more must be done on the evaluation of the business case; all risks must be assessed. An updated model could, e.g., include implications of volume risk stemming from uncertainty about the exact response from a portfolio of end user devices. In practical terms, the business model of aggregators must still be further elaborated, and investment cost for remote control devices must decrease. Additional sources of income for tapping into the demand-side flexibility potential could be developed by providing reserves or ancillary services to the transmission or distribution grid operators. In combination with foreseeable cost reductions for smart devices the aggregator business case might soon become attractive for highly flexible customer segments.

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