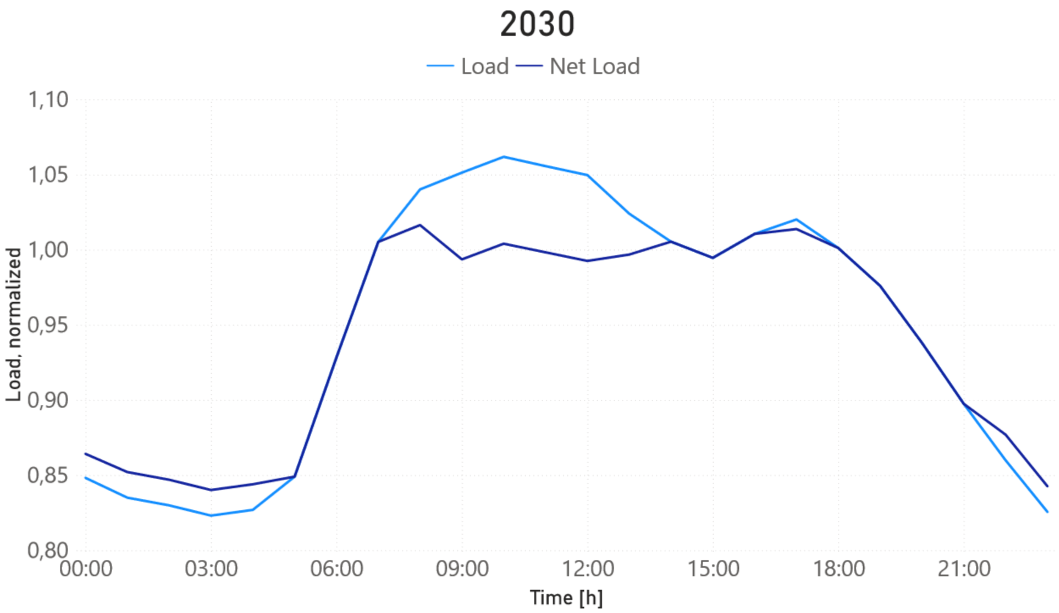

Forecast Modeling of Demand-Side Flexibility

with a focus on power tariffs and local flexibility markets

Master’s thesis in Sustainable Energy Systems

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DEPARTMENT OF ELECTRICAL ENGINEERING

CHALMERS UNIVERSITY OF TECHNOLOGY
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Cover: Load profile of dimensioning system day with net load representing load after models have been implemented.

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Abstract

In a push to combat anthropomorphic climate change and fossil fuel dependence, the electrification of human society is in full swing. Sweden aims to more than double their power consumption by 2040 as an effect. However, with only 14 years left and lead times of building new transmission lines averaging around 10 years, alternatives to grid expansion need to be explored. The use of Demand-Side Management (DSM) strategies would allow for a more effective use of the power grid and allow for further electrification without expanding the grid.

The Distribution System Operators (DSO's) in Sweden have for the past 5-6 years run DSM pilot projects to gauge their efficacy in the Swedish power grid, mainly Local Flexibility Markets (LFM's). A power tariff has been in the works since 2022 and was set for mandatory implementation by start of 2027. Göteborg Energi (GE), DSO in the city of Gothenburg, have implemented voluntary power tariffs and run an LFM, called Effekthandel Väst, together with Mölndal Energi for five seasons. In order to accurately predict how the load on their power grid will develop in the future, these strategies need to be included in their forecasting model.

Modeling systems greatly dependent on human interactions is both complex and complicated. Combined with data scarcity, the need for simplification is significant. A forecast model of DSM would require both a depiction of behavioral response as well as projected future growth. This thesis aims to implement working models of aforementioned strategies into GE's forecast model. As well as identify simplifications and assumptions necessary to create the models and understand their impact on the models.

The models are created via combining existing data over the GE grid with results from prior studies and projected technology developments. The results show varying sensitivity to different parameters with LFM's being most sensitive to duration of flex deliveries and power tariffs to change in power consumption. Different aspects of the models include varying levels of uncertainty, reflected in the difference in high- and low load scenarios. The results further show that DSM strategies can be used to help keep the load below grid constraints but not eliminate the need for further grid expansion completely.

Keywords: Demand-side management, forecast modeling, power grid, DSO, modeling, Local Flexibility Market, Power tariff

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Joacim Suomi Forssblad, Gothenburg, June 2026

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1

Introduction

The world is facing major anthropomorphic climate change and as a reaction the green transition aims to combat this growing threat to human society. One of the key strategies identified to reduce emissions is electrification. Electrification aims to reduce the share of end-use energy powered by fossil fuels, which today is around 80% [2]. The European Green Deal sets targets for de-carbonization and its Fit For 55 initiative aims to reduce CO_2 emissions by 55% by 2030 [3, 4]. Both of these identify electrification of transportation and industry, in conjunction with higher share of renewable power sources, as key factors to achieve these goals. The goals of Sweden are inline with those of the EU. With a target of net zero emissions from power production by 2040 [5], as well as a goal to be able to handle a demand of at least 300 TWh by 2045 [6]. In 2024 Swedens total electricity demand was 140 TWh [7], this entails an increase of 160 TWh by 2045. The planned and ongoing electrification of society is targeted as the main reason for this goal to handle more than double of today's electricity demand. Most of this is attributed to electrification of the transport sector and industries [6].

To help stabilize and ensure the possibility of electrification one of the strategies deployed is demand-side management (DSM), sometimes referenced as demand flexibility. One of the goals of DSM is to reduce the strain on the power grid by moving certain loads to when there is less congestion [8, 9]. This means a more effective use of the power grid and allows for further electrification without expanding the grid. The power grid would still need to be expanded as the entire 160 TWh likely can't be covered by DSM alone [9]. How much and by when is up for debate and could be greatly affected by proper utilization of DSM strategies. With these uncertainties and long process times for expansion of the power grid, proper forecasting is an important aspect to ensure that the grid expands in time to meet the goals.

In Sweden the average time to build a new transmission line is around 10 years [10]. Only around two of those years are for actually building the transmission line. The rest are occupied by appeal processes and planning. Whilst processes don't take as long for regional grids, it still takes years to expand. The regional grids also rely on the transmission grid to deliver power, especially in cities like Gothenburg where roughly 92% of consumed electricity is imported [1]. To not be caught red handed with a lack of power infrastructure in 10 years, the Distribution System Operator (DSO) responsible for the regional grid, needs to be able to predict how power demand will develop in the coming years. Forecasting tools are constantly being used for this purpose and need to update to include things like DSM. Human societies are often characterized as both complex and complicated systems, a combination referred to as wicked systems [11]. This makes things like the power grid difficult to simulate and subsequently to forecast. Simplifications need to be made and understood in order for the simulated forecasts to be utilized properly.

1.1 Background

On a regional scale it is the local DSO which ensures that grid expansions are made on time. The city of Gothenburg has many industries and is a rapidly growing city. This means that the demand for power is projected to increase greatly over the coming years. Both as an effect of electrification and from simply increasing in size. As a means to allow for a larger energy demand to be met Göteborg Energi Nät AB (GENAB), the power grid department of the city-owned DSO Göteborg Energi (GE) in Gothenburg, aims to deploy a number of DSM strategies to increase the effective use of the power grid [1]. Some of their own volition and some spurred on by state mandated efforts. The two main ones being a Local Flexibility Market (LFM) and power tariffs. Both of these strategies have already been implemented in a pilot stage and are becoming a standard part of GENAB's power grid.

As these DSM strategies become a larger part of the power grid, GENAB wants to include them in their forecast model. A model which previously used planned city- and industry expansion, together with historical data, to project future loads. To combat uncertainties associated with forecasting, the GENAB model uses a scenario based system which provides a span of outcomes spanning from high- to low loads. The impact these strategies will have on the grids load profile is uncertain. GENAB wants to know how much capacity these DSM strategies can free up and therefore needs to add them to their forecasting.

1.1.1 Power tariffs

In 2022 the Swedish Energy Markets Inspectorate, Energimarknadsinspektionen (EI), introduced a regulation demanding DSO's in Sweden to introduce power tariffs in their grids by 2027 [12]. A part of this regulation was to exchange the existing grid fee with this tariff and that the tariff levels should be designed such that the cost for customers should not increase. During the spring of 2026 the government decided to suspend this regulation to re-evaluate it's implementation [13]. However most DSO's at this time had already either planned for their implementation or already implemented them. One of the DSO's that was well under way with their implementation of power tariffs was Göteborg Energi. Starting with a pilot of the tariffs in 2025, further developing price plans to not increase the net cost for customers. One of the major learnings from previous pilots and GENAB's was that knowledge on how the tariffs worked was a big block for many customers. Therefore GENAB put a lot of focus on increasing awareness of the tariffs, how they work, and what they aim to do.

The suspension of the tariff occurred after work on this thesis had begun. To avoid redoing months of work this thesis is based on tariff plans prior to government suspension. The suspension invoked GENAB to role back their implementation, instead electing to keep it as an optional price plan to the grid fee [14].

1.1.2 Effekthandel Väst

Göteborg Energi and Mölndal Energi, city of Mölndal's DSO, have since 2022 had a project called Effekthandel Väst (EHV) which is an LFM [15]. The market started of as a pilot program and has been active for 5 seasons. Each season has seen a growth in customers and use. It has since exited the pilot stage and is now a permanent market and part of the power grid. For these early seasons much of the trading have been test purchases aimed to gather information on the market. Both DSO's work continuously to gather new customers and evaluate which types of customers are best suited for the market. Since its conception EHV has grown exponentially each year reaching a customer base able to provide 75 MW of flexibility during the 25/26 season [16]. The season prior that same number was 35 MW.

1.2 Aim and Research Questions

The aim of the project is to model demand-side flexibility strategies and to implement them in an existing forecast model, whilst identifying assumptions and simplifications necessary. The intended outcome is an enhanced forecast model which depicts societal adaptation to the two aforementioned flexibility strategies and their effect on the power system.

The following questions are to be answered in the report and through the work done.
1. How are assumptions made regarding the growth of these strategies and what effects do they have?
2. How can future societal behavior and responses be modeled and what simplifications are needed?
3. Can these flexibility strategies sustain the power grid and its expected growth until the planned grid expansions?

1.3 Limitations

The major limitation of this work was the necessity of conducting it within an existing framework. Since GENAB already has a forecast model and the aim was to implement the DSM strategies into the existing model, the methods and tools were limited. This could lead to models and results that are mainly applicable to GENAB's grid and model. Further, the constraints could prohibit certain approaches and results in models less representative of the systems they depict. Another big limitation has been the size of the datasets processed. With data-points numbering in the millions, some approaches have not been possible since they take too long. This has affected how certain aspects have been modeled and increased reliance on external sources and AI tools when programming. A smaller limitation of this work has been timescale and the fact it was done solo. With such a complex issue there are many ways to increase the level of detail and include different aspects. These things take time and therefore priorities had to be made. Another minor limitation to the work is the presence of a Non-Disclosure Agreement (NDA), which prohibits details regarding exact locations and other customer related data to be disclosed. This however has been a minor limitation since these aspects have not been a necessity for the report.

2

Theory

This report assumes the reader has prior knowledge on modeling, system analysis and the power grid. Therefore subjects like phases in technology growth or the difference between capacity and energy are not explained in detail. Some concepts, of direct importance and used in the report, are explained in detail comparative to its importance within this report. One such being GENAB's subscription capacity to overlaying grid. The subscription capacity details how high the load from GENAB's grid can be before incurring extra costs. The subscription is different for different sectors since different DSO's own the overlaying grid that the sectors are connected to. The subscription capacity is the limit GENAB aims to not surpass and is therefore used as grid capacity in this thesis instead of the physical- or N-1 capacity. The expected increases in grid capacity are based on GENAB's ”worst-case” scenario. Which yields a lower grid capacity than what is expected.

When estimating the growth rate of EHV for the LFM model a Compound Annual Growth Rate (CAGR) was used. The CAGR is calculated according to Equation (2.1) and gives a normalized average of year-on-year growth. The LFMs currently active have only left the pilot stage in the last three years. Which means that data points are scarce and growth is still sporadic. It can therefore be argued that the LFMs are still in a transformative phase, in which case using growth rate of another similar technology is more prudent [17]. Where V_0 is the initial value, V_t is the value after t years, and t is the number of years.

$$CAGR = (\frac{V_t}{V_0})^{\frac{1}{t}} - 1. \tag{2.1}$$

The outer system boundaries for this project are defined as GENAB's power grid whilst the inner boundaries are customer bases as a whole. Meaning that individual customers and their behavior are not looked at but rather the behavior of customer groups. Mainly industrial customers and house owners, for reasons further detailed in Chapter 2.1. This further affected how certain DSM strategies were handled. For example, in the context of power tariffs, Vehicle-to-Grid (V2G) was included in the behavior of households whilst in the context of LFMs it was included via aggregator customers. Instead of being modeled directly.

2.1 Power tariffs

A power tariff is a policy instrument aimed at lessening congestion in the power grid. It achieves this by incurring costs based on how high the customers peak loads were.

its a tariff introducing a movable aspect to the power grid fee that a customer pays each month [18]. According to EI regulation EIFS 2022:1 [12], the tariffs should be divided into four different costs. Firstly a fixed cost, which should be based on the DSO's residual costs and the capacity of the customers subscription. Second an energy cost, which should be based on the DSO's short term variable costs like grid losses and energy costs related to overlaying grids. Third, a customer related cost which should be based on administrative costs, including measurements, which must be fixed for each customer. Lastly a power cost which should be based on the customers utilization of the grid in conjunction with total load of the grid. DSO's are to regulate these costs so that the customer pays roughly the same as for the grid fee prior to the tariff and should not be a source of increased income for the DSO's [12].

2.1.1 At Göteborg Energi

The GENAB power tariff for low voltage customers has four different capacity levels to choose from, ranging from 6 to 43 kW and three different price plans for power costs [14]. According to the planned price model update decided on in GENAB's board meeting 20-2025-0456-04 [19], three price plans would be present. Two of the price plans are on a Time-of-Use (ToU) format whilst the third utilize Real Time Pricing (RTP). The ToU price plans are divided into a blunt and steep version. The power tariff is separate from the electricity contract and if the customer doesn't choose a price plan the blunt ToU plan is the standard. Note that this was the planned implementation before government suspension of mandatory implementation of power tariffs. Therefore it is what was used as a basis in this project. Since the suspension the price plan has been altered.

In order for GENAB's business to be in congruity with EI's regulation, price plans and capacity levels have been divided so that customers can choose alternatives that match their consumption. In addition GENAB applied for and received exception from applying power tariffs to apartment customers [20]. This is because customers living in apartments have a few opportunities to affect their power utilization in a measure meaningful to the power grid and would not be able to affect their costs in any meaningful way.

Studies have shown that the level of engagement from customers is directly related to their knowledge of how the tariff works, how the power grid works, and the goal of the tariff [21]. This has lead GENAB to invest resources on educating their customers on the different aspects of the power tariff. Campaigns explaining how the tariff works and what it aims to accomplish have been the core focus and identified as a means to increase the effectiveness of the tariff. According to GENAB's projections around 80% of customers will choose the blunt ToU with the majority of remaining customers choosing the steep tariff at the offset. The share of customers choosing the steep tariff is expected to shift towards the RTP tariff by 2035 [19].

2.1.1.1 Time-of-Use tariff

A Time-of-Use tariff is, as the name suggests, based on the time in which something is consumed. Usually divided into certain hours and/or months. GENAB's ToU tariff is divided into high and low price hours. The high price hours are during weekdays between 07.00 to 20.00 during the months of November to March, low price hours cover the remaining hours [14]. The power cost for each customer is calculated as an average of the three highest peaks each month. The blunt alternative has a higher fixed cost and lower power cost. When introduction of power tariffs were mandated the blunt plan was the baseline option for all low voltage customers [19]. The steep ToU instead has a lower fixed cost but a higher power cost. Since the government rescinded the mandate of mandatory implementation of power tariffs GENAB has ceased the mandatory implementation of the tariff, keeping it as an optional tariff [14].

2.1.1.2 Real Time Pricing plan

RTP tariffs are updated with a set frequency and follow a separate market or set profile. The RTP price plan of GENAB's power tariff would follow grid congestion and price would be high when the load is high and low when load is low. The tariff was designed with the intent of being a lucrative alternative to customers with a high degree of knowledge of their power consumption and automated home systems [19].

2.2 Local Flexibility Markets

An LFM is a market based instrument that allows DSO's to purchase flexibility from prosumers. A prosumer is an actor that can both play the role of producer or consumer, in this case of power. Flexibility is bought either in the form of up scaling or down scaling [15]. Meaning either increase amount of power produced or reduce amount of power consumed. If one prosumer decides to produce an extra 3 MW of power or another decides to reduce their consumption by 3 MW the effect on the net load of the grid is the same. The DSO also has the possibility to specify which type of flexibility is required if the need arises. Most LFM's have an auction based system where the DSO posts a bid, detailing how much flexibility is needed at a certain time, the actors involved in the market can then choose to accept the bid and is then obligated to provide the flexibility in order to receive the payment. LFM's are a growing sector with new pilots being launched around the EU each year, some markets having left the pilot stage in recent years [22].

2.2.1 Effekthandel Väst

As previously stated, EHV was started in 2022 and finished its 5th season in March 2026. Since its first season the market has seen a steadily increasing share of customers going from 2 in its first season to 32 in the last one, and bought flexibility has gone from 2 MWh to 1209 MWh [16]. With current flexibility capacity of 75MW across all customers. EHV has had three different flexibility services, short and long flex as well as max usage [23]. Actors with a max usage contract received payment if they kept their load under a certain limit during specific months. Max usage was removed going into the 25/26 season due to low efficacy and the incoming power tariff. Long flex contracts work in a similar way but are more modular. Actors sign up to reduce their load with a certain amount during certain weeks or days. In a similar way to max usage actors receive payment if they stay within the limit and face no other consequence than loss of payment if they do not. Short flex works like an auction, where GENAB can place bids for flexibility, utilizing NODES as a platform. Prosumers active on the market get payed an amount relevant to how much of the bid they match as long as they provide at least 75% of the bid, with a maximum of 100%. In the early seasons, reliability was a large issue for the market. Customers would accept the bid and either not deliver enough flex or not deliver at all. Reliability has steadily increased and in the last two seasons (24/25 and 25/26) reliability was above 90% for most bids, which could be seen on internal NODES data. A short-term forecasting model is utilized to predict if the load will surpass grid capacity. The short-term forecast is provided by a third party and is based on weather data. EHV uses Nodes as a market platform, a platform which several LFM's around the world utilize [16].

2.3 GE's forecast model and the Fabrics environment

Göteborg Energi's forecast model is built within the Microsoft Fabrics environment. It is built up with notebooks with Python and/or SQL code, which generate data tables that are uploaded to a, so called, Lakehouse.A Lakehouse is a cloud storage that is connected to the workspace it exists in, storing things like csv files and data tables. Anyone with access to the workspace can access the tables and files within the Lakehouse from any notebook. Enabling the user to utilize data without the need to generate it within the notebook it will be used in. It also allows for multiple users to access the same data source. The load data is divided into scenarios, stations, timestamps, and segments. The segments represent loads from different sectors, e.g city development and industry. The stations indicate which transformer station the load occurs at. The forecast model generates data for three different scenarios, a low-, base-, and high load scenario. The load data is further used in a semantic model which connects data sets via common denominators such as timestamp and station. The connection in the semantic model allows for visualization via power BI that correctly displayed summarized load at a certain time for a certain scenario.

One of the segments in the model is current load, i.e load that exists in the system today, which uses measured load profiles as a base. The data is based on measurements during a year and exists for multiple years, the data is normalized to the highest peak for the most recent year. An assumption of increased energy efficiency is applied, meaning that the load contribution from loads currently active in the system are reduced by 1% each year, for the base load scenario, 2% and 0.5% for low and high respectively. The forecast model generates data over expected future loads based on measured load profiles and data from customers regarding planned expansions. The data over planned expansions is assessed with likelihood factors that differs depending on the scenario. The factor reflects how likely GENAB considers the load to be implemented and how likely it is to reach the reported load. For a low load scenario the likelihood factor would be lower, resulting in a lower additional load and vice verse for the high load scenario. A load value is calculated for each hourly timestamp between current year and end of forecast (2040), scenario, and station. This results in millions of data points for each table.

3

Methods

The aim of the thesis was to design and implement the models in GENAB's existing forecast model. The work began with learning how the existing model worked. This was achieved via a number of consultations with people at GENAB that work with the model and are well versed in their grid. As well as looking through the data produced by the model and the code that builds it. A conceptual map of GENAB's grid was created in conjunction with supervisor at GENAB, as can be seen in Appendix A, Figure A.1. The map shows how GENAB sorts their grid into different sub-stations, stations, trade sectors, and grid sectors as well as their voltage levels and connection points to the overlaying transmission grid. After which focus was on understanding how the data in the forecast model was organized and how it generated the data. This was primarily done by looking through the Fabrics workspace and testing the code, the results of which can be read in chapter 2.3.

This thesis has utilized AI tools in two main ways, generating python and SQL code, and as assistance in finding relevant research papers. The aim of this thesis was to figure out how the flexibility strategies could be modeled not how they could be programmed. Therefore Microsoft Copilot was used to generate an estimated 50-60% of the code used in the models. Prompts were given explaining what the code was supposed to do without gaining access to the entire code. An example of a prompt given would be: ”I have a pandas data frame with 3 columns, Column A contains timestamps, B contains one of three unique strings, C contains a value. I want to summarize all values in C for each unique combination of A and B”. The returned code would be examined to a degree where it was understood how it worked, implemented, and then verified so that it did what it was supposed to. The process could be likened to searching through forums for python functions. When used to find research papers an AI tool called ConsensusAI was utilized. The tool utilize a data bank of over 200 million peer-reviewed research papers and finds the ones that best fit the prompt given [24]. Prompts given where along the line of ”What is the household price elasticity of electricity cost?” or ”How do tariffs on power consumption affect industrial manufacturing loads?”. The AI gives a summary over the articles included, the articles used were read through as any article found through traditional means and was verified to contain the information Consensus claimed. To a lesser extent AI has been utilized for spelling correction and correcting grammar.

3.1 Power tariff model

The model was developed iteratively, beginning with a discussion internally at GENAB to establish the goals and scope of the power tariff. An initial literature review was conducted to further understand the intended targets of the tariff, including a review of EI's charter to gain relevant regulatory context. This was followed by broader information gathering on power tariffs in general, covering their expected effects on the power grid and pilot studies.

In parallel, work began on conceptualizing the system and its constituent parts, with particular attention to how the system was expected to grow over time and how customers might respond to the tariff. A more targeted literature review was subsequently carried out, drawing on both literature and GENAB's internal investigations with a focus on behavioral patterns connected to power tariffs. The key dynamic components of the system were identified and the system map was created, as seen in Appendix A.2. Leverage points where simplifications could be made were identified and highlighted. ToU tariffs were identified to affect behavior during more than just peak load hours, leading to increased load reduction [25]. Combined with the fact that RTP tariffs were assumed to be in a minority, one simplification identified was to combine the behavior of the two tariff types. In grid dimensioning purposes, high load seasons were those of interest, therefore seasonal split could be ignored. Growing sectors could be simplified by altering existing data on load additions with the same parameters as current load.

At its core, the model would need to reduce load during active tariff periods. Since the tariff applies only to the three highest peak loads in a given month, it was assumed that customers will reduce the three highest peaks each day. This stemmed from an assumption that most customers don't track their consumption and therefore just lower their highest peaks daily in stead of each month. Literature indicates that customer behavior is modified both before and after tariff activation periods; to account for this, as well as limited consumer knowledge of their own consumption patterns, an additional two hours per day was incorporated into the affected time windows.

The customer scope was established by ensuring that only customers within the system boundaries were included in the analysis. As GENAB had received an exemption for apartment buildings, only housing and industrial customers were subject to the tariff. Since load data is attributed per station, stations serving neither housing nor industry were removed from the dataset. For the stations including either household- or industrial loads, their load was divided according to how much of that load came from each respective sector. So if a specific station had around 50% industrial loads and 50% apartments, only 50% of that stations loads was used. This split was done in accordance with GENAB's internal data and covered by the NDA. A growth pattern was then introduced to the model based on internal and external research regarding customers' projected uptake of available tariff plans, as detailed in 3.1.1.

An aggregate peak reduction was calculated based on the reduction associated with each tariff and the corresponding share of customers, given by Equation (3.1)

$$R_{tot} = \sum R_i \cdot f_{i,y} \tag{3.1}$$

where R_i is the assumed peak load reduction for tariff i and $f_{i,y}$ is the share of customers with tariff i in year y. Since $f_{i,y}$ is projected to shift from year to year, R_{tot} is recalculated for each year in the forecast.

Code was developed to identify and flag the five highest peaks for each day of the load profile. An existing algorithm from GENAB's forecast calculations was modified for the tariff model. The algorithm iterates over the full annual load profile and applies load modifications to the entire profile in a single pass. It cycles through all scenarios, base years, and stations, repeating the process for each year of the forecast. This procedure is applied exclusively to loads already present within the system. For projected load development, a separate method was employed. Data on planned expansions and new loads for each station and year were incorporated, and the daily peak flagging logic was extended to cover each forecast year. Peak loads within the development data were identified and modified in the same manner as the existing load profiles. This process was carried out separately for housing and industrial loads.

3.1.1 Behavioral assumptions

GENAB's ongoing efforts to increase customer awareness and energy literacy are expected to drive a gradual shift toward the RTP tariff over the forecast period. In line with GENAB's projections 80% of customers are assumed to choose a blunt tariff, whilst the remaining share is assumed to start of with the steep ToU tariff and shift linearly towards the RTP tariff [19].

The share of customers choosing the steep ToU tariff at first is assumed to be 95% of the customers who don't choose the blunt tariff, or 19% of all customers. The remaining 1% of customers are assumed to chose the RTP tariff from the offset. The balance between steep ToU and RTP is for simplicity assumed to flip by the end of the forecast and the shift is assumed to happen linearly. A list was constructed that linearly went from 0.19 to 0.01 over the length of the forecast using python. This calculated the share of steep ToU tariffs each year, the share of RTP tariffs was calculated the same way but with shares reversed.

The model assumes that the five highest peaks of each day will be affected by the tariff. In general ToU power tariffs are characterized by a limited understanding of the customers own consumption patterns and therefore tend to reduce their overall load broadly rather than targeting specific peaks [25, 21]. RTP tariffs on the other hand, would motivate customers to automate consumption to track grid congestion and thereby reduce load at peak hours. The behavior of customers with the two types of tariffs was simplified by aggregating behavior to lower the 5 highest peaks of all customers instead of three which is the target of the ToU tariff. Studies on power tariff efficacy showed that ToU tariffs reduced peak loads by 5-10% when customers had stronger incentives and RTP tariffs by 10-20% [26, 27, 28]. They also showed that ToU tariffs with lower incentives resulted in peak reductions of about 1% on average. R_{blunt} was assumed to 0.01 (1%), R_{steep} to 0.08 (8%) and R_{RTP} to 0.15 (15%).

Studies show that the industrial sector doesn't adjust their behavior to the same extent as households [29]. However, when production is adapted to a power tariff peak reductions can reach above 30% [30]. In general, peak load reduction was reported between around 5-10% with reduction higher than those deemed as outliers. To adjust for fewer peaks being affected by industry, the lower value was used but applied to the same number of peaks as for households. This was done so that code could be reused. Peak reduction for industry, $R_{industry}$, was therefore assumed at 0.05 (5%).

3.1.2 Growth Assumptions

Tariff structures are normally updated on a frequent basis to ensure the tariff has the desired effect in a changing economy. However, this was deemed too complex to implement in the model since the structure of the model is based on the current structure. Therefore the model assumes that the tariff structure remains unchanged throughout the forecast period. This is considered a reasonable assumption, as the current price plan extends to 2035 [19], which approaches the end of the forecast in 2040. Load reduction from tariffs being connected to the load of the housing and industrial sectors are therefore affected by load growth projected for the sectors.

3.2 EHV model

The modeling process began with a series of internal meetings at GENAB to establish a working understanding of how EHV operates. A system flowchart was developed to map out the overall structure, and key aspects of the system were identified through discussions with GENAB supervisor and other colleagues with direct experience working with EHV. This internal knowledge was supplemented by a review of the relevant literature to validate and support the findings. The system map can be seen in Appendix A.3. It highlighted high reliability of bid deliveries and the system was therefore simplified with assumption that all bids would be delivered in full. Another thing highlighted was how bids were placed, which was simplified with assumption that all loads exceeding grid capacity could be identified in time.

Two broad modeling approaches were identified: empirical and predictive. The empirical approach would draw on data from previous seasons to characterize system behavior, whilst the predictive approach would try to emulate the underlying system dynamics. The empirical approach was deemed insufficiently representative of future behavior. Primarily as the available data included test purchases which were conducted to stimulate the market and measure its responsiveness. The market has been live during typically mild seasons which meant that historical data reflected a lower need for flexibility. A predictive model on the other hand would allow for inaccuracies through other means. It would need to include not only the growth and behavior of the market but also emulate when bids would be placed. All would include simplifications and assumptions that could shift the model from an accurate depiction. However, due to the many faults in the empirical data and the presence of future load data in the existing model, the predictive model was chosen.

The predictive model was then mapped in detail, with the key triggers and parameters identified, as seen in Appendix A.3. These included the timing and location of flexibility purchases, reliability, duration and amplitude of flex delivery, available flex capacity, and the expected future customer base. The latter derived from observed trends and an an internal assessment of how well current market needs are being met. The duration of flexibility sources was also determined, with Battery Energy Storage Systems (BESS) and Vehicle-to-Grid (V2G) identified as the primary sources [31]. GENAB identified 5 hours as a target maximum duration for bids.

The remaining variable to be determined was the market growth factor. As the EHV market has only recently transitioned out of the pilot phase, historical data on its growth is limited. Other active LFM's in Sweden and the rest of Europe were identified to inhibit the same problem. A CAGR derived directly from EHV data was therefore considered unrepresentative for forecasting purposes. Instead, a comparison was made with the more mature manual Frequency Restoration Reserve (mFRR) market. Its CAGR was adopted as a reference, in line with established practice for markets in a transformative phase of development.

With all necessary data collected, the modeling work commenced. Stations were first divided into grid sectors according to the area map shown in Figure 3.1. Due to an NDA, the assignment of individual stations to specific areas cannot be disclosed.

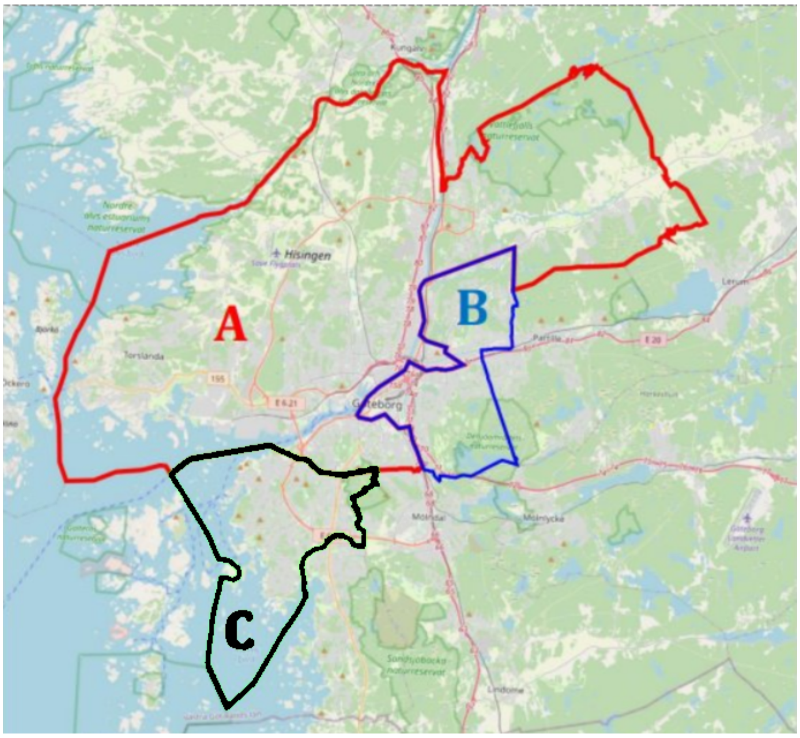


Figure 3.1: Map depicting grid sectors in GENAB's power grid [1].

Data on total flex capacity was then distributed across areas according to Equation (3.2).

$$Flex_{area} = \frac{Sub_{Area}}{Sub_{tot}}, \tag{3.2}$$

where $Flex_{area}$ is the share of the flex capacity of EHV in a specific sector, Sub_{Area} is the subscription cap for a specific sector, and Sub_{tot} is the subscription cap for the entire system, defined as the sum of the subscription caps across all sectors. In accordance to internal GENAB data, current flex capacity of the market was set to 45 MW. Each sector's flex capacity was therefore $Flex_{area} \times 45MW$.

Since EHV activations are governed by subscription capacity and is used as grid capacity for the models, subscription capacity was used as the basis for distributing flex capacity across areas. Projected increases in subscription capacity are given in table 3.1, based on internal data provided by GENAB. For area A, capacity is assumed to increase linearly until 2030, after which each subsequent level is assumed to remain constant until the year indicated in the table. This represents GENAB's "worst case" scenario for grid expansion and was chosen so results evaluate how well the models can handle challenging loads.

Table 3.1: Increase in subscription cap compared to today's value [1].

Trade area	Increase by 2030	Increase by 2035
Area A	20%	30%
Area B	10%	20%
Area C	10%	20%

Data frames were constructed to represent subscription capacity as a function of both year and sector, incorporating the subscription capacity increases outlined previously. These were subsequently mapped to the a load profile data frame so that each data point had a corresponding subscription capacity based on its assigned area and year. The yearly flex capacity for each area was then calculated according to Equation (3.3).

$$C_{y,A} = (1 + G \cdot \Delta Y) \cdot C_{y_0,A}. \tag{3.3}$$

where $C_{y,A}$ is the flex capacity at year y in area A, G is the assumed year-on-year growth rate, ΔY is the number of years between y and the base year y_0, and $C_{y_0,A}$ is the flex capacity for area A at the base year y_0. At a late stage in the project it was noticed that a calculation error was made regarding this equation. Equation (3.3) depicts a linear growth with a percentage increase of the starting value. The YoY growth should be depicted according to Equation (3.4). Which would lead to an exponential growth pattern instead. Since this was noticed at a late stage, the results are based on Equation (3.3), the ramifications of which is further discussed in 5.

$$C_{y,A} = (1 + G)^{\Delta Y} \cdot C_{y_0,A}. \tag{3.4}$$

Flex capacity was mapped to the model in the same manner as grid capacity. Load occurrences were flagged when the load exceeded 95% of grid capacity, with the analysis restricted to the period November through March, reflecting the winter peak season during which the market is active. The model tracked both the frequency and duration of these occurrences, where a single occurrence is defined as a continuous period during which the load remains above the 95% threshold. Additionally, the model checked whether any given occurrence fell within the minimum recovery duration of a preceding occurrence, in order to assess whether a full recovery of the flexibility source would have been possible in the intervening period. Initial runs of the model revealed that a significant number of occurrences exceeded the maximum discharge duration. To address this, the highest peaks within each such occurrence were flagged up to the maximum duration limit.

A number of distinct scenarios were identified based on the characteristics of each occurrence, as shown in Appendix B.1. Each occurrence is characterized by two key properties: amplitude, defined as the magnitude by which the load exceeds grid capacity, and duration, defined as the length of time the load remains above the threshold. The amplitude may be either lower or higher than the available flex capacity. The duration may fall into one of three ranges: below the minimum duration, between the minimum and maximum duration, or above the maximum duration. Furthermore, if an occurrence takes place within the minimum recharge duration following a preceding occurrence, the flexibility source is assumed to not be fully recharged. In this case, the source is assumed to operate at 50% of its rated capacity, serving as an approximation of partial recharge state. The specific calculations applied under each of these scenarios are detailed in Appendix B.

3.2.1 Behavioral Assumptions

One of the historically noted challenges for EHV has been the reliability of flexibility activations. However, reliability has improved in recent seasons, with nearly all purchases in the most recent season achieving a reliability rate exceeding 90%. This improvement was largely attributed to the increasing share of BESS in the flexibility market. Given the assumed growth in the BESS share and the generally improving reliability trend, reliability was not included in the model.

The share of BESS and V2G sources in the flexibility market is assumed to grow over the forecast period [31]. Showing an expected discharge duration at max capacity for 1-4 hours for BESS and a larger variation depending on SOC for V2G. Further, heat pumps and industrial processes have longer durations but is expected to be a smaller part of flexibility resources [31, 32]. Data from EHV has shown that BESS actors have been able to supply flex for a maximum of 2 hours. Therefore a max discharge duration was assumed to 3 hours in the base scenario, since the entire system was not composed of BESS. In accordance to internal GENAB targets, a max duration for flex bids was set to 5 hours.

3.2.2 Growth Assumptions

The assumed CAGR for the mFRR market was calculated to 8% according to data from SVK [33]. The CAGR was also derived from the different Norwegian flexibility markets opperated by NODES [16], for which CAGR estimates of 5% and 15% are available depending on the time horizon considered (2 or 4 years). Direct CAGR calculations based on EHV data yield 14% over the past two years and 30% over three years. The considerable spread across these estimates reflects the inherent uncertainty in applying CAGR to a market that has only recently transitioned out of the pilot phase, where early-stage volatility renders such metrics poorly representative of long-term trends.

It is well established that emerging markets and technologies tend to follow an S-curve growth trajectory, characterized by an initial period of rapid acceleration, followed by a phase of stable growth, and eventually market saturation and stagnation. This behavior was not captured by a constant year-on-year growth rate, but deemed a necessary simplification in the interest of time.

3.3 Sustaining grid expansions

As mentioned previously, the limiting factor on GENAB's power grid is the subscription capacity to the overlaying transmission grids. Therefore subscription capacity has been equated to grid capacity. As a consequence, when answering whether the flexibility strategies can sustain the power grid until planned expansion, the subscription capacity and its planned expansion was used. The grid capacity was calculated as previously described and mapped against load and net load profiles. Using python code the number of times the load and net load exceeded grid capacity was calculated. The number of occasions exceeding capacity for net load was then compared to that of original load.

4

Results

Result figures shown depict a typical cold winter day or week with high load, these are of particular interest since they are dimensioning for the system. All data is normalized to grid capacity. Graphs will display load and net load for different scenarios and models, as well as grid capacity. Results include load reduction depicted in figure, given in MWh and representing total difference between load and net load profiles. Maximum power difference reported indicates maximum difference between profiles. Sensitivity analysis compares change in parameter to resulting difference in either total load reduction or maximum power difference.

Running both models with base line assumptions on the dimensioning day gave the results shown in Table 4.1.

Table 4.1: Effects on load curve during dimensioning day with base line assumptions.

	Max. Power Δ [MW]	Load reduction [MWh]
LFM model	38.1	172
Tariff model	24.7	122

Figure 4.1 describes the net load profile of the LFM model compared to normal load in the year 2030, in a base load scenario. It results in a load reduction of 172 MWh with a max power difference of 38.1 MW.

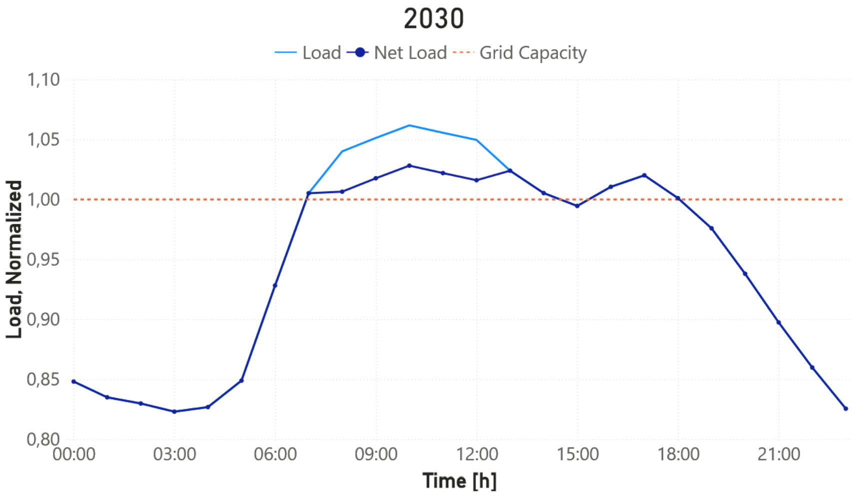


Figure 4.1: Load profile of high load day with base scenario for EHV model

Similarly, Figure 4.2 shows the results of the power tariff model in a base load scenario. Resulting in a max power difference of 24.7 MW and a load reduction of 122 MWh during the day, which is then shifted to night time, which can be seen in the graph. Both figures include the grid capacity as a reference and in both cases the net load reaches above the capacity.

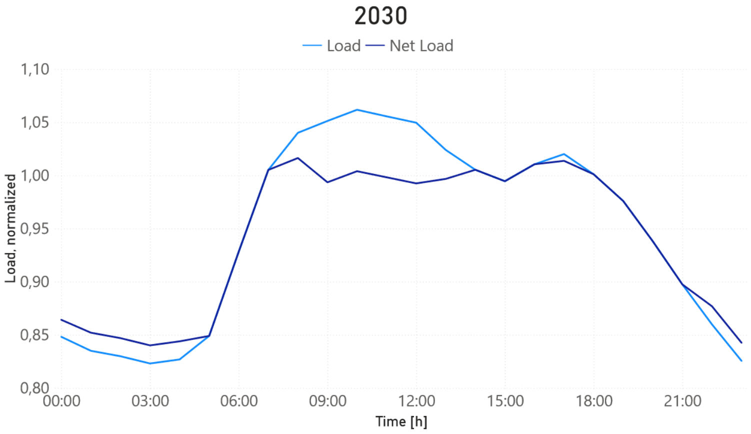


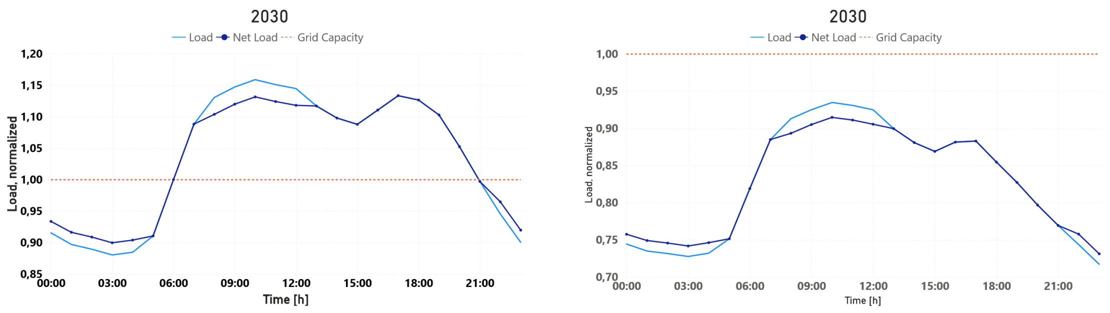
Figure 4.2: Load profile of peak day with base scenario for load and power tariff model

4.1 Growth assumptions

As discussed in Chapter 2, the growth of a technology is done either by comparison to other systems or by fitting system data to an S-curve. Since both power tariffs and LFM's are immature technologies with little reliable data the latter approach was omitted. Instead the power tariff model relies on the internal GENAB data on planned expansions to the power grid and the LFM model uses the CAGR of a similar technology as a reference point.

4.1.1 Power tariff model

As the assumption is that the power tariff will follow GENAB's current pricing model the power tariff model is assumed to work the same for the entire forecast. This assumption, in conjunction with the fact that the power reduction from the tariff is connected to the load curve, results in the growth of the power tariff model being directly connected to the growth of the power grid. It is further assumed that the exception for apartment buildings will be in effect for the entire forecast. The effects of these assumptions are that the impact of the tariff is directly related to the growth of the industrial sector and growth of households. The different load scenarios in the model assume different growths for these sectors, Figure 4.3 shows the effect this has on the power tariff model.



(a) High load scenario **(b)** Low load scenario

Figure 4.3: Load profile for different load scenarios with base scenario tariff

The high load scenario pushes the load far above the capacity limit and the low load far below, clearly illustrated by Figure 4.3. As described by Table 4.2 the high load scenario reduce the load by 138 MWh and the low load by 101 MWh. With max power of 28.0 MW and 20.5 MW respectively. Compared to the results from the base load scenario in Figure 4.2 this is a 13.3 % increase and 17.2% decrease of max power difference respectively. No underlying assumptions in the power tariff model were altered, only the load level affected the results. The peak load in the high load scenario is 13.2% higher than in the base scenario and the low load 17.9% lower. Resulting in an almost one-to-one sensitivity ratio between load profile change and max power difference.

Table 4.2: Effects of load scenario on tariff model

	High load	Low load
Max. Power Δ [MW]	28	20.5
Δ to base scenario [%]	13.3	-17.2
Load Δ [%]	13.2	-17.9
Sensitivity [%]	100.7	96.1

4.1.2 EHV model

The growth of the LFM model is dependent on a higher number of factors compared to the tariff model and therefore have more assumptions connected to it. The model is dependent on the grid capacity which has planned to increase in accordance to the data described in Table 3.1. This is further shown in Figure 4.4, where the grid capacity is shown in comparison to the load profile.

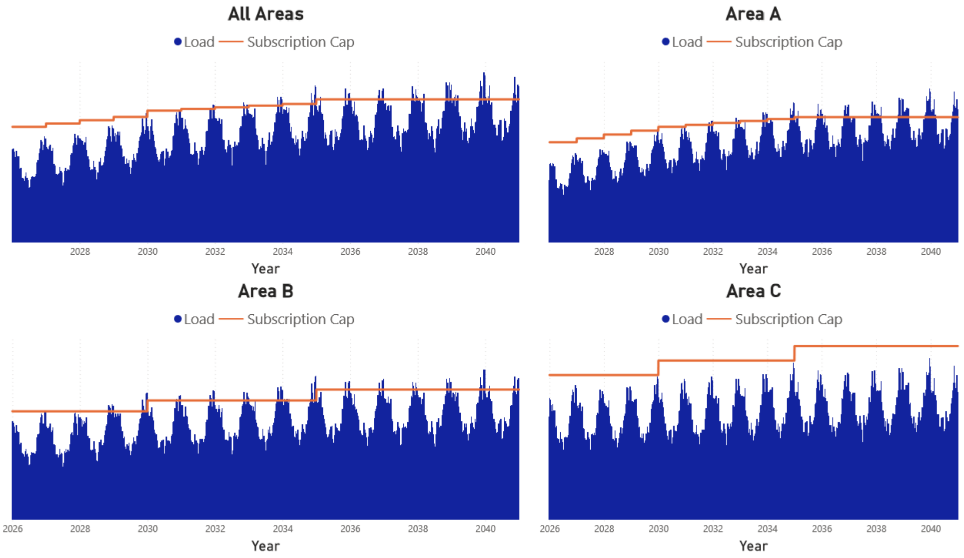


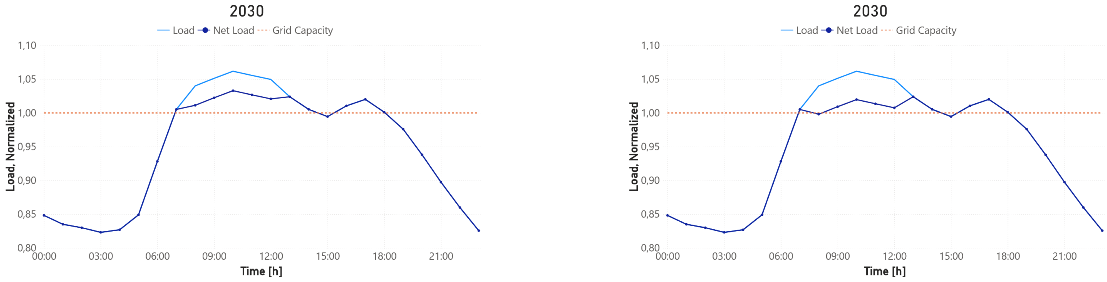
Figure 4.4: Load compared to grid capacity throughout model and divided into areas. All areas (top left) being an aggregate of Area A (top right), Area B (bottom left), and Area C (bottom right).

The growth of the market in the model is connected to the growth of the flexibility capacity. The growth of which is based on the CAGR of a similar market, and calculated to 8% with a three year average. The growth is assumed to happen yearly with a constant factor. When instead calculated based on EHV data the CAGR was much higher and resulted in 15%. Basing calculations on the Norwegian LFM markets the CAGR was instead 4%. The results of which are described in Table 4.3 and below.

Table 4.3: Effects of CAGR assumption on LFM model

	15% CAGR	4% CAGR
Load Reduction [MWh]	215	147
Δ to base scenario [%]	25	-14
CAGR Δ [%]	87.5	-50
Sensitivity [%]	28.6	28

The effect of these different assumptions are further shown in Figure 4.5. The observed load reduction with the lower assumption was 147 MWh and 215 MWh with the higher assumption. Max power difference was 29.4 MW and 42.9 MW respectively. Compared to the the 8% assumption present in Figure 4.1, this equates to a decrease of 14% and increase of 25% for both power difference and load reduction. This equates to a sensitivity of roughly 28.6% considering the 87.5% increase and 50% decrease in growth rate.



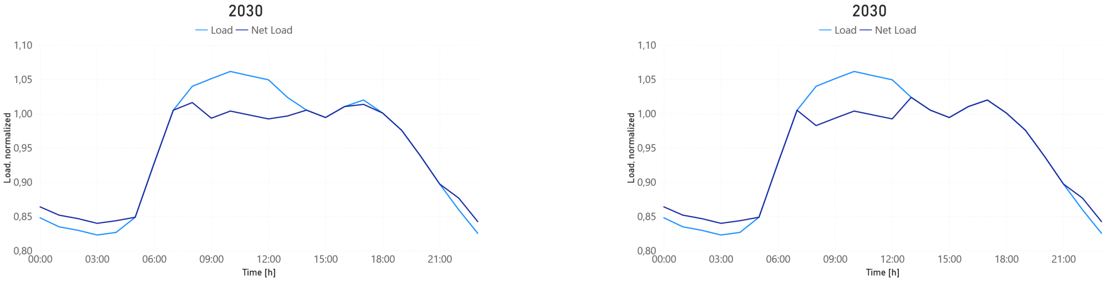
(a) 4% CAGR

(b) 15% CAGR

Figure 4.5: Load profile of EHV model for different growth assumptions

4.2 Future behavior

Both of the models simulate expected growth instead of being based on expected need from the systems. As an effect of the power tariffs being introduced the max usage plan was removed which leads to increased fluctuations in the LFM model. The effect max usage had on the system was expected to be compensated by the power tariff. Figure 4.6 shows the net load when both models are applied. Figure 4.6b shows net load when both models are based on the underlying load profile, whilst Figure 4.6a shows net load when the LFM model is based on load after the power tariff has been applied. The net load when the LFM model is applied after the power tariff has a smoother curve.



(a) EHV reacts to load after tariff **(b)** Models react to load separately

Figure 4.6: Net load profiles of different interactions between models

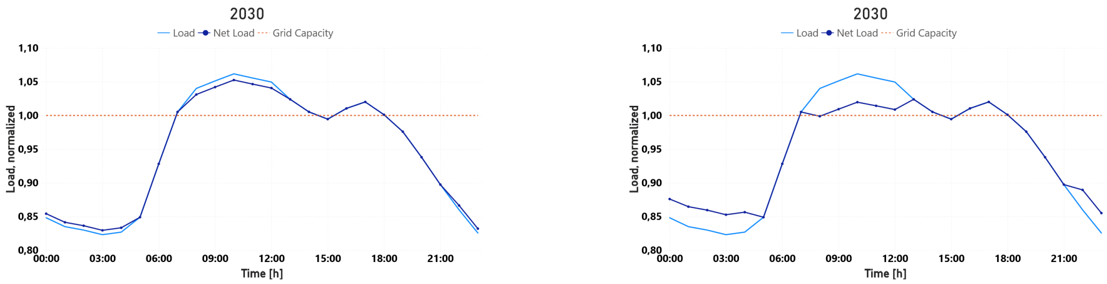
4.2.1 Power tariff model

With GENAB's focus on increasing knowledge the share of customers choosing the more advanced RTP tariff is assumed to increase with time. The model assumes a large majority of customers to choose the blunt ToU tariff. 80% of customers are assumed to choose the blunt tariff, whereas the remaining customer base is assumed to shift from the steep ToU tariff to the RTP tariff linearly with time. The assumption is based on GENAB's expectations from pilot studies as well as data showing that customers with a higher understanding of the tariffs are more active [19, 21]. For industry the level of reduction is assumed to be constant over time. This results in households having an increasing share of effect on tariff load reduction. Multiple assumptions were changed for both the high and low bounds and changed differently. Therefore, the average change in assumptions was used for sensitivity analysis of tariff behavior. The results of which are displayed in Table 4.4 and below in Figure 4.7.

Table 4.4: Effects of underlying assumptions on tariff model

	High assumptions	Low assumptions
Max. Power Δ [MW]	42.9	9.4
Δ to base scenario [%]	73.7	-61.9
Avg. assump. Δ [%]	39.6	-40.2
Sensitivity [%]	186.1	154.0

Peak load reduction for different tariffs was, base line, assumed to the middle of spans discussed in chapter 3.1.1. Figure 4.7 shows the effect these assumptions have, by displaying results when using upper- and lower spans. With low assumptions for both sectors the load is reduced by 46 MWh and 215 MWh with high assumptions, 9.4 MW and 42.9 MW max power difference respectively. This equates to reduction or increase in max power difference, compared to base assumptions, of 61.9% and 73.7% respectively. Resulting in a sensitivity of 54.0% and 86.1% respectively.



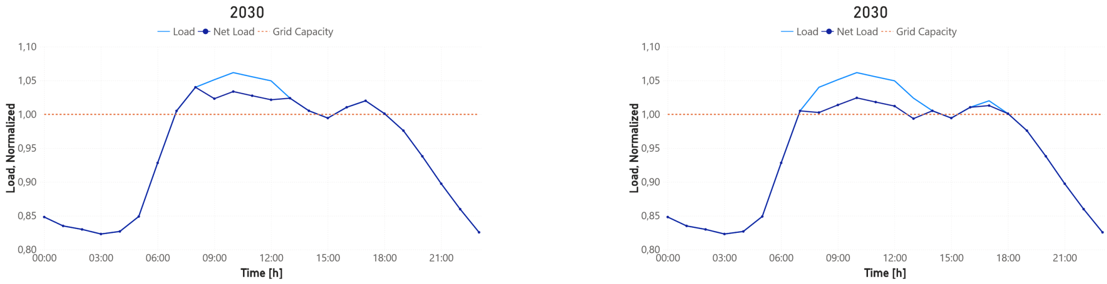
(a) Low assumptions

(b) High assumptions

Figure 4.7: Net load profiles tariff model for different reduction assumptions.

4.2.2 EHV model

In the LFM model the main behavioral assumption, besides whether it reacts to pre or post tariff load, is the duration of the flexibility purchases. BESS and V2G being identified as the main providers of flexibility in the future, lead to the duration being centered around the limitations of those technologies. Today most BESS have a full capacity duration of 2-3 hours. GENAB has identified increasing duration of flex trades as a future target, which combined with expected technological growth could push the limit to 4-5 hours. Since EHV's customer base would not only consist of BESS and V2G, higher numbers than were assumed to account for other sources having longer duration. The base scenario for the LFM model assumes a 3 hour duration at full capacity and 5 hour duration at limited capacity. Figure 4.8 shows the effect of lower- and higher duration assumptions.



(a) Shorter duration, 2-4 hours

(b) Longer duration, 4-6 hours

Figure 4.8: Load profile of EHV model for different duration assumptions, time spans illustrate duration at max capacity and limited capacity.

With a shorter duration the load is reduced by 114 MWh and 229 MWh with a longer duration. Compared to the base scenario in Figure 4.1 it equates to a 33.3% increase/decrease. The load reduction increasing/decreasing by one third equals the change in duration. Indicating that the reductions were not limited by the capacity being reduced from a prior flex purchase.

Table 4.5: Effects of flexibility duration on LFM model

	2-4 hours	4-6 hours
Load Reduction [MWh]	229	114
Δ to base scenario [%]	33.3	-33.3
Duration Δ [%]	33.3–20	-33.3–20
Sensitivity [%]	100–166.6	100–166.6

4.3 Abatement of grid capacity overshoots

From Figure 4.4 we can see that until 2032 only Area B exceeds its grid capacity. Thereafter the load exceeds grid capacity more frequently. Looking closer at a typical high peak day in Figure 4.9, we can see that the total load exceeds the capacity first 2028. Thereafter the duration and amplitude of the excess increases each year.

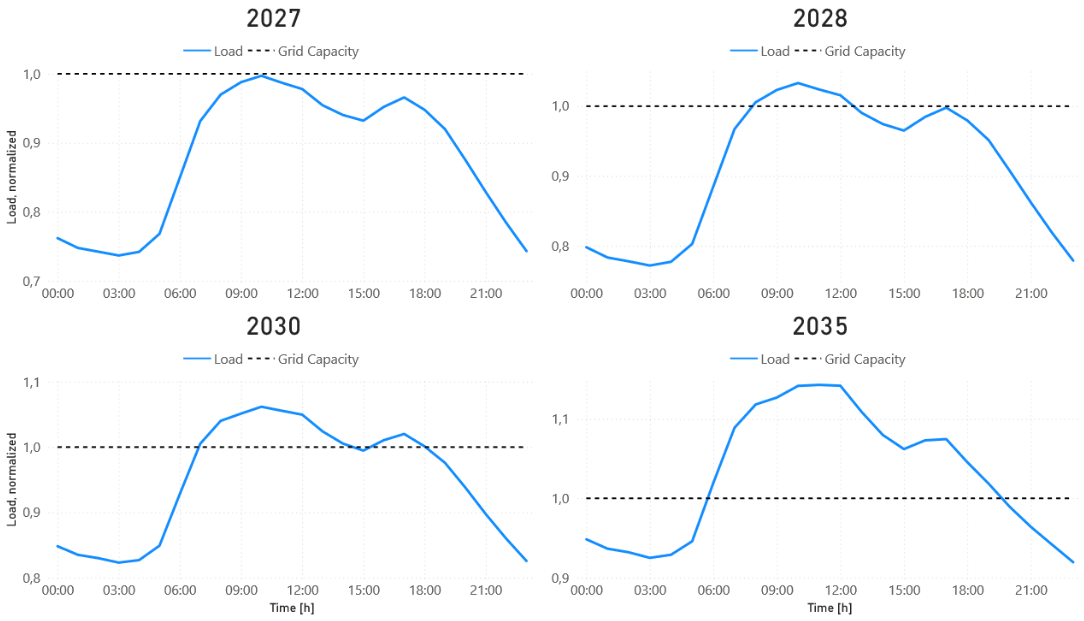
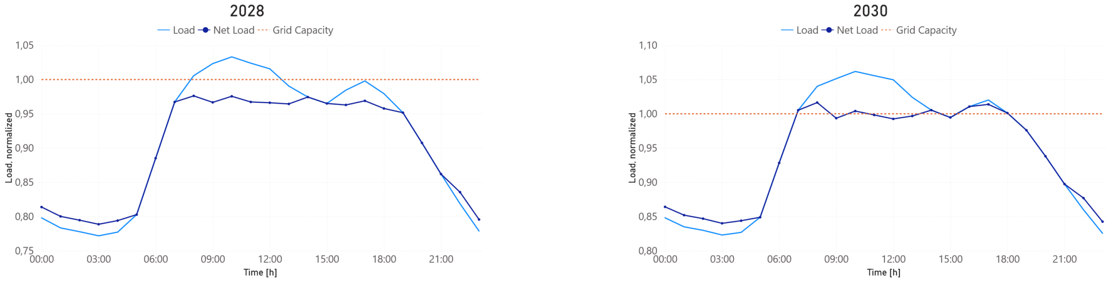
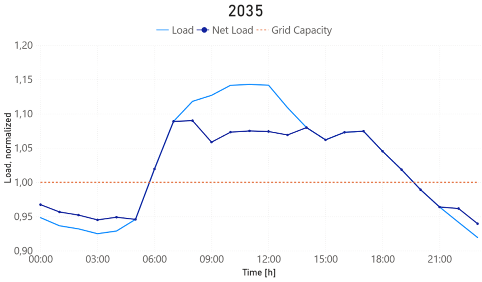


Figure 4.9: Load profile without models applied, compared to grid cap

When instead looking at the net load after the flexibility models are applied, shown in Figure 4.10, the excess load is either removed or reduced in duration and/or amplitude.



(a) Net load 2028 **(b)** Net load 2030



(c) Net load 2035

Figure 4.10: Load and net load compared to capacity, peak day

For 2028 load drops far enough below capacity for second peak to also be affected, whilst for 2030 and 2035 load stays above capacity and therefore LFM doesn't affect those peaks. This results in that total energy reduced is lower in the year 2030 than in the year 2028 despite the power at max decrease is greater, as shown by Table 4.6.

Table 4.6: Maximum power and total load (energy) reduction for occasions in Figure 4.10

Year	2028	2030	2035
Max power [MW]	71,3	77,3	99,8
Energy [MWh]	402,3	383,3	495,1

When zooming out and looking at the entire week surrounding the 26th similar results are present. Figure 4.11 shows the reduction for week 52 in the year 2030 and Figure 4.12 in the year 2035, and show peaks reduced below or closer to grid capacity.

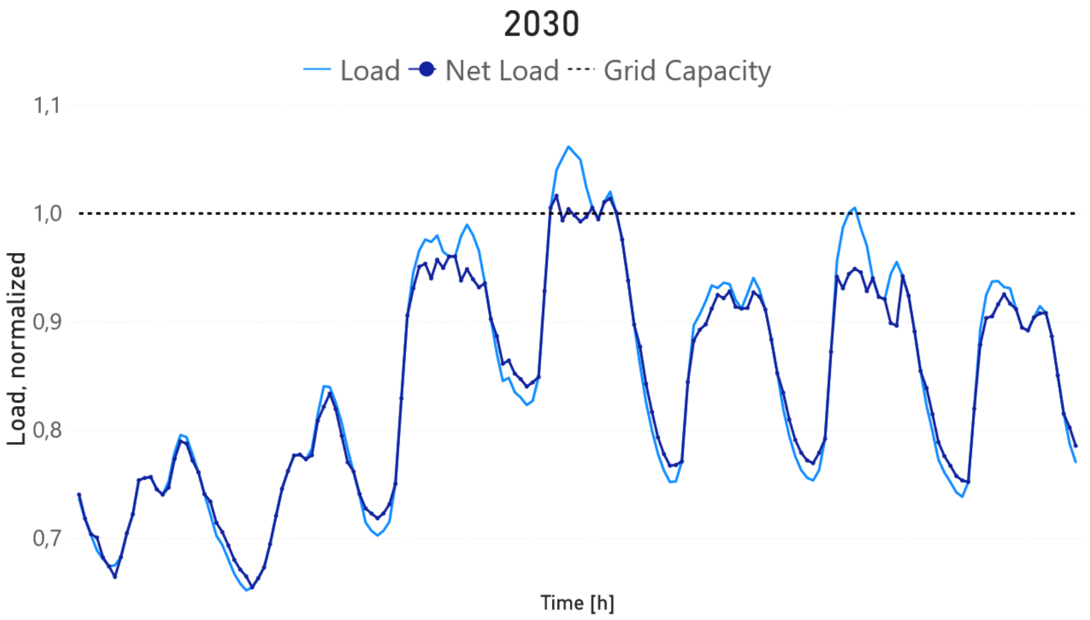


Figure 4.11: Net load Week 52 2030

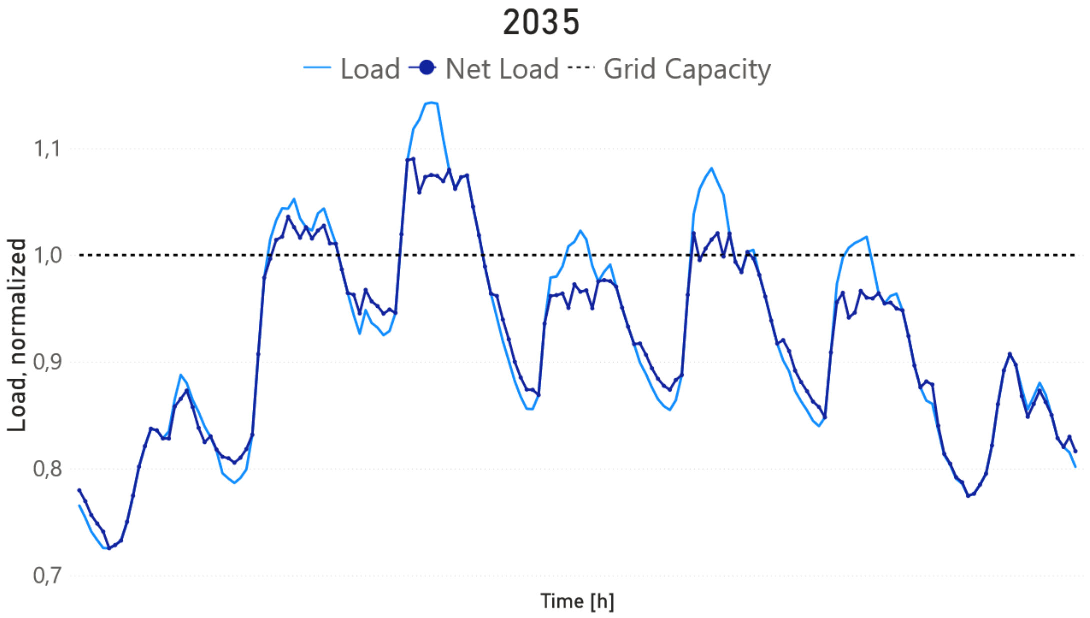


Figure 4.12: Net load Week 52 2035

Figure 4.11 shows that net load gets reduced below capacity for a number of days, see 27th and 29th in Figure 4.12, despite not achieving this during peak day. Further shown in Table 4.7, which details the number of times the load and net load exceed the subscription limit.

Table 4.7: Number of occasions where load exceeds capacity, where net load is after applying flexibility models.

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Load	0	0	7	17	29	108	174	223	262	233	285	350	432	500	625
Net Load	0	0	0	2	8	40	89	130	161	137	173	237	303	381	468
Difference	0	0	7	15	21	68	85	93	101	96	112	113	129	119	157
Diff [%]	-	-	100	88.2	72.4	63.0	48.9	41.8	38.6	41.2	39.3	32.3	29.9	23.8	25.1

The number of peaks exceeding the subscription are predicted to be below zero until 2028. Thereafter the number of occasions increase each year. As is shown in Table 4.7, the models reduce the amount of times this occurs. The number of occasions where the models reduce the load below capacity is described by the ”Difference” row. Which shows an increase most years, with exception to 2035 and 2039. The decrease in 2035 can be explained by the grid capacity increasing. The reason for reduced loads being lower in 2039 than in 2040 is unidentified, but is assumed to be due to a quirk in the data on planned load expansions. The share of occasions removed however is declining after 2028, with exceptions same years as prior. Showing that the load is predicted to increase faster than what the DSM's can handle.

5

Discussion

The results showed that despite the load reductions from the modeled DSM strategies, the load exceeds grid capacity in future scenarios. However, they also show that the number of times, and with how much, the load is expected to exceed capacity could be lowered by a substantial margin. The lowest being 25% of the occurrences in the year 2040. Whether or not this would be enough to be of economic benefit is something that would require further research. However, the results indicate that the strain on the power grid could at least be alleviated as an effect of demand side flexibility. Considering that grid capacity depicts subscription capacity and was assumed to follow GENAB's worst case scenario, the results indicate that the modeled DSM could have a substantial impact on load congestion. Since in the first years almost all occasions where load exceeds grid capacity were alleviated, a scenario with higher grid capacity could entail close to zero occasions of load exceeding capacity.

A sensitivity analysis showed the impact the assumptions have on the outcome of the flexibility models. Different assumptions showed different degrees of impact on the model's outcome. Certain aspects showed low sensitivity whilst others proved much higher. The CAGR calculated for the LFM model showed a lower sensitivity where an 87.5%, almost a doubling, increase in CAGR resulted in a 25% increase in load reduction and a 50% decrease lead to a 14.3% decrease. Resulting in a sensitivity of 28.6%. In contrast the duration of the LFM model showed a one-to-one ratio. Increasing or decreasing the duration by 33.3%, resulted in an equal shift in load reduction. The power tariff model showed an almost one-to-one sensitivity to shift in load scenario. The high load scenario increased the load by roughly 18% and increased the load reduction by 17.3% whilst the low load scenario decreased the load by around 13.2% and decreased load reduction by 13.3%.

Whilst the sensitivity of some parameters proved to be lower than others, none were low enough to be insignificant. Whilst the behavioral assumptions for the power tariff model showed a lower sensitivity than to the load scenarios, the size of the load reduction was larger. A result of a higher uncertainty in the assumption. Like with any predictive model it is essential to understand how the underlying assumptions affect the outcome in order to read the data properly. In the case of the tariff model, if the projections of system growth are wrong the consequences are higher than for the behavioral response. Therefore, ensuring that the system growth is properly handled could be deemed of greater importance to the accuracy of the model. However, it might be easier to refine the behavioral assumptions with more dedicated research or with more data. Since the impact to both power difference and load reduction was greater between the behavioral scenarios.

Despite the lower sensitivity to certain parameters, the effect they have on the result of the models is quite large. There is much work that could be done to lessen the uncertainties and increase the accuracy of the forecast. For example, conducting a deeper analysis on the CAGR of LFM's and fitting data to an S-curve so that growth changes over time. Due to its high sensitivity, something that has the potential to effect the LFM model the most is more thorough research on the projected duration of the flexibility resources, like BESS and V2G. As well as conducting deeper analysis on how the different flexibility sources interact with each other and affect the market.

5.1 Identified faults in the tariff model

With the models being built up from scratch, there are many aspects that with hindsight could, or should, have been done differently. One of those being how the tariff model handles which hours to reduce the load. With such a big majority of customers expected to have a ToU tariff, a flat reduction to peak hours within high price periods could be a better alternative than targeting peaks within the whole day. It would provide a more simplified model that would better reflect how most actors would be affected by the tariff. It would also better reflect seasonal differences since the high price hours only occur in the winter months. However, since high load periods are of greatest interest when dimensioning a power grid, this would be a minor improvement.

On the same track, a way to improve how the system depicts reality would be to split the ToU and RTP tariffs, as well as industry. This would allow for greater control over how large contributions from each sector and customer base would be. It could also allow for increased accuracy since the uncertainties also would be divided.

Very little data exists on how power tariffs actually affect customer behavior, especially within GENAB's network. As power tariffs become more common and more data is available, updating the model to include historical data for assumptions could improve accuracy. The model is also built according to GENAB's price plans prior to government suspending mandatory implementation. The plan for the tariffs look different today than what the model assumes which could give different results.

5.2 Identified faults in the LFM model

As was mentioned in Chapter 3.2, a calculation error was made when calculating the growth rate. The growth was calculated linearly instead of exponentially. The ramifications of which meant a lower increase in available flex capacity for the LFM model. Due to the nature of exponential functions this difference would be larger in the later years. Since most of the results use 2030 as a reference, there has not been enough time for the two functions to diverge greatly. Likely the resulting sensitivity analysis would yield similar results as an affect. However, if it was instead conducted on a later year, results may differ more. The sensitivity analysis showed a low sensitivity to the growth assumption, which indicates that the miss calculation would not affect the results greatly. If the calculation would have been implemented correctly, it is likely that the drop-off seen in 4.7 would be lower but still existing. It is also important to note that the yearly growth calculation was already made as a simplification. Modeling the growth in this way is not representative of how technologies develop over time. Therefore, whilst the results may have been affected, they are still deemed to be relevant.

Flexibility markets are still in a developmental phase and their growth and efficacy is therefore still fluctuating. Recent trends show rapid and accelerating growth, however not enough time has passed to be able to judge if it is a sign of sustained acceleration or random fluctuations in the same direction. Estimating a growth rate for such a system is therefore a complex and complicated matter. Estimating the growth of flexibility markets in the coming 20-30 years could be a whole thesis on its own. Since that was not the aim of this thesis, but rather small part of it, simplifications to the process had to be made. With a more robust analysis of comparative markets, LFM's around the world, or with more historical data a better estimation could potentially be found. A part of the simplification was the assumption that the growth factor will be the same for the entire duration, which would not be the case. Developing an S-curve and using it to have a dynamical growth rate that changes each year would provide a more representative model.

Another factor greatly impacting the results of the model is the way it targets when flexibility trades are needed. The load in the model is based on historical data, and the model can correctly identify all occasions where it surpasses grid capacity. Since trades need to be announced ahead of time combined with the fact that future load is difficult to predict exactly, it would not be possible to always predict when flexibility would be needed. Some occurrences when the load would pass capacity would not be identified whilst other times it would be falsely identified.

5.3 Future Research

Since the aim of this thesis was to built the models and implement them in the existing forecast model, there is much that could be done to improve them. The models are built from scratch and with the time constraints many simplifications had to be made. Adding complexity to the models and further developing many of the simplifications could be of great interest.

Some things that would be of interest for further research have already been touched upon. For example, an extensive study on the growth rate of LFM's. Most of the assumptions made within this thesis have had to be simplified and could use further research in order to improve their accuracy.

One area that has not been discussed is the implementation of other flexibility strategies. This study limits itself to the strategies and systems already in place or planned to be put into place. Conducting further research on what other flexibility strategies could work in the system and how they could be modeled could be of great interest.

Lastly, this thesis has been based around optimizing the use of the power grid. An area of further research would be to instead focus on the economic viability of these flexibility strategies. Are the costs of purchasing flexibility lower than the cost of expanding the grid and connections? What are the actual costs of managing and implementing these systems?

6

Conclusion

The aim of this thesis was to identify assumptions and simplifications necessary to model DSM strategies and to implement them in an existing forecast model. The issue was identified as a wicked system that required analysis and simplification in order to model. Both of the flexibility strategies targeted are still in early stages of development and therefore data scarcity was identified as one of the major complications. Two areas of importance were highlighted, namely system growth, and future behavioral response to the strategies.

Growth of the LFM model was calculated to 8% yearly by comparing it with the growth of the mFRR market. This was further identified as an oversimplification of growth, where a more apt growth cycle would change with time. The power tariff model was assumed to follow the growth of the load in the system, and not grow separately. A sensitivity analysis showed a sensitivity of 28.6% for the growth rate of the LFM model whilst the tariff model had a one-to-one ratio to changes in the load.

For the LFM model market behavior was equated to duration of flex purchases and was set to 3-5 hours. A sensitivity analysis showed a one-to-one ratio between change in duration and total load reduction. In the tariff model, behavior was equated to peak load reduction for different tariff types. Using more conservative assumptions reduced load reduction and power difference with 62% and generous assumptions increase them by 74%.

For 2028 the results showed that 100% of the peaks reaching above grid capacity could be reduced below capacity as an effect of the flexibility strategies. For subsequent years the share of exceeding peaks reduced below capacity decreased each year, reaching just above 25% by end of forecast, in 2040. This was including expected capacity increases, meaning that the flexibility strategies were not able to fully sustain the grid for the duration of the forecast. However, it showed that it could reduce the impact of a growing power demand and help alleviate congestion.

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A

System maps

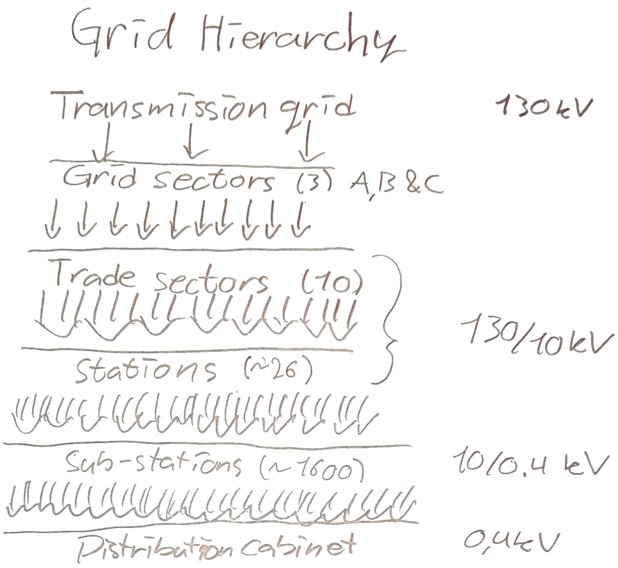

Figure A.1: Göteborg Energi grid hierarchy

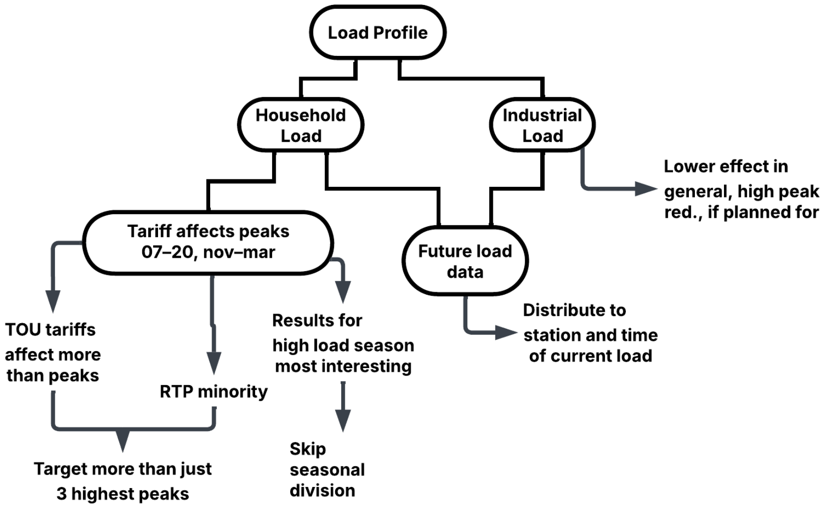

Figure A.2: System map created for tariff model

System maps in Figure A.2 and A.3 show drawn system maps for tariff and LFM model respectively. The circled elements indicate identified key segments and aspects of each system. Free text indicate identified opportunities for simplification.

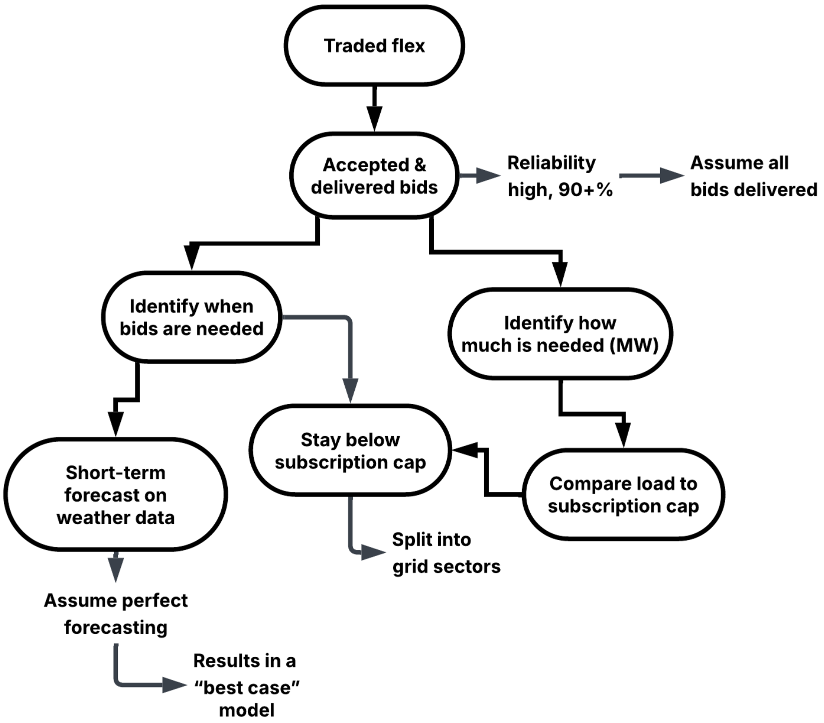

Figure A.3: System map created for LFM model

B

LFM model

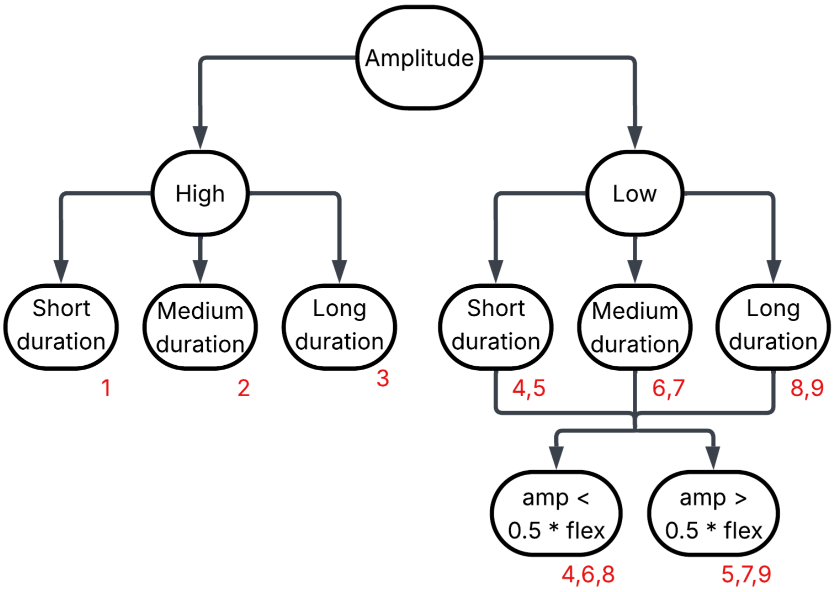

Figure B.1: Flowchart depicting decision tree for LFM model

In Figure B.1 amplitude refers to the difference in load and grid capacity. A high amplitude indicates that load exceeds capacity with more than the assumed flexibility capacity, low indicates lower than capacity. A short duration implies that the occurrence is shorter than the maximum discharge duration. Long duration is longer than the maximum bid duration and medium in between long and short. Lastly the ”amp <(/>) 0.5 * flex” indicates if amplitude is above or below half of the flex capacity, this is tied to assumption of reduced capacity with insufficient recovery time. In total 9 different scenarios are present, indicated by numbering.

B.1 Calculations

Load reduction in the LFM model utilized seven different parameters. Flex capacity of a specific factor, a float in MW denoted C. Load exceeding grid capacity, a float in MW denoted L. Upper and lower duration limit, denoted max_d and min_d respectively. If a flex purchase was made within minimum recovery duration of another purchase, a boolean value denoted W_h. How long load exceeded grid capacity, an integer in hours denoted D. Lastly a boolean value identifying if timestamp is a peak within a long duration, denoted P.

Equations below show how load reduction was calculated for each corresponding scenario denoted in Figure B.1. Factors of the shape $(1 - 0.5 \cdot W_h)$ reduce flex capacity by 50% when insufficient recovery time was allowed, as W_h either has 1 or 0 as it's value.

$$Reduction_1 = C \cdot (1 - 0.5 \cdot W_h) \tag{B.1}$$

$$Reduction_2 = \frac{min_d}{L} \cdot C \cdot (1 - 0.5 \cdot W_h) \tag{B.2}$$

$$Reduction_3 = \frac{min_d}{max_d} \cdot C \cdot (1 - 0.5 \cdot W_h) * P \tag{B.3}$$

$$Reduction_4 = L \tag{B.4}$$

$$Reduction_5 = L \tag{B.5}$$

$$Reduction_6 = L \cdot (1 - W_h) + C \cdot 0.5 \cdot W_h \tag{B.6}$$

$$Reduction_7 = L \tag{B.7}$$

$$Reduction_8 = L \cdot (1 - W_h) + \frac{min_d}{L} \cdot C \cdot 0.5 \cdot W_h \tag{B.8}$$

$$Reduction_9 = (L \cdot (1 - W_h) + \frac{min_d}{max_d} \cdot C \cdot 0.5 \cdot W_h) \cdot P \tag{B.9}$$

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