DTU Wind

Standardization of local flexibility markets through capacity limitation services

Shahatphong Pechrak

DTU Wind-M-0644

July 2023

Author: Shahatphong Pechrak

Title:
Standardization of local flexibility markets through capacity limitation services

DTU Wind and Energy Systems is a department of the Technical University of Denmark with a unique integration of research, education, innovation and public/private sector consulting in the field of wind and energy. Our activities develop new opportunities and technology for the global and Danish exploitation of wind and energy. Research focuses on key technical-scientific fields, which are central for the development, innovation and use of wind energy and provides the basis for advanced education.

DTU Wind-M-0644
July 2023

Project period:
January - July 2023

ECTS: 30

Education: Master of Science

Supervisor(s):

Charalampos Ziras
Zhe Chen
DTU Wind and Energy Systems

Remarks:
This report is submitted as partial fulfillment of the requirements for graduation in the above education at the Technical University of Denmark.

Technical University of Denmark
Department of Wind and Energy Systems
Frederiksborgvej 399
DK-4000 Roskilde
www.wind.dtu.dk

Abstract

The transition towards a sustainable energy future has created a pressing need to integrate renewable energy sources and effectively manage distributed energy resources (DERs). However, the growing adoption of DERs, including electric vehicles (EVs), presents challenges such as congestion and reliability issues in distribution networks. To address these challenges, local flexibility markets (LFMs) have emerged as a promising solution, allowing distribution network operators to access flexibility products and alleviate network congestion.

This thesis focuses on studying LFMs in distribution networks with a specific emphasis on capacity limitation services (CLS) products. The research investigates market clearing methods, settlement processes, and market timelines to optimize the utilization of flexibility resources. Building upon lessons learned from various LFMs, the study introduces LFMs with CLS design options, prioritizing metering points and market participants as essential factors.

Two options, namely aggregated and disaggregated metering, are presented and analyzed using scheduled services and all-time services. By utilizing historical data from 200 households and EVs, a 24-hour load profile with 96-time steps is generated to simulate network congestion. CLS cases are studied based on requests from distribution system operator (DSO) and availability from flexibility service provider (FSP).

Results demonstrate that aggregated metering effectively separates non-participating loads, creating available capacity for participating households and EVs. Disaggregated metering, incorporating sub-meters, further identifies non-participating and non-flexible loads, enabling more accurate allocation of capacity.

Cost analysis reveals that employing disaggregated metering with all-time services represents a reasonable approach, despite the associated higher costs. Simulation experiments conducted with data from different months validate the effectiveness of congestion management strategies, especially when leveraging the highest consumption month of the year. However, increased consumption and fluctuating spot prices significantly impact costs.

Market clearing simulations, employing auction-based mechanisms between DSO and FSPs, highlight the feasibility of pay-as-bid pricing with true cost bidding. Continuous-based markets are proposed for FSPs-to-FSPs interactions, offering valuable insights to provide more incentives for market participation.

In conclusion, this thesis provides insights into implementing CLS in LFMs to manage network congestion. The findings contribute to the standardization of LFMs and emphasize the importance of selecting appropriate market mechanisms to achieve desired outcomes.

Keywords: Local flexibility market, distribution networks, capacity limitation services, market clearing methods, distributed energy resources, network congestion, electric vehicles.

Preface

Preface

This thesis marks the culmination of my research journey for MSc. in Sustainable Energy under the supervision of Charalampos Ziras and Zhe Chen with the work being carried out between January 2023 and July 2023 at the Department of Wind and Energy Systems at the Technical University of Denmark. This thesis constitutes the work of 30 ECTS points.

Acknowlegdment

I am deeply grateful to my supervisors, Charalampos Ziras and Zhe Chen, for their invaluable guidance and support throughout this research. I would also like to express my appreciation to the faculty and staff of the Technical University of Denmark for fostering a stimulating academic environment. I am grateful to the participants and contributors who generously shared their time and expertise, enabling the collection of valuable data. I extend my gratitude to my family and friends for their unwavering support and love. Their encouragement has been a constant source of inspiration. Undertaking this project has been a challenging yet rewarding experience, allowing me to delve into the intricacies of the local flexibility market and contribute to the existing knowledge. With pride, I present this thesis, hoping it lays the foundation for future research and innovation.

Shahatphong Pechrak

Kgs. Lyngby, July, 2023

Contents

List of Figures

List of Tables

Acronyms

BLS baselines services.

CLS capacity limitation services.

DER distributed energy resource.

DN distribution network.

DSO distribution system operator.

EV electric vehicle.

FSP flexibility service provider.

HP heat pump.

ICT information Communications Technology.

LEM local energy market.

LFM local flexibility market.

PAB pay-as-bid.

PAC pay-as-clear.

PCC point of common coupling.

TSO transimission system operator.

UP uniform pricing.

VCG Vickrey–Clarke–Groves.

WTA willingness to accept.

WTP willingness to pay.

CHAPTER 1

Introduction

This chapter presents the background, motivation, and objectives of the thesis including, the thesis outline.

1.1 Background

Climate change is listed as a high-priority threat that affects all regions around the world in many dimensions. It is well known that the main driver of climate change is greenhouse gas emissions produced by human activities, while carbon dioxide (CO_2) is the largest contributor to global warming. With concern about climate change, intensive measures are being implemented in many regions. According to the European climate law, EU countries must cut greenhouse gas emissions by at least 55% by 2030. Their goal is to make the EU climate-neutral by 2050 [1]. The International Energy Agency (IEA) reported in 2021 that the biggest increase in CO_2 emissions by sector occurred in electricity and heat production [2].

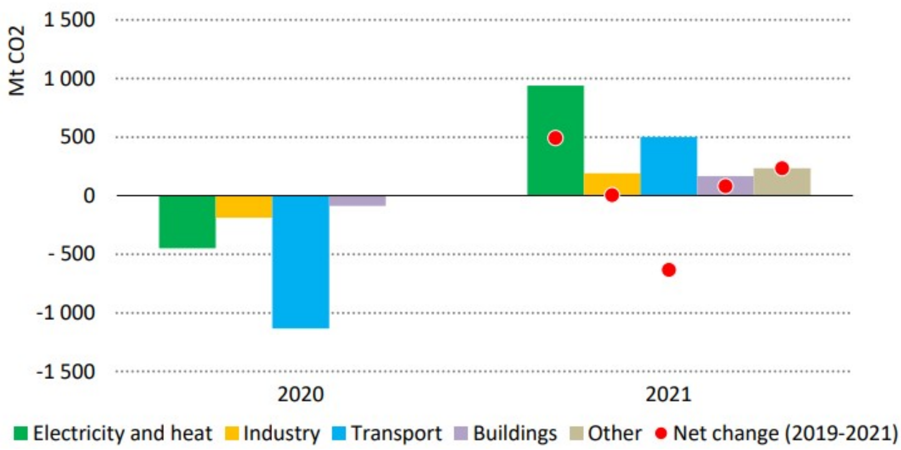

Figure 1.1: Annual change in CO2 emissions by sector [2]

Note. Reprinted from “Global Energy Review: CO2 Emissions in 2021”, by International Energy Agency, 2022,p.6 [2]

In Europe statistics from the European Commission for the second quarter of 2022 show that the energy sector was responsible for about 19% of total greenhouse gas emissions [3]. Therefore, reducing greenhouse gas emissions in the energy sector will lead to significant progress towards achieving climate targets.

To achieve this, energy production from fossil fuel-based generation must be replaced by low-emission energy generation sources. According to the IEA roadmap for the global energy sector's net-zero target by 2050, wind and solar power will be the two biggest sources of renewable energy in total energy generation [4]. Wind and solar power have been widely used in many areas around the world for decades because there are no fuel costs, and the technology for these sources is progressively developing, reducing investment costs. Following the trend of renewable energy, small-scale non-dispatchable renewable energy sources called DERs are accessible for household users, which increase the uncertainty of electricity supply. On the other hand, in Europe, the IEA forecasts that electricity demand will grow by around 14.7% by 2030 compared to 2021 based on the stated policies scenario [5]. The need for electricity is the result of the energy transition and electrification. One of the main factors accelerating electrification is the transition in the transportation sector from fossil fuel-based vehicles to EVs. Without any measures, the uncertainty of the supply side, together with the rising demand in DNs would lead to network congestion problems. Network congestion is a situation where network transfer conditions are violated by an abnormal level of active power, resulting in an overload of network equipment and often excessive voltage limits violations. In general, congestion problems can be solved by load shedding for over-demand and curtailment for oversupply in the short term, while network reinforcement such as increasing equipment capacity and installing auxiliary equipment would be long-term solutions. However, these solutions have many drawbacks for network stakeholders. For instance, in the DSO side, activating load shedding and curtailment entails high compensation costs, while upgrading equipment would lead to very high investment costs. The development of information Communications Technology (ICT) provides the ability to access and control devices on the end-user side such as DERs and EVs, which is known as flexibility. Flexibility can be utilized in many congestion management solutions such as demand response, capacity allocation, dynamic tariffs, and LFMs. ENTSO-E has mentioned that grid flexibility procurement needs to be emphasized, and DERs should be able to sell their services to contribute to their profits. To promote market-based solutions, LFMs could be an interesting solution. LFMs are platforms that allow DSOs to use market-based methods to access flexibility and mitigate network congestion, while customers can benefit by selling their services to the market. LFMs can provide benefits to all market participants, but a vital feature of LFMs is the need for transparency, along with clear service definitions and a market setup that provides the right incentives. There are several LFMs proposals or implementations in different areas with many design options, such as activation/reservation, traded services, timeframes, and market clearing. Two types of services have been introduced: BLS and CLS. Most of the projects employ BLS as the main methodology, but it has been criticized for causing market failures, including being incompatible with the active participation of DERs in the wholesale market. Thus, CLSs appears to be a more appropriate solution. In addition, a proper market-clearing method would provide satisfactory outcomes for all market participants, promoting the development of LFMs in the future.

1.2 Motivation

The objective of this thesis is to propose market-based solutions for congestion management in DNs that reduce overall system costs and increase social welfare. To prevent gaming issues, alternative services for LFMs using CLS are introduced, that various aspects of providing these CLSs have not been clarified and studied. Prior LFMs projects are analyzed for inspiration and guidance. Market design should account for the different perspectives of market parties, such as DSOs, aggregators, and market operators. Market clearing mechanisms used in previous LFMs projects and other electricity markets will be simulated to develop appropriate models for LFMs with CLSs. LFMs should support decentralization by enabling small-scale units to sell their services and maximize profits, not just large-scale flexibility

1.3 Project Objectives

The main goal of this thesis is to apply CLS for LFMs instead of BLS. Market scenarios based on historical data will be simulated with two different market clearing methods: auction-based methods and continuous-based methods. Finally, the market outcomes of the simulation will be discussed and evaluated to be standardized for the future LFMs.

This project focuses on the following specific objectives developed along the report:

- Review market clearing methods for LFMs.
- Introduce an auction-based and a continuous-based clearing in different market timelines with different settlements.
- Study on an application of CLS.
- Create market scenarios using historical data.
- Compare different mechanisms' outcomes regarding participants' cost and social welfare.

1.4 Outline

This thesis is divided into five chapters. Chapter 1 presents the motivation and project objectives. Chapter 2 the literature reviews of relevant research. Chapter 3 presents market design options for LFMs with CLS based on lessons learned from previous studies starting from CLS determining until market clearing mechanisms. Chapter 4 presents study cases formulated from selected market design options by simulation using real historical data. Chapter 5 presents the final conclusion as well as future work.

CHAPTER 2

Literature Review

This chapter explains the concept and goal of local flexibility markets. Then, service procurement methodologies that were employed in the existing local flexibility market are discussed. After that, local flexibility markets that were implemented in different areas are introduced in terms of structure and service employment. Finally, some critical points from different projects on baseline services are presented.

2.1 Purpose of local flexibility markets

The concept of LFMs has been introduced many years ago, and it is one of the market-based methods developed to mitigate congestion problems in DNs. In their study, Jin et al. [6] provide a review of the LFMs concepts. LFMs are defined as platforms used to trade flexibility in specific areas within the power grid layer of DNs. Flexibility is defined as the ability to change load patterns based on control signals, with the ability to control the direction, capacity/amount, time, and location. With the characteristics of market-based methods, exchanging flexibility services in LFMs can provide benefits to all stakeholders and promote market competition. For DSOs, buying flexibility services can solve congestion problems instead of relying on network reinforcement, while end-users can make profits by selling their services. The authors also summarize the types of LFMs into four different categories (shown in figure 2.1), and present key features of each market model. Each model has different benefits and drawbacks. Therefore, the implementation of an LFM would depend on the market context, framework, and purpose.

The demand-side flexibility needed for energy security would be increased significantly due to high network traffic from load electrification. The authors of [7] investigate case studies in Denmark with different possible solutions to utilize demand-side flexibility. There are many potential options that can be employed such as time-of-use tariffs, dynamic tariffs, a finer geographical granularity of power markets, bilateral contracts, and LFMs. Some of them are already proven that they are practical and simple to apply. However, with application criteria based on local perspectives, flexibility solutions should comply with four criteria; effectiveness of congestion management, ease of implementation, market compatibility, and impact on system balancing. LFMs are a suitable solution that supports all listed criteria. Nevertheless, this solution requires an improvement in standardization to make it simple to understand and assess, and increase its economic attractiveness.

Numerous studies have investigated the efficacy of LFMs, and many have demonstrated their practicality in resolving congestion issues. Several operational LFMs are currently in use. For example, UK Power Network employs Picloflex [8], a market platform that

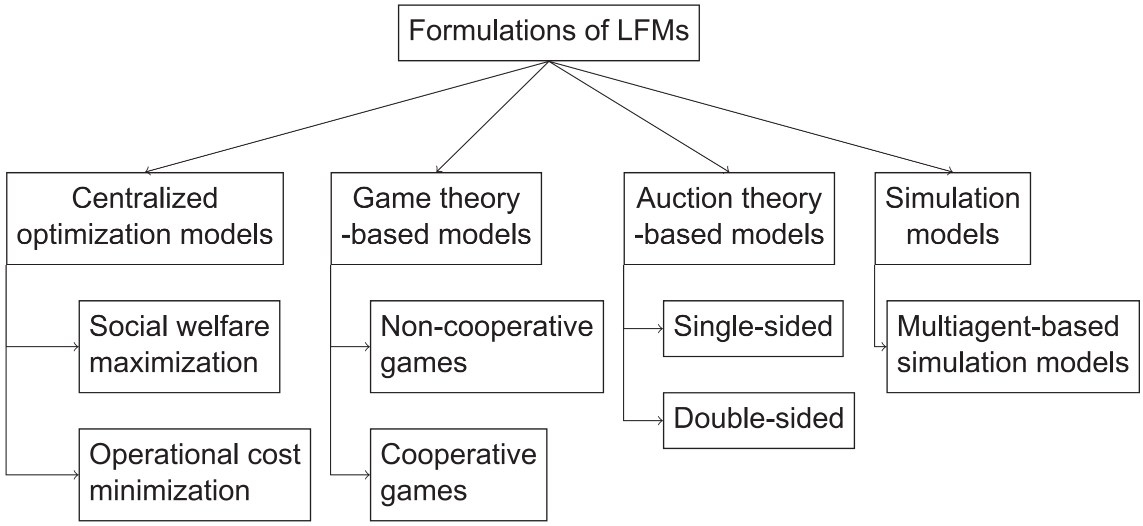

Figure 2.1: Summary of formulations of LFMs

Note. Adapted from from "Local flexibility markets: Literature review on concepts, models and clearing methods". In: Applied Energy 261 (2020), p. 114387 [6]

utilizes long-term agreements to procure flexibility services from prosumers. To prevent over-account costs, prices are capped according to network reinforcement costs. Nord Pool operates another platform, NORDES [9], which trades flexibility in two areas, Germany and Norway. This platform facilitates coordination between DSOs and transimission system operators (TSOs) to manage congestion, voltage, and frequency by procuring short-term and long-term agreements for flexibility services.

The authors of [10] proposed a framework for LFMs that involves three main parties: DSOs, market operators, and aggregators. The DSOs are responsible for calling for flexibility services when there is congestion in the DN. Market operators are responsible for market clearing, settlement, and transactions. Aggregators represent service providers who gather and create flexibility portfolios, which can include prosumers, household flexible loads, EVs, and DERs. In this thesis, the aggregators will be referred to as FSPs to serve the purpose of LFMs.

The distinction between LFMs and local energy markets (LEMs) is important to note. Although both markets are used at a DN level, they serve different purposes. LFMs are designed to trade flexibility services specifically for congestion management. Meanwhile, LEMs are local markets that integrate end-users with DERs and prosumers to trade energy for profit. The authors of [11] introduced the design of an LEM that enables energy exchange among different parties in the DNs. In contrast, LFMs involve three main parties, including DSOs, market operators, and aggregators or FSPs in this thesis, to trade flexibility services to alleviate congestion. Nonetheless, it is worth noting that in some cases, LEMs are implemented to manage congestion indirectly [6].

2.2 Flexibility Services

2.2.1 Baseline services

Baseline services are requested as deviations from a reference profile, which can refer to either consumption or production. These baselines can be provided by FSPs or agreed upon between DSOs and FSPs, depending on the market framework. In their review, the authors of [12] summarize six baseline methods: averaging, regression, control groups, machine learning and hybrid methods, interpolation, and schedules. Baselines can be expressed at any point in the network, ranging from the end-user level up to aggregated units connected under a secondary or primary substation. In some cases, baselines refer to the referenced consumption of FSPs. For instance, during procurement, the baseline of each participating flexibility service needs to be identified beforehand. Then, DSOs will publish a service request for bidding, specifying the needed capacity regulation and service time based on a projection of the regulation required for the congested area, comprising uncontrollable and controllable loads. In the case of upward regulation, the selected FSP needs to reduce its consumption by the amount of bidding capacity. Service delivery verification is the result of the comparison between the referenced baseline and metered values during the service time. For load management services, active power needs to be modified by a specific amount during the service window.

2.2.2 CLSs

CLSs, on the other hand, impose caps on the consumption of FSPs in specified time periods [12]. They are used to limit the total consumption of a network to prevent congestion, for example, load consumption under a transformer. Flexibility capacity of each service provider will be declared after the qualification process. During the service window, DSOs will publish a service request for capacity limitation needed and a service time. The selected FSPs need to keep their consumption under the cleared capacity during the activation period. Service delivery verification is based on the metered values of service providers during the service time. CLSs are similar to capacity subscriptions [13] where end-users subscribe for their maximum consumption and get paid by system operators during the contract period. However, if there is too much flexibility willing to subscribe to such a scheme, market-based settlement may be needed to avoid customer discrimination.

In summary, BLS and CLS are two different types of flexibility services used to manage congestion in DNs. BLS refer to deviations from a reference profile and can be provided by FSPs or agreed upon between DSOs and FSPs. CLS impose caps on the consumption of FSPs in specified time periods to limit total consumption and prevent congestion. Both services require qualification processes and service requests for bidding to ensure successful implementation. Nevertheless, many projects found that there are some issues on BLS application which will be described in section 2.4.

2.3 Local flexibility markets review

European commission review

According to a report by the European Commission [14], several LFMs have been established in Europe, including sthlmflex in Sweden, Norflex in Norway, GOPAS in the Netherlands, enera Flexmarkt in Germany, ENEDIS flexibility tenders in France, IntraFlex and UK flexibility tenders in the United Kingdom. The report provides an overview of these markets, including pre-qualification procedures, flexibility products, market architecture, and activation and settlement methods. One key aspect of these markets is the use of baseline methodologies for procuring settlements. The report also highlights the different products offered by each market, which were designed to support various purposes such as network deferral, congestion management, reliability enhancement, network re-energisation, and system balancing. PAB clearing mechanisms were employed in all market platforms to settle transactions

Local Energy Oxfordshire

Project LEO – Local Energy Oxfordshire [15] [16] [17] investigates a range of flexibility products to enable market participants to offer a variety of services, including frequency response, reactive power, and peak reduction. The products are designed to address specific network issues and provide system-wide benefits. Difference market timeframes of flexibility products are studied such as season-ahead, week-ahead, and day-ahead. Results show that season-ahead procurement has a lower incentive for FSPs because of the high uncertainty of prices, while day-ahead procurement is mostly not available as it required too much effort. The market settlement process is based on PAB mechanism and incorporates the use of baseline methodology to determine the payment for flexibility providers. The baseline methodology used in Project LEO establishes a baseline consumption level for each participant and pays them for the reduction in consumption during periods of system stress. The benefits of the DSOs are used to assess the cost-effectiveness of the implementation by comparing flexibility services payment with grid-saving costs. The grid-saving costs are determined by assuming that the total capacity of the network can be reduced to bring it closer to a frequent utilization level than applied flexibility services to support temporary peak loads. For instance, the frequent utilization level of a 20 MVA transformer is around 15 MVA. Therefore, the transformer size can be reduced to 15 MVA. If there are temporary peak loads that are over 15 MVA, flexibility services will be used.

UK Flexibility Tenders

The Participation Guidance document by UK Power [18] provides guidance to potential market participants on the process of participating in the flexibility market. The document outlines the various flexibility products available, including frequency response, reactive power, and voltage control, and specifies the activation time for each product, ranging from 30 minutes to 24 hours. The settlement process is based on PAB mechanism and includes a baseline methodology that establishes a baseline consumption level for each participant and pays them for the reduction in consumption during periods of system stress. The document also provides guidance on the registration process, bidding process, and requirements for participating in the market, such as the need for appropriate insurance and accreditation. DSOs use a price cap as a maximum offering price for market participants which is corresponding to grid reinforcement costs.

Flexibility Clearing House

The Flexibility Clearing House (FLECH) report [19] categorized load management services for DSOs-markets into five services: PowerCut Planned, PowerCut Urgent, Power Reserve, PowerCap, and PowerMax. PowerCuts are designed to reduce peak load during service time. The difference between planned and urgent services is the activation method. Power Reserve requires DSO activation when a reserve-supply situation is needed. PowerCap and PowerMax limit flexibility consumption, but differ in capacity reference points, with PowerCap identified at DSOs equipment and PowerMax identified at the flexibility side. Procurement uses an auction-based market clearing. Three services require a trigger signal to activate flexibility. To calculate total activation costs, the estimated number of activations for the entire period is defined, combined with reservation costs, to be the maximum offering of DSOs. Both DSOs and the TSO can access the market to obtain services, which requires coordination of flexibility provision between them.

EcoGrid 2.0

The Danish project EcoGrid 2.0 [20] studied an LFM on a 60 kV/10 kV transformer under real conditions with household thermostatically controllable loads. Two flexibility services are introduced: BLS and CLS. In the case of BLS, the rebound effect was added to the study. However, service activation of BLS tends to cause an outage because of a rebound effect. On the other hand, activation of CLSs is able to prevent all potential outage scenarios without consequent implications. Services are procured within a seasonal time-frame in several months ahead. The market used auction-based market clearing with the maximum price of a contract defined by DSOs. There are no additional activation costs for FSPs, but a probability of activation is presented in the offer.

Local flexibility market for grid support services
In the Local flexibility market for grid support services [10], the authors presented an LFM framework for providing grid support services to DNs using real data from smart buildings. The framework includes both a long-term market and a real-time market. In the long-term market, the offering price is composed of two components: a reservation price and an activation price, which are combined into a weighted price for auction purposes. An auction-based trading method is used to clear offering orders with PAB settlement. The weighted price is defined by DSOs to ensure that the service cost is lower than the system investment cost. In the real-time market, both DSOs and FSPs submit their cost curves. The DSO cost curve is calculated based on the loss of life of the transformer in the congested area, while the FSP cost curves are based on their assets. The real-time market is cleared by the auction-based method with PAC at the intersection point between DSOs and FSPs curves. However, the settlement of the real-time market still relies on submitted baseline schedules.

+CityxChange
The authors of [21] suggest applying LFMs as a market mechanism that helps prevent grid congestion and facilitates the incorporation of renewable energy sources. The report outlines a methodology for developing this design framework and demonstrates its application in the case of the +CityxChange lighthouse cities of Trondheim (Norway) and Limerick (Ireland) The project introduces options for a market operation system that can be applied to both the generation and consumption sides. It allows flexibility trading between market participants in addition to DSOs. Two procurement models are presented. First, DSOs buy flexibility services with reservation prices using an auction that suggests auctions once per year. However, on the FSPs, reservation prices may not cover FSPs if their costs are increased due to spot price fluctuations. Second, DSOs buy flexibility services with activation pricing using an FSP price list to determine the service offering curve, then DSOs deploy a demand curve with their willingness to pay. Nevertheless, without any measures, the activation price scheme may create an incentive for exploitation that FSPs adjust their consumption or production with the purpose of being activated by DSOs.

Key success criteria of local flexibility markets
The authors of [22] review existing LFMs and introduced four key success criteria for implementation of LFMs. First, the roles of market participants need to be allocated properly to maintain market properties and transparency. For instance, the roles of DSOs and market operator need to be separated. Second, DSOs need to share some information about LFMs to TSOs to create coordination. Third, certain measures need to be employed to prevent Inc-Dec gaming. Finally, accessibility of market data would reduce market barriers including reducing the minimum size of flexibility.

2.4 Problem of BLSs

The authors of [12] analyze LFMs requirements from several projects and frameworks, and four significant requirements of flexibility services are proposed.

- Transparency and simplicity
- Inclusive use of available flexibility

- Not prone to manipulation
- Compatibility with continuous control

With these requirements, an assessment of baseline methods showed that they cannot satisfy all requirements. For instance, the averaging method used by UK flexibility tenders generated an inflated consumption of non-activation days where baselines can be manipulated. On the other hand, CLSs can support all of the established LFMs service requirements.

Report [14] analyzed pilot projects in the NODES market platform and found that the employment of the baseline methodology created a chance of gaming by FSPs. Therefore, consumption caps are also investigated to be an alternative solution in the future.

One of the key learnings from Project LEO – Local Energy Oxfordshire [15] is that the current baselines methodology generated errors for some DERs. Therefore, alternative baseline methodologies should be studied and applied with different DER types.

The authors of [23] identified points of market failures in LFMs. The main cause of market failures is a problem with submitted schedules called baselines, that associate with the ability of FSPs to control price and quantity. The reason is that FSPs may send untrue schedules to manipulate the market including modifying their flexibility consumption period to trigger DSOs activation for their benefit. They suggest that other product types or services which do not rely on baselines should be considered in LFMs.

CHAPTER 3

Market design options

This chapter presents market design options for the LFM with CLS. First, a general setup is described. Then, relevant market design options implemented in some projects are introduced. Finally, all possible options are discussed to find the most suitable option for this framework.

Market participants In this framework, there are three groups of participants who are involved with the LFM: DSOs, FSPs, and the market operator. The role of DSOs is that of service buyers who send service requests to the market, to eventually acquire services to prevent congestion. FSPs are service providers who sell services in return of financial remuneration. Thus, providing such services needs to cover all relevant opportunity costs. The last involved participant is the market operator who performs market operations. To maintain transparency, the market operator needs to be independent of DSOs.

Services qualification and requirements It is necessary that flexibility needs to be registered before the operation of LFMs. Based on the functioning platform Picloflex [8] [24], there is a process of pre-qualification where flexibility must be registered and declared to the market with qualification of capability, connection, communications, and metering. Thus, it is good practice to use a similar category of qualification that is already implemented to inspire the market design.

Capability: Capability refers to direction, capacity, run time, and response time. With the employment of CLSs, it is used to keep consumption under a specific level, thus, there is only a reduction direction for the services. In terms of capacity, sources of flexibility can be varied on the demand side. The author of [6] provides ideas of possible sources of flexibility that refer to a variety of flexible resources, including distributed generators (DGs), energy storage, and controllable loads like EVs, heat pumps (HPs), and HVAC systems including the application of smart homes and smart buildings. FSP portfolios must be registered. For run time and response time, it is assumed that FSPs are able to control their portfolios using control signals.

Connection point: Connection point refers to the point that flexibility connects to the DNs. To relieve congestion, a service request is made that may include all possible service providers downstream a specified node of the network.

Communications: Communications between DSOs and FSPs are used to receive service instructions that can be phone calls, emails, texts, and application programming interfaces (API). In this framework, this depends on market procurement options. If there are reservation and activation service components, communication would be necessary to ensure reliable activation.

Metering: Metering points must be registered to facilitate service verification. Moreover, metering details such as resolution or summation/per phase metering need to be specified by the DSO to ensure a standardized format for all FSPs.

3.1 Flexibility services

From the literature review in section 2, there are two main types of services in an LFM: BLS and CLS. BLS are associated with a variety of problems related to service definition and settlement (see 2.4). Thus, this thesis only focuses on the employment of CLS to solve congestion. To employ services, first of all, DSOs need to have information about load capacities under the area of interest. If the summation of non-flexible and flexible load installation capacities is lower than the network capacity, there is no chance of congestion in normal operation. Traditionally, some overload protection equipment is installed at point of common couplings (PCCs) such as a fuse and disconnecting switch, to disconnect load out of the network when consumption exceeds network limitations. Based on load concurrency metrics, the total capacity of end-users protection equipment is usually higher than the main protection equipment of the network. The structure of typical DNs is illustrated in figure 3.1

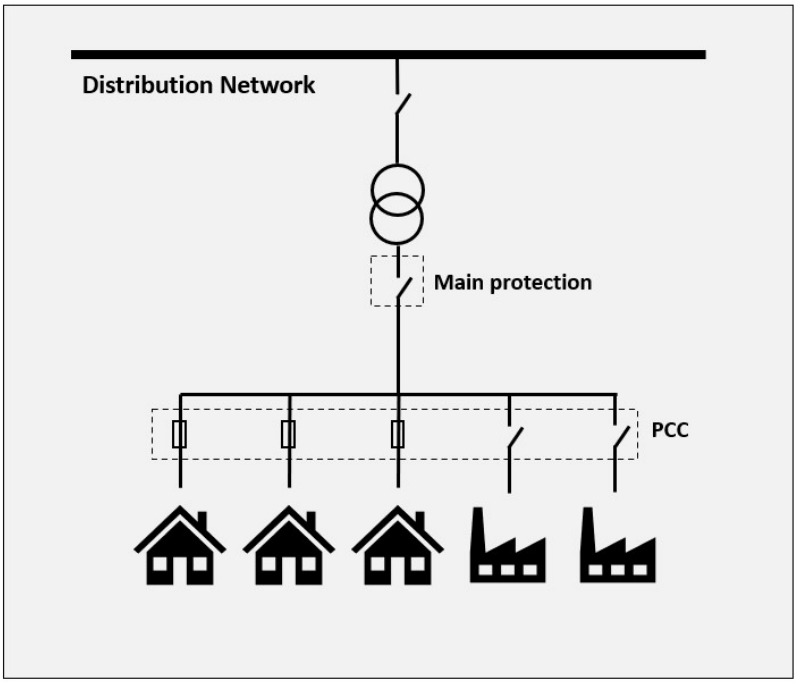

Figure 3.1: The structure of typical DNs with protection equipment

With the high expected increase in demand, DSOs may allow load capacity to be even higher than the network equipment protection to increase asset utilization and reduce reinforcement costs. This scenario is possible because most of the time load consumption is usually lower than its capacity. However, this practice can be the cause of congestion if there is very high consumption during the peak season or due to high load concurrency. In this case, it is assumed that there are three capacity points related to the employment of the services. First, the network capacity would be the main constraint of congestion.

It provides information on when to buy services. Second, customer overload protection capacity such as fuse at PCCs. Third, flexibility capacity. Fuses and flexibility capacity would be a significant reference on service quantity needed. However, flexibility capacity would not be a constant number because of the participation behavior of prosumers in the market. Figure 3.2 presents possible choices that prosumers can choose to participate or not in the market. In general, it would be the case of partial participation that only some prosumers join the market. Therefore, the partial participation case is selected to represent flexibility capacity that related to service requests.

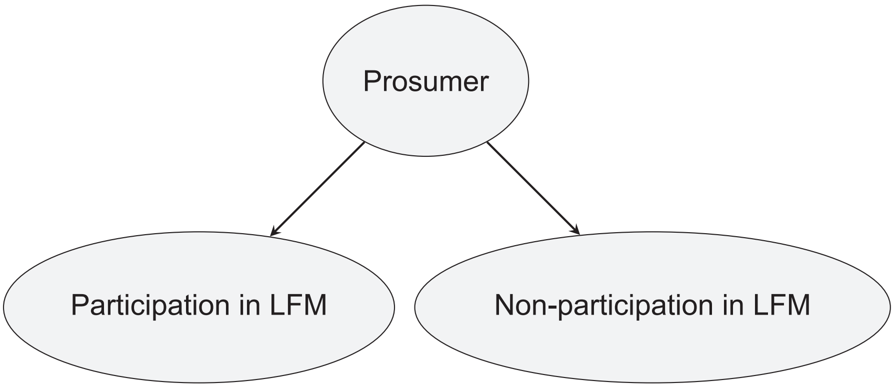

Figure 3.2: Choices for prosumer

Another factor of service employment is the metering point. To monitor the load, DSOs traditionally use a real-time meter at the network equipment, for instance, at feeders and transformers. With the employment of user smart meters like advanced metering infrastructure (AMI), DSOs are able to access consumption through smart meters to obtain individual load profiles for better network management. To utilize LFMs, end-user metering data would be an important part to procure and settle services. However, the metering points of FSPs need to be clarified. There are two ways to measure flexibility services and loads: aggregated and disaggregated metering.

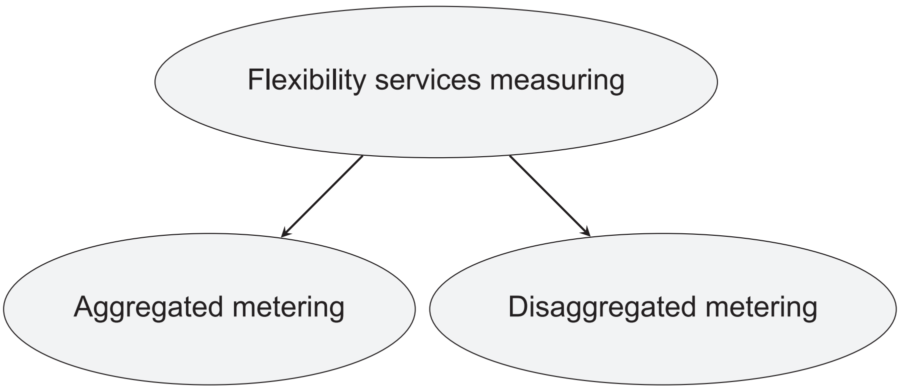

Figure 3.3: Metering options

3.1.1 Aggregated metering

Aggregated metering refers to the case where all consumption (and potentially local generation) of an end-user are metered together by a single meter, as shown in figure 3.4. When considering types of load under prosumer meters, it can be categorized into 4 types. First, a small electricity generation like DERs such as a solar PV rooftop. Second, loads that usually are not controlled and operated upon user's behavior such as refrigerators and internet routers. Third, accessible controllable loads such as EVs and heat pumps which can be accessed by aggregators. Fourth, controllable loads can be controlled by users manually depending on incentives such as laundry machines, and dishwashers.

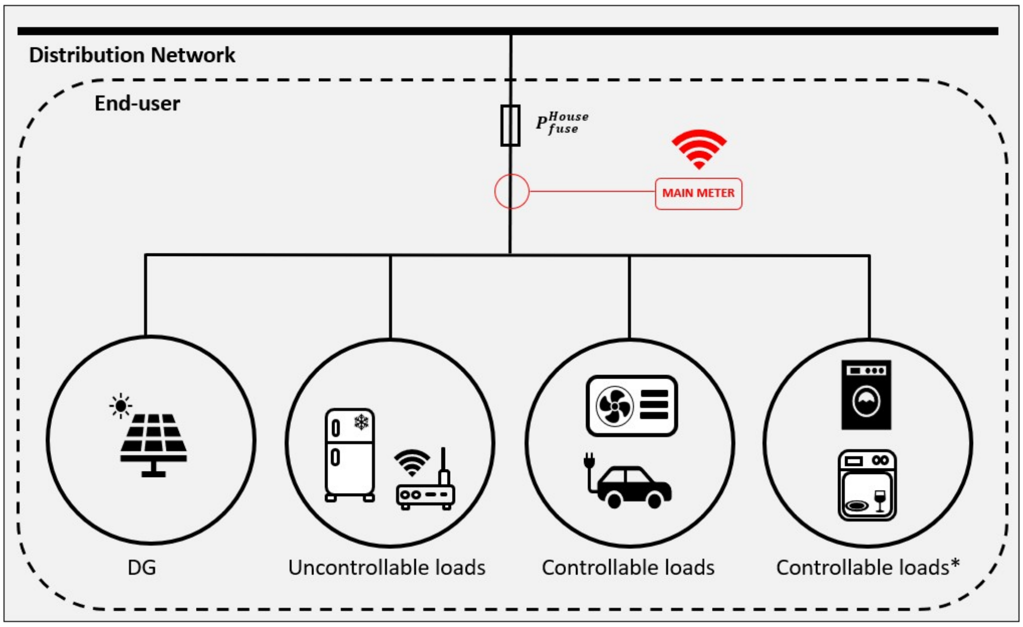

Figure 3.4: Aggregated metering load types

With only one metering point, it is difficult for DSOs to separate flexibility out of the overall load. Besides, the terms flexibility or flexible loads are often loosely defined, because the consumption of a home appliance, such as a washing machine, can be shifted in time in a way similar to an EV. However, in LFMs very often a distinction between EVs or HPs and home appliances is made, with flexibility being requested only from the first category.

In the case of aggregating metering, DSOs need to use aggregated data to employ CLSs. Although the installed capacity of flexible assets may be registered to the market, service verification becomes problematic because metered data includes all loads under the metering point. In this case, a customer's fuse would act as a reference to define the amount of service needed. Then, service requests could be the difference between the aggregated fuse values and the network component limit. However, aggregators may choose to participate or not in the LFM. In that case, service requests would consider only participating aggregators, whose fuse would act as the reference point of CLS.

Service request option for aggregated metering

With historical total load consumption available DSOs are able to define possible congestion events. DSOs have information on non-participating and participating customers that have been registered. Then, DSOs would separate non-participating loads data to define an available capacity of the network that remains for participating loads. After that, the amount of CLS would be called based on the total participating load capacity and the available capacity. An example is shown in figure 3.5. The network has a total fuse capacity of 1500 kW while the network capacity is capable of 1200 kW. During the peak load period, total consumption is higher than the capacity of the network. With the data from the main smart meter and LFMs registration, non-participating loads can be separated from the total loads to determine an available power for participating loads.

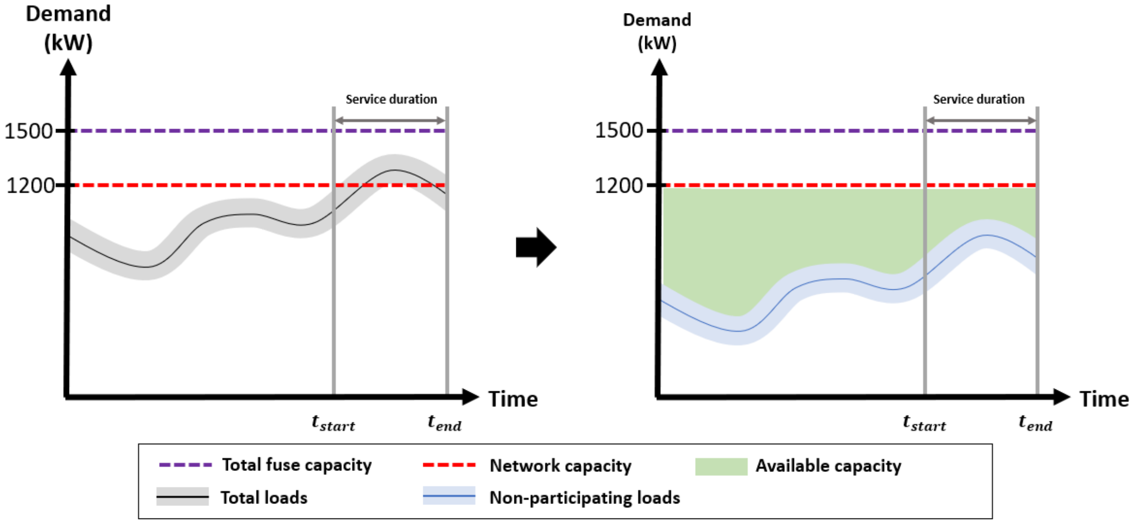

Figure 3.5: Non-participating loads concept for aggregated metering

The lowest available capacity is determined as a reference congestion point at 300 kW. Participating fuse capacity is used as a reference capacity at 700 kW. Then, a CLS request can be calculated based on the participating fuse capacity and the lowest available capacity which is 400 kW, as shown in figure 3.6

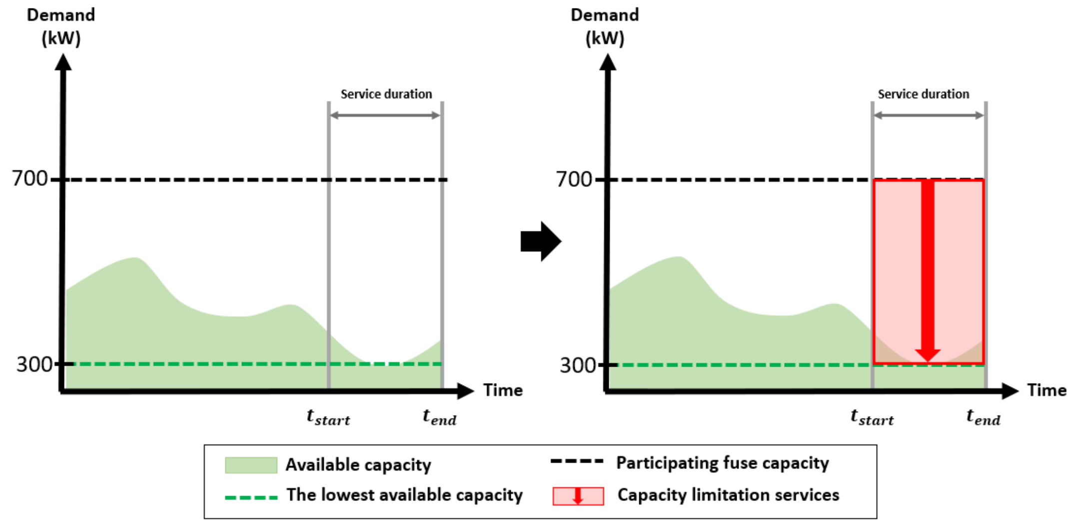

Figure 3.6: CLSs request concept for aggregated metering

Using aggregated metering is simple to integrate with LFMs because in many countries a single smart meter is already installed on most end-users. Therefore, FSPs may face lower market participation costs because additional certified metering devices would not be necessary. On the DSOs side, historical load profiles from smart meters can be used to procure services. A potential advantage of employing aggregated metering is that it allows the provision of flexibility from a variety of assets belonging to an end-user, and not only a designated asset such as an EV or a HP.

3.1.2 Disaggregated metering

In disaggregated metering there is an additional meter for flexibility called a sub-meter, to meter flexible loads. With the data from sub-meters, flexibility services can be called and verified separately from other loads. Therefore, load sub-groups would be categorized differently with the aggregated metering that presents 4 types of loads under the main meter. In this case, they would be only 2 types of loads, i.e., flexible loads measured by the sub-meter and non-flexible net demand shown in figure 3.7.

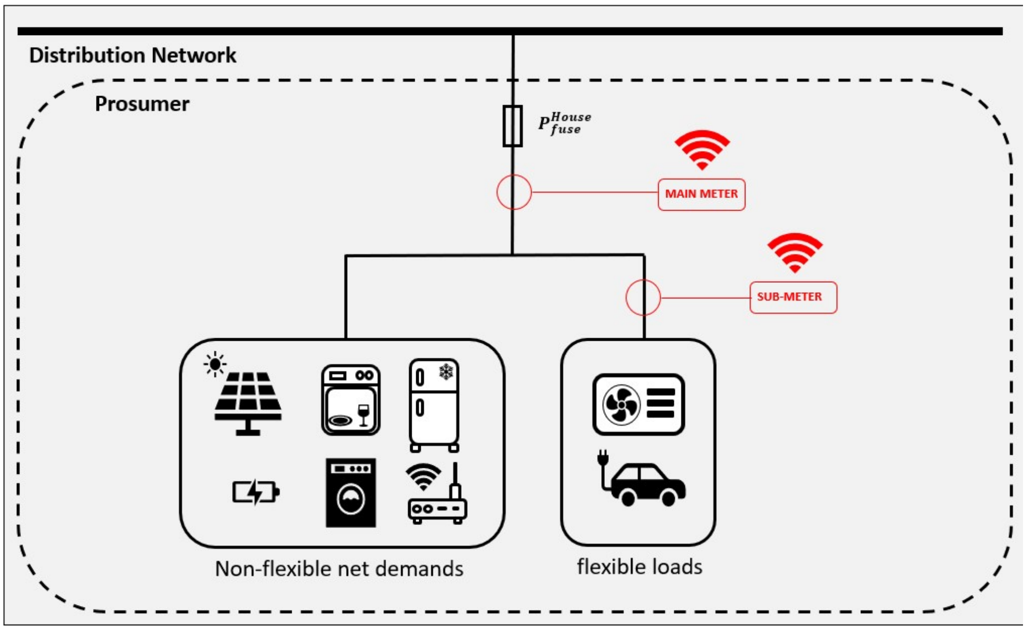

Figure 3.7: Disaggregated metering load types

Despite the existence of a separate meter, information accessibility for DSOs may be a point of concern. Therefore, there are two possible scenarios for that. First, DSOs are able to access the sub-meter readings and use them for load forecasting reasons. Second, □ccess is restricted for DSOs, which requires them to rely mainly on data from the main meter, however, data may be available upon DSO request for service verification.

First scenario: full accessibility on sub-meters

With data from flexibility meters, DSOs can identify non-participating loads and non-flexible loads out of the total load. The available capacity can be determined and reserved for procurement for participating flexible loads only. The method to define a service request would be the same as the aggregated metering case. Starting with determining non-participating loads and non-flexible, the available capacity to be employed as the reference congestion point is found. However, instead of using the participating loads total fuse capacity, flexibility capacity is applied as the reference value. Thus, the amount of CLS would be called based on the participating flexibility capacity and the lowest available capacity. An example is presented in figure 3.8. Using the same network as in the aggregated metering case, the total loads show congestion in the network of 1,200 kW while the total fuse capacity is 1,500 kW. DSOs can identify non-participating and non-flexible loads from data from available data.

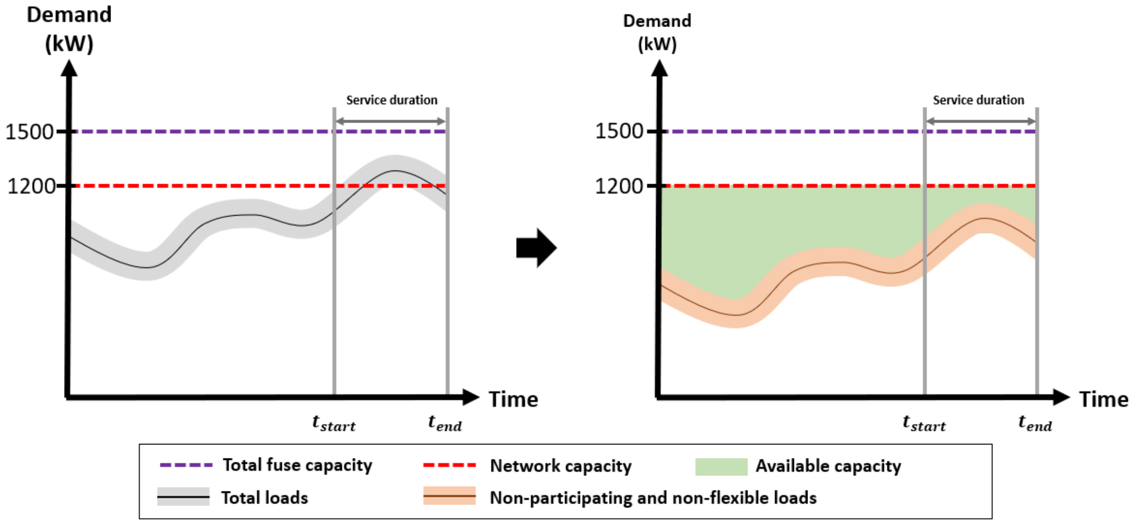

Figure 3.8: Non-participating and non-flexible loads concept for disaggregated metering

In this case, the lowest available capacity is lower than the aggregated metering case because it is only considering the participating flexibility capacity, which is 200 kW. On the other hand, using flexibility capacity, the reference capacity is reduced from 700 to 400 kW. Thus, DSOs need to buy CLS of only 200 kW, as shown in figure 3.9.

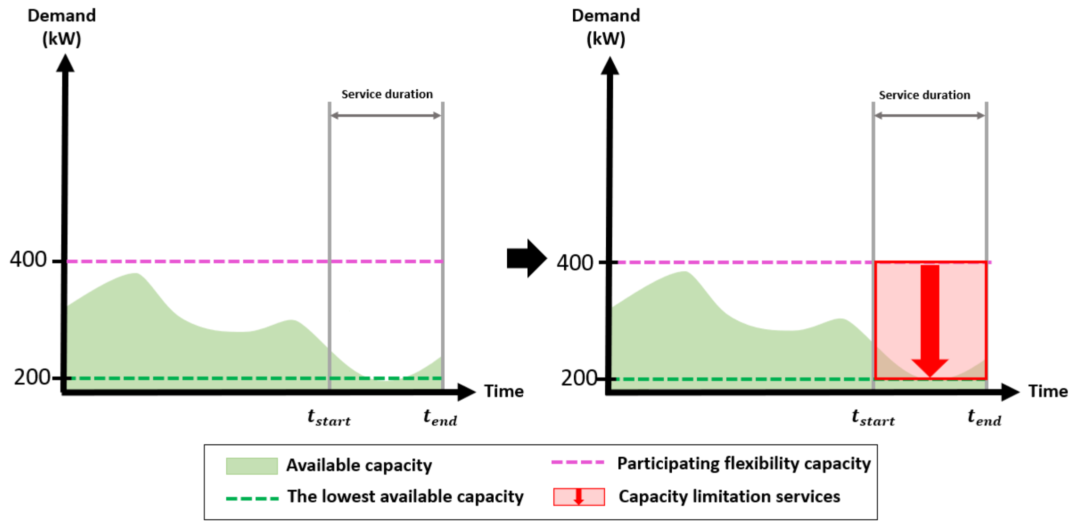

Figure 3.9: CLSs request concept for disaggregated metering (first scenario)

Second scenario: limited accessibility on sub-meters
This case is a combination between the application of the main smart meter and the sub-meters. Although there are sub-meters for flexibility measuring and recording, they may not connect with the data hub because of the limitation of the data center and lack of data communication. Thus, DSOs cannot completely separate non-flexible loads like in the first scenario. DSOs can only identify and forecast non-participating loads, similar to the aggregated metering case. However, DSOs are able to call services based on flexibility capacity with the condition of on-call data from the sub-meter for verification, while the reference point would be an available capacity after considering non-participating loads

like the aggregated metering case. With the same network, the process begins with determining the non-participating loads, as the aggregated metering in figure 3.5. The lowest available capacity for the participating loads is 300 kW. Instead of using the fuse capacity, DSOs apply the flexibility capacity to be the reference capacity which is only 400 kW. Thus, DSOs need a CLS of only 100 kW which is smaller than in the previous cases. The example is illustrated in figure 3.10

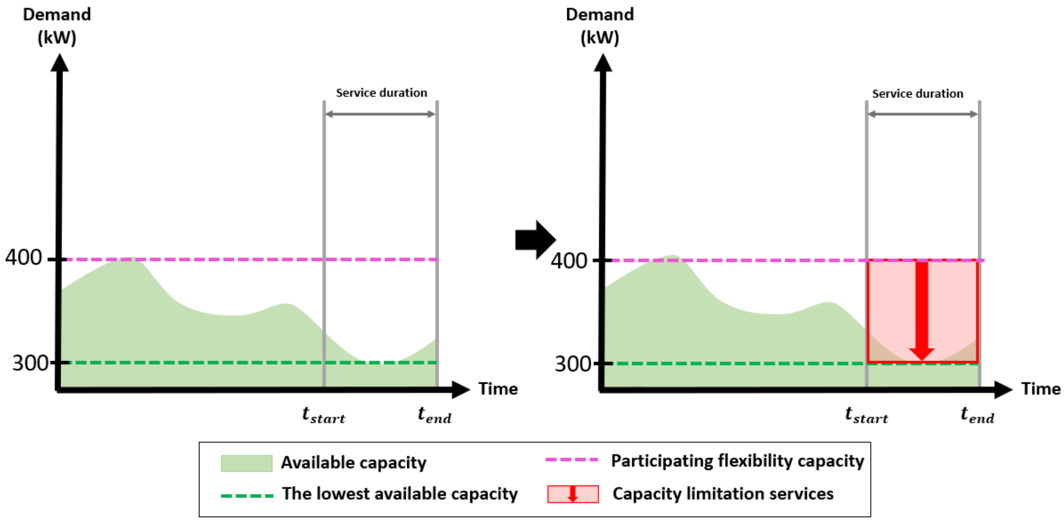

Figure 3.10: CLSs request concept for disaggregated metering (second scenario)

Although the concept of the second scenario includes aggregate data and reference capacity, where flexibility capacity is beneficial for DSOs in terms of lower service requests and data availability, there is the issue that FSPs are only able to access and control their participating assets, and not the rest of the demand of the those customers. Unlike the concept of the aggregated metering case that FSPs need to monitor and evaluate the overall consumption before offering the services. The participating household loads are not monitored from both DSOs and FSPs, which will be a risk to create congestion. Therefore, this concept will not be presented in the next section.

3.1.3 Tradable services

Generally, FSPs who win the bidding will be obliged to provide services following DSOs requirement, and a contract will be signed. However, this commitment would be a drawback if market participants want to adjust those services. On DSO side, if there is a new forecast that the peak load will be lower than the previous forecast, capacity limitation needs can be reduced to increase consumption. On the other hand, for FSPs, if market prices during service windows are lower than expected, they would prefer to consume more electricity. With the idea of tradable services, both market sides are allowed to trade their acquired services many times within the market windows. FSPs may offer to buy some of the services that they obtain from DSOs to the market to relieve capacity limitation by selling it to other FSPs without violating the agreement.

In this thesis, tradable services are introduced as a symmetrical block unit depending on the scale of the market. The reason is that block unit will increase the ease of dealing with CLSs. One issue of CLS is that its concept is easy to misunderstand. For instance, buying 100 kW of CLS is not like buying a capacity subscription, but it means buying 100 kW out of the total registered capacity. FSPs offer service to not consume that amount of capacity during service time. In this case, a block tradable unit of 10 kW will be used as common commodities. FSPs can offer many units depending on their portfolios. When services are needed, DSOs will place a buying order with unit quantity. Then, FSPs place offers to the market. If the offer is accepted, FSPs who accepted to sell the service units need to limit their consumption based on the services already sold. In the first transaction between DSOs and FSPs, an auction-based mechanism will be applied to clear all transactions to minimize DSOs cost. After the first market session, the idea of tradable blocks can be applied. FSPs who may need to obtain more capacity to consume more power, they can place another buying order in the market to buy capacity limitation from other FSPs. The transactions between FSPs are possible, which would be suitable for a continuous-based mechanism because the concept of trading services is used to accommodate changing demands due to factors of uncertainty, similar to the concept of the intra-day market which operates as a PAB continuous market.

Another point of tradable services is about the service period. In a typical situation, flexibility is employed over a period of consecutive days. With the concept of tradable service, it is important to clarify the granularity of tradable units. There are two options that can be implemented with this framework. The first option is the block bids units that bond all consecutive days together. In this way, the service request is published with units and service windows. FSPs who accepted the request need to provide the service for the whole period while the competition only considers the bidding price. The second option is a single block unit of time that employs time granularity such as 1 day. Service windows are split into 1-day granularity. FSPs are able to bid on the service on a specific day. Thus, FSPs must compete with other FSPs by pricing in that day. The reason why a 1-day resolution can be used in this case is that FSPs are able to forecast their day-ahead optimal cost based on knowledge of day-ahead spot prices and EV connection schedules.

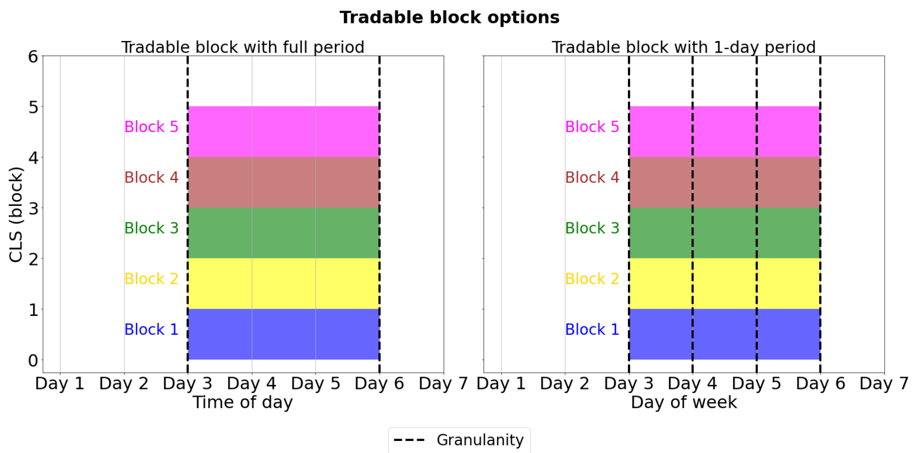

Figure 3.11: CLSs tradable block options

3.2 Procurement components

A procurement component is related to service calling measures. Many projects introduced several ways of procurement, for instance, reservation, activation, and utilization. In long-term services, it is common that services will be paid with a reservation price. FSPs will be paid with the reservation price for availability during service windows although there is no overload event. However, if the forecast leads to an overload in the system, DSOs will send a signal to FSPs to activate their services through platforms, emails, or phone calls depending on the agreement. The activation will be paid in addition to the reservation.

Another option is called utilization, which is applied as a static service that needs to be activated all the time during service windows (without any required activation signal). In the context of LFMs, with lessons learned from other projects, there are two potential options for procurement: reservation with activation, and utilization.

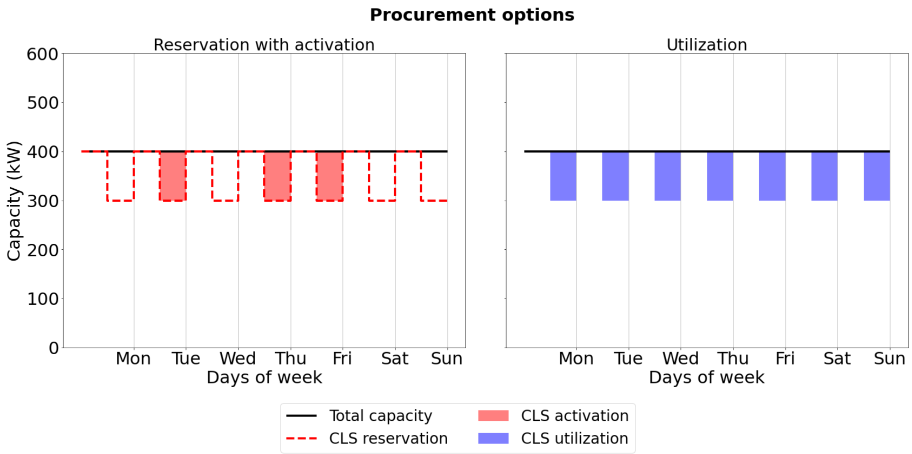

Figure 3.12: CLSs procurement options

Both options can be applied with tradable services. However, the reservation with activation may increase the complication of market activities. For example, a calculating method of a comparable price that combined available components and activation components needs to be defined. One of the LFMs [10] applied weighting for bidding available price and activation price to create a comparable price for market clearing between DSOs and FSPs. On the other hand, trading between FSPs and FSPs may create another issue about the activation from DSOs, i.e., which FSPs should get paid and which prices. Moreover, FSPs know that they can earn more profit with activation, thus they may try to manipulate the market by increasing their consumption to trigger DSOs activation. To avoid the problems, focus will be given only on the utilization case.

3.3 Market lead time

In this framework, there are two significant timestamps in the market which are the timestamp of service lead time and the timestamp of the trading deadline. Service lead time will be published by DSOs. There are many service lead times that were used by different LFMs projects such as long-term, mid-term, short-term, and real-time markets that could be possible design options.

3.3.1 Long-term market

A long-term market is used to procure services a long time ahead, normally one year in advance to employ in a specific period. DSOs can procure services by reserving flexibility in advance to make sure that the flexibility will be available during the service windows. Then, services will be activated if there is congestion. In some projects, FSPs are paid for reservation fees for availability and activation fees when the services are called. In this way, DSOs are able to estimate and compare long-term costs which are related to grid investment costs. That increases the incentive for them. Additionally, the long-term market may need long-term forecasting for service requests which would be a drawback because there is high uncertainty of data. On the other hand, it could provide less incentive for FSPs because of an opportunity loss that they cannot utilize their assets if the market prices are low during the service windows.

3.3.2 Mid-term market

A mid-term market is employed to procure services at least one month in advance but shorter that the long-term market. The application of the mid-term market is able to integrate better forecasting for service employment. On the one hand, mid-term services are able to employ reservation and activation components similar to long-term services. On the other hand, it can also comply with static activation that the service must be activated all the time during the service windows. In some cases, the mid-term market is applied as a seasonal procurement for the season ahead in advance. In terms of incentives, the mid-term market can provide more accurate information for both market sides with fewer uncertainty factors.

3.3.3 Short-term market

The short-term market refers to a short period of service procurement before the activation such as week ahead and day ahead. The application of the short-term market is well-known and used in the spot market. Some projects mention the implementation of LFMs by running in parallel with the spot market. On the FSPs side, the short-term market provides more incentives because they can consider the information of the wholesale market compared with LFMs to make the highest benefit. On DSOs side, although the short-term procurement can increase the accuracy of forecasting, it creates a very high workload for them because of the complexity and a high uncertainty in terms of planning.

3.3.4 Real-time market

The purpose of the real-time market in the context of the electricity market is to procure ancillary services to maintain system balance which would be compatible with the procurement of flexibility to alleviate congestion. However, there is an issue found in several projects where flexibility is often unavailable. Meanwhile, available flexibility is usually offered at a very high price because FSPs know that DSOs are willing to pay that price to prevent costly curtailment or load shedding.

In conclusion, each market lead time contributes different benefits and drawbacks. In terms of data, the shorter market lead time provides the most reliable information at the expense of the workload of forecasting that needs to be done frequently, and high DSO uncertainty. Moreover, unavailable services to procure because of close lead time would be an issue that makes the market inefficient. On the other hand, the long-term market can mitigate the issue of availability and preparation but it costs on high uncertainty. The mid-term market for DSOs services procurement would be the most interesting because it can mitigate some technical problems while it still provides some incentives.

3.4 Market-clearing mechanisms

There are several practical options for market-clearing mechanisms. From the literature review on the LFMs, there are three major methods that were introduced to settle the markets; PAB, uniform pricing (UP), and uni-side VCG. These would be options to apply with the framework of CLS.

3.4.1 PAB

PAB is a method used to clear transactions based on the proposed prices by market participants. The concept of PAB starts with suppliers and consumers submitting their bids and offers, specifying the quantity of units they are willing to supply or purchase at specific prices. The market operator then ranks these bids and offers based on their price levels, from lowest to highest. Transactions are allocated by starting with the lowest price bids and progressing to higher price bids until the available supply and demand are matched. Market players will be paid upon their bidding price. In this framework, DSOs and service buyers offer orders with their maximum willingness to pay (WTP) prices, while service sellers and FSPs bid with their minimum willingness to accept (WTA) prices.

There are two types of market structures that can employ the PAB method: auction-based market and continuous-based market.

Auction-based market

In this market, all orders in the order book are cleared at the end of the market session based on price priority. Generally, selling orders from FSPs are prioritized based on their prices, from lowest to highest. The clearing point is reached when the highest selling price order matches the total buying volume at an acceptable price. Since FSPs are paid upon their submitting prices, markups that top-up from their costs are often used to generate profits. Figure 3.13 show a concept of the auction-based market with PAB and their markups.

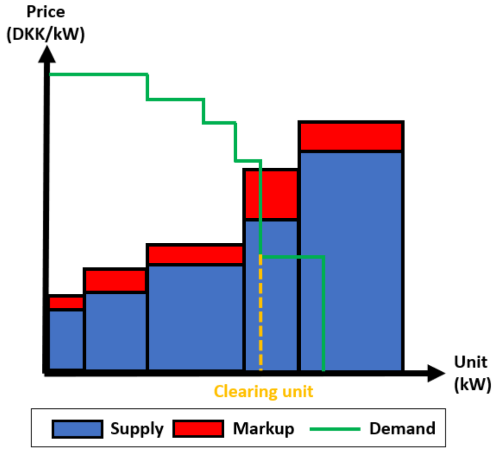

Figure 3.13: An illustration of the auction-based market with PAB

Continuous-based market

The concept of the continuous-based mechanism is to clear the market instantly if all conditions are matched in a consecutive timeframe. Buying orders from DSOs or selling orders from FSPs are first placed in the market and stored in the local order book. After that, if there is a new arrival, it will be checked with standing orders in the local order book. If the new order meets the price conditions with the standing orders in the order book, a transaction will be made. The concept is illustrated in figure 3.14. Applying the idea from [25], all standing orders in the local order book will be managed with the pro-rata method that prioritizes orders based on their prices. Since bids or offers should be presented with their single-price bidding, the cleared price will be determined as the middle point between the highest bid willing to pay and the lowest offer willing to accept. The middle point price is the average price between 2 orders which provides equal pay for both sides. Trading occurs continuously until the market session is closed.

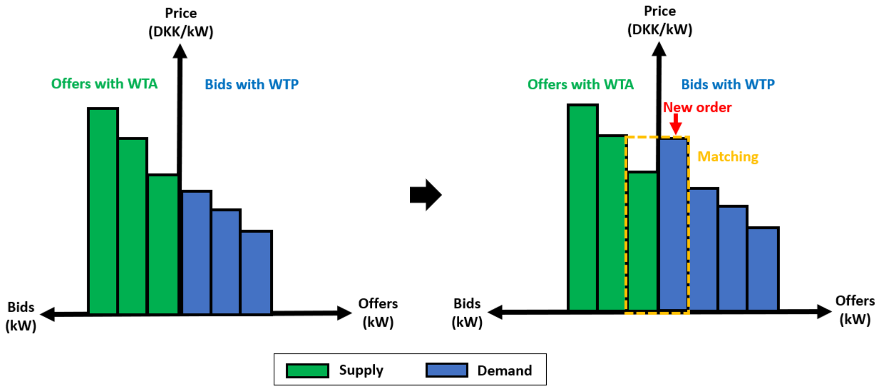

Figure 3.14: An illustration of the continuous-based market with PAB

3.4.2 PAC

PAC usually applies on double-side auctions where both buyers and sellers bid for the services. With PAC, all FSPs will be paid at the market-clearing price for all their blocks. This method is often called UP because it provides the same market clearing prices to settle the market. To make a settlement, sellers send their orders to the market with the minimum WTA price conditions the same as PAB. On the other hand, buyers send their orders with the maximum WTP price. To clear the market, PAC method is only employed in the auction-based market because it needs a clearing session to settle. All selling and buying orders will be prioritized on their prices and will be cleared when the highest selling order reaches the lowest buying order. To simplify, the market operator matches the bids and offers to find the equilibrium point where the quantity demanded equals the quantity supplied. However, all sellers will be paid the same price at the clearing point. For the buyers, if it is a double auction scheme, all buyers will pay the same price at the clearing price.

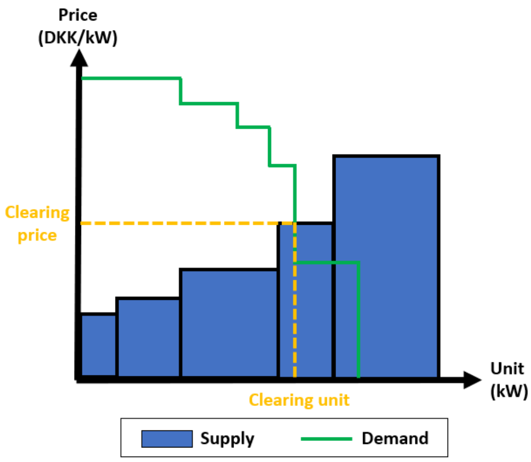

Figure 3.15: An illustration of the auction-based market with PAC

3.4.3 Uni-side VCG

Uni-side VCG is introduced by the authors [26] that developed from VCG to improve its efficiency. VCGs is a truthful auction method. It is commonly used with a single-side auction scheme. In this case, it is an auction of selling orders from FSPs. The concept is that all FSPs bid with their true costs. Then, all bidding orders will be prioritized with their price. The market is cleared when the highest offering price order meets the offering volumes. Each bidder will be paid based on their contribution to the market. For instance, bidder A is selected. To calculate the payment of bidder A, the market has to perform the clearing without bidder A with the same clearing volumes. Then, the next higher-price orders will be selected that increase the overall costs. The contribution of bidder A is the difference between the overall costs of the second market clearing without bidder A and the first market clearing without bidder A. On the other side, it should perform the same with DSOs. However, there is only one DSOs for the trading area. Without the DSOs, the result of the market clearing will be negative. Thus, uni-side VCG is improved by adding DSOs cost constraint that DSOs should be able to cover all costs of the services.

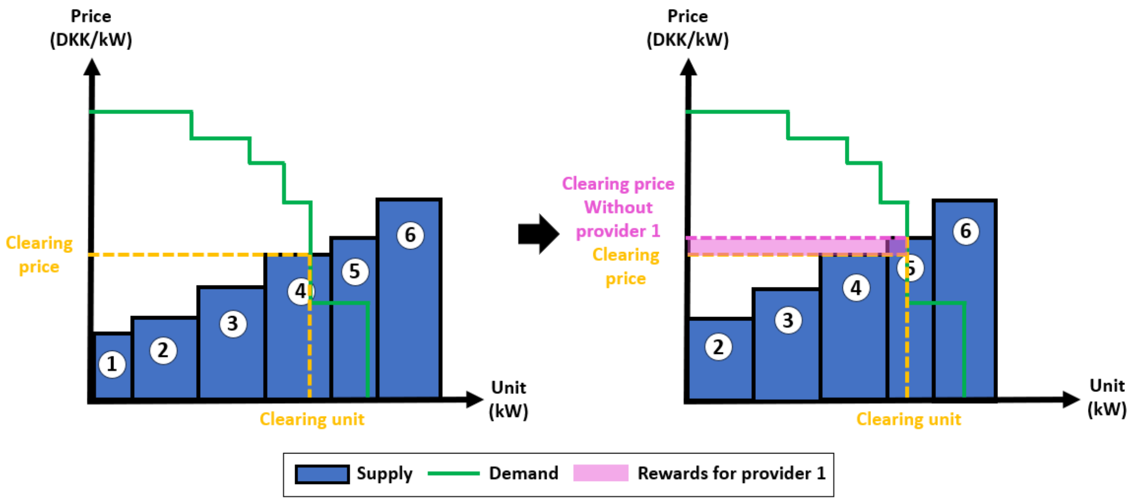

Figure 3.16: uni-side VCG

CHAPTER 4

Study case

This chapter provides study cases based on different market design options. First, the overall case to be studied is described. Then, possible options are employed to determine CLSs and their costs. Finally, the market clearing is simulated with different mechanisms.

4.1 Description of the case studied

4.1.1 Smart meter data

Historical smart meter data is used to represent real user consumption in the system. Data has a 30-min resolution and is originally from the Low Carbon London project that recorded 5,567 households for Dynamic Time of Use (dToU) energy prices experiments [27] that were studied between 2011 to 2014. There are 1,100 users out of 5,567 who were subjected to dToU, while the rest 4,567 were users without dynamic tariffs. In this project, 200 smart meter IDs are randomly selected from 4,567 standard users to be used in the study. Their consumption is assumed to be inflexible. Since the study focuses on congestion in DNs mainly in medium to low voltage transformers, network topology will be not considered. Thus, it is not necessary to create and assign load points to the network.

Besides, congestion is expected to happen mainly during the winter. Therefore, the consumption of the 200 houses during the first 4 weeks of January 2014, which is the highest load month of the year, is used. The 4 weeks start from Saturday 4th January 2014 to Friday 31st January 2014, leading to 28 days of 96 data points each, since a resolution of 15 min is used (data has been upsampled for that reason). Figure 4.1 presents the average daily load profile with a 0.05 confidence interval of quantiles 0.025 and 0.975. With the selected data, the average load is around 122 kW. It is assumed that the typical loading of DN transformers is around 30-50%. Thus, the transformer capacity of the case study is assumed to be equal to 350 kVA.

Another assumption related to the smart meters is the maximum load of each house. With the information of Danish DSO Radius [28], the maximum allowed load of a typical house is 25 A (grid connection), which is around 17.32 kW for a 3-phase system. In this case, the number will be rounded to 17 kW for simplification. Besides, the smart meter data originally came from the UK with UTC timestamps. To comply with the context of this project, data is converted into Danish local time while neglecting other factors that would affect consumption behavior related to the different time zones.

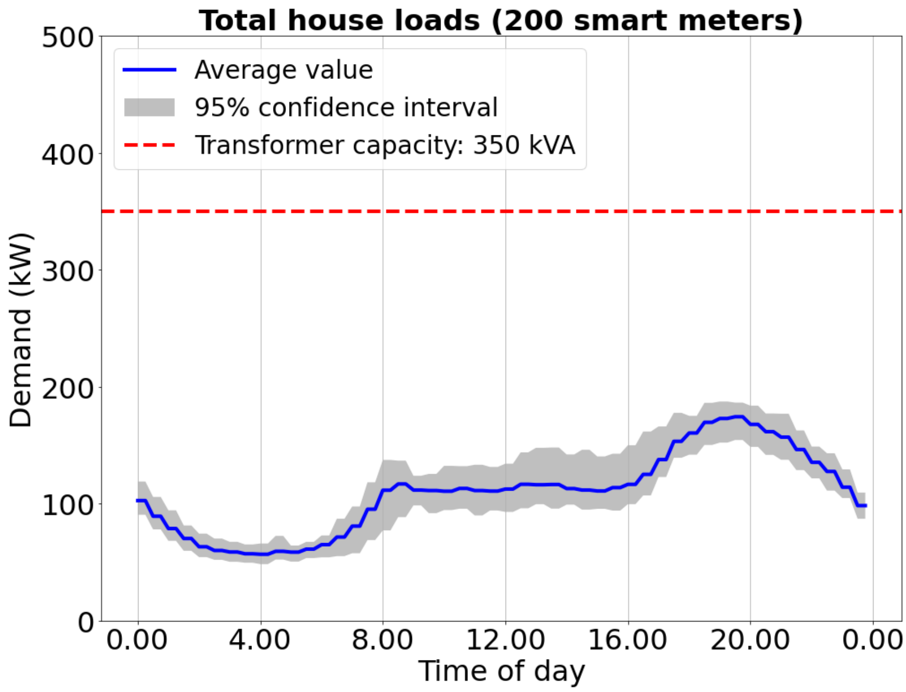

Figure 4.1: Average demand and 95% confidence interval of 200 households over 28 days

4.1.2 EV data

Similar to household consumption, EV data in the project is historical data supplied by Spirii [29], a Danish EVs charge point operator. The EVs data was recorded between September 2021 to March 2023 from chargers located in Denmark. To comply with household data, the EVs data in the same month (January) is selected. However, the smart meter and EV data do not cover the same years. Thus, data in January 2022 of 4 weeks is chosen to start from Saturday 1st January to Friday 28th January to maintain the same weekday characteristic with household data. It is assumed that 50% of the households acquired an EV, which is equal to 100 EVs out of 200 houses. The maximum capacity of 100 EVs chargers is equal to 812.3 kW comprising 54 11 kW chargers, 13 7.4 kW chargers, and 33 3.7 kW chargers. The EV data consists of arrival time, departure time, and charged energy for each charging session, while nominal charging power is inferred from this data. It is assumed that 50% of EVs are interested to participate in the LFM. Therefore, 50 EVs are randomly selected and will be used in the simulations. The maximum capacity of 50 EVs chargers is 411.7 kW containing 27 chargers of 11 kW, 8 chargers of 7.4 kW, and 15 chargers of 3.7 kW.

4.1.3 Charging prices

Real DK2 electricity prices are used to define the true cost associated with providing the investigated flexibility services. DK2 spot prices, along with taxes/tariffs imposed on energy imports in the network of the Danish DSO Radius, are used. Prices are selected in the same timeframe as the EVs data.

4.2 Loads simulation without services

The simulation is conducted in Python, using the CVXPY package [30] and Gurobi [31] as the optimization solver. With dynamic charging prices, prices vary throughout the day depending on demand and supply. EVs are expected to charge with the cheapest cost, meaning that charging would occur when prices are low. The optimization problem of the EVs charging is represented as

$$
\begin{aligned}
\underset{P_{n,t}}{\text{minimize}} \quad & \sum_{t\in\mathcal{T}}\sum_{n\in\mathcal{N}} P_{n,t}\lambda_t\Delta T && && \text{(4.1a)}\\
\text{subject to} \quad & 0 \leq P_{n,t} \leq P^{max}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{A}_n, && \text{(4.1b)}\\
& P_{n,t} = 0, && \forall n \in \mathcal{N}, \forall t \notin \mathcal{A}_n, && \text{(4.1c)}\\
& SOC_{n,t+1} = SOC_{n,t} + \frac{P_{n,t}}{E^{kWh}_n}\Delta T, && \forall n \in \mathcal{N}, \forall t \in \mathcal{A}_n, && \text{(4.1d)}\\
& SOC_{n,t^{dep}_k} = 1, && \forall n \in \mathcal{N}, && \text{(4.1e)}\\
& SOC_{n,t^{arr}_k} = SOC^{arr}_n, && \forall n \in \mathcal{N}, && \text{(4.1f)}\\
& SOC^{arr}_n \leq SOC_{n,t} \leq 1, && \forall n \in \mathcal{N}, \forall t \in \mathcal{A}_n && \text{(4.1g)}
\end{aligned}
$$

$\mathcal{N} = 1, 2, ..., 100$ is a set of 100 EVs, indexed by n. $\mathcal{T} = 1, 2, ..., 2688$ is a set of simulation time steps corresponding to every 15 minutes (t) of 28 days which is 2,688 steps. $A_n \subseteq \mathcal{T}$ is the set that contains the timesteps when EV n is plugged in. $P_{n,t}$ is the charging power in kW. E^{kWh}_n is a charging energy of each EVs. ΔT is the time step length. The objective function 4.2a is to minimize the overall charging cost of EVs. The constraint of equation 4.3b is the limitation of each charger. In this case, EV charging energy is a hard constraint 4.3c that chargers need to fulfill. The result of the EV charging optimization is presented in figure 4.2. The figure shows the average value of 28 days with a 95% confidence interval of quantiles 0.025 and 0.975.

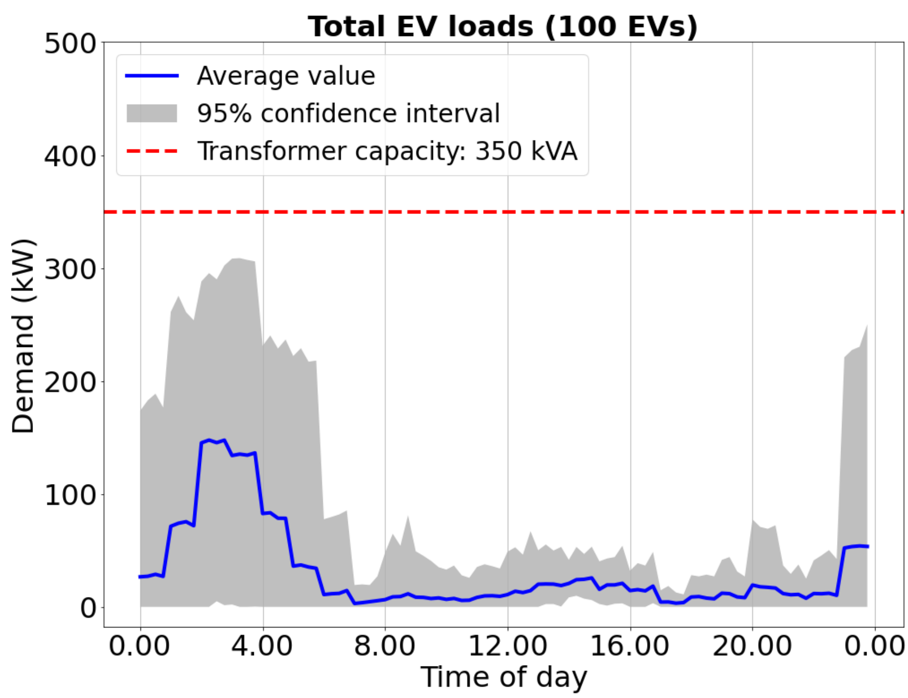

Figure 4.2: Average demand and 95% confidence interval of 100 EVs over 28 days

When combining the historical smart meter data in section 4.1.1, the system load profile of 28 days is shown in figure 4.3. The figure illustrates an average value of a 24-hour load profile with a 95% confidence interval and a load profile of the highest loads day.

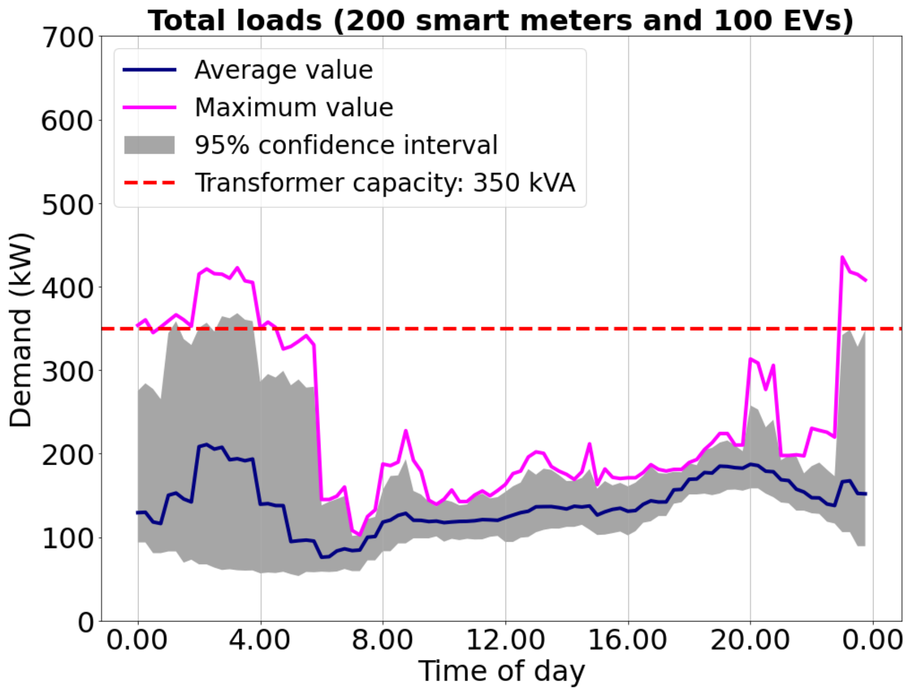

Figure 4.3: Average demand and 95% confidence interval of 200 households and 100 EVs over 28 days

It can be seen that the total consumption of households and EVs can cause congestion to the network transformer. Congestion occurs during the night time when EVs are scheduled to consume power due to the lower energy prices.

4.3 Loads simulation with services

4.3.1 Aggregated metering

First, the scenario of aggregated metering as presented in section 3.1.1, is implemented in the case study. With the assumption that 50 EVs will be participating in the market, in the aggregated metering case services would be offered by 50 selected houses each equipped with an EV, referred to as participating loads.

With the information of the total load profile from figure 4.3 showing that congestion occurs during the night time, there are 2 options to employ CLS. One is scheduled services to cover the night time, and the other option is a service to cover all hours in the service window (called all-time). The flow chart in Figure 4.4 describes the process to define the CLS and verify the result.

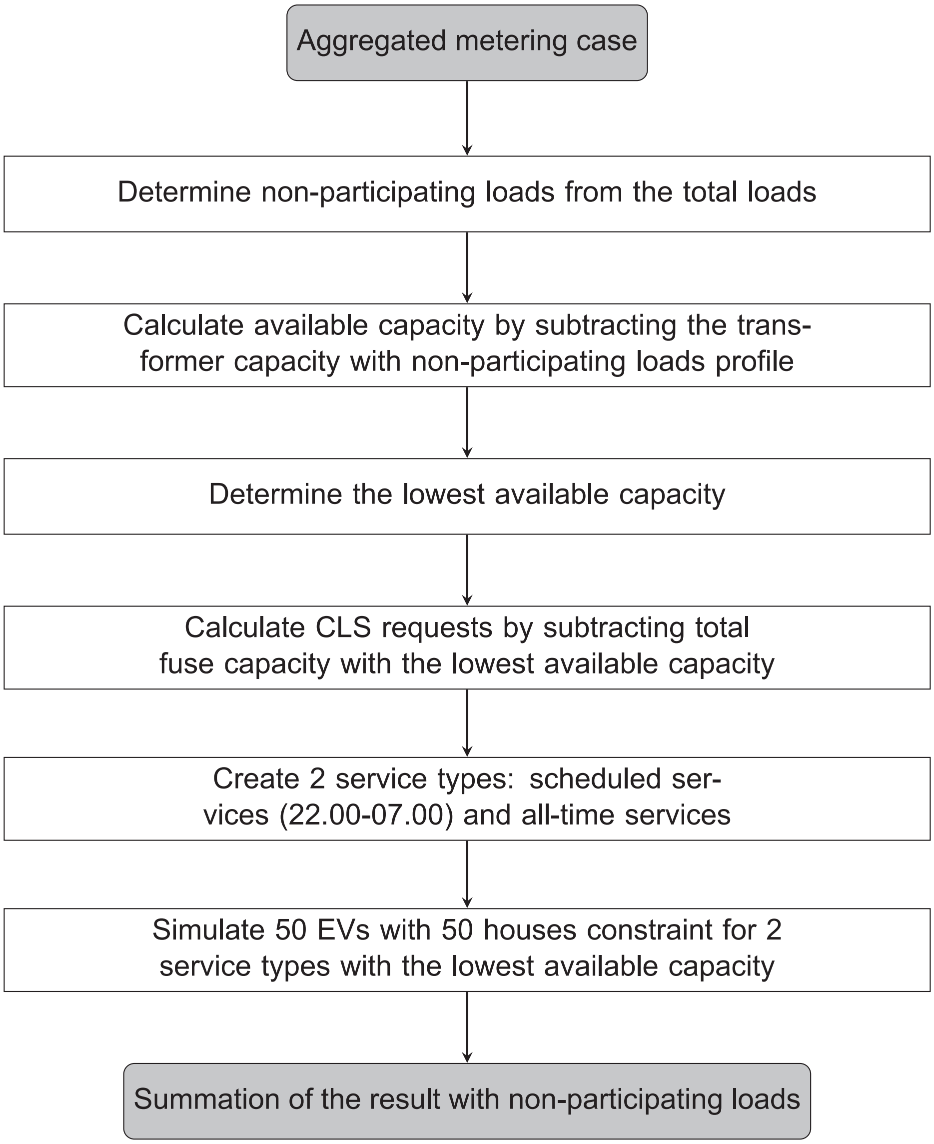

Figure 4.4: Flow chart of aggregated metering with services

Firstly, non-participating loads are defined and plotted in a 24-hours profile. After that, with the non-participating loads, the available capacity can be found. There are two reasonable ways to find the available capacity: by using a quantile (here 0.975) load profile of the 95% confidence interval, and the highest loads day. Figure 4.5 shows non-participating loads containing 150 non-selected houses and 50 non-selected EVs with a 95% confidence interval and max value loads. With those two sets of information between the 95th percentile profile and the highest loads day profile, there are two possible reference points for service requests, upon the 95th percentile line or the max value line.

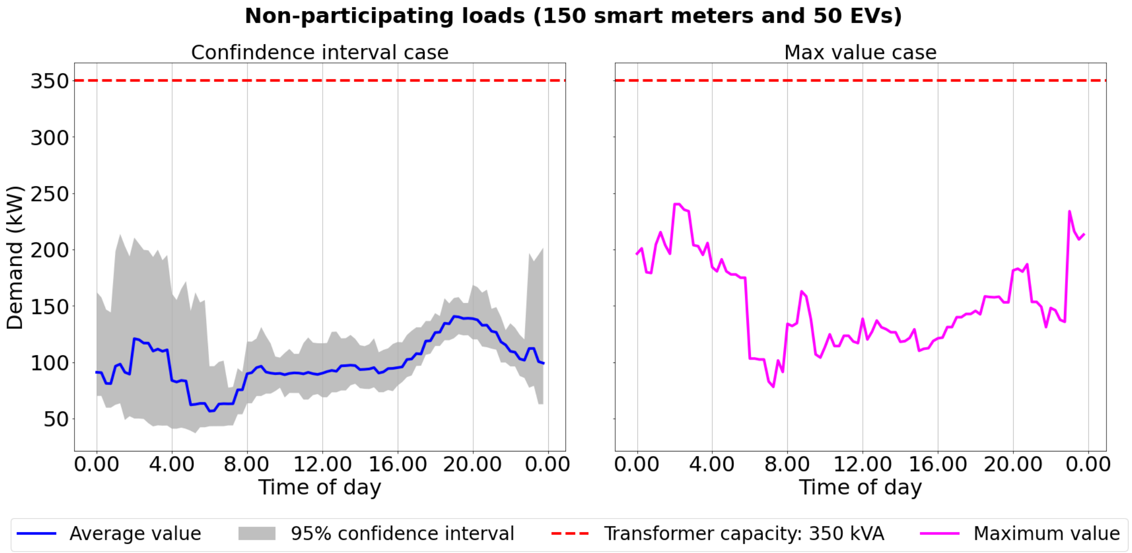

Figure 4.5: Non-participating loads for aggregated metering

Thus, the available capacity of the network is found by subtracting from the transformer capacity the reference loads. Figure 4.6 presents available capacity from the 95th percentile value and max value.

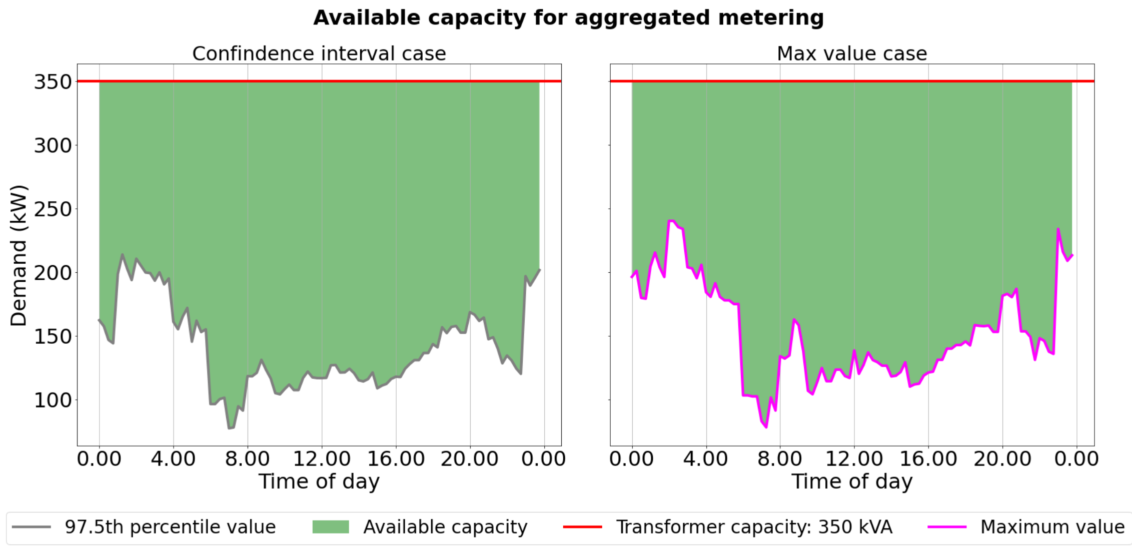

Figure 4.6: Available capacity for aggregated metering

Then, when considering the available capacity, the lowest available capacity of the time series could be a possible congestion period. Therefore, the lowest available capacity point will be used as the consumption limit for participating loads. Figure 4.7 presents the lowest available capacity compared with the capacity of the total participating fuse.

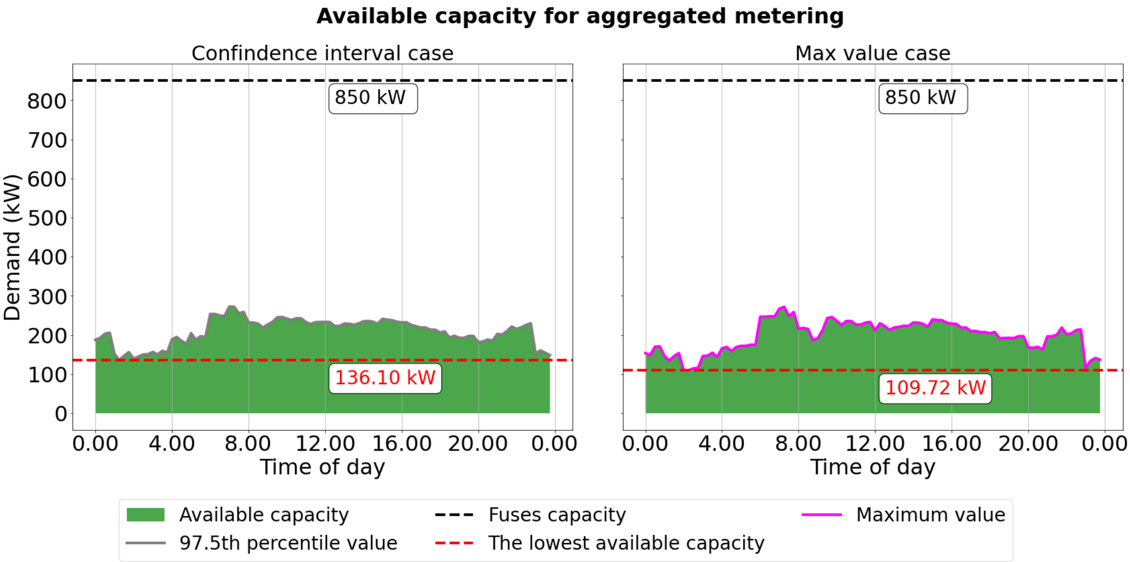

Figure 4.7: Available capacity for aggregated metering

A CLS request is based on the reference capacity, which is the total fuse capacity in the aggregated metering case. CLS request is the difference between the total fuse capacity and the lowest available capacity. Figures 4.8 show the available capacity compared with the total fuse capacity from figures 4.7. Two areas in red and light red present two types of services; scheduled services and all-time services. With the 95th percentile value, the lowest available capacity is around 136.10 kW. Thus, CLS request is the result of the total fuse capacity 850 kW (50 houses with 17 kW fuses) subtracted with the lowest available of 136.10 kW which is 713.90 kW. On the other hand, with the max value, the lowest available capacity is only around 109.72 kW. Therefore, it requires up to 740.28 kW for CLS.

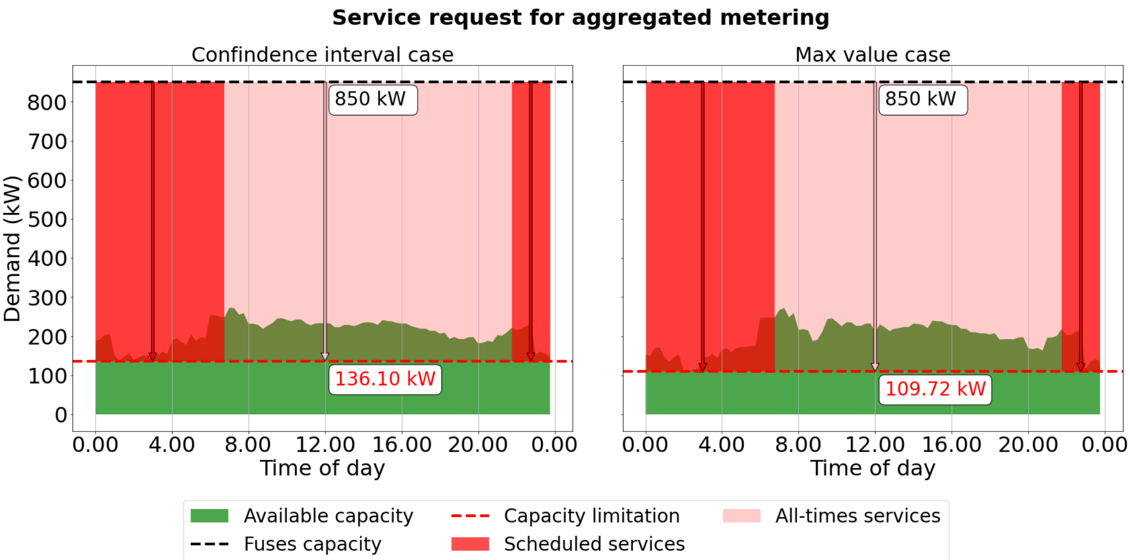

Figure 4.8: Service request for aggregated metering

After CLS and the lowest available capacity are determined, it will be used for an additional constraint of the charging optimization. The optimization problem is formulated as

$$\underset{P_{s,t}}{\text{minimize}} \quad \sum_{t\in\mathcal{T}}\sum_{s\in\mathcal{S}} P_{s,t}\lambda_t\Delta T \tag{4.2a}$$

$$\text{subject to} \quad 0 \le P_{s,t} \le P^{max}_{s,t}, \quad \forall s\in\mathcal{S}, \forall t\in\mathcal{A}_s, \tag{4.2b}$$

$$P_{s,t} = 0, \quad \forall s\in\mathcal{S}, \forall t\notin\mathcal{A}_n, \tag{4.2c}$$

$$SOC_{s,t+1} = SOC_{s,t} + \frac{P_{s,t}}{E^{kWh}_s}\Delta T, \forall s\in\mathcal{N}, \forall t\in\mathcal{A}_s, \tag{4.2d}$$

$$SOC_{s,t^{dep}_k} = 1, \quad \forall s\in\mathcal{S}, \tag{4.2e}$$

$$SOC_{s,t^{arr}_k} = SOC^{arr}_s, \quad \forall s\in\mathcal{S}, \tag{4.2f}$$

$$SOC^{arr}_s \le SOC_{s,t} \le 1, \quad \forall s\in\mathcal{S}, \forall t\in\mathcal{A}_s, \tag{4.2g}$$

$$\sum_{s\in\mathcal{S}} P^{agg}_{s,t} \le P^{cap,fuses}, \quad \forall s\in\mathcal{S}, \forall t\in\mathcal{T}, \tag{4.2h}$$

$$(P_{s,t} + P_{h,t}) = P^{agg}_{s,t}, \quad \forall s\in\mathcal{S}, \forall h\in\mathcal{H}, \forall t\in\mathcal{T} \tag{4.2i}$$

The optimization problem begins with the same structure as the simulation without service. However, with the assumption of participation, a set of participating EVs,$\mathcal{S} = 1, 2, ..., 50$, is used to represent 50 EVs. Each EV is assigned to a smart meter from a set of 50 smart meters,$\mathcal{H} = 1, 2, ..., 50$. There is an additional constraint of capacity limitation. $P^{agg}_{s,t}$ is the aggregated metering power which is the summation of EV power and smart meter load. P^{cap} is the available capacity of the network.

In the case of full-service employment, CLS would solve the congestion in the system. Figure 4.9 presents the total loads in the highest loads day without services and with 2 service types (scheduled services and all-time services).

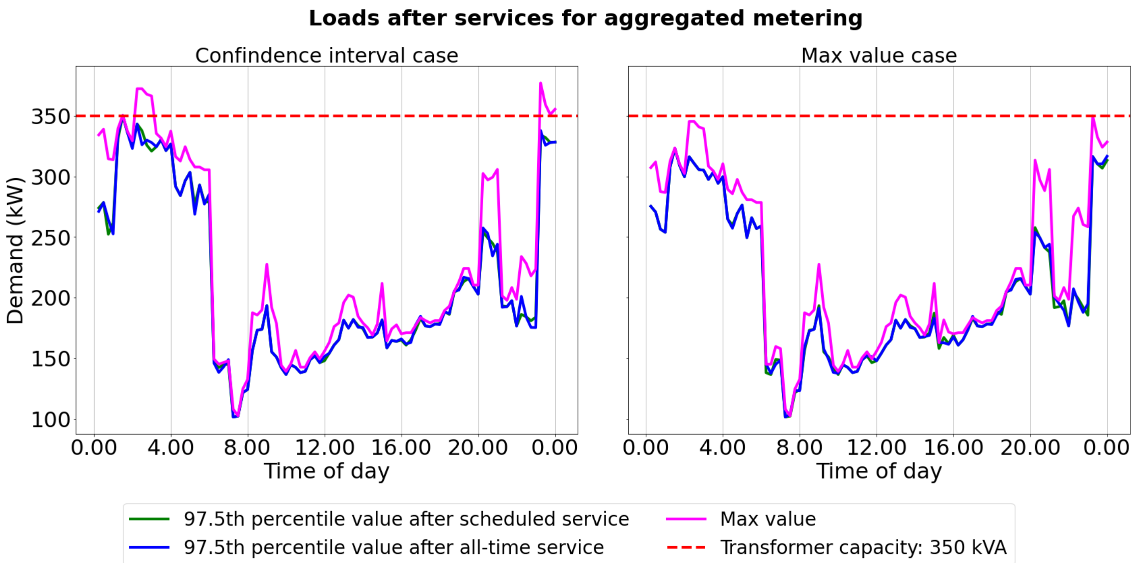

Figure 4.9: Loads after services for aggregated metering

It is clearly seen that services can solve the congestion significantly. With a higher amount of services using the highest loads day reference, the highest confidence interval line after is slightly lower. However, there is an issue with CLS by using the confidence interval as the reference. It cannot mitigate the congestion in the highest loads day. Therefore, using the highest loads day as the reference has a lower risk for service procurement.

In terms of service costs, if there is a CLS, this means that EVs cannot charge in full power during the low prices periods. CLSs increase the charging costs of the EVs. Therefore, the true cost of a CLS is the additional charging cost due to the capacity limit constraint, compared with the unconstrained case. Figure 4.10 illustrates two cost curves of CLS corresponding to 2 service types per day. The true cost of CLS from 0 kW to 670 kW is 0 DKK because the constraint doesn't affect the charging behavior. Note that the total fuse capacity is used as the reference capacity, which is an inflated number, due to the low utilization of inflexible demand. After 700 kW of CLS, costs are increased dramatically while there is only a small difference in costs between the 2 services (all-time and scheduled).

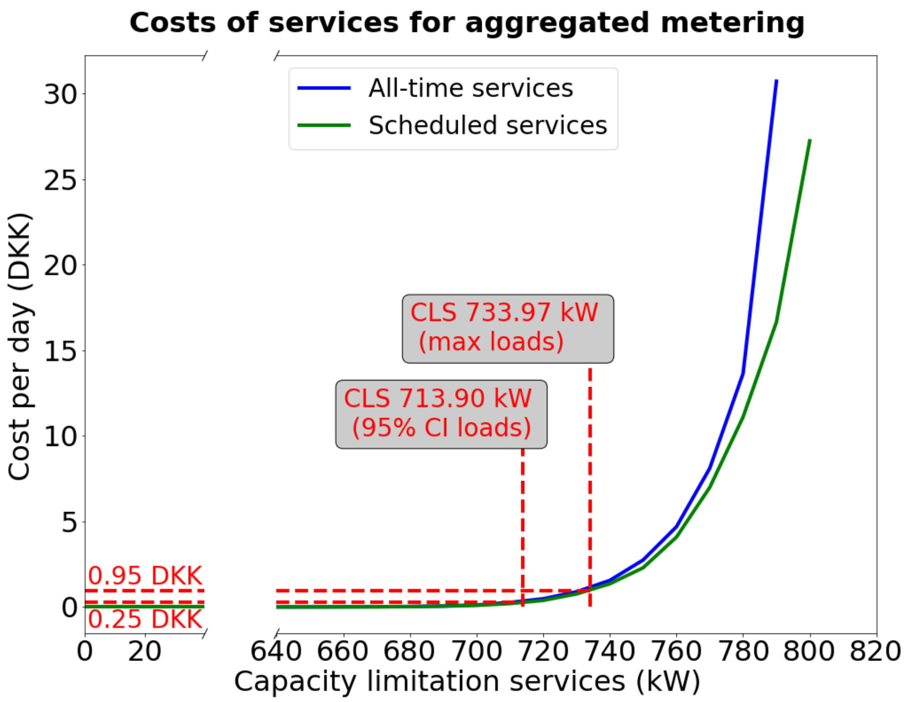

Figure 4.10: Capacity limitation service costs in the aggregated metering case

Finally, CLSs in aggregated metering can mitigate congestion effectively. To reduce the risk of congestion, the highest loads day should be represented as the reference congestion because it would need a higher amount of the service to ensure that even the highest loads cases are covered. In terms of costs, there is no significant difference between scheduled services and all-time services because the chargers are usually operated during nighttime. Moreover, using the highest loads day as the reference would need more CLS than using the confidence interval, by around 20 kW, which would entail a higher cost.

4.3.2 Disaggregated metering

The difference between the disaggregated and aggregated metering case is that flexible load data is able to be recorded separately from the main smart meters using sub-metering. With the assumption that 50 EVs will be participating in the market, the disaggregated metering case would consider only 50 selected EVs for participating loads while the aggregated metering considers both EVs and household loads under the main meter. The flow chart below 4.11 describes the process to define the CLS.

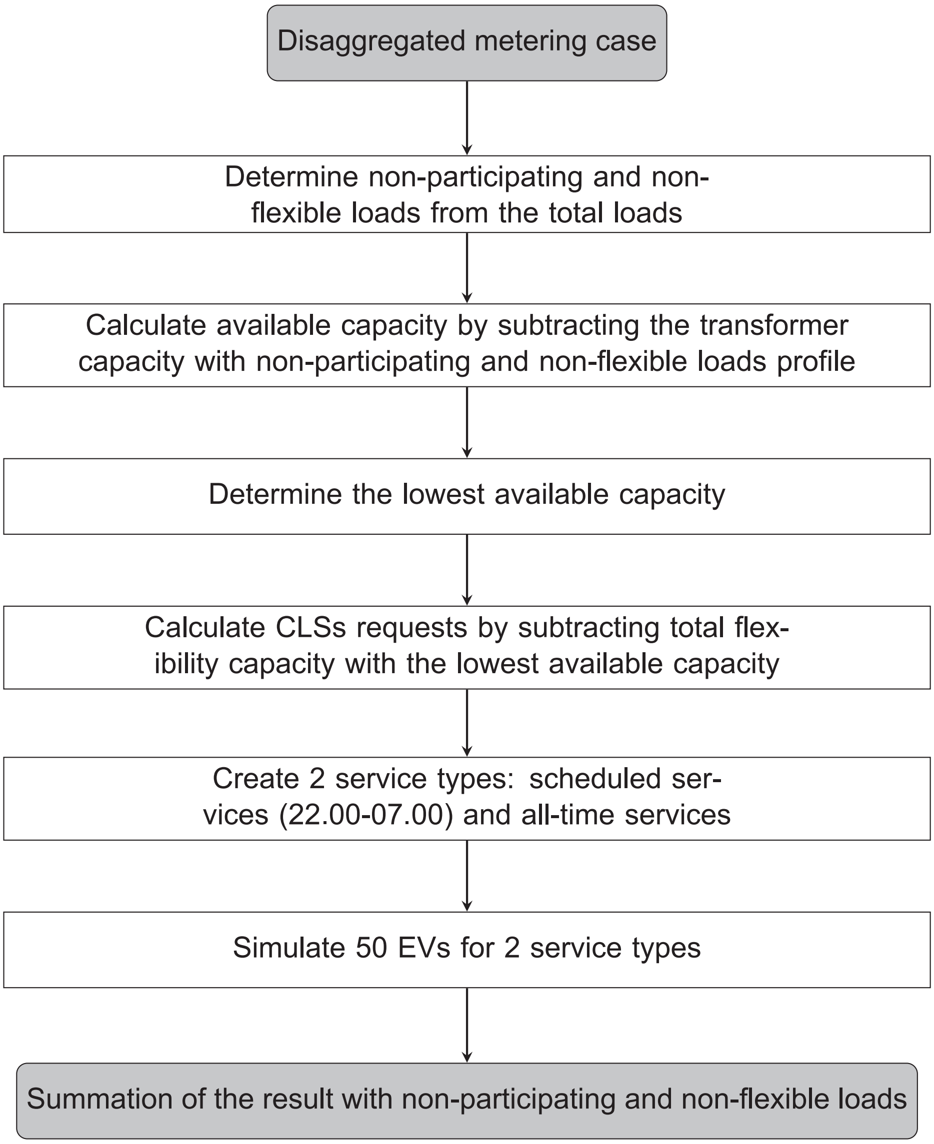

Figure 4.11: Flow chart of disaggregated metering with services

Overall, the process is similar to the aggregated metering case. With sub-meters, non-flexible loads and non-participating loads can be determined. Figure 4.12 shows non-participating and flexible loads containing 200 non-selected houses and 50 non-selected EVs (the previous case has 150 non-selected houses and 50 non-selected EVs) with two reference point between the confidence interval and the max value Loads pattern for the disaggregated metering is comparable with the aggregated metering.

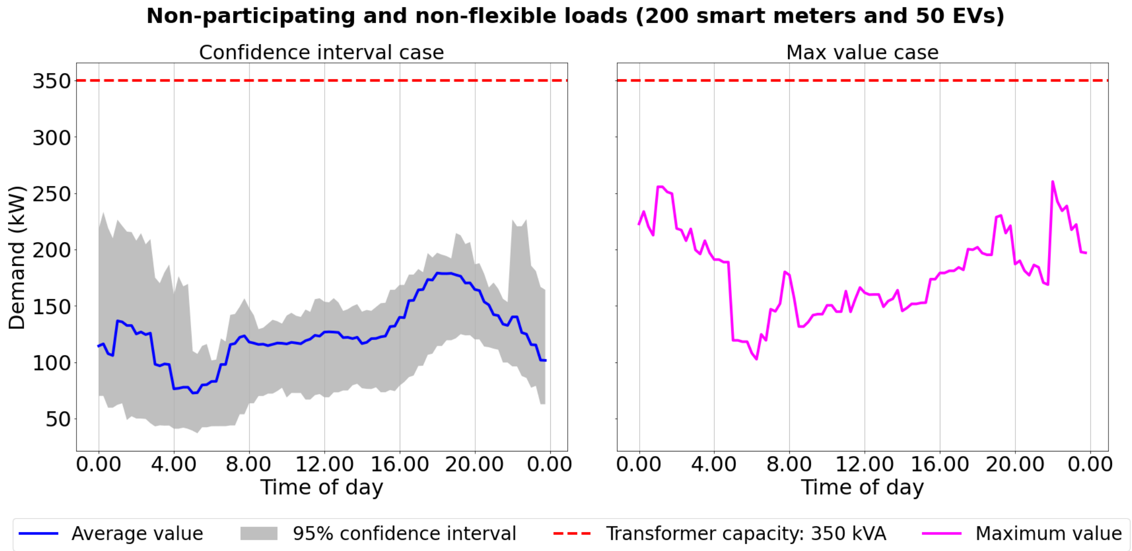

Figure 4.12: Non-participating and non-flexible loads for disaggregated metering

Then, the remaining capacity between the transformer capacity and those loads is the available capacity for participating loads shown in figure 4.13.

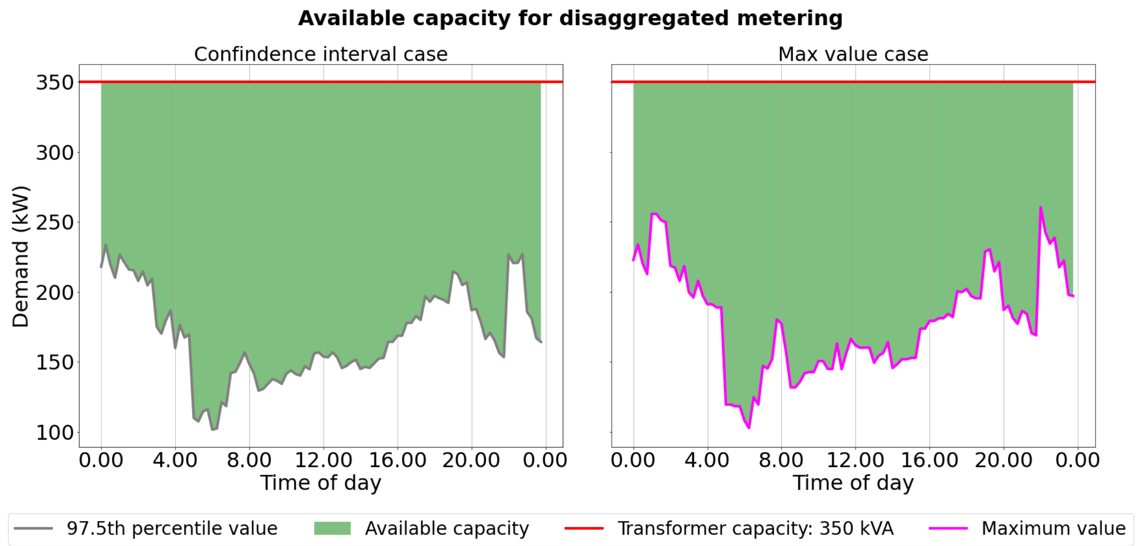

Figure 4.13: Available capacity for disaggregated metering

To find the CLS, the same process with the aggregated metering is applied. However, instead of the total fuse capacity, the total flexibility capacity is the service's reference point. Figure 4.14 presents the available capacity compared with the capacity of the total participating flexibility (EVs).

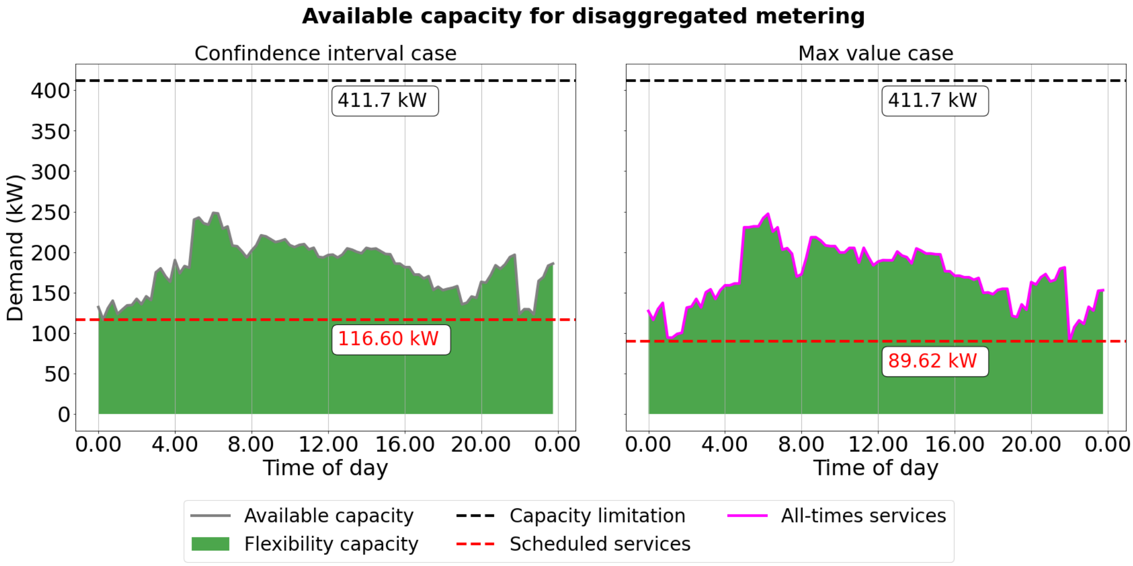

Figure 4.14: Available capacity for disaggregated metering

CLS request is the difference between the total flexibility capacity and the lowest available capacity. Figure 4.15 shows the available capacity compared with the total flexibility capacity. With the 95th percentile value, it requires a service of around 295.10 kW. On the other hand, with the max value, CLS request is slightly higher than using the confidence interval by around 27 kW, and equal to 322.08 kW. Those requests are based on the total flexibility capacity of 411.70 kW (total charger capacity).

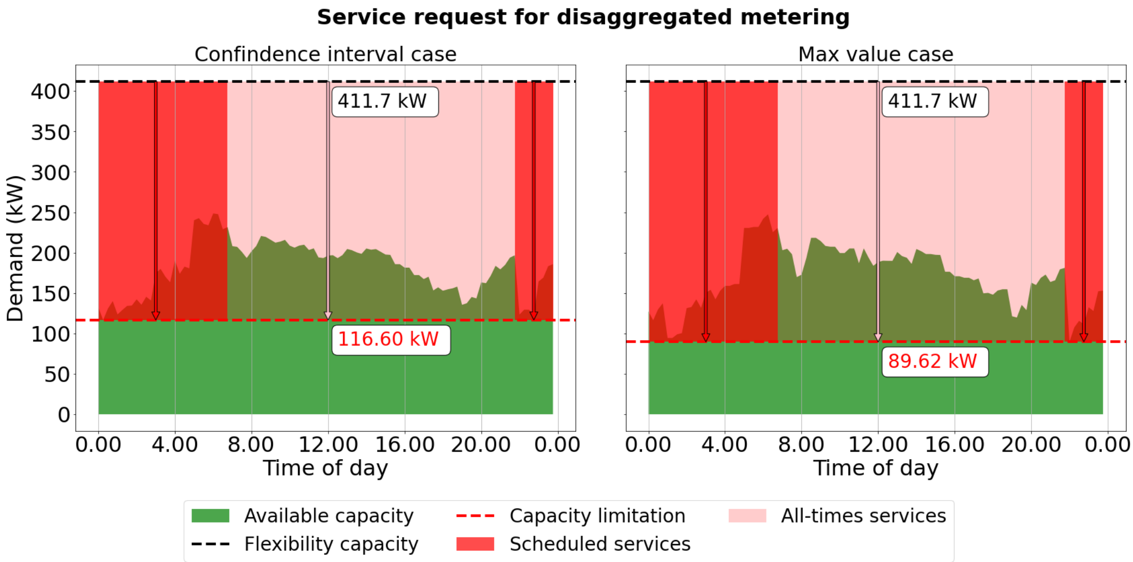

Figure 4.15: Service request for aggregated metering

An optimization problem of the disaggregated metering with CLS is represented in the same structure as the aggregated metering. However, there is a difference in the capacity limitation constraint that household loads are not considered. The problem is formulated as

$$\underset{P_{s,t}}{\text{minimize}} \quad \sum_{t\in\mathcal{T}}\sum_{s\in\mathcal{S}} P_{s,t}\lambda_t\Delta T \tag{4.3a}$$

$$\text{subject to} \quad 0 \le P_{s,t} \le P_{s,t}^{max}, \qquad \forall s\in\mathcal{S}, \forall t\in\mathcal{A}_s, \tag{4.3b}$$

$$P_{s,t} = 0, \qquad \forall s\in\mathcal{S}, \forall t\notin\mathcal{A}_n, \tag{4.3c}$$

$$SOC_{s,t+1} = SOC_{s,t} + \frac{P_{s,t}}{E_s^{kWh}}\Delta T, \forall s\in\mathcal{N}, \forall t\in\mathcal{A}_s, \tag{4.3d}$$

$$SOC_{s,t_k^{dep}} = 1, \qquad \forall s\in\mathcal{S}, \tag{4.3e}$$

$$SOC_{s,t_k^{arr}} = SOC_s^{arr}, \qquad \forall s\in\mathcal{S}, \tag{4.3f}$$

$$SOC_s^{arr} \le SOC_{s,t} \le 1, \qquad \forall s\in\mathcal{S}, \forall t\in\mathcal{A}_s, \tag{4.3g}$$

$$\sum_{s\in\mathcal{S}} P_{s,t} \le P^{cap,flex}, \qquad \forall s\in\mathcal{S}, \forall t\in\mathcal{T} \tag{4.3h}$$

Constraint 4.3h is only considering flexible loads to be limited based on flexibility capacity. With full-service provision, CLS of both cases can solve the congestion in the system.

Figure 4.16 illustrates the total loads after services for both service reference points.

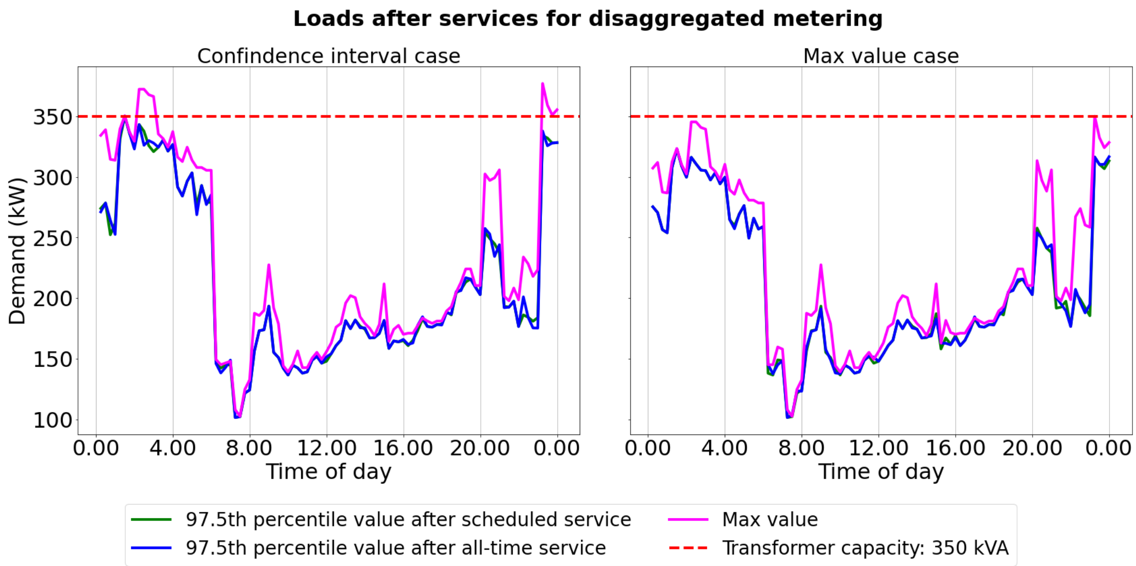

Figure 4.16: Loads after services for aggregated metering

Nevertheless, it shows the same issue with the aggregated metering: using the confidence interval as the reference point for service cannot clear all congestion that occurred on the max value.

In terms of costs, cost curves show the same pattern as the aggregated metering shown in figure 4.17. Without over-estimated capacity like fuse capacity, it needs less amount of CLS to solve the congestion.

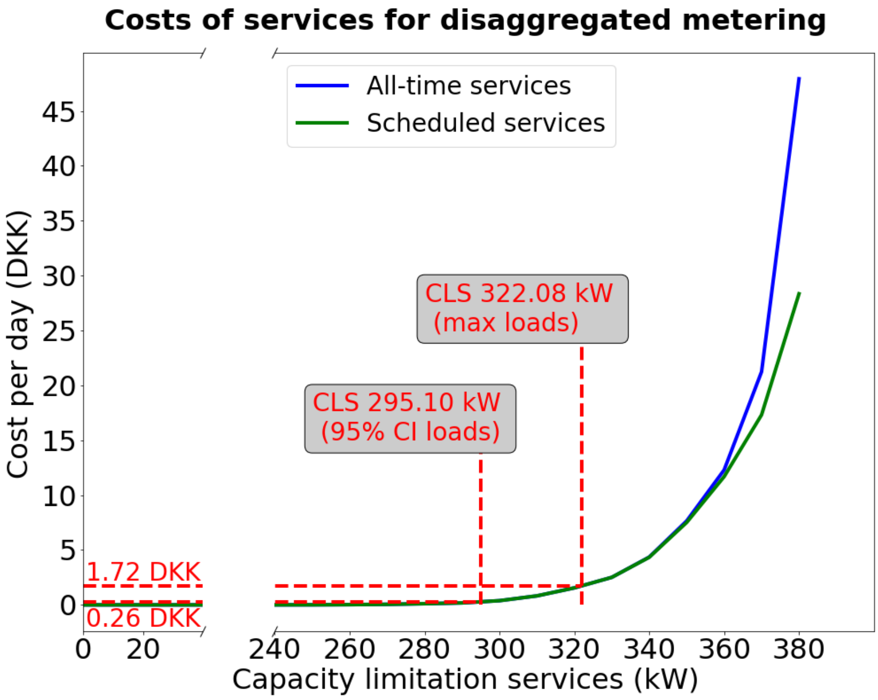

Figure 4.17: Capacity limitation service costs in the disaggregated metering case

4.3.3 Discussion between aggregated and disaggregated metering

Total CLS request

Although both methods provide satisfactory results in terms of congestion management, the amount CLS request in the aggregated metering case is much higher than in the disaggregated metering case. When considering the consumption using a load duration curve, it can be seen that 80 % of the time loads are below 200 kW for both cases. The aggregated metering that considers 50 households and 50 EVs has slightly higher loads. However, with the reference point at the total fuse capacity of 850 kW, there is a non-utilization capacity which is a gap between the fuses capacity and the maximum load of more than 600 kW. Compared with the disaggregated metering case that refers to services from the flexibility capacity of 411.7 kW, the maximum load of 50 EVs is 207.43 kW, reducing the non-utilization capacity to 204.27 kW. The comparison can be seen in figure 4.18

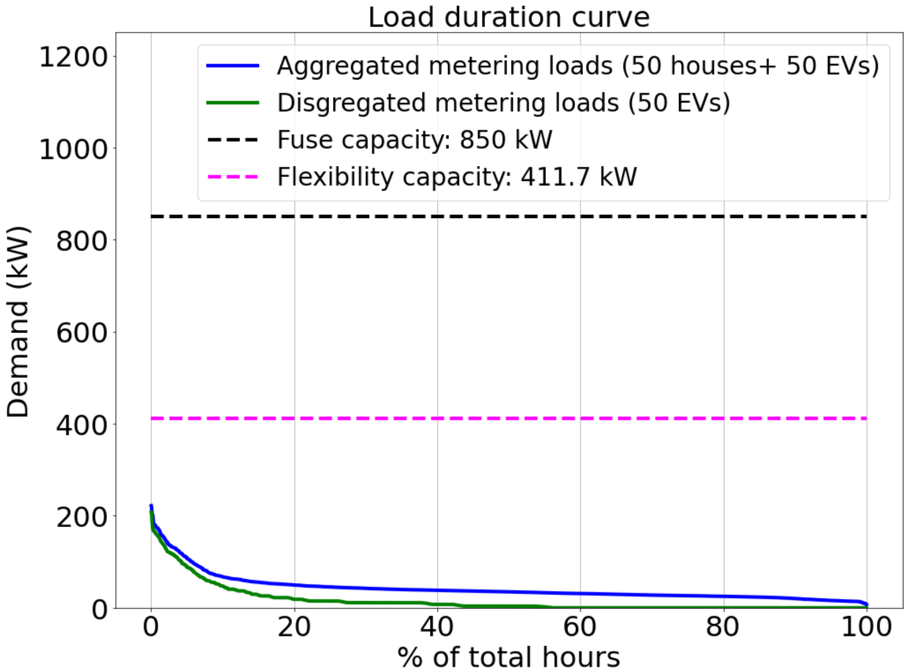

Figure 4.18: Load duration curve between 2 metering cases

Costs different

Figures 4.10 and 4.17 show costs of CLS based on the 95th percentile and max load values. With the same application using max values, it costs 0.95 DKK/day for the aggregated metering while the cost is almost 2 times higher, 1.72 DKK/day, in the case of the disaggregated metering. Figure 4.19 showcases this.

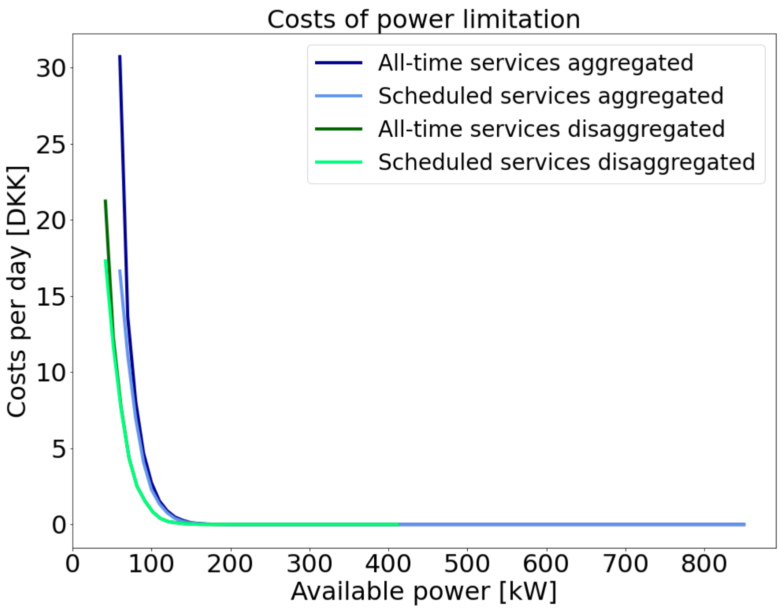

Figure 4.19: Costs of power limitation for every case

The reason why the services in the disaggregated metering case are more expensive is the available power for EVs. The disaggregated metering case has a power limitation of 89.62 kW while the other case has a limitation of 109.72 kW. The numbers for the two cases are not equal due to the household load taken into account for the aggregated metering. Since the max value concept is applied, the maximum value of the household load is used with the maximum value of EVs load for the non-participating loads to determine available power for the participating loads, which in reality households use less than the maximum during most periods. Thus, EVs are able to charge more power in cheaper price periods which made service cost lower. Figure 4.20 illustrates an average value, max value, and 95% confidence interval of EVs load after CLS for the aggregated metering.

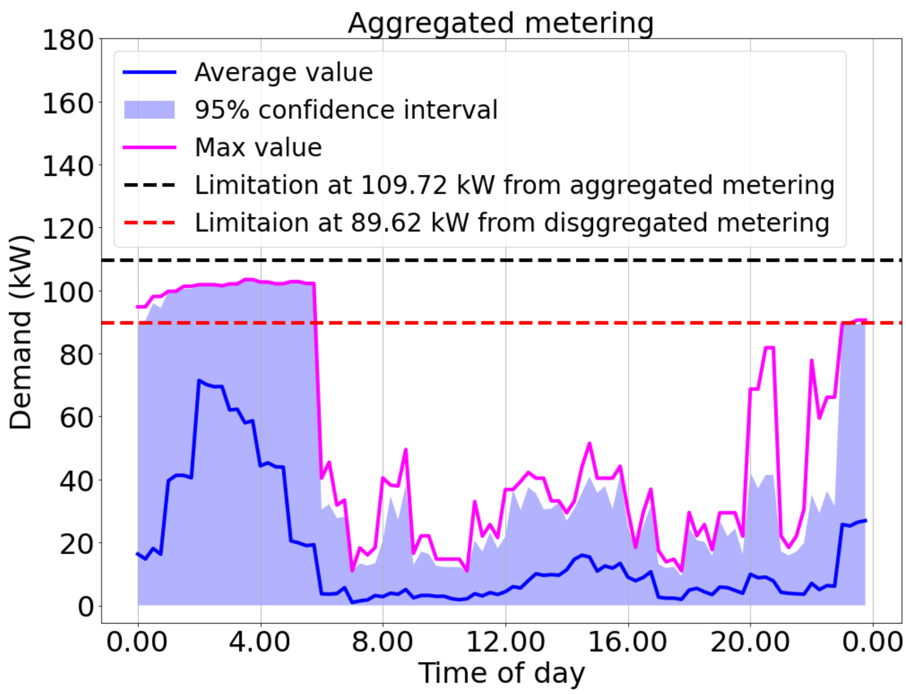

Figure 4.20: Loads after services for the aggregated metering compared with limitation from the disaggregated metering

In conclusion, the implementation of aggregated metering costs less than disaggregated metering. Nevertheless, there is a problem in terms of having to buy a large volume of services compared to the fuse capacity of the house. Another issue is related to accessibility in the main smart meter of prosumers. Generally, the main smart meter is set up and monitored by the DSO, which has an agreement with their customer. Access to customer data may require approval from both parties, which raises questions about the transparency of each aggregator's access to data.

In terms of service types, there is no significant difference between procuring services only in the nighttime and all the time. However, the all-time service has the advantage over the scheduled services in terms of reliability that it is not possible to generate a rebound effect causing another congestion.

4.3.4 An implementation on another period

The previous study illustrates the results that simulated data from January for 4 weeks. With the discussion between aggregated metering and disaggregated metering in the previous section, the application of disaggregated metering with all-time services seems to be more probable in terms of actual use.

In reality, the application of LFMs with CLS is used to prevent congestion in the future, while CLS request is based on historical data and may include forecasting. In this case, it is assumed that the procurement is happening between the end of January and the beginning of February. The CLS is procured based on information in January which is presented in section 4.3.3, then a new set of consumption data from February with the same households and EVs set is applied. Using the same assumption that the smart meter data is selected from the year 2014 and the EV data is selected from the year 2022 while the capacity of the network (the transformer) is 350 kVA.

Figure 4.21 shows the total loads in February with and without CLS. Loads deviation in February presents the same trend as January in that there is a high consumption at night and the maximum load is above 450 kW. After applying the services with the same services as January (322.08 kW), CLS can solve the congestion effectively.

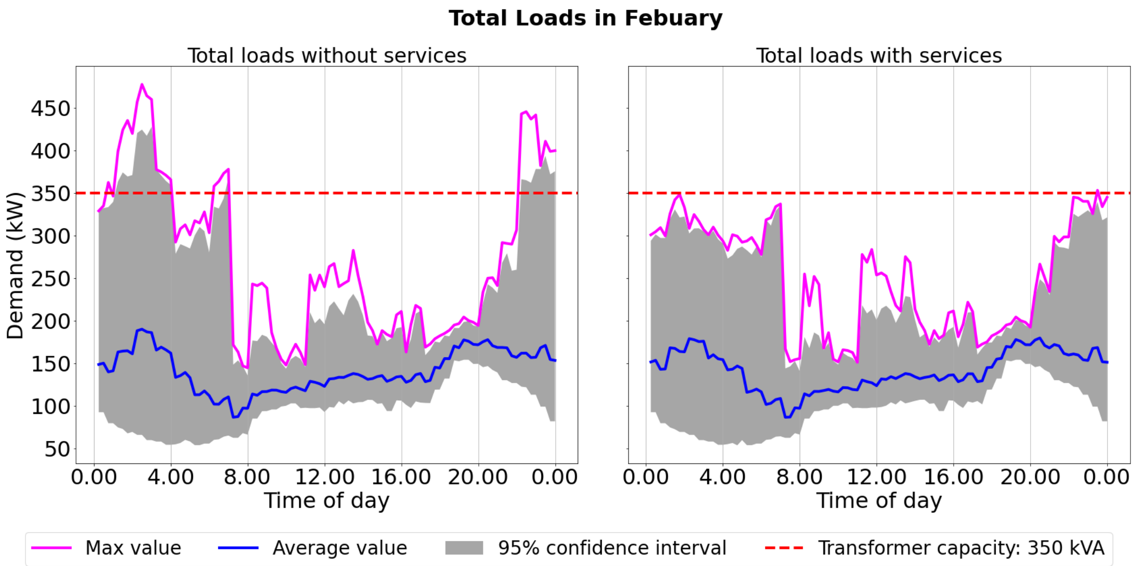

Figure 4.21: The total load in February

However, in terms of cost, with the same amount of services those cost in February 4 times more, compared to the cost in January, as shown in figure 4.22.

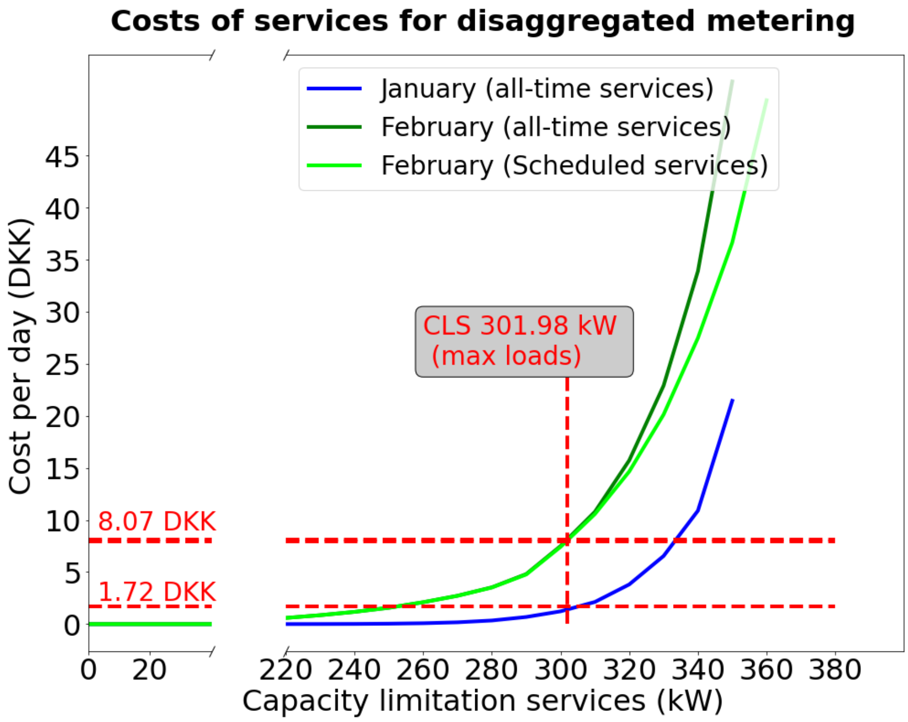

Figure 4.22: Capacity limitation service costs of February

The first reason why cost in February is higher is that the overall EV demand in February is higher. In February, EVs need 11,612.88 kWh of energy, while consumption in January is 10,577.89 kWh: this presents a 10% deviation. The second reason is related to spot prices. The employment of CLS causes the load to be shifted from the cheapest spot price hour to the next cheapest hour, which increases the overall charging cost. An analysis of the price difference between the cheapest hours and the second cheapest hours in figure 4.23 shows that the average difference value in February is 25% higher. Those 2 reasons made the overall service cost in February higher than in January, which will be an important factor to be considered for service procurement.

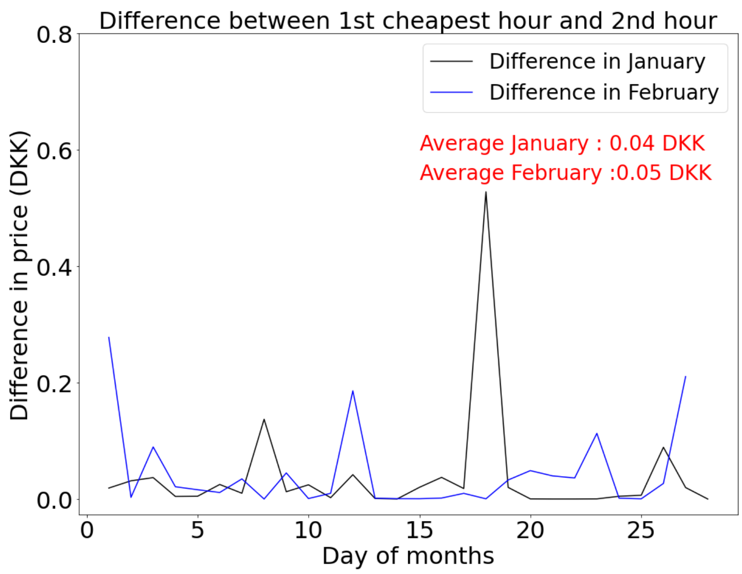

Figure 4.23: Spot prices in January and February

4.4 Market clearing simulation

In section 3.4, common market clearing mechanisms for electricity markets are introduced, namely PAC and PAB, and the uni-side VCG. This section will present market clearing results of the LFM based on the requirement of CLS and their costs in different market mechanisms. On one hand, load scenarios contained smart meter data, and EV data were simulated with optimal prices to present services cost curves for CLS in different levels, which would correspond to the supply curve in the market. On the other hand, the demand curve must be related to DSO benefit from the service. The literature review showed that many LFM projects have a similar goal of deferring grid reinforcement, including other methods for flexibility management such as dynamic tariff, and capacity subscription. Instead of investing in grid reinforcement to solve the congestion, DSOs may choose to pay for cheaper flexibility management. If the cost of CLSs is higher than deferring grid reinforcement, it might not be reasonable to employ them. However, employing these services may bring various benefits to the DSO. For instance, in terms of budget allocation, DSOs can reduce their budget and invest in more profitable projects while paying lower costs for CLSs. It is also beneficial to spread grid investments over time, so that a better labour utilization can be achieved, without concentrating network upgrade projects in a limited time period.

Market demand

In this project, market demand originates from the DSO request that want to procure service instead of investing reinforcement. The current network transformer has 350 kVA of capacity, which may not be sufficient to support large peaks. To avoid congestion, a bigger size of transformer needs to be installed instead of 350 kVA in the same substation. It is assumed that a 660 kVA transformer is a reasonable reinforcement size based on the maximum total loads, and it is a common and standard size. In Denmark, the estimated cost of the 660 kVA transformer is around 300,000 DKK. The number is provided by the Danish Utility Regulator (forsyningstilsynet). Normally, network infrastructure is designed to be operated for a long period such as 25 to 30 years. With the assumption of 30 years lifetime, the investment cost per year is around 10,000 DKK which is equal to 27.4 DKK/day. The cost of investment can be allocated to the alternative solution, the LFMs. In the LFMs, the investment cost is the maximum price that DSOs are willing to pay. The DSO needs at least 322.08 kW of CLS based on the disaggregated metering with max load reference from the previous section 4.3.3. In the section 3.1.3, the idea of tradable block service was introduced, where CLS is split into tradable blocks. With the maximum DSOs budget of 27.4 DKK/day, the average cost of 33 CLS blocks is 0.83 DKK/block/day.

Market supply

The market supply is related to CLS cost curve. With the application of the disaggregated metering in all-time services mentioned in section 4.3.3, the service true cost curve is presented in figure 4.24.

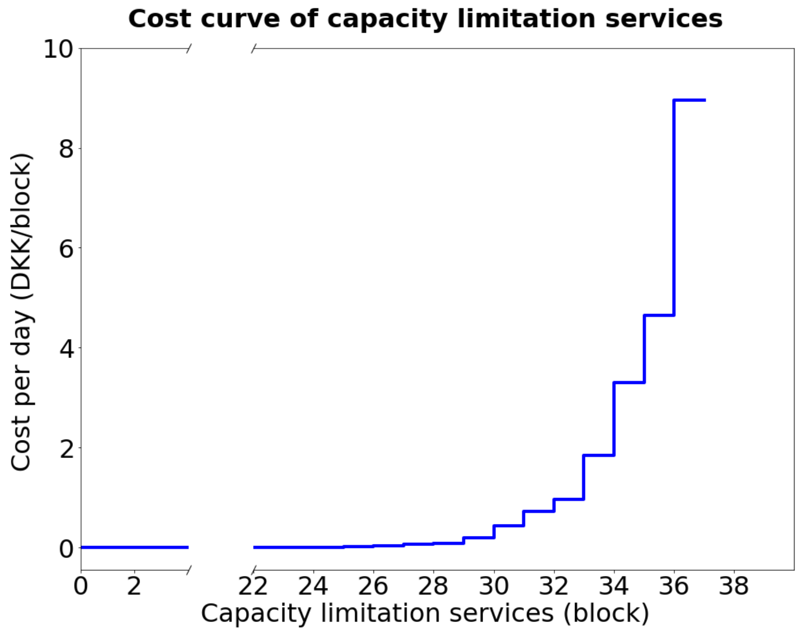

Figure 4.24: CLSs supply curve

However, the cost curve presents the service cost in case there is only 1 service provider, which does not reflect any market competition. Therefore, the 50 participating EVs are divided into 3 groups to present 3 FSP portfolios, as shown in figure 4.25 FSP number 1 has 13 chargers of 11 kW which equals 143 kW. FSP number 2 has 14 chargers of 11 kW which equals 154 kW. FSP number 3 owns the remaining 23 chargers of 3.7 and 7.4 kW corresponding to 114.7 kW.

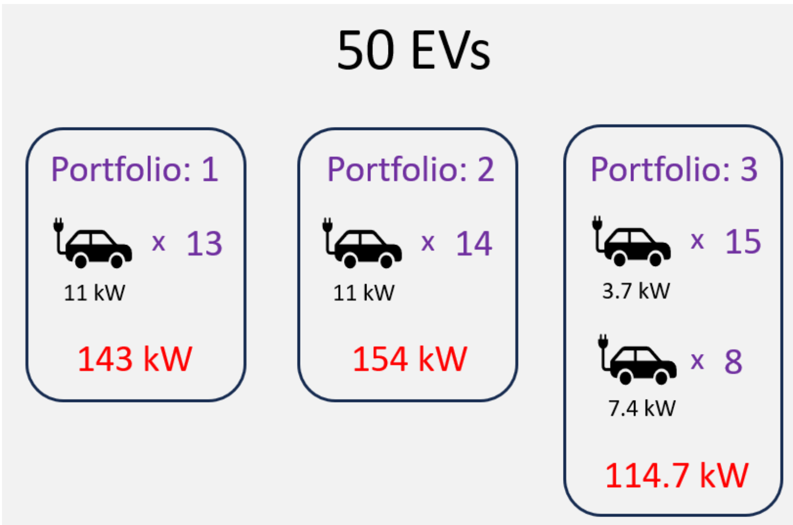

Figure 4.25: FSPs portfolios

After FSP portfolios are defined, each portfolio is simulated with the model 4.3a to determine their individual cost. Figure 4.26 shows the result of the simulations of all 3 FSPs on different CLS blocks.

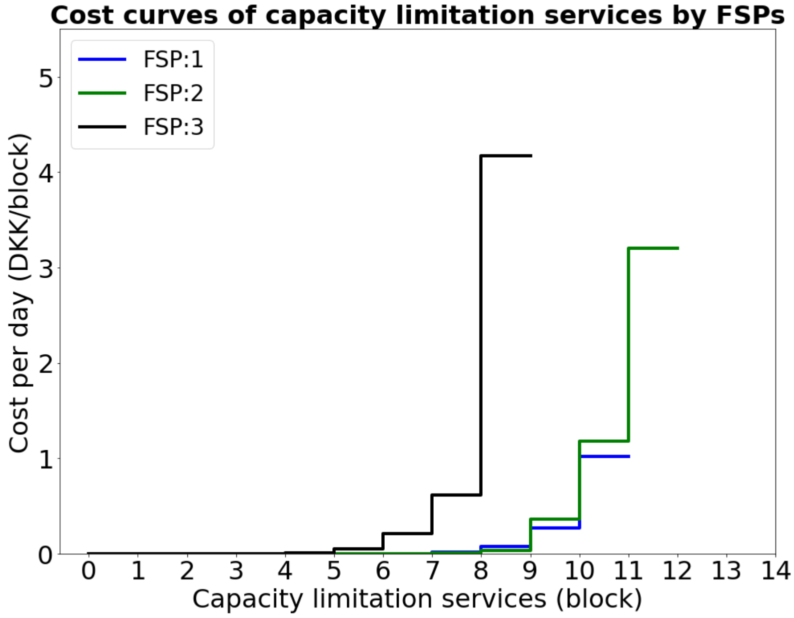

Figure 4.26: CLSs supply curves by FSPs

To participate in the market, offering orders from FSPs are aggregated by sorting their costs, as presented in figure 4.27.

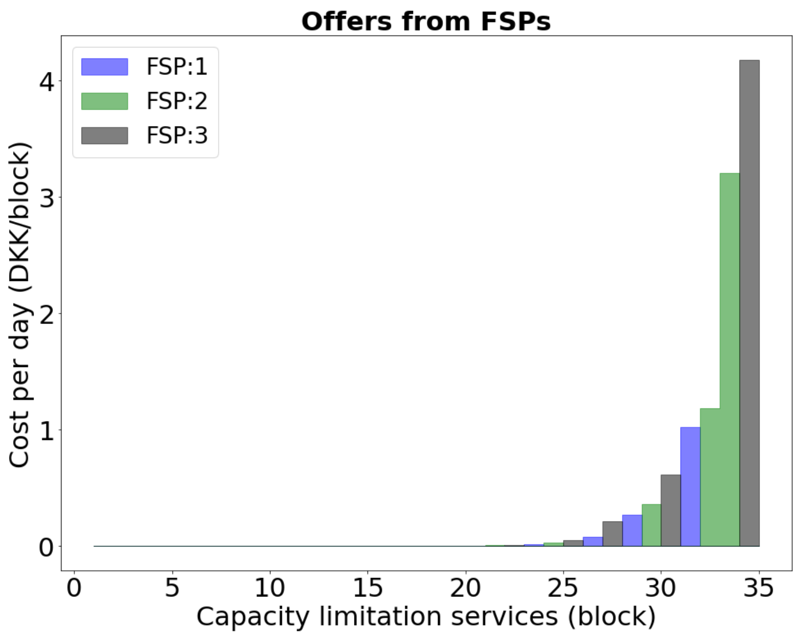

Figure 4.27: Aggregated CLS supply curves by FSPs

4.4.1 First market session

The first session is a transaction between the DSO and FSPs. The auction-based market might be the most appropriate way to procure the services in terms of social welfare. Three available options described in section 3.4 (PAC, PAB, and uni-side VCG) will be applied to see the market results.

PAC

To simulate PAC, an ideal market participation assumption is that the actual marginal costs are applied on bids and offers. From the explanation in section 3.4, the clearing mechanism of the PAC is determining the equilibrium point where demand matches supply. All selected offering orders will be paid at the same (clearing) price. To settle the market, an optimization problem is formulated as

$$\underset{P_f^F}{\text{minimize}} \quad \sum_{f \in \mathcal{F}} C_f P_f^F \tag{4.4a}$$

$$\text{subject to} \quad 0 \leq P_f^F \leq \bar{P}_f^F \quad \forall f \in \mathcal{F}, \tag{4.4b}$$

$$\sum P_f^F = P^{dso}, \tag{4.4c}$$

The objective function is to minimize service costs. P_f^F is a decision variable of CLS, indexed by a set of FSPs offering $\mathcal{F}$. C_f is an offering cost of each FSP. P^{dso} is a parameter from DSOs which is CLS request.

The result of the optimization problem can be seen in figure 4.28. The clearing price is 1.18 DKK/block, which is equal to the price of the last cleared unit.

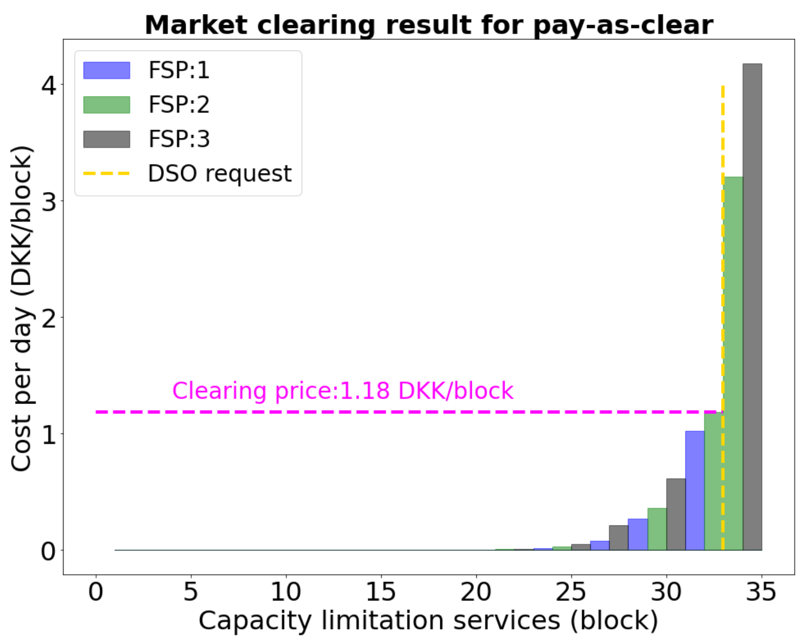

Figure 4.28: PACs market clearing result

In terms of profits and payment, table 4.1 presents payments and profits for each FSP. The total payment by the DSO is 38.96 DKK/day. All FSPs gain significant amounts of profits compared to their cost because of the concept of PAC using the price of the last unit, since the first 19 blocks in the market have zero true cost.

Service providers	Clearing unit (block)	Cost (DKK)	Payment (DKK)	Profits (DKK)
No. 1	12	1.38	14.17	12.79
No. 2	12	1.58	14.17	12.59
No. 3	9	0.89	10.62	9.74
Total	33	3.85	38.96	35.12

Table 4.1: Market clearing result on PAC

Nevertheless, when comparing the market result with DSO budget calculated from reinforcement cost, DSOs have a budget of 27.4 DKK/day with the willingness to pay for each CLS 0.83 DKK/block/day, while the total payment of services is 38.96 DKK/day. It may not be reasonable for DSOs to pay for the service under the assumptions of this case study.

PAB

In section 3.4, the principle of PAB was proposed, where orders are paid at their offering prices. Nevertheless, since there are two market sides, there is a question on which side will be paid for their bidding; a common solution is to settle at the average price between two matched blocks from the offering and demand side. DSOs bid for CLS request with bidding prices, while FSPs offer CLSs at offering prices. In the context of an auction-based market, the LFM with the application of PAB would probably be settled upon the FSPs offering side. An issue of importance with PAB is the bidding price strategy. Since FSPs will be paid upon their offer, they need to add a markup to their true cost, otherwise they will not be able to profit from the services. Since it is difficult to construct a DSO bidding curve and express the willingness of the operator to buy each block, a fixed demand is assumed, to the amount of blocks needed to avoid congestion. Thus, an optimization problem of PAB is formulated as the same with PAC 4.4a, however, instead of using the dual variable as the payment price, FSPs will be paid upon their offering.

The results of market clearing are present in 2 cases between clearing on cost and clearing on cost with markup.

PAB without markup

First of all, without markup, offers from FSPs are similar to offers in the PAC market. The result of market clearing can be seen in figure 4.29. In detail, the total cost and payment of each FSP are shown in table 4.2. FSPs are paid at their true cost, which returns no profits. There is no incentive for FSPs to participate in the market as a result. On the other hand, the DSO needs to pay for the services at the lowest cost of about 3.86 DKK/day, which results in the maximum social welfare of 23.55 DKK/day.

Service providers	Clearing unit (block)	Cost (DKK)	Payment (DKK)	Profits (DKK)
No. 1	12	1.38	1.38	0
No. 2	12	1.58	1.58	0
No. 3	9	0.89	0.89	0
Total	33	3.86	3.86	0

Table 4.2: Market clearing result on PAB without markup

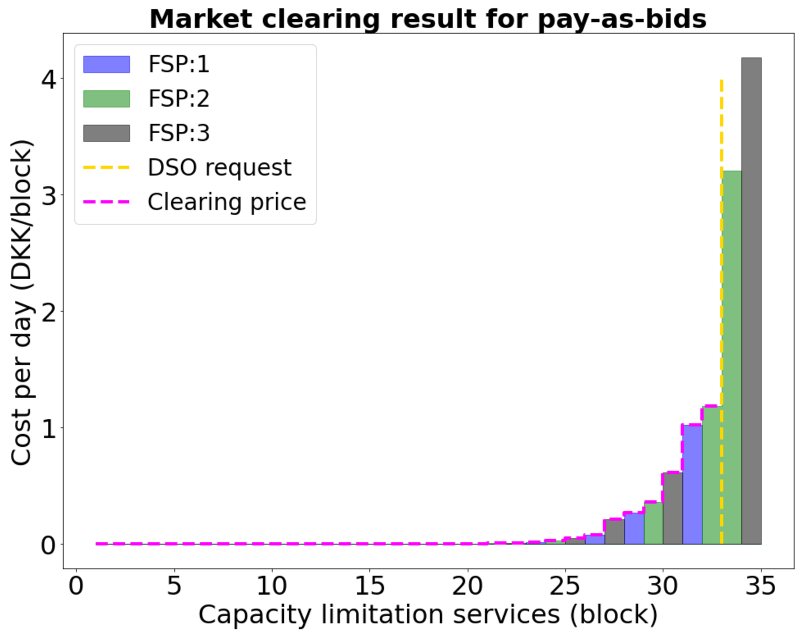

Figure 4.29: Market clearing result for PAB

However, apart from zero profits for FSPs, in reality, the market transaction needs to be performed before the expected congestion period. In this case, it is assumed that the market is performed with a month-ahead lead time. Data from January is used to make the transaction and then the result of CLSs will be employed in the next month, February. With uncertainties of consumption and spot prices, it creates a risk of loss for FSPs if service costs in the next month are higher than the payment from the market. Figure 4.30 compares the costs of services between January and February.

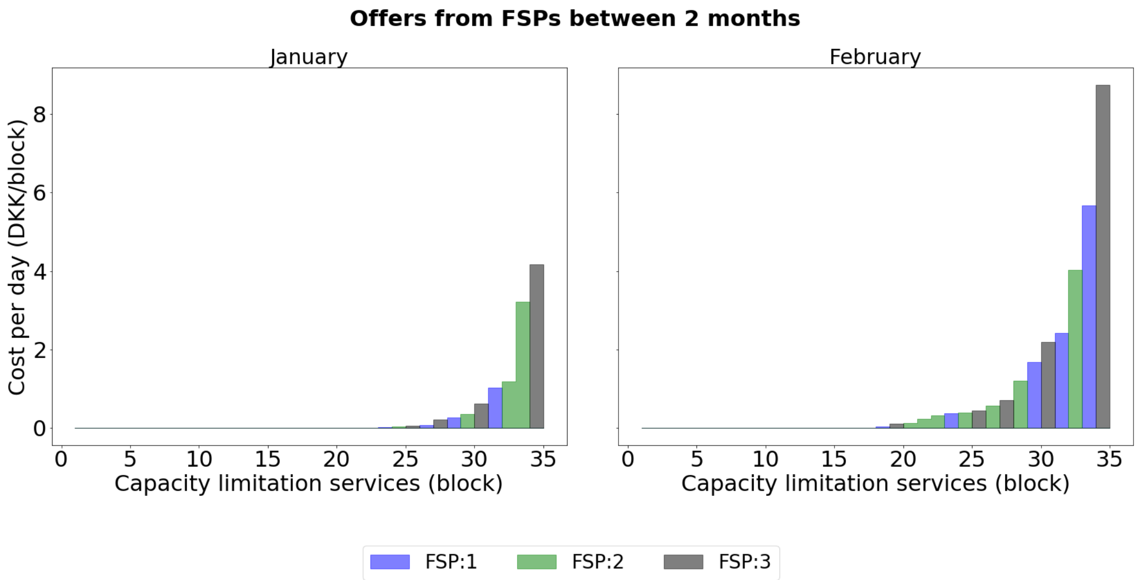

Figure 4.30: Offers comparison between 2 months

The costs dramatically increased in February. With the result of the transaction of 33 blocks from the same FSP, FSP no.1 will lose the highest amount because service costs increase by 638.09% while FSP no.2 suffers less from increased costs. The overall cost rises from 3.86 DKK to 16.48 DKK, more than four times the amount. It is also one the reasons why FSPs need markup for their offers.

Service providers	Clearing unit (block)	Cost in January (DKK)	Cost in February (DKK)	Increase/ Decrease(%)
No. 1	12	1.38	10.17	+638.09
No. 2	12	1.58	2.85	+80.33
No. 3	9	0.89	3.46	+290.55
Total	33	3.86	16.48	+326.94

Table 4.3: Costs comparison between January and February

PAB with markup

In the previous section, the market result that performed without markup price would generate a significant loss for FSPs. Therefore, this section will illustrate a simple concept of the markup price by adding the same number for all offers. Figure 4.31 presents the market result of PAB with markup prices of 0.1 DKK/block, which may be different for each FSP in fact.

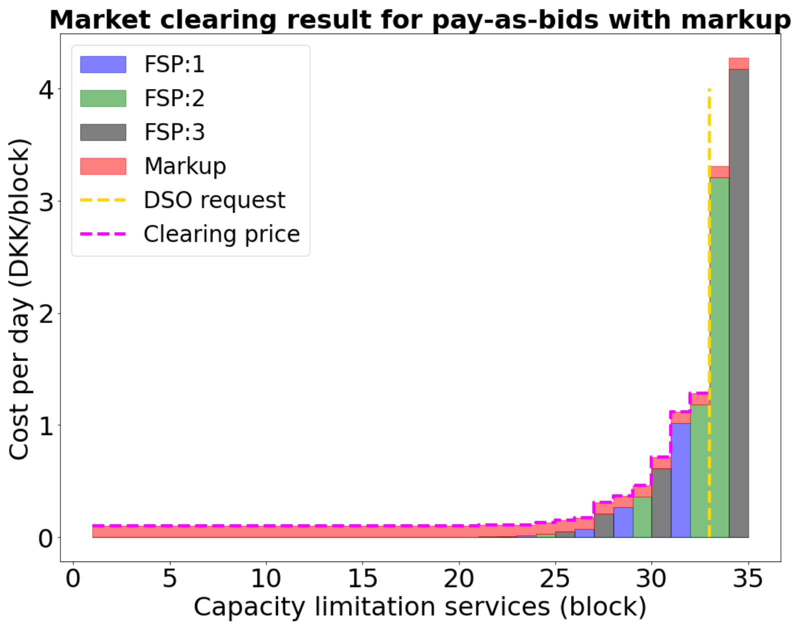

Figure 4.31: Market clearing result for PABs with markup

In terms of social welfare, increasing markup prices would increase profits for FSPs but they also generate higher payment from the DSO, which reduces the social welfare of the market shown in figure 4.32.

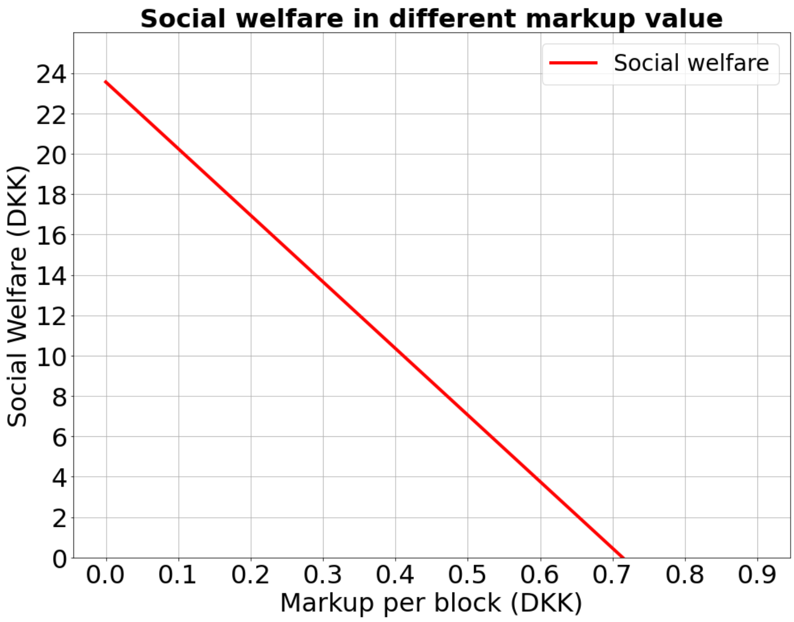

Figure 4.32: Social welfare in different markup values

In conclusion, without the uniform markup prices concept, additional cost (such as the increases in February) would not be covered. For instance, in the case of FSP no.1, CLS must be delivered with the payment of 1.38 DKK/day while service provision in February would cost them 10.17 DKK/day. FSP no.1 needs a total markup of 8.79 DKK/day to cover the additional cost corresponding to 0.73 DKK/block, which is close to the price that the DSO could pay without making social welfare negative.

Uni-side VCG

The idea of uni-side VCG is a new concept introduced to LFMs. This is the mechanism that encourages FSPs to offer their services with the true cost. With the description in section 3.4, it is the auction-based mechanism by clearing the market with all FSPs to generate a reference social welfare value. After that, we proceed with the market clearing again without individual FSPs one by one. FSPs will be paid based on their contribution. The optimization problem of uni-side VCGs is the same as PACs but the set of FSPs is adjusted. Unlike the general situation where many agents provide supply to the market, it seems to be an issue for this case because only 3 FSPs offer services in the market. Without one of them, the transaction cannot be made because due to a lack of supply. This is illustrated in figure 4.33

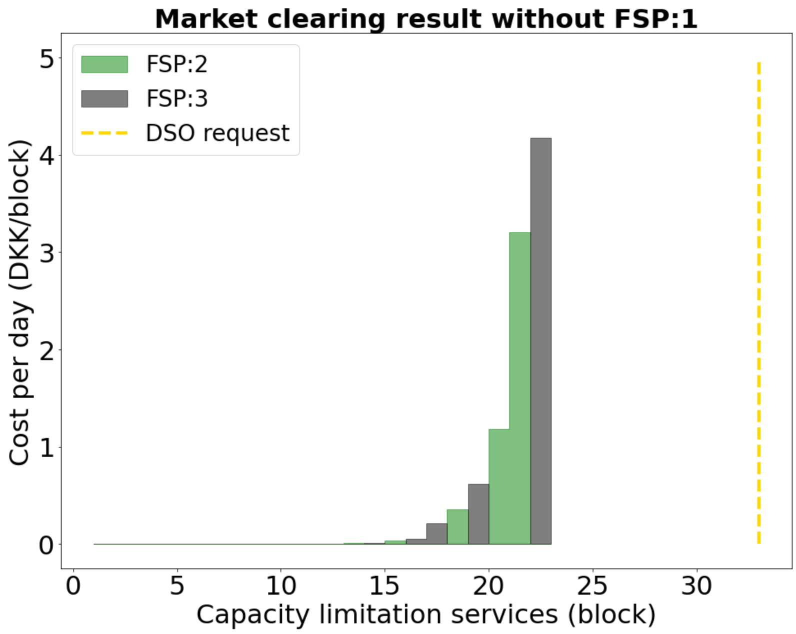

Figure 4.33: Market clearing result for uni-side VCGs

4.4.2 Second market session

This market session aims to allow FSPs to adjust their service among market participants. It is assumed that FSPs have knowledge of day-ahead spot prices and EVs connection schedules. Therefore, they can determine day-ahead optimal costs. FSPs can make their order to trade their services to increase their profits. For instance, FSP no.1 holds 12 CLS blocks from the first market session while buying back 1 block to reduce the limit to 11 CLS blocks can save their optimal cost up to 2 DKK/day. On the other hand, FSP no.2 holds the same 12 CLS blocks from the first market session while selling 1 block more to increase the limit to 13 CLS blocks would increase their optimal cost more 1 DKK/day. Thus, FSP no.1 can bid 1 block with the WTP 2 DKK, and FSP no.2 can offer 1 block with the WTA 1 DKK that orders can be matched.

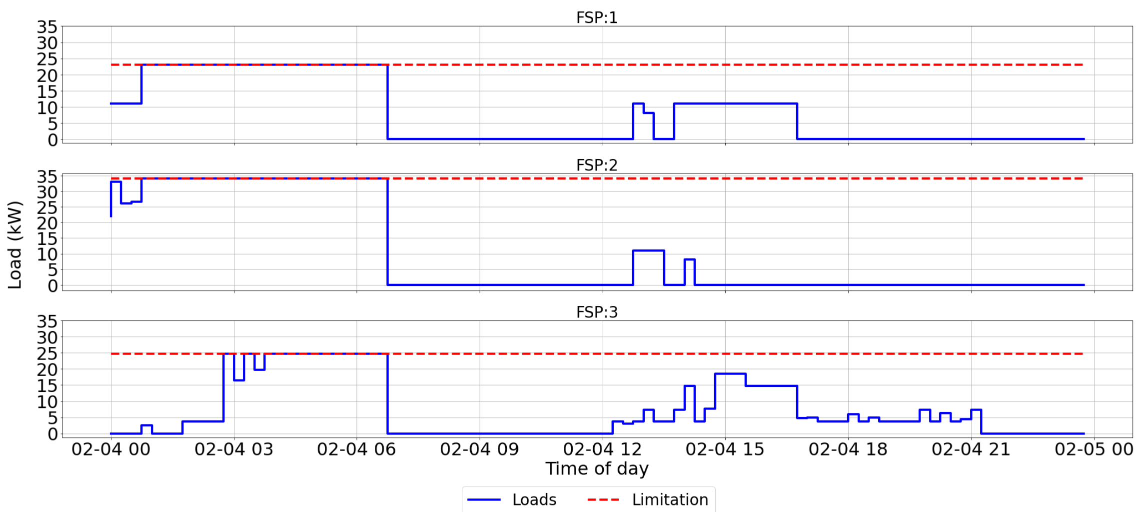

Figure 4.34: EVs load profiles of all FSPs in 4th of February

To illustrate with the study case, EV load profiles of 3 portfolios of 1 day were analyzed. On the day 4th of February, all portfolios consumed power at their limit, however, the consumption duration is different shown in figure 4.34.

When considering costs, table 4.4 shows that an increase of 10 kW of available power for FSP no.2 by buying back 1 CLS block can reduce their optimal cost up to 2.948 DKK/day. There is 1 block available for sale from FSP no.3 which cost them to pay 1.82 DKK/day more for the optimal charging.

Change in service (Block)	Chang in optimal charging cost (DKK/day)		
	FSP:1	FSP:2	FSP:3
Buy 1 blocks	+1.622	+2.948	+0.24
Sell 1 block	N/A	N/A	-1.82

Table 4.4: Change in cost on services adjustment

After knowing day-ahead estimated costs, FSPs can apply those costs to compute orders in the continuous market. Figure 4.35 shows the local order book of the continuous market and the market clearing. With the maximum WTP for 1 block of FSP no. 2 of 2.948 DKK, the order can be matched with the offer from FSP no.3 that WTA 1.82 DKK. Using fair payment, the clearing price is the middle point between the offering price and the bidding price, which is 2.384 DKK. As a result, FSP no.2 pays 2.384 DKK to FSP no.3 then they can save 2.948 DKK from the optimal charging cost which makes them earn 0.564 DKK of profits. On the other hand, FSP no.3 need to pay 1.82 DKK more for the optimal charging cost, however, they receive 2.384 DKK from FSP no.2 which makes them gain 0.564 DKK of profits similar to FSP no.2.

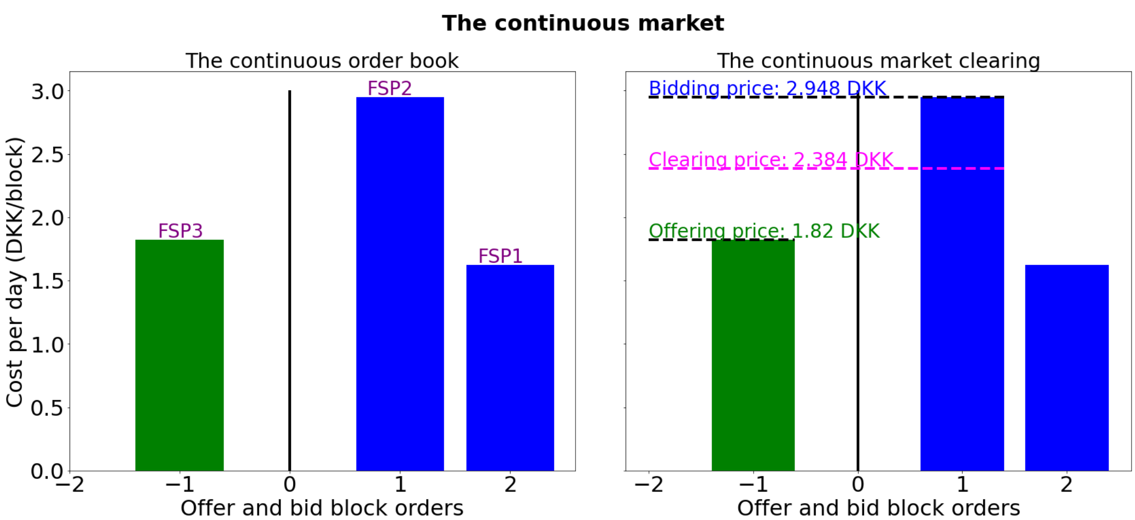

Figure 4.35: the continuous market clearing

In conclusion, the operation of 2nd trading session with the continuous market has the potential to increase the profits of market participants.

CHAPTER 5

Conclusion and future works

This chapter presents the conclusion of the thesis and future work.

5.1 Conclusion

In this thesis, a conventional methodology for implementing CLS in LFMs under network congestion circumstances was developed. The research began with a review of various LFMs, highlighting the challenges associated with employing BLSs and the advantages of using CLSs due to their structural characteristics. Based on these insights, design options for LFMs with CLS were proposed, focusing on metering points and market participants as key factors.

Two main options, i.e., aggregated metering and disaggregated metering, were investigated, considering two service types: scheduled services and all-time services. Historical data from 200 households and EVs were used to generate 24-hour load profiles with 15-minute resolution. The network capacity was artificially reduced to simulate congestion, and the metering concepts were applied to the load profiles. Aggregated metering effectively separated non-participating loads, leaving available capacity for participating households and EVs. Disaggregated metering, utilizing sub-meters, further identified non-participating and non-flexible loads. The results showed that the available capacity varied depending on the metering method and load profiles.

Cost analysis revealed that managing all congestion by using the maximum load values led to higher service costs compared to mitigating congestion within a confidence interval. Disaggregated metering with all-time services emerged as the most reasonable concept for CLS employment, despite the higher costs involved. Accessing the user's main meter for non-FSPs-owned assets proved challenging for FSPs.

To simulate LFM clearing, a tradable block service concept was introduced, and market mechanisms were evaluated. The first session involved transactions between the DSO and FSPs using an auction-based market, while the second session employed a continuous-based market for FSPs-to-FSPs interactions. PAB was identified as the most feasible mechanism for DSO-FSPs transactions, while the continuous market showed potential for generating additional profits by facilitating CLS trading between FSPs.

The findings of this research contribute to the synthesis and interpretation of the study's outcomes, providing insights into CLSs implementation in LFMs. The results highlight the importance of metering concepts, load profiles, cost considerations, and market mechanisms in achieving efficient and economically viable CLSs operations. These findings can guide future research and innovation in LFMs, facilitating the transformation of DNs into dynamic and resilient systems capable of accommodating the evolving energy landscape.

5.2 Future work

Future research in the field of LFMs and CLS can focus on several key areas. Firstly, an implementation with real-world network data can provide more accurate economic aspects of LFMs, including additional factors that can contribute benefits of grid reinforcement deferral. Increasing data samples over a longer period can provide a better understanding for CLS requests from the network. Market offering strategies should be employed to simulate different price scenarios that would reflect market settlement. An application of flexibility supply in LFM would be an interesting concept for CLS. Voltage congestion scenarios are also challenging issues in LFMs. Additionally, analyzing the regulatory and policy frameworks surrounding LFMs can help identify barriers and opportunities for market participation. Scalability considerations, advanced data analytics, and real-world pilot projects are also important areas for future investigation. By addressing these areas, we can enhance the implementation and effectiveness of LFMs, supporting the integration of renewable energy and DERs into the energy systems of the future.

Bibliography

[1] the European Commission. *European Climate Law*. Accessed: 2023-01-23. URL: https://climate.ec.europa.eu/eu-action/european-green-deal/european-climate-law_en.

[2] INTERNATIONAL ENERGY AGENCY. *Global Energy Review: CO2 Emissions in 2021*. Accessed: 2023-01-23. URL: https://iea.blob.core.windows.net/assets/c3086240-732b-4f6a-89d7-db01be018f5e/GlobalEnergyReviewCO2Emissionsin2021.pdf.

[3] *Quarterly greenhouse gas emissions in the EU*. https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Quarterly_greenhouse_gas_emissions_in_the_EU#Greenhouse_gas_emissions. Accessed: 2023-01-23.

[4] INTERNATIONAL ENERGY AGENCY. *IEA : A Roadmap for the Global Energy Sector*. Accessed: 2023-01-23. URL: https://www.iea.org/reports/net-zero-by-2050.

[5] IEA. *World Energy Outlook 2022 – Analysis - IEA*. IEA, 2022. URL: https://www.iea.org/reports/world-energy-outlook-2022.

[6] Xiaolong Jin, Qiuwei Wu, and Hongjie Jia. “Local flexibility markets: Literature review on concepts, models and clearing methods”. In: *Applied Energy* 261 (2020), p. 114387. ISSN: 0306-2619. DOI: https://doi.org/10.1016/j.apenergy.2019.114387. URL: https://www.sciencedirect.com/science/article/pii/S0306261919320744.

[7] Jacob Ostergaard et al. “Energy Security Through Demand-Side Flexibility: The Case of Denmark”. In: *IEEE Power and Energy Magazine* 19.2 (2021), pp. 46–55. DOI: 10.1109/MPE.2020.3043615.

[8] *Piclo Flex*. https://picloflex.com/. Accessed: 2023-02-19.

[9] *NODES*. https://nodesmarket.com/projects/. Accessed: 2023-01-23.

[10] Ioannis Bouloumpasis et al. “Local flexibility market framework for grid support services to distribution networks”. In: *Electrical Engineering* (Mar. 2021). DOI: 10.1007/s00202-021-01248-y. (Visited on 12/18/2021).

[11] Mohsen Khorasany, Yateendra Mishra, and Gerard Ledwich. “Market framework for local energy trading: a review of potential designs and market clearing approaches”. In: *IET Generation, Transmission & Distribution* 12.22 (2018), pp. 5899–5908. DOI: https://doi.org/10.1049/iet-gtd.2018.5309. eprint: https://ietresearch.onlinelibrary.wiley.com/doi/pdf/10.1049/iet-gtd.2018.5309. URL: https://ietresearch.onlinelibrary.wiley.com/doi/abs/10.1049/iet-gtd.2018.5309.

[12] Charalampos Ziras, Carsten Heinrich, and Henrik W. Bindner. “Why baselines are not suited for local flexibility markets”. English. In: *Renewable Sustainable Energy Reviews* 135 (2021). ISSN: 1364-0321. DOI: 10.1016/j.rser.2020.110357.

[13] Roman Hennig et al. “Capacity Subscription Tariffs for Electricity Distribution Networks: Design Choices and Congestion Management”. In: *2020 17th International Conference on the European Energy Market (EEM)*. 2020, pp. 1–6. DOI: 10.1109/EEM49802.2020.9221994.

[14] Chondrogiannis S et al. “Local electricity flexibility markets in Europe”. In: KJ-NA-31-194-EN-N (online) (2022). ISSN: 1831-9424 (online). DOI: 10.2760/9977(online).

[15] *Project LEO – Local Energy Oxfordshire*. https://project-leo.co.uk/. Accessed: 2023-02-01.

[16] *Project LEO and TRANSITION Market Trials Report (Period 1)*. https://project-leo.co.uk/reports/project-leo-and-transition-market-trials-report-period-1/. Accessed: 2023-02-01.

[17] *Project LEO and TRANSITION Market Trials Report (Period 2)*. https://project-leo.co.uk/reports/project-leo-and-transition-market-trials-report-period-2/. Accessed: 2023-02-01.

[18] UK Power Networks. *Participation Guidance Winter 2022 Flexibility Tender*. Accessed: 2023-01-23. URL: https://smartgrid.ukpowernetworks.co.uk/wp-content/uploads/2022/12/Participation-Guidance-PE1-0036-2022_1.1.pdf.

[19] Yi Ding et al. *Development of a dso-market on flexibility services*. English. iPower WP3.8 report, published on www.iPower-net.dk/publications, date:18-03-2013. 2013.

[20] Carsten Heinrich et al. "EcoGrid 2.0: A large-scale field trial of a local flexibility market". English. In: *Applied Energy* 261 (2020). ISSN: 0306-2619. DOI: 10.1016/j.apenergy.2019.114399.

[21] Stian B. Hackett. *+CityxChange*. https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5ca922065&appId=PPGMS. Accessed: 2023-06-13.

[22] Olivier Rebenaque et al. "Success of local flexibility market implementation: A review of current projects". In: *Utilities Policy* 80 (2023), p. 101491. ISSN: 0957-1787. DOI: https://doi.org/10.1016/j.jup.2023.101491. URL: https://www.sciencedirect.com/science/article/pii/S0957178723000036.

[23] Roman Hennig, Simon H. Tindemans, and Laurens De Vries. "Market Failures in Local Flexibility Market Proposals for Distribution Network Congestion Management". In: *2022 18th International Conference on the European Energy Market (EEM)*. Sept. 2022, pp. 1–6. DOI: 10.1109/EEM54602.2022.9920980.

[24] *UK flexibility tenders*. https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services. Accessed: 2023-01-23.

[25] Helge Stefan Esch et al. "Online matching and preferences in future electricity markets". English. In: *Proceedings of the Nineteenth Yale Workshop on Adaptive and Learning Systems*. Nineteenth Yale Workshop on Adaptive and Learning Systems
 ; Conference date: 10-06-2019 Through 12-06-2019. 2019. URL: http://www.eng.yale.edu/css/.

[26] Carsten Heinrich et al. "A local flexibility market mechanism with capacity limitation services". English. In: *Energy Policy* 156 (2022). ISSN: 0301-4215. DOI: 10.1016/j.enpol.2021.112335.

[27] *SmartMeter Energy Consumption Data in London Households*. https://data.london.gov.uk/dataset/smartmeter-energy-use-data-in-london-households. Accessed: 2023-03-29.

[28] *Radius,Connection fee*. https://radiuselnet.dk/tilslutningsbidrag/. Accessed: 2023-05-29.

[29] *Spirii*. https://spirii.com/en. Accessed: 2023-04-29.

[30] Steven Diamond and Stephen Boyd. "CVXPY: A Python-embedded modeling language for convex optimization". In: *Journal of Machine Learning Research* 17.83 (2016), pp. 1–5.

[31] Gurobi Optimization, LLC. *Gurobi Optimizer Reference Manual*. 2023. URL: https://www.gurobi.com.