PRE-FEASIBILITY ANALYSIS OF AN OPERATION STRATEGY FOR A COMBINED HEAT AND POWER PLANT CONNECTED TO A DISTRICT HEATING NETWORK

A SWEDISH CASE STUDY

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Tesi di laurea di:
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L’albero a cui tendevi
La pargoletta mano
Del verde melograno
URLA E BIANCHEGGIA IL MAR!

Alla Nonna Tetta

And as we wind on down the road
Our shadows taller than our soul.
There walks a lady we all know
Who shines white light and wants to show
How evrything still turns to gold.
And if you listen very hard
The tune will come to you at last.
When all are one and one is all
To be a rock and not to roll
[Led Zeppelin]

A papa

Ho ancora la forza di starvi a raccontare
le mie storie di sempre, di come posso amare,
di tutti quegli sbagli che per un
motivo o l’altro so rifare.
E ho ancora la forza di chiedere anche scusa
o di incazzarmi ancora con la coscienza offesa,
di dirvi che comunque la mia parte
ve la posso garantire.
Abito sempre qui da me...
[F. Guccini]

Alla mamma
Abstract

An operation strategy based on the electricity prices trend is discussed and compared with the conventional “Heat Demand driven” strategy for a biomass Combined Heat and Power (CHP) plant connected to a District Heating (DH) network in the Swedish contest. The strategy considers the possibility to switch on the CHP unit when the electricity price is high and to run the plant at the maximum electric generation capacity. On the contrary, when the electricity price is low, the plant is off. The main assumption under this operational strategy is that a Thermal Energy Storage (TES) is included in the system and can match the heat demand. The objective is to show that the “Electricity Prices driven” strategy is more profitable for the power plant by looking at the fuel costs compared with the revenues coming from the electricity sold. To analyse the two strategies, a dynamic model of the CHP plant is implemented using the tool DYESOPT provided by KTH Royal Institute of Technology. A reference CHP plant is identified and a model based on it is realized. The model implementation consists in three steps: the sizing of the plant on Matlab, the dynamic simulation by using the model implemented in Trnsys, and the results validation, comparing the simulated trends with actual measurements. With a proper model for a CHP plant, it is possible to conduct the analysis for the proposed strategy. The simplified approach of considering just the revenues from the electricity sale and the expenses from the fuel consumption, neglecting the other cost items and the transients in the start-up and shut-down of the plant, leads to a significant increase in the revenues from the electricity which over-compensate the extra-costs for the fuel consumed, confirming that improved the flexibility of such power plant can be beneficial.
Una strategia operativa basata sull’andamento dei prezzi dell’energia elettrica viene presentata, discussa e confrontata con la strategia convenzionale basata sulla domanda termica in un impianto di cogenerazione a biomassa connesso a una rete di teleriscaldamento in Svezia. La strategia proposta si basa sulla possibilità di poter decidere se accendere o meno l’impianto a seconda del prezzo dell’energia elettrica, in particolare se il prezzo è alto conviene accendere l’impianto e estrarre quanta più potenza elettrica possibile. Viceversa, se il prezzo è basso, non conviene accendere l’impianto. Alla base di questa idea c’è l’ipotesi che l’impianto sia dotato di un accumulatore di energia termica che possa coprire la domanda termica indipendentemente dalla produzione da parte dell’impianto. In questo modo l’impianto è flessibile e può operare seguendo strategie più convenienti: l’obiettivo è infatti quello di mostrare, guardando ai ricavi derivanti dall’energia elettrica venduta e ai costi associati al consumo di combustibile, che la strategia proposta è più vantaggiosa. L’analisi viene condotta a seguito dell’implementazione di un modello dinamico che possa simulare il comportamento di un impianto reale, usando lo strumento DYEOPT del KTH Royal Institute of Technology. Dapprima si identifica un impianto reale da usare come riferimento; dopodiché il modello viene sviluppato in tre fasi: una parte di dimensionamento su Matlab, la costruzione di un modello dinamico su Trnsys, e la parte di validazione del modello, in cui si confrontano i risultati simulati con gli andamenti reali dei parametri confrontati. La strategia proposta, sebbene trascuri le altre voci di costo e i transitori durante l’accensione e lo spegnimento dell’impianto, conferma che gli extra ricavi derivanti dalla vendita di energia elettrica sono maggiori rispetto agli extra costi legati al maggior consumo di combustibile, rendendo la seconda strategia più conveniente.
Summary

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<tr>
<td>Q</td>
<td>heat energy</td>
</tr>
<tr>
<td>T</td>
<td>temperature</td>
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<tr>
<td>m</td>
<td>mass</td>
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<tr>
<td>c</td>
<td>specific heat</td>
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<tr>
<td>P</td>
<td>mechanical or electrical energy</td>
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### Greek Symbols

<table>
<thead>
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<th>Symbol</th>
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<tbody>
<tr>
<td>η</td>
<td>efficiency</td>
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<tr>
<td>α</td>
<td>power to heat ratio</td>
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### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
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<tr>
<td>DHN</td>
<td>District Heating Network</td>
</tr>
<tr>
<td>DHC</td>
<td>District Heating and Cooling</td>
</tr>
<tr>
<td>TES</td>
<td>Thermal Energy Storage</td>
</tr>
<tr>
<td>LHV</td>
<td>Lower Heating Value</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>USD</td>
<td>United States Dollars</td>
</tr>
<tr>
<td>TIT</td>
<td>Turbine Inlet Temperature</td>
</tr>
<tr>
<td>DEA</td>
<td>Deaerator</td>
</tr>
<tr>
<td>ECO</td>
<td>Economizer</td>
</tr>
<tr>
<td>EVA</td>
<td>Evaporator</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
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<td>---------</td>
<td>--------------------------------------------------</td>
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<tr>
<td>RH</td>
<td>Re-heater</td>
</tr>
<tr>
<td>HPT</td>
<td>High-pressure turbine</td>
</tr>
<tr>
<td>IPT</td>
<td>Intermediate-pressure turbine</td>
</tr>
<tr>
<td>LPT</td>
<td>Low-pressure turbine</td>
</tr>
<tr>
<td>TPES</td>
<td>Total primary energy supply</td>
</tr>
<tr>
<td>MCP</td>
<td>Market clearing price</td>
</tr>
<tr>
<td>LP</td>
<td>Low Pressure</td>
</tr>
<tr>
<td>HP</td>
<td>High Pressure</td>
</tr>
<tr>
<td>PES</td>
<td>Primary energy savings</td>
</tr>
<tr>
<td>TFC</td>
<td>Total Final Consumption</td>
</tr>
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<td>Lower Heating Value</td>
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<tr>
<td>PID</td>
<td>Proportional-Integral-Derivative</td>
</tr>
<tr>
<td>OPEX</td>
<td>Operation &amp; Maintenance Expenditures</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Electricity</td>
</tr>
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<td>CEPCI</td>
<td>Chemical Engineering Plant Cost Index</td>
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Large-scale penetration of wind and solar power into the electricity system is posing new challenges, underpinning the need for efficient and flexible technologies and networks in order to design well-integrated regulation strategies.

The use of renewable power sources, together with a growing trend toward decentralised production, will result in a growing number of small and medium size producers, who will be connected to energy networks and in particular to electricity grids, originally designed for monopolistic markets. Therefore, many new problems related to management and operation of energy transfer will arise [1] [2].

The main issues related to the growing integration of intermittent renewable power generation capacity are the increasing price volatility of the electricity and the generation unpredictability. Wind and solar power generators produce electricity only when the source is available, therefore the only way to change their power output in order to ensure a balance between supply and demand is to switch them off when they interact with other production units. In this context, Combined Heat and Power (CHP) plants, which are capable of high efficiency and flexible operations, represent one of the possible solutions to respond to electricity price variations, and to support intermittent, variable generation. Improving the operational flexibility of CHP plants is considered one of the most important future challenges, by adopting proper measures which allow to decouple
generation of heat and electricity. In this way, CHP units are able to manage the fluctuations in the electricity production, ensuring a proper operation for the grid.

An ability to make the CHP plants’ heat and electricity production at least partially independent will, therefore, increase their profitability. In today’s deregulated electricity markets, electricity can no longer be seen only as a secondary product for CHP installations, but the CHP plant concept need to enable operation according to electricity prices, and thus maximise income from electricity markets.

One of the potential solutions to increase flexibility include the introduction of a Thermal Energy Storage (TES) system, for storing the excess of heat [3] [4]. With heat storage installed, the production of electricity and heat can be uncoupled for a period of time. Such uncoupling is very beneficial for enabling maximum electricity production during the hours where electricity is being paid best. The heat that is not needed (surplus heat) during these production hours is then stored and it can be used when it is required, even if the CHP unit doesn’t operate, for example when the electricity demand is low or when wind power is abundant [5].

CHP plants not only allow an efficient integration of the renewables in the energy system, but also represent one of the sustainable solutions that can be adopted in order to shift towards a more efficient and low-carbon-emissions system. In fact, it is safe to say that CHP technology makes a substantial contribution toward reducing the global warming effects of the use of fuels for heating, as this technology provides a way to use heat that otherwise would be rejected. Analyses show that CHP can provide large primary energy savings in comparison to the separate production of electricity and heat. Moreover, coupling CHPs with a District Heating Network (DHN) is the cheapest method of reducing carbon emissions, according with studies by the Claverton Energy Research Group (2007). The increasing recognition of the importance of the heat sector in the energy policy due to its size and to the costs for decarbonising it has given new impetus to the role that DHN can play when coupled with low-carbon heat sources, such as geothermal, solar thermal and biomass CHP [6] [7].

The purpose of this thesis is to provide a dynamic model for CHP plants and to use it
for make a comparison between two operational strategies. First, a “Heat Driven” strategy is implemented, which represents the typical operation for CHP plants. The results coming from this first analysis are validated using data from a Sweden power plant as a reference. Then, according with what previously said, a strategy based on the electricity prices is identified: assuming to have a storage that can decouple the heat production from the electricity production, it could be more profitable for the CHP plant to be switched on when the electricity prices are high in order to maximise profits. The comparison takes into account just the fuel cost and the revenues from the electricity sold (assuming that the revenues from the heat delivered are the same, since the heat demand has to be satisfied in both the cases) and it shows that the second strategy is more profitable for the power plant. The analysis and all the simulations refer to a week of November 2016, from the 17th to the 23th.

To model and to validate the CHP plant, DYEOPT, an internal tool provided by KTH Royal Institute of Technology, has been used. This tool allows, starting on the definition of some design parameters, to size the power plant with respect to the nominal conditions; to run dynamic simulations of the power plant for different external inputs; to provide an economic analysis.

Figure 1.1 - DYEOPT basic logic flow chart

DYEOPT is based on a “Four Blocks” logic, meaning that each power plant configuration is completely defined when the features of different four blocks are specified, which are: the “Heat Energy Source” block, the “Electric Energy
Generation” block, the “Electric Energy Storage” block and the “Thermal Energy Storage” block. The “Heat Energy Source” block includes all the characteristics about the fuel of the power plant, which can be a fossil fuel, biomass, or the solar radiation and all the interest parameters are specified (e.g. for the solar radiation the Direct Normal Irradiation, the location, the weather data are considered; for fossil fuel and for biomass the Lower Heating Value (LHV) and the cost are set). The “Electric Energy Generation” block is the one where the specific technology for producing electricity is defined in terms of nominal parameters and of reference thermodynamic cycle, and it includes the possibility to design photovoltaic power plants or Rankine cycle-based power plant. The last two blocks are for the definition of the storage features, if it is present, which could be a battery, a thermocline or a two-tanks storage.

Currently, the software tools used within DYESOPT are Matlab and TRNSYS (FORTRAN based). The first one is devoted to the sizing process in order to find out the nominal point of operation of the energy system under analysis. After that, starting from the previously defined steady state results, the second tool performs a
dynamic simulation. TRNSYS allows to create a scheme of the considered technology by linking together different elements. All the elements are taken from a specific library and for each unit the input parameters must be defined; then, the outputs of an element could be the inputs for the following one. Once all the units are properly linked and all the inputs are set, it is possible to run the simulation for the chosen time range and to plot and collect the results. Finally, TRNSYS sends back its outputs to Matlab, so that the techno-economic performance can be evaluated in a post-process phase.

After this brief introduction, the thesis will follow this structure:

- In chapter 2, the basic concepts of CHP and DHN will be presented, both looking at the general technical aspects and at their actual development in the Swedish contest; then a more accurate description of the TES will be carried out, focusing on its working principle.

- In chapter 3, the Swedish CHP plant taken as a reference will be presented and then the main steps about how the CHP model has been implemented will be illustrated. The results coming from the sizing and from the validation will be included in this chapter. Moreover, the evaluation of the Capital Expenditure (CAPEX) and of the specific costs will be discussed.

- In chapter 4, the operational strategy based on the electricity prices will be introduced, stressing on the main assumptions and on the model modifications in this analysis.

- In chapter 5, the results coming from the two strategies will be compared, looking at the fuel cost and at the revenues from the electric energy sold, in the reference week considered.

- In the conclusions, the main results from this analysis will be summarized and proposals for future works and model improvements will be suggested.
CHAPTER 2
THEORETICAL BACKGROUND

In this chapter, the concepts of Combined Heat and Power plant and of District Heating will be presented. The main technical features will be illustrated and then some data concerning their development in Sweden will be provided. Then, the technology of the Thermal Energy Storage will be discussed, stressing on how this component can improve the flexibility of a CHP plant.

2.1 Basic concepts on CHP and DHN

Combined Heat and Power (CHP), or cogeneration, refers to the simultaneous production of mechanical energy, which in most cases is used to produce electric energy, and useful heat. Whereas conventional power stations release waste heat to the environment as a side-product of electricity generation, CHP plants capture the by-product heat to supply process heat or to supply a district heating network with hot water.

Typical CHP technologies include steam turbines, gas turbines, combined cycle gas turbines (a combination of the first two plant types) and gas engines. Other more niche technologies are organic Rankine cycle turbines (similar to steam turbines but using an organic fluid rather than steam) which are suitable for small biomass combustion plants, up to 3 MW, diesel engines, micro turbines (i.e. gas turbines below about 50 kWe) and Stirling engines. The typical power cycle consists in the
compression, heat injection and expansion of a working fluid such as steam, air, or an organic fluid with power generation followed by heat rejection to cool down the working fluid. In CHP, the cycle may be modified so that the amount of extracted steam used for heating purposes can be regulated depending on the demand and the heat can be rejected at a sufficiently high temperature [6].

Figure 2.1 shows the relationship between thermal and electric fuel efficiency: the electric fuel efficiency decreases by extracting useful heat from the CHP plant, but at the same time, the energetic output of useful heat is considerably greater than the loss in electricity production. It could be produced 58 units of electric energy in pure electricity production mode or for example 51 units of electric energy and 32 units of heat energy in extraction mode per 100 units of fuel energy supplied and the overall fuel efficiency thereby sums up to 83%.

The possible savings of combined heat and power production are often illustrated as in Figure 2.2. Typical power stations convert 28-58% of the primary energy of the fuel into useful electric energy, while CHP plants use about 80-90% of the energy supplied by the fuel, ensuring 59% of CO₂ savings. It is important to notice that such comparisons are based on the assumptions that the CHP plant can always cover the heat and electricity demand, all the produced heat is consumed and that the different fuels used in the presented system have the same heating quality and price. With more unfavourable assumptions, which mainly include the effect of a lower demand...
for heat in summer and the different properties of fuels, the CO₂ savings are still estimated to 17% [8].

The concept of combined heat and power generation can be realised with a variety of conventional and unconventional fuels and heat sources. There are successful implementations with fossil fuels as well as with renewable energies, such as biogas, bioethanol, wood pellets or wood chips, or other energy sources, like urban waste or solar heat [7].

District heating is an intelligent and environmentally friendly way system for distributing heat generated from one or more sources and consists in a network of insulated pipes carrying steam or hot water to heat buildings, which can be residential and/or commercial with space heating and/or water heating requirements. Instead of every building having its own boiler, district heating is typically supplied by a central plant which can use advanced methods to run on many different fuels, so benefiting both households and the environment. DHNs provide a major opportunity for the deployment of CHP plants burning biomass, in fact by utilising low grade heat which otherwise might have been wasted, DH systems can provide higher

**Figure 2.2 - Separated production vs. CHP production**
efficiencies and improve pollution control, reducing primary energy supply and addressing fuel poverty.

![Diagram of DH network](image)

*Figure 2.3 - Explanatory sketch of the primary side of a DH network*

The DH network includes the supply line and the return line and it is called primary side, while the consumer circuit - radiator and hot water circuits – are called secondary side. Every substation is connected both to the supply pipe and the return pipe of the DH system. Usually local control systems are used in the dwellings to control the flow through the heat exchangers on both the primary and secondary side. This means that the flow in the supply and return line is not controlled centrally at the heat plant, but is the result of the flows through the substations, together with the return temperature [9].

Whilst a DHN development requires a substantial initial investment to cover the construction of plant, heat network and connections can remain operational for decades with only routine maintenance. The high investment is justified by the fact that different heating sources can be installed and then replaced when they become obsolete, since DHNs are not sensitive to the plant that supplies the heat. This flexibility is becoming more and more important as increased use of biomaterials for heat and electricity supply is being encouraged and it helps create policy to protect both the operator and consumers against fluctuations in market conditions and resource availability.

In DH applications, heat generally below 120 °C but as low as 70 °C is transferred. The heat can be transported over long distances: the current longest case in Europe is probably the Prague system where the length of the main pipeline is 40-60 km from the power station to the heat load with a 200 MW heat capacity [6].
2.2 CHP from a Steam Turbine Power Plant

The classical type of thermal power plant is a steam turbine power plant, whether for the generation of electrical power only or in a CHP plant. Steam turbine power plants can be adapted to run on almost any type of fuel, including “difficult” ones such as, for instance, municipal waste. In this kind of power plant, pressurized water is heated up in a boiler to superheated conditions through the addition of heat that is generated by fuel combustion. The pressurized steam, known as live steam, is sent to a turbine in which it expands and produces mechanical power. The expanded steam passes through a condenser, also known as a calorifier (in the CHP case) in which it is cooled and condensed to saturated liquid state, transferring heat to the district heating water. The CHP plant can be viewed as a plant in which the calorifier has replaced the cold condenser which is cooled by the environment for example sea water in the case of a plant for electrical power generation only. In the calorifier the steam condensation temperature and pressure are higher than in the case of cold condenser. Even though the working principle is the one described above, most steam power plants are not that simple. What it could be found is a feedwater heaters line in which the water temperature is raised by using bleed steam. Typically, pressurization takes place in two stages, first in a cold feedwater pump and then in a second pump. The deaerator (DEA) is a direct contact feedwater heater and serves two purposes: first, any harmful gases (N2, etc.) are driven off, and second, it stabilizes the inlet pressure to the second pump. In the boiler, the water first passes through an economizer (ECO), which brings the water to saturated conditions, then the evaporation takes place in an evaporator (EVA) and after it the temperature is further increased in a superheater. Superheated steam partially expands in a high-pressure turbine (HPT) and then there is the possibility to send it back to the boiler, where a reheating (RH) process can occur. The preheaters alternate with subcoolers, in which the steam which condenses in the preheater downstream is furtherly cooled down to the conditions of subcooled liquid. The thermodynamic significance of feedwater heating and steam reheating is to improve the electrical efficiency by increasing the mean
logarithmic temperature of the heat that is supplied to the steam cycle [10]. This configuration is shown in Figure 2.3.

![Figure 2.4 - Typical CHP configuration from a steam turbine power plant](image)

The steam turbine is a peculiar element of this kind of power plant, since it offers a wide array of designs and complexity to match the desired application and performance specifications. The main attributes can be summarized as follow:

- **The size** can range from under 100 kW to over 250 MW;
- **The custom design** can be decided to meet different objectives, like matching CHP design pressure and temperature requirements in order to deliver the desired thermal output, or maximizing electric efficiency;
- **Steam turbines** offer a wide range of **fuel flexibility**, including coal, oil, natural gas, wood and waste products;

In a typical steam turbine power plant for electric generation only, a *condensing turbine* is used, which discharges vacuum pressure steam to the condenser and the lower is the discharging pressure the higher will be the mechanical power extracted from the turbine. In a CHP plant, since the steam must be released at higher pressure
and temperature, a \textit{back-pressure turbine} is used. In the most advanced cases, an \textit{extraction-condensing turbine} can be employed, which allows to extract a certain amount of steam at the desired pressure for heating purposes, and the remaining steam is expanded to the condensing pressure. These two different possibilities are shown in the figure below [10].

\begin{figure}[h]
  \centering
  \includegraphics[width=0.5\textwidth]{diagram.png}
  \caption{Back-pressure and Extraction-Condensing turbines}
\end{figure}

The typical operation of a CHP power plant is called “Heat Demand Driven”. It means that the circulating mass flow rate of steam in the power plant is chosen with the goal of satisfying the heat demand. If a back-pressure turbine is considered, a certain amount of steam at the required level of pressure and temperature exits the last stage of the LPT, providing the desired increase in temperature to the DH mass flow rate entering the calorifier.
2.3 Swedish energy situation

According with IEA, in 2013, total primary energy supply (TPES) in Sweden amounted to 583 TWh, of which nuclear energy accounted for the largest portion (35%), followed by oil (24%), biomass (22%), and hydropower (11%). Electricity accounted for 125 TWh, or 33%.

Nuclear and hydroelectric power together made up about 84% of Sweden’s electricity generation in 2013, and fossil fuels played a minor role, at just 2.9%. Regarding CHP participation in the electricity production, it accounted for the 12% in 2013 (14.8 TWh, of which 5.6 TWh was produced on industrial sites).
Currently, biomass and waste sources dominate Swedish CHP production. They have a low CO₂ emissions footprint, although they also have relatively low efficiency for electricity production.

More than half of the population is served by DH networks, which make up 58% of total energy use for space and water heating in residential buildings and 79% in commercial and public buildings. Fuel inputs to DH are varied, but in recent decades, biomass has increased its share, becoming the main fuel input for DH networks in 2013, accounting for 60%. In the same year, the contribution coming from industrial excess heat accounted for the 8.3% of DH production [11].

The northern European countries have formed the common electricity market Nord Pool. Electricity spot prices on this market are subject to great fluctuations and are determined through an auction for each delivery period within the next day. After the close of trading at 12:00 noon the spot price is set. All demand and supply offers are sorted by price into an aggregated demand and supply set, also called Merit Order, and the intersection point of the aggregated supply set and the demand curve forms the market clearing price (MCP) and the amount of traded energy. In hours with a low demand (off-peak demand) the MCP is low and only power plants with low marginal costs, like wind turbines and nuclear energy plants, can sell their energy. In high demand hours (peak demand) the MCP increases and also power plants with
relatively high marginal costs can go into production and sell electric energy. In order to prevent grid congestions and imbalances, the Nord Pool grid is divided into a number of geographical bidding areas. Price fluctuations do not only occur over the course of days, but also within the day. There are often two peaks: around 12:00 and 18:00, while prices during the night are notably lower.

District heating markets are local markets. They are characterized by the missing competition between district heat suppliers on one hand and the competition to alternative technologies that supply heat, for example heat pumps, pellet boilers or electric heating, on the other hand. Even the heating demand is characterized by seasonal and daily variations [8].

According with EUROSTAT forecasts, if the CO\(_2\) emissions allowance prices stay constant at 15€/ton (“15-15-15” scenario), the CHP share in electricity production will increase from the 12% in 2013 to 21.2% in 2020. The avoided CO\(_2\) emissions are estimated to be up to 10 Mton per year [6].

### 2.4 Thermal Energy Storage

Thermal energy storages (TES) are systems that enable the collection and preservation of excess heat for later utilization. Practical situations where TES systems are often installed are solar energy systems and other systems where heat availability and utilisation periods do not coincide. The three basic types of TES systems are sensible heat storage, latent heat storage and thermochemical heat storage. Sensible TES systems store heat by changing the temperature of a storage medium such as water, bricks or thermal oils. Latent heat storage systems utilise the heat of fusion that is needed or released when a storage medium changes phase by melting or solidifying. Thermochemical energy storage is based on chemical reactions in inorganic substances. The selection of TES is greatly dependent on the required storage time period, e.g. day-to-day or seasonal, and outer operating conditions.
Sensible heat storages can furthermore be divided into liquid media storages and solid media storages, and water storage belongs to the first category [8].

### 2.4.1 Water Storage

Water has an excellent heat-storage capacity per cubic meter compared with other liquid substances and is also environmentally friendly. It is furthermore inexpensive and not subjected to chemical reactions, but evaporates over a temperature of 100°C. Water is therefore considered to be one of the best storage media, especially at low temperatures, in a range between 0°C and 100°C. Water is also a transport medium of energy, in form of steam inside power plants as well as liquid in radiator systems for space heating. Subsequently water is the most widely used storage medium in space heating, solar and industrial TES [8].

The only proven heat storage technology for use with CHP-DHNs is that of water in steel tanks which are normally cylindrical with volumes of up to ranging from 5 m³ for building scale CHP to 73,000 m³ [7].

Inside the tank, three temperature layers can be recognized. The temperature in the upper layer is equal to the water temperature in the supply pipe from the DH; the temperature in the lowest layer is the same as the water temperature in the return network. Due to a difference in density, the hot and cold water separate with an approximate 1 meter high nonusable separation layer, which represents a mixing zone. When charging the tank (when heat production is higher than the consumption), hot supply water is supplied in the top of the tank simultaneously with extraction of the same amount of cold return water from the bottom. During this process, the hot layer expands and the mixing zone moves downwards. The opposite happens during the discharging process, when hot supply water is extracted from the top with simultaneous supply of cold return water at the bottom. The thermal store is connected to the DHN as illustrated in figure below [7].
To achieve maximum capacity per volume, the temperature difference between top and bottom should be as high as possible and the mixing layer in between as small as possible. This can be obtained establishing plug-flow in the tank, by keeping water inlet and outlet velocity as low and symmetric as possible. To monitor the actual storage situation in the tank, several temperature probes are installed, while the pressure reliefs ensure safe pressure conditions, especially during charging and discharging procedures. From an operational point of view, a cylindrical geometry is preferred and the vertical outline is the most efficient option, since it allows the temperature stratification and favours plug flow through the tank. However, if building restrictions or other circumstances make this impossible, a horizontal outline can also be used. Tank surfaces should be coated to avoid corrosion, and the tanks must use conditioned water. An upper volume made of nitrogen or steam is used to keep out air or oxygen [5].
The CHP configuration when coupled with a water storage is illustrated in the picture below.

The valves are used for feeding and extracting the hot and the cold flow and they are configured to avoid turbulence.
2.4.2 Operational Strategy with TES

It is safe to say that typical CHP operation is constrained by the heat demand. It means that during those periods in which the heat demand is high, e.g. in wintertime, CHP units are subjected to relatively high working conditions, with high electricity production and it could result in heavy wind curtailments. On the contrary, during summertime when the heat demand is low and the electricity price is high, CHP units cannot benefit of these conditions. With the TES installed, the power plant has a flexible operation portfolio, as can be seen in Figure 2.10.

\[\text{Figure 2.12 - Operation portfolio for flexible CHP}\]

In the figure, it possible to recognize four different sectors, regarding high or low electricity prices and high or low heat demand. When the electricity prices are high, the plant can run at high working conditions: the heat can be stored or supplied to the users depending on the heat demand (it is also considered the possibility to have an additional boiler for covering high-peak heat demand). The stored heat can then be used when the electricity prices are low and it is not economical to run the CHP, for example during the night-time or when there is a high feed-in of renewables and in general any time the heat produced by the CHP is not enough to meet the demand. So, installing thermal stores in DH systems allows to eliminate bottlenecks in heat.
production and within the distribution network, together with the opportunity to
enhance revenues by taking advantage of the energy prices variability [7].
CHAPTER 3  
CHP MODEL DEVELOPMENT

Since the objective of the thesis is to observe the feasibility of an operational strategy in a CHP plant, it is essential to have a proper model of the CHP plant. The development of the model follows different steps: as starting point a real CHP plant must be taken as a reference, in order to compare the results coming from the model with the real performance. Then the model considers three key steps: the sizing, the dynamic simulation and the results validation. The sizing consists in a Matlab code which, by using thermodynamic relations, provides the nominal performance and conditions of the considered power plant. The dynamic simulation consists in the implementation of a Trnsys model, with which it is possible to simulate the behaviour of the plant for different external conditions. The result validation is the last step, and it is basically a comparison between the results coming from the model and the real outputs of the plant under the same known conditions. All these steps will be discussed in this chapter, showing the results and the limitations of the model. Finally, a paragraph concerning the CAPEX estimation will be included, stressing on the main cost items for CHP plants.

3.1 Idbäcken CHP plant

The reference CHP plant is Idbäcken power plant, owned by Vattenfall and located in Nyköping (Sweden). As fuel supply mostly wood chips are used and most
of it is from waste wood. The base load conversion technology is represented by a load bubbling fluidised bed furnace, with an installed capacity of 80 MW, which and provides steam at 540°C and 140 bar for the turbine inlet. The turbine consists of one High-Pressure Turbine (HPT) and one Low-Pressure Turbine (LPT), producing 35 MW of electricity. From the exhaust steam, 58 MW of heat is transferred to the district heating system by two condensers. Other components which are not considered in the model are a flue gas condenser of 12 MW, used to preheat the return water, two additional heat boilers of each 30 MW, for high-peak heat demand and an electric boiler of 14 MW.

In Figure 3.1 and Figure 3.2 it is possible to see a simplified layout of Idbäcken power plant and some reference values. Some peculiar features of the plant are the presence of a second low-pressure (LP) deaerator and the double-condenser configuration, with a valve after the high-pressure (HP) condenser and a pump after

![Figure 3.1 - Idbäcken CHP plant with some reference values](image-url)
the low-pressure condenser, in order to match the pressure before the first deaerator inlet.

Figure 3.2 - Idbäcken plant layout

3.2 Input Design Parameters

A set of input parameters are extracted from the available information about Idbäcken. They are used for sizing the plant on Matlab and are summarized in the tables below.

Table 3.1 - Idbäcken nominal parameters

<table>
<thead>
<tr>
<th>Plant Output mode → Heat Driven</th>
<th>DH parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Power set [MW] 35</td>
<td>T_supply [°C] 82</td>
</tr>
<tr>
<td>(\eta_{\text{gen}}) 0.98</td>
<td>pDH [bar] 10</td>
</tr>
<tr>
<td>(\eta_{\text{pump}}) 0.85</td>
<td>m_DH [kg/s] 400.15</td>
</tr>
<tr>
<td>(p_{\text{inHPT}}) [bar] 140</td>
<td>Heat Demand [MW] 58.6</td>
</tr>
<tr>
<td>(T_{\text{inHPT}}) [°C] 540</td>
<td>DoubleApproach 0.44</td>
</tr>
<tr>
<td>(p_{\text{inLPT}}) [bar] 8.16</td>
<td>dT_pinchpoint [°C] 2</td>
</tr>
<tr>
<td>(T_{\text{inLPT}}) [°C] 190.6</td>
<td></td>
</tr>
</tbody>
</table>
Other required information by DYESOPT for the design part are the pressure ratios across the HPT and the LPT. The model gives the possibility to choose between two options: it is possible to assume that the pressure ratio is always the same across the different stages of the turbine (usually this assumption is used when no information about the stages’ pressure is available) or is it possible to set the pressure ratios manually. In this case, since the pressures of the steam extractions are known (Figure 3.1) and also the pressure drop across the extraction lines (not visible in Figure 3.1), the actual value of the pressure ratios is calculated. For the HPT, two stages are considered, since there are two steam extractions, one for the hot preheater and one for the deaerator. For the LPT, just one pressure ratio is directly calculated, referred to the steam extraction for the cold preheater. It is true that there is also another extraction which goes to the LP deaerator and to the HP condenser, but the pressure level of this extraction is calculated following another logic, which looks at the condenser behaviour.

- **Hot Preheater Extraction**

\[ p_{\text{HOT extr}} = 29 \text{ bar}; \quad dp_{\text{HOT extr, line}} = 4.5\% \]

\[ p_{\text{out HPT, 1st}} = p_{\text{HOT extr}}(1 + dp_{\text{HOT extr, line}}) \quad (3.1) \]

\[ \beta_{\text{HPT, 1st}} = \frac{p_{\text{in HPT}}}{p_{\text{out HPT, 1st}}} = 4.6 \quad (3.2) \]

The same logic holds for all the stages:

- **High-Pressure Deaerator Extraction**

\[ p_{\text{HP, DEA extr}} = 8.14 \text{ bar}; \quad dp_{\text{HP, DEA extr, line}} = 5\%; \quad \beta_{\text{HPT, 2st}} = 3.6 \]

- **Cold Preheater Extraction**

\[ p_{\text{COLD extr}} = 2.96 \text{ bar}; \quad dp_{\text{COLD extr, line}} = 3\%; \quad \beta_{\text{LPT, 1st}} = 2.7 \]
One interesting parameter is the one called “Double Approach” in the Table 3.1 on the right. It can be explained looking at the condensers T-Q diagram.

\[ \text{Double Approach} = \frac{T_{\text{out,CondLow}} - T_{\text{return}}}{T_{\text{supply}} - T_{\text{return}}} \]  \hspace{1cm} (3.3)

In nominal conditions this parameter has been evaluated knowing from Vattenfall the information about the steam extractions’ flow rate for both the condensers and the inlet and outlet enthalpy. Therefore, the thermal power exchanged in the two condensers is calculated and also the temperature of the DH mass flow at the LP condenser outlet.

\[ \dot{Q}_{\text{LP cond}} = \dot{m}_{\text{LP steam}} (h_{\text{steam,in,LP cond}} - h_{\text{steam,out,LP cond}}) \]  \hspace{1cm} (3.4)
\[
\dot{Q}_{\text{HP cond}} = m_{\text{HP steam}}(h_{\text{steam in, HP cond}} - h_{\text{steam out, HP cond}})
\] (3.5)

\[
T_{\text{out, LP cond}} = T_{\text{return}} + \frac{Q_{\text{LP cond}}}{m_{\text{DH}} c_p \text{water}}
\] (3.6)

This parameter is not fixed since, depending on the heat demand, the share of the heat provided by the LP condenser and thus the \(T_{\text{out, LP cond}}\), vary, as will be explained later.

### 3.3 Sizing the CHP plant on Matlab

Once all the required input parameters are set, it is possible to proceed with the design of the power plant. Practically in DYEOPT it means to have a code that uses the given inputs for solving thermodynamic equations that the user must implement in order to get the conditions (basically temperature, pressure, enthalpy and mass flow rate) in each point of the power plant. Once all the thermodynamic stages are defined, it is possible to evaluate the powers and the performance of the plant.

This specific CHP technology is based on the Rankine cycle and since DYEOPT is provided by two already existing codes for the Rankine cycle, implemented by previous users for two different applications, my contribution has been to merge them together, with the aim of having just one flexible code able to design different plant’s configurations.

With this purpose, a list of parameters, which can have a value of 1 if the correspondent component is present in the power plant or 0 if it is not, is set, considering the possibility to have:

- A Double condenser or just one condenser (for vacuum pressure steam condensation or for DH applications);
- A valve after the HP condenser and a pump after the LP condenser or just one low-pressure pump;
- A low-pressure deaerator;
- A re-heating process;
➢ The high-pressure deaerator located after the HPT or after the IPT;

The code is written in the most general way and, according with the value of the upper parameters, it can size different plants.

It is possible to recognize five different main sections in the Matlab code used for sizing the CHP plant:

➢ **First section → Stages definition**

In this section, a matrix with a number of rows equal to the number of stages of the cycle is created (every time a flow changes some of its characteristics because it crosses a component or it is subjected to a thermodynamic transformation, a new stage is defined).

➢ **Second section → Pressures definition**

In this section, the pressure of each stage is calculated. Starting from the condensers, on the cold side (DH flow) the thermodynamic conditions are all known. Assuming a $\Delta T_{\text{pinch}}$-point of 2°C, the condensation temperature is then calculated, as the condenser cold-side outlet temperature plus the $\Delta T_{\text{pinch}}$-point. From the temperature, the correspondent saturation pressure is derived (for the two condensers) and the other thermodynamic conditions too.

From this approach, the pressure at which the steam is extracted toward the LP condenser and the HP condenser (together with the LP deaerator), is known and, from the definition of the pressure ratios in the design parameters, all the different extractions’ pressure is evaluated.

To calculate the pressures of the feedwater from the LP deaerator outlet to the boiler inlet, a backwards procedure is applied starting from the HPT inlet and detracting the pressure drops across the boiler, across the safety valve and across preheaters and subcoolers. The pressure at the deaerators feedwater inlet
and outlet is considered equal to the pressure of the steam extraction entering the component.

➢ **Third section → Thermodynamic conditions definition**

Once the pressure in each stage is known, it is possible to directly evaluate the thermodynamic conditions of the saturation stages, which are at the condensers outlet, at the deaerators and preheaters outlet and at the evaporator outlet.

Across the pumps, it is assumed to have a temperature increase proportional to the 3% of the pressure drop, in order to account for the frictions which lead to a slight warming of the flow.

Concerning the flows crossing the preheaters and the subcoolers, it is possible to evaluate the temperature by defining a Terminal Temperature Difference (TTD) at a section of the components. The preheaters adopt a parallel-flow configuration and the TTD is defined at the outlet section, while the subcoolers are normal counter current heat exchangers.

![Figure 3.4 - Preheater and Subcooler qualitative T-Q Diagram](image)

For the preheaters, by knowing the hot-side outlet temperature is it possible to deduce the cold-side outlet temperature; for the subcoolers, starting from the cold-side inlet temperature (the flow is coming out from the pump, so the temperature is known), the hot-side outlet temperature is consequently
calculated. The still unknown thermodynamic points in this system are the preheaters hot-side inlet temperature and the subcoolers cold-side outlet temperature, which will be evaluated later with an energy balance, after the mass flow rate will be known.

➢ **Fourth section → Mass balance and thermodynamic stages completion**

An iterative procedure starts to find the nominal mass flow rate in order to satisfy the heat demand, by guessing a first value, which allows to carry out several mass balances. For the first turbine stage, it is easy to calculate the efficiency, the enthalpy drop and the extracted power, since the mass flow rate crossing it, is equal to the first guess value. An energy balance is applied to the system of hot preheater and subcooler in order to get the steam extraction for the hot preheater, and therefore the steam entering the second HPT stage is known. With this logic, it is possible to proceed along the turbine, getting the amount of steam for all the extractions.

A further part of the code has been developed for the last section of the LPT, where there are the LP deaerator and the two condensers, since this possibility was not accounted in the previous versions of the code.

The portion of steam extraction which goes to the HP condenser is evaluated knowing the thermal power it has to provide and knowing the inlet and outlet enthalpy. The steam flowing through the HP condenser and the steam entering the LP deaerator come from the same LPT stage extraction. Therefore, in order to know the amount of this extraction, the evaluation of the steam required by the LP deaerator is needed. Then another iterative cycle is required for calculating the portion of the extraction which flows into the LP deaerator: an energy balance to the LP deaerator is not sufficient since the enthalpy of the flow at the deaerator inlet (which is the condensate from the two condensers) is unknown. Then the steam flowing in the LP condenser is the remaining amount of steam which flows in the last stage of the LPT, and it is basically a free variable: it means that this amount of steam comes from the previous
calculations, and the iterations will stop when the nominal mass flow rate will ensure at the end the exact amount of steam for the LP condenser which provides the requested heat demand.

At the end of this procedure, all the mass flow rates for the different extractions are known as a function of the first guess value.

➢ Fifth section → Power and performance evaluation

The total thermal power exchanged in the boiler can be calculated as the feedwater mass flow rate times the enthalpy difference across the ECO, the EVA and the SH.

By summing the power extracted in each turbine stage, equal to the steam flow rate crossing the stage times the enthalpy difference across the considered stage, it is possible to get the total mechanical power produced by the HPT and the LPT. The power required by the pumps is calculated as the volumetric flow rate times the pressure drop across the pumps, considering a pump efficiency equal to 0.85. So, at the end the electric power output is founded.

In the condensers, the thermal power transferred is computed on the hot side, so as the thermal power provided by the steam condensation, and it is compared to the heat demand: the circulating mass flow rate will vary until convergence is obtained in the condensers.

Table 3.2 - Sizing results comparison

<table>
<thead>
<tr>
<th></th>
<th>REAL</th>
<th>MATLAB</th>
<th>Err%</th>
<th>REAL</th>
<th>MATLAB</th>
<th>Err%</th>
<th>REAL</th>
<th>MATLAB</th>
<th>Err%</th>
</tr>
</thead>
<tbody>
<tr>
<td>T [°C]</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inlet HPT</td>
<td>540</td>
<td>540</td>
<td></td>
<td>140</td>
<td>140</td>
<td></td>
<td>38,5</td>
<td>38</td>
<td></td>
</tr>
<tr>
<td>Extr to HP_Dea</td>
<td>190,6</td>
<td>190,6</td>
<td>0,0%</td>
<td>8,13</td>
<td>8,12</td>
<td>0,1%</td>
<td>2,8</td>
<td>2,6</td>
<td>7,1%</td>
</tr>
<tr>
<td>Extr to COLD_PH</td>
<td>133</td>
<td>135</td>
<td>1,5%</td>
<td>2,95</td>
<td>3</td>
<td>1,7%</td>
<td>2,8</td>
<td>2,7</td>
<td>3,6%</td>
</tr>
<tr>
<td>Extr to LP_Dea</td>
<td>83</td>
<td>84</td>
<td>1,2%</td>
<td>0,54</td>
<td>0,54</td>
<td>0,0%</td>
<td>0,43</td>
<td>0,41</td>
<td>4,7%</td>
</tr>
<tr>
<td>Inlet Cond HIGH</td>
<td>84</td>
<td>84</td>
<td>0,0%</td>
<td>0,56</td>
<td>0,56</td>
<td>0,0%</td>
<td>15,7</td>
<td>15,6</td>
<td>0,6%</td>
</tr>
<tr>
<td>Inlet Cond LOW</td>
<td>65</td>
<td>64</td>
<td>1,5%</td>
<td>0,25</td>
<td>0,24</td>
<td>4,0%</td>
<td>12,9</td>
<td>12</td>
<td>7,0%</td>
</tr>
</tbody>
</table>
The sizing procedure ends up with a complete description of each point of the plant and by comparing with the actual values from Idbäcken it is possible to understand if the model properly fit the real behaviour of the plant. Table 3.2 shows the values of some illustrative points of the plant compared with the actual values and the related percentage errors. It is possible to observe that the design process has been carried out accurately, since the nominal mass flow rate and the electric power, which can be considered the most significant results, are quite similar.

### 3.4 Dynamic Simulation on Trnsys

The sizing step is fundamental in order to implement a correct Trnsys model: the nominal parameters resulted from the Matlab code are used by the components in Trnsys, together with other inputs, to calculate the outputs. The inputs can come from external files or from other components. In order to make the model work properly, all the input must be specified, otherwise errors occur. If the model is correctly implemented, it is possible to simulate the behaviour of the plant for different variable conditions and analyse the results.

In Figure 3.5 it is possible to observe the CHP model implemented in Trnsys. The simulation is carried out considering one reference week in November 2016, from the 17th to the 23th, for which real measurements were available. The hourly measurements include the electric power produced, the steam mass flow rate in the power plant, the DH return temperature, supply temperature and mass flow rate entering the condensers, and the heat demand, which is basically the thermal power transferred to the DHN.

In order to build a coherent model, some assumptions and some considerations are necessary.

<table>
<thead>
<tr>
<th></th>
<th>REAL (MW)</th>
<th>MATLAB (MW)</th>
<th>Err%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wel</td>
<td>34,815</td>
<td>34,806</td>
<td>0.03%</td>
</tr>
</tbody>
</table>
Figure 3.5 - Trnsys model
Table 3.3 - Trnsys Input Parameters from the design

<table>
<thead>
<tr>
<th>Parameters</th>
<th>HPT_1</th>
<th>HPT_2</th>
<th>LPT_1</th>
<th>LPT_2</th>
<th>LPT_3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inlet Pressure design</td>
<td>bar</td>
<td>140</td>
<td>30,305</td>
<td>8,545</td>
<td>3,19</td>
</tr>
<tr>
<td>Outlet Pressure design</td>
<td>bar</td>
<td>30,305</td>
<td>80,545</td>
<td>3,19</td>
<td>0,556</td>
</tr>
<tr>
<td>Flow rate design</td>
<td>kg/s</td>
<td>38</td>
<td>34</td>
<td>31</td>
<td>28</td>
</tr>
<tr>
<td>Stage Efficiency design</td>
<td>-</td>
<td>0.85</td>
<td>0.86</td>
<td>0.88</td>
<td>0.9</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Pump_LPcond</th>
<th>Pump_DeaLP</th>
<th>Pump_DeaHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inlet Pressure</td>
<td>bar</td>
<td>0.243</td>
<td>0.54</td>
</tr>
<tr>
<td>Density</td>
<td>kg/m³</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>Efficiency</td>
<td>-</td>
<td>0.85</td>
<td>0.85</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Subcooler Cold</th>
<th>Subcooler Hot</th>
<th>Preheater Cold</th>
<th>Preheater Hot</th>
</tr>
</thead>
<tbody>
<tr>
<td>UA</td>
<td>kW/K</td>
<td>39</td>
<td>46</td>
<td>307</td>
</tr>
<tr>
<td>Cp Hot</td>
<td>kJ/kg K</td>
<td>4.2</td>
<td>4.33</td>
<td>//</td>
</tr>
<tr>
<td>Cp Cold</td>
<td>kJ/kg K</td>
<td>4.3</td>
<td>4.69</td>
<td>4.2</td>
</tr>
<tr>
<td>Flow rate Cold ref</td>
<td>kg/s</td>
<td>31</td>
<td>38</td>
<td>31</td>
</tr>
</tbody>
</table>

The three tables above show the parameters calculated in the design step on Matlab sent to the Trnsys model. These are just part of the inputs required by each component. Besides those, the links between different components provide the other required inputs for the model to work.

3.4.1 External inputs

During the considered week, the heat demand in the urban area served by Idbäcken vary, according with the variation of the outdoor temperature mainly. The variation of the heat demand results in a variation of the DH parameters, which are the return temperature, the DH mass flow and the supply temperature. Generally, the variation in the return temperature and in the DH flow derive from control systems downstream the plant, on the consumers’ side, so these parameters are not dependent on the plant management [9].
The supply temperature, on the other hand, is controlled by the plant, by using control systems which mainly consists in a control curve which associates the supply temperature to the outdoor temperature, and the lower is the second one, so the colder is the wheatear, the higher is the first one, in order to deliver more heat (in Appendix A, more information about the control curve of $T_{\text{supply}}$ can be founded). Therefore, the external inputs of the model are the supply temperature, which derives from the outdoor temperature, the return temperature and the DH mass flow in the considered week. These values combined together culminate into the heat demand and they are directly taken from Vattenfall data files.

### 3.4.2 Condensers behaviour

Analysing some data files from Vattenfall, it is possible to observe that for different load conditions the condensers operate in different ways. In particular, by elaborating the available data, two explicative curves for the condensers are derived, shown in Figure 3.6.

![Condensers parameters as function of Heat Demand](image)

In the left side graph, the trend of the steam extractions flow rates as function of the heat demand is shown. It is possible to observe that for high heat demand more steam is extracted for the HP condenser (the red line is above the blue one) and the opposite
occurs for low demand. The point at which this switch occurs is around 40 MW of heat demand. This is coherent with the thermodynamic theories: it is not efficient to use high-pressure steam with a high energy content if a small heating is required. Therefore, in the right graft the share of the thermal power provided by the LP condenser with respect to the total power required is high for low heat demand. These information are useful in order to get the Double Approach parameter for different load conditions, since from it depends the temperature at which the DH flow exits the LP condenser.

Having the trend of the heat demand for the reference week of November, the actual thermal power exchanged in the LP condenser is immediately calculated by multiplying the demand for the factor extrapolated from Figure 3.6. Knowing the power and the trend of the return temperature and of the DH mass flow, the temperature of the DH flow at the LP condenser outlet is immediately calculated for each value of the heat demand, using the equation 3.6.

Elaborating these results, it is possible to extract a plot which shows the trend of the LP condenser outlet temperature of the DH flow with respect to the heat demand.

![Figure 3.7 – Empirical trend of the cold-side LP condenser outlet Temperature as function of the Heat Demand](image)

Since this analysis has been conducted on the real hourly trend of the demand and other parameters, the points related to the cold-side LP condenser outlet temperature are spread in a band of almost 10 °C. Anyway, it is possible to recognize a specific trend of the outlet temperature. The minimum value is for a heat demand of around
45 MW, then for decreasing demand $T_{DHout,LPcond}$ increases, meaning that in the LP condenser the most of the heat exchange is carried out, and it is coherent with the information deriving from Figure 3.6. It has sense that for high heat demand, $T_{DHout,LPcond}$ starts increasing again, since a high thermal power is required so both the condensers work more.

The empirical equation given as input in Trnsys for evaluating for each heat demand, expressed in kW, the temperature at which the DH flow exits the first condenser is the following one:

$$T_{DHout,LPcond} = 2 \cdot 10^{-8} HeatDemand - 0.0018 HeatDemand + 97.079 \quad (3.7)$$

Since the information about the condensers’ temperature inlet and outlet for the cold-side are defined, the condensers can work properly following the same logic described in the Matlab code, in order to get the condition for the steam extractions. They are modelled in Trnsys with two equation blocks, which starting from the DH conditions, calculate the condensation temperature. Then, interacting with the component “X2H” which is able to evaluate the other thermodynamic conditions for a stage, the equation blocks calculate the thermal power resulting from the steam condensation.

### 3.4.3 Boiler

The boiler is modelled as an equation block too, and it calculates the amount of fuel required for bringing the feedwater from the conditions at the outlet of the last preheater to the conditions required at the turbine inlet (540°C, 140 bar).

The Lower Heating Value (LHV) of the fuel, composed mostly by wood waste, is 12107 kJ/kg (Vattenfall information) and the efficiency of the boiler is assumed to be constant and equal to 0.8, in line with reference efficiency values for a bubbling fluidized bed boiler [12].

The simple equations implemented in the equation block are the following ones:

$$\dot{Q}_{boiler} = \dot{m}_{feedwater} (h_{inHPT} - h_{inBOILER}) \quad (3.7)$$
\[
\dot{m}_{\text{fuel}} = \frac{\dot{Q}_{\text{boiler}}}{\eta_{\text{boiler}} \cdot LHV}
\]  

(3.8)

In the equation block representative of the boiler is specified also another empirical equation to account for the pressure drop across the boiler, which are considered dependent on the flow rate. Elaborating other data received from Vattenfall, it is possible to extrapolate a curve which correlates the pressure drop across the boiler with the flow rate, as shown in Figure 3.8. Obviously, the higher is the circulating mass flow rate the higher will be the pressure drops.

![Boiler Pressure Drop](image)

*Figure 3.8- Boiler Pressure drop as function of the flow rate*

It is important to consider this pressure drop because the boiler sends the pressure signal to the pump located after the HP deaerator, which requires the outlet pressure as one of the inputs, and the pressure of the feedwater has to be high enough to win the pressure drops in the boiler.

### 3.5 Trnsys Results

Once the model is correctly implemented on Trnsys and all the inputs are defined, the simulation can run.

In order for the model to find the nominal mass flow rate that has to satisfy the heat demand, a Proportional-Integral-Derivative (PID) controller is used. This controller calculates the control signal required to maintain the control variable at the set point [13]. In the CHP model heat demand driven, the control signal is the required mass
flow rate from the main pump, after the HP deaerator. The control variable is the thermal power coming out from the steam condensation in the condensers, and the set point is the heat demand. So, basically, the nominal mass flow rate is set by the PID in order to make the condensers provide the thermal power which satisfies the demand.

![Diagram](image.png)

Figure 3.9 - District Heating parameters

In Figure 3.9 it is possible to observe the trend of the supply and the return temperature (in blue and red respectively). For the considered week, the supply temperature is more or less constant and equal to around 75°C. This means that the outside temperature didn’t vary significantly. There is just a small peak in correspondence of the morning of the 20th of November, in which the supply temperature reaches 80°C (Appendix A). The trend of the return temperature is quite regular as well and, as previously said, it depends on the control systems used downstream the plant on the consumers’ side. In the same figure, the trend of the heat demand is illustrated in pink, while in yellow is shown the trend of the control variable, which is the thermal power from the steam condensation, set by the PID equal to the set point.

By these results, some considerations can be derived. First, it is possible to notice that the heat demand at the beginning of the simulation time, starts from a value around 35 MW while the yellow line starts from a lower value and requires several
timesteps before reaching the pink one. This happens because the pink line representing the actual heat demand comes out from measurements on the real behaviour of the plant, so even if the simulation window is restricted to just a random week in November, there is a previous history for the demand from the preceding hours. On the other side, the model doesn’t take into account this fact: the only initial constraint is the steam extraction for the HP condenser. This is the reason why the yellow curve starts from a value which basically represents just the heat exchange in the second condenser. Then the PID sends a signal to the pump to increase the mass flow rate in order to reach also in the LP condenser the desired conditions for the heat exchange.

Another observation is that the trend of the yellow line is more regular with respect to the actual trend of the heat demand, which presents sudden variations with irregular trends in some time intervals. The reason is that the heat demand variations are more rapid with respect the PID signal: this component, timestep by timestep, uses an iterative procedure to fit the demand, based on the previous timestep, and in some moments the demand variation is not matched immediately.

Besides these aspects, it is possible to conclude that the PID works properly and in most of the moments it is able to set the power plant operation in order to match the desired output.

Another interesting plot is the one representing the trend of the steam extractions flow rate to the condensers in time, depicted in Figure 3.10.
Figure 3.10 - Steam Extractions for the condensers in time

Here it is possible to notice the condensers operation according with the strategy explained before. In red it is shown the trend of the steam extraction to the HP condenser, while in blue is the trend of the steam going into the LP condenser and in pink the heat demand. It is easy to see that for high value of the heat demand, the red line is above the blue one meaning that more steam is extracted for the HP condenser with respect to the other one.

Also in this plot emerge the fact that the first constraint of the model related to the mass flow rate is the steam extraction for the HP condenser, in fact the red line starts from a value of around 8 m/s, while the blue line starts from zero and then starts to increase.

3.6 Validation

To conclude that the model works properly, the last step is the validation step, in which some parameters coming from the model are compared with the actual trend of the same parameters. If the simulated parameters’ trend matches the real one, the model has been implemented correctly and can be used for later simulations and analysis.
The parameters chosen for the comparison are the circulating mass flow rate, which is the main output of the model since it is the control signal sent by the PID. Then also the electrical power output and the thermal power exchanged in the boiler are compared. The electrical power is computed in Trnsys by summing up the powers produced in each turbine stage. The turbine stage receives as inputs the inlet enthalpy, the inlet mass flow rate, the outlet pressure and the generator efficiency. Starting from these inputs and from the nominal parameters taken from Matlab, the turbine is able to evaluate the inlet pressure, the outlet enthalpy and the electrical power produced.

The trend of the mass flow rate, the electrical power and the boiler thermal power are shown in the figures below, compared with the real ones.

*Figure 3.11 - Trnsys Mass Flow Rate and Real Mass Flow Rate in time*
In the upper figures, in blue is represented the actual trend of the parameters considered while in orange is the trend from the simulation. The same considerations for the figure 3.9 can be done. The simulated trends are always more regular than the actual ones, because of the PID limitations. Moreover, the starting pint of the orange lines is different with respect to the real starting point, as it happened for the
comparison between the heat demand and the thermal power extracted from the steam condensation, and the reasons are the same already explained.

It could be noticed that the trends of the three parameters are very similar, since they are strictly correlated: depending on the heat demand, the amount of the mass flow rate is set and if it is low, the electric power extracted will be low together with the heat required into the boiler for bringing the feedwater to the superheated conditions.

In the considered week, the mass flow rate circulating in the power plant varies between 14 kg/s and 28 kg/s. In correspondence of these two values the electric power produced holds 11 MW and 23 MW and the thermal power absorbed by the feedwater in the boiler is 39 MW and 70 MW.

In Figure 3.11 it is possible to notice that the highest discrepancy in the mass flow rate trends occurs at the timestep 108, which is the 21th of November at the 13:00, and it holds about 3 kg/s. In that point there is a sharp increase in the real circulating mass flow rate, which is reached by the model some timesteps later. Then, even if in the reality the mass flow stabilizes at around 26 kg/s, the model remains at 28 kg/s and for that value the convergence in the heat demand is reached. This is the only significant discrepancy between the real data and the simulated ones, visible also in Figure 3.12 and Figure 3.13, where the power generated is 24 MW instead of 23 MW and the required thermal power is 72 MW instead of 70 MW.

The reasons behind this irregularity can be found in the simplifications inside the model, for example it doesn’t take into account the presence of a flue gases condenser which provides for a part of the heating of the DH flow. In the model all the heating process is carried out by steam condensation, so that it results a higher total mass flow rate in the power plant, more evident when the heat demand is higher, so probably the flue gases condenser contribute is more evident.

Besides these considerations, it is allowed to conclude that the validation process has conducted to acceptable results, and the implemented model suits quite properly the real CHP plant, even though some limitations are present.
3.7 CAPEX Estimation

Before simulating the other strategy, a short analysis of the main items of the direct investment costs has been conducted. The evaluation of the CAPEX is the first step in the calculation of the Levelized Cost of Electricity (LCOE), but also the Operation and Maintenance costs (OPEX) are required, which are the variable costs associated to the annual expenditures of the plant. The OPEX can be estimated if an annual simulation of the plant had been conducted, but since the available data were only for a week in November, it was not possible to carry out an annual analysis for this plant. Therefore, the cost analysis for this specific case is limited to the CAPEX estimation.

DYESOPT allows proceeding with an economic analysis, but the code associated to the CAPEX evaluation was limited. Therefore, my contribution in this sense was to improve the code in a more detailed way, referring to some expressions founded in literature. With this more accurate code, it is possible to perform the economic analysis for each CHP plant, and, if annual data are available, the Levelized Cost of Electricity can be calculated.

Three main blocks must be considered for the estimation of the CAPEX: the biomass feedstock preparation yard, the biomass conversion technology, the power generation block [14].

Biomass feedstock preparation yard refers mainly to the collection, transportation, storage and preparation of the biomass feedstock before it can be used as fuel. The conversion technologies include stocker boilers, Fluidized Bed boilers, gasifiers, digesters and in general the technology used for converting the biomass into another form of energy used for generating heat and/or power. The power generation block refers to the technology used for generating electric power, like steam turbines, gas turbines, internal combustion engines, fuel cells [14] [15].
3.7.1 Feedstock and Preparation Yard Costs

Biomass fired power plants require, unlike other renewables sources, the generation, the collection, the transportation and the storage of the feedstock. These aspects will together result in the feedstock costs, which can represent the 40% – 50% of the total cost of the electricity. Therefore, the economic profitability of a biomass power plant is strongly dependent upon the availability and the security of long-term supplies of feedstock and upon its cost. Feedstock costs are strongly variable depending on the biomass resource and on the transport distances. In general, biomass resources include forest residues, agricultural crops and wastes, recycled wood wastes, animal wastes, municipal and industrial wastes and among these, wood is the most commonly used fuel for heat and power. For those biomass resources like treated or contaminated wastes, which would have disposal costs, the feedstock cost could also be zero. This is true also for wastes and residues from agricultural and industrial processes that are consumed locally. When some distances start to be involved, for example considering the biomass trade of wood chips and pellets, the cost can become important [14] [15].

Idbäcken CHP plant fuel feedstock is mostly represented by wood chips from waste wood and sometimes stem wood chips are bought (Figure 3.14). Waste wood (or recycled waste wood) is a tree biomass that has had a previous use and it can come from demolition or construction of buildings, from manufacturing, discarded wood products. Generally, it represents the most economic source of wood fuels, since its quality is often compromised because of contamination from the previous uses [16].
Stem wood chips on the other hand come from forest residues and the fuel quality is often high with almost no impurities.

In Figure 3.15 it is possible to observe the average price in Sweden for different wood fuels for district heating plants, which are forest wood chips, processing industry residues and waste wood. It is evident that the average price for waste wood (green line) is notably lower with respect to the other two fuels considered: in 2012 the price was 117 SEK/MWh (about 64 €/ton) against above 200 SEK/MWh for wood chips.

The price for the waste wood is basically a gate fee, evaluated as the difference between the selling price and the production costs (transport, crushing, separation of metals & other waste and management), which has to be paid by those, who dispose the waste at the recycling yard [17].
Concerning the preparation yard costs, they are usually expressed as $/ton/day as function of the biomass feedstock throughput (ton/day) as shown in the figure below [14].

Idbäcken’s fuel yard has a maximum capacity of 35000 m³ of fuel and a full storage of fuel will last for approximate 350 hours or two weeks during the heating season. It means that about 100 m³ are used every hour and a procedure of fuel deliveries every day is necessary in order to maintain the stored fuel volume [16]. For that kind of fuels like wood chips the density is usually expressed as “bulk density”, which represents the mass of a portion of a solid fuel divided by the volume of the container which is filled by that portion, and the average density for wood chips is about 260 kg/m³. This means that Idbäcken’s feedstock biomass throughput of 100 m³/hour is
equivalent to about 624 ton/day, leading to a capital cost of about 5 million USD for the preparation yard.

### 3.7.2 Conversion Technology Costs

The biomass is burned in a Bubbling Fluidized Bed boiler, a recent type of technology with the advantages of reduced SO$_2$ and NO$_x$ emissions and capability of burning low-grade fuels impractical to burn with conventional methods. Figure 3.17 shows a representative cut-away view of a fluidized bed boiler.

![Figure 3.17 - Cut-Away View of a Fluidized Bed Boiler](image)

The fuel is injected and burned in a bed of inert particles, suspended by an upward flow of air coming from the bottom. The bed provides a scrubbing action on the fuel, enhancing the combustion process by removing the CO$_2$ and the solids residue and by allowing the oxygen to reach more readily and uniformly the fuel. Fluidized bed boilers can be atmospheric or pressurized and, among the atmospheric ones, there are the bubbling-bed and the circulating-bed units. The second ones are characterized by a higher fluidisation velocity [14] [15].
For the capital costs associated to the boiler, three reference value are founded in literature as function of the biomass feedstock, from which it is possible to derive the following curve [15].

![Boiler Capital Costs](image)

*Figure 3.18 - Boiler Capital Costs*

This curve holds for a boiler producing steam in a range of about 10-20 bar. Since the steam pressure in the considered case is 140 bar, a correction factor of 2 is considered, according to what the literature proposes. Therefore, the estimated capital cost for the Idbäcken boiler is about 51 million USD.

### 3.7.3 Power Generation Block

CHP is an integrated system which produces simultaneously more outputs, so in addition to the conversion technology it must be considered all those components which participate to the electrical power production, which are the prime mover with the related units, and electrical interconnections. Prime movers refer to the equipment driving the system and they include steam turbines, gas turbines, internal combustion engines and fuel cells. In the considered case, the prime mover consists in a steam turbine, so the evaluation of the CAPEX for a steam turbine is carried out. For each component of the power unit, some correlations suggested from literature are applied [18].
Steam Turbine

The cost of the steam turbine is calculated starting from a reference specific cost and a reference power (respectively 110$/kW and 80 MW), considering a scale factor of 0.67.

\[
c_{ST} = c_{ST,ref} \cdot \left( \frac{W_{el}}{W_{el,ref}} \right)^{0.67}
\]  

Then, the cost of the turbine is:

\[
C_{ST} = c_{ST,ref} \cdot W_{el} \cdot f_{temp} \cdot f_{case} \cdot f_{CEPCI}
\]  

\(f_{temp}\) is the temperature correction factor, applied to the section of the turbine with high-temperature entrance conditions and it is calculated as follows.

\[
f_{temp} = 1 + f_{exposure} \cdot 5 \cdot \exp \left\{ \frac{T_{HPTin} - 866}{10.42} \right\}
\]

\[
f_{exposure} = \frac{W_{mechHPT}}{W_{mech}}
\]

\(f_{exposure}\) is a factor evaluated as the share of the mechanical power produced in the high-temperature entrance stages with respect to the total power output. In this case, since there is no reheat, the high-entrance stages are the HPT stages. In the end, \(f_{case}\) accounts for cost increase due to a separate high pressure body, in case of a reheat for example, and it is 1.3.

In the expression an interesting index appears: the Chemical Engineering Plant Cost Index (CEPCI). CEPCI is used to update process plant construction costs from one period to another, accounting for the inflation [19].
The CEPCI-factor is calculated as the ratio between the CEPCI value at the current year and the value at the year in which the investment took place. From Figure 3.19, it is possible to extrapolate the CEPCI for 1997, the year in which Idbäcken was built, while in 2016 CEPCI was about 550 [20]. Therefore, the ratio holds 1.5, and this value is used for updating all the costs.

➢ Condensers

The condensers cost is proportional to the cooling flow capacity and to the surface, by using to two reference costs: $c_1$ equal to 248 $/m^2$ accounts for the surface and $c_2$ equal to 659 $/kg/s$ accounts for the cooling flow capacity. The condensers’ area is calculated from the heat transfer equation, considering the logarithmic mean temperature difference between hot and cold streams and a global heat transfer coefficient $U$ equal to 2200 W/m$^2$K.

$$A_{cond} = \frac{\dot{Q}_{th,cond}}{U \cdot \Delta T_{ml}}$$

(3.14)

$$C_{cond} = (c_1 \cdot A_{cond} + c_2 \cdot \dot{m}_{DH}) \cdot f_{CEPCI}$$

(3.15)
➢ Preheaters

The preheaters’ cost is computed according with this correlation:

\[ C_{PH} = \exp\{11.147 - 0.9186 \log(A_{PH}) + 0.0979 [\log(A_{PH})]^2\} \cdot f_{CEPCI} \quad (3.16) \]

The preheaters’ area is expressed in ft\(^2\) and it has been calculated starting from the \(UA\) parameter, of which calculation steps was already implemented in the Matlab code for the sizing, divided by the global heat transfer coefficient \(U\) equal to 2200 W/m\(^2\)K.

➢ Deaerators

The cost of the deaerators is proportional to the feedwater mass flow rate flowing through them in one hour and the correlation used is:

\[ C_{DEA} = 67 \cdot m_{\text{feedwater}}^{0.78} \cdot f_{CEPCI} \quad (3.17) \]

➢ Pumps

The correlation used for the pumps’ cost is proportional to the electric power consumption of the pump and considers also the pump efficiency.

\[ C_{pump} = 632.22 \cdot W_{el,pump}^{0.71} \cdot f_{eff} \cdot f_{CEPCI} \quad (3.18) \]

\[ f_{eff} = 1 + \frac{0.2}{1 - \eta_{pump}} \quad (3.19) \]

Table 3.3 summarizes all the accounted costs for the CAPEX evaluation.
Table 3.4 - CAPEX cost items

<table>
<thead>
<tr>
<th>CAPEX</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Block</td>
<td></td>
</tr>
<tr>
<td>Prep Yard</td>
<td>$ 5.331,000,00</td>
</tr>
<tr>
<td>Boiler</td>
<td>$ 51,000,000,00</td>
</tr>
<tr>
<td>Power Generation</td>
<td>$ 8,817,000,00</td>
</tr>
<tr>
<td>Steam Turbine</td>
<td>$ 4,240,000,00</td>
</tr>
<tr>
<td>Condensers</td>
<td>$ 2,230,000,00</td>
</tr>
<tr>
<td>PHs</td>
<td>$ 47,000,00</td>
</tr>
<tr>
<td>DEAs</td>
<td>$ 2,000,000,00</td>
</tr>
<tr>
<td>Pumps</td>
<td>$ 300,000,00</td>
</tr>
<tr>
<td>Engineering, construction, civil, planning, grid connection</td>
<td>$ 47,000,000,00</td>
</tr>
<tr>
<td>CAPEX</td>
<td>$ 112,148,000,00</td>
</tr>
<tr>
<td>Specific Costs</td>
<td>$/kW 3,204,23</td>
</tr>
</tbody>
</table>

In Table 3.3 are considered also those costs associated to engineering, construction and grid connection which represent almost the 40% of the CAPEX [14] and the specific cost related to the electric power output of the CHP plant is evaluated.

A specific cost of almost 3200 $/kW is derived, which can be considered in line with some reference data from literature: a document from IRENA stands that there are significant economies of scale for some technologies, and CHP systems comprising a Fluidized Bed boiler and steam turbine are one of these. In fact for technology with a generating capacity of 0.5 MWe, the specific CAPEX is 14790 $/kW, but this drops to just over 4000 $/kW for a 8.8 MW system [14]. So it is reliable to assume that the costs analysis for this specific case with an electric power output of 35 MW is has been carried out properly.

Once the CAPEX are estimated, the LCOE calculation required the OPEX costs, which includes the cost for the tons of fuel consumed during the year, the non-fuel costs, which are both fixed and variable. The fixed O&M costs can range from 1% to
6% of the CAPEX, and include labour, scheduled maintenance. The variable O&M can be from 3.6 $/MWh to 4.8 $/MWh for conversion technologies like boilers [14].

Therefore, considering also other factors, like the discount rate $r$, the cost for ash disposal, the capacity factor and the plant lifetime, the LCOE can be calculated as follows.

$$LCOE = \frac{\sum_{t=1}^{lifetime} \left( CAPEX_t + OPEX_t + FuelCost_t \right)}{\sum_{t=1}^{lifetime} \left( E_t \right)} \left( 1 + r \right)^t$$

Actually, it must be considered a credit for the heat generated, to account for the value of heat, since the expenditures and the fuel costs for a CHP plant are devoted also to the generation of useful thermal power, so it must be included in the evaluation of the LCOE [14].
CHAPTER 4
IMPLEMENTATION OF THE STRATEGY

After the model implementation and its validation, further studies and analysis can be performed. The chapter will focus on the discussion about the operational strategy that it is interesting to investigate, which is the “Electricity Prices Driven” strategy, stressing on the main assumptions and simplification behind its implementation.

4.1 Electricity Prices Driven Strategy

The model implemented and analysed so far refers to a CHP Heat-Driven plant, in which, as already explained, the plant operation is set accordingly to the heat demand on the DH side that has to be satisfied. Therefore, there is no possibility for the power plant to take benefits from the electricity price trend, since the electricity production is a secondary product of the plant.

If the plant were capable of a flexible operation, for example if it had the possibility to store heat using a TES, another operation strategy could be used, more convenient both for the power plant profitability and for the energy system balance. Storing heat allows the power plant to be switched on and to operate not with the goal of satisfying the heat demand, but for example, with the goal of earning more money.
As previously explained, this operation is beneficial from different perspectives: if the electricity price is high, for the CHP plant is profitable to operate at the maximum electrical generation capacity (because high electricity prices correspond to a high electrical demand to satisfy) and the heat produced can be supplied or stored. If the electricity price is low, it means that there is a consistent amount of electric energy coming from renewable sources like wind and it is not convenient for the CHP to be switched on. Thus, in this scenario, if there is the storage, the CHP can be switched off and the storage can provide for the heat demand, otherwise the CHP should have been switched on, with the consequences of a not profitable operation for the plant and also important wind curtailments.

The investigated operation strategy based on the electricity prices is basically the following one: assuming that there is a storage tank, the CHP is switched on and operates at the maximum capacity if the electricity price is high (a limit value is chosen); on the other hand, if the price is low, the CHP is off.

### 4.2 Assumptions and limitations

This approach is very simple and represents just the starting point for future developments and investigations. It assumes that there is a storage that can match the demand, not taking into account other options:

- **CHP on at the maximum capacity and full storage**

  If the CHP is running at the maximum capacity, and there is no heat demand and the storage is already full, the heat generating in the power plant is not useful and would be wasted. It should be considered in this scenario if it would be profitable or not for the plant to operate just for satisfying the electric demand, wasting heat and consuming fuel.
➢ CHP off and empty storage

On the other hand, when the CHP is not running because the electricity price is low, and there is a heat demand to satisfy, the storage must be full enough to cover the demand, otherwise the CHP must be switched on. In this scenario, the operational condition must be the one which, depending on the level of the storage, ensures to cover the demand (so the circulating mass flow rate in the plant has to be selected in order to providing for the amount of steam that the storage cannot match) keeping the expenses as low as possible.

These two extreme cases are not accounted and basically everything concerns the storage conditions is not considered, since the simulation starts from the assumption that the storage can always match the demand.

This is reasonable since the simulation of the proposed strategy is restricted to the week of November, for which the reference data are available, so that, implementing such a simplified analysis within a small range of time is acceptable.

Another assumption is related to the storage size: here the storage size is not considered, and assuming that the storage can match the demand is equivalent to suppose that the storage is big enough for collecting and providing the desired heat. A more accurate analysis should take into account the storage size or, changing perspective, could be performed in order to find the optimal storage size to allow the highest savings.

Moreover, all the costs associated to the start-up and to the shut-down of the plant are neglected. These are very critical aspects that in future more detailed analyses should be considered, since these cost items become more and more important when the number of start-ups increases.
4.3 Strategy Implementation

The strategy is implemented on the same model used for simulating the “Heat Driven” operation. The objective is to observe in the same week of November under the same external conditions what happens on the plant if it operates according with another strategy, in particular what happens on the revenues from the electricity sold, on the fuel consumption.

The Trnsys model already implemented and validated, is modified for suiting the new approach. The logic adopted can be understood by looking at the figure below.

![Figure 4.1 - CHP, DH and TES system](image)

Figure 4.1 is an example about how a CHP-DH system behaves if a water tank is included downstream the power plant. The arrows’ direction corresponds to the charging scenario, in which the heat demand is lower than the thermal output provided by the plant, so part of the DH mass flow is stored in the tank and at the same time the same amount is extracted from the bottom, it mixes with the return DH stream and enters the plant.

When the plant is called to work at the maximum electric generation capacity, even the thermal output will be the highest, and the system will work as the figure above. So it is possible to conclude that with the TES downstream the plant, in the case in
which the maximum electrical power is required, and therefore, the maximum thermal power will be obtained as a consequence, the DH mass flow rate entering the power plant corresponds to the maximum allowed, hence, the nominal one.

This conclusion is important since, to simulate with the Trnsys model the situation in which the maximum electric power output is the set point, the DH mass flow given as an external input to the model is set equal to the nominal one, while the return and supply temperature are kept equal to the previous simulation, so they are taken from the Vattenfall records. In this way, the electrical power extracted is the maximum one in those particular conditions.

Figure 4.2 – Simulated Maximum Electric Power extractable keeping fix $T_{\text{supply}}$ and $T_{\text{return}}$

The upper graph shows the trend of the electric power that could be extracted in the reference week according with the previously specified assumptions in the Trnsys model. It is possible to observe that the power oscillates between 30 MW and 35 MW, and this fluctuation depends upon the combination of the supply and return temperatures. In any case, it is quite close to the nominal power and of course it represents the maximum obtainable value.
The information about the plant operation have to be coupled with the information about the electricity price in the week from the 17th to the 23rd of November.

On the web platform of Nord Pool, it is possible to read the hourly electricity price trend expressed in €/MWh for the different regions participating in the market. The data referred to the south of Sweden are considered and the trend is shown in Figure 4.3.

![Electricity Prices Sweden 17-23 Nov](image)

*Figure 4.3 - Electricity Prices Sweden 17-23 Nov*

As expected, the prices clearly vary among the day, reaching the maximum during the morning hours and the minimum during the night, when the electricity demand is lower. The oscillation is in a range between almost 30 €/MWh and above 45 €/MWh, with an outlier of 10 €/MWh reached in the night between the 20th and the 21st of November.

The limit price arbitrarily chosen for deciding if the plant has to be switched on or off is 35 €/MWh. In Figure 4.4, it is possible to observe graphically during what periods the plant operates. In red is represented the trend of the electricity price, while the blue area is the electrical power that the plant can produce if it always run at the maximum capacity. The limit price of 35 €/MWh (black horizontal line) divides the graph in two regions: above the black line, the plant runs and sells the
electricity at the Elspot price; below the black line, the plant is off. The grey bars define the periods in which the plant is off.

**Figure 4.4 - Trend of the Electric Power produced and electricity prices with the new strategy**

It is important to notice the strong approximation of the analysis, which doesn’t take into account the start-up and shut down periods, but it is assumed that the plant from the moment in which the price is above 35 €/MWh is immediately able to provide the maximum power. This observation is not in line with the real behaviour of the plant and the results obtained should be handled carefully, being aware of this assumption. Anyway, as pre-feasibility analysis, it is reliable to investigate the strategy under these considerations.
In this chapter, the results coming from the two simulations will be collected, analysed and discussed. The attention will be focused on the revenues from the electricity generation and on the expenses from the fuel consumption in the week from the 17th to the 23th of November related to the two operation strategies. After the revenues and the cost will be calculated, a brief description about the heat supply and demand will be conducted, showing the theoretical behaviour of the TES, if it was present.

5.1 Revenues and Costs

The first strategy implemented and analysed was the Heat Driven strategy, in which the plant operation is chosen accordingly with the demand of heat by the consumers. This is the typical operation for a CHP plant without a storage, and the plant is always switched on during the week considered. All the results got from this analysis correspond to the actual operation of Idbäcken power plant. In Figure 5.1 it is possible to observe the trend of the net electric power (blue line) and of the amount of fuel consumed (green line) during the week.
By multiplying the electric power for the electricity price hour by hour, it is possible to obtain the revenues coming from the electricity sold, assuming that the overall electricity produced is sold to the grid.

\[
Revenues_{elec} = \sum_{hour} price_{el} \cdot W_{el}
\]  

(5.1)

The expense associated to the fuel consumption is calculated by knowing the fuel price for the wood waste in Sweden. The overall amount of fuel used in the week is represented by the area under the green line in the plot, and it is calculated by using the trapezoid method.

\[
Fuel_{consumed} = \sum_{i=1}^{168} \frac{(Fuel_i + Fuel_{i-1}) \cdot timestep}{2}
\]  

(5.2)

\[
Cost_{fuel} = price_{fuel} \cdot Fuel_{consumed}
\]  

(5.3)

The revenues obtainable by selling the heat to the consumers are not accounted in the comparison, since the basic assumption is that the heat demand is always satisfied,
whatever strategy is used. Hence, the revenues coming from the thermal contribution are the same in both cases, so they could be neglected.

The alternative strategy considered is the one which starts from the assumption that a water tank is included in the system, so that it is possible to decouple the electric and the thermal production. According with this configuration, the plant is switched on anytime the electricity price is above 35€/MWh and produces as much electric energy as it can, otherwise it is switched off and does not produce any output.

![Revenues](image)

*Figure 5.2 - Revenues from Electricity for the two strategies*

In Figure 5.2 it is possible to observe the trend hour by hour for the revenues coming from the electricity sold. In blue is the trend of the revenues coming from the first strategy, so from the actual operation of the power plant, without the storage. The curve fluctuates strongly depending both upon the trend of the electric power produced, observable in Figure 5.1, and on the trend on the Elspot prices, varying from peaks of above 1000 € to 200 €. In yellow is illustrated the trend of the revenues for the second strategy. During those hours in which the plant is running at
the maximum capacity, the revenues are notably higher with respect to the reference case, always around 1200 € with the lowest value above 1000 €. The trend is irregular with some sharp interruptions in those hours in which the plant is off.

![Revenues and Electric Energy Comparison](image)

**Figure 5.3 - Revenues from Electricity and Electricity production comparison between the two strategies**

Figure 5.3 shows both the cumulated trend of the electric energy produced and the related revenues for the two cases. All the curves are cumulated, meaning that hour by hour the production and the revenues are summed up with the previous values, so at the end of the week it is possible to have the total amount of energy produced and the total revenues for the week. The dark blue area in the graph represents the amount of electric energy produced according with the “Heat Demand Driven” strategy. At the end of the 23th of November, almost 3000 MWh of electric energy are produced and sold according with this strategy. The yellow line identifies the related revenues coming from the electric energy sale at the Elspot price. At the end of the week, around 110000 €. The trend, both for the electric energy and for the
revenues, is linear, without sudden variations. The light blue bars represent the cumulated electric energy produced according with the second strategy. Even if the plant is off in some periods, after two days the curve is already above the dark blue one, and at the end of the week more than 3500 MWh are produced, so 500 MWh more than the first case. In the same way, the cumulative curve of the revenues, depicted by the green line, grows more rapidly than the Heat Driven case, and at the end of the week the revenues coming from the electricity sale amount at more than 140000 €. This time the trend is not linear, but some flat portions of the function are present when the plant is off and no money from electricity are earned.

Concerning the fuel consumption, Figure 5.4 can be exemplificative.

![Figure 5.4 - Cumulative Fuel Consumption Trend](image-url)

It is possible to notice that the orange trend, concerned the Heat Driven case, is linear while the blue one, referred to the Electricity Driven case, is fragmentary. Of course, the blue line is above the orange one, since more fuel is consumed when more electric power is generated, and in those hours in which the plant is one, the slope of the blue segments is higher. This means that hour by hour more fuel is burnt. Then
when the plant is stop and the blue line becomes flat, the orange continues to grow almost reaching the blue one. In the last three days of the week the slope of the orange line increases, since, recalling the Figure 5.1, the electricity production from the plant in its actual configuration, is the highest and so the fuel consumption. At the end of the week, the fuel consumption is not so different: 3389 tons of fuel for Heat Driven strategy and 3475 tons of fuel for the Electricity Driven strategy.

Comparing the revenues from the electricity sale and the expenses from the fuel consumption for the two strategies, the graph below is obtained.

The blue bars are the fuel costs, the orange bars are eh revenues from the electricity, considered as negative costs, and the grey bars represent the net costs afforded by the plant according with the two strategies. The blue cars are quite similar, while the orange bar for the Electricity Driven case is notably longer with respect to the other case. This is the reason why at the end the costs, just looking at the fuel and the electricity, are 25000 € lower than the Heat Driven strategy.

It is possible to conclude, looking at these results, that the second strategy based on the electricity price trend, is more profitable for the plant with respect to the normal
operation, since the revenues from the electricity over-balance the extra costs for the fuel. Based on this conclusion, it is worth to investigate deeply and in a more detailed way the plant behaviour according with the second strategy.

5.2 Heat Demand and Supply

It is interesting to see what happens on the heat generation side when the plant works accordingly with the Electricity Prices Strategy.

Figure 5.6 shows in grey the amount of heat generated hour by hour by the plant if it works accordingly with the second strategy, while the orange bars depict the trend of the actual demand. The heat generated is always higher with respect the demand in the periods when the plant is on. So moments in which the supply is higher alternates with moments in which the supply from the plant is absent and there is a heat demand to satisfy.

Another interesting plot is obtained by analysing the previous data:
1. Hour by hour the difference between the supply and the demand is calculated. When this difference is negative, the hypothetical tank would be in its discharging phase, supplying the heat that the plant can’t provide and matching the demand. On the other hand, when the difference is positive, the tank would be charged.

2. The cumulative amount of the difference is computed, by adding to the value of a certain timestep the value of the previous hours.

This procedure leads to a graph which simulates the behaviour of the hypothetical tank during the week, with the charging and discharging phases alternatively, as can be seen in Figure 5.7.

![Figure 5.7 - Hypothetical behaviour of the tank](image)

The trend of the cumulated difference between heat supply and demand, which can be imagined as the trend of the tank downstream the plant, is interesting. Any time the trend is decreasing, the discharging process is occurring, while, when the trend is increasing positively, the tank is being charged. The horizontal level equal to zero is just a relative reference, but at the begin of the simulation the tank should be full or partially full, at least for providing the first 150 MWh of heat demanded. From this graph, it derives that this hypothetical tank should have the capability to discharge at
least around 300 MWh of heat continuously, considering just the trend of this week of November and looking at the maximum discharging process which occurs around the 121th hour of the simulation.
CONCLUSIONS

The thesis’ objective is to analyse how a biomass CHP plant would respond to an operation strategy based on the electricity prices trend, assuming that a thermal energy storage can match the heat demand. The analysis has been focused on the plant side, looking at the revenues coming from the electricity sale and the costs related to the fuel consumption. The background reasons for starting such a study stand on the awareness that CHP-DH systems, if able to operate in flexible ways, can provide significant benefits in term of renewables integration and CO₂ emissions reduction. Decoupling the thermal and the electrical production by using a TES allows the plant to cover the mismatches and the fluctuations in the electricity production caused by the intermittent operation of renewables, enhancing the profitability of the plant too.

First, a CHP plant operating according with the conventional strategy has been modelled and analysed. The CHP plant used as reference is Idbäcken power plant, located in Nyköping and owned by Vattenfall, connected to a DH network. The plant has an electric nominal capacity of 35 MW and in nominal conditions can provide 58 MWth to the DH water. The main fuel is constituted by wood waste. The conventional strategy is the “Heat Demand driven”, meaning that the plant operational conditions are chosen depending only upon the heat demand to satisfy and the electricity production is just a secondary product. The interface between the
plant and the DH network is represented by two condensers (or calorifiers), in which two streams of steam extracted from the low-pressure turbine condensate, releasing energy used to heat up the DH water. Depending on the heat demand, the pressure at which the steam is extracted for the two condensers will be decided, and also the share of the heat provided by the low-pressure condenser with respect to the high-pressure one.

All these observations have been considered in the model implementation, and the analyses of the system have been conducted by using DYESOPT, an internal tool provided by KTH Royal Institute of Technology. Therefore, once the reference plant has been studied and analysed and all the design input parameters have been identified (Figures 3.1 and 3.2), the implementation of the model has been carried out, following basically three steps:

- The design part has been conducted by using two already existing Matlab codes for designing CHP plants, and merging them together in a unique and flexible code, able to design different CHP configurations. The Matlab scripts related to the definition of the input parameters and to the Rankyne cycle calculations for CHP units have been modified and improved, in order to fit the specific Idbäcken case and also other possibilities.

- A dynamic model of the plant has been implemented in Trnsys. The model simulates the real behaviour of Idbäcken according with the “Heat Demand driven” strategy for a week of November. It receives as external inputs the DH mass flow, the DH return temperature and the DH supply temperature hour by hour from data files provided by Vattenfall. These three parameters together correspond to the hourly heat demand: the model timestep by timestep compares the heat demand with the thermal power provided by the steam condensation in the condensers and it finds the circulating mass flow rate in the power plant which allows to match the heat demand. Some empirical correlations have been integrated into the model for taking into account different aspects. One of the most important is related to the
condensers behaviour for different heat demands. Studying the data provided by Vattenfall, it has been noticed that the thermal power provided by the LP condenser and the related LP steam extraction vary depending on the heat demand, in particular for low heat demands the contribution of the LP condenser is more significant and more steam is extracted (Figure 3.6). Since the amount of heat provided by the LP condenser is variable with the demand, the temperature at which the DH water exits this condenser will be variable too. An empirical correlation has been derived which associates the temperature of the DH water at the LP condenser outlet with the heat demand (Figure 3.7). Another aspect to account for, is related to the pressure drop across the boiler, which varies depending of the circulating feedwater mass flow rate and another empirical correlation has been included in the model (Figure 3.8).

➢ Once the model has been properly implemented, the simulation and the validation have been conducted. The outputs of the model have been compared with the real trend of the same parameters and the main discrepancies have been recognized and discussed (Figures 3.11, 3.12 and 3.13). This step is important because it allows understanding if the model has been implemented correctly, its limitations and if it can be used for conducting further analyses.

These three steps have culminated in a proper implementation of a model for a CHP plant “Heat Demand driven”. The outputs referred to the electric power produced and to the fuel consumption have been used later for performing a comparison between this operation strategy and the other one proposed.

The economic analysis has been partially conducted, by evaluating the CAPEX for the plant. The Matlab code associated to the economic analysis for a CHP plant was quite approximated in DYESOPT, and I have contributed to improve it, especially for the section related to the CAPEX evaluation. Several correlations from literature have been involved for computing the investment costs associated to the preparation
yard, to the boiler and to the power block, with some references to the biomass feedstock costs in Sweden. At the end, a specific cost of around 3200 $/kWh has been computed for the considered plant, result which can be considered compatible with the trends in literature.

After that, the alternative strategy, which is the “Electrical Prices driven” strategy, has been considered. It assumes that if there was a heat storage downstream the power plant that can match the heat demand, the CHP plant can operate at the maximum electric generation capacity when the electricity prices are high, otherwise it can be switched off.

The model already implemented has been used to simulate the plant operation with the goal of extracting always the maximum electric power in the same week of November after the same external inputs. Then, the trend of the electricity prices in Sweden for the same week has been obtained and a limit price of 35 €/MWh is chosen for deciding when the plant is switched on or not.

In the paragraph 4.2 have been discussed the assumptions and the limitations of the strategy analysed. The strategy is implemented basically as it was a binary operation: the plant can be switched on and immediately produces the maximum electric power allowed, or off and the power drops to zero. The transients, the start-up and shut down times and costs are not considered. At the same time, the presence of the storage which can charge or discharge heat is just hypothetical, without considering the transients and the limitations of the storage.

Finally, when the second strategy has been implemented and the simulation has been run, the results have been collected and analysed.

The analysis has been focused only on two aspects: the revenues coming from the electricity sale and the costs related to the fuel consumed. According with the conventional strategy, the revenues amount to 110000 €, while the fuel costs hold 217000 €. The “Electricity Prices driven” strategy leads to a total amount of the revenues from electricity equal to 140000 € and fuel costs of 222000 €. So, the cost avoided, just in terms of fuel costs comparing with the electricity sold, are around 25000 € in a week of November.
It is possible to conclude that if a CHP system would be capable of flexible operations by integrating a TES for example which can decouple the electricity generation from the heat generation, the plant can work according with a more profitable strategy, following the trend of the electricity prices and not of the heat demand. This possibility allows also a better integration of unpredictable renewables in the electricity generation system, since when the price is low, meaning that there is a lot on electric energy coming from the solar or the wind, but the heat demand is high, the plant can be switched off and the heat can be provided by the TES.

This thesis represents a starting point for conducting more accurate analyses and studies in this sense. As first, it would be interesting to simulate the plant behaviour not only for a week but for a year, in order to be able to perform a complete economic analysis, estimating at the end the LCOE. Then, the second strategy proposed should be improved, implementing a Trnsys model which includes the storage tank component, and takes into account the dynamic behaviour of the tank, the transients and the limitations. Further improvements of the model could include a controller, based on a logic associated to the electricity prices. The price trend would be an input of the model and the simulation would account for the time required to the plant from the moment it will be switched on to the moment in which the power will be the maximum. These considerations can lead to different results, and the limit price, in this analysis chosen arbitrarily, can be the result of an optimization problem. Finally, the comparison should take into account all the other costs item, associated to the start-up and to the shut-down of the plant, considering the times required and the maximum number of allowed start-up.
APPENDIX A

CONTROL CURVE AND SUPPLY TEMPERATURE

The DH return temperature and the DH water stream entering the power plant are two parameters which depend on the DH network operation and on consumers’ control systems. On the other hand, the supply temperature, which is the temperature at which the DH water exits the plant and starts flowing into the network, is typically decided by the power plant by using a feed forward control. This control system is based on the idea to use information of a measurable disturbance on the system, like the outdoor temperature, to compensate for its effects, hence, the load variation. This implies the necessity of having a relation between the load and the outdoor temperature, and then a control curve to identifies the supply temperature [9]. The control curve used by Idbäcken which relates the outdoor temperature to the supply temperature is illustrated in the figure below. On the horizontal axis is the outdoor temperature, ranging from -30°C to 20°C, while on the vertical axis is the correspondent supply temperature.
The trend of the supply temperature is decreasing with the outdoor temperature, and it is reasonable: when outside is colder, more heat is required so a higher supply temperature is needed. According with the control curve, anytime the outdoor temperature is higher than 5°C, the supply temperature should be 75°C and for temperatures lower than -20°C the supply temperature is 110°C.

It is interesting to make a comparison between the real trend of the supply temperature, from actual data recorded by Vattenfall, and the trend of the supply temperature based on the control curve.

Two different weeks of November are considered and for those days the outdoor temperature in a location close to Nyköping is obtained. The trends of the actual supply temperature and the theoretical one from the control curve are depicted in the figures below.
The two figures show in red the trend of the supply temperature from the real measurements and in blue the trend which derives from the control curve. In the days from the 6th to the 13th of November, the supply temperature oscillates strongly from 85°C to 95°C meaning that the outside temperature has been always lower than 5°C and sometimes equal to around -10°C. The two curves are almost completely overlapped, and what can be noticed is that the blue curve has more peaks since, moving on the control curve, in the range between -30°C and 5°C, for each small variation in the outdoor temperature there is a new value for the supply temperature. In the reality, the trend is more regular, since in the reality is not possible to match exactly and instantaneously the value suggested by the curve. In the second graph referred to the week from the 17th to the 24th of November, the two trend are very similar too, with just two small differences. During this week, the outside temperature has been for most of the time equal or higher than 5°C so the control signal sent by the control curve has been to set the supply temperature to 75°C. In the reality, it is not possible to keep the temperature perfectly equal to 75°C, since some other uncontrolled disturbance signals interfere.
References


