Norwegian University of Life Sciences
Faculty of Environmental Sciences
and Natural Resource Management

Philosophiae Doctor (PhD)
Thesis 2021:1

Demand flexibility in electricity markets

Forbrukerfleksibilitet i kraftmarkeder

Aleksandra Roos

Demand flexibility in electricity markets

Forbrukerfleksibilitet i kraftmarkeder

Philosophiae Doctor (PhD) Thesis

Aleksandra Roos

Norwegian University of Life Sciences
Faculty of Environmental Sciences and Natural Resource Management

Ås (2021)

Thesis number 2021:1
ISSN 1894-6402
ISBN 978-82-575-1740-3

PhD Supervisors

Professor Torjus Folsland Bolkesjø
Faculty of Environmental Sciences and Natural Resource Management
Norwegian University of Life Sciences

Associate Professor Thomas Martinsen
Faculty of Environmental Sciences and Natural Resource Management
Norwegian University of Life Sciences

PhD Evaluation committee

Dr. Anna Krook-Riekkola
Division of Energy Science
Department of Engineering Sciences and Mathematics
Luleå University of Technology

Dr. Lisa Göransson
Division of Energy Technology
Department of Energy & Environment
Chalmers University of Technology

Professor Erik Trømborg
Faculty of Environmental Sciences and Natural Resource Management
Norwegian University of Life Sciences

PREFACE

This PhD project was a long journey where, between writing papers, I changed workplaces three times and gave birth to three kids. It started in 2012 at the Norwegian University of Life Sciences (NMBU) as a part of an Industrial PhD programme, funded by the Norwegian Research Council and a private company, Enfo, that was working with demand response. Later, the project was transferred to a Norwegian IT company, Sysco. And finally, the project was completed at the Norwegian Water Resources and Energy Directorate (NVE).

I believe that the project benefited from this diversity of workplaces and the people I met. I was able to look at the topic from different angles and get interdisciplinary insight. I worked with people who develop demand response technology and sell technical solutions to customers, people who work with market design, researchers who study power and energy systems on the macro-economic level. I also worked with demand response topic on the governmental level, close to the national regulator. The papers in this PhD are therefore thematically diverse and use a variety of research methods, which I hope is a good thing.

There are many people that I would like to thank for providing me with inspiration, ideas and support during this work. First of all, a big thanks to my first supervisor, Torjus Folsland Bolkesjø, for giving me a lot of support during the whole project and keeping me focused on completing the work, even when things were challenging. A special thanks to Thomas Martinsen for stepping in as the second supervisor at short notice and giving me very useful feedback.

Thanks to Terje Gjengedal, who started the whole project out of nowhere by asking NMBU and Enfo whether they were interested in taking a newly graduated student on as an industrial PhD to study the topic.

Thanks to John Arild Raaen for his innovative spirit and vision about the topic and for giving me many useful insights.

Thanks to Ane Torvanger Brunvoll and Ingrid Helene Magnussen for giving me the final push to complete the work, and to all my colleagues in the Energy Division of NVE for their support.

Thanks to my co-authors, Stig Ø. Ottesen, Torgeir Ericson and Jon Gustav Kirkerud, for their fruitful cooperation.

Thanks to all my former colleagues at Enfo, Sysco and NMBU for always being interested in my work, discussing and brainstorming different topics with me and giving me useful feedback.

Thanks to my wonderful family and friends for believing in me all the way and helping with all possible practical things while I was away and writing, from making food to putting the children to bed. And a very big and special thanks to my husband for being so patient and supportive and for sharing this journey with me. I am submitting this thesis on the ninth anniversary of our wedding, and let it be my gift to you that this work is done.

Oslo, 30th October 2020

Aleksandra Roos

TABLE OF CONTENTS

SUMMARY

Demand flexibility integration is an important measure for the decarbonization of energy systems and a more efficient use of resources. Demand flexibility can provide multiple benefits to the power system and reduce system costs. Adjusting electricity demand to match variable production supports the integration of larger shares of variable renewable energy (VRE). Using demand response for system services provided by network operators can contribute to a more cost-efficient use of infrastructure and resources.

Demand flexibility is a large and complex field of study which includes different markets, different grid voltage levels and different actors. The aim of this PhD project is to study how demand flexibility can be optimally integrated into electricity markets, taking account of the benefits to the power system as a whole and the interplay between different markets. Demand flexibility is studied from the perspective of the whole system, as well as from the private economic perspective of aggregators and electricity consumers.

The thesis includes separate studies which go in depth about specific topics. The whole system perspective is studied in Paper I, which focuses on the value of demand flexibility in spot and reserve markets in power systems with high shares of VRE. The perspective of TSO and DSO is studied in Paper II, which proposes a marketplace for procurement of transmission and distribution system services from demand flexibility. The perspective of demand flexibility aggregator is studied in Paper III which develops an optimization framework for an aggregator participating in the wholesale and the regulation capacity markets. The perspective of private electricity consumers is studied in Paper IV which studies price-based demand response and investments in load control in an energy system.

The results of these studies offer various useful insights. Firstly, demand flexibility was found to significantly decrease the system cost when large shares of VRE are integrated into the system. This happens primarily by replacing reserve provision from coal and gas plants but also by reducing peak load generation due to price response on the wholesale market. Optimal allocation of demand flexibility between reserve and wholesale markets maximizes the system benefits. The results suggest that in systems with large shares of VRE and small shares of base load, more demand flexibility should be placed in the reserve market than in the wholesale power market.

Demand flexibility also benefits the distribution system, and it was also found that new market designs and better coordination between the transmission and distribution levels are important for efficiently integrating demand flexibility and minimizing the total procurement costs. New market designs can ensure that demand flexibility is used to maximize the value for the whole system and not only for single actors.

Next, the results of the studies illustrate that demand flexibility access to many markets is beneficial, from both the system and private economic perspectives. It increases the value of demand flexibility, gives incentives to aggregators' business and ensures that demand flexibility is optimally allocated between markets based on price. However, market interplay can also have negative effects, as when demand flexibility providers favour one particular market with higher profitability and flee from other markets. New market designs for demand flexibility should consider the interplay between different markets.

Finally, modelling demand response to electricity price shows that private investments in demand flexibility are governed by the cost of load control, the daily electricity price variability and the price flattening effect. The price flattening effect implies that demand response to price reduces price volatility in the market, and at some point, no more demand response is feasible. To achieve this optimal demand response level in the wholesale market, it is important to have correct feedback between the market and consumers so that they do not respond more is optimal from the system perspective.

To sum up, the results of this PhD research suggest that efficient integration of demand flexibility into electricity markets implies giving it access to many markets, strengthening the role of aggregators, improving coordination between the distribution and transmission system levels and promoting market designs that optimize demand flexibility use and system value. This thesis illustrates the importance of studying demand response in a holistic perspective, including different markets, actors and system levels.

LIST OF PAPERS

This thesis consists of the following papers:

Paper I	Roos, A., Bolkesjø, T.F. (2018). Value of demand flexibility on spot and reserve electricity markets in future power system with increased shares of variable renewable energy. *Energy,* 144: 207–217. doi:10.1016/j.energy.2017.11.146.
Paper II	Roos, A. (2017). Designing a joint market for procurement of transmission and distribution system services from demand flexibility. *Renewable Energy Focus,* 21: 16–24. doi:10.1016/j.ref.2017.06.004.
Paper III	Roos, A., Ottesen, S.Ø., Bolkesjø, T.F. (2014). Modelling consumer flexibility of an aggregator participating in the wholesale power market and the regulation capacity market. *Energy Procedia*, 58: 79–86. doi:10.1016/j.egypro.2014.10.412.
Paper IV	Roos, A., Ericson, T., Kirkerud, J.G., Bolkesjø, T.F. Analysis of residential demand response in Norway using energy system modelling. *Submitted 23rd October 2020 to International Journal of Electrical Power & Energy Systems.*

LIST OF ABBREVIATIONS

AMS	Advanced metering systems
AS	Ancillary services
BRP	Balance responsible party
CAISO	California Independent System Operator
CHP	Combined heat and power
CPP	Critical peak pricing
DER	Distributed energy resources
DR	Demand response
DSM	Demand-side management
DSO	Distribution system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
GAMS	General Algebraic Modelling System
HV	High voltage
ICT	Information and communication technologies
ISO	Independent system operator
LP	Linear programming
LV	Low voltage
MILP	Mixed integer linear programming
MISO	Midcontinent Independent System Operator, Inc.
NYISO	New York Independent System Operator
PJM	Pennsylvania New Jersey Maryland Interconnect
PV	Photovoltaic (power generation)
RPM	Regulating power market
RTP	Real-time pricing
SG	Smart Grid
ToU	Time-of-use tariff
TSO	Transmission system operator
USEF	Universal Smart Energy Framework
VPP	Virtual power plant
VRE	Variable renewable energy

1. INTRODUCTION

1.1 Role of demand flexibility in power systems

Integration of demand flexibility into electricity markets is an important measure that can contribute to the decarbonization of the energy sector and a more efficient use of resources. Global demand for energy services is increasing in line with population growth and economic development. Many countries have committed to the integration of variable renewable energy (VRE) and the electrification of consumption as major parts of their energy transition plans. The recent global energy transition outlook published by DNV-GL (2020) estimates that VRE will deliver over 60% of the global power mix in 2050, with solar PV and wind power as the largest producers. At the same time, digitalization is creating new opportunities for optimizing energy use. Active flexible consumers can be integrated into the power system and adjust their demand according to the variable production patterns of renewable generation. They can respond to signals from the power system, supporting the integration of larger shares of VRE and contributing into a more optimal use of the energy system infrastructure.

Demand flexibility is not a new resource in the sense that flexibility from large industrial consumers and consumers with large single loads has been used in power system operation for a long time. What is new is the possibility to include flexibility from smaller consumers in the commercial and residential sectors due to the development of smart appliances and control systems. The demand flexibility of these consumers often exists in combination with local generation (e.g. solar panels) or energy storage (e.g. batteries or thermal storage) such that these resources are viewed in combination and referred to as distributed energy resources (DER). Smart integration of DER into a power system will create what is called a smart grid, making the system cheaper, more efficient and more environmentally friendly (IEADSM, 2008).

The advantages of demand-side management in power systems were first discussed as early as 1985 (Gellings & Smith, 1989). The focus at that time was the role of demand-side management in reducing the uncertainty related to future demand, fuel prices and construction costs of power plants. Utilities were facing the need for major investments in production capacity, and demand-side management was expected to make a significant contribution to meeting the future demand. Over the years, the focus has shifted towards emphasizing the role of demand flexibility in successful energy systems' transition towards a low-carbon future and a more sustainable use of resources.

At the general level, the need for demand response arises from the mismatch between power system costs and consumer prices (Northwest Power and Conservation Council, 2016). Power system costs vary significantly from hour to hour because demand and supply change, and balancing power and frequency control are dispatched when needed. At the same time, consumers generally see prices that change very little in the short term. This ultimately results in building more electricity production capacity and transmission infrastructure than would be necessary if customers responded to signals from the market.

Demand flexibility can be studied from different perspectives. As pointed out by the IEA (IEADSM, 2008), the two major perspectives on demand flexibility are energy markets and network management. The energy market perspective includes the benefits that demand flexibility can provide to energy markets, like reducing peak load and supporting the integration of VRE. Network management is concerned with the use of demand flexibility for cost-efficient management of electricity transmission infrastructure. It can be further subdivided into transmission system and distribution system benefits of demand flexibility. A lot of research on demand flexibility focuses on one of these domains, going into depth regarding specific uses of demand flexibility for specific purposes (e.g. Huber et al., 2014; Poudineh & Jamasb, 2014; Zakariazadeh et al., 2014; Göransson et al., 2014; Brouwer et al., 2016; Tveten et al., 2016).

This thesis attempts to study the integration of demand flexibility in a holistic perspective, across different markets and voltage levels in the power system. Both the energy market and the network management perspectives are included in the study.

1.2 Electricity market architecture

The integration of demand flexibility into electricity markets is affected by the electricity market architecture in a given power system. European and U.S. electricity markets are examples of two different market architecture types that create different possibilities and barriers for demand flexibility integration.

The electricity market is fundamentally different from other markets because the traded commodity is a power flow that occurs in real-time and is subject to different technical and transmission constraints (Wilson, 2002). Within a short time frame, it is not feasible to rely only on the wholesale power market because specific kinds of resources are needed immediately and in particular locations. The wholesale power market is just the first in a cascade of options to balance energy flows and maintain reliability. Ancillary services markets are necessary to allow the real-time dispatch of reserves with different response times. Different market architecture handles this special nature of electricity markets in different ways.

Two main approaches to electricity market architecture distinguished in literature are integrated and unbundled. In the *unbundled approach,* the market operator and the transmission system operator (TSO) are different entities, and energy markets are separated from ancillary services markets (Wilson, 2002). This approach is used in European electricity markets, where, historically, the primary objective has been to enable trading of electricity between large national balancing areas (IEA, 2016). The role of the energy market operator (e.g. electricity exchanges such as Nordpool or EPEX) is to settle supply and demand, while the role of national TSOs is to maintain reliability by running their own sequential markets.

An integrated approach implies that an independent system operator (ISO) functions both as the 'system operator' for coordinating reliability and the 'market operator' for establishing market prices (Wilson, 2002). This approach has been adopted by most U.S. power markets, including NYISO, PJM and CAISO, where historically the primary goal has been to ensure the coordination of small balancing areas that were poorly interconnected (IEA, 2016). In the integrated approach, the ISO solves a complex multistage optimization problem called security-constrained unit commitment and dispatch so that the whole system is optimized simultaneously (Chow et al., 2005; Wu et al., 2004).

The integrated approach is more complex than the unbundled approach in terms of system optimization, but it offers greater possibilities to integrate demand flexibility into electricity markets. Firstly, all markets are under the responsibility of the same entity (ISO) so that demand flexibility participation in the wholesale and AS markets can be better coordinated. The ISOs already apply complex optimization techniques and powerful software, which makes it easier to include demand flexibility resources. Secondly, integrated markets are often 'high-resolution' markets (IEA, 2016) with respect to geographical and temporal resolution, meaning they can optimize resources with respect to more detailed information about their grid location and determine electricity price frequently and nearly in real time.[1] They incentivize the use of demand flexibility because it benefits from better grid localization possibilities and dynamic price setting.

In European unbundled electricity markets, the integration of demand flexibility is more fragmentary. TSOs create their own arrangements for demand response focusing on the AS markets. Wholesale market operators incentivize demand response by developing new forms of bids for the demand side and promote their intraday market solutions (Nordpool, 2018). In addition, distribution system operators look for ways to use demand flexibility on a local level for specific distribution system services (Eurelectric, 2013). Therefore, it is especially important to study interdependencies between markets and system levels in the context of demand flexibility integration in Europe.

1.3 Goal and scope

The main objective of this PhD thesis is to study the use of demand flexibility in the power system and answer the following research question: ***What is the optimal way to integrate demand flexibility into electricity markets?*** To answer this question, the following sub-objectives are defined:

- to analyse demand flexibility from a whole system perspective including both wholesale and ancillary services markets;
- to analyse demand flexibility from the perspective of different actors in the power systems to understand their needs and implications for demand flexibility integration. The thesis considers the perspectives of the following actors:
    - transmission system operators,
    - distribution system operators,
    - aggregators, and
    - commercial and residential electricity consumers.

[1] An illustrative example of an integrated 'high-resolution' market is PJM. At PJM, day-ahead wholesale and AS markets are cleared simultaneously using least-cost, security constrained resource commitment and dispatch algorithm (PJM 2017). On an intraday basis, a centralized algorithm calculates prices at 10,000 separate nodes every 5 minutes, and the settlement takes place every hour (IEA 2016). PJM is one of the leading system operators in the U.S. to integrate demand flexibility into wholesale and ancillary services markets (SEDC 2015).

Demand flexibility is not the only source of flexibility in power systems, as will be discussed in Chapter 2.1. There is ongoing research that compares demand flexibility to other flexibility sources, but this topic is outside the scope of this project. This work is based on the assumption that demand flexibility is a valuable resource and should be integrated into electricity markets.

The background for this thesis is the architecture of the European market with its unbundled approach to electricity market organization, as described in the previous chapter. The insights from this thesis are therefore most useful for the European public and in policy debates about electricity markets.

The main focus of this work is the flexibility of small- and medium-sized consumers (residential and commercial sectors), also called distributed demand flexibility (RTE 2020). Flexibility in industry is only considered as part of the national aggregated demand flexibility potential in the study of the whole system perspective.

As mentioned in Chapter 1.1, demand flexibility is often found in combination with other DER (energy storage, distributed generation). This project does not explicitly address other DER; however, the applicability of this research to DER is discussed where relevant.

Business models of aggregators, contractual issues and redistribution of profit between aggregators and customers are outside the scope of this project. It is assumed that as long as the use of demand flexibility in the market is profitable, aggregators will find the best business model and fair settlement rules for their customers.

The first part of this thesis is the synthesis report. It consists of Chapter 1, which gives an introduction into the topic, Chapter 2, which explains the terminology and provides the necessary context, Chapter 3, which describes and discusses the methodology, Chapter 4, which summarizes and discusses the results, and Chapter 5, which offers concluding remarks. The second part of the thesis includes the four papers written during this PhD project.

2. DEMAND FLEXIBILITY IN ENERGY SYSTEMS

2.1 Sources of flexibility in energy systems

Flexibility is broadly defined as a power system's ability to cope with variability and uncertainty in demand and generation (Ma et al., 2013). Traditionally, flexibility from different kinds of power plants with different response times has been used to achieve the balance between generation and consumption. An increase in shares of VRE has started to challenge the traditional way energy systems operate. Due to increased variability and uncertainty of supply, the need for flexibility in energy systems has increased.

Demand flexibility is not the only source of flexibility in the energy system. Other sources of flexibility include flexible generation, energy storage, coupling of the thermal and power sectors and increased network interconnection (Huber et al., 2014; Lund et al., 2015).

Flexible generation is the resource that has traditionally been used by power system operators to balance power systems. Hydropower plants in the Nordic countries are an example of a flexible generation technology that offers the possibility of quickly regulating production at a low cost (Wangensteen, 2012). Pumped hydropower also acts as a battery in the power system and increases flexibility. Many VRE technologies are not very flexible because they have to produce when the input factors are present (wind is blowing, sun is shining). However, techniques exist for regulating the production of some VRE types, such as wind turbines controlling for frequency regulation (Camblong et al., 2012).

Energy storage includes various electric and thermal storage technologies that can be used to shift the energy flow in time and balance VRE production. The scale of storage technologies varies from large-scale grid-level technologies to small-scale technologies of end-users. The development of electric vehicles (EV) has contributed to increasing the potential electric storage capacity of the distribution grid, and a lot of research is being done on the smart use of EV in power system balancing (Kiviluoma & Meibom, 2010; Babrowski et al., 2014; Taljegard et al., 2019). In addition, power-to-hydrogen and power-to-heat energy storage technologies are important flexibility providers (IRENA, 2019). Storage capabilities of district heating systems are widely studied with respect to their flexibility potential (e.g. in Kiviluoma et al. 2017; Kirkerud 2017).

Power and thermal sector coupling includes measures that enable using the flexibility that lies in thermal energy production (heating or cooling) to balance the variable production of VRE. There is a great deal of research on power and thermal sector coupling (e.g. Kirkerud 2017; Arabzadeh et al., 2019; Heinisch et al., 2019; Kiviluoma & Meibom, 2010).

Network interconnection can contribute to reducing the costs of VRE integration and is important to provide security of supply in systems with increasing shares of VRE (Scorah et al., 2012). Both grid strengthening and integration of separate power grids are considered to be means of increasing the power system flexibility (Lund et al., 2015).

Comparison of different flexibility options to mitigate wind and solar power variability is a highly relevant research topic, and there is a significant body of literature comparing the value of different types of flexibility. Brower et al. (2016) found that in systems with large shares of VRE, flexible gas power plants give the largest reduction in system cost, followed by flexible demand, flexible VRE generation and increased interconnection capacity. Kiviluoma et al. (2017) found that, in a big power system with a large amount of reservoir hydropower and VRE, the best flexibility options are heat and power sector coupling and transmission grid expansion, followed by demand response and energy storage. Johansson and Göransson (2020) compared variability management by demand flexibility, electric boilers, batteries, hydrogen storage and biomass-based thermal and power generation and find that load shifting and absorbing the excess electricity using electric boilers or hydrogen production increases the cost-optimal VRE investments in systems with a high VRE share initially. The authors also found synergies between different variability management strategies such that their combination results in a greater increase of VRE capacity. Nagel et al. (2020) found that for a large interconnected power system, demand flexibility has the largest impact on the system cost at low climate targets, but as climate targets get more ambitious, sector coupling and more interconnections become more important.

Comparing different flexibility options is outside the scope of this project, and the general assumption for the rest of the thesis is that demand flexibility has a positive impact on the system cost and is therefore a valuable resource.

2.2 Definition of demand flexibility, demand response and demand-side management

In the literature, different terms are used to describe the flexible capabilities of demand, such as demand flexibility, demand response and demand-side management. It is useful to point out the difference between these terms and clarify their meaning.

Demand flexibility is the share of demand that can potentially be modified. Demand flexibility can be understood as a resource in the energy system that can be activated through different incentives. The International Renewable Energy Agency defines demand-side flexibility as 'the portion of demand in the system (including electrified heat and transport) that can be reduced, increased or shifted within a specific duration' (IRENA, 2019). Their definition includes such sources of demand-side flexibility as sector coupling (power-to-heat, power-to-gas, power-to-hydrogen), smart charging of electric vehicles and smart appliances. It is important to keep in mind that though demand flexibility can be related to other energy carriers than electricity, the ultimate purpose of demand flexibility is related to *changing the electric load*.

Demand response (DR) is the active change in demand in reaction to any kind of signal from the system, or in other words, the utilized demand flexibility potential. This is reflected in the widely used definition published by the U.S. Department of Energy (2006): *'DR is changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.'* As pointed out by Katz (2016), not only price or system signals but also environmental signals can incentivize demand response.

Demand-side management (DSM) is a broader term that includes all measures that *can influence the time pattern or/and amount of electricity demand*, including demand response and load management, strategic conservation, electrification, customer generation and so forth (Gellings & Smith, 1989). The main differences between energy conservation and demand response are the time perspective and the level of consumer comfort. Conservation is an increase in efficiency that reduces energy use in the long term, leaving consumers' levels of service unchanged. Demand response is a change in electricity usage at particular times that may sometimes change the quality or the level of service and even cause overall increase in energy use (Northwest Power and Conservation Council, 2016).

From the point of view of energy system planning, different DSM measures can be hierarchically positioned with respect to how they should be implemented. Measures that permanently reduce electricity consumption should be implemented first, while load control should be the last measure considered. The potential for load control will be reduced as the measures at the bottom of the hierarchy are implemented (Lislebø et al., 2012).

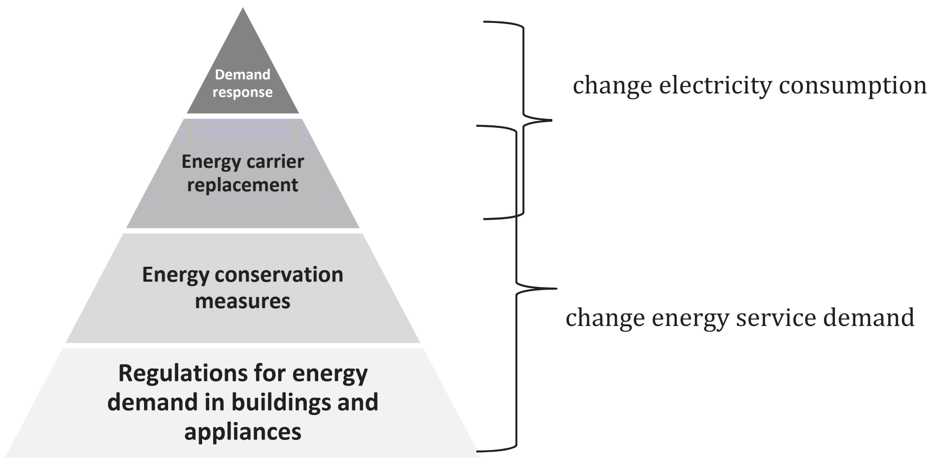

Figure 1. Hierarchy of DSM measures with respect to energy system planning and optimal use of resources. Adapted from Lislebø et al. (2012)

2.3 Classification of demand response

The most commonly used classification is the division of demand response into *explicit* and *implicit* (U.S. Department of Energy, 2006; COWI, 2016):

- ***Explicit (incentive-based)*** demand response refers to a situation where consumers or agents working on their behalf are allowed to participate and provide demand-side resources in different power markets.
- ***Implicit (price-based)*** demand response refers to a situation where consumers can choose to be exposed to time-varying electricity prices or grid tariffs and react to such signals.

One type of demand response that falls between these two categories is *autonomous* demand response. It is defined as load response to decentralized system-based signals (e.g. frequency) rather than to control signals or price signals from a central dispatch centre (Donnely et al., 2012; Molina-García et al., 2011). Autonomous demand response can provide primary frequency regulation through decentralized response to a large number of demand units and is especially relevant in systems where frequency response of generation units is expensive.

This division of demand response into explicit and implicit is also not very precise with respect to small consumers that are represented on the market by balance responsible parties (BRPs). BRPs are agents that are responsible for forecasting electricity consumption, purchasing electricity on the market on behalf of consumers and customer settlement. Their primary task is to be in balance with respect to their market obligations. When the amount of implicit (price-based) demand response becomes significant, BRPs will have to consider this demand response in their forecasting and market bidding processes, for example through flexible electricity purchase bids or imbalance trading on the intraday market. Therefore, implicit demand response will eventually also become a form of explicit demand response.

A similar classification, but with an emphasis on the perspective of power system utilities, is used by the Northwest Power and Conservation Council (2016). Demand response is divided according to its reliability into *firm* and *non-firm*:

- ***Firm*** demand response allows load curtailments to be directly controlled by the utility or scheduled ahead of time. It is characterized by high reliability for meeting system needs.
- ***Non-firm*** demand response involves resources that are outside the utility's direct control since curtailments are based on customer response to pricing signals. It is characterized by low reliability for meeting system needs.

There also is the possibility for overlap in assumed potential between firm demand response programmes and any pricing structure initiatives; in other words, the same DR resources can participate in both. This classification can be applied to demand response with respect to both transmission and distribution system levels.

Another useful classification is the division of load management methods into *direct* and *indirect* (Kostková et al. 2013), presented in Table 1. This classification generally reflects the abovementioned divisions into explicit and implicit, and firm and non-firm, but also includes energy efficiency and customer education as indirect load management methods.

Table 1. Classification of load management approaches (Kostková et al., 2013).

Direct load management	Indirect load management
Direct load control Interruptible tariffs Load curtailment programmes • Demand bidding programmes	Pricing programmes • Time-of-use tariff (ToU) • Real-time pricing (RTP) • Critical peak pricing (CPP) • Extreme day pricing • Extreme day critical peak pricing Rebates and subsidies • Subsidies or rebates for purchasing energy efficient appliances • Rebates for peak demand reduction Educational programmes • Customer information about energy consumption and energy efficient appliances etc.

As new business models for aggregators of demand flexibility emerge, these classifications may become less relevant. For example, a service company for electricity consumers may offer a wide range of services, from direct load control in response to electricity prices to market bidding of aggregated demand flexibility. Electricity consumers may even not be aware of what programmes their flexibility is engaged in as long as load management is done cautiously and does not influence their comfort and as long as they receive sufficient remuneration or energy payment savings for being part of the portfolio.

Depending on the level of automation, demand response can be divided into manual, semi-automated and fully automated (Piette et al., 2006):

- ***Manual demand response*** involves a labour-intensive approach such as manually turning off or changing comfort set points at each equipment switch or controller.
- ***Semi-automated demand response*** involves a pre-programmed demand response strategy initiated by a person via a centralized control system.
- ***Fully-automated demand response*** does not involve human intervention, but is initiated at a home, building, or facility through receipt of an external communications signal.

The level of automation influences the costs of demand response, as discussed in Chapter 2.5.

Demand flexibility resources are often grouped by consumption sector into industrial, tertiary and residential demand flexibility. An equally useful grouping according to the size of consumers and the grid level is used by the French TSO (RTE 2020) that distinguishes between industrial demand response and distributed demand response. ***Industrial demand response*** is different from distributed demand response in that large industrial sites are often connected to the high-voltage grid and have significant load sizes. Industrial demand response is often able to participate in markets directly, without having to be aggregated. ***Distributed demand response*** involves smaller flexibility volumes dispersed in the distribution grid, and market participation requires this flexibility to be aggregated.

2.4 Demand flexibility in different markets

Demand flexibility is a resource that can be used by different actors and in different markets. In some cases, DR gives some specific benefits related to the business or the field of responsibility of a given actor, for example when demand flexibility is used for specific services by TSOs or DSOs, or when it participates in portfolio balancing of a BRP. In other cases, DR is beneficial for the whole system and no particular actor is responsible for adopting its use, as when electricity consumers respond to electricity price and contribute to peak load reduction.

There is extensive literature that elaborates on the benefits of DR for different actors and in different markets. Table 2 summarizes the most important markets for DR, with respect to specific actors in the power system as a whole. The table is based on comprehensive overviews from previous reports (IEADSM 2008; Belhomme et al. 2009; Eurelectric 2013; USEF 2020) and is extended by including the classification of Kostková et al. (2013) to systemize DR programmes according to whether or not they require aggregation with direct load control.

Some of the services mentioned in the table already exist, such as frequency control by TSOs, and the integration of demand flexibility only involves adjusting the market design to make these markets accessible for demand-side resources. Other services have not yet been widely adopted or do not exist. For example, distribution system services from demand flexibility will become relevant only when the DSO's role changes from passive to active distribution system management (Eurelectric, 2013). It is also probable that new markets for demand flexibility will emerge to deliver existing or new services to different actors, as described in the Universal Smart Energy Framework (2020).

Table 2. Overview of markets where demand flexibility participation is relevant as direct or indirect load control.

Market	**Main goal of using demand flexibility**	**Direct load control**	**Indirect load control**
Wholesale electricity market	Meeting peak load. Better demand elasticity. Integration of larger shares of VRE.	Demand response to electricity price (load control by a third party). Direct market bidding (via third party).	Demand response to electricity price (consumers' own response).
AS market for transmission system operator (TSO)	Increased security of supply (especially with respect to larger shares of VRE). Competition with similar services from generation. Avoiding or postponing investments into the grid.	Primary, secondary and tertiary frequency control (as load control by aggregator; as autonomous DR[2])	-
		Short-term congestion management (as load control by aggregator)	-
		Long-term grid capacity management (e.g. national capacity markets[3] where TSOs can enter long-term contracts with aggregators).	Demand response on the wholesale market leading to peak load reduction will affect long-term grid capacity planning.
		Other system services: controlled islanding, network restoration, redundancy n–1	-

[2] **Autonomous DR** is defined in Chapter 2.3.

[3] **National capacity markets** (including strategic reserves) are markets that aim to increase the security of supply by organizing sufficient long-term peak and non-peak capacity. This capacity can be delivered by either the production or the consumption side (USEF, 2020).

		support[4] (load control by aggregator).	
AS market for distribution system operator (DSO)	Handling challenges in the distribution grid due to DER. More cost-efficient distribution grid management.	Short-term congestion management by direct load control (via aggregator)	Short-term congestion management by consumers' response to grid tariffs (e.g. dynamic, variable or CPP[5])
	Avoiding or postponing investments in the grid.	Long-term grid capacity management by entering contracts with aggregator	Long-term grid capacity management by consumers' response to grid tariffs (e.g. ToU[6])
		Voltage control by aggregated demand response (via aggregator)	-
		Other system services: loss management, controlled islanding (load control by aggregator)	-
Services for balance responsible party (BRP)	Minimizing portfolio costs/maximizing profit.	Day-ahead and intraday portfolio optimization[7] (load control by aggregator)	-

[4] ***Controlled islanding*** aims at preventing supply interruption in a given grid section when a fault occurs in a section of the grid feeding into it. ***Network restoration and redundancy (n - 1) support*** refers to actions that help to reduce the duration of outages and restore the system after an outage (USEF, 2020).

[5] ***CPP, variable and dynamic*** grid tariffs are tariff signals from DSOs to consumers that are sent when grid overload is expected. CPP and variable grid tariffs are sent day-ahead, while dynamic tariffs are sent during the day of operation (Rasmussen et al., 2012).

[6] ***Time-of-use*** is a distribution grid tariff with a fixed pattern which is determined for long periods of time (Rasmussen et al., 2012).

[7] ***Day-ahead and intraday portfolio optimization*** implies load shifting from high-price to low-price time intervals on a day-ahead or intraday basis or longer in order to reduce BRP's overall electricity purchase costs and create additional value by intraday trading (USEF, 2020).

Table 2 illustrates that there are many ways of potentially using aggregated demand flexibility in the power system, not only with respect to VRE integration but also in general by making the use of resources and infrastructure more cost-efficient. It also illustrates that direct load control provides more reliable demand response that can be used for more services than indirect load control.

Several services described in Table 2 require demand flexibility with specific technical characteristics (e.g. primary frequency control requires quick response time or autonomous DR). Still, many services can be provided by the ordinary demand flexibility resources, such as disconnecting or shifting of heating, cooling or car charging by residential and commercial consumers. Therefore, we can think of aggregated demand flexibility in the distribution grid as a common pool of resources that can be used in different markets. The following examples illustrate this: electric car charging in Norway is increasing and can either be used to perform load shifting in response to prices using the system developed by (Tibber, 2020) or can potentially contribute to frequency control performed by the Norwegian TSO (pilot testing by Statnett (2019)). Another example is residential electric heating in France, which on the one hand is subject to time-of-use tariffs and contributes to reducing peak load on the grid (IEADSM, 2020) but on the other hand can participate in ancillary services for the TSO via an aggregator (DR program by Voltalis (RTE, 2020)).

We can conclude that there is competition for demand flexibility resources between different markets and actors. While single actors can argue for their own benefit, it is still important to look at different alternatives together and evaluate the best ways to allocate flexibility from a socio-economic point of view. Coordination between different actors is increasingly important, especially between TSOs and DSOs. An aggregator of demand flexibility can be an intermediary that optimizes resources and makes them available for different uses by different actors at different points in time.

2.5 Cost and price of demand response

At a general level, the cost components of demand response include system costs and participant costs (U.S. Department of Energy, 2006). System costs include all types of costs that are incurred during the establishment of a demand flexibility programme. The participant costs include several components, which are illustrated in Figure 2. Just like for generation technologies, two major cost components of demand response are initial costs and operational costs.

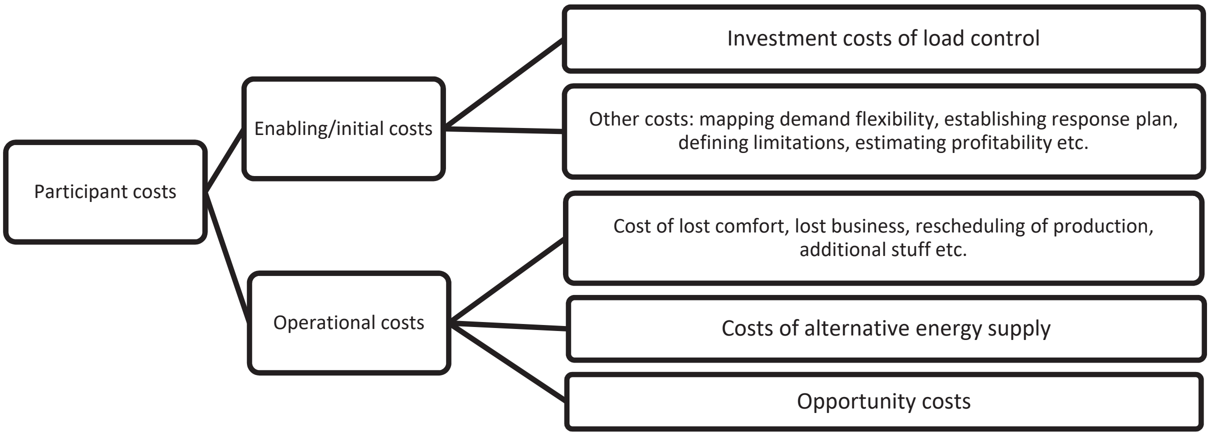

Figure 2. Costs of demand response for electricity consumers. Based on U.S. Department of Energy 2006; Northwest Power and Conservation Council, 2016; Rebours, 2008.

Initial costs include investment costs related to the purchase and installation of the load control technology. For residential customers, this might be the extra cost of purchasing of a smart appliance instead of a usual appliance. For commercial actors, this might be the cost of establishing a more advanced building automation system with load control. Investment cost can be defined per MW if it is divided by the standard load reduction (Northwest Power and Conservation Council, 2016).

The investment cost of demand response will increase with a higher level of automation. Manual demand response (e.g. switching off an electric appliance by hand) can have an investment cost of zero but at the same time a very high variable cost (related to the need to follow price signals, unwillingness to respond or loss of comfort). Previous research has shown that automatic control may be crucial for getting sufficient response, especially for larger consumers (Katz, 2016).

Operational costs are related to the use of demand flexibility and can include the cost of using an alternative energy supply, the cost of loss of comfort, the cost of production shutdown and so forth. If demand flexibility providers participate in several markets or programmes, the variable cost of demand response will include the opportunity cost reflecting the income lost in another market or programme (Rebours, 2008).

The profitability of demand response to electricity price depends on whether or not it is possible to shift load from high price to low price hours. The feasibility of investment in such demand response will depend on the income potential from daily price variation and the variable costs of load shifting. If the variable cost of shifting demand is higher than the price difference between two hours, than demand response is unprofitable. Time-differentiated grid tariffs that are applied on the top of wholesale electricity prices can increase the profitability of such demand response.

Demand flexibility used in AS markets (both for transmission and for distribution systems) receives a direct payment from TSOs/DSOs and is not dependent on wholesale electricity price variations. Just like generation technologies, demand flexibility providers that participate in AS markets should have a two-tier price structure (Rebours, 2008; Rud, 2009) which implies that the price for AS must include

- the reservation price paid to reserve capacity, regardless of whether the capacity is activated or not; and
- the activation price paid to activate the capacity.

For demand flexibility, the reservation price will cover the investment and operational costs and eventually any opportunity costs of not using demand flexibility on the other markets. The activation price will cover any variable costs related to the actual demand response activation. It is important that both transmission and distribution AS markets have a price structure that accurately compensates for the costs of DR.

3. METHODOLOGY

A variety of methods and tools were used in this project, as the different studies had different angles, objectives and scopes. Power system modelling was used to study demand flexibility on a national level over a long time-horizon. The General Algebraic Modeling System (GAMS) software was used to implement the self-developed optimization problems of the joint TSO-DSO market clearing and aggregator's portfolio optimization. TIMES energy system modelling was used to study investments in residential demand response over a long time horizon. Also, R statistical software was used to perform a statistical analysis of solar and wind power variation to determine dynamic reserve requirements for the national power system.

3.1 General aspects of using modelling in demand flexibility studies

Boßmann and Eser (2016) present a comprehensive overview of 117 models studying demand response. They distinguish between three main types of DR models: prescriptive optimization models, descriptive simulation models and econometric models (Boßmann & Eser, 2016). *Optimization models* optimize the choice of technology alternatives in system planning and operation to find the least-cost path. Their aim is to find the system optimum by minimizing or maximizing system variables, which can be system cost, system welfare or system emissions. *Simulation models* lack this system optimization perspective and have more of a descriptive character with respect to a predefined set of assumptions*. Econometric (techno-econometric) models* measure energy system relations using statistical techniques, taking into account cause and effect relationships from microeconomic theory.

Econometric models have traditionally been being used by economists, and in DR studies they are often used to compare different DR pricing schemes or policy (Boßmann & Eser 2016). They are highly dependent on correct input on price elasticity. However, the use of elasticity raises questions like whether demand elasticity can correctly represent automatic demand response (Katz, 2016), whether elasticity measured in one country can be applied to another country and whether it is correct to use the same elasticity in long-run simulations.

Optimization and simulation models provide a more sophisticated representation of the energy system and capture more technical details than econometric models. Therefore, they are well-suited for analysing complex interactions between electricity consumption and VRE. Optimization modelling can be used to study system-wide impacts of DR, small-scale DR applications and individual DR optimization problems.

Important common features of optimization and simulation models that are intended to be used in DR studies can be summarized as follows:

1. ***Disaggregated electricity demand***. Traditionally, the majority of energy and power system models have been highly detailed on the supply side, while the demand side has often been represented at an aggregated level (Martinsson et al., 2014). However, disaggregating demand and finding a balance between the level of detail for the demand and supply sides is important for studying future energy systems with active DER. It is easier to model specific properties of demand flexibility in different sectors when demand is disaggregated. In their review of DR models, Boßmann and Eser (2016) point out that very few models investigate DR measures across three or more energy demand sectors, though it would be an advantage. In addition, Martinsson et al. (2014) discuss the importance of a better representation of the residential and commercial sectors in optimization models. The transport sector is also becoming increasingly important due to increasing electrification. In this project, the TIMES energy system model with disaggregated representation of demand-side is used in Paper IV.
Disaggregating the representation of demand-side by geographical or grid location can be important for studying particular markets (e.g. TSO and DSO markets, like in Paper II) but may only be possible in smaller models. Spatial disaggregation is computationally challenging and requires much more detailed input data.
2. ***The possibility to include different markets*** is an advantage in demand flexibility studies because, as shown in Table 2, demand flexibility can participate in many markets. The biggest challenge is limiting the scope of the modelling problem in order to keep the computational time acceptable. In Paper I, demand response in both wholesale and reserve power markets is modelled, but at the expense of a more aggregated representation of demand side and a limited time horizon.
3. ***The possibility to include sectors other than electricity*** can be important because, as discussed in Chapter 2, demand-side flexibility can come from sector coupling,

including power-to-heat and power-to-hydrogen. Again, the biggest challenge with expanding the model is to keep the computational time acceptable. The TIMES model used in Paper IV includes all sectors of the national energy system, but at the expense of a simplified representation of the system operation and exogenous representation of neighbouring countries.

4. ***Hourly time resolution*** is a standard choice in the models that study demand flexibility (Boßmann & Eser, 2016). In several ancillary services markets where demand flexibility participation is relevant, the time resolution is sub-hourly. However, keeping an hourly temporal resolution may be a sensible trade-off between exactness and computational time (Boßmann & Eser, 2016).

5. ***Technical properties of demand response.*** Important technical properties of demand flexibility resources include the time frame of load shifting, limits on load reduction duration, minimum time between load reductions, response time, energy loss, reconnection peak, linear or non-linear load reduction costs and so on. Not all of these properties can be implemented in a linear optimization. Mixed-integer linear programming (MILP) techniques can be used to capture various properties of demand flexibility (as in Papers II and III) but they may be more suited to specific modelling and simulation problems with limited system boundaries. For full-scale power or energy system models, MILP can greatly increase computational time; therefore, linear approximations of the technical constraints may be a better choice.

Generally, including demand-side resources in energy system modelling implies that the model's demand side becomes more detailed and less aggregated, which makes the whole model more complicated and challenging to solve within an acceptable time frame. Simplifying parts of the model (Martinsson et al., 2014) and model coupling (European Comission Joint Research Centre, 2014) are possible solutions. Also, models that have a modular structure (such as TIMES) are useful because they allow us to increase the complexity of some modules while simplifying other modules and change modules in different projects.

3.2 Power system modelling for studying the benefits of demand response

The objective of Paper I is to model the power system in Germany in 2030 with increased shares of VRE and estimate the cost of power system operation and the value of demand flexibility participation on the spot and reserve markets. To perform the analysis, a special model for power system operation, BalmoREG, was developed based on the Balmorel model.

Balmorel is a partial equilibrium bottom-up linear programming (LP) model originally developed for the power and district heating sectors of the Nordic and Baltic countries by Ravn et al. (2001). The basic version of Balmorel is an open access model available at Balmorel's website (2020) and thoroughly described in Wiese et al. (2018). The model is under constant development and updated for a wide range of research projects, and different research institutions have their own versions of the model with the extensions and updates that they find necessary to implement. In this PhD, the Norwegian University of Life Sciences' version of Balmorel is used; this version was developed and thoroughly documented in previous doctoral research (Tveten 2015; Kirkerud 2017).

The idea behind BalmoREG is to rerun one of the years modelled in Balmorel for only one country and with more details about the balancing power requirements and demand flexibility participation in electricity trade and balancing power provision. BalmoREG's formulation is based on Balmorel, including the objective function, the balance equation and various constraints, but the equations are modified to include demand response and regulation power market, and the model horizon is limited to one year. BalmoREG is soft-linked to Balmorel such that the Balmorel model first runs through all modelled years and BalmorREG only models one chosen year using input from Balmorel.

3.3 GAMS as a tool to simulate market participation of demand flexibility providers

Both Paper II and Paper III present novel modelling frameworks for chosen actors in the power system. Paper II studies the combined optimization problem for a TSO and a DSO that procure demand flexibility services in a joint market. Paper III studies the optimization problem of an aggregator of demand flexibility that is participating in spot and reserve electricity markets. In both papers, classic mathematical optimization problems are formulated, and MILP is used to reproduce the technical characteristics of demand flexibility with a sufficient level of detail. In Paper II, the objective function is the minimization of the total procurement cost for the TSO and the DSO. In Paper III, the objective function is minimizing the total portfolio cost for the aggregator.

Both mathematical optimization problems are implemented in GAMS (GAMS Development Corp., 2020). GAMS is widely used in the academic and industrial energy community for mathematical modelling and optimization purposes, but alternative tools such as Python and Julia (Weibezahn & Kendziorski, 2019) also exist. The TIMES and Balmorel models used in the other papers of this thesis are also implemented in GAMS.[8]

3.4 Energy system modelling for demand response potential assessment

The objective of Paper IV is to study demand response potential in the energy system, and the modelling tool chosen for the study is the TIMES energy system model generator developed within the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA-ETSAP, 2020) and thoroughly documented in Loulou et al. (2016). TIMES is a partial equilibrium bottom-up LP model that solves the surplus maximization problem for an energy system with the level of detail, spatial and geographical resolution that is appropriate for the specific research project. The main advantages of TIMES with respect to demand flexibility modelling is that it is easy to disaggregate demand by defining as many demand technologies as necessary, and it is easy to model investments in technologies; thus the model is well suited for studying demand flexibility potential endogenously. Another advantage of the model is that it is modular, meaning it is easy to simplify some sectors while increasing the level of detail about others.

The implementation of the Norwegian energy system in TIMES has been documented (IFE, 2013). In Paper IV, the model is updated with the latest energy system data and the structure of the residential sector is modified to implement demand flexibility. Soft-linking TIMES to two other models is used to limit the scope of the modelling problem. Also, a model setup with exogenous prices is tested in the paper. This is easily done due to the modularity of TIMES – electricity supply and exchange sector modules are replaced with a module containing electricity price data.

---

[8] TIMES model generator is implemented in GAMS, but there is an interface for model input and output, so the user is not working in GAMS directly.

4. RESULTS AND DISCUSSION

4.1 System-wide impacts of demand flexibility

System-wide impacts of demand flexibility are studied in Paper I based on the example of the German power system with increasing shares of VRE. An important contribution of this paper is that we study demand flexibility as a resource in both the wholesale and reserve power markets to understand the total value of demand flexibility and to see how it should be optimally allocated between different markets.

The need to provide reserves increases the cost of power system operation because a share of generation is reserved for power system balancing. Larger shares of VRE lead to increased reserve requirements because of increasing uncertainty and variability of supply. At the same time, technologies that normally provide reserves are being phased out. In Paper I we study four scenarios for the phase-out of thermal technologies in Germany with different rates of coal plant phase-out, different rates of VRE integration and different roles for gas power plants. We find that the need for reserve provision adds 0.6–8.6% to the total system cost in 2030 depending on the scenario. The lower range corresponds to the scenario where the coal phase-out and VRE integration take place slowly so that there is still a significant share of conventional generation in the system in 2030. The higher range corresponds to the scenario with the largest share of VRE and the smallest share of conventional generation.

Demand flexibility decreases the additional system cost related to reserve requirements in all scenarios. It has the largest impact in scenario with the highest VRE share and the smallest share of conventional generation. Reserved demand flexibility provides between 75% and 86% of the up-regulation reserve in different scenarios replacing reserve provision by coal and gas plants.

In this study we allow the model to determine the optimal allocation of demand flexibility between the wholesale market and the reserve market. The model can either perform actual demand shifting in the wholesale market or keep demand reductions reserved for up-regulation. The more demand flexibility actively responds to wholesale market prices, the less is available for reservation as regulation power. Both ways of using demand flexibility contribute to reducing the total system cost. In the wholesale power market, demand flexibility contributes to reduction of price variability and better adjustment of demand to supply variations. In the reserve market, demand flexibility replaces reserve provision from conventional power plants.

We find that in all scenarios the model allocates a share of demand flexibility to the wholesale market and a share to the regulation power market, but the latter share is always larger. The optimal allocation of demand flexibility between the wholesale and the reserve market varies from 37/63% to 30/70% depending on scenario, with a tendency towards more demand flexibility on reserve markets with larger shares of VRE. This indicates that the system benefits of using demand response to create reserves are more significant than the system benefits of demand response on the wholesale market. The benefits of utilizing demand flexibility for reserves instead of in the wholesale market are most evident in scenarios with small amounts of baseload technologies.

The role of demand flexibility is especially evident for days with either very low or very high VRE production. In the first case, expensive peak-load and back-up units are started to compensate for low VRE production, leading to high electricity prices. In the second case, high VRE production leads to high reserve requirements and the need to keep conventional generation spinning, resulting in electricity surplus, zero prices and VRE curtailment. In both cases, the use of demand flexibility relieves the situation, reducing the need to start peak-load units or curtail VRE.

4.2 Market design for optimal use of demand flexibility

While Paper I illustrates the value of having demand flexibility in wholesale and reserve power markets, Paper II studies reserve provision from demand flexibility in more detail. This paper looks at the market design for the optimal utilization of demand flexibility as ancillary services and considers not only the transmission system but also the distribution system level.

Demand flexibility is a common pool of resources located in the distribution grid that can be used for both transmission and distribution system services. Previous research has demonstrated that aggregated demand response can be used for power system regulation services, congestion management, balancing and other kinds of system services procured by TSOs. At the same time, DSOs can also utilize demand flexibility for short-term or long-term congestion management, voltage control, power quality support and other services.

Different services have different procurement time frames and require demand flexibility with different technical properties and levels of aggregation. In Paper II we investigate two services that are similar with respect to technical properties and procurement time frame: tertiary power system regulation for TSOs and short-term distribution system congestion management for DSOs. These services can, in principle, be procured from the same sources of demand flexibility with a maximum response time of 15 minutes and possible disconnection time of at least 1 hour. The time frames for procurement of these two services would also be similar, with a reservation market running prior to the wholesale electricity market (e.g. day-ahead), and an activation market running in real time. The main difference in service procurement would be the level of aggregation with respect to high-voltage and low-voltage grids.

In Paper II we investigate the possibility of having a joint market for procurement of these two services by TSOs and DSOs and study the advantages of such a market design. We suggest a design where demand flexibility operators (or DER operators if the portfolio also includes distributed generation or storage) make load reduction bids to the joint market specifying the price, the volume and the location of load reduction with respect to different feeders in the distribution grid. The TSO and the DSO specify their demand for service per grid level. We develop a joint clearing procedure for the reservation market, where flexibility bids are optimally allocated between the TSO and the DSO, taking into account their location in the grid and the fact that the TSO can also procure the same service from the generation units. The objective of the market clearing is the minimization of the total procurement cost.

The proposed market framework is tested using a numerical example to illustrate its overall system impact and implications for the TSO and the DSO. We compare simultaneous market clearing with sequential market clearing where the DSO runs a separate market first, and the TSO runs a separate market afterwards. We illustrate that in simultaneous market clearing the total procurement cost for the system is lower than in sequential market clearing because the bids are more optimally allocated between the TSO and the DSO. In sequential procurement, all cheap load reduction bids are taken on the first market by the DSO, which incurs a lower procurement cost. In simultaneous procurement, several cheap load reduction bids are instead allocated to the TSO because this results in a lower total procurement cost. Procurement costs for the DSO alone are thus higher, but from the system perspective, the joint market clearing ensures a cheaper solution.

Joint market clearing also solves several other problems related to the procurement of ancillary services from demand flexibility; for example, it can prevent demand flexibility resources from fleeing a particular market, as can happen with sequential markets for DSOs and TSOs. The clearing prices on TSO markets might be higher if the bids from demand are cleared together with the bids from generation. Therefore, demand flexibility providers can prefer to bid to TSO markets or set a higher price on DSO markets to compensate for the opportunity cost. In a centralized design like the one described in this paper, demand flexibility providers will only have one market platform to place their bids which will prevent demand flexibility from favouring one particular market.

4.3 Participation of aggregated demand flexibility in wholesale and reserve electricity markets

Paper III studies market participation of demand flexibility from the perspective of an aggregator. The aim of the paper is to investigate how an aggregator of demand flexibility from medium-sized commercial consumers can optimize its portfolio and participate in the wholesale electricity market and ancillary services market.

Medium-sized consumers (e.g. process industry, food production sites, office buildings) represent a significant share of demand flexibility potential. These consumers need to be aggregated in order to have sufficient volumes to participate in power system markets. Aggregation and optimal bidding strategies are important to maximize the value of their flexibility.

In this paper we use actual data on Norwegian commercial customers to study what technical parameters are important to consider in the aggregator's portfolio optimization and market bidding problem. The bidding model is based on the Nordic electricity market architecture. Wholesale electricity trading takes place on the day-ahead market run by Nordpool. Regulation power is procured on the regulation power market run by a TSO (which includes a reservation and an activation market).

The objective of the aggregator is to minimize the total energy costs of a portfolio of energy consumers. Demand flexibility can come from load shifting or energy carrier substitution. We find that the most important parameters characterizing demand flexibility in the portfolio with respect to the studied markets are

- response time (must not exceed 15 min) in order to be relevant for the regulation power market
- load share to reduce
- maximum duration of reduction
- maximum time between two reductions
- reconnection peak
- cost of load reduction
- availability during the day/week

When demand flexibility is reserved for regulation power, it becomes unavailable for response on the wholesale electricity market. And conversely, when demand flexibility is used to respond to wholesale market prices, less potential is left for reserve. The aggregator's problem is to find the optimal amount of flexibility to place into each market, depending on the expected clearing price, flexibility costs and the eventual penalty for not being available for activation on the regulation power market. Optimization therefore implies that the volume of flexibility on one market is influenced by the volume on another market.

The developed optimization and bidding framework is tested using actual Norwegian market data from the winter season in 2011 and 2012 when different price levels and price variations were observed on the markets. The value of having automatic load control and energy storage in the portfolio is also tested.

We find that daily price variation is crucial for profitability of flexibility on the wholesale power market, and in the chosen test periods it does not seem to be significant enough, so the model chooses to reserve most of the flexibility for the up-regulation reserve. Capacity payments from the regulation power market strongly increase the value of flexibility for the aggregator. Less demand flexibility is available on the regulation power market in hours 8–11 and 17–19 because demand flexibility is used on the wholesale market during those times to respond to high prices.

Automatic load control and the use of energy storage are found to increase the value of flexibility in the portfolio. Automatic load control has the largest impact because it extends the availability period for demand response (e.g. creates the possibility to shift load at commercial sites outside the normal working hours) which is especially important for income on the regulation power market where resources must be available during many hours.

4.4 Residential DR to electricity price and investment in demand flexibility

Paper IV studies demand response from residential consumers in Norway. In this paper we use energy system modelling with endogenous investments in demand technologies and load control technologies to study residential demand response potential in Norway. We assume that residential consumers in Norway are already able to respond to electricity price as a result of smart meters installed in all households and the possibility of entering spot price hourly contracts. Still, the profitability of investing in load control depends on electricity price variability and the cost of demand response.

Our results show that electricity consumption from residential heating technologies slightly decreases in Norway towards 2040 as a result of energy efficiency, better building standards and decreased heating demand. On the other hand, electricity consumption from car charging and its theoretical demand response potential are increasing due to the electrification of the transport sector.

The economic potential of DR to electricity price will gradually increase towards 2030–2040 as the price variation in Norway grows and the costs of residential load control are reduced. Depending on the scenario, it may reach 37–69% of the theoretical potential in 2040. Based on modelling of investment in demand flexibility, we find that 7– 17% of residential heating appliances and 57–60% of residential car chargers can become flexible by 2040, resulting in a maximum load reduction of between 1940 and 3258 MW due to price response on a normal winter evening.

We observe that demand response from electric cars is more profitable compared to demand response from heating technologies because it has a lower investment cost per kWh/h and because it can benefit from the largest price differences between the daytime and the night-time hours. Demand response from heating technologies is limited by the hours just before/after the morning peaks because heating technologies cannot shift load over long periods of time. Shifting windows have a significant effect on the profitability of demand response.

Modelling results show that there exists an optimal level of demand response in the wholesale market when electricity price volatility is sufficiently reduced, and more demand response becomes unprofitable. The price flattening effect acts as a natural restriction on the economic demand response potential, and our results show that investments into demand flexibility may be overestimated by 10–18% if this effect is not considered.

It is important to have correct feedback between the market and consumers, so that consumers do not perform more DR than necessary from a system perspective. A third-party aggregator performing "controlled" DR on behalf of residential consumers can adjust the level of DR with respect to intraday and real-time market prices.

4.5 Discussion and further work

The work performed for this thesis illustrates the importance of including several markets and different grid levels in demand flexibility studies. Demand flexibility is useful for many actors in the power system, and the same resources can often participate in different markets and DR programmes. The participation of demand flexibility in one market can influence its participation in another market. It is also not straightforward what is the best way to use demand flexibility at a particular time and location from a whole system point of view. Optimization that considers several markets and different grid levels is more complex but gives a more accurate picture of how it is best to allocate demand flexibility.

Demand and other distributed resources are not the only sources of flexibility in energy systems. It is therefore important to compare the value of demand flexibility against other flexibility options in different power systems, especially in those where other cheap sources of flexibility are available. For example, the Scandinavian power system possesses significant flexibility in the form of hydropower which can deliver various services to the power system at low cost. However, the distribution system cannot benefit from this flexibility, so demand-based grid services or demand response to grid tariffs will still be relevant.

Individual differences between power systems will determine the main drivers behind the integration of demand flexibility into electricity markets. In hydropower-dominated regions, the primary focus may be on benefits for the distribution system, while in thermal systems with large shares of VRE, price response and balancing power from flexible demand may be of major interest. At the same time, it is likely that interest in using demand flexibility in one market will trigger its use in other markets. As soon as flexibility is enabled by implementing load control and management technologies, the threshold for using it will become lower.

The role of the aggregator is central to achieving the optimal use of demand flexibility in the power system, and it is important that the regulations clearly define this role. Among European countries, France, Belgium, Ireland and the United Kingdom have all defined the roles of demand flexibility aggregators and given them access to a number of markets (IEA, 2020). France is the only country in Europe that has opened both AS and wholesale power markets to independent aggregators, which was made possible by standardized agreements between BRP and aggregators established in 2013 (Bertoldi et al., 2016). Given access to several markets, an aggregator will optimize its portfolio between the markets in order to maximize profit. This will lead to the optimal demand flexibility allocation based on prices.

In this PhD thesis, we did not study models of customer settlement within an aggregator's portfolio because there can be many models depending on customer size, available markets and whether the aggregator is also a BRP and has other DER or generation assets. As drivers of demand flexibility integration into electricity markets are power system–specific, a variety of business models for aggregators can be expected to emerge in different power systems.

Demand flexibility and DER have transformed the power system, making it less centralized and creating new and more complex types of relations between actors. Therefore, research tools for studying power systems have also become more sophisticated. In this thesis, demand flexibility was studied from different perspectives, and various modelling tools were used, including Balmorel and TIMES energy system models. The general observation from demand flexibility modelling is that it makes the models more complex and requires better model resolution and granularity. Capturing strained power system situations and extreme electricity prices becomes important because these are what trigger the value of flexibility. Methodologically, this can be done by increasing the temporal and geographical resolution of the model, disaggregating technologies, or using stochastic programming. All these methods significantly increase the computational time and make it difficult to model long time horizons and large systems. Soft-linking different models is another possible solution, and the challenge here lies in finding a suitable boundary between the models. Investigating modelling strategies for demand flexibility studies (and DER studies in general) should be an important field of research for the future.

5. CONCLUSIONS

The objective of this PhD has been to answer the research question 'What is the optimal way to integrate demand flexibility into electricity markets?' The performed research demonstrates that it is important to consider the whole system point of view and the interplay between different markets and grid levels when demand flexibility is integrated into power systems.

Demand response has many benefits for the power system. In the wholesale market, DR reduces the peak load generation and supports the integration of VRE. In the reserve market, DR removes the need to keep thermal generation spinning when VRE production is high. Our results indicate that there may be more benefits from allocating more demand flexibility to the reserve market than to the wholesale market in power systems with large shares of VRE. The need to hold reserves constitutes a significant cost in such systems, which can be decreased if demand flexibility is used as a reserve instead of generation units.

It is important to give demand flexibility aggregators access to many markets. An aggregator will optimize its portfolio between markets in order to maximize profits. If the profitability on one market is low, the availability of other markets can support the incentives for the aggregator of demand flexibility. In reserve markets, DR receives a reservation price in addition to the activation price (energy payment) which increases the profitability for aggregators. In the wholesale market, the profitability of demand flexibility is solely determined by the size of electricity price variations as demand flexibility only gets the energy payment.

Daily price variation is important for the profitability of demand response on the wholesale market. A number of markets (e.g. the Nordic power markets with large hydropower shares) do not currently offer sufficient incentives for DR because of small price variations. However, even in Nordic markets, price variation is expected to increase due to larger shares of VRE and more interconnections with European markets. This will incentivize demand response on the wholesale markets and investment in load control and smart appliances.

Demand flexibility can be used for power system services at both the transmission and distribution system levels. An active role for DSOs in distribution system management and better coordination between DSOs and TSOs are widely discussed topics today. Large shares of demand flexibility resources in the distribution grid have technical characteristics that make them suitable for several markets and several types of services. Given a free choice to participate in one market or another, the aggregator will choose the market with the highest price level. If several AS markets run sequentially, for example a DSO market and a TSO market, the aggregator may allocate flexibility to only one market, decreasing liquidity in another market. New approaches to market design and coordination between TSOs and DSOs are important to address these types of challenges. In this project, we propose a joint market clearing for TSOs and DSOs as one of possible ways to optimally allocate flexibility between different voltage levels.

For residential consumers, price-based (implicit) demand response is often considered to be a relevant solution because it does not require aggregation. Residential consumers will only invest in load control solutions and perform demand response if the price variation is large enough. We find that an important factor that determines profitability is the time window for load shifting. For example, electric car charging can be shifted from day to night, making use of the largest price variations in the market, while heating loads have very limited time windows for shifting and are therefore less profitable.

When a large number of residential customers respond to electricity price, the electricity price variation on the wholesale market is reduced. Our results show that there is an optimal level of demand response in the wholesale market when the price variation is sufficiently reduced so that no more demand response is required, and the market reaches a new equilibrium.

All in all, the work done in this PhD thesis suggests that the optimal use of demand flexibility can be achieved through market arrangements that facilitate the use of demand flexibility in many markets, better coordination between distribution and transmission system levels and a stronger role for the aggregator to optimally allocate demand flexibility between markets. Modelling several electricity markets at the same time, including different grid levels and other parts of the energy system, is useful to achieve better insight into the optimal integration of demand flexibility in electricity markets.

BIBLIOGRAPHY

Arabzadeh, V., Pilpola, S., & Lund, P. (2019). Coupling variable renewable electricity production to the heating sector through curtailment and power-to-heat strategies for accelerated emission reduction. *Future Cities and Environment*, 5 (1): 1–10. doi: 10.5334/fce.58

Babrowski, S., Heinrichs, H., Jochem, P., & Fichtner, W. (2014). Load shift potential of electric vehicles in Europe. *Journal of Power Sources,* 255: 283–293. doi:10.1016/j.jpowsour.2014.01.019

Balmorel. (2020). *Balmorel. Energy system model*. Available at: http://www.balmorel.com/ (accessed 08.2020).

Belhomme, R., Sebastian, M., Diop, A., Entem, M., Bouffard, F., & Valtorta, G. e. (2009). *Deliverable 1.1. ADDRESS Technical and Commercial Conceptual Architectures.* ADDRESS - Active Distribution networks with full integration of Demand and distributed Energy Resources.

Bertoldi, P., Zancanella, P., & Boza-Kiss, B. (2016). *Demand Response Status in EU Member States.* European Commission's Joint Research Centre. doi:10.2790/962868

Boßmann, T. & Eser, E. (2016). Model-based assessment of demand-response measures - A comprehensive literature review. *Renewable and Sustainable Energy Reviews*, 57: 1637–1656. doi:http://dx.doi.org/10.1016/j.rser.2015.12.031

Brouwer, A., van den Broek, M., Zappa, W., Turkenburg, W. & Faaij, A. (2016). Least-cost options for integrating intermittent renewables in low-carbon power systems. *Applied Energy*, 161: 48–74. doi:10.1016/j.apenergy.2015.09.090

Camblong, H., Nourdine, S., Vechiu, I., & Tapia, G. (2012). Control of wind turbines for fatigue loads reduction and contribution to the grid primary frequency regulation. *Energy* 48 (1): 284–291. doi:10.1016/j.energy.2012.05.035

Chow, J., De Mello, R., & Cheung, K. (2005). Electricity market design: An integrated approach to reliability assurance. *Proceedings of the IEEE,* 93 (11): 1956–1969. doi:10.1109/JPROC.2005.857493

COWI. (2016). *Impact assessment study on downstream flexibility, price flexibility, demand response & smart metering.* European Comission DG Energy. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/demand_response_ia_study_final_report_12-08-2016.pdf

DNV-GL. (2020). *Energy transition outlook 2020. A global and regional forcast to 2050.*

Donnely, M., Trudnowski, D., Mattix, S. & Dagle, J. (2012). *Autonomous demand response for primary frequency regulation.* U.S. Department of Energy.

Eurelectric. (2013). *Active distribution system management.* Available at: https://www.eurelectric.org/media/1781/asm_full_report_discussion_paper_final-2013-030-0117-01-e.pdf

European Comission Joint Research Centre. (2014). *Addressing flexibility in energy system models.* doi:10.2790/925

GAMS Development Corp. (2020). *GAMS*. Available at: https://www.gams.com/

Gellings, C. W., & Smith, W. M. (1989). Integrating demand-side management into utility planning. *Proceedings of the IEEE*(6). doi:10.1109/5.29331 (accessed 08.2020).

Göransson, L., Goop, J., Unger, T., Odenberger, M., & Johnsson, F. (2014). Linkages between demand-side management and congestion in the European electricity transmission system. *Energy*, 69 (1): 860–872. doi:10.1016/j.energy.2014.03.083

Heinisch, V., Göransson, L., Odenberger, M. & Johnsson, F. (2019). Interconnection of the electricity and heating sectors to support the energy transition in cities. *International Journal of Sustainable Energy Planning and Management*, 24: 57–66. doi:10.5278/ijsepm.3328

Huber, M., Dimkova, D. & Hamacher, T. (2014). Integration of wind and solar power in Europe: Assessment of flexibility requirements. *Energy*, 69 (1): 236–246. doi:10.1016/j.energy.2014.02.109

IEA. (2016). *Re-powering markets. Market design and regulation during the transition to low-carbon power systems.* Available at: https://webstore.iea.org/re-powering-markets

IEA. (2020, June). *Demand response*. Available at: https://www.iea.org/reports/demand-response (accessed 08.2020).

IEADSM. (2008). *Integration of demand side management, distributed generation, renewable energy sources and energy storages. Final synthesis report, vol.1.* IEA DSM Task XVII. Hentet fra http://www.ieadsm.org/task/task-17-integration-of-demand-side-management/

IEADSM. (2020). Hentet fra http://www.ieadsm.org/article/tempo-electricity-traiff/

IEA-ETSAP. (2020). *IEA-ETSAP optimization modeling documentation*. Available at: fra https://iea-etsap.org/index.php/documentation (accessed 08.2020).

IFE. (2013). *TIMES-Norway model documentation.* Hentet fra https://ife.brage.unit.no/ife-xmlui/bitstream/handle/11250/2598277/IFE-KR-E-2013-001.pdf

IRENA. (2019). *Demand-side flexibility for power sector transformation.* Hentet fra https://www.irena.org/publications/2019/Dec/Demand-side-flexibility-for-power-sector-transformation

Johansson, V. & Göransson, L. (2020). Impacts of variation management on cost optimal investments in wind power and solar photovoltaics. *Renewable Energy Focus*, 32: 10–22. doi:10.1016/j.ref.2019.10.003

Katz, J. (2016). *Policy analysis of electricity demand flexibility.* Doctoral dissertation. Kongens Lyngby: Technical University of Denmark, DTU. Available at: https://orbit.dtu.dk/en/publications/policy-analysis-of-electricity-demand-flexibility

Kirkerud, J. (2017). *Energy system flexibility for variable renewable energy integration in Northern Europe.* Doctoral dissertation. Ås: Norwegian University of Life Sciences. Available at: https://static02.nmbu.no/mina/forskning/drgrader/2017-Kirkerud.pdf

Kiviluoma, J. & Meibom, P. (2010). Influence of wind power, plug-in electric vehicles, and heat storages on power. *Energy,* 35: 1244–1255. doi:doi:10.1016/j.energy.2009.11.004

Kiviluoma, J., Rinne, E. & Helistö, N. (2017). Comparison of flexibility options to improve the value of variable power generation. *International Journal of Sustainable Energy* 37 (8): 761–781. doi:10.1080/14786451.2017.1357554

Kostková, K., Omelina, L., Kycina, P. & Jamrich, P. (2013). An introduction to load management. *Electric Power Systems Research*, 95: 184–191. doi:10.1016/j.epsr.2012.09.006

Lislebø, O., RenéeNaper, L., Havskjold, M. & Bakken, E. (2012). *Nettplan Stor-Oslo: Alternativer til nettutbygging. En potensialstudie for Oslo og Akershus. (In Norwegian).* Xrgia AS & EC-group AS . Availble at: https://www.statnett.no/globalassets/her-er-vare-prosjekter/region-ost/nettplan-stor-oslo/alternativer-til-nettinvesteringer-2011.pdf

Loulou, R., Goldstein, G., Kanudia, A., Lettila, A. & Remme, U. (2016). *Documentation for the TIMES Model Part I.* Available at: https://iea-etsap.org/docs/Documentation_for_the_TIMES_Model-Part-I_July-2016.pdf

Lund, P., Lindgren, J., Mikkola, J., & Salpakari, J. (2015). Review of energy system flexibility measures to enable high levels of variable renewable electricity. *Renewable and Sustainable Energy Reviews*, 45: 785–807. doi: 10.1016/j.rser.2015.01.057

Ma, J., Silva, V., Belhomme, R., Kirschen, D. S. & Ochoa, L. F. (2013). Evaluating and planning flexibility in sustainable power systems. *IEEE Transactions on Sustainable Energy,* 4 (1): 200-209. doi:10.1109/TSTE.2012.2212471

Martinsson, F., Krook-Riekkola, A., Lindbloom, J. & Wråke, M. (2014). *Modelling the Swedish residential and service sectros in TIMES: a feasibility study.* IVL Swedish Environmental Research Institute.

Molina-García, A., Bouffard, F. & Kirschen, D. (2011). Decentralized demand-side contribution to primary frequency control. *IEEE Transactions on Power Systems,* 26(1): 411–419. doi:10.1109/TPWRS.2010.2048223

Nagel, M., Kirkerud, J. & Bolkesjø, T. (2020). The economic value of flexibility options in Northern and Central Europe on different emission reduction pathways towards 2030. Unpublised manuscript.

Nordpool. (2018). *European cross-border intraday (XBID) solution and 10 local implementation projects successful go-live*. Available at: https://www.nordpoolgroup.com/message-center-container/newsroom/exchange-message-list/2018/q2/european-cross-border-intraday-xbid-solution-and-10-local-implementation-projects-successful-go-live/ (accessed 09.2020).

Northwest Power and Conservation Council. (2016). *Seventh Northwest Conservation and Electric Power Plan.* Available at: https://www.nwcouncil.org/reports/seventh-power-plan

Piette, M., Watson, D., Motegi, N., Kiliccote, S. & Linkugel, E. (2006). Automated demand response strategies and commissioning commercial building controls. *National Conference on Building Commissioning*.

Poudineh, R. & Jamasb, T. (2014). Distributed generation, storage, demand response and energy efficiency as alternatives to grid capacity enhancement. *Energy policy*, 67: 222–231. doi:10.1016/j.enpol.2013.11.073

Rasmussen, L., Bang, C. & Togeby, M. (2012). *Managing congestion in distribution grids – market design consideration.* Copenhagen: Ea Energy Analyses. Available at: https://pdfs.semanticscholar.org/95b6/4a7ec0e06aa9cdca6afcd92f3700dcc55a70.pdf

Ravn, H. F., Hindsberger, M., Petersen, M., Schmidt, R., Bøg, R., Grönheit, P. E. & Larsen, H. (2001). *Balmorel: a model for analyses of the electricity and CHP markets in the Baltic Sea region.* Balmorel project. Available at: http://www.balmorel.com/images/downloads/balmorel-a-model-for-analyses-of-the-electricity-and-chp-markets-in-the-baltic-sea-region.pdf

Rebours, Y. (2008). *A comprehensive assessment of markets for frequency and voltage control ancillary services.* Doctoral dissertation. Manchester: University of Manchester. Available at: https://tel.archives-ouvertes.fr/tel-00370805

RTE. (2020). 'Felxibility'. Available at: https://bilan-electrique-2018.rte-france.com/demand-response/?lang=en

RTE. (2020). *RTE et Voltalis développent un nouvel outil de flexibilité pour la gestion du réseau électrique en temps réel : l'effacement de consommation électrique chez les particuliers*. Available at: https://www.rte-france.com/actualites/rte-et-voltalis-developpent-un-nouvel-outil-de-flexibilite-pour-la-gestion-du-reseau

Rud, L. (2009). *Essays on electricity markets.* Bergen: Institute for Research in Economics and Business Administration.

Scorah, H., Sopinka, A. & Van Kooten, G. (2012). The economics of storage, transmission and drought: integrating variable wind power into spatially separated electricity grids. *Energy Economics*, 34 (2): 536–541. doi:10.1016/j.eneco.2011.10.021

SEDC. (2015). *Mapping demand response in Europe today.* Brussels: Smart Energy Demand Coalition. Available at: http://www.smarten.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

Statnett. (2019). *More flexible power in Eastern Norway this winter*. Available at: https://www.statnett.no/en/about-statnett/news-and-press-releases/news-archive-2019/more-flexible-power-in-eastern-norway-this-winter/

Taljegard, M., Göransson, L., Odenberger, M. & Johnsson, F. (2019). Electric vehicles as flexibility management strategy for the electricity system – a comparison between different regions of Europe. *Energies*, 12 (13): 2597. doi:10.3390/en12132597

Tibber. (2020). *Lad elbilen smartere.* Availble at: https://tibber.com/no/losninger/smartlading-elbil

Tveten, Å. (2015). *Renewable energy in Northern European power markets: effects, challenges and integration options.* Doctoral dissertation. Ås: Norwegian University of Life Sciences. Available at: https://static02.nmbu.no/mina/forskning/drgrader/2015-Tveten.pdf

Tveten, Å., Bolkesjø, T. & Ilieva, I. (2016). Increased demand-side flexibility: market effects and impacts on variable renewable energy integration. *International Journal of Sustainable Energy Planning and Management*, 11: 33–50. doi:https://doi.org/10.5278/ijsepm.2016.11.4

U.S. Department of Energy. (2006). *Benefits of demand response in electricity markets and recommendations for achieving them.* Available at: https://eetd.lbl.gov/sites/all/files/publications/report-lbnl-1252d.pdf

USEF. (2020). *Universal smart energy framework.* Available at: https://www.usef.energy/download-the-framework/

Wangensteen, I. (2012). *Power system economics – the Nordic electricity market.* Trondheim: Tapir Academic Press.

Wiese, F., Bramstoft, R., Koduvere, H., Alonso, A., Balyk, O., Kirkerud, J., . . . Ravn, H. (2018). Balmorel open source energy system model. *Energy Strategy Reviews*, 20: 26–34. doi:10.1016/j.esr.2018.01.003

Wilson, R. (2002). Architecture of power markets. *Econometrica,* 70(4): 1299–1340. Available at: http://www.jstor.com/stable/3082000

Wu, T., Rothleder, M., Alaywan, Z. & Papalexopoulos, A. (2004). Pricing energy and ancillary services in integrated market systems by an optimal power flow. *EEE Transactions on Power Systems,* 19 (1): 339–347. doi:10.1109/TPWRS.2003.820701

Zakariazadeh, A., Jadid, S. & Siano, P. (2014). Economic-environmental energy and reserve scheduling of smart distribution systems: a multiobjective mathematical programming approach. *Energy Conversion and Management*, 78: 151–164. doi:10.1016/j.enconman.2013.10.051

Paper I Roos, A. & Bolkesjø, T.F. 2018. Value of demand flexibility on spot and reserve electricity markets in future power system with increased shares of variable renewable energy. – Energy 144: 207–217. DOI: 10.1016/j.energy.2017.11.146
Paper II Roos, A. 2017. Designing a joint market for procurement of transmission and distribution system services from demand flexibility. – Renewable Energy Focus 21: 16–24. DOI: 10.1016/j.ref.2017.06.004
Paper III Roos, A., Ottesen, S.Ø. & Bolkesjø, T.F. 2014. Modelling consumer flexibility of an aggregator participating in the wholesale power market and the regulation capacity market. – Energy Procedia 58: 79–86. DOI: 10.1016/j.egypro.2014.10.412
Paper IV Roos, A., Ericson, T., Kirkerud, J.G. & Bolkesjø, T.F. Analysis of residential demand response in Norway using energy system modelling. – International Journal of Electrical Power & Energy Systems. (Submitted)

ISBN: 978-82-575-1740-3
ISSN: 1894-6402

Norwegian University
of Life Sciences

Postboks 5003
NO-1432 Ås, Norway
+47 67 23 00 00
www.nmbu.no

109084 / ANDVORDGRAFISK.NO