INVESTIGATING THE POTENTIAL OF ENERGY SYSTEMS THROUGH OPTIMIZATION AND TECHNOLOGY INTEGRATION

Optimizing interconnected networks for sustainable operations

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ABSTRACT

It is essential that all sectors quickly adapt to the upcoming challenges of climate change and the new energy landscape, characterized by an increased use of renewable energy. Given that the heating sector constitutes a significant part of our total energy consumption, it faces a particular need to adapt to both stricter emission regulations and the growing integration of renewable energy sources within the energy system. This study focused on how a cogeneration company could take advantage of various technological innovations to adapt to the demands of the future. Through sensitivity analysis and mixed-integer linear programming (MILP) optimization, it proves that heat pumps and the combination of Carbon Capture and Storage (CCS) technology and Thermal Energy Storage (TES) are reliable and profitable investments to improve the flexibility and cost effectiveness of volatile energy systems, especially when electricity prices are low. In conclusion, both TES and heat pumps contribute to good system flexibility in cogeneration plants, which is important to meet the needs and challenges of the future.

Keywords: Combined heat and power, district heating, energy transition, thermal energy storage, heat pump, carbon capture and storage, waste heat utilization, energy penalty, optimization, Mixed-Integer linear programing

PREFACE

This degree project was initiated at Mälardalen University during the spring semester 2024 with the primary goal of fulfilling the requirements for Master of Science in Engineering in Energy Systems. The project has been carried out in collaboration with Söderenergi AB in Södertälje and Sigholm Tech AB in Västerås to investigate the possibilities for improving and strengthening the energy system, with the aim of meeting the future challenges of a cogeneration company through the integration of new technology such as heat storage, CCS technology, and heat pumps.

I am deeply grateful for the incredible support, guidance, and feedback I have received from my supervisor at Söderenergi AB, Björn Kjeang Funkqvist, as well as from several other colleagues who have generously shared their insights. I also want to express my gratitude to my supervisor at Sigholm Tech AB, Kristoffer Hermansson, for the extensive support, the invaluable help and above all the insightful expertise he shared from the energy industry. Furthermore, I would like to express my deep gratitude for the support, guidance, and feedback I have received from my supervisor Valentina Zaccaria during the work. I am also grateful for the valuable feedback from my examiner Valentin Scheiff. All their contributions have been truly significant to the success of my project.

A special thanks to my family for their invaluable support throughout the project, especially for believing in me and my ability to succeed.

Västerås, Sweden in June 2024

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SUMMARY

It is essential that all sectors quickly adapt to the upcoming challenges of climate change and the new energy landscape, characterized by an increased use of renewable energy. Given that the heating sector constitutes a significant part of our total energy consumption, it faces a particular need to adapt to both stricter emission regulations and the growing integration of renewable energy sources within the energy system. This study focused on how a cogeneration company, Söderenergi AB, could take advantage of various technological innovations to adapt to the demands of the future. The investigation focused on the use of technologies such as Thermal Energy Storage (TES), Carbon Capture and Storage (CCS) and heat pumps to enable a smooth transition. Through a sensitivity analysis, this study aimed to investigate how these technologies were assessed based on their supporting role in a volatile energy system, with the goal of ensuring high flexibility and cost effectiveness. In addition, different scenarios were explored, including different sizes of heat storage such as accumulator tanks, to assess their impact on system flexibility and total cost.

A comprehensive review of relevant literature has been carried out to gain an insight in how these technologies could help a cogeneration company adapt better to the energy system. The analyzes were carried out using a model developed by Sigholm Tech AB, which for this study was further developed according to the specific cogeneration company. The model used the optimization method mixed-integer linear programming (MILP) and considered factors such as historical electricity prices and heating loads from the year 2023 as a reference point. The model was verified by performing a sensitivity analysis where different assumptions and scenarios were tested to evaluate their impact on the results. In addition, validation was done to compare the model's predictions with historical data to ensure its reliability. By optimizing based on historical data, the model's ability to adapt to different conditions and circumstances could be investigated.

In summary, the results showed that heat pumps appeared to be reliable and profitable alternatives, especially when electricity prices were low. For CCS plants, profitability was strongly linked to the cost of CO_2 capture, with the potential for good returns at low electricity prices. Furthermore, the combination of CCS plant and TES showed advantages in terms of both profitability and total cost savings. Interestingly, both storage tanks and heat pumps contributed to increased flexibility in cogeneration plants. On the other hand, the results from case study B indicate that the size of the storage tanks had less impact on total cost savings and flexibility than expected, although a larger storage tank could increase the safety and reliability of the system.

CONTENT

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

Symbol	Description	Unit
C_{El}	Electricity cost	[SEK]
C_F	Fuel costs	[SEK]
C_{HP}	Production cost for heat pump	[SEK]
C_{Inv}	Total initial investment	[SEK]
C_{Ref}	Total cost of reference case	[SEK]
$C_{Sen,i}$	Total cost for the specific scenario and case	[SEK]
F	Fuel consumption	[MW]
K	Auxiliary variable	[-]
L	Load change costs	[SEK]
N	Number of starts	[-]
Q_{HP}	Heat production of heat pump	[MW]
$Q_{Load\ Change}$	Load change	[MW]
Q_{MAX}	Maximum power	[MW]
Q_{MIN}	Minimum power	[MW]
Q_{demand}	Heat demand	[MW]
Q_{useful}	Useful power output	[MW]
S	Startup costs	[SEK]
x	Energy flow	[MW]
ΔP	Load change	[MW]
η	Efficiency	[-]

ABBREVIATIONS

Abbreviation	Description
CCS	Carbon Capture and Storage
CHP	Combine heat and power
CO_2	Carbon dioxide
COP	Coefficient of Performance
DH	District Heating

Abbreviation	Description
EO1	Fuel oil
HP	Heat Pump
RT	Reclaimed wood
SöE	Söderenergi AB
TB	Pine pitch oil
TES	Thermal Energy Storage

1 INTRODUCTION

With the increasing global warming, it has become necessary to significantly reduce global emissions. This is crucial to effectively limit the global temperature rise in accordance with the Paris Agreement and avoid the serious negative consequences of climate change. (Klimatpolitiska rådet, 2023). The challenges of establishing a global fossil-free energy system are complex and with this transition, adaptation and implementation of green energy solutions will be crucial. This involves optimizing energy conservation and managing intermittent renewable energy for sustainable and eco-friendly energy production. Efficient adaptation to the new energy system is necessary to meet the challenges and requirements that the future energy sector will pose (Energimyndigheten, 2024).

With the increase of renewable energy sources, the use of combined heat and power (CHP) will increase significantly, indicating that CHP can act as a transitional energy source during the shift from fossil energy to renewable energy (Kim et al., 2019). In connection with this, it becomes necessary that the CHP plants can adapt capacity more quickly, reduce the minimum load, shorten the startup time, and be able to handle overloading (J. Wang et al., 2019). A possible strategy to tackle these challenges is to introduce thermal energy storage (TES) (J. Wang et al., 2019), as this approach is expected to improve adaptability to the fluctuating times that are ahead (C. Chen et al., 2023; H. Wang et al., 2015). According to Christidis et al. (2012), the use of storage tanks is an advantageous strategy when operating CHP systems in urban areas where electricity prices vary. Another way to improve the profitability, i.e. based on CO_2 taxes, and sustainability of a CHP plant is the integration of Cabon Capture and Storage (CCS) technology as it stands out as a promising method to reduce carbon dioxide (CO_2) emissions (Tan et al., 2016). However, this technology has inevitable penalties that affect its efficiency, such as the amount of waste heat lost to the environment, as it cannot practically be utilized within the power cycle (Novotny et al., 2017). Connecting a storage tank with CCS may help save wasted heat if it proves both feasible and economically advantageous. Implementation of heat pumps is also a way to use more renewable energy in district heating networks by taking advantage of sources such as wind power (Ommen et al., 2014b).

In collaboration with Söderenergi AB, a supplier of both heat and electricity through cogeneration and heating plants, and Sigholm Tech AB, a company that actively promotes long-term economic sustainability, the aim of this degree project is to improve the energy system at Söderenergi AB by using an optimization software developed by Sigholm Tech AB. The evaluation will focus on new potential components of a cogeneration plant, such as storage tanks and heat pumps, to effectively balance production and demand and thereby ensure availability. Furthermore, given that Söderenergi AB has already decided to implement CCS, it will be interesting to analyze the storage tank in connection with CCS to optimize the use of the waste heat.

1.1 Background

1.1.1 *Cogeneration plants in the Energy Transition*

The role of the cogeneration plants will have a major impact in the energy transition thanks to its high efficiency. In step with the ongoing transition to renewable energy, the electricity load demand for electricity increases, which in turn requires a reliable and flexible energy system (Nuytten et al., 2013). A reliable and flexible energy system enables the diversification of energy sources, where cooperation between several sources becomes necessary to fulfill society's needs. With this, CHP is one of the sources that will be able to balance and supplement the fluctuating production from renewable sources, providing a stable and reliable energy supply (Kim et al., 2019; J. Wang et al., 2019). Given that CHP is flexible, it means that the plant can handle ramp speed, minimal load, and fast start-up time, ensuring efficient adjustment of production levels to balance demand and meet market variations (J. Wang et al., 2019). In addition, the study mentioned that the minimum load enables the production of minimum power during periods of low energy prices, to minimize economic losses and support renewable energy.

Because CHP combines both heat and electricity supply, the efficiency increases, which makes the process more efficient where both energy losses and emissions of greenhouse gases are reduced. Mago & Smith (2012) also show the importance of using more CHP systems because of its reduction in negative emissions, depending on fuel used. In other words, with the right fuel or the right advanced technology, the CHP systems can contribute to reducing or prevent emissions of greenhouse gases or other harmful substances that contribute to climate change or air pollution. This combination of heat and electricity production makes CHP an asset for balancing both the electrical grid and district heating network to ensuring a constant power supply, especially during periods of high demand. Furthermore, by using optimization tools in CHP plants, this can contribute to cost savings by optimizing energy use and reducing operating costs using advanced algorithms and models (Cho et al., 2009). Even if a CHP plant is flexible today, it will not be enough when the energy system integrates more renewable energy sources. Therefore, it will be necessary to further adapt the CHP plant to handle the increasing fluctuations in energy production.

1.1.1.1. *Integration with Thermal Energy Storage*

Thermal energy storage (TES) systems are a good way to improve its current system efficiency in a way that it will be more adaptable and flexible in context to load demand. Nuytten et al. (2013) points out that central thermal energy storage should be implemented to achieve optimal flexibility in the system. An implementation of TES enables more efficient use of renewable energy when it is available, which can lead to reduced energy consumption and increased flexibility as well as the ability to offer services that compensate for challenges related to supply and demand (Li & Zheng, 2016). Furthermore, Turunen et al. (2020) has shown that short-term optimized planning and use of heat accumulators can increase the profitability of CHP production by several percent by lowering operating costs. By optimizing the utilization of renewable energy sources, TES becomes a main tool for achieving a sustainable and resilient energy infrastructure.

One form of TES is heating accumulator, where substance like water is stored and then released when it is needed. By using heat accumulators, flexibility is created to interrupt heat production and supply within the district heating network during periods of low demand (Christidis et al., 2012). Instead, the excess heat can be stored to be distributed during periods of higher demand, where Sarbu & Sebarchievici (2018) notes that this will also improve the thermal reliability and performance of the system. This, in turn, increases the stability and reliability of the district heating system. The flexibility introduced by TES not only improves these properties but also plays a critical role in reducing CO_2 emissions, by avoiding production with high emissions, and reducing energy costs.

Furthermore, by being flexible in how we use energy, control programs can effectively balance TES together with CHP, providing both economic and practical benefits (Streckiene et al., 2009; Verda & Colella, 2011). With this, a CHP plant can produce its maximum capacity and then store it until the demand for either electricity or heat is high. This can help mitigate power peaks and improve grid stability, where companies can also benefit from fluctuations in electricity and heat demand. However, for it to be profitable to implement TES in a CHP system, the size of the TES must be considered as different sizes can lead to different results (Lepiksaar et al., 2021).

1.1.1.2. Integration with Carbon Capture and Storage

Another technique that has generated more interest is Carbon Capture and Storage (CCS), where the focus is to capture the CO_2 emissions from the energy production and then store it in different ways, often underground. This technology has three different methods, which are post-combustion capture, pre-combustion capture, and finally oxy-fuel combustion where fuels are burned in pure oxygen to simplify the separation of CO_2 (Tan et al., 2016). Furthermore, the study also points out that after CO_2 has been captured, it must be transported to a suitable location and then stored. By implementing CCS in current systems, such as CHP, they can continue to produce energy while reducing CO_2 emissions. While renewable energy sources are growing, CCS technology can be a good starting tool to decarbonize the fossil fuel energy system until cleaner alternatives become more widespread.

The costs of implementing a CCS system in a CHP plant are dependent on the specific plant's characteristics, operational environment, and system boundaries (Kärki et al., 2013). In the same way that this affects investment costs, the study shows that electricity prices and CO_2 emission allowances are a contributing factor to whether the feasibility of implementing CCS technology is profitable or not. Given the challenges facing society, the current cost challenges of CCS can be considered almost negligible in terms of reducing CO_2 emissions. Apart from this, other ways may need to be explored to review the viability of CCS, where one way may be to combine TES with CCS to use the waste heat efficiently.

1.1.1.3. Integration with heat pump

Heat pumps play a central role in the energy transition by offering an efficient and sustainable method for heating and cooling. Just like TES, the integration of heat pumps in cogeneration plants enables a significant improvement of the current energy system. These heat pumps can quickly adapt to sudden variations in electricity prices by being used when electricity prices are low to generate heat. Through this method, excess electricity, produced during periods of high renewable energy production, can be efficiently converted into heat, and then stored in the district heating system for later use when demand exceeds renewable energy production (Levihn, 2017; Münster et al., 2012). In this way, heat pumps can act like an energy storage which can absorb and store excess heat from cogeneration plants and other processes.

Furthermore, heat pumps can contribute to release and optimizing the production of both heat and electricity at the cogeneration plants, without being limited by specific production quantities (Ommen et al., 2014b). This means that heat pumps can be adapted to demand and used to provide heat in different sizes and at different times. This means that they can supplement production at the cogeneration plants and function as a flexible complement to meet varying needs.

1.2 Purpose/Aim

The different scenarios that will be compared in this degree project include current energy system, current energy system with heat storage tank, current energy system with CCS technology, current energy system with both CCS technology and heat storage tank, and current energy system with heat pump. The purpose of this degree project is to analyze and identify the potential in various investments and change opportunities, depending on which scenario is investigated. At the same time, a detailed comparison will be carried out between the different scenarios to concretize which ones offer the most profitability and flexibility.

1.3 Research questions

This degree project aims to answer the following research questions to achieve its purpose.

- What is the impact of varying proportions of renewable energy integration in the electricity market on the total cost and flexibility within each scenario compared to the reference scenario?
- What is the impact of different sizes of accumulator tanks on both total cost and overall flexibility of the scenarios considering accumulator tank compared to the reference scenario?
- How do the variations in each scenario impact other facilities within the system, including their operating times and energy quantities?
- Which scenario offers the highest total cost savings relative to the initial investment?

1.4 Delimitation

This degree project will examine the energy system for Söderenergi AB, with a focus on modelling as far as the management goes, excluding the energy system of Stockholm Exergi but including the transmission between the two energy systems.

Furthermore, the pumps in the district heating network will be neglected, and the modelling will only focus on the overall power and energy balance of the current energy system. This is to simplify and strategically focus on the central aspects of the energy system and its possible improvements. The boilers relate to different fuels, with some being more flexible than the other. In this case, the production cost of a fuel per boiler will be used to simplify the model.

Since the energy system will be studied locally, several assumptions will have to be made for each scenario depending on which parameters are used. Some of these main assumptions include district heating load and electricity prices. Further assumptions for these different scenarios can be found in section 4.

2 METHOD

The methodology section of this degree project provides a comprehensive outline of the strategies employed to address the research questions. It covers a detailed description of the literature review, outlines the procedures for data collection, identifies the simulation tools utilized, and includes a validation and verification process for the developed model.

2.1 Literature study

A literature review for this degree project has been conducted to review existing research that is related to cogeneration plants and how different technologies can contribute to reliable and flexible systems. To access information from previous studies, this degree project conducted research using search engines and databases such as Google Scholar, Science Direct, DiVA, and MDPI. Emphasis was placed on prioritizing peer-reviewed studies in the compilation of relevant literature. The keywords that have been used to obtain these literature reviews are as follows: *CHP, CCS, TES, Energy transition, Sensible heat storage, Latent heat storage, Thermochemical storage, Hot potassium carbonate, Amine scrubbing, waste heat utilization, energy penalty, Mixed-Integer Linear Programing, Heat pumps.*

2.2 Data collection

The data collection methods used in this work include a compilation of various metrics and analysis of plant descriptions to make predictions for the different cases. The compilation of measurements for each boiler, such as operating time, power, electricity production and cost, has been examined at Söderenergi AB's facility Igelstaverket with the support of my supervisor at the company. Documents of plant descriptions has been received from my supervisors at Söderenergi AB. In this work, the data will be used to describe each boiler's specific characteristics, including total output, efficiency levels, boiler start-up time, fuel prices and more. In addition to this, historical electricity prices per hour, collected from Nordpool with the cooperation of Söderenergi AB, as well as historical heating load from Söderenergi AB from the year 2023 will be integrated into the model. These will serve as both a structural basis for the optimization and as reference points for the analysis.

2.3 Simulation tool

To achieve the goal of this degree project, several energy system models will be developed with the support of the optimization software Aurora by Sigholm (AbS). A basic optimization model is provided by Sigholm Tech AB, and this model will be further developed and adapted to the energy system at Söderenergi AB. AbS is based on economic optimization, where Mixed-Integer Linear Programming (MILP) is used as an optimization method with the aim of minimizing the total costs of a system. AbS offers services in power and heat production by generating predictions and analyzes using production data. The platform helps organize, analyze, and propose optimal operating strategies for production facilities. (AuroraBySigholm, n.d.). The functions of the program are based on the use of hourly values and offer opportunities for both short- and long-term planning. This program is considered a good tool because of its ability to adapt to different needs and the user-friendly interface.

AbS will be used as the primary tool to perform simulations and collect relevant data as it is of interest of Söderenergi AB to use this tool. The program creates optimal production plans that include operating times, power, electricity production and costs. What will be analyzed is the total of these variables to enable a comparison. The model development and management of historical data are undertaken through programming. In addition, a significant part of the work will involve analyzing the results from different simulations and then comparing the resulting production plans with each other. These different simulations will include different case scenarios for comparison. The first case study A will involve modelling with varying proportions of solar and wind energy integrated within the electricity market in each scenario. This is done by examining how both fluctuating electricity prices and different price levels can affect performance and financial sustainability. The second case study B will involve modelling with different sizes of heat storage tanks and analyzing their impact on the overall flexibility of the energy system. It includes an examination of how different sizes affect the system's handling of excess energy as well as which size provides optimal cost effectiveness versus energy efficiency.

Furthermore, it is important to note that heat storage/accumulators are already represented in AbS, while the CCS technology is modeled considering conditions in the plant, where a simplified model is developed to integrate its impact on production as a condition in the optimization model. This simplified model will be assumed to be a hypothetical plant that will be modeled according to recommendations from the company Söderenergi AB, where an iterative process will be carried out to improve and fine-tune the models.

2.4 Verification and validation of the model

The model will be verified through a thorough sensitivity analysis. In this analysis, different assumptions and case scenarios will be systematically tested to assess their individual impact on the results. In addition to this, comparisons will be made between the model's predictions and historical data to further validate its performance. By carrying out an optimization based on historical data, the model's ability to adapt to different conditions and circumstances can also be carefully examined.

3 LITERATURE STUDY

The literature study of this degree project will provide an overview of what has been accomplished so far in the topic of interest. The first part begins with an introduction of different heat storage technologies within the system. This is followed by a description of various CCS technologies integrated in CHP systems, where information about previous studies' views on the utilization of waste heat from CCS is also presented. In addition, there is a description of heat pump within the system and how they contribute to flexibility. Finally, the basic principles behind how the optimization works are explained.

3.1 Different heat storage technology integrated in CHP systems

A study by Sharma et al. (2009), mentioned that heat storage can be stored in three different ways, which are sensible heat, latent heat, and thermochemical storage. In sensible heat storage, the study addresses that thermal energy is accumulated by increasing the temperature of a solid or liquid material, where the system then benefits from the material's heat capacity and temperature change during charging and discharging. Water is considered the most suitable fluid for sensible heat storage, both because of its low cost and high specific heat capacity (Li, 2016; Sharma et al., 2009). With this, water tanks are commonly used, which means that factors such as tank size, shape, location and flow rates during charging and discharging will affect the thermal stratification in the tank (Li, 2016). Furthermore, Li (2016) emphasizes the importance of optimizing tank design and operating conditions to ensure effective thermal stratification and reduce heat losses during the storage process.

Compared to sensible heat storage, a latent heat storage system uses phase change materials to store or release heat energy, meaning the material melts from solid to liquid to absorb heat or solidifies from liquid to solid to release heat (Tao & He, 2018). The benefit of latent heat storage is that it can handle higher energy densities and smaller temperature variations (Tao & He, 2018), but that the sensible heat storage offers a cheaper and more simple system that is easier to control (Li, 2016). Thermochemical heat storage focus on chemical reactions to absorb and release energy, by breaking and re-forming molecular bonds in a chemical reaction (Aydin et al., 2015). The study points out that this method appears to outperform both sensible and latent heat storage in terms of storage density materials, but that thermochemical heat storage materials require highly efficient heat and mass transfer to perform their thermal processes optimally.

Heat storage techniques are adaptable and can be applied in several areas:

- Both sensible and latent thermal storage systems have shown promise for a variety of thermal applications. Parameshwaran et al. (2012) point out that both technologies have been widely used in the building sector and in solar thermal power plants. Sensible heat storage systems are also widely used in district heating applications, while latent heat storage systems are mainly found as prototypes in laboratory-scale experiment (Li, 2016; Li & Zheng, 2016).

- Thermochemical heat storage is a relatively new and promising technology that appears to have its advantages over sensible and latent heat storage systems. According to Aydin et al. (2015) thermochemical heat storage has potential in various fields, but further research is needed to fully understand its advantages and limitations. The study highlights that the technology can be particularly beneficial for increasing flexibility and supporting the use of renewable energy sources, such as storing heat during the summer for use during the winter period. Furthermore, another study by Desai et al. (2021) highlighted thermochemical heat storage as a potential solution to maximize the utilization of renewable energy sources, especially in the heating and cooling sector. Despite this, it is emphasized that there are still areas that require further development and research for these type of applications (Aydin et al., 2015; Desai et al., 2021; N'Tsoukpoe & Kuznik, 2021).

In this study, the methodology will be modeled after sensible heat storage, both due to its ease of use and its common application in district heating systems. Furthermore, this method is requested by the company in question.

3.2 Different CCS technology in CHP systems

Post-combustion capture, pre-combustion capture and oxy-fuel combustion are the three different categories that the CCS technology can be divided into. According to Tan et al. (2016), an implementation of post-combustion capture appears to be simpler as no major changes are required to the existing system, where chemical absorption is a common method that is particularly effective at low concentrations of CO_2. For chemical absorption, different solvents are used to be able to separate the flue gases from CO_2, where amine solvents are commonly used. Another solvent that appears to have its advantages is the potassium carbonate solution (Borhani et al., 2015). The flow chart of the chemical absorption, Figure 1, is generally the same regardless of the solvent used.

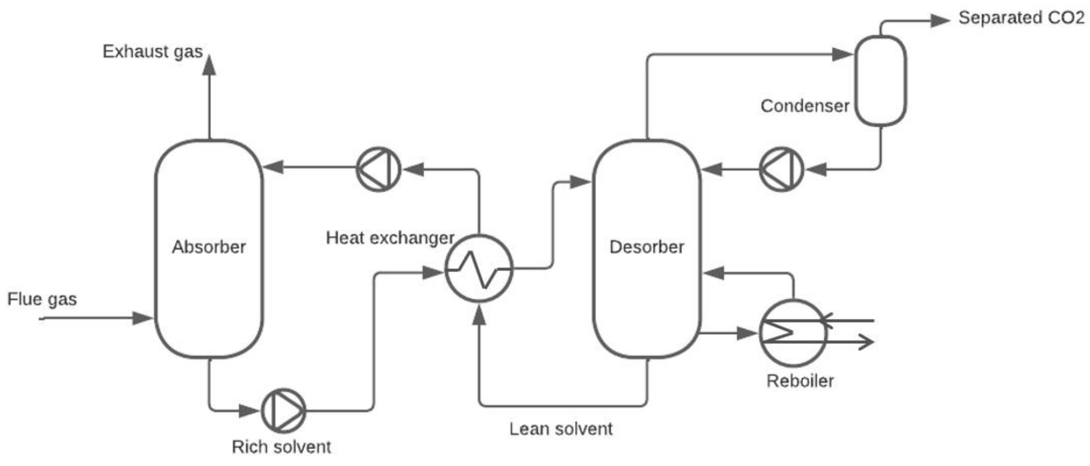

Figure 1-Flow chart of a chemical absorption process. Adapted by (Nagy & Mizsey, 2015)

Explained by both the studies of Nagy et al. (2015) and Tan et al. (2016), the process works in such a way that the flue gases are introduced into the absorber where the solvent is injected to capture CO_2 from the flue gases. From the absorber, the CO_2-rich solvent is taken to the desorber where it comes into contact with the stripping steam from the reboiler and this is done in a way that the CO_2 can leave the desorber without the solvent. This solvent undergoes regeneration when the CO_2 is separated to be reused in the process.

Additionally, Tan et al. (2016) mentions that physical absorption and membrane separation are possible separation methods for pre-combustion capture. The process of physical absorption mainly focusses on separating the CO_2 from the gas mixture of carbon monoxide and hydrogen by using physical solvents, where the separated CO_2 (created by carbon monoxide and steam) is sent for compression, while hydrogen is used in a combined cycle for electricity production (Kanniche et al., 2010; Tan et al., 2016). For membrane separation, especially when a polymer membrane is used, a separation of CO_2 from the flue gas occurs through a process that involves first absorption of CO_2 into the structure of the membrane, then transport of CO_2 through the membrane where other gases are prevented from passing, and finally release of CO_2 on the side of the membrane where the permeate is present (Vaughn & Koros, 2014). The third category, oxy-fuel combustion capture, involves burning a substance in oxygen while reusing the resulting exhaust gases, which consist of CO_2 and water, where the CO_2 stream is also cleaned to remove any gases that cannot condense (Kanniche et al., 2010).

In this case, the company seems to have a stronger interest in post-combustion with chemical absorption as the preferred technology in their energy system.

3.2.1 Waste heat utilization from CCS technology

Although CCS technology is now used by several companies, its cost continues to be a significant barrier to making it economically viable. According to a study by Budinis et al. (2018) this is the main obstacle to a rapid expansion of CCS, but that it is expected to improve in the longer term. Besides the cost barriers, CCS technology also requires a lot of energy for its process to capture and store CO_2, where Harkin et al. (2010) attempt to make the implementation of CCS in coal-fired power plants more cost-effective and feasible through optimization and the use of heat integration. The study shows that combining heat integration with CCS holds significant promise for mitigating the energy penalties associated with CCS use. Using linear programming optimization and heat integration strategies together with CCS in coal power plants, a reduction of up to 50% of the energy penalty can be achieved (Harkin et al., 2010). A heat integration strategy for post-combustion technology, investigated by Pfaff et al. (2010), includes the use of heat from both the condenser above the desorber and the CO_2 compressor intercooler from the CO_2 separation process to preheat the combustion air by up to 0.59 percentage points. This leads to a noticeable improvement in system efficiency.

Furthermore, a study conducted by Novotny et al. (2017) highlight how waste heat recovery, integrated within three different CCS technologies, such as oxyfuel combustion, ammonia-scrubbing based post-combustion and pre-combustion, can significantly increase plant efficiency. By separating streams from the main cycle, this method can both increase efficiency and provide economic benefits. However, it appears that the post-combustion technology only has an efficiency improvement of 0.1 percentage points, unlike the pre-combustion technology that has 4.2 percentage points (Novotny et al., 2017). Using organic Rankine cycle technology for waste heat recovery from the CO_2 compression process seems to be a promising solution to make the system more efficient as well as increase the economic performance of CCS systems (Pei et al., 2014; Ye et al., 2021). Pei et al. (2014) suggest that by modelling waste heat recovery from different compression strategies, such as intercooling and shock wave compression chains, organic Rankine cycle waste heat recovery significantly improves the performance of the shock wave compression chain, resulting in energy savings of up to 30% compared to the intercooling option.

Several studies have highlighted the importance of efficiently utilizing the waste heat from CCS technology in power plants. Despite this, there is still a research gap in defining an optimal direction for the excess heat generated if it is not immediately needed. Instead of letting this heat be lost, there are opportunities to explore and develop methods to integrate and store the excess heat, where a possible solution could be to combine the waste heat with an energy storage, such as an accumulator tank. This integration of excess heat with energy storage systems would not only reduce energy losses but also increase the flexibility and efficiency of the facility significantly more. A study by Chen et al. (2023) have investigated how flexible load management can be integrated with CHP, CCS, and power to gas through an optimal scheduling model. The results showed effective reduction of system peak control pressure and operating costs by including flexible loads, such as electricity and heat. The study also showed reductions in carbon emissions and daily operating costs, highlighting the importance of integrating flexible load management to improve the system's economic and environmental performance.

Chen et al. (2023) emphasize the importance of further research to address the uncertainties associated with the integration of clean energy and aging infrastructure into integrated energy systems. This is an aspect that this degree project will address and explore in more detail.

3.3 Heat pumps integrated in CHP systems

As previously mentioned, the integration of heat pumps into the system will increase the efficiency thanks to their quick adaptability and independent nature in terms of other production quantities. A heat pump works in such a way that heat is moved from a source with a lower temperature to a destination with a higher temperature. To make this possible, a refrigerant is used that circulates through a series of evaporator, compressor, condenser, and expansion valve, which means that the refrigerant absorbs heat from a source such as the air or groundwater via the evaporator and then transfers the heat to a heating system through the condenser. To facilitate this heat transfer, the compressor increases the pressure and temperature of the refrigerant. In this way, a heat pump can efficiently heat a space with minimal energy consumption, making it an energy efficient and environmentally friendly solution for heating.

Ommen et al. (2014b) show through their research that the integration of a heat pump in a cogeneration system can lead to improvements in the overall performance of the system and a reduction in fuel costs. By choosing the right configuration and adapting it to different temperature profiles and needs in the district heating network, the opportunity to optimize heat pump strategies is highlighted to further improve the overall economic performance of the system. A study by Blarke & Lund (2008) highlights how heat pumps in CHP systems can effectively contribute to flexibility by storing energy and redistributing it when needed. The study also highlights that heat pumps have a significant capacity to store cold energy, which resulted in an improvement in power plant fuel efficiency from 92.0% to 97.2%. Furthermore, the research conducted by Wang et al. (2022) showcased the effectiveness of electric heat pumps as waste heat recovery systems within CHP plants. This integration enables the decoupling of heat and electricity production, leading to significant energy savings, particularly evident in scenarios with reduced power demand. However, the study highlights that the efficiency of electric heat pumps systems depends on the coefficient of performance (COP), underscoring the importance of accurate design and operation.

Since both heat pumps and heat storage appear to be beneficial options in terms of increasing the flexibility of CHP systems, several studies have been carried out to investigate how a combination of these two technologies could be implemented. Renaldi et al. (2017) have explored the potential of using heat pumps in combination with TES in residential heating systems as an alternative to conventional systems. The study points out that although it may involve higher initial investment costs compared to natural gas boiler systems, the combination of heat pumps and TES results in lower operating costs over time. This is because the integration of thermal energy storage enables a more efficient use of the heat pump's capacity and takes advantage of periods of lower electricity prices. Although the initial costs may be higher, the long-term savings in operating costs usually result in this combination being a more cost effective and energy efficient option in the long run.

Both Sorknæs (2018) and Tosatto et al. (2023) have emphasized the importance of integrating TES with heat pumps to improve the flexibility and reliability of the district heating network and meet the challenges of increased use of renewable energy. Sorknæs (2018) emphasizes that interest in seasonal thermal energy storage systems in combination with heat pumps has increased, but that the implementation of such systems is more complex compared to short-term thermal energy storage. The study presents a simulation method to deal with this complexity. Tosatto et al. (2023) have found that combining large-scale TES with a heat pump improves the efficiency of the entire system by the heat pump effectively utilizing the heat storage volume to recharge itself. The study highlights the importance of conducting system-level analyzes to understand the overall impact of TES design and heat pump size on energy efficiency and CO_2 savings. It also emphasizes the need for economic evaluations to assess final energy costs, including investments, energy charging costs and savings from reduced gas consumption.

3.4 Modelling and optimization

As previously mentioned, Mixed-Integer Linear Programming (MILP) is used as an optimization method in Aurora by Sigholm (AbS) to minimize the total costs of a system. A study by Bellabdaoui & Teghem (2006) addresses how effective the use of optimization models has become for planning and scheduling, where MILP is a model that stands out through its ability to handle both continuous and discrete decision variables. Another study by Samsatli, S. & Samsatli, N.J. (2018), focuses on using MILP to establish an efficient urban energy system to save energy by optimizing the design and operation of heating and electricity networks. This study explains in simple terms what discrete and continuous decisions mean, where discrete decisions are about deciding whether certain pieces of equipment or infrastructure exist and where they are located, while continuous decisions involve setting the capacity and operation of equipment, for example how much heat and power to be generated at a given time by each unit.

Since the MILP formulation includes both linear functions and integer constraints, it becomes possible to handle a wider class of problems compared to linear programming alone. By integrating linear components and integer constraints into a model, MILP can effectively solve complex problems within various manufacturing companies. Yang et al. (2015), for example, use MILP to minimize the total annual cost by optimizing the design of distributed energy resource systems. The study considers factors such as equipment performance, energy requirements, network limitations and financial considerations. To handle the complex calculation process, the researchers choose to simplify by evaluating only a few days that represent seasonal and daily variations in energy demand. These days capture typical weather conditions and energy use patterns in the area during different periods of the year. The study also considers operating variables that affect the daily operation of the system and treats them as continuous variables. Important constraints, such as energy balances and performance characteristics, are considered to ensure that output matches demand. The study focuses on optimizing the operation of a significant part of the energy system regarding cost efficiency and heat demand. Although the study addresses waste heat recovery, it lacks a detailed focus on cogeneration, including aspects such as heat storage and CCS technologies.

Looking deeper into the study of Bellabdaoui & Teghem (2006), a MILP model has been developed to optimize production planning in manufacturing companies, especially in continuous casting steelmaking processes. The aim of the study is to schedule the production of steel containers to maximize productivity while complying with various constraints. This method is similar to the approach used by Yang et al. (2015), where several constraints, decision variables such as binary and continuous variables, and model parameters such as start times and processing times, are integrated into the model. The difference between the study by Bellabdaoui & Teghem (2006) and Yang et al. (2015) lies in the target definition, where the focus is only on the optimization of steel container production without consideration of cogeneration processes.

Samsatli, S. & Samsatli, N.J. (2018) apply a MILP model in their method, as previously mentioned, which primarily focuses on energy savings by optimizing the configuration and functionality of heat and electricity networks for urban energy systems. Their method involves a zoning of the city and modelling of various aspects such as resource needs, conversion technology, transport infrastructure and storage systems. The mathematical model focuses on ensuring resource balance, where net production, inflows from other zones, imports and withdrawals from energy storage must meet the demands and exports of each resource in each zone and time interval. This method includes constraints on imports, exports, conversion technologies, and storage, along with performance indicators and an objective function to be minimized. The study focuses on optimizing and modelling the entire infrastructure of an energy system, which makes the method more complex than what is covered in this degree project. However, it seems that the model cannot fully handle the complexity that arises from the integration of emerging technologies such as heat pumps and CCS systems into existing CHP systems. Furthermore, their focus on energy savings is not fully compatible with the goal of balancing cost-effectiveness and energy efficiency while considering the interaction of multiple components.

Another study by Möhren et al. (2022) presents an approach to optimize the integration of TES in multiperiod heat integration models, considering both technical and economic aspects. By combining linear programming and MILP techniques with the principles of pinch analysis, the method aims to optimize the performance of the TES system. The study discusses the cost aspects of implementing TES systems, which includes assessments of tank material, insulation, and volume to optimize total costs. This assessment includes capital costs, operational costs, and other relevant factors to calculate the annual costs of the TES integration. Although the study does not directly address the integration of TES with CHP systems, parts and principles from their method will be applicable and useful for this degree project.

The studies cited highlight how MILP addresses various factors via an objective function. Typically, this function aims to minimize costs or energy usage, incorporating constraints tailored to the specific context (Bellabdaoui & Teghem, 2006; Samsatli & Samsatli, 2018; Yang et al., 2015). By applying MILP in this study, the model can contribute with efficient and robust optimization solutions for the energy system being studied. Why MILP seems to be a suitable optimization method for this type of problem formulation is mainly due to its flexibility when it comes to complex conditions unlike LP (linear programming) (Ommen et al., 2014a). The study by Ommen et al. (2014a) highlight that while LP provides a simpler and more structured approach to optimization, MILP introduces additional complexity by considering discrete decision variables, potentially leading to more realistic and detailed results, especially in systems with non-linear relationships and discrete decision requirements.

4 CURRENT STUDY

The current study of this degree project aims to investigate different scenarios and cases to assess their potential for enhancing the current energy system employed by Söderenergi AB. Additionally, the study provides an overview of the existing energy system at Söderenergi AB.

The optimization analysis was usually performed over an annual period to get an overall picture of the system's performance. By basing the optimization on data from the year 2023, which was chosen because it represents current and comparatively normal weather compared to previous years, a more realistic assessment could be made of the total costs for different cases. During this time, changes in the total cost of production were examined depending on different scenarios, which enables the study of other relevant figures and key figures. By analyzing over a year, insights could be obtained about the system's long-term effectiveness and its ability to handle variations in demand and resource availability over time. To carry out annual simulation of the various cases and scenarios, the simulation was divided into two-month sequences. Six such simulations were carried out for each part and case scenario to avoid overly complex calculations and enable a more detailed and manageable analysis. These monthly simulations were then aggregated to generate a full-year overview and provide a comprehensive understanding of system performance over time.

As Yang et al. (2015) explored in their study, the optimization also considered specific weeks during spring and winter, to understand how the production of different boilers was affected by seasons and weather conditions at a deeper level. These time periods were chosen to reflect times when loads are typically high, and temperatures can vary significantly. These different weeks were handled from the monthly simulations. By analyzing the performance of the boilers during different periods of the year, one could gain insights into their behavior and efficiency under varying climatic conditions. This differentiation enables a more detailed and customized optimization of the system to ensure efficient operation and cost minimization throughout the year.

Table 1 lists the days that were examined more closely. These days had been chosen to explore the system's behavior during periods of weather uncertainty and when heating demand was at its highest. This is done to analyze the flexibility of the system in these cases with different scenarios and to observe the performance of the system when all devices were active.

Table 1-Observed time intervals from yearly simulations

2023	
Days during spring	Days during winter
5/3–19/3	1/12–14/12

4.1 Current Energy System at Söderenergi AB

The company Söderenergi AB is a district heating and electricity supplier where cogeneration and heating plants are used to meet demand. To meet this demand, the company has a CHP plant and five heating plants where heating boilers are used. These different facilities are located in different places around Södertälje and near the Stockholm area. The largest area is called the Igelstaverket where the CHP plant (IKV) is located together with a heating plant (IGV) where three different heating boilers are found. IKV, heating boiler 1 (IGV-P1) and heating boiler 3 (IGV-P3) are counted as base production, while heating boiler 2 (IGV-P2) is counted as peak production. These base production plants have flue gas condensation (FGC) integrated into the system. It is also possible to bypass FGC for IGV-P3 and IKV. Since IKV is a CHP plant, there are two main operating modes to maximize its energy utilization. The first option involves running the turbine for electricity production and extracting heat from the condenser (IKV MT). The second option, (IKV DK), means that a bypass past the turbine is used to directly supply heat to the condenser, without the turbine being used for electricity production.

Fittjaverket (FIV) is another area where a heating plant is located containing two heating boilers. At present, however, only one of them is used, which means that one boiler (FIV-P4) will be used in the modelling. This facility is counted as an intermediate and peak load facility. Söderenergi AB also has two heating plants that count as reserve plants where two heating boilers are placed in each facility. These areas are called Huddinge Maskincentral (HMC) and Geneta Panncentral (GPC) and are used as peak production to cover demand during colder periods. It is worth noting that the total power will be used for these two plants, meaning a total power value for HMC (HMC-Tot) and a total power value for GPC (GPC-Tot) as the differences in cost are negligible.

The distribution of district heating takes place through an interconnected district heating network, owned, and operated by market companies in various municipalities such as Telge Nät AB, SFAB and Stockholm Exergi AB. Figure 2 illustrates the distribution of the heat flow within the district heating network between the various production facilities and where the transfer between the two energy systems, Söderenergi AB and Stockholm Exergi, takes place.

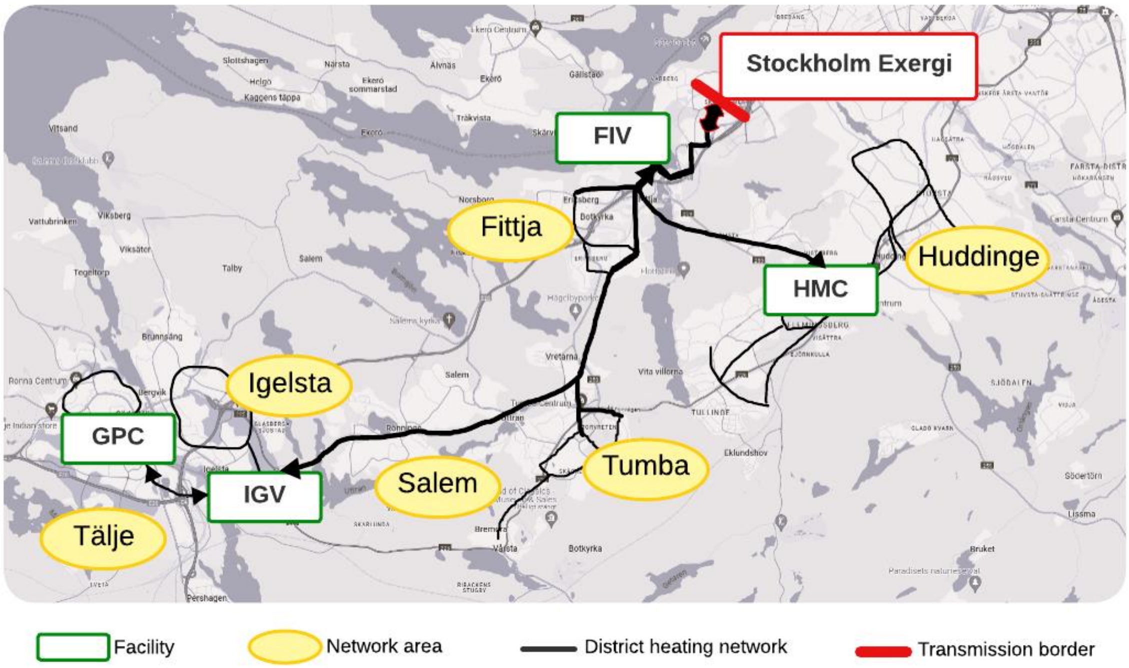

Figure 2-District heating network for Söderenergi AB

There are certain transmission limitations in the district heating network and one of them is that the production from HMC can only provide heat to Huddinge. Within the district heating network, a prominent factor is that a significant part of the heat production from FIV-P4 is delivered to Stockholm Exergi and covers approximately 75-80% of their heat needs. This contrasts with other boilers, where the delivery to Stockholm Exergi from IGV-P3, for example, reaches a maximum of approximately 35%. To get a complete picture of the network's capacity and loads, it is also important to consider the network areas. By identifying and analyzing these areas, a deeper understanding can be gained of the biggest stresses and challenges in the system. Another transmission limitation that may be good to consider is pressure losses. Even if the pumps are neglected, some losses will still occur due to the long distribution distances. The pressure losses will not be included in the model because of its complexity and timeframe of the work, but it is important to be aware of them when analyzing the results.

The data was based on each boiler's characteristics, including total output, efficiency levels, boiler start-up time, fuel prices and more. To further improve the optimization, historical electricity hourly prices and hourly heat loads from 2023 were used to provide a more realistic framework. The weather conditions were used more to be able to analyze how the heat production relates to it. The flexibility of each scenario was investigated over two weeks in March and December 2023, where the optimal schedule without any integration of new technology will serve as the reference scenario. Therefore, the model will be verified and validated to ensure that it reflects the actual result of the heat production during these specific weeks. The input data for the model can be observed in Table 2, containing all the characteristics of each boiler. This type of data was valuable for the model and the optimization to know how the boilers can operate and to know its limitations. The input data consists of maximum and minimum power, efficiency, start costs, minimum start-up time and load change rate for each boiler and if they are using FGC. Electricity and heat exchange only exists for IKV due to its ability to produce both heat and electricity. Historical electricity prices were also obtained through Söderenergi AB.

The initial cost of the turbine represents an assumed initial cost to ensure that the turbine operates at its lowest possible load. This was important to ensure that the optimization process better reflects real operating conditions. By including this start-up cost in the model, the actual process of starting and running the turbine is considered, providing a more realistic picture of system performance and costs.

Table 2-Characteristics for each boiler

Boiler name	Boiler type	Max power [MW]	Min power [MW]	El-exchange [%]	Heat-exchange [%]	Efficiency [%]	Start Costs [SEK]	Min Uptime [h]	Load Change Rate [MW/h]
IKV	Base production plants	250	60	33%	62%	92%	400 000	48	35
IKV MT		155	70				100 000		
IKV G1		82	12				800 000		1 000
IKV DK		230	60						
IKV FGC		55	0			22%			
IGV-P1		80	35			89%	120 000	24	25
IGV-P1 FGC		12	0			15%			
IGV-P3		80	35			89%	240 000	24	25
IGV-P3 FGC		16	0			20%			
FIV-P4	Intermediate plant	130	40			92%	6 767	20	1 000
IGV-P2	Peak production plants	55	20			92%	20 000	2	1 000
HMC-Tot		150	15			88%	3 000	2	1 000
GPC-Tot		60	5			88%	3 000	1	1 000

Figure 3 represents the actual outcome of the heat production from each unit from two weeks in March 2023. These outcomes are aligned with the corresponding electricity prices and weather conditions (b) to clarify the behavior of the system. Each unit and heat load are presented in the box outside the diagrams in each figure. This type of figure, diagram (a), shows how each unit should be operated optimally to maximize system profitability, where this is often is called a production plan. A production plan can be just days, weeks, or a year to have a short-term plan or a long-term plan, depending on the questions asked. The units are stacked on top of each other, with base production at the bottom, followed by intermediate load and peak production at the top. In this case, the most profitable units must operate simultaneously at a certain time to match the total heat demand, which is represented by the thick black line in the diagram. The optimization considers the conditions of these different units to identify the best plan based on external factors such as electricity prices and weather conditions.

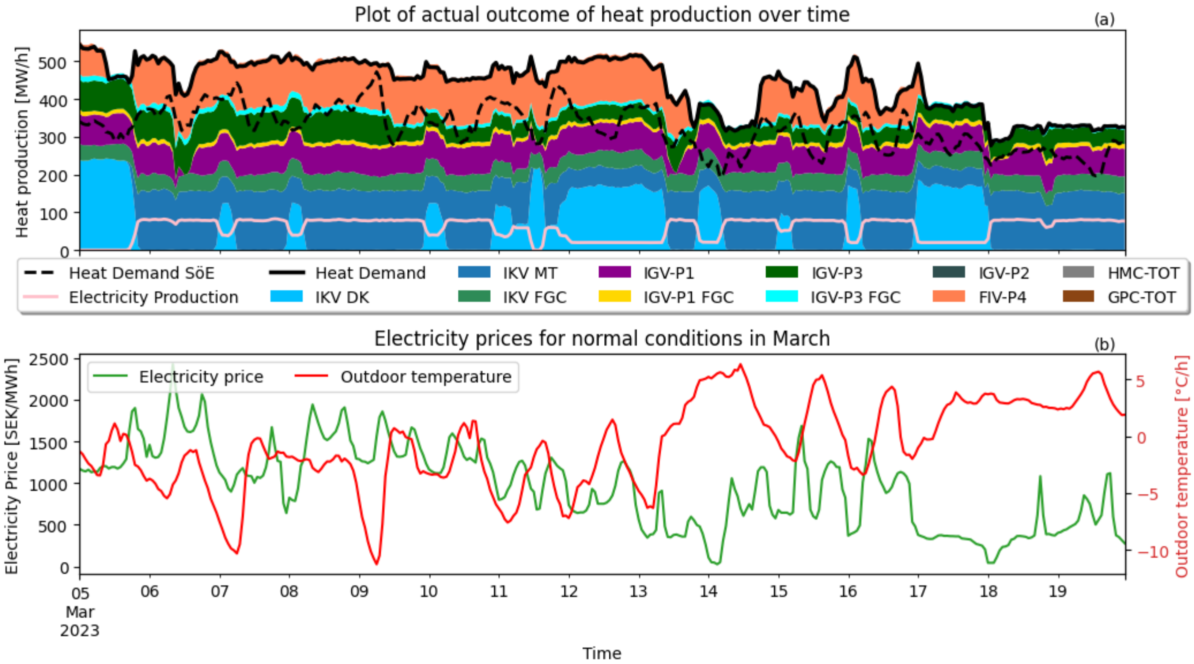

Figure 3-Heat production for actual outcome (a) vs. Historical weather & electricity data (b) for two weeks in March 2023

Figure 4 illustrates the same principle as Figure 3 but for two weeks in December 2023. The data that were used in the optimization were the characteristics of each unit, the historical electricity hourly prices, and the hourly heat loads.

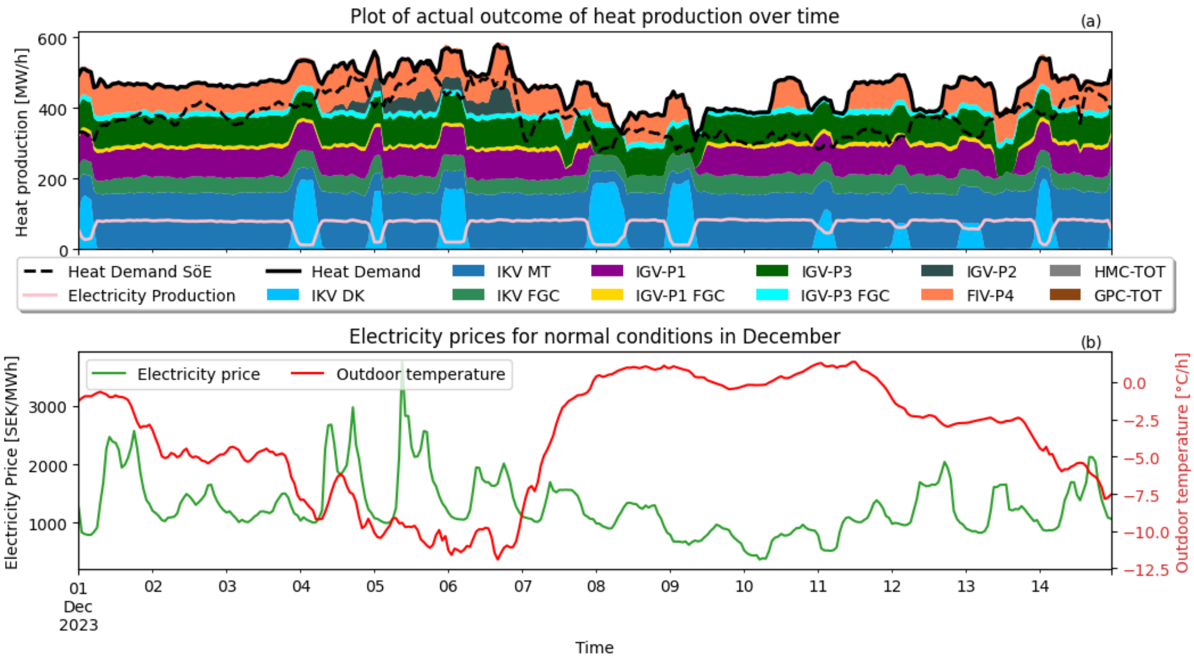

Figure 4-Heat production for actual outcome (a) vs. Historical weather & electricity data (b) for two weeks in December 2023

4.2 Baseline model

The baseline model for this study, obtained by Sigholm Tech AB, was further developed, and adapted to the energy system, described in section 4. Figure 5 shows a simplified flowchart schematic of how the model was structured based on the current energy system, where all boilers were included and their different specific energy flows to cover the energy demand. Since Söderenergi AB and Stockholm Exergi send and distribute heat between themselves when needed, part of the production from Söderenergi AB was exports to Stockholm Exergi. In this case, the import from Stockholm Exergi was not considered in the optimization. This was set as a boundary condition based on the assumption that current operating situations and price pictures required it. Instead, only the units shown in Figure 5 were responsible for the heat production, which represents the production from Söderenergi AB.

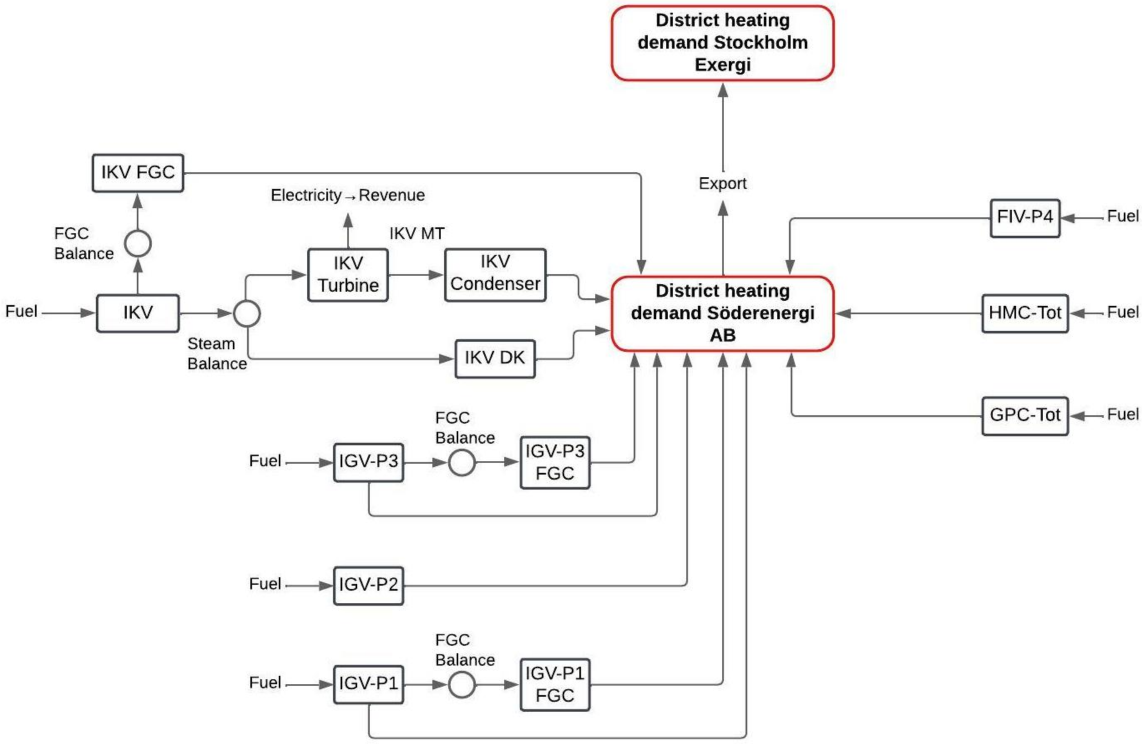

Figure 5-Flowchart of baseline model

Through access to both historical and current data, it was possible to regulate and control all the parameters and variables in the model. It provides comprehensive control of the energy system optimization model and its variables, enabling efficient management and optimization of the process. Based on the literature review, the model was constructed around an objective function as a way to clearly define the optimization goal, as MILP was used as an optimization method. In this case, the objective function was calculated as the sum of the product of the fuel consumption (F) for each time step (t) for each boiler, multiplied by its fuel cost (C_F), and added with startup costs (S) för each time a boiler was started (N) and load change costs (L) for each change in load (ΔP), which was then subtracted by the electricity revenue ($C_{el_{revenue}}$) depending on whether, for example, IKV MT was in operation or not. In other words, the fuel consumption of each boiler was multiplied by its cost per unit of fuel, and these products are summed for all boilers, while considered the electricity revenue, startup costs and load change costs. The objective was to minimize this sum, which indicates that the aim was to reduce the total cost of fuel consumption for all boilers as much as possible, a principle followed by *Equation 1*.

$$Objective\ function = \sum(F_i * C_{F_i} + N_i * S_i + \Delta P_i * L_i) + C_{el_{revenue}}\ [SEK] \qquad \text{Equation 1}$$

In this way, production costs and fuels were needed for each boiler. This information was assumed from data obtained from Söderenergi AB and are presented in Table 3. The production cost for each boiler and fuel they used was an average price over one year. These production costs are arranged in a ranking order from lowest to highest cost. A run cost for IKV was also considered where it represented the operating and maintenance costs. This was considered only for IKV as the prices often vary within this plant compared to other boilers.

Table 3-Ranking order from lowest to highest production cost for each boiler and fuel

Ranking order	Boiler	Fuel
1	**IGV-P1**	Waste
2	**IKV, IGV-P3**	Reclaimed wood (RT)
3	**FIV-P4**	Pellets
4	**IGV-P2**	Pine pitch oil (TB)
5	**HMC, GPC**	Fuel oil (EO1)

The fuel consumption for each boiler, F, was built on the useful output (Q_{useful}) of the specific boiler and its efficiency (η) from *Equation 2*, as the input always will be greater than the output.

$$F_n[t] = \frac{Q_{useful_n}[t]}{\eta_n}\ [MW] \qquad \text{Equation 2}$$

As in the literature review, constraints were needed to obtain a realistic result and to handle the complexity of the problem formulation. In this way, this model also handles several constraints and conditions to be able to reach what the energy system requires and what goal it needs to reach. A specific condition for this case was the heat demand based on *Equation 3*.

$$Q_{demand}[t] = [t] * (x_1 + x_2 + x_3 + x_n)\ [MW] \qquad \text{Equation 3}$$

Where x indicates the different energy flows from how the boilers was operated in each timestep. This condition was needed for the model to reach the goal, which was the heat demand, and at the same time be able to minimize the total costs for the production. Q_{demand} is based on historical data and counts as a reference case for Söderenergi AB. Some limitations in the model were, for example, the knowledge that the boiler was running or not, as seen in *Equations 4* and *5*.

$$I * Q_{MAX} > x[t]\ [MW] \qquad \text{Equation 4}$$

$$I * Q_{MIN} < x[t]\ [MW] \qquad \text{Equation 5}$$

Where (I) represents a binary value that can either be 0 or 1. If it was equal to 1, the boiler was on and vice versa. The variables (Q_{MAX}) and (Q_{MIN}) indicates the maximum and minimum power for each boiler. Furthermore, the load changes depend on various constraints, one of which was the minimum start-up time for each boiler. Another limitation can be that the load changes were either greater or less than the difference between the energy flow at the current time step and the energy flow at the previous time step. These principles and constraints were calculated as *Equation 6* and *7*.

$$Q_{Load\ Change} < (x_n[t] - x_n[t-1])\ [MW] \qquad \textit{Equation 6}$$

$$Q_{Load\ Change} > (x_n[t] - x_n[t-1])\ [MW] \qquad \textit{Equation 7}$$

As can be seen in Figure 5, there are either FGC or steam balances. These balances were built on mass balances, where the flow input is equal to the flow output and are based on similar principle as *Equation 8*. Which path the energy flow takes depends on the costs of fuel as well as electricity prices.

$$x_1[t] = [t](x_2 + x_3)\ [MW] \qquad \textit{Equation 8}$$

Yearly maintenance for each boiler was considered, which means that the specific unit was unavailable for the period it was under maintenance. A yearly maintenance means carrying out a planned review, an examination of a device, system, or process to ensure that it is working correctly, is in good condition and meets relevant standards and requirements.

4.2.1 Limitations of the model

The limitations of the model are that it only considers the power for the whole system. It thus neglects parts such as the surrounding environment, in addition to using the historical outdoor temperature, emission levels from the heat production and all the pumps in the district heating system. The model does not consider previous unforeseen shutdowns or unavailability's from real events. This means that the optimal outcomes probably do not fully reflect reality. Therefore, the reference scenario was considered an ideal situation from the optimization without changes in the electricity price, which enables comparison with other scenarios under similar conditions. Another limitation was that the export to Stockholm Exergi was constant and based on the outcome from the year 2023. This means that if new technologies had been implemented earlier in the system, the export would have varied. In other words, the optimization of the exchange with Stockholm Exergi was not relevant in this scenario.

A further limitation in the model was that the heat storage does not consider the specific technology used, but only its capacity, inflow, outflow, and desired heat level. For the CCS technology, there were limitations as it was not integrated into the model. This means some adjustments were needed to simulate how the CCS plant will work within the system.

As the optimization was based on a sequence of two months to avoid complex calculations, this was seen as a limitation of the model as it only optimizes for two months at a time where the results are then summed afterwards to produce annual results. Additionally, a factor of 0.01-0.05, depending in the month, has been introduced into the optimization to allow the optimization to solve the calculations slightly faster, given the time constraints of the work.

4.3 Modelling of added units

This section provides an insight into each case, how each component was modeled into the current energy system and what assumptions were considered.

4.3.1 Current energy system with heat storage

When using heat storage, i.e. an accumulator tank, it was known that sensible heat storage with water was the technology that would be used in the energy system. However, due to the limitations of the model, this was not considered when implementing this in the model. In this case, the heating storage's charging and discharging processes were directly linked to how the heating system handles variations in the demand and supply of heat energy in the model to maintain a balanced operation. The authors Möhren et al. (2022) and Ashouri et al. (2013) used similar formulas represented by *Equation 9* to calculate and describe the heat storage in the optimization model using MILP.

$$Q_{TES}[t] = Q_{TES}[t-1] + Q_{load}[t] - Q_{unload}[t] \leq Q_{TES,\max}\ [MW] \qquad \textit{Equation 9}$$

Where the energy that was stored in the TES at a certain time $Q_{TES}[t]$ corresponds to the sum of the energy that was stored at the previous time $Q_{TES}[t-1]$ and the change in stored energy $Q_{load}[t] - Q_{unload}[t]$ between these two times. The constraint in *Equation 9* guarantees that the thermal energy stored in the TES does not surpass its maximum storage capacity $Q_{TES,max}$ at any given state. It is worth knowing that the accumulator was there to help balance the system, a system where the heat can be transported and stored to contribute to flexibility and reliability.

To make a rough estimate of tank sizes, an assumption can be that the accumulator tank should be large enough to store approximately 6 to 12 hours of heat production. With a maximum capacity of 250 MW for IKV, it can be assumed that the average production during a day is about half of the maximum capacity, i.e. about 125 MW. Therefore, a typical size of an accumulator tank for a CHP plant with a maximum capacity of 250 MW would be somewhere between 750 MWh (125 MW * 6 hours) and 1,500 MWh (125 MW * 12 hours). The maximum amount of heat that can be stored in the accumulator tank is determined by *Equation 10*, which considers the difference between the highest and the lowest power level.

$$Q_{TES,max} = Q_{TES,\max level} - Q_{TES,\min level}\ [MW] \qquad \textit{Equation 10}$$

In this scenario, the accumulator tank was initially assumed to be 850 MWh, after which both a smaller and a larger size were explored to assess their impact on the system. The maximum inflow and outflow were initially assumed to be 100 MW/h but were tested with a smaller size to see how these variables affect the system. With no available data for an accumulator today, the start and end levels were set to be 500 MWh.

According to the Danish Energy Agency (2018), the volume of the accumulator tank was assumed to be 0.058 MWh/m^3, while the investment cost, according to data from Söderenergi AB, was expected to amount to approximately 4,130 SEK/m^3.

To calculate the total cost savings relative to the initial investment cost, *Equation 11* was used. In this equation, the initial total cost, C_{Ref}, which in this case represents the reference scenario, was subtracted from the total cost from the scenario just tested, $C_{Sen,i}$. The result was then divided by the initial investment for the specific accumulator tank, $C_{Inv,i}$.

$$\frac{(C_{Ref}-C_{Sen,i})}{C_{Inv,i}} \qquad \textit{Equation 11}$$

4.3.2 Current energy system with CCS

Since a CCS plant was implemented in the energy system next to the CHP plant, it was interesting to investigate how the energy system related to it. In this case, CCS was not integrated in the model, which meant it needed to be modeled with a few conditions and equations. Figure 6 represents a flowchart of how the CCS technology was integrated into the system, where it was connected to the cogeneration plant IKV. The CCS plant was considered as a black box, meaning that its performance was judged primarily based on its efficiency and the income generated from captured CO_2. This approach enables a careful evaluation of the technology's contribution to both energy production and carbon dioxide reduction.

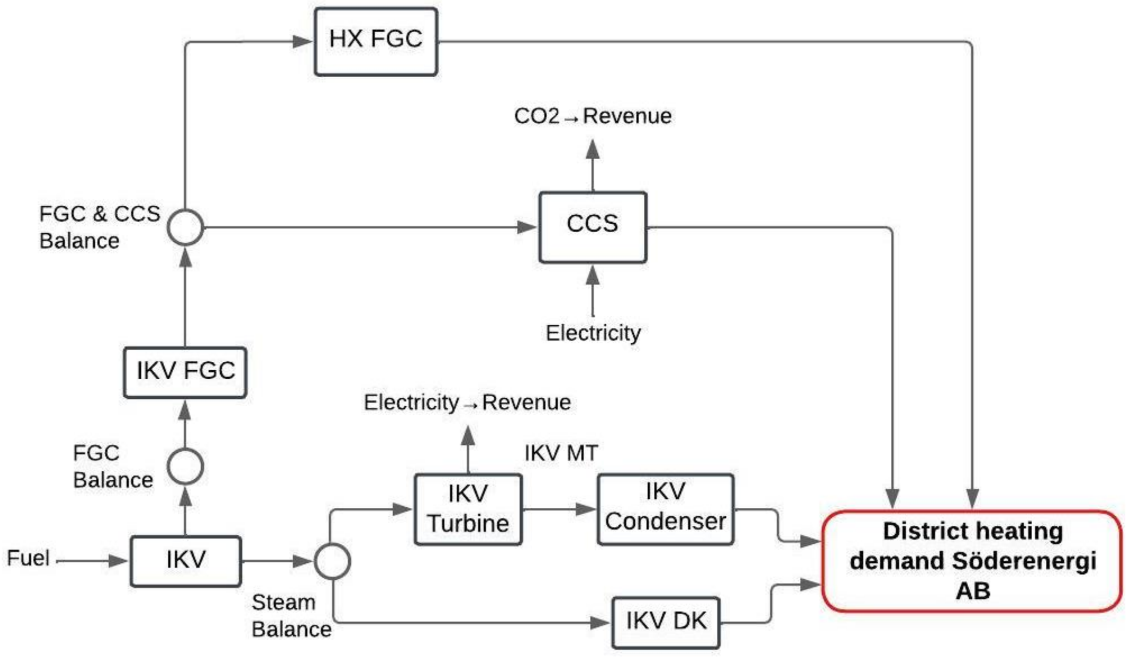

Figure 6-Specific flowchart of CCS technology model

In this case, a new balance, FGC & CCS Balance, was implemented in the model to manage the use of CCS technology. A new heat exchanger, HX FGC, was implemented to enable alternative routes if the system decides to forego using the CCS technology due to specific conditions. Figure 6 clearly shows that CCS technology has two inputs and two outputs. The inputs to the CCS plant include flue gases to efficiently capture CO_2 as well as to provide the necessary electricity to run the plant. The outputs of the CCS plant include the captured CO_2 where revenue was generated as well as waste heat that was reused to help cover the heat demand. With this information, a heat exchanger was integrated into the model to better understand how the CCS plant will operate and interact with the system. Table 4 presents the specifications for the CCS plant, which have been obtained from supervisors at Söderenergi AB. These specifications show how much useful energy was generated in relation to the losses arising from the flue gases. The start cost for the CCS plant was assumed to be the same as IKV as there was no available data for this part.

Table 4-Characteristics of CCS technology

	Electricity demand [MW]	Heat loss condenser IKV FGC [MW]	Heat recovery [MW]	Start Costs [SEK]
CCS	35	4	20	400 000

With this information, a recovery rate of 5 was assumed, where each lost unit of energy from heat loss results in a significant amount of usable energy recovered through waste heat. This means that 4 MW is diverted from the flue gas condensation to power the CCS plant, while a further 20 MW of waste heat is generated. This results in a fivefold increase, ensuring that the optimization understands that the CCS plant produces five times more energy than it consumes from the system. A necessary condition for the CCS facility to be operational was that IKV must be operating at approximately 60-70% of its maximum capacity. This means the CCS plant cannot operate until colder seasons when the demand for heat increases and the cogeneration plant operates at higher output levels. This condition was calculated by *Equation 12*, where $IKV^{activity}[t]$ indicate the power produced by IKV in the specific time step and $CCS^{is\ operating}[t]$ represent a binary value that explains if CCS was available (1) or not (0).

$$IKV^{activity}[t] - (Q_{IKV_{MAX}} * 0.6) \leq CCS^{is\ operating}[t] * 999 \qquad \textit{Equation 12}$$

According to Table 4, it appears that a certain electrical power requirement was required to operate the CCS plant. In this case, an auxiliary variable (K) of 1.75 is used to account for the resulting conditions. Comparing the available electrical energy after CCS with the original electrical energy from the turbine, 85 MW, a ratio of 1.75 was obtained through *Equation 13*.

$$Q_{CCS_{el}} = Q_{G1} - \frac{Q_{G1}}{k}\ [MW] \qquad \textit{Equation 13}$$

In addition, it was known that the CCS plant will work proportionally to the IKV plant. This means, for example, that the CCS plant is expected to operate at full capacity when IKV is in full operation, regardless of what the electricity prices say. To understand how this relationship affects costs and performance, the variables that affect the operation of the CCS facility and its connection to the IKV can be examined. By analyzing this relationship, a more comprehensive strategy can be developed to manage both costs and environmental considerations when operating the facility. These conditions were calculated with *Equation 14*, *Equation 15*, and *Equation 16*, where *Equation 14* and *15* was based on a linearly relationship between maximum and minimum capacity for CCS and IKV. The minimum capacity of the IKV was assumed to be 60% of its maximum capacity. *Equation 16* indicate the time when the CCS plant can be active, which occurs when the IKV is operating at 60% of its maximum capacity. This thus represented the minimum load for the CCS plant.

$$0.15 * IKV^{activity}[t] - 17.5 * CCS^{is-operating}[t] + 999 * \left(1 - CCS^{is-operating}[t]\right) \geq CCS^{activity}[t] \qquad \textit{Equation 14}$$

$$0.15 * IKV^{activity}[t] - 17.5 * CCS^{is-operating}[t] - 999 * \left(1 - CCS^{is-operating}[t]\right) \leq CCS^{activity}[t] \qquad \textit{Equation 15}$$

$$IKV^{activity}[t] - 150 \leq CCS^{is-operating}[t] * 999 \qquad \textit{Equation 16}$$

Furthermore, a scenario analysis was carried out without the specified conditions from *equation 15* and *equation 16*. The aim was to analyze and reflect on how the CCS plant acts without restrictions linked to these conditions and instead in relation to the electricity market. This analysis was particularly relevant as future regulations around CO_2 capture was still uncertain. It may be interesting to examine how the CCS facility operates if the regulations were not introduced with too strict restrictions and to assess how this may affect the total cost.

As the income from captured CO_2 was still unknown, a sensitivity analysis and an iterative process were carried out to determine where it was most profitable to use IKV. A breakeven point was identified to determine when the benefits of using IKV outweigh the costs, which was central to optimizing the system's economic and environmental efficiency. The breakeven point is the point where the revenue from the CCS plant is sufficient to cover the additional costs of operating the CCS technology compared to the normal scenario. In this scenario, the breakpoint was analyzed at different electricity prices when IKV was at maximum capacity, to facilitate the calculations. In this way, an approximate revenue cost per ton of captured CO_2 could be calculated. As the market conditions was uncertain, this approach was adopted to clearly delineate the work. These revenue costs were based on the revenue from the waste heat, i.e. price per MWh of district heating to be able to control the optimization correctly. This variable was calculated by multiplying the maximum amount of CO_2 that IKV could captured at full capacity with the revenue from the sale of the captured CO_2. This result was then divided by the maximum waste heat that could be utilized from the CCS technology to obtain the price per MWh of district heating. According to information and data from Söderenergi AB, IKV had the capacity to capture approximately 95 tons of CO_2 per hour at most.

Three different prices per ton of CO_2 will be investigated, which can be seen in Table 5.

Table 5- Different prices per ton capture CO_2

	Price per ton CO_2 [SEK/ton CO_2]	**Price per MWh district heating [SEK/MWh DH]**
Revenue cost 1	400	1 900
Revenue cost 2	500	2 375
Revenue cost 3	600	2 850

By calculating this point, the company could get an idea of the necessary pricing per ton of CO_2 captured and stored to generate sufficient revenue from the CCS plant and thereby become profitable. This was of critical importance in assessing the financial viability and economic benefits of using CCS technology to reduce CO_2 emissions.

The investment cost of the CCS technology was based on a similar cogeneration plant with a slightly lower maximum capacity, known as Klemetsrud and located in Oslo (Danish Energy Agency, 2021). The CCS technology was based on afterburning technology and follows a similar process as previously described in the literature study. According to Danish Energy Agency (2021), the specific CAPEX was 6.2 million euros per ton of CO_2 emissions per hour, which results in a total investment of approximately 6,744 MSEK in this scenario for the CCS technology. The total cost savings relative to the initial investment cost was calculated with *Equation 11*.

4.3.3 Current energy system with heat storage and CCS

It became interesting to investigate how production was affected by using both the CCS technology and the accumulator in the system. This scenario considered these components using the same data and modelling as before, but with both parts available at the same time. Figure 7 illustrates the connection between the cogeneration plant IKV, the CCS plant and the accumulator tank. In addition, it shows the possibility of bypassing the accumulator to create flexible heat production and adapt the heat storage to the heat demand. The total cost savings relative to the initial investment cost was calculated with *Equation 11*.

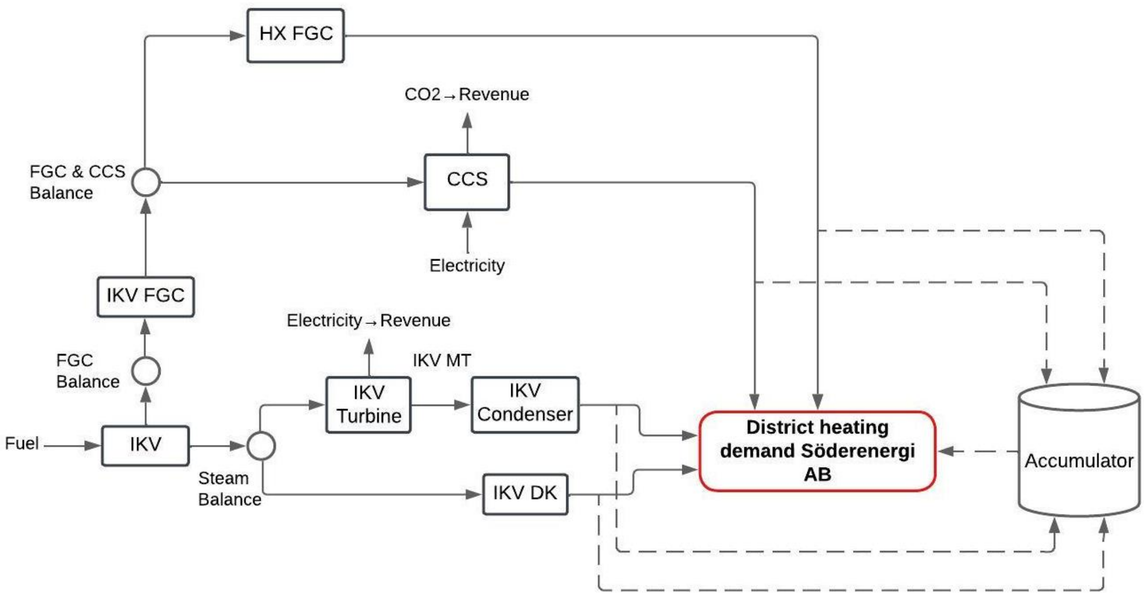

Figure 7-Specific flowchart of CCS technology and accumulator tank model

4.3.4 Current energy system with heat pump

In the scenario where the heat pump (HP) was part of the current energy system, it was based on *Equation 17*, where its production cost $C_{HP}[t]$ was determined by multiplying the electricity cost $C_{El}[t]$ by the heat generated $Q_{HP}[t]$ and then dividing by the COP to estimate the total cost of heat production for the specific timestep. This was done to review what the production costs for the heat pump contrasted with other production parts in the system. A lower electricity cost and a higher COP resulted in a reduced total cost of producing heat with the heat pump. By optimizing with COP values of 3 and 4, it was possible to analyze how this affected the economy. According to the literature review, the heat pump was usually used at lower electricity prices to produce heat and help cover the existing heat load, which was the purpose of this component of the optimization.

$$C_{HP}[t] = C_{el}[t] * \frac{Q_{HP}[t]}{COP} \; [MW] \qquad \textit{Equation 17}$$

The electricity cost $C_{el}[t]$ indicate the amount paid for the electrical energy that the heat pump consumes to operate during the specific hour. This cost usually includes electricity spot prices, electricity taxes, grid charges and electricity certificates, which was also assumed in the calculation of the total electricity price. The heat $Q_{HP}[t]$ represents the amount of heat energy generated by the heat pump in each timestep. COP is a measure of the heat pump's efficiency and shows the ratio between the heat produced and the energy consumed.

The characteristics of the heat pump, in this case, can be seen in Table 6.

Table 6-Characteristics of heat pump

	Max power [MW]	Min power [MW]	COP factor [-]	Load Change Rate [MW/h]	Start Costs [SEK]
HP	50	12	3-4	1 000	1 000

According to supervisors at Söderenergi AB, an initial investment for a 50 MW heat pump was approximately 120 MSEK. The total cost savings relative to the initial investment cost was calculated with *Equation 11*.

4.4 Sensitivity analysis

With different case studies, simulations were run against future scenarios to evaluate the overall cost and flexibility landscape of the energy system. One of these scenarios (case study A) included varying proportions of solar and wind energy integrated into the electricity grid. Thus, different price levels and fluctuating electricity prices were introduced to investigate their impact on system performance and financial sustainability. Another scenario (case study B) experimented with different sizes of thermal storage tanks to analyze their impact on the overall flexibility of the system. This approach helped identify the optimal balance between cost effectiveness and energy efficiency for the energy system.

4.4.1 Case study A

For case study A, electricity prices for the year 2023 were obtained. As this case included a varying mix of solar and wind energy in the energy supply, different varying percentage changes in electricity prices were applied along with different levels of volatility, which controlled the degree of price variation from the expected average. This is because renewable energy sources are intermittent in nature, which means they cannot produce continuously like conventional energy sources. When there is not enough solar or wind, other energy sources must quickly step in to cover the demand, which can lead to sudden changes in prices.

According to future electricity forecasts from Gabrielli et al. (2022) several scenarios indicated higher electricity prices rather than lower ones. This trend towards higher electricity prices was mainly due to rising natural gas prices and solar energy production. The study also showed increased volatility in prices within each day, resulting in more pronounced price spikes. Based on the study of Gabrielli et al. (2022), assumptions were made where electricity price changes are expected to increase or decrease by 30%, while examining different levels of volatility. These different case scenarios can be seen in Table 7, where the reference scenario illustrates a situation where there are no changes in electricity prices and the level of volatility remains unchanged. This represents the optimal current energy system. The effect on total energy production were assessed considering the intermittent nature of these renewable energy sources through these changing electricity prices. A volatility level of 0 represents a scenario where no change in volatility occurs.

Table 7-Different scenarios for case study A

Electricity Price Change	Volatility Level
Scenario A1: 0% change	Scenario A1.1: 0
	Scenario A1.2: 10
	Scenario A1.3: 20
Scenario A2: -30% change	Scenario A2.1: 0
	Scenario A2.2: 10
	Scenario A2.3: 20
Scenario A3: +30% change	Scenario A3.1: 0
	Scenario A3.2: 10
	Scenario A3.3: 20

4.4.2 Case study B

For case study B, the different electricity prices from case study A were also considered to analyze which size of the storage tank was best suited based on cost effectiveness and energy efficiency. Based on the literature review, it was established that factors such as tank size and flow rates during charging and discharging significantly influenced the thermal stratification within the tank. By optimizing the design and operational parameters of the tank, it was possible to enhance thermal stratification and minimize heat losses during the storage process. Hence, case scenarios featuring different sizes of heat storage tanks were systematically optimized and analyzed to evaluate their impact on the overall flexibility of the energy system. This entailed examining the capacity of storage tanks to absorb surplus energy during periods of high renewable energy production and release it during periods of peak demand. Furthermore, an economic assessment was conducted to identify the most sustainable solution in terms of the total cost of the entire energy system.

In addition to the tank with a capacity of 850 MWh, two other tank sizes were also investigated: one with an energy capacity of 700 MWh and another with a capacity of 1,400 MWh. Furthermore, a sensitivity analysis was done where two different maximum inflows and outflows, 50 MW/h and 100 MW/h, from the accumulator tank were compared to see how this affected the total costs. The aim was to evaluate how these different sizes affected the system and what potential cost savings they could provide in relation to the initial investment. Table 8 illustrates how the different scenarios were linked to each other.

Table 8-Different scenarios for case study B

Max inflow/outflow	Tank size
Scenario B1: 50 MW/h	Scenario B1.1: 700 MWh
	Scenario B1.2: 850 MWh
Scenario B2: 100 MW/h	Scenario B2.1: 700 MWh
	Scenario B2.2: 850 MWh
	Scenario A2.3: 1400 MWh

5 RESULTS

This part compares the reference scenario's total cost with potential savings in other scenarios. In addition, the production flexibility is analyzed for the specific scenario explored. Each section focuses on a specific scenario, with an overview in Table 9 of its contributions.

Table 9-Information of each scenario's contribution

Scenario	Case study	Short description of case study scenarios
Scenario 1 – Baseline	Case study A: Effect of electricity price	➢ Scenario A1.1: 0% electricity change, 0 volatility level ➢ Scenario A1.2: 0% electricity change, 10 volatility level ➢ Scenario A1.3: 0% electricity change, 20 volatility level ➢ Scenario A2.1: -30% electricity change, 0 volatility level ➢ Scenario A2.2: -30% electricity change, 10 volatility level ➢ Scenario A2.3: -30% electricity change, 20 volatility level ➢ Scenario A3.1: +30% electricity change, 0 volatility level ➢ Scenario A3.2: +30% electricity change, 10 volatility level ➢ Scenario A3.3: +30% electricity change, 20 volatility level
Scenario 2 – TES	Case study A: Effect of electricity price Case study B: Effect of tank size	➢ Scenario A1-A3: Same as Scenario 1 – Baseline ➢ Scenario B1.1 (50 MW/h): 700 MWh ➢ Scenario B1.2 (50 MW/h): 850 MWh ➢ Scenario B2.1 (100 MW/h): 700 MWh ➢ Scenario B2.2 (100 MW/h): 850 MWh ➢ Scenario B2.3 (100 MW/h): 1400 MWh
Scenario 3 – CCS	Case study A: Effect of electricity price	➢ Scenario A1-A3: Same as Scenario 1 – Baseline
Scenario 4 - TES + CCS	Case study A: Effect of electricity price Case study B: Effect of tank size	➢ Scenario A1-A3: Same as Scenario 1 – Baseline ➢ Scenario B2.2 (100 MW/h): 850 MWh
Scenario 5 – HP	Case study A: Effect of electricity price	➢ Scenario A1-A3: Same as Scenario 1 – Baseline

The first scenario presents a comparison with historical data to show the differences between the optimal and actual results. Next, the second scenario analyzes how the total cost and flexibility differ from the reference case when an accumulator is used in the system, focusing on three different accumulator sizes. The third scenario highlights the changes in total cost and flexibility when only CCS is used in the system. Furthermore, the fourth scenario examines how both CCS and an accumulator tank affect the total cost and flexibility of the system. Finally, the fifth scenario explores how the integration of a heat pump affects the total cost and flexibility of the system compared to other scenarios, where two different COP factors are compared to provide a comprehensive understanding of the potential effects of the heat pump.

Through this structured analysis, one can gain a deeper insight into how different factors affect the total cost and flexibility in energy production. All scenarios are compared to better understand how each individual scenario relates to the different case study scenarios and their adaptability.

5.1 Scenario 1 – Current energy system

In this section, the total cost of the different case study A scenarios will be compared to the reference scenario to determine if any savings occur and to provide a basis for comparison with the other cases. Furthermore, it will be investigated how the optimal heat production would have been compared to the actual outcome during two weeks in March and December 2023. The aim is partly to verify that the model and the optimization are consistent with the actual outcome, and partly to evaluate the relationship between the optimal outcome and case study A.

Total cost savings

Table 10 presents the annual total cost in Swedish currency and the savings in percentage for each case study scenario for scenario 1. The reference scenario reflects a case scenario, A1.1, where price levels and volatility levels remain unchanged, which also is present in annual total cost. The rest of the case scenarios are presented in annual total cost savings followed by an increase or decrease in percentage. An important observation here is that the changes in the total cost savings are more noticeable when there are variations in the price level compared to when the volatility changes.

Table 10-Annual total cost savings of current energy system for different scenarios of case study A

Electricity price Change	Volatility level	Total cost savings [MSEK]
Scenario A1: 0%	Scenario A1.1 – Low (*Reference scenario)*	0 (0.0%)
	Scenario A1.2 – Medium	-0.4 (-0.1%)
	Scenario A1.3 – High	-0.7 (-0.1%)
Scenario A2: -30%	Scenario A2.1 – Low	+75.3 (+11.7%)
	Scenario A2.2 – Medium	+75.9 (+11.8%)
	Scenario A2.3 – High	+75.4 (+11.7%)
Scenario A3: +30%	Scenario A3.1 – Low	-86.6 (-13.4%)
	Scenario A3.2 – Medium	-88.8 (-13.8%)
	Scenario A3.3 – High	-89.4 (-13.9%)

Flexibility of the system

The validation of the heat production between the actual outcome (a) and the optimal outcome (b) of production plans for two weeks in March 2023 is illustrated in Figure 8. The production plans are presented in days. These are also aligned with how electricity prices and weather conditions looked (c) to clarify the behavior of the system. These two weeks (b) belong to the reference scenario. All units have their specific color, which can be observed at the bottom of the figure. The heat production over the line that represents the heat demand for Söderenergi AB is the exported heat production to Stockholm Exergi. This figure shows some deviations between the optimal scenario and the actual outcome. For example, the optimal outcome for increased profitability would have involved an increased use of IKV DK and IGV-P3 to cover the heat production from FIV-P4. It should be noted that the model does not consider unavailability's, which may have affected the results in this case, for example if IGV-P3 became unavailable due to lack of fuel or similar reasons.

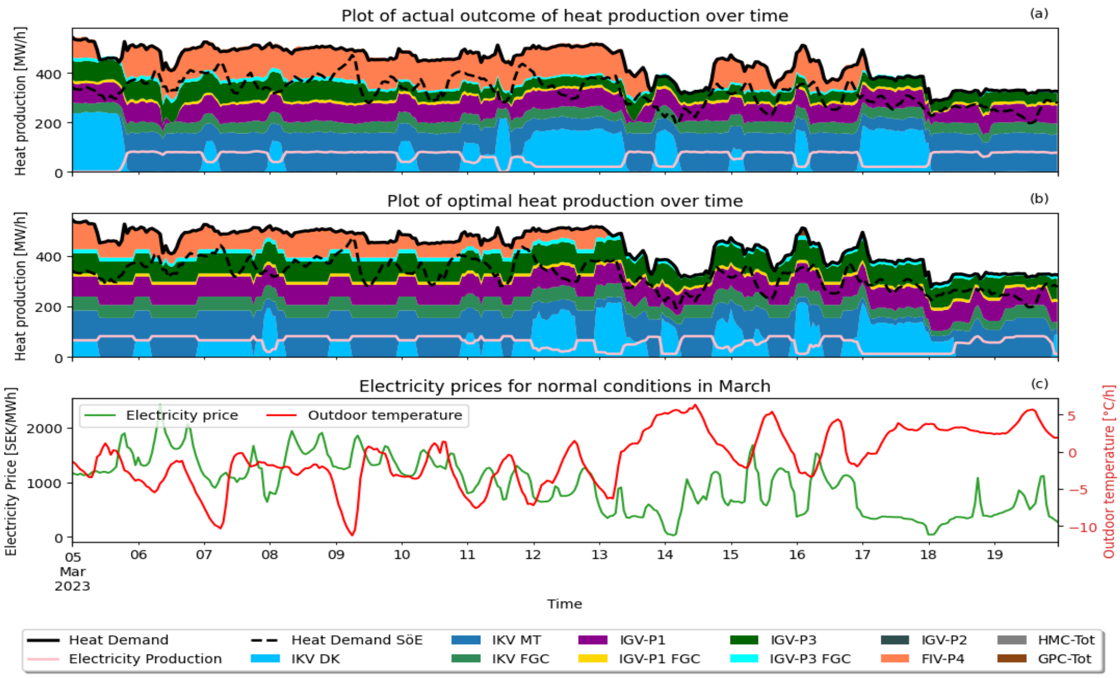

Figure 8-Heat production model verification: Yearly simulation over two weeks (days) in March: (a) Actual outcome, (b) Optimal outcome, (c) Historical weather and electricity data

Figure 9 reflects the same principle as Figure 8, but for two weeks in December 2023. Here, too, deviations between the optimal scenario and the actual outcome are visible. In this case, the figure indicates that to achieve increased profitability, the optimal outcome would require a continued increased use of IKV DK and IGV-P3 to cover the heat production from FIV-P4 and to avoid taking IGV-P2 into operation. It is possible to observe more regulation between IKV DK and IKV MT for both Figure 8 and Figure 9 to even better match electricity prices.

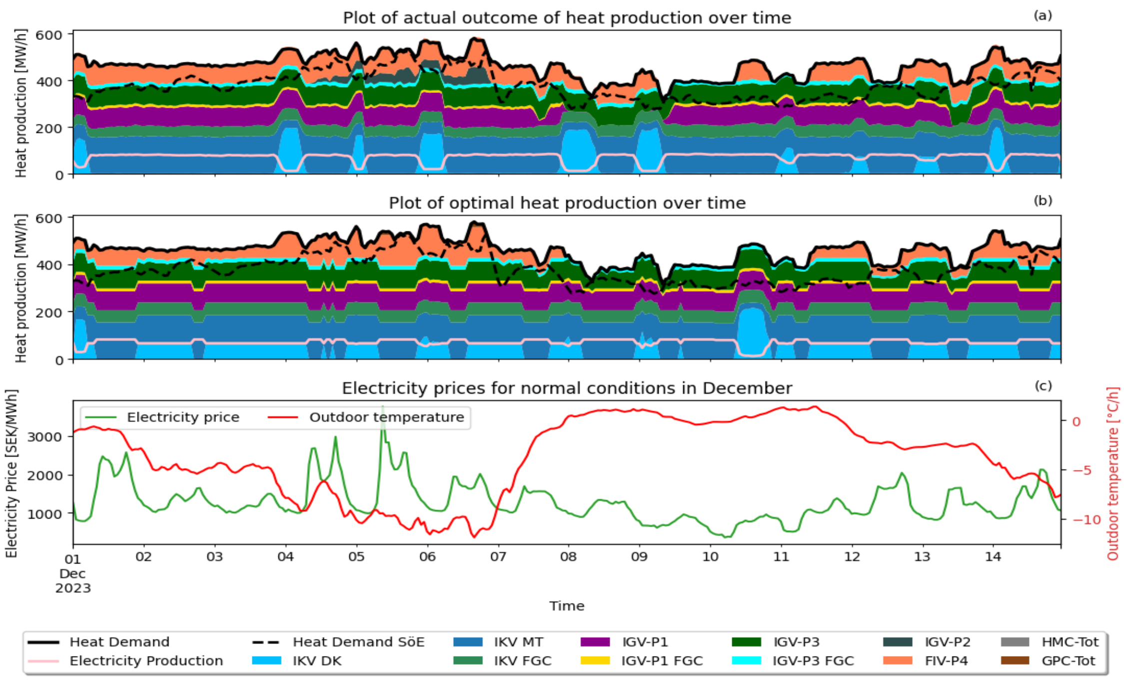

Figure 9-Heat production model verification: Yearly simulation over two weeks (days) in December: (a) Actual outcome, (b) Optimal outcome, (c) Historical weather and electricity data

The total heat production for the different case scenarios A is illustrated in Figure 10, where increased volatility as well as rising and falling electricity price levels are represented along the vertical axis, while the horizontal axis represents the total heat production from each unit. With unchanged volatility and an electricity price level of 0, the reference scenario is represented. This reference scenario will be compared with all other cases to analyze how the system handles variations in production and which units are used. This figure represents the same two weeks in March as earlier from Figure 8. It is observed that the heat production from each boiler is mostly constant in Figure 10, while FIV-P4, IKV DK and IKV MT vary in relation to the electricity price.

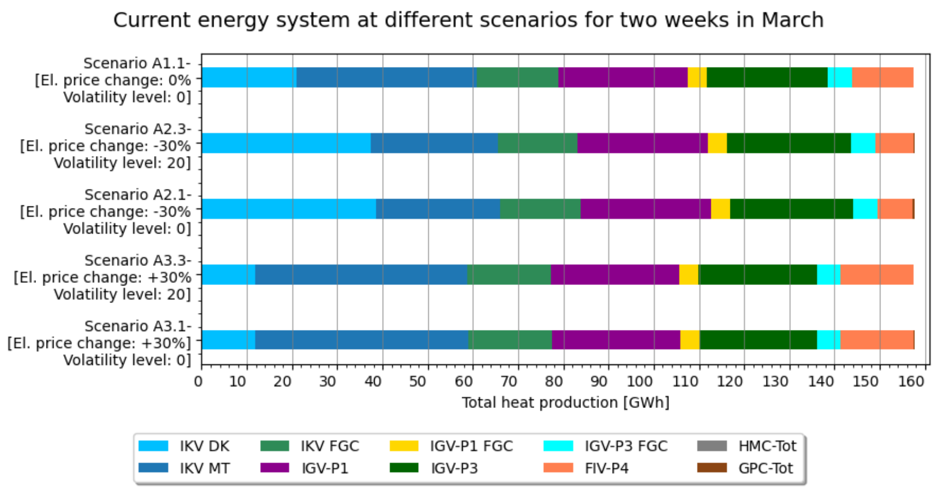

Figure 10-Overview of current energy system flexibility across different scenarios during two weeks in March 2023

Figure 11 represents the same principle as Figure 10, but for the same two weeks in December 2023. One observation compared to Figure 10 is that more peak production occurs in all case scenarios during December. The principles illustrated in Figure 10 and Figure 11 will form the basis for comparisons between the current scenario and other scenarios in terms of how the system handles variations, and whether these variations are judged to be reasonable or not.

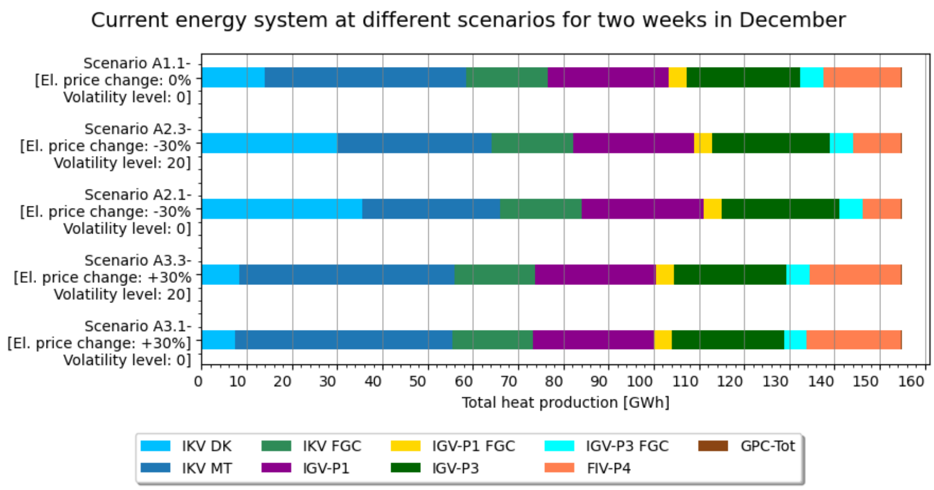

Figure 11-Overview of current energy system flexibility across different scenarios during two weeks in December 2023

The annual total heat production for each unit and scenario is present in Table 11. The different case scenarios show how much heat production differs from the reference scenario 1, A1.1. The table displays conditional formatting where redder shades indicate a decrease, and greener shades indicate an increase. A clear relationship appears between Table 11, Figure 10, and Figure 11, where the heat production from FIV-P4 decreases in scenario A2.1 and A2.3 but increases in scenario A3.1 and A3.3. Likewise, a similar pattern is observed for IKV MT, where production decreases in scenario A2 but increases in scenario A3.

Table 11-Overview of annual total heat production for each unit regarding the current energy system

Electricity price Change	**Unchanged** (A1: 0%)	**Decreased price levels** (A2: -30%)		**Increased price level** (A3: +30%)	
Volatility level	*Reference scenario* (Scenario 1 – A1.1)	**Unchanged** (Scenario 1 – A2.1)	**Increased** (Scenario 1 – A2.3)	**Unchanged** (Scenario 1 – A3.1)	**Increased** (Scenario 1 – A3.3)
IKV-DK [GWh]	329.88	+174.10 (+53%)	+152.30 (+46%)	-78.96 (-24%)	-77.58 (-24%)
IKV-MT [GWh]	576.95	-167.41 (-29%)	-153.94 (-27%)	+79.94 (+14%)	+79 .52 (+14%)
IGV-P1 [GWh]	491.67	+6.36 (+1%)	+5.04 (+1%)	+1.93 (0%)	-4.70 (-1%)
IGV-P3 [GWh]	361.03	+27.58 (+8%)	+33.58 (+9%)	-30.15 (-8%)	-22.07 (-6%)
FIV-P4 [GWh]	101.38	-30.61 (-30%)	-27.93 (-28%)	+20.62 (+20%)	+20.29 (+20%)
IGV-P2 [GWh]	1.86	+0.26 (+14%)	+0.05 (+3%)	+1.44 (+78%)	+0.41 (+22%)
HMC [GWh]	0.85	-0.08 (-10%)	-0.34 (-40%)	+0.44 (+52%)	+0.52 (+61%)
GPC [GWh]	3.44	-0.12 (-3%)	+0.25 (+7%)	+1.45 (+42%)	+1.17 (+34%)

5.2 Scenario 2 – Current energy system with TES

This section represent scenario 2, where both case study A and B can be observed. The structure of this section is like section 5.1, with the difference that a wider range of storage tank sizes is presented here.

Total cost savings

The annual total cost savings for two different sizes of an accumulator tank, 700 MWh and 850 MWh are shown in Table 12, where different values of maximum inflow and outflow from the tank have been tested and compared to the reference scenario. A clear observation that can be made for the table is that the difference in total cost savings over a year is not very large between different values of maximum inflow and outflow regardless of the size of the accumulator tank.

Table 12-Annual total cost savings for an accumulator tank of 700 MWh and 850 MWh with maximum inflow and outflow of both 50 and 100 MW/h

Electricity price Change	**Volatility level**	**Total cost savings [MSEK]** **Scenario B1.1** *(50 MW/h): 700 MWh*	**Total cost savings [MSEK]** **Scenario B2.1** *(50 MW/h): 850 MWh*
Scenario A1: 0%	Scenario A1.1	-20.9 (-3.2%)	-24.5 (-3.8%)
	Scenario A1.2	-21.2 (-3.3%)	-24.1 (-3.7%)
	Scenario A1.3	-20.6 (-3.2%)	-20.6 (-3.8%)
Scenario A2: -30%	Scenario A2.1	+54.8 (+8.5%)	+53.7 (+8.3%)
	Scenario A2.2	+55.6 (+8.6%)	+52.6 (+8.2%)
	Scenario A2.3	+53.1 (+8.2%)	+52.1 (+8.1%)
Scenario A3: +30%	Scenario A3.1	-114.9 (-17.8%)	-115.7 (-18.0%)
	Scenario A3.2	-113.5 (-17.6%)	-116 (-18.0%)
	Scenario A3.3	-113.3 (-17.6%)	-116 (-18.0%)
		Scenario B1.2 *(100 MW/h): 700 MWh*	**Scenario B2.2** *(100 MW/h): 850 MWh*
Scenario A1: 0%	Scenario A1.1	-26.7 (-4.1%)	-31.8 (-4.9%)
	Scenario A1.2	-25.5 (-4.0%)	-30.1 (-4.7%)
	Scenario A1.3	-27.9 (-4.3%)	-30.6 (-4.8%)
Scenario A2: -30%	Scenario A2.1	+51.8 (+8.0%)	+45.2 (+7.0%)
	Scenario A2.2	+49.5 (+7.7%)	+46 (+7.1%)
	Scenario A2.3	+51.3 (+8.0%)	+44.3 (+6.9%)
Scenario A3: +30%	Scenario A3.1	-117.5 (-18.2%)	-123.1 (-19.1%)
	Scenario A3.2	-119.9 (-18.6%)	-120.5 (-18.7%)
	Scenario A3.3	-118.2 (-18.4%)	-122.8 (-19.1%)

Total cost savings over one year for a more extensive accumulator tank of 1,400 MWh, with a maximum inflow and outflow of 100 MW/h are observed in Table 13. With a maximum inflow and outflow of 100 MW/h, the differences between the different sizes vary by no more than 1-2%.

Table 13-Annual total cost savings for an accumulator tank of 1400 MWh with maximum inflow and outflow of 100 MW/h

Electricity price Change	**Volatility level**	**Total cost savings [MSEK]** **Scenario B2.3** *(100 MW/h): 1400 MWh*
Scenario A1: 0%	Scenario A1.1	-36.1 (-5.6%)
	Scenario A1.2	-35 (-5.4%)
	Scenario A1.3	-33.3 (-5.2%)
Scenario A2: -30%	Scenario A2.1	+42 (+6.5%)
	Scenario A2.2	+41.8 (+6.5%)
	Scenario A2.3	+40.9 (+6.4%)
Scenario A3: +30%	Scenario A3.1	-128.2 (-19.9%)
	Scenario A3.2	-127.8 (-19.8%)
	Scenario A3.3	-126.3 (-19.6%)

Total cost savings relative to the initial investment

The annual total cost savings relative to the initial investment for three different accumulator tanks with a maximal inflow and outflow of 100 MW/h is presented in Table 14. Since the variation in the different volatility levels is not very large from Table 12 and Table 13, only the scenarios where no change in volatility occurs are presented.

Table 14-Annual total cost savings relative to the initial investment for accumulator tanks of sizes 700, 850 and 1400 MWh, with a maximum inflow and outflow of 100 MW/h

Electricity price Change	Volatility level	Cost savings relative to the investment – Scenario B2.1	Cost savings relative to the investment – Scenario B2.2	Cost savings relative to the investment – Scenario B2.3
Scenario A1: 0%	A1.1	49%	53%	36%
Scenario A2: -30%	A2.1	43%	50%	33%
Scenario A3: +30%	A3.1	58%	60%	42%

Flexibility of the system

The flexibility of the system when integrating an accumulator tank will be demonstrated in a similar way as in Figure 8, Figure 9, Figure 10 and Figure 11, providing insight into how the system and its optimization handle this integration at different seasons and scenarios. All the units specific color can be observed at the bottom of each figure, where the charging and discharging behavior of the accumulator tank is represented by the orange line. When the line rises, it indicates charging the tank, and when it falls, it indicates emptying the tank. A comparison between the current energy system, with (b) and without (a) an 850 MWh accumulator tank during two weeks in March 2023 is illustrated in Figure 12. The production plan with an accumulator tank (b) is presented in the same case scenarios as the production plan without an implemented accumulator tank (a). The maximum inflow and outflow for this accumulator tank has been set to 100 MW/h. These different diagrams are aligned with the electricity prices and the weather conditions (c) during this period to clarify the behavior of the system. This figure shows how the accumulator tank replaces all peak production and some heat production from the FIV-P4. Furthermore, it can be observed that IKV DK is used a little extra during the nights and shows a more even heat production. This enables charging of the accumulator tank during night hours and its emptying during the day.

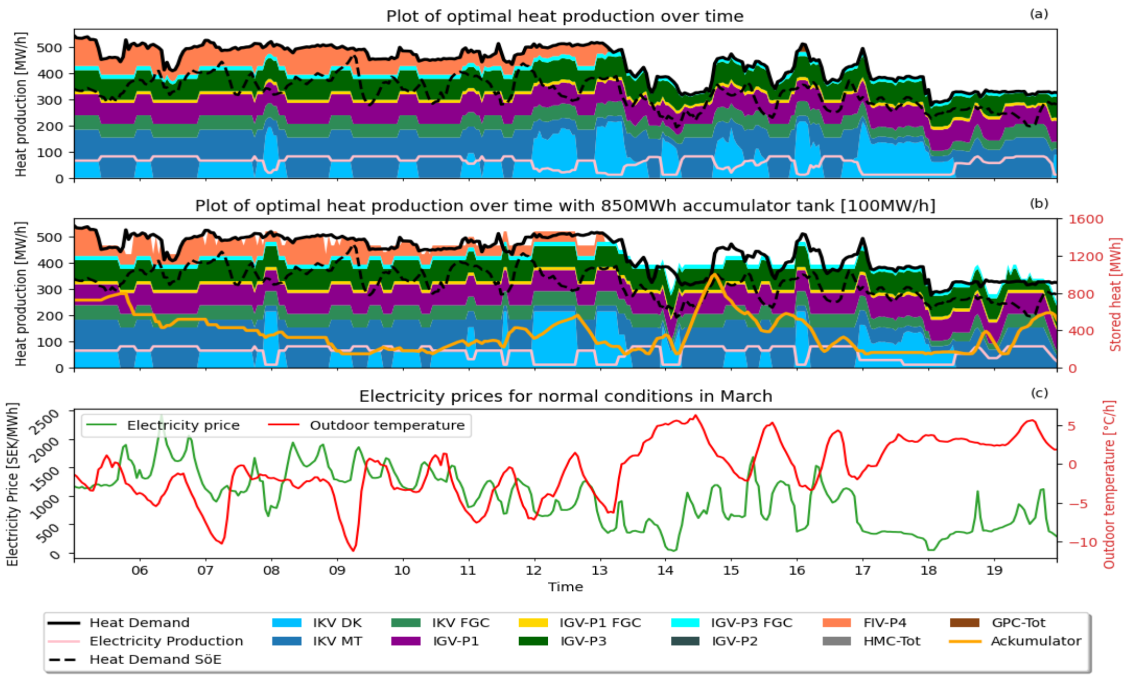

Figure 12-Model behavior with 850 MWh accumulator tank and a maximum inflow/outflow of 100 MW/h over two weeks in March: (a) Optimal outcome, (b) Optimal outcome with 850 MWh tank, (c) Historical weather and electricity data

The same principle as Figure 12 is illustrated in Figure 13, but for two weeks in December 2023. In this case, similar results are observed, where IKV DK is used more evenly to maintain the charge with the accumulator tank. A difference compared to before is that the accumulator tank is used more evenly, unlike what is shown in Figure 12.

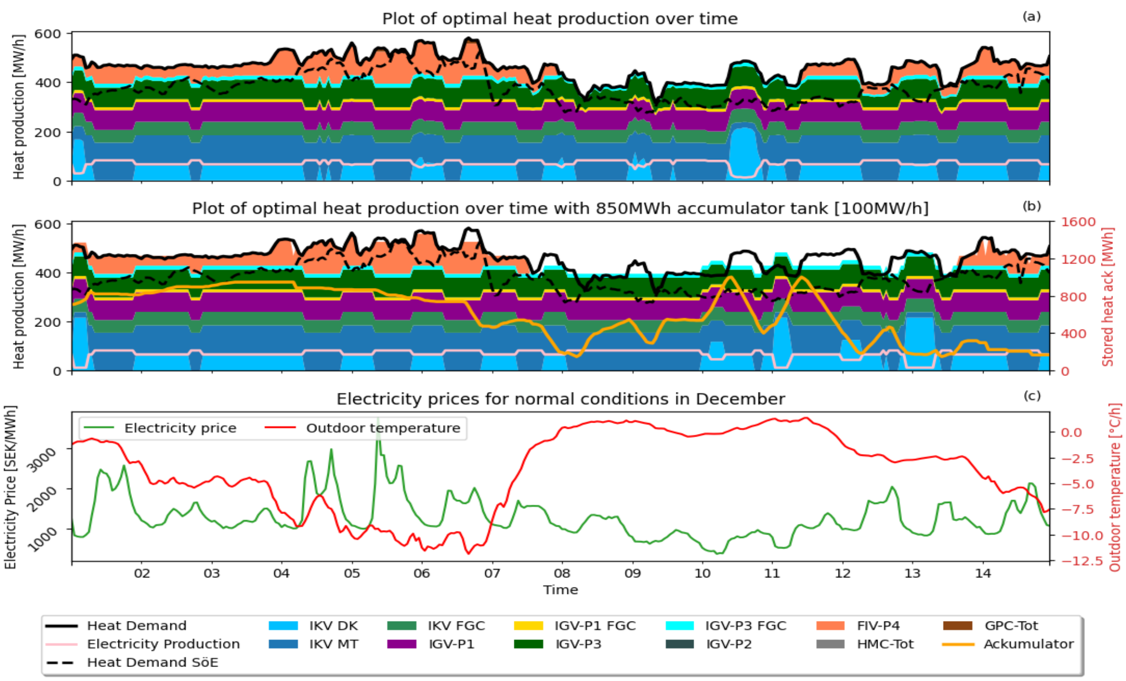

Figure 13-Model behavior with 850 MWh accumulator tank and 100 MW/h max flow over two weeks in December: (a) Optimal outcome, (b) Optimal outcome with 850 MWh tank, (c) Historical weather and electricity data

A comparison between accumulator tanks of sizes 700 MWh and 850 MWh, with a maximum inflow and outflow rate of 50 MW/h during the same two-week period in December 2023 is presented in Figure 14. The purpose of the figure is to investigate the system's handling of the heat load at different sizes of the accumulator tanks and to analyze its behavior under these conditions.

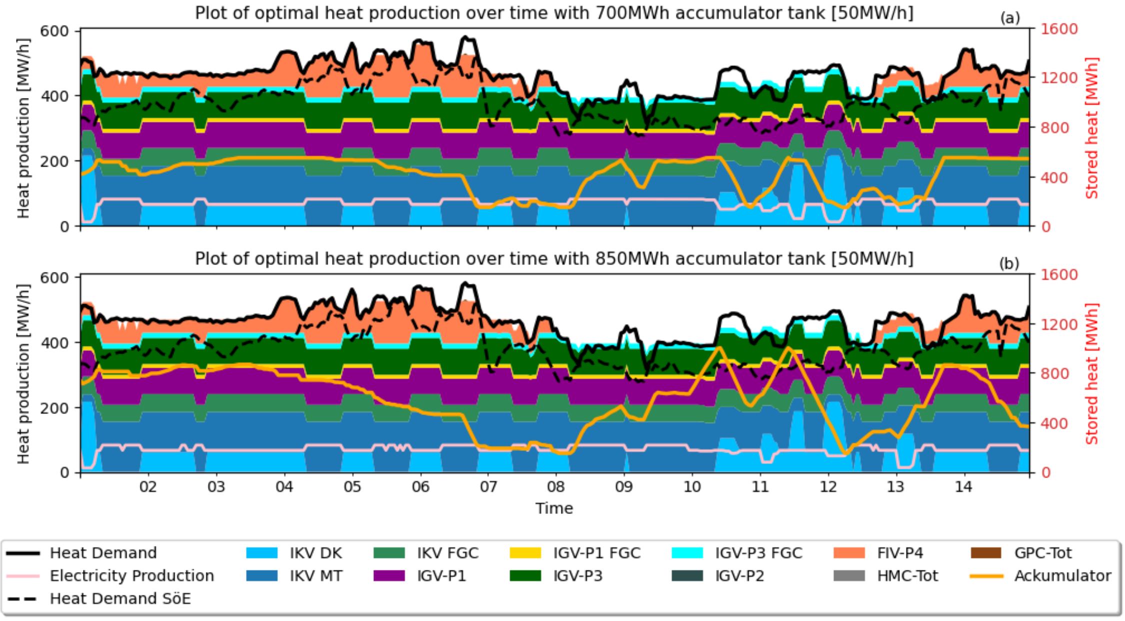

Figure 14-Current energy system with various accumulator tanks and 50 MW/h max flow over two weeks in December 2023: (a) Optimal outcome with 700 MWh tank, (b) Optimal outcome with 850 MWh tank

A comparison between accumulator tanks in the sizes 700 MWh, 850 MWh and 1400 MWh, with a maximum inflow and outflow rate of 100 MW/h during the same two-week period in December 2023 is presented in Figure 15. The goal of this figure is parallel to Figure 14: to explore the flexibility of the system when it comes to matching the heat load at different sizes of the accumulator tanks and to analyze its behavior under these conditions. An observation from Figure 14 and Figure 15 is that the accumulator appears to cover similar production areas regardless of its size. A slightly larger size in Figure 15 can help further reduce heat production from FIV-P4, which can also be seen in the total cost savings for each tank size in Table 12 and Table 13. Similar trends for these two figures can be illustrated during the same two-week period in March, which can be observed in Appendix 1.

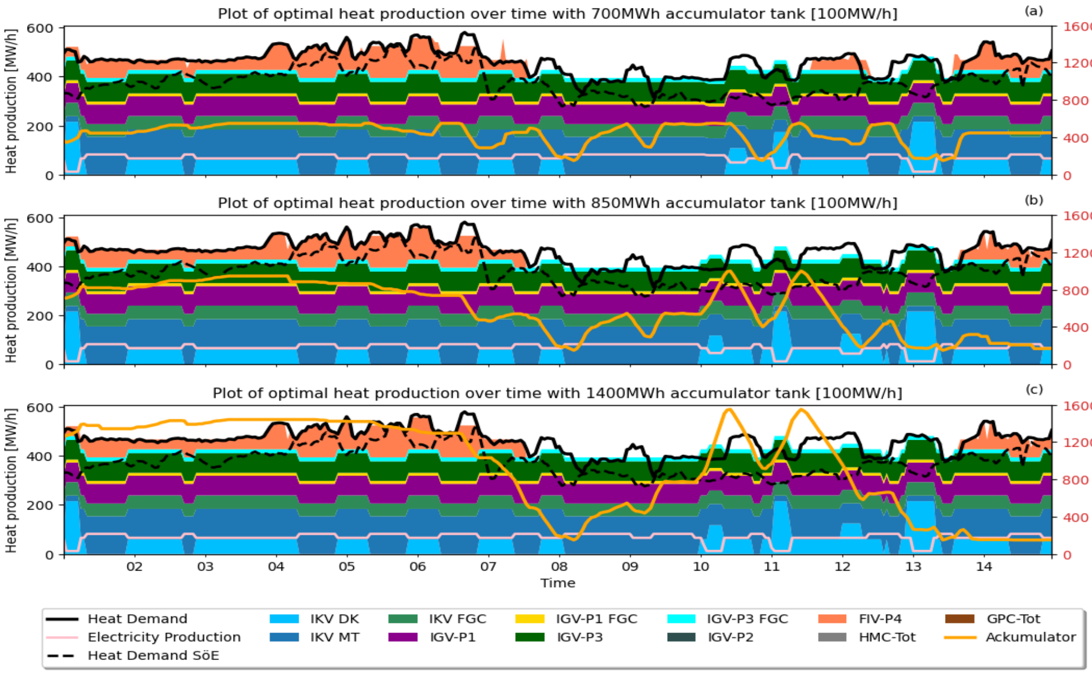

Figure 15-Current energy system with varied accumulator tanks, 100 MW/h max flow over two weeks in December 2023: (a) Optimal outcome with 700 MWh tank, (b) Optimal outcome with 850 MWh tank, (c) Optimal outcome with 1400 MWh tank

The system's total heat production at different sizes of storage tanks within the energy system over different scenarios during the same two-week period in December is observed in Figure 16. An important observation is that a significant part of the peak production is removed regardless of the size of the accumulator tank and the maximum flows. At lower electricity prices, a reduced use of FIV-P4 is observed compared to higher electricity prices. In addition, it is noticeable that there are no significant differences in the total heat production of the various units between the different tank sizes. These analyzes can also be taken from the same two-week period in March, which is presented in Appendix 1.

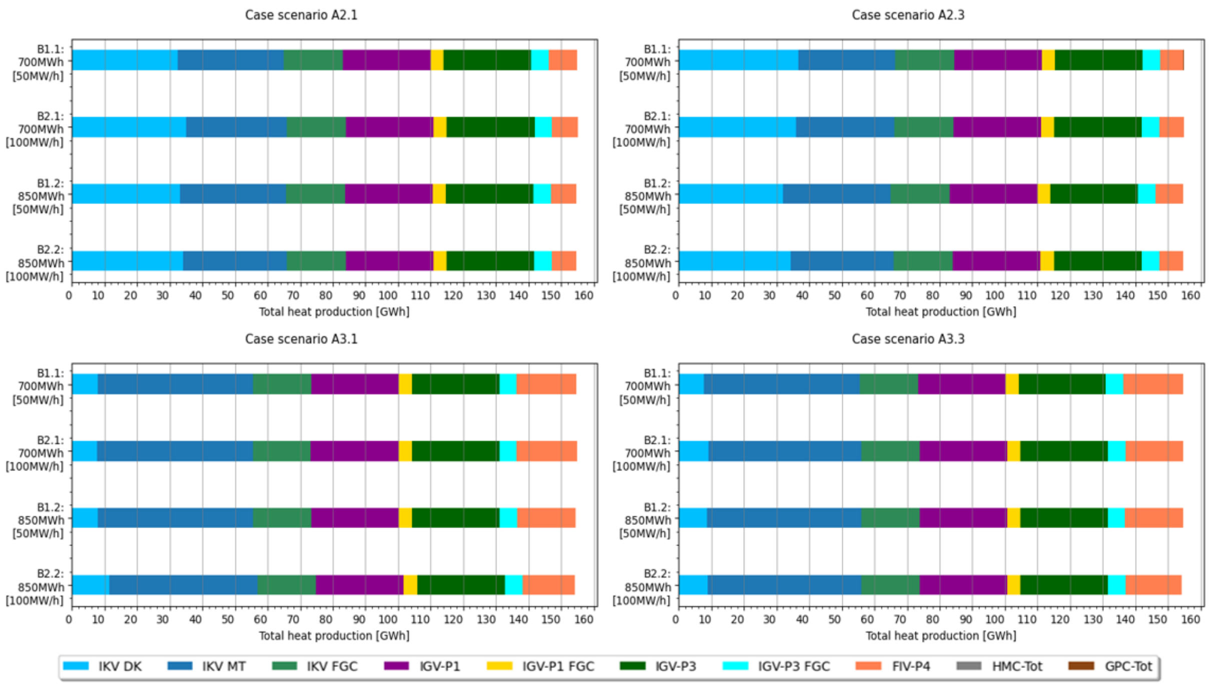

Figure 16-Current energy system with varied accumulator tanks and max flows across scenarios over two weeks in December 2023

The annual total heat production for the current energy system when using an 850 MWh accumulator tank with a maximum inflow and outflow of 100 MW/h is presented in Table 15. Due to the small differences in the total heat production from Figure 16, only values from this case scenario are presented. An observation from this case scenario is that a larger part of production from FIV-P4 has decreased in all case scenarios compared to scenario 1 – A1.1. In addition, a larger proportion of peak production has also decreased, especially from case scenario A2 but also from A3.

Table 15-Overview of annual total heat production for each unit regarding the current energy system with 850 MWh accumulator tank and a max flow of 100 MW/h

Electricity price Change	**A1: 0%**	**A1: 0%**	**A2: -30%**		**A3: +30%**	
Volatility level	Scenario 1 – A1.1 *Reference scenario*	Scenario 2 – A1.1	Scenario 2 – A2.1	Scenario 2 – A2.3	Scenario 2 – A3.1	Scenario 2 – A3.3
IKV-DK [GWh]	329.88	-46.85 (-14%)	+105.36 (+32%)	+107.12 (+32%)	-101.05 (-31%)	-113.87 (-35%)
IKV-MT [GWh]	576.95	+2.63 (0%)	-155.06 (-27%)	-152.96 (-27%)	+91.02 (+16%)	+87.93 (+15%)
IGV-P1 [GWh]	491.67	+22.09 (+4%)	+40.93 (+8%)	+34.94 (+7%)	+16.31 (+3%)	+20.60 (+4%)
IGV-P3 [GWh]	361.03	+38.13 (+11%)	+69.36 (+19%)	+70.41 (+20%)	-8.51 (-2%)	+1.62 (0%)
FIV-P4 [GWh]	101.38	-17.31 (-17%)	-51.02 (-50%)	-50.25 (-50%)	-2.04 (-2%)	+4.13 (+4%)
IGV-P2 [GWh]	1.86	-1.86 (-100%)	-1.86 (-100%)	-1.86 (-100%)	-1.32 (-71%)	-1.86 (-100%)
HMC [GWh]	0.85	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)
GPC [GWh]	3.44	-3.41 (-99%)	-3.38 (-98%)	-3.41 (-99%)	-3.42 (-99%)	-3.43 (-100%)

5.3 Scenario 3 – Current energy system with CCS

This section deals with scenario 3 and provides an overview of case study A. As in section 5.1, the structure follows a similar layout. As the content revolves around the CCS technology, three different scenarios are presented with varying revenue costs for captured CO_2. These revenue costs are specified as 400, 500 and 600 SEK/ton CO_2, as they are around the breakeven point. These revenue costs were chosen using the sensitivity analysis for a time when IKV runs at maximum load, as illustrated in Figure 17. The information for each line can be seen to the right of the figure, where the blue line represents IKV MT, and the red line represents IKV DK. The thicker dashed line next to the blue line shows when the IKV MT is operational and the CCS facility is implemented, while the thinner dashed line next to the IKV DK shows the corresponding situation for that facility. When the thicker dashed lines cross the blue line, this indicates that the system reaches breakeven compared to not having the CCS plant integrated. This means that it is the specific revenue cost of the captured CO_2 that is required to achieve the same production cost as when the CCS plant is not integrated.

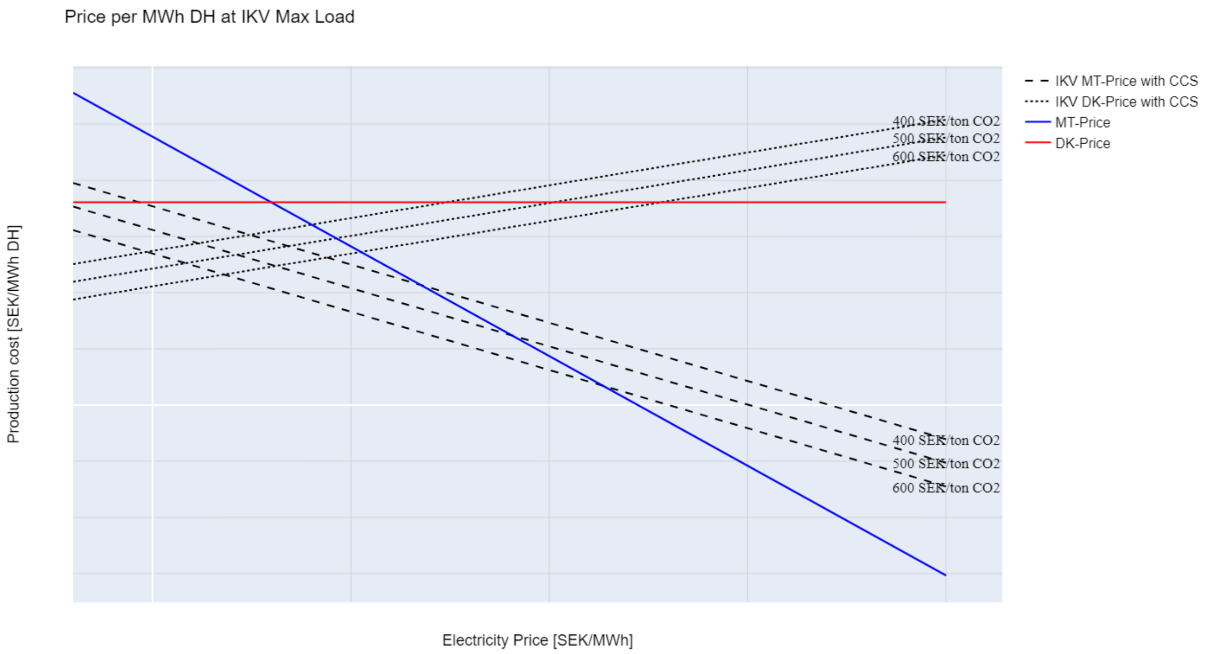

Figure 17-Price per MWh DH at IKV maximum load for various revenue costs for the captured CO_2

5.3.1 Forced CCS facility

This scenario will provide insight into how the system reacts when CCS must operate independently of the current conditions in the electricity market. The CCS plant is linearly linked to how IKV is operating.

Total cost savings

The annual total cost savings for the three different revenue costs for the capture CO_2, where they also are compared to the reference scenario are presented in Table 16. A clear observation here is that the savings increase as the revenue cost of the captured CO_2 increases. The breakeven point is around 500 SEK/ton CO_2 to achieve security in all case scenarios.

Table 16-Annual total cost savings in the case of forced operation of a CCS facility with three different revenue levels for the cost per ton of CO_2

Electricity price Change	Volatility level	Total cost savings [MSEK] – 400 SEK/ton CO_2	Total cost savings [MSEK] – 500 SEK/ton CO_2	Total cost savings [MSEK] – 600 SEK/ton CO_2
Scenario A1: 0%	Scenario A1.1	+2.7 (+0.4%)	-49.9 (-6.4%)	-85.8 (-13.3%)
	Scenario A1.2	+4.3 (+0.7%)	-40.2 (-6.2%)	-85 (-13.2%)
	Scenario A1.3	+2.2 (+0.3%)	-39.1 (-6.1%)	-83.1 (-12.9%)
Scenario A2: -30%	Scenario A2.1	+47 (+7.3%)	+3.6 (+0.6%)	-41.8 (-6.5%)
	Scenario A2.2	+48 (+7.5%)	+5.8 (+0.9%)	-41.5 (-6.4%)
	Scenario A2.3	+45.3 (+7.0%)	+3.2 (+0.5%)	-40.2 (-6.2%)
Scenario A3: +30%	Scenario A3.1	-52.4 (-8.1%)	-95.1 (-14.8%)	-138.3 (-21.5%)
	Scenario A3.2	-49.9 (-7.7%)	-95 (-14.8%)	-139.9 (-21.7%)
	Scenario A3.3	-50.5 (-7.8%)	-95 (-14.8%)	-138.3 (-21.5%)

Total cost savings relative to the initial investment

The annual total cost savings relative to the initial investment for the CCS technology at three different revenue costs for the captured CO_2 are shown in Table 17. As the case scenarios in Table 16 are similar in terms of volatility levels, these changes will not be considered here.

Table 17-Annual total cost savings relative to the initial investment for the CCS plant and the different revenue costs of the captured CO_2

Electricity price Change	Volatility level	Cost savings relative to the investment - 400 SEK/ton CO_2	Cost savings relative to the investment - 500 SEK/ton CO_2	Cost savings relative to the investment - 600 SEK/ton CO_2
Scenario A1: 0%	A1.1	-0.04%	0.61%	1.27%
Scenario A2: -30%	A2.1	0.42%	1.06%	1.74%
Scenario A3: +30%	A3.1	-0.51%	0.13%	0.77%

Flexibility of the system

Because the CCS plant is integrated with how IKV is operating and forced to operate, the power from CCS remains relatively stable regardless of the revenue cost of the captured CO_2. This theory can be illustrated in Figure 18 and Figure 19, where the waste heat from the CCS plant remains the same in all case scenarios. All units presented in the production plans are located at the bottom of the figure, where the CCS plant represents the color lime green. Figure 18 represents the same two-week period during March 2023. The notable difference in this case is the reduced amount from peak production and production from FIV-P4.

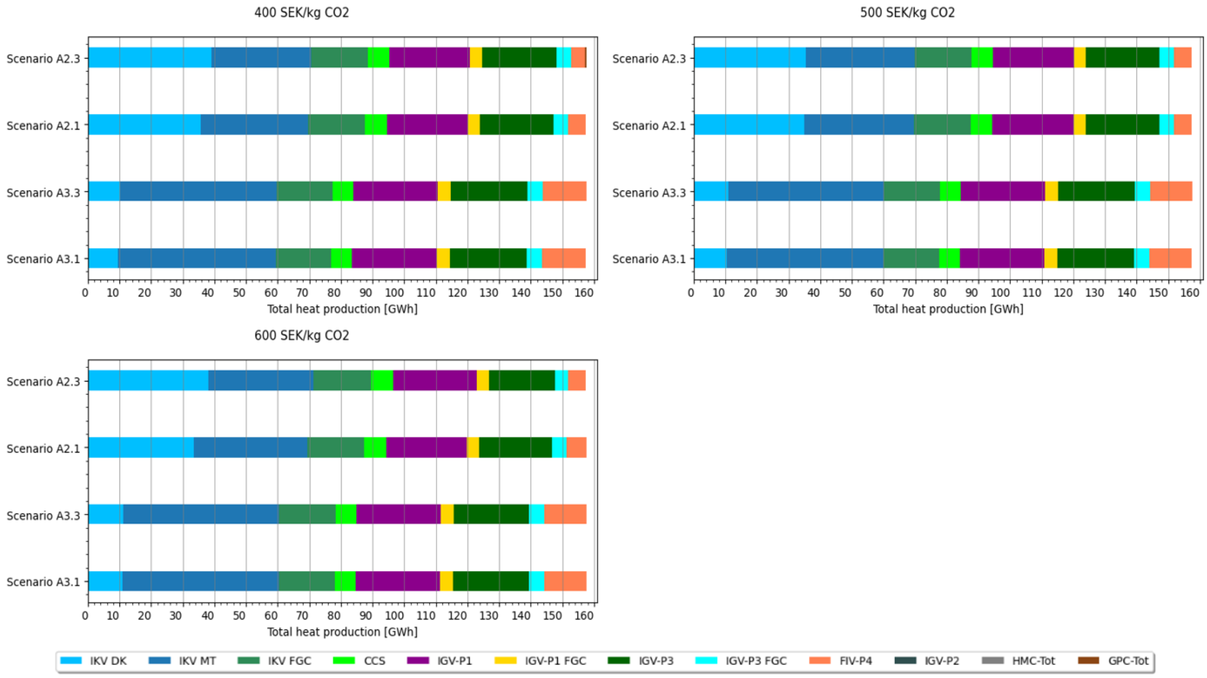

Figure 18-Current energy system with a forced CCS plant and different revenue cost for captured CO_2 across scenarios over two weeks in March 2023

The same principle shown in Figure 18 is illustrated in Figure 19, but for the same two-week period during December 2023. Another observation that emerges from Figure 19 compared to Figure 18 is a slightly increased use of peak production in case scenario A3.

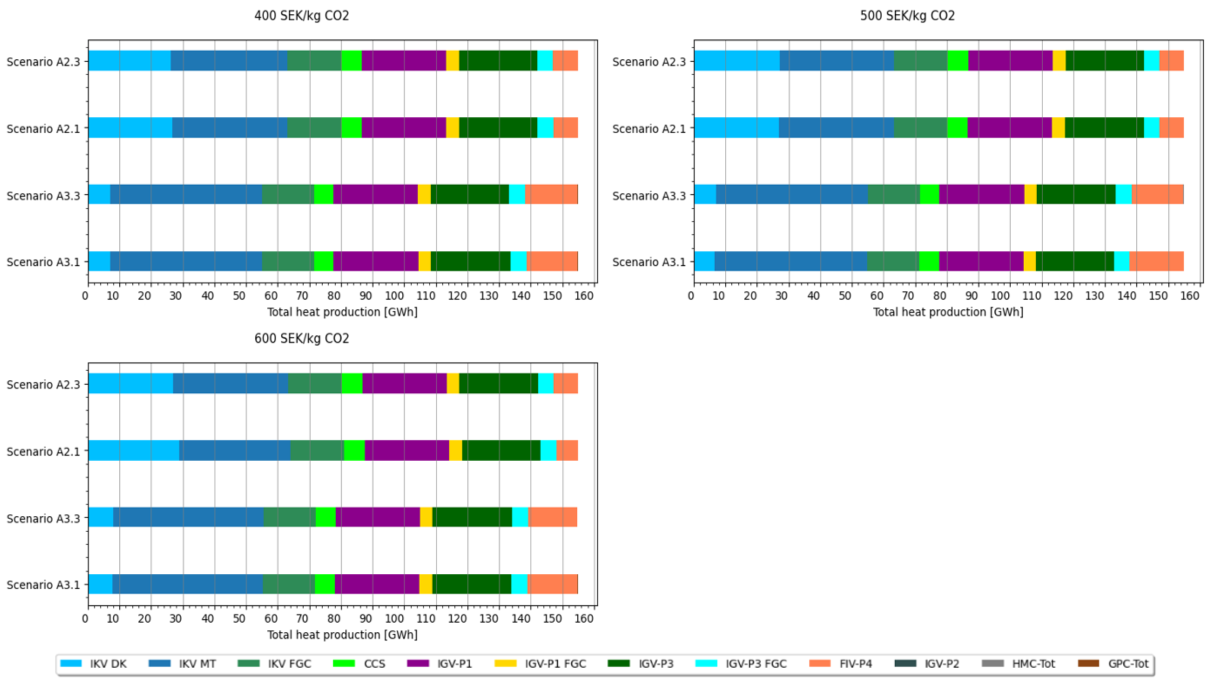

Figure 19-Current energy system with a forced CCS plant and different revenue cost for captured CO_2 across scenarios over two weeks in December 2023

Since CCS is linearly linked to the operation of IKV, only one of three revenue costs of the captured CO_2 will be analyzed to get a detailed insight into how the system reacts to the implementation of the CCS plant, which is shown more clearly in Figure 20. Figure 20 presents the same two-week period during Marh 2023. The production plan with the CCS plant (b) is presented in the same case scenario as the production plan without the CCS plant (a), the reference scenario 1 – A1.1. One observation that can be seen in Figure 20 is the same as noted in the Figure 18 and Figure 19, that the heat production from both FIV-P4 and peak production has decreased. As similar trends can be seen in Figure 18 and Figure 19, only a production plan of March is presented just to observe the degree of flexibility. The production plan of the same two-week period in December can be observed in Appendix 2.

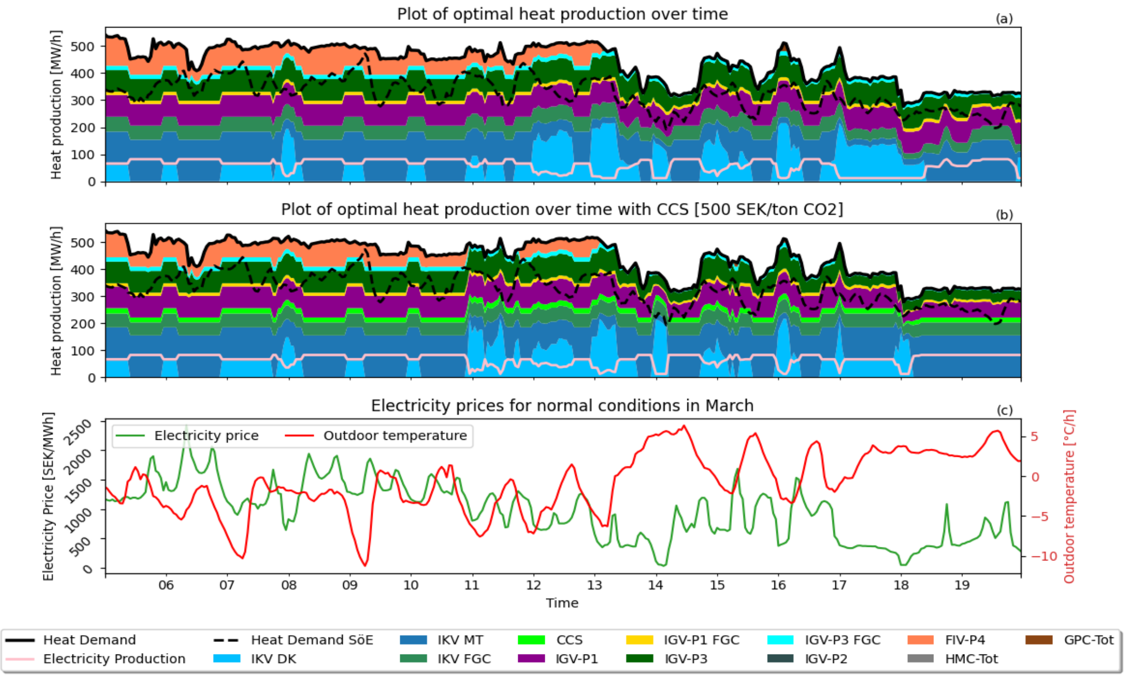

Figure 20-Model behavior with a forced CCS plant and a revenue cost for captured CO2 of 500 SEK/ton CO_2 over two weeks in March: (a) Optimal outcome, (b) Optimal outcome with CCS plant, (c) Historical weather and electricity data

The annual total heat production for the current energy system for scenario 3 is shown in Table 18. A revenue cost of 500 SEK/ton CO_2 has been used because of the CCS plant's independency of the electricity market. Similar trends observed in Table 15 are noted in this case, especially for FIV-P4, although not to the same extent for peak production.

Table 18-Overview of annual total heat production for each unit regarding the current energy system with a CCS plant with a revenue cost of 500 SEK/ton CO_2

Electricity price Change	**A1: 0%**	**A1: 0%**	**A2: -30%**		**A3: +30%**	
Volatility level	Scenario 1 – A1.1 *Reference scenario*	Scenario 3 – A1.1	Scenario 3 – A2.1	Scenario 3 – A2.3	Scenario 3 – A3.1	Scenario 3 – A3.3
IKV-DK [GWh]	329.88	-10.74 (-3%)	+166.98 (+51%)	+150.50 (+46%)	-86.15 (-26%)	-86.26 (-26%)
IKV-MT [GWh]	576.95	+74.86 (+13%)	-63.10 (-11%)	-46.24 (-8%)	+124.63 (+22%)	+123.57 (+21%)
IGV-P1 [GWh]	491.67	-22.82 (-5%)	-17.19 (-3%)	-18.68 (-4%)	-20.82 (-4%)	-23.42 (-5%)
IGV-P3 [GWh]	361.03	-97.48 (-27%)	-107.11 (-30%)	-106.74 (-30%)	-92.83 (-26%)	-91.04 (-25%)
FIV-P4 [GWh]	101.38	-17.79 (-18%)	-46.40 (-46%)	-48.34 (-48%)	-1.60 (-2%)	+0.78 (+1%)
IGV-P2 [GWh]	1.86	-0.84 (-45%)	-0.72 (-39%)	-1.23 (-66%)	-0.30 (-16%)	+0.51 (+28%)
HMC [GWh]	0.85	-0.55 (-65%)	-0.06 (-7%)	+0.05 (+6%)	+0.18 (+21%)	-0.29 (-34%)
GPC [GWh]	3.44	+0.58 (+17%)	+0.75 (+22%)	+0.73 (+21%)	+1.52 (+44%)	+0.64 (+19%)

5.3.2 Unforced CCS facility

This scenario will provide insight into how the system reacts when the CCS plant is dependent on the current conditions on the electricity market. The CCS plant is not linear linked to how IKV is operating, but still has its minimum capacity.

Total cost savings

The annual total cost savings for two different revenue costs for the capture CO_2, where they also are compared to the reference scenario, are presented in Table 19. The same observation as Table 16 can be illustrated in this scenario, where the savings increase as the revenue cost of the captured CO_2 increases. The breakeven point is around 500 SEK/ton CO_2, but with higher security across the other case scenarios compared to Table 16.

Table 19-Annual total cost savings in case of no forced operation of a CCS plant with two different revenue levels for the cost per ton of CO_2

Electricity price Change	Volatility level	Total cost savings [MSEK] 400 SEK/ton CO_2	Total cost savings [MSEK] 500 SEK/ton CO_2
Scenario A1: 0%	Scenario A1.1	-20.7 (-3.2%)	-52 (-8.1%)
	Scenario A1.2	-22.7 (-3.5%)	-50.9 (-7.9%)
	Scenario A1.3	-23.8 (-3.7%)	-52.2 (-8.1%)
Scenario A2: -30%	Scenario A2.1	+41.4 (+6.4%)	+4 (+0.6%)
	Scenario A2.2	+42.4 (+6.6%)	+1.8 (+0.3%)
	Scenario A2.3	+40.4 (+6.3%)	+0.9 (+0.1%)
Scenario A3: +30%	Scenario A3.1	-101.1 (-15.7%)	-123.8 (-19.2%)
	Scenario A3.2	-101.9 (-15.8%)	-124.2 (-19.3%)
	Scenario A3.3	-103.4 (-16.1%)	-125.9 (-19.6%)

Flexibility of the system

In this case, the CCS facility is not forced and not linearly connected to how the IKV works. This means a greater degree of autonomy for the CCS plant, as it is powered by electricity and can relate more to the electricity market. Figure 21 illustrates two weeks in March 2023 and provides an understanding of how the CCS plant works more actively when electricity prices are low and vice versa when electricity prices are high. Furthermore, it can be observed how the production from the CCS plant increases when the revenue costs from the captured CO_2 are higher.

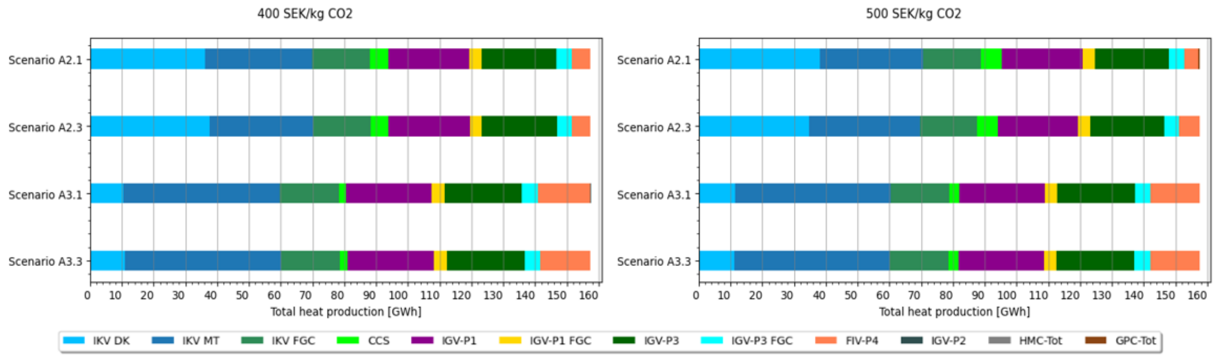

Figure 21-Current energy system with an unforced CCS plant and different revenue cost for captured CO_2 across scenarios over two weeks in March 2023

The same principle as Figure 21 applies for Figure 22, but for two weeks in December 2023. A similar trend is seen in this figure as in Figure 21, but there are some differences in terms of the amount of waste heat produced by CCS.

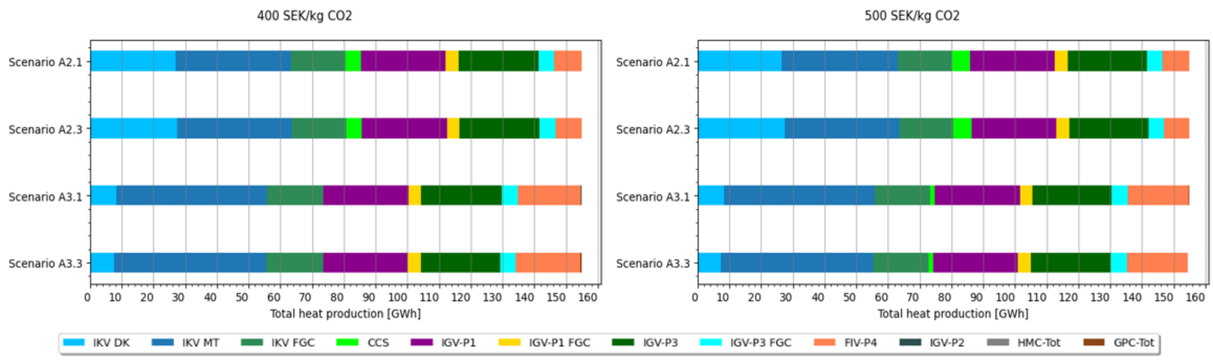

Figure 22-Current energy system with an unforced CCS plant and different revenue cost for captured CO_2 across scenarios over two weeks in December 2023

The production plan for the energy system when the CCS plant is in operation under a scenario where electricity prices remain unchanged for two weeks in March 2023 is shown in Figure 23. Figure 23.a reflects a scenario where the revenue cost of the captured CO_2 is 400 SEK/ton, while Figure 23.b shows the scenario when the revenue cost is 500 SEK/ton of CO_2. Figure 23.c illustrates how the electricity prices and the weather conditions behaved during this specific period. An observation from the beginning of this figure, between March 5th and 13th, is that increased revenue from captured CO_2 is proportional to increased activity of the CCS plant regardless of the electricity prices.

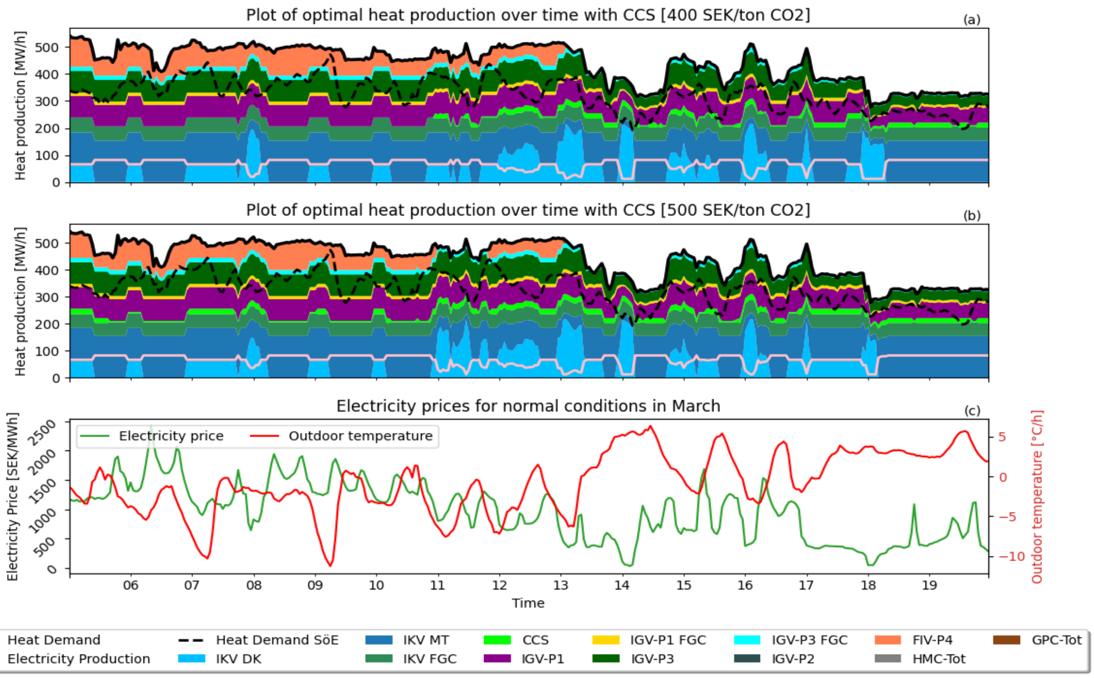

Figure 23-Model behavior with an unforced CCS plant and two different revenue cost for captured CO_2 over two weeks in March: (a) Optimal outcome with CCS [400 SEK/ton CO_2], (b) Optimal outcome with CCS [500 SEK/ton CO_2], (c) Historical weather and electricity data

Figure 24 illustrates the same principle and as Figure 23, but for the same two-week period in December 2023. In this case, a similar trend can be observed as in Figure 23, where an increased revenue from captured CO_2 results in increased activity in the CCS facility regardless of electricity prices. This relationship also coincides with Figure 22, where a reduced proportion of waste heat from CCS is produced.

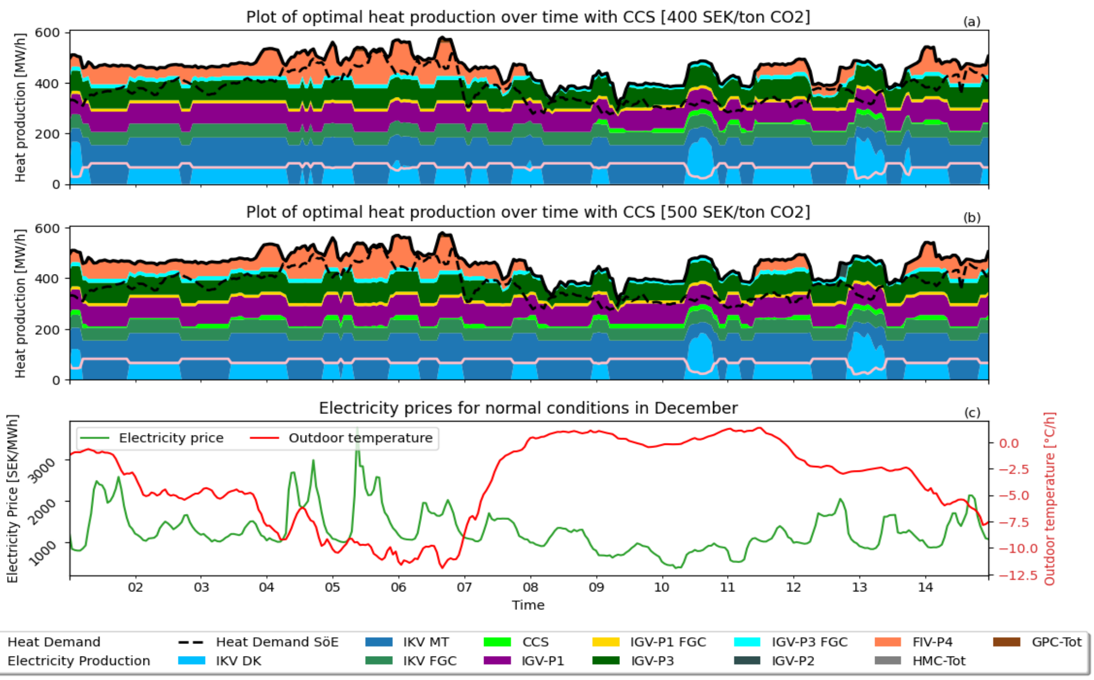

Figure 24-Model behavior with an unforced CCS plant and two different revenue cost for captured CO_2 over two weeks in December: (a) Optimal outcome with CCS [400 SEK/ton CO_2], (b) Optimal outcome with CCS [500 SEK/ton CO_2], (c) Historical weather and electricity data

5.4 Scenario 4 – Current energy system with CCS and TES

In this section, scenario 4 is presented, providing an overview of case study A and B to investigate its impact on the system and flexibility. The section follows the same structure as earlier parts of section 5. In this case, since Table 12 and Table 13 presented minimal differences between the scenarios B1-B2, only one size of the accumulator tank and two revenue cost for the captured CO_2 are shown. In this case, the CCS plant is forced to operate regardless of the electricity market.

Total cost savings

The annal total cost savings when using an 850 MWh accumulator tank, with a max flow of 100 MW/h (B2.2), and a CCS plant, with two revenue cost of 400 and 500 SEK/ton CO_2 are presented in Table 20. The same principle that is used for the revenue cost of captured CO_2 from section 5.3 is also applied here. The higher revenue costs, the greater the savings achieved. In this case, the breakeven point is around 400 SEK/ton CO_2.

Table 20-Annual total cost savings with forced CCS plant [400 & 500 SEK/ton CO_2] and with 850 MWh accumulator tank [100 MW/h]

Electricity price Change	Volatility level	Total costs savings [MSEK] B2.2 + 400 SEK/ton CO_2	Total costs savings [MSEK] B2.2 + 500 SEK/ton CO_2
Scenario A1: 0%	Scenario A1.1	-26.2 (-4.1%)	-71.8 (-11,2%)
	Scenario A1.2	-25.3 (-3.9%)	-71.5 (-11.1%)
	Scenario A1.3	-26.4 (-4.1%)	-73.6 (-11.4%)
Scenario A2: -30%	Scenario A2.1	+17.1 (+2.7%)	-25.5 (-4.0%)
	Scenario A2.2	+19.5 (+3.0%)	-26.3 (-4.1%)
	Scenario A2.3	+19.7 (+3.1%)	-27 (-4.2%)
Scenario A3: +30%	Scenario A3.1	-82.9 (-12.9%)	-127 (-19.7%)
	Scenario A3.2	-26.4 (-4.1%)	-73.6 (-11.4%)
	Scenario A3.3	-81.5 (-12.7%)	-126.9 (-19.7%)

Total cost savings relative to the initial investment

The annual total cost savings relative to the initial investment are shown in Table 21. As the case scenarios in Table 20 are similar in terms of volatility levels, these changes will not be considered here.

Table 21-Annual total cost savings relative to the initial investment for the CCS plant and the different revenue costs of the captured CO_2

Electricity price Change	Volatility level	Cost savings relative to the investment – B2.2 + 400kr/ton CO_2	Cost savings relative to the investment – B2.2 + 500kr/ton CO_2
Scenario A1: 0%	A1.1	0.39%	1.06%
Scenario A2: -30%	A2.1	0.86%	1.48%
Scenario A3: +30%	A3.1	-0.05%	0.59%

Flexibility of the system

The model behavior for scenario 4, where the optimal outcome without any technology integrated (a) and the optimal outcome with the CCS plant and an 850 MWh accumulator tank (b) are shown Figure 25. This figure occurs during the two-week period in March 2023. As the CCS plant is forced to operate, only a revenue cost of 500 SEK/ton CO_2 will be illustrated. An interesting observation is that the accumulator tank and IGV-P3 cover a larger part of the heat production to reduce the production from FIV-P4 even more, which is different from what can be seen in Figure 12.

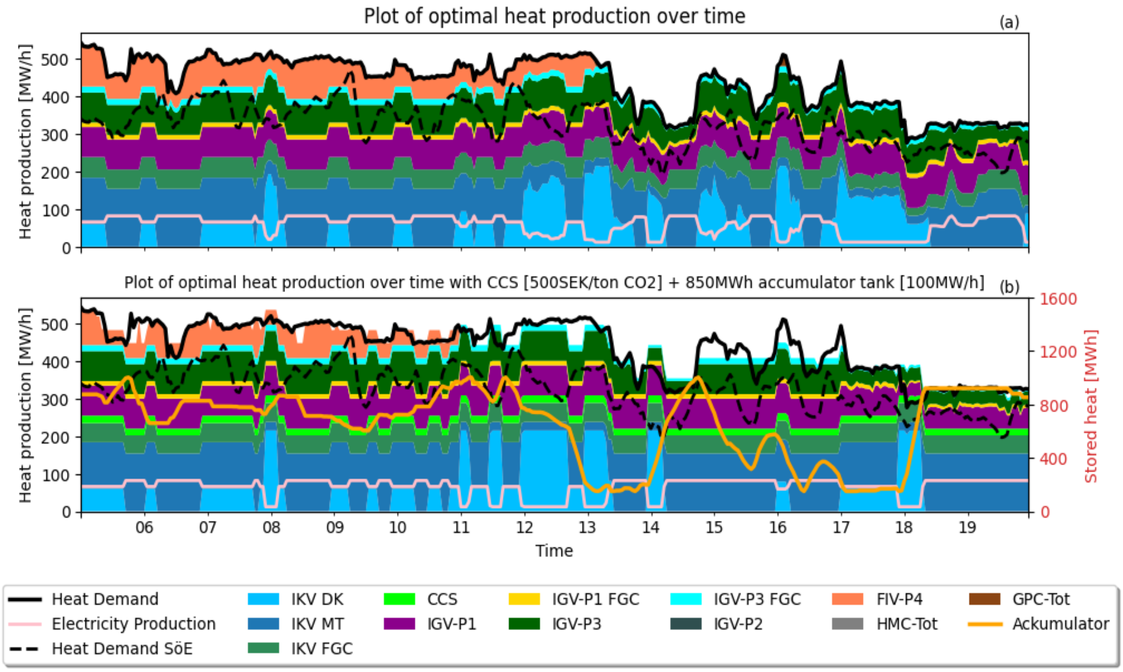

Figure 25-Model behavior with a forced CCS plant and 850 MWh accumulator tank over two weeks in March: (a) Optimal outcome (b) Optimal outcome with CCS [500 SEK/ton CO_2] and with 850 MWh accumulator tank [100 MW/h]

The same principle shown in Figure 25 is illustrated in Figure 26, but for two weeks in December 2023. Just as in Figure 25, the same conclusion can be drawn here, that the combination of the CCS technology and the accumulator tank covers the heat demand more efficiently compared to what is shown in Figure 13.

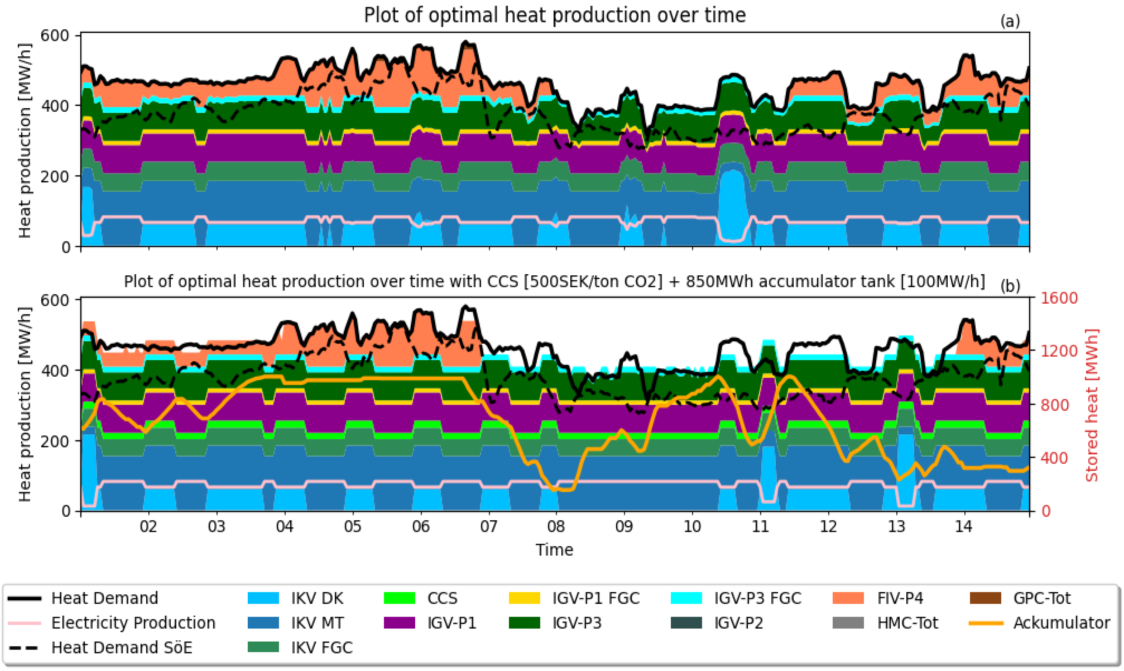

Figure 26-Model behavior with a forced CCS plant and 850 MWh accumulator tank over two weeks in December: (a) Optimal outcome (b) Optimal outcome with CCS [500 SEK/ton CO_2] and with 850 MWh accumulator tank [100 MW/h]

Figure 27 shows how the total heat production from the different units behaves across different case scenarios with the electricity prices during two weeks in March 2023. In this figure, it can be observed that no peak production is used, and further reduction of heat production from FIV-P4 occurs in all four scenarios.

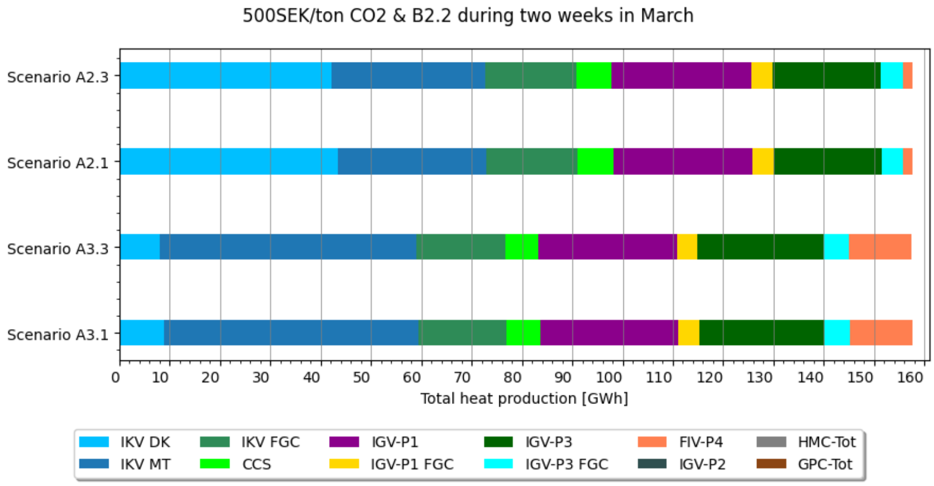

Figure 27-Current energy system with a forced CCS plant [500 SEK/ton CO_2] and with 850 MWh accumulator tank [100 MW/h] across scenarios over two weeks in March 2023

The same ideas illustrated in Figure 27 is also presented in Figure 28, but for the same two-week period in December 2023. One observation from this figure compared to Figure 27 is the slightly increased use of FIV-P4 and the significantly greater amount of heat production from IKV MT.

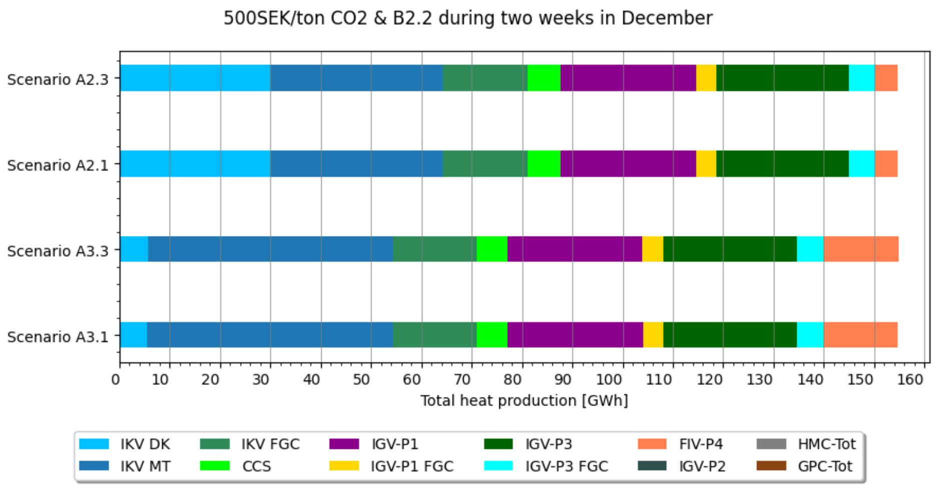

Figure 28-Current energy system with a forced CCS plant [500 SEK/ton CO_2] and with 850 MWh accumulator tank [100 MW/h] across scenarios over two weeks in December 2023

The total annual heat production from each unit across the different case scenarios for scenario 4 is presented in Table 22. This can be linked to what has been observed in Figure 27 and Figure 28, where there is almost no peak production during the year. A small part of the heat production from GPC-Tot occurs during the year.

Table 22-Overview of annual total heat production for each unit regarding the current energy system with a CCS plant [500 SEK/ton CO_2] and an 850 MWh accumulator tank [100 MW/h]

Electricity price Change	**A1: 0%**	**A1: 0%**	**A2: -30%**		**A3: +30%**	
Volatility level	Scenario 1 – A1.1 *Reference scenario*	Scenario 4 – A1.1	Scenario 4 – A2.1	Scenario 4 – A2.3	Scenario 4 – A3.1	Scenario 4 – A3.3
IKV-DK [GWh]	329.88	-1.56 (-0%)	+221.11 (+67%)	+223.11 (+68%)	-87.43 (-27%)	-84.18 (-26%)
IKV-MT [GWh]	576.95	+103.56 (+18%)	-59.65 (-10%)	-71.89 (-12%)	+152.49 (+26%)	+156.17 (+27%)
IGV-P1 [GWh]	491.67	-37.33 (-8%)	-21.56 (-4%)	-10.83 (-2%)	-29.09 (-6%)	-34.23 (-7%)
IGV-P3 [GWh]	361.03	-111.07 (-31%)	-139.89 (-39%)	-140.09 (-39%)	-99.54 (-28%)	-103.47 (-29%)
FIV-P4 [GWh]	101.38	-36.44 (-36%)	-73.35 (-72%)	-71.66 (-71%)	-19.10 (-19%)	-17.89 (-18%)
IGV-P2 [GWh]	1.86	-1.86 (-100%)	-1.86 (-100%)	-1.86 (-100%)	-1.86 (-100%)	-1.86 (-100%)
HMC [GWh]	0.85	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)	-0.85 (-100%)
GPC [GWh]	3.44	-3.41 (-99%)	-3.44 (-100%)	-3.43 (-100%)	-3.35 (-97%)	-2.91 (-85%)

5.5 Scenario 5 – Current energy system with HP

This section represent scenario 5, where a heat pump is implemented into the energy system. In this case, two different COP values are analyzed and compared.

Total cost savings

The annual total cost savings together with the different COP factors and case scenarios can be observed in Table 23. One observation from this table is that the savings increase in connection with increased COP factor.

Table 23-Annual total cost of current energy system with a heat pump and two different COP factors across different scenarios

Electricity price Change	Volatility level	Total costs savings [MSEK] COP factor 3	Total costs savings [MSEK] COP factor 4
Scenario A1: 0%	Scenario A1.1	-47.4 (-7.4%)	-68.9 (-10.7%)
	Scenario A1.2	-42.8 (-6.6%)	-68.2 (-10.6%)
	Scenario A1.3	-46.3 (-7.2%)	-69.8 (-10.8%)
Scenario A2: -30%	Scenario A2.1	+22.5 (+3.5%)	-0.5 (-0.1%)
	Scenario A2.2	+22.1 (+3.4%)	-2.4 (-0.4%)
	Scenario A2.3	+20.1 (+3.1%)	-1.6 (-0.2%)
Scenario A3: +30%	Scenario A3.1	-128 (-19.9%)	-150 (-23.3%)
	Scenario A3.2	-126.1 (-19.6%)	-150.1 (-23.3%)
	Scenario A3.3	-128.4 (-19.9%)	-150.9 (-23.4%)

Total cost savings relative to the initial investment

The annual total cost savings relative to the initial investment for a heat pump with the two different COP factors is presented in Table 24. Due to the small differences in volatility level in Table 23, only the difference in electricity price levels will be presented.

Table 24-Annual total cost savings relative to the initial investment for heat pump and two COP factors

Electricity price Change	Volatility level	Cost savings relative to the investment - COP factor 3	Cost savings relative to the investment - COP factor 4
Scenario A1: 0%	A1.1	40%	57%
Scenario A2: -30%	A2.1	44%	63%
Scenario A3: +30%	A3.1	35%	53%

Flexibility of the system

The total heat production for each unit in the current energy system when a heat pump is integrated at different COP factors of 3 and 4, respectively, during the same two-week period in March 2023 is shown in Figure 29. One observation from this figure is the marked drop in heat production from FIV-P4, with instead a clearer use of the peak production with a COP factor of 4.

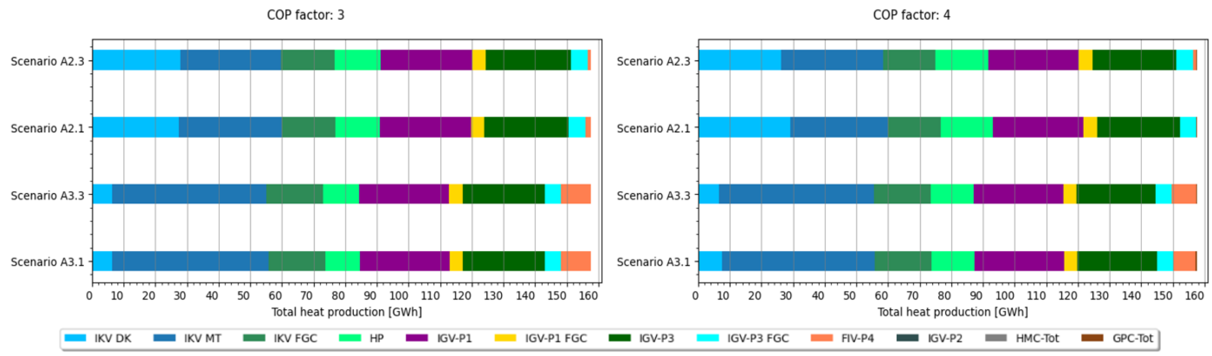

Figure 29-Current energy system with a heat pump and two different COP factors across scenarios over two weeks in March 2023

The same information and principle shown in Figure 29 is illustrated in Figure 30, but for the same two-week period in December 2023. In this case, there is a reduction in heat production from both FIV-P4 and peak production.

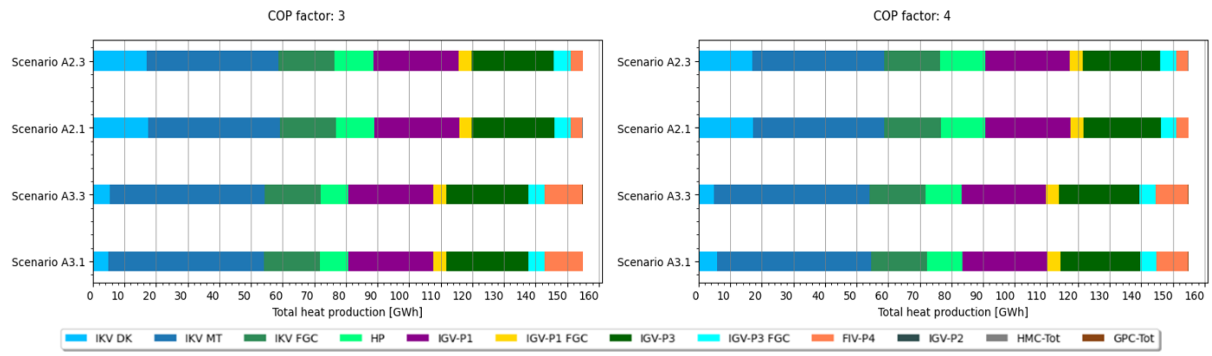

Figure 30-Current energy system with a heat pump and two different COP factors across scenarios over two weeks in December 2023

Only the COP factor 3 will be shown in the following Figure 31 and Figure 32 to observe in more detail how the integration of a heat pump affects the flexibility using a production plan. Figure 31 compares the optimal production plan without a heat pump, the reference scenario 1 – A1.1 (a), with the optimal production plan using a heat pump (b). These production plans are also adjusted for historical electricity prices and weather conditions during the same two-week period in March 2023. This figure shows the relative reduction of FIV-P4 when the heat pump is activated. Furthermore, a clear regulation of the heat pump depending on electricity prices is noted, where it is used more intensively at lower electricity prices and reduces its production during periods of higher prices.

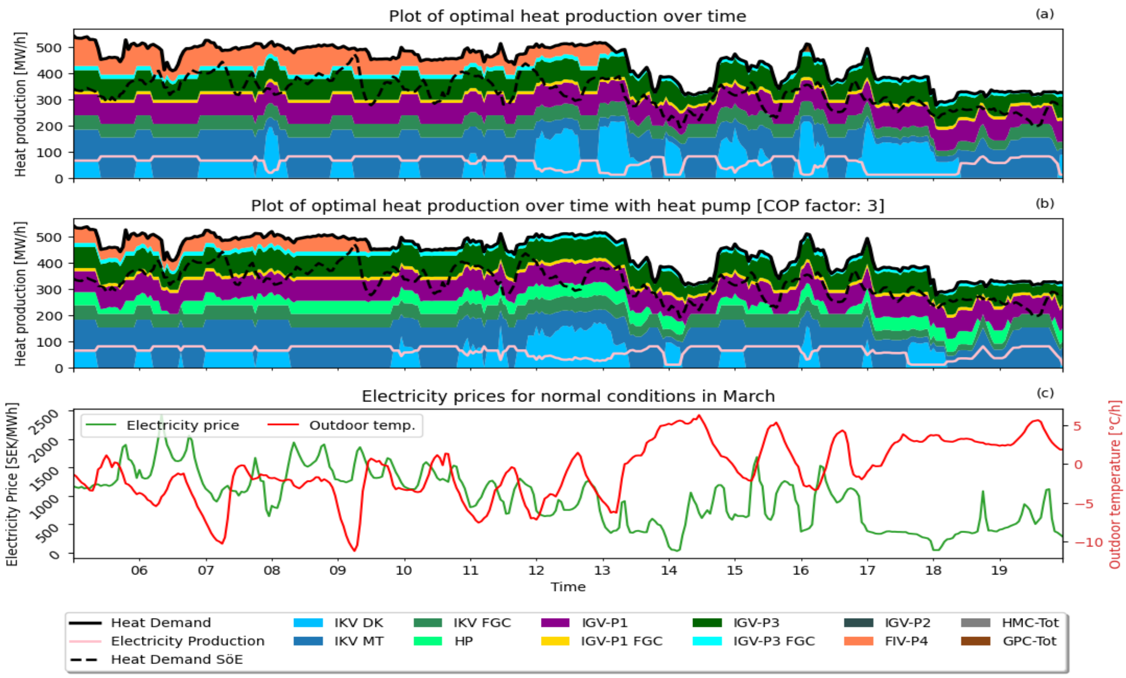

Figure 31-Model behavior with a heat pump over two weeks in March: (a) Optimal outcome, (b) Optimal outcome with a heat pump and COP factor of 3, (c) Historical weather and electricity data

Figure 32 presents the same information as Figure 31, but for two weeks in December 2023. This figure shows a similar trend to Figure 31, but with a lower use of the heat pump due to the higher electricity prices.

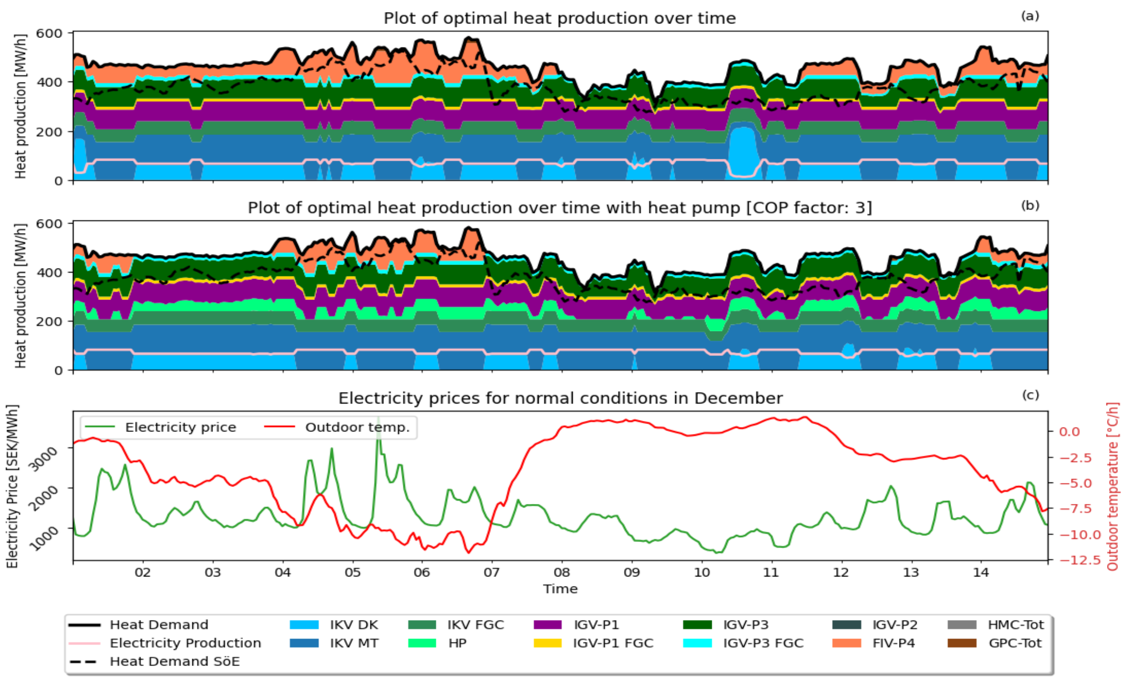

Figure 32-Model behavior with a heat pump over two weeks in December: (a) Optimal outcome, (b) Optimal outcome with a heat pump and COP factor of 3, (c) Historical weather and electricity data

The annual total heat production for each unit when using a heat pump in the energy system with a COP factor of 3 is presented in Table 25. In this table, the large reduction of FIV-P4 can be observed in all case scenarios, which is proportional to the behavior of Figure 29 and Figure 30

Table 25-Overview of annual total heat production for each unit regarding the current energy system with a heat pump and a COP factor of 3

Electricity price Change	**A1: 0%**	**A1: 0%**	**A2: -30%**		**A3: +30%**	
Volatility level	Scenario 1 – A1.1 *Reference scenario*	Scenario 5 – A1.1	Scenario 5 – A2.1	Scenario 5 – A2.3	Scenario 5 – A3.1	Scenario 5 – A3.3
IKV-DK [GWh]	329.88	-124.63 (-38%)	-31.97 (-10%)	-33.74 (-10%)	-203.55 (-62%)	-192.21 (-58%)
IKV-MT [GWh]	576.95	+0.79 (0%)	-127.52 (-22%)	-127.69 (-22%)	+120.87 (+21%)	+116.81 (+20%)
IGV-P1 [GWh]	491.67	-28.21 (-6%)	-25.41 (-5%)	-28.97 (-6%)	-33.02 (-7%)	-34.96 (-7%)
IGV-P3 [GWh]	361.03	-1.83 (-1%)	+26.21 (+7%)	+29.24 (+8%)	-33.16 (-9%)	-36.72 (-10%)
FIV-P4 [GWh]	101.38	-55.06 (-54%)	-76.39 (-75%)	-74.93 (-74%)	-30.17 (-30%)	-30.77 (-30%)
IGV-P2 [GWh]	1.86	-0.46 (-25%)	-0.58 (-31%)	-0.81 (-44%)	-1.68 (-91%)	-1.51 (-81%)
HMC [GWh]	0.85	-0.57 (-67%)	+0.36 (+43%)	-0.10 (-12%)	-0.54 (-63%)	-0.49 (-57%)
GPC [GWh]	3.44	-1.74 (-51%)	-1.25 (-36%)	-1.67 (-49%)	-1.83 (-53%)	-2.03 (-59%)

6 DISCUSSION

In the discussion section, an evaluation and analysis of the results dealing with the research questions is carried out, where the choice of method is also discussed. In addition, it is analyzed how these aspects within cogeneration affect the social, economic and sustainability dimensions.

6.1 Findings evaluation

Scenario 1

By carefully analyzing the modelling and optimization in relation to actual outcomes from March and December 2023, there are interesting similarities to observe between the production plans in Figure 8 and Figure 9. It appears that during the month of March, to increase profitability, an increased use of IKV DK and IGV-P3 was required to compensate for FIV-P4's high production costs for heat production. It is noteworthy that the model does not consider unavailability except during yearly maintenance, which may have affected the results as some units may have been unavailable due to fuel shortages, for example. Additionally, the model does not consider the benefit of heat export, which is due to the fact that FIV-P4 and IKV MT are used more in the actual outcome than the optimal outcome encountered. This is an important aspect to consider as it may affect the reality of the results compared to the model's predictions. Similar reasoning can be applied to December 2023 according to Figure 9. Optimization suggests that increased heat production from IKV DK would have reduced the use of the peak boiler IGV-P2. However, the reason for the use of IGV-P2 in the actual outcome is unclear. A comparative analysis can also be made between Figure 10 and Figure 11 with Table 10 and Table 11 for different case scenarios of electricity prices. It is important to note that changes in total cost are more pronounced at varying price levels compared to volatility levels. This could be related to market dynamics where higher electricity prices can generate increased revenue while lower prices lead to higher costs. However, volatility also plays a crucial role, with higher volatility usually resulting in increased uncertainty regarding decisions on the use of different energy sources and pricing strategies. Sensitivity periods for certain units may occur during periods of declining electricity prices, especially IKV, which may make it difficult to utilize them effectively.

Scenario 2

An interesting observation is that the introduction of an accumulator tank in the system could lead to significant cost savings according to Table 12 and Table 13, especially at high electricity price levels. Through sensitivity analysis of different sizes of accumulator tanks, we can see that the difference in annual total cost savings for each case scenario, A1-A3, does not vary by more than around 1–2%. The major difference still lies in the variation of electricity price levels regardless of the sizes of accumulator tanks, where savings can be as high as between 113–126 MSEK at high electricity prices. This analysis is also clear in Figure 16 where IKV MT is used significantly more at higher electricity price levels. At lower electricity price levels, we can observe increased costs, with the major difference being that it is not as profitable to utilize IKV MT even if an accumulator is integrated. Similar trend can be observed during March. Regarding the volatility levels, we can still see that these do not have a significant difference, but that a certain variation regardless of tank sizes occurs regardless of what the electricity price levels show. This difference in volatility may be due primarily to differences in how quickly different tank sizes can respond to changes in demand and supply. Larger tanks can have a greater buffer capacity, which can help smooth out short-term fluctuations, while smaller tanks can be more sensitive to sudden changes in energy demand. Nevertheless, we can see a total cost saving for operating costs compared to the reference scenario in all case scenarios, which is consistent with previous studies showing that optimized planning and use of heat accumulators could increase profitability in combined heat and power production by reducing operating costs.

By evaluating Figure 12 and Figure 13, we see how heat storage contributes to a reduced production of FIV-P4 and a more even heat production between the units. It seems that IKV MT can be utilized even more when heat storage is used, especially during high power peaks. These assumptions can be related to Table 15, where we can see that peak production is almost neglected and a large part of FIV-P4 is reduced, unlike scenario 1. Production from IKV DK becomes more even to charge the accumulator during nighttime when electricity prices are lowest, as clarified in Figure 12.c and Figure 13.c. The accumulator can play different roles during different periods throughout the year, which is evident in the same figures. During March, when weather conditions are often unstable, we can see that the accumulator is adjusted and regulated differently depending on outdoor temperatures, as illustrated in Figure 12.c. At lower outdoor temperatures, the accumulator seems to struggle to be as active to meet the heat demand, while it appears to play a more prominent role at higher outdoor temperatures. In Figure 13, during a period in December, we observe that the accumulator is used less at the beginning of the period. This can be explained by it being very cold outside and all available heat is needed immediately to meet the demand. There would be no opportunity to recharge the tank if it were emptied at once. Towards the end of the period, as the temperature rises again, the possibility of a more active use of the accumulator to regulate heat supply in a safer way increases. The results from Figure 14 and Figure 15 regarding flexibility suggest that an increased size of the accumulator tank can promote smoother regulation and thereby increase the availability of heat during unexpected periods. Another important factor is the maximum flow capacity of the accumulator tank, which can vary depending on the specific constraints in the energy system where heat storage is implemented. This observation is consistent with what Lepiksaar et al. (2021) emphasize, namely that the size of heat storage needs to be adapted to the specific system, as different sizes can result in different outcomes. This also aligns with the results presented in Table 12 and Table 13.

Scenario 3

According to Tan et al. (2016), the implementation of a CCS facility shows promising results in reducing CO_2 emissions, but there are still challenges suggesting that the technology is not yet economically viable (Kärki et al., 2013; Novotny et al., 2017). This study observes two scenarios where the CCS facility is either forced to operate or has the freedom to operate when it is suitable, to investigate how profitability can be achieved, either through revenues from captured CO_2 or from waste heat. In the scenario where the CCS facility is forced to operate, achieving profitability solely through waste heat can be challenging since the facility requires electricity to operate. Hence, it is crucial to carefully evaluate the revenues from captured CO_2. Currently, it is uncertain how the market will react to the implementation of CCS technology, which justifies the need for a sensitivity analysis to evaluate the cost levels of captured CO_2 required to reach breakeven compared to the normal scenario without CCS. Table 16 shows that a revenue of 500 SEK/ton of CO_2 is the price at which breakeven can be reached, especially across the different case scenarios. It is important to note that these prices do not consider parameters that should influence this value, such as investments and CO_2 storage, meaning the actual breakeven value needs to be significantly higher in the reality. Despite the CCS facility being forced to operate, we can hardly see any difference in the amount of waste heat generated by CCS technology for different revenue prices for captured CO_2, according to Figure 18 and Figure 19. However, we observe a difference in reduced heat production from FIV-P4 and peak production, enabling efficient utilization of waste heat from the CCS facility.

In Figure 20, no significant difference in heat production from IKV can be observed, regardless of whether CCS is used or not. Part of the explanation may be that IKV DK is used slightly more or less in some cases, possibly to support the reduction of FIV-P4 and peak production as much as possible. However, Table 18 and Table 11 show that there are not significant differences between different scenarios regarding annual heat production. This nevertheless indicates that it is possible to benefit from the waste heat from CCS by adjusting other units to avoid overloading the district heating network. On the other hand, regardless of whether the CCS facility contributes to increased sustainability and flexibility, profitability is crucial and depends on the price of captured CO_2. Regarding the volatility levels in this case, we can see in Table 16 that the differences are not as marked as with different accumulator tank sizes. This may have to do with the fact that the CCS plant is forced in this case and is not affected much by what the electricity prices say. However, high volatility in energy prices can lead to unpredictable operating costs, which can affect the economics of CCS.

Since the future market for CCS technology and CHP is uncertain, it may be interesting to examine how it would look if the CCS facility were not bound to constant operation but could be adapted more to market conditions. This is analyzed in section 0, where Table 19 shows a little difference in total cost savings compared to Table 16, regardless of the price of captured CO_2. Moreover, savings increase with higher prices for captured CO_2, which is reasonable since the CCS facility operates with electricity and adjusts to the electricity market. Figure 21 and Figure 22 show that higher prices for captured CO_2 led to increased production from the CCS facility in different scenarios. This is evident in Figure 23 and Figure 24, where increased revenues from captured CO_2 are proportional to increased activity in the CCS facility, regardless of electricity prices. These figures demonstrate how the CCS facility adapts its production to changes in the electricity market, reducing operation at higher electricity prices and vice versa at lower electricity prices. The interesting aspect here is that with higher prices for captured CO_2, the CCS facility will be more active since revenues from other sources also become more valuable.

Scenario 4

Since the CCS facility already offers a certain degree of flexibility concerning waste heat, it is worthwhile to investigate how the combination of a storage tank and a forced CCS facility can further enhance profitability and flexibility. Both Harkin et al. (2010) and Novotny et al. (2017) have emphasized the potential to improve CCS technology through different heat integration strategies to utilize its waste heat. Additionally, research by Harkin et al. (2010) and M. Chen et al. (2023) has demonstrated that optimization methods can effectively improve CCS regardless of the components integrated with the technology. This study, therefore, analyzes these aspects in scenario 4, where Table 20 indicates increased total cost savings compared to using only CCS or a storage tank in the system. Moreover, Figure 25 and Figure 26 clearly demonstrate how this combination more efficiently meets the heat demand, resulting in a significant reduction in FIV-P4 compared to the results in Figure 12 and Figure 13 (with only a storage tank) and Figure 20 (with only CCS). This reasoning can also be observed and compared with Figure 27, Figure 28, and Table 22, where almost all peak units are not used, except for a portion of GPC, and where a larger part of the heat production from FIV-P4 has been reduced. We can observe a decrease in almost all units in Table 22 depending on the case scenario being investigated. A variation of IKV occurs depending on whether electricity price levels rise or fall, but the combination of these two technologies nevertheless shows how well they work together.

The reason GPC is active in scenarios A3.1 and A3.3 may partly be due to high electricity prices, making it economically advantageous to utilize GPC to optimize the utilization of IKV MT. Additionally, frequent fluctuations in the electricity market play a role, where GPC can quickly intervene and cover unexpected power peaks due to its rapid startup time. In this case, we can see that the volatility levels still do not have as much importance, unlike the electricity price levels. However, we can see a similar outcome as in scenario 3, which shows that this combination secures the system even for uncertain periods. The results of this analysis, hence, indicate that a combination of CCS and TES holds promise in achieving both flexibility and profitability in a CHP system. The integration of these components is found to improve the efficiency of the energy system compared to if they were used separately.

Scenario 5

It is also interesting to observe how the energy system adapts when utilizing a heat pump. Table 23 shows similarities with an accumulator tank but with higher total cost savings in case scenarios A1 and A2 regardless of the COP value. Furthermore, higher COP values for the heat pump result in better savings across all case scenarios, aligning with the expectations from *Equation 17*. However, it is worth noting that the difference between various electricity price levels continues to have a greater impact than the difference in volatility levels. This conclusion aligns with previous research, such as Blarke & Lund (2008) and Ommen et al. (2014), emphasizing how heat pumps can enhance the overall economic performance of a CHP system through optimization. This reasoning is supported by the results in Table 23. An interesting observation from Table 23 and Table 20 is that the use of the heat pump separately shows similarities with the combination of an accumulator tank and CCS technology, both in terms of efficiency and system reliability. This highlights the potential for an integrated use of these technologies to optimize performance and security.

In Figure 29 and Figure 30, it is evident how the integration of the heat pump into the system leads to significant reductions in FIV-P4 and peak production across all case scenarios. This indicates increased flexibility, promising regardless of market conditions. Additionally, a well-regulated usage of the heat pump is observed in Figure 31, where its production is adjusted according to electricity prices. During periods of lower electricity prices, the heat pump is utilized more intensively, while production decreases during periods of higher prices. This dynamic contributes to balancing the load on the power grid by utilizing cheaper electricity and reducing consumption during peak load periods. Figure 32 shows a similar trend to Figure 31, however, with slightly less heat pump usage due to higher electricity prices. Despite similar patterns in heat pump regulation, a more restrained usage is noted during periods of higher electricity prices, indicating a clear adaptation to economic factors to optimize energy costs. Table 25 also confirms that heat production from FIV-P4 decreases across all case scenarios, consistent with observations for the two weeks in March and December 2023. Furthermore, a significant reduction in peak production is observed in Table 25, although some is still utilized. This could be attributed to the continued cost-effectiveness of using the heat pump and temporarily activating peak production during unexpected periods when additional heat supply is needed, with FIV-P4 acting as an additional heat source to match the overall heat load.

It is interesting to observe how the integration of the heat pump leads to reduced usage of IKV DK across all case scenarios according to Table 25. This observation highlights the ability of the heat pump to efficiently provide the required heat, reducing the dependence on IKV DK alone. Additionally, an increased proportion of IKV MT is observed in Figure 31 and Figure 32, suggesting that IKV MT is utilized to a greater extent when the heat pump is active. This can be explained by the heat pump providing the extra heat needed, thereby reducing the space for IKV DK, and enabling a more efficient use of IKV MT to maintain the desired heat level. This dynamic demonstrates the advantages of combining different heat sources to optimize system performance and reduce costs. Furthermore, it becomes interesting to investigate where the breaking point for the heat pump and IKV MT goes, as these compete in a way. At high electricity prices and a lower COP factor, IKV MT can have a cost advantage, while at low electricity prices and a high COP factor, the heat pump becomes more economical. Understanding and carefully monitoring these factors is crucial to optimizing the heat production system and minimizing costs in the long term.

6.2 The intersection on Society, Economy, and Sustainability

Through careful result analysis in section 6.1, it becomes clear how the different techniques contribute to flexibility and profitability in their own ways. By comparing these components and observing how they contribute to society, the economy, and sustainability, we could gain a deeper understanding of their effectiveness and potential to meet energy needs sustainably. This analysis provides valuable insights for decision-makers and planners to optimize the performance of the energy system and contribute to a more sustainable future. For example, by introducing an accumulator tank according to scenario 2, we can primarily reduce the load on the electricity grid and district heating network by storing surplus energy during periods of low demand and releasing it during periods of high demand (Christidis et al., 2012; Sarbu & Sebarchievici, 2018). This leads to increased flexibility in the system and reduces the need for inefficient peak plants to meet sudden increases in demand. This is reflected in the result analysis from section 6.1. Similarly, the introduction of a CCS plant has a direct positive impact on society and sustainability by fighting climate change and reducing CO_2 emissions. In addition to contributing to a fossil-free energy system, the technology can also create new job opportunities and economic growth depending on the development of the CCS technology market. By combining an accumulator tank with a CCS plant, the flexibility and reliability of the system are further improved. By utilizing waste heat, the need for peak plants and intermediate load plants is reduced while negative CO_2 emissions are generated. This combination creates higher efficiency by optimizing the use of energy resources and reducing greenhouse gas emissions. Using a heat pump in cogeneration can contribute by reducing dependence on fossil fuels and promoting the use of renewable energy sources. This aspect is also emphasized by Levihn (2017) and Münster et al. (2012), and is consistent with the results analysis in section 6.1. By harnessing energy from the sun, air, or ground, greenhouse gas emissions can be reduced, promoting a more sustainable energy supply. Additionally, the heat pump can contribute to increasing energy efficiency and reducing energy costs in buildings and industrial processes, which is crucial for promoting sustainable development and resource conservation.

Focusing on economic sustainability, we examine various tables to get an overview of which component generates the highest total cost savings relative to the initial investment. According to Table 14, Table 17, Table 21, and Table 24, the accumulator tank and heat pump emerge as the primary contributors to reduced payback periods. Both scenarios, integration of an accumulator tank and a heat pump, show consistent results across different case scenarios. For the accumulator tank, according to Table 14, it is noted that larger tank sizes do not provide proportionally higher total cost savings compared to the initial investment, unlike smaller sizes. This phenomenon can be linked to the minimal variation in cost savings between different tank sizes. The heat pump, according to Table 24, follows a similar pattern to the storage tank, where a higher COP factor shows greater benefit in all case scenarios. At lower electricity price levels, as in case scenario A2, the heat pump tends to provide the greatest benefit with 63%, compared to the accumulator tank which is at most 50%. However, the accumulator tank shows greater benefit in case scenario A3, where the difference between case scenario B2.2 and a COP factor of 4 is 7%. This may be because the system can more easily utilize revenue from electricity sales when an accumulator tank is used, as it does not involve any additional cost to the system. As previously mentioned, the heat pump is more useful in case scenario A2 and less in case scenario A3, which means that when the heat pump is in operation at higher electricity prices, it costs more. The scenario of low electricity prices and high volatility becomes particularly interesting as we move towards a future with more renewable electricity generation. In this case, it seems that the heat pump is the one that secures the system the most. The heat pump can effectively handle variations in electricity prices and availability, making it better suited to meet the challenges that arise with higher volatility in the energy system.

The implementation of CCS, according to Table 17, shows a longer payback period compared to the accumulator tank and heat pump. Although CCS technology shows a long payback period regardless of the cost of captured CO_2, a certain percentage increase is observed with a higher cost of captured CO_2, reflecting the principle shown in Table 16. As Kärki et al. (2013) point out, I believe that both electricity prices and CO_2 emission allowances will still be crucial in assessing the profitability of implementing CCS technology. This reasoning can be clearly explained in section 0 where the CCS plant is dependent on the electricity market and can adapt entirely depending on electricity prices. It is worth noting that the total cost savings increase more when the plant is dependent on the electricity market compared to if it were independent of it. The combination of CCS and an accumulator tank, according to Table 21, shows similar results to when only CCS is used.

Overall, these observations provide insight into the potential of different components to improve system efficiency and reduce costs by including supporting units.

6.3 Analysis of method choice

As previously discussed in the literature review, MILP is a well-known optimization method known for its effectiveness in dealing with optimization problems containing both linear and integer variables. Previous research has successfully used MILP for similar problem formulations, thereby strengthening its credibility as a method. In this study, MILP has been used to optimize a complex energy system with different units operating under varying conditions. This decision is based on the ability of the MILP method to handle both linear and integer variables, which was necessary for the problem formulation of this study. Compared to using LP as an optimization method, this would have limited the research and likely led to unrealistic results, as LP cannot handle the complexity in the energy system in the same way as the MILP method.

7 CONCLUSIONS

The aim of this degree project was to investigate whether one technology is better than the other to implement in a cogeneration plant with the help of modelling and the optimization method MILP. The different technologies that have been explored are different sizes of an accumulator tank, the CSS technology, and a heat pump with different COP factors. The investigation focused on profitability and flexibility in a variable electricity market, with case study A providing detailed insights. The ranking of solutions on their profitability and flexibility is as follows:

Heat pump

The heat pump consistently showed reliable profitability across different electricity market scenarios. For instance, at lower electricity prices (case scenario A2) with a COP factor of 3 or 4, analyses showed a marginal increase in total cost savings of around 3-4%, with another analysis showing a small total cost saving of around -0.4% compared to the reference scenario. This demonstrates the robustness and reliability of a heat pump regardless of market fluctuations.

Accumulator tank

When an accumulator tank is used, the system still generates costs in case scenario A2, where the total cost increases by 6-8% compared to the reference scenario. This indicates that the heat pump is generally more reliable than the accumulator tank across all scenarios. Compared to scenario 1, however, the case scenarios A1-A3 show increased total cost savings in both scenario 5 and scenario 2, where a heat pump and an accumulator are respectively used in the system. Although the heat pump is more reliable overall, the accumulator tank still enhances profitability, particularly when used in combination with other technologies.

When examining different sizes of accumulator tanks in case study B, a smaller importance of different sizes of storage tanks emerges both when it comes to total cost savings and system flexibility. The differences between case scenario B1 and B2 were marginal, with only a 1-2% difference in total cost savings across different electricity price levels (case scenarios A1-A3). However, case scenario B2.2 stands out with the highest total cost savings, amounting to approximately 53-60% of the initial investment. Almost as competitive is case scenario B2.1, which reaches a saving of around 49-58%. It seems that an accumulator tank with a capacity above 1000 MWh would not have such a significant impact on improved profitability given these numbers. When it comes to the flexibility of different tank sizes, most of the benefits lie in safety and reliability. A larger accumulator tank enables anticipation of available heat during unexpected periods in the future. However, the maximum inflow and outflow of heat is limited and depends on each customer's unique system.

Accumulator tank + CCS

Combining an accumulator tank with CCS technology improved profitability and flexibility, particularly in lower electricity price scenarios (case scenario A2). This combination resulted in up to 4% in total cost savings and provided significant benefits in reducing energy demands from peak and intermediate load plants. This integration also showed a strong performance in terms of system flexibility and reliability. The profitability of annual total cost savings is higher than using an accumulator tank, but it is lower relative to the initial investment. This means that the payback period is longer due to the high investment costs of the CCS technology.

CCS technology

The profitability of CCS technology alone was highly dependent on the cost of captured CO_2. At a revenue cost of 500 SEK/ton CO_2, the breakeven point could be reached at low electricity price levels (case scenario A2), which indicates that the reliability of a CCS plant can be achieved under certain conditions. For a non-forced CCS facility, breakeven can also be achieved at a cost of around 500 SEK/ton CO_2, but with higher security across the other case scenarios, which points to increased profitability if the CCS facility can be adapted to the electricity market.

Summary

In conclusion, the heat pump emerged as the most profitable and flexible technology for implementation in a cogeneration plant. Its consistent performance across varying electricity prices highlights its reliability. The accumulator tank, while slightly less reliable than the heat pump, still offered significant improvements in profitability and flexibility, particularly when combined with CCS technology. Different sizes of accumulator tanks showed marginal differences in profitability, with larger tanks providing reliability benefits in heat anticipation. CCS technology alone was the least profitable and most dependent on specific market conditions but showed improved performance when integrated with an accumulator tank.

These findings suggest that a combination of these technologies can be strategically implemented to optimize profitability and flexibility in cogeneration plants. This means that the different scenarios can be advantageously applied to other boilers outside the area shown in this study, as the method is considered a flexible tool that can be adapted to different needs. The integration of different technologies is not that sensitive and primarily involves logical-mathematical calculations. The limitations of the models are adapted to the specific needs of the energy system being analyzed, but these limitations are not overly restrictive. This flexibility allows the models to be widely applied, with adjustments made as needed based on the general characteristics of the system in question. Essentially, while the unique characteristics of each system require some degree of customization, the integration process remains robust and adaptable. This ensures that the method can maintain its effectiveness over a wide range of applications, making it a reliable tool for improving CHP performance and adaptability.

8 SUGGESTIONS FOR FURTHER WORK

To approach more realistic assessments of these different scenarios, a thorough techno-economic analysis is necessary to obtain more precise data. It is particularly important to implement more detailed investment strategies because several assumptions have been made during the work, which may affect the outcome of the assessments. Furthermore, a deeper technical analysis is required by integrating a more complex system where more information and clearer conditions for each unit are considered.

As the future of the CCS technology market is still uncertain, it is important to carry out a careful analysis of the revenue costs of captured CO_2 as well as to explore opportunities to optimize CCS technology to be prepared for future challenges.

Given the promising results from the combination of the CCS technology and an accumulator tank for short-term storage, it would be valuable to explore the potential of combining the CCS technology with long-term storage. With the uncertainty surrounding future emission allowances, this could be an important strategy to be able to use CCS technology effectively even in warmer conditions.

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APPENDIX 1: ADDITIONAL RESULTS FOR SCENARIO 2 DURING MARCH

Figure 1 presents a comparison between B1.1 and B1.2 during the same two-week period in March 2023.

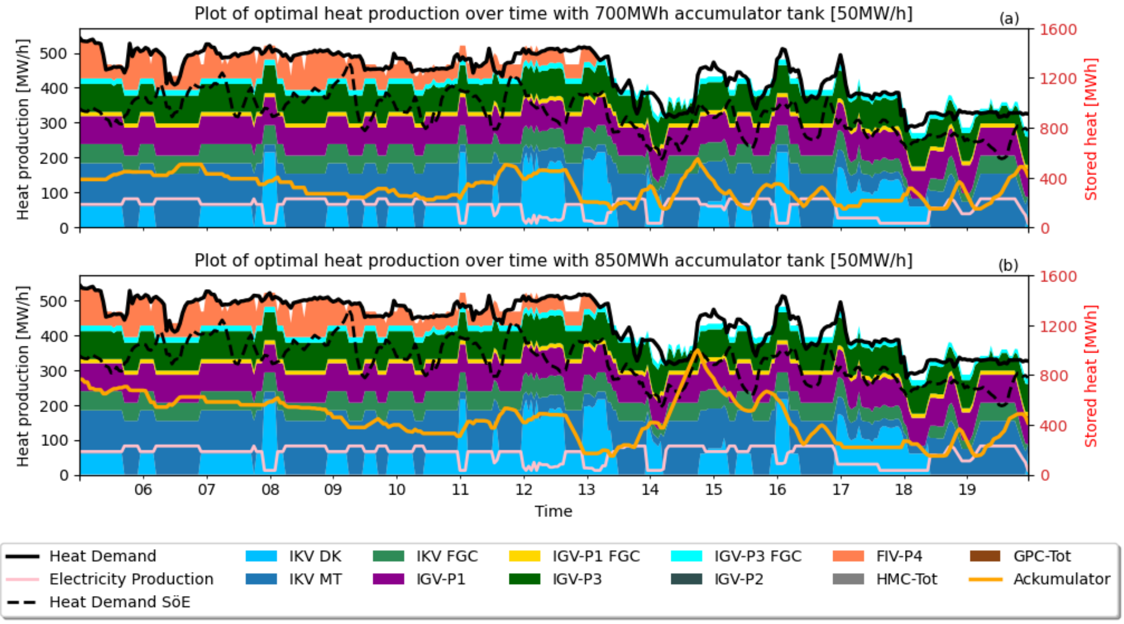

Figure 1-Current energy system with varied accumulator tanks, 50 MW/h max flow over two weeks in March 2023: (a) Optimal outcome with 700 MWh tank, (b) Optimal outcome with 850 MWh tank

Figure 2 presents a comparison between case scenarios B2.1-B2.3 during the same two-week period in March 2023 for scenario 2. As previously mentioned, there is no big difference between the different tank sizes.

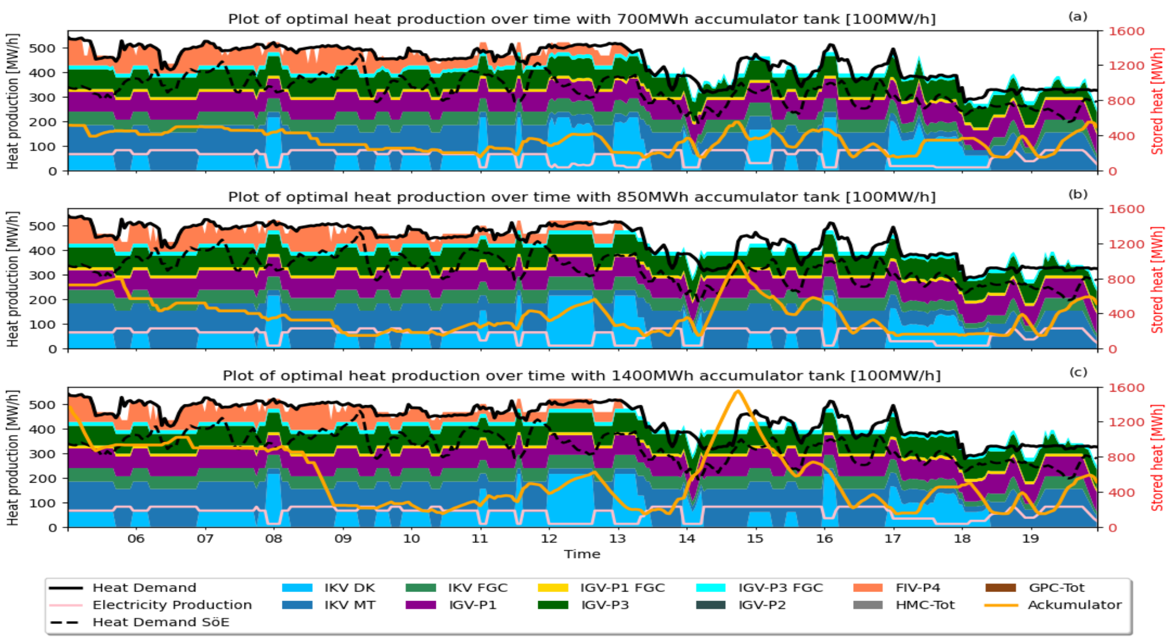

Figure 2-Current energy system with varied accumulator tanks, 100 MW/h max flow over two weeks in March 2023: (a) Optimal outcome with 700 MWh tank, (b) Optimal outcome with 850 MWh tank, (c) Optimal outcome with 1400 MWh tank

Figure 3 illustrates the total heat production across different storage tank sizes in the energy system across different case scenarios during the same two-week period in March 2023. Regardless of tank size and maximum flows, a significant portion of peak production is consistently reduced. Lower electricity prices coincide with reduced use of FIV-P4 compared to higher prices. There are no significant variations in the total heat output between different tank sizes.

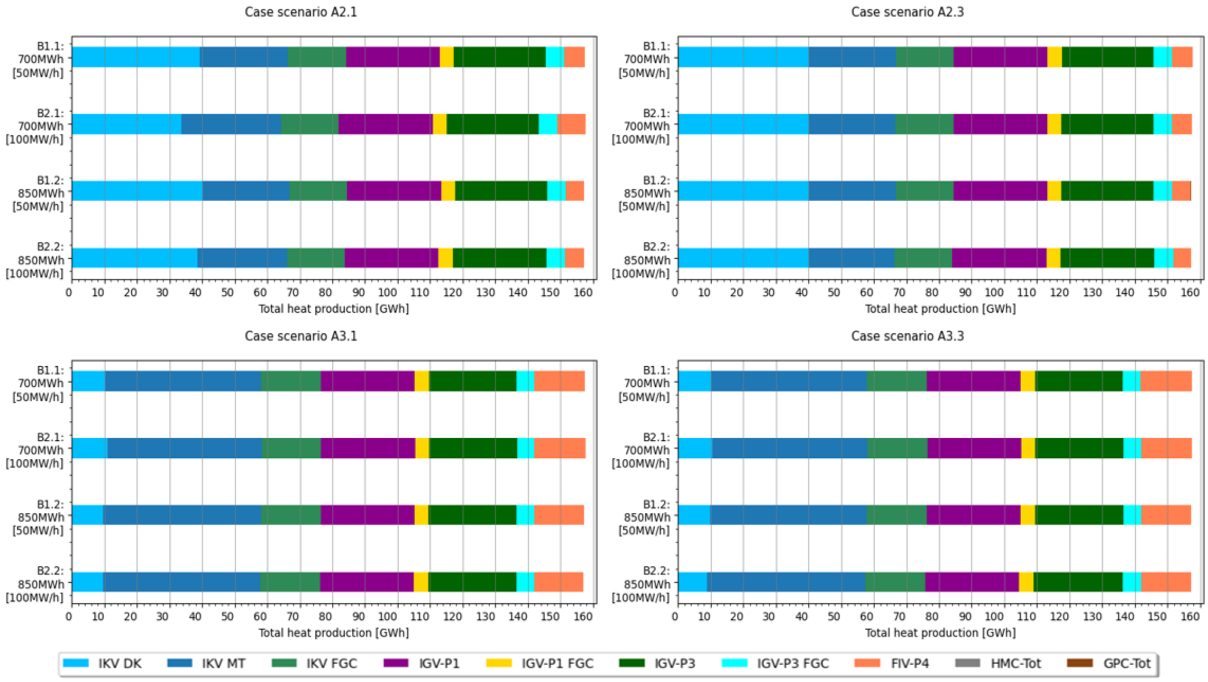

Figure 3- Current energy system with varied accumulator tanks and max flows across scenarios over two weeks in March 2023

APPENDIX 2: ADDITIONAL RESULTS FOR SCENARIO 3 DURING DECEMBER

Figure 4 illustrates the same two-week period during December 2023. The production plan with the CCS plant (b) is presented in the same case scenario as the production plan without the CCS plant (a), the reference scenario 1 – A1.1. One observation that can be seen is that the heat production from both FIV-P4 and peak production has decreased.

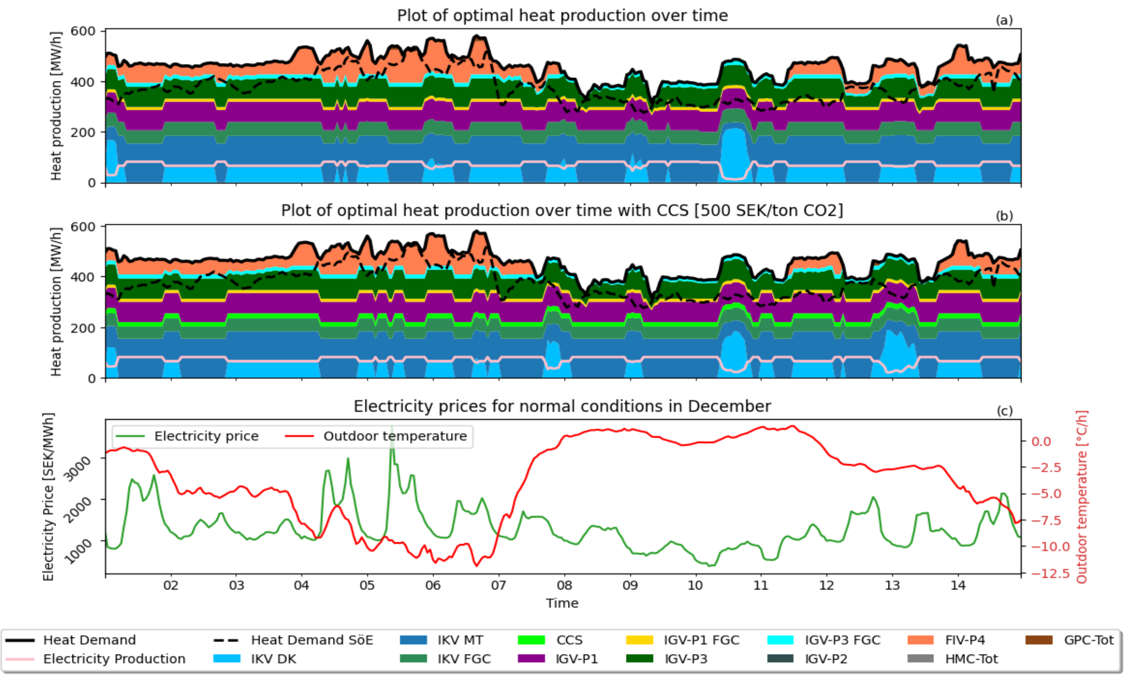

Figure 4-Model behavior with a forced CCS plant and a revenue cost for captured CO2 of 500 SEK/ton CO2 over two weeks in December: (a) Optimal outcome, (b) Optimal outcome with CCS plant, (c) Historical weather and electricity data