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Authors The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.	Matthias Speich, ZHAW-INE, matthias.speich@zhaw.ch Silvia Ulli-Beer, ZHAW-INE, silvia.ulli-beer@zhaw.ch
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sweet swiss energy research for the energy transition

Abstract

This document details the logic in the SCOVILLE simulation framework, developed in WP2 of SWEET-DeCarbCH. It describes the purpose and intended use of the simulation framework, the model structure and process formulation, as well as the required parameters and data. The document discusses the assumptions and uncertainties within the model. This document serves as the reference document for the initial version of SCOVILLE. As the model will be continually extended and improved, deviations from this description are possible in the future.

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1. Introduction

1.1. Background: District Heating and Cooling as Instruments of Municipal Energy Policy

As a growing number of Swiss cities and municipalities make it their policy to reach net-zero greenhouse gas (GHG) emissions by the middle of the century or earlier, the implications for the heating and cooling sector are far-reaching. Since most energy for space heating currently comes from fossil-fueled, decentral heating systems, it is necessary to substitute a large number of heating systems with low-carbon alternatives in the coming decades. District heating and cooling offers the possibility to use locally available heat potentials at scales ranging from building clusters to entire cities and is an alternative to other low-carbon heating systems (such as decentral heat pumps), especially in areas where these are not feasible or impractical due to space, regulations, scarce energy sources, etc. Therefore, many cities and municipalities have started the construction or expansion of district heating systems or foresee such developments in the near future.

However, the development of DH in a city or region is a complex process involving not only technical decisions, but also a consideration of economic, organizational and social questions. As long-lived infrastructure with high investment costs, DH requires careful planning so that decisions made today ensure a sustainable operation over several decades. In the past, DH was developed in Switzerland mainly based on opportunity, with new expansions only realized where a sufficient volume of energy sales to cover investment costs was guaranteed (Jutzeler & Wüthrich, 2021). However, to reach municipal net-zero goals in time, it is often necessary to greatly accelerate the expansion of DHC grids. This changes the economics and governance of DH: municipalities may deem acceptable to plan DH expansions into areas where the economic potential is lower than conventionally applied criteria (Stadt Luzern, 2021). Also, cities may need to define a masterplan, i.e., a long-term schedule of investments and construction works, to ensure that the required infrastructure can be built in time and operated sustainably (Jutzeler & Wüthrich, 2021). In most cases, DH is expected to be financially self-sustainable, so that new investments are paid from the utility's revenues and reserves, not from public funds. However, municipalities have various levers to shape the development of DH over time. These levers can be classified as follows:

- Regulation, within the municipality's competence (e.g., specifying conditions for concession contracts for DH infrastructure).
- Planning and coordination, both at the strategic (e.g., spatial energy planning) and operational levels (e.g., construction schedule).
- Financing of investment costs (e.g., through credits from the public budget, often repayable at more favorable conditions than external financing).
- Incentivization of desired behavior by building owners (e.g., heating system switch, building energy retrofit) through subsidization of investment costs and/or energy consulting, as well as awareness building.

The DH utility, in turn, must define a business model that allows it to fulfill its public mission while remaining financially self-sustainable. Given the increasingly ambitious timeframe and scope of municipal net-zero strategies, a greater array of technological options must be considered to efficiently and effectively integrate renewable and excess heat potentials, which requires a rethinking of the current business model (Lygnerud et al., 2023). A key component of the business model is the tariff model, which should account for the long-term expected costs and revenues (VFS, 2022). At the same time, tariffs should be competitive with alternative heating systems. Also, there have been disagreements between cities and regulatory authorities on what constitutes an appropriate cost level in the context of city-scale grid expansion (Preisüberwacher, 2023; Stadt Bern/ewb, 2023). To conclude, there is an interdependency between municipal energy policy and the commercial success of DH, both of which further depend on the actions of building owners, residents, engineering and planning firms, construction firms, etc. To reach municipal net-zero goals in time, it is therefore essential to appropriately govern this local ecosystem (Speich & Ulli-Beer, 2023).

1.2. Aims of SCOVILLE

SCOVILLE (*Strategy Cockpits for Orchestrated Implementation of Thermal Grids in Cities and Municipalities*) is a simulation framework aimed at assessing strategies for the implementation, modernization and operation of thermal grids in the context of municipal GHG emission reduction strategies.

What does "simulation framework" mean in this context? For a given municipal or regional context, SCOVILLE provides an executable model simulating the evolution of selected key performance indicators over time. However, thermal grids are highly local systems: the suitability of different technical configurations is heavily dependent on local characteristics (e.g., available energy potentials, demand structure, policy framework, etc.). Therefore, for each application to a different city or municipality, the causal relationships differ somewhat and will need to be adapted in the model to reflect local realities. We refer to the SCOVILLE framework as the core logic explaining the dynamics of thermal grid implementation, which we assume to hold over a wide range of technologies and contexts. Therefore, each application of SCOVILLE is a distinct implementation of the core logic.

What is the purpose of SCOVILLE? SCOVILLE supports the strategic planning of thermal grids by enabling collective reflection on the economic and organizational effects of various implementation strategies, as well as on their prospects to reach decarbonization goals in time. Thermal grids are very long-lived and must be planned with a time horizon of several decades. Different technological configurations may have far-reaching implications on the commercial and financial success of a district heating rollout.

What does a SCOVILLE model simulate? A SCOVILLE model takes as input an implementation plan, i.e. a timed schedule of investments into heat (and/or cold) generation and distribution infrastructure together with their intended effects (amount of energy that can be sold in a given area, effects on costs and on the system's environmental performance). Furthermore, each run requires a parametrization to reflect local conditions and assumptions on them. The outputs of a SCOVILLE model are the evolution of selected KPIs over time. The KPIs represent economic targets (profitability, as represented by the net cash flow for the utility), as well as environmental (GHG emission reduction over time) and social indicators (affordability, as represented by the unit price for DH).

1.3. Aims of this document

This document is the reference for the SCOVILLE simulation framework developed in the SWEET-DeCarbCH project. It aims to:

- detail the model's structure (equations and variables),
- lay down the rationale behind their formulation,
- provide an overview of the model's parameters, their meaning and ranges of values,
- specify the data required for an application to a real-world case,

As described above, SCOVILLE is intended to be an adaptable and continuously evolving tool. The scope of this document are the core aspects, which are assumed to be valid and relevant for a wide range of applications.

1.4. Model Availability

The SCOVILLE model as described here is implemented in Vensim (Vensim DSS 10.3.0 was used in development). The Vensim model file is available on https://github.com/mspeich/SCOVILLE under a GPL v3 license.

2. Model formulation

2.1. Overview

2.1.1. Model structure

SCOVILLE is a quantitative implementation of the qualitative model proposed by Speich & Ulli-Beer (2024). The subsystem diagram (Figure 1) gives an overview of the aspects that influence the pace and direction of DHC implementation in the context of municipal decarbonization. The model endogenously simulates a subset of these aspects, whereas the others define the boundary conditions.

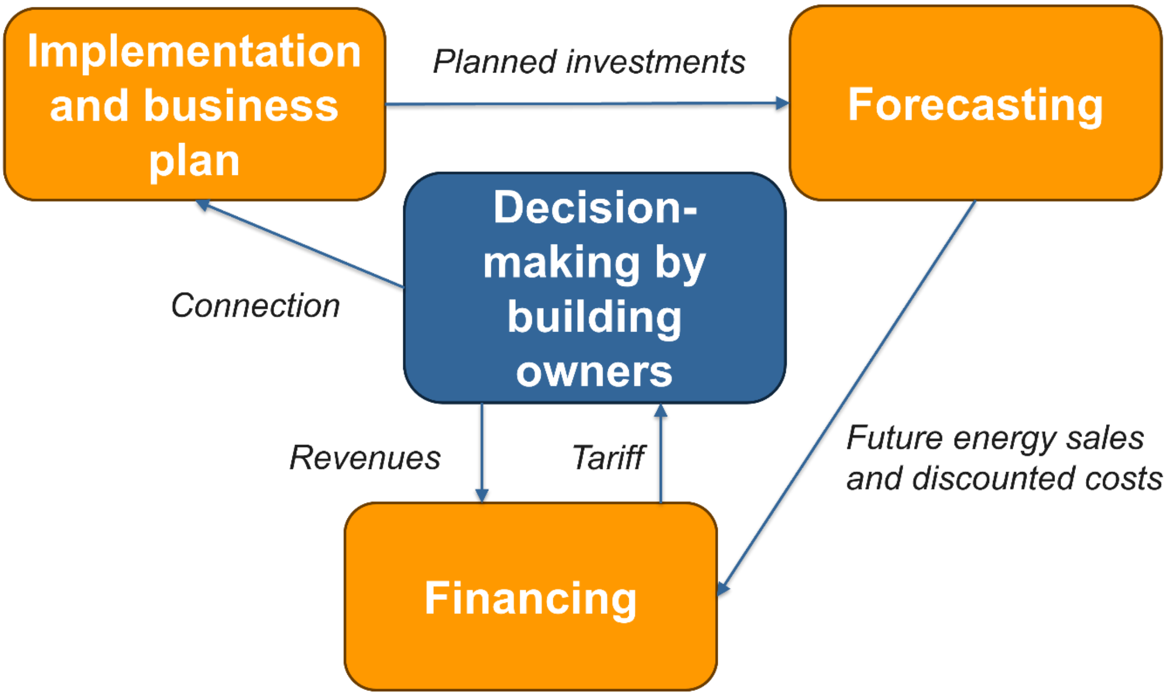

Figure 1: Subsystem diagram of the local DHC system.

The following aspects are modeled endogenously and described in greater detail below:

- At the center of the diagram is the **decision-making by customers**, i.e. building owners. Customers make decisions on their heating system based on their preferences and the information available to them. The perceived utility of different heating systems depends on the criteria applied by different types of building owners (owner-occupiers, private landlords, institutional landlords, as well as public and non-profit owners) and on the characteristics of each heating system. In the case of DHC, the characteristics (economics and environmental impact) change endogenously over the simulation period. Furthermore, the current or future availability of DHC in an area influences the willingness of customers to select this option. Conversely, the connection rate influences the economics of the grid and may influence the viability of future expansions.
- The **infrastructure and business plan** reflects the long-term planning of the infrastructure components to be implemented (an overview of the types of infrastructure components and their characterization in the model is given in Section 2.1.2). The plan specifies which

investment steps are taken at what time. Conceptually, this plan can be understood as the output of strategic energy planning, where such a schedule is defined in accordance with political priorities as well as available energy potentials and technologies. The infrastructure plan may be disturbed through exogenously defined delays to assess their effect on the long-term development.

- To set prices, the utility carries out long-term **forecasts** of costs and energy sales, based on planned investments and the evolution of heat demand.
- The utility's **finances** include the definition of tariffs for DHC. Since the tariffs are expected to be valid for a long time and ensure financial self-sustainability, they are based on long-term forecasts of costs and heat sales, as defined in the infrastructure and business plan.

2.1.2. Types of investments

The model distinguishes between the following types of investments in the DHC infrastructure:

- **Heat/cold generation assets** (e.g., biomass boilers, large-scale heat pumps, heat extraction facilities from waste incineration plants, fossil back-up burners, etc.): these investments enable a certain volume of energy to be sold on the grid. They are described with the following characteristics:
  - Investment cost (CHF).
  - Construction time (Years).
  - Scheduled start of construction (calendar year).
  - Maximal annual energy generation (GWh/a).
  - Specific emissions from DHC (t CO2eq/kWh).
  - Fuel cost (CHF/kWh).
- **Distribution grids**: these investments allow a certain volume of energy to be distributed in a delimited area. They are therefore assigned to a service area. The distribution grid in each area has the following attributes:
  - Investment cost (CHF).
  - Construction time (Years).
  - Scheduled start of construction (calendar year).
  - Scheduled start of customer acquisition (calendar year).
  - Energy transmission capacity at completion (GWh/a).
  - Dependency on other investments (generation, transmission pipes).
  - Maximum waiting time for construction if viability criteria are not met (Years).
- **Transmission pipes**: these investments ensure transmission of energy between the generation facilities and distribution grids. It is not always necessary to build a transmission pipe, since energy can be distributed directly from the generation plants if the service areas are nearby. SCOVILLE does not specify where and whether transmission pipes are necessary. Rather, this is part of the investment plan. Transmission pipes have the following attributes:
  - Investment cost (CHF).
  - Construction time (Years).
  - Scheduled start of construction (calendar year).
  - Energy transmission capacity per area (GWh/a).
- **Large-scale thermal energy storage (LTES)**: these investments modify the share of each fuel or energy source used in the grid. Also, they may increase the amount of energy that can be sold. These effects are not simulated endogenously, but are part of the investment plan. LTES have the following attributes:
  - Investment cost (CHF).

- Construction time (Years).
- Scheduled start of construction (calendar year).
- Additional energy that can be sold (GWh/a).
- The effect on the energy mix in the grid is simulated as a switch.

2.1.3. Types of delays

Delays to infrastructure construction may happen for various reasons and impact the process in different ways. SCOVILLE distinguishes between three types of delays, two of them defined exogenously and one endogenously:

- Delayed construction start (exogenous): this may happen, for example, due to political decision-making, the need to secure sites for infrastructure components, long permitting processes, or the need to coordinate with other engineering works (e.g., road maintenance, other underground infrastructure).
- Slow progress (exogenous): this may happen, for example, due to capacity limitations on the side of the utility or external firms (e.g. engineering or construction firms), supply-chain limitations for key components or unforeseen construction challenges.
- Delayed start of distribution grid expansion due to low subscription rate (endogenous): before the start of each scheduled distribution grid expansion, prospective customers may sign a contract committing them to connecting their building to the grid. Construction proceeds only if a defined amount of connection power has been sold. Therefore, if this amount has not been reached at the scheduled construction start date, construction is delayed while customer acquisition continues. Distribution grids further have an attribute specifying how much this delay can last before the expansion is cancelled.

Furthermore, delays and cancellations may propagate to future investments if they were defined as dependent on previous ones.

2.2. Decision-making by building owners

2.2.1. Representation of buildings and building owners

The model distinguishes between two types of customers: regular buildings, and so-called anchor loads. The latter are large customers whose connection is deemed essential to the viability of the network. This category often comprises large public buildings (e.g., hospitals, schools and university buildings, sport facilities, etc.) or private commercial, residential or industrial buildings. Due to the concentration of high energy use in a single building or cluster, anchor loads present a high potential energy sales volume at a comparatively low cost for service pipes. These customers are treated with high priority in the sales process, or their readiness to connect is even ensured during strategic energy planning. Therefore, in the current model formulation, it is assumed that anchor loads will connect when the distribution grid is available. Conceptually, this means that the infrastructure was planned under the assumption that these buildings will be customers of the grid. The loss of these customers, either before or after connection, can be explored in scenarios reflecting commercial risks. Due to the high diversity of these customers, anchor loads are modeled in bulk for each area.

Regular buildings are also modeled in a highly simplified manner. Indeed, the building park consists of a wide variety of building types, sizes and uses. Furthermore, a connection to the grid may be realized for a single building or for several buildings at the same time. Therefore, a detailed treatment of the building stock is deemed too complex for the purpose of SCOVILLE. Rather, the model assumes a standard geometry for each building. In the implementation presented here, each building has a floor area of 2’000 m^2, which corresponds roughly to a multi-family house with 15 apartments. This is in line with the assumption that the DH expansion is foreseen in areas with multi-family houses and commercial buildings. Differences between areas in the building stock structure can be accounted for in the specific cost of pipes (CHF/kWh; see Section 2.5).

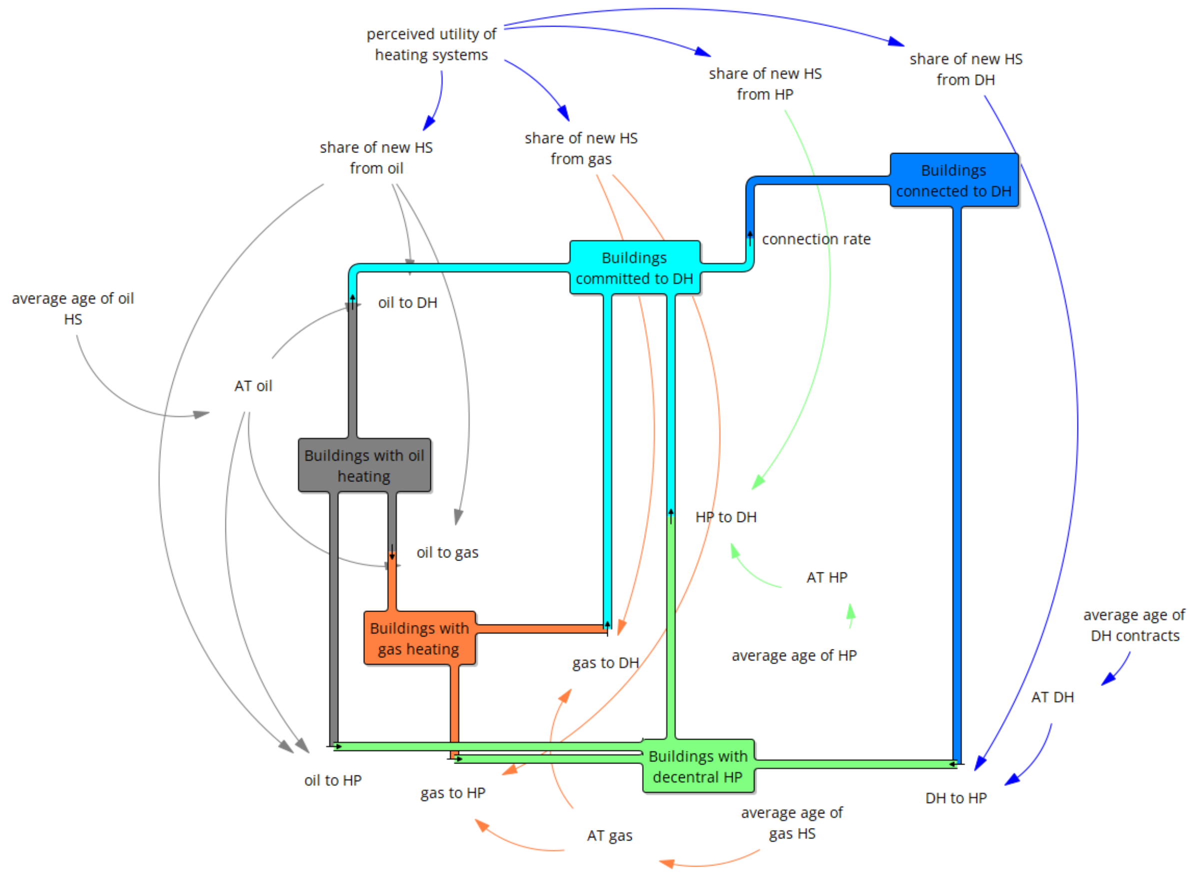

Figure 2: Schematic representation of building stocks and flows between them (i.e. heating system switch).

For each area, the building park is represented as five interconnected stocks representing different heating systems (Figure 2). Four of the stocks corresponds to the heating systems represented in SCOVILLE (oil, natural gas, heat pumps and district heating), while a fifth stock tracks the buildings whose owners have committed to connect to the DH network but who are not yet physically connected (e.g. because the distribution infrastructure is still under construction). In each simulation step, a certain fraction of buildings are transferred from one stock to another, i.e. a fuel switch occurs in some buildings. As represented on Figure 2, the magnitude of these flows (i.e., the number of buildings for which a fuel switch occurs in each time step) is calculated as follows: for each stock, the model calculates a share of buildings opting for each of the available alternatives, based on the perceived utility of the alternative from the point of view of building owners (see Section 2.2.2). The number of buildings for which a fuel switch in a certain direction (e.g., from oil to DH) occurs is therefore calculated as the product of the corresponding share (e.g., 20% of oil-heated buildings who are replacing their heating system in this time step are opting for DH) and the absolute number of buildings of the original stock (e.g., 20 oil-fueled buildings are having their heating system replaced in the current time step). The number of buildings for which a heating system replacement occurs is obtained by dividing the absolute number of buildings in each stock (e.g., 500 oil-heated buildings in a given area) with an appropriate adjustment time ("AT" on Figure 2). Typically, the average lifetime of a heating system is a reasonable value for an AT. For example, if a heating system is assumed to last 25 years, then the number of buildings for which the heating system is being replaced in each time step can be calculated as 1/25 of the absolute number of buildings. However, the assumption that the building age is distributed uniformly across all buildings of a stock does not hold in the context of the energy transition. For this reason, the ATs are calculated dynamically, based on the average age of heating systems in each stock (see Section 2.2.4).

2.2.2. Heating system switch

Buildings are assigned to one of five stocks, depending on the heating system currently installed. Four stocks represent the heating systems represented in the model (oil, gas, DH and HP[1]), whereas a fifth stock keeps track of the buildings that have committed to connecting to DH but have not physically done so yet. These stocks are replicated for each area. Buildings change stocks following the owners' decision to switch heating systems. Each of these flows are modeled as follows:

$$switch_{HS1,HS2} = \frac{HS1 * share_{H1,HS2}}{AT_{HS1}}, \quad (1)$$

where $switch_{HS1,HS2}$ is the number of buildings switching from heating system HS1 to HS2 (e.g. from oil to DH) per year, $HS1$ the number of buildings equipped with HS1, AT_{HS1} represents the share of buildings with HS1 replacing their heating system, $share_{H1,HS2}$ the share of those buildings that chose option HS2.

The share of buildings from HS1 that choose HS2 ($share_{H1,HS2}$) is calculated using a multinomial function in which the perceived utility of heating systems is compared to each other:

$$share_{HS1,HS2} = \frac{e^{(\beta * u_{HS2})}}{\sum_{HS=1}^{n}(\beta * u_{HSn})}, \quad (2)$$

where u_{HSn} is the perceived utility of the n-th heating system option, and β is an empirical shape parameter defining the sensitivity of building owners to the perceived utility.

For simplicity, the model does not allow a heating system change in every direction. Concretely, it is assumed that building owners do not switch back from HP or DHC to a fossil-based system (Table 1). Also, the switch from natural gas to oil is not represented in the model. Furthermore, if the model is applied to a region where the installation of new fossil-fueled heating systems is banned, as is the case in various Swiss cantons, building owners only have the option to choose between HP and DHC (second value in Table 1).

Table 1: Possible heating system changes in a default scenario (first value) and in a scenario where new fossil-fueled heating systems are forbidden (second value).

	To Oil	**To Gas**	**To HP**	**To DHC**
From Oil	Yes / No	Yes / No	Yes / Yes	Yes / Yes
From Gas	No / No	Yes / No	Yes / Yes	Yes / Yes
From HP	No / No	No / No	Yes / Yes	Yes / Yes
From DHC	No / No	No / No	Yes / Yes	Yes / Yes

2.2.3. Perceived utility of heating systems

The perceived utility of each heating system depends on whether its properties are aligned with building owners' preferences and priorities. However, research shows that building owners tend to prefer the same type of heating system that they already have installed (Lehmann et al., 2017). Furthermore, in the case of DHC, utility is subject to two more constraints: having to wait for a connection makes this option less attractive, so that the utility function of DH is reduced with the amount of time it takes until a connection is possible. For each decision option from any $HS1$ to any $HS2$, the perceived utility is modeled as follows:

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[1] Due to the low market share of other decentral renewables-based heating systems, such as biomass-based systems, these are neglected in the model for simplicity.

$$u_{HS2} = ug_{HS2} * (1 - f_{change}) * f_{availability} * f_{scarcity} * f_{familiarity},$$
(3)

where ug_{HS2} is the generic perceived utility of $HS2$, f_{change} a parameter expressing the preference for the current type of heating system (zero if $HS2$ = $HS1$, and assumed to be 0.3 otherwise), $f_{availability}$ reduces the utility of DHC based on whether a connection is immediately possible or it is necessary to wait some years, $f_{scarcity}$ ensures that the available capacity for connection is not exceeded, and $f_{familiarity}$ accounts for the fact that some heating systems are not yet seen as standard by building owners and building professionals, which limits their perceived utility. Here, $f_{familiarity}$ is set to one for all heating systems except HP, which are not perceived as standard in multi-family buildings (Zapata Riveros et al., 2024).

The generic utility of each heating system is a weighted combination of four utility dimensions: 1) financial utility, 2) upfront cost, where higher investment requirements lead to a lower utility, 3) environmental utility, expressed as the specific GHG intensity of each heating system, 4) a scalar representing the convenience of each heating system as perceived by building owners. For DH, financial utility and price stability are determined endogenously, while they are determined exogenously for the other heating systems. The other utility dimensions are assumed to remain constant. Each utility dimension is rated on a scale from zero to one.

The **financial utility** of a heating system HS_i is expressed as the annualized costs of each heating system C_{HSi}, benchmarked against the cheapest option:

$$u_{fin,HSi} = MAX\left(1 - \frac{C_{HSi}}{MIN(C_{HS\,1\ldots n})}, 0\right) \quad (4)$$

With this formulation, the financial utility of the cheapest option is one, and the financial utility of competing options is reduced linearly. If the costs of a heating system are twice as high as the cheapest option, its financial utility is set to zero. The annualized costs C_{HSi} are calculated as the sum of annual energy costs $C_{energy,i}$, annual operation costs $C_{O\&M,i}$ and annualized investment costs:

$$C_{HSi} = C_{energy,i} + C_{O\&M,i} + C_{inv,i} * \frac{d_{HS}*(1+d_{HS})^{p_{HS}}}{(1+d_{HS})^{p_{HS}}-1} \quad (5)$$

where $C_{inv,i}$ are the investment costs for HS_i, d_{HS} the assumed discount factor for a heating system and p_{HS} the assumed lifetime of a heating system.

The **upfront cost utility** accounts for the fact that, independently of annualized costs, a large investment sum can represent a barrier for building owners. We apply here the empirical parametrization used by Kubli (2018) for owners of multi-family houses (Figure 3)

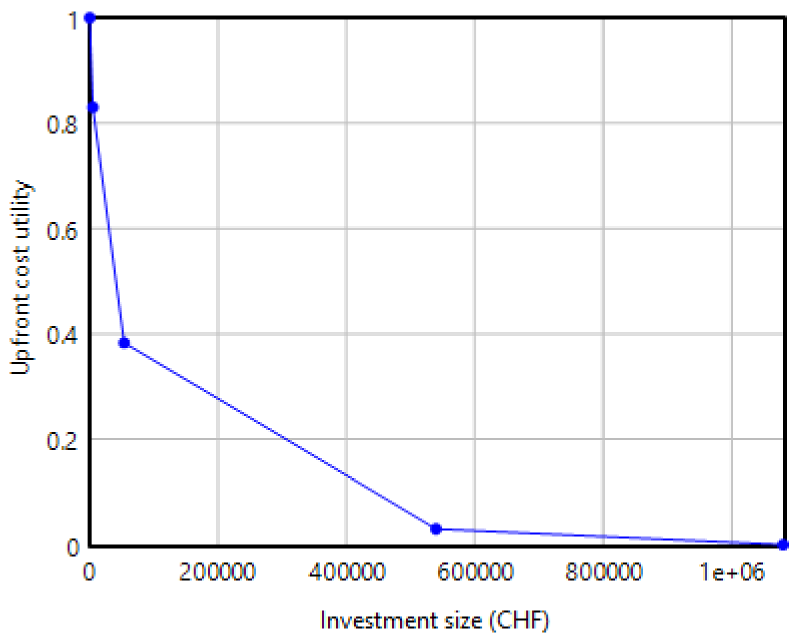

Figure 3: Parametrization of upfront cost utility as a function of investment size, following Kubli (2018).

The **environmental utility** accounts for the fact that building owners are willing to pay a premium for heating systems that they perceive as environmentally less harmful. This may be due to idealistic reasons or strategic considerations, i.e. the expectation of a higher value of the building on the real estate or rental markets. We use here a metric assumed to be readily available to interested building owners, i.e., the specific GHG emissions for each heating systems ($tCO_{2,eq}/kWh$). Here, heating systems are benchmarked against the most polluting option:

$$u_{env,HSi} = 1 - \frac{f_{GHG,HS1}}{MAX(f_{GHG,HS\,1\ldots n})} \tag{6}$$

The environmental utility of the most polluting option is therefore zero, whereas the value for the other heating systems is scaled linearly.

The **convenience utility** of each heating system is assumed to remain constant during the simulation period. As a default, oil and HP are assigned a convenience utility of 0.5, natural gas a value of 0.9 and DH a value of 1.

Furthermore, the model must account for the fact that only a limited amount of capacity can be sold, depending on the installed generation capacity and the transmission capacity of the grid. Therefore, the utility of DH is further constrained by a scarcity function, which steeply decreases towards zero as the available capacity is sold (Figure 4). Such formulations are frequently used in System Dynamics to represent systems with a limited carrying capacity (Sterman, 2000). Following Kubli (2018), the value is less than one before all of the available capacity is sold, to implicitly account for spatial heterogeneity of buildings and infrastructure development.

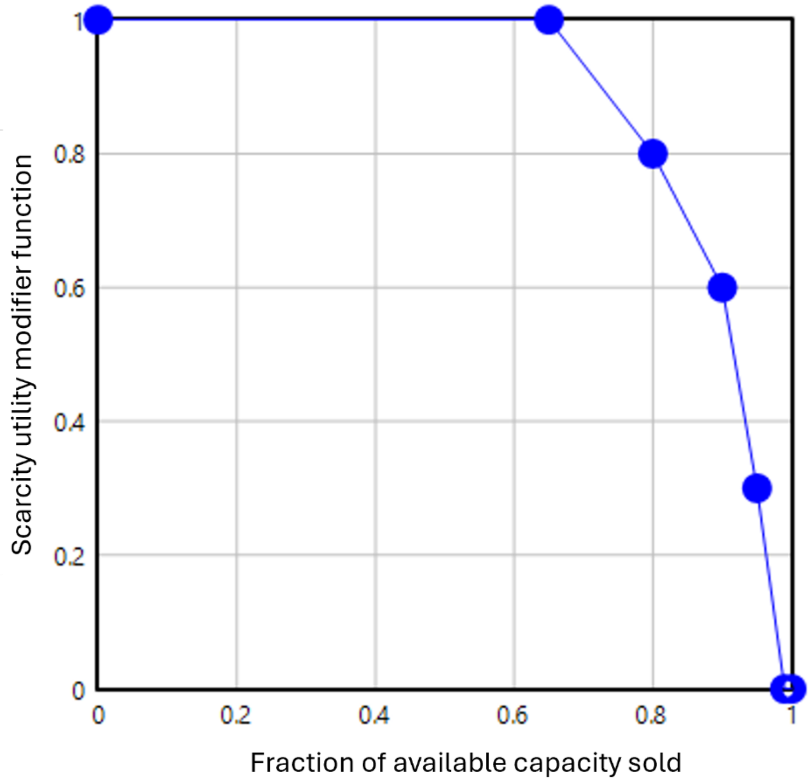

Figure 4: Parameterization of the scarcity utility modifier function, following Kubli (2018).

Finally, to account for the increase in familiarity with HP in MFHs, the model adopts a formulation based on local learning as more HPs are installed: the familiarity multiplier, which takes a value between zero and one, is initialized at a prescribed value. In each step, the current market share of HP is multiplied with a second prescribed parameter, the "effective contact rate", to increase the familiarity value until it reaches its maximum value of one (Struben & Sterman, 2008; Zapata Riveros et al., 2021).

2.2.4. Ageing of heating systems

As mentioned in Section 2.2.1, it is necessary to account for the age of heating systems to appropriately capture the rate of heating system switch in the context of the energy transition. If the adjustment time (i.e., share of buildings for which a heating system is carried out in each time step) is given by the inverse of the lifetime of a heating system (i.e., 1/25th of buildings are having their heating system replaced each year), there are two cases where this assumption becomes problematic:

- In the case of new heating systems (i.e., heat pumps or the expansion of DH to a new area), all heating systems of a corresponding stock are much younger than average. Setting the model to replace 1/25th of these systems would lead to the simulated replacement of heating systems much earlier than the end of their technical lifetime.
- In the case of policy measures that aim at phasing-out fossil fuels (e.g. a ban on new fossil-fueled heating systems), the stock of oil and natural gas-heated buildings is no longer renewed with new heating systems. Replacing 1/25th of these buildings each year would lead to the unrealistic outcome that these stocks are never completely depleted. It is therefore necessary to keep track of the average age of these heating systems and simulate an accelerate replacement rate as they age.

The ageing is tracked following Guzzo et al. (2021): for each heating system type and area, a stock tracks the "total age", i.e. the sum of the age of all heating systems within the stock (Figure 5: Ageing of DH connections as simulated in the model (the same logic applies to HPs).Figure 5). This stock is initialized by multiplying the number of buildings with an assumed initial age value. For new heating system types (e.g., HPs), this number should be low (e.g., 3 years), whereas it should be higher for heating system types that have been used over several decades, such as oil or natural gas-fueled systems (e.g. 15-20 years). The average age is obtained by dividing the total age of heating systems with the number of buildings per stock. The total age stock is increased by one year for each building in each simulation year, and reduced as heating systems are replaced and take their age with them.

The average age in the model is a proxy variable for the number of heating systems that need to be replaced. In the case of new heating systems, the effect of age on the fuel switch rate (see Section 2.2.1) is reflected as follows: if the average age of these heating systems is greater than ten years, the replacement rate is calculated as usual, i.e. by dividing the number of buildings with an assumed technical lifetime (typically, 25 years). If the average age is lower, the replacement rate is reduced linearly from one (average of ten years) to zero (average age of zero years). This formulation is to be viewed as a first approximation and may be refined with more empirical data.

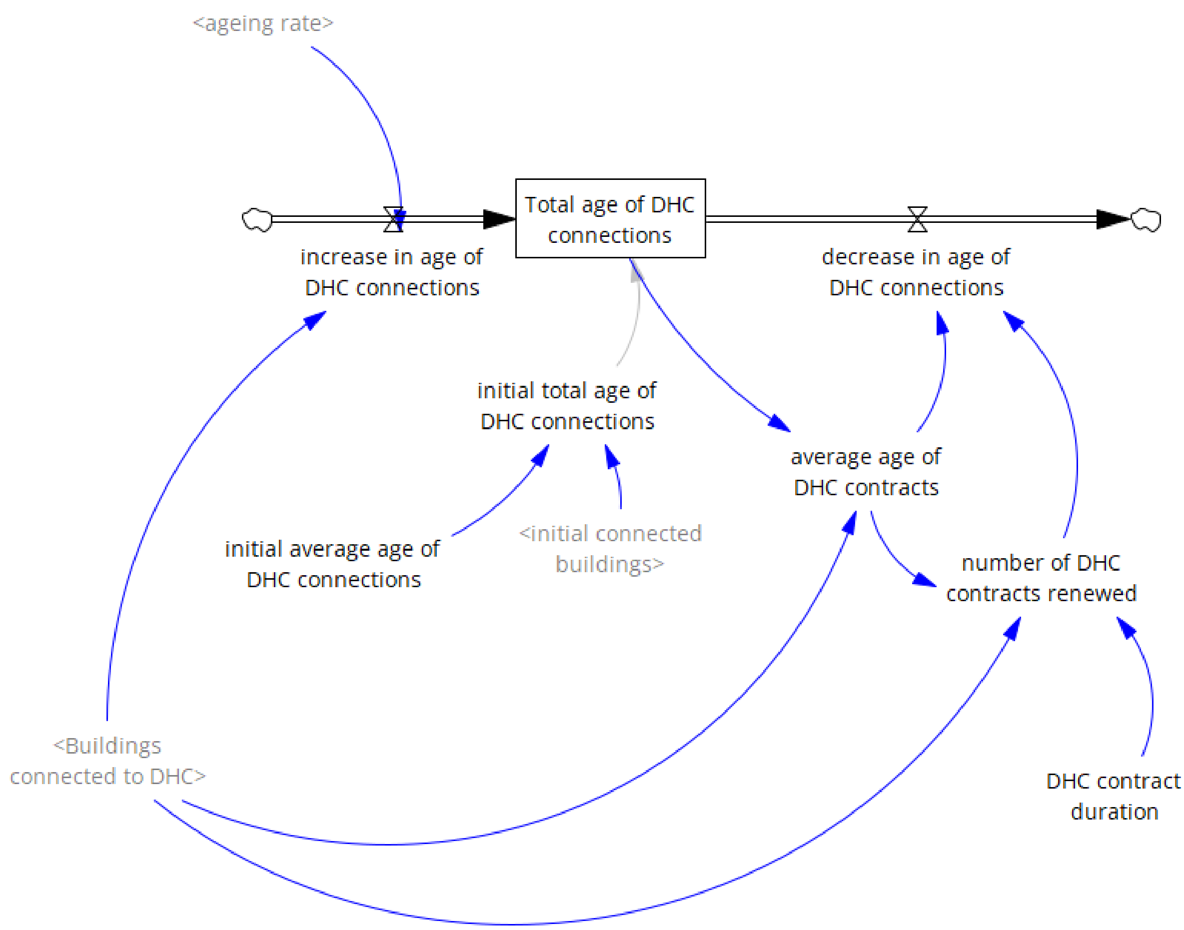

Figure 5: Ageing of DH connections as simulated in the model (the same logic applies to HPs).

In the case of heating system types being faded out, an additional variable is necessary: the "excess age" is defined as the (positive) difference between the average age and the assumed lifetime of heating systems (Figure 6). The purpose is to force the replacement of remaining heating systems as they age. Also here, the average age is a proxy variable and its impact on replacement rate is a first approximation. The adjustment time (see Section 2.2.1) for fossil-fueled heating systems is reduced linearly from its standard value (25 years; when the “excess age” is zero) to an AT of one year (for an “excess age” of ten years). In this case, all remaining heating systems are replaced within one year.

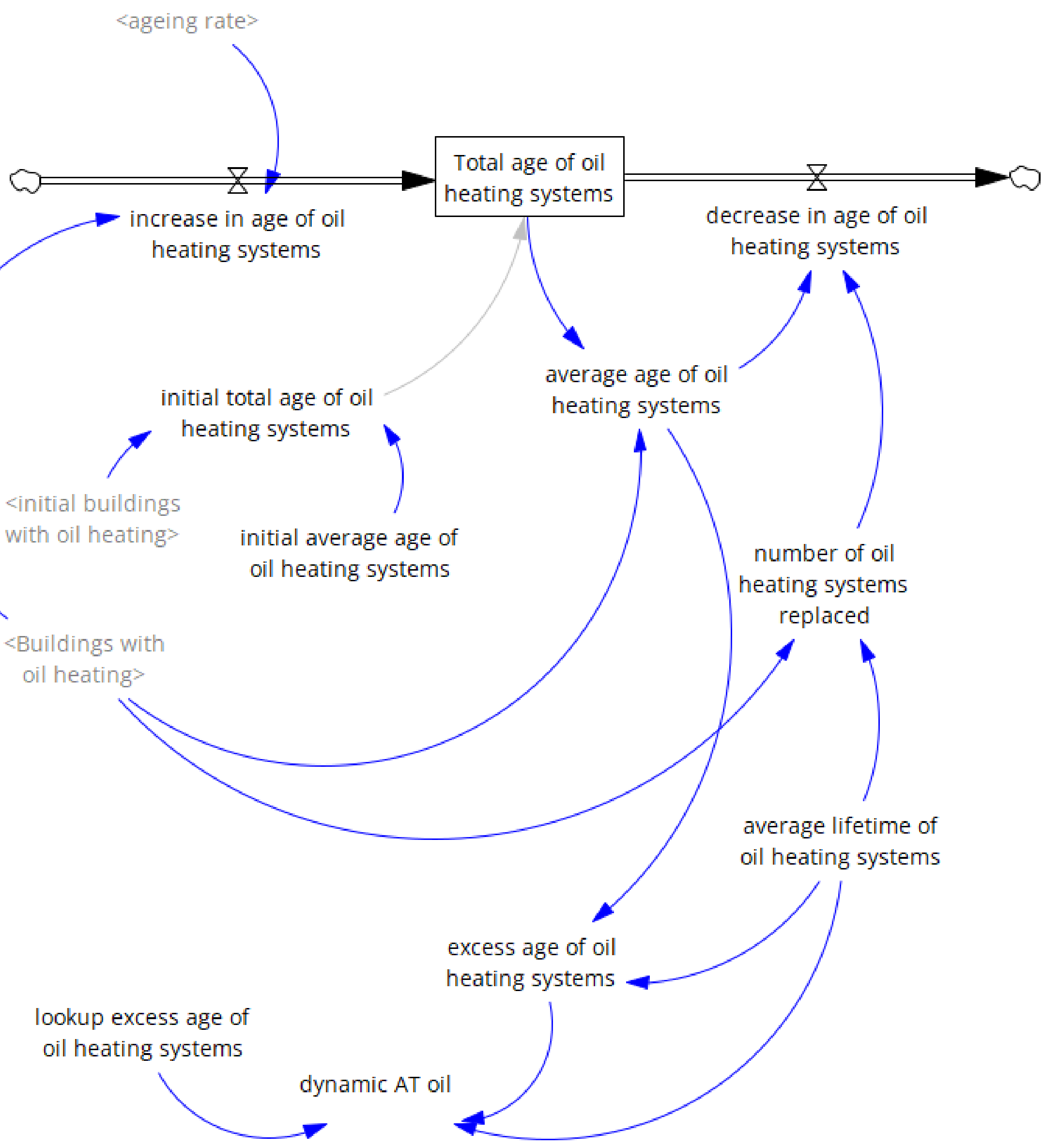

Figure 6: Ageing of fossil fuel-based heating systems as simulated in the model.

2.2.5. Heat demand from buildings

The annual heat consumption of buildings is modeled as the product of heat loss rate and annual heating degree-days. Heat loss rate (W/K) at the building level is understood as the sum of heat loss rates for the individual building components (walls, windows, roof and ground floor), i.e. the product of the U-value and the area of each component. In the simplified representation of buildings used here, building geometry is assumed identical and constant. Therefore, improvements of the energy efficiency of the building envelope are assumed to be obtained through changes in the U-value. In the current model formulation, the improvement of building energy efficiency is not modeled endogenously. Rather, the model allows for the specification of various parameters that describe the current state of buildings in each area and the intensity of retrofit activity:

- The initial heat loss coefficient of buildings (W/K), which implicitly represents the current age and retrofit status of buildings in an area. This variable can be configured based on the user's experience. For example, a value of 800 W/K was used to represent mostly older, unrenovated buildings of the assumed geometry.
- The minimum attainable heat loss coefficient is a function of technical building retrofit potential, but can be adapted to reflect area-specific characteristics (e.g., protected buildings). For example, a value of 200 W/K represents a technical potential unimpeded by building protection regulations.
- The heat loss coefficient improvement rate, a measure of retrofit activity. This rate is specified as a fraction of the *initial* heat loss coefficient. For example, if the initial heat loss coefficient is set to 800 W/K and the heat loss coefficient improvement rate to 1%, then the heat loss coefficient will be reduced by 800*0.01 = 8 W/K each year.
- The annual number of heating degree-days, which represents the site's meteorological conditions and can be specified as a time series to reproduce past dynamics or consider future climate scenarios.

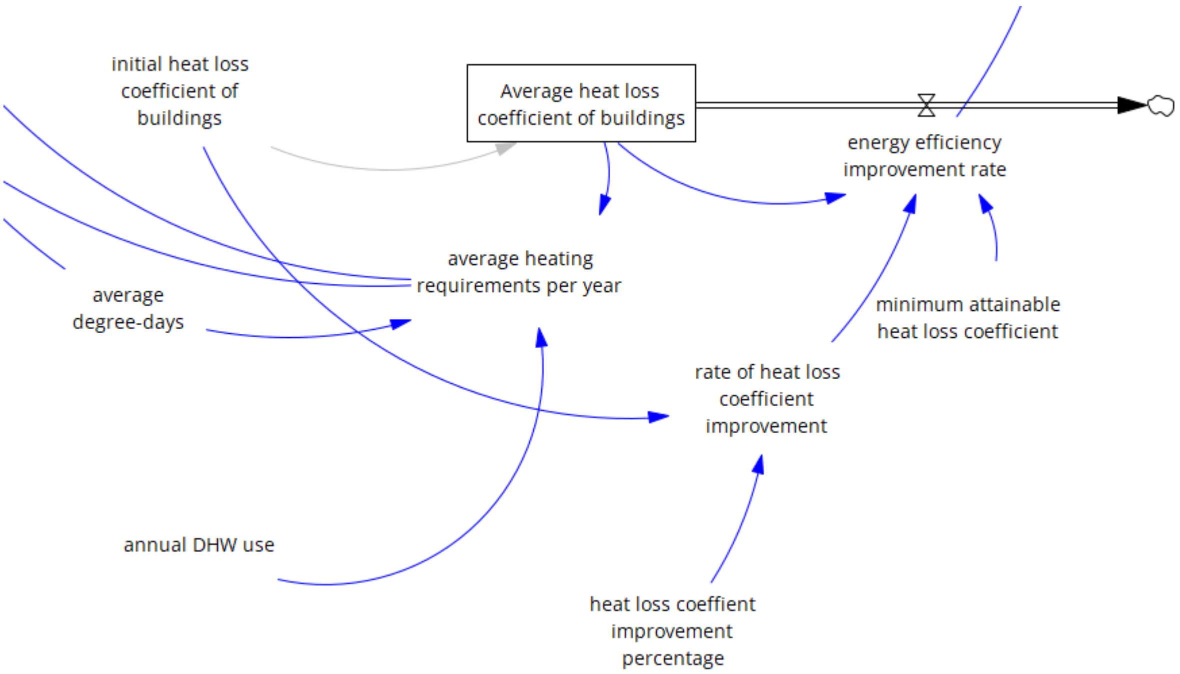

Figure 7: Parameterization of heat demand from buildings.

Heat demand from buildings is obtained as follows (Figure 7): total demand is the sum of heat demand for heating (product of heat loss coefficient and degree-days) and for domestic hot water use (assumed to be constant at 21 kWh/m^{2}a (Kanton Zürich, 2022)).

2.2.6. Available capacity for sale and connection

The proposed infrastructure development plan in an area allow for a finite amount of energy to be transmitted and sold through DH in each area. For simplicity, this "capacity" is represented in the model as an amount of energy per year (kWh/Year), i.e. power is not explicitly included in the model. The available capacity is represented as a stock for each area (Figure 8). For new DH developments, it is assumed that the associated capacity is available for sale since the beginning of the simulation, i.e. buildings can commit to joining the grid before it is built (however, DH is perceived as less attractive if the connection cannot be realized immediately, see Section 2.2.3). In each time step, the available capacity for sale is reduced as new buildings join the grid. At the same time, available capacity increases due to buildings disconnecting, as well as energy efficiency gains from building envelope improvements (see Section 2.2.5)

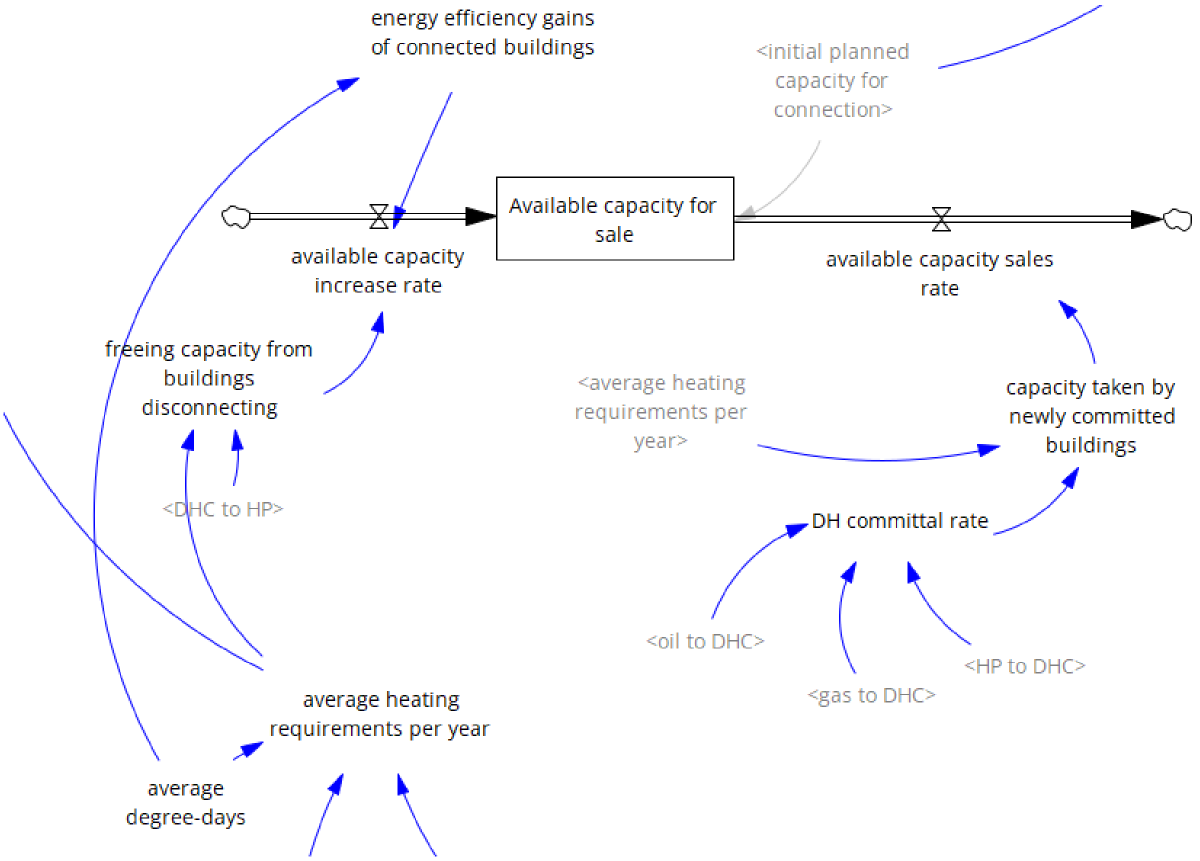

Figure 8: Parameterization of available DH capacity for sale in each area.

The available capacity for connection, which represents the ability to physically connect buildings, is likewise increased by freeing capacity from disconnecting buildings and energy efficiency gains (Figure 9). It is reduced by the connection rate, i.e., buildings being connected to the grid (as opposed to the committal rate used above). In contrast to the capacity for sale, the capacity for connection is available only as the infrastructure is built. Construction takes place according to a fixed schedule, with a prescribed year of construction start and construction duration (see Section 2.5). Construction may be slowed down through a prescribed delay or slow progress (see Section 2.1.3).

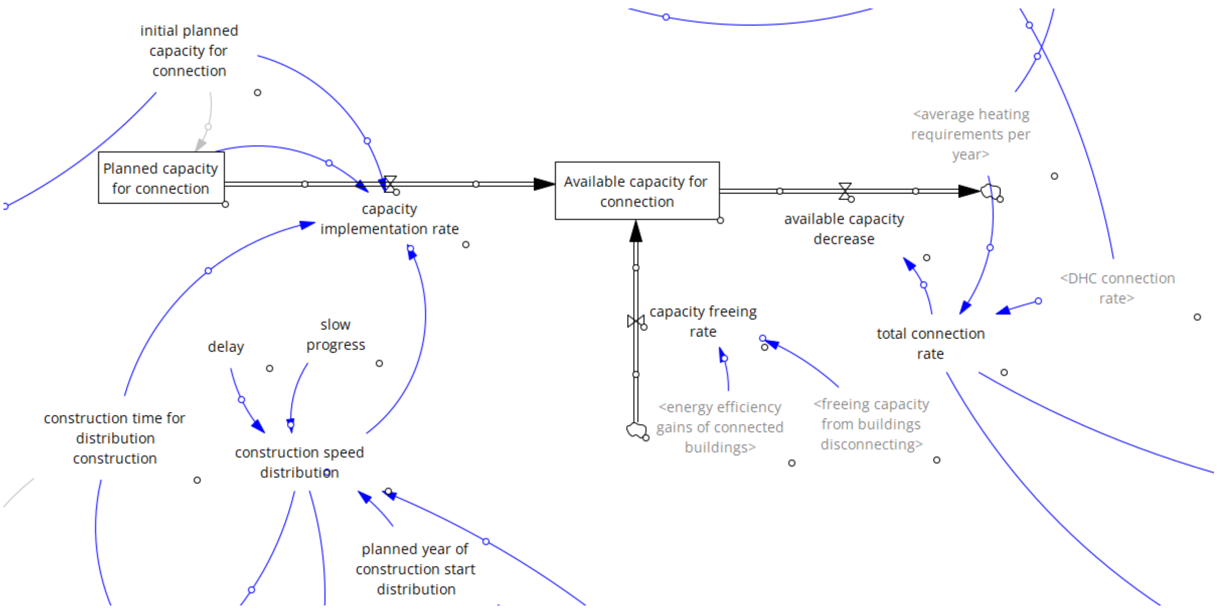

Figure 9: Simulation of available DH capacity for connection in each area.

2.3. Finances and pricing

The financing and pricing subsystem calculates the utility's costs and revenues in each time step, updates the two financial stocks (cash reserve and deficit) and sets the unit price for DH.

2.3.1. Annual cash flow, cash reserve and deficit

In line with current developments in Swiss cities, SCOVILLE is designed to simulate cases where important DH infrastructure developments are foreseen, leading to high investment costs. Investments are made based on a prescribed schedule (see Section 2.5). These investment costs are not paid directly from the utility's balance sheet, but a debt stock is created, which must be amortized according to a prescribed (linear) schedule. It is not specified here whether the investments costs are borrowed internally (e.g., from other business units of the utility) or externally (e.g., from a municipal credit or private lenders). The type of creditor is considered implicitly through the definition of the interest and discount rate. Public utilities are typically required to be financially self-sustainable, so that operating and capital costs must be paid from the annual cash flow and from the utility's reserves. Typically, in years where the cash flow is positive (i.e. the revenues from energy sales are greater than procurement, O&M, personnel and capital costs, as well as taxes and levies), the profit is deposited into the reserves. Conversely, with a negative cash flow, the difference between revenues and costs is withdrawn from the reserves. The formulation presented here allows for a deficit, which represents additional debts within the utility or towards external lenders.

Annual revenues stem primarily from energy sales, whereas subsidies to the utility (e.g. from federal programs) may represent a secondary revenue. For simplicity, it is assumed that the investment costs for service pipes are paid for by the building owner, which is reflected in the investment costs for new DH connections for building owners. Revenues from energy sales are calculated by multiplying the amount of heat delivered with the unit price (see Section 2.3.2 for the pricing model):

$$R_{sales} = energy\ delivered * P_{DH} \tag{7}$$

In the model formulation presented here, a single price level is used for all customer segments (anchor loads and individual buildings). The energy delivered is a function of the heating power requirements per building and the installed anchor loads:

$$energy\ delivered = E_{building} * Buildings + E_{Anchor} \tag{8}$$

where $Q_{building}$ is the annual energy demand per building (kWh; see Section 2.2.5), $Buildings$ the number of buildings connected to the grid, and E_{Anchor} the annual heat demand of anchor loads (kWh).

Annual costs consist of procurement, O&M and capital costs. Procurement costs are limited here to the procurement of fuel, energy (e.g., excess heat) and electricity. The procurement price depends therefore on the energy mix in the thermal grid and is prescribed.

The O&M costs are modeled as a fraction of the infrastructure's replacement value:

$$C_{O\&M} = C_{initial} * f_{O\&M} \tag{9}$$

where the replacement value is a stock keeping track of all investments made. Since it is used as the reference value to model annual O&M costs, this stock is not reduced with amortization or depreciation. Conceptually, the only reduction of this stock should be the retirement of assets. However, due to the long lifetime of DHC infrastructure components, this is omitted here.

Annual capital costs stem from the amortization of investments and interests. In the case considered here, investments are amortized linearly over a fixed duration and with a fixed interest rate. For each investment (see Section 2.1.2), debt is simulated as a stock, which is reduced by a fixed amount each year. Assuming a linear amortization scheme, the annual amortization is obtained by dividing the total cost of each investment by the prescribed amortization period (set to 40 years by default). In addition, interests are paid for the remaining amount of debt each year. If a deficit is accumulated, interests are paid on the current deficit value.

2.3.2. Price adjustment

In this setting, the price must be set so that financial self-sustainability is ensured, and an adequate reserve is maintained. Depending on exogenous factors or endogenous developments, the price may need to be adjusted periodically. However, frequent price adjustments are often unpopular with customers and the public, since long-term price stability is part of the value proposition of DHC[2]. Therefore, DHC price is modeled using a stock-based formulation, following Kubli & Ulli-Beer (2016). Based on our current understanding of pricing policy in Swiss DH utilities, the DH price is calculated as the sum of two stocks: a long-term price, based on forecasted levelized costs, and a short-term price component, aimed at keeping financial indicators (net cash flow, reserve and deficit) at a target level (Figure 10). This representation is not found explicitly in practice but represents an interpretation of observed actions and was elaborated iteratively during model testing.

Two further simplifications are made: first, DHC price is represented as a single value (CHF/kWh), whereas in reality, prices are usually divided into three components (VFS, 2022). This presupposes that the sum of the three price components in a reference building is equal to the levelized cost of energy[3]. The second simplification is that the price is adjusted continuously, whereas such adjustments are discrete, and infrequent in reality. To account for this, each stock is updated to match the indicated price level, with a parameter AT_{tariff} (Years) slowing down the adjustment:

$$\frac{dP_{DH}}{dt} = \frac{P_{DH,ind} - P_{DH}}{AT_{tariff}} \tag{10}$$

[2] It is common practice to adjust the price annually based on inflation, fuel prices or other price indices. These adjustments do not constitute a tariff adjustment in the sense considered here. In this idealized setting, inflation is not explicitly considered.

[3] The weighting of the three components is itself a policy lever: for example, giving more weight to the fixed cost component incentivizes a lower subscription power and targets building owners, whereas weighting the variable cost component more incentivizes efficient energy use and targets users (Speich & Ulli-Beer, 2024). The effects of such interventions may be evaluated by adjusting the model formulation accordingly.

where P_{DH} is the DH price level (CHF/kWh) and $P_{DH,ind}$ the indicated level. This formulation is used for both the long-term and short-term components.

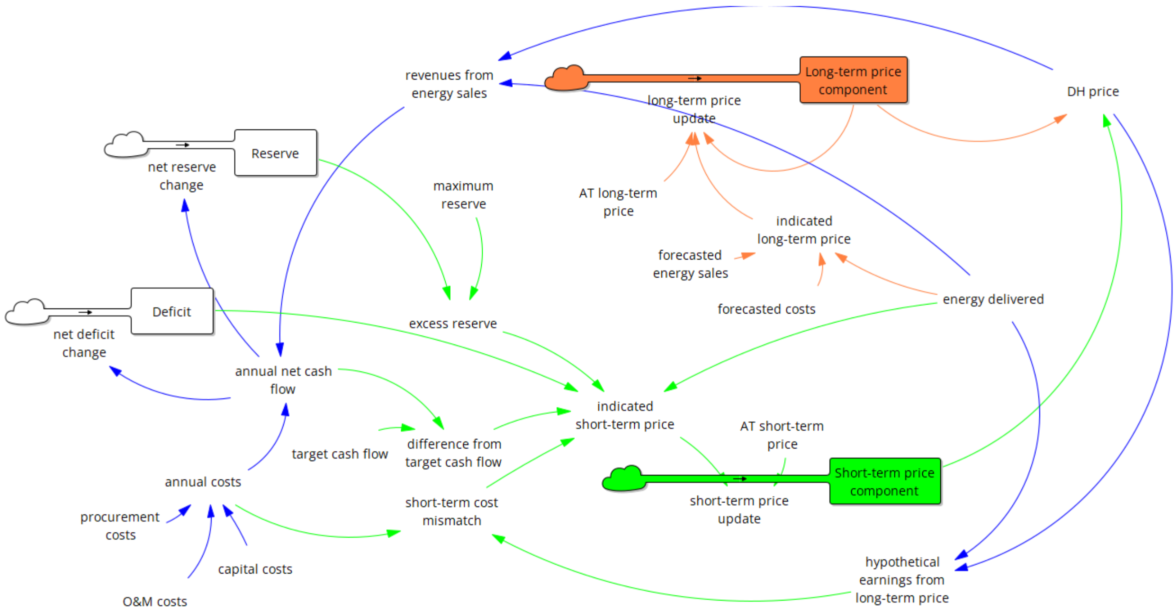

Figure 10: Schematic representation of the pricing mechanism, including a long-term (orange) and a short-term price component (green).

With a long-term infrastructure and business plan in place, the indicated long-term price of DHC $P_{DH,ind}$ (CHF/kWh) is the levelized cost of future heat sales, based on the forecasted discounted costs and energy sales (see Section 2.4). The indicated short-term price is based on three financial indicators, each divided by the annual energy sales (using the sales value from the last time step as a proxy): the difference of the reserve from a maximum level, the height of the deficit, the difference of the net cash flow from a target level (which may be higher than zero to allow for a buffer or profit) and the hypothetical difference between costs and revenues if only the long-term price component was applied. The latter term has the consequence that, for very small values of $AT_{tariffST}$, the DH price reflects short-term dynamics only. However, greater values of $AT_{tariffST}$ give more weight to long-term forecasts.

2.4. Forecasting

The forecasting subsystem produces the two quantities that are required to estimate the indicated price of DH: the expected energy sales and expected costs between the current time and the time horizon. The time horizon can be either a fixed year (e.g., 2070), or a fixed number of years from the current time (e.g., time + 40 years). In this implementation, the following simplifications are made, which may need to be revised for future applications depending on the research question:

- The energy procurement cost stays constant.
- The time horizon (fixed year or moving window) and the discount rate remain constant during the simulation.
- The forecasts of future demand are done based on a linear extrapolation of past demand, with limits to the minimum and maximum demand in the future.

Energy sales are estimated in each area based on scheduled construction steps and the past demand trend, while the following cost components are estimated separately, then summed together:

- Capital costs (amortization and interests from investments).

- O&M costs of existing infrastructure.
- O&M costs of infrastructure to be built.
- Energy procurement costs.

The model assumes that the utility bases its calculations using discounted cash flows. Therefore, all cost components are discounted over the forecasting period using a fixed discount rate. Likewise, in line with usual definitions of levelized energy costs (Aldersey-Williams & Rubert, 2019), the estimated energy sales are discounted as well. In each case, the discounted sum is obtained by calculating the integral of the product of an (exponential) discounting function with the forecasted evolution of the quantity over time.

In areas with an already existing distribution grid, or where construction has already started ("old" areas; Figure 11), the model tracks the evolution of demand (based on buildings connecting and disconnecting as well as energy efficiency gains from envelope retrofits) and uses it to derive a linear trend, which is used to estimate the evolution of demand in the forecasting period.

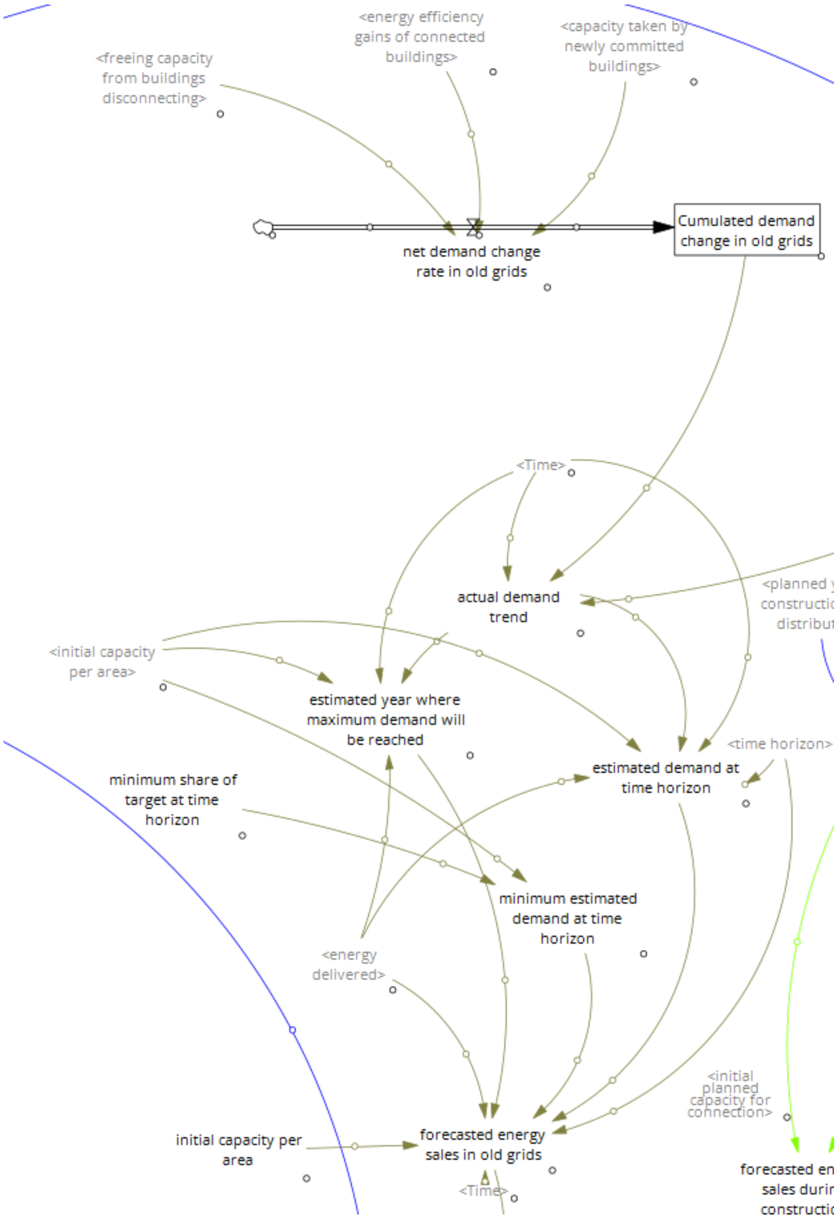

Figure 11: Calculation of forecasted energy sales in areas with an existing distribution grid.

Depending on the current demand and the calculated trend, several situations may occur: the forecasted value at the time horizon is between reasonable minimum and maximum bounds (Figure 12), or the trend is so strongly positive (Figure 13) or negative (Figure 14) that the forecasted value is outside these bounds.

In the first case, estimating future energy demand over the forecasting period is equivalent to calculating the area of the trapezoid delimited by the current time, time horizon and the trend line between them.

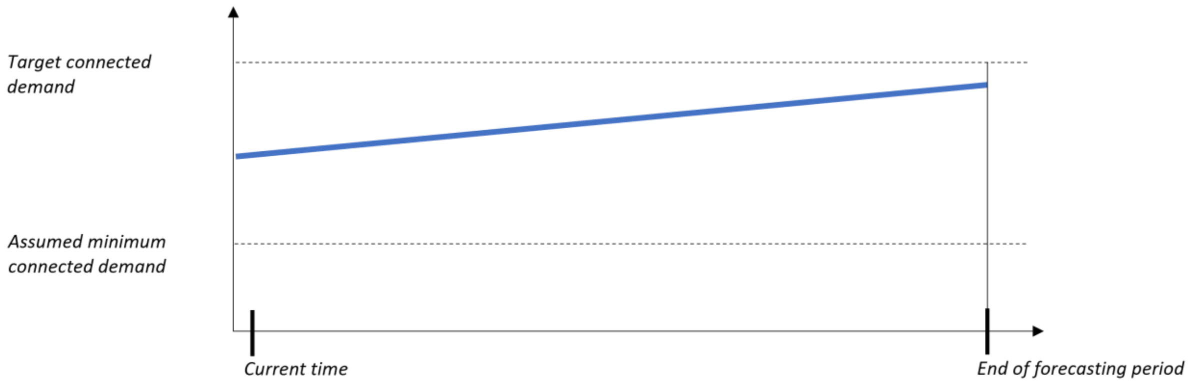

Figure 12: Example of a forecast in an "old" grid (case 1: extrapolated value at time horizon within minimum and maximum bounds).

The model assumes that the utility will not seek to connect more buildings than are required to meet the target for an area. Therefore, if the trend gives a value at time horizon that is greater than the target, it is assumed that the demand will remain at target level from the moment where this is first reached. To estimate cumulated demand, it is therefore necessary to calculate the area of the trapezoid between the current time and the time where target level is reached, as well as the area of the rectangle for the remaining period (Figure 13).

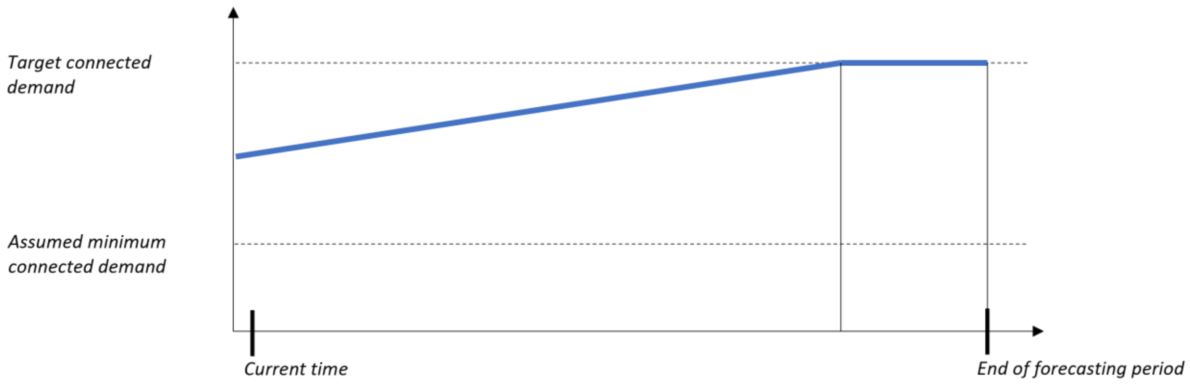

Figure 13: Example of a forecast in an "old" grid (case 2: extrapolated value at time horizon is greater than the target demand).

The model further assumes that there is a lower bound to the forecasted demand. In other words, the utility assumes that the connected demand will not go below a minimum level, even if current trends point towards a lower level. Conceptually, this may reflect the fact that the utility may take corrective measures (e.g., intensifying customer relationship management or acquisition efforts) if demand drops too far. Therefore, if the interpolated value at time horizon is below this minimum level (dashed line on Figure 14), it is automatically set to the minimum (solid line on Figure 14). In this case, estimating the cumulative future energy sales is again simply a matter of calculating the area of the trapezoid.

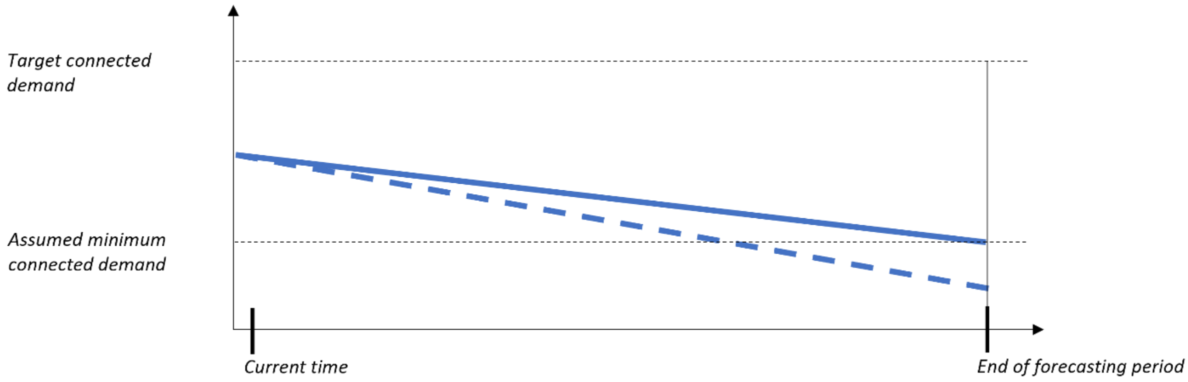

Figure 14: Example of a forecast in an "old" grid (case 3: extrapolated value at time horizon (dashed line) is less than the assumed minimum connected demand).

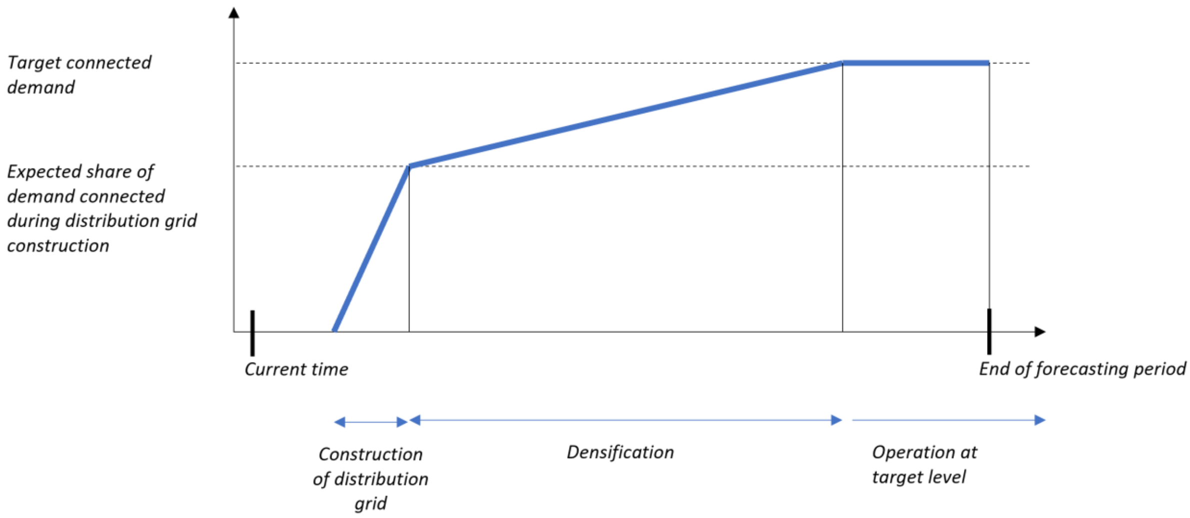

Figure 15: Planned evolution of heat sales in a new area, following the implementation schedule for distribution and service pipes.

The forecast also estimates future heat sales based on the planned development in each area, for which there is no demand trend yet (Figure 15): the expansion of the distribution grid in a new area, typically lasting a few years, is expected to lead to the connection of a certain share of demand. After the construction of the distribution grid is completed, a (typically much longer) period of densification follows, where additional buildings are connected until the target for the connected demand is reached. Therefore, future energy sales and energy procurement costs are estimated by normalizing the area under the blue line in Figure 15 with target annual energy demand. This variable, termed $expected\ development$, is calculated for each area using simple geometric formulae (area of a trapezoid):

$$expected\ development = \frac{T_{dist} * (p_{dist} + s_{dist})}{2} + \frac{T_{dens}(1 + s_{dist})}{2} + (window - T_{dist} - T_{dens}) \qquad (11)$$

where T_{dist} is the remaining time for construction of the distribution grid, p_{dist} the current construction progress of the distribution grid, s_{dist} the expected share of target demand that can be connected during distribution grid construction, T_{dist} the remaining time for densification (the calculation of these variables is described in Section 2.5), and $window$ the length of the forecasting period in years.

Forecasted energy sales are also directly linked to forecasted energy procurement costs. However, since the model uses discounted costs, it is not possible to simply multiply the energy sales numbers with the energy procurement price. Instead, the cumulative discounted energy procurement costs are obtained by integrating the product of the connected demand and the discount factor. The forecasted capital and O&M costs are a likewise calculated as the integral of the product of an exponential discounting rate and the expected annual costs.

2.5. Implementation progress and business plan

The implementation progress and business plan view contains the following stocks: remaining estimated construction time for each investment, remaining credit for each investment, year of infrastructure construction start for the distribution grid in each area, available power for connection in each area, planned anchor loads in each area, connected anchor loads in each area.

The implementation progress of distribution grids, together with connection of anchor loads and other buildings, determines the availability of power for connection in that area. As long as power is available for connection, buildings that have already committed are connected. This determines the implementation progress of service pipes. It is assumed that delays are not expected to last, i.e., the actual implementation progress has no effect on the expected construction rate in the future.

Currently, the implementation plan is implemented independently of the success of previous implementations and the utility's financial situation. Further model extensions may include an explicit feedback, as the utility may be prompted to postpone, reduce or also advance or expand planned investments.

3. Parametrization

3.1. Generic parameters and initial values

An overview of the parameters necessary for a SCOVILLE simulation is given in Table 2, along with values used in a synthetic case study (D2.3.2). Together, these parameters describe the characteristics of the simulation region. Most of these parameters can be disaggregated at the level of each area to reflect area-specific characteristics.

Table 2: Overview of model parameters and default values from a synthetic case study (D2.3.2)

Parameter	**Value**	**Units**
Decision-making by building owners		
Initial number of buildings with HS	Area0: 500, 500, 2'000, 50 Other areas (each): 500, 500, 0, 20	Buildings
Initial average heat loss coefficient of buildings	800	W/K
Minimum attainable heat loss coefficient	100	W/K
Annual heating degree-days	3'125	Degree-days
Rate of heat loss coefficient improvement	8	(W/K)/Year
Annual DHW use	42'000	kWh/Year
Consumer prices for oil, gas, electricity	0.1144, 0.1484, 0.2532	CHF/kWh
Investment costs for HS	66'000, 48'000, 62'000, 120'000	CHF
Specific GHG emissions of HS	0.265, 0.202, 0.0972, 0.0023	
Convenience utility of HS	0.5, 0.9, 1, 0.5	Dimensionless
Weight of utility dimensions	0.25, 0.25, 0.25, 0.25	Dimensionless

(financial, upfront cost, environmental, convenience)		
Beta	3	Dimensionless
Preference for existing HS	0.3	Dimensionless
Initial familiarity with HP in MFH	0.3	Dimensionless
Effective contact rate for HP	0.2	Dimensionless
Finance		
Initial DH price	0.15	CHF/kWh
AT long-term price change	10	Years
AT short-term price change	1	Years
Energy procurement price	0.1	CHF/kWh
O&M cost factor	3%	Dimensionless
Initial infrastructure replacement value	200	MCHF
Initial cash reserve	20	MCHF
Investment and construction plan		
Specific investment cost distribution pipes	1.2	CHF/kWh
Forecasting		
Discount rate	4%	Dimensionless
Time horizon	2075	Year
Amortization period of investments	40	Years

3.2. Decision-making parameters

A key set of parameters is the weighting of utility dimensions by building owners. The choice of these four utility dimensions was based on interpretation of empirical findings in the literature. In the following, we briefly summarize the insights from existing literature and how they may guide the weighting of utility dimensions. The representation is based on the following generic insights:

- Different types of building owners pursue different goals regarding their building: a distinction can be made between private owner-occupiers, private individuals as landlords, institutional landlords, public authorities and non-profit organizations (e.g., housing cooperatives). Private owner-occupiers are primarily interested in ensuring comfort and reducing energy costs. Landlords tend to see their building as an asset and are primarily interested in retaining or increasing its value (a further distinction can be made between, on one side, private landlords and long-term oriented institutional building owners, such as insurance companies or pension funds, and on the other side real estate developers, with a focus on short-term profits). Public authorities and non-profit organizations further pursue mission-driven goals, such as providing affordable housing (Lehmann et al., 2015).

The following insights apply to the group of private landlords and owner-occupiers:

- The decision to retrofit buildings is typically a two-step process, where owners first decide whether they want to retrofit, and decide on the type and depth of retrofit in a second step (Wiencke & Meins, 2012). In the first step, socio-demographic factors, such as age, education or purchasing power of the building owners, are the main determinants. In the second step, the retrofit depth depends primarily on the building owners' goals (Hess et al., 2022). A similar effect was observed for the case of heating system replacements, where such interventions were either triggered by problems or opportunities, followed in a second step by a subjective assessment of the available options (Hecher et al., 2017).

- Private owners of multi-family houses are primarily interested in ensuring their building's value on the rental market. However, due to time constraints, this group typically does not have a long-term strategy for their building, but rather tend to behave reactively (Lehmann et al., 2023). This tends to prevent comprehensive retrofits (Lehmann et al., 2015).
- The capacity to handle administrative workload is an important barrier for private landlords. This may prevent them from taking measures, or to realize their economic benefits: for example, many were found not to increase rents after a retrofit, despite being legally entitled to do so, in order to avoid additional administrative work (Lehmann et al., 2023).

For private and institutional landlords, the following was observed:

- In a statistical analysis of buildings, rental contracts and real estate transactions, Schläpfer et al. (2022) found that buildings with a low-carbon heating system had a higher net rent of CHF 35-45 per month and apartment. The authors attribute this to lower extra costs due to energy savings.
- Schläpfer et al. (2022) also found that real estate investors apply a somewhat higher discount factor to buildings with a fossil fuel-based heating system (10 basis point difference, leading to a difference in market value of 3.3% between buildings with fossil-fueled and low-carbon heating systems). The authors attribute this to lower perceived risks (regarding compliance with public policy and firm-internal policies) as well as potentially more favorable financing conditions in the case of low-carbon heating systems.
- The effects of an energy efficiency retrofit on the market value of a building were separated into three distinct components (Schläpfer & Schmid, 2024): first, the retrofit ensures that the corresponding building component is up-to-date and no further interventions will be required for a long time (this effect would also be reached with a simple refurbishment without energetic improvement); second, buyers are willing to pay a premium for green buildings; third, net rents can be increased. The rent increase is due to two factors: first, investment costs from improvements of the building standard may be partly passed to tenants, and second, energy savings justify an increase in net rents for new contracts.
    - This means that a part of the economic benefits is not realized immediately: the net rent may only be increased with a new contract, i.e., a change of tenants. Building owners with a short-term focus on annual cash flows may therefore see these investments as less worthwhile (Schläpfer & Schmid, 2024).
- Focusing on MINERGIE-certified buildings, Kempf & Syz (2022) found a price premium of 2.45% (Canton of Zurich) to 4.91% (City of Zurich) compared to conventional buildings. This price premium was to 70% attributable to the higher comfort and building quality, whereas an additional 20 to 30% could be attributed to future-proofing the building against stricter regulations. In contrast, the effect of energy savings on the price premium was found to be almost inexistent.

Therefore, the following considerations can be applied to appropriately weight the utility dimensions:

- In areas with a higher share of owner-occupiers, the financial utility and convenience utility dimensions have high priority.
- In areas with a high share of rented buildings, the market value is more important. In the current model formulation, the effects of heating systems on the market value are captured through the environmental utility dimension (see Section 2.2.3).

- The weight of the environmental dimension also depends on the expectations of building owners towards future policy requirements. If stricter requirements are expected, the importance of the environmental dimension increases.
- Public and non-profit landlords give more weight to the financial utility than private landlords, since offering affordable housing is part of their mission.
- Institutional landlords with a short-term horizon may give less weight to the environmental utility, as some of its benefits can be realized in the longer term only.
- Owner-occupiers and private landlords give greater weight to the upfront cost utility than institutional landlords.
- In addition, a higher share of institutional building owners can be thought to increase the value of the *beta* parameter (sensitivity of decision-making to differences in utility, see Section 2.2.3).

3.3. Data requirements

As can be noticed from Table 2, the model requires little data to operate. Concretely, the following data sources can be used:

- A driver of the model is an implementation plan, listing the planned investments in a given strategy (see Section 2.1.2). Such a plan may be the product of strategic energy planning, or may reflect one of several variants being considered in that process. Furthermore, such plans and the corresponding estimation of costs and benefits may be the result of feasibility studies, or might simply be informed through expert judgment.
- To estimate the number of buildings in each area, the Federal Registry of Buildings and Dwellings can be used. The distribution of building size can be used to check whether the standard building geometry is a valid assumption or must be adapted. The Registry further contains information on heating systems at building level. However, this information is not equally reliable in all municipalities. In municipalities where this information is kept up-to-date, it can be used to initialize the number of buildings with each heating system.
- Municipal energy plans often include an inventory of existing heating systems, which may be used to initialize the number of buildings per heating system.
- Some cities provide data on building ownership, which is valuable to parameterize the decision-making parameters (see Section 3.2).
- If available, historical time series of DH connections, energy use or cash flows can be used to calibrate the model.

4. Outlook

4.1. Planned future applications

In line with the objectives of DeCarbCH, the following applications and model extensions are planned:

- Assessing the costs and benefits of various strategies to reduce network temperature (e.g., distribution infrastructure expansion, substation replacement campaigns, digital monitoring of substations). To answer this question, the model will need to be extended to explicitly simulate network temperature (see Speich & Ulli-Beer, 2024 for a conceptual sub-model).
- Evaluating different strategies to leverage flexibility in DH grids (e.g., through decentralized thermal energy storage) with the aim of reducing peak loads, reducing the need for fossil fuels and increasing the utilization of existing infrastructure.
- Assessing development and operation strategies for integrated district heating and cooling.

In these applications, the goal is to create a roadmap scheduling which investments, policy measures, orchestration measures etc. are to be implemented in which order to realize public policy goals.

4.2. Further possibilities

The SCOVILLE simulation framework describes the implementation dynamics of thermal grid portfolios as part of municipal energy and climate strategies. This makes it suitable to answer a wide range of questions related to the energy transition in regions and municipalities. The model can be used to facilitate discussions between actors (utilities, city administration, policymakers, etc.) e.g. around the following issues:

- Clarifying the factors that lead to price fluctuations in DH systems under massive expansion. A shared understanding of these processes may increase acceptance for DH expansion plans and serve as a basis for strategies to avoid adverse social impacts.
- Assisting cities and utilities in assessing the effects of different pricing strategies, e.g., evaluating the consequences of a single tariff across all networks in a municipality (which is often a requirement stemming from municipal policymakers).
- Simulating the coupling of DH network development with environmental boundary conditions, e.g. the long-term temperature change in aquifers using for heating, cooling and storage. Here, use of the model may assist in devising sustainable aquifer management strategies.

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