Optimal design of an EV fast charging station coupled with storage in Stockholm

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Abstract
Is battery energy storage a feasible solution for lowering the operational costs of electric vehicle fast charging and reducing its impact on local grids? The thesis project aims at answering this question for the Swedish scenario. The proposed solution (fast charging station coupled with storage) is modelled in MATLAB, and its performance is tested in the framework provided by Swedish regulation and electricity tariff structure. The analysis is centred on the economic performance of the system. Its cost-effectiveness is assessed by means of an optimisation algorithm, designed for delivering the optimal control strategy and the required equipment sizing. A mixed-integer linear programming (MILP) formulation is utilised. The configuration and operative costs of conventional fast charging stations are used as a benchmark for the output of the optimisation. Sensitivity analysis is conducted on most relevant parameters: charging load, battery price and tariff structure. The modelling of the charging demand is based on statistics from currently implemented 50 kW DC chargers in Sweden. Overall, results show that with current figures the system may be an economically viable solution for both reducing costs and lowering the impact on the local distribution grid, at least during peak-period pricing. However, sensitivity analysis illustrates how system design and performance are highly dependent on input parameters. Among these, electricity tariff was identified as the most important. Consequently, detailed discussion on the influence of this parameter is conducted. Finally, the study shows how the system is in line with most recent directives proposed by the European Commission.

Keywords: fast charging stations, electric vehicle, energy storage system, optimal design, MILP optimisation, cost-effectiveness, grid impact, Sweden.
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List of Abbreviations

2DS Two-Degrees Scenario
AC Alternating Current
BEV Battery Electric Vehicle
BMS Battery Management System
CAES Compressed Air Energy Storage
CCS Memorandum of Understanding
Chademo Charge de Move
CO₂ Carbon Dioxide
COP21 21st Conference of the Parties
DC Direct Current
DOD Depth of Discharge
DSO Distribution System Operator
Ei Energimarknadsinspektionen – Swedish Energy Markets Inspectorate
ESS Energy Storage System
EUR Euro
EV Electric Vehicles
EVSE Electric Vehicle Supply Equipment
FCS Fast Charging Station
FES Flywheel Energy Storage
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>HPC</td>
<td>High Power Charging</td>
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<td>HV</td>
<td>High Voltage</td>
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<tr>
<td>ICE</td>
<td>Internal Combustion Engine</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IEC</td>
<td>International Electrotechnical Commission</td>
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<tr>
<td>IVA</td>
<td>Value Added Tax</td>
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<tr>
<td>LCOE</td>
<td>Levelised Cost of Electricity</td>
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<tr>
<td>Li-ion</td>
<td>Lithium-Ion</td>
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<tr>
<td>LP</td>
<td>Linear Programming</td>
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<tr>
<td>LV</td>
<td>Low Voltage</td>
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<tr>
<td>MILP</td>
<td>Mixed-Integer Linear Programming</td>
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<tr>
<td>MOU</td>
<td>Memorandum of Understanding</td>
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<tr>
<td>MV</td>
<td>Medium Voltage</td>
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<tr>
<td>PHEV</td>
<td>Plug-in Hybrid Electric Vehicle</td>
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<tr>
<td>PHS</td>
<td>Pumped Hydro Storage</td>
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<tr>
<td>PV</td>
<td>Photovoltaic</td>
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<tr>
<td>SEK</td>
<td>Swedish Crown</td>
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<tr>
<td>SMES</td>
<td>Superconduction Magnetic Energy Storage</td>
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<tr>
<td>SvK</td>
<td>Svenska Kraftnät</td>
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<tr>
<td>TSO</td>
<td>Transmission System Operator</td>
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<tr>
<td>UNFCC</td>
<td>United Nations Framework Convention on Climate Change</td>
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<tr>
<td>USD</td>
<td>US Dollar</td>
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<td>V2G</td>
<td>Vehicle-to-grid</td>
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1 Introduction

This chapter begins by providing general background information about electric vehicles and charging stations. The objective is to give the reader an overview of the topic and the basic concepts required to understand the scope of the thesis. This part is followed by the research questions, the objectives that inspired the project and a brief explanation of the methodology. The literature review concludes this first chapter. In this final section, the most relevant papers related to the research topic of the thesis are gathered and a brief description of the findings is provided.

1.1 Background

During the UNFCCC 21st Conference of the Parties (COP21) held in Paris in December 2015, governments’ representatives agreed to keep global average temperature increase below 2°C and to pursue efforts to limit the temperature increase to 1.5°C (UNFCCC, 2015). In order to meet these objectives, a substantial reduction in the greenhouse gas (GHG) emissions needs to be accomplished. According to the IEA, GHG emissions should be reduced to about 15 Gigatons (Gt) by 2050, and efforts should continue after (International Energy Agency, 2016).

The transport sector is a major contributor to GHG emissions, second only to power and heat generation, and accounts for about a quarter of energy-related GHG emissions. According to the IEA 2DS, the transport sector needs to contribute to 18% of the total emissions reduction to 2050, compared to a business-as-usual-scenario, see Figure 1-1 (International Energy Agency, 2016).

![Figure 1-1: GHG emissions by sector to 2050, 2DS versus business-as-usual trajectory. Source (International Energy Agency, 2016)](image)

The electrification of the transport sector is seen as a possible solution to mitigate the negative impact of fossil fuel combustion, both at local and global level (Mwasilu et al., 2014). Vast implementation of electric vehicles, if connected with low-carbon electricity production, can lower global GHG emissions as well as positively affect local air quality (EPRI and NRDC, 2015). Moreover, electric vehicles represent a possibility for integrating stochastic renewable energy production (Mwasilu et al., 2014; Wang et al., 2016).

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1 United Nations Framework Convention on Climate Change.
2 2°C Scenario.
In recent years, EVs\(^3\) market experienced a considerable growth, with over 550 000 vehicles sold globally in 2015 (see Figure 1-2). The Netherlands and Norway registered the highest market share of electric vehicles in 2015, with 10% and 23% respectively (International Energy Agency, 2016). This was mainly due to the favourable policy framework, such as tax exemption or direct subsidies, as high costs and range limitations still constitute a barrier in many cases. However, it must be stated that technology has improved substantially in the last years and battery costs have gone down accordingly, at a yearly rate of about 8% for battery electric vehicles (BEVs) market leaders (International Energy Agency, 2016; Nykvist and Nilsson, 2015). This trend is likely to continue in the short- and mid-term. According to a market analysis of McKinsey, in the last two years only, average prices have halved, from $ 540 to $ 227\(^4\) per kWh, and current projections foresee prices to fall below $190/kWh by 2020 and below the threshold of $100/kWh by 2030 (McKinsey, 2017a).

The battery pack constitutes a significant portion of an EV cost. It is estimated that nowadays it makes up about a third of the cost of the entire vehicle (Randall, 2016a). Consequently, decreasing battery prices enabled car manufacturers to deliver cheaper and cheaper cars. As an example, Tesla announced that its new Model 3 – which broke records hitting 380 000 pre-orders in only 9 months from the launch – will have a range of 345 km, with a starting price of $ 35 000 (McKinsey, 2017b; Tesla, 2017a). Last year, also Nissan and Chevrolet revealed their plans to launch long-range EVs at a price of about $30 000, and many other automakers are likely to follow (Randall, 2016b).

Regarding EVs sales goals, the 2DS of the IEA ETP\(^5\) 2016 sets a deployment target of 140 million cars by 2030, exceeding the 100-million target of the Paris Declaration on Electro-Mobility and Climate Change and Call to Action, announced at COP21. Being the global stock of EVs 1.26 billion in 2015, it is clear that there is still a long way to go to achieve these targets by 2030 (International Energy Agency, 2016). However, recent estimates from Bloomberg Energy Finance (BNEF) and McKinsey show that accomplishing these objectives is possible. Both institutions agree that by mid-2020s price parity between ICE and BEV will be achieved (McKinsey, 2017b; Randall, 2016b). Ownership cost parity will be achieved even sooner for high-utilisation vehicles, such as taxis or delivery vehicles (McKinsey and BNEF, 2016). Decreasing prices, together with favourable policies and technological improvements, have a great potential to reshape the market in the short- and medium term. According to Bloomberg (2016), the 100 million threshold could be achieved before end of 2030 or even sooner, if disruptive innovation were to happen. By 2040 a quarter of the global car fleet could be constituted by EVs (BNEF, 2016).

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\(^3\) Electric vehicles. The definition includes battery electric, plug-in hybrid electric and fuel cell electric vehicles (BEVs, PHEVs and FCEVs).

\(^4\) Projection for Q4 2016, based on the trend registered during Q1-Q3 2016.

\(^5\) Energy Technology Perspectives.
The growth experienced by the EVs market pushed – and will continue to push – the deployment of charging infrastructure. The latter followed a similar trend to the EVs’ and, starting from roughly 20,000 units in 2010, it surged to about 2 million in 2016 (International Energy Agency, 2016; McKinsey, 2017b). The number is bound to increase globally, primarily in developed countries and China, while traditional petrol stations will slowly start to decline. According to Nissan, by 2020 the number of charging stations will overcome the one of petrol stations in the UK (Hirtenstein, 2016). As stated by IHS Markit (2016), by 2020 there will be more than 12 million charging units globally. This figure is likely to be achieved if the huge investments that are being done – or scheduled for the next years – are taken into account.

The majority of the current charging stations are either private or public slow chargers (International Energy Agency, 2016). However, public fast chargers are increasingly attracting the interest of research and industry players. This technology aims at solving the so-called “range anxiety” – which is still perceived as a problem by many possible EV customers – by consistently reducing the recharge time, consequently allowing to travel longer distances (Bai and Lukic, 2013a; McKinsey, 2017b). Tesla is investing large amounts of capital for expanding its fast charging infrastructure and is planning to substantially increase the number of new stations in 2017 (Tesla, 2017b). In Europe, the Nordic countries are devoting particular interest to EVs fast charging infrastructure. In 2015, Sweden fast-chargers more than doubled and in Norway the increase was more than threefold (International Energy Agency, 2016). The big utilities are playing a leading role in the process. Vattenfall already operates several fast chargers and Fortum Charge & Drive is planning to build the first High-Power Charging (HPC) corridor between Helsinki, Stockholm and Oslo. The stations will be able to deliver 150–350 kW, more than Tesla Superechargers, which are currently the most powerful widely-deployed chargers, reaching up to 145 kW (Fortum, 2017a; Lambert, 2016).

As previously stated, vast diffusion of EVs will likely have positive effects at environmental level, both on GHG emissions and air quality. On the other hand, its effects on the electric grid are uncertain. With appropriate scheduling and control strategies, slow charging in residential areas and office parking can serve as a flexible load, offering the possibility to enhance integration of renewable generation. Ekman (2011) investigated the interaction of wind and EVs charging in the Danish power system and found that smart charging can have significant effects on excess wind power production utilisation.

Another interesting concept, which has gained interest in the literature and industry in the last years, is the so-called vehicle-to-grid (V2G). The idea consists in using the EVs storage capacity in a bi-directional manner: not only as a flexible load, but also as power generator. Besides higher integration of renewable generation, V2G can improve grid technical performance, efficiency and reliability by offering both power and energy services (Yilmaz and Krein, 2013). In 2016, the Italian utility Enel launched the world’s first commercial V2G hub in Denmark (Enel, 2016). Despite its progress, several drawbacks hinder V2G large-scale implementation, at least in the short term. First of all, V2G mode intensifies battery degradation due to increased number of charging cycles. Second, consistent upgrading of infrastructure and communication technology is required, with consequent economic burden. Finally, social acceptance, user’s comfort and regulatory framework constitute important barriers (Yilmaz and Krein, 2013; Straubel, 2016).

Several studies show that massive deployment of EVs will likely affect the power distribution grid if no upgrades on the existing system are performed and no smart charging methodologies are implemented (Darabi and Ferdowsi, 2011; Sbordone et al., 2015; Shareef et al., 2016). Effects include voltage instability, increased peak demand, power quality problems, transformer heating and overloading (Shareef et al., 2016). These issues are even more relevant for quick- and fast charging. Due to their nature, focused on minimising charging time, they are not compatible with dynamic charging, considered instead a viable and successful

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6 Power quality refers to the ability of the grid to supply constant and clean electric power. More specifically, these problems may be related to voltage, frequency and wave form. Disturbances on one or more of these parameters may represent a problem for some sensible loads (Tuning, 2017).

7 Dynamic charging basically consists in controlling the speed and timing of the charging process. One of the most logical controlling method is the one proposed by Cao et al. (2012), which consists in scheduling the charging procedure in relation to electricity prices.
means of reducing some of the negative effects of home charging (Cao et al., 2012; Straubel, 2015). Moreover, unpredictable high power demand can seriously affect the system bus voltage and distribution system equipment (Yunus, 2010).

Consequently, research has been focused on the topic of integration of EVs into the power grid. According to Sbordone et al. (2015), two main strategies have been recently investigated as means to handle the impact of EVs on the grid, consisting in:

- increasing power generation capacity (with particular focus on distributed renewable energy), increasing transport capacity of distribution lines and coordinating EVs charging with stochastic renewables;
- implementing charging strategies in a smart-grid framework.

The latter is strictly linked to the diffusion of smart-grid technologies, such as smart meters, ICT\(^8\) and energy storage systems (ESSs). ESSs play a crucial role in smart grids and can become fundamental for the integration of EVs demand on the grid, especially in the case of fast charging stations, which require a substantially higher power if compared to home charging. Typically, domestic charging in Europe has a rated power of less than 3.7 kW, while fast charging can reach up to 120 kW, in the case of Tesla Superchargers (Sbordone et al., 2015; Tesla, 2017c). ESSs can provide both power services and energy services. The former case involves quick exchanges of power, the main focus is on ensuring security and power quality, while in the latter services like load levelling are possible thanks to prolonged exchanges of power. Typically, the energy services require higher capacity (Barsali et al., 2015). ESSs coupled with power control equipment can also contribute to maintain power quality and limit disturbances such as current harmonics (Bai and Lukic, 2013b, 2013c).

Yunus et al. (2011) investigated the impact that a DC fast charging station has on the grid, by means of a stochastic charging model. The researchers developed a MATLAB model and a DIgSILENT\(^9\) model and found out that fast charging stations energy storage is beneficial in terms of limiting the negative effects of fast charging demand on the grid.

The high impact that fast charging stations have on the grid is reflected by pricing, i.e. demand charges. Depending on the utility billing method, a DC fast charger can incur in demand charges of several thousand dollars (McPhail, 2014). Hence, in addition to the previously mentioned services, ESSs may be used to limit or avoid unexpected power peaks. This would allow obtaining a lower overall operation cost of the charging station. From the point of view of distribution system operators (DSOs), peak shaving and load levelling functionalities may avoid the need of upgrading the system (Tweed, 2016).

The literature review showed a lack of a holistic approach, encompassing both technical (sizing, service type investigation and grid impact) and economic analysis (economic viability) aspects for an EV DC fast charging station storage system\(^10\). This project aims at covering this gap, further investigating the role that ESSs can play in the integration of fast charging stations into the electric grid, by studying an ideal fast charging station in the city of Stockholm. The design of the storage system will be conducted, with focus on the economic performance as well as considering the impact on the distribution grid. The study intends to assess the feasibility of the solution and to provide a possible approach to implementing it in other similar applications.

### 1.2 Research Questions and Objectives

The objective of this thesis project is to optimally size the energy storage system for an ideal fast charging station located in the city of Stockholm and to evaluate its impacts, both on the local grid and on the LCOE\(^11\).

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\(^8\) Information and Communication Technology.

\(^9\) DIgSILENT is a power system modelling software.

\(^10\) The most relevant studies on the topic are either missing proper consideration of the electricity tariff or are focused on different loads (e.g. busses or slow charging).

\(^11\) Levelized Cost Of Electricity
for the charging station. The idea is to implement an energy storage system on an already existing fast charging station. Hence, only the additional investment is considered in the analysis. Moreover, the ESS cost is assumed to be borne by the owner of the charging station and not by third parties – e.g. the DSO. However, in the final part of the project, some suggestions in this sense also arise. This project could be further used as a basis to design energy storage systems for different situations, such as other types of charging stations, for EVs or electric buses. The latter could be interesting as electric buses are currently being investigated as a solution for the city of Stockholm (KTH Royal Institute of Technology, 2016; Vattenfall, 2016; Xylia et al., 2017).

Is energy storage an economically viable solution for reducing the LCOE of a DC fast charging station in the city of Stockholm? Which are optimal size and characteristics of such a system and which service\(^\text{12}\) should it provide?

Is energy storage in combination with EV DC fast charging stations effective in reducing the impact of charging load on the local distribution grid?

1.3 Methodology

The thesis project is a modelling study and an empirical approach was used. Data were collected from literature and companies’ interviews and implemented in a mathematical model which results enabled to assess the economic feasibility of the proposed solution for highly used fast chargers in Sweden. Sensitivity analysis was conducted in order to evaluate the impact of the variation of key parameters (i.e. battery cost, electricity tariff and EV charging load) on the final results. Consequently, it was possible to assess under which conditions the economic viability is ensured. Finally, recommendation on electricity pricing that enables a cost-effective battery deployment is provided.

1.3.1 Methodology Description

The first part of the project consisted of an extensive literature review, necessary to gain an overall understanding of the topic and of the scope of the research done so far. Similar studies and projects, such as the ones developed by Bai et al. (2010), Barsali et al. (2015), Fathima and Palanisamy (2015), Sbordone et al. (2015), Yunus et al. (2011) were analysed to understand the necessary data and the methodology to use for approaching the modelling task. The literature review enabled to identify a precise modelling approach, suitable for the scope of the project: it was decided to develop a mixed-integer linear programming (MILP) optimisation model. Among the several analysed, four key-studies were selected for their relevance: Corchero et al. (2012), Ding et al. (2015), Gunter et al. (2013) and Negarestani et al. (2016). The different modelling approaches were studied and their strengths and weaknesses were identified.

Following the literature review, the first step was to analyse the Swedish electricity market. Particularly important was the analysis of different tariffs and connection possibilities. The major part of the information was gathered through researching literature available online, mainly on Nord Pool electricity market and Swedish utilities’ and distribution companies’ websites. However, since not all information was retrievable in this manner, some interviews were conducted with specific involved parties.

Related to the previous step, but with a different goal, was the identification of the regulatory framework for batteries and of the services that storage can offer to distribution companies. This step allowed the identification of the control strategy. Starting from the method proposed by Sbordone et al. (2015), a reasonable control strategy for the battery was identified. The objective was to integrate the control strategy

\(^{12}\) Either power- or energy service. The idea is to investigate whether the storage system should be engaged only for peak shaving or it should be used to shift the energy demand during off-peak periods.
with data about the electricity pricing, to maximise cost-effectiveness of the system. Similarly to the previous step, not all information was publicly available and interviews were conducted. As for the previous step, in order to simplify the analysis, it was chosen to focus on a single utility and a single distribution company, Vattenfall and Vattenfall Eldistribution. These companies were selected among the others for their market share. Vattenfall is responsible for about 30% of the electricity sales in Sweden and Vattenfall Eldistribution is among the three major DSOs in Sweden (Vattenfall, 2017a; Wangel, 2015).

The next step was the study of the load profile of the charging station. Considering the literature study and the scope of this project, it was chosen not to model the load profile using mathematical and probabilistic methods, such as the ones used in Corchero et al. (2012) and Negarestani et al. (2016). Instead, a more empirical approach was taken. The base case charging load was developed thanks to interviews with industry experts, online available data and literature data. Among these, particularly important were data provided by a Swedish special-interest group, Power Circle. The company conducted a study on the charging demand of more than one hundred EV fast charging station in Sweden. The study formed the basis on which an average load profile was built. Based on the insights provided by Power Circle, sensitivity analysis on future possible charging demand was conducted.

A brief analysis of storage technologies available on the market was conducted. However, it was chosen to focus the analysis on lithium-ion batteries only. Both from a technological and an economic point of view this technology seemed to be the most relevant, unless breakthroughs enable other technologies (i.e. flow batteries\textsuperscript{13}) to become more attractive. Data collection of important characteristics for the cost modelling (e.g. cost, capacity, efficiency, depth of discharge (DOD), lifetime, etc.). In similarity with the previous cases, different sources were used, mainly scientific papers, industry reports and interviews with companies active in the sector.

The information and data collected during the previous phases were utilised to build the MILP optimisation model. This formulation can be utilised to solve linear problems, in which both constraints and objective function can be expressed in a linear form. MILP allows also to solve problems in which one or more of the variables are integers. This specific functionality was required to properly simulate battery behaviour (further explanation will be provided in section 5.6). The software environment used was MATLAB. Since the model was thought to serve the perspective of the charging station owner, its objective is the minimisation of the LCOE. This is influenced by both fixed (i.e. cost of the electrical equipment) and operation costs (i.e. electricity purchase, maintenance and replacement of the equipment). Hence, all of these parameters were evaluated from the algorithm before delivering the results. Both power and energy regulation strategies are included in the formulation. However, only optimal results are delivered. The point of view of the distribution company was not considered in the optimisation model (see section 5.5 for further information). However, in the final chapters, this topic will be qualitatively discussed.

Sensitivity analysis was conducted on the most relevant parameters: battery cost, electricity tariff and load profile. The influence of battery cost and different load profiles on final results was investigated and key findings were explained. Sensitivity analysis on the distribution tariffs enabled to provide recommendations for the design of electricity distribution tariffs that allow storage to be cost effective and consequently lower the impact of the charging stations on the grid. This was identified as a key outcome after interviews with a local distribution company.

Once the system was sized, it was possible to obtain the load profile of the whole system (charging station in coordination with storage). This allowed assessing grid impact of the station with and without storage, which can ultimately lead to the identification of the best solution, under given circumstances. Finally, some recommendations for further development of policies or suggestions for additional actions were given based on the results and analysis of the modelling task.

\textsuperscript{13} “A flow battery is a type of rechargeable battery where rechargeability is provided by two chemical components dissolved in liquids contained within the system and most commonly separated by a membrane” (Energy Storage Association, 2017).
1.3.2 Further Possibilities

The aim was to provide a cost-optimised design and a techno-economic analysis of a storage system for a fast EV charger. The solution was tailored for addressing the specific case of Stockholm; hence the direct outcomes will be focused on the Swedish scenario. However, with different input data, the model may be used in the future for the sizing of similar storage systems, e.g. to support electric busses or similar charging systems in other locations.

The study helps owners of the charging stations to understand the value of ESSs and to decide whether to install these systems or not. It also provides information to distribution operators about the different impact that an EV DC fast charging station can have on the grid. In addition, it can support Swedish decision-makers in identifying future requirement for fast charging stations and electricity pricing.

1.3.3 Limitations

The issue of assessing whether storage is an economically viable option for reducing fast charging station (FCS) costs was addressed as an optimisation problem. Delivered results include control strategy, i.e. planned power flows that minimise costs, and optimal size of the equipment (battery, converter, connection fuse and, when needed, transformer). However, the equipment sizes should not be interpreted as a real sizing, but as an indication from where to start a proper sizing. In fact, due to the mathematical formulation, it was not possible to include important parameters, such as load variability or the cost associated to battery degradation. To complement the study, it would be interesting to study the system with a software specifically designed for techno-economic analysis.

Furthermore, the mathematically optimal solution might not be reasonable from a real point of view. In real projects, equipment is often oversized by applying safety factors for increasing the reliability of the system. This would consequently boost costs, distancing the solution from optimality.

The limitations related to the mathematical formulation and load calculation are discussed in detail in section 5.3.

1.4 Literature Review

Due to the increasingly important role that it will play in renewable integration, energy storage has attracted the interest of many studies in the last years. Also EVs fast charging stations gained considerable attention in recent literature, especially in location planning and sizing of the stations (Gong et al., 2016; Shi and Lee, 2015; You and Hsieh, 2014; Zhang et al., 2015). Fewer studies focused on combining the two technologies. The next section contains a literature review of the most relevant publications on the topic.

Yunus et al. (2011) investigated the impact that uncontrolled EV fast charging may have on the grid, using a stochastic modelling approach. The charging load was modelled with MATLAB and based on three parameters: charging power level, vehicles arrival distribution – assumed similar to conventional petrol stations - and daily energy requirement per vehicle. The latter was obtained generating a random normal distribution of battery state of charge (SOC). The grid modelling was done using DIgSILENT and different standard grid architectures were considered. It was found that fast charging stations greatly affect grid in terms of voltage stability and peak power. The use of static var compensation (SVC) and energy storage devices was suggested in order to minimise negative effects. Regarding the storage devices, supercapacitors and flywheels were suggested as viable options by the author in a precedent work (Yunus, 2010). Batteries were not considered, probably due to the high cost that the technology had at the time of the study.

McPhail (2014) evaluated the opportunities that energy storage can offer when coupled to a fast charging station. The author pointed out the weight that demand charges can have on the cost of electricity for high-power users. In the case of the unit studied in the paper, demand charges account for 94.99% of the cost. An ESS is identified as a possible solution. In addition, an ESS may offer additional revenues by providing capacity demand response and ancillary services to the local utility. An economic analysis was performed on a 50-kW charging station deployed in California, served by San Diego Gas and Electric. The results showed
that the payback time of the ESS is 3.25 years, only considering demand charges and time of use tariffs, which can be further reduced to 3, if ancillary services are included. This study shows that energy storage is an economically viable option for fast charging stations. It must be stated, however, that the study lacks rigorous assessment of battery capacity.

Sbordone et al. (2015) described an experimental setup built at ENEA labs, in Italy, in which EV fast charging was coupled with energy storage for reducing the impact on the grid. More specifically, the system was composed by a 22-kW AC charger (switchable to 50 kW DC) and 16-kWh battery. The system was tested on a Nissan Leaf, equipped with a Li-ion battery pack with a capacity of 24 kWh. The team conducted several experiments and analysed the response of the system in different SOC scenarios and implementing different control strategies. The system showed good performance for peak shaving functions, with respect to the main distribution grid. A similar project was launched by Hawaiian Electric Company in collaboration with Greenlots, focused on assessing batteries’ ability to lower the impact of fast charging on the grid (Tweed, 2016). Unfortunately, results are not publicly available yet.

Fathima and Palanisamy (2015) modelled a battery energy storage system for grid-connected wind-PV hybrid system, using MATLAB and a bat optimisation algorithm, with the objective of minimising system cost. The battery is initially sized integrating the difference of generated and utilised power and selecting the maximum value. This is taken as a first value from which to start an iterative economic optimisation process based on the method proposed by Yang (2010).

Another interesting approach on techno-economic modelling of battery storage was taken by Ding et al. (2015), who investigated the role that ESSs can play in reducing grid connection capacity and charging cost for electric buses fast charging stations. The optimal sizing of the system was formulated as a mixed integer nonlinear programming (MINLP) problem, but a conversion to a linear problem was possible without excessive accuracy losses. The objective function consisted in minimising system (ESS and transformer) cost and operating (electricity) cost. The simulation was run using historical data of the Chinese electricity prices and the charging load of a pre-existing charging station. Four different scenarios were analysed and both energy storage and load deferral were considered. The simplest case (no ESS, no load deferral) was used as a benchmark. Despite the additional investment for the ESS, energy storage enabled annual savings of up to 22.95%, compared to the base scenario. A sensitivity analysis on the battery cost was also performed and showed a clear correlation between battery cost and annual operation cost. Considering the decreasing trend of battery prices this is a promising finding.

Bai et al. (2010) investigated the possibility of using energy storage in a fast charging station to lower the grid tie capacity. No real data were available and a simulation was performed assuming reasonable figures from state-of-the-art technology. The load of a charging station with 10 240-kW slots was obtained for a reasonable worst-case scenario. More specifically, it was calculated considering that in a 12-hours period the stations were fully occupied by vehicles with battery SOC, voltage, capacity and charging rate normally distributed around average state-of-the-art values. The simulation showed a great unbalance between average and peak demand. Thus, energy storage was identified as a viable option. A Monte Carlo simulation was conducted for a scenario of 10 vehicles charging. The average power rating and storage capacity of the ESS were selected and supercapacitors were identified as the best option. Statistics for unsatisfied customers were also calculated. The paper looks as well at the configuration of the system. However, economic aspects are totally missing. A similar – although simplified – approach on a single 240-kW charging unit was taken by Joos and Freige (2010). The proposed architecture included a 5.4 kW grid tie and two storage devices: a flywheel and a supercapacitor.

More recent researches suggest different storage technologies. Cunha et al. (2016) examined the possibility of using VRFBs (Vanadium Redox Flow Batteries) in conjunction with fast charging stations. The advantages over batteries consisted in decoupling rated power and rated capacity, as well as more flexible design and longer lifetime. In addition, the system could be implemented in conventional petrol station, using the tanks already in place. A preliminary economic analysis considering the Portuguese electricity market was also conducted and showed positive results. Chen et al. (2011) also identified VRFBs as a
possible technology for large capacity battery storage. The application however was slightly different, as the study focused on integration of renewable energy into the grid. Atmaja and Amin (2015) studied the architecture of a mobile charging station and suggested a combination of batteries (lithium-iron phosphate) and ultracapacitors. The configuration enables to obtain a better voltage and current behaviour. Both Ciccarelli et al. (2013) and Ding et al. (2015) suggested lithium-ion batteries as suitable technologies. Interestingly, both studies identified LiFePO4 batteries as the best technology for this kind of applications. Barsali et al. (2015) studied the role of batteries in a smart grid framework, by providing information on some real cases. According to the authors, energy storage will play an increasingly important role of grid support in the near future. Its economic viability for particular cases was also assessed.

Regarding the operation of a fast charging station with energy storage, interesting insights are provided by Bayram et al. (2011). Unlike other approaches, where the system is sized to meet a certain load demand, the study proposes to size the storage considering the revenues that it can make. Apart from the investment for the system and the operation cost, the model plays with revenues that each vehicle generates and costs for each rejected vehicle. In a following study, Bayram et al. (2012) looks at the possibility of using storage to meet the demand and switch to the grid once the battery cannot perform the task. These papers are however at theoretical level and the method will not be considered during this study. However, it provides an interesting different point of view.

Finally, several papers focused on assessing the impact that fast charging stations have on the distribution grid. Mauri and Valsecchi (2012) specifically focused on measuring the impact of fast charging on the medium-voltage (MV) grid in the city of Milan. The authors studied the voltage drop occurring in the distribution lines. The simulation was conducted by adding the load of EV charging to the pre-existing loads. It was found that, for the specific studied case, no need of upgrade was required. However, it was pointed out that, especially for rural or remote areas, the voltage drop may become unsustainable. Measures such as storage or power controlling were suggested as possible solutions.

Farkas et al. (2013) investigated the impact that fast charging stations deployed among highways may have on the MV grid. The assumption of focusing on highways is quite interesting, as it seems that this technology will be firstly deployed among highways. Examples of such an approach are provided by Tesla Supercharger network and by the plan of Fortum Charge & Drive to connect the Nordic capitals with HPC stations. Similarly to Yunus et al. (2011), the simulation was conducted using DIgSILENT Power Factory for a MV grid, constructed based on real topology data. The load of two charging stations with five 200 kW chargers each was considered. The results show that the HV/MV transformer does not suffer, however, cables and supply transformers overload extremely. Reinforcement was suggested in order to avoid overloading.

Negarestani et al. (2016) studied the implementation of an ESS in a fast charging station for PHEVs. The paper proposed a MILP method for determining the optimal size of an ESS, with the objective of reducing energy and storage costs. In particular, energy losses and life cycle cost were taken into account in the system and a sensibility analysis was conducted by varying these parameters. The optimisation result gave the optimal storage capacity and the optimal energy flow in the charging station. The selected solution enabled higher savings, compared to a no-ESS scenario. The ESS – in this specific case a flywheel – reduced costs and peak demand. It must be stated, however, that a lower round trip efficiency of the storage system and different electricity costs highly influence the system configuration, which in some cases does not include the ESS. In addition, the study does not incorporate constraints forcing the battery to be either charging or discharging at the same time. Without similar constraint, the battery can simultaneously charge and discharge, which is impossible from a technical point of view.

Similarly, Corchero et al. (2012) investigated the optimal sizing of a PEV fast charging station, including storage in the analysis. The PEV charging demand was modelled as a Poisson distribution, thanks to its non-memory features and simplicity. The optimisation problem was formulated as a linear problem (LP). The objective function, compared to Negarestani et al. (2016) goes deeper into the problem, and takes into

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14 High Voltage.
account not only storage and electricity, but also grid tie and power converter costs. O&M costs for storage and converter are considered as well. However, demand charge evaluation is totally missing. The results showed that low prices of storage (200 EUR/kWh) enable up to 60% reduction of daily energy cost. Interestingly, it was found that low prices of electricity bring to a higher grid tie capacity. If the storage prices are low enough it is possible to install large systems that enable to absorb high amounts of electricity from the grid when electricity is cheap and use it during high-price periods. It seems counter-productive, but from a global point of view the grid operation is improved, as cheaper prices reflect little overall demand. Hence, the global grid demand is flattened.

Other papers focused on the integration of charging station, storage and renewable generation (Cairo and Sumper, 2012; Gunter et al., 2013; Huang et al., 2012; Islam et al., 2015). The study of Gunter et al. (2013) is particularly interesting and in-depth developed. The optimal sizing of the ESS, renewable generation and grid tie were conducted with three different approaches. A LP, a MILP and search-based method were implemented. Although the system architecture was not specified, the optimisation formulation was presented in detail. The three algorithms were tested for the case of a residential charger (6 kW AC) in three different locations in the US. Results showed that, due to high storage costs, the configuration that allowed higher savings was the one with maximum available power drawn from the grid, since it reduced the storage size. Lead-acid batteries were considered in the analysis, as Li-ion resulted in a 33% higher lifecycle costs. At the time of the paper, the cost was estimated to be 800 USD/kWh, more than three times higher than 2017 McKinsey estimates for EV battery packs (McKinsey, 2017b). The use of up-to-date costs would surely positively influence the overall cost performance.

This study aims at developing a MILP optimisation algorithm for the sizing of the key components of a fast charging station in Sweden. In order to do so, key aspects of already conducted studies (mainly Corchero et al. (2012), Ding et al. (2015), Gunter et al. (2013) and Negarestani et al. (2016)) were merged with new modelling steps, required to tailor the study to the Swedish scenario. In particular, the model developed takes into consideration demand charges, which are either not modelled or not calculated in the analysis of the four most relevant identified studies.

Another aspect that was missing in the four key studies was that none of them took into account battery cycles to properly identify battery lifetime, which is a key parameter for the optimisation. All four key studies used an initially estimated battery lifetime. To tackle this issue, an iterative process was proposed to take into consideration the actual battery lifetime in the optimisation, instead of maintaining the initial assumed value (see section 4.3.1 for further explanation).

Finally, unlike the majority of the studies (Bai et al., 2010; Corchero et al., 2012; Negarestani et al., 2016) that focused on a configuration with a DC bus bar, this study investigates the AC bus bar configuration. Theoretically, the DC bus bar allows more efficient integration of batteries, DC chargers and, possibly, PV technologies. This design lowers the number of required conversion steps and, thus, reduces the energy losses (Bai et al., 2010). Nevertheless, the AC bus bar layout was chosen as, currently, most of the commercially available chargers are engineered to be connected to the AC grid. In addition, the costs of the hardware for AC bus bar applications is lower than in the DC counterpart, as AC is still the industry standard in electricity distribution (Kristensen et al., 2011). This may change in the near future with the development of smart grid technologies and the increase of DC technologies usage. A further difference from previous conducted studies lies in how the load profile was considered.

1.5 Thesis Structure Overview

The thesis consists of eight chapters. After the introduction, two descriptive chapters provide the reader with some background information about current EV charging technology and energy storage. The third

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15 A bus bar consists of a conducting material which collects and distributes electric power to outgoing feeders (Merriam-Webster Dictionary, 2017).
chapter focuses on the Swedish power sector. Here, special attention is drawn on the distribution and retail electricity prices, which are of particular importance to model the economic impact of the analysed system. In the fifth chapter, the modelling process is described in detail. The load profile calculation and the mathematical formulation of the problem are presented. In the sixth chapter, the main simulation results are shown and briefly commented. The seventh chapter is devoted to an extensive discussion of the results and their implications. Both the economic and grid impact perspective are examined. Finally, the final chapter summarises the key points of discussion and provides the reader with an overview of the work conducted.
2 EV Charging Technology

This chapter will provide an overview of the EV charging infrastructure. After a brief discussion of the currently available charging methodologies, European standards in terms of classification of charging infrastructure and conductive charging systems will be presented. In the final part, the chapter will look at the Swedish current scenario and at future developments, i.e. ultra-fast charging.

2.1 Charging Stations

Similarly to conventional vehicles, EVs require points of refuelling: the so-called charging stations. The purpose of a charging station is to deliver electrical energy from a source – typically the grid – to an EV battery. It consists of physical equipment, which enables the connection between the EV and the distribution grid. Charging stations can be characterised both in terms of power and type of the process. In the following sections, a description of the state of the art methodologies and standards will be given.

2.1.1 Charging Methods

Chargers are the devices that transfer electricity to the battery. Generally, they incorporate a rectifier, which converts electrical power from AC to DC to feed the battery. Research on battery charging methodologies lead to a variety of solutions. Nowadays, it can be divided into three modes: conductive, inductive and battery swapping.

Conductive Charging

Conductive charging is by far the most common. Power is transferred by direct contact. A conductor is utilised to transfer electricity from the power source to the battery. This solution is characterised by simplicity and high efficiency. Several cars currently in the market, among these the Nissan Leaf and Tesla, offer two possibilities of conductive charging. An on-board charger, typically used for low power charging, enables the EV to charge by connecting to the AC grid using only a control device. On the other hand, for high-power applications, the charger is external to the car. This configuration allows high power to be directly delivered to the battery, without the need of conversion in the vehicle.

Inductive Charging

Another interesting application is inductive charging, also known as wireless charging. It takes advantage of an electromagnetic field to transfer electricity to the battery system. Over the previous system, it has advantages of being safe in all weather conditions, as it requires no cables. In addition, it consistently simplifies the charging process. The charging process can in fact start just by stopping the car over a parking spot equipped with a wireless charger. Due to its simplicity several automakers announced that some of their models will be equipped with wireless charging, among these Audi, Mercedes and Porsche (Plugless Power, 2017). This architecture opens different possibilities. This solution is also attracting attention from research institutions for public transport, i.e. electric bus charging. An example is the previously mentioned project at KTH Royal Institute of Technology, which focuses on wireless charging of electric buses when not in movement (KTH, 2016; Scania, 2016). Another project worth mentioning is FABRIC\(^\text{16}\), which focuses on advanced on-road charging solutions. Along with a more “conventional” conductive pantograph, system already tested by Scania and Siemens in Sweden, the project focuses on the development of a wireless charging road (FABRIC, 2017; Scania, 2016b). Basically, several wireless chargers placed in sequence would

\(^\text{16}\) Feasibility Analysis and Development of On-Road Charging Solutions for Future Electric Vehicles.
allow recharge while driving, consequently decreasing the need of bulky batteries. Other similar projects were launched globally (Fagan, 2017).

Battery Swapping

This method consists in physical replacement of empty batteries for full ones in a battery swapping stations. This approach has several benefits. Among these, long battery lives, fast recharge and improved grid impact. In fact, since a lot of batteries are constantly plugged, these can be recharged at any time offering the possibility to avoid peak demands. However, the costs of management of this system and other drawbacks hindered widespread diffusion of this configuration (Shareef et al., 2016). Tesla offered battery swapping for Model S, but it seems to have abandoned the project (Zhang, 2017). Interestingly, China is nowadays the country with the highest number of battery swapping stations in the world (Shareef et al., 2016).

2.1.2 Charging Levels

Specific power configuration varies in each country due to network characteristics and network standards. Thus, different categorisations and standards exist when classifying electric vehicle charging. For example the Electric Power Research Institute (EPRI), together with the Society of Automotive Engineers (SAE), classifies charging levels in AC Level 1, AC Level 2 and DC Level 1 and Level 2 (Shareef et al., 2016). At European level, the International Electrotechnical (IEC) 61851-1 Committee on “Electric vehicle conductive systems” identified four different modes, based on power type, voltage, protection devices and the presence of grounding or control lines. These are (Gaurav and Manimaran, 2016):

- Mode 1 – AC slow charging with a conventional socket with earth protection and limited to 16 A, plugged either into a single-phase line (max voltage 250 V) or a three-phase line (max. voltage 480 V) at 50/60 Hz. This mode is typical for domestic or work environments where the user leaves the car charging for long periods of time.
- Mode 2 – AC slow charging with conventional socket with in cable protection device limited to 32 A. Vehicle and connector have a control pin, while the supply side contains an integrated control box.
- Mode 3 – AC charging limited to 63 A, using an electric vehicle supply equipment (EVSE). The control is assigned to permanently installed equipment on the AC supply side, generally the three-phase network. Public stations generally have this configuration, which is also referred as “semi-fast”.
- Mode 4 – DC fast charging with external charger, which can be further divided into DC level 1 and DC level 2. Similarly to the previous case, the control function is extended to equipment permanently connected to the AC grid. The AC power is converted to DC in the equipment. Typical charging time of Mode 4 is in the order of 30 minutes.

According to power, the same IEC committee also defined three different types according to power (Sbordone et al., 2015):

- Slow charging, with a rated power lower than 3.7 kW, typical of domestic applications;
- Quick charging, characterised by maximum power of 22 kW;
- Fast charging, with a rated power of more than 22 kW.

Since the focus of the thesis project was on fast charging, from the next section on only this charging level will be discussed.

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17 AC or DC.

18 DC level 1 is characterised by maximum voltage of 500 V, maximum current if 80 A and power of 40 kW, while DC level 2 has an increased limit on current (200 A) and a power of 100 kW (Sbordone et al., 2015).
2.1.3 DC Fast Charging Protocols

When it comes to fast charging system, there is a lack of standardisation. Currently, there are four types of DC fast charging systems: CHAdeMO, Combo Charging System (CCS), Tesla Supercharger and the Chinese system. The first three compete in the North American and European market.

CHAdeMO was the first major player in the market. The protocol was developed by a collaboration of TEPCO and Japanese automakers. It contains only the DC standard and is currently limited to 50 kW but 150 kW CHAdeMO is under development (CHAdeMO, 2017). Later, SAE developed the CCS which, in turn, incorporates both AC and DC standards in the same unit (Shareef et al., 2016). Tesla developed its own charging protocol which is implemented in all their Superchargers.

Different cars have different standard connectors. Nissan supports CHAdeMO, while most of the other automakers support CCS. However, currently the most popular protocol is still CHAdeMO. Tesla developed an adapter that enables Tesla owners to connect to CHAdeMO chargers (Herron, 2017).

Many new chargers, such as the one proposed previously mentioned (Evtec and BMT, but also ABB), develop chargers with several sockets. This way, both car owners with CCS and CHAdeMO can easily connect and recharge their vehicles.

However, it seems that, in the future, CCS will become the predominant solution. One of the reasons might be that, as of today, CCS supports higher power. As a result, in Europe a consortium of automakers is planning to build a big HPC network based on CCS technology.

2.1.4 Fast Charging and Ultra-Fast Charging

Currently, most powerful chargers currently available for light EVs can theoretically deliver up to 150 kW DC. Such systems are currently being installed, among the others, by the Swiss company EVTEC and by DBT (DBT, 2017; EVTEC, 2017). However, as of today, the light electric vehicle that charges at highest power is Tesla Model S (or Model X) that can count on Tesla Supercharger network, with a rated power of up to 145 kW (Lambert, 2016). However, future electric vehicles are expected to be able to handle much higher charging powers. In November 2016, a group of major automakers (BMW Group, Daimler AG, Ford Motor Company and Volkswagen Group) signed a Memorandum of Understanding (MOU) for building a brand-independent ultra-fast charging stations network. About 400 ultra-fast charging sites are planned to be built in Europe, with power levels of up to 350 kW. The network will utilise Combined Charging System (CCS) standard, compatible with most of current and future EVs (Daimler, 2017).

As previously mentioned, Fortum Charge & Drive is planning to build a similar network. More specifically, the company is planning to connect Oslo, Stockholm and Helsinki with an HPC corridor, with a power of up to 350 kW (Fortum, 2017b).

2.2 EV Charging in Sweden

According to Power Circle, as of beginning of June 2017, there were 3402 public EV chargers. Considering that in January 2015 there were a total of 876 chargers, the number growth has been tremendous. However, out of these, the number of DC chargers is much lower. At the end of April 2017, there were 220 CCS and 221 CHAdeMO chargers in Sweden, with a maximum power of 50 kW. Notably, the number of Tesla Supercharges was 206, very close to the other two standards. The theoretical power of Tesla Superchargers is in line with the previously mentioned value of 145 kW. Apart from Tesla, three major companies operate charging stations in Sweden: Fortum Charge & Drive, Vattenfall and CLEVER.

Regarding location, the vast majority of the chargers are concentrated in the Stockholm county, with Gothenburg and Gotland following.

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19 Although, the maximum charging power that Tesla’s battery pack can handle currently 120 kW (Lambert, 2016).
3 Energy Storage System

This chapter provides background information about electrical energy storage. An overview of the storage methods and related technologies will be followed by a general description of possible applications. The technology chosen is lithium-ion batteries. This is due to their significant market share for EVs, as well as to additional benefits that will be briefly discussed in this chapter.

The IEA described energy storage as a technology that is able to "absorb energy and store it for a period of time before releasing it to supply energy or power services. Through this process, storage technologies can bridge temporal and (when coupled with other energy infrastructure components) geographical gaps between energy supply and demand" (IEA, 2014).

Energy storage can be categorised by output, which can be either electrical or thermal (cold and warm). Both categories alternatively serve as energy producers and consumers, providing flexibility to energy systems and improving management of energy supply and demand. However, since the thesis focuses on electrical application, this chapter will be centred only on electrical energy storage.

3.1 Energy Storage Overview

At the beginning of the 19th century, the Italian physicist Alessandro Volta invented the first electrochemical storage device, precursor of modern batteries (Danila, 2015). From that moment, the technology experienced an incredible evolution, such that it has currently become an essential part of our everyday life, from mobile phones to laptops and more recently, electric vehicles.

It must be stated however that batteries, despite being the most common in our everyday life, are not the only storage method. Electricity storage can be divided into three main methods: mechanical, electrical and electrochemical (IEA, 2014).

Mechanical Storage

Mechanical storage, consists in storing energy in the form of mechanical energy (potential or kinetic), which can be later converted to electrical power. Flywheel energy storage (FES), compressed air energy storage (CAES) and pumped hydro storage (PHS) are the most relevant technologies.

FES consists in storing kinetic energy in the form of rotation. Recent research in materials and design considerably increased their energy and power density, allowing them to be deployed as spinning reserves at 1.6 MW and 5 kWh (Göğüş, 2009).

CAES consists in compressing and storing ambient air in an underground cavern. To generate electricity, the pressurised air is heated and expanded. The expansion process drives a turbine connected to an electrical generator (ESA, 2017) Finally, potential energy can be stored using water. When there is an excess of electricity or the prices are low, water can be pumped from a lower reservoir to a higher. When needed, the water is let flow down to the lower reservoir driving a turbine (Göğüş, 2009).

PHS is one of the most established storage techniques. Interestingly, as of 2010 PHS accounts for 99% of installed capacity in grids worldwide. The remaining part consists of a mix of CAES, battery, flywheel and hydrogen storage (IEA, 2014). Conventional hydropower reservoirs and run-of-the-river may or not be

20 Throughout the thesis, whenever energy storage is mentioned without specifying whether it is electrical or thermal, it has to be interpreted as electrical energy storage.
21 This is true at least in modern science. In 1938, a German archaeologist discovered a device which is claimed to be the first fuel cell (2200 year old) (Danila, 2015).
22 Hydrogen and synthetic natural gas were not considered, as considered out of the power-to-power concept (Benz, 2015).
considered energy storage. In fact, in these cases there is no double flow of conversion. Consequently, these might be better seen as dispatchable power generation. These units are the most diffused type of hydropower generation in the Nordic countries (Benz, 2015).

Electrical Storage

Electrical storage is characterised by no energy conversion. While in the other methods electrical energy is converted into another form for being stored, this type allows direct electrical energy storage. The major technologies that use this methodology are supercapacitors and superconduction magnetic energy storage (SMES).

Double-layer capacitors – or supercapacitors – are based on the conventional capacitors, but exhibit a much higher energy and power density. However, compared to batteries, these are characterised by much lower energy density, but higher durability (up to one million cycles).

SMES follow an electrodynamic principle. The energy is stored in a magnetic field which is created by the flow of direct current in a superconducting coil, kept under critical temperature (nowadays, around 100 K). The key element of these systems is a coil of superconducting material. This technology is characterised by almost instantaneous response time and high-power delivery capabilities. Few commercial applications are available, mostly used for power quality control (IEC, 2011).

Electrochemical Storage

Electrochemical storage is based on the conversion of chemical energy contained in the active materials into electric energy, by means of an electrochemical oxidation-reduction reverse reaction (Krivik and Baca, 2013). Technologies that utilise this method are lead acid batteries, nickel-cadmium, sodium sulphur, sodium nickel chloride, lithium-ion, metal air and flow batteries. Here, the most widespread of these technologies are described.

Lead acid batteries are the most common technology, commercially deployed since the late 19th century. These are used for several applications, among which solar PV stand-alone systems and emergency power supply systems, as well as starters in ICE vehicles. These systems are characterised by high level of maturity; however, they present several drawbacks: low energy density, use of lead and capacity decrease under high power withdrawal (IEC, 2011).

Another interesting technology is flow batteries. The operating principle is similar to the one of conventional batteries, but a major distinction lies on the fact that the energy storage medium (active materials) is separated from the energy production unit (cell stack). Generally, the active materials are stored in tanks and are pumped into the electrochemical cell when needed (Cunha et al., 2016). An interesting consequence is that these systems could be quickly recharged by pumping renovated electrolytes into the tanks, a desirable feature for mobile applications. However, its low power density hindered diffusion for non-stationary purposes. Interestingly, Cunha et al. (2016) investigated the use of flow batteries, and precisely vanadium redox flow batteries, for energy storage in electric vehicle charging stations.

Lithium-ion is today's fastest growing battery chemistry. Since the early 2000s, it has become the leading technology in small portable devices. Most recently, it has also become the leading technology for BEVs, due to its high power and energy density. There are several Li-ion chemistries, each with different peculiarities. The main disadvantage of this technology lied on high costs, which hindered further development. However, in the last years, thanks to increased production volumes costs have rapidly decreased, making it the most promising battery chemistry. Li-ion batteries show long lifespan (5000-1000 cycles), high energy efficiency (95-98%), operation at low state of charge, as well as a compact and low-maintenance design. The battery requires sophisticated control electronics which on one hand increase manufacturing complexity, but on the other make the system particularly suitable for smart applications (Akhil et al., 2015; Benz, 2015; Eurobat, 2016).

Thanks to its versatility, the technology is being deployed on an extremely wide range of applications, from BEV to portable electronics, but also stationary storage, both at grid and household level. At household
level, it is worth mentioning sonnenBatterie and Tesla’s Powerwall. The latter offers a 14-kWh battery system at 61 000 SEK (Tesla, 2017d). As of 2016, there were about 200 MW of stationary Li-ion batteries operating worldwide in grid connected installations, but the figure is increasing. In the Nordic, Fortum operates the biggest Li-ion battery storage system (a Batcave system with nominal output of 2 MW and 1 MWh capacity) (Fortum, 2017c).

3.2 Electricity Storage Services
The Electricity Storage Handbook, jointly sponsored by the US Department of Energy and Electric Power Research Institute, is one of the most comprehensive documents on electrical energy storage. It identifies five main types of energy services that storage can offer: bulk energy services, ancillary services, transmission infrastructure services, distribution infrastructure services and customer energy management services (Akhil et al., 2015).

**Bulk Energy Services**

Bulk energy services are furtherly divided into electric energy time-shift and electric supply capacity. The first consists utilising the ESS to accumulate electricity when electricity is cheap. The stored energy can later be either utilised or sold during high-price periods. The same concept applies for the production side: excess electricity generated by stochastic renewable, which would be curtailed, can be stored for later use. This type of service applies to both low and large-scale customers.

Electric supply capacity refers to the possibility of using ESSs to defer or reduce the need to increase generation capacity. Under certain circumstances, ESSs could be used to provide additional capacity during peak demand periods, instead of installing additional generation units, which would be used inconstantly. In this case, energy storage cycling is generally lower than in the previous case.

**Ancillary Services**

Ancillary services encompass regulation, reserve capacity, voltage control, black start and other related usages. ESSs are particularly suitable for regulation services. These involve managing power flows to properly match scheduled flows and counterbalance momentary variations. An example of this service is frequency regulation, which is needed to neutralise momentary differences caused by unbalance between supply and demand of electricity. Batteries, due to their ability to act both as loads and as generators can be used both for up and down regulation.

Reserve capacity consists of spinning, non-spinning and supplementary reserves. In general, their duty is to act as reserve capacity that can be engaged when some generating units become unexpectedly unavailable. The response time of the first two\(^{23}\) is within minutes, while the second is in the order of an hour.

Voltage support involves managing reactance on the grid, by offsetting reactance effects that may cause grid instability. Reactive phenomena are usually generated by loads or generators that act as inductors or capacitors.

Storage systems can also play an important role for black start. Basically, they could be used to energise transmission or distribution lines to help them recover from a failure event and help generators to go back on line.

Among other uses, it is worth mentioning load following for renewable generators, which involves levelling out the variability that characterises these energy sources, and frequency response, similar to regulation, but characterised by even lower response time.

**Transmission Infrastructure Services**

Transmission infrastructure services consist in transmission upgrade deferral and congestion relief. Energy storage may be used to defer – and possibly totally avoid – the need of upgrading the transmission

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\(^{23}\)Which differ for the fact that the first is switched on but unloaded, while the second can be off line.
infrastructure. Due to increased overall energy demand, it may happen that peak power loading gets too close to transformers’ and/or power lines’ rated capacities. By putting an ESS downstream and loading it during off-peak periods, it is possible to lower equipment’s loading during peak times.

Congestion occurs when energy cannot be delivered due to bottlenecks in transmission facilities. This may also lead to congestion costs influencing the retail market. It differs from infrastructure deferral because in the first the magnitude of the problem has not reached the point to cause actual power shortages.

ESS could finally be used within transmission systems to improve power transmission quality.

Distribution Infrastructure Services

Distribution infrastructure services are essentially the same as in the previous section, but applied to the distribution grid. Consequently, they will not be explained.

Customer Energy Management Services

The last type of services can be further classified in power quality, power reliability, retail energy time-shift and demand-charge management. The first one involves using storage to protect the user from power quality problems, such as frequency and voltage variations, service interruption (for small periods of time), harmonics and low power factor.

ESSs can be used for improving power reliability; that is, protecting the user from longer periods of service interruption. The ESSs should be sized to provide the load with enough energy to allow normal operation until power is restored.

Retail energy time-shift allows the user to reduce the overall cost of electricity. It is similar to electric energy time-shift, but it is more about particular customer tariffs rather than wholesale electricity prices.

By implementing ESSs, customers have also the possibility of diminishing peak power consumption, thus incurring in lower demand charges. This feature, as well as the previous one, depends on the tariff structure and may not be effective in some cases, i.e. low electricity price differentiation and flat tariffs.

These were all the services that energy storage can provide. It must be stated however that in most of the cases, to increase profitability of the system – or in some cases to justify investment, it may be more reasonable to use the ESS for more than one of the above listed services.

3.3 Energy Storage Considered for the Model

The mathematical formulation of the model does not limit the simulation to a specific storage technology. However, the proposed design and discussion includes only a particular storage method and technology: lithium-ion battery. This technology was chosen over the others for both its technical performances and its projected cost reduction. As previously mentioned, prices of Li-ion batteries are expected to further decrease in the next years. By 2030, the price per kWh is estimated to be in the range of 100 USD/kWh (McKinsey, 2017b; Nykvist and Nilsson, 2015).

In particular, the data for the simulation were provided through personal communication with LG Chem, one of world’s major battery producers. Data are shown in APPENDIX IV.
4 Electricity in Sweden

This chapter provides relevant information regarding the Swedish power sector. After a brief overview, the chapter focuses on the aspects germane for the project, i.e. electricity costs structure. Both the retail prices and the distribution fees are explained, with particular attention to the different tariffs. The analysis of the tariffs was conducted only on two companies: Vattenfall and Vattenfall Eldistribution. Regarding distribution, the problem of network congestion is introduced and European regulation on the topic is briefly explained.

4.1 Electricity in Sweden: An Overview

The Swedish electricity market is composed of several actors, which can be grouped in two major “routes” that connect power producers with final consumers (Svenska Kraftnät, 2017a). As shown in Figure 4-1, the physical transmission (blue) works along with the financial trade of electricity (pink).

Figure 4-1: Schematic visualisation of the Swedish electricity market players. Source (Svenska Kraftnät, n.d.)

The former consists of 559,000 kilometres of power cables, which can be divided three levels: the national transmission grid, the regional distribution network and the local distribution network (Swedish Energy Markets Inspectorate, 2016). Svenska Kraftnät (SvK), a state-controlled public authority, is the owner and operator of the national grid (i.e. Swedish TSO24). Its duties are: 1) transmitting power from generators to substations; 2) maintaining the balance between electricity production and consumption; 3) strengthening the grid, by upgrading old power lines and developing new ones; 4) ensuring fair electricity trading in the power market. Together with its Nordic and Baltic counterparts, it’s the owner of Nord Pool (Svenska Kraftnät, 2017b). The inter-regional transmission is carried out at high voltage (220 kV – 400 kV). To allow connection to the regional grid, the voltage is stepped down to 40-130 kV in various substations. Three large companies own most of the regional distribution grid: Ellevio, Vattenfall Eldistribution and E.ON

24 Transmission System Operator.
Power Grids (Ellevio, 2015; Wangel, 2015). In turn, the local grid connects to the regional grid and distributes power at medium voltage (20 kV or lower). Major customers can have a MV connection – sometimes they are directly served by the regional network – but to allow domestic consumption the voltage must be further stepped down to LV\textsuperscript{25} (230/400 V). About 170 different companies run local grids, several of which owned by municipalities (Ellevio, 2015; Wangel, 2015).

During the 1990s, the Swedish government carried out a reform of the electricity sector, aimed at separating the commercial sides from the non-commercial ones. More specifically, generation, trade and retail were to be done on a commercial basis, following market rules, while grids were to be considered as regulated natural monopolies\textsuperscript{26} and would remain non-commercial. This is in line with European directives that, during the period 1996 to 2009\textsuperscript{27} modified the regulatory framework, allowing the unbundling of the power sector (Wangel, 2015; Zucker et al., 2013). In the case of Sweden, Energimarknadsinspektionen (Ei) is the regulatory agency in charge of supervising grid operations and safeguarding its impartiality (Swedish Energy Markets Inspectorate, 2016).

In the last 20 years, electricity production in Sweden has gradually become highly concentrated, due to the numerous acquisitions and mergers. In 2015, the five biggest utilities – namely, Vattenfall, Fortum Sverige, E.ON/Uniper, Statkraft Sverige and Skellefteå Kraft – collectively accounted for 80.2% of the country’s power generation. The state-owned Vattenfall is the one with the biggest share (40% of the total) (Svensk Energi, 2015). However, the actual share of the power market is lower, as electricity is traded across all Nordic countries.

Electricity producers sell their electricity on the power market where retailers buy it for their customers, charging them for the service. Sweden’s power market is Nord Pool. It is Europe’s leading electricity exchange market offering services across nine European countries (Sweden, Norway, Finland, Denmark, Estonia, Latvia, Lithuania and Germany). About 380 members – trading from 20 countries – are active on Nord Pool. The creation of a shared market was possible thanks to an increased interconnection between participating countries, whose grids are integrated enough to function as a single one, improving efficiency and flexibility (Nord Pool, n.d.; Wangel, 2015). The Nord Pool market is divided into various bidding areas to tackle network congestion, showed in Figure 4-2. When the transmission demand between two zones is higher than the available capacity, market prices are adjusted until congestion is relieved (Thema Consulting

\textsuperscript{25} Low Voltage.

\textsuperscript{26} It is in fact uneconomical to have several different grids that operate in the same area.

\textsuperscript{27} Specifically, 96/92/EC, 2003/54/EC and 2009/72/EC (Zucker et al., 2013).
Group, 2013). In some cases, SvK can manage congestion by increasing/reducing production in specific areas (counter-trading). Costs associated to counter-trading are borne by SvK (Swedish Energy Markets Inspectorate, 2016).

Nord Pool offers both day-ahead trading and intraday trading. In the first, power for the next day is traded. Bids need to be submitted before the noon deadline, after which all orders are elaborated into two curves: an aggregate demand and an aggregate supply curve. The intersection of the two curves determines the price is determined for each hour of the following day in each price area. At this point, as previously stated, if the system gets congested, prices are modified. To support the day-ahead market and increase flexibility, power is also traded in the intraday market.

A final remark should be made on Swedish electricity mix. The Swedish electricity market has been historically developed around hydro power and, after the oil crisis in the early 1970s, nuclear power. In 2015, these sources accounted for 81% of the electricity production. In the same year, just over a tenth of electricity was generated by wind, registering an increase of 44% respect to 2014. Consequently, Sweden electricity production has an extremely low carbon footprint. As of 2013, only Norway and Island performed better (Benz, 2015; Svensk Energi, 2015). In 2012, a new scheme was introduced together with Norway – replacing the old one launched in 2013 – further supporting renewable production. Sweden is aiming to be 100% renewables-powered by 2040 and according to the General Director of Ei, it is on track to achieving the goal (Reuters, 2016).

4.2 Retail

4.2.1 Key Facts

At the end 2015, there were 122 electricity suppliers registered to Elpriskollen.se, the price comparison website managed by Ei. However, it must be stated that this is not an absolute indicator as several local suppliers operate only locally. As for the previous four years, the three largest retail companies provided electricity to about 44% of Swedish customers. The current figure is likely similar (Swedish Energy Markets Inspectorate, 2016).

In 2015, taxes and VAT accounted for 46% of the final cost of electricity. The remaining portion was equally shared between electricity supply and transmission fees (about 27% each). About 85 to 90% of the supply price of electricity corresponds to the cost borne by the supplier to purchase the electricity on Nord Pool. In fact, during 2015, there was a fall in prices in the spot market. This caused the average system price over 2015 to be 19.68 öre/kWh, significantly lower than 2014 and 2013 prices, respectively 26.94 öre/kWh and 32.92 öre/kWh (Swedish Energy Markets Inspectorate, 2016). The remaining part of the electricity bill consists of the cost of electricity certificate, electricity disclosure and administration. On top of this, customers have to pay an electricity tax and VAT. Consequently, the variability of the retail price is not extremely influent on the final customer’s bill, as it accounts for less than a third of the final price.

Customers can choose between several contract options. Apart from the default price, it is possible to choose between variable price and fixed price contracts. The first type is directly depending on the spot price, while the second is based on the supplier’s cost for the electricity purchased in advance. Practically, in fixed price contracts the customer will know the cost of the electricity for one, two or three years ahead, while in variable price the cost is subject to both seasonal and year-to-year variation. This can result in higher or lower prices (Swedish Energy Markets Inspectorate, 2016).

As of 2015, the vast majority of domestic customers had variable price contracts (47%). In 2014, this figure was 6 percentage points lower. According to Ei, the trend is that more and more customers will move to this type of contracts in the future. About a third of the customers choose fixed price contract (Swedish Energy Markets Inspectorate, 2016).
Demand response\textsuperscript{28} tariffs are not yet in place. Ei was commissioned by the Swedish Government to examine the possibility of increasingly implementing demand response tariffs. More specifically, Ei was asked to suggest actions aimed at incentivising different players – both at retail and distribution levels – to stimulate demand response. The commission had to be completed by January 2017 (Swedish Energy Markets Inspectorate, 2016). Unfortunately, no information in English was available at the time of the writing.

4.2.2 Retail Fees: Vattenfall

Electricity price difference can be significant depending on the contract type. In the period between 2010 and 2015, the average difference between the most expensive and the most economical variable contracts was 16\% (Swedish Energy Markets Inspectorate, 2016). For the scope of this thesis, it was chosen to focus only on the ones offered by Vattenfall. Vattenfall offers different types of contracts depending on the type of customers, which can be divided in private or business. As a DC charging station falls into the second category, the private contracts were not considered.

According to their yearly electricity consumption, businesses contracts are divided into three groups: small (below 150 000 kWh/year), medium (between 150 000 kWh/year and 2 GWh/year) and large customers (over 2 GWh/year). According to the data provided by Power Circle, which will be discussed in more detail in section 5.4, the consumption of a DC fast charging station is currently well below the threshold of 150 000 kWh/year. Hence, tariffs offered to small customers were further investigated\textsuperscript{29}. Tariffs are not directly available on Vattenfall website, customers have to call the company’s customer service and request an offer. Offers may differ from day to day – reflecting the variability of the electricity price – and depend on the expected yearly consumption and the connection address. For the current project, the offer was retrieved on May 17th 2017, for a connection in Solna and considers an annual electricity consumption of 75 000 kWh\textsuperscript{30}. Table 4-1 and Table 4-2 summarise the main components of the tariffs, without taking into consideration VAT and electricity tax. The original offer is available in APPENDIX I.

<table>
<thead>
<tr>
<th>Fixed Price Tariff Component</th>
<th>6-months period</th>
<th>12-months period</th>
<th>24-months period</th>
<th>36-months period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Price (öre/kWh)</td>
<td>34.80</td>
<td>35.40</td>
<td>33.90</td>
<td>33.10</td>
</tr>
<tr>
<td>Electricity Certificate (öre/kWh)</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
</tr>
<tr>
<td>Total Electricity Price (öre/kWh)</td>
<td>80.38</td>
<td>81.13</td>
<td>79.25</td>
<td>78.25</td>
</tr>
<tr>
<td>Fixed Fee (SEK/year)</td>
<td>360</td>
<td>360</td>
<td>360</td>
<td>360</td>
</tr>
</tbody>
</table>

Table 4-1: Fixed price tariff - offer of May 17th 2017, connection in Solna and yearly consumption of 75 000 kWh. Source (Vattenfall)

Referring to Table 4-1, total electricity price considers electricity tax and VAT. Electricity tax at the time of the offer was 29.5 öre/kWh, however, on July 1st 2017 it was raised to 32.5 öre/kWh (Vattenfall, 2017b). The former value was considered for the calculations, as the change was notified after the implementation of the tariffs in the model. The general VAT in Sweden is 25\% (Verksamt, n.d.). The same considerations apply to variable price tariff.

\textsuperscript{28} Demand response consists in changing customer’s consumption behaviour to improve the efficiency of the electricity system. To promote demand response, different incentives may be used, e.g. price signals.

\textsuperscript{29} However, it must be stated that special conditions might apply for special loads such as DC charging stations. It was not possible to have direct information from DC fast charging stations owners, probably due to data confidentiality.

\textsuperscript{30} Actually, three different offers for three different expected yearly consumption were required (specifically, for 50 000 kWh/year, 75 000 kWh/year and 100 000 kWh/year). However, the only difference was in the yearly fee (årsavgift), which increased from 330 to 360 and 390 SEK per year.
Table 4-2: Variable price tariff - offer of May 17th 2017, connection in Solna and yearly consumption of 75 000 kWh. Source (Vattenfall)

<table>
<thead>
<tr>
<th>Variable Price Tariff Component</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Price – Monthly Metering Case (öre/kWh)</td>
<td>Monthly average Nord Pool price + 1.8</td>
</tr>
<tr>
<td>Electricity Price – Hourly Metering Case (öre/kWh)</td>
<td>Hourly Nord Pool price + 1.8</td>
</tr>
<tr>
<td>Electricity Certificate (öre/kWh)</td>
<td>Calculated at the end of each the month e.g. 2.85 öre/kWh – January 2017 price (Vattenfall, personal communication)</td>
</tr>
<tr>
<td>Fixed Fee (SEK/year)</td>
<td>360</td>
</tr>
</tbody>
</table>

In the variable price tariff, the price per kWh that the customer pays depends on the type of metering device applied to the connection. In the case of an hourly meter, which can discretise the electricity consumption per hour, the price of electricity will change hourly, according to Nord Pool. On the other hand, with standard metering, the reading is done at the end of each month and the customer bill will depend on the average price of electricity in Nord Pool for that month. The electricity certificate price varies monthly and its value is calculated at the end of each month. For the calculations, the price of January 2017 for Vattenfall customers was utilised.

In order to visualise the trend of electricity prices in the two metering cases, refer to Figure 4-3 and Figure 4-4. For building the graphs, the market prices were retrieved from Nord Pool website31. Here, historical market data are available for all bidding areas and in different currencies. The data displayed are relative to SE3, the bidding area where Stockholm is located (see Figure 4-2), and the currency is Swedish crowns32.

Figure 4-3: Final electricity price for variable price tariff with monthly metering and Nord Pool monthly average price in the period May 2016 to April 2017. Source (Nord Pool, 2017)

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31 [www.nordpoolspot.com](http://www.nordpoolspot.com).

32 In the charts, the vertical axes unit is öre/kWh. Öre is the centesimal subdivision of the Swedish crown.
Figure 4-4: Final electricity prices in the case of hourly metering in four different days and Nord Pool price for January 24th, 2017. Source (Nord Pool, 2017)

Figure 4-4 shows the final electricity price per hour in four different days, two summer days and two winter days. It was tried to select and display various possible trends. It is clear, however, that this has to be taken as a “freeze-frame” of the actual price trend in particular days and no detailed historical research on electricity prices was conducted, as out of the scope of the thesis. Hence, the data have not to be considered as indicators of “typical” patterns.

It is interesting to see that the relative variability of the price in Nord Pool is consistent both during the year and during the day. For example, the average price of November 2016 was double the price of May 2016 (red line Figure 4-3). Similarly, the peak price on January 24th 2017 was 76% higher than the lowest price during the same day (light blue line Figure 4-4). However, since the Nord Pool price is just a component of the final price, the relative difference in the final prices is much lower. In fact, considering all taxes and levies, the final electricity price is more than double the initial Nord Pool price.

For the actual modelling and optimisation, it was chosen to focus only on the variable tariff. In fact, since an ESS was involved, it was interesting to test if it was cost effective to use it for demand shifting as well as for peak shaving. Demand shifting consists in moving the electricity consumption – and purchasing – to different hours of the day when electricity is cheaper by storing it in an ESS for later use. A great difference in electricity prices during the day incentivises these measures. On the other hand, peak shaving aims at lowering the peak power consumption. This can be influenced by the electricity price, but it is mostly affected by demand charges, i.e. the fee that distribution operators apply for maximum power consumption (further explanation will be provided in the next section).

4.3 Distribution

4.3.1 Key Facts

As previously explained, the distribution network is divided into regional and local grids. The first is run by three major companies, while about 170 different companies run the local grids, several of which owned by municipalities (Ellevio, 2015; Wangel, 2015). Distribution is run as a natural monopoly, regulated by Ei.

All companies are obliged to establish a supervision plan, in line with the Swedish Electricity Act 2. This has to be followed by a report that contains the measures implemented following the plan. The purpose of
these documents is to ensure that companies act in a fair manner respect to both customers and competitors (Swedish Energy Markets Inspectorate, 2016).

Generally speaking, Sweden is lagging behind in incentivising distribution operators to invest in demand response and regulatory framework is weak. Currently, no mechanism allows distribution operators to purchase demand-side flexibility. In late 2016 Ei developed a report on the topic. However, results were not available at the time of writing (SEDC, 2017).

Due to the nature of the network sector, tariffs need to be objective and reflect the actual economic burden for the DSO to serve its customers. Low power consumers’ fees consist of a fixed fee and a fee per kWh, with no incentive for lowering their demand during peak periods (SEDC, 2017). On the other hand, the tariff for high-power customers – connection of 55 kW or higher – charges different fees, depending on the time of use. More specifically, there are two periods: peak period and “normal”. Weekdays33 from 6 am to 10 pm during January, February, March, November and December is considered peak period (Vattenfall Eldistribution, 2017). This is the only mechanism currently in place to incentivise a smarter consumption.

Regarding regulations, it is important to mention – due to the direct implications in the project discussion – that in Sweden the same legal entity involved in network operations, cannot be active in other activities not linked to distribution34. This measure avoids cross-subsidisation between companies involved in different sectors (Swedish Energy Markets Inspectorate, 2016). For example, Vattenfall is participating in generation and trade, while Vattenfall Eldistribution deals with network operations. Despite the latter being part of the same vertically integrated undertaking, they are separate in terms of organisation and decision-making, in conformity with European directives (Vattenfall, 2017). Positive effects of this measure are clear, since it prevents discrimination and encourages adequate maintenance of the equipment. However, together with unclear regulation on BESS, both in Sweden and EU, it hinders the implementation of energy storage. In fact, DSOs cannot operate or own electricity storage systems, which could be used for avoiding congestion or improving system’s efficiency. The crucial problem is that there is no clear definition of batteries, which can be both seen as generators and loads, due to their charging and discharging capabilities. The directive does not prevent other electricity entities to utilise storage, but grid fees and taxes may be paid during the system operation (Benz, 2015).

It should be noted that the EU policymakers are currently working to solve these regulatory shortcomings and allow full deployment of technologies like storage and demand response. Specifically, in November 2016, the Commission for Climate Action and Energy presented the legislative proposal “Clean Energy for All Europeans”. In the section of the package addressing electricity regulation35, concrete plans intend to solve the previously-mentioned problems. In addition to a new definition36 of energy storage, aiming to break the generation/consumption dichotomy, the package comes with several proposals. The suggested actions to be taken by member countries include the introduction of better pricing signals that enable the use of storage and demand response, as well as network fees ensuring long-term investment in storage facilities. DSOs and TSOs are specifically suggested to take advantage of ESS to tackle network congestion and improve dispatch efficiency. However, the operation of ESS is promoted as a commercial activity to be conducted by market players and not by regulated entities. Hence, TSOs and DSOs are still not allowed owning or operating this kind of systems. Only in particular situations, when other market players are not

33 Except New Year’s Day, Epiphany, Maundy Thursday, Good Friday, Easter Monday, Christmas Eve, Christmas Day, Boxing Day and New Year’s Eve.
34 As required by the Directive of 2009/72/EC of the European Parliament and of the Council of July 13th, 2009. The directive requires that DSOs part of vertically integrated companies are “independent at least in terms of […] legal form, organisation and decision making from other activities not relating to distribution”. This is binding for vertically integrated undertakings with more than 100 000 served customers, while for smaller entities each EU government can decide autonomously whether to apply it or not (European Union, 2009).
35 The “Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal market in electricity”.
36 “Energy storage, in the electricity system, means the deferring of an amount of the energy that was generated to the moment of use, either as final energy or converted into another energy carrier” (European Commission, 2017).
interested in offering such services, network operators can invest in electricity storage, but under the strict supervision of regulatory agencies (European Commission, 2016).

Due to this regulation, in the final discussion, ownership of the energy storage by DSOs is neglected.

### 4.3.2 Distribution Tariffs in Sweden: Vattenfall Eldistribution

Similarly to the case of electricity supply, also for the distribution service, it was chosen to focus on solely one company: Vattenfall Eldistribution. As for Vattenfall retail, distribution customers are divided into business and private customers. Due to the scope of the study, the focus was on the first type. All information reported in this section is available at Vattenfall Eldistribution website.

Distribution tariffs are divided into three big groups, according to the size of the connection required: fuse subscription, power subscription and regional network fees. The latter applies to very large customers that directly connect to the regional network. These tariffs are characterised by very low transmission fees and very high annual fees. Annual fees consist of a yearly connection fee and an annual power fee. This tariff type was disregarded as the power requirement of a fast charging station is far lower than the one of the typical customers connected to the regional grid. Fuse subscription is limited to 63 A, which allows for a maximum power withdrawal of about 43 kW. A typical DC charging point has a power of 50 kW and — as it can be seen in charging providers websites, e.g. Fortum Charge & Drive – it is generally installed together with a similar DC charging point and/or other AC chargers. Hence, it would not be reasonable to have the available power limited to 43 kW. The analysis consequently focused on power tariffs.

Power tariffs are further divided into two tariff zones, North and South of Sweden. Since the station is placed in Stockholm, the latter was selected. The distribution fees consist of a fixed charge per month, a monthly fee depending on peak power consumption (demand charge) and a transfer charge per kWh consumed. Table 4-3 presents in detail the values of these components for the five different tariffs.

The power tariffs are divided into high-voltage tariffs (N2, N2T and N3) and low-voltage tariffs (N3T and N4). Low-voltage tariffs refer to connections to the 230/400 V AC grid. Companies that have a 6/20 kV connection and own the transformation to 0.4 kV can choose high-voltage subscription. Both were implemented in the optimisation. However, for high-voltage tariffs, the additional cost of the transformer had to be considered, since the selected charging station is designed to be connected to a low-voltage AC line (400 V).

#### Table 4-3: Vattenfall Eldistribution power tariffs for South Sweden. All prices excluding VAT. HV stands for high voltage while LV stands for low voltage. Source (Vattenfall Eldistribution, 2017)

<table>
<thead>
<tr>
<th>Component</th>
<th>N2 HV</th>
<th>N2T HV</th>
<th>N3 HV</th>
<th>N3T LV</th>
<th>N4 LV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge (SEK/month)</td>
<td>220000</td>
<td>23400</td>
<td>24500</td>
<td>3200</td>
<td>365</td>
</tr>
<tr>
<td>Monthly Power Fee (SEK/kW month)</td>
<td>10</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>40</td>
</tr>
<tr>
<td>Peak Period Power Fee (SEK/kW month)</td>
<td>16</td>
<td>41</td>
<td>58</td>
<td>70</td>
<td>0</td>
</tr>
<tr>
<td>Transfer fee peak period (öre/kWh)</td>
<td>5</td>
<td>9.5</td>
<td>19.8</td>
<td>22.1</td>
<td>52.4</td>
</tr>
<tr>
<td>Transfer fee normal (öre/kWh)</td>
<td>2.4</td>
<td>5.2</td>
<td>6.9</td>
<td>9.1</td>
<td>14</td>
</tr>
</tbody>
</table>

In the fixed charge provided in Table 4-3, all other fixed fees are included. For connection to high voltage, these consist in: electrical security fee 750 SEK/year, network monitoring fee 600 SEK/year and electricity fee 2477 SEK/year, for a total of 3827 SEK/year excluding VAT. For connection to low voltage, the taxes are much lower: electrical safety fee 9.50 SEK/year, network monitoring fee 3 SEK/year and electricity fee 45 SEK/year, total 57.50 SEK/year excluding VAT. The stated fixed rates comprise government charges.

37 The power was calculated as follows: $P_{\text{max}} = \sqrt{3} \cdot \text{Fuse Size} \cdot \text{Voltage} = \sqrt{3} \cdot 63 \cdot 400 = 43648 \text{ kW}$. 
Moreover, there are charges related to reactive power consumption. However, since the charger’s power factor is very high, these components were neglected in the calculations.

For the analysed system, the most important parameter – as confirmed by the simulations – consists in the power fee, also referred as demand charge. It consists in a fee which is applied monthly and depends on the peak power withdrawal during the month. It is in place to reflect network costs for delivering energy at high power, which may stress the grid and/or cause congestion. In Sweden, the value of power that is multiplied by the power fee is the calculated is the maximum hourly average consumption\textsuperscript{38}. During off-peak periods, only the monthly demand charge is applied. During peak periods, on top of the monthly power fee the customer must pay a demand charge for the maximum consumption occurred during peak time in that month. Demand charges can be quite consistent in the monthly bill – especially during peak period – and represent the single most significant economic incentive to install an ESS.

### 4.3.3 Connection Fees

In addition to distribution fees, new customers are required to cover the costs for the new connection. These costs depend on the size of the connection and on the crow-fly distance from existing substations. For the calculations, it was assumed that the connection point is within 400 meters from an existing substation\textsuperscript{39}.

<table>
<thead>
<tr>
<th>Main Fuse Size (A)</th>
<th>Cost\textsuperscript{40} (SEK)</th>
<th>Maximum Power (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Larger Fuse</td>
</tr>
<tr>
<td>16 - 25</td>
<td>22 100 + 189 SEK/meter</td>
<td>17.3</td>
</tr>
<tr>
<td>35</td>
<td>35 000 + 189 SEK/meter</td>
<td>24.2</td>
</tr>
<tr>
<td>50 - 63</td>
<td>48 000</td>
<td>44</td>
</tr>
<tr>
<td>80 - 125</td>
<td>85 000</td>
<td>87</td>
</tr>
<tr>
<td>160</td>
<td>100 000</td>
<td>111</td>
</tr>
<tr>
<td>200 - 250</td>
<td>140 000</td>
<td>173</td>
</tr>
<tr>
<td>315 - 500</td>
<td>240 000</td>
<td>346</td>
</tr>
<tr>
<td>600 - 750</td>
<td>340 000</td>
<td>520</td>
</tr>
<tr>
<td>800 - 1000</td>
<td>450 000</td>
<td>693</td>
</tr>
<tr>
<td>1250</td>
<td>560 000</td>
<td>870</td>
</tr>
<tr>
<td>1500</td>
<td>670 000</td>
<td>1039</td>
</tr>
</tbody>
</table>

### 4.3.4 Distribution Network Congestion

As stated in the introduction, one of the key drawbacks of fast charging consists in the impact that it has on local distribution grids. High power withdrawal and unpredictability may be difficult to handle by local grids,\textsuperscript{38}

\textsuperscript{38} Basically, the energy demand over an hour is registered and the average power is computed. This may lead to great imprecision. For example, charging sessions that start close to the end of an hour can withdraw high amount of power for a small period, since only the average during the whole hour is considered for the demand charge. See section 4.3.5 for further discussion on metering resolution.

\textsuperscript{39} It is however important to note that the distance from an existing substation might be much higher for locations in the inner-city centre.

\textsuperscript{40} Costs displayed are relative to 400 meters as crows fly from an existing substation.
especially if already congested. An interviewee at Vattenfall Eldistribution confirmed this issue and revealed that the area of Stockholm and Solna\textsuperscript{41} are currently suffering from occasional congestion, in periods of high demand. In the future, aided by rising population\textsuperscript{42} and EVs diffusion, electricity demand is expected to increase, putting additional pressure on the grid. Ellevio and Vattenfall, are collaborating on the programme “Stockholm Ström”, which aims at improving the current infrastructure (Ellevio, 2015). However, as pointed out by the interviewee, expanding the grid and building new substations is a cumbersome task, which may require several years to be finalised, mainly due to bureaucracy. According to a report from the Royal Swedish Academy of Engineering Sciences (IVA), permits requirement process is currently creating bottlenecks in many important renewal projects. To give an idea, a transmission power line concession takes around 10 to 12 years to be concluded. The actual construction takes about three years; the rest of the time is spent on permits and planning. For a new station, the process takes about 4 to 5 years, with only 1.5 devoted to the installation (IVA, 2016).

With the current pace of diffusion of EVs, actions should be taken sooner. Storage, indeed, could be a viable option to postpone infrastructure investment and ensure grid operation reliability. Interestingly, as part of the previously-mentioned proposal presented by the European Commission in 2016, EU governments are suggested to implement a regulatory framework that enables DSOs to use new technologies – such as storage – to supplant the need for new traditional investments\textsuperscript{43}. More specifically, DSOs\textsuperscript{44} should present development plans to their regulatory agencies every two years. These plans should present the intended investments to connect renewable generation and new loads – including charging stations – and should prove that new technologies\textsuperscript{45} are implemented as a substitute of network expansion (European Commission, 2016). Upon approval of the proposal, great market development of storage systems – similar to the one studied in this project – is to be expected.

4.3.5 The Spanish Model

In Spain, the electricity pricing is quite different from Sweden. Its characteristics make it more efficient in tackling problems of high and fluctuating demand from fast charging stations. It was selected to show a different approach. Of course, the same model cannot be applied in Sweden, as the framework in which it would be applied is totally different. It was not possible to describe in detail the whole Spanish electricity sector; thus, this section’s content was limited. This section aims at briefly describing the key aspects of the tariffs relevant to the thesis topic, by taking as an example the tariff structure offered by Endesa, leading company in the Spanish electricity sector (Endesa, 2017a).

The customer has to sign a single contract with a utility which will provide both retail and distribution service. The periodical bills include both electricity retail costs and distribution fees. Excluding taxes and possible rental of equipment and regardless of the contract type\textsuperscript{46}, there are two separated costs, one related to power and one related to electricity consumption (Endesa, 2017b). While the latter is similar to the Swedish price per kWh, the first is substantially different from the Swedish model. The customer has, in

\textsuperscript{41} Vattenfall Eldistribution is operating in Solna. The grid in the central area of Stockholm is instead managed by Ellevio.

\textsuperscript{42} Stockholm is expected to host 2.6 million people in 2030 (Ellevio, 2015).

\textsuperscript{43} Typically, network expansion.

\textsuperscript{44} Member States can decide whether to apply or not this obligation to undertakings with less than 100 000 customers or operating in isolated areas (European Commission, 2016).

\textsuperscript{45} In particular, “demand response, energy efficiency, energy storage facilities or other resources” (European Commission, 2016).

\textsuperscript{46} In Spain, there are two main tariffs, the “mercado libre” (free market) and the “mercado regulado” (regulated market). Customers can freely choose between the two. In the first, the electricity price follows the electricity market and varies day by day and hour by hour, while in the second the customer knows beforehand the price of the electricity depending on the time of use.
fact, to decide beforehand the maximum power that will be consumed in each of the three billing periods\textsuperscript{47}. Each contracted kW has a cost which is dependent on the period: a kW during peak hours costs more than during off-peak hours or during “low demand” as it can be seen in Table 4-5 (Endesa, 2017c).

<table>
<thead>
<tr>
<th>Power Range</th>
<th>Period</th>
<th>Power Fee [EUR/kW per month]</th>
<th>Energy Fee [EUR/kWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>30 kW &lt; Power ≤ 50 kW</td>
<td>Peak</td>
<td>41.950752</td>
<td>0.165265</td>
</tr>
<tr>
<td></td>
<td>Off-Peak</td>
<td>25.170444</td>
<td>0.132377</td>
</tr>
<tr>
<td></td>
<td>Low Demand</td>
<td>16.780296</td>
<td>0.093509</td>
</tr>
</tbody>
</table>

Table 4-5: Prices for Spanish companies under Endesa’s “Preferente” tariff and contracted power in the range 30-50 kW. Source (Endesa, 2017c)

This pushes the customer to reduce the contracted power during peak periods, thus minimising its impact on the grid when it is most needed. In addition, the distribution operator knows in advance the maximum power that will generally\textsuperscript{48} be consumed by the customer in each of the billing periods. Similarly to Swedish distribution companies, the power profile is registered and its maximum value is considered to ensure the compliance with the CP. If the customer exceeds the contracted power, it will incur in a fine (there is a 5% tolerance margin). If the maximum registered power is lower than 85% of the CP, the customer will pay 85% of the fee (Som Energía, 2016).

Related to the power profile monitoring, there is another important difference that should be mentioned. In Spain, since 2001, for connections with contracted power higher than 15 kW it is mandatory to install monitoring equipment that is able to measure and record the average power profile with a temporal resolution of 15 minutes (Spanish Government, 2001). The shorter resolution forces customers to have a more regular load throughout each hour. To exemplify the impact that a shorter time resolution has on the power fee, refer to Figure 4-5.

\textsuperscript{47} There are three billing periods, which vary depending on the season. For example during winter, 12am-8am is “low” period, 6pm-10pm is “high” period while 8am-6pm and 10pm-12pm is “normal” period (Endesa, 2017c). See APPENDIX III for detailed table.

\textsuperscript{48} Generally - because the contracted power does not imply a physical limit on the power that can be used. In fact, the customer can have different contracted power in each period.
The red line shows a simplified example of a 150-kW HPC station’s demand profile. The graph is plotted over an hour, assumed to match the metered hour. At minute 10, the demand reaches 150 kW and stays so until minute 29, for a total withdrawn energy of 50 kWh. A meter registers the energy withdrawn from the grid in each period and computes the average power demand, dividing total energy by the length of the period $P_{\text{average}} = \frac{\sum E_{\text{consumed}}}{T}$. In the case shown in the graph, a meter with an hourly resolution records an average power demand of 50 kW (blue line). Instead, a meter with a 15-minutes resolution records an average power of 60 kW in the first quarter and of 140 kW in the second. No power is recorded for the rest of the hour. It is clear that, in the latter case, the measuring equipment can better characterise the actual load behaviour, thus enabling the distribution operator to charge their customers more equitably. Assuming a power fee of 10 SEK per kW\(^4\), the customer would be charged 500 SEK in the first case, while 1400 SEK in the second.

The proposed example shows how increasing the detail of measuring equipment – also when maintaining the same tariff scheme – creates a strong incentive for customers to flatten their load demand.

\footnote{\textup{Equal to the monthly power fee that Vattenfall Eldistribution applies to N2 customers.}}
5 Modelling

This chapter covers the core of the thesis project: the modelling process. After a short introduction, where the methods used by previous literature studies are exhibited, the system’s layout, the assumptions, the control strategy, the charging load modelling, the detailed mathematical formulation and the sensitivities are presented.

5.1 Introduction

The literature review enabled to identify the most suitable methodology for the optimal design of the system. The approaches of the most relevant papers will be briefly described in the following paragraph.

Some researchers offered a simplified linear version, which, however, does not allow modelling either/or situations, required to properly take into consideration battery charge and discharge as independent variables. Going back to the literature review presented in Chapter 1, Gunter et al. (2013) showed a formulation with a single variable ($P_{batt}$ – battery power) that assumes positive and negative values depending on whether the energy flows in or out from the ESS. However, in order to do so, it was considered that the battery could never absorb power when the load is different from zero. This is a risky assumption, as there might be cases in which it might be invalid. For example, if the electricity prices are extremely low in a given time period, it could make sense to both charge the battery and satisfy the energy demand. Ding et al. (2015) addressed the issue with a mixed-integer non-linear formulation. However, they showed how the problem could be simplified to a LP, without losing accuracy in the results. Negarestani et al. (2016) used a MILP formulation. However, in the paper is not clearly stated how the integer variables were implemented. The objective function was formulated considering solely electricity purchasing cost at each time interval and energy storage cost. In particular, only one coefficient – that summed both investment and O&M costs - was considered for the energy storage. Other equipment was neglected in the analysis. Corchero et al. (2012) instead, kept a simpler LP approach. However, the objective function was complete and diverse, with equipment and connection costs considered in the optimisation.

In light of all the above, the problem was formulated as a mixed-integer linear problem (MILP). This allowed to properly model battery behaviour. Specifically, binary variables\(^{50}\) were used to create the before mentioned either/or situations, required to force the problem to consider the ESS as either a source of power or as a load. In addition, they were utilised to count costs of some equipment (i.e. transformer and connection fuse) as a step function. The detailed formulation is presented in section 5.5.

The software environment used for the problem implementation was MATLAB. The function used to solve the optimisation problem was “intlinprog”, available on all MATLAB versions, starting from R2014a (MathWorks, 2017).

5.2 System’s Layout

The first step in the modelling process was the identification of the system’s layout. From a broad perspective, a standard fast charger is composed of the grid interface, a transformer (when required) and the chargers (connected to the AC line). When storage is considered, the number of components increases and two main topologies can be utilised: the AC and the DC bus bar configurations, shown in Figure 5-1.

\(^{50}\) Binary variables are variables that can assume only two values. In they could be either 0 or 1.
In the first case, the chargers are connected to the AC bus bar. Consequently, a converter in the charger is required to transform the voltage to DC and feed the vehicles. A similar converter needs to be installed on the battery bank interface. A circuit breaker and a filter are placed on each charger to disconnect it from the grid and to ensure a good level of power quality. In the second case, an AC/DC converter – with filter – is located right after the transformer. Both chargers and storage only need DC/DC converters at the interface with the DC bus bar. Compared to the former, this configuration is theoretically more efficient and economical. Since all the equipment works in DC, fewer conversion steps are required, thus reducing losses and hardware costs. In addition, using one big converter instead of several smaller ones is beneficial from both the efficiency and cost point of view (Bai et al., 2010).

Nevertheless, the AC layout was selected for the analysis. The reason is that, from a practical point of view, it is more convenient. AC systems have been used for long and there are several available standards and technologies. Moreover, as of today, the majority of the chargers are engineered to be connected to the AC grid (ABB, 2017; EVTEC, 2017).

The layout considered for the modelling is a simplified version of the AC bus bar configuration previously presented and is shown in Figure 5-2.

Breakers and filters are neglected for the modelling purpose and the chargers considered include internal converters. The efficiency of the whole system takes into consideration both conversion and electrical inefficiencies. The converter placed between the battery and the bus bar also serves as a battery management system (BMS), regulating charging and discharging process. The actual system would require a control
system that receives information from the single components, monitoring and controlling the behaviour of the “smart microgrid”.

5.3 Assumptions and Limitations

Modelling energy systems, and modelling in general, often requires simplification of the reality. In this section, the main assumptions and simplifications utilised in the problem formulation are described.

- The mathematical formulation of the problem can be adapted to simulate any time period. However, it was chosen to simulate and optimise the system over a period of 24 hours. On one hand, running the simulation over a whole year would tremendously increase the problem’s size and thus, its simulation time, making sensitivity analysis complicated to conduct; on the other, “creating” a load profile over a year, would have been a cumbersome process.
- Due to the optimisation horizon, it was not possible to perfectly take into consideration on-peak and off-peak days. To consider this, both the on-peak and off-peak case will be shown.
- Due to the limited optimisation horizon, day-to-day variation of the charging demand could not be simulated. The charging profile was conceived to reflect an average day.
- The converter cost is assumed to be linearly dependent on its power rating. An interview with industry experts revealed that this value can be considered to be around 800 SEK/kWh. This value was used during the optimisation study.
- Similarly to the previous case, the battery cost is assumed to be linearly dependent on its capacity.
- Battery degradation was not considered in the optimisation. The methodologies implemented by Bordin and Anuta (2017) and Ortega-Vazquez (2014) to calculate degradation costs could not be implemented due to the nature of the problem. In these studies, the battery size is an input parameter, while this project aims at calculating it.
- None of the key studies briefly described at the beginning of the section took into account battery cycles for the economic analysis. The yearly battery cost was considered assuming an expected battery lifetime in years, insert as an input data. Instead, the following project takes into consideration battery usage – by tracking performed cycles – for calculating its actual lifetime. In order to keep the MILP expression, an iterative process was proposed. The lifetime is calculated as follows:

\[
{\text{lifetime}_{\text{batt}}} = \frac{{\text{lifetime throughput}}}{{\text{yearly throughput}}} = \frac{{N_{\text{cycles}}C_{\text{batt},r}}}{{365\sum_{t=1}^{N}E_{\text{batt}}}}
\]

where \(C_{\text{batt},r}\) is the battery rated capacity, \(\sum_{t=1}^{N}E_{\text{batt}}\) is the energy delivered by the battery in a day and \(N_{\text{cycles}}\) is the number of cycles to failure. This is a simplified approach, since the actual cycles to failure depend on several factors, related to both environmental and operative conditions. Among these, the dependence on the depth of discharge is quite significant, as pointed out by Bordin and Anuta (2017). However, during the simulation, it was shown that the battery tends to discharge until reaching the minimum allowable state of charge (10%). Hence, the number of cycles was considered for this value of depth of discharge. Another simplification lies on the calculation of the yearly throughput, which is calculated assuming all days with the same battery utilisation.
- Standard connection costs were considered for the calculations. In particular, it was assumed that the connection point would be within 400m – as the crow flies – from the closest substation.
- It was not possible to simultaneously simulate different tariff types. Hence, the procedure was carried out manually.
• The transformer\(^{51}\) was considered only in the case of high-voltage connection type (See APPENDIX II for detailed tariff tables).

### 5.4 Charging Load

As previously mentioned, instead of a mathematical formulation, an empirical method was used for the charging load modelling. Initially, to have a clear idea of the utilisation of fast charging in Sweden, the major companies active in EV charging business in Sweden\(^{52}\) were contacted. Unfortunately, due to the sensibility of the statistics required, it was not possible to receive precise data. Consequently, a different strategy for the identification of a reasonable charging load was implemented. Data from three different sources were merged together to create a plausible load profile. Statistics on DC fast charging stations in Sweden were retrieved from an analysis conducted by Power Circle, the charging demand of two popular electric vehicles was taken from various sources\(^{53}\) and the typical daily distribution of charging event for DC stations was obtained from a report by CIRCE (2015).

Power Circle, a Swedish special-interest group focused on electrical power, carried out a study on the charging demand of more than one hundred EV fast charging station in Sweden. The analysis was performed on 129 DC charging stations over two-year period, from January 2015 to December 2016. As of 31st December 2016, a total of 190 DC charging points were installed in Sweden, making the analysed group (68% of the total) statistically relevant (Power Circle, 2017a). The stations included in the analysis are located in different parts of Sweden and owned by the major companies active in the fast charging business in Sweden\(^{54}\).

The analysis conducted by Power Circle focused on three parameters related to each station: daily energy consumption, number of charging sessions per day and kWh per session. Looking at the global picture, the figures do not seem particularly promising. A typical DC charging station in Sweden consumes 11.4 kWh per day split in 1.13 sessions. The energy charged per session is on average 10 kWh. However, it must be stated that the variability among the analysed group is considerable. Table 5-1 and Table 5-2 compare the three parameters for the mostly used and the least used charging stations\(^{55}\).

<table>
<thead>
<tr>
<th>Energy Consumption (kWh/day)</th>
<th>Location</th>
<th>Daily Sessions</th>
<th>Location</th>
<th>Energy per Session (kWh/session)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>49.88</td>
<td>Highway</td>
<td>4.07</td>
<td>Highway</td>
<td>19.78</td>
<td>Highway</td>
</tr>
<tr>
<td>44.72</td>
<td>Highway</td>
<td>3.59</td>
<td>Highway</td>
<td>17.18</td>
<td>City</td>
</tr>
<tr>
<td>38.60</td>
<td>City</td>
<td>3.14</td>
<td>Highway</td>
<td>17.05</td>
<td>City</td>
</tr>
<tr>
<td>37.86</td>
<td>Highway</td>
<td>2.90</td>
<td>Highway</td>
<td>16.83</td>
<td>Highway</td>
</tr>
<tr>
<td>37.82</td>
<td>Highway</td>
<td>2.86</td>
<td>City</td>
<td>16.59</td>
<td>City</td>
</tr>
</tbody>
</table>

\(^{51}\) Transformer sizes and relative costs are shown in APPENDIX.

\(^{52}\) Namely, Vattenfall, Fortum Charge & Drive, Clever and Tesla.

\(^{53}\) A Nissan Leaf profile is based on data provided by Shordone et al. (2016), while a Tesla 90D load profile was taken from data displayed on a Tesla Model S 90D (Nyland, 2017).

\(^{54}\) Tesla Superchargers are not included in the analysis.

\(^{55}\) The stations with less than ten charging events were not considered in the sample.
Table 5-2: Figures for the five less utilised stations in Sweden – and their location – according to different parameters.
Source (Power Circle)

<table>
<thead>
<tr>
<th>Energy Consumption (kWh/day)</th>
<th>Location</th>
<th>Daily Sessions</th>
<th>Location</th>
<th>Energy per Session (kWh/session)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.47</td>
<td>City</td>
<td>0.2</td>
<td>City</td>
<td>4.23</td>
<td>City</td>
</tr>
<tr>
<td>1.83</td>
<td>Highway</td>
<td>0.24</td>
<td>Highway</td>
<td>4.27</td>
<td>Highway</td>
</tr>
<tr>
<td>2.45</td>
<td>Highway</td>
<td>0.28</td>
<td>City</td>
<td>5.18</td>
<td>City</td>
</tr>
<tr>
<td>2.51</td>
<td>Highway</td>
<td>0.28</td>
<td>City</td>
<td>5.27</td>
<td>Highway</td>
</tr>
<tr>
<td>2.92</td>
<td>Highway</td>
<td>0.31</td>
<td>Highway</td>
<td>5.86</td>
<td>Highway</td>
</tr>
</tbody>
</table>

Note that listed stations may vary from one parameter to the other, as they were scored independently for each of the different parameters.

As shown by the tables, the data variability is consistent. The least used station charges on average 1.47 kWh/day, while the same figure for the most used is 49.88 kWh. In terms of daily sessions, the best performing station is used 20 times more respect to the least used. Although based only on a small sample, it is interesting to note that in terms of daily energy consumption and number of sessions, stations positioned in highways have higher scores, while stations in cities have higher values of energy per session.

The exact location of the charging station analysed was not provided, however, part of the analysis shows results for a smaller sample of 32 stations, located in Stockholm and close to the Norwegian border, identified as the mostly used stations. For this group, the average energy consumption is 24 kWh/day, the sessions per day are 1.9 and the energy per session is 12.4 kWh. A further statistical investigation focused on the evolution of charging use throughout the studied time period. Results showed a remarkable increase in the utilisation of these systems: all but two charging stations at least doubled their energy consumption during the two-year time span. In light of the two mentioned analysis, it is possible to deduce that stations’ utilisation is higher in Stockholm and close to the Norwegian border and that the utilisation of these systems had been constantly increasing.

For the current project, it was chosen to focus on the sample of stations located in Stockholm and close to the Norwegian border – the ones with the highest utilisation – as more relevant for the purpose of the project. Moreover, highly utilised stations are more likely to implement this kind of systems. Their load profile is also more interesting to analyse from the point of view of grid impact. Figure 5-3 (following page) shows the consumption evolution that these stations experienced during 2016.

The average daily consumption, as of July 2017\textsuperscript{57}, was calculated starting from the value of December 2016 and considering a linear growth of consumption, based on the previous 12 months. Considering the global EV deployment trend shown in Figure 1-2, the actual demand increase will not follow a linear trend. However, the linear approach was selected as a safer option. In APPENDIX VI, the plot is shown in compared to a scenario with a constant monthly increase of 6%, registered during the last five months of 2016. The projected value is 72.67 kWh/day. According to CIRCE (2015), the time of the day when fast charging is most likely to occur is between 4 pm and 8 pm. To a lesser extent, EV users charge on their way to work, from 6 am to 9 am. These data were confirmed by directly contacting two major companies active in EV charging: Tesla and Greenlots\textsuperscript{58}.

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\textsuperscript{56} Stations close to the Norwegian border were assumed to have a similar utilisation level to the ones in the Stockholm area. Thus, it was possible to enlarge the sample for the analysis, making it more statistically relevant.

\textsuperscript{57} At time of the analysis.

\textsuperscript{58} These two companies did not provided information for the US market. It was assumed that Swedish usage does not differ excessively from the US.
Figure 5-3: Daily average consumption of a charging station located in Stockholm or close to the Norwegian border. Source (Power Circle)

The final step was the identification of a charging profile of an electric vehicle, which was retrieved for two different BEV: a Nissan Leaf and a Tesla Model S 90D (Nyland, 2017; Sbordone et al., 2016). These two models are particularly relevant since, as of June 2017, they were the most popular BEV models in Sweden, accounting for more than 65% of the total stock (Power Circle, 2017a). Moreover, considering that Tesla Model X has the same charging characteristics as Model S and that Renault Zoe had no possibility of DC charging, the previously mentioned proportion increases to about 85% (see APPENDIX VII for the complete pie chart).

Figure 5-4 shows the two charging profiles. Tesla’s 90-kWh battery was charged on a Tesla Supercharger from 10 to 90% SOC in about an hour. The Nissan Leaf (capacity 24 kWh) charged on a 50-kW CHAdeMO charger from 15 to 80% SOC in 30 minutes. The energy charged is 70.56 kWh in the first case and 15.68 kWh in the latter.

Figure 5-4: Charging Power Profile of a Tesla Model S 90D (10-90% SOC) and a Nissan Leaf (15-80% SOC). Source (Nyland, 2017; Sbordone et al., 2016)

Considering that most DC chargers in Sweden are 50-kW chargers, either CHAdeMO or CCS, it was decided to adapt the demand to this kind of system. No problem arose for the Nissan Leaf, which was

---

59 Only private cars were considered. As of June 2017, the reported fleet of electric light commercial vehicles was of 1832 units, 60% of which Renault Kangoo Z.E. (not capable of DC charging) and 34% Nissan e-NV200, with the same characteristics of battery and charging as a Nissan Leaf (Nissan, 2017; Power Circle, 2017a; Renault, 2016).

60 As of June 2017, the Renault Zoe brochure reports a maximum charging power of 43 kW AC (Renault, 2017).
already charged using one of these two technologies. On the other hand, Tesla’s charging profile had to be adapted to fit the limit of 50 kW, imposed by these chargers. Consequently, starting from the available data it was decided to create two different profiles: one limited to 50 kW and one proportionally reduced to have a maximum of 50 kW (see APPENDIX VIII).

Creating and simulating one load profile would not allow a discussion on the impact of different loads. Consequently, six different loads were designed to investigate different possibilities (see section 5.7 for detailed information on the different cases). In particular, three cases were based on the data explained so far and differ for the arrangement of the charging sessions. Two cases intended to simulate possible future profiles (two different forecasts for 2020). The last case aimed at simulating an ultra-fast charging station (150 kW) with four chargers (unlike the previous examples, which were considered to be for a station of 2 chargers). This is a case similar to the one of Tesla Superchargers and in line with the HPC of Fortum Charge & Drive, previously introduced. General information on the usage this type of chargers was provided from a personal communication with Tesla US. The load profiles are shown in APPENDIX IX.

Limitations

Different loads were created to simulate different situations. It must be stated, however, that all of them are strongly relying on assumptions and real loads might differ from the ones presented. Current charging stations might be dissimilar both in terms of total energy consumption and charging pattern. This is particularly true for one of the studied cases, for which reliable statistics were not available (see section 5.7). A further comment should be done on future projections. These were based on historic data, but this might not be accurate for a market like the ones of EVs and charging infrastructure, which are characterised by fast – and exponential – expansion (see Figure 1-2). In addition, as of today, these are markets strongly influenced by governmental incentives, which may suddenly change.

The simulation was conducted with a 30-second time step. This size was identified as a compromise between a second- and an hourly-based simulation, ensuring enough detail without excessively enlarging the problem’s size.

5.5 Control Strategy

In a design such as the one proposed in the thesis, a control system is essential for proper functioning. In particular, it is important to define the type of service that the battery needs to provide. In fact, there is no scheme currently in place that allows users to provide services to the distribution operator using batteries. According to the interviewee at Vattenfall Eldistribution, such services have just been implemented in some pilot projects62 and are not likely to be established on a wide scale in the short term. As a result of the above, the point of view of the owner was simulated and the implication that the system has on both the owner and the DSO were investigated. From the point of view of Vattenfall Eldistribution, as of today, the most desirable effects that storage should have on local grids are deferring the need of infrastructure upgrading and congestion management. This is particularly important in the area of Solna, where Vattenfall Eldistribution operates, and where local grid loading is approaching design limitations63.

Consequently, it was chosen to simulate and model the optimal operation considering only the point of view of the customer, i.e. the charging station owner. No constraint on possible behaviour (apart from minimum and maximum state of charge) was implemented in the formulation.

Referring to section 3.3, the only services directly considered in the model are the customer energy management services linked to tariffs. Power quality and power reliability were not considered, as the power

61 Load 4 was created starting from a daily consumption of 120 kWh per day. This is the average daily consumption of all chargers in Sweden for 2020, forecasted by Power Circle. Load 5 was built starting from a daily consumption of 203 kWh, which is the figure for end 2020 assuming the same constant linear increase registered over 2016 for the whole period.

62 Such as Smart Grid Gotland (SEDC, 2017).

63 Information provided during two interviews at Vattenfall.
from the grid was assumed to be constantly available and meeting quality requirements. Basically, the optimal scheduling of power flows and the size of the energy storage were calculated, based on two services: retail energy time-shift and demand-charge management.

The optimisation algorithm calculates all possible solutions and finds the optimal one, i.e. the less expansive from the point of view of the FCS’ owner. No input data on minimum or maximum power, nor peak shaving threshold were implemented.

Reacting to pricing, the system may indirectly perform additional services for the DSO, namely, congestion management and distribution upgrade deferral. It must be stated however, that the formulation does not directly take into account these services. The result analysis will however show that the optimal solution, lowering peak consumption and, on a lower extent, shifting energy demand, can lower grid congestion and delay the need of infrastructure upgrading.

5.6 Mathematical Formulation

As previously stated, the optimal design of the system was formulated as a MILP problem. A MILP problem is a particular case of mathematical programming.

Mathematical programming consists in the use of mathematical models to find the optimal value of a series of decision variables with the purpose of minimising (or maximising) an objective function. The decision variables are subject to a series of constraints, imposed by the nature of the problem. In general, constraints can be mathematically formulated as equalities or inequalities. When the mathematical formulation contains solely linear functions and constraints, the problem can be called a linear optimisation (Bradley et al., 1977).

Generally, LP problems are continuous. That is, decision variables can assume fractional values. Many real-life problems can be formulated as LP. However, in some problems, it simply does not make sense for the decision variables to be non-integer. A LP becomes a mixed-integer linear programming problem if one or more decision variables (but not all) are forced to assume integer values. If all variables are restricted to be integers the problem is referred as a pure integer program (Williams, 1980).

Formally, a MILP problem can be expressed in conical form as:

$$\min \{ c^T x \} \quad \text{subject to} \quad \begin{cases} A \cdot x \leq b \\ D \cdot x = g \\ x_j \text{ integer (for some } j \in n) \end{cases}$$

in which $c^T x$ is the cost function to be minimised; $x, c \in \mathbb{R}^n$ represent respectively the decision variables and the cost vectors. $A$ is a $k \times n$ matrix, $b \in \mathbb{R}^k$, $D$ is a $l \times n$ matrix and $g \in \mathbb{R}^l$ (Gunter et al., 2013; Karloff, 1991). In the following section all the decision variables, costs and parameters, as well as the constraints used in the simulation are shown and briefly explained.

Table 5-3: Table of decision variables

<table>
<thead>
<tr>
<th>Decision Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E_g(t)$</td>
<td>Electricity taken from the grid at each time interval (kWh)</td>
</tr>
<tr>
<td>$E_{gb}(t)$</td>
<td>Electricity taken from the grid to the ESS at each time interval (kWh)</td>
</tr>
<tr>
<td>$E_{bl}(t)$</td>
<td>Electricity taken from the ESS to the load at each time interval (kWh)</td>
</tr>
<tr>
<td>$E_{gl}(t)$</td>
<td>Electricity taken from the grid to the load at each time interval (kWh)</td>
</tr>
<tr>
<td>$S_p(t)$</td>
<td>Energy stored in the ESS at the end of each time interval (kWh)</td>
</tr>
</tbody>
</table>
**Parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k_c(t)$</td>
<td>Binary variable related to the charging process (1 if battery is charging, 0 if not)</td>
</tr>
<tr>
<td>$k_d(t)$</td>
<td>Binary variable related to the discharging process (1 if battery is discharging, 0 if not)</td>
</tr>
<tr>
<td>$P_{gr}$</td>
<td>Rated power of the grid (kW)</td>
</tr>
<tr>
<td>$S_{br}$</td>
<td>Battery rated capacity (kWh)</td>
</tr>
<tr>
<td>$P_{bc,max}$</td>
<td>Maximum battery charging power (kW)</td>
</tr>
<tr>
<td>$P_{bd,max}$</td>
<td>Maximum battery discharging power (kW)</td>
</tr>
<tr>
<td>$E_{h_j}(h)$</td>
<td>Electricity absorbed from the grid at each hour (kWh)</td>
</tr>
<tr>
<td>$E_{h,\text{max}}$</td>
<td>Maximum value of electricity absorbed during all hours $j$ (kWh)</td>
</tr>
<tr>
<td>$E_{h,\text{maxpeak}}$</td>
<td>Maximum value of electricity absorbed during peak hours - $j \in \text{peak period}$ (kWh)</td>
</tr>
<tr>
<td>$k_{ct}$</td>
<td>Binary variable related to the use of the converter (1 if used, 0 if not)</td>
</tr>
<tr>
<td>$k_{tr}$</td>
<td>Binary variable required to associate the transformer cost (always 1)</td>
</tr>
</tbody>
</table>

Some of the variables are redundant: $E_g(t)$ could be rewritten as $E_{g2h}(t) + E_{g2l}(t)$ and $E_{h_j}(h)$ is $\sum_{t \in h_j} E_g(t)$, with $t \in h_j$. However, for simplifying the mathematical formulation, they were treated as separated decision variables.

**Table 5-4: Table of costs and other parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{el,u}(t)$</td>
<td>Electricity price at each time interval [utility component] (SEK/kWh)</td>
</tr>
<tr>
<td>$C_{el,d}(t)$</td>
<td>Electricity price at each time interval [distribution component] (SEK/kWh)</td>
</tr>
<tr>
<td>$C_{DC}$</td>
<td>Demand charge depending on $E_{h,\text{max}}$ - the maximum average hourly consumption in a month (SEK/kW*month)</td>
</tr>
<tr>
<td>$C_{g,c}$</td>
<td>Cost of grid connection dependent on power (SEK/kW)</td>
</tr>
<tr>
<td>$C_{ESS}$</td>
<td>Cost of ESS per kWh (SEK/kWh)</td>
</tr>
<tr>
<td>$C_{conv}$</td>
<td>Converter cost (SEK)</td>
</tr>
<tr>
<td>$C_{t}$</td>
<td>Transformer cost (SEK)</td>
</tr>
<tr>
<td>$T_{lt}$</td>
<td>Expected lifespan of the system (years)</td>
</tr>
<tr>
<td>$\Delta t$</td>
<td>Length of each time step (s)</td>
</tr>
<tr>
<td>$\eta_{\text{charger}}$</td>
<td>EV Charger(s) efficiency</td>
</tr>
<tr>
<td>$\eta_{ch,tot}$</td>
<td>Total battery charging efficiency (multiplication of both converter and battery internal efficiency)</td>
</tr>
<tr>
<td>$\eta_{d,tot}$</td>
<td>Total battery discharging efficiency</td>
</tr>
</tbody>
</table>

---

64 The connection costs, provided in the APPENDIX, are not linearly dependent from the grid rated power. However, in order to maintain the linear formulation of the problem, a cost per kW was extrapolated interpolating provided values. In the final cost estimation, this error is corrected by subtracting the approximated value with the real value.

65 Depending on the selected distribution tariff, the cost will be zero or a value proportional to the transformer size.

66 The lifetime of all the equipment, except the battery, is considered equal to the system’s expected lifespan.
### Constraints

The set of constraints defines the feasible region, that is, the space that contains all the sets of unknowns \( \mathbf{x} \) that satisfy the problem’s constraints. In a two-dimensional linear problem, the feasible region is an area, as shown in Figure 5-5. In a generic \( n \)-dimensional linear problem, the feasible region is an \( n \)-dimensional space, defined as a polytope.

![Figure 5-5: Two-dimensional feasible region. Source (Wikipedia)](image)

In the case of a mixed-integer linear problem, the feasible region is a complex multi-dimensional non-continuous space, due to the presence of variables that can assume only integer values. However, discussing the complex mathematical aspects of MILP is outside of the thesis’ scope and will not be taken further.

The constraints implemented in the MILP optimisation in discussion were herewith presented. Some of them reflect physical constraints while some depend on design decisions; others are built to implement a correct economic formulation. In order to better understand the constraints, it is useful to recall the systems layout, presented in Figure 5-2.

Constraints (1) to (4) represent physical constraints: (1) and (2) represent the energy balance at the node where grid, battery and charger(s) meet. Although the two equations could have been rewritten in one, it was chosen to keep them separate. The first focuses on the energy coming from the grid, which can be either for directly supplying the load, or feeding the battery. The second focuses on how the charging demand can be met: either with the grid or with battery storage.

\[
E_g(t) = E_{g2b}(t) + E_{g2l}(t) \quad (1)
\]

\[
E_{g2l}(t) + E_{b2l}(t) = \frac{E_{\text{load}}}{\eta_{\text{charger}}} \quad (2)
\]

\( \eta_{\text{charger}} \) was introduced to take into consideration the inefficiencies of the EV charger. As a result, the energy provided to the charger needs to be slightly higher than the actual EV charging demand.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \eta_{\text{converter}} )</td>
<td>Converter efficiency</td>
</tr>
<tr>
<td>( \text{SOC}_i )</td>
<td>Initial state of charge (%)</td>
</tr>
<tr>
<td>( \text{SOC}_f )</td>
<td>Final state of charge (%)</td>
</tr>
<tr>
<td>( \text{SOC}_{\text{min}} )</td>
<td>Minimum state of charge (%)</td>
</tr>
<tr>
<td>( \text{SOC}_{\text{max}} )</td>
<td>Maximum state of charge (%)</td>
</tr>
<tr>
<td>( C_{\text{rate},c} )</td>
<td>Charging C-rate (1/h)</td>
</tr>
<tr>
<td>( C_{\text{rate},d} )</td>
<td>Discharging C-rate (1/h)</td>
</tr>
</tbody>
</table>
The battery state of charge is modelled by equation (3)\(^{68}\). The state of charge at the end of each time step \(t\) is equal to the state of charge at the previous time step plus the energy that was fed to the battery, minus the energy that served the load during that time step. As \(E_{g2b}(t)\) and \(E_{b2l}(t)\) represent the energy flowing at the node, it was necessary to introduce \(\eta_{ch,tot}\) and \(\eta_{d,tot}\) in the formulation to count both the inefficiencies of the converter/BMS and the battery charging and discharging process (for the single values, see section 6.1).

\[
S_b(t) = S_b(t - 1) + \eta_{ch,tot} \cdot E_{g2b}(t) - \frac{E_{b2l}(t)}{\eta_{d,tot}} \quad (3)
\]

Having a closer look at the formulation of equation (3), it is clear that \(E_{g2b}(t)\) and \(E_{b2l}(t)\) cannot be simultaneously positive. If so, it would be possible for the battery to both charge and discharge at the same time. This is obviously nonsense, both from a technical and economic point of view. Equations (4a), (4b) and (4c) address this problem, employing the so called big-M method and binary variables \(k_c(t)\) and \(k_d(t)\). Introducing \(M\), a sufficiently large\(^{69}\) constant, enables to link the binary variables to the charging or discharging processes. Focusing on the charging process, (4a) forces \(k_c(t)\) to be 1 if \(E_{g2b}(t)\) is positive. On the other hand, it also forces \(E_{g2b}(t)\) to be 0 if \(k_c(t)=0\). A similar discussion can be made for (4b). (4c) instead, allows just one of the two binary variables to be positive at one time. Clearly, having both binary variables equal to zero is a feasible option. That would mean that the battery is not being used in that time step.

\[
E_{g2b}(t) \leq k_c(t)M \quad (4a)
\]
\[
E_{b2l}(t) \leq k_d(t)M \quad (4b)
\]
\[
k_c(t) + k_d(t) \leq 1, \text{ with } k_c(t), k_d(t) \in \{0,1\} \quad (4c)
\]

Constraints (5), (6) and (7) were formulated to obtain the variables \(P_{g,r}, P_{b,c,max}\) and \(P_{b,d,max}\). Equation (5) relates energy in each time step \(E_g(t)\) with rated power \(P_{g,r}\)\(^{70}\). Equations (6) and (7) define battery maximum discharge and charging power (at battery terminals – hence, \(\eta_{converter}\) needs to be considered).

\[
E_g(t) \leq P_{g,r}\Delta t \quad (5)
\]
\[
\eta_{converter} E_{g2b}(t) \leq P_{b,c,max}\Delta t \quad (6)
\]
\[
\frac{E_{b2l}(t)}{\eta_{converter}} \leq P_{b,d,max}\Delta t \quad (7)
\]

Constraints (8) to (10) represent design constraints on the battery’s behaviour and allow identifying the battery rated capacity \(S_{b,r}\). Constraints (8a) and (8b) force initial and final battery state of charge to be a fixed percentage of \(S_{b,r}\), which is, in fact, an output variable. In this manner, a fixed initial and final SOC (%) are considered, rather than energy content. Constraint (8c), instead, limits the state of charge at each time step to be inside an acceptable range, avoiding overcharge and over discharge of the system.

---

\(^{68}\) Equation (3) is not valid in the first time-step, as there is no \(S_b(t - 1)\). For the initial state of charger refer to equation (4a).

\(^{69}\) “Sufficiently large” should be interpreted as: large enough not to limit the variables describing the energy flow in the battery.

\(^{70}\) If \(\Delta t = 1s\) \(E_g(t)\) becomes power. Also, since energy is expressed in kWh, \(\Delta t\) implemented in the model is actually 3600/\(\Delta t\).
Additionally, it sets the rated battery capacity as the maximum required capacity. Inequalities (9) and (10) limit the battery charging and discharging power according to the C-rates\(^7\):

\[
S_b(1) = S_{b,r} \cdot SOC_i + \eta_{ch,tot} \cdot E_{g,zb}(1) - \frac{E_{gb}(1)}{\eta_{d,tot}} \tag{8a}
\]

\[
S_b(N) = S_{b,r} \cdot SOC_f \tag{8b}
\]

\[
S_{b,r} \cdot SOC_{min} \leq S_b(t) \leq S_{b,r} \cdot SOC_{max} \tag{8c}
\]

\[
P_{b,c,max} \leq C_{rate,c} \cdot S_{b,r} \tag{9}
\]

\[
P_{b,d,max} \leq C_{rate,d} \cdot S_{b,r} \tag{10}
\]

Constraints (11) and (12) are required to measure the distribution demand charge. The demand charge is calculated on the hourly average power demand \((E_{h,j})\), defined by (11). In (12), \(E_{h,max}\) is described as the maximum of the \(E_{h,j}\) in a given month.

\[
E_{h,j} = \sum_{t \in h_j} E_{g}(t) \tag{11}
\]

\[
E_{h,j} \leq E_{h,max} \quad \forall j \in \text{month} \tag{12}
\]

The actual demand charge has two components, one that is valid for the whole month, simulated with constraint (11) and (12), and one that is valid only during the peak period. However, the latter formulation will not be presented, as substantially identical to the previous. The only difference lies in the fact that \(E_{h,max,peak}\) is calculated considering only the hours in the peak period (6am-10pm).

**Objective Function**

The objective function to minimise is the following:

\[
f = \sum_{t \in T} \left( C_{el,u}(t) + C_{el,d}(t) \right) E_{g}(t) + C_{DC} E_{h,max} + C_{ESS} S_{b,r} + \ldots
\]

\[
\ldots + C_{conv} P_{b,d,max} + (C_{g,c} + C_t) P_{gr} \tag{13}
\]

The first two components represent total electricity costs: the electricity cost per kWh (utility and distribution fees) and the demand charge, respectively. The other components represent the battery cost, the converter cost and the costs related to grid tie capacity (connection fee and transformer).

All costs, except \(C_{el,u}(t)\) and \(C_{el,d}(t)\), were actualised to the optimisation horizon, in this case, one day. This was necessary, as costs need to be on a similar order of magnitude to be comparable for the optimisation algorithm. The output \(c' x\) represents a cost per day. To have proper economic performance over a reasonable time span, an automatic NPV is generated.

The actual formulation implemented for grid tie capacity is slightly different. Instead of a linear approach, as described by the formulation used above, a “step” function was implemented by means of binary variables. This was necessary to properly model system’s cost and behaviour. In effect, connection costs are

---

\(^7\) Batteries cannot charge (and discharge) at any power. The C-rate is measured in [1/h] and indicates the rate at which a battery can be charged (or discharged), in relation to its nominal capacity. For example, a 2C discharge rate means that the discharge current will empty the battery in 1/2 hour. Typically, discharge C-rates have higher values than charge ones.
not linear: depending on the fuse and transformer sizes, they have a “step” increase. The following formulation was used for modelling the connection fuse cost:

\[
P_{g,i} \leq k_{c,1}P_{r,1} + k_{c,2}P_{r,2} + \cdots + k_{c,n}P_{r,n} \quad (14)
\]

\[
k_{c,1} + k_{c,2} + \cdots + k_{c,n} \leq 1 \quad (15)
\]

\[
f_c = k_{c,1}C_{c,1} + k_{c,2}C_{c,2} + \cdots + k_{c,n}C_{c,n} \quad (16)
\]

Where each \( k_{c,i} \) is a binary variable, \( P_{r,i} \) is the rated power of the available fuses and \( C_{c,i} \) is the cost associated to the fuse \( i \). \( f_c \) represents the part of the objective function that defines the cost of the connection fuse. In this manner, (14) and (15) force \( P_{g,i} \) to be lower than one of the \( P_{r,i} \). Only one of the \( P_{r,i} \) is considered at one time, thanks to (15). (16) associates the cost of the fuse with rated power \( P_{r,i} \) to each binary variable. However – as previously pointed out – only one \( k_{c,i} \) at time is positive. The programme consequently optimises \( P_{g,i} \) considering the costs as a step function.

A similar approach was taken for the transformer costs.

To get the size of the transformer, a security factor of 10% was applied. A final consideration to be taken into account is that the results of the simulations were sometimes not suitable to be graphed. For example, to recharge the battery with 10 kWh in an hour, if no other restrictions arise, the power profile could be either 10 kW constant for an hour or 40 kW for 15 minutes. The algorithm has a discretisation of 30 seconds. The consequence is that sometimes the variables show tremendous fluctuations from one time-step to the other. In order to avoid this, a series of additional constraints – which will not be discussed – were implemented to limit non-reasonable variability of the system.

### 5.7 Sensitivities

A crucial step in the interpretation of the results is the sensitivity analysis. It helps to understand how different input parameters influence the final results. It is an interesting procedure to both investigate different scenarios and balance uncertainty of some input data. Within the scope of the thesis, three major parameters were identified as key sensitivities: charging load, battery cost and distribution tariff scheme.

#### 1. Charging Load

Probably the most important input data of the model is the charging demand of the station. The assumptions underlying the base case scenario and the other cases were explained in section 5.4. Here, the four cases will be shown in detail in order for the reader to contextualise them (refer to APPENDIX IX).

- **Case 1**\(^{73} \) – A DC fast charging station with rated power of 50 kW (2 slots) with current usage and positioning of the sessions spread during the day. In addition, charging events happen in between two metered hours. This is the best case for the owner’s perspective as the resulting demand charge is lower (see 4.3.2).
- **Case 2** – Same as Case 1 but with closer charging sessions. Charging sessions starting at the beginning of metered hours.
- **Case 3** – Same as Case 1 but with closer charging sessions, two of which overlapping.

---

\(^{72}\) MILP optimisation aims at minimising the objective function, in this case, costs. When it comes to simulating the connection costs, it is not possible to consider them as linear. In fact, there are a limited number of fuse sizes. Hence, when the algorithm looks for the optimal solution, it will see the cost function of the connection as a “step” function. Consider for example that two fuse sizes are available: 10 and 20 W. If the power the fuse needs to handle is higher than 10 W, the second will be chosen. The same would happen with a power of 11, 15 or 19 W. When the power reaches 20 W, a fuse with a higher rating will be necessary.

\(^{73}\) Case 1 is the base case scenario.
• **Case 4** – A DC fast charging station with rated power of 50 kW (2 slots) with daily usage increased by 63%. This value was retrieved from projections by Power Circle on average daily consumption 2020 for all Swedish charging stations in 2020 (Power Circle, 2017b).

• **Case 5** – A DC fast charging station with rated power of 50 kW (2 slots) with daily usage increased by 268% (projection to 2020 for stations located in Stockholm considering a constant linear increase, equal to the one registered during 2016).

• **Case 6** – A possible load for a HPC station (150 kW) with 4 chargers. This is similar to the case of Tesla Superchargers. An approximate number of sessions was retrieved from a personal communication with Tesla US.

### 2. Battery Cost

Another critical parameter is battery cost. For base-case scenario, the cost offered by LG Chem\(^4\), equal to 3200\(^75\) SEK/kWh, was considered, whereas future projections were retrieved from McKinsey (2017). The four analysed cases are summarised below:

- **Price 1** – Current price, equal to 3200 SEK/kWh.
- **Price 2** – 2020 forecasted price, equal to 2000 SEK/kWh.
- **Price 3** – 2030 forecasted price, equal to 1000 SEK/kWh.

### 3. Distribution Tariff

The last parameter selected for the sensitivity analysis is electricity pricing. As shown in chapter 4, distribution fees (particularly, demand charges) have a much higher impact on a consumption pattern similar to the one of a fast charging station. In addition, utility prices mainly depend on Nord Pool price and energy tax. It is unlikely to expect consistent changes in these tariffs in the near future. Likewise, it is improbable to expect utility tariffs tailored to particular customers, such as charging stations, aimed at stabilising their demand in time. In fact, the burden of an uneven demand is borne by the distribution company.

Current distribution tariffs already intend to stabilise the demand, especially during high demand periods. This is done by applying demand charges and fees per kWh depending on time. However, an interviewee at Vattenfall Eldistribution reported that the company is currently investigating the possibility of designing new tariffs to target customers with extremely high and unpredictable demands (i.e. fast charging stations). Hence, the sensitivity analysis was focused on distribution pricing. Unfortunately, precise directives were not provided. It was consequently chosen to investigate both different demand charges and different distribution fees. The following tariffs, further discussed in the next section, were simulated:

<table>
<thead>
<tr>
<th>Component</th>
<th>N4-A LV</th>
<th>N4-B LV</th>
<th>N4-C LV</th>
<th>N4-D LV</th>
<th>N3-A HV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge (SEK/month)</td>
<td>365</td>
<td>365</td>
<td>365</td>
<td>365</td>
<td>2450</td>
</tr>
<tr>
<td>Monthly Power Fee (SEK/kW month)</td>
<td>40</td>
<td>20</td>
<td>86</td>
<td>86</td>
<td>10</td>
</tr>
<tr>
<td>Peak Period Power Fee (SEK/kW month)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>86</td>
</tr>
<tr>
<td>Transfer fee peak period (öre/kWh)</td>
<td>5.1</td>
<td>5.1</td>
<td>14</td>
<td>30</td>
<td>5</td>
</tr>
<tr>
<td>Transfer fee normal (öre/kWh)</td>
<td>78.6</td>
<td>78.6</td>
<td>52.4</td>
<td>30</td>
<td>52.4</td>
</tr>
</tbody>
</table>

\(^4\) Refer to APPENDIX IV for more information.

\(^5\) As of May 2017, the price indicated by the German office was 320 EUR/kWh (retrieved from a non-recorded phone conversation). It has been converted into SEK considering 1 SEK=0.1 EUR.
6 Simulations

This chapter focuses on the simulations. After showing the values utilised throughout the various simulations, the retail prices and distribution tariffs were investigated to assess their impact and possibly simplifying the approach to the problem. A small section focuses on the metering resolution implications, with reference to the Spanish model previously introduced. The last three sections present the sensitivity analysis, studying the influence of different loads, battery price and distribution fees.

6.1 Reference simulation parameters

It was not possible to conduct sensitivity analysis on all input parameters. The following table summarises the input parameters which were kept constant in all simulations, with corresponding value.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>System lifetime (years)</td>
<td>15</td>
<td>In order to conduct the economic analysis system’s lifetime was assumed to be 15 years.</td>
</tr>
<tr>
<td>SOC initial</td>
<td>0.3</td>
<td>During the night charging events do not occur, it was chosen to put a small initial SOC (at 12 am), to avoid quick charge in the hours before 12 am.</td>
</tr>
<tr>
<td>SOC final</td>
<td>0.3</td>
<td>In order to make the battery cycle, initial and final state of charge are equal.</td>
</tr>
<tr>
<td>SOC max</td>
<td>0.9</td>
<td>See APPENDIX IV.</td>
</tr>
<tr>
<td>SOC min</td>
<td>0.1</td>
<td>See APPENDIX IV.</td>
</tr>
<tr>
<td>Battery roundtrip efficiency</td>
<td>0.95</td>
<td>See APPENDIX IV.</td>
</tr>
<tr>
<td>Converter efficiency</td>
<td>0.95</td>
<td>Efficiency of the BMS and bidirectional inverter was considered to be 0.98. ABB products have efficiencies of &gt;0.94 and literature papers present configurations that can achieve efficiencies of 0.98 (ABB, n.d., n.d.; Colmenar-Santos et al., 2016; Pan and Zhang, 2016).</td>
</tr>
<tr>
<td>C-rate (charge/disch.) (1/h)</td>
<td>0.5/2.5</td>
<td>See APPENDIX IV.</td>
</tr>
<tr>
<td>Charger efficiency</td>
<td>0.94</td>
<td>Efficiency of the selected charger (EVTEC, 2017).</td>
</tr>
<tr>
<td>Charger power factor</td>
<td>0.98</td>
<td>Power factor of the selected charger (EVTEC, 2017).</td>
</tr>
<tr>
<td>Converter cost (SEK/kW)</td>
<td>800</td>
<td>Approximate cost per kW of a converter (Pöyry, private consultation).</td>
</tr>
<tr>
<td>Battery cycles</td>
<td>10000</td>
<td>See APPENDIX IV.</td>
</tr>
<tr>
<td>Expected battery lifetime (years)</td>
<td>15 (unless shorter)</td>
<td>In order to simplify the economic analysis, the lifetime of the battery was assumed to be 15 years, unless shorter. The expected lifetime is calculated as shown in section 5.3. If the expected lifetime is shorter than 15 years, it is calculated in the economic analysis with the real value. This is a reasonable assumption, as the battery cost considered by the formulation is actually higher (since considers a shorter lifetime).</td>
</tr>
</tbody>
</table>
6.2 Retail Price Investigation

Initially, few simulations were conducted with constant loads\(^{76}\), in order to assess whether the retail price differences of the hourly variable tariff affected battery usage. As expected, the price variation between different hours is not enough to justify the implementation of a battery system. The savings that can be made by buying electricity when cheaper are not sufficient to counterbalance the cost of the battery and the purchase of the additional electricity that gets lost due to equipment’s inefficiencies\(^{77}\). Consequently, a day with a small variability was selected, i.e. August 17\(^{th}\), 2016 (see Figure 4-4). Compared to the fixed price tariff of 81.13 öre/kWh\(^{78}\), it resulted in 3% lower daily electricity expenditure.

6.3 Distribution Tariff Investigation

A second set of simulations aimed at identifying the most economically advantageous tariff, from the charging station owner’s point of view. Load of Case 1 (see APPENDIX IX) was simulated under all five distribution tariffs, both considering peak and off-peak days.

For Case 1, tariffs N2 and N2T are consistently more expensive than the others, due to the high fixed fees. These tariffs are made for large customers where the lower power fee can counterbalance the high fixed fees. During peak period, tariff N4 – with 179.82 SEK per day – is by far the most convenient, as there are no power charges for peak period. Tariffs N3 and N3T are respectively at 274.27 and 291.80 SEK per day. Results of this first analysis are summarised in Table 6-1.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>N3 Peak</th>
<th>N3T Peak</th>
<th>N4 Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>274.27</td>
<td>291.8</td>
<td>179.82</td>
</tr>
<tr>
<td>Battery Capacity (kWh)</td>
<td>50.84</td>
<td>50.84</td>
<td>42.30</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>590.22</td>
<td>672.58</td>
<td>393.17</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>85.63</td>
<td>88.12</td>
<td>109.27</td>
</tr>
<tr>
<td>CAPEX (SEK)</td>
<td>360 800</td>
<td>257 000</td>
<td>225 840</td>
</tr>
<tr>
<td>Operation (SEK/year)</td>
<td>38 696</td>
<td>40 596</td>
<td>44 961</td>
</tr>
<tr>
<td>Max hourly average power (kW)</td>
<td>5.49</td>
<td>5.49</td>
<td>7.86</td>
</tr>
<tr>
<td>Peak Power Consumption (kW)</td>
<td>42.55</td>
<td>43.28</td>
<td>44.00</td>
</tr>
</tbody>
</table>

Table 6-2 shows the results of Case 1 under different tariffs. N4 remains the most convenient option; however, the reasons are different than during peak period. Here, tariff N4 causes a higher demand charge (since the general power fee, in this, case is higher). What makes it more convenient is the lower monthly fixed fee, which is about one tenth than in the other two cases.

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76 It was chosen to simulate constant loads to assess whether battery would have cycled to allow demand shifting (buying power when cheaper for later consumption). In this case, distribution fees were considered to be constant (off-peak time) not to influence the analysis.

77 Combining the inefficiencies of battery and inverter/BMS, only 85.74% of the energy sent to the ESS is available for consumption.

78 12-month fixed price tariff offered by Vattenfall (see APPENDIX II).
Table 6-2: Selected results for Case 1 during off-peak period, under different tariffs.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>N3 Off-peak</th>
<th>N3T Off-peak</th>
<th>N4 Off-peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>246.98</td>
<td>261.63</td>
<td>153.9</td>
</tr>
<tr>
<td>Battery Capacity (kWh)</td>
<td>35.77</td>
<td>35.77</td>
<td>35.77</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>359.95</td>
<td>359.95</td>
<td>514.22</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>76.13</td>
<td>78.48</td>
<td>87.7362</td>
</tr>
<tr>
<td>CAPEX (SEK)</td>
<td>305 400</td>
<td>201 600</td>
<td>201 600</td>
</tr>
<tr>
<td>Operation (SEK/year)</td>
<td>324 466</td>
<td>33 326</td>
<td>37 094</td>
</tr>
<tr>
<td>Max hourly average power (kW)</td>
<td>10.28</td>
<td>10.28</td>
<td>10.28</td>
</tr>
<tr>
<td>Peak Power Consumption (kW)</td>
<td>44.00</td>
<td>44.00</td>
<td>44.00</td>
</tr>
</tbody>
</table>

However, if the average energy demand increases – and with it power consumption, the situation becomes different, and other tariffs get more convenient. A similar analysis was consequently conducted on Case 6, which is the one that offers the higher average – and peak – demand. In this case tariffs N3 and N3T are both more convenient than tariff N4. More specifically, daily cost in tariff N3 is 113.7 SEK lower than tariff N4 (respectively, equal to 1736.7 SEK/day and 1850.4 SEK/day).

Figure 6-1 and Figure 6-2 show the 3D-plots of the most relevant network tariffs, respectively during peak and off-peak periods. It can be seen that, for low energy consumption and low peak power, tariff N4 is the most convenient, both on peak and off-peak. This is particularly relevant, as current DC fast chargers consumption falls in this range. The implementation of a storage system does not affect the choice of the tariff for this type of stations.

![3D plot of the network tariffs (On Peak).](image)

Figure 6-1: 3D plot of the network tariffs (On Peak). Only N3 and N4 are displayed, as both N2 and N2T were more expensive for the considered ranges of power and energy. N3T was neglected as always slightly more expensive than N3.

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79 Tariffs N2, N2T and N3 are not shown as more expensive in the plotted range of energy consumption and power.

80 For N3, the additional investment for the transformer station is not shown in the graph. However, its contribution on daily costs is minor. The cost of an 800-kVA transformer (APPENDIX V) with a lifetime of 15 years would add approximately 30 SEK per day on tariff N3, causing the blue plane to slightly shift upwards.
Another interesting consideration can be done in the case of increased electricity consumption. In this case, despite the lower power cost, N4 becomes more expensive compared to N3, also during peak time. A last remark must be made considering high peak power demand. In this case, the choice of the tariff depends on whether peak or off-peak times are considered. On peak, N4 is preferable, due to the lower power fee. On the other hand, off-peak, N4 becomes more expensive. Although the difference between the two prices is smaller during off-peak times, on peak period is much shorter than off peak period. In a year, less than a third of the days are peak days.

For Cases 1-5, where hourly average power is below 50 kW and energy consumption is maximum 216.04 kWh (Case 5), tariff N4 will be considered. On the other hand, for Case 6 tariff N3 will be used, since the maximum hourly average power is 192 kW and the energy consumption is 1004.2 kWh.

### 6.4 Metering Resolution Implications

As previously stated, the demand charge is calculated with an hourly metering. This does not allow the distribution company to correctly charge customers for their actual power usage. Figure 6-3 shows Case 1 with tariff N4 on peak time. The blue line indicates the profile of the power flowing from the grid to the battery. As it can be seen, it is extremely variable. In this case, the battery is charged at high power every hour for a small period of time. This behaviour is clearly not the more desirable from the point of view of the grid operator. However, no economic constraint is in place to limit this type of charge. In fact, the hourly metering is intrinsically imprecise and does not impede variability within the hour. The only thing that matters from an economic point of view is essentially the total energy consumption of the specific hour, regardless the actual power curve. A further implication of this metering strategy can be seen in Figure 6-3, looking at the power flowing from the grid to the load during the second session: in the first part (before 5 pm) it has a high value, while after 5 pm the value drops and stays constant for a while before going to zero again. Despite the more complex trend, what the energy meter is able to see is just a constant power in both hours involved in the session (4-5 pm and 5-6 pm).

---

81 For N3, there is a need for additional investment for the transformer station, which is not shown in the graph. However, its contribution on the daily cost is minor. The cost of a 800-kVA transformer (APPENDIX V) with a lifetime of 15 years would add approximately 30 SEK per day on tariff N3, causing the blue plane to slightly shift upwards.

82 Note that this power is profile is the optimal for this specific case and has this trend since the programme knows already the load profile. During real time operation, the charging strategy may be different: e.g. after usage charging battery to the maximum to ensure full availability for an upcoming charging session.
A totally different behaviour would be obtained in the same conditions just by changing the meter resolution to a fraction of an hour, e.g. 15 minutes, as currently implemented in Spain. The impact that this measure would have is shown in Figure 6-4. This is especially evident in Case 1, as charging sessions occur across two metered hours, thus distributing the energy in two hours, lowering the peak consumption. A 15-minute resolution effectively limits this effect, enabling DSO to better assess the actual peak power consumption.

6.5 Implications of various loads

For this section, the different loads will be tested, and the main results will be presented. As a result of the distribution tariff analysis (see section 6.3), Cases 1-5 will be simulated under tariff N4, while for Case 6 tariff N3 will be used.

The power flow is shown for cases where the battery is implemented. Each of the graphs will contain a legend to be interpreted as follows (see Figure 5-2 for system’s layout):

- \( P_{g2b} \): power flowing from the grid to the battery (before BMS/converter);
- \( P_{b2l} \): power flowing from the battery to the load (after BMS/converter);
- \( P_{g2l} \): power flowing from the grid to the load;
- \( P_{\text{load}} \): power required by the car (after the charger – charger efficiency not considered)
- Battery SOC: battery state of charge during the simulation horizon.
The most important cost and design parameters are shown in the tables. Costs were analysed considering an equipment lifetime of 15 years and were equally divided during year and days. Also, battery cost was split evenly in 15 years, except when the expected lifetime was shorter. In this case, the shorter lifetime was considered for costs amortization.

Daily costs were calculated dividing all the costs for the entire lifetime by the total days of operation. A similar procedure was utilised for yearly costs. This is clearly an approximation as it implicitly implies that all days in the year have the same characteristics of load and electricity price. Considering yearly costs in this way also implies that all days are either peak or off-peak days. Consequently, these costs have to be taken as indicators to compare the economic performance of a station with or without ESS, rather than precise cost estimations. As a result, fixed costs not depending from the implementation of the ESS were not considered in the analysis. These include: cost of the chargers, cost of the permits, cost of work and O&M on the equipment. These costs have to be borne by the owner, regardless the implementation of ESS.

The distribution tariffs simulated are valid for connections with fuse size of 80 A or higher. Nevertheless, all possible fuse sizes were simulated, in order to evaluate if storage is effective in lowering the needed connection size.

A final comment should be made on the size of the equipment. The rating proposed in the tables is the optimal, not considering possible security factors, which in some cases might consistently influence the equipment size. The results show the mathematical optimal result, which may be different from the optimal in a real case.

**Case 1 Tariff N4 (On Peak)**

Interestingly, already in *Case 1* it is convenient to install an ESS (rated capacity of 51 kWh), which allows to lower the yearly costs by about 15%. As expected, the most important source of savings is demand charge, which is reduced from 1731.8 to 275.97 SEK per month. However, it is worth to mention the reduction in the price of electricity. Despite the higher power consumption – due to conversion and storage inefficiencies – the electricity price is lower. This is due to the fact that the battery charges at off-peak hours, when electricity is considerably cheaper, mostly due to the tariff structure. During off-peak, the distribution fee is 14 öre/kWh while on peak it is 66.4 öre/kWh. This could appear as a contradiction with what shown in section 6.2, however, it is not. Electricity price variation *alone* is not enough to justify the implementation of an ESS but, if coupled with demand charge reduction, it becomes an asset to decrease operating costs further. Lowered connection size is another driver for cost reduction.

![Figure 6-5: Case 1 under tariff N4 (on peak). For legend, see beginning of section 6.5.](image)

---

83 Except for the transformer, as previously stated.
### Most relevant cost and design parameters for Case 1 under tariff N4 (on peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>180.31</td>
<td>(212.04)</td>
<td>Battery Capacity (kWh)</td>
<td>51.11</td>
<td>(/)</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>65 690</td>
<td>(77 029)</td>
<td>Lifetime (years)</td>
<td>22.77</td>
<td>(/)</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>107.83</td>
<td>(118.71)</td>
<td>Energy Consumed (kWh)</td>
<td>88.88</td>
<td>(80.69)</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>275.97</td>
<td>(1731.8)</td>
<td>Energy Max (kWh/h)</td>
<td>5.52</td>
<td>(34.64)</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>163 540</td>
<td>(/)</td>
<td>Power Converter (kW)</td>
<td>42.83</td>
<td>(/)</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>(106 250)</td>
<td>Peak Power (kW)</td>
<td>24.83</td>
<td>(58.51)</td>
</tr>
<tr>
<td>Converter</td>
<td>34 265</td>
<td>(/)</td>
<td>Transformer</td>
<td>/</td>
<td>(/)</td>
</tr>
</tbody>
</table>

It is interesting to note that the second charge is the one that requires both more energy and higher peak power to be delivered by the storage. This is a consequence of the way demand charge is considered. Despite the higher peak of the other sessions, the second is the one with the largest impact on the bill, as responsible for the highest hourly energy demand (34.64 kWh). The battery is engaged to lower the energy consumption during the hour rather than shaving peaks in power. Paradoxically, a power withdrawal of 100 kW for 2 minutes at 13 pm would not cause the storage to engage, since the resulting hourly consumption would be lower than the threshold imposed by the “worst” hour, i.e. 5-6 pm – for this case. The fact that the three peaks of power flowing from the grid to the load are the same is a coincidence, since all the three charging sessions start 15 minutes before the end of the metered hour. If one started 5 minutes before, the peak power would have been much higher. In this case, the peak power of 24.83 kW is caused by the battery charging power (limited to 0.5 C). However, with a different control strategy, battery charging power can be reduced to a constant value, as shown in Figure 6-4 and Figure 6-6. An interesting comment should be made on battery discharging power. Initially, it was thought that discharging C-rate of the ESS could have created bottlenecks, causing the battery size to increase or limiting the peak power available for EV charging. However, peak battery discharging power hardly reached values above 1C. Two considerations can explain this. First, converter needs to be sized according to the highest power that it has to handle. Consequently, the optimal solution tends to lower as much as possible this power. This is especially evident in Case 3. Secondly, due to the load characteristics, the ratio between maximum power and storage rated capacity never becomes critical.

**Case 2 Tariff N4 (On Peak)**

Case 2 has the same total energy consumption, but the charging sessions are closer and start at the beginning of the metered hour. As previously explained, this leads to a higher hourly average demand: 46.29 kW, compared to 34.63 kW of Case 1, leading to a higher demand charge (2314.3 SEK/month). The implementation of an ESS enables to lower yearly costs by 18%. The reasons for the reduction in price are similar to the previous case: demand charge, electricity price and connection cost – in order of importance. The increase in costs due to battery and converter (17 256 SEK/year) is almost half of the cost reduction that can be obtained by the implementation of the system (32 610 SEK/year).
Compared to the previous case, the size of the battery has to be increased to about 70 kWh. One cause is closer charging sessions: there is no time for charging without negatively affecting the hourly energy consumption between the first and second session (charging there would create a higher demand charge). Another reason is the higher initial value of maximum hourly average consumption, which is reduced by 38.7 kW thanks to the implementation of the ESS. Nearly 70% of the usable battery capacity\(^\text{84}\) is engaged for that particular hour. In this graph, a different control strategy for battery charge is shown: constant charge at low as possible power.

**Table 6-4: Most relevant cost and design parameters for Case 2 under tariff N4 (on peak).**

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>188.95</td>
<td>(231.89)</td>
<td>Battery Capacity (kWh)</td>
<td>69.72</td>
<td>(/)</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>68 826</td>
<td>(84 178)</td>
<td>Lifetime (years)</td>
<td>26.4</td>
<td>(/)</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>101.87</td>
<td>(119.15)</td>
<td>Energy Consumed (kWh)</td>
<td>90.32</td>
<td>(80.69)</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>379.33</td>
<td>(2314.3)</td>
<td>Energy Max (kWh/h)</td>
<td>7.59</td>
<td>(46.29)</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>223 100</td>
<td>(/)</td>
<td>Power Converter (kW)</td>
<td>44.68</td>
<td>(/)</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>(106 250)</td>
<td>Peak Power (kW)</td>
<td>16.07</td>
<td>(58.51)</td>
</tr>
<tr>
<td>Converter</td>
<td>35 743</td>
<td>(/)</td>
<td>Transformer</td>
<td>/</td>
<td>(/)</td>
</tr>
</tbody>
</table>

**Case 3 Tariff N4 (On Peak)**

Case 3 presents an even more concentrated charging profile. Specifically, two charging sessions overlap in the hour between 5 pm and 6 pm, causing an average hourly demand of 58.8 kW and a peak power of 101.76 kW. Similarly to the previous cases, the implementation of the ESS is able to significantly lower yearly costs (lowered by 22%). However, the battery capacity increases notably to 84.34 kWh. Reasons similar to the previous case can explain the high capacity requirement. It is interesting to see that, despite the employment of the ESS, there is still a quick spike in power flowing from the grid to the load (green). This is not due to technical limitations of the battery – it discharging rate is well below the maximum of 2.5 \(C\) – but due to the converter cost. Decreasing the converter cost, the spike disappears, replaced by a plateau. This is a clear example where the theoretical optimum value might not be reasonable in real applications.

\(^{84}\) Of the total battery capacity, only 80% is available for utilisation, due to the minimum and maximum recommended state of charge.
probably does not make sense to have the battery discharging power limited to a small fraction of the available one due to the converter.

Figure 6-7: Case 3 under tariff N4 (on peak). For legend, see beginning of section 6.5.

Table 6-5: Most relevant cost and design parameters for Case 3 under tariff N4 (on peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>196.96</td>
<td>(256.26)</td>
<td>Battery Capacity (kWh)</td>
<td>84.34</td>
<td>(⁄)</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>71 737</td>
<td>(92 959)</td>
<td>Lifetime (years)</td>
<td>29.59</td>
<td>(⁄)</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>96.44</td>
<td>(119.2)</td>
<td>Energy Consumed (kWh)</td>
<td>91.1</td>
<td>(80.69)</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>455.43</td>
<td>(2 939)</td>
<td>Energy Max (kWh/h)</td>
<td>9.11</td>
<td>(58.8)</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>269 890</td>
<td>(⁄)</td>
<td>Power Converter (kW)</td>
<td>60.80</td>
<td>(⁄)</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>(125 000)</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>(101.76)</td>
</tr>
<tr>
<td>Converter</td>
<td>48 636</td>
<td>(⁄)</td>
<td>Transformer</td>
<td>/</td>
<td>(⁄)</td>
</tr>
</tbody>
</table>

Case 4 Tariff N4 (On Peak)

*Case 4* represents a DC fast charging station with a rated power of 50 kW (2 slots) with daily usage increased by 63% respect to the previous cases. The electricity cost is considerably higher than in the previous cases whereas the demand charge is not. Since the station is limited to 2 slots, an increased usage is likely to affect more the electricity consumption rather than the maximum average hourly consumption. The implementation of an energy storage system allows savings, however, compared to the previous cases, to a lower extent: about 9%, from 109 000 SEK a year to about 99 000 SEK.
Figure 6-8: Case 4 under tariff N4 (on peak). For legend, see beginning of section 6.5.

Table 6-6: Most relevant cost and design parameters for Case 4 under tariff N4 (on peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>271.69</td>
<td>(299.82)</td>
<td>Battery Capacity (kWh)</td>
<td>62.6</td>
<td>(%)</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>98 977</td>
<td>(109 000)</td>
<td>Lifetime (years)</td>
<td>26.1</td>
<td>(%)</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>177.99</td>
<td>(193.32)</td>
<td>Energy Consumed (kWh)</td>
<td>140.3</td>
<td>(131.55)</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>688.75</td>
<td>(2 127.0)</td>
<td>Energy Max (kWh/h)</td>
<td>13.76</td>
<td>(42.54)</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>200 320</td>
<td>(106250)</td>
<td>Power Converter (kW)</td>
<td>47.95</td>
<td>(%)</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>(106250)</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>(84.17)</td>
</tr>
<tr>
<td>Converter</td>
<td>38 359</td>
<td>(76620)</td>
<td>Transformer</td>
<td>/</td>
<td>(/)</td>
</tr>
</tbody>
</table>

Case 5 Tariff N4 (On Peak)

Case 5 aims at simulating a possible future scenario to 2020. The energy demand is 216 kWh, 268% more than in Case 1. However, despite the charges overlapping, the maximum average hourly consumption is relatively small: 35.14 kW. In this case, the implementation of the energy storage is still convenient, but the margin is minimal: 0.14%. Several factors contribute to the result: the battery is cycling consistently, shortening its lifetime to less than 12 years. Daily cycling means that battery is also charging when electricity is more expensive. As a result, due to the inefficiencies, the electricity cost is actually higher if storage is implemented. Also, demand charges are reduced, but not to the same extent as in the previous cases.
Figure 6-9: Case 5 under tariff N4 (on peak). For legend, see beginning of section 6.5.

Table 6-7: Most relevant cost and design parameters for Case 5 under tariff N4 (on peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>414.25</td>
<td>(415.16)</td>
<td>Battery Capacity (kWh)</td>
<td>31.71</td>
<td>(/)</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>150 950</td>
<td>(151 160)</td>
<td>Lifetime (years)</td>
<td>11.51*</td>
<td>(/)</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>318.23</td>
<td>(317.56)</td>
<td>Energy Consumed (kWh)</td>
<td>226.08</td>
<td>(216.04)</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>1067.5</td>
<td>(1757.0)</td>
<td>Energy Max (kWh/h)</td>
<td>21.3504</td>
<td>(35.14)</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>101 460</td>
<td>(1757.0)</td>
<td>Power Converter (kW)</td>
<td>69.24</td>
<td>(/)</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>(125 000)</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>109.77</td>
</tr>
<tr>
<td>Converter</td>
<td>55 391</td>
<td>(/)</td>
<td>Transformer</td>
<td>/</td>
<td>(/)</td>
</tr>
</tbody>
</table>

Case 6 Tariff N3 (Off-peak)

Case 6 simulates a high-power charging station with 4 slots with a rated power of 150 kW each. This is a totally different case than the previous one. It was analysed with tariff N3, both in on and off-peak. Since N3 is a tariff for high voltage, a transformer unit to step down the voltage to 400 V is required. The total energy consumed is 1044 kWh and the maximum average hourly consumption is 192 kW.

Notably, during off-peak hours, the implementation of an ESS is not convenient. A possible reason is the relatively low demand charge. In fact, despite the high maximum hourly consumption, the power fee applied is much lower than in previous cases (28 öre/kWh, whereas in the previous cases it was 40 öre/kWh).
Table 6-8: Most relevant cost and design parameters for Case 6 under tariff N3 (off-peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>(1375)</td>
<td></td>
<td>Battery Capacity (kWh)</td>
<td>((/))</td>
<td></td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>(500 070)</td>
<td></td>
<td>Lifetime (years)</td>
<td>((/))</td>
<td></td>
</tr>
<tr>
<td>Electricity Costs</td>
<td>(939.87)</td>
<td></td>
<td>Energy Consumed (kWh)</td>
<td>(1044.2)</td>
<td></td>
</tr>
<tr>
<td>(SEK/day)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Charge</td>
<td>(6 718.6)</td>
<td></td>
<td>Energy Max (kWh/h)</td>
<td>(191.96)</td>
<td></td>
</tr>
<tr>
<td>(SEK/month)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Battery Cost</td>
<td>((/))</td>
<td></td>
<td>Power Converter (kW)</td>
<td>((/))</td>
<td></td>
</tr>
<tr>
<td>Connection</td>
<td>(425 000)</td>
<td></td>
<td>Peak Power (kW)</td>
<td>373.59</td>
<td></td>
</tr>
<tr>
<td>Converter</td>
<td>((/))</td>
<td></td>
<td>Transformer</td>
<td>800 kVA</td>
<td></td>
</tr>
<tr>
<td>Transformer</td>
<td>164 340</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Case 6 Tariff N3 (On Peak)

The simulation of Case 6 during peak time provided very different results. The high-power fee of peak time (86 öre/kWh) makes storage extremely convenient. Despite electricity cost being slightly higher, due to daily battery cycles, the overall yearly cost is lowered by 12.4%. Compared to the case without storage, demand charges and connection fees are reduced by 71 and 75% respectively. It must be stated however that the initial investment for battery and converter amounts to approximately 1.6 million SEK. As it can be seen from Figure 6-10, this is probably the case that better depicts the ideal role of energy storage. Although the charging demand (red) is extremely variable and reaches peaks of 350 kW, the implementation of an ESS is remarkably effective in flattening the load curve: the power withdrawn from the grid is the sum of the power feeding the battery (in blue) and the power directly feeding the load (in green).

![Figure 6-10: Case 6 under tariff N3 (on peak). For legend, see beginning of section 6.5.](image-url)
Table 6-9: Most relevant cost and design parameters for Case 6 under tariff N3 (on peak).

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost 2000</th>
<th>Cost 1000</th>
<th>Cost No ESS</th>
<th>Design Parameter</th>
<th>Value 2000</th>
<th>Value 1000</th>
<th>Value No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>1746.2</td>
<td>1999.4</td>
<td>/</td>
<td>Battery Capacity (kWh)</td>
<td>419.3</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>635 880</td>
<td>725 840</td>
<td>/</td>
<td>Lifetime (years)</td>
<td>19</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Electricity Costs</td>
<td>1120.1</td>
<td>1100.9</td>
<td>/</td>
<td>Energy Consumed (kWh)</td>
<td>1 124.6</td>
<td>1044.2</td>
<td></td>
</tr>
<tr>
<td></td>
<td>5867.6</td>
<td>20 636</td>
<td>/</td>
<td>Energy Max (kWh/h)</td>
<td>54.6</td>
<td>192</td>
<td></td>
</tr>
<tr>
<td>Battery Cost *1000</td>
<td>1 341.7</td>
<td>/</td>
<td>/</td>
<td>Power Converter (kW)</td>
<td>301.7</td>
<td>/</td>
<td></td>
</tr>
<tr>
<td>Connection</td>
<td>106 250</td>
<td>425 000</td>
<td>/</td>
<td>Peak Power (kW)</td>
<td>87</td>
<td>373.6</td>
<td></td>
</tr>
<tr>
<td>Converter</td>
<td>241 330</td>
<td>/</td>
<td>/</td>
<td>Transformer (kVA)</td>
<td>120</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Transformer</td>
<td>103 800</td>
<td>164 340</td>
<td>/</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

6.6 Battery Price Influence

As mentioned earlier, sensitivity analysis was also conducted on battery pricing. Intuitively, if battery price decreases, larger batteries can be implemented at lower cost, increasing the cost effectiveness of the solution. Consequently, for cases where the battery is already convenient, the outcome is predictable. It was chosen to conduct the analysis on the most interesting cases: Case 5 and Case 6 (Off-peak), where storage is not convenient at current pricing, and Case 6 (On Peak).

Case 6 Tariff N3 (Off-peak)

Table 6-10: Costs and design parameters of Case 6 (Off-peak) for different battery prices.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost 2000</th>
<th>Cost 1000</th>
<th>Cost No ESS</th>
<th>Design Parameter</th>
<th>Value 2000</th>
<th>Value 1000</th>
<th>Value No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>1357</td>
<td>1311</td>
<td>1375</td>
<td>Battery Capacity (kWh)</td>
<td>96.2</td>
<td>112.9</td>
<td>/</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>494 190</td>
<td>477 300</td>
<td>500 070</td>
<td>Lifetime (years)</td>
<td>16</td>
<td>17.6</td>
<td>/</td>
</tr>
<tr>
<td>Electricity Costs</td>
<td>957</td>
<td>957</td>
<td>940</td>
<td>Energy Consumed (kWh)</td>
<td>1066.1</td>
<td>1067.5</td>
<td>1044.2</td>
</tr>
<tr>
<td></td>
<td>4224</td>
<td>3985</td>
<td>6719</td>
<td>Energy Max (kWh/h)</td>
<td>120.7</td>
<td>113.9</td>
<td>191.96</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>192 418</td>
<td>112 880</td>
<td>/</td>
<td>Power Converter (kW)</td>
<td>158.5</td>
<td>134.6</td>
<td>/</td>
</tr>
<tr>
<td>Connection</td>
<td>30 000</td>
<td>30 000</td>
<td>42 500</td>
<td>Peak Power (kW)</td>
<td>242.6</td>
<td>256.9</td>
<td>373.59</td>
</tr>
<tr>
<td>Converter</td>
<td>126 790</td>
<td>107 710</td>
<td>/</td>
<td>Transformer (kVA)</td>
<td>315</td>
<td>315</td>
<td>800</td>
</tr>
<tr>
<td>Transformer</td>
<td>123 122</td>
<td>123 122</td>
<td>164 340</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Among the evaluated cases, Case 6 (Off-peak) was the only one in which the implementation of energy storage was not convenient with current battery prices. Table 6-10 shows the simulation results for lower battery prices, i.e. 2000 SEK/kWh and 1000 SEK/kWh. The lower cost enables to profitably implement the storage system, which size is inversely proportional to the price. However, it must be stated that the savings resulting
from the implementation of the system are not high, especially if compared to previous figures. Compared to the case without storage, yearly cost decreases by 1.2 and 4.5%, respectively for battery price of 2000 and 1000 SEK/year. Battery capacity increases, but reaches a maximum of 112.9 kWh, a fourth of the optimal capacity of Case 6 (On Peak) with current battery prices.

Having a closer look at the figures, it is possible to see that while demand charge decreases significantly, the costs of electricity increases, offsetting part of the savings in demand charge. In tariff N3 (off-peak), there is no difference in price during the day. This does not enable any savings from shifting energy consumption during off-peak hours. As a result, due to inefficiencies, the electricity price is higher.

**Case 5 Tariff N4 (Off-peak)**

Lower battery prices enable the implementation of storage, which results in lower prices. Compared to the previous case, decreasing battery price has greater impact on yearly costs. The annual costs decrease by 5.4 and 11%, respectively for battery price of 2000 and 1000 SEK/kWh. In percentage, the decrease in demand charge is lower than in the previous case. However, inferior electricity prices – enabled by different pricing periods – contribute in decreasing operating costs. It is interesting to note that the battery size increases greatly when price diminishes to 2000 SEK/kWh. However, when the price is halved to 1000 SEK/kWh the battery size increases only slightly. As it can be seen from Figure A-7 in APPENDIX X, the battery is charging all the energy before 6 am, when electricity is cheaper. This happens in both cases. The two cases are quite similar in terms of operation strategy; the additional savings are provided mainly by the lower battery price. With regard to connection capacity, the different prices have no impact.

**Case 6 Tariff N3 (On Peak)**

A final analysis was conducted on Case 6. Similarly to the previous cases, lower battery prices increase the cost efficiency of the system. Costs decrease by 5.5 and 9.8%, respectively in the case of 2000 and 1000 SEK/kWh. It is interesting to see that, as for Case 5, battery price and size are not exactly inversely proportional. That is, halving battery price does not cause its size to double.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost 2000</th>
<th>Cost 1000</th>
<th>Cost 3200</th>
<th>Design Parameter</th>
<th>Value 2000</th>
<th>Value 1000</th>
<th>Value 3200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>392</td>
<td>369</td>
<td>414</td>
<td>Battery Capacity (kWh)</td>
<td>131.3</td>
<td>141.2</td>
<td>31.71</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>142 800</td>
<td>134 370</td>
<td>150 950</td>
<td>Lifetime (years)</td>
<td>29.5</td>
<td>29.5</td>
<td>11.51*</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>283</td>
<td>280</td>
<td>318</td>
<td>Energy Consumed (kWh)</td>
<td>232.3</td>
<td>233.4</td>
<td>226.08</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>709</td>
<td>762</td>
<td>1067.5</td>
<td>Energy Max (kWh/h)</td>
<td>14.1</td>
<td>15.25</td>
<td>21.35</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>262 620</td>
<td>141 190</td>
<td>101 460</td>
<td>Power Converter (kW)</td>
<td>69.24</td>
<td>69.24</td>
<td>69.24</td>
</tr>
<tr>
<td>Connection</td>
<td>60 000</td>
<td>60 000</td>
<td>60 000</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>44</td>
<td>44</td>
</tr>
<tr>
<td>Converter</td>
<td>55 391</td>
<td>55 391</td>
<td>55 391</td>
<td>Transformer</td>
<td>/</td>
<td>/</td>
<td>/</td>
</tr>
</tbody>
</table>
An unexpected result is the optimal sizing of transformer and connection, which increases when running the simulation with a price of 1000 SEK/kWh. It could seem counterintuitive – or even wrong. However, the higher rating is due to the fact that the system requires large amounts of energy in a small period during off-peak time. A smaller connection fuse would not allow charging all the required energy within the time limits. Similar results were shown by Corchero et al. (2012). Carefully analysing the simulation results, it was found that the bottleneck was the fixed state of charge of the system at 12 am (see section 6.1). Due to the particular profile of Case 6, the system had no time to charge the battery to 30% by 12 am with a maximum power of 87 kW. By lowering the required state of charge to 20%, the rating of connection fuse and transformer aligned to the other cases. Nevertheless, this shows a possible outcome of low battery prices. If the battery is large enough, under particular pricing schemes, it might be more convenient to charge the system at high power during off-peak periods, thus leading to a higher connection size. From the grid perspective, this could be counterproductive. However, from a global perspective, this may have positive effects, since shifting the demand to off-peak times significantly reduces the stress of the grid when it is most needed, i.e. peak time (Corchero et al., 2012).

Table 6-12: Costs and design parameters of Case 6 (On Peak) for different battery prices.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost 2000</th>
<th>Cost 1000</th>
<th>Cost 3200</th>
<th>Design Parameter</th>
<th>Value 2000</th>
<th>Value 1000</th>
<th>Value 3200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>1650</td>
<td>1575</td>
<td>1746</td>
<td>Battery Capacity (kWh)</td>
<td>427.5</td>
<td>466.4</td>
<td>419.3</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>600 900</td>
<td>573 380</td>
<td>635 880</td>
<td>Lifetime (years)</td>
<td>19.4</td>
<td>22.3</td>
<td>19</td>
</tr>
<tr>
<td>Electricity Costs</td>
<td>1116</td>
<td>1111</td>
<td>1120</td>
<td>Energy Consumed (kWh)</td>
<td>1124</td>
<td>1121</td>
<td>1125</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>5790</td>
<td>5415</td>
<td>5867</td>
<td>Energy Max (kWh/h)</td>
<td>53.9</td>
<td>50.4</td>
<td>54.6</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>854 900</td>
<td>466 420</td>
<td>1 341.7</td>
<td>Power Converter (kW)</td>
<td>301.7</td>
<td>274.8</td>
<td>301.7</td>
</tr>
<tr>
<td>Connection</td>
<td>106 250</td>
<td>175 000</td>
<td>106 250</td>
<td>Peak Power (kW)</td>
<td>87</td>
<td>161.7</td>
<td>87</td>
</tr>
<tr>
<td>Converter</td>
<td>241 330</td>
<td>219 830</td>
<td>241 330</td>
<td>Transformer (kVA)</td>
<td>120</td>
<td>315</td>
<td>120</td>
</tr>
<tr>
<td>Transformer</td>
<td>103 800</td>
<td>123 122</td>
<td>103 800</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

6.7 Pricing Influence

Previous sensitivity analysis enabled to conclude that the most important factor that justifies the implementation of storage is demand charge. However, it has been shown that the contribution of different electricity pricing in lowering operating costs is significant.

In light of what has been found, two different tariffs will be tested, both resulting from modifications of current tariffs. Tariff N4 has a considerable differentiation in electricity pricing between on and off-peak time; however, the demand charge during peak time is the same as during off-peak and lower if compared to tariff N3 (see Table 4-3). On the other hand, tariff N3 has a relatively small difference in electricity price between peak and off-peak.

The tariffs created are summarised in Table 6-13. Tariff N4-A was shaped to investigate the influence of an even higher electricity price difference between peak and off-peak time. N4-B is the same as N4-A, but with
a lower power fee. N4-C is the same as N4 currently in place, but with a higher power fee, equal to the total power fee of tariff N3. N4-D is the same as N4-C but with no price difference between peak and off-peak time. Finally, tariff N3-A aims at simulating a tariff with high power fee and very high differentiation between peak and off-peak prices. Tariff N4-A/B/C/D were tested on Case 5, while tariff N3-A was tested on Case 6.

### Table 6-13: Proposed tariffs for sensitivity analysis.

<table>
<thead>
<tr>
<th>Component</th>
<th>N4-A LV</th>
<th>N4-B LV</th>
<th>N4-C LV</th>
<th>N4-D LV</th>
<th>N3-A HV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge (SEK/month)</td>
<td>365</td>
<td>365</td>
<td>365</td>
<td>365</td>
<td>2450</td>
</tr>
<tr>
<td>Monthly Power Fee (SEK/kW month)</td>
<td>40</td>
<td>20</td>
<td>86</td>
<td>86</td>
<td>10</td>
</tr>
<tr>
<td>Peak Period Power Fee (SEK/kW month)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>86</td>
</tr>
<tr>
<td>Transfer fee peak period (öre/kWh)</td>
<td>5.1</td>
<td>5.1</td>
<td>14</td>
<td>30</td>
<td>5</td>
</tr>
<tr>
<td>Transfer fee normal (öre/kWh)</td>
<td>78.6</td>
<td>78.6</td>
<td>52.4</td>
<td>30</td>
<td>52.4</td>
</tr>
</tbody>
</table>

### Case 5 Tariffs N4-A and N4-B

Tariffs N4-A and N4-B were tested to investigate the effects that a high difference in retail electricity fees has. It was interesting to test it on Case 5, since current pricing does not provide economic incentives to implement storage.

The price difference in tariff N4-A strongly incentivises the implementation of an ESS. A battery of 138 kWh is able to diminish yearly costs by about 8%, from 176 990 to 163 260 SEK per year. Battery is charged during off-peak times and discharged fully during the day to lower demand charge. Despite the higher consumption of electricity deriving from inefficiencies, also electricity expenses are lowered. The ESS performs well in terms of grid impact, keeping the maximum power withdrawal at 44 kW.

### Table 6-14: Costs and design parameters of Case 5 under tariffs N4-A and N4-B.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost N4-A NO ESS</th>
<th>Cost N4-B NO ESS</th>
<th>Battery Capacity (kWh)</th>
<th>Value N4-A</th>
<th>Value N4-B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>448</td>
<td>486</td>
<td>436</td>
<td>456.6</td>
<td>138</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>163260</td>
<td>170990</td>
<td>158990</td>
<td>166450</td>
<td>29.6</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>305</td>
<td>388.3</td>
<td>301</td>
<td>388.3</td>
<td>233</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>746</td>
<td>1757</td>
<td>392</td>
<td>878.5</td>
<td>44</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>441850</td>
<td>/</td>
<td>464860</td>
<td>/</td>
<td>14.9</td>
</tr>
<tr>
<td>Connection</td>
<td>60000</td>
<td>125000</td>
<td>60000</td>
<td>125000</td>
<td>69.2</td>
</tr>
<tr>
<td>Converter</td>
<td>55391</td>
<td>/</td>
<td>55391</td>
<td>/</td>
<td>/</td>
</tr>
</tbody>
</table>

The high price difference is enough to justify the implementation of storage even if tariff N4-B, which has a much lower demand charge (20 SEK/kW). This tariff was created to investigate if – even with a lower demand charge – high electricity pricing was enough to justify the implementation of the ESS. The results are very similar to the ones obtained by applying tariff N4-A, although costs are reduced, due to the lower

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85 Note that yearly cost with this tariff is similar to the one obtained through the simulation with tariff N4.
demand charge. Battery size is slightly increased, to accumulate more energy when more convenient. Electricity costs are in fact slightly lower when compared to tariff N4-A.

Case 5 Tariffs N4-C and N4-D

Tariffs N4-C and N4-D were created to investigate how increased power fees influenced the results of Case 5. The optimal layout of the system includes energy storage (108.5 kWh). This permits to lower yearly costs by 8.6%, from 175 410 to 160 290 SEK per year. The savings are mainly due to the lower demand charge, which decreases from 3778 to 1259 SEK per month. However, savings are enabled by the electricity price as well, due to the price difference between peak and off-peak.

Tariff N4-D aims at assessing if the high-power fee alone is enough to justify the implementation of storage. The electricity fee is the same during peak time and off-peak time, equal to 30 öre per kWh. This figure was selected to maintain consistency in the costs, which were precisely chosen for all previous tariffs to keep yearly costs similar to the ones resulting from the analysis of Case 5 with tariff N4 (section 6.5).

Tariff N4-D still incentivises the use of energy storage, but in a particularly different manner than in previously mentioned cases. Since there is no incentive in purchasing electricity during off-peak time, the battery can charge before each session and deliver its energy during it. The battery cycles are many more than in previous cases and its capacity rating is relatively small (31.7 kWh). Yearly costs are reduced by 3.3%. Demand charge is consistently lowered to 2295 SEK per month however, compared to the previous case, savings are partially reduced by higher electricity costs. Finally, tariff N4-D – as well as N4-B – are effective in reducing grid connection size and shaving consumption peaks.

<table>
<thead>
<tr>
<th>Case 5 Tariffs N4-C and N4-D</th>
</tr>
</thead>
</table>

### Table 6-15: Costs and design parameters of Case 5 under tariffs N4-C and N4-D.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost N4-C</th>
<th>N4-C NO ESS</th>
<th>Cost N4-D</th>
<th>N4-D NO ESS</th>
<th>Design Parameter</th>
<th>Value N4-C</th>
<th>N4-C No ESS</th>
<th>Value N4-D</th>
<th>N4-D No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>440</td>
<td>482.5</td>
<td>407</td>
<td>422</td>
<td>Battery Capacity (kWh)</td>
<td>108.5</td>
<td>/</td>
<td>31.7</td>
<td>/</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>160290</td>
<td>175410</td>
<td>148240</td>
<td>153330</td>
<td>Lifetime (years)</td>
<td>20.9</td>
<td>/</td>
<td>11.3</td>
<td>/</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>297</td>
<td>318</td>
<td>268</td>
<td>257</td>
<td>Energy Consumed (kWh)</td>
<td>235</td>
<td>216</td>
<td>226.3</td>
<td>216</td>
</tr>
<tr>
<td>Demand Change (SEK/month)</td>
<td>1259</td>
<td>3777</td>
<td>2295</td>
<td>3777</td>
<td>Energy Max (kWh/h)</td>
<td>11.7</td>
<td>35</td>
<td>21.4</td>
<td>35</td>
</tr>
<tr>
<td>Battery Cost</td>
<td>347110</td>
<td>/</td>
<td>101460</td>
<td>/</td>
<td>Power Converter (kW)</td>
<td>69.2</td>
<td>/</td>
<td>69.2</td>
<td>/</td>
</tr>
<tr>
<td>Connection</td>
<td>60000</td>
<td>125000</td>
<td>60000</td>
<td>125000</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>110</td>
<td>44</td>
<td>110</td>
</tr>
<tr>
<td>Converter</td>
<td>55391</td>
<td>/</td>
<td>55391</td>
<td>/</td>
<td>Transformer</td>
<td>/</td>
<td>/</td>
<td>/</td>
<td>/</td>
</tr>
</tbody>
</table>

Case 6 Tariffs N3-A

Tariff N3-A was chosen to simulate a possible tariff in which high electricity price differentiation was associated with high – and variable – power fees. Clearly, such a tariff highly incentivises the implementation of an ESS. However, it is interesting how this tariff affects the operation of the system. As it can be seen in Figure 6-11, the energy required for charging the vehicles is almost entirely shifted during off-peak times. During peak period, the battery (yellow) satisfies almost all the energy demand. However, as soon as the peak time is off, the grid provides electricity to the load. During the last charging session, which is almost entirely after 10 pm, the battery is engaged for a very small fraction. The 1.3 MWh battery is charged over night at constant power (about 170 kW). Under tariff N3-A, the yearly cost is only 4.6% more expensive than the annual cost under tariff N3 (on peak) without storage. Interestingly, the maximum hourly average
power consumption does not have a tremendous variation. However, the demand charge corresponding is entirely different, as the maximum is located off-peak.

Figure 6-11: Case 6 analysed with tariff N3-A. For simulating this case, initial and final battery SOC were set to 20%.

This case is clearly an extreme case. It might, however, have interesting implications. By shifting all demand during off-peak time, the system does not cause any additional stress on the local distribution grid, as most of the conventional energy demand is during daytime. Apart from the grid impact perspective, this solution might improve the integration of wind generation, which may be subject to curtailment\(^{86}\) during night, when energy demand is lower. The case analysed shows just two periods, however, by implementing more complex tariffs with different pricing periods, DSOs can implicitly redirect consumption to specific periods of weak demand, thus reducing the stress on the grid. Demand response programme can also have similar effects.

Table 6-16: Costs and design parameters of Case 6 under tariffs N3-A.

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost N3-A</th>
<th>N3-A No ESS</th>
<th>Design Parameter</th>
<th>Value N3-A</th>
<th>N3-A No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>2087</td>
<td>2692</td>
<td>Battery Capacity (kWh)</td>
<td>1300</td>
<td>/</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>760820</td>
<td>977670</td>
<td>Lifetime (years)</td>
<td>29.4</td>
<td>/</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>1032</td>
<td>1602</td>
<td>Energy Consumed (kWh)</td>
<td>1207</td>
<td>1044</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>2279</td>
<td>263940</td>
<td>Energy Max (kWh/h)</td>
<td>166</td>
<td>192</td>
</tr>
<tr>
<td>Battery Cost *1000</td>
<td>4216.5</td>
<td>/</td>
<td>Power Converter (kW)</td>
<td>350</td>
<td>/</td>
</tr>
<tr>
<td>Connection</td>
<td>175000</td>
<td>425000</td>
<td>Peak Power (kW)</td>
<td>173</td>
<td>373.6</td>
</tr>
<tr>
<td>Converter</td>
<td>280180</td>
<td>/</td>
<td>Transformer (kVA)</td>
<td>315</td>
<td>800</td>
</tr>
<tr>
<td>Transformer</td>
<td>123122</td>
<td>164340</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^{86}\) As of today, curtailment in Sweden has not been a major issue and occurred only few times. However, in the future, increased share of wind energy in the market combined with the phase out of nuclear reactors may affect grid stability (Benz, 2015). According to the Nordic Market Report by NordREG (2014), wind can cause strong fluctuations of electricity prices, which may become negative in times of abundance. Ultimately, abundance of wind energy may cause curtailment.
7 Results Implications

This chapter further discusses the previously presented results, focusing on the relevant implications these have in the thesis research questions. It consists of two main sections: the first covers the economic perspective and the second the grid impact perspective. The insights provided by the sensitivity analysis are further discussed throughout the chapter.

7.1 Introduction

Overall, results show that storage can be cost effectively implemented in Swedish fast chargers, also with current usage profile. However, as previously stated, these results should be taken as indicative, as they reflect optimal solutions from a mathematical and theoretical point of view. In real applications, engineers might choose to oversize the equipment, thus reducing the savings margin. In some cases, oversizing the equipment might offset the economic benefits shown in the previous sections. Despite these economic considerations, the sensitivity analysis permitted to identify key factors enabling a cost-effective implementation of ESSs. In addition, results allowed to assess the impact that the solution has on the distribution grid87.

7.2 Economic Perspective

Retail Price

Initially, it was shown how current daily electricity price variation alone is not sufficient to justify the additional costs related to the operation of ESSs. In fact, the additional costs related to the equipment, together with system’s inefficiencies, offset the savings deriving from demand shifting.

Load Pattern

The sensitivity conducted on the load enabled to understand how different charging patterns affect the implementation of ESSs. The key aspects are summarised and described hereafter.

Energy withdrawal per charging session

With current electricity pricing, the energy per charging session is one of the key points to consider. The higher the energy per session, the higher the demand charge, regardless the actual peak power88. High energy withdrawal causes battery size to rapidly increase. As it can be seen by the simulation of Case 1, the available battery capacity is entirely used during the third charging session (Tesla). It is interesting to compare Case 1, with the one shown in APPENDIX XI. The total energy consumption is about 88 kWh in both cases. However, while in Case 1 the energy is absorbed in three sessions – and one of them particularly large – in the case shown in the appendix, the consumption is equally spread in five sessions. The optimal battery size for in the latter case is 15.2 kWh, less than a third than in the former case. Hence, when planning the installation of an energy storage system, a detailed analysis of the expected charging pattern should be carried out.

However, it must be stated that despite the increased battery size, high energy per charging session – with the current low utilisation of charging stations – is the biggest incentive for implementing ESSs. In fact, since several charges are not likely to occur at the same time, the main responsible for increasing the hourly

87 The impact was assessed in a basic manner. It was not possible to retrieve real information from local grid operators. Hence, a simplified qualitative assessment was carried out.

88 Considering that higher energy per session makes the hourly average power consumption to increase accordingly.
average power consumption is the energy withdrawn per session. In fact, Case 1 has a higher cost reduction if compared to the case shown in APPENDIX XI: 14.7% in the first and 4.3% in the latter.

**Positioning during the day**

Also, daily distribution of the charges highly influences battery size. If charges are too close, there might not be time for the battery to recharge. To satisfy the demand without recharging, its rated capacity has to be increased substantially. Ideally, the best-case scenario for ESS to be cost effective is high hourly energy consumption spread in few sessions during the day, to enable the battery to fully charge between the sessions.

**Positioning in the hour**

A further factor is the positioning in the hour of the sessions. In fact, due to low metering resolution, if the charge is split in two metered hours, the calculated hourly average power gets consistently reduced. The worst case is when the charging session starts at the beginning of the hour, since all the energy withdrawn is counted for calculating the hourly average power of that hour.

**Ratio between electricity fee and demand charge**

High-power fees, and consequently high demand charges, were already identified in the introduction as the most important factor incentivising a cost-effective implementation of energy storage. Simulation results confirmed this statement to be true. However, it was found that it is not the high demand charge in absolute terms, but the ratio between electricity fees and demand charge that makes ESS cost efficient. Figure 7-1 shows how yearly costs are divided in Case 1 and Case 5. These two cases are interesting to compare since the demand charge is in both cases around 21 000 SEK per year, but the share that it has on total costs is substantially different. In Case 1 demand charge accounts for 27% of yearly costs, while in the second its share is halved. The implementation of energy storage has entirely different results in the two cases: in Case 1 it allows to substantially decrease costs, while in the second it has a remarkably little effect. It can be concluded that, with current pricing, the share of demand charge on total costs is the primary economic incentive for implementing energy storage.

With current prices, storage is effective in reducing demand charges since the battery capacity required for this purpose is relatively small. On the other hand, since the electricity price difference does not present extreme variations during the day, implementing storage for decreasing retail cost only is not convenient, as much higher capacity would be needed: all the energy required for the day should be purchased during the off-peak period, requiring large storage capacity. Current electricity price difference helps to reduce electricity costs, since more electricity is bought during off-peak periods when it is cheaper. However, it is not the main source of cost reduction. Comparing Figure 7-1 with Figure A-9 (APPENDIX XII), it can be seen that the majority of the savings are due to demand charge reduction. Consequently, if the demand charge proportion on costs is not high, savings would be affected as well.

A last reflexion on the charts in APPENDIX XII can be done focusing on Figure A-10, which pictures the share of costs before and after the implementation of the ESS for Case 6 (On Peak). Connection fees and transformer contribute to the reduction of costs, but to a much lower extent if compared to demand charge. Their share on yearly costs is in fact quite limited, even before the implementation of storage.

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89 If the metering was done with a lower resolution, energy per session and demand charge would be less linked. A lower resolution tends focuses more on the actual peak power, rather than the energy consumption during the hour.

90 This is confirmed by applying the same approach to Case 6. It can be seen that Case 6 (Off Peak) demand charge has share similar to Case 5, respectively 16 and 14%. Instead, in Case 6 (On Peak) – where storage is cost effective – demand charge has a share of 34%.
Battery Price

As expected, lower battery cost improves the economic performance of the system enabling higher savings. For example, for a price of 1000 SEK/kWh, Case 1 becomes 11.6% more convenient than with current prices. However, its effect is quite different throughout the three analysed cases.

Case 6 (Off-peak)

Lower battery prices enabled the implementation of storage, but savings were relatively small. In fact, due to the low power fee and the little difference between on peak and off-peak electricity prices, savings in demand charge were almost entirely offset by additional equipment cost and increased electricity price. Despite the great difference in battery price, if the electricity tariff is not favourable, it is not possible to obtain great cost reductions.

Case 5 (On Peak)

Case 5 reacted better to battery price reduction. Similarly to the previous case, the reason lies in the tariff structure. Tariff N4 has a consistent electricity price difference between peak and off-peak times. Consequently, the lower battery price enables to install a much larger battery to take advantage of the price difference and purchase consistent amounts of electricity at off-peak times (48% of total). Figure A-7 in APPENDIX X shows the power flows of the system in Case 5 for a battery price of 1000 SEK/kWh. The battery is charged at night and discharged during peak hours. This enables to both lower the demand charge and take advantage of cheaper electricity. Interestingly, when comparing the yearly costs of the two different cases of battery price, the difference is almost entirely due to the battery.

Case 6 (On Peak)

Case 6 (On Peak) was already briefly discussed in section 6.6. It shows that in some cases, for an extremely low battery price, it might be convenient to increase connection size and transformers, to allow large withdrawal of energy at off-peak time. However, in this specific case, higher rating could easily be avoided by introducing a different final constraint on battery SOC (see section 6.6).

A final reflection can be done on Case 6 (On Peak). Battery price is relevant, but even with the current price of 3200 SEK/kWh, it accounts for 14% of yearly costs. The vast majority of the expenses are for electricity: Collectively, demand charge, electricity price and fixed fees account for 81% of the bill.

Distribution Tariff

The previous analysis enabled to identify pricing as the major incentive for introducing storage. The study conducted on Case 5 showed how storage could become cost efficient both by acting on retail pricing and power fees. However, different results are obtained depending on the utilised approach.
Electricity Tariff Influence

Increasing price difference between peak period and off-peak period promotes energy purchase during low price periods. If power fees are maintained, the optimal operation of the systems maximises the power withdrawn at off-peak time, keeping the demand charges as low as possible91. The case limit happens when power fees during off-peak times are totally removed: the system charges at very high power during the night in order to save on electricity. This type of operation increases battery rated capacity and does not affect much its lifetime. This kind of operation, similar to the one shown in Figure A-7 in APPENDIX X, is in fact characterised by a single daily deep discharge cycle.

Power Fee Influence

Tariff N4-C showed how, also increasing power fee, promotes the implementation of storage. Maintaining price difference also stimulates energy purchase during off-peak periods. Instead, if the price difference is removed, the optimal control strategy is the opposite of the one presented in Figure A-7. The system tends to charge and discharge the battery several times during the day in between charging sessions. In fact, it does not make sense to purchase electricity at night, since prices are the same. As opposed to the previous case, this kind of pricing signal causes the optimal battery size to consistently decrease. However, due to the several daily cycles, battery lifetime is substantially reduced (see Figure A-11 in APPENDIX XIII).

High Time Differentiation

This case was already briefly described. It shows how high price differentiation, both in terms of electricity and power fees, can redirect consumption. Even the consumption pattern of Case 6, characterised by both high overall energy consumption and high peak demand, can be reshaped by proper pricing. It is interesting to note that this type of pricing enables a battery with rated capacity of 1.3 MWh to be cost-effective.

As previously stated, this is an extreme case. It shows however how pricing can influence the demand of such systems. The introduction of demand response programmes could have similar results. Even more interestingly, this kind of systems could be connected to the DSOs and react to price signals. That is, charging stations with storage, instead of being a threat for local grids, could become a source of stabilisation for the grid: absorbing power when there is abundance and avoiding consumption when the grid is more stressed. Possibly, this kind of systems could even inject power back to the grid if needed, upon proper compensation. DSOs cannot own ESSs their selves, but through proper pricing and demand response programmes grid operators can indirectly take advantage of these systems to help efficient grid management. Reacting to price signals, ESSs could avoid causing stress on the grid and – in some cases – support the grid by injecting power into it.

7.3 Grid Impact Perspective

As previously mentioned, it was not possible to retrieve accurate data on the grid topology in Stockholm. Hence, a qualitative grid impact assessment was conducted. The interviewees at Vattenfall Distribution identified congestion as the main threat that massive deployment of high-power charging stations could cause on the local grid. Infrastructure renewal is the best long-term solution but is costly and the permit process requires a long time. This is in line with what is described in the report “Reliability in Sweden’s Electricity System” issued by IVA (2017). The problem is particularly significant for urban environments, where it is hard to meet increasing electricity demand92. It is also difficult for DSOs to plan long term reliable investments, since the demand growth pace is very high and unpredictable.

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91 It is clear that, if Case 1 was simulated, the system would have totally shifted the demand at off peak periods. In fact, the lower daily consumption would have not caused high power consumption during off peak time. Instead, Case 5, due to its higher daily energy consumption, can cause high demand charges if all the energy is withdrawn at off peak periods.
92 Even if not relevant for the thesis, an interesting fact is that the opposite problem is happening for sparsely populated areas, where fewer and fewer people are connected to the grid. Hence, costs of maintenance for the few connected customers increase (IVA - The Royal Swedish Academy of Engineering Sciences, 2017).
In this environment, a load such as a fast charging station can strongly impact grid operation, especially if high power peaks happen unpredictably and during peak times. Hence, it is clear that loads without storage may create congestion problems for the grid. Looking at the loads shown in APPENDIX IX it is possible to see how these are characterised by high power peaks mostly located in the late afternoon. As it can be seen from the historical data of energy consumption in Nord Pool, this is the most critical moment as it coincides with peak energy demand.

The implementation of ESSs can lower the impact of the FCS in two main ways: stabilising the consumption of the FCS and shifting part of the electricity demand during off-peak periods. The performance of the system was consequently evaluated in terms of how it was able to act on demand, avoiding peaks, and in shifting additional demand during off-peak periods.

**Peak Shaving**

When implemented, ESSs showed good performance in shaving peak power withdrawal. With current consumption patterns (Case 1 to 3) storage enabled to consistently reduce peak demands. In Case 1 peak power withdrawal is reduced by about 57%. A similar figure is obtained for Case 2, while in Case 3 the reduction is even higher (72%). The stabilisation of the demand is particularly evident in Case 3 (On Peak) (Figure 6-10). The power withdrawn from the grid (the sum of the power directly feeding the load and the power flowing to the battery) is consistently stabilised.

However, a comment has to be done on the metering resolution, which hinders more effective shaving and in some cases, might seriously jeopardise proper peak shaving. As previously explained, demand charges in Sweden are calculated on the hourly average power consumption; specifically, on the highest value that this variable has in a month. Figure 4-5 shows the limitations that this strategy has, by comparing the metering of a simplified 150-kW charging session in Sweden and Spain (the latter has a metering resolution of 15 minutes). The lower resolution allows to more fairly charge for the actual peak consumption. In section 6.4, Case 1 was simulated under the same tariff (N4 on peak) but with different metering resolution. Compared to the hourly resolution, the 15-minutes resolution provides a much higher incentive in stabilising energy consumption.

A similar discussion could be done when charging the battery. Here, it is more the control strategy rather than pricing that influences the way the battery charges. Figure 6-5 and Figure 6-6 help to visualise the difference. In the first, the battery charges at high power for a small period of time, while in the second the battery charges at a lower power constantly for several hours. The second behaviour is more desirable from the point of view of the DSO, but currently, no price mechanism incentivises this kind of consumption over the other. In fact, the maximum hourly average power value sets the standard for the whole month. That is, the maximum value is the one used for demand charge calculation. There is no incentive for all the other hourly average consumption values to be consistently lower than the maximum. If the FCS demand is similar to the one presented in Case 1 to 3, this does not cause major problems, but with higher consumption patterns, this may limit the effectiveness of the solution. Reducing the metering resolution is a possible approach. On the other hand, the diffusion of smart grids and smart meters offers the possibility of developing more sophisticated billing methods that take into account the general behaviour of customers, rather than focusing only on peak demand.

**Demand Shifting**

Under current pricing, the primary incentive for the implementation of storage is demand charge. Consequently, if loads are spread during the day, it is more convenient to install smaller batteries and make them cycle more, thus reducing the share of energy purchased at off-peak times. However, if the difference in electricity price becomes more consistent (tariffs N4-A and N4-B), then it gets more convenient to install larger batteries and use them for both peak shaving and demand shifting. Similar effects are shown for a reduction in battery price (Figure A-7 in APPENDIX X). Under these circumstances, it makes sense to install larger batteries which enable to increase the share of off-peak electricity consumption.
High price differentiation

Finally, it was shown how high price differentiation could have significant effects on consumption behaviour. Figure 6-11 illustrates the best-case scenario: the fast charging station has virtually no impact on the grid during peak time, as all the required energy is purchased at night. It is a borderline case, but it provides insights on how high price differentiation can reshape consumption patterns. DSOs could institute different periods with high price difference, thus inducing FCSs to purchase electricity when more desirable.

The introduction of demand response programmes can further decrease the impact of FCSs. If larger batteries are installed, they could be automatically controlled to react to sudden price differences. This way, FCSs could absorb energy when there is an abundance or the grid is not congested. On the other hand, the system could stop purchasing electricity if there is power shortage or the grid congested.
8 Conclusions

This chapter concludes the thesis project, providing the reader with an overview of the work conducted and the results' interpretation. The key findings described in the previous sections are briefly discussed and fit into a broader perspective. Some comments on future possible developments, based on proposed regulations, are also provided.

The purpose of this master's thesis was to investigate the role that battery energy storage can play when coupled with an electric vehicle fast charging station in Sweden. More specifically, the analysis was centred on inquiring its ability to lower fast charging station's costs as well as to reduce the impact of high-power EV charging on local grids.

The literature review provided a solid basis on which the thesis project was built. In line with previous publications, it was chosen to reframe the problem as an optimisation study, aimed at finding the most cost-effective solution. A mixed-integer linear programming formulation was implemented in MATLAB. Contrary to the most relevant papers found in literature, the approach utilised for the load identification was more empirical, rather than mathematical. It was also found that no previous study was specifically tailored for the Swedish case.

With the help of statistic on Swedish fast chargers, a reasonable charging profile for FCS currently in place in Stockholm was built. This was implemented in the model, together with economic data. Due to the high variation expected for some critical parameters in the next years – and to allow a better understanding of the impact that different input data have on the problem – sensitivity analysis was conducted on load profile, battery price, and distribution tariffs.

Results showed that, overall, with the current price of Li-ion batteries, the estimated load profiles and the tariffs in place at the moment, energy storage is a viable option to both improve the economic performance and lower grid impact of FCS in Stockholm. However, different input parameters lead to considerably different results, both in terms of costs and network impact.

Different loads were shown to significantly influence the cost effectiveness of the design, while projected lower battery prices were proven to positively affect the results. Yet, electricity pricing was confirmed to be the most important parameter. Studying a particular load under the same tariff, but considering the fees variation between peak and off-peak periods, lead to entirely different results. Specifically, the crucial parameter is demand charge, and its share on total costs. Considering current price difference between on- and off-peak periods, demand charge is the primary cost component in which battery can act to lower operation costs. A small share of demand charge in the total costs leaves little relative space for cost reduction.

In the low-voltage tariff (N4), for example, where electricity price differentiation is considerable, electricity cost reduction contributes to increase savings, but on a lesser extent. This might be because fast charging stations, compared to more conventional loads (i.e., buildings or industries) with the same energy consumption, exhibit higher average power withdrawal. This is due to their purpose: deliver energy at very high power. Especially with current low consumption, the ratio of power over energy is considerably high. However, since electricity is by far the largest source of costs among the considered components. The cost of chargers and their installation, as well as costs for permits were neglected, as approximately the same regardless the installation of the ESS. These were consequently neglected as only the different costs were relevant when comparing the two solutions.

\[93\] Namely, battery price and load profile.

\[94\] Among the considered components. The cost of chargers and their installation, as well as costs for permits were neglected, as approximately the same regardless the installation of the ESS. These were consequently neglected as only the different costs were relevant when comparing the two solutions.
different tariffs, a possible way of tackling this cost could be self-production of electricity, for example by using solar PV. Solar production coincides with peak time, when grid prices are higher. Thus, charging the battery with solar energy may be convenient. However, assessment of the specific case must be done as PV production might be too low. These considerations offer the opportunity to mention some possible future developments of the model. Further work could be performed on the programme to include in the optimisation the option of on-site renewable energy generation (i.e., PV panels that are becoming more and more affordable). Renewable energy production could help meet the energy demand with an even lower grid impact. On the side, it could improve the image of the station and, consequently, positively impact its usage.

Another interesting finding was the low share of equipment cost. Initially, cost reduction was expected both from operation, i.e. lower electricity costs, and lower sizing of the equipment, mainly transformer, and connection. However, it was shown that the reduction in the expense for this equipment contributes only marginally to overall savings. In fact, despite savings in initial investment might be consistent, when dividing these by the years of operation their importance is reduced. In light of their low contribution to savings, it might not be reasonable to decrease their rating. For reliability reasons, a higher rating might be chosen during the implementation of the system. This highlights a significant limitation of the optimisation programme: it selects the mathematical optimal point, which may not be reasonable in real life situations. Its result should be taken as a starting point from further modelling, which can be carried out with a software specifically designed for techno-economical modelling of energy projects, such as Homer Energy.\textsuperscript{95}

It was also shown how highly differentiated pricing – in both power fees and retail electricity prices – can strongly influence FCS control strategy. This proves how DSOs, by modifying prices, can make storage not only cost-efficient for the owner, but also totally reshape its consumption behaviour. This would allow to almost entirely avoid consumption during peak periods. The diffusion of smart meters and smart equipment offers the possibility to further improve price differentiation, making storage systems able to instantly react to price variations during the day. In this way, FCS could actively participate to demand response, offering services to the local grid.

In the next years, this kind of tariff is likely to be implemented. Interviewees at Vattenfall Eldistribution revealed how the company is already looking at different pricing schemes. On top of that, at the end of 2016, the European Commission issued a proposal for new directives regarding electricity market. As discussed in section 4.3, sections of the document specifically address the integration of electric vehicles and storage systems in the electric grid. As part of the proposal, DSOs are required to provide pricing schemes that allow a cost-effective integration of storage in the electric system. Besides, grid operators are expected to firstly tackle grid congestion by utilising alternatives to network expansion, such as demand response programmes and energy storage systems.

If the given incentives are enough, they could provide favourable conditions for a new entity to enter the market: ESS operators. In fact, since DSOs cannot own storage systems, it might be possible for another market player to offer services to the grid. A smart neighbourhood could share large storage facilities that serve different purposes, among these, fast charging station support. This could be particularly important for small businesses to enter the market of EV charging. In fact, too high investment costs for battery systems could hinder the participation of start-ups in EV charging. Buying the service would allow a better cost management.

In conclusion, it seems that combining FCS and battery storage is a good solution, which can assist widespread diffusion of electric vehicles. Together with other initiatives, it can help Sweden to move a step further towards its ambitious goal of decarbonising the transport sector.

\textsuperscript{95} It must be stated, however, that this software cannot replace the optimisation programme previously realised. In fact, Homer does not calculate the optimal sizing by itself; it just tests and compares the different possible scenarios provided by the user.

ABB, n.d. Power Conversion System for ESS 100 kW to 30 MW Bi-directional Inverters.

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Appendices

APPENDIX I: Vattenfall Retail Tariff

Datum: 2017-05-17

Prisförslag – Företagsavtal

Priserna gäller t.o.m. 2017-05-19, kl 16.30

Acceptera genom att ringa eller skicka e-post till oss. Skriftlig bekräftelse översändes efter accept.

<table>
<thead>
<tr>
<th>Närområde</th>
<th>Anläggninga ID</th>
<th>Anl adress</th>
<th>Anl Postnr</th>
<th>Anl Ort</th>
</tr>
</thead>
<tbody>
<tr>
<td>HUV</td>
<td>735999100XXXXXXX</td>
<td>Fiktiv adress</td>
<td>169 56</td>
<td>Solna</td>
</tr>
</tbody>
</table>

Total årsförbrukning, 75,000 kWh

Leveransstart, fictiv datum

<table>
<thead>
<tr>
<th>Fast elpris:</th>
<th>6 mån</th>
<th>12 mån</th>
<th>24 mån</th>
<th>36 mån</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elpris, öre/kWh</td>
<td>34,80</td>
<td>35,40</td>
<td>35,90</td>
<td>33,10</td>
</tr>
<tr>
<td>Kostnad för elcertifikat, öre/kWh</td>
<td>Ingår</td>
<td>Ingår</td>
<td>Ingår</td>
<td>Ingår</td>
</tr>
<tr>
<td>Totalt elpris, öre/kWh</td>
<td>80,38</td>
<td>81,13</td>
<td>79,25</td>
<td>78,25</td>
</tr>
<tr>
<td>Fast avgift, kr/år och anläggning</td>
<td>360</td>
<td>360</td>
<td>360</td>
<td>360</td>
</tr>
</tbody>
</table>

Rörligt elpris:

| Påslag schablonräkn. öre/kWh | Inköpspris + 1,8 |
| Påslag timavräkn. öre/kWh | Inköpspris per timme + 1,8 |
| Kostnad för elcertifikat, öre/kWh | Beräknas enligt punkt 10 i avtalssvillkoren |
| Fast avgift, kr/år och anläggning | 360 |

Tillval:

| El från Vattenkraft, öre/kWh | 0,0 |
| El från Kärnkraft, öre/kWh | 0,0 |
| El från Vindkraft, öre/kWh | 1,9 |
| El från Solkraft, öre/kWh | 1,9 |


Med vänlig hälsning
Vattenfall kundservice AB

Härmed godkänns ovanstående:

Ort och datum: ............................................

..........................................................
Kundens underskrift
Namnförtydligande

---

96 Tariff retrieved on May 7th 2017. Applicable to businesses with yearly electricity consumption below 150 000 kWh. In this specific case, an approximate consumption of 75 000 kWh/year was considered.
1. Avtalets ingående och omfattning

Avtalet ("Avtalet") ingår från den dag Vattenfall accepterat Kundens beställning. Sedanvid kreditprovning kan genomföras och leda till att beställningen ej accepteras. Avtalet levereras med de villkor från detta avtal för skiftnedanställning och för förklaran av Kund som är tillämpliga från detta avtal. 

2. Skatter och övriga avgifter


3. Avtaletstående avtal


4. Avtalets utgång


5. Avtalets avbrott


6. Avtalets avbrott


7. Avtalets avbrott


8. Avtalets avbrott


9. Avtalets avbrott


10. Avtalets avbrott


11. Avtalets avbrott


12. Avtalets avbrott


13. Avtalets avbrott


14. Avtalets avbrott


15. Avtalets avbrott


16. Avtalets avbrott


17. Avtalets avbrott


18. Avtalets avbrott


19. Avtalets avbrott


20. Avtalets avbrott

APPENDIX II: Vattenfall Eldistribution Distribution Tariffs

OMRÅDE SÖDER

Nättaurifffirst

<table>
<thead>
<tr>
<th>Högpåning</th>
<th>Lågspåning</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>N2</td>
</tr>
<tr>
<td>Fast avgift</td>
<td>220 000</td>
</tr>
<tr>
<td></td>
<td>3 200</td>
</tr>
<tr>
<td>Månadseffektavgift</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td>70</td>
</tr>
<tr>
<td>Högeläsningsavgift</td>
<td>5,0</td>
</tr>
<tr>
<td></td>
<td>22,1</td>
</tr>
<tr>
<td>Overföringsavgift</td>
<td>2,4</td>
</tr>
<tr>
<td>högsttid*</td>
<td>9,1</td>
</tr>
<tr>
<td></td>
<td>65,5 kVh</td>
</tr>
</tbody>
</table>

* Alla priser exklusive moms.
** Högeläsningsutbytning är tillämplig under december-
varje årliga anslutningsavgift för ett-effektiva företag.

Vill du veta mer?

Besök vattenfalleldistribution.se/kundservice.

97 Power Tariff (Effektabonnemang) for South Sweden.
**APPENDIX III: Spanish Billing Periods**

The following table shows the distribution during the year of the three billing period in Spain. This table was retrieved – and translated – from Endesa website and refers to “Preferente” tariff for companies (original version available at: https://www.endesaclientes.com/empresas/tarifa-preferente.html).

Green stands for “low” period, red stands for “high” period and light blu is for “normal” period. High period is the most expensive while “low” period is the cheapest.

<table>
<thead>
<tr>
<th>Period</th>
<th>12am - 8am</th>
<th>8am - 11am</th>
<th>11am - 3pm</th>
<th>3pm - 6pm</th>
<th>6pm - 10pm</th>
<th>10pm - 12pm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peninsula and Canary Islands</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balearic Islands</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**APPENDIX IV: Battery Data**

As previously stated, battery data were retrieved from a phone communication with an LG Chem employee based in Germany. The contact was found in the LG Chem battery catalogue (available at: http://www.lgchem.com/global/ess/ess/product-detail-PDEC0001#guide\nCautionsWrap).

The following table summarises the key information provided:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roundtrip efficiency</td>
<td>95%</td>
</tr>
<tr>
<td>Maximum charging C-rate</td>
<td>1 C</td>
</tr>
<tr>
<td>Minimum discharging C-rate</td>
<td>2.5 C</td>
</tr>
<tr>
<td>Optimal charging C-rate</td>
<td>0.5 C</td>
</tr>
<tr>
<td>Suggested operative SOC</td>
<td>10% to 90%</td>
</tr>
<tr>
<td>Battery cycle life</td>
<td>10 000 – 12 000 cycles(^98)</td>
</tr>
<tr>
<td>End of life available capacity</td>
<td>70% of the nominal capacity</td>
</tr>
<tr>
<td>Warranty</td>
<td>10 years(^99)</td>
</tr>
<tr>
<td>Inverter type</td>
<td>Bi-directional inverter – compatible with CANBUS/MODBUS protocols</td>
</tr>
<tr>
<td>Voltage Range</td>
<td>700 – 1000 V</td>
</tr>
<tr>
<td>Cost</td>
<td>320 EUR/kWh (3200 SEK/kWh)</td>
</tr>
</tbody>
</table>

\(^{98}\) Under optimal conditions.
\(^{99}\) This is just an indicative value. Actual warranty is defined case by case depending on the expected operative conditions of the ESS.
APPENDIX V: Transformer Costs

The transformer costs were provided by Pöyry Sweden AB. Four sizes were considered and detailed pricing is shown in the following table:

<table>
<thead>
<tr>
<th>Transformer Station</th>
<th>Unit</th>
<th>Cost (Work) [SEK]</th>
<th>Cost (Material) [SEK]</th>
<th>Cost (Extra) [SEK]</th>
<th>Cost (Total) [SEK]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer Station 120 kVA</td>
<td>each</td>
<td>3 800</td>
<td>90 000</td>
<td>10 002</td>
<td>103 802</td>
</tr>
<tr>
<td>Transformer Station 315 kVA</td>
<td>each</td>
<td>4 009</td>
<td>107 979</td>
<td>11133</td>
<td>123 122</td>
</tr>
<tr>
<td>Transformer Station 800 kVA (Plate Shell)</td>
<td>each</td>
<td>4 268</td>
<td>148 911</td>
<td>11158</td>
<td>164 337</td>
</tr>
<tr>
<td>Transformer Station 1250 kVA (concrete)</td>
<td>each</td>
<td>7 166</td>
<td>322 370</td>
<td>12962</td>
<td>342 498</td>
</tr>
</tbody>
</table>

APPENDIX VI: Forecast of Daily Energy Consumption for FCS in Stockholm by the end of 2017

Figure A-1: Forecast of daily energy consumption for FCS in Stockholm to the end of 2017. The red line represents linear interpolation and projection, while the blue represents the projection assuming a 6% monthly increase.

Figure A-2: Forecast of daily energy consumption for FCS in Stockholm to the end of 2017. The red line represents linear interpolation and projection, while the blue represents the projection assuming a 10% monthly increase.
APPENDIX VII: Swedish BEV stock as of June 9th, 2017

Swedish BEV stock

![Swedish BEV stock chart]

Figure A-3: Swedish BEV Stock as of June 8th, 2017.
Source (Power Circle, 2017a)

APPENDIX VIII: Adapted Tesla’s Load Profiles and 150-kW HPC Profiles

![Adapted Tesla’s Load Profiles and 150-kW HPC Profiles]

Figure A-4: Pilot profiles calculated starting from Tesla’s 90 D profile. “Charging Profile Cut” was calculated by putting a limit on the maximum value of Tesla's profile. “Charging Profile Proportional” was computed by multiplying the original profile for a constant K<1, selected in a way to limit the maximum power withdrawal to 50 kW.

Figure A-5: Pilot profiles of a 150-kW charging session. These profiles were built starting from the original profiles of a Tesla 90D and a Nissan Leaf and proportionally increasing their values to reach a maximum charging power of 150 kW.
Figure A-6: Simulated load profiles, Case 1 (top left) and Case 6 (bottom right). Cases 1 to 3 are made up by the same three single car charging profiles, arranged in different pattern. Case 1 is the best-case scenario (sessions spread during the day), while Case 3 is the worst (highly concentrated, with two cars charging at the same time). Case 4 and 5 represent the same station, with an increased utilisation. Case 6 aims at modelling the demand of an ultra-fast charging station with 4 chargers of up to 150 kW. In cases 1 to 4 the system is composed by two 50-kW DC chargers.
APPENDIX X: Case 5 Tariff N4 (On Peak) Battery Price 1000 SEK/kWh

![Figure A-7: Case 5 Tariff N4 (On Peak) Battery Price 1000 SEK/kWh.](image)

APPENDIX XI: Case 1-B Tariff N4 (On Peak)

![Figure A-8: Case 1-B (same energy consumption as Case 1 but distributed in more sessions) under tariff N4 (On Peak).](image)

<table>
<thead>
<tr>
<th>Cost Parameter</th>
<th>Cost</th>
<th>No ESS</th>
<th>Design Parameter</th>
<th>Value</th>
<th>No ESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Costs (SEK/day)</td>
<td>179</td>
<td>187</td>
<td>Battery Capacity (kWh)</td>
<td>15.2</td>
<td>/</td>
</tr>
<tr>
<td>Yearly Cost (SEK/year)</td>
<td>652170</td>
<td>681720</td>
<td>Lifetime (years)</td>
<td>12</td>
<td>/</td>
</tr>
<tr>
<td>Electricity Costs (SEK/day)</td>
<td>124</td>
<td>681720</td>
<td>Energy Consumed (kWh)</td>
<td>88.7</td>
<td>84</td>
</tr>
<tr>
<td>Demand Charge (SEK/month)</td>
<td>433</td>
<td>841</td>
<td>Energy Max (kWh/h)</td>
<td>8.7</td>
<td>16.8</td>
</tr>
<tr>
<td>Battery Cost *1000</td>
<td>48606</td>
<td>/</td>
<td>Power Converter (kW)</td>
<td>22</td>
<td>/</td>
</tr>
<tr>
<td>Connection</td>
<td>60000</td>
<td>106250</td>
<td>Peak Power (kW)</td>
<td>44</td>
<td>58.51</td>
</tr>
<tr>
<td>Converter</td>
<td>17641</td>
<td>/</td>
<td>Transformer (kVA)</td>
<td>/</td>
<td>/</td>
</tr>
</tbody>
</table>

Table A-1: Most relevant costs and design parameters for Case 1-B (same energy consumption as Case 1 but distributed in more sessions) under tariff N4 (On Peak).
APPENDIX XII: Share of costs referred to the initial costs of the systems without storage

Figure A-9: Pie charts representing the share on yearly cost with storage in different cases. Note that the shares are calculated considering the as yearly cost the cost of the system without ESS. This allows visualising the total savings (i.e. difference) and the relative share difference of the different components.

Case 6 - No ESS

Figure A-10: Pie charts representing the share on yearly cost before and after the implementation of storage for Case 6 (On Peak). Note that the shares are calculated considering the as yearly cost the cost of the system without ESS. This allows visualising the total savings (i.e. difference) and the relative share difference of the different components.
APPENDIX XIII: Case 5 Tariff N4-D

Figure A-11: Case 5 Tariff N4-C.