Doctoral theses at NTNU, 2022:394

Sigurd Bjarghov

Designing grid tariffs and local electricity markets for peak demand reduction in distribution grids

Doctoral thesis

NTNU
Norwegian University of Science and Technology
Thesis for the Degree of Philosophiae Doctor
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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ISBN 978-82-326-5671-4 (printed ver.)
ISBN 978-82-326-5387-4 (electronic ver.)
ISSN 1503-8181 (printed ver.)
ISSN 2703-8084 (online ver.)

Doctoral theses at NTNU, 2022:394

Printed by NTNU Grafisk senter

Preface

The presented research was carried out at the Department of Electric Power Engineering in the Electricity Markets and Energy System Planning group at the Norwegian University of Science and Technology (NTNU). The main supervisor during this work was Hossein Farahmand (NTNU), with co-supervision from Magnus Korpås (NTNU).

The research was performed during a four-year period from September 2018 to August 2022, with a nine month research stay, between January 2020 to November 2020 at École Polytechnique Fédérale de Lausanne in Lausanne, Switzerland. The work presented in this thesis was generated under the financing from NTNU Digital Economy project, which is a part of the NTNU Digital Transformation Initiative. The candidate was also associated with FME CINELDI during his PhD.

The thesis is based on a paper collection, bound together by a thesis which provides necessary information about the work, the background and relevance to research. The research is presented in a joint context, summarizing the contributions of each article as well as the thesis as a whole.

Acknowledgements

Albeit stressful at times, working as a PhD candidate is fun and provides a mesmerizing combination of freedom and responsibility which has let me dive into topics that I am passionate about in a way that I truly appreciate. On the way, I met so many fun, caring and clever people that have made life enjoyable.

My favorite part of the last years has been to meet and work with people. Cooperating is in my opinion essential not only to conduct quality research, but to make the work so much more enjoyable. I want to thank my supervisors, Hossein Farahmand and Magnus Korpås, for useful discussions and for being so supportive, also when I suspected that you did not necessarily agree with my choices. I also want to specially thank Kjersti Berg and Gro Klæboe for their insightful feedback while writing my thesis. Thanks must also be extended to my colleagues at EPFL in Switzerland, Rachid Cherkaoui and Mohsen Kalantar-Neyestanaki. I also want to acknowledge the support I had from the DigEco project and from FME CINELDI.

I would never have been able to conduct the research in this thesis without cooperating with some brilliant people. A special thanks goes to Gerard Doorman, who through insightful discussions and thorough feedback helped me develop as a researcher. Further, I really want to highlight the colloquiums I had with Stian Backe and Magnus Askeland, which led to a number of good publications and discussions. Another special thanks goes to the Matthias Hofmann for the close and insightful collaboration we had at the end of my PhD, as well as the support from Markus Löschenbrand to help me organize eight co-authors for our review paper. I really enjoyed working with all of you.

The friends I made at the office, made my time at NTNU a lifelong memory. In chronological order, I want to thank Kaveh, Dimitri, Venkat, Christian, Kasper, Stine, Linn Emelie, Marthe, Emil, Aurora, Gro, Kjersti, Mari, Erik, Runar, Luke and Matias. To have good relations to the people you work with is important to me, and I feel lucky to have met all of you and to have been part of the incredible EMESP group.

Last but not least, I want to thank my family for their unconditional support, and my friends both in Norway and Europe for all the fun we have while playing board games, cross-country and telemark skiing, going out, playing football, running, hiking & more. I feel privileged to get to spend time with all of you.

Summary

The decarbonization of the power system is envisioned to be a key part of European Union's goal to be climate neutral by 2050. By shifting from large fossil fuel generation to climate-friendly renewable energy sources, such as wind and solar, electricity can serve as a green energy carrier, facilitating the electrification of the heat, transport, and industrial sector. This development requires significant investments in costly grid construction. Some of these costly upgrades can be postponed or avoided by efficiently integration consumers by unlocking demand side flexibility. Shifting power system flexibility that has traditionally been on the supply side, to the demand side, requires new market design and price signals which incentivizes flexible response. Under more sophisticated price signals, distributed energy resources can provide services to the grid, such as peak demand reduction.

Existing research focuses primarily on centralized control of distributed energy resources for planning and operation of distribution grids, but there is an increasing need for research on developments on the consumer side, especially related to multi-stakeholder environments and design of efficient price signals that achieves the sought development of reduced peak demand in distribution grids. In addition, local electricity markets may provide alternative coordination mechanisms to centralized control, that are more in line with current regulation. A change towards more cost reflective grid tariffs is hence of increasing interest, not only because existing research has pointed out the inadequacy of the current grid tariffs designs, but also because they are fairer and avoid unintended cross-subsidization between consumer groups.

This thesis investigates the design of grid tariffs and local electricity markets, focusing on their capabilities of reducing peak demand in distribution grids. Using energy system analysis, the conclusions presented in this thesis are mainly drawn by analyzing the results from energy system optimization models. Policy implications with analyses on socio-economic aspects are also significant part of this work, with analyses focusing on the trade-offs between cost reflectivity and fairness. Hence, the thesis also provides some interdisciplinary insights, containing analyses and advice for policy makers and regulators.

the overarching contributions of this thesis are the extensive comparisons of grid tariff designs and their capability of reducing the peak demand. In addition, a comprehensive overview of the potential role of local electricity markets are provided, and further investigated as a framework for enabling coordination mechanism that tackle demand coincidence factor-related challenges. Following the contributions from each research article, a broader discussion on the future role of grid tariffs and local electricity is conducted, focusing on the policy implications.

The findings of this thesis imply that grid tariffs should be redesigned to support the decarbonization-by-electrification trend. Grid tariff design should not be limited to specific cost components, but rather focus on the design parameters described in this thesis, such as peak basis and ex ante versus ex post peak rate period setting. Further, grid tariffs can be designed to impact the peak demand on different grid levels, which should be considered by the distribution system operator in the choice of tariff scheme. Albeit less efficient on higher grid levels, capacity subscription tariffs prove relatively efficient and cost reflective on multiple grid levels, without creating new peak loads when subject to load shifting. In addition, capacity subscription tariffs can be combined with coordination from capacity trading in local electricity markets to increase its efficiency and deal with the coincidence factor challenge of price signal design. Lastly, capacity subscription tariffs provide stable cost recovery, are fairer than volumetric flat tariffs, and the optimal subscription level can be found using methods suggested in this thesis.

Contents

1 Introduction

In this chapter, an overview of the thesis is presented. Firstly, Section 1.1 provides the underlying motivation for the work, followed by the scope and assumptions of the thesis in Section 1.2. Further, the research questions that this thesis attempts to answer are presented in Section 1.3. Then the publications that constitute the backbone of this thesis are listed in Section 1.4, followed by a description of the thesis overview in Section 1.5.

1.1 Motivation

Since 2015, practically every country in the world has committed to reducing global warming to below two degrees compared to pre-industrial times [1]. As one of the sectors which can realistically transition to a close-to-zero emission state, the power system faces drastic changes from high to low-emission power production [2, 3]. This mostly involves a shift from fossil fuel-based thermal power plants to low-emission electricity resources such as wind, solar, biomass, hydropower, and nuclear. Wind and solar are expected to make up the majority of the low-emission share due to competitive costs, relatively high social acceptance, and the ability to scale.

A key to a decarbonized economy is to a shift towards electricity as an energy carrier, which could involve electrification of industry [4], heating and transport [5]. For large-scale electrification of these sectors, massive investments in the electricity grids must be made [4]. In Norway, the frequency of new, large scale connection requests is so high that the transmission system operator expects to struggle to build grids fast enough [6]. A method to promote efficient use of electricity grids is by integrating consumers effectively, i.e. unlocking flexibility at consumer level in order to reduce peak demand. This type of *consumer integration* requires a market reform, more adjusted for the consumer era [7]. Such a transition also involves the design and implementation of more cost reflective grid tariffs [8], as the current tariff designs may be insufficient for future power systems with active electricity customers [9]. Designing more cost reflective tariffs, may result in a more *grid-friendly* integration of consumers, with the potential of speeding up the transition to a sustainable & renewable power system.

A consequence of more weather dependent renewable wind and solar generation, is the need for more flexibility in the system as wind and solar are not as schedulable as traditional thermal power plants [10]. Further, a significant share of new solar capacity will be small-scale installations [11], often behind-the-meter, introducing what is often referred to as prosumers: consumers with production. Prosumers are envisioned as a central piece in the energy transition [12]. In order to meet climate targets fast enough [13], electricity consumer integration must be quick and requires systematic change in market structures, price signals, and regulation in order to correctly incentivize end-user participation in power systems [8]. This kind of integration could not only assist in the integration of distributed energy resources, but also provide services to the power system in terms of congestion management, balancing products and voltage management [14]. Thus, the European transmission system operator entity ENTSO-E has mentioned distributed energy resources as one of the key assets that are required for active system management, i.e., accessing flexibility in the distribution grid [14].

Since many of the end-users projected to own distributed production and flexibility become market agents, it is important to note that their decisions will be as individual stakeholders acting in their own interest [15]. Hence, the price signals consumers are subject to should be aligned with a sustainable development of the power system [16]. This involves not only being incentivized to adjust to variable renewable generation, but also adjusting demand to utilize the distribution grid as efficiently as possible. Distributed energy resources possess locational advantages, which may be used to defer grid investments if controlled smartly [17, 18]. In order to transition to a more consumer-centric power system, consumers need mainly two things: 1) correct price signals to utilize flexible resources in coherence with a sustainable power system, and 2) a way of coordinating these resources locally to ensure grid-friendly utilization of the distribution grid.

A low hanging fruit to send a price signal to every electricity consumer, is by introducing grid tariff designs which provide efficient price signals. The second point can be achieved by centrally coordinating resources, but this requires multiple changes in regulation and overall a hard-to-imagine-transformation in the trust of consumers for someone else to act on their behalf. Thus, it seems likely that local electricity markets with multi-stakeholder market platforms will emerge. Nonetheless, the regulator becomes an essential facilitator to ensure fair and efficient rules and for price signals towards electricity customers to be efficiently integrated, which requires regulatory and policy aspects related to consumer integration to be investigated further.

1.2 Scope and assumptions

This thesis first and foremost examines a variety of grid tariff designs, and their role as price signals that may provide efficient and cost-reflective price signals for distributed energy resources. As highlighted by the Council of European Energy Regulators, cost reflectivity is the most important as it least to economic efficiency [19], which thus receives the most attention in this thesis. Secondly, the role of local electricity markets as an enabler for efficient coordination is discussed, under the assumption of a multi-stakeholder competitive market environment. Lastly, grid tariff design criteria such as efficiency, cost recovery and fairness, as well as quantifying the price signal conflict between grid tariffs and electricity spot prices, are discussed.

The work of this thesis is part of the Digital Economy (DigEco) project (see [20] which is a part of the NTNU Digital Transformation initiative [21]. This initiative is an umbrella spanning over nine projects pursuing research on development and application of digital, transformative technology. DigEco aims to combine technologies with market and business models, allowing radical change in speed, scale, and scope for economic activities, transactions, products and services. In addition, the PhD work is associated with the Center for Intelligent Electricity Distribution (FME CINELDI) [22], which is a part of The Norwegian Research Council's strategy to finance research on environmentally friendly energy. CINELDI's goal is to develop the electricity distribution grid of the future, working towards higher flexibility, resilience, and efficiency of the distribution grid.

This thesis combines the topics of DigEco and CINELDI by focusing on the design of price signals, i.e. grid tariffs, and the role of local electricity markets. The thesis aims to look at the problem both from the electricity grid side, as well as the business model aspects. Contrary to significant amounts of research on electricity grids, this thesis aims to analyze the incentive and rational economic behavior of consumers when subject to new price signals, rather than optimizing the operation of distributed energy resources from a centralized view, i.e. the view of the distribution system operator.

The overarching question of this thesis is *"How can grid tariffs be designed to facilitate grid-friendly consumer integration, with and without the coordination effect from local electricity markets?"* The thesis aims to answer this question through a number of more specific research questions, followed by publications which aim to fully or partially answer these research questions. Yet, the broadness of the question requires some scope limitations. The conducted research presented in this thesis mainly consists of case study analyses on consumer demand response. The case studies presented in the thesis articles include small, conceptual case studies aiming to showcase mechanisms and large scale case studies using real, metered consumer load data which allows for giving quantitative answers to specific questions.

The choice to focus on grid tariffs and electricity markets developed from primarily looking at local electricity markets and multi-bilateral trading, finding that the research mainly circled topics like cost savings, energy sharing and local empowerment. Despite being important topics, the lack of research on the impact local electricity markets have on grid investments and operation was surprising, especially when the cost savings found in studies on multi-bilateral trading were achieved by ignoring the electricity grid completely, or by not applying them to local trades.

Researching local electricity markets in combination with grid tariff designs meant focusing mostly on residential customers. An efficient way to approach this issue was to formulate optimization models which mimic the operation and dispatch of flexible resources when subject to different price signals and market designs. This approach is advantageous as it mimics how customers will respond, assuming that they use some kind of automated response controlled by aggregators or smart energy service providers. This means focusing more on the detail of modeling customers, rather than complex power system or AC optimal power flow models. Instead, using the demand profile as an indicator of how strained the electricity grid is, has been used in order to measure the consumer influence on the electricity grid. This is a simplification that holds up relatively well, considering that the most important cost driver in distribution grids are related to capacity dimensioning [19, 23]. This is because the grid is dimensioned for handling the peak demand during the lifetime of the hardware, meaning often 30 years or more. In addition, this problem is relevant to all grid levels, including transmission level.

The thesis emphasizes analysis of energy systems, local electricity markets and price signal design, and therefore focuses more on the results than the modeling techniques. A consequence of this is that a number of models, some simple, some more advanced, have been developed to answer the research questions. The main takeaways revolve around the analysis of the results and, to be even concrete, around the conceptual, qualitative observations rather than the quantitative results.

1.3 Research questions

The contributions' of this thesis are mostly empirical and build on development of optimization models to analyze the impact of price signals from different grid tariff designs. Further, qualitative analyses of local electricity markets have been performed, as well as some economic impact analysis of grid tariffs. The following research questions have been developed in this thesis:

RQ1: How well do capacity-based grid tariffs and local electricity markets synergize in order to incentivize consumers to reduce peak demand?

RQ2: How well do capacity subscription tariffs perform in terms of cost reflectivity, cost recovery and fairness?

RQ3: Which grid tariff designs are the most cost reflective and efficient at reducing peak demand at different grid levels?

RQ4: Aiming to reduce peak demand, is there a price signal conflict between electricity spot prices and grid tariffs?

RQ1 revolves around highlighting the advantages of coordination mechanisms from local electricity markets. Grid tariff design is a very central topic in this thesis, especially capacity subscription tariffs which receive extra attention in this PhD thesis through RQ2. RQ3 supplement RQ2 by comparing a variety of grid tariff designs, focusing on how well they incentivize peak demand reduction. Lastly, RQ4 builds on RQ3 by investigating the influence of electricity spot prices on consumer demand response. By answering these four research questions, the thesis aims to explore the role of grid tariffs and local electricity markets in the future power system.

1.4 List of publications

The articles published as a part of this thesis are listed below. The listed articles contain the main scientific contributions of this PhD thesis and are thoroughly described in Chapter 3. They are also printed in the Publications chapter of this thesis. The papers are numbered in the list below and will be referred to as papers I-V for the remainder of this thesis. Papers I, II, III, and V were first-authored by the candidate, whereas Paper IV is first-authored by Matthias Hofmann and is currently under review by Elsevier Energy Policy. The Contributor Roles Taxonomy can be found in Appendix C

I. S. Bjarghov, M. Löschenbrand, A.U.N. Ibn Saif, R. Alonso Pedrero, C. Pfeiffer, S. K. Khadem, M. Rabelhofer, F. Revheim and H. Farahmand, "Developments and challenges in local electricity markets: A comprehensive review" in *IEEE Access, vol. 9, pp. 58910-58943, 2021.*
DOI: https://doi.org/10.1109/ACCESS.2021.3071830

II. S. Bjarghov, H. Farahmand, G. Doorman, "Capacity subscription grid tariff efficiency and the impact of uncertainty on the subscribed level" in *Elsevier*

Energy Policy, Volume 165, 2022.
DOI: https://doi.org/10.1016/j.enpol.2022.112972

III. S. Bjarghov, M. Askeland and S. Backe, "Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach", in *17th International Conference on the European Energy Market (EEM)*, 2020. DOI: https://doi.org/10.1109/EEM49802.2020.9221966. This paper won the 2nd best paper award of the conference.

IV. M. Hofmann, S. Bjarghov, H. Sæle, K. Byskov Lindberg "A comparison of the peak demand reduction performance of various energy-based and capacity-based tariffs at different grid levels" submitted to *Elsevier Energy Policy*

V. S. Bjarghov, M. Hofmann, "Grid tariffs for peak demand reduction: Is there a price signal conflict with electricity spot prices?", accepted at *18th International Conference on the European Energy Market (EEM)*, 2022.

A number of other publications have been published during the PhD period, which have not been included in the thesis for either 1) being outside the scope of the thesis, or 2) only contain minor contributions from the candidate.

- M. Askeland, S. Backe, S. Bjarghov and M. Korpås, "Helping end-users help each other: Coordinating development and operation of distributed resources through local power markets and grid tariffs" in *Elsevier Energy Economics, Volume 94, 2021.*
  DOI: https://doi.org/10.1016/j.eneco.2020.105065

- M. Askeland, S. Backe, S. Bjarghov, K. Byskov Lindberg and M. Korpås, "Activating the potential of decentralized flexibility and energy resources to increase the EV hosting capacity: A case study of a multi-stakeholder local electricity system in Norway," in *Elsevier Smart Energy, Volume 3, 2021.*
  DOI: https://doi.org/10.1016/j.segy.2021.100034

- D. Pinel, S. Bjarghov and M. Korpås, "Impact of Grid Tariffs Design on the Zero Emission Neighborhoods Energy System Investments," in *IEEE Milan PowerTech, 2019,*. DOI: https://doi.org/10.1109/PTC.2019.8810942

- S. Bjarghov, M. Kalantar-Neyestanaki, R. Cherkaoui and H. Farahmand, "Battery Degradation-Aware Congestion Management in Local Flexibility Markets", in *IEEE Madrid PowerTech, 2021.*
  DOI: https://doi.org/10.1109/PowerTech46648.2021.9494829

- S. Bjarghov and G. Doorman, "Utilizing End-User Flexibility for Demand Management Under Capacity Subscription Tariffs," in *15th International*

Conference on the European Energy Market (EEM), 2018.
DOI: https://doi.org/10.1109/EEM.2018.8469832

- O. M. Almenning, S. Bjarghov and H. Farahmand, "Reducing neighborhood peak loads with implicit peer-to-peer energy trading under subscribed capacity tariffs," in *International Conference on Smart Energy Systems and Technologies (SEST),* 2019,
DOI: https://doi.org/10.1109/SEST.2019.8849067.

1.5 Thesis structure

The thesis consists of four chapters, starting with introduction and background in Chapter 1 and Chapter 2, respectively. This part contextualizes the thesis by providing the motivation, aim and scope of the work, followed by an introduction to the research area and a review of the state of the art literature on the relevant topics. Chapter 3 contains the main work in the thesis, presenting the contributions and main findings of the thesis. First, the overview of the published papers and which research question they answer is presented, followed by the contribution of each paper. Finally, a summary of the answer to each research question, supported by discussions of the work and their relevance to the research topic. Lastly, concluding remarks and suggestions for future work are suggested in Chapter 4.

In addition, Appendix A contains descriptions of grid tariff designs, whereas a general formulation of the consumer problem, as well as the competitive local electricity market formulation developed in this thesis can be found in Appendix B.

2 Background and literature review

This chapter provides the background and literature review of the chosen research tools and methodologies used in the papers and that constitute the backbone of this thesis.

2.1 Optimization models and energy system analysis

With the exception of Paper I, the results and contributions from each paper have been acquired using optimization models. Optimization models are essentially mathematical programs in which the aim is to find the optimal solution inside the feasible solution space. This translates to finding a global maximum or minimum formulated as a value function based on variables and parameters, namely the objective function. The objective function is subject to a series of equality and inequality constraints, which make up the boundaries of the problem [24]. In energy system modeling, mathematical programs in the shape of optimization models are commonly used to find optimal solutions to problems related to planning, dispatch and control of assets [25]. As an increasing share of small-scale renewable generation as well as flexible loads and assets are installed in the low-voltage grids, there is an increased relevance for applying similar optimization models for dispatching distributed energy resources in the distribution grid.

No mathematical programs represent reality 100%, meaning that it is up to researchers to determine how precise is precise enough. In addition, the models are no better than the data provided, which is particularly important when the contributions of the research are related to the analysis rather than the technical modeling aspects. In this thesis, the models also include simplifications and have limitations, which are discussed in Chapter 3.

2.1.1 Consumer modeling: reacting to price signals

Distribution grids are natural monopolies as it is highly inefficient to build them in parallel [26]. Hence, grid tariffs have mainly been designed to recover the costs of the distribution grid owner [27]. The traditional inflexibility of loads made grid tariff design a relatively simple task, as there was no point in designing tariffs which provided incentives to reduce peak loads. With the introduction of distributed energy resources and demand response, this has changed, hence creating a need for designing grid tariffs that are more cost reflective [8, 28]. This has been enabled by the European Union's Third Energy Package which requires member states to implement smart meters [29]. With basis in this development, regulators and distribution grid owners can design tariffs which consider the optimal response from different customer types on different grid levels in order to see the efficiency and cost reflectiveness of the grid tariff design. Hence, in this thesis, optimization models are used to analyze the response of customers when subject to grid tariff costs. This can be done by formulating the cost minimization problem of a customer, subject to the price signals from the grid tariff as well as adding the constraints representing the demand response or flexibility assets. The customer cost minimization problem can either be analyzed standalone, or as a cost minimization of a formation of consumers in energy communities [30]. The results from these optimization models provide insight into not only the cost reflectivity, i.e. ability to reduce peak loads, but also into what the potential consumer cost savings are. The new peak loads can be acquired from the residual load profiles, which as explained in Section 1.2, function as a proxy of how cost reflective the grid tariff design is, as the long-term marginal cost of distribution grids are tied to grid capacity [19, 31].

2.1.2 Accounting for uncertainty in decision making

Stochastic programs allow for analyzing decision making considering uncertainty in decisive parameters [32]. There exists a variety of methods to solve stochastic programs, but the most general approach is a two-stage stochastic program, which involves first and second stage variables. The first stage decisions represents the decisions that must be made, not knowing how the uncertainty will realize. The second stage variables are the decisions in each realizable scenario, and are reactive after the uncertainty is realized. The uncertainty is typically represented by a number of scenarios where the values of the uncertain parameters is different in each scenario, or by providing the probability density function of the uncertain parameters and then apply sampling methods [32]. The first stage decisions are equal in every scenario, whereas the second stage variables represent the recourse action, and are (normally) different in each scenario.

Stochastic programs can be used to analyze problems when the uncertainty is decisive for the objective of the problem. For residential customers, the annual load is uncertain as it depends heavily on climate, either by the need for heating during winter, or by the need for air-conditioning during summer.

Large differences in annual demand could result in significant variations in annual costs for the customer, which also means significant variations in income for the distribution grid owner. This stands in conflict with the principle of cost recovery and predictability, which are key design criteria for grid tariffs [33, 34]. Stochastic programs can also assist customers in grid tariff designs which requires some kind of ex ante decision from the customer. Examples of this are capacity subscription tariffs which require a decision on the subscription level ex ante [35], or under measured peak demand tariffs when customers might face challenges with multi-objective problems, aiming to both minimize monthly peaks while also self-balancing photovoltaic production [36]. In general, any dynamic tariff where a temporal aspect of the grid tariff is decided close to real-time, could require consideration of uncertainty [37].

2.1.3 Cooperative and competitive market modeling

Research on energy communities and neighborhoods often assume either cooperative or competitive coordination structures, as shown in Figure 2.1. Cooperative models aim to minimize the overall costs of the customers inside the energy community, and build on the overall assumption of willingness to share a common good, namely energy [38]. Although cooperative approaches do not share the competitive aspects of a market, this is sometimes referred to as local market modeling in the literature. Cooperative models assume full control of the system that is being optimized. The approach has the advantage of being able to optimally share assets among different shareholders, and mobilize social cooperation and resilience in the energy community [39]. Because the community also acts as a unit to other markets (similar to virtual power plants, see [40, 41]), the community may sell services to the distribution grid or other markets [39]. Regulation that allows for sharing of distributed generation inside energy communities is under assessment in Norway [42], but is currently legally challenging in most countries [43]. However, the cooperative approach also requires distribution of welfare as all the stakeholders, i.e. consumers, may not be better off after the community has minimized the overall costs. This challenge raises new issues related to acceptance and fairness.

Contrary to cooperative approaches, competitive approaches assume a multi-stakeholder environment in which all agents act in their own interest. In terms of mathematical programming, this means that the system can be solved by combining optimization problems that are connected by using a complementarity problem formulation. In local electricity markets, it is common to start by formulating the problem of all stakeholders, and transform that problem by deriving the Karush-Kuhn-Tucker conditions [24]. The derived Karush-Kuhn-Tucker conditions of every stakeholder can be written as complementarity constraints, and solved as an equation system either by using the PATH solver [44], by reformulating the problem into a mixed integer linear program using the Big-M method, or by using special order set variables [45]. Given that the Karush-Kuhn-Tucker conditions are necessary and sufficient (see [46]), mixed complementarity problems find Nash equilibrium solutions, meaning that all stakeholders in the game are satisfied with the solution and are not better off by changing their decisions. A mathematical model formulation of cooperative and competitive market modeling is provided in Appendix B

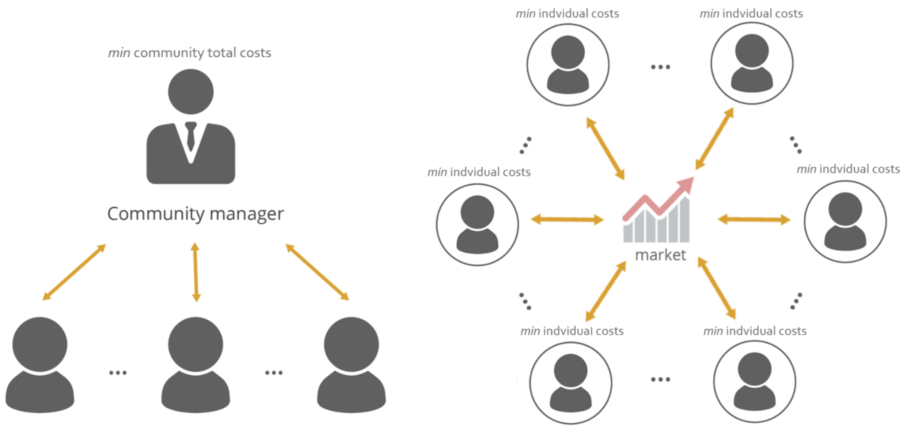

Figure 2.1: Cooperative (left) and competitive (right) local market modeling.

Both cooperative and competitive approaches have their benefits. Cooperative approaches are capable of finding optimal solutions for energy system problems, and hence give insight into the feasibility space of the problem. By knowing what the optimal outcome is given optimal control and cooperation, the solution can work as a benchmark solution when trying to achieve similar results in real life or in competitive games. The approach is also commonly used in national and European power system models as the assumptions of perfect competition synergizes well with the cost-optimality assumption of cost-minimizing problems. As most energy system models can be (or can be simplified to be) formulated as linear or mixed-integer linear programs, they scale well due to the maturity of solving these types of problems. This allows for insights provided by large-scale models that contain large systems with high levels of detail. On the other hand, approaches based on competitive games provide insights into a multi-stakeholder system, which has more resemblance to real markets. Competitive approaches are also more in line with current regulation, as common metering of neighborhoods and energy communities is not possible under the current regulation in most countries. Equilibrium problems also provide insights into the dynamics of the market problem, which lets researchers gain additional information about the energy systems' strengths and vulnerabilities.

2.2 The role of grid tariffs

2.2.1 Grid tariff design criteria

Aiming to reach emission targets, electrification of heating, transport and industry are considered as key aspects in order to move from carbon-intensive energy sources to use of clean, renewable electricity [4, 47]. At the household level, peak electricity demand is expected to rise as a consequence of electric vehicle charging and electrification of heating. The distribution grid is thus expected to face higher peak loads in the coming years, requiring significant grid investments.

With the above-mentioned developments, some regulators in Europe have considered or proposed new grid tariff structures in order to reduce the need for grid investments by introducing more efficient grid tariffs [48, 49], in the sense of more cost-reflective and precise price signals. The proposed grid tariff structures aim to incentivize demand response during peak load hours, either by setting a price on capacity use, or by introducing time-of-use-based tariffs which penalize electricity consumption in hours with high demand. A change in grid tariff structure can raise issues such as fairness and energy poverty-related social issues. In the Clean Energy For All Europeans package [50], the EU commission states that vulnerable consumers should be protected from socially unfair changes. Any grid tariff structure change will indisputably result in a redistribution of costs among consumers (which is the goal), but should nevertheless avoid undesirable side effects rendering especially vulnerable consumer groups worse off. For example, over-dimensioned capacity-based price signals can result in wealthy consumers shifting costs onto vulnerable consumers as they are able to invest in distributed energy resources to avoid grid tariffs [9, 51].

A price signal should hence also not only be centered around economic efficiency, but consider other aspects such as cost-recovery and income stability for the distribution system operator (DSO), as well as social fairness and acceptance, with the latter having been a particularly difficult aspect in the Norwegian energy debate [52]. The main design aspects are covered both in research [53], and is also broadly agreed upon by multiple stakeholder organizations in Europe, such as ACER [33], CEER [19,23] and EDSO [34]. The main design criteria are shown in Figure 2.2 can be summarized as follows:

- **Cost reflectivity**: Costs that reflect the consumer costs imposed on the grid, including 1) fixed and residual costs to having an electricity grid, 2) costs that reflect the short-term costs of transporting electricity through the grid and 3) long-term marginal costs of having available capacity in the grid.

- **Cost recovery**: Costs are sufficiently transferred onto the consumers, ensuring that the distribution system operator recovers their costs.

- **Fairness**: Avoiding discrimination between different customer groups and technologies, unless the discrimination is *due*. Often difficult to define because there are different costs related to transporting electricity to different customers with the same load profile.

- **Complexity**: Cost structures are not too complex, but rather understandable for the consumers. Complexity is related to spatial and temporal parameters of the cost components, i.e. time-of-use pricing, capacity-based, combination of the two, or dynamically adjusted prices depending on grid status.

- **Predictability**: Ensuring relatively stable costs for the consumers, subsequently leading to stable income for the distribution system operator. Consumers should to some degree be able to predict their costs and when prices are high.

- **Transparency**: Transparency and openness regarding distribution system operator costs, and how their costs are reflected in the grid tariff costs. Particularly important if some grid tariffs are designed to create cross-subsidies between customer groups.

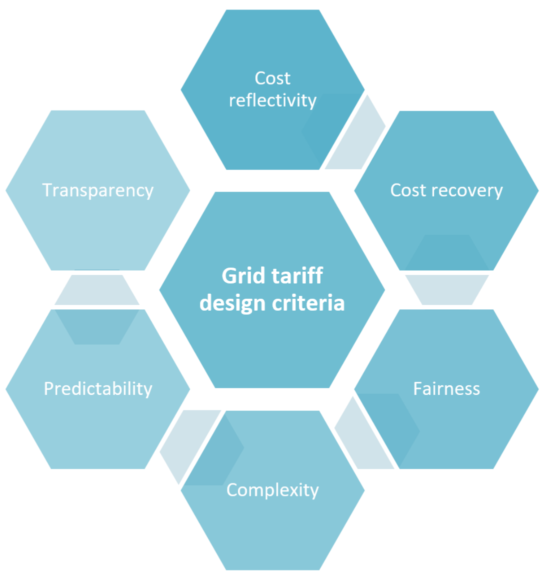

Figure 2.2: The most important grid tariff design criteria.

Without fulfilling these criteria, the grid tariff design will unlikely result in *acceptance*, ultimately requiring sufficient communication about the advantages and disadvantages of the chosen grid tariff design. No grid tariff can fulfill all the criteria perfectly [8]. Yet, both Norwegian and European regulators are considering a shift towards more future-proof grid tariffs [19, 33, 54], with the primary aim of shifting towards more cost reflective grid tariff designs, at the expense of simplicity. The most common grid tariff designs are described in Appendix A.

2.2.2 Grid tariff cost reflectivity - designing price signals

Grid tariff cost reflectivity has been subject to investigation in the literature, often in combination with distributed energy resources and their ability to reduce peak loads. Distributed energy resources can, in theory, provide many benefits, but few or no incentives for grid-friendly use of distributed energy resources exists in the current power system [8,49]. This has led to an increased focus on capacity-based grid tariffs, as they price the actual scarce resource in the grid, namely capacity. Albeit contested by other price signals, grid tariffs make up a significant share of the total electricity bill for end-users, and thus have potential to be designed in a way which incentivizes grid-friendly electricity use. This is currently not the case, as grid tariffs mostly come in the form of volumetric tariffs in the residential sector [8], which has a clear incentive for energy efficiency measures, but none for reducing peak loads.

Measured peak demand (often referred to as demand charges) are more widespread for commercial customers, and involve a per-kilowatt-cost for the peak demand during a month or year. This provides an incentive to reduce peak loads as the peak load sets the cost of the entire invoice period. Especially consumers with low utilization factors (essentially consumers with few but high peak load hours) has strong incentives to invest in demand response in order to reduce their grid tariff costs. Albeit efficient in some cases [55–57], the tariff has two significant drawbacks: 1) a high peak early in the invoice period removes all incentives to keep reduced peak loads for the remainder of the invoice period [58] and 2), individual peak loads do not necessarily coincide with system peak loads and thus are not guaranteed to provide efficient price signals [59]. Further, measured peak demand might also lead to over-investments from consumers opting to react to price signals [9], nuancing the results from [60] which found measured peak demand charges to have many upsides in terms of cost reflectivity. What was also mentioned in [60], was the fact that measured peak demand does not necessarily need to be based on the individual monthly peak of a single consumer. A more dynamic design based on the system peaks or combined with time-of-use tariffs is also an option, with the latter found to be highly efficient [53, 61]. This essentially boils down to whether or not the tariff attempts to reduce peak loads on system or local level [35].

An alternative to measured peak demand is a grid tariff based on capacity subscription, which is extensively analyzed in this thesis. In capacity subscription-based tariffs, consumers subscribe to a capacity level, with some resemblance to internet subscription with specific bandwidth speeds. The tariff structure includes a monthly fixed cost, as well as a cost per kilowatt per year of subscribing to a capacity level. For all consumption below the subscription level, there is a small energy term per kilowatt-hour, representing marginal losses in the transmission grid. Consumption above the subscription level is subject to an excess energy term per kilowatt-hour which is 10-20 times higher than the energy term. The design concept originally described in [62], and rediscovered in more recent years after being proposed by the Norwegian regulator as a potential new grid tariff structure [63]. Capacity subscription tariffs differs from measured peak demand as there is a constant incentive to avoid peak loads to avoid the excess energy term. Although an early high peak does not remove the incentive to reduce peak loads for the remainder of the invoice period, the price signal is also weaker per kilowatt compared to measured peak demand. In addition, if excess energy consumption cannot be avoided, there is no incentive to flatten the load profile.

Another aspect of capacity subscription tariffs is the fact that the consumers have to make a decision on how much capacity to subscribe to. Two immediate questions are often raised: 1) how to find a good subscription level and 2) what is the consequence of choosing the wrong subscription level? The latter appears to be relatively unproblematic as shown in preliminary work by the thesis author [64], as subscribing to a higher capacity than what is optimal results in higher subscription costs but lower excess energy costs, and vice versa when subscribing to a lower capacity. This can be described as a dampening effect, as sub-optimal subscription level choices do not significantly influence consumer costs. The former question, together with research questions presented in Section 1.3 on capacity subscription tariffs are answered in Chapter 3.

Both measured peak demand and capacity-based tariff structures have the advantage of removing cross-subsidization of distributed generation that does not reduce peak loads [58, 65, 66]. This is an important question to illuminate, as it requires an answer to the most central question of grid tariff design: "what is the purpose of grid tariffs?". If cost-reflectivity is the most important key performance indicator, it is clear that volumetric grid tariffs do not perform well, because behind-the-meter photovoltaics are subsidized as they result in lower grid tariff costs for the photovoltaic owner, but do not reduce their need for grid as their peak loads are assumed to remain the same. However, if the goal is to support investments in e.g. residential photovoltaic, the tariff works well to lower the levelized cost of electricity of the investment. When considering capacity-based tariffs, some consumer groups will be worse off than before. In that case, it should be analyzed whether or not it is because the group that is worse off was previously subsidized by other consumer groups, or because the price signal is not very precise.

One of the best arguments against capacity-based grid tariffs is their lack of guarantee that individual consumer peak reduction coincides with system peak loads [67][1]. This translates to the price signal not being cost reflective enough, and requires one of two options: 1) coordination between consumers or 2) a grid tariff that adapts to the state of the grid - a dynamic grid tariff. These two options are the basis of the research questions presented in Section 1.3. The first option suggests a local electricity market (or any other coordination mechanism), whereas the second option is based on the fact that a dynamic price signal is better suited to capture the marginal cost of using electricity at different time periods.

Capacity-based grid tariffs have been suggested and found highly promising with respect to the future power system [8], especially as they avoid the creation of new peak loads, which is a well-known problem with time-varying energy-based tariffs [54]. This problem occurs due to the coordinated use of flexible resources or demand when a low-price period occurs after a period of higher prices [23]. Energy-based tariffs mainly come in the shape of time-of-use tariffs, but could also appear as critical peak pricing tariffs, when prices are higher during the most constrained days. Although capacity is not priced in these tariffs, they have the advantage that the prices are based on the system peaks (or the expected system peaks), rather than the individual peaks of each consumer. This is coherent with the concept of cost reflectiveness, as grid costs are mostly related system peaks [59, 60, 68]. On the contrary, capacity-based tariffs (at least the non-dynamic ones) are not based on system peaks, and could lead to efficiency related issues. Multiple studies have shown that although individual peak loads are reduced, the aggregated peaks are reduced significantly less due to the coincidence factor [68]. If only applied dynamically during congested hours, individual peaks might increase whereas aggregated peaks might decrease [69], highlighting the importance of temporal design of the tariffs.

2.2.3 Grid tariff cost level determination

When designing grid tariffs, the cost levels of the different cost parameters must be determined. Many studies of grid tariff design and local electricity markets revolve around analyzing the cost savings potential when investing in flexibility or behind-the-meter generation. However, the cost savings provided by the flexibility assets are often based on dispatching flexible assets to avoid the costly aspects of the grid tariff design, regardless of how much lower costs they

[1]In this case, the system refers to different parts of the grid, as peak reductions are required at different grid levels at different times.

inflict on the distribution grid. These types of studies provide insight into flexibility dispatch and incentives for investments in distributed energy resources, but can not be used for determining whether or not a grid tariff is well designed. There are two approaches to tackle this challenge: 1) design the grid tariff endogenously [9, 70] or, 2) determine the grid tariff cost levels using backwards calculation before and after applying flexibility. The first approach also works well when combining grid tariffs and local electricity markets, ensuring that there is no welfare transfer from the distribution grid customer base to the customers that are considered in the model [9, 71]. Under the second approach, it is important to first ensure that the DSO income (and hence the customer cost) is similar under the current and suggested grid tariff designs. Secondly, the customer cost savings should not exceed the actual cost reductions observed by the DSO when flexibility is applied. This is an important concept, because if the cost savings of the customers are higher than the DSO's costs, the DSO has to subsequently increase cost levels to recover its costs [70]. Hence, the cost reflectiveness of an exogenously designed grid tariff should be measured by its ability to reduce peak loads in combination with the cost savings, rather than by cost savings alone.

2.3 Decentralization of markets and energy resources

Historically, power systems have been organized as top-down systems with the demand side considered as static, with close-to-zero price elasticity. The supply side thus has to adjust their production to match the demand at all times. The transition to a power system with more distributed generation represents a paradigm shift in this sense as demand, to a greater extent, has to adapt to match the generation. As opposed to the traditional electricity markets, local electricity markets have smaller pools of participants within close spatial proximity, rather than a large set of participants which span over wide areas. Alongside an increase in local market participants, a series of challenges arise. More distributed energy resources add complexity. Further, they must be integrated into the power system without compromising reliability, security and quality of supply and voltage levels. In this context, local electricity markets are tools which facilitate efficient use of distributed energy resources. Widespread integration of distributed generation and flexible demand has led to a bottom-up revolution in the power system [72].

Electricity markets have been subject to competition in most of Europe since the 1990s, meaning that every participant aims to maximize their individual objective, often by optimizing a portfolio of assets (generation or demand) in order to minimize costs or maximize welfare. Assuming that agents do not use market power, their focus lies solely on their own resources and their own outcome when making decisions on generation, consumption and bids. In a competitive market, the state where no agent can be better off by changing their decisions is often referred to as the Nash equilibrium. This competition can be formulated using the Karush-Kuhn-Tucker conditions [73].

Non-cooperative games benefit from large number of participants, which results in very efficient competition. The competitive market does not only ensure profits for every participant but also provides incentives for research and developments and other investments which results in high socio-economic welfare. In addition, non-cooperative games results in competition which further ensures efficient use of resources.

2.3.1 Local electricity markets coordination mechanisms

Local electricity markets are mainly organized either as cooperative or competitive games. In contrast to competitive games, cooperative games assume that a group of market participants make decisions in order to maximize or minimize a common objective such as a welfare-maximization or cost minimization, respectively. This approach is more prevalent in local electricity markets as the market participants are fewer, not as professional and do not necessarily know how to operate their assets optimally. Thus, communities of cooperating end-users can develop, using a professional entity to operate their assets on their behalf, often referred to as a community manager [39]. The community manager then acts on behalf of the community and handles communication and trading in the community as well as interactions with the outside, i.e. the electricity wholesale market and reserve markets.

Local electricity markets may increase resource efficiency, as not every market participant is able to invest in different technologies such as generation or flexibility due to location, space issues or upfront costs. However, purchasing flexibility or generation from other participants in the market can result in a more efficient use of resources as the resources can be installed and operated by those who can [74], but the market ensures access to the resource in exchange for the market price. Further, the current regulation in many countries does not allow for common metering between end-users in a community [43], creating a significant barrier in the transition to cooperative games. This barrier can be avoided completely in non-cooperative games as each market participant still acts solely in its own interest, and is metered accordingly, in line with regulation.

Cooperative games in the shape of energy communities benefit from the ability to efficiently operate the available assets in the community portfolio, enhancing cooperation and sharing of common goods and investments [7]. Further, communities allow access to markets that individual agents would otherwise access due to too small electricity quantities [75]. A community can be formed due to geographical proximity such as a neighborhood [76, 77] or a microgrid [78, 79]. However, being geographically close is not a necessity [80]. A community can also be formed based on common goals of objectives from different participants, such as energy sharing [39]. Common interests and goals can be used in order to mobilize based on social cooperation, for example by aiming to reduce greenhouse gas emissions, maximize use of local generation or helping people who experience energy poverty. Although the motivation might be social, an unintentional consequence of organizing as a community could be the ability to provide grid services as the community manager can access new markets using the community members' assets.

A drawback of these communities is the lack of guarantee of fairness and necessity of information sharing. Reaching the preference of every community member requires some compromise and it is important to have a fair cost redistribution scheme in place in order to avoid some members being worse off in order to achieve a higher community welfare [39]. Methods based on exchanging dual variables to achieve market clearing have been studied in [38,81], iterating in order to converge towards a consensus based on the alternating direction method of multipliers [82]. The exchange of duals in order to achieve consensus has clear synergies with communities as the full-scale centralized problem can be intractable due to non-convex characteristics or the vastness of the problem. By exchanging duals, each market participants can optimize their individual problems in a distributed fashion, avoiding over-sharing of information between community members.

2.3.2 Centralized markets clearing approaches

In a market environment, there is no cost-minimizing (or welfare-maximizing) entity which directly controls the assets of each agent. Rather than controlling the assets, each market participant optimizes their own portfolio of assets and submits bids to a market operator which subsequently results in a market clearing. The market clearing is based on the supply and demand bids and results in a market price which all market participants are subject to (assuming uniform pricing). The control of distributed energy resources is a complicated problem with many assets that need to be controlled. In order to have proper control without requiring information sharing between market participants, centralized markets offer a way to share sensitive information about each agent's utility function, which essentially contains information about their highly private cost functions. In the context of local electricity markets, it is possible to achieve similar market clearing results as in a decentralized market under the assumption of a market operator supervisor node [38]. Centralized market approaches benefit from being more in line with existing markets. This allows for a widespread integration of local electricity markets because these markets have a supervisory node that may interact with wholesale and balancing markets, as well as the distribution system operator [83]. As residential end-users have many uncertainty-related aspects, such as electricity demand, availability of flexibility, and renewable generation profiles, it is also useful to a have supervisory node that coordinates trading, and handles uncertainty in local intraday markets [84].

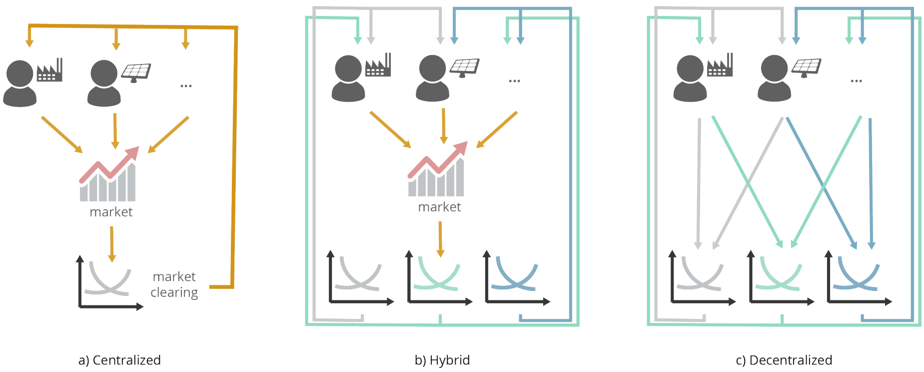

Figure 2.3: Overview of centralized, hybrid and decentralized local electricity market clearing topologies.

2.3.3 Decentralized market clearing approaches

Decentralized markets represent fully democratized electricity markets with multi-bilateral economic dispatch, or peer-to-peer trading. In this approach, there is no market coordinator that facilitates the trades, and rather than a uniform price for the entire market, the price is set in each bilateral trade. A fully decentralized market has significant advantages to centralized markets with respect to privacy. Dual variables can be exchanged to avoid sharing of private information. However, these convergence methods are sometimes slow, and insight into other agents' information might occur as the duals contain some information on their utility function [85]. In addition, other challenges, such as information asymmetry, arise, meaning that not every market participant has access to the same information. This can result in a biased market outcome [86].

Decentralized markets have significantly more complex mechanisms in terms of communication as there needs to be many more interactions between market participants to be able to converge to a market outcome. In some cases, a compromise on the trade-off between the volume in communication and social welfare must be made [87]. However, when one node fails or is corrupt, a decentralized multi-bilateral structure can easily avoid these nodes in order to keep the market from failing, whereas a centralized market is completely dependent on the supervisory node functioning properly.

3 Contributions and main findings

This chapter contains an overview of the published articles, followed by a summary and the main contributions of each article in Section 3.1. Each research question is discussed and answered in Section 3.2, followed by some broader discussions in Section 3.3

3.1 Contributions of papers

The paper overview presented in Figure 3.1 provides the context and connection between the published articles in this thesis. The papers mainly cover two research areas¿ grid tariff design and local electricity markets. The papers focusing on grid tariffs consider individual and coordinated response, whereas the local electricity market papers focus on coordination mechanisms and challenges. A number of optimization models have been developed in the presented papers. The optimization model background is provided in Section 2.1, and an overview of which model types are used in which papers is provided in Table 3.1.

Each paper is presented individually, starting by contextualizing the work. This is done by providing a recap of related literature, explaining the novelty of each article, followed by a presentation of the main contributions. Thereafter, a brief description of the methodology is presented, followed by the main results and findings. Lastly, the limitations of the work are discussed.

Table 3.1: Model approaches, stakeholder point of view, and flexibility assets considered.

Paper	Model type	Stakeholders modeled	Flexibility
I	N/A (overview provided)	N/A (overview provided)	N/A
II	Two-stage stochastic program	Individual end-users	Load reduction
III	Mixed complementarity program	Competitive energy community	Batteries
IV	Linear program	Individual end-users	Load reduction & load shifting
V	Linear program	Individual end-users	Load reduction

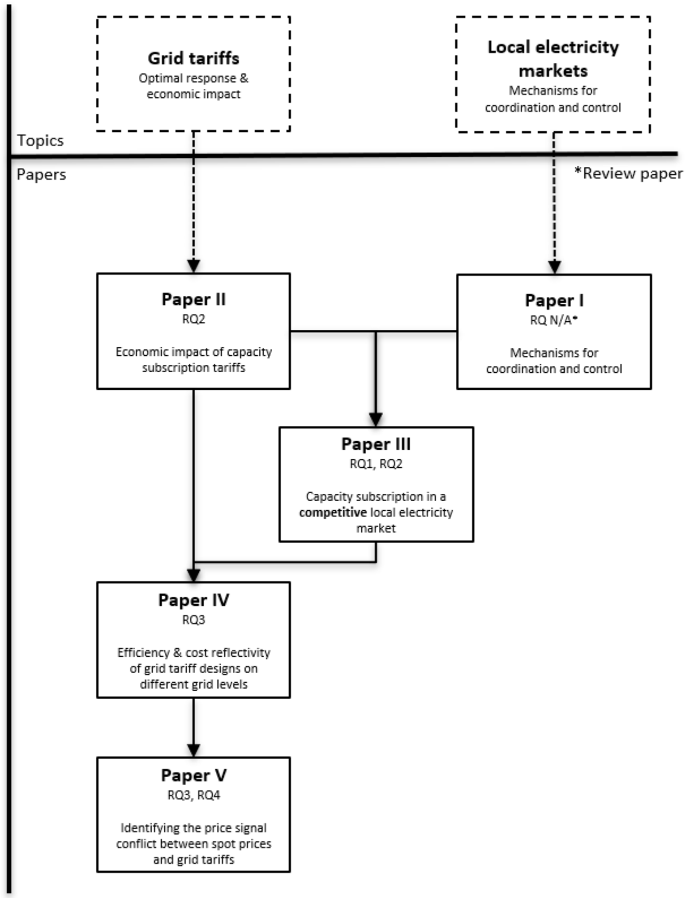

Figure 3.1: An overview of the connection between the research articles in the thesis. Each box indicates one paper, and each is paired with the research questions addressed in the respective papers.

3.1.1 Paper I: Developments and challenges in local electricity markets: A comprehensive review

Paper I is a literature review of state-of-the-art research on local electricity markets, focusing on the developments and challenges in local electricity markets research and projects. The paper was written with the motivation if embracing the widespread opportunities and challenges offered by local electricity markets, aiming to perform a comprehensive review of the technical and regulatory challenges in their implementation and modeling.

This review article separates itself from previous reviews on end-user trading, which has more or less revolved around multi-bilateral trades, i.e. peer-to-peer trading. As this thesis revolves more around the impact of local electricity markets on the electricity grid, a basis was found to look more into the technical aspects related to that rather than multi-bilateral trading models. Studies of peer-to-peer projects and implementation of decentralized market clearing approaches were presented in Ref. [80], which is then further expanded in Ref. [88] where an information and communication technology systems review is also presented. Ref. [39] focuses on centralized and decentralized market designs, emphasizing the advantages and disadvantages of community-based and full peer-to-peer markets, as well as the welfare change under the assumed designs. Ref. [89] illuminates challenges related to architectures and power routing. Furthermore, Ref. [90] reviews papers in the virtual layer, combining the aspects of market design comparison, architectures and information technology systems. An investigation of local multi-bilateral trading information technology systems and architectures is included in Ref. [91] and Ref. [92], while an extensive survey of distributed optimization models of the power system is the focal point of [93]. In Table 3.2, the above-mentioned literature reviews on similar topics are listed, with Paper I at the bottom to clarify the novelty of this paper.

Table 3.2: Taxonomy table for literature review articles on distributed energy systems, Peer-to-peer trading and local electricity markets.

Ref	**Scope**	**Focus**
[80]	Peer-to-peer (local and distributed)	Projects and implementation
[88]	Peer-to-peer (local and distributed)	ICT systems and implementation
[94]	Local markets	Market design comparison
[39]	Peer-to-peer (local and distributed)	Market design comparison
[89]	Peer-to-peer (local and distributed)	Challenges, architectures and power routing
[90]	Peer-to-peer (local and distributed)	Market design comparison, Architectures and ICT systems
[91]	Peer-to-peer (local)	ICT systems
[92]	Peer-to-peer (local)	Architectures and ICT systems
[93]	Distributed optimization	Models
Paper I	Local electricity markets	Challenges, models and implementation

The main contributions of this paper are:

- An in-depth analysis of the challenges of local electricity markets.
- A state-of-the-art introduction to, and review of, mathematical models for local electricity markets.
- An extended overview of existing local electricity market pilot projects and implementation technologies with a focus on the outlined challenges.

The review methodology of this review paper was to categorize research articles, technical reports, and project documentation by which sub-topics they cover. This resulted in a large set of tables by which the papers can be categorized, with respect to challenges, modeling features, and project topics. By systematic review, the challenges were split into five categories that are listed below and found in Figure 3.2, namely:

1. Distribution of generation
2. Integration of demand response
3. Decentralization of markets
4. Existing and emerging legal boundaries
5. Socioeconomic aspects

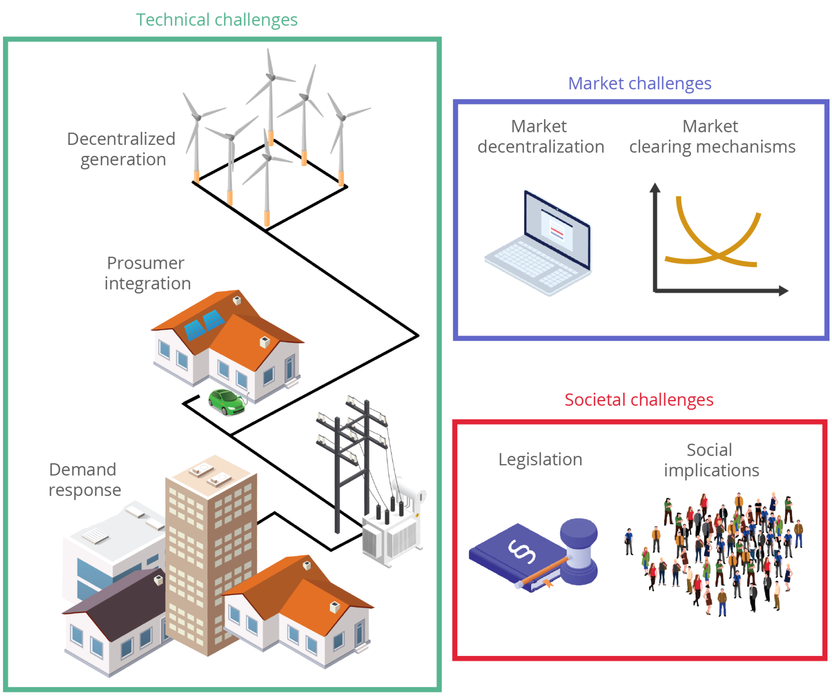

Figure 3.2: Overview of the main challenges related to local electricity markets.

3.1.2 Paper II: Capacity subscription grid tariff efficiency and the impact of uncertainty on the subscribed level

Paper II attempts to answer research question 2, focusing on the evaluation of static and dynamic subscribed capacity tariffs in terms of efficiency, fairness and cost-recovery. The impact on passive consumers (with neither production nor flexibility) under static and dynamic CS tariffs for 84 customers with six years of demand data is analyzed. Welfare distribution (or rather redistribution) under new grid tariff designs is a vital performance indicator as the regulation [23, 33] clearly states that grid tariffs are meant to be cost reflective and provide stable DSO income. Ideally, consumer costs also should have stability under the assumption that demand profiles remain similar, as significant changes in consumer costs can result in low acceptance.

Although covered in previous research [62, 64], capacity subscription tariffs are not well-known in research. They were heavily debated in Norway as part of the redesign process of the grid tariff structure. The tariff is based on consumers making a choice on what capacity to subscribe to, which requires some knowledge about their demand data. This knowledge was recently made available through the introduction of smart meters and Elhub [95], providing end-users with data about their own consumption, both historical and real-time data.

These types of analyses have been conducted in previous studies on other tariffs. Efficiency and fairness of measured peak demand, postage-stamp and Ramsey pricing was provided in [96]. The redistribution of welfare under measured peak demand has been subject to investigation in a number of studies [59,60,65,97,98]. A more cost reflective redistribution was found to be the case in [97], where costs were shifted from customer groups with relatively low peak demand to those with high peak demand. Capacity-based tariffs were also found to be more fair than flat, peak, and Ramsey pricing [98]. Capacity-based tariffs also benefit from not disproportionately impacting low-income customers [60]. However, capacity-based tariffs were claimed to be inefficient due to the lack of guarantee that individual and system peak coincide [59, 67]. Hence, this paper attempts to not only investigate the efficiency and fairness of the relatively undiscovered capacity subscription tariff design, but also investigate a dynamic version which restricts demand to the subscription limit during hours with capacity scarcity. The main contributions of this paper are the following:

- It analyzes the economic impact of static and dynamic capacity subscription grid tariffs for a large sample of consumers over multiple years.
- It proposes a method to determine the optimal subscription level based on a stochastic approach and demonstrates the advantages of this method compared with the naive approach of using the previous year's data.

- It demonstrates how many consumers who experience significant cost deviations from capacity subscription tariffs compared with existing tariffs, in relation to their relative peak demand.
- Under dynamic capacity subscription, where demand is limited only when there is a grid scarcity, an investigation of the difference in how much capacity consumers procure to avoid excessive demand limitations compared to the static variant is performed, modeled by an assumed discomfort function.

The analyses in this paper are based on recalculating consumer costs under the suggested grid tariff designs, finding the redistribution of annual costs. The costs of the flat volumetric tariff scheme are compared to the costs under the suggested static and dynamic capacity subscription tariffs, considering a large set of consumers with six years of data. The cost levels are found based on the backwards calculations described in Section 2.2. Because the capacity subscription tariff is based on ex ante choices, i.e., finding an optimal subscription limit, we also use historical load data to find the optimal subscribed capacity under uncertainty. This is done using a two-stage stochastic program with the first-stage decision being the subscription level, whereas the second stage involves realizing the costs under uncertainty in load in discrete scenarios.

Another complicating factor when analyzing consumer load data is the dependence on climate, as load profiles are strongly dependent on temperature in Norway. This is due to the high share of electric heating, which makes up around 80 percent of the electricity demand for residential consumers in Norway [99]. Because the temperature differs significantly from year to year, it is important to gather load data for multiple years. In Paper II, real metered load data from 84 consumers from six years which covers warm, average, and cold winters. This gives the study additional robustness as the welfare distribution spread can be seen over two dimensions.

The novelty of this work is the analysis on the economic impact of capacity subscription tariffs, which has not before been covered as extensively in the literature. The paper also suggests a dynamic capacity subscription tariff that takes grid conditions into account. The main findings can be summarized as follows:

- Capacity subscription tariffs are more cost reflective than flat, volumetric tariffs, based on the regression shown in Figure 3.3. This results in a removal of cross-subsidization between customers with relatively high peak demand to those with low peak demand.
- For static capacity subscription tariffs, cost recovery for the DSO is as stable

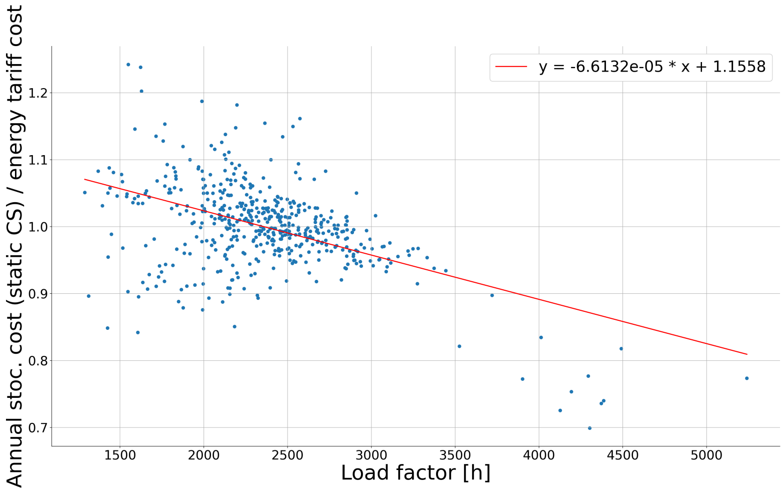

Figure 3.3: Scatter plots of static capacity subscription costs compared to the energy-based tariff, in relation to the load factor. Linear regression is shown as a red line.

as under flat, volumetric tariffs. The cost recovery is not as predictable under the dynamic capacity subscription tariff.

- A stochastic approach using the customer's own historical load data is accurate for finding a good subscription level, compared to the deterministic, perfect-foresight-solution subscription level.

- Dynamic capacity subscription tariffs are also more cost reflective than flat, volumetric tariffs, but come at the cost of less predictability and more unstable cost recovery for the distribution system operator.

One of the main results found, was the increased cost-reflectivity of static capacity subscription tariffs as shown in Figure 3.3. The results further indicate that regulators should consider capacity subscription tariffs to achieve higher cost reflectivity. Further, the cost recovery appears stable and predictable, as historical load data covering both cold and warm winters were included in the data set. The dynamic capacity subscription tariff is even more efficient, but has cost recovery-related problems, while also being more prone to high cost variations if the subscription level, also when the suggested stochastic approach. Under the static capacity subscription tariff, advising consumers on their subscription level with the suggested model is very precise. On average, the approach results in less than 1% higher costs compared to the deterministic, perfect-foresight-solution, with a few just a few outliers having more than 5% higher costs.

The main limitation of this work is related to the modeling of load limitation activations. In this paper, the activation of peak rate periods was based on the load data of the customers. The work could also have included the impact of load limitation activations from the transmission system operator, or in higher levels of the distribution grid. This analysis would not only have increased insights into the impact of load uncertainty, but also provided insight into combined need for activations from distribution and transmission system operators. Lastly, there is no information about the customer types in the analysis. Information on heating source, number of electric vehicles, building type, and household income would have given extra knowledge regarding the fairness from a social equity perspective.

3.1.3 Paper III: Peer-to-peer trading under subscribed capacity tariffs - An equilibrium approach

The peak demand reduction potential of different grid tariff structures is one of the most important treats of grid tariff designs [8]. Capacity subscription tariffs were found to be able to reduce peak demand in neighborhoods with high levels of distributed energy resources [30, 35]. In addition, a neighborhood-level tariff is introduced in Ref. [30], which is currently not possible in most countries due to regulatory reasons. When comparing individual and neighborhood level tariff structures, Ref. [35] found that combined tariffs between multiple stakeholders had lower peak demand than under individual tariffs.

This paper introduces individual capacity subscription tariffs in combination with a local peer-to-peer electricity market. By combining the two, customers can rent capacity from each other, essentially introducing a local market for renting capacity, as visualized in Figure 3.4. The main contributions of this article are:

- Presentation of a mixed complementarity problem formulation of how capacity subscription tariffs, together with local electricity market trading, can coordinate end-users to reduce peak demand in neighborhoods.
- A conceptual case study demonstration of how a local electricity market can function as an alternative to centralized tariffs.
- Showcasing the advantages of renting capacity from neighbors, effectively negating the issue of coinciding peaks.

The methodology is based on finding the peak demand reduction in the case study. To represent the competitive nature of a local electricity peer-to-peer market, a mixed complementarity program is used to highlight how the combination of static grid tariff price signals and local electricity markets can be used to integrate flexible consumers in a grid-friendly manner, i.e. by

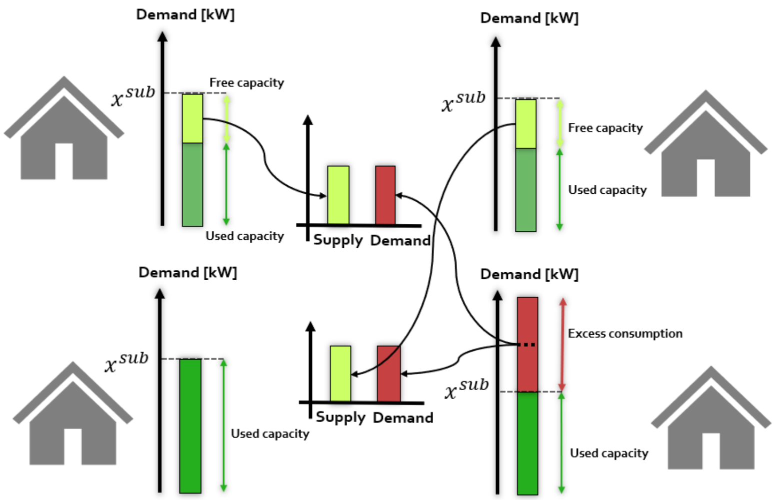

Figure 3.4: Example of how the local market provides a coordination mechanism to optimally use capacity among customers.

incentivizing reduced aggregated peak demand from the consumers. Solving such a model gives us the equilibrium solution in which no stakeholders want to change their decisions. This allows insight into how the price signal performs under decentralized decision making, rather than under a centralized approach that assumes perfect cooperation between consumers.

The resulting load profile with and without the introduction of the local electricity market is shown in Figure 3.5. The main findings of Paper III are as follows:

- The combination of a capacity subscription tariffs and a local electricity market reduces the aggregated peak demand of market participants. In the local electricity market case, the peak demand is reduced by 20% compared to the non-market case.
- The capacity trading mechanism provided by the local market ensures the use of the cheapest available asset for reducing peak demand.

This paper laid the groundwork for two journal papers on capacity trading and the combination of capacity-based tariffs and local electricity markets [71, 74], in which the thesis author also contributed. These articles are recommended for those interested in this topic, as they contain an extension of this work, but are not subject to a more detailed investigation in this thesis.

The reduced income of the distribution system operator as a consequence of peak

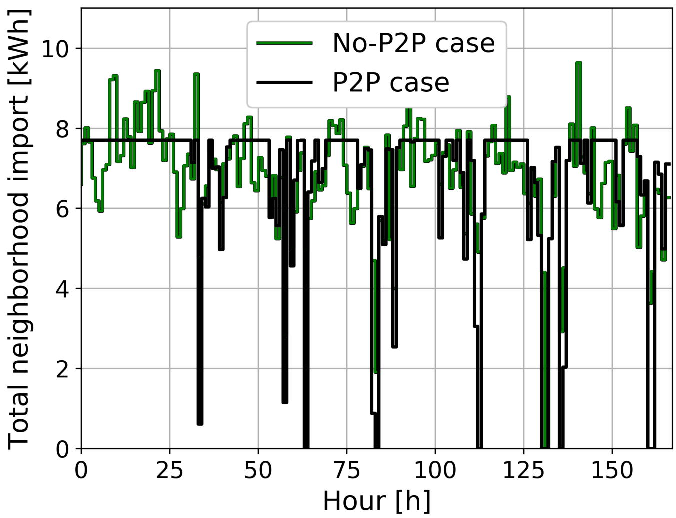

Figure 3.5: Comparison of load profiles with and without a local electricity peer-to-peer market.

demand reduction limits the insight provided by this paper. Cost recovery could have been ensured in this article by either modeling the price signal endogenously (as considered in [71, 74]), or by investigating whether the reduced income of the distribution grid operator matches the potential cost savings from the peak demand reduction. Further, the paper assumes perfect foresight and information sharing in the multi-stakeholder environment. In the conceptual case study, the assumption of perfect competition limits the insights somewhat, requiring further research on other pricing mechanisms in local electricity markets.

3.1.4 Paper IV: A comparison of the peak demand reduction performance of various energy-based and capacity-based tariffs at different grid levels

Judging by all the grid tariff design criteria highlighted in Section 2.2, cost-reflectivity arguably remains the most important one as it ensures efficient grid use and provides proper investment signals to grid owners [4, 19, 33]. Grid tariff cost reflectivity has been investigated by quantitative simulation studies, often focusing on the impact of distributed energy resources. Capacity subscription tariffs [53] and measured peak demand [55–57] prove efficient compared to existing tariff structures. Alternatively, a grid tariff design combining measured peak demand with time-varying energy-based costs (i.e. time-of-use) can be used [53, 55], which is in line with what the Norwegian regulator has chosen to implement [100].

Time-of-use tariffs on the other hand, may result in increased peak demand [57] due to the synchronization effect from many customers targeting the same low price time periods (often referred to as the rebound effect). Further, time-of-use tariffs are more commonly (but not necessarily) designed to target system peaks rather than individual peaks. This is an issue with most capacity-based grid tariffs, because individual and system peaks do not necessarily coincide [59, 68]. On the other hand, static capacity-based tariffs tend to decrease individual peak demand significantly more than system peak demand [101]. Vice versa, time-of-use tariffs which aim to price system peak demand hours, reduces system peaks more than individual loads [102].

There are many studies that consider the cost reflectivity of grid tariff designs, but they often neither consider a larger variety of grid tariff designs, nor take a step back and reflect on the design parameters and their impact on the results. Hence, Paper IV attempts to close this research gap by analyzing the peak demand reduction from a selection of six energy-based and capacity-based tariffs, focusing on comparing and discussing the design parameters. In addition, we consider a large-scale case study with thousands of customers, allowing for investigation of peak demand reduction on multiple grid levels. The main contributions of this article are:

- Analysis of grid tariffs cost reflectivity and efficiency in terms of reducing peak demand on multiple grid levels.
- Investigation of the impact of flexibility characteristics used to reduce peak demand.
- Highlighting the importance of grid tariff design parameters, i.e. if the grid tariff price signal is based on individual or system peak demand, and if the price signals are provided ex ante or ex post.
- Illuminating the spread in peak demand reduction potential in different part of the grids considering commercial and residential customers.

The main goal of Paper IV is to compare the performance of various grid tariff designs by evaluating their ability to reduce the peak demand on lower and higher grid levels. This study is performed by formulating a cost-minimizing optimization problem of 3,608 customers subject to the price signal from six different grid tariff designs, and aggregating their response to find the impact on peak demand reduction.

Grid tariffs can fundamentally be separated by their "peak basis" design, which we argue is whether the tariff is based on the individual peak of the end user or on the grid peak. It should be expected that the individually peak based ones perform better on lower grid levels and grid peak models better on higher grid levels. Therefore, it is interesting to compare the tariff performance on different grid levels. The comparison is explicitly limited to price signals from grid tariff and does not cover other dynamic price signals, such as, for example, the spot price of electricity, which may alter the end user price of electricity. The reasoning behind this conscious narrowing of the scope is to allow for an undisturbed comparison of the grid tariffs without the inclusion of other price signals. In addition, the robustness of the comparison results will be further analyzed by changing some of the assumptions and parameters of grid tariff designs and available demand flexibility. This includes flexibility type, flexible energy volume, flexible power capacity, as well as temporal tariff parameters.

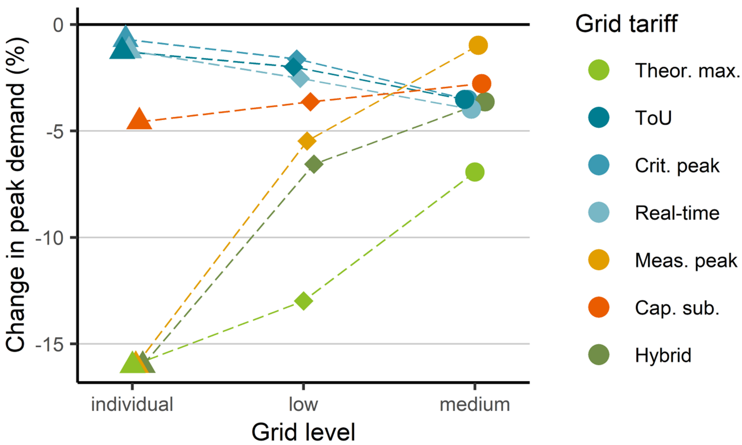

Figure 3.6: Comparison of peak demand reduction results on individual, low voltage, and medium voltage level.

The main findings of this paper are shown in Figure 3.6. The main findings can be summarized as follows:

- Grid tariff design performance is highly dependent on peak basis. Tariff designs based on individual peak demand perform better on individual and low grid levels, whereas tariff designs based on system peaks perform better on higher grid levels.
- Grid tariffs based on ex ante price signals result in new, higher demand peaks, whereas tariffs based on ex post price signals do not.
- Capacity subscription is the most robust tariff design as it performs well regardless of grid level and flexibility type.

- A hybrid tariff combining ex ante and ex post price signals, as well as targeting both individual and grid peaks, has the highest performance assuming load reduction.

- Due to the relatively flat load profile during peak demand days, system peak reduction is more dependent on flexible energy volume than on flexible power capacity of the demand response.

The findings in this work are limited by the simplifications in the modeling. Firstly, the flexibility characteristics considered in the case study were homogeneous, whereas in reality, demand side management will consist of a combination of flexibility assets and demand response. The chosen approach to model flexibility as a generic response rather than flexibility assets has computational advantages as each linear program is faster to solve, but limits insight into the impact of different flexibility assets. Further, the study includes commercial customers, who are already subject to measured peak demand tariffs. Hence, their load profiles might already contain some type of demand response. Another limitation is the lack of price elasticity in the model, which would have provided better insights into by how much customers respond to different price signal strengths. Finally, we do not consider uncertainty in load, improving the response ability of some tariffs due to perfect foresight.

3.1.5 Paper V: Grid tariffs for peak demand reduction: Is there a price signal conflict with electricity spot prices?

Analysis on demand response from a combined spot price and grid tariff signal has been proposed in the literature [103]. Yet, the importance of peak pricing in order to realized system benefits from distributed flexibility is important, regardless of what cost components make up the observed price signal from the customer side [31].

Paper V is an extension of the work from Paper IV, which investigated the efficiency of grid tariff designs in terms of reducing peak demand on different grid levels. However, grid tariffs are not the only price signal consumers are exposed to. Grid tariffs have historically made up roughly one third of the total electricity bill in Norway, with taxes and electricity spot prices also taking one third each [104]. Consumers on fixed price contracts will not respond to spot prices, but due to historically low prices, more than 95% of Norwegian residential consumers are on spot price or variable price contracts [105]. During the end of 2021 and winter of 2022, Europe experienced historically high electricity spot prices at a size which easily could "outperform" the most suggested grid tariff structures in the sense that consumers would react to the price signal from the electricity spot prices, rather than from the grid tariff.

This raises the questions: Is there a price signal conflict between electricity spot prices and different grid tariff designs, and how large is it? This is of particular interest as there is often (but not always) a correlation between high electricity prices and cold winters with high demand, which is also the dimensioning factor for grid expansion. Summarized, the main contributions of this article are the following:

- A quantification of the price signal conflict between electricity spot prices and grid tariffs, with respect to reducing peak demand.
- A comparison of peak demand reduction under different grid tariff designs, when exposed to both real-time electricity spot prices and no spot prices.

This article attempts to answer these questions by simulating demand response for peak demand reduction, using historical spot prices and real, metered data from 3,608 consumers in Oslo, Norway, from November 2020 to October 2021. The methodology and data set are identical to in Paper IV, but investigate fewer grid tariff designs and parameters, and instead focus on the impact of electricity spot prices. The simulation period (winter 2021) also had the highest ever recorded electricity peak consumption in Norway, which makes the case highly interesting. If the cold, premise-setting winters for grid expansions might include very high spot prices, which grid tariff designs are the most robust in order to achieve peak demand reduction in those few days that might occur as seldom as every decade?

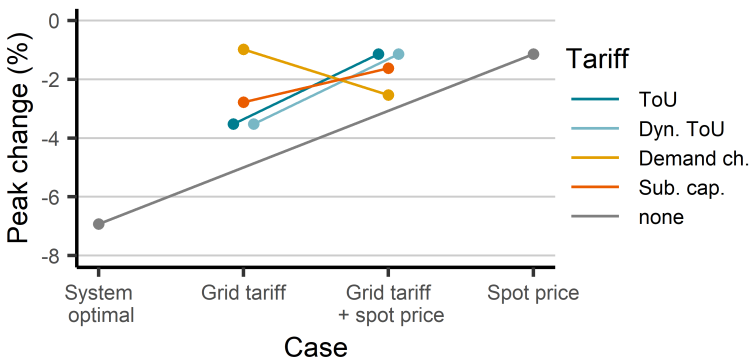

Figure 3.7: Comparison of peak demand reduction results.

The main results of the paper are shown in Figure 3.7, and the main findings can be summarized as follows:

- When subject to electricity spot prices, the aggregated consumer response results in smaller reductions in peak demand, except for measured peak demand which performed better with spot prices. Hence, under the model assumptions, there is a conflict between spot prices and grid tariffs for peak demand reduction.
- Spot price fluctuations trigger automatic demand response, using all available flexibility in a limited time period, rather than spreading it out over multiple hours. This effect reduces overall peak demand reduction because the peak demand is relatively flat during peak demand days.
- The spot price correlation with peak demand is stronger on a daily than yearly basis.

The limitations of this work are very similar to the ones in the Paper IV, as the same model is used. Again, it can be mentioned that sensitivity analysis on electricity spot prices (i.e. from different years) could also have been considered. However, consumers can observe the electricity spot price before managing their demand, which limits the importance of short-term uncertainty of load.

3.2 Summary and discussion of research questions

3.2.1 RQ1: How well do capacity subscription tariffs and local electricity markets synergize in order to incentivize consumers to reduce peak demand?

A fundamental issue with static grid tariff designs is the lack of guarantee that consumer peak and system peak coincide, i.e. how scarce capacity is in the temporal and spatial dimension. This can be solved by either having a dynamic price signal which adapts to the grid status (as described in Paper II), or by aggregating and coordinating the flexibility assets in clusters/formations of customers. These clusters are often referred to as energy communities or neighborhoods [7], and assume some centralized control, where the community minimizes aggregated costs.

Paper III attempts to highlight the effect of having a multi-stakeholder optimization framework in which agents act in their own interest. The grid tariff design is provided as an exogenous price signal and the main focus is on investigating the local electricity market's ability to trade in order to ensure optimal dispatch of flexibility assets. The paper does not assume centralized control (like in [30, 106]), but is rather solved by formulating a Nash game, using a mixed complementary program. In this optimization model, the consumers trade in the local electricity market simultaneously as they schedule batteries. By comparing the local peer-to-peer electricity market case with a non-trading case, the market case proves able to reduce peak demand by 20% in a relatively small, stylized case study. By trading their capacity quota, i.e. buying unused capacity from others when above their individual subscription limit, or selling their own capacity when available, the consumer group is able to reduce peak demand as they have market access to flexibility.

In Paper IV, it was observed that capacity subscription tariffs were much stronger on lower grid levels than when aggregated at higher grid levels, as the tariff is designed based on individual peaks. The coordination mechanism from Paper III negates this effect. However, this might not help if the goal is to reduce the peak demand on higher grid levels, as the load between different parts of the grid may not coincide. Hence, it would be interesting to further investigate a local electricity market concept which adapts to grid status, including as many consumers as possible inside the congested area.

The main takeaways and answers to RQ1 are the following:

- The local electricity market ensures optimal coordination of flexibility resources through capacity trading, without any agent being worse off, hence synergizing very well with subscription tariffs.
- There are clear synergies between capacity subscription grid tariffs and local electricity markets, as the local electricty market negates the coincidence factor issue. Depending on the grid level that faces congestion challenges, the market should be adapted to match the congested area.

3.2.2 RQ2: How well do capacity subscription tariffs perform in terms of efficiency, cost-recovery and fairness?

Capacity subscription tariffs have been investigated in Paper II-V. In this RQ, the focus is on the contributions from Paper II and V as they answer the RQ in the most precise fashion.

Capacity subscription tariffs are relatively complex in the sense that they require customers to make an active choice ex ante by subscribing to a capacity. This was one of the main arguments against the introduction of this tariff in Norway, as the DSOs were reluctant about the consequences of subscribing to a sub-optimal level, and, understandably so, did not want to have the responsibility on advising their customers on subscription levels. Capacity subscription tariffs are designed to be fairer in terms of being economically efficient and cost reflective; however, the welfare redistribution could be interpreted as an economic punishment for “normal” consumption by the population. The goal of the tariff is not only to provide an incentive to reduce customer peak demand, but, just as importantly, redistribute the welfare distribution so that customers with flat load profiles do not subsidize customers with high peaks or distributed generation. Either way, what is fair in terms of being economically cost reflective and what is comprehended as fair by the customers is not always coherent. This further leads to a discussion on what is fair, what is discrimination, and what is due discrimination.

Paper IV showed that capacity subscription tariffs are promising compared to most other grid tariff designs in terms of reducing peak demand, both on low and medium voltage level. Although outperformed by some other tariffs designs in specific cases, only capacity subscription tariffs reduced the peak demand both on all grid levels, both under load reduction and load shifting. The design benefits from having a clear incentive to reduce individual peak demand, but also gives significant incentives to reduce peak demand whenever the customer is above the subscription level, which also potentially contributes to reducing the peak demand of the system. It also avoids the creation of new peak demand, unlike the energy-based grid tariff designs.

Dynamic capacity subscription tariffs also prove to be fairer than volumetric tariffs, but may open a Pandora’s box of new issues related to the trade-offs between cost reflectivity and discrimination. If only consumers in congested grid areas are to be limited, the concept of economic efficiency is kept, but contests the concept of non-discrimination. It seems reasonable that due discrimination should not apply to consumers that live in areas with weaker electricity grids, as they have little or no way of influencing that outcome, and policy makers should consider mechanisms to cover the discomfort costs to those who are in congested areas as discussed in Paper II.

In terms of fairness, the tariff performs well as shown, where the results highlight how the expected annual customer costs are reduced with lower peak demand. In addition, Paper II also showcases the robustness of the tariff, which is arguably also a part of the fairness as the tariff design does not result in volatile customer costs due to sub-optimal subscription levels. This is highlighted by showing cost deviations from year to year when subscribing to sub-optimal levels, which are comparable to the cost deviations under the current, volumetric tariff design.

The main takeaways and answers to RQ2 are the following:

- Under the assumptions of this work, capacity subscription tariffs are the most robust of the tested grid tariff designs in terms of cost reflectivity, measured by their ability to reduce peak demand on different grid levels, both under reducible and shiftable loads.

- Using historical load data and stochastic programming, a robust subscription level can be found for customers without increasing the variation in annual customer costs, and hence also DSO cost recovery.
- Capacity subscription tariffs are fairer than volumetric tariffs, as the costs are shifted from those with relatively low peak demand to those with relatively high peak demand.
- Dynamic capacity subscription tariffs result in significantly higher economic consequences under sub-optimal subscription levels, and has higher variation in annual consumer costs, mostly due to significant variation in annual number of hours with grid scarcity. The economic impact for customers is hence also higher as customers with peak demand that coincide with system peak demand have significantly higher costs.

3.2.3 RQ3: Which grid tariff designs are the most cost reflective and efficient at reducing peak demand at different grid levels?

Determining the most cost reflective grid tariff design is a complicated task, as the question depends on what type of flexibility is available and at what grid level the peak demand reduction should be achieved. The question also avoids a lot of other complicated aspects of designing a cost reflective tariff, such as acceptance, complexity and cost-recovery [19, 33, 107]. This thesis covers the efficiency question by comparing different grid tariffs designs' ability to reduce peak demand at different grid levels by looking at real metered data from 3,608 customers.

The most cost reflective grid tariff design in terms of peak demand reduction is according to the findings of Paper IV, case dependent, but there are two grid tariff designs that outperform the others: 1) a hybrid tariff and 2) capacity subscription tariffs. The hybrid tariff outperforms all tariffs in the low voltage grid, but also does second best in the medium voltage grid, only barely beaten by the real-time pricing tariff. The hybrid tariff builds on the principle that both individual and system peak basis should be considered, by both having a price signal which incentivizes a reduction in individual peak demand as well as a price signal targeting system peak demand. As electricity grids are dimensioned for the peak demand over the next decades, it is intuitive that a grid tariff design which reduces the capacity use of an individual customer is important. However, if the individual peak does not coincide with the peak of the aggregated load of the grid level, the benefit of reducing individual peak demand is reduced. Thus, secondly, the other necessary characteristic is a price signal that incentivizes a reduction in system peak demand, which is what time-of-use tariffs do. The combination of the two price signals allows for the most efficient price signal, whereas a price signal that only focuses on one or the other is less efficient. Yet, the balance between the two price signals must be carefully weighed, as one might dominate and result in new peak demand under load shifting, as shown in Paper IV.

The main takeaways and answers to RQ3 are the following:

- Individual peak-based tariff designs, i.e., capacity-based tariffs, perform better on lower grid levels, whereas grid peak-based tariff designs, i.e., time-varying energy-based tariffs, perform better on higher grid levels.
- Combining a time-of-use and measured peak demand, the hybrid tariff has a good performance on all grid levels, except on higher grid levels under load shifting. The capacity subscription tariff is, according to our study, the most robust, as it reduces peak demand regardless of case study.
- None of the grid tariff designs are efficient in peak reduction since more than 95 % of the hours the tariffs trigger demand response are non-peak hours regardless of the grid level.
- Automatized demand response with load shifting based on cost minimization may lead to higher peak demands with grid tariffs that have the same price in each hour for all end-users, i.e., time-of-use, critical peak pricing, and real-time pricing, whereas capacity-based tariffs limit the creation of new peaks.
- The performance of the tariffs compared to each other is robust even if the availability of demand flexibility changes or tariffs are implemented to only one customer group, either residential or commercial.

3.2.4 RQ4: Aiming to reduce peak demand, is there a price signal conflict between electricity spot prices and grid tariffs?

Designing the grid tariff designs in a vacuum, i.e., without considering other aspects of the customers' electricity bills, limits the insight into customers' demand response when subject to different grid tariff designs. The electricity bill mainly consists of three cost components: grid tariffs, electricity prices and taxes. In most countries, these cost components have a fixed term and a volumetric energy term. Grid tariff designs with dynamic cost components such as capacity terms or time-dependent energy terms introduce new price signals that can be adapted to. However, these grid tariff cost components may conflict with electricity spot prices, under the assumption that customers are on variable or spot price electricity contracts, which is the case of more than 90 % of Norwegian consumers.

Hence, Paper V extends the research performed in Paper IV by adding spot prices to the simulations on time-of-use, critical peak pricing, capacity subscription and measured peak demand, in order to illuminate how the record high spot prices of the winter 2020/2021 impacted the demand response of the same customer data set as used in Paper IV. The results conclude that there is a price signal conflict between all the grid tariff designs, but perhaps not in the expected way. The measured peak demand improves when also subject to electricity spot prices, but this is only because it performs so poorly in the first place. The other grid tariff designs, on the other hand, achieve worse peak demand reduction when electricity spot prices are added to the price signal, meaning that there is a significant conflict. Alongside quantifying the price signal conflict with each grid tariff, one of the main findings is that the peak demand days do not correspond well with peak spot price days. However, the lack of correlation was not particularly important, because during the peak demand days, the spot price coincided well with the peak demand in each hour. Nonetheless, the peak demand reduction was not as efficient, because all the available flexibility was used during the few hours where the spot price was the highest, rather than spreading it out over many hours. This sounds better than it is, because the peak demand is quite flat in the peak demand day. Hence, one of the main findings of the article, similarly as in Paper IV, is that energy flexibility is more important for peak demand reduction than power flexibility. Also, under the assumption of inelastic demand response, i.e., the level of demand response does not increase the stronger the price signal, the spot price level does not matter, as an automated demand response will always target the peak hours regardless.

The main takeaways and answers to RQ4 are the following:

- There is a significant price signal conflict between electricity spot prices and most grid tariff designs, but not on an hourly basis. Instead, spot prices results in a concentration of demand response during a few hours, weakening the overall demand response capability of the price signal from grid tariffs.
- The flexibility characteristics impact the results significantly, as more energy intensive flexibility is more efficient for peak demand reduction.

3.3 Policy implications and the role of grid tariffs in the future

The role of grid tariffs has traditionally been to recover the costs of the distribution grid owner, and has subsequently barely changed as there are no or few incentives for distribution grid owners to innovate. This might seem natural, as distribution grids are natural monopolies and not subject to competition for obvious efficiency reasons. However, the research presented in this thesis strengthens one of the core hypotheses when starting this work: volumetric, flat tariffs are inadequate for modern power systems. They lead to inefficient consumption, grid investments, have unintended cross-subsidies and provide no incentive for customers to reduce the overall costs of building and operating electricity grids. Driven by the increased affordability of information and communications technologies, the roll-out of smart meters enable detailed monitoring that facilitates more efficient pricing.

"How well can grid tariffs reduce peak demand?" is raised as a question throughout the thesis and is investigated in papers III - VI. This question is important in Norway, because the planned electrification of transport and industrial activities is expected to result in an increase in annual electricity consumption from 138 TWh (2021) to 175-200 TWh in 2040 [108]. A consequence of such a consumption increase, is that the electricity grid requires significant investments in transmission and distribution grids to transmit the electricity to the new consumption. The long lead times of electricity grid construction slows this development down [6], which encourages solutions to reduce peak demand from both new and existing consumption. The results from Paper III, shows significant peak demand reduction potential, with peak demand reduced by 20%. These conceptual results are promising, whereas the quantitative results has some limitations as the case study is relatively small and conceptual. In Paper IV & V, the large-scale case study is much more realistic and also consider different grid levels. The papers were not meant to quantify the peak demand reduction, but rather compare grid tariff designs' abilities to reduce peak demand. Yet, the papers used relatively realistic flexibility levels based on real studies, and found peak demand reductions of 6.6 and 3.6 % at low and medium voltage level, respectively. Although the results are somewhat more promising in the high flex scenarios, these numbers are relatively modest and imply that a change in grid tariff design has some, but limited, potential to reduce the need for grid investments. Nonetheless, even a modest reduction in peak demand can delay the need for some grid investments which is helpful considering the lead times for grid construction [6]. In addition, a more cost reflective grid tariff design sends a signal to customers to consider these prices when investing in e.g., electric vehicle chargers or other electricity-intensive equipment.

Although flat, volumetric tariff structures are arguably insufficient, this does not mean that designing good tariffs is an easy task. During the work performed in this PhD, it quickly became clear that designing efficient, cost-reflective tariffs come at the cost of complexity and fairness. In Paper II, we argue that it is efficient and cost-reflective to only restrict customers to their capacity subscription level during peak demand hours. Still, we acknowledge the inefficiency with respect to location, i.e., customers who are located in non-congested grid areas are restricted similarly to those in congested grid areas. This is not in line with concepts of cost reflectivity, and could be improved by only restricting customers in the weak grid areas, while also developing compensation mechanisms to those grid customers to negate the fairness issues such as by, for example in the shape of reduced fixed costs. The thesis also bases most of the findings on results from deterministic optimization models, which imitate automated, perfect responses. In reality, it may be harder to “extract” the same flexibility from customers if the grid tariff structures are too complex, i.e., the customers do not understand how to react to the price signals. Except for Paper II, no price elasticity is modeled, which implies that the response is the same regardless of the price level, which has been proven not to be the case in Norway [109].

Many studies have highlighted the need for temporal design of tariffs with respect to when there is capacity scarcity. This requires grid tariffs to have a dynamic element, as the price signal has to be stronger only during peak demand hours. This however introduces two challenges. The first challenge is that variation in number of hours with capacity scarcity will differ from year to year, as shown in Paper II. As a consequence, the number of hours with strong price signals can differ significantly from year to year and month to month. This subsequently leads to low predictability in consumer costs and hence, DSO income. The second problem is related to price signal strength. If the grid tariff is designed to recover the distribution grid owner cost in a very short time period, it leads to very high prices during those hours. Further, this results in strong incentives to invest in demand response or even back-up solutions which allows for complete disconnection from the grid. This might sound appealing, but has significant drawbacks, i.e. that the distribution grid owners might not be able to recover their costs fully, and also lets wealthy customers invest in capital-intensive technology which allows them to push costs onto less wealthy customer segments (as discussed in [9]). Essentially, this discussion boils down to finding the optimal number of high price periods. If there are too few, the price signal will be too strong for the above-mentioned reasons, whereas too many will result in the price signal not triggering any response. Policy makers should therefore consider yearly variations before designing such tariffs. One method could be to set a minimum and maximum number of hours with critical peak pricing, even if it is not economically efficient to do so, in order to keep annual consumer costs within acceptable limits. This topic could be pursued more extensively in future work.

The research performed in Paper IV indicated that flexibility with high volume of energy contributes more to peak demand reduction than flexibility with high power capacity, regardless of which grid tariff design was used. This was not an intended research question of the paper, yet an important finding of the study. Such a finding suggests that regulators should consider measures which either increase energy efficiency during peak demand hours (typically heating), or flexibility which is capable of shifting high amounts of energy, rather having a high power capacity with low energy amounts. Subsidy design is not a topic of this thesis, but the results justify a suggestion for a more energy-intensive focus from policy makers, for example by supporting installation of smart control of space heating of electric hot water tanks. In general, insulation of homes which reduces the electricity demand during winter should overall contribute well to reducing peak demand, regardless of grid tariff design.

Due to the planned electrification of industry, the Norwegian regulator has implemented a concept where new commercial consumers may connect under the condition that they should fully or partially disconnect when asked to [110]. Such a deal might prove more efficient than a widespread implementation of grid tariffs, as it is possible to target new, grid-intensive commercial consumers rather than large portions of households. It is also a more direct approach, where activations are based on temporal and spatial needs, supporting the concepts of economic efficiency. It could also be argued that the discrimination is due, as the commercial customers would otherwise have to pay part of the costs for grid upgrades. Conditional right to connect might prevail more practical than imposing grid tariffs on residential consumers, especially in cases where the commercial consumer contributes to a large share of the peak demand in a specific area. Hence, policymakers may consider developing a framework that shifts the responsibility onto commercial consumers to a larger degree (i.e., using contracts based on conditional rights to connect), where the spatial characteristics of the grid suggests so.

4 Conclusion

4.1 Concluding remarks

In this PhD thesis, the role of grid tariffs and local electricity markets for peak demand reduction is investigated. The work revolves around designing grid tariffs that are more cost reflective, focusing particularly on the Norwegian system with high peak demand during winter due to the high level of electric heating. Capacity subscription tariffs have received extra attention in this PhD thesis, as a consequence of being the main suggestion from the Norwegian regulator at the beginning of the PhD period.

The current flat, volumetric tariff results in cross-subsidies and inadequate incentives for peak demand reduction. A shift to more cost reflective grid tariff designs contributes to reducing peak demand, which can defer grid investments and provide incentives for investments in peak-load-reducing technologies. Papers IV and V found that the most important design parameters when designing grid tariffs are "peak basis" and "peak rate period setting". Peak basis refers to whether the main cost is related to the individual or system peak. Not surprisingly, tariffs based on grid peaks perform better on system level, whereas tariffs based on individual peaks perform better on lower grid levels. Based on the work performed in this thesis, capacity subscription is the best overall performing tariff, as it performs well on all grid levels as well as under different flexibility characteristics. Hybrid tariffs with both individual and system peak basis cost components perform best under load reduction, but similarly to the ex-ante tariffs, create new peak demand increases due to the synchronized re-connection of rescheduled load shifting. This is a consequence of all grid tariffs with ex-ante peak rate period setting, as the prices are set before the event and customers can react. When the peak rate period is determined ex post, customers have to manage their load profiles during the entire billing period. Highlighting the importance of peak basis and peak rate period setting adds onto existing knowledge focusing mainly on energy-based and capacity-based tariffs, whereas the research in this PhD highlights the impact of the aforementioned design concepts rather than the cost components directly.

Since grid tariffs are not the only price signal electricity customers are subject to, this thesis investigates the effect of electricity spot prices when analyzing the peak demand reduction ability of different grid tariff designs. The findings of this thesis imply that there was a conflict between electricity spot prices and grid tariffs under the premise-setting peak demand day in Norway, and that under the effect of spot prices, the aggregated customer demand response was worse than without spot prices, except for under measured peak demand. Although the spot prices and electricity demand did not correlate well on a yearly basis, the correlation on daily basis during peak demand days was strong, resulting in demand response targeting the most important hours. Yet, a fundamental issue with spot prices is that they will result in synchronization effects because automated demand response targets the same hours.

Under current regulation, grid tariffs have a fundamental challenge because they attempt to lower the aggregated peak demand, but are forced to send price signals to individual consumers, and consider the response of a single customer, rather than the aggregated response. To coordinate the response of individual customers, local electricity markets as facilitators for flexibility coordination were modeled and found to be highly efficient for peak demand reduction. This effect is achieved by aligning the incentives of the distribution grid owner and the electricity customers. The well-synergizing combination of capacity subscription tariffs and local electricity markets based on capacity trading, allow consumers to trade surplus capacity from their tariff subscription level. This thesis provides a solution to the main drawback of capacity-based tariffs, namely the lack of coincidence between individual and system peak demand. The suggested approach also has the advantage of being in line with the current regulatory framework and market structures, as flexibility can be coordinated without shifting from individual to area level metering. The competitive market framework also provides efficient investment signals for demand side management, as customers can invest in flexibility not only for managing their own demand, but also for trading capacity with others. This could potentially also avoid over-investment in demand side management due to the flexibility of being available in the local electricity market, efficiently using all available resources.

As consumers become more and more flexible, the peak demand reduction potential increases. The results of this thesis show that flexibility characteristics are decisive for how well peak demand can be reduced. Because the peak demand is relatively flat during peak demand days, flexibility with higher energy volumes is more important than flexibility with high power reduction potential. Hence, this thesis advices policy makers to promote energy-intensive flexibility, rather than power-intensive, because power intensive flexibility will target the cheapest hours and spend all available flexibility in just a few hours, rather than spreading it out. This is especially the case for ex-ante tariffs whereas the effect can be somewhat negated by ex-post tariffs, especially when coordinated by capacity trading in local electricity markets.

Capacity subscription tariffs were the leading choice from the Norwegian regulator when Norway was to implement a more cost reflective tariffs. The suggestion faced resistance both in the public and by some distribution grid owners due to challenges related to cost recovery, the requirement of an ex ante choice on subscription level and lastly, the coincidence factor issue. Based on these challenges, this thesis developed a method to find an optimal subscription level under uncertainty, which proved able to keep stable consumer costs as well as stable cost recovery for the distribution grid operators. In addition, a dynamic capacity subscription tariff was suggested in this thesis, which only limits customers to their subscription limit during hours with capacity scarcity. Although more cost reflective, this tariff struggled more with stable costs for consumers and the distribution grid operator. Based on this analysis, this thesis brings up a new research question by discussing the fundamental issue with dynamic grid tariffs: What is the optimal level of peak price hours? While leaving this topic as a suggestion for future research, the thesis has highlighted that cost reflectivity comes at the cost of predictability and cost recovery for the distribution system operator, and should be carefully considered when designing dynamic capacity tariffs.

4.2 Future work

Grid tariff design is an intricate exercise which ultimately is about making the least-bad choice, considering a number of trade-offs. These trade-offs involve, but are not limited to, complexity, fairness, acceptance, cost recovery, cost reflectivity, and transparency. The research in this thesis can be extended in multiple directions, spanning from social aspects of grid tariffs, to economic impact and the value of peak demand reduction in power systems.

Peak load reduction as a consequence of implementing more cost reflective grid tariffs may postpone or even avoid grid investments. Yet, the value of these deferred grid investments is highly uncertain and based on grid owners' risk profile. Further research could investigate the value of peak demand reduction in this sense, which is particularly relevant as the Norwegian transmission system operator has announced that it is challenging to build grids fast enough to incorporate new, electrified demand.

Dynamic grid tariffs are a natural development of static grid tariffs, as they consider coincidence between customer and system loads, adding another layer in the search for higher cost reflectivity. This search often comes at the cost of other important grid tariff design aspects, such as cost recovery, fairness and complexity. How to design dynamic grid tariffs with the optimal number of peak price hours, only targeting customers in capacity-scarce areas of the grid, remains an important research question. Differentiating number of peak price hours between customers seems natural as it is more cost reflective, but requires research on compensation mechanisms to avoid discrimination. The peak demand reduction potential of dynamic capacity tariffs, preferably considering price elasticity, also requires further investigation.

The presented coordination mechanism based on capacity trading in local electricity markets have significant advantages, but still requires testing under more realistic circumstances. A real-life implementation in a pilot project is a potential next step, including research on the impact of uncertainty in load, local renewable generation and availability of flexibility. The local electricity market is also likely to be operated by a third party, inviting further research on the structure of such a local electricity market.

In this thesis, the coordination benefits from local electricity markets were tested in combination with capacity subscription grid tariffs. This study could be extended to investigate a number of grid tariff designs, highlighting their impact on different grid levels. Further, the presented research suggests that local electricity markets may lead to more efficient price signals for consumers who want to invest in demand side management. Lastly, in local electricity markets, the liquidity in the market could be sub-optimal due to a small number of market participants, leading to potential risk of market power abuse. These effects could be investigated more thoroughly, focusing on detecting and prohibiting widespread market power abuse in emerging local electricity markets.

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Publications

Paper I

The paper **"Developments and challenges in local electricity markets: A comprehensive review"** is published in **IEEE Access**. The final published paper is reprinted here without changes in compliance with the CC-BY 4.0 license[1] it is published under.

Cite as:
S. Bjarghov, M. Löschenbrand, A.U.N. Ibn Saif, R. Alonso Pedrero, C. Pfeiffer, S. K. Khadem, M. Rabelhofer, F. Revheim and H. Farahmand
"Developments and challenges in local electricity markets: A comprehensive review"
Elsevier Energy Policy, vol. 9, p. 58910-58943, 2021.
DOI: 10.1109/ACCESS.2021.3071830
URL: https://doi.org/10.1109/ACCESS.2021.3071830

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Date of publication xxxx 00, 0000, date of current version xxxx 00, 0000.

Digital Object Identifier 10.1109/ACCESS.2017.DOI

Developments and Challenges in Local Electricity Markets: A Comprehensive Review

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This work is a result of the project "BEYOND - Blockchain-based ElectricitY trading for the integration Of National and Decentralized local markets" funded by the European Union and the Norwegian Research Council (grant number: 309182/E20). This paper was prepared as a part of the Digital Economy (DigEco) project funded by the NTNU Digital Transformation Initiative (p. nr. 2495996).

ABSTRACT In recent years, power systems have undergone changes in the landscape of generation and the definition of the associated stakeholders. With the increase in distributed renewable generation and small- to medium-sized consumers starting to actively participate on the supply side, a suitable incorporation of decentralized agents into the power system is required. A promising scheme to support this shift would be local electricity markets. These provide an opportunity to extend the liberal wholesale markets for electrical power found in Europe and the United States to the communal level. Compared to these more established markets, local energy markets neither have few practical implementations nor standardized frameworks. In order to classify the types of local electricity markets, the presented paper therefore starts with the challenges that these markets attempt to solve. This is then extended to an analysis of the theoretical and practical background with a focus on these derived challenges. The theoretical background is provided in the form of an introduction to state-of-the-art models and the associated literature, the practical background is provided in form of a summary of ongoing and recent projects on local electricity markets. As a result, this paper presents a foundation for future research and projects attempting to approach the here presented challenges in distribution of generation, integration of demand response, decentralization of markets and legal and social issues via local electricity markets.

INDEX TERMS Distributed Generation, Distribution Grid, Decentralized Markets, Local Electricity Markets, Peer-to-Peer, Smart Grid

Contents

I. INTRODUCTION

A. MOTIVATION AND CONTRIBUTIONS

The power sector is undergoing a transition driven by the integration of distributed energy resources and energy storage in order to electrify the other sectors, including transport, heat and industrial processes. Proliferation of grid automation and digital technologies has enabled the new design and operation of local electricity markets (LEM). These are nationally decentralized trading solutions that aim to connect consumers and generators that are in close spatial proximity.

They are a result of recent structural changes in power systems due to an increase in distributed energy resources. This comes as a result of drastic investment cost reductions in small-scale flexibility assets and production that has led to a decentralization of agents in the power system. These new agents primarily consist of or manage end-users whose aim is to invest in behind-the-meter local production for self-consumption, or use local flexibility in order to react to price signals.

The use of distributed energy resources can not only lead to more efficient energy use as the production is moved closer to the consumption, but also a lower carbon footprint than conventional power production from thermal plants. Active consumers who are able to produce electricity, also referred to as prosumers, are envisioned as a central and sustainable part of the energy transition of the European Union [1]. In addition, direct power system participation of smaller-scale prosumers, e.g. small businesses or households, has become a core focus of the European Union's electricity strategy [2]. However, for prosumer integration to happen fast enough to meet climate targets, price signals and subsequently market structure must be changed in order to correctly incentivize end-users to participate actively in the power system.

Such an integration could not only allow for an expansion of renewable generation, it would also provide opportunities for future grid planning and stability. As such, the European transmission system operator network ENTSO-E highlights distributed energy resources as key assets that must be made available for the distribution and transmission system operators (DSO/TSO) using active system management techniques to access the flexibility in the distribution grid [3].

However, an increasing number of agents in the distribution grid also results in a series of challenges for the system operators, as an essential part of dealing with increased distributed energy resources is integrating them into the power system without compromising the security or quality of supply. Challenges with frequency balancing, congestion management, bi-directional power flow and variable renewable generation are paired with technological, social and legislative challenges such as fairness and acceptance.

In order to embrace the widespread opportunities and challenges offered by local electricity markets, the power system operators require an assessment of the existing operational models and regulatory aspect. The primary goal of this paper is to perform a comprehensive review of the technical and regulatory challenges in the implementation and modeling of local electricity market structures, and provide possible solutions to overcome these challenges.

The summary of the provided meta-review of literature review papers presented in Table 1 shows that, aside from Ref. [4], literature reviews on local markets were performed with a focus on peer-to-peer (P2P) trading mechanisms. As a result, specific challenges for local electricity markets have been underrepresented in literature reviews. This is the gap this paper aims to fill. In addition, this paper aims to build on the discovered challenges of implementation and specifically address them within the analysis of the models and implementations it provides. In summary, the contributions of this work are the following:

- An in-depth analysis of the challenges of local electricity markets (not restricted to peer-to-peer trading).
- A state-of-the-art introduction on and review of mathematical models for local electricity markets.
- An extended overview of existing local electricity market projects and implementation technologies with a focus on the outlined challenges.

This stands in contrast to the P2P-focused literature studies. Projects and implementation of these sutides have been covered in Ref. [5]. This was expanded in Ref. [6] where an Information and Communication Technology (ICT) systems review was also performed. Ref. [7] focused on centralized and decentralized market designs, whereas Ref. [8] illuminated challenges related to architectures and power routing. Furthermore, Ref. [9] reviewed papers in the virtual layer, combining the aspects of market design comparison, architectures and ICT systems. Local P2P trading ICT systems and architectures were subject to review in Ref. [10] and Ref. [11], while an extensive survey of distributed optimization models of the power system was the focal point of [12].

The presented paper is organized as follows: an overview of local electricity markets is presented in this section. Challenges of such markets are addressed in Section II. A review of modeling approaches for local electricity markets and associated distribution grid problems follows in Section III, itself followed by an overview of existing projects and their implementation in Section IV. Concluding remarks and suggestions for future work are provided in Section V.

TABLE 1: Previous Literature Reviews on Local Electricity Markets and Related Topics

Reference	Scope	Focus
[5]	peer-to-peer (local & distributed)	projects & implementation
[6]	peer-to-peer (local & distributed)	ICT systems & implementation
[4]	local markets	market design comparison
[7]	peer-to-peer (local & distributed)	market design comparison
[8]	peer-to-peer (local & distributed)	challenges, architectures & power routing
[9]	peer-to-peer (local & distributed)	market design comparison, architectures & ICT systems
[10]	peer-to-peer (local)	ICT systems
[11]	peer-to-peer (local)	architectures & ICT systems
[12]	distributed optimization	models
this paper	local markets	challenges, models & implementation

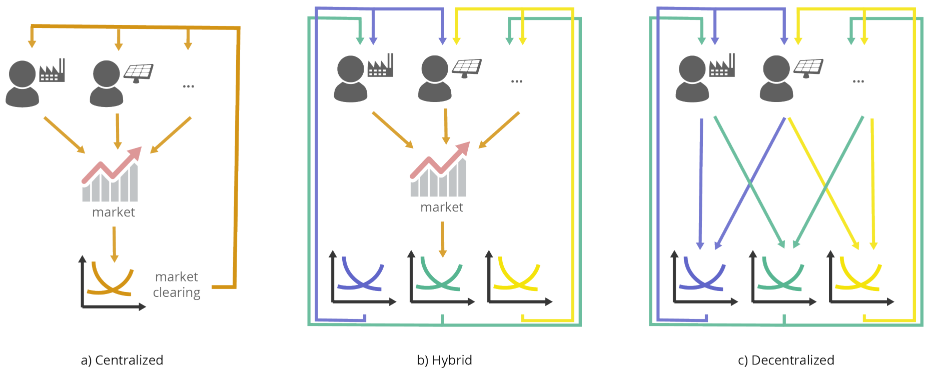


FIGURE 1: Local electricity market clearing topologies.

B. INTRODUCTION TO LOCAL ENERGY AND ELECTRICITY MARKETS

Traditionally, power systems involved a top-down approach where large-scale producers and (industry) consumers made upper-level decisions and small-scale producers and consumers were involved as reactive instead of active decision makers. An increase in distributed resources in both supply and demand, however, has led to a bottom-up revolution in the energy system [13]. In particular, renewable generation has been shown to have positive impacts on local communities, e.g. through supporting rural electrification [14], [15]. As this paper will illustrate later, distribution of such resources, however, will also lead to potential challenges. For example, planning uncertainty can increase and large-scale coordination can suffer.

As mentioned previously, in the context of distributed generation, local electricity markets are a tool to decentralize the coordination of participants in a grid, by unifying participants behind a common denominator - local electricity market prices. These market prices aim to facilitate local trade, or in other words, prioritize the exchange of energy resources in smaller spatial distances over larger distances.

These local electricity markets are closely related to the empowerment of the end-consumer of electricity, and thus the formation of local energy communities. The main objectives of participants in local energy trading can be defined as a reduction of energy costs, gaining (at least partial) independence from utility companies and/or protection of the environment [16]. The participation in such markets also has the potential to raise local energy production and to create jobs and stimulate economic growth in the region [17], which can be additional motivational factors. As outlined in Ref. [18], distributed investments into local generation are essential for the large-scale integration of renewable generation within power systems under liberalized markets and local electricity markets are a tool to support such issues. This is also shown in Article 16 of the “Clean Energy for all Europeans” package of the European Union which projects energy communities, and thus small-scale financial entities, to account for 17% of installed wind capacity and 21% of solar capacity by 2030 [19]. Furthermore, even though the characteristics of local electricity markets lie in bottom-up, i.e. grassroots, initiatives with consumer empowerment as a core pillar [20] a European Commission review of 72 EU projects related to local energy communities [21] concludes that DSOs have a central role in the development and operation of local electricity markets. Ref. [22] further postulates that DSO-TSO cooperation also plays a central role in the coordination of local electricity markets in the power system. However, and similar to wholesale markets, a single, local electricity market design does not exist.

Conceptually speaking, the interaction of agents can be separated into either peer-to-peer (directly, from participant to participant) or pool-trading (indirectly, via the aggregate of the market), with latter being the norm in implementations of wholesale markets on electricity [23].

Ref. [24] structures the different participants of local electricity markets in their interaction with the grid as peer-to-peer, participant-to-microgrid, participant-to-pool.

In terms of their market-side interactions, however, there are three distinct topologies that we identify based on the literature presented below in this paper as shown in Figure 1:

- Pool market trading (centralized)
- Hybrid market where peer-to-peer trading can be initiated via an exchange
- Full peer-to-peer trading with bilateral trades only

In terms of literature we can see a clear focus on papers discussing local electricity markets via exchange-traded/auctioned peer-to-peer, but can also find various examples of the other types.

In similar manner to market topology and nesting in the grid, there is also the discussion of integration into higher-level markets and the role of local electricity markets within the national market biome. This ranges from a consideration of local electricity markets as micro-grids to models of multi-market frameworks that consider hedging between markets and legal aspects of implementation via virtual power plants and balancing entities. Selection of an appropriate design is thus not a straight-forward but instead a multi-factor decision, as shown in the discussion of real projects in Section IV of this paper.

Therefore, this paper starts by introducing the potential challenges that local electricity markets might face before giving an overview of the models utilized to tackle these challenges in Section II.

II. CHALLENGES OF LOCAL ELECTRICITY MARKETS

Compared to traditional markets that usually manage large pools of participants over wide areas, local electricity markets usually show smaller pools of participants. In the electricity grid, traditional markets operate on a transmission grid level, whereas local electricity markets operate on a distribution grid level. The necessary consideration of reactive energy in the latter leads to non-linearity of the AC grid problem that requires consideration in the market model [25]. In traditional wholesale markets, these constraints are implemented via linearized DC approximations [26], leading to less complexity in the analyzed grid.

Thus, even though generally showing a smaller number of participants compared to traditional markets, local electricity markets encounter several unique challenges in fulfilling their purposes. These **purposes** of local electricity markets can be defined as the following [27]:

- Balance local demand to match intermittent supply.
- Manage congestion and transmission/distribution constraints.
- Support financial management of participants that takes into account location and network needs.
- Replace/postpone grid investments with utilization of local flexibility.

As discussed above, the **challenges** associated with local electricity markets and their implementation deviate from traditional liberalized power markets which do not need to consider the grid with such fine detail. As a result, challenges of local electricity markets are interlinked with the challenges of optimal operations of distribution grids [28]:

- Structural and cultural differences make general application of one single solution to various national grids difficult or impossible.
- Changes in power systems (more intermittent generation and more demand elasticity) might change the role of generators from a passive entity reacting to consumption to a more active role. This might increase the requirement for further grid tariffs for generators,
- Inefficient operation of storage (from a grid perspective) could lead to additional distribution cost.d
- Cost-reflective distribution grids are essential for the success of integration of electric vehicles, especially charging stations.

TABLE 2: Challenges of Local Markets

Challenge	Tag	Source
Changes in line losses	A	[29], [30]
Changes in voltage levels	A	[29], [30]
Changes in power quality	A	[29], [30]
Changes in fault current levels	A	[29], [30]
Changes in requirements for protection systems	A	[29], [30]
Potential reduction in system reliability	A	[29], [30]
Lack of studies on system loadability and voltage security under distributed generation	A	[31]
Risk of increasing electricity cost	A C D E	[32]–[35]
Potential waste of resources	A	[32]
Less choice of supply	A	[32]
Negative environmental effects	A	[32]
Increase of computational complexity	A B	[36]–[39]
Non-unified, location-dependent incentives process could impede investments	A	[40], [41]

Challenge	Tag	Source
No "all-in-one" solution for stakeholder incentives	A B D E	[17], [40]–[47]
Distributed generation is more susceptible to structural, regulatory, social and technical changes than centralized generation	A	[48]
Requirement of coordination and potential of resulting conflicts	A C	[49]–[53]
Similar tariffs might lead to different outcomes locally	A B D	[33], [43], [44], [54]
Forecasts of individuals are more error-prone than forecast of aggregates	B	[55], [56]
Correlation of behavior and subsequent control issues due to wrong (price) signals	B	[57], [58]
Different tariffs in different parts of the distribution grid can lead to transmission system issues	B	[42]
Requirement of real-time control	B C	[59], [60]
Requirement to upgrade existing meters and software for energy flow management	B C D	[11], [61]–[63]
Requirements for multi-period models brings threat of computational intractability	B	[64], [65]
No "all-in-one" solution for all types of demand response	B	[56]
Entrance barriers might be too high for voluntary participants	B	[66]
Response to price signal might vary depending on the individual	B	[67], [68]
Requirement for new consumer-centric/prosumer-centric algorithmic solutions on trading and optimization	C E	[5], [11], [17], [47], [69]–[73]
Fairness for all market participants in terms of, e.g., equal benefit, consumer roles and rights, access, energy sharing due to size differences, distribution of taxes and fees	C D E	[5], [11], [33], [44]–[46], [71]

Challenge	Tag	Source
Real-time markets may lead to lower energy prices, price volatility, uncertainty amongst consumers and imbalances of demand and supply	C	[74], [75]
Changes of traditional roles and responsibilities, market-structural factors such as cost and risks, product definitions and communication of demand-side effects	C	[11], [76]
Markets are required to be robust to systemic changes such as carbon prices, feed-in-tariffs for renewables, etc.	C	[77]
Data security, privacy, access and responsibilities	C D E	[11], [17], [44], [47], [52], [53], [61], [62], [70], [71], [78]–[81]
Scalability issues of communication devices	C	[4], [11], [53], [70], [82]
Metering without a centralized authority needs to be reliable and trusted	C E	[53], [71]
Data storage infrastructure and management	C	[53]
Addressing of different consumer objectives, such as profit maximization, decarbonization or supply security	C E	[11], [16]
Relationships within local markets as well as between existing markets, and other emerging entities remain unclear	C D E	[4], [43], [44], [47]
Interoperability between communication technologies	C	[4], [53], [62]
Rigid energy market regulations	D	[7], [33], [43], [83], [84]
Need to protect elderly, socially disadvantaged, and price sensitive customers	D E	[16], [44], [53]

Challenge	Tag	Source
Enforcement of law, as digital contracts may not be appropriately regulated	D	[62]
Legal integration into the legal framework for distribution and transmission networks	D	[33]
Stakeholders in current market framework might lobby against changes	D	[85]
Encouragement of participation	E	[45], [46], [71]
Dealing with conflicting stakeholder interests, expectations and preferences	E	[5], [16], [17], [71]–[73]

Another important aspect is that achieving the large-scale implementation of such markets and fulfilling the main goals of optimizing grid operation (and thus fulfilling sub goals such as reducing CO2 emissions) also requires adequate remuneration of the involved stakeholders (ranging from end consumers and prosumers to grid operators and traditional large-scale generators). Neglecting either of these aspects in the design could lead to a potential disparity between the goals of local electricity markets and the policies utilized to implement them [86].

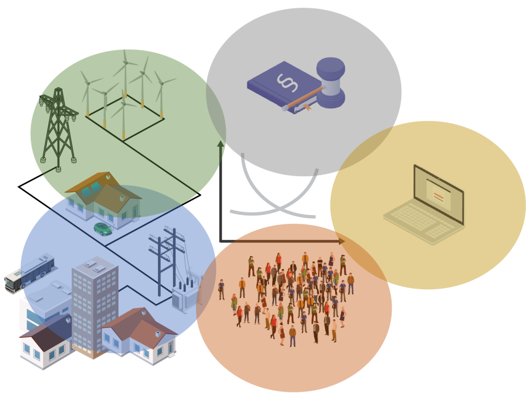


FIGURE 2: Identified main challenges

Based on this, the crucial challenges for successfully establishing and operating local electricity markets in Figure 2 and Table 2 were formulated. These will subsequently be expanded upon below.

A. DISTRIBUTION OF GENERATION

One goal of implementing local electricity markets is to enable distribution of generation. This means installing, generally smaller, capacities in a larger number of locations in the grid. The goal is to better utilize local resources (e.g. available wind and solar capacities) and decrease distribution and transmission cost.

Specifically, Ref. [32] lists several goals of distributed generation:

1. liberalization of electricity markets
1.1. peak shaving
1.2. reliability and power quality support
1.3. substitution of transmission and distribution capacities
1.4. ancillary service support
2. environmental concerns
2.1. combined heat and power generation
2.2. efficient use of cheaper generation forms

Enforcing such a distribution of generation has a variety on impacts on the operation of the grid. Ref. [29] and subsequently Ref. [30] categorize them as changes in line losses, changes in voltage levels, changes in power quality (voltage flicker and harmonics), changes in fault current levels, changes in requirements of protection systems and a potential reduction in system reliability.

In regards to these technical constraints, system loadability and voltage security have been underrepresented in studies regarding distributed generation [31].

As mentioned in Ref. [32], distributing generation can further pose several structural challenges. One of these is that distributed generation shows a higher per kW price than localized generation. In general, wasting resources due to localized economic inefficiency is a challenge in the distribution of generation. In addition, energy security could be threatened due to lower diversification of generation resources. Furthermore, power quality can be negatively affected in various ways such as system frequency effects due to household appliances and changes in power flows from the different grid levels (traditionally, the flow is unidirectional from transmission to distribution grid, but with decentralized generation this flow would be bidirectional and changing continuously). In addition to these general problems of all forms of decentralized generation, Ref. [32] also illustrates challenges that could be imposed by a decentralization of specifically thermal generation: less supply choices of primary fuel sources and thus potential negative environmental impacts.

As described in Ref. [36], distributing such generation thus requires adequate locational price/cost signals such as locational network and energy prices. These should remunerate the balancing/grid-responsible parties whilst fulfilling the fairness principles of deregulated markets. Applied in practical settings, implementation of such locational signals can however lead to a dramatic increase in computational complexity [37]. This is especially important considering multi-energy systems which could further amplify this computational complexity on a local level [38].

Furthermore, varying localized "soft cost" such as permission/inspection/interconnection cost can distort installation incentives and lead to generation capacities being installed in sup-optimal locations [40]. As further discussed in Ref. [41], these wrong incentives might even impede installation of beneficial local capacity. This also shows a larger problem with distributed generation - it is susceptible to external effects, not only through regulatory or political factors but also through behavioristic or technological factors [48]. On an aggregated, national level these changes might have a less severe impact than on the local level.

In combination with demand response, distributed generation can also offer potential for local coordination and offer congestion relief [49]. Issues in coordination would thus lead to congestion issues in systems that are designed on the premise of this form of congestion relief. This is also shown in Ref. [50], which analyzes a number of European projects on decentralized generation, of which all consider demand response via local households at least to a certain degree.

A trait similarly shared with demand response is the question of adequate remuneration of the grid providers, which mostly comes in the form of tariffs. The impact of these tariffs can vary locally and lead to distortion of investments in capacities [54].

B. INTEGRATION OF DEMAND RESPONSE

Similar to distributed generation, i.e. the supply side, the demand side can also be affected by a smaller pool of participants. As such, forecasts of individual demand sources can be error-prone, thus localized markets should allow for a certain degree of aggregation [55]. This is especially important considering that end-consumers can be vastly inhomogeneous, further amplifying this error [56].

In contrast to this, large-scale aggregation can also lead to a loss of accuracy in terms of control. Particularly on transmission grid levels, centralized price signals can lead to control issues on the distribution grid level, especially considering the control of deferrable loads. For example, Ref. [57] illustrates how centralized price signals lead to correlated behavior in electrical vehicles. Another example is provided by Ref. [58] that shows how central price signals cause synchronization of water heater startups and thus lead to load kickbacks. In a local electricity market, these effects also have to be considered as well when aggregating demand response.

Utilizing price signals dependent on time or special incentives (i.e. tariffs) is a common tool to implement decentralized price signals. However, different rules in various distribution grids can lead to coordination problems within the transmission grids [42].

Furthermore, considering demand response effects of residential appliances in an appropriate manner requires methods to utilize algorithms capable of performing real-time control [59]. Therefore, local electricity markets have to be designed with operational speed in mind. This is a challenge that stands in conflict with the goal of appropriately modeling the non-linearities of AC power flows, which usually leads to higher computational complexity. This problem is amplified by models considering storage units and/or electric vehicles requiring multi-period-optimization, thus further increasing the complexity of those problems [39]. This problem is particularly highlighted by Ref. [64] that illustrates how utilities under storage (specifically electric vehicles, local batteries or storage heaters) show the highest financial benefits. However, such problems are computationally highly intractable and could therefore lead to problems finding global optima and thus the most beneficial outcomes [65].

This problem of computational complexity is further amplified by the fact that different forms of demand response require different measures. Ref. [56] illustrates this and shows, for example, how time of use pricing can support storable loads but curtailable loads require dynamic load capping.

Such complexity can also affect the demand response providers (i.e. consumers/prosumers). Under voluntary participation the need for additional investments into technology and the variations caused by intermittent renewable generation might lead to complications that might provide too high an entrance barrier for voluntary participants [66].

Another factor is the behavioristic component of demand response. For example, users can show different price responses [67]. Again, in systems with fewer participants such as local electricity markets these effects could be amplified over the aggregated wholesale markets. This is especially challenging consideringthat wrong assumptions and thus wrong incentives set by the demand response manager (e.g. the local electricity market provider) could lead to adverse effects and push demand response providers towards behavior contrary to the desired goals [68].

C. DECENTRALIZATION OF MARKETS

Designing functional local electricity markets does not only require coping with the previous requirements on computational complexity and modeling the specific components in appropriate manner, but also requires functional interaction of these components. Key components of a local electricity market are the microgrid setup, the grid connection, the ICT system, the market and pricing mechanism, the energy management trading systems and the regulation behind them. To what extent these components are fulfilled depends on the roles market participants take and how they execute them [87].

Because of the computational complexity of such markets, advanced trading algorithms are required to manage and coordinate the conduction of both trading and demand response [69]. According to Ref. [47], trading schemes can only be considered successful if they supply at least 50% of people's energy needs for the duration of implementation.

Furthermore, a two-way communication infrastructure requires an ambitious architecture with several market layers [11], [70]. The implementation of such an infrastructure comes with high investment costs, which can be a deterrent for the development of local electricity markets. Additionally, transaction fees for such an infrastructure may provide an extra cost in the case of adopting certain ICT technologies [11], [53], [61]–[63], [70]. In addition to this, there is also a need for appropriate schemes for the distribution of taxes and fees for local energy trading [44]. The question arises whether taxes or fees should still to be covered by the supplier or rather by the energy community itself. This also incorporates the risk of increasing marginal cost, i.e. additional cost per kWh sold [33], [34].

Similar to the real-time issues with demand response, the markets themselves have real-time components. This comes as a result of traditional electricity markets showing a larger pool of participants, allowing for variable but pre-announced prices, which is not possible in local electricity markets [60]. Trading in local electricity markets usually takes place in smaller timeframes. Interactions are thus either in a day-ahead timescale (1-hour intervals) or in real-time (5- to 15-minute intervals). Real-time markets may provide a lower average price of energy which can make it more attractive compared to day-ahead models. However, real-time processing leads to a higher volatility in prices [74]. This could cause uncertainty for consumers. Non-volatile prices in real-time markets lead to an imbalance of demand and supply as naturally the demand for energy increases if the price is low [75].

As Ref. [76] discusses, establishing markets also requires a degree of standardization that could deviate from the real grid topology and situation. The paper specifically mentions the following crucial aspects: roles and responsibilities, market-structural factors such as cost and risks, product definitions and communication of demand-side aspects. Local electricity market design should be general enough to support a wide variety of real-life systems on these aspects. In addition, the markets need to be designed to be adjustable enough to support interaction with policy makers. This means that operation of markets needs to be robust to the introduction of carbon pricing, feed-in tariffs for renewable energy, regulation and subsidies [77].

Effective coordination between TSOs and DSOs is of importance for the stability of the grid and should thus be a core aspect of market decentralization. Examples of challenges in this area are the sharing of measurements and forecasts, coordination under emergency situations, coordinated power quality support and coordination of balancing services [51], [53]. Design of local electricity markets has to support those mechanisms, but also aim to keep the privacy of the involved private parties and thus reduce the unnecessary sharing of information. Sharing this information also requires appropriate systems that allow for the coordination of the decentralized, independent systems that local electricity markets entail [52].

These systems have to support data security in order to support the functionality of, and ensure trust in the market. According to Ref. [79], potential threats include impersonation, data manipulation, eavesdropping, privacy breaches, disputes and denial-of-service. Appropriate privacy and security measures have to ensure a reduction in the risk of these threats to a level that allows reliable operation of the local electricity markets and the distribution grids behind them. In relation to this, the required two-way communication network also raises questions of such privacy and security, i.e. responsibilities and data access, to avoid issues caused by non-transparent energy markets. In particular, security vulnerabilities may include submission of fake contracts, double spending of energy or money, modification of transactions and denial-of-service attacks on the system [61], [78].

A central component of local electricity markets is thus a sophisticated ICT infrastructure that ensures this security whilst establishing transparency and connection points for the market participants. This can be technically challenging to implement for an increasing number of participants, in particular in centralized local electricity market structures [4], [11], [53], [70], [82]. Implementation of a control and trading system requires several key features. Latency in emergency cases, the probability of delivering the information in a given deadline, the capability of the system to combat ambient conditions or the scalability of the network are some of them [53], [88]. In relation to security, smart meter validity is necessary to ensure trust in the market as these are the providers of the input data from participants [53]. Moreover, local electricity markets may require big-data storage applications. Deciding how the data is stored and who owns it can be a challenge in itself [53].

Centralized markets (as shown in Figure 1) pursue a single objective, e.g. mutual economic benefit and profit maximization, reduction and minimization of energy generation, consumption or cost, minimization of greenhouse gas emissions, system efficiency, reliability, stability and congestion management improvement, system loss reduction, minimization of voltage and frequency deviations, supply security for each participant, and maximization of social welfare. Thus, they are not ideal to implement in local electricity markets with a heterogeneous nature in which the participants' objectives deviate strongly from each other. In addition the previously mentioned cyber-attacks could be potentially more damaging in centralized topologies, due to the collection of data on one central platform. Moreover, the influence of large members in the market could lead to an unfair and biased energy sharing [11].

In decentralized markets (as shown in Figure 1), the uncoordinated interaction could lead to a competition amongst the participants which causes price imbalances and market inefficiencies [11]. In addition to the interaction within the local electricity market itself, the interaction with existing energy markets is essential in order to implement local electricity markets. According to Ref. [5] and [4], this interaction deserves further attention in future literature. The interoperability between the technologies deployed throughout the energy sector is highlighted by [62] as fundamental to allow this interaction and it may suppose a crucial factor to consider during the design and adoption of the ICT system. The interoperability may refer to both the development of new communication standards between, for example, different blockchain protocols, as well as to the interaction of different systems or techniques. In addition, the adoption of hardware must be compatible with the ICT layer deployed [53].

D. LEGAL FRAMEWORK OF IMPLEMENTATION

EU Directive 2019/944 [2] allows consumers to unite as "citizen energy communities" and exchange energy on a local level. This directive authorizes member states to allow citizen energy communities to act as distribution system operators either under the general scheme or as "closed distribution system operators". The provisions of this directive on citizen energy communities only clarify those aspects of distribution system operation that are likely to be relevant for citizen energy communities.

However, due to the still restrictive regulations of the energy market and the more recently published directive, business models for energy sharing via local electricity markets are still very rarely put into commercial practice [83].

Similar to the previously discussed demand response in Section II-B, no "one-size-fits-all" solutions can be established in respect to local energy trading [43]. As a result, the provisions adopted in the current EU directive [2] remain relatively open to interpretation. Although the role and responsibility of prosumers and local electricity markets is to a large extent clarified by this directive, further demand for regulatory clarification remains. The Council of European Energy Regulators [33] argues that existing market principles such as unbundling, consumer rights or cost-sharing principles applicable to energy networks could theoretically be circumvented by the introduction of citizen energy communities.

Given that local electricity trading predominantly takes place in local electricity markets, integration into national law on grid regulation will be crucial in order to enable local electricity markets within energy communities [7], [33], [84].

Moreover, specification of market design concepts is crucial in terms of establishing the legal framework. As such, appropriate incentives for flexibility have to be elaborated on [43], [44]. As already discussed in Section II-A and Section II-B, these incentives can be conflicting.

By EU regulation [2], smart consumption and production meters must be able to communicate supply-demand load matching within short time steps in order to identify conditions for self-consumption and assign an energy value for billing purposes. According to the previously discussed challenges in demand response (Section II-B) and market decentralization (Section II-C), local electricity markets may require upgrades to existing meters and software for managing the flow of electricity. Thus, regulations need to clarify who is responsible for such upgrades [61], [78].

Hence, the protection of vulnerable, i.e. elderly, socially disadvantaged, and price-sensitive [53] consumers in the context of local energy trading remains a somewhat challenging task [44]. As Energy Communities can link production and supply more closely, it is necessary to maintain the same consumer rights for participants in energy communities. Discrimination should be prevented, thus ensuring democratization of energy [5]. Consequently, consumers can neither be forced, nor prevented from joining an energy community as long as they meet the technical requirements. They have to be authorized to choose or change their supplier at will and to be informed accordingly about the conditions of supply. In particular, active consumers should be aware that they are responsible for their imbalances stated in Section II-A and Section II-B [33], [43], [44].

In the case of decentralized local electricity markets, the enforcement of law if a promised energy service is not delivered can pose a challenge as digital contracts (e.g. smart contracts) may not be appropriately regulated [62]. In line with the challenges mentioned in Section II-C, the adopted ICT must ensure data portability, an appropriate quality of service, and data protection for customers must be ensured. Other market players must not be disadvantaged under any circumstances [11], [33], [44], [62], [70], [80]. The current legislative environment might also limit the integration of technologies that do not provide sufficient flexibility (e.g. permissionless blockchains), as they might not provide flexibility to manipulate private data [62].

Furthermore, the given regulatory framework can significantly limit the profitability of local trading. There are two ways to implement the proposed market concepts: Either the regulation must be fundamentally changed so that the specific assumptions of the proposed concepts can be implemented, or the market concept must be adapted so that it fits into the regulatory framework. Changes in the regulatory framework carry the risk that pure electricity consumers have to bear higher expenses due to increased self-consumption rates. This has the result that in most models, the total fixed grid costs are distributed amongst lower grid consumption, which primarily affects pure consumers [35].

Member states are free to allow Energy Communities to own the grid infrastructure itself. In such a case, an appropriate legal integration into the legal framework for distribution and transmission networks has to be ensured [33].

Another potential challenge to the implementation of decentralization in the electricity grid is shown in Ref. [85] which outlines that stakeholders profiting from existing regulatory implementation barriers could be incentivized to use their lobbying powers to uphold the status quo in order to maintain their current business models.

As mentioned above, there are further challenges concerning the relationship between local electricity markets, existing electricity markets, and other emerging entities such as DSO [43], [44]. Fundamentally, the reorganization of the highly regulated energy industry is a challenging task. To disrupt the status quo, results from a wide range of implemented case studies from around the world are required [83].

E. SOCIAL ASPECTS

The main system design challenge in local electricity markets is to develop schemes and business models that encourage participants to contribute and trade energy with one another [45], [46], [71]. In order to motivate people to participate in a local energy trading paradigm, various social and behavioral aspects must be taken into account. On the one hand these include people's values, opinions and emotions. [16]. On the other hand interests and expectations also need to be considered [46], [73]. These may differ and conflict with each other. Similarly, they can also differ within the groups of prosumers and consumers themselves. As people's willingness to participate depends on these aspects, the design and implementation of new local energy trading schemes and business models discussed in Section II-C has to be consumer- as well as prosumer-centric and take into account both groups' interests and expectations [5], [17], [46], [71], [72]. The heterogeneity of prosumers' preferences must also be taken into account [72]. Although different preferences should be separately considered, heterogeneous prosumer preferences do not automatically have to differ regarding common objectives at the local energy exchange [16].

For both prosumers as well as consumers, cost factors play a major role. Economic benefit is considered the primary motivation for participation in a local energy exchange [17], [73]. This is also reflected in the fact that the relevance of locally generated energy seems to appear insignificant if it incurs higher costs for the users [17]. As described in Section II-D, payment procedures need to be secure and easily manageable in order to be accepted by the public [73].

Besides economic growth, additional incentive values for participation in local energy trading need to be defined [17] such as providing equal benefits to all prosumers [45]. Participation has to be rewarded at any time regardless of whether the participant acts solely as a buyer or in addition as a seller [46]. Moreover, consumers are by definition less engaged than prosumers as their interaction is unidirectional instead of bidirectional. For most prosumers, autonomy, personal and business image play a more significant role than consumptional needs. For consumers, this is not the case [73]. Local energy trading necessitates the prosumers relying on each other for trading electricity. Without a centralized authority the trust between users and their trust in the technology needs to be constantly maintained. Aside from guaranteeing users' security and privacy, discrimination needs to be avoided and equal access for all users needs to be enabled [71].

Further findings show that people are more likely to participate in localized trading schemes that operate at the region/city level and that involve their local council. Project framing needs to emphasize anonymity of consumer data [47]. The selection of an appropriate data-management technology will determine the level of anonymity of the participants. Insufficient data management can be a drawback for businesses due to commercially sensitive data [53]. Public blockchains offer pseudonyms and limit the possibility of analyzing the identity behind the addresses [89]. However, this may also contradict the common way that DSOs deal with distribution grids, where customers are identified and physical entities - people - are responsible for energy consumption [53], [62].

TABLE 3: Overview of challenges addressed in the model approach literature.

Source	**Addressed Challenge**				
	A	**B**	**C**	**D**	**E**
[90]	x	x	x		
[69]	x	x	x		x
[91]	x	x	x		
[92]	x	x	x		
[93]	x	x	x		
[94]	x	x	x	x	
[95]	x		x		
[60]		x			
[96]	x		x		
[97]					x
[98]		x			
[99]	x	x	x		
[100]	x		x	x	
[101]	x	x	x		
[102]	x	x	x	x	
[46]	x	x	x		x
[103]	x	x	x		
[104]	x		x		
[105]			x		
[106]	x	x			
[107]	x		x		
[108]	x	x	x		
[109]		x	x		
[110]	x	x	x		
[111]	x	x	x		
[112]	x	x	x		
[113]		x	x		
[114]			x		
[115]	x	x	x	x	
[116]		x	x	x	
[117]	x	x		x	
[118]		x		x	x

Source	Addressed Challenge				
	A	B	C	D	E
[119]	x	x	x	x	
[120]	x	x	x	x	
[121]			x		
[122]					x
[80]	x	x	x		x
[123]	x		x		
[124]			x		
[125]	x		x		
[45]			x		x
[126]	x		x		
[127]			x		
[128]		x	x		
[129]	x	x	x		
[130]	x		x		
[115]	x		x		
[131]	x		x		
[132]	x	x			
[133]	x	x			

Nomenclature

Indexes	
i	generation/demand unit
b	bus
j	market participant
t	period
Variables	
P	active power
Q	reactive power
δ	voltage angles
V	voltage magnitude
x	market participant decision
y	market clearing decision
λ	inequality constraint dual variable
μ	equality constraint dual variable
S	storage state
Functions	
C	generation cost/consumption utility function
C'	purchase cost/sales profit function
P^B	bus injection
P^L	line load
MC	market clearing function
H	inequality grid constraints
G	equality grid constraints
$\mathcal{Q}$	Lagrangian relaxation
Sets	
I	generation/demand units
Additional notation	
$\underline{\cdot}$	lower limits
$\bar{\cdot}$	upper limits

III. MODELING APPROACHES

This chapter explains the most common models of local electricity markets with a focus on the introduced challenges. The reviewed literature is related to grid representation, decentralization of markets, cooperative/competitive games, distributed control, demand response, uncertainty and related technologies. The considered papers and their relation to particular challenges are shown in Table 3.

A. GRID REPRESENTATION

In its simplest form, the operational problem within the grid is to match demand and supply under minimization of cost, whilst enforcing line limits:

$$\max_{P} \sum_{i \in I} C_i^d(P_i) - C_i^g(P_i) \tag{1a}$$

$$\text{s.t.} \quad \underline{P}_i \leq P_i \leq \bar{P}_i \quad \forall i \tag{1b}$$

In problem (2) the objective shown in (1a) is to maximize system welfare by adjusting active power under a (most often convex) cost function. The limits of the active power are provided in (2b). In traditional optimal power flow (OPF) problems, demand is considered as inelastic, i.e. $\underline{P}_i = \bar{P}_i$ for a demand unit i. In this case, the utility function of such demand units is not considered in the objective, leading to $C_i^d(P_i) = 0$ and the objective being a traditional generation cost minimization problem. In local electricity markets however, utilizing demand response could be achieved via a utility function (i.e. a negative cost function). Consumption would then be represented via negative limits on the active power, i.e. lower limits of $\underline{P}_i < 0$ and upper limits of $\bar{P}_i \leq 0$. A prosumer could then be implemented either via splitting the unit up into an individual consumer or producer, or allowing negative lower limits and positive upper limits with an adequate cost function. This problem is convex if the cost function is convex.

One of the key goals of local electricity markets is the alleviation of challenges within the power grid, specifically low-voltage grids. As such, most models that implement and/or analyze local electricity markets consider a form of (distribution) grid, are mostly implemented as an OPF problem.

A popular form of such an OPF is provided by the DC OPF representation, where voltage magnitudes are approximated to one, and reactive power and transmission losses are neglected. This is a common representation in transmission grid problems.

$$\min_{P,\delta} \sum_{i \in I} C_i(P_i) \tag{2a}$$

$$\text{s.t.} \quad \underline{P}_i \leq P_i \leq \bar{P}_i \quad \forall i \tag{2b}$$

$$P_b^B(\delta_b) = \sum_{i \in I_b} P_i \quad \forall b \tag{2c}$$

$$\underline{P}_{b_1,b_2}^L \leq P_{b_1,b_2}^L(\delta_{b_1}, \delta_{b_2}) \leq \bar{P}_{b_1,b_2}^L \quad \forall b_1, b_2 \tag{2d}$$

The objective of this optimization problem, shown in (2a), is, as in (1a), maximizing system welfare, as well as incorporating voltage angles. In addition to the previous constraint on active power limits it also considers Kirchhoff's equations. The balance within a bus b is enforced by (2c) and the line flow limits are enforced by (2d). In this problem, both bus balance P^B and line balance P^L are kept as convex functions.

The shown DC OPF is also often referred to as DC approximation, due to it being an approximation of the AC reality, which does not consider additional grid aspects such as reactive loads, line resistance and voltage magnitudes. The convexity of problem (2) makes such as DC approximation of the OPF problem a popular choice. Moreover, the DC OPF problem represents a linearization of the nonlinear AC OPF problem. The linearity and convexity have led to the DC OPF being the basis for most literature on power markets considering the grid, as they make finding the equilibrium points a tractable problem and are thus able to ensure fairness. A solution to a non-linear and non-convex problem is by definition a local solution, meaning that it cannot be ensured that it is the optimal point for all participants.

As previously mentioned, local electricity markets specifically aim to solve problems in low voltage grids, which would require incorporation of the same model components that lead to non-convexities in the power flow equations. Some papers solve this dilemma by decoupling the market clearing problem from the power flow problem and solving both separately, with others accepting this decoupling of the problem as a premise and not incorporating power flow equations into their model at all. However, some literature sources still rely on a form of AC OPF:

$$\min_{P,Q,\delta,V} \sum_{i\in I} C_i(P_i) \tag{3a}$$

$$\text{s.t.} \quad \underline{P}_i \le P_i \le \bar{P}_i \quad \forall i \tag{3b}$$

$$\underline{Q}_i \le Q_i \le \bar{Q}_i \quad \forall i \tag{3c}$$

$$\underline{\delta}_b \le \delta_b \le \bar{\delta}_b \quad \forall b \tag{3d}$$

$$\underline{V}_b \le V_b \le \bar{V}_b \quad \forall b \tag{3e}$$

$$P_b^B(V_b,\delta_b) = \sum_{i\in I_b} P_i \quad \forall b \tag{3f}$$

$$Q_b^B(V_b,\delta_b) = \sum_{i\in I_b} Q_i \quad \forall b \tag{3g}$$

The optimization problem now has two additional decision variables - the voltage magnitude and the reactive power. All of the four decision variables have their respective limits enforced via (3b) to (3e). Kirchhoff's equations are represented via the bus balance constraints for active power in (3f) and (3g) respectively. These AC power flow equations are the contributors of the non-convexity of the AC OPF problem, as they usually depend on a sine/cosine formulation of the voltage angles. Further information on variations of power flow equations and the optimal power flow can be found in the more comprehensive study provided in Ref. [134]. These include, for example, formulations considering storage or uncertainty, which are both aspects that play considerable roles in local electricity market models.

The non-convexities in this problem lead to solutions being local instead of global, meaning that it cannot be ensured that a found solution is actually welfare-optimal. This is a problem that has led to adequate pricing issues in examples such as AC locational marginal prices [37], and is a significant hurdle in terms of fair remuneration.

Thus, when disregarding the type of non-convex AC OPF problem, most of the papers utilize a form of convex approximation of the AC OPF, with the previously introduced DC power flow approximation or the second-order conic relaxation [135] as popular examples. The reason for this is that a non-convex representation stands in direct contrast to fairness. This results in many of the main technical/computational challenges of solving real grid problems, discussed in Section II, contradicting the main social challenge of fair distribution of resources. This will be further discussed in the subsequent subsection on market clearing, using the more general notation of H and G as a representation of the chosen grid constraints.

Local electricity markets empower investments in renewable generation and flexibility in the distribution grid, but also impose new challenges with respect to quality of supply onto the DSO. Peer-to-peer trading and local electricity markets have received significant attention in state-of-the-art research, using mathematical models to ensure fairness, market efficiency and incentives for DER. After a market is cleared and transactions are established in the financial (virtual) layer, its effect will be imposed on the physical layer. An important next step is to incorporate grid challenges into the mathematical formulation, either directly or indirectly, ensuring that the imposed impact on the physical layer is feasible and does not cause further issues, as presented in Section II.

The literature discussing grid challenges related to local electricity markets is shown in Table 4. In addition, the sources are presented below.

1) Literature, focus: power flow

Modeling the AC-PF problem or parts of it has been performed in a series of studies. It should be noted that, unlike the AC OPF problem, the AC power flow (AC-PF) problem does not attempt to optimally dispatch distributed energy resources, but analyses the distribution grid impact of the market clearing decisions. An approach for the DSO to access flexibility through a local electricity market is suggested in Ref. [113]. This model clears the local electricity market and runs an AC-PF of the instance to check for congestion issues. The aggregator is then responsible for finding a new dispatch in the local electricity market. In Ref. [92], an auction-based local peer-to-peer market clearing with post clearing analysis of a low voltage network is suggested. The analysis focuses on investigating network problems that a financially attractive peer-to-peer market can introduce. Simulations performed on a low-voltage network

TABLE 4: Papers considering grid related challenges.

Paper	AC PF	DC PF	Congestions	Voltages	Tariffs	Policy
[90]	x		x	x		
[69]					x	x
[91]	x		x	x		
[92]	x		x	x		
[93]	x		x	x	x	
[94]	x		x	x		
[95]	x		x	x	x	
[60]		x	x	x		
[99]		x	x	x		x
[102]			x			x
[104]	x		x	x		
[105]		x	x			
[106]		x	x			
[107]		x	x			
[109]		x	x			
[112]			x		x	x
[113]	x		x	x		
[114]	x		x	x		
[116]		x	x		x	
[117]			x		x	
[118]			x		x	x
[119]			x		x	x
[80]		x	x			
[125]	x			x		
[126]	x		x	x		
[130]	x			x		
[131]	x		x	x		

show that voltage limits are violated using a local peer-to-peer market. In addition, losses are increased by 4.1%. In Ref. [95], storage decisions are included into the local electricity market problem via a multi-period AC OPF. The market is established via locational marginal pricing and is cleared centrally, thus bringing the problem closer to a centralized dispatch problem than a liberalized local electricity market implementation. In Ref. [104], a collaborative Nash bargaining game over a multi-period AC power flow is implemented. The model uses various approximations such as a second order conic representation of the non-convexities in the power flow, a decomposition to separate the optimal power flow and the bidding problem as well as a Lagrangian relaxation approach for the state constraints. An unbalanced 3-phase power flow model was used in [136] in order to add details on phase-level.

In the distribution system, local flexibility can be made available to the DSO by using price signals from grid tariffs. In Ref. [94] the authors suggest a combination of these grid tariffs and power flow simulations. The suggested approach clears the market, solves the power flow problem and then adds network tariffs to the conducted trades. In addition, the model adds a power loss factor as well as penalization terms for all agents. The results show that lines can be considerably less congested under the proposed method compared to the existing market. Community-based and decentralized peer-to-peer approaches are compared in [93], where the authors highlight that the different market schemes impact voltage levels significantly. This is done using distributed optimal power flow, extracting distributed locational marginal prices as a result of the grid constraints. [125] assesses network power losses associated with peer-to-peer trading through an analysis of the physical layer. Losses occurring under peer-to-peer conditions are estimated by a simulation model utilizing an effective nodes-per-area concept, and compared with existing losses in non-peer-to-peer systems.

Distributed optimal power flows have therefore been investigated in [114]. They show synergy with the distributed nature of local electricity markets. Such a distributed approach is also reviewed as a promising method of ensuring proper voltage control with decentralized control in Ref. [130]. However, as discussed in Ref [91], the implementation of such distributed models requires radical changes in market design primarily due to technical and market design barriers.

Moreover, DC power flow approaches with exogenous cost allocations are used to avoid congestions [116]. Based on the Newton method, Ref. [60] addresses challenges related to congestions and distribution grid expansion. A DSO pricing approach based on distributed locational marginal pricing is presented in [99], where linearized power flow constraints are considered.

B. MARKET REPRESENTATION

In a market setting, there is no welfare-maximizing agent (or *benevolent dictator*) that has direct control of each producer/consumer/prosumer and tries to minimize the global cost function (i.e. maximize the welfare). Instead, either a market operator (as in traditional electric power markets)/community manager or the market participants themselves (as in modern peer-to-peer markets) set their bids in order to obtain a market clearing result and produce/consume accordingly. This means that market participants submit their respective bids under usually imperfect information on aspects such as the other participants cost/utility functions and are remunerated accordingly.

In its generalized form a centralized, traditional electricity market clearing can be presented via utilizing H and G to represent the inequality and equality constraints of the previously introduced grid problems:

$$\min_{x_i \forall i \in I_j} \sum_{i \in I_j} C_i'(x_i, y) \quad \forall j \tag{4a}$$

$$\min_{y} \sum_{i \in I} MC_i(x, y) \tag{4b}$$

$$\text{s.t.} \quad \begin{aligned} H(x,y) &\leq 0 \\ G(x,y) &= 0 \end{aligned} \tag{4c}$$

The objective functions in (4a) represent the individual profit maximization/cost minimization problem of the market participants - i.e. a consumer minimizing their cost or a prosumer/producer maximizing their profits. Each participant j supplies a bid x to the market, whereas most commonly these aspects are prices or power. Often in local electricity markets, these participants hold a single unit, thus $\text{card}(I_j) = 1$, but they can also be demand/supply/hybrid aggregators that hold a number of units $\text{card}(I_j) > 1$. In a centralized market, these units are coordinated via a central decision maker, the market operator/community manager, whose objective is the cost minimization within the market as depicted in (4b). This operator has a separate market clearing function for each participant. This function MC could, for example, be assumed as $MC = C$ in case of perfect information. Additionally, it could be a minimization of imports to the grid or a minimization of assumed cost functions. The clearing results, which could be a clearing price or a clearing quantity on power will then in turn affect the individual player problems, leading to the optimization being a so-called Nash game.

Another potential representation is a market that refrains from using a dedicated decision maker to yield the market clearing results but instead clears the market in decentralized manner (i.e. peer-to-peer):

$$\min_{x_i, y_i \forall i \in I_j} \sum_{i \in I_j} C_i'(x_i, y) \quad \forall j \tag{5a}$$

$$\text{s.t.} \quad \begin{aligned} H(x, y) &\leq 0 \\ G(x, y) &= 0 \end{aligned} \tag{5b}$$

In this case, the intermediary of a market operator/community manager is removed, leading to the players directly influencing the market clearing parameters of other players y^i whilst relying on all of the other players' decisions. An example of a peer-to-peer market implementation would be price and power quantity bids in form of vector x_i and accepted quantities from other players in the form of vector y_i. A visual comparison of centralized and decentralized market clearings is provided in Figure 3.

The main reason for such a decentralized model would be to reduce the requirement for information centralization, as there is no need for a central market clearing entity that is informed about the specifications of the players. Nonetheless, the trade-off between an accurate grid representation and fairness is still inherited in this formulation. Additionally, both the centralized and decentralized problem have multiple objectives that further complicate the optimization. This will be discussed in the subsequent subsection on the representation of competition.

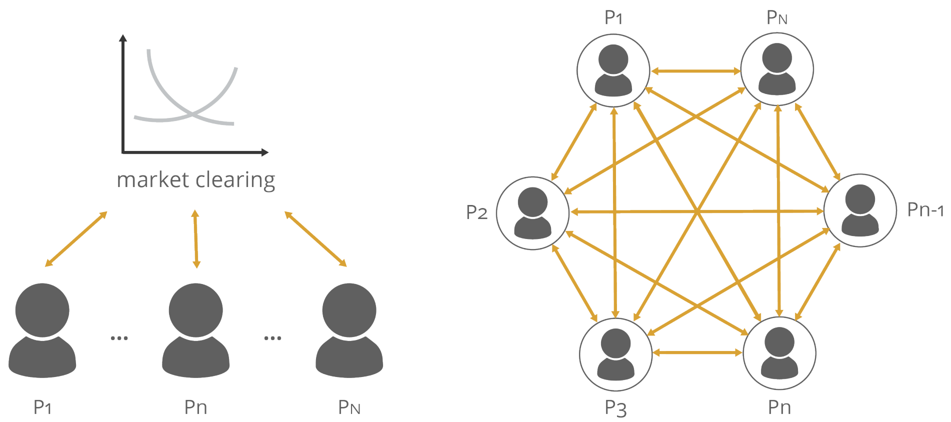
The papers related to the market design are displayed in Table 5 and will be introduced below.

TABLE 5: Papers considering market design related challenges.

Paper	Centralized market clearing	Decentralized market clearing	Balancing products	Demand response
[90]	x			
[69]		x		
[91]		x		
[92]		x		
[93]	x	x		x
[94]	x			
[95]	x		x	
[60]	x			x
[96]		x		
[97]	x			
[98]	x			
[99]		x		
[100]	x		x	x
[101]	x			
[102]		x		x
[46]	x			
[104]	x			
[105]		x		
[106]	x		x	x
[107]	x			x
[108]	x		x	x
[109]	x	x	x	x
[110]		x		x
[111]	x			x
[112]	x			x
[113]	x			
[114]	x			x
[115]	x			x
[116]	x			
[117]	x			x
[118]	x			x
[119]	x			
[120]	x		x	x
[121]		x		
[122]	x			x
[80]	x	x		x
[125]			x	
[126]		x		
[128]		x		x
[129]		x		
[115]			x	
[131]	x			
[132]	x			
[133]	x			x

1) Literature, focus: Centralized market clearing

Centralized market clearings provide a method to share sensitive information about utility functions of each agent with only a central entity, the market operator or community manager. In Ref. [102], the authors prove that centralized energy communities can achieve similar market clearings as a fully decentralized peer-to-peer market under the assumption of a supervisory node with access to utility functions of all involved agents. Both were found to be viable approaches in Ref. [93], which however found centralized community-based approaches ensured DSO interests to a greater extent. Other advantages of such centralized energy collectives are the adaptability to the existing market design as well as future market designs in terms of balancing, wholesale and ancillary service provision [102]. The role of the community operator would therefore be to supervise and ensure conver-



a) Centralized market clearing with uniform pricing b) Decentralized P2P market clearing with discriminatory pricing

FIGURE 3: Centralized and decentralized clearing.

gence to optimality of trades inside the community as well as acting on behalf of the community with other markets such as flexibility or ancillary service markets.

Ref. [137] defines the need for less information flow between the market operator/community manager and the peers, but also highlights the need for coordination from a supervisory node to lower costs and increase self-consumption inside the community. Another aspect often ignored in local electricity market research is the necessity for coordination in intraday markets due to uncertainty in load and distributed generation in the local electricity market. In Ref. [120], a local intraday market is suggested to handle deviations from the scheduled demand and production, coordinated by a central market clearing entity. A similar multi-market model approach is shown in Ref. [100], where a local electricity market is positioned within a wholesale electricity market. The main hurdle for implementation is the computational complexity, which stems from the necessity of a two-stage stochastic program scenario generation as each market has its own clearing period that provides updated information on uncertainties. Local trades are prioritized for the intraday market. In order to ensure scalability, this paper utilizes scenario reduction techniques. Further approaches considering community managers are also shown in Refs. [138], [139].

2) Literature, focus: Decentralized market clearing

As discussed above, in markets with decentralized market clearings, information is not sent to a supervisory node but is performed in a multi-bilateral fashion between agents in the system. This poses challenges for the DSO as it is computationally demanding to influence the flexibility and transactions to facilitate healthy operation of the grid. A full peer-to-peer market design with complete multi-bilateral energy dispatch was designed in Ref. [105]. In addition, Lagrangian relaxation and the alternating direction method of multipliers (further introduced below in Section III-D) are recommended in Ref. [7] due to their ability to define the individual objective of each end-user while still considering privacy issues in decentralized market clearing. Here, end-users share only their volume and willingness to pay for electricity, keeping asset information and similar aspects private.

Auction-based approaches are also viable methods for clearing local electricity markets, as they scale well compared to grid-based methods such as optimal power flow or location marginal pricing based methods. Auction-based approaches benefit from the fact that the market clearing follows an automated set of rules and can be solved in a distributed fashion by the involved agents. Continuous double auctions have been demonstrated in Ref. [140], where trading with a shared electric energy storage in an energy community is proposed. In Ref. [91], zero intelligence trading algorithms were investigated to match buyer and seller bids in local peer-to-peer markets, also allowing for a lack of market supervisor. Iterative continuous double auctions have also been applied on energy trading in microgrids [141]. The use of local electricity markets with peer-to-peer transactions, based on continuous double auctions together with blockchain technology, was suggested for charging of plug-in hybrid electric vehicles in Ref. [128], where sensitive information about the vehicles would remain private. Integration of flexible resources into electricity markets using continuous double auctions in a prediction-integration strategy optimization model is suggested in Ref. [142]. Similarly, Ref. [123] proposes a comparative analysis of various auction mechanisms and bidding strategies for solar electricity trading. The economic efficiencies and impacts of the different strategies on market conditions are simulated through a case study, considering participants in a microgrid at varying photovoltaics penetration levels. Ref. [110] proposes a framework that allows for continuous auctions in order to match distributed demand and supply in a microgrid. The model utilizes a distributed peer-to-peer approach with the goal of profit maximization of its agents, whilst minimizing information-sharing. Clustering is suggested in Ref. [97] as an approach to increase efficiency of a market clearing heuristic solving the auction problem of a local power exchange. The paper aims to ensure optimal fairness in a non-convex problem (i.e. a problem where finding the optimal global fairness solution is "NP-hard"). An attempt to incorporate information asymmetry into local electricity markets is presented in Ref. [143]. To do so it uses a utility function formulation and explores both centralized and decentralized local electricity markets. In addition, it analyses the issue of privacy. The model is non-convex and thus scalability is again an issue here.

A common theme of the mentioned studies is that grid concerns are not specifically included, indicating open research avenues on integration of DSO requests in decentralized local electricity market clearing.

C. COMPETITION REPRESENTATION

The previously introduced market representation implements a model under competition in which every participant aims to individually maximize their respective results. Disregarding the form of competition (Cournot, Stackelberg, Bertrand), the players will only focus on their individual outcome when making their bidding/consumption/generation or any other decision. In literature, it is common to focus on the decisions yielding the Nash equilibria, i.e. the x and y values where none of the participants can further reduce their cost. Assuming the dual variables of the grid inequality and equality constraints are denoted as λ and μ respectively allows to reformulate the Karush-Kuhn-Tucker conditions for the Nash game:

$$\frac{\partial \mathcal{Q}(x,y,\lambda,\mu)}{\partial x_i} = 0 \quad \forall i \tag{6a}$$

$$\frac{\partial \mathcal{Q}(x,y,\lambda,\mu)}{\partial y} = 0 \tag{6b}$$

$$0 \leq \lambda \perp H(x,y) = 0 \tag{6c}$$

$$G(x,y) = 0 \tag{6d}$$

$$\mu \in \mathbb{R}, \lambda \in \mathbb{R}^+ \tag{6e}$$

In general, for a feasible problem and convex functions, this problem will converge to a Nash equilibrium solution, i.e. to a point where no participant can decrease their cost. Further information on Karush-Kuhn-Tucker and related optimality conditions (included non-convex cases) can be found in Ref. [144].

In contrast to competitive models stand cooperative models. In traditional wholesale power markets, such models are less prevalent, which can not only be explained by the large number of participants but also by the goals of the competitive markets to ensure profits for its participants in order to sustain additional ventures such as future investments and R&D into the right products for the market. An illustrative example of the difference between cooperative and competitive models can be found in Figure 4. In the cooperative case, a central entity (e.g. community manager) minimizes the total cost of the agents, whereas in the competitive case all agents minimize their individual costs.

On smaller scales, i.e. in local electricity markets, cooperative market models are more prevalent. This can not only be explained due to a lower number of competitors but also due to the goal of collaborative markets that is to ensure optimal fairness for all its participants. In such a model, the market is cleared for the welfare-maximizing solution and the participants are remunerated according to maximum fairness. The reason is that the fairest solution might not be the welfare-maximizing solution. An example is that of a monopolist which in a competitive market would be able to extract a higher profit/lower cost by utilizing their market power to influence prices. A welfare-optimizing market under fair cooperation would thus remunerate the monopolist not utilizing their market power to do so but instead choosing the welfare-maximum with an accordingly higher share of the end result.

The cooperative approach is less standardized than the competitive approach, as many methods, such as Shapley and Harsanyi values, are intractable for larger problems, thus only allowing for limited scalability. Some local electricity market model designs oversee this hurdle and only conceptualize small systems, whilst others specifically approach this limitation via approaches to increase computational performance. Within local decentralized markets, an established technique to approach collaboration instead of fair distribution is via bargaining solutions. The Nash bargaining game is a common way to implement this:

$$\min_{x,y} \prod_j \Big(\sum_{i \in I_j} C_i(P_i) - \sum_{i \in I_j} C'_i(x_i, y) \Big) \tag{7a}$$

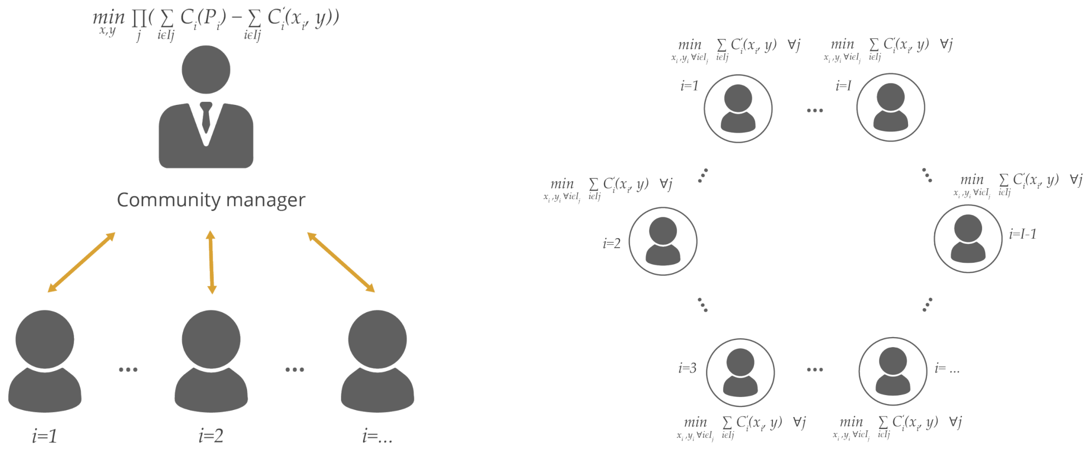
$$\text{s.t.} \quad \begin{aligned} H(x,y) &\leq 0 \\ G(x,y) &= 0 \end{aligned} \tag{7b}$$

$$\text{where} \quad P \subseteq x \tag{7c}$$

The bargaining solution given in (7a) is thus the product of the system cost under cooperation C minus the system cost under competition C' over each player.

However, not all solutions of local electricity markets require information-sharing entities to decide on market results. In fact, peer-to-peer markets are often specifically designed to minimize information sharing and allow for decentralized optimization principles. This does not only provide advantages in data security, it also supports the scalability of such optimization techniques. This will be discussed in the following subsection on distributed optimization.

Tab. Table 6 summarizes the solution approaches for the models presented in literature. In addition, they are described in detail below.



(a) Cooperative game (b) Competitive game

FIGURE 4: Comparison of objective function structures in cooperative and competitive games.

1) Literature, focus: Cooperative games

Since individual agents' interests are not explicitly considered in the centralized approach, this approach is often used for benchmark models that provide the system welfare optimum. To provide an example, Ref. [98] analyzed the impact of risk-neutral and risk-averse agents in local electricity markets. An optimal matching of stochastic load and local generation is presented in Ref. [60]. In Ref. [115], it was found that decentralized batteries lead to almost 20% of savings compared to one centralized battery in a localized peer-to-peer market. Similarly, Refs. [112], [117] found that best-case coordination of flexible assets in a neighborhood could reduce peak loads.

As described previously, aggregators are market entities designed to deal with centralized control. They are able to coordinate end-users in markets as well as interact directly with the DSO. In Ref. [113], the DSO performs an AC-PF analysis after each market clearing and informs the aggregator if congestions or voltage problems arise. In that case, the aggregator is forced to change their generation schedule in order to avoid congestions.

2) Literature, focus: Competitive games

In Ref. [145], local generation and consumption coordination is implemented using a game-theoretic approach. The paper finds that that sparsity in peer behavior resulted in higher savings and lower peak loads. Flexibility assets are coordinated using a local peer-to-peer market in Ref. [146], where end-users in a neighborhood coordinate their consumption under a subscribed capacity network tariff design. By implementing a local electricity market, end-users can rent subscribed capacity from other agents in order to reduce neighborhood peak loads. Further, Ref. [129] proposes a general framework for implementing a retail energy market as an electricity market structure with large distributed energy resources. The framework enables consumers to participate directly in the market and aims to be profitable for the prosumers, as well as maximizing the expected profit of the distributed energy resources by analyzing uncertainties. Complementarity models using the Karush Kuhn Tucker conditions can be extended to Stackelberg games by introducing a two-level approach. This is performed in Ref. [9] where a Stackelberg formulation (sometimes referred to as MPEC, math program with equilibrium constraints) is used to optimally design grid tariffs in order to avoid high peak loads from the prosumers in the market. A Stackelberg approach is also used in Ref. [132], where a bilevel game where consumers react to prosumers within a non-cooperative peer-to-peer market is designed. The paper is based on a logarithmic formulation of utility curves and a welfare-maximization approach for market clearing. Similarly, in Ref. [101], a Stackelberg market clearing model for local electricity trading in a microgrid is proposed. Sellers are assumed to be taking the role of leaders and buyers the role of followers. The paper shows that under consideration of the taken assumptions by the players, i.e. the buyers basing their decisions on the sellers' as well as rational, selfish players with access to full information, the proposed market model finds the unique Nash equilibrium. A Nash game for a sharing mechanism between prosumers that utilizes auctions is proposed in Ref. [122]. It provides a proof for the Nash equilibrium of the game existing and being unique in addition to being socially optimal. Further, Ref. [46] demonstrates a collaborative game within a local electricity market. It solely focuses on the socio-economical impacts of such and disregards other factors such as uncertainty of supply or the underlying grid. In their analysis the authors find that a coalitional game can provide

TABLE 6: Papers considering model-approach-related challenges.

Paper	Optimization	Auctions	Cooperative	Competitive	Scalability	Uncertainty
[90]	x		x			
[69]		x		x		
[91]	x	x		x		
[92]		x		x		
[93]	x	x	x	x		
[94]	x			x		
[95]	x			x		x
[60]	x	x	x			x
[96]	x	x		x	x	
[97]	x	x		x	x	
[98]	x	x		x		
[99]	x	x		x		
[100]	x		x		x	
[101]	x			x		
[102]	x		x			
[46]			x			
[104]	x	x	x		x	
[105]	x		x			
[106]	x			x		x
[107]	x			x		x
[108]	x			x		x
[109]	x			x		x
[142]	x	x			x	x
[110]	x	x		x		
[111]	x			x		x
[112]	x		x			
[113]	x		x			
[114]	x			x		
[115]	x		x			
[116]	x			x		
[117]	x		x			
[118]	x			x		
[119]	x			x		
[120]	x		x			x
[121]	x			x	x	
[122]	x	x	x			x
[80]	x	x		x	x	
[123]		x				
[124]				x	x	x
[45]				x		
[126]	x			x		
[127]				x	x	
[128]	x	x		x		
[129]				x		x
[130]	x			x		
[115]	x			x		
[131]	x		x		x	
[132]	x			x		
[133]	x			x		

the required financial incentives for customers of electricity to participate in local exchange of energy. The authors in Ref. [45] utilize a motivational psychology framework in order to design a decentralized local electricity market trading scheme which aims to increase user participation. A game-theoretic approach is applied in order to validate the scheme. In this context, Ref. [124] evaluates how automated negotiation strategies regarding energy exchange contracts can increase system efficiency and fairness through the proposed negotiated allocations. The approach is also robust to uncertainty in demand and generation.

A comprehensive cost recovery approach is used in Ref. [118] where the leader (DSO) scales and chooses between three grid tariff structures to minimize peak loads from end-users in a non-cooperative game. Similarly, Ref. [96] models a local energy system behind a feeder (i.e. without network constraints) where both electricity and hydrogen are traded. The model is a hybrid between Bertrand and Cournot models, where every agent maximizes their own benefits. The model also includes privacy considerations and discussions. In addition, the model mentions that due to its location in the distribution grid, the number of participants could potentially be large. Thus, the model focuses on adequate sizing. This is demonstrated by the included case studies, which involve a hundred households competing over 24 hours.

D. DISTRIBUTED OPTIMIZATION

Distributed optimization is the optimization of an entire system via the optimization of its components. This has the advantage that individuals can optimize their respective results and coordinate with each other within the system via external inputs. In local electricity markets, a common technique to implement distributed optimization is the Alternating Direction Method of Multipliers (ADMM). This method is a combination of dual decomposition and the augmented Lagrangian method. The objective function of a local electricity market problem suited for the ADMM can be represented by the following:

$$\min_{x,y} \sum_{j} \sum_{i \in I_j} C_i'(x_i, y) + \sum_{i \in I} MC_i(x, y) \tag{8}$$

The ADMM updates the dual values stepwise via primal descent and dual ascent until both primal and dual problems are converged. The method only requires equality constraints, but inequalities can be incorporated into the augmented Lagrangian relaxation. For the sake of notational simplicity, further information on the algorithm will be omitted but can be found in the comprehensive review on this technique presented in Ref. [147]. Semantically speaking, the problem can be described as each player individually optimizing their results (local computation) and the market operator/community manager coordinating their results via the dual variables of the constraints. Additional techniques for distributed optimization exist and can for instance be found in Ref. [148]. Nonetheless, it can be stated in general that problem convexity, and thus a convex grid representation, is key for such global optimization methods. Equally, this convexity is a focus for further additions to the grid and/or bidding problem, some of which will be discussed below.

1) Literature, focus: Distributed Optimization

ADMM algorithms have been widely described in the literature due to their capability of solving convex problems by splitting them into more tractable problems. This is demonstrated by Ref. [131] where scalability and privacy issues are highlighted as advantages of ADMM. A consensus version of the method is showcased in Ref. [116], where a competitive equilibrium can be achieved in a distributed manner. A unified formulation for consensus ADMM under different market designs is presented in Ref. [121], where the market design can be conveniently changed by changing the utilized communication links. The authors also claim faster convergence and better resilience to asynchronous behaviors. ADMM is used to combine the DC OPF formulation with trading in Ref. [126], where an integrated blockchain-based energy management platform for bilateral trading which optimizes the energy flows in a microgrid is designed. The optimization problem is broken down by the ADMM and a smart contract executes the role of a virtual aggregator. A similar approach is investigated in Ref. [149], where a consensus + innovation approach to solve the local electricity market clearing is used. Compared to ADMM, this approach was found to converge faster for peer-to-peer coordination within a microgrid. Ref. [107] uses a centralized market to deal with demand responses expressed as utility functions and generation uncertainty. The paper achieves this by utilization of a a Value at Risk formulation and an iterative algorithm (based on ADMM) for the distributed optimization. A bi-level problem is formulated in Ref. [111], where an energy-sharing model is implemented considering prosumer willingness to trade. The multi-agent framework allows the model to be solved in a distributed iterative way rather than by formulating an equilibrium problem with equilibrium constraints (EPEC), as there the model does not require an objective function in the upper level.

E. ADDITIONAL MODEL COMPONENTS

Even though, and as illustrated later in Section IV, topology, market types, participants, sizes and many other aspects of local electricity market implementations differ internationally, certain modeling components are shared amongst the various models and implementations. Some of these will be discussed here.

A common aspect is the connection to balancing the local grid via exports/imports from a larger network. This is the most common trait shared amongst the models, as most of the models do not aim to implement microgrids but instead aim to solve local problems nested in larger national/regional grids. Some models solve this via bi-level models such as the aforementioned Stackelberg games. In the notation shown below, however, the simplest implementation would be via an import/export agent i with a cost function C_i similar to the purchasing/selling price of a national/regional market (for example intraday wholesale market prices) and unlimited import/export capacities of $\underline{P}_i$ and $\bar{P}_i$. In most models, this import/export agent is also integrated into the market operator/community manager, as the profit maximization of such an agent in this way is not considered part of the competition.

Another common model component is a state constraint in the form of:

$$S_{i,t} = S_{i,t-1} - P_{i,t} \tag{9}$$

Here, t denotes the specific period and S the state of the storage device. In addition, many models often consider degradation cost of the batteries and charging inefficiencies as the power stored will not be equal to the power discharged. Nonetheless, even this simple formulation can create problems in model scalability. This is a general problem in such models and is also an active research topic within the field of multi-period optimal power flows (see Ref. [150] for further information).

A third example of an additional aspect would be uncertainty in parameters. In local electricity markets, this could, for example, mean uncertainty in wholesale prices (thus on the cost functions C), on the limits of the generation units $\underline{P}$ and $\bar{P}$ or similarly on the availability of demand flexibility. As both possibilistic and probabilistic as well as hybrid methods have found their way into power system analysis, no de-facto standard for inclusion of uncertainty in local electricity markets can yet be identified. However, a growing literature base of such models can be expected in the future. This is due to the discussion on forecast accuracy in Section II which outlines how uncertainty increases in smaller scales.

1) Literature, focus: Grid tariffs

An alternative to modeling grid constraints is implicitly modeling the grid or the potential grid impact. As discussed previously, an all-in-one solution is unachievable for real-world problems. Specifically, grid tariffs are often challenged in terms of fairness and comprehensiveness for the customer [151]. A Stackelberg game incorporating grid tariffs is suggested in Ref. [118]. The leader (DSO) scales and chooses between three grid tariff structures to minimize peak loads in the distribution grid. Similarly, Ref. [119] designed an optimal cost-recovery based grid tariff with the goal of minimizing peak imports from an energy community. A more direct approach is considered in Ref. [116], where network charges are allocated based on electrical distance to reduce stress on the grid in a local electricity market.

2) Literature, focus: Uncertainty modeling

An intraday local electricity market is suggested in Ref. [120] as a mechanism to deal with uncertainty in prices, demand and photovoltaic production. The intraday market is represented as the second stage in a two-stage stochastic program, where deviations from the day-ahead market position can be corrected in the intraday market. The same idea is extended to a three-stage model in Ref. [133], which describes a multi-stage local electricity market formulation.

The focus of the paper is the coordination between storage, demand response and other flexible resources over longer timeframes. Uncertainty is also considered in Ref. [142], which uses a special form of a neural network trained via a random update based on the Moore-Penrose inverse instead of gradient descent, in order to find the optimal bidding strategy in an uncertain peer-to-peer market for electricity. The model reinforces its initial assumption based on prior literature: a profit-maximizing agent is able to make continuous profits via peer-to-peer trading.

In addition, Ref. [106] aims to unify scheduling decisions under uncertainty with peer-to-peer trading of intermittent renewables, with a focus on the scheduling decisions. It considers a multi-period problem that implements electric vehicles and local storage. It also considers forecasting errors, with most uncertainties being represented in Gaussian form.

A bi-level formulation of an upper level wholesale market and a lower level local electricity market is demonstrated in Ref. [109]. The upper level market facilitates trade between large generators (thermal plants, hydropower plants, wind power plants), while the lower level market facilitates trade between distributed generation, electric vehicles and demand response units. The model utilizes a scenario formulation to implement uncertainty. Ref. [108] discusses coordination of demand response and uncertain generation in the form of wind power via a competitive peer-to-peer reserve market. The model considers uncertainty in the form of a Conditional Value at Risk formulation. Within a bi-level problem, the wind plant operators purchase demand response in order to prevent higher losses on the balancing market. Risk aversity among prosumers is also discussed in Ref. [127], where bilateral contract networks are utilized for energy trading within centralized local electricity markets. Both real-time and forward markets are assessed with utility-maximizing preferences.

3) Literature, focus: Information and communication technologies

As mentioned in Section II, a key factor in the practical implementation of local electricity market models is the data and information exchange. One of the most common proposed technologies to ensure the communication between parties in local electricity markets is distributed ledgers, i.e. blockchain.

A considerable number of papers explore distributed ledger technologies as the core enablers for automatized market platforms [62], [152]–[154]. In the context of local electricity markets, the literature principally focuses on the technical ICT features of blockchain [155]–[159]. For example, Ref. [160] determines the cryptography mechanism to allow for a secure trading system. The paper proposes the utilization of asymmetric encryption to resist security attacks in bi-lateral markets and secure the settlement of monetary transactions. Other sources pay more attention to scalability issues or the definition of contracts between agents. In Ref. [161] the authors explore Merkle Trees to reduce the number of transactions and allow the entry of more participants. By using this particular configuration, Ref. [161] proposes a demand response market capable of balancing the system by implementing incentives and penalty rates which enforce the demanded flexibility levels.

Ref. [155] suggests real-time bidding to guarantee the privacy of bids before the clearing of the market is performed. This approach combines sealed quotations with aleatory strings. The latter is used as a private key for automatic verification of the real bid. By the adoption of this system, Ref. [155] aims to enforce confidentiality and trust among participants. In a more recent study, Ref. [156] also employs sealed quotations, but applied to an electric vehicle focused trading platform. The paper proposes blockchain as the communication layer for direct monetary transactions between charging and discharging vehicles. This is in line with Ref. [159] where the authors implement a market platform where participants are rewarded when they charge their vehicle during peak loads caused by renewable energy. With a wider perspective of the utility of blockchain, Ref. [157] presents the technology as the facilitator for bidding, contracting, and settling economic transactions within a community supplied by renewable solar energy. The author argues that blockchain should be carefully implemented due to its associated financial risks, high requirements for computational resources and associated transaction cost.

The studies in Ref. [15], [145], [161] extend the application of blockchain to automatic activation of electric devices (specifically appliances and HVAC systems). By the combination of smart controllers and blockchain, Ref. [15] proposes that the operations of the devices are dictated by a smart contract. The communication of the signals is made through blockchain and aims to ensure optimal information access for participants.

Another line of research in the literature about blockchain applications in local electricity markets is the linkage between power system control models (e.g. voltage control) with market clearing model. Ref. [158] deploys a blockchain ledger to send signals from the market clearing model to the power flow analysis algorithm to technically analyze the impact on the distribution network. With a similar objective, Ref. [156] shows AC power flows results that validate the viability of the trading outputs. Alternatively, Ref. [15] directly introduces grid constraints in the market model to determine the energy transactions.

IV. LOCAL ELECTRICITY MARKET IMPLEMENTATION

In recent years, numerous Research and Development (R&D) projects implementing local electricity markets have been deployed across Europe. One of the key metrics of the R&D projects is the product offerings of the local electricity market, whether energy, flexibility or both combined [162]. Local electricity markets might also deal with establishing marketplaces to acquire end-users' resources to offer flexibility to potential purchasers of such, e.g. distribution system operator, transmission system operator and balance responsible party. This can be conducted with or without the involvement of a mediator such as a local electricity market operator or aggregator.

This section enumerates key R&D projects addressing the challenges presented in Section II. It also explores the projects based on the key aspects presented in Section III on the market modeling techniques. The scope of this chapter incorporates completed or on-going *European research and demonstration projects in real-life environments*. These projects fall into a technology readiness level (TRL, as defined by the European Commission) in between 5 and 8, with the purpose to validate and demonstrate their projects in real-life environments and thus have close to market-ready products [163].

A. KEY CHALLENGES ADDRESSED

1) Grid operational challenges

As mentioned in Section II, one of the key advantages of implementing local electricity markets is to provide direct or indirect grid support. Thus, most of the R&D projects here approach the operational challenges in the distribution grid. Within these projects, congestion management is the most common challenge approached. Additional projects also focus on grid services such as voltage management and line loss reduction.

An example for a project dealing with such grid challenges is provided by the InterFlex project, which considers islanding support to be one of the project's business cases and evaluates a scenario that aims to maximize the duration of the power supply after an unintentional disconnection from the main grid. The concept is based on an aggregator operating a local storage system from which the DSO is able to buy flexibility. An additional, separate storage system run by the DSO ensures power quality and grid safety [164]. Similarly, the PEBBLES project intends to optimize the relation between grid expansion and smart solutions for distribution systems. Particular focus is placed on evaluating decentralized solutions and the advantages of utilizing blockchain technology [165].

2) TSO-DSO coordination

As discussed in Section II, proper coordination of TSO and DSO is a key aspect that needs to be incorporated into the local electricity market. It is particularly important for the local electricity market deployed to relieve local grid congestion and provide balancing and ancillary services using the flexibility of end-users' assets. The projects SmartNet and GOPACS are working on TSO-DSO coordination from different dimensions. SmartNet explored different TSO-DSO co-ordination schemes to obtain ancillary services from distributed resources on low voltage and medium voltage levels [166]. Two out of five TSO-DSO coordination schemes tested in the project deployed local flexibility markets with DSOs as the operator to solve local congestion management and to achieve balancing on the local level. The GOPACS project is initiated by the Dutch TSO and four DSOs to develop a market-based mechanism to alleviate grid congestion [167], [168]. GOPACS provides the intermediary platform with TSO-DSO coordination functionalities to avoid double activation of the same end-users' asset. In the UK, the TSO-DSO operated pilot project Power Potential [169] explores the provision of reactive power support and dynamic voltage control for the transmission grid from the perspective of distributed energy resources connected in the distribution grid through TSO-DSO coordination [170]. The service providers are selected through day-ahead auctions and receive payment for availability and utilization [171].

3) Synergy with central market

In order to reduce risks related to local electricity market uncertainty, revenue volatility and to have better value proposition for end-users' assets, it is advantageous for end-users providing flexibility to have access to multiple markets ranging from a local level to a national level. The ENERA Epex Spot [172] project investigates flexibility markets on demand and operates in parallel with a central wholesale market on an intraday time horizon. The TSO and DSO coordinate and initiate the local flexibility market based on forecasted grid congestions.

The interaction of local electricity markets with existing markets requires a definition of timescale and sequence where trading takes place. Most of the local electricity market R&D projects focus on trading within an intraday timeframe. This is due to its closeness to real-time operation and the resulting reduced chance of forecasting errors. Although prevalent in theoretical models, there are few practical implementation projects which involve day-ahead market timeframes along with an intraday timeframe. The PEBBLES project, aimed at local balancing of locally generated power, allows energy trading in both dayahead and intraday markets to reduce the effect of forecasting error [173]. Projects like Piclo [174] and PicloFlex [175] provide trading opportunities with lead time ranging from an intraday timeframe to months in advance.

4) Enhancement of Hosting Capacity

Hosting capacity analysis is performed in the grid to quantify the amount of distributed energy resources that can be accommodated beyond which grid upgrade is necessary for reliable grid operation. Balancing of generation and demand is appearing as a key grid operational challenge due to the intermittent nature of renewable energy, hindering the hosting capacity of the power system. Some of the local electricity market R&D projects, aimed at local balancing of locally generated energy, enhances the hosting capacity of the grid. Projects Quartierstrom [176], LAMP [177] and NRGcoin [178] are full peer-to-peer based market examples which focus on local balancing of locally generated electricity. Piclo [174], Vanderbron [179] and sonnenCommunity [180] are some examples of projects that have hybrid market structure, which matches energy supply and demand

and supports local balancing of energy usage among the participants. These projects have improved integration of growing renewable penetration in the distribution network and empower end-users with active trading participation. The German SINTEG New 4.0: ENKO project [181] aims to utilize local loads through local flexibility platforms to avoid renewable energy curtailment. In this project, payment for flexibility is determined upon negotiation between the flexibility buyer and provider before bidding.

5) Product differentiation

As discussed in Section II, another key driver of local electricity markets is the possibility to recognize electricity as a differentiated product for consumers with heterogeneous preferences. The NRGcoin project [178] develops unique smart contract based local electricity market which facilitates emission-free energy producers and consumers to trade locally with each other using a blockchain-based virtual currency and without being exposed to volatility of electricity market. Thus it enables end-users to express preferences for local, emission-free energy. The Energy Collective project [182] deploys consensus-based pricing, depending upon user preferences, e.g. consumption of locally generated energy and/or energy low on emissions.

6) Forecasting

Forecasting of renewable energy resources is one of the key aspects to facilitate integration of intermittent renewable energy sources. The market approach for dealing with the potential of forecasting errors is the implementation of sequential market structures such as day-ahead markets, intraday markets, local flexibility markets and ancillary service markets. The Smart4RES project [183] is focused on not only improving the performance of renewable energy forecasting but also the value chain incorporating data science approaches in grid and market applications. One of the use cases investigated in the project is to analyze the impact of uncertainty associated in renewable generation while providing flexibility to the DSO which allows avoidance of grid congestion [184].

7) Cybersecurity

Safeguarding against cybersecurity threats has appeared as an emerging reliability challenge for a more digitalized future electric grid. Providing the market power to the end-user through localized market adds a new dimension to the problem and thus further amplifies the threat. A growing number of local electricity market implementation projects are utilizing blockchain technology for automated trading due to the previously discussed tamper-proof nature of the technology. Quartierstrom, LAMP, NRGcoin, PEBBLES are all examples of such projects. Further, a necessity to assess vulnerability of the energy system towards cyber-attacks exists. The EnergyShield project aims to utilize state-of-art cybersecurity tools to assess vulnerability of the electric network by carrying out simulated threats and analyzing responses within the entire value chain of the system [185].

8) Demand response

Aside from small-scale generation facilities, there are a wide variety of demand resources connected to distribution networks that offer potential for flexibility. The scale of demand resources also ranges from a residential to an industrial scale. Among other applications, the available technology incorporates storage, heat pumps, electric transports and power-to-gas/heat plants. Even though most of the real-life projects intend to be technology-neutral, some of the demonstration projects focus on different categories of demand resources. The InterFlex project [186] has six demonstration sites in five EU countries. Each of the demonstration sites implements different demand response schemes utilizing different types of assets to tap flexibility through direct DSO control or a local flexibility market [187]. The SINTEG New 4.0: ENKO project [181] tests medium-scale loads ranging from electric vehicles to heat/electric storage, combined heat plants and industrial processes. In addition to this some projects are entirely focused on storage. To provide an example, the StoreNet project [188] explores a market platform for procuring flexibility from end-users' storage facilities to serve the DSO's needs for congestion and voltage management. In addition, it attempts to evaluate business cases for end-users conducting energy arbitrage [189]. Project sonnenCommunity provides a peer-to-peer energy trading platform to prosumers, similar to projects such as Piclo and Vandebron, with a special emphasis on storage. The INVADE project explores a cloud-based flexibility management platform intended to manage a wide range of storage facilities: mobile facilities such as electric vehicles, centralized facilities such as central battery energy storage in substation and residential batteries [190].

B. MODELING APPROACH

1) Market Structure

A local electricity market structure with a central entity responsible for managing the local electricity market appears prevalent in the R&D projects. The R&D projects with such a structure are matured and currently more focused on ICT structure, scalability, and optimality of market design, developing different business models, incorporation into existing markets and cybersecurity. Compared to traditional wholesale market structures, the fully decentralized structure, without any central agent and market participants involved in bilateral trading, employed in some of the local electricity market is still nascent. Local electricity market projects emphasizing on energy trading among end-users usually take the form of any of the previously mentioned market structures. The Vandebron [179] project is an example of a centralized market structure while Quartierstrom [176] falls under the fully decentralized category. However, local electricity market projects with a focus on flexibility trading possess market structure with a central entity, responsible for

TABLE 7: Key representative local market R&D projects.

Project Name	Grid services	Market topology	Participants	Market clearing	Objective/ Outcomes
iPower (Denmark)	CM, VM	Centralized & Hybrid	Buyer: DSO Seller: Aggregator	Optimization-based & auction-based	Control scheme and market mechanism to mobilize flexibility from end-user to DSO/TSO by utilizing demand response.
InterFlex (Europe)	CM	Hybrid	Buyer: DSO Seller: Aggregator, Large prosumer	Auction-based	Tools and process for local flexibility market to solve the existing and future grid constraints
EMPOWER (Europe)	CM	Centralized	Buyer: DSO Seller: Aggregator, Prosumer	Optimization-based	Cloud-based ICT platform and user app to facilitate local market.
Quartierstrom* (Switzerland)	LB	Decentralized	Buyer: Prosumer, Consumer Seller: Prosumer, Producer	Auction-based	Bilateral trading of locally produced solar energy for local consumption.
Energy Collective (Denmark)	LB, CM	Hybrid	Buyer: Prosumer, Consumer Seller: Prosumer, Producer	Distributed optimization-based	Deployment of local market with provision of consumer preferences.
NRGcoin* (Europe)	LB	Decentralized	Buyer: Prosumer, Consumer Seller: Prosumer, Producer	Agent-based model	Smart contract based trading platform, that co-exists with wholesale market structure, also incentivizes the consumption of local, green energy.
SonnenCommunity (Germany)	LB	Hybrid	Buyer: Prosumer, Consumer Seller: Prosumer, Producer	Auction-based	Trading platform replicating the role of energy supplier, who links consumers and producers with storage system in focus.
LAMP* (Germany)	LB	Decentralized	Buyer: Prosumer, Consumer Seller: Prosumer, Producer	Auction-based	Bilateral trading of local solar energy within neighbors in microgrid.
P2P-SmarTest (Europe)	CM, VM	Hybrid	Buyer: Aggregator, Microgrid trader Seller: Microgrid trader, Prosumer	Distributed optimization-based	Control and ICT architecture for microgrid to facilitate peer-to-peer trading in energy market and ancillary service market.
DOMINOES (Europe)	CM	Hybrid	Buyer: DSO, Supplier, TSO Seller: Aggregator, Prosumer	Auction-based	Market platform that enables prosumers to engage with other prosumers and also with different central market actors.
PEBBLES* (Germany)	CM	Decentralized	Buyer: DSO Seller: Prosumer	Auction-based	Energy trading platform with congestion management functionalities embedded in matching algorithm.
SmartNet (Europe)	CM, VM, LLR	Hybrid	Buyer: TSO,DSO Seller: Aggregator	Auction-based, pay-as-clear	Different DSO-TSO co-ordination schemes to procure ancillary services from distributed resources in distribution network.
ENERA (Germany)	CM	Hybrid	Buyer: DSO, TSO (in future) Seller: Aggregator	Continuous trading, pay-as-bid	Market-based congestion management through regional, "on-demand" flexibility market covering regional distribution area.
NODES (Europe)	CM	Hybrid	Buyer: DSO, TSO (in future) Seller: Aggregator	Continuous trading, pay-as-bid	Marketplace to tap additional flexibility potential for enhancing congestion management to improve grid operation.
GOPACS (Netherland)	CM	Hybrid	Buyer: TSO, DSO Seller: Aggregator	Continuous trading, pay-as-bid	Development of integrated TSO-DSO coordination platform to procure flexibility timeframe to avoid congestion.
Piclo Flex (UK)	CM, VM	Hybrid	Buyer: DSO Seller: Aggregator, Large prosumer	Continuous trading, pay-as-bid	Development of marketplace for multiple DSOs to procure flexibity.
Cornwall [191] (UK)	CM	Hybrid	Buyer: DSO Seller: Aggregator, Large prosumer	Auction-based	Virtual marketplace to procure flexibility services from homes and businesses to serve the need of DSO and TSO in co-ordination.
StoreNet (Ireland)	CM, VM	Centralized	Buyer: DSO Seller: Aggregator, Prosumer	Optimization-based	Market platform to procure flexibility from end-users' storage facilities through aggregator to serve DSO's need.
FlexGrid (Europe)	CM, VM	Centralized	Buyer: DSO, TSO Seller: Aggregator, Prosumer	Pay-as-bid, Auction-based	Automated trading platform for all market actors, grid management platform for DSO/TSO, flexibility aggregation tool for aggregators.
Power Potential (UK)	VM	Hybrid	Buyer: DSO, TSO Seller: Aggregator, Large prosumer	Auction-based	Market platform for reactive power support and dynamic voltage control for transmission grid from distributed energy resources connected in the distribution grid through TSO-DSO co-ordination.

CM: Congestion Management, VM:Voltage Management, LB: Local Balancing, LLR: Line Loss Reduction.
* Projects implementing blockchain technology.

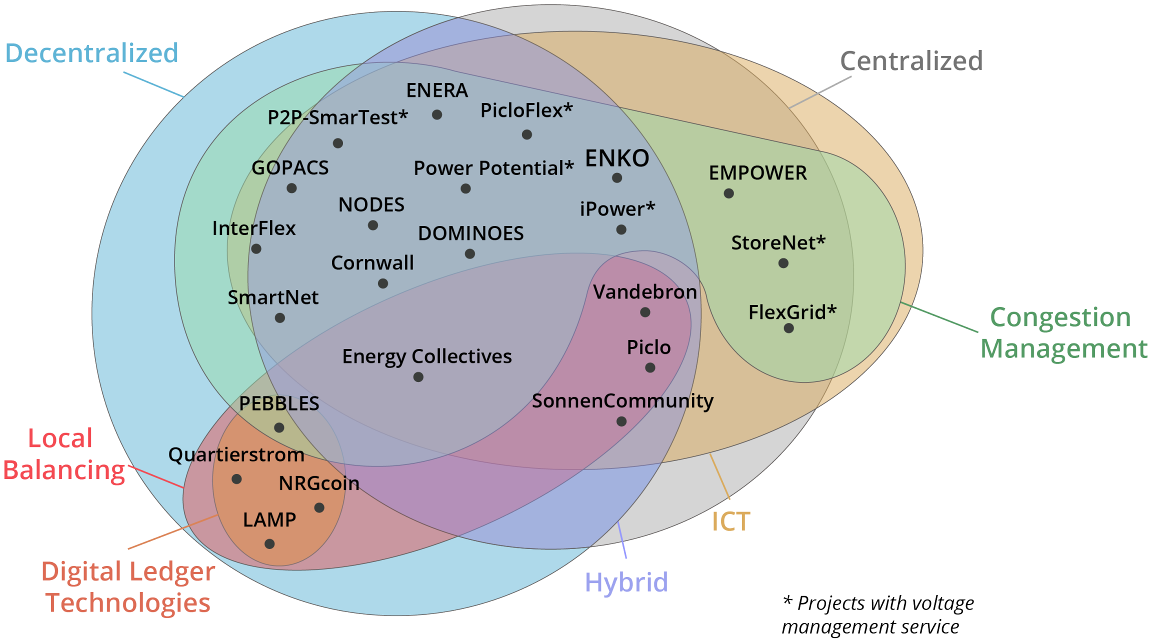


FIGURE 5: Key R&D projects with necessary key features.

aggregating flexibility from small-scale end-users to trade with external flexibility buyers and thus provide examples of a hybrid approach. iPower is such a local flexibility market project with a community-based structure where the DSO and TSO submit their flexibility requirements and aggregators offer to sell flexibility from end-users [192], [193].

2) Grid modeling

Integration of grid constraints into the market design is another crucial aspect of the local electricity market. Currently, R&D projects incorporate grid constraints either explicitly through mathematical formulation in market clearing as discussed in Section III or implicitly through solving power flow equations separately to validate market positions. The SmartNet project tested a range of network models with various market clearing algorithms to understand the computational tractability and validate different types of problem constraints covered. Finally, it applied a DC model for its transmission network model along with a comprehensive second-order cone programming model (SOCP) for the distribution network [194]. Such a SOCP convexification takes into account line losses, bus voltages and both active/reactive power flows. The DOMINOES project assigns the DSO the role of a technical validator for the market dispatch. This is formulated as an external actor, hence the network model is not included in the market clearing algorithm [195]. The PEBBLES project enforces a matching algorithm allowing a maximum volume which can be submitted/retrieved by individual participants in order to respect the capacity boundaries of the grid assets. The restrictions are dynamic and depend upon the underlying grid topology and the forecasts of renewables and loads [173]. The Quartierstrom project investigated locational grid tariffs incentivizing local consumption on the community level and reduced grid usage at higher voltage [176]. The FLEXGRID project envisions a novel market architecture where transmission-level market operators and distribution-level flexibility operators iteratively clear the market while considering the distribution network constraints, the bids from distribution network connected resources and the forecasted locational marginal price at the transmission node [196].

3) Market Clearing

The literature also shows a trend for both centralized and decentralized market clearing mechanisms in local electricity market R&D projects. The EMPOWER project implements a centralized market clearing platform that selects flexibility providers based on an optimization problem formulated to serve the DSO requests at minimum cost [197]. The P2P-SmarTest project presents a comparative analysis of two decentralized market clearing approaches: a dual decomposition theory based optimization technique and a non-cooperative game theoretic model [198]. The PEBBLES project executed an auction-based market matching algorithm and uses blockchain to settle contracts [173]. The Nodes Market project [199], [200] as well as the Enera

[172] and GOPACS [168] projects are focused on intraday timeframes and implement continuous trading as employed in traditional European intraday markets. The choice of the market clearing approach in the R&D projects depends upon the objectives and structure of the local electricity markets. Centralized market clearing approaches are prioritized in projects where trustworthy relations exist between end-users and the chosen local electricity market clearing entity and where scalability is not a crucial concern due to the limited number of participants in the market design. Projects with an emphasis on limited sensitive data sharing among market participants and less scalability on the other hand mostly implement decentralized market clearing approaches.

Table 7 presents key R&D local electricity market projects across Europe summarizing key features: grid services, market models, major market participants and market clearing approaches. Figure 5 further provides an illustration of key features of the projects enumerated in Table 7.

V. CONCLUSION

This paper presents a comprehensive review on the topic of local electricity markets, with a specific focus on recent literature and on the challenges of their modeling, implementation, analysis and management. To achieve this, the paper starts with an introduction to the topic and an analysis of previous literature studies that show a lack of literature on local electricity markets that extend beyond peer-to-peer implementation. Focusing on a more general level and including all three identified topologies - centralized, hybrid and decentralized local electricity markets, the paper then categorizes the challenges associated with local electricity markets. These challenges are classified into five areas: distribution of generation, integration of demand response, decentralization of markets, the legal framework of implementation and the associated social aspects.

Next, the paper introduces modeling approaches via a technical summary of analysis and operational models whilst pointing to specific recent literature examples. These examples are also classified into various categories, for example based on the applied market clearing mechanisms, the physical grid or other technical specifications such as the consideration of uncertainty and balancing markets/services. The resulting chapter on modeling offers an overview of the theoretical side of local electricity market implementation, analysis and administration and thus provides a starting point for prospective model users and researchers alike. The practical aspects of such local electricity markets are then discussed in the final part of the paper, which introduces numerous, mainly European projects realizing local electricity markets. Similar to the theoretical models, these practical projects are also categorized by their main focus and further put into relation to the previously derived challenges in order to present a mapping of the project landscape.

In the analysis we found a lack of literature specifically focusing on the challenges of integration of uncertainty, coordination of grid and local electricity market resources, scalability of theoretical approaches, specifically for hardly tractable problems such as multi-period problems, and standardization of methods and topologies.

In conclusion it can be stated that the paper provides a general analysis of the research on local electricity markets, incorporating quantitative as well as qualitative aspects whilst structuring and classifying the available literature with a strong focus on the derived challenges. In contrast to the majority share of previous literature studies listed in the introduction, the main focus of this paper does not lie specifically on peer-to-peer markets and Information and Communication Technologies, thus distinguishing it from the bulk of research on the topic. Albeit it introduces and discusses these topics, it takes a more holistic view and instead focuses on the localization and thus more on associated aspects such as the physical grid or social aspects.

Thus, the paper provides a starting point for future research into establishing local electricity markets. Due to a focus on the challenges it is able to provide a foundation for topics of growing importance such as increasing uncertainty, distribution of generation resources and growing democratization of the power grid and its' generation assets.

ACKNOWLEDGEMENT

The authors want to thank the partners and project consortium of the project "BEYOND - Blockchain based ElectricitY trading for the integration Of National and Decentralized local markets" as well as the European Union and the Norwegian Research Council for making this research possible. This paper was prepared as a part of the Digital Economy (DigEco) project funded by the NTNU Digital Transformation Initiative (p. nr. 2495996).

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Paper II

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Cite as:
S. Bjarghov, H. Farahmand, G. Doorman
"Capacity subscription grid tariff efficiency and the impact of uncertainty on the subscribed level"
Elsevier Energy Policy, Volume 165, 2022.
DOI: 10.1016/j.enpol.2022.112972
URL: `https://doi.org/10.1016/j.enpol.2022.112972`

Energy Policy 165 (2022) 112972

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Capacity subscription grid tariff efficiency and the impact of uncertainty on the subscribed level

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ARTICLE INFO

Keywords:
Grid tariffs
Capacity subscription
Efficiency
Peak pricing
Uncertainty

ABSTRACT

While volume-based grid tariffs have been the norm for residential consumers, capacity-based tariffs will become more relevant with the increasing electrification of society. A further development is capacity subscription, where consumers are financially penalised for exceeding their subscribed capacity, or alternatively their demand is limited to the subscribed level. The penalty or limitation can either be static (always active) or dynamic, meaning that it is only activated when there are active grid constraints. We investigate the cost impact for static and dynamic capacity subscription tariffs, for 84 consumers based on six years of historical load data. We use several approaches for finding the optimal subscription level ex ante. The results show that annual costs remain both stable and similar for most consumers, with a few exceptions for those that have high peak demand. In the case of a physical limitation, it is important to use a stochastic approach for the optimal subscription level to avoid excessive demand limitations. Facing increased peak loads due to electrification, regulators should consider a move to capacity-based tariffs in order to reduce cross-subsidisation between consumers and increase cost reflectivity without impacting the DSO cost recovery.

1. Introduction

1.1. Background

As a measure to reduce greenhouse gas emissions by 55% in order to reach the 2030 climate targets (Government, 2021), Norway is considering a significant increase in electricity consumption by electrifying transport, off-shore installations such as gas power plants at oil and gas platforms, as well as various industries (Haukeli et al., 2020; Statnett, 2020). Meanwhile, household peak loads are expected to increase due to charging of electric vehicles (EVs) and electrification of heating. This might increase peaks loads in parts of the grid, which could result in significant expected grid investments in coming years.

Against the backdrop of these developments and with the intention to reduce grid investments, the Norwegian regulator (RME) proposed several new grid tariff structures to incentivise demand response during peak load hours. One of the suggestions by the Norwegian regulator, is a capacity subscription (CS) tariff, where customers subscribe to a capacity level. Similar to current grid tariff structures, it contains an annual fixed cost reflecting the distribution system operator's (DSO) fixed costs. In addition, there is a capacity cost per kilowatt, with some resemblance to an internet subscription with a specific bandwidth speed. Demand below the subscription level has a small energy term, which reflects marginal grid losses, whereas demand above has a high energy term, which penalises excess use. This CS tariff thus incentivises customers to keep their demand below the subscribed capacity level. The tariff is "static" in the sense that it always penalises excess consumption, regardless of whether the grid has any congestions. This is sub-optimal in terms of cost-reflectiveness, as consumers are penalised for their peak demand whether there is a system peak or not.

To address the issue of system versus consumer peak coincidence, we suggest a "dynamic" CS as an alternative, where capacity limits are only activated when there is scarcity of grid capacity. In the case of scarcity, consumers are physically limited to their subscribed capacity using load limiting devices (LLD), unlike the static version where only an excess energy term has to be paid.[1] This dynamic capacity subscription concept is more efficient because there is no penalty for using capacity when there is no scarcity. This form for capacity subscription was first presented in (Doorman, 2005), but there it focused on the power market

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[1] It would also be possible to use a "financial" version, which would include payment for excess demand like in the static tariff. The excess cost coefficient would be higher because activation is done only sporadically.

https://doi.org/10.1016/j.enpol.2022.112972
Received 4 November 2021; Received in revised form 25 March 2022; Accepted 4 April 2022
Available online 25 April 2022

Nomenclature

Indices and Sets

J	Set of value of cut load segments, index j
S	Set of load scenarios, index s
T	Set of time steps, index t
T^{act}	Set of time steps with activation from the DSO

Parameters

C^{fix}	Annual fixed grid tariff cost $[\frac{€}{year}]$
C^{h}	Grid tariff excess energy cost $[\frac{€}{kWh}]$
C^{l}	Grid tariff energy cost $[\frac{€}{kWh}]$
C^{sub}	Grid tariff subscribed capacity cost per kW per year $[\frac{€}{kW-year}]$
$C_j^{V\,CL}$	Value of cut load $[\frac{€}{kWh}]$
L_{ts}	Load [kWh/h]

Variables

x^{sub}	Subscribed capacity [kW]
$x_{tsj}^{V\,CL}$	Cut load in segment j [kWh/h]
x_{ts}^{h}	Bought electricity above sub. cap. [kWh/h]
x_{ts}^{l}	Bought electricity below sub. cap. [kWh/h]

instead of the grid. "Activations" of the LLDs would be done by the DSOs, which issue warnings in advance. Customers then have a reasonable amount of time to plan for reducing demand during the activations, directly by demand response or indirectly by utilizing flexibility from distributed energy resources (DER), such as space heating, batteries or electric vehicles. Smart meters make it possible not only to analyse demand patterns to find a fitting subscription limit but also to implement such a grid tariff structure.

In previous work by the authors, "static" and "dynamic" CS tariffs were analysed for a single customer for one year (Bjarghov and Doorman, 2018), where the results showed mainly two things: sub-optimal static subscribed capacity levels do not critically influence annual costs, and the dynamic optimal subscribed capacity level depends heavily on amount of activations, which is unknown ex ante. Furthermore, the need for a more extensive study covering more customers and uncertainty in demand was highlighted. Capacity subscription was also found to be the market design that was closest to optimum and leads to highest surplus on the consumer side rather than the supply side (Doorman and Botterud, 2008).

The issue of social fairness has been raised in response to the suggested network tariff change. Although new price signals and incentives to shift towards more grid-friendly demand profiles can result in reduced socioeconomic costs, this may have undesirable distributional side effects. In essence, customers with grid-friendly demand profiles should have reduced costs and vice versa, given a properly designed, cost reflective grid tariff structure. The EU commission has highlighted in the "Clean Energy For All Europeans" package (E. Commission, 2019) that *"The package also contains a number of measures aimed at protecting the most vulnerable consumers"*. It is thus important to consider if vulnerable consumers could be harmed by the proposed tariff change. Further, economic efficiency is not the only criterion of a grid tariff design. For the DSO, cost-recovery and stability of annual revenues are particularly important. On the consumer side, fairness and acceptance are considered to be of high importance. These qualitative criteria are challenging to define, which makes grid tariff design a difficult task (Brown et al., 2015; Pérez Arriaga and Knittel, 2016). Still, the change from energy-based to capacity-based tariffs is also taking place in the Dutch speaking part of Belgium, Flanders, which will introduce a capacity-based grid tariff from mid 2022. For households and small companies, this is based in the rolling-average monthly 15-min peak, with a minimum value of 2.5 kW (VREG, 2020).

1.2. Literature overview

Fairness-related issues of grid tariffs have also been discussed in recent literature. A redistribution of costs between residential consumers was shown in (Saele, 2017), where up to 15% of the costs were shifted from consumers with low peak loads to consumers with high peak loads. A cost-redistribution could mean exposing vulnerable consumers, but demand charges do not disproportionately impact low-income customers (Hledik and Greenstein, 2016), and in general does not result in very large cost re-distributions. Further, (Burger et al., 2020) points out that a two-part tariff mitigates the potential average increase in tariff costs for low-income customers. Capacity tariffs are found to be more fair than flat, peak and Ramsey pricing in (Neuteleers et al., 2017). Although working well, capacity-based tariffs might lead to over-investments in demand response or other types of flexibility which might lead to other competition-related issues where flexibility owners push costs over on other customers (Schittekatte et al., 2018). Thus, it is vital to not over-dimension capacity-based price signals, as the lack of "flexibility capital" in combination with substantial price signals might increase energy poverty for vulnerable consumers, forcing a squeeze between daily chores and cost of electricity use (Fjellsaa et al., 2021).

An advantage of capacity-based tariff structures is the removal of cross-subsidisation of distributed generation, which is an increasing issue with the rapid increase in photovoltaic panels (Schreiber and Hochloff, 2013; Hledik, 2014; Picciariello et al., 2015). (Jargstorf et al., 2013) also claimed that tariffs were more efficient with a fixed, energy-based and capacity-based share to reduce cross-subsidies.

Demand charges are relatively common for commercial and industrial customers. With the use of smart metering, the peak load of a certain time period (typically monthly) is measured and the consumer pays per kilowatt or megawatt peak. The authors in (Schreiber and Hochloff, 2013), observe that demand charges (like in Flanders (VREG, 2020)) have the "early peak" issue where an early peak in a monthly measured network tariff structure removes incentives for reducing peak loads for the rest of the tariff period. This does not occur with CS tariffs as the excess energy term applies for all peaks above the subscription level. Further, (Bartusch et al., 2011) showed that consumers were relatively positive to demand-based tariffs under the assumption that the consumers could easily monitor their demand.

Like the static version of the capacity subscription tariff, demand charges are inefficient if the customer peak does not coincide with system peak (Borenstein, 2016). There has also been claims that energy-based tariff costs correlate strongly with peak-demand, suggesting that demand-based tariffs are unnecessary (Blank and Gegax, 2014). This is supported by (Borenstein, 2016) in which the authors also question whether demand charges are cost-reflective as system and consumer peak do not necessarily coincide. However, these claims were made before the increase in residential peak loads seen in countries with a high share of EVs (Saele and Petersen, 2018).

Developments towards lower marginal costs of energy and more capital intensive technologies presently increase interest in solutions based on capacity subscription, both for energy and grid tariffs. Lack of capacity in distribution grids was highlighted as an important barrier for electric vehicle (EV) integration in Norway. In addition to the authors' previous work, (Backe et al., 2020; Pinel et al., 2019; Almenning et al., 2019) pinpoint that the coincidence factor of consumer versus system peaks can be dealt with by forming energy communities (under a neighbourhood tariff). Similar results are achieved in (Hennig et al., 2020), which showed an increased capability of integrating EVs into the distribution grid under a CS tariff scheme. Also under competitive, local electricity market schemes, the market is able to flatten peak loads (Bjarghov et al., 2020). An example is shown in (Askeland et al., 2021), where the concept of EV integration was demonstrated in a real case study in Norway, where a neighbourhood were able to adopt more EVs by coordinating flexible resources under capacity-based tariffs. Consumers adapting to grid tariffs is an apparent consequence of higher distributed energy resources shares in the future.

1.3. Contributions & paper organisation

The purpose of this paper is to investigate the economic impact and efficiency of CS tariffs on consumers and DSO. Therefore, we analyse the impact on passive consumers (with neither production nor flexibility) under static and dynamic CS tariffs for 84 customers with six years of demand data. The main contributions of this paper are the following:

- We analyse the economic impact of static and dynamic capacity subscription grid tariffs for larger sample of consumers over multiple years.
- We propose a method to determine the optimal subscription level based on a stochastic approach and demonstrate the advantages of this method compared with the naive approach of using the previous year's data.
- We demonstrate how many consumers that experience significant cost deviations from capacity subscription tariffs compared with existing tariffs, in relation to their relative peak loads.
- Under dynamic capacity subscription, where demand is limited only when there is a grid scarcity, we investigate the difference in how much capacity consumers procure to avoid excessive demand limitations compared to the static variant, modelled by an assumed discomfort function.

The remainder of the paper is organised as follows: Section 2 discusses the CS grid tariff design. The model is presented in Section 3, followed by the case study description in Section 4. Results and discussions are then presented in Section 5, followed by conclusions and further work suggestions in Section 6.

2. Capacity tariffs

2.1. Static capacity tariff

The capacity subscription tariff proposed by the regulator has four components: a fixed annual cost (€), a capacity cost (€/kW), an energy cost (€/kWh) and an excess demand charge (€/kWh). Note that, in addition to the grid tariff, the consumer pays for electricity and taxes, but in this paper we only focus on the grid tariff. The annual consumer grid cost is calculated as shown in (1).

$$C^{tot} = C^{fix} + C^{sub} \cdot x^{sub} + \sum_t (C^l \cdot x^l_t + C^h \cdot x^h_t) \tag{1}$$

In (1), x^{sub} is the subscribed capacity, x^l the annual consumption below the subscribed capacity level and x_h the demand in excess of the subscribed capacity. C^l is meant to cover the average losses in the grid and is typically around 0.5 €ct/kWh. Because C^h is significantly higher, the consumer has an incentive to keep demand below the subscribed capacity, x_{sub}. Finally, C^{fix} represents the fixed costs and C^{sub} is the cost per kilowatt subscribed capacity per year.

According to the regulation, the grid companies that apply CS tariffs will be obliged to recommend the x^{sub} minimising C^{tot} to the consumer. Because hourly demand data will be available, this is in principle an easy task based on ex post data. An updated proposal required that the last 12 months are used for determining the subscription level; it is changed dynamically each month. In our analyses, we will find the optimal x^{sub} based on six years of data, but we will also look at other ways to find x^{sub}.

In this study, customers can subscribe to any capacity, whereas, in reality, it is reasonable to assume that customers have to choose between discrete steps with e.g. 0.25, 0.5 or 1 kW intervals. A high resolution of choices makes it more complicated for customers to choose, whereas a low resolution, with e.g. 1 kW intervals would create sub-optimal conditions for customers with a low consumption due to a high deviation between optimal subscribed capacity (e.g. 1.5 kW, and the choices that would be 1 or 2 kW). This is less relevant as annual demand (and thus average demand) increases. We abstract from this issue and assume a continuous scale in our study to get a more precise idea of which subscription levels are optimal.

One of the design parameters of subscription-based tariffs is the frequency of subscription level updates. From the perspective of the DSO, annual subscription might be preferable, especially when demand is strongly influenced by seasonal variations. On the other hand, consumers need flexibility with respect to changing circumstances. Examples of changing circumstances that heavily influences the optimal subscription limit could be moving or investments in demand increasing/decreasing assets such as EVs, house insulation upgrades or heat pumps.

In this paper, we (among other approaches) investigate a subscription level which is decided annually ex ante. However, in a real implementation it must be possible to adjust the level during the year, without allowing consumers to subscribe to a low level in a typical low load season (summer in a cold climate) and then increase subscription during a high load season. If this were allowed, capacity prices would need to be adjusted correspondingly. The approach proposed by the Norwegian regulator, to base subscription on demand during the last 12 months, updated on a monthly basis, solves the problem of the frequency of update, but is sub-optimal as we will show in this paper. Moreover, it only partly takes into account major changes in demand, which will only slowly result in a corresponding change in subscribed capacity. Another possibility is that capacity is paid for on an annual basis, but that is a secondary market for shorter commitment periods. We do not elaborate on this issue in this paper, but it is an open issue for further research.

2.2. Dynamic capacity tariff

Capacity subscription was proposed in (Doorman and Botterud, 2008) for the power market. In (Doorman and De Vries), the authors also indicated the possibility to use the same model for the grid tariff structure. An essential feature of the dynamic CS is that demand is limited to the subscribed capacity when there is scarcity in the system (i.e. not enough generation capacity in the "market case" or an active grid constraint in the present context). In such cases, the DSO (or TSO) activates a Load Limiting Device (LLD), effectively limiting demand. To make this acceptable for the consumer, it is necessary to have intelligent load control that keeps demand below the subscribed limit, by switching off non-essential demand like floor heating or other appliances. Delaying the charging of EVs is also very well suited to keeping demand right below the limit. Here we use the term "dynamic" CS, to distinguish it from the tariff proposed by the Norwegian regulator (vard Hansen et al., 2017). The consumer cost is very similar to equation (1), but there is no excess consumption above the subscription level, because demand is limited instead. On the other hand, the consumer experiences a partial loss of load, which in effect is a welfare loss that needs to be considered in the cost optimisation. The annual customer total cost under the dynamic CS tariff scheme is presented in (2).

$$C^{tot} = C^{fix} + C^{sub} \cdot x^{sub} + \sum_t (C^l \cdot x^l_t + \sum_j C^{V\ CL}_j \cdot x^{V\ CL}_{tj}) \tag{2}$$

The costs are very similar to the static CS tariff, but instead of an excess energy term, consumers experience a discomfort cost ($C^{V\ CL}_j$ which increases the more load $x^{V\ CL}_{tj}$ is cut. Because the discomfort costs increases exponentially as more load is cut, this is segmented (indexed by j) in a piecewise linearised fashion. The discomfort costs are discussed in detail in Section 2.2.1.

2.2.1. Discomfort costs

To determine the optimal subscription level for dynamic CS, the consumer cost of having to reduce load must be taken into account. This cost cannot be observed, like the excess demand cost C^h under the static CS tariff. The value of lost load typically depends on customer type and duration of disconnection, and represents the discomfort costs of electricity not served. However, under the dynamic CS scheme, the load is only limited and not completely disconnected. As stated in Section 2.2, intelligent load control can be utilised, disconnecting only non-essential demand, which further leads to lower comfort loss. The value of cut load (C^{VCL}) is a function of how much load is disconnected, and is based on the value of lost load (VoLL), which is an estimate of the discomfort cost of not having any load served in euro per kilowatthour. We use the formulation in (3), which was also used in (Bjarghov and Doorman, 2018).

$$C^{VCL} = \frac{VoLL}{1 - e^{-b \cdot L}}\left(1 - e^{-b(L - x^{sub})}\right) \quad (3)$$

Value of cut load is represented as a value between 0 and VoLL as a non-linear curve as demonstrated in (3). The curve steepness is given by b. The load L and subscribed capacity level x^{sub} decides the discomfort cost in a certain time period. If L never exceeds x^{sub} (which translates to subscribing to the maximum demand), discomfort costs will be zero. The impact of different values of b is visualised in Fig. 1. A steep VCL curve (high b) translates to the consumer having high discomfort costs of curtailing a relatively low share of the consumer's load. A low steepness (low b) implies that the consumer is quite flexible and can curtail more load without experiencing high discomfort. In this paper, we assume a steepness b of 8, resulting in a relatively steep discomfort cost curve, as shown in Fig. 1. This level implies that the cost of flexibility (and thus discomfort costs) is relatively high, and also only results in small reductions in load. In reality, this level could be adapted to each individual customer based on their real discomfort costs.

If a consumer has a peak load of 5 kW, the curtailment of 1 kW (20%) should have a similar discomfort cost as a consumer with a 10 kW peak load who is curtailed 2 kW (also 20%). This is a necessary simplification made to be able to compare curtailment of different customer types. In this approach, C_j^{VCL} is decided based on the maximum load of the consumer in the specific year that is simulated. The consequence is that 1 kW of curtailment is not given the same discomfort cost for all consumers. The value of lost load depends on customer type, duration and time (Schröder and Kuckshinrichs, 2015), but we simplify by setting it to 5 €/kWh.

2.2.2. Activation of capacity subscription

An important advantage of the dynamics CS tariff is that it does not punish load above the consumer's subscription limit in non-scarce hours, and thus avoids the welfare loss caused by excess payment for a non-scarce resource. It also rewards flexible users who can reduce their consumption when the system requires it the most, or customers who simply do not have a high consumption when there is grid scarcity, as those consumers could subscribe to lower capacities and thus reduce their annul grid tariff costs. The system peak load varies from year to year because some winters are colder than others. The DSO will therefore invest in grid capacity that covers the highest peak in not only a year, but for several years. If there is a considerable penetration of electrical heating, this means that a winter without very cold periods could have no capacity scarcity, whereas years with cold periods would result in many hours with capacity scarcity. This makes it challenging to find a correct number of activations. If the DSO sets the threshold for activation relatively low, there could be so many activations that customers are incentivised to subscribe to a capacity close to their peak load to avoid high discomfort costs. The mentioned scenario would not increase social welfare much as the situation would remain quite similar as it is today where end-users indirectly pay to use whatever peak they want. If the threshold is high, the entire basis for choosing a subscription limit is based on very few hours per decade, which incentivises speculation in subscribing to 0 kW as well as demand response investments. This could make it difficult for the DSO to recover their existing costs, although they are reduced somewhat due a reduced peak load. To keep a good compromise between the two, there needs to be some activations each year, even if there is no severe capacity scarcity in the system.

Although the CS tariff primarily aims to reduce costly future distribution grid investments by incentivising customers to reduce peak loads, the DSO is not the only stakeholder here. The TSO who owns the transmission grid also has an interest in reducing future grid investments by avoiding growth in capacity use in areas with an increase in load. TSO and DSO interests therefore align because DSOs pay transmission grid rent in the hour where the total peak demand is the highest in the region. It is therefore realistic that both distribution and transmission grid-related congestions could lead to activations. Note that in this study we only base activations on local congestions.

Another important aspect of activations based on local congestions is if activations should be across the whole DSO grid (to avoid discrimination) or if they can be limited to overloaded radials only. Clearly, the latter would be the efficient solution, but it may contradict with rules on equal treatment. The present rules in Norway do not allow, e.g., different tariffs within the same DSO area, but it is not evident that a different number of LLD activations would fall under this requirement. However, this looks probable. On the other hand, it is clearly inefficient to activate LLDs across the whole DSO area because one or two radials are overloading, and this problem increases as the DSOs merge and become larger. A possible solution could be to reduce the fixed part of the tariff C^{fix} for consumers on "weak" radials that can expect more LLD activations.

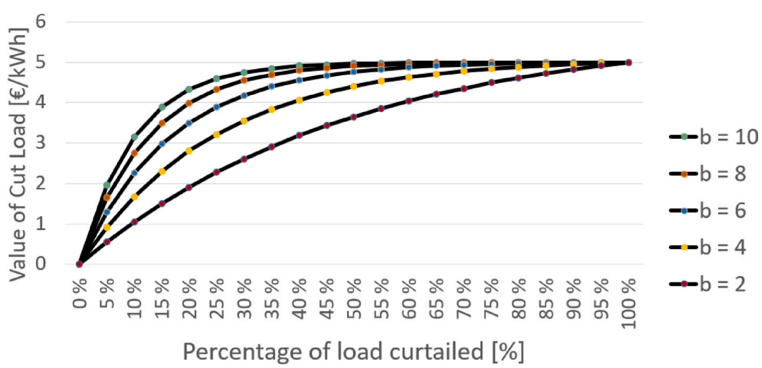


Fig. 1. Value of cut load with different steepness levels. VoLL is 5 €/kWh.

3. Model

3.1. Stochastic optimal static subscribed capacity problem

In Norway, the demand is weather dependent due to high penetration of electrical heating. Future demand is therefore unknown and varies from year to year. Therefore, choosing the optimal subscription level is a stochastic problem. We model this by using a number of historical weather years, represented by the index s, each having a probability p_s. Ideally, these years should present a statistically representative sample for the expected weather conditions. The consumer's objective function is given by (4).

$$\min\ C^{fix} + x^{sub}C^{sub} + \sum_{s}\sum_{t} p_s(x^l_{ts}C^l + x^h_{ts}\cdot C^h) \tag{4}$$

Energy bought from the grid is split into energy below (x^l_{ts}) and above (x^h_{ts}) the subscribed capacity x^{sub} in (5) and (6). The total energy bought must cover the load of the consumer L_{ts} which is subject to uncertainty.

$$x^l_{ts} + x^h_{ts} = L_{ts} \quad \forall t, s \tag{5}$$

$$x^l_{ts} \le x^{sub} \quad \forall t, s \tag{6}$$

3.2. Stochastic optimal dynamic subscribed capacity problem

In this case, the consumer's objective function is given by (7). The objective is straightforward, with an annual fixed cost, a subscription cost and an energy fee. In contrast to the static CS tariff, excess energy use is no longer possible, and the discomfort cost C^{VCL}_j replaces C^h. Because consumers have different load profiles and annual demand, C^{VCL}_j must be tailored for each consumer. The values used in these simulations are based on the curve presented in Fig. 1.

$$\min\ C^{fix} + x^{sub}C^{sub} + \sum_{s}\sum_{t} p_s\left[\left(x^l_{ts}\cdot C^l + x^{VCL}_{tsj}\cdot C^{VCL}_j\right]\right. \tag{7}$$

Energy from the grid is split into energy below (x^l_{ts}) the subscribed capacity x^{sub} and the partially curtailed load x^{VCL}_{tsj} above this capacity in (8) and (9). The import is only limited to the subscribed capacity during activations, defined in T^{act} as shown in (9), and further discussed in Section 2.2.2.

$$x^l_{ts} + \sum_{j} x^{VCL}_{tsj} = L_{ts} \quad \forall t, s \tag{8}$$

$$x^l_{ts} \le x^{sub}_t \quad \forall t \in T^{act}, s \tag{9}$$

4. Case study

Hourly load data from 84 customers in the NO1 price zone for the period 2013–2018 were used in the analysis. Because of privacy rules, the data could not be coupled to heating source or other information that might explain the load profiles. To analyse the impact of CS tariffs, the consumer costs under historical load data has been simulated with the existing energy tariff alongside the static and dynamic CS tariff schemes. An overview of all the simulations performed is presented in Fig. 2. They are further explained in the subsequent sections.

4.1. Customer data

A box plot of the spread in full load hours of the consumers is shown in Fig. 3. Full load hours are defined as the total annual demand divided by the peak load. A high number indicates that the peak load is significantly higher than the average load and vice versa. Full load hours therefore indicate whether or not the customer has a flat, stable demand profile or few, large demand spikes.

The median value is around 2300 h for all years. It is lowest in 2014 and highest in 2017, the warmest and next coldest year, respectively, cf. Section 5.1. This looks counter intuitive as one would expect the highest demand in the coldest year. However, even warmer years have a few cold days resulting in high demand. On the other hand, cold years have high energy consumption, which reduces the full load hours, and consequently there is no direct relation between the lowest temperature and the number of full load hours.

4.2. Grid tariff costs

The underlying principle when setting the prices for the CS tariffs is that the income of the DSO remains the same after the transition from the present energy tariff. The annual fixed cost is set to the same for both CS tariffs. This is also the case for the energy term, which is set to the cost of marginal losses, estimated at about 0.5 €ct/kWh. We then vary the capacity cost until we find the level that results in approximately the same (aggregated) consumer costs as with the present tariff. All cost levels for CS and existing energy-based tariffs are shown in Table 1 and Table 2, respectively. Finally, it is assumed that consumers do not adapt to the new tariff.[2]

The short-term consumer benefit does not change under the static CS tariff. It does change for the dynamic variant, which is taken into account through the calculation of the discomfort costs, cf. Section 2.2.1.

Correctly pricing the dynamic CS tariff is not straightforward, because the underlying principle of DSO cost recovery must be reconsidered. When demand is physically limited to the subscribed capacity, DSO revenues are reduced, because there is no payment for excess demand. On the other hand, over time, this has the potential of significantly reducing grid investments. We therefore argue that it is acceptable that DSO revenues decrease with dynamic capacity subscription, because costs will decrease over time. Instead, we consider that the consumers on aggregate should not be worse off when also taking into account the increase in consumer costs (or rather, reduction in benefit) caused by the demand reduction during LLD activation. The increase in consumer costs is calculated using the VCL model explained in Section 3.2. The consumer cost is also an expected value, as the number of activations is unknown in advance. The value of lost load is set to 5 €/*year*, staying in line with most European countries, especially in Northern Europe (ACER; Swinand and Natraj, 2019). It is slightly above the present technical limit in the Nordpool day-ahead market of 4.5 €/*year*.

4.3. Activations

As mentioned in Section 2, we base activations on local congestions. We assume that the DSO activates the LLDs when the aggregated load of the 84 customers exceeds 390 kWh/h (peak load is 458 kWh/h). This is based on the idea that this would be the limit in the local grid, but the number is chosen to obtain results that illustrate the impact of the various tariff choices well. This means that we get a total of 291 h of activation in 6 years, or 0.55% of the time. Those time periods represent the time periods in T^{act} as shown in (9). We see from Table 3 that more than half of the activations occur in 2015, whereas 2013 and 2016 have very few activations with only 13 and 10, respectively.

We used the same probability of occurring for each of the six years, because it is difficult to map those years convincingly on longer historical records of winter temperatures. Even if this could be accomplished, it is not a good measure of the number of activations, as argued

[2] This is, of course, a conservative assumption. By adapting behaviour, especially consumers with high peak demand, will save costs and become better off than shown in the subsequent analyses. The whole point of introducing capacity-based tariffs is to change consumer behaviour. Note that for dynamic capacity subscription, there is an imposed change in behaviour, i.e. keeping demand below the subscription limit during LLD activations.

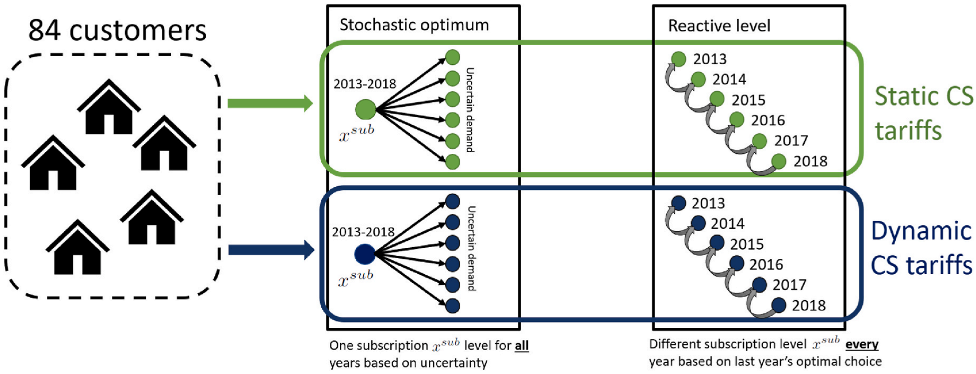


Fig. 2. Overview of the case studies.

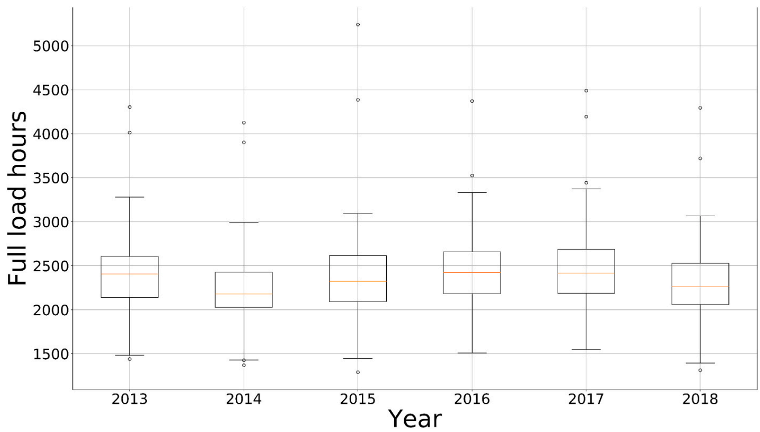


Fig. 3. Boxplot of 84 customers' full load hours. The median is shown as the orange middle line. The box contains the 25 and 75% quartiles, whereas the whiskers are 1.5 standard deviations. Outliers can be found outside the whiskers. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 1
Capacity subscription tariff costs.

Cost element	Cost	Unit
Fixed cost	135	*€/year*
Capacity cost (static)	67.5	*€/year*
Capacity cost (dynamic)	54	*€/year*
Energy term	0.5	*€ct/kWh*
Excess energy term	10	*€ct/kWh*
Value of lost load	5	*€/kWh*

Table 2
Present energy tariff costs.

Cost element	Cost	Unit
Fixed cost	204.6	$\frac{€}{year}$
Energy term	1.859	$\frac{€ct}{kWh}$

above. How probabilities should be allocated, to the number of activations is a key topic for further research, as this is an important parameter for the optimal subscription level.

Table 3
Overview of activations for all years.

Activations	2013	2014	2015	2016	2017	2018	Total
Hours	13 h	42 h	148 h	10 h	19 h	59 h	291 h
% of hours	4.5%	14.4%	50.9%	3.4%	6.5%	20.3%	100%

5. Results & discussion

An important question for capacity subscription is: to what level of capacity should a particular consumer subscribe? With perfect foresight on demand and activations, this is a simple optimisation problem, but in reality, demand and prices are, of course, unknown. Still, the perfect foresight solution can be used as a benchmark. We compare this with two other, realistic options:

- Stochastic optimal subscribed capacity (stochastic optimum)
- Reactive subscribed capacity (reactive level).

The *stochastic optimal subscribed capacity* is the subscription level resulting in the lowest expected annual cost under uncertainty. By considering uncertainty in domestic load, both high or low consumption profiles are taken into account when choosing a capacity level.

The *reactive subscribed capacity* is the subscribed capacity level based on the optimal level from the previous year. Essentially, this approach uses the exact same demand profile and activation pattern as from the previous year.

We find the stochastic optimum, based on the six scenarios with load profiles for 2013–2018. Temperatures dominate the load profiles in Norway due to high share of electric heating in households, making it important to have load data from both warm and cold winters to analyse the impact of the resulting consumption.

As stated before, we only consider grid tariff costs, and ignore taxes, fees and electricity prices.

5.1. Static capacity subscription

5.1.1. Stochastic approach

Under static CS tariffs, the optimal subscribed capacity level results in the best trade-off between capacity costs and the excess energy term costs. Although there are some variations in the optimal subscribed capacity from year to year, the spread is not very large as seen in Fig. 4. The figure compares the annual deterministic optimum to the stochastic optimum. The mean values are in all cases within a 5 margin, whereas the second and third quartile are in all cases within a 10% margin of the stochastic optimum. The most extreme cases show deviations up to 50%, but the whiskers (1.5 STD) mostly stay within a 2% margin.

Due to the perfect foresight, the deterministic optimum will result in lower costs than compared to stochastic optimum. The annual grid tariff costs under the deterministic optimum is therefore never higher than under the stochastic optimum, as shown in Fig. 5. However, the spread in costs is tiny. In almost all the cases, the cost when subscribing to the deterministic optimum and not the stochastic optimum is less than 3% higher. Outliers show that the costs can deviate up to roughly 14%, but this is rare. The spread in costs is surprisingly low compared to the spread in optimal subscribed capacity. However, this is fairly logical, as a higher subscription level results in high capacity costs and lower excess energy costs and vice versa, which is coherent with the results from (Bjarghov and Doorman, 2018).

The sorted curve in Fig. 6 indicates how the new CS tariff compares to the existing energy tariff. The graph shows that the consumer annual costs increases the most in 2018. The 2016 costs reach similar maximum deviations, but not for as many consumers. These results imply that in 2018, the stochastic level is further away from the ex-post optimal deterministic level. This is confirmed in Fig. 4, which shows that a significant number of consumers would preferably subscribe to both lower and higher capacities (the spread is relatively large). However, the costs over the six years are the same (which is how the tariff cost level was set), meaning that costs simply deviate from year to year. This is further elaborated and discussed in Fig. 9, which shows that costs differ from year to year, but not more than the existing energy tariff scheme.

5.1.2. Reactive approach

The stochastic approach requires several years of data in addition to being somewhat complicated. A more straightforward approach would be to use the data from the most recent year. As previously stated, we therefore use the term *reactive subscribed capacity level*, which refers to using the optimal subscribed capacity of the previous year in the current year. For example, the reactive level corresponds to finding the optimal subscribed capacity of 2013 ex post and subscribing to that level in 2014.

The reactive level costs compared to the more robust stochastic approach mostly results in slightly higher costs on average. From Fig. 7, it can be deduced that subscribing to the wrong CS level mostly results in non-dramatic consequences as only outliers exceed an increased cost of 16% compared to the stochastic approach. This is good news for DSOs that are afraid of their customers making sub-optimal choices instead of using the more robust stochastic approach. Outliers give up to 60% increased costs.

The same results as in Fig. 7 is illustrated as a sorted curve in Fig. 8, where we see that acting reactively works relatively well for roughly 80–90% of the consumers (who only experience up to +10% cost increase), but results in high price increases for some consumers.

Looking at the results from a distance, Fig. 9 shows that costs increase by 1.2–2.0% for the total customer group when always subscribing to the reactive subscribed capacity level compared to the deterministic optimum. The figure also shows that there is a significant variation in annual costs, regardless of the tariff. This is good for the DSO, who is interested in predictable cost-recovery, but also for customers who should not experience increasing cost fluctuations with CS tariffs. Of the CS tariffs, the deterministic optimum is obviously always lowest, whereas the stochastic optimum mostly gives lower costs than the reactive, except for 2018 when the reactive subscribed capacity level gives slightly better results. This exception occurs if the demand profiles from two years match relatively well, and both deviate somewhat from the stochastic level. In general, the spread from year to year is relatively small and does not vary more than the existing energy tariff.

5.2. Dynamic capacity subscription

Under the dynamic CS tariff scheme, the load profile characteristics in terms of seasonal variations, flatness and “spikiness” significantly influence the results because activation of the LLD only causes discomfort costs to the consumer if the system peak correlates with the consumer peak. The DSO forecasts demand peaks and sends activations based on expected grid congestions. As peak load hours occur when demand is high, it is natural to assume that the correlation between consumer peak loads and neighbourhood peak loads are high. However, this is not always the case for the individual customer. Customers with flatter load profiles and/or customers with other heating sources than electricity do not necessarily share peak loads with the system. Customers with low correlation between individual peaks and activations will therefore be able to subscribe to relatively low capacities because the discomfort costs during activations are low. Flexible customers who can reduce load during activations will also be rewarded with the dynamic CS tariff. We do not model any flexibility assets in this study, but model demand flexibility implicitly by curtailing some load under the dynamic CS tariff scheme.

5.2.1. Stochastic approach

Results show that customers subscribe to significantly higher capacities under the dynamic compared to the static CS tariff, with the median increase roughly 30% higher, as seen in Fig. 10. This is mostly due to the difference in excess energy cost, which is 0.1 € in the static case, but up to 5 € (VoLL) in the dynamic case because the customers are physically limited, cf. Fig. 1. The capacity cost is also somewhat lower in the dynamic case (adjusted to match the DSO cost recovery). The spread is relatively large, with some customers preferring to subscribe to as little as 40% under the dynamic compared to the static CS tariff, indicating that their peak loads are not coinciding with activations, or that their load profiles are flat. This stands in contrast to some exceptions on the other side of the scale, where two customers subscribe to more than 60% more in the dynamic case, indicating a high correlation between activations and peak loads. It is therefore natural that they would subscribe to more (and thus pay more) because activations result in more load shedding. Due to the heavy variation in deterministic dynamic CS levels, the importance of using a stochastic approach is clear.

Compared to the old energy tariff, Fig. 11 shows a significant spread in annual costs under the dynamic CS tariff. 2015 especially has higher costs due to the high number of activations leading to higher VCL.

5.2.2. Reactive approach

In general, the deterministic optimal subscribed capacity level under the dynamic CS level varies much more from year to year due to the

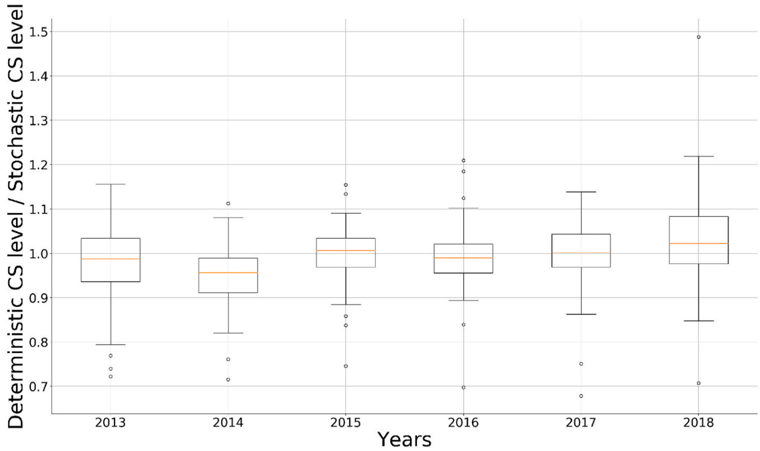


Fig. 4. Boxplot of 84 customers' annual optimal subscribed capacity relative to the stochastic optimum.

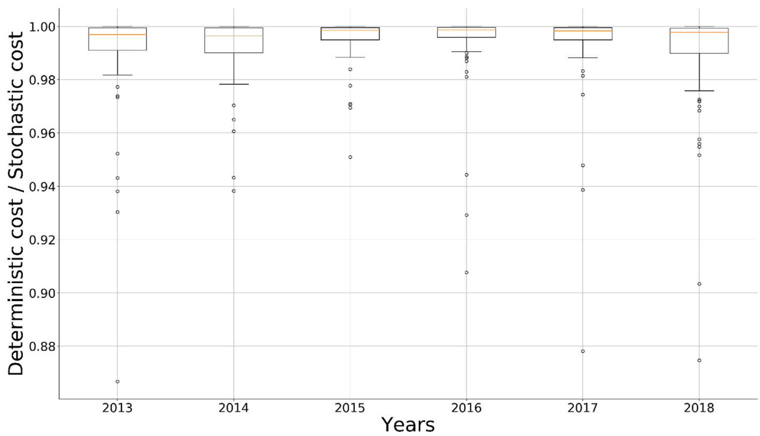


Fig. 5. Box plot of 84 customers' annual cost when subscribing to the deterministic optimal level, relative to the stochastic optimal level.

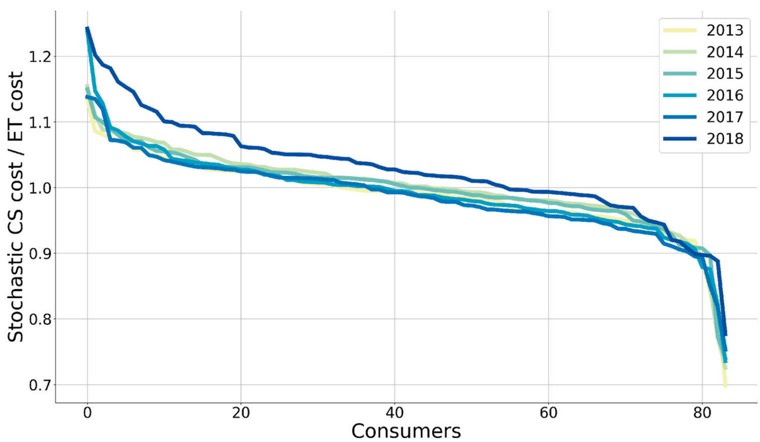


Fig. 6. Sorted annual simulated stochastic customer cost relative to energy tariff costs.

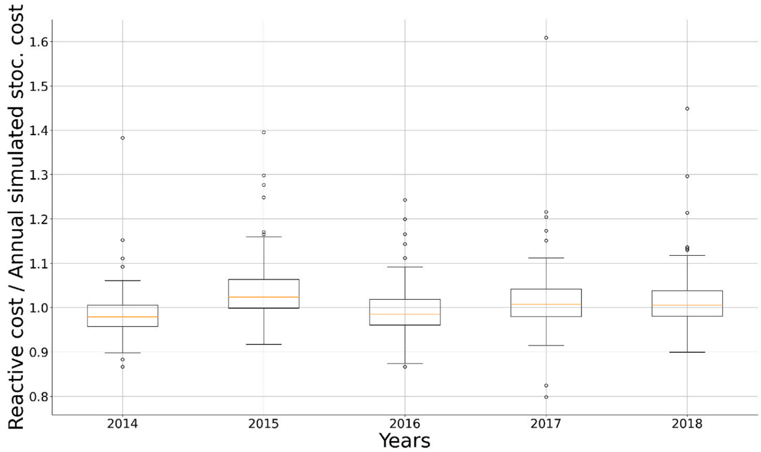


Fig. 7. Boxplot of reactive costs relative to annual simulated stochastic costs. Subscribing reactively gives a higher expected cost, but can in some years pay off as the stochastic cost is not always optimal for all individual years resulting in a relatively large spread in costs.

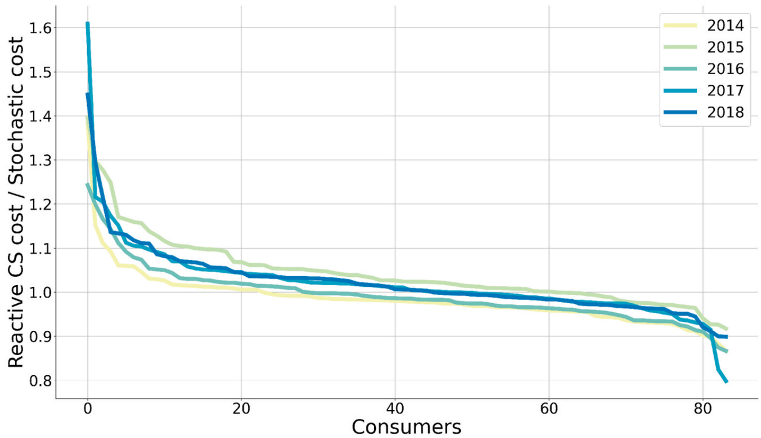


Fig. 8. Sorted curve of reactive costs relative to annual simulated stochastic costs.

difference in number of activations. In a year with few activations, the optimal subscription level can be as low as zero or close to zero because of the low VCL cost. On the other hand, years with many activations results, in a high optimal deterministic subscription level. This shows that the reactive approach cannot be used for dynamic CS.

In Fig. 12, the aggregated annual consumer costs are shown. The blue bars (bottom) represent actual monetary costs (which corresponds to the DSO's income), whereas the red bars on top of the blue are discomfort costs related to the value of cut load and are not monetary costs. The costs under the existing energy tariff scheme are shown as black bars. Acting reactively clearly results in the highest costs as consumers subscribe to sub-optimal levels. This leads to either extremely high discomfort costs if they have insufficient subscribed capacity (as shown in 2017), or close to zero discomfort costs due to subscribing to a high capacity (as shown in 2016). Both cases result from reacting to few or many load limitation activations from the previous year. This also leads to unacceptable variations in the DSO's revenues. When using the stochastic approach, the costs are more stable and relatively similar to the energy tariff costs. The average total cost (monetary + discomfort) are the same (by calibration), but this results in somewhat lower revenues to the DSO. In the long run, this seems acceptable, as dynamic CS probably is very efficient in reducing peak demand, reducing the need for grid investments. Under the stochastic approach, the DSO income is also relatively stable and does not vary more than the energy-based tariff scheme. This is good news for DSOs who rely on stable income. The theoretical optimal costs are of course lower than the other approaches. The optimal approach can be used for benchmarking, as perfect foresight is not possible. Still, the costs in the optimal case are sometimes very close or even as high as the energy tariff costs, as a result of the variation in number of activations which makes some years more costly under the dynamic tariff.

Fig. 13 in particular clearly illustrates that reactive determination of the subscription level is a strategy that cannot be used for dynamic capacity subscription. More advanced strategy like the proposed stochastic strategy are necessary and are no impediment to implementation of dynamic capacity subscription given the present availability of data and support tools on smart phones. A summary of the results presented in Figs. 9 and 12 are shown in Table 4 and Table 5, respectively.

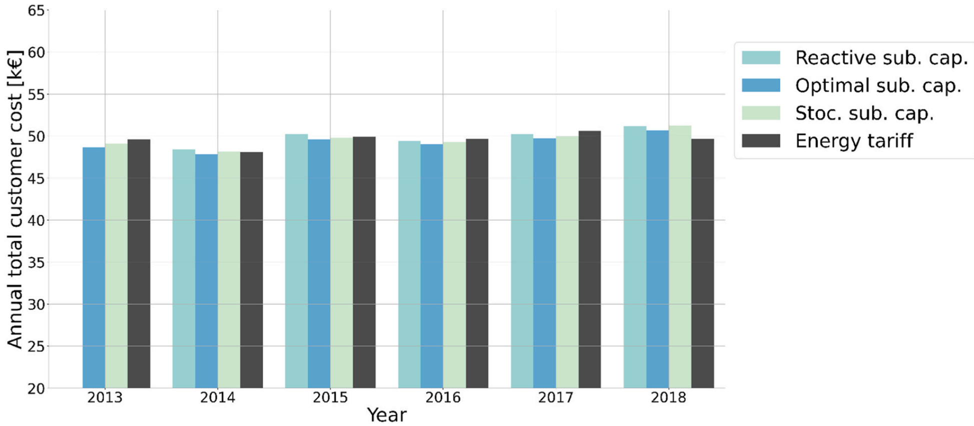


Fig. 9. Aggregated annual consumer costs under the different approaches (static CS).

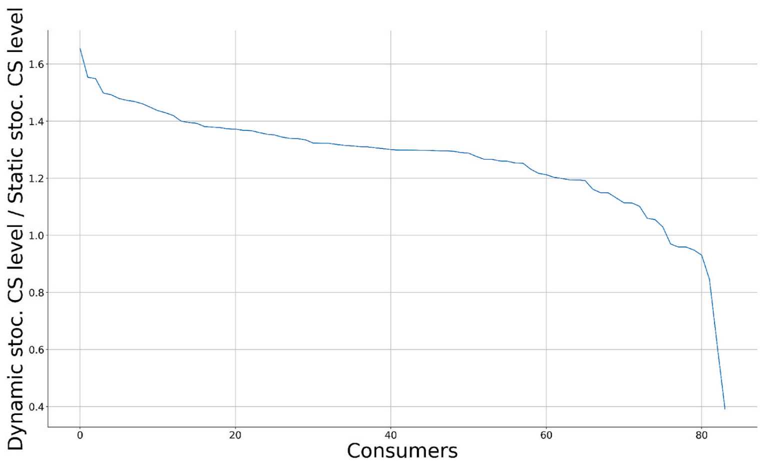


Fig. 10. Stochastic dynamic CS level relative to stochastic static CS level.

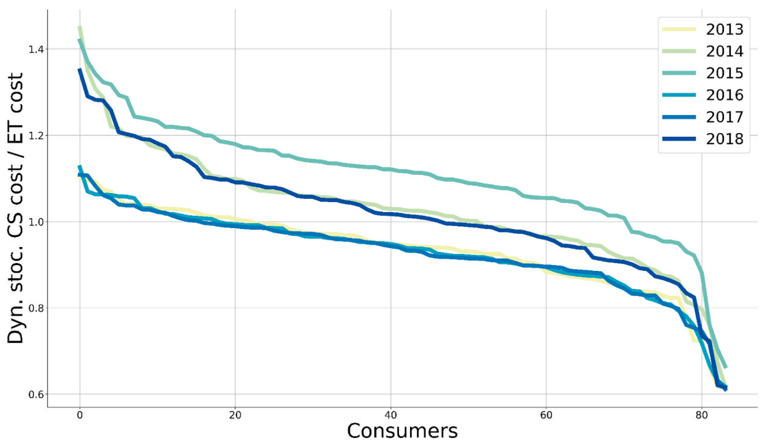


Fig. 11. Annual simulated dynamic costs compared to energy tariff costs.

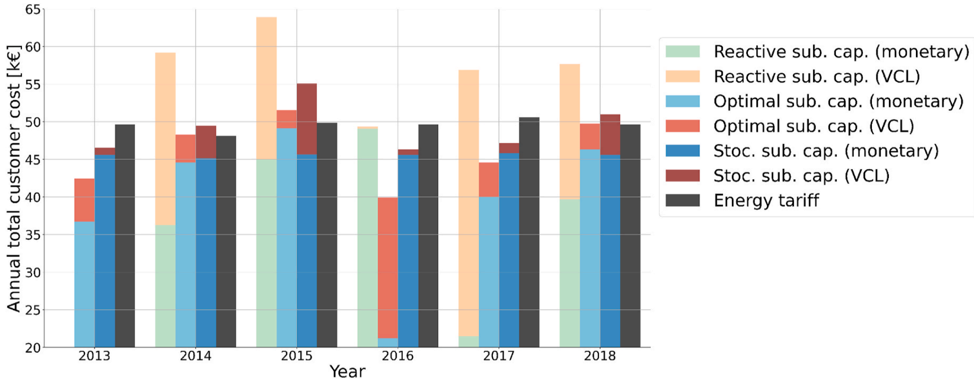


Fig. 12. Aggregated annual consumer costs under the different approaches (dynamic CS).

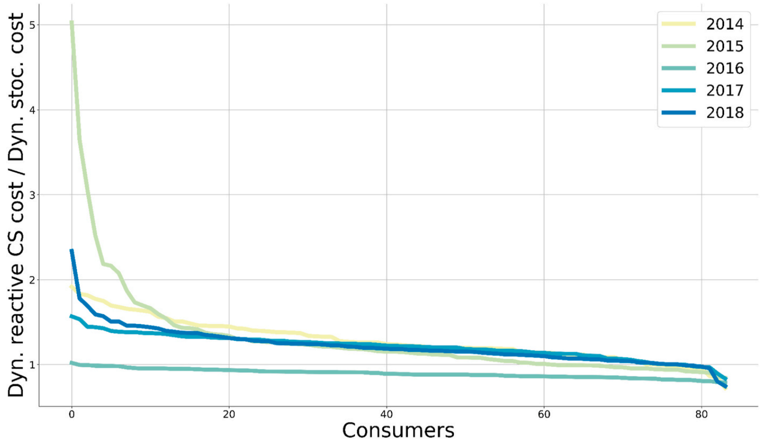


Fig. 13. Dynamic CS reactive costs relative to annual simulated dynamic CS costs.

Table 4
Costs per case in k€, under the static capacity subscription tariff.

	2013	2014	2015	2016	2017	2018
Reactive monetary	N/A	48.42	50.25	49.41	50.26	51.16
Optimal monetary	48.67	47.85	49.61	49.05	49.72	50.68
Stochastic monetary	49.12	48.20	49.82	49.32	50.01	51.25
Energy tariff	49.63	48.12	49.89	49.65	50.61	49.68

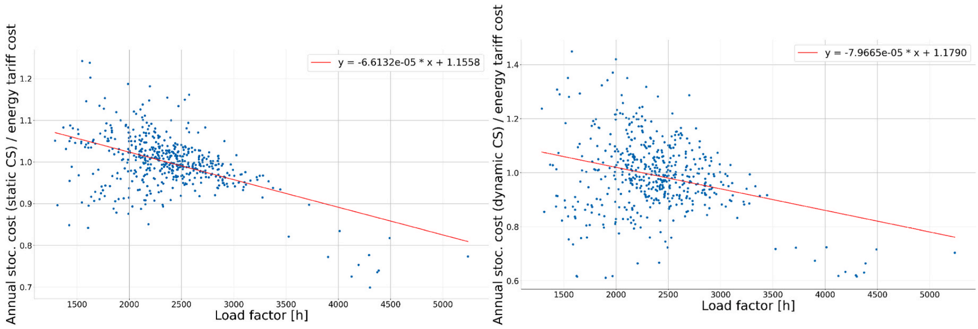
Table 5
Costs per case in k€, under the dynamic capacity subscription tariff.

	2013	2014	2015	2016	2017	2018
Reactive monetary	N/A	36.31	45.05	49.08	21.48	39.71
Reactive total	N/A	59.19	63.90	49.39	56.92	57.67
Optimal monetary	36.73	44.59	49.15	21.24	39.97	46.32
Optimal total	42.45	48.30	51.59	39.91	44.60	49.74
Stochastic monetary	45.58	45.17	45.64	45.58	45.84	45.59
Stochastic total	46.56	49.48	55.12	46.31	47.19	51.03
Energy tariff	49.63	48.12	49.89	49.65	50.61	49.68

5.3. Consequences for consumers and the DSO

The correlation between load factor and cost-redistribution under the static and dynamic CS tariffs is shown in Fig. 14a and Fig. 14b, respectively. The load factor is similar to full load hour term used for power production, and is equal to annual consumption divided by peak demand. A low and high load factor implies that the peak load is high or low compared to the annual consumption, respectively. A high load factor is associated with flat low profiles which should be rewarded by CS tariffs. This trend is shown clearly in the results. However, there is a spread in the data, which stems from the fact that peak load is not always the deciding factor. If a consumer has a high peak load in just a few hours, but a flat profile otherwise, this is not penalised as heavily by the CS tariffs. In the dynamic CS case, the spread is even larger as it also consider coincidence with system peaks. Consumers with peak loads outside of the system peak loads are not penalised as heavily as those who coincide with system peaks.

Some of the negative impacts of consumer versus system peak coincidence could be improved by only activating load limitation in parts of the grid where there is scarcity. However, this is not allowed according to Norwegian regulation. This challenging compromise between cost-reflectivity and fairness could be solved by the regulators. To achieve this, the regulator and DSOs could investigate methods to properly compensate consumers that are located in areas with more



(a) Static CS tariff.

(b) Dynamic CS tariff.

Fig. 14. Scatter plots of static and dynamic CS costs compared to the energy-based tariff, in relation to the load factor. Linear regression is shown as red lines. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

frequent load limitations, for example in the form of reduced fixed costs. This is of increasing importance in countries where there are few, large DSOs, with many customers. In those countries, it would be very inefficient to limit load on all of them.

Currently, consumers with high peak loads are being subsidised by consumers with flatter load profiles that have lower contributions to system peaks. A potential move from energy-based to capacity-based network tariffs has significant cost-reflectiveness advantages, as consumers would have an incentive to reduce their peak load. As shown in Fig. 12, the DSO income is somewhat reduced when moving to dynamic CS tariffs as the cost is shifted onto the consumer in the shape of discomfort costs.[3] This could be difficult for DSOs in the short-term who rely on steady income. In the case of a move towards a dynamic CS tariff, we therefore recommend a somewhat slower transition in terms of reducing the grid tariff prices until the DSOs starts to see lower grid investment costs. This transition period also benefits from the fact that the more data, the better advice to consumers can be given. In general, Figs. 9 and 12 shows that DSOs can not expect the variance in annual income to increase(given that the stochastic approach is applied), and should thus not be used as an argument against moving towards capacity-based tariffs. A final important concern is the increased complexity of the CS tariffs and consumer communication. It will be of crucial importance to prepare consumers for the change and explain the reasons behind. Empowering consumers, part of the European Green Deal, necessarily also requires increased consumer awareness of their electricity demand, and how to affect it. Explaining changes in tariffs is challenging, but also a necessary ingredient in involving and empowering consumers for the future power system.

6. Conclusions & policy implications

This paper demonstrates the change in annual grid tariff costs for a sample of household customers when applying capacity-based tariff structures. Two types of capacity subscription tariffs were analysed; static and dynamic subscribed capacity. Under the static capacity subscription tariff, results show that using a stochastic approach to determine the subscribed capacity level using several years with historical consumption data results in annual costs close to the perfect foresight theoretical optimum. Acting reactively (based on the previous year's conditions), works reasonably well for most consumers, but leads to significantly increased costs for a few consumers. The DSO cost recovery is equally stable as under the energy tariff, with tiny variations from year to year. Under the dynamic CS tariff, consumers are only limited during hours with grid scarcity. The stochastic approach is significantly better than acting reactively as the number of activations from year to year is very different. Subscribing reactively leads to huge variations in subscribed capacity from year to year, resulting in unacceptable demand limitations and wide variations in annual DSO revenues. This approach cannot be used in practice. This can to some extent be avoided by requiring a minimum subscription level.

Overall, the static CS tariff results in low to moderate changes in annual costs for consumers, is robust to sub-optimal subscription levels and does not result in increased variance in costs compared to the existing energy tariff. Regulators should consider moving to such tariffs in the future, as capacity subscription tariffs benefit from being more cost-reflective while maintaining a stable DSO income. Advising consumers on optimal subscription levels is also fairly easy with the suggested method, implying that regulator/DSO should be able to help consumers find a reasonable subscription level. The tariffs also redistribute costs between consumers based on their peak loads, removing some cross-subsidisation from consumers with low peak loads to consumers with high peak loads.

The impact of the dynamic CS tariff are more difficult to assess, because in addition to the actual payments from consumer to DSO, also the loss of consumer welfare due to demand limitations need to be taken into account. We use a simple, assumed cost function for this effect. On the other hand, the dynamic CS tariff offers a much more precise limitation on load which is more efficient, as no load limitations or excess energy fees exist during hours with no grid scarcity. The monetary costs for the consumers are relatively stable but somewhat lower. In the case of a transition to dynamic capacity-subscription tariffs, the regulator should consider a transition period before the grid tariff prices are reduced according to the reduced future grid investments. In order to avoid load limitation on many consumers in large DSO areas, the regulator should look into methods to compensate consumers who are frequently limited, which would increase overall efficiency of the tariff.

Further work might look deeper in the effect on particular consumer segments, based on customer type data and heating sources, which could have shed extra light on what type of consumers experience different cost impacts. When differentiating by customer type, the value of lost load could also be different from consumer to consumer. A sensitivity analysis on the value of lost load would therefore be of interest in order to see how the cost-redistribution would be affected. Future work is recommended to look more extensively into the impact of activation scenarios, adding consumer flexibility and addressing the consumer types implications. A method to estimate optimal subscription for dynamic capacity subscription if no previous data (or only a short period) is available should also be of interest for further work. Moreover, the

[3] The DSO income is the same when discomfort costs are included, but because they are not monetary costs, the income is somewhat reduced.

dynamic CS tariff could be extended to only limiting load in grid areas with congestions. However, this may not be allowed under existing regulation.

CRediT authorship contribution statement

Sigurd Bjarghov: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data curation, Resources, Writing – original draft, Writing – review & editing, Visualization. **Hossein Farahmand:** Writing – review & editing, Supervision, Funding acquisition. **Gerard Doorman:** Conceptualization, Methodology, Formal analysis, Investigation, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgement

This work was funded by the "DigEco - Digital Economy" project funded by the NTNU Digital Transformation Initiative (project number: 2495996). This work has been supported by CINELDI – Centre for intelligent electricity distribution, an 8-year Research Centre under the FME scheme (Centre for Environment-friendly Energy Research, 257626/E20) of the Norwegian Research Council. We would like to thank Roman Hennig and Laurens de Vries at TU Delft, and Matthias Hofmann at Statnett for their useful input and contributions.

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Paper III

The paper **"Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach"** is published by **IEEE** in the conference proceedings of the **17th International Conference on the European Energy Market (EEM)**. The accepted version of the paper is reprinted here with permission from the authors and publisher, ©2020 IEEE.

Cite as:
S. Bjarghov, M. Askeland and S. Backe,
"Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach","
17th Int. Conf. Eur. Energy Mark. (EEM), 2020.
DOI: 10.1109/EEM49802.2020.9221966
URL: `https://doi.org/10.1109/EEM49802.2020.9221966`

Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach

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***Abstract*—Local peer-to-peer (P2P) markets are envisioned as a promising market design to integrate the increasing number of agents in the distribution grid. To incentivize grid-friendly consumption profiles, we suggest a subscribed capacity tariff where end-users pay for a capacity level with a high excess energy term. The P2P market functions as a capacity market where end-users buy capacity from other agents when needed. We demonstrate the concept by formulating the local P2P market equilibrium problem as a mixed complementarity problem (MCP). Analysis of a neighborhood case study shows that both aggregated peak load and agent costs decreases.**

***Index Terms*—Peer-to-peer, capacity tariffs, local markets, battery flexibility**

NOMENCLATURE

Indices and Sets

p	Set of prosumers p
q	Set of prosumers q
t	Time index

Parameters

A_p^{ch}, A_p^{dis}	Battery ch./disch. efficiency [%]
C^a	P2P trading adm. cost [$\frac{€ct}{kWh}$]
C^h	Grid tariff excess energy cost [$\frac{€ct}{kWh}$]
C^l	Grid tariff energy cost [$\frac{€ct}{kWh}$]
C^{sub}	Capacity cost per kW [$\frac{€}{kW\cdot year}$]
C_t^{DA}	Day-ahead spot price [$\frac{€ct}{kWh}$]
E_p^{max}	Max. battery SOC [kWh]
G_{pt}^{PV}	PV production [kWh/h]
L_{pt}	Inflexible load [kWh/h]
Q_p^{ch}	Max. battery charging power [kW]
Q_p^{dis}	Max. battery discharging power [kW]

Variables

λ_{pqt}^{P2P}	P2P market clear price between p and q [$\frac{€ct}{kWh}$]
e_{pt}	Battery state of charge [kWh]
q_{pt}^{ch}	Battery charging [kWh]
q_{pt}^{dis}	Battery discharging [kWh]
x_p^{sub}	Subscribed capacity [kW]
x_{pqt}^{buy}	P2P electricity bought by p from q. Negative is sold from p to q [kWh]
x_{pt}^{buy}	Total bought electricity [kWh/h]
x_{pt}^{h}	Bought electricity above sub. cap. [kWh/h]
x_{pt}^{l}	Bought electricity below sub. cap. [kWh/h]
x_{pt}^{sell}	Sold electricity [kWh/h]

I. INTRODUCTION

As part of solving the climate challenge, the EU has emphazised that the consumer's importance changes when forming new incentives and market design[1]. With an increasing worldwide share of variable renewable energy production, the difficulty of balancing supply and demand increases. With the described development, flexibility is expected to be covered by the demand side to a greater extent. In order to unlock flexibility from thermal storage, batteries, and electric vehicles from the end-user, a market design that incentivizes and promotes demand response is needed.

Simultaneously, distribution system operators (DSO) are seeing peak trends in the distribution grid due to increasing demand and more power-intensive assets such as electric vehicles [2]. Today, most grid tariff structures are energy, and not capacity-based, meaning there is a lack of incentive to avoid high consumption peaks. By pricing the scarce resource (capacity), end-users will have better incentives to reduce peak loads and flatten their load profile. Capacity based tariffs were first described in 2005 [3], but have recently gained renewed attention in Norway as the Norwegian regulator has suggested capacity based tariffs to deal with the mentioned challenges [4]. Previous work on the impact of storage when finding optimal subscribed capacity has been done [5], but without coordination with other end-users.

As technologies like smart meters, ICT systems, and distributed energy resources (DER) such as batteries and photovoltaic (PV) have decreased in price, end-users are transforming from consumers to active agents with local production and flexibility, referred to as prosumers. P2P markets have widely been suggested in the literature as a market design that fully empowers the conscious energy citizen. Multiple market designs spanning from community-based to full P2P markets have been described in [6]. Full peer-to-peer markets represent complete democratization of electricity trade, where preferences such as origin, emission-factor, locality, and production type could be embedded into the electricity trade. However, such systems are futuristic due to the drastic need for robust ICT systems, a potentially slow convergence towards trading consensus, and unclarity in regulation [7], [8]. In a neighbourhood, electricity trading is more manageable, and significant cost savings have been shown when imposing a local P2P market in a neighbourhood with storage assets and local production under a centralized control scheme [9]. Also, [10] and [11] showed that the subscribed capacity tariffs provide strong price signals to reduce peak loads in neighborhoods, especially under centralized metering and billing. One of the shortcomings in the mentioned studies is the assumption of centralized control. In energy markets with many agents, complementarity models are more powerful when analyzing the impact of price signals and market designs, as the rational economic behaviour (best response) of each agent is taken into account. Approaches based on non-cooperative game theoretic models with Nash equilibrium (NE) have been considered in multiple studies, often based on Karush-Kuhn-Tucker conditions. A formulation based on alternating direction method of multipliers (ADMM) is shown in [12]. Alternatively, agent-based models based on complementarity constraints can be formulated directly as a mixed complementarity problem (MCP) or as a Stackelberg game that can be used to model agent behaviour under different market designs [13]. Stackelberg games for design of grid tariffs was demonstrated in [14], [15], where the DSO is modelled as the tariff-setting leader under cost-recovery conditios. Although these papers formulate a realistic interaction between the DSO and costumers through grid tariffs, a local market mechanism is not included.

With the presented context, we extend the study presented in [10] by solving the problem using an equilibrium model for decentralized decisions in a local P2P market under subscribed capacity tariffs. The main contribution of this paper is that we show how subscribed capacity tariffs together with local P2P trading can coordinate end-users to reduce peak loads in neighborhoods. Further, we show how a local P2P market can function as an alternative to centralized tariffs.

The rest of the paper is organized as follows: Section II discusses the market- and grid tariff design. The model is the presented in Section III, followed by the case study description in Section IV. Results and discussions are then presented in Section V before concluding remarks are done in Section VI.

II. Market design

A. Subscribed capacity tariffs

Norway is currently changing to a capacity-based grid tariff structure to better reflect the upstream costs of the distribution grid. The clear drawback of a volumetric tariff structure is that costs are unevenly distributed as grid investments are mostly related to capacity, not energy. Thus, two end-users with equal annual consumption would have an similiar bill, although the end-users trending towards higher peaks in hours with grid scarcity causes a higher cost for the system.

In this paper, we investigate the impact of subscribed capacity tariffs where agents subscribe to a capacity annually and pay for that capacity. The tariff has three cost components, a cost for subscribed capacity C^{sub}, an energy term for consumption below the subscribed capacity C^{l} and an excess energy term C^{h}. The energy term reflects the marginal grid losses, whereas the excess energy term functions as a penalty for excess consumption. This tariff is beneficial compared to a purely volumetric tariff because it reflects the scarce grid capacity.

B. Local P2P markets

A local market is essentially a nano-market where end-users can trade with each other as an alternative to buying from the retailer. The advantages of a local market platform are the creation of incentives for local production and possible coordination of flexibility.

Local P2P markets are similar, but have bilateral trades instead of a pool market for trading. The result is discriminatory prices instead of uniform pricing. An interesting advantage of P2P trades is the possibility of treating electricity as a heterogeneous product both concerning where and how it is produced, but also when and for what it is consumed. In this paper, however, we will only consider risk-neutral and rational agents. Discriminatory pricing still benefits from the fact that different agents have different willingness to pay due to the individual tariffs, export of local production, and opportunity costs from batteries.

C. Synergies of subscribed capacity tariffs and local P2P markets

The analysis in [10] and [11], showed that subscribed capacity tariffs work better on an aggregated level (e.g., a neighborhood) because of the coincidence factor, meaning that not every end-user has peak loads at the same time. However, both studies rely on centralized control to ensure optimal coordination of flexibility. In this paper, tariffs and decisions are decentralized (per agent) instead of centralized. Furthermore, rather than centralized and direct load control, the P2P market handles the coordination of flexibility under decentralized decision-making.

With this tariff structure combined with a P2P market, we introduce a market that serves two purposes: (1) trading of flexibility from battery storage, and (2) a quota market for the right to use capacity. The first concept is widely agreed upon in both real-life projects and research, simply that local markets are useful for sales of excess PV production for local consumption. Besides, batteries can be used for electricity arbitrage based on spot prices. However, arbitrage-based trade is not necessarily beneficial for the power system as new demand peaks can be created. The second purpose (2) answers this challenge by adding capacity to the list of tradable products. Because each end-user has paid for a capacity limit, excess capacity can be sold in the P2P market. Agents with available capacity either due to coincidence or flexibility assets can sell a capacity quota when needed by other agents who are about to exceed their subscribed capacity. Indirectly, the aggregated consumption of the P2P market will have an incentive to stay below the aggregated subscribed capacity limit.

In fig. 1, a conceptual trading example is visualized. The bottom left agent is consuming precisely the amount he has subscribed to, whereas the top left and top right agent has

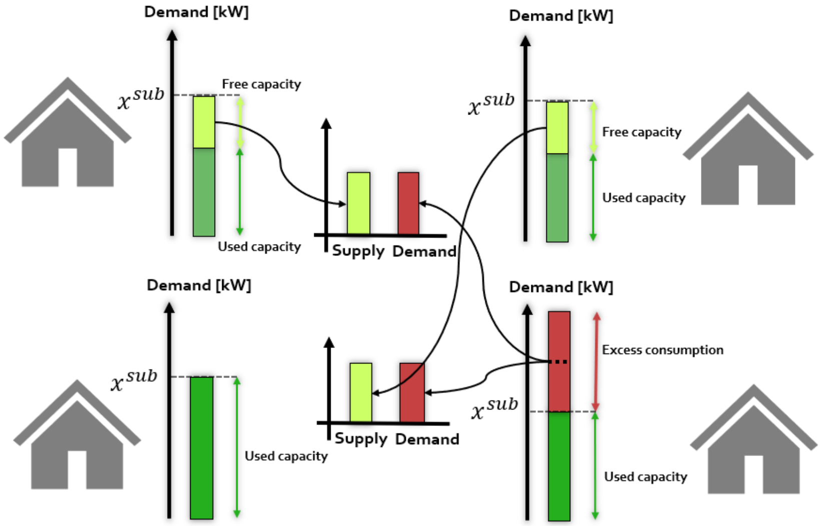

Fig. 1. Capacity peer-to-peer trading example.

some free capacity. As the agents on the bottom right side has excess consumption, he/she is interested in buying the capacity available from the market rather than paying the overcharge fee.

III. Model

Modeling decentralized decisions is essential when analyzing the impact of a specific grid tariff or other market design features. In this paper, we show how the DSO can use subscribed capacity tariffs to reduce peak loads in neighborhoods using local markets. The DSO is not modeled explicitly, but we use the grid tariff rates suggested by the Norwegian regulator as a set of exogenous price signals meant to incentivize grid friendly operation of DER. The local market is the enabler, which allows for capacity trading between the agents in the system.

The model is formulated to illuminate the impact of local markets under subscribed capacity tariffs modeled with decentralized decision making. We demonstrate this by formulating the prosumer problem as an electricity bill cost minimization problem, or in essence, maximizing the prosumer's surplus. The local P2P market facilitates capacity trading with discriminatory prices. The prosumers interact with the market through their trades with the retailer and the other agents in the local market.

A. Prosumer problem

The prosumer problem is a cost minimization, where the goal is to minimize the costs of importing electricity to cover the demand. Costs are related to buying electricity on the day-ahead spot market, grid tariff costs, and P2P trading costs. Locally produced electricity can be sold to the day-ahead market or to other peers without grid tariff costs. The objective function is given by (1). The model finds optimal import/export both with the retailer and in the local P2P market. In addition, the subscribed capacity level x_p^{sub} is optimized at each prosumer.

Dual values associated with the constraints are provided and based on the KKT-conditions of this problem, the optimality conditions are formulated as MCP in the Appendix. The MCP formulation allows us to simultaneously solve the prosumer problems with P2P market interaction and derive the Nash equilibrium[1].

$$\begin{aligned}\forall p \quad \min x_p^{sub} C^{sub} + \sum_t [(x_{pt}^{buy} - x_{pt}^{sell}) C_t^{DA} \\ + x_{pt}^l \cdot P^l + x_{pt}^h \cdot P^h + \sum_q (\lambda_{pqt}^{P2P} + P^a) x_{pqt}^{P2P}] \quad (1)\end{aligned}$$

Import from the grid are split into import below x_{pt}^l and above x_{pt}^h the subscribed capacity x_p^{sub} in (2) and (3).

$$\forall pt \quad x_{pt}^l + x_{pt}^h - x_{pt}^{buy} = 0 \quad (\nu_{pt}^{tot}) \qquad (2)$$

$$\forall pt \quad x_{pt}^l - x_p^{sub} \leq 0 \quad (\nu_{pt}^{sub}) \qquad (3)$$

The energy balance is given by (4).

[1]The problem is implemented in GAMS and solved by the PATH solver.

$$\forall pt \quad x_{pt}^{buy} - x_{pt}^{sell} + \sum_{q} x_{pqt}^{P2P}$$
$$- L_{pt} + G_{pt}^{PV} - q_{pt}^{ch} + q_{pt}^{dis} = 0 \quad (\nu_{pt}^{eb}) \tag{4}$$

Furthermore, the battery state of charge (SOC) balance is given by (5a) and (5b), where (5b) ensures that the SOC in the first and last time period are the same. The bounds on maximum state of charge and max (dis)charging power are given by (5c)-(5e).

$$\forall p(t < t_{end}) \quad e_{p(t+1)} - e_{pt}$$
$$- q_{pt}^{ch} A_p^{ch} + \frac{q_{pt}^{dis}}{A_p^{dis}} = 0 \quad (\beta_{pt}^{soc}) \tag{5a}$$
$$\forall p(t = t_{end}) \quad e_{pt_0} - e_{pt_{end}}$$
$$- q_{pt_{end}}^{ch} A_p^{ch} + \frac{q_{pt_{end}}^{dis}}{A_p^{dis}} = 0 \quad (\beta_{pt_{end}}^{soc}) \tag{5b}$$
$$\forall pt \quad q_{pt}^{ch} - Q_p^{ch} \leq 0 \quad (\beta_{pt}^{ch}) \tag{5c}$$
$$\forall pt \quad q_{pt}^{dis} - Q_p^{dis} \leq 0 \quad (\beta_{pt}^{dis}) \tag{5d}$$
$$\forall pt \quad e_{pt} - E_p^{max} \leq 0 \quad (\beta_{pt}^{max}) \tag{5e}$$

B. Peer-to-peer market clearing conditions

The market operator ensures balance in all trades between peer p and q, where the dual λ_{pqt}^{P2P} is the discriminatory price between agent p and q as shown in (6). Because we have bilateral trades, prices depend on the objective function of each prosumer.

$$\forall pqt \quad x_{pqt}^{P2P} + x_{qpt}^{P2P} = 0 \quad (\lambda_{pqt}^{P2P}) \tag{6}$$

IV. Case Study

We simulate the problem with four agents for one week with hourly time resolution. Prosumer P1 and P2 have batteries of 10 and 5 kWh, respectively.

- Agent #1: 10 kWh battery, 95 % one-way efficiency
- Agent #2: 5 kWh battery, 96 % one-way efficiency
- Agent #3: -
- Agent #4: -

The model determines the optimal subscribed capacity of each agent, as well as the operation of assets and trades with the retailer and the local peer-to-peer market. This is done by simulating with load and PV data from Norway.

We perform the following two case studies:

- Without local P2P markets. End-users optimize their own assets in order to minimize costs.
- With local P2P market. Similiar to above, but end-users can interact through P2P trading.

V. Results and discussion

By simulating 1 week, we gain insight in optimal operation of flexible assets, subscribed capacity and the share of trades with the retailer and the local P2P market. The results in table I show that by adding a P2P market, a reduction in optimal subscribed capacity for prosumers P3 and P4 is achieved, where as P1 and P2 have relatively similar optimal limits. This reduction is driven by the ability to trade with the other prosumers who have access to battery storage. P1 and P2 can use their batteries actively to sell capacity to P3 and P4 when needed, whereas when no market is available, P3 and P4 must subscribe to higher capacities to lower their bills. The results underline that with the right incentives, local markets facilitate grid friendly consumption patterns due to the locational properties of the market.

TABLE I
Optimal subscribed capacity in kW.

	P1	P2	P3	P4
P2P	1.963	1.905	1.914	1.929
No P2P	1.912	1.917	2.470	2.520

This is further confirmed by looking at fig. 2, where we see a lowering of the highest imports with the P2P market compared to the case without. By using the batteries from P1 and P2, the local P2P market is utilized to provide capacity to agents P3 and P4, allowing them to stay below their reduced subscription limits. As shown in the graph, the imports never exceed their aggregated subscribed capacity, whereas the import is higher in the case with no market. This clearly implies that the market works as a coordination tool and that centralized metering and control is not required to reduce peak loads in a neighborhood.

Battery storage plays a vital role in keeping the import levels below the the subscribed capacity limits. In the No-P2P case, only the agents with battery storage can reduce their import level below the subscription limit. Battery SOC never reaches its maximum in the No-P2P as a consequence, because the agent has no incentive to use the battery. This stands in contrast with the P2P case where both batteries are used to their max. SOC as shown in fig. 4

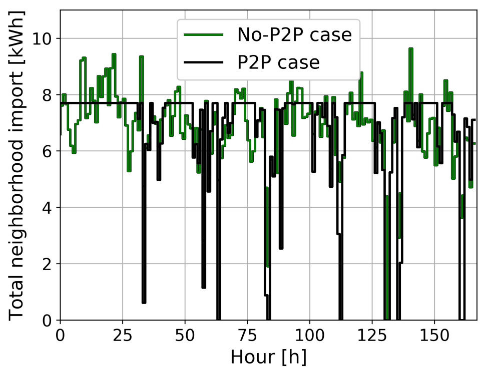

Fig. 2. Total end-user import over 1 week.

The aggregated subscribed capacity can be considered as the "neighborhood" optimal subscribed capacity, as it allows for zero excess energy consumption as shown in fig. 2. Because

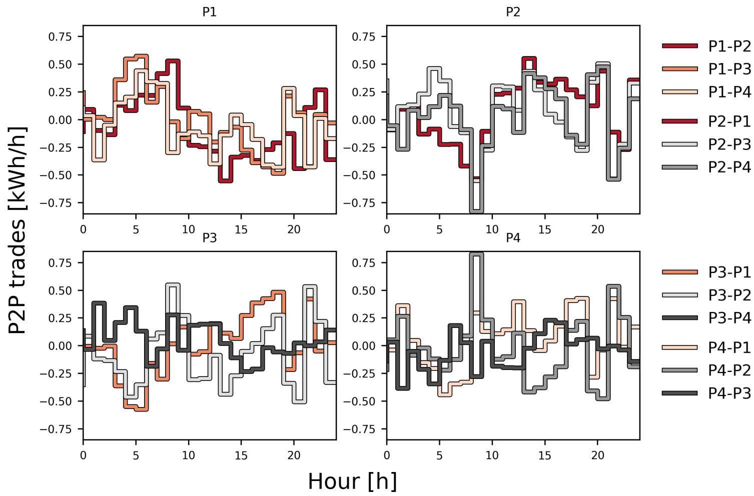

Fig. 3. P2P trading in the first 24 hours of the week.

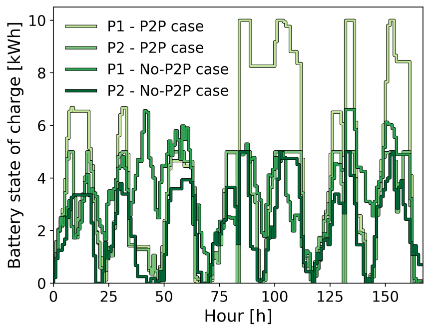

Fig. 4. Battery state of charge in the P2P and no-P2P case.

the P2P market functions as an alternative to centralized coordination, trade happen frequently as a consequence fig. 3. This is the case because the aggregated subscribed capacity is pushed to its minimum, forcing every agent to utilize their limit to the fullest. This strategy results in battery-discharge covered peak loads when the aggregated load surpasses the aggregated subscription limit. In essence, the neighborhood minimizes the possible subscription limit and then uses it to its maximum in the P2P market. This also explains why the aggregated load very often lies on the exact aggregated subscription limit.

Finally, the total electricity costs of the total time horizon for all agents are shown in table II. The reduced costs of €4.6 or 8 % is relatively small. However, it is achieved while still reducing neighborhood peak load by 20 % from 9.64 to 7.71 kWh/h, meaning that these are savings achieved while still saving costs for the DSO. The lost income of the DSO is recovered due to decreased costs, assuming that the tariff is cost reflecting and assures DSO cost recovery. An interesting take is that the agents without batteries are the ones who are reducing their costs the most. This implies that there is a surplus of storage in the case study, which is also confirmed in fig. 4 where agents P1 and P2 most of the time are not using their storage to the fullest, implying a surplus of supply compared to demand in terms of flexibility. In other words, the storage owners compete, resulting in P2P prices close to their alternative opportunity cost of flexibility.

TABLE II
COSTS PER AGENT IN THE P2P AND NO-P2P CASE IN EURO.

Weekly cost	**P1**	**P2**	**P3**	**P4**	**Total**
No-P2P	€13.2	€12.1	€14.7	€15.3	€55.3
P2P	€13.1	€12.0	€12.4	€13.2	€50.7

VI. CONCLUSION

We conclude by stating that the local P2P market reduces neighborhood peak loads in combination with capacity tariffs, and works as a useful trading scheme where all agent's preferences are satisfied due to the equilibrium in the market clearing. Peak loads as well as agent costs are decreased, implying synergy between the tariff structure and a local P2P market.

Further work includes cost analysis for each agent, as well as a more complex analysis of how the heterogenous bilateral market price between agent-pairs reflect their opportunity and penalty costs. Futhermore, case studies including investment analysis as well as market efficiency analysis could be performed.

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APPENDIX

As both the market clearing and the prosumer problem are linear, the KKT-conditions are necessary and sufficient for optimality. The final MCP formulation consists of the KKT-conditions of each peer, as well as the P2P market clearing.

First, the market clearing (7):

$$\forall pqt \quad x^{P2P}_{pqt} + x^{P2P}_{qpt} = 0 \quad \perp \lambda^{P2P}_{pqt} \tag{7}$$

followed by the prosumer problem (8a)-(13e).

$$\forall p \quad x^{sub} - \sum_t \nu^{sub}_{pt} \geq 0 \perp x^{sub}_p \geq 0 \tag{8a}$$

$$\forall pt \quad C^l + \nu^{tot}_{pt} + \nu^{sub}_{pt} \geq 0 \perp x^l_{pt} \geq 0 \tag{8b}$$

$$\forall pt \quad C^h + \nu^{tot}_{pt} \geq 0 \perp x^h_{pt} \geq 0 \tag{8c}$$

$$\forall pt \quad C^{DA}_t - \nu^{tot}_{pt} + \nu^{eb}_{pt} \geq 0 \perp x^{buy}_{pt} \geq 0 \tag{8d}$$

$$\forall pt \quad -C^{DA}_t - \nu^{eb}_{pt} \geq 0 \perp x^{sell}_{pt} \geq 0 \tag{8e}$$

$$\forall pqt \quad \lambda^{P2P}_{pqt} + \nu^{eb}_{pt} + P^a \geq 0 \perp x^{P2P}_{pqt} \tag{9}$$

$$\forall pt \quad -\nu^{eb}_{pt} - \beta^{soc}_{pt} A^{ch}_p + \beta^{ch}_{pt} \geq 0 \perp q^{ch}_{pt} \geq 0 \tag{10a}$$

$$\forall pt \quad \nu^{eb}_{pt} + \frac{\beta^{soc}_{pt}}{A^{dis}_p} + \beta^{dis}_{pt} \geq 0 \perp q^{dis}_{pt} \geq 0 \tag{10b}$$

$$\forall p(t > t_0) \quad \beta^{soc}_{p(t-1)} - \beta^{soc}_{pt} + \beta^{max}_{pt} \geq 0 \perp e_{pt} \geq 0 \tag{10c}$$

$$\forall p(t = t_0) \quad \beta^{soc}_{pt_{end}} - \beta^{soc}_{pt_0} + \beta^{max}_{pt_0} \geq 0 \perp e_{pt} \geq 0 \tag{10d}$$

$$\forall pt \quad x^l_{pt} + x^h_{pt} - x^{buy}_{pt} = 0 \quad \perp \nu^{tot}_{pt} \tag{11a}$$

$$\forall pt \quad x^l_{pt} - x^{sub}_p \leq 0 \perp \nu^{sub}_{pt} \geq 0 \tag{11b}$$

$$\begin{aligned}\forall pt \quad & x^{buy}_{pt} - x^{sell}_{pt} + \sum_q x^{P2P}_{pqt} \\ & - L_{pt} + G^{PV}_{pt} - q^{ch}_{pt} + q^{dis}_{pt} = 0 \perp \nu^{eb}_{pt}\end{aligned} \tag{12}$$

$$\forall pt \quad q^{ch}_{pt} - Q^{ch}_p \leq 0 \perp \beta^{ch}_{pt} \geq 0 \tag{13a}$$

$$\forall pt \quad q^{dis}_{pt} - Q^{dis}_p \leq 0 \perp \beta^{dis}_{pt} \geq 0 \tag{13b}$$

$$\forall pt \quad e_{pt} - E^{max}_p \leq 0 \perp \beta^{max}_{pt} \geq 0 \tag{13c}$$

$$\begin{aligned}&\forall p(t < t_{end}) \quad e_{p(t+1)} - e_{pt} \\ &- q^{ch}_{pt}\eta^{ch}_p + \frac{q^{dis}_{pt}}{\eta^{dis}_p} = 0 \quad \perp \beta^{soc}_{pt}\end{aligned} \tag{13d}$$

$$\begin{aligned}&\forall p(t = t_{end}) \quad e_{pt_0} - e^{soc}_{pt_{end}} \\ &- q^{ch}_{pt_{end}} A^{ch}_p + \frac{q^{dis}_{pt_{end}}}{A^{dis}_p} = 0 \perp \beta^{soc}_{pt}\end{aligned} \tag{13e}$$

Paper IV

The paper **"A comparison of the peak demand reduction performance of various energy-based and capacity-based tariffs at different grid levels"** was submitted for review to **Elsevier** in the journal **Energy Policy** in August 2022.

This paper is submitted for publication and is therefore not included.

Paper V

The paper **"Grid tariffs for peak demand reduction: Is there a price signal conflict with electricity spot prices?"** was accepted by **IEEE** and is to be published in the conference proceedings of the **18th International Conference on the European Energy Market (EEM)**. The accepted version of the paper is reprinted here with permission from the authors and publisher, ©2022 IEEE.

Cite as:
S. Bjarghov, M. Hofmann
"Grid tariffs for peak demand reduction: Is there a price signal conflict with electricity spot prices?"
Accepted in *18th Int. Conf. Eur. Energy Mark. (EEM)*, 2022.

Grid Tariffs for Peak Demand Reduction: Is there a Price Signal Conflict with Electricity Spot Prices?

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***Abstract*—The electricity grid is expected to require vast investments due to the decarbonization-by-electrification trend, calling for a change in grid tariff design which provides proper incentives for reducing peak loads. However, price signals from grid tariffs could be "distorted" from electricity spot prices which also represents a significant of the total consumer electricity bill. This paper attempts to identify whether there is a price signal conflict between grid tariffs and spot prices. Four different grid tariff designs are compared, using a generic demand response model as part of a cost-minimizing linear program to simulate the reduction in peak load. The method is applied to metered electricity demand from 3608 consumers in Oslo, Norway. Results show that new grid tariff designs reduce peak loads by 1-4%, and that reduction in peak load is smaller when consumers are subject to electricity spot prices.**

***Index Terms*—Grid tariffs, demand response, price signal conflict, peak load reduction, spot prices**

I. Introduction

Aiming to reduce 55% of carbon emissions by 2030 [1], Norway plans extensive electrification in the transport and industrial sectors [2], [3]. As a consequence, the transmission and distribution grid operators are facing vast amounts of connection requests from commercial consumers. As it is demanding to build grids at sufficient speed to incorporate these new grid connection requests, it is of increasing importance to ensure efficient use of existing grids. Meanwhile, the distribution grid is expecting increased peak demand due to electrification of transport and other power-intensive loads which in addition to urbanization trends results in an expected increase in congestions, also in low voltage grids.

A solution to this development could be achieved by moving from flat, volumetric grid tariff designs to time-of-use or capacity-based grid tariffs. With redesigned grid tariffs, electricity peak loads can be reduced by implicit flexibility, i.e. consumers reacting to price signals by reducing or shifting demand, often referred to as demand response.

The future power system requires more precise pricing mechanisms as integration of demand side flexibility and distributed generation introduces new challenges, especially in the distribution grid. Volumetric grid tariffs do not sufficiently represent cost-reflectivity and are already responsible for inefficient investments and operational decisions [4]. Implicit flexibility through price signals also avoids struggles with market manipulation and baseline related issues such as local flexibility markets may [5].

A variety of grid tariff designs to incentivize peak demand reduction from flexibility have been suggested in recent literature. Optimal time-of-use tariff design is one option, and should preferably be demand-based to achieve peak load reductions [6]. The design of time-of-use tariffs can be difficult, as the welfare increase is dependent on which technologies exist on consumers side in terms of demand response cost [7].

Of the capacity-based grid tariffs, the measured peak demand tariff structure (often referred to as demand charges) has received significant attention due to the welfare redistribution under higher shares of renewable generation in the distribution grid [8]. Still, coincidence-related issues, i.e. the lack of guarantee that residential peak and system peak coincide reduces the welfare gain significantly [9], suggesting that dynamic tariffs which adapt to the grid status are more likely to increase welfare [10]. Capacity subscription tariffs also provide incentives reduce peak loads in neighborhoods with residential consumers and similar local energy systems, both under cooperative [11] and competitive market conditions [12]. The grid tariff design not only impacts operation, but also investments in decarbonized neighborhoods [13].

However, grid tariffs are not the only price signal consumers are exposed to. Grid tariffs have historically made up roughly one third of the total electricity bill in Norway, with taxes and electricity spot prices also taking one third each. During the end of 2021 and winter of 2022, Europe has experienced historically high electricity spot prices at a size which easily could "outperform" the most suggested grid tariff structures in the sense that consumers would react to the price signal from the electricity spot prices, rather than from the grid tariff. Analysis on demand response from a combined spot price and grid tariff signal has been proposed in the literature, but are often complex and difficult to implement [14]. Consumers on fixed price contracts will not respond to spot prices, but due to historically low prices, more than 95% of Norwegian residential consumers are on spot price or variable price contracts [15].

This raises the questions: Is there a price signal conflict between electricity spot prices and different grid tariff designs, and how large is it? This is of particular interest as there is often (but not always) a correlation between high electricity prices and cold winters with high demand, which also is the dimensioning factor for grid expansion. In other words, if the cold, premise-setting winters for grid expansions might include very high spot prices, which grid tariff designs are the most robust in order to achieve peak load reduction in those few days which might occur as seldom as every decade?

This article attempts to answer these questions by simulating demand response for peak demand reduction, using historical spot prices and real, metered data from 3608 consumers in Oslo, Norway, from November 2020 to October 2021. Summarized, the main contributions of this article are the following:

- A quantification of the price signal conflict between electricity spot prices and grid tariffs, with respect to reducing peak loads.
- A comparison of peak demand reduction under different grid tariff designs, when exposed to both real-time electricity spot prices and no spot prices.

The remainder of the paper is organized as follows: Section II discusses the different grid tariff designs. The method and optimization model is presented in Section III, followed by the case study description in Section IV. Results and discussions are then presented in Section V, followed by conclusions and further work suggestions in Section VI.

II. Grid tariffs

Grid tariffs represent the cost of transferring electricity from the place of generation to consumption. Ideally, they should reflect both the long- and short-term marginal cost of transferring electricity, but this is a burdensome task as the real cost depends on complex mechanisms. Grid tariffs are designed not only to be cost-reflective, but also after a number of a criteria such as cost-efficiency, cost-recovery, complexity, implementation burden, acceptance, transparency and fairness [16], [17]. Often, there is a reverse relationship between these criteria, making tariff design a task of finding the least-worse alternative with respect to all the criteria [4].

Traditionally, grid tariffs have been designed to transfer costs from the distribution system operators to the consumers in a simple manner. Volumetric tariffs have done this job relatively well with respect to simplicity and cost-recovery, but is especially inefficient in terms of incentivizing flexibility response from consumers for peak reduction, which is the main focus of this article.

Grid tariffs are often split into three types of costs: a) fixed, b) volumetric and c) capacity-based costs, aiming to represent different types of costs related to administration, as well as short and long-term marginal costs of electricity consumption [18]. In this article, we look into two time-of-use tariffs, as well as two types of capacity-based tariffs. The list of tariff models is based on literature and proposed tariffs in Norway, limited to distribution grid tariffs. The included tariffs are presented below, whereas the cost levels can be found in Table I.

1) Subscribed capacity: Capacity-subscription tariffs are based on consumers subscribing to a capacity ex-ante, which has a cost per kilowatt, for example annually. Consumption below the subscribed level is subject to a small energy term, often reflective of the marginal losses in the grid, whereas consumption above the level is subject to an excess energy term which is significantly higher. Consumers then have an incentive to stay below the subscribed capacity.

2) Measured peak demand: Measured peak demand is based on the consumers peak demand in a given time period, typically monthly. Consumers have then an incentive to have a low peak demand, which is measured as the highest electricity use in one hour.

3) Static time-of-use: Static time-of-use has a volumetric cost part with predetermined energy cost that can shift from hour to hour, aiming to incentivize use when the demand is low and similarly penalizing consumption when the demand is high and possible congestions in the grid occur. Typically, this involves having a higher price per kilowatt-hour in the morning and in the evening, with the option of seasonal variation.

4) Critical peak pricing: Unlike the static time-of-use, critical peak pricing is only active when there is scarcity in the grid. This can be defined as a certain number of days per year with the highest grid utilization, adding a very high energy term during the peak load hours of those days.

III. Method

A. Approach

The method used in this paper is to simulate the total demand response from a large set of consumers. The demand response model is described in Section III-B. The simulation is performed by formulating an optimization model which minimizes costs of each individual consumer, formulated as a linear program. This results in a new demand curve after consumers have tried to reduce costs using the modeled demand response, which then is used to discuss the efficiency of the different grid tariff designs, both with and without being subject to spot prices. The optimization model is introduced in Section III-B, whereas the specific data and simulated cases are presented in Section IV.

B. Optimization model

The consumer problem is formulated as a linear cost minimizing program aiming to minimize the sum of electricity costs C^e (if applicable), grid tariff costs C^g and flexibility usage costs C^f as shown in (1). The full nomenclature can be found in the Appendix.

$$\min C^e + C^g + C^f \tag{1}$$

The total electricity cost C^e is given by (2), whereas the flexibility cost C^f is described in (9).

$$C^e = \sum_t x_t^i C_t^{spot} \tag{2}$$

The grid tariff costs C^g are described in the following subsections.

1) Subscribed capacity tariff: Capacity subscription tariffs involve consumers taking an active choice where they subscribe to a capacity level (X^{sub}) once a year, which is associated with a capacity cost C^{sub} per kilowatt. Electricity consumption of the end-user is split into demand below (x_t^l) and above (x_t^h) the subscription level as shown in in (3a) and (3b). Under this grid tariff structure, we assume that all consumers subscribe to their optimal level which is found by setting X^{sub} as a variable in the consumer problem. However, this level will not be the same with and without flexibility assets. We therefore find the optimal subscribed capacity first, and then set this value as a fixed parameter in the problem again when flexibility is added.

$$x_t^l + x_t^h = x_t^i c \tag{3a}$$
$$x_t^l \leq X^{sub} \quad \forall t \tag{3b}$$

Finally, the grid cost function is given by (4), where demand below and above the subscribed capacity are associated with the energy cost term C^{ET} and excess energy cost term C^h, respectively.

$$C^g = x^{sub} \cdot C^{sub} + \sum_t (x_t^l C^{ET} + x_t^h C^h) \tag{4}$$

2) Measured peak demand tariff: Measured peak demand penalizes the monthly peak demand of the consumer x_m^{max} by a specific cost per kW peak C^{peak}. The cost function is given by (5). The general energy term C^{ET} is added, similar to the other tariffs. Additionally, another constraint to enforce the peak demand cost is needed as shown in (6).

$$C^g = \sum_m x_m^{max} C^{peak} + \sum_t x_t C^{ET} \tag{5}$$

$$x_t^i \leq x_m^{max} \quad \forall t \tag{6}$$

3) Time-of-use tariff: The time-of-use tariff adds a specific cost of using electricity at different time steps as shown in Table I. Outside the peak price hours, there is a volumetric energy term C^{ET}.

$$C^g = \sum_t x_t^i C_t^{TOU} \tag{7}$$

4) Critical peak pricing tariff: The critical peak pricing tariff has a very high cost term for a selected number of days per year, based on which days have the highest peak loads. Outside those hours, the price has a regular energy term C^{ET}.

$$C^g = \sum_t x_t^i C_t^{CPP} \tag{8}$$

The cost of flexibility C^f is given by Equation (9), which adds a cost C^{red} per kilowatt-hour of reduced electricity demand. This is not a monetary cost, but a discomfort cost, representing the discomfort of responding to price signals.

$$C^f = \sum_t q_t^{red} \cdot C^{red} \tag{9}$$

The energy balance is given by (10), where the new load series x_t^i is the sum of the original load L_t minus the demand reduction q_t^{red}.

$$x_t^i = L_t - q_t^{red} \quad \forall t \tag{10}$$

The flexibility is modeled as the ability to reduce load without shifting to other hours and is modeled in generic terms rather than as assets. The advantage of this modeling approach is the ability to emulate a general demand response from a set of consumers, without the computational efforts of asset modeling. It also draws advantage from not assuming what kind of flexibility assets that exist, or will exist in the future. Instead, the model represent a generic flexibility response specified by 2 parameters:

- Max. possible power reduction in an hour, Q^{flex}, in % of demand in that hour
- Max. possible electricity demand reduction in a day, E^{flex}, in % of demand that day

These two parameters set a limit to how much power can be reduced in an hour, as well as how much energy can be reduced per day, as shown in (11a) and (11b), respectively. The values of these parameters are determined based on results of international studies [19], [20] as well as Norwegian studies [21], [22].

$$q_t^{red} \leq Q^{flex} \cdot L_t \quad \forall t \tag{11a}$$
$$\sum_{t \in d} q_t^{red} \leq E^{flex} \cdot \sum_{t \in d} L_t \quad \forall d \tag{11b}$$

It is assumed that such a representation of flexibility is relatively accurate when modeling large sets of consumers, although the spread in flexibility response from each individual consumer obviously is not equal as assumed in this study. Additionally, the following assumptions were made:

- The discomfort cost parameter C^{red} is high enough to reflect an assumed discomfort cost of being flexible, but small enough to trigger activation for all tariffs.
- If several hours are equally optimal for reduction (ToU, subscribed capacity), the relative reduction is equal in all these hours.

IV. Case Study & Data

The case study and data are similar as in [23], where hourly electricity load data from 3608 consumers, including 3081 household consumers and 527 commercial consumers, were used for the analysis. The households stand for 47 % of the electricity demand, and the commercial consumers for 53 % respectively. The consumers are located at 112 different substations, under the same transformer in Oslo, Norway, and the metered data are from the period November 2020 to

October 2021. In addition, historical spot prices and demand from the price zone NO1 are collected for the same period. These data period is of particular interest because the winter of 2020/2021 saw the highest measured electricity consumption in Norway.

Several cases are studied to understand the difference in achieved grid peak demand reduction, and are listed below. They include two benchmark tests, as well as a performance analysis of the four grid tariffs described in Section II. The grid tariff case includes the test of the grid tariffs without any spot price signal. This is expanded in the grid tariff and spot price case, which includes the combined price signal from each of the four grid tariffs as well as the spot price. Finally, the system optimal response and the spot price case represent the benchmark tests. The system optimal response case is defined as the system's maximum ability to reduce peak load with the available flexibility, and assuming that reduction is coordinated between all consumers. The spot price case is the cost minimizing response under spot prices only. In summary the following cases are analyzed:

- System optimal response case
- Grid tariff case
- Grid tariffs plus spot price case
- Spot price case

TABLE I: Cost levels for all grid tariffs.

Symbol	Cost level	Comment
C^{ET}	0.25 $\frac{NOK}{kWh}$	Applied to all tariffs
C^{TOU}	1.2 $\frac{NOK}{kWh}$	06-22 during winter except weekends and holidays, energy term otherwise
C^{CPP}	4.5 $\frac{NOK}{kWh}$	06-22, during the 20 peak load days
C^{sub}	1000 $\frac{NOK}{kW-year}$	Cost per kilowatt subscribed capacity per year
C^{h}	1.65 $\frac{NOK}{kWh}$	Cost for electricity above subscription level, energy term when under
C^{peak}	75 $\frac{NOK}{kW-month}$	Cost for peak load per month

As the cost-recovery should be similar if there is no demand response, all the cost parameters of grid tariffs are determined using backwards calculation with respect to the existing energy tariff. The cost levels are shown in Table I.

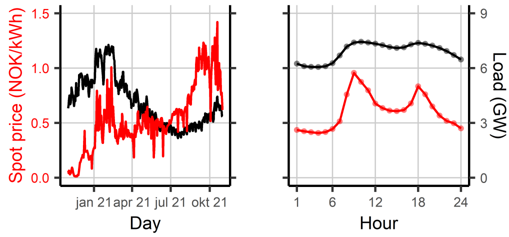
The parameters Q^{flex} and E^{flex} for available demand flexibility were chosen based on the aforementioned studies on demand response and are set to 25% and 2.5%, respectively.

V. Results & discussion

A. Simultaneity of peak demand and peak spot prices

The spot price is the result of the market equilibrium between supply and demand bids on the day ahead market. Therefore, everything else equal, a higher electricity demand implies higher spot prices. In addition, other factors, as for example fuel prices and weather, change the supply bids and in consequence the spot price. These effects can also be observed in the historical demand and spot prices in the case study.

On peak load days, as shown in Figure 1b, the demand and spot price have the same profile, meaning that the spot price gives the price signal in the right hours. However, when



(a) Daily (b) Hourly

Fig. 1: Average daily and hourly load and spot prices in NO1 for a year and all days with demand over 90% of peak demand.

comparing demand and price on the yearly scale, days with high demand does not necessarily imply a high spot price. Figure 1a shows that the price sometimes correlates well with high demand, but not always. In other words, the spot price might sometimes "interfere" with the grid tariff price signal.

Since the case study looks into daily flexibility, the price signal from spot prices should strengthen the incentive to avoid electricity consumption in peak demand hours on a daily basis. However, the peak demand hours have an almost flat profile, whereas the spot price has larger variations, leading to a strong incentive to reduce demand in a few peak demand hours and not over all peak demand hours.

B. Strength of price signals

The incentive given through the various grid tariffs or the spot price differs. Based on the specification of the grid tariffs and the historic data, the short-term price signals can theoretically reach values up to 1.2 NOK/kWh for static ToU, 4.5 NOK/kWh for the critical peak pricing tariff, 75.25 NOK/kWh/h for measured peak demand, and 1.65 NOK/kWh for capacity subscription, compared to the maximum spot price of 2.57 NOK/kWh. On an aggregated level, the price signal is strongest from the critical peak pricing tariff since the cost are distributed over a few days and are in place for all consumers. In theory, the measured peak demand tariff gives an even stronger price signal, but only on individual level. Since the monthly peak of all customers is not in the same hour, the aggregated price signal is far lower.

As an example, Figure 2 compares the price signals on the aggregated grid level for the day with the highest peak demand for ToU, measured peak demand, capacity subscription and spot price. The results show clearly that subscribed capacity gives the weakest price signal on that day, whereas measured peak demand and the ToU-tariffs give a strong price signal. The spot price is lower than these, but adds an hourly price differentiation to the ToU-tariffs.

C. Peak change with energy reducing flexibility

The results are presented for all cases, i.e. maximum achievable peak reduction with optimal response, price signal from the various grid tariffs, both grid tariffs and spot price, and the

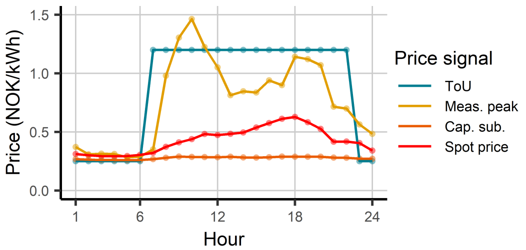


Fig. 2: Comparison of price signals from grid tariffs and spot price on the day with maximum demand.

spot price alone. The theoretically maximum peak reduction with system optimal response is 6.9 %, whereas the spot price alone leads to a significant lower reduction of only 1.1 %. Grid tariffs achieve a peak reduction between 1 to 3.5 %. However, as Figure 3 shows, all grid tariffs, besides measured peak demand, achieve an even lower peak reduction when the additional price signal from the spot price is present. The negative effect is largest for the time-of-use tariffs and the achieved peak reduction is then equal to the case with spot price as single price signal. The measured peak demand tariff leads to the largest peak reduction in combination with the spot price.

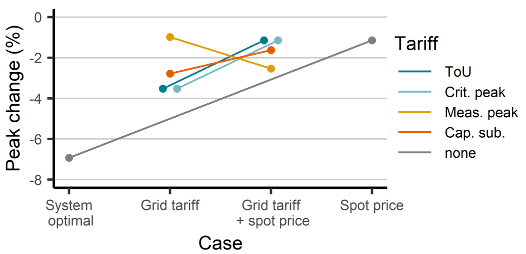


Fig. 3: Peak demand reduction results for all cases and grid tariffs.

The explanation for these results is that time-of-use tariffs have a fixed cost per kWh in the peak hours and therewith, the spot price becomes the predominant price signal in these hours since it varies from hour to hour. In the optimization, all flexibility is therefore used in the hours with the highest spot prices, whereas it otherwise is distributed evenly over all hours with equal peak prices in the ToU-tariffs. Since a reduction of the peak demand needs a load reduction of all hours between 8-21, the achieved peak reduction with spot prices is lower.

Figure 4 exemplifies these results by showing the load changes on the day with the highest peak demand for the grid tariffs ToU, measured peak demand and capacity subscription with and without spot price. The critical peak pricing tariff is not presented since the results are equal to the ToU-tariff.

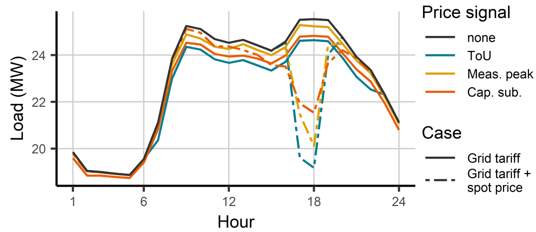


Fig. 4: Load change results on the day with maximum demand for various grid tariffs with and without spot price.

On this day the spot price was highest in the afternoon peak demand hours, but not in the morning peak demand hours. Therefore, in the time-of-use tariffs together with the spot price, the load is only reduced in the afternoon hours. The same effect is also present in the subscribed capacity tariff. However, in the measured peak demand tariff, only a minor share of the customers have their monthly peak on the grid peak day. Therefore, the additional price signal from the spot price uses mainly unused flexibility to reduce the load in the hours with highest spot price, leading to an increase in peak reduction for this tariff.

VI. Conclusions and Further Work

This paper demonstrates different grid tariffs designs ability to reduce peak loads, with and without an additional price signal from electricity spot prices. The data shows that in this study, there is no correlation between peak load and peak spot prices over the year, but that the correlation between spot prices and load on peak load days is strong. When subject to electricity spot prices, the consumer demand response leads to smaller reductions in peak load, except for measured peak demand which performed better together with spot prices. Another conclusion is that even small spot price fluctuations in combination with automatic demand response will lead to use of all flexibility in a few hours. Since the load is high over many hours on peak load days, this leads to inefficient demand response and a low reduction in peak demand. Further work should investigate the impact of different flexibility characteristics from different consumer groups, as this impacts the ability to reduce peak loads.

Acknowledgements

This work was funded by the “DigEco - Digital Economy” project from the NTNU Digital Transformation Initiative (project number 2495996), Statnett SF, and the Norwegian research council (project number 286513). In addition, it has been supported by CINELDI – Centre for intelligent electricity distribution, an 8-year Research Centre under the FME scheme (Centre for Environment-friendly Energy Research, 257626/E20) of the Norwegian Research Council. The authors thank Kjersti Vøllestad from Elvia for providing the electricity consumption data.

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Appendix

Nomenclature

Indices and Sets

D	Set of days, index d
M	Set of months, index m
T	Set of hourly time steps, index t

Parameters

C^{ET}	Energy term [$\frac{€}{kWh}$]
C^{e}	Total electricity cost [€]
C^{f}	Total flexibility use cost [€]
C^{g}	Total grid tariff cost [€]
C^{h}	Energy term above capacity subscription level [$\frac{€}{kWh}$]
C^{peak}	Measured peak demand peak cost[$\frac{€}{kWh}$]
C^{red}	Discomfort cost of reducing load [$\frac{€}{kWh}$]
C^{spot}	Electricity spot price [$\frac{€}{kWh}$]
C^{sub}	Annual capacity subscription cost[$\frac{€}{kW \times year}$]
C_t^{CPP}	Critical peak pricing grid tariff [$\frac{€}{kWh}$]
C_t^{TOU}	Static time-of-use grid tariff [$\frac{€}{kWh}$]
L_t	Original load series [kWh/h]
E^{flex}	Share of reducible energy in a day [%]
Q^{flex}	Share of reducible load in an hour [%]

Variables

q_t^{red}	Load reduction [kWh/h]
x^{sub}	Capacity subscription level [kW]
x_m^{max}	Monthly peak demand [kWh/h]
x_t^{h}	Electricity consumption above sub. cap. [kWh/h]
x_t^{i}	New load series with demand response [kWh/h]
x_t^{l}	Electricity consumption below sub. cap. [kWh/h]

Appendices

Appendix A: Grid tariff design descriptions

In this chapter, a general description of grid tariff designs is provided. First, the typical grid tariff cost components are presented. Secondly, a description of the most common tariff structures is presented.

A.1 Grid tariff cost components

Most residential grid tariffs in Europe were established under a traditional top-down power system, in which generation was dominated by large, controllable thermal power plants and the demand side was considered to be highly inflexible. Albeit still the case, the "thermal" era finds itself likely to be replaced by the renewable era, as electricity production from renewable energy resources is predicted to represent the majority of the generation in Europe by 2050. As a significant share of this generation will be located in the distribution grid and behind-the-meter at end-user level, grid tariff designs from the thermal era are going to be outdated. In addition to the distributed generation, the share of flexible, power-intensive loads, the current grid tariff schemes are also expected to perform poorly in terms of cost-reflectivity, fairness and grid-friendliness.

Grid tariffs considered in this thesis are made up by three different cost components:

- Fixed costs
- Volumetric costs
- Capacity costs

Fixed costs represent the fixed costs for the distribution system operator, and which recur regardless of the demand profile of the consumers. These costs typically represent the difference between network costs and the revenues collected through clear cost-causality.
Volumetric costs represent the cost per kilowatt-hour of energy delivered. Volumetric costs can be flat, but also have a spatial and temporal dimension, e.g., in the form of time-of-use tariffs, which have different prices in different

time periods during the day or season. Although not common in Europe, distributed locational marginal prices offer spatial differentiation in costs based on grid status. Further, volumetric costs may be capacity-dependent, when a low energy term is applied to demand below a certain threshold, and a high excess energy term is applied to demand above the threshold.
Capacity costs are costs associated with power withdrawn from the grid over a certain time period, often measured per hour (kilowatt-hour-per-hour). Capacity costs can be in the shape of measured peak demand, when the peak demand in one hour, or the average of a few hours, decides the costs for a given billing period (e.g. monthly). Subscribing to a capacity is also an option, when consumers have to pay an excess energy term per kilowatt-hour consumed above the level, or are required to stay below the subscription level at all times, or during certain time periods when there are grid congestions.

A.2 Grid tariff designs

In the following section, a brief description of the most common tariff designs are described and visualized.

A.2.1 Fixed tariffs

Fixed tariffs are the simplest form of grid tariffs, requiring no metering or information about the consumer. The main advantages of this tariff structure are simplicity, and low administration costs, as well as stable costs and income for end-users and distribution grid operators, respectively. However, the tariff is not cost reflective as consumers have no incentive to reduce consumption nor peak loads to save costs.

Consumption-differentiated fixed tariffs are a slightly more advanced version of fixed tariffs, as consumers are divided into groups depending on annual consumption. In a stairs-like fashion, consumers are then divided into groups with the consequence that higher consumption does not lead to higher costs until a threshold is reached. When reached, costs immediately increase to the next level.

A.2.2 Volumetric tariffs

Volumetric tariffs are the most widespread type of grid tariff in Europe today. Since metering is common, it is very simple to bill consumers based on their consumption over a given time period (typically monthly). Volumetric tariffs provide an incentive to reduce the volumetric consumption of electricity, which rewards investments in energy efficiency as well as behind-the-meter electricity production. Under the assumption that demand profiles are relatively similar, the approach is cost reflective as volumetric consumption translates to a specific peak demand during the system's peak hours. However, assuming similar load profiles is an increasingly unrealistic assumption, especially in future power systems where electrification of heating, transport and behind-the-meter generation is expected to be more common. The tariff is flat, as shown in Figure A.1.

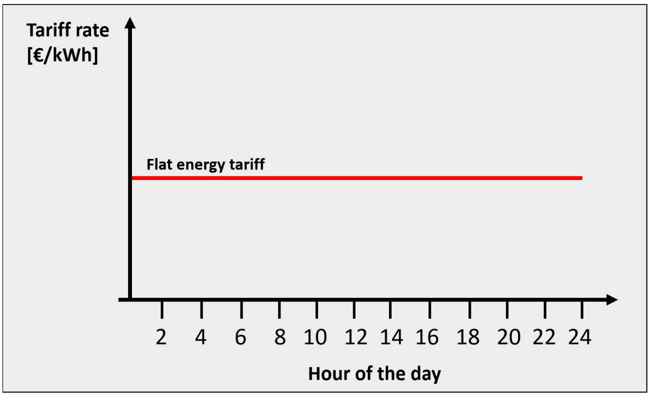

Figure A.1: Flat, volumetric tariff with a fixed cost per energy unit.

A.2.3 Time-of-use tariffs

Similar to volumetric tariffs, time-of-use tariffs have a cost per kilowatt-hour consumed. The cost depends on the time of consumption and is often based on some general consumption trends in the grid, pricing consumption during peak load hours higher than during non-constrained hours. Typically, the peak price hours occur during the day, typically during the morning and evening peak, when the demand is the highest. Alternatively, it lasts the entire day during winter, as shown in Figure A.2. During the night, consumption is generally low and has a low energy term to incentivize load shifting to the night. Time-of-use tariffs also have the option of only introducing time-dependent pricing during seasons when consumption is higher.

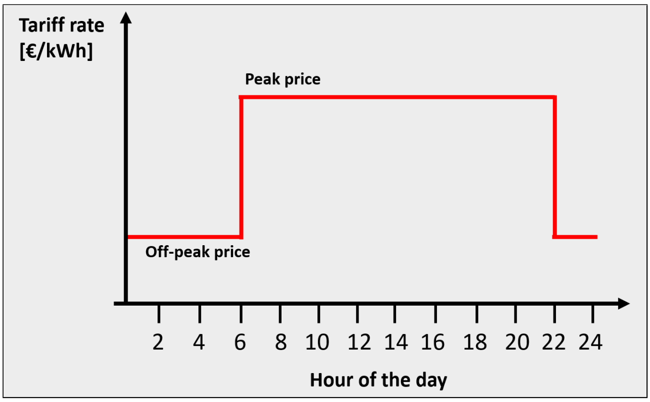

Figure A.2: Time-of-use tariff with high costs during the day. Peak price periods can be adjusted, and also seasonal.

A.2.4 Critical peak pricing tariffs

Under critical peak pricing tariffs, the time dependent prices are only introduced in some days a year, announced by the DSO the day before. The tariff can target the high consumption days specifically with stronger price signals during peak demand hours as visualized in Figure A.3. As previously mentioned, static time-of-use tariffs also can be introduced only in some time periods, but these time periods typically last for months, and have lower prices than the dynamic version. The critical peak pricing variant has the advantage of targeting specific days directly with strong price signals, but also introduces high costs for consumers who are unable to react to the price signals.

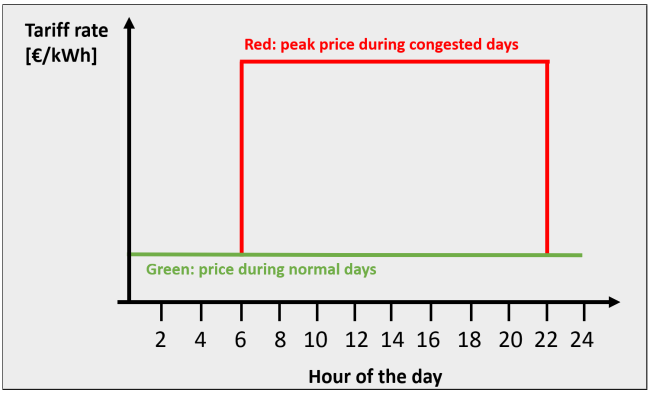

Figure A.3: Critical peak pricing, in which peak costs are significantly higher than normal costs, but only valid during limited days per year.

A.2.5 Static capacity subscription tariffs

Capacity subscription tariffs are based on consumers making an active choice by subscribing to a capacity level, which has some resemblance to an internet subscription in which the consumer subscribes to a specific bandwidth. Consumption below the subscription level has a small energy term per kilowatthour which reflects the marginal losses in the grid, whereas consumption above the subscription level is subject to an excess energy term that is significantly higher than the energy term. This grid tariff structure provides incentives to stay below the subscription level as shown in Figure A.4.

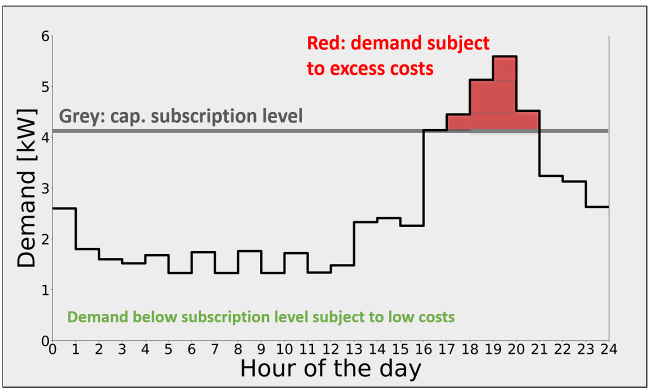

Figure A.4: Capacity subscription tariff, where all demand above the subscription limit is subject to excess costs, whereas demand below is subject to very small costs.

Consumers can choose to subscribe to a low level and aim to reduce their peak loads, or subscribe to higher levels if they lack flexibility options or the willingness to stay below the limit. This capacity-based tariff structure is relatively efficient at reducing individual peak loads at all times as consumers constantly have an incentive to flatten their load profiles. However, this incentive also remains when there is no scarcity on capacity in the grid, which is conflict with the concept of economic efficiency.

A.2.6 Dynamic capacity subscription tariffs

Unlike the static version of subscription-based capacity tariffs, the dynamic version has no constraints when there are no congestions in the grid as visualized in Figure A.5. When there are grid congestions, consumers are either limited to their subscription level or have to pay a very high excess energy term for consumption above the subscription level. As grid congestions rarely happen, the dynamic version has the advantage of not restricting consumption unless required. It also provides a very strong price signal during capacity scarcity, as demand is limited or highly penalized in a few hours per year.

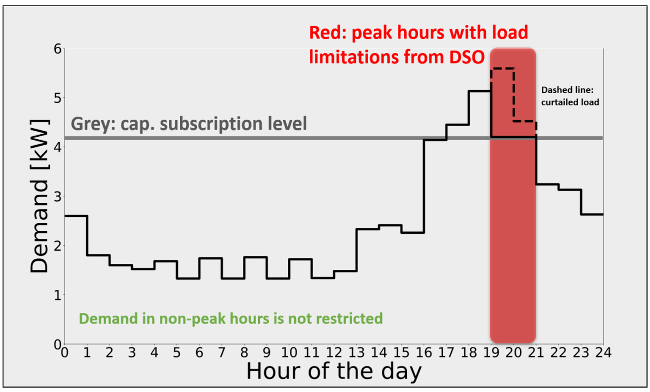

Figure A.5: Dynamic capacity subscription tariff, where demand is limited to subscription level during DSO activations, shown in red. Curtailment or flexibile response is then required.

A.2.7 Measured peak demand

Measured peak demand (also known as demand charges) is based on the peak load over a specific time period as shown in Figure A.6. The peak load can be measured as the peak load in a single hour or the average of multiple hours. By linking costs purely to the peak demand, consumers have a strong incentive to avoid high peak loads. This type of tariff is common for commercial consumers, often metering the monthly peak load to set the cost. The tariff is relatively simple as all costs are connected to the peak load, and no active choice needs to be done ex ante, unlike with capacity subscription tariffs. However, measured peak demand is also individual and could in theory result in peak-demand-related costs when there is no or little scarcity in the grid, similar to static capacity subscription tariffs. In addition, measured peak demand suffers from the consumer not necessarily knowing when their peak load might occur.

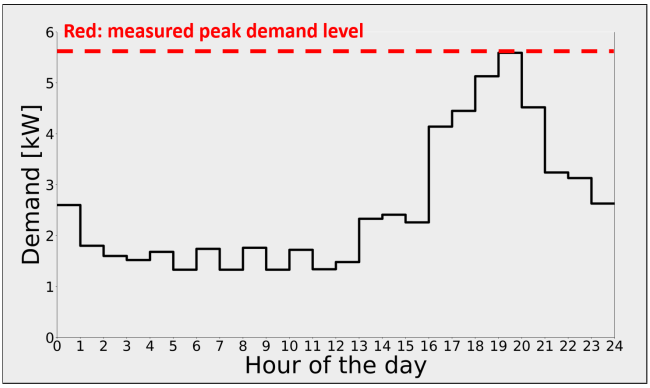

Figure A.6: In measured peak demand tariffs, the peak determines the price. The plot shows the concept daily basis, but the measurement period is normally monthly.

Appendix B: Local electricity market formulation

A general formulation of a local electricity market, similar to the one modeled in Paper III [111] is derived in this Appendix. All variables are non-negative unless stated otherwise. Variables are given by small letters, whereas Parameters are are given by large letters. All primal variables are from the Latin alphabet, whereas dual variables are from the Greek.

B.1 Consumer problem

The local electricity market formulation starts by formulating the cost minimization problem of a single consumer c, which is part of the consumer set $c \in C$. As shown in (B.1), the problem minimizes costs related to importing electricity from the grid over the time horizon, resulting in electricity costs c^e and grid tariff costs c^g. Costs related to taxes and fees are neglected in this problem for simplicity.

$$\forall c \quad \min c^e + c^g \tag{B.1}$$

Electricity costs are based on the import x^i_{ct} and export x^e_{ct} of electricity, where we assume that the consumer pays the day-ahead electricity spot price C^{DA}_t for import in each time period, and receives the same price in the case of export to the grid. Grid tariffs costs depend on the grid tariff design. In this formulation, we consider capacity subscription tariffs, and that the subscription level X^{sub}_c is determined exogenously. Hence, the objective function can be formulated as in (B.2)

$$\forall c \quad \min \sum_t (x^i_{ct} - x^e_{ct}) C^{DA}_t + \sum_t (x^l_{ct} C^l + x^h_{ct} C^h) \tag{B.2}$$

Import from the grid (or retailer) x^i_{ct} is split into two variables to reflect consumption below (x^l_{ct}) and above (x^h_{ct}) the subscription level X^{sub}_c as shown in (B.3) and (B.4)[1]. Note that X^{sub}_c could be included in the objective as a

[1] The substitution in (B.3) is not necessary, but included as it is a more intuitive formulation.

variable with an associated cost, in order to find the optimal capacity subscription level. Grid tariff costs related to importing electricity below and above the subscription level are given by C^l and C^h, respectively.

$$\forall ct \quad x^l_{ct} + x^h_{ct} - x^i_{ct} = 0 \quad (\nu^{tot}_{ct}) \tag{B.3}$$

$$\forall ct \quad x^l_{ct} - X^{sub}_c \leq 0 \quad (\nu^{sub}_{ct}) \tag{B.4}$$

The energy balance that ensures that consumer load L_{ct} is met, can be formulated as per (B.5). From here, we include the dual variables of each constraint for the competitive local electricity market formulation. Further, we assume that the consumers may have generation G^{PV}_{ct} from photovoltaic (PV) production and/or storage flexibility. We therefore include PV and a battery storage in the formulation.

$$\forall ct \quad x^i_{ct} - x^e_{ct} - L_{ct} + G^{PV}_{ct} - q^{ch}_{ct} + q^{dis}_{ct} = 0 \quad (\nu^{eb}_{ct}) \tag{B.5}$$

Further, the necessary battery storage constraints are presented in (B.6a)-(B.6e). The energy level of the battery is given by e_{ct} and is bounded between the maximum battery state of charge E^{max}_c. The battery charge/discharge variables $(q^{ch}_{ct}, q^{dis}_{ct})$ are associated with their upper bound, Q^{max}_c, as well as their respective efficiencies A^{ch}_c, A^{dis}_c. We avoid binding the start and end storage levels, but ensure that they remain the same in (B.6b).

$$\forall c(t < t_{end}) \quad e_{c(t+1)} - e_{ct} - q^{ch}_{ct} A^{ch}_c + \frac{q^{dis}_{ct}}{A^{dis}_c} = 0 \quad (\beta^{soc}_{ct}) \tag{B.6a}$$

$$\forall c(t = t_{end}) \quad e_{c0} - e_{ct} - q^{ch}_{ct} A^{ch}_c + \frac{q^{dis}_{ct}}{A^{dis}_c} = 0 \quad (\beta^{soc}_{ct}) \tag{B.6b}$$

$$\forall ct \quad q^{ch}_{ct} - Q^{max}_c \leq 0 \quad (\beta^{ch}_{ct}) \tag{B.6c}$$

$$\forall ct \quad q^{dis}_{ct} - Q^{max}_c \leq 0 \quad (\beta^{dis}_{ct}) \tag{B.6d}$$

$$\forall ct \quad e_{ct} - E^{max}_c \leq 0 \quad (\beta^{max}_{ct}) \tag{B.6e}$$

B.2 Energy community formulation

We formulate a simplified energy community problem by assuming that all assets are behind-the-meter and owned by individual consumers. We also assume that the community aims to minimize the total costs of the community, basically assuming a cooperative game with ex-post mechanisms to share benefits and costs.

The problem formulation remains similar, but the objective function now aims to minimize total costs as shown in (B.7)

$$\min \sum_{ct} (x^i_{ct} - x^e_{ct}) C^{DA}_t + \sum_{ct} (x^l_{ct} C^l + x^h_{ct} C^h) \tag{B.7}$$

In addition, we now assume that the community members can import ($x^{LM,i}_{ct}$) and export ($x^{LM,e}_{ct}$) electricity between each other as shown in (B.8).

$$\forall t \quad \sum_{c} (x^{LM,i}_{ct} - x^{LM,e}_{ct}) = 0 \tag{B.8}$$

This subsequently changes the energy balance equation (B.9). Note that there are still no costs or prices connected to the sharing of electricity as the community is assumed to be cooperating.

$$\forall ct \quad x^i_{ct} - x^e_{ct} - L_{ct} + G^{PV}_{ct} - q^{ch}_{ct} + q^{dis}_{ct} + x^{LM,i}_{ct} - x^{LM,e}_{ct} = 0 \quad (\nu^{eb}_{ct}) \tag{B.9}$$

B.3 Local electricity market formulation

The cooperative game can be formulated as a competitive game with a Nash equilibrium solution by deriving the Karush-Kuhn-Tucker (KKT) conditions of the community problem. As the problem is linear, the KKT conditions are necessary and sufficient for optimality. This results in a mixed complementarity program (MCP), with an additional market clearing constraint. The MCP can be solved directly using the PATH solver [112] in Julia/GAMS, or be reformulated as a mixed integer linear program using the "Big-M" approach or by using special order sets [45].

First, the market clearing (B.10), which is similar as in the community problem, but now has an associated dual λ^{LM}_t, representing the market clearing price, which is now considered in the objective of each consumer. The market operator problem is unique as it matches demand and supply in the market clearing constraint.

$$\forall t \quad \sum_c (x_{ct}^{LM,i} - x_{ct}^{LM,e}) = 0 \quad \perp \lambda_t^{LM} \tag{B.10}$$

The consumer objective from (B.2) can now be further derived to (B.11), which contains the costs and revenues related to trading in the local electricity market. In addition, an administration cost C^a is added to purchasing of electricity, representing an envisioned cost of facilitating a trade, while also avoiding model issues related to multiple optimal solutions.

$$\begin{aligned} \min \sum_t (x_{ct}^i - x_{ct}^e) C_t^{DA} + \sum_t (x_{ct}^l C^l + x_{ct}^h C^h) \\ + \sum_t (x_{ct}^{LM,i} - x_{ct}^{LM,e}) \lambda_t^{LM} + \sum_t x_{ct}^{LM,i} C^a \end{aligned} \tag{B.11}$$

From this basis, the Karush-Kuhn-Tucker conditions can be derived to represent the local electricity market competitive game (B.12a)-(B.14e). All variables are non-negative, with the exception of the duals related to the equality constraints, which are free.

$$\forall ct \quad C^l + \nu_{ct}^{tot} + \nu_{ct}^{sub} \geq 0 \perp x_{ct}^l \geq 0 \tag{B.12a}$$
$$\forall ct \quad C^h + \nu_{ct}^{tot} \geq 0 \perp x_{ct}^h \geq 0 \tag{B.12b}$$
$$\forall ct \quad C_t^{DA} - \nu_{ct}^{tot} + \nu_{ct}^{eb} \geq 0 \perp x_{ct}^i \geq 0 \tag{B.12c}$$
$$\forall ct \quad - C_t^{DA} - \nu_{ct}^{eb} \geq 0 \perp x_{ct}^e \geq 0 \tag{B.12d}$$
$$\forall ct \quad \lambda_t^{LM} + \nu_{ct}^{eb} + C^a \geq 0 \perp x_{ct}^{LM,i} \tag{B.12e}$$
$$\forall ct \quad - \lambda_t^{LM} - \nu_{ct}^{eb} \geq 0 \perp x_{ct}^{LM,e} \tag{B.12f}$$
$$\tag{B.12g}$$

$$\forall ct \quad -\nu^{eb}_{ct} - \beta^{soc}_{ct} A^{ch}_{c} + \beta^{ch}_{ct} \geq 0 \perp q^{ch}_{ct} \geq 0 \tag{B.13a}$$

$$\forall ct \quad \nu^{eb}_{ct} + \frac{\beta^{soc}_{ct}}{A^{dis}_{c}} + \beta^{dis}_{ct} \geq 0 \perp q^{dis}_{ct} \geq 0 \tag{B.13b}$$

$$\forall c(t > t_0) \quad \beta^{soc}_{c(t-1)} - \beta^{soc}_{ct} + \beta^{max}_{ct} \geq 0 \perp e_{ct} \geq 0 \tag{B.13c}$$

$$\forall c(t = t_0) \quad \beta^{soc}_{ct_{end}} - \beta^{soc}_{c0} + \beta^{max}_{c0} \geq 0 \perp e_{c0} \geq 0 \tag{B.13d}$$

$$\forall ct \quad x^{l}_{ct} + x^{h}_{ct} - x^{i}_{ct} = 0 \perp \nu^{tot}_{ct} \tag{B.13e}$$

$$\forall ct \quad x^{l}_{ct} - X^{sub}_{c} \leq 0 \perp \nu^{sub}_{ct} \geq 0 \tag{B.13f}$$

$$\forall ct \quad x^{i}_{ct} - x^{e}_{ct} + x^{LM,i}_{ct} - x^{LM,e}_{ct} - L_{ct} + G^{PV}_{ct} - q^{ch}_{ct} + q^{dis}_{ct} = 0 \perp \nu^{eb}_{ct} \tag{B.13g}$$

(B.13h)

$$\forall ct \quad q^{ch}_{ct} - Q^{ch}_{c} \leq 0 \perp \beta^{ch}_{ct} \geq 0 \tag{B.14a}$$

$$\forall ct \quad q^{dis}_{ct} - Q^{dis}_{c} \leq 0 \perp \beta^{dis}_{ct} \geq 0 \tag{B.14b}$$

$$\forall ct \quad e_{ct} - E^{max}_{c} \leq 0 \perp \beta^{max}_{ct} \geq 0 \tag{B.14c}$$

$$\forall c(t < t_{end}) \quad e_{c(t+1)} - e_{ct} - q^{ch}_{ct}\eta^{ch}_{c} + \frac{q^{dis}_{ct}}{\eta^{dis}_{c}} = 0 \perp \beta^{soc}_{ct} \tag{B.14d}$$

$$\forall c(t = t_{end}) \quad e_{c0} - e^{soc}_{ct} - q^{ch}_{ct} A^{ch}_{c} + \frac{q^{dis}_{ct}}{A^{dis}_{c}} = 0 \perp \beta^{soc}_{ct} \tag{B.14e}$$

Appendix C: Credit author statement

The articles in this thesis have been published with the support of many excellent researchers, which are listed below. Based on [113], the “CRedit Author Statement” taxonomy is presented in Table C.1. We use the 14 roles to provide a taxonomy, which states the roles typically played by contributors to scientific scholarly output. The roles describe each contributor’s specific contribution to the scholarly output.

- Sigurd Bjarghov (SB)
- Hossein Farahmand (HF)
- Matthias Hofmann (MH)
- Gerard Doorman (GD)
- Magnus Askeland (MA)
- Stian Backe (SBa)
- Hanne Sæle (HS)
- Karen Byskov Lindberg (KBL)
- Markus Löschenbrand (ML)
- Aziz U. N. Ibn Saif (AIS)
- Raquel Alonso Pedrero (RAP)
- Christian Pfeiffer (CP)
- Shafiuzzaman K. Khadem (SK)
- Marion Rabelhofer (MR)
- Frida Revheim (FR)

Conceptualization: Ideas; formulation or evolution of overarching research goals and aims.

Methodology: Development or design of methodology; creation of models.

Software: Programming/software development; designing computer programs; implementation of the computer code and supporting algorithms; testing of existing code components.

Validation: Verification/whether as a part of the activity or separate/of the overall replication/reproducibility of results/experiments and other research outputs.

Formal analysis: Application of statistical/mathematical/computational/or other formal techniques to analyze or synthesize study data.

Investigation: Conducting a research and investigation process/specifically performing the experiments/or data/evidence collection.

Resources: Provision of study materials/reagents/materials/patients/laboratory samples/animals/instrumentation/computing resources/or other analysis tools.

Data curation: Management activities to annotate (produce metadata)/scrub data and maintain research data (including software code/where it is necessary for interpreting the data itself) for initial use and later re-use.

Writing – original draft: Preparation/creation and/or presentation of the published work/specifically writing the initial draft (including substantive translation).

Writing – review & editing: Preparation/creation and/or presentation of the published work by those from the original research group/specifically critical review/commentary or revision – including pre- or post-publication stages.

Visualization: Preparation/creation and/or presentation of the published work /specifically visualization/data presentation.

Supervision: Oversight and leadership responsibility for the research activity planning and execution/including mentorship external to the core team.

Project administration: Management and coordination responsibility for the research activity planning and execution.

Funding acquisition: Acquisition of the financial support for the project leading to this publication.

Table C.1: Credit author statment

	Paper I	Paper II	Paper III	Paper IV	Paper V
Conceptualization	SB, ML	SB, GD	SB, MA, SBa	SB, MH, KL	SB, MH
Methodology	SB, ML	SB, GD	SB, MA	SB, MH	SB, MH
Software	SB, ML	SB	SB, MA	SB, MH	SB, MH
Validation	SB, ML	SB	SB, MA, SBa	SB, MH, HS, KL	SB, MH
Formal analysis	SB, ML	SB, GD	SB	SB, MH	SB, MH
Investigation	SB, ML	SB, GD	SB, MA, SBa	SB, MH	SB, MH
Resources	SB, ML	SB	MA	SB, MH	SB, MH
Data curation	SB	SB	SB	MH	MH
Writing - original draft	SB, ML, AIS, RAP, CP, SK, MR, FR	SB	SB	MH	SB
Writing - review & editing	SB, ML, HF	SB, GD, HF	SB, MA, SBa	SB, MH, HS, KL	SB, MH
Visualization	SB, ML, AIS, RAP, CP	SB, GD	SB	MH	SB, MH
Supervision	HF	GD, HF	N/A	KL	N/A
Project administration	SB, ML	SB	SB	MH	SB
Funding aquisition	N/A	HF	N/A	N/A	N/A

ISBN 978-82-326-5671-4 (printed ver.)
ISBN 978-82-326-5387-4 (electronic ver.)
ISSN 1503-8181 (printed ver.)
ISSN 2703-8084 (online ver.)

NTNU
Norwegian University of
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