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Technoeconomical analysis of Nuclear district heating - a case study of connecting the Forsmark Nuclear Power Plant to Stockholm and Uppsala District heating networks

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Sammanfattning

Denna avhandling undersöker den tekno-ekonomiska genomförbarheten av att införa kärnkraftsbaserad fjärrvärme genom att ansluta Forsmarks kärnkraftverk (NPP) till fjärrvärmenäten (DHN) i Stockholm och Uppsala. Mot bakgrund av stigande biobränslepriser och det miljömässiga kravet att minska växthusgasutsläppen från avfallsförbränning, återbesöker och vidareutvecklar denna studie tidigare analyser av kärmeintegrering i fjärrvärmesystem. En detaljerad tekno-ekonomisk modell för ett långväga värmetransportsystem (HTS) utvecklas, som inkluderar beräkningar av värme- och tryckförluster, optimering av rörlayout och kostnadsmodellering inklusive analys av nettonuvärde (NPV). Data hämtas från litteratur, ingenjörsantaganden och branschdata, särskilt från Vattenfall. Modellen optimeras med avseende på nyckelvariabler såsom rördiameter, installerad värmekapacitet samt fram- och returtemperaturer. Resultaten visar att kärnkraftsbaserad fjärrvärme, under nuvarande och förväntade marknadsförhållanden, kan vara ett kostnadseffektivt och lågutsläppande alternativ för baslastvärme, särskilt i framtida fjärrvärmesystem som reducerar eller fasar ut avfallsförbränning.

Nyckelord

Första nyckelordet, Andra nyckelordet, Tredje nyckelordet, Fjärde nyckelordet, Femte nyckelordet

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Abstract

This thesis investigates the techno-economic feasibility of implementing nuclear district heating by connecting the Forsmark Nuclear Power Plant (NPP) to the district heating networks (DHNs) of Stockholm and Uppsala. In light of rising biofuel prices and the environmental imperative to reduce greenhouse gas emissions from waste incineration, this study revisits and expands upon earlier assessments of nuclear heat integration. A detailed techno-economic model of a long-distance Heat Transportation System (HTS) is developed, incorporating thermal and pressure loss calculations, pipeline layout optimization, and cost modeling including Net Present Value (NPV) analysis. Data is sourced from literature, engineering assumptions, and industry data, particularly from Vattenfall. The model is optimized for key variables such as pipeline diameter, installed heat capacity, and supply and return temperatures. Results show that under current and projected market conditions, nuclear heating can be a cost-effective and low-emission alternative for base-load heat supply, particularly when integrated with future DHN configurations that reduce or phase out waste incineration. The study concludes that strategic investment in HTS infrastructure can enhance the sustainability and economic efficiency of urban heat supply in Sweden.

Keywords:

Nuclear District Heating, Techno-Economic Feasibility, Heat Transportation System (HTS), Optimization, Net Present Value (NPV), District Heating Networks (DHN), Forsmark Nuclear Power Plant, Thermal Modeling, Energy Systems, Sustainability

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0.1 Acronyms

DHN District Heating Network

NPP Nuclear Power Plant

HTS Heat Transportation System

HOB Heat Only Boiler

CHP Combined Heat and Power

LCOH Levelized Cost of Heat

SMR Small Modular Reactor

AVC Average Variable Cost

VC Variable Cost

MC Marginal Cost

NPV Net Present Value

BAU Business as Usual

CCS Carbon Capture and Storage

TOC Total Operational Cost

OC Operational Cost

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Chapter 1

Introduction

1.1 Background

In 2023 the production of power and district heating represented 9% of Sweden's total greenhouse gas emissions[25] Out of this, 80 % is estimated to come from waste incineration alone. In order to comply with the Paris Agreement and limit global warming to 1.5 degrees by 2050, it is imperative to limit the emissions of greenhouse gas emissions, and utility companies such as Vattenfall have committed to meeting net-zero targets [32]. As such, there is a need to replace or reduce the carbon emitting waste incineration in the DHNs.

One way to provide a DHN with fossil-free heat is to supply it from a Nuclear Power Plant (NPP) by modifying it for cogeneration. This option was explored for the case of providing the Stockholm DHN with waste heat from the Forsmark NPP in a 2011 study [1]. At the time, nuclear heating in the Stockholm DHN was found to not be economicaly feasible due to high costs, particularly from the construction of the long heat transportation pipelines. However, bio fuels, with which most of the Stockholm DHN is run, have recently seen a steep increase in price following Russia's invasion of Ukraine and the subsequent disruption of European energy supply. This has drastically changed the conditions on the DH market.

In the context of utilities' strive to deal with waste incineration's greenhouse gas emissions, and with the changed conditions on the district heating market, this study will revisits the prospects of introducing nuclear district heating in the Stockholm area. this will be done in the form of a case study exploring the techno-economical feasability. To support this objective, a model has been developed to optimize the sizing of the Heat Transportation System (HTS). This approach builds upon previous optimization studies ([8, 7]) and is applied to evaluate the feasibility and potential of integrating nuclear heating.

1.2 Problem

The most fundamental decision to make when configuring an HTS is that of which heat transfer capacity to install. In the literature there have been extensive efforts in optimizing the HTSs technical specifications, such as diameter, temperatures, and placement of pumping stations; however, the installed heat transfer capacity has mostly been assumed a priori, often times simply calculated as a flat rate based on the DHNs heat load. The methodical optimization of the installed heat transfer capacity has not been well studied in the context of long-distance HTS for nuclear district heating. This, despite it being a key variable for decision makers. -How can a model be designed for optimization that both consider pipe sizing in a branching HTS, and accounts for DH market conditions? -under what conditions are nuclear heating from Forsmark techno-economically feasible in the Stockholm area?

1.3 Purpose

In order to address the issues mentioned above, this paper will aim to propose a model for determining an optimal dimensioning for a long distance branchingHTS considering the DH system configuration. This model will then be used to explore the techno-economic viability of integrating nuclear heating with district heating networks with a long-distance branchingHTS in the Stockholm area . This to demonstrate a model that will allow for better assessments of feasibility for similar projects.

1.4 Goal

This study aims to explore the techno-economic viability of a HTS connecting Forsmark NPP to Stockholm DHN under the current price situation on the district heating market. This will be done by: 1 - optimizing the installed capacity of the HTS in respect of the system cost of the DHN taking into account the merit order and production cost of current heat production, and 2 - optimizing the technical specifications of the HTS such as diameter, temperatures and placement of pumping stations.

1.5 Benefits, Ethics and Sustainability

One of the primary benefits is the potential for cost reduction in district heating production. By utilizing waste heat from nuclear power plants, utilities can lower their operational costs, and by that achieving an overall low production cost for DH. Furthermore, using existing nuclear infrastructure for heat production can improve overall system efficiency by capturing and utilizing thermal energy that would otherwise be discarded.

However, the use of nuclear energy might raise public opinion challenges. Primarily concerns related to safety and public acceptance. The potential consequences of nuclear accidents remain a significant concern for many stakeholders. Deployment of nuclear heating therefore requires transparent communication of risks, inclusive stakeholder engagement, and robust safety protocols.

From a sustainability perspective, nuclear heating can contribute positively to climate and environmental goals. It offers a low-carbon alternative to conventional heat sources such as waste incineration, which result in greenhouse gas emissions. Replacing such sources with nuclear heat can help reduce the carbon footprint of district heating systems. Moreover, substituting biofuel-based combined heat and power (CHP) plants with nuclear heating can free up biomass resources for other applications, such as in certain industrial processes. This has potential to enhance the overall resource efficiency of the energy system.

1.6 Methodology

The methodology includes a literature review to identify research gaps, followed by the development of a Heat Transportation System (HTS) model that integrates thermodynamic principles and economic evaluation. Quantitative data, such as temperature profiles, pipe dimensions, and operational costs, are gathered from literature and datasets (notably from Vattenfall). These inputs inform a numerical model that calculates parameters like heat loss, pressure drop, and Net Present Value (NPV).

The model is then applied to the Forsmark−Stockholm/Uppsala case, using a Genetic Algorithm optimization to determine ideal pipeline configurations. A sensitivity analysis further assesses the robustness of results under different economic and operational scenarios, ensuring comprehensive validation of findings.

1.7 Stakeholders

This thesis has been conducted as part of a Master’s programme at KTH Royal Institute of Technology and carried out in collaboration with Vattenfall.

1.8 Delimitations

In order to extract heat from the Forsmark NPP, it is necessary to make some plant modifications that might be potentially complex. To delimit this study and keep the optimization simple, the details of the heat extraction at the NPP are left out. Heat is assumed to be produced with a certain loss of electricity, and at a certain cost per installed heat production capacity, based on previous studies. Also, the dynamics of the dual production of power and heat in the CHP plants present in the DHNs will be ignored for this study. Instead they’ll be assumed to have a fixed heat production cost to simplify the modeling.

1.9 Outline

In Section 1.1 a short review of relevant background knowledge is presented as well as relevant literature in the field of nuclear district heating. In Section **??** the method is presented and in Section **??** the model is explained as well as the optimization approach. The results when applying the model to the case study are presented in Section **??**, as well as a sensitivity analysis. In Section **??** conclusions are presented as well as suggestions for future studies in this field.

Chapter 2

Related Work

2.1 Related Work

The study of nuclear district heating has received increased attention in recent years. There has been a lot of studies recently on using Small Modular Reactor (SMR)´s for district heating ([16]; [27]; [28]) the benefits of doing that would be to eliminate the need of long distance HTSs as SMRs can be placed close to the heat load(XXX). However there are also multiple studies that have focused on the connection of conventional power plants to district heating networks([9]; [20]; [12]; [18]). [20] and [9] investigates the prospect of connecting Paris to the NPP in Nogent-sur-Seine at a distance of 95 km. They show that the cost of transportation infrastructure stands for around 50% of the Levelized Cost of Heat (LCOH) for the Nogent-sur-seine to Paris case. [15] investigates connecting the Loviisa NPP to Helsingfors with a 1000 MW capacity pipeline over a distance of 77 km, and in [12] multiple European cities are investigated with connection distances ranging from 2 - 90 km. Outside of Europe studies have also been made in China. For example, a study proposes an unconventional approach of combined freshwater and heat supply using nuclear heat in northern China([26]).

One study of particular interest for the case study in this article is an Elforsk report from 2011 investigating the connection of the Forsmark NPP with the DHN of the Stockholm metropolitan area ([1]), which is a case that is studied in this article. In the report two options of 1000 MW and 1500 MW respectively are investigated with results pointing to marginally lower average heat prices with the 1500 MW option(280 and 283 SEK/MW for the 1500 and 1000 MW cases respectively). However, both options offered significantly higher average heat prices than the Business as Usual (BAU) scenario at 238 SEK/ MW. [1] also investigates the prospect of diverting a flow (50 MW or 100 MW) from the pipeline to the DHN in the city of Uppsala, located approximately halfway in-between Stockholm and Forsmark. They conclude that the overall economic feasibility is increased by connecting Uppsala to the system. The report also notes that the results are sensitive to fuel prices; an increase of 36% in biofuel prices would result in nuclear heating being price competitive[1].

When it comes to modeling of HTSs there are several studies providing useful insight; [8] provides a model using a two-phase optimization to determine the optimal dimensioning of such a system, taking into account insulation and pipe aging, terrain elevation, and ground temperature seasonality. [8] then applies this model for the case of a NPP in northern Poland being connected to Gdynia/Gdansk over a distance of 40 km. Hirsch's model does however only cover a single set of supply and return pipelines between two nodes without branching.

In a follow-up study, [7] proposes a more comprehensive model that also considers the use of parallel pipelines. Single larger diameter pipes were found to be more optimal in this study.

In addition, [10] explores the techno-economic prospects of long distance HTS and attempts to determine the maximum distance between heat load and heat source for which a HTS can be financially viable. They found that with higher delivered heat, and higher heat prices, the feasible transfer distance increased. With 1000 MW of delivered heat, a transfer distance on the scale of 100 km was shown to be feasible for heat prices shy of 40€/MWh in 2018.

2.2 cost estimation

There are no examples of large scale (>500 MW) Nuclear district heating systems having been built. The costs for the pipeline must thus be estimated. In [9](2016) the cost for the pipeline is estimated as 9.5 M€/km for a set of supply and return pipelines with a diameter of 1.600 m each. Furthermore [9] estimated the NPP modifications to cost 200 M€. In[8] a more detailed price estimation is given, where the pipe cost per length is estimated as a 2nd degree polynomial function of the pipe diameter. In addition they assume a pump station cost of 3.5M€/station, where each station had a pressure gain of 1 MPa. [1] assumes costs of 18 MSEK and 23 MSEK per km for a 1000 MW and a 1500 MW pipe respectively(one-way). This corresponds to a 1.2 m diameter pipe and a 1.4 m diameter pipe respectively. In addition to the pipe cost, [1] also account for a cost for tunnels and a cost for trenches at 63 MSEK/km and 10 MSEK/km respectively for the 1000 MW alternative and 66 MSEK/KM and 12 MSEK/km for the 1500 MW alternative.

Many studies also assume a heat price for which produced heat can be sold[20, 9, 8]

2.3 District heating in Stockholm and Uppsala

Stockholm's district heating system - dating back to the 1950s - consist of formerly local systems that are now mostly interconnected. These interconnected local systems are not centrally owned: there are 4 main utility companies that own parts of the grid where they have monopoly on heat distribution. The largest of these utilities is Stockholm Exergi followed by E.on Järfälla, Norrenergi, Söderenergi, and Vattenfall[1] (not in order of size)[13]. Conversely, the smaller Uppsala district heating network is owned by a single utility - Vattenfall. A 2011 elforsk report estimates the annual demand in the whole Stockholm DHN to amount to 12.5 TWh[1] , whereas [13] estimates it to amount to 12 TWh in 2017. These estimates are fairly in line with the Energiföretagen annual delivered heat per district heating grid database([3]). The values for Stockholm and Uppsala can be seen in2.3.1.

Stockholm and Uppsala, being cities in northern Europe with comparably harsh winters, have very seasonal heat loads. In summer, the load is mainly derived from tap water usage, whereas in winter space heating is the predominant load. The base load production

[1] Vattenfalls grid is close to, but currently not connected to the Stockholm DHN

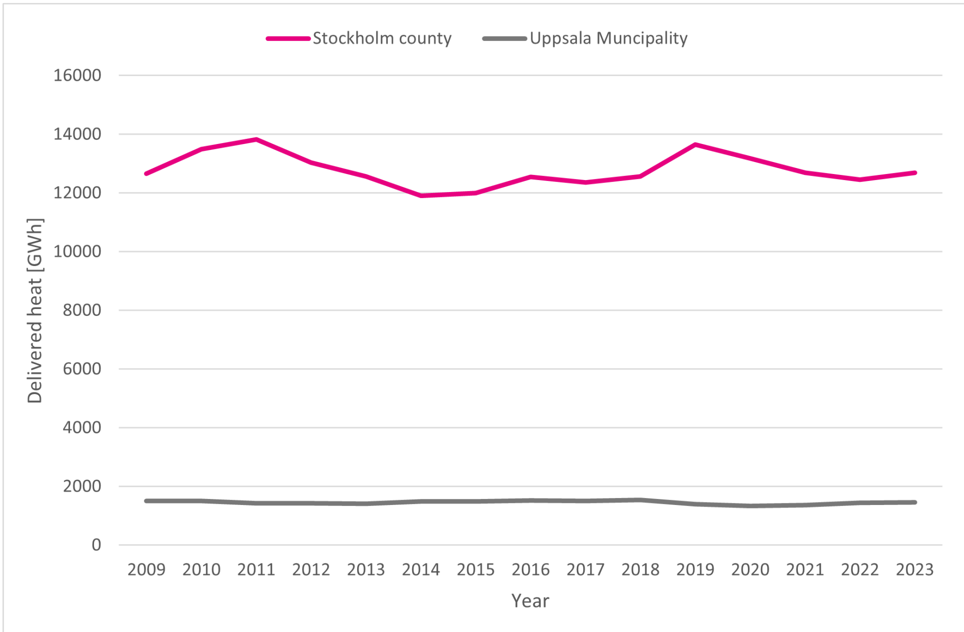


Figure 2.3.1: Annual district heating heat delivery in Stockholm and Uppsala. Values are adjusted for a normal year using energy indexes

in Stockholm is mainly supplied by waste incineration plants, middle load by bio-fueled Combined Heat and Power (CHP)s and Heat Pumps, whereas peak load is mostly covered by bio-oil Heat Only Boiler (HOB)s and fossil-oil HOBs[13].

Chapter 3

Models, Methodologies and Methods

3.1 Methodology

This study is based on a positivist research philosophy - effectively relying on quantifiable observations, assuming objective results, and adopting a deductive research approach [21].

More precisely, a model is developed that allows for estimating the techno-economical feasibility of a long distance HTS taking into account the thermodynamic properties of the system. A data collection was conducted in which relevant quantitative inputs to the model were collected. The deciding variables were then optimized for this model, allowing for an optimally dimensioned HTS. The model was then applied for the specific case of a HTS connecting Forsmark NPP with the Stockholm and Uppsala DHNs. Finally a sensitivity analysis was conducted. Each of these steps are described more closely below.

3.2 Literature Review

An initial semi-structured explorative literature review was conducted in order to identify research gaps in the research field of nuclear district heating. for this purpose a search was made on web of science where the keyword used was ”nuclear district heating”. From the resulting 537 articles the highly relevant ones were identified and cross referencing was used to find further literature.

3.3 Data Collection

The model used in this study needs an amount of technical, physical and economical parameters. The process for attaining values for these parameters has been largely ad hoc, with some values being adopted from related literature, some being common engineering assumptions, and some being provided by Vattenfall, operating the Uppsala DHN. Most notably, the DH-load profile, and corresponding air-temperature were taken from a Vattenfall data set. For a more detailed account of the parameters, see 4.

3.4 HTS Model

In this section the HTS model is described in detail. The model can roughly be described as in 3.4.1. In the base is a physics model which can be divided in two parts; 1. A heat transfer model, describing how the HTS will lose heat over distance based on thermodynamic relations, and 2. A pressure model that similarly determines the pressure losses. These physics models are then the base for an economic model- resulting in an economic appraisal of the entire DH-production system. These models are then used to evaluate different scenarios for the case study. Each of the sub-models will be described in detail here.

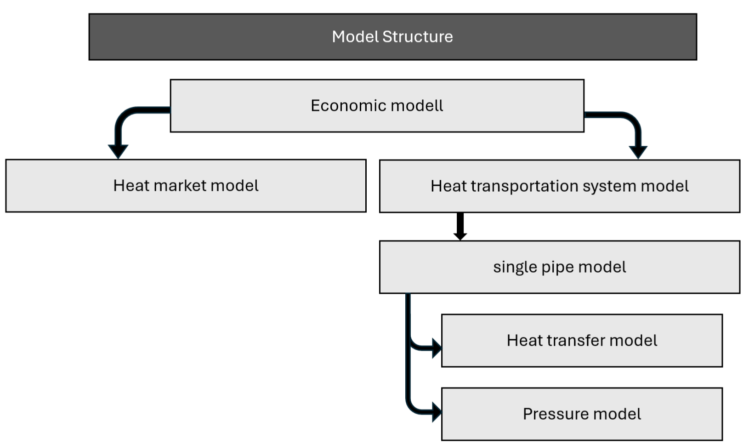


Figure 3.4.1: simple representation of the HTS model structure

The HTS model encompasses the supply and return pipelines between Forsmark NPP and Stockholm and Uppsala DHN. The Stockholm district heating network consists of a number of partly interconnected grids with different ownership. For convenience, the Stockholm DHN is simplified in the model as a point-like heat load, assuming that these grids are all connected, and that there is no restriction in transfer capacity between them. Also the heat load in Uppsala is assumed to be point-like.

The pipelines to Uppsala - with its smaller heat load - branches of from the main pipeline approximately halfway between Forsmark and Stockholm. The boundaries of the Physics model are drawn at the heat exchangers with the DHNs and NPP respectively. However, in the economic model, the cost for the necessary NPP modifications will be assumed and the other production plants in respective DHN will be taken into account when determining the system operating cost. A simple representation of this model layout is presented in 3.4.2.

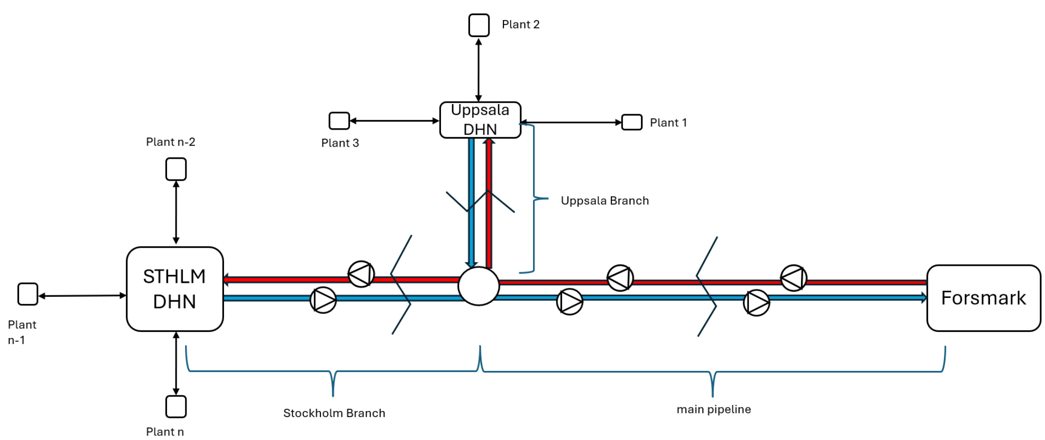


Figure 3.4.2: Simple HTS model

3.4.1 Pipe Layout

The HTS, with its branches to different locations needs to be split up for the analysis. To do this in an organized manner the notations used for the HTS in the rest of this paper will be introduced here. A part of the HTS connecting two nodes (intersection, DHN connection, or nuclear plant connection) is referred to as a branch. Following table 5.1.1 clarifies what index the different branches will be referred with.

	Notation	**Forsmark – intersection**	**intersection – Uppsala**	**intersection – Stockholm**
Branch index	$b \in \mathbb{B}$	0	1	2
Connection index	c_b	None	0	0
Load node	$Q_{\text{DH},b}$	none	Uppsala	Stockholm
Distance [km]	d_b	75	7	75

Table 3.4.1: Branch data for district heating network

All variables related to a certain branch are to be subscripted with the branch index. However, many calculations are done within one branch, and for simplicity the branch subscript is removed in those occasions. In a similar fashion the subscripts for supply and return lines are removed when not necessary.

Discretization

Even within a branch there is a need to discretise the pipeline into sections of a specific length. Within each such section the temperature, heat, pressure etc are assumed to be constant. The heat and pressure equations presented below are applied for each of these pipe sections. The set of sections in the pipeline is denoted as $\mathbb{S}_{\text{sections}} = \left\{1, 2, \ldots, \frac{distance_b}{\text{section\_length}}\right\}$. For the purpose of this study, a section length of 1000 m has been assumed.

3.4.2 Physics Model

Heat Transfer Model

For the calculation of heat transfer from the pipeline to its environment, it is looked at per pipe section. the conditions within these sections are assumed to be steady state, but affects the conditions in the following sections. To solve for the heat loss in the pipe, one-dimensional heat transfer is assumed, as the heat loss is normal to the pipe surface and thus there is thermal symmetry around the centerline of the pipe. To further simplify the problem, we disregard the thermal conductivity of the steel pipe, thus only regarding the insulation. furthermore we assume that the temperature is uniform inside the pipe as well as in the ground outside it. We can thus calculate the radial heat conduction through the pipe surface according to equation 3.1

$$\dot{Q}_{\text{loss},i} = \frac{2\pi\, l\, k\, (T_i - T_{\text{ground}})}{\ln\left(\frac{r_{\text{in}}+r}{r}\right)} \quad \forall i \in \mathbb{S}_{\text{sections}} \tag{3.1}$$

Where:

i denotes the section number,

l is the section length,

k is the thermal conductivity of the insulation,

T_i is the water temperature in pipe section i,

T_{ground} is the ground temperature,

r_{in} is the insulation thickness, and

r is the inner radius of the pipe.

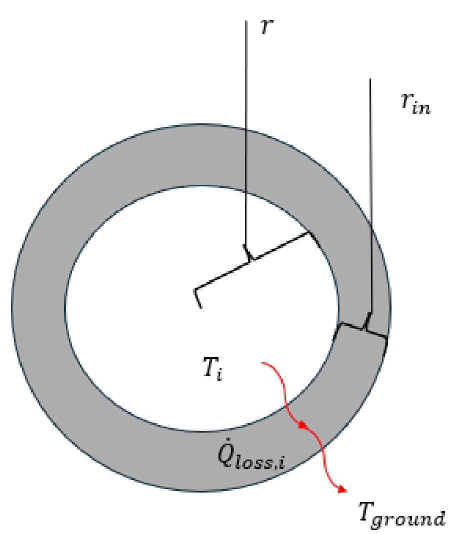


Figure 3.4.3: Illustration of radial heat conduction through pipe surface

Knowing $\dot{Q}_{\text{loss},i}$ we can now calculate the temperature loss $T_{\text{loss},i}$, and get the temperature in the next pipe section $i+1$. This can be done through the relation 3.2:

$$T_{\text{i+1}} - T_i = T_{\text{loss},i} = \frac{\dot{Q}_{\text{loss},i}}{\dot{m} \cdot c_p} \quad \forall i \in \mathbb{S}_{\text{sections}} \tag{3.2}$$

Where $\dot{m}$ is the mass flow of water in the pipe measured in kg/s and c_p is the specific heat capacity of water. c_p can be easily found,

The following equation(3.3) is needed for determining the Heat rate at the start, and end of a branch supply or return line.

$$\dot{Q}_b^{out} = \dot{Q}_b^{in} + \dot{Q}_{b,\text{loss}} \tag{3.3}$$

Where $\dot{Q}_{b,\text{loss}}$ represents the cumulative heat losses in branch b for either the supply or return line. $\dot{Q}_{b,\text{loss}}$ is found through taking the sum of heat losses for all sections in the pipeline. $\dot{Q}_b^{in}$ is the heat at the start of the branch, and $\dot{Q}_b^{out}$ is the heat rate at the end of the branch. Eq 3.3 applies for either the supply line or the return line. The equation for in and outgoing temperatures in a branch is the same.

Heat Transfer Between Branches

The initiation of the heat transfer model in each branch's supply and return flow depends on the values of previous branches in accordance with the initialization flow described below.

Initialization Flow:
1. Calculate the Main branch($b = 0$) supply line heat transfer using eq 3.1, and eq 3.2.
2. Branches connected to the main branch ($c_b = 0$) are initialized with the outgoing values from the main branch using eq 3.4, and eq 3.5.
The temperature at the start of a branch is equal to the temperature in the end of the previous branch. The heat rate also has to be split according to what portion of the mass flow goes

to the branch.

$$T_b^{\text{in}} = T_{c_b}^{\text{out}} \tag{3.4}$$

$$\dot{Q}_b^{\text{in}} = \dot{Q}_{c_b}^{\text{out}} \cdot \frac{\dot{m}_b}{\dot{m}_{c_b}} \tag{3.5}$$

where $\dot{Q}_{c_b}^{\text{out}}$ is determined according to Equation 3.3.

3. Each branch (1,2) then calculates its own temperature and heat losses for each section with 3.1, and 3.2 4. At the load nodes, the branch supply lines will initialize the return lines according to eq 3.6, and eq 3.7.

$$Q_{b,\text{return}}^{\text{in}} = Q_{b,\text{supply}}^{\text{out}} - \dot{Q}_{\text{DH},b}, \qquad \text{if branch } b \text{ has a load node} \tag{3.6}$$

$$T_{b,\text{return}}^{\text{in}} = T_{b,\text{supply}}^{\text{out}} - \frac{\dot{Q}_{\text{DH},b}}{\dot{m}_b \cdot \eta_{\text{HX}_{\text{DH}}} \cdot c_p}, \qquad \text{if branch } b \text{ has a load node} \tag{3.7}$$

5. In the confluence of two branches' return lines(e.g. b_1, b_2), the corresponding branch (b_0 such that $b_0 = c_{b_1} = c_{b_2}$) is initialized as in eq **??** for the temperature, and as in eq 3.9 for the heat rate.

$$T_{b,return}^{in} = \frac{\sum\limits_{i \in \mathbb{B},\ c_i = b} T_{i,\text{return}}^{\text{out}} \cdot \dot{m}_i}{\sum\limits_{i \in \mathbb{B},\ c_i = b} \dot{m}_i} \tag{3.8}$$

$$\dot{Q}_{b,return}^{in} = \sum_{i \in \mathbb{B},\ c_i = b} \dot{Q}_{i,return}^{out} \tag{3.9}$$

Mass Flow Model

The mass flow rate $\dot{m}_b$ within each pipeline branch $b \in \mathbb{B}$ is governed by the thermal energy exchange at either end of the branch. The mass flow is assumed to be constant throughout each branch, for both the supply and return pipelines. The determination of $\dot{m}_b$ is most easily done at the boundaries of the HTS, which gives the following cases:

- At the **NPP end** (branch $b = 0$), the supply and return temperatures are treated as decision variables. However, the heat transfer rate $\dot{Q}_{\text{NPP}}$ is not known a priori and must be inferred from the system behavior.
- At the **district heating end** (branches $b \in \mathbb{B}_{\text{load}} = \{1, 2, \dots\}$), the thermal demand $\dot{Q}_{\text{DH},b}$ is known, while the corresponding supply and return temperatures are not.

To compute the mass flow in each case, we apply the standard heat transfer relation across a heat exchanger:

$$\dot{m}_b = \frac{\dot{Q}}{\eta_{\text{HX}} \cdot \Delta T \cdot c_p} \tag{3.10}$$

where:

- $\dot{Q}$ is the heat transferred,
- η_{HX} is the efficiency of the heat exchanger,
- ΔT is the temperature difference across the exchanger,
- c_p is the specific heat capacity of the working fluid.

This general expression is applied specifically as follows:

For the NPP-connected branch $b = 0$:

$$\dot{m}_0 = \frac{\dot{Q}_{\text{NPP}}}{\eta_{\text{HX}_{\text{NPP}}} \cdot \Delta T_{\text{NPP}} \cdot c_p} \tag{3.11}$$

For the district heating branches $b \in \mathbb{B}_{\text{load}}$:

$$\dot{m}_b = \frac{\dot{Q}_{\text{DH},b}}{\eta_{\text{HX}_{\text{DH}}} \cdot \Delta T_{\text{DH},b} \cdot c_p} \tag{3.12}$$

Combining this with the following relation **??**, which connects the $\dot{Q}_{DH}$ to the $\dot{Q}_{NPP}$ via the total heat losses of the system, allows for solving for the mass flow rate if the heat loss is known. However, the heat loss does in turn depend on the mass flow rate. The mass flow rate is determined numerically using these relations, which is explained further in 3.5.

$$\dot{Q}_{NPP} = \sum_{i \in \mathbb{B}} \dot{Q}_{DH,i} + \dot{Q}_{loss,supply,i} + \dot{Q}_{loss,return,i} \tag{3.13}$$

Pressure Model

The linear pressure drop over the pipeline can be determined using the Darcy-Weisbach equation 3.14:

$$\Delta p_i = f \cdot \frac{l}{D} \cdot \frac{\rho v^2}{2} \quad \forall i \in \mathbb{S}_{\text{sections}} \tag{3.14}$$

where:

- Δp_i is the pressure loss in pipe section i,
- f is the Darcy friction factor,
- l is the length of the pipe section,
- D is the diameter of the pipe,
- ρ is the water density,
- v is the flow velocity.

The Darcy friction factor f for rough tubes with turbulent flow can be determined using a moody chart which gives an empirical relation between said friction factor f, the surface roughness ξ and Reynolds number Re. Re can be determined using equation 3.15.

$$Re = \frac{v \cdot d \cdot \rho}{\mu} \tag{3.15}$$

Where μ is the dynamic viscosity of water (assumed to be constant). The velocity v can be linked to the mass flow using the following relation 3.16:

$$v = \frac{\dot{m} \cdot A}{\rho} \tag{3.16}$$

Where A is the cross section area given by $A = \frac{\pi \cdot D^2}{4}$.

Equation 3.14 does not actually need any length segmentation, and the pressure loss can be determined over the whole pipe length at once. However, physical limitations on what pressures can be allowed in the pipeline are imposed on the system. The pressure may not be too high, to not break the pipe, and it cannot be allowed to go below saturation pressure, nor below atmospheric pressure. In the model an upper pressure limit of 1.6 MPa has been used.These pressure restrictions mean that pump-stations need to be placed along the pipeline to keep the pressure within the permitted range. The placements of these pump stations can be determined with 3.17 using the pipeline segmentation and a boolean dummy variable s_i.

$$p_{i+1} = p_i - \Delta p_i + p_{pump} \cdot s_i \quad \forall i \in \mathbb{S}_{\text{sections}} \tag{3.17}$$

where:

$$s_i = \begin{cases} 1 & \text{if } p_i - \Delta p_i \leq p_{\text{min}}, \\ 0 & \text{if } p_i - \Delta p_i > p_{\text{min}}, \end{cases} \quad \forall i \in \mathbb{S}_{\text{sections}}$$

So if the linear pressure loss brings the pressure for the next section below the minimum pressure (saturation pressure times a safety factor), there will be a pump station in sector i that increases the pressure by p_{pump}. This will ensure that pressure is kept within the permitted range along the whole pipe.

$$W_{\text{pump}} = \eta_{\text{pump}} \cdot \sum_{i \in \mathbb{S}_{\text{sections}}} p_{\text{pump}} \cdot s_i \tag{3.18}$$

As for the boundaries and for initializing the pressure of each branch's supply and return lines, the relations are quite simple. The main's supply line is initialized as $p^{in}_{0,supply} = p_{nom}$, where p_{nom} is the nominal pressure. For the supply line branches 1 and 2 the pressure is simply set as the outgoing pressure of the main line: $p^{in}_{b,supply} = p^{out}_{c_b,supply}$. The pressure in the first section of the return pipe in branches 1 and 2, are initialized as: $p^{in}_{b,return} = p^{out}_{b,supply} - \Delta p_{b,exchanger}$ for$b = 1, 2$, where $\Delta p_{b,exchanger}$ is the pressure drop in the heat exchanger with the DHN. At the confluence of return lines (e.g. b_1, b_2, the pressure in the main line (b_0 such that $b_0 = c_{b_1} = c_{b_2}$) will heuristically be set as the lower of the two incoming pressures.

3.4.3 Economical Model

Dispatch and Merit Order

The merit order of the DH market, assuming perfect market conditions, is determined by the Marginal Cost (MC) of each production method. The MC, is the cost of increasing the produced quantity marginally. It can be said that the MC is the derivate of the VC. for the purposes of this paper, MC is determined using the Variable Cost (VC) according to eq 3.19.

$$\mathrm{MC}_{\dot{Q}_{\mathrm{DH}},t} = \frac{\mathrm{VC}_{\dot{Q}_{\mathrm{DH}},t} - \mathrm{VC}_{\dot{Q}_{\mathrm{DH}}-\Delta\dot{Q}_{\mathrm{DH}},t}}{\Delta\dot{Q}_{\mathrm{DH}}} \tag{3.19}$$

At the same time a plant will not go into operation if the price is below the Average Variable Cost (AVC) line, determined with eq 3.20.

$$\mathrm{AVC}_{q,t} = \frac{\mathrm{VC}_{q,t}}{\dot{Q}_{DH,q,t}} \tag{3.20}$$

To model the system, an assumption for the the marginal prices of the different production methods is needed. To simplify the calculations, a constant AVC independent of the production volume has been assumed for all production methods except nuclear and electric. This fixed AVC will result in the MC being constant and equal to the AVC as shown in eq. 3.21 using eq. 3.20 and eq. 3.19. The production methods will not produce if the price is below their AVC.

$$\mathrm{MC}_{q,t} = \frac{\mathrm{AVC} \cdot \dot{Q}_{DH,q,t} - \mathrm{AVC} \cdot \dot{Q}_{DH,q-\Delta q,t}}{\dot{Q}_{DH,q,t} - \dot{Q}_{DH,q-\Delta q,t}} = \mathrm{AVC} \cdot \frac{\dot{Q}_{DH,q,t} - \dot{Q}_{DH,q-\Delta q,t}}{\dot{Q}_{DH,q,t} - \dot{Q}_{DH,q-\Delta q,t}} = \mathrm{AVC} \tag{3.21}$$

Additionally, the start- up and shut- down costs and times of the production plants are ignored in this model.

For nuclear heat, we can calculate the VC based on the operational conditions of the HTS which will depend on the nuclear heat demanded by the DHN's ($\dot{Q}_{b,demand}$), on the ground temperature(T_{ground}), and on the electricity price. The dependence of these operational conditions can be found using the equation 3.22. Based on that variable cost, we can then get the Marginal cost with 3.19.

$$\mathrm{VC}_{q,t} = P_{\text{loss}}(Q_{\text{DH}}, T_{\text{ground}}) \cdot \pi_{\text{el}} + P_{\text{pump}}(Q_{\text{DH}}, T_{\text{ground}}) \cdot (\pi_{\text{el}} + \tau_{\text{el}} + \phi_{\text{grid}}) \tag{3.22}$$

where:

- $VC_{q,t}$ —Variable cost at time t.
- $P_{\text{loss}}(Q_{\text{DH}}, T_{\text{ground}})$ —lost power in the nuclear plant as a function of heat production and ground temperature .
- π_{el} —Electricity price.
- $P_{\text{pump}}(Q_{\text{DH}}, T_{\text{ground}})$ —Power required for pumping, as a function of delivered heat Q_{DH} and ground temperature T_{ground}.
- τ_{el} —Electricity tax.
- ϕ_{grid} —Grid fee.

The power loss at the nuclear plant, P_{loss}, is determined by eq 3.23, and the pumping power,

P_{pump}, is determined by eq 3.24

$$P_{\text{loss}} = Q_{\text{NPP}}(Q_{\text{DH}}, T_{\text{ground}}) \cdot T_{\text{supply}} \cdot k_{\text{power loss}} + T_{\text{supply}} \cdot m_{\text{power loss}}$$
$$\text{where } k_{\text{power loss}} \text{ and } m_{\text{power loss}} \text{ are coefficients of a linear relationship} \tag{3.23}$$

$$P_{\text{pump, el}} = P_{\text{pump}}(Q_{\text{DH}}, T_{\text{ground}}) \cdot (\pi_{\text{el}} + \tau_{\text{el}} + \phi_{\text{grid}})$$
$$\text{where } \tau_{\text{el}} \text{ is the electricity tax, and } \phi_{\text{grid}} \text{ is the grid fee} \tag{3.24}$$

$$\text{VC}_{q,t} = W_{\text{pump},q,t} \cdot \pi_{\text{el},t} \tag{3.25}$$

Note that heat losses in the HTS result in an increased $\dot{Q}_{NPP}$ according to 3.13. This incurres further power losses at the NPP, increasing the VC. Likewise, the pumps have a cost of electricity to operate them. Through these two costs, the design of the pipeline affects its operational cost. It should also be noted that the price of lost power production at the plant is lower than that of power consumption for pumps, as the pumps also are susceptible to electricity tax and grid fees, whereas the cost of lost income from power production is simply the spot price on the electricity market.

Net Present Value

The cost of investment for the HTS is calculated as 3.26:

$$\begin{aligned}\text{Investment cost} = {} & n_{\text{pump stations}} \times C_{\text{station}} \\ & + \sum_{b \in \mathbb{B}} d_b \times \left(\alpha D_b^2 + \beta D_b + \gamma\right) \\ & + \dot{Q}_{\text{installed}} \times c_{\text{plant modification}}\end{aligned} \tag{3.26}$$

Where:

- $n_{\text{pump stations}}$: Number of pump stations.
- C_{station}: Cost per pump station
- d_b: distance in branch b
- α, β, γ: coefficients for the pipeline cost function.
- D_b: Diameter of the pipeline in branch b.
- $\dot{Q}_{\text{installed}}$: Installed capacity.
- $c_{\text{plant\_modification}}$: Specific plant modification cost [SEK/MW].

It is thus assumed that the investment cost will depend on the pipe diameter as a second degree polynomial function. The construction cost of pump stations and that of the NPP modifications are then added. For the Total Operational Cost (TOC) we will regard the costs of operating the entire DHN production across both Uppsala and Stockholm. The costs will depend largely on the allocation of heat production, as the different production methods have largely varying production costs. The is calculated as eq 3.27 using the individual production methods's Operational Cost (OC) determined by eq 3.28.

$$TOC_d = \sum_{i \text{ in Production methods}} OC_i \cdot 24 \quad \text{for } d \in [0, 365] \tag{3.27}$$

$$OC_{i,d} = \text{AVC}_{i,d} \cdot P_{i,d} \quad \text{for } i \in \text{Production methods, and } d \in [0, 365] \tag{3.28}$$

These daily total operational costs TOC_i for day i, can then be summed over a year to get the annual operational costs **AOC!** (**AOC!**). (assumed to only consist of variable costs) With the **AOC!**, it is possible to calculate the Net Present Value NPV according to 3.29.

$$NPV = \text{investment cost} + \sum_{y=1}^{\text{lifetime}} \frac{AOC_y}{(1+r)^y} \tag{3.29}$$

Where AOC_y is the total operational cost of the entire DHN production system for year y, and r is the discount rate.

Worthy to note is that no income is included in the NPV equation. This study will regard the nuclear heating investment as an operational rationalization on a DHN system level. Only costs that are changed by introducing nuclear district heating to the system are included and the benchmark for comparison is thus not a NPV of 0, but rather the NPV (considering the same costs entries) of an unchanged system, that is the BAU.

3.5 Optimization

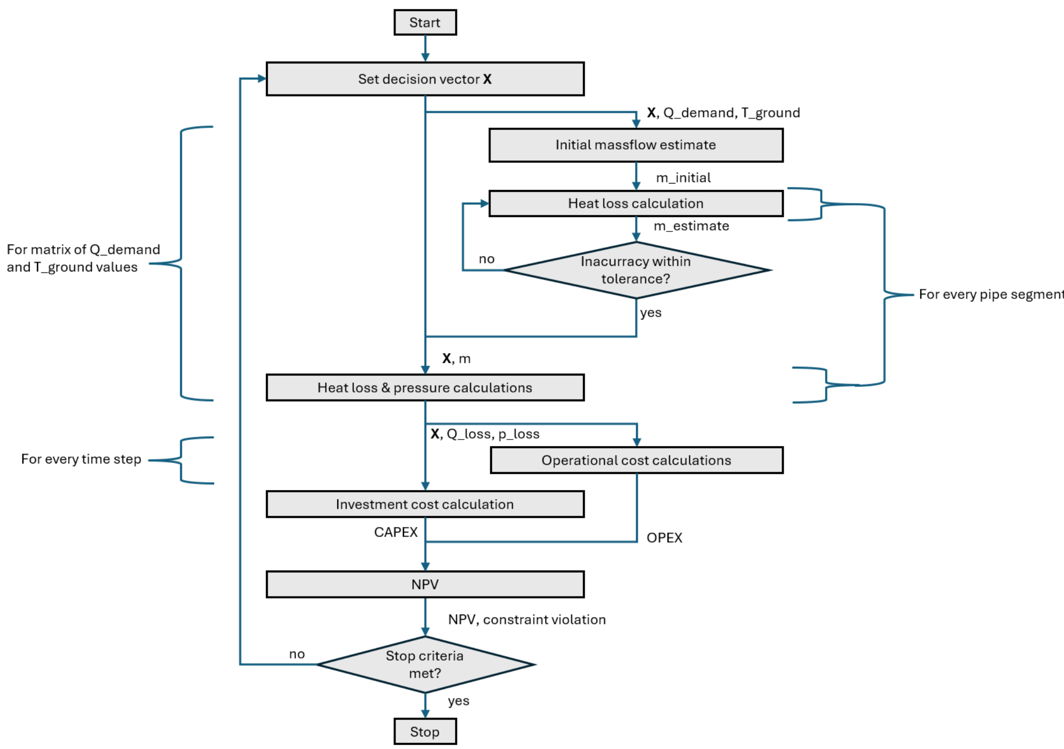


Figure 3.5.1: Flowchart of optimization process

The optimization process is that of 3.5.1. It iterates through the heat transfer, pressure, and economic models described above. Two factor merits further explanation however. That is 1) the determination of the massflow in the model by an iterative process and 2) how operational conditions are interpolated rather than calculating them daily.

3.5.1 Iterative Mass Flow Estimation Process

The equations governing heat transfer, temperature, and pressure—outlined in Section **??** —require the mass flow rate to be known. To address this, an iterative procedure adapted from [8] is employed. While originally developed for non-branching HTSs, this method has been extended here to accommodate branching HTS configurations.

The process begins by estimating heat losses using Equation 3.1. Instead of dividing the pipeline into smaller segments, each supply or return pipe within a branch is treated as a single section of length l. This simplification assumes a constant temperature along each pipe, which leads to an initial overestimation of the mass flow.

Heat losses are first calculated for branches 1 and 2, assuming that both the supply and return temperatures are equal to those at the NPP. Using these losses, the initial mass flow rates for each branch are estimated via Equation 3.12. These branch losses are then aggregated with the heat loss from the main branch ($b = 0$), calculated in the same manner.

The estimated total heat load at the NPP, $\dot{Q}_{\text{NPP,estimation}}$, is then computed using Equation 3.13, which incorporates both the estimated total heat loss and the district heating demands $\dot{Q}_{\text{DH},b}$. This value is used in Equation 3.11 to determine the mass flow in the main branch.

Subsequently, the initial mass flow estimates for branches 1 and 2 are scaled relative to the main branch mass flow using Equation 3.30:

$$\dot{m}_{b,\text{estimate}} = \dot{m}_{0,\text{estimate}} \cdot \frac{\dot{m}_{b,\text{initial estimate}}}{\sum\limits_{b \in \mathbb{B},\ c_b = 0} \dot{m}_{b,\text{initial estimate}}} \quad \text{for } b \in \mathbb{B},\ c_b = 0 \tag{3.30}$$

With this initial estimate, the full initialization process described in Section 3.4.2 is executed across all branches and sections. The resulting mass flow and heat loss values are then used to update the estimate of $\dot{Q}_{\text{NPP}}$. This iterative process continues until the return temperature deviation $\left|T^{\text{out}}_{b=0,\text{return,estimate}} - T_{\text{return}}\right|$, denoted as the inaccuracy ϵ, falls below a predefined threshold. In this study, an inaccuracy of less than 0.1°C is considered acceptable.

3.5.2 Interpolation-Based Reduction of Iterative Computations

As described in Section 3.4.3, the calculation of the VC for the HTS requires knowledge of both the pumping power W_{pump} and the thermal output from the nuclear power plant $\dot{Q}_{\text{NPP}}$ for each time step. With a daily resolution, this would necessitate performing the iterative mass flow estimation process 365 times—once for each day of the year.

However, since both W_{pump} and $\dot{Q}_{\text{NPP}}$ are functions solely of the ground temperature T_{ground} and the district heating demand $\dot{Q}_{\text{demand, total}}$, a more computationally efficient approach can be employed. Instead of performing the full iterative procedure for each time step, these quantities can be precomputed for a discrete set of T_{ground} and $\dot{Q}_{\text{demand, total}}$ values. Then, for each time step, the required values can be estimated using linear interpolation.

In this study, five representative values of $\dot{Q}_{\text{demand, total}}$, ranging from zero to the total installed capacity, and seven values of T_{ground}, spanning the annual minimum to maximum ground temperatures, are selected. This results in a total of $5 \times 7 = 35$ unique combinations. The iterative mass flow estimation is performed only for these 35 cases. During the simulation, the values of W_{pump} and $\dot{Q}_{\text{NPP}}$ for any given day are obtained through interpolation from this precomputed dataset, reducing the computational load from 365 to 35 iterations while maintaining acceptable accuracy.

3.5.3 Decision Variables

The decision variables are the variables that the optimizer will adjust to optimize an objective function. For the case of this study, those decision variables are the following:

Name	**type**	**Unit**
installed capacity per branch	array	MW
diameter per branch	array	m
supply temperature	scalar	K
return temperature	scalar	K

These variables are then compiled into a decision vector **x** of length: $2 + n_{branches} + n_{loads}$

$$\mathbf{x} = \begin{pmatrix} \text{installed capacity}_1 \\ \text{installed capacity}_2 \\ \text{diameter}_0 \\ \text{diameter}_1 \\ \text{diameter}_2 \\ \text{supply\_temp} \\ \text{return\_temp} \end{pmatrix}$$

3.5.4 Objective Function

The objective that will be optimized for is the Net Present Value (NPV) - which is to be maximized. The objective function is that of 3.29. Note that the NPV function is non-linear (inherited from the investment cost eq 3.26) why the problem cannot be solved with **LP!** (**LP!**).

3.5.5 Constraints

Some constraints need to be addressed in order to make sure the model is realistic. One such constraint is the load matching constraint which dictates that for each time step the production in the system must be equal to the heat load of that period(3.31).

$$\sum_{p=1}^{n_p} \dot{Q}_{p,t} = \dot{Q}_{load,t} \tag{3.31}$$

Furthermore, due to wear on the pipes at high flow velocities, there is a need to impose an upper limit, v_{max}, to the velocity in the pipe.

$$v_{i,t} \leq v_{max} \quad \forall i \in \mathbb{S}_{\text{sections}}, t \in [T_{min}, n_t] \tag{3.32}$$

3.5.6 Optimization Method

For this study a Genetic Algorithm (GA) Optimization approach has been adopted. This optimization method is based on an initialization with random guesses that then iteratively converge towards an optimum.

3.6 Scenarios

The above described model will be applied to the case of a HTS connecting Forsmark NPP with the Stockholm and Uppsala DHNs.

3.7 Sensitivity Analysis

In order to account for the uncertainties in the parameter values - especially as they might change drastically over the HTS's lifetime - a set of different parameter values will be regarded. This will allow to explore different possibilities with changes in price conditions for biofuels and electricity, and different estimations on HTS investment costs. This approach will both allow to compare the results of this study to previous studies through imitating their inputs, as well as exploring a number of possible futures, uncovering more precisely under what conditions this would be feasible, further increasing the validity of this study.

Chapter 4

case study: Forsmark & Stockholm

This chapter comprehensively describes the work done.

The model and optimization approach described in chapter 3 is applied for the case of a heat transport system connecting the Forsmark NPP to the DHNs in Stockholm and Uppsala. In this chapter, the choice of parameter values and assumptions related to the site specific conditions will be presented.

4.1 Heat load in Stockholm and Uppsala

A Vattenfall dataset containing the hourly heat load and air temperature for Uppsala was used for the Uppsala heat profile in this case study. For the Stockholm DHN - consisting of a number of partly interconnected grids with different ownership - it is significantly harder to attain the necessary primary data to compile hourly aggregated heat loads. Instead, an approach of simply scaling the Uppsala DHN heat profile with the Stockholm DHN annual heat load was adopted. The Stockholm DHN annual heat load was estimated by summing the heat loads of all DH grids in the Stockholm county as found in the Energiföretagen heat delivery database [3]. Note that this include the Jordbro DHN that is as of today not connected to the main Stockholm DHN. For the purpose of this paper it will however be considered as connected. The energy-index-normal-year-adjusted yearly delivered heat for these DHNs can be found in Appendix A. Taking the average of the adjusted DHN delivered heat in the Stockholm county over the years 2013-2023 results in an annual heat load of 12.6 TWh - in line with the numbers presented in 2. For convenience, this number is assumed to remain constant over the economic lifetime of the HTS. Scaling the Uppsala load profile so that it sums up to the Stockholm DHN annual heat load gives an approximate load profile for Stockholm. The load profiles are presented in 4.1.1 below.

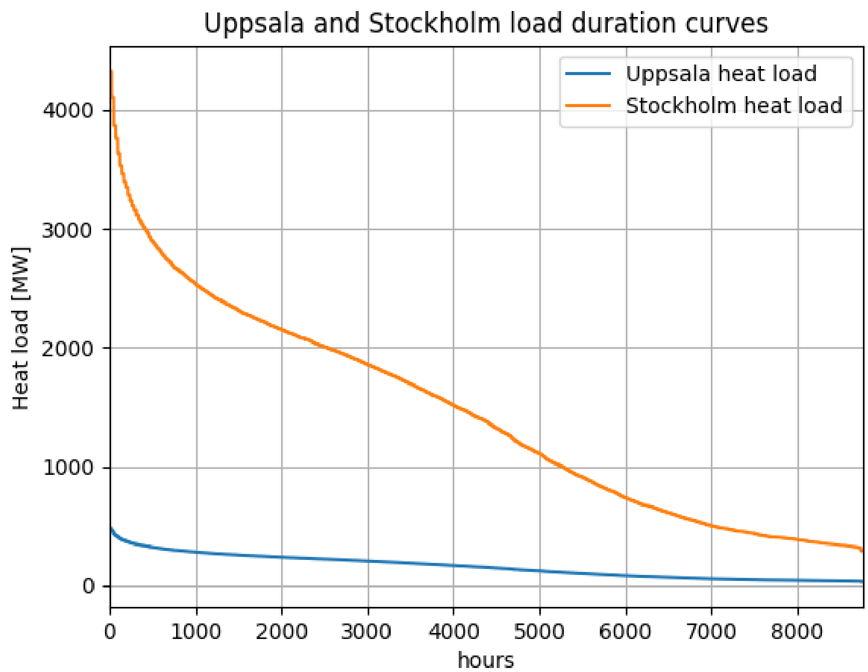


Figure 4.1.1: Uppsala and Stockholm load duration curves

However these profiles needs to be adjusted to fit the time step used for the optimization. This is done by taking the average hourly load over each time step resulting in a step-wise load profile as in **??**

4.2 Ground temperature

In the model, a ground temperature is needed for each time step. The ground temperature is assumed to be constant along the entire pipeline at each time step. Hourly air temperature data for Uppsala was used to approximate the ground temperature. Missing data points were filled in using linear interpolation. An empirical linear relation presented in [29] was used to attain the ground temperature from the Uppsala air temperature data. The relation can be seen in equation 4.1.

$$T_{g,d} = 0.6063 \cdot T_d + 8.0754 \quad \text{for all days } d \tag{4.1}$$

Where $T_{g,d}$ is the average daily ground temperature at 1.5m depth for day d, and T_d is the average daily air temperature for day d. Applying this equation to the Uppsala temperature series gives the ground temperatures presented in 4.2.1

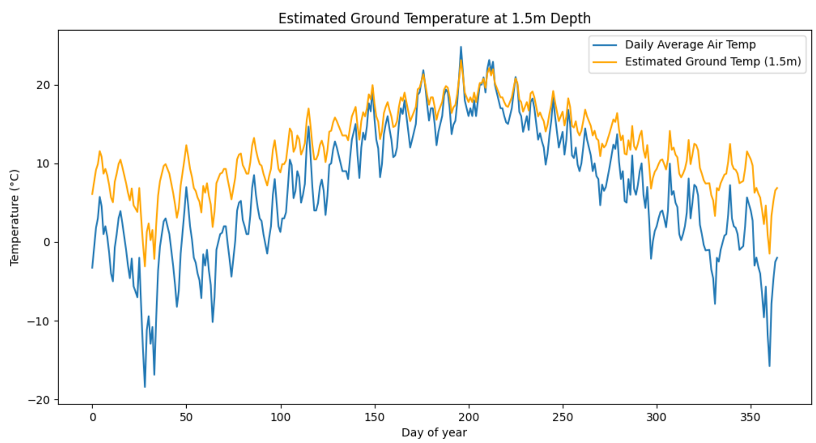


Figure 4.2.1

4.3 DHN Capacities - current layout

The installed capacities of different production facilities in the Stockholm and Uppsala DHNs have been estimated. The production facilities have also been categorized according to what fuel type they use in their heat production. A set of production categories have been compiled based on the prevalent fuel types in the Stockholm and Uppsala DHNs. A suitable set of fuel categories based on the aforementioned criteria is the following:

- **Waste** - encompassing both household and industrial waste

- **Wood chips/grot**[1] - grouped together as they are both low-refined wood fuels with similar price levels
- **Wood pellets** - a more refined wood fuel with a higher price
- **Bio oil** - highly refined and expensive bio fuel
- **Fossil** - fossil fuels. Mostly oil.
- **Electric** - power consuming heat production such as heat pumps and electric boilers
- **Nuclear** - the heat supplied via the HTS to the DHN

When assigning a fuel category to the production facilities, the category selection is based on the main fuel used in the facility.

Another important distinction is that between HOB and CHP facilities. The CHP facilities are run not simply based on the price they can sell their produced heat at, but also based on its electricity production. This gives CHPs an advantage as, the MC of producing heat is low if they're already this places CHP facilities lower in the merit order compared to their HOB counterparts using the same fuel. This distinction between CHP and HOB facilities is not made in this study.

The current DH production grouped into the aforementioned fuel categories for Uppsala and Stockholm are presented below.

Uppsala

For Uppsala DHN, Vattenfall provided the capacities and fuel types for each production facility as shown in 4.3.1:

Stockholm

For the Stockholm DHN the installed capacity per facility was given from Stockholm Exergi [**personal communication**]. This data was combined with the installed capacity in the Jordbro DHN[33]. A summary of the installed capacity per fuel type is presented in 4.3.2 below. Information about the COPs of the heat pumps, and the installed power in some of

[1] grot: branches and treetops

Fuel Type	Installed Capacity [MWth]
Waste	150
Wood chips/grot	90
Wood pellets	100
Bio oil	100
Electric (boilers)	60
sum:	**510**

Table 4.3.1: Production Facilities in Uppsala

the CHPs are found in Appendix A. It is compiled from a variety of sources [22, 17, 13, 14, 33]. but is not as up to date as table 4.3.2 below regarding the installed capacity.

Fuel type	**Installed capacity [MWth]**
Bio oil	811
Electric(Heat Pumps)	595
Fossil	655
Waste	314
Wood chips/grot	1137
Wood pellets	625
Grand Total	**4137**

Table 4.3.2: Installed capacity per fuel type in Stockholm DHN

4.4 Economic assumptions

One major economic assumption is the marginal costs for all production categories in the DHN. To mitigate the risk of inaccurate marginal cost assumptions a number of scenarios will be covered. In the base scenario, the following flat marginal costs will be assumed for the following production methods:

- Waste: 150 SEK/MWh
- Wood chips/Grot: 450 SEK/MWh
- Wood pellets: 550 SEK/MWh

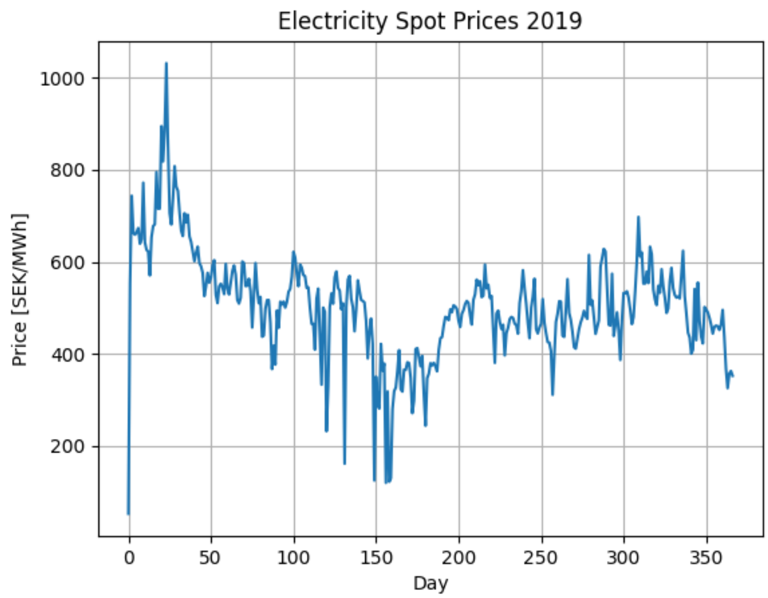


Figure 4.4.1: Inflation adjusted Daily average Spot prices for SE3 2019

- Bio-oil: 1500 SEK/MWh
- Fossil: 1500 SEK/MWh

For the heat pumps and electric boilers, the marginal cost will not depend on any fuel price, but rather on the price of electricity. For this purpose, an hourly electricity price data set for SE3[5] has been used, where the past electricity prices has been converted to SEK and adjusted for inflation according to [2] and [24]. For 2019, the year used for the base scenario, the yearly average electricity price amounted to 504 SEK/MWh.

The heat pumps are assumed to have an average COP of 3.33, and the electric boilers of 1. When calculating the costs for these, a network fee and an electricity tax rate is added to the cost.

The marginal cost for nuclear district heating is calculated in accordance with chapter 3. The economic parameters needed to calculate the operational and investment costs of the HTS are the following:

Parameter	**base value**	**Unit**
lifetime	30	years
discount rate	0.07	-
pump station cost	44	MSEK/unit
network fee	650	SEK/MWh
electricity tax	430	SEK/MWh
specific plant modification cost	790 000	SEK/MW

The discount rate is set at 0.07. A commercial discount rate would likely be somewhat lower, for example, the CAPM[6.1] can give an indication of such rates. Using industry betas for the U.S utility industry from [4] we get $\beta = 0.39$. Combining this with 2024 years market risk premium,($(E(R_m) - R_f)$ of 6.1%, and a risk free rate, R_f, of 2.9% [23], will give expected return on investment $E(R_i)$ as in 6.1. This expected return would represent a more reasonable commercial discount rate for projects in the utility industry under current market conditions. However, as this particular project is in quite a different scale than usual projects, it can be assumed to incur a riskpremie. Consequently, the somewhat increased discount rate of 0.07 is used for the base case.

$$\begin{aligned} E(R_i) &= R_f + \beta(E(R_m) - R_f) \\ &= 0.029 + 0.93 \cdot 0.061 \\ &= 0.053 \end{aligned} \tag{4.2}$$

In the sensitivity analysis the discount rate is shifted. A discount rate of 0.03 following the example of [9], is explored. This is a low interest rate most suitable for government-backed infrastructure projects. On the other end a high discount rate of 0.10 will be looked at too.

The technical lifetime of the pipeline is estimated at 30 years. This estimate is fairly conservative, as [6] advises that pipelines operating at temperatures below 115°C should be considered to have a lifetime exceeding 50 years. However, since that exceeds the expected lifetime of current production facilities at Forsmark [INSERT SOURCE], the more conservative assumption of a lifetime of 30 years is preferred.

When it comes to the modifications necessary at the power plant, there have been two options considered: 1) a complete Turbin bypass, where excess heat capacity in the boiler is being used for district heat production, and 2) diverging flows form different parts in the steam cycle, resulting in reduced power production proportional to the produced heat. These options have great effect on the marginal cost of the nuclear heat: the former does not incur any additions to the variable cost, whereas the latter has to account for the loss of electricity production in the plant when determining the variable cost.

4.4.1 pipeline cost modeling

The cost of constructing the pipeline is complex, areas to account for include the cost of materials for the pipe and the insulation, the cost of the land and the excavation, and the cost of labour for welding etc. In order to reduce this complexity, the total cost is reduced to depend solely on the pipe diameter as a second-degree polynomial. The equation was fitted using Vattenfall DH pipeline cost forecasts, and can be seen in 4.4.2. However, the forecasted costs are based on data from projects in urban areas, and the pipeline for this case study will largely be laid in rural environments. Since construction in rural areas is less complicated and disrupting than in urban areas, one can expect a reduced cost profile. To account for this, the total pipeline cost will be multiplied by a factor 0.7.

4.4.2 Power loss at heat production

The steam cycle of the NPP has not been studied in this paper. Instead we rely on the findings of [1], which provided functions describing the power loss to heat production relation in the steam cycle depending on the supply temperature. In [1] the calculations were made for two supply temperatures; 95°C and 130°C, where the lower supply temperature resulted in smaller power losses. Generalizing this to a span of temperatures by linear interpolation, one can achieve the relation in eq 4.3 where power loss is determined by heat output and supply temperature.

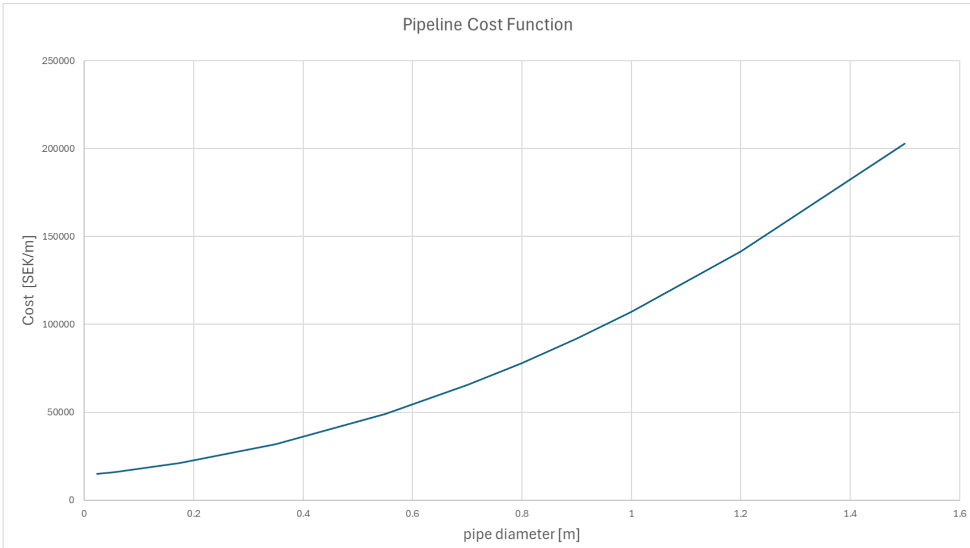


Figure 4.4.2: Pipeline construction cost for supply and return pipeline pairs in a single trench per meter and pipe diameter

$$P_{loss} = Q_{npp} \cdot T_{\text{supply}} \cdot k + T_{\text{supply}} \cdot m \tag{4.3}$$

using the results in [1], will give, on average, $k = 0.00096$, and $m = 0.06319$ if T_{supply} is given in °C. In figure 4.4.3 this relation is shown for some temperatures.

4.5 Cases and Scenarios

In this study, three different scenarios are explored, each representing a possible future layout of the district heating (DH) production system. These scenarios serve as baselines to which the addition of nuclear heat production—defined by the cases in table 4.5.1 — will be evaluated. Of particular interest is the role of waste incineration heat plants in the system.

The explanaition of the cases is the following: BAU: No nuclear heating added to the system. Base: Fixed capacity of nuclear heating added(1000 MW to Stockholm DHN and 50 MW to Uppsala DHN) High: Fixed capacity of nuclear heating added(1500 MW

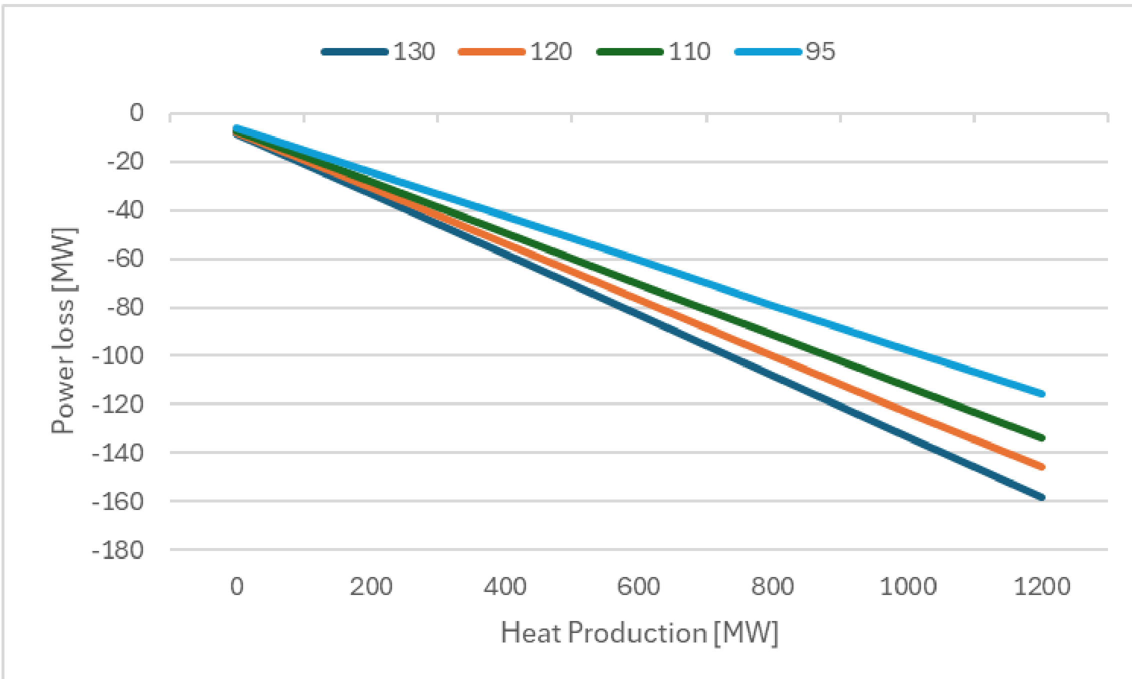


Figure 4.4.3: Power loss in power plant per supply temperature and Heat production

to Stockholm DHN and 100 MW to Uppsala DHN) Optimized: The added capacity of nuclear heating is determined by the optimization.

The reason for the specified capacities in the base and high cases is to ease comparison with [1], which used those capacities for their calculations.

The first scenario models the current system layout, where no changes are made to the existing waste incineration capacity. Nuclear heat is added according to the defined cases (BAU, base, high, and optimized), allowing for evaluation of its integration into the present-day system.

In the second and third scenarios , waste incineration capacity is reduced by half, and 100% respectively, reflecting a future where improved material recycling, reduced waste imports, or the decommissioning of older plants lowers available capacity. Nuclear heat is added as in Scenario 1, with an additional "replace only" case where introduced nuclear capacity directly replaces the removed incineration capacity.

Scenario	**Case**	**Nuclear Capacity [MW]**
No reduction to waste incineration	BAU	0
	base	1000, 50
	high	1500, 100
	Optimized	t.b.d.
50% reduction in waste incineration	BAU	0
	base	1000, 50
	high	1500, 100
	Optimized	t.b.d.
	replace only	75, 150
100% reduction in waste incineration	BAU	0
	base	1000, 50
	high	1500, 100
	Optimized	t.b.d.
	replace only	150, 300

Table 4.5.1: Nuclear Capacity Scenarios under Different Waste Incineration Reduction Levels

4.6 Other modeling Parameters

Parameters:

Name	**value**	**Unit**
Thermal conductivity	0.029	W/(mK)
insulation thickness	0.10	m
heat exchanger efficiency	1	-
pi	math.pi	-
nominal pressure	1.5×10^6	Pa
surface roughness	0.1×10^{-3}	m
gravitational acceleration	9.82	m/s^2
pump pressure	1×10^6	Pa
pump efficiency	0.75	-
cp	liquid water at 373.15 K and 1 MPa	J/(kg K)
distance:	150×10^3	m
section length	10^3	m
lowest ground temperature	269	K
discrete set of ground temperatures	[269, 273, 277, 281, 285, 289, 293]	K
discrete set of heat rates	[0.2, 0.4, 0.6, 0.8, 1.0]	K
max velocity	4.0	m/s
lifetime	30	years
density	liquid water at 373.15 K and 1 MPa	kg/m^3

The thermal conductivity value is based on the recommendations in the SS-EN253:2019 standard[6].

The discrete set of ground temperatures are the ones used for the interpolation in 3.5. The discrete heat rate values for this interpolation are determined by the installed capacity, which is multiplied by the discrete set of heat rates from the table above.

Chapter 5

Result and Analysis

5.1 Result/Analysis

In this section, the results of this paper will be presented. First, technical results relating to the performance of the pipeline will be presented, then results on how the DH system will perform economically in different scenarios. These results will be discussed and a sensitivity analysis will be conducted to account for uncertainties in the value of some important variables.

For this result section We will start by looking at a base case in the Technical results, and for the subsequent economical analysis a number of cases will be considered. The base case is that of a pipeline with a fixed installed capacity of 1000 MW to Stockholm, and 50 MW to Uppsala.

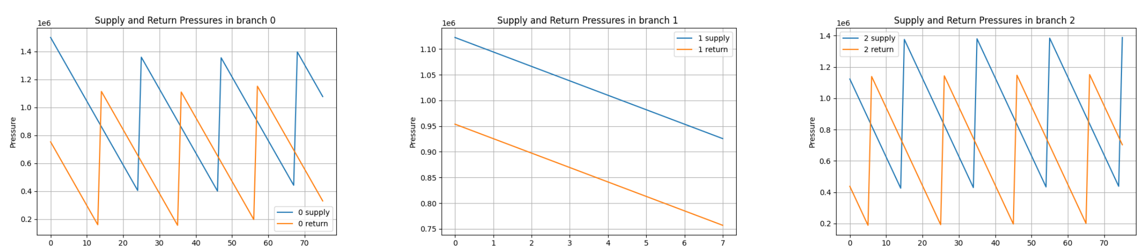
5.1.1 Technical results

For the base case we will assume an HTS with an installed capacity of 1000 MW to Stockholm and 50 MW to Uppsala. Optimizing the diameter, supply temperature, and return temperature for this HTS, gives the following values presented in 5.1.1 when run at full installed capacity and the minimum modeled ground temperature. As one might expect based on its low relative installed capacity and distance, one can see that the mass flow and heat loss in the Uppsala branch is significantly lower than those of the other branches. We can also see that even in the most extreme operational conditions (at capacity, with minimum ground temperature) the flow velocity remains well below the maximum velocity limit of 4 m/s.

Branch	**Main (0)**	**Uppsala (1)**	**Stockholm (2)**
Installed capacity [MW]	1050	50	1000
Distance [km]	75	7	75
Diameter [m]	1.14	0.40	1.13
Heat loss [MW]	14.5	0.5	14
Number of pump stations	6	0	8
Mass flow [kg/s]	3202	152	3050
Velocity [m/s]	3.11	1.28	3.19

Table 5.1.1: System characteristics for each branch

In figure 5.1.1 below the pressure in each section of the different branches of the pipeline can be seen. The sudden spikes occur at the spots where pump stations that increase pressure are placed. Note that the start of the return pressure values is on the left in the graph, just as for the supply pressure values. The branches are numbered as 0: main, 1: Uppsala, and 2: Stockholm. The return lines contain water at a lower temperature, allowing the return lines to reach lower pressures without risk of the water evaporating. this can be seen in the figures as the return lines are shifted down relative to the supply lines. In the branch to Uppsala, which is only 7 km long, we can see that pressure never drops to the minimum allowable pressure. This confirms that there is no need to install any pump stations at all in the Uppsala branch as presented in 5.1.1.



(a) main line (b) Uppsala branch (c) Stockholm branch

Figure 5.1.1: Pressure over distance in the different parts of the pipeline [Pa]

KPI	Value
Heat loss rate [%]	2.7
Pumping power [MW_{el}]	34
Lost NPP power production [MW_{el}]	132
Supply temperature [°C]	120
Return temperature [°C]	40

Table 5.1.2: Key Technical Metrics for the HTS

In table 5.1.2 some technical metrics of the HTS are presented. the achieved heat loss rate, given as the total heat loss over the total heat production is 2.7%. this can be compared to [9], [8] and [20] who calculate heat losses of X Y and Z respectively. The lost power production at the plant amounts to 132MW corresponding to 12% of the total heat delivered to the HTS. The supply and return temperatures when optimized have assumed their respective boundary values, This result is consistent with that of [8].

5.1.2 Economical Results

For the economical results, we will first present the results of the current state of the system as the model describes it, that is, the BAU. This will then be compared with the adding 1000 MW nuclear heat for Stockholm and 50 MW for Uppsala in the base case. Then the KPI's for all studied cases will be presented for each scenario in an overview.

BAU

In table 5.1.3 the operational results per fuel type summed over both Uppsala and Stockholm are presented. Also the average Heat pump price is presented (note that the capacity in this cathegory in Uppsala is actually Electric boilers whereas that for Stockholm is heat pumps which have vastly different variable costs) in table 5.1.4 the NPV and system cost of the BAU case are presented. this will be the referens values to which the nuclear heating cases will be compared. The following figures (5.1.2, 5.1.3) show the load profile and merit order of Stocholm and Uppsala DHN's respectively. With them one can clearly see what fuel types are base load and how much of each fuel category are used for a certain

Fuel Type	Ann. Production [TWh]	Full-load Hours	Ann. Cost [MSEK]	Avg. Var. Cost [SEK/MWh]
Bio oil	0.32	347.1	474	1500
Fossil	0.05	76	73.8	1500
Heat Pump	2.3	3570.1	1130	328.4
Waste	3.7	8068.7	562	150
Wood chips/grot	6.6	5334.9	2950	450
Wood pellets	1.0	1383.4	552	550
Total	14		5730	410

Table 5.1.3: Annual production, and cost by fuel type

Metric	Value
System LCOH [SEK/MWh]	410
Net Present Value (NPV) [SEK]	-7.61e+10

Table 5.1.4: Key Economic Indicators

number of days in a year. For example, its clear that the cotslier fuels such as bio-oil and fossil are only employed a few days per year during peak load.

Base case

For the base case we've assumed the same 1000 MW to Stockholm and 50 MW to Uppsala pipeline as in 5.1.1. by comparing table5.1.5 (with nuclear heating) with table 5.1.3(BAU) you can see how this affects the system cost and production. The total annual production is the same in both cases, as this is regulated by the demand, as stated in the constraints

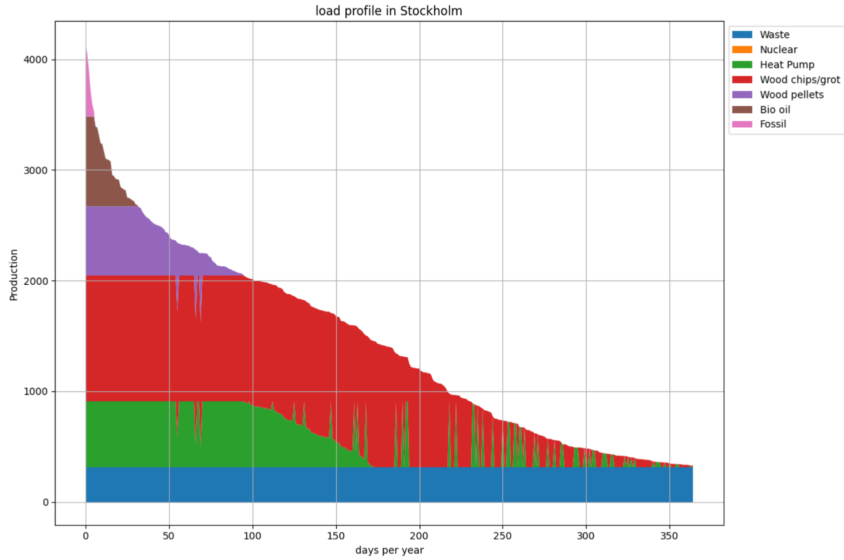


Figure 5.1.2: Load profile with merit order in Stockholm

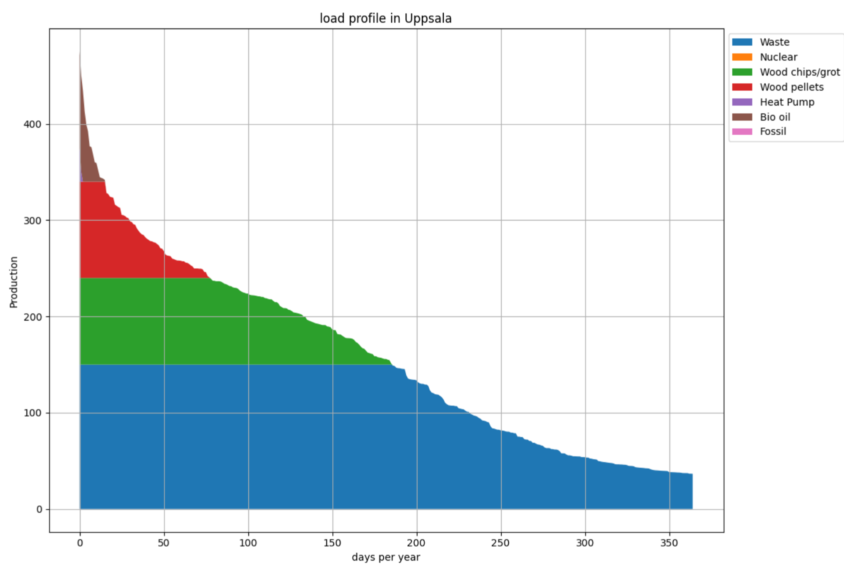


Figure 5.1.3: Load profile with merit order in Uppsala

to the optimization (eq 3.31) However we can see that the nuclear heating has taken up a significant share of this of around 44%, corresponding to 5920 full-load hours. This can be clearly seen in the load profiles where nuclear heating takes up a large share of base load (see fig 5.1.4, and fig 5.1.5) that in the BAU is taken by primarily Wood chip/grot. We can also observe a noticeable drop in the total Annual cost from 5730 MSEK to 3210 MSEK, this because of the significantly lower AVC that the nuclear heating has of only 122 SEK/MW compared to more than 450 SEK/MWh for other production methods excluding waste incineration. Note that this AVC only accounts for the OPEX of the Nuclear heating. The nuclear LCOH is significantly higher.

Fuel Type	**Ann. Production [TWh]**	**Full-load Hours**	**Ann. Cost [MSEK]**	**Avg. Var. Cost [SEK/MWh]**
Bio oil	0.04	39.4	54	1500
Fossil	0	0	0	1500
Heat Pump	0.48	731	230	479
Waste	3.74	8070	562	150
Wood chips/grot	3.30	2690	1490	450
Wood pellets	0.22	300	120	550
Nuclear	6.22	5920	757	322[1]
Total	14.00		3210	211

Table 5.1.5: Annual production, and cost by fuel type

In 5.1.5 and 5.1.4 the load profile, with merit order of the production methods are presented for Uppsala and Stockholm. The spikes in the heat pump category in Stockholm occur on dates with very low electricity prices when the heat pumps have lower prices than the wood chip/grot category.

[1] This value is the LCOH for nuclear heating, as it makes for a better comparision. AVC alone would be 122 SEK/MWh.

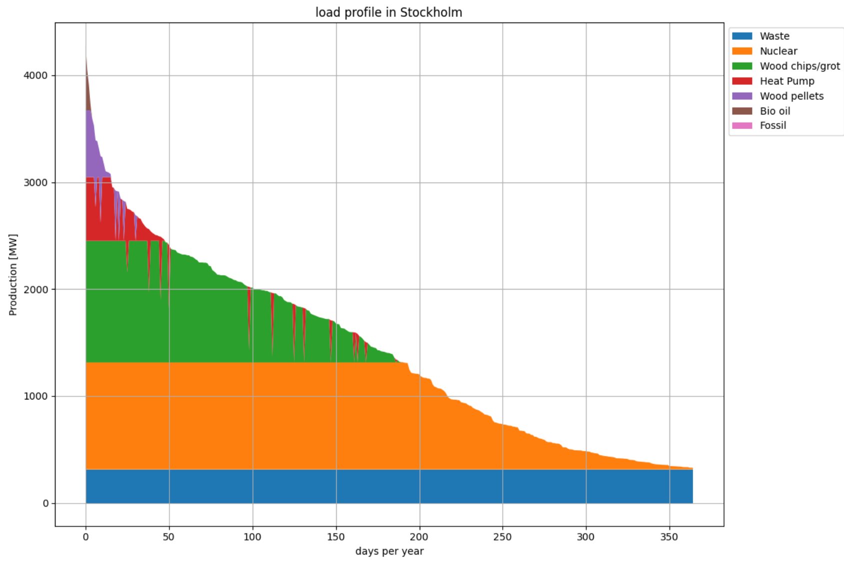


Figure 5.1.4: Load profile with merit order in Stockholm

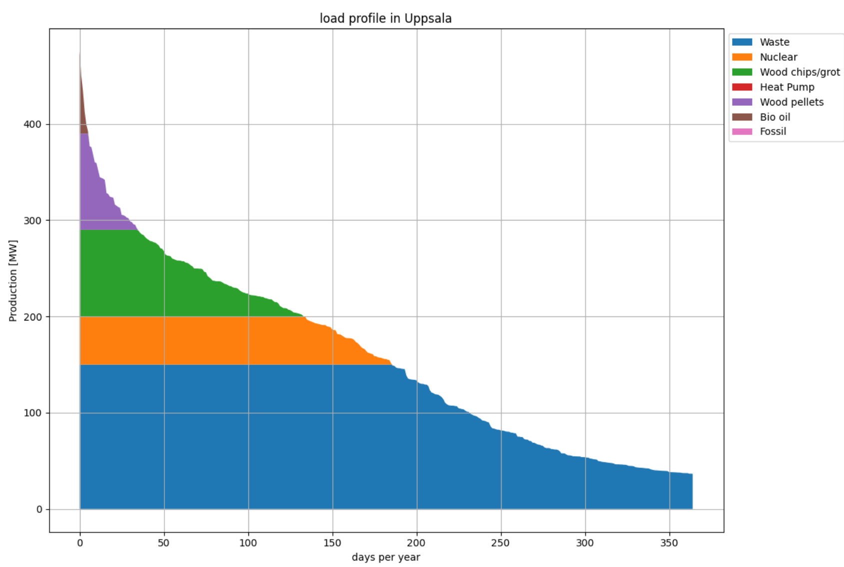


Figure 5.1.5: Load profile with merit order in Uppsala

In fig5.1.6 a breakdown of the nuclear heating LCOH is presented. It can be seen that 62% of the LCOH comes from CAPEX, where most comes from the construction of the pipelines, and only a small part (3% of LCOH) comes from modifications at the nuclear power plant. The remaining 39% comes from OPEX which is made up of electricity costs for pumping (16% of LCOH), and powerproduction loss at the NPP (22% of LCOH). This can be compared to the results in [9] where 7.6% of LCOH comes from plant modifications, around 50% from pipeline construction(of which 8% from tubes, 23% from trenches, and 12% from tunnels), and 22.8 % from electricity losses. [9] also accounts for costs of conception (with cost entries such as safety studies and engineering), and distribution standing for around 10% of cost together. These costs have not been estimated in this study. [9](2016), studying a pipeline Paris-Nogent over a distance of approximately 90 km achieves a LCOH of 56 €/MWh in their "low" scenario(42 €/MWh in their "high" scenario), compared with 322 SEK/MWh for the base case in this study. Their higher LCOH could be caused by higher assumed electricity prices (70€/MWh), a shorter technical lifetime of only 20 years and the use of tunnels which have a significantly higher cost per km than trenches. Their lower price share for construction cost could be explained by the shorter distance.

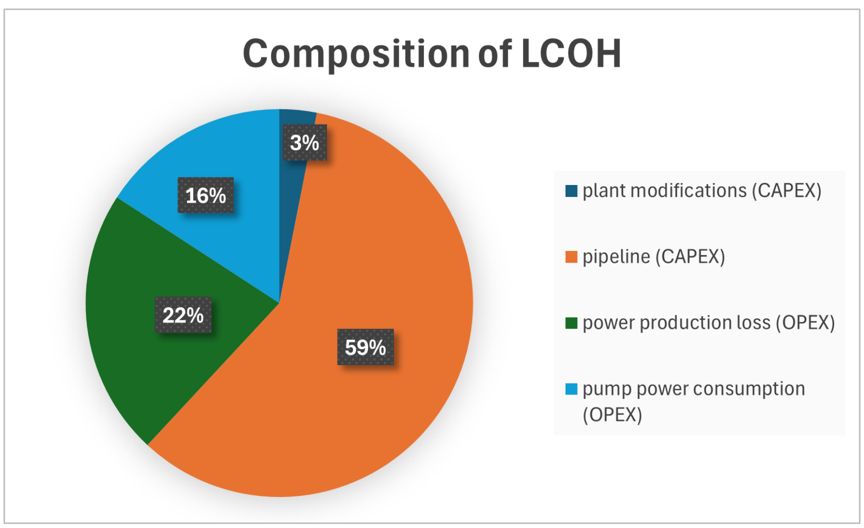


Figure 5.1.6: cost breakdown of LCOH for nuclear heating in the base case

The system cost, measured in SEK/MWh, serves as a metric of the system's average cost of production, with only the CAPEX of the nuclear HTS included, similar to how the NPV

Metric	Value	Unit
Annual System Production	1.4e+07	MWh/h
Number of Pump Stations	14	–
Total Pumping Power	38.8	MW
Power Production Loss at NPP	132	MW
Maximum Heat Loss	29	MW
Heat Transportation Capacity at NPP	1.08e+03	MW
TC Net	3.21e+09	SEK
Investment Cost	1.66e+10	SEK
Total Capacity	1.05e+03	MW
Cost Power Loss	4.43e+08	SEK
Cost Pumping Power	3.15e+08	SEK
Max Velocity	3.36	m/s
System cost	318	SEK/MWh
Nuclear LCOH	322	SEK/MWh
NPV	-6.24e+10	SEK

Table 5.1.6: Summary of Key System Metrics

is calculated. While this limits the system cost's accuracy in representing the total cost of the system (excluding fixed costs for other production methods), it remains valid for comparing configurations where the CAPEX of other facilities is assumed constant. Also, note how this cost is actually lower than the nuclear heating LCOH (318 vs 322), this can be explained by the large production - 3.75 TWh - of the much cheaper waste incineration, bringing down the average cost of the system.

These findings can be contextualized by comparing them with the results presented in \cite{angstrom_kylvattenvarme_2011}, where the system cost was estimated at 264 SEK/MWh for a similar configuration involving nuclear heat supply from Forsmark to Uppsala and Stockholm, assuming the same installed capacity as in the base case of this study. Their analysis also reported a lower levelized cost of heat (LCOH) for nuclear heating, at 274 SEK/MWh. Notably, their business-as-usual (BAU) scenario yielded a significantly lower system cost of 238 SEK/MWh, primarily attributed to substantially lower costs associated with biofuel-based heat production. This comparison underscores the influence of biofuel price trends on the relative economic competitiveness of nuclear heating, suggesting that recent increases in biofuel costs may contribute to the improved profitability of nuclear options observed in this study.

No Reduction in Waste Incineration Scenario

Table 5.1.7 below, presents a comparison of the performance of the different cases under the scenario where no changes are made to the current level of waste incineration.

The system cost shows a clear downward trend from the BAU case (410.0 SEK/MWh) to the Optimized case (277.0 SEK/MWh). This indicates that introducing nuclear heating in the system can significantly reduce operational costs.

A similar trend can be seen for the LCOH and NPV, where both numbers improve as the installed capacity increases up until the optimized capacity of 1817 MW to Stockholm and 330 MW to Uppsala. Higher capacities than this are, however, expected to perform worse.

Investment costs, represented by CAPEX, also rise with increasing capacity—from 16.6 BSEK in the Base case to 24.0 BSEK in the Optimized case. Despite the higher upfront investment, the Optimized case offers the best overall performance, combining the lowest system cost and LCOH with the most favorable NPV among the evaluated configurations.

Scenario:	**No Reduction in Waste Incineration**			
Case	BAU	Base	High	Optimized
Capacity (MW)	0	1000, 50	1500, 100	1817, 330
System Cost (SEK/MWh)	410.0	318.0	288.0	277.0
$LCOH_{nuclear}$ **(SEK/MWh)**	-	322.0	310.0	308.0
NPV (BSEK)	-75.1	-59.2	-53.6	-51.5
CAPEX (BSEK)	-	16.6	20.6	24.1

Table 5.1.7: System performance under the 'No Reduction in Waste Incineration' scenario

50% Reduction in Waste Incineration Scenario

For this Scenario 75 MW of waste incineration capacity in Uppsala DHN and 150 MW in Stockholm DHN have been removed. This of course results in higher system costs in the BAU case(465 SEK/MWh compared to 410 SEK/MWh in the previous scenario), since the waste is replaced by more expensive fuels.

This reduction in system performance is present for all the cases, although it diminishes with increased nuclear heating capacity, from a system cost increase, relative to the no reduction scenario, of 55 SEK/MWH in the BAU down to only 16 SEK/MWh in the high case. (the optimized cases can't be compared in this manner since they have completely different capacities) A similar reduction in NPV can also be seen across all cases.

However, when isolating the nuclear heating, looking at its LCOH, it seem to fare better in this scenario than in the "No Reduction in Waste Incineration" scenario, as indicated by the LCOH being lower for both base, high and optimized case. This is intuitive as the Nuclear heating now replace some of the waste incinerations base load, bringing up the full-load hours, and spreading the CAPEX (which remains the same) over a greater production quantity. that means that nuclear heating is more useful in a system with reduced waste incineration even as the system in total is more expensive.

One interesting result can be seen when comparing the optimized case across the scenarios, the optimal nuclear heat capacity has increased when waste incineration capacity is reduced. in fact, at 2000 MW for Stockholm it has reached the upper capacity boundary imposed on the model. The feasability of extracting as much as 2400 MWth or above from the Forsmark NPPs , has not been studied and it is an arbitrary boundary. However, in the event that it would be possible to extract even more heat, then that would likely have even better performance.

For the reduced waste incineration scenarios, an additional case has been regarded in which nuclear heating is dimensioned to only cover the removed waste capacity. For this scenario the replacement only case performs better than the BAU when the waste is removed, but worse than when no waste capacity is removed(in scenario 1). That is, choosing to replace waste incineration capacity with nuclear heating reduces the system performance if retaining the waste capacity is an option. However, this will of course change if for example incineration plants are retired and its capacity is forced away. In that case the comparison should be made to alternative replacements options, such as a new incineration plant, or a bio-fueled Carbon Capture and Storage (CCS) CHP-plant for instance.

Scenario:	**50% Reduction in Waste Incineration**				
Case	BAU	Base	High	Optimized	Replacement only
Capacity (MW)	0	1000, 50	1500, 100	2000, 400	75, 150
System Cost (SEK/MWh)	465	343	304	278	448
$LCOH_{nuclear}$ **(SEK/MWh)**	-	299	289	285	448
NPV (BSEK)	-86.4	-63.7	-56.4	-51.8	-83.2
CAPEX (BSEK)	-	16.8	20.6	26.2	7.2

Table 5.1.8: System performance under 50% reduction in waste incineration

100% Reduction in Waste Incineration Scenario

This scenario completely removes the waste incineration from the system.

Scenario:	**100% Reduction in Waste Incineration**				
Case	BAU	Base	High	Optimized	Replacement only
Capacity (MW)	BAU	1000, 50	1500, 100	500, 2000	150, 300
System Cost (SEK/MWh)	537	377	324	281	458
NPP_LCOH (SEK/MWh)	-	280	269	263	324
NPV (BSEK)	-99.7	-70.1	-60.3	-52.3	-85.2
CAPEX (BSEK)	-	16.9	21.4	26.6	9.6

Table 5.1.9: System performance under 100% reduction in waste incineration

Emissions

These reduced waste incineration scenarios are interesting if looked at solely based on the imminent retiring of some of the current waste incineration facilities, but when regarded from a sustainability perspective one can see another dimension of it. Around 52% of the carbon emissions of waste are fossil[11]. As companies in the district heating industry set out to meet their net zero targets, they must either completely eliminate waste incineration or compensate for its emissions with CCS. This makes these reduced waste incineration scenarios highly relevant, even when they increase the system cost.

Assuming fossil carbon emissions of 158 kg CO2 eqv per MWh [30], and removing a total of 450 MW of waste incineration capacity - corresponding to an annual heat production of 3.7 TWh - fossil carbon emissions can be reduced by 585 000 metric tons. This corresponds to approximately 1.6% of Sweden's annual carbon emissions[19], or 15% of all carbon emissions from heat and power production in Sweden [25].

CHP Model Limitations

One limitation of these results is that they ignore the distinction between CHPs and HOBs in the DHN. In A.1.2 one can see that approximately 350 MW electric capacity is installed in non-waste incineration CHP facilities within the Stockholm DHN. These plants, if operating for electricity production, will also produce heat as a byproduct, and that at a low marginal cost. Thus, as a rule of thumbs, whenever they are operating for electricity production they'd also deliver heat to the DHN. Since introducing Nuclear heating reduces the use of both woodchips/grot and wood pellets (both of which have facilities with electric capacity) it is needed to also account for the price of lost electricity production from these facilities, which has not been done.

To asses the impact of this, a short calculation can be made. At full capacity of 350MW electric, and an average spot price of 500 SEK/MW, the hourly cost of not operating these CHP plants could be as much as 175 000 SEK/h. Comparing the full load hours of wood chips in the BAU with the base case we see a reduction by 3040 hours from 5730 to 2690. This corresponds to an annual lost income for electricity production of $500 \cdot 350 \cdot 3040 = 532$ MSEK, to compare with the total annual cost of 3210 MSEK in the base case and 5730 MSEK in the BAU.

Ignoring this effect has an impact on the reliability of these results, as it underestimates the costs of replacing CHP with nuclear heating. particularly the optimal dimensioning will be affected.

5.2 Sensitivity Analysis

The results presented above are based on uncertain parameter values that are susceptible to change during the lifetime of a HTS, and that actors might have varying opinions on. To account for this, a sensitivity analysis is conducted examining what the LCOH for the nuclear heating would be if these parameter values were to change. The most impactful parameters that will be altered in this sensitivity analysis, and their change relative to their base values (presented in chapeter 4) are presented in table 5.2.1.

Parameter	**Parameter Adjustments**
Electricity price	+100%, -25%
CAPEX	+25%, -25%
Bio fuel prices	+25%, -25%
Power loss at plant	+100%
Lifetime	+15y, -15y
Discount rate	10%, 3%

Table 5.2.1: Sensitivity analysis parameters and their considered values

A one-at-a-time sensitivity analysis was performed, where each parameter was varied independently while keeping all others constant, thereby isolating individual effects and ignoring potential cross-parameter interactions.

The results of the sensitivity analysis are presented in Table \ref{tab:npp_lcoe_sensitivity} and visualized in Figure \ref{fig:lcoh_sens}. We can see that the most impactful parameter for determining the LCOH is the investment cost where a change of +-1% in investment cost result in a change of 0.6% in LCOH., we can also see that the assumed discount rate is important. An increased lifetime doesn't change the LCOH by much, as the gains of each added year are discounted. Decreasing the lifetime has a much larger normalized impact as that removes less discounted operational gains.

The resulting LCOHs for some adjusted parameters are of special interest. When the electricity price is increased by 100% its average is close to 1000 SEK/MWh, which is

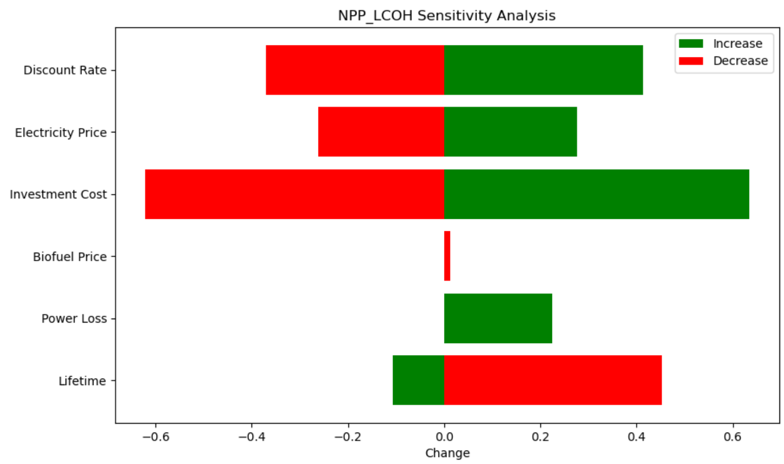


Figure 5.2.1: Sensitivity analysis of normalized Levelized Cost of Heat (LCOH) change per 1% variation in input parameters

Parameter	**Nuclear Heating LCOH (SEK/MWh)**
Base Case (section 5.1.2)	322
discount rate = 10%	379
discount rate = 3%	254
el. price +100%	411
el. price -25%	301
inv. cost +25%	373
inv. cost -25%	272
power loss at plant +100%	394
lifetime +15 years	305
lifetime -15 years	395

Table 5.2.2: LCOH values for different sensitivity analysis parameters

the assumed value in [1], and a doubled power production loss at the NPP will resemble the expected losses when optimized turbines are not available [1]. In addition, increasing the lifetime by 15 years to 45 years will bring it close to the expected technical lifetime of the pipes [6]. Instead lowering the lifetime to 15 years is more in line with a case where the lifetimes of the Forsmark NPP units are not extended[31]. We can see that the LCOH with a doubled power loss at the NPP will increase a lot to 394 SEK/MWh. The LCOE is also sensitive to a shorter lifetime of 15 years, bringing it up to 395 SEK/MWh.

Chapter 6

Discussions and Conclusions

6.1 Discussion

This study introduces a novel model for optimizing HTSs' connecting a centralized heat source—such as a NPP—to multiple DHNs through a branching pipeline. In contrast to prior models such as those presented by [8, 7], the model developed here extends functionality by allowing for pipeline branching and the inclusion of current heat production assets within the target DHNs.

One key simplification in this model is the treatment of alternative production methods using constant AVCs, without including CAPEX and fixed costs for those plants. While this limits the precision of the economic dispatch component, it also reduces input data requirements. More complex representations of marginal cost (MC) as a function of production volume, however, would require a reworking of the dispatch algorithm.

Technical Performance and Comparison with Prior Studies

In the base case, with 1000 MW supplied to Stockholm and 50 MW to Uppsala, the Heat Transportation System (HTS) achieved a heat loss rate of only 2.7%, with system-level efficiency and pressures remaining within acceptable operational limits. These technical outcomes are in between the results in prior modeling by [20](less than 2% losses for a 150 km line) and [8] (between 2 and 1.5% for a 40 km pipeline).

The results of this study offer valuable insights into the feasibility of integrating nuclear heat into existing district heating networks (DHNs), particularly those in Stockholm and Uppsala. Compared to earlier studies —such as the 2011 Elforsk report[1], which concluded that nuclear district heating was not economically viable —this thesis shows significant improvements in feasibility under present-day conditions. The new economic situation, with increased biofuel prices and fossil-free energy policies, contributes to a more favorable outlook for nuclear heat integration. This is reafirmed by the sensitivity analysis in [1] which indicates increased bio fuel prices could render nuclear heating economically feasible.

However, there are some key assumptions that have changed that might also have contributed to this change of outcome:

Firstly, in this study it is assumed that the entire length of the pipeline can be put in trenches, whereas [1] as well as [9] both assume that a significant pipeline length in more urban areas closest to the major heat load will need to be put in tunnels. This is an altercation that significantly increases the construction cost. Wether it is possible to use trenches in these areas has not been assessed in this paper, so this assumption can reasonably be argued with. However, the sensitivity analysis should provide some coverage of the case where the investment cost is greatly increased.

Secondly, in this paper the CHP plant have been simply modeled without regards to their dual production of electricity and heat. in reality, their MC for heat production should be complex as it will depend also on the electricity price at the time of production, as the share of VC that the heat production needs to cover will be that remaining after the income from power production is deducted. In 5.1 a short calculation accounting for lost electricity production at reduction of heat production from CHP facilities indicate that this effect can have a large impact on the resulting system cost and on the solution to the optimization problem.

This paper confirms the claim that large-scale HTS pipelines can be technically viable over distances exceeding 100 km[20], and suggest that it is viable for an even larger distance of 150 km. The optimized supply and return temperatures also converged to the limits of the modeled operational range, consistent with findings from earlier work[8], reinforcing the robustness of the current model.

Economically, the Net Present Value (NPV) analysis under various scenarios reveals that nuclear heating becomes increasingly competitive when waste incineration capacity is reduced as envisioned in scenarios 2 and 3. This indicates that future system changes, such as facility retirements or policy shifts in favor of net zero production, could create a more beneficial environment for nuclear integration.

However, several limitations must be acknowledged. For example, start-up and shut down costs and times are ignored in this model. Additionally, the technical complexity and costs of retrofitting the Forsmark NPP for heat extraction are simplified using static assumptions from literature, which may underestimate engineering and regulatory challenges.

Discount Rate Considerations

The sensitivity analysis 5.2 indicates that discount rate plays a central role in evaluating the economic feasibility of this project. In this study, a discount rate of 7% has been applied.

A more typical commercial discount rate can be derived from the Capital Asset Pricing Model (CAPM), as shown in Equation 6.1. Using industry beta values for the U.S. utility sector provided by [4], where $\beta = 0.39$, in combination with a 2024 market risk premium of $(E(R_m) - R_f) = 6.1\%$ and a risk-free rate of $R_f = 2.9\%$ [23], the expected return on investment is calculated as:

$$E(R_i) = R_f + \beta(E(R_m) - R_f) = 0.029 + 0.39 \cdot 0.061 = 0.053 = 5.3\% \tag{6.1}$$

This 5.3% return serves as a reasonable estimate for a standard utility-sector investment under current market conditions. However, the scale and complexity of the proposed heat transport system are significantly greater than those of typical utility projects, introducing increased technical and financial risk. Taking this into account, the 7% discount rate used in the base case analysis ensures a conservative and realistic economic evaluation of the project.

Nuclear Power Plant Lifetime Considerations

The technical and economic lifetime of the Nuclear Power Plants (NPPs) is a critical factor in determining the feasibility of the proposed HTS. In this study, a conservative lifetime of 30 years has been assumed for the HTS, however that presupposes that the remaining operational lifetime of the Forsmark NPP units exceed this.

In fact, the owners of the Forsmark NPP intend to extend the lifetimes of the Forsmark NPP units from 60 to 80 years, making them operational well into the 2060s - beyond the supposed HTS lifetime of 30 years[31].

6.2 Conclusions

Overall, the findings of this study suggest that nuclear district heating, once considered infeasible, warrants renewed consideration—particularly in a future energy system focused on carbon reduction. The modeling framework developed here provides a flexible and extensible tool for evaluating similar integration projects across other regions or nuclear plants. However there is a need to expand on this model to account for inaccuracies in the modeling of alternative production metods, in particular that of CHP plants.

Future Work

Future research should further refine the economic model by incorporating more accurate modeling of CHP plants as well as variable AVCs. Incorporation of more detailed regulatory and safety considerations would also be useful as well as a more comprehensive study of the pipeline path, calculating a more exact distance in respect of existing infrastructure and the layout of the current DHN. Factors such as road and railway crossings, protected cultural and natural sites, and locations of building that has to be circumvented could largely impact the pipeline construction cost. Renewed attention to nuclear heating is recommended as this study shows how the changed conditions make nuclear district heating potentially economically viable, even over large distances.

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Appendix - Contents

0.1 Acronyms IV

A Appendix A **1**

A.1 Appendices 1

B Appendix B **4**

Chapter A

Appendix A

A.1 Appendices

Important, but complementary material/results can be placed in appendices. This includes details of any implementation (practical work stages, etc.), large data sets, etc.”

Year:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Bro	30.1	30.2	28.6	34.2	31.4	29.1	31.1	27.2	30.3	30.6	0.0	0.0	0.0	0.0	
Bålsta	32.1	34.9	40.7	34.2	34.6	28.3	33.0	33.6	36.1	34.7	34.9	34.5	33.6		
Drefviken	482.8	498.0	481.4	484.0	500.7	487.0	485.2	506.3	511.4	508.3	495.7	485.0	472.1	466.4	468.3
Gustavsberg	47.9	50.8	47.2	51.5	55.4	54.3	51.8	59.2	69.8	75.5	73.3	72.3	73.0	72.0	74.6
Hallstavik	15.2	16.7	16.2	16.3	16.2	15.9	17.1	17.5	17.7	17.5	17.7	17.1	16.4	15.9	15.4
Huddinge Municipality	0.0	569.2	550.6	548.5	0.0	0.0	0.0	0.0							
Järfälla Municipality	312.1	323.9	312.4	310.2	290.5	279.3	279.3	274.5	288.6	314.7	412.9	436.6	409.9	385.1	351.4
Järna	49.2	49.0	50.8	46.1	46.1	46.9	45.8	46.3	46.6	46.3	46.2	47.2	43.5	45.7	45.1
Kungsängen	50.8	51.6	49.7	51.4	51.8	50.1	51.5	51.1	53.8	58.4	0.0	0.0	0.0	0.0	
Rimbo	18.1	19.3	18.6	19.5	19.6	19.3	20.9	17.9	18.0	18.2	17.9	17.3	17.6	17.9	17.1
Saltsjöbaden	40.3	0.0	0.0	30.9	30.0	30.7	30.0	29.6	29.4	28.1	28.3	28.0	26.5	24.8	
Sollentuna	339.9	351.4	335.8	338.2	338.6	322.1	372.1	335.7	330.9	333.6	325.9	314.1	314.7	313.2	325.1
Stockholm	8163.2	8393.1	8739.8	8011.9	8000.0	7582.4	7568.1	7979.3	7885.0	7982.4	9024.4	8650.2	8232.8	8084.8	8271.1
Sundbyberg-Solna	1060.0	1105.8	1067.5	1084.7	1105.8	1051.4	1060.1	1108.9	1082.4	1105.8	1087.7	1041.8	1026.9	1003.2	1030.5
Södertälje	756.9	741.0	806.5	728.3	751.2	657.3	693.4	717.9	715.0	741.5	725.8	719.0	718.1	694.0	701.3
Södertörn Fjärrvärme Totalt	1070.9	1097.8	1130.7	1048.0	1049.4	1009.4	998.2	1040.7	1043.4	1062.7	1047.6	1017.5	1001.6	983.2	1007.9
Täby	0.0	0.0	0.0	67.4	80.8	91.9	95.5	136.7	143.5	150.4	156.1	150.5	151.3	150.7	159.4
Vallentuna	59.0	64.5	61.8	64.8	64.0	61.4	62.5	63.5	65.4	64.7	64.7	62.3	63.6	64.7	66.4
Vaxholm	25.3	25.6	25.3	24.9	24.7	24.5	25.6	26.8	27.0	25.4	25.2	25.2	24.0	23.4	23.6
Åkers styckebruk	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Österåker	66.7	66.0	68.5	71.8	70.7	69.0	68.8	70.2	70.6	65.8	67.5	67.5	68.1		
Stockholm county	**12629**	**13489**	**13832**	**13036**	**12563**	**11910**	**11991**	**12543**	**12359**	**12566**	**13656**	**13185**	**12696**	**12449**	**12684**

Table A.1.1: Yearly delivered heat for DHNs in Stockholm county[MWh]

Production Facility	**Fuel**	**Heat [MW]**	**Power [MW]**	**Owner**
Solna värmepump 1-4	Electricity	100		Norrenergi
Solna P1-P2	Wood pellets	106		Norrenergi
Solna P3	Fossil	83		Norrenergi
Solna P4	Wood pellets	92		Norrenergi
Solna P5	Fossil	92		Norrenergi
Sundbyberg HVP1	Bio oil	46		Norrenergi
Sundbyberg HVP2	Bio oil	46		Norrenergi
Sundbyberg HVP3	Bio oil	50		Norrenergi
Sundbyberg värmepump 5-8	Electricity	7.5		Norrenergi
Ropsten 1,2,3	Electricity	251	-74	Fortum
Hammarby	Electricity	248	-71	Fortum
Nimrod	Electricity	36	-11	Fortum
Other	Electricity	125	-38	Fortum
Electric Boilers	Electricity	300	-300	Fortum
KVV8	Wood chips/grot	315	132	Fortum
KVV6	Fossil	350	145	Fortum
KVV1	Fossil	330	250	Fortum
Högdalen 1-4	Waste	82	22.5	Fortum
Högdalen 6	Waste	105	38	Fortum
Hässelby 1-3	Wood pellets	185	69	Fortum
Brista 1 (B1)	Wood chips/grot	76	41	Fortum
Brista 2 (B2)	Waste	50.5	20.5	Fortum
Högbytorp	Waste	65	25	E.ON Järfälla
Igelsta CHP	Wood chips/grot	200	85	Söderenergi
Igelsta B1	Waste	80		Söderenergi
Igelsta B2	Bio oil	95		Söderenergi
Igelsta B3	Wood chips/grot	95		Söderenergi
Fittja	Wood pellets	380		Söderenergi
Ekobacken	Wood pellets	39.5		Vattenfall
Jordbro	Wood chips/grot	283	20	Vattenfall
Bollmora	Bio oil	36		Vattenfall
Fisksätra	Bio oil	20		Vattenfall

Table A.1.2: Heat and Power by Production Facility and Fuel Type in Stockholm DHN

Chapter B

Appendix B

This is only slightly related to the rest of the report. the figures below present the daily heat production for Uppsala and Stockholm for the base case in the no reduction of waste incineration scenario.

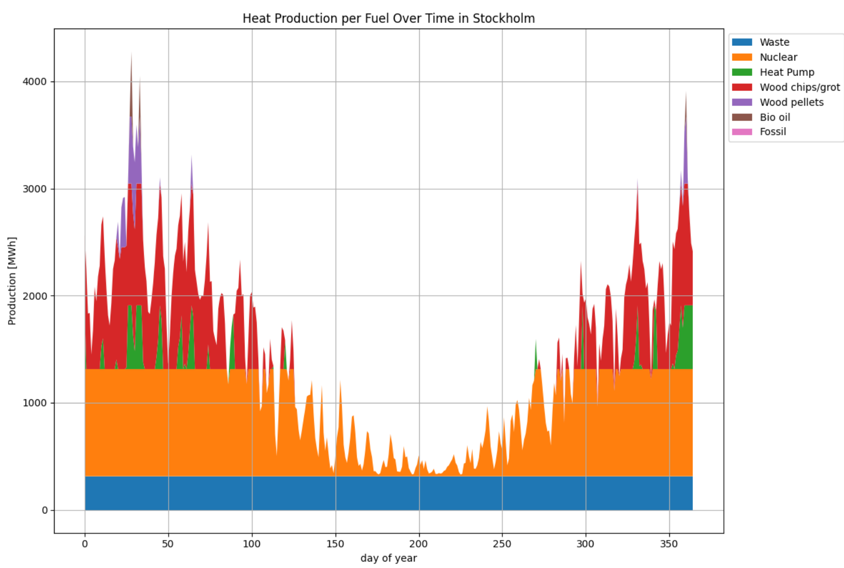

Figure B.0.1: Load and heat production in Stockholm

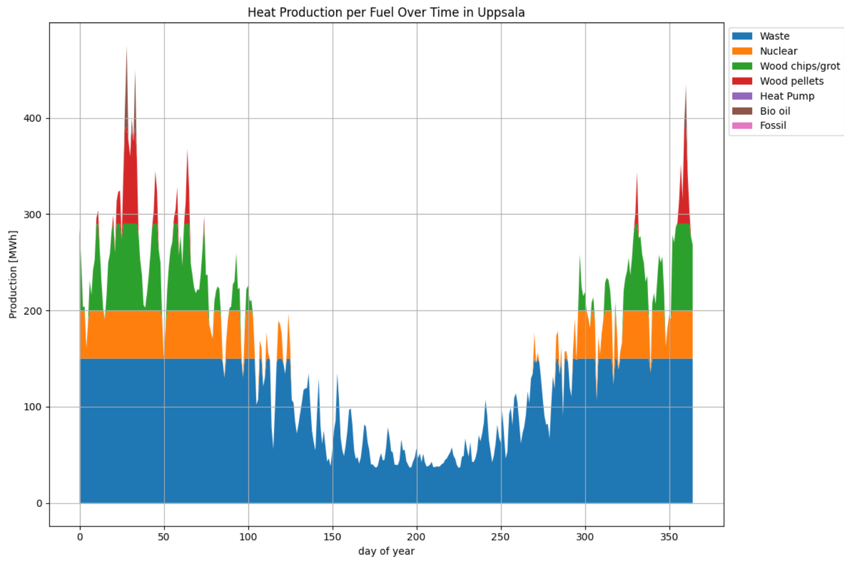

Figure B.0.2: Load and heat production in Uppsala

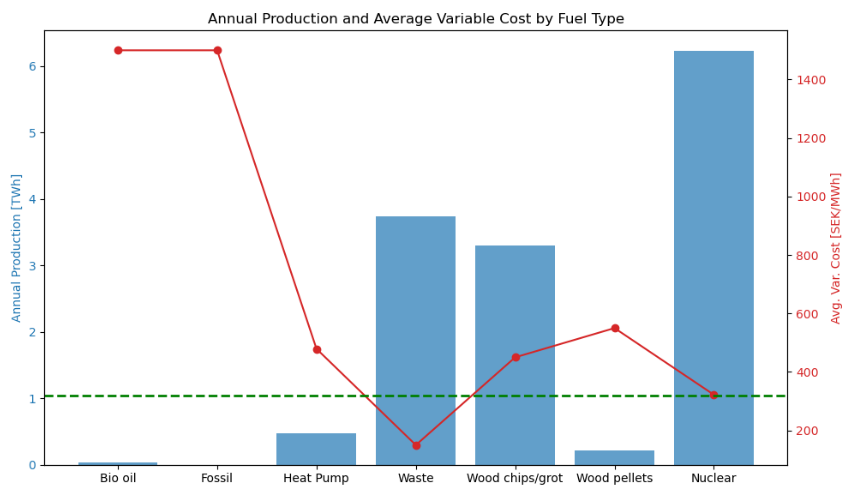

Figure B.0.3: System cost and heat production mix in basecase

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