DTU Wind and Energy Systems

Business cases and technological trends in vehicle-to-grid applications for residential users and fleet vehicles

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DTU Wind & 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 energy. Our activities develop new opportunities and technology for the global and Danish exploitation of wind 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 at the education.

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Approval

This master thesis has been submitted to the Department of Wind and Energy Systems at the Technical University of Denmark in partial fulfillment of the requirements for acquiring a Master of Science in Engineering in Sustainable Energy - Electric Energy Systems at the Technical University of Denmark.

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It is assumed that the reader has a basic knowledge in the areas of electrical engineering and mathematical programming modelling.

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Abstract

Replacing traditional vehicles with internal combustion engines holds significant importance in the context of decarbonization efforts. The successful integration of electric vehicles (EVs) is deemed critical for achieving this transition. However, the widespread adoption of EVs across private, commercial, and public entities needs a carefully devised strategy to mitigate potential challenges stemming from both a lack of acceptance and constraints within the power system. So-called vehicle-to-everything (V2X) services have the potential to address these issues, but currently remain unused in real-life scenarios due to their uncertain technical and economic feasibility. For this reason, this research project is dedicated to investigating the suitability and economic viability of V2X services specifically for residential users (RUs) and fleet vehicles in eastern Denmark. According to state-of-the-art literature, promising V2X services were identified as realistic business models. For the RU case, vehicle-to-home (V2H) behind the meter (BTM) and V2H front of the meter (FTM) were selected, while for fleet cases, the selected services are vehicle-to-building (V2B) FTM and vehicle-to-grid (V2G) frequency-controlled disturbance reserve (FCR-D). Subsequently, mathematical modeling is employed to formulate optimization models for each business case, aiming to simulate a year of operation with the aid of historical data. The results are then analyzed for their economical viability in comparison to a baseline scenario where no V2X service is implemented. For the RU case, the optimization yields average cost savings of 1,127 DKK leading to an amortization period of 5 to 69 years, depending on the V2X service, user type, and charging equipment supplier. Out of the selected services and user types, V2H BTM is most beneficial when applied to a *remote* user. The business models developed for fleet vehicles proved less feasible, V2B FTM did not yield cost savings. Conversely, V2G FCR-D led to savings of 1,752 Thousand (Tsd.) DKK, allowing an amortization within 26 to 51 years, depending on the equipment supplier. The implementation of all considered services faces challenges, as commercially available charging equipment and vehicles are still rare, and there are no standardized technical specifications. Additionally, the regulatory framework does not put a policy emphasis on these services. Rather than addressing their specific features, it categorizes them as both consumer and generator.

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List of Acronyms

ARC Amager Ressourcecenter

BRP balance responsible party

BSP balance service provider

BTM behind the meter

CCS combined charging system

DSO distribution system operator

EV electric vehicle

FCR frequency-controlled containment reserve

FCR-D frequency-controlled disturbance reserve

FCR-N frequency-controlled normal operation reserve

FEC full equivalent cycle

FFR fast frequency reserve

FRR frequency-controlled restoration reserve

FSM frequency sensitive mode

FTM front of the meter

LER limited energy reservoir

LFSM limited frequency sensitive mode

PA price arbitrage

PCC point of common coupling

PES production electricity supplier

PV photovoltaic

RES renewable energy sources

RoCoF rate of change of frequency

RR restoration reserve

RU residential user

SOC state of charge

SOH state of health

ToU time of use

Tsd. Thousand

TSO transmission system operator

V2B vehicle-to-building

V2C vehicle-to-community

V2G vehicle-to-grid

V2H vehicle-to-home

V2L vehicle-to-load

V2X vehicle-to-everything

VAT value added tax

1 Introduction

Efforts for reducing human society's impact on the environment and climate are growing around the world. While the deployed strategies take various forms, most countries agree that a sustainable solution for individual transport is required. To still reduce carbon emissions in this part of the sector, one technology is often seen as essential: The EV. However, to adopt the ambitious goals, set by the EU or other entities, society needs to be convinced of the benefit of EVs. As for the introduction of every new technology, the rising presence of EVs sparks concerns, from worries about their range, price, and the sustainability of their production to their impact on the electricity grid. Here, one buzzword is often thrown in which is supposed to counter at least some of the aforementioned concerns: V2X services. V2X refers to services provided by the battery of the EV to generate additional value while the vehicle is not utilized for driving, according to Thompson et al. [1]. This includes implementations with only one EV like V2H, especially suitable for private owners, as well as EV fleet services that are suitable for companies or larger entities, e.g. V2B.

Driving the development and implementation of such V2X services and the required technological infrastructure to enhance coordination between renewable energy sources (RES) and EVs to reduce emissions and promote decarbonization of road transport is the main goal of the project EV4EU [2]. This project funded by the European Union's program Horizon Europe aims to *"design and implement V2X management strategies to facilitate EVs' mass deployment"* [3]. Therefore, testing various user-centric approaches will involve not only developing services and methodologies but also tools, apps, and an open exchange platform for stakeholders and systems. The development is conducted under consideration of its impact on EV batteries, the environment, the power system, stakeholders' business models, and the transformation of cities. Finally, the V2X management strategies will be tested at four demonstration sites which are located in Greece, Portugal, Slovenia, and Denmark to enable a validation of the developed solutions and business models [2]. As a part of EV4EU, the project presented in this report aims to explore the profitability of V2X services in Denmark for RU and fleet vehicles. Specifically, the focus lies on the eastern part of Denmark, including the island of Zealand with the capital region and the island of Bornholm. From the perspective of the power system, the area is also called DK2. RU are considered as EV owners having the possibility to connect their vehicle at home, enabling a coupling to household consumption. As fleet vehicles, though, a group of EVs is regarded which acts as one entity to provide V2X services. Two V2X services are selected for each, the RU case and fleet vehicles, based on research on their expected feasibility. Furthermore, a suitable EV fleet will be selected, considering previous research and fleets implemented in Denmark. According to the services, four business models are developed and implemented as mathematical optimization models. Input scalars and parameters, like electricity prices or consumption, are chosen to make the optimization models as realistic as possible. Since the feasibility of the V2X services is of interest, the optimization models are designed to minimize overall electricity costs, including the electricity demand of connected buildings but also the charging of the considered EV. Additionally, depending on the service, revenues are considered, e.g. from grid feed-in, as a reduction of the costs.

V2X services have been under investigation for a while, however, the situation in the energy market is changing. In the year 2022, extreme electricity prices occurred throughout Europe. Additionally, Denmark introduced so-called time of use (ToU) tariffs in 2023, putting an increased tariff on consumption in peak hours and therefore contributing to an even more varying electricity price. At the same time, EVs are largely adopted, including private and public fleets. Thus, even though studies of V2X services have been conducted in the past, recent developments suggest that the profitability of V2X services could have changed, drawing from newly created opportunities. That is why, the presented project is set to assess the economic feasibility of selected V2X services for RU and fleet vehicles. Hereby, the focus lies on the following research questions:

- **Which V2X services are feasible for RU and EV fleets?**
  After selecting the most promising V2X services for RU and EV fleets, suitable business models will be developed. Those business models will then be tested by implementing optimization programs considering technical, economic, and regulatory restrictions. The results of this analysis will then be used to assess the feasibility of the V2X for EV fleets and RU.
- **Which are the most influential factors affecting the profitability of V2X services for EV fleets and RU?**
  Following the assessment of the feasibility of the selected V2X services, the influencing factors will be analyzed. Since especially regulatory and economic aspects determine the profitability and attractiveness of such services, cost structures, charging patterns, and revenue streams resulting from the optimizations will be regarded to detect the most influential factors.
- **Which regarded V2X service leads to the most battery degradation?**
  The implementation of EV and V2X services is supposed to increase sustainable development. However, when regarding batteries, the materials used for their production and therefore their lifetime and life cycle are often controversial topics. Consequently, the additional degradation caused by V2X services will also be considered in the developed models. Furthermore, the results will be used to determine the service affecting the battery of the EV most.
- **How can V2X services be made more feasible/attractive for EV fleets and RU?**
  At last, the insights gained from analyzing the different V2X services and EV fleets will be used to make recommendations for changes in regulation and economic frameworks which could lead to an increased attractiveness of V2X services.

To investigate the presented research questions, first, the two V2X services for each, the RU and fleet vehicles need to be selected, as well as the EV fleet to be regarded. The related research backing up the selection is consulted in Section 2.1. To enable the development of feasible business models for the selected services and fleet, regulatory and technical requirements are considered, including arising costs, and the needed charging equipment. The outcomes of this section are then used to develop four business models, of which two are suitable for RU and two for the selected fleet vehicles. These business models are the basis of the mathematical optimization models, presented in Section 4. In addition to describing the objective function and necessary constraints, all input scalar and parameters will be explained. Finally, in Section 5, the results of the optimization models will be presented and analyzed to answer the research questions posed previously.

2 Review of related literature

Since there are plenty of V2X services, various of them were regarded and compared to decide on the most promising ones. Therefore, state-of-the-art literature is consolidated in Section 2.1, assessing the feasibility of relevant V2X studies, including simulations, mathematical models, and real-world trials. Afterwards, in Section 2.2, the technical and regulatory requirements to implement the selected V2X services will be analyzed to enable the development of the business and optimization models. Lastly, suitable products will be investigated in Section 2.3 to ensure the inclusion of realistic parameters and to establish if such services could even be implemented by RU and EV fleet managers. This will include EVs as well as the charging equipment.

2.1 State-of-the-art V2X research

V2X services are categorized and named in different ways in the literature. Therefore, at first, a classification will be established as well as definitions for each service. Afterwards, the selection of the V2X services to be regarded for the business and optimization models will be explained.

2.1.1 Classification

Thompson et al. [1] propose to distinguish between V2G, V2H, V2B, vehicle-to-load (V2L) and vehicle-to-community (V2C). Hereby, V2G is used to describe energy services provided to the power grid utilizing the battery of the EV. V2H, on the other hand, refers to optimizing the electricity consumption of a household with an EV or using it as an emergency power backup. V2B has the same objective as V2H but is applied to commercial and industrial buildings, utilizing aggregated EVs or fleets to account for the increased energy and power consumption. V2L and V2C refer to any service of energy provision from an EV to a load, and aggregated EVs being connected to the distribution grid for services in a scale of a residential community, respectively [1]. Most research, like the International Renewable Energy Agency IRENA [4] and Pearre et al. [5], concentrates on V2G, V2H and V2B, though and therefore follow Thompson et al. [1] in their classification structure based on the infrastructure the services are provided to.

Still, other categorizations are used, for example by Gschwendtner et al. [6]. Hereby, V2X services are divided into transmission system operator (TSO) services, distribution system operator (DSO) services, and Vehicle-to-customer, depending on the institution, company, or person the service is targeting. TSO and DSO services correspond to services summarized under V2G, while Vehicle-to-customer includes V2H as well as V2B. However, since this classification is not commonly used in literature and is found to be less distinctive, the categorization presented first will be used in the following. The classification is shown in Figure 1.

As mentioned before, V2H and V2B offer similar services, but on a different scale to either residential or commercial and industrial customers. The services can be summarized as: price arbitrage (PA) BTM, PA FTM, and emergency backup. While BTM refers to power flows not "passing" the meter from the household to the grid, meaning all power transfer conducted as V2X service is only between EV and household, the term FTM is applied to services requiring power flows between the EV and the grid. Consequently, PA BTM is used to take advantage of price differences during the day by charging the EV during hours of cheap electricity prices and discharging it to cover on-site consumption during times of expensive electricity prices. PA FTM functions similarly, only that the surplus energy charged to the EV is not exclusively used to cover on-site consumption but also sold to the power grid. When not done by a household but, for example, a fleet, some research classifies it as V2G, like Thompson et al. [1]. However, there is no direct interaction with the wholesale electricity market or any grid manager, it is here classified as V2B for EV fleets, following Pearre et al. [5]. Emergency backup, on the other hand, refers to providing energy to a consumer in case of an outage [1]. As for the higher classification of V2H, V2G, and V2B there is no unified naming of the described services. Furthermore, some literature lists more services for V2B and V2H, like demand response or RES balancing [1, 5, 6]. Hereby, demand response refers to adjusting the charge or discharge rate of the EV according to the grid condition, as defined by Thompson et al. [1], while RES balancing aims to reduce curtailment. However, since electricity prices in Denmark indicate if demand or RES in-feed is high or low, PA of any kind automatically includes the provision of demand response or RES balancing. For this reason, no separation between them is done in the following.

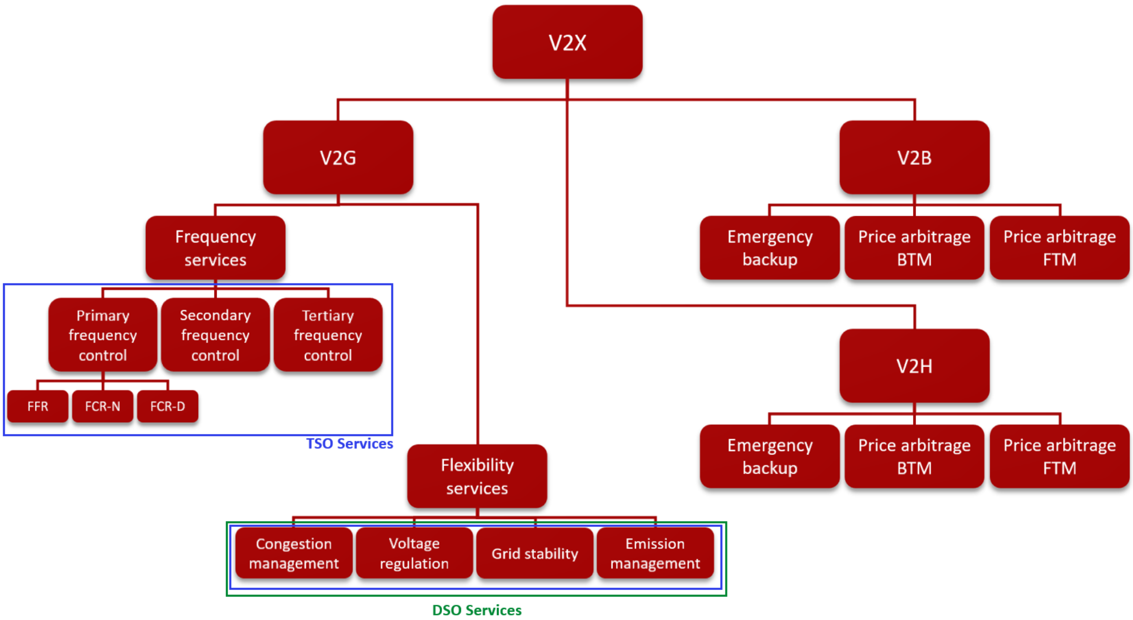


Figure 1: Classification of V2X services

For V2G, a general classification into frequency and flexibility services is applied, where the latter represents services tackling local problems of a power system, e.g. voltage regulation, according to Sevdari et al. [7]. Frequency services, on the other hand, concern a grid-wide parameter: the frequency. However, Gschwendtner et al. [6] and Arias et al. [8] distinguish between TSO and DSO services, assigning several V2X services to both categories as seen in Figure 1. Consequently, the classification of Sevdari et al. [7] is preferred. The specific services summarized under flexibility services are named and defined differently among researchers and even further split up in some literature, like by Sevdari et al. [7]. However, for reasons of simplicity, this is not done as part of the classification outlined in this work. Congestion management often refers to reducing the charging power of an EV following an economic incentive, e.g. high electricity prices, or other incentives to relieve highly loaded equipment, such as transformers or lines [6–8]. Some literature, though, calls it demand response, like Thompson et al. [1]. Since the latter is a very broad category that insinuates the inclusion of every action of adjusting demand, e.g. peak shaving, load shifting, etc., the described service will be referred to as congestion management in the following. Furthermore, voltage regulation is classified as a flexibility service by Sevdari et al. [7]. For EVs this involves providing active or reactive power support. This service is also referred to as voltage control, voltage support, or reactive and active power support in the literature [1, 5, 6, 8]. Third, Sevdari et al. [7] classify grid stability services, which include actions following the grid code to support system stability. Most literature, though, mentions the services summarized under grid stability separately, like Pearre et al. [5], Gschwendtner et al. [6], and Arias et al. [8]. Lastly, emission management shall be mentioned where consumption is reduced when there is a high share of polluting generators supplying energy to the grid [7]. However, this kind of service is not mentioned in most of the other reviewed literature.

Frequency services are separated into primary, secondary, and tertiary frequency control, as well as synthetic inertia. The first three refer to the common frequency control mechanisms in a power system, requiring different activation times, according to Zecchino et al. [9] and are regarded as frequency regulation or control by Thompson et al. [1], Pearre et al. [5], Gschwendtner et al. [6], Sevdari et al. [7], and Zecchino et al. [9]. Synthetic inertia, though, is rarely mentioned in research. It is supposed to reduce the rate at which the frequency changes, the rate of change of frequency (RoCoF), "by injecting power into the system", as stated by Sevdari et al. [7]. Primary frequency control, or frequency containment reserve in DK2 is divided into fast frequency reserve (FFR), frequency-controlled normal operation reserve (FCR-N), and FCR-D where the latter is only activated when the frequency deviation exceeds a certain value while FCR-N is used symmetrically for all deviations [9]. FFR, though, is delivered to support the frequency-controlled containment reserve (FCR) in the Nordic Power System [7]. Secondary frequency control is mostly referred to as frequency-controlled restoration reserve (FRR), aiming to reduce or restore the initial frequency deviation. At last, tertiary frequency reserves, the restoration reserve (RR) are activated to restore the frequency back to the normal value in case of longer-lasting disturbances [7].

2.1.2 Selection

After having established the definition of different V2X services and their classification in the previous section, the services that are to be regarded for the optimization have to be chosen. The selection, considering several different factors, will be described in Section 2.1.2.1. However, since there are also various EV fleets that could be suitable for V2X services, their characteristics will be explored as well. Therefore, recent trials and studies will be analyzed in Section 2.1.2.2 to enable a broad overview of EV fleets.

2.1.2.1 V2X services

To select the V2X services considered for the optimization model, different aspects are seen as decisive:

- Existence of a market
- Economical attractiveness
- Energy intensity
- Trials
- Suitability for EV fleets and RU

While the existence of a market can often be used to assess the economical feasibility, the energy intensity is included to consider potential battery degradation. Trials will be regarded as well to estimate the availability of data and the research need. The aforementioned aspects are also used to specify, if the service is suitable for single EVs from residential users, fleets, or both of them. The technical feasibility, though, will not be regarded since it has been already proven for the described services, as stated by Pearre et al. [5] and Sevdari et al. [7].

Providing emergency backup as a V2X service has been commercially implemented for V2H in Japan, according to Pearre et al. [5], which indicates an economic potential. Nonetheless, it is difficult to quantify the financial value. There is no market for the service, but for commercial and industrial customers the value of productivity could be considered [5]. However, it is highly dependent on the industry and company. For V2H application, the financial quantification is even more difficult since the value of preventing power outages would have to be determined for households, as stated by Pearre et al. [5]. Still, the service would be suitable for EV fleets and RU and is less energy-intensive since grid outages are rare [10].

For PA BTM there is no market but also no requirement for one. In contrast, PA FTM needs an existing market, like the wholesale electricity market in Denmark, since end users need to be able to react to dynamic price developments. However, it does not require a market where the service is offered and purchased. PA FTM is not as economically attractive as PA BTM, which has a high financial potential, according to Thompson et al. [1], since costs associated with grid feed-in reduce or erase the profit. Still, the energy intensity is estimated to be medium for the service while PA FTM should have a similar or higher energy intensity. The reason for that is the possible daily use of the battery of the EV for covering household or building consumption. While household consumption is limited to a few kWh, applying PA FTM could mean selling as much as the battery capacity and user constraints allow, to ensure economic feasibility. However, implementing PA BTM for a fleet could also exhibit high energy intensity, depending on the building supplied by the fleet. For both services, several trials have been or are still conducted, as stated by Gschwendtner et al. [6] and Marinelli et al. [11]. Due to the presented reasons, Emergency backup will not be regarded in the optimization models. Instead PA BTM and PA FTM will be investigated for RU application while only the latter will be explored for EV fleets. In the following PA BTM for RU will be referred to as V2H BTM, while PA FTM for RU will be called V2H FTM. Also, PA FTM for fleets will be named V2B FTM.

In the previous section V2G services were categorized into frequency and flexibility services. However, to assess the feasibility of these applications, the classification in TSO and DSO services can be utilized again. Although the usefulness of DSO services is highlighted by some, for example, Thompson et al. [1], there is no established market in most countries, including Denmark [6, 8]. Therefore, the financial potential is difficult to assess but some flexibility services, e.g. voltage regulation, are estimated to be less economically attractive by Thompson et al. [1]. Still, DSO services would be suitable for both, RU and EV fleets but their energy intensity cannot be safely estimated, as of now, due to limited research and trials [6, 8]. However, the results of the Parker Project [10] indicate a low energy intensity for congestion management, compared to PA for V2H and frequency services. For the last service defined as flexibility service, emission management, little information can be found in the literature. There is no economic incentive, specifically designed to avoid consumption of polluting generation units in Denmark. However, low electricity prices and high RES show a high correlation [12]. Therefore, emission management will not be regarded separately since it can be implemented within the scope of PA.

Conversely, frequency services are and have been investigated extensively. Since a market is already in existence in most countries, including Denmark, their economic attractiveness can be more easily quantified. Several studies and trials indicate a high economic potential for frequency services, as reported by Thompson et al. [1], Pearre et al. [5], and Aziz et al. [13], especially primary frequency control. Since secondary and tertiary frequency control reserves are activated less often than primary frequency control reserves and exhibit lower prices according to Aziz et al. [13], their financial attractiveness is lower. Due to the needed availability and capacity to participate in the frequency regulation market, though, the services are only suitable for EV fleets. Nevertheless, secondary and tertiary frequency control reserves are activated less often, so their energy intensity is lower than for primary frequency control. Taking a closer look at the latter shows, that especially FCR-N occurs frequently [10]. Consequently, this service exhibits a higher economic potential, as shown in the Parker Project [10], when also considering the higher prices of FCR-N. FFR, however, is not commercially available, as stated by Sevdari et al. [7] but would exhibit similar characteristics as described for FCR-D. Considering the before-mentioned information, FCR is chosen as a service for the models of EV fleets. Since a high energy intensity is expected from FCR-N, leading to battery degradation and therefore losses for the EV owners, FCR-D is chosen to be considered for the optimization - despite its lower economic attractiveness. Specifically, it was decided to model FCR-D up provision. FCR-D up requires discharging the fleet vehicles, so it induces a high SOC to be maintained, which results in higher battery degradation. Due to this mismatch between different cost aspects, FCR-D up is considered more interesting for the optimization, regardless of higher prices for FCR-D down reserve.

2.1.2.2 EV fleets

In addition to selecting promising V2X services to investigate, the focus of this project for EV fleets needs to be chosen. Looking at trials, it is apparent that most of them have been focusing on commercial fleets with their charging stations located at work, as specified by Gschwendtner et al. [6]. Table 1 shows a collection of relevant V2X trials and studies from the last five years. 11 out of the 20 shown trials and studies considered Frequency services. Furthermore, the trials were conducted primarily using small EVs. Larger vehicles, like vans, busses, or trucks are less often regarded, although Bus2Grid, Blue Bird School Bus V2G Commercialization Project, V2Go, and E-Flex are projects contributing to research on such fleets. Trials like Sciurus or Powerloop, however, consider aggregated, domestic fleets where EVs are charged at home but are coordinated to act as a fleet. Such fleets will not be regarded in the following, though, since RU will be investigated separately from fleets and as independently acting units. Still, since most trials and studies focus on commercial fleets charging at offices and considering small EVs, the optimization models developed in the following will explore public fleets, consisting of larger vehicles.

To conduct relevant research based on realistic data, existing EV fleets in Denmark are considered. The Danish public transport authority Movia operates electric public busses in East Denmark, following a plan to deploy 56 of them by 2019 and up to 200 - 250 by 2023 [14]. It is unknown if they are used for V2X services but as shown by Manzolli et al. [15] operating costs of busses can be significantly reduced by implementing the provision of such services. Furthermore, ARC is taking over household waste collection in Copenhagen and is, according to the Resource and Waste Plan of the municipality, obliged to use primarily electric garbage trucks. Already in August 2022, 24 such trucks were put into service, while the fleet is supposed to be increased to 100 vehicles by 2023

[16]. Again, it is unknown if ARC is utilizing V2X for their fleet. At the same time, electric trucks from Volvo are converted into concrete mixer trucks to be deployed in Denmark by the Danish company Unicon [17]. Furthermore, companies like Danfoss are utilizing electric vans for different kinds of operations [18]. It is consequently apparent that fleets of larger EV are being implemented in Denmark. Thus, for the following investigation, two relevant fleets are chosen: electric public buses and electric garbage trucks. To make the optimization model as realistic as possible, several fleet operators were contacted to get information about the vehicles. While no data about electric bus fleets was received, ARC provided information about their refuse truck fleet. Thus, only a refuse truck fleet will be considered for the optimization models.

Table 1: Collection of recent trials and studies

	Trial/Study	Type	Location	Time period	Charging technology	Service	Source
ACES	Trial + Study	Aggregated fleet	DK	2017 - 2020	DC	FCR-N, DSO services	[19]
Parker Project	Trial	Commercial fleet	DK	2016 - 2018	DC	FCR-N, FCR-D	[10]
GridMotion Project	Trial	Commercial, aggregated fleets	FR	2017 - 2019	DC & AC	TSO & DSO services	[20]
New Motion V2G	Trial	Commercial, aggregated fleets	NL	2016 - 2018	DC	Frequency control	[21]
Share the sun	Trial	Aggregated fleet	NL, BE	2019 - 2021	DC	Frequency control, DSO services, PA	[22, 23]
Bus2Grid	Trial	Public fleet	UK	2018 - ongoing	AC	Frequency control, PA	[24, 25]
e4future	Trial	Fleet	UK	2018-2022	DC	Frequency control, DSO services, PA	[26, 27]
Powerloop	Trial	Aggregated domestic fleet	UK	2018 - 2022	DC	TSO services	[28]
Sciurus	Trial	Aggregated domestic fleet	UK	2018 - 2021	DC	Frequency services, PA	[29]
V2Street	Trial	Aggregated fleet	UK	2018 - 2020	-	DSO service	[30]
V2Go	Trial	Commercial fleet	UK	2018 - ongoing	AC	Frequency control, PA	[31, 32]
E-Flex	Trial	Commercial fleet	UK	2018 - ongoing	-	Frequency control, PA DSO services	[33]
Blue Bird School Bus V2G Project	Trial	Public fleet	US	2017 - ongoing	DC	PA, Flexibility services	[34]
Polestar project: V2X	Trial	Commercial fleet	SE	2021 - 2024	-	V2G	[35]
ACDC Project	Trial + Study	Aggregated fleet	DK	2020 - 2023	DC	FCR-N	[36]
Charging Infrastructure 2.0	Trial	Aggregated domestic fleet	DE	2018 - 2022	DC	Flexibility services	[11, 37]
INSULAE	Trial + Study	Aggregated fleet	DK, HR, PT	2019 - 2023	DC	-	[11, 38]
BDL	Trial	RU, aggregated fleet	DE	2019 - 2022	DC	PA, Frequency control	[39]
Electric bus coordinated charging strategy	Study	Public fleet	PT	2022	-	PA	[15]
Optimized power dispatch for smart building(s) and electric vehicles with V2X operation	Study	Commercial fleet	PK	2022	-	PA	[40]
EV4EU	Trail + Study	RU, aggregated, commercial and public fleets	DK, GR, PT, SI	2022 - ongoing	-	V2X services	[2]

2.2 Requirements for V2X implementation

In the last section, several V2X services and EV fleets have been selected to be investigated in the optimization. However, before defining the business models in Section 3 as a basis for the optimization, the requirements to implement V2X services need to be clarified. Therefore, Section 2.2.1 deals with the regulatory framework to identify the market structure, access to the market, costs and remuneration mechanisms, as well as the technical regulation. Afterwards, the physical technical requirements for charging equipment and vehicles will be analyzed in Section 2.2.2.

2.2.1 Regulatory requirements

This section examines the regulatory background that governs the provision of the selected services: V2H BTM, V2H FTM, V2B FTM and V2G FCR-D, in DK2. First, it reviews the markets in which each service is provided. Depending on the proceedings of each market the pricing for each service can be determined. Furthermore, the active market participants construct the path to access the market for private customers. Consequently, there is an associated cost each market participant applies for their participation in trading the service. Finally, each service provision is regulated by technical requirements that must be met to be allowed to offer the service.

2.2.1.1 Electricity markets in Denmark

The trading of electricity is organized in pools or exchanges. Each one of these is divided into several marketplaces depending on the time horizon that is traded: day-ahead, intraday, and regulating/balancing (real-time). Denmark participates in the Nordpool wholesale market, which includes: Elspot, the day-ahead market; and Elbas, the intra-day market. Commonly, the day-ahead market is the preferred marketplace for short-term transactions. Later adjustments of day-ahead contracts are possible in the intra-day market. Finally, in the real-time operation, there could be a mismatch between production and demand. It is then the responsibility of Denmark's TSO Energinet, to ensure the balance between production and demand through the regulation/balancing market.

The day-ahead market is essentially an auction of sellers and buyers with a settlement according to the merit order principle. The market is cleared every day where producers offer energy to sell and retailers, and in general, a balance responsible party (BRP) buys electricity for its consumers [41]. The intra-day market, on the other hand, is a continuous market, where from day-ahead gate closure up until one hour before real-time, any pair of buyers and sellers can sign bilateral contracts to adjust their day-ahead schedules. The contracts are handled through a central platform. The regulating/balancing market combines as a single market mechanism the regulation market, where the TSO buys power reserve capacity, and the balancing market, where the reserved capacity can be activated if needed. The balancing market has a gate closure and a clearing mechanism similar to the day-ahead market. Consequently, the V2G FCR-D is traded in the regulating/balancing market. The services V2H BTM, V2B FTM and V2B FTM, though, are traded in the day-ahead market, where electricity is bought and sold.

Typically consumers buy electricity from the electricity supplier, who is their primary contact with the electricity system. In turn, the electricity suppliers buy power from the market through a balance responsible actor to sell it to the customer. The electricity supplier is in charge of collecting payments for consumption, taxes, tariffs, and transport from the customer. Finally, the balance responsible actor buys electricity in the wholesale energy markets on behalf of the suppliers. They are financially responsible for imbalances between expected and actual consumption during the operating day [42].

It is also important to mention aggregators responsible for aggregating controllable electricity consumption and production. The current legal framework in Denmark guarantees that the aggregator has direct access to the regulating market without requiring to enter an agreement with other market participants, for instance: the electricity supplier and BRP associated to a customer [43]. Aggregator models may vary, they can be electricity suppliers or act as independent aggregators. In the case of the latter, they do not themselves assume responsibility for balancing. However, they should provide compensation towards any imbalances incurred by other BRPs because of their regulation actions. Currently, in Denmark, aggregators deal with the automation of smart charging of EVs aiming to charge in the cheapest hour or to interrupt by offering savings and discounts on the consumer electricity bill.

2.2.1.2 Market access

RUs or entities taking advantage of V2H or V2B FTM are treated as auto-producers of electricity. An auto-producer is an electricity consumer who produces electricity. They are classified into large or small power generation plants depending on whether their rated electrical input exceeds 50 kW for photovoltaic systems, 25 kW for wind turbines, and 11 kW for other generation installations. To be considered an auto-producer, the installation in question must be connected to its own consumption installation. The measurement of electricity production and consumption are to be carried out by Energinet while the costs related should be borne by the auto-producer [44]. However, auto-producers cannot participate independently in the wholesale electricity market, rather they have to enter into an agreement with a production electricity supplier (PES) [42]. The PES is a special type of supplier who sells electricity to or purchases electricity from a person or entity covered by a customer number on the wholesale market [45]. As of now, six PES exist in Denmark, which purchase electricity from private plant owners of solar, wind, or battery technologies. Consequently, feeding electricity into the grid using EVs must be managed by a PES.

When it comes to participating in the ancillary service market, to provide most frequency services an entity has to have a contract with a BRP. If supply involves one or more of the energy-poor system services, like FFR, FCR and FCR-D, the entity can report directly to Energinet without a BRP, if it is registered as a balance service provider (BSP). A BSP is a company that meets the qualification requirements for one of the mentioned ancillary services (see Section 2.2.1.6) and that has an ”Agreement on the supply of balancing services without energy supplies” signed with Energinet [46]. Thus, a supplier of balancing services can be an electricity producer, an electricity consumer, or an actor/aggregator who disposes of specific target consumption/production to provide balancing services.

In brief, RUs and entities in V2H FTM and V2B FTM are classified as auto-producers of electricity and need a PES to access the day ahead market, whereas a normal electricity supplier is sufficient for RUs in V2H BTM. In contrast to that, access to the regulating/balancing market in V2G FCR-D may vary as several options can apply. However in the business model in subsection 3.4 the interaction with the regulation market is considered through an aggregator.

2.2.1.3 Payment and pricing

The V2X services selected in Section 2.1.2.1 include different mechanisms to generate revenue. Thus, the regulations regarding their respective pricing and payment are presented separately, starting with the mechanism of FTM.

Payment and pricing for FTM

The net settlement of auto-producers is specified in [47]. The calculations are based on measured production of electricity, done through measurements denoted M1, and measured delivery of electricity to and from the electricity supply network, denoted M2 and M3, respectively. Net electricity consumption can be thus calculated with M3-M2. The net settlement of auto-producers is divided into three groups. In Group 1 total production and consumption are treated separately on an hourly basis. There must be a consumer electricity supplier to take care of the gross consumption M3 and a production electricity supplier to attend to the entire measured production M1. For Group 2 both production and consumption will be measured together on an hourly basis. For each hour it will be either: net consumption, handled by the consumption supplier, or net production, handled by the production supplier. The participants of Group 6 were offered an annual settlement, but this practice ended in 2020 [48].

PES business models may vary, however, in the scope of this project Group 1 settlement will be contemplated for V2H FTM and V2B FTM. Hereby, they purchase from their customers the hourly measured electricity production $M1_{(t)}$, in kWh, at a price referred to as the spot price hour by hour, in Dkk/kWh, as seen in Equation 1.

$$p_{FTM} = \pi^{spot}_{(t)} \cdot M1_{(t)} \tag{1}$$

Payment and pricing for FCR-D

FCR-D reserve is procured at daily auctions in the regulation market. The bids must include an hour-by-hour volume and a price for the day of operation. The volume stated is the number of MW that the bidder is offering to make available. The price is the price per MW per hour asked by the bidder to make the volume stated available. Each bid must be entered for a minimum of 0.1 MW. Generally, in a bid time series (procured per day) volumes may change from hour to hour, but the price must be the same. If the market participant uses block bids, the volume must be the same within each block [49].

All bids accepted will receive an availability payment corresponding to the participant's bidding price (pay-as-bid). No calculation is made of energy volumes supplied from frequency-controlled disturbance reserves. Indeed, the service providers do not receive any payment for the energy delivered from FCR-D activation. Therefore, for V2G FCR-D let $p_{FCR-D,up}$ denote the payment given to the supplier for FCR-D upward provision. It is the product of the capacity reserve kept for upward FCR-D provision $C_{resup,D}$, in MW, and the price bid for the capacity reserve, $\lambda_{resup,D}$, in €/MW, as shown in Equation 2.

$$p_{FCR-D,up} = \lambda_{resup,D} \cdot C_{resup,D} \tag{2}$$

For downward reserve the formulation is similar:

$$p_{FCR-D,down} = \lambda_{resdown,D} \cdot C_{resdown,D} \tag{3}$$

2.2.1.4 Costs

Generally, power consumption costs include several components specified in Table 2 in the consumers pay division. These components are added on top of the hourly spot price $\pi^{spot}_{(t)}$, as denoted by Equation 4.

$$\pi^{el} = \left(\pi^{spot}_{(t)} + \tau^{n} + \tau^{s} + \tau^{ToU} + tax^{el}\right) \cdot (1 + VAT) \tag{4}$$

First, from the side of the TSO there is the network tariff τ^n and system tariff τ^s whose values are stated in Table 2 [50].

Table 2: TSO tariffs in 2023

Energinet's electricity tariffs in 2023	
Consumers pay	
Network tariff	0.058 DKK/kWh
System tariff	0.054 DKK/kWh
Producers pay	
Feed-in tariff in consumption-dominated areas	0.003 DKK/kWh
Feed-in tariff in production surplus areas	0.009 DKK/kWh
Balance tariff for production	0.0016 DKK/kWh

Next, from the side of the DSO, there is the ToU tariff τ^{ToU}. This tariff makes a distinction between low, high, and peak load hours. Furthermore, it varies seasonally between summer and winter. Here as well, the division of customers is introduced. Residential or private customers are classified within category C, while medium-sized and large businesses are classified as A or B customers. The specific values for the ToU tariff for consumers in category C are shown in Table 3 where winter is defined from October to March and summer from April to September [51]. They apply for the RU cases of V2H BTM and FTM.

Table 3: Seasonal ToU tariff for general consumers, current prices for October 2023 [51]

Season	**Low load** 12 am - 6 am	**High load** 6 am - 5 pm & 9 pm - 12 am	**Peak load** 5 pm - 9 pm
Winter time [DKK/kWh]	0.1126	0.3378	1.0133
Summer time [DKK/kWh]	0.1126	0.1689	0.4391

The values for the ToU for business consumers, for instance, A-low are shown in Table 4. Here, one more distinction is made between weekdays and weekends. These values apply for consumers in V2B FTM and V2G FCR-D. It is assumed that a fleet operator would be considered a so-called A-low consumer.

Table 4: Seasonal ToU tariff for A-low consumers, current prices for October 2023 [51]

	Winter			**Summer**	
	Low load	**High load**	**Peak load**	**Low load**	**High load**
Weekday	12am - 6am	9pm - 12am	6am - 9pm	12am - 6am	6am - 12am
Weekend	12am - 6am	6am - 12am	-	all day	-
Tariff DKK/kWh	0.013	0.0391	0.0781	0.013	0.0391

Finally, there is a fixed state electricity tax tax^{el} amounting to 0.761 DKK/kWh [51], that is adjusted annually. Additionally, the general value added tax (VAT) rate is 25 % of the price charged. The latter is also charged to the overall electricity price of business consumers.

Now, turning to consumers who also feed electricity into the grid, different costs arise, specifically in the case of V2H FTM, V2B FTM and V2G FCR-D. These costs are summarized by Equation 5.

$$cost^{feedin} = \tau^{TSO} + \tau^{DSO} + \tau^{PES} \tag{5}$$

Costs charged by the TSO are presented in the producers pay division of Table 2. They include the feed-in tariff and balance tariff, which conform to the TSO producer cost τ^{TSO}. A DSO producer cost τ^{DSO} is also incurred. It consists of a feed-in tariff corresponding to each customer category: 0.0056 DKK/kWh for category C and 0.0032 DKK/kWh for category A-low. Finally, auto-producers incur in a PES tariff τ^{PES} as part of their agreement of representation in the market which may vary between different PES.

Now focusing on V2G FCR-D, it is assumed that access to the regulating market occurs through an aggregator. This intermediary imposes service fees. Unfortunately, details regarding the specific value of these fees remain elusive. While it is possible to assert that the private entity delivering this service could function autonomously as a BSP, the V2G FCR-D model is limited by the absence of information about this cost.

Finally, consumers are also subject to different yearly subscriptions. For instance, DSO subscription and an electricity supplier subscription. On the other hand, general consumers who count as auto-producers are subject to the so-called own-producer subscription and an availability subscription. The own-producer subscription is 648 DKK for category C and 2,727 DKK for A-low. In both categories, the availability subscription amounts to 65 DKK for auto-producers without an independent production meter [51]; here subscription values are presented excluding VAT. These subscription costs, being independent of the consumption or production of electricity, are not considered in the optimization models. However, they must be considered for the results and are consequently added to the costs resulting from the optimization.

2.2.1.5 Technical regulation on energy storage facilities

Electrical energy storage facilities are defined in [52] as facilities that can store and deliver electrical energy. They may consist of several separate inverters and electrical energy storage units. These facilities are classified in relation to total rated power in the point of connection and if they are permanently or temporarily connected to the grid. Category ”T” corresponds to two-way chargers (V2G) used by EVs, regardless of rated power, where the electrical energy is primarily used for propulsion (see Section 1.1.12 in [52]). Electrical energy storage facilities must comply with technical minimum requirements to be connected to the public electricity supply grid. In the case of facilities in category ”T”, they must meet power quality requirements of DC content and current imbalance. They must also comply with connection requirements for automatic connection and active power gradient. These functions are defined in Table 5 for DK2. Requirements marked with a ”*” are mandatory for Category ”T” facilities. The remaining requirements in Table 5 are not obligatory but represent the less stringent requisites related to ancillary service provision, for instance, normal operating conditions and control functions. Similar to [53], Table 5 reviews them in consideration of potential strengthening of requirements for Category ”T”.

Table 5: Technical requirements on electrical energy storage facilities for DK2. *marks requirements that apply for category "T"

Requirement	Function	Description	Section
Power quality	DC content*	Injection of DC current must be limited to 0.5 % of the rated current.	5.1.1.1 in [52]
	Current Imbalance*	Current imbalance must not exceed 16 A between the three phases.	5.1.1.2 in [52]
	Flickering		5.1.1.4 in [52]
	Harmonics		5.1.1.5 in [52]
Connection	Automatic connection*	Connection may take place at the earliest 3 min after voltage has come within tolerance range ±10 % of the normal rated system voltage and grid frequency is within range of 49.9 and 50.1 Hz	4.3.1 in [52]
	Active power gradient*	At connection, the active power gradient must be between 1 % and 20 % of rated power, snot exceeding 60 MW/min	4.3.1 in [52]
Normal operation	Voltage dips	Must withstand voltage dips of +10 % and -15 %, without being disconnected	4.3.2 in [52]
	Frequency deviations	Must withstand frequency deviations between 49 Hz and 51 Hz, without being disconnected	4.3.2 in [52]
	Trip out	Units can trip out of 47.5-51.5 Hz	4.3.2 in [52]
Control	Absolute power constraint	The facility must never exceeds its rated power	6.2.4.1.1 in [52]
	Active power ramp rate	The facility limit the change of active power to a minimum of 1 % and a maximum of 20 % of rated power per minute, not exceeding 60 MW/min	6.2.4.1.2 in [52]
	limited frequency sensitive mode (LFSM)	Automatic upward or downward adjustment of active power in response to grid frequencies outside the reference frequency threshold with the objective of stabilizing the grid frequency.	6.2.1 in [52]
	frequency sensitive mode (FSM)	Control of active power to stabilize grid frequency to f_0 = 50.00 Hz.	6.2.3 in [52]
	Reactive power		6.3.1 in [52]
	Power factor		6.3.2 in [52]

In Table 5 frequency control functions are divided into LFSM and FSM. The focus here is in FSM which is utilized to provide the primary frequency ancillary services described in Section 2.1.2.1. In DK2 FSM is divided in two: FCR-N, which is inside the range f_4 and f_5, and FCR-D, which exists in the intervals between f_1 to f_4 and f_5 to f_2, as explained in Figure 2. It can be seen that FCR-D is divided into FCR-D upwards and FCR-D downwards. Electrical energy storage facilities must be discharged to provide FCR-D upwards and recharged to provide FCR-D downwards. FSM is required only for facilities of 3 MW or higher. Regulation must be done without delay and take no more than one second, or 10 seconds if parameters are changed.

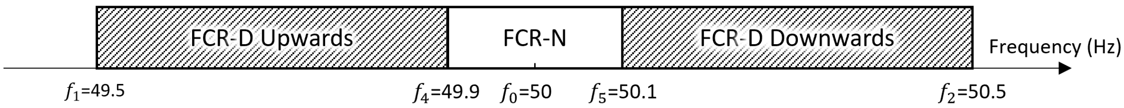


Figure 2: Frequency control activation range

If a market participant fails to deliver the sold reserve capacity repeatedly, the most severe penalty is exclusion from participating in the market [54]. Finally, it is important to mention that protection requiring adherence to tripping times and the exchange of signals and data are also included in the regulation.

2.2.1.6 Technical regulation on ancillary services

Requirements to be met by suppliers of ancillary services vary slightly depending on the service and the area to be supplied. For DK2 there are five types of ancillary services detailed in [49], from which the present study focuses only on primary reserve for disturbances FCR-D, as specified in Section 2.1.2.1.

FCR-D is a fast reserve activated automatically in the event of substantial frequency deviations. FCR-D is an asymmetrical service, which means that up-regulation and down-regulation are purchased separately. FCR-D up-regulation is activated at frequencies less than 49.9 Hz and FCR-D down-regulation is activated at frequencies greater than 50.1 Hz, as explained by Figure 2. They must remain active until balance is restored or until the manual reserve takes over the supply of power. Additionally, FCR-D can be delivered in two ways: as a dynamic reserve or a static reserve. Both types must be able to:

- Supply upward power at frequencies between 49.9 Hz and 49.5 Hz or supply downward power between 50.1 Hz and 50.5 Hz.
- Deliver a response within 2.5 seconds.
- Supply 86 % of the response within 7.5 seconds.
- Supply energy within 7.5 seconds corresponding to 3.2 seconds times the power sold.

Static reserves must also be able to deactivate within 15 minutes. For units that cannot provide full energy support for two consecutive hours, considered as a limited energy reservoir (LER), for instance, batteries, additional requirements apply:

- Must have an energy management system consisting of normal and alert states, to ensure enough energy is available to activate FCR.
- Must have a storage capacity of a minimum of 20 minutes to handle long-lasting frequency deviations.
- Must reserve 20 % of the capacity to ensure a scope of action for the energy management system. This 20 % cannot be sold in the market.

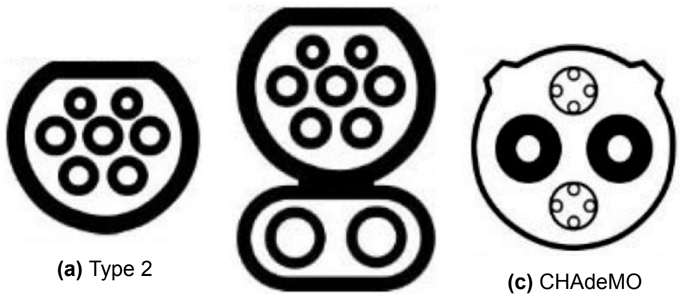
A delivery can consist of mixed supplies from demand and generation units with the same BRP. In essence, V2G FCR-D can be considered as a LER static reserve, whose activation requires almost no energy. Nevertheless, requirements for a reservation of 20 % of the capacity and a minimum of 20 minutes to handle long-lasting frequency deviations, must be considered when providing the service. Finally, the bidding process, in its simplest form is bidding in individual hours for just one product; either up or down reserves. Other applicable requirements like response time, power quality, and automatic connection are possible to be met according to previous trials in Table 1 but are irrelevant to the business model.

2.2.2 Technical requirements

Additionally to the technical regulations presented in Sections 2.2.1.5 and 2.2.1.6, several more general technical requirements need to be mentioned when considering the implementation of V2X services. While most EV owners use unidirectional chargers, enabling them to transfer power from the socket to the battery of their vehicle, V2X requires chargers capable of charging and discharging. Such devices are called bidirectional. They consist of one or more power conversion stages, located partly or completely on or off-board of the EV. Furthermore, chargers can use AC or DC current. The latter enables higher charging powers and faster charging times since a power conversion stage within the vehicle is avoided. Hereby, all charger components are located in the charging station, in other words, off-board. The kind of charging current used consequently determines the placement of the power conversion stages, although the location is more flexible for AC chargers. However, for EVs capable of AC and DC charging, the on-board charger is bypassed when choosing DC mode [55, 56]. To successfully implement V2X applications, though, a smart charger is needed. This means that the charger needs to be able to assess, e.g. the SOC of the battery, the status of the grid, or the power generation or consumption of the site where it is connected, to follow the defined charging strategy.

Additionally, the necessary communication infrastructure has to be available, to, for example, receive signals from the electricity market, a potential aggregator, or the system operator [57].

In practical implementation, different connector types are used to charge or discharge an EV. In Europe, the combined charging system (CCS) Combo 2, see Figure 3b, or the Type 2 socket, see Figure 3a are applied, where the latter is only suitable for AC charging. CCS Combo 2 allows AC and DC charging and is comprised of a Type 2 socket and two DC charging pins. Such pins also characterize CHAdeMO chargers, see Figure 3c, which are commonly found in Japan. Some charging stations and EVs in Europe utilize this kind of connector. However, in the 2014 directive on alternative fuels infrastructure (AFID), only Type 2 and CCS chargers are prescribed for all charging points in the EU. Investments in multi-standard chargers, including CHAdeMO, CCS, and Type 2 connectors, can receive funding though [58]. Still, CHAdeMO is pursuing the EU for ”a minimum mandate for multistandard charge points” [59].



(a) Type 2

(b) CCS Combo 2

(c) CHAdeMO

Figure 3: Different types of connectors [55]

Furthermore, the norm IEC 61851 specifies charging modes to classify chargers, based on charging power and time. Mode 1 to 3 refer to AC charging, of which mode 3 is the fastest with a charging power of up to 43 kW and current of up to 63 A. This mode also requires a dedicated cable and power socket, control, communication, and security features on the EV side. As mode 3 is the fastest for AC operation and is applied worldwide, it is commonly used for V2X services. Nonetheless, according to the IEC 61851, charging mode 4 enables even faster charging but requires DC operation. Charging powers are specified for up to 400 kW (100 V and 200 A) while requiring the same features as charging mode 3 [55, 56].

There are certain additional technical requirements to be met to provide frequency control. As specified in 2.2.1, EVs providing FCR-D need to respond within 2.5 seconds and supply 86 % within 7.5 seconds. According to Zecchino et al. [9], activation times tested for local and remote control approaches amount to 4 and 7 seconds, respectively. It is not mentioned, though, if the activation time just corresponds to a response of the controller or the actual supply of power. However, several trials [7, 10, 19, 39] have proven the technical feasibility of EVs providing frequency control. Therefore, technical specifications like activation time and power quality will not be discussed further, since they are also not required for the optimization model.

2.3 Available products

However, before diving into the business models to be investigated, it needs to be clarified if there are chargers and vehicles available to implement V2X applications. Table 6 presents a collection of chargers capable of bidirectional charging and their specifications. However, only 2 out of the 14 reviewed chargers are commercially available in their respective countries, none of them in Denmark. Hereby, openWB denotes that their charger openWB Pro is capable of bidirectional operation but the function is deactivated when the charger is delivered due to no regulation in place and the absence of V2X-compatible vehicles. Also, several companies have announced bidirectional chargers in Europe and offer reservations or requests regarding their products, e.g. KOSTAL, ambibox, or Evtec. Furthermore, Silla and Enphase are in the process of developing bidirectional chargers. Except for KOSTAL all found chargers rely on DC, utilizing CCS or in certain cases CHAdeMO. Suppliers from the US refer to CCS 1, the American standard of the system, while European companies implement chargers with CCS 2. KOSTAL was involved in the BDL trial where they supplied DC chargers, but they offer bidirectional AC charging stations as well. Another company involved in a trial is Rhombus. They produced the RES-HD60-V2G for the Blue Bird School Bus V2G Project conducted in the US, in collaboration with Nuuve which provides the software for V2X implementation. Nuuve is also involved in European trials, like the Parker Project and E-Flex.

Table 6: Collection of V2X capable chargers

Name	Company	Region	Power [kW]	Current [A]	Maximum efficiency [%]	Charging type	Commercialized?	Source
openWB Pro	openWB	DE	11/22	-	-	Type 2	Yes, in DE.	[60]
Quasar	Wallbox	ES	12.8	48	97	CCS (DC)	No.	[61, 62]
Pro Charger 2	Smartfox	AT	11/22	-	-	-	No.	[63]
sospeso&charge	Evtec	CH	10	-	-	CCS (DC), CHAdeMO	On request.	[64]
BDL-wallbox	KOSTAL	DE	Charging: 11 Discharging: 10	-	-	AC/DC (DC in BDL)	On request.	[39, 65]
dcbel r16	dcbel	USA	15.2	Charging: 38 Discharging: 32/64	Charging: 96.3 Discharging: 98.4	(! ((!)DC), CHAdeMO	No.	[66]
Green Motion DC 22	eaton	USA	22	55	96	CCS (DC), CHAdeMO	Unclear.	[67, 68]
Alpitronic HYC50	Mobilize	AT, DE	50	150	-	CCS (DC), CHAdeMO	On request.	[69]
Duke 44	Silla	IT	-	-	-	DC	No.	[70]
Bidirectional EV Charger	Enphase	USA	-	-	-	CCS (DC), CHAdeMO	No.	[71]
Ambicharge DC Wallbox	ambibox	DE	11/22	30/70	-	CCS (DC)	No.	[72, 73]
Charge Station Pro	Ford	USA	19.2	80	-	CCS (DC)	Yes, in the US.	[74]
RES-HD60-V2G	Rhombus, Nuuve	USA	69	200	95	CCS (DC)	No.	[75]
RES-HD125-V2G	Rhombus, Nuuve	USA	125	200	95	CCS (DC)	No.	[76]
BMPU-R2	Watt&Well	FR	11	32	95	CCS (DC), CHAdeMO	On request.	[77]
Fronius Symo 6.0-3-M	Fronius	AT	6	8.7	87.8 - 98	CCS (DC), CHAdeMO	Yes.	[78]

Most of the charging station suppliers do not specify compatible cars, however, Evtec lists the following as compatible with their bidirectional charger: Honda e, Nissan Leaf (after 2013), Mitsubishi iMiEV, Mitsubishi Outlander PHEV, Peugeot iON (from 2016) and Citroen C-Zero. The models from Nissan and Mitsubishi are also mentioned to be compatible with the Rhombus chargers. The BDL-wallbox, on the other hand, was applied with the BMW i3, however, the vehicle does not seem to be commercially capable of bidirectional charging. Ford recommends using its charging station in combination with their EV. They also specify a price, amounting to 1,202 € [79]. European suppliers, like Wallbox or openWB, though, settle for higher prices of 4,125 € [62] and 2,125 € [60], respectively. The same suppliers offer unidirectional chargers in the same power range for 660 € [80] and 1,214 € [81], respectively. All prices were adjusted to include the VAT applied in Denmark.

In addition to the previously mentioned V2X-capable EVs, several other companies are claiming to have implemented bidirectional operation for their vehicles. They are listed in

Table 7: Collection of V2X compatible EVs

Name	Vehicle type	Capacity [kWh]	Consumption [kWh/100km]	Source
Honda e	Passenger car	68.8	18.2	[87]
Nissan Leaf	Passenger car	39/59	16.6 - 17.8	[88]
Nissan e-NV200	Passenger car	30/40	25.9	[89]
Peugeot iOn	Passenger car	14.5	17	[90]
Polestar 3	Passenger car	111	-	[91]
Renault 5 E-Tech	Passenger car	-	-	[92]
Volvo EX90	Passenger car	111	21.1	[93, 94]
BYD AD Enviro200EV	City bus	348	-	[95]
All American RE Electric	School bus	-	-	[34]

Table 2.3 with their specifications. While passenger cars, like Polestar 3 or Volvo EX90, exhibit a battery capacity of 111 kWh, the capacity of the other cars ranges between 14.5 and 69 kWh. The latter value also corresponds to the average usable battery capacity of EVs [82]. In contrast, the city bus BYD AD Enviro200EV used for the Bus2Grid trial, has a larger battery. With 348 kWh it is close to the 350 kWh specified for the city bus Ebusco 2.2, utilized for public transport in Copenhagen [83, 84]. Electric refuse trucks, like the Scania 25L or Mercedes eEconic, are used in Denmark, presenting capacities of 297 and 291 kWh, respectively [85, 86]. However, these trucks are not ready for bidirectional operation. While there is no consumption given for the heavy-duty vehicles found, passenger cars consume between 16.6 and 25.9 kWh/100km. Hereby, the upper part of the spectrum is taken up by the Nissan e-NV200 and Volvo EX90, which are larger. Therefore, higher values would need to be considered for heavy-duty vehicles. However, even for the school bus All American RE Electric, applied in the Blue Bird School Bus V2G Project, no consumption was specified.

3 Business models for residential users and fleet vehicles

Based on the reviewed literature, promising V2X services have been chosen to be investigated in Section 2.1.2. According to the technical and regulatory requirements presented in Section 2.2, business models for each of the services are now developed and presented in the following, starting with V2H BTM in Section 3.1. The business models as well as the knowledge about regulatory and technical requirements acquired in Section 2.2 will then be used as a framework to develop the optimization models in Section 4.

3.1 V2H BTM

As classified in Section 2.1.1, V2H BTM refers to a household having a normal grid connection, only drawing power from the power grid, while having an EV and connecting it at home. However, the vehicle is connected via a bidirectional charger to the household, so it can charge and discharge (see Figure 4). This installation can be utilized to reduce electricity costs by optimizing the time at which the household is drawing energy from the power grid. Since the electricity price for general consumers is not fixed, there are cheaper and more expensive hours to consume energy. Especially the so-called ToU tariff leads to significant price differences. ToU are used to incentivize certain consumption behaviors by defining different load periods during which the tariff varies. In Denmark, periods of low, high, and peak load are defined, where the latter exhibits the highest tariff and spans the time period between 5 pm and 9 pm. During the summer months, April til September, the peak load tariff is twice as high as the high load and three times as high as the low load tariff (see Section 4.2 for exact values). During winter, October til March, the difference is even more significant [51].

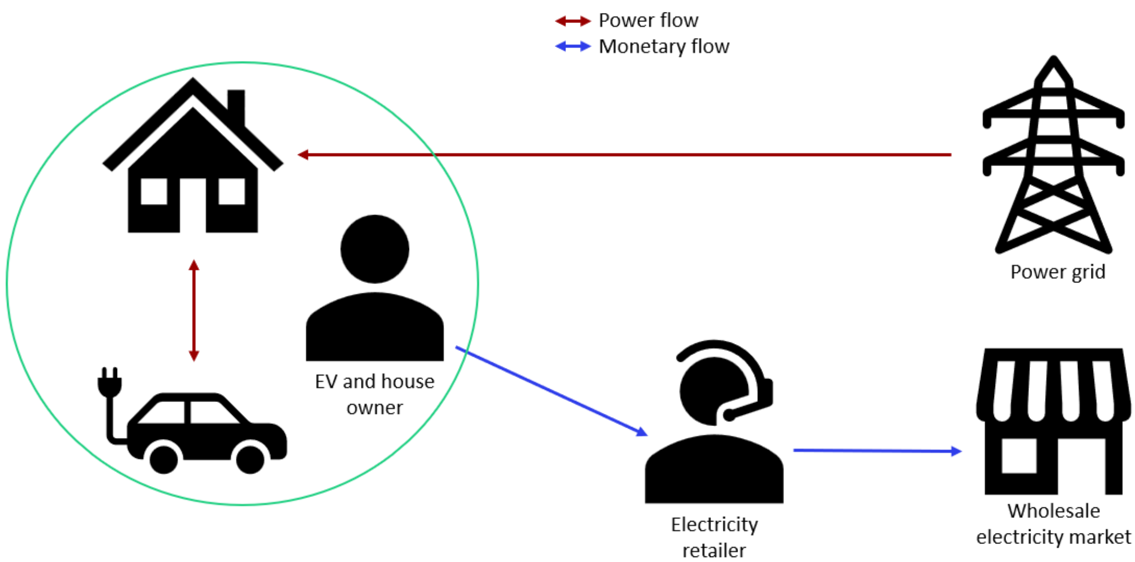


Figure 4: Agents and assets involved in V2H BTM and their relations

This price mechanism can be utilized to achieve cost savings by implementing V2H BTM. To avoid high electricity prices during peak hours, the EV can be discharged to supply household consumption. Still, the vehicle has to be charged for supplying the needed energy, as well as enabling the owner to use it for their driving needs (e.g. commuting to the workplace). Consequently, within the scope of this business model, the EV can be charged or discharged at any time, as long as it is present at the house. The goal is to reduce electricity costs, compared to if the household would not implement V2H

BTM while considering costs caused by the additional battery degradation. The resulting electricity consumption from the power grid is billed according to all arising tariffs, taxes, and the spot price via the electricity retailer, which purchases energy from the wholesale electricity market for its customers. The power and monetary flows, as well as all involved agents and assets, are shown in Figure 4.

3.2 V2H FTM

The business model of V2H FTM shows similarities to the previous one. As indicated in Figure 5, the agents and assets involved are identical. However, the electricity retailer is replaced by a PES. According to the regulations presented in Section 2.2.1, such an entity is needed to participate in the wholesale electricity market as a general consumer, as intended in this kind of business model. The EV is again bidirectionally connected to the house. Additionally, though, the household is not only able to draw power from the grid but also able to feed in power. Since a single general consumer's feed-in is not high enough to participate in the wholesale electricity market, the PES is needed, taking care of providing the consumer with power and selling their production. A PES sells the generated energy of smaller entities, e.g. households, as seen in Figure 5. However, the optimization for this business model will only regard a single household.

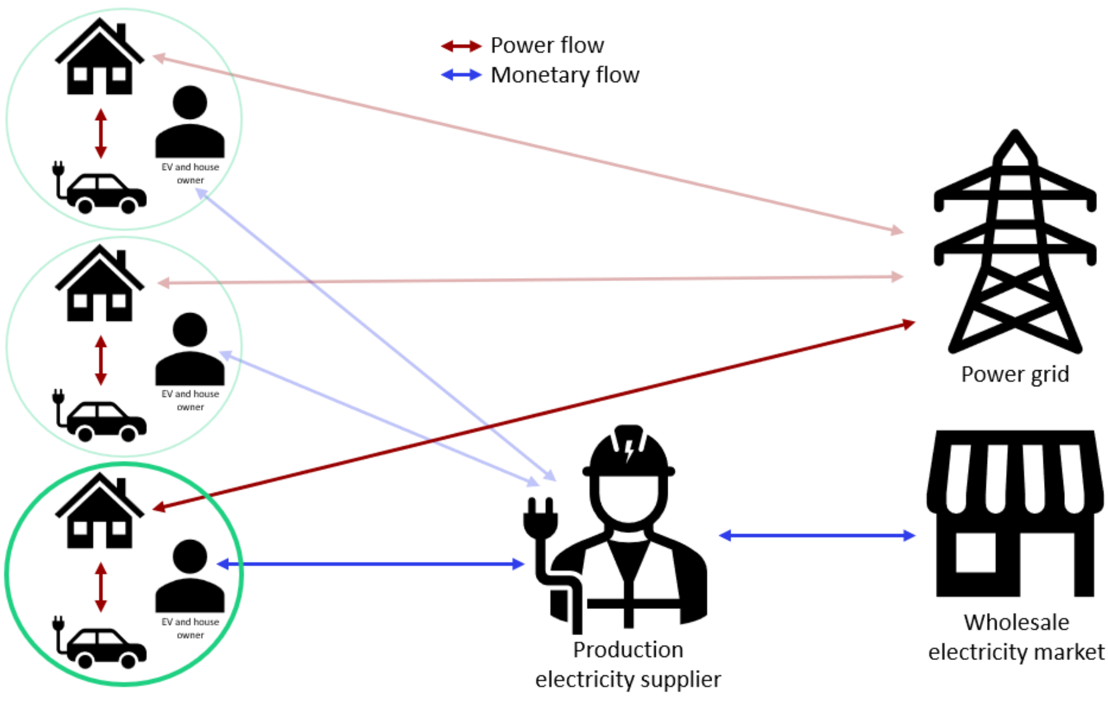


Figure 5: Agents and assets involved in V2H FTM and their relations

As in the previous section, the objective of the business model is to reduce electricity costs by adjusting the consumption. Therefore, the EV can be charged and discharged at any time at which it is present at the house, so household consumption can be covered by the vehicle. Furthermore, the EV can charge surplus energy during time periods of low electricity prices and sell it during periods of high prices. While for the bought electricity, all applicable tariffs, taxes and the spot price need to be considered, the household would receive the spot price for its sold energy. However, additional fees from the PES need to be deducted from the spot price, as explained in Section 2.2.1. The resulting profit from selling energy is deducted from the electricity and battery degradation costs.

3.3 V2B FTM

The before-mentioned V2X service FTM cannot only be applied to RU but also to EV fleets. The EV fleet could be owned by a private company or a public institution. However, in this study, the focus is set on a refuse truck fleet, as justified in Section 2.1.2. Furthermore, the electricity consumption of a building at the depot of the EV fleet is considered, as well as photovoltaic (PV) panels. All three instances are connected through a point of common coupling (PCC) which marks the grid connection, as seen in Figure 6. The objective of the business model is to reduce overall electricity costs, hence the EV fleet manager is assumed to be responsible not only for the consumption of the vehicles but also for the building and the feed-in of the PV panels.

The EVs can be charged and discharged at any time, as long as they are available at the depot, to cover the building's consumption or make use of the PV production. Additionally, the vehicle's consumption while used for normal operation and battery degradation costs will also be taken into account. As before, surplus energy from the EVs or the PV panels can be fed into the power grid to generate revenue to lower the overall costs. Therefore, a PES is needed to handle the buying and selling of electricity. Depending on the size of the fleet, the operating company or institution could participate in the wholesale electricity market themselves. Still, as the entities considered are not working within the energy industry, it would be beneficial to acquire the required capabilities to manage all interactions with the electricity market through a dedicated department. In the scope of this study, it is consequently assumed that the EV fleet manager would choose to work with a PES, considering the reduction of time and cost investment. Hereby, the same cost and revenue streams become relevant as mentioned in Section 3.2. Figure 6 illustrates the power and monetary flows, as well as all involved agents and assets.

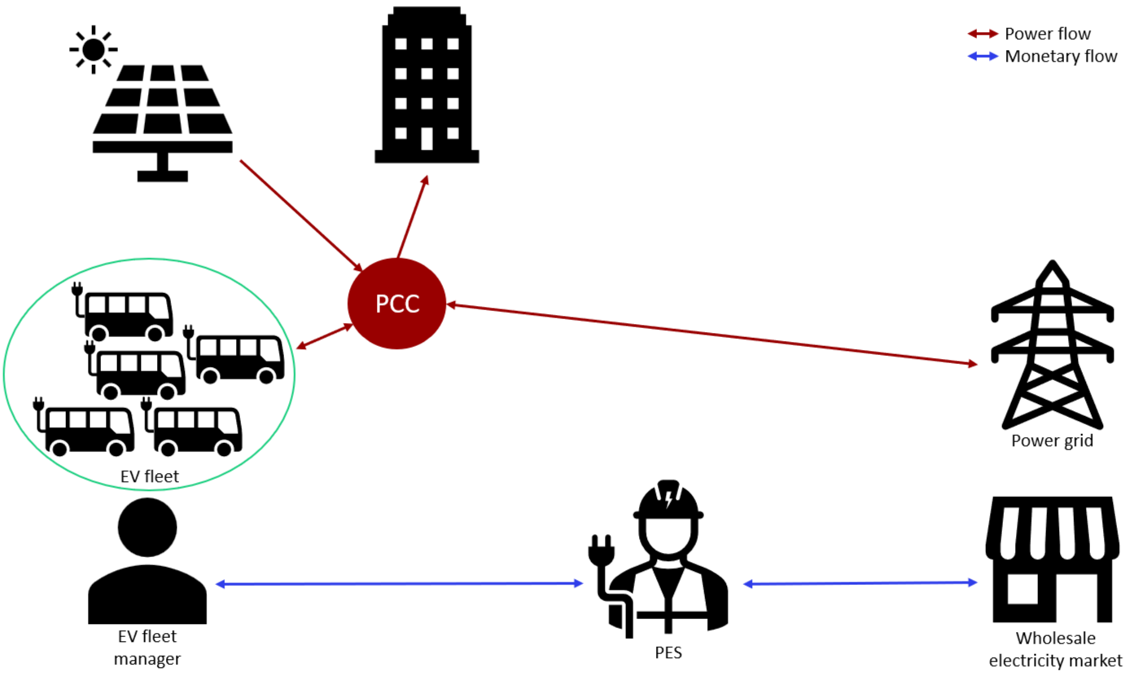


Figure 6: Agents and assets involved in V2B FTM and their relations

3.4 V2G FCR-D

The last business model to be considered can be seen as an extension of the model of V2B FTM, presented in Section 3.3. In addition to participating in the wholesale electricity market through a PES, though, the EV fleet also offers frequency control in the ancillary services market. To provide the power capacity sold in the market, though, enough production has to be available at the depot. As decided in Section 2.1.2.1, specifically the provision of FCR-D up is considered. While the electrical installation does not need to be changed to offer frequency control, an aggregator or BRP is needed to participate in the ancillary services market, as specified in Section 2.2.1.2. While the EV fleet manager could theoretically act as an aggregator, it is unlikely due to time and cost investments. The resulting construct of agents and assets involved in the V2G FCR-D business model is illustrated in Figure 7.

The revenue generated by providing FCR-D up and feeding electricity into the grid is used to reduce the overall electricity costs. However, additional costs due to engaging with a PES, and battery degradation will also be considered in the optimization model.

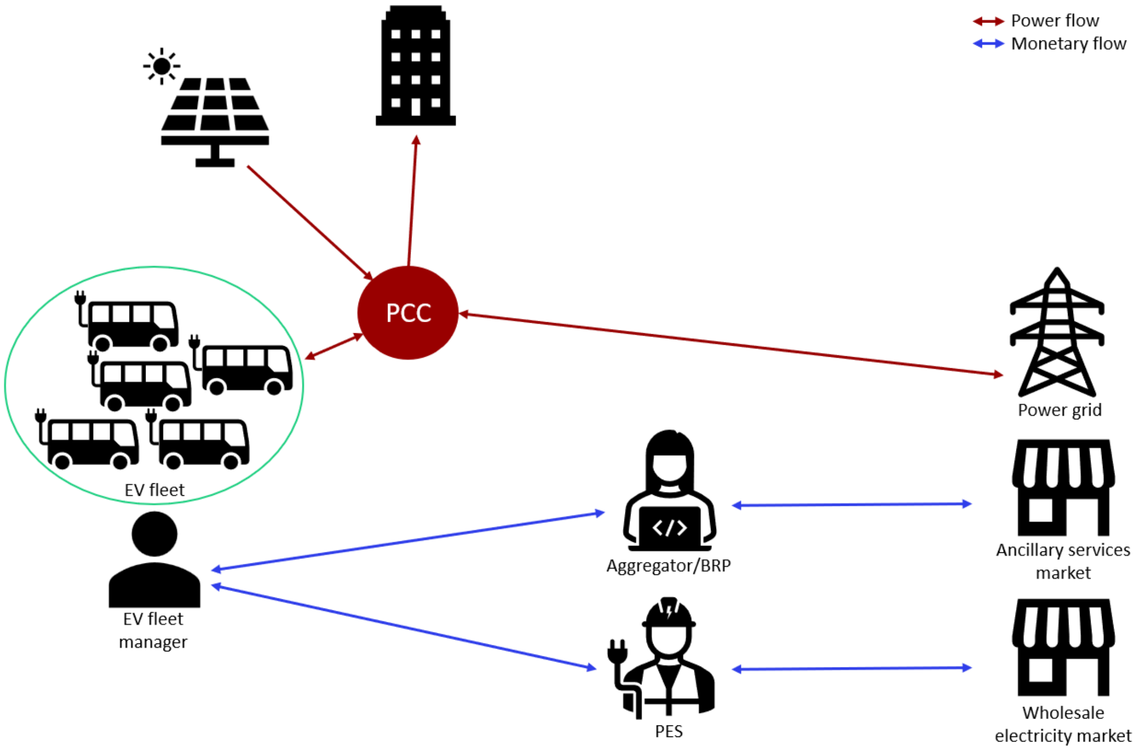


Figure 7: Agents and assets involved in V2G FCR-D and their relations

4 Optimization of V2X services

In this section, the previously presented business models are implemented as mathematical optimization models. Therefore, an objective function is formulated, specifying the goal of the optimization. Furthermore, constraints are implemented to define system boundaries and assumptions to make the optimization as realistic as possible and to follow the requirements for V2X services as presented in Section 2.2. The objective functions and constraints are described below, see Section 4.2, 4.3, 4.4 and 4.5, for each business model, as well as all input parameters, and variables. To enable a sound understanding of the subject matter, the general idea and structure of the optimization models will be described first in Section 4.1.

4.1 General idea of the optimization

The presented optimization uses mathematical formulations in the form of an objective function and constraints to simulate the business models proposed in Section 3. Additionally, input data will be prepared and included in the models, e.g. electricity prices or EV availability, which enables the models to define so-called decision variables to find the optimal outcome. In the case of the optimization models presented in the following, the optimal outcome will be the one leading to the lowest overall cost. The decision variables and input data will then be analyzed to conclude the opportunities and challenges created by the business models.

While the overall optimization will be done for a whole year, the created model will run day by day. If this model were to run for a whole year at once, it would have perfect foresight since all input data would be available for the whole year already on day 1. This does, however, not reflect reality, since especially electricity, spot, and FCR-D prices are only known one day in advance. Therefore, a so-called rolling horizon is implemented as illustrated in Figure 8. The optimization of the model at the initial date can only be based on the historical prices of this respective day, the so-called *control period*. Additionally, a *look-ahead period* is implemented which includes the whole next day. Using a persistence forecast, the input data is designed so that the prices for each day are predicted to be the same on the next day. Based on the actual and predicted information for the first and the second day, the model sets the decision variables for these two days. For this reason, the so-called *prediction horizon* of the model on each day is 48 hours, corresponding to two days. After finishing the optimization for the first day, the values for the decision variables are saved and the model moves on to the second day. At this point, the model gets the actual data for the second and the predicted data for the third day and optimizes based on the new information. This process is repeated for each day of the year. While the values for the *look-ahead period* are saved for each day, only the values for the *control period* will later be considered for analyzing the results.

The persistence forecast is only applied to price and FCR-D parameters in the models. For other parameters, e.g. household consumption, the foresight is also reduced to two days using the rolling horizon. However, hereby, the actual values are used for the *control* and the *look-ahead period* following the assumption that RU and EV fleets can accurately plan the next day and know this data beforehand.

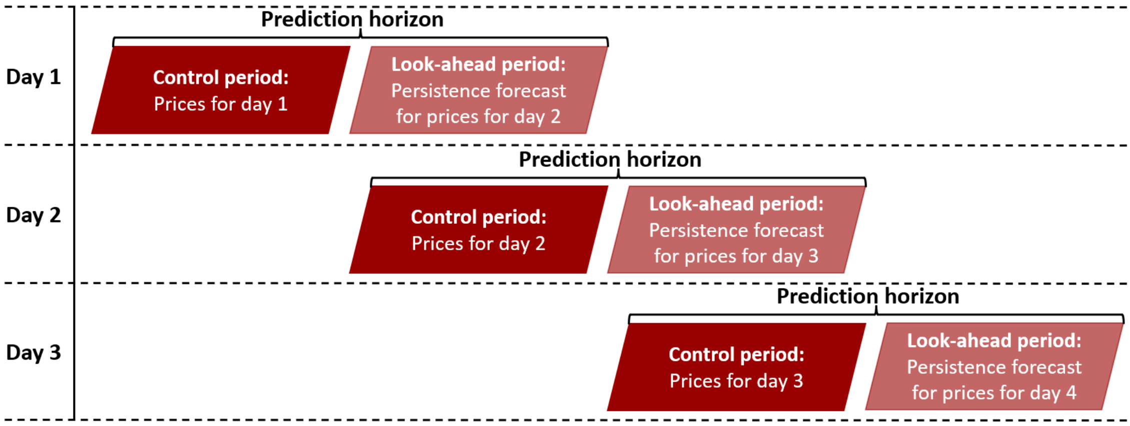


Figure 8: Principle of the rolling horizon with persistence forecast for prices

4.2 V2H BTM

At first, the mathematical models corresponding to the business models for RUs, as presented in Section 3.1 and 3.2 will be described. As for all considered models, the overall goal of V2H BTM is to minimize electricity costs for a year while charging the EV for necessary driving distances and covering household demand by discharging the vehicle to the household. Among others, these inputs are included in Figure 9 which illustrates the general functioning of the optimization model. The decision variables and inputs needed for the optimization model will be presented in detail in the following so that the objective function and constraints can be understood when described afterwards.

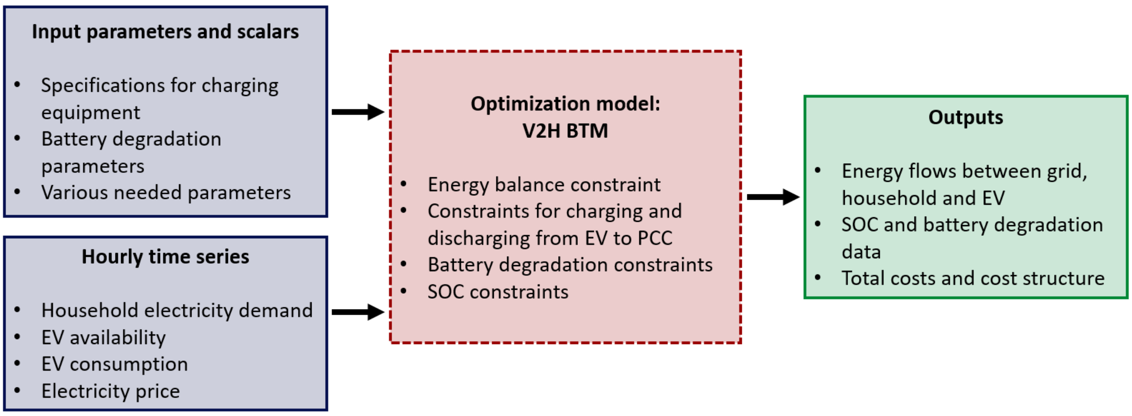


Figure 9: General functioning, as well as inputs and outputs of V2H BTM optimization model

4.2.1 Decision variables

To specify the decision variables, several so-called sets need to be defined. Each set represents a series of the same kind (e.g. hours in one year or users of a group), which are used to define the size of decision variables. The sets and decision variables are presented in Table 8. In total six sets are used in the V2H BTM model, where t represents the hourly time steps in the optimization, with the end value T being 48. Hence, T represents the length of the prediction horizon explained in Section 4.1. However, to implement the rolling horizon with a day-by-day optimization, the set of day is created, where Day^{num} represents the total number of days considered. Additionally, each day belongs either to summer S or winter W sets according to the ToU tariff, seen in Section 2.2.1.4.

Table 8: Sets and decision variables for V2H BTM

	Value	Unit	Description
Sets			
t	$\in T$	h	Time steps of the optimization
u	$\in U$	-	Users regarded in the optimization
day	$\in Day^{num}$	-	Used for implementing rolling horizon
s	$\in S$	-	Days in the summer
w	$\in W$	-	Days in the winter
p	$\in P^{sc}/P^{sd}$	-	Power steps in charging or discharging mode
Decision variables			
$E^{grid}_{t,u}$	$\in \mathbb{R}^{+}_{0}$	kWh	Energy drawn by the household from the grid
$E^{dis}_{t,u}$	$\in \mathbb{R}^{-}_{0}$	kWh	Energy discharged from EV to house, seen from EV side
$E^{char}_{t,u}$	$\in \mathbb{R}^{+}_{0}$	kWh	Energy charged to EV from house, seen from EV side
$E^{dis\_pcc}_{t,u}$	$\in \mathbb{R}^{-}_{0}$	kWh	Energy discharged from EV to house, seen from house side
$E^{char\_pcc}_{t,u}$	$\in \mathbb{R}^{+}_{0}$	kWh	Energy charged to EV from house, seen from house side
$deg^{cal}_{day,t,u}$	$\in \mathbb{R}^{+}_{0}$	$\frac{\%^{SOH}}{h}$	Calendar capacity loss
$SOC_{day,t,u}$	$\in \mathbb{R}^{+}_{0}$	kWh	Energy stored in EV
$y_{day,t,u}$	$\in \{0,1\}$	-	Implies going beyond the operating threshold of SOC
$time^{char}_{t,p,u}$	$\in \mathbb{Z}^{+}_{0}$	-	Number of charging windows in an hour for charging
$time^{dis}_{t,p,u}$	$\in \mathbb{Z}^{+}_{0}$	-	Number of charging windows in an hour for discharging

Furthermore, u and p are defined as indices of the sets U and P. While the latter specifies the number of charging or discharging steps with the total number of steps being P^{sc} and P^{sd}, respectively, U represents the users considered in the optimization. For the case of RU, three user types are considered with different driving behaviors resulting mostly from their mode of working. They will be described in more detail in Section 4.2.2.

As seen in Table 8, several decision variables are defined for different energy flows considered. They are defined as continuous variables, however, they are limited to being either negative or positive due to how the constraints are implemented. For example, charging variables can only be positive, while discharging variables can only be negative. All decision variables considering energy flows carry the unit kWh and are defined for each time step $t \in T$ and user $u \in U$. Following the principle of the rolling horizon, for each day of the optimization, they are defined for all three users for 48 hours. In the results, though, only the first 24 hours of each day will be considered, since the second 24 hours only represent the planned schedule which might change in the optimization of the next day.

The SOC is also stored in kWh, can take positive, continuous values, and is defined for each day, hour, and user. Again, for each day, only the first 24 hours are later considered in the presentation of the results. At last, two positive integer decision variables are defined, depending on time steps $t \in T$, power steps $p \in P^{sc}/P^{sd}$ and users $u \in U$. These variables are used to ensure that only one power step is used per charging and discharging window and define the number of time windows used in an hour for charging or discharging.

The $deg^{cal}_{day,t,u}$ registers in percentage % the state of health (SOH) loss per hour while the variable $y_{day,t,u}$ assumes a true value when the battery operates above the SOC^{max} and accelerates its calendar degradation.

4.2.2 Input parameters

All input parameters and scalars are shown in Table 9. P_p^{char} and P_p^{dis} represent the eight charging and discharging steps, respectively, as percentages of the maximum power P^{char_max} or P^{dis_max}. These values are based on the previously presented Fronius Symo 6.0-3-M (see Section 2.3) and are shown in Table 23 in the appendix. Corresponding to the same equipment, the charging and discharging efficiencies of each power step are defined. Although most chargers allow charging and discharging with a power up to 11 or 22 kW, a 6 kW charger was chosen. That is due to the general household demand which is much lower than 11 or especially 22 kW. Therefore, a low power range would always be used which would lead to lower charging and discharging efficiencies. Consequently, choosing charging equipment with a lower maximum power, reduces energy losses.

Furthermore, a time series of the electricity price for consumers $\pi_{day,t}^{el}$ for every hour of the year is needed for the optimization. The total electricity price is comprised of different components. One of them is the spot price at the wholesale electricity market. The spot prices from 2019 to 2023 are presented in Figure 10. Spot prices from DK2 for the optimization model were taken from the year 2021 [96], considering that they are the most recent prices that resemble 2023; for which the prices were not fully available at the point of model creation. The prices for 2022 were excluded due to the special situation of the energy market, causing extreme variations as seen in Figure 10. However, several tariffs and taxes have to be added to the spot price, as mentioned in Section 2.2.1. These components belong to the year 2023, given that the latest values are the most accurate to asses the present viability of each case. Furthermore, the ToU tariff was only introduced in 2023, so taking the tariffs and taxes from 2021 would lead to neglecting an important factor making V2X more profitable. At last, the VAT of 25 % is applied to all components. As explained in Section 4.1, a rolling horizon with a persistence forecast is implemented for $\pi_{day,t}^{el}$.

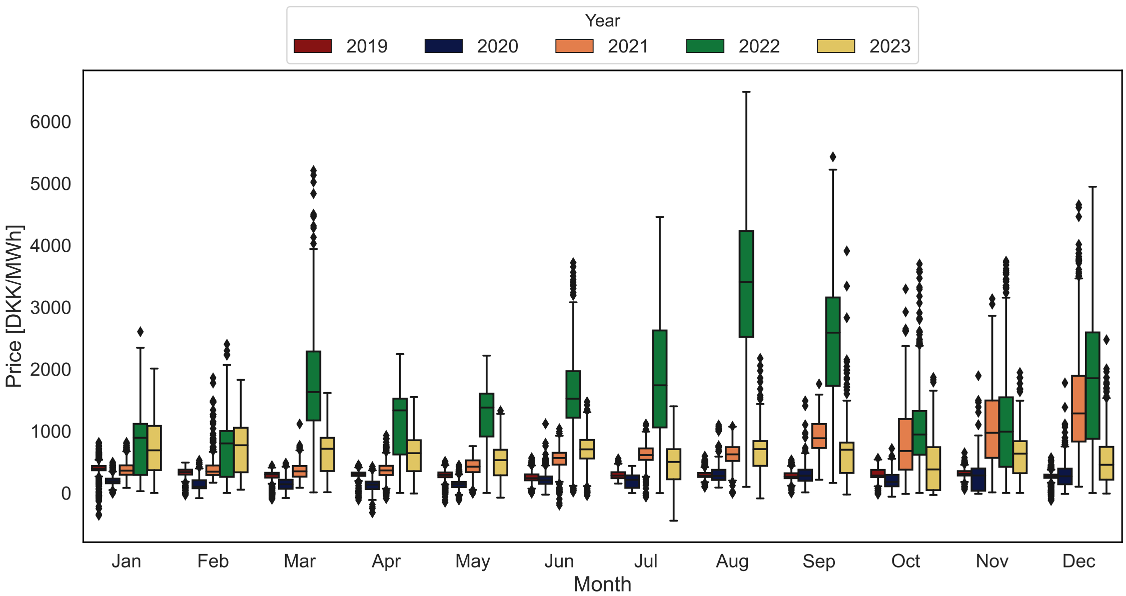


Figure 10: Nord Pool day-ahead spot prices for DK2

Table 9: Parameters and scalars for V2H BTM

	Value	Unit	Description	Source
Parameters				
P_p^{char}	-	kW	Percent of maximum power of each charging power step	[78]
P_p^{dis}	-	kW	Percent of maximum power of each discharging power step	[78]
η_p^{char}	-	-	Efficiency of each charging power step	[78]
η_p^{dis}	-	-	Efficiency of each discharging power step	[78]
$D_{day,t}^r$	-	kWh	Household demand	[97, 98]
$home_{day,t,u}^r$	-	-	Integer variable indicating if EV is available (1 = available, 0 = unavailable)	own asm.
$consumption_{day,t,u}^{flat\_r}$	-	kWh/h	Driving consumption of EV	[88, 99, 100]
$\pi_{day,t}^{el}$	-	DKK/kWh	Electricity price for household consumers	[51, 96, 101]
Scalar				
$exchange^{rate}$	7.46	DKK/€	Exchange rate from DKK to Euros	[102]
$capacity$	59	kWh	Capacity of the EV, based on Nissan Leaf 2022	[88]
bat_cost	180	€/kWh	Cost for battery depending on kWh	[103]
$SOH^{lifetime}$	30	%	Loss of SOH after which EV battery needs to be replaced	[103]
SOH_loss^{cycle}	$\frac{3}{1000}$	%/FEC	Percent of SOH lost for each FEC	[103]
SOC^{min}	$0.3 \cdot capacity$	kWh	Minimum SOC for EV battery	own asm.
SOC^{max}	$0.65 \cdot capacity$	kWh	Maximum SOC for EV battery	[104]
SOH^{init}	100	kWh	Initial SOH for EV batteries	own asm.
P^{char_max}	6	kW	Maximum charging power for EV battery	[78]
P^{dis_max}	6	kW	Maximum discharging power for EV battery	[78]
ω	6	-	Number of charging windows in an hour	own asm.
Day^{num}	365	-	Number of days considered in model	own asm.
$deg_{ba,s}^{cal}$	1.14E-04	$\frac{\%^{SOH}}{h}$	Base calendar capacity loss per hour at 20°C	[105]
$deg_{ad,s}^{cal}$	3.26E-05	$\frac{\%^{SOH}}{h}$	Additional calendar capacity loss per hour for high SOC at 20°C	[105]
$deg_{ba,w}^{cal}$	8.97E-05	$\frac{\%^{SOH}}{h}$	Base calendar capacity loss per hour at 10°C	[105]
$deg_{ad,w}^{cal}$	3.26E-05	$\frac{\%^{SOH}}{h}$	Additional calendar capacity loss per hour for high SOC at 10°C	[105]
$cost^{cal\_deg}$	2641	$DKK/\%SOH$	Calendar degradation cost	own asm.

4.2.2.1 Household demand

To apply the electricity prices to evaluate the overall costs of a household, its demand $D_{day,t}$ in kWh is specified for each hour of the year. For the analysis, three different data sets are regarded: First, the hourly demand of a Danish household from the Zealand area, as presented by the Danish DSO Radius [97]. The values are specified for detached houses without electric heating since such households are considered to be most likely to have private charging points and the opportunity to supply their own demand. Furthermore, this household type covers the highest share in Zealand. Hereby, the hourly data for a weekday and a weekend day was taken for each month of the year. The data from January to September is for the year 2023, while the data set from October to December is from 2021. To match the electricity prices, the values for weekdays and weekends were applied to match the constellation of weekdays in 2021. The year 2022 was not considered due to the special situation in the energy market. However, taking this data neglects variations during different week- or weekend days and does not consider different profiles for weekdays which are holidays. This leads to the data being smoother so that spikes in the demand are generally evened out. Consequently, the business model might not be as profitable since the demand spike in the early evening is flattened and therefore, high electricity prices are less influential. To consider a more realistic demand including peaks, it was considered to use another data set. The University of Applied Sciences for Technology and Economy (HTW) in Berlin, Germany, recorded household demand in a minute resolution for the year 2010. While in total 74 load profiles were documented, only one data set was taken which resembled the standard German load profile the most. However, since the model is working with time steps of one hour, the average hourly demand was computed. Additionally, the maximum of each hour was taken to generate a third, more extreme data set. Further analysis of the two demand data sets generated from the HTW data revealed that the yearly consumption of the averaged values is about half of the normal Danish household electricity consumption. The maximum values were more than twice as high as the Danish household electricity consumption. Consequently, it was decided to consider the average value from the DSO Radius.

4.2.2.2 Availability of the EV

When looking at a RU, considering the availability of the EV is essential to create a realistic model. To implement the availability, the parameter $home^{r}_{day,t,u}$ is introduced, consisting of a binary value for each hour of the year, where 1 indicates the user being at home, having the EV connected and 0 representing the absence of the vehicle. For reasons of simplicity, it is assumed that the EV is only charged and discharged at the house of the user. For the V2H BTM case, three different user types u were considered. The so-called *on-site* user is working at their workplace every day, meaning they will be away to commute and work from 7 am til 5 pm every weekday. Furthermore, it is considered that the user is away with the car every Saturday from 9 am until 3 pm but is home the whole Sunday. For the model, every week is considered to be the same and adjusted to the weekdays of 2021. No vacation, holidays, or other irregularities are regarded. While the weekend pattern is the same for all three user types, the weekday availability of the second one, the *remote* user, differs from the *on-site* user. The *remote* user is always working from home, however, it is considered that they do leave the house for a few hours every day for errands, getting groceries, etc. That is why, the *remote* user's EV is considered unavailable from 8 to 10 pm on Monday and Tuesday and 9 to 11 am on Wednesday and Thursday. The vehicle is considered to be at home during the whole Friday. Furthermore, the *hybrid* user is established as a mixture of the two other types. As the *on-site* user, the *hybrid* user is commuting and working from 7 am until 5 pm on Monday, Tuesday and Wednesday. On Thursday and Friday, the *hybrid* user is working from home, but the EV is unavailable on these days from 8 to 10 pm, e.g. for buying groceries. The ratio of *remote* and *on-site* work days is based on [106].

4.2.2.3 Consumption of the EV

Based on the availability of the EV, stored in $home^{r}_{day,t,u}$, the consumption of the vehicle $consumption^{flat\_r}_{day,t,u}$ is defined for each hour of the year and each user. Although the consumption of the vehicle does not vary significantly depending on the hour, the model does not consider the distance it covers when being away from the house. Other than the driving consumption and discharging to the house, no other depletion of the SOC is considered in the model. To evaluate the driving consumption, the distance covered during each unavailability slot is estimated and used to compute the total consumption in kWh. Afterwards, the total consumption is spread over all the hours the EV is away. While the resulting consumption pattern is not exact, it was chosen to get an estimate for the driving consumption since the model focuses on the overall charging and discharging costs and revenues. Using the nominal consumption of the Nissan Leaf of 172 Wh/km, based on the medium of the range found in Section 2.3, seasonal values are derived to account for differing consumption due to outdoor temperatures. According to Dost et al.

[100], consumption during summer is 29 % lower than the nominal value, while being increased by 18 % during the winter. Hereby, the months considered for summer are June until September, and for winter December until March. However, due to simplicity and the seasonal definition for the ToU tariff, the winter deviation is taken for the months of October to March and the summer deviation from April to September. The study in [100] was conducted in Germany, so climatic conditions are similar to Denmark. Furthermore, the EV used for the study were Mitsubishi i-MiEV and Peugeot iOn. These models are smaller than the Nissan Leaf, however, their nominal consumption of 170 Wh/km is close to the one of the Nissan Leaf. Considering its consumption and the deviations found in [100], the summer consumption amounts to 121 Wh/km and the winter consumption to 202 Wh/km. To calculate the final values for each unavailability slot, lastly, the distances covered during the time period of absence and the amount of hours of each slot need to be defined. For the commute to work and working hours, a distance of 57.4 km, based on the average commuting distance in the region of Zealand [99], and a duration of nine hours are considered. However, only 10 km are assumed for the two-hour slots of the *remote* and *hybrid* user. Finally, the Saturday day trip is considered to cover in total 100 km, lasting for six hours. Summarizing the aforementioned, the consumption per hour is computed as follows, exemplary for a summer weekday of the *on-site* user:

$$\frac{consumption^{summer} \cdot distance}{duration} = \frac{121\frac{\text{Wh}}{\text{km}} \cdot 57.4\text{km}}{10\text{h}} = 697\frac{\text{Wh}}{\text{h}} = 0.7\frac{\text{kWh}}{\text{h}} \tag{6}$$

4.2.2.4 Battery degradation

While the model is designed to minimize costs by covering household demand by excess energy stored in the EV battery, this practice of reducing the electricity bill does entail costs. The charging and discharging of a battery leads to its degradation which eventually will reduce its capacity, leading to the necessity of replacing the battery. Since the process of fully charging and discharging a battery is called a full equivalent cycle (FEC), this kind of degradation is labeled cycle degradation. Generally, it is dependent on the temperature, the SOC, the charge current, and the depth of discharge. However, considering the total energy throughput and the resulting FEC is assumed a good estimate for the cost calculation, according to Thompson [107]. For this consideration, first, the total battery cost for replacement has to be defined. Thingvad et al. [103] consider 180 €/kWh. Since the EV regarded in the model is the Nissan Leaf, its capacity of 59 kWh is assumed [88], leading to:

$$bat\_cost^{total} = capacity \cdot bat\_cost = 59 \text{ kWh} \cdot 180\frac{\text{€}}{\text{kWh}} \cdot 7.46\frac{\text{DKK}}{\text{€}} = 79,225 \text{ DKK} \tag{7}$$

The total cost for replacing the EV battery bat_cost$^{\text{total}}$ arises only, when the battery needs to be replaced. While capacity reduction can be expressed in kWh, often the SOH is used to specify the state of the capacity. When at full capacity, the SOH amounts to 100 %^{SOH}. According to Thingvad et al. [103], a battery can be used for vehicular application until it has lost between 20 and 30 %^{SOH} of its initial capacity. Second-life applications, e.g. as stationary storage, can be implemented to up until 50 %^{SOH} loss [103], however, this case will not be considered in the model. Using the $SOH^{lifetime} = 30$ %^{SOH} and bat_cost$^{\text{total}}$, an average cost per percent of SOH lost cost$^{\text{SOH_loss}}$ can be determined:

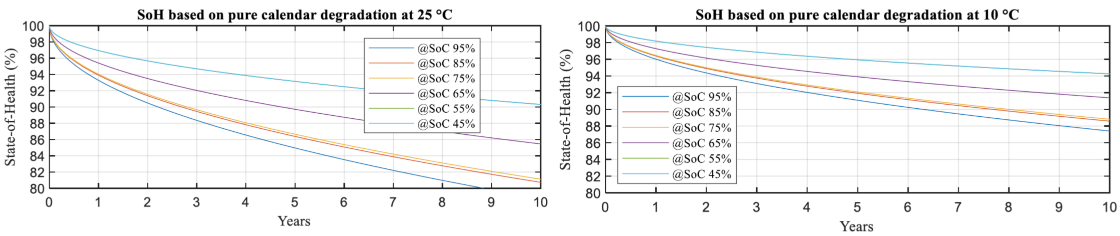
$$cost^{SOH\_loss} = \frac{bat\_cost^{total}}{SOH^{lifetime}} = \frac{79,225 \text{ DKK}}{30 \text{ \%}^{SOH}} = 2,641 \frac{\text{DKK}}{\text{\%}^{SOH}} \quad (8)$$

However, as mentioned before, the total energy throughput of the battery is supposed to be used to estimate the cycle degradation cost. Therefore, the in Equation 8 determined cost needs to be converted. Thingvad et al. [103] estimate that 2 to 3 $\%^{SOH}$ are lost for each 1,000 FEC. Assuming SOH_loss^{cycle} to be 3 $\%^{SOH}$:

$$cost^{cycle} = SOH\_loss^{cycle} \cdot cost^{SOH\_loss} = \frac{3\%^{SOH}}{1,000 \text{ FEC}} \cdot 2,641 \frac{\text{DKK}}{\text{\%}^{SOH}} = 8 \frac{\text{DKK}}{\text{FEC}} \quad (9)$$

This cost per cycle $cost^{cycle}$ can then be used in the model to estimate the cost caused by cycle degradation of the battery, incentivizing the model not to extensively exploit the EV battery. The SOH_loss^{cycle} will furthermore be used to calculate the final SOH at the end of the simulation. Therefore, an initial SOH of 100 $\%^{SOH}$ is assumed for each user. The loss of capacity of a battery over one year is minor, though, as shown by Marinelli et al. [105]. The reduction of usable battery capacity during the time horizon of the optimization is therefore considered negligible.

Nevertheless, costs associated with calendar degradation will also be regarded. For lithium-ion cells high SOC levels accelerate calendar aging. Moreover, Keil [104] demonstrates that the calendar aging does not increase steadily with the SOC, instead plateau regions where the capacity fade is similar exist. There is a transition phase between low and high calendar degradation at approximately 65 % SOH. This value is set up as the SOC^{max} as specified in section 4.2.2.



(a) Summer calendar degradation **(b)** Winter calendar degradation

Figure 11: Calendar degradation

Figure 11 shows the capacity fade at different SOC and battery temperatures, after a storage period of 10 years [105]. The base calendar degradation rate was estimated at 65 % SOC from the graph and assumed to be linear over the years, excluding the first year where degradation is high respective to consecutive years. The additional degradation is taken as the change in degradation when considering 75 % SOC. Figure 11 also shows that high temperature negatively affects lifetime. The model assumes 25°C to correspond to the mean temperature in summer and 10°C in winter. The resulting values are reported in Table 9. The associated cost of the calendar degradation is derived in Equation 10. Here the total battery cost is divided by the SOH loss after which the battery's lifetime is considered to be over. As an example, the values considered in Equation 10 correspond to the residential cases and are shown in Table 9. For the EV fleets cases, the formulation stays the same, but the capacity differs.

$$cost^{cal\_deg} = \frac{capacity \cdot bat\_cost}{SOH^{lifetime}} = \frac{59\ \text{kWh} \cdot 180\frac{\text{€}}{\text{kWh}} \cdot 7.46\frac{\text{DKK}}{\text{€}}}{30\%} = 2,641\frac{\text{DKK}}{\%^{SOH}} \tag{10}$$

For the lower bound of the SOC, a SOC^{min} of 30 % is established, similar to [108]. The SOC^{min} is taken as a value that should not be crossed. The reason for that is the assumption that users might want to keep an emergency charge for unexpected driving needs. With the established minimum, around 100 km can be covered under nominal consumption (see Section 4.2.2.3), so the user could commute in case of a work emergency. Furthermore, the 30 % are seen as a value that can also be provided by inexperienced EV users which generally are more hesitant to keep a low SOC even when not needing the vehicle.

4.2.3 Objective function

The objective function of the optimization for the V2H BTM is comprised of three different parts, as seen in Equation 11. Since the house owner has to cover costs for its household consumption and the charging of the EV, the objective function is chosen to minimize overall costs.

$$\begin{aligned} &\min_{E^{grid}_{t,u}, E^{char}_{t,u}, E^{dis}_{t,u}, deg^{cal}_{day,t,u}} \\ &\sum_{t \in T, u \in U} E^{grid}_{t,u} \cdot \pi^{el}_{day,t} + \sum_{t \in T, u \in U} deg^{cal}_{day,t,u} \cdot cost^{cal\_deg} \\ &+ \sum_{uinU} \frac{\sum_{t \in T} E^{char}_{t,u} - E^{dis}_{t,u} + consumption^{flat\_r}_{day,t,u}}{2 \cdot capacity} \cdot cost^{cycle} \end{aligned} \tag{11}$$

The first sum of the function calculates arising costs for electricity consumption from the grid $E^{grid}_{t,u}$, using the consumer electricity price $\pi^{el}_{day,t}$. Furthermore, the costs resulting from calendar battery degradation are determined by multiplying the calendar capacity loss $deg^{cal}_{day,t,u}$ with the associated costs $cost^{cal\_deg}$ (see Section 4.2.2). Lastly, the costs occurring due to cycle battery degradation are computed. Hereby, the energy throughput from charging and discharging the EV is summed up and added to the driving consumption $consumption^{flat\_r}_{day,t,u}$. Since $E^{dis}_{t,u}$ can only be negative, it is subtracted from $E^{char}_{t,u}$ to add them up. Dividing the total sum of energy throughput by twice the battery capacity leads to the cycles which are then multiplied by the associated costs (see Section 4.2.2).

4.2.4 Constraints

To implement system boundaries and assumptions to make the optimization as realistic as possible, constraints need to be added to the program. First of all, an energy balance has to be established to ensure that energy charged to $E^{char\_pcc}_{t,u}$ and discharged from the EV $E^{dis\_pcc}_{t,u}$ is reflected in the energy drawn from the grid $E^{grid}_{t,u}$ while supplying the demand of the household $D^{r}_{day,t}$. This constraint is enforced for all users u and all time steps t, expressed in the term $\forall\ t \in T,\ u \in U$.

$$E^{grid}_{t,u} \geq D^{r}_{day,t} + E^{char\_pcc}_{t,u} + E^{dis\_pcc}_{t,u} \quad \forall\ t \in T,\ u \in U \tag{12}$$

All variables in Equation 12, except for the $E_{t,u}^{dis\_pcc}$ have a positive sign since load convention is used. Instead of the equal sign, a greater or equal sign is used to leave the model more flexibility. However, this does not impact the accuracy of the registered costs associated with $E_{t,u}^{grid}$, since the energy on the household side can only be greater, not lower, than the energy drawn from the grid. Therefore, the model will still try to achieve equality between the two sides.

The following four constraints focus on the charging and discharging of the EV. For Equation 13, P_p^{char} represents the possible charging steps and η_p^{char} the corresponding efficiency. The variable $time_{t,p,u}^{char}$ specifies how many 10 min charging windows are assigned to different charging steps for each hour t and user u. Hereby, the scalar ω indicates the number of charging slots in an hour. Summing over all charging steps p therefore leads to the total energy $E_{t,u}^{char}$ charged to the EV. Equation 14 follows the same logic for the discharging process. However, the power is divided by the efficiency, since the charging equipment will draw more energy from the EV battery than it will receive to compensate for losses.

$$E_{t,u}^{char} = \sum_{p \in P^{sc}} P_p^{char} \cdot \eta_p^{char} \cdot \frac{time_{t,p,u}^{char}}{\omega} \quad \forall\, t \in T,\ u \in U \tag{13}$$

$$E_{t,u}^{dis} = \sum_{p \in P^{sd}} \frac{P_p^{dis}}{\eta_p^{dis}} \cdot \frac{time_{t,p,u}^{dis}}{\omega} \quad \forall\, t \in T,\ u \in U \tag{14}$$

Equation 15 and Equation 16 are established in the same manner. The only difference is the missing charging and discharging efficiency which is due to $E_{t,u}^{char\_pcc}$ and $E_{t,u}^{dis\_pcc}$ representing the energy at the PCC to the household and the grid:

$$E_{t,u}^{char\_pcc} = \sum_{p \in P^{sc}} P_p^{char} \cdot \frac{time_{t,p,u}^{char}}{\omega} \quad \forall\, t \in T,\ u \in U \tag{15}$$

$$E_{t,u}^{dis\_pcc} = \sum_{p \in P^{sd}} P_p^{dis} \cdot \frac{time_{t,p,u}^{dis}}{\omega} \quad \forall\, t \in T,\ u \in U \tag{16}$$

To correctly establish the registration of the charging windows, two more constraints need to be implemented. The first one, Equation 17, ensures that the EV can only be charged or discharged within a charging window, not both at the same time, by setting the product of their sums over the charging steps p to 0:

$$\sum_{p \in P^{sc}} \frac{time_{t,p,u}^{char}}{\omega} \cdot \sum_{p \in P^{sd}} \frac{time_{t,p,u}^{dis}}{\omega} = 0 \quad \forall\, t \in T,\ u \in U \tag{17}$$

Furthermore, Equation 18 ensures that the sum over all charging steps p of $time_{t,p,u}^{char}$ can take the maximum value of ω, which would mean that all charging windows are covered by the charging process. However, the sum over all discharging steps p of $time_{t,p,u}^{dis}$ can also take a value lower than ω if not all time slots are covered by charging. Moreover, charging and discharging should only be possible if the EV is available at home which is why the greatest possible value of the sum of both terms is multiplied by the availability variable $home^{r}_{day,t,u}$.

$$\sum_{p \in P^{sc}} \frac{time^{char}_{t,p,u}}{\omega} + \sum_{p \in P^{sd}} \frac{time^{dis}_{t,p,u}}{\omega} \leq 1 \cdot home^{r}_{day,t,u} \quad \forall\, t \in T,\ u \in U \tag{18}$$

After establishing all constraints related to the power and energy flows, the storage of the energy in the EV battery has to be defined. Therefore, three constraints concerning the SOC are implemented. Equation 19 sets the minimum and maximum boundaries of the SOC. For the maximum limit the decision variable $y_{day,t,u}$ allows to operate below SOC^{max} or up until the battery's capacity. In each hour, $y_{day,t,u}$ assumes a true value when the battery operates above the defined threshold.

$$SOC^{min} \leq SOC_{day,t,u} \leq capacity \cdot y_{day,t,u} + SOC^{max} \cdot (1 - y_{day,t,u}) \quad \forall\, t \in T,\ u \in U \tag{19}$$

Equation 20 and Equation 21 calculate the incurred calendar degradation $deg^{cal}_{day,t,u}$. These constraints distinguish between the base and additional battery degradation resulting from exceeding the SOC^{max} level. Furthermore, they take into account seasonal variations in degradation.

$$deg^{cal}_{day,t,u} \geq deg^{cal}_{ba,s} + deg^{cal}_{ad,s} \cdot y_{day,t,u} \quad \forall\, t \in T,\ u \in U,\ day \in S \tag{20}$$

$$deg^{cal}_{day,t,u} \geq deg^{cal}_{ba,w} + deg^{cal}_{ad,w} \cdot y_{day,t,u} \quad \forall\, t \in T,\ u \in U,\ day \in W \tag{21}$$

At last, the SOC needs to be calculated for each hour and user in Equation 22. The three expressions behind the curly brackets are if-statements, of which the first one ensures that the last SOC of the previous day $SOC^{last}_{day-1,24,u}$ is considered for the first hour of each day. This is necessary because of the implementation of the rolling horizon explained in 4.1, which optimizes day after day and not for the whole year at once. However, since there is no day to refer back to on the first day of the simulation, a second if-statement is specified, establishing that SOC^{min} is used for the first hour. In all other cases, meaning for the rest of the hours of all days except the first, the SOC of the previous hours is taken $SOC_{day,t-1,u}$. All three if-expressions results in the value 0 being considered, if the specific case is not met. At last, to implement the increased or decreased energy in the EV battery by charging and discharging, the respective variables are added to the previous SOC. Furthermore, the driving consumption of the EV is considered by deducting $consumption^{flat\_r}_{day,t,u}$. Therefore, $SOC_{day,t,u}$ represents the energy content of the battery at the end of each t.

$$SOC_{day,t,u} = \begin{cases} SOC^{last}_{day-1,24,u} & \text{,if } day \geq 2 \wedge t = 1 \\ 0 & \text{,if } day < 2 \wedge t > 1 \end{cases}$$
$$+ \begin{cases} SOC^{min} & \text{,if } day = 1 \wedge t = 1 \\ 0 & \text{,if } day > 1 \wedge t > 1 \end{cases}$$
$$+ \begin{cases} SOC_{day,t-1,u} & \text{,if } t \geq 2 \\ 0 & \text{,if } t < 2 \end{cases}$$
$$+E^{dchar}_{t,u} + E^{dis}_{t,u} - consumption^{flat\_r}_{day,t,u} \quad \forall\, t \in T,\ u \in U \tag{22}$$

4.3 V2H FTM

While for V2H BTM the RU is not selling any electricity to the grid, the business model V2H FTM considers feeding electricity into the grid. Otherwise, the two business models are very similar, leading them to share common features. This can also be observed when regarding Figure 12. To avoid repetition, only parameters, variables, and constraints that were modified or added to the model shown in Section 4.2 will be presented.

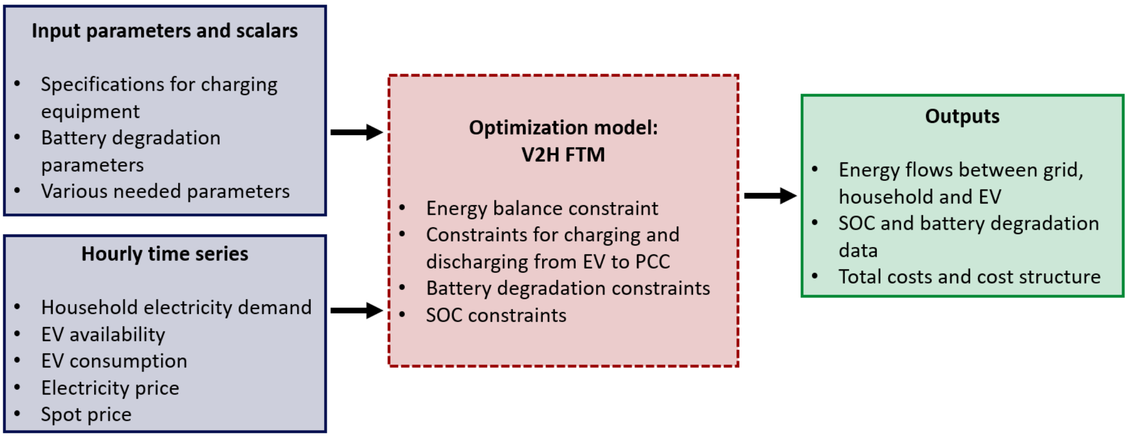


Figure 12: General functioning, as well as inputs and outputs of V2H FTM optimization model

4.3.1 Decision variables

The optimization model of V2H FTM uses all the decision variables of V2H BTM. Furthermore, $E^{grid\_feedin}_{t,u}$ is introduced which represents the energy fed into the grid by the household (see Table 10). Due to the load convention being used, the variable can only take negative values.

Table 10: Decision variables for V2H FTM

	Value	Unit	Description
$E^{grid\_feedin}_{t,u}$	$\in \mathbb{R}^-_0$	kWh	Energy fed into the grid by the household

4.3.2 Input parameters

As with the decision variables, all input parameters of the V2H BTM optimization are also used in the V2H FTM model. Additionally, new scalars and parameters presented in Table 11 are used. Since the energy fed into the grid is sold at the spot price of the wholesale electricity market, $\pi^{spot}_{day,t}$ is defined for each hour of each day. As explained in Section 4.1, a rolling horizon with persistence forecast is implemented for the prices taken from [96]. Furthermore, several tariffs need to be considered in the model, of which two are imposed by Energinet on each kWh produced [101]. The feed-in tariff for consumption-dominated areas of 0.003 DKK/kWh and balance tariff of 0.0016 DKK/kWh are summarized in the scalar τ^{TSO}. Furthermore, the tariff imposed by the DSO is denoted as τ^{DSO}. The PES, needed to handle the feed-in of electricity for the RU (see Section 2.2.1), also places a tariff on each fed-in kWh which is represented by τ^{PES}. For this tariff the value 0.04 DKK/kWh was taken from Nettøpower, one of the registered PES in Denmark [109].

Table 11: Parameters and scalars for V2H BTM

	Value	Unit	Description	Source
Parameters				
$\pi^{spot}_{day,t}$	-	DKK/kWh	Electricity price for household consumers	[96]
Scalar				
τ^{TSO}	0.0046	DKK/kWh	Feed-in and balance tariffs imposed on producing electricity, set by TSO Energinet	[101]
τ^{DSO}	0.0056	DKK/kWh	Feed-in tariff imposed on producing electricity, set by DSO Cerius	[51]
τ^{PES}	0.04	DKK/kWh	Tariff imposed on handling electricity feed-in by PES Nettøpower	[109]

As mentioned in Section 2.2.1.4, several yearly fixed costs arise for auto-producers without a production meter. Since the household would become such an entity when feeding electricity into the grid and it is assumed that they would not have a separate meter, the yearly subscriptions apply. However, they are not considered in the optimization model itself, since they are fixed and cannot be optimized by the program. To paint the complete picture of the costs of V2H FTM they will still be added after completing the optimization and will be presented in the results in Section 5.2.3.

4.3.3 Objective function

The objective function of the model contains the same summations as Equation 11, presented in Section 4.2. However, there are two more terms added, as seen in Equation 23.

$$\begin{aligned}
&\min_{E^{grid}_{t,u}, E^{grid_feedin}_{t,u}, E^{char}_{t,u}, E^{dis}_{t,u}, E^{deg}_{t,u}} \\
&\sum_{t\in T, u\in U} E^{grid}_{t,u} \cdot \pi^{el}_{day,t} + \sum_{t\in T, u\in U} E^{deg}_{t,u} \cdot cost^{cal_deg} \\
&+ \sum_{u\in U} \frac{\sum_{t\in T} E^{char}_{t,u} - E^{dis}_{t,u} + consumption^{flat_r}_{day,t,u}}{2 \cdot capacity} \cdot cost^{cycle} \\
&- \sum_{t\in T, u\in U} -E^{grid_feedin}_{t,u} \cdot \pi^{spot}_{day,t} + \sum_{t\in T, u\in U} -E^{grid_feedin}_{t,u} \cdot (\tau^{TSO} + \tau^{PES} + \tau^{DSO})
\end{aligned} \tag{23}$$

Since the objective function minimizes electricity costs, the revenue generated from selling electricity back to the grid is deducted from the cost. Therefore, the sum over all time steps

t and users u of $E^{grid\_feedin}_{t,u}$ being multiplied with the spot price $\pi^{spot}_{day,t}$ is taken. Still, each kWh fed into the grid also causes costs, which are considered by adding the sum over all time steps t and users u of $E^{grid\_feedin}_{t,u}$ multiplied with all arising tariffs.

4.3.4 Constraints

Due to the addition of the variable $E^{grid\_feedin}_{t,u}$, the energy balance constraint (see Equation 12) needs to be adjusted. Since the variable has a negative sign and is supposed to enable $E^{dis\_pcc}_{t,u}$ to be greater than the demand $D^{r}_{day,t}$, it is added on the grid side, as seen in Equation 24.

$$E^{grid}_{t,u} + E^{grid\_feedin}_{t,u} \geq D^{r}_{day,t} + E^{char\_pcc}_{t,u} + E^{dis\_pcc}_{t,u} \quad \forall\, t \in T,\ u \in U \tag{24}$$

4.4 V2B FTM

In the two previous sections, optimization models for RUs owning an EV were developed. However, V2X services can also be applied to EV fleets. As specified in Section 2.1.2, some services are especially interesting when EVs can provide a higher capacity and power. Therefore, two business models for implementing V2X for EV fleets were developed in Section 3. The first one, V2B FTM, considers an EV fleet which is charged at a depot. As described in Section 3.3, it is considered that the fleet can be used to cover the consumption of a nearby building. Furthermore, PV production is included which can be used to cover the demand of the building or the EV fleet charging. Thus, the building, the PV panels, and the EVs are connected via a PCC.

Although the business model differs from the ones considering V2H, most variables, inputs, and constraints are the same or similar for V2B FTM, see Figure 13. As in the previous sections, first, the newly added or modified decision variables and input parameters will be described. Afterwards, the objective function and constraints are presented.

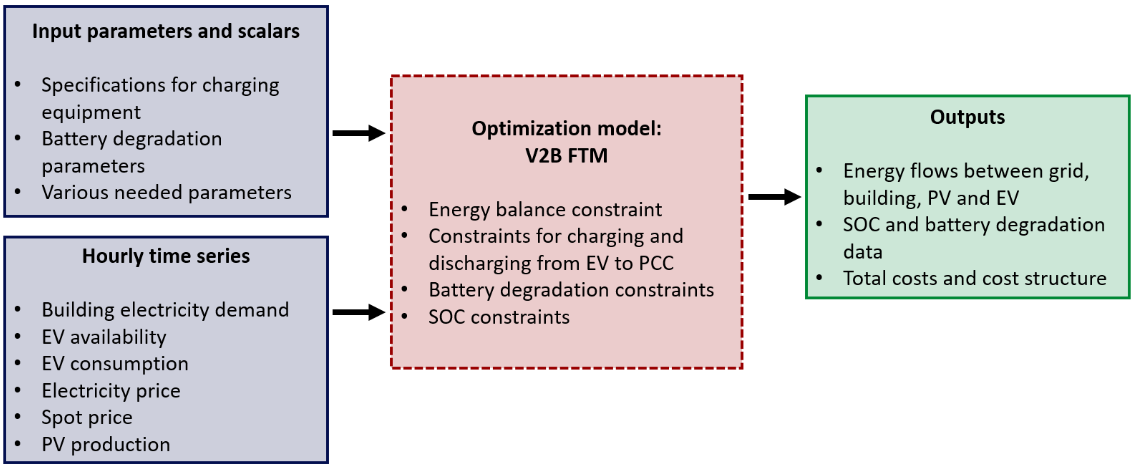


Figure 13: General functioning, as well as inputs and outputs of V2B FTM optimization model

4.4.1 Decision variables

In contrast to the business models of V2H, no user types are considered. However, since a fleet consists of several vehicles, they are distinguished by establishing the set of v. Based on an e-mail interview conducted with ARC, a waste management company in

Copenhagen operating a fleet of electric refuse trucks, the number of vehicles V considered for the optimization model is set to 100 [110]. To observe the behavior of the different vehicles, e.g. regarding the energy charged $E_{t,v}^{char}$ and discharged $E_{t,v}^{dis}$, all affected decision variables are made dependent on the vehicle v. They are denoted in Table 12. However, since for V2B FTM, a PCC is needed to combine the EV fleet with a building and PV panels on site, the grid connection does not depend on each vehicle. Hence, the decision variables E_t^{grid} and $E_t^{grid\_feedin}$ are only based on the time steps t.

Table 12: Sets and decision variables for V2B FTM

	Value	Unit	Description
Sets			
v	$\in V$	-	Vehicles in the regarded EV fleet
Decision variables			
E_t^{grid}	$\in \mathbb{R}_0^+$	kWh	Energy drawn from the grid
$E_t^{grid\_feedin}$	$\in \mathbb{R}_0^+$	kWh	Energy fed into the grid
$E_{t,v}^{dis}$	$\in \mathbb{R}_0^-$	kWh	Energy discharged from EV fleet, seen from EV side
$E_{t,v}^{char}$	$\in \mathbb{R}_0^+$	kWh	Energy charged to EV fleet, seen from EV side
$E_{t,v}^{dis\_pcc}$	$\in \mathbb{R}_0^-$	kWh	Energy discharged from EV fleet, seen from PCC
$E_{t,v}^{char\_pcc}$	$\in \mathbb{R}_0^+$	kWh	Energy charged to EV fleet, seen from PCC
$deg_{day,t,v}^{cal}$	$\in \mathbb{R}_0^+$	kWh	Energy in battery, related to total capacity, leading to calendar degradation
$y_{day,t,v}$	$\in \{0,1\}$	-	Binary indicating if SOC threshold is exceeded for a vehicle (1 = exceeded, 0 = not exceeded)
$SOC_{day,t,v}$	$\in \mathbb{R}_0^+$	kWh	Energy stored in each EV of the fleet
$time_{t,p,v}$	$\in \mathbb{Z}_0^+$	-	Number of charging windows in an hour for charging
$time_{t,p,v}^{dis}$	$\in \mathbb{Z}_0^+$	-	Number of charging windows in an hour for discharging

4.4.2 Input parameters

To enable the implementation of the new decision variables, several new input parameters had to be defined. Previously mentioned costs, like for battery degradation and grid feed-in costs, as well as the spot price, stay the same and are not revised in this section. The only exception are DSO tariffs, τ^{DSO}, and τ^{ToU}, which are adjusted for consumer category A-low. The latter forms part of the electricity consumption price and therefore sets it apart from the residential price. Table 13 shows all newly added or modified input parameters and scalars. While the demand $D_{day,t}^r$ is still dependent on each day and hour, its values were changed to match the consumption of a building, e.g. an office building. Therefore, data from Campus Bornholm was taken which was provided in the scope of the projects of EV4EU and INSULAE (see Table 1). The dataset spans from 01.01.2018 to 30.09.2020 in hourly resolution. Since the optimization model is set out for the time frame of one year, the values from 2018 were selected. As described in Section 4.2.2 the electricity prices are from 2021 which starts with a different weekday than 2018. Due to electricity consumption and prices showing varying patterns for different days of the week, the demand data was adjusted to match 2021 by removing several days at the beginning of January and adding them at the end of December.

As in Zepter et al. [111], data from EV4EU and INSULAE was also used to model PV production $PVprod\_r_{day,t}$ on site connected to the PCC. Following load convention, $PVprod\_r_{day,t}$ only has negative values. The data corresponds to a collection of PV panels providing 61 kWp. To estimate how much could be provided by PV panels at the depot of a refuse truck fleet, the area covered by the charging stations and connected trucks of ARC was measured on Google Maps to be around 2,300 m^2. Considering a PV panel of 1.6 m^2 can produce 0.31 kW [112], the area at ARC could provide around 450 kW. Since the nominal power of the potential PV panels at the depot is 7.5 times higher than the one from the original data set, the hourly values were scaled up by 7.5. At the moment the area at ARC does not show a covered depot on Google Maps. For the optimization, though, it is assumed that a similar PV production is realistic for an EV truck fleet, which could be provided by PV panels on the depot, another building's roof or by free-standing panels.

Furthermore, the variable $home^r_{day,t,u}$, used in both V2H models, was changed. The new variable, $availability^r_{day,t}$, is no longer dependent on a user, however, it was also not made dependent on the different vehicles. The reason for this is the nature of the EV fleet. The availability of the vehicles is based on ARC's trucks being away from the depot from 6 am until 5 pm. Since no difference was made between the vehicles, all of them share the same variable $availability^r_{day,t}$. The same goes for the consumption $consumption^{flat\_r}_{day,t}$, where the consumption per km was based on ARC's vehicles covering 75 km per day while consuming 170 kWh/day. The resulting nominal consumption is therefore calculated to be 2.3 kWh/km. Assuming the same variation in summer and winter as specified in Section 4.2.2.3 and time away from the depot, results in a summer consumption of around 11 kWh/h and a winter consumption of 18 kWh/h. ARC furthermore specified that their vehicles are from Volvo and Scania but did not provide the type of model. While trucks from these companies were not found to be V2X compatible in Section 2.3, the values from ARC will still be used to consider the potential of an existing EV fleet.

ARC provided information about the capacity of their electric refuse trucks, as well as their charging power and the available chargers, see Table 13. However, ARC did not specify a minimum SOC for each EV of the fleet. Therefore, it is kept at 30 %. With this charge the EVs could then cover around 40 km, considering nominal consumption (see Section 4.4.2). Since this situation is considered to be unlikely, though, the minimum SOC is not chosen to cover the whole distance covered by the electric refuse trucks per day of 75 km.

Table 13: Parameters and scalars for V2B BTM

	Value	Unit	Description	Source
Parameters				
$D^r_{day,t}$	-	kWh	Building demand	[2, 38]
$availability^r_{day,t}$	-	-	Integer variable indicating if EV is available (1 = available, 0 = unavailable)	[110]
$consumption^{flat\_r}_{day,t}$	-	kWh/h	Driving consumption of EV	[110]
$PV^{prod\_r}_{day,t}$	-	kWh	Energy generated by PV panels at EV fleet depot	[2, 38]
Scalar				
$capacity$	300	kWh	Capacity of each fleet vehicle, based on	[110]
P^{char_max}	100	kW	Maximum charging power for EV battery	[110]
P^{dis_max}	100	kW	Maximum discharging power for EV battery	[110]
SOC^{min}	30	%	Minimum SOC to cover emergency charge	
τ^{DSO}	0.0032	DKK/kWh	Feed-in tariff imposed on producing electricity, set by DSO Cerius	[51]

4.4.3 Objective function

As in the previous model, presented in Section 4.2 and 4.3, the overall goal of the optimization model is to minimize electricity costs. Since the EV fleet operator is responsible for not only the fleet but also the building's electricity consumption and the PV panels, all three instances are electrically connected at a grid connection point. Hence, Equation 25 is the same as in the V2H FTM case, except for E_t^{grid} and $E_t^{grid\_feedin}$ only being dependant on the time steps t, combining all consumption and feed-in at the PCC. Otherwise, the first three terms represent the same costs as in the other models.

$$
\begin{aligned}
&\min_{E_t^{grid}, E_t^{grid\_feedin}, E_{t,v}^{char}, E_{t,v}^{dis}, E_{t,v}^{char\_pcc}, E_{t,v}^{dis\_pcc}, cal_{t,v}^{deg}} \\
&\sum_{t \in T} E_t^{grid} \cdot \pi_{day,t}^{el} + \sum_{t \in T, v \in V} cal_{t,v}^{deg} \cdot cost^{cal\_deg} \\
&+ \sum_{v \in V} \frac{\sum_{t \in T} E_{t,v}^{char} - E_{t,v}^{dis} + consumption_{day,t}^{flat\_r}}{2 \cdot capacity} \cdot cost^{cycle} \\
&- \sum_{t \in T} -E_t^{grid\_feedin} \cdot \pi_{day,t}^{spot} + \sum_{t \in T} -E_t^{grid\_feedin} \cdot (\tau^{TSO} + \tau^{PES})
\end{aligned}
\tag{25}
$$

4.4.4 Constraints

To implement the PCC, the energy balance constraint needs to be changed, as displayed in Equation 26. While E_t^{grid} and $E_t^{grid\_feedin}$ are added up on the left side since $E_t^{grid\_feedin}$ carries a negative sign, the PV production $PV_{day,t}^{prod\_r}$, the demand $D_{day,t}^{r}$ and the sum of all charging and discharging $E_{t,v}^{char\_pcc}$ $E_{t,v}^{dis\_pcc}$ are considered on the right side of the greater or equal sing. As mentioned in Section 4.2, this sign grants more flexibility to the model while not impairing the outcome. Since the model is set to minimize costs associated with a greater E_t^{grid}, it will try to make the equation as equal as possible. Correspondingly, increasing the negative $E_t^{grid\_feedin}$ will reduce the revenue. Following load convention, $PV_{day,t}^{prod\_r}$, being negative, is added to the demand $D_{day,t}^{r}$. All charging and discharging activity is then summed up for all vehicles v, to get the total EV demand or feed-in when the sum is positive or negative, respectively.

$$
E_t^{grid} + E_t^{grid\_feedin} \geq PV_{day,t}^{prod\_r} + D_{day,t}^{r} + \sum_{v \in V} \left(E_{t,v}^{char\_pcc} + E_{t,v}^{dis\_pcc} \right) \quad \forall\, t \in T \tag{26}
$$

Furthermore, all other constraints were changed to match the new set of vehicles v. For an example, refer to Equation 27.

$$
E_{t,v}^{char} = \sum_{p \in P^{sc}} P_p^{char} \cdot \eta_p^{char} \cdot \frac{time_{t,p,v}}{w} \quad \forall\, t \in T, v \in V \tag{27}
$$

4.5 V2G FCR-D

The last optimization model is an extension of V2B FCR-D. In addition to selling electricity to the grid, though, the business model also allows to offer FCR-D up reserve at the ancillary service market. Therefore, several new decision variables, input parameters, and constraints need to be defined to follow the regulatory requirements specified in Section 2.2.1. The general functioning with inputs and outputs, as well as a summary of the content of the optimization model, is displayed in Figure 14. All new or modified parameters and constraints mentioned in the figure are explained in detail in the following.

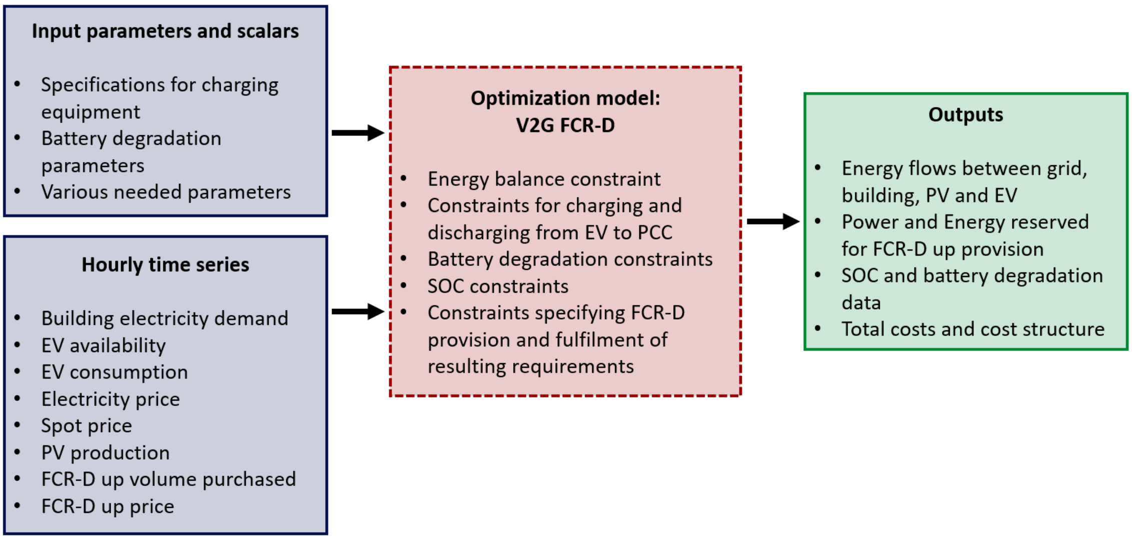


Figure 14: General functioning, as well as inputs and outputs of V2G FCR-D optimization model

4.5.1 Decision variables

For FCR-D an agent can sell a certain amount of power in the ancillary services market. Therefore, $P_t^{res,up}$ is defined which represents the power reserved for FCR-D. The variable is defined to be only negative for each time step t, so the service can be provided by all assets connected to the PCC. The requirements presented in Section 2.2.1 specify, though, that energy corresponding to the power sold in the market, has to be guaranteed by the seller. Consequently, $E_t^{res,up}$ is defined. As shown in Table 14, another variable called $res_{t,p,v}^{up}$ is implemented as a binary to specify the power step chosen for providing FCR-D.

Table 14: Decision variables for V2G FCR-D

	Value	Unit	Description
$P_t^{res,up}$	$\in \mathbb{R}_0^-$	kW	Power for FCR-D up reserve
$E_t^{res,up}$	$\in \mathbb{R}_0^+$	kWh	Energy for FCR-D up reserve
$res_{t,p,v}^{up}$	$\in \{0,1\}$	-	Power step for FCR-D up reserve

4.5.2 Input parameters

To build the V2G FCR-D model two more parameters need to be added. They are shown in Table 15 and include the FCR-D price and volume. The price is set in € per MW but converted to DKK/kW to be used in the model. The value provided by Energinet is total price of FCR-D up reserve in all areas. The volume, conversely, corresponds to each hour in the area of DK2. For the price, as well as the volume, the average of the two auction types available for FCR-D up is considered. The values correspond to 2023, which is the first year in which they were provided in this form by Energinet. As for other parameters, the weekdays were adjusted to match the weekdays of 2021. Furthermore, the foresight of the model is reduced for both parameters, as described in Section 4.1, using a persistence forecast. The model is not allowed, though, to cover the whole volume of FCR-D purchased with the EV fleet. Since there are other participants in the regulating market and the auction is conducted as pay-as-bid, it cannot be expected that the full volume of purchased FCR-D will be sold by the EV fleet at the average price. There is no data available about the volume supplied by each market participant, so the maximum share covered by the fleet vehicles $share$ is assumed to be 5 %.

Table 15: Parameters and scalars for V2G FCR-D

	Value	Unit	Description	Source
Parameters				
$\pi_{day,t}^{FCR-D,up}$	-	DKK/kW	Price per kW power reserved for FCR-D up	[113]
$vol_{day,t}^{FCR-D,up}$	-	kW	Total volume of FCR-D up purchased	[113]
Scalar				
SOC^{min}	30	%	Minimum SOC to cover FCR-D requirements and emergency charge	own asm.
$share$	5	%	Maximum market share EV fleet is allowed to cover	own asm.

Additionally, in Section 2.2.1.6 it is mentioned that 20 % of the capacity of an agent providing FCR-D needs to be reserved for the energy management system. Choosing SOC^{min} to be 30 %, therefore, covers the requirement while still leaving 10 % more for emergencies, as discussed in Section 4.4.2. It was also discussed to add the 20 % of capacity requirement to the 30 % of emergency charge. However, setting 50 % as a minimum SOC was considered to make the optimization model and an actual EV fleet inflexible, hence, SOC^{min} was kept at 30 %.

4.5.3 Objective function

As in the other models, the goal of the optimization is to minimize electricity costs. Hence, the first three terms of Equation 28 represent the costs for electricity drawn from the grid, calendar degradation, and cycle degradation, respectively. In addition to the cost and revenue factors for the grid feed-in, the revenue from the FCR-D provision is added to reduce the overall costs, by multiplying the reserved power $P_t^{res,up}$ with the FCR-D price $\pi_{day,t}^{FCR-D,up}$. Since $P_t^{res,up}$ can only be negative, the sum is added, leading to the revenue being subtracted from the overall costs.

$$
\begin{aligned}
&\min_{E_t^{grid}, E_t^{grid\_feedin}, E_{t,v}^{char}, E_{t,v}^{dis}, E_{t,v}^{char\_pcc}, E_{t,v}^{dis\_pcc}, cal_{t,v}^{deg}} \\
&\sum_{t \in T} E_t^{grid} \cdot \pi_{day,t}^{el} + \sum_{t \in T, v \in V} cal_{t,v}^{deg} \cdot cost^{cal\_deg} \\
&+ \sum_{v \in V} \frac{\sum_{t \in T} E_{t,v}^{char} - E_{t,v}^{dis} + consumption_{day,t}^{flat\_r}}{2 \cdot capacity} \cdot cost^{cycle} \\
&- \sum_{t \in T} -E_t^{grid\_feedin} \cdot \pi_{day,t}^{spot} + \sum_{t \in T} -E_t^{grid\_feedin} \cdot (\tau^{TSO} + \tau^{PES}) \\
&+ \sum_{t \in T} P_t^{res,up} \cdot \pi_{day,t}^{FCR-D,up}
\end{aligned}
\tag{28}
$$

4.5.4 Constraints

All constraints used in the model of V2B FTM, presented in Section 4.4, are also used in this model. However, several constraints need to be added to implement the provision of FCR-D up. Since power provision is sold in the regulating market, in Equation 29 the discharging power is summed for all vehicles v. P_p^{dis} represents the possible discharging steps p and η_p^{dis} the corresponding efficiencies. The binary $res_{t,p,v}^{up}$ indicates which discharging step is selected for each vehicle by setting only one discharging step p to 1 for each vehicle v. By summing the product of the mentioned variables for all vehicles and discharging steps, the total discharging power is calculated and stored in $P_t^{res,up}$ for each hour t. As explained before, a less or equal sign is selected to grant more flexibility to the model.

$$
P_t^{res,up} \leq \sum_{v \in V, p \in P^{sd}} \frac{P_p^{dis} \cdot res_{t,p,v}^{up}}{\eta_p^{dis}} \quad \forall\, t \in T \tag{29}
$$

However, to implement that only one discharging step p can be selected for each vehicle v for each hour. Hence, in Equation 30 the sum over all discharging steps p is set to be less or equal to 1.

$$
\sum_{p \in P^{sd}} res_{t,p,v}^{up} \leq 1 \quad \forall\, t \in T,\ v \in V \tag{30}
$$

As indicated earlier in other cases, the vehicles have to be at the depot to be able to provide the power sold for FCR-D. Consequently, the $availability_{day,t}$, which is 0 when the EV is unavailable and 1 when it is present at the depot, is multiplied by the volume $vol_{day,t}^{FCR-D,up}$. For each time step t the value of the FCR-D power sold can therefore not exceed the maximum defined market share of the total volume of the reserve purchased by the Danish TSO Energinet. So, the optimization model can decide to supply as much $P_t^{res,up}$ as it can provide while applying the previously explained constraints. In reality, Energinet decides which FCR-D to buy to fulfill the demand. In contrast, in the optimization model, it is assumed that all $P_t^{res,up}$ which the EV fleet operator decides to sell is bought by Energinet.

$$
P_t^{res,up} \leq availability_{day,t} \cdot vol_{day,t}^{FCR-D,up} \cdot share \quad \forall\, t \in T \tag{31}
$$

Furthermore, as specified in Section 2.2.1.6, a unit selling power for FCR-D in the ancillary services market needs to be able to provide this power for at least 20 min. The time steps used in the optimization models are hours, so 20 min represents $\frac{1}{3} \cdot 1\ hour$. The resulting energy reserve needed for an hour in which FCR-D provision is considered is consequently computed as shown in Equation 32.

$$E_t^{res,up} \geq -P_t^{res,up} \cdot \frac{1}{3} \quad \forall\, t \in T \tag{32}$$

The constraint shown in Equation 32 stores the energy needed to fulfill the requirements to sell FCR-D. However, so far this energy is not related to the storage of the EV fleet which is why Equation 33 is implemented. Since the EV fleet needs to always have the minimum SOC, as specified in Section 4.2.2, the sum of SOC^{min} for all vehicles v is added to the $E_t^{res,up}$ provided by all EVs together. To ensure that the required energy is stored in the vehicles, the sum of the $SOC_{day,t,v}$ over the vehicles at each hour is greater or equal than the aforementioned term. This way not only the 20 min energy provision is guaranteed but also the SOC^{min}, as specified in Section 4.5.2.

$$\sum_{v \in V} SOC_{day,t,v} \geq E_t^{res,up} + \sum_{v \in V} SOC^{min} \quad \forall\, t \in T \tag{33}$$

It is worth mentioning that in the optimization model, the energy discharged from the EV fleet in case of activation of the sold FCR-D up reserve is not considered. The Nordic power system frequency rarely falls below 49.9 Hz, to be exact only about 1 % of the time. Therefore, the energy invested in actually providing FCR-D is deemed negligible, as specified by Thingvad et al. [114], and not implemented in the optimization model.

5 Results

After implementing the business models presented in Section 3 as optimization models in Section 4, the results are presented in the following. First, the outcome of the business models for RU, V2H BTM and FTM, are discussed in Section 5.1, including economic results, e.g. cost structure, and technical results like charging patterns. At the end of Section 5.1, the two business models for RU are compared to identify the suitability for household implementation.

In Section 5.2 the results of the two business models applicable for fleet vehicles are presented, starting with V2B FTM. Economic and technical results are considered, including cost aspects and generation and demand patterns. After regarding V2B FTM and V2G FCR-D separately, the two business models are compared to assess their advantages and disadvantages for fleet vehicles. The cases for RU will, however, not be compared to the cases considering fleet vehicles due to the extremely different scale of provided power, energy, and requested demand. While all results will be presented in DKK, the most important values, and figures are also reported in € in the appendix, starting with Table 24.

5.1 Residential users

The following business models for RU consider household demand coupled with an EV, which is connected to the electricity grid. In the BTM case, the vehicle is only able to charge from and discharge to the household. In contrast, for the FTM model the EV is also able to feed electricity into the grid. The economic and technical results of the optimization models derived from V2H BTM and FTM are presented below which will be compared in the final section.

5.1.1 V2H BTM

Due to the variability of electricity prices in Denmark, the business models developed for households are expected to enable cost savings for the RU. For V2H BTM Table 16 shows the overall yearly results for all three user types. Since the overall electricity costs were minimized, the unidirectional case is shown as a comparison as well.

Table 16: Yearly results of V2H BTM compared to unidirectional case

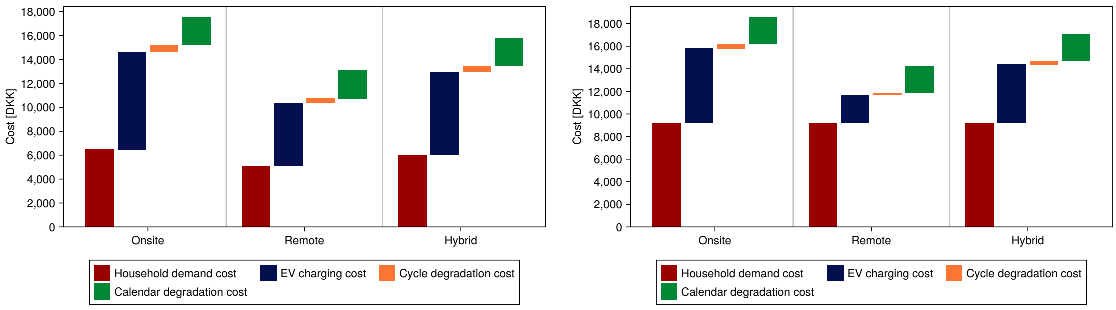
	Total cost [DKK]	E^{grid} [kWh]	E^{char_pcc} [kWh]	E^{dis_pcc} [kWh]	SOH [%]
Bidirectional case					
On-site	17,546	7,377	4,438	1,054	98.88
Remote	13,105	5,362	2,930	1,657	98.96
Hybrid	15,796	6,594	3,818	1,248	98.91
Unidirectional case					
On-site	18,581	7,227	3,338	-	98.94
Remote	14,189	5,094	1,205	-	99.05
Hybrid	17,059	6,407	2,518	-	98.98

Regarding the total cost, it is apparent that for each user the overall costs were reduced. The greatest reduction was achieved for the *remote* user, with 1,084 DKK or 8 % of the initial costs from the unidirectional case. For the *hybrid* user, the overall costs were reduced by 7 %. For the *on-site* user only 6 % of reduction was achieved. This is due to the *on-site* user having the least flexibility of the three since they are always away from the house for work during the weekdays. Therefore, the electricity demand during the day cannot be covered by the EV. Still, the difference between the savings of the *remote* and the *on-site* user amounts to only 50 DKK. The higher difference in percentage is consequently primarily rooted in the higher overall costs for the *on-site* user which exhibits a high demand for driving and the user's inflexibility. However, the results show that even with a relatively rigid schedule, cost savings can be achieved, possibly because of the peak hours with the highest prices occurring while the EV is present. The total costs shown in Table 16 include not only the electricity demand for charging the EV and supplying the household but also the costs assigned to using the battery. Consequently, they do not reflect the cost savings for electricity demand. The cost structure will be regarded in detail in Section 5.1.1.1.

Interestingly, the cost savings achieved for each user are not reflected in less electricity drawn from the grid E^{grid}. On the contrary, the *on-site*, *remote* and *hybrid* user increased their demand from the grid by 2 %, 5 % and 3 %, respectively. At the same time, the energy charged to the EV shows a rise of 33 %, 143 %, and 52 % for the respective users. Concluding from this significant increase in charging not being reflected in the electricity drawn from the grid, the household demand being covered by discharging the EV outweighs most of the increased charging demand. Furthermore, the reduction in cost despite an increased electricity demand at the grid connection point highlights the impact of the variable electricity prices. The especially high increase in charging demand of the *remote* user is caused by the optimization program choosing to cover as much of the household demand as possible by discharging the EV, leading to an increased charging rate when there are low electricity prices. In the unidirectional case of the *remote* user, the EV cannot be discharged and can therefore only cover its driving demand by charging. The assumed driving need is very low which is why after introducing bidirectional operation, the charging demand more than doubles for the *remote* user. To verify this conclusion, the charging patterns of all users will be assessed more closely in Section 5.1.1.2. Also, the cycling and calendar degradation effects will be regarded in more detail. Table 16 shows, however, that the SOH at the end of the simulated year does not differ much from the bi- to the unidirectional case. Implementing V2H BTM did increase the SOH loss for all users though. The *remote* user's battery exhibits the highest, increased loss of 0.09 %.

5.1.1.1 Economic results

Although the SOH loss does not seem notable, it entails costs that make up a significant part of the total cost. As displayed in Figure 15, the calendar degradation cost amounts to a bit less than 2,400 DKK for each user in V2H BTM and the unidirectional case. Therefore, it is the third biggest cost for all cases. In the case of the *remote* user for unidirectional operation, the charging cost is almost as high as the calendar degradation cost. The cycling degradation cost, on the other hand, is the lowest for each user in each case. However, they are increased by implementing V2H BTM for all users, especially for the *remote* users where they are more than doubled. In the previous section, it was already established that the charging demand increased immensely. Hence, more cycling degradation leading to higher costs is inevitable. Even so, the cycling degradation does not have a notable impact on the costs when comparing the unidirectional case and V2H BTM since other cost factors are much more impactful.



(a) Bidirectional case **(b)** Unidirectional case

Figure 15: Structure of yearly costs for unidirectional operation and V2H BTM

The highest price factors are the ones caused by household demand and the charging demand. For the case of unidirectional operation, seen in Figure 15b, the costs caused by the household demand are the same for all users since the EV cannot discharge to cover any demand. The costs of charging the EV reflect the driving demand of the three users for unidirectional operation, so the *on-site* user exhibits the highest and the *remote* user the lowest costs. The latter also holds for the V2H BTM business model. The charging costs, though, exceed the household electricity costs for all users of the bidirectional case, especially the *on-site* user. Its charging costs are 26 % higher than the household electricity costs while they are showing only a 14 % and 3 % difference for the *hybrid* and *remote* user. This might not seem intuitive at first, since the *on-site* user is absent for most of the weekday, hence, the household electricity demand is covered by drawing from the grid. Still, the driving demand is more impactful. In the following, Section 5.1.1.2, the aforementioned economic outcomes will be extended by regarding their technical implications.

5.1.1.2 Technical results

Although the household demand of all users was set to be the same for the optimization model of V2H BTM, their overall electricity demand from the grid differs. The electricity they draw from the grid is illustrated in Figure 16, together with the consumer's electricity price for the first full week in January 2021 (04.01. - 10.01.2021). The week displayed starts with a Monday, so the last two days represent the weekend days. For a better overview, the different days are separated by a thicker, grey vertical line.

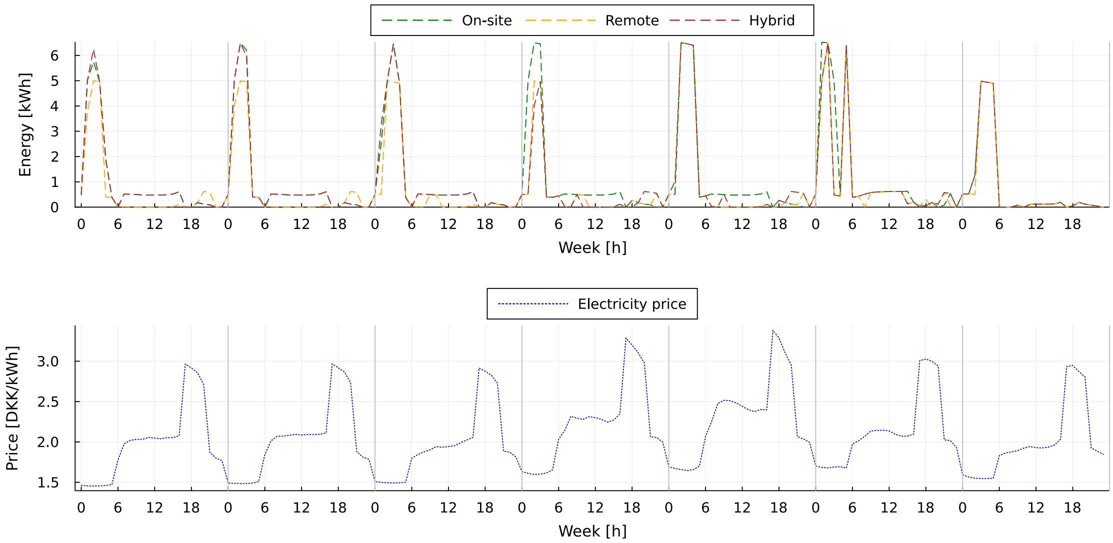


Figure 16: Electricity drawn from the grid per user and electricity price for a week in January

When regarding the electricity demand of the three users, it is apparent that they exhibit a similar general pattern, where a high demand of 5 to 6 kW occurs between 12 am and 6 am in the morning. The household electricity demand is not that extreme, so this peak demand must be primarily caused by charging the EV. This can be seen in Figure 17, which shows the charging and discharging behaviors of all users for the same week as Figure 16. As seen in the lower part of Figure 16, the time window of high demand correlates with the lowest electricity price during the day, where also the ToU tariff (see Section 2.2.1.4) is at its minimum. When the electricity price is at its peak, between 5 pm and 9 pm, the optimization model tries to avoid drawing electricity from the grid for all three users by discharging the EV, see Figure 17. However, since the *remote* user's implemented driving pattern expects him to be away on Monday and Tuesday during peak hours, its household demand cannot be fully covered. During the day this user draws very little or no electricity from the grid but covers it by discharging its EV, illustrated in Figure 17. Even the *remote* user's peak demand is mostly lower than the one of the other users, due to them having to cover a greater driving demand and the household demand after returning home. This observation can also be made when regarding Figure 18. The *remote* user mostly exhibits the lowest SOC, as its driving demand is lower than for the other users.

Furthermore, it is visible that the *hybrid* user's behavior changes during the week. This user behaves like the *on-site* user from Monday to Wednesday, while following a similar pattern as the *remote* user for Thursday and Friday. Hence, its electricity drawn from the grid is also covered by discharging the EV for the last two working days of the week, see Figure 16 and Figure 17. The *on-site* user, though, does not have the flexibility of being at home during working days, which is why its EV is never discharged between 7 am and 5 pm, see Figure 17. Still, on the weekend all three users have the same driving demand, as seen in Figure 18. Looking at the SOC on Friday shows that the *remote* and *hybrid* user charge their vehicle more than for the other working days, resulting in a higher SOC at the end of Friday, see Figure 18.

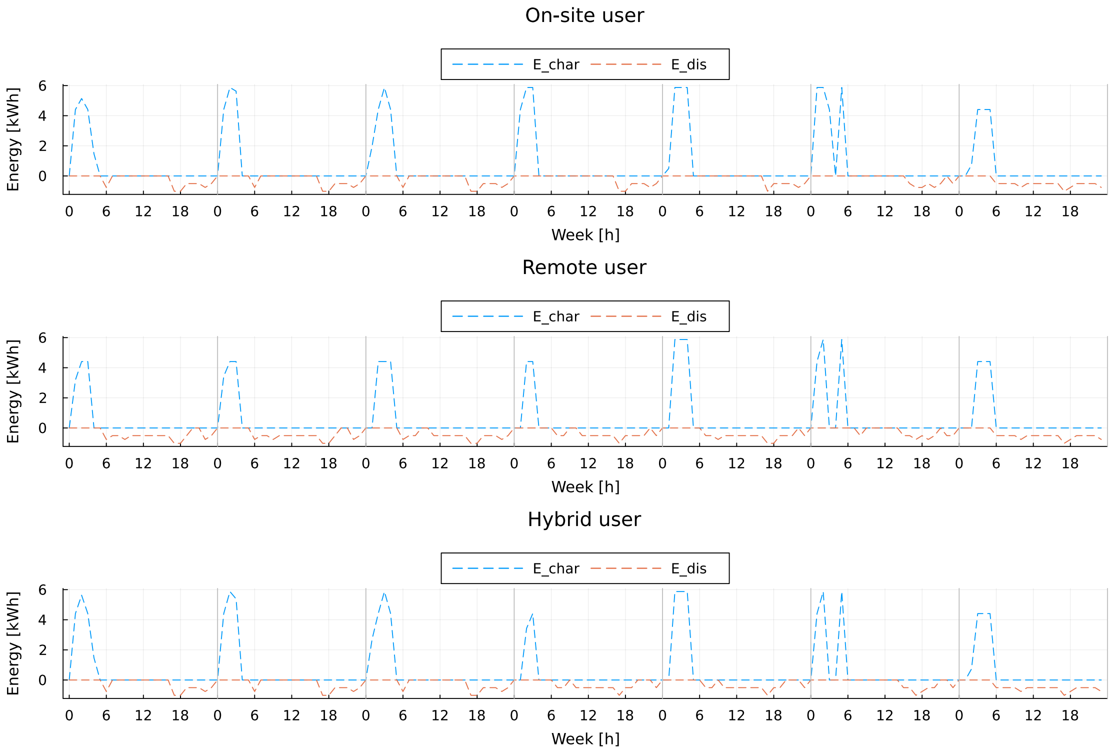


Figure 17: Charging and discharging behavior of all users for a week in January

The higher SOC at the end of Friday is increased at night, so that on Saturday morning it is high enough for all users to fulfill the driving demand of Saturday, as seen in Figure 18. Looking at the charging behavior shows two spikes during that time (see Figure 17), which cannot be observed for any other day during the displayed week. This behavior can be explained by the model avoiding increased battery calendar degradation. As specified in Section 4.2.2.4, exceeding the SOC of 65 % causes higher degradation. Figure 18 shows that the EVs of all users are charged to approximately 65 %. Then the charging is stopped for around an hour and continues to reach 70 %. Right after this SOC is reached, the EVs leave the household and the highest driving demand of the week occurs. It can therefore be concluded that the optimization model tries to avoid costs caused by high levels of SOC leading to more battery degradation. However, since the high SOC is necessary to fulfill the driving demand of Saturday, it reduces the time in which exceedance happens.

The two spikes on Saturday morning also illustrate that the maximum charging power of the EVs of 6 kW limits the flexibility of the optimization model or actual users. With a higher charging power, the EVs could have been charged at once to reach the required SOC while avoiding having the vehicle on stand-by with a high SOC. As illustrated in Figure 17, the model chooses mostly the highest possible charging power step, which grants the highest efficiency. Only for the *remote* user, a lower charging power step is selected, so less cycling and therefore lower associated cycling degradation costs seem more cost-effective than choosing the highest efficiency. For the discharging activity, though, a low efficiency accompanying lower discharging steps is not avoided. Therefore, the price difference of around 1.5 DKK between the cheapest hours during night and the rest of the day, especially the peak hours, is significant enough to outweigh higher energy losses while discharging.

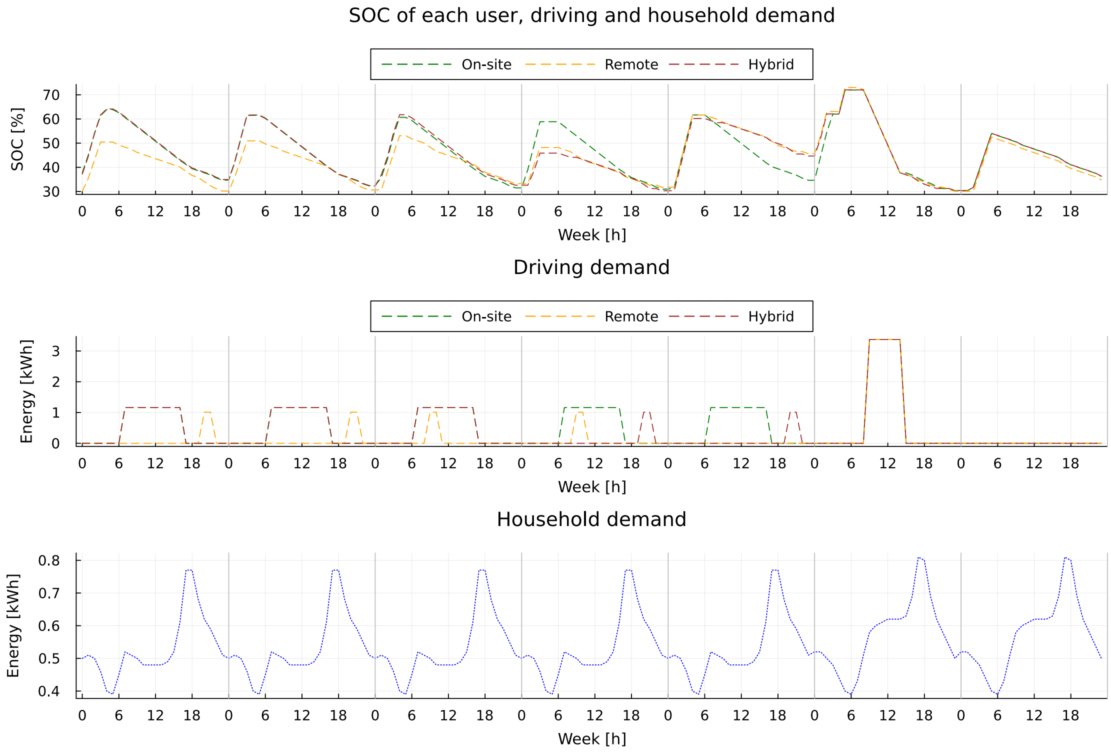


Figure 18: SOC of each user, driving and household demand for a week in January

All previously shown figures focus on a week in January, a winter month. Electricity prices, driving consumption, and household demand change with the season. Hence, a summer week also has to be regarded to gain a full picture of the optimization. A week in July (05.07. - 11.07.2021) is chosen, starting with a Monday. Figure 19 shows the electricity drawn from the grid by each user. Compared to the week in January (see Figure 16), there is less of a repetitive pattern in this week. For the *on-site* user, which exhibits the same behavior for every working day, spikes of up to 6 kW still occur on all working days, around 6 am. As for the discussed week in January, these peaks are caused by charging the EV, see Figure 20. Interestingly, this time slot does not yield the cheapest electricity price, as seen in the lower part of Figure 19. It can also be seen that the price difference between the cheapest hour of the night and 6 am is minor but does increase slightly for Thursday morning, where all user's EVs are indeed charged during the cheapest hours, see Figure 19. The optimization is set out to find the optimal solution to, in the case of this project minimize costs. However, it stops when the requirement of the so-called MIP gap is fulfilled. In short, this gap defines how close the calculated solution is to the best optimal solution, allowing a balance between having an optimal solution and not extending the computational time for too long. In the case of the V2H BTM model, the MIP gap was set to 10 % which allows a good optimal solution with an acceptable computational time. Still, this aspect of optimization leads to very minor improvements not being considered by the model. Thus, small price differences leading to slightly decreased costs, as in the case of some of the charging spikes in summer, were overlooked by the model.

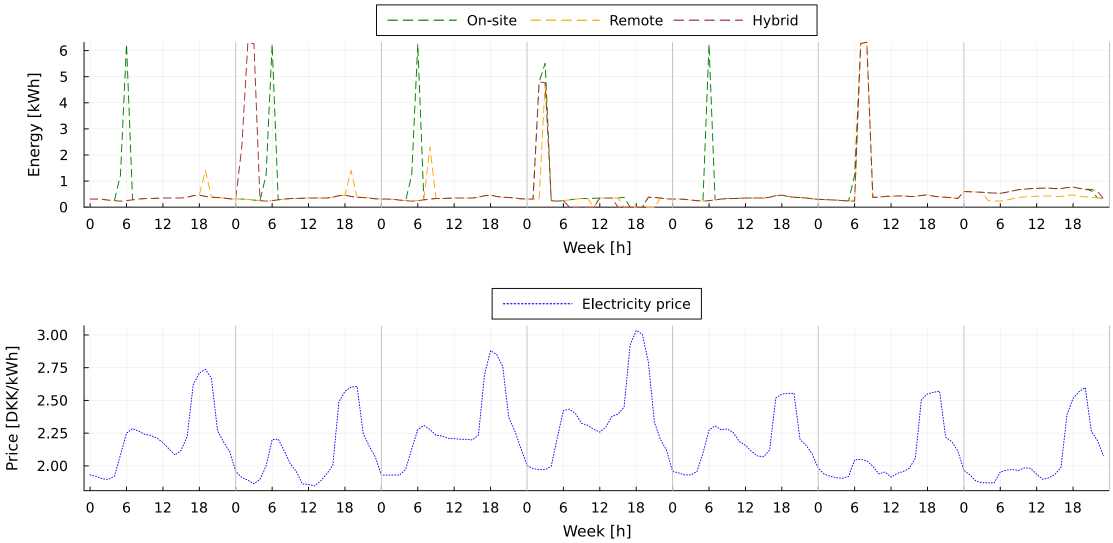


Figure 19: Electricity drawn from the grid per user and electricity price for a week in July

The price differences on Thursday did seem to be relevant, though. All users use their EV to cover household consumption, see Figure 19 and Figure 20, during the peak electricity price hours of this day. This does not happen during the rest of the week which is very different from the week in January. The *remote* and *hybrid* user only cover their own consumption during the day by the EV on Thursday. Consequently, the difference in price of around 0.75 DKK, half of the price delta in January, is too low to generate relevant cost-savings, while considering cycling degradation and energy losses due to low efficiency. In fact, the household consumption, being half of the one in January, forces the EV to choose even lower discharging steps than in January which inherently have a lower efficiency.

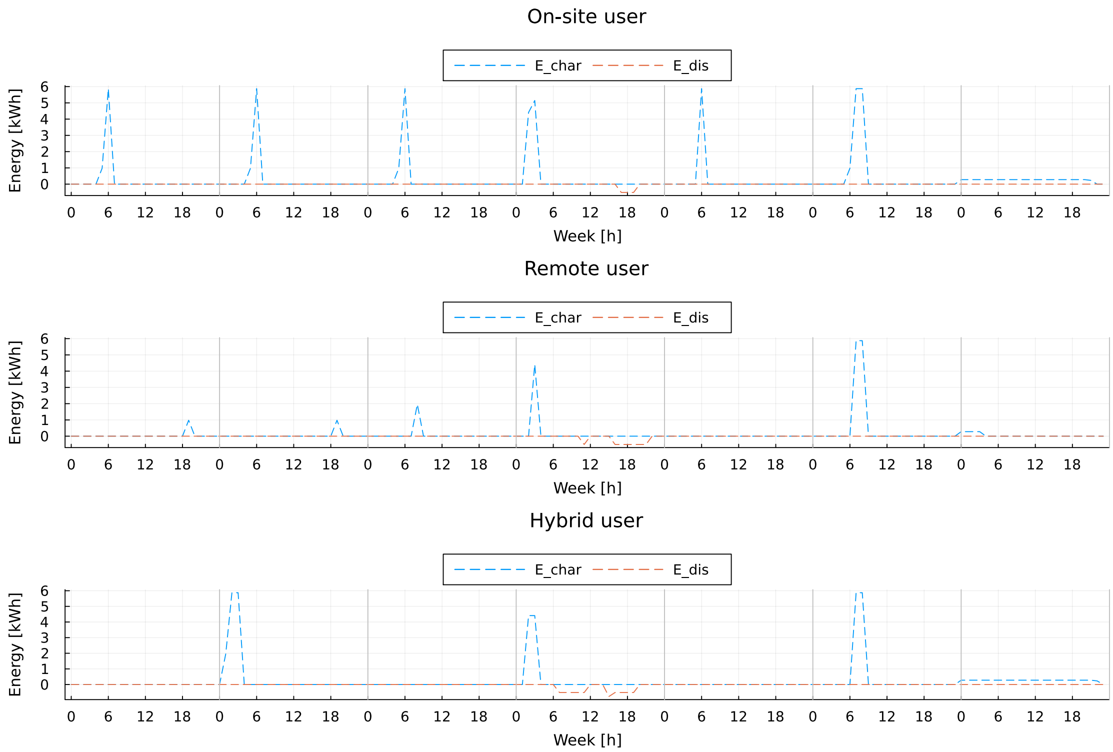


Figure 20: Charging and discharging behavior of all users for a week in July

Like for the *on-site* user, the *remote* user's EV is only charged right before it needs to cover a driving demand, see Figure 20 and Figure 21. Interestingly, the optimization model chooses to charge on Monday and Tuesday during the most expensive hour, around 6 pm, right before the EV is absent for a short time, see driving demand in Figure 18. Only the price increase in the middle of the week makes it worth it to charge earlier during a cheaper hour, otherwise, the EV is just charged right before it is needed without consideration of low efficiencies of low charging steps or the electricity price.

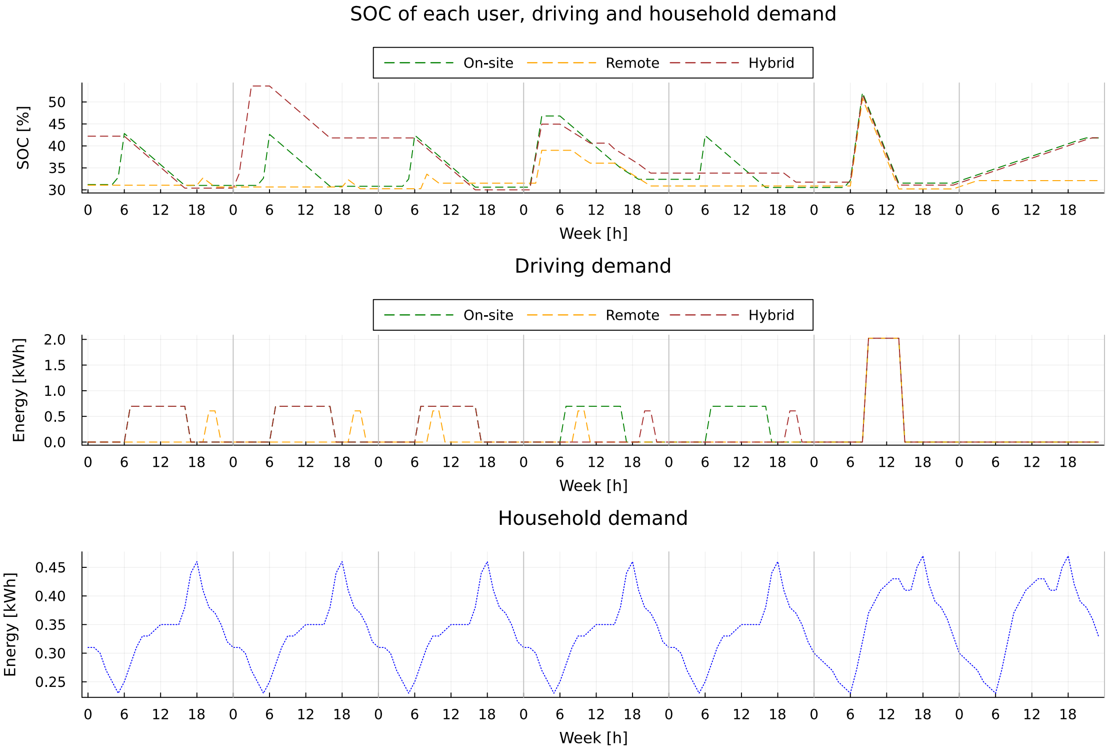


Figure 21: SOC of each user, driving and household demand for a week in July

The only user charging its EV to a high SOC in July is the *hybrid* user, see Figure 21. It does not exceed the maximum SOC leading to increased battery degradation, so there are no higher costs than when charging it to around 40 % or 50 % as the other users. However, charging this much, see Tuesday in Figure 20, at once enables the user to choose a higher charging power which correlates with a higher efficiency. Consequently, less energy is lost. The *on-site* and *remote* users also exhibit this behavior to an extent, on Wednesday and Thursday of the regarded week. The reason for that could be the previously mentioned higher electricity prices.

Overall, the optimization model chooses to charge the EV during times of the lowest electricity prices and covers household demand by discharging the EV while the electricity prices are high. This way cost-savings are indeed achieved compared to the unidirectional reference case. However, if the price differences are not significant enough, avoiding cycling degradation or high energy losses due to low efficiencies is more cost-effective and therefore chosen by the model. Furthermore, the price differences define if the EVs are discharged during peak hours, so small deltas and low electricity demand from the household lead to the procedure not being worth it. The regarded weeks indicate, though, that especially during times of generally higher electricity prices, like the winter months, users with different usage profiles charge at the same time. While having three users with each having a maximum of 6 kW drawn from the grid is manageable, scaling V2X up to a whole city optimizing their electricity consumption could lead to a new overnight peak. Consequently, the ToU tariffs could incentivize the creation of a new demand peak, defeating the purpose that they were supposed to serve.

5.1.2 V2H FTM

In the same way here price arbitrage is used as a strategy for cost reduction for the overall consumption of the RU. However, now there is the possibility to either cover on-site consumption or sell surplus energy charged back into the grid. For V2H FTM Table 17 displays the yearly results from the optimization model.

Table 17: Yearly results of V2H FTM compared to unidirectional case

	Total cost [DKK]	**Feed-in profit [DKK]**	**E^{grid} [kWh]**	**E^{grid_feedin} [kWh]**	**E^{char_pcc} [kWh]**	**E^{dis_pcc} [kWh]**	**SOH [%]**
Bidirectional case							
On-site	17,496	572	7,648	368	4,626	1,235	98.87
Remote	13,073	1,049	5,849	675	3,192	1,908	98.94
Hybrid	15,779	681	6,916	448	3,995	1,417	98.90
Unidirectional case							
On-site	18,581	-	7,227	-	3,338	-	98.94
Remote	14,189	-	5,094	-	1,205	-	99.05
Hybrid	17,059	-	6,407	-	2,518	-	98.98

The table introduces new information. Specifically, E^{grid_feedin} is distinguished from E^{grid} in that the former denotes energy flows into the grid, while the latter signifies flows from the grid. Likewise, there is a related feed-in profit. Consequently, total costs not only represent the costs of electricity consumption and battery degradation, but also the feed-in profit accounted as a mitigating element contributing to cost reduction. Finally, the unidirectional case is presented again as a baseline against which results can be compared. Overall the total costs in the bidirectional case are lower than in the unidirectional costs. On average, V2H FTM accounts for 1,160 DKK yearly cost reduction. Amongst the user categories, the *hybrid* and *remote* profiles reached approximately a reduction of 7.7 % relative to the unidirectional case. The lowest cost reduction was 5.8 % for the *on-site* user, which does not fall far behind the others.

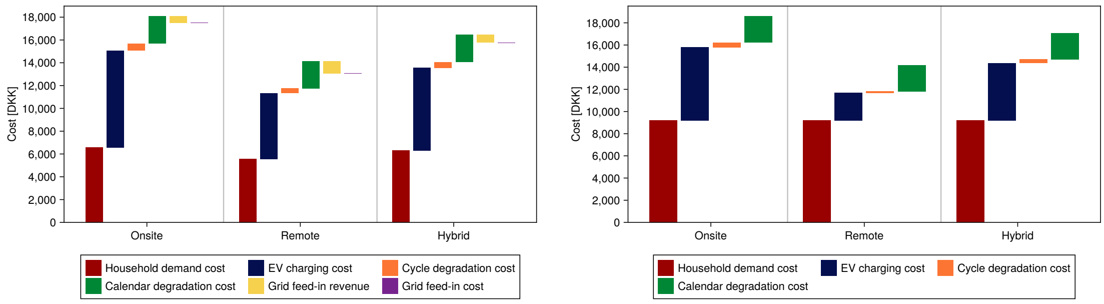
On the contrary, there is a big difference in the energy drawn from the grid across the users. Certainly E^{grid} increases relative to the unidirectional case, for instance: 5.8 % for *on-site*, 14.8 % for *remote* and 7.9 % for *hybrid* users. Here the highest availability to perform price arbitrage and the lowest driving demand set apart the *remote* user from the other profiles. Furthermore, since the electricity and driving demands are kept constant, the increase in E^{grid} is explained by the increase in E^{char_pcc}. Similarly as subsubsection 5.1.1 the increase in E^{char_pcc} is not proportional to E^{grid}. This suggests energy drawn from the grid is stored first in the EV and then discharged when convenient, highlighting the opportunity for price arbitrage.

Indeed, from the E^{dis_pcc} on average 68 % goes to satisfy electricity demand, while the remaining 32 % is fed back into the grid. The ratio of E^{grid_feedin} in relation to E^{grid} is 11.5 % for *remote* user, 6.5 % for *hybrid* and 4.8 % for *on-site*. Although the ratio is small, the related profit represents a high percentage of the total cost reduction between the bi- and unidirectional cases. It represents almost the full cost reduction for the *remote* user, while it amounts to more than half of the savings for the on-site and *hybrid* user.

Finally, it is noteworthy to point out that although the battery usage increased, by E^{char_pcc} and E^{dis_pcc}, the SOH at the end of the simulated year is similar to the baseline. This suggests it is optimal to perform FTM strategies while adhering to an appropriate battery operation with respect to battery degradation.

5.1.2.1 Economic results

To further explore the results, the cost structures for V2H FTM and the unidirectional case are shown side to side in Figure 22. Here components of total cost are presented individually for each RU. It is important to mention that feed-in profit, discussed previously, is now divided into grid feed-in revenue and grid feed-in cost. Each individual component adds up to the total cost, except grid feed-in revenue which reduces the cost structure.



(a) Bidirectional case

(b) Unidirectional case

Figure 22: Structure of yearly costs for unidirectional operation and V2H FTM

In Figure 22a it can be seen that the biggest element in the cost structure of each user is the EV charging. In contrast with Figure 22b, where the biggest component is the household demand. Indeed, increased charging of the EV enables it to either discharge to satisfy household demand or feed energy back into the grid. EV charging cost increased for *on-site* 1,915 DKK, for *remote* 3,269 DKK and for *hybrid* 2,071 DKK in respect to the unidirectional case. Considering that 68 % of the energy charged to the EV is discharged to satisfy household demand, two-thirds of the increased cost of charging can be related to the reduction in household demand. Household demand cost was reduced by 2,619 DKK, 3,618 DKK and 2,887 DKK, for *on-site*, *remote* and *hybrid* users respectively. On average, regarding these two components, there is a net benefit of almost 1,400 DKK of cost savings.

Increased charging of the EV also enabled it to discharge back into the grid. In this case, 32 % of the increase in EV charging costs can be attributed to the grid feed-in revenue. When compared, EV charging cost increase is similar to the feed-in profit. In consequence, there is almost no benefit in cost savings for feeding into the grid. The cost savings are reduced even further by the grid feed-in cost, though this is the smallest cost in the structure. The remaining cost components are related to battery degradation. Even though cycle degradation costs increase considerably from unidirectional to the bidirectional case, again they are not impactful in the cost structure. Calendar degradation cost is the dominant between these two, representing 15.6 % on average of the total cost. In contrast with cycle degradation cost, calendar cost stays almost the same between unidirectional and bidirectional operation. This suggests that the model sees no restriction in cycling the battery for bidirectional purposes, as long as it is operated optimally within the normal range of SOC.

5.1.2.2 Technical results

Now the vehicle offering V2H FTM, as defined by the business model, is investigated through several plots summarizing its yearly operation. Its operation is divided seasonally into winter and summer. Figure 23 presents the electricity demand from the grid together with the electricity price for winter, specifically the first full week of January 2021 (04.01. - 10.01.2021).

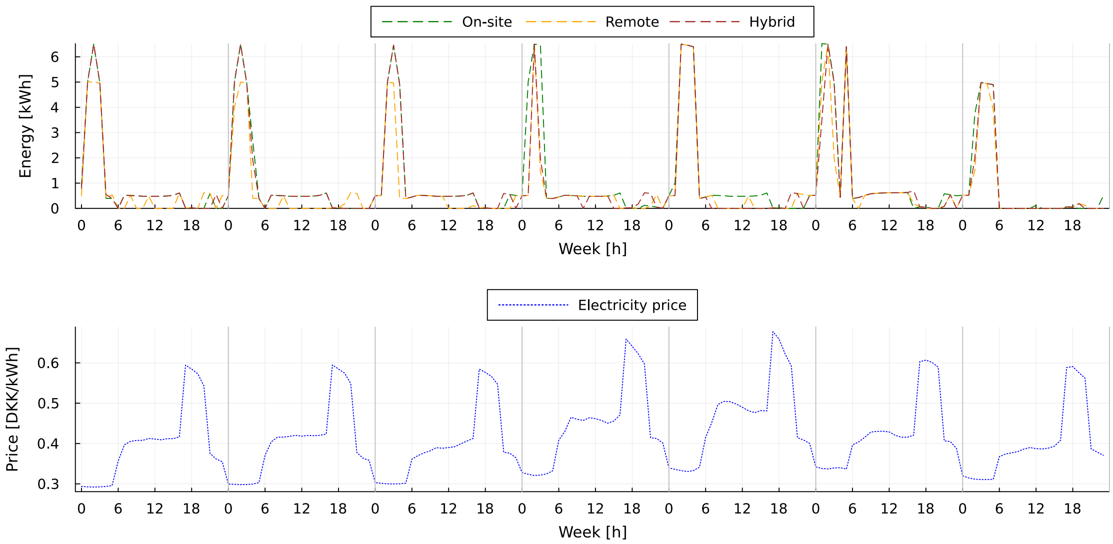


Figure 23: Electricity drawn from the grid per user and electricity price for a week in January

It can be noted that the general demand profile is similar for every day of the week. There is a high demand of 5 kWh or 6 kWh between 12 am and 6 am, where the electricity price is low. The peak demand can be attributed to the EV charging, see Figure 24. Its value is far greater than household demand, as presented in Figure 26, and matches the maximum capacity of the EV charger. Again, when the electricity price peaks at 6 pm, there is never energy drawn from the grid, so household demand is satisfied by discharging the EV, see Figure 24. In between the RU the *remote* profile presents the lowest demand peaks compared to the others from Monday to Wednesday. This can be explained by its higher availability to perform the service and lower driving demand. This is also true for Sunday, where the demand for all users is similarly low since they share the same high availability and low driving demand. On Friday and Saturday, the demand peak is at its highest for all users, additionally, the charging sessions are extended. On Saturday, there are two peaks of demand of the same magnitude in the morning. Thursday and Friday differ from the other days in that high electricity prices and spot prices occur. The spot prices are shown in Figure 25 for the same week in winter.

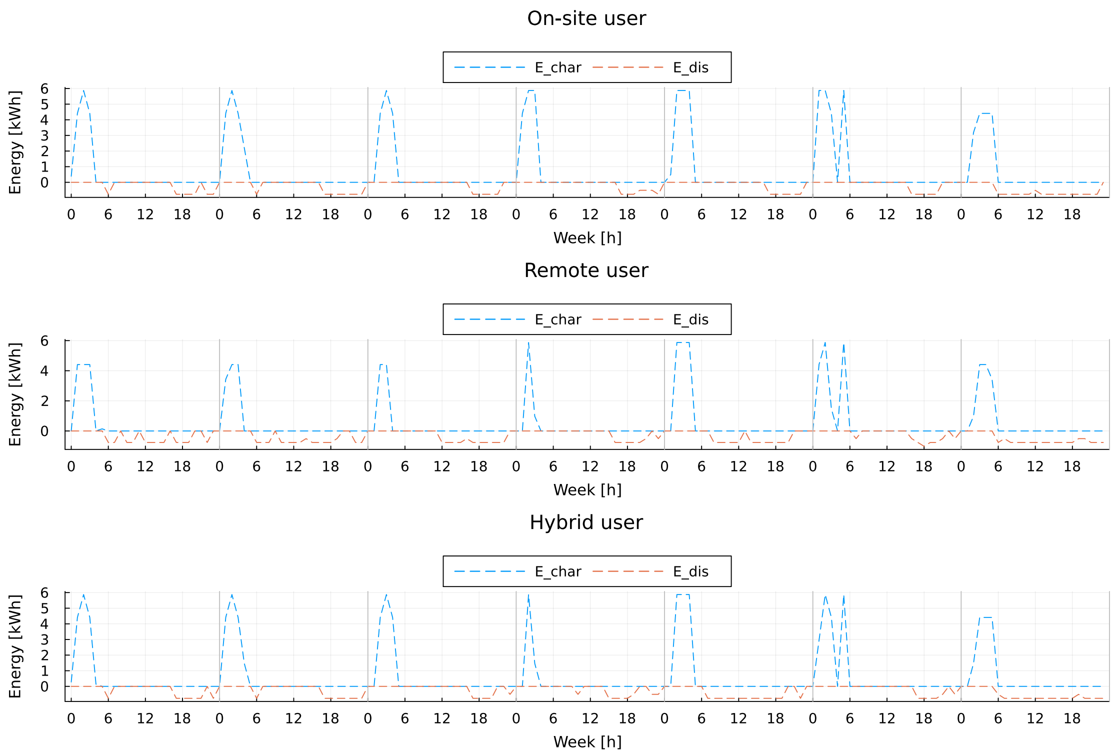


Figure 24: Charging and discharging behavior of all users for a week in January

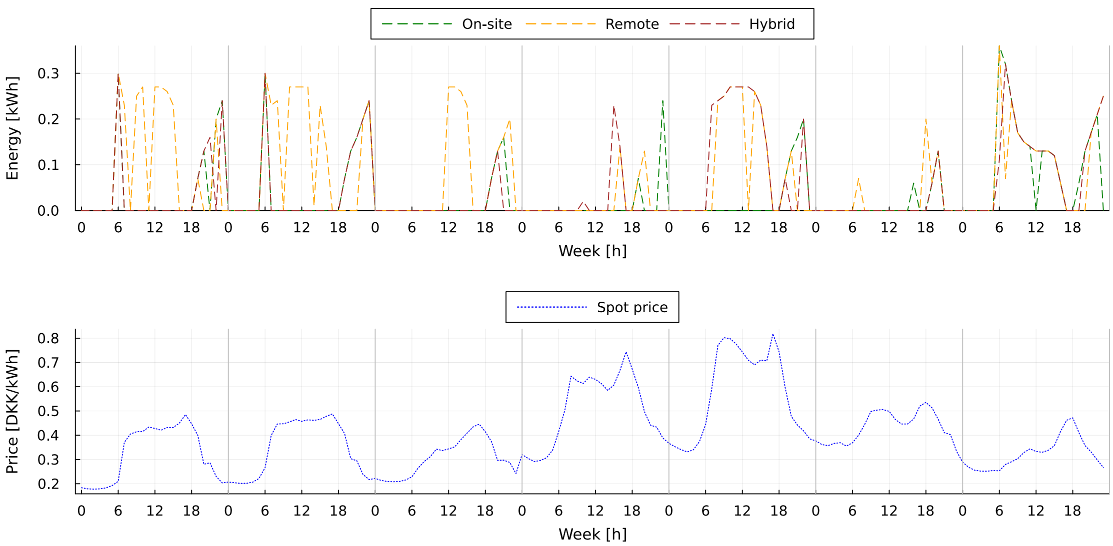


Figure 25: Electricity fed into the grid per user and spot price for a week in January

Figure 25 also presents the electricity sold back into the grid per RU. Most of the overall low feed-in does not occur when the highest spot prices happen, which is on Thursday and Friday. The spot price is highest around 5 pm, however, energy is fed in before 5 pm or after 6 pm. In these two hours, priority is given to satisfy household demand. At least for winter, the maximum spot price is lower than the minimum electricity price for each day, representing a loss when selling electricity back to the grid. In light of the aforementioned, it can be concluded that rather than feeding electricity into the grid, the bigger charging session observed on Friday, was performed to satisfy household demand as much as possible during the afternoon and early evening.

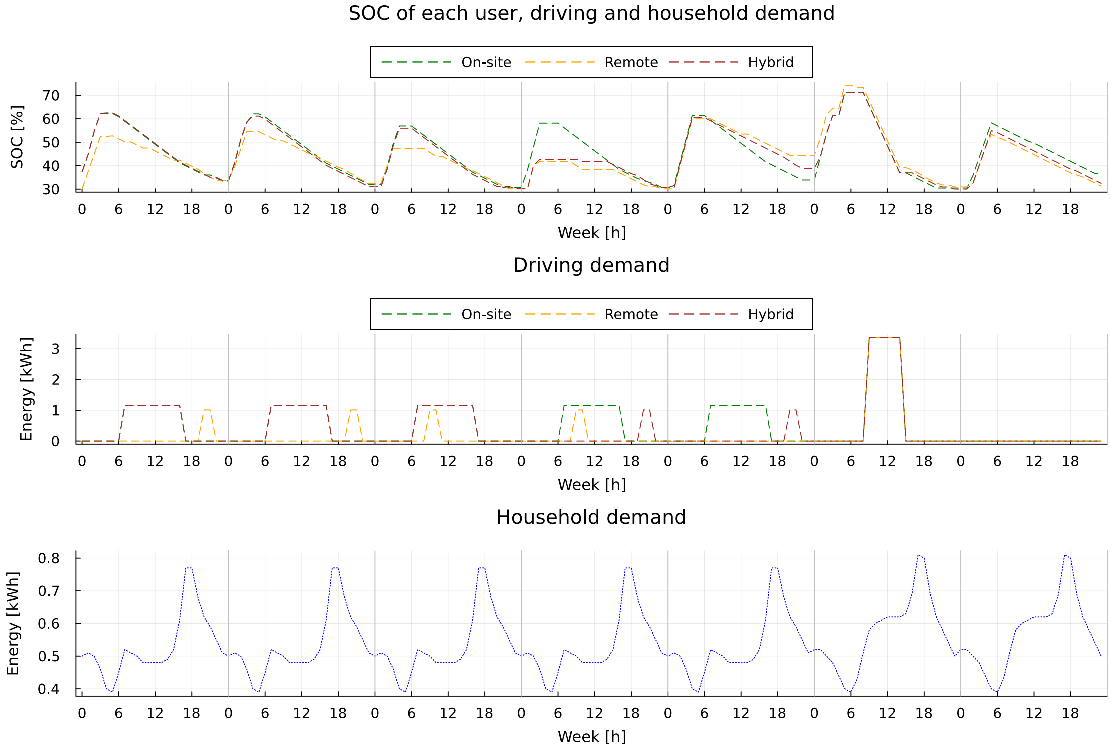


Figure 26: SOC per user for a week in January

The optimal battery operation for V2H FTM is reflected on the SOC. The plot in Figure 26 shows the SOC for each user for the same week in January. Here it can be noticed that the SOC descends to its lowest on Thursday, while it peaks on Friday and Saturday. Indeed, on Saturday the SOC even exceeds the threshold of optimal operation. This is explained by the occurrence of the highest driving demand for all users. The car is expected to be available after 3 pm, after which it is optimal to discharge and satisfy household demand. Given what is to come it is decided to store a great amount of energy earlier on. Interestingly, first, the SOC rises to the limit on a first charging session, followed by a second session in which it rises above the limit until 70 %, right before the driving demand begins. The reason behind these two peaks on Saturday, is to avoid high calendar degradation costs as explained in paragraph 5.1.1.2.

Finally, Thursday and Friday are opposed to each other by having low and high SOC, respectively, despite them having the highest electricity and spot prices of the week. The only difference between them is the period of time where a gap between low and high electricity prices can be profitable. Even though it is more expensive to charge in the morning for both days, on Friday it is largely beneficial to satisfy household demand all afternoon long, which may not be the case on Thursday.

Now the focus is shifted to summer, to perform an overall review of the optimization. The graph in Figure 27 shows the electricity drawn from the grid for each RU together with the electricity prices for the chosen week in July (05.07. - 11.07.2021).

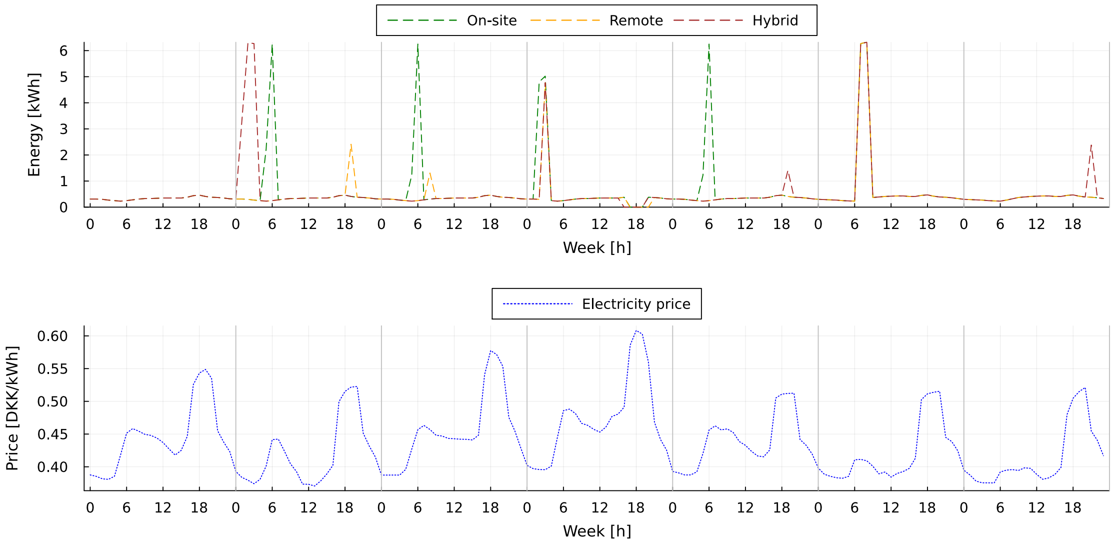


Figure 27: Electricity drawn from the grid per user and electricity price for a week in July

Here, the electricity demand profile rather than presenting a common pattern like in winter, differs from day to day and between RU. Still, it can be said that most of the demand peaks happen around 6 am, caused again by the charging of the EV. These peaks however do not necessarily coincide with the lowest electricity price. Taking a closer look at the electricity prices shows, that compared with Figure 23 prices in summer are slightly lower than in winter. At the same time, the price difference within a day is lower in summer than in winter. To further comprehend the resulting electricity demand, the electricity charged and discharged are presented in Figure 28 for each user on the same week of summer.

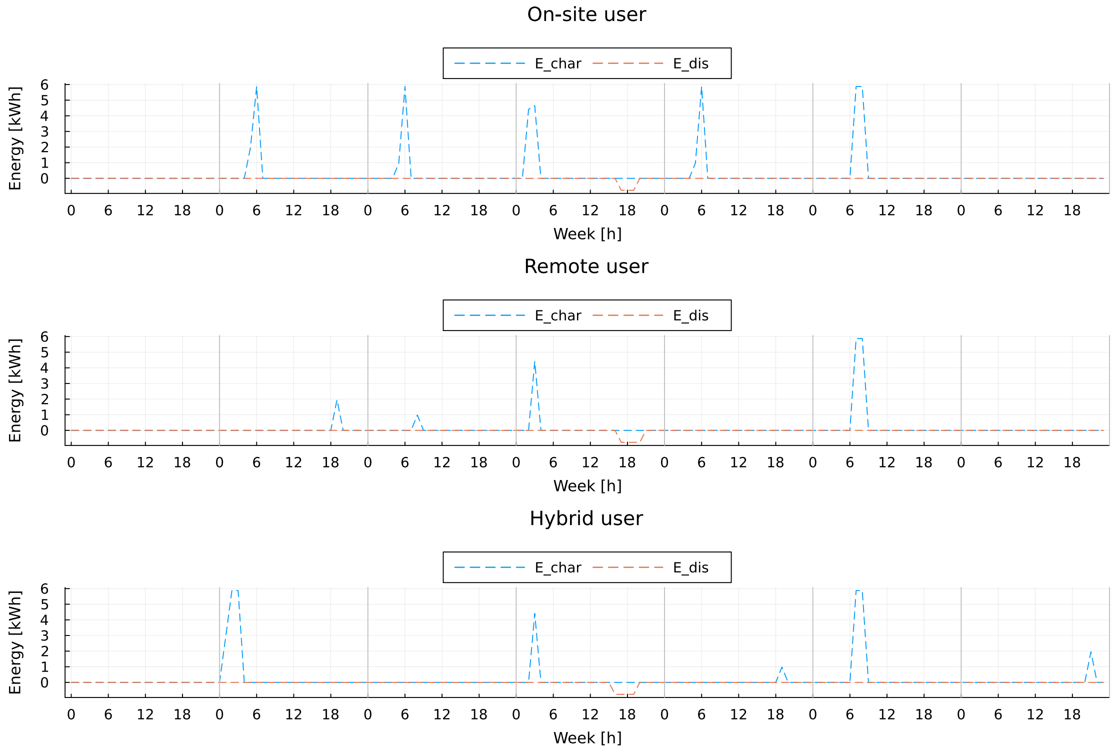


Figure 28: Charging and discharging behavior of all users for a week in July

For this week, there is energy discharged from the EV only on Thursday for all users. This is because Thursday has the highest daily difference between minimum and maximum electricity prices. Similarly to winter, the charging session coincides with the lowest electricity price. As before, the energy is mainly used to satisfy household demand. However, some of it is also fed back into the grid. The energy fed into the grid is presented in Figure 29 together with its corresponding spot price. Unsurprisingly, energy is fed back into the grid just on Thursday, for the same reasons explained above. Furthermore, E^{grid_feedin} coincides with the peaks in spot price. Conversely, for the rest of the days, the price difference seems to be negligible. Hence, there is no discharge to satisfy household consumption nor feed into the grid.

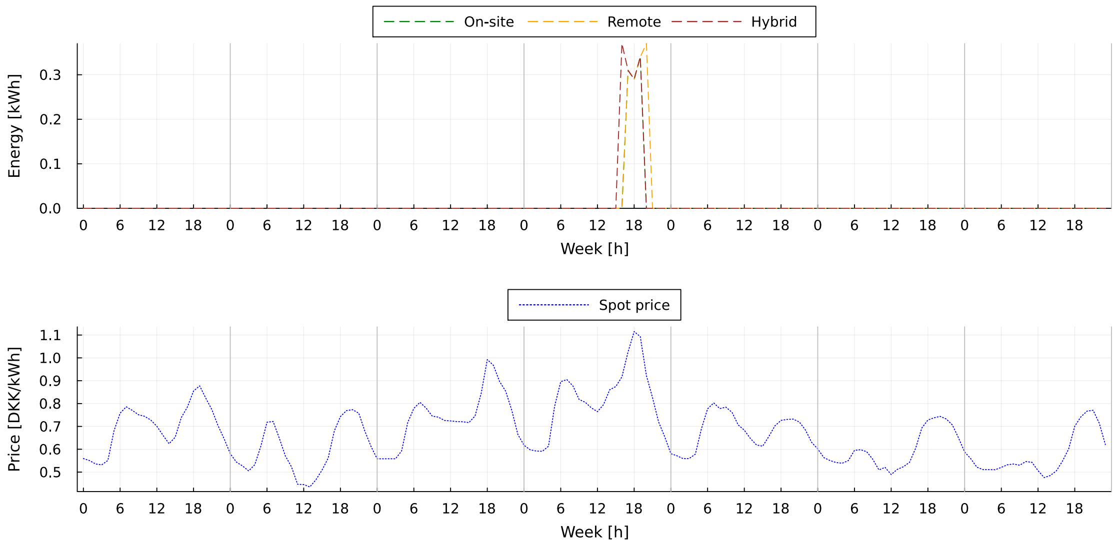


Figure 29: Electricity fed into the grid per user and spot price for a week in July

Charging of the EV is performed just right before a driving session, which can be seen in Figure 30. Since the EV is generally not used for other purposes than driving, there is no reason to exceed the threshold of normal operation of the battery. The SOC is kept within range, which is just enough to satisfy the driving demand. Hence, low-power charging sessions are carried on despite the consequent efficiency losses, which are disregarded.

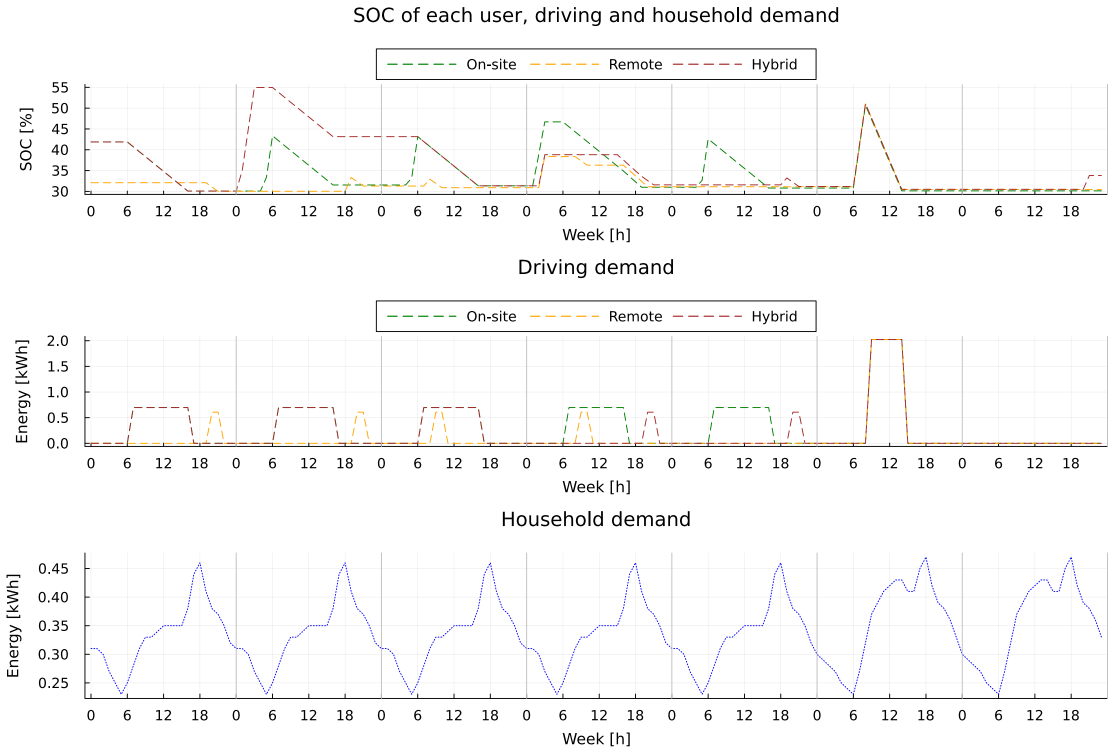


Figure 30: SOC of each user, driving and household demand for a week in July

5.1.3 Comparison of business model for residential users

Overall, the operation of the different RU is very similar for the business model of V2H BTM and FTM. Especially in winter, the grid consumption is almost the same, as well as the charging and discharging pattern and the SOC in the regarded week. This also holds for the summer, however, there is a bit more variation in the pattern of grid consumption and charging spikes. Still, the model applies the same strategy, by charging at the periods of cheapest electricity prices and covering household consumption in peak hours by discharging the EV - as long as the price difference is relevant, which especially applies in winter. Interestingly, the grid feed-in does not have a relevant impact on the technical operation and consequently does not change the economic outcome significantly.

The cost structure of both business models is similar, except for the additional grid feed-in revenue and associated costs. The energy discharged from the EVs of the users increased by 17 %, 15 % and 13 % for the *on-site*, *remote* and *hybrid* user, respectively, from the BTM to the FTM case. The values are seen in Table 18. As a result, charging also increased for all three users with the *remote* user displaying the highest value of 9 %. For all users, the percentage of increased energy charged to the EV is directly reflected in the grid consumption, underlining the immense impact of the charging activity on the overall energy drawn from the grid. Despite the increase in all energy flows, the total costs were only reduced by a maximum of 0.28 % for the *on-site* user, see Table 18, from the BTM to the FTM case, while the SOH loss increased slightly. This does not seem significant enough to argue for the implementation of V2H FTM, in comparison to V2H BTM - especially when regarding the arising yearly costs.

Table 18: Yearly results of V2H FTM compared to V2H BTM

	Total cost [%]	**E^{grid} [%]**	**E^{char_pcc} [%]**	**E^{dis_pcc} [%]**	**SOH [%]**
On-site	-0.28	+4	+4	+17	-0.01
Remote	-0.24	+9	+9	+15	-0.02
Hybrid	-0.11	+5	+5	+13	-0.01

As mentioned in Section 2.2.1.4, feeding into the grid requires a user to pay yearly subscriptions, which add up to 713 DKK. Consequently, the cost savings achieved by V2H FTM, in relation to the unidirectional case, are decreased to 372, 403 and 567 DKK for the *on-site*, *remote* and *hybrid* user, respectively. For the V2H BTM business model, no additional fixed costs arise. To consider the investment costs for a bidirectional charger, the prices for uni- and bidirectional equipment can be regarded, as presented in Section 2.3. The price difference between the two types of chargers of the two producers Wallbox and openWB amounts to 20,217 and 6,714 DKK, respectively. The resulting amortization period in years is shown in Table 19. The price difference of openWB leads to a much lower amortization period of 5 to 7 years for the V2H BTM case, while for the Wallbox charger 20 to 25 years can be considered. For the V2H FTM business model, though, the amortization is more than doubled for both producers and all users, with the longest time period of 69 years arising for the *on-site* user and the Wallbox charger. Even for the *remote* user, which denotes the highest savings in both models, amortization would take 12 to 46 years for V2H FTM, based on the current prices.

Table 19: Amortisation of V2H FTM and V2H BTM in years

	V2H BTM		**V2H FTM**	
	Wallbox	openWB	Wallbox	openWB
On-site	25	7	69	18
Remote	24	6	64	17
Hybrid	20	5	46	12

In contrast to that, the amortization period for the producer openWB of 5 to 6 years for all three users for the V2H BTM business model is acceptable. However, there is barely a bidirectional charger commercially available right now. The ones which are, e.g., the openWB Pro, state bidirectional capabilities but point out that the feature can only be activated when necessary regulation is in place. Therefore, a RU might struggle to acquire such a charger. Nevertheless, considering regulations in Denmark, applying the V2H BTM business model poses fewer challenges than V2H FTM, since the grid interaction does not change immensely. If a smart charging strategy had already been applied before, high demand spikes would have mostly occurred during the operation already. V2H BTM would only slightly increase these spikes since household demand is very small compared to the overall charged energy. Consequently, V2H BTM is more suitable for RU than V2H FTM, in terms of economic feasibility and actual implementation. For FTM operation, the grid feed-in results in more costs, including additional charging costs, feed-in fees, and yearly subscription, than it can generate revenue, resulting in a net loss. To make it more economically attractive, feed-in fees and subscriptions could be reduced. Otherwise, having a higher capacity to sell might increase the revenue and therefore generate a profit, e.g. by applying FTM to a fleet. This will be explored in the next section.

5.2 Fleet vehicles

Other than the RU cases, V2H BTM and FTM, the fleet optimization models do not consider different users. However, instead of one per user, 100 vehicles are regarded which are connected to a PCC. At the latter, also PV panels and a building are coupled together. Therefore, the energy flows of all three assets can be utilized for the optimization since a common manager, e.g. the EV fleet manager, is considered. As for the RU models, the results of each model will be presented in the following, starting with V2B FTM in Section 5.2.1. Afterwards, the V2G FCR-D case will be regarded, to finally compare the suitability of both models for fleet vehicles in Section 5.2.3. Due to computational constraints, days exceeding a certain time limit when executing the optimization were skipped for both models. In total, for the V2B FTM model these were 22, for the V2G FCR-D 26 days got skipped. To make the results comparable to the unidirectional fleet case, the same days were erased for the yearly results and the cost structure. This means that the values for the unidirectional case presented in Section 5.2.1 and 5.2.2 differ since different days are skipped and therefore erased for the two business models.

5.2.1 V2B FTM

Running the optimization model, presented in Section 4.4, for one year leads to the overall results shown in Table 20. For modeling the business models of fleet vehicles, the costs were again minimized, accounting for electricity costs for building demand, charging the EVs, and revenue from grid feed-in from the connected PV panels. Additionally, potential discharging of the EVs is considered. To put the costs resulting from implementing V2B FTM in perspective, a unidirectional case was created, like for the RU. Hereby, the EV fleet, building demand, and PV have the same characteristics as for bidirectional operation and are connected via a PCC. Consequently, energy can still be fed into the grid, due to the presence of PV panels. The only difference from the unidirectional to the bidirectional case is the discharging of the EV fleet to the PCC.

The results presented in Table 20 show that the bidirectional operation of V2B FTM yields an increase in costs of 495 Tsd. DKK or 7 %. In contrast to that, the profit derived from feeding electricity into the grid also increased by 8 %. It is also apparent that more energy was drawn from the grid for bidirectional operation, amounting to 6 %, while the grid feed-in decreased by around 9 %. Hence, the grid feed-in must have been more profit-effective for the bidirectional case, since a lower feed-in led to a higher profit. Discharging the EVs probably enabled grid feed-in at higher prices, while for the unidirectional operation, the occurrence of PV production limited the period available for grid feed-in. In Section 5.2.1.2 the charging and discharging behavior will therefore be explored in more detail to check this conclusion.

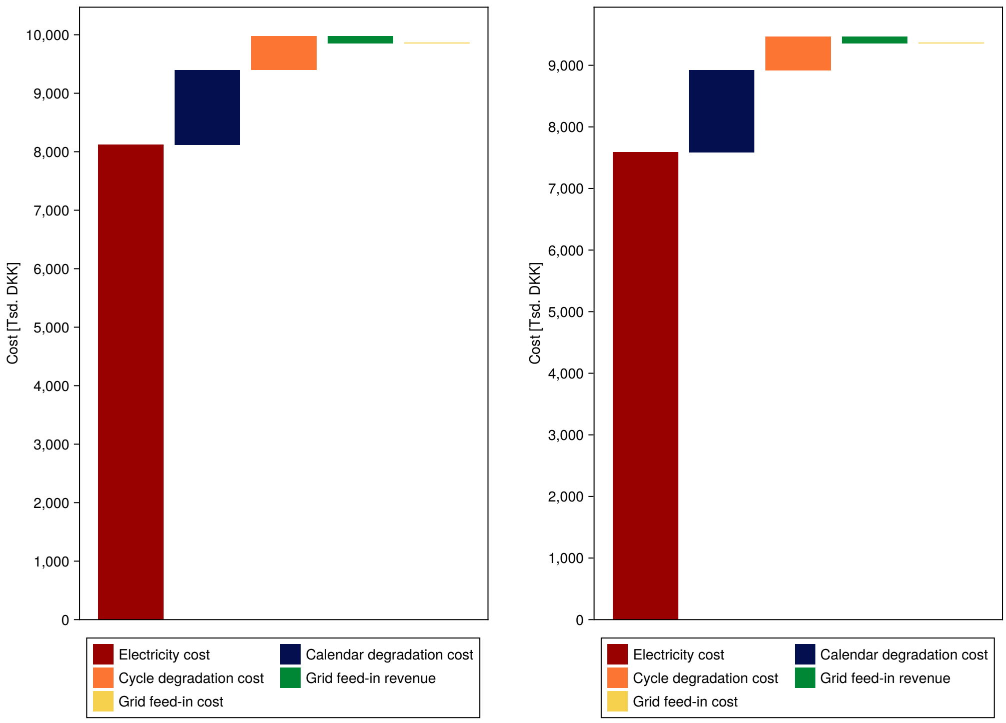
It is also noteworthy that while the energy charged to the fleet vehicles increased by 364 MWh or 9 %, the energy drawn from the grid only denotes a rise of 284 MWh. Thus, the higher degree of freedom offered by bidirectional operation enabled the EVs and the connected building to utilize the PV production more for self-consumption. In fact, for unidirectional operation, 45 % of the PV production was fed into the grid, and the rest was utilized for self-consumption. In the V2B FTM optimization model, the grid feed-in purely from PV reaches only 37 %. For this model, some of the feed-in cannot be distinctively assigned to either the EV fleet or the PV panels, due to the connection at the PCC. There is an additional 16,102 kWh fed into the grid by a mix of the two, which represents 3 % of the total PV production. Consequently, the percentage of PV production utilized for building demand or EV charging can be anywhere between 60 % and 63 %. Still, the overall grid feed-in did not decrease immensely since the fleet vehicles were able to discharge, therefore outweighing some of the missing feed-in from the PV. Their feed-in amounts to 2 % of the total energy fed into the grid, while 8 % are covered by a mix of EV discharging and PV. The leftover 90 % was purely covered by PV production.

Table 20: Yearly results of V2B FTM compared to unidirectional case

	Total cost [Tsd. DKK]	Feed-in profit [Tsd. DKK]	E^{grid} [MWh]	E^{grid_feedin} [MWh]	E^{char_pcc} [MWh]	E^{dis_pcc} [MWh]
Bidirectional case	9,861	112	4,713	193	4,497	58
Unidirectional case	9,366	104	4,430	212	4,133	-

5.2.1.1 Economic results

The overall yearly results presented before show some interesting findings. Their economic implications will therefore be discussed in this section. Figure 31 shows the cost structure of both, the bi- and the unidirectional operation of the fleet vehicles. Both cases have the same general structure, where the electricity costs make up 82 %, and 81 % of the total costs for bi- and unidirectional operation, respectively. The costs caused by calendar degradation amount to 1,274 and 1,332 Tsd. DKK, representing 13 % and 14 % of their respective total costs. Considering the total costs for battery degradation, cycling costs only make up about 31 % for V2B FTM, while taking up 29 % in unidirectional operation. While the calendar costs decreased slightly for bidirectional operation, cycling costs increased from 549 Tsd. DKK in the unidirectional to 577 Tsd. DKK in the bidirectional case. This does not come as a surprise, considering the increased energy charged to the fleet vehicles and the discharged energy shown in Table 20.



(a) Bidirectional case **(b)** Unidirectional case

Figure 31: Structure of yearly costs for unidirectional operation and V2B FTM

Figure 31 also indicates that the profit from grid feed-in only minimally reduces the overall costs, to be exact by only 1 % for both cases. The costs induced directly by tariffs (see Section 2.2.1.4) for grid feed-in are almost negligible compared to the total costs, though. Overall, the cost structures of uni- and bidirectional operation only display slight variations.

5.2.1.2 Technical results

As for the optimization model for RU (see Section 5.1), a week in January (04.01. - 10.01.2021) and in July/August (26.07. - 01.08.2021) are regarded to observe the behavior of the EV fleet. Figure 32 displays the electricity drawn from the grid at the PCC where the building and all EV chargers are connected. For a better overview, the energy charged by the whole EV fleet is shown, as well as the building demand and the electricity price. Notably, the energy drawn from the grid is mostly comprised of the energy charged to the EV fleet which, in this week, occurs only between 12 am and 6 am. During that time the electricity price is at its lowest. It is also apparent that the model schedules the charging towards the end of the possible period at 6 am. This way it is avoided that the EVs maintain a high SOC for a longer time which leads to higher calendar degradation and consequently increased costs.

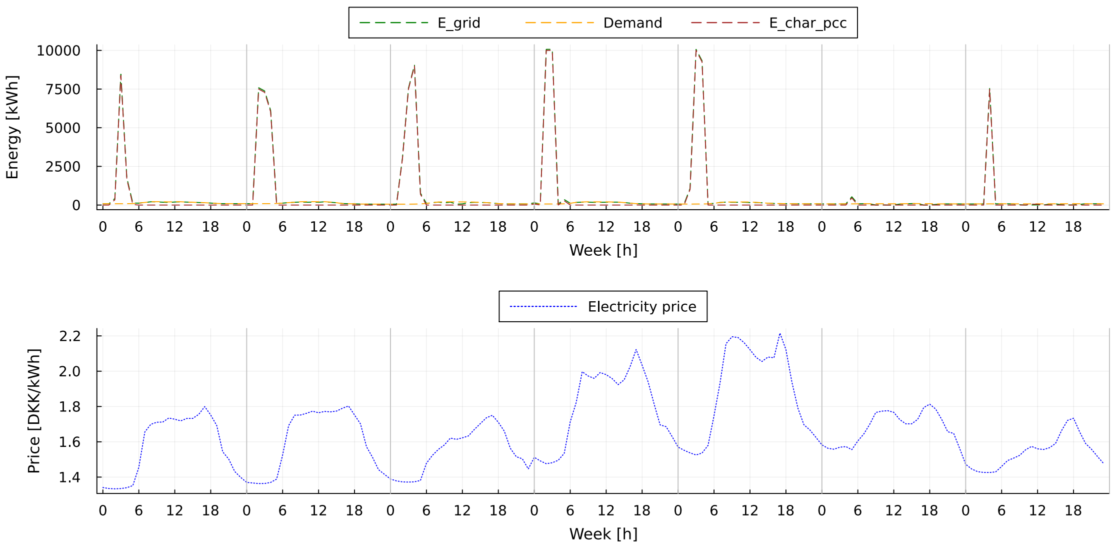


Figure 32: Electricity drawn from the grid, building demand, fleet charging, and electricity price for a week in January

However, during the EV fleet's presence at the depot, electricity is still drawn from the grid to cover the building demand, which is very low compared to the EV fleet's charging demand. Due to the different structure of the ToU for A-low consumers, the peak electricity prices occur mostly during the day, when the fleet vehicles are absent from the depot. However, in winter, the peak ToU tariff persists until 9 pm, but the fleet is still not covering any demand. This aspect can be explained when taking a closer look at the average SOC of all EVs, seen in the graph in the middle of Figure 33. The energy charged in the morning of every day is utilized to achieve an average SOC of the fleet of almost 100 % which is depleted from 6 am to 5 pm to cover driving demand. That is the time in which all of the fleet vehicles are away from the depot following their normal operation as refuse trucks. By the end of the shift, on average, the minimum SOC of 30 % is reached. If they would charge after returning to the depot to cover building demand at a later time, the charging would occur during the peak hours of the electricity prices. Hence, although the battery capacity of the refuse trucks amounts to 300 kWh, their driving consumption is too high to leave any relevant extra charge for after the shift.

Furthermore, as for the RU, the optimization model mostly chooses a high charging power. Since the model considers 100 vehicles which can each charge or discharge with a maximum power of 100 kW, a total of 10 MWh can be drawn from the grid by the fleet. The approximate charging spikes on Wednesday to Friday during the week displayed in Figure 33 indicate the EVs charging at their maximum power since the graph shows the total energy charged to and discharged from the whole fleet. In other instances lower charging steps were chosen, resulting in a lower efficiency. Since the driving demand during the day makes it imperative to charge the battery to be almost full, the high charging power chosen does not necessarily indicate that the model tries to avoid lower charging efficiencies. For instance, on the weekend the model prefers low charging steps, raising the SOC to a maximum of less than 60 % on Sunday, see Figure 33. Here, the SOC only decreases slightly over the whole day. The reason for this could be the low electricity price in the morning on the weekend and the possibility of covering building demand during the day since the refuse trucks do not leave the depot. However, this SOC lies below the critical SOC of 65 % at which calendar degradation increases and it is apparent that the optimization model does not decide to charge the EVs fully on Sunday as needed for Monday morning. The increased degradation above 65 % is avoided, thus, low electricity prices do not outweigh additional calendar degradation costs.

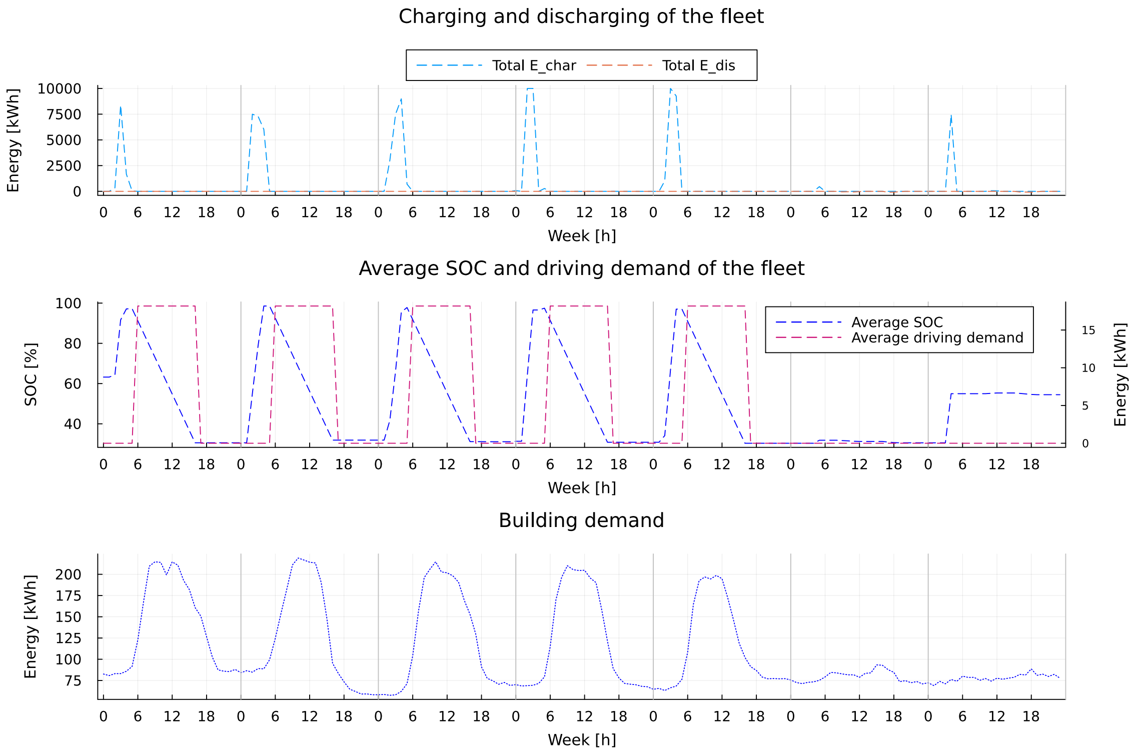


Figure 33: Fleet charging and discharging, average SOC of the fleet and building demand for a week in January

Compared to the charging activity seen in Figure 33, the discharging of the EV fleet on the weekend is almost negligible. Figure 34 offers a closer look at the total energy discharged from all fleet vehicles to the PCC. Additionally, the energy fed into the grid at the PCC, the PV production, and the spot price are displayed. It can be observed that the maximum energy discharged from the EV fleet amounts to 90 kWh, which represents barely 1 % of the maximum power charged to the fleet. The discharging sessions on Saturday and Sunday, as seen in Figure 34, are not used to feed electricity into the grid but to cover the demand of the connected building. Hereby, it is most likely that not all EVs are discharging a bit at the same time but that one vehicle is selected and can therefore operate with a higher discharging power, correlating with higher efficiencies. The spot price, though, is not high enough during the available time slots to encourage grid feed-in, considering energy losses due to efficiency and costs incurred by grid feed-in and the necessary charging. In Figure 34 it is furthermore visible that the PV production in the displayed January week is never fed into the grid, due to the same reasons why the EVs do not feed into the grid. Since most of the PV production occurs during midday, it cannot be used to charge the EV fleet during the working days. The optimization model therefore utilizes it to cover building consumption which is always higher than PV production - except on Sunday. On this day, the excess PV production is charged to the EV fleet, to supply some of the energy needed for the next shift on Monday. Compared to the overall capacity and charging power, the PV production only slightly increases the SOC, see Figure 33. While the grid impact caused by the discharging of the EV fleet and the in-feed of the PV panels does not seem impactful in the regarded week, having 10 MWh charging spikes could pose a challenge to DSOs. No limit for the power drawn or fed into the grid was found in the regulations affecting the business model of V2B FTM. However, DSOs would need to be informed of the charging power to avoid overloading and thereby damaging equipment.

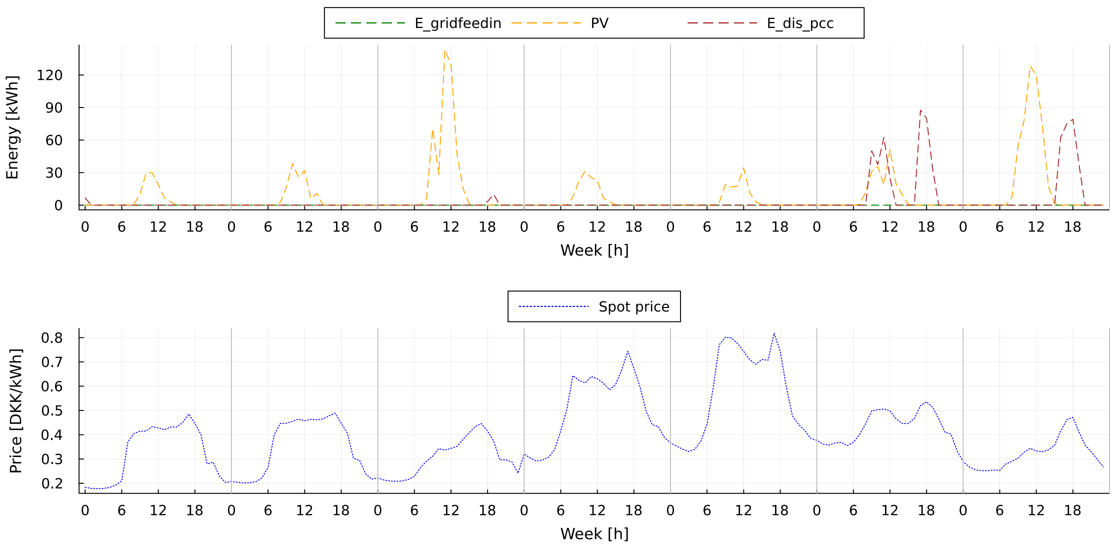


Figure 34: Electricity fed into the grid, fleet charging and discharging, PV production and spot price for a week in January

For the summer, as seen in Figure 35 for a week in July, the maximum height of the demand spikes reaches 10 MWh like in the winter week. As before they correlate with charging the EV fleet during the night, so the pattern is similar despite the lower overall electricity price. The demand spikes are however shorter than in winter. It is furthermore noteworthy, that multiple charging spikes occur on Wednesday and Thursday, where there is first a high one and afterwards a smaller one. This behavior has already been observed for the RU case. As seen in Figure 36, on Monday, Wednesday, and Thursday, the EV fleet is first charged to around 65 %, the SOC after which higher calendar degradation occurs. The lower charging spike is then used to reach the necessary SOC for daily driving demand. Therefore, the higher calendar costs incentivize the model to charge during the slightly higher electricity price towards 6 am, see Wednesday morning in Figure 35 and choose lower charging efficiencies. Interestingly, for the night of Wednesday to Thursday, the model decides to charge earlier right before midnight. Due to the implemented persistence forecast (see Section 4.1), the model assumes Thursday to have the same electricity prices as Wednesday. Consequently, the price before midnight would be lower than after midnight, so the model decides to charge to save costs. However, prices fall even more on Thursday, resulting in the charging decision seeming ill-advised.

Figure 36 additionally shows that the maximum SOC reached in the displayed week is around 70 %, so the decreased driving consumption during summer saves 30 % of charge compared to winter. The excess charge after returning to the depot is discharged to cover building demand during peak hours from Monday to Wednesday and Friday, as seen in Figure 37. Only on Saturday evening, the EVs are discharged to feed into the grid. The price at that time is higher than during the rest of the day but still lower than for most of the week. Before the discharge the PV panels produce a maximum of 300 kWh, exceeding building demand which arrives at a maximum of 30 kWh during the weekend. Hence, the surplus PV production is used to charge some fleet vehicles, as seen in the average SOC displayed in Figure 36. Saturday evening, the price peak is then used to discharge the stored energy to the grid and generate revenue. Thus, the added flexibility of bidirectional operation enables the fleet operator to more efficiently utilize price variations for increased grid feed-in profit, as pointed out in Section 5.2.1.

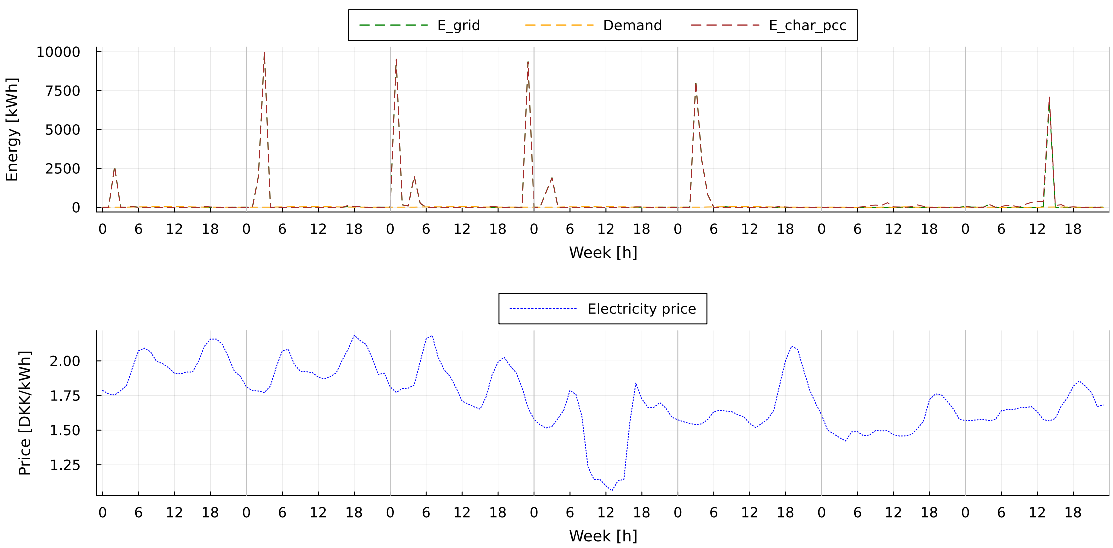


Figure 35: Electricity drawn from the grid, building demand, fleet charging, and electricity price for a week in July

Most of the grid feed-in displayed in Figure 37, though, results from PV production. During the displayed July week the maximum energy fed into the grid is thrice as high as in January, reaching around 400 kWh on Friday. The maximum PV production is only slightly higher. Due to the building demand not even reaching one-third of the one in winter with a maximum of 60 kWh, most of the PV production can still be fed into the grid. Nevertheless, on Sunday when the production reaches almost 400 kWh again, all of it is used to charge the EV fleet (see SOC in Figure 36). Thus, it is shown again that the costs saved for electricity consumption are greater than the cost-reducing revenue of grid feed-in.

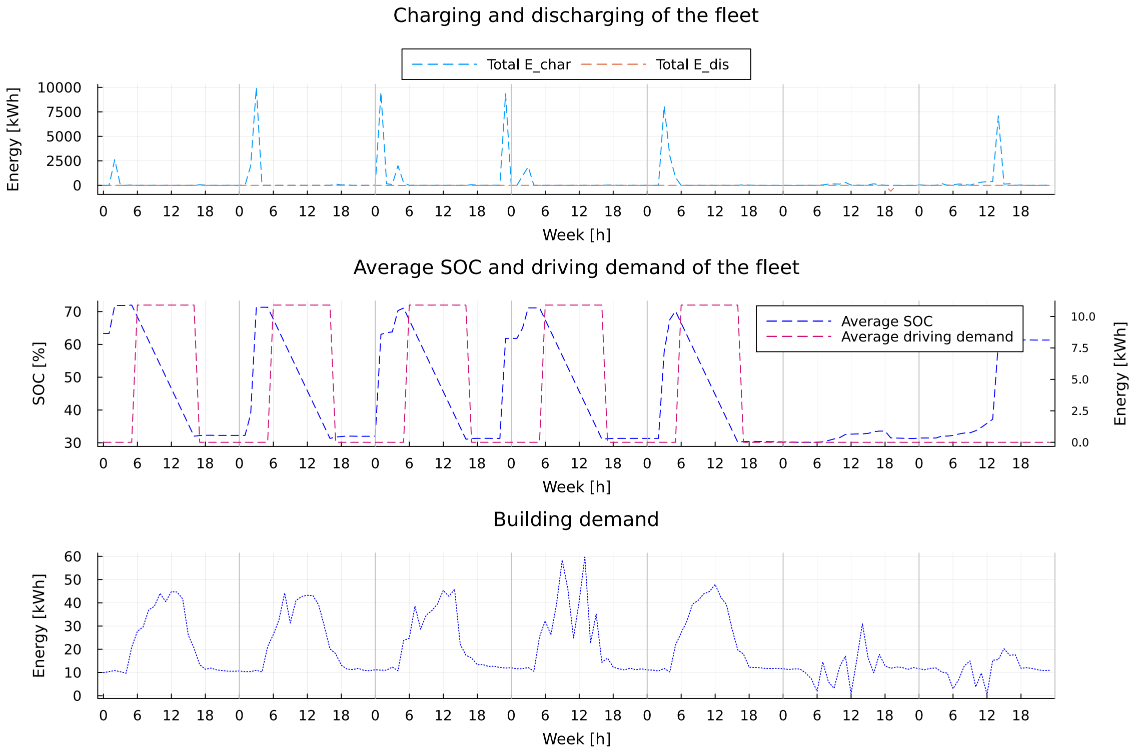


Figure 36: Fleet charging and discharging, average SOC of the fleet and building demand for a week in July

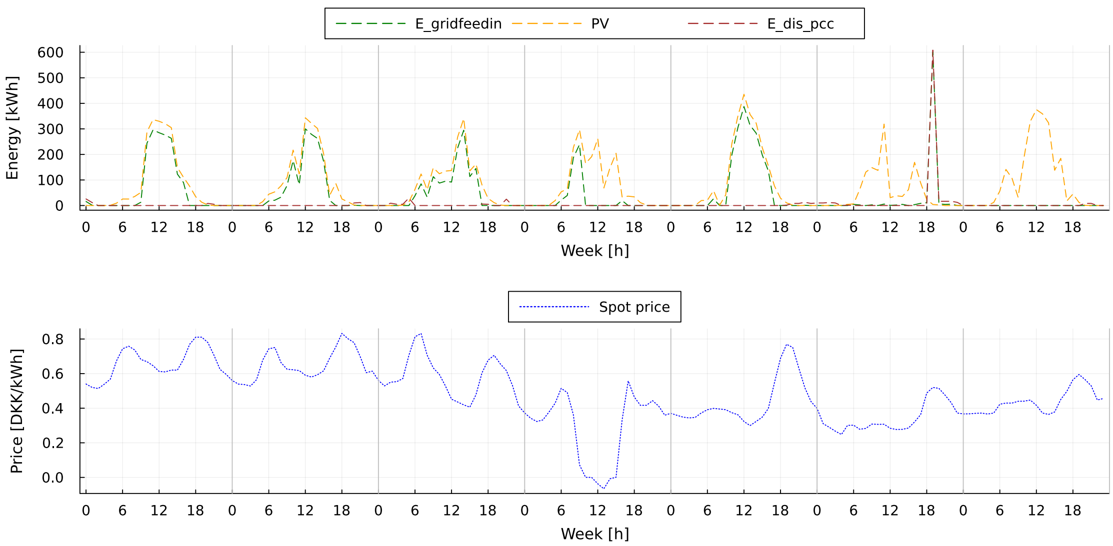


Figure 37: Electricity fed into the grid, fleet charging and discharging, PV production and spot price for a week in July

5.2.2 V2G FCR-D

In the case of the V2G model, the fleet can offer reserve capacity for sale in the regulating market. The optimization results are displayed in Table 21. It is important to note that, as the primary objective remains cost minimization, the table presents all values as positive for easier understanding, although revenues that reduce the costs are accounted for as negative in the optimization and the overall results.

Table 21: Yearly results of V2G compared to unidirectional case

	Total cost [Tsd. DKK]	Feed-in profit [Tsd. DKK]	FCR-D profit [Tsd. DKK]	E^{grid} [MWh]	E^{grid_feedin} [MWh]	E^{char_pcc} [MWh]	E^{dis_pcc} [MWh]	$P^{res,up}$ [MW]
Bidirectional case	7,396	140	2,143	4,570	218	4,367	82	8,033
Unidirectional case	9,148	104	-	4,337	214	4,054	-	-

To summarize the outcomes of offering reserve capacity new information is presented. $P^{res,up}$ summarizes the reserve capacity sold in the regulating market, and FCR-D profit is its related compensation. Accordingly, total cost includes FCR-D profit as a mitigation element for cost reduction. Again, the unidirectional case is presented as a benchmark against which results can be compared. Compared to the unidirectional case, the optimization in V2G results in a decrease in total cost by 1,752 Tsd. DKK, predominantly attributable to the FCR-D profit. Notably, the FCR-D profit not only significantly surpasses the total cost reduction but also demonstrates its capacity to single-handily offset the increase in all other incurred costs when an EV fleet transitions from unidirectional to bidirectional operation.

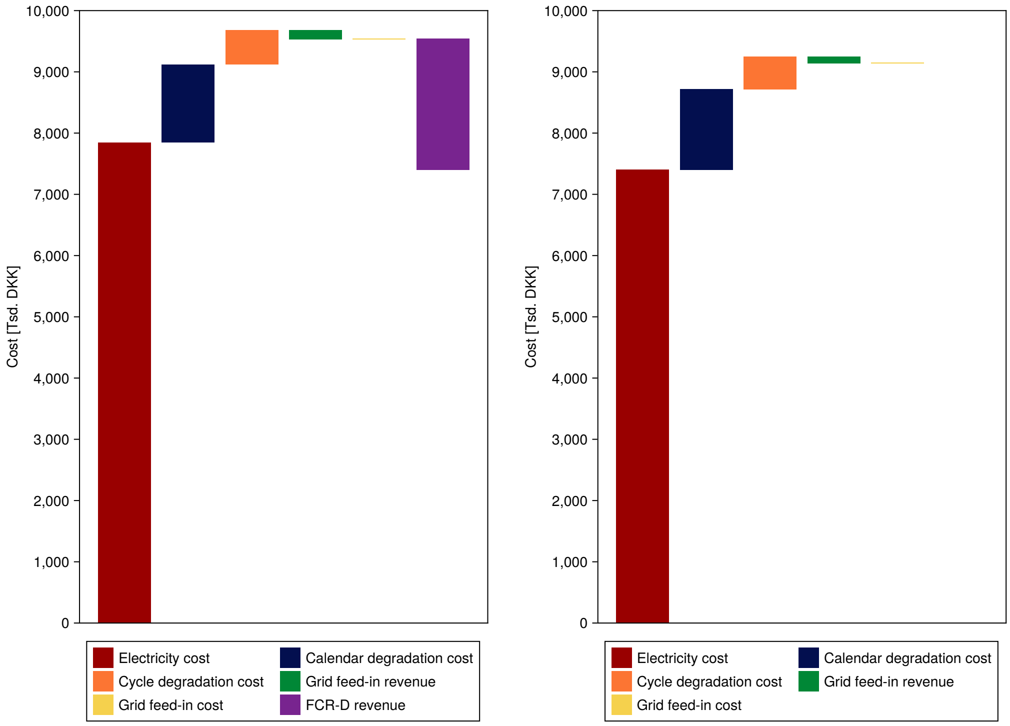
It is, however, essential to address certain limitations in the model. The assumption that the bid offers have an optimal price, leading to their consistent acceptance, implies that the bid price always aligns with the average market price considered in the model. Consequently, it is possible to sell as much capacity as it is constrained by the model at the highest price possible. Here, out of the 5 % of market share allowed, $P^{res,up}$ amounts for 3 %; these two values relative to the total purchased FCR-D reserve by Energinet in 2023. Nevertheless, performing this service proves to be feasible and desirable for EV fleet's operation.

The V2G operation of the fleet leads to an increase of 5.4 % of demand from the grid and 7.7 % increase of energy charged to the EVs, respective to the unidirectional case. One-fourth of this increased charged energy is discharged to either satisfy household demand or feed-in energy back into the grid. The remaining three-fourths result as a consequence of satisfying the minimum requirements of storage capacity for ancillary services explained in paragraph 2.2.1.6. Though FCR-D service is an energy-poor system service, as the main component of cost mitigation it still drives the increase in E^{char_pcc}.

It is difficult to trace exactly where energy is utilized in the optimization model, feed-in or building demand, but 80 % of energy fed into the grid is sourced exclusively from PV, 1.6 % from the discharge of the EV fleet and the remaining 18.3 % is sourced from both at the same time. Hence, at most 20 % of energy fed into the grid was decided to be an optimal price opportunity, and the fleet discharge aided in its supply. As seen, E^{grid_feedin} is not the priority in the model. However, there is a much bigger increase in feed-in profit of 34.5 % than feed-in energy of 1.7 %, when compared to the unidirectional case. Owing to its marginal influence and similar behaviour, discussed in subsubsection 5.2.1, grid feed-in will be disregarded in the subsequent results discussion.

5.2.2.1 Economic results

To further analyze the results, the cost structure for V2G FCR-D and the unidirectional case are illustrated in Figure 38. This graph breaks down the different parts of the overall cost, namely costs and revenues. Specifically, feed-in profit is split into cost and revenue components. Here costs increase the cost structure whereas revenues reduce it. For a simplified analysis costs and revenues would be inspected separately.



(a) Bidirectional case

(b) Unidirectional case

Figure 38: Structure of yearly costs for unidirectional operation and V2G FCR-D

In both bidirectional and unidirectional operations, the distribution of costs is similar. The primary cost component is the electricity cost, constituting 80 %, followed by the calendar cost at 14 %, and finally, the cycle cost at 6 %. Given that electricity cost is the predominant factor in both models, it can be attributed to the driving demand of the EV fleet, a common feature shared between both cases. Total costs increased from 9,262 to 9,689 Tsd. DKK when transitioning from unidirectional to bidirectional operation, representing a 427 Tsd. DKK or nearly a 5 % increase in costs. Consequently, there is not a substantial rise in costs associated with bidirectional operation. The primary cost driver, electricity cost, contributes to the overall increase, mainly due to the increased charging of the EV fleet. However, the second most relevant cost, the calendar cost, experiences a slight decrease of 44 Tsd. DKK. This reduction in calendar cost is linked to a decrease in the SOC, resulting in lower battery degradation. In contrast, the cycle cost increases by 26 Tsd. DKK. Despite the increased utilization of the EV fleet, the overall degradation of the battery declines thanks to the flexibility offered by bidirectional operation.

The marginal increase in cost is compensated by the opportunity to significantly boost revenue through FCR-D profit. As illustrated in Figure 38a, this component outweighs any other, effectively reducing the overall cost. Notably, while there might be some deduction from an aggregator fee, not considered here, providing this service remains cost-effective.

5.2.2.2 Technical results

As previously done for the other optimization models a week in winter, January (04.01. - 10.01.2021), and in summer, July (26.07. - 01.08.2021), are inspected closely to analyze the behavior of the EV fleet. Figure 39 illustrates the electricity drawn from the grid to meet the building and EV fleet demand during the winter period. Additionally, the electricity price is included for a better overview.

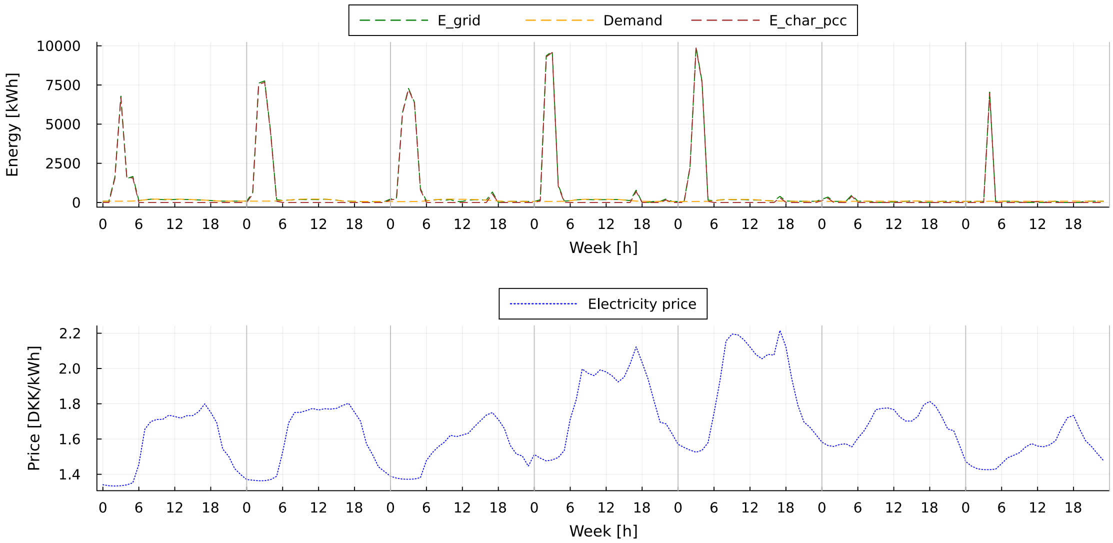


Figure 39: Electricity drawn from the grid, building demand, fleet charging, and electricity price for a week in January

Energy drawn from the grid almost exclusively happens during the morning between 12 am and 6 am, this period coincides with the period of the day when the electricity price is at its lowest. Additionally, it happens in high peaks of around 7,500 to 10,000 kWh. As seen in Figure 39, the charging demand from the EV fleet matches the profile of E_{grid}. Hence, these peaks are used to charge the EV fleet to meet its driving demand which occurs right after the charging session ends. The driving demand can be seen in Figure 41. Apart from these peaks, the energy drawn from the grid is low and follows the building demand throughout the day. The highest charging peaks occur on Thursday and Friday where there is a valley in the electricity price during the morning. Conversely, from Monday to Wednesday there are low electricity prices that spread flat across several hours before noon, allowing for extended charging sessions. Regarding the weekend, Saturday and Sunday follow the same behavior explained in Section 5.2.1.2. Finally, other than the peaks, small charging sessions are performed after 5 pm; right after the driving demand of the fleet ends on Wednesday, Thursday, and Friday.

The main driver for cost reduction was identified to be the FCR-D profit. Figure 40 illustrates the reserved FCR-D volume by the fleet $P^{res,up}$, together with the constrained volume that can be offered. For a comprehensive overview of the service the FCR-D up regulation price is also presented. Notably, the reserved FCR-D up volume aligns with the volume that can be sold, except when the EV fleet is not connected. This means the model deems it optimal to offer the regulating service at all times. For instance, on the weekend when the EV fleet remains available all day long. Additionally, there are more FCR-D up reserves demanded on Thursday, Friday, and Saturday, which makes the offer of $P^{res,up}$ rise as well, as it tries to satisfy the whole demand.

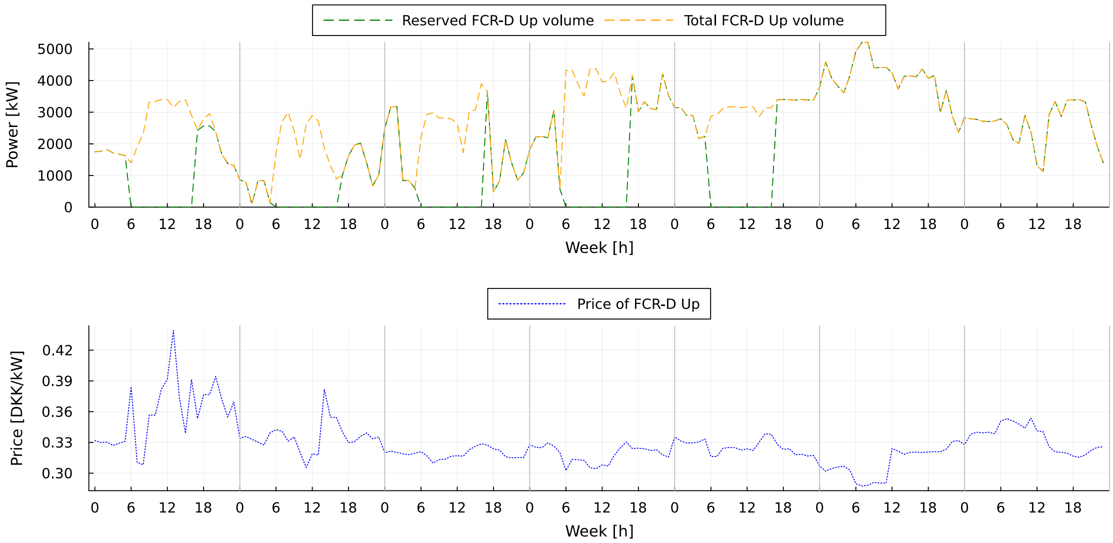


Figure 40: FCR-D Up total volume, reserved volume, and regulation price for a week in January

Focusing now on the regulation price depicted in Figure 40, it rises to its highest on Monday and Tuesday. These peaks occur in the afternoon when the EV fleet is not available and thus FCR-D reserves cannot be offered. Nevertheless, these price spikes are generally close to the average regulating price. Ultimately, regardless of the price the reserved capacity offered is driven mainly by how much volume is demanded. As the FCR-D up reserve is offered as much as possible, Figure 41 displays its effects on the operation of the EV fleet looking at the SOC, driving demand and total energy charged and discharged.

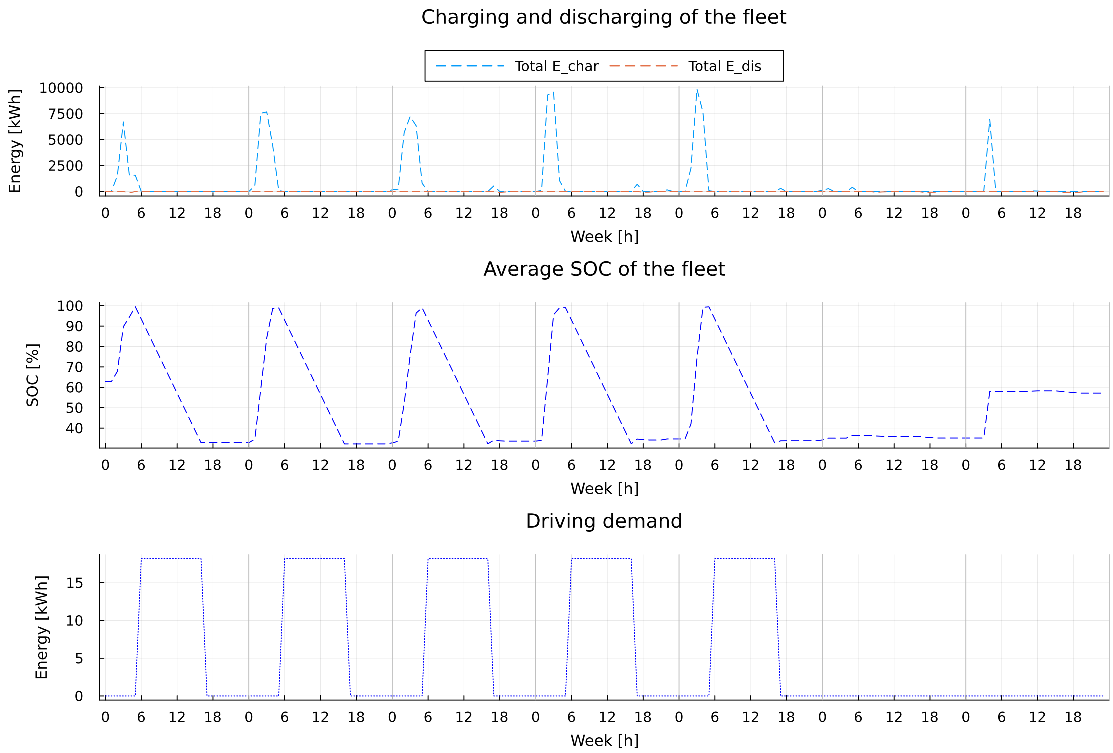


Figure 41: Fleet charging and discharging, average SOC of the fleet and driving demand for a week in January

In Figure 41 it can be observed that the SOC exceeds the maximum SOC threshold and even rises to 100 % every weekday, as it was also seen in Section 5.2.1. This entails a higher calendar degradation but is a consequence of the immense driving demand of the EV fleet. In contrast, on Saturday and Sunday when there is no driving demand to be satisfied, the SOC is kept within the threshold.

As discussed previously aside from the charging peaks, there are also some small charging sessions occurring after the driving demand, see Figure 41. They take the SOC a little above the minimum level allowed. The reason for this is to satisfy the requirement of stored energy, $E^{res,up}$, to be able to offer FCR-D up reserve. To better exemplify this Figure 42 outlines the ratio between reserved FCR-D energy and total battery capacity, which represents the portion of the EV fleet's SOC taken up to offer the ancillary service.

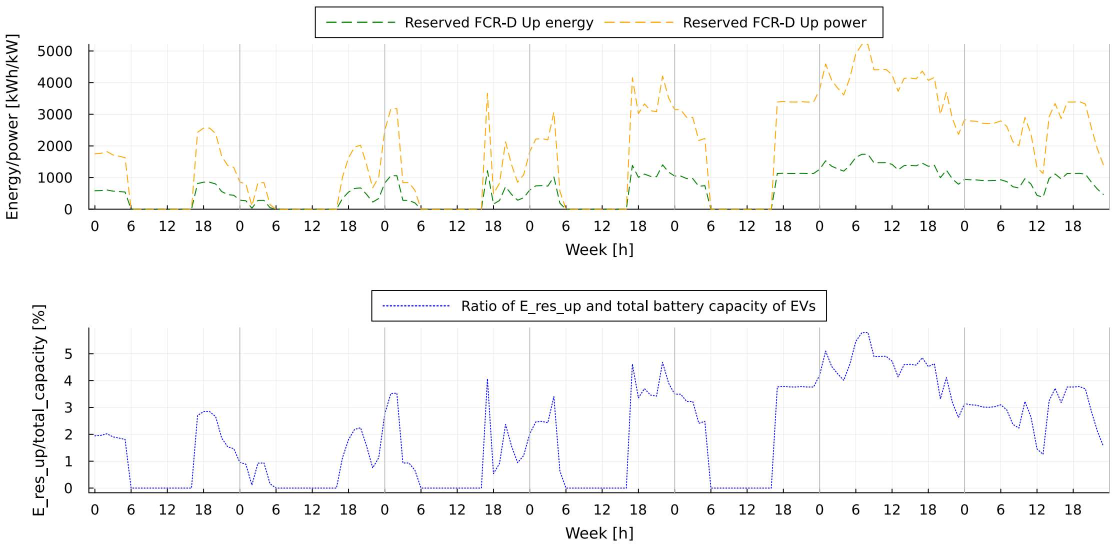


Figure 42: Reserved FCR-D power, reserved FCR-D energy and ratio between reserved FCR-D energy and total battery capacity for a week in January

As seen, reserved FCR-D energy normally represents around 1 % to 3 % of the total capacity of the fleet. Therefore, any increase on the SOC where there is no driving demand is caused by offering FCR-D up reserve capacity. Hence, providing this service increases the energy needed to operate the EV fleet. This goes in line with the analysis of the yearly results in Section 5.2.2. Nevertheless, the increase is rather small and corresponds to the small charging sessions that cause it.

It is important to note that the same energy stored for FCR-D reserves can be utilized to offer reserve capacity $P^{res,up}$ for several hours. For example, on weekdays the EV fleet is charged just once right after 5 pm, when its driving session is over. Then the FCR-D service is offered non-stop from 5 pm to 5am as seen in Figure 40. The variability of the FCR-D service offered, is only constrained by how much can be sold. To evaluate the profitability of this service Figure 43 compares the electricity price at which energy is acquired and the FCR-D up regulation price at which the ancillary service can be sold.

From Figure 43 it is clear that the FCR-D up regulation price is much lower than the electricity price. For example, the average FCR-D up regulation price is around 0.33 DKK/kW while the minimum electricity price at which the EV fleet could be charged up is approximately 1.3 DKK/kWh. In fact, the actual electricity price at which energy is charged to offer FCR-D service is close to the daily peak. This is because it is the time at which the EV fleet returns to the depot. However, offering this service is still beneficial since one short charging session is required and afterwards the SOC can be kept for several hours. The reason for that is that FCR-D up reserve is an energy-poor service that is rarely activated, meaning that only a small amount of energy is ever discharged. Thus $P^{res,up}$ can span for several hours overcoming the high cost of one short charging session.

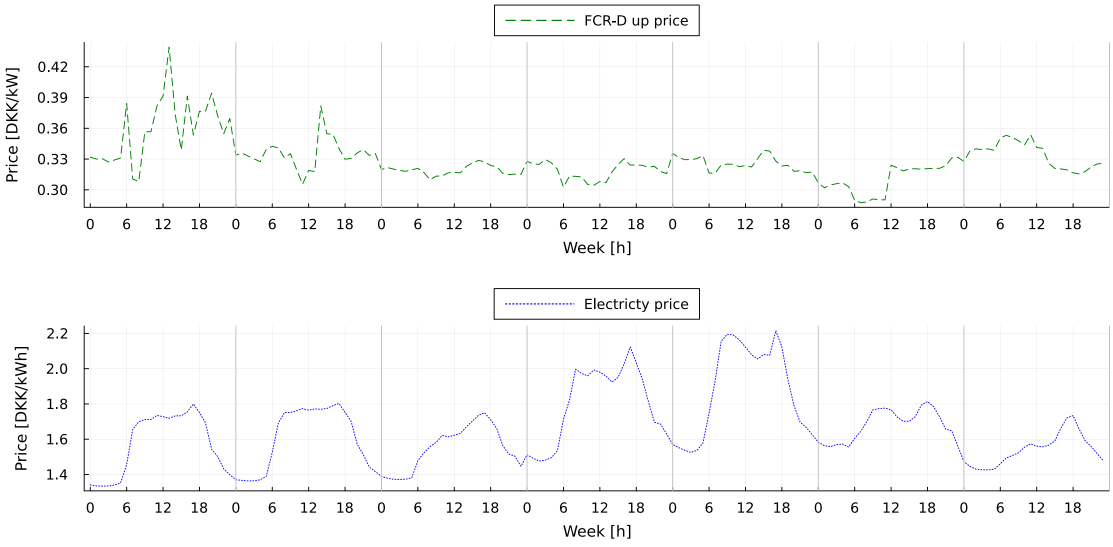


Figure 43: FCR-D up regulation price and electricity price for a week in January

What has been discussed previously also applies to summer. The operation of the EV fleet for a week in July is outlined by the energy charged and discharged, the average SOC, and the driving demand, as illustrated in Figure 44.

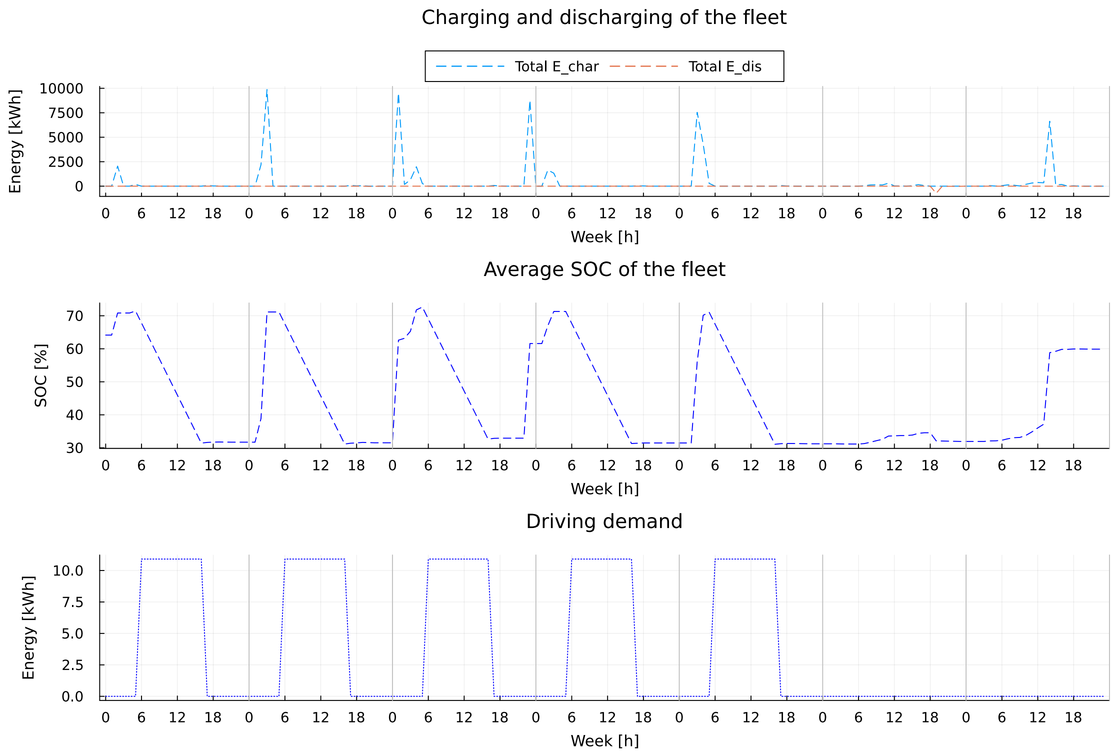


Figure 44: Fleet charging and discharging, average SOC of the fleet and driving demand for a week in July

Remarkably, the SOC level is kept around 70 %, much lower than in winter. The reason for this is the lower driving demand during summer. With no need to utilize the full storage capacity, a more effective management of calendar degradation is achieved preventing prolonged periods of high SOC. Two charging sessions are conducted in the morning to prepare the EV fleet. As for the other optimization models, this operation ensures the fleet not having to maintain a high SOC, leading to increased calendar degradation. In contrast to winter, there are no additional charging sessions beyond the morning peaks. Figure 45 explains how this distinct behavior fits together with the offering of FCR-D up reserves.

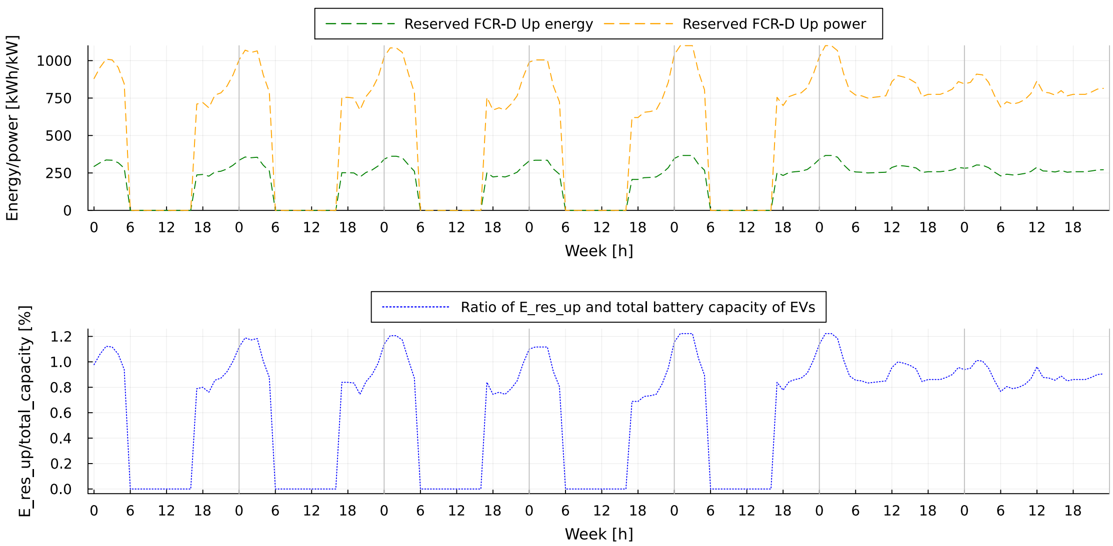


Figure 45: Reserved FCR-D power, reserved FCR-D energy, and the ratio between reserved FCR-D energy and total battery capacity for a week in July

As illustrated in the graph, the optimization offers as much reserves as possible at all times for summer, similar to winter. Nonetheless, the total FCR-D up volume demanded by the market is lower than in winter. As a consequence, the capacity of the total SOC of the EV fleet needs as stored energy to offer FCR-D up reserves is lower, at most 1.2 %. This, along with the fact that not all the battery capacity is needed to satisfy the driving demand, means charging the EV fleet solely in the morning is enough for both purposes. A comparison between the price of electricity to attain the stored energy and the FCR-D up regulating selling price is portrayed in Figure 46. Compared to winter, in summer the FCR-D up regulating prices are lower and electricity prices are higher. Additionally, there is a reduced spread between the minimum and maximum electricity prices. Despite the low difference, the charging session intended for FCR-D up service is now performed in the morning. Even if the value of the regulating service is lower, it is worthwhile to offer the FCR-D up regulating service throughout several hours for the same reason discussed previously for winter.

Ultimately, V2G operation does not entail a big change in the charging and discharging patterns of an EV fleet, as the additional energy stored is low. Furthermore, V2G operation offering FCR-D up regulating service is suitable for the high levels of SOC and the schedule imposed by the driving demand of the EV fleet. Regardless of the difference between electricity price and FCR-D regulating price, the ancillary service proves to be beneficial as long as it can be offered in consecutive hours. Thus, the only observed constraint is the share of the total FCR-D up that can be attained by bidding in the market.

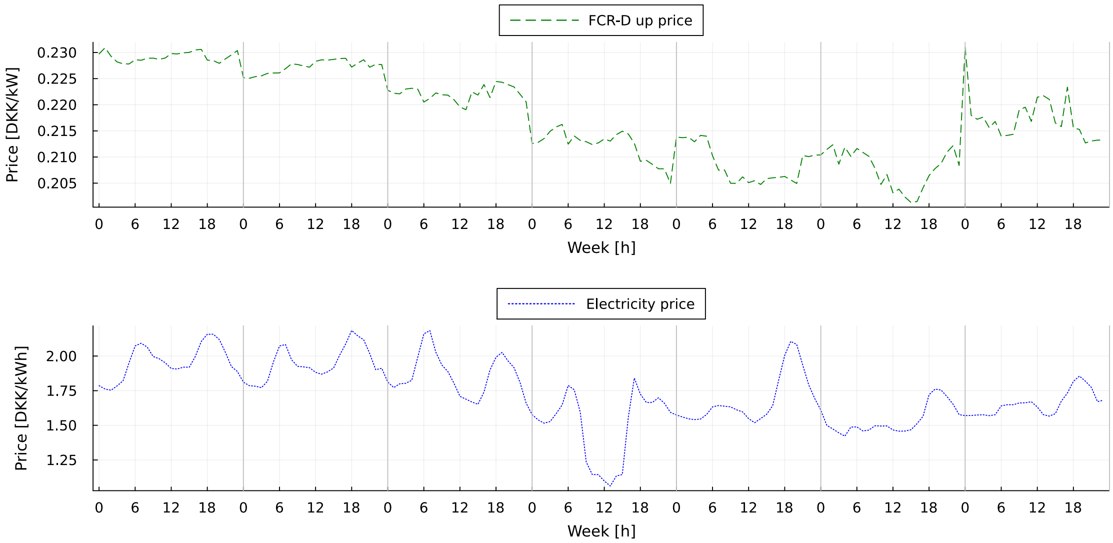


Figure 46: FCR-D Up regulation price and electricity price for a week in July

5.2.3 Comparison of business model for fleet vehicles

In brief, in the case of EV fleets the transition from unidirectional to bidirectional operation is small. The EV fleet is charged more and thus the total electricity demanded from the grid increases slightly, just around 6 %. Yet, high demand peaks of 10 MWh happen because the charging sessions are grouped in the hour with the lowest electricity price, generally in the morning. In fact, in bidirectional operation, the EV fleet degradation cost is slightly lower than in unidirectional operation. In both bidirectional cases, EV batteries see greater use, and thus cycling degradation cost increases. However, discharging the batteries enables better calendar degradation management, which has a higher influence and drives down overall degradation costs. Though in both bidirectional operations degradation costs are similar, V2G FCR-D would entail higher degradation if more FCR-D up regulation is provided or the capacity of the fleet was lower. Ultimately, the distribution of the cost structure of the EV fleet is similar for unidirectional and bidirectional operation. The main cost is the electricity consumed for both operations, caused by the high driving demand the fleet requires. Nevertheless, bidirectional operation does increase the operating costs because more energy is consumed from the grid as higher usage is experienced by the EV fleet's batteries.

Here, a critical difference arises between both bidirectional operations. While the benefits from V2G FCR-D succeed to outweigh the increase in cost, V2B FTM fails. V2G FCR-D effectively drives total costs down by 1,752 Tsd. DKK because of the profit it receives by offering the FCR-D regulating capacity in the market. Deducting the costs for yearly subscriptions of 2,792 DKK, as described in Section 2.2.1.4, results in final savings of 1,749 Tsd. DKK. To put these savings into perspective, investment costs for having bidirectional chargers for the whole fleet are regarded. Since no price could be found for a bidirectional charger with a power output of 100 kW, the price for a unidirectional charger was taken as a reference. The company ABB offers the Terra DC 124 charger for 63,750 € (adjusted to Danish VAT), which is capable of supplying 120 kW to one vehicle or 60 kW to two vehicles [115]. To find a reasonable price difference for a bidirectional charger with the required power, the price difference found for the charging equipment of Wallbox and openWB is scaled up. Therefore, the factor of power difference between the unidirectional Wallbox charger (7.4 kW), the openWB charger (11 kW), and the ABB charger (120 kW) is considered, amounting to roughly 16 for Wallbox and 11 for openWB. The factors are afterwards multiplied with the respective price difference, as presented in Section 5.1.3, and added to the price of the unidirectional charger from ABB. Hence, the total price for one bidirectional 120 kW charger is estimated to be between 60,941 to 119,937 €, or 454,619 to 894,728 DKK. The total investment for 100 chargers would therefore be between 45,462 Tsd. to 89,473 Tsd. DKK, resulting in an amortization period of 26 to 51 years. While this time frame is most likely unattractive to fleet operators, the costs are only a rough estimate and do not consider potential scaling effects due to the amount of chargers purchased which could lower the overall investment costs. Furthermore, the prices of bidirectional chargers can be expected to decrease in the future due to progressing technical developments.

However, V2G FCR-D is especially suitable for the rigid schedule of the selected EV fleet. The service can be offered for several consecutive hours and oftentimes does not require an actual discharge. On the contrary, V2B FTM as a business model would rely on discharging energy for grid feed-in to generate an income. This proved not to be beneficial in the context of the low difference between minimum and maximum electricity prices within a day, plus the extra payments the EV fleet is subjected to as an auto-producer of energy. Table 22 outlines the percentual difference of V2G FCR-D with respect to V2B FTM.

Table 22: Yearly results of V2G FCR-D compared to V2B FTM

Total cost [%]	**Feed-in profit [%]**	**E**^{grid} **[%]**	**E**$^{grid\_feedin}$ **[%]**	**E**$^{char\_pcc}$ **[%]**	**E**$^{dis\_pcc}$ **[%]**
-25	+25	-3	+13	-3	+41

Regardless of the small benefit posed by feeding energy into the grid, the flexibility of bidirectional operation increased the earnings of feeding electricity much more than the increase in energy fed back. Surprisingly, there is more grid feed-in in V2G FCR-D than in V2B FTM. It is not profitable to feed in electricity from the EV fleet when charged from the grid. However, it is done more often in V2G FCR-D because energy charged can earn income from both: as a reserve for FCR-D and then as electricity discharged into the grid. Thus, in V2B FTM the main focus is to utilize PV more effectively by charging the EV fleet and occasionally discharging it to cover building demand when the electricity price is higher.

6 Conclusion

Although EVs are not the sole solution for decarbonizing the transport sector, they are an important part of the measures that have to be taken to create a more sustainable future. V2X services can be used to support the extensive implementation of EVs, which is why, in the scope of this work, four of them were selected to be analyzed with respect to their suitability for RU or fleet vehicles. While two services making use of electricity price arbitrage, V2H BTM and V2H FTM, were chosen to be explored for RU application, V2B FTM and V2G FCR-D were selected for the fleet case. For each of the services, a business model was developed, whereby an EV owner living in a detached house was considered for the RU case, enabling a connection between vehicle and house to cover household demand in both business models. Additionally, feed-in from the EV into the grid was regarded for V2H FTM. The fleet vehicles were also able to feed into the grid for both business models while being connected to the grid, an office building, and PV panels through a PCC. Based on the business models, mathematical optimization models to simulate one year of operation were created.

To answer the first research question posed in this work, the feasibility of several business models was assessed. Notably, in all cases, the regarded user or fleet was able to uphold their normal operation specified in the model, while still supplying the different services. For the RU case, both models yield savings of 1,084 DKK for V2H BTM and 1,160 DKK for V2H FTM. However, additional yearly costs erase the slightly higher savings of FTM, leading to an extensive amortization period for the bidirectional charging equipment. Thus, V2H BTM is deemed more feasible for RU and is expected to allow payback within 5 to 7 years for certain suppliers. Even for the regarded fleet V2B FTM is not feasible and leads to a cost increase compared to unidirectional operation instead of a decrease, without even considering yearly fixed costs. For the V2G FCR-D business model, though, deducting the yearly costs results in saving 1,749 Tsd. DKK. Nonetheless, considering the investment costs for bidirectional chargers for the whole fleet implies 26 to 51 years of amortization. Since the economics of scale and progressing technical development will reduce the costs, V2G FCR-D could become more profitable in the future.

It is apparent that grid feed-in did not yield any relevant profit to generate savings for both, the RU and the fleet case of FTM, since electricity prices always exceed the spot price. To answer the second research question, the electricity price is overall one of the most influential factors affecting the profitability of V2X services. Specifically, having a high variation of the price during the day enables the RU or the fleet to take advantage of periods with cheap electricity prices for charging and discharge to cover building demand during peak hours. Hereby, the ToU tariffs play a key role as they create lows and peaks artificially in addition to the ups and downs of the spot price. However, to make use of these variations, the usage pattern of the RU or the fleet vehicles needs to be compatible. Looking at the V2H business models shows that the *remote* and *hybrid* users could achieve the most savings since a higher availability of the EV allows for effective use of price variations. Thus, a user with a flexible schedule could achieve more savings than a user bound to a fixed routine. Contrary to that, the rigid schedule enabled the fleet offering FCR-D to generate high profits. Although the FCR-D price was lower than the electricity price paid for charging, offering the service for consecutive hours proved profitable. Thus, a fleet exhibiting less predictability would be less suitable for this service. Yet, such a fleet could profit more from V2B FTM, since the PV production occurring during the day could be stored to be fed into the grid at higher prices. Hence, the profitability of V2X services highly depends on the characteristics of the fleet or EV usage.

While the increased calendar degradation cost after a certain SOC also influenced the profitability of the business models, it mostly affected the charging patterns and did not increase costs in a significant way. The results show that introducing grid feed-in for the RU in V2H FTM led to a minor increase in SOH loss compared to V2H BTM. Even for the two fleet business models the average battery degradation is similar. Nevertheless, if the regarded fleet was to take on a higher share of FCR-D provision in the market or another fleet with a lower total battery capacity would take the same market share, the needed SOC to comply with the energy reserve requirement of the service could exceed 65 %. Thus, in these cases, providing FCR-D would significantly increase calendar degradation and surpass the battery impact of V2B FTM.

Even so, the business model of V2B FTM needs to be made more feasible if fleet operators are to be encouraged to apply it. One way would be lowering the various fees paid for each kWh fed into the grid or the yearly subscription costs, especially for RU. These fees emerge because the regulatory framework in Denmark categorizes battery storage resources as both generator and consumer, rather than implementing a policy that recognizes them as assets for the energy system. The costs of subscription could be overcome by gathering several RU to act as one entity. If regulation is extended for such cases, yearly costs could be split and therefore reduced for each individual RU. Additionally, using a price forecast for several days could reduce the dependency on electricity price variations during one day. This, however, would require the RU or fleet operator to be flexible enough to follow the price variations. Hence, this might not be an effective improvement for the regarded refuse truck fleet. However, it should be taken into consideration to decrease the lower bound of the SOC implemented for the fleet. This minimum was kept to fulfill the requirements of offering FCR-D, however, it resulted in a very high SOC for the fleet vehicles, especially in winter. While this increased the calendar degradation and resulting costs, the fleet did not have enough charge left to supply building demand after returning to the depot. Thus, lowering the minimum SOC could improve the overall profitability of V2B FTM.

However, the outcomes of the optimization model have to be regarded with care and under consideration of certain limitations. Essentially, there is limited access to information about EVs and individual household data. In this work, the availability and flexibility of the user was assumed. Since these factors have a crucial impact on the suitability of a specific V2X service, data from a real-world trial would alter the outcomes of the simulation, especially for the RU which are often less predictable. Further research could consider more variable usage patterns for the RU or fleets with a different daily schedule. Furthermore, optimization models of aggregated RU or fleets can be performed where feed-in costs are diluted down. Additionally, the FCR-D model did not consider aggregator costs. As seen, the regulatory framework in Denmark already accounts for aggregators, however, information about their tariffs and operations was not provided. Clarifying these aspects could enhance the deployment of V2X services involving aggregators. Nevertheless, in V2G FCR-D optimal bidding was assumed using recorded market data. Here, the use of robust optimization can account for uncertainty in price and volume of FCR-D. This could be explored in further work, as well as offering FCR-D down instead of up reserve or both services in parallel. Thus, although some V2X already yield savings, as shown in this work, there are still several uncertain parameters to be investigated. However, real-world data or trials would help immensely to establish the profitability of the regarded services. The demonstration projects of EV4EU are therefore right on time to strengthen the confidence in the successful implementation of V2X services.

Appendix

Table 23: Charging and discharging parameters [78]

P_p^{char}	P_p^{dis}	η_p^{char}	η_p^{dis}
0.05	0.05	0.926	0.926
0.1	0.1	0.956	0.956
0.2	0.2	0.971	0.971
0.25	0.25	0.975	0.975
0.3	0.3	0.977	0.977
0.5	0.5	0.98	0.98
0.75	0.75	0.98	0.98
1	1	0.979	0.979

Table 24: Yearly results of residential user cases in €

	Total cost [€]
V2H BTM	
On-site	2,352
Remote	1,757
Hybrid	2,117
V2H FTM	
On-site	2,345
Remote	1,752
Hybrid	2,115
Unidirectional case	
On-site	2,491
Remote	1,902
Hybrid	2,287

Table 25: Yearly results for fleet vehicles in €

	Total cost [Tsd. €]	**Feed-in profit [Tsd. €]**	**FCR-D profit [Tsd. €]**
V2B FTM	1,322	15	-
V2G FCR-D	991	19	287
Unidirectional case	1,226	14	-

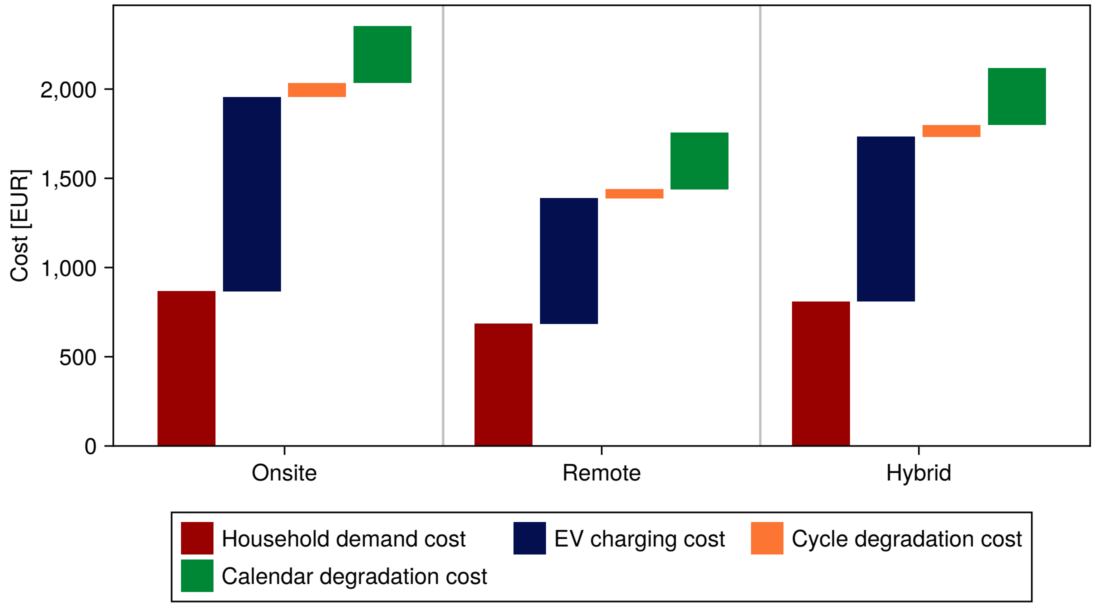


Figure 47: Structure of yearly costs for V2H BTM in €

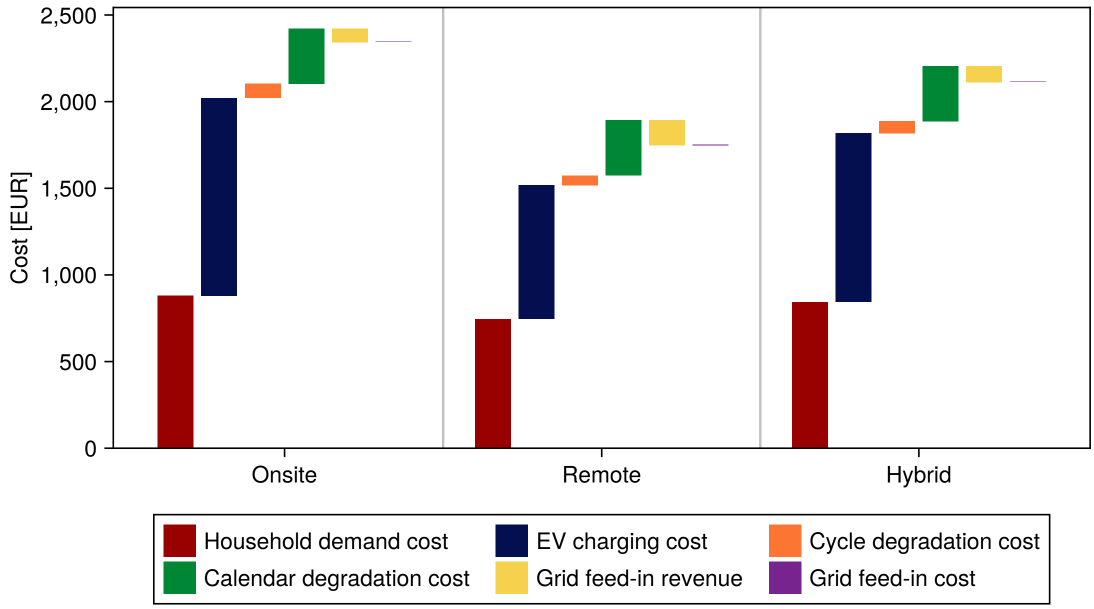


Figure 48: Structure of yearly costs for V2H FTM in €

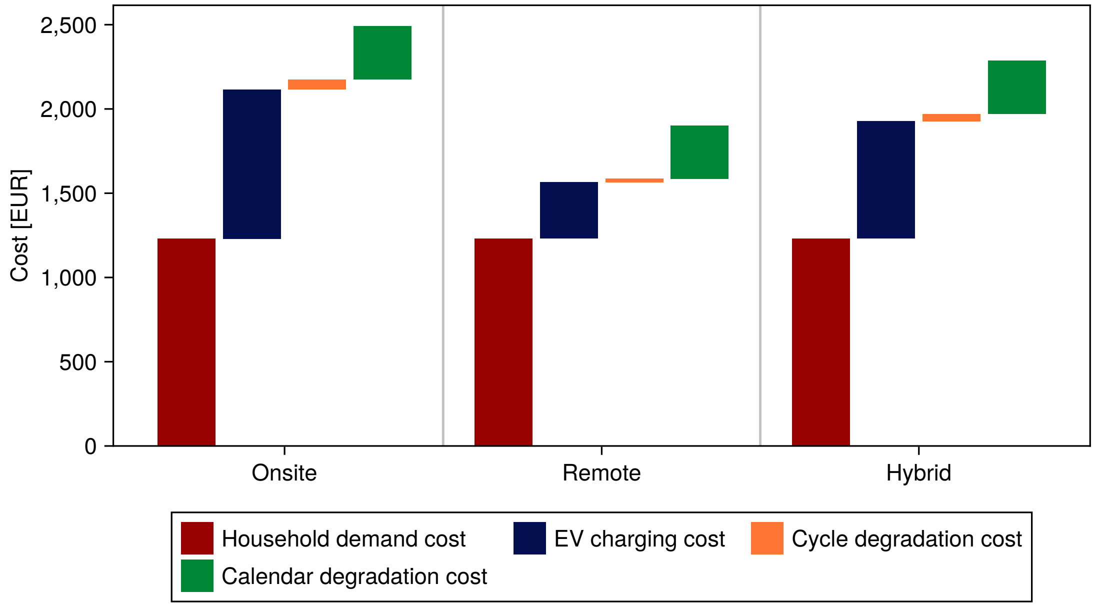


Figure 49: Structure of yearly costs for unidirectional RU case in €

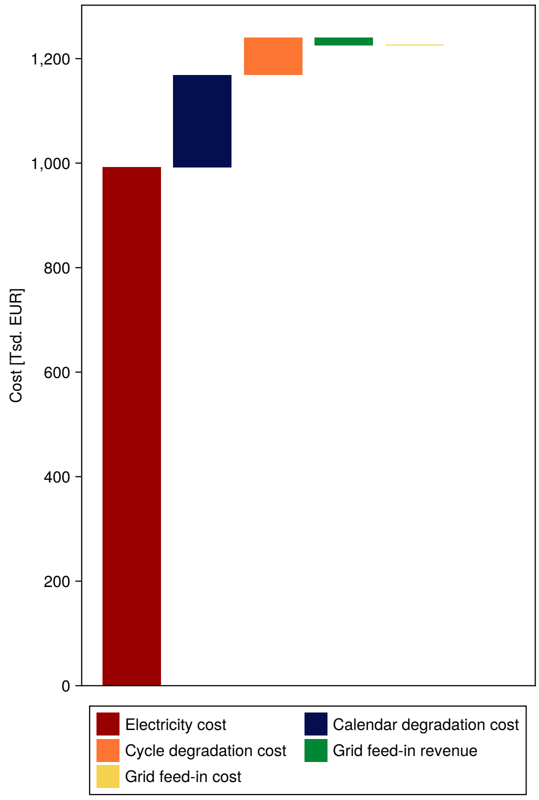


Figure 50: Structure of yearly costs for V2B FTM in €

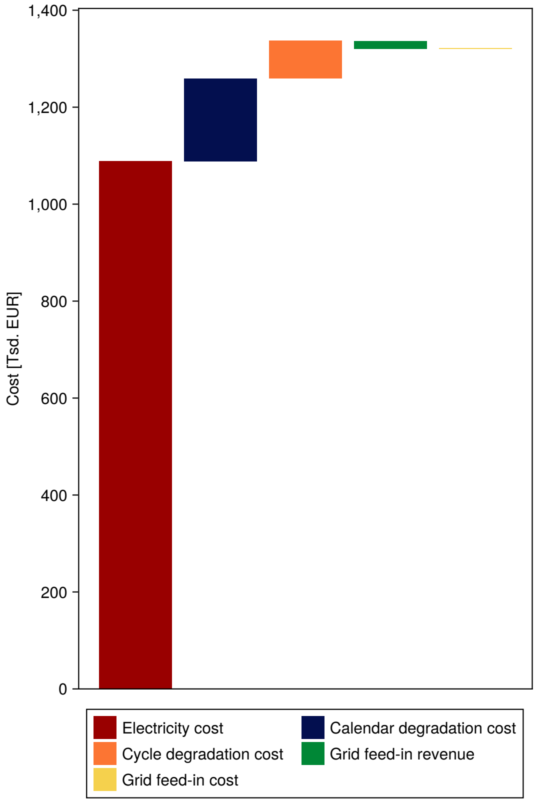


Figure 51: Structure of yearly costs for V2G FCR-D in €

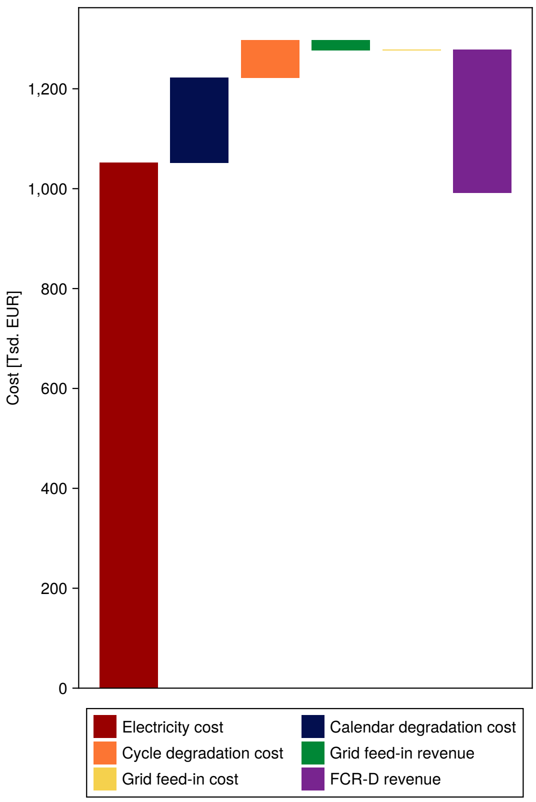


Figure 52: Structure of yearly costs for unidirectional fleet case in €

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