D4.6

Publishable report on District heating cost modelling and advised billing cases

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ABOUT RELATED

RELaTED is a joint initiative of 14 industrial companies, and research institutes across from various countries in Europe aimed at pushing forward Low Temperature District Heating networks with increased use of Renewable Energy Sources.

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DE-CARBONISING DISTRICT HEATING SYSTEMS

District heating (DH) systems are one of the most energy efficient heating systems in urban environments, with proven reliability within many decades already. DHs are identified as key systems to achieve the de-carbonization of heating energy in European Cities.

Renewable and waste heat sources are foreseen at the same time as de-carbonized heat sources and the way to guarantee competitive energy costs with limited influence of fossil fuel supply price volatility. To achieve this, a transition is needed in DHs, comprising not only measures to improve overall performance (temperature level reductions, improvement of substations, etc.), but to guarantee system viability as a whole in a context of reduced heat loads with the transition to NZEB (Near Zero Energy Buildings).

RELaTED deploys a decentralized, Ultra-Low Temperature (ULT) DH network concept, which allows for the incorporation of low-grade heat sources with minimal constraints, larger shares of renewable energy sources (RES) and distributed heat sources. ULT DH reduces operational costs due to fewer heat losses, better energy performance of heat generation plants and extensive use of de-carbonized energy sources at low marginal costs.

In the transition towards NZEB and PEH (plus energy houses), RELaTED allows for a prosumer scheme, where positive buildings deliver energy to the grid.

LIMITATIONS OF CURRENT DH NETWORKS

DH systems were designed many decades ago. In most cases, they are designed and operated to distribute heat at about 80°C to consumers. Their capacity to reduce operational temperatures is related to radiator capacity to deliver sufficient heat to meet comfortable temperatures in buildings and to allow for the safe preparation of domestic hot water (DHW) preparation. DHW limits potential temperature reductions due to the need to avoid legionella-related issues. Depending on specific national regulations, storage temperatures in the range of 55-75ºC are prescribed.

OVERALL RELATED CONCEPT

RELaTED pursues the development of DH networks with service temperature levels as low as 40-50ºC. In many alternatives, traditional DHW preparation methods are substituted by “innovative methods”. In these concepts, mains water is primarily heated by the DH, and then complemented by electric heaters/boosters up to the required temperature levels. In more advanced alternatives, heat pumps are used for such purposes.

In RELaTED every single building is converted into an energy node, where so-called triple function substations (3FS) allow for bi-directional heat exchange between the building and the network, with the additional functionality of grid injection of excess local solar heat. In fact, adaptations are made to Building Integrated Solar Thermal (BIST) systems to adapt them to Low Temperature (BILTST), with reduced local storage, as the connection to the DH makes it redundant.

Additionally, District-heating connected Reversible Heat Pump systems (DHRHP) allow for recovery of exhaust heat from cooling applications (e.g. air conditioning, ventilation, etc.).

ULT DH

Even before the consideration of further technological improvements, ULT temperature levels substantially improve the performance of heat production systems. Furthermore, ULT allows for the integration of virtually any waste heat source from industry, sewage, etc.

RELaTED builds atop of the existing trend for integration of large solar thermal plants systems in DH networks, some of them comprising large seasonal storage systems. RELaTED incorporates large ST plants, but also provides the framework for the integration of BIST into the main ULT DH concept.

With lower fluid temperature when compared regular BIST integration levels, performance levels are expected to rise by 20%, due to lower heat loses. An additional 80% rise is calculated when avoiding local storage due to direct DH connection. The RELaTED ULT network acting as a perfect heat sink avoids storage stagnation situations, thus allowing for larger ST performance levels.

DHRHP systems allow for the de-coupling of temperature levels in DH network and Building level HVAC systems. With the DH as heat source, stable temperatures at 35-40ºC ensure stable COP levels of 6-7 for the DHRHP all-year-round. These units provide an economic way for the preparation of DHW, while at the same time allowing for the connection of buildings with higher temperatures in their HVAC design (i.e. older buildings).

The RELaTED concept, when implemented with a substantial share of RES provides a robust framework to ensure the economic viability of DH networks, in the context of the transition of the building stock to NZEB along the following decades.

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Acronyms

3FS: Triple Function substation

BILSTS: Building Integrated Solar Thermal System

CHP: Combined Heat and Power plant

CNGB: Condensing Natural Gas Boilers

D: Deliverable

DH: District Heating

DHN: District Heating Network

DHRHP: District Heating Reversable Heat Pump

FGC: Flue Gas Condensation

GWh: Gigawatt per hour

HOB: Heating Only Boiler

HVAC: Heating, ventilation, and air conditioning

kWh: Kilowatt per hour

LCoE: Levelized cost of energy

LST: Large Solar Thermal

LT: Low temperature

MWh: Megawatt per hour

NG: Natural gas

NZEB: Nearly Zero Energy Buildings

O&M: Operation and maintenance

PbP: Payback Period

RES: Renewable Energy Sources

ST: Solar Thermal

ULT: Ultra Low Temperature

ULTDH: Ultra Low Temperature District Heating

WP: Work Package

w/w HP: water to water Heat Pump

1. Executive Summary

This report represents a publishable summary of the major activities that took place during WP4 – Economic feasibility & business analysis and the key findings. The main findings are divided into three sections: (1) Energy Price Assessment; (2) district heating cost modelling; (3) and the customer case for residential & tertiary customers, as well as heat producers.

Energy Price Assessment:

The following are the key findings of the Energy Price Assessment:

- Costs associated to fossil fuels are extremely variable. During the initial 2 decades of the XXI century, oscillations in the range of [-80% - +200%] have occurred. Price evolutions of fossil fuels are related to many macro-economic conditions and are highly impacted by geopolitical stability.
- In all scenarios, fossil fuel costs will steadily rise over the next decades.
- Local fuels such as biomass are virtually stable but limited in capacity. Price variations are mainly related to local production/consumption balance. In large systems (i.e. Belgrade), the potential use of biomass shall be checked against local production capacity. Otherwise, supply shortages may appear.
- Renewable energy sources are difficult to price. In most cases, energy costs for solar systems are linked to particular investment costs and marginal heat supply costs in each DH network. To achieve operational economies in DH systems, heat supply costs associated to renewable energy sources should be indexed to the operational costs of these systems rather than to the marginal energy cost in the system.

District heating cost modelling:

The district heating cost modelling section assessed the costs associated with different heat production plants on the long-term energy planning of DH. This assessment was done in the context of two case studies, one of the Belgrade DH

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network (Serbia) and one of the Tartu DH network (Estonia). The following results were obtained:

Belgrade Case study results of the energy and economic analysis:

- The interconnection between different heating districts in Belgrade would highly reduce the total generation costs in the network. However, some of the existing plants should be removed (or at least reduce their importance) from the production mix.
- Moreover, the functioning mode (increased interconnection of DH networks) together with the incorporation of some renewable energy sources to the generation mix will reduce the total cost of the heat and reducing the CO_2 emission to the environment.
- In fact, large renewable energy sources utilization factors could be achieved with ~3000 full time operational hours for large solar thermal systems. Thus, greater installed capacity should be explored for renewable energy sources.

Tartu Case study results of the energy and economic analysis:

- Current state of the network results to be a highly-efficient energy system with very competitive heat price. The biomass-fired CHP and waste streams are the basis of the heat production in most part of the year.
- However, an increasing demand in the buildings' side can exceed the production capacity of the existing heating plants. Due to the perspective of the operator the demand to increase, new heat producer will be needed in the future.
- Recovery of waste heat results to be a very efficient and economically feasible option. The optimal functioning mode for this DH network starts from the gradual reduction of the supply temperature, increasing the efficiency of all the plants.
- The next step is the introduction of renewable energy sources and, most optimally, waste heat to the production mix. Heat pump introduction shall be considered only with heat pumps at greater performance levels.

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The customer case for residential customers, tertiary customers, and heat producers

The customer cases of the transition towards an ultra-low temperature DH for residential and tertiary customers were conducted in the context of cases in Belgrade (Serbia), and Tartu (Estonia). To make the transition to ULTDH feasible, it is needed to make it cost-competitive compared to single building heating technologies. The case studies applied the RELaTED concept – using triple function subsystems, solar panels, and reversible heat pumps – with the following results for both customer segments in each city:

Belgrade – Residential and Tertiary conclusions:

- The savings for both residential and tertiary buildings is highly dependent on the energy prices.
- For both residential and tertiary buildings, higher savings are related to glazed collectors coupled to a HP that operates according to heat/electricity price. Small increases of the electricity price sharply reduce the profitability of the solar system coupled with HP.
- For residential buildings, savings in the energy bill led to payback times of around 15 years.
- For tertiary buildings, savings in the energy bill led to payback times of around 6 years, but small increases of the electricity price, sharply reduce the profitability of the solar system coupled with HP.
- Thus, the solar irradiation availability is sufficient to warrant the use of solar panels throughout the year and the heat and electricity prices are favourable and the RELaTED technology is a promising solution that can be applied for residential buildings in climates like Belgrade.

Tartu – Residential and Tertiary conclusions:

- For both residential and tertiary buildings, solar irradiation levels in Tartu are seasonal dependent. Values are very low in winter and increase in spring and summer.

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- Low irradiation levels and cold outdoor temperatures during the winter limit the opportunity for solar energy to only 4 months in the year.
- High DH heat and low electricity prices allow to have significant economical savings in absolute terms but since the contribution to the solar systems to buildings' heat loads is rather small, payback periods remain high.
- Therefore, a solar thermal façade for residential buildings in Tartu is not an economically attractive option.

Heat Producer case:

For the feasibility analysis of potential new sources for existing ULTDH, a business model is developed considering the price of heat and the investments needed for general heat producer cases. When applied to study the viability of specific heat purchase study cases, the following conclusions are obtained:

- The use of ULTDH network in combination with CHP, reversible heat pumps for heating & cooling, solar systems, and waste heat improves the performance in every case.
- Investments in renewable energy sources typically require important investments but marginal costs may be almost non-existent. In these cases, heat prices should be set to guarantee fair return of investment but avoiding the indexing of these heat sources to fuel costs in international markets.
- For heat recovery investments in industrial plants, payback periods in the range of 5 years are possible if stable heat consumption is achieved with competitive costs of heat.

2. Introduction

Since the introduction of DH, there have been three subsequent generations of DH (1st – 3rd generation) which can be characterized by an increase in energy efficiency, decrease in heat loss, and a decrease in the water return and supply temperature (Lund et al., 2014). Following this trend, 4th generation DH and ULTDH have shown to be a highly efficient, environmentally friendly, and a cost-effective solution for heating and cooling. But to achieve this, conversion of DHNs is needed.

To facilitate the conversion towards ULTDH, the RELaTED project has developed an innovative concept of decentralized ULTDH networks, which allows for the incorporation of low-grade heat sources with minimal constraints. But to increase the uptake of this system, it is vital to ensure the economic viability for DH systems in their transition to ULTDH.

The RELaTED project has addressed this issue in WP4 – Economic feasibility & business analysis. This report, D4.6, serves as a summary of the main findings for this WP as it relates to the profitable operation of the RELaTED DH networks. The topics to be covered are shown in table 1 below.

Table 1 Summary of topics for D4.6.

Topic	Associated deliverable(s)
Energy price assessment	D4.1 – Energy price assessment
District heating cost modelling	D4.2 – District heating cost modelling
The customer case for residential customers, tertiary customers and heat producers.	D4.3 – Dwelling customer case D4.4 – Commercial customer case D4.5 – Heat producer case

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3. Energy price assessment

3.1. Introduction

The energy price assessment provides a comprehensive review of the costs for the main heat production systems and primary energy sources associated with District Heating systems in Europe. Within this study, a review of heat production technologies and fuels is presented where the present, medium, and long-term energy costs and business cases for DH are identified.

3.2. Heating technologies, fuel costs, & security of supply

Heating technologies

District heating networks can be fed by various heat generation sources, including combustion plants (based on fossil fuel or biomass), co-generation plants (combined heat & power (CHP)), or renewable-based plants. The combination of multiple heat sources is beneficial, especially for large district heating schemes, as it allows shifting from source to source depending on specific conditions and market prices.

The main technologies assessed in the RELaTED project are: (1) CHP; (2) Boiler stations; (3) Solar thermal plants; (4) and heat pump systems. A summary for each heat production source can be found in Annex **Table *8***.

Fuel costs

The purpose of this section is to describe the wholesale cost for fuels commonly used in DH. These fuel types include: (1) Natural gas; (2) coal; (3) oil; (4) biomass; (5) electricity; (6) waste heat systems; (7) waste incineration; (8) and industrial waste heat.

General trends, including the past, present, and future for each fuel cost are provided (Annex Table 9). It is important to note that waste heat streams are not

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included in this table because waste heat sources are usually free (not including investment costs) so there are no price projections.

Fossil fuels and electricity show the most price volatility. Several factors, like source of the fuel type, availability, and geopolitical challenges can compound to either increase the cost or reduce the cost for these fuel types. Biomass, waste incineration, and industrial waste heat sources show less price volatility.

Security of supply

The heating sector shows a clear dependency on fossil fuel supplies. By incorporating RES into the mix, this dependency is expected to reduce. However, securing strategic resources remains critical in the short to medium time frame. To secure these fuel sources, several scenarios have been assessed and are summarized in ***Table 2***.

Table 2 Summary of security scenarios to secure energy supply.

Security Scenario	Overview of scheme
Relevance of energy imports & price volatility	The EU depends on imports for 88% and 69% of its oil[1] and natural gas[2] imports. Geopolitical issues related to suppliers have led to fossil fuel oscillations of 50-100% over the last decade.
Investments in infrastructure	Energy supply systems generally imply large investments. Long term supply contracts are needed to guarantee the use of energy infrastructures for several decades.
Development of a spot market in western EU	The primary energy market in EU has proven to be inelastic to domestic demand, and with little resiliency to international trends. The development of a local spot market in western Europe has allowed for natural gas of several countries to be traded, leading to a certain freedom in the cost of natural gas.
Capacity modulation & price fixation	Oscillations in the range of 10-20% of the yearly contracted amount are commonly allowed in long term supply contracts. Net prices are commonly fixed based on average oil prices and €/$ exchange rate of the preceding quarter.
Context of DH operator	For DH operators, long term supply agreements should guarantee a smooth transition into the new, decarbonized DH environment. Thus, the following aspects should be included: - De-indexation natural gas supplies from oil prices - Periodic revisions of oil supply quantities to meet the evolution of the de-carbonised DH

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[1] A Study on Oil Dependency in the EU, Cambridge Economics, 2016

[2] EU Energy in Figures. Statistical Pocketbook 2017. European Commission, 2017

Operational conditions & scenarios for profitable investment

The integration of new heat production systems is necessary for ensuring the economic viability for DH systems. Thus, DH networks should consider the following scenarios for profitable investment into DH:

Table 3 Summary of operations conditions & scenarios for profitable investment.

Operational conditions and scenarios	Specific conditions/rationale
Internal return rate of investments in new production facilities.	• Reference return rate for energy related infrastructure: 10% • Minimum reasonable return rate for underperformance (-20%) of investments: 5%
The benefits of LT / ULT conversion of DH network needs to be shared among all stakeholders.	• Investments may occur in heat production plants, substations at different locations in the network, internal HVAC systems in buildings. • In the case of increased plant performance due to LT operation, the reduction of operational (fuel) costs to meet the same load needs to be shared among stakeholders.
Economic metrics for all existing plants should be revisited, considering that margins are kept in acceptable levels.	• Overall, facilities with full-load equivalent operational time above 3000h[3] will remain profitable. • Operational revenue must be kept positive, with internal return rate in similar levels as those foreseen when the investment was performed. This can be accomplished by incorporating/strengthening of a fee for availability of backup heat production. • In the case of high redundancy in heat production, the progressive closing down of production facilities needs to be planned.

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[3] This figure is highly speculative and will depend on specific conditions for each production facility & DH network.

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The system will be modified so that cost reduction in heat production is used to compensate all stakeholders.	• No heat producer can be affected. • Final users must find ULT DH profitable (e.g. price reduction compared to business as usual DH & alternative heat production systems). • DH operators must keep the system profitable. The introduction of RES cannot result in economic imbalance of the full system.

3.3. Summary of energy price assessment

In this section, energy costs have been reviewed, considering investment costs, fuel costs and performance levels for different heat production systems and are summarised in Annex Table 10. Based on this summary, several conclusions can be made:

- Costs associated to fossil fuels are extremely variable. During the initial 2 decades of the XXI century, oscillations in the range of [-80% - +200%] have occurred. Price evolutions of fossil fuels are related to many macro-economic conditions and are highly impacted by geopolitical stability.
- In all scenarios, fossil fuel costs will steadily rise over the next decades.
- Local fuels such as biomass are virtually stable but limited in capacity. Price variations are mainly related to local production/consumption balance. In large systems (i.e. Belgrade), the potential use of biomass shall be checked against local production capacity. Otherwise, supply shortages may appear.
- Renewable Energy Sources are difficult to price. In most cases, energy costs for solar systems are linked to particular investment costs and marginal heat supply costs in each DH network. To achieve operational economies in DH systems, heat supply costs associated to Renewable Energy Sources should be indexed to the operational costs of these systems rather than to the marginal energy cost in the system.

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4. District heating cost modelling

The work reflected in this section addresses the long-term energy planning of DH networks and considers the evolution of systems towards greater efficiency, lower distribution temperatures, greater shares of renewable energy and the incorporation of distributed renewables in the context of an increase of NZEBs.

In D4.2, an assessment was performed based on the large DHs already in operation within RELaTED (Tartu & Belgrade). A cost model was constructed, where operation costs are defined for each heat production technology, allowing for hourly prioritization of heat production technologies based on their marginal costs. This cost model is used to develop scenario analysis where various potential evolutions of the DH network are studied. Technology, production mix and fuel price evolutions are assessed.

This section will provide an overview of the cost model used and the main conclusions extracted from the application of this model to two study cases.

4.1. Cost model basis

A cost model is developed, where the marginal costs are calculated for a DH network on an hourly basis. This cost model is used to calculate the multi-year heat production mix in the DH networks.

This model includes the energy simulation and the fuel cost evolution along different scenarios of specific DH networks. The input variables for this model are the main characteristics of the heating network.

The input data used for the model are:

- **Production Plants' Capacity:** Number of production plants, their nominal capacity, availability, and the fuel source used for heat production.
- **District heating demand calculation:** Hourly demand for the whole district network is matched by producers. In some DH networks, this

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information is available, while in others, synthetic load profiles are constructed based on aggregated (e.g. monthly) data.

- **DH supply & return temperatures:** These are the supply and return temperatures for the DH network. They are important variables for two reasons: (1) heat losses are directly related to the distribution temperatures. (2) Connection of distributed heat sources, such as heat pumps, is completely dependent on the temperatures in the grid.
- **Efficiency levels of production plants:** The use of fuel sources in the production of plants (in case they use one) depends on the efficiency capacity of the plants to transform the internal energy of the fuel to useful heating energy. Each heat production technology has a different efficiency level and depending on the mixture of these production plants used, it could impact the operation costs for the heat production plants.

4.2. Case studies

The cost model described in Section 3.1 was applied to two different cases, the Tartu and Belgrade DH networks. Using the cost model, different scenarios are tested to assess the price of heat and the share of RES produced in each DHN. The main conclusions obtained are:

Tartu

The results of the case study in Tartu yielded the following conclusions:

- The biomass-based CHP is the most dominant producer, with the highest operability range. This production facility uses a relatively low-cost fuel (biomass) and enables an economic return from the sale of electricity. This way, it shows very competitive operational costs compared with other base load plants, when considering the net operational costs (cost -incomes).
- There is an expected heat load increase in the future (1, 5, and 20 years). This load increase will lead to increased use of peak production centrals,

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reducing the share of biomass and increasing the cost of energy. Thus, there is a need to increase the base production capacity. Adding a biomass HOB with a capacity in the range of 50MW is considered to be beneficial.

- The trend towards heat load increase can be substantially mitigated by reductions in distribution loss and building retrofits.
- The introduction of heat pumps and solar thermal systems have a minor impact in the DH heat production mix. They are insufficient to meet the heat load increase, and their effect is mostly limited to mild periods of the year (where there is already an excess production capacity).
- Overall, the introduction of RES impacts in a reduction of ~15% in yearly CHP production levels, mostly during summer periods.

Considering the above issues, it would be wise to promote the increase of Waste heat streams in the system rather than climate-dependent systems as Waste heat streams contribute with a relatively constant heat source.

In economic terms, the following conclusions are made:

- The CHP plant is subsidized in its initial operational years. The heat costs in the first year of simulation is completely influenced by the subsidy for the electricity produced in CHP. This way, negative values for the operational costs are achieved. Due to the negative value of the cost for the CHP, the heat cost is around -2 EUR/MWh when subsidies are still active.
- When the CHP ends to receive the subsidy for the electricity production, the heat cost increases from-2 EUR/MWh to 3 EUR/MWh.
- When the demand of the district increases, the plants fired with natural gas increase the delivered energy. For this reason, the price of heat increases, and the RES share decreases.

- The use of heat-pumps in the heat generation mix is almost negligible due to the relatively lower costs of other heat production technologies. Thus, their introduction in the network should be considered with care.

- The lowest heat price is achieved by year 20 with the introduction of a biomass-fired boiler. The low price of the biomass and the high efficiency of this type of facilities reduce the total cost in the network. Moreover, the RES share is increased.

Taking the energy and economic analysis together, the following conclusions can be made for Tartu:

- Current state of the network results to be a highly-efficient energy system with very competitive heat price. The biomass-fired CHP and waste streams are the basis of the heat production in most part of the year.

- However, an increasing demand in the buildings' side can exceed the production capacity of the existing heating plants. Due to the perspective of the operator the demand to increase, new heat producer will be needed in the future.

- Recovery of waste heat results to be a very efficient and economically feasible option.

- The optimal functioning mode for this DH network starts form the gradual reduction of the supply temperature, increasing the efficiency of all the plants. The next step is the introduction of RES (most optimally waste heat) to the production mix. Heat pump introduction shall be considered only with heat pumps at greater performance levels.

Belgrade

The results of the case study in Belgrade in terms of the energy and economic analysis for the given scenarios lead to the following conclusions:

- The current production capacity of the DH network is excessive. Partly it is understood that the current state of limited interconnection between

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sectors of the DH network makes necessary to oversize the network production capacity.

- One key investment (already foreseen by BEOELEK) is the increased interconnection of heat supply areas in the city.
- After the simulation of the district interconnection, the production capacity still seems to be oversized, having some of the energy production facilities with less than 100 full-load operation hours in a whole year, with some of them completely switched off.
- An increase in the demand results in a reduction of the final price thanks to the increase of efficiency of the plants working at higher capacity. When the demand increases, the share of Novi Beograd plant energy production also increases, making the final price reduce.

Taking this into account, the following conclusions can be drawn for the DH in Belgrade:

- As a conclusion from the study in this DH network, the interconnection between district would highly reduce the total generation costs in the network. However, some of the existing plants should be removed (or at least reduce their importance) from the production mix.
- Moreover, this new functioning mode together with the incorporation of some RES to the generation mix will reduce the total cost of the heat and reducing the CO_2 emission to the environment.
- In fact, large RES utilization factors are achieved, with ~3000 full time operational hours for LST. Thus, greater installed capacity should be explored for RES.

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5. The business case for ULTDH using RELaTED technologies – Residential and Tertiary customers, and Heat producers

5.1. Residential and non-residential customers

There is a need to make the business case RELaTED technologies to make ULTDH feasible compared to single building heating technologies. In this regard, business cases for these concepts and main conclusions obtained in previous deliverables are presented. The fundamentals for the conclusions presented are grounded on the context of a case study in Tartu, Estonia, and Belgrade, Serbia, where the ROI was determined for such an investment.

Given that DH is a dynamic and complex process, it is important to understand the elements which can impact the cost for both residential and non-residential customers. To this end, the following components need to be assessed:

- **Alternative heating technologies and RELaTED technologies:** For the RELaTED concept to be a feasible option, it needs to be cost competitive with onsite alternative heat production sources. If the RELaTED concept costs more than alternative heat sources, it will not be feasible. It is important to note that there is little variation between onsite heating options for residential buildings and non-residential buildings. The size, efficiency, and heat production capacity of the onsite heating solution – heat pump, boiler, etc. - will depend on the heat demand for the building. The main heating technologies studied are: CNGB; Air/Water HP; Solar thermal; Waste heat.

- **Taxonomy of buildings:** the heating needs patterns of the buildings supplied by the DHN are important to determine the economic feasibility. Therefore, it is important to consider in the analysis their size, age, and energy efficiency. Highly efficient buildings such as NZEB are particularly important for ULTDH as the optimal temperature for interior heat can be

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achieved at lower supply temperatures; thus, making ULTDH more effective (Lund et al., 2014).

- **Relevant regulatory frameworks:** financial incentives and energy efficient directives that limit fossil fuels are crucial for the feasibility of LTDH.
- **Pricing schemes:** common pricing schemes for DH customers include the cost-plus model and the marginal cost pricing model. The cost-plus model is used in regulated DH markets and is the most common. In this model, the price for heat is tied to the production costs, so if it costs more to produce heat, than the consumer will pay more. The marginal cost model is primarily used in de-regulated DH markets. Simply, the marginal cost for DH is the cost for one more unit of heat. The main difference is between the two is that in regulated markets, the cost the consumer pays is tied to the production costs for heat, where the de-regulated market, the DH company can set their own price and charge below market value

Finally, a cost assessment using data provided by BEOELEK and Fortum (DH companies in Belgrade and Tartu respectively) is conducted to assess the feasibility of using the RELaTED concept in both cities.

5.2. Cost assessment

Considering the above components, a cost assessment for producing competitive onsite heat using the RELaTED concept was conducted in Tartu and Belgrade for both residential and non-residential buildings.

For each city, cases which outline different strategies for thermal loads were applied. The different cases are described as follows:

Case 1: There is no solar production, and the building requires a specific amount of heat. This energy is then supplied by the DH network. The only heat flow is from the flow line of the DH up to the building.

Case 2: Energy is produced in the solar field, but it is not sufficient to meet building demand and collector's outlet temperature is not enough to meet the thermal loads. A w/w HP located at building level is used for increasing the temperature to service conditions.

Case 3: There is no instant heating demand in the building. in this case all the energy production in the solar field (if any) will be injected to the DH network. If the temperature of the solar heat exceeds the supply line of the DH, then the heat is injected to the supply. If not, the heat is injected in the return line of the DH network.

Case 4: Solar production exceeds heating demand in the building and the output temperature of the solar field exceeds the temperature of the supply line. In this case, the whole demand of the building is met by the heat production in the solar field, and excess heat from the ST systems is injected to the supply line of the DH network.

Case 5: Energy is produced in the solar field, but it is not sufficient to meet building demand and collector's outlet temperature is not enough to meet the thermal loads. A w/w HP located at building level is used for increasing the temperature to service condition when is more cost/effective than doing it with DH. Basically, it decides when to use the HP or direct heat from the district heating when $1 - \frac{heat\ prize\ (\frac{€}{kWh})}{electricity\ prize\ (\frac{€}{kWh})} \leq \frac{generation}{thermal\ load}$.

Based on these cases, different scenarios were tested to assess the feasibility for buildings to integrate the RELaTED system at the building level connected to a LTDH network. The results of this assessment were applied to residential and non-residential buildings and are described in the following sections.

5.2.1. Belgrade - Residential

Data sent by BEOELEK shows that the average DH consumption for civil flats is 132kWh/m^2 per year. This heat use can be further split in heat for DHW needs and space heating.

DHW may represent around 5% of the heating needs during the coldest months and 10% during spring and fall. During summer, DHW demand will be 100% of the heating needs. From the heat demand, it can be concluded that space heating represents a great amount of energy compared to DHW.

4 scenarios were assessed:

Scenario1: there is no ST. Thermal loads are met with the DH all year round. Case 1 all the time.

Scenario 2: ST based on unglazed panels without thermal storage. Case 1, 2, 3 and 4 applied each instant.

Scenario 3: ST based on unglazed panels. Total area has been reduced compared to scenario 2, since panels performance is higher for the glazed ones. It can reach to performances of around 60-70% from April to October, reducing to 40% in winter months; whilst non-glazed barely reach 40% in summer months.

Scenario 4: glazed panels but with the operation rule on when to use the HP or the DH to reach the service conditions when local production is not enough.

The use of onsite produced heat will be reliant on heat/electricity prices, and this ratio make change the locally deployed energy ratios. At low heating prices, the savings on the scenario 2-3 are low and the business case is not feasible, as the heating bought from the DHN is affordable and the investments on the solar fields are not paid back by the savings. Same comments apply for scenario 4. Higher electricity prices decrease even more the savings as the cost for operating the auxiliary equipment (such as pumps), increases.

With heat prices increase, the savings for scenarios 2-4 increase, being maximum at low electricity prices. The highest savings are obtained for the highest heat/electricity ratio for scenario 4. The economic figures for this case are as follows:

Table 4 Levelized cost of energy and payback period with the current energy carriers' prices in the case study analysis for Belgrade under the scenario with higher savings.

LCoE (c€/kWh for 15 years)	**8.8**
PbP (years)	15

Summary for residential buildings in Belgrade

- When taken to the annual energy bill, the savings and the energy sold to the network may represent 20-30% of the energy bill. It is noteworthy that these figures are highly dependent on the energy prices. Higher savings are related to glazed ST coupled to a HP that operates according to heat/electricity price. Small increases of the electricity price sharply reduce the profitability of the ST coupled with HP.
- Savings in the energy bill lead to payback times of around 15years.

Based on these findings, the following conclusions can be drawn:

- The RELaTED technology is a promising solution that can be applied for residential buildings in climates similar to Belgrade.
- The solar irradiation availability is sufficient to warrant the use of solar panels throughout the year and the heat and electricity prices are favourable.

5.2.2. Tartu – Residential

The DH company in Tartu, Fortum, has provided heating use data of three apartment building during 2017 at an hourly granularity, which was used for the study. As said previously, space heating represents a great amount of energy compared to DHW. The same strategy to supply heat is proposed as the residential case in Tartu.

The following four scenarios have been assessed for residential in Tartu:

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Scenario1: There is no ST. Thermal loads are met with the DH all year round. Case 1 all the time.

Scenario 2: Unglazed panels. Not estimated because their poor performance on vertical plane under Tartu's environmental conditions.

Scenario 3: Glazed panels without thermal storage. Case 1, 2, 3 and 4 applied in each instance.

Scenario 4: Glazed panels but with the operation rule on when to use the HP or the DH to reach the service conditions when local production is not enough.

As in the case of Belgrade, the use of onsite produced heat will be very much reliant on heat/electricity prices, and this ratio make change the locally deployed energy ratios. At low heating prices, the savings on the scenario 3-4 are low as the investments on the solar fields and the heat pump are not paid back by the savings on heat bought. Higher electricity prices decrease even more the savings as the cost for operating the auxiliary equipment (such as pumps), increases.

However, with heat prices increase, the savings for scenarios 3-4 increase; indeed, at low electricity prices, it is better to consume 100% of heating from onsite sources. The economic figures obtained from the cost benefit analysis for the scenario considering the current energy prices in Tartu, in which electricity is more expensive than average purchased heat, is as follows:

Table 5 Levelized cost of energy and payback period with the current energy carriers' prices in the residential case in Tartu under current energy price scenario.

LCoE (c€/kWh for 15 years)	**10.7**
PbP (years)	32

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Summary for residential buildings in Tartu

- There is no ST direct production in winter harsh months (November to February), low irradiation levels and low outdoor temperatures lead to have higher losses than production.

- Low irradiation levels and cold outdoor temperatures during the winter limit the opportunity for solar energy to only 4 months in the year.

Based on these findings, the following conclusions can be drawn:

- A solar thermal façade for residential buildings in Tartu is not an economically attractive option.

5.2.3. Belgrade – Non-residential

Similar to the above explained, the same methodology used for residential buildings has been used to assess the cost comparison of RELaTED technologies for non-residential customers.

In this case study, a school building in Belgrade has been analysed as business case with the following findings:

Table 6 Levelized cost of energy and payback period with the current energy carriers' prices in the non-residential case in Belgrade under current energy price scenario.

LCoE (c€/kWh for 15 years)	**8,5**
PbP (years)	6

Summary for non-residential buildings in Belgrade

- East façades have been prioritized for installing the panels, since solar irradiation levels coincide with the highest instant thermal load and no thermal storage is foreseen.

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- When taken to the annual energy bill, the estimated savings and the energy sold to the network, may represent 50% of the energy bill on the best scenario. It is noteworthy that these figures are highly dependent on the energy prices. Higher savings are related to glazed ST coupled to a HP that operates according to heat/electricity price.

- Savings in the energy bill lead to payback times of around 6 years, but small increases of the electricity price, sharply reduce the profitability of the ST coupled with HP.

Based on these findings, the following conclusions can be drawn:

- The RELaTED technology is a promising solution that can be applied for residential buildings in climates similar to Belgrade.

- The solar irradiation availability is sufficient to warrant the use of solar panels throughout the year and the heat and electricity prices are favourable.

5.2.4. Tartu – Non-residential

The same methodology used for residential buildings has been used to assess the cost comparison of RELaTED technologies for non-residential customers.

In this case study, a food market in Tartu has been analysed as business case with the following findings:

Table 7 Levelized cost of energy and payback period with the current energy carriers' prices in the non-residential case in Belgrade under current energy price scenario.

LCoE (c€/kWh for 15 years)	**9.8**
PbP (years)	27

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Summary for non-residential building in Tartu

- Space heating is provided all year round except in summer season, that is from June to mid-September, and building uses heat the 24 hours, 7 days a week, although energy demand on Sundays is lower. With regards to hourly profiles, power is higher at nigh time, and in a certain hour midday. In harsh winter weeks, power can double the number when compared to late spring.

- Solar irradiation levels in Tartu are seasonal dependent. Values are very low in winter and increase in spring and summer. South facade is the vertical plane with highest irradiation level and can reach peak values of 800W/m^2, but averages of 500W/m^2 in spring/summertime.

- Glazed ST collectors are expected to be connected in arrays of 6 panels in series. Taking into consideration Tartu's conditions, this may lead to performances of 9-30% in wintertime (Nov, Dec, Jan, Feb and March) and around 50% for spring- summer time.

- Different heat and electricity price scenario have been conducted range and the main outcomes are:
  - Solar field (directly) can contribute to 5% of the annual thermal needs of the buildings, which leads to payback periods of around 27 years.
  - It contributes significantly to summer months, and the surplus is sold to the DH. For these scenarios, there must be other buildings that demand high quantities of heat summer months within the DH network, otherwise it will not be profitable to sell the locally produced heat.
  - For low electricity prices, lower than heat, HP delivers the remaining thermal loads, but with very low COPs, in January, February it would work basically at COPs of 1.
  - High DH heat and low electricity prices allow to have significant economical savings in absolute terms but since the contribution to the

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ST to buildings' heat loads is rather small, payback periods remain high.

Based on these findings, the following conclusions can be drawn:

- A solar thermal façade in Tartu is not an economically attractive option. Low irradiation levels and cold outdoor temperatures during the winter indicates limits the opportunity for solar energy to only 4 months out of the year.

5.3. Heat producers

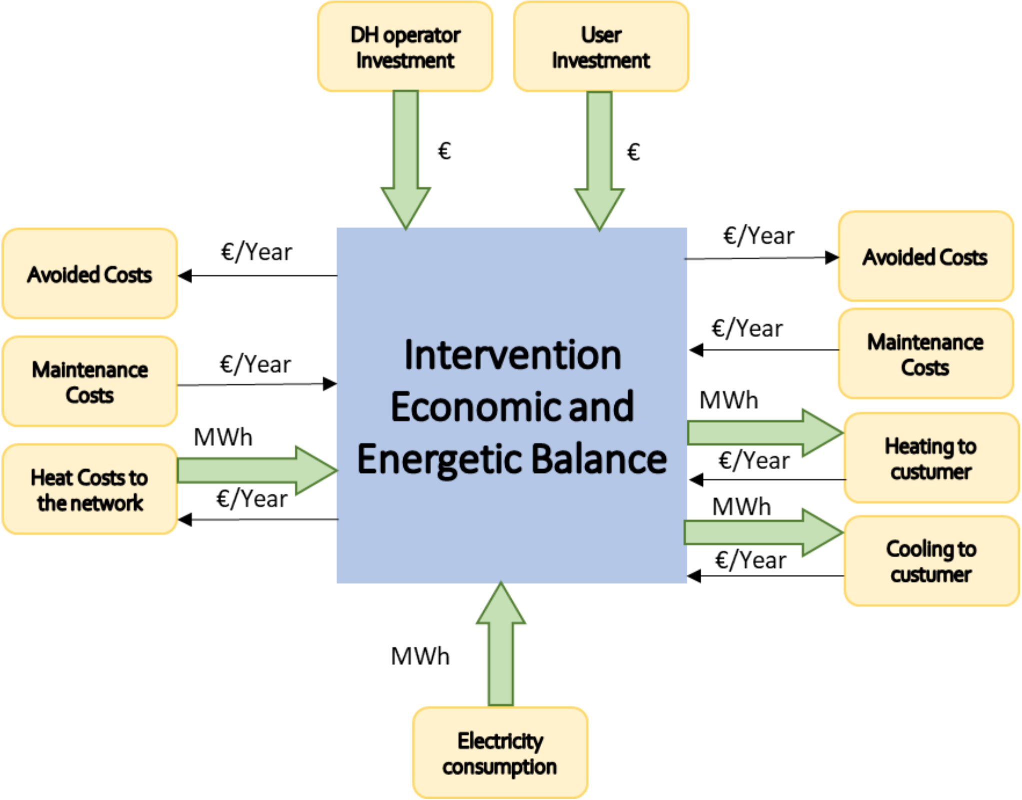
The business case for heat producers should be based on a heat price that ensures a fair ROI for integrating low grades sources such as waste heat sources and solar thermal energy into a ULTDH network. The main heat producers involved in such investments are (1) DH companies who manage combined heat and power (CHP) plants and heat pumps (HP), (2) and heat producers of waste heat or solar thermal energy who can be the building or company owner from where these heat sources are being produced.

To accomplish this, an economic model for measuring the impact of transitioning to an LTDH/ULTDH will be introduced.

Economic model

To assess competing heat production technologies for DH networks and the potential of RES/waste heat for DH heat production, an economic model is proposed to simulate the potential cashflow of the heat producer to support the investment into new heating installations. The model focuses on the energetic and economic effects based on the variable-flows that are represented in next figure. The parameters for the economic model are shown in the schematic below. The figure is divided into the operator (left side) and the user (right side):

Figure 1 Economic model



Economic inputs

This includes capital expenses and operational costs that are non-energy related for the new installations[4]:

- ***Operator investment:*** The investment made, in monetary units, by the DH operator.
- ***User investment:*** the tariff term that represents the investment made for this intervention.
- ***Maintenance costs:*** to the operator.
- ***Maintenance costs:*** to the user.

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[4] New installations refers to the heat production technologies that are installed to integrate the new heat source into the DHN.

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Economic figures related with energy flows

This includes energy costs, such as service costs, paid by users in the new installations.

- ***Heat to the network:*** associated revenues from supplying heat to DHN (output).
- ***Heating to customer:*** the associated costs (input) for including the price of the heat delivered to the customer after the intervention.
- ***Cooling to customer:*** with the costs associated (input) for including the price of the cold delivered to the customer after the intervention.
- ***Electricity consumption (input):*** The electricity consumption (in MWh) that is used in the new installations.

Economic outputs

These terms include the simulated economic output of avoided costs due to efficiency improvements in the new installations. It is not a real economic flux, but a simulated figure used to represent the improvement on operational costs due to the increase of efficiency. The terms included are:

- ***DH avoided costs***;
- ***User avoided costs***.

In the case of the user's investments, they will not be paid off by the direct income from heat production, but by the reduction of the service costs (avoided costs). In the case of the operator, the investment will be paid off by an increase on the input flow of heating into the network (with the associated revenues) and the avoided costs.

Other terms that contribute to the recovery of the investments are neglected in this approach to evaluate the feasibility. These terms included heat loss due to distribution, a term important in evaluating the feasibility of transforming DHNs into ULTDHs, but it can be neglected in this simplified approach since it aims at studying the feasibility of including new energy sources such as waste heat or solar thermal systems.

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The model allows the user to identify viable heat purchase scenarios and to identify and define those heat prices. The goal is to ensure a fair ROI for heat producers of large-scale heat productions and setting an almost-fixed cost scheme for heat producers that facilitates the profitable operation of DH networks.

Conclusions

For the feasibility analysis of potential new sources for existing ULTDH, a business model is developed considering the price of heat and the investments needed for general heat producer cases. When applied to study the viability of specific heat purchase study cases, the following conclusions are obtained:

- The use of ULTDH network in combination with CHP, reversible heat pumps for heating & cooling, solar systems, and waste heat improves the performance in every case.
- For large scale heat productions to be economically successful to all stakeholders, it is fundamental to define the heat price that ensures a fair ROI to heat producers and low operational costs to the DH.
- For heat recovery investments in industrial plants, payback periods in the range of 5 years are possible if stable heat consumption is achieved with competitive costs of heat.
- Investments in RES typically require important investments but marginal costs may be almost non-existent. In these cases, heat prices should be set to guarantee fair Return of Investment (ROI) but avoiding the indexing of these heat sources to fuel costs in international markets.

6. Annex: Additional Tables

Table 8 DH heating technologies overview [source: 1-5].

	Boiler stations	Combined Heat & Power (CHP)	Solar thermal plants (CSHP)	Heat pump systems
Typical application	Back-up or peak load coverage	Base load	Combined with additional heat generation systems	Base load or complement to renewable systems
Type of fuel(s)	Gas, oil, biomass, waste	Gas, oil, biomass, waste	Solar radiation	Electricity + Low-temp. heat (geothermal, sewage or other)
Rated power (MW heat)	0.5 to 20 MW (gas), 0.3 to 5 MW (biomass), 15–50 MW (waste)	2 to 50 MW (gas) 10 to 50 MW (biomass, waste heat)	3 to 50 MW	10-15 MW per well (geothermal), 1-10 MW per unit (other HP)
Service temperature	80–140 °C	80–140 °C		80–85 °C
Performance levels	97–108% net efficiency	Electric efficiency 29%, heat efficiency 64–77%		COP 1.7–3.8
Seasonality	Gas ~100%, Biomass 96–98%	~90%	High seasonal variation, storage necessary	Slight seasonal variation, depending on source

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Investment cost	100 k€/MW (gas), 250–500 k€/MW (pellets), 0.5–1 M€/MW (wood chips/straw), >1 M€/MW (waste)	2.6 M€/MW (biomass), 7–10 M€/W (waste)	400 €/MWh/year	2 M€/MW (absorption HP, geothermal) 500–800 k€/MW (electric HP)
Service span	30–40 years (gas), 20 years (biomass, waste)	20–30 years (biomass), 20 years (waste)	30 years	20–25 years

Table 9 Summary table of past, present, and future fuel costs [source: 1-5].

Natural Gas				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2017	4.9	USD/MBTU	14
Maximum in 20 years	2008	10.79	USD/MBTU	30
Minimum in 20 years	1998	1.9	USD/MBTU	5
Foreseen cost	2025	7.9	USD/MBTU	22
	2030	8.6	USD/MBTU	24
Coal				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2018 (Feb)	7.64	EUR/MWh	7.64
Maximum in 20 years	2008	147.67	USD/t	17.6
Minimum in 20 years	1999	28.79	USD/t	3.44
Foreseen cost	2025	77	USD/t	9
	2030	80	USD/t	10

Oil				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2018 (May)	76	USD/barrel	37
Maximum in 20 years	2012	112	USD/barrel	55
Minimum in 20 years	1998	13	USD/barrel	6
Foreseen cost	2025	83	USD/barrel	41
	2030	94	USD/barrel	46
Biomass (woodchips)				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2017	13	EUR/MWh	13
Maximum in 20 years	2014	15	EUR/MWh	15
Minimum in 20 years	2016	11	EUR/MWh	11
Foreseen cost	2025		EUR/MWh	13 (Price stability)
	2030		EUR/MWh	14-15 (Price stability)

Biomass (Woodpellets in Estonia)				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2017	32	EUR/MWh	32
Maximum in 20 years	2014	36	EUR/MWh	36
Minimum in 20 years	2016	20	EUR/MWh	20
Foreseen cost	2025	32	EUR/MWh	31
	2030	32	EUR/MWh	31
Electricity				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2016	114	EUR/MWh	114
Maximum in 20 years	2014	120	EUR/MWh	120
Minimum in 20 years	2009	102	EUR/MWh	102
Foreseen cost	2025	38.8[5] to 60.3[6]	EUR/MWh	38.8- to 53
	2030	41.81 to 69.8	EUR/MWh	41.8 to 69.8

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[5] lower price scenario

[6] higher price scenario

Waste heat incineration				
	Year	**Cost**	**Cost Unit**	**Cost [€/MWh]**
Present	2018		EUR/MWh	30.49
Maximum in 20 years	2018		EUR/MWh	30.60
Minimum in 20 years	2016		EUR/MWh	30.26
Foreseen cost	2025		EUR/MWh	30.60*
	2030		EUR/MWh	30.60*

Table 10 **Price assessment summary [source: 1-5].**

Heat Sources	Cost of primary energy in the present	Cost of primary energy in 2030	Technologies available & Performance level	Investment costs (EUR/MW)	Operational Cost (EUR/MWh)
Natural Gas	Around 14 EUR/MWh depending on the location	The incrementation will round 80%, 24-30 EUR/MWh	CHP (from 2 to 50 MW) and HOB (from 0.2 MW to 20 MW) CHP: 64-77% HOBoilers: 97-108% (Condensation boilers)	Gas boilers investment around 100k€/MW	Natural gas boilers 10k€/MWh (2-5% of investment costs)
Oil	From 20 to 60 EUR/MWh depending on the location	From 30 to 80 EUR/MWh depending on the location	CHP Oil Boilers (from 0.15 MW to 1MW) Same performance levels as NG CHP	Oil Boilers investment around 70 k€/MW	Similar to the natural gas ones. (2-5% of investment costs)
Biomass	Woodchips around 13 EUR/MWh Pellets around 32 EUR/MWh	Woodchips around 14-15 EUR/MWh and pellets 32 EUR/MWh	Biomass HOBboilers (only heat) and biomass CHP Waste heat from ORC	CHP with biomass is about 2.6 M€/MW	Similar to the natural gas ones. 1.8-3% of investment costs

Electricity	In the present is situated between 70 & 120 EUR/MWh	41.8-69.8 EUR/MWh	Electric Heat pump/ Electric heating COP 1.7-3.8	500-800k€/MW	4-7% of investment costs
Solar Thermal energy	Each market will set heat price. Source itself value is 0	Same	LST (Large Solar thermal) from 3 to 50 BILSTS (Building integrated solar thermal)	LST: from few kW to GW BILST: Depending on the façade/roof.	O&M costs are very reduced in both cases
Waste-Heat	Each market will set heat price. Source itself value is 0	Same	Heat pumps with low temperature sources (from 1 to 10 MW) CHP	CHP with waste heat 7-10M€/MW	± 2.5% of investment costs
Geothermal	Each market will set heat price. Source itself value is 0	Same	Heat pumps with low temperature sources (from 10 to 15MW)	Geothermal source heat pump ± 1.7-1.9 M€/MW	± 2.5% of investment costs

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