CHALMERS
UNIVERSITY OF TECHNOLOGY

Replication of Local Energy Management Systems to an Urban Region

Master's thesis in Sustainable Energy Systems

NIMA MIRZAEI ALAVIJEH
CRISTINA ALEMANY BENAYAS

Department of Electric power engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
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A study for replication possibilities of Fossil-free Emission District (FED) project

Focusing on applicability or possibilities of an energy community set up in different districts in the city of Gothenburg

NIMA MIRZAEI ALAVIJEH
CRISTINA ALEMANY BENAYAS

Department of Electric Power Engineering
Division of Electric engineering
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NIMA MIRZAEI ALAVIJEH
CRISTINA ALEMANY BENAYAS

Supervisor: David Steen, Electric Power Engineering and Claes Sommansson, Johanneberg Science Park
Examiner: Anh Tuan Le, Electric Power Engineering

Master's Thesis 2017:EENX30
Electric Power Engineering
Division of Division name
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

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Abstract

Integration of more distributed renewable energy resources (RES) technologies in the past few years has led to reliability and stability issues in the energy systems due to the mismatch between the demand and the intermittent RES production. Local Energy Management (LEM) system have been discussed as part of the solution for these challenges. In this thesis, the replication of LEMs to an urban district is studied in collaboration with an EU-funded project called FED at Johanneberg Science Park.
In this study, total electricity and heating cost of sample districts from Gothenburg are optimized considering two cases of with and without LEMs in place. Three consumer types of houses, apartments and services are considered to simulate these districts. Each of these consumers own different assets such as solar PVs, batteries, demand response capabilities, auxiliary heat pumps and thermal energy storage tanks. The aspects studied in the replication study are the size of the district, composition of consumers types, penetration level of assets and cost structure of the system. The performance of the LEM has been evaluated regarding the cost, emissions, self sufficiency, peak reductions and the changes in usage of flexibility assets.
According to the results from the model, not any considerable change in the performance has been observed by changing the size of the district whereas the sample district with the consumer composition of all three types showed a 5 to 53% performance increase (depending on the performance indicator) compared to single consumer type districts. From the different penetration levels studied, the scenario with 40% penetration of all assets achieved the best LEM performance. When implementing higher penetration levels, the amount of electricity exchanged internally is decreased since all buildings own a large installed capacity and the electric peak performance indicator is worsened. Moreover, the study shows the cost structure has a great impact on the LEM's performance.
The study on the size and composition of the district can help with where to implement LEMs in urban regions; whereas the cost structure study would be helpful in how to implement it. The study can be used by different stakeholders affected by LEMs (e.g. DSOs, retailers and future aggregators).

Keywords: Distributed energy systems, local energy communities, local energy market, multiple energy system integration.

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1

Introduction

1.1 Motivations

As the global concern about climate change is increasing, different countries has started to act upon reducing emission of green house gasses into the atmosphere. These endeavors have brought-up new trends and phase changes in the energy and transportation sectors.

The main trend in the energy sector can be the integration of renewable energy sources (RES) into the electricity systems [1]. Two of the main characteristics of RES are their intermittent generation essence and their distributed allocation compared to centralized conventional thermal plants. The intermittent character of RES can cause difficulties in handling reliability and stability of the grid especially as the share of the RES and distributed generation (DG) in the system is increased [2, 3]. Moreover, the distributed allocation of not only RES generation but also CHP units (e.g. in UK [4] or Denmark [5]) is very different compared to the conventional centralized system and requires a paradigm shift in the energy system architecture.

Furthermore, transportation sector and especially automotive industry is moving very fast toward electrification of transportation in order to reduce local emissions and also green house gases emissions as the electricity generation sources are becoming greener. However, this has led to challenges at the distribution level and can cause high peak demands in the system as the share of EVs is increasing [6]. The increase in number of EVs are especially noticeable in countries like Norway and Netherlands [7].

In addition, ICT sector is also growing fast and trends like internet of things (IoT), blockchain, etc has enabled new possibilities for smarter systems which can help solving a part of the challenges in energy and transportation sector [8].

Due to all these aspects, cities such as Gothenburg are implementing plans towards sustainability. The Climate Program for Gothenburg include strategies which aims to promote and facilitate small-scale production of renewable electricity in order to fulfill the objective of "By 2030, the City of Gothenburg produces at least 500 GWh of renewable electricity" [9]. Regarding district heating, there is a very ambitious goal as well of "By 2030, all district heating derives from renewable energy sources, waste incineration and residual heat from industry" [9]. Nowadays the natural gas and oil make up approximately 20 percent of the district heating mix, which might be replaced by other energy sources or used more optimally by making use of the flexibility potential from personal heat pumps or CHP [9].

In order to get one step closer to this city goals and to find a solution to the challenges mentioned above, local energy management systems (LEM) (or local energy communities) have a potential. The endeavours have already started in that regard with the application of a LEM at the Chalmers campus area within the Fossil-free Energy District (FED). To follow-up on this project, the possibilities to implement it to urban areas is studied in this thesis.

1.2 Aim and scope

The Aim of the study is to better understand the behaviour of local energy communities in urban districts. The districts can have different composition of prosumer types and different characteristics.

The scope of the thesis focuses on modelling a local energy community using a cost-optimization model. It considers a dispatch model, where different areas of Gothenburg are modelled and different scenarios are built. By changing the area and scenarios, different archetypes can be built and their performance under a LEM structure evaluated.

The different districts chosen will provide different district composition regarding percentage of houses, apartments and services. The scenarios refer to: different level of penetration or distribution algorithms of distributed generation (DG); different tariffs. The economic and technical benefits are studied and discussed for each of the stakeholders; and are measured by KPIs which are chosen to represent the chosen benefits.

The main questions that are aimed to be answered in this study:

- What are the benefits of an energy community?
- How do the benefits (performance) change depending on the consumer composition (houses, apartments, services) of the district?
- How does the size of the district affect the performance an energy community?

- How is the performance affected by different penetration levels of PVs, batteries or thermal energy storage (TES)?
- How do different parts of pricing structure affect the performance?

1.3 Report structure

The report structure consists of theory, method, results and discussion, and conclusion chapters.

In the theory chapter the challenges of the current energy system are presented and how the idea of LEM can be a solution or step forward to solve these problems, is presented. Then, the idea of LEM is explained deeper as well as the different possible LEM's set-ups and some examples of related projects on LEMs are provided. Later, the LEM's benefits and barriers are discussed. The theory chapter also explains the involved stakeholders, what their role is and how LEM could affect them.

The method part explains the followed process to answer the research questions. In this case, the method has been to build a dispatch model and therefore it is explained there. In addition to the model formulation all the input data and its processing is described. Finally, this chapter includes the evaluation method followed, where the KPIs and conducted sensitivity analyses are introduced.

In the results and discussion chapter, the sensitivity analyses results are presented and discussed.

The conclusion chapter summarizes and depicts the most important findings and at the end, suggestions are provided for future studies.

2

Theory and Background

In this chapter a general overview of current system's challenges is provided and afterwards the potential value and barriers of local energy markets are discussed from technical, regulatory, economical and environmental aspects. At the end, to get a perspective over how LEMs affect different stakeholders and therefore choosing the right key performance indicators (KPI) for the study, LEMs are discussed with respect to different stakeholders.

2.1 Challenges of the current system

Nowadays, the rapid grow in DG has raised many technical concerns regarding voltage regulation, supply security and reliability, system stability, equipment control, protection, line overloads and safety. All these challenges come as a consequence of a structural change in the power system where generation variability is becoming greater than demand fluctuations [2, 3].

The current power system has a vertical architecture where the exact power output and location of the big generation units is known and just adjusted to cover the demand. However, with the increase in number of intermittent DG, the system might be forced to work with an horizontal architecture where the demand has to adapt itself to the generation levels [2].

When DG connected to the distribution level has a large share, the power generated in a specific area might be larger than its demand and cause the power to flow from load to the substations. The voltage control techniques are based on the fact that power flows from medium to low voltage level using tap changing at substation transformers, voltage regulators and capacitors on the feeders. With bidirectional power flow, voltage stability and control will be affected creating low or over voltages [10]. This reverse flow will potentially mean higher transmission losses in the system [11].

Regarding reactive power generation and consumption capabilities of DG, they strongly differ depending on the specific technology. Whereas most of the generators in small or medium DG size are asynchronous, other technologies such as PVs generates power in a totally different way producing direct current. However, almost all DG units include a power electronic interface that has reactive power control capabilities. Using this feature in a smart way, could greatly benefit grid stability and generators could be rewarded for it [10]. Local markets are a very promising feature for reactive power trading since it would allow reactive power exchange between parties located at a relatively close electric distance.

Looking at challenges regarding the market set-up, the main issues with the current set-up are that it is a not site-dependent and a real-time market [12]. However, these characteristics are crucial when integrating DG. In a mono-price system, areas with scarcity or surplus of supply are not differentiated. However, since the DG units are spreaded geographically, a site-based price is needed in which the characteristics of each region are reflected. For example, in areas where DG is difficult to implement, such as high populated cities, the price can be higher in order to encourage more investments. Furthermore, when having different area markets, the local power trading would be prioritized and consequently allowing reduction of transmission losses [13, 12].

In the current market where energy is traded one day ahead, forecasting uncertainties become a very important issues. A real-time market will reduce forecast uncertainties and will therefore create less risk for DG owners. However it would mean a lot of effort for small units or prosumers to handle the administrative works. Therefore, in this case they might need a full automated system or an aggregator agent for handling the administrative work.

Looking at social concerns, the increasing share of RES might raise local resistance towards further developments and decrease public acceptance of DG. Therefore, involvement of neighbours and people from the region is very important in order to negotiate more local RES integration [12].

2.2 Local energy markets

In this section different market set-ups are compared and how local energy markets can help the challenges of the current system is discussed. At the end, some examples of projects carried on this subject is brought up.

Before getting to explanation of LEMs, it worth mentioning a few definitions like what are different related terms used in the literature and what do we mean by flexibility from now on in this study.

Eid et al.[14] has made a categorization of different terms used in local energy management research area which helps in having the same definitions while discussing.

In local energy management, a part of the research is focused on only electricity; however, some researchers focus on having different energy carriers like electricity, heating and gas together in one system. The terms used in the literature can be categorized as follow:

- Only electricity
  - Smart grids
  - Virtual power plants
  - Micro-grids
- Different energy carriers
  - Energy hubs
  - Smart energy systems

In this study multi-energy carrier systems of heat and electricity are considered and the term local energy community and local energy markets are used for the local energy management system.

One of the main benefits from a LEM which is always mentioned is flexibility. However, the definition of flexibility should be clearly stated. Flexibility is not only demand response. Flexibility includes storage, production and demand response [15]. It can be defined as the ability to modify generation and/or consumption patterns based on external signals from the energy system.

Flexibility has different attributes[15]: direction, power, duration, starting time and location. The direction of the flexibility provided indicates if it is upwards or downwards. Upward flexibility is when a unit feeds into the system or decrease its consumption. Downward flexibility is when a unit decrease generation, store or increase its consumption [15].

The way of using flexibility involves a flexibility management system (or policies/price signals) which motivates activation of flexibilities. The reason is that just by installing smart grids' solutions and DER and smart meters, the system would not end up in having an efficient operation regarding local supply, storage and demand. So, a flexibility management system is required to make these interactions efficiently. There are different methods to control flexibility [16]:

- Direct control (Controlled by central actor e.g. aggregator)
- Semi direct control (Where the users selects the desirable time periods when the load can be readjusted automatically)

- Indirect signals. Including the time signals:
  - Real-time pricing(RTP)
  - Time-of-use pricing (TOU)
  - Critical-peak pricing (CPP)
  - Peak time rebates (PTR)

In this study, the dispatch plan of different assets (i.e. batteries, heat pumps, demand response, etc.) is controlled with direct control by the community manager. However, the indirect signals (e.g. dynamic prices) are used also as an input for the community manager.

2.2.1 Set-up

Apart from the type of energy carrier involved in the market, generally the market design for trading energy can be divided in three set-ups. These set-ups are centralized, hybrid and peer to peer (P2P) (figure 2.1). Examples for these different architectures can be current conventional centralized markets, LEMs with aggregator and peer to peer energy trading.

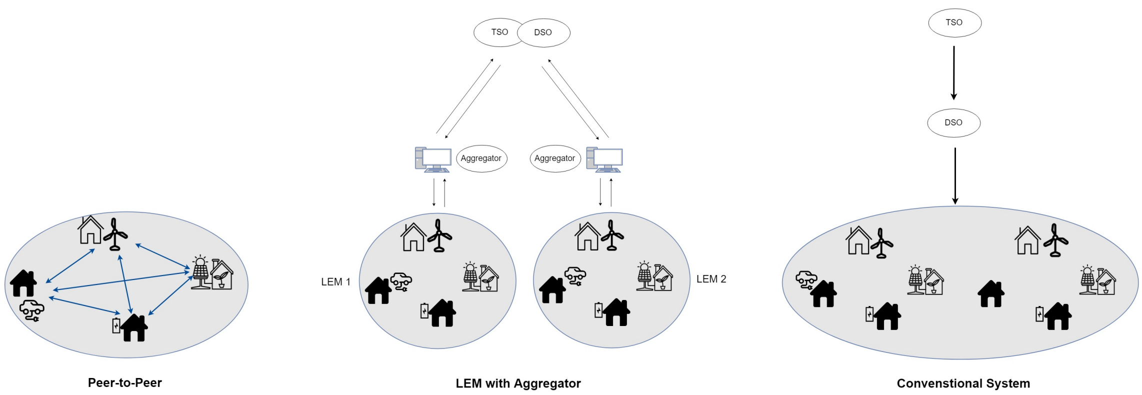


Figure 2.1: Different market set-ups for trading energy

Conventional markets and P2P markets are the two extreme cases of market design. However, LEM with an aggregator is a middle ground which holds some pros and cons compared to extreme cases. In LEMs, the local communities can be formed geographically and also virtually, depending on ownership or type of usage [17].

In conventional market set-ups the control of the system is centralized and end users cannot directly affect the market while in more decentralized set-ups, small consumers and prosumers can participate in the market either directly in P2P architectures or through and aggregator in architectures with an aggregator. Moreover, in decentralized architectures a high level of intelligence and administrative work load would be on the small participants which is a down side for these type of architectures. However, these administrative work loads can be relieved with the help of new ICT technologies to become more automated through an aggregator in architectures with and aggregator available [17, 18, 19].

For a better understanding of what the differences are between these market set-ups, their characteristics are summarized in table 2.1.

Table 2.1: Different market set-up characteristics[17, 19]

Conventional (Today)	**LEM with Aggregator**	**Peer-to-peer**
• Hierarchical	• Hybrid	• Horizontal
• Limited control on demand side behaviour	• Demand side management (DSM) capabilities	• DSM capabilties
• Lack of local signals	• Facilitate local signals' use	• Facilitate local signals' use
• Low administrative work for end users	• Medium administrative work through aggregator	• High administrative work on each end user
• Individuals cannot participate directly	• Medium participation	• High participation
• Optimal use of resources		• Not optimal use of resources

From energy carrier point of view, conventionally different energy carriers like electricity, thermal (district heating and cooling) and chemical (natural gas) are traded and dispatched in separate markets and with different set-ups. However, by integrating these energy carriers and dispatching them together, not only the energy system can be operated better but also more optimal decision making on investments is possible [17].

An example of how integration of energy carriers help the energy system can be seen in the study done by F. Hvelplund et al. [4]. In this study, CHP and heat pump (HP) units are used for integrating high wind shares in danish energy system. The strategy for avoiding curtailment is to reduce the output of the CHP plant in case of high wind production and use the extra electricity produced by wind turbines instead of electricity generated by CHPs and use the electricity through HPs to support deficit in heating demand with reduction in heat production of CHP plants.

2.2.2 LEM projects

In this section a review on recent research projects and test beds for decentralized markets is provided. Table 2.2 shows a brief comparison between these projects.

Table 2.2: Examples of projects on decentralized energy markets

Project	Year and Country	Market Type	Energy Carrier
Fossil Free emission District[17]	2017, Gothenburg, Sweden	LEM with aggregator	EL, DH, DC
EMPOWER[20]	2015, Hvaler, Norway	LEM with aggregator	EL
The Nobel Project[21]	2015, Alginet, Spain	Peer-to peer	EL
Cornwall LEM Project[22, 23]	2017, Cornwall, UK	LEM with aggregator	EL,(work is carrying on for gas users also)
Power Matching City (PMC)[19, 24]	2007, Hoogkerk, Netherlands	Peer-to-peer	EL, heating (micro CHP & hybrid HP)
Energie Koplopers[19]	2015, Heerhugowaard, Netherlands	LEM with aggregator	EL, heating (EL boiler & HP)

On top of local energy management system, there is a need for a system to connect different stakeholders together. For example, a very recent project specially related with flexibility is the Flexiciency project. As part of the Flexiciency project was designing of a market place for trading flexibility which is called the EU Market Place (MP). EU MP in this project provides the possibility of faster and cheaper integration of aggregators. EU MP can facilitate easier participation of the aggregators in new balancing markets (e.g. in another country) by removing variety of regulatory and technical barriers. In addition, EU MP can help TSOs and DSOs in finding the appropriate aggregators.

The steps of how the stakeholders can use the flexibility and how the flexibility is activated is as follow:

1. The aggregator sends to the participants the list of all the available flexibility offers. An offer is characterized by a market (area) of interest, a period of time, an amount of consumption/generation flexibility and a price.

2. From the user interface, the DSO operator can accept (or “acquire”) and offer; the acquisition message is sent to the aggregator that will flag the offer as “reserved”, following the first-come-first-serve policy.

3. Upon the flexibility period, the DSO sends the flexibility activation message. The aggregator informs the required partners to actuate flexibility and gives a confirmation back to the DSO.

4. At the end of flexibility period a load profile is sent by the aggregator to the DSO in order to certify the results of the provided flexibility [25].

2.2.3 Benefits from LEM

As LEM tries to manage the demand and production locally, the power fluctuations from intermittent DG sources could be handled locally, isolating the grid from those variations and therefore allowing higher DG integration with less disturbances for the main grid. At the same time, as demand is primarily covered by local generation, less is imported or exported from/to the main grid and therefore transmission costs and losses can be reduced [18].

Local energy markets can reduce network peaks by encouraging demand side management and local power generation. This happens because when there is a peak, the spot electricity price is higher and therefore it becomes beneficial to produce locally or reduce loads. Peak shaving is specially noticeable when matching different demand patterns in the same local market, such as residential and office buildings. Aggregating a group of customers that will not demand its maximum at the same time, will be beneficial for all parties. In integrated energy markets, the peaks can be reduced thanks to the possibility of using another energy carrier to cover a specific power demand. A clear example would be heating load that could be supplied by electric power (heat pumps), district heating or even gas boilers [19, 26, 17].

The electricity distribution system operators (DSO) can use the local energy sources to ensure system functionality. The LEM can provide ancillary services to the grid, thus helping the DSO to ensure power quality at the distribution level without requiring additional investments. In this case the DSO would buy the services needed from the local flexibility market [27].

Focusing on social aspects, C. Giotitsas et al. [28] point out the following advantages of implementing a LEM: it lowers market power and speculation typical in centralized generation, it allows private management of energy resources, increases environmental awareness and public acceptance toward DG, offers greater supply security and empowers diversification of technological solutions for different locations. The diffusion of residential photovoltaics (PV) panels is strongly affected by the neighbourhood peer effects (social influence) [29], which makes the PV distribution not evenly spread and therefore creating hot spots in determined areas. If there is no local market, all DG compete in the big market where their effect is small and not site dependant. However, when having a local market the location is taken into account.

2.2.4 Barriers

The barriers for implementation of LEMs can be categorized into technical, regulatory, economical, and environmental aspects.

2.2.4.1 Technical

The development stage of the ICT will determine the market feature, automation and control level achieved. The ICT system provides: a software platform where market operations and transactions take place and ensures the access to all market participants; grid monitoring; physical infrastructure representing the control systems at generation/consumption side; and communication system between all market agents[17] [26]. ICT platform is necessary to achieve an optimal market implementation and it can be a challenge if the technology is not yet developed.

Regarding the power generating technologies, one weakness of a LEM scenario is that small-scale power production has lower efficiency in comparison with large-scale for some specific technologies. However, this system has lower losses that could compensate for the decrease in efficiency [28].

Another technical challenge is the integration of different energy carriers in one market. The challenge is that the market structure and value chains of each energy carrier is different and it's hard to integrate them in the same market as they are today.

Lack of smart meters is another barrier. According to the Third Energy Package of the EU energy market legislation, all member states are required to ensure the implementation of smart metering to consumers in cases where the cost-benefit analysis is positive. There is a roll out target of at least 80% market penetration for electricity by 2020 [30]. However this roll-out is at different stage in various EU-countries and standardization measures must be applied. Even though the DSO is in most cases the responsible for implementation and operation of smart meters, this is not the case for all member states [31]. Furthermore this metering equipment should be compatible with the system management and control software [32].

The last technical barrier relates to how the information and communication technology will achieve a secure and transparent local trading platform. The most suggested solution is the application of blockchain, which would bring transparency, security and continuous tracing. However block-chain is not yet a mature technology regarding this specific application [32]. It is also important to highlight that the data handled in such a system is sensitive and/or confidential, which implies that cyber security must be ensured [32].

2.2.4.2 Regulatory and legal

Issues regarding regulatory framework include both market and legislative related aspects. As the first barrier, the aggregator role is not clearly defined in the majority of European countries. The aggregator service could be used at different market mechanism (day-ahead market, intra-day market and primary, secondary and tertiary reserve). Legislation regarding services at each market mechanism is different in each country, which makes it difficult to compare between countries. However, it is noticeable that nordic countries are more open to aggregator services in contrast to southern European countries which hesitate to allow those services [33].

Even when legislation allows LEM implementation there are several market design regulation that would not allow a successful implementation. The market regulation that would limit LEM are: minimum bid, symmetric bidding (upward and downward regulation) and activation time[33].

Another challenge regarding market set up is how to build flexibility provider bids. On one side, flexibility services have various dimensions (capacity, duration, ramp rate, direction, energy, response time and location) to take into account. On the other side, DG technologies have very heterogeneous characteristics when looking at regulating services. While PV panels could just choose between producing or not, batteries could provide bidirectional capabilities (discharge or charge)[34].

Minimum bid size is a significant barrier for aggregators of small units. Size of local energy markets can be chosen in a way that the aggregated bid surpasses the minimum bid limit [33].

Symmetric bidding requirement can be another barrier in some reserve markets. The requirement imposes having symmetric upward and downward regulation while aggregation might be unidirectional in some periods [33].

Activation time requirement is another barrier which is basically designed for big generation units. Sometimes the contracted reserve is required to be online for 10h which is not possible for small resources [33].

If the aggregator and retailer are separated parties, a compensation mechanism should be designed for the penalties retailers get as a result of aggregator changing the loads and production levels. Alternatively, retailer and aggregator can be merged into one party and provide the service or DSO could take the responsibility of demand side management (DSM). However, in the liberalized structures, DSO are not allowed to use DSM for commercial purposes due to unbundling of the DSO from the market.

In a retail competition environment, it would not be beneficial for retailers that have supply contracts with customers when an independent aggregator is able to make changes in their supply programs to the end-users. Compensations for the retailer must be considered, because the aggregator is changing the loads and do adjustments for flexibility.

There are also other regulation barriers like the double taxation problem. For example the prosumers owning batteries, pay twice the tax for the energy. Moreover, power tariffs are charged per building (concrete border), which is a big barrier if the larger DG units are going to be installed in one building but used by several neighbouring buildings owned by the same owner.

2.2.4.3 Economic

Split-incentive problems can emerge in energy community developments, in cases where its benefits split between various stakeholders but its costs belong exclusively to investors [32].

Installation of smart meters in Europe costs on average 200-250 € [35]. Since the benefit of activating DSM will be for many stakeholders(i.e. consumer, retailer, DSO, aggregator), the cost should be also divided between these parties. For example, if retailer initiates the investment, what will happen if the customer changes the retailer. Or if the DSO settles the investment, it can be used to change prices to alter the consumption for network purposes which is a competitive advantage compared to the retailer [36]. Therefore until a defined business model is not written, non of the parties will take the first move and initiate the investment.

On the costumer side, the economic benefits from being active will decrease as more people gets active. This might decrease the willingness to participate. Furthermore, all costumers will enjoy the benefits from the LEM regardless of their participation in it.

The DSO revenue from grid fees might be decreased, meaning less capacity of investments in grid development and maintenance. Which might end up with an increase in grid fee, which would affect even the consumers not taking part in the local market [32].

By introducing DR, the revenue from traditional peaking units would be moved to aggregators and might remove their available capacity for the reliability of the system.

Traditional energy market actors such as retailers could see LEM as a threat since their market share and positioning would be decreased, however they could also embrace this as a new business opportunity. The same goes for centralized generation that might need to change their commercial strategy and business model until a new market equilibrium is found [32].

One more barrier regarding customers engagement is that lowering greenhouse emissions and empowering local growth might not be attractive benefit for consumer that tend to have more attainable, tangible and easily quantifiable goals [37].

2.2.4.4 Environmental side effects

An environmental side effect of DR is that instead of peak reduction and valley filling, a shifted peak is usually observed [36]. This means depending on the energy system composition, a peaker with natural gas as fuel might be replaced with a base load coal power plant. Therefore, there is a possibility that emissions increase as a result [38]. However, a higher CO_2 tax can help solving this issue [36].

2.3 Stakeholders analysis

In this section, an overview of the different advantages and disadvantages of LEM for each stakeholder are presented. A summary of the section is shown in figure 2.2.

2.3.1 Transmission System Operator

The main goal of the TSO is to ensure overall system security and guarantee frequency system balancing [39].

In Sweden, Svenska kraftnät is responsible for managing the national grid so that it is sustainable, cost-effective and reliable. It has overall responsibility for ensuring that all parts of the power system work together in a reliable way and that the system is constantly in balance. It is also responsible for being reday for planning in case of emergencies or wars. However, it has no long-term responsibility for maintaining resources to handle the power balance in a transition of the electricity system [40].

2.3.2 Distribution System Operation

The Distribution System Operator (DSO) is responsible for providing reliable electricity and maintain the distribution network. They are also required to plan and develop their networks so as to accommodate a potential peak demand increase and the future connection of new loads and Distributed Generation (DG) units, always seeking the maximization of overall economic efficiency [31]. The DSO expenditure can be classified into OPEX (operational) and CAPEX (capital). In Europe DSOs are mostly subjected to incentive regulation which means their OPEX should be decreased by a certain percentage each year. This makes DSOs not interested in the implementation of flexibility management systems since those would increase their operational costs, even though the capital costs could be decreased. Debates are ongoing for whether or not to exclude smart grid investments from regulatory framework.

Unbundling of DSOs is another aspect which should be taken into consideration. European energy networks are subject to unbundling requirements which oblige Member States to ensure the separation of vertically integrated energy companies.

The result is the separation of energy companies into the different stages of energy supply (generation, production, distribution, transmission and supply) [41]. This implies that the DSO can not be merged with production parties or retailers. In other words, the DSO could not be the aggregator of a LEM district since it would imply owing or dispatching generation unit.

It is important to mention that higher communication and coordination between the DSO and TSO will be needed as LEMs develop. Since the DSO constraint management will also affect the TSO's grid and balancing of the system. Therefore, both actors will need to coordinate their actions and exchange relevant data. It might be also difficult to allocate the benefits for TSO and DSO separately. The benefits from a LEM set-up for the DSO and TSO are:

- Avoid distribution network investment costs, not only because of DER capacity additions, but also due to increased flexibility and more efficient overall network operations [32]
- Decrease stress in the distribution, due to a decrease of power demand [32]
- Balancing and ancillary services offered by customer-owned DER provide important support to the network operations supporting the reliability, flexibility, and responsiveness of the overall power system and allow DER utilization at larger scales [32]
- Power quality at the distribution level can also be improved by the various flexible DER and the sophisticated power electronics present [42]
- Reduced electricity technical losses[39]
- Reduced curtailment of distributed generation and reduce outages time[39]
- Outage/fault management[39]
- Real-time energy monitoring and/or billing[32]

On the other hand, implementing a LEM structure would also mean the following extra costs for the DSO [17]:

- Costs for ICT infrastructure
- Increased costs for customer services and support
- Costs for system services
- Reduced revenue due to lower energy purchases from the grid and hence a need for new tariff models

- Risk of cyber security

2.3.3 Retailers

Retailers goal is to buy electricity from the wholesale market and sale it to the end users. When implementing a LEM, smart meters will be installed providing valuable information to retailer in order to have better insights on load behaviour and real-time consumption. Furthermore, using a flexibility management system will create new business models for retailers to participate in balancing markets, ancillary services and congestion markets.

Energy service companies (ESCOs) which provide and manage all energy carriers together. It can substitute conventional retailers or merge with aggregator and flexibility management party trade flexibility also.

The disadvantage for the retailers under a LEM raises when other parties are controlling the flexibility of the retailer's customers by changing their demand profile. This might create balancing problems for the retailers that had predicted a different load and might lead to extra costs.

2.3.4 Future aggregators

Aggregators' goal is to aggregate different customers in order to manage their demand and flexibility as a whole.

The main advantage with it is that by aggregating, it helps providing the possibility of participation of customers which have values lower than minimum trading value. Aggregators are bringing advantages to both customers and operators, and can simultaneously generate profit by providing their core services [32]. They create a new business model by using the aggregated flexibility of small costumers that before was not used, it helps managing the resources more effectively.

2.3.5 End users and prosumers

Traditionally customers don't have much involvement and insight on their consumption. But with development of smart grids and smart homes, customers can be more aware of their consumption and electricity price and contribute in the energy system. However, privacy on data is an aspects which require attention for further involvement of the customers.

The benefits for consumers or flexibility providers are:

- They can be rewarded by a financial compensation and they can optimise their bill by: getting paid for the flexibility service supplied, obtain benefits from time of use tariffs or DSO/TSO return revenues to consumers via a relevant price control mechanism [39].

- Be able to trade their energy generation surplus

- By combining the available capacity from multiple electricity customers, aggregators can make offers in balancing and ancillary markets that comply with minimum capacity requirements, thus enabling the efficient participation of small prosumers that may otherwise not be possible

- Enhance security of supply

- Competition motivates companies to develop further their services and products in the interest of customers, in terms of both variety and price. More, the continued development of LEMs will increase pressure over traditional power industry players to adapt their operations towards more customer-oriented approaches [32]. This is in line with the European Commission "Clean Energy for all Europeans", among its priorities are the empowerment of customers through more active involvement in the European Union (EU) energy system, allowing them a better control over their energy consumption and an improved response to price signals, by taking advantage of the local availability of renewable resources [43].

At the same time the prosumers or flexibility providers would encounter some extra costs:

- Investment cost in flexibility resources

- Operational costs of the flexibility resources. For instance cycling costs.

- Costs of the ICT infrastructure

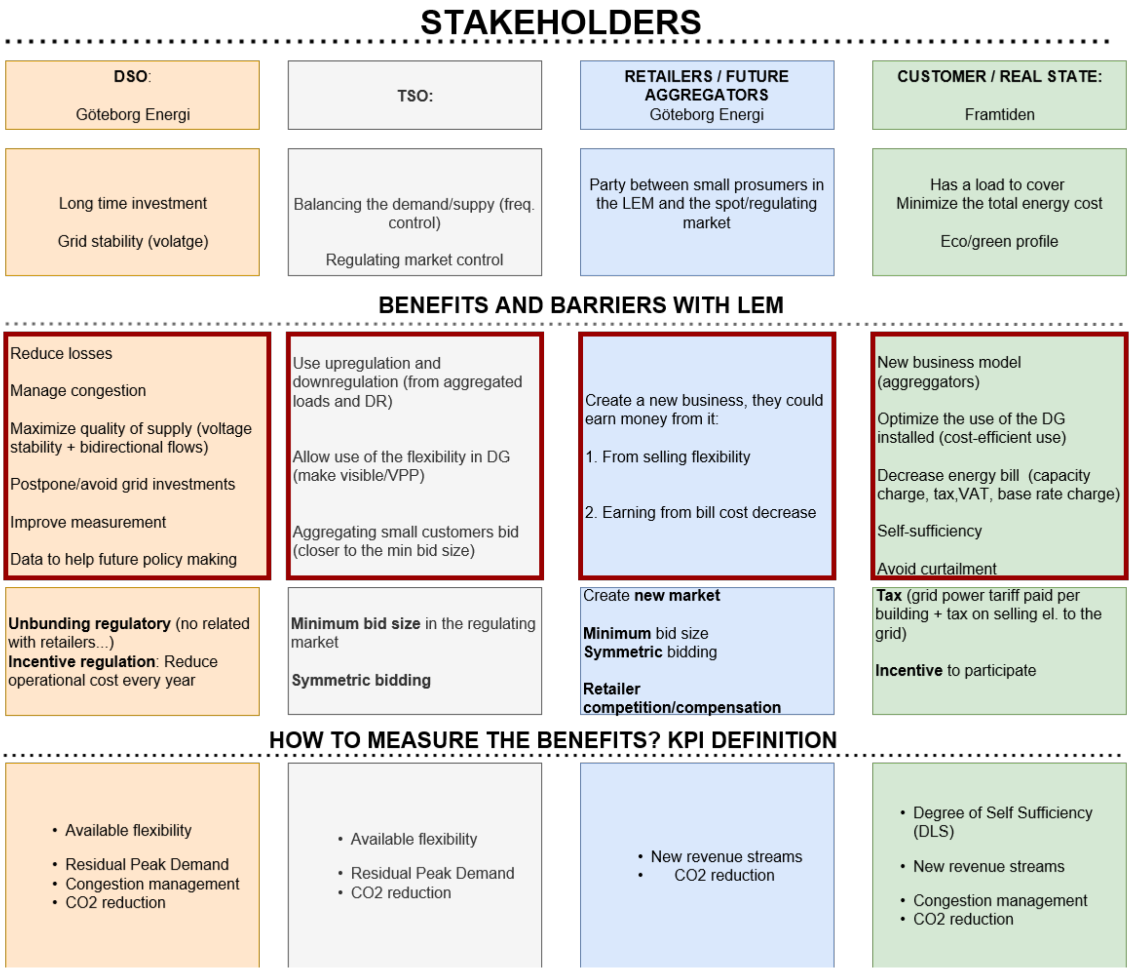


Figure 2.2: Stakeholders business goal, benefits, barriers and how to measure their benefit from a LEM set up.

3

Methods

In this Chapter the method for answering the research questions is provided. It includes an overview of the whole process, presenting the input data, model's formulation, KPIs for answering the research questions and sensitivity analyses carried out for better understanding of the system's dynamics.

3.1 Methodology

The LEM set-up chosen consists of an aggregator or optimizer that controls all costumers appliances and assets in order to reduce the cost of the whole community. It is assumed that the aggregator has full control over the costumers appliances and assets as long as it is between the specified constraints. The prosumers then, have full trust over the aggregator and follow his prescriptions.

In order to show the big picture of how the systems works, different modules of the modelling process and their connections are illustrated in figure 3.1. On the left side all inputs needed to the model are named. The arrows show which inputs that are use in each process. The grey box represents the model itself which includes both the processing of input data, the optimization and the post-processing of the results. The processing of input data process consists of two parts: load curve generation and asset distribution. First, both heating and electric load curves are created based on the usage type using the corresponding LFP (load fraction profiles). For the heating part, it is also required to know the percentage of buildings with each heating type (electric boiler, heat pump or DH) and the characteristics of the hot water (HW) use regarding amount of energy and profile. Secondly, based on the penetration level of each asset (PV, Battery, HP and TES) and using distribution algorithms; each building gets a determined asset capacity. The optimizing part chooses which assets to dispatch in order to minimize the cost for the whole community (objective function). The optimization is done twice: once allowing internal exchange within the prosumers (LEM in place) and once where internal exchanged is not allowed. The results from the optimization are then utilized to calculate the KPIs and create the electricity and heating dispatch plots.

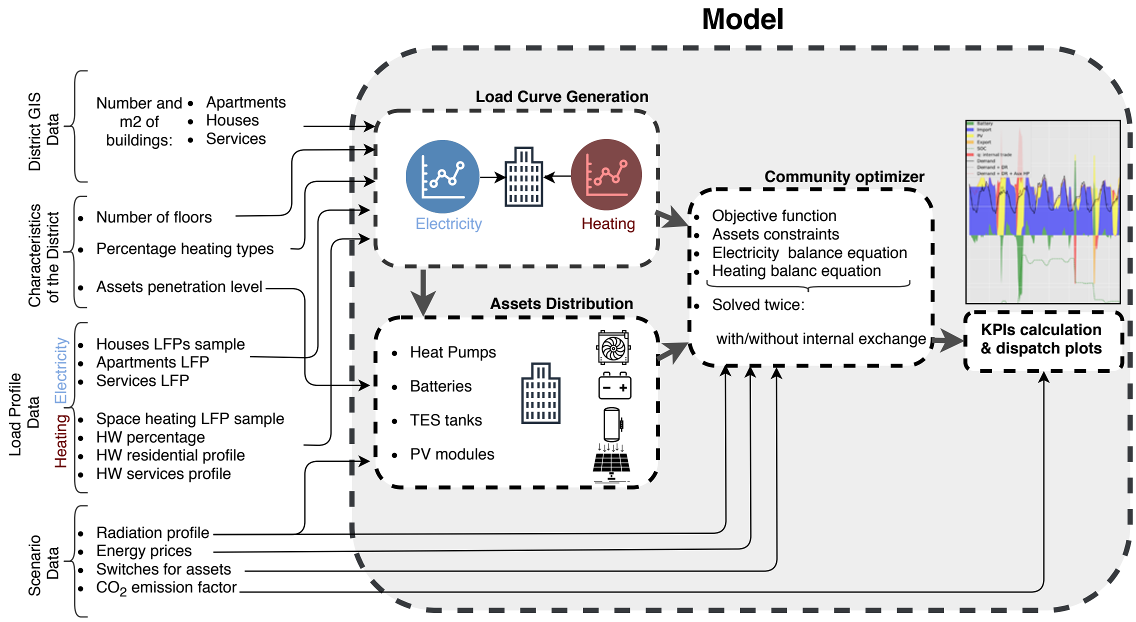


Figure 3.1: The general overview of different modules of the model.

In the following sections, first the inputs to the model and their origins are explained and afterwards the formulation, algorithms and how the inputs have been used, are explained.

3.2 Input data

The input data can be categorized into 4 main groups: GIS data for the district, characteristics of the district, load profiles and characteristic data of each scenario.

3.2.1 GIS or spatial data

Data has been provided by Lantmäteriet and it includes the building types in Gothenburg with a categorization of 46 different usage types [44]. Out of these different usage types, the ones shown in table 3.1 cover 95.5% of the built area in the city. The building usage codes has been grouped together into 4 different consumer types which are presented in table 3.2. This classification is done to simplify the modelling and to match the data available for load profiles [45].

In this study the industry consumer types are not included due to the difficulty in assigning a standard load curve to them. Therefore, the areas selected for analysis are areas without a big share of industries. The model would put up a warning if more than 5% of the district's area is out of services, houses or multi-family dwellings.

Table 3.1: Share of different building usage types in Gothenburg and their corresponding codes in Lantmäteriet report [44].

Type code	Area (m^2)	Type	Share of tot	Sum
133	4774384	Apartment block,	0.185774674	0.95426
130	4756332	Small house, stand-alone	0.185072255	
699	3440978	Detached complementary building	0.133890873	
499	2632030	Services	0.102414131	
299	1874049	Industry	0.072920591	
247	1283099	Metal or machine industry	0.049926302	
132	1132093	Small house, townhouse	0.044050523	
319	1098350	School	0.042737564	
240	921299.1	Other manufacturing industry	0.035848401	
253	703115.4	Other industrial building	0.027358717	

Table 3.2: Categorization of consumers and their shares.

Consumer types	Considered codes	Area(m^2)	Share
Services	499, 319, 399, 321, 317, 313	4703330	21%
Houses	130, 131, 132, 135	6594892	30%
Multi-family	133	4774384	21%
Industry	299, 247, 240, 253, 246	4966539	22%
	Sum	21039145	95%

It's also worth mentioning that usage code 699 for Komplementbyggnad is excluded from share calculations because they are asuumed not to have any energy consumption.

The area from the GIS data is corresponding to the footprint of the buildings. Therefore, an average number of floors is considered for different consumer types for better estimation of the load curves. This values are chosen for each area in order to be as close to reality as possible.

3.2.2 Characteristics of the district

3.2.2.1 Percentage of DH connected users

The other type of spatial data used in the study is the map of the district heating network of Gothenburg. When selecting the area to study, the buildings with access to district heating can be identified. Therefore an approximate percentage of the buildings with access to DH is chosen and given to the model as an input. To adapt the model as much as possible to the reality, the percentage of each building type (house, apartments and services) has to be given to the model. This is done because when choosing areas just on the border of the district heating network, most of the buildings without access to it are houses and therefore is fairer to assign a specific percentage to them.

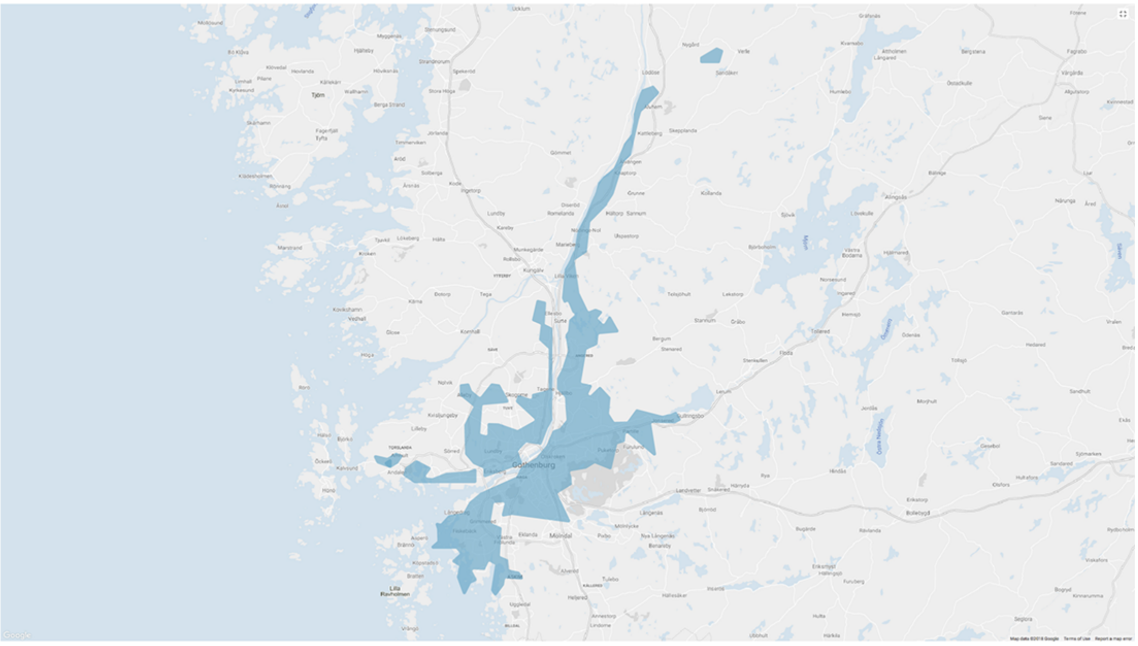


Figure 3.2: District heating network map [46]

3.2.2.2 Capacity of assets in the district

For each district, the penetration level of penetration and capacity of different assets can be set. In this way the performance of energy community can be evaluated for different scenarios with different levels of assets availability.

3.2.2.3 Number of floors

The average number of floors per building type is specified for each area. However, when this information is not known, the assumed floor numbers is presented in table 3.3 for areas in Gothenburg.

Table 3.3: Number of floors for each consumer type.

	Services	Houses	Multi-family dwellings
Number of floors	4	2	4

3.2.3 Load profiles

Load profiles in this study have been gathered from different sources. The origin and the type of data is explained in this section. Later on, these data are processed and assigned by the algorithm explained in section 3.3.8.5 for load curve assignment algorithm.

Source of the load profiles data (LFP) is presented in table 3.4.

Table 3.4: Origin of the LFPs

Load type	Consumer type	Source
	Services	Göteborg Energi
Electricity	Houses	E.ON measurement campaign
	Multi-family dwelling	Göteborg Energi
	Services	Division of Energy Technology, Chalmers
Heat	Houses	Division of Energy Technology, Chalmers
	Multi-family dwelling	Division of Energy Technology, Chalmers

The electric load profiles for houses are obtained from a E.ON measurement campaign of 2220 households in Sweden during the year 2012. Whereas for services and apartments, the LFP utilized was provided by Göteborg Energi. Specifically, the average load profiles for different SNI (Swedish Standard Industrial Classification) codes was known.

The heating load profiles for all usage types was provided by the Energy Technology department at Chalmers. Where according to the heat transfer characteristics of Swedish building stock, the space heating demand can be calculated. This calculation was performed according to the weather conditions in 2012. The heating demand for hot water (HW) is then added to the space heating load. The total load is considered as a percentage of the total heating demand and also which percentage corresponds to the weekends or weekdays.

3.2.4 Weather

The only weather data used for the model was the PV generation profiles per installed capacity for PV panels facing North, East, West and South for a tilt angle of 30 degrees. The profiles were obtained from [47].

3.2.5 Energy prices

3.2.5.1 Electricity

When importing electricity from the grid the price structures used is as shown in Figure 3.3 from [36]. The electricity price is divided into: energy, network charges and others costs.

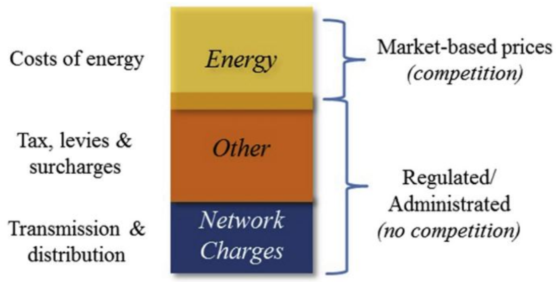


Figure 3.3: Cost breakdown of electricity in a liberalized system [36]

The energy price is a market-based price obtained from Nordpool for each specific hour in the area SE3 for 2016 [48]. In order to start, both loads and prices from the same week day, the first two days of the electricity price are removed. Then, both demands and prices start on Sunday.

The network charges part corresponds to the fee that consumers have to pay for using the distribution and transmission grid. The value used in this work corresponds to 0.31 SEK/kWh [17].

The last part of the electricity price includes: the electric green certificate and the power tariff. The green certificate prices and the yearly quote are obtained from [49]. The quota when buying electricity from the grid is obtained from [49] for the year 2016.

In this study, the power tariff adds a cost of the type SEK/kW · month depending on the maximum annual peak. The fees used are obtained from [46]. Where, a fee of 23.5 $SEK/kW, month$ is considered for connections of less than 44kW and a fee of 44 $SEK/kW, month$ for larger connections.

When selling electricity to the grid, prosumers get paid the energy price, the green certificate and the tax return term. Therefore, it is assumed that no taxes or grid tariffs are paid when selling the electricity to the centralized system. The green certificate price is the same as when buying electricity and the quota considered is 1 (assuming all electric generation in the community renewable). The tax return term promotes exporting electricity. According to Sweden's tax agency, private consumers can get 0.6 SEK/kWh back if they have local electricity generation [50].

This tax return is limited to a maximum generation capacity and tax return amount. Furthermore it is only applied to private costumers. For simplification and also prevention of quadratic functions, the tax return is simply assumed to be 0.6 SEK/kWh on export to the grid for all type of consumers and without considering limits on capacity or amount received.

3.2.5.2 DH

The hourly price for district heating was created specifically for the FED project in order to see the effect of energy hubs, combining different energy carriers. As one of the goals of the study is to asses the flexibility and response to price signals, the hourly prices shown in red at Figure 3.4 are used. This values are based on the seasonal price (shown in blue in Figure 3.4 from [46]) and takes into account the peak tariff and the price changes based on the return temperature. This values are from the year 2016 so, the two first days of the year are removed to match the weekdays with those in the demand data from 2012. However, in Göteborg Energi the price consists of: a fixed value per season as shown in blue in Figure 3.4 and a peak power tariff.

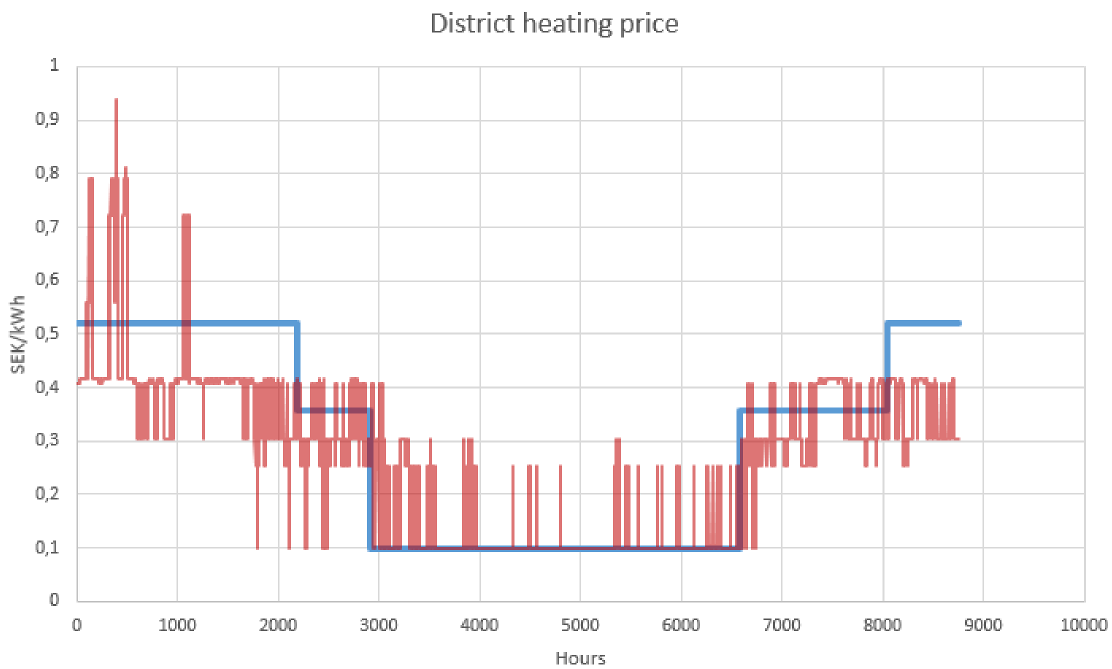


Figure 3.4: District heating price

3.2.6 Assets' running costs

Except the energy price, no maintenance and running cost is assumed for the assets in this study.

3.2.7 Switches for assets and functionalities

As another input, it's possible to decide which type of assets or cost functions to include in the optimization. This feature has been added to make the assessment on behaviour and effect of different assets. Switches which can be used in the model are:

- PV panels
- Batteries
- Auxiliary heat pumps
- Demand response
- Power tariff
- Tax return policy
- Energy trade within the community
- Thermal energy storage tank (TES)

3.3 Model

As it was shown in figure 3.1, the process can be divided into 3 main blocks: assets distribution block, load assignment block and community optimizer block. Which are going to be explained further in this section.

3.3.1 Community optimizer

In this section the governing equations and the optimization model are explained. The initiation of the model formulation is from the model used by Moret et al. [51]. However, it has been changed a lot to match the purpose of this study. A general overview of the market and system structure is presented in figure 3.5. The optimal economic dispatch is obtained from minimizing the total cost for the community (by the community manager) while the energy balance is applied at each prosumer.

The variables used in the governing equations are presented in table 3.5.

The generation units includes the distributed generation units located at the partic-

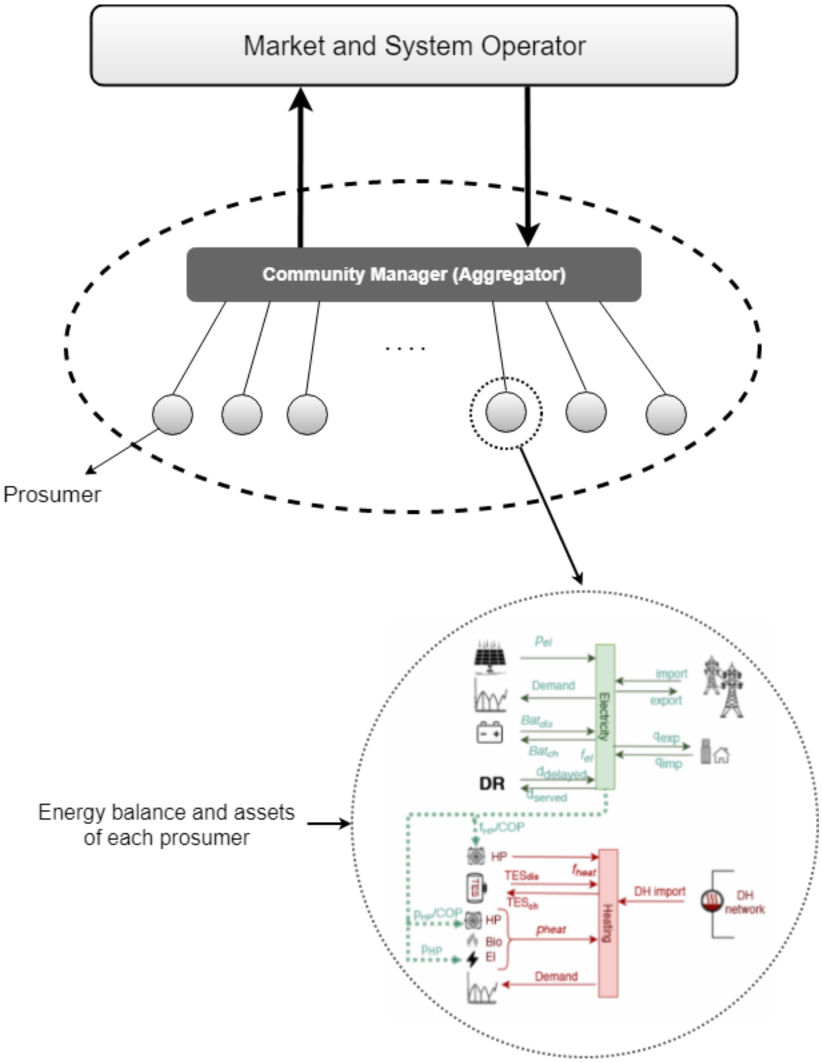


Figure 3.5: System structure scheme in which the model formulation is implemented.

Table 3.5: Model variables used to formulate the problem. All units are in kWh.

Variables			Description
Generation	$p\_el_{bld,unit,h}$	PV	Electricity production on PV panels for building bld at hour h.
	$p\_h_{bld,unit,h}$	HP	Heat production of HP for building bld (which only has HP for covering it's heat demand) at hour h.
Flexibility	$f\_el_{bld,unit,h}$	Battery	Controlled by $ChBat_{bld,h}$ and $DischBat_{bld,h}$
		DR	Controlled by demand delayed($dd_{bld,h}$), demand on hold ($dh_{bld,h}$) and demand served ($ds_{bld,h}$)
	$f\_h_{bld,unit,h}$	Aux. HP	Heat production of auxiliary HP for providing flexibility
		TES	Controlled by $TESch_{bld,h}$ and $TESdisch_{bld,h}$
Trade	$q_{imp,bld,h}$		Internal import from the community
	$q_{exp,bld,h}$		Internal export to the community
	$imp_{bld,h}$		Electricity import from the external grid
	$exp_{bld,h}$		Electricity export to the external grid
	$DH_{imp_{bld,h}}$		Heat import from the DH network

ular prosumer (it includes PV modules or heat pumps among others). The demand represents the hourly electric and heating load of the prosumer. The flexibility in electricity side includes demand response (DR) and batteries. DR is two directional and can have positive values for when consumption is increased and negative in case of load reduction. However, decision variables for batteries are Bat_{Ch} and Bat_{DisCh}. Flexibility on the heating side includes auxiliary (Aux.) HPs and TES. The prosumer can either import or export from the external grid, or trade internally within the community. All of the import and export, and internal import and export variables are defined as positive variables.

The objective function, Equation 3.1, is to minimize the total cost of the whole community over a period of time.

$$\begin{aligned} Cost = \sum_{bld}(\sum_{h} Cost.imp_{bld,h} + Cost.q_{bld,h} - Cost.exp_{bld,h} \\ + Cost.DHimp_{bld,h}) + Cost.P.tariff_{bld}) \end{aligned} \tag{3.1}$$

where $Cost.imp_{bld,h}$ expressed in Equation 3.2 corresponds to the cost from buying electricity from the grid. The term $Cost.exp_{bld,h}$ is the cost when selling electricity to the grid (note the negative sign), which is calculated according to Equation 3.3. The cost $Cost.q_{bld,h}$ represents the cost When trading electricity within the community and it is calculated with the Equation 3.4. On the heating side, the term $Cost.DHimp_{bld,h}$ takes into account the cost from importing heat from the district heating network.

$$Cost.imp_{bld,h} = imp_{bld,h} \cdot ImportElPrice_h \tag{3.2}$$

$$Cost.exp_{bld,h} = exp_{bld,h} \cdot ExportElPrice_h \tag{3.3}$$

$$Cost.q_{bld,h} = q_{imp_{bld,h}} \cdot \gamma \quad \forall q_{bld,unit,h} \geq 0 \tag{3.4}$$

Where the parameters and variables are further explained in subsection 3.3.7.

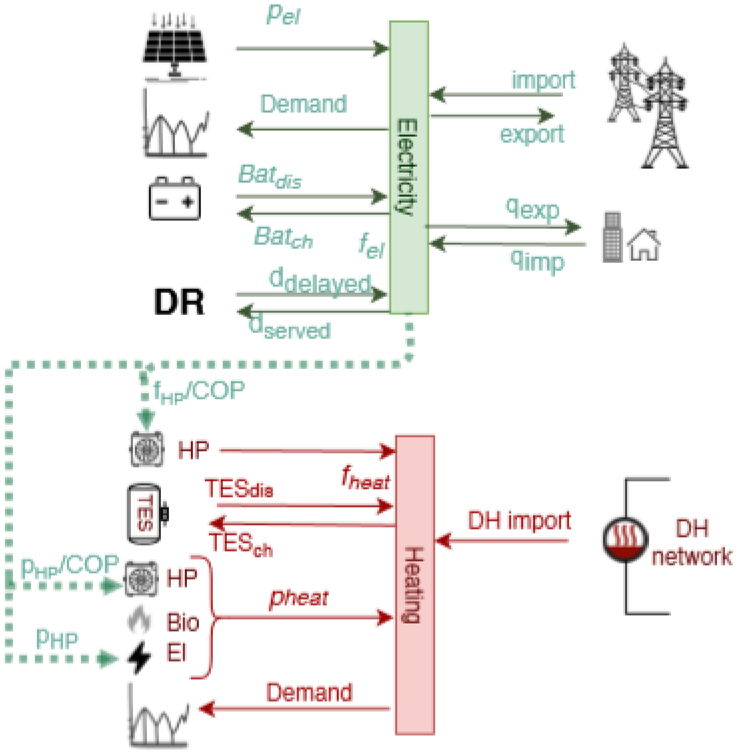


Figure 3.6: Prosumer's electricity and heating balance

The electricity energy balance at each building is illustrated at figure 3.6 and equation 3.5. The balancing equation, ensures the demand is covered at each building and each hour. In case that the building is heated by electricity (e.g. via heat pumps), the heating load is added to the electricity demand and the balance is calculated as:

$$Gen_{el} + Flex_{el} - HPs\ Demand - Load_{el} + Exchange + Import - Export = 0 \quad \forall bld, h \tag{3.5}$$

where the Gen_{el} term consist of the sum of the electricity generated by the different electricity generation assets as shown in Equation 3.6. In this study, the only asset considered is PV. The $Flex_{el}$ term includes all electricity provided by the flexibility units of the electricity system (Batteries and Demand Response) calculated according to Equation 3.7. The term $HPDemand$ refers to the electricity consumed by the HPs calculated as in Equation 3.8. It includes auxiliary HPs and those from buildings with HP as the only heating source type.$Exchange$ includes the internal exchange of electricity within the community obtained as in Equation 3.9. The last terms $Import$ and $Export$ represent the electricity bought or sold to the main grid respectively.

$$Gen_{el} = \sum_{unit} p\_el_{bld,unit,h} \tag{3.6}$$

$$Flex_{el} = +f\_el_{bld,DisBat,h} - f\_el_{bld,ChBat,h} + f\_el_{bld,dd,h} - f\_el_{bld,ds,h} \tag{3.7}$$

$$HP\ Demand = +\frac{p\_h_{bld,HP,h}}{COP_{HP}} + \frac{f\_h_{bld,HP,h}}{COP_{HP}} \tag{3.8}$$

$$Exchange = q_{imp,bld,h} - q_{exp,bld,h} \tag{3.9}$$

Next equation make sure that the sum of internal trade over all buildings is zero for each hour, representing that the same amount in bought and sold internally.

$$\sum_{bld} q_{imp,bld,h} - \sum_{bld} q_{exp,bld,h} = 0 \quad \forall h \tag{3.10}$$

The heat energy balance is illustrated in equation 3.11.

$$Gen_{heat} + Flex_{heat} - Load_{heat} + DHimp_{bld,h} = 0 \quad \forall bld, h \tag{3.11}$$

where the term Gen_{heat} is calculated as in Equation 3.12 and represents the heat supplied by means of HP, electric boiler and biofuels according to the heating type of each house. The term $Flex$ includes the heat provided by the flexibility units of the heating system (TES and auxiliary HP) which is calculated as in Equation 3.13. Finally, the term $DHimp_{bld,h}$ represents the heat purchased from the DH network by those buildings with DH as heating source.

$$Gen_{heat} = \sum_{unit} p\_h_{bld,unit,h} \tag{3.12}$$

$$Flex = f\_h_{bld,DisTES,h} + f_{bld,ChTES,h} + f\_h_{bld,AuxHP,h} \tag{3.13}$$

3.3.2 Battery

The batteries are added to the model as to provide an extra flexibility asset for the electric system. The unitary values of power and energy for batteries are specified in the table 3.6.

Table 3.6: Specifications for Batteries

Parameter name	Parameter	Value
Battery Power per unit(kW)	P_bat	5
Battery Energy (kWh)	E_bat	13.5
One way battery efficiency	eff_bat	0.95
Maximum SOC level	SOC_max	0.9
Minimum SOC level	SOC_min	0.2
Start level of SOC	SOC_start	0.2

The model variables are:

$SOC_{bld,h}$: State of charge for each building bld and at the end of hour h

$ChBat_{bld,h}$: Charging power for each building bld and hour h

$DisBat_{bld,h}$: Discharging power for each building bld and hour h

The formulation for electric batteries is as follows:

$$SOC_{bld,h} = SOC_{start} + \frac{chBat_{bld,h}}{Bat_E cap_{bld}} * eff_{bat} - \frac{disBat_{bld,h}}{Bat_E cap_{bld}} / eff_{bat} \quad \forall bld, h = 1 \tag{3.14}$$

$$SOC_{bld,h} = SOC_{bld,h-1} + \frac{chBat_{bld,h}}{Bat_E cap_{bld}} * eff_{bat} - \frac{disBat_{bld,h}}{Bat_E cap_{bld}} / eff_{bat} \quad \forall bld, h \geq 2 \tag{3.15}$$

$$chBat_{bld,h} \leq Bat_P cap_{bld} \quad \forall bld, h \tag{3.16}$$

$$disBat_{bld,h} \leq Bat_P cap_{bld} \quad \forall bld, h \tag{3.17}$$

$$SOC_{min} \geq SOC_{bld,h} \leq SOC_{max} \quad \forall bld, h \tag{3.18}$$

$$SOC_{bld,LastHour} \geq SOC_{min} \quad \forall bld, h \tag{3.19}$$

3.3.3 Thermal energy storage (TES)

The thermal energy storage considered in this study are hot water tanks. The parameters specified for this asset are listed in Table 3.7.

The formulation for TES is as follows:

$$TESen_{bld,h} \leq K_{loss} \cdot TES_{start} + TESch_{bld,h} \cdot TES_{eff} - \frac{TESdisch_{bld,h}}{TES_{eff}} \quad \forall bld, h = 1 \tag{3.20}$$

Table 3.7: Specifications for Thermal Energy Storage

Parameter name	Parameter	Value
Tank volume (m3)	*TES_Vmax*	0.1514
Energy density (kWh/m3)	*TES_density*	39
Efficiency for charging and discharging	*TES_eff*	0.9
Hourly Loss Fraction	*TES_hourly_loss_fraction*	0.9992
Maximum discharge capacity (kWh/h tank)	*TES_dis_max*	1.97
Maximum charging capacity (kWh/h tank)	*TES_ch_max*	1.97
Initial state of the tank (% of the tank capacity)	*TESen_initial*	0.6

$$\begin{aligned} TESen_{bld,h} \leq & K_{loss} \cdot TES_{start}(TESen_{bld,k-1} \\ & + TESch_{bld,h} \cdot TES_{eff} - \frac{TESdisch_{bld,h}}{TES_{eff}}) \quad \forall bld, h \geq 2 \end{aligned} \tag{3.21}$$

$TESen_{bld,h}$: Energy content in kWh of the tank for each building *bld* and hour *h*

$TESch_{bld,h}$: Charging power for each building *bld* and hour *h*

$TESch_{bld,h}$: Discharging power for each building *bld* and hour *h*

Where:

$$TES_{start} = TESen_{initial} \cdot TEScap_{bld} \tag{3.22}$$

$$TESch_{bld,h} \leq TESmax_{ch,bld} \quad \forall bld, h \tag{3.23}$$

$$TESdis_{bld,h} \leq TESmax_{dis,bld} \quad \forall bld, h \tag{3.24}$$

$$TESen_{bld,h} \leq TESmax_{cap,bld} \quad \forall bld, h \tag{3.25}$$

$$TESen_{bld,h} \geq TES_{start} \quad \forall bld, h \tag{3.26}$$

This thermal flexibility, allows the buildings to store heat in the tank and cover the demand at another time step.

3.3.4 PV panels

PV modules are also added to the model as a local electricity generating unit. PV panels only add an extra constraint to the model. It limits the PV generation available each hour according to the radiation profile. The radiation depends on the hour and also on the building orientation. There are different radiation profiles depending on if the building is facing North, East, West or South as is illustrated in figure 3.7. Where the parameter $Radiation_{bld,h}$ is in the form PV generation per PV capacity installed.

$$pEl_{bld,PV,h} \leq PVcap_{bld} \cdot Radiation_{bld,h} \tag{3.27}$$

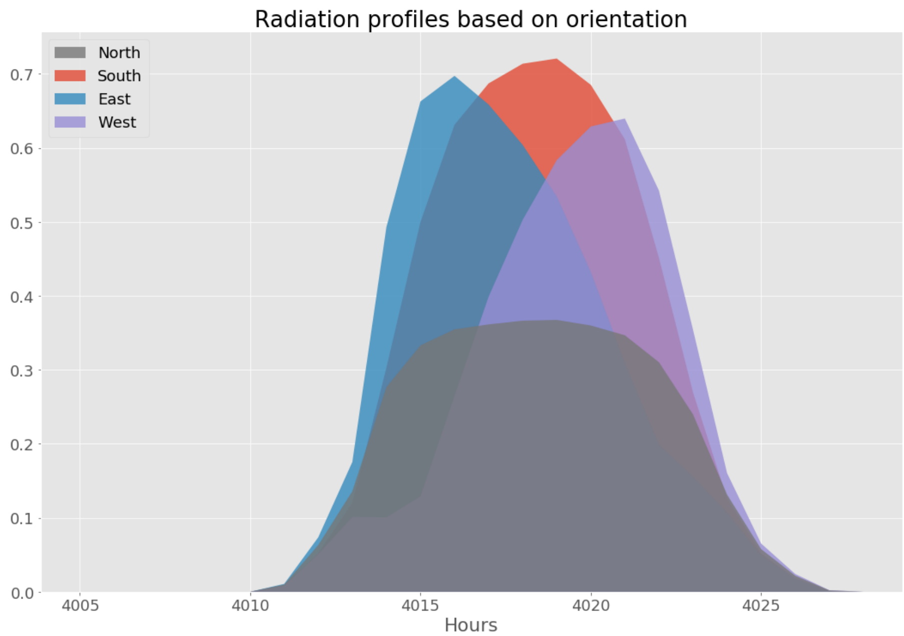


Figure 3.7: Radiation profile for buildings facing South, North, East and West. Expressed in generation per capacity installed of PV panels.

3.3.5 Demand response

At [52] two type of demand response are identified: load shedding for demand that can be reallocated and load shifting for that which can be removed. In this study, only load shifting strategies are used. The DSM is implemented using the same formulation as at [53].

$$dh_{bld,h} \leq \sum_{l=0}^{L-1} dd_{bld,h-l} \quad \forall bld, h = 1+12, ..., 8760-12 \tag{3.28}$$

$dd_{bld,h}$: Delayed demand at building bld and hour h

$dh_{bld,h}$: Demand put on hold at building bld and hour h

L: Delay time. Demand has to be served within 12 hours

$$dh_{bld,h} \leq \sum_{l=1}^{L} ds_{bld,h+l} \quad \forall bld, h = 1+12, ..., 8760-12 \tag{3.29}$$

$$dh_{bld,h} = dh_{bld,h-1} + dd_{bld,h} - ds_{bld,h} \quad \forall bld, h \tag{3.30}$$

$$dd_{bld,h} \leq 0.05 \cdot \frac{\sum_{h-1}^{h+2} demand_{bld,h}}{3} \quad \forall bld, h \tag{3.31}$$

$$ds_{bld,h} \leq 0.1 \cdot max(demand_{bld,h} : h = h, ..., h + 24) \quad \forall bld, h \tag{3.32}$$

The demand on hold at each hour is calculated as the dh the previous hour plus the demand delayed minus the demand served at the current hour, as shown at 3.30. The dh is keeping track of the dh from all previous hours and ensures that dh does not exceed the limit in Equation 3.28 and 3.29. Meaning that the dh has to be served within the delay time of 12 hours. This equation might be easier understand by looking at figure 3.8. The grey area represent the net change in the demand (ds-dd), when it is positive the demand is increased and when it is negative the demand is decreased. The black line represent dh, the demand on hold increases when we are delaying/decreasing the demand and decreases when we serve it. Therefore, when the net change in demand is positive and we are increasing the demand, the demand on hold decreases.

Equation 3.31 represent the DSM penetration level, 5% of the load within the 4 hour period that can be shifted. While Equation 3.32 represents that 10% of the maximum load within 24 hour period can be served. The limit for ds is higher that for dd to show that dd from different hours can be served at one single hour.

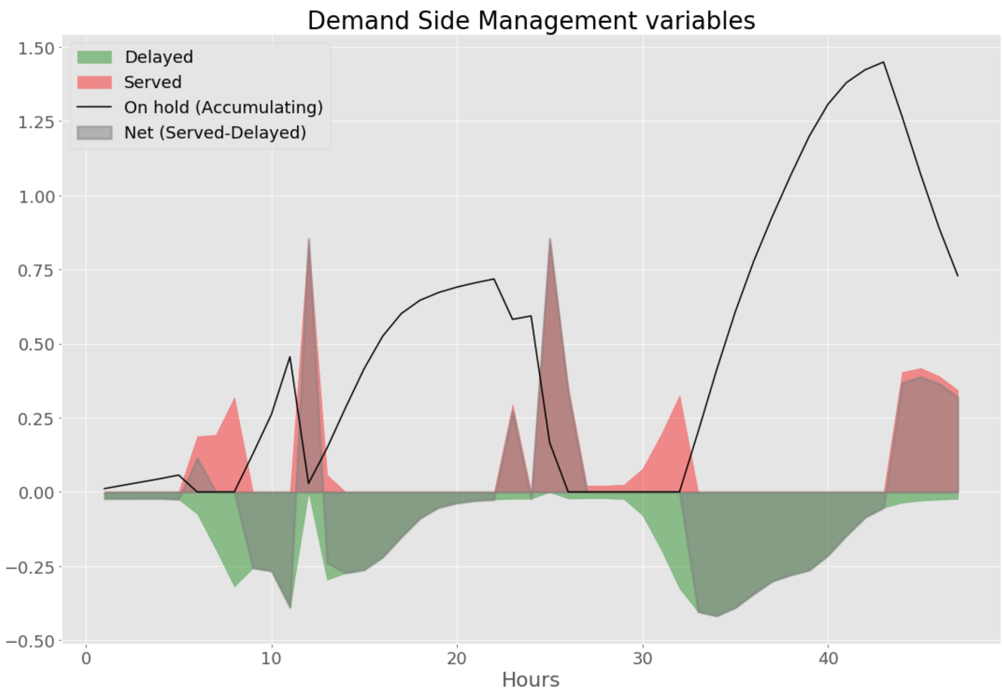


Figure 3.8: Representation of the variables involved in DSM: Delayed demand(dd), Served demand(ds) and demand On hold(dh).

3.3.6 Heat pump

In the model, heat pumps are classified into flexibility($fheat_{bld,hp,h}$) and production ($pheat_{bld,hp,h}$) heat pumps.

The production HPs represent the heat pumps assigned to those buildings with 'Heat Pump' as heating type. In other words, the buildings that use a heat pump as their only heating source. Therefore, the variable $pheat_{bld,hp,h}$ does not have an upper limit for those buildings with HP as heating source. However, all the other buildings are not allowed to produce any heat with these HP, since they have other heating source assigned. To ensure this, $pheat_{bld,hp,h}$ upper limit is set to 0 for these buildings as shown in Equation 3.33.

$$pheat_{bld,hp,h} = 0 \quad \forall bld, h \quad \text{If heating type of bld} \neq heat\ \ pump \tag{3.33}$$

The same formulation is applied to buildings with electric boiler or DH. If the building has DH as heating type, it will not have any restriction regarding DH import but it will not be allowed to use the electric boiler or the heat pumps.

In other words, all buildings have all heat sources but only one can be used primarily and all others are set to 0.

The flexibility heat pumps are added to the district as auxiliary HP for those buildings with DH access. The aim is to increase the connection between the electric and heating system. Those buildings with both district heating and heat pump, will be able to switch energy carrier as a respond to price signals. In this case the production of heat from flexibility heat pumps is limited to the capacity assigned to each building, as shown in Equation 3.34.

$$fheat_{bld,hp,h} \leq HP_{cap}(bld) \quad \forall bld, h \tag{3.34}$$

For simplicity, the heat pump type is not specified and a constant coefficient of performance (COP) of 3.15 is used [54].

3.3.7 Cost function

3.3.7.1 Electricity cost

The electricity import price formulation in this study can be seen in equation 3.35.

$$ImportPrice_{el,h} = El.Spot_h + Grid.tariff + tax + El.Certificate_h \cdot Quote \quad (3.35)$$

The power tariff term is included in the model as another cost term shown in Equation 3.36.

$$Cost_{P_{tariff}} = fee_{bld} \cdot fuse_{bld} \cdot \text{numberofmonths} \quad (3.36)$$

where $fuse_{bld}$ corresponds to the electric power peak over the running time, calculated as in Equation 3.37. The term fee_{bld} is the corresponding power tariff price (23.8 SEK/kW month when the fuse is lower than 44kW or 44 SEK/kW month for larger fuse).

$$fuse_{bld} \geq exp_{bld,h} + imp_{bld,h} + q_{imp,bld,h} + q_{exp,bld,h} \quad (3.37)$$

Equations 3.38 and 3.39 finds out the value of the $tariff_{level}$ based on if the $fuse_{bld}$ is over or under 44 kW. The $tariff_{level}$ is a binary value which takes 0 if fuse is less than 44kW and 1 if it's higher. This $tariff_{level}$ makes sure to use the right fee level in Equation 3.36 with the help of indicator constraints. "An indicator constraint $y = f \to a^T x \leq b$ states that if the binary indicator variable y has the value $f \in \{0, 1\}$ in a given solution, then the linear constraint $a^T x \leq b$ has to be satisfied. On the other hand, if $y \neq f$ (i.e., $y = 1 - f$) then the linear constraint may be violated" [55]. In this case if the $tariff_{level}$ is 0, the fee used in Equation 3.36 is 23.8 SEK/kW month. When the $tariff_{level}$ is 1, the fee used in Equation 3.36 is 44 SEK/kW month.

$$fuse_{bld} - 44kW \leq tariff_{level} * M \quad (3.38)$$

$$44kW - fuse_{bld} \leq (1 - tariff_{level}) * M \quad (3.39)$$

M represents a big number. To prevent numerical errors or wrong results, M value shouldn't be too big or very small. However, it should be chosen big enough that it can find the fuse values. In this case, it has been chosen to be 2000 so that it would be still bigger than fuses.

The electricity export price is shown in Equation 3.40.

$$ExportElPrice_h = El.Spot_h + El.Certificate_h + Tax.Return \quad (3.40)$$

3.3.7.2 Internal exchange cost

When exchanging electricity within the community the grid is not considered to be owned by the community and therefore a grid tariff has to be paid for using it. The expression that sets the price for internal exchange is called gamma and is presented in equation 3.41.

$$\gamma = Gridtariff + q_{imp_{bld,h}} \cdot 0.001 \quad \forall q_{imp_{bld,h}} \geq 0 \tag{3.41}$$

As the gamma function multiplies the internal trade, the grid tariff is being paid for all energy traded inside the community. Only q_{imp} is considered so that the grid tariff is only paid once, in this case only the customer importing electricity.

The second term $q[bld, h] \cdot 0.001$ of the expression builds an incremental function that makes trading more expensive the bigger the volumes traded are. The aim with this function is to prevent the optimizer from importing all external electricity by one single building and then sending it to the rest of buildings. Which is the case when the incremental function is not in place. Because as the optimizer minimizes for the whole community, it does not care which building is importing the electricity and importing its cost.

3.3.8 Assets and load curves assignment

3.3.8.1 PV assignment algorithm

The total PV capacity for the whole district is given to the model as the ratio between electricity generated by PV over the total electric demand (Equation 3.42). The $PVcapacity_{district}$ is then calculated using 3.43. The $PVcapacity_{district}$ is distributed assigning to each building the same percentage of the roof that will have PV panels. The process followed to allocate the PV capacity is shown in figure 3.9. The percentage of the building with PV panels ($Area_{PV,bld}$) is calculated according to Equation 3.44 and PV capacity of each building is then assigned according to Equation 3.45.

$$\%Penetration_{PV} = \frac{PVgeneration_{district}}{ElectricLoad_{el,district}} \tag{3.42}$$

$$PVcapacity_{district} = \frac{ElectricLoad_{district} * \%Penetration_{PV}}{Radiation_{mean}} \tag{3.43}$$

$$ShareArea_{PV} = \frac{\frac{PV_{cap}}{PV_{density}}}{Area_{total}} \tag{3.44}$$

$$PVcapacity_{bld} = ShareArea_{PV,bld} \cdot Area_{bld} \cdot PVdensity \tag{3.45}$$

Where all areas are in m^2 and refer to the roof top area. The PV density corresponds to 0.20065 kW/m^2.

Due to the wide variation of buildings taken into account, it could happen that houses with big roof areas and relatively low loads, get assigned unreasonable amounts of PV modules. To avoid this phenomena, a limit based on Array-to-Load Ratio (ALR) is used [56].

ALR is used to have an indicator that relates the PV capacity with the load. The ALR is calculated for each building as the PV capacity installed divided by the hourly average demand in Watts based on the annual demand. The maximum level of ALR desired is an input to the model.

$$ALR_{bld} = \frac{PVcapacity_{bld}}{\frac{\sum_{h=0}^{8760} ElectricLoad_{bld,h}}{8760}} \tag{3.46}$$

The algorithm to take into account the ALR value is as follows:

- The ALR of each building is calculated after assigning the PV capacity according to Equations 3.45 and 3.44.
- If the ALR of the building is higher than the limit imposed (ALR_{max}), the $PVcapacity_{bld}$ is set to $PVcapacity_{bld} = ALR_{max} * \frac{\sum_{h=0}^{8760} ElectricLoad_{bld,h}}{8760}$ and the extra capacity is added to a parameter named 'extra' that will be distributed among the other buildings that did not reach ALR_{max}.
- As the extra capacity is reallocated to others building, it has to be checked that the area with PV is smaller than the rooftop area. In case the area required for the PV capacity is greater than the area available, the PV capacity is fixed to $PVcapacity_{bld} = Area_{bld} * PV_{density}$
- The allocation is considered finished when the PV capacity assigned represents at least 95% of the capacity assigned to the district.

In order to understand what each value of ALR represents, Figure3.10 shows the share of the annual electricity demand met by the PV installation for different ALR values calculated [56].

ALR max is assumed to be 6 in the model. Because with a penetration of 40%, it was the lowest value for which the $PVcapacity_{district}$ could be distributed for the areas considered. This way, the ALR of the majority of the buildings reached the ALR figure/pv.png

Figure 3.9: Distribution algorithm for PV panels

max, meaning that the $PVcapacity_{bld}$ allocated to each building correlates with its load. For penetration levels over 40% the ALR maximum can be calculated as the $PVcapacity_{district}$ divided by the sum of all buildings mean electric load.

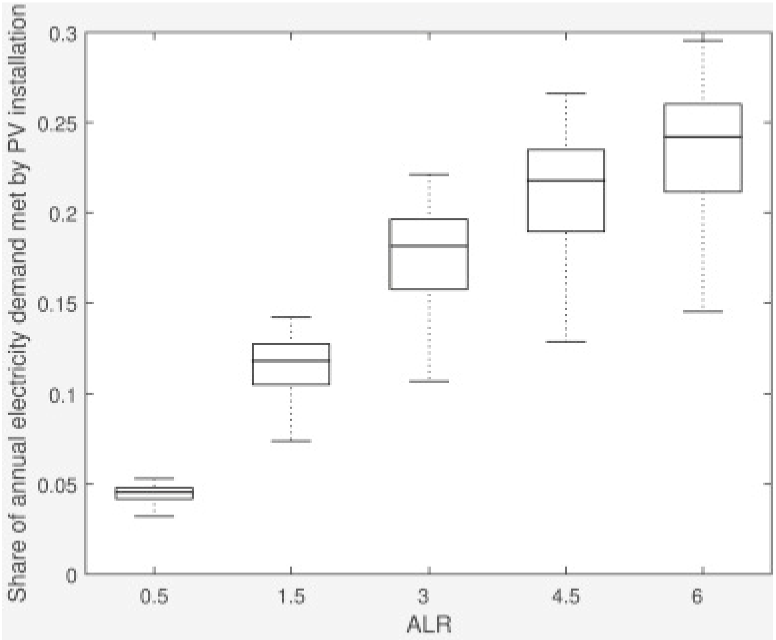


Figure 3.10: The share of the households annual electricity demand met by the PV installations at different ALRs. The bars represent the 25th and 75th percentiles, the whiskers indicating the range of values seen for different households [56].

The second part of the PV distribution was to assigned a different azimuth to each building. Each building has a different orientation which affects the solar radiation and the exact time when it happens. Therefore according to how the selected area looks like, the percentage of houses facing north, south, east and west can be adjusted and given to the model as an input. As base case, it is considered that 50%, 25%, 25%, 0% of the buildings are facing South, East, West and North respectively. The model will randomly assign the orientation to different buildings independently on the geographical location. Each orientation will use a different hourly solar radiation profile.

3.3.8.2 Battery assignment algorithm

The input to the model is the total battery capacity of the district which is given as a percentage of the average electric daily demand in kWh. Then the algorithm shown in Figure 3.11 distributes those kW among the different buildings, following the process:

- The algorithm chooses a random building with no battery assigned and then, assigns a number of batteries depending on its daily load. Where the ranges are chosen so that the middle value of the range is double as big as the energy capacity of the battery assigned. For example, for the range [40-60] the middle daily load is 50kWh and the energy capacity of two batteries is 27kWh.

- This assignment is followed until a minimum of 95% of the battery district capacity is allocated. Some of them will have capacity assigned while others not, but the assignment process will finish when the district battery capacity is reached.
- Each battery corresponds to a power capacity of 5 kW and an energy capacity of 13.5kWh, using the specifications for a Tesla Powerwall[57].
- For high level of penetration, when all buildings have already been assigned a battery capacity, the algorithm follows the same process adding more battery capacity to the one already assigned.

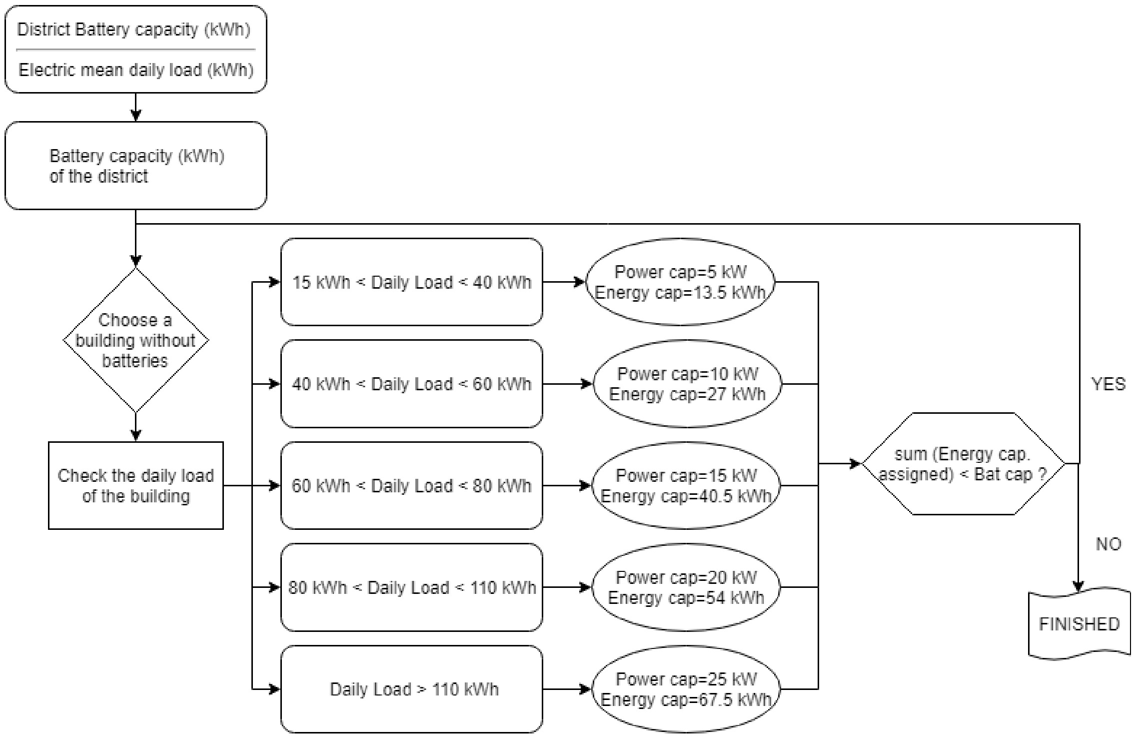


Figure 3.11: Distribution algorithm for batteries. The daily load is the average demand of a day over the year, calculated by adding up all the demand during a year and dividing it by the number of days.

3.3.8.3 HP assignment algorithm

This section refers to the heat pumps distributed among buildings with district heating access, which are assigned in order to provide extra flexibility and increase the connection between the electric and heating system. The total heat pump capacity to the region is given to the model as a percentage of the heating mean demand (kW) over the year of the buildings with DH as heating source (Equation 3.47. That total capacity is distributed as shown in Figure 3.12. First, the percentage of the mean heating load over the year that is covered with the given HP capacity($LoadShare_{HP}$) is calculated with Equation 3.48. Dividing the district capacity by the sum of the mean heating demands for each building with DH as heating source. Then the $HPcapacity_{bld}$ is assigned using Equation 3.49.

$$\%Penetration_{HP} = \frac{HPcapacity_{district}}{\sum_{bld} HeatingLoad_{mean,bld}} \forall \text{bld with DH} \tag{3.47}$$

$$LoadShare_{HP} = \frac{HPcapacity_{district}}{\sum_{bld} HeatingLoad_{mean,bld}} \forall \text{bld with DH} \tag{3.48}$$

$$HPcapacity_{bld} = LoadShare_{HP} \cdot HeatingLoad_{mean,bld} \tag{3.49}$$

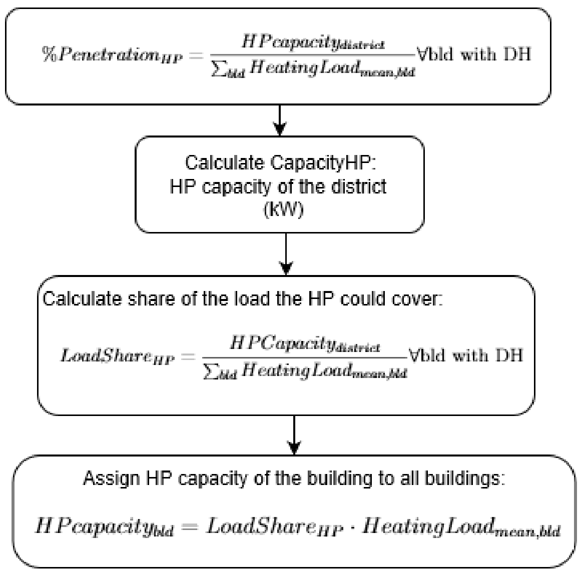


Figure 3.12: Distribution algorithm for HP

3.3.8.4 TES assignment algorithm

The TES energy capacity for the whole district is specified for the chosen region as a percentage of the district average daily heating demand in kWh. Then this capacity is distributed among the buildings as shown in Figure 3.13, following the process:

- First one random building is chosen. The building does not have a TES capacity assigned and it is heated by HP, electricity or DH.

- The usage type of the building (house, apartment or services) is checked. For houses, one tank is assigned per household. For apartments, one tank is assigned every 100 m2. For services one tank is assigned per floor.

- The size of the tank is 0.1514 m3 (40 gallon), which is a typically tank capacity used in the residential sector [58]. Considering a temperature range to exchange heat of 35°C for water, the energy density of the tank is 39 kWh/m3 and consequently the energy capacity of the tank is 5.9 kWh.

- At the same time, the maximum charging and discharging rate is assigned as one third of the tank energy capacity, which corresponds to 1.97 kWh/h per tank.

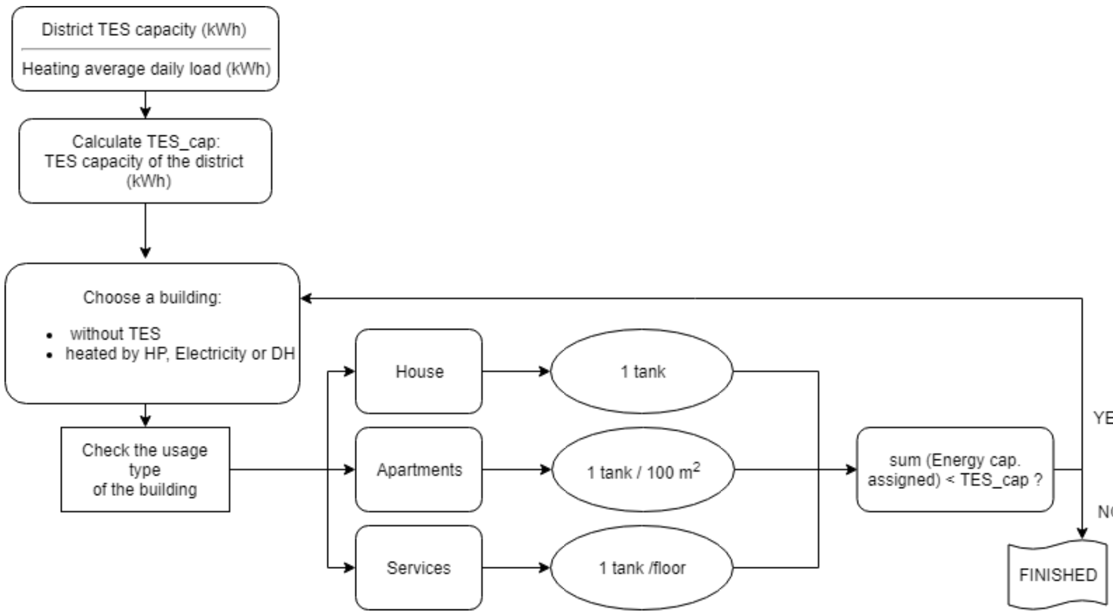


Figure 3.13: Distribution algorithm for TES

3.3.8.5 Load curve assignment algorithm

3.3.8.5.1 Electric Load

The electric load profiles are generated differently depending on the type of usage of the building. As explained in subsection 3.2.1 the buildings are classified into three different types based on their usage type: service, apartment and houses. Figure 3.14 shows schematically the process followed.

From the spatial data file the footprint and the usage type of each building is obtained. The first step is to obtain the total area of the buildings by multiplying times the average number of floors for each type (This parameter can be adjusted if the height of the buildings in the selected area is known).

The second step generates the load fraction profiles (LFP). Where each hour of the year contains the fraction of the yearly load, so that the sum over the year adds up to 1. To obtain the LFP, the data from measurements is divided by the total yearly demand. The measurements used are:

- SERVICES AND APARTMENTS: The measurements are from the city of Gothenburg for different SNI codes, where the average load per each SNI code is provided. The codes used are for: banks, cultural buildings, schools and apartments. Th average LFP is randomized to obain slightly different profiles for each building. By multiplying each hour times a random value between 0.95 and 1.05.

- HOUSES: The LPs are obtained from an E. ON measurement campaign on 2220 households (2012). Where the houses where filtered by postal code, keeping only those located at a similar latitude as Gothenburg (Postal codes between 10000 and 72000). The electric load of each building is divided by the total yearly load to obtain the LFP.

Once the LFP is known for each building, it is multiplied times the corresponding energy intensity and area of the building. The intensity values from [59] in kWh/m2 are 35, 119 and 61 for houses, services and apartments respectively. The intensity for services has been readjusted to 80 kWh/m2 in order to match with a sample area where the composition and demand was known.

3.3.8.5.2 Heating Load

The heating loads are obtained from the department of Space, Earth and Environment, (division of Energy Technology) were different buildings types are modelled based on their heat transfer characteristics to calculate the losses and therefore the space heating demand. The result is an hourly heating demand in kWh/m2 for a whole year. This process is done for houses, apartments and non-residential buildings to obtain the heat required for space heating purposes.

Hot water (HW) fraction load profile of residential consumers for one day are taken from a review done by Fuentes et al. [60]. They are used to build up the yearly consumption of hot water. The steps are as below:

- Fraction load curve building

- Including the weekly variations by increasing the HW consumption in the weekend with a factor of 1.18 [61].

- Using a hourly randomizer between 0.95 and 1.05 to make variations in the load for different buildings

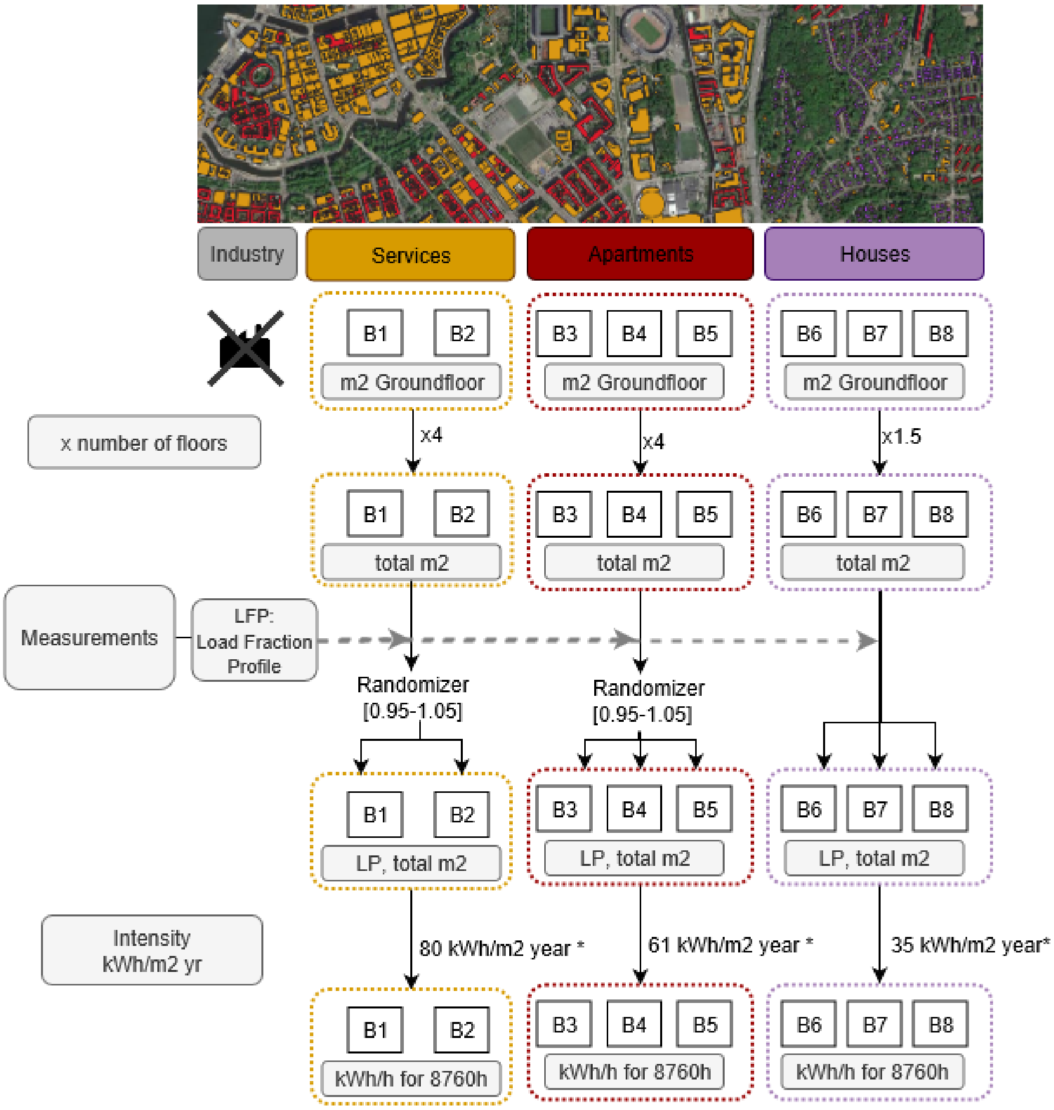


Figure 3.14: Processed followed to assign electric load profile to each building.

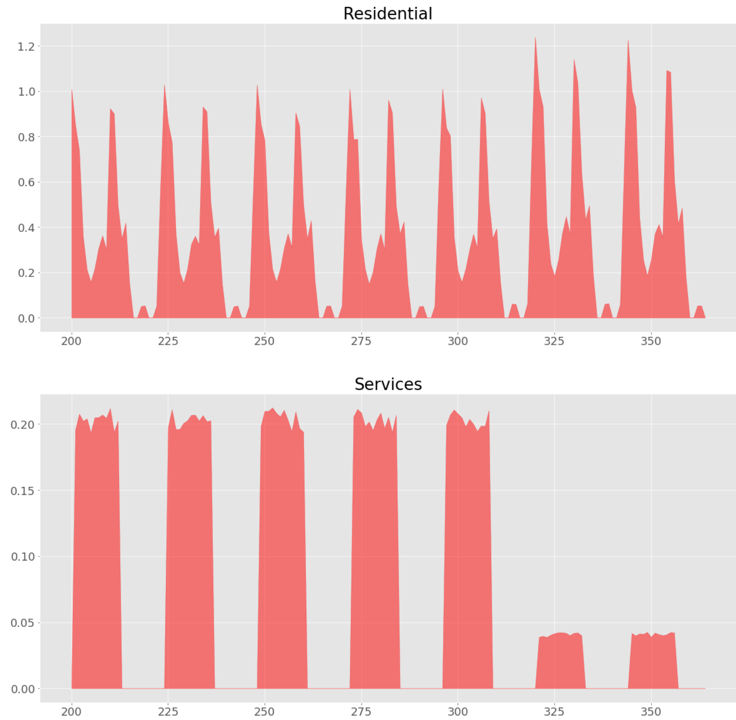


Figure 3.15: Hot water load for services and residential buildings. From Monday to Sunday.

- Using an average yearly percentage of total heating load which is because of HW demand [62].

For services, the HW load curve is very dependent on the service type (figure 3.16). As the services in this study is a mix of offices and commercial buildings, the hot water load curve is decided to be flat but only available for a few hours (figure 3.15). The rest of the steps are similar to the steps for residential buildings.

Each building of the model is assigned a heating load (including space heating and hot water) based on their usage type (houses, apartments and services). The heating source used to cover the demand is assigned based on Table 3.8 from [59]. However, biofuels were not considered during this study and therefore the percentages used are the ones excluding biofuels. The reason behind this simplification is that the buildings with biofuels do not have connection between heating and electricity system in this system. Therefore, no change was seen in the dispatch of this buildings. As the heating type assignment is based per number of buildings, when the biggest building gets assigned biofuel as heating source, the results were drastically changed.

Taking Apartments as an example, the process is:

- Assign a percentage of the apartment buildings that have access to the DH network (80% for example)

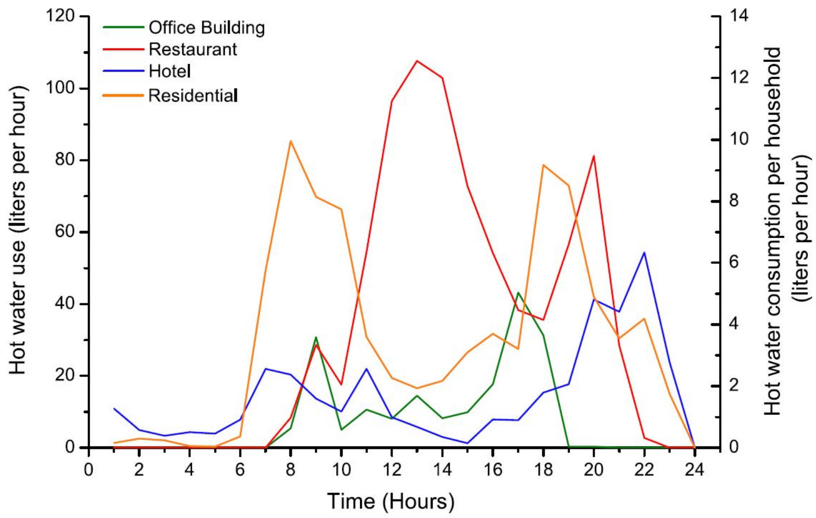


Figure 3.16: HW daily load for different type of services [60].

- The rest of buildings (20%) are assigned a heating type/source. A heat pump to 62% of the 20% and electricity to 38%.

Table 3.8: Energy sources used for space heating and hot water purposes **The DH percentages are specific for each area.*

Heating code	Name	Houses		Apartments		Services	
		Excluding biofuels	Including biofuels	Excluding biofuels	Including biofuels	Excluding biofuels	Including biofuels
2	Electricity	56,47	38,27	38,23	38,23	50	41,11
9	Biofuels	0	32,23	0	0	0	17,76
11	Heat Pump	43,52	29,49	61,77	61,76	50	41,11
4	District Heating	20		80		70	

3.4 Archetypes and scenarios definition

The districts studied are categorized by the percentage of area belonging to services, houses and apartments. Single type compositions are areas with only one building usage type (100% houses, apartments or services). These archetypes are used to identify the main distinctive characteristics of each usage type. Then, mixed compositions are studied to investigate how mixing can affect the performance of the local energy community.

The districts mentioned above are tested under four different weeks in the year, one week in spring, summer, autumn and winter. The main characteristics of these four time periods are shown in table 3.9.

Each season corresponds to a week starting on: 4th April for spring, 27th of June for summer, 6th September for autumn and 12th January for winter. This four weeks are chosen to see the difference in the LEM performance under different weather conditions but also under different price curves.

Table 3.9: An example of specifications for each week (season). Values correspond to the sum over all buildings and over all hours of a sample district.

	Electric load kWh	Heating load kWh	Space heating %	Hot water %	Radiation kWh/kW capacity
Summer	23876,54	2578,90	0,00	100,00	144,41
Winter	28859,41	50297,85	94,85	5,42	3,20
Autumn	24908,40	6762,88	63,60	36,40	28,24
Spring	24567,60	37705,65	93,40	7,07	17,33

To prevent any later confusion, it can be seen in table 3.9 that summer and autumn in this study are the sunnier and warmer weeks compared to spring and winter.

3.5 KPIs

A deep study for defining the KPIs has been done at an early stage in order to identify all data required to calculate the indicators. The KPI´s are chosen to check if the benefits from LEM named in the theory are actually achieved. Firstly, the potential benefits from each stakeholder were listed so to choose indicators that represent each of them. Secondly, this KPIs were classified into economical, technical and environmental. Though, all of them are interconnected and one indicator could be interpreted as economic and technical at the same time.

3.5.1 Economical

The two main economical benefits from implementing a local market at the distribution level are: preventing future investments for the DSO and new revenue streams that depending on the market structure will belong to a different agent. It can be the conventional retailer, an ESCO, a new aggregator or the real-state companies that start benefiting from optimizing and aggregating the consumers load. At the same time this new revenue should also be noticed by the prosumers so to incentives market participation.

The reduction of future investment is related to technical aspects, for instance to how much the peak is reduced or how much flexibility is provided. Therefore, this aspects is taken into account in the technical KPIs.

The tool to measure the new revenue streams strongly depends on what is considered as base scenario. In this work the base scenario consists of the same generation units installed in each building but trading within neighbours is restricted. This is done by not allowing internal trading, setting $q_{imp} = 0$. The difference in cost with and without a LEM represents the cost savings.

$$KPI_{NewRevenues} = \frac{Cost_{base} - Cost_{LEM}}{Cost_{base}} * 100 \tag{3.50}$$

3.5.2 Technical

Regarding technical benefits from the LEM, the three main benefits were peak reduction, self-sufficiency and variation management.

The peak reduction is measured as the sum of percentage peak reduction at each hour times a weighting factor. The weighting factor purpose is to include the importance of when and at which situation the peak takes place. At each hour the weighting factor is calculated as the current peak at that hour in the grid divided by the maximum daily peak of the grid. This way, the peaks occurring during high demand periods are more prejudicial than those occurring during night. The biggest the KPI value is, the best the archetype is regarding peak reduction.

$$KPI_{peak} = \sum_t \frac{P_{base}(t) - P_{LEM}(t)}{P_{base}(t)} * \frac{P_{GRID}(t)}{P_{maxGRID}} \tag{3.51}$$

.

The **degree of self-sufficiency** is a very important benefit from building an energy market, mainly regarding public engagement and security of supply. Furthermore, if less energy is imported from the grid less losses will be at the transmission level. Instead of generating energy at the transmission level and transmit it to the distribution level, the electricity is generated already at the distribution level and consume locally avoiding losses.

However, this reasoning strongly depends on the system considered, since an area with high penetration of renewable might produce more than it is consume at the distribution level which would generate reverse power flow towards the transmission level which originates even greater losses. As the exact losses are hard to allocate since the origin of the electricity generation is unknown, the potential reduction is seen as percentage of reduction in imported energy from the wholesale market. But keeping in mind, that this is only true for a system with lower penetration levels of distributed generation.

$$KPI_{selfSufficiency} = \frac{Import_{base} - Import_{LEM}}{Import_{base}} * 100 \tag{3.52}$$

The third technical benefit is related to the capacity of the archetypes to provide flexibility. The flexibility assets in the district are: TES for the heating system;

batteries and DR for the electricity system; and HP that provide flexibility in both systems but are considered in the heating flexibility. Two different KPIs are considered, one fr the heating system and other for the electric system. In order to be able to compare archetypes with different sizes, the KPI is defined as :

$$KPI_{flex} = \frac{f_{base} - f_{LEM}}{f_{base}} \tag{3.53}$$

3.5.3 Environmental

The benefits named before are beneficial for the environment as: they reduce losses and therefore generation, it helps integrating more renewable energy sources or it provides a more efficient use of resources. However, the benefit which is more directly related to the environment is the CO_2 reduction. This is measure by comparing the CO_2 emitted from the generation of all the energy before and after LEM. To do so, an emission factor is assigned to all local generation units as well to the energy bought from the grid. The KPI is defined as percentage of CO_2 reduction as is shown below.

$$KPI_{CO_2} = \frac{Emissions_{base} - Emissions_{LEM}}{Emissions_{base}} * 100 \tag{3.54}$$

The CO_2 emission calculation is very important and could change the results considerably depending on the allocation considered. For this study, the same values as for [17] are used. As our work studies the difference in emissions between two scenarios, the risk of using not appropriate values for CO_2 emissions are somehow decreased. The values used are shown in Tables 3.10 and 3.10.

Based on those intensities and taking into account the marginal generation unit, the CO_2 factor for electricity and district heating is calculated. The CO_2 factor represents the grams of CO_2 per kWh bought from the external electric grid or district heating network.

3.6 Carried out analyses

In this section the different analyses which has been carried out are explained. The first two analyses (section 3.6.1 and 3.6.2) are carried out for better understanding of the reasons behind the achieved results in other analyses aiming to answer the research questions.

Except analyses on district size and composition (sections 3.6.3 and 3.6.4) , the rest of the analyses are carried out on a reference district presented in table 3.12.

Table 3.10: CO_2 emissions factor gCO_2eq/kWh used for the different electric power generation technologies used in the electric grid. All values in gCO_2eq/kWh

Technology	**Intensity (gCO_2eq/kWh)**
Biomass	230
Coal	820
Gas	490
Hydro	24
Nuclear	12
Oil	650
Solar	45
Wind	11
Geothermal	38
Unknown	700
Hydro-discharge	46
Hydro-charge	0

Table 3.11: CO_2 emissions factor gCO_2eq/kWh used for the different plants supplying heat to the district heating network of Gothenburg. For heat pumps, corresponds to the COP value.

Technology	**Intensity (gCO_2eq/kWh)**
Biomass HOB	79
Biomass CHP	6.7
Natural Gas HOB	248
Natural Gas CHP	177
Oil HOB	339
Refinery Heat	0
Waste Incineration CHP	98
Heat Pump	3.4

Table 3.12: Reference district characteristics. 18H-43L-39S represents 18% houses(H) type, 43% apartments (L) and 39% services (S).

Composition	Size (number of buildings)	Assets' penetration level
18H-43L-39S	41	40%

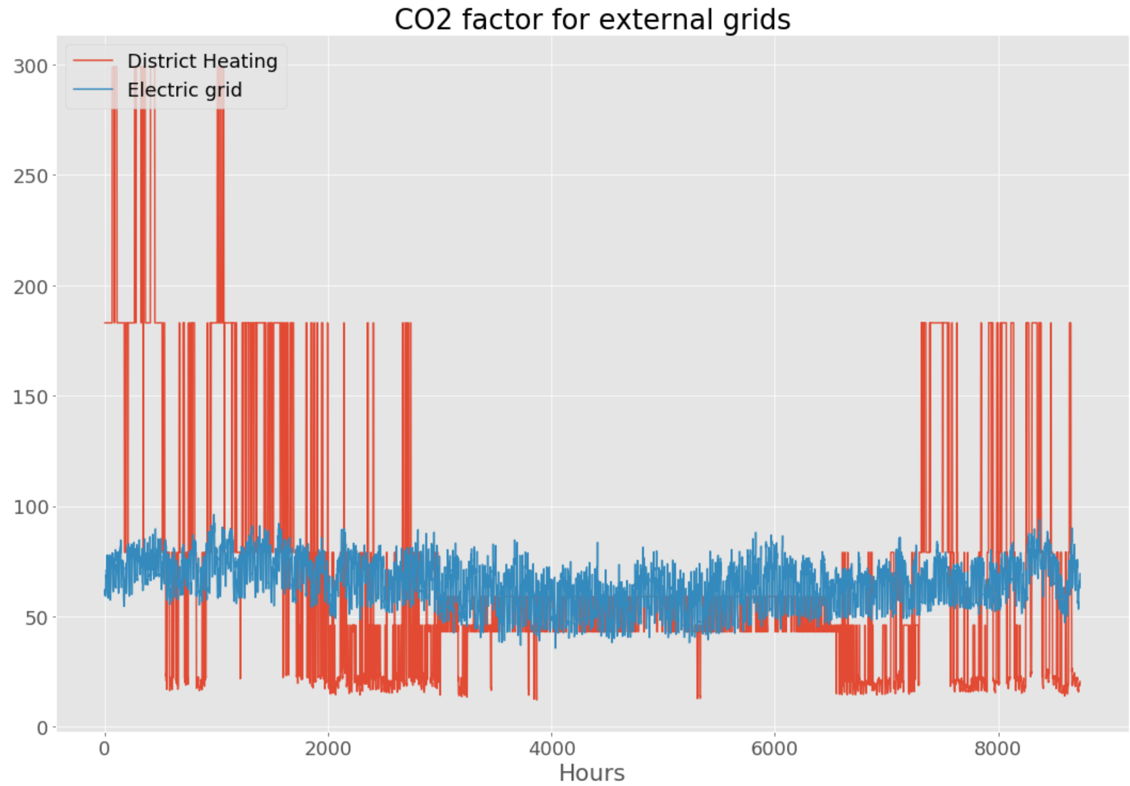


Figure 3.17: CO2 emission factor in gCO_2eq/kWh for energy purchased from the external grid.

3.6.1 Effect of random distribution

The distribution of assets follows the algorithms explained at Chapter 3.3.8 and might affect the results. To study its effect, the model was run several times redistributing the assets each run to see how the results were changed.

3.6.2 Effect of enabling energy exchange on assets behaviour

In this section, how each asset's dispatch is affected when enabling energy sharing within the community is analyzed. The assets considered are: DR, TES, Battery and auxiliary HP.

To disable the energy sharing in the community, the value of internal energy exchange variable was forced to be zero.

3.6.3 Performance depending on district size

The sensitivity analysis on the size of the district was carried out for 2 different compositions and in 3 different sizes each (see table 3.13). In the analysis the assets' level of penetration is assumed to be 40% to make sure there is enough capacity available and at the same time a grid dependency would be present.

The composition percentages are based on the foot print area of the different buildings. Moreover, the selected areas are real areas selected in the city. This is the reason behind the fact that the number of buildings in each size is not the same (e.g size Small is 21 in one composition and 23 in other).

The reason that all sizes are selected in the range less than 100 buildings is due to computational power limitation.

Table 3.13: The different districts used in size sensitivity analysis. 100H-0L-0S represents 100% houses(H) type, 0% apartments (L) and 0% services (S).

Composition	Size	Number of buildings
	Small (S)	21
100H-0L-0S	Medium (M)	45
	Large (L)	103
	S	23
50H-50L-0S	M	39
	L	74

3.6.4 Performance depending on district composition

In this analysis the aim is to understand if the usage type composition of the district would have an effect on the performance of the LEM or not. To study this, 7 different compositions have been considered which can be seen in table 3.14. Due to the results from sensitivity analysis on size, it has been observed that the size don't have big effect on the results, therefore the sizes of different compositions are not adjusted to be the same; however, they have been selected to be at the same level. The assets' level of penetration is assumed to be at 40% with the same reason as explained in sensitivity on district's size.

Except the 33H-33L-33S composition the rest of the areas are real areas selected from Gothenburg. 33H-33L-33S composition with the size around Medium was hard to find in the city. Therefore, 33H-33L-33S composition was made by concatenating buildings from different areas to each other. The composition percentages are based on the foot print area of the buildings in each usage type.

The reason that all sizes are selected in the range less than 100 buildings is due to computational power limitation.

Table 3.14: The different districts used in composition sensitivity analysis. 100H-0L-0S represents 100% houses(H) type, 0% apartments (L) and 0% services (S).

Composition	Number of buildings
100H-0L-0S	45
0H-100L-0S	58
0H-0L-100S	45
50H-50L-0S	65
50H-0L-50S	51
0H-50L-50S	60
33H-33L-33S	52

3.6.5 Effect of assets' penetration

During this chapter, different penetration levels for HP, PV, TES and Batteries are evaluated. The behaviour of each asset as well as its consequences in imports, exports, external trade and LEM performance is compared betwee penetration levels. The penetration levels considered are listed in Table 3.15.

Table 3.15: Penetration levels of each asset considered for the sensitivity analysis on penetration.

Scenario	Battery	TES	Heat Pump	PV
1	20 %	20 %	20 %	20 %
2	40 %	40 %	40 %	40 %
3	60 %	60 %	60 %	60 %
4	60 %	20 %	20 %	20 %
5	20 %	60 %	20 %	20 %
6	20 %	20 %	60 %	20 %
7	20 %	20 %	20 %	60 %

3.6.6 Effect of cost structure

In this analysis the effect of changes in the regulation or tariffs into the LEM behaviour is studied. Both the electricity power tariff and the internal exchange cost function are investigated.

3.6.6.1 Power Tariff

The power tariff sets a cost to the maximum level of power imported or exported at each building. The first study, analysis how the LEM's dispatch reacts to different fee levels when having a 40% penetration for all assets. The initial fee tariffs are: 23.8 and 44 SEK/kW · month for buildings with maximum power import or export below or over 44 kW respectively. The new tariffs are obtained from reducing the tariffs by: 0%, 30%, 50%, 80% and 100%. Where reducing 0% is equivalent to using the starting prices and reducing 100% means eliminating the power tariff; the price of the power peak is therefore increasing.

The second study builds a new power tariff that sets a cost on the power peak of the whole community instead of at each building individually. The peak is calculated as the maximum value of the imported or exported electricity from the grid. In this case, the internal trade is not considered because it is inside the community while the fuse is just at the border of the community. To do so, the limit of 44kW that separated the two tariff levels was readjusted according to the new size. The limit was then set to a percentage of district's maximum electric demand of the week. The percentages considered were from 100% to 25%.

3.6.6.2 Internal exchange cost function (Gamma)

The internal exchange cost function has two parts: the grid tariff and the incremental function. As it is explained in Chapter 3.3.7.2. When exchanging within the community the DSO's grids is being used and therefore the grid tariff must be paid. However, if the LEM participants should pay the full grid tariff or just a percentage could be discussed. Since the internal exchange use only a limited part of the distribution grid and not at all the transmission grid. To show how this change in the regulation would affect the amount of energy traded, the district's dispatch is optimized for different grid tariffs. The different grid tariffs studied include from 100% to a 0.01% of the current grid tariff, 0.31 SEK/kWh.

The second part of the cost function is also analyzed. In this case, the incremental function is activated and deactivated to see the change in the LEM behaviour.

3.6.6.3 Tax return

All buildings gets a tax return of 0.6 SEK for every kWh of electricity exported. This increases the price of the exported electricity and therefore decreases the difference between import and export, which has an impact on the amount of energy exchanged internally. In this section the effect of tax return is analyzed for each season.

4

Results and discussion

In this chapter the results from the conducted analyses are presented and discussed.

4.1 Effect of random distribution

During the whole modelling process to simulate a district with LEM, there are two main parts (load generation and assets distribution) where randomization is used and may affect the results.

The load generation part includes both the electric and heating load; as well as the heating types assigned to each building. The total electric load varies 5% above and below the average electric load. The cause for this differences might come from the randomization of the apartments and services loads, where each hour of each building demand is multiplied times a random value between 0.95 and 1.95 in order to get slightly different curves. The houses electric loads can also be the cause of the 5% variations since each house gets a random load chosen from a sample. The total heating load is kept almost constant between all runs, with a maximum difference of 0.013% from the average heating load. However, the amount of kWh heated by each heating type do vary considerably between runs. The percentage of the total heating load assigned to each heating type (electric boiler, DH or heat pump) is shown in figure 4.1. It can be observed that the demand covered by HP changes from representing a 9.6% to a 22% of the total heating demand. This is because the assignment is based on number of buildings instead of on load. In districts with a considerable big building, the percentages of load cover by its heating type will be increased.

Regarding the assets distribution, their effect is analyzed by looking at the results and comparing the use of each asset between runs.

The cause for these differences might come from different sources. For the case of PV, the differences come mainly from the size of the buildings assigned North, East

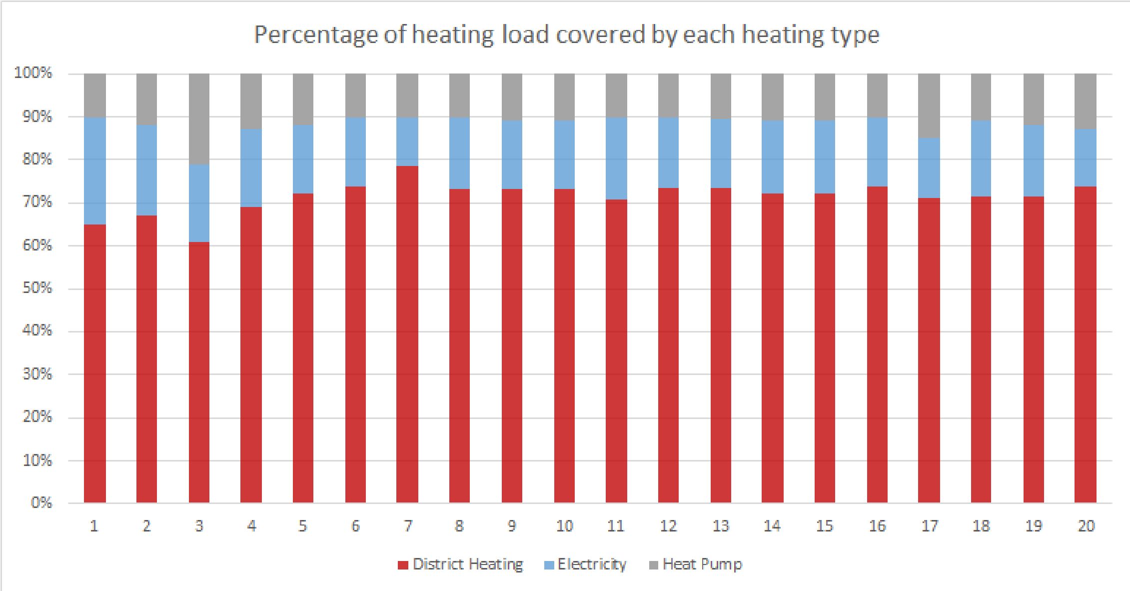


Figure 4.1: Share of the total heating load covered by each heating type. x-axis represents different runs for testing repeatability of the model.

Table 4.1: Maximum difference in kWh activated of PV, HP, Battery and TES between different runs

	PV		HP		Battery		TES	
	Maximum difference	Average (kWh)	Maximum difference	Average (kWh)	Maximum difference	Average (kWh)	Maximum difference	Average (kWh)
Spring	2.5 %	8552,09	9.35 %	17773,68	5.5 %	1349,45	10.09 %	3816,89
Summer	1.26 %	21306,12	43.28 %	135,55	11.7 %	2250,26	16.93 %	431,81
Autumn	3.77 %	13834,04	8.12 %	166,40	8.55 %	1837,93	19.8 %	627,86
Winter	8.71 %	1548,98	9.26 %	35708,63	5.15 %	7755,32	3.98 %	6250,38

or West. A building with a high PV capacity installed gets assigned a different orientation each run, which affects the PV output in each season. At the same time the PV penetration is specified as the amount of kW which would generate a certain percentage of the demand. Therefore, the differences in PV generation between runs must be related with the variation in the electric load. The variations are the biggest for the case of the HP. It is hard to see where do these variations come from. On reason could be the amount of load covered by each heating type shown in figure 4.1. Since the use of the HP will be influence by the size and type of the building they are assigned to. Another reason is that the HP assignment is based on the mean heating load of the building, which might vary slightly between simulation. The differences in the battery use could be attributed to the distribution algorithm. As the distribution is finished once the total district capacity has been assigned, the size and type of buildings that get a battery vary from run to run.. The same reason could be the cause for the differences in the TES dispatch. The type of building that gets a TES assigned, regarding usage type and heating type, will affect the profitability of the TES and therefore its dispatch. In this case, another source for differences is that TES assignment is just based on the usage type (house, apartment or services) without taking into account differences in load. This will also create inequalities in the ratio TES capacity over load.

It is also observed that the difference is considerably bigger when the average kWh is a small number, which is often the case for HPs and TES during autumn and summer. As the KPIs are based on differences between the results with and without LEM, this observation should be taken into account.

The conclusion from this sensitivity analysis is that several factors from the distribution do affect the results and the performance of the LEM. Which means that the way assets are distributed among the buildings do affect the performance of a LEM. In order to eliminate or mitigate the effect of distribution in the following studies, each scenario is evaluated 5 times (distributing all assets again each time) and the average from the 5 simulations is the one considered to compare scenarios.

4.2 Effect of enabling energy exchange on assets' behaviour

In this section the change in the behaviour of different assets is discussed when allowing the internal energy exchange (trade) between the members of the energy community.

Before getting to the behaviour change of each asset, a general observation is that the changes in the assets are not very significant. However, the sum of changes in the assets is much less than the internal trade. Therefore, it seems that with energy exchanging enabled, the energy is more traded and consumed for real-time consumption rather than storage or other assets.

4.2.1 DR

The results show that in summer, autumn and winter, the usage of DR is decreased when the internal trade is allowed. The percentage of reduction varies depending on the season. The amount of decrease for the reference area considered in the analysis is presented in table 4.2.

Table 4.2: The change in the DR usage when enabling internal trade (sharing) within the community

Composition	Season	DR usage change (%)
Reference district (18H-43L-39S)	Spring	-0.3
	Summer	-3.9
	Autumn	-3.4
	Winter	-3.2

We think one cause of this decrease is related to power tariffs. In seasons with high solar radiation in our study (summer and autumn), the prosumers has lot of solar production which needs to be consumed, sold(shared) or curtailed. The solution is a mix of these different options. As the prosumers want to avoid curtailment and earn as much profit as possible, sharing or exporting is a better option. However, this might cause high costs regarding the power tariffs for the prosumer, therefore, when the prosumers cannot share their assets with each other, they try to consume more in peak PV production hours to avoid higher power tariff costs, but when the sharing is allowed between prosumers, the aggregated value for the community is more than the cost for power tariff and prosumers would like to reduce their consumption (compared to the case with no trade), so that they can share more energy with the other prosumers in the community. It can be seen in figure 4.2 that the DR is decreased at the same time as the building starts to export to the community instead of to the outside grid.

In winter the decrease is due to another reason. In the sample week from winter the price variations are much more than other seasons and therefore batteries are used the most in this season. DR can be considered as a short term, limited capacity, storage. Therefore, highest usage of DR can also be seen in this week. However, batteries have better storage length because DR is limited to a time shift of 12 hours. Thus, when the internal trade is allowed they can be more useful than DR regarding reducing the dependency on outer grid in high price hours. We think it can be one reason why DR is decreasing in cheap hours to allow more charging of batteries still within the previous power tariff level. More discussion is done on batteries behaviour in section 4.2.3. As the amount of reduction in DR is not always close to

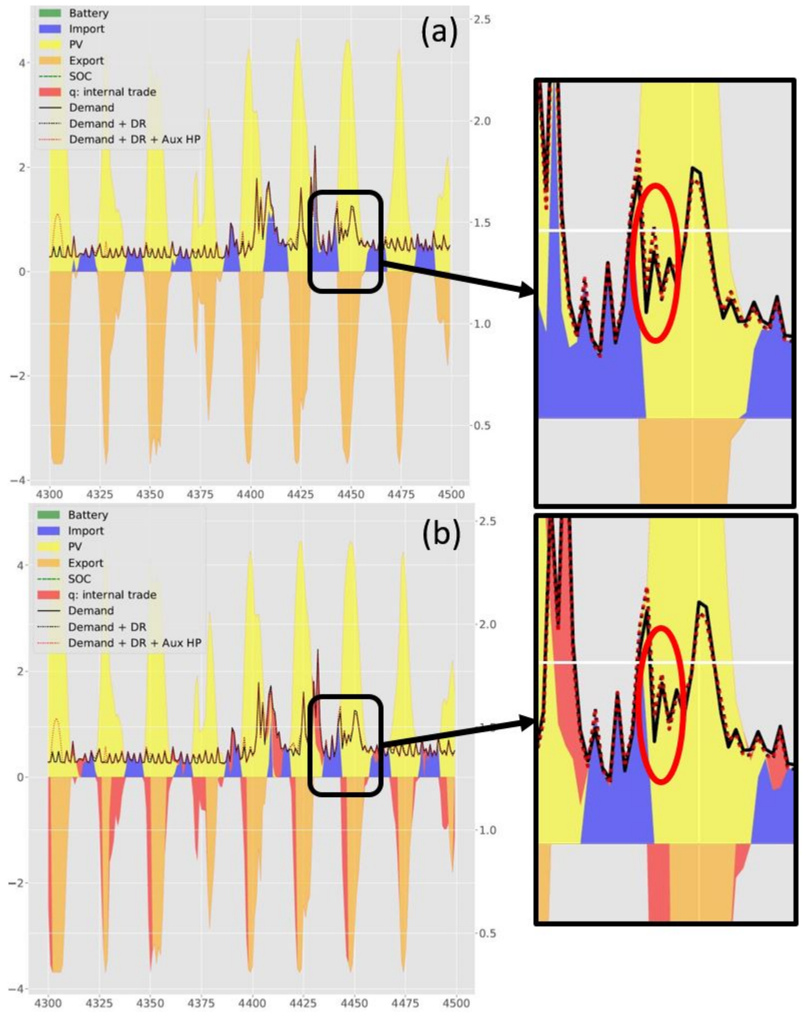


Figure 4.2: DR reduction when enabling internal trade. (a): a building behaviour when internal trade is off, (b) the same case but when the internal trade is on

the amount of increase in batteries, we expect that this is not the only reason why DR is reduced in winter.

Another reason might be related to the power tariff. To have a better understanding over this behaviour, an analysis carried out on the behaviour when the power tariff is not imposed on the prosumers and the results can be seen in table 4.3 which shows increase in using of DR.

Table 4.3: The change in the DR usage when enabling internal trade (sharing) within the community- The case without power tariff

Composition	Season	DR usage change (%)
Reference district (18H-43L-39S)- no power tariff	Spring	+3.5
	Summer	+4.1
	Autumn	+2.0
	Winter	+4.2

In the case without power tariff, there is no power limit. Therefore, there's no need to make room for internal trade or more battery usage and they can happen at the same time in an increasing manner.

4.2.2 TES

The results from our reference area shows that the TES usage is changing as presented in table 4.4.

Table 4.4: The change in the TES usage when enabling internal trade (sharing) within the community

Composition	Season	TES usage change (%)
Reference district (18H-43L-39S)	Spring	-0.3
	Summer	-2.8
	Autumn	-0.7
	Winter	0

The decrease in TES usage is more noticeable in districts with composition 0H-0L-100S and 0H-50L-50S in summer and autumn. It has been observed that services type prosumers with lot of solar production in summer, would charge and discharge TES at the same time so that they can lose energy, or in other words curtail energy (figure 4.3). This behaviour happens because of the weekends when the load of the building is very low, however, the solar generation is very high and the building has no batteries. Therefore, these prosumers empty their TES (dump energy/curtailment) in order to be able to charge the TES with their auxiliary HPs. In this way they would be able to avoid paying high power tariff costs of exporting.

However, when the trading is allowed, it's observed that the prosumer would prefer not to dump the energy and instead use the auxiliary HP less and share its excess of production with other buildings in the community (figure 4.3). Such behaviour is the reason behind reduction of TES usage after enabling the internal trade.

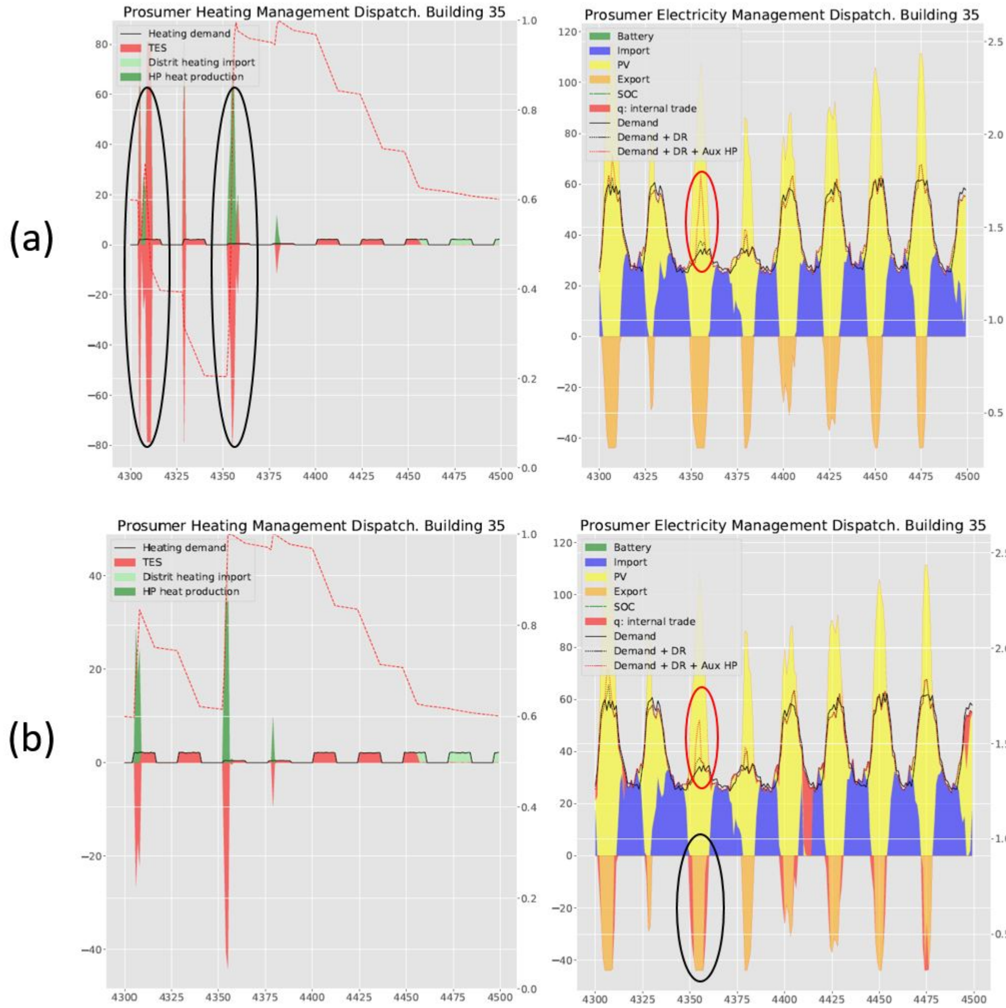


Figure 4.3: TES reduction when enabling internal trade. (a): a service building behaviour when internal trade is off, (b) the same case but when the internal trade is on.

4.2.3 Battery

The results from our reference area shows that the battery usage is changing as presented in table 4.5.

The reason for this increase in the sunny weeks (summer and autumn) is that the prosumers get access to each others assets and therefore it would be beneficial to store the excess energy in other prosumers' batteries. One guess about why the

Table 4.5: The change in the battery usage when enabling internal trade (sharing) within the community

Composition	Season	Battery usage change (%)
Reference district (18H-43L-39S)	Spring	+0.2
	Summer	+1.0
	Autumn	+3.0
	Winter	+0.4

increase is more in autumn is that in summer most of each prosumer is used for their own PV production, thus, not much capacity is left for the excess production of other prosumers.

4.2.4 Auxiliary HP

Table 4.6: The change in the auxiliary HP usage when enabling internal trade (sharing) within the community

Composition	Season	Aux. HP usage change (%)
Reference district (18H-43L-39S)	Spring	+0.2
	Summer	-1.2
	Autumn	0
	Winter	0

As it's observed (table 4.6) the behaviour of auxiliary HPs are not changing much with and without trading. The possible reason can be that these HPs operation are mainly dependant on the price difference of the DH and EL carrier. The only behaviour change is in the summer which is coupled with the change in TES behaviour and forced usage of HPs in order to consume excess energy and avoid the high power tariff costs.

4.3 Performance depending on district's size

By testing the size for the two compositions, it's observed that the electricity related KPIs which are not connected to heating KPIs would change less than 10%.

Therefore, it seems that different sizes of areas wouldn't change the electricity KPIs more than ±10%. However, since the other KPIs would change more than that, in

Table 4.7: Sensitivity analysis on size of the district. Values are equal to deviation of the size from the average of all three sizes for that KPI. Deviations $< \pm 5\%$, $< \pm 10\%$ and $> \pm 15\%$ are colored in green, black and red.

KPIs	100H-0L-0S			50H-50L-0S		
	Small	Medium	Large	Small	Medium	Large
Emissions (%)	-8,0	4,6	3,5	-1,5	-1,3	2,8
Cost (%)	-4,9	2,7	2,2	0,0	1,3	-1,3
self_{el} (%)	-7,0	3,6	3,4	-1,1	-2,5	3,6
$\text{self}_{\text{heat}}$ (%)	-35,8	67,3	-31,6	-82,1	85,1	-3,1
peak_{el}	-0,6	1,9	-1,3	-1,1	1,5	-0,4
$\text{peak}_{\text{heat}}$	-97,8	153,4	-55,6	-76,6	71,7	4,8
flex_{el} (%)	-8,3	-2,8	11,2	69,3	-27,3	-42,1
$\text{flex}_{\text{heat}}$ (%)	-7,8	-8,8	16,6	-9,3	-113,3	122,6

the composition analysis it has been tried to keep the size around 'Medium' in all compositions.

We guess that changes in the heating KPIs can be due to different reasons. First is the fact that the order of magnitude for heating KPIs are very small ($10^{-7} - 10^{-3}$) therefore very small changes in these KPIs would lead to large difference in form of percentage. Secondly, as it has been discussed in distribution repeatability, the distribution affects the heating side more which could be the reason for larger variations on heating KPIs. Moreover, as discussed in the TES and auxiliary HPs behaviour section, there are different solutions for dispatching heating and usage of the heating assets, and this can be another reason for variation in heating KPIs.

All in all, better conclusions can be made with revising the TES constraints, so that dumping energy won't happen through TES (by charging and discharging), and instead dumping energy happens at PV production with a curtailment flexibility parameter.

Another observation on the size was about how repeatability of the model improves with increasing the size of the district (figure 4.4) and it can be seen with increasing the size, the KPIs' variation will decrease.

This can be due to the effect from distribution of load curves and different assets and it can show that with increase in the size, the performance of the district won't be affected much, if there would be abnormalities like a large building with high capacity of assets. Based on this observation, better conclusions can be made if the size sensitivity analysis is done at a larger scale of districts.

Figure 4.4: Effect of the district's size on the repeatability of the model. The graphs are for 100H-0L-0S area and (S),(M),(L) represent small, medium and large size.

4.4 Performance depending on district's composition

Results from analyzing different usage type compositions shown in table 3.14 shows that the performance is different depending on the composition, season and each KPI (figure 4.5 and 4.6). A unique general trend hasn't been observed regarding if a specific composition is always performing better. However, on average the districts with more than one usage type show better performance with respect to the defined KPIs. These results can be seen in figure 4.5 and 4.6 and table 4.8.

Table 4.8: The changes in different KPIs with the number of usage types in the district. The change is the average over the seasons with respect to 1 type mix. Positive values represent improvement of the KPIs.

KPIs	**1 type**	**2 type**	**3 type**
Emissions	0%	38%	53%
Cost	0%	33%	34%
Self_{el}	0%	38%	51%
Self_{h}	0%	380%	47%
Peak_{el}	0%	6%	5%
Peak_{h}	0%	68%	-130%
Flex_{el}	0%	22%	-56%
Flex_{h}	0%	-75%	-88%

It can be seen in table 4.8 that the emission, cost, self EL and peak EL KPIs are getting better by moving from 1 usage type to 2 usage types. By moving from 2 types 3 types, emission and self EL is getting better; however, cost and peak EL doesn't change considerably. Thus, we can make the conclusion that the mix types has a better performance compared to singular usage types. The other KPIs are not discussed because of the reasons mentioned for the heating assets' behaviour in sections 4.1 and 4.2.

It can be seen that the cost savings are not considerable (figure 4.5). However, it is worth mentioning that the cost KPI depends on many pricing factors behind. For example, in our model the tax return policy is considered for local production without any limitation on the prosumer type and without any limitation on the size and amount of production. However, in reality the tax return policy is entitled to only households and limited by size of the production unit and the total yearly production. Therefore, in reality, prosumers gain much less in case of exporting to the grid. Thus, it's expected that the LEM concept shows better results regarding the cost KPI. To get a better insight, a case has been analyzed without any tax return policy and the results are presented in section 4.6.3 which shows 28% cost reduction in summer and 7% in autumn.

Generally, it has been observed that the different compositions show lower performance in cold seasons (spring and winter) and reacting very similar to each other. There can be different reasons for this behaviour. First, in these seasons the local production (PV) is very low and having local production has shown a great impact on the performance of local energy communities. Besides, at the same time the consumption is very high because of heating load which would make this production share even lower. Thus, basically the potential benefit is lower when sharing is allowed between different prosumers. Moreover, since a big part of the load is heating in these seasons and in our model heating trade and sharing is not possible between different prosumers, the potential benefit of the LEM concept is lower.

Another observation is that in Flexibility Heat KPI, a large reduction is observed. This has its roots in the behaviour of TES in services user type in sunny seasons. This behaviour is explained thoroughly in section 4.2.2. The emission KPI and EL self sufficiency KPI is directly correlated to how much the import from the grid has been reduced with enabling energy sharing between prosumers based on the definition of the KPIs in section 3.5 plus the fact that the energy source in the district is RES. The results demonstrate that in sunny seasons, the local production can be managed better if we have a district which is composed of different usage types.

Figure 4.5: All KPIs except peak KPIs for different district compositions in different seasons. Single type is the average of the districts with only one usage type. 2 type is the mixes with two usage types, etc.

Regarding the peak KPIs on electricity, mix of different compositions have a slight

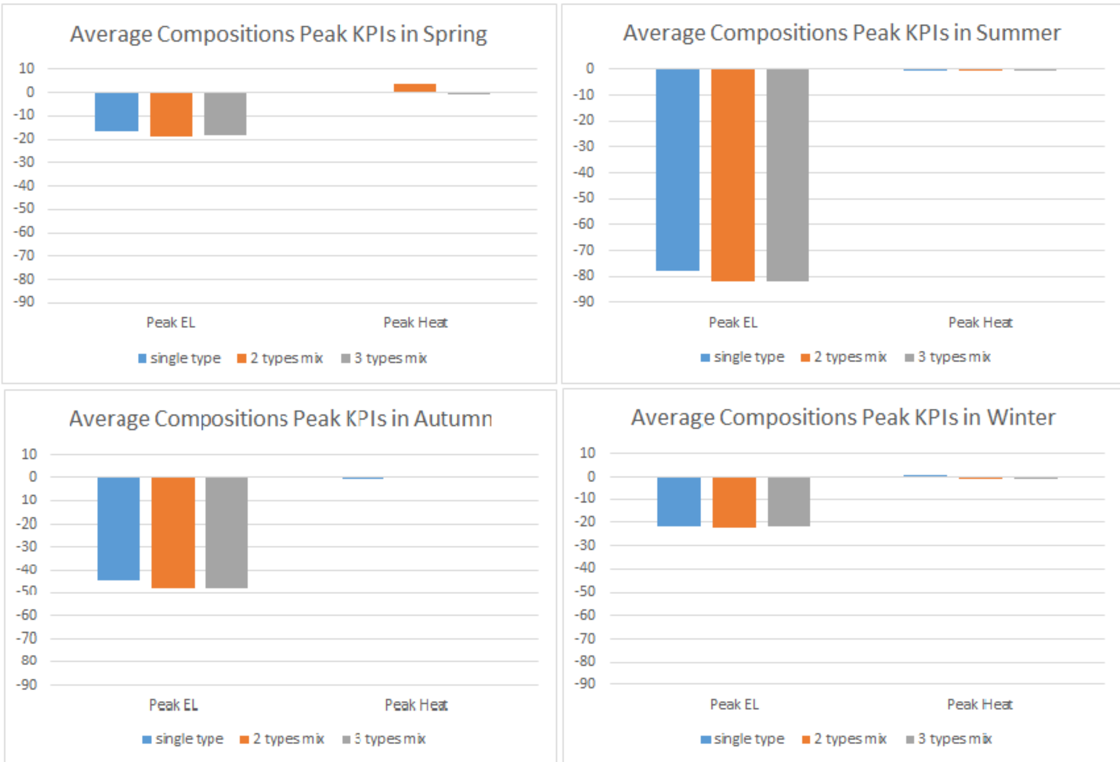


Figure 4.6: Peak related KPIs for different district compositions in different seasons. Single type is the average of the districts with only one usage type. 2 type is the mixes with two usage types, etc.

increase in performance (figure 4.6). However, the peak KPI on heating side doesn't show much difference or sometimes even increase in the peaks (figure 4.6). A possible reason behind this behaviour is the pricing signal of the heating which is not very dynamic and matching the city's DH load (figure 4.7). However, it can been seen in figure 4.7 that the EL price signal is matching pretty well the load of the city. All in all, since the assets react mainly to the financial signals and structure, a dynamic and local pricing would lead to more beneficial behaviour of prosumers.

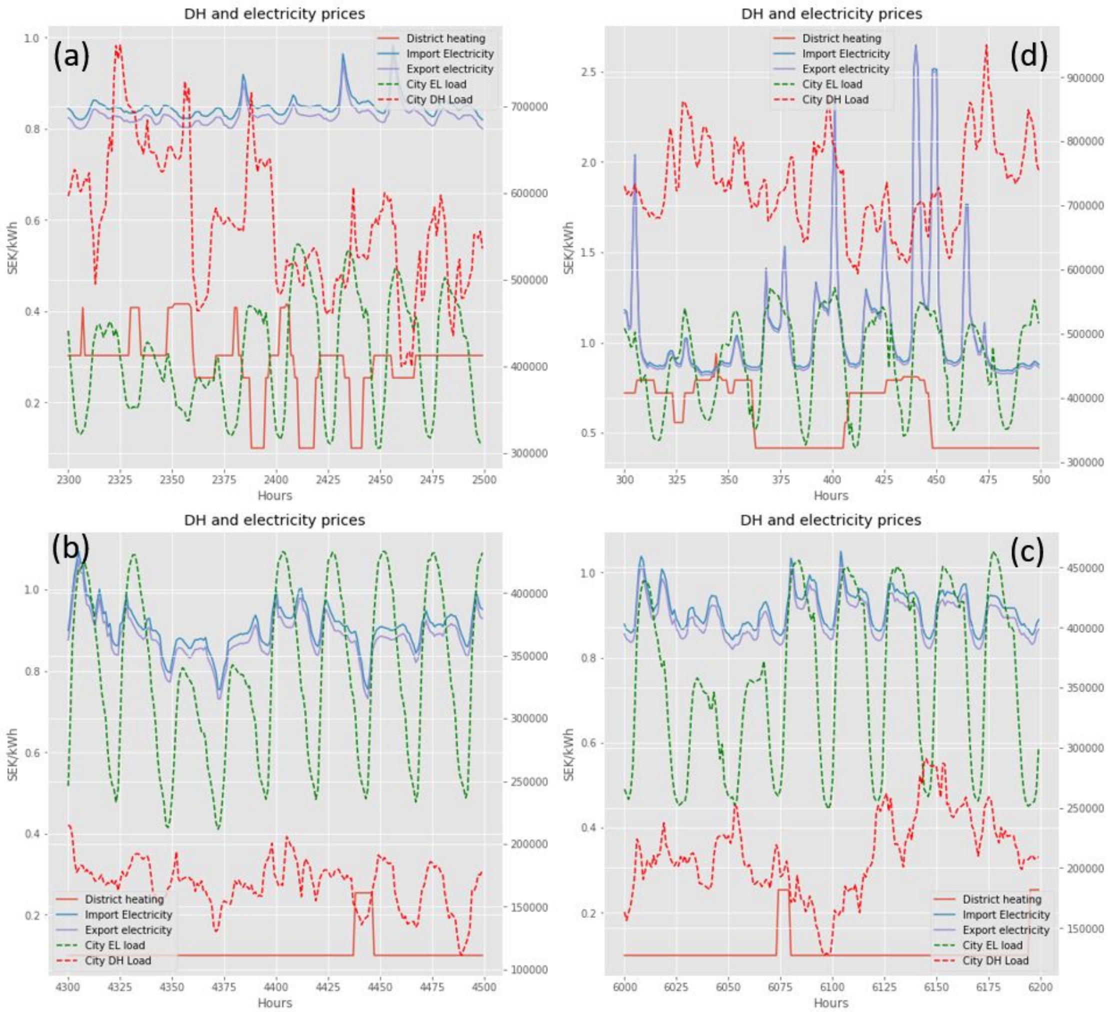


Figure 4.7: City EL and DH loads and pricing signals for these energy carriers for different seasons. (a) Spring, (b) Summer, (c) Autumn, (d) Winter

4.5 Behaviour under different assets' penetration level

The first step is to analyze how is each asset activated depending on the penetration level of the rest of assets. At the same time, this is related with the scenario summer, spring, autumn and winter.

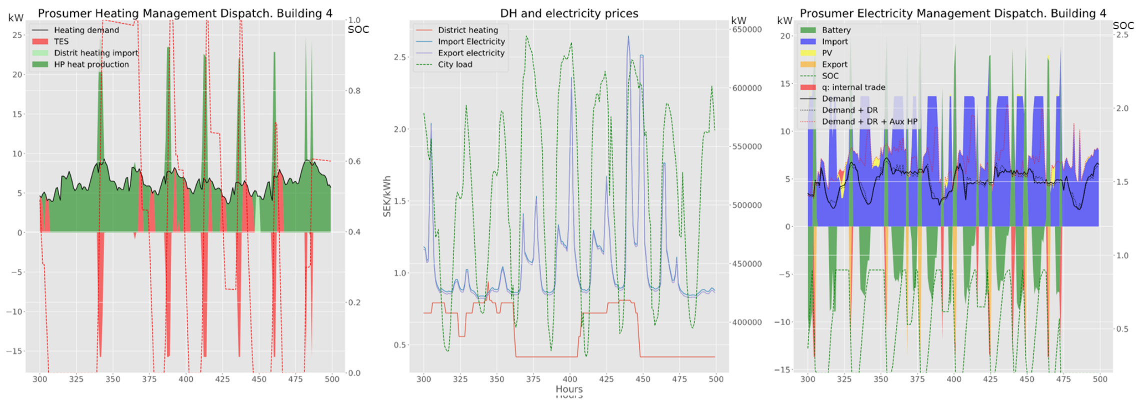
Figure 4.8: Asset's activation under different penetration levels

- PV: The PV generation matches perfectly the PV penetration. When the PV penetration is increased, so does the PV generation. Because PV generation is completely free in this model. However, there is a big difference between seasons due to the radiation profiles. For instance, having a 20% of the yearly load covered by PV generation (20% penetration) implies a PV generation of 784 kWh during a winter week and of 10611 kWh during a summer week.

- HP: The HP is extremely more used during the seasons with high heating load (spring and winter). It is interesting to note that when increasing the HP capacity, the output does not changed as much as for other assets. The output even decreases when increasing the capacity during spring. This is because the auxiliary HPs are dispatch only when the DH price is less than 3.15 (COP) times the electricity price; and that situation happens a limited number of times. So the HP use is determined by this price signals that are the same for all penetration levels. The other assets penetration increase the HP usage if they can provide cheaper electricity by producing locally (PV) or by shifting cheap electricity prices (Battery or TES). However, a high penetration level of TES when the DH price is low (spring), might reduce the use of HPs because the tank would instead be used to store heat from the DH when it is cheap and consequently using the HPs less. As a consequence, the HP usage decreases when increasing the TES penetration level during spring. This effect can be seen in figure 4.9. During the spring time, the DH price is smaller than 3.15 times the electricity price around the hours 2390, 2415 and 2430. Around these hours, heat from the DH is imported to cover the demand and to charge the

TES tank to its maximum capacity. The rest of the hours, the HP is used since electricity price is lower than the DH price times the heat pump's COP. In other words, the HP will be used as long as its cost is lower than that incurred when buying from the DH. Which taking into account the heat pump's COP results in $Price_{el} \cdot \frac{Demand_{heat}}{COP} \leq Price_{DH} \cdot Demand_{heat} \implies Price_{el} \leq Price_{DH} \cdot COP$. During the winter period, both DH and electricity prices are closer to each other and varying more often. In this case the HP is cheaper and therefore used almost all the hours to cover the demand and charge the TES tanks. As shown in figure 4.9, during the low electricity prices (for instance at hour 380) the HP fills the TES tank to discharge it during the high electricity price hours (during hour 400).

A. Spring



B. Winter

Figure 4.9: Dispatch output for electric and heating system with asset's penetration level of 40%.

That is why the HP are used the most and the DH import is low during winter. Furthermore, the HP cost is lowered during winter because of the big use of the batteries that provide the HP with electricity bought at cheaper prices.

- TES:

When the TES capacity increases, so does the TES usage. TES is used more during the seasons with high heating load and with big oscillations in the DH price. In order to see how much TES is used, the total amount energy used to charge TES is divided by the total TES capacity. This ratio represents which percentage of the total capacity has been charged. In figure 4.10, 100% means that the TES (tanks) has been charged once and 200% that it has been charged to its full capacity twice. It can be seen that for summer, spring and autumn when adding more capacity, this capacity is used even more. However, when increasing the TES energy capacity during winter, the percentage of the energy capacity that is used decreases. This might be because during spring, autumn and summer the TES is used during specific hours when the DH price is considerably lower and the tanks are then charged to its maximum capacity. As the DH import does not have a capacity limit, when adding more TES energy capacity, it can be used as much.

However during winter the TES is more often charged with the auxiliary HP that uses electricity. Therefore, it is possible that the auxiliary HPs capacity is not enough to charge the tanks completely during the low electricity price hours.

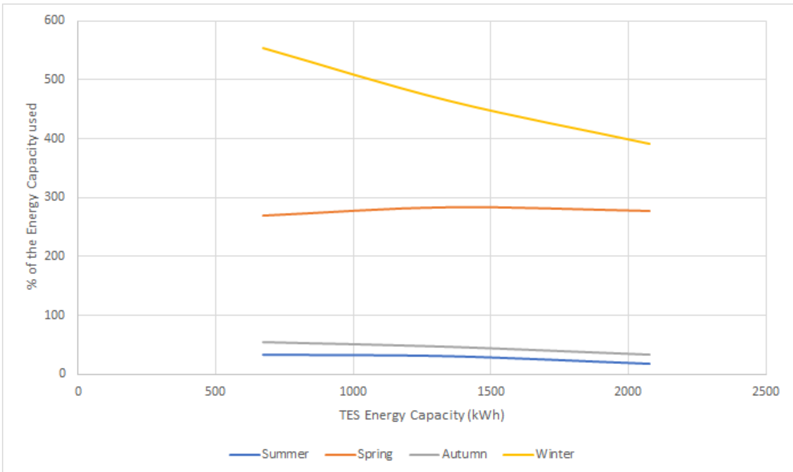


Figure 4.10: Total kWh of TES used for charging over the total capacity of the district.

Due to the TES formulation, the final state of the tank has to be the same as that at the start. This forces all buildings with tanks to at least cover the losses even though TES is not activated for its economical profitability.

- Battery:

Batteries are utilized the most during winter, as shown in figure 4.11. This is mainly due to the fact that the electricity price varies more during winter, making batteries more profitable. In figure 4.9 it is seen that the same building with the same assets capacity, uses the batteries much more during winter to store the electricity during the cheap hours and sell it during the expensive hours.

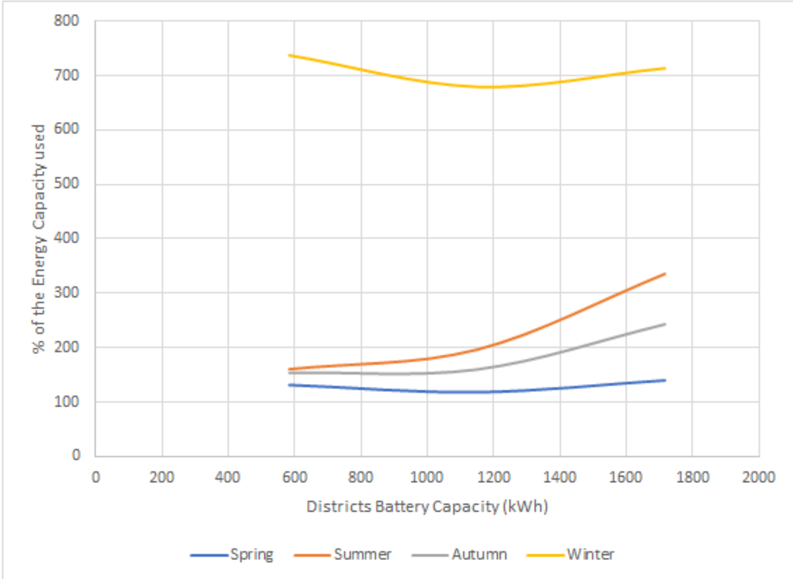


Figure 4.11: Percentage of the total energy capacity of the district that has been charged.

But it also affects that the DH price is high during winter and as a consequence the heating load is covered with electricity when possible, which increases the electricity demand.

The battery usage is related to the PV penetration level. In scenario 7 (PV penetration 60% and the rest to 20%) the batteries are used almost as much as when its penetration was 40%. In other words, without increasing the battery capacity and just by increasing the PV penetration, the battery usage increases. This effect is seen during spring, autumn and summer when the PV radiation is higher. It can be observed in figure 4.8, specially during summer. The reason is seen in figure 4.9 where the battery stores the buildings extra PV generation and the one imported from other buildings.

This effect is not seen during winter, because the PV generation is low and the batteries use is based on the price difference instead of on managing extra PV generation.

The second step is to analyze which are the consequences on import, export, internal trade and peaks from the behaviours found previously.

- Import electricity:

  The import of electricity is mainly affected by the PV generation. When increasing it, the import of electricity from the outside grid decreases.

  However, during the winter week when solar radiation is lower, the import of electricity depends on the battery use. The batteries are used to import and export electricity at different hours in order to earn the price difference between import and export. When the battery penetration level increases, so does the import. Which increases faster than the export due to the fact that the battery losses also become a bigger number.

- Import DH:

  The import from DH tends to decrease when PV generation is high, since then the HPs are run with the electricity generated from the PV panels. This effect is seen specially during summer in scenario 7. The DH import is lowest when having 40% penetration level of all assets for summer, spring and autumn, which corresponds to the weeks with highest PV generation. When the penetration level is 60% (scenario 3) the DH import does not follow the trend expected. It is expected to reduce the DH import as a greater part of the load could be covered by the electricity produced by the PV panels, however the DH import increases. One reasons behind this might be the power tariff which creates a higher cost when having a big PV generation and therefore a shift to the DH would reduce electric peaks. Another reason might be the big capacity available of batteries and TES that allows shifting the load along longer periods of times, making a more optimal use of the price changes. During winter, the DH import is related with the use of batteries, HPs and TES. When both three usages are highest, the DH import is lowest and vice-versa.

- Export of electricity:

  The amount of exported electricity increases with the PV penetration level for the sunnier seasons. While for the winter season more electricity is exported when the batteries are used more. Since the batteries are making profit of price differences, importing at low prices and exporting at high prices. This behaviour is true for all penetration levels. It should be noted that the exported amount decreases considerably between scenario 7 and 3. This is because when the other assets other than PV also have a high penetration level, they can absorbed the PV excesses and use them in other moments. The export peak is increased as the PV generation increases. When all penetrations are set to 60%, the export peak is reduced compared to only PV 60%, except for winter. During the winter week, the export peak is related to the battery use and therefore it is greater when the battery penetration is higher. The HP increases a bit the peak when having 60% penetration as it shifts load that was covered with DH to the electricity system.

- Internal trade:

  Looking at figure 4.12 it is observed a first increase in internal trade from increasing assets penetration from 20% to 40%. Which could be expected, mainly for the sunny seasons where the PV generation excess can be sent to the neighbour. Then, it reduces again with 60% penetration. A reason could

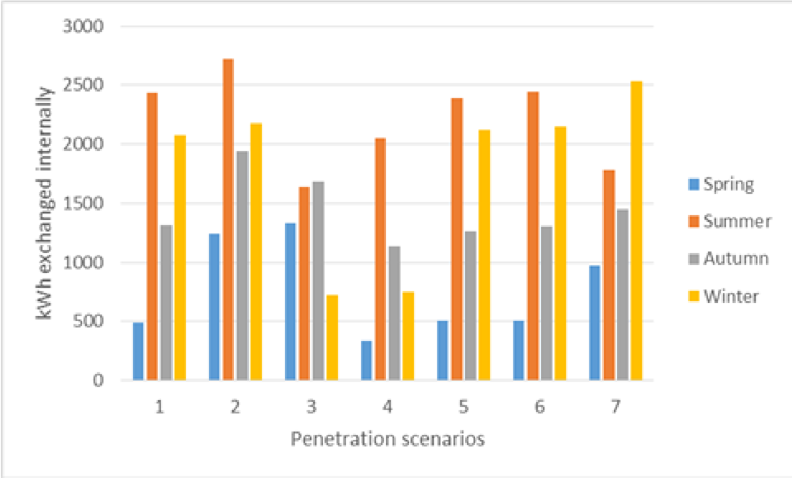


Figure 4.12: Amount of kWh exchanged internally for each scenario of the level of penetration analysis

be that when the internal rate reaches higher values the incremental function of gamma might become too big and therefore, exporting more beneficial than trading internally. This is why this effect is only seen in summer, autumn and winter when the internal exchange is higher. Another reasoning could be that this effect is a result of the power tariff. The peaks become that big that the power tariff fee starts to be the higher price of 44 instead of 23.8 SEK/kW month. As a consequence, internal exchange to use the neighbors flexibility units and reduce peaks is not needed anymore and instead more electricity is exported.

Regarding the last scenarios, the amount of exchanged energy is generally lower with 60% battery penetration and higher for 60% HP or TES penetration. When having 60% penetration, the internal exchange increases except for summer when it instead decreases. This might be because the PV generation is that big that more internal exchange is not needed as all flexibility assets or demand are covered and instead the electricity is exported. The final step is to see how the aspects commented above affect the LEM and the KPIs. It is seen that the KPIs related with the electricity system follow a similar pattern as the internal exchange graph shown in figure 4.12. The KPI for CO_2 is shown in figure 4.13 to show this relation. Note that the KPIs are calculated as reduction of emissions which means that all values are negative. When internal trade is high, the KPI will be better meaning that the number will be smaller. The two figures are mirrored.

As a conclusion, it is seen that scenario 2 was the scenario with the best LEM performance. Which corresponds to a 40% penetration level for all assets. It has almost the best performance for all seasons and for most of electric related KPIs.

It is worth mentioning that the KPI for cost reduction in scenario 3 had a

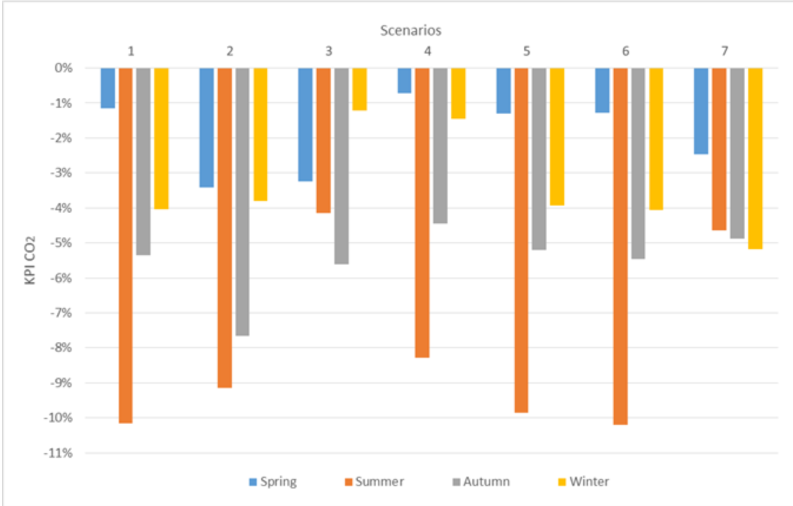


Figure 4.13: KPI for CO_2 emissions for each scenario and season.

positive value, meaning that cost increases when trade is allowed. Which could not be understand if considering that the optimizer could have chosen itself to not trade. As a consequence, one should take into account that in areas with high penetration level of generating units, the cost could be negative and therefore a positive cost reduction KPI means an increase in earnings.

4.6 Behaviour under different cost structures

4.6.1 Power Tariff

4.6.1.1 Analysis on power tariff's price

The power tariff price consists of two price levels of 23.8 and 44 SEK/kW month depending on if the fuse level is lower or higher than 44kW, correspondingly. When the price of the power tariff is increased (both price levels) the district is expected to reduce the peaks since they would cause a higher cost. The first behaviours that are true for all seasons are: both import and export electricity peaks are reduced, the total cost is increased and the amount of electricity imported and exported is decreased. The DH import increases as it covers the heating demand and allows reducing the electricity peak. As it could be expected there is a shift from electricity to DH. Because a higher power tariff means a higher electricity price which makes DH more profitable than electricity more often.

For spring and winter that have high heating loads, the energy imported from DH increases while the use of auxiliary HP decreases. In both seasons, there is shift from electricity to DH as a way of reducing the electric peak. However, this shift is done in different ways.

In spring, which has a low DH price, the TES is used more and it is charged importing heat from the DH network. Which increase the maximum peaks in the DH system (from 7kW to 14kW in a specific building). When there is no power tariff, the batteries create huge peaks by increasing drastically the import during the cheapest hours and the export during the most expensive hours (figure 4.14, left). However, this behaviour changes completely when the power tariff is activated and the use of battery drops rapidly. When the power tariff price increases, the battery use increases slowly and it is used to reduce peaks and flattened out the imports.

The internal exchange is lowest when there is no power tariff, since as peaks are not economically punished there is a big potential revenue from buying and selling at the cheapest and more expensive hour respectively. There is more benefits in importing and exporting than in trading internally, which has a cost which increases incrementally with the amount exchanged. But when the power tariff is in place the internal trade increases because batteries can not be use in the same way as before, because the peaks are punished.

When the power tariff is at its maximum price, the electricity becomes more expensive and the difference in cost between using DH or electricity becomes bigger. As a consequence, the DH import increases rapidly and the use of auxiliary HP decreases fast. As the energy is shifted to the heating system, the internal exchange decreases because it is only allowed for electricity. In other words, the internal trade is first decrease because peaks start to imply a cost and then it starts to go down again when the peaks become to expensive and the heating load is being covered with DH. As a consequence the KPIs and LEM performance are best when the power tariff is reduced 50% which corresponds to the highest internal exchange.

In contrast with spring, during winter the DH and electricity price are closer to each other which makes auxiliary HP cheaper than DH. This is why the auxiliary HP are used more during the winter week. The batteries are also used a lot due to the big variation in the electricity price. However, both assets are used less as the power tariff price increases and instead more energy is imported from the DH network. The power tariff increases the cost of electricity and not the DH, which makes that in more occasions the DH becomes more profitable. Regarding internal exchange, it increases slightly when the power tariff price increases. However, the differences are really small and as a consequence the KPIs and LEM performance is similar for all power tariff prices.

The summer seasons have a huge PV generation that dominates the behaviour. The low heating load is mainly covered by imported DH as it is cheaper during summer. When the power tariff price increases the peaks have to reduced and to do so it is not enough to shift to DH because of the big PV penetration. To handle the extra PV generation, batteries and auxiliary HPs are used. The battery use is very high when there is no power tariff because batteries are just used to import and export during the cheapest and most expensive hour to make profit.

As it can be seen in figure 4.14, when there is no power tariff the batteries create big peaks. Once the power tariff is on place, its use increases as the price increases. Because each time it is more beneficial to reduce the peak and the batteries achieve this by moving the demand and flattering the imports. The internal trade also helps handling the extra PV generation that does not happen at all buildings at the same time. This is because the buildings have different orientations and therefore the solar radiation is not at its maximum at the same hour for all buildings. It can be seen in figure 4.14 that buildings import internally during the hours next to the PV generation hours and export internally when it is generating from its own PV. As the internal trade is higher when the power tariff is higher, the KPIs and LEM performance are also best at that situation.

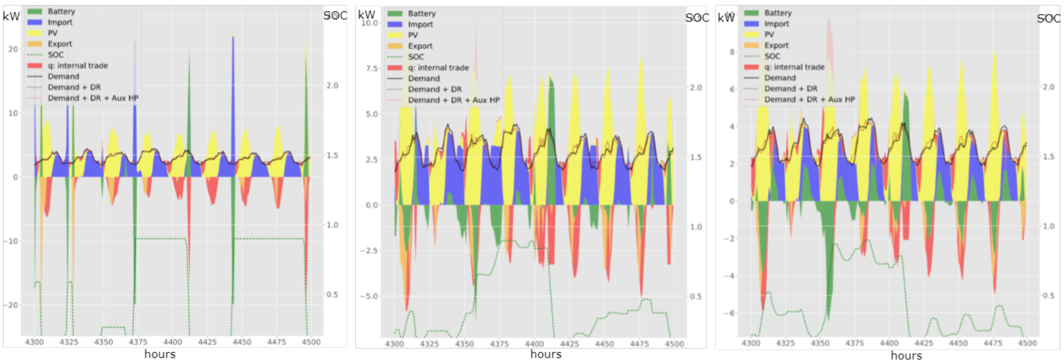


Figure 4.14: Electricity dispatch for a building during summer with: no power tariff(left), 50% of the initial power tariff price (centre) and the initial power tariff cost(right).

Autumn is very similar to summer but then the solar production is lower and there is more heating demand. This is why the extra PV production is managed by increasing the auxiliary HP and the internal trade is indeed decreased.

4.6.1.2 Power tariff for the whole district

The effect of this new power tariff set up on the import and export peaks, the amount of energy exchanged internally and the assets dispatch is investigated in this section. Special attention is given to how the effects change when changing the power tariff level at which the price becomes more expensive.

Figure 4.15 shows how the peaks change when changing the level of the power tariff during spring.

When the level is low, all peaks are over the set power tariff level (which means

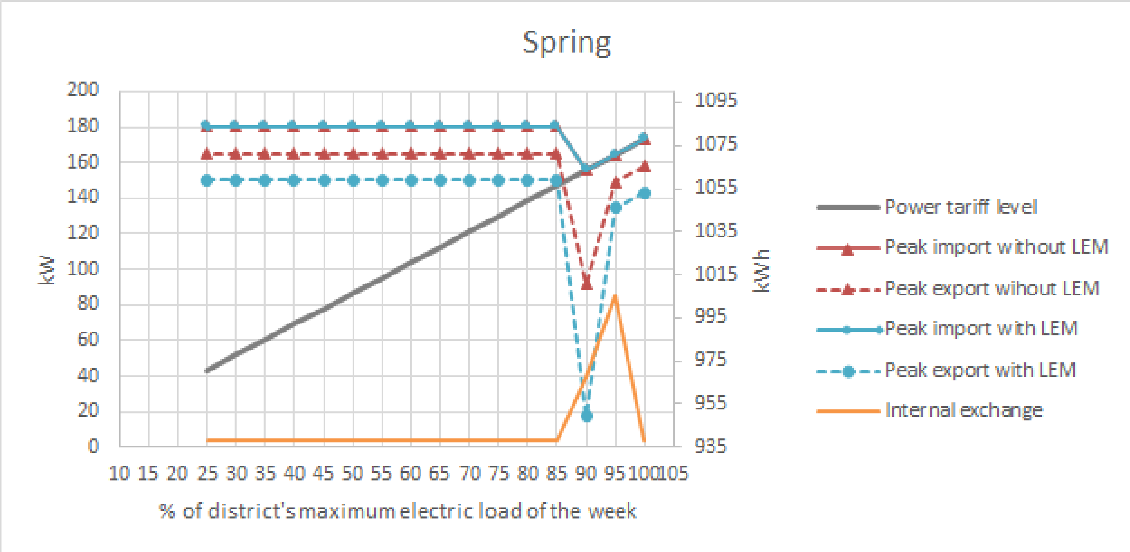


Figure 4.15: District import and export peaks behaviour with and without LEM.

that the power tariff price paid is already the higher one of 44 SEK/kW month. The level is that low that the import peak needs to be over it in order to cover the demand. However, when the power tariff level increases it becomes possible to reduce a bit the district peak by increasing the use of batteries, TES, DH import and internal trade. The export peak is decreased because the internal trade increase and because when using more flexibility units, the losses increase. This way, the highest peaks are flattened just enough to stay below the power tariff level and pay the lower price.

It is also observed that the export peak is kept always lower than the import peak, which shows that the import peak is the one limiting and that the spring season has low local generation.

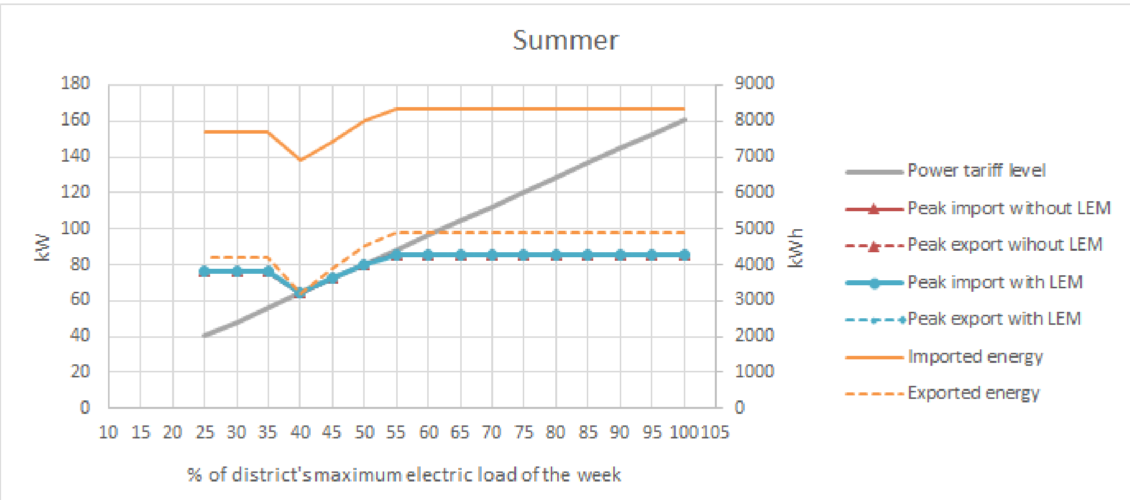


Figure 4.16: District import and export peaks behaviour with and without LEM.

During the summer and autumn period the PV generation is very big and therefore the export peak is the one limiting. Figure 4.16 shows how the import and export peak are overlapping for all power tariff levels. When the limit is low, the district peak is kept over the limit as it might be too costly or impossible to reduce the peak to such a level. When the level increases, the district peak is decreased so to be just below the power tariff level and pay the cheaper price. The way it decreases the peak is by dispatching the auxiliary HP. When there is no option to be below the power tariff level, the energy from the PV panels is exported and the heating covered with DH.

When it becomes possible to be below the power tariff level, the export peak is reduced by using the energy from PV to run the auxiliary HP. The batteries and TES are also used extra when the export peak follows the power tariff level, since they help moving part of the demand and shaving the peaks.

When the power tariff continue increasing, the export peak of the districts stays constant. The district optimizer finds a new stable point below the power tariff level, where the price is always the lower one. It is noted that the peak stable point is higher when the peak is below the power tariff level than when the peak is over the power tariff level. This is due to the fact that when being above the power tariff level, the power tariff price is the more expensive one and therefore the optimum dispatch has lower peaks.

Winter assembles the spring behaviour because both seasons have low PV generation and high heating load. However, during winter the DH and electricity prices are closer and the electricity price varies a lot. That is why the batteries are more profitable and therefore more used during the winter period. Due to the high use of batteries, the import and export peaks are much higher than the 100% of the maximum electric load of the district. Consequently, the power tariff level does not affect the dispatch during the winter season.

4.6.2 Internal exchange

From changing the percentage of the grid tariff paid when exchanging internally, figure 4.17 is obtained. It shows at which point the internal exchange increase drastically for each season. This fast change is because the internal trade becomes beneficial when its cost is lower than the difference between import and export. If the cost of trading internally is higher, the prosumers would rather export their over production than send it to another participant. The prosumer will only send to another participants if the avoided cost from not importing that energy is higher than the export and the internal exchange cost together.

For all seasons the exchange start when the grid tariff cost considered is between 8% and 4% of 0.31 SEK/kWh. As the difference between import and export electricity

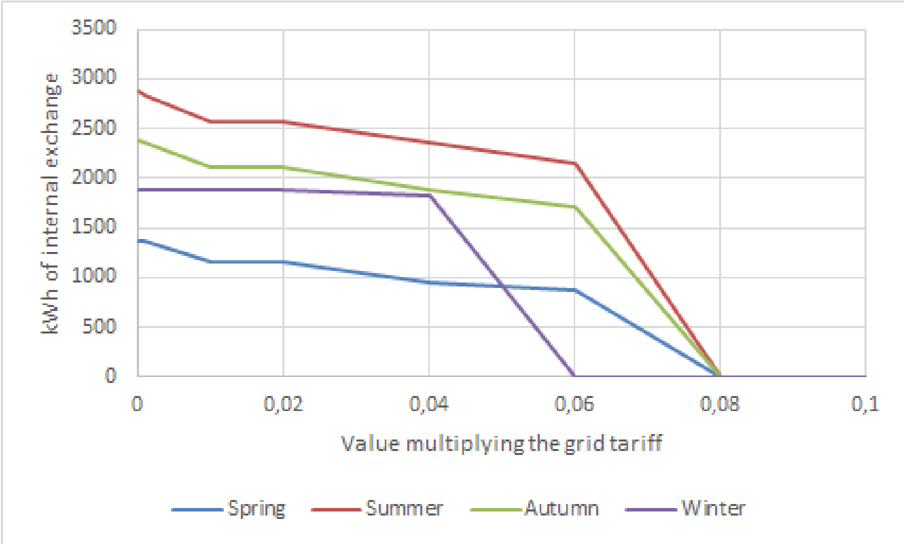


Figure 4.17: Amount of kWh exchanges internally for different percentages of the grid tariff cost

price is different at each season, it is expected that the exchange starts at a slightly different percentage of the grid tariff. Therefore, a new study using smaller steps was carried on to find the exact percentages at which the internal trade starts. The exact percentages values are presented in Table 4.9. Where the average difference between import and export for each season are presented. Winter has the smallest difference, 0.01575 SEK/kWh, which means it will require the lowest grid tariff cost to make internal exchange profitable.

Table 4.9: Average price difference between import and export in SEK/kWh and percentage of the grid tariff at which the internal exchange starts for each season.

Season	Price difference (Import - Export)	% of grid tariff 0.31 SEK / kWh	Resulting internal grid tariff (SEK / kWh)
Spring	0.0199	6.4	0.064x0.31 = 0.0198
Summer	0.0232	7.4	0.074x0.31 = 0.0229
Autumn	0.0225	7.2	0.072x0.31 = 0.022
Winter	0.0157	5	0.05x0.31 = 0.0155

In Table 4.9 shows the exact point at which the internal exchange starts for each season. The trade starts exactly when the difference between import and export equals the grid tariff cost. Therefore, when the price difference is small, as in winter, the percentage of the grid tariff will need to be smaller, 5%. Whereas when the price difference is bigger, as in summer, the percentage of the grid tariff can be a bigger, 7.4%.

The incremental function makes the internal exchange more expensive when the amount exchanged is bigger. This way the optimizer prefers to exchange a bit with each building instead of exchanging only with one, spreading the internal exchange more uniformly. However, this extra cost might cause some internal exchanges to not happen. Therefore when activating or deactivating the incremental function, the cost and amount of electricity exchanged was analyzed.

The amount of kWh exchanged internally was the same both having the incremental function and without it. Except for summer, where the internal exchange decreases 0.23% when activating the incremental function. The internal exchanged cost was increased less than 1% when activating the incremental function for all seasons. The assets use was kept constant from a district perspective. Looking at each individual building, the imported electricity from the community changed. It is shown in figure 4.18 that building 23, reduces its import drastically when implementing the incremental function. The electricity that building 23 does not import anymore is instead distributed among the rest of buildings.

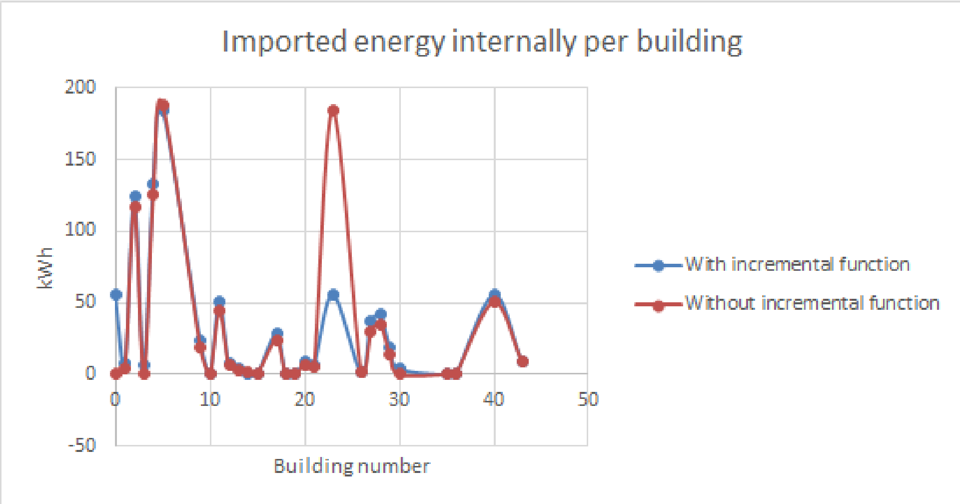


Figure 4.18: Imported internal electricity (kWh) per building during winter, with the incremental function in place and without.

4.6.3 Tax return

The main trends that are true for all seasons when disabling the tax return are: the amount of imported electricity decreases and the amount of electricity exchanged internally increases, as shown in figure 4.19.

A way of interpreting these results is thinking that if the selling price of electricity decreases, the prosumers prefer to share their over production instead of exporting. This result relates to the one obtained in the previous chapter. If the difference between import and export price is bigger (decrease in the export price), the internal exchange increases as it becomes more profitable.

There are two different behaviours regarding how the assets react when disabling the tax return. Spring and winter that have low PV generation react in one way, while summer and autumn that have big PV penetration react differently.

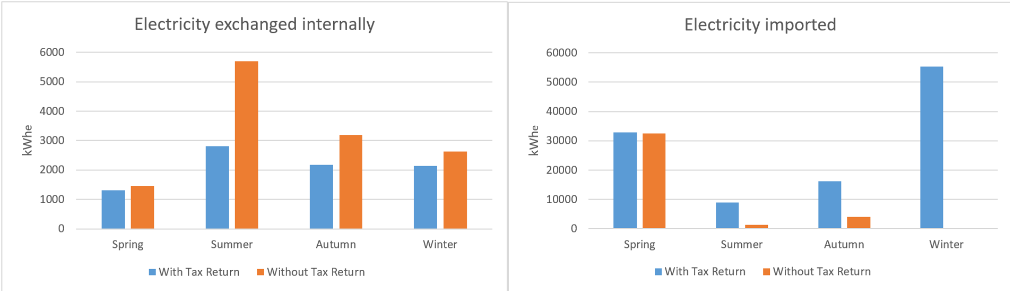


Figure 4.19: Difference in kWh_e exchanged internally and imported from the grid between having or not the tax return policy in place.

The seasons with high local generation, increase the use of batteries when disabling the tax return. As they get paid less when exporting the electricity, it is instead used internally. The batteries store the locally generated electricity during the sunny hours to use it during the afternoon when the demand is still high but the solar radiation decreases. Regarding auxiliary HP and TES, both increase when disabling the tax return. As said before, the local generation is now used internally and as a consequence all flexibility units are used more instead of exporting that electricity.

The seasons with low local generation, decrease the use of batteries. In this cases the generation do not cover the full demand, so when disabling the tax return, the generated electricity is exchanged internally and consumed in real time to cover the demand. While before, it was stored in batteries to be sold during high price hours. Regarding the auxiliary HPs behaviour when removing the tax return, their use decreases in spring while it increases in winter. The opposite behaviour is seen for TES and DH import, that increases in spring and decreases in winter. This behaviours might be related to the fact that DH is cheaper during spring while electricity is cheaper during winter.

5

Conclusion

According to the results from our model, it has been observed that the following factors have a noticeable impact on the behaviour and performance of the local energy community concept:

- The amount of local production
- The cost structure and especially the difference between the export and import prices, power tariffs and grid fees.
- Price signals
- Composition of the area

The results has shown in case of availability of local production (in this case PV production in sunnier seasons) the performance of the local energy community is better from technical, economical and environmental perspectives.

It has been observed that the pricing structure has a big impact on the behaviour of the prosumers and as a result the performance of the local energy community. Policies like tax return on local production would affect the price difference between export and import to/from the grid which could be optimized in favor of the grid situation. Due to the simplifications in modelling this policy, in reality it's expected that the cost savings and the performance of the local energy community would be better in comparison to our model.

Moreover, the grid fee on internal trade (exchange) has shown a great impact on willingness of the prosumers to participate and exchange energy with each other. Also, it has been observed that the power tariff costs is a big part of the prosumers' costs and affecting their decision for dispatching their assets.

Another observation was the importance of locally adjusted and more real-time price signals which are matching the city's demand especially on the DH side. In this case the behaviour of prosumers would be better aligned with the expected benefits of the local energy communities implementation.

Regarding the composition of the district, it has been observed that the districts with more usage types have better performance especially in seasons with high local energy production.

With the tested sizes, the electricity KPIs hasn't shown much variation when changing the size of the district. However, results show that the variations in different runs of the same district would decrease with increase of the district's size. It is worth mentioning that further a study is needed for analyzing much bigger areas and see the rebound effect of the local energy communities on the outer grid.

5.1 Assumptions and limitations

In this chapter a list of assumptions or limitation of our model is presented. They are mentioned as they might have affected the results obtained and could also be a starting point when doing further studies with the model.

5.1.1 Demand related

One limitation is usage types codes and that commercial and offices are all categorized as services. The other limitation is that industry usage types are not included and in case of selecting an area with industrial users, they would be omitted from the users and assumed that they don't exist.

The electric load profiles are taken either from a sample with many different profiles or from a single representative load that is hourly randomized. As real measurements from each area are not available and the goal with the model is to be general, this approximation had to be made.

The electric energy intensity (kWh/m2) is considered the same for all buildings with same usage type, using an average value for the whole Sweden. The electricity demand of Gothenburg is from year 2016 while the prices from 2012. Peak reductions are driven by price signals but the KPI for peak reduction are weighted with the Gothenburg load.

5.1.2 Model related

The assignment algorithm chosen are not optimized, one could instead distribute the assets so to get the best LEM performance.

Model doesn't consider any costs related to investments and it's just been built to analyze the behaviour of the community and users.

All technologies used are simplified. For instance, the temperature dependence of the PV panel performance is not considering. The starting and finishing state for battery and TES are considered to be the same, though in reality those levels will depend on the week and would change when modelling more than one week.

The model do not include the modelling of the power or district heating network. This mean that the power flow and its constraints are disregarded for simplicity and focus on a system perspective.

5.2 Future study suggestions

Due to the complexity of the system and the breadth of the topic, lot of more interesting aspects can be studied and analyzed. However, because if the time limitation, it wasn't possible for the scope of this study to address all of these aspects. Therefore, as a suggestion for future studies, the following topics can be interesting to look at:

- Study for other cities and countries with different weather and load patterns
- Effect of different local energy communities on each other when they implemented beside each other
- Rebounding effects of the local energy communities on the bigger system in case of considerable implementation's extent
- If orientation is affecting the results a lot, then in high penetration of panels, improvements are needed in orientation assignment.
- Hot water load curves for services can be improved.
- More detailed analysis on penetration level of different assets
- Addition of more production types to the system e.g. micro CHP units
- An analysis on the effect of more locally adjusted and real-time pricing signals
- An analysis on the performance of local energy communities with future energy prices and scenarios
- An analysis of the concept considering the integration of EV into load and availability of car-to-grid technology

- A study to find out which is the best way to distribute the assets so to achieve the best performance

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