DIVISION SAFETY AND TRANSPORT
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Profit estimation for district heating systems when participating in electricity and ancillary service markets

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RISE Report 2023:86

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Abstract

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Profits generated by district heating systems when participating in ancillary service markets in the electricity sector are studied in this report. An hourly scheduling model is developed to optimally schedule district heating units to meet the heat demand, minimize costs and maximize revenues from electricity markets. The output is used to evaluate the additional profits made by participating in the existing Swedish ancillary markets in addition to the day-ahead electricity market. Case studies are run in two district heating systems, one in Nyköping and one in Gothenburg, for the historical years of 2021 and 2022. Nyköping's system is also used to evaluate potential profits from ancillary service markets in future scenarios for 2025, 2035 and 2045. Finally, Nyköping's system is used to evaluate potential additional profits generated by two investments that enhance the flexibility that can be provided to the electricity sector: better CHP ramp rates and larger thermal storage.

The analysis of the results shows, for both historical and future years, that participating in ancillary services brings about additional profits. These vary depending on the year, studied district heating system. Profits from electricity markets are shown to increase by up to 40% in Nyköping and 200% in Gothenburg when looking at the historical years. Doubling the CHP ramp rates ability for delivering ancillary services or doubling the size of the heat storage are shown to result in up to another 6% of additional profits. In the future scenarios, profits from electricity markets are shown to increase by up to 94%.

Key words: sector coupling, district heating, day-ahead market, ancillary service markets, mFRR, aFRR, FCR.

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Content

1 Introduction

The SeCoHeat project aims at investigating potential incomes from ancillary service markets that can be made by district heating systems. In this deliverable, the additional profits that can be made by two different district heating systems when participating in ancillary services are quantified both for the two historical years of 2021 and 2022, and for scenarios for 2025, 2035 and 2045. In addition, the added value of making investments to enhance the flexibility provided by district heating system to the electricity system is studied. An optimization-based model to schedule district heating units hourly to maximize profits has been developed.

The scheduling model is described in Section 2~~2~~. The two district heating systems (of Nyköping and Gothenburg) are described in Section 3~~3~~. The evaluation of the additional profits that could have been made in 2021 and 2022 by participating in ancillary service markets is presented in Section 4~~4~~. The corresponding evaluation for scenarios for 2025, 2035 and 2045 for Nyköping is presented in Section 5~~5~~. Finally, Section 6~~6~~ presents what added profits could be made in Nyköping by making investments to increase flexibility in that system.

2 Optimization model description

An optimization model has been developed to evaluate the potential profits that district heating systems can make from ancillary service markets. In this section, the model is briefly described. The full formulation can be found as an appendix to this report.

The optimization model uses the following input data:

- A period to analyze (typically a week).
- A district heating system described as its units and their technical parameters (efficiency, installed capacity, ramping rates, fuel costs, …)
- Hourly heat demand for the period of interest.
- A list of at most two markets on which trading decisions are optimized (e.g., day-ahead only or day-ahead and one ancillary service market)
- Hourly prices on these markets for the period of interest.
- Activation scenarios for the ancillary service market of interest (i.e., hourly energy activation volumes), see the full formulation for a description of these scenarios.

The output of the model includes:

- Optimal hourly scheduling of the district heating units in the different activation scenarios.
- Hourly costs and revenues.

The optimization model is built upon the following assumptions and key principles:

- It is a MILP formulation.
- The heat demand must be satisfied during all hours for all activation scenarios of ancillary services (hard constraint).
- If heat storage units are present, they must be filled with the same amount of heat at the end of the period of interest as they are at the start.

- One activation scenario is used in the objective function to compute the costs and revenues to be minimized. This scenario contains the expected volume of ancillary service activation and thus corresponds to how the district heating system is expected to be operated.
- The other activation scenarios are used to model constraints that the district heating system must fulfil when providing ancillary services but the costs and revenues in these scenarios are not considered in the objective function. There is typically one full activation scenario for either up- or down-regulation in the case of ancillary services in one direction only, or two full activation scenarios for both up- and down-regulation. These full activation scenarios capture the fact that, although the expected activation is less than the offered volumes, the system still must be ready, if needed, to fully activate the offered volumes during all hours in which it participates in ancillary services.
- If more than one market is evaluated, the model co-optimizes trading decisions on these two markets. An alternative would be to have sequential optimization models where only the first market is considered in a first stage and then, the leftover flexibility capacity is offered in a second stage to the second market. This latter alternative has not been considered here.
- Electricity market prices are activation scenarios are assumed to be known. In reality, these quantities must be forecasted. The results of this report are thus best-case results assuming perfect information.

3 Studied district heating systems

3.1 Nyköping

Vattenfall operates Idbäcksverket in the municipality of Nyköping. This plant has one biofuel CHP unit complemented with two biofuel heat-only units for baseload operation and some oil-fired peak load boilers. The plant is also equipped with a cooler where excess heat can be dumped. The total installed capacity for heat production is 234 MW and the electric installed capacity is 35 MW. A hot water tank for heat storage with capacity 350 MWh is available.

3.2 Gothenburg

Göteborg Energi operates the district heating network in the city of Gothenburg, which is the second-largest city in Sweden. Production units include 3 CHP plans, one running on wood chips and two on natural gas, 6 heat boilers (with different fuels: natural gas, fuel oil, wood pellets, and bio oil) and one heat pump. Both the CHP units and the heat pump can provide flexibility to the electricity system, the CHP units by increasing or decreasing electricity production, and the heat pump by increasing or reducing its electricity consumption. The total installed capacity for heat production is 1520 MW and the installed electricity production capacity in the CHP units is 690 MW. A heat storage with a capacity of 1000 MWh is available.

4 Case study 1: evaluation of potential historical profits from ancillary service markets.

In this case study, the following markets have been evaluated using historical data from 2021 and 2022 to compute the potential profits from these markets: mFRR up and down, aFRR up and down, FCR-N, FCR-D up and down.

In order to evaluate the yearly profits, the optimization model is run a week at a time. Only one week is simulated for each month of the year to keep the running time manageable. The results are then extrapolated from the 12 simulated weeks to get yearly profits.

4.1 Results

4.1.1 Nyköping

The results are shown in Figure 1 for the district heating system in Nyköping. If participating only day-ahead, the yearly profits from the system are 302 Mkr in 2021 and 378 Mkr in 2022.

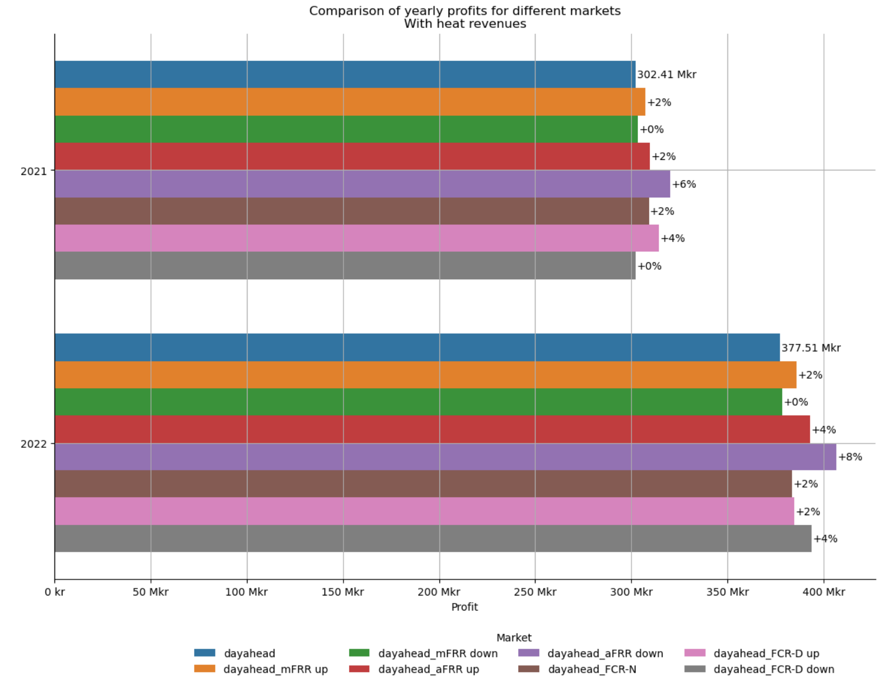

Figure 1: Profits in Nyköping including revenues from selling heat. The bar annotations indicate yearly profits in Mkr for the day-ahead market and the additional profit (in percentage) on top of the day-ahead profits for the other markets.

The most profitable ancillary market in both years is aFRR down, the participation in which results in additional profits of 6% in 2021 and 8% in 2022. Participating in aFRR down does not require withholding production from the day-ahead market while at the same time receiving a remuneration for the sold capacity and for the activated energy. This is the reason why this market is the most profitable.

In 2021, the FCR-D down market was not in place yet, which is why the additional profits from this market are 0 for that year. For 2022, the first year of operation of this market, it is the second most profitable. As for aFRR down, participating in FCR-D down does not require withholding production from the day-ahead market. Activation on the FCR-D down market is much less frequent than for the aFRR down market due to the FCR-D products targeting higher frequencies than the aFRR products. Activation is also not compensated in the case of the FCR-D markets.

The weekly averages of the prices on the day-ahead and ancillary service markets are shown in Figure 2. It can be seen that, between weeks 20 and 40 in 2022, the FCR-D down prices were lower than the aFRR down prices. This explains why participating in aFRR down is more profitable than participating in FCR-D down.

In both 2021 and 2022, participating in mFRR down would not have resulted in additional profits. The reason for this is the high day-ahead price situation in these years to which mFRR prices are closely related. Actors participating in the mFRR down market make a profit by buying back already sold production on the day-ahead and intraday markets at the mFRR down price, which results in electricity production price savings (at the cost of the mFRR down prices). High mFRR down prices means lower revenues from participating in this market, since the profit made from mFRR down is driven by the difference between the saved electricity production prices and mFRR down prices: for a given unit, the higher the mFRR down prices the lower the profitability from this market. It only makes sense to participate in mFRR down when the electricity production cost savings are larger than the mFRR down prices, that is, when the mFRR down prices are low enough. Given the high prices in the years 2021 and 2022, it happened very seldom that this was the case, thus limiting the profitability of participating in mFRR down.

It can be observed that whereas aFRR down was the most profitable markets in both 2021 and 2022, the other markets rank differently. For examples, the top 5 markets in 2021 were aFRR down followed by FCR-D up, aFRR up, FCR-N and mFRR up. In 2022, however, the top 5 markets were aFRR down followed by FCR-D down, aFRR up, FCR-D up and mFRR down.

The general conclusion is that down-regulating markets with capacity compensation (aFRR down and FCR-D down) are in general the most profitable markets. However, it can be noticed that, interestingly, the aFRR up market is as profitable as the FCR-D down market in 2022. This can be explained by the aFRR up capacity prices being higher than the FCR-D down prices in 2022 (see Figure 2), thus compensating somewhat for the loss of revenues from the day-ahead market (for the capacity reserved for aFRR up). Also, the activated capacity for aFRR up receives compensation, while it is not the case for FCR-D down. This compensation is priced at the mFRR up prices, which were high in 2022, much higher than FCR-D down prices (see Figure 2), thus contributing to making the aFRR up market as profitable as the FCR-D down market despite the loss of day-ahead revenues.

to compute the potential profits

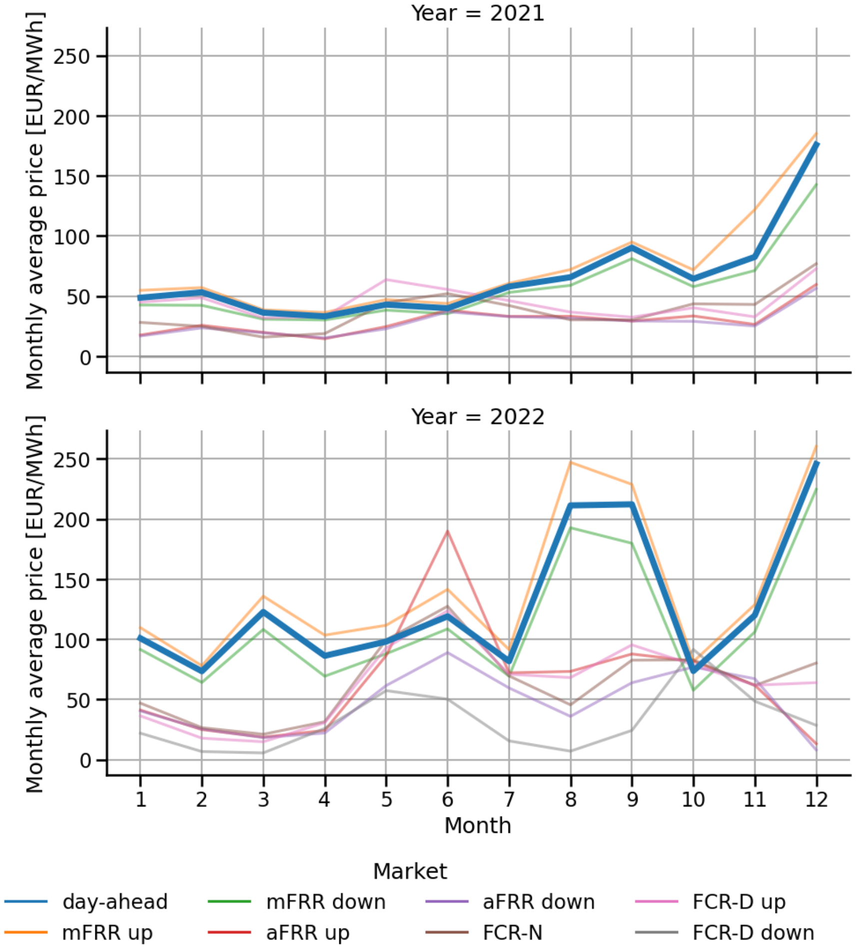

Figure 2: Monthly average prices in the different electricity markets in SE3 for 2021 and 2022. The day-ahead prices have been emphasized for clarity.

The profit in Figure 1 includes revenues from selling heat and electricity and costs for start-ups of units and fuel costs. The revenues from selling heat are assumed to be equal to a fixed yearly price multiplied by the heat demand. Therefore, these revenues do not depend on which electricity markets the system participates in. They amount to a large share of the total profits: 256 Mkr in 2021 and 246 Mkr in 2022. In Figure 3, the profits from the different ancillary service markets without the revenues from heat production are compared.

The results in Figure 3 show the profits excluding the revenues from selling heat, which better highlights the differences between participating in different electricity markets. It can now be seen that participation in the mFRR down market also improves the yearly profits, albeit only marginally. This was not visible when including revenues from heat production in Figure 1. Furthermore, while the additional profits from ancillary services in Figure 1 were only marginal compared to the total profits including revenues from heat production, it can be seen in Figure 2 that participation in ancillary services can actually bring significant profit increases compared to participating in day-ahead only.

As far as the comparison of profitability between different ancillary service markets is concerned, the conclusions are the same as above for Figure 1 in term of the order of profitability of different ancillary service markets. Therefore, as explained above, the profitability is typically highest for down-regulation markets with capacity compensation (aFRR down and FCR-D down).

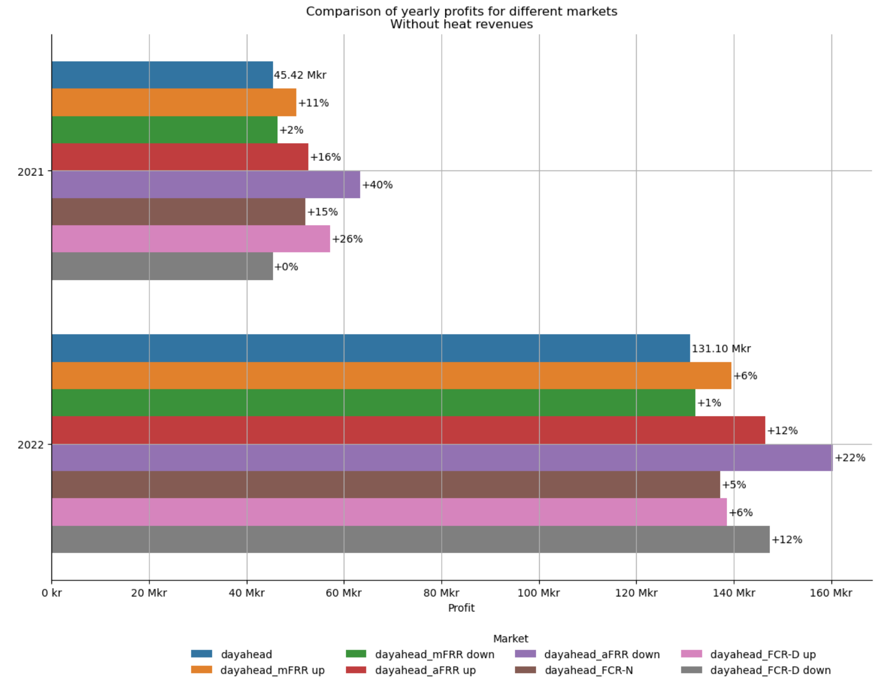

Figure 3: Profits in Nyköping, not including revenues and costs from producing heat. The bar annotations indicate yearly profits (without heat revenues) in Mkr for the day-ahead market and the additional profit (in percentage) on top of the day-ahead profits for the other markets.

4.1.2 Gothenburg

The profits generated between January and March and in December have been computed for Gothenburg's district heating system. The reason for the period to be limited to January to March and December is that, throughout the year, excess heat from industries is injected into Gothenburg's district heating system, which creates period with zero heat demand from the district heating production units outside of the winter months. Therefore, there is no need for extra heat production in Gothenburg and, consequently, no potential participation in electricity markets. These periods with zero heat demand also create difficulty for the optimization solver for months with a combination of zero and nonzero heat demand, resulting in a very slow convergence process to find the optimal solution for April to November. As will be seen in Section 4.1.34.1.3, the same phenomenon does not occur in the VF system.

The profits in the GE system for the simulated period (January, February, March and December) are shown including the heat revenues in Figure 4.

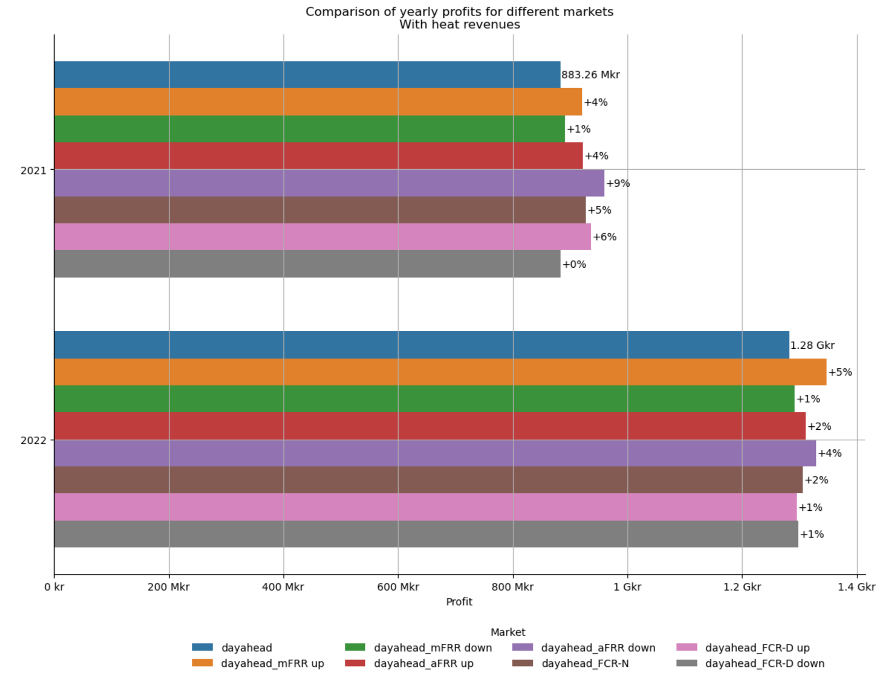

Figure 4: Profits in Gothenburg including revenues from selling heat, for the months January, February, March and December. The bar annotations indicate yearly profits in Mkr for the day-ahead market and the additional profit (in percentage) on top of the day-ahead profits for the other markets.

Error! Reference source not found. Figure 5 shows the profits in the same months (January, February, March and December) without including the revenues from selling heat. It can be seen that when excluding the revenues from selling heat, it was very profitable to participate in ancillary services in 2021 with for example an increase of 200% of the profits for aFRR down (**Error! Reference source not found.**Figure 5). This exceptional profitability is not visible when including revenues from selling heat, emphasizing that the share of profits from the electricity sector is small compared to that of the heat sector. Still, participating in aFRR down in 2021 would have brought about additional profits of close to 10% of total profits (Figure 4).

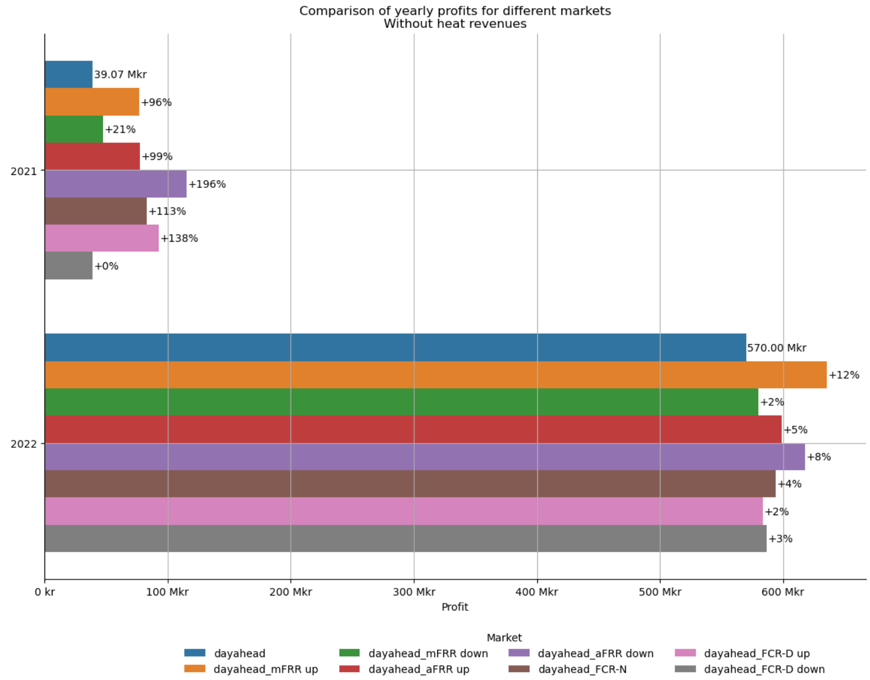

Figure 5: Profits in Gothenburg excluding revenues from selling heat, for the months January, February, March and December. The bar annotations indicate yearly profits in Mkr for the day-ahead market and the additional profit (in percentage) on top of the day-ahead profits for the other markets.

For 2022, the additional profits compared to day-ahead are smaller. This is most likely due to the high day-ahead prices in 2022. Interestingly, in 2022, the mFRR up market would have been the most profitable one in the GE system. mFRR up prices are very high during the simulated winter months, as seen in Figure 2. mFRR up is not procured every hour by the TSO. For hours during which it is not procured, the district heating system can provide capacity to the day-ahead and get day-ahead prices instead, which are also very high during the simulated winter months. The net effect is that mFRR up is indeed very profitable.

Also, the FCR-D down market in 2022 was not as profitable as it was in the Nyköping case. This highlights that the potential profits from participating in ancillary service markets are very system specific and conclusions from one system cannot be generalized to another system. More insights into why this is the case are given in the next section.

4.1.3 Comparison between the two systems

Differences in heat demand

The heat demand determines what production units are needed to be online to supply this demand. Both systems have short-term storage, which provides some leeway in matching heat production and heat demand. At one end of the spectrum, if the heat demand is zero, all units will be off which means that no flexibility can be provided to the electricity sector. At the other end of the spectrum, when heat demand is high, most of the capacity must be committed to supplying the heat demand, which limits the amount of capacity available for providing flexibility to the electricity sector.

Figure 6Figure 6 shows the hourly heat demand as percentage of the maximum hourly heat demand during 2021. The maximum hourly heat demand was 900 MWh in Gothenburg and 100 MWh in Nyköping during 2021.

From the middle of April until the third week of November, there are periods with zero residual heat demand in Gothenburg (GE). From June to September, this occurs most of the time. During the same periods, there is always a small residual heat demand in Nyköping's system (VF) while the heat demand in Gothenburg is often zero. For the reasons mentioned in the previous section, the profits in Gothenburg are therefore calculated only for the months of January, February, March and December.

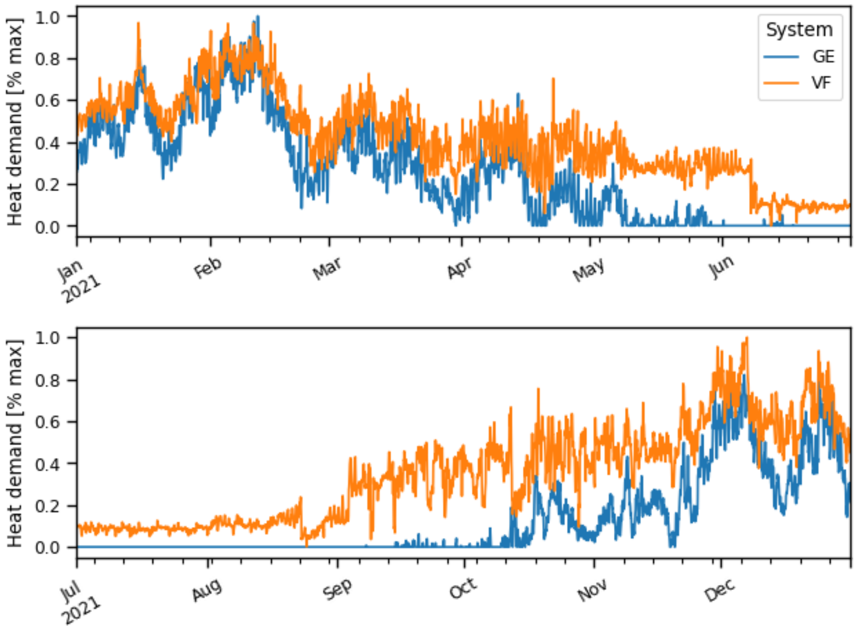

Figure 6: Comparison of the hourly heat demand in the systems operated by Göteborg Energi in Gothenburg (GE) and Vattenfall in Nyköping (VF).

Differences in production-side flexibility

In addition to differences in the heat demand, the two systems have different mixes of production units and storage, thus resulting in different amounts of flexibility that can be offered to the electricity sector. A way to measure this amount of flexibility is to quantify how much capacity the system can contribute with to the day-ahead and ancillary service markets. The quantification of this capacity is driven by both economic and technical drivers. From the model presented in Section 2~~2~~, it is possible to extract for each hour: (1) the capacity offered to the day-ahead market and (2) the maximal technical capacity left to be offered to one ancillary service market. The sum of these two values will be taken here as a measure of the hourly flexibility contribution (in MWh/MW) to the electricity sector. This flexibility contribution is presented in **Error! Reference source not found.**~~Figure 7~~ on a monthly basis for the two systems (VF and GE) in 2020 and 2021, and for all day-ahead and ancillary service markets.

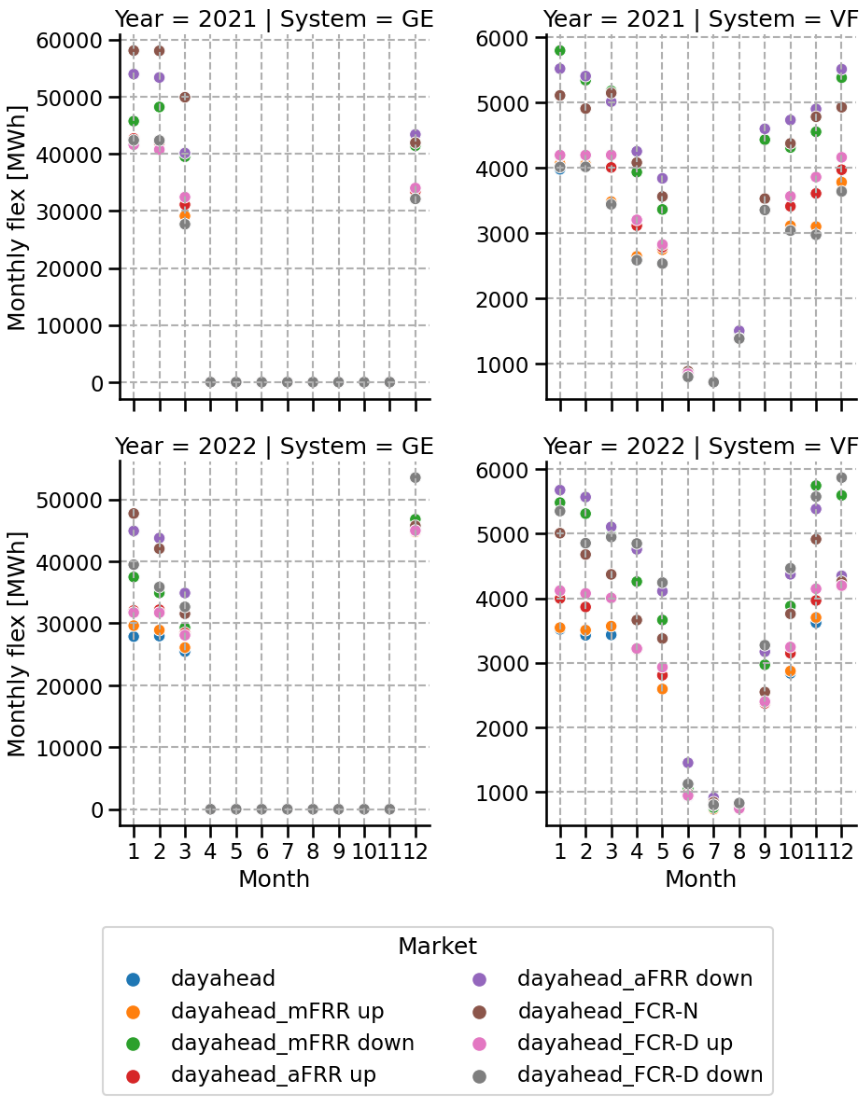

Figure 7: Monthly flexibility potential in MWh that can be offered to ancillary services, measured as the sum of the hourly maximum possible activation for each ancillary services.

As noted above, the maximum flexibility potential is a result from the optimal scheduling. Therefore, it also reflects the trade-off between offering the capacity to the day-ahead market or to the ancillary service markets (for up-regulation markets). If prices make the day-ahead market more profitable, the scheduler will try to offer as much electricity as possible to the day-ahead market, thus leaving less capacity for the ancillary service, and vice versa. This can be seen clearly when comparing mFRR up (orange dots) with FCR-D up (pink dots) and aFRR up (red dots). Ramping rate requirements are less stringent for mFRR than for the other two markets. The theoretical flexibility potential should therefore be higher for mFRR up than for the other two up-regulation markets. However, as can be seen in **Error! Reference source not found.**~~Figure 7~~, the flexibility potential for mFRR up is often lower than that of the other two markets. The reason is that it is more often more profitable to participate in FCR-D up and aFRR up than it is for mFRR up. Therefore, the scheduler chooses to use more capacity to the day-ahead market when co-optimizing with mFRR up, thus leaving less capacity for mFRR up.

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For down-regulation markets, the flexibility potential decreases away from the winter. For these markets, the potential is proportional to the day-ahead production plan. The largest units with a coupling to the electricity sector are CHP units in both systems. Due to the dependency between heat and electricity production, the larger the heat production the larger the electricity production in general. An exception to this is periods with very high heat demand where the operating region of these units typically trade-off electricity production for more heat production, which can happen during peak hours in the winter. In the case of VF's system, summer months were simulated. It can be seen that the amount of flexibility drops dramatically between June and August, as a result of the very low heat demand during these months, see Figure 6.

Figure 8 shows the additional monthly profits (in percent relative to the day-ahead profits) for 2021 (upper row) and the two systems (Vattenfall's Nyköping system on the left column and Göteborg Energi's Gothenburg system on the right).

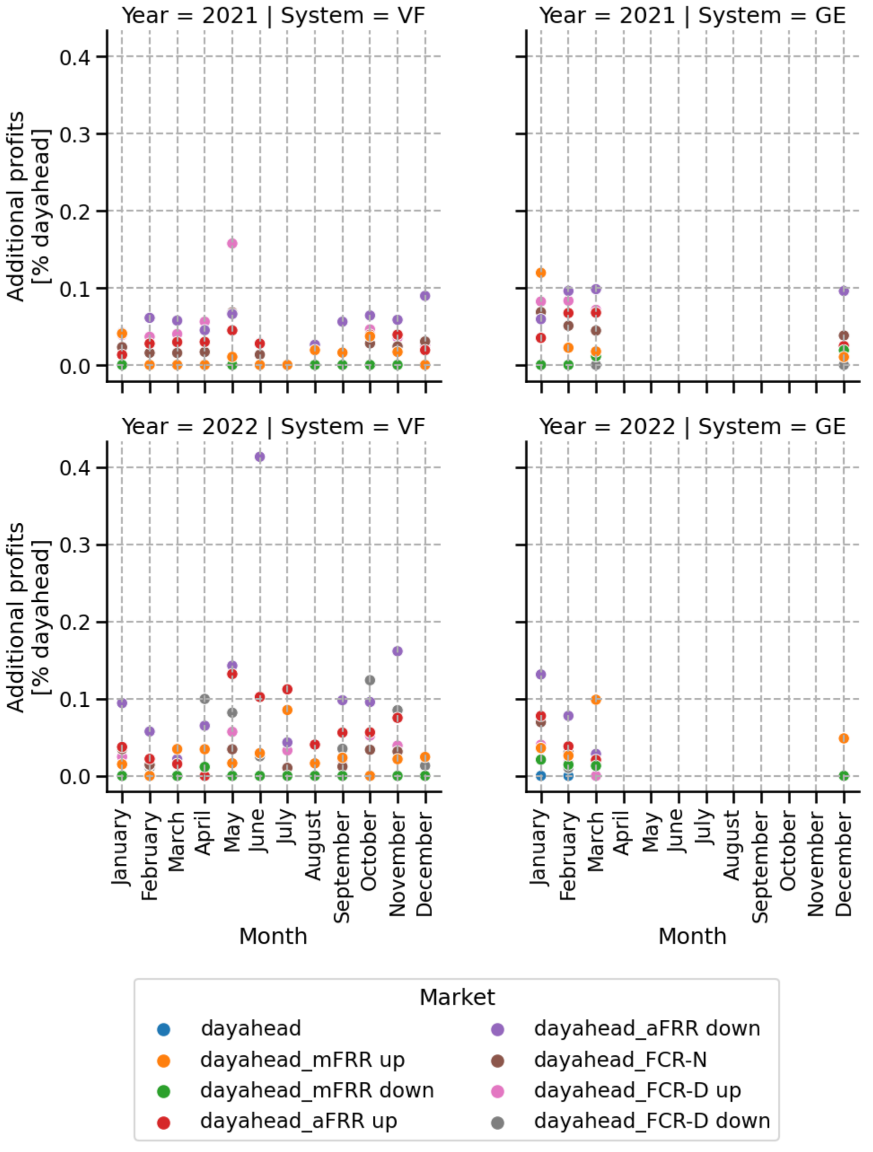

Figure 8: Comparison of additional monthly profits (including heat revenues) as percentage of monthly day-ahead profits in the Vattenfall system (VF in Nyköping) and in the Göteborg Energi system (GE in Gothenburg). Note that, for the GE system, profits were only evaluated for months January, February, March and December for the GE system.

In both systems, aFRR down is the most profitable market for most of the months. The profitability order of the ancillary service markets is similar in both systems. December 2022 is the month with least profitability for participating in ancillary service markets, the reason being the very high day-ahead prices as can be seen in Figure 2. During that month, it was profitable in both systems to participate in mFRR up, due to the fact that mFRR up prices are always higher than day-ahead prices. In VF's system (denoted VF in the figure), it is also somewhat profitable to participate in FCR-D down, while it is not for GE's system.

4.2 Applicability of the profit analysis

There are several assumptions and modelling designs that are important to highlight to understand the applicability of the profit analysis in the previous section:

- Price uncertainty is not accounted for since historical prices on the ancillary service markets are used in the case studies.
- Uncertainty on the activation volumes is not accounted for, which is important for markets with energy compensation (mFRR, aFRR and FCR-N markets).
- The day-ahead and ancillary service market are co-optimized. In reality, although close in time, the procurements by the TSO on the different markets occur at different times. This assumption is particularly important for the mFRR up and down markets. Indeed, these markets close the day after the day-ahead market and are particularly difficult to forecast both in terms of potential activation (whether there will be need for up- or down-regulation) and prices. Because of this uncertainty, trading decisions for the mFRR markets are never co-optimized with trading decisions for the day-ahead market by market participants. Instead, market participants co-optimize participation on the intraday market and the mFRR market, when trading on the intraday market a handful of hours before operation at which point the mFRR market forecasts become more reliable. Intraday market is not considered in this project. For other markets, it could assume that market participants co-optimize to some extent their trading decisions.
- Uncertainty on the heat demand is not considered.

These assumptions mean that the profit analyses are best-case estimates of how much profit could be made on the different ancillary service markets. As explained above, the discrepancy between these base-case estimates and actual profits is expected to be the highest for the mFRR market.

5 Case study 2: Evaluation of the value of participating in ancillary services in future years

In this case study, the existing systems in Nyköping and Gothenburg are simulated in some day-ahead electricity price scenarios for 2025, 2035 and 2045. These day-ahead price scenarios are combined with historical reference years to create scenarios for the heat demand and ancillary services. The profits made by the district heating operators are computed for different ancillary service markets in all combinations of these scenarios. In total, 9 scenarios for day-ahead electricity prices are simulated, combined with two reference years, for a total of 18 simulated cases. In each case, the yearly profits for the day-ahead and ancillary service markets are computed.

Section 5.15.1 presents the day-ahead electricity price scenarios used in the simulations. Section 5.25.2 presents how historical reference years are used to create scenarios for heat demand and ancillary services. Section 5.35.3 presents the results from the simulations in the two systems.

5.1 Scenarios for electricity prices

Table 1 lists the electricity price scenarios used in this case study. The scenarios "EF", "EP", "FM" and "SF" from Svk's long-term market analysis exist for 2035 and 2045. In total, 9 scenarios have been used: 1 for 2025 and 4 for 2035 and 2045. These scenarios differ in terms of electricity demand and production mix. For details, the reader is referred to [1] and [2].

Table 1: List of electricity price scenarios.

Short name	Scenario	Year
2025	Scenario from Svk's short-term market analysis	2025
EF	Scenario "Electrification renewables" from Svk's long-term market analysis	2035 and 2045
EP	Scenario "Electrification plannable" from Svk's long-term market analysis	2035 and 2045
FM	Scenario "Roadmap mixed" from Svk's long-term market analysis	2035 and 2045
SF	Scenario "Small-scale renewables" from Svk's long-term market analysis	2035 and 2045

Figure 2 shows the weekly average prices in the 9 simulated scenarios. As can be seen, the 9 scenarios cover a wide range of possible future electricity prices.

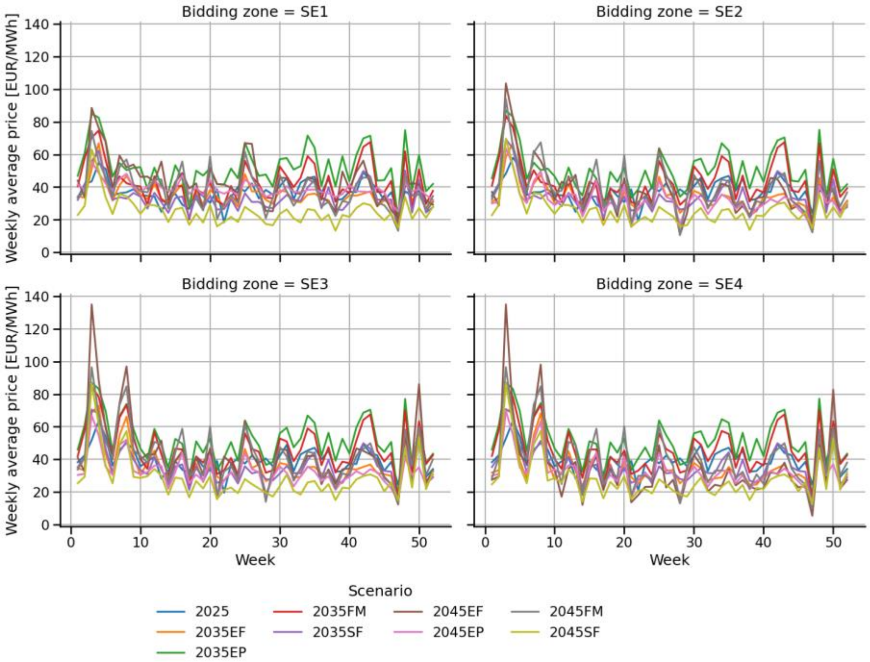

Figure 9: Weekly average prices in the 9 simulated scenarios.

5.2 Scenarios for heat demand and ancillary services

In addition to the scenarios for day-ahead electricity prices, the model presented in Section 22 requires hourly time series for: heat demand, ancillary service prices, ancillary service activation levels.

In this project, these time series were obtained by using the two historical years 2021 and 2022 as reference years and with the following assumptions:

- For heat demand and ancillary service activation levels, the time series is set to be the same as in the reference year.
- For ancillary service (AS) prices, time series are constructed by adjusting the prices from the reference year with the different between the day-ahead (DA) prices in the chosen scenario and in the reference year. For example, assume that, for a given hour, the AS price is 50 EUR/MW in the reference year and the DA prices are 100 EUR/MWh and 75 EUR/MW in the reference year and chosen scenario, respectively. Then the AS price for that scenario would be 50 + (75-100) = 25 EUR/MW. These generated AS prices are capped at an upper limit equal to the maximum hourly AS price in the reference year. For the lower cap limit, generated mFRR down prices are allowed to deviate by a maximum of 100

EUR/MW lower from the DA prices in the scenario. Other AS prices are capped at a lower limit of 5 EUR/MW.

- The CHP ramp rates for participating in ancillary services are set in line with the results from [3] and [4].

5.3 Results

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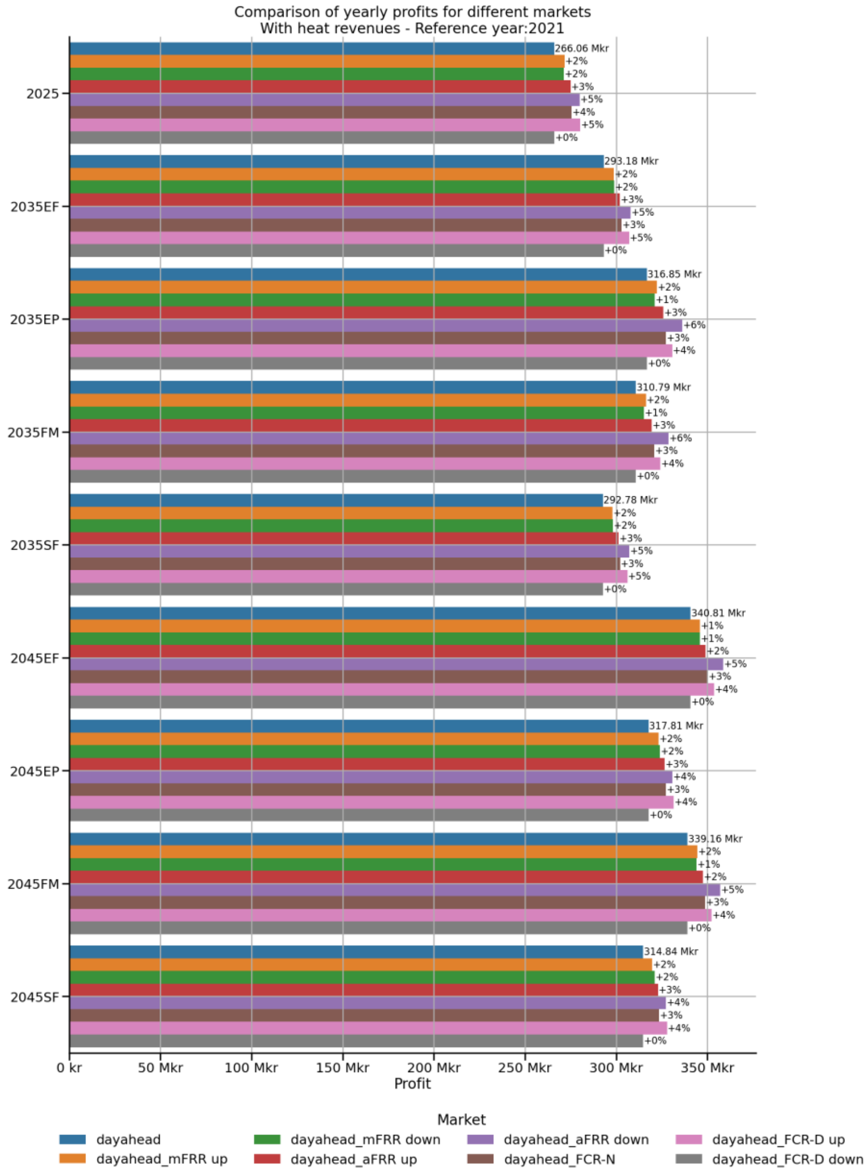

Figure 10: Total yearly profits in the simulated scenarios with 2021 as reference year.

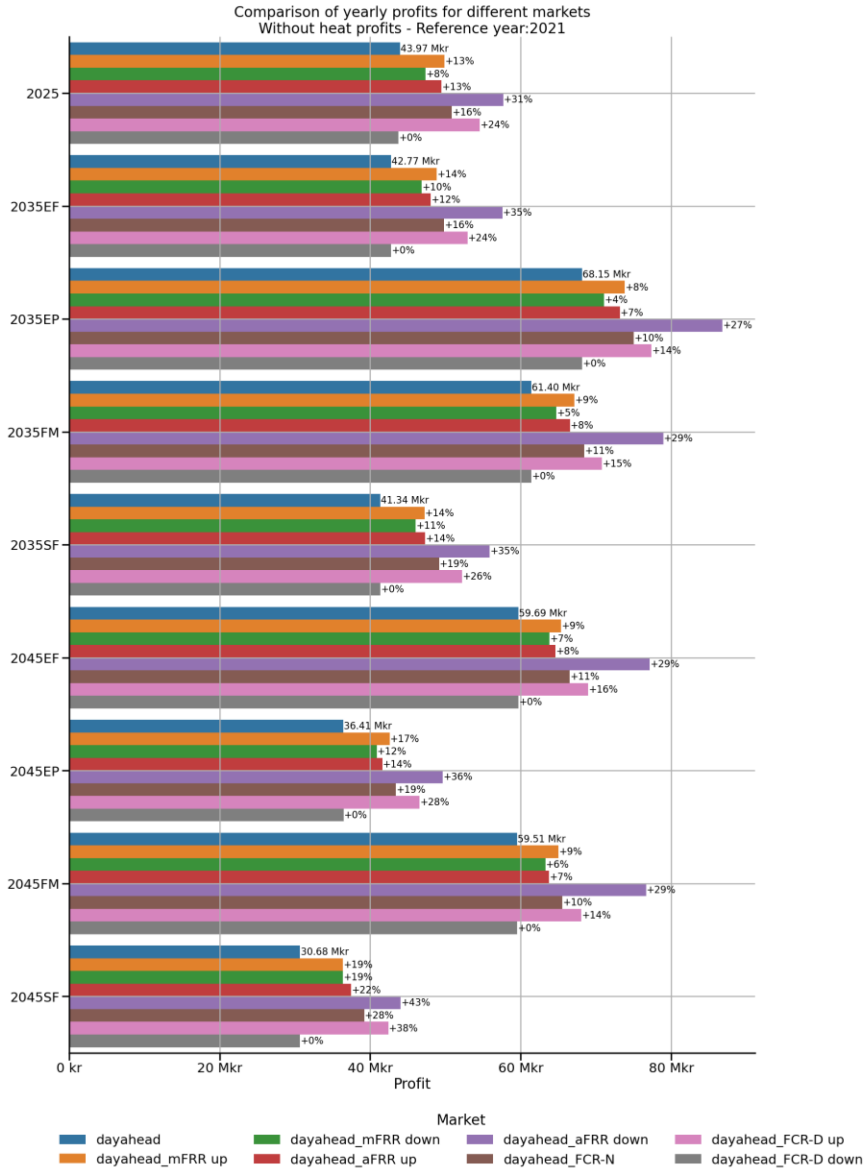

Figure 11: Yearly profits for electricity production (i.e. excluding profits related to heat production) in the simulated scenarios with 2021 as a reference year.

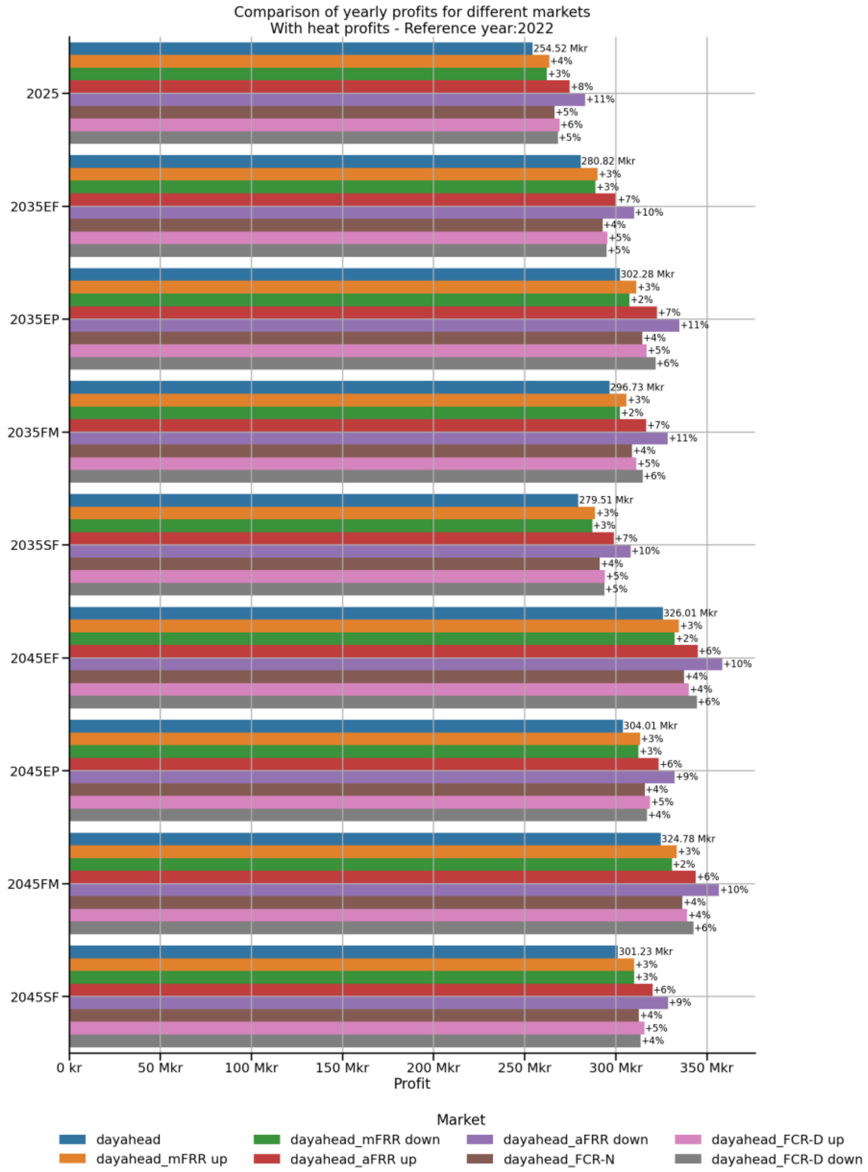

Figure 12: Total yearly profits in the simulated scenarios with 2022 as reference year.

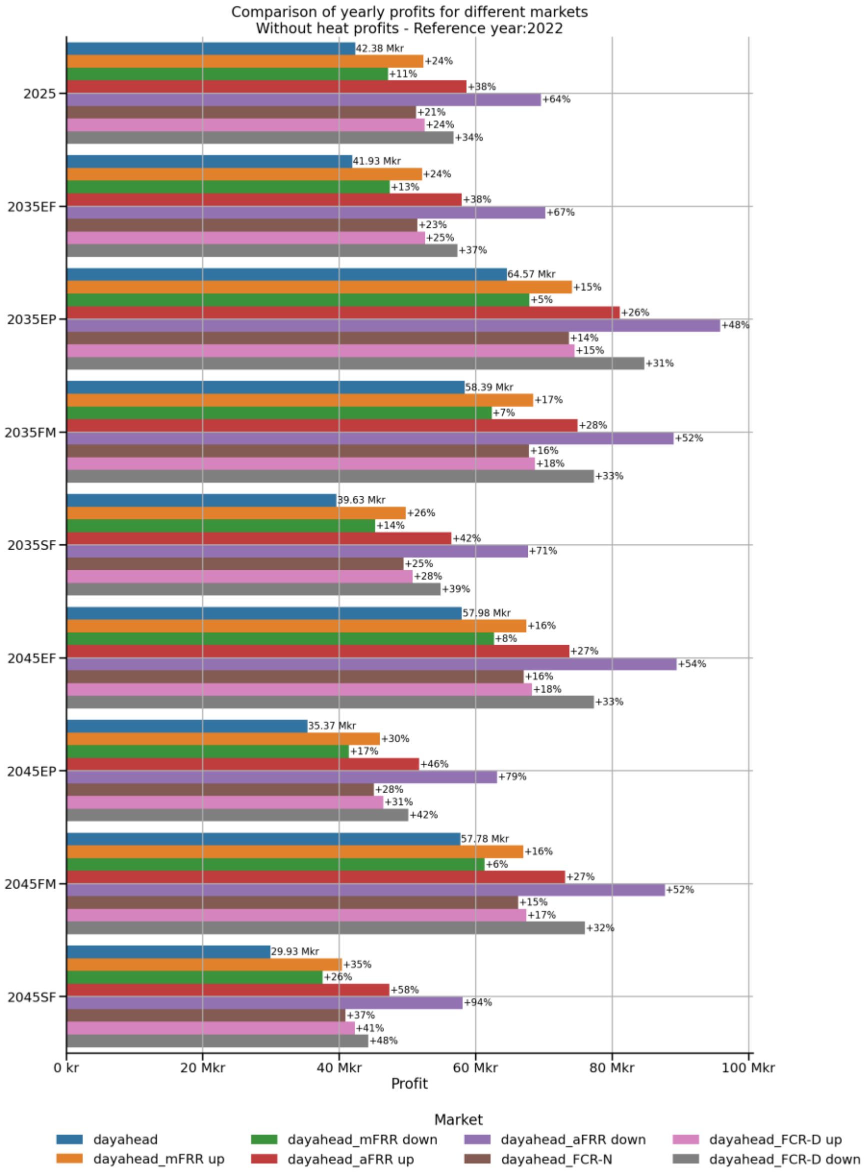

Figure 13: Yearly profits for electricity production (i.e. excluding profits from heat production) with 2022 as reference year.

As was the case in case study 1 presented in Section 44, participating in ancillary service markets only increase total yearly profits marginally in both reference years, as can be seen from **Error! Reference source not found.**~~Figure 10~~ and **Error! Reference source not found.**~~Figure 12~~. The most profitable ancillary market is the aFRR down market, which brings an additional total profit of at most 6% with 2021 as reference year (in scenarios 2035EP and 2035FM) and 11% with 2022. Looking at yearly profits from only electricity production in **Error! Reference source not found.**Figure 11 and **Error! Reference source not found.**Figure 13 allows us to get a better understanding of the impact of participating in ancillary services. It can be seen that participating in aFRR down increases yearly profits from electricity production by as much as 43% with 2021 as reference year (in scenario 2045SF) and 94% with 2022.

With 2021 as reference year, the second most profitable market, in some scenarios even as profitable as the aFRR down market, is consistently the FCR-D up market. This was not the case in case study 1 when looking at 2021, indicating that the price differences between day-ahead, aFRR down and FCR-up have changed in the future scenarios, despite these future scenarios using 2021 as the reference year. It can be explained by several factors. First, as explained in Section 5.25.2, prices for aFRR down and FCR-D up are generated for future scenarios by adjusting prices from the reference year by the difference between the day-ahead prices in the considered future scenario and in the reference year. In this step, prices from the reference year for aFRR down and FCR-D up are therefore adjusted in the same way. However, these adjusted prices are then capped at a lower limit of 5 EUR/MWh. Therefore, depending on how far the prices for aFRR down and FCR-D up are from this cap, they will be affected differently. A second difference comes from the fact that activation for aFRR down is compensated with mFRR down prices, whereas activation for FCR-D up does not receive compensation. A third difference comes from the fact that the offered capacity for FCR-D up must be withheld from the day-ahead market and, therefore, the corresponding revenues from day-ahead are lost. The day-ahead prices in the last quarter of 2021 started to increase sharply (see Figure 2), whereas the day-ahead prices in the future scenarios are at a lower level (see Figure 9Figure 9). Therefore, in the future scenarios, the loss of day-ahead revenues for participating in FCR-D up is lower.

With 2022 as reference year, aFRR down is always the most profitable market by some margin. The second most profitable market is always aFRR up, sometimes on par with the FCR-D down market (which did not exist with 2021 as a reference year). It is interesting to observe that the markets that require withholding capacity from the day-ahead market (i.e., the up-regulation markets and the FCR-N market) perform better in the future scenarios with 2022 as reference year, compared to the historical 2022 year in case study 1. The reason stems from the day-ahead price differences between 2022 and the future scenarios. As discussed above, day-ahead prices started to increase sharply by the last quarter of 2021. This increase continued and even took off even more in 2022, leading to extremely high day-ahead prices especially in the last 3 quarters of 2022, see Figure 2. In comparison, day-ahead prices in the future scenarios are much lower, see Figure 9Figure 9. Hence, withholding capacity from the day-ahead market comes at a lower cost in these future scenarios compared to the historical year of 2022. This increases the profitability in participating in the up-regulation and FCR-N markets.

A last noteworthy observation from these figures is the comparison between the ranking of the ancillary service markets in terms of profitability when comparing profits with and without considering heat production. Taking 2022 as reference year and the scenario 2025 as an example, we can compare **Error! Reference source not found.**Figure 12 with **Error! Reference source not found.**Figure 13. When considering the total profits (including profits from heat production) in **Error! Reference source not** found.~~Figure 12~~, the ancillary service markets ranked in descending order of profitability are: aFRR down (+11% compared to day-ahead only), aFRR up (+8%), FCR-D up (+6%), FCR-N and FCR-D down (+5% each), mFRR up (+4%) and mFRR down (+3%). When excluding profits from heat production in Error! Reference source not found.~~Figure 13~~, this order changes: aFRR down (+64%), aFRR up (+38%), FCR-D down (+34%), mFRR up and FCR-D up (+24% each), FCR-N (+21%) and mFRR down (+11%). In the latter case, FCR-D down seems to have become more profitable than FCR-D up and FCR-N, and mFRR up more profitable than FCR-N. The reason for this change in order can be found in the profits from heat production that, in Error! Reference source not found.~~Figure 13~~, are removed from the total profits shown in Error! Reference source not found.~~Figure 12~~. The profits from heat production are computed as the difference between two terms: revenues from selling heat minus costs for producing heat. The revenues from selling heat are computed as a fixed billing price multiplied with the yearly heat demand. It is therefore independent of the participation in ancillary services. The second term, however, depends on this participation. Participating in ancillary services may entail dispatching the heat production units in a different way. It could for example be reducing electricity production from a CHP unit to hold some reserves for one ancillary service. This may then result in a decrease in heat production in that same unit because of the dependency between heat and electricity production in CHP units. Since the heat demand is constant, a decrease in heat production in a CHP unit must be compensated by increase heat production somewhere else. Therefore, the cost for heat production may become higher than if the system did not participate in ancillary services. Since the volumes of participation in different ancillary services are different, the costs for heat production will also be different. This can explain why, for example, mFRR up seems to be more profitable when looking at the yearly profits without considering the revenues from heat production.

The observation in the previous paragraph points to a pitfall of focusing only on profits from electricity production: heat and electricity production are strongly interlinked in district heating systems and profits from one sector strongly impacts profits from the other sector.

6 Case study 3: Evaluation of the value of added flexibility for investment decisions

There are various ways of adding flexibility in a district heating system in order to enhance the sector coupling possibility with the electricity system. In another deliverable from this project [5], different parts of district heating systems that contribute to flexibility and various ways to improve this flexibility have been analysed in more detail. In this section, two different types of added flexibility will be quantified: (1) a larger water cistern and (2) improvements in existing CHP plants.

In order to quantify these two types of flexibility, the Nyköping system in case study 1 from Section 4~~4~~ will be taken as a reference case. It will be modified to create two new systems:

- System "Larger storage" will have the same characteristics as the reference case but with a water cistern that is twice as large.
- System "Improved CHP" will have the same characteristics as the reference case but with the assumption that some investments were done to double the maximum amount of capacity that the CHP plant can contribute with to participate in ancillary service markets. No assumption will be made here as to what specific investments are made to reach these improvements.

The model from Section 22 is then run in the same way as for the reference case in case study 1. The comparison of the yearly profits will allow us to quantify the added value of these two types of flexibility. In investment studies, this added value could then be used to inform investment decisions by comparing it to the CAPEX cost for these two types of investments.

The yearly profits in the original system and the two systems with increased flexibility are shown in Figure 14 and Figure 15. As before, the differences between different markets and systems appear more clearly when looking at the yearly profits without revenues from selling heat.

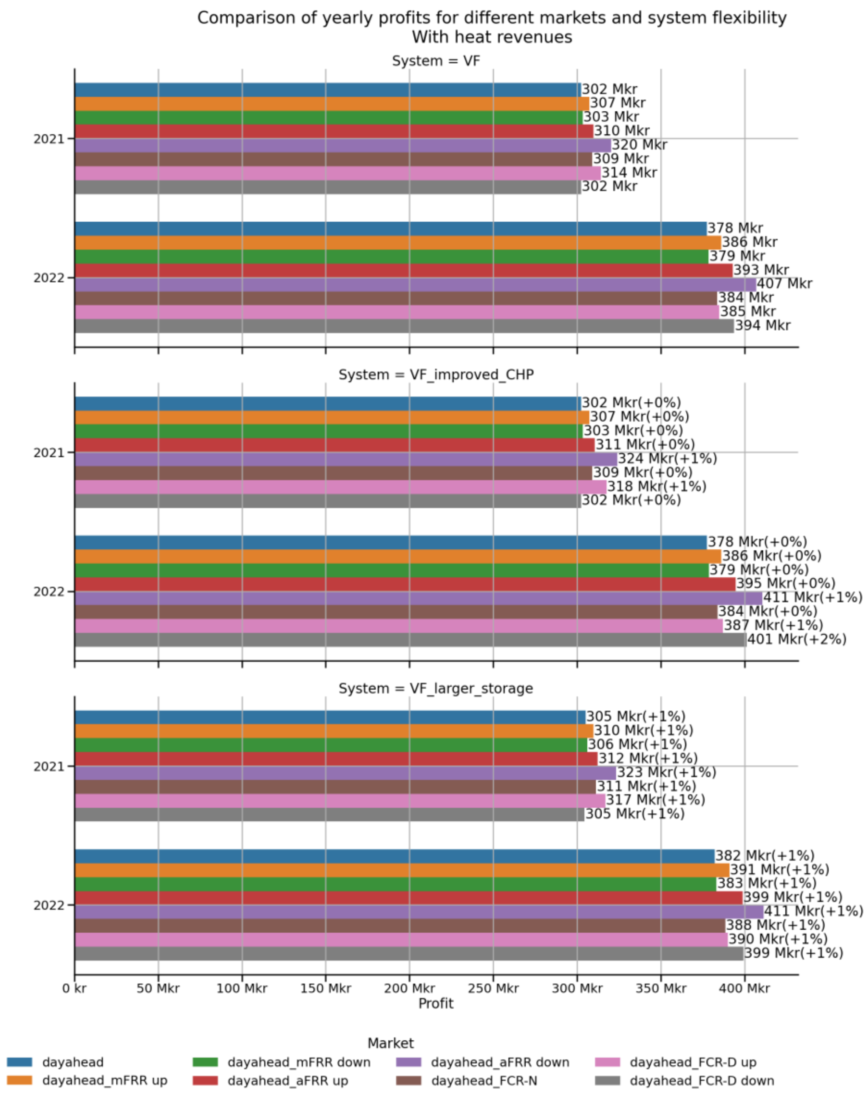

Figure 14: Comparison of the yearly profits in Nyköping's system with different flexibility options. The original system is 'VF' and corresponds to the topmost set of results. The results for the two improved systems ('VF_improved_CHP' and 'VF_larger_storage') are shown in the middle and bottommost sets of results. For the original system, absolute profits are shown. For the improved system, additional profits relative to the original system are also shown in percent. Example: In 2022, for the "VF_improved_CHP" system, the profits from participating in day-ahead and FCR-D down are 401 Mkr, which is 2% more than the profits from the same markets and year in the original system (394 Mkr).

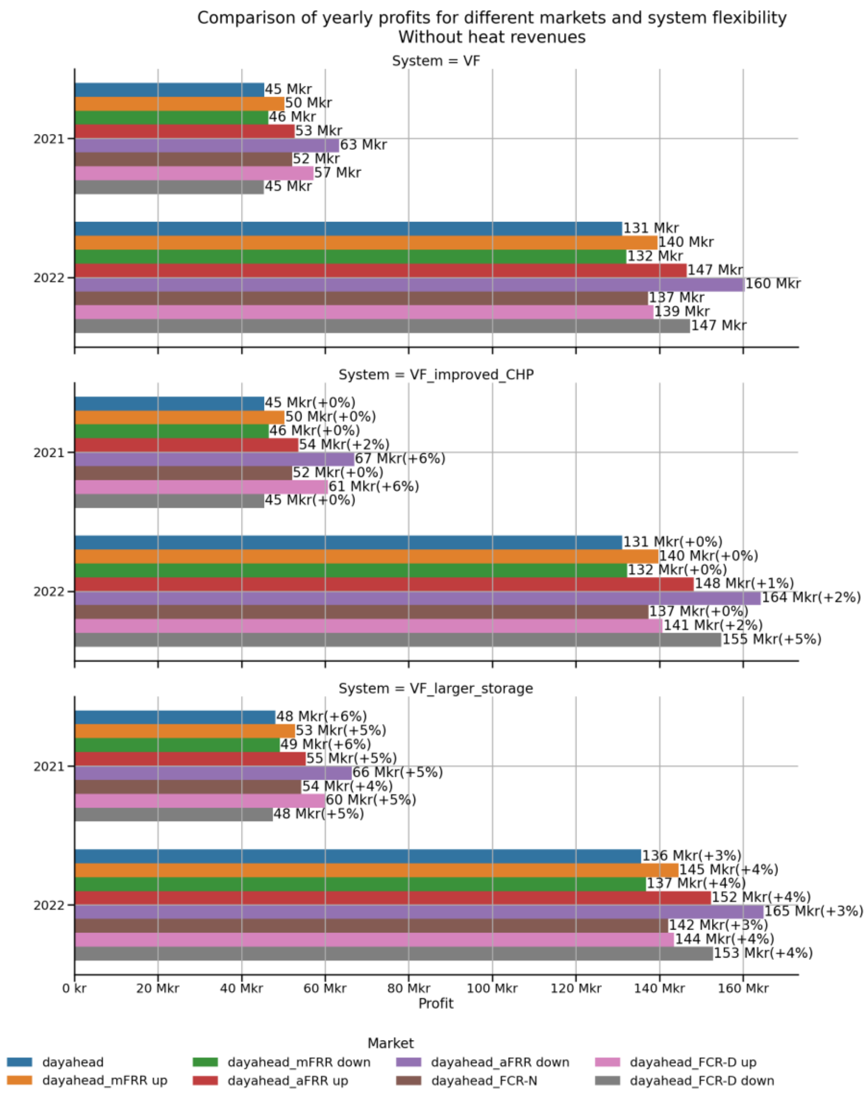

Figure 15: Comparison of the yearly profits (excluding revenues from selling heat) in Nyköping's system with different flexibility options.

For the systems with added flexibility, the additional profits in each market compared to the original system are indicated in percent next to each bar in the figures. It can be seen that the flexibility improvements bring about additional profits and that both improvements (improved CHP ramp rates and larger storage) both lead to additional profits in the same order of magnitude. One important difference is that, in the case of the larger storage, profits are improved even in the case when the district system only participates in the day-ahead market. In the "improved CHP" system, the added flexibility impacts only the ramp rates for delivering ancillary services and, therefore, do not bring added flexibility in the day-ahead only case. Furthermore, specifically for aFRR up (red bars) and FCR-N (brown bars), additional profits are consistently higher with the larger storage option than with the improved CHP option. In fact, the improved CHP case does not bring any additional profit in the case of FCR-N, indicating that ramp rates are not a limiting factor for this market.

The additional profits brought by the improved flexibility should be weighed against their CAPEX costs when taking decision on their profitability. This has not been considered here and is left as future work.

7 Conclusions

In this report, the additional profits that district heating systems can make by participating in ancillary service markets have been analysed. A model has been developed to optimally schedule the district heating units on an hourly basis to minimize costs (mainly fuel costs and start-up costs) and to maximize revenues from the electricity day-ahead and ancillary service markets. The additional profits from ancillary service markets are computed compared to the baseline case of only participating in the day-ahead market. The methodology is applied in several case studies.

In the first case study, historical years of 2021 and 2022 were simulated for two district heating systems: one located in the municipality of Nyköping and operated by Vattenfall and one located in the municipality of Gothenburg and operated by Göteborg Energi. The two district systems are located in similar latitudes in Sweden and the heat demand therefore have similar seasonal variations. They are some differences between the two systems, however. Gothenburg's system is more than 3 times larger in terms of peak heat demand. It also received industrial waste heat that is not controllable.

Overall, the analyses show that it is profitable to participate in ancillary service markets and that it can bring up to 10% of additional yearly profits compared to only participating in the day-ahead market. This number represents additional yearly profits considering revenues from selling heat. These heat revenues do not depend on the participation in ancillary service markets and represent a large share of the total profits. Focusing only on profits from selling capacity to the electricity sector, i.e. excluding the heat revenues, additional yearly profits can be up to 40% in Nyköping's system and up to 200% in Gothenburg's system. The results vary from year to year and from ancillary service market to ancillary service market. The actual additional profits depend on electricity price variations, the underlying heat demand that must be met by the district heating systems and the amount of flexibility that can be provided to the electricity system. Overall, the aFRR down market has been shown to be the most profitable market in most cases. Participating in the aFRR down market results in frequent activations since its activation range is close to the nominal frequency in the electricity grid. If district heating owners prefer participating in markets with less frequent activations, the FCR-D down market (newly launched in 2022) is among the top profitable markets. FCR-D down capacity is activated only during larger frequency deviations in the electricity grid.

In the second case study, scenarios for 2025, 2035 and 2045 were simulated for Nyköping's system to evaluate the benefits in participating in ancillary markets in these years. Whereas 2021 and 2022 were exceptional years in terms of the high level of day-ahead electricity prices (with monthly average up to 200 EUR/MWh), the simulated future electricity price scenarios are much lower. In this setting, participating in up-regulation markets do not entail as much a loss due to the capacity withheld from the day-ahead market in future years compared to historical years. Hence, while aFRR down is still the most profitable market in the future scenarios, FCR-D up comes close to be as profitable in some scenarios. In some scenarios for future years, participating in aFRR down brings up to 10 % of additional total profits in future years and up to 94% of additional profits when excluding the profits made from selling heat.

The third and final case study looked at the effect of investing in additional flexibility. Nyköping's system was modified to create two improved systems: one with twice as high CHP ramp rates for ancillary services and one with a double large storage. These improved systems were simulated for the historical years of 2021 and 2022. The results show that investments in a larger storage bring about slightly higher additional profits, up to 6% for 2021 and almost 4% for 2022 when excluding heat revenues.

In summary, this report has shown that it is in many cases profitable for district heating system to participate in ancillary services both today and in future scenarios. It has also been shown that investments in additional flexibility towards the electricity sector can generate additional profits.

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