THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Decentralization in energy systems

Low-carbon technologies and sector coupling on the household, community and city scales

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Gothenburg, Sweden 2021

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ISBN 978-91-7905-478-6

Doktorsavhandlingar vid Chalmers tekniska högskola
Ny serie nr 4945
ISSN 0346-718X

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Printed by Chalmers Reproservice
Gothenburg, Sweden 2021

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Abstract

The number of installations of distributed energy technologies, such as solar photovoltaic (PV) and battery systems, has increased dramatically in recent decades. The required transition towards a decarbonized energy system entails electrification of the different sectors. Both these developments provide new opportunities for energy autonomy and sector coupling in decentralized systems, and allow local actors to contribute to reducing their climate impact.

The aim of this thesis is to study the utilization of local energy technologies and the potential for system flexibility in three decentralized energy systems: prosumer households, prosumer communities, and city energy systems. In addition, the thesis investigates the interactions of decentralized systems with the surrounding regional energy system.

In this work, four techno-economic energy system optimization models are used. In the first model, PV-battery systems in prosumer households are analyzed within the North European electricity system dispatch. In the second model, they are examined as part of prosumer communities. In the third, city-scale model the investment and dispatch in the electricity and district heating sectors are optimized, while considering flexible and inflexible charging of electric cars and buses. The fourth model combines the city and regional scales, to study the operation, design and interaction of both systems, while considering different connection capacities for electricity exchange between the systems.

The results show that the economic incentives for electricity self-consumption in prosumer households promote a way of utilizing household battery systems that is not in line with the least-cost dispatch of the electricity system. Consequently, prosumer households are, within the current tariff structure, unlikely to provide flexibility that would assist the balancing of intermittency in the regional electricity system. In prosumer communities, where prosumer households have the possibility to share electricity, a financial benefit accrues to the participating households primarily when there is a reduced connection capacity for electricity exchange to the energy provider.

For city energy systems, it is shown that power-to-heat technologies in combination with thermal storage systems and flexibility with regards to the charging of battery electric vehicles facilitate the uptake of local solar PV. The city electric car fleet provides the potential to postpone up to 85% of the demand for charging, which leads to more than twice the share of solar PV in the electricity mix for charging, as compared with inflexible charging. A 50% connection capacity between the city-scale and regional-scale energy systems implies only 3% higher costs for the installation and operation of energy technologies on both scales, as compared with a system that has 100% connection capacity.

This thesis outlines the potential for increased decentralization of the energy supply and highlights the need for strategies to integrate decentralized and centralized energy systems.

Keywords: Energy systems modeling, Decentralization, Prosumers, Energy community, Smart city, Sector coupling, Electric vehicles, Energy system flexibility

List of appended papers

This thesis is based on the work in the following papers, referred to by Roman numerals in the text:

I. Heinisch, V., Odenberger, M., Göransson, L., Johnsson, F. **Prosumers in the Electricity System—Household vs. System Optimization of the Operation of Residential Photovoltaic Battery Systems.** *Frontiers in Energy Research* 6 (2019). https://doi.org/10.3389/fenrg.2018.00145.

II. Heinisch, V., Odenberger, M., Göransson, L., Johnsson, F. **Organizing Prosumers into Electricity Trading Communities: Costs to Attain Electricity Transfer Limitations and Self-sufficiency Goals.** *International Journal of Energy Research*, July 25, 2019, er.4720. https://doi.org/10.1002/er.4720.

III. Heinisch, V., Göransson, L., Odenberger, M., Johnsson, F**. Interconnection of the Electricity and Heating Sectors to Support the Energy Transition in Cities.** *International Journal of Sustainable Energy Planning and Management* 24 (2019). https://doi.org/10.5278/ijsepm.3328.

IV. Heinisch, V., Göransson, L., Erlandsson, R., Hodel, H., Johnsson, F., Odenberger, M, **Smart electric vehicle charging strategies for sectoral coupling in a city energy system**. *Applied Energy* 2021;288:116640. https://doi.org/10.1016/j.apenergy.2021.116640.

V. Heinisch, V., Göransson, L., Odenberger, M., Johnsson, F. **The impact of limited electricity connection capacity on energy transitions in cities**, Submitted for publication

Authors' contributions:

Verena Heinisch is the principal author of all five papers and has conducted the modeling and analyses. Filip Johnsson, Mikael Odenberger and Lisa Göransson have contributed with discussions and editing to all five papers and have supervised the work. Lisa Göransson has contributed to the method development in **Papers II–V**. Henrik Hodel and Rasmus Erlandsson have performed the modeling and analysis of electric buses in **Paper IV**.

Other publications by the author not included in this thesis:

Duvignau, R., Heinisch, V., Göransson, L., Gulisano, V., Papatriantafilou, M. “Small-Scale Communities Are Sufficient for Cost- and Data-Efficient Peer-to-Peer Energy Sharing.” In *Proceedings of the Eleventh ACM International Conference on Future Energy Systems*, 35–46. E-Energy ’20. https://doi.org/10.1145/3396851.3397741.

Heinisch, V. and Tuan L. A. Effects of Power-to-Gas on Power Systems: A Case Study of Denmark. In *2015 IEEE Eindhoven PowerTech*, 1–6, 2015. https://doi.org/10.1109/PTC.2015.7232587.

Acknowledgments

Many people along the way have had a positive impact on this PhD journey, and I am grateful for everyone that has contributed with guidance, support, collaborations, ideas and time throughout these years.

A big thank you to my supervisors, for giving me the opportunity to take on this project, for everything I could learn from you during this time and for all the advice, guidance and feedback. Filip, thank you for your valuable input to the project and the planning, and for always taking the time to give detailed comments on all articles, which really helped me improve my writing. Mikael, thank you for our discussions, for joining project meetings all over Sweden, and for not letting me forget the link between my research and the real world. And Lisa, thank you for the large part you played in my development as a researcher. I learnt so much from collaborating on the development of modeling approaches and article ideas, you are a big inspiration in how you approach your own research, and, thank you for your support when it was needed.

I am grateful for the financial support from the Swedish Energy Agency, and for the possibility to participate in the Forskarskolan Energisystem. I learnt a lot from meeting researchers from different disciplines and Universities, and from discussing the importance of interdisciplinarity in energy systems research. To my FoES project group, thank you for all the interesting discussions, for your thoughts on my research that allowed me to broaden my perspective and for your interest in my work. Thank you also to my PhD colleagues at FoES for the shared experiences during this PhD journey.

The work at Energy Technology would not have been the same without my amazing current and former colleagues, many of which have become dear friends. Thank you for all the research- and non-research-related talks and the social activities. A special thanks to my colleagues in the energy systems group, who are creating an inspiring and motivating work environment. Emil, thank you for not only sharing an office with me, but also so much of your experience and of your time. Thank you to the A-Team for always helping out with any issues that could arise and for the encouraging words. A big thanks to Vincent for the language-editing of all my papers and this thesis. Thank you also to Therese at feelgood for teaching me about the importance of talking about taking care of our wellbeing at work.

I'm thankful for my friends, in Gothenburg, in Sweden and scattered over different countries, who are there to share the successes and challenges, and so many great and fun memories. To my Swedish family, thank you for welcoming me and making me feel at home here. To my family in Austria, thank you for always providing a place I can come back to and for cheering me on in everything I set my mind on. Robin, thank you for your support on this journey and beyond; I can't wait for all of our future adventures together.

Verena Heinisch,
Ljungdalen, April 2021

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Abbreviations and terminology

Abbreviations:

BEB	Battery electric bus
BEC	Battery electric car
BEV	Battery electric vehicle
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CO_2	Carbon dioxide
DER	Distributed energy resources
DG	Distributed generation
DH	District heating
DSM	Demand-side management
EV	Electric vehicle
HOB	Heat-only boiler
HP	Heat pump
ICT	Information and communication technology
LCT	Low-carbon technology
P2P	Peer-to-peer
PtH	Power-to-heat
PV	Photovoltaic
TES	Thermal energy storage
V2G	Vehicle-to-grid
VMS	Variation management strategy
VRE	Variable renewable energy

Description of terms used in this thesis:

Prosumer household: In this work, residential households that are equipped with photovoltaic (PV)-battery systems and, as a consequence, can generate and store electricity on their property. The term *prosumer* describes the ability of these households to both *pro*duce and con*sume* electricity.

Prosumer community: In this work, and for the modeling in **Paper II**, a group of two or more prosumer households that can share electricity, here assuming a low cost for the sharing of electricity.

City energy system: The unit of analysis in **Papers III** and **IV**, which in this work includes the city electricity and district heating demands and supply, as well as the transport demand of electric cars and buses, which is supplied by charging inside the city.

Decentralized and centralized energy systems: The three small-scale systems studied in this work (*cf.* the three definitions above) are referred to as *decentralized energy systems*. These are studied in relation to the large-scale, more-*centralized* electricity system, which in this work is represented by one or more spot market regions (see Chapter 1 of this thesis for more details).

Energy system scale: The energy systems studied in this work (i.e., prosumer households, prosumer communities, city energy systems and spot market regions) differ in terms of their system boundaries and sizes and, thus, are throughout this work and in **Paper V** referred to as energy system scales.

Inflexible charging: A charging strategy for electric vehicles (EVs), which charges the vehicles directly upon arrival and thus, offers no flexibility in the charging.

Smart charging: A charging strategy that allows for postponing of EV charging, while charging so as to meet the vehicle driving demand. In this work, smart charging is scheduled according to the energy system optimization modeling.

Connection capacity: In this work, the term *connection capacity* is used to describe the capacity that is available for electricity exchange between city-scale and regional-scale energy systems, which is the focus of the modeling in **Paper V** and is also utilized in the modeling in **Papers III** and **IV**. The term is also used to define the capacity for electricity exchange between prosumer households or communities and the energy provider, in **Paper II**.

Local energy balancing: The use of energy technologies and system flexibility to supply the demand for electricity and heat inside decentralized energy systems through local generation (considering an hourly time resolution) is in this thesis referred to as *local energy balancing*.

The terms 'energy system' and 'energy' in this thesis include different energy system sectors and energy carriers, while the terms 'electricity' and 'electricity system' are used in those sections that are exclusively about the supply and demand of electricity.

CHAPTER 1:
Introduction

The urgency attached to the energy transition in all sectors of the energy system has prompted a multitude of actors to make investments in low-carbon technologies and to develop strategies that assure a low climate impact and high energy efficiency. With measures and targets set and proposed on different scales in the energy system, a major challenge that lies ahead is the efficient coordination of the energy system transition across scales and sectors. This work investigates the decarbonization of energy systems on the scales of prosumer households, prosumer communities and city energy systems and studies their integration and interactions with the surrounding regional energy system to which they are connected. With the focus on the city scale, this thesis analyzes the benefits that can be potentially derived from synergies between the electricity, district heating, and electric transport sectors.

The rapid decrease in the cost of renewable energy technologies that has occurred over the last decade [1] has made these technologies an essential element of the transition towards a carbon-neutral energy system. Many renewable energy technologies are highly scalable, i.e., they can be installed as large-scale systems, such as solar parks, and on small scales, such as rooftop photovoltaic (PV) panels. Thus, low-carbon energy technologies (LCT; in this work, technologies for the generation and storage of electricity and heat are considered) have become available to different actors, resulting in a growing number of small-scale LCT being installed in, for example, residential households [2], energy communities [3], and city energy systems [4]. Consequently, small-scale generation technologies are now more often located closer to energy demand, and when applied in combination with the flexibility that can be provided through storage technologies or demand-side management (DSM), the balancing of supply and demand is possible in smaller geographic areas or in electricity distribution grids. These developments have been recognized as elements of decentralized energy systems [5], which increasingly disrupt and compete with the historically centralized energy system setup.

A growing body of scientific literature details the characteristics of more-decentralized and more-centralized visions for the energy system transition, and investigates the factors that influence the direction of the development of the energy system, as well as the potential for integration of decentralized and centralized energy system solutions [5–11]. Decentralized energy systems typically comprise a large number of small generation units with many owners/operators and an oftentimes reduced electricity exchange with the centralized system [5,7,8]. Decentralization of the electricity supply contributes to a reduced requirement for expansion of the transmission infrastructure, if local balancing of supply and demand prevails [12]. However, with increased levels of electricity generation in decentralized systems, it becomes important to handle bidirectional power flows, as decentralized systems can at different times be energy sources or sinks. Information and communication technologies (ICT) are considered an important element of decentralized energy system setups. Thus, energy systems that are predominantly decentralized require types of infrastructure investments that differ from those in the traditional, centralized system setup [9]. As co-existence of centralized and decentralized energy system developments is expected [5,8,9], there is a need to attain a better understanding of: i) the factors that influence the operation and design of decentralized energy systems; and ii) the ways in which they interact with and affect the centralized energy system.

The incentives and motives for increasing local, small-scale generation in decentralized systems are diverse. In the residential sector, for instance, retail prices for electricity are generally higher than the spot market prices for electricity, reflecting the taxes and fees that are included in tariffs for residential customers. Thus, decreasing costs for small-scale generation technologies can make it financially attractive for household customers to substitute (parts of) the electricity that they purchase from the energy provider with electricity generated on their own property (e.g., using solar PV). In addition, the contribution to environmental benefits associated with emission reductions have been found to act as an incentive to install renewable energy technologies in decentralized systems [8,12]. In community-scale systems and local energy initiatives, the desire for increased energy independence is frequently stated as a motive for increasing local energy generation [7,13].

In city energy systems, there exist a multitude of challenges in the process of ensuring a sustainable energy supply for a growing urban population. Thus, various factors affect the development towards decentralization in cities. As demand centers for electricity, heating and cooling and transport, cities will have to play a critical role in efforts towards the energy transition [4]. The presence of different energy carriers in city energy systems and often local infrastructures for district heating and cooling, gas grids or transport systems create strong prerequisites for utilizing the synergies between decarbonization strategies in different sectors of the energy system. Local energy generation technologies, such as solar PV on rooftops or integrated into buildings or units for combined heat and power (CHP) generation, are not only a possible source of low-cost energy within the city but can also defer necessary expansions to the electricity system infrastructure in fast-growing cities by supplying the demand locally. Although studies of different decentralized energy systems have been reported in the literature, there is a lack of studies that explore different scales of decentralization and investigate the interactions of decentralized systems with the regional energy system to which they are connected.

1.1. Aim and scope

The overall aim of this thesis is to analyze the impact that decentralization has on the design and the modeling of future decarbonized energy systems. Decentralization is studied on different scales in the energy system, i.e., residential *prosumer households*, an aggregation of prosumer households into *prosumer communities*, and on the scale of *city energy systems*. With regards to these decentralized systems, techno-economic factors that affect the local generation and the balancing of energy supply and demand are investigated. In addition, the impacts on and the interactions with the centralized system, here represented by electricity spot market regions, are considered. On the city scale, the possible benefits from sector coupling between the electricity and district heating systems and the electrification of private car and public bus transport are investigated. More specifically, the thesis addresses the following research questions:

i. What are the techno-economic incentives for investment and operation of PV-battery systems in prosumer households and prosumer communities? (**Papers I** and **II**)
    - How does battery system operation differ from the prosumer perspective and from the centralized system perspective?
    - How does the electricity exchange to the energy provider differ, when considering individual prosumer households or prosumer communities?

ii. What role does sector coupling play in the decarbonization of city energy systems? (**Papers III** and **IV**)
    - What is the function of local storage systems for electricity and heat in the city energy system?
    - How large is the potential to schedule smart charging of electric cars and buses so as to facilitate the local energy balancing within city energy systems and the uptake of local electricity generation?

iii. How does the level of connection capacity between city-scale and regional-scale energy systems impact system design and costs on both scales? (**Paper V**)

The different decentralized energy systems in this work are modeled so as to explore the similarities and differences between these energy systems scales. Thus, the research questions have been chosen to address the same areas of interest for each decentralized energy system scale, i.e., the operation of local energy technologies, the utilization of system flexibility, and the interactions with the surrounding system. The modeling includes different technology options for the generation and storage of electricity and heat, to supply the demand profiles with a 1- or 3-hour time resolution. However, no detailed representation of the electricity and district heating grid infrastructures is included in the modeling. The possible impacts on the magnitude and patterns of the electricity and heating demand from energy efficiency measures or the flexible operation of equipment such as appliances for ventilation or heating inside buildings are outside the scope of this work. All the modeling in this thesis is done within the Swedish/Nordic context; the generalizability and applicability of the findings to other systems are discussed individually in the appended papers. The models used in this work are optimization models that identify the least-cost alternative for the operation and design of the energy systems at different scales, considering the respective system boundaries and techno-economic constraints.

Figure 1-1 provides an overview of the energy system scales (i.e., the three decentralized systems of prosumer households, prosumer communities and city energy systems, and the scale of spot market regions as representative of the centralized system) and of the energy system sectors (electricity, district heating and transport), which are covered in each of the appended papers. **Papers I** and **II** focus on the electricity sector, **Paper III** studies the coupling of the electricity and district heating sectors, and in **Papers IV** and **V** electricity, district heating and the charging of electric vehicles (EVs) are considered. In **Paper I**, residential prosumer households are modeled within two Swedish spot market regions, while also considering the surrounding market regions in the Nordic system. In **Paper II**, the aggregation of prosumer households into communities of up to 100 households is investigated. **Papers III** and **IV** provide case studies for the energy system in the city of Gothenburg, and in **Paper V** the modeling of city-scale energy systems (as an aggregate of the electricity, district heating and private car transport demands in three Swedish cities) is dynamically linked to the modeling of the spot market region in which they are located.

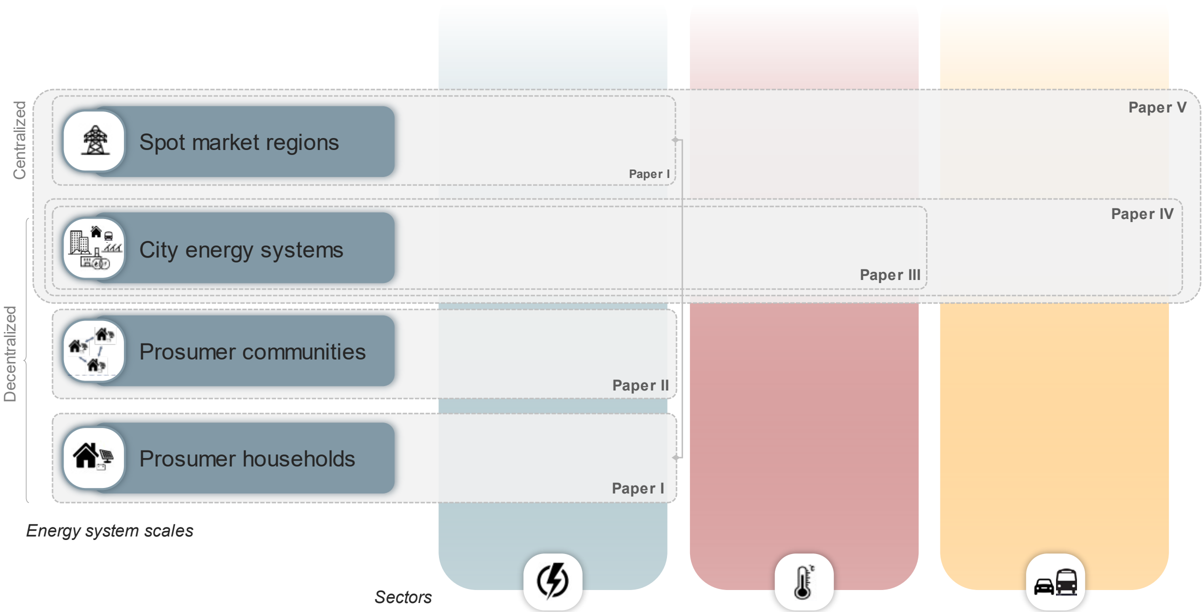

Figure 1-1: Overview of the energy system scales (i.e., the three decentralized systems studied in this work and the centralized system on the scale of spot market regions) and of the sectors (i.e., the electricity, district heating and transport sectors) that are considered in the five appended papers.

1.2. Contribution of this work

This thesis consists of an introductory essay and five appended papers, which contribute to the understanding of the design, operation and interaction of energy systems on different scales. Different models have been developed and used in the papers to study the different energy system scales.

In **Paper I**, an existing electricity system dispatch model is utilized and complemented with equations to represent the battery system operation on the market region scale. The paper studies prosumers households in two southern Swedish market regions and reports on the mismatch of the incentives for cost-optimal battery operation in prosumer households and the cost-optimal dispatch in the electricity system.

In **Paper II**, a model is developed to compare PV-battery system investments and operation in: i) individual prosumer households; and ii) prosumer communities in which households have the option to share electricity with each other. This work adds to the existing research on community systems by analyzing the benefits of prosumer communities in terms of attainable cost savings for prosumers and the differences in PV-battery system sizes between individual prosumers and communities.

In **Paper III**, a city energy system optimization model is developed to study the roles of local generation and storage technologies, as well as the flexibility that can be obtained from sector coupling, for the energy transition in growing cities.

In **Paper IV**, the model is developed further to integrate the charging of electric cars and buses into the city energy system optimization, while comparing non-flexible and smart charging strategies. The strength of the model is that it allows for a combined analysis of the city electricity, district heating and electric transport sectors, as well as the optimization of both investments in and operations of local energy technologies, with a time resolution that accounts for hourly variations in supply and demand over a period of one year.

Paper V introduces a modeling approach that dynamically links the energy systems on the city and market region scales and evaluates the impact that the level of connection capacity between the two scales has on the design of decarbonized energy systems. In contrast to other studies, the modeling considers the design and operation of both the city and regional systems and evaluates different levels of connection capacity, i.e., the available capacity for electricity trade between the scales.

1.3. Outline

This introductory essay outlines the key findings of the five papers within the context of the overall aims of the thesis and is structured as follows. Chapter 1 introduces the context and aims of the work. Chapter 2 provides background on decentralization and sector coupling in energy systems and presents related research. In Chapter 3, the models used in and developed for this thesis, as well as the input data are described. Chapter 4 presents the key findings from the five appended papers. In Chapter 5, concluding remarks in relation to the research questions of this thesis are presented, and reflections are made with regard to the analysis of different energy system scales, as well as the possible directions of future work within this research area.

CHAPTER 2:
Background and related work

In this section, the three decentralized systems that are in focus in this thesis are described: prosumer households, prosumer communities, and city energy systems. Related works that study these systems are presented. In addition, the concepts of sector coupling and energy system flexibility are briefly explained.

The traditionally centralized European electricity system is increasingly being disrupted by investments in small-scale generation and storage technologies, most notably solar PV and batteries, which are owned by different stakeholders and are often connected to low-voltage networks. While these so-called ‘distributed technologies’ can be integrated into a centralized system, they can also accelerate the development towards a more decentralized system that involves to a greater extent the local balancing of generation and demand [8].

Terminology: Distributed and decentralized

In the context of energy systems, the terms *distributed* and *decentralized* are both used in connection to the installation of small-scale energy technologies. *Distributed generation* (DG) is defined as electricity generation that is connected directly to the distribution network or that is on the customer side of the meter [14]. *Distributed energy resources* (DER) include generation and storage technologies, as well as demand-side management (DSM) [8]. The term *decentralized* is often used to describe the direct opposite to centralized energy systems, as in this thesis, and usually involves not only the small-scale generation of energy, but also the local balancing of supply and demand or potential synergies between energy carriers or energy system sectors on a local scale.

Local energy balancing and synergies between different energy system sectors are facilitated by the increased utilization of electricity as an energy carrier. This is a consequence of the trend towards electrification for the decarbonization of different parts of the energy system. An example is the increased usage of battery electric vehicles (BEVs), which are charged at different, distributed locations in the energy system. Thus, not only distributed energy technologies, but also the emergence of new electricity demands are influencing the future operation and design of the electricity and energy systems.

2.1. Decentralization on different scales

In decentralized energy systems, the use of distributed energy technologies and the possibilities for local balancing of the energy supply and demand allow for increased energy independence, for which the terms defined below are used in the literature.

Terminology: Self-consumption, self-sufficiency and energy autonomy

Self-consumption in a decentralized system, according to the definition of Luthander et al. [15], is the share of the locally generated electricity that is utilized locally. *Self-sufficiency* is a measure of the share of the local electricity demand that can be supplied by locally generated electricity. Both measures can be calculated for different periods of time; most common is an annual evaluation. The term *energy autonomy*, as defined by Rae and Bradley [16], is similar to full self-sufficiency in that it describes a system that can function fully without any energy import, thereby entailing sufficient levels of local energy generation and storage. While *complete energy autonomy* requires a system to function fully off-grid, the term is also used to describe *tendencies towards higher energy autonomy* through the employment of local energy technologies, or in terms of *balanced energy autonomy*, which describes systems in which the annual net local generation equals or exceeds the annual net demand [17,18]. Additionally, the term energy autonomy reflects the ability of stakeholders to self-determine their energy provision [19].

Different levels of energy autonomy have been investigated on different energy system scales, from the building, neighborhood and community scales to regional and national systems [19]. With respect to the modeling of energy autonomy and local energy balancing in decentralized systems, many previous studies have focused on the residential sector, rather than including different energy system sectors, and there is a scarcity of studies that focus on the system impacts from decentralized energy autonomy [17].

In this thesis, three different scales of decentralized energy systems are studied with respect to local energy balancing and sector coupling. The following sections provide background to each of the three scales and present related studies that focus on techno-economic analyses of these systems. A selection of the related work is presented, it is not the aim of this thesis to provide a complete literature review of the research areas.

2.1.1. Prosumer households

The installation of small-scale energy technologies to generate and store electricity in residential households is, according to the IEA-RETD [20], driven by four types of factors: i) economic drivers, such as technology costs or the levels of retail electricity prices; ii) behavioral drivers, such as the desire for increased energy autonomy or the ambition to contribute to a renewable electricity supply; iii) technological advances, such as the improvement of PV and battery storage technologies; and iv) national conditions, such as the rooftop space available for PV panels or the electricity grid conditions. In general, residential households that install technologies for the generation (and possibly, the storage) of electricity on their property are called *prosumers*.

Terminology: Prosumers of electricity

In the energy system context, the term *prosumer* describes a user of electricity that both *pro*duces and con*sumes* energy [21–23]. Prosumers can be completely energy-independent, i.e., off-grid. However, most prosumers are connected to an electricity grid and supply parts of their electricity demand through electricity exchange with an energy provider. While this definition is applicable to all different types of electricity users, e.g., industrial or commercial customers, in this thesis the term prosumer is used solely to describe residential prosumer households.

Table 2-1 provides an overview of techno-economic studies conducted on prosumer households, grouped into three research areas, which are related to the work of this thesis. Previous studies have investigated the topics of self-sufficiency and self-consumption in prosumer households, as well as the economic conditions related to household-scale generation and storage systems, and have analyzed the impacts that prosumer households have on the electricity system. While self-consumption of electricity in prosumer households is possible with PV standalone systems, combining solar PV with battery storage systems allows for higher levels of self-consumption and self-sufficiency, as the usage of electricity can be shifted to a later time. Luthander et al. [15] have reported an increase in self-consumption of 10–24 percentage points when using battery storage capacities of 0.5–1.0 kWh per installed kW solar PV. Nyholm et al. [24] have reported a 20–50 percentage point increase with battery capacities of 0.15–100 kWh. Both of those studies compared PV systems with and without batteries. Modeling studies that investigate the attainable levels of prosumer self-sufficiency consider different sizes and configurations of PV-battery systems and are carried out with time resolutions that range from at least 1 hour down to minutes, so as to capture the variations in household electricity demands.

With regards to economic conditions, the potential financial benefits accrued from household-scale self-consumption of electricity have been found to be dependent upon the electricity price levels, the retail electricity tariff systems (including feed-in-tariffs and net-metering schemes), and the investment costs and subsidy schemes for investments in small-scale generation and storage technologies. The self-consumption of electricity from prosumer PV systems can be increased if EVs or heat pumps are present in the household [25,26]. However, as the operation of only the prosumer PV-battery systems is the focus of **Paper I** of this work, the literature overview concentrates on these technologies. Other aspects related to prosumer households that are not covered in detail here include the operation and stability of distribution grids in connection to the increasing levels of DG or non-techno-economic factors that influence the spread of prosumer households.

The operation of household-scale generation and storage systems and the subsequent self-consumption of electricity leads to a difference in the interaction of prosumer households with the electricity system as compared to consumer households. Prosumers typically consume less electricity from the grid and they often feed surplus electricity back to the centralized system. Thus, a large proportion of prosumers has the potential to influence significantly the operation of centralized electricity systems [2]. The modeling studies that analyze this impact of prosumer households on the centralized system (see **Table 2-1**) are described here in more detail, as **Paper I** of this thesis can also be linked to this series of techno-economic system analyses. Using modeling approaches similar to the modeling in **Paper I** of this work, Soini et al. [27] and Schill et al. [28] have compared modeling cases in which the dispatch of prosumer PV-battery systems is optimized according to a prosumer cost optimization (which involves a high share of self-consumption) to modeling cases in which the dispatch of the PV-battery systems is completely integrated into, and thus steered by, the optimization of the centralized electricity system. Both studies show that increased prosumer self-consumption increases the operational cost of the centralized electricity system, as compared to a PV-battery system dispatch that is optimized in accordance with the electricity system dispatch. This is in line with the findings from **Paper I** of this work. Klein et al. [29] have proposed a market alignment indicator to measure how closely the prosumer-controlled dispatch of PV-battery systems matches the centralized electricity system operation, showing that hourly varying electricity prices for the feed-in and consumption of electricity in prosumer households improve the market alignment.

Table 2-1: Overview of selected previous studies on prosumer households and their impacts on the energy system (own categorization).

Research focus	Details	References
Increased self-sufficiency in prosumer households	Operation and investment of prosumer generation and storage systems to increase household self-sufficiency	[15,24,30–34]
Economic conditions for prosumer households	Operation and investment of prosumer generation and storage systems with the goal of achieving financial benefits	[22,31,35–39]
Impacts of residential prosumers on the energy system	Impacts of household-scale generation, storage, and self-consumption on the operation of national electricity systems	[2,26–28, 40,41]

2.1.2. Prosumer communities

As a consequence of increasing small-scale generation and storage systems and the growing number of prosumer households, local energy initiatives have emerged [42,43]. A frequently used term for local initiatives that have as their goal to increase the local generation of renewable energy, and thus, self-sufficiency and energy autonomy, is *energy communities*. Setups for the local trading or sharing of energy between actors such as prosumer and consumer households are often called *peer-to-peer* (P2P) energy trading systems. P2P energy trading systems have been described as being suitable for the coordination of a large share of distributed generation and storage systems from a high number of prosumer households [21,44,45]. For the work of this thesis and in **Paper II**, the term *prosumer community* has been chosen to emphasize that the modeling includes prosumer households only as participants in the community system and that no consumer households are considered.

Table 2-2 presents the focus areas of previous studies on energy communities and P2P energy trading systems. To provide an overview of the research that is related to the work in this thesis, the previous studies are categorized as: techno-economic analyses of energy communities, some of which are on the topic of community energy storage; studies of market designs for P2P systems; studies of the motives for the formation of energy communities; and investigations of real P2P trial projects. Techno-economic studies of community systems analyze the factors that influence the design and operation of community energy systems, such as the optimal sizes of generation and storage systems for different community setups and compositions, as well as the financial gains that could accrue to the energy community from local self-consumption and local sharing of electricity. Increased profitability of PV systems has been found for energy communities, as compared to individual buildings, as well as a higher potential for cost savings in communities with a greater variety of load profiles [46]. One specific area on which techno-economic studies have focused is community energy storage systems, i.e., storage units that are shared and jointly operated by members of an energy community. Thus, community energy storage units can confer similar benefits as the individual storage systems in prosumer households, i.e., facilitate the self-consumption of locally generated electricity and provide financial benefits to the energy community. Barbour et al. [47] have compared batteries in individual prosumer households to community battery storage units and have found that the optimal battery size in a community is 65% of that in individual households, and that community battery systems are more efficient at reducing the need for electricity import from the surrounding system. The setup and results of the study of Barbour et al. [47] are comparable to the analysis and results in **Paper II** of this work. Instead of looking at community energy systems, **Paper II** analyzes the possibility to share electricity within a community energy system, which implies the use of the battery storage capacity for the benefit of the community.

The market designs for P2P energy trading suggested in literature (see references in **Table 2-2**) often include either the direct interaction of prosumers or a form of organized system, which implies a community manager, aggregator or the formation of virtual power plants to manage prosumer-scale resources. The group of studies that focuses on the motives for forming and joining community energy and P2P trading systems lists, next to the potential costs savings, the motivation to support the energy transition or the willingness to become more energy self-sufficient. The functioning and user motives linked to real P2P systems have been studied through the example of the Brooklyn Microgrid project and a P2P trial project in western Australia. In **Table 2-2***,* the literature concerning the European, North American and Australian energy systems is considered; however, P2P and community energy systems can also aid efforts towards electrification and the functioning of rural micro- and mini-grids in other parts of the world and reduce the costs of energy supply in remote areas. Moreover, this thesis focuses on electricity as an energy carrier in community systems, which is considered in **Paper II**. Thus, the parts of the literature on energy hubs and local multi-energy systems on the neighborhood scale have not been reviewed here.

Table 2-2: Overview of selected previous studies on community energy and peer-to-peer trading systems (own categorization).

Research focus	Details	References
Techno-economic system design and operation	Quantitative analyses of technology investment and operation in communities	[46,48–50]
Community energy storage	Techno-economic parameters for energy storage units shared within a community	[47,51–54]
Market mechanisms for community-based P2P trading	Market designs, value of P2P transactions	[21,44,45,55]
Motives for the emergence of community systems	Factors influencing the emergence of and participation in community systems	[3,13,42,56]
Case studies on real P2P electricity trading projects	Experiences from the Brooklyn Microgrid and a P2P market trial in Western Australia	[56,57]

In relation to energy communities, a clear set of regulations concerning energy trading and self-consumption is often lacking. However, some recent actions taken by the European Union (EU) may facilitate the establishment of energy communities. The EU has acknowledged the important roles of energy communities and citizen-driven energy actions in the *Clean Energy for all Europeans Package* [58], where terms such as ‘renewable energy communities’, ‘citizen energy communities’ and the ‘renewable self-consumer’ are defined. In particular, the *Internal Electricity Market Directive* [59] and the *Renewable Energy Directive* [60] set out the goals of a framework for consumer participation in energy markets and the right of individual households and renewable energy communities to generate, consume, share or sell renewable energy, which will soon have to be incorporated into national laws and regulations in EU Member States [61,62].

2.1.3. City energy systems

City energy systems are an important focus area for the energy transition, as they not only are responsible for more than 70% of the CO_2 emissions linked to global final energy use [63,64], but they are also expected to expand substantially, such that it is estimated that cities will accommodate about two-thirds of the global population by Year 2050 [65]. In an increasing number of cities, local energy targets and strategies are defined, which often involve energy technologies that are installed on the city scale [4,66]. However, a challenge for the city-scale energy transition is that integrating the planning of energy solutions into the existing practices of urban design and planning creates an increasingly complex process that requires different areas of expertise and strong collaborations between energy and urban planners [4,67]. Furthermore, the energy targets defined in city energy strategies require the involvement of different businesses and stakeholders to be put into practice through, for instance, the installation of energy technologies.

Future developments in cities that strive towards sustainability in different areas are often collectively referred to as *the smart city*. While the literature does not provide a definitive definition of *smart cities*, the most common usages of the term refer to cities with efficient integration between sectors, infrastructures, resources and actors, so as to tackle various challenges, such as urbanization and population growth, while also striving for improved climate, environmental, societal and economic performances. Smart city visions often involve areas such as energy supply, mobility, waste management and air and water quality, and they usually include the use of ICT [68–70]. In this thesis and in the appended **Papers III** and **IV**, the term *city energy system* is mainly used to highlight the focus on energy supply and demand. The topics of sustainable energy supply and efficient collaboration between sectors in city energy systems are an important part of smart cities. The city energy system is, similar to the 'geographic-plus' definition used by Keirstead et al. [71], described as the energy technologies that lie within the city's geographic boundaries plus easily traceable upstream flows, i.e., in this work, electricity that is imported to be consumed within the city.

An immediate or imminent need to expand the electricity grid infrastructure for the import of electricity from the surrounding energy system has been identified in several Swedish cities. Bottlenecks in the current grid infrastructure exist or are expected to occur due to the increased electricity demand in cities, which is attributed to rapid city growth and electrification as an essential element of the energy system decarbonization pathway [72–74]. An alternative or complementary strategy to electricity grid expansion projects, which often have long project lead-times, is the increased local generation of electricity inside the city energy system and the utilization of flexibility from local energy storage or sector coupling.

Cities and urban districts provide good conditions for sector coupling, due to the physical proximity of the energy demands for, e.g., electricity, heating and cooling and to fulfill transport needs. In combination with increased electrification, this allows for synergies in the decarbonization of different parts of the city energy system, which has been studied previously [75,76] and is investigated in **Papers III** and **IV** of this thesis. While the decarbonization of city energy systems has been investigated in case studies with different system boundaries, a common finding has been that the share of renewable electricity generation in cities can be increased through the utilization of flexibility from storage systems [77,78] and from the use of electricity for heat production [79,80]. In the city transport sector, fuel switching away from fossil fuels has a direct positive impact on local air and noise pollution levels. Moreover, the use of electricity as an energy carrier in individual cars and public transport systems, such as subways, trams and buses, enables the use of local synergies [81–83]. Sector coupling and flexibility in electricity and district heating systems and in the charging of EVs are described in Chapter 2.2.

For a quantitative analysis of energy solutions and energy transition scenarios for cities, urban energy system models (UESMs) are often used to support the local planning and decision-making processes. Numerous modeling approaches and tools are found in the literature and have been applied to study different focus areas in city energy systems. **Table 2-3** gives an overview of four review studies in the field of UESMs. Models for the city scale differ from each other, for instance, in terms of their temporal and spatial scales and with respect to the target audience [71]. Key challenges related to the use of UESMs include the areas of transparency and reproducibility, modeling of human behavior, and the communication of modeling results [84], as well as model complexity, data quality and uncertainty, model integration, and policy relevance [71]. Suggestions for further improvements in the field of UESMs include: the development of more comprehensive models that consider several energy intervention areas and the most relevant technologies and stakeholders [70]; the consideration of methods such as cloud computing, activity-based modeling, sensitivity analyses and improved data collection techniques [71]; and the development of integrated modeling approaches and more comprehensive scenarios that include social factors and system imperfections, as well as institutional solutions such as centralized energy data collection and regulation, frameworks to support municipal energy planning, and training programs for municipal energy departments [84].

Table 2-3: Overview of four review studies on urban energy system models (UESMs).

Focus of the review	Details	Ref.
Gaps in the UESM field and potential solutions	Outline of the technical, methodological and institutional challenges, and technical and institutional solutions	[84]
Approaches, challenges and opportunities in UESMs	Outline of models for technology design, building design, urban climate, systems design, and policy assessment and the associated main challenges	[71]
Application areas for district-scale models	Outline of modeling approaches that focus on district heating, renewable energy and the urban micro-climate	[85]
Scope of UESMs within five energy intervention areas	Outline of the five intervention areas of generation, storage, infrastructure, facilities, and transport, as well as strategies for future modeling approaches	[70]

Energy transition strategies in cities and the operation of city energy systems influence and are influenced by the surrounding energy system on the regional or national scale. Thus, for efficient decarbonization, the planning and operation of energy systems on the city and regional or national scales should be in alignment [86]. Few modeling studies, however, have used modeling that combines the operation and design of both these energy systems, as is done in **Paper V** of this thesis. Previous works have analyzed the amounts and timings of excess electricity in city and national energy systems as a measure of how well-integrated these systems are [87], and have modeled and compared decarbonization pathways in cities and national energy systems, while considering different system limitations and available technologies for both systems [88,89].

2.2. Sector coupling and energy system flexibility

Electrification is regarded as a major element in the decarbonization of the energy system. The increased usage of electricity as an energy carrier in sectors and processes that have traditionally been dominated by fossil fuels naturally links these sectors to the electricity system and the operation of the electricity system. In recent years, the term s*mart energy system* has been used to describe energy systems that have a focus on the integration of different sectors, such as the electricity, heating and cooling, building and transport sectors, and the utilization of flexibilities derived from synergies between sectors and from the use of storage systems [90,91] (a definition and review of the state-of-the-art for smart energy systems are given in [92]). Various studies have used energy system modeling for the analysis of synergies between sectors for efficient decarbonization of the energy system (for example [93–95]). Current barriers to increased sector coupling include the need for collaboration between stakeholders with different business models, the required access to data, and the need for sector-overlapping regulations [96].

The electricity output from variable renewable energy (VRE) technologies, such as wind and solar power, fluctuates on different time-scales, and this is connected to the fluctuations inherent to wind speed and solar irradiation. Thus, measures to handle these variations on the supply and demand sides, as well as through infrastructure expansions are important for future sustainable energy systems with a high share of renewables. A review of different energy system flexibility measures is provided in [97]. Comparison and categorization of variation management strategies (VMS), i.e., strategies to handle variations from VRE such as the use of storage systems or the flexible use of electricity in the heating or transport sectors, can be found in [98]. The following subsections provide a brief overview of the possibilities for securing flexibility from storage systems and sector coupling in the electricity and heating sectors, and the flexibility of BEV charging, as these are covered in **Papers III–V** of this thesis. Another source of flexibility in the energy system is the flexible operation of reservoir hydropower, which is considered in the modeling of **Paper V**. Reservoirs can act as a buffer that enables the scale-up and scale-down of hydropower generation.

2.2.1. Flexibility in the electricity and heating sectors

Energy storage systems can be utilized to shift the usage of energy to a later time. Battery storage systems have been found to be most suitable for short-term storage, usually intra-day storage, and thus are often used in combination with solar PV [97,99]. Thermal energy storage systems (TES) are suitable for applications in domestic, district heating and industrial setups and can be used for energy storage from short-term up to seasonal storage [100–102]. TES can be employed in district heating systems to help balance the heat supply and demand [103–105]. Another source of flexibility for district heating systems is the flexible operation of CHP units and power-to-heat (PtH) technologies, such as heat pumps or electric boilers [106–108]. Through their ability to utilize surplus electricity from VRE generation, PtH technologies can facilitate the integration of wind power and solar PV into the energy system [79,109,110].

2.2.2. Flexibility in electric vehicle charging

The electrification of the road transport sector entails a new demand for electricity, which has to be integrated into existing electricity and energy systems [111–115]. Strategies for the electrification of road transport may comprise indirect electrification, where electricity is used to produce electrofuels or hydrogen to run fuel cell-equipped vehicles, or direct electrification, which includes the use of BEVs or electric road systems. In this thesis, only the static charging of battery electric cars and buses (BECs and BEBs, respectively) is investigated with regards to the electrification of road transport.

A substantial increase in the number of BEVs implies not only an increase in the electricity demand, but also the introduction of a large battery storage capacity within the system. Vehicles are often parked more frequently and during longer periods of time than is strictly required for the charging of the battery for their next trip. For instance, statistics on measured driving patterns of private passenger cars in western Sweden reveal that the average vehicle in that dataset is parked around 93% of the time each day, and that almost 90% of the stops are longer than 8 hours [116]. In combination with an extensive charging infrastructure, this characteristic allows for flexibility in vehicle charging.

Flexible or smart charging represents charging that is scheduled not only according to the transport needs of the vehicle user but that is also adapted to the electricity system conditions [117]. Smart charging can be combined with vehicle-to-grid (V2G) discharge [118], i.e., the discharge of stored electricity from the vehicle to the electricity system. Flexibility conferred by smart charging and V2G can improve the integration of VRE or provide power system services, which can have positive effects on network congestion and network reinforcement needs [114,117,119–121]. Specifically, the potential synergies between solar PV and BEVs have been proposed in literature, as smart charging and V2G can be used in combination with distributed small-scale solar PV systems, so as to increase the self-consumption of electricity and flatten the net-load profile [26,72,122–125]. An alternative to BEVs in the decarbonization strategies for road transport is the use of fuel cell-powered cars [126,127]. However, this is outside the scope of this thesis.

CHAPTER 3:

Models and input data

In this work, four different linear cost minimizing modeling approaches with different system setups have been utilized. This section provides an overview of the models and the most important assumptions and input data used in the five appended papers.

In **Figure 3-1**, the four models with their main input data and main outputs are presented. In **Paper I**, the EPOD dispatch model in combination with a household cost optimization is utilized to study residential PV-battery systems from the prosumer and system (i.e., the market region) perspectives, as explained further in Chapter 3.1. For **Paper II**, a prosumer community model is developed to analyze PV-battery system sizes and prosumer household costs, as described in Chapter 3.2. **Papers III** and **IV** introduce a city energy system optimization model that is used to study the benefits of coupling the electricity and district heating sectors (**Paper III**) and the flexibility associated with electric car and bus charging (**Paper IV**). The city-scale model is presented in Chapter 3.3. For **Paper V**, the modeling performed on the city scale is combined with the ENODE model, which optimizes investment and dispatch on the market region scale, to study the impacts of different levels of transfer capacity between the city and the market region scales on system designs and costs, as detailed in Chapter 3.4.

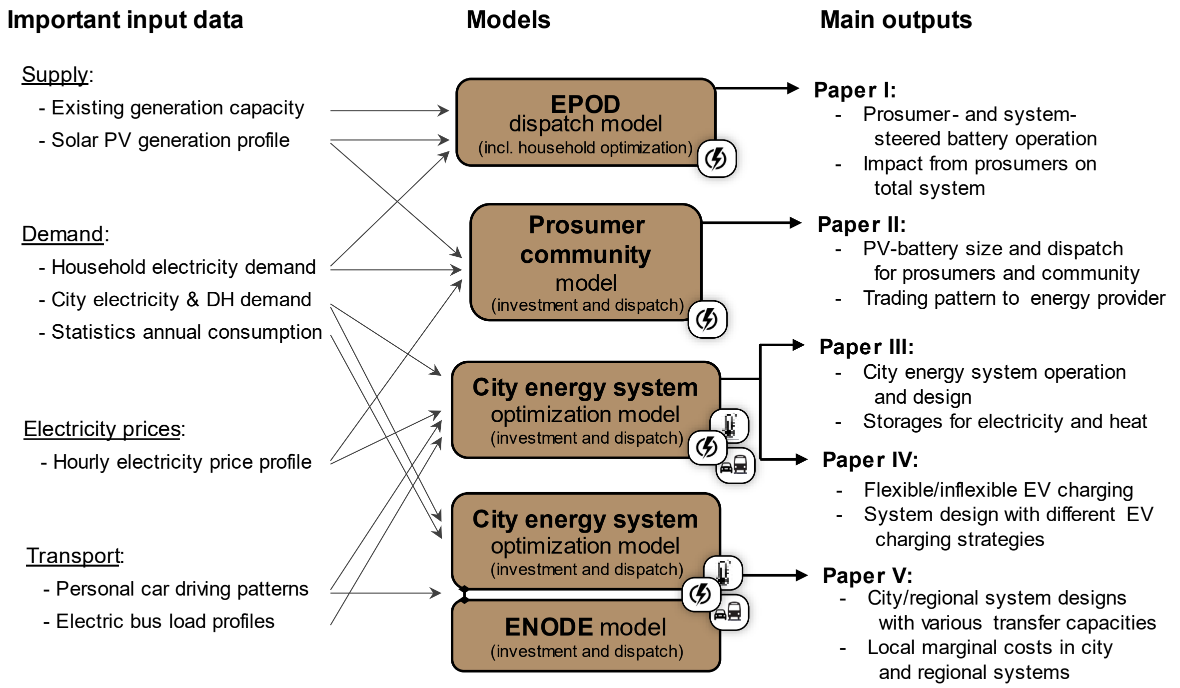

Figure 3-1: Overview of the models used in this work and their respective main inputs and outputs. [The symbols refer to the electricity, district heating (DH) and transport sectors in the models.]

With respect to input data several of the models utilize the same or similar input data, as indicated by the arrows on the left side of **Figure 3-1**. Measured household load profiles are used to represent prosumer households in **Papers I** and **II**. Electricity and heat load profiles from the city of Gothenburg are considered for the modeling on the city scale in **Papers III**–**V**. Statistics on annual electricity and heat consumption levels in different Swedish municipalities are utilized for the scaling of the city demand profiles to represent the three largest cities within a market region in **Paper V**, as city-specific demand profiles were not available for all three cities. Hourly electricity price profiles (albeit with different profiles used in the individual papers) are inputs to the modeling in **Papers II**–**IV** and represent the spot market prices for electricity. Car traveling patterns are used to calculate the electricity demands of electric cars in **Papers IV** and **V**, while electric buses are part of the modeling in **Paper IV**. The EPOD model, used for **Paper I**, optimizes the dispatch of the electricity generation capacity in several market regions, and this is exogenously given to the model (the existing generation capacities are outputs from an investment model, as explained in Chapter 3.1). The ENODE model, applied in **Paper V**, optimizes both the investments in and dispatch of energy technologies in one market region and considers a Greenfield approach (i.e., no existing capacity in place).

All the models used in this work are linear optimization models that minimize the total costs for one model year, i.e., the fixed and variable costs for the energy system dispatch in **Paper I** and in **Papers III**–**V**, the PV-battery system operation in prosumer households in **Papers I** and **II**, and the investment costs for city-scale and regional-scale generation and storage capacity in **Papers III**–**V** and the PV-battery capacities in **Papers I** and **II**. The objective functions of the individual models are given in the following chapters. The models represent different energy systems scales with different system boundaries. However, all the models utilized are deterministic and include perfect foresight. These types of energy system optimization models are often described as representing a central planner perspective, i.e., modeling the best outcome for society as a whole, which is useful as input to planning decisions for the energy transition. These models usually do not capture the diversity of actors present in the energy system or the driving forces towards an energy transition other than the cost rationale, and they often handle uncertainties about future developments through different scenarios and modeling cases.

3.1. Prosumer households in the electricity system, EPOD model (Paper I)

Two versions of the EPOD electricity system dispatch model are used in this work to study PV-battery system operation from the prosumer household perspective (i.e., minimizing the annual household electricity costs) and from the electricity system perspective (i.e., a total system cost optimization). The EPOD model is a linear electricity system dispatch model that minimizes the total costs for electricity generation in 50 regions (EU plus Norway, Switzerland and the UK). The model was first presented in [128] and further developed in [129–132]. The EPOD model is run with an hourly time resolution for a target year. The electricity system design (i.e., power plant capacities and transmission lines) that is used as an input to the EPOD model is derived from the electricity system investment model ELIN [130,133,134]. The ELIN model takes into consideration the existing electricity generation infrastructure and its age structure (based on the Chalmers power plant database, originally presented in [135]) and minimizes investment costs for the period of 2020–2050 in 16 time-steps each year, while considering a CO_2 target. (Newer versions of the ELIN model [114,115] utilize 20 representative days with an hourly time resolution per investment period for each period of 10 years.) Both the EPOD and the ELIN model focus exclusively on the electricity sector.

In this work, the following two extensions to the original EPOD model are utilized: i) a modeling approach developed by Goop et al. [129] (also described in [130]) that iteratively links the minimization of the total costs for electricity generation in the EPOD dispatch model to the minimization of household annual electricity costs; and ii) a representation of stationary batteries, which are included in the total system dispatch and cost minimization of the EPOD model (*cf.* Eqs. (3) to (6) in **Paper I**). As shown in **Figure 3-2**, the output from the modeling with the iterative approach that combines the EPOD model with the household cost optimization is used to represent the *prosumer household perspective* in this thesis, i.e., the dispatch of PV-battery systems that is cost-optimal to prosumer households. The output from the modeling with the EPOD model that includes the dispatch of battery systems in the total system cost optimization is used to represent the *electricity system perspective*. The PV-battery system capacities that are installed in each prosumer household are the same for the prosumer household and electricity system perspectives and are an output from the household cost optimization.

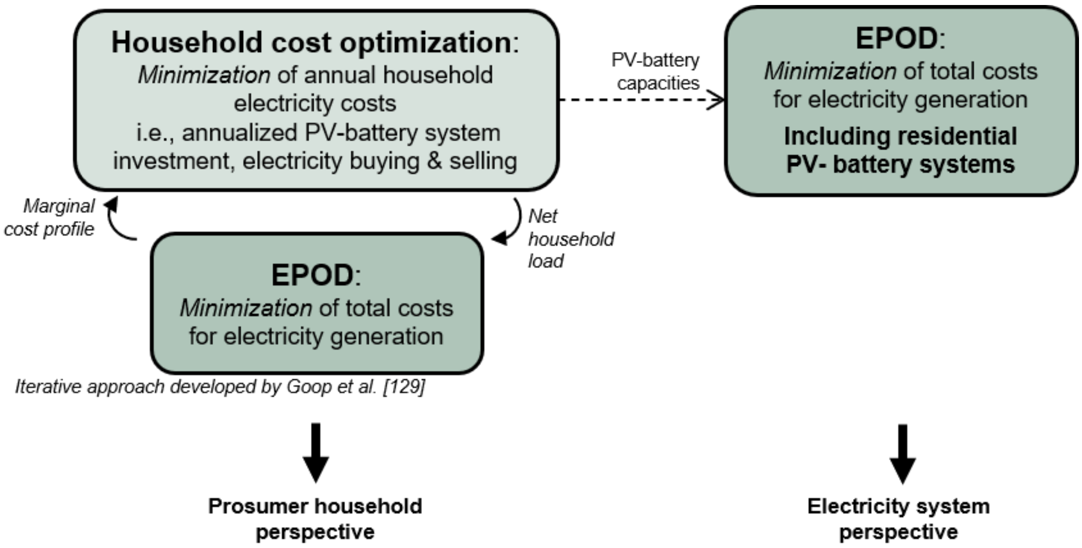

Figure 3-2: The two extensions of the EPOD model used in this work to represent the prosumer household perspective and the electricity system perspective for the dispatch of residential PV-battery systems.

The objective function of the EPOD model (used for both the prosumer household and the electricity system perspectives) is written as follows:

$$MIN\ C^{tot} = \sum_{i \in I} \sum_{p \in P_i} \sum_{t \in T} (C_{p,t}^{run}\ p_{p,t} +\ c_{p,t}^{cycl}) \qquad \text{Eq. (1)}$$

where I is the set of model regions, P_i is the set of power plant aggregates per region i, and T is the set of time-steps. The total costs, C^{tot}, consist of the running costs, $C_{p,t}^{run}$, for the electricity generation, $p_{p,t}$, and the cycling costs, $c_{p,t}^{cycl}$; all these parameters are given per plant aggregate p and time-step t. The cycling costs are not fixed but vary depending on the operation, i.e., start-ups and part-load operation, of thermal power plants.

For the prosumer perspective (the left-hand side of **Figure 3-2**), the EPOD model is linked to a household cost optimization, in which the annual costs to cover the household electricity demands are minimized. The household cost optimization includes the possibility for each household to invest in PV-battery systems. The household cost optimization is expressed as follows:

$$MIN\ C^{tot} = \sum_{h \in H} (c_h^{inv} + \sum_{t \in T} c_{h,t}^{el}) \qquad \text{Eq. (2)}$$

where H is the set of prosumer households and T is the set of time-steps. The total electricity costs for all households, C^{tot}, consist of the annualized investment costs for the different PV-battery capacities installed in each household, c_h^{inv}, and the variable electricity costs, $c_{h,t}^{el}$, which represent the annual costs paid for electricity that is purchased by the household minus an amount that is reimbursed to the prosumers for surplus electricity that is not used within their households.

To link the household cost optimization with the EPOD model (left-hand side of **Figure 3-2**), as described by Goop et al. [129], the marginal costs of electricity generation from the EPOD model are used as the hourly electricity price profile according to which prosumer households are assumed to purchase electricity (taking into consideration the taxes and fees in residential retail electricity prices) or are reimbursed for the surplus electricity that they feed into the grid. The household cost optimization is run for 2,104 households in southern Sweden and the resulting net-load (i.e., the amount of electricity that the prosumer households consume from the grid, considering in-house generation and storage of electricity through PV-battery systems) is scaled up to represent all the residential households in the EPOD modeling. The household net-load updates the electricity demand in a new EPOD model run, which then creates a new marginal cost profile that is used in the household cost optimization and so forth. The iterative process continues until convergence or a maximum number of iterations is reached. In this thesis, the modeling results from the final iteration are utilized. In this way:

- the *prosumer household perspective* includes the results for the PV-battery system dispatch as being cost-optimal for the prosumer households [*cf.* Eq. (2)] and the electricity system dispatch, taking into consideration the household net-loads.

For the electricity system perspective, the PV-battery capacities from the household optimization are dispatched in accordance with the total system cost minimization [Eq. (1)] in the EPOD model (the right-hand side of **Figure 3-2**). In this way:

- the *electricity system perspective* includes the dispatch of the residential PV-battery systems as being optimal for the electricity system and yields a different result for the total electricity system dispatch than it does for the prosumer household perspective.

In **Paper I,** PV-battery systems are considered for all the residential households of the two Swedish spot market regions SE3 and SE4 (for both the prosumer household and electricity system perspectives), while a total of 25 EPOD regions is considered in the modeling to represent the impact from trade to and from other modeling regions. System compositions for Year 2032 from the ELIN model are used for a scenario that includes a high share of renewables for electricity generation and a cap on CO_2 emissions (see **Paper I** for details of the ELIN scenarios utilized). The data that represent prosumer household loads stem from a measurement campaign in Swedish single-family households conducted in 2012 by E.ON. The hourly load profiles were first presented by Nyholm et al.[24], and further details can be found in [129,136].

3.2. Prosumer community model (Paper II)

The prosumer community model has been developed for this thesis and is used to compare the operation and investment of PV-battery systems for individual prosumer households and prosumers that have the possibility to share electricity within a prosumer community. The model is a linear cost-optimization model that minimizes the annual household electricity costs for the sum of all households. The option to share electricity within the prosumer community is enabled for model runs that represent the *prosumer community* and is disabled for model runs that consider *individual prosumer households*, as shown in **Figure 3-3**. In addition, two different constraints are used in two sets of model runs: i) a constraint on *limited connection capacity*; and ii) a constraint on the *level of self-sufficiency*. The limited connection capacity constraint in the modeling imposes a maximum limit (different values for different modeling cases) on the available grid capacity for electricity exchange between the energy provider and the prosumer households or the prosumer community. (The constraint does not affect the capacity for electricity exchange between members of the prosumer community.) This constraint reflects a situation in which prosumer households strive to reduce their reliance on the local grid operator. The constraint on the level of self-sufficiency reflects the ambition of prosumer households and prosumer communities to become more energy-independent and, thus, less-reliant on the energy operator for the supply of electricity. The model formulations of both the constraints and their implications are described in detail in **Paper II**.

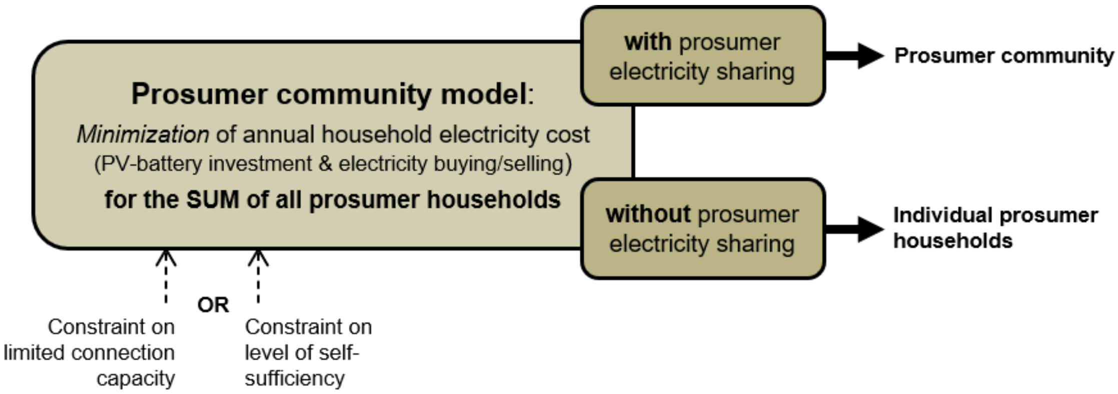

Figure 3-3: Overview of the objective and the constraints imposed on the prosumer community model to compare the individual prosumer households and the prosumer community.

The objective function of the prosumer community model is the same household electricity cost minimization as that used for the prosumer households in **Paper I** (see Chapter 3.1), and is expressed as follows:

$$MIN\ C^{tot} = \sum_{h \in H} (c_h^{inv} + \sum_{t \in T} c_{h,t}^{el}) \qquad \text{Eq. (3)}$$

where H is the set of prosumer households included in the modeling and T is the set of time-steps. The total costs for the prosumer households, C^{tot}, are the annualized investment costs for the household PV-battery systems, C_h^{inv}, and the variable electricity costs for electricity that is purchased from the energy provider minus any reimbursement for surplus electricity, $C_{h,t}^{el}$. The assumptions made with respect to the retail tariff conditions in the modeling are that the costs for purchased electricity and the reimbursements to prosumers are based on an hourly electricity price profile, which is given as an input to the model and represents the electricity spot market price. On top of the hourly price profile, an energy tax and value-added tax (VAT) are considered for the electricity that is purchased from the energy provider and a small reimbursement for the surplus electricity that is not utilized within the prosumer household. For the sharing of electricity within the prosumer community, a small cost (i.e., 100-times lower than the spot market electricity price) is considered, so as to avoid 'unnecessary' electricity exchange between prosumers in the model.

Figure 3-4 shows which electricity flows are possible within the model. The generation profile for solar PV, the electricity demand profile, and the variables for battery charging and discharging are modeled for each prosumer household. Thus, the optimization yields different PV-battery system sizes for each prosumer household, and the household electricity demand is preferably supplied by these in-house PV-battery systems. In those modeling cases in which electricity sharing within the prosumer community is enabled, the electricity demand can also be supplied by surplus electricity from other prosumer households (albeit subject to a small surcharge). Each prosumer household can purchase electricity from the energy provider and receive reimbursement for surplus electricity. Thus, the battery systems can be used by the prosumer household to store surplus electricity from solar PV and to react to price variations in the hourly price profile for electricity that is bought from and sold to the energy provider. Ideally, the prosumer household buys electricity at times of low electricity prices with the option to store it in the household battery if it is not utilized to supply the household electricity demand directly, and sells surplus electricity during periods of high hourly electricity prices.

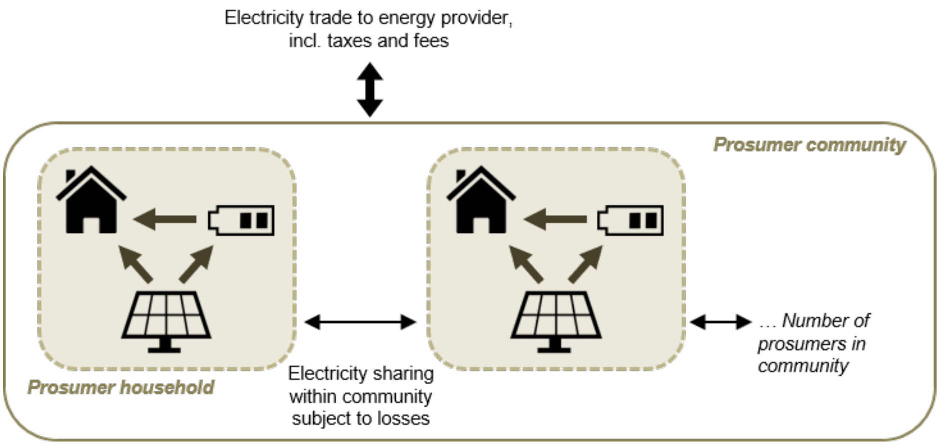

Figure 3-4: Possible electricity flows within the prosumer households, within the prosumer community, and to the energy utility in the prosumer community model.

In **Paper II** of this thesis, the prosumer community model is applied to various sizes of prosumer communities, i.e., from 2 prosumer households up to 101 prosumer households, modeled both as individual households and as part of the prosumer community. The same measured household load dataset as that used for the modeling of prosumer households within the electricity system presented in Chapter 3.1 is applied. However, for the analysis of prosumer communities in this thesis, households that are located geographically close to each other have been chosen, i.e., households with the same postal code in southern Sweden. The hourly solar PV generation profile is derived from a previously described model [137], which is based on solar radiation data from MERRA and takes into account the geographic locations of the prosumer households.

3.3. City energy system optimization model (Papers III and IV)

The city energy system optimization model has been developed for this work to study sector coupling and the flexibility potential of the city electricity, district heating and transport (i.e., BEC and BEB charging) sectors. The model is a linear optimization model that minimizes the annualized investment and operational costs of energy technologies for the generation and storage of electricity and heat in the city energy system, as well as the costs for electricity import to the city. Energy balances for electricity and heat ensure that the demands for electricity and heat in the city are met at each time-step. Due to the combined optimization of electricity, district heating and BEV charging, it is possible to study the use of electricity for the production of heat and charging of BEVs while taking into account the operation and design of the city electricity system.

The objective function of the city energy system optimization model is:

$$MIN: \; C^{tot} = \sum_{i \in \mathrm{I}} \left(C_i^{inv} s_i + \sum_{t \in T} (C_i^{run} p_{i,t} + \; C_i^{run} q_{i,t}) \right) + \sum_{t \in T} C_t^{el} w_t \qquad \text{Eq. (4)}$$

where I is the set of technologies and T is the set of time-steps. The total system costs, C^{tot}, consist of the investment costs, C_i^{inv}, for investments in new capacity s_i per technology i, the variable running costs, C_i^{run}, for the electricity generated, $p_{i,t}$, and the heat produced, $q_{i,t}$, per technology i and time-step t, and the electricity costs, C_t^{el}, for each unit of electricity, w_t, that is imported to the city per time-step t.

Figure 3-5 gives an overview of the model. The city electricity demand can be supplied by local generation technologies such as solar PV or gas turbines, or by imported electricity. The electricity import is limited by the connection capacity. The costs for electricity import are set by an hourly electricity price profile, which represents the hourly spot market price. Flexibility in the electricity and district heating systems (the focus of **Paper III**) can be provided by storage systems for electricity and heat and through the operation of PtH technologies. Thermal storage systems include tank storage units, usually for smaller storage volumes, and pit storage units, which can be used for storing large volumes. As PtH technologies, heat pumps and electric boilers are considered, both of which link the electricity and district heating sectors by utilizing electricity for the production of heat. The district heating demand can further be supplied by CHP plants that generate both electricity and heat according to a fixed alpha-value, and by heat-only boilers. The potentials for flexibility provided by the flexible charging of electric private cars and public buses, and by V2G for electric cars is the focus of **Paper IV**. The modeling includes three BEV charging strategies:

i) *Inflexible charging*, whereby the vehicles are charged at each stop longer than one hour, until the battery is full or the vehicle leaves for the next trip;
ii) *Smart charging*, whereby charging can be postponed according to the energy system optimization, such that the total city energy system cost is minimized, while the vehicle driving demand is fulfilled at each time-step; and
iii) *Vehicle-to-grid (V2G)*, which is smart charging with the possibility to discharge the vehicle batteries back to the city energy system.

The demand for driving is modeled as an aggregated hourly profile for the entire BEC fleet and for four different categories in the BEB fleet. The four BEB categories are designed to differentiate between buses of the public transport fleet that are driven only during hours of peak driving demand and buses that are driven for the majority of the day. Since the driving patterns of individual cars do not follow the same regular schedule as public buses, no categories are applied to the BEC fleet. The aggregated transport demand profile implies that battery charging and discharging is, in the modeling, controlled and approximated by a single battery energy balance for the BEC fleet and every BEB category (considering input data for the share of the fleet that is parked and charging at each time-step). The impact of modeling an aggregated EV transport demand profile, as compared to modeling individual profiles, has been investigated previously [138], and using an aggregated profile has been found to be sufficient when the car batteries are 30 kWh or larger and charging is not restricted to the home location.

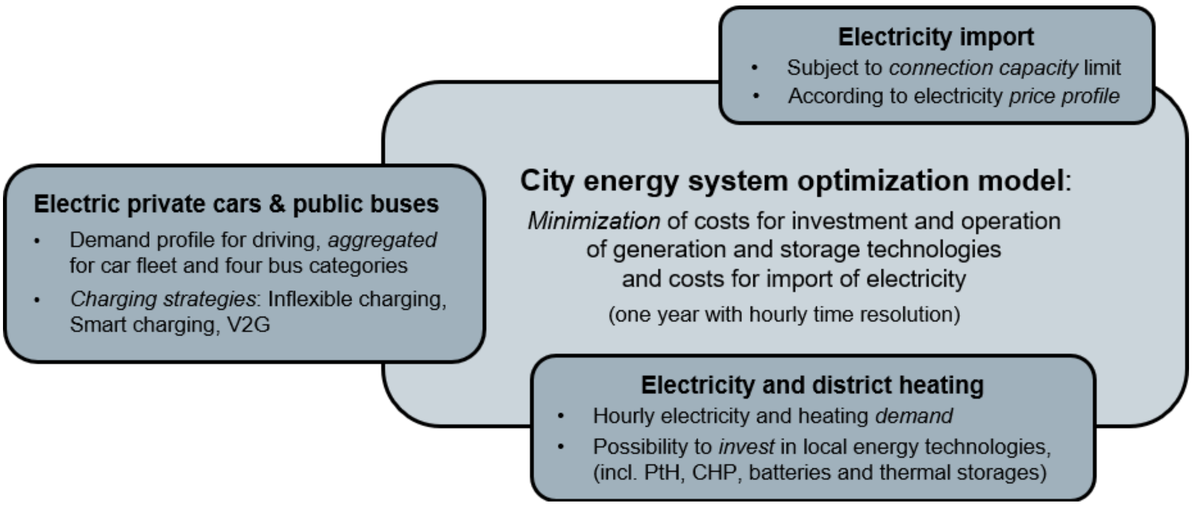

Figure 3-5: Overview of the sectors that are considered in the city energy system optimization model. Electric cars and buses are included in the modeling in Paper IV but not in Paper III.
[PtH, Power-to-heat; CHP, combined heat and power; V2G, vehicle-to-grid]

In this thesis, the model is applied in case studies of the city of Gothenburg in western Sweden. With respect to input data, real hourly load profiles from Year 2012 are used for the demand profiles for electricity and district heating in the model, and are scaled up to represent assumptions as to future demand growth. In both **Papers III** and **IV**, the existing capacity for electricity and heat generation in the city of Gothenburg is considered. However, the strict constraint on zero emissions from electricity and heat generation (to represent assumptions close to Year 2050) results in new investments in renewable energy technologies. The driving patterns for electric cars are based on a GPS measurement campaign conducted in western

Sweden [116,139]. The electricity demand for driving per hour from the 426 cars is calculated, and the profiles are scaled up to represent the electrification of 60% of the current private car fleet in the city. The electricity demand profiles for buses are based on the bus timetables in Gothenburg from Year 2016 and the corresponding driving distances. Moreover, 100% electrification of the current public inner-city bus fleet with high-power charging at each line's turnaround stop is assumed. Details of the modeling and input data are found in **Papers III** and **IV**.

3.4. Integrating city- and regional-scale modeling (Paper V)

To study the impacts of the connection capacity between city-scale and regional-scale energy systems on the system design and operation, two models, i.e., the city energy system optimization model (presented in Chapter 3.3) and the ENODE model, have been refined and combined into a single model for this work. The ENODE model was first presented in [140] and has been further developed in [100,141–143]. The combined model used in this thesis is a linear cost optimization model that minimizes the total costs for investment and operation in the electricity and district heating sectors on both scales, i.e., the city-scale energy system and the regional-scale energy system combined. Linking the modeling of the city and the regional scales allows to study the interactions between both systems and to analyze the generation and storage capacities on both scales, considering different levels of connection capacity.

As shown in **Figure 3-6**, the city-scale and the regional-scale energy systems are modeled as one modeling node each, with a variable for electricity exchange between the scales. In the modeling performed in **Paper V** of this thesis, the regional scale represents the Swedish spot market region SE3 and the city scale is the aggregated demand of the three largest cities in the same market region, i.e., the cities of Gothenburg, Stockholm and Uppsala. (The demand that is modeled on the city scale is, thereby, excluded from the regional scale.) Thus, the regional-scale system includes the demand from smaller cities and towns (<200,000 inhabitants) and rural areas, as well as the large-scale generation technologies that are located outside of cities. The modeling considers the electricity and district heating systems and the electricity demand for the charging of electric cars in both modeling nodes. Some technologies, i.e., hydropower, wind power and nuclear power, are available on the regional scale but not on the city scale. The electricity exchange between the city-scale and regional-scale nodes is limited by the connection capacity, which is varied in the different modeling cases, so as to study the impacts that the connection capacity has on energy system designs and operations. Energy balances for both nodes ensure that the demands for electricity, district heating and car transport are met on both the city and the regional scales.

The marginal values of the energy balances for electricity and heat are used as an indicator of the local values for electricity and heat in the city-scale and regional-scale energy systems. In time-steps with congestion between the two modeling nodes, i.e., the connection capacity for electricity exchange between the city and the regional system is fully utilized, the marginal costs of electricity in the city and regional system differ.

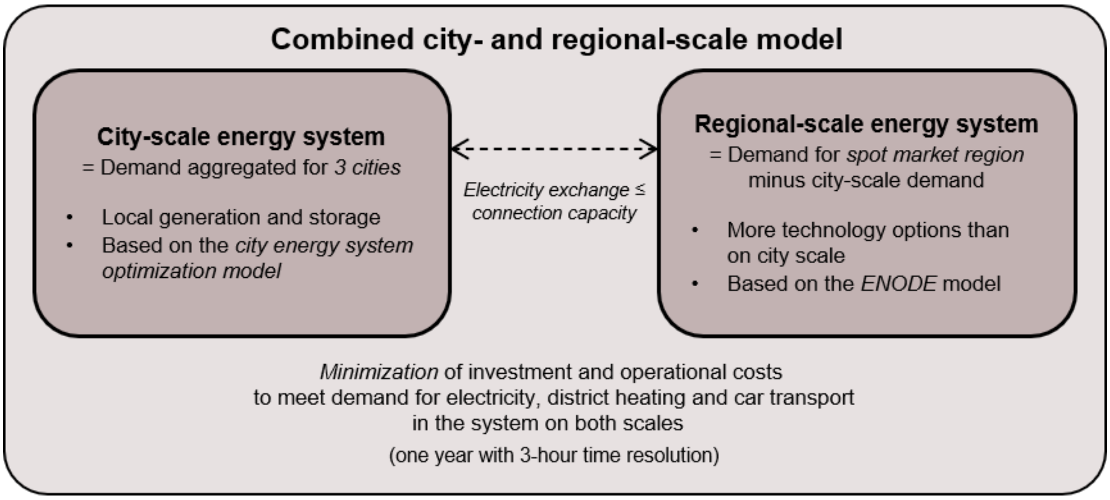

Figure 3-6: Overview of the model that links the city- and regional-scale energy systems (based on combining the city energy system optimization model and the ENODE model into one model).

The objective function of the city-scale and regional-scale model is written as:

$$MIN:\ C^{tot} = \sum_{i\in I}\sum_{r\in R}\left((C_i^{inv} + C_i^{OMfix})\, s_{i,r} + \sum_{t\in T}\left(C_i^{run}(p_{i,r,t} + q_{i,r,t}\right) + \sum_{r2\in R\setminus r}\left(x_{r,r2,t}C^{tr}\right))\right) \qquad \text{Eq. (5)}$$

where I is the set of technologies, R is the set of modeling nodes, i.e., the city-scale and the regional-scale nodes, and T is the set of time-steps. The total system costs, C^{tot}, consider the investment costs and the fixed operation and maintenance costs, C_i^{inv} and C_i^{OMfix}, respectively, per unit of capacity, s_i. In addition, the variable running costs, C_i^{run}, are calculated for the electricity generated, $p_{i,t}$, and the heat produced, $q_{i,t}$. A small transmission cost, C^{tr}, is considered for the electricity exchange $x_{r,r2,t}$ per time-step t between the two energy system nodes, i.e., the city-scale node and the regional-scale node.

To represent the differences in magnitudes of the energy systems on the city and regional scales, statistical data on the annual electricity and district heating demands [144] and the number of registered cars [145] per Swedish municipality are utilized. The municipalities are categorized to represent the three cities of the city-scale modeling node and the remainder of the market region for the regional-scale node; the hourly profiles for electricity, district heating and transport demand are scaled accordingly (see **Paper V** for details). The modeling considers the solar generation profiles from the model presented in [137], and the wind power generation profiles for different wind classes on the regional scale, which are based on the work in [146].

CHAPTER 4:

Main results

*This section describes the main findings from the appended **Papers I–V** in relation to the overall aim of this work. Chapter 4.1 addresses the research question: i) 'What are the techno-economic incentives for investment and operation of PV-battery systems in prosumer households and prosumer communities?' Chapter 4.2 is on sector coupling in city energy systems and, therefore, links to the research question: ii) 'What role does sector coupling play in the decarbonization of city energy systems?' Chapter 4.3 presents results on the integration of the city-scale and regional-scale energy systems and contributes to the research question: iii) 'How does the level of connection capacity between city-scale and regional-scale energy systems impact system design and costs on both scales?'*

4.1. Operation of and investment in residential PV-battery systems

The analysis of residential PV-battery systems in this thesis focuses on the impacts from considering different scales and system boundaries. In individual prosumer households (**Papers I** and **II**), the cost-optimal operation and sizes of the PV-battery systems depend to a large extent on the household electricity demand profiles and the retail electricity tariffs, through which prosumers purchase and sell electricity from and to their energy provider. The possibility for prosumers to share electricity (as in the prosumer community modeled in **Paper II**) implies a larger potential for local self-consumption of electricity from solar PV within a prosumer community, as compared to individual prosumer households. Another consequence of community energy systems is that the peaks in electricity demand, which occur at different times in different households, can be smoothened through the aggregation of the electricity demands of several prosumer households. The difference between the price of purchased electricity and the amount of reimbursement for sold electricity reflected in residential retail tariffs implies that a larger focus on self-consumption is more beneficial to prosumer households than adapting their battery system operations to incentives such as hourly electricity prices. Thus, the techno-economic utilization of PV-battery systems in prosumer households does not align with the total electricity system dispatch on the centralized scale (in this work, the spot market region), as shown in **Paper I**.

4.1.1. The role of prosumer households in the electricity system

The difference in battery system operation between the prosumer household and electricity system perspectives is shown in **Figure 4-1**, which presents results from the modeling conducted in **Paper I**. The PV-battery system capacities stem from a household annual electricity cost optimization; the same capacities are considered for the analysis of battery operation from the prosumer and electricity system perspectives. The incentive to self-consume electricity from solar PV (due to the difference in retail price between purchasing and selling electricity), results in a diurnal shape for the pattern of charging and discharging of battery systems when they are operated from the prosumer household perspective (red line in **Figure 4-1b**). As a consequence, the storage level in the battery systems (**Figure 4-1c**) varies according to a similar pattern as the generation from solar PV in the prosumer households (**Figure 4-1a**). In contrast, when operated from the electricity system perspective (gray dotted lines in **Figure 4-1**, **b** and **c**), the batteries are utilized less frequently, but are charged and discharged with more energy at once. Thus, the battery storage level remains constant for longer periods when considering the electricity system perspective, as compared to the prosumer household perspective.

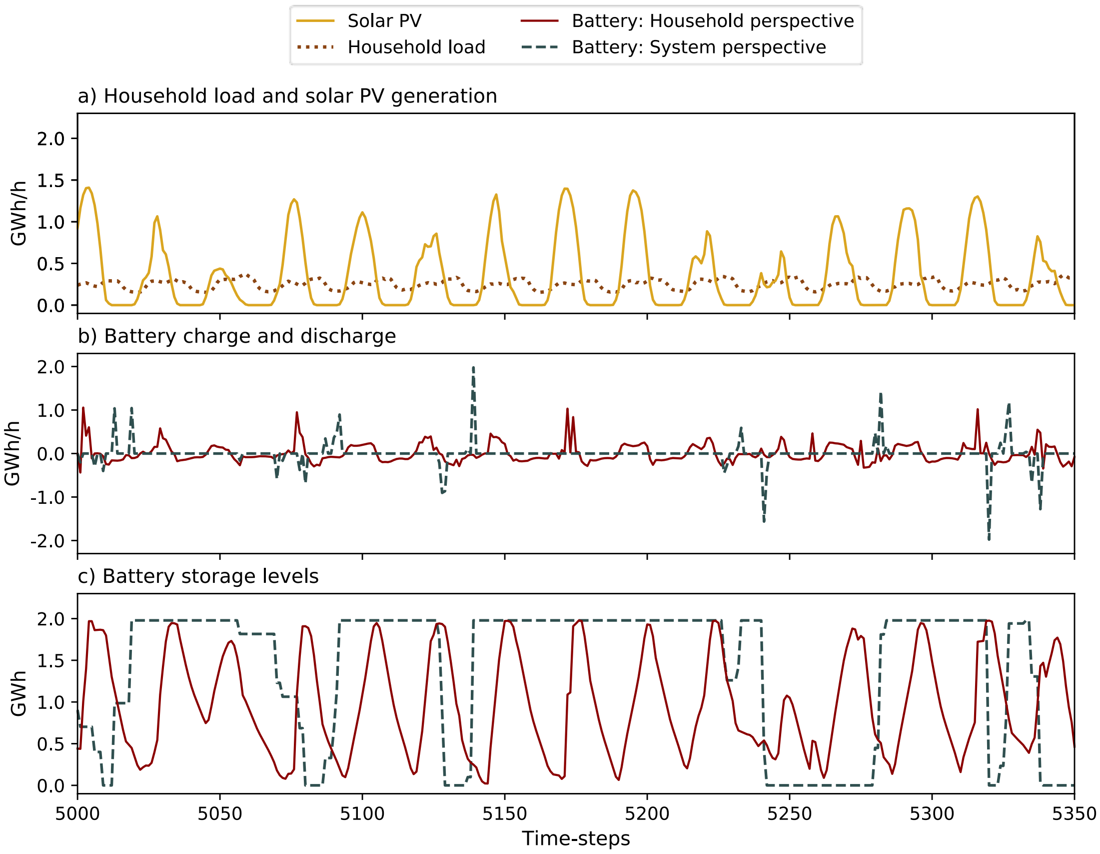

Figure 4-1: Difference in residential battery system operation from the prosumer household and electricity system perspectives. The panels show the household load and solar PV generation (a), the battery charge and discharge [positive and negative *y*-axes] (b), and the battery storage levels (c), for the time-steps of about two weeks. [Adapted from Figure 4 in Paper I]

When included in the total system dispatch, i.e., the electricity system perspective, battery system operation is influenced by different technologies. As examples: i) the charging of batteries according to the electricity system perspective is on several occasions timed so as to charge surplus electricity from wind power; and ii) the discharging of battery systems is used to avoid power plant start-ups or the use of expensive peak power generation during net-load peaks (i.e., hours with high electricity demand and/or low wind power generation). While in reality, battery system operation is informed by forecasts of electricity demand and wind power, this is not the case for the modeling in this work, in which perfect foresight is assumed. However, the results highlight the potential benefits of battery system dispatch:

- Increased self-consumption of electricity from solar PV, when operated according to the prosumer household perspective; and
- The avoidance of expensive peak power generation and power plant start-ups, when considered as part of the total electricity system optimization.

The difference in the operation of battery systems when optimizing according to the prosumer households or the electricity system affects the electricity system dispatch and the cost of electricity generation, as described in **Paper I**. The average running costs (calculated in €/MWh) in the two southern Swedish market regions in which prosumer households are considered in the modeling are 2.3% and 4%, respectively, lower when batteries are operated according to the electricity system instead of the prosumer household perspective. The power plant start-up costs for the entire modeled year are 31% and 22%, respectively, lower when adopting the electricity system rather than the prosumer household perspective. Thus, the dispatch of battery systems according to the prosumer household cost minimization is not in line with the electricity system cost minimization. However, the economic benefit to prosumer households of operating battery systems so as to increase their self-consumption is, with the retail tariff system modeled in this work, greater than the benefit to the electricity system from the electricity system-controlled dispatch of the battery systems (for more details, see **Paper I**).

4.1.2. Individual prosumers versus prosumer communities

In the prosumer community considered in the modeling for **Paper II**, the prosumer households are assumed to be able to share electricity with each other. Thus, with the assumptions made in this work, electricity from local solar PV can be self-consumed in all the households of the prosumer community. This results in some differences in the PV-battery capacities between the modeling cases with individual prosumer households and the cases with prosumer communities (**Paper II**), as shown in **Figure 4-2** for cases that include five prosumer households. (Modeling cases including a different number of households follow the same general pattern.) Two main findings can be highlighted in **Figure 4-2**:

- If self-sufficiency is the motivation for acquiring PV-battery systems, there is little to be gained from being part of a prosumer community, as compared to acting as individual households.
- In modeling cases that impose a limit on the connection capacity, a benefit of being part of a prosumer community is found for capacity limits that correspond to 40% of the maximum demand or that are stricter. In those cases, the optimization modeling shows a clear difference in PV-battery capacities between prosumer communities and individual prosumer households.

The greater impact on the difference in PV-battery sizes between individual households and prosumer communities when there is a constraint on the connection capacity limit, as compared to when the goal is self-sufficiency, can be explained by the nature of the residential household loads. Household loads differ with respect to the timing of their peak demands, which is to a large extent influenced by occupant behaviors, such as in the utilization of appliances. The large share of the electricity demand, however, from electric heating, ventilation and refrigeration is similar in all prosumer households. Thus, to cover a large share of the electricity demand using locally generated electricity, i.e., to achieve a certain level of self-sufficiency, requires very similar PV-battery capacities in individual households and prosumer communities. However, when there is a connection capacity limit, the different timings of the demand peaks in different households mean that the sharing of electricity within the prosumer community enables the peak demand in one household to be supplied by electricity from another prosumer household. Thus, the lower PV-battery capacities in the prosumer community are sufficient to fulfill the constraint.

The prosumer household costs in the modeling described in **Paper II** consist of the investment costs for PV-battery systems and the costs and reimbursements for the electricity purchased from and sold to the energy provider. Thus, the difference in PV-battery sizes between individual prosumers and the prosumer community in the modeling cases with connection capacity limits of 40% or stricter (**Figure 4-2a**) result in the greatest monetary benefits to prosumer households from being part of a prosumer community. The modeling conducted in this work shows that communities that consist of only prosumer households (i.e., no consumer households without generation and storage or electricity consumers other than residential customers) are more beneficial to the participating households in terms of reducing the peak in electricity exchange to the energy provider than with respect to reaching a certain level of self-sufficiency.

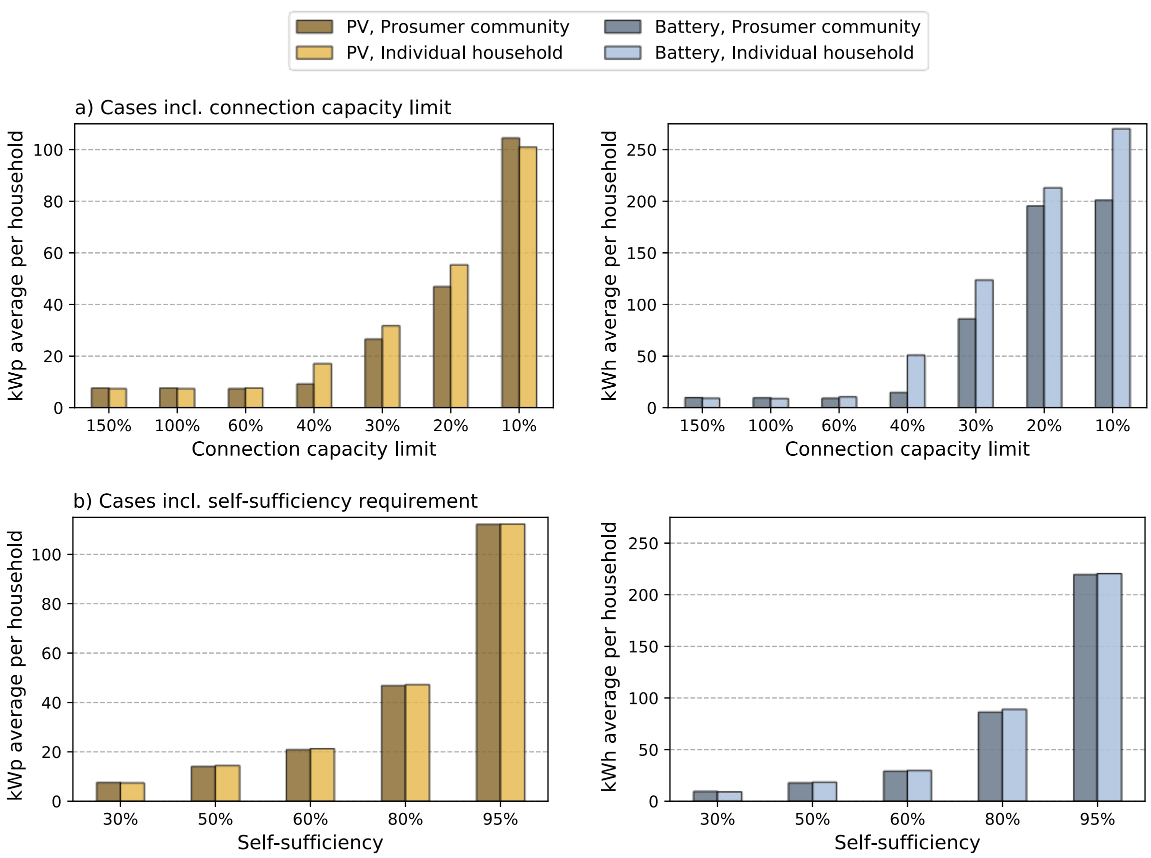

Figure 4-2: Investments in residential PV-battery systems, for prosumers that are part of a prosumer community and for individual prosumer households. The cases include a constraint on limited connection capacity (a), and on the level of self-sufficiency (b) and are modeled for five prosumer households. [Adapted from Figures 4 and A3 in Paper II]

In **Figure 4-3**, the electricity exchange of individual prosumers and the prosumer community with the energy provider, is compared (results from **Paper II**), sorted from the time-step with the highest to the time-step with the lowest electricity exchange. It is evident that the electricity exchange profile of the prosumer community involves more time-steps of electricity exchange at the full available connection capacity and more time-steps without electricity exchange to the energy provider than does the profile of the individual prosumer households. This pattern illustrates that in the modeling, the prosumer households prefer local sharing of electricity over electricity exchange with the energy provider (i.e., the time-steps without electricity exchange in **Figure 4-3**), as local self-consumption is cheaper than purchasing electricity from the energy provider. Furthermore, the pattern shows that the sharing of electricity within the community enables the households to concentrate greater amounts of electricity exchange to the energy provider to certain time-steps (i.e., the electricity exchange at the full available connection capacity in **Figure 4-3**). The electricity exchange to the energy provider is conducted according to an hourly price profile. Thus, the prosumer households can reduce their costs by bundling the electricity exchange to those hours during which the electricity price is most beneficial to them (i.e., low price for purchasing electricity and high price for selling surplus electricity). With connection capacity limits that are less strict than 40%, the electricity exchange profiles for individual prosumers and the prosumer community are more similar to each other.

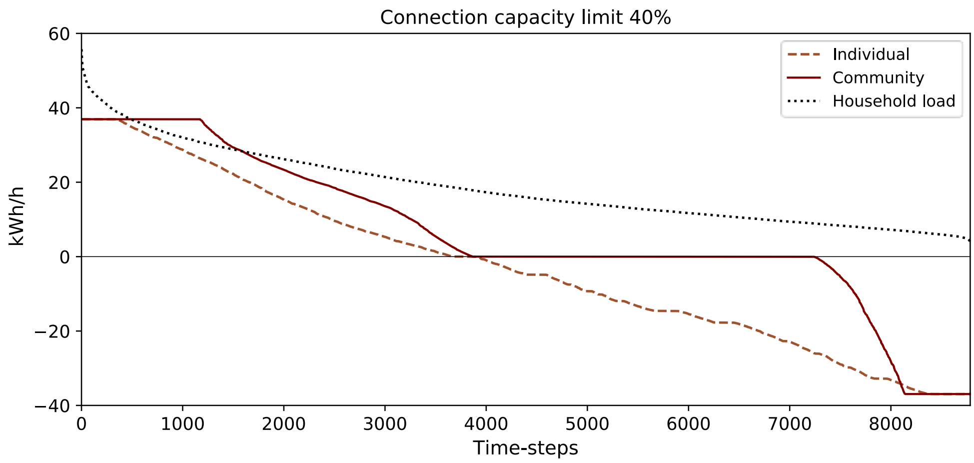

Figure 4-3: Electricity exchange with the energy provider, i.e., electricity purchased and sold by prosumer households (the positive and negative *y*-axis), sorted from highest to lowest, for individual prosumers and a prosumer community. The modeling cases include ten households and involve a connection capacity limit of 40%. [Adapted from Figure 5 in Paper II]

4.2. Sector coupling in city energy systems

For the city energy systems, in this work, the potential synergies between the electricity, district heating and transport sectors are analyzed. In both case studies of the city of Gothenburg (i.e., **Papers III** and **IV**), modeling cases were considered in which the hour of maximum city electricity demand exceeds the connection capacity that limits the possible import of electricity to the city. This is to represent the city growth in terms of urbanization and the increase in electricity demand due to the electrification of sectors and processes that have previously been run on fossil fuels. These developments can lead to a situation in which the city growth outpaces the lead times of projects concerned with the expansion of the electricity grid infrastructure into city energy systems, i.e., the connection capacity.

Investments in technologies for the local generation of electricity in the techno-economic model are affected by the need to supply hours of high electricity demand. Furthermore, local technologies represent a low-cost option for the supply of electricity to the city (low investment costs for solar PV and the dual functionality of CHP plants, which can supply both electricity and heat). The modeling in both **Papers III** and **IV** shows a clear connection between the availability of low-cost local electricity generation, i.e., solar PV, and the increased utilization of PtH technologies to supply heat to the district heating system. Flexibility in the energy demand or from the flexible operation of energy storage systems can shift the usage of energy to a later time and, thereby, increase the self-consumption of electricity and heat within the city energy system and decrease the import of electricity, especially during hours of high electricity prices. For instance, thermal energy storage systems facilitate the storage of heat over periods that range from a couple of hours up to seasonal storage, enabling more-flexible operation of PtH technologies, as shown in **Paper III**.

The electrification of cars and buses in the city energy system introduces a new electricity demand to the city energy system that has to be met. However, as the period during which vehicles are parked often exceeds the time that vehicles need to charge, there is a potential for flexibility in electric vehicle charging that can be utilized through smart charging strategies to benefit the city energy system optimization, as described in **Paper IV**. With the optimization modeling in this thesis, there is an impact of the flexibility of smart BEV charging on the city energy systems with respect to the hourly energy system operation and the energy system design, i.e., investments in local energy technologies.

4.2.1. Flexibility in the electricity and district heating systems

The potential synergies associated with the operation of the city electricity and district heating systems and the role of storage systems in facilitating these synergies are investigated in **Paper III**. **Figure 4-4** shows the operation of thermal energy storage systems over a period of one year, from the modeling of the city energy system in Gothenburg in Year 2050 (see **Paper III** for details of the modeling assumptions). Tank storage units (**Figure 4-4a**) are used for short-term storage, i.e., hours up to days, and thus, for the short-term balancing of heat supply and demand. Pit storage units are suitable for longer storage periods, from days and weeks (**Figure 4-4b**) up to seasonal storage, as shown in **Figure 4-4c**. The pit storage systems with connected heat pumps (**Figure 4-4c**) experience lower annual losses than pit storage systems without the connected heat pumps (**Figure 4-4b**) and are therefore more suitable longer-term storage of thermal energy. Both types of pit storage show a clear seasonal pattern. Thermal energy from the pit storage units is utilized to help supply the city's heat demand during the winter months, which can reduce the capacity required for units that usually supply peak heating demands, such as heat-only boilers. The pit storage units without heat pumps are charged and discharged more often than the pit storage units with connected heat pumps, with the latter undergoing one long period of charging and one long period of discharging during the year. The charging of both types of pit storage systems during summer is largely in connection with PtH operation, as is explained in **Figure 4-5**.

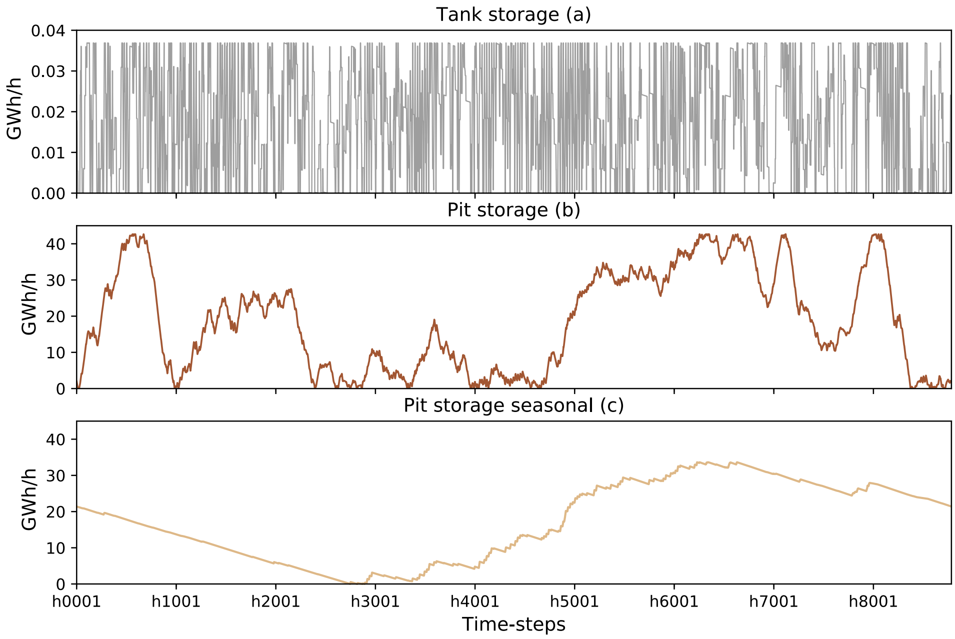

Figure 4-4: Operation of thermal energy storage systems, i.e., tank storages (a), pit storages without connected heat pumps (b), and pit storages with connected heat pumps, which are used as seasonal storage (c), in the Gothenburg city energy system, all shown for one model year.

[Results from the modeling case *Low Cost PV* in Paper III, which assumes investment costs of 300€/kWp for solar PV in the model Year 2050 and a biomass fuel price of 40€/MWh; for details of the modeling assumptions, see Paper III].

Figure 4-5 shows the dynamics of the operation of solar PV, battery storage systems, PtH, and pit storage units for the example of two summer weeks, from the modeling of the Gothenburg energy system with a high share of solar PV in **Paper III**. Battery storage systems are suitable for short-term storage, i.e., intra-day up to a few days, and are mainly used in connection with solar PV generation (in much the same way as the residential battery storage systems in prosumer households in **Papers I** and **II**, as discussed in Chapter 4.1). Thus, the storage levels in the battery systems, as shown in **Figure 4-5a**, often increase during periods of solar PV generation, and the battery is discharged during time-steps with low or zero solar PV generation, to help supply the city electricity demand.

The availability of electricity from solar PV, especially during summertime, correlates not only with the charge and discharge patterns of the battery systems, but also with the PtH operation in the city energy system. **Figure 4-5b** shows the heat output from PtH operation and the industrial excess heat that is utilized in the district heating system, in comparison with the hourly district heating demand in the city. It is clear that the time-steps during which the PtH technologies are operated such that the heat output in combination with the industrial excess heat exceeds the total city heating demand also exhibit a high level of generation from solar PV. As shown in **Figure 4-5c**, the thermal energy that is not utilized to supply the heating demand is used in pit storage systems. The operation of the pit storage without heat pumps (the dark-brown line in **Figure 4-5c**) also reveals that pit storage units are sometimes discharged in order to supply the heating demand in the city, e.g., during times of low solar generation, e.g., time-steps 4,230 to 4,240 in **Figure 4-5**. In line with **Figure 4-4b**, more thermal energy from PtH is used to charge the pit storage systems during the second half of the summer (not shown in **Figure 4-5**). It should be noted that the technologies depicted in **Figure 4-5** represent a selection of the technologies available within the modeled city energy system, which are here used to explain the coupling of the electricity and heating sectors. Other technologies include CHP units and heat-only boilers, which play important roles in supplying the city heating demand during wintertime.

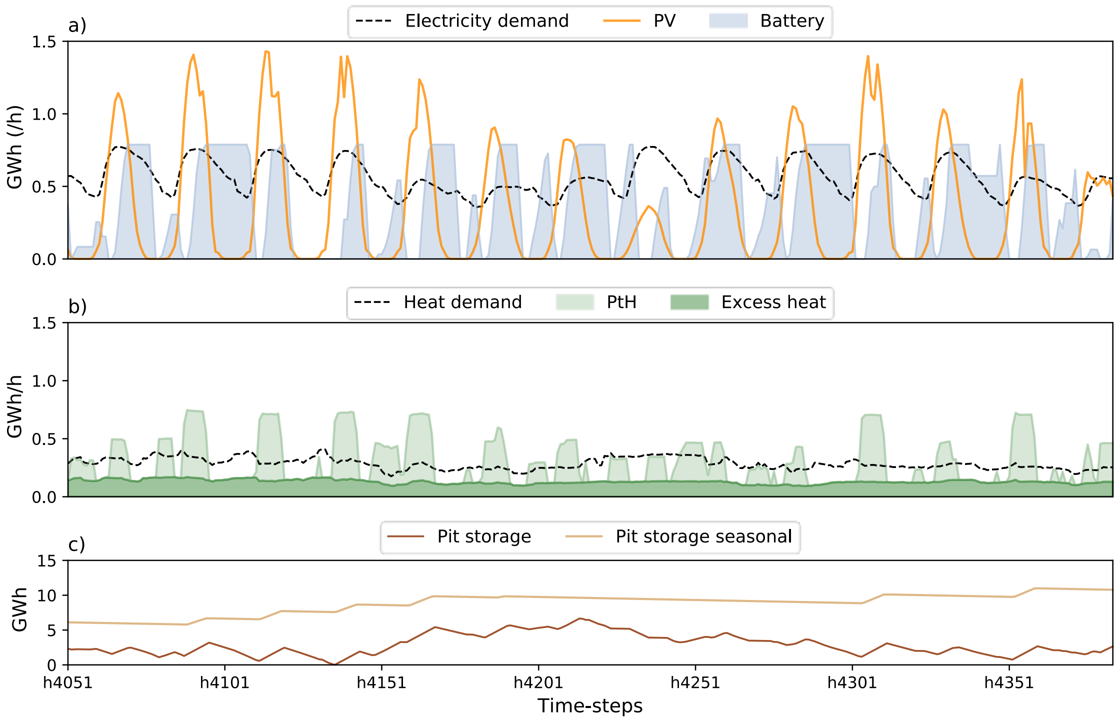

Figure 4-5: Operation of solar PV and battery storage systems (a), PtH technologies and industrial excess heat (b), and pit storage systems with and without connected heat pumps - denoted 'pit storage' and 'pit storage seasonal', respectively (c), all for two weeks of summer in the modeling. The electricity demand in (a) is the existing electricity demand, i.e., not including the electricity utilized for PtH technologies or battery charging. For PtH in (b), the heat output is shown.

[Results from the modeling case *Low Cost PV* in Paper III, which assumes investment costs of 300€/kWp for solar PV in the model Year 2050 and a biomass fuel price of 40€/MWh; for details of the modeling assumptions, see Paper III].

4.2.2. Charging of electric cars and buses

The potential for flexibility of charging differs for battery electric private cars and buses, as investigated in **Paper IV** of this work. The driving patterns of the fleet of private cars are more diverse than those of the fleet of public buses, which consist of scheduled trips with regular stops. Private cars are frequently parked over long periods and driving is often over short distances. However, batteries for private cars are usually sized so as to allow longer driving distances without intermediate charging. Thus, private cars can often continue without charging for longer periods and do not have to be charged at every stop during daily use. These patterns result in a greater potential to postpone the charging of BECs as compared to BEBs, as shown in **Figure 4-6** for the example of one winter week from the modeling in **Paper IV**. The difference between the inflexible charging strategy, whereby vehicles are charged directly when being parked, and the smart charging strategy, which allows to postpone the charging in accordance with the energy system optimization, is larger for BECs than for BEBs (**Figure 4-6, a** and **c**). The large battery capacity of the BEC fleet (an electrification level of 60% of the current car fleet is assumed) allows for longer periods without charging (*cf.* the battery storage level in **Figure 4-6b**) than is the case in the BEB fleet, for which charging can only be postponed within the same day (**Figure 4-6d**). However, it should be kept in mind that the modeling method, which considers an aggregated profile for the driving demand of the vehicle fleet (and includes perfect foresight) overestimates somewhat the potential for flexibility in vehicle charging, due to limitations linked to individual driving profiles that are not represented.

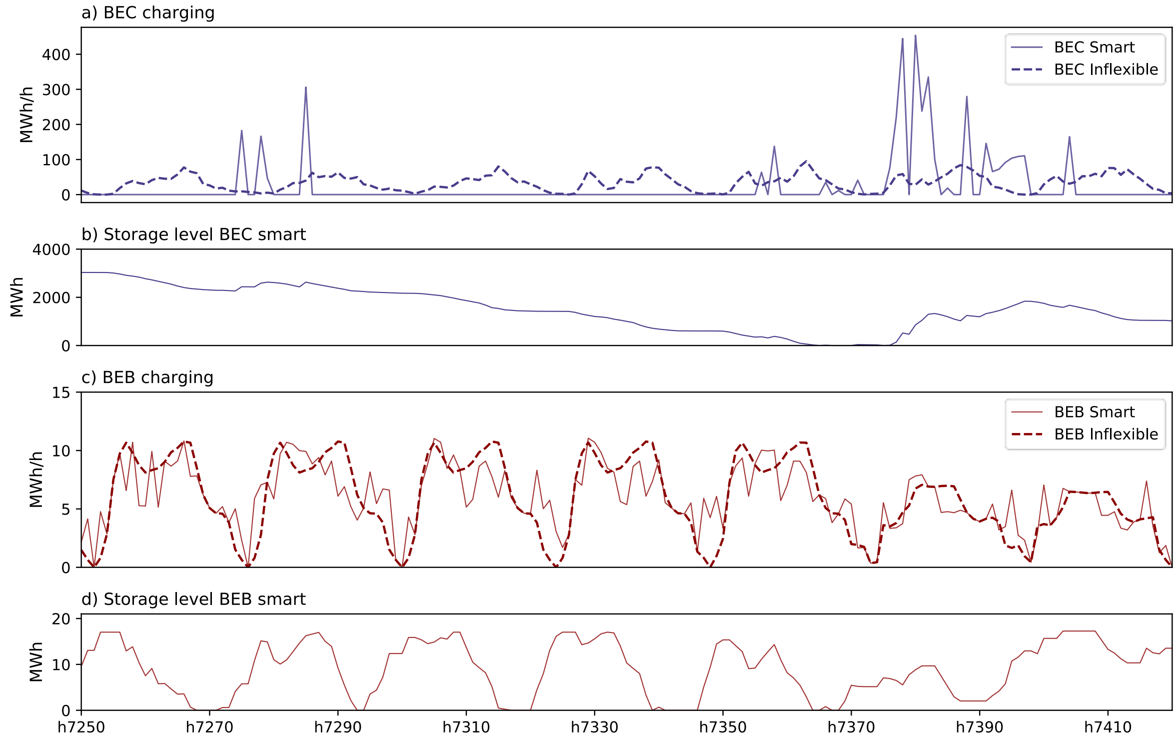

Figure 4-6: Smart and inflexible charging of electric cars, BEC (a) and buses, BEB (c), and the corresponding battery storage levels (b) and (d), for one week in the modeling, with Saturday and Sunday furthest to the right in each panel. The useable battery storage volumes are plotted; the actual battery sizes would need to be larger, as complete discharge of the battery should be avoided. [Source: Figure 5 in Paper IV]

With a smart charging strategy, the charging of BECs is often postponed to hours of high local generation. Thus, in a system with extensive employment of solar PV, a smart charging strategy for BECs enables greater uptake of local solar PV. This can also be seen in the electricity mix for BEC charging, which has been calculated as 62% of solar PV in the electricity mix for smart charging, as compared to 24% in the electricity mix for inflexible charging. **Figure 4-6** shows an example of one winter week. During summer, when solar PV generation is generally higher, the periods of postponed BEC charging are usually shorter. The charging of BEBs, though less flexible, matches well with the solar generation profiles, even with an inflexible charging strategy (as the bus driving demand is concentrated during daytime). This results in shares of 31% and 32%, respectively, for solar PV in the electricity mix for inflexible and smart BEB charging. V2G used in combination with a smart charging strategy for the BEC fleet not only increases the uptake of electricity generated by local solar PV, but also eliminates the need for stationary batteries, as instead the vehicle batteries fulfill this function (for details, see **Paper III**).

With respect to investments in the city energy system, the increased electricity demand from BECs facilitates larger investments in solar PV capacity in all the modeling cases with BECs, as compared to those cases without BECs, independent of the charging strategy used. However, due to the lack of flexibility in BEC charging, the larger solar PV capacity is combined with a larger stationery battery capacity in the case of inflexible charging. With smart BEC charging, the need for stationary batteries is reduced compared to the case without BEVs. As an alternative to local generation and storage, i.e., here, the investments in solar PV and battery systems, the increased electricity demand from BECs can also be supplied through increased electricity import to the city, if the electricity grid infrastructure allows for this or is expanded accordingly. The charging of BEVs also affects the district heating sector. PtH technologies are invested in to a lesser extent with all the BEC charging strategies, as compared to a modeling case without BECs. Instead, investments in CHP plants increase slightly. This reflects the fact that some of the electricity that is generated by solar PV is used to charge the cars in the modeling cases with BECs, so less electricity is used for PtH. Consequently, larger capacities of CHP plants are needed to supply the city heating demand in these cases.

4.3. Implications from limited connections between city and regional scales

In **Papers III** and **IV**, the city energy system has been studied independently of the surrounding energy system, with an electricity price profile used as a representation of the spot market prices for electricity. Thus, the modeling approach described in **Paper V** was developed to link dynamically the modeling of the city energy system with the modeling of the regional energy system, i.e., the spot market region. Combining both energy system scales into one model allows to study how the designs and operations of both systems are optimally integrated, and to investigate the impacts that different levels of connection capacity between them have on both systems. Different connection capacities are studied to understand how cost- and resource-intensive the increased local generation and self-consumption of electricity on the city scale is, in a situation where city electricity demand is larger than the capacities of the current infrastructure (e.g., caused by fast-growing cities or increased inner-city electrification). In addition, and in contrast to the modeling performed for **Papers III** and **IV**, the combined model allows for an analysis of how the pattern of the electricity exchange between the two systems is not only affected by the city's need to import electricity, but also by the operation and dispatch of the energy system on the regional scale.

4.3.1. System designs for different levels of connection capacity

Figure 4-7 shows the investments in the city-scale and regional-scale energy systems in modeling cases with different connection capacities, i.e., connection capacities corresponding to 100%, 75%, 50% and 0% of the maximum city-scale load. The results are from the modeling in **Paper V**, with the Nord Pool spot market region SE3 representing the regional scale, and the three largest cities (Stockholm, Gothenburg and Uppsala) in the same region representing the city scale. The three cities are aggregated into a single node in the modeling and are, thus, referred to as the 'city energy system'. The system designs in the different modeling cases show a progressive redistribution of generation capacity from the regional scale to the city scale with decreasing connection capacities. The lower levels of wind power capacity seen in the regional system with decreasing connection capacities (**Figure 4-7b**) can be explained by the lower level of electricity exchange to the city-scale energy system. The smaller wind power capacities in the cases with lower connection capacities are paired with larger PtH and pit storage capacities on the regional scale. This pattern indicates that the electricity exchange to the city energy system is not only used to supply the city with electricity, but is also adapted to the variations in wind power generation on the regional scale. Thus, as a consequence of lower connection capacities between the city and regional systems, other technologies are utilized on the regional scale to manage the variations from wind power generation (i.e., mainly PtH with pit storage systems and flexible generation from hydropower).

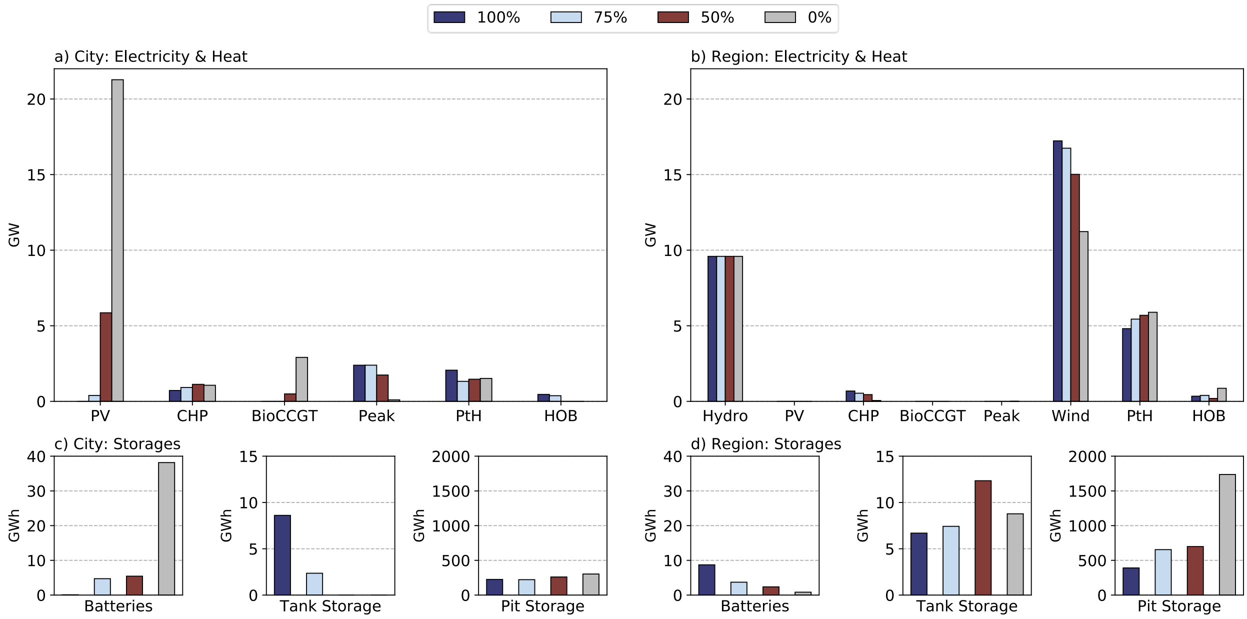

Figure 4-7: System design on the city and regional scales, for modeling cases with different connection capacities. Capacities for electricity and heat generation in the city-scale (a) and regional-scale (b) energy systems, and storage technologies for the city (c) and regional (d) scales.
[Source: Figure 3 in Paper V, Results from the *Base* cases]

[CHP, Combined heat and power plants (for which the electricity generation capacity is plotted); CCGT, combined cycle power plants; Peak, gas turbines used for peak power generation; PtH, power-to-heat technologies, for which the heat generation capacity is plotted; HOB, heat-only boilers (with the exception of electric boilers, which are included in PtH)].

The linkage between regional-scale wind power generation and the pattern of the electricity exchange is also evident in **Figure 4-8**. With a connection capacity of 100% (i.e., the left-hand side of **Figure 4-8**), the peaks and lows in the electricity exchange profile follow a similar pattern as the variations in wind power generation during several periods of the model year. Moreover, peaks in the operation of the city-scale PtH also frequently coincide with peaks in the regional-scale wind power generation. On the other hand, with 50% connection capacity (i.e., the right-hand side of **Figure 4-8**), PtH operation in the city energy system is concentrated to the summer months when the electricity demand in the city is lowest and the level of generation from solar PV is high. Furthermore, the periods of low electricity exchange often coincide with high levels of city-scale solar PV generation. (Note that the installed capacities differ in the cases with different connection capacities, and that there is no city-scale solar PV in the case with 100% connection capacity.) These findings highlight the suitability of PtH technologies for balancing fluctuations in wind power generation, and that this ability is dependent upon sufficient connection capacity between regional-scale systems with wind power and cities and towns with district heating systems. (The heating demand and production included on the regional scale in the modeling represent district heating systems in smaller cities and towns, which are not the three cities represented on the city scale. It is assumed that these locations do not experience the same urbanization effects and, thus, the challenges with bottlenecks in the electricity infrastructure are assumed to be less severe.) Additional figures showing the hourly operation of the city-scale and regional-scale energy systems and the electricity exchange between them can be found in the Supplementary material to **Paper V**.

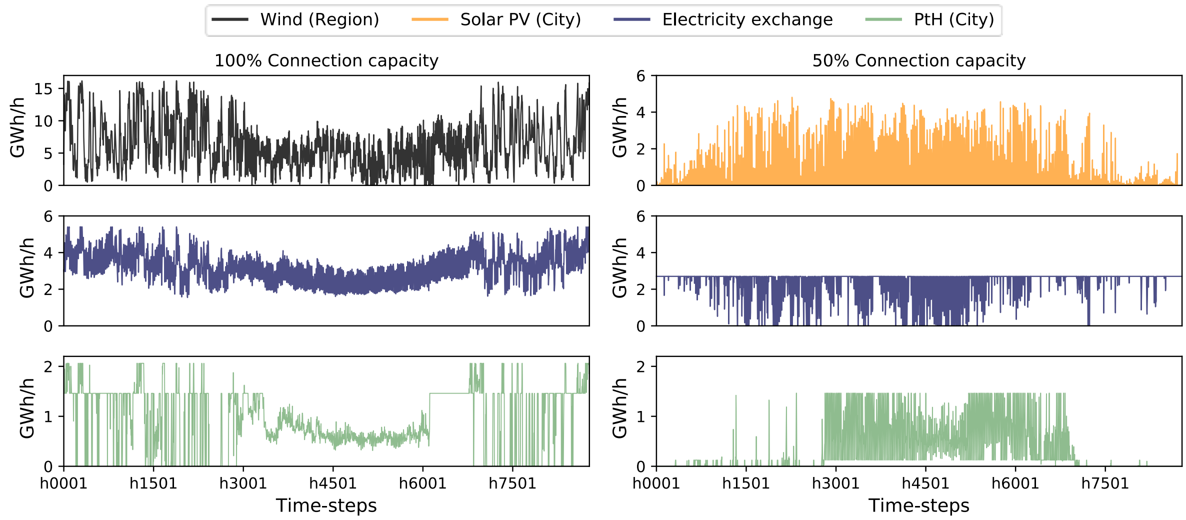

Figure 4-8: Operation of wind power on the regional scale, solar power on the city scale, the electricity exchange between the city and regional scales, and PtH operation on the city scale, for modeling cases with 100% (left panels) and 50% (right panels) connection capacities. [Results from the modeling of the *Base* cases in Paper V]

In the city energy system, the decreasing levels of connection capacity lead to increasing levels of local electricity generation, i.e., a high level of solar PV in the modeling results (**Figure 4-7a**). A completely isolated city energy system, represented by 0% connection capacity in the modeling, certainly requires high capacities for local electricity generation. However, the investments in the city-scale energy system are similar for cases with connection capacities of 75% and 100%, and the system with 50% connection capacity resembles more closely the system designs with higher connection capacities than a system with 0% connection capacity. (The solar PV capacities in the city energy system result in sizes equal to 10%, 107% and about 400% of the maximum city load hour in the cases with 75%, 50% and 0% connection capacity, respectively.) Thus, these results indicate that for city energy systems in which flexibilities in the electricity, district heating and private car transport sectors are utilized, a somewhat limited connection capacity to the regional system (i.e., a limit of about 75% of the maximum city load or higher) requires only a small change in the installed capacity, as compared to a system in which the maximum city load can be fully supplied by electricity imports (i.e., 100% connection capacity).

4.3.2. System costs versus local costs of electricity

With respect to the costs of the decarbonized city and regional energy systems, **Figure 4-9a** reveals that the total system costs (i.e., the costs for investment and operation in both the city-scale and the regional-scale energy systems) are similar with connection capacities of 50% to 100%. The total system costs differ considerably only in the case without electricity exchange to the city energy system, i.e., 0% connection capacity (results from **Paper V**). As shown in **Figure 4-7**, the system designs with 75% and 100% connection capacities are similar, and thus, come at similar costs. However, the system design with 50% connection capacity results in total system costs that are only about 3% higher than that with a connection capacity of 100% (although **Figure 4-7** shows a redistribution of generation capacity from the regional-scale to the city-scale energy system, as compared to the cases with larger connection capacities).

In **Figure 4-9b**, the average marginal costs of electricity in the city and the regional energy systems are shown, which are an indicator of the local costs for electricity in both systems. In the city energy system, the average marginal costs for the cases with connection capacities of 75% and 100% are similar to each other, as well as to the marginal costs in the regional system. Similar marginal costs in the city and the regional energy systems indicate low levels of congestion between the systems in those cases. However, with a connection capacity of 50%, the marginal costs in the city energy system are about 50% higher than when there is a connection capacity of 100%. Although the difference in total system costs between these cases is only 3%, a lower connection capacity implies that a larger share of the investments are taken on the city scale. This, consequently, leads to higher marginal costs for electricity within the city energy system. Marginal prices in the city energy system are not currently linked to the prices that customers pay for the electricity inside the city. Nonetheless, congestion in the electricity exchange to the regional energy system and the need for large investments in local electricity generation may affect the possibilities for city growth and the attractiveness for new business and industries.

The average marginal costs in the regional-scale energy system in **Figure 4-9b** are similar for all connection capacities, with a slight decrease observed with decreasing connection capacities. This decrease can be explained by the lower overall generation capacity that is installed when less electricity exchange to the city energy system is possible. With lower generation capacity, cheaper technology options, i.e., primarily better sites for wind power, are sufficient.

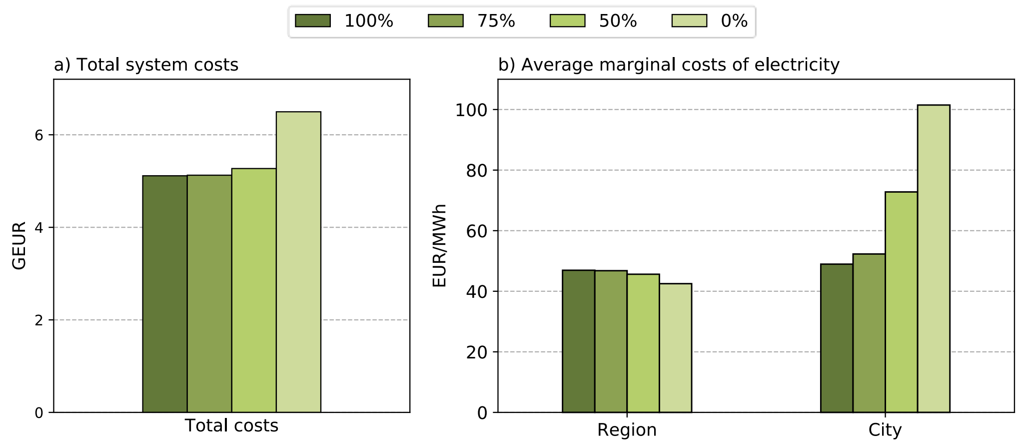

Figure 4-9: Total system costs (a) and average local marginal costs for electricity on the city and regional scales (b), for modeling cases with different connection capacities. [Adapted from Figures 7 and 8 in Paper V, Results from the *Base* cases]

CHAPTER 5:
Discussion and conclusions

This thesis investigates investments in and the operation of low-carbon technologies on different scales in the energy system, the importance of sector coupling for the cost- and resource-efficient decarbonization of city energy systems, and how the level of connection capacity between city and regional scales influences energy system designs. In this section, the contributions that have been made to the research questions posed in Chapter 1 are summarized. Thereafter, reflections are made regarding decentralization on different energy system scales. Finally, directions for further work within the research area are proposed.

5.1. Summary of contributions to addressing the research questions

In the context of the research questions posed in Chapter 1, the findings and conclusions from this work can be summarized as presented below.

*i. What are the techno-economic incentives for investment and operation of PV-battery systems in prosumer households and prosumer communities? (**Papers I** and **II**)*

For *prosumer households*, the self-consumption of electricity is preferable over the purchase of electricity from and selling of excess electricity to an energy provider. This is mainly because residential retail tariffs are generally designed such that the cost of purchasing electricity is higher than the reimbursement that prosumers receive for their excess electricity (these are the conditions modeled in this work). This results in battery system operation with a clear diurnal pattern, which is different from the optimal electricity system dispatch, in which batteries are charged and discharged less frequently but with higher amounts of energy at each time. A high share of prosumer households with increased self-consumption increases the operational costs of the electricity system. As shown in **Paper I** of this work, the difference between the costs for purchased electricity and the reimbursements for surplus electricity in residential retail tariffs entail a larger monetary benefit to prosumers, in a situation in which battery systems are controlled by prosumer households, than to the electricity system, in a situation in which batteries are controlled by the electricity system. Under these conditions, prosumer households are unlikely to contribute with flexibility to balance intermittency in the centralized electricity system.

Sharing of electricity in a *prosumer community* enhances the possibilities for self-consumption of locally generated electricity. Financial benefits to prosumer households from being part of a prosumer community are in **Paper II** of this work primarily found in those cases that have a strict limit imposed on the connection capacity that is available for electricity exchange to the energy provider (i.e., a limit of 40% of the maximum load or stricter). These cases represent a situation in which prosumer communities seek increased independence from the local grid operator or in which the capacity is to be reduced to lower grid costs. Only the cases with strict limits on connection capacity yield differences in the PV-battery system investments of individual prosumers and prosumer communities. The local sharing of electricity within a prosumer community alters the pattern of electricity exchange with the energy provider, such that the purchase and selling of electricity is concentrated more towards the hours with electricity prices that are favorable to the prosumers (i.e., low prices for the purchase and high prices for the selling of electricity). In addition, there are more hours of no electricity exchange with the energy provider. Thus, whether prosumer households schedule their electricity usage individually or share electricity locally in a prosumer community needs to be considered when assessing the possible impacts of residential prosumers on the centralized electricity system.

*ii. What role does sector coupling play in the decarbonization of city energy systems? (**Papers III** and **IV**)*

Thermal energy storages in *city energy systems* used in combination with PtH technologies are found to provide flexibility that supports the uptake of electricity from local sources, such as solar PV, as shown in the modeling results of **Papers III** and **IV**. While battery storage units, similar to their usage in prosumer households, are preferably used for the short-term shifting of electricity, TESs are suitable also for long-term storage, i.e., the shifting of energy between weeks and seasons. In city energy systems in which low-cost electricity from solar PV is available, excess electricity can be used in PtH technologies to produce heat during the summer months. This can then, through storage in TES, help to supply the peak heating demands in the city during wintertime. Thus, the costs for running more-expensive units such as heat-only boilers, which are often used to supply the hours of peak heating demand, can be avoided. CHP plants are less important in the investigation of synergies between the electricity and district heating sectors presented in this thesis, due to the strong availability of low-cost solar PV in the city energy systems modeled. In systems with lower shares of solar PV, as investigated in **Paper III,** a clear connection between CHP operation and TES charging is evident.

With regards to electrified transport in city energy systems, a greater potential for flexibility in charging is found for battery electric cars as compared to battery electric buses. Scheduling BEC charging in accordance with the city energy system optimization in **Paper IV** (i.e., a smart charging strategy), results in a charging pattern in which 85% of the charging is postponed, as compared to an inflexible charging strategy in which cars are charged directly while parked. (With both the smart and inflexible charging strategies, the driving demand of the cars is met.) Smart charging in accordance with the city energy system optimization more than doubles the share of solar PV in the electricity mix for charging, as compared to an inflexible charging strategy. A prerequisite for the utilization of flexibility in electric vehicles for the benefit of the city energy system is the widespread availability of a charging infrastructure that is adapted to smart charging. While the charging of the BEB fleet is much less flexible than the charging of the BEC fleet, the daytime driving schedule makes electrification a suitable decarbonization strategy for public buses, in combination with an increased number of local solar PV installations.

The flexibility from the district heating and the electrified transport sectors is only beneficial for the balancing of variations inside the city electricity system and for promoting the local self-consumption of electricity, when it is provided at the right times. Thus, either coordination and joint planning between sectors and stakeholders in the city energy system or financial incentives, such as time-varying local price signals, are necessary to establish the value of flexibility in cities. Although neither of these measures is currently in place in city energy systems, they have the potential to facilitate decarbonization of city energy systems.

*iii. How does the level of connection capacity between city-scale and regional-scale energy systems impact system design and costs on both scales? (**Paper V**)*

Growing cities and increased levels of electrification are likely to require an expansion of the electricity system infrastructure, so as to be able to fully supply the maximum city electricity demand using electricity that is imported to the city (in this work, the connection capacities between cities and the surrounding regional energy system are considered). An alternative to connection capacity expansion is to increase local generation and balancing in cities. The modeling in **Paper V** shows that energy systems with a connection capacity of 50% of the maximum city load, as compared to 100%, and subsequent larger installations of energy technologies on the city scale, result in not more than a 3% increase in total system costs (i.e., investment and operational costs linked to the city-scale and regional-scale energy systems, not considering the costs for connection capacity). This result indicates that for cities in which the flexibility of different energy system sectors is utilized, local energy technologies can replace or delay the need for expansion of the connection capacity. However, the analysis in **Paper V** also reveals 50% higher local marginal costs for electricity in the city energy systems in a case with 50% (as compared to 100%) connection capacity. Currently, electricity prices are determined on the market region scale and, thus, they do not encourage investments in city-scale energy technologies in cases of bottlenecks in the connection capacity to the regional system. Moreover, the setting of electricity prices on the market region scale does not incentivize the utilization of city energy system flexibility for local energy balancing, as these electricity prices reflect variations in generation and demand within the whole market region rather than in the city energy system.

5.2. Reflections on the decentralization on different energy system scales

While the research questions in this thesis focus on the findings from the individual investigations of decentralized energy systems and their interactions with the centralized system, this section provides reflections from the work on all the different energy system scales and on the role of decentralization in future energy systems.

- *Planning for the energy transition will involve coordinating different incentives and actors within decentralized energy systems.*

For residential households, a retail tariff structure that includes a clear difference in the prices for purchased electricity and reimbursements for excess electricity incentivizes the installation of local generation and storage technologies, and their utilization so as to increase self-consumption. In city energy systems, local targets for the city energy transition or the necessity to supply fast-growing cities with energy serve as a motivation for the installation of local energy technologies. There are currently only limited economic incentives in the Nordic electricity market setup to increase the self-consumption of energy inside city energy systems. However, the favorable conditions for the utilization of synergies between different sectors of the city energy system indicate the potential for increased energy autonomy in cities. This thesis shows that energy technologies and local balancing in decentralized systems affect the surrounding system, i.e., for example, the hourly pattern of electricity exchange (**Papers II** and **V**) and the operation and design of the regional energy systems (**Paper I** and **V**). Thus, energy targets for national and regional energy systems can benefit from a consideration of decentralized systems and from an assessment of: i) which actors are expected to advance the installation of distributed energy technologies; and ii) which current or potential future incentives will likely have impacts on the self-consumption and local balancing in decentralized energy systems.

- *Flexibility in local energy systems can be used to balance local or regional variations in energy supply and demand.*

The presence of large demands for heating or personal transport in cities, in combination with the ongoing development towards electrification, provides good conditions for sector coupling in city energy systems. The modeling in this work reveals that the flexible operation of PtH technologies in the district heating systems of cities in combination with thermal storage can be used for the uptake of local solar PV (**Paper III**). However, it can also be used to balance variations in the intermittent wind power generation in the regional energy system (**Paper V**). To enable the balancing of regional wind power generation, sufficient connection capacity needs to be in place. The facilitation of local balancing and self-consumption in city energy systems requires business models that enable cooperation between different local energy system sectors and an indication of when increased or postponed energy usage is most beneficial to the local system. Although not analyzed in this work, also residential households and communities can exploit the synergies between electricity, heating and transport through, for instance, the installation of heat pumps or smart EV charging. The extent to which the flexibility in decentralized energy systems is likely in the future to be utilized to increase local self-consumption or to contribute to balancing intermittency outside of the decentralized system is uncertain. The use of flexibility depends on the incentives offered by potential local and regional energy market setups in future energy systems, and it will affect the interactions of decentralized and centralized energy systems.

- *The local utilization of system flexibility can be accomplished through coordination of a low number of stakeholders in close proximity, although a focus on local balancing can also exacerbate inefficiencies in the energy system*.

In energy systems that have a large share of distributed energy technologies and flexibility of energy usage, the balancing of supply and demand requires extensive sharing of information within the system. A focus on local energy balancing and sector coupling in decentralized systems may limit the need for coordination and communication to a confined system boundary. Sector coupling in decentralized systems is also likely to involve a low number of actors in close proximity. This has the potential to facilitate collaboration between the actors, thereby advancing the local energy transition. However, a focus on local balancing and planning within decentralized systems comes with risks of inefficiencies in the operation of the regional/national energy system and in the utilization of resources. Therefore, achieving a balance between the full integration of energy system scales and sectors and the associated increased requirement for large-scale communication and coordination will have to be a priority in future energy systems.

5.3. Further research

Research that has the goal of understanding the roles of decentralized energy systems and their interactions with the surrounding system can be extended in different directions. A selection of areas proposed for future work is discussed in this section.

With respect to the modeling of the three decentralized energy system scales studied in this work, several avenues of additional research are of interest. Concerning energy technologies on the residential scale, especially in energy communities, the practical implementation of concepts for local self-consumption and local energy trading should be investigated further. This entails, for instance, addressing questions regarding how prosumers can participate in (local) energy markets, how prices for P2P energy trading are determined, and which data need to be available and shared for effective energy management in households or communities. With regard to city energy systems, further analyses could involve a higher level of detail (as compared to the modeling in this thesis) concerning the different types of energy consumers present in cities. This could involve making distinctions between, for instance, residential, commercial and industrial energy demands or different types of buildings such as single- and multi-family buildings, offices, public buildings, etc. Furthermore, the city energy system model used in this work could be further developed to include spatial resolution inside the city, such as different districts or differentiation between the city center, outskirts and commercial centers. High spatial resolution inside the city would allow for investigations of bottlenecks inside the city energy system and analyses of where the installation of generation or storage technologies and the integration of new demands (such as in charging stations for electric vehicles or the provision of flexibility to the city energy systems) are most beneficial. In this thesis, the design and operation of the city energy system have been modeled for one future year in each model run. However, the modeling of transition pathways for the city energy system, taking into account cost developments over time and continuously stricter climate goals, could provide a more complete understanding of the steps needed to decarbonize fully the city energy systems.

There are expected to be multiple impacts from decentralization on the centralized energy system. These impacts will encompass technical, economic, social and environmental aspects. Different studies, including the papers in this thesis, have contributed to a better understanding of one or several of these factors, often for a specific system setup or a case study. However, for a more complete picture of the system impacts from decentralization, it is advantageous to have greater generalizability and comparability between different system scales and across geographic locations. One way to analyze the different systems and system scales is to utilize indicators that can be applied to and compared for different decentralized energy systems. Examples of indicators that describe the interactions of decentralized systems with their surrounding energy systems have been proposed in the literature, including the fraction and distribution of time that decentralized energy systems are energy-autonomous [7] and the hourly need for electricity import and the potential for electricity export in decentralized systems [87]. Other potential areas for the development of indicators to study decentralized energy systems are the utilization and costs of electricity grid infrastructure, and the question as to how well emissions reduction goals and resource utilization in decentralized systems align with the national energy actions [86]. The use of indicators allows to compare the case studies in this thesis to other decentralized systems, such as different cities or different energy community setups, in order to draw broader conclusions as to the impacts of decentralization on centralized energy systems. In addition, studies that use a set of parameters or indicators for the comparison of different decentralized energy systems or energy system scales can provide useful inputs for developing strategies and regulations that consider decentralization in future energy systems.

Finally, many current studies on decentralized energy systems focus on technology applications and operations and often lack a systematic analysis of the socio-technical dimensions of decentralization or the diversity of concerned stakeholders [17,19]. This thesis has investigated the techno-economic potential for local self-consumption and sector coupling in decentralized energy systems. However, in small-scale systems, other aspects such as individual preferences and choices and factors such as trust and the willingness to cooperate can both facilitate and hinder developments towards decentralization and sector coupling [13,19]. Thus, the findings of this work should be discussed in light of the results of studies that analyze driving forces and barriers for the formation of decentralized energy systems. Moreover, studies that combine socio-technical and socio-economic analyses with technical, economic and environmental investigations of decentralized systems, and studies that analyze the impacts from a diversity of actors on the planning and design of future energy systems and on the role of decentralization in those deserve more attention in future research

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