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Electricity spot price-controlled battery in a multifamily residential building

Master’s thesis in the Master’s Programme Sustainable Energy Systems

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CHALMERS UNIVERSITY OF TECHNOLOGY
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Cover:
A 3D view of the south façade of the reference building modeled in IDA ICE by author.
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ABSTRACT

In recent years, the rising cost of electricity has prompted growing interest in solar photovoltaic (PV) and batteries. Understanding the interaction between electricity demand, battery control strategies, and electricity production from solar PV is crucial for designing coupled systems. This thesis examines the economic potential of integrating an electricity spot price-controlled battery in a multifamily residential building in Förlanda, Kungsbacka. Various control strategies are explored using IDA ICE software for simulations, focusing on utilizing the battery to exploit lower electricity prices through arbitrage. Additionally, the nine simulation cases are economically assessed from the perspectives of both a facility company and a private homeowner.

The results for the facility company cost perspective indicated that, based on 2023 spot prices, a standalone battery increased annual costs by 6 300 SEK, while coupling the battery with a solar PV system increased costs by 500 to 2 400 SEK, depending on the battery control strategy. However, a standalone solar PV system decreased annual costs by 2 900 SEK, based on the equivalent annual cost (EAC) method. This suggests that batteries for arbitrage, in buildings of similar size and energy performance as the reference building, are not profitable for facility companies. For private homeowners eligible for subsidies, a battery could be economically viable if coupled with a solar PV system. However, even here, the annual savings from a standalone solar PV system decreased from 4 900 SEK to 3 400 SEK when coupled with a battery. Likewise, a battery without solar PV increased annual costs by 1 800 to 2 600 SEK. Thus, the solar PV system alone was the economically recommended investment for both cost perspectives.

Furthermore, two sensitivity analyses were conducted: one to assess the economic implications of using different historical spot prices (2020 – 2023) in simulations, and the other to explore the inclusion of minimum arbitrage criteria for battery utilization to enhance profitability. The results indicated that different yearly spot prices could significantly alter the economic outcome and that battery control strategies benefited from restraining battery utilization during days with low price spread.

Key words: IDA ICE, energy simulation, battery, solar PV, spot price.

Contents

Preface

This master's thesis is part of the Master's Programme Sustainable Energy Systems at Chalmers University of Technology, carried out from January to June 2024. The thesis was performed at the Department of Architecture and Civil Engineering.

The thesis project was supervised by Angela Sasic Kalagasidis, Professor, and Torbjörn Lindholm, Senior Lecturer, at Chalmers University of Technology, and was done in collaboration with EQUA Solutions and WSP. Thank you for all the help and advice!

I would like to express gratitude to Magnus Heier at EQUA Solutions, and to Anders Fremling and Sonja Kildishev at WSP for all their help with IDA ICE modeling and supervision. Thanks to Christer Kilersjö CEO at Eksta Bostads AB for providing the necessary data to model the building in Förlanda, and to EQUA Solutions for providing a license for their IDA ICE software. I would also like to thank all other personnel at Eksta Bostads AB, EQUA Solutions and WSP who have been involved in this thesis for their support.

Göteborg June 2024

Mohammed Hadrous

Notations

BBR – Swedish building regulation

BEN – Boverket’s regulations and general advice (2016:12) on determination of the building’s energy usage during normal operation and a normal year.

Boverket – The Swedish National Board of Housing, Building and Planning

COP – Coefficient of performance

DOD – Depth of discharge

FTX – Mechanical ventilation with heat recovery

GSHP – Ground source heat pump

PV – Photovoltaic

PVT – Photovoltaic Thermal

SFP – Specific fan power [kW/m^3/s)]

1 Introduction

In this chapter, the thesis background and its objectives are discussed, along with a site analysis for the building in Förlanda. The chapter also outlines the limitations and questions addressed in the thesis.

1.1 Background

The Swedish Energy Agency (Energimyndigheten) reports a consistent rise in solar panel installations. From 2021 to 2023, installation rates have doubled annually. In 2021, there were 26 500 installations generating 500 MW [1]. By 2022, the number rose to 55 000 installations with a combined power of 800 MW [2]. In 2023, installations exceeded 100 000, contributing to an installed solar power capacity of approximately 1 600 MW [3].

This significant increase in solar panel adoption coincided with record-high electricity prices in 2022, averaging 145 öre/kWh, a 128% increase from the previous year [4]. Consequently, interest in batteries has risen sharply. The Swedish Tax Agency (Skatteverket) offers tax deductions for private home battery installations. In 2021, approximately 1 700 private homeowners claimed these deductions [5]. By 2022, the number soared by 600% to around 12 000 batteries eligible for tax deductions. In 2023, the figure rose further to 40 550.

The recent uplift in electricity prices has led consumers to become more aware of electricity markets and methods to capitalize on them. Batteries offer various benefits, including storing excess solar energy, facilitating frequency regulation, and engaging in spot price arbitrage.

The thesis investigates the integration of an electricity spot price-controlled battery in a multifamily residential building in Förlanda in Kungsbacka, using IDA ICE for simulations. Dynamic optimization of energy storage is based on the 2023 electricity spot prices in Sweden, with a focus on utilizing the spot price-controlled battery to capitalize on the lower electricity prices (arbitrage), particularly during nighttime. Given the building features a ground source heat pump (GSHP) for heating and a mechanical ventilation with heat recovery (FTX) ventilation system, both contributing to an electricity demand, it is well suited to benefit from a battery integration.

Furthermore, a life cycle cost analysis provides economic insights for such an investment. From a building owner's perspective, having an hourly spot price contract for purchased electricity presents a potential economic benefit, especially in buildings with high electricity demand. The total electricity price with an hourly contract is not only dependent on the hourly price on the spot market but also sometimes on a power tariff based on maximum power use during a certain period. In addition to the economic benefits for building owners, the integration of a battery also contributes to the stability of the national electricity grid. By shifting some electric energy demand from peak load periods to periods with lower loads, there is a benefit for the electric grid.

1.2 Aim

This thesis aims to assess the feasibility and economic viability of integrating an electricity spot price-controlled battery into a multifamily residential building with

GSHP and FTX. The study seeks to understand the potential economic benefits for facility companies and private homeowners, particularly in the context of high electricity demand, and to evaluate a solar photovoltaic (PV) and battery coupled system on building energy demand.

The main questions of this thesis are:

i. What battery control strategies are preferred?
ii. Could spot price-controlled batteries be a profitable investment?
iii. How does the integration of solar PV and batteries impact building energy demand and the overall profitability?
iv. How does the integration affect building power demand?

1.3 Case study

The subject of this thesis is a multifamily residential low-energy building located in Förlanda, south of Göteborg, within the municipality of Kungsbacka. Constructed in 2021, this building is one of four identical structures owned by the municipal property company Eksta Bostads AB [6]. An overview of the property area can be seen in Appendix A. The building façades, section drawings and floor plants are depicted in Appendix B. With a total heated area of 340 m^2, it comprises two stories and features two apartments on the first floor (approximately 84 m^2 each) and two on the second floor (around 62 m^2 each), along with two garages.

For this project, the building with a south-facing roof was selected to optimize integration with solar panels. Each apartment is equipped with individual mechanical ventilation systems with heat recovery. Heating for the first floor units relies on water-based floor heating, while the second floor apartments are equipped with water radiators. Two 55 kW heat pumps, integrated with solar photovoltaic thermal (PVT), supply heat for these buildings and six older structures. This particular building was chosen for its recent construction and possession of essential documentation for modeling purposes. Additionally, it provides measured data on tenants' electricity and hot water consumption for each apartment.

1.4 Limitations

While this study explores various applications of batteries, it does not simulate the profitability of using them for frequency regulation. However, the theoretical framework and estimated profitability provided by relevant stakeholders are detailed in the theory and discussion chapters. Additionally, modeling the complete energy system for all ten buildings in Förlanda is beyond the scope of this research, instead, a simplified heating system has been considered.

Furthermore, the study relies on historical spot prices, and the model does not incorporate present-day spot prices. Lastly, it focuses exclusively on a single building and does not consider surrounding buildings in its analysis.

2 Theory

This chapter presents the theory, general concepts, and recent research underpinning the method used in this thesis. It covers fundamental aspects of energy storage, batteries, and solar PV systems. Additionally, the chapter explains the basics of how the electricity market operates and the cost structure of electricity bills. It also discusses demand side management strategies and how these can be leveraged to profit from battery usage. Furthermore, an overview of solar PV and battery subsidies in Sweden is provided, along with methods for economic assessment. Lastly, the chapter includes an overview of the energy situation in Förlanda.

2.1 Energy storage

Energy storage has a positive effect on a building’s energy efficiency. Energy can be stored either as thermal energy [7], or electrical energy [8]. Energy storage contributes to the potential reduction of a building’s peak demand for heating and cooling.

There are two main types of thermal energy storage techniques: passive and active [7]. Passive thermal energy storage acts as a thermal buffer, leading to more stable indoor temperatures, rather than directly reducing heating or cooling demand. Passive techniques can be further divided into latent and sensible storage. Latent thermal storage uses phase change materials to store energy, while sensible thermal storage uses materials with high thermal mass.

In contrast, active thermal energy storage systems require deliberate energy input to function as intended, often through the use of electricity to power fans or pumps [7]. One common technique for storing heat energy in buildings is through hot water tanks, which have various applications. Another active storage technology involves integrating thermal storage directly into the building structure, such as using a floor heating system.

Storage duration can vary widely [7]. An example of short-term storage is night ventilation, where the building is cooled during the night to reduce the cooling demand during the day. On the other hand, long-term storage is seasonal, as seen with boreholes. Boreholes store thermal energy during warmer months and are utilized by a heat pump during colder months. They can also be integrated with technologies such as solar PVT. Since heat pumps operate on electricity, reducing purchased electricity during peak demand can also be achieved by discharging electricity from batteries.

2.2 Batteries

A battery is a device based on electrochemical principles that facilitates the conversion of chemical energy into electrical energy and back again [9], [10]. This conversion process occurs through oxidation-reduction reactions, where chemical compounds within the battery undergo changes in their oxidation states. When the battery is discharging, chemical energy stored within its components is converted into electrical energy, powering external devices. Conversely, during charging, electrical energy from an external source is used to drive the oxidation-reduction reactions, restoring the chemical energy stored within the battery for later use.

Recent technological advances and cost reductions in renewable energy generation and battery energy storage have fueled the growth of environmentally friendly energy solutions [11]. These developments have made renewable generation more accessible and efficient, while advancements in battery technology have decreased storage costs and improved battery efficiency, size, and weight.

2.2.1 Various types of batteries

There are various types of batteries such as lead-acid (Pb-acid), nickel-cadmium (NiCd), nickel-metal hydride (Ni-MH), sodium sulfide (Na-S), and lithium-ion (Li-ion) [9], [12], [13].

Lead-acid batteries utilizes lead dioxide at the anode and sponge lead at the cathode, with options for liquid electrolyte (sulfuric acid and distilled water) or paste/gel electrolyte with a pressure-regulating valve [12]. Advantages include low cost [9], [12], tolerance for intensive use, allows for large depth of discharge (DOD), and high efficiency between 75% to 80%. Some of the disadvantages are short lifespan (500 to 1000 cycles) and low power density between 30 to 50 Wh/kg. Lead-acid batteries may also require some maintenance.

Nickel-cadmium batteries has a cadmium anode and nickel hydroxide cathode with a potassium hydroxide electrolyte [12]. In these batteries there are no relationship between voltage and the charge level, therefore the charging is by constant current. Some advantages of nickel-cadmium batteries are that they have long life cycle lasting for more than 3 500 cycles and can reach up to 50 000 cycles if used optimally. They have higher power density of 50 to 75 Wh/kg. However, nickel-cadmium batteries are expensive and have an approximately 10% self-discharge rate per month.

Nickel-metal hydride batteries are composed of metal hydride cathode and a nickel hydroxide anode and is a modification of the nickel-cadmium battery [12]. In addition to the advantages of a nickel-cadmium battery, the nickel-metal hydride battery has a higher energy density between 60 to 120 Wh/kg. However, the self-discharge rate is higher and in the range of 15% to 20% per month. The self-discharge rate can be reduced by having a small charge current. The battery type has short lifespan of 300 to 500 cycles. Both the nickel-cadmium and nickel-metal hydride batteries are associated with high cost [9].

Sodium sulfide batteries are composed of a sodium cathode and a sulfur anode and a ceramic compound of aluminum oxide as electrolyte and separator [12]. These types of batteries have a fast response time and have long lifespan due to the liquid electrodes that are unaffected by changes in temperature. Some disadvantages are that the cell voltages should be controlled as to avoid unwanted effects and the batteries operates at high temperatures due to the chemical reactions at around 270°C to 350°C. Therefore, it requires control and protection system.

Litium-ion batteries are generally based on compounds with graphite in the cathode and lithium in the anode [12]. Common commercial types are lithium-cobalt oxide, lithium-cobalt phosphate or lithium-manganese oxide. The charging and discharging process relies on the insertion and removal (disinsertion) of lithium ions, resulting in the conversion of chemical energy into electrical energy. The advantages of lithium-ion batteries are high energy density of 75 to 125 Wh/kg and low self-discharge effect. They have high efficiency between 80-95% and long lifespan [12], [14]. Some disadvantages are its low tolerance for overload, susceptible to high temperatures and expensive in comparison to other battery types [9], [12]. The lithium-ion battery plays an increasingly important role among the various types of batteries due to its high energy to weight (specific energy) and energy to volume (energy density) ratios [13].

2.2.2 How Lithium-ion batteries work

The general structure of a battery is an electrochemical cell that contains electrodes and electrolyte, which is a chemical solution [12]. The electrodes are the anode and the cathode that are connected by a conductive material. A principal schematic of an electrochemical cell can be seen in Figure 1.

In lithium-ion batteries, the electrolyte consists of a liquid and a semisolid/solid-state [14]. Common electrolyte liquids are of lithium salts e.g., $LiBF_4$, $LiPF_6$, $LiN(CF_3SO_2)_2$, and LiBOB. The salts are dissolved in organic carbonates. The composition of the semisolid/solid-state electrolytes are lithium salts as the conducting salts and high molecular weight polymer matrices.

Oxidation occurs in the anode material and reduction occurs in the material of the cathode [14]. The anode is the negative electrode, to which electrons migrate during battery discharge. During battery charging, the electrons migrate back to the cathode, the positive electrode. Lithium ions migrate between the anode and cathode via the electrolyte that connects them [14]. When the battery is discharging, lithium ions from the anode are released and diffused to the cathode.

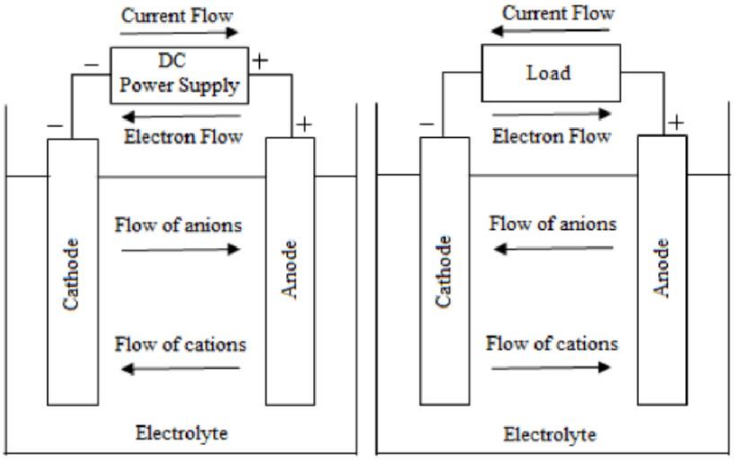


Figure 1. Charge (left) and discharge (right) characteristics of a battery cell [10].

Self-discharge rate measures how quickly a cell loses its stored energy while not in use due to unwanted chemical reactions within the cell. This reduces the amount of energy available for discharge. According to Khan et al., self-discharge characteristics of lithium batteries can range from 5% to 10% per month [15]. However, Roth et al. noted that past research suggested self-discharge rates at room temperature were 2% to 3% per month, whereas more recent studies have shown rates below 0.1% per month [16].

2.2.3 Battery connections in series

Batteries can be connected in either series or parallel. When connected in series the ideal assumption is that the batteries are identical regarding end of charge/discharge characteristics [10]. Batteries connected in series are charged using a single charger, meaning they share a common voltage source. However, this setup can often result in undercharging or overcharging of batteries due to differences in their individual parameters. To ensure proper recharging in series, batteries should ideally have identical parameters such as state of charge, impedance, temperature, and so forth. Mismatched batteries connected in series pose challenges for proper recharging, as the presence of even one battery with different parameters can lead to overcharging or undercharging issues. When a battery reaches its full charge, i.e., charge current of less than 3% of its rated capacity, the excess power supplied to the battery is no longer used for recharging and instead becomes heat in the cell. This leads to a rise in both cell temperature and internal pressure. Therefore, it's recommended to disconnect a fully charged battery from the charging circuit or maintain it within the recommended float voltage range.

2.2.4 Battery performance equations

The depth of discharge (DOD) is an important parameter and refers to how much of the battery storage capacity that is utilized [17], [18]. A battery that cycles between 20% and 100% charged has a DOD of 80%. Having a lower DOD increases the lifespan of a battery, since less cycles are used. However, to utilize the same amount of energy from the battery, a smaller DOD requires a larger battery which increases the investment cost. Therefore, to appropriately size the battery, the DOD in combination with the discharge efficiency must be taken into account in regards to meeting energy output demands. Energy losses due to charging efficiency does not impact the sizing of the battery. In Equation (1) the expression for DOD can be seen, where SOC stands for the battery's state of charge:

$$DOD = SOC_{max} - SOC_{min} \tag{1}$$

In Equation (2), an expression for the utilized (net) battery capacity is seen which is determined by SOC_{max} and SOC_{min} or the DOD [19]:

$$E_{net} = E \times (SOC_{max} - SOC_{min}) = E \times DOD \tag{2}$$

The C-rate is the ratio between the charging or discharging power of a battery denoted as P, expressed in kilowatts (kW), and its rated energy storage capacity denoted as E, measured in kilowatt-hours (kWh) [9], [19]. The discharging power is usually the same as charging power in conventional batteries with an AC/DC converter [17]. The equation for C-rate is given in Equation (3):

$$C_{rate} = \frac{P}{E}\ [h^{-1}] \tag{3}$$

Battery energy losses, based on charged and discharged energy is expressed in Equation (4) [19]:

$$E_{loss} = E_{charged} - E_{discharged} \tag{4}$$

If the charging and discharging efficiencies are known, then the relation between charged and discharged energy is according to the following Equation (5) [17]:

$$E_{in} = \frac{E_{out}}{\eta_{charging} \times \eta_{discharging}} = \frac{E_{out}}{\eta_{system}} \tag{5}$$

A battery's lifespan is based on the number of charge/discharge cycles without any noticeable negative effects on the battery performance [12]. The number of cycles could be calculated, assuming that the initial and final SOC levels are the same, as given by Equation (6):

$$Cycles = \frac{E_{charged}}{E} \tag{6}$$

2.3 Solar PV

Solar photovoltaic (PV) technology enables the direct conversion of solar radiation into electricity [20]. A PV system is composed of cells, each containing layers of semi-conductive material. The conversion of sunlight into electricity occurs when light strikes the cell, creating an electric field across the layers, which causes electricity to flow. The electrical power generated by each cell depends on the intensity of the light hitting it.

The most common material used for solar PVs is silicon, due to its high efficiency [20]. Crystalline silicon, which has the highest efficiencies, can be either mono-crystalline or poly-crystalline. Mono-crystalline solar PVs, which can exceed 20% efficiency, are more efficient than poly-crystalline ones.

Mono-crystalline solar PV modules have an average annual power degradation rate of 1.55%, according to research by Atia et al. [21], which observed 11 years of outdoor operating solar PVs. Research by Quansah and Adaramola [22], found that grid-connected modules had maximum power degradation rates ranging from 1.3% to 1.9% annually for both poly-crystalline and mono-crystalline silicon modules. Off-grid connected solar PVs with battery-charging showed degradation rates of 0.9% for a 32-year-old system and 6.5% per year for a 10-year-old system. The expected lifespan of solar PVs is commonly considered to be 25 years [23], based on performance guarantees which ensure 80% of power output after 25 years of operation.

The peak or nominal power of solar PV systems is typically measured under standard test conditions (STC) and expressed in kilowatts peak (kW_p) [24].The STC for solar PVs corresponds to an irradiance of 1 000 W/m^2 and a cell temperature of 25°C [25]. It is common for the actual performance of solar PVs to be 15% to 20% lower than their nominal power [26]. In Sweden, solar PV systems typically yield between 700 and 1 000 kWh per kW_p installed, equivalent to approximately 150 kWh per square meter of solar PV.

2.3.1 Solar PV coupled with battery

The self-use of electricity produced from solar PV is limited due to the mismatch between electricity demand and the hours when electricity is produced [27]. To increase the amount of energy directly consumed by tenants or homeowners, storing electrical energy in a battery is a viable solution. The electricity produced by solar PV systems is direct current (DC), the same as the current from and to a battery [28]. A common guideline for sizing a battery system with a solar PV installation is to match the kWh capacity of the battery to the kW_p rating of the installed solar panels [29].

A battery can be connected to either the AC or DC side of the solar PV inverter [27], [28]. This means the battery is connected either before, on the DC side, or after the inverter on the AC side. An AC-coupled battery is equipped with bidirectional battery inverters, while DC-coupled batteries usually have unidirectional inverters integrated. There are also DC-coupled systems that use bidirectional inverters, allowing them to be charged from the AC side.

2.4 Electricity market

In Sweden there are four electricity areas, SE1, SE2, SE3, and SE4 [30], [31]. The norther part of Sweden is SE1 and the most southern part of belongs to SE4. Göteborg and Stockholm belong to SE3. In northern Sweden, SE1 and SE2, there is an over production of electricity, while in the southern Sweden, SE3 and SE4, there is an under production of electricity due to higher demand. Transmission lines have capacity limitations, and therefore, during parts of the year the electricity prices in SE1 and SE2 are lower than SE3 and SE4 [31], [32], [33].

The day-ahead market refers to market trades occurring one day-ahead of electricity delivery, which is carried out in the Nord Pool electricity marketplace in the Nordic countries [34], [30], [32]. The selling and buying bids for the next day are submitted by the actors at latest at 12:00 Central European Time (CET), and the electricity prices for the next day are published at latest 13:00 CET. The bids include the amount of electricity to be sold or purchased, at what price and in which electricity areas. Nord Pool's Day-ahead market is available in 15 countries for 21 bidding zones [35]. The spot price is then set according to the intersection of supply and demand curves for each hour. The competitive market ensures that electricity is produced at the lowest price during all hours [36].In the day-ahead market, marginal price is used, i.e. the price is set according to the most expensive producing source employed for each specific hour, see Figure 2.

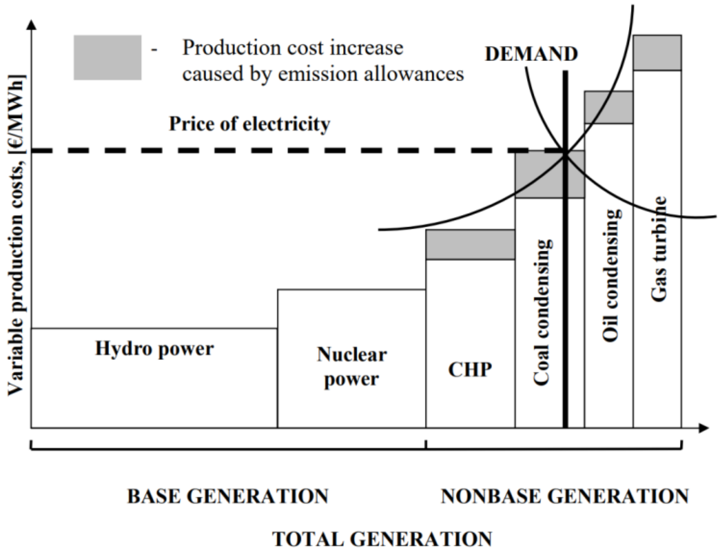


Figure 2. Formation of the day-ahead electricity price [37].

The intraday market is a market for electricity consumers that can provide flexibility by adjusting their demand [34]. Since bidding is based on forecasting models, this market enables correction but includes fees. The market opens at 14:00 CET the day before and closes 1 hour before electricity is delivered. The intraday market is available across 14 countries and has gained increasing interest due to the growing amount of renewable intermittent production, which poses challenges for participants to be in balance on the day-ahead market [38].

2.4.1 Electricity costs

The cost of electricity for a consumer is based on two bills, one from the distribution company and one from the trading company. The distribution company is responsible for the electricity grid in the area, for example in Göteborg it is Göteborg Energi, and in Kungsbacka its Ellevio. The consumer does not have a choice of choosing the distribution company, it is dependent on who owns and are responsible for the electricity grid. The trading company, on the other hand, can be chosen. In Sweden there are approximately 130 companies to choose from [39].

The bills are based on fixed and variable costs [39]. The fixed cost is a monthly or annual fee, while the variable cost is based on electricity consumption. In addition to the spot price, the variable costs include markup, electricity certificates, and energy tax. Detailed information on electricity costs can be found in Chapter 3.3.1.

Furthermore, there is a peak power demand tariff [40]. As of 2022, 20 out of the 150 distribution companies in Sweden use a peak power tariff. The cost structure varies between these companies; the tariff could be based on the single highest power peak during a year, the highest monthly peak, an average of the highest few hours during a year or on a monthly basis, or other criteria set by the distribution company. It is more common for large companies and industries to have a peak power demand tariff due to their higher power demand, whereas private homeowners are usually excluded. The Swedish Energy Markets Inspectorate (Ei) has decided that all distribution companies must include peak power tariffs by January 1, 2027. This decision will impact private homeowners and smaller companies, who typically are not currently on a peak power demand tariff contract.

2.5 Demand side management

Demand side management refers to actions taken to influence the pattern and magnitude of end-use electricity consumption [41]. Examples include peak shaving, which reduces peak power demand, and load shifting, which involves shifting consumption from high-priced to low-priced hours.

Load shifting involves rescheduling electric activities for another time, such as flexible heating, using household appliances, charging electric vehicles, or utilizing battery storage [34]. On the other hand, peak shaving entails temporarily reducing electricity consumption without the need to compensate later. For example, industries with high electricity consumption may choose to decrease production during high-priced hours. Similarly, households with both electric and alternative heating methods may turn off or reduce electric heating during peak hours and use alternative heating sources instead.

2.6 Ways to profit from batteries

Profiting and reducing the energy bill from battery utilization can be achieved by load shifting and by reducing peak power demand [42], [8]. Utilizing batteries to provide ancillary services is another option for generating profit from battery investments [8], [43], [44]. In the two sub-chapters, these methods are accounted for.

2.6.1 Arbitrage by load shifting

One of the most popular applications of battery storage in power systems are spot price arbitrage [45], and it is also the most commonly studied revenue source for storing electrical energy [8]. This is an example of load shifting. Spot price arbitrage involves charging the battery during low-priced hours and discharging it during high-priced hours, thereby yielding economic benefits. This is made possible by changes in electricity demand and supply curves, which in turn influence the price of electricity [11]. As long as the volume of electricity bought and sold for spot price arbitrage remains relatively small compared to the overall market volume, it will have negligible impact on the market price.

As storage technologies become more common, they will eventually affect the market price [8]. In such cases, the discharge from storage technologies can reduce the need for generation from the most expensive generators, thereby lowering peak prices. In contrast, when storage technologies are charging, demand increases, potentially leading to higher prices. This dynamic reduces the potential for spot price arbitrage by increasing the cost of charging and decreasing the profit from discharging.

Arbitrage strategies should take into account round-trip efficiency, as it is a critical factor that influences the strategy [46]. Sensitivity analyses conducted by T. Mercier, M. Olivier, and E. De Jaeger to assess the impact of round-trip efficiency and storage duration on storage profitability revealed that in markets with low arbitrage values, profitability remains low even with very high round-trip efficiency and storage duration [47]. Results from the study was that the main factor for the potential of energy arbitrage was market variations. Round-trip efficiency was identified as the second contributing factor, with storage capacity being the last. In countries such as Sweden and Norway, arbitrage values have consistently been low, attributed to a high share of hydro power and large reservoirs resulting in stable day-ahead market prices. By contrast, in countries with higher arbitrage values, the marginal value of round-trip efficiency becomes more significant.

2.6.2 Ancillary services

The demand for ancillary services is increasing [48], especially with the growing share of renewable power production [41]. System stability issues are more likely to occur in this context and can be mitigated by ancillary services. These services are provided on different time scales, ranging from milliseconds to approximately three days.

The frequency in the Nordic electric grid should be maintained at 50 Hz [49]. Frequency above 50 Hz indicates that the electricity produced exceeds demand, while frequency below 50 Hz suggests that demand exceeds production.

Energy storage, such as batteries, can contribute to maintaining frequency balance [44]. When frequency falls below 50 Hz, batteries can discharge to increase frequency, and when frequency exceeds 50 Hz, they can charge to increase demand and balance frequency.

Transmission system operators in the European Union are generally not allowed to own energy storage facilities, with a few exceptions [44]. To maintain the desired frequency at 50 Hz, the transmission system operator in Sweden, Svenska Kraftnät, purchases ancillary services from the ancillary service market (balancing market) [43], [49]. Only balancing responsible actors can bid on the ancillary service market, while private homeowners can only provide ancillary services through subcontracts with balancing responsible actors. Revenues from ancillary services are market-dependent and based on specific setup and compensation policies for different markets [8].

There are three ancillary services markets in Sweden [50]. CoordiNET, an ongoing project financed by the European Union in 2020, operating in seven countries and found in four regions in Sweden [51]. Sthlmflex is the market in Stockholm. In Göteborg there is the Effekthandel Väst market [52].

In Sweden, there are currently 11 large battery parks with a combined storage capacity of 107 MWh already in use [53]. This combined storage capacity is set to increase substantially, with 27 new parks under construction, with a total storage capacity of 496 MWh, expected to be operational by 2024. Furthermore, plans for an additional 46 parks with a combined storage capacity of 2 851 MWh are underway, which would increase the current storage capacity by a factor of 32. The driving force behind these investments has been a highly profitable market. However, the precise impact of these battery parks on market prices, as well as the timing of such effects, remains uncertain.

The minimum power requirement for ancillary services bids is 100 kW, which can be achieved by aggregating privately owned batteries [54]. Private individuals can choose to sub-lend their batteries, for example, to companies like CheckWatt, which connect the batteries to the virtual power plant *Currently* [55]. When sub-lending the battery it is under the control of CheckWatt, which determines its utilization. The state of charge is typically maintained at around 50% to enable discharge and charge if necessary [56].

The revenue for private individuals is determined by battery power and availability, rather than whether the battery was utilized for ancillary services. According to CheckWatt, having a battery with a capacity of 1 kW could generate 3 097 SEK in yearly revenue [57]. Revenue increases linearly with increased battery power. These revenue estimations are based on market prices from 2020 to the present.

2.7 Subsidy for solar PV and batteries

In Sweden, there is a tax reduction subsidy available for installing green technologies, such as solar PV and batteries, for private homeowners (excluding facility companies) [58]. The subsidy is limited to 50 000 SEK per year per person [59]. It reduces the investment cost for grid-connected solar PV and its installation by 20%, while for batteries and/or electric vehicle charging stations, and their respective installation costs, the reduction is 50%.

If non-tax-deductible expenses, such as travel costs, are included in the total cost of installing solar PV or batteries, the tax-deductible portion is 97% of the total cost [39]. This results in a tax reduction of 19.4% for solar PV and 48.5% for batteries, both calculated on the total cost, including installation.

As of 2024, Skatteverket's new interpretation [58] of Regulation (2016:899) on subsidies for the storage of self-produced electrical energy [60], specifies the accepted use of batteries to qualify for the subsidy. The requirement is that batteries must be used exclusively or almost exclusively to store self-produced electricity. This means that batteries purchased for ancillary services are not eligible for the subsidy [5].

2.8 Economic assessment

Life cycle cost analysis is used as an economic assessment method to calculate and compare the cost of a system or investment over its entire lifespan [61]. To calculate the life cycle cost of alternatives with different investment lifespans, the equivalent annual cost (EAC) method can be used [62]. The EAC combines all future costs into a single annual cost. The alternative with the lowest EAC is considered the optimal investment. The EAC is calculated by multiplying the net present value (NPV) by the annuity factor (A_f), as shown in Equation (7):

$$EAC = NPV \times A_f \tag{7}$$

The NPV is calculated according to Equation (8) [19]:

$$NPV = C_0 + \sum_{i}^{n} \frac{C_i}{(1 + r_d)^i} \tag{8}$$

In the equation for NPV, C_0 represents the investment cost, while *n* denotes the longest lifespan of the investments if there are several. The variable r_d stands for the discount rate, and C_i is the annual cost for year *i*. By introducing an energy price growth rate in addition to inflation, the NPV equation is expressed as follows:

$$NPV = C_0 + \sum_{i}^{n} \frac{C_i \times (1 + r_e)^i}{(1 + r_d)^i} \tag{9}$$

In Equation (9), r_e represents the energy price growth rate. To equally distribute a present value over n years, the annuity factor can be used. The annuity factor can be expressed as shown in Equation (10) [63]:

$$A_f = \frac{i}{1 - (1 + i)^{-n}} = \frac{i(1 + i)^n}{(1 + i)^n - 1} \tag{10}$$

Furthermore, the payback period (PBP) can be used to assess the economic value of an investment. The PBP measures the amount of time required to recover the investment cost [61]. Although the PBP method is easy to use, it is recommended primarily for initial and quick estimations due to its simplicity [63]. To determine if the PBP is less than the lifespan of the system, the investment cost is divided by the annual net savings. The annual net savings are compared to a reference case or considered as an annual cash flow resulting from the investment. The expression for PBP, without considering the discount rate, is shown in Equation (11) below:

$$PBP = \frac{C_0}{annual\,net\,savings} \tag{11}$$

2.9 Energy system in Förlanda

In Förlanda, the energy system comprises two 55 kW Thermia Mega L ground source heat pumps equipped with hot gas circuits, supplemented by solar PVT panels. There are ten boreholes: four older boreholes with an average depth of 163 meters, and six boreholes drilled around the year 2021, reaching a depth of 200 meters with a groundwater depth of 4 meters.

Additionally, the system includes two 0.5 m^3 accumulator tanks and one 0.5 m^3 hot water heater. It efficiently delivers both heat and hot water to ten buildings, four of which are constructed during 2021. Notably, one of these four newly constructed buildings is the focus of this report, featuring floor heating on the first floor and radiators on the second floor.

The accumulator tanks maintain low-temperature storage, while the hot water heater is integrated into the heat pumps' hot gas circuit, operating at temperatures ranging between 80°C and 90°C. For a visual representation, refer to the energy system layout provided in Appendix C, with a simplified schematic depicted in Figure 3, created using draw.io software.

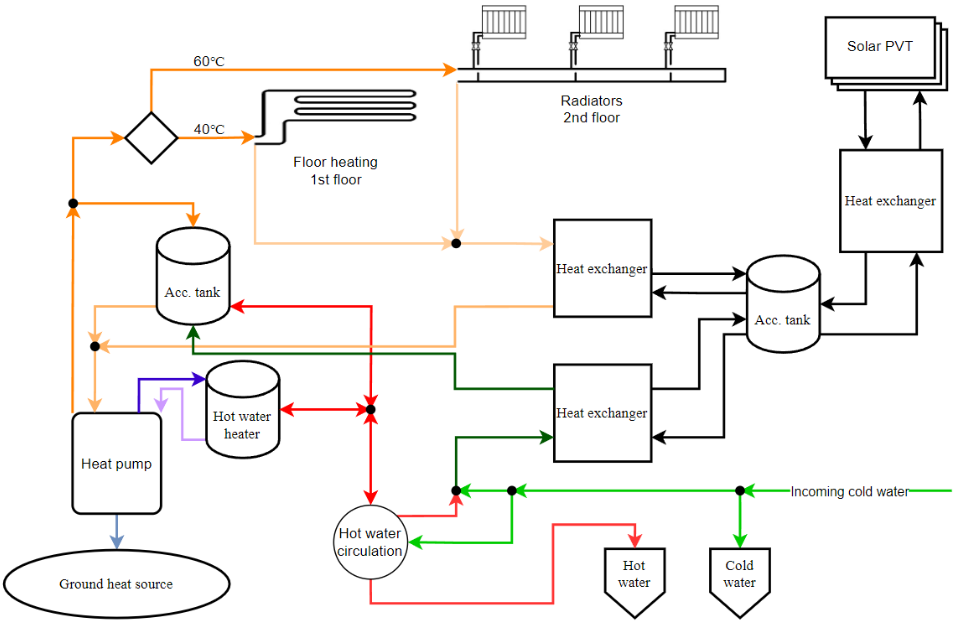


Figure 3. Simplified schematic of the heating energy system in Förlanda.

3 Method

A multifamily residential building is modeled in IDA ICE 5 simulation program, which includes developed models for ground source heat pump and mechanical ventilation with heat recovery.

The study is performed in following steps:

1. Literature study of the topic:
   Identifying possibilities, limitations, and key findings.

2. Data collection:
   Collecting building information; floor plans, heat pump and fan performance, ventilation rates, building materials, window types, number of residents, temperature setpoints and hot water consumption.

3. Modeling:
   Modeling the building in IDA ICE simulation software and implementation of measured electricity and hot water consumption from previous year (2023) to ensure the accuracy of the model.

4. Forecasting model:
   Development of a forecasting model in Excel for battery control based on electricity spot prices from 2023 and implementation into IDA ICE software. The forecasting model should identify next day's optimal prices for arbitrage.

5. Simulations:
   With historical climate data and electricity spot prices using the forecast model to figure out the annual economic benefit. Simulations are affected by outdoor temperature and user-behaviors which varies based on the day of the week.

6. Sensitivity analyses:
   Sensitivity analysis of simulating with different years' electricity spot prices (2020 – 2023), and additionally to analyze the profitability of including a minimum arbitrage criteria for battery control strategy.

7. Economic assessment:
   A life cycle cost analysis, based on the equivalent annual cost (EAC) method, is used for economic assessment for the simulation cases. Additionally, the payback period method is employed.

The method is described in more detail in the following sub-chapters.

3.1 Simulation model

The simulation software used for reconstructing the building in Förlanda into a simulation model was IDA ICE 5.0.0.1 from EQUA Simulation A.B [64]. IDA ICE is a well-known dynamic whole-year simulation software [65]. Some examples of its application are building energy models, thermal indoor climate, daylight and assessment of energy renovation measures. The IDA ICE software has been shown to have high model accuracy [66]. The simulation software has been validated, i.e. the computational models give reasonable values, with respect to ANSI/ASHRAE standard 140-2004 *Standard Method of Test for the Evaluation of Building Energy Analysis Computer Programs* [67].

3.1.1 Building model and input data

One out of four identical buildings in Förlanda were modeled in IDA ICE. Although their orientations differ, the selected building faces south. Building documents for these structures, provided by Eksta Bostads AB, were in the form of PDF and CAD files. Details such as wall, roof, and slab thickness, insulation, and material components, obtained from the provided files, were meticulously added to IDA ICE in accordance with the construction documents. AutoCAD was used to take measurements, ensuring precise implementation of components. Ventilation rates for both supply and extract systems were incorporated into the apartments zones based on ventilation specifications. Moreover, the specific fan power (SFP) and heat exchanger efficiency for the air handling unit in IDA ICE were obtained from manufacturer documents. Windows and doors were also included in the model to ensure accurate U-values, along with the correct frame-to-glass ratio for windows. The average building envelope and windows U-values are outlined Appendix D and thermal bridges in Appendix E.

The occupancy per apartment, were determined based on the Swedish National Board of Housing, Building and Planning's (Boverket) *regulations and general advice (2016:12) on determination of the building's energy usage during normal operation and a normal year* (BEN) [68] and the Sveby report from 2012 [69]. According to these references, the average occupancy in the building is 14 hours per day. On average, a two-room apartment accommodates 1.63 occupants, while a three-room apartment accommodates 2.18 occupants. The indoor temperature setpoint is maintained at 21℃, and 70% of the internal gains from equipment are utilized within the building. Input for internal loads from equipment and lighting, as well as hot water consumption are based on measured values and accounted for in Chapter 3.1.3. For more data and information, refer to Table 17 in Appendix D.

In IDA ICE, modeling is conducted from an internal perspective to represent the thermal zone. Consequently, the inclined garage and dormer roof is simulated as flat in IDA ICE. The reference building model can be seen in Figure 4. This contrast can be observed by comparing the roof representations in Appendix B.

The apartments were divided into thermal zones in IDA ICE. The 84 m^2 three-bedroom apartments on the first floor were simulated with five thermal zones, and the 64 m^2 two-bedroom apartments on the second floor had six thermal zones. Details can be seen in Appendix F.

Figure 4. A 3D view of the south façade of the reference building modeled in IDA ICE.

3.1.2 Model simplifications

The energy system in Förlanda has two 55 kW heat pumps and solar PVT to provide heating for ten buildings and is described in more detail in Chapter 2.9. However, in the IDA ICE model, the solar PVT has been excluded, and instead, an 8 kW heat pump with a COP of 4.3 has been used. The COP is based on measured values provided by Eksta Bostads AB. Additionally, although there are 10 boreholes in the actual system, the model only includes one borehole, with a depth of 200 meters.

In the IDA ICE model, nearby buildings have been excluded. To assess the potential impact of shading from surrounding structures, an extreme scenario was tested by introducing a shading obstacle measuring 10 meters wide and 5 meters high, positioned 10 meters away from the building's south side (refer to Appendix G). The actual configuration of surrounding buildings is depicted in Appendix A.

The outcome of this extreme shading scenario revealed an increase in electricity consumption for heating by 80 kWh, from 7 190 to 7 270 kWh/yr. It can be inferred that modeling the actual nearby shading buildings would likely result in less than an 80 kWh per year increase in electricity consumption for heating. This assumption is based on the fact that these nearby buildings are situated further away from the modeled building and do not cast shade from the south. Therefore, the shading obstacle was excluded from further consideration in the model.

To simulate window openings, and the effect on the building heat storage, *ideal coolers* with 25°C as cooling setpoint was used in IDA ICE. The energy for the coolers is excluded from the results and only serve the purpose of not overestimating building heat storage.

A simplification made in the simulation model involves the use of internally closed doors instead of scheduling door openings and closings. Ventilation exchange between thermal zones/rooms is still enabled by the leakage feature in IDA ICE. To justify this simplification aimed at reducing simulation time, two simulations were conducted: one with constant closed internal doors and the other with scheduled openings from 06:00 to 09:00. The IDA ICE models simulated did not include solar panels or batteries, opting for a simplified version. The results showed that by maintaining constant closed internal doors, the simulation time decreased from 21 to 16 minutes, saving 5 minutes. The energy consumption for facility electricity (non-domestic) was 7 373 kWh/yr for the closed-door simulation and 7 372 kWh/yr for the scheduled simulation. Therefore, the decision to utilize constantly closed internal doors in the simulation models was deemed justified, as it achieved comparable energy performance while reducing simulation time.

3.1.3 Tenants' energy consumption

In the model, hot water, and tenants' (domestic) electricity consumption (for equipment and lighting) was incorporated using actual consumption data. However, the specific apartments to which the hot water and electricity consumption belonged were not specified, meaning the data could belong to any of the sixteen apartments in the four multifamily residential buildings in Förlanda.

To address data gaps ranging from one to six hours in the measured values, interpolation between preceding and succeeding data points was performed in Excel. The missing values are due to connection issues. To supplement missing data for hot water and domestic electricity consumption in 2023, corresponding values (day of the week and hour of the day) were extrapolated from the available 2022 data.

The major data gaps for hot water and tenants' electricity consumption in 2023 was:

- 2023-06-15 04:00 to 2023-06-19 12:00 (~4 days)
- 2023-08-22 18:00 to 2023-09-25 13:00 (~1 month)
- 2023-11-16 23:00 to 2023-11-17 18:00 (~1 day)
- 2023-12-15 19:00 to 2023-12-19 08:00 (~4 day)

3.1.3.1 Hot water and electricity use

The total hot water consumption for the four apartments in one of the buildings in Förlanda during 2023 was 75.4 m^3, while the cold water consumption was 159 m^3. Comparing the hot water consumption in Förlanda with the standards outlined in BEN, the 75.4 m^3 of hot water corresponds to 1 658.8 kWh/yr [68]. In contrast, the reference value set by the Swedish Building Regulation (BBR) and BEN for hot water heated by ground source heat pumps is 3 400 kWh/yr for a 340 m^2 multifamily residential building. Thus, the actual consumption was approximately 50% lower than the BEN reference value. This conversion from cubic meters to energy is derived from Equation (12), which calculates the energy for hot water based on the annual volume of cubic meters of hot water used:

$$E_{hw} = \frac{V_{hw} \times 55}{\eta_{hw}} \tag{12}$$

The symbol E_{hw} represents the energy used for hot water production in kilowatt-hours, while V_{hw} denotes the volume of hot water in cubic meters. The factor 55 is a conversion factor for cubic meters to kilowatt-hours, and n_{hw} represents the efficiency for hot water production. According to BEN, the efficiency for producing hot water with ground source heat pumps is 2.5 [68]. The reference value for multifamily residential buildings is calculated using Equation (13):

$$E_{hw} = \frac{25 \times A_{temp}}{\eta_{hw}} \tag{13}$$

The factor 25 is the conversion factor from heated floor area (above 10℃) denoted A_{temp} to energy in kilowatt-hours used for hot water. For single-family houses the conversion factor is 20.

Hot water is not included in the rent in Förlanda, instead each apartment is equipped with a measuring meter for hot water, which determines the monthly cost. By excluding hot water from the rent, tenants are incentivized to reduce their consumption, thereby lowering their monthly payments. The average hot water consumption pattern for the four apartments on weekdays is illustrated in Figure 5. Monday through Thursday exhibit similar patterns, while Fridays show a lower peak from 18:00 to 20:00.

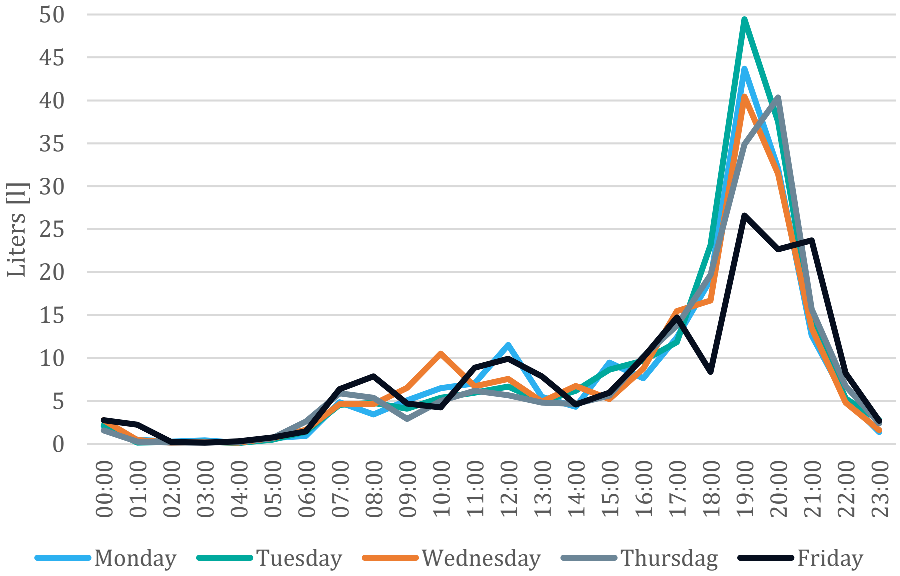


Figure 5. Average hot water consumption per hour during weekdays in Förlanda.

Comparing hot water consumption during an average weekday with that of an average Saturday and Sunday, as shown in Figure 6, reveals a noticeable decrease in the evening peak on Saturday. Additionally, there is a slight uptick in consumption during the weekends around noon.

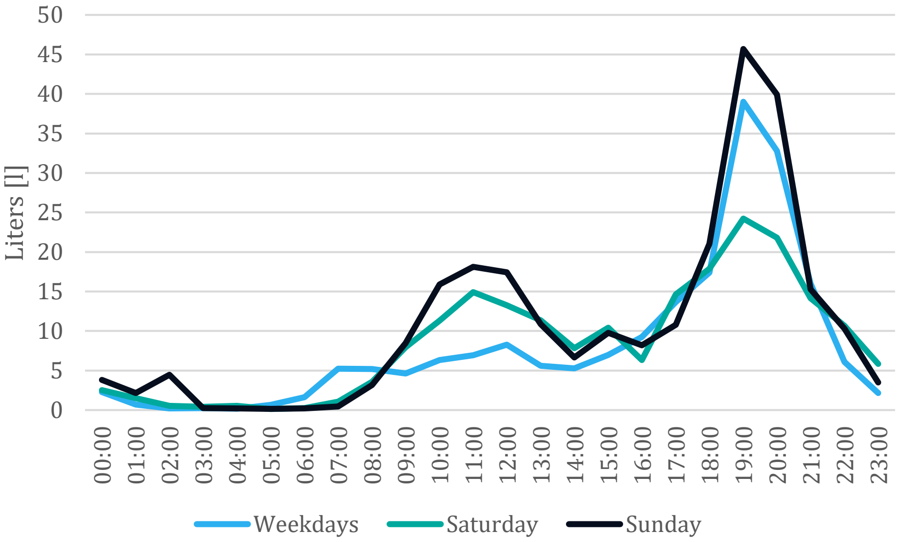


Figure 6. Average hot water consumption per hour during weekdays and weekends.

To implement the tenant hot water consumption profile in IDA ICE, the data points from Figure 6 were used and normalized to the highest peak during weekdays, Saturday, and Sundays respectively. The normalization was necessary due to the software's limitation in handling hourly hot water consumption values. The result can be seen in Figure 7 below. The normalized values were manually added in IDA ICE, and the total yearly hot water consumption was averaged out per each day of the year. The appearance of the IDA ICE graphs can be observed in Figure 51, Figure 52 and Figure 53 in Appendix H.

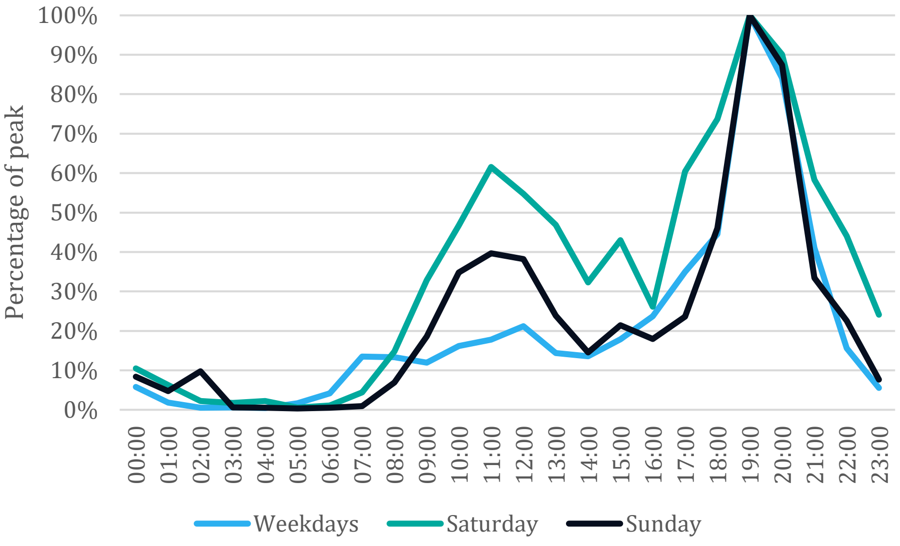


Figure 7. Normalized average hot water distribution profile used as input in IDA ICE.

3.1.3.2 Tenant electricity

Hourly tenants' (domestic) electricity consumption profiles were incorporated into IDA ICE to represent equipment and lighting consumption for the four apartments. The total domestic electricity consumption amounted to approximately 7 700 kWh/yr corresponding to 26.3 kWh/m^2/yr. The distribution among the four apartments varied and can be seen in Table 1.

The consumption pattern, serving as the input signal for IDA ICE, can be found in Figure 54 in Appendix I. It reveals that apartment 3 exhibits three peak periods and low consumption throughout the rest of the year. While the overall consumption pattern resembles that of apartment 4, the specific consumption pattern of apartment 3 was omitted from the model. Instead, the consumption profile of apartment 4 was applied to apartment 3 as well. In this context, *apartment 3* and *apartment 4* refer to the second floor apartments.

Table 1. Measured tenants' electricity consumption during 2023.

Apartment number	Area [m^2]	Total Electricity [kWh/yr]	Electricity per area [kWh/m^2/yr]
1	84	3 463	41.2
2	84	2 010	23.9
3	62	1 060	17.1
4	62	1 160	18.7
Total	292	7 693	26.3

To provide context for these values, the expected domestic electricity use for new single-family houses and residential apartments is 30 kWh/m^2/yr, divided into 79% for equipment and 21% for lighting [68], [69]. However, the allocation was adjusted to 85% for equipment and 15% for lighting to avoid overestimating the consumption of lighting. The electricity consumption was then allocated to the thermal zones of each apartment based on the assumptions outlined in Table 2 and Table 3.

Table 2. Domestic electricity allocation for first floor apartments.

Room	Equipment	Lighting
Main bedroom	8.5%	2%
Kitchen	38.25%	4%
Living room	17%	5%
Small bedroom	4.25%	2%
WC	17%	2%
Total	85%	15%

Table 3. Domestic electricity allocation for second floor apartments.

Room	Equipment	Lighting
Bedroom	8.5%	3%
Kitchen	42.5%	4%
Living room	17%	6%
WC	17%	2%
Total	85%	15%

3.1.4 Battery & forecasting model

In IDA ICE 5.0, there are two battery sizes available, each capable of being connected in series and parallel configurations if additional capacity is required. After simulating the reference case (see Chapter 3.2 for simulation cases), it was observed that the smaller 6.5 kWh (134 Ah) battery size was preferred over the larger 13.1 kWh (264 Ah) battery. Both batteries are Tesla Powerwall lithium-ion units with a depth of discharge (DOD) of 80%. The batteries are utilized daily, considering their DOD, which allows for about 80% of a cycle per day. Over the course of a 366-day year, this consumption translates to approximately 290 cycles annually. The batteries have a C-rate of 0.33, meaning that they charge and discharge in three hours. The efficiency of DC (solar PV) to DC (battery) conversion is 98%, while the efficiency of DC (battery) to AC conversion is 95%. Additionally, the batteries feature a built-in capacity fade as a simulation result, which can be found in Appendix J.

The batteries discharge to meet the facility and tenant electricity demand but do not export to the electricity grid. When combined with solar PV, the battery discharge is secondary, meaning there are situations where the battery has a discharge control signal but does not discharge. This occurs when the solar PV generates sufficient electricity to meet both the facility and tenants demand. In such cases, if the battery were to discharge, the surplus energy would be sold to the grid. Therefore, if the solar PV can cover the facility and tenant demand, the stored electrical energy in the battery remains preserved.

In IDA ICE, control signals are interpolated between each value. For example, if the logical signal is 0 at 12:00 and 1 at 13:00, it would be 0.5 at 12:30, and so on. This interpolation directly impacts the charging and discharging of the battery. However, given that the spot price remains fixed each hour, it's crucial for the battery control signal to align accordingly. To tackle this challenge, additional time steps have been integrated into the generated schedules which are elaborated in the sub-chapters below. An illustrative example of this adjustment is provided in Appendix K. This solution minimizes the interpolation of control signals from one hour to the next, focusing instead on interpolation within narrower intervals, such as between hour 1.9999 and hour 2.

The sub-chapters below detail the two main control strategies: *fixed* and *spot price*. Simulation cases involving a combination of these strategies or variations thereof are discussed in Chapter 3.2.

3.1.4.1 Fixed control strategy

The *fixed* control strategy for battery charging and discharging is based on historical spot price averages obtained from the Danish Energinet’s Energi Data Service [70], covering the years 2020 to 2023. The electricity area is SE3 in Sweden. Hourly spot prices for each year were compiled into a dataset, and Excel was used to calculate the average hourly values.

As illustrated in Figure 8, the three lowest-priced hours occur between 01:00 and 04:00, while the three highest-priced hours are between 08:00 and 09:00, and 17:00 and 19:00. The figure depicts an interpolation between hourly spot prices. It should be noted that spot prices remain fixed throughout each hour and change at the beginning of a new hour. Appendix L summarizes the average spot price values in Table 18. This consistent pattern across the four-year span establishes these hours as *fixed* control signals to prompt the battery for charging or discharging. Charging is scheduled daily from 01:00 to 04:00, while discharging takes place at 08:00 to 09:00 and 17:00 to 19:00.

Finally, logical signals for the battery were generated in Excel and imported as a control schedule for the battery in IDA ICE to implement. Consideration was given to the time shift between winter and summer time, and adjustments were made accordingly.

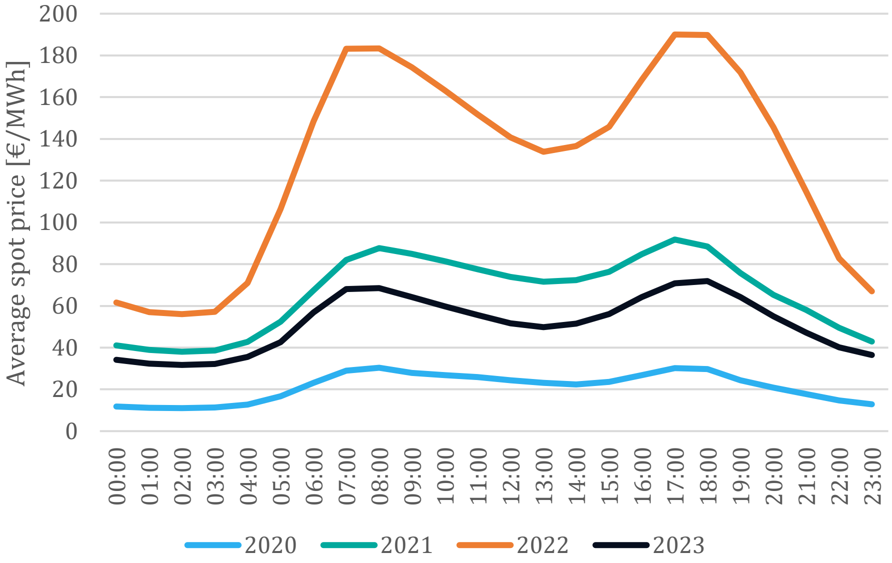


Figure 8. Average spot prices per hour for the years 2020 – 2023.

3.1.4.2 Spot price control strategy

The *spot price* control strategy involves charging and discharging the battery during the three lowest- and highest-priced hours each day, adapting daily to fluctuations in spot prices. The control schedule was generated in Excel, with spot prices evaluated over a 24-hour interval.

Initially, the interval spanned from 00:00 to 24:00 daily, assessing spot prices throughout this period. However, observations from simulations revealed instances where the battery was signaled to charge at night (e.g., 21:00 – 24:00) and then continued charging after midnight, rendering the charging signals redundant as the battery was already fully charged. This raised questions about the optimal charging hours based on price.

As a solution, an alternative approach was adopted by analyzing the average spot prices from 2020 to 2023, as shown in Figure 8. Recognizing that transitioning between 24-hour intervals should occur during hours unlikely to include the highest or lowest priced hours, attention was focused on mid-priced hours of the day, typically around 11:00 to 15:00. Consequently, the interval starting point was set at 12:00 daily, enabling assessment of spot prices from, for instance, January 1st 12:00 to January 2nd 12:00. This adjustment offsets the optimal spot price interval by 12 hours for a standard daily cycle, reducing the risk of multiple charging signals within a single 24-hour period and into the next, potentially increasing yearly battery cycles.

Throughout 2023, the average of the three highest-priced spot prices within each 24-hour period consistently exceeded the corresponding average of the three lowest-priced hours within the same period by at least 16.6%. However, this control strategy does not account for the minimum difference required between the highest- and lowest-priced hours to ensure profitability, considering battery system losses. The inclusion of a minimum arbitrage threshold is further explored in a sensitivity analysis detailed in Chapter 3.4.2, in response to the simulation results of yearly battery system losses.

3.1.5 Solar PV

The available southern roof area of approximately 40 m^2 have been utilized completely. Simulations incorporating solar PV feature a nominal power output of 7.44 kW, with a total power capacity of 7.2 kW including the inverters. This setup comprises 24 solar panels, each with a capacity of 310 W. The dimensions of each solar panel are 992 x 1640 mm, with a total area of 1.63 m^2 per panel. The panels have an efficiency rating of 19%. The building model equipped with solar PV is depicted in Figure 9.

Figure 9. A 3D view of the building modeled in IDA ICE, featuring 7.44 kW$_p$ solar PV.

3.1.6 Trading contracts in IDA ICE

By default, IDA ICE includes trading contracts between the facility and utility provider, as well as between the tenant and utility provider. To facilitate trading between the facility and the tenants within the IDA ICE model, a trading contract had to be established between the two parties. Figure 8 illustrates the energy contracts, including the available trading contracts in IDA ICE 5, for a building utilizing heat pump, solar PV, and battery storage. Additionally, the examples of energy contracts depicted in Figure 10 and Figure 11 are sourced from the EQUA Simulation AB tutorial document [71].

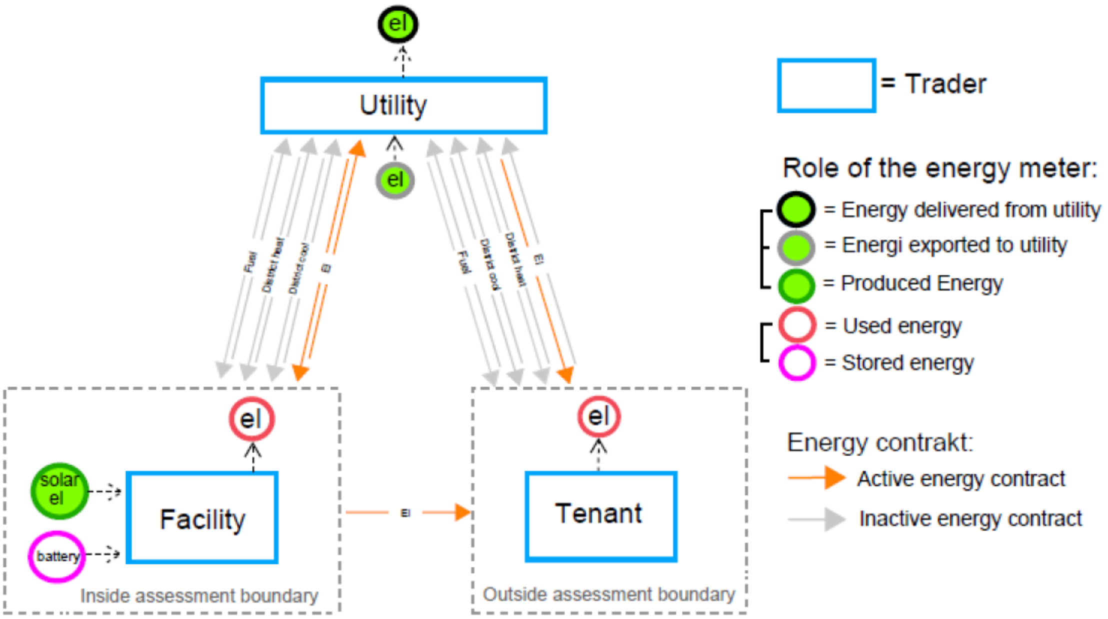


Figure 10. Trading contracts in IDA ICE 5 for a building utilizing heat pump, solar PV, and battery storage, which can also be provided to the tenants [71].

To ensure that excess electricity from solar PV and battery storage is used for tenants before being sold to the electricity grid, arbitrary purchase and selling prices need to be set up. In Figure 11, an example of prices is provided, demonstrating that the pricing structure incentivizes the facility to prioritize supplying electricity to tenants over selling it back to the grid. This approach proves to be more economical for the facility, as illustrated by the example.

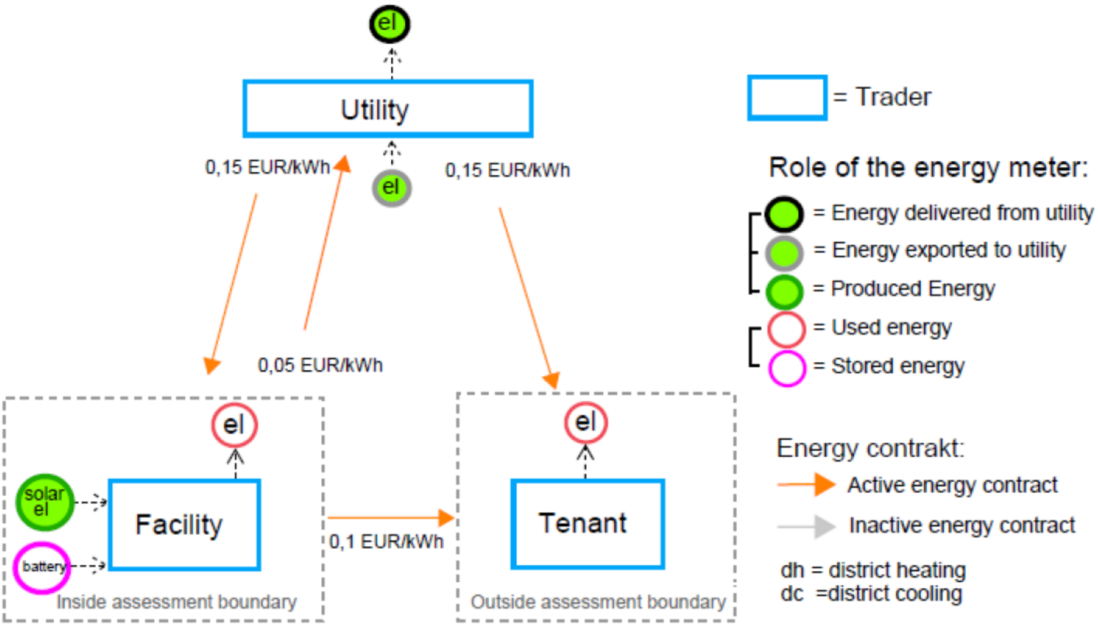


Figure 11. An example of electricity pricing incentivizing supply to tenants over selling to the grid in IDA ICE 5 [71].

3.2 Simulation cases

In this thesis, the simulation cases considered for the building in Förlanda utilize spot prices from the year 2023 and are outlined as follows:

1) Reference case – without solar PV and without battery storage

The reference case is the building model with input data according to Chapters 3.1.1 and 3.1.3.

2) Solar PV

Simulated with 24 solar panels (300 W each) which have a total installed power of 7.2 kW_P (including the inverter) in this case, as well as in Cases 5 to 9 below.

3) Battery – *fixed* control
4) Battery – *spot price* control

The battery has a storage capacity of 6.5 kWh and a C-rate of 0.33, enabling complete charging and discharging within three hours. The *fixed* control arbitrage strategy charges and discharges at the same hour every day, whereas the *spot price* control identifies the three lowest and highest spot prices of the day to optimize charging and discharging. For more details on the control strategies, refer to the corresponding sub-chapters in Chapter 3.1.4.

5) Solar PV and battery – *fixed* control
6) Solar PV and battery – *spot price* control
7) Solar PV and battery – *spot price* control with fixed discharge between 08:00 – 09:00 daily.
8) Solar PV and battery – *spot price* discharge. Battery only charges from solar PV over-production.
9) Solar PV and battery – *spot price* discharge. *Spot price* charge during winter period, and during summer, charging only from solar PV over-production.

Simulation cases 5 through 9 combine solar PV and battery. Cases 5 and 6 represent a combination of solar PV with the two main battery control strategies: *fixed* and *spot price* control. Meanwhile, cases 7 through 9 feature a mix of *fixed* and *spot price* control strategies for the battery, as outlined below.

In case 7, a fixed discharge occurs every morning between 08:00 and 09:00, aiming to have storage capacity available before potential solar PV over-production during midday. Case 8 focuses on maximizing battery charging from solar PV over-production to minimize export to the grid.

Case 9 is determined by the solar PV production and export results from case 2, as depicted in Figure 18 in Chapter 4.1.1. Each period, spanning six months, was selected based on the results. During the winter period (14 September 12:00 to 15 March 11:59), the battery charging strategy follows a *spot price* approach. Conversely, during the summer period (15 March 12:00 to 14 September 11:59), the battery exclusively charges from solar PV over-production, as this period exhibited the highest levels of solar PV over-production according to the results from Figure 18.

3.3 Economic assessment

In this chapter, the method used for the economic assessment of the simulation cases is presented. The assessment is based on variable electricity prices and investment costs for solar PV and battery storage. Two points of view have been considered: one from the perspective of a facility company and the other from that of a private homeowner. As a facility company, the owner does not pay for tenant electricity, while a private homeowner is responsible for all electricity used in the building.

Hourly results from simulation cases have been used to assess the annual variable electricity costs by calculating the hourly cost of bought and sold electricity in Excel. In the case of the facility company's perspective, the electricity sold to the tenant has been priced the same as the electricity bought by the facility. Each facility company may have different policies and prices for selling electricity to their tenants, which are produced by solar PV and batteries.

In Förlanda, the tenants are billed for their hot water consumption, while in IDA ICE, the hot water demand is placed on the facility owner. A simplification of this economic assessment is therefore that the cost of hot water similarly falls on the facility owner. However, since the cost is fixed and not affected by the different cases, the cost difference between the cases remains the same.

3.3.1 Electricity prices

The economic assessment is based on variable electricity prices for both bought and sold electricity. The cost of electricity is based on costs from the distribution and trading company respectively. The distribution company prices were obtained from Ellevio AB [72], [73], and prices for the trading company were obtained from Mälarenergi AB with assistance from their customer service [74].

In Appendix M, distribution costs by Ellevio for companies and private homeowners can be found, detailing fixed, variable, and peak power demand tariffs in Table 19 and Table 20, while Appendix N contains trading costs by Mälarenergi for both actors, providing details on fixed and variable costs. Variable costs include markup, electricity certificates, base fees, and power reserve fees, as outlined in Table 21 and Table 22.

Additionally, Appendix O displays the price for sold/exported electricity to the grid for both companies and private individuals in Table 23 and Table 24. A notable difference is that Mälarenergi charges companies a fee for sold electricity, while no additional charge is applied for private contracts.

Table 4 summarizes the variable and fixed costs to the distribution and trading companies, as well as the earnings from sold electricity from the perspectives of a facility company and a private homeowner. Prices listed as ranges are explained in the corresponding appendices and are based on periods of high and low demand.

Table 4. Summary of electricity prices, in addition to spot price, for facility companies and private homeowners. Prices include 25% VAT, with exemption for sold electricity.

	Facility company	Private homeowner	Unit
Variable prices:			
Distribution company	0.66 – 1.24	0.84	SEK/kWh
Trading company	0.04	0.10	SEK/kWh
Sold electricity	0.63 – 0.64	0.65 – 0.67	SEK/kWh
Peak power tariff	116.25	-----	SEK/kW/month
Fixed costs:			
Distribution company	3 900	10 320	SEK/yr
Trading company	-----	420	SEK/yr

3.3.2 Investment costs

The investment cost for a battery, including installation, averages 7 600 SEK/kWh, including VAT and without subsidies, as reported by HemSol [75]. For private homeowners, the total investment cost could be reduced by 48.5% due to subsidies. Consequently, the subsidized battery cost, including VAT, is 3 914 SEK/kWh.

Investment costs for solar PV are estimated at 16 000 SEK/kW$_p$, including VAT and without subsidies, based on figures from HemSol [76], Energimyndigheten [77], and a 2022 survey by The International Energy Agency (IEA) [72]. The IEA survey uses data from Energimyndigheten. HemSol also offers a service where price estimates from companies can be obtained, which has been used to verify the estimated battery and solar PV investment costs. The subsidy for solar PV for private homeowners is 19.4% of the total investment cost, reducing the cost to 12 896 SEK/kW$_p$.

In the simulations, a 6.5 kWh battery was used, costing 49 400 SEK without the subsidy and 25 441 SEK with the subsidy. The cost for a 7.44 kW$_p$ solar PV system is 119 040 SEK, reduced to 95 946 SEK with the subsidy. Note that the subsidy is only applicable to private homeowners and not to facility companies. The investment costs are summarized in Table 5.

Table 5. Summary of battery and solar PV investment costs. The costs for the private homeowner include the solar PV and battery subsides.

Investment	Facility company	Private homeowner	Unit
Battery (6.5 kWh)	49 400	25 441	SEK Incl. 25% VAT
Solar PV (7.44 kW$_p$)	119 040	95 946	SEK Incl. 25% VAT

3.3.3 Equivalent annual cost & payback period

Equivalent annual cost (EAC) and payback period (PBP) were calculated in Excel to assess and compare the economic viability of simulation cases. The equations utilized are outlined in Chapter 2.8. To determine the cost differences between the simulation cases, the annual variable electricity cost was calculated. By combining the variable electricity cost with fixed electricity expenses and the investment cost for solar PV and battery, as detailed in the preceding sub-chapters, the EAC and payback periods were derived.

The battery was estimated to operate for 4 000 cycles, corresponding to common battery guarantees of 10 years assuming approximately one cycle per day [29], [78]. As a result, the lifespan of the battery varied for each simulation case depending on the number of cycles per year. Additionally, the EAC calculations incorporated a battery capacity fade factor, derived from the IDA ICE simulations. This factor varies for each case, reflecting the battery's cycle consumption.

The EAC calculations also factored in an annual solar PV power degradation rate of 1.6% and an economic lifespan of 25 years, as outlined in Chapter 2.3. It was assumed that a new inverter for the solar PV system would be needed after 13 years at a cost of 20% of the total investment [79], which amounts to 23 808 SEK based on the solar PV investment cost of 119 040 SEK.

Marginal EAC was determined by comparing the EAC of each simulation case to that of the reference case. The calculations were performed with a discount rate of 5% and an annual energy price growth rate of 2%. Additionally, payback was calculated by dividing the net present value of investment costs with annual savings relative to the reference case. A summary of the parameters used is provided in Table 6.

Table 6. Summary of economic assessment parameters.

Parameters	Value
Discount rate [%]	5
Energy price growth rate [%/yr]	2
Battery – cycles	4 000
Battery – capacity fade (range) [%/yr]	2.2 – 4.1
Solar PV – lifespan [years]	25
Solar PV – new inverter after 13 years [SEK]	23 808
Solar PV – power degradation rate [%/yr]	1.6

3.4 Sensitivity analysis

Based on the results of the nine simulation cases, sensitivity analysis was conducted on case 6 which features solar PV and battery with spot price control. Case 9 was chosen due to the combination of solar PV and battery, as well as the control strategy. In two following sub-chapters, the sensitivity analyses conducted are further described in detail.

Based on the results of the nine simulation cases, two sensitivity analyses were conducted on simulation Case 6, which features solar PV and battery with spot price control. Case 6 was chosen due to the combination of solar PV and battery, as well as the control strategy. The two subsequent sub-chapters provide further detail on the conducted sensitivity analyses.

3.4.1 Different yearly spot prices

The first sensitivity analysis involved simulating Case 6 with spot prices for the years 2020 to 2023. The reference case and Case 2 with only solar PV are used as comparison for economic assessment. Spot prices obtained in EUR were converted to SEK using average exchange rates retrieved from the European Central Bank [80], as shown in Table 7.

Table 7. Average exchange rates from EUR to SEK for the years 2020 – 2023.

Year	2020	2021	2022	2023
Exchange rate [EUR to SEK]	10.48	10.15	10.63	11.48

3.4.2 Minimum arbitrage criterion

The second sensitivity analysis explores the effect of including a spot price arbitrage criterion for battery control. This criterion requires that the arbitrage must exceed a certain threshold, stated as a factor between the three highest priced hours and the three lowest priced hours. The factor is expressed by Equation (14):

$$Arbitrage\ factor \leq \frac{\sum Three\ highest\ priced\ hours}{\sum Three\ lowest\ priced\ hours} \tag{14}$$

Battery control strategies in simulation cases prior to this sensitivity analysis were applied daily, without considering battery efficiency or whether it would be economically beneficial to not use the battery. In those cases, the arbitrage factor was equal to 1, serving as the reference factor for this analysis. The arbitrage factors used in this analysis are 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, and 4.0. These factors were initially used to generate new logical signals for the battery in Excel and then imported as control schedules in IDA ICE for battery implementation. In Figure 12 the number of days the battery is utilized, based on 2023 spot prices, as a function of the arbitrage factor can be seen.

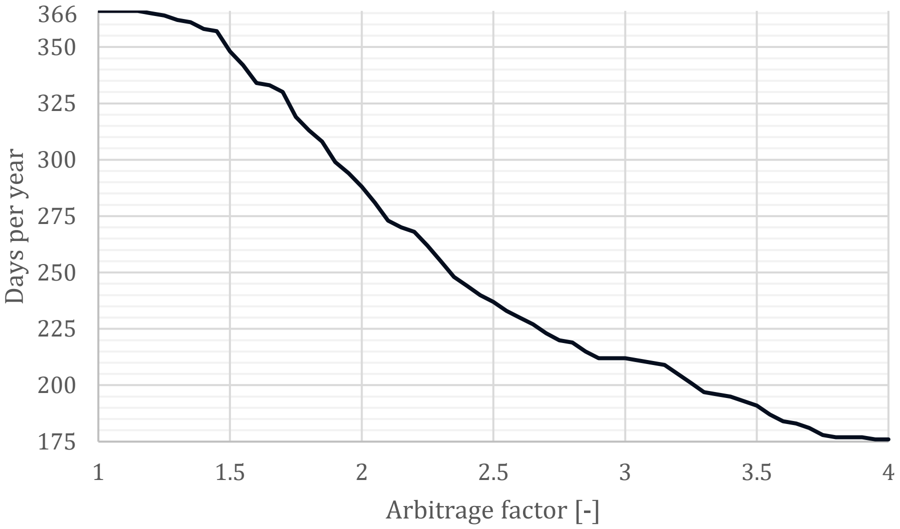


Figure 12. Number of day for battery utilization as a function of arbitrage factor, based on 2023 spot prices.

The output from the IDA ICE simulations for the sensitivity analysis conducted was used to assess the annual variable cost of electricity, as described in Chapter 3.3. The results regarding the impact of the arbitrage factor on the annual variable cost are presented in Chapter 4.3.1.

Figure 13 illustrates the variations in spot prices for different years, plotted against the arbitrage factor as explained in the preceding chapter. The graph demonstrates the greater discrepancy between daily high and low-priced hours. Specifically, spot prices in 2022 exhibit the highest daily variations, whereas those in 2021 show the lowest. Notably, negative spot prices were observed on 3 days in 2020, 2 days in 2021, 8 days in 2022, and 48 days in 2023. It's evident that higher daily variations benefit spot price arbitrage, leading to increased earnings. The results regarding the impact of different yearly spot prices on the annual variable cost are presented in Chapter 4.3.1.

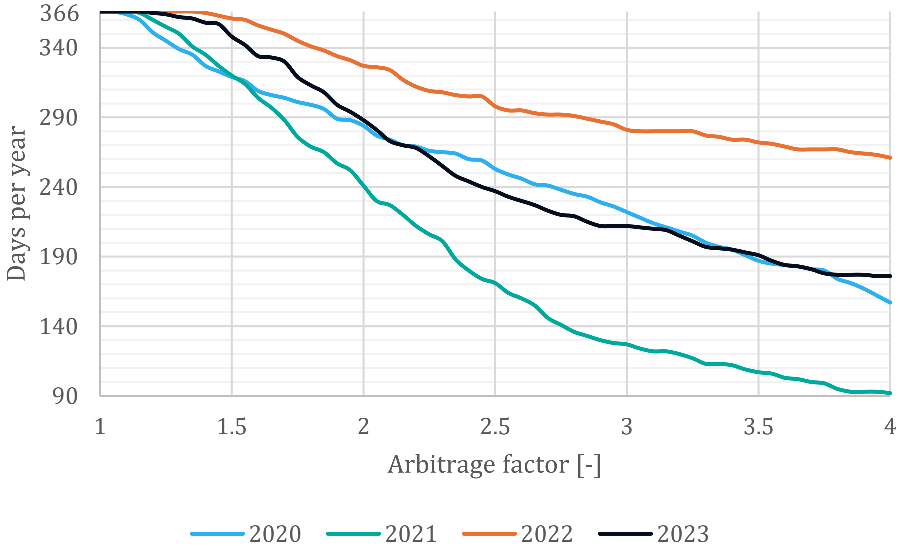


Figure 13. Spot price variations for the years 2020 – 2023 expressed in days as a function of arbitrage factor.

3.5 Report writing

In accordance with Chalmers *Regulations for the use of AI tools in thesis work* [81], the use of AI tools has been used to improve the structure of sentences and paragraphs to increase the readability of this thesis. The AI tools that have been used is mainly ChatGPT [82], and to some extent Grammarly [83]. AI tools have not been used as a source/reference for statements, but exclusively to improve the choice of language and formulations.

4 Results

This chapter presents and discusses the results of this thesis. First, the energy simulation results are introduced, followed by an economic assessment. Finally, the results from the sensitivity analyses are discussed.

4.1 Simulation results

In this chapter, the simulation results for the nine cases are presented and discussed. The sub-chapters include results on the battery performance, electricity production from solar PV, building energy balance and tenant electricity consumption.

4.1.1 Battery

The 6.5 kWh battery is used in simulation Cases 3 to 9. Figure 14 and Figure 15 illustrates the spot price dynamics over a 72-hour period in January and June respectively, displayed on the left Y-axis. Additionally, it showcases the control signal/strategy for two main methods: *fixed* control and *spot price* control strategy, represented on the secondary Y-axis.

In the case of *spot price* control, the 24-hour interval spans from 12:00 to 11:59 the following day, as described in Chapter 3.1.4.2. In this context, the *spot price* control strategy demonstrates the dynamic adjustment of battery operations in response to real-time spot prices.

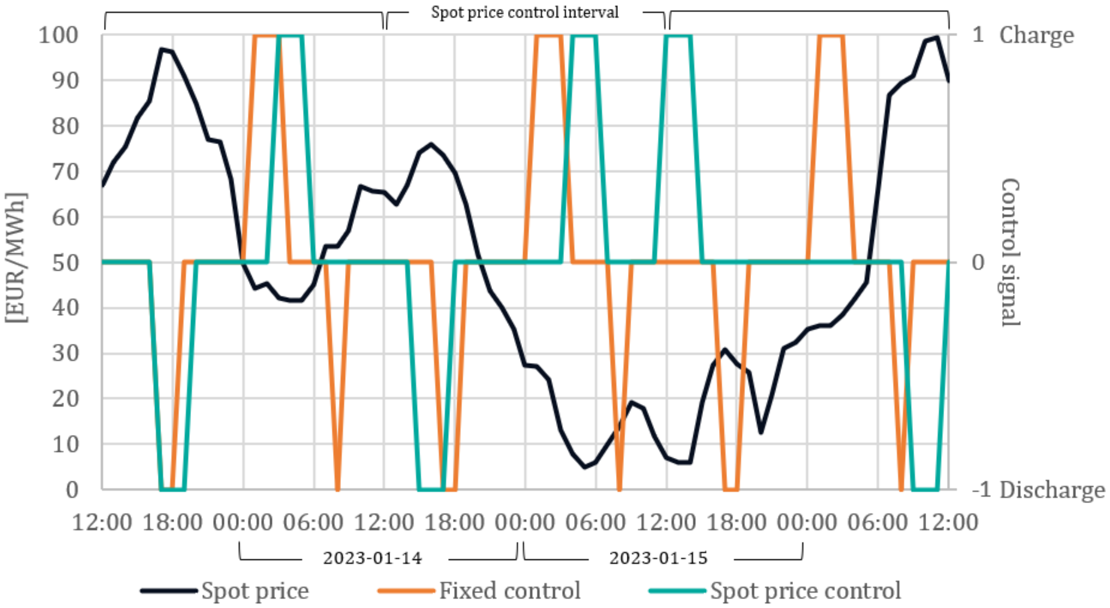


Figure 14. Spot price and battery control signals during a 72-hour period in January 2023.

Comparing Figure 14 and Figure 15, spot prices are lower in June than in January due to increased demand during the winter period. The *spot price* control strategy adapts to spot price variations, while *fixed* control remains unaffected.

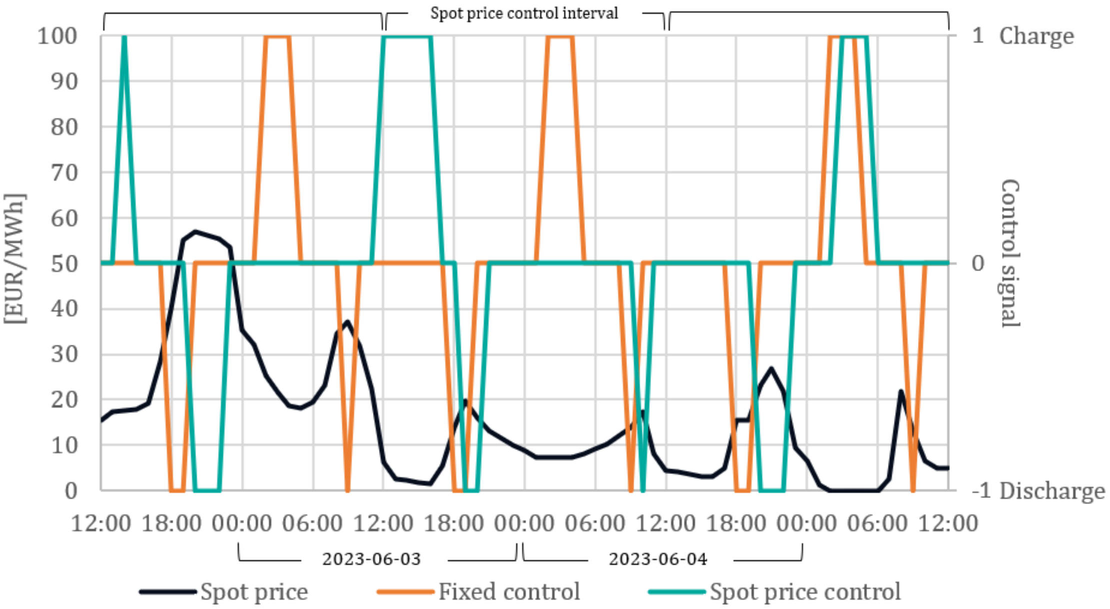
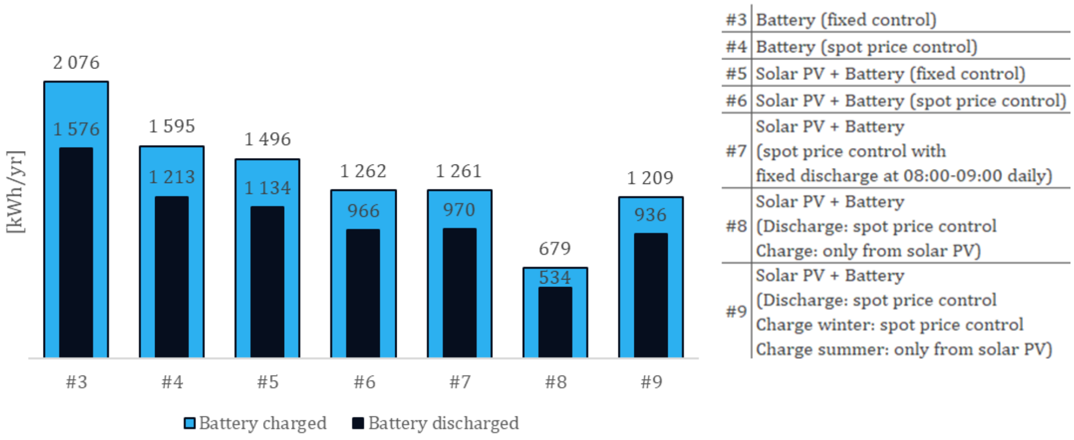


Figure 15. Spot price and battery control signals during a 72-hour period in June 2023.

In Figure 16 the total charged and discharged energy utilized by the battery can be seen for the simulation Cases 3 to 9. The difference between Cases 3 and 4, both with a standalone battery, is that the *fixed* control strategy in Case 3 discharges more frequently compared to with *spot price* control strategy in Case 4. The *fixed* control strategy discharges the battery when the historical average spot price has been at its highest and coincides with higher tenant electricity demand. The *spot price* control signals the battery to discharge during the highest spot prices, however, the facility and tenants' electricity demand limits the discharge energy since the battery does not discharge to the grid.



#3	Battery (fixed control)
#4	Battery (spot price control)
#5	Solar PV + Battery (fixed control)
#6	Solar PV + Battery (spot price control)
#7	Solar PV + Battery (spot price control with fixed discharge at 08:00-09:00 daily)
#8	Solar PV + Battery (Discharge: spot price control Charge: only from solar PV)
#9	Solar PV + Battery (Discharge: spot price control Charge winter: spot price control Charge summer: only from solar PV)

Figure 16. Total annual battery charge and discharge energy, the difference indicating energy losses.

The difference between charged and discharged energy in Figure 16 indicates battery losses, which are further illustrated in Figure 17 as a function of total charged energy. Battery losses are calculated according to Equation (4). The yearly battery system losses range from 21.4% to 24.1%. In general, the more the battery has been charged, the more energy losses.

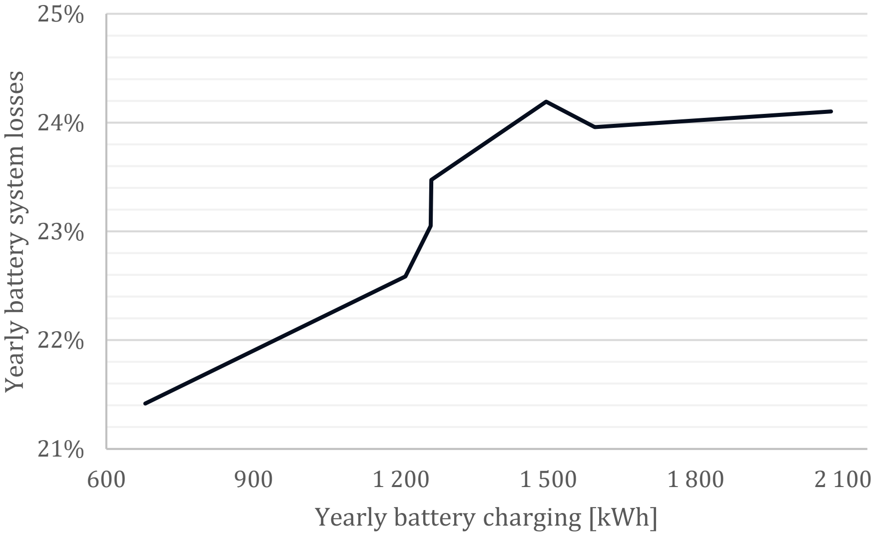


Figure 17. Battery yearly system losses as a function of stored energy.

Table 8 presents the battery cycles used in simulation Cases 3 to 9, calculated according to Equation (6). The battery capacity fade and lifespan are determined by the number of cycles utilized per year, with a total lifespan based on 4 000 cycles. On average, the capacity fade was 0.0154% per cycle.

Table 8. Summary of battery simulation results for Cases 3 to 9.

Case	#3	#4	#5	#6	#7	#8	#9
Cycles per year	319	245	230	194	194	105	186
Capacity fade	4.1%	3.5%	3.4%	3.1%	3.1%	2.2%	3.1%
Lifespan [years]	13	16	17	21	21	38	22

4.1.2 Solar PV production

The 7.44 kW solar PV system generates 7 287 kWh per year, corresponding to 979 kWh/kW$_P$. Of this, approximately 20% is utilized for facility electricity, and 30% for domestic electricity. In simulation case 2, where the building is equipped with solar PV but no battery, the total electricity purchased by the facility decreased by 1 550 kWh, from 5 850 kWh to 4 300 kWh. Similarly, the total purchased domestic electricity decreased by 2 050 kWh, from 7 800 kWh to 5 750 kWh. This implies that approximately 50% of the generated electricity is exported. The monthly solar PV production and exported electricity are shown in Figure 18.

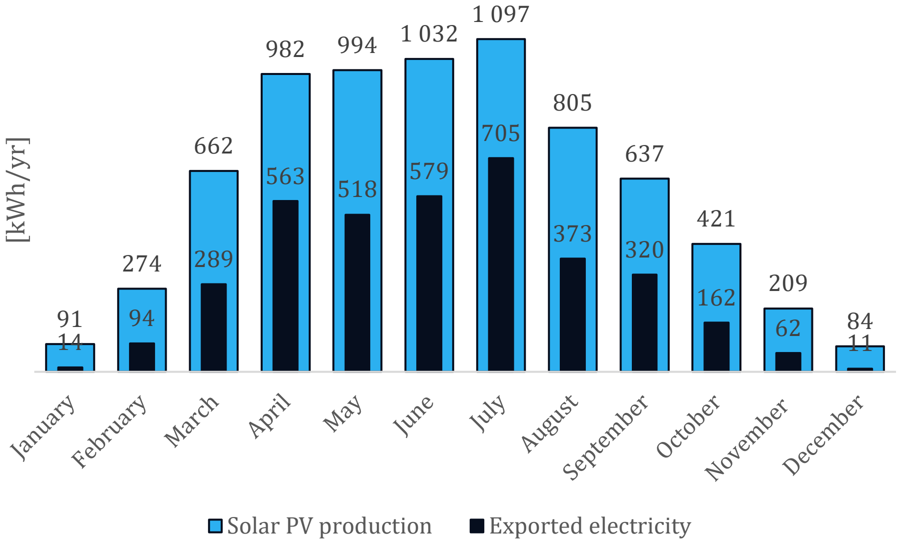


Figure 18. Solar PV production and exported electricity based on simulation Case 2 with solar PV and without battery storage.

4.1.3 Energy balance

The energy balance for the nine simulation cases can be seen in Figure 19 and include facility and tenant demand. The energy demand for the reference building is approximately 5 850 kWh for facility heating and hot water, and approximately 7 800 kWh for tenant electricity consumption for equipment and lighting. The solar PV production is approximately 7 300 kWh/yr, as stated in Chapter 4.1.1.

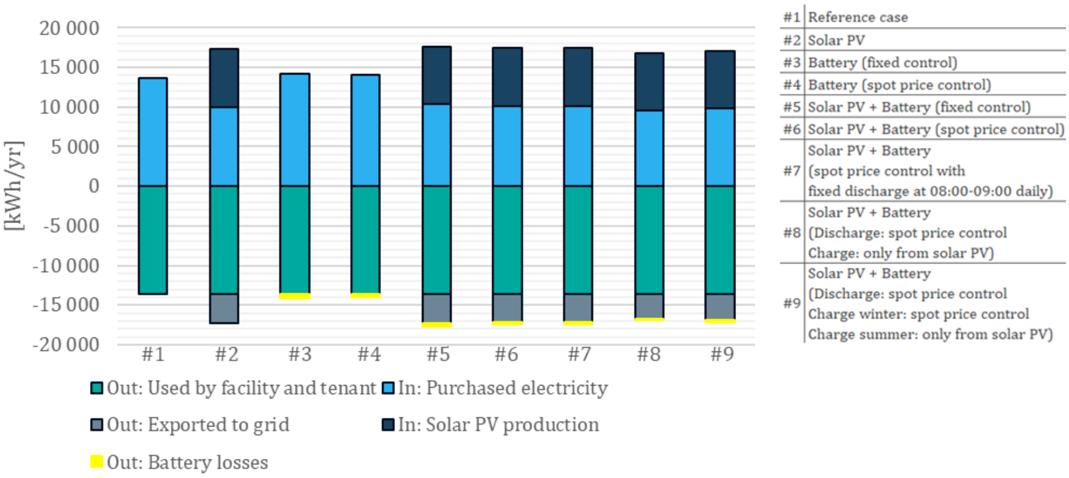


Figure 19. Electrical energy balance for facility and tenant consumption.

In the reference case, the purchased electricity matches the total demand. In Case 2, purchased electricity decreases due to solar PV production, with 50% being exported. Conversely, purchased electricity increases in Cases 3 and 4 due to battery losses. Cases

5 to 9 illustrate a combination of solar PV production, battery losses, and electricity exported to the grid.

4.1.4 Tenant electricity

The tenant electricity demand for equipment and lighting in Förlanda was 7 793 kWh/yr. Figure 20 depicts the total tenant demand and the share bought from the electricity grid. Simulation Cases 2 and 3 reveal energy discharged from the battery utilized by tenants, resulting in reduced electricity purchased from the grid. In Case 2 and Cases 5 to 9, the impact of solar PV in combination with the battery is evident, leading to a decrease in purchased electricity from the grid by approximately 2 000 to 2 600 kWh/yr.

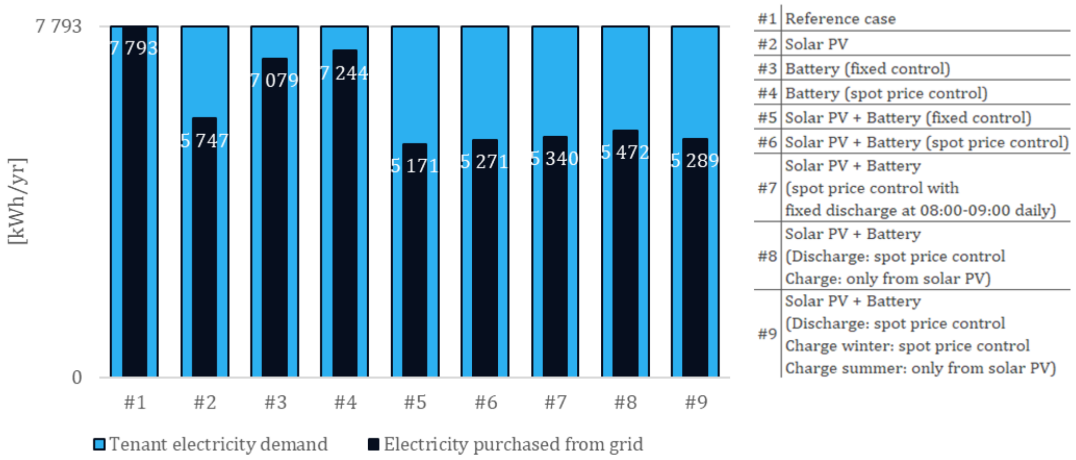


Figure 20. Tenant electricity demand and share purchased from electricity grid.

In Figure 21, the share of tenant electricity purchased from the facility company, or the electricity grid can be seen. The solar PV reduce purchased electricity from grid by approximately 26% in simulation Case 2. In Cases 5 to 9, featuring solar PV and battery, the electricity purchased from grid is reduced by approximately 30% to 34%.

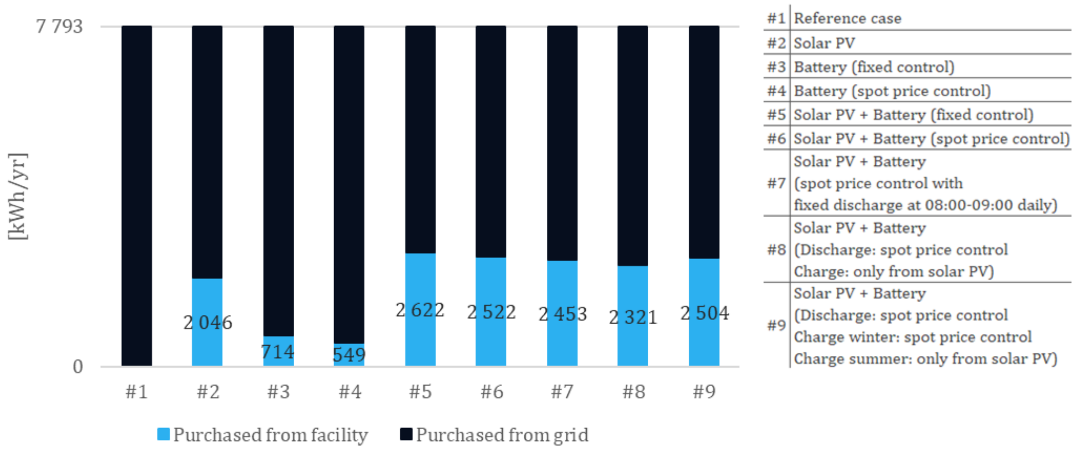


Figure 21. Distribution of tenant electricity bought from the facility and electricity grid.

4.2 Economic assessment

In this chapter, an economic assessment is conducted for simulation Cases 1 to 9. The assessment considers two cost perspectives: firstly, that of the facility company, and secondly, that of a private homeowner. Each perspective includes results for variable costs, equivalent annual cost, and payback period methods.

4.2.1 Facility company cost perspective

The facility company perspective excludes tenant electricity, such as electricity used for equipment and lighting. The distribution company Ellevio charges facility companies a peak power demand tariff. Electricity purchased by tenants from solar PV production or battery discharge is priced the same as electricity sold to the grid.

4.2.1.1 Variable costs

The annual variable cost of electricity serves as the basis for calculating the EAC and PBP. These variable costs were determined based on hourly electricity consumption, spot prices, and fees charged by distribution and trading companies. In Figure 22, the total annual variable costs and a summary of the monthly peak power demand tariffs are presented from the perspective of a facility company. In simulation cases where the total cost exceeds the power tariff, the difference between them accounts for additional electricity fees such as energy tax, company markups, and the cost of electricity certificates. Conversely, in Cases 5, 6, 7, and 9, the power tariff exceeds the total cost. This net cost reduction is attributed to earnings from sold electricity, which surpasses the additional electricity costs. It is important to note that the power tariff includes both facility and tenant electricity peak demand.

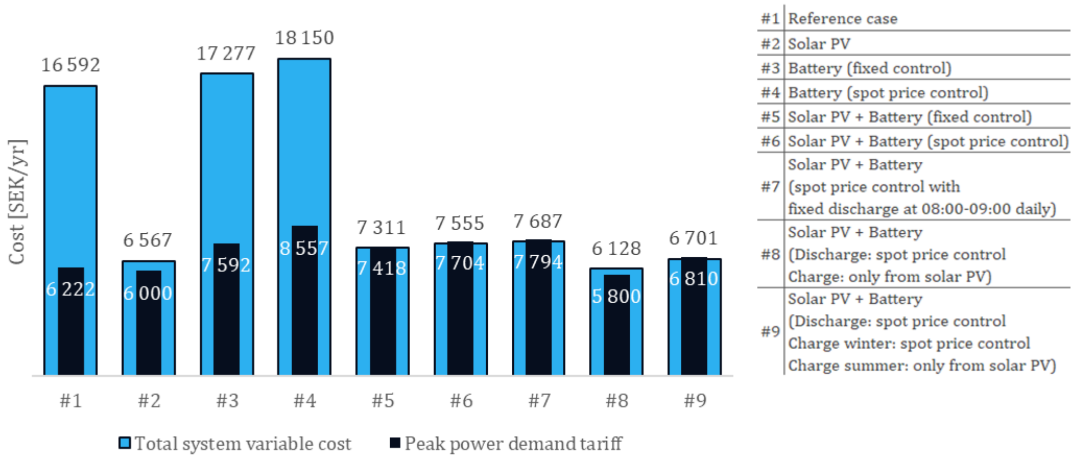


Figure 22. Annual variable cost and peak power demand tariff (value in white) for each case from a facility company perspective.

It is evident that installing the 6.5 kWh battery without solar PV (Cases 3 and 4) increases the cost of purchased electricity. The annual savings for these cases can be observed in Figure 23, derived by comparing costs to the reference case. The two highest savings are observed in Cases 2 and 8. In Case 8, the battery control strategy utilizes solar PV over-production and does not charge the battery by purchasing electricity from the grid.

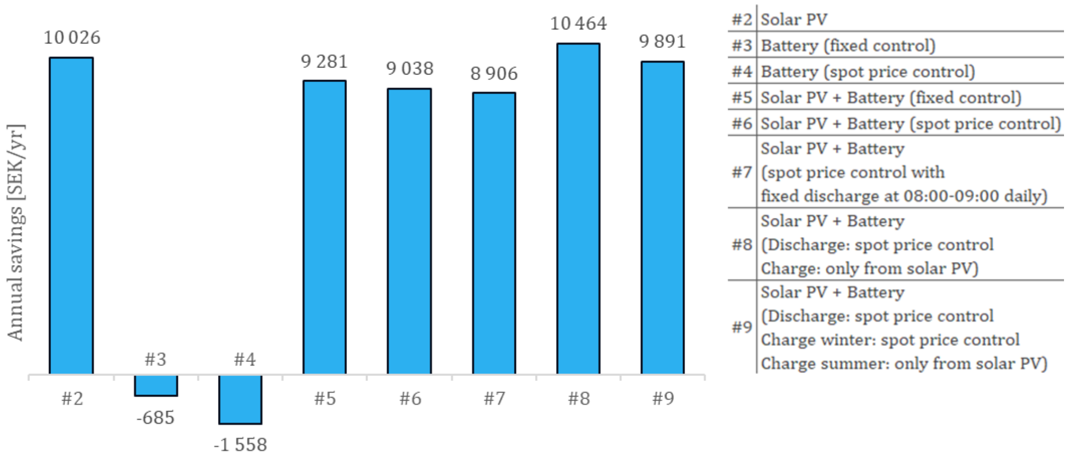


Figure 23. Annual savings for Cases 2 to 9 compared to the reference case.

The primary factor contributing to the increased cost in Cases 3 and 4 compared to the reference case is the higher peak power demand tariff. This tariff decreases in Case 2, where only solar PV is utilized, and in Case 8, where both solar PV and a battery are used, with the battery's charging limited to solar PV over-production.

However, the use of the battery increased the cost of the peak power demand tariff. This increase in the power tariff could be attributed to the discrepancy between peak power demand and the hours when the battery charges, which typically occur during periods of lower power demand. To achieve a reduction in peak power demand, the charging power of the battery should be less than the discrepancy between peak demand hours and charging hours. If not, the consequence, as shown in the figure, is an increase in the power tariff due to new monthly peak hours resulting from the battery charging, which adds to the power demand of the building. The charging power of the battery is approximately 2.2 kW. Figure 24 displays the peak power demand for simulation Cases 1, 3, and 4.

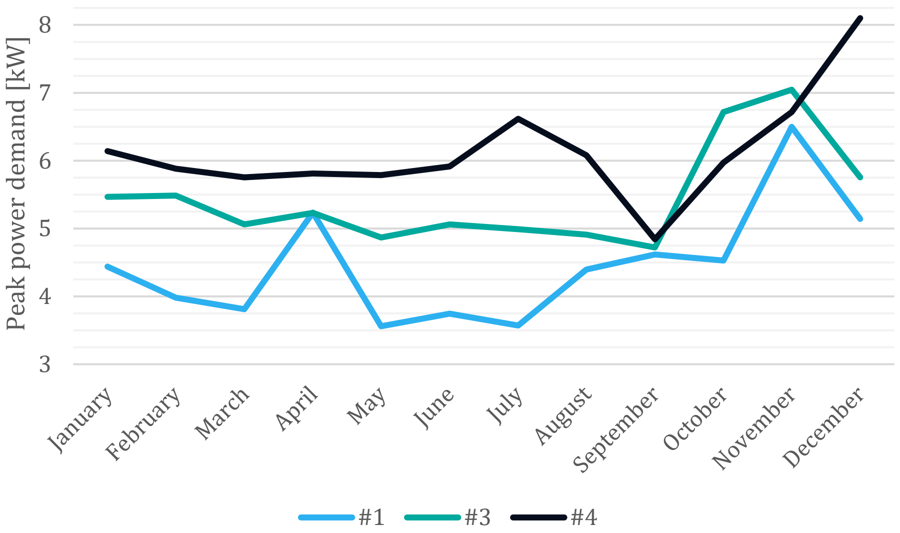


Figure 24. Comparison of monthly peak power demand for Cases 1, 3 and 4.

4.2.1.2 Equivalent annual cost & payback period

The annual variable cost of electricity, including sold and purchased electricity from the grid and the monthly peak power demand tariff, combined with the fixed cost of electricity for each simulation case, was used for the EAC method. The reference case, a building without solar PV or a battery, had an equivalent annual cost of 25 485 SEK/yr. The marginal EAC of simulation Cases 2 to 9, compared to the reference case, is shown in Figure 25. A negative marginal EAC represents annual savings, while a positive marginal EAC indicates an increase in annual cost, signifying an economic loss.

Case 2, with solar PV, reduced the EAC by approximately 2 900 SEK annually. However, the results for Cases 3 to 9 show an increase in the EAC, indicating that investing in a battery, with or without solar PV, would not reduce annual costs. Consequently, the facility company would not achieve any savings to offset the investment costs. Therefore, the only investment that is profitable based on the EAC method is Case 2, i.e., solar PV without a battery from the cost perspective of a facility company.

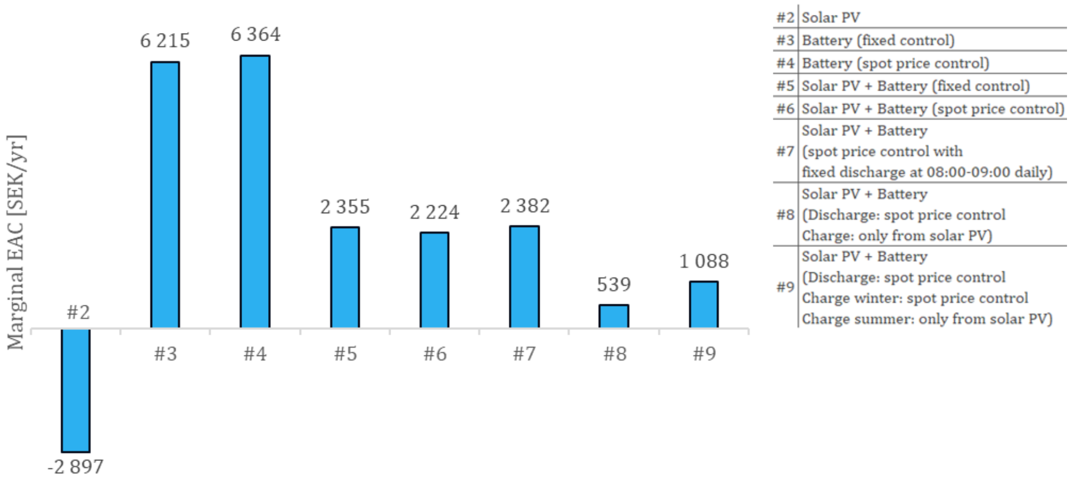


Figure 25. Marginal EAC for Cases 2 to 9 from a facility company cost perspective.

The results for total EAC, marginal EAC, and payback period are summarized in Table 9. The reference case has no payback period since it does not involve any system investment. Cases 3 and 4 show increased annual costs, meaning no savings, so the PBP method does not provide a payback period for these cases.

Cases 2 and 5 to 9 have annual savings calculated without a discount rate and energy price growth rate, so they are not directly comparable to the marginal EAC. The payback period for Case 2 (solar PV) is 13.1 years, which is less than the expected lifespan of 25 years for the solar PV system.

Cases 5 to 9 have varied lifespans: Case 5 has the lowest battery lifespan of 17 years (see Table 8 in Chapter 4.1.1), while Cases 6, 7, and 9 have battery lifespans of 21 – 22 years. Case 8 has a battery lifespan of 38 years due to a low number of cycles per year. However, payback periods of more than 17 years are not considered profitable investments, especially when the discount rate is not considered. Combined with the marginal EAC results, the solar PV and battery systems are not economically justified. In contrast, only the solar PV system (Case 2) is economically justified.

Table 9. Summary of total EAC, marginal EAC and PBP results from a facility company cost perspective.

Case	#1	#2	#3	#4	#5	#6	#7	#8	#9
EAC_{Total} [SEK/yr]	25 485	22 587	31 700	31 848	27 840	27 708	27 867	26 024	26 573
$EAC_{Marginal}$ [SEK/yr]	Ref.	-2 897	6 215	6 364	2 355	2 224	2 382	539	1 088
PBP [yrs]	-----	13.1	X	X	19.5	20.0	20.3	17.3	18.3

4.2.2 Private homeowner cost perspective

The private homeowner perspective includes all electricity used in the building. Unlike facility companies, private homeowners are not charged by the distribution company Ellevio for the peak power demand tariff. Additionally, private homeowners are eligible for subsidies for solar PV and/or battery storage investments, which is a significant advantage compared to the facility company cost perspective.

4.2.2.1 Variable costs

From the perspective of a private homeowner, the results of the total annual variable costs are presented in Figure 26. Total costs are reduced in all simulation cases compared to the reference case, which stands at 23 972 SEK/yr. However, the yearly cost reductions in Cases 3 and 4 using only battery ranges between 155 and 420 SEK/yr. Therefore, the primary savings in Cases 5 to 9 are attributed to solar PV. The variation in total costs for Cases 5 to 9 depends on the battery control strategy and does not deviate more than 272 SEK/yr between the lowest cost (Case 9) and the highest cost (Case 5), though this doesn't consider battery cycles. As a private homeowner, there is no peak power demand tariff.

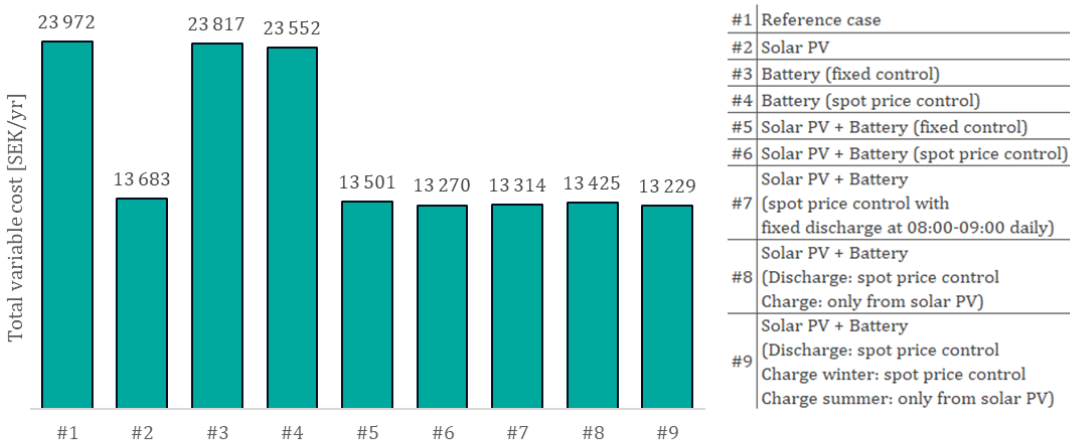


Figure 26. Total annual variable cost from a private homeowner cost perspective.

The savings, compared to the reference case, are illustrated in Figure 27. Savings for Case 2 and Cases 5 to 9 range between approximately 10 300 and 10 700 SEK/yr. However, variable cost savings for Cases 3 and 4, battery without solar PV, amount to 155 and 420 SEK/yr, respectively. Comparing battery control strategies, Case 4 with *spot price* control saves more annually compared to Case 3 with *fixed* control, attributed to a more optimized arbitrage strategy.

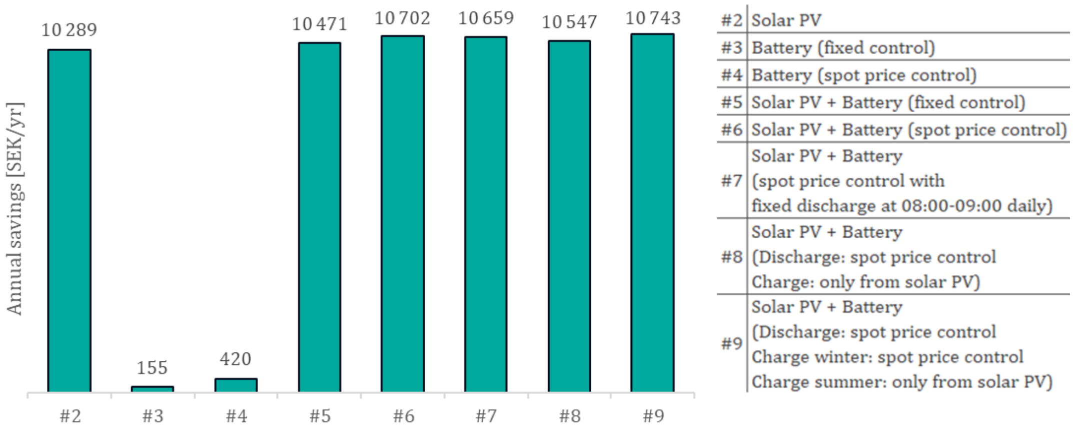


Figure 27. Annual savings for Cases 2 to 9 compared to reference case from a private homeowner cost perspective.

4.2.2.2 Equivalent annual cost & payback period

The economic assessment of solar PV and/or battery storage investments differs significantly between private homeowners and facility companies. The fixed cost for a private homeowner is higher compared to the facility company. To the distribution company Ellevio, the fixed cost is 10 320 SEK/yr for the private homeowners and 3 900 SEK/yr for facility companies. However, private homeowners are not charged for peak power demand tariffs. Additionally, private homeowners have a fixed cost of 420 SEK/yr to Mälarenergi, the electricity trading company, while facility companies do not incur this cost. Importantly, private homeowners are eligible for subsidies on solar PV and/or battery storage investments, while facility companies are not.

The reference EAC for private homeowners was 43 169 SEK/yr. Figure 28 shows the marginal EAC for simulation Cases 2 to 9. Notably, all cases with solar PV (with or without battery storage) reduce the annual cost. This contrasts with the facility company perspective shown in Figure 25, where only solar PV (Case 2) is economically justified.

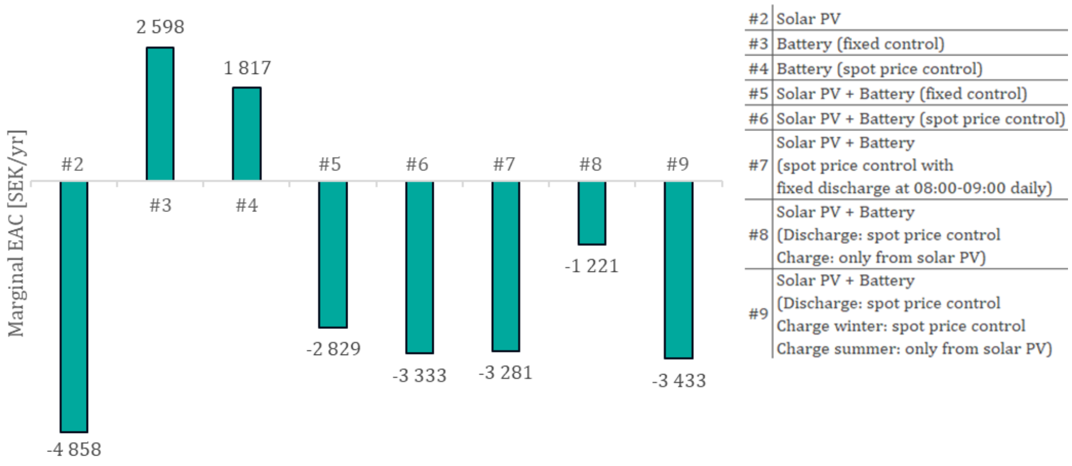


Figure 28. Marginal EAC for Cases 2 to 9 from a private homeowner cost perspective.

Two key reasons make battery storage investments more viable for private homeowners than a facility company:

i. Subsidies reduce 48.5% of the battery investment cost.
ii. Electricity used for domestic purposes is valued higher compared to when a facility company sells discharged battery electricity to tenants.

This is evident in Case 8 (battery charging only from solar PV over-production), which shows a noticeable difference between private homeowner and facility company perspectives. Case 8, with the least number of battery cycles, demonstrates that less battery utilization increases annual costs for private homeowners due to underutilized investment. Conversely, for facility companies, selling electricity to tenants is less profitable, and higher battery utilization increases costs. Therefore, Case 8 results in less cost increase for facility companies.

Figure 28 also shows that Cases 3 and 4, which only use battery storage, would increase annual costs. Additionally, the savings from the solar PV system alone (Case 2) at approximately 4 900 SEK/yr are reduced when coupled with battery storage (Cases 5 to 9).

In summary, Figure 28 indicates that while battery storage coupled with solar PV can reduce annual costs for a private homeowner cost perspective, investing solely in a solar PV system is most justified as it maximizes cost reduction.

Finally, the PBP is lowest at 10.6 years for Case 2 with only solar PV. Coupling solar PV with a battery (Cases 5 to 9) increases the PBP to 12.5 – 12.8 years, as shown in Table 10. Investing in a battery without solar PV (Cases 3 and 4) results in a PBP that exceeds the battery's lifespan. The PBPs for Cases 5 to 9, relative to their specific battery lifespans, are lower and therefore, according to the PBP method, are economically justified. However, the PBP method is a simplified economic assessment tool and should only be used as an initial assessment or in combination with methods like the EAC.

Table 10. Summary of total EAC, marginal EAC and PBP results from a private homeowner cost perspective.

Case	#1	#2	#3	#4	#5	#6	#7	#8	#9
EAC_{Total} [SEK/yr]	43 169	38 311	45 768	44 987	40 341	39 836	39 888	41 949	39 737
$EAC_{Marginal}$ [SEK/yr]	Ref.	-4 858	2 598	1 817	-2 829	-3 333	-3 281	-1 221	-3 433
PBP [yrs]	-----	10.6	164.1	60.6	12.8	12.5	12.6	12.7	12.5

4.3 Sensitivity analysis

In the sub-chapter the sensitivity analyses: *different yearly spot prices* and *arbitrage difference* are presented and their effect on yearly system variable costs are examined.

4.3.1 Different yearly spot prices

This sensitivity analysis examines the economic implications for Cases 1, 2, and 6 when using different historical spot prices from 2020 to 2023. A comparison of the average hourly prices for the four years can be found in Figure 8 in Chapter 3.1.4.1. Cases 1 (reference) and 2 (only solar PV) do not include a battery and therefore did not need to be re-simulated in IDA ICE. The economic re-assessment for these cases using different historical spot prices only affected the financial outcome and not the amount of sold or purchased electricity.

For Case 6, which includes solar PV and a battery with *spot price* control, the control signals to the battery change based on the historical spot prices used. The battery is still intended to be charged during the three lowest-priced hours and discharged during the three highest-priced hours each day, but the specific timing of these hours can vary with different historical spot prices. Additionally, historical spot prices can affect whether battery discharge control signals coincide with high electricity demand or if low SOC levels coincide with solar PV over-production.

Table 11 shows the number of cycles per year, annual capacity fade, and battery lifespan for Case 6 with four different historical spot prices as input for battery control signals. The simulation results indicate that battery utilization does not differ significantly based on the historical spot prices used. The number of cycles with the *spot price* control strategy is around 190 cycles per year, corresponding to a lifespan of 21 – 22 years. The battery capacity fade is approximately 3.1% per year.

Chapters 4.3.1.1 and 4.3.1.2 detail the economic impact of using different historical spot prices to calculate annual variable cost, EAC, and PBP for the two cost perspectives: facility company and private homeowner.

Table 11. Summary of battery simulation results for Case 6, simulated with different yearly spot prices.

Spot price year	2020	2021	2022	2023
Cycles per year	187	180	189	194
Capacity fade	3.1%	3.1%	3.1%	3.1%
Lifespan [yrs]	21	22	21	21

4.3.1.1 Facility company cost perspective

The annual variable costs from the cost perspective of a facility company for Case 6, using four different historical spot prices, are illustrated in Figure 29. The results indicate a significant cost reduction when using spot prices from 2022, which were record high. Despite the high spot prices in 2022, the annual variable cost of electricity was the lowest compared to prices from 2020, 2021, and 2023. The facility company profits overall when spot prices are high, even though the cost of purchased electricity is also higher. This is due to the increased profit from selling electricity to the grid and tenants. The peak power demand tariff is less affected by different years' spot prices, likely because battery charging at low spot prices coincides with high tenant electricity consumption.

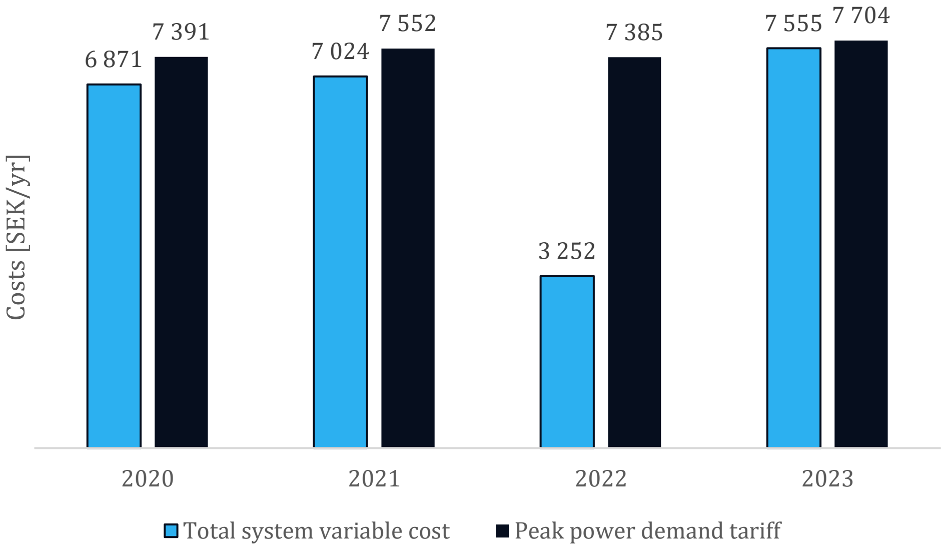


Figure 29. Total annual variable cost and peak power demand tariff for Case 6 based on different years spot prices (2020 – 2023) from a facility company cost perspective.

In Figure 30, the total EAC for Cases 1, 2, and 6 is presented. The results indicate that the reference building (Case 1) does not benefit from higher spot prices. For instance, in 2022, costs increased by approximately 50% compared to the lowest cost year, 2020. However, buildings equipped with solar PV (Case 2 and Case 6) benefit from higher spot prices. In Case 2, the lowest annual cost was recorded in 2022, a year with record-high spot prices, due to increased earnings from selling electricity. Similarly, this trend is observed in Case 6.

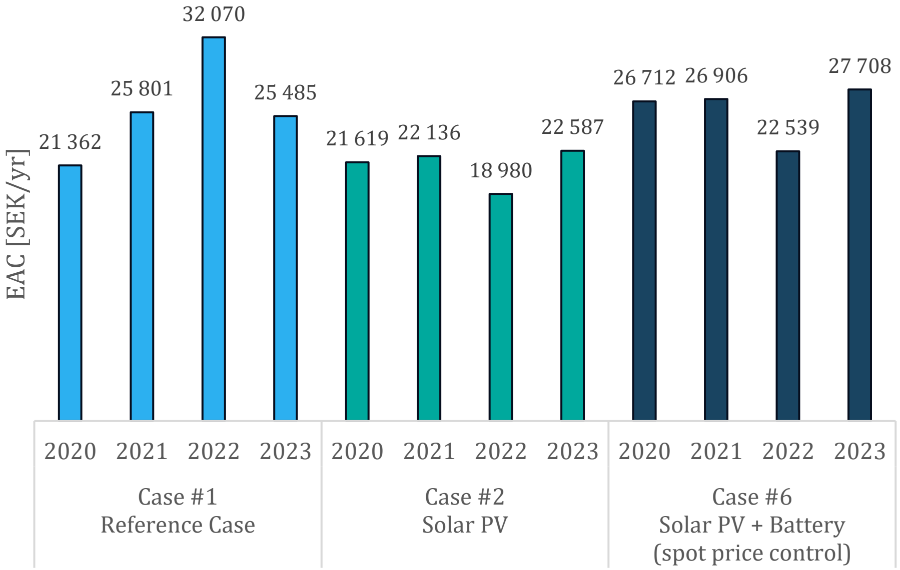


Figure 30. EAC results for Cases 1, 2 and 6 using spot prices from 2020 – 2023 from a facility company cost perspective.

When evaluating the investment using the PBP method, the results indicate that higher spot prices are beneficial as they reduce the PBP, as seen in Table 12. For instance, with spot prices based on 2022, the PBP for investing in solar PV alone (Case 2) is 7.2 years. However, when coupling the solar PV with a battery (Case 6), the PBP increases to 9.7 years. During 2020, which featured the lowest average spot prices, the PBP for the solar PV system in Case 2 was 17.7 years. The PBP for Case 2 varies from 7.2 to 17.7 years, while for Case 6, it varies from 9.7 to 28.3 years. The sensitivity analysis shows that different historical spot prices significantly impact the outcome.

Table 12. PBP results for Cases 2 and 6 based on spot prices from 2020 – 2023 from a facility company cost perspective.

Spot price year	2020	2021	2022	2023
PBP Case #2 [yrs]	17.7	12.4	7.2	13.1
PBP Case #6 [yrs]	28.3	18.4	9.7	20.0

4.3.1.2 Private homeowner cost perspective

From the perspective of a private homeowner, variable costs were highest when using spot prices from 2022, as illustrated in Figure 30. This contrasts with the cost perspective of a facility company, which benefited from higher spot prices, such as those in 2022. The facility company, which purchases less electricity and sells approximately 30% of solar PV production to the tenants and 50% to the grid, is less affected by higher prices. This is because the higher spot prices are offset by increased earnings when electricity is exported to the grid or sold to tenants during high-priced hours. In contrast, the private homeowner bears the cost of domestic electricity, for equipment and lighting, in addition to the costs the facility company incurs. This additional expense diminishes the positive economic impact of selling electricity during periods of higher spot prices.

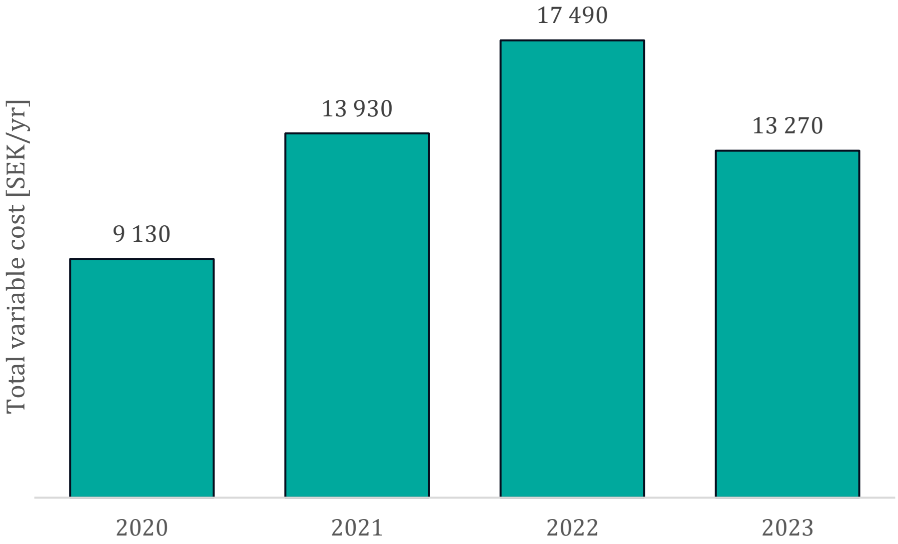


Figure 31. Total annual variable cost for Case 6 based on different years spot prices (2020 – 2023) from a private homeowner cost perspective.

In Figure 32, the total EAC for Cases 1, 2, and 6 is presented. Unlike the facility company's cost perspective, these results indicate that the EAC follows the average spot price trends from 2020 to 2023, with 2022 being the highest, followed by 2021, 2023, and lastly 2020. However, as observed, the cost does not increase as significantly in Cases 2 and 6 compared to the reference case when spot prices are high, such as in 2022. The cost increased by approximately 75% in 2022 compared to 2020 for the reference case, whereas for Case 2, it increased by 38%, and for Case 6, it increased by 31%.

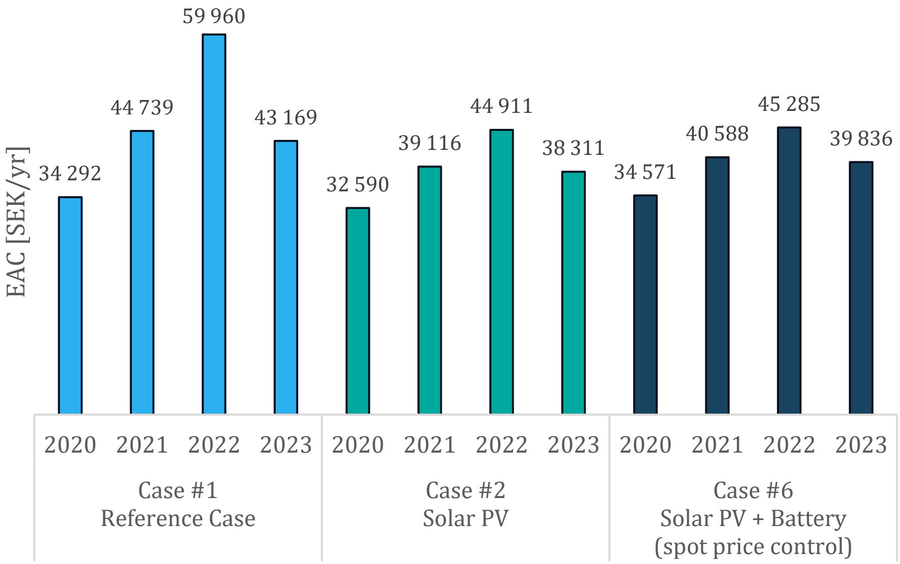


Figure 32. EAC results for Cases 1, 2 and 6 using spot prices from 2020 – 2023 from a private homeowner cost perspective.

The PBP, shown in Table 13, for Case 2 reveals an inverse relationship with the annual variable cost and EAC: the higher the yearly spot prices, the shorter the PBP. This is because the PBP method accounts for savings from the solar PV system, and higher spot prices increase earnings from solar PV, while the investment cost remains unchanged. A similar trend is observed for Case 6. As concluded in the preceding chapter, EAC and PBP results vary based on historical spot prices. The results from both EAC and PBP highlight the uncertainty of economic assessment due to the variance that can occur depending on which year's historical spot prices are used.

Table 13. PBP results for Cases 2 and 6 based on spot prices from 2020 – 2023 from a private homeowner cost perspective.

Spot price year	2020	2021	2022	2023
PBP Case #2 [yrs]	14.1	9.9	5.8	10.6
PBP Case #6 [yrs]	17.4	11.9	6.7	12.5

4.3.2 Minimum arbitrage criterion

The sensitivity analysis investigates the impact of incorporating a minimum arbitrage criterion on Case 6, which includes solar PV and a battery with *spot price* control. This analysis focuses on how the annual variable cost, EAC, and PBP are affected by this criterion, aiming to enhance profitability. The minimum arbitrage factor represents the difference between the three highest and lowest spot prices within a 24-hour period. The sensitivity analysis uses spot prices from the year 2023.

By including a minimum arbitrage factor, the battery avoids charging and discharging on days with low arbitrage values. This restriction aims to save the number of cycles and prolong the battery's lifespan by avoiding operations during days when low arbitrage values might result in financial losses due to battery inefficiencies.

The arbitrage factors used in this sensitivity analysis range from 1.0 to 4.0 in increments of 0.5, as shown in Table 14. The number of battery cycles per year decreases as the minimum arbitrage factor increases, reflecting fewer operational days.

Battery cycles range from 194 cycles per year when utilized daily (arbitrage factor of 1.0) to 82 cycles per year for an arbitrage factor of 4.0. This reduction in cycles saves more than 50% of the annual cycles, thereby extending the battery lifespan from 21 to 49 years, based on a total of 4 000 cycles. The capacity fade ranges from 3.1% to 2.9% per year.

The economic impact on annual variable cost, EAC and PBP of incorporating different arbitrage criterion are detailed in Chapters 4.3.2.1 and 4.3.2.2 for the two cost perspectives: facility company and private homeowner.

Table 14. Summary of battery simulation results for Case 6 with different minimum arbitrage factors.

Arbitrage factor	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Cycles per year	194	186	149	119	102	91	82
Capacity fade	3.1%	3.1%	2.9%	2.9%	2.9%	2.9%	3.0%
Lifespan [yrs]	21	22	27	34	39	44	49

4.3.2.1 Facility company cost perspective

In Figure 33, the total annual variable cost and peak power demand tariffs are shown from the cost perspective of a facility company. Notably, the annual cost is reduced the most when the battery control strategy includes an arbitrage factor of 2.5. This reduction amounts to 259 SEK/yr, decreasing from 7 555 to 7 296 SEK/yr.

The peak power demand tariff decreases with an increased arbitrage factor, likely due to battery charging at low spot prices coinciding with high tenant electricity consumption. A higher arbitrage factor implies less frequent battery usage, thereby reducing the likelihood of battery charging coinciding with higher off-peak demand hours.

The primary difference between the cases lies in the number of battery cycles used, as presented in Table 14. Intuitively, this demonstrates that the greater the difference between the highest and lowest spot prices, the less the battery is utilized. The results suggest that, based on 2023 spot prices, the number of cycles could be reduced from 194 to 82 by implementing a requirement that the three highest-priced hours for discharge are at least four times more expensive than the three lowest-priced hours for charging the battery (an arbitrage factor of 4.0). However, this outcome is specific to the 2023 spot prices, and using spot prices from different years would yield different results. Nonetheless, the analysis indicates that restricting daily battery usage may prolong its lifespan and enhance annual savings, particularly if daily price variations are not sufficiently large.

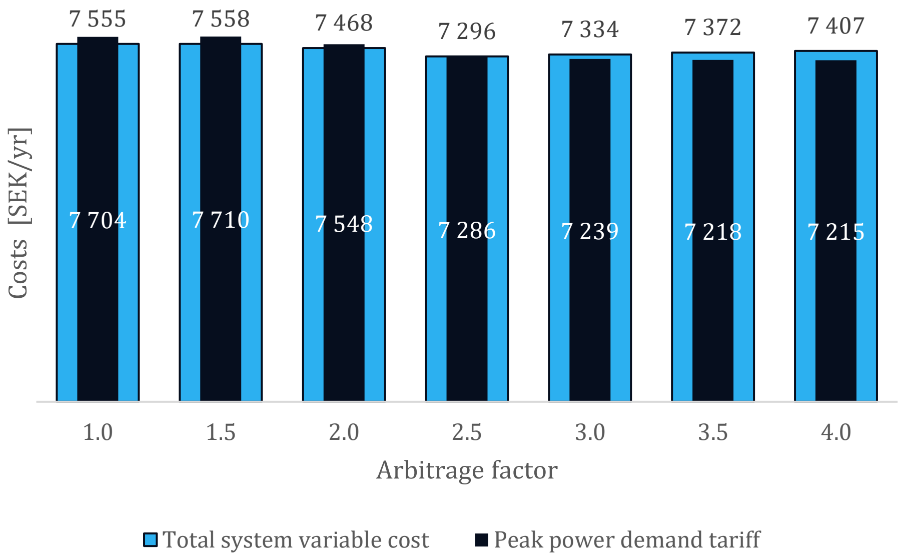


Figure 33. Annual variable cost and peak power demand tariff (values in white) for the inclusion of arbitrage factor for Case 6. From a facility company cost perspective.

The marginal EAC for simulation Case 6 with different arbitrage factors is shown in Figure 33, along with Case 2 (only solar PV) for comparison. The EAC values are relative to the reference building without solar PV or a battery, which had a total EAC of 25 485 SEK/yr as stated in Chapter 4.2.1.2.

Interestingly, while higher arbitrage factors of 2.0 or more decreased annual variable costs and reduced the number of battery cycles per year, the marginal EAC increased for some arbitrage factors. The arbitrage factor of 1.0, representing daily battery usage, decreases its marginal EAC from 2 224 to 1 846 SEK/yr when the factor increases to 2.0, the optimal arbitrage factor for 2023 spot prices. Despite this improvement, Case 6 remains economically unjustifiable, even with the inclusion of an arbitrage factor.

The increased marginal EAC for arbitrage factors 3.5 and 4.0 can be explained by the battery lifespans of 44 and 49 years, respectively. Longer lifespans prolong the earnings from the battery investment, and since the EAC method considers a discount rate of 5% and battery capacity fade, the EAC increases despite the slight reduction of annual variable cost with these higher arbitrage factors.

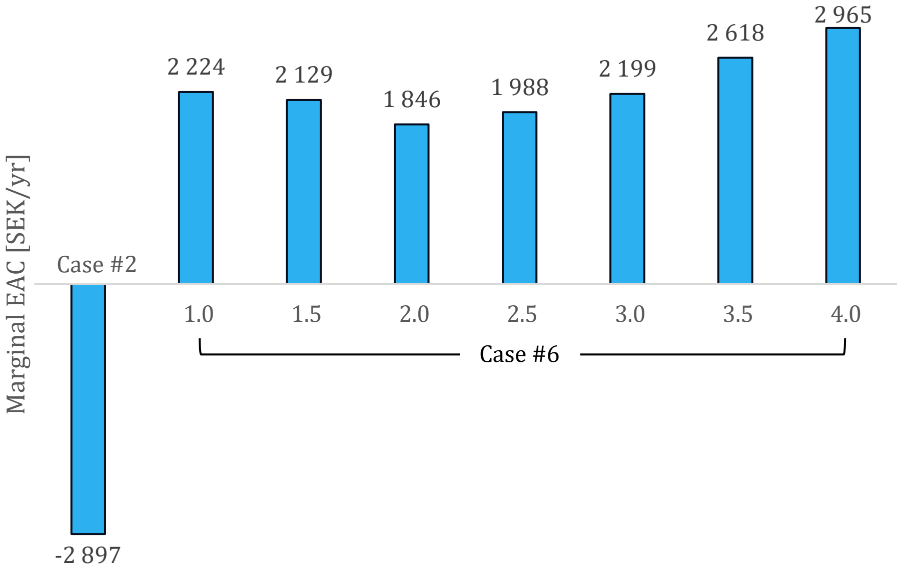


Figure 34. Marginal EAC for Cases 2 and 6, were Case 6 includes different arbitrage factors for battery control strategy from a facility company cost perspective.

Since the PBP method does not consider the discount rate, unlike the EAC method, the PBP improved with the inclusion of arbitrage factors. For the 2023 spot prices, the optimal arbitrage factor was 2.5 according to the PBP results, as shown in Table 15.

Table 15. PBP results for Cases 2 and 6, were Case 6 includes different arbitrage factors for battery control strategy from a facility company cost perspective.

Case	#2	#6	#6	#6	#6	#6	#6	#6
Arbitrage factor	-----	1.0	1.5	2.0	2.5	3.0	3.5	4.0
PBP [yrs]	13.1	20.0	20.0	19.8	19.5	19.6	19.6	19.7

4.3.2.2 Private homeowner cost perspective

From the perspective of a private homeowner, unlike the facility company perspective, annual variable costs decrease with higher arbitrage factors. This suggests that increased battery usage reduces yearly costs. Using arbitrage factors of 3.5 and 4.0 increases yearly costs by 110 and 134 SEK/yr, respectively, compared to Case 6 with an arbitrage factor of 1.0, as shown in Figure 35.

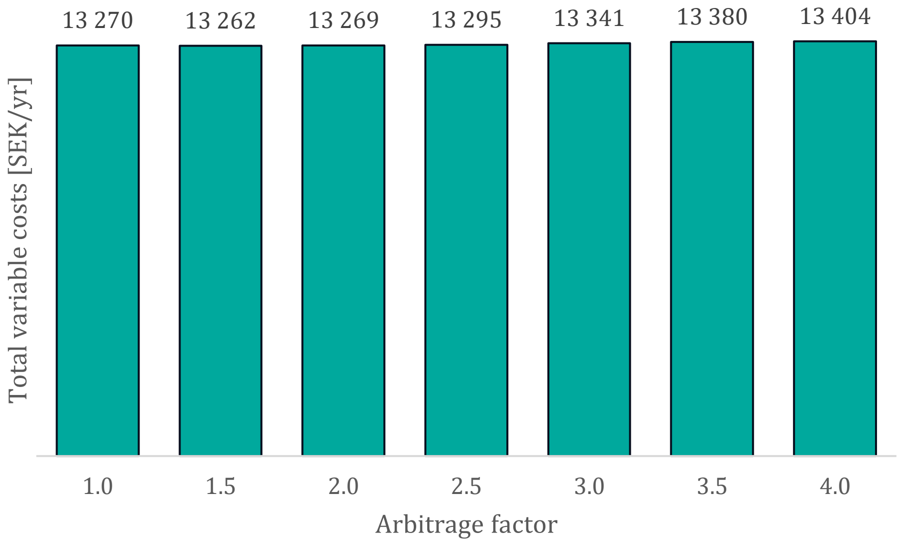


Figure 35. Total annual variable cost for the inclusion of arbitrage factor for Case 6. From a private homeowner cost perspective.

The marginal EAC for simulation Case 6 with different arbitrage factors is shown in Figure 35, along with Case 2 (only solar PV) for comparison. The EAC values are relative to the reference building without solar PV or a battery, which had a total EAC of 43 169 SEK/yr as stated in Chapter 4.2.2.2.

The only EAC higher than the reference building was Case 6 with an arbitrage factor of 4.0 as illustrated in Figure 36. Although the optimal arbitrage factor based on marginal EAC is 1.5, the differences between factors 1.0, 1.5, and 2.0 are not substantial. However, the figure also demonstrates that arbitrage factors from 2.5 to 4.0 significantly impact marginal EAC, indicating a trend where increasing the arbitrage factor also increases marginal EAC.

In contrast, all arbitrage factors from the facility company perspective resulted in EAC higher than that of the reference building. The effect of the subsidy is evident for private homeowners when comparing Figure 36 with Figure 34, which depict marginal EAC from the facility company perspective with different arbitrage factors. Private homeowners eligible for the subsidy have their solar PV and battery investment economically justified based on the EAC method, while the facility company does not.

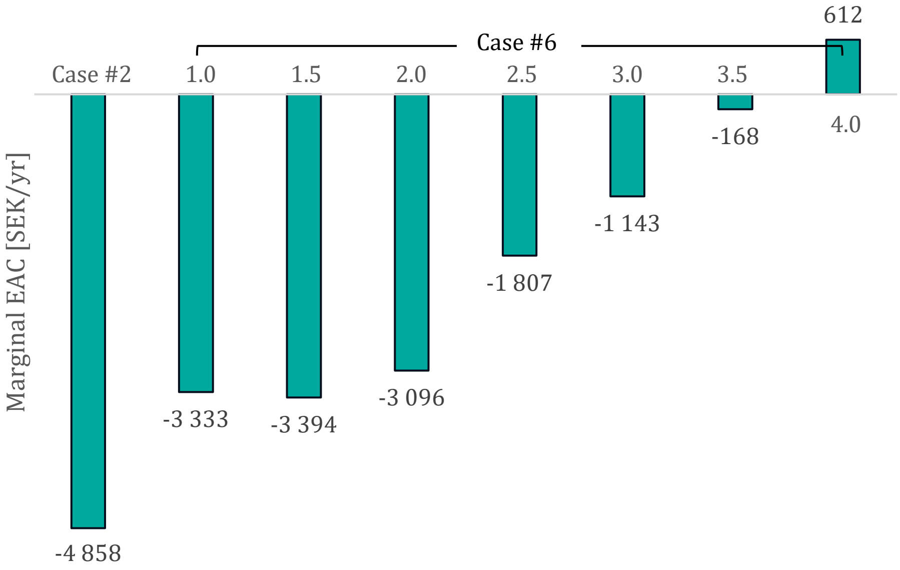


Figure 36. Marginal EAC for Cases 2 and 6, were Case 6 includes different arbitrage factors for battery control strategy. From a private homeowner cost perspective.

The effect of arbitrage factor on PBP is insignificant, varying from 12.5 years to 12.7 years, as can be seen in Table 16. The overall effect of the inclusion of an arbitrage factor is important for battery control strategies, as shown in this sensitivity analysis, for both a facility company and private homeowner cost perspective.

Table 16. PBP results for Cases 2 and 6, were Case 6 includes different arbitrage factors for battery control strategy from a private homeowner cost perspective.

Case	#2	#6	#6	#6	#6	#6	#6	#6
Arbitrage factor	-----	1.0	1.5	2.0	2.5	3.0	3.5	4.0
PBP [yrs]	10.6	12.5	12.5	12.5	12.6	12.6	12.7	12.7

5 Discussion

The thesis addressed four main questions. Below are the questions and summarized answers followed by a general discussion on results and limitations:

i. *What battery control strategies are preferred?*

Several battery control strategies were tested through simulations, consisting of two main battery control strategies, *fixed* and *spot price* control, as well as combination of these strategies or variations thereof. From the facility company perspective and based on EAC, the preferred strategy was Case 8, which used *spot price* control for battery discharge while charging was only from solar PV over-production. This was due to low facility electricity demand and the fact that part of the discharged energy was sold to tenants at the same price as electricity sold to the grid, which is less than the cost of purchased electricity. If a higher share of the battery energy had been used for facility electricity, such as powering fans or the heat pump, more savings could have been achieved. Combined with battery losses, this was not sufficient to cover the investment.

Conversely, from a private homeowner perspective based on EAC, the preferred strategy was Case 6 with a *spot price* control strategy. A more sophisticated battery control strategy should consider the next day's prices, planning charging and discharging accordingly, while simultaneously accounting for battery system losses and minimum spot price variation requirement (arbitrage factor).

ii. *Could spot price-controlled batteries be a profitable investment?*

Batteries for arbitrage could only be economically justified from a private homeowner cost perspective when coupled with solar PV and receiving subsidies for both system investments. However, a solar PV investment alone proved more profitable. A solar PV system without a battery (Case 2) had a decreased marginal EAC of approximately 4 850 SEK/yr, corresponding to annual savings due to the investment compared to the reference case. When coupled with a battery with *spot price* control (Case 6), the marginal EAC was decreased by approximately 3 350 SEK/yr. Although the coupled systems still generated annual savings, they were 1 500 SEK less each year due to the added battery.

For a facility company, not eligible for the subsidy, the investment cost of the battery could not be reimbursed by earnings from spot price arbitrage. The results might differ with a battery of different capacity better suited for the building's required facility electricity.

iii. *How does the integration of solar PV and batteries impact building energy demand and the overall profitability?*

The integration of solar PV reduces the building's energy demand by producing electricity used for facility and tenant electricity demand. Excess electricity is sold to the grid or stored for later use if coupled with a battery. Although a combined solar PV and battery system decreases the building's overall energy demand compared to the reference case, the battery itself increases the energy demand due to system losses, resulting in higher energy input than output.

iv. How does the integration affect building power demand?

The principle of load shifting aims to reduce demand during high-priced hours by discharging the battery, which is then compensated by charging during low-priced hours, flattening the power demand curve.

However, the integration of the battery unexpectedly increased peak power demand, leading to a rise in tariff costs. This outcome occurred because the battery typically charges during low-priced hours, which coincided with periods of higher electricity demand. Moreover, if the battery's power exceeds the difference between peak demand and demand during low-priced hours, it can inadvertently create a new peak, resulting in increased costs. Additionally, the charging power of the battery, approximately 2.2 kW in the simulation, contributed to this effect.

In summary, while shifting demand to low-priced hours for battery charging is intended to reduce costs, it unexpectedly led to an increase in peak power demand and tariff costs. This suggests that determining the battery power and C-rate should consider both the building's peak power demand and the demand during low-priced hours intended for battery charging.

Regarding the profitability of battery investments, the results indicate that arbitrage is not the optimal use of a battery. However, batteries can be used for ancillary services, which have recently been earning around 3 000 SEK/kW. For the 2.2 kW battery used in the simulation, this would amount to 6 600 SEK/year. In contrast, earnings from arbitrage were only 420 SEK/year for a battery with *spot price* control without solar PV, from a private homeowner cost perspective. The battery did not provide savings for the facility company, instead it increased costs. Therefore, ancillary services present a more attractive use for home batteries, although investments in batteries for ancillary services do not qualify for subsidies.

The highest calculated expected lifespan of the battery was 49 years for Case 6 with an arbitrage factor of 4.0, based on sensitivity analysis. However, this lifespan estimate is likely unrealistic for practical purposes. Investing in an expensive battery with high system losses and infrequent use is economically risky. The sensitivity analysis showed that the arbitrage factor, which prevents the battery from being used when the daily price spread is below a certain threshold, is crucial in increasing profitability while reducing the number of cycles used. Spot prices fluctuate over time, and if future price spreads are higher, batteries used for arbitrage could become more profitable.

Sensitivity analysis was conducted on the economic impact of different historical spot prices, highlighting its importance. However, further research could investigate how different battery parameters, such as varying DOD and C-rates, affect the outcomes. Overall, the battery model in IDA ICE proved to be well developed, as it included different voltage and current levels and accounted for capacity fade based on usage frequency.

Considering the limitations of the IDA ICE model compared to the actual building in Förlanda, the main difference lies in not modeling the entire heating system, which includes two 55 kW heat pumps with solar PVT that provide heat to ten nearby buildings. The model included measured tenant electricity and hot water consumption, but data for the heating system was unavailable. The effects of using standardized hot water and tenant electricity values were not considered. The tenant electricity consumption was on average 26.3 kWh/m²/year, similar to the standardized value of 30. However, the actual energy for hot water was half of the standardized value, which could have been an interesting comparison.

6 Conclusions

This thesis examined the economic potential of integrating a spot price-controlled battery in a multifamily residential building in Förlanda, Kungsbacka. The building was modeled using IDA ICE software for energy simulations. Various control strategies were tested to understand the interaction between electricity demand, battery control signals, and solar PV electricity production. The hourly energy demand from the simulation outputs was converted into costs based on hourly spot prices and electricity expenses to the distribution and trading companies. The nine simulation cases were economically assessed using the equivalent annual cost (EAC) method and, to some extent, the payback period (PBP) method. The economic assessment featured two cost perspectives: a facility company and a private homeowner eligible for subsidies.

The simulations included a 7.44 kW_p solar PV system and a 6.5 kWh battery with a C-rate of 0.33, corresponding to approximately 2.2 kW charging/discharging power. The investment cost of the solar PV system was approximately 119 000 SEK, reduced to 96 000 SEK including VAT with the subsidy. The battery investment cost was approximately 49 000 SEK without the subsidy and 25 000 SEK with it.

The results indicated that batteries for arbitrage were not profitable for facility companies. However, investing in solar PV without a battery was profitable from the facility company cost perspective. The solar PV system reduced EAC by 2 900 SEK/yr, while a standalone battery with *fixed* or *spot price* control increased EAC by approximately 6 300 SEK/yr. The coupled system, which combined the reduced EAC from solar PV and the increased EAC from the battery, resulted in an increased EAC ranging from 500 to 2 400 SEK/yr for Cases 5 to 9.

In contrast, for a private homeowner, the profitability of the solar PV system could offset the cost of the battery. The solar PV system alone reduced EAC by approximately 4 900 SEK/yr and had a PBP of 10.6 years. The standalone battery increased marginal EAC by 1 800 to 2 600 SEK/yr depending on the control strategy. The decreased EAC for the coupled system ranged from 1 200 to 3 400 SEK/yr. Therefore, the conclusion was that the solar PV system alone was the economically recommended investment.

The first sensitivity analysis showed that different historical spot prices significantly affected the results, especially considering the record-high prices in 2022. These high prices reduced the annual cost of electricity for the facility company but increased it for the private homeowner. The second sensitivity analysis revealed that implementing a minimum arbitrage price spread criterion could increase profitability and reduce the number of battery cycles per year.

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Appendices

A. Property overview

Figure 37. Overview of the property area in Förlanda, Kungsbacka.

B. Façade, section and floor plan drawings

Figure 38. Façade towards south.

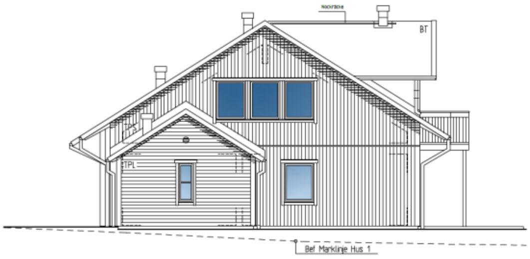


Figure 39. Façade towards west.

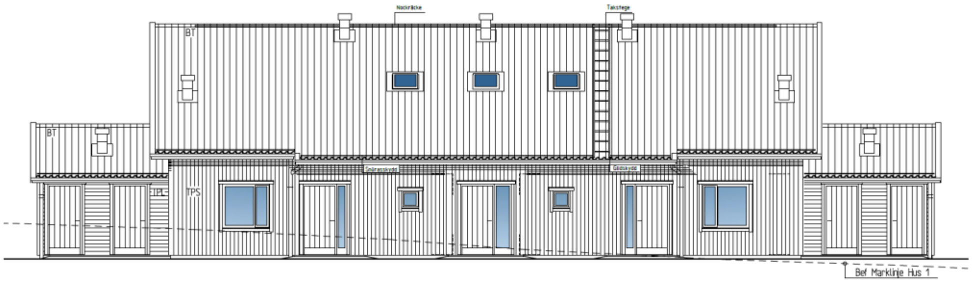
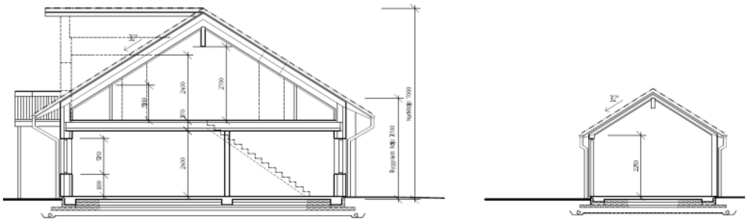


Figure 40. Façade towards north.

Figure 41. Façade towards east.


Sektion A - A

Sektion B - B

Figure 42. Section drawing of the building and garage.

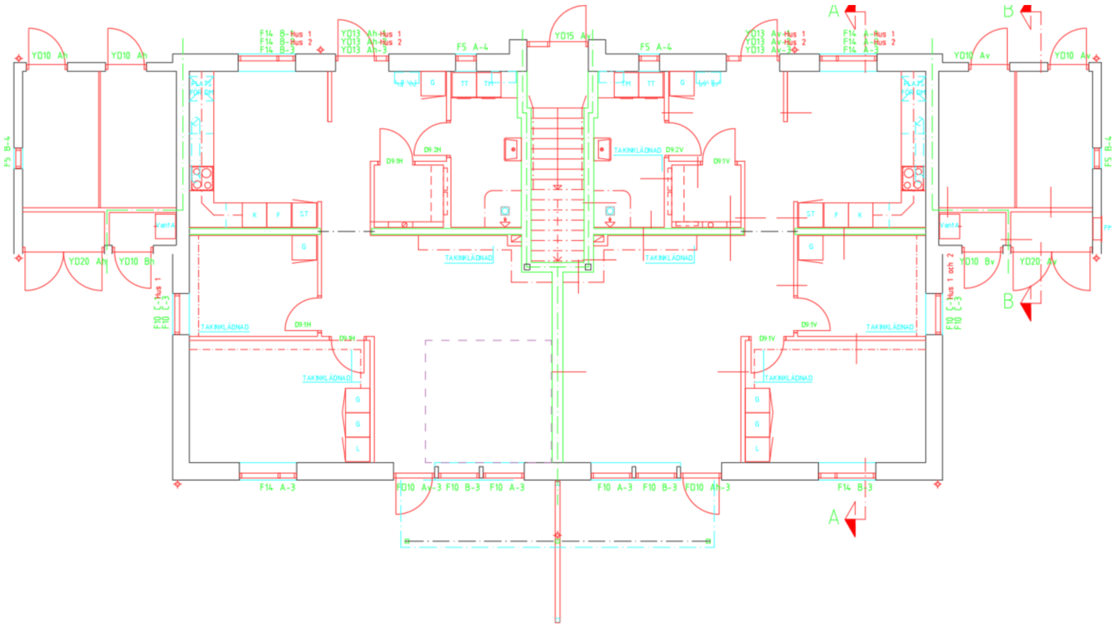


Figure 43. First floor plan.

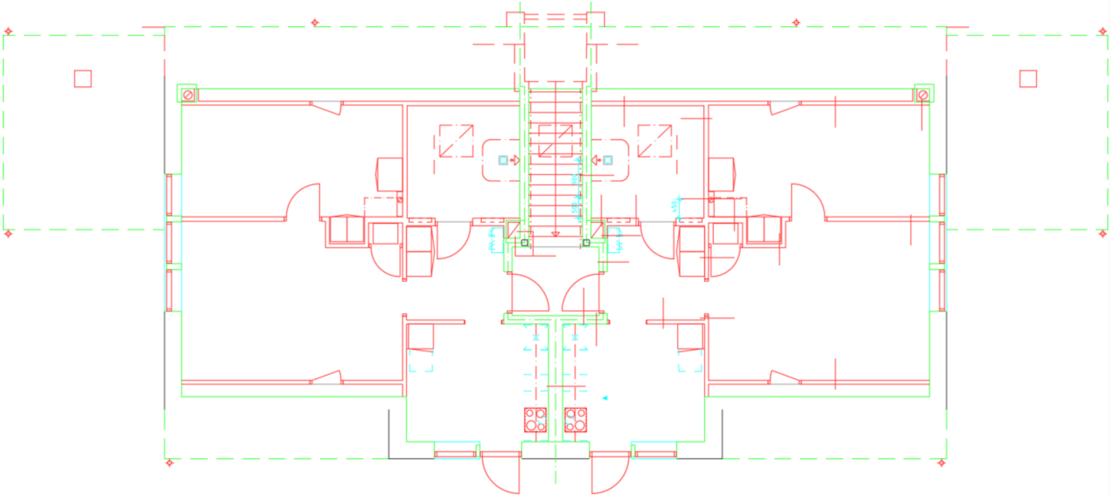


Figure 44. Second floor plan.

C. Energy system

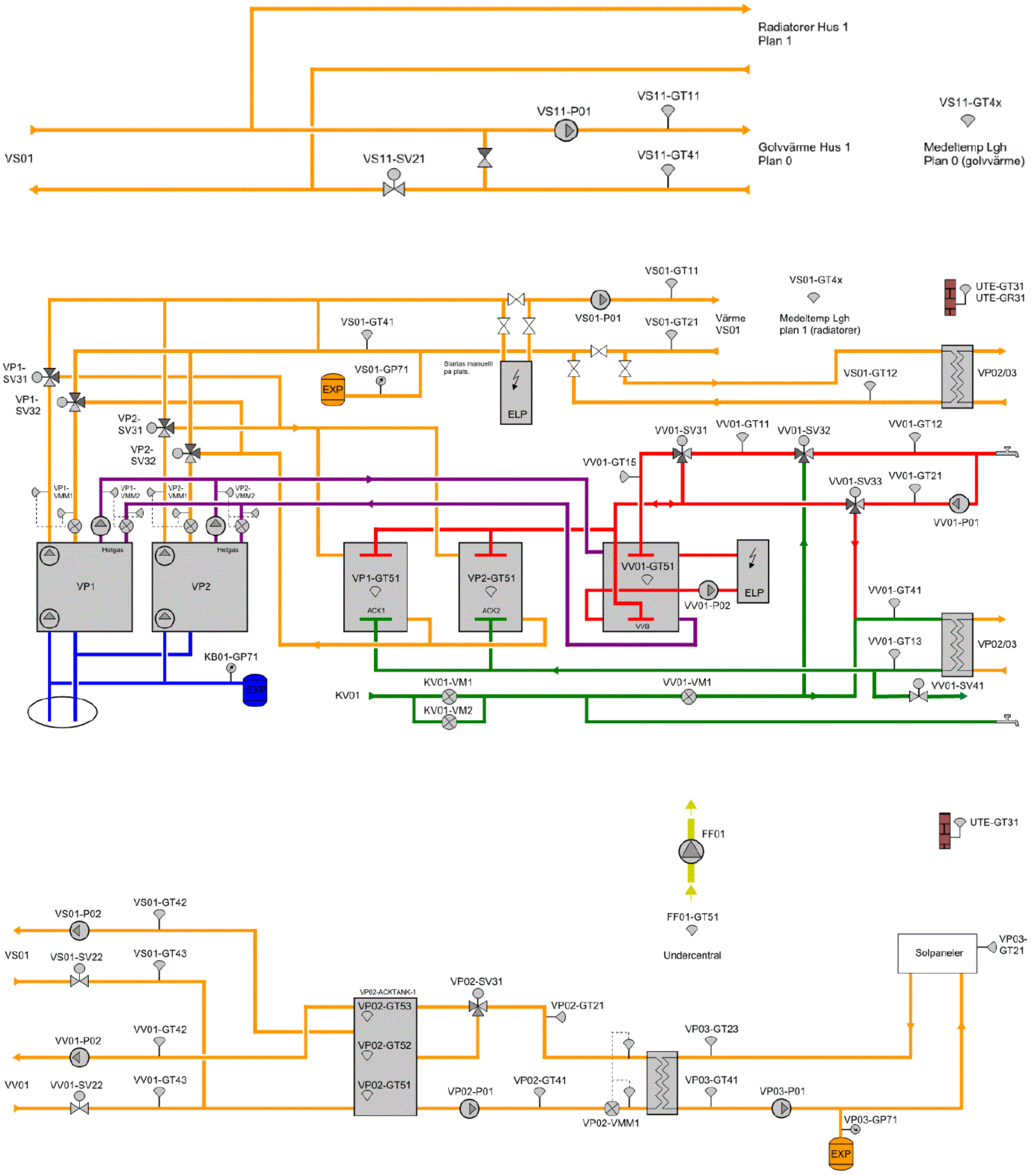


Figure 45. Overview of the heating energy system for the buildings in Förlanda.

D. Simulation input data

Table 17. Summary of simulation input data used in IDA ICE models.

Building properties	**Values**	**Notes**
General		
Climate file	Kungsbacka	
Location	Göteborg - Säve	
Number of thermal zones	26 in total. 1^{st} floor ap. = 5 zones ^{2st} floor ap. = 6 zones 4 Additional zones	See Appendix F. One thermal zone for each garage and two for the staircase/entrance.
Heated area above 10℃ [A_{temp}]	340 m^2 1^{st} floor ap. = 84 m^2 ^{2st} floor ap. = 81 m^2	Including the two storage areas in each of the two upper apartments due to non-insulated walls, i.e. heated above 10℃. Second floor apartment is 62 m^2, excluding the two storage areas of 7.5 and 11.5 m^2. The total heated area is including the staircase/entrance that is heated to 15℃ and excluding the two garages.
Heating		
Type	GSHP	Ground source heat pump
COP	4.3 [-]	Coefficient of performance
Water-based floor heating	2.95 kW	First floor apartments
Water-based radiators	2.9 kW	Staircase and second floor apartments
Energy losses	10%	Assumed system losses for the electricity heating system
Ventilation		
Type	FTX	Mechanical ventilation with heat recovery. Each apartment is equipped with its own ventilation system.
Ventilation principle	CAV	Constant air volume, 8760 h per year.
Ventilation rate	1^{st} floor ap. = 30 l/s ^{2st} floor ap. = 25 l/s	Supply and extract air
Efficiency	85%	According to manufacturer its 87.9% and 87.5%. Assumed 85% due to impact from air filters.
SFP	1.1 kW/(m^3/s)	Specific fan power according to manufacturer. Supply fan = 0.6 kW/(m^3/s) Exhaust fan = 0.5 kW/(m^3/s)
Windows		
G-value	51%	From construction/building documents
Light transmittance	74%	
U-value	0.9 W/m^2/K	

Frame to window ratios	Mixed	Based on CAD drawings
Construction (U-values)		
Building roof	0.076 $W/m^2/K$	From construction/building documents
Garage roof	0.142 $W/m^2/K$	
Building external walls	0.15 $W/m^2/K$	
Garage external walls	0.33 $W/m^2/K$	
Additional input		
No. of persons	1st floor ap. = 2.18	[68], [69]
	2nd floor ap. = 1.63	The occupancy schedules assumed can be seen in Figure 50 in Appendix H.
Hot water circulation losses	10 $kWh/m^2/yr$	Assumed
Tenant electricity	26.3 $kWh/m^2/yr$ 95% equipment 5% lighting	See Chapter 3.1.3.2
Indoor temperature	21°C	Setpoint value
Staircase temperature	15°C	Setpoint value
Infiltration (air leakage)	0.6 $l/s/m^2$ external surface	At 50 Pa pressure difference
External lights	60 W, 5 lamps, 12 W each	Assumed to be used between 05:00 to 09:00 from mid August to mid June. ~4800 hours/yr.
Thermal bridges	32.6 W/K	The setup in IDA ICE can be seen in Appendix E. Corresponding to 20% of total transmission losses.

E. Thermal bridges in IDA ICE model

Thermal bridges

External wall / internal slab	0.06	W/K/(m joint)*
External wall / internal wall	0.03	W/K/(m joint)*
External wall / external wall	0.03	W/K/(m joint)
External windows perimeter	0.07	W/K/(m perim)
External doors perimeter	0.07	W/K/(m perim)
Roof / external walls	0.06	W/K/(m joint)
External slab / external walls	0.12	W/K/(m joint)
Balcony floor / external walls	0.1	W/K/(m joint)
External floor towards amb. air/internal wall	0	W/K/(m joint)*
Roof / Internal walls	0	W/K/(m joint)*
External walls, inner corner	0	W/K/(m joint)
External slab / external walls, inner corner	0	W/K/(m joint)
Roof / external walls, inner corner	0	W/K/(m joint)
Total envelope (incl. roof and ground)	0	W/(K*m²envelope)

Figure 46. Thermal bridges settings in IDA ICE model.

F. Thermal zones in the apartments

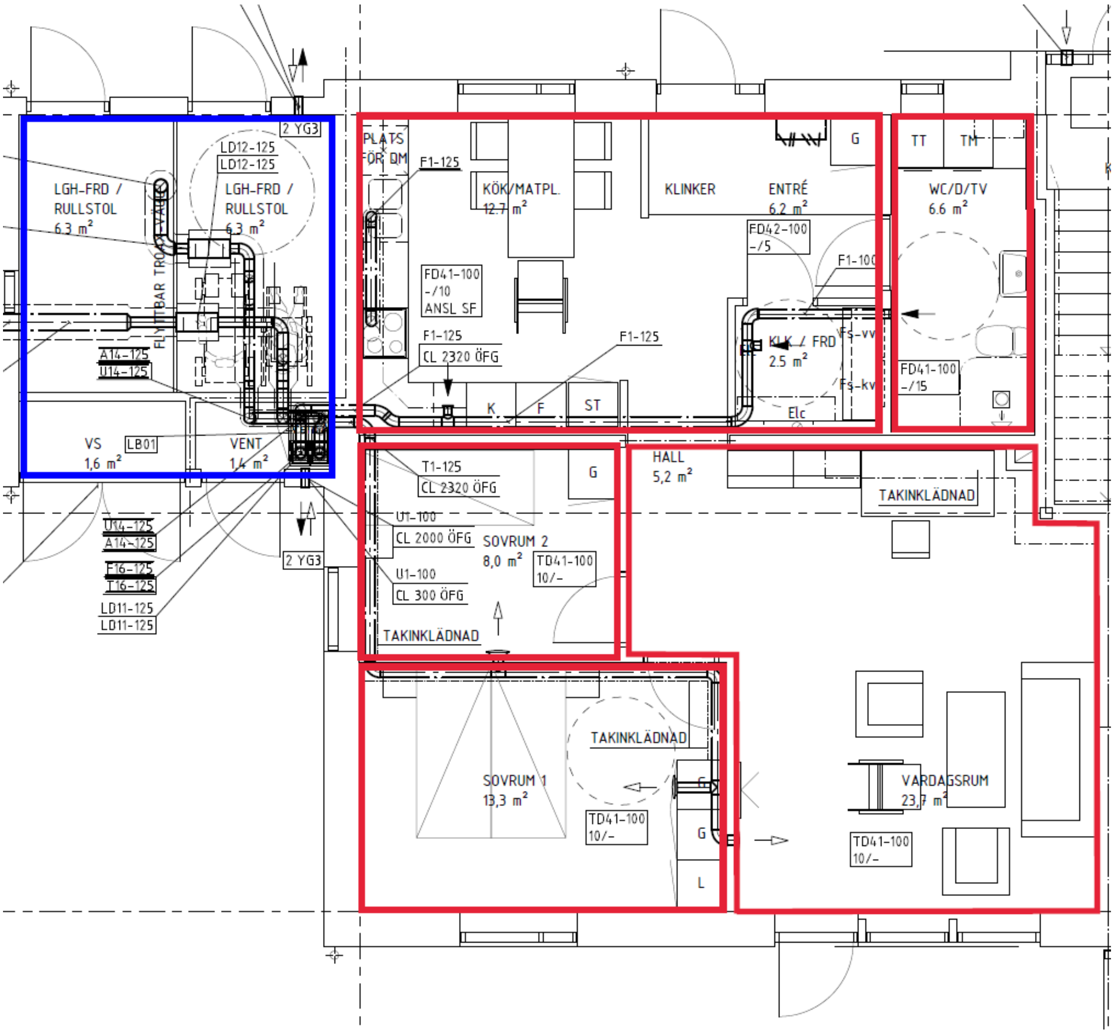


Figure 47. First floor apartment thermal zones (red) and thermal zone for the garage (blue).

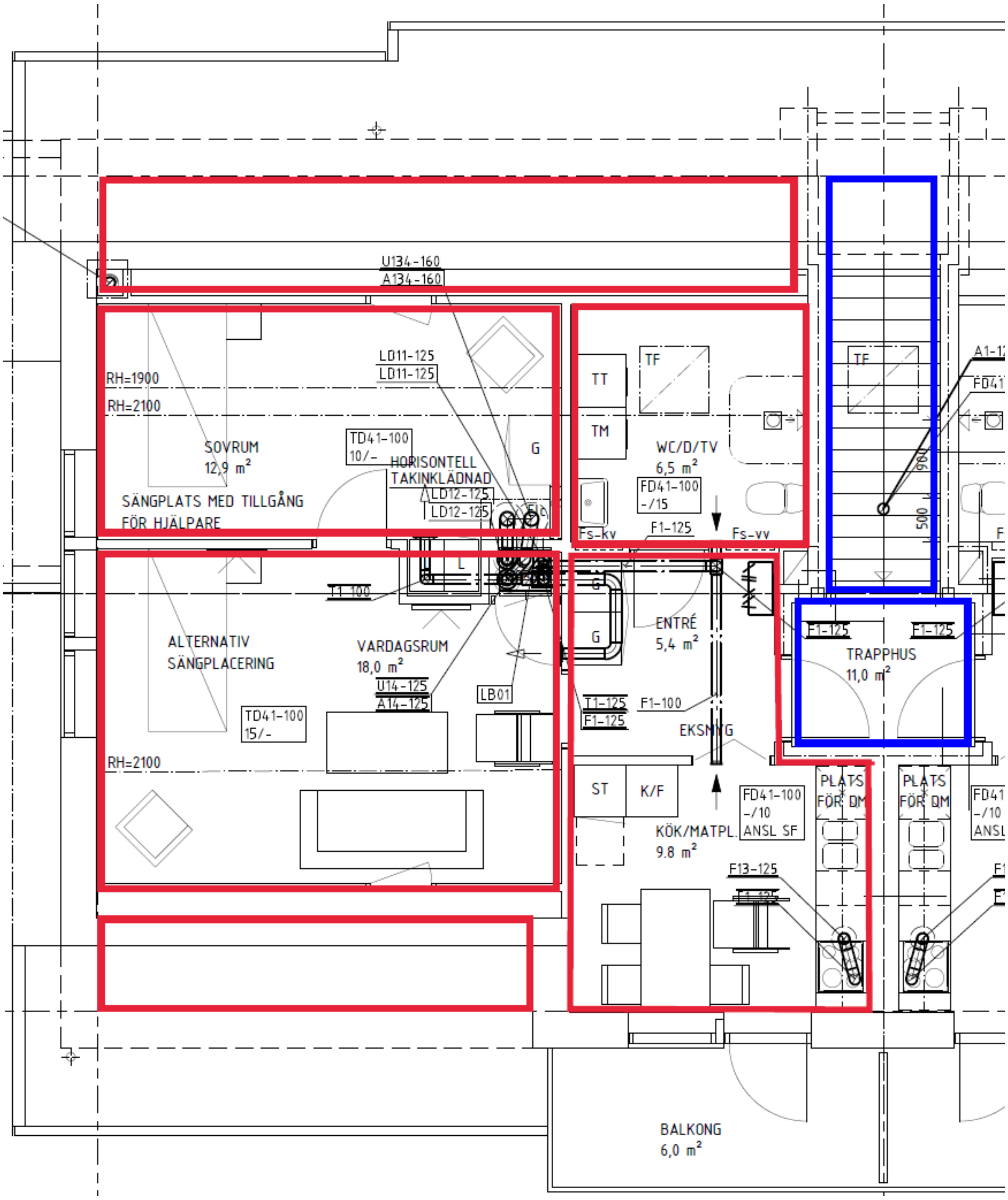
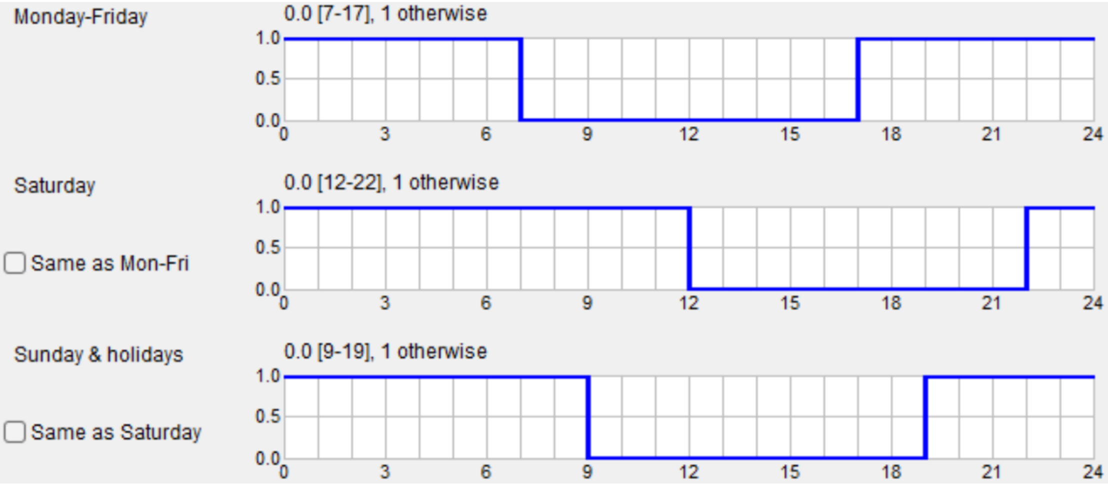


Figure 48. Second floor apartment thermal zones (red) and the staircase and apartment entrance (blue).

G. IDA ICE model with shading object

Figure 49. An excessive shading object to assess the effect on building energy demand.

H. Schedules



Monday-Friday

0.0 [7-17], 1 otherwise

Saturday

0.0 [12-22], 1 otherwise

☐ Same as Mon-Fri

Sunday & holidays

0.0 [9-19], 1 otherwise

☐ Same as Saturday

Figure 50. Occupancy schedule used in IDA ICE simulation models.

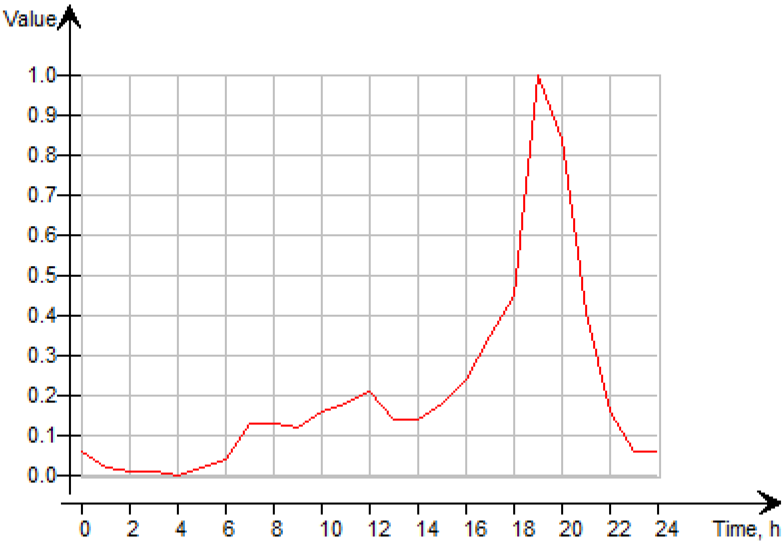


Figure 51. Normalized average hot water distribution profile used in IDA ICE for weekdays.

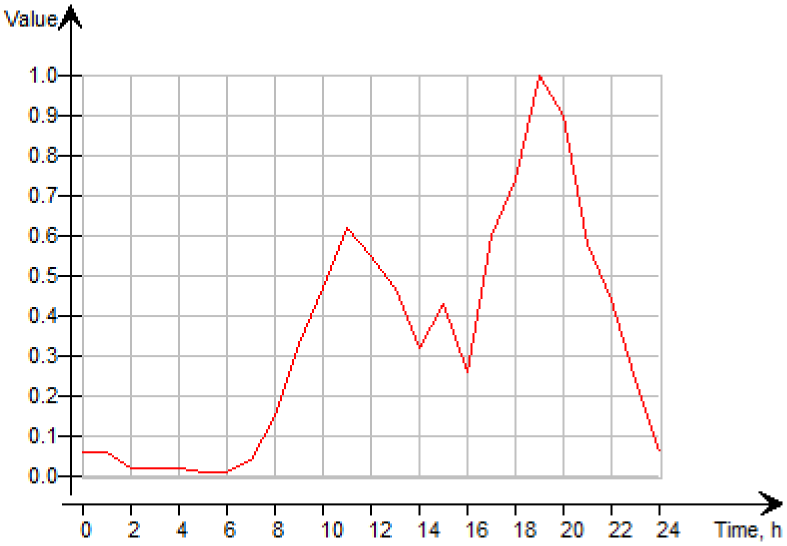


Figure 52. Normalized average hot water distribution profile used in IDA ICE for Saturdays.

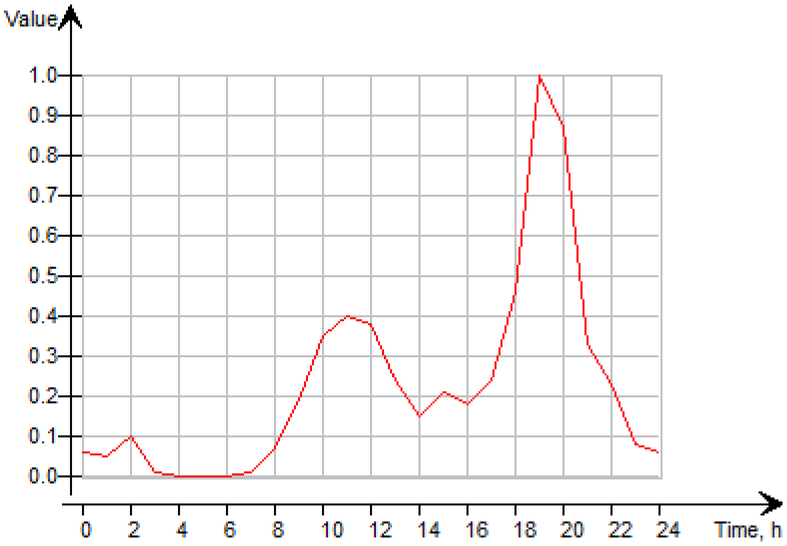


Figure 53. Normalized average hot water distribution profile used in IDA ICE for Sundays and Holidays.

I. Tenants’ electricity consumption

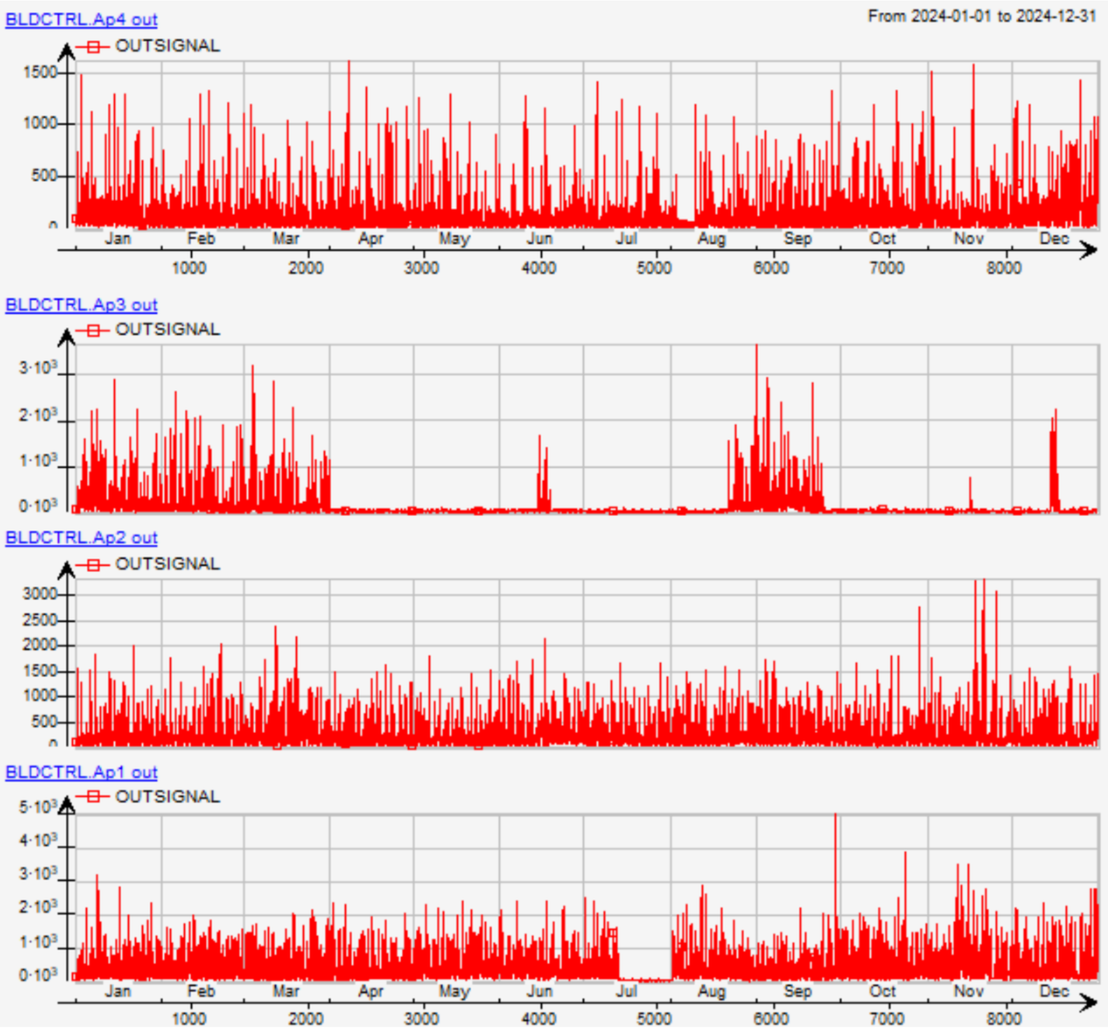


Figure 54. Tenants’ (domestic) electricity consumption [W] for the four apartments in Förlanda. Apartment 3 is excluded due to (month) long periods of non-consumption.

J. Battery capacity fade

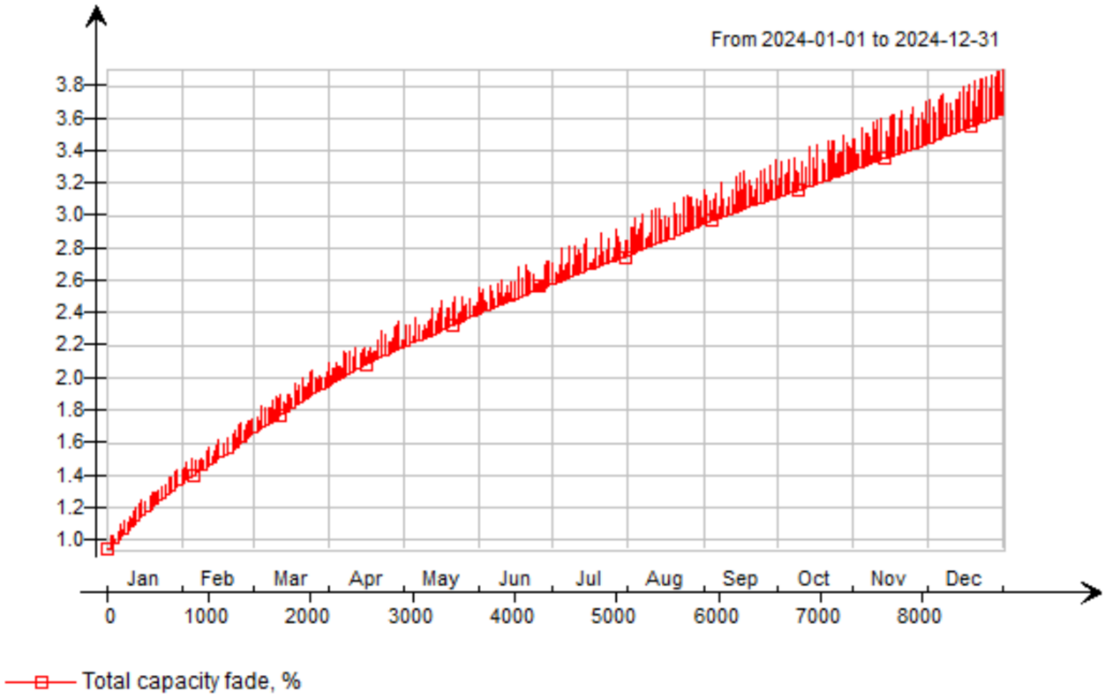
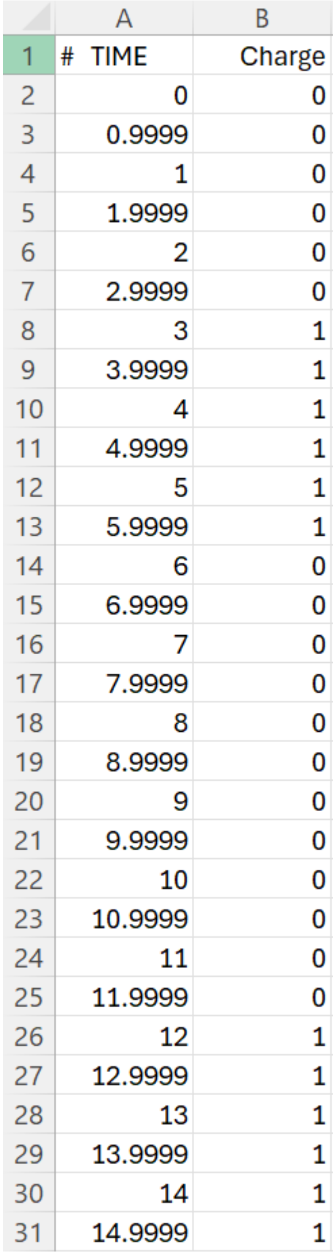


Figure 55. Battery capacity fade, simulation output for case 4 with 6.5 kWh battery and spot price control strategy.

K. Solution to control signals interpolation



	A	B
1	# TIME	Charge
2	0	0
3	0.9999	0
4	1	0
5	1.9999	0
6	2	0
7	2.9999	0
8	3	1
9	3.9999	1
10	4	1
11	4.9999	1
12	5	1
13	5.9999	1
14	6	0
15	6.9999	0
16	7	0
17	7.9999	0
18	8	0
19	8.9999	0
20	9	0
21	9.9999	0
22	10	0
23	10.9999	0
24	11	0
25	11.9999	0
26	12	1
27	12.9999	1
28	13	1
29	13.9999	1
30	14	1
31	14.9999	1

Figure 56. Example of reduced interpolation between battery control signals.

L. Average historical spot prices

Table 18. Dataset for average spot prices for the years 2020 – 2023. The highlighted values are the three lowest-priced (01:00 – 04:00) and highest-priced (08:00 – 09:00 and 17:00 – 19:00) hours of the day on average.

Hour	2020	2021	2022	2023
00–01	11.8	41.1	61.7	34.2
01–02	11.2	38.9	57.0	32.4
02–03	11.0	38.0	56.1	31.7
03–04	11.3	38.6	57.2	32.1
04–05	12.7	42.8	71.0	35.5
05–06	16.7	52.4	106.4	42.6
06–07	23.2	67.5	148.4	56.9
07–08	29.0	82.1	183.2	68.1
08–09	30.4	87.7	183.3	68.5
09–10	27.9	84.9	174.3	64.3
10–11	26.8	81.4	163.3	59.8
11–12	25.8	77.6	151.7	55.6
12–13	24.4	73.9	140.7	51.7
13–14	23.1	71.6	133.8	49.8
14–15	22.4	72.3	136.6	51.5
15–16	23.7	76.3	145.8	56.1
16–17	26.8	84.8	168.4	64.2
17–18	30.2	91.8	190.0	70.9
18–19	29.7	88.4	189.8	71.9
19–20	24.3	75.8	171.9	64.2
20–21	20.9	65.3	145.7	55.1
21–22	17.8	58.1	114.8	47.3
22–23	14.7	49.5	82.8	40.1
23–24	12.8	43.0	67.0	36.5

M. Electricity price: distribution company

Table 19. Ellevio electricity prices for company customers.

Ellevio – Company prices	Price incl. 25% VAT	Unit
Fixed cost	3 900	SEK/yr
Peak power demand tariff[1]	116.25	SEK*kW/month
Variable costs:		
-High demand period[2]	0.70	SEK/kWh
-Low demand period	0.12	SEK/kWh
Energy tax	0.54	SEK/kWh
Total variable costs (range)	0.66 – 1.24	SEK/kWh

Table 20. Ellevio electricity prices for private homeowners.

Ellevio – Private prices	Price incl. 25% VAT	Unit
Fixed cost	10 320	SEK/yr
Variable cost	0.30	SEK/kWh
Energy tax	0.54	SEK/kWh
Total variable costs	0.84	SEK/kWh

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[1] The monthly peak power demand tariff is based on the single highest average hourly demand.

[2] High demand period is weekdays between 06:00 – 22:00 from 1st of November to 31st of March, exception of Holidays.

N. Electricity price: trading company

Table 21. Mälarenergi electricity prices for company customers.

Mälarenergi – Company prices	Price incl. 25% VAT [SEK]	Unit
Variable costs:		
-Markup	0.015375	SEK/kWh
-Electricity certificate	0.000273	SEK/kWh
-SvK base fee[3]	0.023000	SEK/kWh
-SvK power reserve fee	0.001250	SEK/kWh
Total variable costs	0.039898	SEK/kWh

Table 22. Mälarenergi electricity prices for private homeowners.

Mälarenergi – Private prices	Price incl. 25% VAT [SEK]	Unit
Fixed cost	420	SEK/yr
Variable costs:		
-Markup	0.03625	SEK/kWh
-Electricity certificate	0.00650	SEK/kWh
-SvK base fee	0.03600	SEK/kWh
-SvK power reserve fee	0.02250	SEK/kWh
Total variable costs	0.10150	SEK/kWh

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[3] SvK (Svenska kraftnät) is the transmission system operator in Sweden.

O. Electricity price: exported electricity

Table 23. Earnings from exported electricity for facility companies obtained from Ellevio, Mälarenergi and Skatteverket.

Company prices	Price ex. VAT [SEK]	Unit
Ellevio:		
-High demand period[4]	0.065	SEK/kWh
-Low demand period	0.054	SEK/kWh
Mälarenergi	-0.028	SEK/kWh
Skatteverket	0.6	SEK/kWh
Total variable costs (range)	0.626 – 0.637	SEK/kWh

Table 24. Earnings from exported electricity for private homeowners obtained from Ellevio, Mälarenergi and Skatteverket.

Private prices	Price ex. VAT [SEK]	Unit
Ellevio:		
-High demand period	0.065	SEK/kWh
-Low demand period	0.054	SEK/kWh
Mälarenergi	0	SEK/kWh
Skatteverket	0.6	SEK/kWh
Total variable costs (range)	0.654 – 0.665	SEK/kWh

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[4] High demand period is weekdays between 06:00 – 22:00 from 1st of November to 31st of March, exception of Holidays.

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