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The future of CHP gas turbines

The case study of Rya CHP and the city of Gothenburg

Degree project report in Sustainable Energy Systems

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Cover: View of Rya CHP plant, with render of the new bio-steam boiler. [Illustration: White arkitekter/Göteborg Energi]

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Abstract

This thesis investigates the future role of the Rya combined heat and power (CHP) plant in the future energy system of Gothenburg, with a particular focus on the replacement of natural gas with alternative renewable fuels, suitable for gas turbines. The study evaluates a selection of biofuels and electrofuels, assessing costs, logistics, availability, environmental impact, toxicity, and technical compatibility. A linear programming model was used to simulate energy system scenarios for the years 2030 and 2050, integrating electricity and district heating networks, together with a model describing the plant with a higher level of detail. The analysis investigates various fuel cost structures, and considers both a societal and actor perspective regarding the operation of the Rya power plant. Results identify fuels like biomethane, biomethanol, and e-methanol as viable options for the operation of Rya CHP in the future. The feasibility of these solutions, however, is highly dependent on market conditions and policy developments. The role of Rya CHP is expected to shift towards peak-load generation, due to the generally higher costs of operation, contributing to the system flexibility in the context of an increase in the penetration of renewable-based energy sources (RES). The findings offer an insight into cost-effective and sustainable fuel strategies for the transition of urban combined-cycle CHP plants towards a fossil-free future.

Keywords: renewable fuels, gas turbines, electricity, district heating, CHP, Gothenburg, linear programming, energy system modelling, cost optimisation

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Sist men inte minst så hade det inte varit minst lika roligt utan alla skratt i exjobbsrummet i pauserna. Och tack för fika, det bästa bränslet som finns!

Filippo Da Corte Vecchino & Hanna Johnsson, Gothenburg, June 2025

List of Acronyms

Below is the list of acronyms and abbreviations that have been used throughout this thesis listed in alphabetical order:

aFRR	automatic Frequency Restoration Reserve
BB	Bio-steam Boiler
BECCS	Bioenergy with Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CCGT-BP	Combined Cycle Gas Turbine with Back Pressure
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2-eq	Carbon Dioxide Equivalent
DAC	Direct Air Capture
DH	District Heating
DK	Direct Condenser
DME	Dimethyl ether
E-fuels	Electrofuels
FAME	Fatty Acid Methyl Ester
FFR	Fast Frequency Reserve
FRR	Frequency Restoration Reserve
GHG	Greenhouse Gas
GT	Gas Turbine
H_2	Hydrogen
HRSG	Heat Recovery Steam Generator
HVO	Hydrotreated Vegetable Oil
IEA	International Energy Agency
ILUC	Indirect Land-Use Change
LBG	Liquefied Biogas
LCOE	Levelised Cost Of Energy
LHV	Lower Heating Value
LP	Linear Programming
MeOH	Methanol
mFRR	manual Frequency Restoration Reserve
MIP	Mixed Integer Programming
NO_x	Nitrogen Oxides

RED	EU Renewable Energy Directive
RES	Renewable-based Energy Sources
RME	Rapeseed Methyl Ester
SF	Supplementary Firing
ST	Steam Turbine
SVO	Straight Vegetable Oil
TSO	Transmission System Operator
VRE	Variable Renewable Electricity

Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables that have been used throughout this thesis.

Indices

t	Index for time step
f	Index for fuel
i	Index for component
s	Index for storage

Sets

$\mathcal{T}$	Set of all time steps
$\mathcal{T}_{ready}$	Subset to $\mathcal{T}$ for all time steps when Rya CHP is fully ready
$\mathcal{T}_{cool}$	Subset to $\mathcal{T}$ for all time steps when cooling is needed
$\mathcal{F}$	Set of all fuels used in Rya CHP plant
$\mathcal{F}_{GT}$	Subset to F for all fuels used in gas turbines
$\mathcal{F}_{market}$	Subset to F_{GT} for all market fuels
$\mathcal{F}_{truck}$	Subset to F_{market} for all fuels supplied by truck
$\mathcal{F}_{grid}$	Subset to F_{market} for all fuels supplied by pipeline
$\mathcal{I}$	Set of all components in Rya CHP plant
$\mathcal{I}_{fuel}$	Subset to $\mathcal{I}$ for all components consuming alternative fuels
$\mathcal{I}_{el}$	Subset to $\mathcal{I}$ for all components producing electricity
$\mathcal{I}_{dh}$	Subset to $\mathcal{I}$ for all components producing district heating
$\mathcal{I}_{steam}$	Subset to $\mathcal{I}$ for all components producing steam
$\mathcal{I}_{GT}$	Subset to $\mathcal{I}$ for all gas turbines
$\mathcal{I}_{SF}$	Subset to $\mathcal{I}$ for all supplementary firing units
$\mathcal{I}_{start}$	Subset to $\mathcal{I}$ for all components with limited flexibility
$\mathcal{S}$	Set of all fuel storages in Rya CHP plant

Parameters

Av_f	Fuel availability, for fuel f [GWh]
Cap_i	Installed capacity, for component i
$Maxload_i$	Maximum load level, for component i
$Minload_i$	Maximum load level, for component i
$\eta_{tot,i}$	Total efficiency (or COP), for component i
$\eta_{el,i}$	Electrical efficiency, for component i
$\eta_{min,i}$	Electrical efficiency, for component i, when operating at minimum load level
$Truck_t$	Fuel delivery by truck (yes or no), at time t
$Cap_{max,s}$	Maximum installation capacity, for storage s
Fh_{BB}	Factor between district heating production (heat extraction from flue gas) and steam generation, for the bio-steam boiler
R_i	Ratio between minimum and maximum load, for component i
C_f^{fuel}	Fuel costs, for fuel f [M€/GWh]
C_i^{fix}	Fixed O&M costs, for component i [M€/GW/year]
C_i^{var}	Variable O&M costs, for component i [M€/GWh]
$C_i^{startup}$	Start-up costs, for component i [M€/GWh]
$C_i^{partload}$	Part-load costs, for component i [M€/GWh]
C_s^{inv}	Investment costs, for storage s [M€/GW/year]
C_s^{fix}	Fixed O&M costs, for storage s [M€/GW/year]
P_t^{el}	Electricity price in SE3 area at time t [M€/GWh]
P_t^{dh}	Marginal cost of heat at time t [M€/GWh]
P_t^{H2}	Marginal cost of hydrogen at time t [M€/GWh]

Variables

$fuel_{i,t}$	Fuel consumption by component i at time t [GWh/h]
$fsh_{i,f,t}$	Fuel consumption by component i and fuel f at time t [GWh/h]
$fpr_{f,t}$	Fuel purchase by fuel f at time t [GWh/h]
$ftr_{f,t}$	Support variable, regulating fuel purchase by trucks, for fuel f at time t [GWh/h]
$gen_{i,t}$	Energy production by component i at time t [GWh/h]
$gel_{i,t}$	Electricity generation by component i at time t [GWh/h]
$gdh_{i,t}$	District heating generation by component i at time t [GWh/h]
$gst_{i,t}$	Steam production by component i at time t [GWh/h]
cap_s	Fuel storage size, for storage s [GWh]
$lvl_{s,t}$	Fuel storage level, for storage s at time t [GWh]
$chg_{s,t}$	Fuel charge, for storage s at time t [GWh/h]
$dch_{s,t}$	Fuel discharge, for storage s at time t [GWh/h]

$spin_{i,t}$	Section 4.1.1: hot capacity available for generation, for component i at time t [GWh/h];
	Section 4.1.2: binary variable, defining if component i is running at time t
$on_{i,t}$	Section 4.1.1: increase in hot capacity, for component i at time t [GWh/h];
	Section 4.1.2: binary variable, defining if component i is starting at time t
$c_{i,t}^{startup}$	Start-up costs, for component i at time t [M€/h]
$c_{i,t}^{startup}$	Part-load costs, for component i at time t [M€/h]
$fuel_{Rya\,CHP,t}$	Fuel consumption of Rya CHP plant at time t [GWh/h]
$el_{Rya\,CHP,t}$	Electricity generation of Rya CHP plant at time t [GWh/h]
$dh_{Rya\,CHP,t}$	District heating generation of Rya CHP plant at time t [GWh/h]
$c_{Rya\,CHP}^{tot}$	Total costs for Rya CHP plant [M€/year]
$p_{Rya\,CHP}^{tot}$	Total profits for Rya CHP plant [M€/year]

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1
Introduction

The energy system in Europe is in transition. According to the International Energy Agency (IEA) [1], the share of renewable power generation is increasing and in 2022 approximately 40% of the electricity was produced from solar PV, wind, hydro, biofuels, and waste. However, most of the electricity generation still relies on thermal generation, in particular from non-renewable fuels. The fuels currently used in the European energy mix are coal, oil, natural gas, uranium, biofuels, and waste [2]. Natural gas makes up 25% of the total energy supply and produces 29% of the total carbon dioxide (CO_2) emissions from fuel combustion in Europe [2][3]. The European Green Deal sets a goal for zero emissions by 2050 [4] and makes it necessary to transition from fossil fuels.

Gas-based generation plays an important role in energy systems with a growing share of intermittent renewable-based energy sources (RES), acting as backup capacity when intermittent power generation is lacking. The need for backup generation increases due to climate change driving extreme weather events, leading to constraints in the gas market. Furthermore, natural gas has a recent history of market price fluctuations, caused by geopolitical tensions [5].

Gothenburg is the second biggest city in Sweden, undergoing a growth in electricity demand and a transition to fossil-free energy production. The largest electricity and heat producing plant in Gothenburg is Rya combined heat and power (CHP) plant, a combined cycle gas turbine with back pressure (CCGT-BP) which is currently feeding on gas from the gas network in southwestern Sweden.

With an increasing share of variable renewable electricity (VRE) in the system, the strategic placement of Rya CHP can cover periods of peak consumption and help unload the distribution grid. For this reason, combined with an expected increase of fuel costs, as natural gas is replaced with non-fossil fuels, the role of Rya CHP is likely to change in the future. Following the EU goals and aims towards net-zero emissions and Göteborgs Stad's aim for close to zero emissions by 2030, Rya CHP is a key point in the energy transition of the city, considering the plant has historically been one of the biggest fossil emitters out of the electricity and heat production units in Gothenburg [6].

1.1 Aim and scope

The objective of this project is to assess the role of Rya CHP in future energy system scenarios. In this study, future renewable fuels for gas turbines are investigated, as this technology has been relying on natural gas to high extent. The future energy system of Gothenburg is investigated for shorter and longer time frame, using Gothenburg with Rya CHP as a case study for the future of gas turbines and combined heat and power production. By applying a cost optimisation model to the municipality of Gothenburg, the goal is to find the most cost-effective solution to satisfy the electricity and heating demand of the city of Gothenburg.

The objective is analysed based on the following research questions, evaluated for the time frames short-term (year 2030) and long-term (year 2050), and from the perspective of both the society and the actors involved.

Question 1 Which renewable fuels are suitable to replace the use of natural gas in Rya CHP plant?

- What are the fuel price forecasts?
- How do the fuels differ in terms of distribution and storage logistics?
- Are the fuels sustainable in terms of availability, environmental impact and toxicity?

Question 2 How will the role of Rya CHP change in a future energy system of Gothenburg with the implementation of renewable fuels?

- What are the electricity and district heating production patterns of the plant going to look like?
- How is the rest of the energy system of Gothenburg going to be in the different scenarios?

Question 3 Which mix of renewable fuels is best suited for the future role of Rya CHP in each scenario, considering the results from both question 1 and 2?

1.2 Delimitations

The scope of the study has been established within some boundaries.

The future potential for ancillary services and the involvement of Rya CHP plant in the flexibility market have been left out from the modelling. This limitation of the scope was necessary for it to be appropriate for the time frame of the project. Due to the unsure future of ancillary services, in rapid and constant evolution, the collection and implementation in the model of numerical figures regarding demand and cost forecasts would have required extensive work. For the scope of the work to go in that direction, different premises would have been necessary.

The assessment of the renewable fuels has been conducted focusing, when possible, on the use in the energy sector and in the Swedish setting. Due to the fuels market complexity, however, the investigation is relying also on data from global sources and transport sector studies.

The availability of biofuels in the future system has been investigated, but not modelled with definitive figures for all the fuels included in the models. The implementation of such data would have required a high degree of assumptions, based on policies, interconnection between sectors and conversion technologies, leading to uncertain results.

The possibility to produce electrofuels within the system, using an endogenous hydrogen feedstock, has been discussed but not modelled. This implementation would have required an extended analysis of the possible overlap with the industrial system already integrated in the energy system modelled.

The level of detail and choices regarding the modelling are addressed in depth in Chapter 4.

2
Background

According to ACCEL [7], the industry in Västra Götaland is experiencing an ongoing phase-out of fossil fuels, making the electrification crucial for a successful transition of this sector. Göteborg Energi estimates close to a doubling of the peak power demand in Gothenburg and West Sweden due to the fast electrification and rapid growth in variable renewable electricity generation [6]. Larger share of renewable energy in the electricity system leads to higher share of non dispatchable electricity generation. This development in combination with increasing electricity demand can lead to the need to have flexible back-up power facilities. To enable a higher supply of power in the county, ACCEL [7] states that both grid reinforcements and increased power generation is necessary, as well as efficient and flexible use of the electricity. Grid reinforcements have the most potential to increase the power supply, since they could alleviate current bottlenecks. However, the planned grid reinforcements will be done in up to 10 years and are expected to only cover half of the forecasted consumption, so CHP plants and gas turbines are a valid alternative to handle the expected gap in power supply. In addition, the use of CHP plants and gas turbines can relieve the grid capacity since these kinds of facilities often are close to the consumers.

2.1 The electricity system

Currently, in normal conditions, the power demand of Gothenburg is supplied with imported power from the North-European power grid, mainly coming from Sweden. The electricity generation within Gothenburg, illustrated in Figure 2.1, supplies 10% of the demand. However, during events of high demand, the local production sites fulfil 30% of the power demand in Gothenburg, with Rya CHP producing most [6].

In the future, wind power is expected to cover the highest share of the electricity production in Västra Götaland and ACCEL [7] states that it will reduce the need for dispatchable production from, for instance, gas turbines. However, at the same time, CHP production will be important in the future to supply peak hour demand, since the facilities are often close to the consumers. To do so, CHP plants need to become more flexible and adjustable to the future energy systems. Schlachtberger

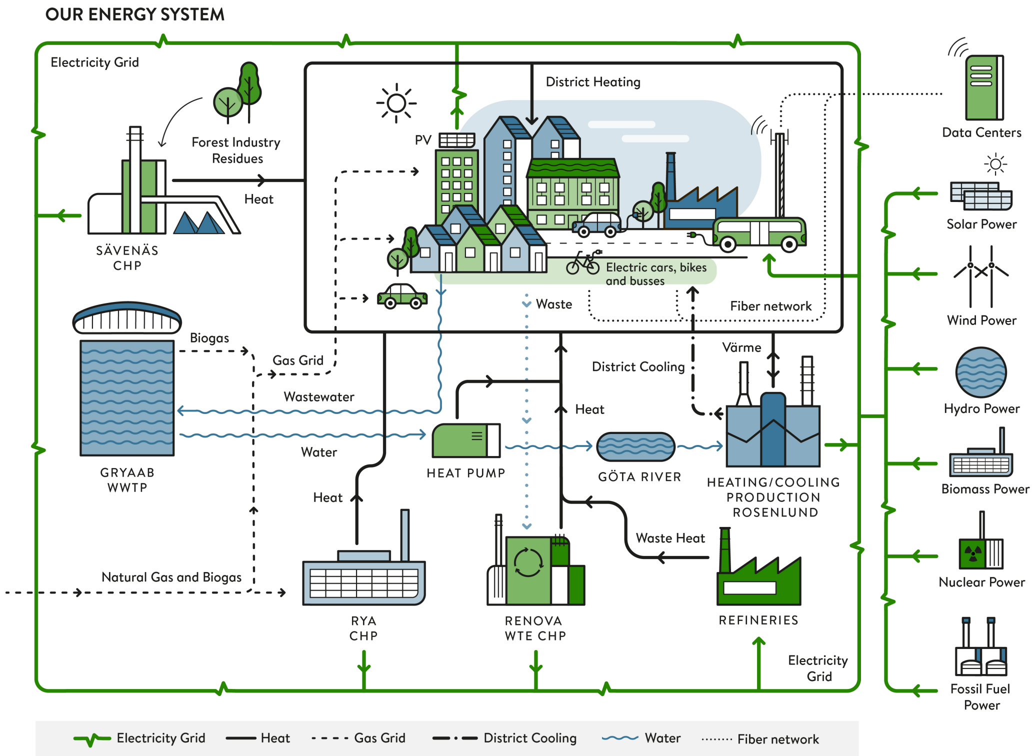

Figure 2.1: Schematic representation of Göteborg Energi's system. Illustration: Göteborg Energi

et al. [8] concludes that flexible backup power generation is required in a European electricity system with a high share of intermittent electricity generation, as will be the case of Västra Götaland in the future with more wind power capacity. These two points imply that the electricity generation of CHP plants is probable to go towards more peak production, as the production is going to decrease but the flexible CHP production will still be needed to back up the more variable energy system.

2.1.1 Ancillary Services

The demand for ancillary services in Sweden is forecasted to grow until 2030, according to Svenska Kraftnät [9]. The purpose of the ancillary services is to intervene in case of low system inertia or imbalances in the power grid.

Fast Frequency Reserve (FFR) is the fastest of all ancillary services, responding within a second, and is needed when the system inertia is at low levels. The system inertia level is dependent on the share of RES in the power system, meaning future scenarios with higher share of RES are forecasted to have more events of low system inertia. Since the frequency of the power system is common throughout the Nordic synchronous area, the procurement of FFR happens on a national level. Due to the expected increase in demand for FFR in the future, a crucial role will be played by the integration of advanced technologies, like battery storage or demand-side management [9]. However, production units with synchronous generators and large rotating masses, like nuclear or hydro plants, are able to provide inertia to the system and therefore reduce the need for FFR. Large size local units, like Rya CHP, could also play a role in the regulation of the frequency.

Frequency deviations from 50 Hz due to imbalances or disturbances, on the other hand, are restored with Frequency Restoration Reserve (FRR). FRR can be of two types, automatic (aFRR) or manual (mFRR), and procure both upwards or downwards regulation. The time to reach full activation is 5 minutes for aFFR and 15 minutes for mFRR. Sweden, Denmark, and Finland share a common mFRR capacity market since 2024 and the Nordic transmission system operator (TSO) plans to connect to the European market platform for mFRR in 2027/2028. Currently, the main units providing mFRR are hydro, wind and CHP plants, together with battery storage and demand response. For the ancillary services related to imbalances and disturbances, emphasis is put on resources that are geographically close to the origin of the issue, because of the grid capacity limitations [9]. As a result, local CHP plants can play an important role for this type of frequency regulation. Moreover, the fast response of gas turbines, within 15 minutes, makes them a suitable option for the mFRR market.

2.2 The district heating system

The district heating system of Gothenburg, as shown in Figure 2.1, consists of two CHP plants, Rya CHP and Sävenäs CHP, various heat-only boilers (HOB), and heat pumps (HP). The city receives also waste heat from St1 and Preem's refineries, as well as Renova's waste-to-energy plant [10]. In 2024, the total heat supply in the city was 3.4 TWh [11].

Recently, an accumulator tank was built to enhance the flexibility of the district heating system [12]. This thermal storage has a capacity of 900 MWh and can store district heating from the system and provide it to the city when needed.

As CHP plants produce both heat and electricity, their operation depends on both the electricity price and the heat demand, although production can tend to follow one of them more. Increasing the volatility of the electricity price leads to promotion of flexible CHP operation, causing the production to follow the electricity price profile instead of the heat demand [13].

2.3 Rya CHP

Rya CHP is the largest production facility of Göteborg Energi, commissioned in 2006 [6]. It plays an important role for the flexibility of the district heating system and currently uses mostly biogas from the western gas network. The plant is a combined heat and power gas turbine combined cycle plant, consisting of its current configuration including three parallel lines, each one with a gas turbine (GT) of 45 MW capacity, a supplementary firing burner (SF), a single-pressure heat recovery steam generator (HRSG); and a steam turbine (ST) with a capacity of 133 MW [13], as illustrated in Figure 2.2. Due to its variety of components, the plant can operate in different modes with a high level of freedom in the share of heat and electricity produced throughout the year, differently from other CHPs which are bounded by a defined power-to-heat ratio. The operational time depends on the temperature of cold winters, electricity prices, natural gas prices, as well as other fuel prices. In 2024, the plant produced 122 GWh of electricity and 152 GWh of district heating.

In addition to the current layout, a fourth line is currently under construction and is going to become operative at the end of 2025, with 2027 being the first full year of operation. The installation consists of a biomass-fired steam boiler (BB), fuelled with wood chips and forest residues, set to produce 150 MW of heat and provide 40 MW of additional electricity in the existing steam turbine [14][15]. The different production pattern of this fourth line, compared to the three existing ones, is going to enhance the flexibility of the plant by making electricity generation and heat production more independent. The plan is to operate the BB often during wintertime to satisfy the heat demand, while the GTs are going to be activated more sporadically, during high electricity price events or to cover peaks of electricity demand. Figure 2.2 illustrates a schematic representation of the plant with the four lines active in 2030, expansion of Figure 3 in Beiron et al. [13].

According to Göteborg Energi, there is room for future upgrade of the GTs, when approaching the end of their lifetime [14]. This update is likely going to happen between 2030 and 2050 and should increase further the installed capacity of the plant with additional 20-40 MW_{el}.

2.3.1 Current fuels

The current primary fuel source of Rya CHP plant is the southwestern Swedish gas grid, fed by the Danish grid, which is, in turn, connected to the European mainland. The gas pipelines are mainly injected with natural gas, while only 30% consists of biomethane, upgraded biogas with the same properties as natural gas [16]. In order to fulfil the sustainability goal set for 2025 [6], Göteborg Energi purchases biomethane from the gas network via the green gas principle, which en-

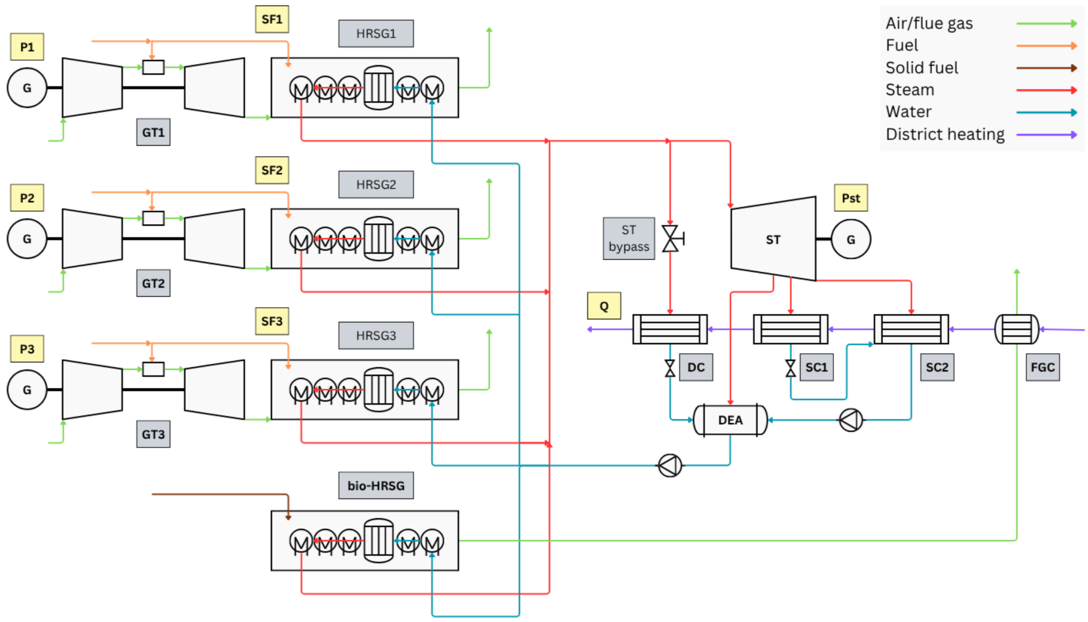

Figure 2.2: Simplified process schematic of Rya CHP plant.

ables biomethane to be traded virtually within Sweden and exporting countries. Methane bought via the green gas principle is considered sustainable according to the Swedish sustainability law, given that the biogas fulfils the sustainability criteria [17]. Using this principle when purchasing biomethane, the cost structure consists of the grid tariff, network tariff, gas price and the guarantee of origin for biogas [18]. The guarantee of origin is a sustainability certification that guarantees that the biogas complies with the requirements of RED (EU Renewable Energy Directive) and calculates the corresponding greenhouse gas (GHG) emissions using the RED methodology [18]. According to Göteborg Energi, the access to biogas certificates shifts, which leads to Rya CHP occasionally needing fossil natural gas to produce electricity and district heating. On the other side, wind power's growth in the coming years is set to favour the production of hydrogen (H_2) and electrofuels (e-fuels), synthetic fuels made from CO_2 using electrolysis [19]. Therefore, Göteborg Energi is open to the investigation of a vast range of fuels that can power Rya CHP.

3
Fuels Assessment

Göteborg Energi is collaborating with Siemens Energy since 2019 to find renewable fuels suitable for the three Siemens SGT-800 (industrial gas turbine) installed in Rya CHP plant [20]. Therefore, the selection of fuels investigated in this project is inspired by the portfolio of options present on Siemens Energy's webpage [21]. The gas turbines at hand are flexible in terms of fuel, allowing the use of both gaseous and liquid fuels. They have the possibility of dual-fuel operation, switching between liquid and gaseous fuels or running on fuels of different kinds simultaneously.

According to the IEA [22], low-emission fuels can be grouped into gaseous fuels, e.g. biogases, hydrogen and synthetic methane, and liquid fuels, e.g. liquid biofuels, ammonia and synthetic liquid hydrocarbon fuels produced from H_2 and CO_2. Most of these low-emission fuels can be used in gas turbines and other co-generation technologies [19]. In the literature, it is common to have a category distinction between electrofuels (or e-fuels), produced with renewable electricity and H_2 synthesis, and biofuels, derived from biological sources. However, this is not a strict categorisation and it is possible to produce fuels with green H_2 and bio-CO_2, which would then be considered bio-electrofuels [23].

Stefanizzi et al. [24] presents the combination of hydrogen with conventional hydrocarbons as a promising solution for the transition towards decarbonised energy systems, when considering the technical limitations of gas turbines. Although hydrogen is a carbon-free fuel per se, for it to be called green H_2 and considered a carbon-neutral option, it has to be produced through electrolysis using renewable electricity. Hydrogen has high gravimetric energy density, which makes it a promising fuel, but a low volumetric energy density, which leads to problems of space and safety, due to the large volumes and the high compression required for storage [19][24]. Moreover, operating with H_2 can involve risks linked to its thermophysical properties, e.g. high flammability and low explosion temperature [19].

A solution to the technical limitation of hydrogen could be the production of e-fuels, i.e., e-methane, e-methanol and e-ammonia. These fuels are identified as promising potential renewable fuels, that can be utilised as indirect chemical storage and can also be combusted directly [24][25].

Biogas and syngas are other suitable alternatives to natural gas, but the sources of biomass and waste to produce them are limited. Furthermore, syngas has lower energy density than methane and biogas usually needs to be upgraded to biomethane before being injected in the gas grid [19].

Lastly, alternative liquid biofuels, e.g. biodiesel, bioethanol, bio-oil and straight vegetable oil (SVO), are candidates for the use in stationary power production. Liquid biofuels are suitable for gas turbines, though adjustments to the plants could be necessary according to the combustion characteristics of each fuel. Their utilisation would be facilitated by the further development of the research on multi-fuel capability [26].

The distinction between gaseous and liquid fuels is, however, useful when analysing the storage and distribution of each fuel and will often be highlighted in further investigation. Additionally, distinguishing between biofuels and electrofuels has benefits for the fuel assessment. Even though identical from a physical and chemical point of view, and therefore also in terms of performance in a GT, fuels from different feedstocks often differ in terms of life-cycle sustainability, and affect the regulatory framework.

In the case of biofuels, EU defines biofuels as gaseous or liquid renewable fuels for the transport sector and they are further divided into three main categories: biofuels produced from food and feed crops, advanced biofuels, and biofuels using mature technologies derived from resources not suitable for human food or animal feed such as waste cooking oil and animal fats [27][28].

European policies are affecting the path for which biofuels are considered sustainable. As can be seen in Figure 3.1, the distinction between different biofuel feedstocks became relevant in 2015 with the Indirect Land-Use Change (ILUC) Directive [28]. RED II establishes a sustainability criteria for the use of biofuels, focusing on the risk of ILUC, imposing that as biofuels production expand, previous non-crop land is used to fulfil the expanded need for biomass feedstocks, for both food and biofuel production. If the previous land was, for instance, forests, wetlands and peatlands this leads to CO_2 stored in trees and soil is released when cultivating the land. To approach this, limits are set on high ILUC-risk biofuels and a criteria to certify low ILUC-risk fuels has been introduced [29]. Additional land at the expense of forest and peat lands is at risk of increasing carbon dioxide equivalent (CO_2-eq) emissions rather than reducing them compared to fossil fuels [28].

On the other hand, when it comes to e-fuels, the regulatory framework is mainly focused on the life-cycle CO_2-equivalent emissions of the fuel to determine its sustainability. Electrofuels are defined as renewable if derived from green H_2, i.e. hydrogen produced with electrolysis using renewable electricity, and other clean resources, like biogenic CO_2, syngas or nitrogen. Due to boundaries of the EU Taxonomy for

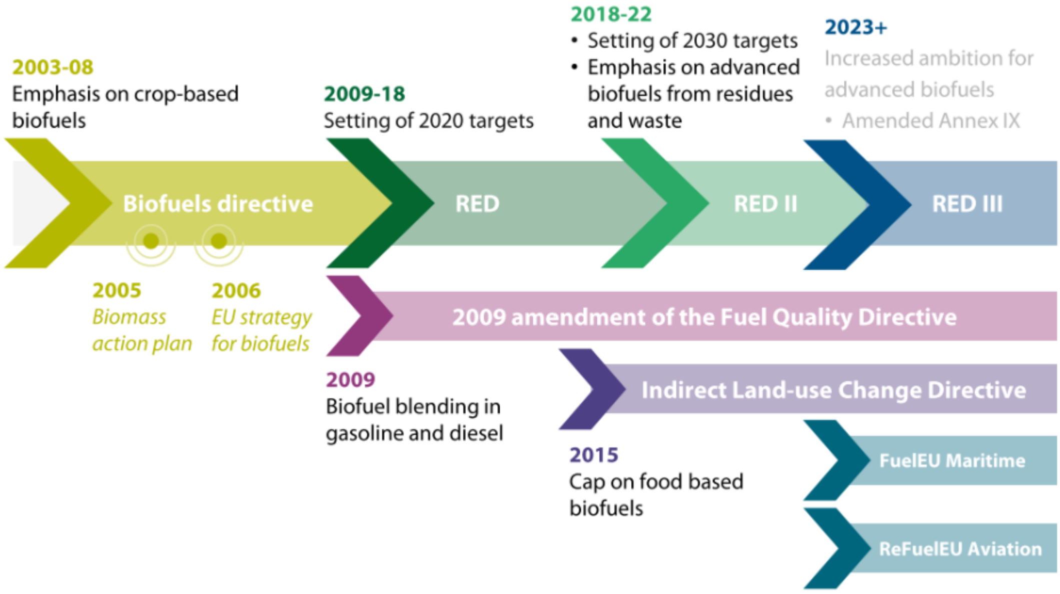

Figure 3.1: Key developments in EU policy for biofuels. [28], CC BY 4.0

Cogeneration of heat/cool and power [30][31], in the case of a plant running on a mix of both biofuels and e-fuels, the contribution criteria to be followed are the ones regarding renewable fuels. Therefore, the assessed fuels are going to be considered suitable for the implementation if the life-cycle CO_2-eq emissions are lower than 100 gCO_2-eq per 1 kWh of energy output from the co-generation (kWh_{CHP}), taking into account efficiency and losses [31].

3.1 Biofuels

In this section, the biofuels are described in terms of costs, logistics, availability, environmental impact, toxicity, and performance in gas turbines, with emphasis on the feedstocks and the current state of the production.

3.1.1 Biogas & biomethane

Biogas can be produced from a wide variety of feedstocks, including energy crops and residues [28]. In Sweden 2022, approximately 2.28 TWh of biogas was produced, the main feedstocks were bio-waste, residues, and sewage sludge. In addition, 1.90 TWh of biogas was imported from Denmark [32].

In 2018, almost two-thirds of the total biogas production was used for electricity and heat generation worldwide. Biogas can be used in the co-generation facilities directly or be upgraded to biomethane and injected into the gas network. Biomethane is exchangeable with natural gas and can be used in the existing transmission and distribution infrastructure or end-user equipment. The global share of produced biogas that is upgraded to biomethane is small but currently growing [33]. However in Sweden, the share is approximately 65% of the biogas produced and of the upgraded biogas around 20% was injected into the gas network in southwestern Sweden in 2022 [32]. Biogas and biomethane can also be transported on the roads, as compressed gas or liquefied biogas (LBG), LBG is mainly used in the transportation sector [34].

The IEA [33] forecasts a 50% increase for the potential of sustainable biogas production worldwide. As a part of the REPowerEU plan, the biomethane production should be expanded to 35 billion cubic metres until 2030, in 2023 the production was around 22 billion cubic metres [35][36]. The aim is promoting the production expansion to use sustainable feedstocks, meaning feedstocks that do not imply with food production or leading to land-use change related issues [35].

The production potential in Sweden in 2030 depends on the policy trajectory. It ranges from 9-22 TWh and including forest residues potential, it could increase to 74 TWh. A technical estimate for anaerobic digestion by year 2030 is 14-15 TWh [32]. The cost of gas from the Swedish grid using Danish biogas in 2030 is estimated to approximately 53 €/MWh including guarantee of origin for biogas, the gas price, the network tariff and the grid tariff, excluding the Swedish grid fees [18]. Due to current policies, Danish biogas is cheaper than Swedish biogas [6].

In 2050, the potential of biomethane in EU and 10 neighbouring countries is estimated to 1100 TWh, including the feedstocks agricultural residues, intermediate crop residues, biowaste, industrial waste, manure and green waste. If also the feedstocks forest residues, forest wood and pruning are included the potential becomes 1700 TWh [37]. The estimate from the study done by Engie [37], resulted in the levelised cost of energy (LCOE) of biomethane to 76 €/MWh in 2050 using the 1100 TWh potential, where 60% of the potential biomethane production could have a lower cost.

3.1.2 FAME

Fatty acid methyl ester (FAME) is a biodiesel available on the market, especially for the transport sector as a blend-in fuel. FAME is produced from the transesterification of SVO [26]. In Sweden, FAME is produced in the form of rapeseed methyl ester (RME), coming from rapeseed oil. From 2023 to 2030, the RME production in Sweden is estimated to decrease from 1.9 to 0.5 TWh based on planned production facilities. In comparison, the other type of biodiesel, hydrotreated vegetable oil (HVO), is instead increasing its production capacity in Sweden [38][39]. The price range of FAME is estimated to 78-196 €/MWh for 2030 based on historical price ranges as it is a commercial fuel [40]. As mentioned in the beginning of this section, feed and food crops are critical for future production because of EU regulations, making FAME a less sustainable fuel. Furthermore, the cultivation of rapeseed has a strong impact also on the life-cycle CO_2-eq emissions of FAME, estimated around 164 gCO_2-eq/kWh_{fuel} (or 178 gCO_2-eq/kWh_{CHP}[1]) [41], which exceeds the emission limit of 100 gCO_2-eq set in Section 3.

3.1.3 HVO

HVO is a biodiesel produced from SVO, animal fats and waste oils that undergo hydrogenation and isomerisation processes. The SVO is derived from crops including food and feed crops and is therefore a less sustainable feedstock for HVO [26]. Production of HVO from used cooking oil (UCO), other waste oils or animal fats results in lower life-cycle CO_2-equivalent emissions [41]. Sweden imports 90% of the HVO consumed, and the main feedstocks are waste from the food industry and trade and agricultural waste and residues. The HVO used in Sweden 2023 resulted in GHG emissions of 19.5 g CO2eq/MJ which is five times higher emissions compared to other liquid biofuels used in Sweden (excluding FAME) [42].

Karlsson H. et al. [43] has investigated the future potential of producing HVO from Swedish raw materials. HVO production from lignocellulosic materials have economic potential of 7.07 TWh, waste and residual oils have technical potential of 0.54 TWh and oilseed crops grown as cover crops or on marginal land, have technical potential of maximum 2.70 TWh, per year by 2050. HVO is similar to conventional jet fuel [26], making it a promising fuel for GT. The cost for HVO in 2030 is estimated to 96-240 €/MWh based on historical prices as it is a commercial fuel [44]. Due to HVO being a market fuel, it is difficult to find production costs using other feedstocks.

3.1.4 Bioethanol

Bioethanol is a commercial biofuel and the current main feedstocks are food and feed crops making it a potential unsustainable biofuel for the future supply needs. Similarly to the case of RME, the origin of the feedstocks has an impact on the life-cycle CO_2-eq emissions, on average 100 gCO_2-eq/kWh_{CHP}[2] [41]. Additionally, bioethanol has 63% the calorific value compared to fossil diesel, which can imply higher overall operating cost for gas turbines because of the large volumes needed to operate at the same load [26]. Further, bioethanol has technical challenges related to low flash point temperature, which leads to the need for extra care along the fuel line with respect to tightness, explosion, and fire protection [26][45]. Therefore, ethanol is suggested to be blended with more viscous and conventional fuels to compensate

[1] Co-generation efficiency of 0,92
[2] Co-generation efficiency of 0,92

this issue [26]. The price range of bioethanol is estimated to 70-182 €/MWh, based on historical prices as it is a commercial fuel [40].

3.1.5 Biomethanol

Methanol is a widely used chemical and an important raw material for the chemical industry and the demand for methanol is growing. Methanol is also used to produce biodiesel and the gaseous fuel dimethyl ether (DME). Biomethanol can be derived from municipal waste, forestry and agricultural waste and by-products, biogas, sewage and black liquor from the pulp and paper industry [46]. The sources for producing biomethanol makes it an advanced biofuel according to the EU definition mentioned earlier in Section 3. Out of all liquid biofuels used in Sweden 2023, biomethanol has the lowest emissions of CO2-eq of 0.2 g CO2eq/MJ [42]. The interest in methanol as a fuel is growing, especially in the maritime transport sector. Already, several ships are fuelled with methanol, for example the Stena Line ferry operating between Gothenburg and Kiel [46]. Methanol is storable as a liquid fuel and can be transported in barges, chemical tankers, rail tankers and trucks or be accessed via pipelines [46][47].

The lower heating value (LHV) for methanol is 19.8 MJ/kg, approximately half of the LHV for petrol [47]. Methanol has the same classification as petrol and diesel when it comes to toxicity. Potential biomass availability for biomethanol in 2030 in Europe is estimated to 525-850 Mt/year dry biomass, after meeting other demands, taking into account the feedstocks agricultural residues, additional biomass from sustainable forestry, wastes and industrial crops on released agricultural land [46]. According to the Methanol Institute [48], several biomethanol-producing facilities are planned for operation in Sweden before 2030, such as Liquid Forest and Project AIR. The projects result in a production volume of 1.77 TWh/year in 2030.

3.2 Electrofuels

In this section, the electrofuels are described in terms of costs, logistics, availability, environmental impact, toxicity, and performance in gas turbines, with emphasis on the forecasts for production costs and future development.

3.2.1 Hydrogen

Green hydrogen is a fundamental part of the investigation of future energy system scenarios, since it is expected to be endogenously produced in integration with the energy system of Gothenburg. When it comes to the use in gas turbines, H_2 is an important resource both as a fuel itself and as a feedstock for the synthesis of other fuels, such as e-methanol, e-methane and e-ammonia [49].

In order to fuel Rya CHP, hydrogen can be blended into the existing gas network or fed directly to the plant. The volume of hydrogen that can be mixed into the gas network is expected to be 5-10% of the volume in the near future, using the existing infrastructure and end-consumer installations. However, with modifications, in 2030 it could be possible to reach a 15- 20% volume ratio of hydrogen in the gas network [50]. This technical limitation limits the possible hydrogen use if relying on the gas network for supply.

Due to its lower ignition energy and higher flame speed compared with natural gas, the use of hydrogen poses technical challenges for combustion systems [21]. At the current stage of research, there seem to be limitations on the maximum amount of hydrogen in the fuel mix fed to gas turbines. For H_2 contents exceeding 75% in volume, which corresponds to 50% in energy, gas turbines need design upgrades that would make them fit for running on 100% pure hydrogen, but not other fuels any more [51][52].

The production cost of green hydrogen is currently in a range between 115 and 173 €/MWh [49]. As the cost of the electrolysers is set to decrease in the future years, the forecasts for the hydrogen production costs in 2030 and 2050 are respectively 52-92 €/MWh and 26-58 €/MWh [46]. The production cost of green hydrogen is also dependent on the price of electricity. Consequently, the availability of green hydrogen is set to increase in a future energy system with excess of renewable electricity, incentivised also by the great demand for this resource from refineries and steel industry.

3.2.2 E-methanol

Methanol can be produced directly from CO_2 and H_2 through a catalytic reaction and can be called e-methanol if the hydrogen used in the process comes from electrolysis using electricity from renewable sources [46]. Nowadays, green H_2 covers only 4% of the total production globally [46] and only 0.2% of the methanol is derived from renewable sources, including also the biomethanol described in Section 3.1.5 [49]. Moreover, due to the the life-cycle CO_2-equivalent emission limits for the renewable fuels, the CO_2 used in the process has to be biogenic, e.g. from bioenergy with carbon capture and storage (BECCS), or coming from direct air capture (DAC). A large yield of captured CO_2 in Sweden is the one coming from waste incineration plants, whose carbon yield is approximately 1.5 Mton/year. As the main source of fossil CO_2 is the plastic waste, sorting it from the rest or using the corresponding share of CO_2 for other purposes, could make waste a viable feedstock. Considering only the biogenic carbon share, which is commonly assumed to be 60% of the total, the e-methanol production would require approximately 30 TWh of electricity, around 20% of the Swedish total electricity production [53]. According to the Methanol Institute [48], e-methanol will be produced in four different facilities in Sweden by year 2030, for a total of 2.21 TWh.

According to IRENA and the Methanol Institute [46], the production cost for e-methanol is highly dependent on the cost of hydrogen feedstock and is forecasted to have a range of 78-130 €/MWh in 2030 and 44-112 €/MWh in 2050. The port of Gothenburg, in collaboration with Stena Line, has the ambition to become the primary bunkering hub for renewable methanol in Northern Europe [54]. This could contribute to the abatement of the production costs of renewable methanol in Gothenburg.

3.2.3 E-methane

Similarly to e-methanol, fully renewable e-methane can be produced with electricity from renewable sources and CO_2 from biogenic sources. However, e-methane can be produced with different processes: catalytic methanation and biomethanation [55]. The first one is a high temperature chemical reaction, similar to the synthesis of methanol. The other, instead, is an anaerobic digestion in which microorganism are involved to facilitate the reaction between H_2 and CO_2, acting as a biological catalyst [56]. When implemented *in-situ*, with H_2 inserted directly in biogas digesters, the outcome of the reaction is substantially the upgrade of biogas into biomethane. In the case of *ex-situ* biomethanation, instead, the CO_2 feedstock can be biogas, syngas or pure carbon dioxide, making it a viable option for systems developing CCS and green H_2 production.

Production costs for e-methane can vary significantly, depending on the type of methanation, the cost of hydrogen and the CO_2 source, with estimates of 75-195 €/MWh in 2030 and 60-140 €/MWh in 2050 [57]. Depending on the location of the e-methane production sites, this fuel could be fed directly to Rya CHP plant or injected in the gas network.

3.2.4 E-ammonia

Ammonia is commonly produced for industrial purposes with the Haber-Bosch process, combining H_2 and N_2 in conditions of high temperature and pressure [56]. When the hydrogen used in the reaction is green H_2, the product can be considered *green ammonia* [49][56]. The research of Siemens regarding the combustion in gas turbines is focused on both direct and cracked ammonia [21]. The interest into this fuel is due to it being an efficient hydrogen carrier, with higher energy density than H_2, with well-established production and distribution processes [21].

However, some technical challenges come from the use of this fuel in gas turbines, since the lower flame speed and the high NO_x emission can affect the combustion systems [21]. Moreover, ammonia is highly corrosive and toxic. If inhaled, ammonia can cause permanent respiratory damages and is severely dangerous if it is ingested or comes into contact with skin or eyes [58]. The life-cycle CO_2-equivalent emissions for the production of e-ammonia can vary from study to study, depending on the renewable electricity sources considered. Based on the range of values found, the average is 105 gCO_2-eq/kWh_{CHP}[3] [59]. These issues play a very important role in the assessment of this fuel.

3.3 Summary

The fuel assessment resulted in a comparison of the fuels, evaluating the cost in the years 2030 and 2050, together with logistics, availability, environment, toxicity, and how suitable the fuels are for the use in GTs. The cost of the fuels, summarised in Table 3.1, are the range of production cost expected for each fuel in both 2030 and 2050. The only exception is biomethane, for which the costs are defined as fixed values. The use of biomethane is the state of the art in Rya CHP, therefore using it as a benchmark allows for an evaluation of the costs of all the other fuels. During the literature study, only production methods and feedstocks relevant for this case study have been taken into account, often combining different sources. The costs, often retrieved in different currencies and units, have been standardised and are expressed in €/MWh, as the original values are collected in Table A1 in Appendix A.

Table 3.1: List of fuels investigated and respective costs for 2030 and 2050.

Fuel	**Cost 2030** [€/MWh]		**Cost 2050** [€/MWh]	
Biomethane	53	[18]	76	[37]
LBG	78 - 222	[57]	55 - 81	[57]
Biomethanol	57 - 177	[46]	40 - 154	[46]
Bioethanol	70 - 182	[40]	-	
FAME	78 - 196	[40]	-	
HVO	96 - 240	[40]	-	
Hydrogen	52 - 92	[46]	26 - 58	[46]
E-methane	70 - 195	[57]	60 - 140	[57]
E-methanol	80 - 144	[46]	44 - 110	[46]
E-ammonia	86 - 180	[59]	62 - 114	[59]

[3]Co-generation efficiency of 0,92

Logistics is relevant to evaluate how the fuels can be integrated in the model and the cost structure that comes to their implementation. The availability assessment takes into consideration the forecasts for the future production volumes of the fuels, together with the type of feedstock and how the competition with other sectors is going to affect it. For fuels currently not available on the market yet, the approach was to consider the availability of the fuel, and any eventual limitations, once commercialised. The environmental parameter is mainly based on the life-cycle CO_2-equivalent emissions of each fuel. For the bio-based fuels, though, it is accounting also the resource use, showing an overlap with the availability parameter. While looking at the toxicity of each fuel, it is relevant to know if a fuel is toxic, upon which kind of exposure and with which consequences for humans. Eventual toxicity effects for nature are considered in the environmental assessment. Lastly, the use in gas turbines is evaluated considering the stage of research and testing of the fuel conducted by Siemens, analysing eventual results regarding performances or technical limitations. The results of this qualitative evaluation are shown in Figure 3.2.

Fuel	Logistics	Availability	Environment	Toxicity	GT use
Biomethane	gas pipeline	✓ (green)	✓ (green)	✓ (green)	✓ (green)
LBG	tank storage	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Biomethanol	tank storage	✓ (green)	✓ (green)	✓ (yellow)	? (purple)
Bioethanol	tank storage	✗ (red)	✓ (yellow)	✓ (green)	? (purple)
RME	tank storage	✗ (red)	✓ (yellow)	✓ (green)	✗ (red)
HVO	tank storage	✓ (yellow)	✓ (green)	✓ (green)	✓ (yellow)
Hydrogen	gas pipeline	endogenous	✓ (green)	✓ (green)	✓ (yellow)
E-methane	gas pipeline	✓ (green) /endogenous	✓ (green)	✓ (green)	✓ (green)
E-methanol	tank storage	✓ (green) /endogenous	✓ (green)	✓ (yellow)	? (purple)
E-ammonia	tank storage	✓ (green) /endogenous	✓ (yellow)	✗ (red)	✓ (yellow)

Figure 3.2: Fuel assessment overview showing the evaluated parameters for each researched fuel. Green indicates promising, yellow indicates potential issues and red indicates evident issues. Purple question marks show small-scale testing only.

The comparison is used to evaluate each fuel's potential as a future renewable fuel for Rya CHP. The fuels with relatively good performance from the evaluation will be further investigated in the study. In the following section it is motivated which fuels will be considered for the future scenarios of 2030 and 2050.

The environmental parameter has resulted in some biofuels using more sustainable feedstocks compared to the biofuels mainly using food and feed crops as feedstock. Due to current EU regulations and goals that have been described in the beginning of the fuel assessment regarding biomass feedstocks, biomethanol, biomethane, and HVO are considered most sustainable from the environmental parameter, assuming that HVO will use only sustainable feedstocks in the future, i.e waste oils and residues. Bioethanol and RME are commercial fuels, however they rely on food and feed crops, potentially affecting the future availability negatively due to the previously described EU regulations. In addition, both RME and bioethanol exceeds the EU taxonomy regulation earlier mentioned.

Since bioethanol and RME are used as blend-in fuels in the transport sector, it is assumed that the transport sector is willing to pay more for these fuels compared to the electricity- and heat production sector. Methanol and ethanol as fuels have similar properties, both have low calorific value, and they would probably imply similar problems when combusted in GTs. However, biomethanol can to higher security depend on sustainable feedstocks compared to bioethanol, also reflected in the CO_2 emissions from the fuels. This results in the fact that biomethanol compared to bioethanol is a more promising option considering the parameters availability and environment. The same reasoning was used for biodiesels (including HVO and RME), where the limited availability of feedstock resources and lower sustainability of RME, compared to HVO, led to the conclusion that HVO is a more promising fuel for GT and will be further investigated.

Biomethane and LBG are both evaluated as potential future renewable fuels for GT as all parameters show potential as shown in figure 3.2. The parameters of environment and availability are promising for both 2030 and 2050 and biomethane is the most promising fuel looking at GT use. The difference between LBG and biomethane is the logistics and production, which results in different costs. Both fuels will be further investigated in the modelling, to evaluate which alternative is most cost-competitive in future scenarios.

Bio-based fuels are a rather complicated market, as the different fuels often compete with the same feedstocks. As an example for this complexity, production of biomethanol can be used. Usually in Sweden today, forest residues are used in DH production and CHP production. Meaning that if forest residues are instead used to produce biomethanol, other ways are needed to fulfil the DH and CHP production. For instance by producing more electricity to be consumed by heat pumps [53]. Biomethanol can also be produced using biogas as resource, also adding to the complexity of the availability for biomethanol. If biogas is used to produce biomethanol, it means less biomethane can be produced. In addition, the fuels have different feedstock potentials depending on which resources are considered, for instance both HVO and biomethane have increased feedstock potential if lignocellulosic materials and forest residues are included. In summary, the availability parameter is highly dependent on how biomass will be used, but also the policy trajectory will define from which kind of sources biomass can come from.

Regarding the e-fuels, hydrogen, e-methane and e-methanol are all more promising in relation to e-ammonia due to the investigated parameters, especially the parameters of toxicity and environment lead to exclusion of further investigation of e-ammonia. e-methanol seems to be promising considering the upcoming facilities in Sweden in addition to assumed availability because of the growing demand from industry such as the shipping sector and the chemical industry. Comparing e-methanol to e-methane, e-methanol is a more promising fuel in Gothenburg considering the shipping sector and since there are ongoing projects of new facilities before 2030.

In summary, fuels that are further investigated for 2030 are biomethane, LBG, HVO, hydrogen, biomethanol, and e-methanol. Fuels that are further investigated for 2050 are biomethane, LBG, HVO, hydrogen, biomethanol, e-methanol, and e-methane. E-ammonia, RME and bioethanol are excluded for further investigation and the modelling of the scenarios.

4 Methodology

4.1 Model description

The investigation of the use of renewable fuels in Rya CHP and its impact on the role of the plant in the energy system of Gothenburg is conducted with the help of a linear optimisation model. The energy system in which Rya CHP operates is described by an investment model of the city of Gothenburg, hereby referred to as *City Model*, running over one year, with an hourly time resolution, and minimising the total system costs. The model takes into consideration the interconnections of the urban energy system with other sectors, such as residential, commercial, transportation and industrial, fulfilling their demands for electricity, heat and hydrogen.

The City Model was originally developed for the investigation of the interconnections between electricity and district heating systems by Heinisch et al. [60]. It was further expanded by Heinisch et al. [61] with the implementation of electric cars and public transportation and finally by Rosén et al. [62] with the addition of the hydrogen system and the connection with other nodes located in Lysekil and Stenungsund.

The main focus of the model iterations carried out by Heinisch and Rosén was placed on the investment decisions shaping the future energy system in order to satisfy the growing electricity demand, react to the new electricity prices and support the energy transition of the city. The description of the current situation regarding the existing capacity of different technology aggregates was not crucial for the studies, due to the freedom of the model to invest in new capacity if needed, using the most cost-effective option.

The aim of this project, instead, revolves around a singular plant and its interactions with the electricity and heating systems of the city. Therefore, the model has been updated to the current configuration of the system. By means of constant dialogue with Göteborg Energi, it was possible to gather information about the rated power of each plant, previsions on which of those are going to be active in 2030 and possible plans for 2050. The installed capacities implemented in the City Model are reported in Tables 4.1 and 4.2, split between gas turbines and steam turbine for Rya CHP.

Table 4.1: List of existing capacities included in the City Model in 2030.

Tech	Fuel	Capacity	Real life plant
CCGT-BP	mix	0.135+0.141 GW_{el}	Rya CHP (GTs + ST)
CHP	biomass	0.013 GW_{el}	Sävenäs CHP
HP	electricity	0.160 GW_{heat}	Rya HPs
HOB	pellets	0.124 GW_{heat}	Rya HOB
HOB	biomethane	0.070+0.125 GW_{heat}	Sävenäs HOB + Rosenlund HOB
TTES	-	0.900 GWh_{heat}	Accumulator

Table 4.2: List of existing capacities included in the City Model in 2050.

Tech	Fuel	Capacity	Real life plant
CCGT-BP	mix	0.170+0.141 GW_{el}	Rya CHP (GTs + ST)

Additionally to the capacities defined as existing, the City Model is free to choose between a large number of technologies to fulfil the electricity and heating demands of the city in the most cost-effective way. The investment decisions and the behaviour of the technologies are subject to some limitations, defined in the model, in order to provide plausible results.

The key model limitations considered for this study are the following:

- the maximum wind capacity is 1 GW_{el} for offshore installations and null for onshore ones;
- the maximum PV capacity is 1.9 GW_{el} for rooftop installations and 0.1 GW_{el} for optimal tilt ones;
- the investment in gas-based technologies, i.e., peak GT, CCGT, and CCGT-BP, is possible only if fuelled with biomethane;
- the investment in H_2 storage is possible only in the form of tanks, since lined rock cavern (LRC) are not a viable option due to the geological conformation of Gothenburg;
- the transmission capacity of the electricity grid is 895 MW_{el} in 2030 and increases of 650 MW_{el} by 2050;
- the waste heat supply is the same between 2030 and 2050.

The validity of the last assumption, regarding the waste heat availability, can be discussed and has been object of sensitivity analysis, with results in Section 5.2.5.

Rya CHP plant is characterised by a variety of operating configurations, as described previously in Section 2.3, which increase the level of complexity necessary to describe it. Therefore, although included in the City Model as an existing capacity, the plant has been defined in detail by a model constructed for this purpose, given the name of *Rya Model*.

This model can be run either in integration with the City Model, minimising the costs of its operation together with the rest of the system, or independently, shifting the aim of the investigation towards maximising the profits for the plant operators.

Differently from the other CHP technologies defined in the City Model, Rya CHP is not characterised by a fixed power-to-heat ratio, and the production levels of electricity and district heating depend on which demand is the driver for the plant operation at each time. In order to convey the operational flexibility of the plant, each of its components needs to be described separately while modelling. In addition to the current layout of Rya CHP, the investigation takes into account the new bio-steam boiler, integrated as a fourth line, in parallel to the three gas turbines.

In the Rya Model, the plant is the ensemble of the following components: three gas turbines (GT1, GT2 and GT3), with respective supplementary firing (SF1, SF2 and SF3), a bio-steam boiler (BB), a steam turbine (ST), which includes the subsequent condensers, and a direct condenser (DK). The interactions between the components are regulated from the balance of four different energy carriers: fuel, steam, electricity and district heating.

The function of the different components in the Rya Model, outlined in Figure 4.1, can be summarised as follows:

- GTs consume fuel to produce electricity and steam;
- SFs consume fuel to produce steam;
- BB consumes fuel to produce steam and district heating;
- ST consumes steam to produce electricity and district heating;
- DK consumes steam to produce district heating.

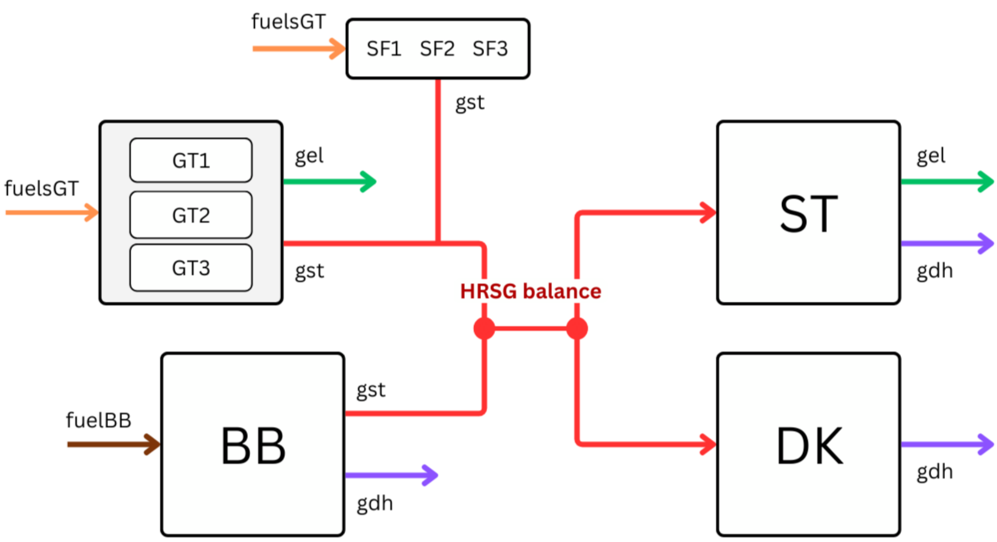

Figure 4.1: Schematisation of the Rya Model

The core structure of the model is hereby described, together with the essential sets, parameters, variables and equations, defined in .

The total plant costs over one year ($c^{tot}_{Rya\,CHP}$), as described in Equation 4.1, include costs for the fuel consumption (C^{fuel}_{f}), fixed (C^{fix}_{i}) and variable (C^{var}_{i}) O&M costs for each component, start-up ($c^{startup}_{i}$) and part-load ($c^{partload}_{i}$) costs for the components with limited flexibility, and investment costs (C^{inv}_{s}) and fixed O&M costs (C^{fix}_{s}) for the fuel storage units.

$$\begin{aligned}
c^{tot}_{Rya\,CHP} = & \sum_{t \in T} (C^{fuel}_{biomass} * fuel_{BB,t} + \sum_{f \in F_{market}} C^{fuel}_{f} * fpr_{f,t}) + \\
& + \sum_{i \in I_{el}} (C^{fix}_{i} * Cap_{i} + \sum_{t \in T} C^{var}_{i} * gel_{i,t}) + \\
& + C^{fix}_{BB} * Cap_{BB} + \sum_{t \in T} C^{var}_{BB} * gst_{BB,t} + \\
& + \sum_{t \in T} \sum_{i \in I_{start}} c^{startup}_{i,t} + \sum_{t \in T} \sum_{i \in I_{GT}} c^{partload}_{i,t} + \\
& + \sum_{s \in S} (C^{inv}_{s} * crf_{s} + C^{fix}_{s}) * cap_{s}
\end{aligned} \tag{4.1}$$

The choice of the mix of alternative fuels used in the plant is described by Equation 4.2, which establishes the correlation between fuel use by component ($fuel_{i,t}$) and fuel use by fuel type ($fsh_{i,f,t}$). Equations (4.3)–(4.5) set the limits for the H_2 use ($fsh_{i,H2,t}$) in the gas turbines and the availability of each fuel (Av_{f}) over the year, as well as establishing the balance between the fuel use ($fsh_{i,f,t}$) and the fuel purchase ($fpr_{f,t}$).

$$\sum_{f \in F} fsh_{i,f,t} \geq fuel_{i,t} \quad \forall i \in I_{fuel} \quad \forall t \in T \tag{4.2}$$

$$fsh_{i,H2,t} \leq 0.5 * fuel_{i,t} \quad \forall i \in I_{GT} \quad \forall t \in T \tag{4.3}$$

$$\sum_{t \in T} fpr_{f,t} \leq Av_{f} \quad \forall f \in F_{market} \tag{4.4}$$

$$\sum_{t \in T} fsh_{f,t} \leq \sum_{t \in T} fpr_{f,t} \quad \forall f \in F_{market} \tag{4.5}$$

The fuel consumption ($fuel_{i,t}$) of the components is correlated to their generation ($gen_{i,t}$) via Equations 4.6 and 4.7.

$$fuel_{i,t} \geq \frac{gen_{i,t}}{\eta_{tot,i}} \quad \forall i \in I_{fuel} \quad \forall t \in T \tag{4.6}$$

$$fuel_{BB,t} \geq \frac{gst_{BB,t}}{\eta_{tot,BB}} \quad \forall t \in T \tag{4.7}$$

Equations (4.8)–(4.12) define the energy balance over gas turbines, supplementary firing, bio-steam boiler, steam turbine, and direct condenser respectively. The balance over the steam generators, labelled as *HRSG balance* in Figure 4.1, is described by Equation 4.13. The production of electricity ($gel_{i,t}$) over the total generation ($gen_{i,t}$) is specified for gas turbines and steam turbine by Equation 4.14, while the ratio between district heating production ($gdh_{i,t}$) and steam generation ($gst_{i,t}$) in the bio-steam boiler follows Equation 4.15.

$$gen_{i,t} = gel_{i,t} + gst_{i,t} \quad \forall i \in I_{GT} \quad \forall t \in T \tag{4.8}$$

$$gen_{i,t} = gst_{i,t} \quad \forall i \in I_{SF} \quad \forall t \in T \tag{4.9}$$

$$gen_{BB,t} = gst_{BB,t} + gdh_{BB,t} \quad \forall t \in T \tag{4.10}$$

$$gen_{ST,t} = gel_{ST,t} + gdh_{ST,t} \quad \forall t \in T \tag{4.11}$$

$$gen_{DK,t} = gdh_{DK,t} \quad \forall t \in T \tag{4.12}$$

$$\sum_{i \in I_{fuel}} gst_{i,t} + gst_{BB,t} = \frac{gen_{ST,t}}{\eta_{tot,ST}} + \frac{gen_{DK,t}}{\eta_{tot,DK}} \quad \forall t \in T \tag{4.13}$$

$$gel_{i,t} = gen_{i,t} * \frac{\eta_{el,i}}{\eta_{tot,i}} \quad \forall i \in I_{el} \quad \forall t \in T \tag{4.14}$$

$$gdh_{BB,t} = F_{BB} * gst_{BB,t} \quad \forall t \in T \tag{4.15}$$

The fuel storage dynamics are defined in Equations 4.16–4.20, describing the balance of the storage level ($lvl_{s,t}$) and its limit, as well as charge ($chg_{s,t}$) and discharge ($dch_{s,t}$), in relation to its (cap_s).

$$lvl_{s,t+1} = lvl_{s,t} + chg_{s,t} - dch_{s,t} \quad \forall s \in S \quad \forall t \in T \tag{4.16}$$

$$cap_s \leq Cap_{max,s} \quad \forall s \in S \quad \forall t \in T \tag{4.17}$$

$$lvl_{s,t} \leq cap_s \quad \forall s \in S \quad \forall t \in T \tag{4.18}$$

$$chg_{s,t} \leq cap_s \quad \forall s \in S \quad \forall t \in T \tag{4.19}$$

$$dch_{s,t} \leq cap_s * dr_s \quad \forall s \in S \quad \forall t \in T \tag{4.20}$$

Equations (4.21)–(4.23) establish the correlations between storage charge ($chg_{s,t}$) and fuel purchase ($fpr_{f,t}$), while Equations (4.24)–(4.26) define the ones between storage discharge ($dch_{s,t}$) and fuel use ($fsh_{i,f,t}$).

$$chg_{hydrogen,t} \leq fpr_{H2,t} \quad \forall t \in T \tag{4.21}$$

$$chg_{liquidgas,t} \leq fpr_{LBG,t} \quad \forall t \in T \tag{4.22}$$

$$chg_{methanol,t} \leq fpr_{bioMeOH,t} + fpr_{eMeOH,t} \quad \forall t \in T \tag{4.23}$$

$$dch_{hydrogen,t} \geq \sum_{i \in I_{fuel}} fsh_{i,H2,t} \quad \forall t \in T \tag{4.24}$$

$$dch_{liquidgas,t} \geq \sum_{i \in I_{fuel}} fsh_{i,LBG,t} \quad \forall t \in T \tag{4.25}$$

$$dch_{methanol,t} \geq \sum_{i \in I_{fuel}} (fsh_{i,bioMeOH,t} + fsh_{i,eMeOH,t}) \quad \forall t \in T \tag{4.26}$$

The logistics of the fuel purchase ($fpr_{f,t}$) are described in Equations 4.27 and 4.28, respectively for trucks and pipelines.

$$fpr_{f,t} \leq ftr_{f,t} * Truck_t \quad \forall f \in F_{truck} \quad \forall t \in T \tag{4.27}$$

$$fpr_{f,t} \geq \sum_{i \in I_{fuel}} fsh_{i,f,t} \quad \forall f \in F_{grid} \quad \forall t \in T \tag{4.28}$$

Lastly, the Rya Model generates three global variables representing the fuel consumption ($fuel_{Rya\,CHP,t}$), the electricity production ($el_{Rya\,CHP,t}$) and the district heating production ($dh_{Rya\,CHP,t}$) of the plant, described respectively by Equations 4.29, 4.30 and 4.31. These variables are functional to the evaluation of the results, together with the total costs ($c^{tot}_{Rya\,CHP}$) obtained from Equation 4.1.

$$fuel_{Rya\,CHP,t} = \sum_{i \in I_{fuel}} fuel_{i,t} \quad \forall t \in T \tag{4.29}$$

$$el_{Rya\,CHP,t} = \sum_{i \in I_{el}} gel_{i,t} \quad \forall t \in T \tag{4.30}$$

$$dh_{Rya\,CHP,t} = \sum_{i \in I_{dh}} gdh_{i,t} \quad \forall t \in T \tag{4.31}$$

4.1.1 LP version

The integration of the Rya Model with the City Model proceeds with a linear programming (LP) approach, due to the computational effort necessary to solve a model with this large number of variables with other methods.

In order to couple the two models, the global variable $c^{tot}_{Rya\,CHP}$ is included in the objective function of the City Model, aiming to minimise the total costs of the system. Moreover, the electricity generation $el_{Rya\,CHP,t}$ and the district heating production $dh_{Rya\,CHP,t}$ are added on the supply side of the electricity balance and district heating balance of the city, respectively. Lastly, since hydrogen is a fuel endogenous to the system, its supply to the plant is defined by the integration of the variable $fpr_{H2,t}$ in the hydrogen balance equation present in the City Model, on the demand side.

In the LP version of the Rya Model, the maximum and minimum loads of the components are described by the parameters $Maxload_i$ and $Minload_i$. Within the properties of the components, $Maxload_i$ is defined as a limit in GWh for electricity, district heating and steam, together with the percentage R_i, representing the ratio between $Minload_i$ and $Maxload_i$. The load level limit at each time step is set by declaring upper bounds $gel.up_{i,t}$, $gdh.up_{i,t}$ and $gst.up_{i,t}$ for each generation variable.

When it comes to the operational flexibility of the components, the method used is the one described as *two-variable approach* in Göransson [63]. This method requires the introduction of two new positive variables, $spin_{i,t}$ and $on_{i,t}$, that represent respectively the hot capacity available for generation and its increase, for each component i at each time step t.

The variable $spin_{i,t}$ is defined by the equations:

$$gen_{i,t} \leq spin_{i,t} \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.32}$$

$$gen_{i,t} \geq spin_{i,t} * R_i \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.33}$$

giving time-dependent upper and lower limits for the generation.

Due to the different purpose of each component, Equations 4.36 and 4.37 are implemented in the model as:

$$gel_{i,t} \leq spin_{i,t} \quad \forall i \in I_{el} \quad \forall t \in T \tag{4.34}$$

$$gel_{i,t} \geq spin_{i,t} * R_{el,i} \quad \forall i \in I_{el} \quad \forall t \in T \tag{4.35}$$

$$gst_{BB,t} \leq spin_{BB,t} \quad \forall t \in T \tag{4.36}$$

$$gst_{BB,t} \geq spin_{BB,t} * R_{st,BB} \quad \forall t \in T \tag{4.37}$$

The variable $on_{i,t}$ is defined by the equation:

$$on_{i,t} \geq spin_{i,t} - spin_{i,t-1} \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.38}$$

The cost for starting the components is then proportional to the value of $on_{i,t}$, with the equation:

$$c_{i,t}^{startup} \geq on_{i,t} * C_i^{startup} \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.39}$$

The start-up time of each component is translated into limiting the variation of $spin_{i,t}$ with the equation:

$$on_{i,t} \geq gen.up_{i,t} - spin_{i,t-k} \quad \forall k \in K \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.40}$$

where K is the start-up time of the component.

The part-load operation of the gas turbines results in additional costs, described by the equation:

$$c_{i,t}^{partload} \geq (spin_{i,t} - gel_{i,t}) * C_i^{partload} \quad \forall i \in I_{GT} \quad \forall t \in T \tag{4.41}$$

The parameter $C_i^{partload}$ represents the cost of additional fuel[1] used due to the loss of efficiency experienced by the turbines when operating in part-load, and is defined as in Equation 4.42.

$$C_i^{partload} = (\frac{1}{Maxload_i - Minload_i})(\frac{C_i^{fuel}}{\eta_{min,i}} - \frac{C_i^{fuel}}{\eta_{el,i}}) \quad \forall i \in I_{GT} \tag{4.42}$$

This linear solution is the same one used in the City Model and is fitting for technology aggregates, describing production patterns with a reduced level of detail while staying faithful to the flexibility of the units. In the case of the Rya Model, this method is used to constrain the generation of the single components of the plant to their flexibility limitations, delivering a feasible production pattern, but likely underestimating the entity of the start-up costs. A higher level of detail can be found with the method described next, implemented when modelling Rya CHP in soft-link with the City Model.

4.1.2 MIP version

The cost optimisation of the Rya Model in soft connection with the City Model allows for the use of a Mixed Integer Programming (MIP) approach.

While allowing for a better description of the technologies, MIP solutions introduce a large number of variables and increase drastically the computational effort, making it challenging to implement those in a model as large as the City Model. However, the MIP approach is of interest when analysing the behaviour of Rya CHP plant semi-independently from the rest of the system.

The objective function in the MIP version of the Rya Model is maximising the profit of the plant over one year, in contrary to minimising the costs, following the equation:

$$MAX\ p_{Rya\,CHP}^{tot} = \sum_{t \in T} el_{Rya\,CHP,t} * P_{el,t} + \sum_{t \in T} dh_{Rya\,CHP,t} * P_{dh,t} - c_{Rya\,CHP}^{tot} \tag{4.43}$$

where $P_{el,t}$ is the electricity price in SE3 at each time t, while $P_{dh,t}$ is the marginal cost of heat at each time t as obtained by the City Model.

[1] C_i^{fuel} is estimated as the median of the cost of the fuels implemented in each scenario, since LP modelling doesn't allow multiplication between variables

The cost for the hydrogen consumption, previously endogenous to the system, is here included in the total cost of the plant as the product of $fpr_{H2,t}$ and $P_{H2,t}$, marginal cost of hydrogen at each time t as obtained by the City Model.

The flexibility of the components in the MIP version is regulated with a *IP approach*, as it is described in Göransson [63]. The same variables as before, $spin_{i,t}$ and $on_{i,t}$, are introduced, representing however different concepts.

The binary variable $spin_{i,t}$ is used to indicate whether a component is ready to run (1) or not (0), while the positive variable $on_{i,t}$ indicates if the component is starting (1) or not (0) in the considered time step. The equation describing the variables is:

$$on_{i,t-T_{start,i}} \geq spin_{i,t} - spin_{i,t-1} \quad \forall i \in I \quad \forall t \in T \tag{4.44}$$

where $T_{start,i}$ is the start-up time of the component.

The components are then assigned a start-up cost every time $on_{i,t}$ equals 1, following the equation:

$$c_{i,t}^{startup} \geq on_{i,t} * C_i^{startup} \quad \forall i \in I_{start} \quad \forall t \in T \tag{4.45}$$

The costs related to part-load operation for the gas turbines are here calculated as:

$$c_{i,t}^{partload} \geq (spin_{i,t} * Maxload_i - gel_{i,t}) * C_i^{partload} \quad \forall i \in I_{GT} \quad \forall t \in T \tag{4.46}$$

with $C_i^{partload}$ defined as in Equation 4.42.

The variable $spin_{i,t}$ is also used to describe the generation limits for each component, with the equations:

$$gen_{i,t} \geq spin_{i,t} * Minload_i \quad \forall i \in I \quad \forall t \in T \tag{4.47}$$

$$gen_{i,t} \leq spin_{i,t} * Maxload_i \quad \forall i \in I \quad \forall t \in T \tag{4.48}$$

where $Minload_i$ and $Maxload_i$ are respectively the minimum and maximum loads of the component, here both defined as values in GWh.

Since the components of Rya CHP plant produce energy in the form of different carriers, the equations above are implemented in the model as:

$$gel_{i,t} \geq spin_{i,t} * Minload_{el,i} \quad \forall i \in I \quad \forall t \in T \tag{4.49}$$

$$gel_{i,t} \leq spin_{i,t} * Maxload_{el,i} \quad \forall i \in I \quad \forall t \in T \tag{4.50}$$

$$gst_{i,t} \geq spin_{i,t} * Minload_{st,i} \quad \forall i \in I \quad \forall t \in T \tag{4.51}$$

$$gst_{i,t} \leq spin_{i,t} * Maxload_{st,i} \quad \forall i \in I \quad \forall t \in T \tag{4.52}$$

Exception to this method is $gdh_{i,t}$, limiting only the load of the direct condenser (DK), component not subject to start-up limitations. The maximum load of DK is therefore defined with $gdh.up_{i,t}$, similarly to the LP approach.

The implementation of a MIP approach reflects the true technical limitations of each component in Rya CHP plant, without reducing the level of detail.

4.2 Scenario definition

The outcome of this investigation is highly dependent on the specifics of the system in which Rya CHP plant is operating. The core of each distinct scenario is defined by a matrix of time frame, *2030* or *2050*, perspective, *Societal* or *Actor*, and fuel cost structure, *Low Fuel Cost* or *High Fuel Cost*.

4.2.1 Time frame

The study is focused on both a short-term and a long-term investigation, respectively set in 2030 and 2050.

The two time frames have relevant differences when it comes to costs, for the renewable fuels, as shown by the forecasts in Table 3.1, and for many technologies that can be included in the system, both in terms of investment and operation.

Moreover, the system itself is expected to change between the two time frames. In the 2030 case, the technologies considered as existing are the main ones currently present in the system: Rya CHP plant, Sävenäs CHP plant, a pellets-fuelled HOB located in Rya and a thermal accumulator. In the 2050 case, instead, Rya CHP is the only plant labelled as existing, with a larger gas turbine capacity. In between the two time frames, in fact, the gas turbine are going to get past their lifetime and, with this necessary renovation of the plant, it is possible to assume an expansion of their capacity. Sävenäs CHP plant is expected to be decommissioned between 2030 and 2050 and the uncertainties about the appearance of the system on the long-term make it more reasonable for the model to establish the investment in new capacities.

Additionally, between 2030 and 2050 the presence of green H_2 in the city is expected to increase, which can have an impact on the use of this fuel in Rya CHP plant.

4.2.2 Perspective

The focus on the study can differ according to the definition of the optimal case, which in turn depends on the approach followed. Therefore, the investigation is conducted from two distinct perspectives.

The first one, referred to as Societal perspective, is more in compliance with the goals of an academic study, aiming for minimising the costs for the entire energy system and proposing solutions for the energy transition of the city. This approach is carried out with the LP optimisation, interconnecting the City Model and the Rya Model. For a successful investigation from a Societal perspective, the level of detail in the modelling and the choice of the parameters have to be uniform between the two models. Rya CHP plant is then operating in a complete energy system and competing with other technologies to satisfy the demand for electricity and heat.

The other approach, defined as Actor perspective, is focused on maximising the profit for the operator of Rya CHP plant, namely Göteborg Energi, and can lay the foundations for a business case. With this type of investigation, it is possible to establish in which conditions it is profitable for Rya CHP to operate, taking into account the price levels for electricity and district heating. The implementation of a MIP model enables a higher technical resolution on the plant behaviour and the independence from the City Model allows the analysis of more parameters, like the implementation of increasing grid fees for the gas network.

4.2.3 Fuel cost structure

Due to the uncertainty regarding the cost of each fuels in the future, it is necessary to identify cost structure configurations based on the wide range of values found.

The assumed base case is a Low Fuel Cost scenario, where the lower limit of the cost interval is taken for each fuel. This is opposed to a High Fuel Cost case, where the mean value of each cost range is chosen, to observe how the role of the plant in the system changes as it becomes more expensive to run. As biomethane is the fuel currently used in Rya CHP plant, however, the cost of this fuel in the scenarios is used as a benchmark, and the value selected is therefore univocal and not defined by a cost range.

Lastly, as stated earlier, it is possible to perform sensitivity analysis on the impact of fuel costs, by implementing additional costs for different types of fuels or case-specific cost structures.

4.3 Assumptions

The results coming from the models are dependent on, and sometimes limited by, the assumptions made in the construction of the scenarios. Some of these assumptions are common throughout all the analysis, while others are specific to each case and define the nature of the investigation in each scenario.

The aspect of the modelling that requires the largest number of assumptions is the fuels selected, together with their properties. The fuels included in the Rya Model are biomass, consisting of the forest residues powering the bio-steam boiler, and a mix of renewable fuels, which is fed to both the gas turbines and the supplementary firing units. The composition of this mix is variable for each hour, chosen by the model optimisation, and depends on the cost structure of the fuels, including storage parameters, and their availability.

The two classifications of the fuels proposed in Section 3 are useful to identify certain aspects of the integration of the fuels in the model. When it comes to the categorisation based on physical properties, gaseous fuels are delivered to the plant from the existing gas network or other pipeline systems, while liquid fuels require the modelling of a storage on site, with annexed investment costs. The distinction between sources, instead, is relevant because bio-based fuels are purchased from the global market, while electrofuels can be either purchased from the global market or produced in integration with the energy system of the city.

Some bio-based fuels are also characterised by limitations to the fuel availability, depending on either a limited feedstock supply or competition with other sectors, e.g. road transport and aviation.

4.3.1 Fuel costs and fuel availability

In this section the cost for the fuels on the market and their availability limits implemented in the models are described, together with the assumptions and calculations used to determine them.

The costs for biomethane found in literature, as shown in Table 3.1, are set as the benchmark fuel costs for the Low Fuel Cost case. Biomethane is mainly imported from Denmark via the gas network [64], and therefore, assuming this is going to be the case also in 2030, the Danish price for biomethane is selected for the Low Fuel Cost case in 2030. Since in 2050 the European biomethane production is expected to increase, an estimated common market price, reported in Table 3.1, is used in the Low Fuel Cost case.

Biomass costs are uncertain, highly depending on the feedstocks. A lower case cost for forest residues is assumed to be 25 €/MWh in 2030 and 36 €/MWh in 2050.

These values consider a correlation between the prices of biomass and biomethane, increasing linearly from 2030 to 2050.

For the High Fuel Cost cases, in both time frames, the fuel cost for biomass and biomethane are respectively 40 €/MWh and 77 €/MWh, as originally included in the City Model.

Availability limits are defined for biomethanol and e-methanol based on the future plans for production units in Sweden in 2030 and 2050. As in Section 3, the Swedish production of biomethanol in 2030 is expected to be 1.77 TWh. To implement an availability limit in the model, dependent on this value, it is necessary to establish the volume of biomethanol production available for electricity generation. Currently, around 10 % of the bioenergy from forest in Sweden is used for energy purposes [65]. Taking into consideration a similar share for biomethanol consumption, it is possible to assume that not more than 177 GWh/year of biomethanol are going to be available for energy production in 2030. Since Rya CHP is only one of many production plants in Sweden running on bioenergy, this value should be seen as a very upper limit.

Following the same approach for e-methanol, using 10% of the Swedish-produced e-methanol as an upper limit results in 221 GWh/year available in 2030. The availability limits in 2050 for biomethanol and e-methanol are calculated in the same way, starting from the planned production capacities for Sweden in 2050.

Hydrogen is considered an endogenous fuel and is integrated directly in the energy balance of the city model for the Societal perspective. For the Actor perspective the marginal cost of hydrogen is implemented as a hourly cost profile derived from the results of the Societal perspective optimisation. The cost for HVO is constant in the two time frames, due to lack of data of production cost forecasts.

The cost and availability values of the fuels are summarised in Tables 4.3 and 4.4, respectively for 2030 and 2050, as they are included in the models.

Table 4.3: Fuel costs and availabilities implemented in the models in 2030.

Fuel	**Low cost** [€/MWh]	**High cost** [€/MWh]	**Availability** [GWh/year]
Biomass	25	40	-
Biomethane	53	77	-
LBG	78	127	-
Biomethanol	57	117	177
Hydrogen	endogenous	endogenous	-
HVO	96	168	-
E-methanol	78	104	221

Table 4.4: Fuel costs and availabilities implemented in the models in 2050.

Fuel	**Low cost** [€/MWh]	**High cost** [€/MWh]	**Availability** [GWh/year]
Biomass	36	40	-
Biomethane	76	77	-
LBG	55	68	-
Biomethanol	44	99	958
Hydrogen	endogenous	endogenous	-
HVO	96	168	-
E-methane	60	100	-
E-methanol	44	78	338

4.3.2 Logistics and storage

In this section the logistics of the fuel distribution and storage are described. Fuels with similar composition but different feedstock, like biomethane and e-methane or biomethanol and e-methanol, are hereby considered the same fuel.

Methane is fed to Rya CHP plant through the existing gas network, therefore no specific assumptions are needed. Hydrogen can be mixed into the gas grid as well, but there is also the possibility to invest in storage tanks, either within the hydrogen system of the city or on site. HVO, LBG and methanol have each specific characteristic that require different solutions for distribution and storage.

Since Preem is currently producing HVO within Gothenburg [66], this fuel is assumed to be produced close-by in the harbour area, with the possibility of being pumped directly to Rya CHP without any investment in storage capacity.

Biomethanol and e-methanol are assumed to be transported to Rya CHP plant by truck, based on the current plans for production unit placements described in Section 3. The same modality is assumed to be valid for LBG. The truck delivery is scheduled five times a day, at 8.00, 10.00, 12.00, 14.00 and 16.00, assuming that one truck for each fuel can arrive at these hours. With an estimated truck volume of 45 m^3 [67], every delivery is 194 MWh, each, for biomethanol and e-methanol and 262 MWh for LBG.

The storage properties, as included in the Rya Model, are collected in Tables 4.5 and 4.6, respectively for 2030 and 2050. The respective assumptions are summarised in Appendix B.1.

Table 4.5: Storage properties for 2030

Fuel storage	**CAPEX** [€/MWh]	**OPEX** [€/MWh/year]	**Lifetime** [years]	**Discharge rate** [%/size]
LBG tank	60	1.8	25	1
Methanol tank	40	8.8	30	14
Hydrogen tank	48000	531.7	30	100

Table 4.6: Storage properties for 2050

Fuel storage	**CAPEX** [€/MWh]	**OPEX** [€/MWh/year]	**Lifetime** [years]	**Discharge rate** [%/size]
LBG tank	60	1.8	25	1
Methanol tank	40	8.8	30	14
Hydrogen tank	22000	425.4	30	100

4.3.3 Grid fees

Grid fees are implemented for sensitivity analysis in the Actor perspective to evaluate the effect on the fuel mix in the plant and the overall effect on the fuel consumption. This allows to investigate how the role of Rya CHP plant changes when using gaseous fuels from the gas network in southwestern Sweden.

The grid fees affect all fuels distributed via the gas network, and are therefore added to the fuel cost of biomethane in 2030 and of biomethane and e-methane in 2050.

The implementation of grid fees is conducted in two steps, corresponding to a Low Grid Fee case and a High Grid Fee case. The Low Grid Fee case consists in the introduction of the monthly grid prices for year 2024/2025 from Swedegas [68]. For the High Grid Fee case, the grid fees are increased with 49.4%, following the forecasts of Swedegas for the grid fees increase up to year 2029/2030 [69]. The monthly grid fees implemented in the model are shown in Table 4.7 and are used in both time frames. A comparison graph of the monthly price of biomethane resulting in 2030 with the implementation of grid fees, with the prices of biomethanol and e-methanol for the Low Fuel Cost case, is shown in Figure 4.2.

Table 4.7: Monthly grid fee variation used for the Actor Perspective, including a low grid fee case and a high grid fee case (values are similar for 2030 and 2050).

Month	**Low grid fee case** [€/MWh]	**High grid fee case** [€/MWh]
January	18.10	27.04
February	22.30	33.32
March	14.10	21.07
April	9.40	14.04
May	5.10	7.62
June	4.70	7.02
July	4.50	6.72
August	4.50	6.72
September	5.70	8.52
October	11.10	16.58
November	12.50	18.68
December	17.10	25.55

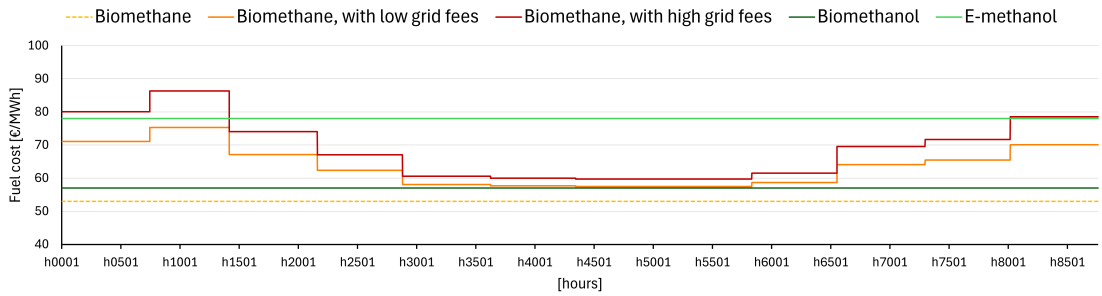

Figure 4.2: Fuel costs in the Actor perspective for the Low Fuel Cost case in 2030, showing hourly price variation of biomethane when adding the grid fee costs, in comparison with the price of biomethanol and e-methanol.

5
Results

5.1 Year 2030

The supply of electricity and heat in Gothenburg in 2030 for the Low Fuel Cost scenario, are illustrated in Figures 5.1 and 5.2, respectively.

Over the year, the most convenient source for electricity is the import from the rest of Sweden, covering more than 90% of the supply. The two existing CHP plants, Rya and Sävenäs, are operating mainly during the winter time, when electricity prices and heat demand are higher, for a total of about 3700 hours each. Rya CHP has total generation of 306 GWh_{el}/year, while Sävenäs CHP only produces 40 GWh_{el}/year. The City Model additionally opts for an investment in a 100 MW_{el} PV park, which corresponds to the maximum capacity allowed by the model.

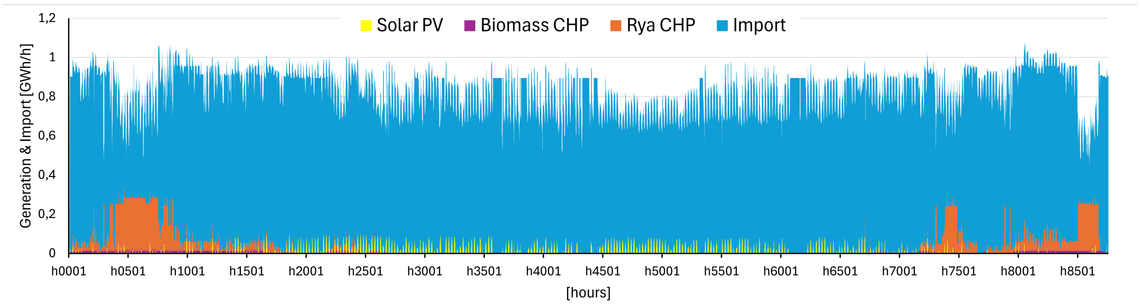

Figure 5.1: Electricity supply profile over one year in the Low Fuel Cost 2030 case, as obtained from the City Model.

In the district heating system around 50% of the demand is fulfilled by waste heat from St1, Preem and Renova. The rest of the heat supply comes from existing installations and the City Model doesn't invest in any additional capacity. Sävenäs CHP and the pellet-fuelled heat-only boilers (HOB) contribute to the base-load production during winter and mid-season with 388 GWh_{heat}/year and 578 GWh_{heat}/year respectively. Rya CHP supplies heat to the system mainly during winter, for a total of 580 GWh_{heat}. Lastly, the heat pumps (HP) and the biogas HOBs are activated when the demand is peaking, providing 145 GWh_{heat}/year and 49 GWh_{heat}/year respectively.

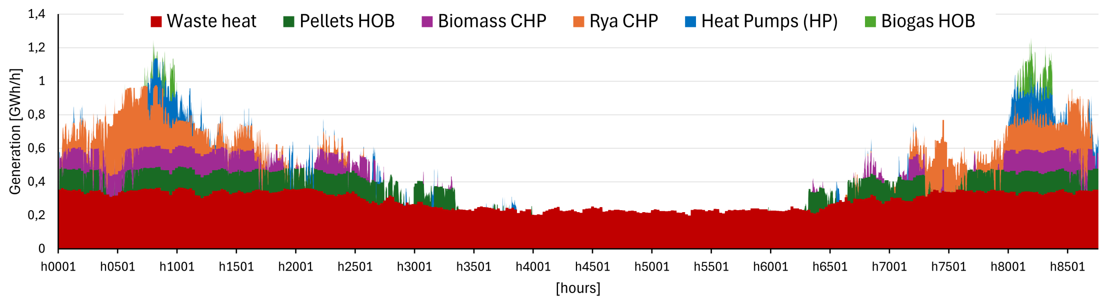

Figure 5.2: District heating supply profile over one year in the Low Fuel Cost 2030 case, as obtained from the City Model.

No investments are made by the City Model in the hydrogen system, since the industrial demand for green H_2 is null in 2030 and the use of the fuel in Rya CHP is not cost-effective considering the high costs of electrolysers and H2 storage tanks.

5.1.1 Increase in fuel costs

The effects of increasing the fuel costs in the system are highlighted in Figure 5.3, describing the differences in terms of electricity and district heating production between the Low Fuel Cost case and the High Fuel Cost case.

The fuel cost increase affects all technologies consuming biomass, alternative renewable fuels, or both. The generation of Rya CHP of 25% for electricity and 20% for district heating. Sävenäs CHP, instead, experiences a decrease of 10% for the both the electricity and district heating production, due to the fixed power-to-heat ratio. Finally, the biogas HOBs, which were the most convenient option for the peak production of heat in the Low Fuel Cost case, produce 33% less.

The response of the system to the lack of electricity supply is to import 174 GWh_{el} more, corresponding to an increase of 3%. The additional amount of electricity imported throughout the year exceeds the decrease in production of the two CHPs, increasing the total supply of electricity to the city by 1%.

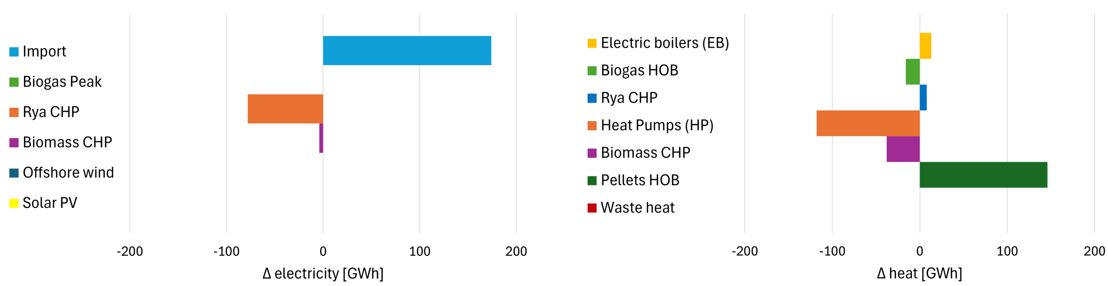

Figure 5.3: Delta production [GWh] of electricity (left) and district heating (right) for the entire year in 2030, going from Low Fuel Cost case to High Fuel Cost case.

On the heating side, instead, the City Model invests in 20 MW_{heat} of additional pellets HOB capacity, increasing the supply from this technology by 25%. Moreover, the HPs supply 6% more heat and an investment in 13 MW_{heat} of electric boilers (EB) is made, to compensate the missing peak production.

The differences between the dispatch of Rya CHP in the Low Fuel Cost case and in the High Fuel Cost case are described in Figures 5.4 and 5.5, representing respectively electricity and district heating production of the plant over one year.

In the High Fuel Cost case, Rya CHP visibly assumes a more peaking behaviour compared to the Low Fuel Cost case. The operation of the plant is mainly confined to the winter time, during hours with higher electricity prices. The generation of electricity is more volatile and reaches maximum capacity less often compared to the Low Fuel Cost case. Although the district heating production is more limited and with lower peaks as well, Rya CHP still constantly delivers heat to the city at the beginning and at the end of the year also in the High Fuel Cost case.

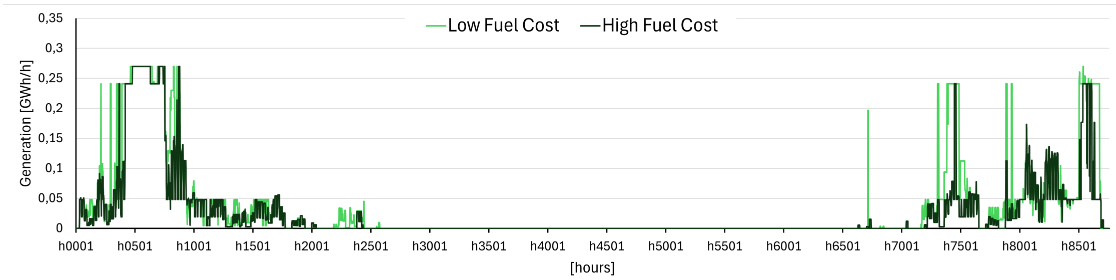

Figure 5.4: Electricity supply profile over one year for Rya CHP in 2030 for both Fuel Cost cases, as obtained from the City Model.

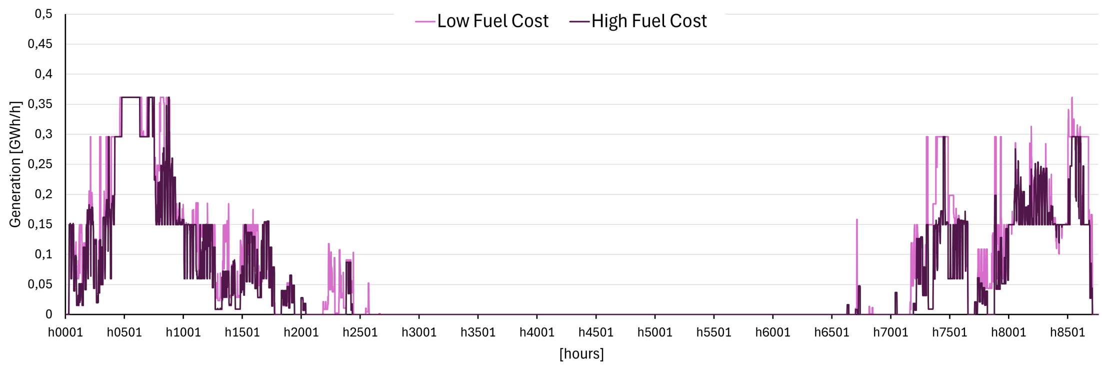

Figure 5.5: District heating supply profiles over one year for Rya CHP in 2030 for both Fuel Cost cases, as obtained from the City Model.

In both cases, Rya CHP is fuelled only with biomass (bio-steam boiler) and biomethane (gas turbines and supplementary firing). Even with the fuel cost increase, biomethane is the cheapest of the GT fuels and is available to satisfy the entire fuel demand for the optimised electricity and heat production. While in the Low Fuel Cost case the consumption of biomass and biomethane is similar, 332 GWh_{fuel} and 335 GWh_{fuel} respectively, the increase in fuel costs has a greater impact on the use of biomethane, reduced by 44%, compared to the one of biomass, reduced by 17%.

The operation of the plant over the year is described for each component by Figures 5.6 and 5.7, showing respectively the electricity generation and the district heating production in both the cases presented earlier.

The gas turbines are activated as peaking technology, producing electricity and steam during instances when the electricity price is high. This behaviour is emphasised at the end of the year, when the electricity price is more volatile. In the High Fuel Cost case all three gas turbines are activated more sporadically compared to Low Fuel Cost case, except for 300 hours of consecutive maximum load operation at the beginning of the year. The electricity generation of the steam turbine, instead, highly depends on the steam generation of the bio-steam boiler and closely follows its operation.

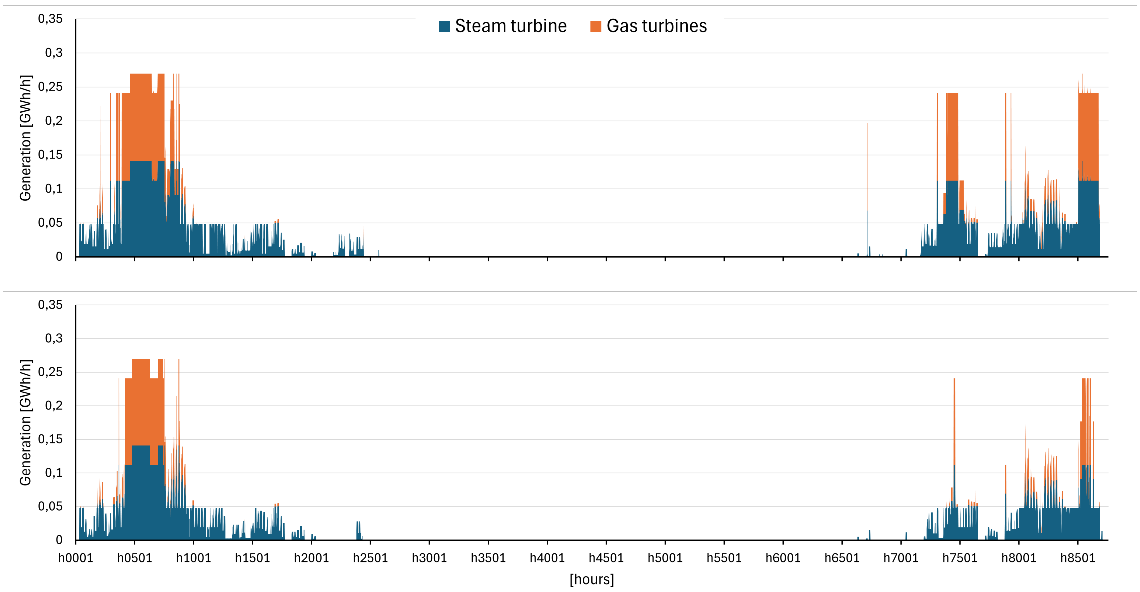

Figure 5.6: Electricity generation for each component over one year in 2030, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

The bio-steam boiler runs for almost the entire winter and sporadically during the mid-season, driven by the heat demand. The behaviour of the bio-steam boiler changes when increasing the fuel costs, reducing its operational time from 3534 hours/year to 3089 hours/year and running at full load approximately 50% of the time. Similarly to the steam turbine generation, also the production of heat from the steam turbine condensers and from the direct condensers depend on the operation

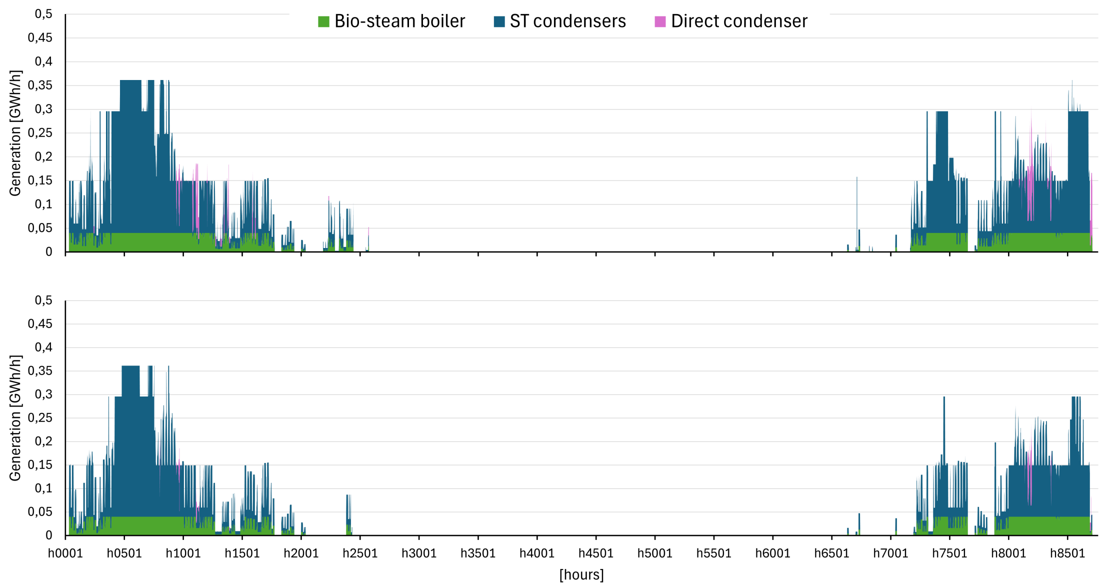

Figure 5.7: District heating production for each component over one year in 2030, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

of the bio-steam boiler. In some moments, when the electricity price is low and the heat demand is high, the steam coming from the bio-steam boiler is almost entirely diverted to the direct condenser and the plant produces almost exclusively heat. These events are fewer and shorter in the High Fuel Cost case, since the production of heat only is less cost-effective with more expensive fuels.

5.1.2 Shift of perspective: from Society to Actor

The outcome of the cost optimisation from the Actor perspective is highlighted in Figure 5.8, representing the differences in electricity and district heating production between the two perspectives in both Low Fuel Cost case and High Fuel Cost case.

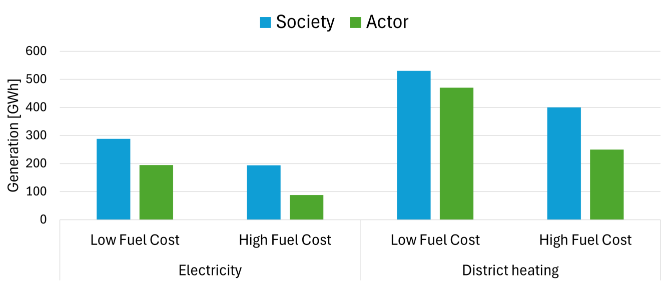

Figure 5.8: Comparison between Societal and Actor perspective in 2030, taking into account electricity and district heating production in both Low Fuel Cost and High Fuel Cost cases.

With the shift of perspective, Rya CHP plant is running only when it is profitable, reacting directly to the electricity price from SE3 and the marginal cost of heat from the City Model. This results in an overall decrease in electricity generation in the Actor perspective, with a value of 195 GWh_{el}/year, corresponding to 68% of the Societal base case. The impact of the fuel cost increase is even more visible with a profit-maximising approach, since Rya CHP generates only 88 GWh_{el}/year.

The total yearly district heating production is approximately the same for the two perspectives in the Low Fuel Cost case. However, the heat supply decreases significantly more when increasing the fuel costs in the Actor perspective, with a reduction of 47%, compared to the Societal perspective, where the reduction was 25%.

The dispatch of the gas turbines decreases drastically when shifting from the Societal to the Actor perspective. The largest differences in the dispatch of the gas turbines between the Societal and Actor perspective are visible at the end of the year, when the price of electricity is lower, as shown in Figure 5.9.

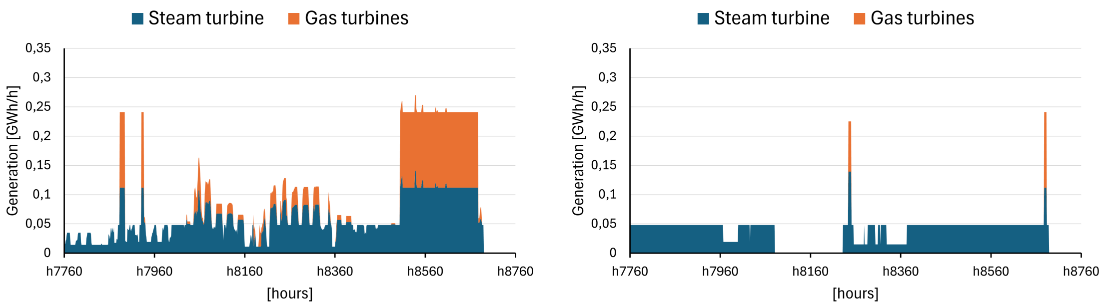

Figure 5.9: Electricity generation over the last 1000 hours of the year in Low Fuel Cost 2030 case, from Societal perspective (left) and Actor perspective (right), as obtained from the Rya Model.

The deviation of steam generated from the bio-steam boiler to the direct condenser is more evident as well, as shown in Figure 5.10, highlighting how the marginal cost of heat is the leading source of revenue at the end of the year.

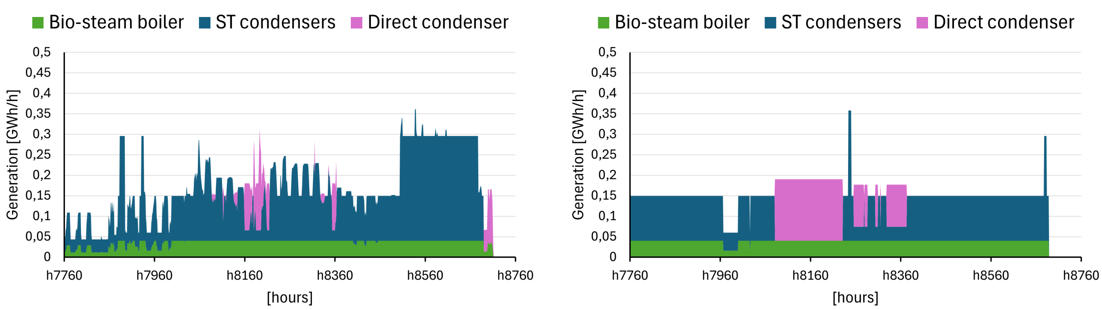

Figure 5.10: District heating production over the last 1000 hours of the year in Low Fuel Cost 2030 case, from Societal perspective (left) and Actor perspective (right), as obtained from the Rya Model.

In the High Fuel Cost case, the behaviour observed is even more prominent and results in very limited production of electricity or heat at the end of the year, as shown in Figure 5.11. Following the Societal approach, Rya CHP is often operating in the time interval observed, driven by the heat demand of the city. Similarly to the Low Fuel Cost case, shifting to the Actor perspective shows in which instances the City Model forces the plant to operate, even though it would be unprofitable.

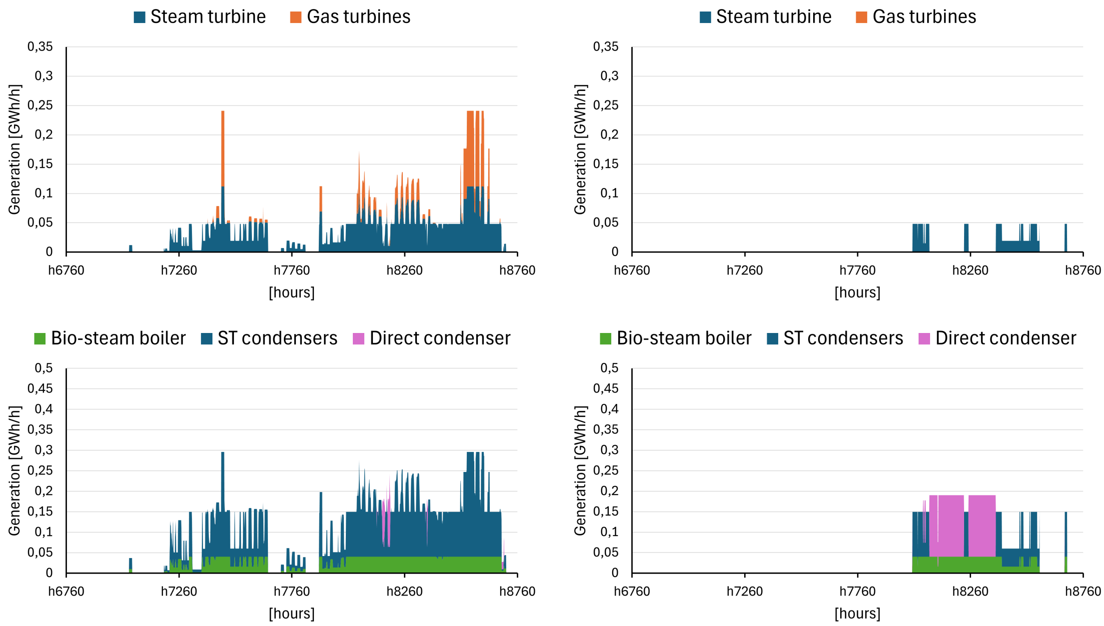

Figure 5.11: Electricity (above) and district heating (below) production over the last 2000 hours of the year in High Fuel Cost 2030 case, from Societal perspective (left) and Actor perspective (right), as obtained from the Rya Model.

Moreover, since in the Actor perspective the behaviour of the components is regulated by binary variables, it is possible to identify the exact number of start-ups and operating hours, represented in Figures 5.27 and C6 (in Appendix C) respectively. In 2030, the gas turbines start 7 times in the Low Fuel Cost case and 3 times in the High Fuel Cost case, leading to a decrease in the overall electricity generation of the plant in the High Fuel Cost case. The gas turbines also run a very limited number of hours, around 400 in the Low Fuel Cost case and 200 in the High Fuel Cost case, but operate mostly at full load level in both cases.

5.1.3 Sensitivity analysis: impact of grid fees

In this section the impact of gas network fees on the operation of the plant is analysed from the Actor perspective. Increasing the cost of the fuels distributed via the gas network with grid fees, as presented in Section 4.3.3, allows to perform a sensitivity analysis on the fuel cost structure.

The implementation of grid fees leads to a higher cost of biomethane in 2030, resulting in a reduction in the use of biomethane and in the overall fuel consumption in the gas turbines, as shown in Figure 5.12. The total GT fuel consumption reduces from 169 to 93 GWh_{fuel}/year when implementing the High Grid Fee case, corresponding to a reduction with 43%.

In the Low Fuel Cost case with Low Grid Fee case, biomethane is more expensive than biomethanol throughout the entire year, not considering the storage costs. Biomethanol is therefore used as primary fuel, with a complementary use of biomethane due to logistics limitations, such as the storage level of methanol. Furthermore, increasing the grid fee in the Low Fuel Cost case leads to an even higher cost for biomethane, with an additional decrease in fuel consumption and the introduction of e-methanol in the fuel mix, as shown in Figure 5.12.

E-methanol has significantly higher cost than biomethanol, however due to logistic limitations, it is used to fulfil the needed GT fuel consumption during peaking hours in the beginning of the year. E-methanol is purchased in the beginning of the year when its price is lower than biomethane with the High Grid Fee case, as shown in Figure 4.2. Despite biomethane with the High Grid Fee case has the highest cost of the three fuels used during the peaking hours at the beginning of the year, it is profitable to use it when the electricity price is high.

In the High Fuel Cost case, the implementation of grid fees does not impact the fuel mix, and biomethane is the only fuel used in the gas turbines. However, the overall fuel consumption is reduced as the grid fees increase, as shown in Figure C7 in Appendix C.

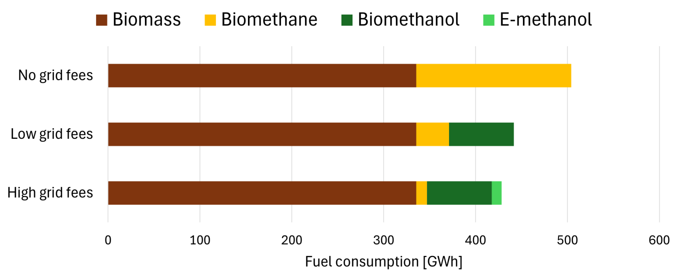

Figure 5.12: Fuel consumption in the Low Fuel Cost 2030 case from the Actor perspective, with no, low and high grid fees.

5.2 Year 2050

The production profiles of electricity and district heating in the energy system of 2050 are illustrated respectively in Figures 5.13 and 5.15 for the Low Fuel Cost case.

The transmission capacity is increased from 895 MW_{el} in 2030 to 1545 MW_{el} in 2050, but with the electricity demand increasing as well, the grid connection is still not enough to fulfil the whole demand, and thus, more electricity generation within the city is required. As described previously, it is assumed that of all capacity that is installed today, Rya CHP is the only power plant that will remain in the system by 2050, with an increase GT capacity. The resulting generation of the plant in 2050 is 396 GWh_{el}/year and 659 GWh_{heat}/year. This corresponds to 29% more electricity and 14% more district heating compared to 2030.

Similarly to 2030, the City Model invests in 100 MW_{el} of PV in 2050. However, due to the increased electricity demand and the introduction of hydrogen demand for the industry, the results of the optimisation show a prominent investment in offshore wind, with a capacity of 840 MW_{el}, absent in 2030.

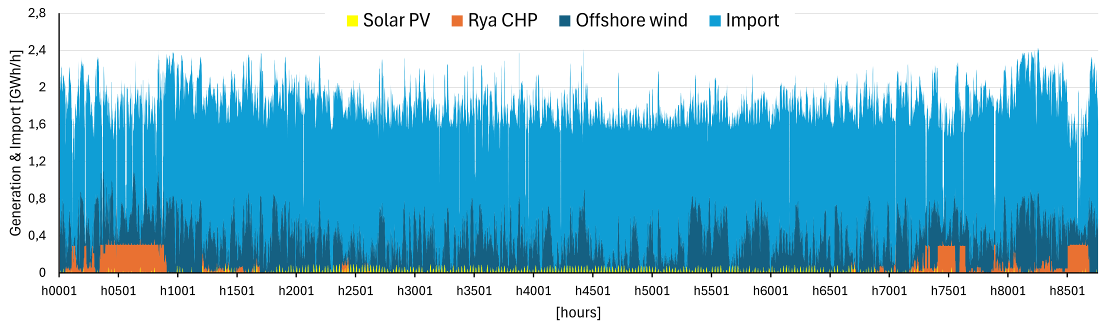

Figure 5.13: Electricity supply profile over one year in the Low Fuel Cost 2050 case, as obtained from the City Model.

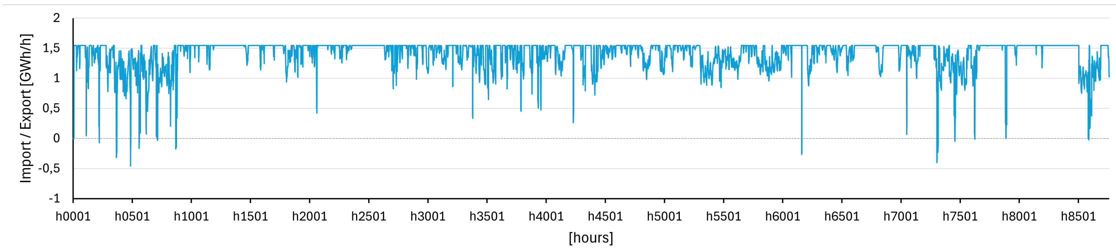

Figure 5.14: Import (+) and export (-) of electricity over one year in the Low Fuel Cost 2050 case, as obtained from the City Model.

In Figure 5.14, it is possible to observe instances in which the system is exporting electricity, i.e., negative values on the y-axis, due to the coincidence of good wind conditions and high electricity prices. The simultaneous production at almost full capacity of both Rya CHP and wind farms can, in fact, exceed the electricity demand of the city.

The district heating system in 2050 has a similar layout to the one of 2030, with waste heat covering around 60% of the supply. However, since Rya CHP plant is the only technology defined as existing capacity, the model can freely choose how to fulfil the rest of the heat demand, previously met by Sävenäs CHP and by the pellet HOB.

The solution of the City Model includes investments in pellet-fuelled HOB and HP, operating during both winter and mid-season. The HOB is similar in size to the one in the 2030 scenarios, with a capacity of 126 MW_{heat}, while the investment in HP is 124 MW_{heat}, 22% smaller than the existing HP in 2030, but operating more frequently. Lastly, the peak demand is satisfied by the EB, with a capacity of 254 MW_{heat}, whereas in 2030 it was supplied by biogas HOB and HP.

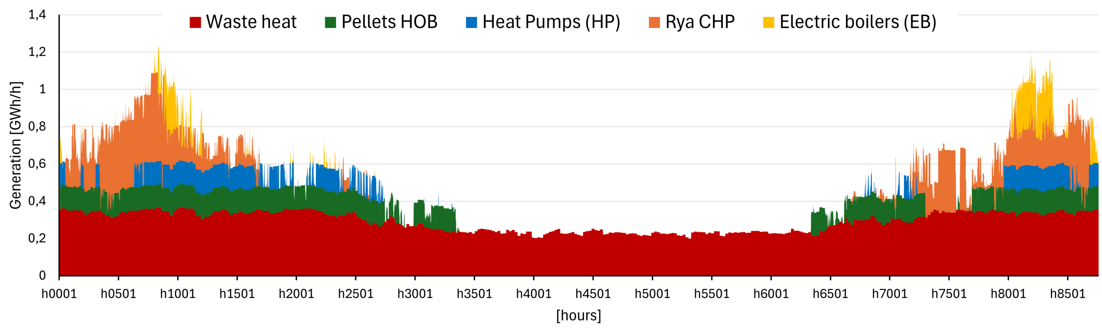

Figure 5.15: District heating supply profile over one year in the Low Fuel Cost 2050 case, as obtained from the modelling.

5.2.1 Increase in fuel costs

The differences in terms of electricity and district heating production between the Low Fuel Cost and High Fuel Cost cases are highlighted in Figure 5.16.

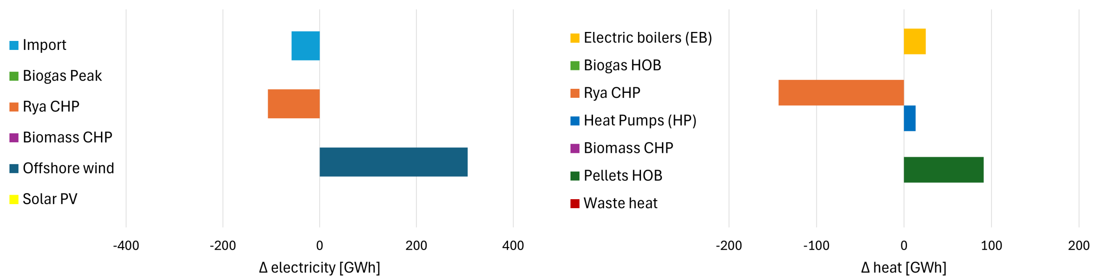

Figure 5.16: Delta production [GWh] of electricity (left) and district heating (right) for the entire year in 2050, going from Low Fuel Cost case to High Fuel Cost case.

The fuel cost increase affects mainly Rya CHP, the only technology consuming biomass and alternative renewable fuels. As an outcome, in the High Fuel Cost case the plant produces 289 GWh_{el}/year and 516 GWh_{heat}, corresponding to a reduction of 27% and 23% respectively compared to the Low Fuel Cost case.

Because of the limitation in grid transmission capacity, the demand for electricity needs to be fulfilled without increasing the import. The cheapest option for the City Model is to produce more from offshore wind. Since wind is not dispatchable, the solution is to invest in 10% more capacity, resulting in an equal increase in the electricity supply from this technology over the entire year.

On the heating side, instead, the missing supply, previously provided by Rya CHP, is split between HOB, HP and EB, with a growth of 14%, 10% and 13% respectively when increasing the fuel costs.

Similarly to 2030, the dispatch of Rya CHP for the generation of electricity assumes a more peaking behaviour with an increase in fuel costs, as illustrated in Figure 5.17. Additionally, the plant operates more often at higher loads in the Low Fuel Cost case than in the High Fuel Cost case. Compared to 2030, however, Rya CHP produces electricity at maximum load for more hours also in the High Fuel Cost case, favoured by the larger number of instances with high electricity price.

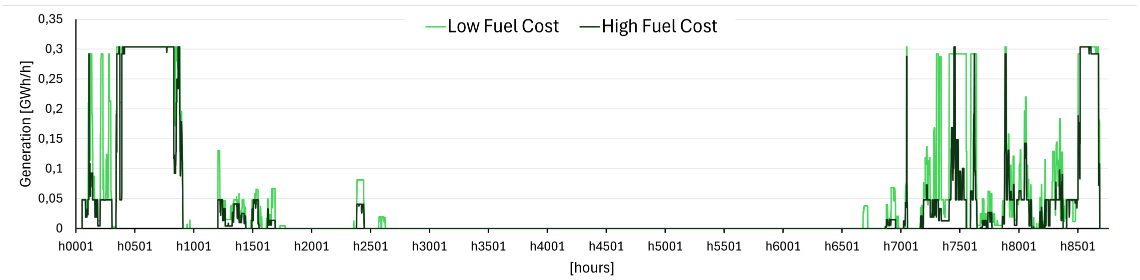

Figure 5.17: Electricity supply profile over one year for Rya CHP in 2050 for both Fuel Cost cases, as obtained from the City Model.

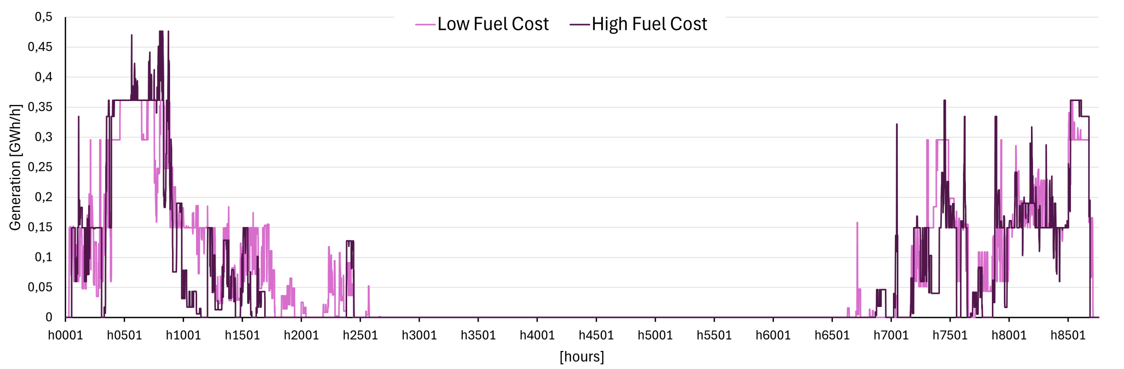

Figure 5.18: District heating supply profile over one year for Rya CHP in 2050 for both Fuel Cost cases, as obtained from the City Model.

The heat production of Rya CHP also has a different profile when increasing the fuel costs, as visible in Figure 5.18. The load levels are lower, especially in the mid-season, decreasing the overall district heating production of the plant. Compared to 2030, Rya CHP supplies heat to the system for a fewer number of hours, operating mostly during the winter time and sporadically in spring and autumn.

In 2050, biomethane is the only fuel with price increase compared to 2030, leading to Rya CHP using other fuels as well, as shown in Figure 5.19. In the Low Fuel Cost case, the mix of fuels used in gas turbines and supplementary firing is biomethanol, e-methanol, LBG and e-methane, with a total consumption of respectively 180 GWh_{fuel}/year, 99 GWh_{fuel}/year, 141 GWh_{fuel}/year and 160 GWh_{fuel}/year. In the High Fuel Cost case, the price increase for biomethane is substantially smaller than for the other fuels, making it the second cheapest option for the use in gas turbines after LBG. The fuel consumption over the year in the High Fuel Cost case is 124 GWh_{fuel} of LBG and 249 GWh_{fuel} of biomethane.

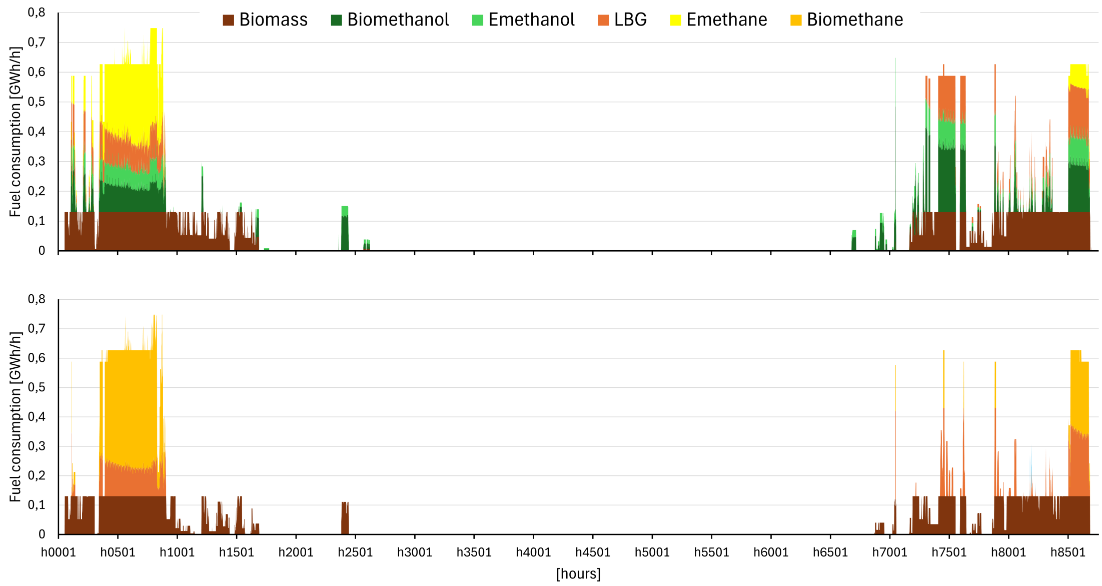

Figure 5.19: Fuel consumption over one year in 2050, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

Due to the storage and logistics constraints implemented, Rya CHP is using up to the fourth cheapest gas turbine fuel option to provide the optimised electricity and district heating production to the energy system. The amount of methanol and LBG used in each case is, in fact, dependent on the storage level of the respective storages throughout the year, illustrated in Figure 5.20.

In the Low Fuel Cost case, the model invests in storage capacities as large as the maximum size limit, namely 30 GWh for LBG and 50 GWh for methanol. In the High Fuel Cost case, instead, the only fuel storage needed is for LBG, with a 30

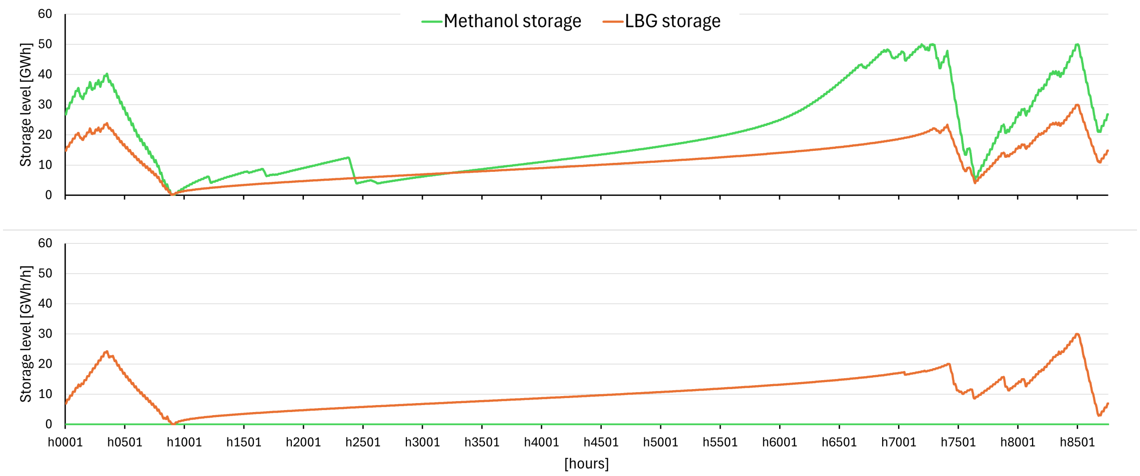

Figure 5.20: Storage level for different fuels over one year in 2050, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

GWh installation. The storage sizes are a limiting factor for the choice of the fuel mix in both cases in the peaks of operation, especially at the end of the year.

The fuel delivery schedule, described in Section 4.3, has an impact on the composition of the fuel mix as well, affecting how quickly the storages are charged. The storage charge is a bottleneck at the end of the winter, when the plant needs to run on e-methane, in the Low Fuel Cost case, or biomethane, in the High Fuel Cost case, since the storage level of the liquid fuels doesn't reach the size of the tank.

The bio-steam boiler runs on biomass, which has increased in price linearly with biomethane from 2030 to 2050 in the Low Fuel Cost case. However, since the biomass price in the High Fuel Cost cases is the same in both years, the fuel cost increase is smaller in 2050 compared to 2030. Despite this increase being small, the operational hours of the bio-steam boiler decreases of 10% between the Low Fuel Cost case and High Fuel Cost case. In addition, the production level of the bio-steam boiler is more variable, with consequences on the operation of the steam turbine, its subsequent condensers and the direct condenser.

The bio-steam boiler operation is driven by the heat demand and is almost continuous throughout the winter season in the Low Fuel Cost case, as shown in Figure 5.21. Compared to 2030, there is notable reduction in the operating hours of the bio-steam boiler, despite the total generation of district heating remains relatively stable. In 2050, the plant produces heat for a fewer hours of operation with higher load levels, rather than over the majority of winter and mid-season. In some of these instances, the heat supply requested from Rya CHP is such that the supplementary firing units are activated, the steam is completely diverted to the direct condenser and Rya CHP operates like a heat-only plant.

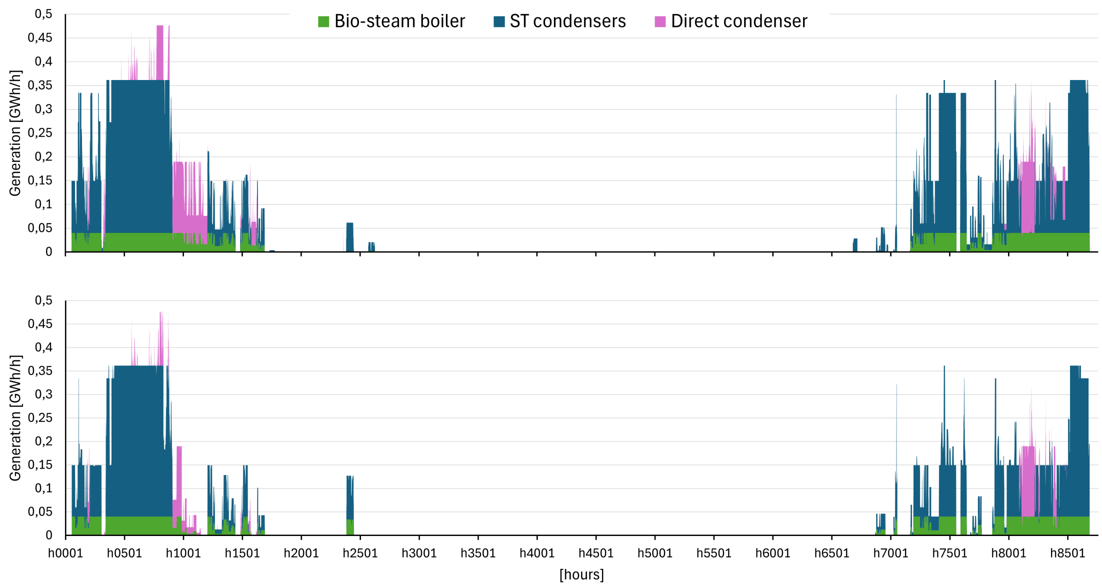

Figure 5.21: District heating generation for each component over one year in 2050, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

The behaviour of the plant in 2050 is justified by the rest of the district heating system. As observed in Figure 5.15, the share of heat previously supplied by Rya CHP plant is largely covered by HOB and HP, which serve as base-load for the system during the winter months and in the mid-season. The abundance of electricity-to-heat technologies in the system, as their operation is highly dependant on the cost of electricity, makes Rya CHP the main heat supplier when the electricity price is higher. Rya CHP, then, transitions to the role of a peak-producer for heat generation, especially in the High Fuel Cost case.

The electricity generation of the plant, represented in Figure 5.22, has similar characteristics to the heat production. The steam turbine follows the operation of the bio-boiler, even though there are instances when it doesn't run in favour of the direct condensation of the steam, as mentioned before.

The gas turbines are instead running consistently only three times, reduced to two with the fuel cost increase, at the beginning and at the end of the year, activating sporadically in the autumn. The high electricity price events, however, make it so that when the gas turbines are running, they produce electricity mostly at full load. Comparing the Low Fuel Cost case in 2030 and 2050, the gas turbines run respectively 1287 hours/year and 1730 hours/year, of which around 50% coincidences with full load hours in both time frames. When considering the gas turbines in the High Fuel Cost case in 2050, full load operation increases to 65% of the total.

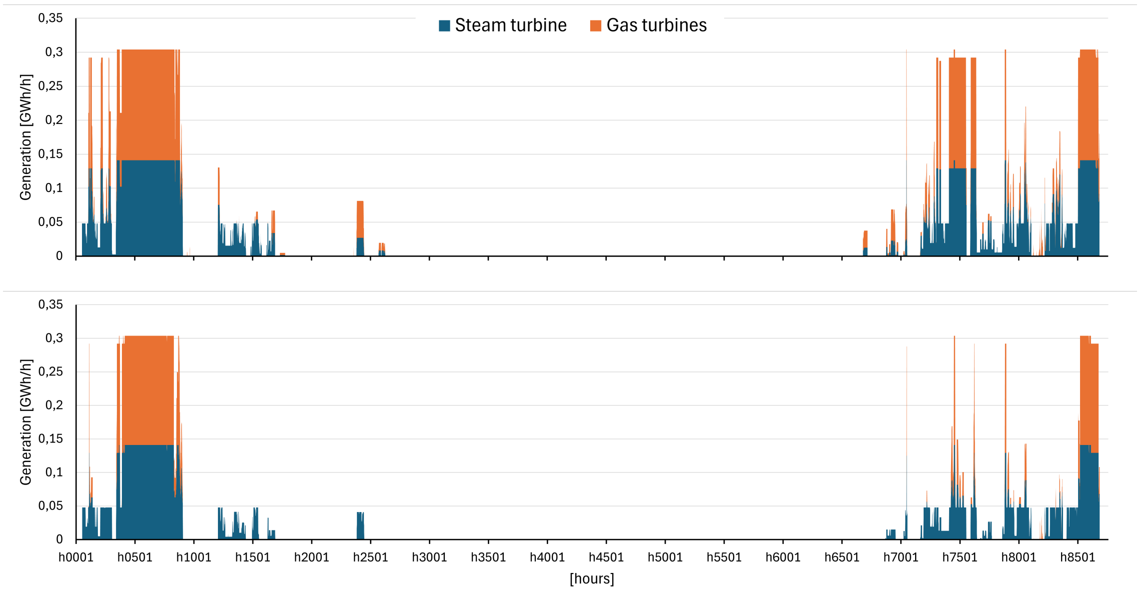

Figure 5.22: Electricity generation for each component over one year in 2050, in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

5.2.2 Shift of perspective: from Society to Actor

In 2050, the yearly production of both electricity and district heating is significantly higher in the Actor perspective compared to the Societal perspective, compared to 2030, when the effect was the opposite when going to the Actor perspective. In the Low Fuel Cost case, the plant generates 541 GWh_{el}/year and 751 GWh_{heat}/year. In contrast with 2030, the plant has a similar reaction to the fuel cost increase between the two perspectives, as shown in Figure 5.23. The reduction of electricity generation from the Low Fuel Cost case to the High Fuel cost case in 2050 is approximately 25% in both perspectives, while the district heating production sees a decrease of 19% in the Actor perspective and 23% in the Societal perspective. Increasing the fuel costs in the Actor perspective in 2050, has a lower effect on the electricity generation compared to 2030, where the reduction was 44%.

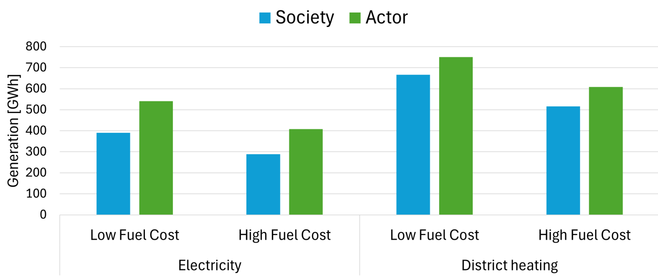

Figure 5.23: Comparison between Societal and Actor perspective in 2050, taking into account electricity and district heating production in both Fuel Cost cases.

Following just the electricity price and the marginal cost of heat, the behaviour of Rya CHP analysed from the Actor perspective accentuates the trends already visible in the results from the Societal perspective. The dispatch of each component assumes generally a step-function behaviour, visible in Figure C3 in Appendix C, either not running or operating at almost full load.

Maximizing the profit for the plant instead of minimizing the total system costs, the model decides to run the entirety of Rya CHP plant for long time periods, characterised by high electricity price, and completely shut down when the electricity prices are lower.

The Actor approach allows for the detailed investigation of different trends across the scenarios, comparing 2030 with 2050 and the Low Fuel Cost case with the High Fuel Cost case.

The correlation between the behaviour of the gas turbines and the SE3 electricity price can be seen by looking at the operation of Rya in the form of duration curves, as in Figure 5.24. In all four duration curves, it is clearly visible that the gas turbines operate mainly above a certain electricity price. The generation of the gas turbine is the key indicator of electricity-driven operation of the plant, since the steam turbine is running in correlation with the bio-steam boiler and with the condensers and is often producing electricity even though the plant is focused on supplying heat.

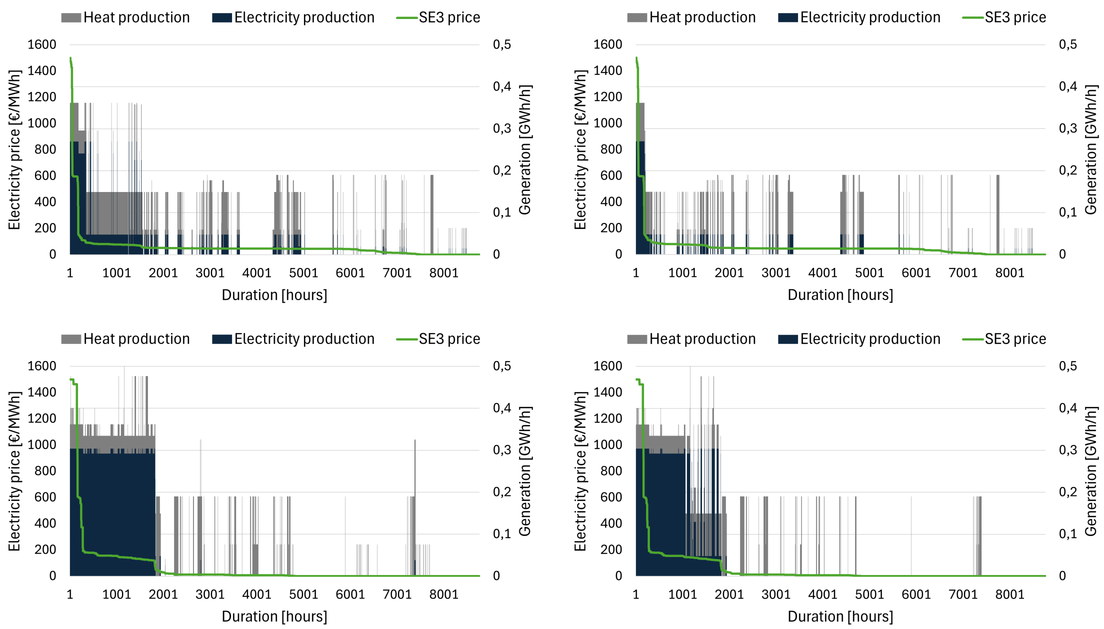

Figure 5.24: Duration curves of the production of electricity and heat in relation to the SE3 electricity price for the Actor perspective. The cases on the same row are set in the same year, respectively 2030 (above) and 2050 (below), while the columns represent the fuel cost cases, Low Fuel Cost (left) and High Fuel Cost (right).

The threshold electricity price is the one at which the revenue is higher than the cost of the fuels used and, therefore, is representative for the conditions of each scenario. In 2030, it is 104 €/MWh$_{el}$ in the Low Fuel Cost case and 143 €/MWh$_{el}$ in the High Fuel Cost case. In 2050, the values increase to 110 €/MWh$_{el}$ in the Low Fuel Cost case and 146 €/MWh$_{el}$ in the High Fuel Cost case, corresponding respectively to 6% and 2% more. Looking at the implementation of higher fuel costs, instead, the increase is 27% in 2030 and 25% in 2050. Therefore, the change of time frame doesn't affect the threshold price as much as the fuel cost increase.

The major distinction between 2030 and 2050, as mentioned, is not the value of the switching point, but rather the amount of instances when the electricity price is higher or equal. Due to the longer duration of high electricity price in 2050 compared to 2030, the gas turbines run more often and the plant operation is more electricity-focused. This correlates with the number of hours in which Rya CHP operates at full load, analysed in more detail later.

The duration curves in Figure 5.24 show that the gas turbine operate also in instances when the electricity price is not very high. In these hours, the marginal cost of heat is high enough to cover the operational costs and generate profit, so the gas turbines operate heat-driven.

The pattern of the duration curves is not defined as clearly for results from the Societal perspective, represented in Figure C5 in Appendix C for reference. This is due to the reduced technical resolution and the operation of the plant not being bound only to the cost of electricity.

Nevertheless, the differences between the two perspectives can be analysed with the comparison of the duration curves for the marginal cost of electricity and for the electricity price of SE3, illustrated in Figure 5.25 for both 2030 and 2050.

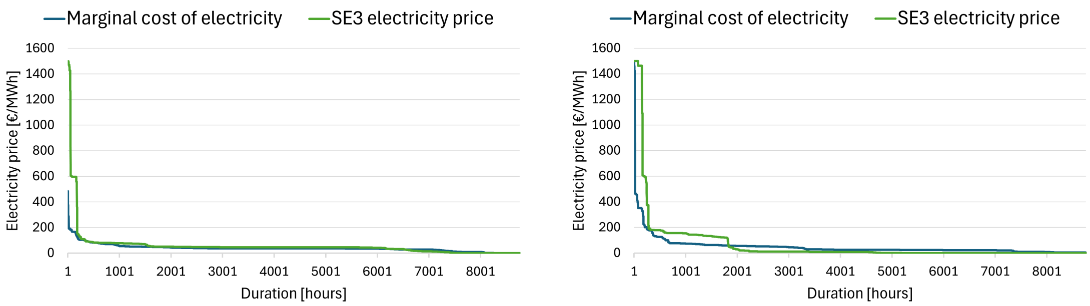

Figure 5.25: The marginal cost of electricity from the Societal perspective for the Low Fuel Cost case and SE3 electricity price for 2030 (left) and 2050 (right).

In both time frames, the marginal cost has a more even hourly distribution, transitioning smoothly from high to low costs, as opposed to the electricity price which changes more drastically. The maximum value for the marginal cost of electricity, however, differs between the two time frames being approximately 500 €/MWh in 2030 and in 1500 €/MWh in 2050. As a consequence, in 2030 the marginal cost of electricity tends to be lower or equal to the SE3 electricity price throughout the entire year. In 2050, instead, the electricity price is higher for around 2000 hours, but a crossover point is clearly visible for when the marginal cost becomes higher than the electricity price. This value corresponds to the electricity price at which the gas turbines start operating in the Low Fuel Cost case in 2050, as in Figure 5.24.

The longer duration of high electricity price events in 2050 allows Rya CHP to operate longer than in 2030, in the Actor perspective. In the Societal perspective, instead, the operation of the plant is favoured in instances where the marginal cost of electricity is lower than the electricity price, meaning that for the system running Rya CHP is more cost-effective than importing from SE3. At the same time, the plant keeps operating also when the marginal cost decreases, if supply of electricity and heat are needed.

The behaviour of Rya CHP is well represented also by the variable power-to-heat ratio of the plant, determining how much electricity is generated compared to the district heating. In general, the power-to-heat ratios are higher in 2050, as shown in Figure 5.26, meaning that the operation of Rya CHP is more focused on the electricity generation. There are notable instances, however, where the power-to-heat ratio has a value in 2030, but not in 2050. This corresponds to certain periods of 2050 when the coincidence of high heat demand and low electricity price makes the plant supply only to the district heating system.

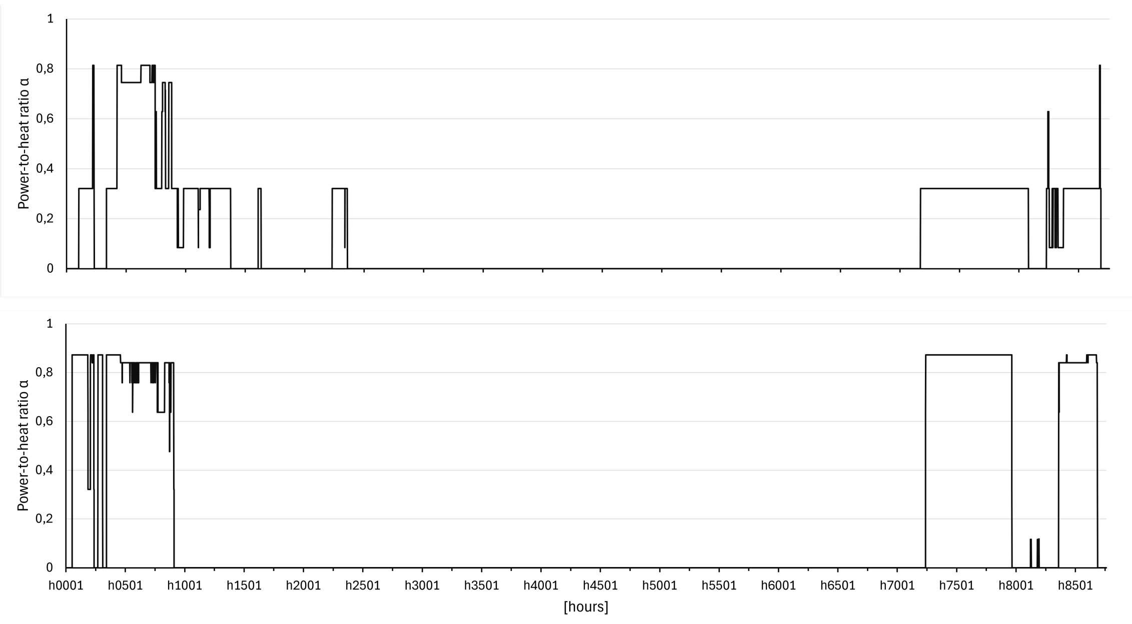

Figure 5.26: Power-to-heat ratio profiles from the Actor perspective for 2030 (above) and 2050 (below), for the Low Fuel Cost cases.

The differences in behaviour for each component of Rya CHP is highlighted by the number of start-ups, shown in Figure 5.27, and by the number hours at which the plant operates, reported in Figure C6 in Appendix C.

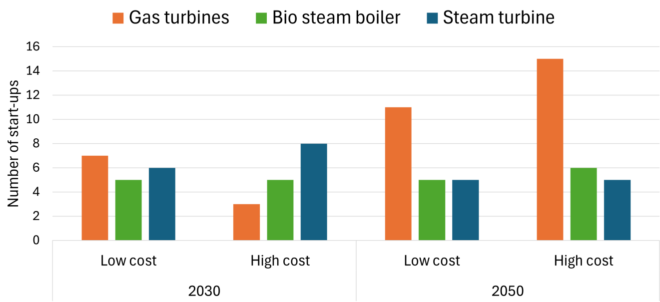

Figure 5.27: Number of start-ups for each component in the Low Fuel Cost and High Fuel Cost cases, in both time frames from the Actor perspective.

The gas turbines tend to start more frequently in 2050 compared to 2030, with 5 more instances in the Low Fuel Cost case and 12 more in the High Fuel Cost case. With the increase in fuel costs, the number of operating hours for the gas turbines decreases, as well as the one at full load. Being more expensive to run, they deviate from constant electricity generation and assume a more volatile behaviour in the autumn, which explains also the increased number of start-ups in 2050. The steam turbine start up less in 2050 compared to 2030 and, although the hours of operation at full load increase in 2050, it rarely operates at maximum capacity. The bio-steam boiler, on the other hand, is producing steam and district heating mostly at full load in both time frames, with a similar amount of start-ups throughout all cases.

5.2.3 Sensitivity analysis: impact of grid fees

In this section the impact of grid fees added to biomethane and e-methane is analysed from the Actor perspective for 2050.

In the Low Fuel Cost case several fuels are used in the gas turbines of Rya CHP throughout the year. The effect of the implementation of grid fees on the fuel consumption of the plant is represented in Figure 5.28. Comparing the Low Fuel Cost case without grid fees, with Low Grid Fee cost and High Grid Fee cost, LBG, biomethanol and e-methanol are unchanged between the cases and the respective yearly consumption is 162 GWh, 148 GWh and 98 GWh. The consumption of e-methane is reduced of 39% in the Low Grid Fee case and additionally of 28% in the High Grid Fee case. However, in the High Grid Fee case, part of the reduction in e-methane consumption is due to the use of 39 GWh of hydrogen, corresponding to 7% of the total GT fuel mix. The size of the hydrogen storage installation needed in this case is 0.23 GWh. Hydrogen is purchased when the marginal cost, obtained from the City Model, is low and stored until needed in the plant. Nevertheless, hydrogen is not used when implementing Low, nor High Grid Fee cases in the High Fuel Cost case for the Actor perspective, as shown in Figure C8 in Appendix C.

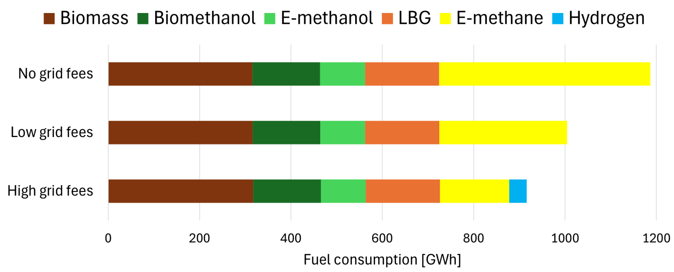

Figure 5.28: Fuel consumption in the Low Fuel Cost 2050 case from the Actor perspective, with no, low and high grid fees.

5.2.4 Sensitivity analysis: impact of storage size

The limitations set for the maximum size of each fuel storage are proven to have a great impact on the results for 2050. In the Low Fuel Cost case, especially, this assumption leads to Rya CHP using up to the fourth cheapest fuel option. The following sensitivity analysis looks into the optimal choice of fuel mix without any limitations regarding the fuel storage investments.

The total production of electricity and district heating of the plant in this scenario is 450 GWh_{el} and 744 GWh_{heat}, corresponding to an increase of 15% and 12% respectively compared to the Low Fuel Cost case in 2050 with storage size limitations. The generation profiles over the year are reported in Figure C9 in Appendix C.

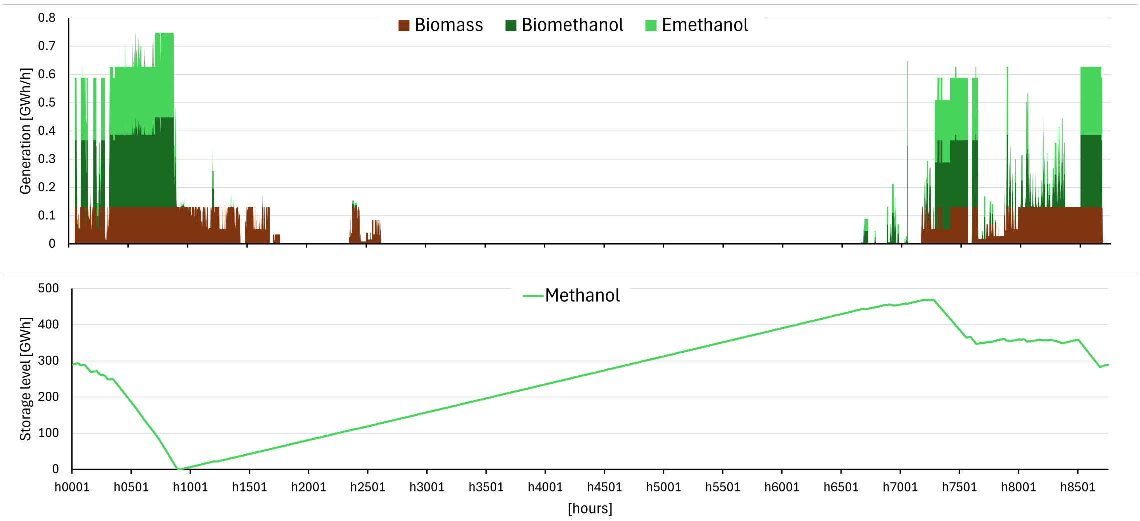

Figure 5.29: Fuel consumption (above) and storage level (below) over one year in the Low Fuel Cost 2050 case without storage size limitations, as obtained from the Rya Model.

The fuel consumption of Rya CHP is represented in Figure 5.29, as well as the storage level throughout the year. The most cost-effective solution for the model in this case is to invest only in methanol storage tanks and purchase biomethanol and e-methanol, almost in equal amounts, being limited by the delivery schedule of each fuel. The size of the methanol storage installed is 470 GWh, corresponding to more than 100000 m^3, similar in volume to the storage of a small refinery.

The investment in such a large fuel storage could be regarded as excessive, while the 50 GWh limitation could be considered too restrictive. Further study can then take into account the investigation of the appropriate dimension for a fuel storage installation in the area.

5.2.5 Sensitivity analysis: waste heat availability

As mentioned in the description of the City Model in Section 4.1, the availability of the waste heat supply can decrease between 2030 and 2050, due to the lower plastic fraction in the incinerated waste and the phase-out from fossil fuels in the refineries. The entity of this reduction in previous iteration of the City Model, such as in Rosén et al. [62], was 70%.

The results of the optimisation in the Low Fuel Cost 2050 case with reduced industrial excess heat are shown in Figure 5.30.

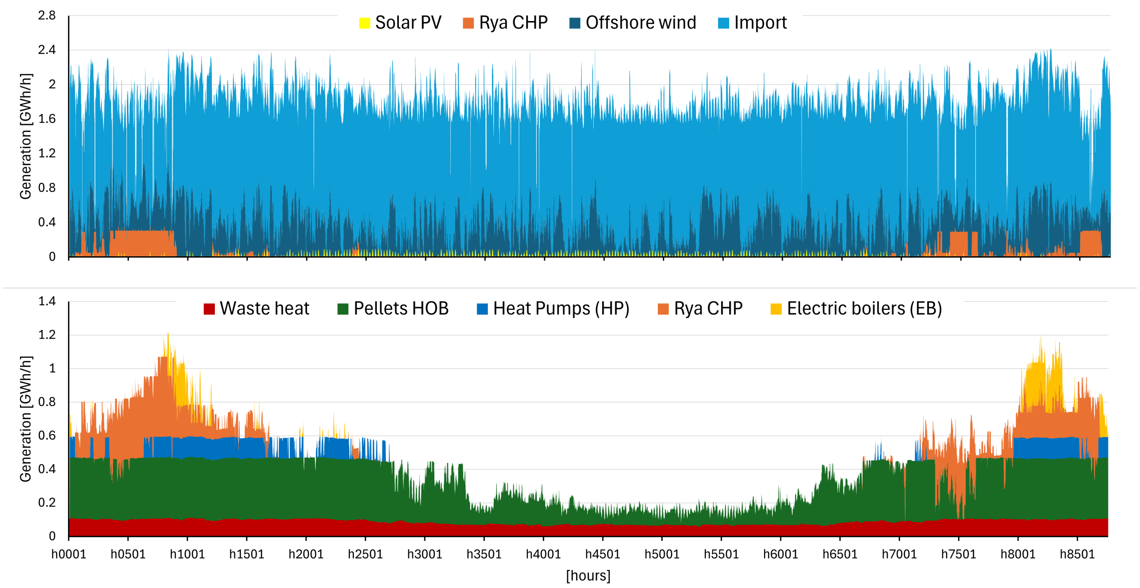

Figure 5.30: Electricity (above) and district heating (below) supply profiles over one year in the Low Fuel Cost 2050 case with reduced waste heat availability, as obtained from the City Model.

It is possible to notice how the most prominent change in the system is the increase in heat production of the pellets-fuelled HOBs, more than 3.5 times larger compared to the original Low Fuel Cost 2050 case. The City Model invests in an additional 260 MW_{heat} of HOB capacity, since it is the cheapest supplier of district heating after the industrial waste heat. The operation of Rya CHP does not show major changes resulting from the lower waste heat availability.

6
Discussion

The future role of Rya CHP, as addressed in this study, highly depends on the electricity price and cost of fuels in the future, on both short- and long-term. Increasing fuel costs, the electricity production of Rya CHP is driven towards peaking-behaviour as RES increase in the energy system, which in 2050 means increased investment in offshore wind turbines. In future scenarios, the operation of Rya CHP is forecasted to become more electricity-driven, rather than heat-driven, due to the frequently high electricity prices. Between 2030 and 2050, in fact, the electricity generation increases more than the district heating production, as the energy system of Gothenburg favours electricity-to-heat technologies, like HPs and EBs.

Analysing the results, it is important to discuss the impact of the assumptions. Rya CHP is mostly generating during events of high electricity price, so the choice of the electricity price profiles used in the model has a large impact on the generation patterns of the plant over the year. The nature of these price profiles lies behind the differences between the results in the two time frames. However, it also implies that price profile forecasts based on different reference years, on which depend the weather conditions, or actualised with different methods, could lead to different results.

The Societal and Actor perspectives have different outcomes, as they are optimised under different conditions. Increasing the cost of the fuels has a larger impact on the total generation of Rya CHP from the Actor perspective compared to the Societal one. The Actor approach is, in fact, detached from any type of demand and is not influenced by the production patterns of the other technologies in the system, which in the Societal scenarios often force Rya CHP to operate adapting to the system variations in order to minimise the total costs. Another important factor is the choice of the modelling method: LP for the Societal perspective and MIP for the Actor one. This distinction affects the behaviour of Rya CHP in the definition of minimum loads and start-up costs for each component of the plant, more detailed in the MIP version thanks to the use of binary variables. As an outcome, the load level of electricity and heat in the Actor perspective is less prone to vary load from hour to hour. Finally, the behaviour of Rya CHP in the Actor perspective is also reflecting the aim of maximising the profit. If a component is started, due to the price conditions being favourable, it is most convenient to run it at full-load. Additionally, the electricity price in the Actor perspective is not affected by the operation as it is in the Societal one during the optimisation, adding to the convenience for Rya CHP to operate at either full or minimum load.

In 2030, the yearly production of Rya CHP is higher in the Societal perspective compared to the Actor perspective, contrary to 2050. This implies that operating Rya CHP is often the most cost-effective solution for the system in 2030, even though then it would not be as profitable to run from the point of view of the actor operating it. In 2050, on the other hand, the profitable generation of Rya CHP exceeds the optimal production from a Societal perspective, as other technologies can provide cheaper electricity compared to Rya CHP.

In all scenarios, according to the results obtained from the models, Rya CHP produces electricity exclusively during winter and mid-season, but never in summertime. Taking into consideration potential low system inertia due to higher share of wind and solar power in future scenarios, Rya CHP could possibly be a local provider of inertia, thanks to the synchronous generation of the ST, when the BB is already running. However, since the plant is not regularly operating during summer, it could potentially play a role only during winter and mid-season. On the other hand, taking a role in the mFRR market, in the future Rya CHP could have the opportunity to make revenue also during summer. As battery storage is a potential provider of ancillary services, introducing revenue possibilities from mFRR market in the model, the gas turbines of Rya CHP are probably going to compete with batteries, as well as with other gas turbine installations, as bid-takers on the mFRR market in 2030, and possibly in 2050.

Integrating the outcome of the fuel assessment with the results of the modelling, biomethane is the preferable option for 2030. It is an environmentally and economically sustainable fuel, without any combustion issues in gas turbines. Depending on how the gas network fees develop, biomethanol could be more cost-effective compared to biomethane, even considering the investment costs for methanol storage. However, considering higher costs for all the fuels, biomethane is the most cost-effective option also including grid fees. A promising alternative is to have a fuel mix of both biomethane and biomethanol, where biomethanol can be stored and used during high price events for biomethane. Although promising, biomethanol is an uncertain option for the use in gas turbines. The tests and evaluations about its performance in gas turbines are still in early phase, leading to the potential necessity of investments to adapt the current installation to this fuel. In addition, biomethane is currently a more available resource than biomethanol, as production of biomethanol is still limited to few production units in Sweden. Furthermore, both fuels can come from the same feedstocks, and biomethanol can be produced directly from biogas, adding to the uncertainty of the future market shares of the two fuels. On one hand, renewable methanol could grow due to requests from the industrial and transport sectors, but on the other hand biomethane has large potential in the energy sector for both heating and electricity.

In 2050, the results suggest to implement a mix of up to four fuels every hour. In the case with cheaper fuels, renewable methanol is the most cost-competitive one, considering the costs for both production and storage. The difference in price between biomethanol and e-methanol is small and uncertain, therefore the choice of feedstock is mostly dictated by the fuel distribution logistics. Increasing the constraints regarding the fuel deliveries by truck and the maximum storage capacities, it would be possible to run the gas turbines in Rya CHP only on renewable methanol, without the need to complement with more expensive fuels such as LBG. The plausibility of the investments in fuel storage can be discussed in terms of size, number and type. Having more than one type of storage would increase the complexity of the plant and require larger spaces. Due to the economy of scale, a fewer number of storages with a larger size could be the optimal solution. However, relying on more than one fuel can be a safer way to secure electricity and heat production in case of supply limitations for some fuels, for instance because of geopolitical tensions and biomass availability.

The uncertainty regarding the fuel costs in 2050 is high, therefore, depending on the development of hydrogen demand and production in the city, hydrogen could be a viable fuel option for gas turbines in 2050. Moreover, modelling the electrofuels production from hydrogen endogenous to the system, instead of considering them as market fuels, could contribute to their cost-effectiveness, as well as making them less convenient, depending on the logistics of the production itself.

Although LBG can also be considered a cost-effective option, being a product of biomethane makes it probably more expensive than renewable methane in gas-form, from a market perspective, due to the liquefaction costs. It is relevant to the discussion of the results how the range of costs of LBG considered for 2050 reaches lower values than the cost of biomethane, since one is assumed to come from a global market while the other from a European one, bounded to the Danish-Swedish gas network for the distribution. The hypothesis of increased grid fees, moreover, makes LBG a more convenient option than biomethane, in case of liquefaction at the biogas production plant. Finally, although HVO is very convenient from a logistics standpoint and test runs with this fuel have already been done in Rya CHP, it is never considered a viable option by the model. The reason for this is the high costs of HVO, influenced from the global market by the price of diesel, and the uncertainties regarding long-term forecasts.

The selection of several fuels for the operation of Rya CHP leads also to uncertainties regarding specific technical limitations for the gas turbines. It is still unclear if the gas turbines might need different kinds of upgrading in order to enable operation of specific fuels, which may not be suitable for another fuel in the mix. The simultaneous combustion of different fuels should therefore be investigated more closely for different fuel mixes in order for the actors to make decisions about any investment in gas turbine upgrades.

7
Conclusion

The role of Rya CHP in the future energy system depends largely on the price of electricity and fuel costs in both the short- and long-term investigations. In 2050, as the installation of RES in the system increases, the production of Rya CHP tends to be steered towards a more peaking operation pattern. Rya CHP also shifts towards higher power-to-heat ratios in 2050 compared to 2030, indicating a greater focus on electricity production once the plant is operating. Moreover, in this study, Rya CHP produces electricity and heat exclusively during winter and mid-season.

When it comes to the fuel evaluation, the most suitable solution seems to be a mix of fuels, with the exact composition depending on the conditions of each scenario. According to the results of the study, the most cost-effective fuel in 2030 is biomethane. In 2050, both renewable methanol and renewable methane are viable options, taking into consideration different cost structures. Both fuels have potential to be produced sustainably in environmental terms as biofuels or electrofuels. However, their availability is dependent on future policies and development of other sectors transitioning from fossil fuels, such as the transport and chemical industry sectors. The biomass resources allowed as feedstocks can become more stringent and lead to higher competition for renewable fuels, while the electrofuels are dependent on the price of renewable electricity and investments in hydrogen technology in the energy system. The future cost of the fuels, together with storage and logistics parameters, prove to be important factors for the cost-effectiveness and the practical use of the fuels.

In conclusion, the study shows that the transition towards renewable fuels in gas turbine CHP plants is a valuable solution for energy systems like the one in Gothenburg, due to the key role played by this type of plants during peak-production events.

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Appendix

A Appendix A

Fuel data and assumptions

The cost of the fuels found in the literature are reported in their original units in Table A1.

Table A1: Fuel costs in the original units found in the literature.

Fuel	**Cost 2030**	Ref	**Cost 2050**	Ref
Biomethane	133 DKK/GJ	[18]	69 €/MWh_{HHV}	[37]
LBG	24-68 $/MMBtu	[57]	17-25 $/MMBtu	[57]
Biomethanol	327-1013 $/ton	[46]	227-553 $/ton	[46]
Bioethanol	5-13 SEK/liter	[40]	-	
FAME	8-20 SEK/liter	[40]	-	
HVO	10-25 SEK/liter	[40]	-	
Hydrogen	1800-1620 $/ton	[46]	900-2000 $/ton	[46]
E-methane	70-195 €/MWh	[57]	60-140 €/MWh	[57]
E-methanol	460-825 $/ton[1]	[46]	250-630 $/ton	[46]
E-ammonia	25-52 $/GJ	[59]	17-33 $/GJ	[59]

The conversion factors used are:
1 $ (USD) = 0.96 €
1 DKK = 0.13 €
1 SEK = 0.09 €
1 MWh_{LHV} = 1.107 MWh_{HHV} for biomethane

The costs in 2030 for bioethanol, FAME and HVO are based on historical prices from 2020 to 2023. Due to the lack of forecasts for 2050, the costs were assumed to be the same in the two time frames.

[1] The range of cost reported in the source is 820-1620 $/$ton_{MeOH}$ for 2020.
With the cost of green hydrogen going from 4000-8000 $/ton in 2020 to 1800-3200 $/ton in 2030, the cost of e-methanol can be actualised to 460-825 $/$ton_{MeOH}$ in 2030.

The lower heating values, both gravimetric and volumetric, and the densities considered for each fuel are reported in Table A2.

Table A2: Lower heating value and density of fuels implemented in the model.

Fuel	**LHV**	**LHV**	**LHV**	**LHV**	**density**
Gaseous fuels	[MJ/kg]	[MJ/m^3]	[kWh/kg]	[kWh/m^3]	[kg/m^3]
Biogas	49.3	36	13.7	10.0	0.730
Hydrogen	120	10.8	33.3	3.0	0.090
E-methane	49.3	36	13.7	10.0	0.730
Liquid fuels	[MJ/kg]	[MJ/L]	[kWh/kg]	[kWh/L]	[kg/L]
LBG	49.3	21.4	13.7	5.9	0.433
Biomethanol	19.9	15.7	5.5	4.4	0.790
HVO	44.1	34.4	12.2	9.6	0.780
E-methanol	19.9	15.7	5.5	4.4	0.790

B Appendix B

Technology data and assumptions

The technical parameters used to define each component of Rya CHP plant in the LP model are summarised in Tables B3 and B4, for 2030 and 2050 respectively.

Table B3: Technology-related assumptions used in the Rya Model (LP, 2030).

	GT1	GT2	GT3	SF1	SF2	SF3	ST	BB	DK
η_{tot}	0.92	0.91	0.90	0.95	0.95	0.95	1.05	1.15	1
η_{el}	0.360	0.356	0.352	-	-	-	0.320	-	-
η_{min}	0.238	0.235	0.232	-	-	-	-	-	-
$Minload_{el}$ [%]	34%	34%	34%	0	0	0	10%	0	0
$Maxload_{el}$ [$\mathrm{GW_{el}}$]	0.0435	0.0435	0.0435	0	0	0	0.141	0	0
$Maxload_{dh}$ [$\mathrm{GW_{dh}}$]	0	0	0	0	0	0	0.350	0.040	0.286
$Minload_{st}$ [%]	0	0	0	0	0	0	0	40%	0
$Maxload_{st}$ [$\mathrm{GW_{st}}$]	0.0668	0.0668	0.0668	0.076	0.076	0.076	0	0.150	0
$T^{startup}$ [h]	0	0	0	0	0	0	6	8	0
$C^{startup}$ [€/MW]	20.2	20.2	20.2	0	0	0	42.9	56.9	0
$C^{partload}$ [€/MWh]	110.5	110.5	110.5	0	0	0	0	0	0

Table B4: Technology-related assumptions used in the Rya Model (LP, 2050).

	GT1	GT2	GT3	SF1	SF2	SF3	ST	BB	DK
η_{tot}	0.92	0.91	0.90	0.95	0.95	0.95	1.05	1.15	1
η_{el}	0.360	0.356	0.352	-	-	-	0.320	-	-
η_{min}	0.238	0.235	0.232	-	-	-	-	-	-
$Minload_{el}$ [%]	27%	27%	27%	0	0	0	10%	0	0
$Maxload_{el}$ [$\mathrm{GW_{el}}$]	0.055	0.055	0.055	0	0	0	0.141	0	0
$Maxload_{dh}$ [$\mathrm{GW_{dh}}$]	0	0	0	0	0	0	0.350	0.040	0.286
$Minload_{st}$ [%]	0	0	0	0	0	0	0	40%	0
$Maxload_{st}$ [$\mathrm{GW_{st}}$]	0.0845	0.0845	0.0845	0.076	0.076	0.076	0	0.150	0
$T^{startup}$ [h]	0	0	0	0	0	0	6	8	0
$C^{startup}$ [€/MW]	20.2	20.2	20.2	0	0	0	42.9	56.9	0
$C^{partload}$ [€/MWh]	77.5	77.5	77.5	0	0	0	0	0	0

The technical parameters used to define each component of Rya CHP plant in the MIP model are summarised in Tables B5 and B5, for 2030 and 2050 respectively.

Table B5: Technology-related assumptions used in the Rya Model (MIP, 2030).

	GT1	GT2	GT3	SF1	SF2	SF3	ST	BB	DK
η_{tot}	0.92	0.91	0.90	0.95	0.95	0.95	1.05	1.15	1
η_{el}	0.360	0.356	0.352	-	-	-	0.320	-	-
η_{min}	0.238	0.235	0.232	-	-	-	-	-	-
$Minload_{el}$ [$\mathrm{GW_{el}}$]	0.015	0.015	0.015	0	0	0	0.015	0	0
$Maxload_{el}$ [$\mathrm{GW_{el}}$]	0.0435	0.0435	0.0435	0	0	0	0.141	0	0
$Maxload_{dh}$ [$\mathrm{GW_{dh}}$]	0	0	0	0	0	0	0.350	0.040	0.286
$Minload_{st}$ [$\mathrm{GW_{st}}$]	0.0415	0.0415	0.0415	0.100	0.100	0.100	0	0.060	0
$Maxload_{st}$ [$\mathrm{GW_{st}}$]	0.0668	0.0668	0.0668	0.076	0.076	0.076	0	0.150	0
$T^{startup}$ [h]	0	0	0	0	0	0	6	8	0
$C^{startup}$ [€/MW]	20.2	20.2	20.2	0	0	0	42.9	56.9	0
$C^{partload}$ [€/MWh]	110.5	110.5	110.5	0	0	0	0	0	0

Table B6: Technology-related assumptions used in the Rya Model (MIP, 2050).

	GT1	GT2	GT3	SF1	SF2	SF3	ST	BB	DK
η_{tot}	0.92	0.91	0.90	0.95	0.95	0.95	1.05	1.15	1
η_{el}	0.360	0.356	0.352	-	-	-	0.320	-	-
η_{min}	0.238	0.235	0.232	-	-	-	-	-	-
$Minload_{el}$ [$\mathrm{GW_{el}}$]	0.015	0.015	0.015	0	0	0	0.015	0	0
$Maxload_{el}$ [$\mathrm{GW_{el}}$]	0.055	0.055	0.055	0	0	0	0.141	0	0
$Maxload_{dh}$ [$\mathrm{GW_{dh}}$]	0	0	0	0	0	0	0.350	0.040	0.286
$Minload_{st}$ [$\mathrm{GW_{st}}$]	0.0415	0.0415	0.0415	0.100	0.100	0.100	0	0.060	0
$Maxload_{st}$ [$\mathrm{GW_{st}}$]	0.0845	0.0845	0.0845	0.076	0.076	0.076	0	0.150	0
$T^{startup}$ [h]	0	0	0	0	0	0	6	8	0
$C^{startup}$ [€/MW]	20.2	20.2	20.2	0	0	0	42.9	56.9	0
$C^{partload}$ [€/MWh]	77.5	77.5	77.5	0	0	0	0	0	0

B.1 Storage properties

LBG requires cryogenic storage in order to stay in liquid form, at temperatures as low as -162°C [70]. Therefore, an investment in storage tanks is necessary to use the fuel in Rya CHP. The capital investment cost for LBG storage is assumed to be 60 €/$MWh_{installed}$, based on a low pressure API620 tank for ammonia [71]. The lifetime is assumed to be 25 years, while the maintenance cost is 3% of the annual capital costs [72], resulting in an assumption of 1.8 €/$MWh_{installed}$/year for the fixed O&M costs of the modelled LBG storage. Moreover, the discharge rate is assumed to be 1% of the size of the storage [72].

As mentioned earlier, biomethanol and e-methanol have the same fuel properties and are considered to be the same fuel once delivered on site. Methanol storage is assumed to be similar to water tanks and the capital cost is 40 €/$MWh_{installed}$ and the O&M cost is 8.8 €/$MWh_{installed}$/year calculated from "Large-Scale Hot Water Tanks (steel)" in the Danish Energy Agency database [73]. The lifetime of hot water tanks is 40 years [73], but since methanol is a corrosive substance, in the model it is assumed to be 30 years. The discharge rate is 14%/size, based on the discharge rate for the accumulator.

It is supposed that the volume of each storage tank can't exceed approximately 5000 m^3, similarly to the fuel tanks present in the harbour area, and the maximum number of tanks is assumed to be 2 for methanol and 1 for LBG. These premises result in investment limitations for the maximum storage capacity of 50 GWh for methanol and 30 GWh for LBG.

The hydrogen system of the City Model already includes the possibility to invest in H_2 storage tanks. However, for the MIP version it is necessary to integrate this technology in the Rya Model as well. Hydrogen storage, as implemented in the City Model, has a capital cost of 48000 €/$MWh_{installed}$ in 2030 and 22000 €/$MWh_{installed}$ in 2050 [73]. The O&M costs are 531.7 €/$MWh_{installed}$/year in 2030 and 425.4 €/$MWh_{installed}$/year in 2050 [73]. There is no specifications for a discharge rate for this technology.

C Appendix C

Additional results

The results of the optimisation in the Low Fuel Cost and High Fuel Cost case in 2030 from the Actor perspective are illustrated in Figures C1 and C2, for electricity generation and district heating production respectively.

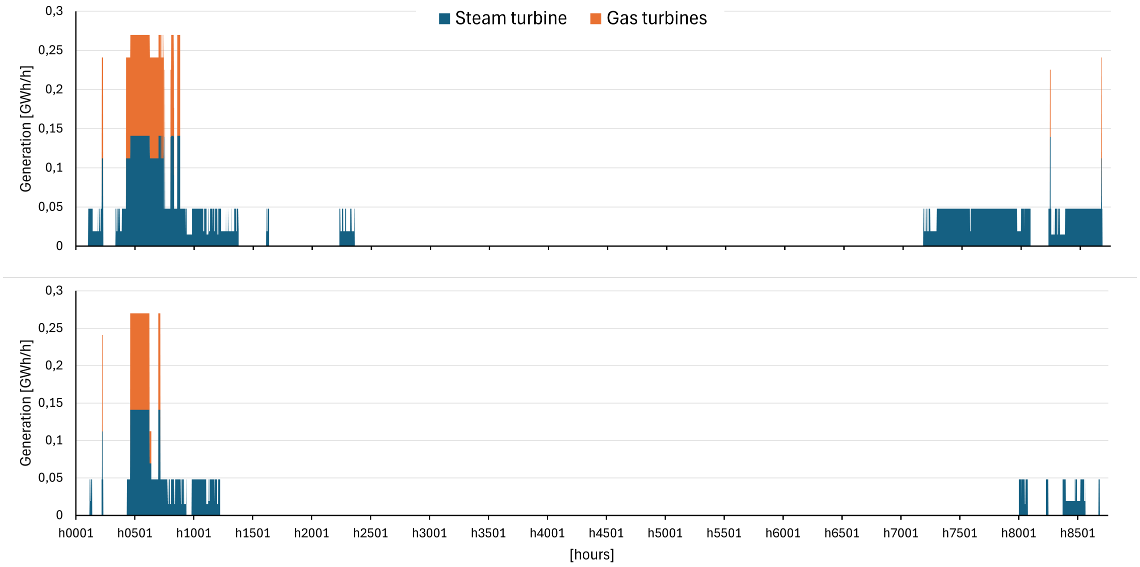

Figure C1: Electricity generation for each component over one year in 2030, from Actor perspective in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

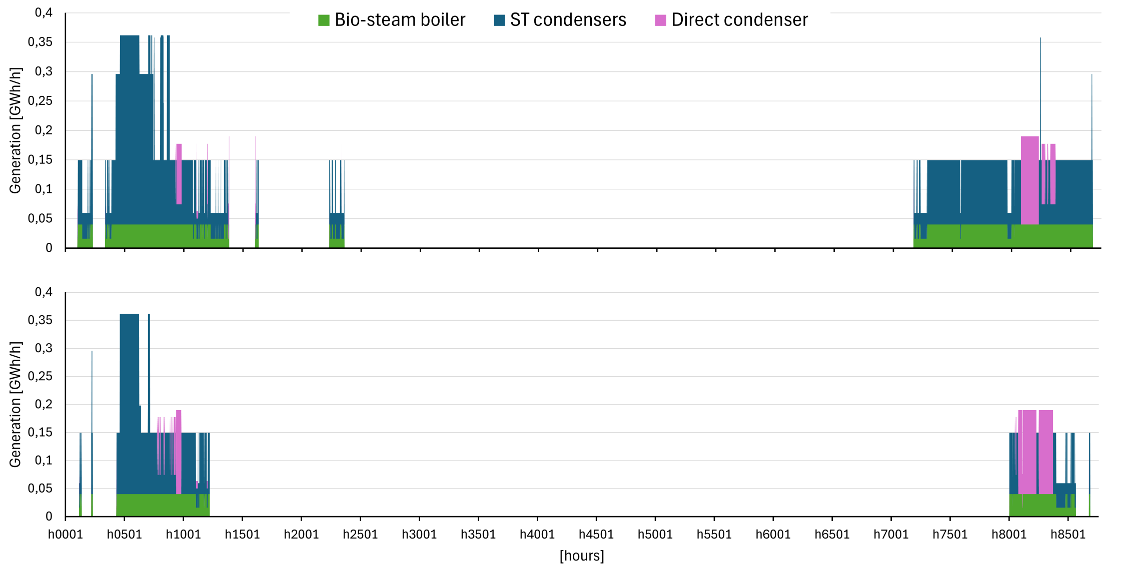

Figure C2: District heating production for each component over one year in 2030, from Actor perspective in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

The results of the optimisation in the Low Fuel Cost and High Fuel Cost case in 2050 from the Actor perspective are illustrated in Figures C3 and C4, for electricity generation and district heating production respectively.

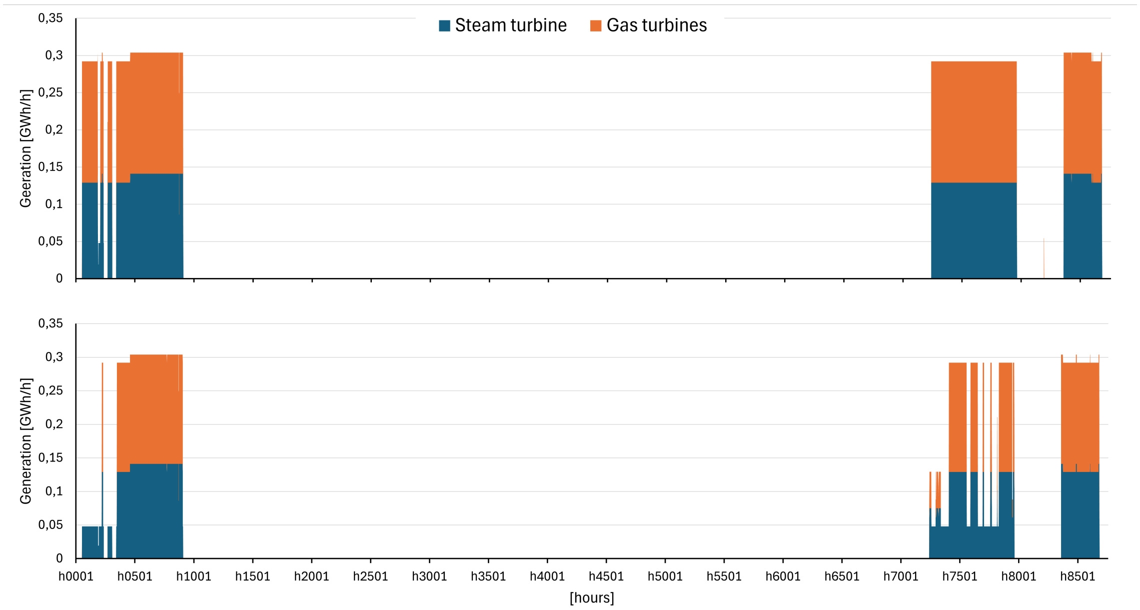

Figure C3: Electricity generation for each component over one year in 2050, from Actor perspective in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

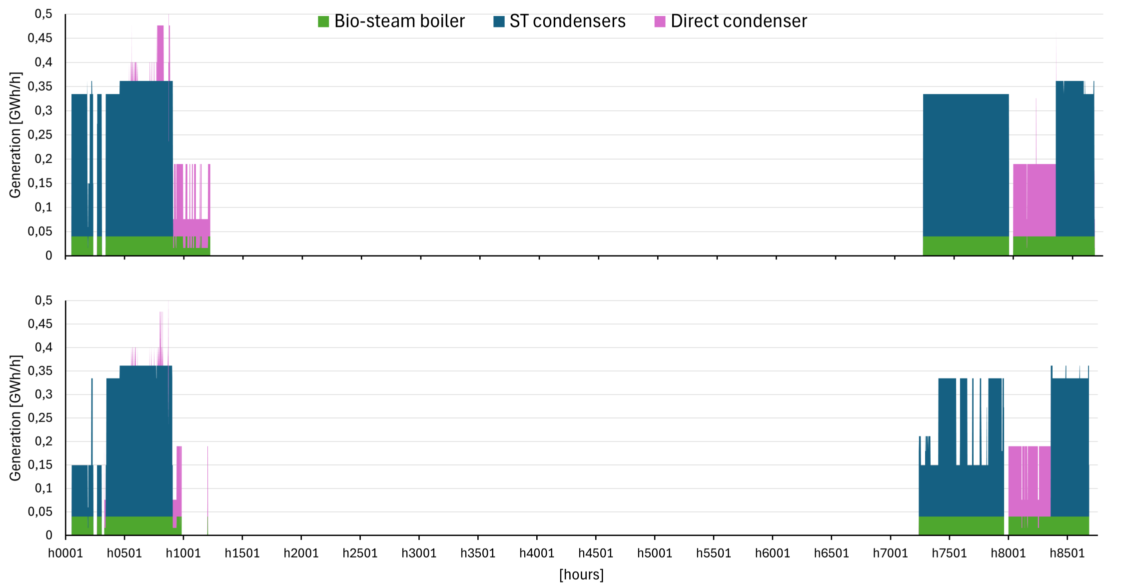

Figure C4: District heating production for each component over one year in 2050, from Actor perspective in the Low Fuel Cost case (above) and in the High Fuel Cost case (below), as obtained from the Rya Model.

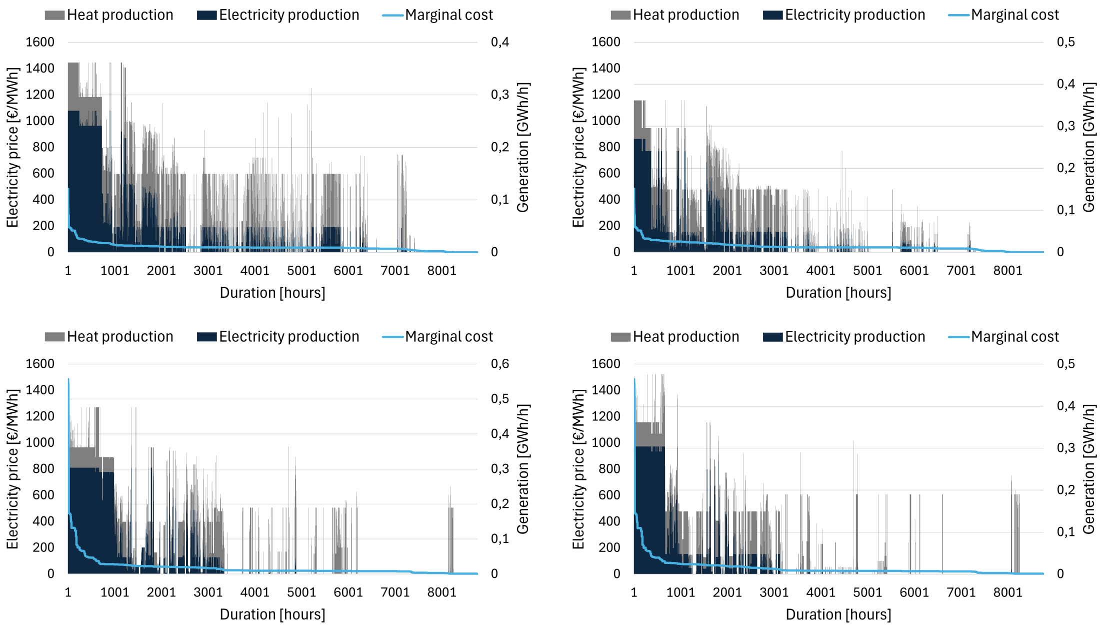

Figure C5: Duration curves of the electricity marginal cost for the Societal perspective, from above: 2030 Low Fuel Cost (left) and High Fuel Cost (right) and 2050 Low Fuel Cost (left) and High Fuel Cost (right).

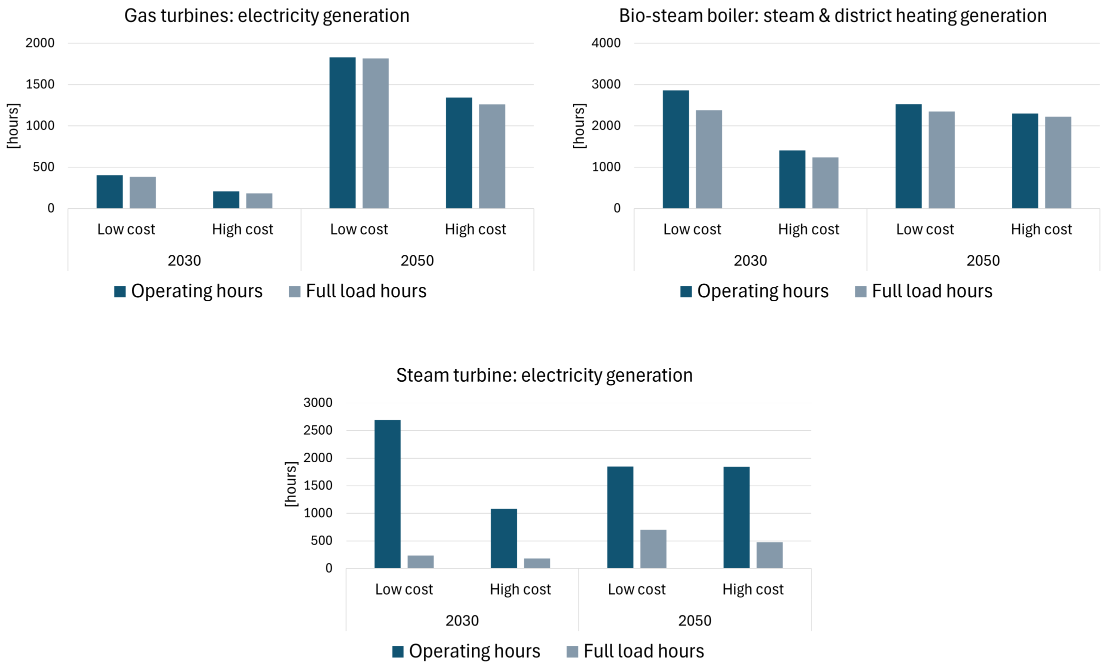

Figure C6: Number of operating hours for gas turbines (top left), bio-steam boiler (top right) and steam turbine (bottom) in the Low Fuel Cost and High Fuel Cost cases, in both time frames from the Actor perspective.

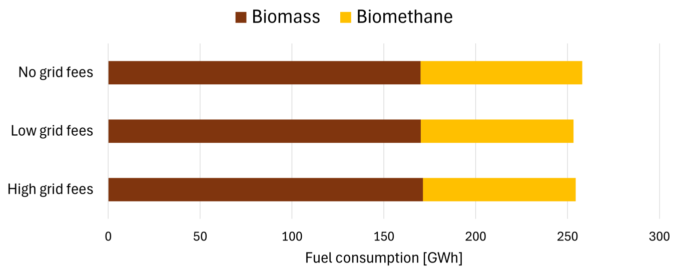

Figure C7: Fuel consumption in the High Fuel Cost 2030 case from the Actor perspective, with no, low and high grid fees.

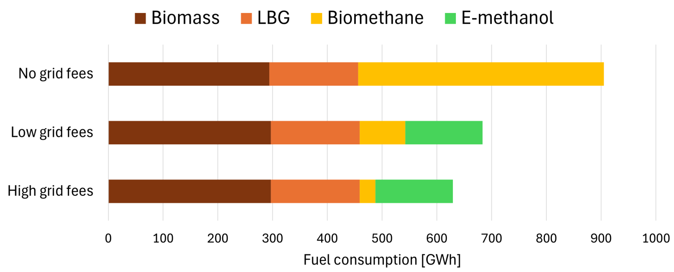

Figure C8: Fuel consumption in the High Fuel Cost 2050 case from the Actor perspective, with no, low and high grid fees.

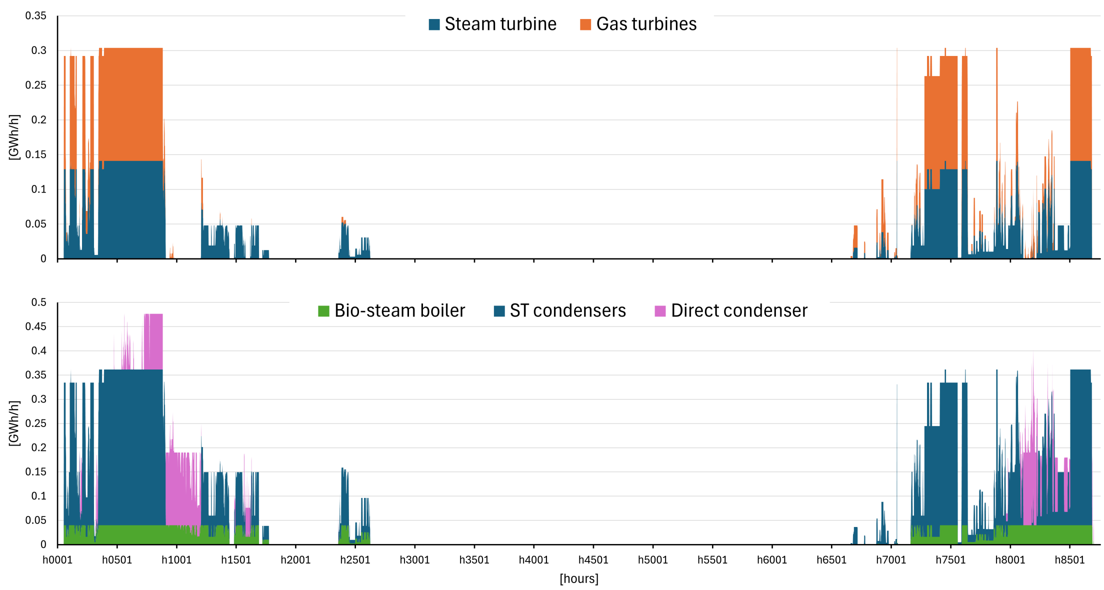

Figure C9: Electricity generation (above) and district heating production (below) over one year in the Low Fuel Cost 2050 case in the Societal perspective, without fuel storage size limitation, as obtained from the Rya Model.

D Appendix D

List of contributors

Thank you to the following people, listed in alphabetical order, who dedicated some of their time to our project, being available for interviews and providing essential data and inputs.

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