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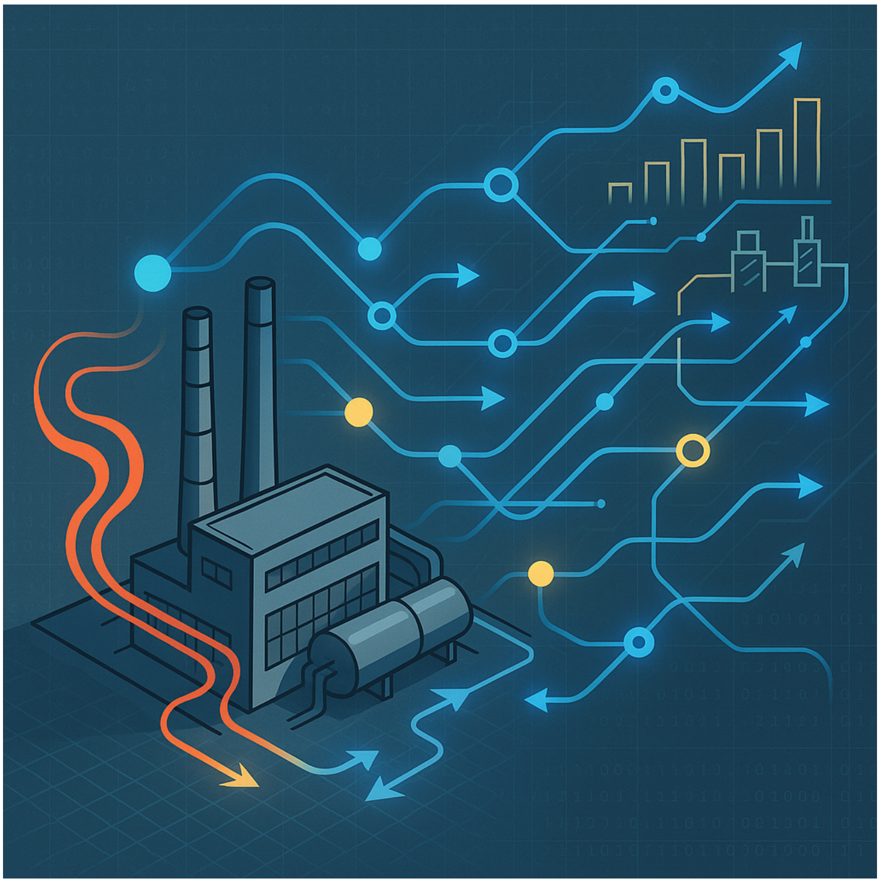

Optimizing Market Engagement: Strategic Models for District Heating Companies' Participation in Electricity Markets

Master's thesis in Engineering mathematics and computational science

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Cover: Illustration of a typical Combined heat and power unit with lines representing heat and electricity.

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Abstract

District heating companies in Sweden are presented with opportunities to participate in newer electricity markets beyond the spot market, such as intraday and ancillary markets. However, navigating these markets requires advanced and complex strategies due to the varying market rules, market timings, and operational constraints of combined heat and power units. This thesis develops a flexible mixed-integer linear programming model to optimize multi-market participation for district heating companies. The model integrates the market rules and all possible operational constraints to determine profit-maximizing strategies across electricity markets. Simulations using historical data showed that there is great value in participating in one additional ancillary market, with increases in profit ranging from 35% to 1100% depending on season. We also noticed that participation in more than two to three markets yields less profit increase, but on the other hand an increased complexity for daily operations in the district heating companies, suggesting that two to three markets is a balanced amount of participation. Since the technical qualifications for the ancillary markets are tough, many district heating companies might not have the opportunity to participate in more than one or two such markets, which strengthens this result. A comparison with Utilifeed's baseline model highlights the accuracy of our model and the added value of incorporating it in Utilifeed's model. The results show the importance of enabling district heating companies to navigate the complexity of multi-market participation, improving profitability while supporting the grid balancing.

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Jacob Burman, Gothenburg, June 2025

List of Acronyms

Below is the list of acronyms used throughout this thesis listed in alphabetical order:

aFRR	Automatic Frequency Restoration Reserve
CHP	Combined Heat and Power plant
(D-1)	One day before delivery
(D-0)	Same day of delivery
DH	District heating
FCR-D	Frequency Containment Reserve - Disturbance
FCR-N	Frequency Containment Reserve - Normal
FFR	Fast Frequency Response
HOB	Heat Only Boiler
LP	Linear Programming
mFRR	Manual Frequency Restoration Reserve
MILP	Mixed-Integer Linear Programming
SVK	Svenska Kraftnät
TSO	Transmission System Operator

Contents

1

Introduction

1.1 The Role of District Heating in the European Energy Transition

Half of the total energy use in the EU stems from heating and cooling. Currently, 9% of the heat in the EU is provided by district heating (DH), but there is a potential for expansion to support the decarbonization of Europe [1]. DH is a well-established industry in Sweden that meets approximately half of the country's heat demand. Aside from producing heat, many district heating companies have combined heat and power (CHP) plants, which can also produce electrical power. What they can do then is to optimize the operation of the CHP and other assets in their network to minimize their operational costs, which amounts to the difference between the cost of running the assets and the income from the sold electricity. Normally, the DH companies only look at the day-ahead electricity market. In times of imbalances, they are forced to trade on the intraday market, however, not in an optimized manner. A new area with a lot of potential is to also participate in any of the ancillary markets, and in a more tactical manner on the intraday market, However, this makes the bidding strategies extremely complex, and better decision support for the DH companies is needed.

This project is in collaboration with Utilifeed, a company that develops and provides a software–as–a–service (SaaS) data platform that is used by many DH companies in Sweden and Europe [2]. Utilifeed provides expertise in DH system data analysis, optimization of energy systems, and business development. Utilifeed handles a huge energy data set every day and builds analyst tools based on machine learning and mathematical optimization. One of the company's tools is a production optimization tool where the DH companies get support regarding how to operate their production plants (including the CHP) depending on varying values of such entities as fuel and electricity prices.

1.2 Motivation for Market Participation Strategies

The purpose of this master thesis is to develop strategies for the DH companies to use when deciding on which, and how large volume on each, electricity market to place bids on for each time step. The electricity markets included should preferably be day-ahead, intraday, and relevant ancillary service markets for CHPs.

1.3 Objective of the Thesis

The aim of this project is to deliver a versatile model that can be used to give support to district heating companies on how large volume, when, and to which markets to place electricity and capacity bids. The aim is to make this model a part of Utilifeed's existing model to enhance its capabilities.

1.4 Scope and Assumptions

Utilifeed has access to electricity price data for the spot market, including historical forecasts, historical actual prices, and forecasts for future prices up to seven days ahead. There is publicly available historical data on the ancillary market; however, no historical data of predictions on this market. There is data available for the intra-day market, however, it was not available during the time frame of this project. In this project, we will assume that Utilifeed will have access to all types of predictions and historical prices in the future, and we can therefore use a naive implementation in the project. The price for producing electricity and the price for adjusting the production rate of electricity will follow a simple model in order to keep the focus of this report on the electricity markets and not on the production of heat.

2

Theoretical and Market Background

This chapter covers the optimization background needed to understand the model. It also explains the information needed about the current electricity markets in Europe and Sweden to collect all necessary information in one place. Finally, we define the assumptions made about DH companies and their operational structure.

2.1 Mathematical Optmimization Background

In this section, we will define mixed-integer linear programs, modeling tricks, and explain what happens under the hood of a solver with an example.

2.1.1 Mixed Integer and Linear Optimization

A standard linear optimization problem (LP) is defined as to

$$\begin{aligned} z^* := \underset{\boldsymbol{x}}{\text{minimize}} \quad & \boldsymbol{c}^T\boldsymbol{x}, \\ \text{subject to} \quad & A\boldsymbol{x} \geq \boldsymbol{a}, \\ & \boldsymbol{x} \geq \boldsymbol{0}, \end{aligned}$$

where $\boldsymbol{c} \in \mathbb{R}^n$, $A \in \mathbb{R}^{m \times n}$, $\boldsymbol{a} \in \mathbb{R}^m$ and $\boldsymbol{x} \in \mathbb{R}^n$. Introducing integer variables $\boldsymbol{y} \in \mathbb{N}^r$, an extended problem is defined as to

$$\begin{aligned} z^* := \underset{\boldsymbol{x},\boldsymbol{y}}{\text{minimize}} \quad & \boldsymbol{c}^T\boldsymbol{x} + \boldsymbol{d}^T\boldsymbol{y}, \\ \text{subject to} \quad & A\boldsymbol{x} + B\boldsymbol{y} \geq \boldsymbol{a}, \\ & \boldsymbol{x} \geq \boldsymbol{0}, \\ & \boldsymbol{y} \in \mathbb{N}^r, \end{aligned}$$

where $\boldsymbol{d} \in \mathbb{R}^r$, and $B \in \mathbb{R}^{m \times r}$. This type of problem is called a mixed-integer linear program (MILP) and is one of the NP-complete problems listed by R.M. Karp [3]. Examples of problems that can be modeled as LP or MILP are resource allocation, transportation planning and bidding strategies to mention a few.

2.1.2 LP representation of the absolute value and max functions

When working with a linear program, it is sometimes necessary to incorporate piecewise linear functions such as the absolute value and max function. To create linearity, we use optimization modeling tricks.

2.1.2.1 Absolute value

Let $x \in \mathbb{R}$ and $y \in \mathbb{R}$ be two variables and $U := |x - y|$ be the absolute value of their difference. Then, an example model can look like

$$\begin{aligned} z^* := \underset{x,y,U}{\text{maximize}} \quad & ax + by - cU, && (2.1a)\\ \text{subject to} \quad & x - y \leq U && (2.1b)\\ & y - x \leq U && (2.1c)\\ & x, y, U \geq 0, && (2.1d) \end{aligned}$$

where, a, b, $c \geq 0$. As we want to maximize (2.1a), we want to minimize U. In (2.1b) and (2.1c) we model U as the largest of the two possible differences. Since U is minimized, it will be equal to the largest difference [4]. This trick is used in Chapter 3 to model ramping costs, where the change in production between consecutive time steps is penalized.

2.1.2.2 Max function

The common method for modeling the max function in LPs is one using binary variables with big-M method. Big-M is used to model the maximum function of two variables, we define w =max$\{x_1, x_2\}$, which corresponds to a piecewise linear function of x_1 and x_2. For this, we need to introduce a binary variable that will take the value 0 or 1 depending on which of x_1 and x_2 is the largest. The logic follows by considering which of the variables x_1 and x_2 takes the larger value and observing how the constraints.

$$\begin{aligned} w &\geq x_1, && (2.2a)\\ w &\geq x_2, && (2.2b)\\ w &\leq x_1 + Mz, && (2.2c)\\ w &\leq x_2 + M(1 - z), && (2.2d)\\ x_1, x_2 &\geq 0, && (2.2e)\\ z &\in \{0, 1\}, && (2.2f) \end{aligned}$$

enforce that condition. This, however, requires the introduction of a binary variable, which is fine if we only have one. However, the problem complexity will scale too much if too many binary variables are present. This general definition covers all possible scenarios where w can be maximized or part of complicating constraints. We have more knowledge of the structure and can therefor apply simplifications to reduce the complexity of the LP. The scenario can be described with $w + y \leq l$, where $y \geq 0$ is a variable and $l \geq 0$ is a parameter. This means that the largest value of x_1 and x_2 sets the upper limit of y. In the model to be produced in this thesis, the only interaction of x_1 and x_2 is in the objective function where they are added together, albeit multiplied with other factors. With this knowledge we can apply the continuous version where we avoid adding the variable w and translate it into a linear system of inequalities

$$\begin{aligned} x_1 + y &\leq l \\ x_2 + y &\leq l. \end{aligned}$$

This construction gives the required functionality while avoiding the complexity of binary variables. The max function is needed for a specific type of bid described in Chapter 3.

2.1.3 The Branch-and-Bound for integer linear programming

Many mixed-integer linear optimization solvers today, e.g, Gurobi [5] and Highspy [6], use mathematically based algorithms to solve mixed-integer linear optimization problems efficiently. One common and easy-to-understand method is the branch-and-bound method. It is characterized by the name, where branching means that the problem partitions the feasible set into multiple branches of smaller problem instances that are subsequently solved. Bounding refers to the upper and lower bounds given by the branches, these are used to eliminate branches that already are outside the bounds. The method is initialized by relaxing the integer constraints on the variables to be continuous, Tardos [7] has shown that any linear program can be solved to proven optimality in polynomial time. This creates a relaxed problem that is a linear optimization problem, which can be solved much more efficient by e.g. the simplex method [8]. However, it will likely have non-integer solutions—let us call such a solution x^*. The Branch–and–Bound method creates more constraints that force the solution to eventually become an integer solution without removing any feasible integer solutions. To accomplish this, solve the problem without any constraints of integrality, let it be x_1^*, and create two subproblems, one with the added constraint $x_1 \leq \lfloor x_1^* \rfloor$ and the other with the added constraint $x_1 \geq \lceil x_1^* \rceil$. Start by solving one of these subproblems, (i) if the subproblem is infeasible we can disregard and prune this branch, (ii) if the subproblem has an integer solution we record the objective value and prune this branch, (iii) if the objective value is worse than the best integer solution found we can disregard and prune this branch and (iv) if the solution has a fractional variable value we repeat the process of branching the subproblem into two subproblems until there are no more branches to explore. This might seem like a complicated process. However, as all subproblems are LPs, each problem can be solved efficiently. We note that the total amount of potential branches are 2^n for binary variables, not general integers, where n is the number of variables. Let us look at an example of how solvers like Highspy and Gurobi handle this without the input of the user. Let our problem only have integer variables without a loss of generality. Let the problem be

$$
\begin{aligned}
z^* = \underset{\boldsymbol{x}}{\text{minimize}} \quad & 5x_1 + 7x_2 && \text{(2.4a)}\\
& x_1 + x_2 \geq 6 && \text{(2.4b)}\\
& 4x_1 + 9x_2 \geq 36 && \text{(2.4c)}\\
& x_1, x_2 \geq 0 && \text{(2.4d)}\\
& x_1, x_2 \in \mathbb{Z} && \text{(2.4e)}
\end{aligned}
$$

Iteration 0: Let L_0 be the LP relaxed problem of (2.4), i.e, L_0 is defined by (2.4a)–(2.4d). This problem has an optimal solution at $x^0 = (3.6, 2.4)$ with an objective value of $z_0^* = 34.8$. Let us now create two new problems, corresponding to the branches in the Branch–and–Bound tree, one with the additional constraint $x_1 \geq 4$ and one with the constraint $x_1 \leq 3$.

Iteration 1: Let $L_1 := L_0 \wedge (x_1 \geq 4)$. Here the optimal solution is at $x^1 = (4, 2.\overline{2})$ with an objective value of $z_1^* = 35.\overline{5}$. As this has a non-integer solution, we create two new subproblems, one with the additional constraint $x_2 \geq 3$ and one with the constraint $x_2 \leq 2$.

Iteration 2: Let $L_2 := L_1 \wedge (x_2 \geq 3)$. The optimal solution is at $x^2 = (4, 3)$ with an objective value of $z_2^* = 41$. This is an integer solution, so we save this as the best solution found so far and stop branching down this path.

Iteration 3: Let $L_3 := L_1 \wedge (x_2 \leq 2)$. This has an optimal solution at $x^3 = (4.5, 2)$ with an objective value of $z_3^* = 36.5$. As this value is lower than that of our current best solution, we continue branching—the two new branches with constraints are $x_1 \geq 5$ and $x_1 \leq 4$

Iteration 4: Let $L_4 := L_3 \wedge (x_1 \geq 5)$. This has an optimal solution at $x^4 = (5, 1.\overline{7}$ with an objective value of $z_4^* = 37.\overline{4}$. This value is once again lower than that of our best solution found so far, so we branch again with $x_2 \geq 2$ and $x_2 \leq 1$.

Iteration 5: Let $L_5 := L_4 \wedge (x_2 \geq 2)$. Here we get an integer solution at $x^5 = (5, 2)$ with an objective value of $z_5^* = 39$, which is a new best, so we now save x^5 as the best solution found so far.

Iteration 6: Let $L_6 := L_4 \wedge (x_2 \leq 1)$. This has an optimal solution at $x^6 = (6.75, 1)$ with an objective value of $z_6^* = 40.75$. As this value is greater than that of the best solution found so far, we prune this branch.

Iteration 7: Let $L_7 := L_3 \wedge (x_1 \leq 4)$. This problem is infeasible, so we prune this branch.

Iteration 8: Let $L_8 := L_0 \wedge (x_1 \leq 3)$. Now the optimal solution is at $x^8 = (3,3)$ with objective value $z_8^* = 36$. This is an integer solution, so we save the solution as the best one found so far.

There are no more branches to explore, and we can conclude that the best integer solution to (2.4) is at $x = (3,3)$.

2.2 District Heating

This section explains how a DH company can be configured and how it produces electricity.

A DH company typically has some combination of Heat Only Boilers (HOBs), Combined Heat and Power units (CHPs), an accumulator tank, and an oil heat generator. A HOB produces heat by burning fuel, either biomass or waste. A CHP produces heat and electricity simultaneously by running hot steam through a turbine. In this project we model a CHP, however, the other types of modules affect the inputs to the model. An accumulator tank is a battery for heat, which is well isolated to keep heat for longer. It is beneficial to charge an accumulator tank when the energy demand and/or energy costs are low, and to discharge it when the demand and/or costs are higher. Using an accumulator tank also helps to create a more stable production plan for the machines as the tank manages smaller inconsistencies in the heat demand. Lastly, the oil heat generator is aimed for emergencies when heat demand spikes and the other units cannot cover the extra demand. Running an oil generator is very expensive and is therefore avoided as much as possible.

The CHP is slow at adjusting the level of generation of electricity through its turbine, specifically upwards. Many CHPs can redirect the steam, to quickly down regulate the electricity production, although this is not necessarily desirable since quick regulations may tear equipment faster.

2.3 Electricity Market Overview

This section introduces the structure of the electricity grid, going into more detail for the markets relevant to DH companies. The electricity market in Sweden is divided into three main segments: spot, intraday, and ancillary—each with different sub-markets having different pricing mechanisms, trading windows, and bid structures. Understanding each of these is crucial for modeling and optimal market participation. As we limit the model to allocate production or capacity volume for each market and not which types of bids should be placed in the auctions, we will mention the bid types but not go into their detail.

2.3.1 Market Structure Overview

Electricity markets in Europe are designed to ensure the balance of supply and demand in both the short and long term, while maintaining grid stability. Specifically in Sweden, there are electricity systems divided into multiple market categories, each with a specific purpose. An actor such as a DH company with a CHP unit can participate in many of these markets in order to maximize its revenue and to improve its operational efficiency.

2.3.1.1 Roles of Market Participants

The three primary actors in the electricity markets are the following

Producers: Those who create electricity, such as companies with wind power, solar power, nuclear power, hydro power, or a DH company with a CHP.

Consumers: Large industrial facilities, DH companies with electrical boilers, or electricity retailers that buy electricity on behalf of end users.

Transmission System Operators (TSOs): In Sweden, Svenska Kraftnät (SVK) is responsible for keeping the balance in the grid by managing real-time grid operations through the ancillary markets [9].

Each of these actors has different roles in the different market segments. For instance, selling capacity on the ancillary markets requires strict technical requirements such as fast ramping rates and quick availability.

2.3.1.2 Market Segments

The electricity markets in Sweden can be grouped into three categories, based on their purpose and the actors trading.

Spot Market. This is the main market where producers sell electricity and consumers buy electricity. This market's purpose is to be the central market connecting producers and consumers. Bids are made in advance, typically one day before, and market clearing sets the electricity prices per time step for the next day. Time steps are the span of time to deliver electricity, these are changing and are therefore assumed to be arbitrary lengths in this report.

Intraday Market. As the trading occurs some time before the delivery, predictions can be inaccurate, and unexpected incidents can occur, changing the total production as well as consumption demands. This means that actors sometimes need to change their positions that they proccured on the clearing of the spor market. This is done through either auctions or continuous trading on the intraday market which happens between the auction of the spot market and delivery time step.

Ancillary Market. At the time of delivery, the predictions can be inaccurate, and unforeseen disturbances such as cables breaking or power plants suddenly needing to shut down can occur. The adjustment from the Intraday trading is therefore not enough, and the ancillary markets are needed. Here, SVK is buying capacity to produce electricity to be able to regulate the levels of production and consumption. There are different ancillary markets for different needs, depending on the size, length and foreseeability of the disturbance. These are FCR (Frequency Containment Reserve), aFRR (Automatic Frequency Restoration Reserve), mFRR (Manual Frequency Restoration Reserve), and FFR (Fast Frequency Reserve).

Each market differs in timing, bidding types, and wether electricity or capacity is traded—all of which influence how DH companies participate in the markets. The diversity of rules and formats makes the participation in multiple markets strategically complex.

2.3.1.3 Summary Comparison

	Spot market	**Intraday market**	**Ancillary market**
Type of market	Electricity	Electricity	Capacity Electricity
Actors selling	Producers	Consumers & Producers	Consumer & Producers
Actors buying	Consumers	Consumers & Producers	SVK

Table 2.1: An overview of types of markets and actors on each market.

2.3.2 Spot market

The spot market is the main way to trade electricity. In Sweden and many European countries, Nord Pool is a big trading platform, which is why we will base the theory on this platform for this project. Here, consumers and producers submit bids the day before delivery (D-1), setting the electricity price for each of the time units.

All bids on the spot market are submitted before noon (CET) on the day before delivery (D-1) for electricity delivered on (D-0), which is the day of delivery. Participants place bids specifying the amount, price, and time of delivery. For each time of delivery, these bids create a supply and demand curves—of price as function of volume—the intersection of which determines the marginal price and volume, which in turn sets the electricity price for the time step. All accepted bids for this time step are set to this uniform clearing price. This is called paid–as–cleared and is common when trading electricity.

There are two main bid structures, single and block bids [13]. There are two types of single bids: a price-independent single bid specifies a volume to be traded if the clearing price falls within a defined floor and ceiling range—a price-dependent single bid is a function of price. Block bids span multiple consecutive time steps and are either fully accepted or fully rejected. A block bid can have characteristics such as curtailable, linked, exclusive, and flexi. These characteristics create more flexibility, but the single bid is more relevant to DH companies as they can change production level between time steps. However, many DH companies take advantage of block bids by creating a consistent and predictive load which simplifies production planning.

The spot market is the entry point for a DH company with a CHP to start trading electricity. With the straightforward amounts and predicted prices, this is the safest and simplest market to trade on. The ability to plan production based on known commitments makes this market straightforward for DH companies to participate in. However, the spot market has its limitations. Since the bids must be made in advance, forecast errors in heat demand and electricity prices can lead to suboptimal production plans and allocations. Because of this, the interest in participating in the intraday and ancillary markets is increasing for flexible producers such as DH companies. Nonetheless, the spot market remains the foundation for electricity trading and plays a central role in the optimization model developed in this thesis.

2.3.3 Intraday markets

The Intraday markets enable consumers and producers to adjust their positions and commitments from the clearing of the spot market. There are multiple reasons for actors to change positions: unexpected amounts or prices, changes in weather, or changes in heat demand. Nord Pool is the platform where actors trade on the Intraday market, which consists of two trading formats: auctions and continuous trading. The auctions have the same type of bids and clearing price calculation as the spot market. These auctions currently happen three times per delivery day, at 15:00 (D-1), 22:00 (D-1), and 10:00 (D-0) CET [14].

The continuous Intraday market works similarly as when trading stocks. An actor puts an offer on the market, and if another actor buys the offer, the price is set to the offer's original bid price. Some traits that an offer can have are iceberg which hides the total amount to trade, execution constraints which are traded immediately upon submission, or a linked basket which is are multiple execution constraints orders linked together [15]. These traits are useful for companies with larger production capacities, however, they create modeling complexity that outweighs strategic benefits for smaller companies like DH companies.

As DH companies mainly deal with heat production which is varying, there are scenarios ion which a change in position is necessary. However, most DH companies have multiple heat production units, which means that the change in heat demand can be solved in other ways. This market is volatile, as it is tough to predict when companies want to change their positions. While hydro and nuclear power provide stable power generation, wind and solar depend heavily on weather forecasts. This creates an uncertainty in the available generation during volatile weather. Flexible DH companies can exploit this volatility by adjusting production up or down to match market needs.

2.3.4 Ancillary markets

In real-time operations, electricity supply and demand occasionally deviate from expected values, requiring quick actions. In Sweden, this is planning and control are handled by SVK who manage the trading on ancillary markets, mostly with regard to electricity production capacity rather than electricity production. In the case of a disturbance, SVK activates capacity, which retains the balance in the grid [9].

2.3.4.1 Frequency Containment Reserves (FCR)

Deviations in the grid have different characteristics, denoted normal deviations and disturbances, respectively.

FCR-N (Normal) market. This is a capacity market which stabilizes small frequency deviations that occur mostly because of minor differences in committed production/consumption and what happened during the current time step. This is the only market in which the up and down regulation is not separated into two different markets.

FCR-D (Disturbance) market. This is a capacity market which is activated when larger deviations occur, such as power plants unexpectedly turning off. This requires a quick response time and two separate markets, one with upward and one with downward regulation.

Technical data for the FCR markets. For each month SVK decides for each time step during the month and each market, the amount of capacity that should be bought. These amounts are published before each month on SVK's website [16]. The required ramping rate, the speed til full activation, for the FCR-N market is 2 min, while the FCR-D market is 30 sec. The length of the activation is at least 20 minutes for the FCR-D markets and around one hour for the FCR-N market. This does not mean that the bids are fully activated during the whole time step, but rather that a varying percentage of the bid is activated during the time step. There are two types of bids, single and block bids, having no special characteristics, meaning that both get either fully accepted or fully rejected. There are currently two auctions, one at 00:30 and one at 18:00 (CET) [10]. The bids must have a resolution of 0.1 MW and 0.01 EUR.

2.3.4.2 Frequency Restoration Reserves (aFRR and mFRR)

For longer and larger imbalances in the system requiring restoration, there are two types of markets, automatic and manual. These two take over the balancing from the FCR markets, so the system is ready to deal with new imbalances.

aFRR (automatic) market. This is a capacity market which activates automatically through signals from SVK. This characteristic suits electricity production plants, which are able to change production levels without affecting other factors.

mFRR (manual) market. This market is divided into both capacity and production. It is activated manually by the TSO to easen the load of the FCR-D market during longer disturbances. These markets can also be activated before a disturbance occurs if the knowledge exists beforehand. This is the only ancillary market where capacity is traded first, before the electricity is traded.

Technical data for the FRR markets. Here, SVK also decides the capacity needed in each time step. The ramping rate here are the slowest with aFRR having 5 min, and mFRR having 15 min. The total capacity for mFRR is about eight times bigger than that of the aFRR, making it more attractive. The duration of activation is around one hour for both types of markets. There is one auction where all capacity of the FRR markets is traded, currently at 07:30 (D-1) CET [11][12]. These markets are paid–as–cleared with the marginal price. Bids must have a resolution of 1 MW and are either single, block, or exclusive. Except for price and volume, divisibility is a factor, meaning that a percentage of the bid is flexible to be partially accepted. The mFRR electricity market has an auction, which occurs 45 minutes before each delivery time step. If capacity has been procured on the mFRR capacity market, the provider is obligated to submit a corresponding bid on the mFRR electricity market, with a volume no less than the procured capacity. Here, the bids are more flexible, however, there are no block bids as the auctions for each delivery time step happen at different times. The bid formats are single, exclusive, and multipart bids—where acceptance proceeds in price order until the demand is satisfied. Note that this market is paid–as–cleared with the marginal price.

2.3.4.3 Strategic Participation for DH companies

The technical data for the capacity markets are summarized in Table 2.2. Another market is called Fast Frequency Reserve (FFR), which is primarily composed of batteries and has a short activation time of 30 seconds, making it an unfeasible market for DH companies. All these markets operate through changes in production directly from the power plants, since batteries would struggle with longer activation times as they have limitations in storage compared to a power plant which can continuously produce electricity. Participation in aFRR is challenging for CHPs, as the automatic activation requires immediate heat production compensation, which may be tough for operators of the CHPs to handle. The way a CHP is creating power is by running steam through a turbine that spins. Turbines can take some time to start up as they are big and thus a slow acceleration. This makes the FCR-D up market tough to participate in, considering the required fast ramping rate. However, as many CHPs can re-route the steam to decrease electricity production quick, the FCR-D down market becomes available to some DH companies. The FCR-N market has a slower ramping rate and tends to have less capacity to trade, making it viable for DH companies in general. The mFRR market is the biggest one, including both capacity and electricity, and a slow ramping time. These factors make the mFRR market the simplest and most attractive ancillary market for DH companies.

	FFR	FCR-D up	FCR-D down	FCR-N	aFRR	mFRR
Time to deliver full capacity	ca 1 sec	ca 30 sec	ca 30 sec	ca 2 min	5 min	15 min
Minimum bid size (MW)	0.5	0.1	0.1	0.1	1	1
Maximum capacity per hour (MW)	105	542	524	224	111	890
Duration of activation	$\leq$ 30 sec	$\geq$ 20 min	$\geq$ 20 min	1 hour	1 hour	1 hour
Time of auctions	Once per year	00:30 (D-1) 18:00 (D-1)	00:30 (D-1) 18:00 (D-1)	00:30 (D-1) 18:00 (D-1)	07:30 (D-1)	07:30 (D-1)
Producer compensated for delivered electricity	No	No	No	Yes	Yes	Yes

Table 2.2: Technical information about the capacity markets for the ancillary reserves.

2.3.5 Auction order

Summarizing all auctions into a timeline results in the graph shown in Figure 2.1. The results from the previous auction are available before making decisions for the next auction. This reduces uncertainty and helps make real-world operations feasible since we will have more information when participating in the next auction.

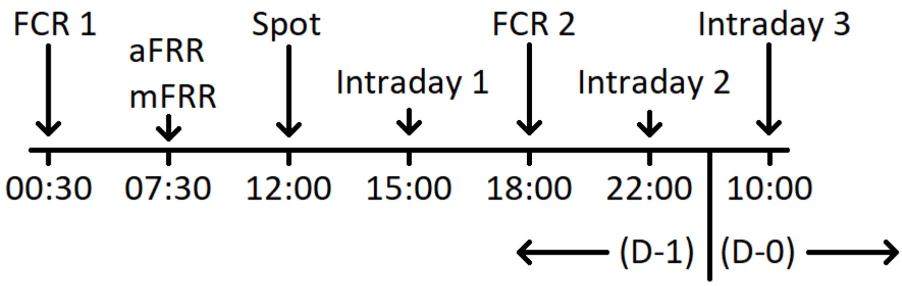

Figure 2.1: Timeline over the market auctions, excluding the intraday continuous as its continuously traded and the mFRR electricity market as it is traded every time step.

2.4 Key Modeling Assumptions

This thesis aims to create a flexible optimization model adaptable to a wide range of DH companies. Many of the model's parameters are company-specific and typically known only internally. Due to limited access to data protected by the companies, assumptions based on conversations with industry professionals are employed. These assumptions do not alter the structure or generality of the model, instead, they affect the results produced to evaluate the model.

2.4.1 Heat Demand and Production Limits

The model assumes that the heat demand of the DH company must be satisfied. This creates a varying upper limit on the production and consumption of electricity, since the CHP can be at different heat production levels, leaving different amounts of electricity production available. This is because there is a limit of the total amount of heat and electricity produced, and the two changes the limits of the other. In our model, these limits are kept constant for simplicity; however, when connected with Utilifeed's model, these limits may vary. Ramping limits and associated costs are included in the model and the values of these are based on typical characteristics and discussions with industry professionals.

2.4.2 Cost Structure

Electricity production costs are modeled using the heat production marginal cost [EUR/MWh]: this is the cost of increasing the most expensive active units' heat output. This is how DH companies operate in practice. The marginal cost is fixed for each season but varies between simulation periods to reflect operational shifts. Since no consensus exists regarding ramping costs, it is modeled as a fixed percentage of the production cost.

2.4.3 Market Data and Price Forecasts

To test the model, price data from the different markets are needed. For the spot market, both historical prices and historical predictions are available. There are historical data for prices on all ancillary markets published on mimers website [17]; however, no predictions. There is no data regarding the intraday market and therefore the intraday market not be used in the simulations, however, it will be a part of the model in the case of availability of this data in the future.

2.4.4 Data sources and Geographical Scope

All market data used in this thesis are based on the Swedish bidding zone SE3, which includes larger cities as Stockholm and Gothenburg. While the historical prices and historical predictions from the spot market are used extensively, they are proprietary and cannot be published in this report.

3

The Mathematical Model

This chapter describes the mathematical formulation of the MILP model used to optimize market participation for DH companies. The summarized version of the sets, parameters, variables, and constraints can be found in Appendix A. We start with a conceptual overview outlining how the model's components interact. Following this, we define the physical constraints on electricity production and consumption, based on mechanical limitations and boundaries. The next section models ramping behavior, introducing auxiliary variables associated with production changes and costs. We then describe market participation constraints, describing which markets are available and when bidding is allowed. Then, we introduce the initial conditions and accepted bids to ensure feasibility when making bids. The valuation section specifies how the profitability is calculated for each market, based on predicted price, operational costs, and average activation times. Finally, we define the objective function, which integrates all components into a profit-maximizing framework. The problem consists of maximizing revenue minus costs. We model the distribution, how much volume on each market, of bids on each market at each time step. This means that we do not simulate bidding strategies, but rather, which distribution of bids is the most desirable.

Due to the market rules being different across markets, and markets fulfilling different needs, many sets are needed to provide a formulation that is general enough to take note of possible future system changes. We use the set $\mathcal{M}^{\text{FCR}}$ to represent all FCR markets since these are traded at the same time for both auctions, and bids follow the same rules. Continuing with the set $\mathcal{M}^{\text{FRR}}$, this set collects the aFRR markets and the capacity markets for mFRR, as these bids are made at the same time, and they follow the same bid structure. Then, $\mathcal{M}^{\text{S}}$, $\mathcal{M}^{\text{I}}$, and $\mathcal{M}^{\text{IC}}$ capture the electricity markets: spot, intraday, and intraday continuous, respectively. There is also the need to know which markets regulate up and which regulate down, giving us $\mathcal{M}^{\text{prod}}$ and $\mathcal{M}^{\text{cons}}$, capturing the FCR and aFRR markets. The mFRR electricity market set is called $\mathcal{M}^{\text{mFRR}}$, capturing both up and down markets. Lastly, we need to separate mFRR up and down, for both capacity and electricity, giving us the two sets $\mathcal{M}^{\text{mFRR up}}$ and $\mathcal{M}^{\text{mFRR down}}$. This information is visualized in Table 3.1, where black boxes indicate that an auction on the indicated market is part of the respective set of markets displayed in the top row.

During the period of making bids, there are groups of auctions spread throughout the day, as illustrated in Figure 2.1. We define the time interval between two groups of auctions as a market step. At market step zero, no bids are placed;

this is denoted as $\mathcal{K}_0 := \emptyset$. The first auction is the first FCR auction, when bids for FCR-N and both FCR-D markets are placed, which creates market step one, defined as $\mathcal{K}_1 := \mathcal{K}_0 \cup \{$FCR-D up 1, FCR-D down 1, FCR-N$\}$. Which markets that are in each market step is listed in Table 3.1, giving us the general definition $\mathcal{K}_j = \mathcal{K}_{j-1} \cup \{\text{Market: Market step} = j\}$ for $j \in \{1 \dots 7\}$ with $\mathcal{K}_0 = \emptyset$. The last three markets in Table 3.1 are continuous and are therefore not a part of any set of $\mathcal{K}_j$, the visualization of this is in Table C.1.

Market (auctions)	**Step**	$\mathcal{M}^{\text{FCR}}$	$\mathcal{M}^{\text{FRR}}$	$\mathcal{M}^{\text{S}}$	$\mathcal{M}^{\text{I}}$	$\mathcal{M}^{\text{IC}}$	$\mathcal{M}^{\text{prod}}$	$\mathcal{M}^{\text{cons}}$	$\mathcal{M}^{\text{mFRR}}$	$\mathcal{M}^{\text{mFRR up}}$	$\mathcal{M}^{\text{mFRR down}}$	$\mathcal{M}$
FCR-D up 1	1	■					■					■
FCR-D down 1	1	■						■				■
FCR-N 1	1	■					■	■				■
aFRR up	2		■				■					■
aFRR down	2		■					■				■
mFRR capacity up	2		■							■		■
mFRR capacity down	2		■								■	■
Spot	3			■								■
Intraday 1	4				■							■
FCR-D up 2	5	■					■					■
FCR-D down 2	5	■						■				■
FCR-N 2	5	■					■	■				■
Intraday 2	6				■							■
Intraday 3	7				■							■
Intraday continuous					■	■						■
mFRR electricity up									■	■		■
mFRR electricity down									■		■	■

Table 3.1: Visualization of which markets and market auctions are in each set of markets and corresponding market step, with the sets in the top row and auctions in the left-most column.

In our mathematical model, time is discretized into time step, each typically representing one hour or 15 minutes, and which are employed in the electricity markets' bidding structure. We define $\mathcal{T}$ as the set of indices for time steps during day (D-0). Hence, for time steps of one hour, $\mathcal{T} = \{1, \dots, 24\}$, and for time steps of 15 minutes, $\mathcal{T} = \{1, \dots, 96\}$. We define $g \in \mathbb{R}^+$ [h] to be the time step length, this is needed to convert everything into the same units.

3.1 Production and Consumption Constraints

District heating companies must obey technical and operational limitations during bidding. These constraints ensure that production and consumption decisions are feasible across all electricity and capacity markets.

3.1.1 Production constraints

We start by noting that there is a limit on the amount of electricity that can be produced and consumed in any given time step. We denote these limits as l_t^{prod} and l_t^{cons}, respectively, for time steps $t \in \mathcal{T}$. Producing mean to burning fuel to create electricity and sell it. Consuming electricity means that heat is produced instead of electricity, which reduces heat production in another machine, saving money as the need to burn fuel is reduced. The production and consumption limits will mainly be affected by heat demand and mechanical limitations and will differ vastly between companies as well as between time steps and will be set by the greater model that this model will be a subpart of. We define variables ${}^{\mathrm{h}}x_{m,t}$ [MWh] that represents the volume of the bid reserved for electricity in markets $m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}$ and $x_{m,t}$ [MW] that represents the volume of bid reserved for capacity in markets $m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}$. As the clearing on the mFRR market may vary between energy and capacity, we model the constraints (3.1a) and (3.1b), each with different implications on production feasibility using the max function trick from Section (2.1.2.2). This operation is possible because of the multipart bids, where one can define parts of the bid to be sold at a set price. In each time step, the sum of of the bid volumes on the mFRR (energy) or mFRR (capacity) market, the upregulatory markets, the spot market, and the intraday markets should not exceed the production limit (where the capacity terms are multiplied by the length of each time step). For each time step $t \in \mathcal{T}$, these constraints are expressed as

$$
{}^{\mathrm{h}}x_{m,t} + \sum_{p \in \mathcal{M}^{\mathrm{prod}}} gx_{p,t} + \sum_{s \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}}} {}^{\mathrm{h}}x_{s,t} \leq gl_t^{\mathrm{prod}}, \quad m \in \mathcal{M}^{\mathrm{mFRR\ up}} \cap \mathcal{M}^{\mathrm{mFRR}}, \tag{3.1a}
$$

$$
gx_{m,t} + \sum_{p \in \mathcal{M}^{\mathrm{prod}}} gx_{p,t} + \sum_{s \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}}} {}^{\mathrm{h}}x_{s,t} \leq gl_t^{\mathrm{prod}}, \quad m \in \mathcal{M}^{\mathrm{mFRR\ up}} \cap \mathcal{M}^{\mathrm{FRR}}. \tag{3.1b}
$$

3.1.2 Consumption Constraints

We now consider the total consumption or the down-regulatory limit. In each market step, the sum of the bid volumes on the mFRR (energy) or mFRR (capacity) market and the down regulatory markets minus the sum of the bid volumes on the spot and intraday markets should not exceed the consumption limit. For each time step $t \in \mathcal{T}$, these constraints are expressed as

$$
{}^{\mathrm{h}}x_{m,t} + \sum_{c \in \mathcal{M}^{\mathrm{cons}}} gx_{c,t} - \sum_{s \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}}} {}^{\mathrm{h}}x_{s,t} \leq gl_t^{\mathrm{cons}}, \quad m \in \mathcal{M}^{\mathrm{mFRR\ down}} \cap \mathcal{M}^{\mathrm{mFRR}} \tag{3.2a}
$$

$$
gx_{m,t} + \sum_{c \in \mathcal{M}^{\mathrm{cons}}} gx_{c,t} - \sum_{s \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}}} {}^{\mathrm{h}}x_{s,t} \leq gl_t^{\mathrm{cons}}, \quad m \in \mathcal{M}^{\mathrm{mFRR\ down}} \cap \mathcal{M}^{\mathrm{FRR}} \tag{3.2b}
$$

3.1.3 Balancing Regulation Limits

We need to constrain the total bid volumes on the different balancing markets, since there are physical limits on the volume that can be regulated during each time step. We denote these limits as l_t^{prodB} and l_t^{consB}, limiting the up regulatory and down regulatory bids, respectively. In the case of activation on multiple markets, is must be possible to regulate everything, meaning that the sum of up and down regulatory bids are limited, respectively. The constraints are analogous to (3.1b) and (3.2b), but with a lower limit (the electricity bid volumes from the spot and intraday markets are not included, as these are not regulatory markets). For each time step $t \in \mathcal{T}$, these constraints are expressed as

$$
\begin{aligned}
{}^{\mathrm{h}}x_{m,t} + \sum_{p \in \mathcal{M}^{\mathrm{prod}}} gx_{p,t} &\leq gl_t^{\mathrm{prodB}}, && m \in \mathcal{M}^{\mathrm{mFRR\ up}} \cap \mathcal{M}^{\mathrm{mFRR}} && \text{(3.3a)}\\
gx_{m,t} + \sum_{p \in \mathcal{M}^{\mathrm{prod}}} gx_{p,t} &\leq gl_t^{\mathrm{prodB}}, && m \in \mathcal{M}^{\mathrm{mFRR\ up}} \cap \mathcal{M}^{\mathrm{FRR}} && \text{(3.3b)}\\
{}^{\mathrm{h}}x_{m,t} + \sum_{c \in \mathcal{M}^{\mathrm{cons}}} gx_{c,t} &\leq gl_t^{\mathrm{consB}}, && m \in \mathcal{M}^{\mathrm{mFRR\ down}} \cap \mathcal{M}^{\mathrm{mFRR}} && \text{(3.3c)}\\
gx_{m,t} + \sum_{c \in \mathcal{M}^{\mathrm{cons}}} gx_{c,t} &\leq gl_t^{\mathrm{consB}}, && m \in \mathcal{M}^{\mathrm{mFRR\ down}} \cap \mathcal{M}^{\mathrm{FRR}} && \text{(3.3d)}
\end{aligned}
$$

3.2 Ramping Behavior

To compute ramping costs, the change in electricity production between consecutive time steps is tracked. The change is penalized in the objective function to discourage frequent adjustments. The total electricity production during time step t is defined as u_t [MWh/h] in (3.4a). We then derive the absolute change U_t [MWh/h] in (3.4b) and (3.4c) using u_t and the absolute value trick from Section 2.1.2.1. The sign parameter f_m equals 1 for up-regulation bids ($m \in \mathcal{M}^{\mathrm{mFRR\ up}} \cap \mathcal{M}^{\mathrm{mFRR}}$) and -1 for down-regulatory bids ($m \in \mathcal{M}^{\mathrm{mFRR\ down}} \cap \mathcal{M}^{\mathrm{mFRR}}$). We also limit the total ramping in both directions with a^{up} [MWh/h] in (3.4d) and a^{down} [MWh/h] in (3.4e).

$$
\begin{aligned}
\sum_{i \in \mathcal{M}^{\mathrm{I}} \cup \mathcal{M}^{\mathcal{S}}} {}^{\mathrm{h}}x_{i,t} g^{-1} + \sum_{m \in \mathcal{M}^{\mathrm{mFRR}}} f_m\, {}^{\mathrm{h}}x_{m,t} g^{-1} &= u_t, && t \in \mathcal{T} && \text{(3.4a)}\\
u_t - u_{t-1} &\leq U_t, && t \in \mathcal{T} && \text{(3.4b)}\\
u_{t-1} - u_t &\leq U_t, && t \in \mathcal{T} && \text{(3.4c)}\\
u_t - u_{t-1} &\leq a^{\mathrm{up}}, && t \in \mathcal{T} && \text{(3.4d)}\\
u_{t-1} - u_t &\leq a^{\mathrm{down}}, && t \in \mathcal{T}. && \text{(3.4e)}
\end{aligned}
$$

These constraints allow the model to penalize rapid production changes while enforcing technical ramping limits.

3.3 Market Participation Constraints

Operational staffing limitations during night hours may restrict the ability to manage quick production changes actively. Let the set of active hours where there is personnel working to be $\mathcal{T}^{\mathrm{active}}$. However, participation in the spot market is always maintained due to its predictable structure and the company's ability to plan operations. Participation in markets is further restricted due to which production units are certified or technically compatible, let the set of such markets be denoted $\mathcal{M}^{\mathrm{active}}$. Obtaining approval involves a cost and time-intensive certification process, making it a significant investment for DH companies. Finally, even with optimization support, the complexity of managing multiple markets with different bid types in parallel may exceed human operational capacity. Due to these circumstances, we include the constraints

$$
\begin{aligned}
x_{m,t} &= 0, && t \in \mathcal{T} \setminus \mathcal{T}^{\text{active}}, m \in \mathcal{M}^{\text{FCR}} \cup \mathcal{M}^{\text{FRR}}, && \text{(3.5a)}\\
{}^{\text{h}}x_{m,t} &= 0, && t \in \mathcal{T} \setminus \mathcal{T}^{\text{active}}, m \in \mathcal{M}^{\text{mFRR}} \cup \mathcal{M}^{\text{I}}, && \text{(3.5b)}\\
x_{m,t} &= 0, && t \in \mathcal{T}, m \in \mathcal{M} \setminus \mathcal{M}^{\text{active}}, && \text{(3.5c)}\\
{}^{\text{h}}x_{m,t} &= 0, && t \in \mathcal{T}, m \in \mathcal{M} \setminus \mathcal{M}^{\text{active}}, && \text{(3.5d)}
\end{aligned}
$$

which limit the participation to defined time windows and approved markets. The constraints (3.5d) ensure that the model aligns with practical and regulatory realities.

3.4 Initial Condition and Accepted Bids

In each market step $j \in \{1,_l dots, 7\}$, volumes of bids that have already been accepted in previous market steps must be respected to enforce feasibility and reflect commitments already made on markets in previous market steps. The volume of these accepted bids are denoted ${}^{\text{h}}b_{k,t}$ [MWh] for electricity bids and $b_{k,t}$ [MW] for capacity bids, with $k \in \mathcal{K}_j$. The model fixes these volumes to their respective variables, allowing new decisions to be made for variables corresponding to the remaining market steps. Once the day of delivery (D-0) has begun, we define $\bar{t}$ as the current time step and $\bar{\mathcal{T}}_{\bar{t}}$ as the set of time steps already passed on day (D-0). Accepted volumes on the intraday continuous market and the mFRR electricity markets up to time step $\bar{t}$ are fixed. While this has a limited impact on future decisions, it is needed to calculate the total profits and losses accurately. Finally, we define the initial bidding state at time step $t = 0$ to anchor the production schedule for the day according to

$$
\begin{aligned}
x_{k,t} &= b_{k,t}, && t \in \mathcal{T}, k \in \mathcal{K}_j, && \text{(3.6a)}\\
{}^{\text{h}}x_{k,t} &= {}^{\text{h}}b_{k,t}, && t \in \mathcal{T}, k \in \mathcal{K}_j, && \text{(3.6b)}\\
{}^{\text{h}}x_{m,t} &= {}^{\text{h}}b_{m,t}, && t \in \bar{\mathcal{T}}_{\bar{t}}, m \in \mathcal{M}^{\text{IC}} \cup \mathcal{M}^{\text{mFRR}}, && \text{(3.6c)}\\
x_{m,0} &= b_{m,0}, && m \in \mathcal{M}, && \text{(3.6d)}
\end{aligned}
$$

where (3.6a) fixes previously accepted capacity volumes, (3.6b) fixes previously accepted electricity volumes, (3.6c) fixes volumes accepted on continuous markets up to the current time step $\bar{t}$ and (3.6d) sets the initial production state at time step $t = 0$.

3.5 Valuation of Market Participation

To quantify the profitability of bid volumes, we define the value per volume parameters as ${}^{h}v_{m,t}$ [EUR/MWh] for electricity bids and $v_{m,t}$ [EUR/MW] for capacity bids. These parameters depend on predicted prices, production costs, ramping costs, and expected activation levels and durations on balancing markets. Electricity markets are straightforward: the bid value equals the predicted price minus the cost of producing electricity, as no activation uncertainty is involved. The exception is the mFRR electricity down market, where the production cost is instead added, since the bid results in reduced electricity generation. The mFRR capacity market values are based solely on the predicted price, as activation is handled separately by the corresponding mFRR electricity market. The FCR-D up market, includes the ramping up cost, the length of an activation and the ramping down cost. This sum is multiplied by the average activation and subtracted from the predicted price to result in the value of the bid volume. Further, the increased production adds extra production costs based on the length of the activation. The FCR-D down market works analogously, except that the production cost is instead added, as the electricity production is reduced. Other balancing markets also include a term for electricity value, based on the cleared price of the mFRR electricity markets. The FCR-N market, must consider up and down regulation, so both terms are subtracted from the predicted price. The terms are expressed in Table 3.2 with the market steps j. Note that both ${}^{h}v_{m,t}$ and $v_{m,t}$ are in this table depending on whether it is an electricity or ancillary market, respectively.

j	m	**Market**	**Value of bid per volume** ($v_{m,t}$ **or** ${}^{h}v_{m,t}$)
1	0	FCR-D up 1	$p_{0,t} - d_{0,t}(2r + {}^{h}d_{0,t}c)$
	1	FCR-D down 1	$p_{1,t} - d_{1,t}(2r - {}^{h}d_{1,t}c)$
	2	FCR-N 1	$p_{2,t} - d^{\text{up}}_{2,t}(2r + {}^{h}d^{\text{up}}_{2,t}(c - p_{15,t})) - d^{\text{down}}_{2,t}(2r - {}^{h}d^{\text{down}}_{2,t}(c + p_{16,t}))$
2	3	aFRR up	$p_{3,t} - d_{3,t}(2r + {}^{h}d_{3,t}(c - p_{15,t}))$
	4	aFRR down	$p_{4,t} - d_{4,t}(2r - {}^{h}d_{4,t}(c + p_{16,t}))$
	5	mFRR capacity up	$p_{5,t}$
	6	mFRR capacity down	$p_{6,t}$
3	7	Spot	$p_{7,t} - c$
4	8	Intraday 1	$p_{8,t} - c$
5	9	FCR-D up 2	$p_{9,t} - d_{0,t}(2r + {}^{h}d_{0,t}c)$
	10	FCR-D down 2	$p_{10,t} - d_{1,t}(2r - {}^{h}d_{1,t}c)$
	11	FCR-N 2	$p_{11,t} - d^{\text{up}}_{2,t}(2r + {}^{h}d^{\text{up}}_{2,t}(c - p_{15,t})) - d^{\text{down}}_{2,t}(2r - {}^{h}d^{\text{down}}_{2,t}(c + p_{16,t}))$
6	12	Intraday 2	$p_{12,t} - c$
7	13	Intraday 3	$p_{13,t} - c$
	14	Intraday continuous	$p_{14,t} - c$
	15	mFRR electricity up	$p_{15,t} - c$
	16	mFRR electricity down	$p_{16,t} + c$

Table 3.2: Corresponding between market index m and market step j, and definition of the value of a bid per volume unit on market m.

3.6 Optimization Objective Function

Having defined all components, we now formulate the objective function. The objective is to maximize the profit, defined as the total value of accepted bids across all markets and time steps, minus the ramping costs. Production costs are calculated in the valuation of bids, the term is not directly required in the objective function. The objective function in market step j is thus given by

$$z^{j+1} = \sum_{t \in \mathcal{T}} \Bigg(\sum_{m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}} v_{m,t} x_{m,t} + \sum_{m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}} {}^{\mathrm{h}}v_{m,t} \, {}^{\mathrm{h}}x_{m,t} - rU_t \Bigg). \tag{3.7}$$

4

Computational Tests and Results

This chapter outlines the evaluation of our optimization model through computations. We begin by specifying the base scenario, assumptions, and parameter values, followed by an analysis of profit and revenue breakdowns. We then compare the outputs with those of Utilifeed's current model to investigate the accuracy of our model. We conduct a sensitivity analysis on key input variables to understand how the parameters affect the outcome. Finally, we investigate the value of multi-market participation to compare the value of participating in additional markets. This evaluation framework is designed to provide technical validation and practical insights into optimizing market engagement for district heating companies.

4.1 Scenario Setup and Parameter Definitions

The tests were carried out using Gurobi [5] in Python [18] on an ideapad laptop with an Intel(R) Core(TM) i5-7200U CPU @ 2.50GHz processor. All computations made are relatively quick, being done in less than 10 seconds.

This subsection outlines the parameter values and scenario assumptions for simulating market participation. Given the diversity of technical constraints among CHP units, a general CHP setup is used, based on information from Utilifeed. Market prices are taken from publicly available ancillary service datasets [17], while spot market prices—being proprietary—are not disclosed. Table 4.1 summarizes assumed parameter values for the generic CHP scenario; these will differ in each CHP and will be set by each DH company to reflect their operations. Unless otherwise noted, values are fixed across scenarios, with selected parameters further explored in Section 4.3.

Category	Parameter	Value	Unit	Notes
Production cost (c)	Spring	60	EUR/MWh	Fixed by season
	Summer	40	EUR/MWh	Based on 2024 data
	Fall	60	EUR/MWh	
	Winter	80	EUR/MWh	
Ramping	Ramping cost (r)	$0.1 \cdot c$	EUR/MW	
	Upward limit (u^{up})	5	MW	Based on typical
	Downward limit (u^{down})	5	MW	operational flexibility.
Balancing limits	Production limit (l_t^{prodB})	5	MW	
	Consumption limit (l_t^{consB})	5	MW	
Operational constraints	Max production (l_t^{prod})	15	MW	
	Max consumption (l_t^{cons})	0	MW	
Simulation configuration	Time resolution (g)	1	h	Hourly time steps
	Initial state ($b_{m,0}$ and ${}^{\text{h}}b_{m,0}$)	**0**	MW and MWh	No pre-existing bid commitments
Activation assumptions	Expected activation ($d_{m,t}$)	10	%	Fraction of bid expected to activate
	Duration (${}^{\text{h}}d_{m_t}$)	1	h	
Market Participation	Active hours ($\mathcal{T}^{\text{active}}$)	6-20	h	Reflects typical staffing window

Table 4.1: Table of values for parameters for a general CHP.

The computational results are based on monthly data from March, June, September, and December. Each simulation compares participation in the spot market alone with the inclusion of one balancing market. For clarity, we abbreviate the combinations to the balance market seen in Table 4.2.

Abbreviation	Market combination
Spot	Spot
FCR-D down	Spot + FCR-D down
FCR-N	Spot + FCR-N
mFRR up	Spot + mFRR up
mFRR down	Spot + mFRR down

Table 4.2: Abbreviations for each combination of markets.

4.2 Profit Composition Analysis

This section breaks down the profit and revenue composition using the values in Table 4.1 for the market participation combinations defined in Table 4.2.

4.2.1 Profit Breakdown

The breakdown consists of revenue ($p_{m,t}x_{m,t}$ and ${}^{\text{h}}p_{m,t}\,{}^{\text{h}}x_{m,t}$), production costs ($cx_{m,t}$ and $c\,{}^{h}x_{m,t}$), ramping costs (rU_t), balancing gains ($v_{m,t}x_{m,t} - p_{m,t}x_{m,t}$ and ${}^{\text{h}}v_{m,t}\,{}^{\text{h}}x_{m,t} - {}^{\text{h}}p_{m,t}\,{}^{\text{h}}x_{m,t}$), and profit. With balancing gains being defined as the money saved and gained from activation on balancing markets. Profit is calculated by adding revenue and balancing gain, then subtracting production and ramping costs.

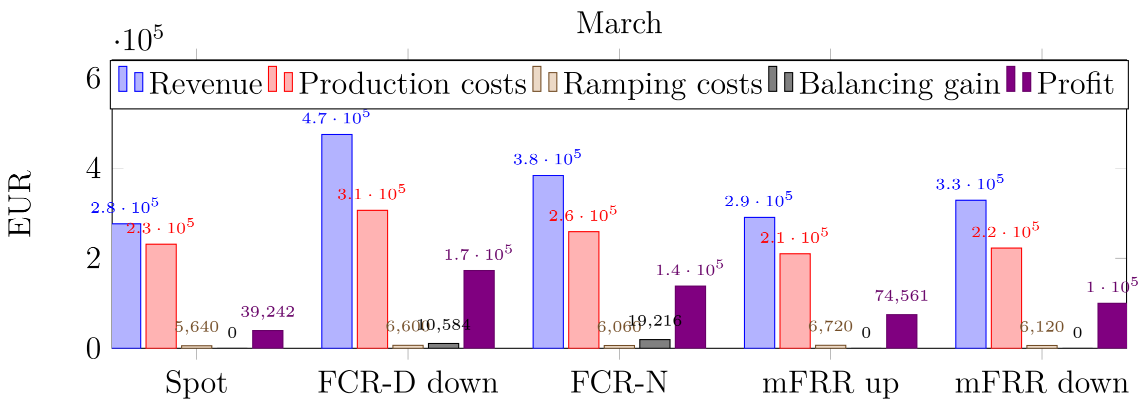

Figure 4.1: Breakdown of revenue, production costs, ramping costs, balancing gain and profit per combination of markets in Table 4.2 for March.

The results for the March case shows a clear increase in profit from participation in all of the studied market combinations as to compared to only spot participation. The most substantial improvement occurs when participating in the FCR-D down market, yielding more than four times the profit as compared to the spot market alone. This increase stems from the higher compensation for balancing in this month, while ramping and production costs remain manageable.

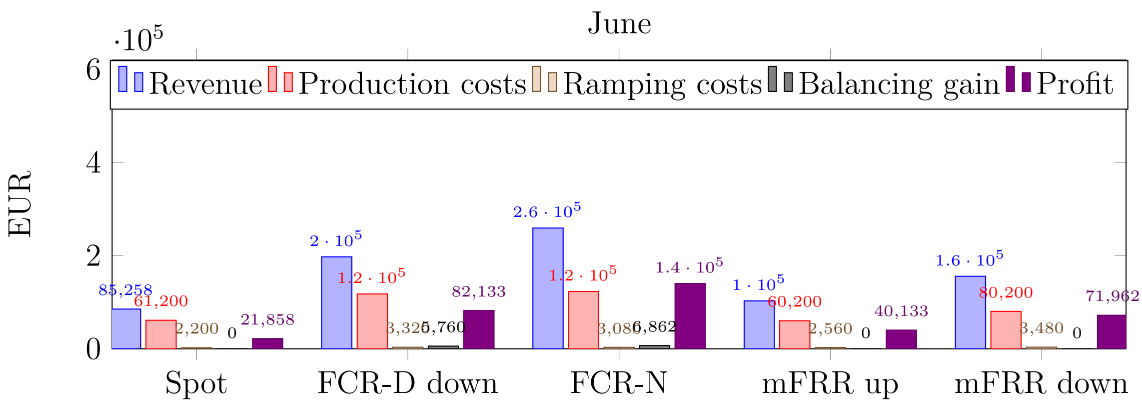

Figure 4.2: Breakdown of revenue, production costs, ramping costs, balancing gain and profit per combination of markets in Table 4.2 for June.

The results for the June case has lower profits and revenues overall, reflecting the reduced electricity consumption during the summer and the generally lower electricity prices. Nevertheless, participation in the FCR-N market increases the profit by almost seven times as compared to only being on the spot market. Although the absolute gains are smaller than in March, the relative gains are still significant.

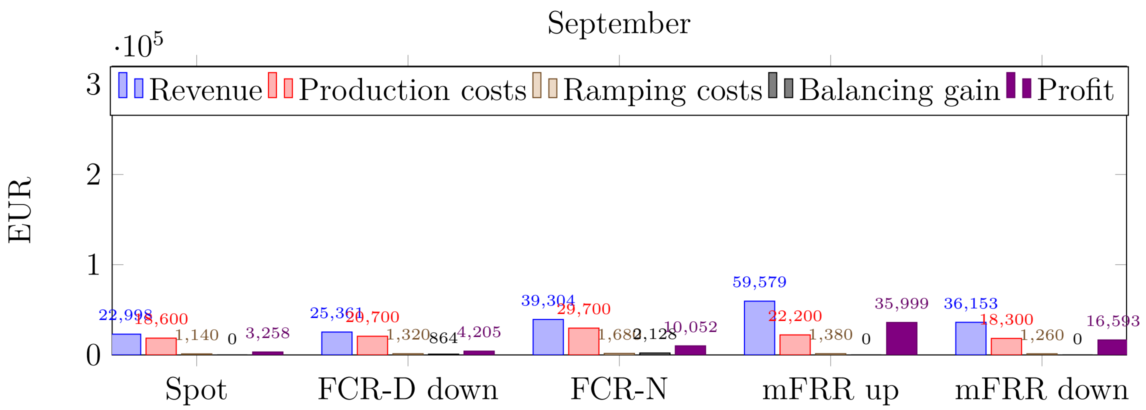

Figure 4.3: Breakdown of revenue, production costs, ramping costs, balancing gain and profit per combination of markets in Table 4.2 for September.

The results for the September case is the least profitable month overall. This is likely due to the low electricity price and possibly an overestimation of production costs within the model. Despite low figures, participation in the mFRR up market yields an increase of profits by eleven times as compared to the spot market alone. While this figure is impressive in relative terms, the actual number remains modest. Since the numbers are comparatively low in September, only relevant results will be displayed and analyzed in the coming sections.

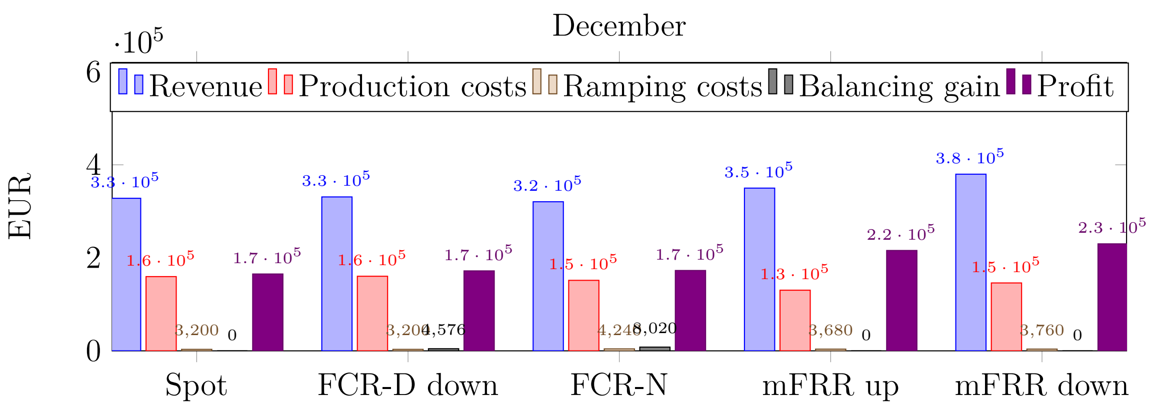

Figure 4.4: Breakdown of revenue, production costs, ramping costs, balancing gain and profit per combination of markets in Table 4.2 for December.

The results for the December case has the highest electricity prices due to high demand, making it the most lucrative month. Participation in the mFRR down market gives the highest increase, with profits increasing with 35%.

In all, participation in balancing market improves profitability in every month examined. Each of the investigated balancing markets emerges as the most profitable in one scenario each, highlighting the importance of multi-market participation over the year.

4.2.2 Revenue by Market Segment

This segment breaks down where the revenue stems from by dividing it into three categories: spot, capacity, and electricity. All four investigated markets are capacity markets with mFRR up and down additionally having an electricity market which is defined as the category electricity.

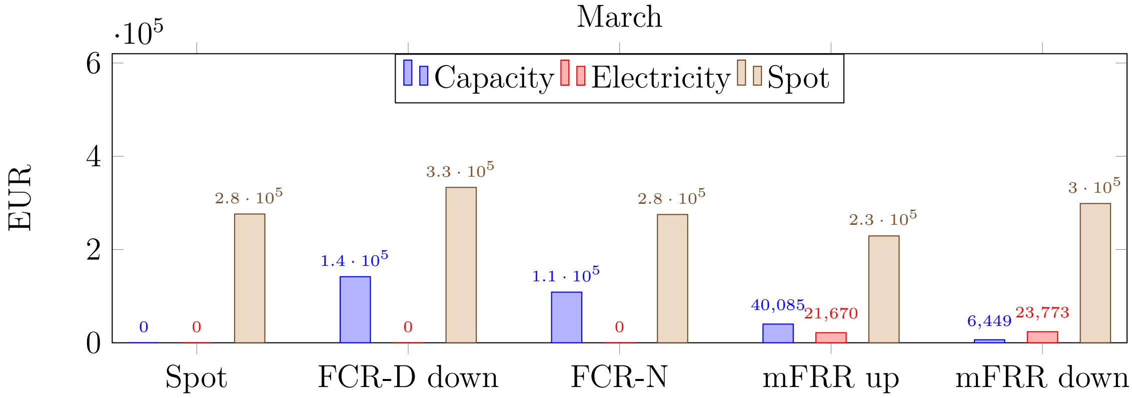

Figure 4.5: Breakdown of revenue by capacity, electricity, and the spot market for each market combination for the March case.

The March case shows an increase in revenue from the spot market when also taking part in the FCR-D down and mFRR down markets as compared to the spot market alone. This is likely because electricity production alone is unprofitable, but it is profitable to offer capacity simultaneously as there is a revenue from offering capacity and a saving from reducing production.

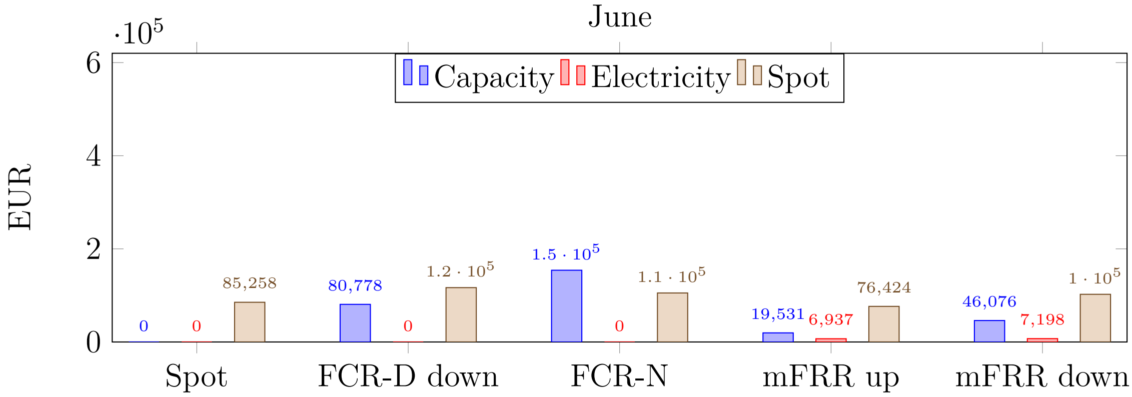

Figure 4.6: Breakdown of revenue by capacity, electricity, and the spot market for each market combination for the June case.

The June case shows a substantial increase in revenue from the FCR-N market as to compared to the spot market alone, which in this case exceeds that of the spot market. The increase from the FCR-D market is also significant, showing a similar trend where there is an increase in revenue from the spot market while participating in a downregulatory market, which was observed in Section 4.2.1.

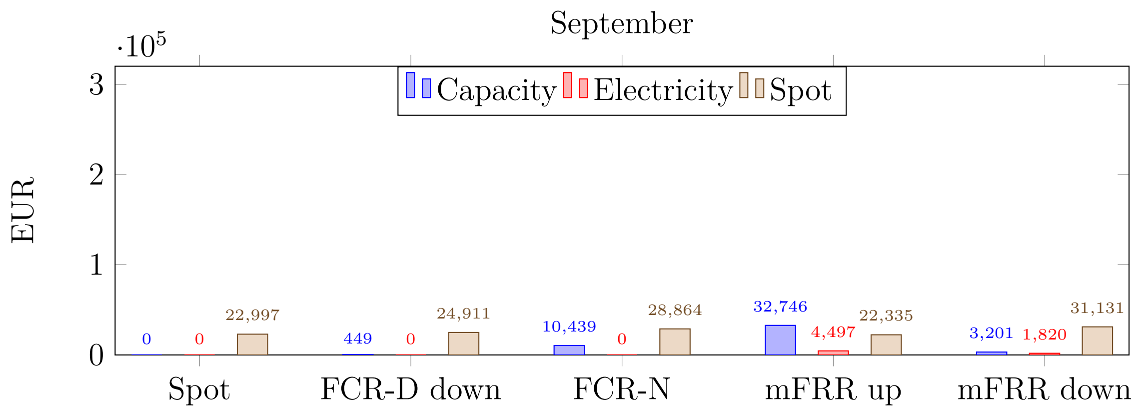

Figure 4.7: Breakdown of revenue by capacity, electricity, and the spot market for each market combination for the September case.

The September case shows a marginal change in revenue from the spot market revenue compared to scenarios with participating in a balancing market. However, participation in the mFRR up market shows a notable increase, making it the most profitable market.

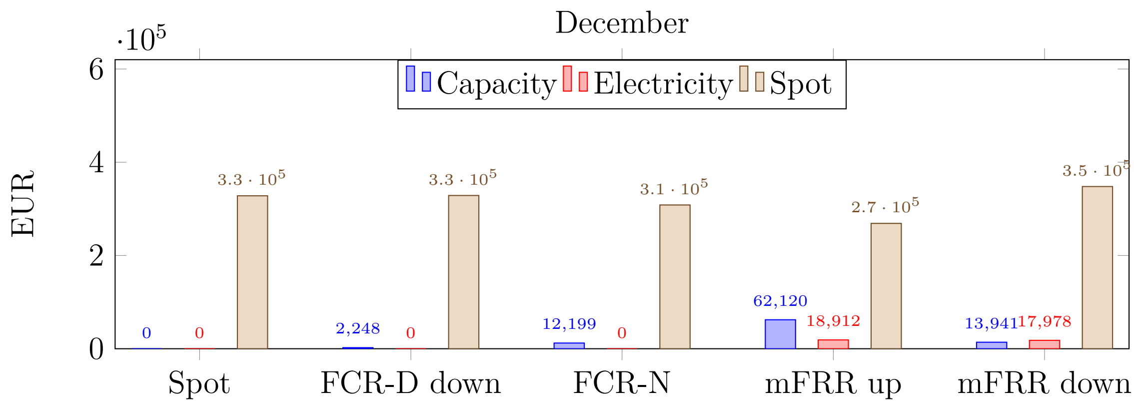

Figure 4.8: Breakdown of revenue by capacity, electricity, and the spot market for each market combination for the December case.

The December case is characterized by high spot market revenues across all scenarios due to high energy demand. Although the revenue from the mFRR up market is the greatest, it is associated with a decrease in the spot market revenue. In contrast, the increase in revenue from the spot market when participating in the mFRR down market is the greatest, making it the most profitable combination.

Overall, participation in balancing markets changes the bidding on the spot market, significantly affecting the total revenue. While balance markets show an increase in revenue and profit, the spot market remains the primary revenue source and continues being the cornerstone in electricity market participation.

4.2.3 Comparison with Utilifeed Baseline

To validate the model developed in this thesis, we compare its results with Utilifeed's existing model, which is limited to spot market participation for selling electricity. However, it also models the heat demand and multiple heat generation sources, making it more comprehensive than this thesis' model. Simulations are conducted using historical data over the same months, enabling a direct comparison of production volumes and revenue outcomes. One key difference is that Utilifeed's model uses a dynamic, data-driven operational cost based on heat generation and system configuration, while this thesis' model uses a fixed operational cost. This simplification significantly impacts comparability, as operational costs vary considerably across different heat-generating units. For instance, in March and December, Utilifeed's model activate a third heat production unit during two separate periods spaced a few days apart. Since the starting costs exceed those of operating at minimum load for the few days, the unit remains active even when not strictly necessary to fulfill the heat demand. In this case, the CHP produces electricity to reduce losses, even if the marginal price exceeds the selling price. This explains why Utilifeed's model produces more electricity and has a higher revenue, but is relatively close to this thesis model's result in March and December, as shown in Table 4.3 and visualized in Figure 4.9 and 4.10. In June and September, there is only a CHP running, however, the usage of an accumulator tank produces unstable operational costs. This results in a more profitable operational strategy for Utilifeed, as heat production can be made during lower demand periods, and electricity can be sold continuously throughout the month due to the low net operational cost. This highlights how the assumptions of externally managed heat production and fixed production costs influence our model's performance. Nonetheless, a consistently higher available capacity increases opportunities for electricity and capacity market participation. This is true for all possible market combinations in our model, as the comparative results stay relevant. This supports this model's robustness and demonstrates its practical value when integrated with Utilifeed's existing model.

Production cost (EUR/MWh)	Month	Revenue from Utilifeed's model (k EUR)	Revenue from our model (k EUR)	Production from Utilifeed's model (GWh)	Production from our model (GWh)
40.68	March	594	501	9.83	8.18
32.31	June	262	151	7.56	3.41
27.33	September	137	70	4.76	1.43
39.68	December	521	449	5.44	4.21

Table 4.3: Breakdown of revenue from the spot market and production of electricity between Utilifeed's model and our model in the four month cases.

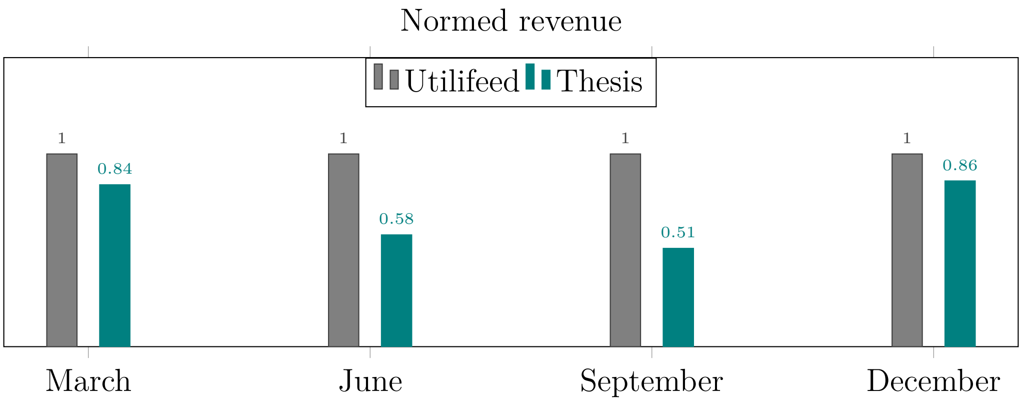

Figure 4.9: Normed revenue values with Utilifeed as base.

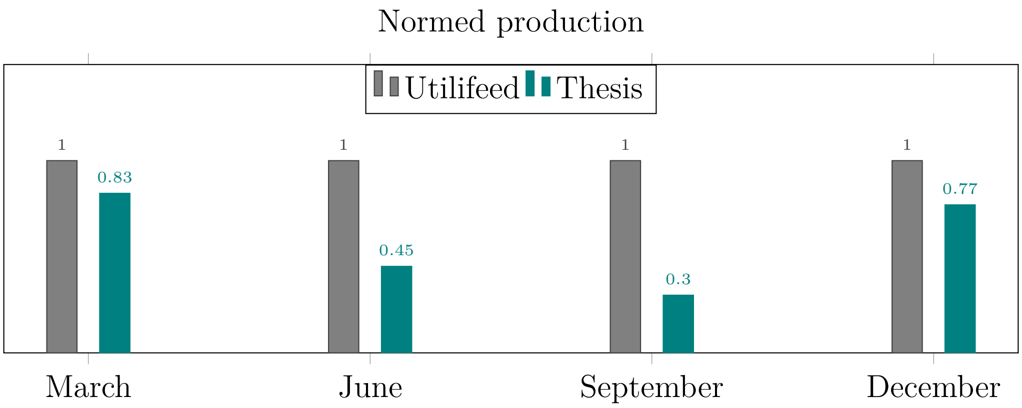

Figure 4.10: Normed electricity production with Utilifeed as base.

4.3 Sensitivity Analysis

This section analyzes how the change in production cost and average activation of the balance markets affect the profits.

4.3.1 Production Cost Variation

We analyze the effect of changing the production cost by varying it by 20 EUR/MWh in both directions. In Figure 4.11 the center-most column in each heatmap represents the base-case values (which are used for the results presented in Section 4.2).

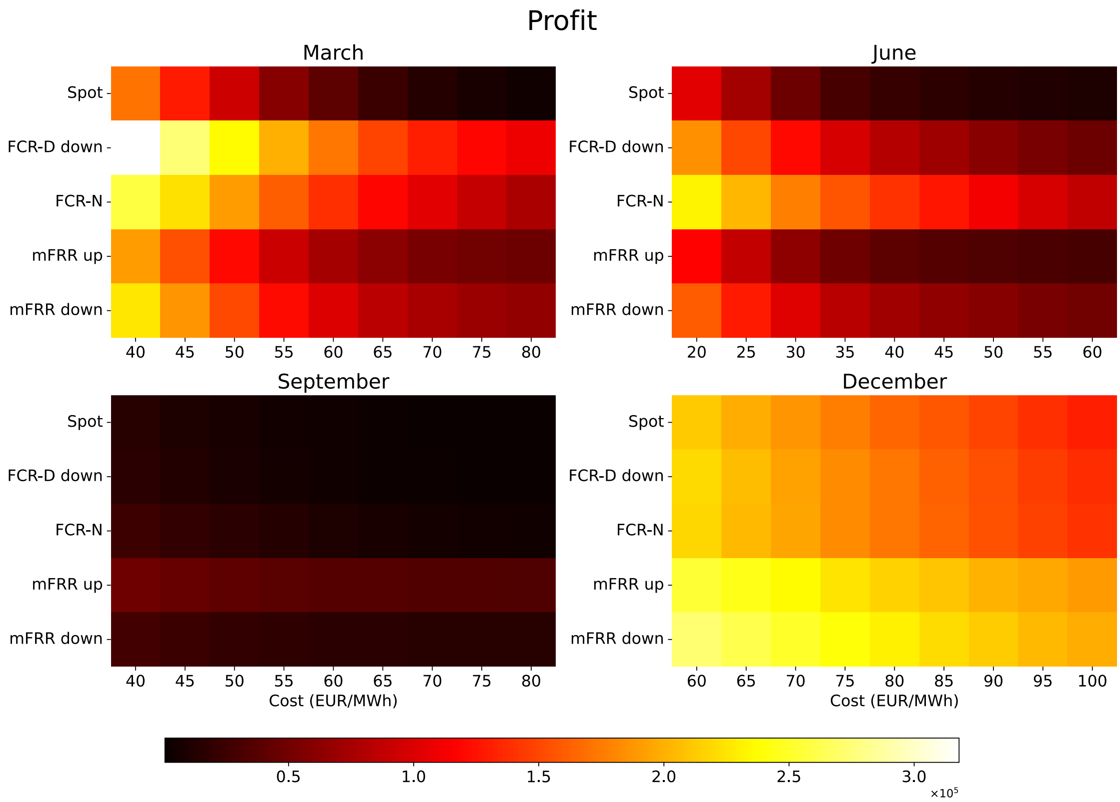

Figure 4.11: Heat map for profits (EUR) for all months with varying production costs.

The March case displays a wide range of profits when comparing the extremes. This is likely due to the average compensation for electricity production falling within the tested range of production costs. Comparing the most profitable market, FCR-D down, with the spot market, the differences of the maximum and minimum production cost scenarios remain relatively small. This indicates that the compensation for the FCR-D down market remains relatively stable, even when doubling the production cost.

The June case has less variation in profit between the highest and lowest profit. It also shows overall smaller profit changes between different production costs. A similar pattern to FCR-D down in March is seen in June for FCR-N, where the largest change in profit seems to originate from the spot market rather than the balancing market as the change in profit is similar across all tested market combinations.

The September case appears largely unaffected by changes in production cost, as profits remain nearly constant across all configurations. This mitigates concerns about the potentially overestimated production price mentioned in Section 4.2.1. It reinforces the result from Utilifeed's model, which showed a similarly low revenue in September.

The December case generates the highest overall profits, with minimal differences between the low and high production cost scenarios. The high revenue from the spot market decrease the impact of the change in production cost and the impact of the ancillary markets, as shown in Figure 4.8.

To summarize, the trends regarding the decrease in profits from increased production costs are consistent across all four month cases, strengthening the model's reliability. A uniform decrease in profit with increasing production cost across scenarios, aligning with theoretical expectations. We see wider ranges in March and June, indicating that the average compensation falls within the tested range. While September and December have more uniform profits throughout the tested intervals of production costs, indicating that the average compensation falls outside the tested range. This highlights the importance of lowering production costs during March and June, since the net gain is notable. In September, a large reduction in production cost is needed to increase profits, possibly outweighing the benefits gained. December shows little change in profit, indicating that the value of lowering production costs is less impactful, although profitable. Finally, the absence of outliers further supports the model's stability under varying input conditions.

4.3.2 Balance Volume Activation Levels

This subsection analyzes how the change in average activation affects the profit composition, using the same categories, Balancing gain and profit, as in Section 4.2.1. Since the average activation is a parameter in this model, it will affect the behavior in bid strategies. Only the FCR and aFRR markets are affected by this parameter, since these markets have uncertainty about activation. All other markets gives a production plan ahead of delivery.

4.3.2.1 FCR-D down

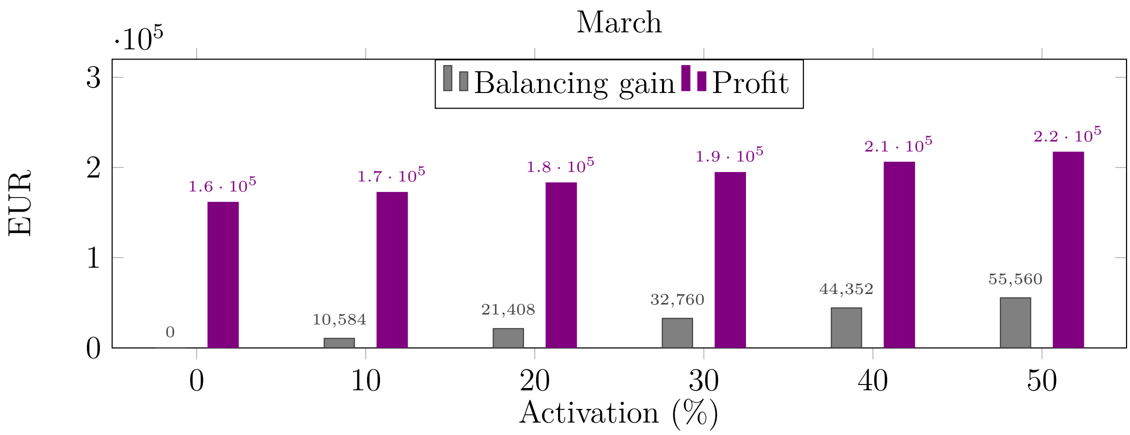

Figure 4.12: Breakdown of balancing gain and profit for different percentual activations of the FCR-D down market for the March case.

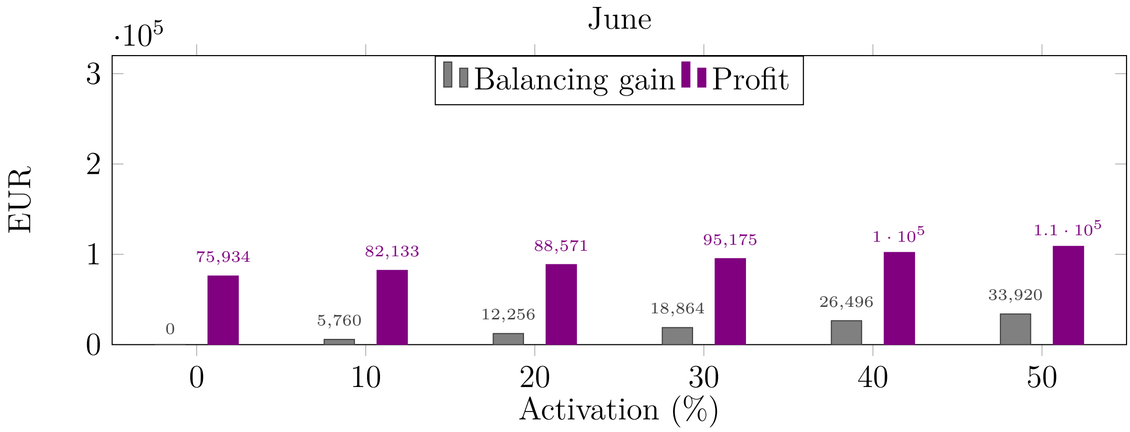

Figure 4.13: Breakdown of balancing gain and profit for different percentual activations of the FCR-D down market for the June case.

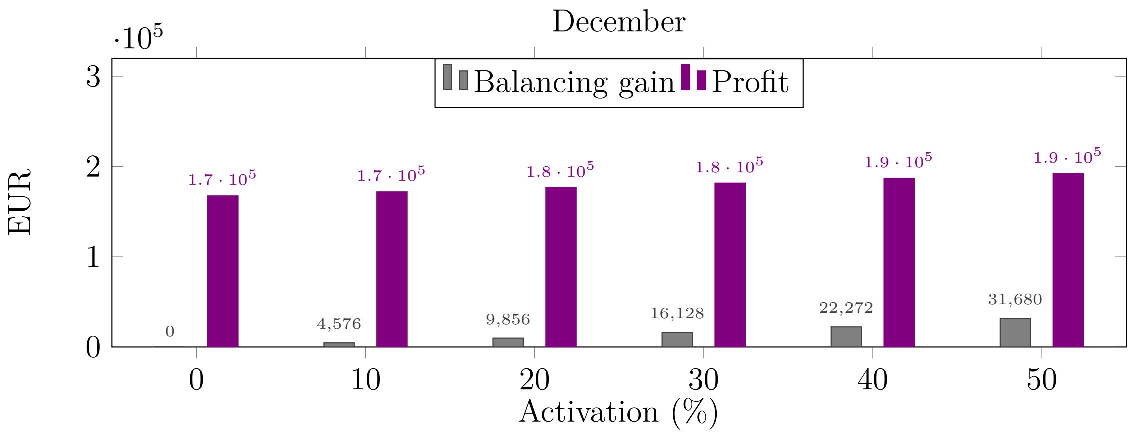

Figure 4.14: Breakdown of balancing gain and profit for different percentual activations of the FCR-D down market for the December case.

Participating in the FCR-D down proves beneficial in all tested month cases shown in Figure 4.12, 4.13, and 4.14 as increased activation lowers production, which reduces costs, while maintaining revenue levels. The increase in percentual activation results in higher revenue, as there are more profitable opportunities to sell on the spot market and regulate down on the balancing market. This aligns with theoretical assumptions, since the company frequently gets paid for electricity not produced.

4.3.2.2 FCR-N

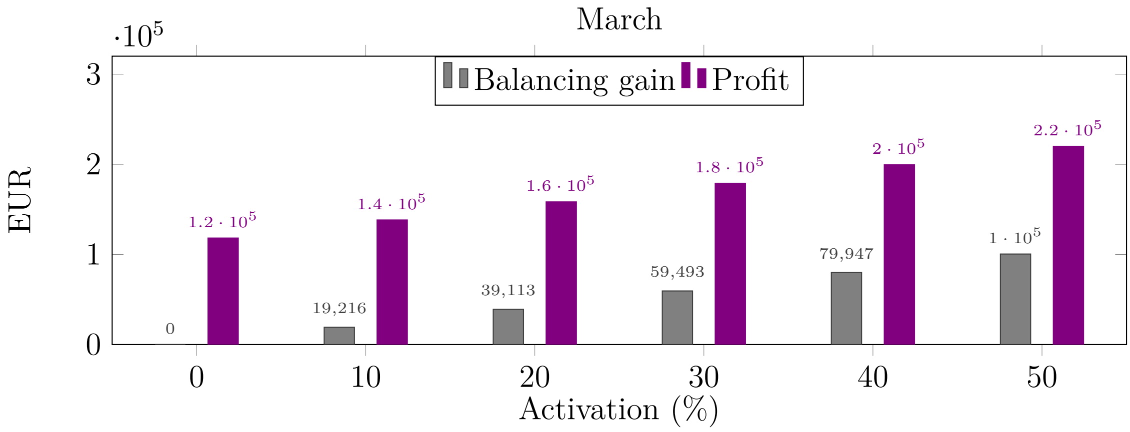

Figure 4.15: Breakdown of balancing gain and profit with different percentual activations on the FCR-N market for the March case.

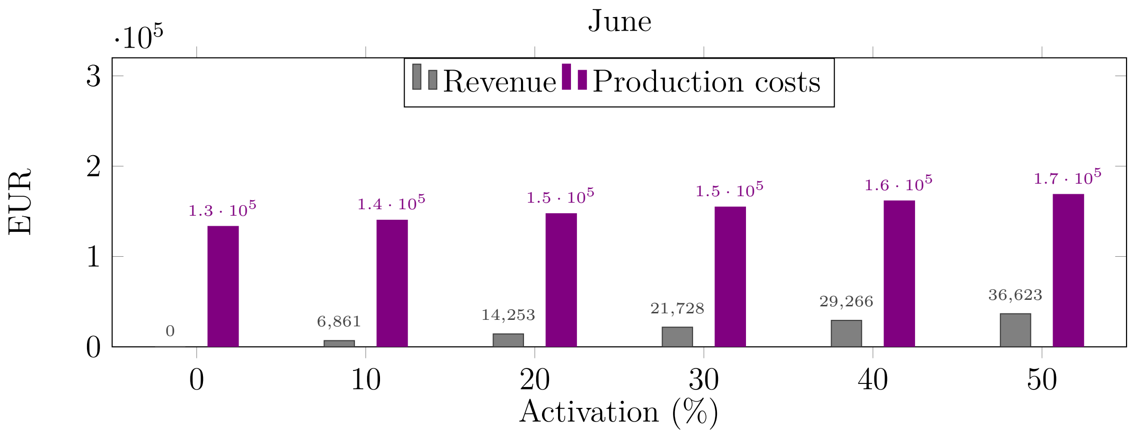

Figure 4.16: Breakdown of balancing gain and profit with different percentual activations on the FCR-N market for the June case.

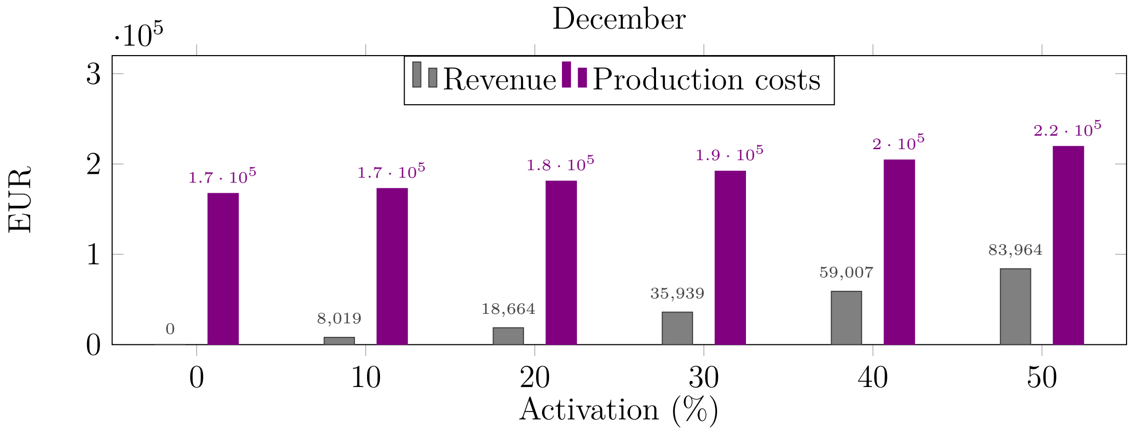

Figure 4.17: Breakdown of balancing gain and profit with different percentual activations on the FCR-N market for the December case.

Electricity regulation on the FCR-N market is compensated by the clearing prices of the mFRR electricity markets. This means that bid strategies involving higher activations in both directions tend to increase profitability as shown in Figure 4.15, 4.16, and 4.17. Since FCR-N regulates both up and down, with the average activation in both directions being equal, based on the assumptions, the net gain from saving production cost is zero, with a net negative cost from the ramping. However, mFRR market prices often exceed the ramping costs assumed here, thereby increasing the profitability of regulation in both directions. The trends are consistent across all months, with both revenue and production costs remaining relatively stable across varying activation percentages. The increase in profit stems from the comparatively large balancing gain.

To summarize, a significant benefit follows from higher activation of both FCR-D down and FCR-N. Notably, the model yields an increased profit compared to the spot market, even at zero percent activation, indicating that the worst-case scenario remains profitable, with any activation beyond zero only increasing profitability. Since historical average activation data is unavailable, each DH company must independently track activation patterns to improve their bid strategies.

4.4 Effect of Multi-Market Participation

This section examines the impact of the number of markets included on the resulting optimal revenue and profit, and identifies the market additions that yield the greatest benefit for each month case. We use the model to compute which additions of markets that yield the largest profit, by constraining the allowed number if markets included beyond the spot market. Since the markets are not necessarily included in the same order for different month cases, Figures 4.18, 4.19, 4.20, and 4.21 illustrate the revenue and profit as functions of the maximum allowed number of included additional markets. The markets included and their order are listed in Table 4.4.

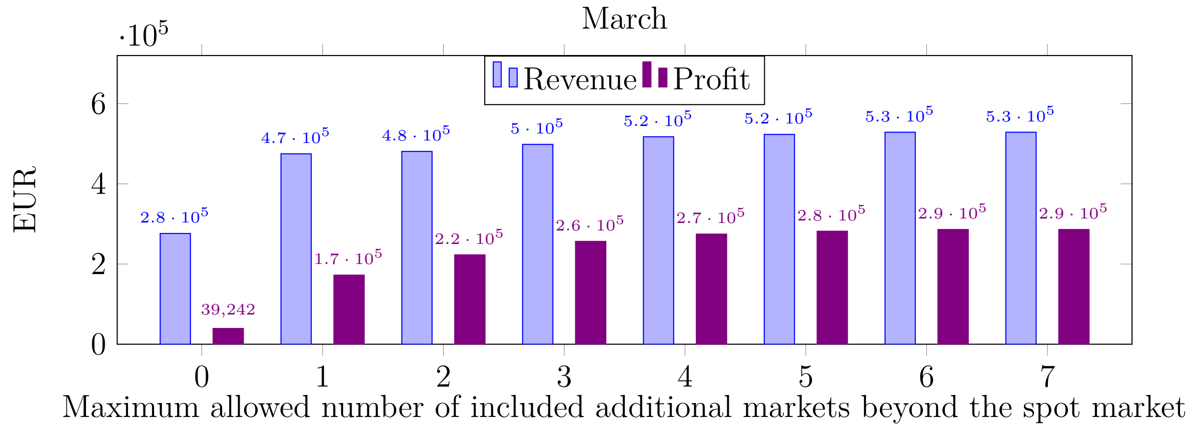

Figure 4.18: Breakdown of the revenue and profit for upper limits of the numbers of additionally added markets in the March case, with the order of inclusion of markets are shown in Table 4.4.

The March case shows a substantial profit increase for each added market up to three markets. Although additional markets continue to show incremental profits, the associated operational complexity may outweigh the financial benefits. The addition of the FCR-D down market, displayed in Table 4.4 increases the revenue from the spot market, shown in Table B.1. The addition of FCR-N increases revenue slightly and significantly lowers revenue from the spot market which in turn lowers total production costs, resulting in a notable profit gain. This trend continues with each increase of allowed number of markets, but the differences diminish quickly after the third added market.

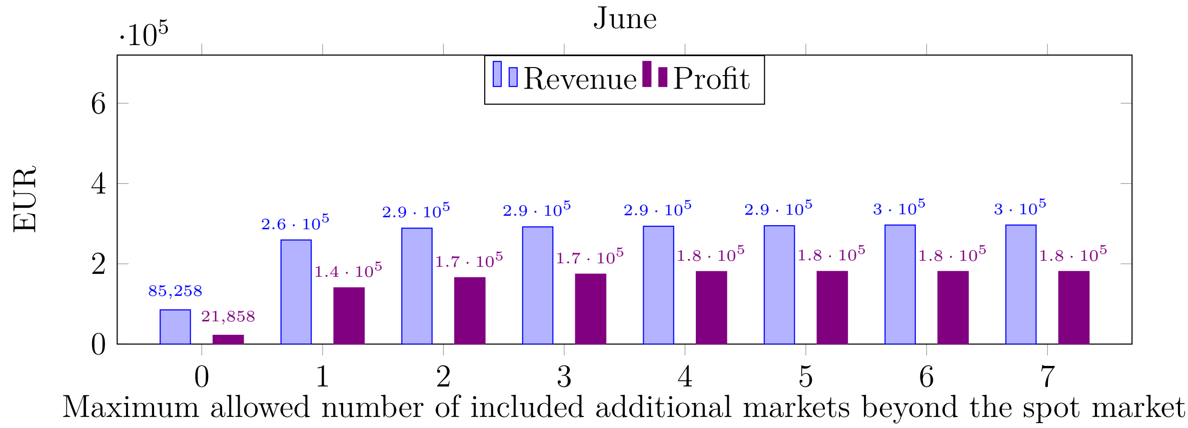

Figure 4.19: Breakdown of the revenue and profit for upper limits of the numbers of additionally added markets in the June case, with the order of inclusion of markets are shown in Table 4.4.

The June case follows a pattern similar to that of March, though the significant increase of benefits diminish after the second market. Here, the first market added is the FCR-N, and the second one is FCR-D, the same two added first in March, but the other way around. This strengthens the market selection strategy used in this thesis, confirming its significant impact on profitability.

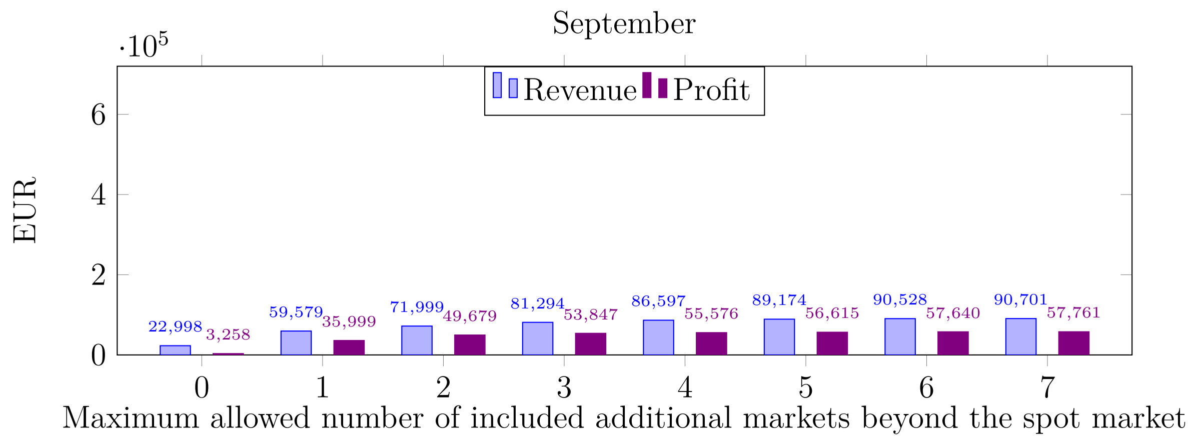

Figure 4.20: Breakdown of the revenue and profit for upper limits of the numbers of additionally added markets in the September case, with the order of inclusion of markets are shown in Table 4.4.

The September case maintains the general trend, where the first two added markets resulted in significant profit increases. However, the first two markets added here are mFRR up and mFRR down, showing the relevance of analyzing these two in addition to the FCR markets.

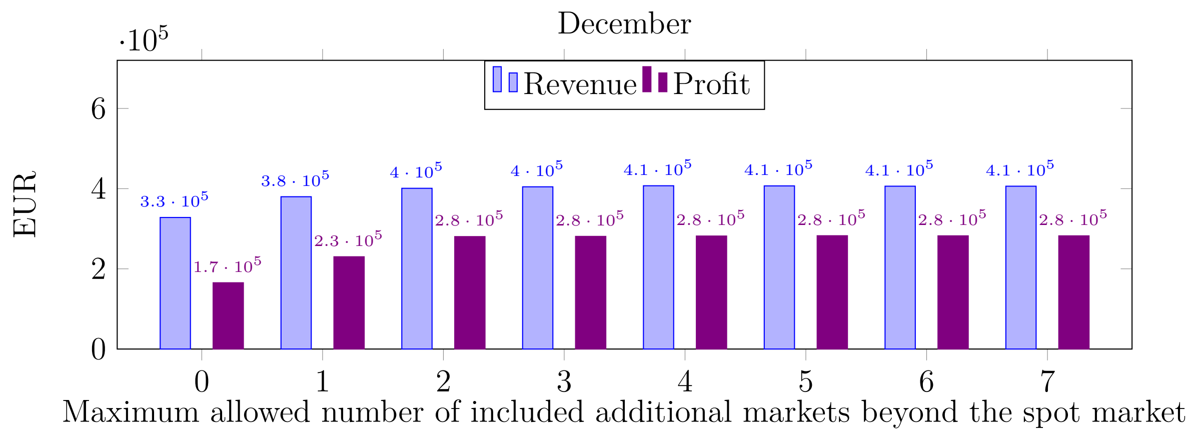

Figure 4.21: Breakdown of the revenue and profit for upper limits of the numbers of additionally added markets in the December case, with the order of inclusion of markets are shown in Table 4.4.

The December case exhibits a similar trend, with the increase in profitability stopping after two markets. There is a significant increase in revenue and a significant decrease in production cost. The mFRR down market is added first, with the mFRR up market added afterwards, further reinforcing their relevance to the analysis.

To summarize, there is a different market that is the most profitable each month, furthering the importance of multi-market participation. Since activation levels are assumed to be low, the balancing gains component remains insignificant in each scenario. Table 4.4 shows a trend with mFRR down and FCR-N being closest to the top, followed by mFRR up, FCR-D down, and then the remaining markets. This order does not account for profit increases, as FCR-D down is the most beneficial by a significant margin in March, as illustrated in Figure 4.1. Additionally, September consistently yields the lowest profits, reducing the impact of the order in which markets are added for this month case.

#	**March**	**June**	**September**	**December**
1	FCR-D down	FCR-N	mFRR up	mFRR down
2	FCR-N	FCR-D down	mFRR down	mFRR up
3	mFRR down	mFRR down	FCR-N	FCR-N
4	mFRR up	mFRR up	aFRR down	aFRR up
5	FCR-D up	FCR-D up	FCR-D up	FCR-D down
6	aFRR down	aFRR down	aFRR up	FCR-D up
7	aFRR up	aFRR up	FCR-D down	aFRR down

Table 4.4: Order of market additions by month case.

A detailed composition of market revenues is represented found in Table B.1, where we notice that the addition of a seventh market in the March and June case does not change the distribution of bid volumes.

Month	Max amount of markets	FCR-D up 1	FCR-D down 1	FCR-N 1	aFRR up	aFRR down	mFRR cap up	mFRR cap down	Spot	FCR-D up 2	FCR-D down 2	FCR-N 2	mFRR el up	mFRR el down
March	0	0	0	0	0	0	0	0	276181	0	0	0	0	0
March	1	0	19981	0	0	0	0	0	333202	0	121736	0	0	0
March	2	0	5846	48058	0	0	0	0	286535	0	109502	30909	0	0
March	3	0	4477	35240	0	0	0	1968	300026	0	105290	28590	0	22817
March	4	0	8026	20611	0	0	29829	1968	284777	0	106774	27559	15106	22817
March	5	3046	8488	18458	0	0	26805	1968	281609	12885	107193	27434	12516	22817
March	6	3136	6502	16846	0	6658	27674	1968	283265	12885	106870	27209	12861	22817
March	7	3136	6502	16846	0	6658	27674	1968	283265	12885	106870	27209	12861	22817
June	0	0	0	0	0	0	0	0	85258	0	0	0	0	0
June	1	0	0	102783	0	0	0	0	105245	0	0	51302	0	0
June	2	0	4817	81812	0	0	0	0	110999	0	40486	50652	0	0
June	3	0	2181	65238	0	0	0	13922	115933	0	39656	48959	0	6068
June	4	0	3811	55187	0	0	10787	15636	111428	0	41356	47563	915	6838
June	5	2811	4311	52453	0	0	9866	17891	111615	2230	41546	44611	710	6838
June	6	2855	3987	47876	0	5102	10205	16733	113085	2325	41486	44611	1422	6838
June	7	2855	3987	47876	0	5102	10205	16733	113085	2325	41486	44611	1422	6838
September	0	0	0	0	0	0	0	0	22997	0	0	0	0	0
September	1	0	0	0	0	0	32746	0	22335	0	0	0	4497	0
September	2	0	0	0	0	0	32729	3196	29755	0	0	0	4497	1820
September	3	0	0	1922	0	0	31580	3037	32686	0	0	6064	4172	1830
September	4	0	0	742	0	2872	32184	3011	35296	0	0	5964	4694	1830
September	5	368	0	641	0	2872	30767	3011	35035	3988	0	5964	4694	1830
September	6	368	0	641	1860	3122	30271	3011	35224	3813	0	5964	4419	1830
September	7	368	13	541	1860	3122	30271	3011	35224	4073	0	5964	4419	1830
December	0	0	0	0	0	0	0	0	328035	0	0	0	0	0
December	1	0	0	0	0	0	0	13941	347903	0	0	0	0	17978
December	2	0	0	0	0	0	61679	13856	288389	0	0	0	18912	17978
December	3	0	0	2336	0	0	59701	12506	291618	0	0	1495	18912	17978
December	4	0	0	2336	3928	0	58450	12601	291618	0	0	1355	18912	17978
December	5	0	630	2276	4083	0	58618	11446	291618	0	183	1116	18912	17978
December	6	176	630	2276	4083	0	58460	11446	290561	250	183	1116	18912	17978
December	7	176	630	2276	4143	73	58460	11446	290561	250	183	971	18912	17978

Table 4.5: Breakdown of revenue per market with different numbers of markets for each month ranging from zero to seven ancillary markets.

5
Conclusions and Further Work

This chapter summarizes and concludes the results, also indicating what can be done to further improve this work.

5.1 Recap of Objective and Motivation

This thesis has developed an optimization model that supports DH companies in making more strategic bidding decisions across multiple electricity markets—spot, intraday, and ancillary markets—to maximize profit and operational efficiency. In response to the increasing complexity of multi-market participation, the model offers a systematic optimization approach.

5.2 Summary of Developed Model

We have used MILP theory to formulate a model that integrates production/consumption constraints, ramping behavior, market rules, and valuation logic for each market. The model integrates operational and market constraints through a modular, parameterized structure, allowing any DH company to integrate the model into their current operations. While the model currently implements basic price forecasts, its structure allows for improved accuracy with enhanced forecasting integration in future versions. Incorporating expected activation levels proved crucial as explicited in Section 4.3.2, influencing bid valuation and bidding strategies.

5.3 Key Computational Findings

Computations demonstrated consistent profitability improvements across all investigated month cases and scenarios, with profit improvements ranging from 35% to 1100%. For the lowest relative level of improvement (35%), the model generated a monthly net gain in profits of approximately 60.000 EUR. We found that there is not one single best market to include, but rather, each of the four tested markets showed to be the most profitable in one month case each. There are eight more months to test to see which ones perform the best in each. In every month case tested, the most profitable order of adding markets to trade on was different. However, beyond two added ancillary markets, profitability gains diminished, suggesting a practical cap on simultaneous market participation. This shows that DH companies should qualify their CHPs for all relevant markets to be able to participate in the most profitable markets each month.

The sensitivity analysis with respect to production costs and average activation levels shows a stable change in results, suggesting that the parameter values should not be cherry-picked to produce the best results possible. Analyzing the participation in the FCR markets, showing the benefits even during worst-case scenarios, strengthens the importance of multi-market participation.

5.4 Comparison with Utilifeed's Baseline

To further reinforce the practical viability of our model, we compared it with Utilifeed's proven model. This comparison highlighted the simplifications' impact on outcomes and model accuracy. While the deviations were explainable, accurately quantifying them would require an extensive system-level integration, beyond this thesis' scope. The next step would be to implement our model with Utilifeed's model to compare the differences, as all other factors would remain constant. Such an implementation should build on the existing tools by enhancing Utilifeed's capabilities with optimized multi-market participation.

5.5 Practical Implications for DH companies

Our developed model can guide DH companies in expanding their operations into multi-market participation. The model helps navigate the market complexity through heavy parameterization, ensuring alignment between operational and market constraints, minimizing the risk of real-world infeasibility. Before launching this model into production, integration with relevant testing must be done to validate the model. However, the simplified modeling assumptions yield useful strategic insights, connecting how the coordination of capacity and electricity bids enhances profitability.

5.6 Limitations and Future Work

Collecting the thoughts for future work, incorporating the intraday market, unlocks more markets to potentially participate in. Implementing heat demand, heat boilers, and an accumulator tank will produce results that simulate reality closely. This integration should leverage Utilifeed's proven model to enhance realism and accuracy. We focused the analysis on the geographical zone SE3, as prices and capacities vary throughout Sweden and other countries; more in-depth testing in other regions needs to be done to show its full capacity. Lastly, while bid placement strategies were not modeled due to limitations and company-specific variation, future work could explore stochastic or risk-based formulations to reflect real-world bidding behavior.

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A

Appendix A

Sets & Indices

$\mathcal{T}$	t	Set of time steps for a 24 hours period
$\mathcal{T}^{\text{active}}$	t	Set of time steps to participate in balance markets
$\bar{\mathcal{T}}_{\bar{t}}$	t	Set of time steps occurred at time $\bar{t}$ (D-0)
$\mathcal{M}^{\text{S}}$	s	Set of the spot market
$\mathcal{M}^{\text{I}}$	i	Set of the intraday markets
$\mathcal{M}^{\text{IC}}$	i	Set of the intraday continuous market
$\mathcal{M}^{\text{prod}}$	p	Set of balancing production capacity markets except mFRR
$\mathcal{M}^{\text{cons}}$	c	Set of balancing consumption capacity markets except mFRR
$\mathcal{M}^{\text{FCR}}$	m	Set of all FCR capacity markets
$\mathcal{M}^{\text{FCR}}$	m	Set of all FRR capacity markets
$\mathcal{M}^{\text{mFRR}}$	m	Set of mFRR electricity markets
$\mathcal{M}^{\text{mFRR up}}$	m	Set of the mFRR up markets
$\mathcal{M}^{\text{mFRR down}}$	m	Set of the mFRR down markets
$\mathcal{M}^{\text{active}}$	m	Set of markets participating in
$\mathcal{M}$	m	Set of all markets
$\mathcal{K}_j$	k	Set of market auctions occurred at market step j

Parameters

l_t^{prod}	Upper limit of electric power production at time $t \in \mathcal{T}$ (MW)
l_t^{up}	Upper limit of up regulatory balance capacity at time $t \in \mathcal{T}$ (MW)
l_t^{conc}	Upper limit of electric power consumption at time $t \in \mathcal{T}$ (MW)
l_t^{down}	Upper limit of down regulatory balance capacity at time $t \in \mathcal{T}$ (MW)

$e^{\mathrm{hi}}_{m,t}$	Upper limit for a bid on market $m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}$ at time $t \in \mathcal{T}$ (MW)
${}^{\mathrm{h}}e^{\mathrm{hi}}_{m,t}$	Upper limit for a bid on market $m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{I}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}$ at time $t \in \mathcal{T}$ (MWh)
${}^{\mathrm{h}}c$	Cost of producing electricity (EUR/MWh)
$p_{m,t}$	Predicted price on market $m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}$ at time $t \in \mathcal{T}$ (EUR/MW)
$p_{m,t}$	Predicted price on market $m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{I}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}$ at time $t \in \mathcal{T}$ (EUR/MWh)
r	Cost of changing production (ramping cost) (EUR/MW)
a^{up}	Maximum upward ramping rate from time step to next time step (MW)
a^{down}	Maximum downward ramping rate from time step to next time step (MW)
${}^{\mathrm{h}}d_{m,t}$	Expected length of activation on balancing market $m \in \mathcal{M}^{\mathrm{prod}} \cup \mathcal{M}^{\mathrm{cons}}$ at time $t \in \mathcal{T}$ (h)
$d_{m,t}$	Expected percentage of bid of activation on balancing market $m \in \mathcal{M}^{\mathrm{prod}} \cup \mathcal{M}^{\mathrm{cons}}$ at time $t \in \mathcal{T}$ (%)
$b_{k,t}$	Accepted bid on market $k \in \mathcal{K}_j \cap (\mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}})$ at market step j and time $t \in \mathcal{T}$ (MW)
${}^{\mathrm{h}}b_{k,t}$	Accepted bid on market $k \in \mathcal{K}_j \cap (\mathcal{M}^{\mathrm{S}} \cup \mathcal{I}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}})$ at market step j and time $t \in \mathcal{T}$ (MWh)
$v_{m,t}$	Value of bid on market $m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}$ at time $t \in \mathcal{T}$ (EUR/MW), see table 3.2
${}^{\mathrm{h}}v_{m,t}$	Value of bid on market $m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{I}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}$ at time $t \in \mathcal{T}$ (EUR/MWh), see table 3.2
g	step length (h)
f_m	1 if $m \in \mathcal{M}^{\mathrm{mFRR}} \cap \mathcal{M}^{\mathrm{mFRR\ up}}$ and -1 if $m \in \mathcal{M}^{\mathrm{mFRR}} \cap \mathcal{M}^{\mathrm{mFRR\ down}}$
j	Current market step, see table 3.2
$\bar{t}$	Current time step in (D-0)

Decision variables

$x_{m,t}$	Size of bid on market $m \in \mathcal{M}^{\mathrm{FCR}} \cup \mathcal{M}^{\mathrm{FRR}}$ at time $t \in \mathcal{T}$ (MW)
${}^{\mathrm{h}}x_{m,t}$	Size of bid on market $m \in \mathcal{M}^{\mathrm{S}} \cup \mathcal{M}^{\mathrm{I}} \cup \mathcal{M}^{\mathrm{mFRR}}$ at time $t \in \mathcal{T}$ (MWh)
u_t	Auxiliary variable to help write the model (MW)

U_t Auxiliary that is the size of change between time steps (MW)

Summary of the Complete Model

$$\underset{\boldsymbol{x_{m,t}},\boldsymbol{U_t},\boldsymbol{u_t}}{\text{maximize}} \quad z^{j+1} = \sum_{t\in\mathcal{T}}\Big(\sum_{m\in\mathcal{M}^{\text{FCR}}\cup\mathcal{M}^{\text{FRR}}} v_{m,t}x_{m,t} + \sum_{m\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}\cup\mathcal{M}^{\text{mFRR}}} {}^{\text{h}}v_{m,t}\,{}^{\text{h}}x_{m,t} - rU_t\Big) \tag{A.1}$$

subject to

$$ {}^{\text{h}}x_{m,t} \le {}^{\text{h}}e^{\text{hi}}_{m,t}, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}\cup\mathcal{M}^{\text{mFRR}} \tag{A.2}$$

$$ x_{m,t} \le e^{\text{hi}}_{m,t}, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{FCR}}\cup\mathcal{M}^{\text{FRR}} \tag{A.3}$$

$$ {}^{\text{h}}x_{m,t} + \sum_{p\in\mathcal{M}^{\text{prod}}} gx_{p,t} + \sum_{s\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}} {}^{\text{h}}x_{s,t} \le gl^{\text{prod}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR up}}\cap\mathcal{M}^{\text{mFRR}} \tag{A.4}$$

$$ gx_{m,t} + \sum_{p\in\mathcal{M}^{\text{prod}}} gx_{p,t} + \sum_{s\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}} {}^{\text{h}}x_{s,t} \le gl^{\text{prod}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR up}}\cap\mathcal{M}^{\text{FRR}} \tag{A.5}$$

$$ {}^{\text{h}}x_{m,t} + \sum_{c\in\mathcal{M}^{\text{cons}}} gx_{c,t} - \sum_{s\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}} {}^{\text{h}}x_{s,t} \le gl^{\text{cons}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR down}}\cap\mathcal{M}^{\text{mFRR}} \tag{A.6}$$

$$ gx_{m,t} + \sum_{c\in\mathcal{M}^{\text{cons}}} gx_{c,t} - \sum_{s\in\mathcal{M}^{\text{S}}\cup\mathcal{M}^{\text{I}}} {}^{\text{h}}x_{s,t} \le gl^{\text{cons}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR down}}\cap\mathcal{M}^{\text{FRR}} \tag{A.7}$$

$$ {}^{\text{h}}x_{m,t} + \sum_{p\in\mathcal{M}^{\text{prod}}} gx_{p,t} \le gl^{\text{prodB}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR up}}\cap\mathcal{M}^{\text{mFRR}} \tag{A.8}$$

$$ gx_{m,t} + \sum_{p\in\mathcal{M}^{\text{prod}}} gx_{p,t} \le gl^{\text{prodB}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR up}}\cap\mathcal{M}^{\text{FRR}} \tag{A.9}$$

$$ {}^{\text{h}}x_{m,t} + \sum_{c\in\mathcal{M}^{\text{cons}}} gx_{c,t} \le gl^{\text{consB}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR down}}\cap\mathcal{M}^{\text{mFRR}} \tag{A.10}$$

$$ gx_{m,t} + \sum_{c\in\mathcal{M}^{\text{cons}}} gx_{c,t} \le gl^{\text{consB}}_t, \quad t\in\mathcal{T}, m\in\mathcal{M}^{\text{mFRR down}}\cap\mathcal{M}^{\text{FRR}} \tag{A.11}$$

$$ u_t - u_{t-1} \le U_t, \quad t\in\mathcal{T} \tag{A.12}$$

$$ u_{t-1} - u_t \le U_t, \quad t\in\mathcal{T} \tag{A.13}$$

$$ u_t - u_{t-1} \le a^{\text{up}}, \quad t\in\mathcal{T} \tag{A.14}$$

$$ u_{t-1} - u_t \le a^{\text{down}}, \quad t\in\mathcal{T} \tag{A.15}$$

$$ \sum_{i\in\mathcal{M}^{\text{I}}\cup\mathcal{M}^{\mathcal{S}}} {}^{\text{h}}x_{i,t}g^{-1} + \sum_{m\in\mathcal{M}^{\text{mFRR}}} f_m\,{}^{\text{h}}x_{m,t}g^{-1} = u_t, \quad t\in\mathcal{T} \tag{A.16}$$

$$ x_{m,t} = 0, \quad t\in\mathcal{T}\setminus\mathcal{T}^{\text{active}}, m\in\mathcal{M}^{\text{FCR}}\cup\mathcal{M}^{\text{FRR}} \tag{A.17}$$

$$
\begin{aligned}
{}^{\mathrm{h}}x_{m,t} &= 0, && t \in \mathcal{T} \setminus \mathcal{T}^{\mathrm{active}}, m \in \mathcal{M}^{\mathrm{mFRR}} \cup \mathcal{M}^{\mathrm{I}} && \text{(A.18)}\\
x_{m,t} &= 0, && t \in \mathcal{T}, m \in \mathcal{M} \setminus \mathcal{M}^{\mathrm{active}} && \text{(A.19)}\\
{}^{\mathrm{h}}x_{m,t} &= 0, && t \in \mathcal{T}, m \in \mathcal{M} \setminus \mathcal{M}^{\mathrm{active}} && \text{(A.20)}\\
x_{k,t} &= b_{k,t}, && t \in \mathcal{T}, k \in \mathcal{K}_j && \text{(A.21)}\\
{}^{\mathrm{h}}x_{k,t} &= {}^{\mathrm{h}}b_{k,t}, && t \in \mathcal{T}, k \in \mathcal{K}_j && \text{(A.22)}\\
{}^{\mathrm{h}}x_{m,t} &= {}^{\mathrm{h}}b_{m,t}, && t \in \bar{\mathcal{T}}_{\bar{t}}, m \in \mathcal{M}^{\mathrm{IC}} \cup \mathcal{M}^{\mathrm{mFRR}} && \text{(A.23)}\\
x_{m,0} &= b_{m,0}, && m \in \mathcal{M} && \text{(A.24)}\\
x_{m,t}, U_t &\geq 0, && t \in \mathcal{T}, m \in \mathcal{M}^{\mathrm{mFRR}} && \text{(A.25)}\\
10x_{m,t} &\in \mathbb{N}, && t \in \mathcal{T}, m \in \mathcal{M}^{\mathrm{FCR}} && \text{(A.26)}\\
x_{m,t} &\in \mathbb{N}, && t \in \mathcal{T}, m \in \mathcal{M}^{\mathrm{FRR}} && \text{(A.27)}\\
x_{m,t} &\in \mathbb{R}, && t \in \mathcal{T}, m \in \mathcal{I} \cup \mathcal{S} && \text{(A.28)}
\end{aligned}
$$

B

Appendix 2

Month	FCR-D up 1	FCR-D down 1	FCR-N 1	aFRR up	aFRR down	mFRR cap up	mFRR cap down	Spot	FCR-D up 2	FCR-D down 2	FCR-N 2	mFRR el up	mFRR el down
March	0	0	0	0	0	0	0	276181	0	0	0	0	0
March	0	19981	0	0	0	0	0	333202	0	121736	0	0	0
March	0	5846	48058	0	0	0	0	286535	0	109502	30909	0	0
March	0	4477	35240	0	0	0	1968	300026	0	105290	28590	0	22817
March	0	8026	20611	0	0	29829	1968	284777	0	106774	27559	15106	22817
March	3046	8488	18458	0	0	26805	1968	281609	12885	107193	27434	12516	22817
March	3136	6502	16846	0	6658	27674	1968	283265	12885	106870	27209	12861	22817
March	3136	6502	16846	0	6658	27674	1968	283265	12885	106870	27209	12861	22817
June	0	0	0	0	0	0	0	85258	0	0	0	0	0
June	0	0	102783	0	0	0	0	105245	0	0	51302	0	0
June	0	4817	81812	0	0	0	0	110999	0	40486	50652	0	0
June	0	2181	65238	0	0	0	13922	115933	0	39656	48959	0	6068
June	0	3811	55187	0	0	10787	15636	111428	0	41356	47563	915	6838
June	2811	4311	52453	0	0	9866	17891	111615	2230	41546	44611	710	6838
June	2855	3987	47876	0	5102	10205	16733	113085	2325	41486	44611	1422	6838
June	2855	3987	47876	0	5102	10205	16733	113085	2325	41486	44611	1422	6838
September	0	0	0	0	0	0	0	22997	0	0	0	0	0
September	0	0	0	0	0	32746	0	22335	0	0	0	4497	0
September	0	0	0	0	0	32729	3196	29755	0	0	0	4497	1820
September	0	0	1922	0	0	31580	3037	32686	0	0	6064	4172	1830
September	0	0	742	0	2872	32184	3011	35296	0	0	5964	4694	1830
September	368	0	641	0	2872	30767	3011	35035	3988	0	5964	4694	1830
September	368	0	641	1860	3122	30271	3011	35224	3813	0	5964	4419	1830
September	368	13	541	1860	3122	30271	3011	35224	4073	0	5964	4419	1830
December	0	0	0	0	0	0	0	328035	0	0	0	0	0
December	0	0	0	0	0	0	13941	347903	0	0	0	0	17978
December	0	0	0	0	0	61679	13856	288389	0	0	0	18912	17978
December	0	0	2336	0	0	59701	12506	291618	0	0	1495	18912	17978
December	0	0	2336	3928	0	58450	12601	291618	0	0	1355	18912	17978
December	0	630	2276	4083	0	58618	11446	291618	0	183	1116	18912	17978
December	176	630	2276	4083	0	58460	11446	290561	250	183	1116	18912	17978
December	176	630	2276	4143	73	58460	11446	290561	250	183	971	18912	17978

Table B.1: Breakdown of revenue per market with different numbers of markets for each mont,h ranging from zero to seven ancillary markets.

C

Appendix 4

	$\mathcal{K}_1$	$\mathcal{K}_2$	$\mathcal{K}_3$	$\mathcal{K}_4$	$\mathcal{K}_5$	$\mathcal{K}_6$	$\mathcal{K}_7$
FCR-D up 1	■	■	■	■	■	■	■
FCR-D down 1	■	■	■	■	■	■	■
FCR-N 1	■	■	■	■	■	■	■
aFRR up		■	■	■	■	■	■
aFRR down		■	■	■	■	■	■
mFRR capacity up		■	■	■	■	■	■
mFRR capacity down		■	■	■	■	■	■
Spot			■	■	■	■	■
Intraday 1				■	■	■	■
FCR-D up 2					■	■	■
FCR-D down 2					■	■	■
FCR-N 2					■	■	■
Intraday 2						■	■
Intraday 3							■
Intraday continuous							
mFRR electricity up							
mFRR electricity down							

Table C.1: Visualization of the markets that gets included in each market step.

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