Doctoral theses at NTNU, 2022:229

Magnus Askeland

Policy issues for distributed energy resources as a part of larger energy systems

Doctoral thesis

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Norwegian University of Science and Technology
Thesis for the Degree of Philosophiae Doctor
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Preface

The research presented in this thesis 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 Professor Magnus Korpås (NTNU), and co-supervisors were Ove Wolfgang (SINTEF) and Karen Byskov Lindberg (NTNU/SINTEF).

The work presented in this thesis has been generated during the timeline of the PhD project, from August 2018 to December 2021. The research was carried out at NTNU and SINTEF Energy Research in Trondheim and during a research stay at SINTEF Community in Oslo from August 2018 to March 2019.

The candidate was during the PhD employed at SINTEF Energy as an institute PhD which was financed by a grant from the Research Council in Norway. The PhD project is part of the FME ZEN research centre.

The PhD thesis is organised in a paper-based format, and the main goal is to put the research that has been carried out in a joint context and provide relevant background information.

Acknowledgements

The journey towards a PhD has been a substantial personal project but would not have been possible without the people that have supported me along the way. During this time, I have been fortunate to meet people who have enriched my life both academically and personally.

First, I would like to thank my supervisor Professor Magnus Korpås for guiding me through these years with your academic experience and leadership. You have let me pursue my research interests while teaching me the joy of research. I would also like to thank my co-supervisors, Ove Wolfgang and Karen Byskov Lindberg at SINTEF, for providing valuable discussions and ensuring the relevance of my research.

I would also like to thank the people I have collaborated closely with during these years; Stian Backe, Sigurd Bjarghov, Thorsten Burandt, Lars Arne Bø, Steven A. Gabriel, Laurent Georges, Stefan Jaehnert, and Dimitri Pinel have my deepest gratitude. You have been vital collaborators and discussion partners.

Working at SINTEF as an institute PhD has been an enrichment and great for connecting with highly competent people to develop ideas and relating the research to practical applications, and I would like to thank all my colleagues at SINTEF. The close connection to NTNU has also been an essential ingredient, and I would like to thank the people at both the Department of Electric Power Engineering and the Department of Industrial Economics for the unique academic environment you represent. Also, I am thankful to the Zero Emission Neighbourhoods research centre for providing an environment full of collaboration possibilities, multi-disciplinary insight, and industry connections.

I want to thank my family and friends for their support and encouragement. Thanks to my daughter Anniken for letting me explore the world through your eyes every day. Finally, to my wife Vibeke, thank you for being my life partner and supporting me all the way.

Summary

The thesis presents work on designing end-user price signals with a neighbourhood perspective when the grid users respond to the conditions set at their system boundary. A particular emphasis is on aspects that arise when the system boundary is expanded from a single building to an area level. The work is structured under three main topics that span across multiple aggregation levels and stakeholder perspectives:

- **Identification and assessment of regulatory challenges:** A qualitative identification and assessment of regulatory challenges that arise when the system boundary is expanded from a single building to a neighbourhood.
- **Distribution grid pricing:** Studying the implications of various grid tariff structures in multi-stakeholder decision-making settings.
- **Mechanisms to achieve coordination:** Investigating the potential role of local market mechanisms as a supplementary tool to achieve local coordination and the potential feedback effect on grid tariffs.

Decarbonisation of the energy system requires a transition towards carbon-neutral energy carriers and a sufficient energy supply from renewable sources. Hence, investments in the appropriate technological solutions are required to match demand with renewable energy generation at both the temporal and spatial level. To achieve these targets, energy solutions are required both in the form of large-scale assets at the backbone of the energy system and local resources at the distribution grid level. Since the decisions made by individual stakeholders drive the deployment and operation of energy resources, the regulatory framework must provide the appropriate incentives. An essential part of this larger picture at the distribution grid level is to ensure efficient deployment and operation of energy resources and grid capacity. From a stakeholder perspective, it is beneficial to optimise energy use and generation with the perspective of an individual building. However, expanding the system boundary from individual buildings to an area level opens several possibilities since energy systems can be optimised by exploiting a more comprehensive range of resources while avoiding or deferring costly grid upgrades. Therefore, the regulatory framework becomes a pivotal facilitator to provide appropriate incentives for optimal deployment and operation of energy-related assets at an area level.

The methods used to carry out the research are based on energy system analysis with a particular focus on socio-economics and a qualitative assessment of the

relevant regulatory framework. This forms an interdisciplinary approach that is applied to relevant cases where pricing mechanisms can be detrimental to achieving an optimal outcome. The considered cases are inspired by ongoing pilot projects in zero emission neighbourhood (ZEN) and other related research projects.

This thesis's most important overarching contribution is the insight into how area-level pricing mechanisms can be designed to facilitate efficient use of energy-related assets and flexibility at the local level while keeping the interaction with the centralised power market intact. The main contributions of this thesis can be summarised as:

- **C1 Identification of regulatory issues:** The thesis includes assessments of the regulatory framework related to distributed energy resources (DERs) on an area level. Regulatory issues that can create mismatches between stakeholder incentives and system optimality at a larger spatial scope are identified.

- **C2 Development of modelling frameworks:** Several models are developed based on the premise of decentralised decision-making in neighbourhood energy systems. These models calculate the outcomes based on decentralised decision making under various regulatory designs, which are benchmarked to the corresponding system optimal outcome. Combined, these models form a suitable framework for studying the effect of regulatory designs and pricing mechanisms on the deployment and operation of decentralised energy resources.

- **C3 Regulatory assessments:** Based on cost efficiency under decentralised decision-making and the requirement that grid pricing structures should not be excessively complicated, the research includes assessments on how the regulatory framework can be adapted to facilitate optimal solutions on a multi-stakeholder level. This includes both how to incentivise the appropriate amount and location of DERs and how to facilitate favourable operational patterns on an area level.

This thesis provides an overview of the underlying motivation, research structure, methodological principles, and overarching conclusions of the research that has been carried out. Hence, the thesis aims to complement rather than repeat the content of the articles, which includes detailed descriptions of methodologies, results, and references.

List of abbreviations

DER Distributed energy resource

DSO Distribution system operator

EPBD Energy performance of buildings directive

EU European Union

EV Electric vehicle

FME ZEB Research Centre on Zero Emission Buildings

FME ZEN Research Centre on Zero Emission Neighbourhoods in Smart Cities

ICT Information and communications technology

KKT Karush-Kuhn-Tucker

MILP Mixed-integer linear program

MPEC Mathematical program with equilibrium constraints

NTNU The Norwegian University of Science and Technology

P2P Peer-to-peer

PV Photovoltaic

SOS Special ordered set

ZEB Zero energy building

ZEN Zero emission neighbourhood

Contents

1 List of papers

This thesis is comprised of the following publications, listed in chronological order:

EEM19: Magnus Askeland and Magnus Korpås. Interaction of DSO and local energy systems through network tariffs. In *16th International Conference on the European Energy Market (EEM)*, 2019

ZEB19: Magnus Askeland, Stian Backe, and Karen Byskov Lindberg. Zero energy at the neighbourhood scale: Regulatory challenges regarding billing practices in Norway. *IOP Conference Series: Earth and Environmental Science*, 352(1), 2019

EEM20: 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

ENSYS: Magnus Askeland, Thorsten Burandt, and Steven A. Gabriel. A Stochastic MPEC Approach for Grid Tariff Design with Demand Side Flexibility. *Energy Systems*, 2020

ECON: Magnus Askeland, Stian Backe, Sigurd Bjarghov, and Magnus Korpås. Helping end-users help each other: Coordinating development and operation of distributed resources through local power markets and grid tariffs. *Energy Economics*, 94, 2021

SMART: Magnus Askeland, Stian Backe, Sigurd Bjarghov, Karen Byskov Lindberg, and Magnus 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. *Smart Energy*, 3, 2021

EIENDOM: Eivind Junker, Magnus Askeland, and Lars Arne Bø. Bestemmelser om energi- og miljøkrav i reguleringsplaner – i lys av konseptet nullutslippsnabolag. *Tidsskrift for Eiendomsrett*, 2, 2022

A credit author statement of the contributions from the various authors is provided in appendix A.

In addition to the main articles, several other publications have resulted during the PhD project. Although they represent scientific contributions, the supporting publications listed below only have a minor relevance to the scope of this thesis:

- Ove Wolfgang, Magnus Askeland, Stian Backe, Jonathan Fagerstrøm, Pedro Crespo del Granado, Matthias Hofman, Stefan Jaehnert, Ann Kristin Kvellheim, Hector Maranon-Ledesma, Kjetil Midthun, Pernille Seljom, Tomas Skjølsvold, Hanne Sæle, and William Throndsen. Prosumers' role in the future energy system [Position paper], 2018
- Magnus Askeland, Stefan Jaehnert, and Magnus Korpås. Equilibrium assessment of storage technologies in a power market with capacity remuneration. *Sustainable Energy Technologies and Assessments*, 31:228–235, 2019
- Laurent Georges, Elin Storlien, Magnus Askeland, and Karen Byskov Lindberg. Development of a data-driven model to characterize the heat storage of the building thermal mass in energy planning tools. *E3S Web of Conferences*, 246, 2021
- Stian Backe, Dimitri Pinel, Magnus Askeland, Karen Byskov Lindberg, Magnus Korpås, and Asgeir Tomasgard. Zero Emission Neighbourhoods in the European Energy System. Technical report, NTNU/SINTEF, 2021
- Stian Backe, Dimitri Pinel, Magnus Askeland, Karen Byskov Lindberg, Magnus Korpås, and Asgeir Tomasgard. Exploring the link between the EU emissions trading system and net-zero emission neighbourhoods. *Energy And Buildings [under review]*

2 Introduction

This chapter provides an overview of the research that has been carried out. First, the underlying motivation is described in section 2.1. After that, the scope and research questions are described in section 2.2. The context of the research is provided in section 2.3, section 2.4, and section 2.5. Section 2.6 gives an overview of how the different publications relate to each other, how they fit into the overall scope and objectives of the PhD project and the resulting contributions. Last, section 2.7 describes the structure of the remaining parts of the thesis.

2.1 Motivation

Decarbonisation of the energy system requires a transition towards carbon-neutral energy carriers and a sufficient energy supply from renewable sources. However, energy resources come in many forms ranging from large-scale projects connected at the backbone of the energy system to small scale distributed deployment at the consumer level. Hence, investments in the appropriate technological solutions are required so that we are able to match demand with renewable energy generation at both the temporal and spatial levels. The optimal strategy for deploying energy resources is not universal and depends on many conditions such as cost, infrastructure needs, and resource availability. In addition, it is essential to consider how flexibility can be efficiently used to decrease the cost of energy and utilise renewable resources.

Since the decisions made by individual stakeholders drive the deployment and operation of energy resources at all levels in the energy system, the regulatory framework must provide an appropriate framework to facilitate cost-effective solutions. An essential part of this larger picture at the distribution grid level is to ensure efficient deployment and operation of energy resources and grid capacity. Hence, expanding the system boundary from individual buildings to an area level opens several possibilities since energy systems can be optimised by exploiting a more comprehensive range of resources while avoiding or deferring grid upgrades. Therefore, the regulatory framework becomes a pivotal facilitator to provide appropriate incentives for optimal deployment and operation of energy-related assets at an area level. Thus, to tackle the challenges posed by a carbon-neutral energy system cost-effectively, it is essential to consider how policies and markets can be designed to promote an optimal deployment of energy resources and corresponding optimal operation of flexible assets.

2.2 Scope and objectives

This thesis focuses on how incentives should be designed to efficiently allocate energy resources in a multi-stakeholder setting in local energy systems. An important assumption is that we have rational market participants react optimally to their boundary conditions.

This PhD work is part of the Research Centre on Zero Emission Neighbourhoods in Smart Cities (FME ZEN) which was established by the Research Council in Norway in 2017 [13]. FME ZEN is the successor of the Research Centre on Zero Emission Buildings (FME ZEB) [14].

The overall goal of FME ZEN is to create solutions for the zero-emission buildings and neighbourhoods of the future. The research in the ZEN centre is multidisciplinary and done in close collaboration with partners that are relevant for planning and deployment of ZEN areas. The Norwegian University of Science and Technology (NTNU) is the host of FME ZEN and leads the Centre while SINTEF Community and SINTEF Energy are research partners. In addition, centre partners are representing municipal and regional governments, property owners, developers, consultants and architects, information and communications technology (ICT) companies, contractors, energy companies, manufacturers of materials and products and governmental organisations.

The research presented in this thesis investigates how current and potential regulations and market mechanisms impact the deployment and operation of distributed energy resources in the context of ZEN. The research has been carried out through qualitative assessments of relevant topics, development of models that can represent stakeholder behaviour and interaction, and applying those models to analyse relevant cases. The focus is on fundamental multi-stakeholder efficiency considerations rather than improving the modelling detail of energy systems. Therefore, the modelling framework that has been developed is simplified in terms of technical detail and does not attempt to replace existing models for energy system analysis or optimal local energy system design. Instead, it tries to complement these approaches by providing insight regarding the design of regulatory conditions and price signals. Hence, the main focus is to consider how the regulatory framework can be designed so that decentralised decisions concerning distributed energy resources are harmonised with their impact on the larger energy system.

The following research questions have been formulated to describe the starting point of the research that has been carried out:

RQ1 What are the policy aspects regarding DERs as a part of larger energy systems, and how are the incentives related to DERs affected by the regulatory framework?

- Which regulatory challenges arise when the spatial scope changes from the building level to a neighbourhood? (ZEB19)
- How does the regulatory approach in the building- and energy sector compare, and what are the implications for the area planning of local authorities? (EIENDOM)
- What are the implications of decision-making modelling structures in the context of local energy systems? (EEM19)

RQ2 What are the implications of prospective market mechanisms within ZEN and for the interaction between ZEN and the rest of the energy system?

- To which extent can grid tariffs be used as an instrument to incentivise load shifting on a multi-stakeholder level? (ENSYS)
- How can local trading coordinate end-users to reduce peak loads in neighbourhoods? (EEM20).
- How can local electricity trading affect the cost-optimal deployment and operation of DERs in neighbourhoods, and what is the potential impact on grid investments? (ECON)
- How can price signals be designed to both fit into existing market structures and coordinate energy use between stakeholders, and what is the potential to increase the electric vehicle (EV) hosting capacity? (SMART)

All these research questions are formed with the intent of relating the research to ongoing projects. Furthermore, the aim is to consider mechanisms that, to a large extent, are compatible with current market structures and relevant for ZEN.

2.3 Decentralisation of energy resources and flexibility

Economies of scale typically decrease the cost of generating electricity by building larger power plants (see, e.g., [15]). Nevertheless, DERs have gained increased interest during the last decade due to cost reductions and promotion through policies. Although the unit cost of capacity can be higher for DERs than for larger assets, the potential profitability of decentralised assets is driven mainly by the potential of avoided costs since the grid needs to be dimensioned for the peak usage of electricity. Therefore, due to the locational properties of DERs, it might be relevant to invest in decentralised resources to reduce or postpone the need for infrastructure upgrades [16]. Also, it can be easier to gain public acceptance when the resources are integrated with local communities. For instance, the cost of onshore wind power has seen rapid decreases but is still associated with conflicts for new projects because of their impact on the local environment [17]. In contrast, decentralised resources such as photovoltaic (PV) systems are less disputed because they generally use the area without an externality cost, and the local residents usually initiate the projects.

In addition to the decentralisation of generation assets, the potential for flexible demand is also increasing. Under the Third Energy Package, European Union (EU) member states are required to implement smart meters, and most countries have an implementation strategy in place [18]. The implementation rate differs by country, but all Norwegian households have had smart meters installed from 2019. Smart meters provide automated metering with an hourly or sub-hourly resolution, enabling load shifting incentives through price signals. At the same time, there is an increasing flexibility potential in the electricity consumption because of emerging technologies that can control energy use and the introduction of new demand types with inherent flexibility. Most notably, the cost of controlling heating systems with energy storage is decreasing (see, e.g., [19]) while the personal transport sector is seeing significant electrification through battery electric vehicles that can have flexible charging schedules. Due to the current policy, the EV share in Norway is rapidly increasing as described in [20], and is at the time of writing dominating the sales of personal transport vehicles. An increasing amount of EVs means that the amount of consumed electricity will increase, but since EV charging can be relatively flexible, it can, in principle, be coordinated to avoid peak periods and utilise available renewable energy as demonstrated in [21].

Integrating and coordinating DERs as a part of the larger energy system is, however, not straightforward. Since the deployment of each generation asset is mainly up to individuals, the development can be challenging to coordinate. Furthermore, the operation of flexible demand is also controlled based on the boundary conditions for the stakeholder who owns it. Since uncoordinated deployment and operation of decentralised resources can give suboptimal solutions, the incentives need to be designed to avoid suboptimal outcomes seen from the perspective of the larger energy system.

2.4 Grid tariff design in the context of active consumers

Natural monopolies occur when it is most effective that one firm serves an entire market (see, e.g., [22]). Electricity grids constitute a natural monopoly because it is not viable to build parallel infrastructure to create competition [23, p. 297-312].

Therefore, the economics of electricity grids is primarily based on minimising the costs of the grid infrastructure while providing the service to its users. As a result, the cost of running a grid company is shared among its users through the electricity grid tariffs. Traditionally, the load has been considered inflexible, and the purpose of grid tariffs has been to recover the cost of building, maintaining and operating electricity grids. However, as end-users are increasingly responding to price signals, demand flexibility can be activated as a part of the DSOs toolbox (see, e.g., [24, 25]). Therefore, the grid tariff has also become an instrument that can change the load profiles through the incentives provided. If the tariffs do not provide cost-reflective and precise incentives, it can lead to inefficiencies related to investments and operational patterns that are not aligned with a cost-effective development of the system as a whole.

The long-run cost of distribution grids is tied mainly to the peak load since it drives the need for grid capacity (see, e.g., [26]). Grid tariffs have historically, due to practical reasons, been significantly based on the volumetric amount of electricity used. However, the volumetric use of electricity is not an accurate representation of the need for capacity and can therefore give a misalignment of incentives. With responsive end-users, the mismatch between grid pricing and the actual upstream cost can give suboptimal outcomes since the end-users are incentivised to reduce the volume of electricity they use rather than the peak electricity usage. In light of more active end-users, the energy regulators in Europe suggests that a grid tariff adaption is needed to account for the capacity-based aspect of the grid connection [26]. Grid tariffs need to strike a balance between simplicity and efficiency, and a very precise grid tariff might need to be complex in terms of spatial and temporal resolution to reflect the actual upstream grid cost. Therefore, there is an ongoing debate around how future grid tariffs should be designed in both regulatory and academic circles, and this thesis aims to provide new information on this topic.

2.5 Ambitions at the building and neighbourhood scale

Buildings constitute about 40% of total primary energy consumption [27]. To reduce the amount of energy required by buildings, the EU has set ambitious targets through the energy performance of buildings directive (EPBD), most recently in a 2018 revision [28]. Among other things, the EPBD promotes development towards cost-effective zero energy buildings (ZEBs). The ambitious policy targets for the building sector has sparked significant research interest regarding the concept of ZEBs. Although the interpretation of theZEB concept is differing (see, e.g., [29] for an overview), the general idea is a very energy-efficient building with some sort of on-site energy generation resource to compensate the remaining energy use.

As a follow-up of the ZEB concept, the idea of extending the system boundary to an area level has emerged. Expanding the boundary beyond the building level, the EU has launched *100 Climate-Neutral and Smart Cities by 2030* as one of the Horizon Europe missions [30] and a strategy to create cross-sectoral links to optimise the energy system as a whole [31]. The advantage of taking an area perspective instead of single buildings is that it might be possible to achieve more cost-effective solutions. For instance, planning energy solutions with a spatial scope that spans several stakeholders can enable favourable exploitation of flexible assets and available energy generation resources. Therefore, it can be more efficient to consider the deployment of energy resources and operation of flexibility assets for the neighbourhood as a whole rather than each building to be self-serving. This expands the solution space is illustrated in fig. 2.1. For instance, one location within the neighbourhood might have an advantage regarding renewable generation potential. In that case, it makes sense to exploit this common resource instead of each building trying to fulfil its individual zero energy balance.

Area-level optimisation of energy systems motivates the energy hub concept initially proposed by the authors in [32]. This concept is widely adopted in scientific studies, see, e.g., [33–36] which considers energy system optimization for spatially confined systems. The papers [37, 38] provide an overview of scientific contributions based on the energy hub approach. An energy hub approach can plan the optimal energy system expansion and operation, but an inherent assumption is that the system is centrally controlled. The assumption of centralised control at an area level is not compatible with a regulatory framework where individual participation and choice of retailer is one of the pillars of market efficiency. For instance, the Norwegian Energy Law [39] aims to create a level playing field for competing retailers and therefore prohibits bundling of several end-users into one measuring point [40].

When the system boundary is expanded from the building level to the neighbourhood level, there is added complexity because more than one stakeholder is involved. As a result, the incentives faced by the stakeholders may not support the optimal solution found by an optimisation approach that assumes centralised optimisation across stakeholders. For instance, the stakeholders might prefer optimising each building individually "behind-the-meter", although there exist more efficient solutions when an area is optimised in a holistic perspective. To study how incentives can be aligned to avoid suboptimal outcomes, it is necessary also to consider the incentive structures in place through microeconomic analyses.

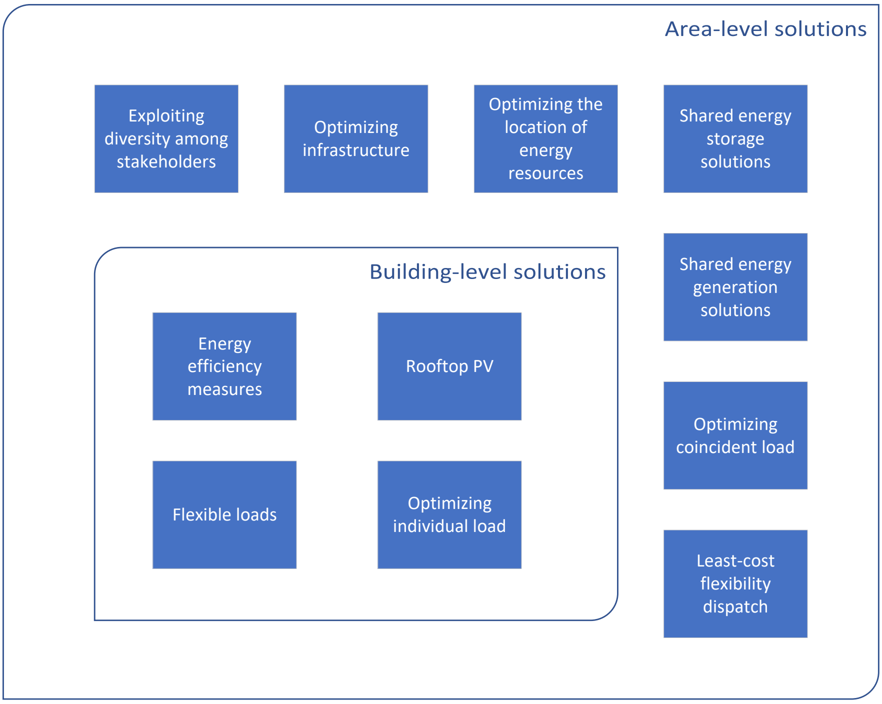


Figure 2.1: Conceptual illustration of how expanding the system boundary from the building to an area level also expands the solution space.

2.6 Research and contributions overview

The PhD project has been carried out through academic publications. These cover different aspects of the overall scope but use different angles to explore the overarching research questions. Figure 2.2 shows the relation between the articles and which research questions and contributions they cover.

ZEB19 and EEM19 form a starting point for the following work in this thesis. The goal of ZEB19 was to identify and assess critical regulatory challenges regarding energy resources and energy use in ZEN areas. EEM19 considers the importance of providing precise price signals when the interaction between a distribution system operator (DSO) and end-users investing in DERs is considered.

The articles ECON, EEM20, and ENSYS investigate the issues identified in ZEB19 and EEM19 in greater depth. EEM20 formulates a trading mechanism between end-users and investigates how establishing a trading mechanism can

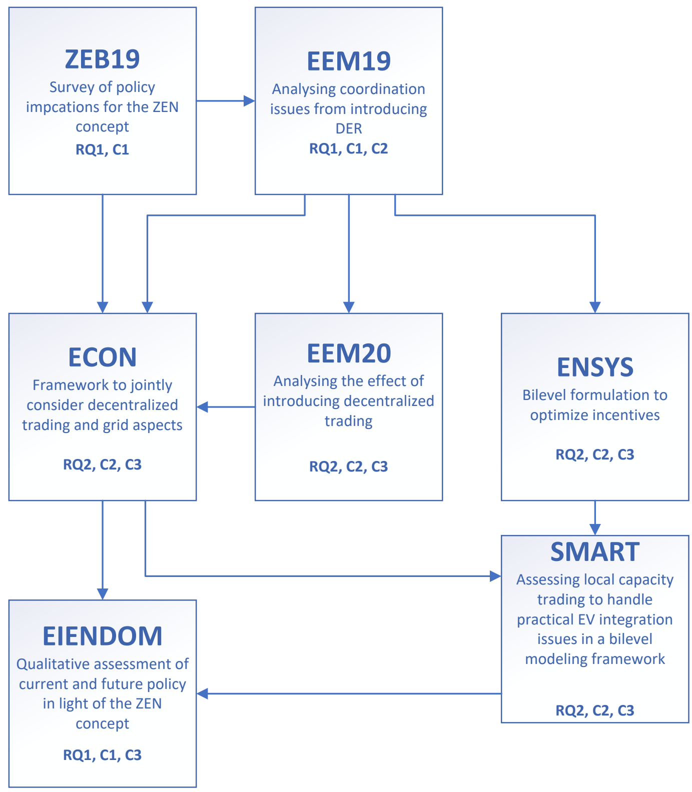


Figure 2.2: Overview of the structure of the research in this thesis. The figure shows the relation between the publications and how these relates to the research questions and contributions.

impact the electricity grid. ECON creates a holistic framework to investigate local market mechanisms under regulated tariffs. ENSYS considers bilevel optimisation of tariffs where the tariff signal can incentivise load shifting.

Finally, the articles SMART and EIENDOM serve to put the research in a practical context. SMART formulates a capacity-trading solution compatible with the ongoing push towards capacity-based grid tariff structures and analyses the potential for alleviating grid stress in an ongoing project. EIENDOM provides a qualitative assessment regarding regulations and technical possibilities in the joint context of the building- and energy sectors.

Based on the main articles, the following overarching contributions can be derived:

C1 Identification of regulatory issues: The thesis includes assessments of the regulatory framework related to DERs on an area level. Regulatory issues that can create mismatches between stakeholder incentives and system optimality at a larger spatial scope are identified.

C2 Development of modelling frameworks: Several models are developed based on the premise of decentralised decision-making in neighbourhood energy systems. These models calculate the outcomes based on decentralised decision making under various regulatory designs, which are benchmarked to the corresponding system optimal outcome. Combined, these models form a suitable framework for studying the effect of regulatory designs and pricing mechanisms on the deployment and operation of decentralised energy resources.

C3 Regulatory assessments: Based on cost efficiency under decentralised decision-making and the requirement that grid pricing structures should not be excessively complicated, the research includes assessments on how the regulatory framework can be adapted to facilitate optimal solutions on a multi-stakeholder level. This includes both how to incentivise the appropriate amount and location of DERs and how to facilitate favourable operational patterns on an area level.

Further details, including a description of the origin of these contributions, is described in chapter 4.

2.7 Thesis structure

Chapter 3 - Research methodology

This chapter provides information on the underlying methodological principles that have been utilised. The chapter's objective is to supplement the introduction and the papers by providing a high-level framework that can be used to understand the methodological approach taken in the research.

Chapter 4 - Contributions

This chapter presents the research contributions of this thesis. The chapter is organised into three sections covering different topics of the overall research objectives. The relation to the underlying methodological principles presented in chapter 3, key takeaways, and limitations are described on a paper-by-paper basis.

Chapter 5 - Conclusions

The overall conclusions and policy recommendations that can be drawn based on the sum of the PhD research are presented in this chapter. The chapter also includes recommendations for further research that can be pursued.

3 Research methodology

This chapter provides a high-level introduction to selected background material. Note that the aim is not to provide a complete overview of related methodologies but rather to provide relevant excerpts that enhance the understanding of the publications in this thesis.

3.1 Socio-economic principles

This section gives a brief introduction to the core principles that are applied to study neighbourhood-scale energy systems in this thesis. For further reading on this topic, [41] is a recommended starting point.

3.1.1 Payoff and best response

Contrary to centralised decision-making, a game is a decision-making situation where stakeholders affect each other through their actions. Furthermore, the payoff for any given stakeholder is the payoff from choosing a given set of actions [41, p. 1-2]. In the context of optimisation problems, the payoff is used as the objective function to be optimised under a set of constraints.

In a game including several stakeholders, the payoff following an action is often dependent on the actions of the other stakeholders [41, p. 2-8]. The best response of a stakeholder is the strategy that provides the best outcome, taking the choices of the other stakeholders into account. In this regard, their best response depends on the actions of the other stakeholders and is the set of actions that maximises the stakeholder's payoff in the different situations that can occur as a result of choices made by other stakeholders.

Based on these concepts, a payoff matrix for a game with two stakeholders is presented in table 3.1. The payoff function before the comma is related to stakeholder A while the payoff function after the comma is related to stakeholder B. For instance, $A_1(B_2)$ denotes the payoff received by stakeholder A when it chooses action 1 and stakeholder B chooses action 2. Here we see that the payoff for stakeholder A depends on its own actions and on the actions of stakeholder B, and vice versa.

The best response for stakeholder A is the action that provides the best payoff, but

Table 3.1: Payoff matrix for a simple game with two stakeholders.

		Stakeholder B	
		Action B_1	Action B_2
Stakeholder A	Action A_1	$A_1(B_1)$,$B_1(A_1)$	$A_1(B_2)$,$B_2(A_1)$
	Action A_2	$A_2(B_1)$,$B_1(A_2)$	$A_2(B_2)$,$B_2(A_2)$

as the matrix reveals, this depends on which action is chosen by player B. Hence, a game-theoretic decision-making structure means that while each stakeholder undertakes independent decisions, a given stakeholder's boundary conditions are not static since they depend on what other stakeholders do.

3.1.2 Welfare maximization and equilibrium

After introducing the concepts in the previous section, we now consider the outcome of games. Unlike a centralised decision-making structure with an optimal solution, games have one or more equilibrium solutions. A Nash equilibrium occurs when we have a situation where the actions of all stakeholders are known, and none of the stakeholders prefers to deviate from their chosen set of actions [41, p. 8].

To explain the concept of equilibrium, the normal-form game in table 3.2 can be considered. Let us say the stakeholders have chosen actions (A_2, B_2), giving a payoff of 4 to each stakeholder. It can be observed that both of them have an incentive to deviate to action 1 instead since it gives a larger payoff[1]. Therefore, by a unilateral choice of stakeholder B, the game transitions to the situation of (A_2, B_1), which provides a payoff of 5 to stakeholder A and 7 to stakeholder B. Both are better off, but stakeholder A still prefers to choose action A_1. After this change, the game ends up in the situation with actions (A_1, B_1), giving both stakeholders a profit of 10. After the game has ended up in this situation, none of the stakeholders wishes to alter their decisions, and we have a Nash equilibrium.

Table 3.2: Example game with two stakeholders.

		Stakeholder B	
		Action B_1	Action B_2
Stakeholder A	Action A_1	10,10	7,5
	Action A_2	5,7	4,4

In the previous example, both stakeholders are better off in the Nash equilibrium than in the other situations. Hence, the Nash equilibrium also maximises the

[1] It is assumed that the stakeholders are interested in maximising their payoff, such as firms maximising profits.

total payoff, or social welfare, of the system. Social welfare maximisation is guaranteed under system optimisation taking all costs and benefits into account. Social welfare maximisation can also occur under decentralized decision-making, but is not guaranteed unless the requirements of a perfect market are present. A situation where the Nash equilibrium is not characterised by maximisation of social welfare is described in the following.

To relate the concept of a suboptimal Nash equilibrium to the topic of this thesis, the game in table 3.3 is constructed. This situation is inspired by the classic example "The Prisoners Dilemma" in [42]. In the constructed game, two stakeholders can decide between consuming a low or high amount of energy. Furthermore, it is assumed that the total bill will be equally divided between them based on their total consumption. In the situation (low,low), we see that both stakeholders are relatively happy since they use enough energy to cover their most essential needs and have a relatively modest electricity bill. However, (low,low) is not a Nash equilibrium because both stakeholders prefer to increase their demand to be better off when the other stakeholder pays half the cost. A potential increase in energy use might be related to taking more baths or keeping the indoor temperature at a higher level instead of adding an additional layer of clothes. If stakeholder A increases its demand, the game transitions to (high,low) where stakeholder A is thrilled because half the cost of the increased energy use is paid by stakeholder B. Stakeholder B is, however, not happy with the (high,low) situation because it has a high bill while keeping the consumption low. Therefore, stakeholder B is also incentivised to increase the consumption, and the game ends up with demand (high,high), with both stakeholders relatively unhappy because they have a high bill without really needing to use that much energy. Contrary to (low,low), (high,high) is a Nash equilibrium because none of the stakeholders prefers to unilaterally deviate from their decision since that would leave them in an even worse situation.

Table 3.3: Example energy consumption game with two stakeholders that share the same metering point and choose how much energy to consume.

		Stakeholder B	
		Low consumption	High consumption
Stakeholder A	Low consumption	🙂,🙂	☹️,😁
	High consumption	😁,☹️	😐,😐

The example in table 3.3 illustrates how solutions with suboptimal outcomes can occur under decentralised decision-making. Although both stakeholders would be better off with the (low,low) solution, the system ends up in (high,high). This type of incentive alignment problem is relevant for power systems because the aggregate load profile drives the total costs. Hence, price signals that do not align incentives with the imposed costs and benefits on the overall system can give suboptimal outcomes such as the following series of events:

1. The aggregate peak load increases more than necessary.
2. Grid investments that could have been avoided or deferred need to be done.
3. The costs of using the grid increases more than necessary.
4. Total welfare in the system decreases.

3.1.3 Dynamic games

The previous sections considered static games where all stakeholders simultaneously choose their actions. A dynamic game differs from this because it includes sequential decision-making where one or more stakeholder decisions depend on previous decisions by another stakeholder.

To explain the concept of dynamic games, fig. 3.1 is provided. This is a classic setup for a sequential game where one stakeholder moves first:

1. Stakeholder A chooses action A_1 or A_2.
2. Stakeholder B observes the choice made by stakeholder A and chooses action B_1 or B_2.
3. Payoffs for both stakeholders depend on the choices made by both stakeholders.

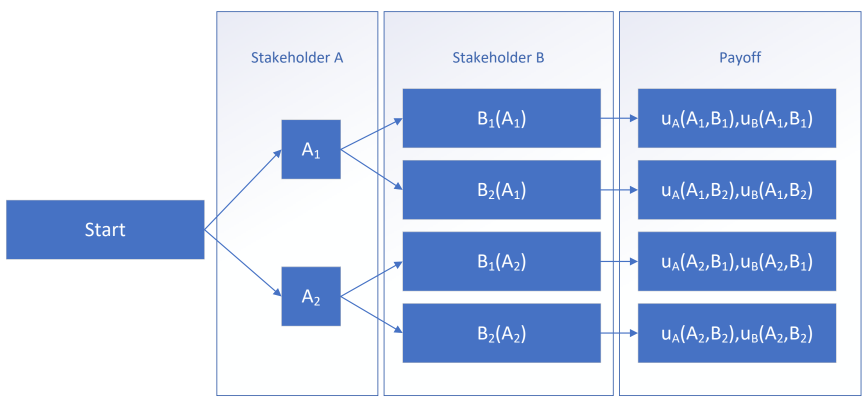


Figure 3.1: Example of a dynamic game with two periods and two stakeholders, on extensive form.

Credibility is a crucial element in these types of games [41, p. 55-129]. Suppose that action A_2 by stakeholder A is very harmful to stakeholder B. In that case, one could imagine stakeholder B imposing a threat on stakeholder A that it will choose action B_2 which negatively affects stakeholder A if A chooses A_2. This threat is, however, only credible if eq. (3.1) holds[2].

$$u_B(A_2, B_2) \geq u_B(A_2, B_1) \tag{3.1}$$

Equation (3.1) states that given a choice of A_2 by stakeholder A, stakeholder B will only choose B_2 if the utility of doing so is higher than the utility of choosing B_1. If eq. (3.1) does not hold, the threat is noncredible because it is not in stakeholder B's best interest to carry out the threat. Therefore, sequential decision making under perfect information means that the first mover takes the subsequent movers' best responses into account and does not need to consider other possible responses.

Sequential games with two periods where one stakeholder, the leader, decides something in the first period and one or more stakeholders (followers) observes the decision by the leader and initiate a static game based on the leader's decision falls into the category of Stackelberg games [43]. Stackelberg games with such a bilevel structure represent the decision-making structure of many different economic problems and are applied in several of the articles in this thesis.

3.1.4 Pareto optimality and policy design

The term Pareto optimality is named after the economist Vilfredo Pareto (1848–1923), and is a situation where the solution can not be changed to make at least one stakeholder better off while not making any of the other stakeholders worse off. Pareto improvement can be achieved if the situation can be improved for at least one stakeholder without negatively affecting any other stakeholder.

The potential for Pareto improvements can be vital to gain acceptance for proposed regulatory changes. To explain how policy changes can lead to Pareto improvements, we revisit the energy consumption game from section 3.1.2 which is presented on normal form in table 3.3. The equilibrium solution (high,high) is Pareto dominated by (low,low) because both stakeholders are better off in the (low,low) situation. However, the assumed policy is that the energy bill is shared equally on the two stakeholders, and this billing practice results in (high,high) becoming the equilibrium solution.

Based on the initial energy consumption game result, it is relevant to consider

[2]Note that other types of game structures such as repeated games would add complexity to this discussion, but these are not included here.

how the policy could be redesigned to realise Pareto improvements. One solution could be to change the metering structure from shared to individual billing so that each stakeholder pays for the individual consumption rather than half the total consumption. In the case of individual billing, we end up with the normal form game presented in table 3.4. In this revised energy consumption game, both stakeholders have an incentive to keep a low consumption[3], and the Nash equilibrium becomes (low,low) instead of (high,high). Note that the only changes in the game are related to the (low,high) and (high,low) situations while the (low,low) and (high,high) situations are unchanged. By aligning incentives, the game now ends up in a new Nash equilibrium that Pareto dominates the initial equilibrium.

		Stakeholder B	
		Low consumption	High consumption
Stakeholder A	Low consumption	🙂,🙂	🙂,😐
	High consumption	😐,🙂	😐,😐

Table 3.4: Revised energy consumption game with two stakeholders that have individual metering points and choose how much energy to consume.

Although these examples are significantly simplified, they highlight the fundamental principles behind the motivation in this thesis. They describe the underlying principles used in exploring how to design the regulatory framework to facilitate outcomes that are efficient on a system level, also under the decentralised decision-making market structures we currently find in neighbourhood energy systems.

3.2 Modeling decision-making structures

While the previous section describes the fundamental principles behind decentralised decision-making and equilibrium solutions, the focus in this section is to explain how such problems can be modelled in the form of mathematical problems.

Figure 3.2 gives an overview of the properties of different game-theoretic problem classes that are relevant for this thesis and which situations they can represent. While the advantage of such formulations is that they can represent interesting decision-making structures, model tractability becomes an issue. The linearisation of complementarity constraints represent a computational challenge and limits the possible technical detail, the number of stakeholders, and the number of time steps that can be included.

[3]In other words, low consumption becomes the dominant strategy; it is preferred regardless of the choice made by the other stakeholder.

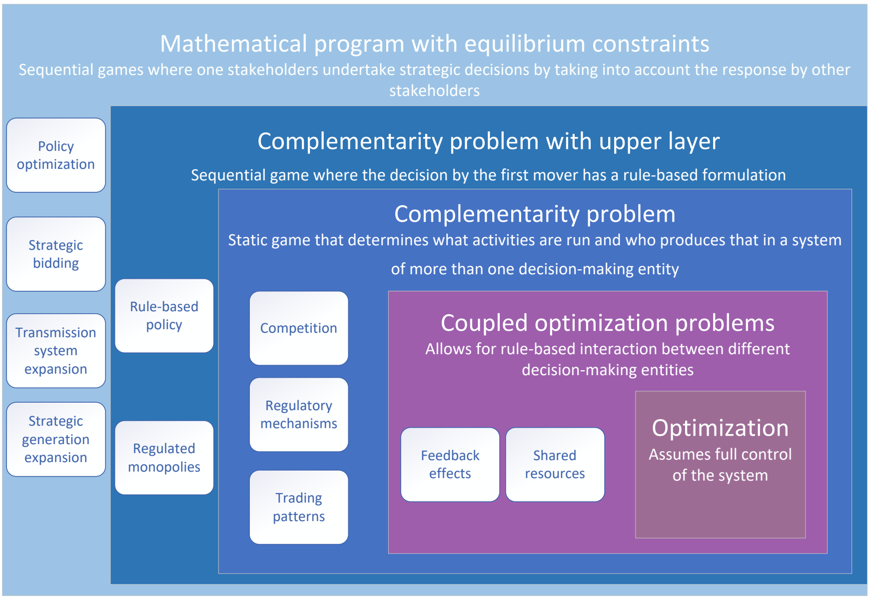


Figure 3.2: Overview of the problem structures used in this thesis. Each level describe a problem structure with description of the decision-making assumptions that are applicable.

It should be noted that this section only gives a brief introduction to some key concepts and formulation methods based on relevance for the research in this thesis. For a more extensive overview of formulation methods and applications of complementarity models to energy-related situations, the reader is referred to [44].

3.2.1 Optimization problems and equilibrium conditions

First, we consider the possibilities and limitations of formulating an optimisation problem. An optimisation problem aims to find the best solution among all feasible solutions. The general formulation of an optimization problem is depicted in eq. (3.2) based on [45, p. 127]. Equation (3.2) formulates the task of minimising the objective function subject to inequality and equality constraints.

$$\begin{aligned} \text{minimize} \quad & \mathrm{f}(x) \\ \text{subject to} \quad & \mathrm{g_i}(x) \leq 0, i = 1, ..., m \\ & \mathrm{h_j}(x) = 0, j = 1, ..., p \end{aligned} \tag{3.2}$$

An optimisation problem assumes full control of the system that is optimised. Under this assumption, the scope of variables that can be included in the problem is limited by the decisions that are under control by the represented decision-making entity. Therefore, a system of several stakeholders might require the formulation of several optimisation problems. If the optimisation problems depend on each other, it might be possible to formulate the interaction mechanism between them using a rule-based approach and iteratively solve the system of optimisation problems until convergence of the equilibrium condition. Suppose such a solution process can be formulated. In that case, the advantage of this formulation method is that it scales well with the number of stakeholders and that the optimisation problems of the individual stakeholders can be solved in parallel, enabling the representation of relatively large systems.

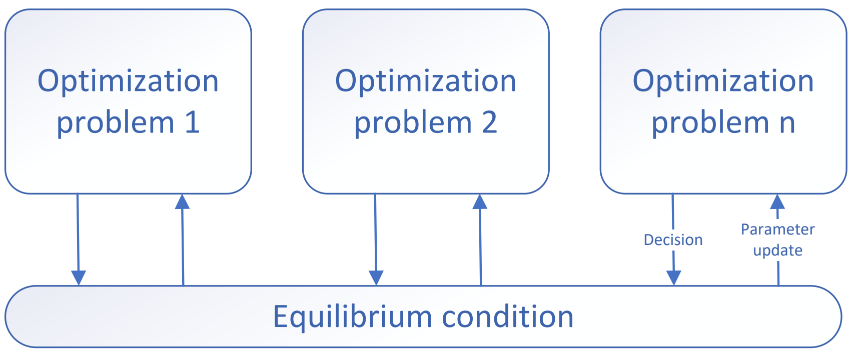


Figure 3.3: Conceptual illustration of how to solve optimization problems that are coupled through equilibrium conditions.

Figure 3.3 describes how several optimisation problems can be coupled by equilibrium conditions. In this setup, each optimisation problem is solved independently before an equilibrium condition is calculated based on the output of all optimisation problems. One example of such a system is the use of grid capacity, where the optimisation problem of each stakeholder independently determines how much grid capacity to use before the equilibrium condition calculates the cost of using the grid. The updated cost of using the grid is then passed back to the optimisation problems for the individual stakeholders as a change in their exogenous input parameters, and the process is repeated.

One can easily imagine that the process of iteratively solving several optimisation problems and updating some parameters through the equilibrium condition could go on forever without finding the equilibrium solution. Therefore, it is crucial that a rule-based calculation can be applied to the interaction between stakeholders and that the solution algorithm is tailored to make the system converge to an equilibrium solution.

3.2.2 Complementarity problems

An alternative to coupling independent optimisation problems by the use of algorithms is to formulate a complementarity problem. The concept of the linear complementarity problem was generalised by Cottle and Dantzig [46], and as a result, the research interest for this class of problem gained traction. A complementarity problem consists of the optimality conditions of all stakeholders in a given system which is then solved simultaneously[4]. The fundamental form of a linear complementarity problem is the following (see, e.g., [47]): given $M \in R^{n \times n}$, $q \in R^n$, find $w \in R^n$, $x \in R^n$ satisfying:

$$\begin{aligned} &w = Mx + q \\ &w, x \geq 0 \\ &x^T w = 0 \end{aligned} \tag{3.3}$$

Since w is a slack variable, eq. (3.3) can be reformulated as:

$$\begin{aligned} &Mx + q \geq 0 \\ &x \geq 0 \\ &x^T (Mx + q) = 0 \end{aligned} \tag{3.4}$$

The formulation of complementarity conditions should then result in a square system with the number of variables equal to the number of equations. If we substitute $f(x) = Mx+q$, a complementarity condition can be represented according to eq. (3.5), which is the typical formulation for a complementarity condition that can be directly implemented in software. It states that the equation $f(x)$ is perpendicular to the complementarity variable x, which is a compact notation for the formulation in eq. (3.6).

$$f(x) \geq 0 \perp x \geq 0 \tag{3.5}$$

[4]Note that a complementarity problem can also be formulated for only a single stakeholder.

The essence of a complementarity condition is to formulate the requirement that either the function and the perpendicular variable can be nonzero, but not both.

$$\begin{aligned} & f(x) \geq 0 \\ & x \geq 0 \\ & f(x) * x = 0 \end{aligned} \tag{3.6}$$

Formulating a complementarity problem can start with the optimisation problems for all stakeholders in the system under consideration. Based on these, the optimality conditions can be formulated by deriving the Karush-Kuhn-Tucker (KKT) conditions (see, e.g., [45, p. 243-249]) of the problem. Hence, the complementarity conditions representing the underlying optimisation problems can be formulated and solved according to the following procedure:

1. Formulate optimisation problems for each market participant.
2. Derive the KKT conditions of the optimisation problem.
3. Write the KKT conditions on complementarity form.
4. Solve the system of equations either analytically or by the use of suitable software.

To complete the discussion on how to construct a complementarity formulation, appendix B provides an example of how to formulate the complementarity problem and solve it analytically.

Analytically solving equilibrium problems can provide valuable insight since the dynamics of the stakeholder interaction are exposed. In practical applications, complementarity problems can be solved by optimisation software such as the PATH solver [48] for relatively large problem sizes.

3.2.3 Mathematical programs with equilibrium constraints

The bilevel structure of dynamic games with two periods, also known as Stackelberg leader-follower games, can be represented by an mathematical programs with equilibrium constraints (MPECs) [49]. The general structure of an MPEC is that we have one optimisation problem that is constrained by one or more optimisation problems as depicted in eq. (3.7). Such a formulation implies that we have one stakeholder that takes the reactions of the following stakeholders into account when deciding on what to do. Hence, the leader's decision variables are considered as parameters in the optimisation problems of the followers.

$$\begin{aligned} &\text{minimize} && \text{Leader objective} \\ &\text{subject to} && \text{Leader technical constraints} \\ & && \text{Follower optimization problem 1} \\ & && \text{Follower optimization problem 2} \\ & && ... \end{aligned} \tag{3.7}$$

An MPEC is often formulated with an optimisation problem that takes into account the best response from a single-level equilibrium problem. Hence, eq. (3.7) can also be formulated according to the structure in eq. (3.8), where the complementarity formulation represents the follower optimisation problems.

$$\begin{aligned} &\text{minimize} && \text{Leader objective} \\ &\text{subject to} && \text{Leader technical constraints} \\ & && \text{Complementarity formulation of followers} \end{aligned} \tag{3.8}$$

To solve an MPEC formulation, it is necessary to reformulate the complementarity conditions so these can be added as constraints to the optimization problem of the leader. Complementarity constraints can be linearized through a mixed-integer linear program (MILP) formulation; As described in [4], complementarity conditions on the form:

$$f(x) \geq 0 \perp x \geq 0 \tag{3.9}$$

Can be replaced by the Fortuny-Amat reformulation [50]:

$$f(x) \geq 0, x \geq 0, f(x) \leq \alpha * M, x \leq (1 - \alpha) * M \tag{3.10}$$

Where α is a binary variable, and M is a large enough constant. Choosing an appropriate value for M is important for numerical stability but can be a challenging task in itself, as described by the authors in [51].

To overcome the issues concerning a "big-M" formulation, the complementarity conditions can also be transformed by using special ordered set (SOS) of type 1 variables as presented by the authors in [52]. Hence, (3.9) can be reformulated into the following:

$$f(x) \geq 0, x \geq 0 \tag{3.11}$$

$$u = \frac{x + f(x)}{2} \tag{3.12}$$

$$v^{+} - v^{-} = \frac{x - f(x)}{2} \tag{3.13}$$

$$u - (v^{+} + v^{-}) = 0 \tag{3.14}$$

Where v^{+}, v^{-} are SOS type 1 variables.

The SOS of type 1 based approach provides a globally optimal solution in a computationally efficient way. In addition, it is not necessary to specify an appropriate value for M to ensure that the complementarity conditions are not violated.

4 Contributions

This chapter is comprised of seven articles that form the basis for the overall contributions of this thesis. For consistency, the research contributions presented in section 2.6 are restated with a supplementary specification of their origin:

C1 Identification of regulatory issues: The thesis includes assessments of the regulatory framework related to DERs on an area level. Regulatory issues that can create mismatches between stakeholder incentives and system optimality at a larger spatial scope are identified.

The first contribution is based on the following identified regulatory issues:

- Decentralised decision-making regarding DER investment and operation can yield excessive investments and suboptimal operational patterns. Moreover, increased distributed energy storage investments can potentially reduce the coincident peak load but fail to do so under the studied capacity-based tariff structures. (EEM19)
- The incentives to facilitate optimal area-level energy systems strongly depends on the ownership structure. Solutions that align incentives at the local level while maintaining market efficiency in the larger energy system are required. (ZEB19)
- The concept of ZEN challenges the regulatory framework because of the need for local specification of requirements and extension of the system boundary beyond individual buildings. Development of the regulatory framework is required but poses a challenge because of different regulatory approaches in the building- and energy sectors and the interplay between national and local regulations. (EIENDOM)

C2 Development of modelling frameworks: Several models are developed based on the premise of decentralised decision-making in neighbourhood energy systems. These models calculate the outcomes based on decentralised decision making under various regulatory designs, which are benchmarked to the corresponding system optimal outcome. Combined, these models form a suitable framework for studying the effect of regulatory designs and pricing mechanisms on the deployment and operation of decentralised energy resources.

The second contribution is comprised of the following modelling contributions:

- An algorithm-based bilevel equilibrium model with consumers interacting with the DSO through network tariffs. (EEM19)
- A complementarity problem formulation to model the interaction between stakeholders through a local peer-to-peer (P2P) market with subscribed capacity tariffs (EEM20)
- A bilevel MPEC model for optimising electricity network tariffs subject to active end-users. (ENSYS)
- An algorithm-based bilevel model that considers stakeholder responses to a local market mechanism and its feedback effect on regulated grid tariffs. (ECON)
- A bilevel MPEC model to optimise grid tariffs subject to decentralised DER operation and local capacity trading to alleviate grid congestion. (SMART)

C3 Regulatory assessments: Based on cost efficiency under decentralised decision-making and the requirement that grid pricing structures should not be excessively complicated, the research includes assessments on how the regulatory framework can be adapted to facilitate optimal solutions on a multi-stakeholder level. This includes both how to incentivise the appropriate amount and location of DERs and how to facilitate favourable operational patterns on an area level.

The third contribution is based on the following regulatory implications:

- Local markets can potentially function as an alternative to centralised neighbourhood-level tariffs. (EEM20)
- An electricity tariff structure with capacity discounts during low-load periods can incentivise load shifting but might be difficult to implement in practice. The main issues are related to a potential need for frequent updates of discounted periods and rebound effects due to load shifting. (ENSYS)
- Local market mechanisms can, when combined with relatively simple capacity-based tariffs, reduce total system costs, promote optimal deployment and operation of DER and defer grid costs. (ECON)
- Adding capacity trading among local stakeholders to a capacity-based tariff scheme is an alternative to more general local electricity markets. It can aid to effectively signal grid scarcity when the coincident load is high while also avoiding unnecessary load shifting when the grid load is low. (SMART)
- In the Norwegian context, local planning authorities can formulate ZEN-related requirements during the area planning phase to a larger extent than current practice implies. (EIENDOM)

The articles are listed under their respective research topic. First, section 4.1 gives a qualitative assessment of the regulatory framework in light of the ZEN concept. After that, research on grid tariff design and its limitations of avoiding suboptimal outcomes in the context of an active demand side is presented in section 4.2. Finally, the coordination aspects of multi-stakeholder energy systems with decentralised energy resources are presented to investigate mechanisms that can support a near-optimal outcome under decentralised decision making are considered in section 4.3.

4.1 Identification and assessment of regulatory challenges related to energy solutions for the ZEN concept

As the system boundary is expanded from a single building to a neighbourhood, the need to consider regulatory structures with a multi-stakeholder and multi-sector perspective arises [53,54]. Therefore, when changing the system boundary from ZEB to ZEN, the corresponding regulatory challenges need to be identified. Two articles fit this topic, ZEB19 and EIENDOM. Both articles qualitatively consider regulatory implications of going from the ZEB to the ZEN concept. The first article, ZEB19, builds inspiration from ongoing projects and literature in the scientific and regulatory domain to identify and discuss regulatory challenges related to the expansion of the system boundary from a single building to a neighbourhood. The second article, EIENDOM, concerns the regulatory approaches in the building- and energy sectors, and the flexibility for local planning authorities in Norway to make provisions in light of the ZEN concept is discussed and compared with current practice.

4.1.1 Paper ZEB19: Zero energy at the neighbourhood scale: Regulatory challenges regarding billing practices in Norway

If the ZEB concept is to evolve into ZEN as a part of the energy policy toolbox, it is crucial that the regulatory framework promotes efficient solutions. This article explores the regulatory implications of expanding the system boundary from a single building to a neighbourhood focusing on energy resources. The article explores crucial challenges through interaction with stakeholders and literature review in the scientific and regulatory domain. Furthermore, the impact of ownership structure is investigated and explained through two ongoing projects in Norway.

Key takeaways

The aim of this article is mainly to provide an overview of how the concept of ZEN fit into the current regulatory framework and the issues that arise when multiple stakeholders are present. The article identifies and discusses ongoing regulatory issues faced by developers of ZEN areas. With a focus on economic efficiency and incentive design, critical challenges for optimal deployment and operation of energy resources are discussed and related to ongoing projects in Norway. It is suggested that the technical possibilities regarding cost-effective energy solutions in ZEN are limited by the regulatory framework in the case of local energy systems with multiple stakeholders. Therefore, a distinction is made between ZEN where all buildings and resources are owned by a single entity (S-ZEN) and ZEN with multiple owners involved (M-ZEN). Key takeaways from the article are:

- For S-ZEN, the area-level situation is comparable to that of a single building. Thus, the owner has appropriate incentives to optimise the operation of energy-related assets based on the area-level energy balance as long as a single metering point towards the larger energy system is established.

- M-ZEN lack incentives for efficient utilisation of energy resources in a multi-stakeholder setting. The current incentive structures can give suboptimal solutions on an area level due to billing practices that promote behind-the-meter optimisation on a building per building basis rather than optimal solutions for an area as a whole.

- Although regulations vary between different countries, the issues faced by M-ZEN are relevant in a general sense because there currently does not exist a best practice for energy sharing in a multi-stakeholder setting.

Limitations and future research

The scope of the article is limited to the identification of regulatory issues when we change the spatial scope from the building level (ZEB) to an area level (ZEN). Therefore, the development of prospective solutions can be considered in further work. This can go in the direction of looking into tariff structures and other mechanisms to investigate how price signals can be redesigned to promote efficient interaction between stakeholders in ZEN while maintaining economic efficiency in the overall power system.

4.1.2 Paper EIENDOM: Provisions on energy- and environmental requirements in zoning plans - in light of the concept zero emission neighbourhoods

The article considers the legal right of local authorities for setting energy and environmental requirements in the area planning phase and identifies regulatory challenges regarding the establishment of ZEN areas.

Since the article is intended for a Norwegian journal, a summary in English is provided in appendix C.

Key takeaways

National minimum requirements regarding the energy performance of buildings are set based on socio-economic cost-optimality criteria. However, the economics can vary depending on local factors, and the motivation behind this article is that national minimum requirements might need to be further specified according to local conditions and ambitions at the municipality level. Local conditions are especially relevant for energy planning since it is often preferable to plan and operate energy solutions with a holistic view on an area level. Therefore, achieving optimal development and operation for an area might require a predetermined direction set by the area planning authority and corresponding alignment of stakeholder incentives. Key takeaways from the article can be summarised as:

- Although the overall goal is to avoid market failures in both sectors, the regulatory approach in the building- and energy sectors differs significantly. The main difference is that the building sector directly regulates various building properties while the energy sector tries to underpin efficient markets.

- Energy-related aspects apart from the energy requirements of buildings are outside the scope of the local area planning authority. Therefore, area development in line with the ZEN concept also requires changes in the energy regulations to facilitate optimal energy solutions involving multiple stakeholders.

- Contrary to currently established practice, the article suggests that local authorities in principle can specify stricter local building regulations than the national minimum levels.

Limitations and future research

The article builds mainly on information from previous research and a rigorous evaluation of the current regulatory framework. Therefore, validation of the findings is left for further work and can be performed in the context of pilot projects with regulatory exemptions.

4.2 Distribution grid pricing and its limitations

Two articles fit the topic of this section, EEM19 and ENSYS. Both articles investigate the impact of tariff structures on decentralised decisions and benchmark the tariff-based outcomes against the system optimal solution.

EEM19 focuses on volumetric and capacity-based tariffs in a situation with a relatively homogeneous group of end-users that can invest in generation and storage assets. Compared to EEM19, ENSYS also introduces a time-dependent tariff component in a system where the stakeholders are more diverse. EEM19 uses an algorithm to determine the equilibrium solution with cost-recovering network tariffs in a bilevel decision-making structure, while ENSYS employs a formal bilevel optimisation to determine the optimal tariffs.

4.2.1 Designing grid tariffs in electricity grids with an increasing share of responsive end-users

The role of electricity grid tariffs has traditionally been to recover the costs of distributing electrical energy from the grid users. The reason for not using a market-based mechanism is that electricity grids are not suitable for competition because they include elements corresponding to natural monopolies. As a consequence of an increasing possibility of distribution grid end-users becoming active due to demand-side deployment of energy resources and demand flexibility, optimal development of the electricity grid requires grid tariffs to be adapted to provide efficient signals for indirect load control (see, e.g., [55, 56]).

Based on the development in the energy system towards increased renewable supply, both centrally and distributed, and increased amounts of decentralised flexibility, grid tariff design has gained increased research traction. Grid tariff design is a complex topic because it spans across several aggregation levels and stakeholder perspectives while striking a balance between several counteracting criteria. The following will provide an overview of related academic research on grid tariff design in the context of the research presented in this thesis section.

One research category focuses on assessing the effect of potential tariff schemes by taking the perspective of individual stakeholders and investigating how a change in the grid tariffs would affect the specific consumer type and technology under consideration. In the articles [57–59], the authors investigate how the use of electricity in district heating networks is affected by possible future tariff designs and argues that the load profile can be significantly adapted depending on the tariff used. The effect of tariff designs on choices on the end-user level is also a relevant research topic within this category, and PV-coupled battery systems are optimised for a selection of tariff designs by the authors in [60]. Using related approaches, the impact of tariff designs on the adoption of battery storage is considered by the authors in [61], while the authors in [62] evaluate how the relation between EVs and DERs are affected by different tariff designs.

The reaction to tariff structures can also be considered in the form of a local system of several load types and other technologies interacting with the surrounding grid as one joint entity. For instance, selected grid tariff structures are applied to the ZEN concept by the authors in [35], which assumes that the tariff is applied at the boundary of the neighbourhood energy system and that resources within the neighbourhood can be optimally allocated in response to the neighbourhood-level tariff design. The authors in [11] consider the effect of individual and collective tariff structures and find that the collective tariff performs better due to resolved coordination issues.

These studies demonstrate the strengths and limitations inherent in a single-level optimisation approach. This line of research can formulate detailed representations of individual stakeholders and technologies but is, by design, unable to represent the system-level effects of multiple stakeholders reacting to the price signals they are exposed to. A general conclusion that can be drawn based on research on grid tariff design that takes the view of individual market participants is that tariff design is essential for the activation of potential demand-side response. However, a single-stakeholder optimisation-based approach treats the tariffs as a static input to an optimisation model. Hence, potential feedback effects between the tariff setting entity and the grid users can only be included as a discussion element.

A second research category within the topic of tariff design aims to assess broader socio-economic implications of tariff designs by taking a top-down policy-level view. For example, the authors in [63] considers the representation and behaviour of the end-users is based on hourly data for a low voltage network user with a PV system in Spain, and the economic effects of various net-metering methods are analysed. Relying on data for over 1000 customers, the authors in [64] investigate the impact of various tariff schemes on these customers depending on the availability of demand-side flexibility assets and find that demand charges would not disproportionately impact low-income customers. Also, cross-subsidies between consumer groups due to lack of demand charges were identified based on customer meter data in [65]. Based on the premise of fixed household loads, the authors in [66] use a grid planning approach to investigate the system-level consequences of volumetric and capacity-based grid tariffs. Aiming to investigate implications of tariff designs on the system level, the authors in [67] investigate the impact of tariff design on the level of prosumers. Based on pricing theory, the authors in [68] formulates a method for allocating grid costs based on historical data to formulate fundamental principles for collecting residual costs in a system where the grid users have the ability to invest in DER. The authors in [69] use contract theory and socio-economic criteria to analytically derive optimal tariffs under various conditions in a system with heterogenous prosumers.

Contrary to the single-stakeholder approach in the first category, the policy-level research in the second category aims to investigate the bigger picture. Consequently, the possibilities for representation of stakeholder responses due to tariff changes are limited. Customer behaviour is taken as given when investigating the distributional effects of tariff design. Hence, because the focus is on the policy level, this category of top-down approaches needs to simplify the representation of end-user responses and their underlying decision-making processes.

A third category considers both the regulatory level and includes a fundamental representation of the reactions of the grid users in a framework resembling a dynamic game that incorporates both single-level stakeholder-centric optimisation and the policy-level assessment. Following this philosophy, a simulation-based methodology for investigating the evolution of tariff rates and responses from the grid users that can deploy DERs is conducted in the studies [70–72]. These studies provide insight regarding how various DSO remuneration strategies affects the long-term development in the electricity grid, and the authors in [72] also considers social network effects to simulate the deployment of assets at the grid user level.

Bilevel models are suitable for investigating how the design of price signals impacts the system's cost-effectiveness when the tariff setting entity considers the grid users' reactions to a policy change. In this regard, the design of optimal grid usage tariffs with a particular focus on the operational aspect is considered by the authors in [73]. The research presented in this section of the thesis falls into this third category through the use of bilevel modelling frameworks, and the main inspiration has been the studies [74] and [75] that both considers techno-economic effects of grid tariff design in the context of end-users reacting to the tariffs imposed on them. Additionally, the authors in [76] investigate the impact of regulatory constraints in a similar context. Following this research direction, this thesis investigates the interaction between the grid entity and customers through game-theoretic approaches that can investigate the interplay between tariff levels and customer reactions.

4.2.2 Paper EEM19: Interaction of DSO and local energy systems through network tariffs

This paper formulates an equilibrium model to investigate the interaction between a DSO and several buildings to study the effect of decentralised decision-making regarding investments and operation of energy resources. The buildings are relatively homogeneous since they can invest in the same types of energy assets (batteries and PV systems) at similar costs but differ due to unique underlying load profiles.

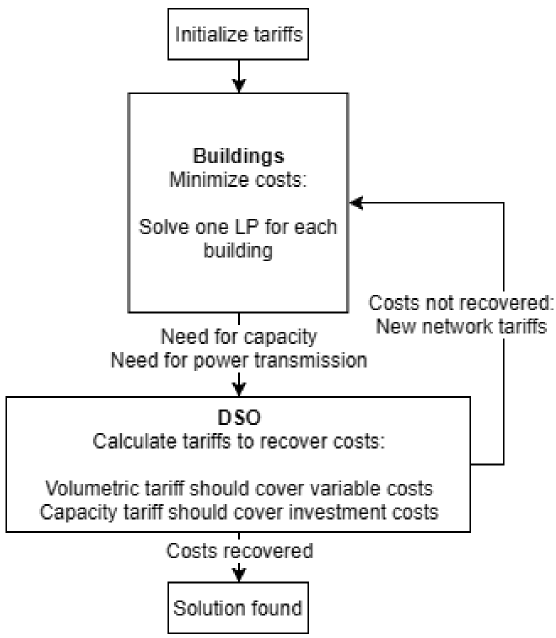


Figure 4.1: Outline of the bilevel solution procedure used in the article, adopted from [1], © 2019 IEEE.

Methodological overview

Based on the concept of a dynamic game presented in section 3.1.3, the interaction between a DSO and the grid users is modelled. The overall equilibrium model is based on solving one optimisation problem for each building before calculating the cost-recovering network tariffs. An iterative approach according to fig. 4.1 is thereafter used to calculate the equilibrium solution, which both satisfies the cost-recovery conditions of the DSO and also is compliant with the best response for all the grid users. The model follows the structure presented in section 3.2.1. In addition to the equilibrium solution that respects decentralised decision-making, a system optimisation model with centralised minimisation of total system costs is formulated and used as a benchmark.

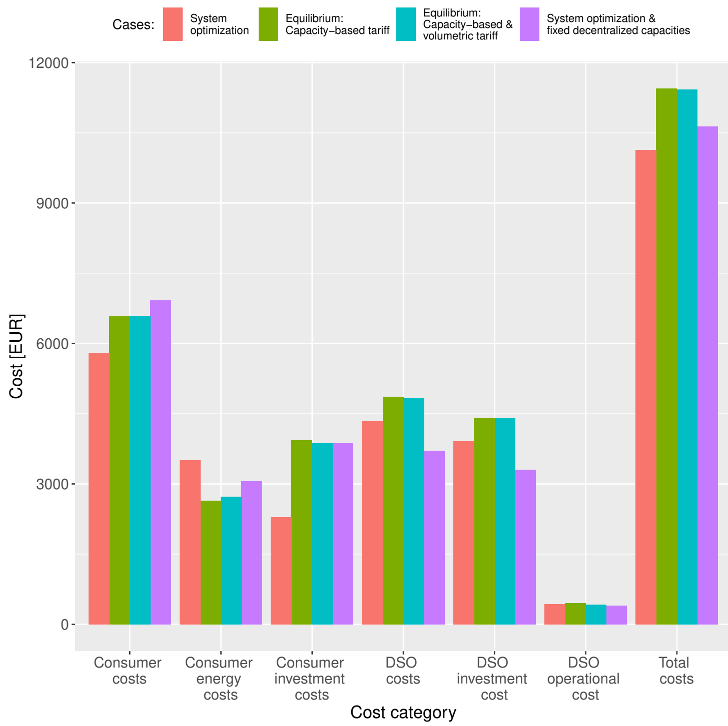


Figure 4.2: Results reporting total costs for different categories under varying decision-making assumptions in the EEM19 article. Figures adopted from [1], © 2019 IEEE.

Key takeaways

One approach to study the deployment of decentralised energy resources assumes that the entire local system is controlled centrally. However, the regulatory framework currently in place implies a different decision-making structure. Therefore, the main goal of this article is to develop a game-theoretic framework that can investigate how decentralised decision-making impacts the optimal investment and operation strategies in local energy systems and benchmark it against a system optimal solution. Key takeaways include:

- A bilevel Stackelberg-type modelling structure can capture the interaction between the DSO and one or more end-users. Using such a modelling approach, an iterative rule-based algorithm for equilibrium calculation can be used under the assumption of cost recovery rules for the DSO.

- Total costs increase when the equilibrium solution under capacity-based grid tariffs is compared to the system optimisation. The cost increase presented in fig. 4.2 is mainly due to incentives for self-consumption of energy, resulting in excess investments in decentralised assets and uncoordinated operation.

- As illustrated in fig. 4.3, more flexible resources may not always give reduced need for grid capacity. The case study reveals how uncoordinated battery operation gives a higher peak load for tariff-based equilibrium solutions than for the system optimisation despite having more investments in batteries.

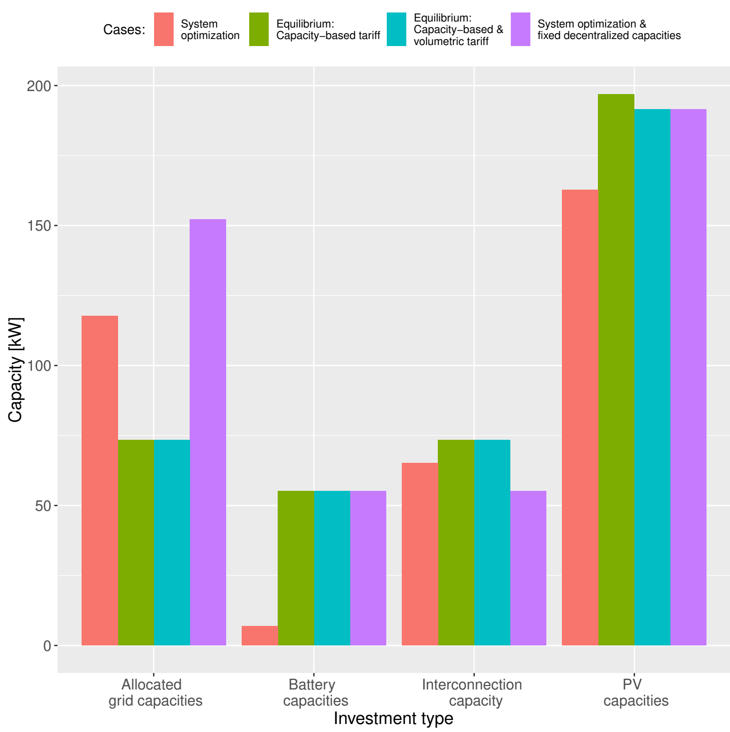


Figure 4.3: Results reporting capacities for different categories under varying decision-making assumptions in the EEM19 article. Figures adopted from [1], © 2019 IEEE.

Limitations and future research

This article provides preliminary research on the impact of different decision-making assumptions. The focus is on representing the interaction between the stakeholders, and the modelling detail is, therefore, limited. The numerical results are sensitive to changes in parameter values, but the study provides qualitative insight on a general level because of the comparative design of the study. Investment costs for energy resources are assumed to be very low because of the goal of representing a case where investments in energy resources at the building level are driven by economic profitability. Despite these shortcomings, the article's central insight is based on comparative studies and the outcomes would, therefore, be similar for other setups as long as the buildings independently control flexible assets. The presented research can be extended by:

- Investigating other tariff design options, possibly in combination with other price signals.
- Analysis of other system setups and inclusion of other energy generation options and flexibility technologies.
- Looking into the effect of a more diverse set of stakeholders at the local level.

4.2.3 Paper ENSYS: A Stochastic MPEC Approach for Grid Tariff Design with Demand Side Flexibility

The paper investigates a DSO's optimisation of cost components in predetermined grid tariff structures subject to end-user responses. When determining the tariffs, the DSO needs to take into account the possibility of different realisations of demand, power prices and renewable generation.

Methodological overview

An outline of the model is provided in fig. 4.4. The model is formulated as a bilevel Stackelberg-type game where the DSO is the leader and multiple end-users acts as followers. The interaction between the DSO and end-users is formulated in an MPEC modelling approach as described in section 3.2.3. In the game-theoretic model setup, the DSO determines how to use the tariffs for the purpose of lowering the total system costs, taking into account the reaction by end-users adapting their load profiles to minimise their individual costs. The obtained solution is the tariffs that provide the highest social welfare for the system as a whole under the constraint that the individual stakeholders react according to their best response.

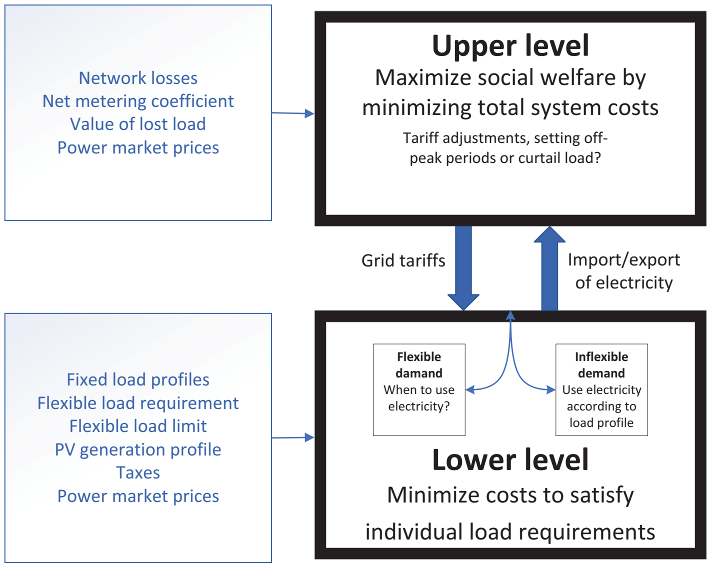


Figure 4.4: Outline of of the model structure, adopted from [4].

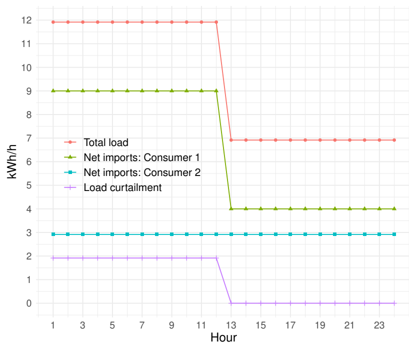
Case studies compare the results for different tariff structures with decentralised decision-making and benchmark them against the system optimal solution. The modelled stakeholders are diverse since they have different load profiles and control different flexibility assets in a system where the network is close to its capacity limit. Results are presented for deterministic and stochastic examples.

Key takeaways

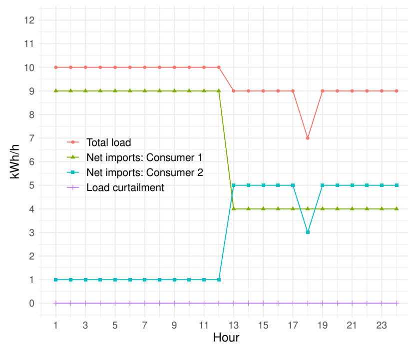
The article investigates how grid tariffs can be adapted to provide a more efficient price signal for indirect load control. Rather than assessing the effect of various tariff structures on specific end-user types, the equilibrium between the DSO and the end-users is represented in a game-theoretic framework. Key takeaways include:

- The article demonstrates how flat capacity-based tariffs incentivise a flattening of individual peak loads but does not fully activate the flexibility potential because load shifting incentives are limited.
- Appropriate pricing mechanisms can be detrimental to avoid load curtailment when electricity systems are close to their capacity limit, see fig. 4.5.
- Introducing a time-dependent tariff component such as off-peak periods can

provide an effective price signal to incentivise flexible consumers to adapt their load profiles.



(a) Operational pattern with a flat capacity-based tariff.



(b) Operational pattern with capacity-based tariff and off-peak periods.

Figure 4.5: Using off-peak periods to shift energy use can avoid load curtailment. The figure shows operational decisions for two different tariff structures with decentralized decision-making. Figures adopted from [4].

Limitations and future research

The tractable problem size is limited because several computational challenges are present. First, the representation of complementarity conditions makes the solution space non-convex. Furthermore, we have time-linking constraints within each scenario due to the presence of flexible charging demand. Last we have upper-level decision variables that affect all scenarios. Several aspects, such as the modelling of the grid and load behaviour, have been simplified to capture the dynamics between different stakeholders under these computational limitations.

Future development of methods that improve the computational performance can increase the realism in the modelling framework. A vital issue to explore is how to incentivise load shifting while also avoiding potential rebound effects due to shifted load. Also, the potential tariff designs investigated in this paper can be tested in pilot projects.

4.3 Mechanisms to achieve coordination of local energy resources and flexibility

This section includes three articles, EEM20, ECON, and SMART. All these articles include local market mechanisms as a tool to achieve local coordination and include the DSO perspective.

In EEM20, the regulatory framework is fixed by exogenously specifying the tariff design, and the main focus is on investigating peer-to-peer trading patterns under the given tariff structure. ECON considers both investment and operational decisions in a bilevel modelling structure to consider local market mechanisms under cost-recovery constraints for the DSO. SMART focuses on the operational aspects when a bilevel grid tariff modelling problem is applied to a Norwegian case where electrification of vehicles puts strain on the local grid to investigate how innovation in pricing mechanisms can increase the EV hosting capacity.

The modelling approaches are related but have some distinct differences. EEM20 solves a single-level complementarity problem to calculate the equilibrium solution when stakeholders are allowed to trade energy bilaterally. ECON formulates an algorithm-based approach to iteratively solve a complementarity problem with local trading of energy and the DSO planning problem. Last, SMART formulates an MPEC to solve for the optimal tariff levels by taking into account flexibility activation and capacity trading at the local level.

4.3.1 Extending regulated grid tariffs with local market mechanisms

Section 4.2 describes the research context of grid tariff design and their limitations when the spatial and temporal detail is limited. Supplementing tariffs with mechanisms to facilitate optimal deployment and operation of energy resources and flexibility assets on an area level is, therefore, an interesting possibility for providing efficient incentives in a multi-stakeholder environment.

The concept of energy communities is an alternative to local markets and implies that several stakeholders pool their resources and optimise the use of assets, essentially self-consuming on a multi-stakeholder level [77]. Instead of formalising a local market, the system is optimised on a multi-stakeholder level, and a cost and benefit allocation is performed (see, e.g., [78–80]). Energy communities requiring a centralised decision-making structure and subsequently allocation of costs and benefits among the participants can provide a goal regarding the cost-effectiveness of fully decentralised decision-making. Hence, the concept of energy communities based on centralised control is an interesting option but is not within the scope of this thesis since the aim is to investigate local pricing mechanisms under decentralised decision-making structures.

Interaction between agents at the local level can be achieved through local market mechanisms. In this regard, [81–86] provides an extensive overview on the topic of local market design. The design and implications of decentralised markets at the distribution grid level have been investigated in recent studies. In [87] the authors analyse P2P trading for matching inflexible local generation with flexible demand in a microgrid, and they find that the trading triggers peak load reduction. The authors in [88] analyse P2P trading in a neighbourhood focusing on trading in response to a subscribed grid tariff, and they also find that P2P trading triggers a reduction of peak loads. Local trading mechanisms can also allow the inclusion of product differentiation to take externalities into account. Product differentiation in local trading mechanisms is a general concept, and the authors in [89] demonstrate how it can represent grid costs in the local market. The authors in [90] propose a framework where flexibility services can be efficiently traded between prosumers, DSOs and balance responsible parties. Also, a related approach where aggregators act as intermediaries between the DSO and grid users is proposed by the authors in [91] which finds that flexibility trading mechanisms can provide Pareto efficient outcomes, which also allows the DSO to manage the local grid constraints. The authors in [92] focus on the role of batteries in P2P trading, and their results highlight economic viability from an end-user perspective. The implications of local energy trading in an area where the energy supply is severely constrained were considered by the authors in [93] which found that such trading was not able to resolve the structural power shortage in the area under consideration, suggesting that the dependence on the external grid should not be neglected. The research on local energy trading mechanisms is significant, but there is a lack of studies that also considers a reaction through the regulated tariff from DSO as a consequence of the implementation of local trading.

The feedback effect between a grid entity and end-users represents another related research direction. Interaction between an electricity retailer and consumers in a bilevel demand response program is studied by the authors in [94]. A game between an aggregator and EV consumers is formulated by the authors in [95]. The authors in [74–76, 96] considers the efficiency-related and distributional effects of recovering grid costs through grid tariffs with different assumptions regarding how end-users respond. The authors investigate the interaction between energy communities and a grid entity in [97], which assumes that the energy community behaves as one joint stakeholder. Although these articles consider feedback effects concerning grid tariff design and end-user responses, the concept of local market mechanisms is not included.

Game-theoretic aspects concerning energy system stakeholder interaction are also considered in the context of smart grids. In [98], the authors recognise the decentralised decision-making structure within a smart grid and propose an energy management scheme based on noncooperative game theory while the authors in [99] designs an auction-based scheme for sharing of energy storage. Using a similar approach, a method to discriminate price per energy unit within a smart grid is demonstrated by the authors in [100]. In the smart grid context, EV charging is increasingly relevant since it represents a highly flexible load that can be used to balance the system, and in [101] the authors propose a network model with self-interest pursuing EVs as a means of transporting energy between districts. Furthermore, a bi-objective method considering both the overall cost and user convenience for EV charging is formulated by the authors in [102]. These papers have a high level of abstraction (e.g., related to user preferences) since the focus is on the design of trading mechanisms within smart grids on a conceptual level without considering existing pricing structures such as electricity grid tariffs in the model framework.

Studies that combine both grid tariff design and local market mechanisms are rare. One recent example is the authors in [103] which investigates grid tariff design in conjunction with nodal prices while keeping a fixed pricing structure for inflexible consumers. Given the available literature, the contribution from this thesis is the assessment of the economics related to local market mechanisms and the feedback effects of such mechanisms on grid tariff design. Hence, this section of the thesis aims to bridge the gap between these two research directions by considering how grid tariff design and local market mechanisms can be used to provide efficient incentives on a multi-stakeholder level.

4.3.2 Paper EEM20: Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach

The article investigates the effect of including a P2P trading scheme for local energy under subscribed capacity grid tariffs.

Methodological overview

Tariff levels are exogenously given, and the equilibrium solution is calculated by formulating a single-level complementarity model according to the general structure presented in section 3.2.2. In this setup, the participants in the local market simultaneously decide how to operate flexible energy assets while engaging in bilateral trades.

A case study including four stakeholders with different flexibility assets is conducted. The situation without local trading is compared with an equivalent case where bilateral trades are allowed.

Key takeaways

The article explores how local bilateral trades can improve coordination and reduce peak grid usage at the aggregated level. Instead of assuming a centralised optimisation at the local level, the equilibrium under decentralised decision-making is calculated. Key takeaways include:

- The market works as a coordination tool for flexible resources and reduces the aggregate neighbourhood peak load.
- Subscribed capacities are reduced by introducing the trading mechanism, and frequent trading occurs to allocate available capacity within the neighbourhood rather than increasing the subscribed capacity.
- Competition among the flexibility providers significantly reduces the cost of the non-flexible stakeholders because local power prices are close to the opportunity cost of flexibility assets.

Limitations and future research

The DSOs income is reduced when tariff levels are fixed, and the introduction of trading reduces subscribed capacities. The article takes a static view regarding tariff levels, and the implications of this assumption could be investigated further. Also, the majority of cost savings are given to the non-flexible stakeholders because the setup inherently assumes perfect competition between flexibility providers and only includes operational decisions. Regarding the business case for investing in local flexibility assets, it could be interesting to investigate other payoff allocation schemes and the implications of strategic behaviour at the local level.

4.3.3 Paper ECON: Helping end-users help each other: Coordinating development and operation of distributed resources through local power markets and grid tariffs

The article presents a game-theoretic approach that includes both a local trading mechanism and the DSO perspective. The feedback effect between operational- and investment decisions, network costs and grid tariffs is explored in a holistic modelling framework.

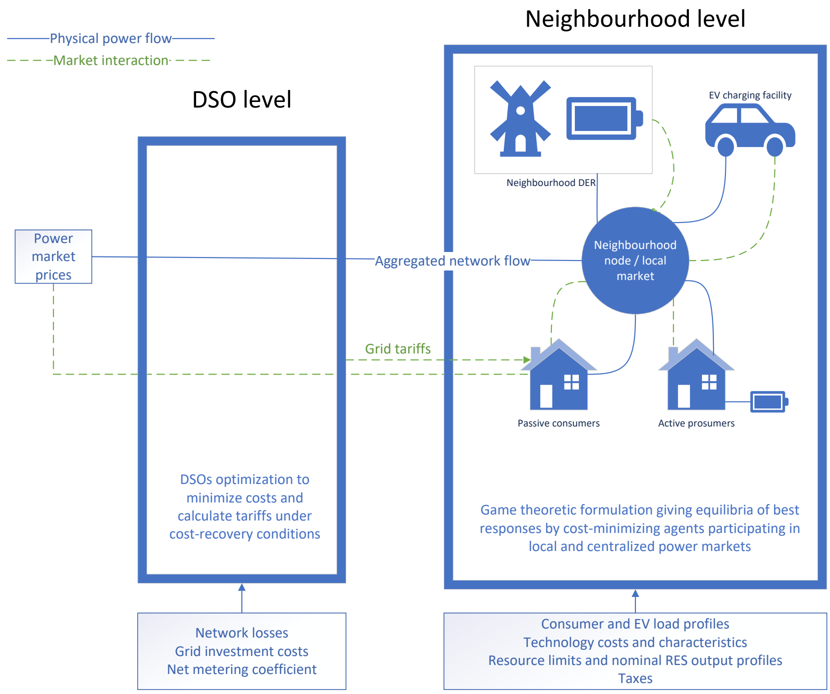


Figure 4.6: Outline of of the model structure, adopted from [5].

Methodological overview

The model is outlined in fig. 4.6 and comprises a dynamic game (see section section 3.1.3) of two levels that interact through pricing mechanisms and grid usage. Instead of a formal MPEC formulation, the bilevel structure is implemented through an algorithm that represents the interaction between the DSO and neighbourhood level. The solution procedure repeatedly computes an optimisation problem for the DSO level and a complementarity problem (see section 3.2.2) for the neighbourhood level where tariff levels are calculated based on cost-recovery constraints and updated with a decreasing step size. The main advantage of this approach is that network use is captured due to the tariff level, while tariff levels are also calculated based on the incurred grid costs due to network usage. Therefore, the obtained equilibrium solution is compatible with the best response for all stakeholders in the neighbourhood system and also ensures cost-recovery for the DSO.

The developed model is used to investigate the efficiency of current and prospective pricing mechanisms in a constructed case based on an ongoing pilot project in Norway. The analysis demonstrates how local market activity impact the regulated tariff rates because the trading of local energy can defer some of the DSOs costs.

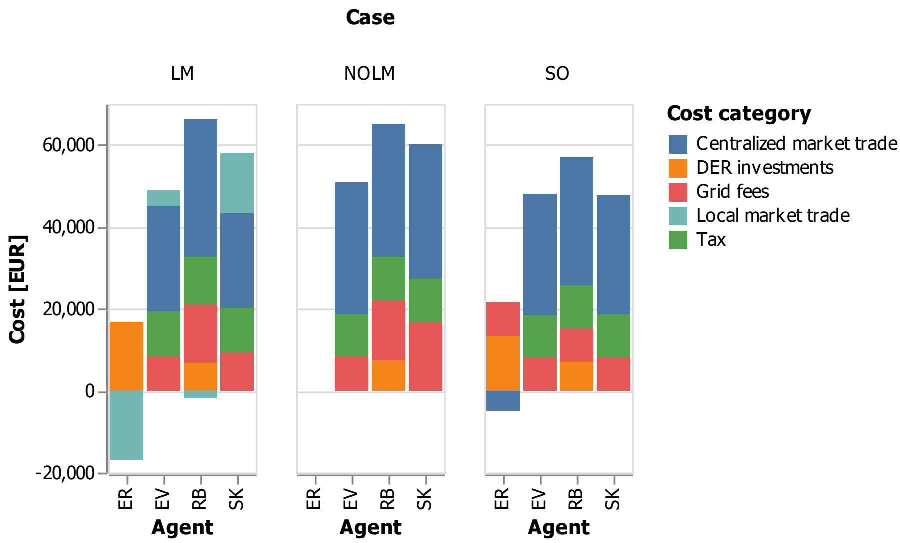


Figure 4.7: Cost allocation per stakeholder for three cases: Decentralized decision-making with local market (LM), decentralized decision-making without local market (NOLM) and centralized decision-making (SO). The four bars represent the stakeholder groups in the system; energy resources (ER), electric vehicle charging (EV), residential buildings (RB), and school and kindergarten (SK). Figure adopted from [5].

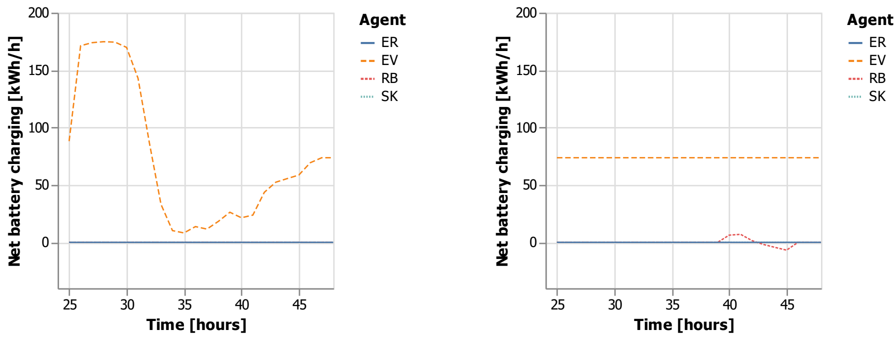
Key takeaways

The article combines two related research avenues by considering both grid tariff design and local market mechanisms in a consistent modelling framework. By focusing on fundamental game-theoretic aspects and capturing feedback effects between decisions at the neighbourhood level, grid development and tariff levels, valuable insights can be obtained. Hence, key takeaways include:

- The findings suggest that supplementing capacity-based tariffs with local trading mechanisms can decrease total costs and reduce or defer grid investments by aligning stakeholder incentives with the costs and benefits of the overall energy system.
- Despite an increase in tariff levels, the situation with local trading Pareto-

dominates the situation without a local market. Some stakeholders experience a reduction of their cost level while none experience a cost increase.

- The regulatory framework can be detrimental for the profitability of investments and the business case of planning energy solutions based on cost-effectiveness for the neighbourhood as a whole. This dependency can be seen from fig. 4.7 where investments in the local energy resource plant (ER) requires the local trading mechanism.
- Operational patterns are significantly affected by local trading patterns. Figure 4.8 highlights how the EV charging schedule can be altered for the benefit of the overall system. Rather than flattening the EV charging load, the local market coordinates EV charging to take place at times with low grid utilisation.



(a) Operational pattern with local market.

(b) Operational pattern without local market.

Figure 4.8: EV charging and battery operation during 'the critical winter day'. Figures adopted from [5].

Limitations and future research

Grid costs are one of the main drivers of the analysis, and these are simplified as a linear function of capacity. In practice, they are lumpy, at least on the local level. The lumpiness of investments may suggest that value creation by local market mechanisms will be more related to the ability to defer or avoid grid investments than to reduce the capacity in the case of grid upgrades taking place. Hence, the dynamics related to investment lumpiness could be explored in future research. Another critical issue to explore in the future is how to implement trading mechanisms that are scalable and reliable while protecting private information.

4.3.4 Paper SMART: Activating the potential of decentralised flexibility and energy resources to increase the EV hosting capacity: A case study of a multi-stakeholder local electricity system in Norway

This article investigates how the amount of EVs in a geographically confined area can be increased without a need for significant grid upgrades by implementing price signals that give efficient solutions for the local system while also being compatible with the current market structures.

Methodological overview

The model developed in this article is outlined in fig. 4.9 and represents a bilevel dynamic game (see section 3.1.3) where the DSO moves first by determining the tariff levels while the end-users responds by simultaneously determining the operation of their energy assets and local capacity trading. The model is inspired by the different models used in EEM19, ENSYS and ECON, and is tailored to fit the case under consideration and the idea of capacity trading as an integral part of a capacity-based grid tariff. The setup is a bilevel game between the tariff setting entity (DSO) and the end-users. The equilibrium at the neighbourhood level for a given set of tariff levels is formulated as a complementarity problem (see section 3.2.2). Furthermore, the tariffs are optimised in a MPEC modelling framework (see section 3.2.3) that includes a linearised representation of the neighbourhood complementarity problem. The MPEC model optimises tariff levels in order to minimise the total operational costs for the system.

A case study representing a relatively common situation in Norway is conducted. Norway's national policies for incentivising EV deployment have given a significant increase in the amount of EVs that needs charging. As the amount of EVs increases, the grid infrastructure in residential areas can not always handle significant EV charging on top of the existing peak load for the system. Hence, it is crucial to consider how the EV hosting capacity can be increased within the existing infrastructure limits. Therefore, the article investigates price signals that incentivise flexible demand to shift load based on the overall load situation.

Key takeaways

The article conceptually demonstrates how a capacity-based tariff with capacity trading can relieve grid stress and increase the EV hosting capacity. Figure 4.10 highlights how the load increase due to electrification can be handled when end-users optimise operational decisions under capacity-based tariffs with

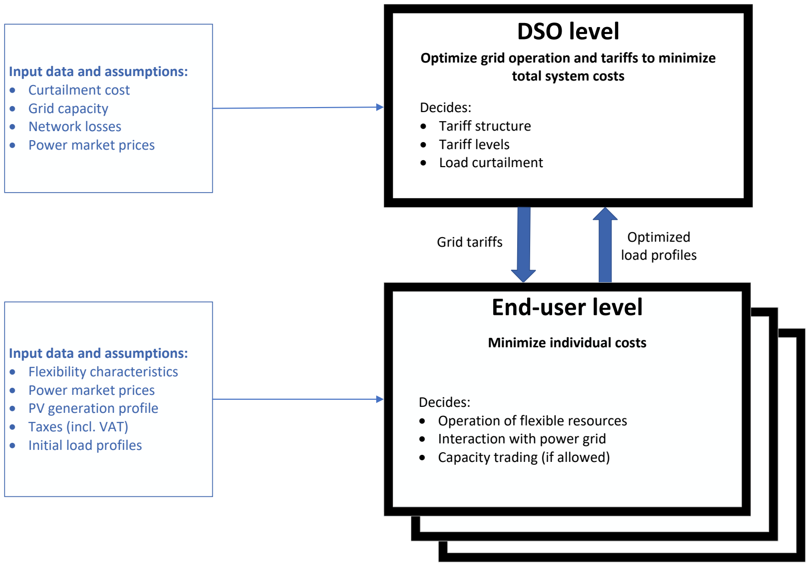


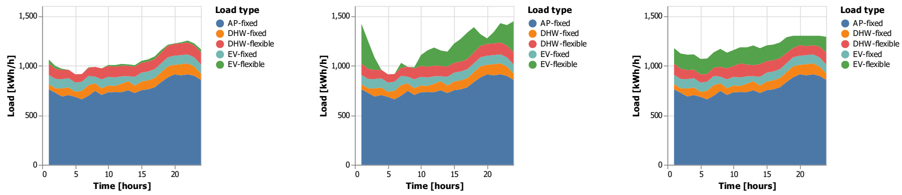
Figure 4.9: Outline of of the model structure, adopted from [6].

local capacity trading as a mechanism to adjust their individual capacity usage. The main point of the article is to investigate how optimal incentive structures can look like and how they can facilitate increased EV charging. Key takeaways include:

- Capacity trading between stakeholders has two main effects: It avoids the occurrence of unnecessary load shifting during low-load periods and lowers the peak load for the aggregate system during high-load periods.

- When appropriate pricing signals are in place, there can be a merit-order effect among flexibility assets. The case study demonstrated that when not needed for peak load reduction, the tap water heaters with relatively high self-discharge rates tries reduce their energy losses rather than contributing to reducing the peak load.

- The findings suggest that to reap the full potential of decentralised flexibility, it can be beneficial to allow flexibility trading among end-users as a tool to adjust their individual peak loads.



(a) Original load profiles.

(b) Load profiles after tenfold increase in EV charging.

(c) Load profiles after optimization under measured peak tariff with capacity trading.

Figure 4.10: An example of how load increase due to vehicle electrification can be managed by capacity-based tariffs with capacity trading. Fixed and flexible load for three categories is included; apartments (AP), hot water and related loads (DHW), and charging of electric vehicles (EV). Figures adopted from [6].

Limitations and future research

The decision-making structures combined with time-linking constraints for flexible demand represent a significant computational complexity, limiting the modelling detail and extent. Therefore, the bilevel model was computed for only a single day which was identified as critical based on simulations from a full year. This means that instead of a monthly peak, the capacity-based tariff was billed based on a daily peak load. Also, the numerical results rely heavily on the imposed assumptions. Despite these shortcomings, the article provides insight on a general level since it focuses on the fundamental effects of different pricing mechanisms and which situations they can increase the value of flexibility.

The approach in this article assumes rational responses from all involved stakeholders. Further research could investigate the motivation and behaviour of end-users, possibly by implementing pricing mechanisms in line with the findings of this paper.

5 Conclusion

5.1 Concluding remarks

This work investigates how incentives can be designed to achieve an efficient allocation of energy resources in a multi-stakeholder setting. The work includes a survey of policy aspects when the system boundary is expanded from the building level to neighbourhoods. To create a starting point, relevant literature in the scientific and regulatory domains has been qualitatively considered and related to relevant projects where it is beneficial to exploit energy resources and flexibility on an area level. Furthermore, a suitable modelling framework for conducting comparative studies under various regulatory and decision-making assumptions has been developed. The models used in this work considers decentralised decision-making structures and the importance of incentive design in achieving optimal energy solutions at a spatial scope that spans multiple stakeholders. The developed models have been used to carry out analyses that investigate fundamental aspects related to regulatory frameworks and pricing mechanisms in the context of DERs and flexibility in neighbourhood-scale energy systems. Through this work, fundamental issues have been identified and possible solutions to facilitate optimal deployment and operation of distributed energy resources have been suggested.

Regulatory challenges related to the ZEN concept were identified with the perspective of energy solutions and provisions in zoning plans. Regarding energy assets, the current regulatory framework fits well with the concept of individual buildings but can give suboptimal outcomes in a multi-stakeholder setting because of incentives leading to behind-the-meter optimisation rather than area-level energy planning. Also, the regulatory frameworks in the building-and energy sectors differ significantly. While the energy-related regulations focus primarily on underpinning well-functioning markets, the building sector is oriented towards direct regulation of various building properties. Local conditions can affect the optimal design of such requirements. Based on the findings of this project, it can be concluded that the regulatory leeway of local planning authorities to create regulatory provisions on energy-related aspects is more extensive than current practice implies.

The decision-making structure of a DSO imposing tariffs on end-users was modelled and benchmarked against the corresponding outcome when the system is centrally optimised. Although capacity-based tariffs can be a proxy for the grid capacity of the DSO, such tariffs are also imprecise because end-users optimise behind their individual meter. Consequently, optimisation of individual load balances with the goal of reducing the individual peak load may not be aligned with the goal of reducing the coincident peak load. These dynamics were explored, and it was concluded that they could give suboptimal outcomes such as over-investment in decentralised energy resources and suboptimal operation from an area-level perspective. Hence, relying on capacity-based tariffs alone might not yield the desired results due to coordination issues, and the findings suggest that more flexibility in the system can have a limited ability to decrease the aggregate peak load if pricing mechanisms are not improved. One option to address the fundamental coordination issues of capacity-based tariffs is to employ a capacity-based tariff with a capacity discount during low-load periods. However, such DSO signals to incentivise load shifting might need a high temporal and spatial resolution to provide a precise enough price signal. Furthermore, a DSO signal to incentivise load shifting requires detailed knowledge about the response, and there is a risk of creating new peak load problems during periods that historically had a low load if the response is more prominent than anticipated when the tariff was determined.

Since grid tariffs alone have some fundamental limitations when it comes to incentivising load shifting, mechanisms to coordinate flexibility at the local level were modelled and analysed to evaluate the potential for local trading mechanisms. The comparative studies that were conducted suggest that a combination of a relatively simple capacity-based tariff and a local trading mechanism can decrease total costs and reduce the aggregate peak load by aligning stakeholder incentives with the costs and benefits for the overall energy system. The main advantage of using a local trading mechanism instead of a DSO signal to incentivise load shifting is that it is more precise and can avoid the risk of undesirable rebound effects due to more load shifting than anticipated. Despite these advantages, it is essential to note that the deployment of such local markets could represent an added cost and complexity. To reduce the complexity of flexibility trading, local coordination can also be achieved by incorporating capacity trading in the tariff structure itself. Incorporating capacity trading can be a direct extension of capacity-based tariff schemes and can, potentially, be a cost-effective alternative to introduce flexibility trading. Also, such capacity trading would not require significant changes in the regulatory framework and market structures. In addition to reducing the aggregate peak load, local trading mechanisms also avoid the occurrence of unnecessary load shifting because extra capacity can be procured at low costs during low-load periods.

To reach the climate targets, it is necessary to shift energy use towards renewable energy carriers and build sufficient renewable generation assets. To facilitate a cost-optimal transition of the overall energy system, the infrastructure, generation assets and flexibility options must be optimally deployed and operated at a temporal and spatial level. Therefore, the regulatory framework and market structures must provide appropriate incentives for market participants at both the backbone of the energy system and at the decentralised level. Therefore, this thesis considers the regulatory direction regarding neighbourhood energy systems to improve the utilisation of grid infrastructure and optimise the use of resources at the local level.

It is essential to recognise that not all stakeholders can adapt their load profile to the price signals received. Therefore, it should be possible for the non-flexible stakeholders to procure flexibility from those that are flexible instead of providing price signals that aim to reduce the individual peak load of all stakeholders. Hence, the price signals should incentivise flexible stakeholders to adapt their load profiles to the overall situation in the system rather than flattening their individual load profiles. The need for multi-stakeholder pricing mechanisms is not only a matter of reducing the aggregate peak load; it is also crucial to avoid unnecessary load shifting and investments based on individual behind-the-meter optimisation. In essence, it is vital to consider how to activate the available flexibility in the best way for the total system. For new areas, extra capacity can be relatively inexpensive since the marginal cost of increased capacity can be low compared to the cost of the overall infrastructure construction. Therefore, the value of local coordination mechanisms might be highest in areas where the peak load is increasing, and the introduction of more efficient price signals can postpone or avoid grid investments altogether.

5.2 Recommendations for further research

The topic of how to create incentives for efficient deployment and operation of decentralised energy resources spans across many perspectives and layers. These include but are not limited to national and local regulatory design, development of business models, and deployment of technical solutions. Hence, the presented research can be extended in several directions.

Although the presented work proposes a conceptual design of mechanisms, it is relevant to consider how they can be implemented. Activating flexibility will likely be performed by third parties that optimise the operation of assets on behalf of the individual owners. Therefore, the exact structure of such a setup can be considered in future research by applying derivatives of the proposed concepts proposed in pilot areas.

Price formation in local flexibility markets is another critical area to investigate. The market needs to be designed in a way that does not require sharing too much information and avoids exertion of market power, which can be an issue in the case of relatively few stakeholders participating in the market. Therefore, future research can investigate the role of and interaction between DSOs, aggregators, and end-users in the organisation of such markets.

The presented research assumes rational behaviour of the stakeholders and participation of both flexible and non-flexible stakeholders to realise the full potential of decentralised flexibility. These assumptions are relevant for further research and might span several scientific research areas. Furthermore, it is interesting to see how participation rates can be increased and how the non-flexible stakeholders can be involved.

The value of imposing regulatory changes and establishing mechanisms for flexibility trading depends on locational properties. Therefore, assessing the potential for efficiency gains for different areas to identify where different regulatory changes can bring value can be an interesting research topic. These potential gains can then be compared to the countervailing cost and complexity related to the establishment and operation of the trading mechanism.

In addition to these general recommendations, limitations and possible directions for further research were identified on a paper-by-paper basis in chapter 4.

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Publications

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Interaction of DSO and local energy systems through network tariffs

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***Abstract*—One crucial factor that influences distributed energy resource investments and operation is the grid tariffs. If the price signal passed on to the consumer is not representative of the actual impact of the decentralized decisions on the power system, we may get inefficiencies. The main problem considered in this research is the interaction of a network operator and consumers to study how grid tariffs should be designed to facilitate favorable decentralized decisions. An equilibrium model based on tariffs is developed and benchmarked against a system optimization to study the effect of capacity-based and volumetric grid tariffs when the grid costs are a function of the decentralized decisions. The results show that both a volumetric and capacity-based tariff scheme provides a suboptimal outcome compared to the system optimal solution. Suboptimal decentralized decisions in the perspective of the overall power system is a result of the tariff schemes not being able to represent the actual network costs. Based on the findings, more innovative tariff schemes or related market mechanisms are needed to facilitate decentralized decisions that are aligned with the costs and benefits for the overall power system.**

***Index Terms*—Network tariffs, bi-level optimization, distributed energy resources, incentives.**

I. INTRODUCTION

Buildings are becoming an increasingly active part of the power system due to the introduction of generation assets at the consumer level and utilization of demand-side flexibility. These changes can be attributed to cost decreases of technologies such as photovoltaics (PV) and promotion of energy efficient buildings with distributed generation through policies such as the EPBD [1]. In light of these changes, it is essential to consider if current regulatory frameworks supports decentralized decisions that are also optimal for the overall power system.

One crucial factor that influence distributed energy resource (DER) investments and operation is the grid tariffs. The grid tariff structure is usually decided by the regulator and the rate is determined by the distribution grid operator (DSO). In most countries, DSOs are monopolies with the objective of recovering their costs within specified limits determined by the regulator. However, if the price signal passed on to the final consumer is not representative of the actual system costs of the decentralized decisions, we may get inefficiencies. For example, if the grid tariffs do not provide a good representation of the network costs, consumers may over-invest in DER to an extent that requires costly grid upgrades. Such behavior could arguably be avoided if the grid tariffs appropriately represent the real upstream cost of the decentralized decisions since the consumer then would consider the actual cost for the rest of the power system and adjust investments and operation accordingly. The value of DER is site and time-dependent as argued by [2] and according to [3] which provide a review of system costs for PV integration, a "generalized cost" cannot be obtained.

To address DER deployment and consumer flexibility, two main modeling approaches can be used: System optimization and decentralized equilibrium. In a system optimization approach such as [4], one optimization problem is formulated for the entire system under consideration, and the optimal investments and operation of DER is calculated. On the other hand, in a decentralized approach, it is recognized that the individual market participants do their optimization based on the information available to them (energy prices, grid tariffs). Therefore, the result from a decentralized approach may have higher total costs compared to a system optimization if the price signals are not a perfect proxy of the upstream costs.

The main inspiration for this paper is [5] which consider sunk cost recovery through grid tariffs for active and passive consumers in a game theoretic equilibrium model. Many interesting observations are made regarding the adverse effects of non-cooperative behaviour. Furthermore, [6] propose a mathematical framework that considers PV investment and operational decisions under volumetric and capacity network tariff schemes in a decentralized approach benchmarked against a central planner optimization. However, in these papers, the total network costs are not dependent on decentralized decisions. In contrast to the sunk cost approach, we consider the case that grid costs are a function of the decentralized decisions made by individual consumers.

The main contribution in this paper is an assessment of the interaction between a DSO and consumers in a game theoretic setting. Furthermore, we assess the impact of imperfect local information at the distributed level when total grid costs are a function of the decentralized decisions. A structure with consumers interacting with the DSO through network tariffs is modeled using a bilevel equilibrium approach. The equilibrium model is benchmarked against a system optimization where all investment and operational decisions are made centrally to minimize total costs.

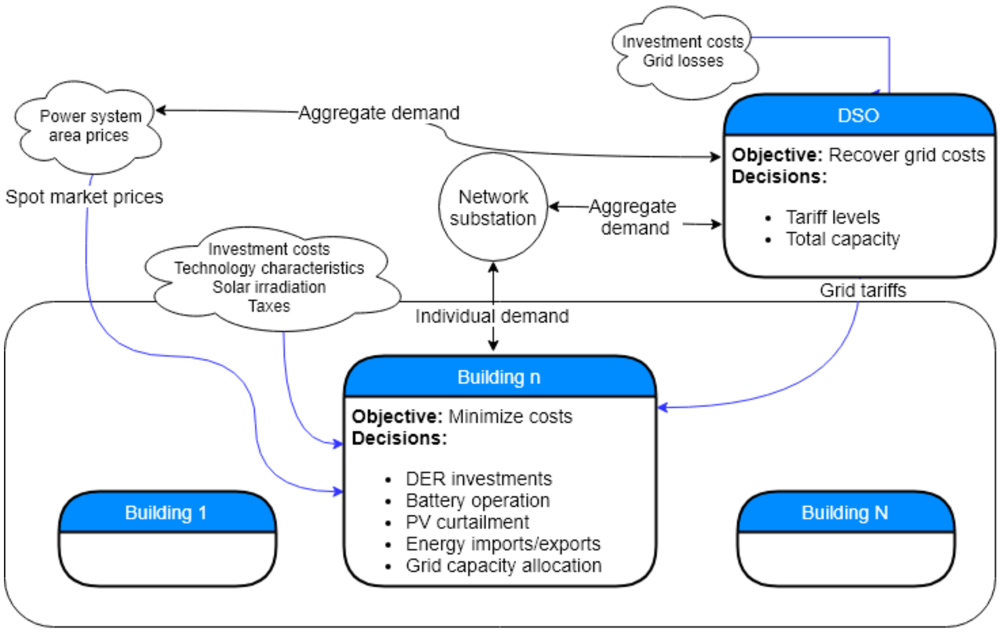

Fig. 1. Schematic of the modeled system

II. Methodology

The findings are based on a mathematical model that is under development. The model used for this paper is is implemented in Julia for Mathematical Optimization (JuMP) [7]. In this paper we provide a conceptual description of the model features while details can be obtained from [8].

A. System description

We consider a system where buildings and a DSO interact according to Fig. 1. The role of the DSO is to connect individual buildings to the power market. For simplicity, we consider the case that one or more buildings are connected to the same node in the network with resulting total network usage according to the sum of buildings connected.

The structure of this model is a bilevel Stackelberg game [9] with multiple followers, where the DSO is the leader, and the consumers are the followers. The interaction between the DSO and the buildings is through network tariffs.

B. DSOs problem

The leader in the bilevel game is the DSO which sets the network tariffs that are applied to the consumers in the lower level. The role of the DSO is to build and maintain infrastructure connecting consumers to the power market. Our formulation considers the case where the interconnection capacity for an area is to be decided, and therefore the DSOs costs is a function of the decisions on the lower level. Since we consider the case of an area with new demand, our model does not include sunk costs. Sunk costs could easily be included through a fixed network tariff, but such a fixed tariff would not influence the investment and/or operational decisions and is therefore omitted for simplicity.

The DSOs decision variables are the network tariffs which are set to recover the costs. We consider two types of tariffs: volumetric (EUR/kWh) and capacity-based (EUR/kW).

C. Consumers problem

The consumers minimize their annualized investment costs and operational costs for one year.

$$Cost_c = Cost_c^N + Cost_c^{PM} + Cost_c^T + Cost_c^G \qquad (1)$$

Equation (1) describes consumer costs, which include investment costs ($Cost_c^N$), energy costs ($Cost_c^{PM}$), taxes ($Cost_c^T$) and grid costs ($Cost_c^G$). The latter term is influenced by the grid tariffs that are treated as parameters in the consumer problems. The buildings have load profiles that need to be covered by either purchase of power from the power market (subject to grid tariffs) or investments in PV generation assets. The consumers also have the possibility of temporal shifting of their load through battery investments.

D. System optimization vs. equilibrium solution

Two model structures are considered: A system optimization and a bilevel equilibrium. The system optimization structure serves as a benchmark and means that all decision variables, both at the building and DSO level, are assumed to be controlled by one entity. Furthermore, system optimization means that the problem is formulated as one optimization problem minimizing total costs in (2). The system optimization approach do not consider grid tariffs since costs both at the DSO and consumer level are included directly.

$$Cost_{tot} = Cost_{DSO} + \sum_{c=1}^{C} (Cost_c^I + Cost_c^{PM} + Cost_c^T) \quad (2)$$

We formulate the same system as a bilevel game since it is not realistic to assume that all decisions are made centrally in the real world. In this formulation, the buildings do their optimization based on the local information available to them. Specifically, this differs from the system optimization because the network costs are represented by the network tariffs, which are not a perfect representation of the actual network costs. Therefore, the total costs of a bilevel formulation will usually be higher than for the system optimization, except in the case of a perfect tariff scheme.

E. Solution procedures

For the system optimization, all costs according to equation (2) are included in one objective function subject to constraints both at the building and DSO level.

For the bilevel equilibrium, several solution approaches are possible. The model can be formulated as a mathematical program with equilibrium constraints (MPEC) [10], which would be suitable in the case of a DSO pursuing an optimization problem since the DSO would need to take into account the effect its decisions have on the lower level problem. However, our model only considers the case that the DSO needs to recover the costs according to specific rules. Besides, the MPEC formulation would be a nonlinear and nonconvex problem, limiting the tractable problem size. Therefore, we design a solution procedure that iteratively finds the tariffs as outlined in Fig. 2. A significant advantage of the chosen solution procedure is that the consumer problems can be solved independently within each iteration. The decomposition of individual building problems means that the computational burden scales linearly to the number of buildings since each building added to the model only implies solving one additional optimization problem.

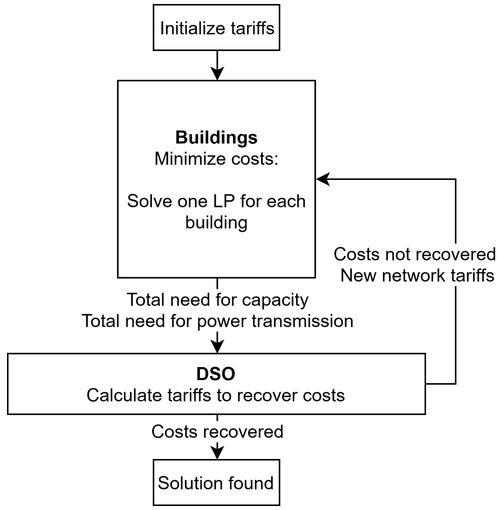

Fig. 2. Outline of bilevel solution procedure, inspired by [5]

TABLE I
INPUT PARAMETERS

Parameter	Value
Network capacity cost	60 EUR/kW/year
Power system losses	6% of transferred energy
Market price	Spot prices 2016 for area NO1
Building demand	Hourly load profiles for 2016
Electricity tax	0.016 EUR/kWh
PV investment cost	13 EUR/kWp/year
PV system losses	14%
Battery investment cost	20 EUR/kWh/year
Battery capacity factor	0.50 kW/kWh
Battery self-discharge	0.1 %/h
Battery converter losses	2%

III. CASE STUDY

A. Input data and assumptions

In this paper, we consider buildings that are connected to the same network node as visualized in Fig. 1. Since this is a stylized example to investigate DSO interaction between consumers and a DSO, we focus on constructing a case that highlights the effect of decentralized decisions. This section will briefly explain the data that has been used to construct the example. An overview of the parameters can be found in table I.

Network costs: The cost of upgrading network capacity varies from feeder to feeder and therefore can take many different values. In [11] they found that the value of network deferral can be as large as 60 USD/kW-year in the case of a saturated feeder. Our case of building precisely the necessary amount of network capacity is similar to the situation with a saturated feeder, and based on this we assume an annualized cost of 60 EUR/kW for network capacity expansion. In line with [12], the network losses have been set to 6%.

Market Data: Power market prices for the year of 2016 are gathered from Nord Pool spot [13]. In addition to the market price, the consumers also have to pay a tax according to [14] for power purchases. We do not include any tax on energy exports from the buildings.

Building data: We use metering data from 10 residential buildings in southern Norway. The buildings have the opportunity to invest in PV capacity and batteries to shift their load in time.

PV costs have dropped and are expected to continue to do so. According to [15] we can expect costs in the range of 120-210 EUR/kWp in the year 2050. Based on this, we assume a cost of 165 EUR/kWp annualized with a 5% interest rate over 20 years. PV generation data (in kWh/kWp) with a temporal resolution of 1 hour for the location of the buildings in southern Norway has been obtained from the tool PVGIS [16] assuming system losses of 14% related to the PV system and inverter.

Batteries from electric vehicles can be repurposed for stationary use at a lower cost. Although costs and performance characteristics of repurposed batteries are uncertain, we have assumed 200 EUR/kWh based on the findings in [17], annualized with a 5% interest rate over 10 years.

It should be noted that the costs for PV and batteries have been set quite low in our case study to highlight the effect of decentralized decisions in a scenario where DER are profitable.

B. Results and discussion

The models co-optimize investments and operational decisions. Investments can be local in the form of batteries and PV at each consumer or system related in the form of grid capacity. It should be noted that the results are highly dependent on our assumptions and that our primary interest is the comparison of the cases to relate decentralized decisions based on tariffs to a system optimal solution, not the numerical results for any individual case. We carry out a case study for four different situations to assess the impact of decentralized decisions on the system:

1) System optimization: Decisions at the DSO and consumer level are controlled directly to minimize total costs.
2) Equilibrium with capacity-based tariff: Consumers minimize costs subject to capacity-based network tariff determined by the DSO.
3) Equilibrium with capacity-based and volumetric tariff: Consumers minimize cost subject to capacity-based and volumetric tariffs determined by the DSO.
4) System optimization with fixed PV and battery capacities: Decisions at the DSO and consumer level are controlled directly to minimize total costs. Investments in PV and batteries are fixed according to case 3).

System optimization vs. equilibrium: We now compare the system optimization in case 1) with cases 2) and 3), which are equilibrium solutions of the same system. Case 2) has a capacity-based tariff only while case 3) has both a volumetric and capacity-based tariff to represent the network costs. Table II compare characteristics for cases 1) to 3).

TABLE II
DIFFERENCE BETWEEN SYSTEM OPTIMIZATION AND EQUILIBRIUM

	1): SO	2): EQ	3): EQ
Volumetric tariff [EUR/kWh]	NA	NA	0.001547
Capacity-based tariff [EUR/kW]	NA	66.23	60.00
Total costs change [%]	0	+12.9	+12.7
Imports change [%]	0	+0.21	-5.70
Consumer exports change [%]	0	+35.01	+17.34
PV generation change [%]	0	+20.94	+18.87

The system optimization serves as the benchmark since it has the lowest possible total costs. At first glance, we see that the total costs increase by almost 13% when we use the equilibrium approach compared to system optimization. The increase in total costs is a result of the non-cooperative pursuit of a cost-minimization goal at the consumer level with an imperfect network tariff. It can be observed that the total amount of energy that is exported increased by 35% in the case of a capacity-based tariff, but only a 17% increase is observed in the case of both a volumetric and capacity-based tariff. Compared to case 2, the tariff scheme applied in case 3) increases the profitability of self-consuming energy inside the boundary of the individual building since any exchange with the grid are subject to a volumetric tariff. The volumetric tariff acts a transaction cost for trading with the grid, disincentivising such trading. Therefore, the volumetric tariff explains the significant decrease in imports and exports while PV generation is only slightly affected due to the increase in self-consumption.

Investment decisions for the different cases can be found in Fig. 3 and cost characteristics can be found in Fig. 4. In general, the equilibrium model over-invest in the local resources (PV and batteries) compared to the system optimal solution. Also, more interconnection capacity is necessary as well which seems counter-intuitive since it should be possible and beneficial for the system to decrease the interconnection capacity with the increased amount of local resources. However, the explanation for the increase in total interconnection capacity despite the increase in local resources is that the tariffs do not convey information about the coincidental peak to the consumers since the capacity-based tariff only depends on the peak of the individual consumer. The root of this problem lies in the fact that the capacity-based tariff is flat over the year, and therefore do not communicate any time-dependent information about the scarcity of grid capacity.

Optimal operation of suboptimal investments: The increase in total capacity for the equilibrium cases motivated case 4). In case 4), we fixed the PV and battery capacities according to the results in case 3) to see what a system optimization would do with the predetermined amount of local resources. It can be observed that the system optimization with fixed decentralized capacities is able to decrease the amount of interconnection capacity below the equilibrium solution, and even below the previous system optimal solution as well. The decrease below the previous system optimal amount of interconnection capacity is that the increased amount of batteries makes it possible to reduce the grid load even more. It should be noted that case 4) has higher total costs than case 1) since we fix the PV and battery capacities at a suboptimal level. In other words, it would be better to reduce the amount of DER and increase the grid capacity to some extent. Case 4) highlight that the equilibrium solution in cases 2) and 3) provide not only suboptimal investments but also a suboptimal operation of the system since a system optimization can perform better with the same amount of decentralized resources.

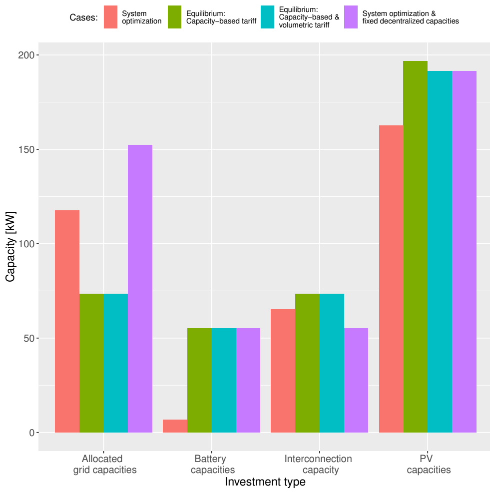

Fig. 3. Investments in capacities for four different cases

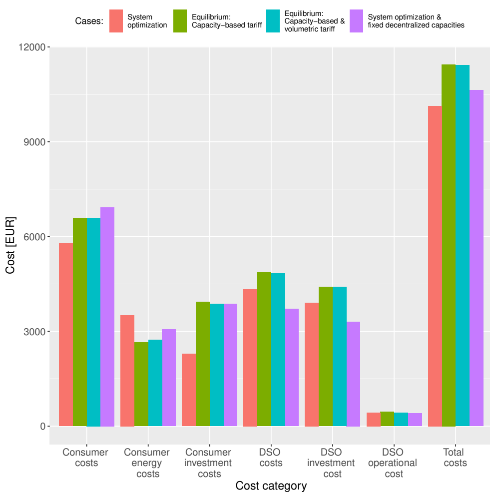

Fig. 4. Detailed cost characteristics for four different cases

Grid utilization and coincidental peak: An interesting observation is that the allocated grid capacities are higher in the system optimization than in the equilibrium despite the increased interconnection capacity in the equilibrium cases. The increased allocation of grid capacities can be explained by the fact that they do not happen in the same moment in time in the case of a system optimization due to different load profiles. In the system optimization, the consumers do not consider the allocated grid capacities as a direct cost since the interconnection capacity is only affected by the total coincidental peak of all consumers. The interconnection capacity and total allocated grid capacity is equal in the equilibrium cases because the capacity-based tariff represents a cost to all consumers based on their peak. In the equilibrium cases, the individual peaks of all consumers occur at the same moment in time due to the similarity of the load profiles, power market prices, PV generation profiles and flattening of demand by batteries.

IV. Conclusion

In this paper, we have compared a system optimization approach with equilibrium solutions of the same system to study the effect of tariffs on the obtained solution. The system under consideration consists of consumers that are connected to the power market through a DSOs network. A case study was carried out based on metering data from 10 consumers in southern Norway.

Our results show that an equilibrium solution using volumetric and capacity-based network tariffs increase the total system costs compared to a system optimal solution. One reason for the cost increase is because the tariffs incentivizes increased amounts of investments in resources at the consumer level. In addition to the increase in decentralized resources, the batteries are operated in a sub-optimal manner from an overall system perspective. Increased amounts of batteries should be able to reduce the peak load in the system, but this does not happen with the tariff schemes considered. The total costs are increased with decentralized decisions because of the effects of non-cooperative behaviour to minimize individual costs. A prospective solution to overcome the problem of suboptimal decentralized decisions would be to coordinate resources locally at a higher level than individual buildings. Local coordination of resources can be similar to a system optimization, but requires that the coordinating entity has access to information about the impact on the rest of the power system and is able to properly remunerate the consumers.

From a socio-economic view, the tariff schemes studied in this paper do not utilize the resources in the system optimally since the consumers lack information about what the other consumers are doing. Ideally, the tariff scheme should not penalize consumers for having a high load if the total load in the grid is low at that moment in time. Although a system optimal solution theoretically provides the optimal decisions, a decentralized modeling approach is more realistic and is necessary for studying if the system optimal solution is supported through regulations and price signals. Our results show that flat volumetric and capacity-based tariffs are not sufficient to facilitate decentralized decisions that are also system optimal. Tariff design and local price signals are important topics which the authors plan to direct further research.

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Zero energy at the neighbourhood scale: Regulatory challenges regarding billing practices in Norway

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Zero energy at the neighbourhood scale: Regulatory challenges regarding billing practices in Norway

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Abstract. Buildings are becoming an increasingly active part of the power system due to the ongoing deployment of decentralized energy resources. To reap the added value that may be realized by zero emission neighbourhoods, it is important that the regulatory framework promotes an efficient development with buildings as an integrated and active part of the power system. When considering energy resources at the neighbourhood level and energy flows within neighbourhoods in Norway, the regulatory framework is challenged by innovative technical solutions. Therefore, it is necessary to explore how deployment of energy resources in neighbourhoods fit together with existing regulations and market mechanisms. Challenges concerning decentralized energy resources are identified based on discussions with stakeholders in Norway and a review of relevant literature in the scientific and regulatory domain. Key challenges for the deployment of energy resources in ZEN are identified, explained through examples, and related to ongoing projects in Norway. It is found that incentives regarding decentralized energy resources are highly dependent on the ownership structure, and therefore a distinction between two major classes of ZEN is made.

1. Introduction

The primary goal of the Norwegian energy law [1] is to ensure economic efficiency in the power system by creating a level playing field for competition in the power market. One major factor is the principle of individual metering to allow every consumer to decide on their electricity supplier, which increase the competition in the power market. The energy law was introduced in the 1990s, at a time where demand was viewed as fixed and the potential for cost reductions were on the supply side. However, there is an ongoing increase in energy-related measures including energy generation resources deployed at the building level. As we move from a goal of zero-energy on a building level towards the neighbourhood scale, it is essential that the regulatory framework continues to promote economic efficiency when buildings become an integrated and active part of the power system.

1.1. Zero-energy buildings

Buildings constitute about 40% of total primary energy consumption in Europe and the US [2]. To reduce the amount of energy required by buildings, the European Union (EU) has set ambitious targets through the energy performance of buildings directives (EPBD), most recently in a 2018 revision [3]. Among other things, the EPBD promote development towards cost-effective nearly zero energy buildings (NZEBs) by 2020.

Although the exact definition of NZEB is not clearly defined, the development towards NZEBs in the building sector means that we move from focusing on reducing energy needs through passive buildings towards also generating energy at the distributed level to accommodate increasingly ambitious targets [4]. Due to the flexible definition of what a zero-energy building is, different interpretations exist in the scientific literature, and despite different interpretation for the 'zero' balance in the EU [5], national policy are driving the development of ZEB.

1.2. Zero-energy at the neighbourhood scale

The concept of zero energy can also be considered at other scales than individual buildings, for example, neighbourhood, district or city level. Marique and Reiter [6] articulate three main energy uses at the neighbourhood level: building energy consumption, the production of on-site renewable energy and transportation energy. When the scope of zero energy is extended beyond individual buildings, the system boundary change from individual buildings to groups of buildings. In the following, such groups of buildings of any size will be referred to as 'zero energy neighbourhoods' (ZEN).

In the following, we categorize ZEN into two different classes based on owner structure: S-ZEN, which is owned by a single entity, and M-ZEN, where multiple owners are present. To illustrate the difference, we provide two examples:

- Campus Evenstad (S-ZEN): A university campus, including student housing, offices and teaching facilities. It is developed, owned and operated by a single institution (Statsbygg).
- Verksbyen Fredrikstad (M-ZEN): One of the largest residential neighborhood development projects in Fredrikstad, Norway [7]. The project is developed by Arca Nova, and the area include several owners of the buildings.

By extending the system boundary to several buildings, it is possible to obtain additional benefits as compared to considering individual buildings separately. Benefits of considering the ZEN scale compared to ZEB include possibilities to build energy resources at the most favorable locations [8], decreased unit costs compared to smaller systems [9], and coordinated balancing of the energy needs of buildings to achieve a more flexible cumulative load profile [10]. In addition to improved conditions for deployment of energy resources, ZEN also facilitates investments that are not available for individual buildings, such as large-scale solar plants in [9].

Along with the benefits, ZEN also introduce challenges when compared to ZEB. Technically, an increased amount of buildings means more complex systems need to be designed and operated compared to the case of one individual building. Furthermore, when buildings become a more integrated and active part of the power system, regulations, taxes, and tariffs need to be designed in a way that facilitates decentralized decisions that are also system optimal.

1.3. Remuneration models for local energy generation

Investments in renewable energy generation assets is increasingly being made by non-utility type stakeholders, e.g. home owners and public institutions. Traditional consumers thus become *prosumers*: consumers that also generate energy. The growth of prosumers is partly a result of policies, and has been especially prominent for solar photovoltaic (PV) panels. For a prosumer, there are two common categories of remuneration models based on generation: (1) a net-metering policy based on (volumetric) energy [11] and (2) a Feed-in Tariff (FiT) [12].

The net-metering policy allows a prosumer to offset electricity consumption from the grid with local production defined over a measuring period (e.g. hourly, daily, monthly, yearly). The longer the measuring period, the more likely the net-metering policy is to reduce the electricity bill of the prosumer. The FiT policy offers a fixed payment for prosumers and requires metering of the local generator. Prosumers subject to a FiT face no price risk except the future removal of the policy [12].

Net-metering policies are found to be financially bad for utilities and end-users without local generation as the lost revenue for utilities cannot be balanced by the saved costs from reduced power grid usage (referred to as the 'revenue erosion effect' [13]). Some fear this could lead to a utility 'death spiral' [14] where using the power grid becomes increasingly expensive as more end-users partly produce their own energy, which would lead more end-users to produce their own energy, and so on. Adjusting remuneration models to be partly based on peak demand will likely be a better measure to allocate costs among grid connected consumers and prevent the utility death spiral [11].

In Norway, the policy framework is favourable for S-ZEN. The prosumer policy ('plusskundeordningen') is a net-metering policy that applies to one meter per prosumer. The prosumer policy grants an exception from the conventional need for a regulatory concession to be an electricity producer in Norway, and it is subject to a requirement that the delivered power to the grid does not exceed 100 kW. The payment to prosumers for surplus energy is usually higher than wholesale electricity spot price, but can vary depending on the retailer contract. Prosumers can get additional remuneration from the joint certificate market [15] for Norway and Sweden if a production plant is commissioned before 2022. Since 2019, it is also more economically viable for small-scale producers (< 1 MW installed capacity) to apply for producer concession after a change in the producer tariff from being dependent on installed capacity to being dependent on net energy delivered to the grid [16].

1.4. Content of the paper

The feasibility of achieving a zero energy balance is dependent on rules and regulations for consumption, production, and pricing of energy. The present paper aims to provide an overview of current regulatory challenges concerning energy resources in ZEN with a particular focus on Norway. Topics covered include why ZEN poses challenges compared to ZEB, and how the concept of ZEN fits current regulations, tariffs, and incentives.

2. Regulatory challenges for ZEN

The following section describes two regulatory challenges that need to be addressed for consistent integration of ZEN in the Norwegian power system: (1) Balancing energy between buildings and (2) Sharing energy resources. These challenges have been identified based on discussions with stakeholders in Norway and a review of relevant literature both in the scientific and regulatory domain.

2.1. Balancing energy between buildings

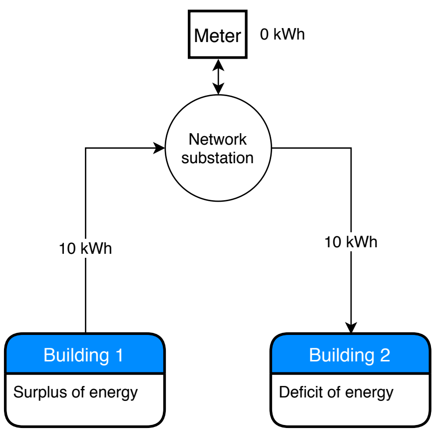
Different types of buildings (residential buildings, schools, offices) may not have their peak energy usage at the same moment in time due to 'the coincidence factor' [17]. The coincidence factor means that the capacity connecting a neighbourhood to the rest of the power system generally is less than the sum of individual peaks in the neighbourhood. This cumulative load profile can be further improved by coordinating energy usage within a ZEN. Coordination of loads can potentially lead to cost reductions since the total amount of capacity connecting the ZEN to the rest of the power system can be reduced. The view that (a) the zero energy concept should be applied to a higher level and (b) energy should be shared between buildings is supported by e.g. [4, 18, 19, 20, 21]. In this context, [21] argue for an energy hub concept to extend the system boundary and realize a system with higher flexibility due to the availability of multiple energy sources and sharing of energy among various consumers and producers.

We now turn to the Norwegian context and the incentives towards consumers for sharing energy between buildings.

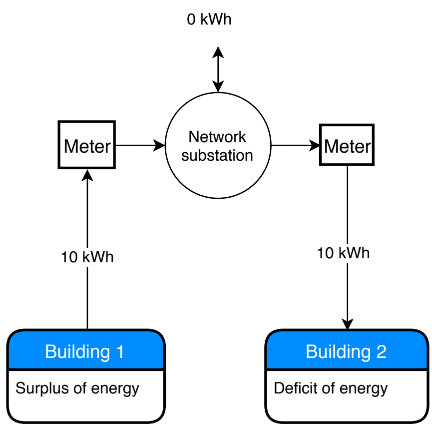
In the case of S-ZEN, all the energy resources and the demand are owned by the same stakeholder although they could be spread across several buildings. An example of this is Campus Evenstad which was described in Section 1.2. In S-ZEN projects, the energy usage within the ZEN can be efficiently balanced before the surplus or deficit is traded with the rest of the power system. Since grid charges and taxes are applied at the interface between the ZEN and the rest of the power system, the owner of S-ZENs has incentives to balance out their energy as much as possible before interacting with the grid since this is most economical.

The other class of ZEN, namely the M-ZEN, is more complicated than the S-ZEN when considering energy flows between buildings. The difference occurs because the energy needs to be transferred from one owner to another. Such transfer of energy requires some trading between the two owners, either directly or through a third party.

We use an illustrative example with two buildings as depicted in figure 1 to compare the case of the two classes of ZEN. For simplicity, we only consider electric energy and one hour of operation. During this hour, Building 1 has a surplus of 10 kWh, while Building 2 has a deficit of 10 kWh. Furthermore, we assume that the grid tariff and energy prices are both 0.50 NOK/kWh resulting in a total cost of 1 NOK/kWh for imports and an income of 0.50 NOK/kWh for exports, assuming the grid cost does not apply for exported energy.



(a) Single-owned ZEN (S-ZEN)



(b) ZEN with multiple owners (M-ZEN)

Figure 1: Illustrative example of energy sharing

In the case of S-ZEN, both buildings are owned by the same stakeholder, so these buildings are metered together at the interface to the rest of the power system (see figure 1a). Costs charged are zero as calculated in (1):

$$Cost^a = 1\frac{\text{NOK}}{\text{kWh}} * (10 - 10)\text{kWh} = 0\ \text{NOK} \tag{1}$$

Next, we consider the M-ZEN case where two different stakeholders own these two buildings. We now calculate the costs for each of the buildings separately since they are not metered together (see figure 1b). The result is a total cost of 5 NOK as calculated in (2):

$$Cost^b = 0.5\frac{\text{NOK}}{\text{kWh}} * (-10)\text{kWh} + 1\frac{\text{NOK}}{\text{kWh}} * 10\text{kWh} = 5\ \text{NOK} \tag{2}$$

Although our example is simplified, it can be observed that energy balancing between buildings in ZEN is not supported by the regulatory framework in the case of M-ZEN. The problem occurs as the individual owners do not have any incentives to cooperate in shifting their demand to balance the energy within the ZEN. The regulatory framework provide incentives to consume locally produced energy behind the meter, which in M-ZEN means avoiding surplus energy for single buildings. One might ask if it is possible for several owners located geographically close to each other to establish one common interface towards the rest of the power system, but this is prohibited by Norwegian regulations [22] requiring individual costumers to be metered separately. The current regulatory framework in Norway only allows trading of electricity between two consumers producing energy (prosumers) through a third party (an energy retailer and the local distribution system operator).

This is indeed a challenge for projects in Norway such as Verksbyen in Fredrikstad which will consist of multiple owners that could potentially be able to balance their energy usage locally, but lack incentives for doing so with the current regulatory framework. As an extension of this argument, [23] note that products and markets for demand response should be developed further in several EU countries.

2.2. Shared energy resources

The concept of ZEN facilitates several stakeholders pooling their financial resources together to be able to build larger power generating facilities. One typical example would be an apartment block in which the different apartment owners build a shared PV-plant on the roof or building facade.

So far, with the concept of ZEB, the distinction of on-site vs. off-site resources has been clear due to the well-defined system boundary. In the context of ZEB, [24] argue that if a generation system is behind the meter, it is on-site. Otherwise, it is off-site. This distinction is challenged by the concept of shared energy resources in a ZEN since the system boundary is not as well defined as for a single building. In some cases, it might be optimal to build larger shared plants within the ZEN, but located outside the meters of the individual households.

To illustrate the economics of shared energy resources, we will consider an illustrative example as depicted in figure 2. The example has been based on the business model of energy resources in Verksbyen Fredrikstad excluding the effect of a Feed-in Tariff (FiT). The reason for excluding FiT is that such policies represent an artificial market price and therefore inherent uncertainty regarding the development of future policies. In our example, we consider an operational hour in which a household and the shared consumption (e.g. EV-charging) requires 10 kWh while the shared generation facility generates 20 kWh.

We now look at this system in more detail. First, we consider the shared facilities in which both the consumption and the generation is behind the same metering point. Such a billing practice means that for any energy consumed directly, grid charges are avoided. A result of this is that it is possible to define a local energy price which is higher than the spot price and lower than the retail electricity price which include spot price added grid charges and taxes:

$$\text{spot price} \leq \text{LCOE} \leq \text{local energy price} \leq \text{retail electricity price} \tag{3}$$

The levelized cost of energy (LCOE) is the lifetime costs divided by energy generation and therefore represent the minimum remuneration per unit of energy to pay back an investment in energy resources. The electricity spot price, e.g. at Nord Pool Spot [25] for nordic countries, is usually lower than the LCOE for distributed energy resources as stated in (3) so it is not profitable to invest in such resources solely to feed it into the electricity grid. Furthermore, (3) states that the LCOE can be lower than the retail electricity price. Therefore, if (3) holds, it is possible to define a local energy price which is larger than the LCOE for energy that is consumed directly. This means that even if distributed energy resources in ZEN are not competitive to

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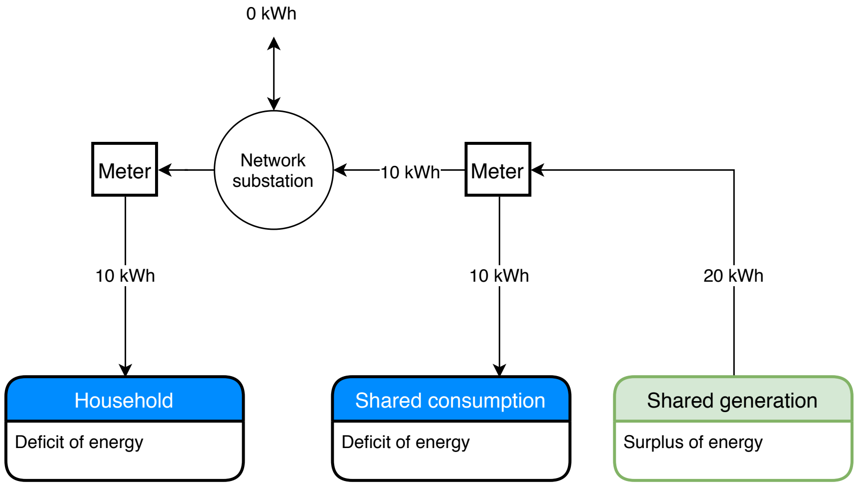

Figure 2: Illustrative example of shared energy resources

large-scale resources in the power market, they may have a place in the power system since they can provide a locational value due to the effect of reducing load as proposed in [26]. This is supported by e.g. [27] which argue that the payment received for exporting excess energy to the grid is insufficient. The underlying reason for this is that distributed generation in ZEN lack the economies of scale which reduce the LCOE for large-scale generation facilities.

We now look at the incentives of the household in this ZEN, which is not behind the same meter as the shared generation. It might be possible for these households to shift their load to some extent in order to match their consumption to the generation. However, due to the pricing policies, the households do not have any incentives for engaging in such behavior. This finding pose a problem since consumers are not incentivized to alleviate grid stress and defer grid investments since their local pricing information do not include the state of the local energy resources.

The issue of shared energy resources is highly relevant for Verksbyen which currently has a plus costumer scheme in place with with an agreement for 0.8 NOK/kWh for any surplus energy fed into the grid. However, the developer of the project consider this price to be highly uncertain since it can change on short notice while investments in energy resources have a long lifetime. Since the project needs to make their decisions subject to regulatory uncertainty, the net present value calculations are based on the assumption that no such agreement is in place since it is an artificial market price. This is in principle a robust optimization approach, and the result is that investments decisions in Verksbyen are based on current market prices and regulatory conditions as depicted in our example.

3. Discussion and conclusions

We have through examples and economic principles shown how current pricing policies in Norway do not offer proper incentives to align behavior by individual stakeholders in ZEN with multiple owners with efficient operation of the overall ZEN. We have demonstrated that when demand response and efficient sharing of energy resources is possible, the current Norwegian billing practices do not offer incentives for the activation of such potential. Furthermore, it should also be noted that grid companies will need to recover their sunk costs, but efficient pricing policies to properly incentivize consumer behavior can activate the potential of local coordination and reduce the need of grid upgrades. The findings of this paper indicate that the current technical possibilities are ahead of the regulatory framework. Regulatory innovation to fill the gap of missing local incentives can take a multitude of forms, ranging from adapting the network tariffs to implementing other kinds of market mechanisms.

Incentives for energy balancing between buildings and sharing energy resources depends on the ownership structure of the ZEN. The critical distinction is between a single-owned ZEN (S-ZEN) and ZEN with multiple owners (M-ZEN). For S-ZEN, the owner has incentives for balancing the energy needs of the various buildings and generation facilities, while this is not the case for M-ZEN. The difference occurs because of billing practices since the interface to the rest of the power system is different for the two classes. In Norway, there is a lot of interest in local energy generation, but to deploy such assets efficiently for M-ZEN, it is necessary to design market mechanisms that enable utilization of such assets at the time of generation. In the case of M-ZEN, this raises the need for local energy trading between stakeholders within ZEN while also maintaining individual metering to facilitate economic efficiency in the overall power system. Therefore, it is worth considering how the locational value of energy can be exploited while maintaining economic efficiency in the overall power system.

The issues addressed in this paper is largely based on the premise that self-consumption is the most important factor to make decentralized energy resources profitable in Norway. However, the incentives vary across Europe as found in [28, 29] which compared support policies for decentralized photovoltaic systems. For instance, the Flemish policy differs from Norwegian billing practices and do not promote self-consumption since the electricity usage is netted out over a period of time. Germany employs on a Feed-in Tariff to guarantee a minimum selling price, which currently is lower than the electricity price resulting in incentives promoting self-consumption similarly as the situation in Norway. However, if the Feed-in tariff rate approaches the electricity retail price, such as in France, the incentives for self-consumption will disappear. Despite the varying incentives facing individual consumers in different countries, the issues concerning M-ZEN are relevant in a more general sense since there is currently no best practice regarding sharing of energy when multiple owners are present.

This article provides insight into how current pricing policies may need to evolve due to the on-going deployment of ZEN in the power system. Regarding policy development, a recent report from the Norwegian Water Resources and Energy Directorate (NVE) emphasize the need for a regulatory sandbox regime to allow testing of policies by providing temporary regulatory exceptions [30]. The findings in this article provide a starting point for further research on how we can design efficient market mechanisms and pricing policies to incentivize decentralized decisions that are also beneficial for the larger power system.

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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.

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}^{P2P}	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]

1 Introduction

As part of solving the climate challenge, the EU has emphasised 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 conditions. 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 2 discusses the market- and grid tariff design. The model is the presented in Section 3, followed by the case study description in Section 4. Results and discussions are then presented in Section 5 before concluding remarks are done in Section 6.

2 Market design

2.1 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 similar 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.

2.2 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.

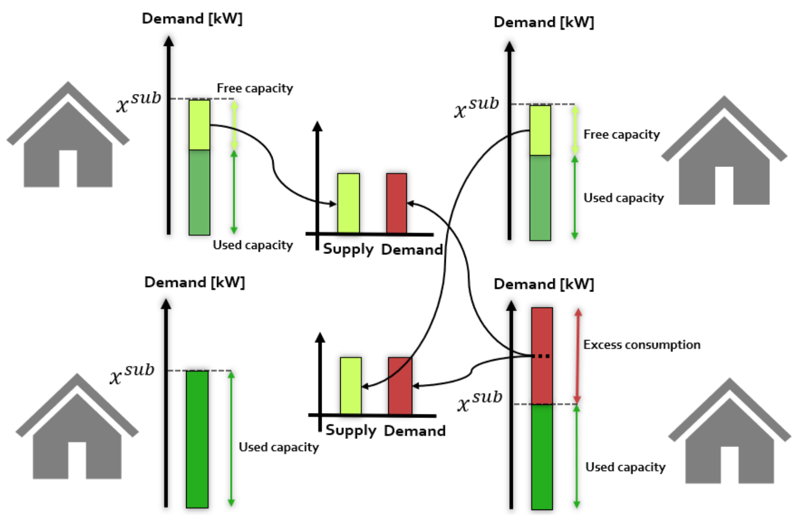

Figure 1: Capacity peer-to-peer trading example.

2.3 Synergies of 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 tradeable 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 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.

3 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.

3.1 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].

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

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).

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

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

The energy balance is given by (4).

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

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).

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

$$\forall p(t < t_{end}) \quad e_{p(t+1)} - e_{pt}$$
$$- q^{ch}_{pt} A^{ch}_p + \frac{q^{dis}_{pt}}{A^{dis}_p} = 0 \quad (\beta^{soc}_{pt}) \tag{5a}$$
$$\forall p(t = t_{end}) \quad e_{pt_0} - e_{pt_{end}}$$
$$- q^{ch}_{pt_{end}} A^{ch}_p + \frac{q^{dis}_{pt_{end}}}{A^{dis}_p} = 0 \quad (\beta^{soc}_{pt_{end}}) \tag{5b}$$
$$\forall pt \quad q^{ch}_{pt} - Q^{ch}_p \leq 0 \quad (\beta^{ch}_{pt}) \tag{5c}$$
$$\forall pt \quad q^{dis}_{pt} - Q^{dis}_p \leq 0 \quad (\beta^{dis}_{pt}) \tag{5d}$$
$$\forall pt \quad e_{pt} - E^{max}_p \leq 0 \quad (\beta^{max}_{pt}) \tag{5e}$$

3.2 Peer-to-peer market clearing conditions

The market operator ensures balance in all trades between peer p and q, where the dual λ^{P2P}_{pqt} 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.

$$\forall pqt \quad x^{P2P}_{pqt} + x^{P2P}_{qpt} = 0 \quad (\lambda^{P2P}_{pqt}) \tag{6}$$

4 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 eff.
- Agent #2: 2 kWp PV, 5 kWh battery, 96 % one-way eff.
- Agent #3: 2 kWp PV
- 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. Similar to above, but end-users can interact through P2P trading.

5 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 1 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 1: 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

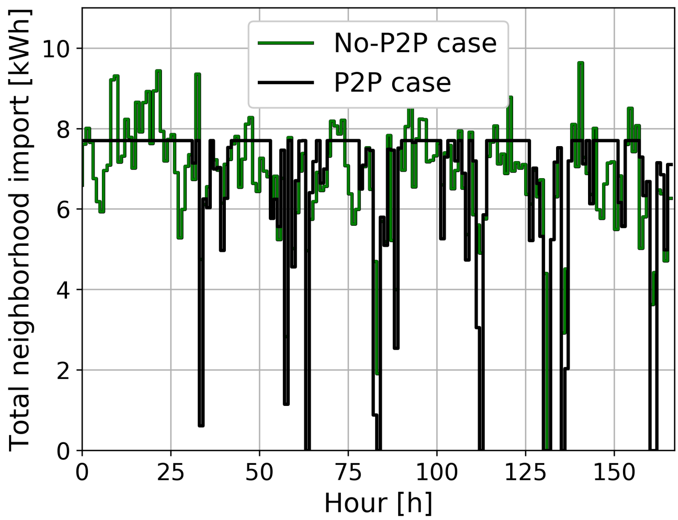

Figure 2: Total end-user import over 1 week.

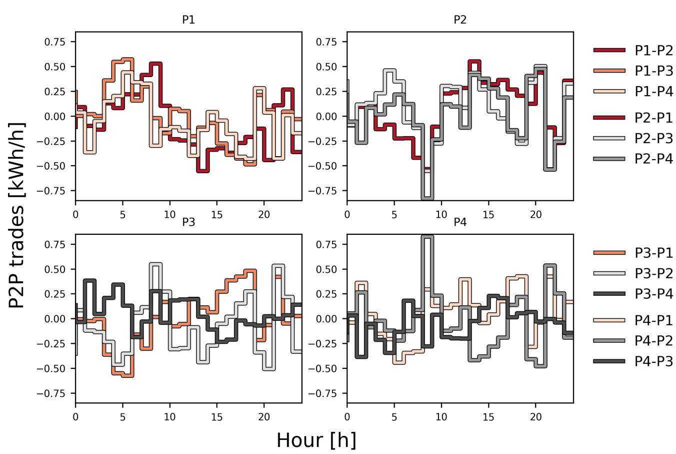

Figure 3: P2P trading in the first 24 hours of the week.

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 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

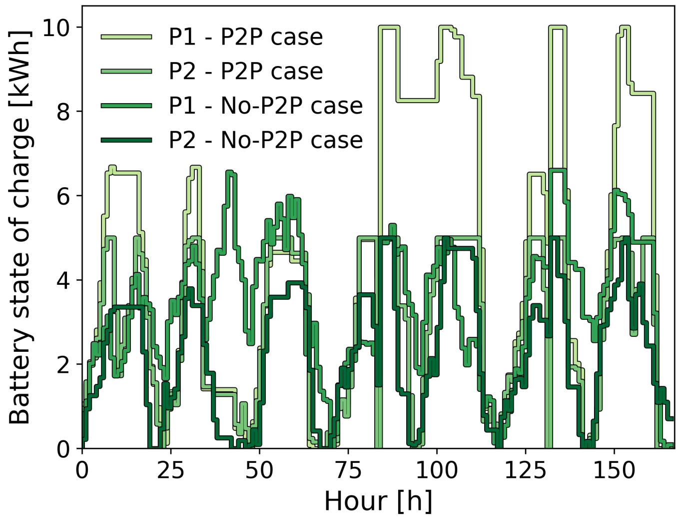

Figure 4: Battery state of charge in the P2P and no-P2P case.

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.

Table 2: 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

Finally, the total electricity costs of the total time horizon for all agents are shown in table 2. 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.

6 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):

$$\forall pqt \quad x_{pqt}^{P2P} + x_{qpt}^{P2P} = 0 \quad \perp \lambda_{pqt}^{P2P} \tag{7}$$

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

$$\forall p \quad x^{sub} - \sum_t \nu_{pt}^{sub} \geq 0 \perp x_p^{sub} \geq 0 \tag{8a}$$

$$\forall pt \quad C^l + \nu_{pt}^{tot} + \nu_{pt}^{sub} \geq 0 \perp x_{pt}^l \geq 0 \tag{8b}$$

$$\forall pt \quad C^h + \nu_{pt}^{tot} \geq 0 \perp x_{pt}^h \geq 0 \tag{8c}$$

$$\forall pt \quad C_t^{DA} - \nu_{pt}^{tot} + \nu_{pt}^{eb} \geq 0 \perp x_{pt}^{buy} \geq 0 \tag{8d}$$

$$\forall pt \quad -C_t^{DA} - \nu_{pt}^{eb} \geq 0 \perp x_{pt}^{sell} \geq 0 \tag{8e}$$

$$\forall pqt \quad \lambda_{pqt}^{P2P} + \nu_{pt}^{eb} + P^{a} \geq 0 \perp x_{pqt}^{P2P} \tag{9}$$

$$\forall pt \quad -\nu_{pt}^{eb} - \beta_{pt}^{soc} A_{p}^{ch} + \beta_{pt}^{ch} \geq 0 \perp q_{pt}^{ch} \geq 0 \tag{10a}$$

$$\forall pt \quad \nu_{pt}^{eb} + \frac{\beta_{pt}^{soc}}{A_{p}^{dis}} + \beta_{pt}^{dis} \geq 0 \perp q_{pt}^{dis} \geq 0 \tag{10b}$$

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

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

$$\forall pt \quad x_{pt}^{l} + x_{pt}^{h} - x_{pt}^{buy} = 0 \quad \perp \nu_{pt}^{tot} \tag{11a}$$

$$\forall pt \quad x_{pt}^{l} - x_{p}^{sub} \leq 0 \perp \nu_{pt}^{sub} \geq 0 \tag{11b}$$

$$\begin{aligned} \forall pt \quad & x_{pt}^{buy} - x_{pt}^{sell} + \sum_{q} x_{pqt}^{P2P} \\ & - L_{pt} + G_{pt}^{PV} - q_{pt}^{ch} + q_{pt}^{dis} = 0 \perp \nu_{pt}^{eb} \end{aligned} \tag{12}$$

$$\forall pt \quad q_{pt}^{ch} - Q_{p}^{ch} \leq 0 \perp \beta_{pt}^{ch} \geq 0 \tag{13a}$$

$$\forall pt \quad q_{pt}^{dis} - Q_{p}^{dis} \leq 0 \perp \beta_{pt}^{dis} \geq 0 \tag{13b}$$

$$\forall pt \quad e_{pt} - E_{p}^{max} \leq 0 \perp \beta_{pt}^{max} \geq 0 \tag{13c}$$

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

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

Paper ENSYS

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ORIGINAL PAPER

A stochastic MPEC approach for grid tariff design with demand-side flexibility

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Abstract

As the end-users increasingly can provide flexibility to the power system, it is important to consider how this flexibility can be activated as a resource for the grid. Electricity network tariffs is one option that can be used to activate this flexibility. Therefore, by designing efficient grid tariffs, it might be possible to reduce the total costs in the power system by incentivizing a change in consumption patterns. This paper provides a methodology for optimal grid tariff design under decentralized decision-making and uncertainty in demand, power prices, and renewable generation. A bilevel model is formulated to adequately describe the interaction between the end-users and a distribution system operator. In addition, a centralized decision-making model is provided for benchmarking purposes. The bilevel model is reformulated as a mixed-integer linear problem solvable by branch-and-cut techniques. Results based on both deterministic and stochastic settings are presented and discussed. The findings suggest how electricity grid tariffs should be designed to provide an efficient price signal for reducing aggregate network peaks.

Keywords Bilevel problem · Grid tariffs · Mathematical program with equilibrium constraints (MPEC) · Uncertainty

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1 Introduction

1.1 Background

The transition from traditional, inelastic, electricity demand to more flexible consumers, means that the paradigm of demand as a passive load is no longer valid since demand can react to price signals. By introducing prosumers, who can both consume and produce electricity, the grid tariffs should provide efficient price signals to align the optimal end-user decisions with efficient utilization of the power system at a larger scale to avoid a sub-optimal outcome as demonstrated in [1].

Grid tariffs are mostly implemented as fixed amounts (€/consumer), volumetric charges (€/kWh), and possibly capacity-based (€/kW) charges. Although variations exist, electricity network tariffs can generally be reduced to these three fundamental structures [2]. A general issue regarding network tariffs is that there does not exist an ideal policy since it is necessary to balance efficiency with other aspects [3]. One principal problem of current grid tariff structures in Europe is that they primarily consist of fixed and volumetric charges. This is, as presented in [4–6], not a sufficient proxy for the overall network costs since the main cost driver is the need for sufficient capacity to handle peak loads.

Capacity-based tariffs may be a prospective solution since they more accurately reflect the upstream grid costs than volumetric tariffs as argued in [7, 8]. However, a flat capacity-based tariff scheme provides incentives to stay below the maximum usage in all hours, regardless of the congestion in the network. Furthermore, a flat capacity-based tariff neglects the fact that the grid load usually is well below the capacity.

The overall research question we consider in this paper is: *How can we, by using fairly simple network tariffs, incentivize flexible end-users to efficiently adapt their consumption patterns?* We address the problems concerning flat tariffs and present a novel approach by formulating the electricity grid tariff design problem with a bilevel structure in the context of prosumers at the end-user level. Various network tariff structures are optimized subject to the prosumers best response in a game theoretical framework, which is benchmarked against a centralized system optimization.

1.2 Literature review

Overall, the existing literature modeling electricity grid tariffs can be assigned to two different groups. One major group focuses on the impact of various tariff structures for specific consumer types and technologies [9–12]. In general, this line of research is able to assess the impact of various tariff schemes on these stakeholders. The approach in this research area differs from our research because they treat the grid tariffs as exogenous parameters and do not attempt to design the tariffs optimally by considering the consumers and the grid as an integrated system.

The second line of research is more closely related to our work, approaches the subject of electricity grid tariffs by determining an equilibrium between end-users and a grid entity (e.g., DSO). This means that it is necessary to consider a bilevel problem. Using an equilibrium approach, [13–15] formulate a problem by defining the lower level as a system of optimization problems and iteratively calculating the tariffs until network costs equal the charges. The aforementioned approaches are limited to selecting the level of flat tariffs, and do not allow for consideration of different scenarios and determining off-peak periods since a loop-based model structure is employed.

Equilibrium models are widely applied to power market research because of the ability to represent various market structures and interactions between market participants. The properties of the tariff design problem addressed in this paper are consistent with Stackelberg-type games [16], which are characterized by a leader who moves first and one or more followers acting optimally in response to the leader's decisions. Games with a Stackelberg structure can be formulated as mathematical problems with equilibrium constraints (MPECs) [17]. MPEC models are used for investigating aspects such as strategic investment decisions [18–20], strategic bidding in electricity markets [21, 22] and for determining optimal generation schedules and prices to minimize total consumer payments [23]

The MPEC approach has recently been used for various forms of indirect load control where some entity tries to induce a change in end-user behaviour through pricing mechanisms. In [24], the Stackelberg relationship between retailers and consumers is formulated as a MPEC where the upper-level retailer tries to maximize its profit by choosing the price-signal subject to the response by consumers. Furthermore, [25] formulate a model of a similiar structure for the interaction between an EV aggregator and EV consumers.

In this paper we consider a DSO as the leader in a Stackelberg-type game. In this context, [26] formulates a DSO interacting with power markets to derive trading strategies. Furthermore the bi-level relationshop between a DSO and aggregators is modeled with direct contracting of the aggregator resources in [27]. The authors in [28] take a top-down approach by formulating a MPEC to determine the optimal DSO policy tailored to control feed-in to the grid. The policy mechanism is modeled directly as a technical limitation on each end-user rather than formulating price signals for indirect load control.

Although the MPEC formulation is increasingly being used in the context of decentralized energy resources, the related literature is limited and the authors have not identified any prior papers which formulate a MPEC approach for investigating indirect load control through grid tariffs to provide incentives for efficient end-user coordination.

1.3 Contributions

Fundamentally, grid tariffs is a price signal that comes on top of the electricity price. However, due to the need for simplicity, it is not possible to tailor the tariff for each time step. Rather, a structure where cost components are predictable for the end-user is needed.

In this work, we address the gap in the literature concerning tariff optimization as a tool for indirect load control and analyze how a fairly simple tariff scheme can be used to activate end-user flexibility and efficiently reduce grid load by developing an MPEC. This paper provides a novel method of determining grid tariffs that can provide more efficient grid pricing and reduce total system costs. The primary contributions of this paper are as follows:

- Development of a stochastic MPEC model for optimizing electricity network tariffs subject to active end-users. The model formulates end-users responding to the tariffs determined by the DSO. Uncertainty is represented by stochastic demand, market prices, and PV output.
- Formulation of an electricity network tariff structure capable of incentivizing flexible end-users to efficiently shift their electricity consumption.
- Analyses that highlight the model features and assess how demand flexibility can be efficiently activated by grid tariffs in a setting with limited grid capacity and decentralized decision-making. The case studies are benchmarked against a system optimal solution with centralized decision-making.

1.4 Structure of paper

The rest of this paper is structured as follows. Section 2 describes the leader and follower optimization problems and how these are coupled in an overall system. A description of both a system optimization model used for benchmarking and the MPEC formulation is provided. Furthermore, Sect. 3 describes reformulations and the computational setup used. Section 4 presents the case study results. Finally, conclusions are drawn in Sect. 5.

2 Model formulation

In this section, we formulate the lower-level and upper-level problems considered as part of the MPEC. Then, the resulting MPEC where the DSO decides the tariffs applied to the consumers as depicted in Fig. 1 is formulated.[1] An explanation of the symbols used is provided in "Appendix 1".

The variables of the lower level (end-user) problems can be adapted for each scenario. This means that the end-users do not consider the stochasticity since all their decisions are scenario-dependent. The uncertainty of the problem is considered in the upper level since the DSO needs to set the tariffs non-anticipatively, based on the different realizations of load, PV generation and power prices. Each realization of the uncertain parameters induce a different response from the lower level. This forms a two-stage stochastic program within the bilevel structure of the MPEC model:

[1] It is assumed that the DSO has detailed information about the end-users of electricity. However, this information might not be available in practice and an approximation of the end-user response would have to be formulated based on empirical data.

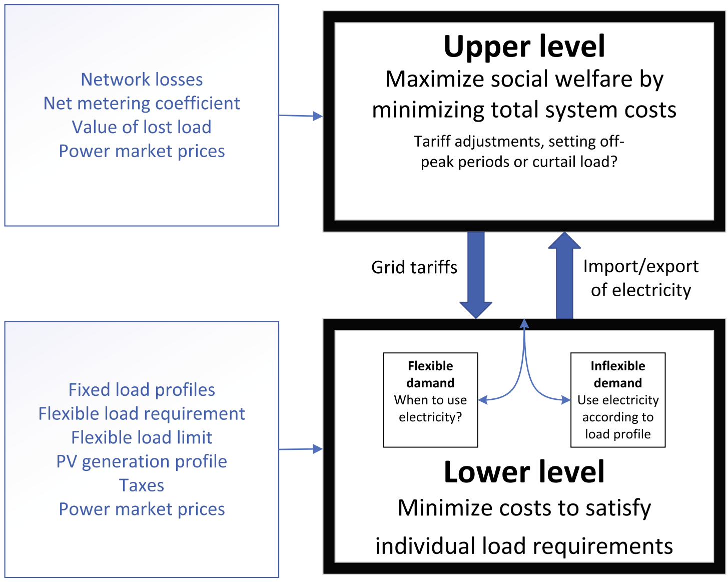


Fig. 1 Structure of the modeled bilevel tariff optimization problem

- Planning stage: The DSO sets tariff levels and off-peak hours.
- Operational stage: The end-users decides how to operate flexible resources and the DSO decides if load needs to be curtailed.

2.1 Lower-level formulation

The lower level comprise the end-users of electricity, which can be either consumers or prosumers. Lower-level decisions occur at the operational stage. The problem of the individual end-user is described as an optimization problem that is similar for both consumers and prosumers. However, for regular consumers, many of the variables will be zero as there are no generation resources or flexible load. A fully passive consumer will simply exhibit the specified demand on the grid without any decentralized decision-making involved. We indicate the dual variables associated with each of the constraints (5)–(9).

2.1.1 Objective function

We assume the objective of the end-users is to minimize their costs according to (1). Three scenario-dependent cost components are included: cost of purchasing power from the power market, $Cost^P_{c,s}$, taxes, $Cost^T_{c,s}$, and grid costs, $Cost^G_{c,s}$. Note that the actual grid costs are not considered at the end-user level since these costs are imposed indirectly through the network tariffs.

$$Min\ :\ Cost_{c,s} = Cost^P_{c,s} + Cost^T_{c,s} + Cost^G_{c,s} \tag{1}$$

Where the components of (1) are defined in (2)–(4).

$$Cost^{P}_{c,s} = \sum_{h=1}^{H} (e^{I}_{c,s,h} \times (1 + VAT) - e^{E}_{c,s,h}) \times P_{s,h} \tag{2}$$

$$Cost^{T}_{c,s} = (1 + VAT) \times T \times \sum_{h=1}^{H} e^{I}_{c,s,h} \tag{3}$$

$$Cost^{G}_{c,s} = (1 + VAT)\left(\sum_{h=1}^{H} (e^{I}_{c,s,h} - NM \times e^{E}_{c,s,h}) \times vnt + c^{G}_{c,s} \times cnt \right) \tag{4}$$

Note here the NM parameter that quantifies to which extent the electricity exports are subject to net metering:

- $NM = 1$: The end-user only pays volumetric charge for net imports.
- $NM = 0$: The end-user pays volumetric charge for all imports.
- $NM = -1$: The end-user pays volumetric charge for both imports and exports.

2.1.2 Energy balance

The energy balance of the prosumer is described by (5) and states that energy imports subtracted exports must be equal to fixed and flexible demand subtracted generation from PV.

$$\forall c, \forall s, \forall h : D_{c,s,h} + d^{\Delta+}_{c,s,h} - g_{c,s,h} = e^{I}_{c,s,h} - e^{E}_{c,s,h} \quad (\lambda^{EB}_{c,s,h}) \tag{5}$$

2.1.3 Flexible load

EV charging requires an amount of electric energy for each day. Therefore, (6) describes the total flexible load for each scenario. This means that a flexible consumer can choose when to consume the flexible load, as long as the total load across all hours in a scenario is equal to the specified amount.

$$\forall c, \forall s : D^{\Delta-}_{c,s} = \sum_{h=1}^{H} d^{\Delta+}_{c,s,h} \quad (\lambda^{FL}_{c,s}) \tag{6}$$

The maximum flexible load during each time step is limited by (7). This is analogous to EV charging capacity, which depend on the AC/DC converter.

$$\forall c, \forall s, \forall h : d^{\Delta+}_{c,s,h} \leq U^{\Delta+}_{c,s,h} \quad (\mu^{FC}_{c,s,h}) \tag{7}$$

2.1.4 Peak power

The capacity-based part of the grid tariff is based on the measured peak power that is either drawn from or injected to the grid. Therefore, the end-user has to subscribe to the maximum power according to (8). This determines the variable $c^G_{c,s}$ which is subjected to the capacity-based tariff. However, during the off-peak hours set by the DSO (if $op_{s,h} = 1$), the constraint is relaxed to allow for increased grid utilization by not including measurements during those hours in the calculation.

$$\forall c, \forall s, \forall h : e^I_{c,s,h} + e^E_{c,s,h} \leq c^G_{c,s} + D^{MAX}_c \times op_{s,h} \quad (\mu^G_{c,s,h}) \tag{8}$$

2.1.5 PV generation

PV generation is described by (9) and has the option of curtailing generation in the case of situations with an over-production.

$$\forall c, \forall s, \forall h : g_{c,s,h} \leq U^{PV}_c \times G_{c,s,h} \quad (\mu^{PV}_{c,s,h}) \tag{9}$$

2.2 MCP formulation of lower level

The optimization problems of the end-users are linear and with convex constraints. Due to these properties, the individual optimization problems can be replaced by their Karush–Kuhn–Tucker (KKT) optimality conditions formulated as MCP conditions in (10)–(19) below.

$$\forall c, \forall s, \forall h : (P_{s,h} + T + vnt) \times (1 + VAT) - \lambda^{EB}_{c,s,h} + \mu^G_{c,s,h} \geq 0 \perp e^I_{c,s,h} \geq 0 \tag{10}$$

$$\forall c, \forall s, \forall h : -P_{s,h} - NM \times vnt \times (1 + VAT) + \lambda^{EB}_{c,s,h} + \mu^G_{c,s,h} \geq 0 \perp e^E_{c,s,h} \geq 0 \tag{11}$$

$$\forall c, \forall s : (1 + VAT) \times cnt - \sum_{h=1}^{H} \mu^G_{c,s,h} \geq 0 \perp c^G_{c,s} \geq 0 \tag{12}$$

$$\forall c, \forall s, \forall h : \lambda^{EB}_{c,s,h} - \lambda^{FL}_{c,s} + \mu^{FC}_{c,s,h} \geq 0 \perp d^{\Delta+}_{c,s,h} \geq 0 \tag{13}$$

$$\forall c, \forall s, \forall h : -\lambda^{EB}_{c,s,h} + \mu^{PV}_{c,s,h} \geq 0 \perp g^{PV}_{c,s,h} \geq 0 \tag{14}$$

$$\forall c, \forall s, \forall h : e^I_{c,s,h} - e^E_{c,s,h} - D_{c,s,h} - d^{\Delta+}_{c,s,h} + g_{c,s,h} = 0 \perp \lambda^{EB}_{c,s,h} \tag{15}$$

$$\forall c, \forall s, \forall h : c^G_{c,s} + D^{MAX}_c \times op_{s,h} - e^I_{c,s,h} - e^E_{c,s,h} \geq 0 \perp \mu^G_{c,s,h} \geq 0 \tag{16}$$

$$\forall c, \forall s, \forall h : U_c^{PV} \times G_{c,s,h} - g_{c,s,h}^{PV} \geq 0 \perp \mu_{c,s,h}^{PV} \geq 0 \tag{17}$$

$$\forall c, \forall s : \sum_{h=1}^{H} d_{c,s,h}^{\Delta+} - D_{c,s}^{\Delta-} = 0 \perp \lambda_{c,j}^{FL} \tag{18}$$

$$\forall c, \forall s, \forall h : U_{c,s,h}^{\Delta+} - d_{c,s,h}^{\Delta+} \geq 0 \perp \mu_{c,s,h}^{FC} \geq 0 \tag{19}$$

2.3 Upper-level formulation

The upper level comprise the DSO which is responsible for connecting the end-users to the electricity grid. Upper-level decisions include determining the grid tariffs at the planning stage and curtailment of load at the operational stage.

2.3.1 DSO costs

The DSO is responsible for building and maintaining the electricity grid. The costs related to the DSO are network losses and load curtailment costs. These costs related to the DSO's activities are described by (20).

$$Cost_s^{DSO} = \sum_{h=1}^{H} (e_{s,h}^G \times L^G \times P_{s,h} + ls_{s,h} \times VLL) \tag{20}$$

2.3.2 Transmission of electricity

The DSO needs to transfer electricity at each time step according to the total imports or exports generated by the end-users described by (21).

$$\forall s, \forall h : e_{s,h}^G = \left| \sum_{c=1}^{C} (e_{c,s,h}^I - e_{c,s,h}^E) \right| \tag{21}$$

It should be noted that due to the possibility of exports to the grid, (21) includes an absolute value function, which we handle as described in Sect. 3.1.1.

2.3.3 Interconnection capacity

The interconnection capacity needs to cover the electricity transferred less load curtailment according to (22). It should be noted that the effect of load curtailment is neglected in the lower level problem because it is assumed that the curtailment cost considered by the DSO (*VLL*) represents the end-user cost of curtailment.

$$\forall s, \forall h : F^G \geq e_{s,h}^G - ls_{s,h} \tag{22}$$

In the case of curtailment due to transmission arising from exports to the grid (grid capacity violated and $e^{G}_{s,h}$ is based on export), the load curtailment is interpreted as generation curtailment.

2.3.4 Total system costs

In the modeled system, costs occur both at the end-user and DSO levels. The total costs in the system are described by (23). The tariff costs are not included since these would be added to consumer costs and subtracted from the DSO's costs, resulting in zero net contribution towards total costs. Therefore, neglecting cost recovery for the DSO, the grid tariffs are purely tools to incentivize end-user behavior in this model.[2]

$$TC = \sum_{s=1}^{S} A \times W_s \times \left(Cost^{DSO}_{s} + \sum_{c=1}^{C} (Cost^{P}_{c,s} + Cost^{T}_{c,s}) \right) \tag{23}$$

2.4 System optimization model

The benchmark case is a system optimization where all decisions are made centrally. This would for example be the case if the DSO could directly control EV charging at the consumer level. The system optimization means that the bilevel problem is replaced by a linear problem which considers all costs and technical restrictions both at the DSO and end-user level directly. The system optimization is formulated below:

$$\text{Min } TC \tag{24}$$

Subject to technical constraints (5)–(9) and (21)–(22).

2.5 Bilevel model

Similar to the system optimization, we consider that the DSO tries to maximize social welfare by minimizing total costs. Therefore, the DSO considers not only it's own costs, but also the end-user costs. Contrary to the system optimization, the DSO can not directly control resources on the end-user level. Instead, the lower-level response is included indirectly through the complementarity conditions. In this problem the DSO use indirect load control through tariffs to reduce the total system costs.

Using the previously defined equations, the bilevel model formulation becomes:

$$\text{Min } TC \tag{25}$$

[2] Cost recovery for the DSO is not included. Cost recovery could be imposed through a fixed network tariff to collect the residual cost. Such a fixed network tariff would have no influence on our results since the end-users are unable to take any active measures to avoid it.

Subject to technical constraints (21)–(22) and complementarity conditions (10)–(19).

Note that the objectives of the end-users and the DSO coincides. Despite this property, it is not possible to translate the bilevel model to a single-level problem since we assume grid costs are passed on through grid tariffs rather than a perfect representation of the true DSO cost structure. Hence, the grid tariffs need to be optimized to provide the most efficient incentives that are possible within the boundary of the tariff design.

2.6 Limitations

This paper aims to tackle a complex issue on that span across different aggregation levels in the power system. The physical modeling of network and loads is simplified since the focus of this paper is on investigating different tariff structures to incentivize efficient temporal shifting of energy. Since we focus on balancing energy on an hourly timescale, voltage constraints are not considered. Furthermore, we consider the flexibility to be represented through flexible EV charging where the specified amount of energy needs to be satisfied for each scenario.

Despite these limitations, the modeling results are insightful for the following reasons:

- The model is compatible with current pricing mechanisms that work on an hourly basis due to metering limitations. The model can also easily be adapted to sub-hourly resolutions in the case of more frequent metering.
- EV charging represent a particularly flexible type of demand and should be considered when determining tariff policies.
- Realistic grid tariff structures that can potentially be implemented within existing regulatory frameworks are considered.

3 Solution approach

3.1 Linearization methods

The model formulated in Sect. 2.5 contain two sources of nonlinearities:

- Absolute value term in the upper-level constraint (21).
- Complementarity conditions (10)–(19) in the MPEC formulation (shown as $\perp$).

The following sections will describe how the problem is reformulated to handle these computationally.

3.1.1 Line flow constraint

The amount of transferred electricity is described by an absolute value function (21) since it is the maximum of either imports or exports. However, since losses have nonnegative costs with nonnegative power market prices, a cost minimizing DSO will select the lowest amount of grid transfer possible. Therefore, equality (21) can be replaced by inequalities (26)–(27), which does not include absolute value terms, as long as power market prices are nonnegative.

$$\forall s, \forall h : e^G_{s,h} \geq \sum_{c=1}^{C} (e^I_{c,s,h} - e^E_{c,s,h}) \tag{26}$$

$$\forall s, \forall h : e^G_{s,h} \geq \sum_{c=1}^{C} (e^E_{c,s,h} - e^I_{c,s,h}) \tag{27}$$

3.1.2 Complementarity conditions

The complementarity conditions on the form:

$$f(x) \geq 0 \perp x \geq 0 \tag{28}$$

Can be replaced by:

$$f(x) \geq 0, x \geq 0, f(x) \leq \alpha \times M, x \leq (1 - \alpha) \times M \tag{29}$$

Where α is a binary variable and M is a large enough constant. However, choosing an appropriate value for M is important for numerical stability, but can be a challenging task in itself [29]. To overcome the issues concerning a "big-M" formulation, the complementarity conditions can also be transformed by using SOS type 1 variables as presented in [30]. Hence, (28) can be reformulated into the following:

$$f(x) \geq 0, x \geq 0 \tag{30}$$

$$u = \frac{x + f(x)}{2} \tag{31}$$

$$v^+ - v^- = \frac{x - f(x)}{2} \tag{32}$$

$$u - (v^+ + v^-) = 0 \tag{33}$$

Where v^+, v^- are SOS type 1 variables.

The SOS type 1 based approach provides a global optimal solution in a computationally efficient way. In addition, we avoid having to specify an appropriate value for M to ensure that the complementarity conditions are not violated. Therefore, complementarity conditions (10)–(19) are linearized using the SOS type 1 approach, forming a MILP.

3.2 Computational set-up

The models are implemented in GAMS v27.3.0 and solved as LP for the benchmark case and MILP for the MPEC cases by CPLEX v12.9.0.0 on a personal computer with an Intel(R) Core(TM) i7-8850H 6-core CPU and 32GB of RAM.

3.2.1 System optimization

The system optimization is formulated as a linear problem which with the linearized line flow constraint can be solved directly by off the shelf optimization software.

3.2.2 MPEC

After the linearizations described in Sects. 3.1.1 and 3.1.2, the MPEC is reformulated into a MILP with SOS1 variables to handle the complementarity conditions. The resulting formulation can be directly solved with commercial MILP solvers. A relative gap tolerance of 1% was used in all cases.

The MPEC is computationlly challenging and the tractable problem size is limited. This is mainly due to the following aspects:

- Linking of hourly problems within each scenario through the flexible charging constraint.
- Upper-level decisions such as tariff levels which affect all scenarios.

Despite the computational limitations, it is possible to use this framework to investigate the efficiency of various tariff structures with flexible end-users.

4 Case studies

In this section, we present results for the following cases:

- SO: System optimal solution
- MPEC-F: MPEC with flat capacity based tariff ($op_{s,h}$ fixed at zero).
- MPEC-P: MPEC with capacity-based tariff and scenario dependent off-peak period selection ($op_{s,h}$ binary and decided by DSO). The off-peak periods does not have to be equal across all scenarios.
- MPEC-PN: MPEC with capacity-based tariff and off-peak period constrained by nonanticipativity ($op_{s,h} = op_h$ binary and decided by DSO). In this case, the off-peak periods need to be the same in all scenarios.

MPEC-F is the case with the simplest form of a capacity-based tariff, where the measured peak load over all hours within a scenario determines the cost regardless of when it occurs. This creates an incentive for each end-user to flatten their load profile. In the MPEC-P and MPEC-PN case, we introduce the possibility of off-peak hours. Capacity usage during the off-peak hours are not measured so the end-users can have a high load during these hours without incurring extra costs. Off-peak hours creates an incentive for load-shifting to these hours, which can be beneficial in the case of low-load periods or periods with high injection of renewable energy in the distribution grid. The difference between the MPEC-P and MPEC-PN cases is that in the first case the off-peak hours can be different for each scenario while in the latter case, the off-peak hours need to be equal across all scenarios. These cases are benchmarked against the system optimal model (SO) to assess the efficiency of the various tariff schemes.

We assume that end-users pay volumetric charges on imports, but not exports and that the electricity is not net metered. Hence, a parameter setting for *NM* of zero is used in this paper. This is in line with current practice in several European countries.

4.1 Deterministic example

For simplicity, we first consider a deterministic example of one scenario with a fixed and a flexible load and limited grid capacity. The scenario comprise one day with two segments which are denoted segment 1 and 2, respectively. Segment 1 comprise the first 12 h of the day, while segment 2 comprise the second 12 h. The fixed load is high in the first segment, and low in the second segment. Furthermore, the electricity price is low in the first segment and high in the second segment. This means that we have a situation where fixed demand is high when electricity prices are low and opposite. Therefore, with limited grid capacity, it is beneficial for the grid if most of the flexible load occur in the high-price period to avoid load curtailment. An overview of the input data for the illustrative example is provided in Table 1.

Since we only consider one scenario, case MPEC-PN is not included in the illustrative example. All cases were solved in less than 1 minute. Results are provided in Table 2 and Fig. 2.

The benchmark case is SO, which takes a central planning approach. The MPEC cases can be compared to the SO case to assess the performance of the different tariff schemes. Regarding total costs, MPEC-P is equal to SO, while MPEC-F has higher total costs due to load curtailment occurring in segment 1. The load curtailment can be explained by the flat tariff scheme in MPEC-F, which means that the prosumer has incentives to keep the maximum load as low as possible in any hour. Hence, the lowest peak load is obtained by dividing the total load of 70kWh by 24 h, resulting in a flat load of 2.92kWh/h for the entire day. This operational pattern can be observed in Fig. 2b. Therefore, since the DSO is unable to provide any time-dependent incentives, case MPEC-F results in load curtailment during the first segment of the day even though the load could be served in segment 2.

In contrast to MPEC-F, load curtailment is completely avoided in case MPEC-P since segment 2 is set as off-peak by the DSO. Hence, because of the off-peak period, the prosumer has incentives to shift most of the load towards segment 2, even though the power prices are higher in this segment. These findings highlight a key problem with flat capacity-based tariffs since such tariffs will only incentivize each consumer to flatten their load profile individually. However, the peak grid load is the sum of individual loads which may not be

Table 1 Input parameters for illustrative example

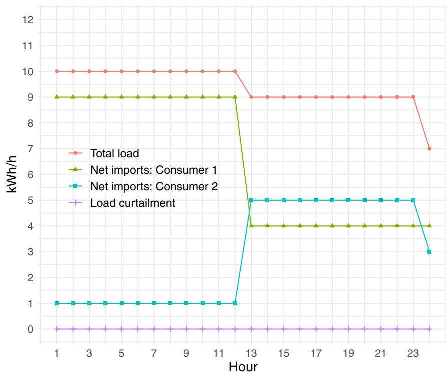
Parameter	Symbol	Value
Time horizon	A	365 days
Fixed load in segment 1	$D_{1,s,h}$	9 kWh/h
Fixed load in segment 2	$D_{1,s,h}$	4 kWh/h
Flexible load	$D^{\Delta-}_{1,s}, D^{\Delta-}_{2,s}$	0 kWh/day, 70 kWh/day
Transmission capacity	F^{G}	10 kW
PV generation	$G_{c,s,h}$	0
Transmission losses	L^{G}	6%
Net metering coefficient	NM	0
Market price in segment 1	$P_{s,h}$	0.05 EUR/kWh
Market price in segment 2	$P_{s,h}$	0.10 EUR/kWh
Electricity tax	T	0.016 EUR/kWh
Flexible load limit	$U^{\Delta+}_{c,s,h}$	5 kW
PV capacity	U^{PV}_{c}	0 kW
Value-added tax	VAT	25%
Load curtailment cost	VLL	3 EUR/kWh
Scenario weight	W_s	1

coincident with individual peaks. Another problem with a flat tariff scheme is that it will induce a change in end-user behaviour also when the grid has no need for a such flexibility, creating socio-economic losses due to the associated discomfort for end-users. This suggest that a flat capacity-based tariff do not reflect the true grid costs in an accurate way and that the incentives need to be more efficient. As such, introducing off-peak periods may be a prospective solution to communicate how load should be shifted in a coordinated fashion across multiple end-users.

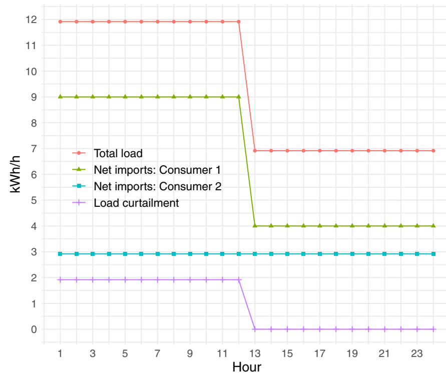
Next, the aspects of decentralized generation and stochasticity concerning the realizations of load, generation and power prices are considered.

4.2 Stochasticity and decentralized generation

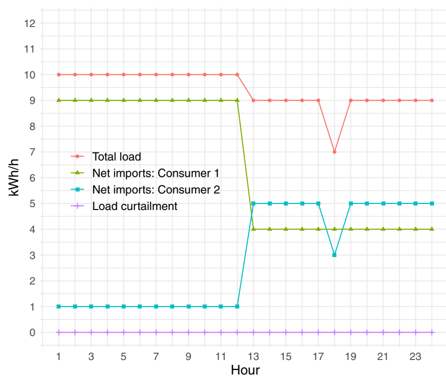
Next, we consider the case of residential load coupled with a PV generation and an EV charging facility. We assume consumer 1 is an inflexible residential load for 1000 m^2 of apartments. Furthermore, consumer 1 also has a PV system with an installed capacity of 50 kW. Consumer 2 is an EV charging facility who shares the grid connection with consumer 1. Since the grid connection is shared between these consumers, coordinated EV-charging can potentially be important for the DSO, because it impacts the total load. However, the restriction on aggregate load can not be imposed directly on the end-users so such coordination need to be achieved through the grid tariffs.



(a) Case SO: Operational pattern in the system optimal solution.



(b) Case MPEC-F: Operational pattern with flat capacity-based tariff.



(c) Case MPEC-P: Operational pattern with capacity-based tariff and off-peak periods.

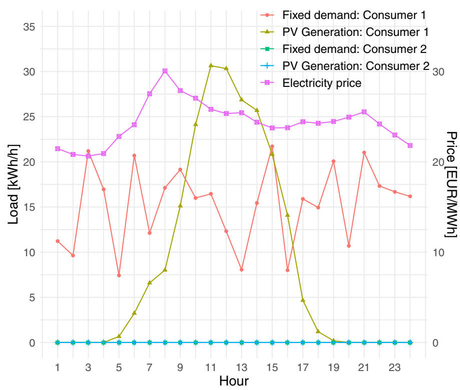
Fig. 2 Illustrative example: operational decisions for centralized optimization and two different tariff structures with decentralized decision-making

Table 2 Illustrative example: key results

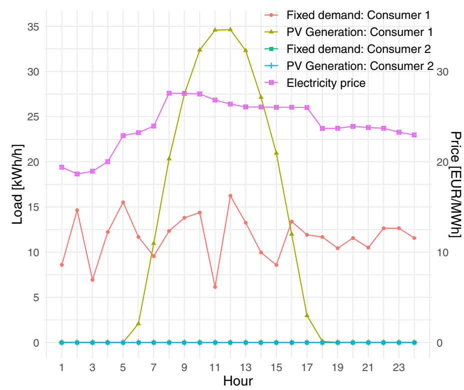
	SO	MPEC-F	MPEC-P
Total costs (EUR)	9587	34222	9587
Cost change	0%	+257%	0%
Curtailment (kWh)	0	8395	0
cnt (EUR/kW)	NA	0.6	0.6
vnt (EUR/kWh)	NA	0	0
Optimality gap	Optimal	0.052%	Optimal
CPU time	<1 min	<1 min	<1 min

Table 3 Input parameters for the stochastic example

Parameter	Symbol	Value
Time horizon	A	365 days
Fixed load	$D_{c,s,h}$	See Fig. 3
Flexible load	$D^{\Delta-}_{1,s}, D^{\Delta-}_{2,s}$	0 kWh/day, 200 kWh/day
Transmission capacity	F^{G}	25 kW
PV generation	$G_{c,s,h}$	See Fig. 3
Transmission losses	L^{G}	6%
Net metering coefficient	NM	0
Electricity price	$P_{s,h}$	See Fig. 3
Electricity tax	T	0.016 EUR/kWh
Flexible load limit	$U^{\Delta+}_{c,s,h}$	20 kW
PV capacity	U^{PV}_{1}, U^{PV}_{2}	50 kW, 0 kW
Value-added tax	VAT	25%
Load curtailment cost	VLL	3 EUR/kWh
Scenario weight	W_1, W_2	0.493, 0.507



(a) Scenario 1: High fixed load.



(b) Scenario 2: Low fixed load.

Fig. 3 Input-data for the two scenarios considered in the stochastic example

4.2.1 Input data

Input data for the stochastic cases is provided in Table 3. Demand data representing 1000 m^2 of apartments is generated according to the methodology presented in [31]. We cluster the data into two representative days, or scenarios, by applying a hierarchical clustering algorithm. The algorithm minimizes the distance between two days using PV generation, demand, and electricity price for each hour of the day as observations. The scenario-dependent information, presented in Fig. 3, is: (1) load profile for fixed demand, (2) PV generation, and (3) power market prices. Furthermore, we assume that a current interconnection capacity of 25 kW exists, and that is is not possible to increase the interconnection capacity. Scenario 1 has an overall higher load than scenario 2 for consumer 1. Also, there is a significant variation of the fixed demand within the day. Therefore, to avoid load curtailment, it is preferable for the DSO if consumer 2 perform the EV charging when consumer 1 has a low load.

4.2.2 Results

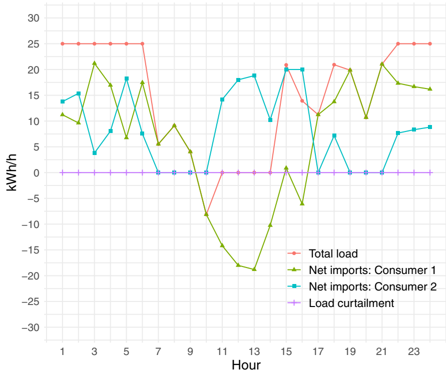
Computationally, the main difference compared to the illustrative example is that more than one scenario is considered. When increasing the number of scenarios, the computational burden increases because some decisions at the upper level are nonanticipative. Hence, even though the lower-level problems are completely scenario dependent, the overall bilevel problem can not be directly decomposed by the individual scenarios.

Figures 4 and 5 provide information about the operational decisions in scenario 1 with a high fixed load and scenario 2 with a lower fixed load, respectively. Case MPEC-F, with a flat capacity-based tariff, gives a similar result as for the deterministic case since the flexible demand of consumer 2 is simply divided by the number of hours in the day to give the minimum charging capacity during each time step. This operational pattern can be observed in Fig. 4b, where the total load exceeds the interconnection capacity during some time steps. Therefore, with 200 kWh of charging during the day, the flexible load is 8.33 kWh for each hour. This results in load curtailment when the fixed demand is above 16.67 kWh per time step since the total capacity of 25kW would be exceeded. This occurs in scenario 1, but not in scenario 2 as the fixed load of consumer 1 is low enough to allow for 8.33 kWh of charging during all time steps. Another observation is that during the middle of the day, the PV system at consumer 1 produces significant amounts of electricity by PV, which could be directly used for EV charging at consumer 2. However, due to the flat tariff structure, consumer 2 does not have any incentives to try to shift charging to these hours.

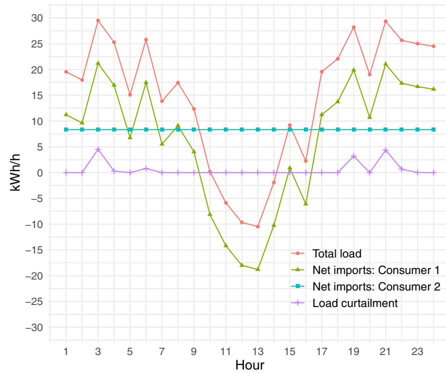
Some key results are provided in Table 4. It can be observed that total costs for cases MPEC-P and MPEC-PN comes close to the theoretically optimal result in case SO. The difference between MPEC-P and MPEC-PN is that in MPEC-P, the DSO can select off-peak hours for each scenario individually, whereas for MPEC-PN, the off-peak hours have to be equal for all scenarios. Similiarly to the illustrative example, we observe that the volumetric tariff (vnt) is set to zero in all cases since the DSO is unable to use the volumetric tariff for providing efficient incentives. In the case of a cost-recovery criterion for the DSO, the volumetric tariff could be used for the purpose of collecting residual costs.

Operational patterns for case MPEC-P in scenario 1 is provided in Fig. 4c. We see that in contrast to case MPEC-F, the load for consumer 2 changes over time as a response to the off-peak periods set by the DSO. As a result, load curtailment is completely avoided since consumer 2 is incentivized to consume as much as possible when consumer 1 produce significant amounts of electricity from the PV system.

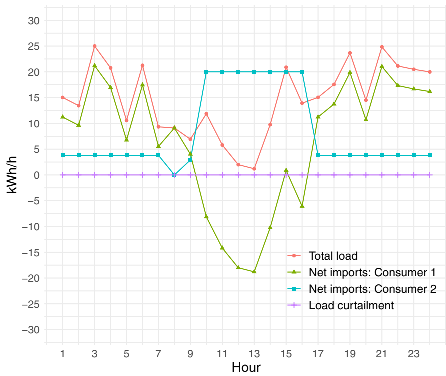
Having off-peak hours depend on the scenario might be unrealistic in practice due to the added complexity and need for frequently communicating the off-peak hours to the end-users. Therefore, Case MPEC-PN ensures that off-peak hours need to be equal for all scenarios by adding nonanticipativity constraints to the off-peak period selection.



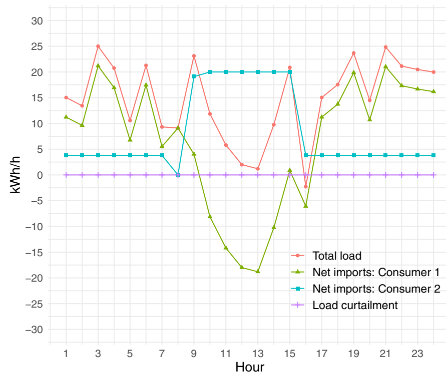
(a) Case SO: Operation pattern in the system optimal solution.



(b) Case MPEC-F: Operational pattern with flat capacity-based tariff.



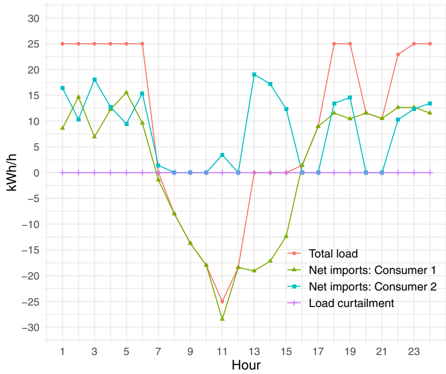
(c) Case MPEC-P: Operational pattern with capacity-based tariff and scenario dependent off-peak period selection.



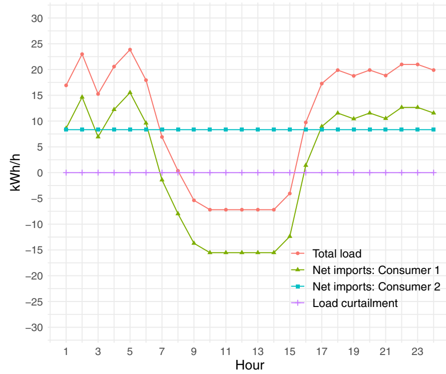
(d) Case MPEC-PN: Operational pattern with capacity-based tariff and scenario independent off-peak period selection.

Fig. 4 Stochastic example: operational decisions in scenario 1

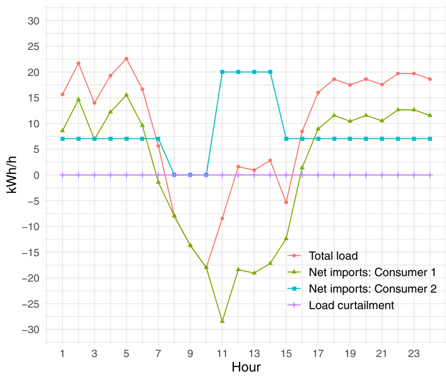
The nonanticipativity constraint alters the operational patterns slightly as shown in Figs. 4d and 5d, but the overall benefit of including off-peak periods is intact. It should be noted that to simplify the examples, we consider the off-peak periods as a binary variable. In practical applications, a DSO might want to employ this in a partial way, by allowing a limited amount of extra capacity usage during certain hours with a low grid load. This way, potential issues related to rebound effects of load shifting can be reduced.



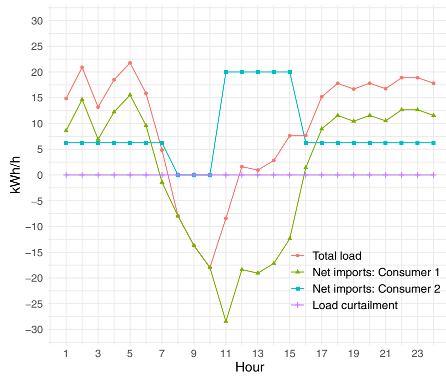
(a) Case SO: Operation pattern in the system optimal solution.



(b) Case MPEC-F: Operational pattern with flat capacity-based tariff.



(c) Case MPEC-P: Operational pattern with capacity-based tariff and scenario dependent off-peak periods.



(d) Case MPEC-PN: Operational pattern with capacity-based tariff and scenario independent off-peak periods.

Fig. 5 Stochastic example: operational decisions in scenario 2

Table 4 Case study: key results

	SO	MPEC-F	MPEC-P	MPEC-PN
Total costs (EUR)	5850	10875	5949	5969
Cost change	0%	+85.9%	+1.7%	+2.0%
Curtailment (kWh)	0	1594	0	0
cnt (EUR/kW-day)	NA	0.13699	0.06743	0.07154
vnt (EUR/kWh]	NA	0	0	0
Optimality gap	Optimal	0.05%	1%	1%
CPU time	< 1 min	< 1 min	11.3 h	13.6 h

5 Conclusions

In this paper, a methodology for optimal grid tariff design under decentralized decision-making is presented. The presented bilevel model include a realistic formulation of the interaction between the end-user and distribution system operator. Uncertainty is included in the form of scenarios for fixed demand, PV generation, and electricity market prices. In addition, a centralized decision-making model is provided for benchmarking of the various tariff schemes.

An illustrative example to highlight the model features in a deterministic setting and a stochastic case study is presented. The case studies describes how flexible consumers can be incentivized to change their consumption patterns to reduce overall power system costs. By including off-peak periods, the flexible consumer can effectively be incentivized to shift the charging to off-peak hours and hours with significant PV generation available at the local level. In contrast, a flat capacity-based tariff structure is not able to provide efficient incentives for load shifting.

Therefore, it can be concluded that in light of flexible end-users the electricity network tariff scheme should include a time-dependent capacity-based component such as partial or full off-peak hours to provide efficient incentives for load shifting.

The presented model is tractable, but computationally expensive. Despite this limitation, the model is a novel application of the MPEC formulation, tailored to investigating electicity grid tariffs under decentralized decision-making and uncertainty. Further work is needed to speed up the calculations when increasing the amount of scenarios.

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Appendix: Nomenclature

This appendix defines the mathematical symbols used in the model.

Sets

$c \in [c1, \dots, C]$ Consumers

$s \in [s1, \dots, S]$ Scenarios

$h \in [h1, \ldots, H]$ Hours

Parameters

A	Time horizon considered (days)
$D_{c,s,h}$	Fixed load at consumer c in scenario s and time step h (kWh/h)
$D^{\Delta-}_{c,s}$	Flexible load at consumer c in scenario s (kWh)
D^{MAX}_{c}	Peak electricity load at consumer c (kWh/h)
F^{G}	Existing transmission capacity (kW)
$G_{c,s,h}$	Availability of PV at consumer c in scenario s and hour h (kWh/h/kW)
L^{G}	Transmission losses (%)
NM	Net metering coefficient
$P_{s,h}$	Power market price in scenario s and hour h (EUR/kWh)
T	Electricity tax (EUR/kWh)
$U^{\Delta+}_{c,s,h}$	Flexible load limit at consumer c in scenario s and hour h (kW)
U^{PV}_{c}	Installed capacity of PV at consumer c (kW)
VAT	Value-added tax (%)
VLL	Cost of load curtailment for DSO (EUR/kWh)
W_s	Weight for each scenario

Upper-level variables

cnt	Capacity-based network tariff (EUR/kW-day)
$e^{G}_{s,h}$	Total grid load in scenario s and hour h (kWh/h)
$ls_{s,h}$	Load curtailment in scenario s and hour h (kWh/h)
$op_{s,h}$	Off-peak variable determined by DSO in scenario s and hour h
vnt	Volumetric network tariff (EUR/kWh)

Lower-level variables

$c^{G}_{c,s}$	Grid capacity subscribed at consumer c in scenario s (kW)
$d^{\Delta+}_{c,s,h}$	Flexible load at consumer c in scenario s and hour h (kWh/h)
$e^{I}_{c,s,h}$	Energy imported from grid at consumer c in scenario s and hour h (kWh/h)
$e^{E}_{c,s,h}$	Energy exported to grid at consumer c in scenario s and hour h (kWh/h)
$g_{c,s,h}$	Electricity generation from PV at consumer c in scenario s and hour h (kWh/h)

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Helping end-users help each other: Coordinating development and operation of distributed resources through local power markets and grid tariffs

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ABSTRACT

There is an ongoing transition in the power system towards an increasing amount of flexible resources and generation technologies at the distribution system level. An appealing alternative to facilitate efficient utilization of such decentralized energy resources is to coordinate the power at the neighbourhood level. This paper proposes a game-theoretic framework to analyze a local trading mechanism and its feedback effect on grid tariffs under cost recovery conditions for the distribution system operator. The novelty of the proposed framework is to consider both long-term and short-term aspects to evaluate the socio-economic value of establishing a local trading mechanism. Under our assumptions, the main finding is that the establishment of local electricity markets can decrease the total costs by facilitating coordination of resources and thus create higher socio-economic value than the uncoordinated solution. Furthermore, a sensitivity analysis on the tariff levels reveals that there are two equilibrium solutions, one where the grid costs are exactly balanced by tariff income and one where the neighbourhood decides to disconnect from the larger power system. These results indicate that although a local trading mechanism can reduce the need for grid capacity, it may not be cost optimal for neighbourhoods to become completely self-sufficient.

1. Introduction

One of the fundamental issues in power system economics is the potential of market failure due to a lack of demand-side elasticity (Stoft, 2002). At the distribution grid level, inelastic demand means that real-time control problems have traditionally been resolved at the grid infrastructure planning stage so that capacity is robustly adequate to cover the peak load (Strbac, 2008). However, there is an ongoing transition within power system development due to an increasing amount of flexible resources at the distribution grid level (Eid et al., 2016).

The price-responsiveness from end-users increase because of two fundamental drivers: (1) the information available to the end-users is increasing due to deployment of smart metering technologies, and (2) increased deployment of electricity as an energy carrier for potentially flexible demand types. Smart meters are currently being deployed throughout Europe, enabling hourly or sub-hourly billing of electricity consumption (Zhou and Brown, 2017). Such price variations can induce a change in consumption patterns if flexible energy resources such as smart management of heating systems and electric vehicle (EV) charging are available (Faruqui et al., 2010; Salpakari et al., 2017; Knezović et al., 2017).

An appealing alternative to facilitate efficient utilization of decentralized energy resources (DERs) is to balance the power at the neighbourhood level (Heinisch et al., 2019). However, as described in Askeland et al. (2019), the current regulatory framework in Norway and several other countries may not facilitate efficient decentralized decision-making when multiple stakeholders are involved.

This paper uses a game-theoretic framework to investigate a local trading mechanism, and its feedback effect on grid tariffs under cost recovering conditions for the distribution system operator (DSO) in a neighbourhood context. An equilibrium model comprising two levels is developed to study the efficiency of current and prospective pricing mechanisms. Also, a system optimization model serves as a benchmarking tool.

Abbreviations: **DER**, Distributed Energy Resources; **DSO**, Distribution System Operator; **ER**, 'Energy resources' agent group; **EV**, Electric Vehicle / 'Electric vehicle charging facility' agent group; **KKT**, Karush-Kuhn-Tucker; **LM**, 'Local market' case study; **MCP**, Mixed Complementarity Problem; **MPEC**, Mathematical Program with Equilibrium Constraints; **NOLM**, 'No local market' case study; **P2P**, Peer-to-peer; **RB**, 'Residential buildings' agent group; **SK**, 'Combined school and kindergarten' agent group; **SO**, 'System optimization' case study; **ZEN**, Zero Emission Neighbourhood.

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The remainder of this paper is organized as follows. In section 2 we provide a survey of related literature. The modeling framework is presented in section 3. The data used for a case study is presented in section 4. Section 5 presents results from the case study before conclusions are drawn in section 6.

2. Literature review

An adaptation of electricity grid pricing mechanisms is increasingly being addressed in the scientific literature. This paper is at the intersection between two related research topics, namely electricity grid tariff design and local electricity markets.

Electricity grids are natural monopolies due to economies of scale. Traditionally, the DSO is the sole owner of the electricity grid in a given area and passes the costs on to the end-user as fixed and volumetric grid tariffs (Eid et al., 2014). However, the current tariff structures can create distorted incentives for end-users to invest excessively in DERs (Eid et al., 2014; Pollitt, 2018). Capacity-based tariffs are being proposed as a prospective solution since it will be a better representation of the upstream grid costs and create an incentive to reduce the peak load (Simshauser, 2016). However, a reduction of individual peaks may not always be effective at reducing aggregate peak load (Backe et al., 2020), and several scholars suggest that the potential welfare gains from capacity-based tariffs can be limited (Passey et al., 2017; Brown and Sappington, 2018). In this context, we contribute to the literature by investigating how a combination of grid tariffs and local markets can provide incentives for efficient development and operation of the distribution grid.

There exists a rather large body of literature related to investigating the impact of various tariff schemes on specific end-user groups, see e.g. Kirkerud et al. (2016); Parra and Patel (2016); Bergaentzlé et al. (2019); Sandberg et al. (2019); Pinel et al. (2019); Backe et al. (2020). These studies investigate how the business case and decisions of different types of agents are affected by changes in the tariff structure. Our paper differs from this line of research because we consider the electricity grid tariffs as a modeling result in a bilevel approach rather than an input to a single level optimization problem.

Our work considers the interaction between the distribution network level and the end-users under cost recovery conditions for the DSO. In this regard, the approach of this paper is related to the research summarized in Table 1. However, some distinct differences can be pointed out since our research also include the interaction between agents at the local level through a local market mechanism. Besides, we consider grid investments and operation as a function of the aggregate neighbourhood load.

Interaction between agents at the local level can be achieved through 'peer-to-peer' (P2P) trading or other forms of local market mechanisms (Sousa et al., 2019). In Zhang et al. (2018) the authors analyze P2P trading for matching inflexible local generation with flexible demand in a microgrid, and they find that the trading triggers peak load reduction. Almenning et al. (2019) also analyzes P2P trading in a neighbourhood focusing on trading in response to a subscribed grid tariff, and they also find that P2P trading triggers a reduction of high loads. Lüth et al. (2018) focuses on the role of batteries in P2P trading, and their results highlight economic viability from an end-user perspective. None of these studies (Zhang et al., 2018; Almenning et al., 2019; Lüth et al., 2018) consider a reaction by the DSO (i.e., adjustment of the grid capacity) as a consequence of trading in a neighbourhood.

The properties of the problem addressed in this paper are consistent with non-cooperative Stackelberg-type games (Von Stackelberg, 2010), which are characterized by a leader who moves first and one or more followers acting optimally in response to the leader's decisions. Games with a Stackelberg structure can be formulated as mathematical programs with equilibrium constraints (MPECs) (Luo et al., 1996). This is the case for Zugno et al. (2013), Momber et al. (2016), Schittekatte and Meeus (2020), and Askeland et al. (2020) who formulate MPECs to investigate the effect of indirect load control. In this paper, we use an iterative procedure to solve the set of non-linear equations similar to Schittekatte et al. (2018), Hoarau and Perez (2019), Askeland and Korpås (2019), and Abada et al. (2020). The reason for choosing this procedure instead of an MPEC approach is that an iterative procedure has computational advantages over an MPEC formulation, which would severely impact our tractable problem size. Furthermore, there is no need for an MPEC formulation since the grid tariff structure we consider can effectively be handled by an iterative procedure based on cost recovery rules for the DSO. We formulate the neighbourhood equilibrium as a complementarity problem (Gabriel et al., 2012). A complementarity problem is the combination of the Karush-Kuhn-Tucker (KKT) conditions (Kuhn and Tucker, 1951) of all agents, which are being solved simultaneously to derive the equilibrium. Complementarity modeling is particularly useful for power market modeling since the introduction of dual variables in the model formulation allows for market interactions between agents to be formulated directly. More details on complementarity modeling for energy modeling purposes can be found in Gabriel et al. (2012). The complementarity formulation for the neighbourhood level allows for interaction between agents within the neighbourhood level and enables an investigation of local electricity markets without introducing the computational difficulties of an MPEC formulation.

To summarize, this paper brings together two related bodies of literature by considering both grid tariff design and a local market mechanism in a consistent modeling approach. Furthermore, the proposed approach allows for local markets to be coupled to existing market structures and allow consumers to choose which market to trade in. No prior works that consider local markets and its feedback effect on grid development and grid tariffs have been identified, and we aim to contribute to closing this gap in the literature.

3. Method

This section presents the game-theoretic setup that has been developed. First, the optimization problems of the agents in the neighbourhood and the DSO are presented. Thereafter, the solution procedure for coupling the two levels are described before the input data

Table 1
Related research on indirect load control.

Reference	Tariff calculation	Grid costs considered	Interaction between agents
Zugno et al. (2013)	MPEC	No	Retailer - consumer
Momber et al. (2016)	MPEC	No	Aggregator - EV consumer
Schittekatte et al. (2018)	Iterative procedure	Sunk	DSO - consumer
Hoarau and Perez (2019)	Iterative procedure	Sunk	DSO - consumer
Askeland and Korpås (2019)	Iterative procedure	Prospective	DSO - consumer
Abada et al. (2020)	Iterative procedure	Sunk	DSO - community
Schittekatte and Meeus (2020)	MPEC	Prospective	DSO - consumer
Askeland et al. (2020)	MPEC	Sunk	DSO - consumer
This paper	Iterative procedure	Prospective	DSO - consumer and between consumers

for the case study is presented. In the presented model, the following core assumptions are made:

- Grid charges only apply to electricity purchased from the wholesale power market and not on locally traded electricity. Since locally traded electricity is balanced locally at each time step, the local trade does not contribute to the capacity-based charge.
- We assume that there is sufficient grid capacity within the local system. Therefore, only the connection between the neighbourhood and the larger power system is constrained.
- We assume that the DSO can not choose to curtail load or generation. Hence, it is necessary to build sufficient capacity to cover the peak network usage. Although the economics concerning load or generation curtailment is outside the scope of this paper, this is an aspect that could be considered in further work.

3.1. Model overview

An outline of the model is presented in Fig. 1. The structure is a bilevel model where some decisions are made on the DSO level while others occur on the neighbourhood level. We consider the DSO as the leader in the Stackelberg game since it sets the grid tariff rates while the end-user agents responds to the tariff determined by the DSO. Decision variables at one level are perceived as parameters for the other level. One example is the level of grid tariffs, which is determined based on cost recovery criteria on the DSO level but perceived as parameters by the agents at the neighbourhood level. The benefit of this bilevel structure in our modeling framework is the ability to analyze the feedback effect between neighbourhood response, coordination, DSO strategy, and regulatory framework. Appendix A provides an overview of mathematical symbols and describes how the parameters and variables relates to each level in the overall model.

3.2. Neighbourhood level

In this section, the problem of the individual agent in the neighbourhood is described as an optimization problem. The agents can be of different types: customer with inflexible load, prosumer, EV charging facility, owner of a power plant and grid storage, or a combination of these. The model formulation presented in this section allows for all of these types of agents to be represented through different parameter settings.

Since the optimization problems for the agents in the neighbourhood are linear, their KKT conditions are both necessary and sufficient for global optimality (Kuhn and Tucker, 1951). Hence, to allow for the modeling of a local market mechanism, the optimization problems for the agents in the neighbourhood are represented through their KKT conditions, which are formulated as a mixed complementarity problem (MCP) in Appendix B. We indicate dual variables associated with each of the constraints. These dual variables are used in the MCP formulation of the problem.

3.2.1. Objective function of neighbourhood agents

The objective of the neighbourhood agents is to minimize their individual costs according to (1a). Details of the cost components are described in (1b) - (1f). These costs consist of investments in storage and energy resources ($Cost_c^N$), energy from the power market ($Cost_c^P$), energy from the local market ($Cost_c^L$), electricity taxes ($Cost_c^T$), and grid charges ($Cost_c^G$). The grid charges apply to energy purchased from the

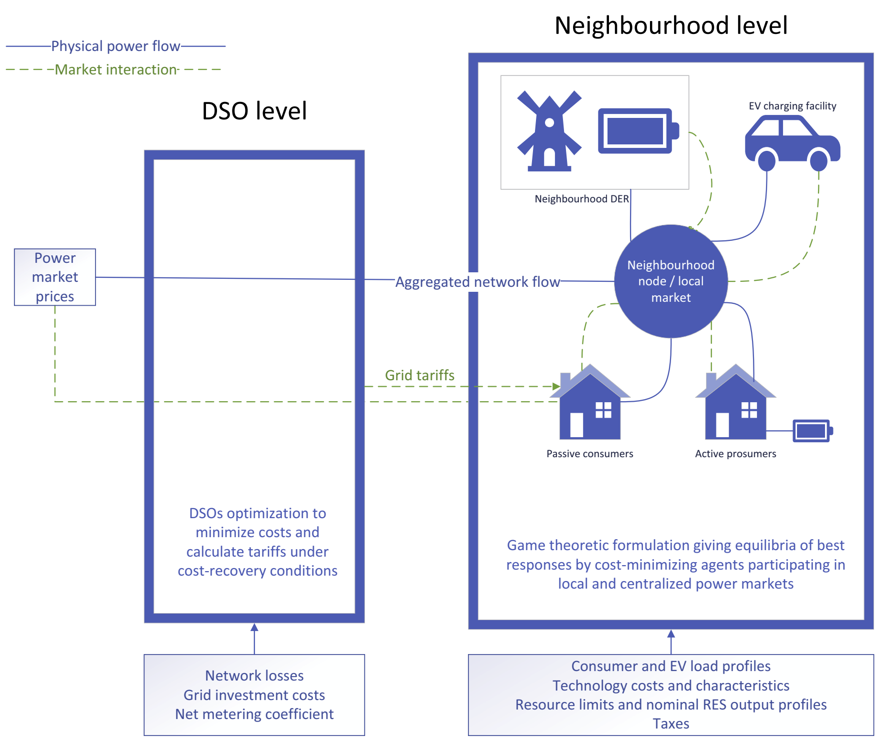


Fig. 1. Outline of the model structure.

power market, but not to locally traded energy. The actual grid costs are not considered directly at the building level since these costs are imposed indirectly through the grid tariffs (*vnt* and *cnt*).

$$Min: Cost_c = Cost_c^N + Cost_c^P + Cost_c^L + Cost_c^T + Cost_c^G \tag{1a}$$

$$Cost_c^N = I_c^S * c_c^S + I_c^E * c_c^E \tag{1b}$$

$$Cost_c^P = \sum_{h=1}^{H} W_h * \left(imp_{c,h}^P - exp_{c,h}^P\right) * \lambda_h^P \tag{1c}$$

$$Cost_c^L = \sum_{h=1}^{H} W_h * \left(imp_{c,h}^L - exp_{c,h}^L\right) * \lambda_h^L \tag{1d}$$

$$Cost_c^T = \sum_{h=1}^{H} W_h * \left(imp_{c,h}^P + imp_{c,h}^L\right) * T \tag{1e}$$

$$Cost_c^G = \sum_{h=1}^{H} W_h * \left(imp_{c,h}^P - NM * exp_{c,h}^P\right) * vnt + c_c^G * cnt \tag{1f}$$

In these equations, W_h denotes the scaling factor to provide operational costs on an annual basis. To represent annual costs the scaling factor takes the value $W_h = \frac{8760}{H}$ for hourly time-steps.

3.2.2. Energy balance

The energy balance of the agents is described by (2) and states that energy imports subtracted exports must be equal to fixed and flexible demand subtracted generation from PV at each agent.

$$\begin{aligned} & D_{c,h} + d_{c,h}^{\Delta+} - d_{c,h}^{\Delta-} - g_{c,h}^E \\ & = imp_{c,h}^P - exp_{c,h}^P + imp_{c,h}^L - exp_{c,h}^L \ \forall c, h \quad \left(\lambda_{c,h}^{EB}\right) \end{aligned} \tag{2}$$

The agents can trade both with the local and centralized electricity markets to satisfy their energy balance.

3.2.3. Battery charge level

A battery makes it possible to shift energy load temporally. This temporal load shifting is represented in (3), which describes how the charge level depends on the charge level in the previous time step and on the battery operation. Converter losses are imposed through the parameter L_c, while self-discharge of the battery from one time-step to the next is imposed through the parameter R_c.

$$\begin{aligned} & s_{c,h} = s_{c,h-1} * (1 - R_c) \\ & + d_{c,h}^{\Delta+} * (1 - L_c^S) - d_{c,h}^{\Delta-} * (1 + L_c^S) - D_{c,h}^{\Delta-} \ \forall c, h > 1 \ (\lambda_{c,h}^{S1}) \end{aligned} \tag{3}$$

The battery formulation allows for the representation of both a bidirectional battery which can store electricity for later use and unidirectional EV charging. In the case of EV charging, the parameter $D_{c,h}^{\Delta-}$ represents the energy used for EV driving needs.

We specify boundary conditions for the battery charge level as described in (4). This means that the charge level in the last time-step is linked to the first time step. Thereby, we do not need to specify the initial charge level since the optimization model calculates it.

$$\begin{aligned} & s_{c,1} = s_{c,H} * (1 - R_c) \\ & + d_{c,1}^{\Delta+} * \left(1 - L_c^S\right) - d_{c,1}^{\Delta-} * \left(1 + L_c^S\right) - D_{c,1}^{\Delta-} \ \forall c \quad \left(\lambda_{c,1}^{S1}\right) \end{aligned} \tag{4}$$

Potentially, this formulation can result in simultaneous charge and discharge during the same time step. However, positive converter losses and energy costs will prevent this from occurring due to the associated costs.

3.2.4. Storage capacity

The agent decides the storage capacity to be installed, so the case that the economic benefit of having an additional unit of storage exceeds the investment costs will trigger additional investments. However, a maximum limit on battery storage capacity can be imposed according to (5). In order to represent agents without investment options, the maximum capacity limit can be set to zero.

$$c_c^S \le U_c^S \ \forall c \quad \left(\mu_c^{S2}\right) \tag{5}$$

Furthermore, the amount of energy that can be stored and the installed storage capacity limits the converter capacities according to (6)–(8). In the case of unidirectional EV charging, the discharging power factor (P_c^{dis}) can be set to zero. Note that the model is also capable of handling vehicle-to-grid directly, but this is out of the scope of this paper.

$$s_{c,h} \le c_c^S \ \forall \ c, h \quad \left(\mu_{c,h}^{S3}\right) \tag{6}$$

$$d_{c,h}^{\Delta+} \le c_c^S * P_c^{ch} \ \forall \ c, h \quad \left(\mu_{c,h}^{S4}\right) \tag{7}$$

$$d_{c,h}^{\Delta-} \le c_c^S * P_c^{dis} \ \forall \ c, h \quad \left(\mu_{c,h}^{S5}\right) \tag{8}$$

3.2.5. Measured peak power

Measured peak power at each end-user is equal to the maximum power injected to or withdrawn from the wholesale power market according to (9). Although the maximum load usually occurs as a result of an import situation, we also account for situations where the peak power is defined by exports to the grid. This means that we assume a grid tariff scheme where the agents have to pay a capacity-based grid tariff for their measured peak power for the whole period considered.

$$imp_{c,h}^P + exp_{c,h}^P \le c_c^G \ \forall \ c, h \quad \left(\mu_{c,h}^G\right) \tag{9}$$

Note that electricity traded in the local market do not influence the agent's peak power since any electricity sold locally also has to be consumed by the other agents at the local level.

3.2.6. Energy resource capacity and generation

Similar to energy storage, the agent can invest in energy resources such as rooftop PV. A limit, for example due to limited rooftop area, can be imposed according to (10). This value can also be set to zero if the agent cannot invest in energy resources due to factors outside the modeling framework.

$$c_c^E \le U_c^E \ \forall \ c \quad \left(\mu_c^{E1}\right) \tag{10}$$

Electricity generation, $g_{c,h}^E$, is described by (11) and has the option of generation curtailment, by generating below the limit given by the resource availability. The maximum output is the nominal generation each time-step multiplied with the installed capacity. Hence, the nominal generation is specified according to e.g., wind or solar conditions.

$$g_{c,h}^E \le c_c^E * G_{c,h}^E \ \forall \ c, h \quad \left(\mu_{c,h}^{E2}\right) \tag{11}$$

3.2.7. Local energy market

The local exports must equal the local imports according to (12). We assume that there are no grid constraints at the local level, making trading with the neighbours an alternative to purchasing energy from the grid.

$$\sum_{c=1}^{C}\left(imp_{c,h}^{L}-exp_{c,h}^{L}\right)=0\ \forall\ h\quad\left(\lambda_{h}^{L}\right) \tag{12}$$

Note that this is the equilibrium condition in the neighbourhood. The dual value of this constraint becomes the market price in the local energy market. The local market price is the value of energy at the local level, considering both short-term operation and long-term investments.

3.3. DSO level

The DSO level describes the optimization problem of the DSO in a regulatory context. In this problem, the decisions at the neighbourhood level regarding investments, operation, and trading in the local and wholesale markets are perceived as parameters outside the DSOs control. Based on the aggregate neighbourhood-level decisions, grid capacity investments and tariff levels are optimized.

3.3.1. Objective function of the DSO

The objective of the DSO is to minimize the grid costs, as formulated in (13a). With the DSO as a perfectly regulated leader, the DSOs goal would be welfare maximization by reducing the combined costs of the DSO and all the end-user agents. However, in our modeling framework the DSO considers the end-user agent decisions as parameters and therefore only the DSOs costs are considered by the DSO. This has a close resemblence to how DSOs are currently regulated in Norway[1] since the regulator defines a maximum income and the self-interest pursuing DSO is incentivized to reduce costs in order to increase profits. The costs faced by the DSO consist of investment costs and variable costs. Potential sunk costs are assumed to be collected through a fixed annual fee independent of this optimization problem. Since the DSO has no decisions related to the sunk costs, these are not included in the objective function.

$$Min:\ Cost_{DSO}=Cost_{DSO}^{N}+Cost_{DSO}^{V} \tag{13a}$$

$Cost_{DSO}^{N}$ is the investment cost for additional grid capacity and consists of the amount of capacity multiplied with annualized investment costs as described in (13b). The DSOs variable costs, $Cost_{DSO}^{V}$, consist of linear network losses, according to (13c).

$$Cost_{DSO}^{N}=I_{DSO}^{G}*c_{DSO}^{G} \tag{13b}$$

$$Cost_{DSO}^{V}=\sum_{h=1}^{H}W_{h}*e_{h}^{G}*L^{G}*\lambda_{h}^{P} \tag{13c}$$

3.3.2. Neighbourhood load

Given that some neighbourhood agents might export to the power market while others import from it, these individual flows are aggregated for each time step to calculate the total net electricity flow in to or out from the neighbourhood. Therefore, the electricity flow to/from the neighbourhood is the absolute value of the aggregate trading with the power market. To maintain the linear properties of the problem, the network imports are represented by (14) while exports are represented by (15). Only one of these terms will have a nonzero value at each time step and the total electricity transmission is calculated in (16). This formulation is valid as long as power market prices are non-negative since the transmission of electricity is penalized in the objective function due to the associated losses.

[1] https://www.nve.no/norwegian-energy-regulatory-authority/economic-regulation/

$$e_{h}^{GI}\geq\sum_{c=1}^{C}\left(imp_{c,h}^{P}-exp_{c,h}^{P}\right)\ \forall h \tag{14}$$

$$e_{h}^{GE}\geq\sum_{c=1}^{C}\left(exp_{c,h}^{P}-imp_{c,h}^{P}\right)\ \forall h \tag{15}$$

$$e_{h}^{G}=e_{h}^{GI}+e_{h}^{GE}\ \forall h \tag{16}$$

Note that the electricity trade within the local market is not a part of the DSOs consideration since the supply and demand remain within the neighbourhood level.

3.3.3. Grid capacity

The DSO needs to ensure enough capacity for the transmission of electricity, as described in (17). The network capacity consists of already built infrastructure given exogenously, and investments in infrastructure. We assume that the DSO do not have the option of curtailment as an alternative to building grid capacity.

$$C_{DSO}^{G}+c_{DSO}^{N}\geq e_{h}^{G}\ \forall h \tag{17}$$

3.3.4. Grid tariff calculation

Based on the optimization, the DSO also calculates the resulting grid tariffs according to (18) for the volumetric tariff $\left(\frac{EUR}{kWh}\right)$and (19) for the capacity-based tariff $\left(\frac{EUR}{kW}\right)$. Here, it is assumed that the DSO will recover the variable costs through the volumetric tariff and investment costs through the capacity-based tariff. For simplicity, and since the aim is to investigate the economic feasibility of substituting grid capacity with local flexibility, we do not include sunk cost recovery. Sunk cost recovery is a topic that has been extensively considered in Schittekatte et al. (2018) and Hoarau and Perez (2019).

$$vnt=\frac{Cost_{DSO}^{V}}{\sum_{c=1}^{C}\sum_{h=1}^{H}W_{h}*\left(imp_{c,h}^{P}-NM*exp_{c,h}^{P}\right)} \tag{18}$$

$$cnt=\frac{Cost_{DSO}^{N}}{\sum_{c=1}^{C}c_{c}^{G}} \tag{19}$$

Note that with this formulation, all the DSOs costs are recovered through the tariff income from the neighbourhood agents. Cost recovery at the DSO level means that cost differences in the resulting cases are due to the effect of regulations on system costs and not because of grid tariff avoidance. Therefore, this setup, with all the DSOs costs recovered by the tariff income, enables a holistic investigation of tariff design in combination with local energy markets.

3.4. Solution approaches

Even though the physical properties of the system are the same, the different decision-making assumptions require different solution approaches. Both a centralized optimization and a game-theoretic equilibrium is computed to assess the efficiency of various pricing mechanisms. The main difference between these approaches lies in the decision-making assumptions. For the system optimization, it is assumed that all investment and operational decisions on both the DSO and the neighbourhood agent level are made by one entity. Such a system optimal solution provide the theoretically best outcome in terms of total costs, but the assumption that agent decisions (such as DER investments and operation) can be controlled centrally is not valid in a market context since such choices are up to the individual agents. Contrary to system optimization, the game-theoretic equilibrium approach allows for decentralized decision-making by the individual agents and the DSO. Decentralized decision-making requires modeling of the pricing mechanism between the agents such as grid tariffs and local market prices.

3.4.1. Centralized optimization

For the centralized optimization, all the direct costs on both the DSO and neighbourhood agent levels are combined in one objective function, as described in (20).

$$Min: \ Cost_{DSO} + \sum_{c=1}^{C} \left(Cost_c^N + Cost_c^P + Cost_c^T \right) \tag{20}$$

Furthermore, we include the technical constraints for the neighbourhood agents in (2)–(12) and for the DSO in (14)–(17). Note that we include the local market balance since it taxes energy transfer from one agent to another in the same way as the equilibrium. Furthermore, the grid tariff cost component is not included since the DSOs costs are considered directly instead.

The centralized optimization forms a single linear programming problem which is solved directly in GAMS with the CPLEX solver.

3.4.2. Decentralized decision-making

In the case of decentralized decision-making, we assume non-cooperative behaviour for all the agents in the model. Therefore, each agent optimizes their individual objective function and interact with the other agents through pricing mechanisms. Decentralized decisions require a game-theoretic equilibrium approach with two levels: (1) The DSO level, and (2) The neighbourhood agent level. The DSO level is solved by treating the variables of the neighbourhood agents as parameters and solving the optimization problem in section 3.3. The neighbourhood agent equilibrium requires a complementarity formulation due to the interaction between the agents in the local market. Therefore, the neighbourhood agent problem described in section 3.2 is represented by its KKT conditions formulated as MCP conditions in Appendix B.

Modeling of two levels requires a solution algorithm to iterate until convergence is reached. The convergence criterion is that the cost recovering grid tariffs do not change from one iteration to the next. The iterative solution algorithm presented in Fig. 2 is inspired by the procedure employed in Schittekatte et al. (2018) and can be described as follows:

1. Initialize the algorithm with starting tariff values (e.g., zero).
2. For the given tariffs, calculate the equilibrium of the neighbourhood level by solving the complementarity problem presented in Appendix B.
3. For the resulting grid transmission, solve the DSOs optimization problem presented in section 3.3.
4. For the given set of cost recovery tariffs, compare to previous tariffs and determine if change is lower than convergence tolerance.
5. If tariff convergence not reached: Update tariffs with decreasing step size and go to step 2.
6. If tariff convergence is reached: Equilibrium solution with DSO cost recovery found.

A decreasing step size is employed to ensure stable progress towards the equilibrium point. As we change the tariffs, the neighbourhood has a unique equilibrium for each set of grid tariffs since the KKT conditions are necessary and sufficient for optimality. An increase in grid tariffs gives the following effects:

- **DSO income effect 1:** A change in tariff levels will give a positive change on the tariff income per unit of capacity and electricity consumption.
- **DSO income effect 2:** A change in tariff levels will have a zero or negative effect on the contracted capacity and electricity consumption since grid usage might be substituted by something else.
- **DSO cost effect:** A change in tariff levels will give a zero or negative change in DSO costs since the grid usage will stay constant or be decreased when the cost of using grid capacity is increased.

Hence, because a change in tariff levels work in different directions, a change in tariff levels can give both a positive and negative change in DSO profits. Therefore, the model can potentially have several equilibrium solutions that satisfy the DSO cost recovery constraint. We do a tariff sensitivity analysis in section 5.4 that demonstrates the existence of two equilibrium points for the case considered in this paper. However, it should be noted that the existence of two equilibrium point in our analysis is not a general result since the DSO profit is a nonmonotone function of the grid tariffs. More details regarding the equilibrium tariffs and convergence of the model can be found in section 5.4.

The decentralized model is also implemented in GAMS and solved as a linear program with the CPLEX solver for the DSO level. The neighbourhood equilibrium is calculated by solving the complementarity formulation in Appendix B using the PATH solver. These models are solved iteratively until convergence is reached (see Fig. 2).

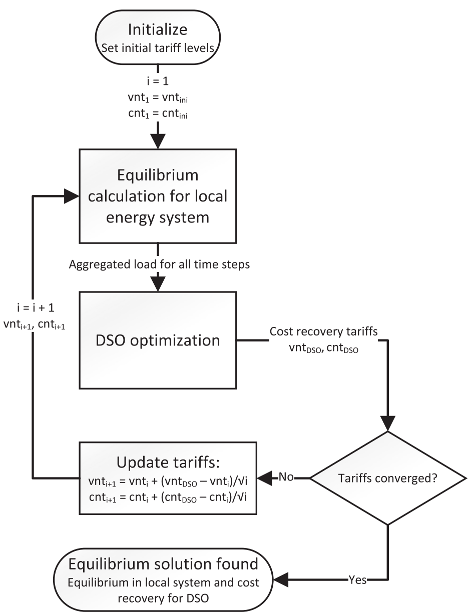


Fig. 2. Outline of equilibrium solution algorithm.

4. Case study

This section describes the input data used for the case study. The system we model is inspired by the Zero Emission Neighbourhood (ZEN[2]) pilot project called Ydalir.[3] Investment costs are represented through their annual payment costs with an interest rate of 5% and technology-specific lifetimes.

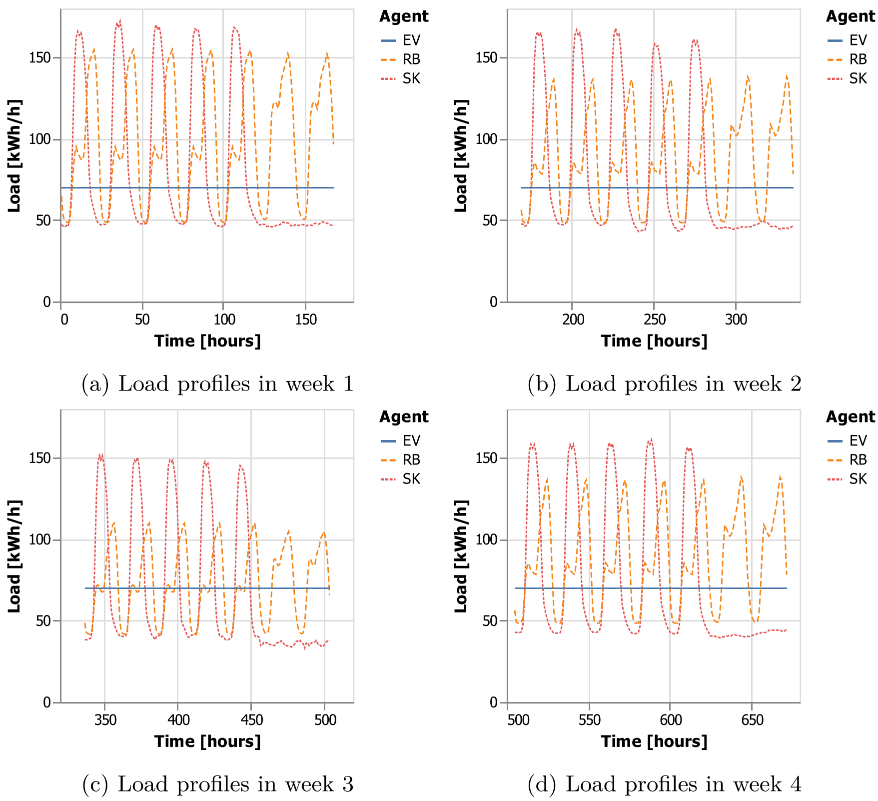
4.1. Agents and load profiles

Since the focus of this paper is on the interaction between agents with different characteristics under various regulatory frameworks, agents are categorized by five agent groups: Combined school and kindergarten (SK), residential buildings (RB), large scale energy resources

[2] https://fmezen.no/
[3] https://www.ydalirbydel.no/ydalir/

Table 2
Agents represented in the model.

Agent group	Load profile	Investment options	Flexible resources
Combined school and kindergarten (SK)	3000 m^2 kindergarten +7000 m^2 school	N/A	N/A
Residential buildings (RB)	20,000 m^2	Batteries and PV available	Battery operation and PV curtailment
Large scale energy resources (ER)	N/A	Batteries and PV available at lower cost	Battery operation and PV curtailment
EV charging facility (EV)	Charging of 200 EVs per day	N/A	Charging of EVs
Distribution system owner (DSO)	Aggregate load of neighbourhood agents	Grid capacity	N/A



(a) Load profiles in week 1

(b) Load profiles in week 2

(c) Load profiles in week 3

(d) Load profiles in week 4

Fig. 3. Load profiles for the neighbourhood agents.

(ER), EV charging facility (EV), and distribution system operator (DSO). An overview of the characteristics of each group can be found in Table 2.

Electricity load profiles for agents SK and RB have been generated based on the floor area according to the methodology presented in Lindberg et al. (2019). We generate four representative weeks for a year, one for each season. Regarding the demand for EV charging, a yearly driving distance of 14,000 km per vehicle is assumed.[4] Further, one electric car needs 0.2 kWh per km (Sørensen et al., 2018), so one car needs about $\frac{14{,}000}{365}*0.2 = 8$ kWh/day. For 200 EVs, we get a daily charging need of about 1,600 kWh/day. Based on these assumptions, a charging need of 70 kWh for each hour is specified for the EV agent. The load profiles for the neighbourhood agents are presented in Fig. 3.

The energy resource agent (ER) does not have any load profile specified but can invest in batteries and PV capacity to trade electricity with other neighbourhood agents or the power market. Lastly, the DSOs load profile is the aggregate load of all the other neighbourhood agent groups.

4.2. Technology costs and characteristics

In the modeled system, some of the agents can invest in technologies such as grid capacity, PV systems, and batteries. Also, the EV agent has inherent flexibility regarding when to charge the EVs.

The DSO is responsible for the grid capacity connecting the neighbourhood to the transmission network. For the regional grid in Norway, the transmission fee is approximately 50 €/kW of peak power measured at the point of the TSOs grid.[5] Furthermore, it is assumed that the DSOs costs are approximately equal to the transmission

[4] SSB, Road traffic volumes 2005–2018, https://www.ssb.no/en/statbank/table/12576/

[5] https://www.statnett.no/en/for-stakeholders-in-the-power-industry/tariffs/this-years-tariff. Accessed: 2020-10-07]

system cost per unit of capacity. This gives an assumed total cost of 100 €/kW of grid capacity, which is used for the case study. In general, grid costs are lumpy and vary depending on site-specific properties. However, since our interest is mainly regarding game-theoretic aspects of pricing mechanisms, this simplification is appropriate for investigating such fundamental pricing aspects. In our case study, all network capacity needs to be built. In addition to the investments, network losses are specified to 6%.

The Danish energy agency publish characteristics for a range of technologies including PV and batteries.[6] The technology costs for the ER agent is based on the general technology cost in 2020 where the utility-scale PV systems cost is 0.42 M€/MWp. Note that this cost level is very low in the context of neighbourhood-scale systems, but we use it to illustrate a situation where it is cost optimal for end-users to invest in PV systems. It can also be argued that this cost is realistic as a consequence of investment subsidies.[7] Using an interest rate of 5% and a lifetime of 20 years, this translates to an annual cost of 34 €/kWp for the ER agent. Large scale lithium-ion battery costs are currently around 150 €/kWh. Assuming a lifetime of 10 years for batteries and an interest rate of 5% gives an annual cost of 19 €/kWh for battery capacity.

It is assumed that because of economies of scale, small scale systems cost more than large scale ones per unit of capacity. A premium of 20% is therefore assumed for smaller systems, which in this example applies to the RB agent. Therefore, the annual PV cost is 40.8€/kWp, while annual battery costs are 22.8 €/kWh for the RB agent.

Converter losses are assumed to be 5% for batteries in both directions. Furthermore, the power/energy for batteries is assumed to be fixed at 0.5 kW/kWh. The self-discharge of batteries is assumed to be 0.1% per hour.

For the EV agent, we assume the flexibility associated with the charging of EVs is 8 hours by specifying an EV storage capacity of $70 * 8 = 560$ kWh. In addition, the charging capacity factor is set to 0.5 to allow for a charging capacity of up to 280 kW. No discharge to the grid is allowed by setting the discharging capacity factor to zero. EV charging losses are equal to the bi-directional batteries at 5%.

The nominal PV generation data is obtained from PVGIS[8] for the location of the Ydalir project. After PV-system losses, the annual PV generation is 779 kWh/kWp of installed capacity. Nominal PV generation for the four representative weeks is presented in Fig. 4.

4.3. Market price and regulatory assumptions

End-users can have different contracts ranging from spot price based contracts varying each time step to fixed price contracts. For simplicity, and in order to focus on the variability of load profiles and decentralized generation, the wholesale energy price is set to 0.05€/kWh for all time steps. For systems with large shares of energy communities, there might be an effect on the wholesale price, but this aspect is out of the scope of this work. This means that the time-varying input data is limited to the load profiles and PV generation.

Electricity consumption is usually subjected to taxes. In this paper, it is assumed that such a tax applies to power imports from both the wholesale power market and the local market and is specified to 1.6¢/kWh according to the current taxes on electric power in Norway.[9]

The grid tariffs are endogenous to the model, but it is necessary to specify the net metering coefficient exogenously. In this case study, the net metering coefficient has been set to zero, which means that only electricity imports are subject to the volumetric grid tariffs. This is in line with current practice in several countries, including Norway.

4.4. Regulatory frameworks

The analyses are based on three different cases:

1. **Case LM:** Assumes decentralized decision-making where the agents in the neighbourhood optimize their individual objective, but can trade with each other. The neighbourhood agents can also trade with the wholesale power market, and the DSO agent sets the grid tariffs for such trades based on cost-recovery conditions.
2. **Case NOLM:** Similiar to case LM, but local trades are not allowed. This situation is similar to current regulations in many countries.
3. **Case SO:** System optimization model used for benchmarking. All decisions are assumed to be made centrally to minimize the total system cost for the neighbourhood and the DSO as a whole. The system cost incorporates the grid costs directly in addition to costs for all neighbourhood agents. Grid costs are distributed evenly by dividing the total grid costs by the number of agents in the neighbourhood.

5. Results and discussion

5.1. Total system costs and resource allocation

First, we focus on the system as a whole under different regulatory frameworks. Fig. 5 provide information on total system costs and how these costs are distributed among the neighbourhood agents. The DSO is not represented explicitly as an agent in these figures since the grid costs are imposed on the neighbourhood agents through the grid fees. Since the grid costs are forwarded to the neighbourhood agents through the grid tariffs, the net costs for the DSO are zero. Furthermore, Table 3 provides more detailed information regarding costs, tariffs, and investments.

The total costs are lowest in the SO case, which provides a benchmark for the cases with decentralized decision-making. We use the SO case as a benchmark since it provides the optimal solution for the system as a whole when the aim is to minimize total costs. Hence, from an efficiency point of view, policies should aim to achieve a solution close to the SO solution under decentralized decision-making. Compared to the SO solution, we observe a cost increase of 1.2% for the LM case where local trading is allowed and 4.1% for the NOLM case where no trading occurs within the neighbourhood. In addition to the total cost decrease, the LM solution pareto-dominates the NOLM solution since no agent is worse off and some are better off when the local market is included. The grid capacity is the same for the LM and the SO cases, while it is significantly higher in the NOLM case. The fact that the LM case provides a system with the same grid capacity as in the SO case indicates that the combination of decentralized trading and a rather simple grid tariff scheme can impose the grid costs on end-users in a cost-reflective way.

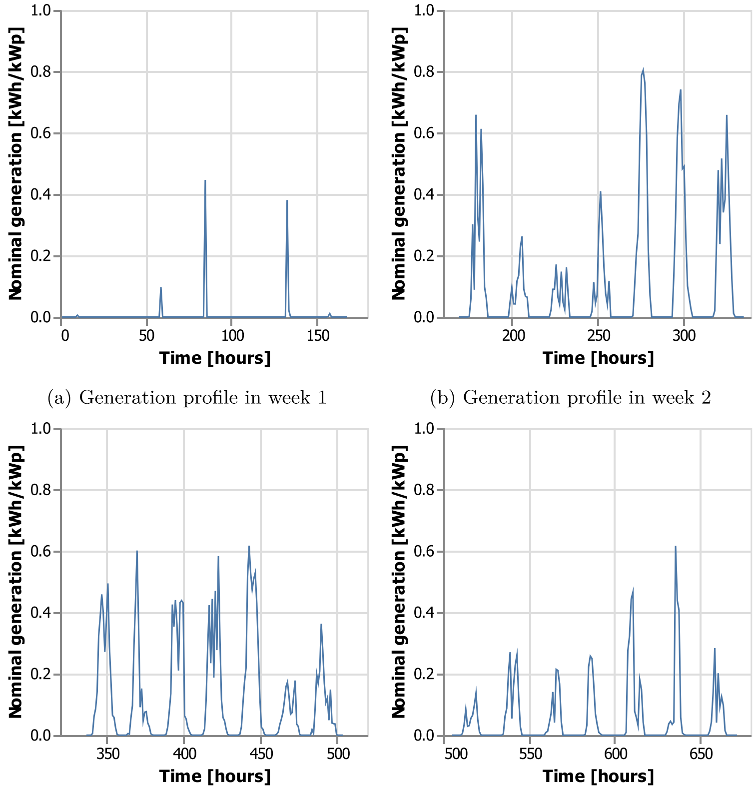
In general, the LM solution can not achieve lower total costs than the SO solution since it is not technically possible to achieve lower costs than the centralized optimization. Also, if we keep the tariff rates fixed, the LM solution will never have higher total costs than the NOLM solution since the neighbourhood agents can always choose to not trade and achieve the NOLM outcome. Hence, if tariff rates does not change, the LM solution will always be equal to or between the system optimal solution and the NOLM solution. However, since the tariff rates are designed as a response to the neighbourhood equilibrium, some agents might be negatively affected by the introduction of such a market. The composition of the neighbourhood agents will be important for the benefits provided by the local market. The market has the highest value when there are some inflexible and some flexible agents since such a situation means that we need a mechanism to incentivize the flexible agents to flatten the coincident peak for the neighbourhood rather than their individual peak.

6 https://ens.dk/en/our-services/projections-and-models/technology-data [Accessed: 2020-02-04]

7 https://www.enova.no/privat/alle-energitiltak/solenergi/el-produksjon-/

8 https://ec.europa.eu/jrc/en/pvgis

9 https://www.skatteetaten.no/en/business-and-organisation/vat-and-duties/excise-duties/about-the-excise-duties/electrical-power-tax/ [Accessed: 2020-10-07.]



(a) Generation profile in week 1 (b) Generation profile in week 2

(c) Generation profile in week 3 (d) Generation profile in week 4

Fig. 4. Nominal PV generation in the neighbourhood.

Comparing the LM and the NOLM cases, it can be observed that a local market can efficiently allocate the resources in the neighbourhood since the solution is close to the SO case. In the following, we will dig deeper into these findings to explain how local market mechanisms can benefit both the DSO and other neighbourhood agents.

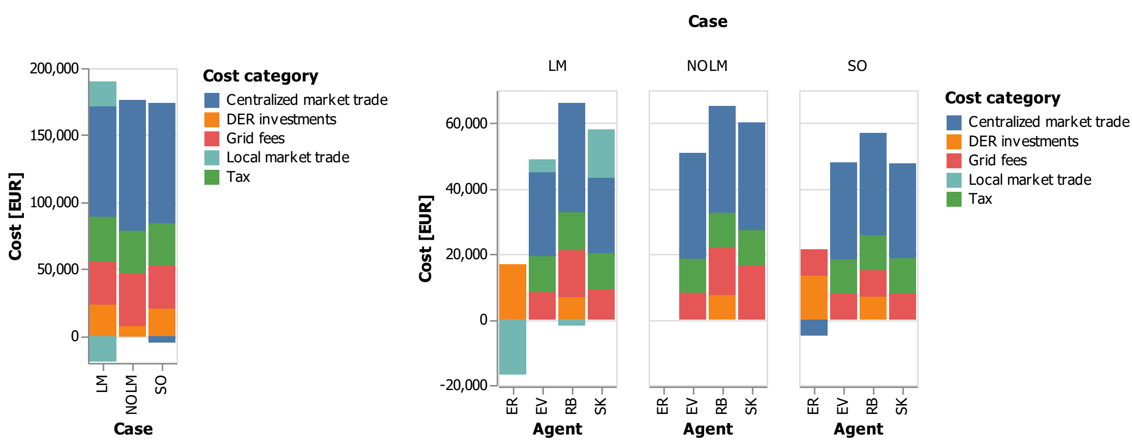


Fig. 5. Total system costs (left) and cost allocation per agent (right) for three cases: Decentralized decision-making with local market (LM), decentralized decision-making without local market (NOLM) and centralized decision-making (SO).

Table 3
Overview of key results for three cases: Decentralized decision-making with local market (LM), decentralized decision-making without local market (NOLM) and centralized decision-making (SO). Cost data are for one year based on the four weeks condidered in the analyses.

	LM	NOLM	SO
Total costs [€]	171,148	176,089	169,174
Net costs ER agent [€]	0	0	16,637
Net costs EV agent [€]	48,853	50,834	47,967
Net costs RB agent [€]	64,256	65,119	56,936
Net costs SK agent [€]	58,039	60,136	47,634
Volumetric tariff [¢/kWh]	0.301	0.299	N/A
Capacity-based tariff [€/kW]	100	85.5	N/A
Grid capacity [kW]	271	337	271
Total PV [kW]	663	175	568
ER agent PV [kW]	495	0	395
RB agent PV [kW]	168	175	173
Total battery [kWh]	0	14	0
ER agent battery [kWh]	0	0	0
RB agent battery [kWh]	0	14	0

5.2. Business case for stakeholders and assets

Now, we focus on the difference between the LM and the NOLM cases. The NOLM case is most representative of current regulatory frameworks in Europe.

The ER agent has no load profile but can invest in energy resources if this turns out to be profitable. Therefore, the ER agent can obtain zero costs if no investments are made. This happens in the NOLM case, where all electricity needs to be traded with the wholesale electricity market. Since the available neighbourhood-scale plants cannot recover the investment costs by participating in the wholesale market, no investments are made by the ER agent when there is no local market. Instead, despite higher unit costs, neighbourhood investments are exclusively made by the RB agent, which invests in a PV system with batteries to decrease the agents' individual costs through behind the meter optimization.

Fig. 5 also reveal that the investments in a PV system become profitable for the ER agent when the local market is introduced. Furthermore, Table 3 shows that the ER agent has zero costs also in the LM case since it invests until the point that the income from the local market exactly balances the investment costs.[10]

Investments made by the ER agent are exclusively in a PV system in the LM case, and there are no investments in batteries for the neighbourhood for neither the LM case nor the SO case (see Table 3). Consequently, batteries are not able to reduce the total system costs since no battery investments occur in the SO case. Despite the lack of bidirectional batteries in the LM and the SO cases, the neighbourhood has a significant flexibility resource through the EV agent since neighbourhood load balancing can efficiently be performed by appropriate charging of the EVs within certain limits. Additional investments in batteries are only profitable in the NOLM case for the RB agent (see Table 3). The battery investments occur in the NOLM case because each agent optimizes behind their own meter and, therefore, can benefit from investing in resources that limit their interaction with the grid. However, such individualistic behaviour produces higher total system costs because the regulatory framework triggers sub-optimal investments. Sub-optimal investments also induce sub-optimal operations, which we elaborate on next.

5.3. Pricing mechanisms and operational decisions

One key finding from the previous sections is that the local market can reduce the required grid capacity to the neighbourhood (see Table 3). This is feasible because the aggregate neighbourhood peak load is reduced in the LM and the SO cases compared to the NOLM case. Fig. 6 shows the aggregate load for the week with the highest load (week 1) along with the local market price. Note that the price can be very high and such price spikes might be hard to monitor in practice. Price spikes can also give the impression of market power, although such effects are outside the scope of this paper since we model the neighbourhood agents as price-takers. The introduction of a local market leads to better coordination of the flexible resources in the neighbourhood, and the aggregate peak load is 20% lower in the LM and SO cases compared to the NOLM case. When the market is not available, we see load spikes even though the agents are faced with a grid tariff penalizing high loads. The lacking aggregate neighbourhood peak load reduction in the NOLM case happens because the agents with flexible resources are incentivized to reduce their individual peak load rather than contributing to reducing the aggregate neighbourhood peak load.

Fig. 7 highlights the importance of coordination within the neighbourhood. The plot represents 24 h during the winter season when the original aggregate neighbourhood peak load is the highest (time steps 25–48), and we will refer to this time period as 'the critical winter day'. It is evident that during 'the critical winter day', the neighbourhood agents all employ a flat trading profile seen from the wholesale power market in the LM case compared to the NOLM case. Constant power purchase from the centralized power market would not be possible for the SK agent in particular without the local market since the SK agent has no flexible resources, and its demand varies over the day.

Since trading with the centralized power market is rather constant during this day, we can extract some information from how the agents interact with the local market, as depicted in Fig. 8. For example, the EV agent buys more than 100 kWh/h during the first 5 h through the SK and RB agents in the local power market, and the EVs are charged while the SK and RB agents have unused capacity. Note that the local trading happens even though the SK and RB agents do not produce energy, but are forwarding power bought from the centralized power market. The roles are switched during daytime when the EV and RB agents sell power to the SK agent during the second half of the day.

Note that the EV sales are not due to discharging (vehicle-to-grid) from the EVs; it is electricity purchased from the centralized power market by the EV agent that is sold in the local market instead of being used for EV charging. The forwarding of power from the centralized market via neighbourhood agents occurs because of the tariff scheme in place, where the agents pay for their individual peak load. When agents have unused capacity (low load), they choose to use this capacity to buy more power than needed for their own consumption and sell it to other neighbourhood agents that need it. Forwarding power to a neighbouring agent is an illustration of how local markets can facilitate coordination among different stakeholders by creating appropriate incentives for coordination. The incentives are created because the grid capacity is free of charge for end-users that are not close to their peak power while it is expensive for end-users that are close to their peak power. Hence, since different agents value the same resource differently, the business case for a local market is created. Consequently, situations where the aggregate neighbourhood load is high will be signalled to the end-users through high prices in the local market when all the end-users are close to their peak load.

These findings highlight that with the local market framework, agent EV charges the EVs during the first part of the day in order to balance the electricity consumption for the neighbourhood as a whole. Without the local market, the rational choice for the EV agent is to spread the EV charging evenly throughout the day to minimize the agents individual peak load, regardless of the overall load situation (see Fig. 9). Such individualistic incentives are consistent with the situation without a local market (NOLM) and result in a higher aggregate neighbourhood peak load, as depicted in Fig. 6.

[10] The ER agent does not turn a profit due to the price-taker assumption inherent in the equilibrium conditions in the model.

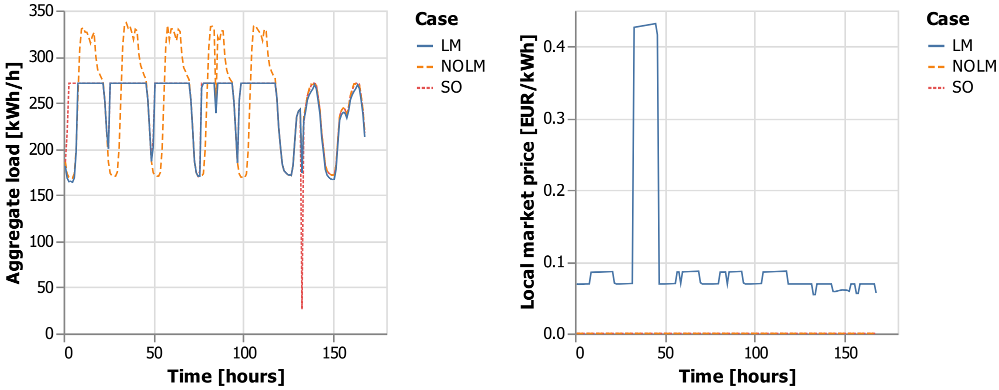


Fig. 6. Aggregate load for three different regulatory frameworks (left) and corresponding local market price for the LM case (right) during the winter week.

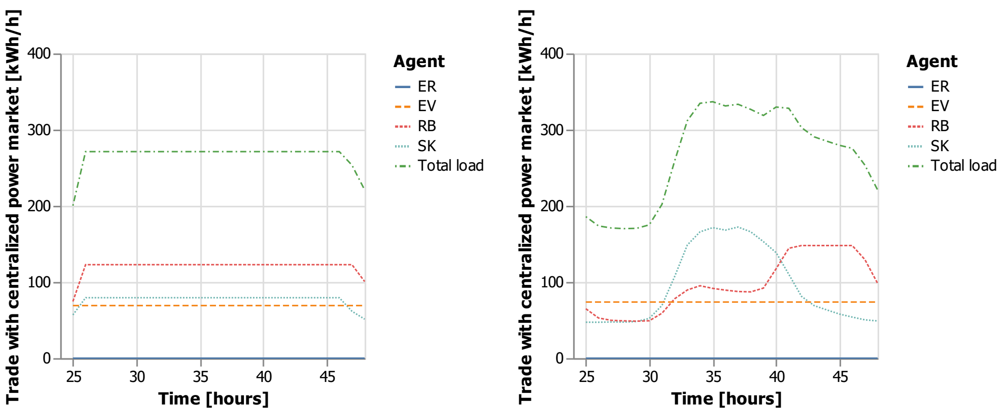


Fig. 7. Trading with the centralized power market during 'the critical winter day' when the local market is available (left) and without the local market (right).

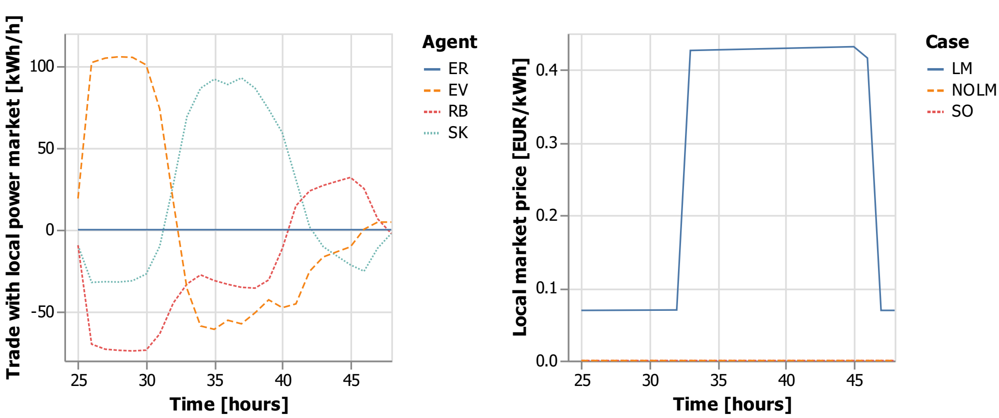


Fig. 8. Trading in local market (left) and corresponding local market price (right) during the critical winter day (hours 25–48).

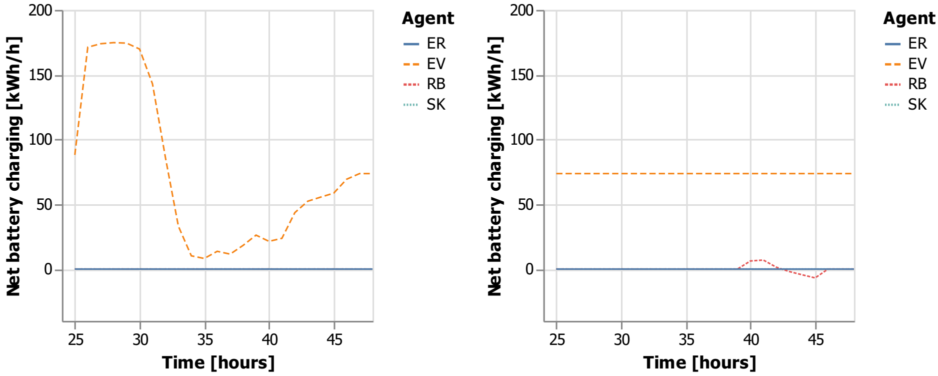


Fig. 9. EV charging and battery operation during 'the critical winter day' when the local market is available (left) and without the local market (right).

5.4. Equilibrium tariffs and DSO cost recovery

For completeness, we explore what happens when the tariffs deviate from the equilibrium state for the LM case. Fig. 10 presents how the DSOs profit, and the grid capacity changes when we vary the tariffs from zero and upwards. The base tariffs, representing a 0% deviation, are equivalent to case LM. We run analyses using the MCP model starting from a tariff deviation of −100% and increase the tariffs in 10% intervals. Agent ER and RB invest in increasing amounts of PV and batteries as the tariffs increase since interaction with the wholesale market becomes increasingly expensive.

Fig. 10 shows that we have two equilibria that satisfy the DSO cost recovery criterion of zero profits. The first equilibrium occurs at a tariff deviation of 0%, which is the LM solution where the DSOs expenses are exactly balanced by tariff income. The second equilibrium occurs when the tariffs are increased by more than 42 times (+4,210%) from the first equilibrium level. The second equilibrium occurs when the tariffs becomes so high that the neighbourhood agents decide to be completely self-sufficient, and the DSO has no investments and no income. These results indicate that it can be costly to replace the grid entirely with decentralized resources.

5.5. Impact of tax rate on the results

So far, we have included an electricity tax on imports from both the wholesale power market and the local market. However, such a tax inherently promotes behind the meter optimization in the local market and therefore we expect the tax rate to limit the trading in the local market. To investigate the effect of the electricity tax rate on the results, we compare the results for different tax rates in the LM case.

Table 4 reports the results for three different electricity tax rates: 1) zero taxes, 2) tax as before, 3) double tax rate. The total costs are almost equal to the SO case when we remove the electricity tax and the LM solution becomes more expensive than the SO solution as the electricity tax is incresed. The reason for the deviation from the system optimal solution is mainly that the tax limits the trading in the local market since the agents need to pay a premium on electricity imports from the other agents in the local market.

The tax rate makes imports from both the wholesale and local markets more expensive. An increase in the tax rate mainly affects the PV capacity in the local system. When there is no tax on electricity, all the PV capacity is installed at the ER agent since it has the lowest investment costs. As the tax increases, the PV capacity shifts to the RB agent

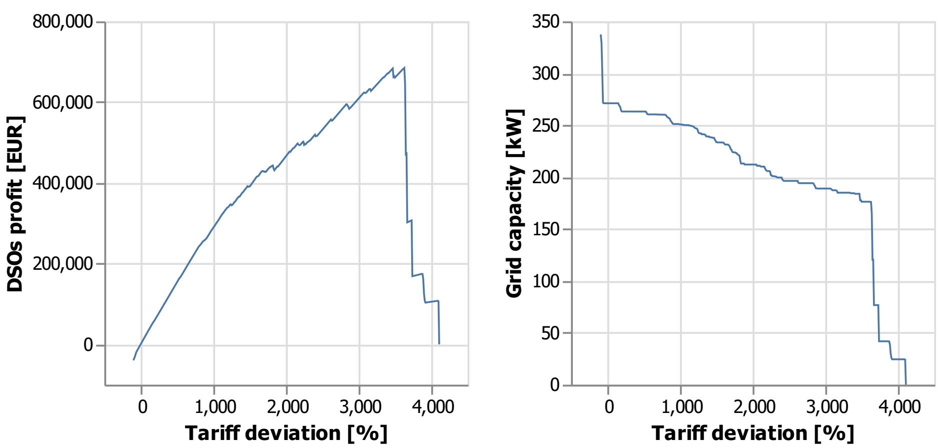


Fig. 10. Response by neighbourhood to increasing grid tariffs. Figure shows DSOs profit (left) and the grid capacity (right). The figures start at a − 100% deviation from the tariffs in the LM case.

Table 4
Sensitivity to tax change for the LM case.

	Tax = 0	Tax = 1.6	Tax = 3.2
Cost change from SO [%]	+0.01	+1.17	+1.97
Volumetric tariff [¢/kWh]	0.300	0.301	0.301
Capacity-based tariff [€/kW]	100	100	100
Grid capacity [kW]	271	271	271
Total PV [kW]	610	663	769
ER agent PV [kW]	610	495	460
RB agent PV [kW]	0	168	309
Total Battery [kWh]	0	0	0

as the cost reduction from self-consumption of energy dominates the investment cost increase at the RB agent. The ER agent, however, decreases investments because it becomes less competitive in the local market when its product is taxed. In total, the PV capacity increases with a higher tax rate since the increase at the RB agent is higher than the decrease at the ER agent.

6. Conclusion and policy implications

In this paper, we propose a game-theoretic framework to analyze a local trading mechanism and its feedback effect on grid tariffs under cost recovering conditions for the DSO. In this game-theoretic model, we construct a case study which is inspired by regulatory issues that have been identified in an ongoing pilot project in Norway. Our results are based on calculations using representative data from four weeks, where each week represents one season of the year.

Within our assumptions, our main finding is that the establishment of a local electricity market in a neighbourhood pareto-dominates the situation without a local market and could decrease the total costs by facilitating local coordination of resources and thus create socio-economic value. The novelty of our analysis is to show how local market activity does not just save costs for neighbourhood stakeholders, but in fact, impacts the regulated tariff rates as the local market activity defer some of the DSO costs. When we compare the establishment of a local market with a regulatory framework without any local market, we observe a reduction in total costs including the need for grid capacity for the system as a whole.

The local market creates value because it is able to coordinate the flexible assets on the neighbourhood level rather than at the individual end-user level. The presence of a capacity-based tariff in combination with a local market mechanism is crucial for these findings since it creates the appropriate price signal to lower the aggregate peak load for the neighbourhood. The peak load is reduced because the local market price reflects the scarcity of capacity in the overall neighbourhood.

Two equilibrium solutions satisfy the DSO cost-recovery criterion: (1) The DSOs costs are exactly balanced by tariff income and a significant interaction between the neighbourhood and the larger power system and (2) at very high tariffs the neighbourhood decides to completely disconnect from the larger power system. In the second equilibrium, the DSO has zero costs and income. These results indicate that although a local trading mechanism can reduce the need for grid capacity, it can be costly to disconnect from the system completely.

Local electricity markets are currently prohibited in most parts of the world. Although the establishment of a local electricity market shows promising potential according to our results, there are several considerations to be made upon evaluating the allowance of local electricity trading. Firstly, the cost of establishing and administrating a local electricity market cannot exceed its net saving potential. With automation and smart metering infrastructure, this countervailing cost is hopefully small enough. Secondly, the saving potential identified in our analysis is dependent on rational and reliable reactions by distributed market participants to reduce peak neighbourhood load rather than increasing the grid capacity. Thirdly, the highest value of establishing a local market is likely to be related to deferring grid development, i.e., defer upgrading grid capacity in an area where power outtake is increasing.

Whether a DSO is willing to depend on the rational reactions by market participants rather than relying on robust development and dimensioning of grid infrastructure is worth considering. An underlying assumption in this paper is that the agents are risk-neutral and, therefore, purely motivated by reducing their expected costs. However, since different regulatory frameworks might fundamentally affect the cost distribution for the involved stakeholders, further research could go in the direction of including risk preferences in the modeling framework.

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Appendix A Mathematical symbols

Nomenclature

Sets	
$c \in [1,\ldots,C]$	Neighbourhood agents
$h \in [1,\ldots,H]$	Hours
Parameters	
λ_h^P	Power market price in hour h (€/kWh)
C^G	Existing transmission capacity (kW)
$D_{c,\,h}$	Electricity demand in hour h (kWh/h)
$D_{c,\,h}^{\Delta-}$	EV demand in hour h (kWh/h)
$G_{c,\,h}^E$	Energy resource availability at agent c in hour h (kW/kWp)
I_c^E, I_c^S	Annualized investment costs at agent c (€/kW/year)
I^G	Annualized investment cost for grid capacity (€/kW/year)
L^G	Transmission losses (%)
L_c^S	Energy storage converter losses at agent c (%)
NM	Net-metering coefficient
P_c^{ch}	Energy storage capacity ratio for charging at agent c (kW/kWh)
P_c^{dis}	Energy storage capacity ratio for discharging at agent c (kW/kWh)
R_c	Energy storage self-discharge at agent c (%/h)
T	Excise tax (€/kWh)
U_c^E, U_c^S	Resource limits at agent c (kW)
W_h	Weight of hour h (h/h)
Upper-level variables	
c_{DSO}^G	Investment in interconnection capacity (kW)
cnt	Capacity-based network tariff (€/kW)
e_h^{GE}	Neighbourhood exports in hour h (kWh/h)
e_h^G	Neighbourhood load in hour h (kWh/h)
e_h^{GI}	Neighbourhood imports in hour h (kWh/h)
vnt	Volumetric network tariff (€/kWh)
Lower-level variables	
$exp_{c,\,h}^P$	Energy exported to grid at agent c in hour h (kWh/h)
λ_h^L	Market price in the local market in hour h (€/kWh)
c_c^E	Energy resource capacity at agent c (kW)
c_c^G	Measured peak load at agent c (kW)
c_c^S	Storage capacity at agent c (kWh)
$d_{c,\,h}^{\Delta+}, d_{c,\,h}^{\Delta-}$	Battery charge/discharge at agent c in hour h (kWh/h)
$exp_{c,\,h}^L$	Energy exported to local market at agent c in hour h (kWh/h)
$g_{c,\,h}^E$	Energy generation at agent c in hour h (kWh/h)
$imp_{c,\,h}^P$	Energy imported from grid at agent c in hour h (kWh/h)
$imp_{c,\,h}^L$	Energy imported from local market at agent c in hour h (kWh/h)
$s_{c,\,h}$	Battery state of charge at agent c in hour h (kWh)

Appendix B MCP formulation of local energy system

We derive the KKT conditions of the neighbourhood level based on the optimization problem described in section 3.2. Since our original problem is linear and has a convex feasible area, the KKT conditions are necessary and sufficient.

$$I_c^S + \mu_c^{S2} - \sum_{h=1}^{H}\left(\mu_{c,h}^{S3} + P_c^{ch} * \mu_{c,h}^{S4} + P_c^{dis} * \mu_{c,h}^{S5}\right) \geq 0 \perp c_c^S \geq 0 \ \forall c \tag{B.1}$$

$$I_c^E + \mu_c^{E1} - \sum_{h=1}^{H} \mu_{c,h}^{E2} * G_{c,h}^E \geq 0 \perp c_c^E \geq 0 \ \forall c \tag{B.2}$$

$$W_h * \left(\lambda_h^P + T + vnt\right) -\lambda_{c,h}^{EB} + \mu_{c,h}^G \geq 0 \perp imp_{c,h}^P \geq 0 \ \forall c,h \tag{B.3}$$

$$-W_h * \left(\lambda_h^P + NM{*}vnt\right) + \lambda_{c,h}^{EB} + \mu_{c,h}^G \geq 0 \perp \ exp_{c,h}^P \geq 0 \ \forall c,h \tag{B.4}$$

$$W_h * \left(\lambda_h^L + T\right) - \lambda_{c,h}^{EB} \geq 0 \perp imp_{c,h}^L \geq 0 \ \forall c,h \tag{B.5}$$

$$-W_h * \lambda_h^L + \lambda_{c,h}^{EB} \geq 0 \perp \ exp_{c,h}^L \geq 0 \ \forall c,h \tag{B.6}$$

$$cnt - \sum_{h=1}^{H} \mu_{c,h}^G \geq 0 \perp c_c^G \geq 0 \ \forall c \tag{B.7}$$

$$\lambda_{c,h}^{EB} - \left(1 - L_c^S\right) * \lambda_{c,h}^{S1} + \mu_{c,h}^{S4} \geq 0 \perp d_{c,h}^{\Delta+} \geq 0 \ \forall c,h \tag{B.8}$$

$$\left(1 + L_c^S\right) * \lambda_{c,h}^{S1} - \lambda_{c,h}^{EB} + \mu_{c,h}^{S5} \geq 0 \perp d_{c,h}^{\Delta-} \geq 0 \ \forall c,h \tag{B.9}$$

$$-\lambda_{c,h}^{EB} + \mu_{c,h}^{E2} \geq 0 \perp g_{c,h}^E \geq 0 \ \forall c,h \tag{B.10}$$

$$\lambda_{c,h}^{S1} - (1 - R_c) * \lambda_{c,h+1}^{S1} + \mu_{c,h}^{S3} \geq 0 \perp s_{c,h} \geq 0 \ \forall c, h{<}H \tag{B.11}$$

$$\lambda_{c,H}^{S1} - (1 - R_c) * \lambda_{c,1}^{S1} + \mu_{c,H}^{S3} \geq 0 \perp s_{c,H} \geq 0 \ \forall c \tag{B.12}$$

$$imp_{c,h}^P - exp_{c,h}^P + imp_{c,h}^L - exp_{c,h}^L - D_{c,h} - d_{c,h}^{\Delta+} + d_{c,h}^{\Delta-} + g_{c,h}^E = 0 \perp \lambda_{c,h}^{EB} \ \forall c,h \tag{B.13}$$

$$(1 - R_c) * s_{c,h-1} + (1 - L_c) * d_{c,h}^{\Delta+} - (1 + L_c) * d_{c,h}^{\Delta-} - D_{c,h}^{\Delta-} - s_{c,h} = 0 \perp \lambda_{c,h}^{S1} \ \forall c, h{>}1 \tag{B.14}$$

$$(1 - R_c) * s_{c,H} + (1 - L_c) * d_{c,1}^{\Delta+} - (1 + L_c) * d_{c,1}^{\Delta-} - D_{c,h}^{\Delta-} - s_{c,1} = 0 \perp \lambda_{c,1}^{S1} \ \forall c \tag{B.15}$$

$$U_c^S - c_c^S \geq 0 \perp \mu_c^{S2} \geq 0 \ \forall c \tag{B.16}$$

$$c_c^S - s_{c,h} \geq 0 \perp \mu_{c,h}^{S3} \geq 0 \ \forall c,h \tag{B.17}$$

$$c_c^S * P_c^S - d_{c,h}^{\Delta+} \geq 0 \perp \mu_{c,h}^{S4} \geq 0 \ \forall c,h \tag{B.18}$$

$$c_c^S * P_c^S - d_{c,h}^{\Delta-} \geq 0 \perp \mu_{c,h}^{S5} \geq 0 \ \forall c,h \tag{B.19}$$

$$c_c^G - imp_{c,h}^P - exp_{c,h}^P \geq 0 \perp \mu_{c,h}^G \geq 0 \ \forall c,h \tag{B.20}$$

$$U_c^E - c_c^E \geq 0 \perp \mu_c^{E1} \geq 0 \ \forall c \tag{B.21}$$

$$c_c^E * G_{c,h}^E - g_{c,h}^E \geq 0 \perp \mu_{c,h}^{E2} \geq 0 \ \forall c,h \tag{B.22}$$

$$\sum_{c=1}^{C}\left(exp_{c,h}^L - imp_{c,h}^L\right) = 0 \perp \lambda_h^L \ \forall h \tag{B.23}$$

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Helping end-users help each other: Coordinating development and operation of distributed resources through local power markets and grid tariffs.

Magnus Askeland: Conceptualization, Methodology, Software, Validation, Investigation, Writing - Original Draft, Writing - Review & Editing, Visualization.

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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

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ABSTRACT

The increasing amount of flexible load in the energy system represents both a challenge and an opportunity. One primary source of load growth is the electrification of the transport sector and the subsequent charging of electric vehicles, which is a load type that can potentially adjust their load profiles. However, to activate the full potential of end-user flexibility, it is necessary to develop pricing mechanisms that can promote efficient load responses on a larger scale. In this paper, a trading mechanism is proposed and analysed within a capacity-based grid tariff scheme by formulating a game-theoretic framework that includes decentralized decision-making by self-interest pursuing end-users. The model is applied to a real-world case in Norway, and it is demonstrated how electrification of vehicles can be achieved with the existing infrastructure. It is found that capacity-based grid tariffs have a limited ability to reduce the coincident peak load in the system since they mainly incentivize individual peak load reductions. However, by including a capacity trading mechanism within the capacity-based tariff structure, we demonstrate that it is possible to increase the value of flexibility since the flexible end-users are incentivized to coordinate their flexibility dispatch with other stakeholders.

1. Introduction

At the distribution grid level, multiple stakeholders are sharing the same interconnection capacity. Due to the distribution grid's radial structure, the capacity needs to be sufficient to handle the coincident peak load for all the stakeholders sharing the same network connection point. Changing consumption patterns that increase grid load due to more power-intensive appliances, electrification of transport, and decentralized resources poses a challenge for the distribution grid. The peak load can increase rapidly compared to the need for energy (see, e.g., [1]). Since the need for grid capacity is driven by the coincident peak load, coordination across several stakeholders can increase the local utilization of energy resources and promote efficient dispatch of flexible load types.

For example, electric vehicle (EV) deployment is considered a challenge due to the added demand and an opportunity to increase grid utilization, given the inherent flexibility regarding when the charging occurs. Keeping everything else static, electrification of transport means that the need for electric energy increases. However, due to the flexibility potential in EV charging, the increase in energy need does not necessarily imply a significant impact on peak load [2,3].

Due to these trends at the end-user level, it becomes increasingly important to consider how efficient operation of flexible resources at the end-user level can be facilitated [4]. In a deregulated electricity market, the individual end-users are billed separately and can control their assets' operation according to their preferences. This means that it is necessary to create incentives that can facilitate an efficient operation of flexible resources to avoid unnecessary and costly coincident peak load increases. Hence, this paper's main objective is to investigate how the amount of EVs in a geographically confined area can be increased without significant grid upgrades by designing efficient pricing signals that fit into existing market structures.

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After this introduction, the paper is structured as follows. First, section 2 presents the research context and the contributions of this paper. Next, in section 3 we formulate the modeling framework that has been developed to carry out the research before the case study setup is presented in section 4. After that, results and discussion of these are presented in section 5, including a discussion of practical implications. Finally, conclusions are drawn in section 6.

2. Related literature

2.1. Modeling of neighbourhood energy systems

Because of increased amounts of decentralized energy resources (DER) and flexible assets at the end-user level, it is relevant to model energy systems at the neighbourhood level to investigate how such systems should ideally be designed and operated. A fundamental principle that can be used to categorize such models is whether they assume centralized or decentralized control of end-user assets.

A rather large body of literature assumes centralized control of neighbourhood assets through the energy hub concept initially proposed in [5], which has been applied in several scientific studies [6,7,8,9,10,11]. The energy hub concept does not include grid tariffs at the end-user level since grid congestion is handled at the neighbourhood level instead. Since the energy hub concept requires centralized control of all assets at the neighbourhood level, it is not directly compatible with the current market structure, which is based on individual metering and end-users making their own decisions. Centralized control models can assess how the local system should ideally be designed and operated; however, they are not suited to evaluate the proper design of incentives within the neighbourhood.

Representation of decentralized decision-making in neighbourhoods requires game-theoretic modeling approaches. The literature on neighbourhood energy models with decentralized decision-making is rather scarce compared to the literature assuming centralized control. In [12,13,14], the authors formulates the tariff design problem in game-theoretic settings with cost-recovery conditions for the distribution grid operator (DSO). We have previously applied this approach [15,16], and found that there is a risk that grid tariffs can provide both suboptimal investment levels and suboptimal operation of the flexible assets. However, these papers are limited to a simple tariff design structure and predefined rules for setting the tariff levels.

Game-theoretic aspects concerning stakeholder interaction are also considered in the smart grid research community. In [17], the authors recognize the decentralized decision-making structure within a smart grid and propose an energy management scheme based on noncooperative game theory while [18] designs an auction-based scheme for sharing of energy storage. Using a similar approach, a method to discriminate price per energy unit within a smart grid is demonstrated in [19]. In the smart grid context, EV charging is increasingly relevant since it represents a highly flexible load that can be used to balance the system, and [20] propose a network model with self-interest pursuing EVs as a means of transporting energy between districts. Furthermore, a bi-objective method considering both the overall cost and user convenience for EV charging is formulated in [21]. These papers have a high level of abstraction (e.g., related to user preferences) since the focus is on the design of trading mechanisms within smart grids on a conceptual level without considering existing pricing structures such as electricity grid tariffs in the model framework. The present study takes a more practical approach to complement this literature by investigating pricing mechanisms that fit into existing market structures and applying them to an ongoing project challenged by EV integration issues.

Mathematical programs with equilibrium constraints (MPECs) can be used to formulate Stackelberg leader-follower games such as the tariff design problem in a mathematically consistent way (see, e.g., [22,23]). [24,25], utilize MPEC formulations to optimize a grid tariff design when considering the reaction from the end-users [25]. formulates the tariff design problem with regulatory constraints for the DSO. Furthermore, in our previous work [24], a tariff scheme with a time-dependent component was introduced to tune the capacity-based tariff. However, none of them consider a tariff component with interaction among the end-users as a tool to address the inherent flaws of imperfect network tariffs.

It can be argued that end-users with flexible assets will operate these resources to their own benefit rather than considering the neighbourhood's objective as a whole. Thus, the operation of assets is only aligned with the overall system's objective if the incentives are appropriately designed. This paper fits within the category of game-theoretic approaches, and we aim to investigate the proper design of grid tariffs and local trading mechanisms to facilitate efficient utilization of the grid capacity under decentralized decision-making.

2.2. Prospective grid tariff designs in Europe and Norway

Traditionally, domestic electricity loads have been regarded as inflexible, and the electricity grid tariff has served mainly as a mechanism to share the bill of providing electricity grids among the users of the grid. For practical reasons, the electricity grid tariffs for residential consumers have historically consisted of two parts: a fixed and a volumetric component.

As the amount of flexible loads and automatic control options increase, there is an ongoing debate in industry, regulatory, and academic circles regarding how to properly design grid tariffs to achieve more efficient utilization of the electricity grid through cost-reflective tariffs. A recent paper from the energy regulators in Europe [26] suggests that a power-based tariff component is needed to account for the capacity-based aspect of the grid connection. The conclusion that capacity-based tariffs are needed is in line with several scientific findings during recent years [27,28]. Despite the evidence that a capacity-based network component is needed, there is an ongoing debate regarding how it should be designed. In this context [13], highlights the problems regarding sunk cost recovery through capacity-based tariffs when end-users react to the tariff implemented. Also, in our previous works [15,16,29] we have demonstrated that an uncoordinated solution based on capacity-based tariffs may result in sub-optimal flexibility responses, which motivates the tariff design proposed in this paper.

In Norway, one of the capacity-based tariff structures that the regulator suggests is the subscribed capacity tariff originally formulated in [30]. With a subscribed capacity tariff, the end-user decides on the amount of contracted capacity and then needs to pay an overcharge fee for any excess load. Another variation of a capacity-based tariff structure is the measured peak tariff, where the end-user's maximum load over a given period is subject to a capacity-based fee.

A reduction of individual peak loads may not necessarily be effective at reducing the aggregate peak load, and a previous paper considering tariff designs found that it would be beneficial to design the network tariff based on several consumers' combined load rather than individual loads [29]. However, centralized control was assumed to achieve coordination among the end-users and do not consider how to properly remunerate the individual end-users if a combined tariff is implemented. In contrast, this paper seeks to address this gap by formulating a model that can determine the optimal grid tariff structure and handle the coordination aspects as an integrated part of the grid tariff structure rather than assuming centralized control.

2.3. Contributions

Assessment of how individual end-users should be remunerated when contributing to neighbourhood objectives requires consideration of the noncooperative aspects of neighbourhood stakeholders when tariff designs are to be assessed. In contrast to existing literature that assumes centralized control of flexible assets, our methodology captures the end-user's price incentives that may enable trading between the stakeholders. This paper, therefore, formulates a Stackelberg model to investigate individual responses to prospective grid tariff schemes as a tool to facilitate efficient utilization of existing grid capacity. Our approach endogenously determines the optimal grid tariffs and the design of optimal remuneration schemes for the individual end-user. This paper is based on issues that have been raised in our previous work [15,16,24,29,31,32], and the novel contributions are:

- Formulation of a model suitable for investigating different regulatory frameworks concerning grid tariff design in smart energy systems.
- Extension of established pricing structures with a mechanism for interaction between end-users to incentivize a practical and efficient allocation of capacity.
- Application of these concepts to a real-life project to analyse how the grid tariff design can increase the value of flexibility when integrating EVs in urban areas.

3. Method

This section presents the developed modeling framework to investigate grid tariff optimization with local capacity trading. First, the optimization problems of the DSO and the end-users are presented. After that, the solution procedure for coupling the two levels is described in section 3.4. A nomenclature is included in section 3.1, which provides an overview of mathematical symbols and describes how the parameters and variables relate to each level in the overall model. In the formulation of the model, the following core assumptions are made:

- The DSO does not consider the tariff income when making decisions since it is purely motivated by lowering the total system costs.
- Cost recovery for the DSO is not considered since the focus is on using capacity-based and volumetric tariffs to activate implicit flexibility at the end-user level.
- The possibility of load curtailment is a part of the DSOs planning problem since we do not consider grid investments to avoid curtailment.

3.1. Model overview

An outline of the bilevel model is presented in Fig. 1. In this model, some decisions are made at the DSO level, while others occur at the neighbourhood level, and decision variables at one level are perceived as parameters for the other level. The DSO determines the tariff structure, and the tariff levels for the chosen structure are endogenous variables at the DSO level but exogenous parameters at the neighbourhood level. Also, the DSO can not directly control operational decisions at the end-user level but can incentivize a change in consumption patterns through the grid tariffs. The benefit of formally representing this bilevel structure is the ability to analyse the feedback effect between neighbourhood responses, indirect coordination of flexible assets, DSO strategy, and regulatory frameworks.

Nomenclature	
Sets	
$\omega \in [1, \ldots, \Omega]$	Scenarios
$\psi \in [1, \ldots, \Psi]$	Transmission segments
$c \in [1, \ldots, C]$	End-users
$h \in [1, \ldots, H]$	Hours
Parameters	
C^G_ψ	Transmission segment capacity (kW)
CF^{ch}_c	Energy storage capacity ratio for charging (kW/kWh)
CF^{dis}_c	Energy storage capacity ratio for discharging (kW/kWh)
$D_{c,\omega,h}$	Load profile (kWh/h)
$D^{\Delta-}_{c,\omega,h}$	Outtake from storage (kWh/h)
F	Capacity trading fee (€/kW/h)
$G_{c,\omega,h}$	Energy resource availability (kW/kWp)
L^G_ψ	Transmission losses (%)
L^{ES}_c	Energy storage converter losses (%)
M	Penalty factor (€/kWh)
$P_{\omega,h}$	Power market price in hour h (€/kWh)
R_c	Energy storage self-discharge (%/h)
T	Excise tax (€/kWh)
U^{ER}_c	Energy resource capacity (kW)
U^{ES}_c	Energy storage capacity (kWh)
VAT	Value added tax (%)
$VOLL$	Value of lost load (€/kWh)
W_ω	Scenario weight (days)
DSO-level variables	
a_M, a_S	Artificial variables for network tariff selection logic
cnt^M_ω	Measured peak network tariff (€/kW)
cnt^S	Subscribed capacity network tariff (€/kW)
$d^{pen+}_{c,\omega,h}, d^{pen-}_{c,\omega,h}$	Energy storage penalty terms (kWh/h)
$e^G_{\omega,h}$	Neighbourhood load (kWh/h)
$ls_{\omega,h}$	Load curtailment (kWh/h)
$lt_{\omega,h,\psi}$	Transmission segment usage (%)
n^{LIM}	Capacity trading limit (kWh/h)
$n^{pen+}_{\omega,h}, n^{pen-}_{\omega,h}$	Capacity trading penalty terms (kWh/h)
oc^S	Over-usage charge (kWh/h)
vnt^E	Volumetric network tariff for exports (€/kWh)
vnt^M, vnt^S	Volumetric network tariff for imports (€/kWh)
Neighbourhood-level variables	
$\lambda^N_{\omega,h}$	Price for renting capacity (€/kWh/h)
$d^{\Delta+}_{c,\omega,h}$	Energy storage charging (kWh/h)
$d^{\Delta-}_{c,\omega,h}$	Energy storage discharge (kWh/h)
$_{c,\omega,h}$	Energy exported to grid (kWh/h)
$g^{ER}_{c,\omega,h}$	Energy generation (kWh/h)
$imp_{c,\omega,h}$	Energy imported from grid (kWh/h)
$n^+_{c,\omega,h}$	Renting of capacity (kWh/h)
$n^-_{c,\omega,h}$	Provision of capacity (kWh/h)
$n^M_{c,\omega}$	Measured peak capacity (kWh/h)
n^S_c	Subscribed capacity (kWh/h)
$o_{c,\omega,h}$	Energy usage above subscribed capacity (kWh/h)
$s_{c,\omega,h}$	Energy storage charge level (kWh)

3.2. DSO level

The DSO level describes the optimization problem of the DSO depicted in Fig. 1 in a regulatory context. In this problem, the neighbourhood level decisions regarding investments and operation are perceived as parameters outside the DSOs' direct control. However, the end-users decisions can be affected indirectly through the tariff design. Based on the neighbourhood-level responses, fixed load curtailment and tariff levels are optimized.

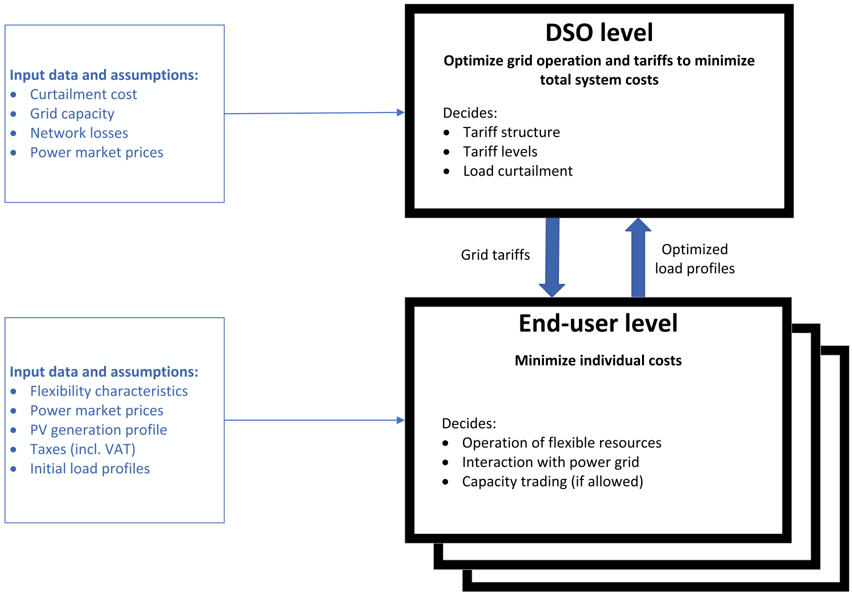


Fig. 1. Outline of the model structure.

3.3. Cost function of the DSO

The costs faced by the DSO for the considered operational period are depicted in (1). The first term in (1) quantifies costs related to losses through a piecewise linear loss function where the DSO needs to select segments ($lt_{\omega,h,\psi}$) with different losses (L^G_{ψ}). The intuition is that losses increase with the utilization of the capacity, which is further explained in section 3.2.3. The second term in (1) identifies load curtailment costs as a linear function of curtailed load ($ls_{\omega,h}$) and the value of lost load ($VOLL$). Potential sunk costs are not included in the cost function since these are not dependent on any of the decision variables in the optimization problem.

$$Cost_{DSO} = \sum_{\omega=1}^{\Omega}\sum_{h=1}^{H} W_{\omega} * \left(\sum_{\psi=1}^{\Psi} lt_{\omega,h,\psi} * L^G_{\psi} * P_{\omega,h} + ls_{\omega,h} * VOLL\right) \quad (1)$$

3.4. Electricity transmission

Given that some end-users might export to the power market while others import from it, the electricity flow to/from the neighbourhood is the absolute value of the aggregate net exchange with the power grid. To maintain the linear properties of the problem, the network flow is identified through (2a) and (2b). These constraints will correctly describe the aggregate load as long as power market prices are non-negative since excess electricity transmission is penalized when minimizing the cost function (1).

$$e^G_{\omega,h} \geq \sum_{c=1}^{C}(imp_{c,\omega,h} - exp_{c,\omega,h}) \quad \forall \omega, h \quad (2a)$$

$$e^G_{\omega,h} \geq \sum_{c=1}^{C}(exp_{c,\omega,h} - imp_{c,\omega,h}) \quad \forall \omega, h \quad (2b)$$

3.5. Losses and grid capacity

Network losses increase quadratic as the load increases, and (3a) - (3b) are formulated to represent piecewise linear losses. Losses incurred are a combination of losses in the different load segments ψ. Furthermore, according to (3a), the DSO needs to choose line segments with sufficient capacity, C^G_{ψ}, or incur curtailment ($ls_{\omega,h}$). Curtailment is a safety mechanism with higher costs than the cost of losses, and the DSO will usually exhaust all transmission segments before curtailing load. $lt_{\omega,h,\psi}$ is the fraction of usage for each transmission segment, and (3b) ensure that the sum of these fractions is equal to 1. Defining $lt_{\omega,h,\psi}$ as an SOS type 2 variable in the set Ψ, requires a combination of a maximum of two neighbouring capacity segments to be chosen.

$$\sum_{\psi=1}^{\Psi} lt_{\omega,h,\psi} * C^G_{\psi} + ls_{\omega,h} \geq e^G_{\omega,h} \quad \forall \omega, h \quad (3a)$$

$$\sum_{\psi=1}^{\Psi} lt_{\omega,h,\psi} = 1 \quad \forall \omega, h \quad (3b)$$

3.6. Grid tariff constraints

The DSO needs to choose between a measured peak and a subscribed capacity tariff structure and decide tariff levels for the implemented structure. The implementation of these tariffs at the end-user level is explained in section 3.3.1. The requirement that only one of the designs can be implemented is formulated according to (4a) - (4b). Artificial variables of SOS type 1, a_M, and a_S, couples the tariff designs and force the cost components of one design to be zero while the other can take any positive value. If the DSO wants to implement the measured peak tariff structure, it means that the variable a_M takes a positive value. The SOS1 relation between a_M and a_S then requires that the subscribed capacity tariff's cost components need to be zero and vice versa.

$$cnt^M_\omega + vnt^M \leq a_M \quad \forall \omega \tag{4a}$$

$$cnt^S + vnt^S + oc^S \leq a_S \tag{4b}$$

All variables in the DSO problem, except the volumetric export tariff (vnt^E), are non-negative. The volumetric export tariff can be negative, meaning end-users save grid costs by exporting to the grid. The DSO will choose a negative export tariff if the export it incentivizes lowers the network losses, e.g., because local exports can go directly to other end-users. Constraint (5) is included to avoid situations where simultaneous import and export occur due to profit from energy looping.

$$vnt^M + vnt^S + vnt^E \geq 0 \tag{5}$$

3.7. Neighbourhood level

In this section, the problem of the individual end-user in the neighbourhood is described as an optimization problem. The end-user can be of different types: Inflexible load, flexible load, EV charging facility, owner of a power plant and storage, or a combination of these. The model formulation presented in this section allows all of these end-users to be represented through parameter specifications.

Since the optimization problems for the neighbourhood end-users are linear, their Karush-Kuhn-Tucker (KKT) conditions are sufficient for global optimality. Hence, to represent their best responses to changes in other end-users or DSO strategies, the problems for the end-users are represented through their KKT conditions, which are formulated as a mixed complementarity problem in A. We indicate dual variables associated with each of the constraints, which are used for the complementarity formulation of the problem.

3.8. Objective function of neighbourhood end-users

The objective of the neighbourhood end-users is to minimize their individual costs according to (6a). Details of the cost components are described in (6b) - (6e). These costs consist of energy purchase from the power market ($Cost^P_c$), electricity taxes and capacity trading fees ($Cost^T_c$), grid tariff costs ($Cost^G_c$), and capacity trading cost or income ($Cost^N_c$).

$$Cost_c = Cost^P_c + Cost^T_c + Cost^G_c + Cost^N_c \tag{6a}$$

$$Cost^P_c = \sum_{\omega=1}^{\Omega} \sum_{h=1}^{H} W_\omega * \left((1+VAT)*imp_{c,\omega,h} - exp_{c,\omega,h} \right) * P_{\omega,h} \tag{6b}$$

$$Cost^T_c = \sum_{\omega=1}^{\Omega} \sum_{h=1}^{H} W_\omega * \left((1+VAT)*imp_{c,\omega,h}*T + n^+_{c,\omega,h}*F \right) \tag{6c}$$

$$\begin{aligned} Cost^G_c = n^S_c*cnt^S + \sum_{\omega=1}^{\Omega} W_\omega * \Bigg(n^M_{c,\omega}*cnt^M_\omega + \sum_{h=1}^{H} imp_{c,\omega,h} * \left(vnt^M \right. \\ \left. + vnt^S \right) + exp_{c,\omega,h}*vnt^E + o_{c,\omega,h}*oc^S \Bigg) \end{aligned} \tag{6d}$$

$$Cost^N_c = \sum_{\omega=1}^{\Omega} \sum_{h=1}^{H} W_\omega * \lambda^N_{\omega,h} * \left(n^+_{c,\omega,h} - n^-_{c,\omega,h} \right) \tag{6e}$$

The grid costs in (6d) requires some elaboration. There is a regulatory decision to employ either the measured peak tariff or the subscribed capacity tariff structures at the DSO level. Note that it is not feasible to employ a combination of both tariff schemes. First, if a measured peak tariff is employed, the tariff components with superscript S will be zero in (6d). Likewise, if a subscribed capacity tariff is employed, the tariff components with superscript M will be zero in (6d). Hence, the grid tariff costs are reduced to the resulting tariff structure. The tariff consists of two components in the case of a measured peak tariff or three components in the case of a subscribed capacity tariff:

1. A volumetric fee per kWh (vnt^M or vnt^S) for electricity consumption.
2. A capacity-based fee per kW (cnt^M_ω or cnt^S) for the contracted capacity.
3. An overcharge fee per kWh above the subscribed capacity (oc^S) in the case of a subscribed capacity tariff structure.

The model includes a trading mechanism between the end-users. Constraints (6e) describe the income or cost due to capacity trading. The term is calculated for all end-users based on the amount of capacity bought ($n^+_{c,\omega,h}$), sold ($n^-_{c,\omega,h}$), and the time-dependent price of capacity originating from the dual variable of the neighbourhood capacity market formulated in section 3.3.6 ($\lambda^N_{\omega,h}$).

3.9. Energy balance

The energy balance of the end-users is described by (7) and states that energy imports subtracted exports must be equal to initial demand modified by storage operation subtracted generation from PV at each end-user for every hour and scenario.

$$\begin{aligned} D_{c,\omega,h} + d^{\Delta+}_{c,\omega,h} - d^{\Delta-}_{c,\omega,h} - g^{ER}_{c,\omega,h} = imp_{c,\omega,h} \\ - exp_{c,\omega,h} \quad \forall c, \omega, h \quad \left(\lambda^{EB}_{c,\omega,h} \right) \end{aligned} \tag{7}$$

3.10. Energy storage

Energy storage makes it possible to shift energy load or generation temporally. This temporal load shifting is represented in (8a), which describes how the charge level depends on the storage level in the previous time step and the operation. Converter losses are imposed linearly through the parameter L_c, while self-discharge from one time-step to the next is imposed through the parameter R_c. Inventory constraints are computationally challenging since these link all time-steps together, and therefore the formulation includes slack terms ($d^{pen+}_{c,\omega,h}, d^{pen-}_{c,\omega,h}$) that are considered as parameters at the end-user level. These terms are zero in the obtained solution due to the penalty incurred in the objective function (13) but speed up the progress of the solver since they allow for the discovery of solutions that are close to satisfying the inventory constraints.

$$s_{c,\omega,h} = s_{c,\omega,h-1}*(1-R_c) - D^{\Delta-}_{c,\omega,h} + d^{\Delta+}_{c,\omega,h}*\left(1-L^{ES}_c\right) - d^{\Delta-}_{c,\omega,h}*\left(1+L^{ES}_c\right) + d^{pen+}_{c,\omega,h} - d^{pen-}_{c,\omega,h} \quad \forall c,\omega,h>1 \quad \left(\lambda^{ES1}_{c,\omega,h}\right) \tag{8a}$$

The formulation allows for representing various kinds of storage, including a bidirectional battery, unidirectional EV charging, and DHW heating. Outtake from the storage, for example related to EV driving or DHW usage, is represented by the parameter $D^{\Delta-}_{c,\omega,h}$. We specify boundary conditions for the storage charge level, as described in (8b). The boundary conditions mean that the charge level in the last time-step is round coupled to the first time step in each scenario. Thereby, we do not need to specify the initial charge level since the optimization model calculates it.

$$s_{c,\omega,1} = s_{c,\omega,H}*(1-R_c) - D^{\Delta-}_{c,\omega,1} + d^{\Delta+}_{c,\omega,1}*\left(1-L^{ES}_c\right) - d^{\Delta-}_{c,\omega,1}*\left(1+L^{ES}_c\right) + d^{pen+}_{c,\omega,1} - d^{pen-}_{c,\omega,1} \quad \forall c,\omega \quad \left(\lambda^{ES1}_{c,\omega,1}\right) \tag{8b}$$

Furthermore, the amount of energy that can be stored, charged, and discharged by each end-user during each hour and scenario are limited according to the maximum capacity (9a) - (9c). In the case of unidirectional EV charging or DHW heating, the discharging factor is set to zero.

$$s_{c,\omega,h} \le U^{ES}_c \quad \forall c,\omega,h \quad \left(\mu^{ES2}_{c,\omega,h}\right) \tag{9a}$$

$$d^{\Delta+}_{c,\omega,h} \le U^{ES}_c * CF^{ch}_c \quad \forall c,\omega,h \quad \left(\mu^{ES3}_{c,\omega,h}\right) \tag{9b}$$

$$d^{\Delta-}_{c,\omega,h} \le U^{ES}_c * CF^{dis}_c \quad \forall c,\omega,h \quad \left(\mu^{ES4}_{c,\omega,h}\right) \tag{9c}$$

3.11. Energy resources

Energy output from distributed energy resources, $g^{ER}_{c,h}$, is described by (10) and has the option of generation curtailment by generating less than the hourly resource availability. The maximum output is the resource availability in each time-step multiplied with the installed capacity, where the resource availability is specified according to, e.g., wind or solar conditions.

$$g^{ER}_{c,\omega,h} \le U^{ER}_c * G_{c,\omega,h} \quad \forall c,\omega,h \quad \left(\mu^{ER}_{c,\omega,h}\right) \tag{10}$$

3.12. Tariff-related constraints

The model allows for one of two different tariff designs, namely measured peak power and subscribed capacity, billable depending on different cost components.

Measured peak power at each end-user is equal to the maximum power withdrawn from the wholesale power market and is identified through constraint (11a) where at least 1 h will be binding for each end-user and scenario in the optimal solution.

$$imp_{c,\omega,h} \le n^M_{c,\omega} + n^+_{c,\omega,h} - n^-_{c,\omega,h} \quad \forall c,\omega,h \quad \left(\mu^M_{c,\omega,h}\right) \tag{11a}$$

With a subscribed tariff, every end-user's optimal subscribed capacity level needs to be determined, and consumption beyond this limit in any hour or scenario will be billed at a higher volumetric tariff rate than consumption below the subscription. This is ensured by constraint (11b) where the grid import cannot exceed the end-user's subscription level and over-usage.

$$imp_{c,\omega,h} \le n^S_c + o_{c,\omega,h} + n^+_{c,\omega,h} - n^-_{c,\omega,h} \quad \forall c,\omega,h \quad \left(\mu^S_{c,\omega,h}\right) \tag{11b}$$

The model allows for trading of grid capacity among the end-users through presence of the variables $n^+_{c,\omega,h}$ and $n^-_{c,\omega,h}$ in (11a) and (11b). Trading removes or adds capacity to the limit and therefore provides an additional mechanism to contract capacity. However, the rented capacity needs to origin from other end-users as described in section 3.3.6. The trading can be limited through the upper-level variable n^{LIM} according to (11c). When trading of capacity is not allowed, n^{LIM} is set to zero.

$$n^+_{c,\omega,h} + n^-_{c,\omega,h} \le n^{LIM} \quad \forall c,\omega,h \quad \left(\mu^N_{c,\omega,h}\right) \tag{11c}$$

Depending on the tariff design, either constraint (11a) or (11b) will be binding for at least 1 h for all end-users and scenarios and thus incur end-user grid costs through the tariff components in the objective function. This is because the tariff design that is not implemented will have zero costs in all end-users objective functions according to (4a) - (4b) in the DSO level. For example, if a subscribed capacity-based tariff is chosen, cnt^M_ω will be zero in (6d), and thus $n^M_{c,\omega}$ can take any feasible value in the optimal solution because it does not affect the objective function of the end-user. Hence, due to zero costs for the tariff that is not implemented, only one of constraints (11a) or (11b) will have a positive dual value for at least 1 h per end-user and scenario. The decision-making related to the tariff design is further elaborated in the DSO problem formulation in Section 3.2.

3.13. Capacity trading mechanism

Since we assume that grid congestion occurs on the neighbourhood level rather than at each individual end-user, (12) specifies the capacity trading between the neighbourhood end-users. The capacity market is cleared for every time step, and the dual variable of the local capacity market becomes the short-term marginal cost of capacity considered by the end-users.

$$\sum_{c=1}^{C}\left(n^+_{c,\omega,h} - n^-_{c,\omega,h}\right) + n^{pen+}_{\omega,h} - n^{pen-}_{\omega,h} = 0 \quad \forall \omega,h \quad \left(\lambda^N_{\omega,h}\right) \tag{12}$$

Note that this is the equilibrium condition in the neighbourhood, ensuring that demand and supply for the capacity match for each time step. The dual value of this constraint becomes the hourly uniform price for renting or providing capacity in the end-user objective function. The capacity trading couples all end-user problems together and makes the overall problem difficult to solve since all end-user KKT conditions need to be solved simultaneously. Therefore, slack terms ($n^{pen+}_{\omega,h}, n^{pen-}_{\omega,h}$) are included. The slack terms are zero in the final solution due to the penalization in the objective. Similar to the storage level slack terms, these improve the computational performance by allowing intermediate solutions that are close to satisfying the equilibrium condition.

3.14. Solution approaches

The overall optimization occurs at the DSO level, and we assume that the DSO is interested in minimizing total system costs. As depicted in Table 1, two main formulations are used: (1) system optimization and (2) bilevel model.

The objective function for the system is formulated in (13). This objective includes costs at the DSO and end-user level in addition to penalty terms for violating the energy storage and market balances. The penalty terms are included since this was found to enable a more efficient search for candidate solutions in the MILP tree. Thus, the penalty factor (M) needs to be sufficiently high to ensure solutions without positive penalty terms. For the analyses in this paper, a penalty term of $M = 10$ was found to be sufficient.

$$
\begin{aligned}
Cost = Cost_{DSO} + \sum_{c=1}^{C} \ Cost_c^P + Cost_c^T \Big) + M * \sum_{\omega=1}^{\Omega} \sum_{h=1}^{H} \\
W_\omega * \left(\sum_{c=1}^{C} \ d_{c,\omega,h}^{pen+} + d_{c,\omega,h}^{pen-} \right) + n_{\omega,h}^{pen+} + n_{\omega,h}^{pen-} \Bigg)
\end{aligned} \tag{13}
$$

The system optimization assumes centralized and direct control of all resources at the end-user level and serves as a benchmark. In this formulation, we relax the requirement of noncooperative behaviour and optimize the system as a whole. Therefore, all technical constraints are included, but the end-user optimality conditions are excluded from the problem. Since we include the DSOs costs directly, there is no interaction through grid tariffs in the system optimization model. The optimization considers all costs at both the DSO and end-user level and finds the optimal operation of all assets; thus, grid tariffs are not used. In contrast to system optimization, the bilevel model captures the aspect of decentralized control of flexible assets and seeks to design the optimal incentives. Hence, the optimality conditions are included since the DSO needs to consider the best response by the end-users when designing the policy instead of only respecting technical constraints. End-user responses are implemented by linearizing the KKT-conditions using SOS1 variables according to the methodology proposed by [33].

4. Case study setup and input data

4.1. The Røverkollen housing cooperative

In 2017, the Oslo municipality decided to reduce its greenhouse gas (GHG) emissions by 95% within 2030 compared to the 2009-level. Currently, about 50% of Oslo's GHG emissions are caused by transportation, and hence modular changes of personal transport (from car to bus, bike, or walking), as well as electrification, are seen as one of the main strategies to reach the city's climate target [1]. In Oslo, about 70% of inhabitants live in apartments with limited access to charging points at home. Studies have shown that limited charging possibilities are a significant barrier for individuals to shift from fossil to electric cars (see, e.g., Ref. [34]. Therefore, the Oslo municipality grants investment support for charging points connected to housing cooperatives. This paper has chosen the Røverkollen housing cooperative as a case study, which is the main pilot in the EU-project GreenCharge. Røverkollen has 246 apartments and is situated north-east of Oslo. Each apartment has access to their personal parking space in a 4-story garage. Currently, 26 charging points are actively in use, but the garage grid connection should handle the complete electrification of all 230 vehicles.

The case study is a neighbourhood of six apartment blocks and a garage with EVs and a PV system. The blocks have a shared supply of DHW heated by air-sourced heat pumps (ASHP) coupled with electric boilers. The apartments at Røverkollen are heated by electric radiators, creating a prominent peak of the neighbourhood's aggregate electricity load during winter. The garage has four floors, and each floor has an entrance with electric heating cables in the ground to prevent icing for safety reasons.

4.2. System setup

In our case study, we have defined three end-user types (described in section 4.4) and one DSO (described in section 4.3) as depicted in Fig. 2. In addition to the stakeholders involved, the figure also shows the two different decision-making assumptions that are investigated: a) the centralized optimization treating all stakeholders as one joint agent acting to the best for the total system, and b) the bilevel game with four stakeholders, one upper and three lower, optimized individually based on their self-interest. Note that the bilevel model in Fig. 2b has additional system boundaries compared to the centralized optimization in Fig. 2a since each stakeholder optimizes individually.

The input data is gathered from the Røverkollen housing cooperative (see section 4.1) and the local DSO, Elvia. In the following, the properties of the input data will be described. Based on the properties of the available data, we employ an hourly time-step ($H = 24$).

4.3. DSO and overall system

Table 2 presents the parameters related to prices, taxes, and existing infrastructure. The power market price is assumed to be constant because we want to isolate the temporal variations to the end-users load profiles.

The DSO faces costs related to network losses and load curtailment costs. Based on the load profiles, we specify a maximum capacity of 1300 kW, sufficient to cover the historical peak load but not enough for large amounts of uncoordinated EV charging coinciding with the peak load. The specification of the maximum capacity is a critical assumption for this paper since we aim to investigate how we can create incentives that allow for EV charging without significantly increasing the peak load. We represent the electric losses as a quadratic function of load, and we assume that an average loss of 6%[2] occurs when the load is at half the capacity. The losses are represented by a piecewise linear formulation as described in section 3 by using four segments, each with a capacity of 325 kW, as presented in Fig. 3.

4.4. End-users

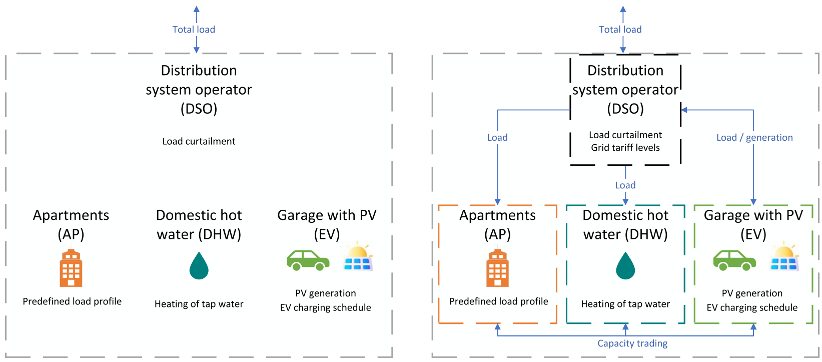
Table 3 presents the technology parameters for each stakeholder in the considered system. In addition, there are three sources of temporally variable data:

[1] www.oslo.kommune.no/politics-and-administration/green-oslo/best-practices/oslo-s-climate-strategy-and-climate-budget/[Accessed: 2020-12-04].

[2] data.worldbank.org/indicator/EG.ELC.LOSS.ZS?locations = NO[Accessed: 2020-12-10].

Table 1
Solution approaches.

	System optimization	Bilevel model
Problem type	MILP	MPEC reformulated as MILP
Solver	CPLEX	CPLEX
DSO cost representation	Directly	Grid tariffs
Decision-making structure	Centralized	Decentralized
Objective	Minimize (13)	Minimize (13)
Constraints at the DSO level	(2a) - (3b)	(2a) - (5)
Constraints at the end-user level	(7)–(10)	(A.1) - (A.23)



(a) Centralized optimization. All operational decisions are controlled directly by the DSO. (b) Bilevel game where decisions are made based on the stakeholders own self-interests.

Fig. 2. System boundaries for the different modeling approaches.

1. Load profiles
2. Outtake from storage
3. PV generation

The load profiles are gathered from the central electricity metering data hub in Norway, Elhub[3]. The following subsections describe how the properties of each end-user have been specified.

4.5. Apartments (AP)

The load of the apartments consists of electricity use for lighting, electric appliances, and space heating demand. Hot tap water is provided through a shared system and is not included in the apartments' load profile. Although space heating, in theory, could be controlled flexibly, suitable equipment for flexible load activation is currently not present. It can be argued that the apartments may have implicit flexibility due to a potential behaviour change, but such effects are outside the scope of this paper. Therefore, the only decisions relevant for this end-user is renting/provision of grid capacity. Hence, the apartments are represented as an inflexible load based on aggregated load data provided by the DSO.

4.6. Garage (EV)

The garage's load consists of electricity use for lighting, heating cables, and charging of EVs. We assume the EV charging to be flexible and the rest of the load as inflexible.

To identify the fixed load related to lights and snow melting, this data was obtained from the period before the PV system and EV charging in the garage was introduced. Also, the garage has a flexible load related to EV charging, but there were no temporal load profile data of EVs being charged inside the garage available at the time of this work. Therefore the aggregate EV load from 4 semi-fast EV chargers situated outside the garage was used as a proxy. Furthermore, this EV load profile was scaled to reflect the current 26 EVs currently being charged inside the garage, assuming a driving distance of 14000 km per year. Based on information of the actual cars, the average storage capacity of the EVs' batteries is assumed to be 30 kWh per car, and for simplicity, we assume that 25% of the capacity is available for smart charging at any time.

Table 2
Input data related to the overall system.

Parameter	Symbol	**Value**
Maximum network capacity	C^G_{Ψ}	1300 kW
Network segment capacities	C^G_{ψ}	See Fig. 3
Network segment losses	L^G_{ψ}	See Fig. 3
Consumption excise tax	T	1.713 ¢/kWh
Local capacity trading fee	F	1 ¢/kW/h
Power market price	$P_{\omega,h}$	5 ¢/kWh
Value of lost load	$VOLL$	2 €/kWh
Value-added tax	VAT	25%

The garage also has a PV system of 70 kW. Since the PV system did not yet have metering data available at the time of this work, PV data was simulated using renewables.ninja[4] [35] for the location of the Røverkollen housing cooperative using properties of the existing system with 50% east/50% west orientation and 10° tilt.

[3] https://elhub.no/.

[4] https://www.renewables.ninja/.

Table 3
Input data related to each stakeholder in the local system.

Parameter	Symbol	AP	EV	DHW
Charging converter losses [%]	L_c^{ES}	–	5	0
Charging ratio [kW/kWh]	CF_c^{ch}	–	0.467	0.50
Discharging ratio [kW/kWh]	CF_c^{dis}	–	0	0
Energy storage self-discharge [%/h]	R_c	–	0.1	1
Energy resource capacity [kW]	U_c^{ER}	0	70	0
Energy storage capacity [kWh]	U_c^{ES}	0	195	406

4.7. Domestic hot water (DHW)

The DHW load reflects electricity use for heating of domestic hot water in a shared facility that provides hot tap water from a central unit to each apartment. Also, some electricity is used to light the staircases inside the apartment blocks and electric heating cables to avoid ice on the walkways between the blocks. The DHW end-user does not have any generation resources.

Parts of the load related to tap water heating have been characterized as flexible since the hot water tanks allow for some temperature deviation without negatively affecting the users. Based on an assumed ΔT of 30 °C, the total volume of the tanks, and the heat capacity of water, the tanks' energy storage capacity is estimated to 406 kWh. The charging ratio was calculated by assuming the charging capacity to be equal to the peak load and dividing this by the storage capacity.

4.8. Identifying the critical day

We identify the critical day as the day containing the highest total load in the system based on an entire year. In general, the peak load for residential buildings in Norway occurs during the winter due to significant heating needs covered through electricity. In our dataset, the critical day was found to be on the 31st of January. In the following, the critical day load profiles are used as a basis for the analyses in this paper and are provided in Fig. 4.

4.9. Cases

Based on the presented input data, five different cases are analysed:

1. **Case FIX:** No activation of flexibility, decisions are fixed to the underlying input data.
2. **Case SO:** All decisions are controlled directly by the DSO to minimize the system's total costs.
3. **Case MP:** Neighbourhood-level decisions are decentralized while the DSO decides a measured peak tariff for indirect load control.
4. **Case SC:** Neighbourhood-level decisions are decentralized while the DSO decides a subscribed capacity tariff for indirect load control.
5. **Case MPT:** Like case MP, but also includes a capacity trading mechanism between the end-users.

Here, SO is calculated using the system optimization setup outlined in Fig. 2a, while MP, SC, and MPT are calculated using the bilevel approach outlined in Fig. 2b. FIX yields the same result regardless of the setup since all operational decisions are fixed.

In the MP and SC cases, the only information exchange between the stakeholders is the grid tariffs imposed on the end-users by the DSO. In case MPT, there is also an interaction between the end-users since a capacity market with a uniform price is established

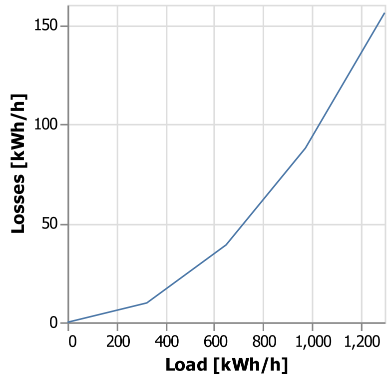


Fig. 3. Network losses (L_Ψ^G) as a function of the aggregate load (C_Ψ^G).

where each end-user decides how much capacity it wants to procure from or sell to the market at each time step. This implementation differs from a peer-to-peer market since each end-user interacts with the local pool rather than directly with other end-users, but it is similar at a conceptual level. The information required to clear this market is bids with capacity and prices from the participants for each time step. Since it is not realistic that end-users will engage directly in such a market, this trading process can be handled by optimization software on behalf of the end-users or through an aggregator.

5. Results and discussion

5.1. Current situation

We start by solving the model based on the historical data for the critical day as described in section 4, with the load profiles as described in Fig. 4a where the amount of EV charging is relatively modest (26 vehicles). In these initial analyses, the total costs do not vary between different tariff structures because the peak load is always lower than the grid's capacity and the DSO is unable to shift load from peak load periods to when the total load is lower.

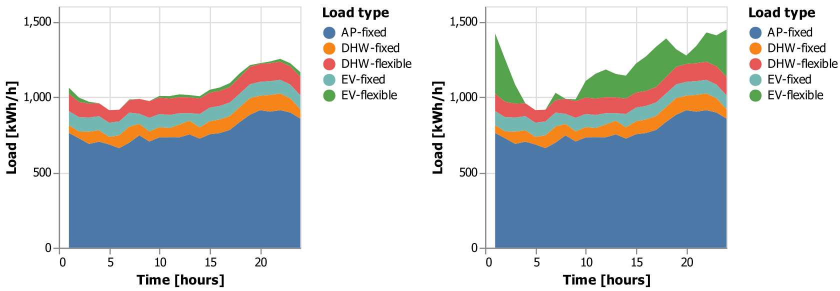
When tariffs are implemented instead of the direct control of decentralized assets, the DSO prefers to either employ zero tariffs in the case of the measured peak tariffs or a very low capacity-based tariff in the case of a subscribed capacity tariff.[5] This DSO choice indicates that, when there is no risk of curtailment, the DSO cannot improve the system operation by employing a measured peak tariff and only marginally improves the system's operation when a subscribed capacity tariff is employed.

Compared to the overall costs, the losses only contribute to a small amount, and therefore the difference is small when the total load is not close to the capacity of the grid connection (C_Ψ^G). However, this paper's primary motivation is to assess how various tariff schemes can handle increased EV load in the system, which we explore next.

5.2. Electrification of vehicles

In Norway, it is expected that within 2030 most cars will be

[5] We investigate the outcome for each of the tariff designs by exogenously specifying $a_S = 0$ to study a measured peak tariff or $a_M = 0$ to study a subscribed capacity tariff.



(a) Current load profiles of the housing cooperative, with electrification of 26 EVs.

(b) Load profiles with full electrification of vehicles, EV charging is scaled up by a factor of 10.

Fig. 4. Load profiles for the critical day. The end-users DHW and EV are separated in two load types to represent fixed and flexible load.

electrified. To assess this situation for the Røverkollen housing cooperative, the EV load is scaled up by a factor of 10, representing complete electrification of all vehicles in the garage as presented in Fig. 4b.

5.3. Cost distribution and value of flexibility

Key results on costs, load curtailment, and tariff levels are reported in Table 4. Net costs are calculated according to (6a) for the end-users, and (1) for the DSO. The cases FIX and SO represent a worst and best case, respectively, since FIX represents the case without flexibility activation while SO represents the case with optimal activation of flexible assets from a system optimization perspective. Therefore, the value of flexibility is calculated based on the cost difference to the case without any activation of flexibility (FIX). Regardless of the decision-making structure, we see that flexibility is useful for reducing the total costs and that the obtained value of flexibility is dependent on the tariff structure. The SO solution provides an upper bound for the value of flexibility since all flexible resources are controlled directly to minimize the total system costs. Without centralized control, we see from Table 4 that it is beneficial to introduce a local trading mechanism (MPT) as this gives a significantly higher value of flexibility than the pure individual tariffs (SC and MP).

The SO case demonstrates that load curtailment is avoidable under centralized control. The main reason for the higher cost in MP and SC is that although load curtailment is reduced compared to FIX, the incentive structures fail to avoid it altogether. Case MPT demonstrates that it is possible to completely avoid the load curtailment and achieve total costs close to the system optimal solution also under decentralized control. In the next section, we explain further how load profiles are affected by the various decision-making assumptions and regulatory frameworks.

5.4. Load profiles and flexibility potential

The total load and load profiles for the different stakeholders are presented in Fig. 5. The aggregate load is plotted in Fig. 5a, which reveals that although all cases have the same underlying load profiles, the optimized load profiles are different for the different cases. The only stakeholder with a constant load pattern is the apartment load in Fig. 5b, which is unchanged because it does not have any flexibility. Hence, it cannot adapt the load pattern to changing regulatory frameworks. Fig. 5c and d plots the optimized load profiles for the garage and the water heating, and since these stakeholders have flexible assets, the optimized load profiles changes depending on the regulatory framework. A key observation is that the MP and SC tariff structures mainly reduces individual peak loads, while the coincident peak load is reduced by lowering the garage load when the apartment load is high for the MPT tariff structure, which is more in line with the optimal operation represented by the SO case.

The maximum capacity of the connection is 1300 kW, which is exceeded when there is no flexibility activation with 679 kWh of curtailment in case FIX. Furthermore, the tariff structures in cases MP and SC reduce the curtailment to 130 kWh (−81%) by incentivizing a flattening of the flexible end-users' load profiles. It is technically possible to avoid curtailment entirely as, presented in SO, where centralized control is assumed. Furthermore, when the assumption of centralized control is removed, and capacity trading among end-users is allowed in the MPT case, curtailment is avoided also under decentralized control. The coordination between stakeholders in case MPT highlights the fundamental impact of introducing capacity trading: Rather than incentivizing all end-users to flatten their load, it is more efficient to create an incentive that induces those with the flexibility to support a flattening of the aggregate load.

5.5. Capacity trade and flexibility operation

The effect of a capacity trading scheme can be observed in Fig. 6, which presents the capacity trading between the end-users and compares the storage operation for the measured peak tariff with and without capacity trading for the MPT and MP cases, respectively. Fig. 6a illustrates that there is no capacity trading for most of the hours since the potential benefit does not justify paying the trading fee. However, during the evening, there is a scarcity situation that induces the AP end-user to procure capacity, mainly from the EV end-user. Thus, it can be observed that when the overall grid capacity is scarce, the trading mechanism can allocate the available capacity to where it is needed by providing an incentive for the flexible stakeholders to adapt their storage operation.

Even though capacity trading only occurs when there is a scarcity situation, the trading mechanism between the end-users induces a change in the operational patterns for the entire day. Fig. 6b compares the EV and DHW end-users storage operation for the MP and MPT cases, and it is evident that the capacity market has a significant impact on the filling of the storage. For the EV end-user, we see that the storage filling is higher in the MPT case until the AP end-user procures capacity, which is done to prepare the storage in anticipation of the load reduction needed in the evening.

The DHW storage operation also changes when the capacity trading is available, but not to relieve grid stress. In fact, the DHW load increases during the evening peak of the aggregate load, and this occurs because the EV end-user has enough flexibility to even out the total grid load. Furthermore, since the self-discharge is high

Table 4
Overview of key results.

Case	FIX	SO	MP	SC	MPT
Decision-making structure	–	Fig. 2a	Fig. 2b	Fig. 2b	Fig. 2b
Total costs [€]	3957	2609	2871	2871	2613
Net costs AP [€]	1554	1554	1784	1765	1625
Net costs EV [€]	479	480	541	541	499
Net costs DHW [€]	374	374	424	424	390
Net costs DSO1 [€]	1550	201	122	141	98
Value of flexibility [€]	0	1348	1086	1086	1344
Load curtailment [kWh]	679	0	130	130	0
Volumetric tariff [¢/kWh]	–	–	0	0	0
Capacity-based tariff [€/kW]	–	–	0.2522	0.2522	0.0794
Over-usage charge [¢/kW]	–	–	–	2.1822	–
Export tariff [¢/kW]	–	–	0	0	0

[1] Positive net DSO costs are not covered through the capacity-based and volumetric tariffs. These costs can be collected through e.g., a fixed tariff component, but this consideration is outside the scope of this paper.

at the DHW end-user relative to the EV end-user, DHW tries to avoid preheating more water than necessary. These observations show that flexibility dispatch, in this case by EV, has effects beyond reducing peak load; it also allows DHW to reduce its operational costs.

5.6. Practical implications

The game-theoretic aspects considered represent a significant computational complexity. Therefore, it was necessary to limit the temporal horizon and focus the analyses on one day to demonstrate how tariffs can relieve grid congestion and provide a more efficient allocation of resources. Also, the flexibility potential is characterized by using a simplified formulation due to a lack of more detailed data and the need to limit the computational complexity. Our results might overestimate the value of flexibility since more details in the modeling of flexibility might introduce additional operational constraints not captured by our model. However, we have tried to limit the flexibility potential by assuming that only 25% of the EVs are controllable at any time, and it is possible that we underestimate the share of controllable EVs and that our results underestimate the flexibility potential. Despite this limitation, our model provides a general formulation of flexibility that can be used to assess the efficiency of different pricing mechanisms in a comparative way.

Our analyses conceptually demonstrate the efficiency of a capacity-based tariff in relieving grid congestion when trading of capacity is allowed between the end-users. In practical applications, the peak measurement period may be longer than one day, e.g., one month. Nevertheless, if the end-users are interested in lowering their measured peak for a period different than one day, the incentive structure remains the same. The capacity trading can both reduce the occurrence of unnecessary load shifting and lower the peak load for the aggregate system depending on the situation in the grid:

- Low-load periods: If the network capacity is not challenged, end-users will have an unused capacity that can be rented out without any inconvenience. Thus, this capacity can be rented at low or zero costs and removes unnecessary behaviour changes if some end-users prefer high usage of capacity during such periods.
- High-load periods: If the network capacity is challenged, most or all end-users will fully utilize their capacity either due to their underlying load or due to renting out to other end-users. Hence, rental of capacity will be costly, and the capacity will be allocated to those with the highest willingness to pay.

Based on this, a capacity-based tariff with trading of capacity among end-users provides efficient incentives for flexibility operation regardless of the measuring period for the tariff. The challenges facing the Røverkollen housing cooperative are representative of a general trend, and to avoid sub-optimal solutions on the neighbourhood scale, a mechanism to incentivize resource coordination is needed in a multi-stakeholder system. In principle, a similar outcome can be achieved by centralized control and an allocation scheme for the obtained savings, but such a setup is not compatible with the current market structure in Norway.

The case-specific properties that drive our results are network capacity, underlying load profiles, and the technologies present in the system. However, our implemented tariff designs are generic fees per unit of energy usage (kWh) and per unit of capacity (kW) and could therefore be tested on different cases. In this work, we assumed the tariff components to be fully adjustable, but some countries may have regulations regarding the level of tariff components.

Introducing capacity trading in addition to a capacity-based grid tariff is beneficial for both grid companies and end-users. First, grid companies can reduce their costs by introducing capacity trading since the coincident peak load is reduced, and the daily operation becomes more efficient. The peak load reduction is the most crucial aspect in this regard since grid infrastructure upgrades can be reduced or postponed. Secondly, the end-users will also save costs since they ultimately need to bear the grid costs. On the end-user level, the capacity trading mechanism can be beneficial for inflexible end-users since they can reduce their costs by procuring capacity from flexible end-users, while flexible end-users can create an income stream by adapting their load patterns.

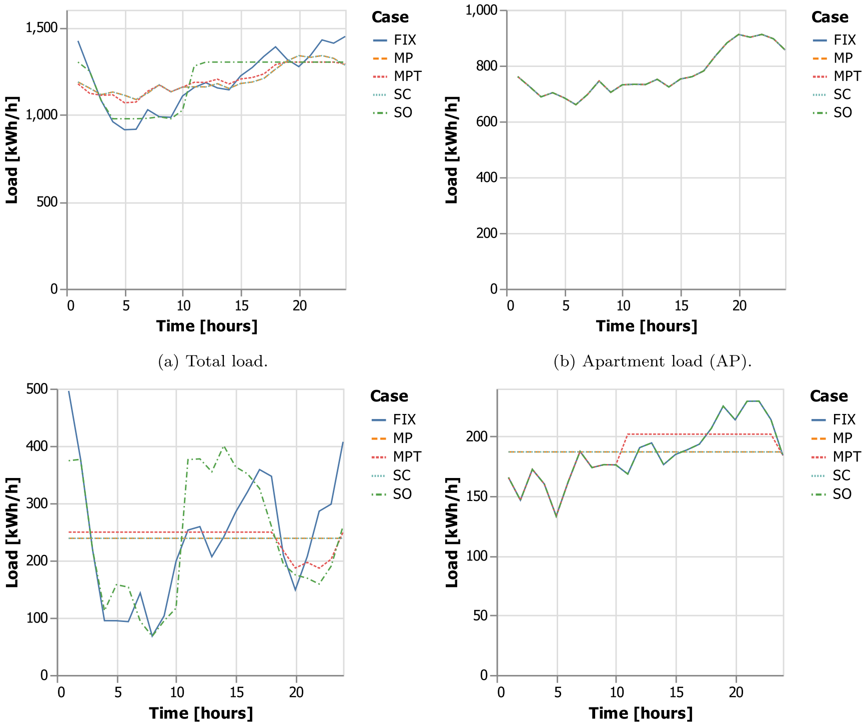
6. Conclusion

This paper investigates prospective tariff schemes, including capacity trading between end-users in a game-theoretical modeling framework. The model is applied to a real-life project with different stakeholders involved to investigate how we can design a regulatory framework that facilitates an increasing amount of EV charging in the system by efficiently exploiting the flexibility potential. Different regulatory frameworks are compared to extract information regarding how tariff schemes can enable a favorable outcome for the system compatible with the individual stakeholders' self-interest.

Integration of EVs in multi-stakeholder electricity systems necessitates a smarter design of the pricing mechanisms because the need for grid capacity is based on the coincident peak load rather than individual peak loads. Based on this study, we conclude that a combination of capacity-based grid tariffs and a capacity trading mechanism within the tariff structure is a feasible solution to increase the EV hosting capacity. The main advantage of adding a capacity-trading mechanism between end-users is the ability to efficiently incentivize temporal load shifts to allocate the capacity to where it is most needed.

It is vital to consider the applicability of pricing mechanisms, and in this regard, capacity trading can be implemented as a part of capacity-based grid tariffs. The mechanisms proposed in this paper are compatible with the current market structures in many countries if the regulatory framework is adapted according to the following two steps:

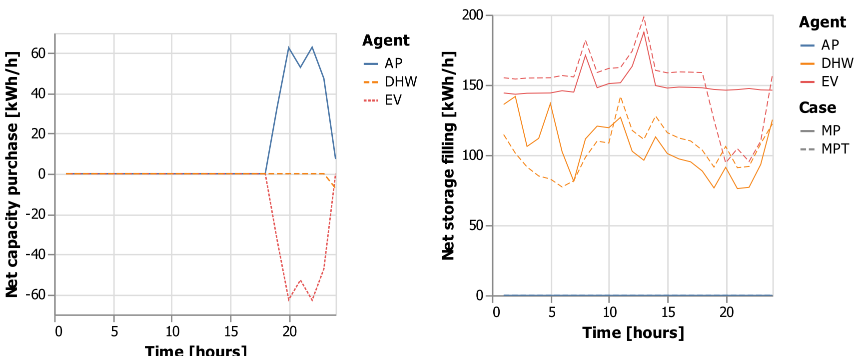
- **Step 1:** A grid tariff structure where the peak load significantly affects the cost of using the grid.
- **Step 2:** Possibilities for trading flexibility across different end-users as a tool to adjust the individual peak load.



(a) Total load. (b) Apartment load (AP).

(c) Garage load (EV). (d) Domestic hot water load (DHW).

Fig. 5. Load profiles for the different cases when EV load is increased. Note that some of the plots are coinciding.



(a) Net capacity purchase positions for the MPT case. (b) Comparison of net storage filling in cases MP and MPT.

Fig. 6. Capacity interaction between end-users and storage filling operation.

Although the regulators in many countries currently adapt the regulations according to step 1, we conclude that step 2 is also required to reap the full potential of end-user flexibility. Trading of flexibility can take many forms, and an important area for further research is how trading schemes can be implemented in practice to benefit both grid companies and end-users. In this context, the end-users motivation and behaviour are vital aspects to consider in future research, and the concepts presented in this paper can be tested in neighbourhood-scale systems. Also, future research could go in the direction of investigating the end-user willingness to participate in trading schemes and the possibility of flexible stakeholders exercising market power in local electricity systems.

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.

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Appendix A

MCP formulation of local energy system

We derive the KKT conditions of the neighbourhood level based on the optimization problem described in section 3.3. Since our original problem is linear and has a convex feasible area, the KKT conditions are necessary and sufficient for optimality.

$$W_\omega*(1+VAT)*(P_{\omega,h}+T)+W_\omega*\left(vnt^M+vnt^S\right)-\lambda^{EB}_{c,\omega,h}+\mu^M_{c,\omega,h}+\mu^S_{c,\omega,h}\geq 0\perp imp_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.1}$$

$$W_\omega*\left(-P_{\omega,h}+vnt^E\right)+\lambda^{EB}_{c,\omega,h}\geq 0\perp exp_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.2}$$

$$W_\omega*\left(F+\lambda^N_{\omega,h}\right)-\mu^M_{c,\omega,h}-\mu^S_{c,\omega,h}+\mu^N_{c,\omega,h}\geq 0\perp n^+_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.3}$$

$$W_\omega*\left(-\lambda^N_{\omega,h}\right)+\mu^M_{c,\omega,h}+\mu^S_{c,\omega,h}+\mu^N_{c,\omega,h}\geq 0\perp n^-_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.4}$$

$$W_\omega*oc^S-\mu^S_{c,\omega,h}\geq 0\perp o_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.5}$$

$$W_\omega*cnt^M_\omega-\sum_{h=1}^{H}\mu^M_{c,\omega,h}\geq 0\perp n^M_{c,\omega}\geq 0\quad \forall c,\omega \tag{A.6}$$

$$cnt^S-\sum_{\omega=1}^{\Omega}\sum_{h=1}^{H}\mu^S_{c,\omega,h}\geq 0\perp n^S_c\geq 0\quad \forall c \tag{A.7}$$

$$\lambda^{EB}_{c,\omega,h}-\left(1-L^{ES}_c\right)*\lambda^{ES1}_{c,\omega,h}+\mu^{ES3}_{c,\omega,h}\geq 0\perp d^{\Delta+}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.8}$$

$$-\lambda^{EB}_{c,\omega,h}+\left(1+L^{ES}_c\right)*\lambda^{ES1}_{c,\omega,h}+\mu^{ES4}_{c,\omega,h}\geq 0\perp d^{\Delta-}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.9}$$

$$\lambda^{ES1}_{c,\omega,h}-(1-R_c)*\lambda^{ES1}_{c,\omega,h+1}+\mu^{ES2}_{c,\omega,h}\geq 0\perp s_{c,\omega,h}\geq 0\quad \forall c,\omega,h<H \tag{A.10}$$

$$\lambda^{ES1}_{c,\omega,H}-(1-R_c)*\lambda^{ES1}_{c,\omega,1}+\mu^{ES2}_{c,\omega,H}\geq 0\perp s_{c,\omega,H}\geq 0\quad \forall c,\omega,h=H \tag{A.11}$$

$$-\lambda^{EB}_{c,\omega,h}+\mu^{ER}_{c,\omega,h}\geq 0\perp g^{ER}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.12}$$

$$imp_{c,\omega,h}-exp_{c,\omega,h}-D_{c,\omega,h}-d^{\Delta+}_{c,\omega,h}+d^{\Delta-}_{c,\omega,h}+g^{ER}_{c,\omega,h}=0\perp\lambda^{EB}_{c,\omega,h}\quad \forall c,\omega,h \tag{A.13}$$

$$s_{c,\omega,h-1}*(1-R_c)+d^{\Delta+}_{c,\omega,h}*\left(1-L^{ES}_c\right)-d^{\Delta-}_{c,\omega,h}*\left(1+L^{ES}_c\right)-D^{\Delta-}_{c,\omega,h}-s_{c,\omega,h}+d^{pen+}_{c,\omega,h}-d^{pen-}_{c,\omega,h}=0\perp\lambda^{ES1}_{c,\omega,h}\quad \forall c,\omega,h>1 \tag{A.14}$$

$$s_{c,\omega,H}*(1-R_c)+d^{\Delta+}_{c,\omega,1}*\left(1-L^{ES}_c\right)-d^{\Delta-}_{c,\omega,1}*\left(1+L^{ES}_c\right)-D^{\Delta-}_{c,\omega,1}-s_{c,\omega,1}+d^{pen+}_{c,\omega,h}-d^{pen-}_{c,\omega,h}=0\perp\lambda^{ES1}_{c,\omega,1}\quad \forall c,\omega,h=1 \tag{A.15}$$

$$U^{ES}_c-s_{c,\omega,h}\geq 0\perp\mu^{ES2}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.16}$$

$$U^{ES}_c*CF^{ch}_c-d^{\Delta+}_{c,\omega,h}\geq 0\perp\mu^{ES3}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.17}$$

$$U^{ES}_c*CF^{dis}_c-d^{\Delta-}_{c,\omega,h}\geq 0\perp\mu^{ES4}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.18}$$

$$U^{ER}_c*G_{c,\omega,h}-g^{ER}_{c,\omega,h}\geq 0\perp\mu^{ER}_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.19}$$

$$n^M_{c,\omega}+n^+_{c,\omega,h}-n^-_{c,\omega,h}-imp_{c,\omega,h}\geq 0\perp\mu^M_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.20}$$

$$n^S_c+o_{c,\omega,h}+n^+_{c,\omega,h}-n^-_{c,\omega,h}-imp_{c,\omega,h}\geq 0\perp\mu^S_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.21}$$

$$n^{LIM}-n^+_{c,\omega,h}-n^-_{c,\omega,h}\geq 0\perp\mu^N_{c,\omega,h}\geq 0\quad \forall c,\omega,h \tag{A.22}$$

$$\sum_{c=1}^{C}\left(n^+_{c,\omega,h}-n^-_{c,\omega,h}+n^{pen+}_{c,\omega,h}-n^{pen-}_{c,\omega,h}\right)=0\perp\lambda^N_{\omega,h}\quad \forall\omega,h \tag{A.23}$$

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EIENDOM

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Bestemmelser om energi- og miljøkrav i reguleringsplaner – i lys av konseptet nullutslippsnabolag

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Sammendrag

Nullutslippsnabolag er områder med ambisjon om å redusere direkte og indirekte klimagassutslipp mot null. En av utfordringene kommuner og eiere/utbyggere møter når de vil bygge i tråd med normene for nullutslippsnabolag, er mangel på samordning mellom regler for arealplanlegging og energiproduksjon/-omsetning. Forskning viser at det i økende grad er det regulatoriske rammeverket som hindrer utviklingen, heller enn tekniske begrensninger. Artikkelen behandler energisamarbeid som virkemiddel, behovet for regulering av markedet for å oppnå ønsket samarbeid, og planmyndighetenes rettslige adgang til å vedta planbestemmelser om energirelaterte krav til bygninger. Konklusjonen er at dagens regelverk gir rom for relevante planbestemmelser, men at en lovendring vil kunne redusere usikkerhet og bidra til å fremme omforente mål.

Nøkkelord: nullutslippsnabolag, planbestemmelser, energiplanlegging, klimagassregnskap

1 Tema og problemstilling

Arealbruk i Norge styres i stor grad av arealplaner med hjemmel i lov 27. juni 2008 nr. 71 om planlegging og byggesaksbehandling (plan- og bygningsloven, pbl.) Plan- og bygningsloven er en omfattende og viktig lov for samfunnsutvikling generelt og arealbruk spesielt, og skal i utgangspunktet avstemme og balansere en rekke interesser. Klima- og miljøhensyn er blant de sentrale interessene loven skal ivareta. Redusert energibruk og økt andel fornybar energi faller derfor klart innenfor lovens formål.

Alle arealplaner inneholder tre elementer: et kart hvor ulike bruksformål m.m. er markert (*plankart*), en beskrivelse av planens bakgrunn og intensjon (*planbeskrivelse*), samt konkrete bestemmelser til planen (*planbestemmelser*). Planbestemmelser er en av mulighetene myndighetene har til å differensiere arealbruk innenfor arealformål, eller spesifisere bruken av formålet. Sammen med plankartet er planbestemmelsene rettslig bindende for både offentlige og private aktører. Byggetillatelser må dermed oppfylle krav fastsatt i bestemmelser, og unngå konflikt med aktuelle forbud disse inneholder.

Artikkelens tema er kommunens mulighet til å gi bestemmelser om energi- og klimakrav i reguleringsplaner. Bakgrunnen for å diskutere spørsmålet er nasjonale og lokale myndigheters ønske om å utvikle det bygde miljø i en mer klima- og ressursvennlig retning, blant annet ved å redusere energibruk i bygg og fremme lokal produksjon av energi.[1]

Aktører i bransjen har særlig fremhevet behov for planbestemmelser som virkemiddel for å fremme miljøhensynet, eksempelvis gjennom konsepter som nullutslippsnabolag. Imidlertid viser både kommuner og utbyggere til at «uklare grenser mellom plan og TEK skaper usikkerhet. Utbyggerne opplever i tillegg at plankravene kan være i direkte motstrid til TEK».[2] Oppfatningen av uklarhet kan ha sammenheng med en forestilling om forbud mot parallelle krav i henholdsvis planbestemmelser og regler i lovens byggesaksdel/forskrift om tekniske krav til bygg.

I punkt 2 drøftes hvorfor energisamarbeid på nabolagsnivå kan gi bedre resultater enn styring fra sak til sak. Aktørene og markedet har imidlertid behov for forutsigbare og langsiktige

[1] Bø, Junker og Askeland, «ZEN og lovverket», FME ZEN, Elverum vekst og Ydalir, «Kommuner har alt klart for mer klimavennlig utbygging, men stoppes av paragrafer!», 17. juli 2019.
[2] Ulstein mfl., «Praktisering av byggteknisk forskrift og planbestemmelser på tvers av landets kommuner».

rammevilkår – som kan oppnås gjennom planbestemmelser. Den sentrale problemstillingen vi diskuterer i punkt 3, er derfor hvilken adgang kommunen har til å sette krav til energibruk og klimabelastning i planer. Som illustrasjon underveis brukes behov og mulige løsninger knyttet til nullutslippsnabolag.

2 Konseptet nullutslippsnabolag og behovet for regulering

2.1 Hvorfor nullutslippsnabolag?

Nullutslippsbygninger (*zero emission buildings* – ZEB) begynner å bli et innarbeidet begrep, og definisjonen representerer en klimaambisjon for enkeltbygg som overgår de alminnelige tekniske kravene.[3] Fra et regulatorisk perspektiv er nullutslippsbygninger relativt uproblematiske, da det rettslige rammeverket er godt tilpasset enkeltbygg. Når det bygde miljø skal utvikles i energi- og klimavennlig retning, er det mer hensiktsmessig å konsentrere seg om områder heller enn enkeltbygg. På områdenivå kan man finne mer effektive løsninger for blant annet energibruk enn hva som er mulig ved å se på bygninger som separate enheter. For at klimaambisjoner skal kunne etterstrebes så effektivt som mulig, er det derfor nødvendig å utvide fokuset fra enkeltbygg til område.

Nullutslippsnabolag (*zero emission neighbourhoods* – ZEN) er et konsept som gjør det mulig å planlegge områder og utnytte ressurser bedre på tvers av aktører.[4] Konseptet er relativt nytt, men er i ferd med å etablere seg på linje med ZEB.[5] Når fokuset flyttes fra bygg til område, øker kompleksiteten siden flere aktører er involvert. Erfaringer viser at lovverk og andre rammevilkår er noe mindre tilpasset nullutslippsnabolag enn enkeltbygninger. I arbeidet med ZEN-pilotområder har kommuner støtt på utfordringer som tyder på at det i økende grad er det regulatoriske rammeverket som hindrer utviklingen, heller enn tekniske begrensninger.

Ved å flytte fokus fra å behandle enkeltbygninger på individuelt nivå til å se på løsninger på nabolagsnivå er det mulig å realisere samfunnsøkonomiske gevinster. Når det gjelder energiressurser, er det ønskelig å få til et samspill på tvers av bygninger og aktører fordi de ulike aktørene har ulike egenskaper og disponerer ulike ressurser. Et eksempel på dette er at man kan få en mye mer effektiv drift ved å la nabolagets samlede last være grunnlag for

[3] Forskningssenteret ZEB, «Zeb definisjoner».
[4] Marianne Kjendseth Wiik mfl., «Zero Emission Neighbourhoods in Smart Cities».
[5] Brozovsky, Gustavsen og Gaitani, «Zero Emission Neighbourhoods and Positive Energy Districts – A State-of-the-Art Review».

nettleien, fremfor at hver enkelt får en regning basert på sin egen maksimale last.[6] Mange vitenskapelige arbeider bygger på en forutsetning om at investeringer og drift optimeres på nabolagnivå,[7] selv om dette ikke er en regulatorisk realitet.

2.2 Forskjeller mellom gjeldende reguleringsmetoder for energi- og arealbruk

De regulatoriske rammeverkene for bygg- og energisektoren hviler på nokså ulike premisser, som medfører at regelverkene til dels mangler nødvendig samordning. I begge sektorer er poenget å avhjelpe markedssvikter, men måten disse håndteres på, er forskjellig. I bygningssektoren bruker myndighetene i hovedsak direkte regulering for å styre løsningene samfunnet får, mens i energisektoren overlater myndighetene helst til markedet å komme frem til de konkrete løsningene. Ved utvikling av nullutslippsnabolag ønsker man å se på bygninger som en integrert del av energisystemet, og det er behov for at regelverkene kobles tettere sammen. Grenseflaten mellom sektorene er imidlertid utfordrende da de regulatoriske rammeverkene ikke ble designet ut fra at de skulle passe sammen. De følgende avsnittene går nærmere inn på markedene for henholdsvis bygg og energi, og utfordringene knyttet til reguleringen av disse.

I byggsektoren forekommer markedssviktene gjerne på bakgrunn av manglende samsvar mellom insentiver, eksempelvis ved at det er leietaker som betaler for energien som brukes, mens byggeier må bekoste oppgraderinger som får ned oppvarmingskostnaden.[8] Forskning tyder på at aktørene i eiendomsmarkedet ikke opptrer rasjonelt som individuelle aktører, siden energieffektiviteten til et bygg ikke gjenspeiler seg i markedsprisen som oppnås.[9] EUs bygningsenergidirektiv er et eksempel på at direkte regulering brukes for å tilstrebe resultatet av et perfekt marked. Direktivet krever at hvert land skal stille kostnadsoptimale krav vedrørende hvordan bygg blir konstruert.[10] I Norge stilles disse kravene gjennom minimumskrav til konstruksjon av bygninger.

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[6] Backe, Kara og Tomasgard, «Comparing Individual and Coordinated Demand Response with Dynamic and Static Power Grid Tariffs».
[7] Se bl.a. Sadeghi mfl., «The Energy Hub»; Orehounig, Evins, og Dorer, «Integration of Decentralized Energy Systems in Neighbourhoods Using the Energy Hub Approach»; Pinel, Korpås og B. Lindberg, «Impact of the CO 2 Factor of Electricity and the External CO 2 Compensation Price on Zero Emission Neighborhoods' Energy System Design».
[8] Kholodilin, Mense og Michelsen, «The Market Value of Energy Efficiency in Buildings and the Mode of Tenure».
[9] Se f.eks. Gram-Hanssen mfl., «Do Homeowners Use Energy Labels?»; Fuerst mfl., «Energy Performance Ratings and House Prices in Wales».
[10] European Parliament, Directive (EU) 2018/844 of the European Parliament and of the Council of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency.

Hva som er kostnadsoptimalt, vil imidlertid variere ut fra hvor i Norge man er. For eksempel vil det sannsynligvis være kostnadseffektivt med tykkere isolasjon i veggen på Røros enn langs sørlandskysten. Ved direkte regulering gjennom absolutte, nasjonale krav blir det vanskelig å gjøre slike lokale tilpasninger, siden kommunene mangler adgang til å vurdere og fastsette normer etter lokale behov. Alternativet til slike nasjonale krav er å la markedet finne den kostnadsoptimale tilpasningen selv. Nasjonale regler som byggteknisk forskrift[11] representerer i denne sammenheng en minimumsstandard, og utbyggere står fritt til selv å velge høyere standarder dersom markedet etterspør dette. Dette krever imidlertid at markedet er velfungerende i den forstand at det optimale utfallet faktisk oppnås.

I energibransjen lar man i hovedsak markedet komme frem til løsningen, og fokuset til de regulatoriske myndighetene er på hvordan man kan fjerne markedssvikter, heller enn å finne ut hvilke krav man skal stille. Kraftregningen til sluttbruker består av én kostnad for produksjon av energien og én kostnad for transport gjennom kraftnettet, i tillegg til skatter og avgifter. For energiproduksjon er et eksempel på den regulatoriske myndighetens forsøk på å skape konkurranse blant kraftleverandører kravet om at alle sluttkunder fritt skal kunne velge hvem man vil handle strøm fra, og at informasjonen som gis fra leverandørene, skal være enkel å sammenligne.

Reguleringen av transport av strøm er et annet eksempel på hvordan myndighetene forsøker å styrke markedet. Distribusjonsnett har en fundamental markedssvikt da dette er et naturlig monopol, blant annet på grunn av stordriftsfordeler og at det er uhensiktsmessig med parallell infrastruktur for å skape konkurranse. Her benyttes også markedsinsentiver som et styringsverktøy fra de regulatoriske myndighetene, selv om man ikke kan etablere konkurranse i tradisjonell forstand.[12] I nettbransjen er direkte konkurranse mellom aktørene erstattet med et system hvor selskapene gis insentiver til å gjøre det bedre enn snittet: «Gulroten» er at effektiv drift åpner for høyere overskudd.

Det er riktignok noen unntak fra de generelle karakteristikkene som skiller reguleringen i bygg- og energisektoren. Det forekommer at direkte regulering også brukes i energibransjen, og et eksempel på dette er at kunder med egen energiproduksjon (gjerne kalt plusskunder) gis unntak fra konsesjonsplikt for salg av elektrisk energi så lenge de ikke mater inn mer enn 100 kW på nettet.[13] Et tilsvarende eksempel fra byggsektoren der man prøver å forbedre

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[11] Forskrift om tekniske krav til byggverk (byggteknisk forskrift).
[12] Falch, *Rett til nett*, s. 20–40.
[13] Forskrift om økonomisk og teknisk rapportering, inntektsramme for nettvirksomheten og tariffer.

markedet, er at man har begynt å stille krav om energimerking av bygg. Ordningen skal påvirke hvordan markedet fungerer, ved å avhjelpe markedssvikten som går på tilgangen på informasjon.[14] Det er likevel verdt å understreke forskjellen i underliggende motiver og mekanismer mellom de to områdene: «Konkurranseretten er dominert av overveielser knyttet til samfunnsøkonomisk effektivitet. Forvaltningsretten er på den annen side dominert av overveielser knyttet til rettssikkerhet og saklighet.»[15]

2.3 Regulatorisk risiko som faktor for langsiktige beslutninger

Dagens regulatoriske rammeverk vanskeliggjør koordinering av energiløsninger på tvers av aktører/bygg, særlig grunnet insentivstrukturen.[16] Energiloven er i stor grad tilpasset enkeltbygg og dermed mindre egnet for å få til energibalansering på nabolagsnivå. Gjeldende regelverk har i så måte et misforhold mellom hva som er optimalt hvis man ser på nabolaget under ett, og hva som er fornuftig fra et privatøkonomisk perspektiv. Et annet vesentlig element er regulatorisk risiko – altså muligheten for at regelendringer kan påvirke den fremtidige lønnsomheten av investeringer.

Ved valg av rettslige løsninger er det nødvendig å ta hensyn til de mange og til dels motstridende interesser på området. Et sentralt eksempel er at investeringer i bygningskropp og energitekniske løsninger som regel har lang levetid. Man regner normalt med å drifte et solcelleanlegg i minst 20 år,[17] og en enebolig bygges for å vare i mange tiår. Dermed blir reguleringens forutsigbarhet og regulatorisk risiko en viktig faktor når man skal gjøre slike investeringer.

I energibransjen gis unntak fra regler i forbindelse med å teste nye løsninger i en begrenset tidsperiode, gjerne fra ett til fem år. For nyskapende energiløsninger på nabolagsnivå er gjerne hele forretningsmodellen basert på slike regulatoriske unntaksforhold, og man er avhengig av en viss lønnsomhet i driftsfasen for at investeringen skal kunne forsvares. Fornybare energiressurser har en spesiell kostnadsstruktur i form av at de har høye investeringskostnader, og driftskostnader ned mot null.

[14] Olaussen, Oust og Solstad, «Energy Performance Certificates – Informing the Informed or the Indifferent?»; Jensen, Hansen og Kragh, «Market Response to the Public Display of Energy Performance Rating at Property Sales».
[15] Hammer, «Ingvald Falch: Rett til nett.»
[16] Askeland, Backe og Lindberg, «Zero Energy at the Neighbourhood Scale».
[17] Lai og McCulloch, «Levelized Cost of Electricity for Solar Photovoltaic and Electrical Energy Storage».

Denne kostnadsstrukturen gjør at slike investeringer er særlig sårbare for langsiktig regulatorisk risiko da de er avhengige av en viss driftsmessig lønnsomhet over en periode på flere tiår for å være konkurransedyktige. Ved kortsiktige regulatoriske unntak må investor ta økonomisk høyde for at unntaket bortfaller, og at man etter utløpet av unntaksperioden går tilbake til ordinært regelverk. På grunn av denne motsetningen mellom unntakets varighet og investeringens levetid har unntak etter energiregelverket begrenset evne til å utløse investeringer i ny teknologi.

I byggsektoren kan det derimot gis dispensasjon fra reglene i plan- og bygningsloven eller bestemmelser fastsatt i samsvar med loven. Kommunen kan gi både varig og midlertidig dispensasjon. Eksempler på tema det gis dispensasjon fra, er arealformål, byggegrenser og høydekrav samt ulike plankrav. Det kan også dispenseres fra byggteknisk forskrift (TEK17) for både nye prosjekter og tiltak på eksisterende bygninger. For tiltak på eksisterende bygg vil ofte unntaksbestemmelsene i § 31-2 være bedre egnet, og mer i tråd med lovens system, ettersom disse uttrykkelig gir adgang til å fravike gjeldende krav uten den omfattende dispensasjonsprosessen.[18] TEK17 er som nevnt en minimumsforskrift. Så lenge kravene i forskriften blir oppfylt, er det ingen hindringer for å «overoppfylle». Det er dermed intet behov for dispensasjon hvis utbygger *ønsker* energiløsninger som går utover TEK17. Poenget er at dispensasjoner for bygningskroppen ofte gis som varige dispensasjoner, og gir dermed en tryggere ramme enn energibransjens unntak som normalt gis for inntil 5 år.

2.4 Plan- og bygningsregler som virkemiddel for energipolitikk og -teknologi

Faktorene ovenfor viser hvorfor arealplanlegging er et viktig virkemiddel for å realisere målsettinger innen energibruk og klima. Plan- og bygningsloven er samtidig en lov hvor politikere kan utøve en del skjønn. Rammen for både regler og skjønn er lovens overordnede mål, nemlig å «fremme bærekraftig utvikling til beste for den enkelte, samfunnet og framtidige generasjoner» (§ 1-1 første ledd). Bærekraftig utvikling er i seg selv et utfordrende konsept og kan til tider synes å ha interne konflikter. Diskusjonen om bærekraftbegrepets kjerne og periferi faller klart utenfor rammene for denne artikkelen.

En annen kjensgjerning er at konsepter som bærekraftig utvikling er i stadig utvikling. Innholdet og balansen i begrepet kan endres over tid, og da vil også behovet for innhold i forvaltningens vedtak endres. Gjennom å gi lovregler som skal fremme bærekraftig utvikling, sørger Stortinget for et regelverk som holder seg oppdatert selv om det naturvitenskapelige

[18] Norsk Kommunalteknisk Forening, «Tekniske krav ved tiltak i eksisterende bygg».

eller politiske grunnlaget endrer seg. Riktignok kan dynamiske regler være negativt for lovens formål om forutsigbarhet, som både skal beskytte investeringer og gjøre det enklere for bedrifter å overholde regelverket. Når det gjelder forutsigbarhet, vil det ha stor betydning hvordan endringene skjer: Hensynet til forutsigbarhet kan oppfylles ved relativt store og hyppige endringer hvis innhold, tidspunkt og eventuelle overgangsordninger er gjennomtenkte og godt organiserte.

Et eksempel på at innholdet i bærekraftsbegrepet kan utvikle seg, er at produksjon og bruk av energi er i endring. Introduksjonen av ny teknologi, som solceller og elbiler, har skapt nye behov og muligheter. Private husstander og bedrifter kan i større grad enn før produsere egen strøm. Denne utviklingen er klart i tråd med EUs planlagte revisjon av kraftmarkedet (arbeidet omtales tidvis som «the Winter Package»).[19] Imidlertid gjør lovverket at lokale produsenter i utgangspunktet er henvist til å bruke strømmen selv.

En nylig vurdering av forholdet mellom norsk lovgivning og konseptet nullutslippsnabolag dokumenterer flere problemstillinger.[20] Ønsker private produsenter å levere strøm til nettet, må de for eksempel både ha egnet utstyr og særskilt avtale med eieren av nettet i området. Et tenkelig alternativ er å gi private mulighet til å handle energi direkte seg imellom, noe som også muliggjør mer gunstige forretningsmodeller og dermed mer utbygging av lokale energiløsninger.[21] Norges energi- og vassdragsmyndighet utga i 2019 en rapport om det norske energiregelverket og slike lokale energimarkeder.[22] Rapporten konstaterte at det var betydelige rettslige barrierer for å etablere og drive lokal handel med energi på en hensiktsmessig måte. Reguleringsmyndigheten kan gi unntak for å teste ut lokale markedsmekanismer, men som diskutert ovenfor vil unntak med kun noen års varighet være lite egnet til å realisere slike prosjekter. Innholdet i rapporten var knyttet til energilovgivning, og den vurderte i liten grad forholdet til plan- og bygningsloven.

Problemstillinger knyttet til energipolitiske og -tekniske endringer er også kjent internasjonalt: Allerede i 2009 diskuterte Lončar mfl. rettslige og markedsmessige forutsetninger for arbeid med «samproduksjon» av elektrisk energi i Kroatia. Forfatterne undersøkte rettslige og markedsmessige forutsetninger for småskala produksjon av energi av

[19] European Commission, «Clean Energy for All Europeans».
[20] Bø, Junker og Askeland, «ZEN og lovverket».
[21] Askeland mfl., «Helping End-Users Help Each Other».
[22] THEMA Consulting Group og Multiconsult Norge AS, «Descriptive study of Local Energy Communities».

boligeiere.[23] En tilsvarende tilnærming ble brukt av britiske forskere som studerte innovasjoner innen energilagring.[24] En voksende trend i næringen er etablering av lokale mikronett («microgrids») hvor en avgrenset gruppe tilbydere og brukere er koblet sammen direkte og kan opptre som én enhet mot hovednettet.[25] Både i slike mikronett og tradisjonelle kraftnett er forbrukerens rolle i endring – fra den tradisjonelle konsumenten til en hybrid produsent/konsument (prosument, *prosumer*).[26] Imidlertid er denne utviklingen utfordrende fra et regulatorisk perspektiv, da retten til å kreve fellesmåling falt bort i 2010. Enkeltkunder skal nå som hovedregel ha individuell måling og avregning av strømforbruk.[27] Mangfoldet av hensyn som skal ivaretas, og innslaget av politisk skjønn, gjør krysningspunktet mellom energipolitikk og arealregulering særlig komplekst.

2.5 Behovet for planbestemmelser

Gjennomgangen i dette kapittelet viser at det er betydelige forskjeller mellom markedene for energi og bygg. Ulikhetene kommer blant annet til syne i hvordan markedene er regulert. Mens aktører i energibransjen stort sett forholder seg til indirekte regulering og insentiver (f.eks. å drive mer effektivt enn snittet i sektoren), er byggebransjen stort sett regulert gjennom direkte krav til sluttproduktet (f.eks. krav til høyde, lys, tetthet, isolasjonseffekt osv. på bygninger).

Ulikheten gjør det vanskelig å oppnå nullutslippsnabolag ved hjelp av energiregelverket. Det er behov for å benytte regelverket om arealdisponering og bygg i tillegg. Neste kapittel undersøker i hvilken grad kommunen kan bidra til etablering av nullutslippsnabolag gjennom sin myndighet etter plan- og bygningsregelverket.

Både teknologisk og politisk utvikling trekker i retning av økt lokal produksjon av fornybar energi. For å støtte og realisere en slik utvikling vil det antagelig være nødvendig å benytte plansystemet, for å sikre at energi- og arealbruk koordineres. Spørsmålet er i denne sammenheng begrenset til i hvilken grad lovverket gir mulighet for å stille energirelaterte krav i planbestemmelser. Dette avhenger av en tolkning av loven, blant annet knyttet til formålet om bærekraftig utvikling.

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[23] Lončar, Duić og Bogdan, «An analysis of the legal and market framework for the cogeneration sector in Croatia».
[24] Castagneto Gissey, Dodds og Radcliffe, «Market and regulatory barriers to electrical energy storage innovation».
[25] Hirsch, Parag og Guerrero, «Microgrids», 403.
[26] Wolfgang mfl., *Prosumers' Role in the Future Energy System*.
[27] Forskrift om økonomisk og teknisk rapportering, inntektsramme for nettvirksomheten og tariffer.

Eiere og utbyggere som kontrollerer et samlet område, kan fritt velge å bygge i tråd med konseptet nullutslippsnabolag. Tilsvarende kan kommunen inngå privatrettslige avtaler om slikt samarbeid hvis kommunen for eksempel selger tomtene til et prosjekt. Slike situasjoner faller imidlertid utenfor denne artikkelens tema. Problemstillingen med planbestemmelser blir først aktuell når kommunen *som planmyndighet* ønsker å *pålegge andre å utføre sine bygg på en bestemt måte*.

Reglene i byggteknisk forskrift bygger på flere hensyn, blant annet hva som er samfunnsøkonomisk gunstig. Beregningen av samfunnsøkonomisk verdi kan være forskjellig fra sted til sted, og derfor vil det i utgangspunktet være fornuftig å tilpasse løsninger ut fra lokale forhold. Samtidig brukes samfunnsøkonomi også som et argument for å ha samme regler over hele landet, slik at arkitekter, rådgivende ingeniører og andre aktører slipper å tilpasse seg hver enkelt kommune. Ulempen med dette er at løsningene blir «one size, fits all» (eller i praksis muligens «fits none»).

Et argument for å la være å ha lokale regler for det som reguleres nasjonalt, er at det er opp til aktørene å selv komme frem til bedre løsninger lokalt. Problemet med dette er imidlertid at hva som er samfunnsøkonomisk optimalt, ikke nødvendigvis sammenfaller med hva som er bedriftsøkonomisk optimalt. Eksempelvis kan en samfunnsøkonomisk beregning vise at om man gjennomfører en ny type energiløsning i et område, vil dette være gunstig dersom alle er med på det. Samtidig kan det være bedriftsøkonomisk lønnsomt for enkeltaktører å avvike fra dette, og hvis dette skjer, forringes samfunnsøkonomien for området som en helhet. For å unngå slike problemer er det gunstig om lokale myndigheter kan styre valg av løsninger på tvers av aktører. På samme måte som andre inngrep i markeder må naturligvis slike lokale krav avveies mot og holdes innenfor konkurranserettslige rammer (herunder EU/EØS-krav på området). Detaljer om konkurranseretten faller imidlertid utenfor denne artikkelens ramme.

Den videre undersøkelse av kommunens adgang til å fastsette planbestemmelser følger alminnelig rettslig metode. I det avsluttende kapittelet flytter vi oppmerksomheten noe videre, fra gjeldende rett til hvordan virkemidler kan utvikles for bedre å imøtekomme behovet skapt av politisk og teknologisk utvikling. Avslutningsvis oppsummerer vi våre funn.

3 Adgang til å gi planbestemmelser om energi- og miljøkrav

3.1 Systematisk plassering og historisk utvikling

Plan- og bygningsloven skiller mellom to nivåer for kommunale arealplaner – den overordnede kommuneplanen, og den detaljerte reguleringsplanen. Begge typer planer kan ha planbestemmelser, men hjemlene for mulige bestemmelser er noe mer begrensede for kommuneplanen (§§ 11-9, 11-10 og 11-11). Loven gir også rom for å gi statlige planbestemmelser (§ 6-3) og regionale planbestemmelser (§ 8-5). For temaet energibruk i bygg er imidlertid kommunens reguleringsplannivå det klart viktigste siden det i all hovedsak er denne plantypen som danner grunnlaget for byggesøknader. Videre i denne artikkelen begrenser vi derfor diskusjonen til reglene om reguleringsplaner, nærmere bestemt § 12-7.

Det er også viktig å skille mellom plan- og byggesaksdelen i loven. I planfasen har kommunen stort spillerom og kan i utgangspunktet fritt velge om de skal igangsette planarbeid, og i så fall hvordan planarbeidet skal innrettes. Etter loven kan riktignok private (grunneiere, utbyggere) fremme forslag til planer, som eventuelt overtas av kommunen og får status tilsvarende kommunens egne. I praksis utgjør private planforslag majoriteten av planer som behandles. Det er likevel kommunen som avgjør om planforslaget skal vedtas – private har intet rettskrav på å få gjennomført sine forslag.

Når det gjelder byggesaksdelen, er det derimot utbygger alene som har initiativet, og tradisjonelt har *byggeretten* stått sterkt i plan- og bygningsretten.[28] Denne rettigheten er nær forbundet med eiendomsretten: Så lenge man følger lover og regler, har man rett til å utnytte eiendommen sin som man vil. Lovens system for byggesak er med andre ord lovbundet: Hvis en søknad er i tråd med lov, relevante forskrifter og gjeldende planer, har tiltakshaver krav på tillatelse (pbl. § 21-4). Forvaltningen har i utgangspunktet ingen adgang til å avslå søknader den mener er lite hensiktsmessige.[29]

Ettersom byggeretten har så sterk posisjon, er den allmenne oppfatning at vedtak som begrenser retten, krever hjemmel i lov – på samme måte som andre inngrep i privat eiendomsrett eller autonomi. Hovedregelen om begrensning av byggeretten har vært lovens vilkår om at tiltaket må oppfylle krav «gitt i eller i medhold av» plan- og bygningsloven, se § 21-4. Planbestemmelser er gitt i medhold av loven, og faller derfor innenfor regelen. Metoden med å gi utfyllende, skriftlige bestemmelser var anerkjent allerede da den første riksdekkende bygningsloven ble vedtatt i 1965.[30]

[28] Reusch, *Plan- og bygningsrett i et nøtteskall*.
[29] Reusch, «Adgangen til å stille vilkår ved tillatelser etter plan- og bygningsloven», s. 26–27.
[30] Pedersen mfl., *Plan- og bygningsrett*, del 1:33.

De første hjemlene for å begrense byggeretten gjennom det som i dag kalles planbestemmelser, var imidlertid svært spesifikke. Loven ga opprinnelig adgang til å angi utformingen av konkrete tiltak, slik som plassering, høyde og utforming av bygg. Etter hvert oppstod flere behov, og lovens liste over lovlige bestemmelser ble sakte utvidet. Ved den påfølgende revisjonen av loven i 1985 ble systemet endret, slik at loven heller ga *rammer* for hva det kunne gis bestemmelser om.

Med 2008-loven ble det igjen innført en liste over alle lovlige bestemmelser, henholdsvis §§ 11-9 til 11-11 for kommuneplannivået og § 12-7 nr. 1-14 for reguleringsplaner. Loven innebar samtidig en ytterligere utvidelse av muligheten for bestemmelser. Prinsipielt gikk likevel loven tilbake til ordningen med en fullstendig oppregning av mulige bestemmelser. I forarbeidene påpeker departementet at selv om § 12-9 må regnes som uttømmende, «er den formulert så vidt at den vil kunne dekke alle relevante forhold».[31]

Selv om loven og forarbeidene kan gi inntrykk av at handlingsrommet for bestemmelser er tilnærmet ubegrenset, er det naturlig nok flere begrensninger. En oppfatning som tilsynelatende har bred tilslutning i praksis, er at planbestemmelser normalt ikke kan gå inn på virkeområdet til andre lover og forskrifter. Et typisk eksempel er tekniske krav til byggverk, som forutsettes styrt av byggesaksdelen i loven, og da særlig kapittel 29. I dette kapittelet undersøker vi de alminnelige tolkningsfaktorene for rettsregler – lov, forarbeider, praksis og teori – med sikte på å undersøke denne og andre grenser. Dessuten diskuterer vi hvordan utviklingen i energipolitikk og -teknologi kan påvirke tolkningen.

3.2 Lov og forarbeider om grenser for bestemmelser

Lovens rammer for å gi bestemmelser til reguleringsplaner fremgår av § 12-7. I § 12-7 lister loven opp en rekke typer krav som kan stilles i reguleringsplaner. Opplistingen er uttømmende, men i henhold til forarbeidene skal den altså omfatte alle «relevante forhold».[32] Hva som menes med relevante forhold, må tolkes i lys av lovens formål og system samt forarbeider, veiledning og teori.

Lovens ordlyd i § 12-7 nr. 3 og 4 taler for at det kan gis bestemmelser til reguleringsplaner om krav til energibruk. Etter nr. 3 kan kommunen vedta bestemmelser om «grenseverdier for tillatt forurensning og andre krav til miljøkvalitet i planområdet». Regelen er etter ordlyden

[31] Ot.prp. nr. 32 (2007–2008) Om lov om planlegging og byggesaksbehandling (plan- og bygningsloven) (plandelen), s. 232.
[32] Ot.prp. nr. 32 (2007–2008) Om lov om planlegging og byggesaksbehandling (plan- og bygningsloven) (plandelen), s. 32.

knyttet til direkte negativ miljøpåvirkning, slik som utslipp fra industri osv. Forarbeidene legger også vekt på forurensningshensynet – men det er ingen tydelige indikasjoner på at hjemmelen er begrenset til tradisjonell forurensning (miljøgifter, sot, partikler mv.) For bestemmelser om utslipp og påvirkning skriver departementet i forarbeidene at det «forutsettes at kommunen har hjemmel til dette i forhold til andre regler om forurensning, særlig forurensningsloven».[33]

I paragrafens nr. 4 gir loven kommunen myndighet til å vedta bestemmelser om «funksjons- og kvalitetskrav til bygninger, anlegg og utearealer, herunder krav for å sikre hensynet til helse, miljø, sikkerhet». Også her dekker ordlyden isolert sett krav til bygninger med sikte på å redusere energibruk, for å kunne ivareta miljøhensyn. I forarbeidene er hjemmelen eksemplifisert med «krav til kvalitet og utforming som sikrer definerte funksjonskrav, knyttet til f.eks. forebyggende helsevern, sikkerhet mot ulykker, god luftkvalitet, avfallsløsninger».[34] Eksemplene illustrerer et bredt spekter av tema som kan reguleres i bestemmelser. Et funksjonskrav som av hensyn til miljø (energisparing) satte krav om økt isolasjon i veggen, ville falt naturlig innenfor definisjonen. Det samme gjelder en bestemmelse som av hensyn til miljøet stilte krav om en viss lokal energiproduksjon pr. kvadratmeter.

Lovens ordlyd og forarbeidenes kommentarer til de enkelte bestemmelser gir med andre ord rom for å stille krav til energiforbruk og -produksjon i reguleringsplaner. I merknaden til hjemmelen for kommuneplanbestemmelser kommenterer imidlertid departementet at intensjonen er å beholde «det eksisterende skillet mellom krav som stilles i plan og krav som stilles i teknisk forskrift til plan- og bygningsloven.» Energikrav for det enkelte bygg nevnes som et av eksemplene på tema som bare skal reguleres av byggteknisk forskrift. Selv om bemerkningene om skillet mellom planbestemmelser og krav til det enkelte bygg står i forbindelse med bestemmelser til kommuneplanen, er det grunn til å tro at samme tankegang har vært gjeldende for reguleringsplaner. I motsatt fall ville det vært naturlig å ha en merknad om det i kommentarene til § 12-7.

3.3 Nasjonal veiledning og uttalelser om planbestemmelser

Regjeringens veiledning til reglene om planbestemmelser inngår i veiledningen om reguleringsplaner. Veiledningen til reguleringsplaner etter nåværende lov har kommet i to

[33] Ot.prp. nr. 32 (2007–2008) Om lov om planlegging og byggesaksbehandling (plan- og bygningsloven) (plandelen), s. 233.
[34] Ot.prp. nr. 32 (2007–2008) Om lov om planlegging og byggesaksbehandling (plan- og bygningsloven) (plandelen), s. 233.

utgaver, henholdsvis T-1490 (2011) og dagens Reguleringsplanveileder (2018). Den tidligere veilederen var i stor grad basert på forarbeidene, inkludert forutsetningen om at krav til det enkelte bygg skal følge av byggteknisk forskrift.[35] Samtidig fastholdt veiledningen at § 12-7 skal bidra til å oppnå formålet om «å få den best mulige arealbruk totalt sett etter en helhetlig avveining av de ulike interesser».[36]

Dagens veileder gjentar poenget om at reguleringsbestemmelsene må innordne seg etter det som ellers er fastsatt i plan- og bygningslovgivningen, men åpner for at bestemmelser «kan brukes til å utdype eller presisere de øvrige lovbestemmelsene». Senere i samme punkt understreker likevel departementet at «[d]et kan ikke gis bestemmelser som er i strid med nasjonalt regelverk, som f.eks. forskrift om tekniske krav til byggverk (TEK)».[37]

I veiledningen viser departementet også til en ekstern undersøkelse av hvordan kommuner bruker bestemmelser.[38] Undersøkelsen viser at kommuner i en viss grad bruker planbestemmelser til å gjenta eller presisere tekniske krav i strid med TEK. I noen tilfeller oppstår motstrid mellom TEK og reguleringsplanen. Uoverensstemmelse mellom krav kan skape uforutsigbarhet og økte kostnader både for utbygger og kommunen. For denne artikkelens tema er det verdt å merke seg en pussig detalj i veilederen: I omtalen av den eksterne undersøkelsen viser departementet til at bestemmelser med kobling til TEK ofte gjelder «universell utforming og tilgjengelighet, *energikilder*, radonsikring og støy».[39] Mens både universell utforming, radonsikring og støy er særskilt behandlet i rapporten, er energi knapt nevnt. Uten grunnlagsmaterialet er det umulig å undersøke dette nærmere, men tilsynelatende kan departementet ha fremhevet energi mer enn det var grunnlag for.

Kommunens hjemmel for å vedta planbestemmelser er altså ment å være dekkende for de behov som kan oppstå. Samtidig påstås det betydelige innskrenkninger med hensyn til tekniske krav. Politisk og teknologisk utvikling har tilsynelatende skapt et misforhold mellom det som var lovens intensjon (å kunne gi bestemmelser om alle relevante forhold), og behov i samfunnet (å kunne gi planbestemmelser om energibruk i de enkelte bygg). Nasjonal veiledning kan dermed bidra til å hindre en ønsket dynamisk utvikling.

3.4 Forvaltnings- og rettspraksis om planbestemmelser

[35] Miljøverndepartementet, «Reguleringsplan veileder T-1490», s. 56.
[36] Miljøverndepartementet, s. 47.
[37] Kommunal- og moderniseringsdepartementet, «Reguleringsplanveileder» pkt. 6.2.
[38] Ulstein mfl., «Praktisering av byggteknisk forskrift og planbestemmelser på tvers av landets kommuner».
[39] Kommunal- og moderniseringsdepartementet, «Reguleringsplanveileder» pkt. 6.2, uthevet her.

En annen vesentlig faktor for tolkingen av muligheten til å vedta planbestemmelser om energikrav er forvaltningspraksis. Som nevnt i innledningen har adgangen til å stille bestemmelser betydelig historie i norsk arealforvaltning. Regelverket har utviklet seg i takt med behov og praktisering, og praksis vil dermed være en relevant faktor for forståelsen. Forvaltningspraksis kan imidlertid være vanskelig å fastlegge. En mulig kilde er veiledning, som for eksempel kan bygge på «best practice» eller typetilfeller. I tråd med dette kan nasjonalforvaltningens veiledning om reguleringsplaner (gjennomgått ovenfor) anses som et uttrykk for forvaltningspraksis. Som nevnt ovenfor trekker denne i retning av at konkrete krav til energibruk i enkeltbygg faller utenfor hjemmelen i § 12-7.

Noen tegn om praksis kan også hentes ut fra teori, samt korrespondanse med departementet om ulike spørsmål. Teorien behandler vi separat i delkapittel 3-5. Her vil vi bare kort nevne eksempler på hvordan korrespondanse med departementet bidrar til å klargjøre praksis: I 2015 skrev Boligbyggernes landsforbund til ansvarlig departement (Kommunal- og moderniseringsdepartementet, KMD) med spørsmål om lovens § 12-7 ga hjemmel for krav om «grønne tak», altså tak dekket med jord og planter. Svaret var at departementet fortsatt anså andre formelle regler som en grense for planbestemmelser, men at på områder hvor det ikke finnes noen særskilte regler i lov eller forskrift, har i utgangspunktet kommunen anledning til å gi de bestemmelser den måtte ønske.[40]

Et lignende brev ble besvart omtrent samtidig, hvor spørsmålet gjaldt kommunens adgang til å kreve ladeplasser for elbiler. Departementets svar var at siden dette var et aspekt som falt utenfor de konkrete kravene i TEK, kunne kommunen fritt stille krav – så lenge behovet ble vurdert konkret og reelt.[41] Fra og med 1. juli 2021 krever TEK at parkeringsplasser i nye prosjekter klargjøres for ladeanlegg.[42] Etter vårt syn vil departementets svar fortsatt være relevant og gjeldende, da det er betydelig forskjell på klargjøring for ladeanlegg og faktiske ladeplasser.

Endelig spurte Kristiansand kommune i 2018 om det var adgang til å stille krav om bruk av tre i bygg på grunn av klimahensyn. Departementet svarte at det var adgang til dette, både ut fra estetiske og miljømessige hensyn. Funksjonskrav i TEK (brann, lyd osv.) må naturligvis

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[40] Kommunal- og moderniseringsdepartementet, «§ 12-7 Kommunenes adgang til å stille tekniske krav i plan».
[41] Kommunal- og moderniseringsdepartementet, «§ 12-7 – spørsmål om reguleringsbestemmelser om ladepunkter for elbiler».
[42] Forskrift om tekniske krav til byggverk (byggteknisk forskrift) § 8-8.

oppfylles uansett.[43] Denne korrespondansen viser at det foregår en diskusjon om praktiseringen av hjemlenes rekkevidde. Usikkerhet og/eller uenighet knyttet til hvor langt kommunen kan gå i å stille krav til utbyggere, gjør at partene fra tid til annen ber om avklaring fra departementet.[44]

Om saken ikke finner sin løsning gjennom korrespondanse med departementet, kan den ende i rettsvesenet. Som rettskilde er det vesentlig enklere å behandle rettspraksis enn forvaltningspraksis, fordi systemet bidrar til å spesifisere og dokumentere sakene. Ulempen med rettspraksis er at det gjerne er tvilstilfellene som kommer til behandling, og at de dermed gir et lite representativt bilde av virkeligheten. Når det gjelder adgangen til å vedta planbestemmelser om energikrav, har det så vidt vites aldri blitt prøvd en sak for de alminnelige domstoler.

Selv om behandlingen av energikrav er fraværende, går det an å trekke paralleller til utviklingen på andre områder: I 2019 ble to saker prøvd for Oslo tingrett, hvor utbyggere påstod at henholdsvis planbestemmelser om rekkefølgekrav og utbygningsavtaler manglet rettslig grunnlag.[45] Utbyggerne vant begge sakene i tingretten, men kommunen anket og vant begge sakene i lagmannsretten. Begge sakene ble deretter anket videre til Høyesterett. Den ene ble avvist av ankeutvalget.[46] Høyesterett valgte imidlertid å behandle saken om en rekkefølgebestemmelse om en tursti – den såkalte Bispelua-saken.[47] Høyesterett kom til at begrunnelsen i fylkesmannens (statsforvalterens) avgjørelse[48] ga uttrykk for en feilaktig rettsoppfatning, og at saken derfor måtte sendes tilbake til lagmannsretten. Høyesteretts begrunnelse ga lite veiledning for vurderingen av adgangen til å stille miljø- og energikrav etter § 12-7.

3.5 Juridisk teori om planbestemmelser

Juridisk teori kan bidra til både å belyse hvordan forvaltningen praktiserer reglene, og til å supplere tolkningen av regelen (gjennom argumentasjon basert på prinsipper, system, formål, mulighet for håndhevelse mv.) Planbestemmelser er relativt lite problematisert i juridisk teori.

[43] Kommunal- og moderniseringsdepartementet, «Spørsmål om pbl. § 12-7 gir hjemmel til å gi reguleringsbestemmelse om bruk av tre», 31. mai 2019.
[44] Se også kommentarer om klimaperspektivet i disse sakene i Holth, «Plan- og bygningsloven. Vår viktigste klimalov?».
[45] Hauge, «Nødvendighetskriteriene i plan- og bygningsloven §§ 12-7 og 17-3 tredje ledd – to nye tingrettsdommer om rekkefølgekrav og utbyggingsavtaler».
[46] HR-2021-1142-U Tullinkvartalet (avvist anke).
[47] HR-2021-953-A Bispelua.
[48] Fylkesmannen i Oslo og Akershus, vedtak 22. april 2017

Lovkommentarer og lærebøker baserer sin omtale i stor grad på lovtekst, forarbeider og veiledning nevnt ovenfor.[49]

Databasen Idunn omfatter totalt ca. 38 000 artikler, men søk etter «planbestemmelser» gir i skrivende stund bare 32 treff. Tilsvarende gir søk etter «føresegner plan» 30 treff. Søk i hele Lovdata PROs oversikt over juridiske artikler etter «planbestemm*» gir bare 18 resultater, og «føresegn» + henvisning til plan- og bygningsloven gir 12. Det er betydelig overlapping blant treffene. Av artiklene er det bare et fåtall som kan belyse spørsmålet om kommunens adgang til å vedta planbestemmelser om energikrav. Her fremhever vi bare dem vi mener er mest relevante.

I artikkelen «Miljøkrav for akvakultur i kommunale arealplaner» diskuterer Svein *Kornerud* kommunens adgang til å fastsette planbestemmelser om oppdrett.[50] Hans synspunkt er at kommunen har nokså stor frihet på grunn av lovens helhetlige formål. Kornerud unngår imidlertid å trekke tydelige yttergrenser for sitt standpunkt. Argumentene i artikkelen har dessuten den begrensning at akvakulturanlegg faller utenfor TEK17 – og at skillet mellom forhold som dekkes av TEK17, og alt annet, ikke er diskutert. Artikkelen er imidlertid relevant fordi den diskuterer forholdet mellom kommunens handlingsrom og lovens formål.[51] Korneruds konklusjon går tilsynelatende noe lenger enn *Myklebust*, som bare konstaterer plan- og bygningslovens tydelige miljøformål.[52]

Jan Gudmund *Aanerud* står bak artikkelen «Tolkning av reguleringsplaner», som i hovedsak handler om tolking og anvendelse av skriftlige planbestemmelser i planer basert på private planforslag. Aanerud beskriver hvordan uklare bestemmelser kan medføre unødige kostnader og ulemper. Videre viser artikkelen på en grundig og pedagogisk måte hvordan planbestemmelser tidvis må tolkes. I den forbindelse underbygger han sterkt *planbeskrivelsens* betydning ved tolking av planbestemmelser.[53]

Marianne *Reusch* diskuterer «[a]dgangen til å stille vilkår ved tillatelser etter plan- og bygningsloven», og kommer i den forbindelse også innom bruk og omfang av planbestemmelser. Hun påpeker blant annet utviklingen knyttet til planbestemmelsers fysiske og geografiske tilknytning til formålet: Tidligere var det forventet tettere sammenheng

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[49] Se bl.a. Holth og Winge, *Plan- og bygningsrett*; Pedersen mfl., *Plan- og bygningsrett*; Innjord, *Plan- og bygningsloven med kommentarer, bind 1, plandelen*.
[50] Kornerud, «Miljøkrav for akvakultur i kommunale arealplaner».
[51] Kornerud, s. 52.
[52] Myklebust, «Miljøkrav i saker som gjeld akvakultur», s. 184–85.
[53] Aanerud, «Tolkning av reguleringsplaner», s. 142, 149 flg.

mellom vilkår og tillatelser, men det er i stor grad akseptert at tilknytningen er mer indirekte.[54]

Som kilde til den faktiske praktiseringen reflekterer teorien i stor grad det samme bildet som dannes av forarbeider, nasjonal veiledning og rettspraksis: Det eksisterer et skille mellom krav til det enkelte bygg, som behandles i hovedsak i teknisk forskrift, og krav i planer, som dreier seg om andre forhold. I argumentasjonen er det imidlertid klare fordeler ved oppmyking av dette skillet: Skal planer kunne fylle sin funksjon, er det nødvendig at også visse aspekter ved bygningers tekniske standard kan reguleres.

3.6 Tolking av § 12-7 i lys av lovens ordlyd, formål og system

Vi mener gjennomgangen av lovens ordlyd, forarbeidene, veiledning, praksis og teori gir et tosidig inntrykk: På den ene siden opererer forarbeider og litteratur (veiledning, eksterne rapporter m.m.) med et budskap om at kommunen som planmyndighet har tilnærmet ubegrenset myndighet. Samtidig har det utviklet seg en praksis hvor innholdet i en forskrift (TEK) regnes som en absolutt grense for kommunens adgang til å vedta bestemmelser. Grensen mellom plan og byggesak er i liten grad begrunnet i kildene, men kan ha sammenheng med den tidligere sektordelingen av plan- og bygningsretten: Planer tilhørte miljøforvaltningen, mens byggesaksreglene var Kommunaldepartementets domene. Selv om loven nå er samlet i ett departement, kan skillet henge igjen i praktiseringen. Ønske om å unngå dobbeltregulering kan også være en faktor. Synkrone krav på nasjonalt nivå er dessuten en fordel for byggenæringen, som slipper å tilpasse løsninger til hvert enkelt byggeprosjekt. Forutsigbarhet og standardiserte løsninger er presumtivt en fordel for kunder/forbrukere, gjennom at sluttkostnaden kan bli lavere.

Begrensningen utgjør imidlertid et reelt hinder for å etterstrebe lovens mål om bærekraftig utvikling knyttet til reduksjon av energibruk, for eksempel gjennom etablering av nullutslippsnabolag. Vi mener derfor det er grunn til å stille spørsmål ved det antatte skillet mellom krav til det enkelte bygg og andre krav.

For det første er det verdt å merke seg at loven ikke inneholder noen regel om derogasjon – altså at forskrift skal gjelde foran lov. I mangel av en slik derogasjonsregel må eventuelle konflikter mellom lov og forskrifter tolkes i tråd med alminnelige prinsipper. I så fall vil lovens intensjon om å gi hjemmel for alle relevante bestemmelser veie tungt.

[54] Reusch, «Adgangen til å stille vilkår ved tillatelser etter plan- og bygningsloven».

På samme måte viser andre bestemmelser i loven at det på langt nær eksisterer noe enhetlig, gjennomført skille mellom krav som stilles til planområdet, og krav som stilles til det enkelte bygg. For eksempel kan kommunen i vid utstrekning avgjøre bygningers visuelle utforming, både gjennom planbestemmelser og gjennom vilkår til den enkelte søknad (§ 29-2). «De fleste forhold vedrørende bygningers utseende og ytre utførelse kan fastlegges ved bruk av kartsymboler og bestemmelser. Planen kan gå langt i detaljering. Eksempel: Fasadeoppriss kan bindes opp i planen og den kan fastsette vindusplassering av hensyn til å unngå naboinnsyn.»[55] Kommunen kan også gi dispensasjon fra tekniske krav hvis vilkårene i loven er oppfylt (§ 19-2).

En streng grense for å stille krav knyttet til forhold regulert i TEK kan også gi vanskelige grensetilfeller. Hvis en bestemmelse stiller krav til veggtykkelse, vil det kunne ha betydning for U-verdi (dvs. energibehov, som er regulert i TEK). Kommunen kan imidlertid begrunne kravet som en visuell faktor. Det fremstår som lite hensiktsmessig hvis kommunens motiv skal ha avgjørende betydning for om bestemmelsen er lovlig. En slik tolkning kan oppmuntre kommuner til å bruke det visuelle/estetiske som hjemmel (§ 12-7 nr. 1) – selv om det kanskje i praksis er en underliggende intensjon om å redusere energibruken. Vi mener hensynet til forutberegnelighet og åpenhet taler sterkt for at bestemmelsers formål må være lettfattelige og klare.

Et annet argument for å tillate bestemmelser knyttet til det enkelte bygg er lovens formål. Departementet skrev i forarbeidene at § 12-7 var uttømmende, men likevel skulle gi rom for alle relevante bestemmelser. I veiledningen om reguleringsplaner fastslår departementet at en del tema faller utenfor det som kan reguleres gjennom bestemmelser i plan- og bygningsloven (slik som regulering av aktivitet og virksomhet). Like fullt, påpeker veiledningsteksten, er det vid hjemmel etter pbl. § 12-7 til å stille vilkår for å fremme formålet med planen. Slike vilkår kan også i stor grad rettes mot virksomhet og aktivitet som motvirker de hensyn som planen skal ivareta. Bygge- og arealbruksrestriksjonene samt vilkårene for gjennomføring vil derfor både direkte og indirekte påvirke virksomhet og drift i stor grad.[56]

Her antyder departementet at hjemmelen kan fortolkes nokså liberalt, så lenge man utformer bestemmelsene på en måte som opprettholder det formelle skillet mellom bygging/arealbruk og aktivitet/virksomhet. For eksempel kan en planbestemmelse neppe kreve at en

[55] Miljøverndepartementet, «Reguleringsplan veileder T-1490», s. 49.
[56] Miljøverndepartementet, s. 48.

næringseiendom regulert til bevertning skal ha en bestemt profil (lunsj-kafé, restaurant, pub, nattklubb e.l.) Planbestemmelser om utforming, belysning, støy, parkering o.l. kan derimot i praksis gjøre det veldig vanskelig å drive for eksempel en bar / et serveringssted med relativt mye støy.

Lovens formål er å fremme bærekraftig utvikling, og planlegging skal legge vekt på langsiktige løsninger. Det fremstår som lite hensiktsmessig at et vesentlig område av arealbruken (tekniske krav til det enkelte bygg) skal være unntatt fra en viktig del av kommunens virkemidler.

3.7 Særlig om bestemmelser med krav til anleggsfasen

Et spørsmål som jevnlig dukker opp i diskusjoner om nullutslippsnabolag, er hva som gjelder for anleggsfasen i byggeprosjekter, og i hvilken grad kommunen kan stille krav til denne. Nullutslippsnabolag er nemlig kjennetegnet av at de planlegges, designes og drives ut fra et mål om null «klimagassutslipp over livsløpet».[57] En anleggsperiode hvor mye drives av fossilt drivstoff, vil kunne gjøre det umulig å oppnå et nullutslippsnabolag.

Derfor oppstår spørsmålet om kommunen gjennom planbestemmelser også kan påvirke anleggsfasen gjennom planbestemmelser. Som nevnt ovenfor gjelder § 12-7 nr. 4 uttrykkelig også «anlegg», og det er dermed mulig å tro at også anleggsfasen kan være objekt for bestemmelser. Etter begrepsbruken i teknisk forskrift er det imidlertid mer nærliggende å tolke lovens uttrykk slik at det knytter seg til ventilasjonsanlegg, sprinkleranlegg eller avløpsanlegg – altså konkrete anlegg integrert i eller nær knyttet til selve byggverket.

Et annet moment i vurderingen er at loven gir rom for å sette bestemmelser om krav til undersøkelser og overvåkning av ulike faktorer, § 12-7 nr. 12. På dette området har det vært vanlig å stille prosessuelle krav, for eksempel gjennom at en arealplan inkluderer en planbestemmelse om at det skal lages en miljøoppfølgingsplan (MOP). Det rettslige elementet i en slik bestemmelse vil bare være selve plikten til å lage planen, og spesifiserte undersøkelser og overvåkninger. Konkrete tiltak eller vilkår som må oppfylles, må knyttes til andre hjemler.

Eventuelle krav til anleggsfasen vil uansett neppe komme i konflikt med TEK slik at problemstillingen om grensen mellom plan og enkeltbygg settes på spissen. Av de aktuelle

[57] Marianne Kjendseth Wiik mfl., «Zero Emission Neighbourhoods in Smart Cities», s. 49; Bø, Junker, og Askeland, «ZEN og lovverket», s. 21.

hjemlene i dagens lov overlapper § 12-7 nr. 3 lite direkte med det som reguleres av TEK. § 12-7 nr. 4 omfatter «bygninger, anlegg og utearealer», mens TEK omtaler sitt virkeområde som «byggverk» (TEK17 § 1-3 (b)). Forskriftens uttrykk omfatter bygninger, konstruksjoner og anlegg «så langt det er relevant».[58]

Kravene til energi i TEK17 følger av forskriftens kapittel 14. I veiledningen til kapittelet står det at kapittelet «gjelder alle bygninger med mindre annet er angitt».[59] Basert på en isolert tolkning vil konstruksjoner og anlegg dermed falle utenfor, og kan i utgangspunktet styres fritt med hensyn til energi. Imidlertid vil den praktiske nytten av denne muligheten trolig være liten. Isolasjonskrav (U-verdier) og netto energibehov er lite relevante for andre ting enn bygninger, og den totale effekten vil også være begrenset.

En annen potensiell begrensning av planmyndighetens hjemmel til å fastsette planbestemmelser for anleggsfasen er at reglene kan tenkes å gripe inn i andre deler av lovverket. Hvis en bestemmelse om anleggsfasen stiller krav til utslipp, vi det være parallelt til forurensningslovens regler. Tilsvarende vil krav til fossilfrie kjøretøy ligge nær typegodkjenning av kjøretøy. Det er imidlertid fast og langvarig praksis for at visse overordnede hensyn kan og skal ivaretas på tvers av ulike sektorer og forvaltningsorganer – særlig i prosesser med helhetlig formål, som arealplanlegging. En viktig dom på området er Lunner pukkverk-dommen, som konstaterte prinsippet allerede i 1993.[60]

Endelig kan krav til anleggsfasen også begrenses av grensen mot regulering av virksomhet: Som gjennomgått ovenfor skal planbestemmelser knytte seg til bruken av arealer, ikke privatrettslige forhold eller den konkrete driften. Dette er i større grad et spørsmål om utforming av bestemmelsen; så lenge kravene som stilles er generelle, unngås konflikt.

Hvorvidt lovens hjemmel dekker innholdsmessige krav til anleggsfasen (slik som «fossilfrie anleggsplasser»), er etter dette et relativt åpent spørsmål. Hverken loven, forskrifter, veiledning eller teori synes å gi direkte svar på problemstillingen. Til støtte for tolkingen vil vi derfor også her trekke inn formålshensyn og rettstekniske hensyn: Skal loven gi best mulig forutsetninger for å oppfylle målet om bærekraftig utvikling, vil det være hensiktsmessig å kunne stille krav også til anleggsfasen. Det samme gjelder rettstekniske hensyn: Anleggsfasen utgjør en vesentlig del av byggesaken og har stor praktisk sammenheng med selve

[58] Direktoratet for byggkvalitet, «Byggteknisk forskrift (TEK17) med veiledning», til § 1-3 b.
[59] Direktoratet for byggkvalitet til kap. 14.
[60] Rt. 1993 s. 528 (Lunner pukkverk).

byggverket. Hvis anleggsfasen faller utenfor reglene om planbestemmelser, vil det vesentlig redusere muligheten kommunen har til å påvirke gjennomføringen av byggeprosjekter

Parallelt med arbeidet med denne artikkelen har spørsmålet om utslipps- og fossilfrie anleggsplasser vært diskutert og utredet i bransjen og av myndighetene. Advokatfirmaet Hjort DA og Planavdelingen i Kommunal- og moderniseringsdepartementet har vurdert hjemmelsgrunnlaget for planbestemmelser om henholdsvis *utslippsfrie* og *fossilfrie* anleggsplasser. Hjort konkluderer med at spørsmålet er «komplisert og tvilsomt», men at bestemmelser om utslippsfrie anleggsplasser sannsynligvis faller utenfor hjemmelen i nåværende lov.[61] Planavdelingen trekker samme konklusjon om fossilfrie anleggsplasser, dog med en noe annerledes begrunnelse.[62] Ingen av utredningene går spesifikt inn på energikrav eller nullutslipp som konsept for bygg. Vår oppfatning er derfor at konklusjonene kan bli annerledes i tilfeller som det vi drøfter her.

3.8 Særlig om bestemmelser med krav til klimagassregnskap og -reduksjon

Som nevnt er det et bærende element for nullutslippsnabolag at klimagassutslipp søkes redusert til null.[63] Et nødvendig virkemiddel for å kunne redusere utslipp er å vite nok om kilder til og omfang av utslippene. Kunnskap om bygningers klimapåvirkning kan organiseres i det som kalles klimagassregnskap. Målet med slike regnskap er å kunne sammenligne klimapåvirkningen av ulike varianter av utvikling. I den nasjonale veiviseren for bærekraftige offentlige anskaffelser beskrives virkemiddelet på denne måten: «Ved å lage klimagassregnskap for bygget, med klimagassutslipp fra materialbruk identifiseres de største utslippene. […] Et klimagassregnskap viser hvor det bør settes inn tiltak for å redusere totale utslipp.»[64]

Utarbeiding av klimagassregnskap er et anerkjent og ofte brukt krav i reguleringsplaner. Hjemmelen er § 12-7 nr. 12 om «nærmere undersøkelser før gjennomføring av planen». Planbestemmelsen kan også spesifisere hvilke tema som skal inkluderes, og hvilken metode som skal benyttes. For eksempel har Standard Norge utviklet et eget system for

[61] Zimmermann mfl., «Vurdering av om gjeldende plan- og bygningslov gir hjemmel til å innføre krav om utslippsfrie bygge- og anleggsplasser».
[62] Kommunal- og moderniseringsdepartementet, «§ 12-7 Anmodning om tolkningsuttalelse – hjemmel for krav om fossilfri anleggsplass i reguleringsplan».
[63] Marianne Kjendseth Wiik mfl., «Zero Emission Neighbourhoods in Smart Cities».
[64] Direktoratet for forvaltning og økonomistyring, «Kriterieveiviseren».

klimagassberegninger i bygninger – NS 3720.[65] Denne type regnskap gir et sammenlignbart grunnlag for å vurdere utslippene fra ulike bygg på plan- og prosjektstadiet.

Spørsmålet i denne sammenheng er om kommunen i planfasen også har anledning til å stille krav om nivåer – altså hvilke nivåer klimagassutslipp som kan tillates i et planområde. Til sammenligning står kommunen rimelig fritt som byggherre, og bærekraftsveiviseren foreslår formuleringer som «Klimagassutslipp skal samlet reduseres med minst 40 % sammenlignet med et referansebygg».[66]

Gjennomgangen i denne artikkelen har vist at skillet mellom planbestemmelser og tekniske krav til det enkelte bygg trolig er mindre tydelig enn oppfatning og praksis skulle tilsi. Det finnes mange eksempler på krav om klimagassregnskap, men så vidt oss bekjent har ingen kommuner stilt konkrete krav om reduksjon av klimagasser i planbestemmelser. En grundig gjennomgang av kildematerialet, sammen med den senere tids uttalelser fra departementet, gir etter vår mening grunn til å revurdere gjeldende holdning og praksis.

Plan- og bygningsloven § 12-7 nr. 3 gir hjemmel for å begrense «tillatt forurensning og andre krav til miljøkvalitet i planområdet». Klimagassutslipp kan utvilsomt regnes som forurensning. Det kan riktignok diskuteres om utslipp knyttet til produksjon av byggematerialer skjer i planområdet, alternativt om det er noe poeng å stille krav til minimering av klimaendringer «i planområdet». Det interessante med dette punktet i paragrafen er imidlertid at ordlyden eksplisitt påpeker at kommunen kan gi planbestemmelser også av hensyn til forhold *utenfor* planområdet. Også lovens § 12-7 nr. 4 gir etter ordlyden mulighet for å sette krav til bygninger av hensyn til miljøet. Selv om dette punktet mangler uttrykkelig henvisning til forhold utenfor planområdet, er «miljø» et hensyn som sjelden gir mening ta hensyn til bare innenfor det enkelte planområdet.

Vi mener etter dette at kommunen også har adgang til å kreve konkrete nivåer av klimagassutslipp i planbestemmelser, både etter § 12-7 nr. 3 og 4. Resultatet følger av en nokså omfattende tolkning og navigering mellom ulike bestemmelser i regelverket.

3.9 Energi- og miljøkrav i planbestemmelser – behov for ny hjemmel?

Basert på kildene mener vi det er klare argumenter for å utfordre den rådende oppfatning om at adgangen til å gi planbestemmelser begrenses av innholdet i TEK. Kommunen har allerede

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[65] Standard Norge, «NS 3720:2018».
[66] Direktoratet for forvaltning og økonomistyring, «Kriterieveiviseren».

flere muligheter til å påvirke utformingen av det enkelte bygg – herunder av hensyn til estetikk, miljø og omgivelser. Argumenter knyttet til lovens formål og system taler for at bestemmelser også må kunne skjerpe krav fastsatt i TEK, så lenge motivet og det faglige grunnlaget er holdbart. Planbeskrivelser kan være en viktig tolkningsfaktor for å anvende bestemmelser i tråd med intensjonen.

Selv om loven etter en slik tolkning kan gi rom for krav om visse aspekter ved nullutslippsnabolag, kan det være gode grunner til å vurdere en ny hjemmel i lovens § 12-7. Et sentralt hensyn vil være det pedagogiske aspektet. Plan- og bygningsloven er et regelverk som i stor grad anvendes av personer med annen faglig hovedprofil enn juss (ingeniører, arkitekter, planleggere mv.). Loven er derfor strukturert på en oversiktlig og hovedsakelig kronologisk måte, og selve paragrafene er formulert relativt utfyllende. Et annet viktig poeng vil være å oppklare forholdet mellom planbestemmelser og tekniske forhold.

For å tilrettelegge for nullutslippsnabolag vil det etter vårt syn være en fordel om lovgiver vedtok et tilleggspunkt til listen over tillatte bestemmelser i § 12-7. En ny hjemmel for bestemmelser kunne for eksempel vært modellert etter eksisterende regel om tilrettelegging for fjernvarme, og krav om tilknytning til slikt tilbud (§ 12-7 nr. 8). Innenfor et område kunne det fastsettes krav om samarbeid og utforming av det enkelte bygg, med mål om å bli et nullutslippsnabolag.

En annen eksisterende hjemmel som kan tjene som inspirasjon for en regel om energiplanlegging, er § 11-8 tredje ledd bokstav e. (Paragrafen står i kapittelet om kommuneplanen, og etter § 12-6 skal hensynssoner «legges til grunn» i reguleringsplanarbeidet.) Den aktuelle typen hensynssoner stiller krav til felles planlegging for flere eiendommer. Gjennom bestemmelser til slike soner blir kravet rettslig bindende. I tråd med det som er beskrevet ovenfor om nullutslippsnabolag, er samarbeid mellom flere aktører ofte en forutsetning for å oppnå gode løsninger.

En eller flere slike nye planbestemmelser vil bare utgjøre en del av den rettslige løsningen for å fremme nullutslippsnabolag. Som denne artikkelen viser, vil det også være nødvendig med endringer i energiregelverket. Noen sentrale elementer fremheves i punkt 4 nedenfor. Konkrete detaljer om dette faller imidlertid utenfor artikkelens rammer.

4 Implikasjoner for regulering og praktisering

4.1 Energiplanlegging i nabolagsperspektiv

Regelverket om produksjon og handel med energi har en klar og direkte forbindelse til reglene om arealplanlegging og -forvaltning: Både produksjon og konsum av energi finner sted på et fysisk område. Overføring av energi har også et betydelig «fotavtrykk» – særlig merkbart utenfor tettbygd strøk. Med tanke på lovens formål om samordning fremstår det derfor noe paradoksalt når anlegg for overføring og omforming av elektrisk energi i all hovedsak er unntatt plan- og bygningsloven (§ 1-3). (Utfordringer knyttet til forholdet mellom plan- og bygningsloven og energilovgivningen er blant annet diskutert av Winge.[67]) Spørsmålet om lokalisering av vindkraftanlegg ble aktualisert høsten 2020 da Stortinget diskuterte retningslinjer for konsesjonsbehandling.[68] Selv om problematikken ligner, faller spørsmål om plassering av høyspentlinjer og vindkraft på siden av artikkelens tema.

I kapittel 2 argumenterte vi for at det vil være mer effektivt at energiplanlegging har et større perspektiv enn enkeltbygg, da det er mer effektivt med helhetlige løsninger enn at hver enkelt aktør skal planlegge og drifte sine systemer individuelt. Nabolagssamarbeid forutsetter imidlertid at aktørene har egeninteresse av å handle i tråd med hva som er mest gunstig for nabolaget som en helhet. Her gir dagens regulatoriske rammeverk manglende samsvar mellom hva som er optimalt hvis man ser på nabolaget under ett, og hva som er fornuftig fra et privatøkonomisk perspektiv.

Dette har konsekvenser ved at selv om utbygger ønsker å være mer ambisiøs enn de byggtekniske minimumskravene, er det ikke nødvendigvis lønnsomt å tenke helhetlig rundt energiløsningene. For eksempel kan det være mer kostnadseffektivt å etablere et felles anlegg for energiproduksjon og lagring i nabolaget enn å bygge flere mindre anlegg. Her mener vi at det regulatoriske rammeverket bør tilpasses slik at det i større grad blir privatøkonomisk lønnsomt å samarbeide om energiløsninger på tvers av aktører. Dette kan oppnås gjennom at avregningsobjektet blir mer fleksibelt, og at man åpner for at aktører kan handle energi og/eller nettkapasitet med hverandre for å kunne samarbeide om nabolagets totale energibalanse.

Regulatorisk risiko ble særskilt belyst i punkt 2.3, og vi viste til at kortsiktige unntak som for eksempel å tillate lokal energihandel vil ha begrenset evne til å realisere investeringer i kapitalintensive teknologier som solcelleanlegg. Et mulig grep for å redusere den regulatoriske risikoen uten å måtte gi unntakene lengre varighet er at det etableres et fond

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[67] Winge, *Kampen om arealene*.
[68] Olje- og energidepartementet, Meld. St. 28 (2019–2020).

eller lignende som kan sikre investorene mot manglende lønnsomhet, der utbetaling kan defineres ut ifra om unntaket videreføres eller ikke. En slik mekanisme vil kunne være egnet til å utløse investeringer da den langsiktige, regulatoriske risikoen flyttes fra byggeier til organet som forvalter et slikt fond. Rent praktisk kan man for eksempel benytte Enova som forvalter av denne mekanismen, og i så fall benytter man en forsikring mot fremtidig risiko som utløsende mekanisme heller enn direkte støtte.

Energilovens målsetting om å skape økonomisk effektivitet må bevares samtidig som man tar hensyn til de behovene nullutslippsnabolag skaper. I denne sammenheng er det viktig å bevare aspektet om fritt leverandørvalg for kunder. Gjeninnføring av fellesmåling er neppe veien å gå. Imidlertid vil det kunne legges mekanismer for lokalt samarbeid på toppen av dagens markedsstruktur gjennom etablering av lokale energimarkeder eller ulike former for felles avregning av nettleie. Dersom det åpnes for slike samarbeidsmekanismer, bør disse være frivillige ved at enkeltkundene selv bestemmer hvilke markeder de ønsker å delta i.

Det at enkeltkunder selv skal være ansvarlig for å optimalisere driften av sine tekniske systemer, er imidlertid urealistisk, og driftsoptimaliseringen kan foregå ved at kunden inngår en kontrakt med en tredjepart som optimaliserer driften av energiressursene på vegne av kunden. Her kan kunden spesifisere sine preferanser i form av elementer som innetemperatur og når bilen skal være fulladet, og så tar tredjeparten seg av å optimere driften av de fleksible ressursene innenfor dette. I dag finnes det aktører som utfører slike tjenester innenfor rammene til enkeltbygg,[69] og teknologien ligger til rette for at slike tredjeparter også vil kunne optimalisere ressurser på tvers av kunder dersom det etableres markedsmekanismer som gjør dette gunstig.

4.2 Oppsummering og implikasjoner

Tema for denne artikkelen er hvilke muligheter kommunen har til å stille energi- og miljøkrav i planfasen – og mer spesifikt hvilke regulatoriske utfordringer som oppstår i arbeidet med å etablere nullutslippsnabolag. For å opprette et nullutslippsnabolag i tråd med rådende definisjoner er det flere faktorer som må være til stede: Bygninger må ha visse tekniske kvaliteter (først og fremst lavt energibehov), og infrastruktur må gi mulighet for samarbeid/stordriftsfordeler, for eksempel knyttet til kollektivtransport og lokalt energisamarbeid.

[69] F.eks. Tibber: https://tibber.com/no

Visse nødvendige forutsetninger faller utenfor kommunens styringsmulighet som planmyndighet. Dette gjelder blant annet de nødvendige markedsmekanismene for å fremme gode løsninger på tvers av enkeltbygg og aktører. På grunn av disse faktorene vil plan- og bygningsloven alene være utilstrekkelig til å garantere etablering av nullutslippsnabolag. Skal kommunen være sikker på at et område utvikles i tråd med konseptet, må også det regulatoriske rammeverket på energisiden støtte opp om dette.

Gjennom artikkelen har vi imidlertid vist at kommunen kan fremme forutsetningene for nullutslippsnabolag betydelig gjennom planbestemmelser. Vi mener det er lite holdbart å gå ut fra at kommunens mulighet til å sette planbestemmelser styres ensidig av innholdet i byggteknisk forskrift. Forskriften er rettslig sett underordnet loven, og ingen kilder antyder intensjon om derogasjon – altså overføring av myndighet fra Stortinget til departementet/direktoratet. Begrunnelsen synes primært å være en arbeidsfordeling mellom det som gjelder henholdsvis «planfaglige» og «bygningstekniske» aspekter.

Når målet er å opprette nullutslippsnabolag, og dermed knyttet til klimagassreduksjon, mener vi eksisterende regelverk gir mulighet for å stille strengere krav enn minimumskravene i byggteknisk forskrift. I denne vurderingen er det også relevant å nevne at hverken grunneier, utbygger eller andre har noen rettslig vernet forventning om å utnytte et areal før byggetillatelse er gitt. I prinsippet er det helt opp til planmyndigheten om en eiendom skal kunne utvikles. Selv om en plan er vedtatt, kan den endres uten konsekvenser for kommunen. Fremtidig arealbruk er dermed enklere å regulere enn for eksempel igangværende virksomhet.

Siden skillet mellom planbestemmelser og tekniske krav er nokså innarbeidet, er det likevel grunn til å vurdere en presisering av loven og veiledningen. En bekreftelse av rettstilstanden gjennom endring av praksis vil kreve kommuner med stab og politikere som vil teste grensene. Utvikling gjennom praksis vil lede til en mer tilfeldig (og trolig langvarig) prosess. Derfor mener vi at en presisering av plan- og bygningsloven er nødvendig for å avklare kommunens hjemmel til å fastsette bestemmelser i reguleringsplaner, og fremme etableringen av nullutslippsnabolag på en hensiktsmessig måte.

5 Forfatternes bidrag og finansiering

EJ: konsept, førsteutkast, metode, planbestemmelser, konklusjoner, struktur/formattering,
MA: innledning, metode, energiloven, insentiver for energiplanlegging,

gjennomlesing/kommentarer, LAB: konsept, sertifiseringsordninger, dispensasjon, gjennomlesing/kommentar. Alle forfatterne har lest og godkjent den endelige teksten.

Artikkelen er skrevet i forbindelse med arbeid i Forskningssenteret for nullutslippsområder i smarte byer (FME ZEN), inkludert workshop og ZEN-case om lovverket,[70] samt dialog med en rekke pilotområder med relevante problemstillinger. Forfatterne er takknemlige for støtten fra ZEN-partnerne og Norges forskningsråd (prosjektnr. 257660). Forfatterne er ukjente med eventuelle interessekonflikter.

Forfatterne ønsker å rette en stor takk til redaksjonen og den anonyme fagfellen som har bidratt med gode og samvittighetsfulle innspill.

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Appendices

Appendix A: Credit Author Statement

This thesis is based on seven publications with multiple authors involved. This section is provided to state the roles of the authors. The authors responsible for the publications are:

- Eivind Junker (EJ)
- Lars Arne Bø (LB)
- Karen Byskov Lindberg (KL)
- Magnus Askeland (MA)
- Magnus Korpås (MK)
- Sigurd Bjarghov (SBj)
- Steven Adam Gabriel (SG)
- Stian Backe (SBa)
- Thorsten Burandt (TB)

Based on [104] this work uses a high-level taxonomy including 14 roles that can be used to represent the roles typically played by contributors to scientific scholarly output. The roles describe each contributor's specific contribution to the scholarly output:

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

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.

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

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

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

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

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

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

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

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

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

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

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.

Table A.1 provide an overview of which roles each author has had in the papers this thesis is based on.

Table A.1: Credit author statement

	EEM19	ZEB19	EEM20	ENSYS	ECON	SMART	EIENDOM
Conceptualization	MA and MK	MA and SBa	MA, SBa and SBj	MA	MA, MK, SBa and SBj	KL, MA, SBa and SBj	EJ, LB and MA
Data curation	MA	N/A	SBj	MA and TB	MA	MA	N/A
Formal Analysis	MA	N/A	SBj	MA	MA	MA	N/A
Funding acquisition	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Investigation	MA	MA and SBa	MA, SBa and SBj	MA and TB	MA	MA	EJ, LB and MA
Methodology	MA and MK	MA and SBa	MA and SBj	MA, SG and TB	MA, MK and SBa	MA and KL	EJ and MA
Project administration	MA	MA	SBj	MA	MA	MA	EJ
Resources	MK	KL	MA	SG and TB	MK	KL	LB and MA
Software	MA	N/A	MA and SBj	MA and TB	MA	MA	N/A
Supervision	MK	KL	N/A	SG	MK	KL and MK	N/A
Validation	MA and MK	KL, MA and SBa	MA, SBa and SBj	MA and TB	MA, MK, SBa and SBj	MA and KL	EJ, LB and MA
Visualization	MA	MA	SBj	MA	MA	MA	N/A
Writing – original draft	MA	MA	SBj	MA and TB	MA	MA	EJ, LB and MA
Writing – review/edit	MA and MK	KL, MA and SBa	MA, SBa and SBj	MA, SG and TB	MA, MK, SBa and SBj	KL, MA, MK, SBa and SBj	EJ, LB and MA

Appendix B: Complementarity problem example

A simple equilibrium problem is formulated to demonstrate how this can be represented as a complementarity model. For simplicity, all variables are nonnegative.

B.1 Problem formulation

First, we have the optimization problem of a power-producing company in eq. (B.1).

$$\begin{aligned} &\text{minimize} \quad && -\sum_{f=1}^{F}\sum_{h=1}^{H}(\lambda_h - MC_{f,h}) * g_{f,h} \\ &\text{subject to} \quad && g_{f,h} \leq G_{f,h}^{max} \quad (\mu_{f,h}^{max}), \quad \forall f, \forall h \end{aligned} \tag{B.1}$$

The power producer seeks to maximize profits over several generators (f) and hours (h). Maximization of profits is equivalent to minimizing negated profits, which is the difference between the market price (λ_h) and marginal costs ($MC_{f,h}$) multiplied with the output ($g_{f,h}$). The restriction states that the output from each generator can not exceed the maximum output (G_f^{max})

The demand side is formulated in eq. (B.2) which seeks to minimize the costs of energy. The cost of demanded energy is the market price multiplied by the demanded energy (d_h). The demand side has a restriction that requires that the demanded energy is at least the specified amount (D_h^{min}). With this formulation, the demanded energy will be as low as possible for positive power prices, and therefore equal to the specified amount. For negative power prices, the problem becomes unconstrained and would therefore require additional constraints. This demand-side formulation could have been represented by a single parameter D_h^{min}, but a simple optimization problem is used to illustrate how a complementarity problem is formed based on different optimization problems.

$$\begin{aligned} &\text{minimize} \quad && \sum_{h=1}^{h}\lambda_h * d_h \\ &\text{subject to} \quad && D_h^{min} \leq d_h \quad (\mu_h^{dem}), \quad \forall h \end{aligned} \tag{B.2}$$

The market operators problem is formulated in eq. (B.3) and is the problem of minimizing curtailment costs. Curtailment costs are the curtailment price (P^{max}) multiplied with the load curtailment (lc_h). The market operator's problem is special since it includes market clearing, which states that demand subtracted load curtailment must equal the supply. The dual variable of the market-clearing is specified as the market price, which is considered by the market participants.

$$\begin{aligned} \text{minimize} \quad & P^{max} * lc_h \\ \text{subject to} \quad & d_h - lc_h = \sum_{f=1}^{F} \sum_{h=1}^{H} g_{f,h} \quad (\lambda_h), \quad \forall h \end{aligned} \tag{B.3}$$

KKT conditions of these optimization problems are necessary for optimality. Since we have linear optimization problems, derivation with respect to decision variables and dual variables is also sufficient for optimality.

Differentiating the producer problem wrt. $g_{f,h}$ gives the optimality condition related to generation:

$$MC_{f,h} - \lambda_h + \mu_{f,h}^{max} \geq 0 \perp g_{f,h} \geq 0, \quad \forall f, h \tag{B.4}$$

Differentiating the producer problem wrt. $\mu_{f,h}^{max}$ gives the maximum generation constraint:

$$G_{f,h}^{max} - g_{f,h} \geq 0 \perp \mu_{f,h}^{max} \geq 0, \quad \forall f, h \tag{B.5}$$

Differentiating the demand problem wrt. d_h gives the optimality condition for demand:

$$\lambda_h - \mu_h^{dem} \geq 0 \perp d_h \geq 0, \quad \forall h \tag{B.6}$$

Differentiating the demand problem wrt. μ_h^{dem} gives the constraint on required demand:

$$d_h - D_h^{min} \geq 0 \perp \mu_h^{dem} \geq 0, \quad \forall h \tag{B.7}$$

Differentiating the market clearing problem wrt. lc_h gives the optimality condition for load curtailment:

$$P^{max} - \lambda_h \geq 0 \perp lc_h \geq 0, \quad \forall h \tag{B.8}$$

Differentiating the market clearing problem wrt. λ_h gives the price setting constraint

$$d_h - lc_h = \sum_{f=1}^{F} \sum_{h=1}^{H} g_{f,h} \perp \lambda_h, \quad \forall h \tag{B.9}$$

Equations (B.4) to (B.9) represent a square system of equations that is directly implementable in suitable software such as GAMS [105].

B.2 Problem simplification

To provide the reader with an introduction to this type of problem formulation, the complementarity problem is now solved analytically. For clarity, the system of equations is simplified by removing the indexes f and h, representing operational decisions for one hour with one generator. For the purpose of illustrating the problem we set $MC = 100\frac{EUR}{MWh}$, $D^{min} = 10MWh$, $G^{max} = 50MWh$, and $P^{max} = 3000\frac{EUR}{MWh}$. Hence, we have 6 equations (B.10-B.15) with 6 unknown variables (g, μ^{max}, d, μ^{dem}, lc, λ):

$$100 - \lambda + \mu^{max} \geq 0 \perp g \geq 0 \tag{B.10}$$

$$50 - g \geq 0 \perp \mu^{max} \geq 0 \tag{B.11}$$

$$\lambda - \mu^{dem} \geq 0 \perp d \geq 0 \tag{B.12}$$

$$d - 10 \geq 0 \perp \mu^{dem} \geq 0 \tag{B.13}$$

$$3000 - \lambda \geq 0 \perp lc \geq 0, \tag{B.14}$$

$$d - lc = g \perp \lambda \tag{B.15}$$

B.3 Analytical solution

The problem is now solved analytically. In order to solve it directly based on simple logic, it is first assumed that the generator is producing. After that, it is assumed that the generator is not producing. It is thereafter found that only one of the assumptions is valid and that there is only one equilibrium solution.

B.3.1 Generator is producing

First, it is assumed that the generator is producing. $g > 0$ requires through eq. (B.10) that $100 - \lambda + \mu^{max} = 0$, which can be rearranged into:

$$\lambda = 100 + \mu^{max} \tag{B.16}$$

Equation (B.13) states that $d \geq 10$ and therefore implies $d > 0$. Hence, since the complementary variable is positive in eq. (B.12), the equation must hold at equality and we have:

$$\lambda = \mu^{dem} \tag{B.17}$$

Combining eq. (B.16) and eq. (B.17) gives $\mu^{dem} = 100 + \mu^{max}$ and implies $\mu^{dem} > 0$. Trough eq. (B.13) the equation must hold at equality when the complementary variable is positive. Therefore:

$$d = 10 \tag{B.18}$$

Equation (B.15) and $lc \geq 0$ implies that $g \leq 10$. Therefore, $50 - g > 0$ and the complementary variable in eq. (B.11) must be zero:

$$\mu^{max} = 0. \tag{B.19}$$

Setting eq. (B.19) into eq. (B.16) gives that:

$$\lambda = 100 \tag{B.20}$$

Setting eq. (B.20) into eq. (B.17) gives that:

$$\mu^{dem} = 100 \tag{B.21}$$

Setting eq. (B.20) into eq. (B.14) gives that $3000 - \lambda > 0$ and the complementary variable must be zero:

$$lc = 0 \tag{B.22}$$

Setting eq. (B.22) into eq. (B.15) gives that $d = g = 10$

The equilibrium solution when the generator is producing is $\mathbf{d} = \mathbf{10}$, $\mathbf{g} = \mathbf{10}$, $\lambda = \mathbf{100}$, $\mathbf{lc} = \mathbf{0}$, $\mu^{\mathbf{max}} = \mathbf{0}$, and $\mu^{\mathbf{dem}} = \mathbf{100}$.

We based the analytical solution on the premise that the generator is producing. Therefore, we need to explore the situation that the generator is not producing.

B.3.2 Generator is not producing

Now it is assumed that the generator is not producing. Setting $g = 0$ into eq. (B.15) means that:

$$d = lc \tag{B.23}$$

eq. (B.13) requires that $d \geq 10$ which implies $d > 0$ and $lc > 0$.

$lc > 0$ means that the complementary equation in eq. (B.14) holds at equality and:

$$\lambda = 3000 \tag{B.24}$$

$d > 0$ means that the complementary equation in eq. (B.12) holds at equality and by setting in eq. (B.24) we get:

$$\mu^{dem} = 3000 \tag{B.25}$$

$g = 0$ gives $50 - g = 50 > 0$ and requires that the complementary variable in eq. (B.11) is zero:

$$\mu^{max} = 0 \tag{B.26}$$

Setting eq. (B.24) and eq. (B.26) into eq. (B.10) requires that $100 - 3000 + 0 = -2900 \geq 0$ which is impossible. Therefore the generator must be producing and the previously found solution is the only equilibrium solution.

Appendix C: English summary of the EIENDOM article

This summary follows the same structure as the article, and the goal is to provide an overview of the article's content for non-Norwegian readers. The core content is summarised, while the elaborate discussions found in the article are left out.

C.1 Subject matter and scope

The Norwegian area use is largely controlled by area plans with a legal basis in the Plan- and Building Act, an extensive law for societal development. The goal is to balance several interests, and climate and environmental concerns are among those. Consequently, the reduction of energy use in buildings and an increased share of renewable energy is within the law's intent.

The scope of the article is the municipality's possibility to provide provisions on energy- and environmental requirements in zoning plans. The motivating background to discuss this is national and local authorities' interest in developing the built environment in a more climate- and resource-friendly direction.

The overarching issue discussed in this article is how municipalities can formulate requirements for energy use and climate impact in area plans. This issue is illustrated through requirements and solutions in the context of ZEN.

C.2 Zero emission neighbourhoods and the need for regulation

C.2.1 Why zero emission neighbourhoods?

The regulatory framework fits well with the ZEB concept since each building is treated as a separate entity. However, more efficient solutions can be found by extending the spatial scope beyond individual buildings because energy solutions often require an area perspective.

ZEN is, compared to ZEB, a relatively new concept that enables more efficient use of resources on a multi-stakeholder level. Expanding the system boundary to an area level increases the complexity because several stakeholders are involved. ZEN pilot areas indicate that the regulatory framework currently limits the possibilities because of technical possibilities that span multiple stakeholders.

C.2.2 Differences between regulatory frameworks in the building- and energy sectors

The regulatory approaches in the building- and energy sector have some fundamental differences despite their overarching goal of resolving market inefficiencies. Although there are exceptions, the building sector relies mainly on direct regulation while the energy sector lets the market decide the outcome. Through the concept of ZEN there is a need to consider buildings as an integrated part of the energy system. Consequently, there is a need for tighter coupling between these regulatory frameworks, which is challenging due to their distinct differences.

C.2.3 Regulatory risk as a factor in long-term decisions

The current regulatory framework and incentive structures create a misalignment between the optimal solutions on an area level and optimal choices made by individual stakeholders. Therefore, a crucial element to consider is regulatory risk, the possibility that regulatory changes can affect the business model of investments. Regulatory risk is relevant as many energy-related investment decisions are relatively long-term. Hence, the predictability of the business environment and regulations becomes an essential factor for such investments.

In the energy sector, it is possible to apply for regulatory exemptions to test new solutions, usually from one to five years. For energy-related solutions on a ZEN level, the entire business model of the investment may rely on the exemption since the investment cost requires some level of profitability during the operation phase. At the same time, the cost structure of renewable energy resources is characterised by high upfront capital costs and operational costs close to zero. This kind of cost structure is especially vulnerable to long-term regulatory risk since operational profitability of several decades might be required to recover the investment cost. Hence, for relatively short-term regulatory exemptions, an investor needs to consider the possibility that the exemption will expire at the end of the period. Thus, there can be a mismatch between the duration of the exemption and the investment. Consequently, there will be limited potential for such exemptions to trigger investments in technology characterised by high upfront costs and low operational costs.

Regulatory exemptions are also given in the building sector, such as land use, building limits, height limits, and various requirements. These exemptions can be both temporary and permanent, but exemptions related to the building envelope are usually permanent. Hence, this provides more reliable conditions than the 5-year exemption commonly used in the energy sector.

C.2.4 Planning and building provisions as a tool for energy policy and technology deployment

Under the Plan- and Building Act, it is possible to exert some judicial assessment to promote sustainable development. At the same time, the concept of sustainable development is constantly changing due to changes in the scientific and political basis. Therefore, updating the regulatory framework according to these changes is necessary. Hence, the need for adapting the regulatory framework might inherently introduce regulatory risk, but this risk can be mitigated through properly designed transitional arrangements.

In the context of ZEN, it might be preferable that individuals export locally generated electricity to be used by other stakeholders nearby. Therefore, one alternative is to allow local markets for such energy exchange and enable business models for local energy solutions. However, there are significant regulatory and practical barriers regarding establishing and operating such local markets. In light of the previous discussion on regulatory risk, it is also unrealistic that short-term regulatory exemptions will realise such projects.

C.2.5 The need for area provisions

This article has identified significant differences in the regulatory approach between the energy- and building sectors. These differences make it challenging to achieve ZEN solely through the energy-related regulations, which should therefore be supplemented by the area- and building regulations. Therefore, appendix C.3 considers the possibilities for municipal authorities to promote ZEN under the law as it is.

The building regulations are based on several concerns, including the premise of socio-economical efficiency. However, the economics might be different depending on local conditions, and it might be appropriate to adapt regulations based on these. At the same time, the requirement of economic efficiency is also an argument for having the general requirements at a national level to avoid industry stakeholders having to tailor their product based on the rules at the municipality level.

One argument for not having local requirements for those aspects that are regulated on a national level is that it is up to the market stakeholders to develop optimal solutions under local conditions. However, the optimal solutions from a socio-economic point of view might not be aligned with the optimal solution from the economic perspective of the various involved stakeholders. To solve such issues, it could be beneficial if local authorities could undertake some overarching decisions regarding the choice of solutions on a multi-stakeholder level.

C.3 The possibilities for energy- and environmental provisions in area regulation

This section considers the possibilities for municipal authorities to provide energy- and environmental provisions in their area regulation. Based on a rigorous evaluation of the law as it is, the following main points are argued:

- The municipal authority has significant freedom to act during the area planning phase where it is possible to create provisions for the long-term development of an area. One limitation is that area provisions can not extend into the scope of other laws and regulations.
- In contrast to the area planning phase, the freedom to act is passed to the area developer in the building application phase, and the municipal authority is required to approve applications that obey relevant regulations.
- National authorities have communicated that the national building regulations have exclusive responsibility for providing energy-related building requirements. However, based on the word of the law and the legislative background for the individual provisions, it should be possible to formulate requirements related to energy use and generation in zoning plans.
- It is impossible to conclude on the opportunity to formulate area provisions on energy-related requirements based on administrative practices. There is also a lack of legal precedent on the topic.
- The review of relevant material gives a two-sided impression; The preparatory works and the literature suggest that zoning authorities have almost unlimited power, while there is an ongoing practice that municipalities can not pass provisions regarding aspects regulated in the national building regulations.
- Whether the legal basis is sufficient for regulating the construction phase remains an open question. It is further argued that such regulations should be appropriate based on an intent of sustainable development.

- So far, municipalities have only required reporting of climate gas emissions. The evaluation of relevant material suggests that municipal authorities can go one step further and regulate permitted levels of climate gas emissions.

The review of relevant material suggests that the current regulatory practice limiting local regulations on aspects regulated in the national building requirements (TEK) can be challenged. The arguments regarding the legislative intent and system suggest that it is possible to intensify the national regulations at a local level, as long as the motive and technical basis is sound.

C.4 Implications for regulation and practice

C.4.1 Energy planning with a neighbourhood perspective

Efficient energy solutions on a neighbourhood level require that stakeholders' motivation is aligned with the impact on the neighbourhood-level system. However, there is currently a mismatch between optimality for a neighbourhood as a whole and from an individual perspective because there is a lack of incentives for optimising energy use and investments across stakeholders. The consequence is that even if an area developer has high ambitions regarding the local energy-related solutions, it might not be possible to recover the related costs. One example is that establishing a shared facility for energy generation and storage might be more cost-effective than constructing several smaller systems. However, the business case of such shared resources is dependent on favourable conditions for optimising the total energy balance of the neighbourhood rather than each stakeholder focusing on its individual energy balance.

Regulatory risk is an essential factor to consider, and it has been argued that temporary exemptions for a few years, such as energy trading on a local level, will have a limited ability to realise investments in capital-intensive technologies. In this regard, a possible way to reduce the regulatory risk without extending the regulatory exemptions can be to establish a regulated fund that insures the stakeholders from such risk. Hence, the payment would be defined as dependant on whether the exemption is continued or not. This type of mechanism can potentially trigger investments because the long-term regulatory risk is moved from the building owners to the fund's administrator.

It is vital to preserve the energy law's goal of promoting efficiency in the overall energy system while also adapting according to the needs of zero emission neighbourhoods. It is, for example, not viable to reintroduce shared metering of energy. However, it can be possible to add mechanisms that facilitate optimal area-level energy solutions on top of the current market structures.

C.4.2 Summary and implications

The topic of this article is to consider the municipalities' possibility of posing energy- and environmental requirements during the area planning phase - and, more specifically, to identify the regulatory challenges arising related to zero emission neighbourhoods. The central elements required for such a neighbourhood is that the buildings need to have certain technical qualities and that the local infrastructure must facilitate efficient solutions.

Some necessary conditions are outside the municipality's control as an area planning authority. These include the legal basis for potential mechanisms that can facilitate efficient energy solutions across individual buildings and stakeholders. Due to these aspects, the Plan- and Building Act alone will be insufficient for facilitating the establishment of zero emission neighbourhoods. Hence, the concept of zero emission neighbourhoods depends on relevant adjustments in the energy-related regulatory framework.

This article has demonstrated that municipalities can, to a significant extent, facilitate the premises for zero emission neighbourhoods through zoning provisions. The authors argue that municipality-level zoning provisions can go beyond the national building regulations and formulate stricter requirements. The regulation is subordinate to the law, and no sources indicate an intention of derogation. Instead, it seems that the justification for the current practice is a division of work between area planning-related and building-specific aspects. With the intent of establishing zero emission neighbourhoods, which is tied to reducing the climate footprint, the authors argue that the existing regulatory framework allows local intensification of the national building requirements.

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