TRANSFORMATION PATHS OF LOCAL DISTRICT HEATING WITH ELECTRICITY AND HEAT SECTOR COUPLING IN GERMANY

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1 Introduction

The scope of this paper is to combine a techno-economic approach to transformation processes in energy systems with a focus on district heating. The approach represents a knowledge base for the modelling of different district heating systems and is therefore an important basis for future research in the energy economics field. The methodology considers the most recent regulatory framework of Germany and the analysis of 4 district heating systems.

1.1 Regulatory Framework

In addition to the burdens (e.g. EEG levy) and incentives (e.g. CO2 price) of end-user prices, the subsidy conditions are decisive for the attractiveness of investments. The basic assumption is that existing or planned subsidies will be continued until 2030 and then change to technology-open incentives (in the model from 2035 to 2050).

In addition, the regulatory framework conditions are decisive for the economic viability of individual technologies. Incentives to spur innovative technologies can be considered. Another possibility is subsidies in the form of investment incentives or operating premiums (CAPEX or OPEX subsidies).

a) Combined-Heat-and-Power Act (Kraft-Wärme-Kopplungsgesetz – KWKG)

For Combined-Heat-and-Power **(**CHP) heat, small Gas Turbines and for large Combined Cycle Gas Turbine (CCGT), the first assumptions according to KWKG [1] are considered for investments made from 2020 until the end of 2029. A subsidy is assumed with a maximum utilization per year (4000 h/year in 2020; 3500 h/year in 2025; 3000 h/year in 2030; 2500 h/year in 2035; 2000 h/year in 2040), limited to the first 30,000 Full Load Hours. Thus, the **KWKG incentive** does not have a cross-border cost effect and does not change plant use in the electricity market.

For the period after 2030, a Capital Expenditures (CAPEX) subsidy is assumed equal to 40 % of the investment cost. The surcharge eligibility for new or expanded heating networks that are supplied with at least 75% CHP heat or at least 75% in combination with CHP heat, renewable energy heat and waste heat.

b) Federal funding for efficient heating networks (Bundesförderung für Effiziente Wärmenetze - BEW)

Here, federal funding [2] describes the support for the market penetration of large heat pumps and solar themal collectors through two mechanisms. First, a thermal generation ***premium*** (subsidy) for the heat generation in €/MWh (thermal) for investments done in 2020 if it comes from Renewable Energy (RE) sources, regardless of the capacity. Second, 40% CAPEX subsidy for the period after 2030.

To compensate for high electricity cost on the electricity market, the heat pumps have reduced variable network charges in the low voltage level. For these, the operation of the heat pump must be allowed to be flexible, including a separate metering point in order to reduce congestion in the power grid. This mechanism was introduced in the Section 14a of the German Energy Industry Act [3] **(Energiewirtschaftsgesetz - EnWG)**

2 Methodology

In the area of fundamental model-based overall system investment and deployment planning, mathematical models have been improving lately [4] [5] to determine economically optimal scenarios, taking into account new developments in energy supply technologies. In order for this to be the case, the models need to have additional economic and energy-flow connections in the mathematical representation of the underlying problem. Firstly, to relate the investment decision-making process with regard to a predominant CO_2 target reduction. Secondly, to connect the heat demand coverage and the influence of electricity market prices. The following subsections present such a model.

2.1 Portfolio optimization

In energy economics, a portfolio of energy production facilities or an expansion of assets can be modelled as a decision making process of a long-term investment problem with optimal planning. The combination of classical unit commitment [6] and investment optimization lets us solve these problems.

The objective function maximizes the profits, defined as income minus costs $(i_t - c_t)$, in the short time horizon, while taking into account the long term investment costs c_{inv} for the facilities, as follows:

$$maximizing \sum_{t \in T} (i_t - c_t) \cdot f - c_{inv} \cdot f \qquad \textit{Equation 1}$$

The net present value discount factor f for investments and annual cash flows considers the expected rate of return *ERR* and the year of investment or cash flow *year*, as follows:

$$f = \frac{1}{(1 + EER)^{year}} \qquad \textit{Equation 2}$$

The income i_t considers for every hour *t*, the purchasing price $\rho_{l,t}$of each electrical or thermal energy consumption *sink l* of set *L*. The hourly energy consumption $P_{l,t}$ represents the hourly load curve of each energy sink. Additional, each Engine *e* can have a variable *premium* as a thermal (RE) generation dependant incentive (see Section 1.1, b) or a fixed investment (CAPEX) *incentive* (see Section 1.1, a), depending on the type of technology.

$$i_t = \sum_{l \in L} P_{l,t} \cdot \rho_{l,t} + \sum_{e \in E} (premium_{e,t} + incentive_{e,t}) \qquad \textit{Equation 3}$$

The *cost* c_t has three factors; the first one depends on the start-up binary variable and its associated cost in €/h. The second factor considers the hourly generation $p_{e,t}^{out}$ for each engine *e* of set E and its operating, fuel and CO_2 variable costs in €/MWh. The third factor multiplies the operating state binary variable $s_{e,t}^{on}$ by the engine maximum output capacity P_e^{max} and the fixed cost $\rho_{e,t}^{fix}$, which is given in €/MW.

$$c_t = \sum_{e \in E} s_{e,t}^{start} \cdot \rho_e^{start} + p_{e,t}^{out}(\rho_{e,t}^{on} + \rho_{e,t}^{fuel} + \rho_{e,t}^{CO2}) + s_{e,t}^{on} \cdot \rho_{e,t}^{fix} \cdot P_e^{max} \qquad \textit{Equation 4}$$

The investment cost c_{inv} considers the investment cost $\rho_{e,t}^{inv}$ in €/MW, the maximum capacity P_e^{max} and the investment binary variable $s_{e,t}^{inv}$, for every candidate generation unit

$$c_{inv} = \sum_{e \in E} \rho_{e,t}^{inv} \cdot P_e^{max} \cdot s_{e,t}^{inv} \qquad \textit{Equation 5}$$

Two sets of binary variables relations are required. The equality constraint for the operational binary variables $s_{e,t}^{on}, s_{e,t}^{start}, s_{e,t}^{off}$ defining the relation of in-operation state, the start-up state and the shut-down state. Similarly, the investment binary variables $s_{e,t}^{inv\_on}, s_{e,t}^{inv}, s_{e,t}^{decom}$ relation of in-operation investment, the investment point in time and the decommissioning point in time. The Equation 8 limits the investment to one occurrence only.

$$s_{e,t}^{on} - s_{e,t-1}^{on} = s_{e,t}^{start} - s_{e,t}^{off} \qquad \textit{Equation 6}$$

$$s_{e,t}^{inv\_on} - s_{e,t-1}^{inv\_on} = s_{e,t}^{inv} - s_{e,t}^{decom} \qquad \textit{Equation 7}$$

$$s_{e,t}^{inv\_on} + s_{e,t}^{decom} \leq 1 \qquad \textit{Equation 8}$$

To connect both models, making the operation dependent on the investment point in time, we add a last relation.

$$s_{e,t}^{inv\_on} \geq s_{e,t}^{on} \qquad \textit{Equation 9}$$

The thermal energy output is equal to the input energy $p_{e,t}^{in}$ for each engine, multiplied by its primary resource conversion efficiency $\eta_e^{prim}$and limited by its rated maximum and minimum capacities:

$$P_e^{min} \leq \eta_e^{prim} \cdot p_{e,t}^{in} \leq P_e^{max} \qquad \textit{Equation 10}$$

To the particular case of the *CHP*s we add the relation with a secondary efficiency η_{chp}^{second}, where Equation 10, serves also to limit but the electrical energy output $p_{chp,t}^{out}$. For the thermal output we add the variable $p_{chp,t}^{out \rightarrow second}$.

$$p_{chp,t}^{out \rightarrow second} = p_{chp,t}^{out} \cdot \frac{\eta_{chp}^{second}}{\eta_{chp}^{prim}} \qquad \textit{Equation 11}$$

For the Heat Pumps, instead of the previous defined efficiencies, we use the Coefficient of Performance (COP), which depends on source temperature, e.g. underground water, and heat supply temperature time series

$$COP_{hp,t} = \eta_{hp}^{prim} \cdot \frac{T_{hp,t}^{sink}}{T_{hp,t}^{sink} - T_{hp,t}^{source}} \qquad \textit{Equation 12}$$

The electricity balance Equation 13 states the generation of unit *e* if it is a CHP engine. For the electricity consumption $P_{electrical}$ is not given any time series as parameter and is equal to the sum of electricity production, resulting from the consideration of electricity market prices in Equation 3.

$$\sum_{e \in E} p_{e,t}^{out} = P_{electrical,t} \qquad \textit{Equation 13}$$

The thermal energy balance Equation 14, states that the supply and demand need to be equal. For instance, a CHP engine will have thermal energy production in the form of a secondary output $p_{e,t}^{out \rightarrow second}$, while the rest of the generation units (e.g. heat pumps) will have thermal energy production in the form of a primary output $p_{e,t}^{out}$without secondary output.

$$\sum_{e \in E} p_{e,t}^{out} + \sum_{e \in E} p_{e,t}^{out \rightarrow second} = P_{thermal,t} \qquad \textit{Equation 14}$$

This model provides as results optimal long term investment timing and short term scheduling of the generation units to cover the heat demand, under consideration of the electricity prices.

The equation system presented defines an optimal cost-based transformation path, but more specific for this paper, it is implemented for a district heating system in a region of Germany. In the following section, the possible combinations of technologies are presented as result of the hourly operation of sector coupling between electricity and heat. This means that individual investment projects are evaluated as a district heating supply technologies portfolio with regard to their economic efficiency. The simulation environment will optimize the operational decision making of combined heat and power plants, heat pumps, solar thermal, district heating consumers and heat storage systems.

3 Simulation and definition of parameters

The Fraunhofer IEE tool investSCOPE is used for the microeconomic optimization of transformation paths. It is based on the Python[1] package Pyomo. The path optimization tool supports investment decisions, by determination of optimal technologies, installed capacities and optimal investment times while maximizing the net present value (NPV). The NPV calculation includes the investment costs, fixed and variable operating costs, investment subsidies and operating premiums, as well as revenues from energy selling, explained in the Section 2.1. The period under consideration is 35 years (2018-2052), taking representatives of 5-year periods, defining 7 support years, i.e. 2020, 2025, 2030, 2035, 2040, 2045 and 2050.

The subordinate tool microSCOPE performs the unit commitment and economic dispatch optimization for characteristic weeks in the support years, in the following referred to as "type weeks" [7] . It ensures the coverage of the load and further simulates operating costs and revenues via economical short-term schedules of the plants.

InvestSCOPE can be used for path optimization of portfolios in the electricity, heat and mobility sectors or for sector-coupled analysis. The methodology is explained in the following with exclusive reference to district heating.

[1] https://www.python.org/ and http://www.pyomo.org

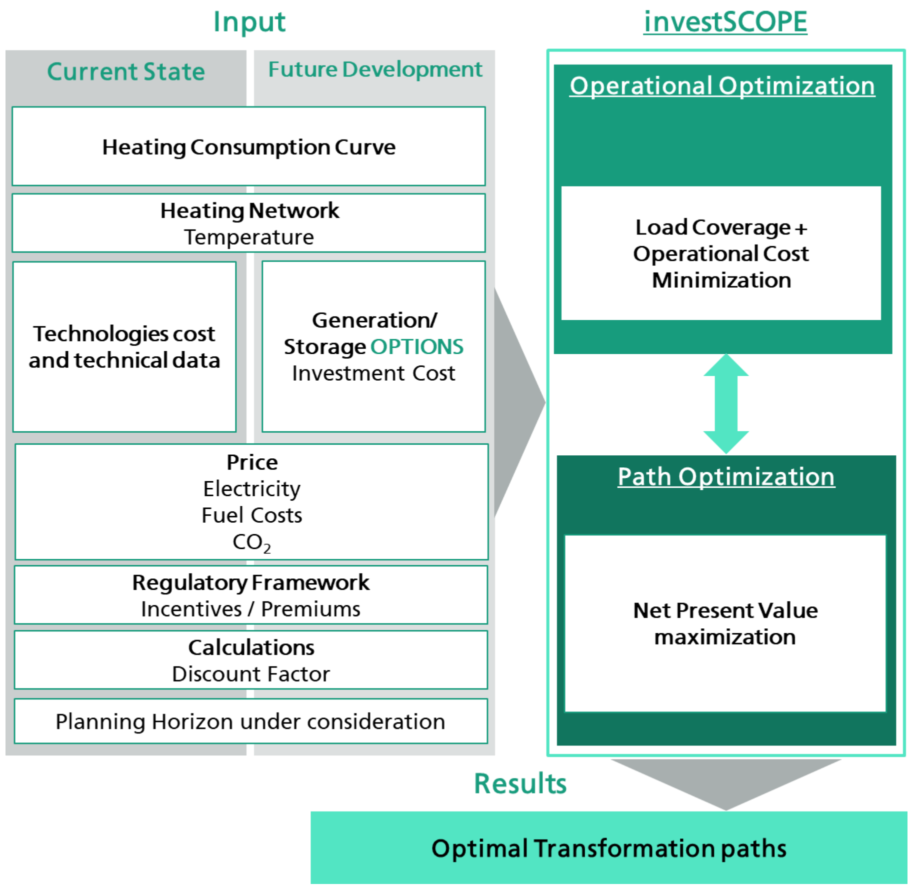

Figure 1 Structure of the simulation environment

3.1 *Inputs to the district heating model*

Input for the optimization tool is information about the current state of the district heating systems as well as assumptions for the future development. For modeling the heat supply system, this includes the annual demand of 770 GWh/year in support year 2020 and future heat demand with a network densification until 2030 to 900 GWh/year and maximum heat load of approx. 410 MW. The heat demand decreases due to refurbishment measures, etc. to 620 GWh/a in the support year 2050.

Characteristic data on the heat network (e.g., current and future temperatures), is considered as follows. [8]

Year	**2020**	**2030**	**2040**	**2050**
Winter Flow Temperature	90°C	90°C	80°C	72°C
Transition Flow Temperature	90°C	90°C	80°C	72°C
Summer Flow Temperature	75°C	75°C	75°C	72°C

Table 1 Flow temperatures for the Heat Pump at the bivalence point

Today's electricity, fuel and CO_2 prices are given as time series, as well as assumptions about future developments in this regard. Finally, a discount rate must be given to the microeconomic optimization for the calculation of the NPV equal to 7%. Electricity prices, levies, CO_2 prices, gas prices from macroeconomic future scenarios based on political decisions in "Climate Action Programme 2020" [9], presented below in *Figure 2* .

Due to inflation (assumption 2%), future nominal incentives lose real value. In addition, future revenues in the model are reduced by the inflation-adjusted discount rate.

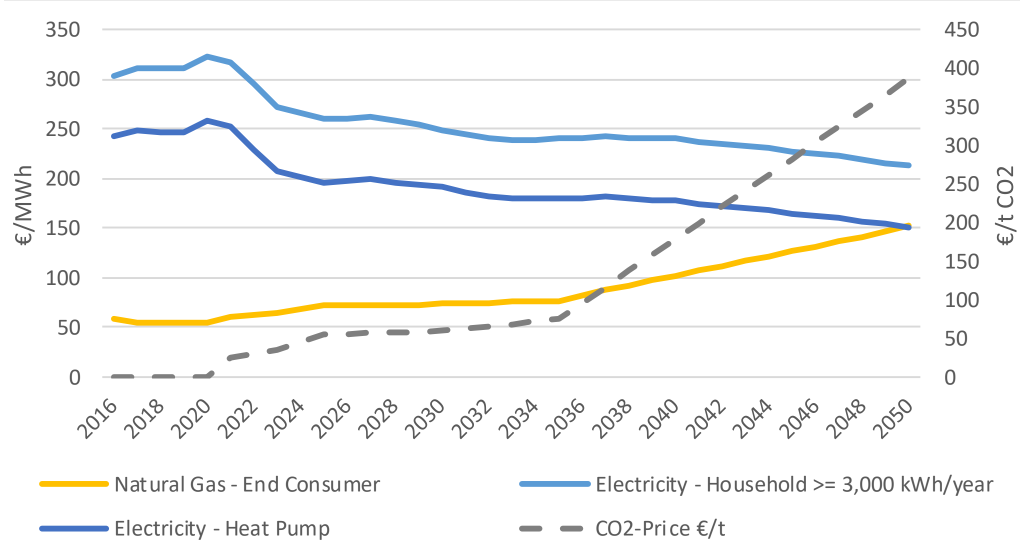

Figure 2 Development of end-user prices

The current inventory of generators, including technology-specific characteristics such as fuels, efficiencies, and fixed and variable operating costs are considered. The *Coal-fired* CHP technology is not available as an investment option. The *Natural Gas* (NG) fired CCGT are available for investment.

Technology	**Maximum Capacity**	**Available for investment.**
Coal-fired CHP [MW_{el}]	46 x 2	No
NG-fired CCGT [MW_{el}]	200	Yes

Table 2 Installed Capacity of existing generation units.

A specification of the optional technologies to be added with corresponding characteristics, is provided in the form of blocks with certain capacities, including investment costs, which investSCOPE can combine optimally.

Optional Technology	**Capacity per Block**	**Lifetime [years]**
NG-fired medium CHP [MW_{el}]	40	30
NG-fired small CHP [MW_{el}]	20	20
NG Boiler [MW_{th}]	40	20
Wood Boiler [MW_{th}]	30	20
Electrical Boiler [MW_{th}]	30	20
Large-scale Heat Pump [MW_{th}]	20	25
Solarthermal [MW_{th}]	15	25
Industrial Waste Heat [MW_{th}]	15	35
Short-term Heat Storage [MWh_{th}]	1,450	35

Table 3 Installed Capacity of optional technologies.

For new CHPs and CCGT is considered the fix investment incentive for the first 30,000 Full Load Hours, according to the KWKG frame of the Section 1.1. a). As from 2030, a 40% CAPEX subsidy is possible.

For the Heat Pumps, a fast penetration is not realistic. Therefore, the model implements the option of 20 MW (thermal) capacity for 2020 and an additional 20 MW alternative for 2025. For support years 2020 and 2025 a thermal generation premium is available. Here we assume RE electricity as energy source. Also, from 2025 it is possible to invest in more heat pumps but without a premium. The 40 % CAPEX subsidy is possible from 2030 onward according to the BEW framework explained in the Section 1.1, b).

The capacity for Solarthermal Parabolic Collectors is limited to 10 MW (thermal) until 2025. For support years 2020 and 2025 the RE thermal generation premium is available. As from 2030, a 40% CAPEX subsidy explained in the Section 1.1 b) is considered.

The Industrial Municipal Waste Heat is considered to be limited to 15 MW and does not consider any incentive.

Considering the information above, we can now build the base scenario and three scenarios with large existing CHP plants. All optional technologies of *Table 3* are available for all scenarios:

- **Base scenario/ Reference scenario**: No existing plants.
- **Scenario CCGT2035**: Combined cycle plant gas turbine phase-out in 2035.
- **Scenario Coal-CHP 2025:** Coal CHP phase-out of first unit in 2025 and the second unit in 2030.
- **Scenario Coal CHP 2030:** Coal CHP phase-out of first unit in 2030 and the second unit in 2035.

The optimization is a MILP problem written in a Python environment. The simulation was done on a computer cluster with 8 computing nodes, each with 2 Intel XEON E5-2698v3 sixteen-core processors clocked at 2.30 GHz with 256 GB RAM memory and solved with CPLEX, using the Pyomo package.

4 Results Analysis

A portfolio of different technologies defines the cost-optimal transformation path of the district heating, that also outline when is the investment needed. The heat generation and investment costs are presented for periods of 5 year, having 7 support years to put in perspective the Base Scenario.

4.1 Reference scenario without existing plants

In the reference scenario, there are no existing plants. Instead, sufficient capacity must be installed in the start support year of 2020 to meet the entire heat demand. Optional technologies are, as mentioned above, large-scale heat pumps, ground-mounted solar thermal collectors, a moderate amount of industrial waste heat, and natural gas-fired CHP. The commitment to a certain amount of heat pumps and solar thermal collectors is favored by an RE operating *premium* (subsidy). The discount factor is 7%. Electricity and other fuel prices are derived from the German government's decision on the "Climate Action Programme 2020" [9] ("Klimaschutzpaket" in German).

At the beginning of the 35 year period under consideration, a portfolio of natural gas CHP, large-scale heat pumps and small shares of solar thermal energy is built up. Waste heat from industry is used for the base load, as this is available at low costs (marginal cost of base-load generators). Due to the RE *premium*, heat pumps will be installed as early as 2020 and 2025 - in line with a limited potential.

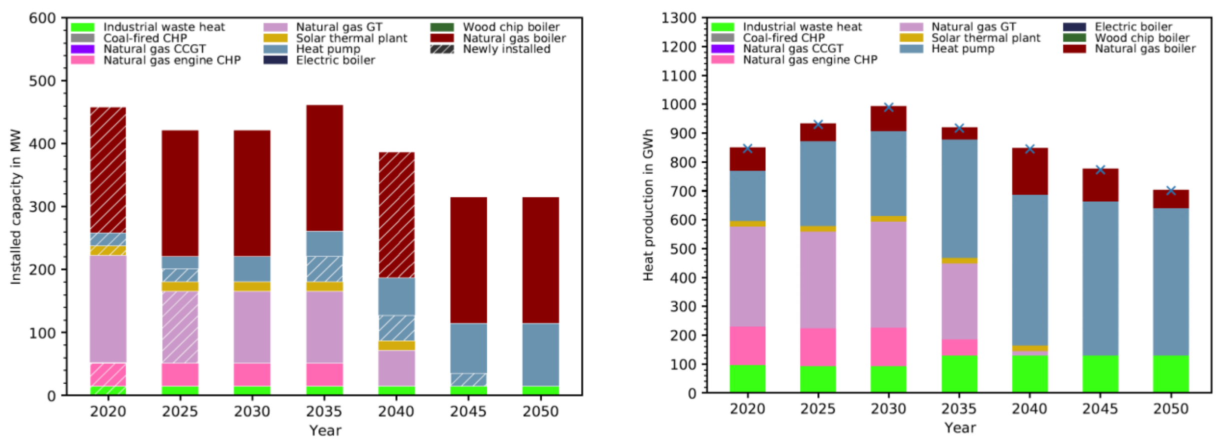

Figure 3 Installed and newly installed capacity (left figure) and the heat demand (right figure) corresponding to each support year for **reference scenario**

In 2020, NG-fired CHP will also still be significantly expanded due to the fixed investment incentive (subsidy) under the KWK-G and will also be used extensively due to the requirement for minimum operating hours to claim the former. When the CHP plants reach the end of their lifetime, additional heat pumps are successively added and assume a dominant role in generation from 2035 on. New CHP is not built because it is no longer competitive against heat pumps in the long-term due to decreasing electricity prices in the future.

Large-scale heat pumps are supplemented by NG boilers until the end, with NG boilers making a larger transitional contribution to heat generation in 2040. Later the boilers are being pushed back to peak load by heat pumps. Waste heat potential is exploited throughout.

This transformation path results in RE shares of about 34% in the support year of 2020, 43% in 2025, 41% in 2030, 61% in 2035, 79% in 2040, 86% in 2045, and finally 91% in 2050.

4.2 Impact of large existing CHP

The results of the optimization with a large existing CHP (CCGT) with a long remaining life-time (until 2035) show that this is supplemented by a small NG-fired CHP in the start year 2020. In addition, waste heat is integrated and a NG boiler is commissioned, as in the reference scenario. The heat pump potential is exploited as in the reference scenario due to the RE *premium*. Solar thermal collectors, however, are not added at all. This can be explained by the fact that the CCGT has to meet certain operating hours in accordance with the KWK-G and, thus, covers the base load to such a large extent even in the summer time, that an investment in solar thermal collectors would not be economical despite the RE *premium*. The CCGT will be largely replaced by heat pumps at its phase-out in 2035.

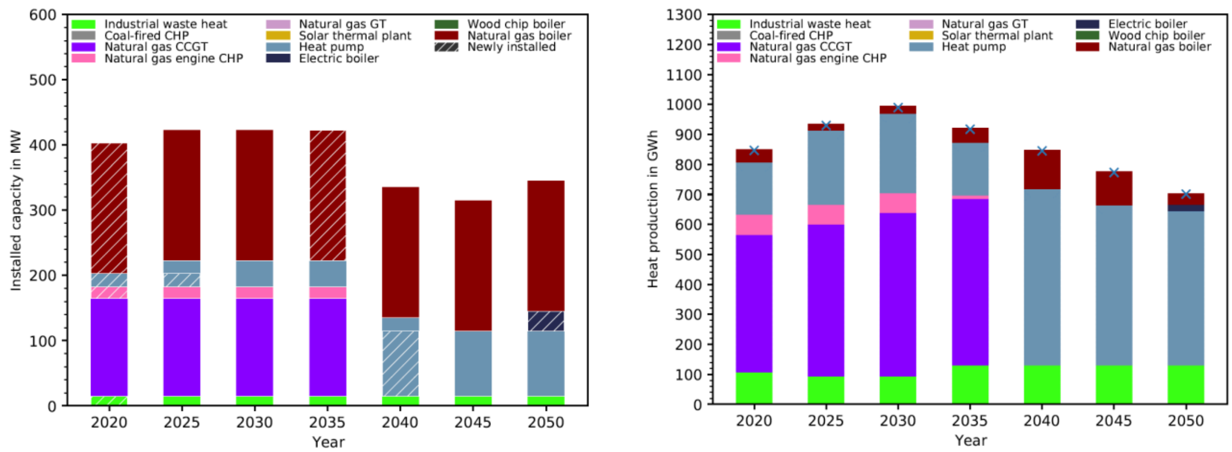

Figure 4 Installed and newly installed capacity (left figure) and the heat demand (right figure) corresponding to each support year for **Scenario CCGT2035**.

An electrical boiler in addition to the NG boiler satisfies a peak demand in 2050. Electrode (electrical) boilers come into play in those scenarios with a large capacity of existing plants, because the latter delay the installation of the other RE technologies compared to the reference scenario.

The following results are based on the assumption of an existing coal-fired CHP in the portfolio of the exemplary district heating supply system, with phase-out in two blocks. In the first case analyzed, there is an early phase-out in the 2020s, and in the second case, a later phase out in the 2030s.

Coal-fired CHP will not be able to run as long as CCGT plants, according to the “Act to reduce and end coal-fired power generation” (**Kohleausstiegsgesetz** in German) initiated by the German government and due to the high emission factors. Therefore, the impact of existing coal-fired CHP is also considered, with an earlier (first block 2025, second block 2030) and a later (first block 2030, second block 2035) phase-out.

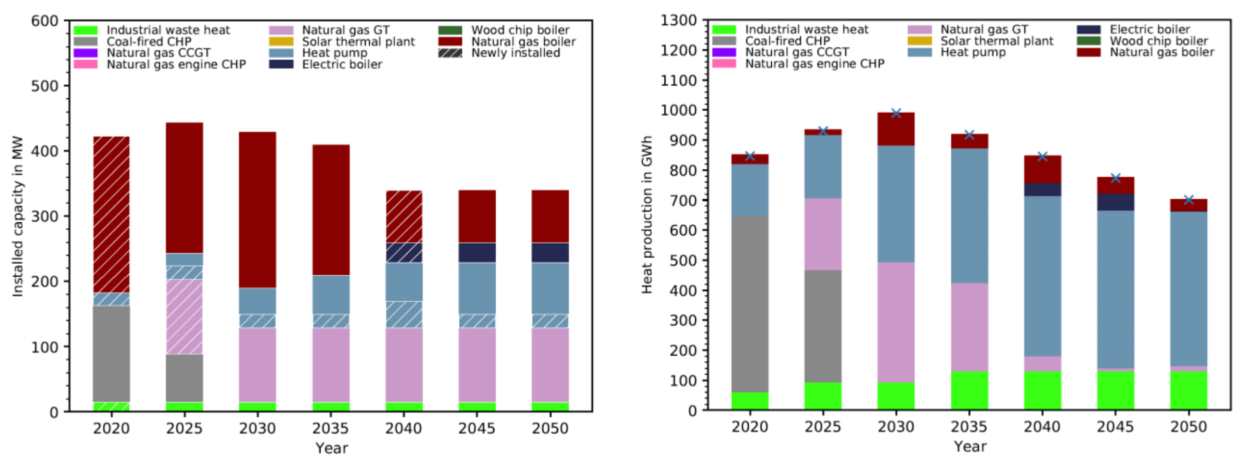

Figure 5 Installed and newly installed capacity (left figure) and the heat demand (right figure) corresponding to each support year for **Scenario Coal-CHP 2025**

The first unit of the early phase-out Coal-fired CHP is replaced in 2025 by a NG-fired CHP, namely a gas turbine as we can see in the *Figure 5*. The phase-out of the second Coal-fired CHP takes place at the same time as an increasing heat demand occurs (due to compression as in the reference scenario) and is compensated by an increasing capacity of large-scale heat pumps. Here the potential of the heat pump is entirely exploited, not only taking advantage of the operating subsidy but using the CAPEX subsidy of 40% of the investment costs as well. As peak load generation, electrode boilers will be built in combination with NG boilers from 2040.

The longer operation of coal-fired CHP primarily leads to increased investment in NG boilers. These are temporarily (2030-2040) used extensively, i.e. well beyond peak load, until heat pumps become cheaper in base load operation and become more prevalent in later years. The higher capacities of NG boilers prevent the addition of electrode boilers.

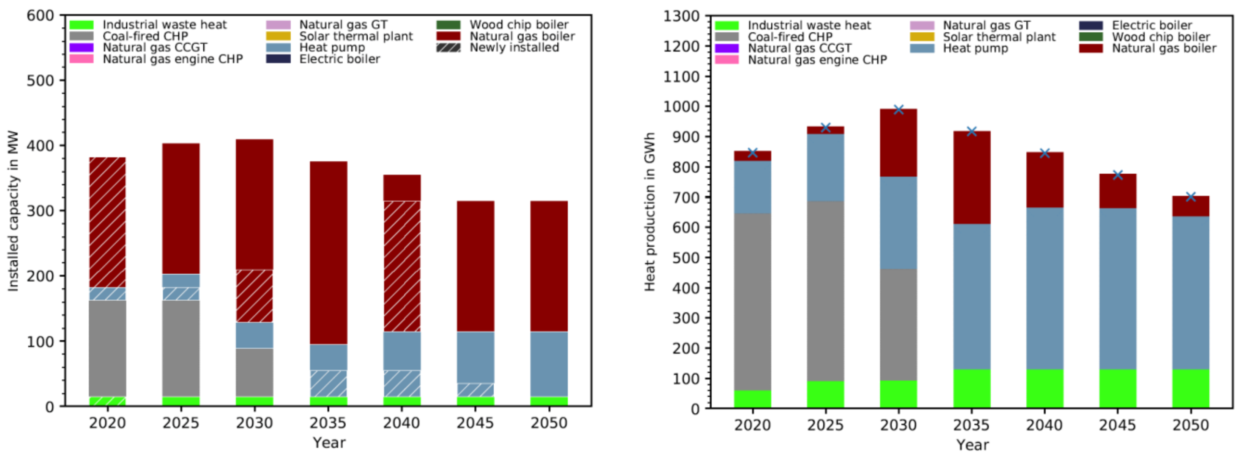

Figure 6 Installed and newly installed capacity (left figure) and the heat demand (right figure) corresponding to each support year for **Scenario Coal CHP 2030**

The RE shares turn out to be significantly lower than in the reference scenario, especially after the phase-out of the large fossil plants, depending on the lifetime of the existing plants. The shares are up to a quarter lower depending on the scenario. The reason for this is the compensation of the lack of capacity by a temporarily significantly higher use of NG boilers. A decade after the phase-out of large-scale CHP, a similar share of “green” heat is achieved through the gradual expansion of RE technologies along with a withdrawal of NG as an energy source to the peak load.

4.3 Discussion

The results of the micro-economic optimization described above show that large-scale heat pumps in particular play an important role in the decarbonization of the district heating supply. Despite subsidies, ground-mounted solar thermal energy is only being expanded to a minor extent. Rooftop solar thermal technology is not included in these considerations.

With the applied RE heat subsidy in the form of an operational premium, a high load factor of the heat pumps can be stimulated. However, the limitation of subsidies for large projects under state aid law can be a major obstacle for individual companies to apply for the subsidies and invest in large-scale heat pumps. On the other hand, a more dynamic development of the technology and its production than assumed here would be conceivable, with a smaller reduction of the operation subsidy in 2025 or a continuation until 2030 as well as the implementation of projects with a larger capacity than 20 MW.

On the other hand, the scenarios examined for the study [8] , result in an average annual subsidy requirement of €3 billion/a - estimated in simplified terms and extrapolated to the whole of Germany - of which two thirds account for the expansion of heating networks and one third for RE heat subsidies.

The key to a long-term absolute dominance of large-scale heat pumps lies in a cost-by-cause principle, low electricity costs in the long run and an increase of efficiency (efficient heat grids, technology development). Nevertheless, to enable such a market ramp-up, subsidies in the form of an operating subsidy - accompanied by other measures - are necessary in the early years to compensate for the currently very high electricity cost components in Germany, i.e. taxes and levies.

The integration of industrial waste heat can be an alternative to an increased expansion of large heat pumps. Industrial waste heat comes along with a risk of failure, though, that needs backup capacity. Decisions on a case-by-case basis are necessary here, depending on local potentials and other circumstances.

Continuing to operate an existing large CHP plant for many years reduces the incentives to invest more quickly in RE heat and thus leads to lower RE shares, especially in the short and medium term. The later expansion of RE heat generators can only be compensated a decade after phase-out, which can be as late as the year 2050. Smaller capacities of natural gas CHP and NG boilers are needed, nonetheless, to build the bridge to unlock heat pump potentials. In the long run, if CHP and Power-to-Heat (PtH) applications in process heat are eliminated due to the use of BECCS to generate negative emissions, this will not be compensated by more PtH in district heating, but via more condensing power plants. However, if solid biomass is not used in district heating, this will increase the importance of efficient heat generators such as large-scale heat pumps, geothermal plants and industrial waste heat.

5 Conclusions

Heat pumps are becoming the central technology for supplying and decarbonizing district heating systems that are to be greatly expanded to target climate objectives. In addition to centralized large-scale heat pumps in dense urban areas, which can be fed via rivers, sewage treatment plants and lakes, these can also be neighborhood heat pumps (geothermal probe fields regenerated by cooling or solar thermal, sewers, subway shafts, etc.) in smaller networks or suburban areas. Regardless of the application type, the market ramp-up must start early in order to achieve politically set climate protection targets with high RE shares in the heat supply.

Despite other options, an increased expansion and transformation of the existing district heating supply systems is necessary to achieve the climate protection targets anyway. To achieve sufficiently high RE shares, strong (financial) support is needed for all RE heat generation technologies in the short to medium term, whether to support investment costs (solar thermal, geothermal), incentivize high operating hours (heat pumps), or adapt infrastructure (lowering supply temperatures, expanding networks and heat storage capacity). However, ground-mounted solar thermal collectors are installed only at lower capacities even with subsidies.

In addition, industrial waste heat utilization, deep geothermal energy (if potentials exist) and efficient peak load technologies in district heating networks are relevant. Natural gas CHP and NG boilers are bridging technologies in district heating. The reasons for this are the early expansion of the heating network in this case and the resulting increase in heat demand due to the assumed densification and the coal phase-out, as well as the medium- to long-term German climate protection targets.

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