# D6.4 – FLEXYNETS-TRADING policies

**Fifth generation, low temperature, high exergy district heating and cooling networks**

**FLEXYNETS**

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**Lead beneficiary:** ACCIONA


**Belén Gomez-Uribarri**, ACCIONA

Roberto Fedrizzi, EURAC

Marco Cozzini, EURAC

Matteo D'Antoni, EURAC


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# Table of Contents

# 1 Introduction

The distributed energy generation approach elaborated within FLEXYNETS produces heat marketability and management issues: a change of paradigm is needed to move from the actual "monopolistic" generation, distribution and trading structure implemented in today's DHC networks, to a structure where multiple actors can play the role of the energy provider and where even the final consumers can economically profit from their waste heat provided to the network.

Trading strategies developed, allowing thermal and electric energy exchange on this "free-market" are described in this report.

Trading strategies must stimulate on the one hand energy production from local RESs and waste heat, and during peak hours. On the other hand, they must boost energy storage practices and off-peak drawing from the network. With respect to the first element, a number of sources can be considered as suitable for integration, starting from high temperature solar thermal fields moving to urban-available, low-cost waste heat provided by supermarkets, data centres and air-conditioning systems. With regard to the second, as the source of thermal energy cannot be switched on and off on demand, the thermal capacity of the network has to be wisely set up and managed at centralised and diffused levels (storage tanks at producers and users side).

While the technical management of the storage capacity is treated as part of the WP4 activities, installing thermal storage tanks at customer site (both final user and prosumer) produces contractual issues due to the additional volume needed in the technical room (compared to traditional solutions) and to the eventual demand side management.

Conversely, integrating diffused thermal energy producers in the network involves a certain risk to the energy utility company as the energy delivery through the years is not fully assured: what happens if the provider moves or goes bankrupted? Contracts assuring penalties against missing energy delivered, would reduce the risk for the utility company but probably also dishearten entrepreneurs from consider the eventual integration.

Solving these and other non-technical barriers at the early stages of the technology market entry is of utmost importance for the future of the sector, and requires analysing:

- Suitable business models
- Proper public incentives and
- Investment/revenue levels needed for the integration of the diffused sources to be profitable

As a first step, incentive schemes available at national and Community level will be studied, together with business models actually exploited in the renewables and energy efficiency sectors. The national electricity management and incentives strategies will be taken as a reference, since they have generated a number of innovative solutions as a consequence of the diffused utilisation of PV plants exchanging electricity with the grids. These will serve as best practices to be taken into consideration when policies incentivising 5$^{th}$ generation DHC are studied and devised.

Secondly, a number of operation scenarios will be elaborated accounting for the integration of large and small size producers and prosumers. These will be the tool demonstrating the economic viability potential of the FLEXYNETS solutions both from the energy providers' and consumers' perspectives.

# 2 Incentive schemes and regulations

The different existing incentives schemes and regulations that affect thermal and electrical network market will be investigated in this section.

The majority of the common incentives mechanisms in EU focus on increasing the energy efficiency and boosting the distributed energy production spread, and can be classified in three main categories:

- Regulatory Policies
- Financial Incentives and
- Public financing

This said, what is available in most of the EU member states is a combination of different nature incentives[1].

| INCENTIVE MECHANISMS AND SUPPORT SCHEMES | | |
|---|---|---|
| **Regulatory Policies** | **Financial Incentives** | **Public Financing** |
| Feed-in-Tariff (FiT) | Capital subsidy, grant, or rebate | Public/System Benefit Funds |
| Premium Tariffs | Tax incentives and Credits | Public Investment and Financing |
| Local content bonus | Reduced VAT | Public competitive bidding |
| Utility Quota Obligation | Accelerated depreciation of assets | Public/System Benefit Funds |
| Net Metering | Exemption from custom duties | Public competitive bidding |
| Obligation and Mandate | Energy production payment | |
| Tradable Renewable Energy Certificate | | |

*Table 1 – List of Incentive mechanism and support schemes.*

## 2.1 Regulatory Policies

### 2.1.1 Net-metering/Net billing

It is a simple billing arrangement that ensures consumers who generate some or all of their own energy receive one for one credit for any electricity their systems generate in excess of the amount consumed within a billing period. In this case, production and consumption are compensated over a

1 http://www.map.ren21.net/PDF/ProfilePDF.aspx?idcountry=122

larger time frame (up to one year), and the network is regarded as a long term storage solution, with the own generated electricity being occasionally injected and consumed later on.

In a net metering program, a utility effectively pays the customer the retail rate for any generation that is fed back into the grid. When this refund is done in kWh, we talk about net metering. If a monetary discount is done in the next electric bill, then we refer to net billing.

This solution applies actually to the electricity market.

### 2.1.2 Feed-in-Tariff (FIT)[2]

The FIT is set up as a generation rate or as a fixed price per kWh produced or added as a bonus to the selling price in the market ("feed-in-premium" FIP). Once more, this solution applies to the electricity market. Rates tend to be significantly higher than the market price of electricity, trying to compensate for lower externalities of alternative energy sources (renewables, cogeneration...) over conventional sources.

FIT programs are similar to net metering programs but differ significantly in one key aspect: the power generated by a utility customer's system is compensated at the rate set by the FIT rather than the retail electricity rate. This generation is treated independently from the customer's own electricity use, which is billed at the utility's regular retail rates.

In general, feed-in tariff rates that lead to significant additional renewable energy investment are set above the retail cost of electricity. The premium level may depend on the underlying program motivation and goals: FIT programs associated with more ambitious goals (e.g., an explicit capacity target, or a certain level of renewable energy credits, or to support a domestic renewable energy industry) may need to set the rate well in excess of the existing retail price.

A FIT is a performance-based incentive and in that respect is more similar to production tax credits and the renewable energy credits than to investment tax credits or other investment subsidies. In several countries, FITs are typically used in combination with one or more of these other incentives.

Feed-in tariffs vary widely in execution. Typically, feed-in tariffs specify:

- **Eligible technologies** — FITs generally include among other solar PV, but may include other renewable technologies. The German and Danish programs where the policy was tested and developed, initially focused on supporting wind.
- Rate and contract terms — most contracts are long term (10-20 years). This assures project owners of a stable long-term revenue stream. Utilities often set rates that depend on project size (smaller projects tend to receive higher rates) and technology (solar PV tends to receive higher rates than other technologies). Rates can also depend on the overall program goal or size limits (e.g., tariffs that decrease as capacity approaches the program ceiling), and utilities or states may revise their tariffs in cases of over- or under-subscription.
- System size and sector restrictions — Most FIT programs have a maximum size for individual projects and may limit participation to certain sectors.
- Program size limitations — most programs designate a cumulative ceiling, set either annually or at the program level, capping the amount of capacity that can take advantage of the tariff. This is an important cost containment mechanism for FIT programs.

[2] http://www.pv-magazine.com/services/feed-in-tariffs/feed-in-tariffs-for-various-countries/#axzz3B0jzapey

### 2.1.3 Tradable Renewable Energy Certificates

Renewable Energy Certificates (RECs), also known as Green tags, Renewable Energy Credits, Renewable Electricity Certificates, or Tradable Renewable Certificates (TRCs), are tradable, non-tangible energy commodities that represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource (renewable electricity). Tradable certificates have been used as a compliance mechanism for a variety of policies including Renewable Portfolio Standards (RPS) (also known as renewable energy mandates), renewable energy targets, and greenhouse emissions mitigation schemes such as cap and trade and carbon tax policies. Tradable certificates are also used in voluntary markets and are purchased by companies and organizations to reduce carbon footprints and support renewable energy markets.

Tradable certificates alone may not be an effective policy if high non-economic barriers exist. Investors may perceive higher risk with tradable certificate programs compared to other types of incentives where the support level is known (e.g., feed-in tariffs) and because of the typically shorter support periods.

### 2.1.4 Premium Tariffs

Under the concept of premium tariff is understood the premium-price option, which offers a premium on top of the spot market electricity price. This achieves one of two objectives: i) to explicitly account for the environmental and societal attributes of the renewable energies, or ii) to help approximate renewables generation costs. In this market-dependent model, the payment level is directly tied to the electricity market price, rewarding renewable energies developers when market prices increase, and potentially penalizing them when they drop.

### 2.1.5 Utility Quota Obligations

Generally called Renewable Portfolio Standard (RPS), renewables obligations or quota policies. A standard requiring that a minimum percentage of generation sold or capacity installed is provided by renewable energy. Obligated utilities are required to ensure that the target is met.

In this category falls also the “green certificates”, whereby generating utilities are required to achieve a certain percentage of their annual production from renewable energy sources, by obtaining green certificates (for example, for each MWh produced) that can be exchanged in the generation market with other companies. Under an RPS, declining price caps for the certificates can be included as a means to reduce long-term incentive levels.

### 2.1.6 Local content bonus

It is a percent bonus on the purchase price of a system if at least a specific portion of the added value of the entire installed system is local (regional, national, continental).

## 2.2 Financial Incentives

### 2.2.1 Capital subsidy, grant, or rebate

Reducing the installed cost of an energy project (renewable energy or high energy efficiency) capital subsidies and grants are often paid in lump sum payments, while rebates are frequently determined on a €/kW basis. This kind of support is used with other supporting policies to be effective, such as net metering for example (Kubert & Sinclair 2011).

Consistency and duration improve the use of the incentive by avoiding confusion in the market and building awareness of the rebate. Rebates ideally should reflect existing market trends, cost of alternative technologies, and program goals (e.g., intended size of market). Additionally, incentive levels are differentiated for residential, commercial, and public sectors (Ellingson et al. 2010). Rebates set at the appropriate level incentivise market up-take, while avoiding windfall profits to system owners (Kubert & Sinclair 2011).

Declining incentive blocks contain program costs by reducing incentive amounts as target capacity levels are reached, reflecting increased economies of scale as markets mature (Kubert & Sinclair 2011). Rebates are most effective when used for market-ready technologies with capacity for cost reductions. Complementary programs include tax incentives and feed-in tariffs (Lantz et al. 2009). Grants based on project needs ensure that sufficient funds are provided without over subsidizing the project; other incentives received by applicants should be considered when determining funding needs for a given project (Kubert & Sinclair 2011). On-going project technical and financial assistance increases the likelihood of the project being completed on time and successfully.

Focused Requests for Proposals (RFPs) for grant applications enable programs to select projects that fit program goals (Kubert & Sinclair 2011). Milestone-based payments encourage timely progress for the project by releasing funds once certain project implementation steps are met. Programs can also require milestone deposits that are released as the project reaches certain implementation steps (Kubert & Sinclair 2011).

### 2.2.2 Tax incentives and credits

Governments can provide tax incentives to renewable energy and self-consumption projects by one of two ways. First, governments can reduce the liability of a particular tax via a deduction that allows a portion of the expense of a particular investment to be subtracted from a taxpayers' adjusted gross income. Second, governments can provide tax credits, refundable tax credits, and cash grants that either allow the taxpayer to subtract a certain portion of the cost from the amount of taxes owed or provide a refund if the credit exceeds the amount of gross tax owed. Main types of tax incentives used include: *corporate tax incentives, personal tax incentives, property tax incentives, and sales or value-added incentives*. Tax incentives can be paired with a variety of other policies and incentives, including renewable energy mandates/tradable certificates and rebates.

### 2.2.3 Reduced VAT

For renewable energy installations, in some countries, renewables systems are defined as energy saving devices and a reduced VAT is charged.

### 2.2.4 Accelerated depreciation of assets

Depreciation is an important tool for businesses to recover certain capital costs over the property's lifetime. Allowing businesses to deduct the depreciable basis over a few years reduces tax liability and accelerates the rate of return on a solar investment. This has been a significant driver for the solar industry and other energy industries. Accelerated depreciation, along with other successful energy tax incentives has helped fuel unprecedented growth in annual solar installations.

### 2.2.5 Renewable production payment (REP)

They are a competitive alternative to Renewable Energy Credits (REC's). Although the intent with both methods is the same, REP's have proven to offer benefits to local jobs, businesses and economies while making the growth fundable and lendable by financial institutions. Renewable

Energy Payments are the mechanisms or instruments at the heart of specific state, provincial or national renewable energy policies. REPs are incentives for homeowners, farmers, businesses, etc., to become producers of renewable energy, or to increase their production of renewable energy. As such, they increase the local overall production and use of renewable energy, and decrease the consumption and burning of fossil fuels.

## 2.3 Public Financing

### 2.3.1 Public/system benefit funds

They are collected through a variety of means, including €/kWh charges on electric and gas utility bills, flat charges on bills, and environmental and other fees from energy companies. Funds can be redistributed to support clean energy programs and incentives.

It is necessary to determine goals for the fund before establishing programs and incentives to ensure that objectives are met, through setting measureable targets such as MW installed and monitor progress.

Keeping funding sources consistent allows annual excess funds to carry over and maintain funds for the programs. Appropriate legislative language and public acknowledgement of the benefits of the fund may help to prevent reallocation or a reduction in funds.

Fund allocations, uses, and eligible technologies should be transparent to state officials, policymakers, and the public (REN21 2009). Renewable portfolio standards, energy efficiency standards, tax credits, and loan programs are complementary to public/system benefit funds.

### 2.3.2 Public Investment and Financing

Renewable energy companies often have difficulty gaining access to financing, and to address this barrier, governments have provided loans to renewable energy project developers and manufacturers. Often, these loans are "soft" loans consisting of any combination of below-market interest rates, longer loan tenors than those available from private banks.

In the U.S. several states and local governments have used revolving loan funds, which are intended to be self-sustaining with loan repayments recapitalizing the available funding. Governments have also made investments in research and development and facilities such as technology incubators in efforts to catalyse renewable energy deployment. Programs that target borrowers unable to access financing at reasonable rates optimally leverage funds while avoiding competition with private loan markets. Longer amortization schedules enable payments to match cash flows from energy sold. Low interest rates attract participation to the programs, while low application burden reduces time and money spent on paperwork and fees (Kubert & Sinclair 2011).

In EU, DHC systems usually need financial support from the national, regional or local governments, because they require a high investment capital and the economic profitability is difficult to achieve. The most common financial support schemes consist of:

- Direct financial support, such as: revenue support schemes to renewable energies and CHP (usually feed-in premiums); investment subsidies from EU or national, regional and local funds; long-term adapted debt funding, which can be offered by national banks EU institutions like the European Investment Bank; etc.
- Indirect financial support, in particular relevant tax incentives such as environmental taxes or reduced VAT to final users of low-carbon services.

National policies and regulatory frameworks in EU try to facilitate more and more the installation of DHC systems, developing direct or indirect funding programmes or mechanisms and reducing obstacles to implement systems in their territories.

Some common policies in EU are gathered below:

- In Italy, France, Germany and Spain, implication of local governments and stakeholders use to be deeper than observed from the national authorities, in general terms. In this scenario, DHC systems use to be implemented through the concession of the project design, construction, operation and maintenance to a private of a public consortium. Sometimes, the local authority help to finance the projects, through its territorial development plans, and the final consumers cover the contracted debt by mean of the payment of the energy invoice. The private or public concessionaire operates the facilities until the end of the contract; usually when the loan has been paid.
- In Estonia and Denmark, a more conservative but resolute policy within a highly centralized scheme, consisting of supporting those DHC systems which have proven to provide the most economic heat or cold supply, is given good results. In Denmark, the expansion of DHC systems was driven by the introduction of environmental taxes.
- In Sweden, environmental taxes were also established by the central government. Sweden has chosen a hybrid scheme to promote the implementation of DHC systems. A central regulatory body provides local authorities and the industry with guidelines and benchmarks, aimed at securing transparency to consumers and relevant control and steering of operators. Public and private local agents remain the control of the local development and build & operate the DHC systems, but with the guaranties obtained thanks to the state-sponsored policies and regulations.

### 2.3.3 Public competitive bidding

Competitive bids are offers extended by businesses in which they detail proposed compensation that they will receive in exchange for executing a specific task or tasks. These tasks can range from providing services for a set period of time. Among those a public authority can request to design, construct and operate a particular project with a specific quantity of renewable energy capacity and/or energy efficiency level.

### 2.3.4 Showcase of public financial model: Paris Saclay DHC System[3]

The "Smart District Heating and Cooling in Paris Saclay (France)" has been chosen as an example of a DHC project financed through public mechanisms, within the category of "Public/system benefit funds". Below are explained this showcase more in detail.

- Project overview:

  Paris Saclay Smart District Heating and Cooling Network, currently in construction, will be composed by renewable energy sources, low temperature exchange networks, heating and cooling demand management, heat storage and connection with the electrical and natural gas distribution grids.

  The project has been implemented in a large area around 1.800.00 m$^2$, close to Paris, within an urban development zone called "ZAC", in French (Zone d'Aménagement Concertée). Its execution started in 2015 and will finish in 2028. The phase 1 is foreseen to finish on 2021.

[3] Literature references: (1), (2), (3), (4).

New technologies, among them innovative renewable energy systems, will be included in the course of project's development.

The Paris Saclay Smart DHC Network is being financed by public support, which bears the system's financial and commercial risks and set up the tariff applied in order to balance the accounts of the public funds intended to support this kind of projects.

The planned total investment of the DHC network is 50 million euro.

- System description:

The first phase of the Smart DHC system in Paris Saclay comprises 7 municipalities, in which the low energy consumption buildings are the dominant trend.

The main data and energy mix of the DHC installation are:

| | |
|---|---|
| DH market share | 100 % |
| Heating & Cooling capacity | DH: 37 MW<br>DC: 10 MW |
| Heat &Cold production | DH: 40 GWh/y<br>DC: 10 GWh/y |
| Km network (double-pipe) | DH and DC : 10 km |
| $CO_2$ emissions (heating) | <100 kg/MWh |

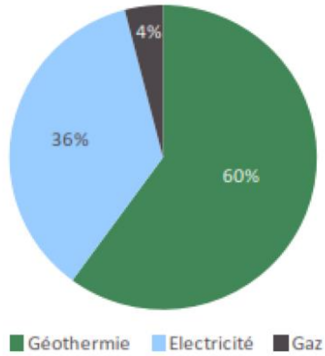


*Figure 1 – Main data and energy mix of Saclay DHC system* (1)

The heat and cooling supply will be addressed to cover the demand of a large number of science, engineering and business schools and R&D centres (550 000 m²), student residencies (158 000 m²), family housing (360 000 m²), office spaces (560 000 m²) and shopping & public facilities (86 000 m²).

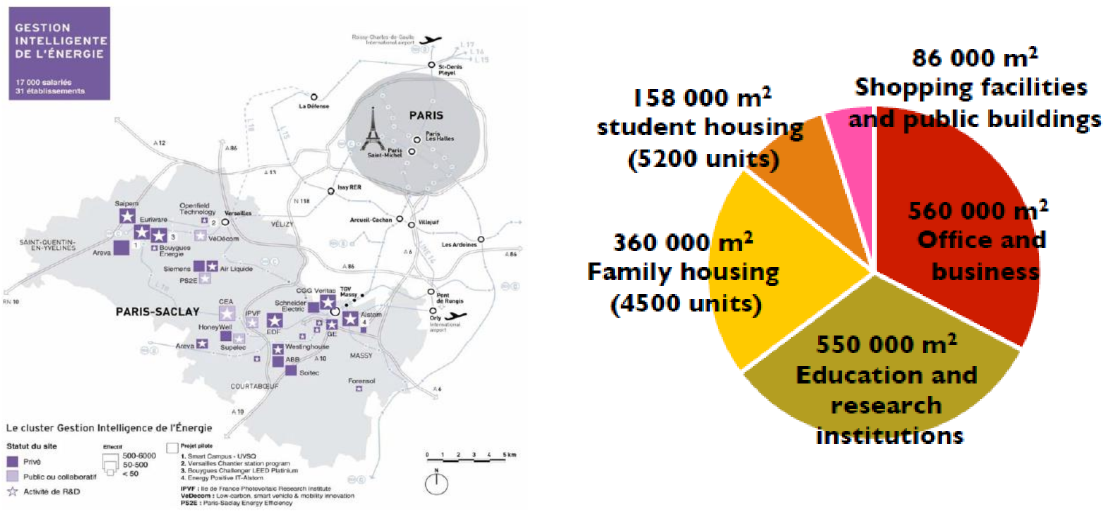


*Figure 2 – Smart DHC facility in Paris Saclay area and share of energy demand* (2) (3)

The DHC system will finally include 4 kinds of different sub-systems: geothermal system, gas boilers plants, heat pumps stations and heating and cooling networks.

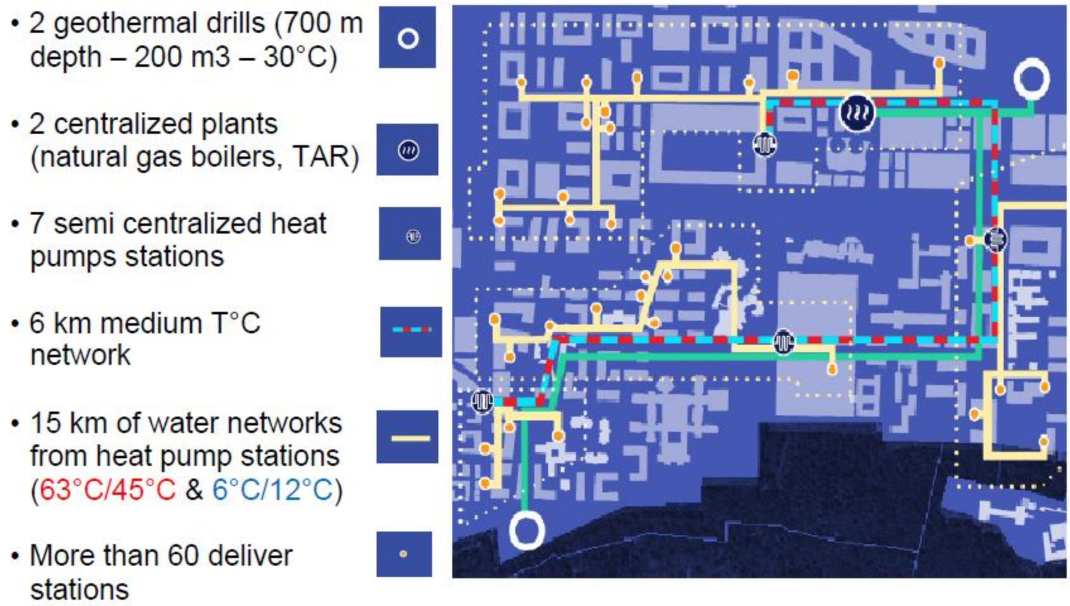


*Figure 3 – Sub-systems of the Paris-Saclay DHC system* (3)

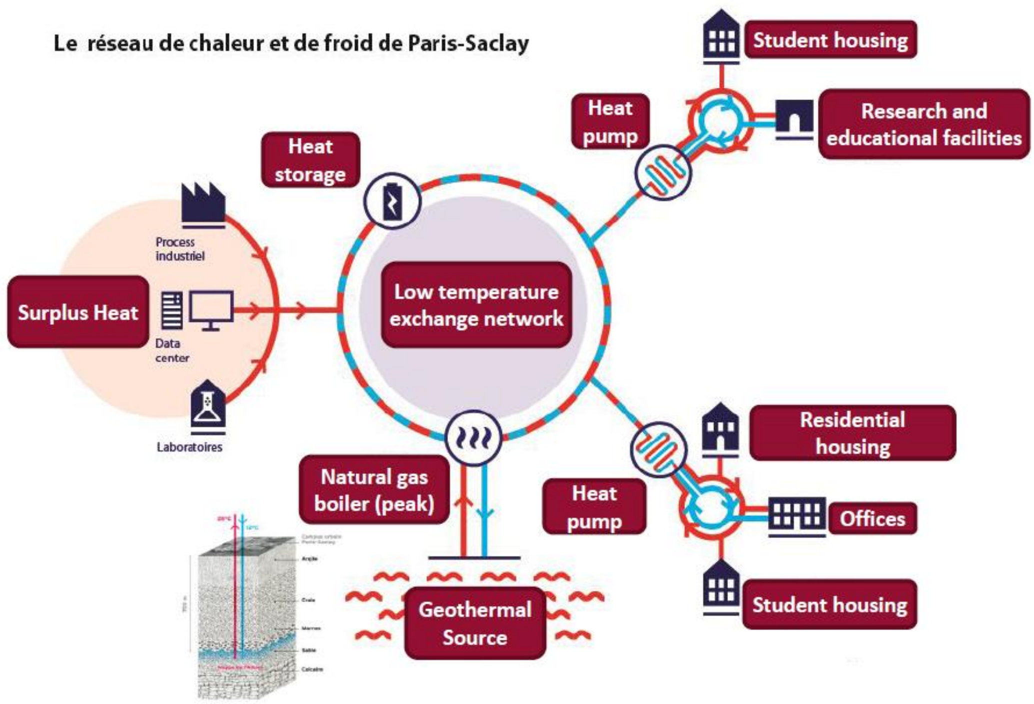


*Figure 4 – General principle of the smart DHC network of Paris Saclay* (4)

The different heating and cooling demand curves related to the wide diversity of final users, composed of educational, service and residential buildings, will allow a high level of flexibility in the energy management, aimed to the optimization of the global energy balance. The diversity of complementary energy sources will contribute to the same purpose, considering not only the energy availability to cover the existing demand but also the price of the energy sources in order to achieve the maximum energy and economic efficiency. In this regards, as an example, the smart use of the heat pumps will allow each costumer to reinject energy in behalf of other consumers and the electrical peaks will be able to be shaved. The centralized network operation centre will allow, in turns, predicting demand with the help of the information transferred by the building management systems.

The technical principle of Paris Saclay DHC network is represented in Figure 4.

- Public financial mechanism:

DHC systems have been recently included in the public subsidies boosted by the use of renewable sources for energy generation. The Heat Funds implemented in France provide funds to promote the installation of renewable energies and measures to save and recover waste heat in DHC systems. These funds are available for collective housing, municipalities, county governments and interested privates companies. Several preliminary conditions, related to the level of demand covered by renewable sources and the linear network density, are applied to be able to access to these benefits.

The French Agency of the Environment and the Control of Energy (ADEME) is the public body in charge of analysing the energy projects and granting the correspondent public subsidies, on the basis of technical, financial and sustainability factors, among which innovation is one of the main concepts.

The autonomous governmental Paris-Saclay Development Agency (EPAPS) is the main contracting authority for the urban planning and development of the area in question. EPAPS is composed of 20 members, including 3 state representatives, 10 local municipalities' representatives and 7 educational and economic development representatives. Among its responsibilities are the energy supply and management of the buildings and public facilities it is included the Paris-Saclay DHC system.

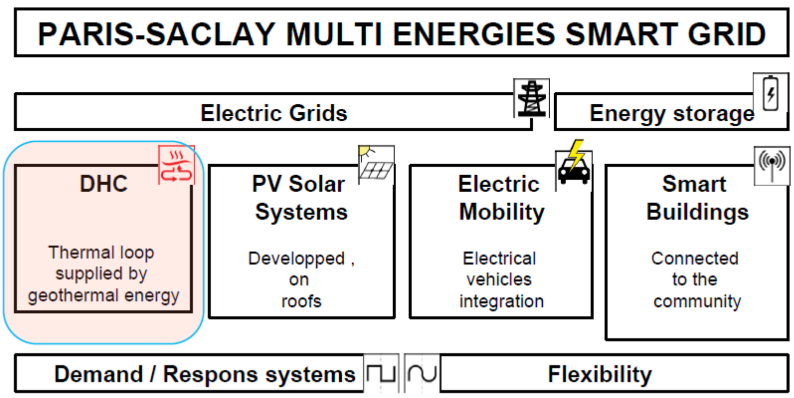


*Figure 5 – The DHC system integrated in the complex energy/building/mobility scenario controlled by EPAPS* [(3)]

It works, in coordination with the local authorities and the real estate developers, for the construction of the infrastructures needed to implement high efficiency heating, cooling and electricity networks.

Finally, Idex-Egis is the private consortium which won the public tendering intended to carry out the design, build and operate the DHC system.

Figure below shows the financial flows on which the Paris-Saclay DHC project was financed.

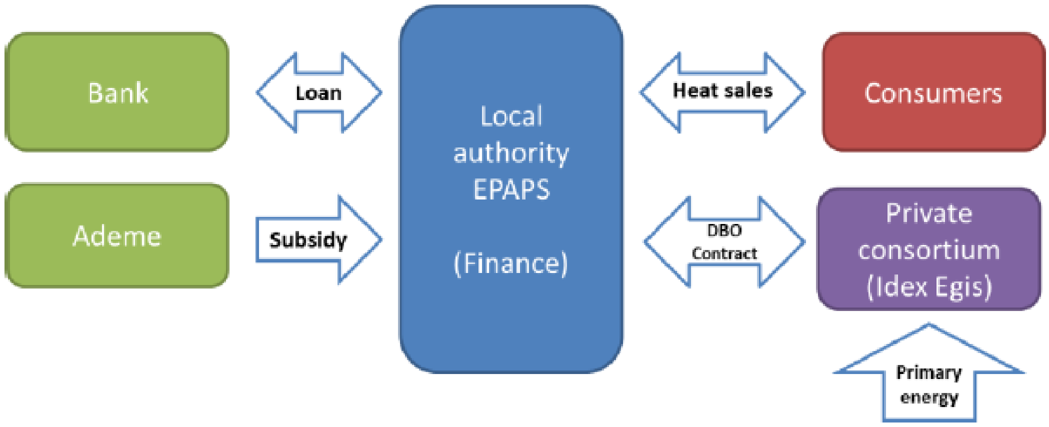


*Figure 6 – Paris Saclay Smart DHC system financial flows* (1)

The subsidies provided by ADEME reached 10 million euro, for a project of 50 million euro, a supporting level higher than usual because of the system efficiency of the network, the associated environmental benefits and the innovative technologies and measures involved. The equity provided and the debt contracted were 30 % and 70 %, respectively, to be paid down in 20 years with 1,89 interest rate. The invoices paid by the final consumers, on the basis of the tariffs yearly set up by EPAPS, are intended to cover this debt. The business model adopted for Paris-Saclay system (Build–Operate–Transfer, BOT) is explained in more detail in the next sub-chapter, Business Models for ESCOs.

## 2.4 Private supporting mechanisms[4]

In the last years the support systems for more efficient systems have been highly modified. This situation has induced companies to look for new ways of financing this kind of systems.

Regardless of the public support reduction in most of the EU countries, the European Commission continues boosting the usage of environmental-friendly and high-efficient HVAC systems in building sector. This issue has resulted in new alternative ways for financing this kind of projects carried by European companies trying to attract private capital replacing the old financing schemes.

A new challenge for the private capital is open in this sector by filling the finance and investment gap needs for this type of projects. New financing tools appear on this market, such as capital mezzanine and junior debt or crowdfunding.

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[4] The state of renewable energies in Europe. Edition 2015 15th EurObserv'ER Report

Capital mezzanine: is a subordinated debt, in which repayment from the project revenues takes place after operation costs and senior debt service coming from banks. The capital mezzanine is a more expensive debt, with rates of return around 15% because of its higher risks with some advantages:

- It is easy to access and can be provided more quickly to the project than a senior debt.
- It doesn't imply as much loss on the project control for the developer than equity financing
- It may convince banks to finance the project easily. As it strengthens the possibility of being paid back in case of default.

In case the mezzanine load is not paid back in time or in full, it gives the lender the right to convert it into equity.

Crowdfunding: it gathers many small sums of money from a large number of small inverters to finance a large project. It uses to be boosted via internet, starting with an individual initiative which is supported by a growing number of stakeholders. An organization platform use to be created to launch the project binding the common will of all its participants.

As an example, it can be mentioned the European investment platform CITIZENERGY for the citizen investment in renewable energy projects[5]. In its website it is explained:

> *"Renewable energy is inevitably decentralised which allows regionalised energy production and the participation of consumers as 'prosumers' (people who themselves produce the energy they consume). We are currently on the cusp of a new Europe and as European citizens we have the unique opportunity to shape the energy production and supply that we want. CITIZENERGY offers more than just the opportunity to investment in renewable energy projects (it lets European citizens participate in the future of Europe's energy mix). By choosing the projects you want to support and fund, you can build the energy infrastructure you want. Coming in May 2015, CITIZENERGY is an online renewable energy investment platform that will:*
>
> *1. Match EU citizens with investment opportunities in renewable energy projects across Europe.*
>
> *2. Support local renewable energy projects and their promoters, e.g. cooperatives and developers.*
>
> *3. Setup a European network of citizen energy initiatives, identify barriers to citizen investment and provide recommendations.*
>
> *4. Promote the European-wide transfer of key business models that help finance renewable energy projects".*

Regarding the crowdfunding private mechanism support, it also comments that:

> *"Main barriers to citizen engagement and investment in RES projects in at least 10 countries (DE, ES, FR, NL, PT, UK and other countries where citizen RES projects are implemented during the leveraging stage) are identified and recommendations towards the creation of an European framework that favours citizen engagement in community energy initiatives are developed, contributing to the ongoing demand for a common framework for citizen investment (crowdfunding), will be developed".*

5 https://ec.europa.eu/energy/intelligent/projects/en/projects/citizenergy

# 3 Business models assessment

The core of the FLEXYNETS TRADING concept is the energy exchange among buildings via a district heating and cooling network. Trading excess of locally generated energy is possible to other buildings in the network or to the district heating and cooling company. The 4th generation DHC technology allows widely developing this concept on the bases of its advantages in comparison with the previous generations.

The progressive advances achieved from the 1st generation to the 4th one have been traditionally related to the transport procedure and the network temperature. As a reminder:

- 1st generation basically consisted of a steam-based system.
- 2nd generation systems worked with high network supply temperatures, above 100 °C.
- 3rd generation systems (currently the more usual) use medium temperature, between 80 °C to 100 °C.
- 4th generation DHC systems significantly reduce the network supply temperatures down to those required by the consumer, in order to match more efficiently supply and demand and to have a more effective control over the heat losses associated with the transport, which can be reduced up to 75 %, compared with the conventional systems, with a well-designed distribution network.

As an example, the showcase analysed in the previous chapter (Paris Saclay DHC network) has 1 medium temperature network, with temperatures between 15°C - 30 °C, to feed the heat pump stations and 7 hot water networks, with temperatures between 63-45 °C, connecting the heat pump stations with the buildings. 7 cold water networks, with temperature between 6 °C -12 °C, are in charge of the cooling supply.

Naturally, the adoption of the 4th generation technology has a direct influence on the economic feasibility of the DHC projects: investment, production and transport costs can be reduced according to the reduction of the temperature range. This fact could make DHC systems competitive compared with the traditional heat and cool generation systems.

Different actors use to be involved in the business models adopted for DHC networks:

- Building occupants/owners (producers, prosumers, consumers)
- Energy Service companies (ESCO)
- Facility managers
- Demand Side Management (DSM) Aggregators
- Distribution System Operators (DSO) and Transmission System Operators (TSO).

<u>Building occupants/owners:</u> They are the end users, and can be energy consumer, producer or prosumer. They are any legal entity that exchanges energy via the power grid or a heating/ cooling network, they can produce energy but this is not its primary activity. Its role is to fix needs and preferences that are driving the whole business model.

<u>Energy Service Company (ESCO)</u>: It is a company that provides a range of energy solutions focused on achieving energy saving. The main role is to provide integrated management services and

developing, implementing and providing or arranging financing for upfront investments in more efficient systems for its clients.

Facility manager: It can be the facility owner, a third- party operator or the systems operation responsible within a facility. In case when a third party company takes care of the facility management it is possible to include in its role additional services as maintenance, cleaning services, etc. among others; in this case the facility manager role can be considered inside an ESCO role. The main role of the facility manager is to ensure an energy efficient building operation.

DSM Aggregators: they trade on the energy exchange market on behalf of members of their portfolio, including energy retailers. They may own energy plants or trade energy on behalf of energy generation parties. Aggregators' role is to act as mediators of consumers towards participation in demand Response (DR) programs.

Distribution system Operators (DSO): they are responsible of the electricity distribution in a reliable and efficient way for low-voltage distribution systems. They have to prevent the overcapacity in the grid so their interest is focused on peak shaving. In the heating and cooling sector, the DHC network facility manager plays the role of the DSO.

Transmission System Operators (TSO): they are responsible of the electricity transmission in a reliable and efficient way for high and very-high voltage transmission systems. They are also responsible for the balance in their control area matching their control mechanisms (starting up, and shutting down additional production units).

In the DHC networks segment, while end consumers and prosumers interact with ESCOs, utility managers and DSM aggregators, the latter cooperate with electricity grids DSOs towards the efficient use of the grid itself. TSOs are normally not involved at this level of trading, due to the small size, therefore influence, of the electric energy lots managed.

## 3.1 Business Models for ESCOs

Different business models for ESCOs are already used in Europe, they have been imported from USA, where they have been developed since 1970s as the main tool to boost energy market in the field of Energy Efficiency projects.

### 3.1.1 Energy performance contracts (EPC)

This type of business model is based on a partnership between customer and an Energy Service Company allowing the costumer to improve the demand side of their facilities with additional savings in energy consumption and in energy bills.

This model is based on the facility performance. In other words, the ESCO will be remunerated depending on the energy savings achieved and the cost savings obtained by the Energy efficiency measures will be invested in financing the project. The ESCO must guarantee a minimum level of energy savings.

Different structures of EPC are available, but the most common are shared-saving and guaranteed-saving. These types of models result in complex contracts that make them not very suitable for small projects because of their high transaction costs but, on the other hand, they are very well suited for large scale projects. Generally, they have a long payback time, which make them less attractive for the private sector.

Another feature of the EPC is that the energy baseline is hard to set up and the measurement and verification process needed to follow the project results might be expensive.

The following table shows the main strengths and weaknesses for the business models described:

| | Business Model | Strengths | Weaknesses |
|---|---|---|---|
| A | EPC with shared shavings | Win-Win | ESCO finances the project and is responsible for the loan repay |
| B | EPC with guaranteed savings | Performance risk. Extra saving as bonus for ESCO | Customer finances the project.<br>ESCO assumes the risk of project's performance, if savings are nor achieved the ESCO |
| C | Variable contract term EPC | It is possible to extend the contract term if obtained savings are less than expected | ESCO finances the total investment of the project and it is totally responsible for repaying the loan |
| D | Energy Supply contract ESC | ESCO receives a fee for the services.<br>Costumer receives a cost efficiency solution, quality of the service and an "all included" ( installation and maintenance) for the energy production facilities | ESCO manages the cost and risk of the delivered service contracted |
| E | Integrated energy contract | Extends the ESC models including demand-side EE measures. Combines two objectives: energy demand reduction applying demand-side EE measures and efficient supply of useful energy with the prioritisation of renewable energy sources | ESCO finances the total investment of the project and it is responsible for repaying the loan |
| F | Built-Own-Operate-Transfer BOOT | Customer are charged according to the service delivered by the ESCO incorporating capital and operating cost recovery and project profit | ESCO finances the total investment of the project and it is responsible for repaying the loan being also responsible for the energy management and operational costs. |
| G | Build–Operate–Transfer (BOT) or Build-Own-Operate-Transfer (BOOT) | Customer are charged according to the service delivered by the ESCO incorporating capital and operating cost recovery and project profit | ESCO finances the total investment of the project and it is responsible for repaying the loan being also responsible for the energy management and operational costs. |

*Table 2: Strengths and weaknesses of business models for ESCOs*

Following, each business model is described more in detail, and a showcase is included:

A - EPC Shared saving

In shared-saving EPCs, the ESCO finances the implementation of energy efficiency measures at customer facilities. Savings achieved with the project are shared between the client and the ESCO during a specific period determined in the contract, based on the share rates previously agreed.

The financing obtained by the ESCO for the project implementation is as usual. Generally, these projects are focused on measurements at the demand side but they can also consider the supply side.

The duration of these contracts depends on the measures set up and their respective investment requirements. They can go from long-term contracts lasting 8-15 years, to short term ones of 2-3 years.

B - EPC Guaranteed saving

In this case, the ESCO assumes the risks of the project's performance. Project financing is obtained by the customer, while the ESCO guarantees a minimum level of energy savings. When savings exceed the level guaranteed, these can be overtaken by the ESCO or split between the customer and the ESCO.

C- EPC Variable contract

This type of contracts is characterized by the fact that the ESCO is the one who designs, finances and implements the project and receives a percentage of energy savings until it has paid its capital investment and the rate of return. After that the energy savings are completely turned onto the customer.

D - Energy supply contract (ESC)

In this case, the ESCO assumes the responsibility of providing the customer with a set of energy services. Operation and maintenance of the equipment are overtaken by the ESCO, which sells the useful energy to the customer. In this case, the costs for equipment upgrades, renovation and repairs are borne by the ESCO, while the ownership remains by the customer.

Typical examples of this type of contract are projects related to Photovoltaics (PV), combined heat and power (CHP), or biomass heat supply installations. The services provided by the ESCO include planning and installation of equipment, energy distribution as well as operation and maintenance of the production facilities and fuel procurement.

The main objective in this kind of contract is an efficient energy supply with a lower operation cost in order to maximize the ESCO earnings, providing at the same time security of supply. In ESCs, the Energy Efficiency measures are applied on supply side and incentives are not focused on lower demand side consumption.

These are the most oriented to decentralized energy supply solutions as it is the case of FLEXYNETS.

Differences between EPC and ESC are that when EPC focuses on energy savings, while ESC focus on guaranteeing energy supply.

E - Integrated energy contract (IEC)

This contract is a combination of an ESC and an EPC, including energy efficiency demand side measures to an ESC. Thus, two different objectives are achieved: reduction of energy demand and efficient supply of the useful energy demand.

This type of contract includes energy efficiency measures as installation modernization, lower consumption and maintenance costs, as well as improvement of the energy indicators.

IEC prioritizes demand side energy efficiency measures before supply side measures solving some of the problems in EPC (Complex and expensive) and in ESC (supplied oriented).

<u>F - Build–Operate–Transfer (BOT) or Build-Own-Operate-Transfer (BOOT)</u>

In the Build–operate–transfer (BOT) or build–own–operate–transfer (BOOT) the ESCO develops the project, builds/deploys, operates with the owner and at the end of the contract transfers the installation/system to the customer. Operation enables the project to recover its investment. They are typical used in projects focused on producing systems as CHP or PV plants.

BOT, or BOOT, is a long term supply contract being the customer charged depending on the service delivered. The ESCO investment and operational costs are covered by subscription fees. Because of the long term nature, the fees are usually raised during the contract period. It can be stated that the BOOT model is similar to a loan made by the ESCO to the Customer, including energy management during the contract period.

### 3.1.2 Showcase of business model: Paris Saclay DHC System (1)

Paris Saclay DHC System has adopted a Build–Operate–Transfer (BOT) business model.

EPAPS decided to build the Paris Saclay DHC network in 2013. Since then, it is in charge of the project development; which include the design, building and operation of the installation until 2030 (a new management contract is envisaged after 2021 and until 2030, although decisions are yet to be made about this operational framework). The ownership and operational responsibilities of the facilities will be transferred to the public administration (local municipalities) at the end of the concession agreement, after 2030, which will decide about the future contractual operation model of the DHC grid.

An expert partner (Tilia) was contracted by EPAPS to provide technical support for the feasibility study of the project, including tender full organisation and quality control in realisation and operation. A call for tenders was organized, in 2014, in order to select a private consortium to design, build and operate the network until 2021. The public tender was won by Idex-Egis.

<table>
<tr><th colspan="2">DHC activities</th><th>Paris Saclay Smart DHC grid (DBO)</th><th>Concession mode</th></tr>
<tr><td colspan="2">Strategic direction of DHC</td><td>Local authority (EPAPS)</td><td>Local authority</td></tr>
<tr><td rowspan="2">Management of the DHC system</td><td>Regulation of the DHC grid (tariff, quality of service)</td><td rowspan="2">Local authority (EPAPS)</td><td rowspan="6">Private Contractor</td></tr>
<tr><td>Technical and economical optimization</td></tr>
<tr><td rowspan="4">operational execution of the service</td><td>Conception<br>Realization</td><td rowspan="3">Private Contractor (Idex Egis)</td></tr>
<tr><td>Operation<br>Maintenance</td></tr>
<tr><td>24h technical assistance</td></tr>
<tr><td>Commercialization<br>Invoicing</td><td>Local authority (EPAPS)</td></tr>
</table>

*Figure 7 – Paris Saclay Smart DHC system financial flows* (1)

Therefore, main differences between the chosen BOT business model and a classical concession contracts are:

- EPAPS bears the financing charge and risk of the investment and construction phase and is responsible for the heating and cooling sales and customer management. The volume and billing risk is not transferred to Idex-Egis consortium.
- Idex-Egis, has technical and economic performance targets to fulfil within the commissioning and operation phase (2021).

The following figure gathers the main differences between the BOT business model and a classical concession contracts. The columns on the right indicate the responsible party for each of the DHC activities listed on the first column.

The main advantage of select a BOT business models consists of the fact that the EPAPS retains the entire control of the global energy development of the area, in accordance with other responsibilities in building and mobility matters, and it may boost the use of the most innovative solution in order to increase the global efficiency of the installation, in a complex energy scenario with different energy sources, extensive heating, cooling and electricity networks and a wide and diverse range of energy demands.

## 3.2 Business models for DSM aggregators

Apart from ESCOs, DSM aggregators can play an important role inside the business models for FLEXYNETS TRADING solutions.

With Demand Response (DR) a tariff or program is meant that has been established to promote changes in the consumption pattern (electric) by end-users considering the electricity prices changes over time, or in other way to promote payments that induce lower energy use when market prices are higher or when the grid (network) reliability is compromised. DR makes possible to reduce the need of additional investments in peaking generation by shifting the consumption away from times of extremely high demand. It adds stability to the system, it lowers the need of coal or gas fired spinning reserves for a power supply at short notice. DR programs can be split into two groups:

### 3.2.1 Explicit DR schemes (incentive-based)

Consumers receive direct payments to change their consumption upon request, which is triggered by activation of balancing services, differences in electricity prices or constraints on the network. Consumers can earn from their own flexibility consumption individually or by contracting with an aggregator that can be a third party aggregator or the customer’s supplier.

### 3.2.2 Implicit DR schemes (price-based)

Consumers can choose between being exposed to time-varying electricity prices or time-varying network tariff (or both) that partly reflect the value or cost of electricity and/or transportation in different periods and react those prices differences depending on their own possibilities and constraints.

Many customers participate in Explicit DR through and aggregator, and at the same time they also participate in an Implicit DR program through more or less dynamic tariffs. The two are activated at different times and serve different purposes within the markets. While consumer will typically receive a lower bill by participating in a dynamic pricing program, they will receive direct payment for participating in an Explicit DR program. In that way, Explicit DR provides an operation tool for system operators to adjust load and in the other side Implicit DR allows customers to benefit from price fluctuations in the wholesale energy market.

The main regulation frameworks for DR business model are:

- **The Electricity Directive 2009/72/EC**: defines the concept "EE/demand side management"
- **The Energy Efficiency Directive (EED)-2012/27/EU**: constitutes a major step towards the development of DR in Europe. According to its Art 15.2, Member States were required to undertake an assessment of EE potentials of their gas and electricity infrastructure
- **Network Codes for energy Transmission**: a set of rules drafted by European Network of Transmission System Operators for Electricity (ENTSO-E), with guidance from the agency for Cooperation of Energy Regulators (ACER) to facilitate the harmonisation, integration and efficiency of European electricity market

# 4 TRADING solutions

A number of operation scenarios are elaborated in this section accounting for the integration of large and small size producers and prosumers, as a way to rationalise on the economic viability potential of different approaches adopted.

In particular, the questions to be answered are:

- What energy sources are worth to be integrated from the economic perspective?
- What price shall be granted to each energy source?
- What business models are reasonable from the energy utility and the customer perspectives (based on the entity bearing the investment cost)?
- What incentives can decision makers use to promote fifth generation district heating and cooling networks?

To do this, we decided to follow a TOP–DOWN approach based on the heating costs of potential customers: for the DHC network technology to be widely adopted, the price of the heat delivered to the final customers must be lower or equal to the price they would pay with a conventional non-renewable solution. In this section, we have considered a gas boiler system providing heat, and an air driven compression chillers delivering air-conditioning to the customer building as the reference, market technologies.

Clearly, incentives and public/private funding contribute indirectly to the economic viability of the solution this, but first we must understand how far/close to the market the solutions proposed are. For this reason, the public involvement is here disregarded.

Following this approach, since reversible heat pumps are needed to deliver thermal energy at the correct temperature levels for the heating uses, the customer must pay both electricity and thermal energy provided at evaporator (from the network). If the above objective is pursued, the reference energy bill ($Q_H C_{ref}$), must equal the sum of the electricity ($\frac{Q_H}{SCOP} C_{el}$) and DH network $\left(Q_H \left(1 - \frac{1}{SCOP}\right) C_{DH}\right)$ bills:

$$Q_H C_{ref} = \frac{Q_H}{SCOP} C_{el} + Q_H \left(1 - \frac{1}{SCOP}\right) C_{DH}$$

Where $Q_H$ is the space heating + domestic hot water demand of the single customers, $C_{el}$ is the specific cost of electricity (€/kWh) and $C_{DH}$ is the specific cost of heat distributed through the DHC network. Consequently, if the specific prices of the reference fuel (e.g. natural gas) and of the electricity are known, the maximum price allowed for the thermal energy delivered through the network is only dependent on the average seasonal COP (SCOP) of the heat pump plant used at customer side:

$$C_{DH} = \frac{C_{ref} - \frac{C_{el}}{SCOP}}{\left(1 - \frac{1}{SCOP}\right)}$$

The latter is again somehow dependent on the specific substation employed and on the temperature of the network.

Indeed, the maximum price allowed for the network thermal energy delivered depends on a number of parameters influenced by local conditions, however a preliminary parametric analysis can be performed accounting for EU representative ranges.

Figure 8 reports on the DH energy price vs. reference heating price as a function of local electricity price and substations' SCOP. As far as the SCOP increases from 3.5 (value typical of geothermal systems) to 6 (eventually available at FLEXYNETS average network temperatures), the DH energy price becomes more and more independent of the electricity price.

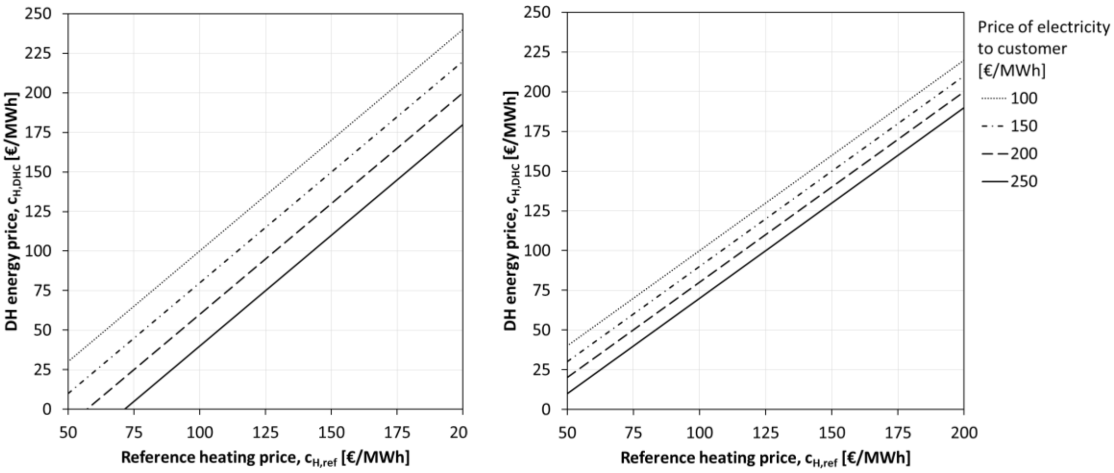


*Figure 8 – DH energy price based on local electricity price, reference heating price and HP plant SCOP: SCOP 3.5 on the left, SCOP 6 on the right*

Based on this chart, a threshold can be set to the DH energy price as it is reported in Figure 9: in this example a gas retail price of 100 €/MWh has been assumed, typical of a European final small residential consumers. The price paid by the customer is not only due to gas consumption, since it also must include the initial investment and the annual maintenance, which can be accounted for adding around 40% on top of the consumption portion: the overall annualised investment, maintenance and running costs can amount to around 140 €/MWh for a modern floor mounted condensing gas boiler. If we assume that the customer pays 150 €/MWh for the electricity driving the heat pump system (electricity prices vary largely between 100 and 250 €/MWh), then the DH energy price can peak around 135 €/MWh (SCOP = 6).

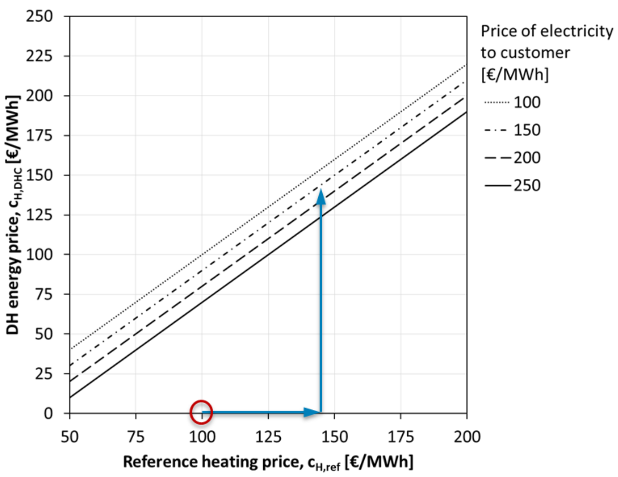


*Figure 9 – DH energy price based on local electricity price of 150 €/MWh, reference heating price of 140 €/MWh and HP plant SCOP of 6*

Based on this price, the utility company revenues vary as a function of the thermal energy harvesting and distribution costs. Figure 10 shows the annual revenues of the utility company (on the x-axis of the left chart) for annualised costs of energy harvesting and distribution varying from 30 to 130 €/MWh. The lower range side is typical of waste-heat recovery solutions, while the higher limit is related to utilisation of renewable energy sources.

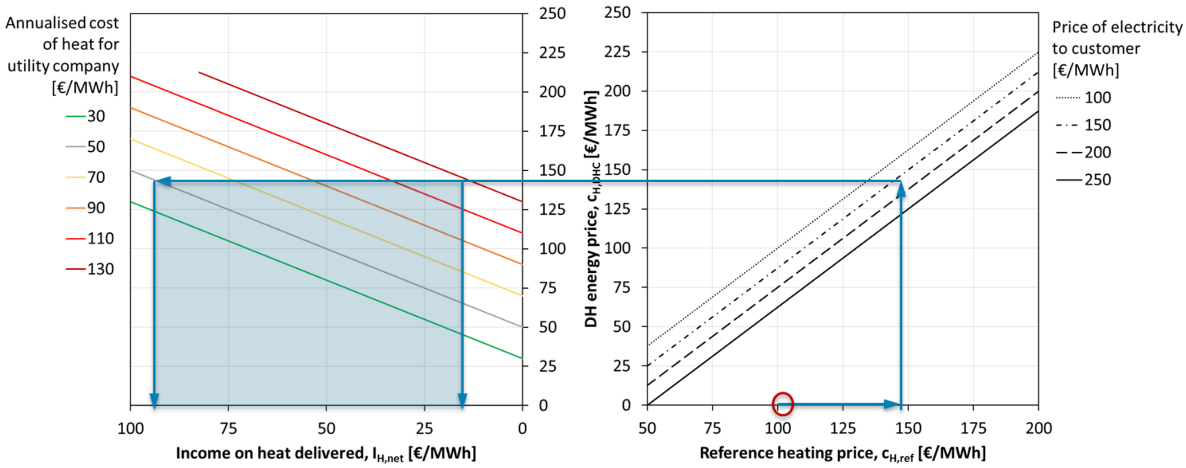


*Figure 10 – Revenues (on the x-axis) based on the annualised costs of energy harvesting and distribution*

The harvesting costs strongly depend also on the business cases and business models adopted, mainly in relation to the horizon set for the return of the investment and to the actor that bears the initial investment. Figure 11 reports on the variants of business models accounted for in this report.

We consider two main segments: the first accounts for Energy Producers providing thermal energy to the network either from waste or renewables heat. The investment cost for the integration of the energy source into the network can be on the Producer itself or on a third part company. In the first case, the Producer has strong interest in the implementation of the measure since it experiences direct benefits, e.g. electricity savings for a datacentre air-conditioning. In the second case, the third party can be the energy utility managing the network, an ESCO or an Aggregator acting as intermediary between the energy source and the network manager. For both combinations it is possible in principle that the thermal energy harvested is remunerated or not, and that the electricity needed to drive the Production substation is paid by the Producer or by the third part company.

A meaningful case is represented for example by the above datacentre, which integration to the network is implemented by the utility company that also pays for the electricity running the substation. In this case, the datacentre owner encounters a reduced energy consumption without any initial investment and minimal disruption during construction; therefore, it might well be that the owner is inclined to render its thermal energy free available.

On the opposite, if the datacentre owner bears the initial investment costs and pays for the substation's electricity, indeed some sort of remuneration must be set in place.

The second segment mainly looks at residential and office prosumers gathering thermal energy from the network for space heating and DHW preparation or providing thermal energy to the network during space cooling operation. Once more, the investment and the substation's electricity costs can be considered on the property owner or on the utility company (ESCO, Aggregator respectively). The business cases one can imagine are largely the same as in the previous case, however here we can also imagine that harvesting waste heat from space cooling is sold to the customer as a cooling service. Therefore, the utility company gets a revenue both from selling energy for heating purposes and gathering energy from summer cooling.

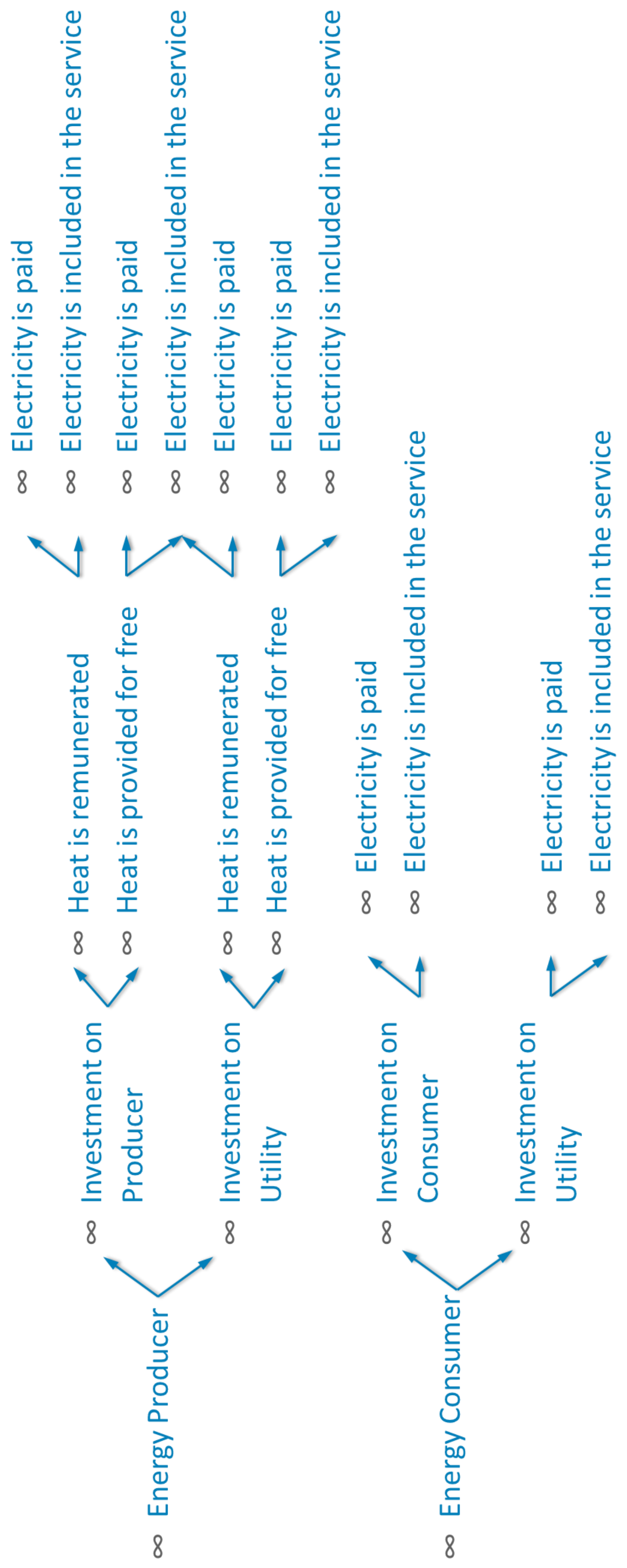


*Figure 11 – Variants of business models dedicated to thermal energy Producers and Consumers*

## 4.1 Energy Producer

In this section, we report on initial economic evaluations with respect to some exemplary business cases. These do not aim to represent the overall range of solutions possibly encountered, rather some representative practices showing the economic sustainability of the utilisation of renewable and waste heat sources in 5th generation DHC networks.

### 4.1.1 Waste Heat from a supermarket provided for free to the Utility Company – Investment on the Utility Company

This business case is represented by the integration of waste heat recovered from the heat rejection system of a medium size supermarket. The refrigeration plant of a supermarket is normally driven by a set of $CO_2$ chillers rejecting heat by means of a dry-cooler. Moreover, as the reliability of food quality and healthiness must be highest, refrigerators operate 24/7 at almost-constant conditions, which makes them seamless waste heat sources to FLEXYNETS networks. Retail managers are extremely sensitive to reducing refrigeration costs and several technologies are approaching the market in this sector. Typical thermal capacities of the refrigeration plant of an average size supermarket is in the range of 150 kW.

In this case, we consider that the design rejection temperature to the network (e.g. 25 °C) is not sufficient to be directly recovered, thus a substation including a heat pump is used to connect the supermarket to the network and to rise waste heat temperature from 25 °C to 40 °C. Due to the very limited temperature lift, the latter condition corresponds to SCOPs easily exceeding 6.

*Table 3 – LCoE of the waste heat recovered into the network – investment and electricity costs on network manager*

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 150,447.15 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 6 | - |
| Cost of electricity | 100 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 16.72 | €/MWh |
| Cost of heat 2 (Investment) | € 8.36 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 16.67 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 33.38 | €/MWh |
| Cost of heat 2 (total) | € 25.02 | €/MWh |

In case the investment (explanations of investment costs are reported through Deliverable 3.2 - Integration of substations into DHC networks) is borne by a public utility company the return of the investment can be considered in the range of 20 years and the cost of the investment can be quite low. Table 3 reports on top the initial investment and maintenance costs of the substation installed. With an interest rate of 4% on the debt paying the investment (public investments are considered here), the annualised investment amounts to around 150,000 €, corresponding to an annuity of 8.4% over the 20 years horizon. The annualised cost of the waste heat recovered is proportional to the SCOP of the substation, the electricity price and the operation hours of the substation. In this simulation, we assume these parameters

- SCOP = 6
- electricity price of 100 €/MWh typical of large consumers (i.e. the utility company)
- operation variable between 3,000 and 6,000 hours. In the first case, waste heat is recovered only during winter season, while in the second case, it is harvested through most of the year.

Consequently to these hypotheses, the cost related to recovering waste thermal energy into the network, varies between 8 and 17 €/MWh. The cost related to the electricity consumption is in this case equal to 16.7 € per MWh of thermal energy delivered to the network,

Overall, the cost of the waste heat harvested on the network managing company ranges between 25 and 33 €/MWh.

*Table 4 – LCoE of the waste heat recovered into the network – investment costs on network manager and electricity cost on customer*

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 150,447.15 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 6 | - |
| Cost of electricity | 150 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 16.72 | €/MWh |
| Cost of heat 2 (Investment) | € 8.36 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 25.00 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 41.72 | €/MWh |
| Cost of heat 2 (total) | € 33.36 | €/MWh |

Moving the electricity costs on the "Producer" would indeed reduce the risk on the investment for the utility company but would results in higher overall costs, since normally electricity fares to retail are higher than the above and in the range of 150 €/MWh. In this case, the total cost of the waste heat harvested would increase to 33 – 42 €/MWh.

In both scenarios, costs of the thermal energy made available to the network are well comparable with production costs via a large gas boiler plant (30 – 50 €/MWh). Indeed, the above values disregard the infrastructural costs related to set up the network pipelines themselves.

### 4.1.2 Waste Heat from a supermarket provided for free to the Utility Company – Investment on the supermarket owner

In this business case, we consider the same supermarket and substation configuration as in the previous section. However, we move the investment on the supermarket owner.

In this scenario, the shop owner cannot wait for 20 years to see the investment paid back, on the contrary, the return of the investment has to be minimum: Table 5 show a case where return time of 5 years and a higher interest rate equal to 7% are considered.

*Table 5 - LCoE of the waste heat recovered into the network – investment costs on customer and electricity costs on network manager (left side table), or electricity cost on customer (right side table)*

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 7% | - |
| Investment Horizon | 5 | years |
| Annualised Investment | € 114,250.81 | € |
| Annuity | 25.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 6 | - |
| Cost of electricity | 100 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € - | €/MWh |
| Cost of heat 2 (Investment) | € - | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 16.67 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € 50.78 | €/MWh |
| Cost of heat 2 (prosumer) | € 25.39 | €/MWh |
| | | |
| Cost of heat 1 (total) | € 67.44 | €/MWh |
| Cost of heat 2 (total) | € 42.06 | €/MWh |

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 7% | - |
| Investment Horizon | 5 | years |
| Annualised Investment | € 114,250.81 | € |
| Annuity | 25.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 6 | - |
| Cost of electricity | 150 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € - | €/MWh |
| Cost of heat 2 (Investment) | € - | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 25.00 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € 50.78 | €/MWh |
| Cost of heat 2 (prosumer) | € 25.39 | €/MWh |
| | | |
| Cost of heat 1 (total) | € 75.78 | €/MWh |
| Cost of heat 2 (total) | € 50.39 | €/MWh |

The annualised cost of the substation decreases to 114,000 € but the overall waste heat recovery cost increases considerably: the cost of thermal energy harvesting boosts to 25 - 51 €/MWh of thermal energy exchanged. In these scenarios, this corresponds to the remuneration the network manager owes to the supermarket for the energy they make available. The cost of electricity remains the same in the 2 scenarios reported in the above tables.

The overall cost of heat distributed varies therefore between 42 and 75 €/MWh.

This model is particularly convenient for the network manager as all the investment risk is shifted onto the supermarket owner, eventually together with electricity costs. However, the remuneration needed during the first 5 years after the installation might be unbearable. Here is where public incentives can play a role: accelerated depreciation and renewable production payment schemes over a limited timeframe (e.g. 5 years), can move the initial burden to the public finances, facilitating the investment and incentivising the adoption of these solutions at selected tertiary buildings.

Public compensation of thermal energy to the network in the range of 20 to 35 €/MWh (for example with a scheme like Italian “Certificati Bianchi”) would guarantee the same remuneration of the investment for the network manager as in the previous section’s scenarios.

### 4.1.3 Waste Heat from a supermarket provided for free to the Utility Company – direct recovery without heat pump – Investment on the Utility Company

Table 6 reports on the same business case as in section 4.1.1. Here however we consider that the network is maintained always at temperatures (e.g. 10 °C) sufficient for the direct waste heat recovery from the refrigeration system. In this case, the equivalent SCOP of the substation increases easily to 20. Thus, the contribution of the electricity component to the overall harvested heat is largely independent of the specific electricity price (5 to 7.5 €/MWh).

The overall annualised costs remain confined between 13 and 25 €/MWh. Indeed, this is an economically suitable source of heat; however, it produces higher electricity costs to the users of the network (mainly the residential ones), who will have lower-temperature heat available with respect to the previous scenarios’.

*Table 6 - LCoE of the waste heat recovered into the network – direct heat recovery and electricity costs on network manager (left side table), or electricity cost on customer (right side table)*

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 150,447.15 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 20 | - |
| Cost of electricity | 100 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 16.72 | €/MWh |
| Cost of heat 2 (Investment) | € 8.36 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 5.00 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 21.72 | €/MWh |
| Cost of heat 2 (total) | € 13.36 | €/MWh |

| | | |
|---|---|---|
| Investment per kW | 600 | €/kW |
| Capacity | 150 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 90,000.00 | € |
| Maintenance Cost | € 900.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 150,447.15 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 20 | - |
| Cost of electricity | 150 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 16.72 | €/MWh |
| Cost of heat 2 (Investment) | € 8.36 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 7.50 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 24.22 | €/MWh |
| Cost of heat 2 (total) | € 15.86 | €/MWh |

### 4.1.4 Renewable Heat

As it can be derived from Deliverable 3.2 - Integration of substations into DHC networks, the availability of economically affordable waste heat and renewable energy is of utmost importance for the FLEXYNETS concept. If thermal energy distributed through the FLEXYNETS network is produced by a central gas boiler, the levelised cost of energy is higher than in conventional DH plants, since the investment and operation costs of the single buildings substations surmounts the conventional ones'.

The previous sections, show that waste heat harvest from selected productive sites can be significantly cheaper than producing heat through central gas boilers.

FLEXYNETS also analysed the utilisation of different renewable energy sources including solar thermal energy and geothermal energy.

With respect to the solar source, different integrations of flat plate and concentrating collectors where studied both to directly feed energy to the network and in combination with ORC units for combined production of heat (provided to the network at low temperature) and electricity.

Performance with alternative configurations, for different locations and network temperatures are compared in [6]. The systems are simulated in order to calculate energy outputs including dynamic effects. These results are then coupled to economic estimates to assess their feasibility.

It was found that, while clearly challenging, the considered systems have some feasibility margin. Due to the significant investment costs of current ORC systems, many operation hours are needed through the year in order these solutions economically convenient. This requires extending operation beyond the period of solar availability. Thus, the option of using a backup gas boiler is considered. While technically and economically convenient, this is environmentally questionable. Alternative solutions can be provided by biomass boilers or thermal storages.

The FLEXYNETS context improves the feasibility of the considered solar-ORC system, as it lowers the condensation temperature of the ORC thereby increasing its efficiency. Moreover, it offers higher self-consumption opportunities (due to the use of heat pumps), allowing to assume higher values for electricity.

The levelised cost of thermal energy of the latter solutions is in the range of 35 – 40 €/MWh. This can be compared to producing solar thermal heat directly delivered to the network, that varies between 27 €/MWh when flat plate collectors are tackled and 38 €/MWh when concentrating technologies are accounted for.

The reported ranges show that in spite of the evident challenges posed by a solar-ORC solution, it can be interesting to continue similar investigations, with the purpose of developing more diversified solutions for the next energy system.

When geothermal energy is in focus, boreholes or water wells can be used to draw energy from the ground. Deliverable 2.3 - Large Storage Systems for DHC Networks (sections 3.4 and 3.5) reports on the scales of economy for large, seasonal thermal storage tanks that can be used in DHC networks. Although costs are provided for storages set up, investments costs can be considered in the same range when the systems are used as energy sources.

Investments between 1000 and 2000 €/kW for borehole solutions are assessed, while initial costs can diminish by about 25% with respect to open systems. The values are strongly dependent on local geological and economic conditions. Table 7 reports on the calculation of the LCoE of thermal energy fed into the network, based on the above ranges (750 to 2000 €/kW).

Using the same investment period and interest rate we assumed in section 4.1.1 in relation to a utility company bearing the investment, and considering that heat is fed directly into a network that is operated at the same temperature of the ground water, the overall cost of heat can vary between 15 – 25 €/MWh in the most suitable scenario (right table) and 30 – 60 €/MWh in the worst case (left table).

Obviously, boreholes and wells lifes are much longer than 20 years (i.e. 30 years and longer) but a reasonable investment cannot be calculated on a time horizon farther than this. In addition, it can be noted how investments in these scenarios are much larger than in previous cases: annualised investments of 1.2 to 3.3 M€ can be encountered for modest size plants providing 1MW of thermal energy to the network. Conversely to distributed waste heat sources, normally renewable energy sources require significant initial investments.

Once more, public investments could be of help in these scenarios, both to contribute covering the high investment and/or to remunerate the energy delivered in those cases (e.g. left table) where the cost of heat is larger than in conventional systems.

We did not consider in our calculations easier available sources as see water and rivers/channels: in these instances, heat would be more affordable than in the cases studied, as it is readily available where it is needed, and excavation costs are avoided.

*Table 7 – LCoE of ground source heat scenarios.*

| | | |
|---|---|---|
| Investment per kW | 2000 | €/kW |
| Capacity | 1000 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 2,000,000.00 | € |
| Maintenance Cost | € 20,000.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 3,343,270.01 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 20 | - |
| Cost of electricity | 100 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 55.72 | €/MWh |
| Cost of heat 2 (Investment) | € 27.86 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 5.00 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 60.72 | €/MWh |
| Cost of heat 2 (total) | € 32.86 | €/MWh |

| | | |
|---|---|---|
| Investment per kW | 750 | €/kW |
| Capacity | 1000 | kW |
| Maintenance | 1% | -/year |
| Investment Cost | € 750,000.00 | € |
| Maintenance Cost | € 7,500.00 | €/year |
| | | |
| interest rate | 4% | - |
| Investment Horizon | 20 | years |
| Annualised Investment | € 1,253,726.25 | € |
| Annuity | 8.4% | - |
| | | |
| Operation hours 1 | 3000 | hours/year |
| Operation hours 2 | 6000 | hours/year |
| SCOP | 20 | - |
| Cost of electricity | 100 | €/MWh |
| | | |
| Cost of heat 1 (Investment) | € 20.90 | €/MWh |
| Cost of heat 2 (Investment) | € 10.45 | €/MWh |
| | | |
| Cost of heat 1 (electricity) | € 5.00 | €/MWh |
| | | |
| Cost of heat 1 (prosumer) | € - | €/MWh |
| Cost of heat 2 (prosumer) | € - | €/MWh |
| | | |
| Cost of heat 1 (total) | € 25.90 | €/MWh |
| Cost of heat 2 (total) | € 15.45 | €/MWh |

## 4.2 Energy Prosumer

According to the example reported in the charts of Figure 12, the revenues associated to the above energy harvesting are noteworthy, as the costs for harvesting thermal energy in the network vary between around 15 €/MWh and 60 €/MWh in all cases considered.

These specific costs are parametrised versus the thermal energy distributed through the network, while the amount delivered to buildings is higher, being the composition of DH energy and electricity consumed by the heat pumps at prosumers buildings. To be used in Figure 12 they have therefore to be recalculated based on the heating demand of the building, namely the SCOP of the heat pumps at prosumer site.

Moreover, the above costs do not yet account for the investment related to the installation of the Prosumer substation. As this entails a heat pump, the latter is significantly higher compared to 3rd generation solutions and to conventional gas boiler plants.

The total cost of a domestic substation with heat pump and thermal storage tank can range around 800 - 1000 €/kW of thermal capacity set up, if the substation is installed on site, compared to around 200 €/kW for a small 10 kW unit down to 50 €/kW for a large 500 kW substation.

In addition, Deliverable 3.2 - Integration of substations into DHC networks shows also how the cost related to the installation of the network pipelines can be around 12 €/MWh.

In the following sections, we assess the additional annualised cost of heat harvested for the utility; again, a number of business cases are presented.

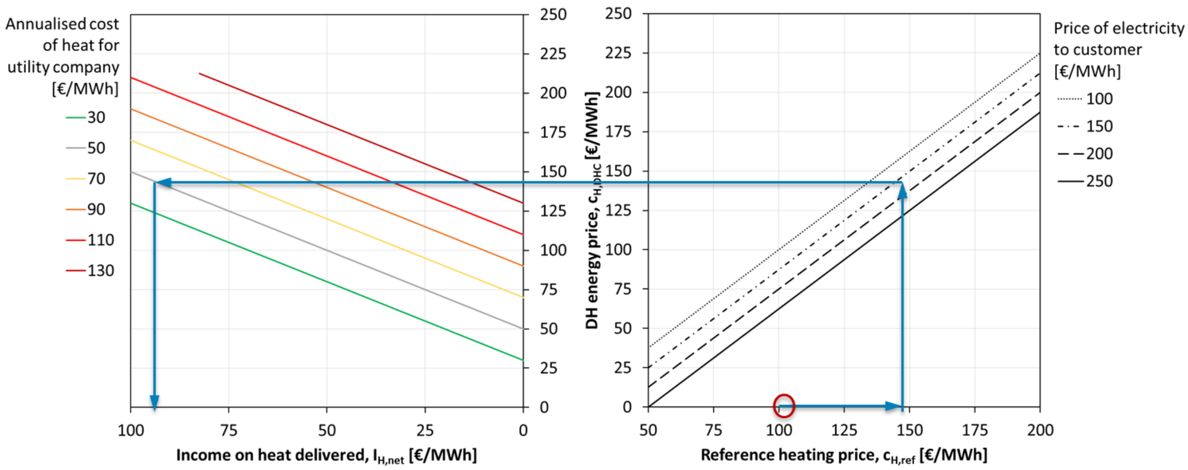


*Figure 12 - Revenues (on the x-axis) based on the annualised costs of energy harvesting and distribution (heat pump SCOP at building = 6, electricity specific cost = 150 €/MWh)*

### 4.2.1 Substation installed by the Utility Company – Investment costs on the Utility Company

Table 8 shows the economic assessment for a 20 kW thermal capacity substation installed in a typical 10 dwellings multifamily building (100 m$^2$ and 7000 kWh/y heating demand each). Investment costs for the installation of the substation have been set to 800 - 1000 €/kW and maintenance costs to 2 % a year.

In this business case, the utility company managing the network bears the investment with a horizon for the return of the investment of 10 years and an 8% interest rate, which is a suitable investment also for an ESCO. The same also pays for the operation costs (electricity consumption) of the substation, with a rate of 100 €/kWh. The operation hours calculated are 3500 per year, while the SCOP considered is equal to 4 (corresponding to a lift between about 15 °C and 50 °C).

In this scenario, the price of the energy delivered to the building substation can peak 153 €/MWh based on the equations reported at the beginning of the chapter.

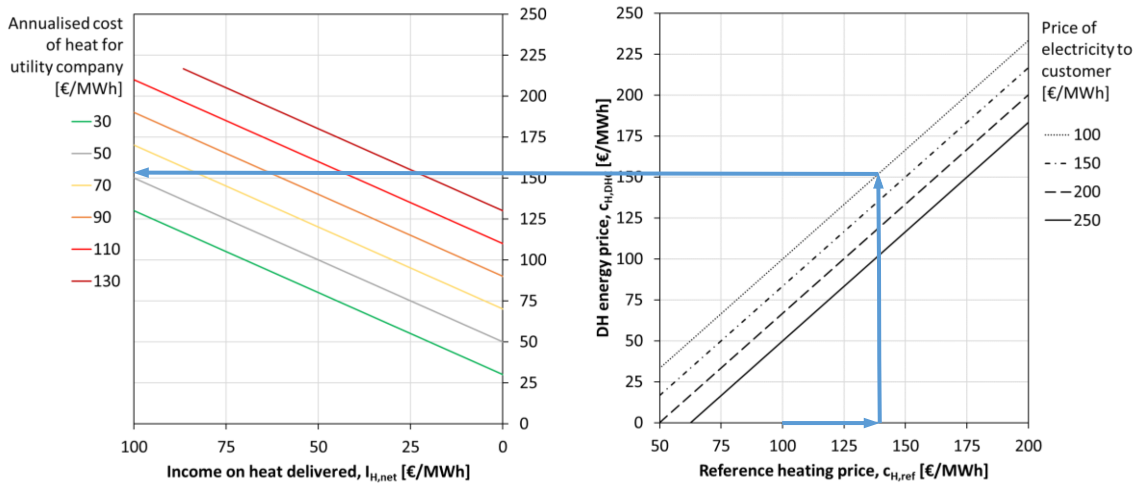


*Figure 13 – DH energy maximum price to the customer based on heat pump SCOP at building = 4, electricity specific cost = 100 €/MWh*

The cost of the thermal energy provided from the network to the house substation (left column "network side") is 51 and 64 €/MWh, while the cost of the electricity is 33 €/MWh (once more parametrised to the MWh of thermal energy from the network to the substation). The same costs parametrised to the thermal energy provided from the substation to the building amount to about 38 – 48 €/MWh for the thermal energy and 25 €/MWh for the electric energy (right column "building side").

*Table 8 - LCoE of the waste heat delivered from the network. Electricity on the Utility Company*

| | | | | | | |
|---|---|---|---|---|---|---|
| Investment per kW | 800 | | €/kW | 1000 | | €/kW |
| Capacity | 20 | | kW | 20 | | kW |
| Maintenance | 2% | | -/year | 2% | | -/year |
| Investment Cost | € 16,000.00 | | € | € 20,000.00 | | € |
| Maintenance Cost | € 320.00 | | €/year | € 400.00 | | €/year |
| | | | | | | |
| interest rate | 8% | | - | 8% | | - |
| Investment Horizon | 10 | | years | 10 | | years |
| Annualised Investment | € 27,044.72 | | € | € 33,805.90 | | € |
| Annuity | 16.9% | | - | 16.9% | | - |
| | | | | | | |
| Operation hours | 3500 | | hours/year | 3500 | | hours/year |
| SCOP | 4 | | - | 4 | | - |
| Cost of electricity | 100 | | €/MWh | 100 | | €/MWh |
| | network side | building side | | network side | building side | |
| Cost of heat (Investment) | € 51.51 | € 38.64 | €/MWh | € 64.39 | € 48.29 | €/MWh |
| | | | | | | |
| Cost of heat (electricity) | € 33.33 | € 25.00 | €/MWh | € 33.33 | € 25.00 | €/MWh |

Summing heat harvesting, distribution and delivery to the final customers, the overall cost of heat provided from the network to the building substations can be calculated accounting for:

- Cost of energy harvest = 15 to 60 €/MWh
- Cost of energy distribution = 12 €/MWh
- Cost of energy delivery to houses = 84 to 97 €/MWh

therefore, it can vary between 111 €/MWh and 169 €/MWh (parametrised over the distributed energy). These values include already the revenues related to the installation of the substations (8% over 10 years), the electric energy driving the substation and the maintenance services offered by the network manager (utility company, ESCO, etc.).

This solution is well representative of ESCOs or Aggregators investing in the installation of the substations at customers' homes/offices, and offering a full service including energy delivery and systems maintenance. The ESCO or Aggregator would profit from the efficient operation of the plant and of optimised purchase of electricity from the grid and DH energy from the network.

If we compare the above costs with the 153 €/MWh maximum price to the customer, still margins (around 40 €/MWh) are possible in the best case, while a negative outcome is obtained in the worst case (see Figure 14).

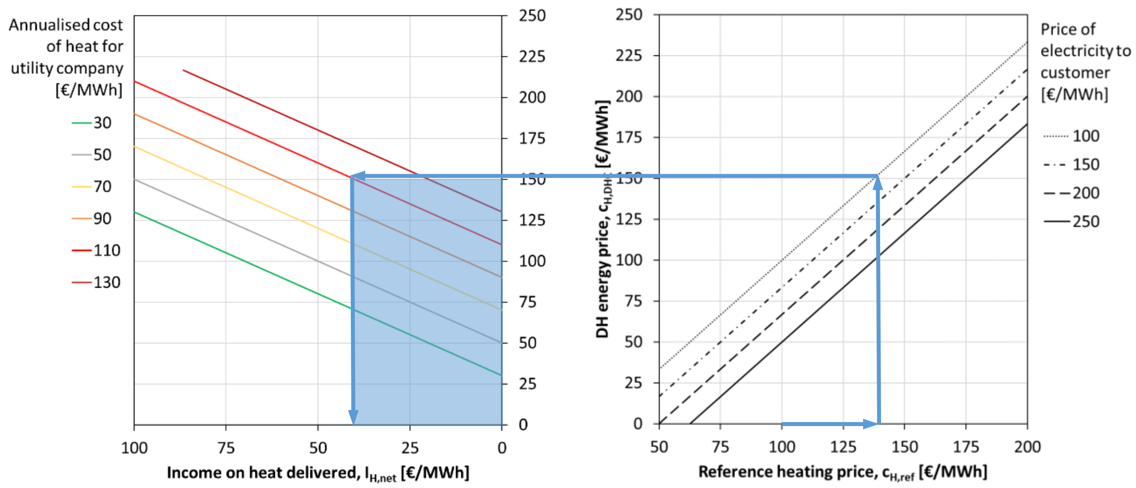


*Figure 14 - Revenues (on the x-axis) based on the annualised costs of energy harvesting and distribution (heat pump SCOP at building = 4, electricity specific cost = 100 €/MWh)*

Once more, the highest costs are related to the installation and operation of the substations at the building side. Slightly better performance can be obtained if the network temperature is increased compared to this simulation; still the trends remain unchanged. On the contrary, much better performance could be obtained by working on reducing the substation initial cost.

This can be done by means of industrialisation and prefabrication: a prefabricated substation that is standardised and manufactured in a factory to be plug-and-play mounted on site, can reduce the initial investment by 50%. In this case, the cost of delivering energy to the houses would shrink to around 60 €/MWh.

As it has been anticipated in the previous sections, harvesting affordable waste heat and renewable energy is also of utmost importance: the highest range of costs for energy harvest are hardly sustainable without any incentive scheme adopted.

### 4.2.2 Substation installed by the Utility Company – Investment costs on the building owner

This business case represents the minimum investment risk condition for the network manager. The building owner bears the overall investment, maintenance and electricity costs, while the network manager only takes care of the thermal energy delivery from the network to the substation. This clearly would be hardly satisfactory for a household owner but could be viable for example for a social housing company.

In this example, we consider that the investment is borne by the owner without any financing, which results in a considerably reduced annualised investment with respect to the previous case. In the above hypothesis the owner also directly manages the optimised acquisition of electricity from the grid, what could be possible again for large companies with relevance at local level.

The cost of heat decreases in this case to 57 - 62 €/MWh (parametrised over the building energy demand), which corresponds to 76 – 83 €/MWh of heat delivered from the network to the substation.

*Table 9 - LCoE of the waste heat delivered from the network. Electricity on the building owner*

| | | | | | | |
|---|---|---|---|---|---|---|
| Investment per kW | 800 | | €/kW | 1000 | | €/kW |
| Capacity | 20 | | kW | 20 | | kW |
| Maintenance | 2% | | -/year | 2% | | -/year |
| Investment Cost | € 16,000.00 | | € | € 20,000.00 | | € |
| Maintenance Cost | € 320.00 | | €/year | € 400.00 | | €/year |
| | | | | | | |
| interest rate | 0% | | - | 0% | | - |
| Investment Horizon | 15 | | years | 15 | | years |
| Annualised Investment | € 20,800.00 | | € | € 26,000.00 | | € |
| Annuity | 8.7% | | - | 8.7% | | - |
| | | | | | | |
| Operation hours | 3500 | | hours/year | 3500 | | hours/year |
| SCOP | 4 | | - | 4 | | - |
| Cost of electricity | 150 | | €/MWh | 150 | | €/MWh |
| | network side | building side | | network side | building side | |
| Cost of heat (Investment) | € 26.41 | € 19.81 | €/MWh | € 33.02 | € 24.76 | €/MWh |
| | | | | | | |
| Cost of heat (electricity) | € 50.00 | € 37.50 | €/MWh | € 50.00 | € 37.50 | €/MWh |

Summing all the cost contributions, the overall cost of heat delivered to the building substations accounts for:

- Cost of energy harvest = 15 to 60 €/MWh
- Cost of energy distribution = 12 €/MWh
- Cost of energy delivery to houses = 76 to 83 €/MWh

therefore, it can vary between 105 €/MWh and 155 €/MWh (parametrised over the distributed energy). Although investment costs are lower, electricity expenses are relevantly higher, thus resulting in outcomes similar to the ones presented in the previous section.

As a final consideration, when coupled with the "harvesting" case in 4.1.1 and 4.1.3, this solution would represent the case of a Utility Company that only bears the investment and maintenance costs for the installation and expansion of the network, while the integration of Producers and Prosumers would be mostly carried out by means of private financing (and eventual public incentives).

### 4.2.3 Substation installed by the Utility Company – Investment costs on the Utility Company – space cooling service provided

So far, we have considered the network being used to provide cooling/refrigeration services to large users such as supermarkets and datacentres, while only heating services have been considered for other customers like office and residential. When cooling loads for air-conditioning are covered by the network, three business cases can be identified:

1. Space cooling is offered as a commodity to the customer, who therefore pays the service to the network manager
2. Space cooling is provided for free to the customer: in this scenario, the air-conditioning service is seen as another useful heat source suitable to balance the network loads, but it is not one of the main network sources, thus it is "unnecessary"
3. Space cooling is remunerated to the building owner: the waste heat produced is seen as a needed heat source, as it is one of the main heat sources to the network, thus it is paid by the utility to the customer. This can be a realistic scenario in northern countries during summertime, when relevant cooling loads could counterbalance DHW production loads. Here compensation mechanisms could be set into place that partially discount the waste energy rejected to the network from the energy gathered by the substations.

As can be seen in section 6.1 of Deliverable 3.2, residential buildings cooling demand can vary largely depending on the specific climate between 7 and 40 kWh/m$^2$ of living area per year (London and Rome climates are considered here). If we consider the cooling season to last 3 months in northern countries (June to August) and around 4 months in southern ones (June to September), the DHW demand along the same periods is around 6 – 8 kWh/m$^2$ (25 kWh/m$^2$ yearly average DHW demand).

This shows as business case 1 is needed in southern countries if all customers connected to the network benefit of space cooling, since large cooling loads should be managed and covered at central level via chillers or geothermal sinks (i.e. water wells, rivers, boreholes, etc.). Models 2 and 3 can apply to northern countries where cooling loads somehow match DHW uses, or to southern locations if only part of the customers profit of space cooling services. The latter can be the case of a city quarter where a mixture of existing buildings (without scape cooling distribution) and newly built coexist.

The project FP7 iNSPiRe has calculated space cooling costs for a number of climates and technologies exploited (www.inspirefp7.eu – Deliverable 6.5): assuming multi-split units as the actually most exploited reference technology, seasonal performance factors (SPF) of up to 5 (related to state of the art, newly installed products) can be considered for the calculations. If we take the small multifamily houses with 45 kWh/m$^2$y heating demand assessed in Deliverable 3.2, which features a living area of 500 m$^2$ over 10 apartments, 3500 to 20000 kWh of space cooling yearly demand is calculated for the whole building. As multi-splits are normally connected to the main switch of the dwelling, electricity tariffs higher than dedicated to central plants are normally encountered: in the following scenarios, specific costs varying between 150 and 250 €/MWh of electric energy used are supposed. This results in energy bills for the whole building of:

- Northern countries = 105 to 175 €/y
- Southern countries = 600 to 1000 €/y

or in other words, the cost of space cooling ranges between 30 and 50 €/MWh; these values do not account for installation and maintenance costs, which are quite remarkable: annualised costs can range between 1000 and 1500 €/y over an investment horizon of 20 years that correspond to:

- Northern countries installation + maintenance = 280 - 430 €/MWh
- Southern countries installation + maintenance = 50 - 75 €/MWh.

This proves again that hardly cooling can be sold on the market as a commodity in northern countries, since investment and maintenance are significantly more expensive than electricity uses.

Table 10 and Table 11 report on the waste heat costs harvested in the business cases 2 and 3, assuming a seasonal performance of the substation equal to 6 as in section 4.1.1 The left side of Table 10 shows the heat cost when waste heat is gathered for free: as investment and maintenance has been already accounted for with respect to the heating service, here only electricity costs are considered. Parametrised over the waste heat recovered, the cost is lower than 15 €/MWh. If we assume that waste heat is worth up to 30 €/MWh, a remuneration to the building owner in the range of 15 €/MWh is still suitable (right side of Table 10).

*Table 10 – Space cooling costs based on different remunerations of the waste heat. 175 equivalent operation hours = 3.500 kWh. Electricity cost on network manager*

| | | | | | | |
|---|---|---|---|---|---|---|
| Operation hours | 175 | | hours/year | 175 | | hours/year |
| SCOP | 6 | | - | 6 | | - |
| Cost of electricity | 100 | | €/MWh | 100 | | €/MWh |
| | network side | building side | | network side | building side | |
| Remuneration | € - | € - | €/MWh | € 15.71 | € 18.33 | €/MWh |
| | | | | | | |
| Cost of electricity | € 14.29 | € 16.67 | €/MWh | € 14.29 | € 16.67 | €/MWh |

*Table 11 – Space cooling costs based on different remunerations of the waste heat. 175 equivalent operation hours = 3.500 kWh. Electricity cost on building owner*

| | | | | | | |
|---|---|---|---|---|---|---|
| Operation hours | 175 | | hours/year | 175 | | hours/year |
| SCOP | 6 | | - | 6 | | - |
| Cost of electricity | 150 | | €/MWh | 150 | | €/MWh |
| | network side | building side | | network side | building side | |
| Remuneration | € - | € - | €/MWh | € 30.00 | € 35.00 | €/MWh |
| | | | | | | |
| Cost of electricity | € 21.43 | € 25.00 | €/MWh | € 21.43 | € 25.00 | €/MWh |

When electricity costs are on the building owner, waste heat is truly gathered for free (Table 11, left). Once more a remuneration to the customer can be imagined as a suitable business case, to incentivise connecting to the network and rejecting heat during summertime, if needed in the specific DHC network.

Finally, Table 12 reports on a business case 1 example, where the small multifamily house requires 20 MWh of space cooling through the summer season (southern country case, the rejected heat amounts to 23.3 MWh with SCOP of the heat pump equal to 6). Also in this case, we consider only electricity costs, as investment and maintenance have been accounted for in the heating costs. If space cooling is worth 80 to 125 €/MWh (see previous page), the network manager can value the rejected heat harvested in the range of 68 to 107 €/MWh -space cooling value paid by the customer, parametrised over waste heat rejected to the network-; the electricity consumption amounting to about 14 €/MWh, the network manager can expect positive margins related to the space cooling service between 54 and 93 €/MWh.

*Table 12 – Margins on space cooling for an application in a southern region with 1000 equivalent operation hours = 20.000 kWh*

| | | | | | | |
|---|---|---|---|---|---|---|
| Investment per kW | 0 | | €/kW | 0 | | €/kW |
| Capacity | 20 | | kW | 20 | | kW |
| Maintenance | 0% | | -/year | 0% | | -/year |
| Investment Cost | € - | | € | € - | | € |
| Maintenance Cost | € - | | €/year | € - | | €/year |
| | | | | | | |
| interest rate | 0% | | - | 0% | | - |
| Investment Horizon | 15 | | years | 15 | | years |
| Annualised Investment | € - | | € | € - | | € |
| Annuity | 0.0% | | - | 0.0% | | - |
| | | | | | | |
| Operation hours | 1000 | | hours/year | 1000 | | hours/year |
| SCOP | 6 | | - | 6 | | - |
| Cost of electricity | 100 | | €/MWh | 100 | | €/MWh |
| | network side | building side | | network side | building side | |
| Price of space cooling | -€ 68.57 | -€ 80.00 | €/MWh | -€ 107.14 | -€ 125.00 | €/MWh |
| | | | | | | |
| Cost of electricity | € 14.29 | € - | €/MWh | € 14.29 | € - | €/MWh |

If all the buildings connected to the network are provided space cooling, part of the heat can be used to cover DHW loads. Summing waste heat harvesting, distribution and delivery back to the final customers, the overall cost of heat distributed from the network to the building substations can be calculated as:

- Cost of energy harvest = -54 to -93 €/MWh
- Cost of energy distribution = 12 €/MWh
- Cost of energy delivery to houses = 84 to 97 €/MWh

This clearly improves the business case reported in section 4.2.1 as the overall cost of the energy delivered back to the building is in the range of 16 to 42 €/MWh. However, this is only valid with respect to the about 3.5 MWh of DHW demand needed during summertime, which in turn requires about 2.6 MWh of energy drawn from the network (heat pump SCOP equal to 4 as in previous sections).

In other words, in this scenario around 10% of the rejected heat harvested from space cooling, can be conveniently exploited to cover DHW loads. Therefore, either space cooling is offered only to a lot of customers suitable to conveniently balance DHW loads over the network, or the excess heat is rejected at central level.

The first instance is ideal but seemingly it produces contractual issues, since heat harvest from other sources necessary during winter and swing seasons (supermarkets, datacentres, etc.) should be interrupted over summer. Moreover, it requires that enough thermal storage is installed as to match space cooling to DHW loads over a day period.

On the contrary, reasonably, rejected heat from space cooling can be used to partially balance DHW loads with fixed network distribution temperature or to higher the network temperature in order to produce optimised substations COPs. The rest needs to be in any case rejected: referring once more to Deliverable 3.2 (section 6.2), the cost of installing and operating a central chiller is about 20 €/MWh. If the costs for setting up and operating a geothermal field or a water well are considered in the heating service, these heat rejection solutions are even cheaper, since only electricity consumption for pumping needs to be counted.

Despite the central heat rejection solution, business models contemplating space cooling to households are meaningful both in northern and in southern countries, since the cost of the service is lower than using multi-split units for the same purpose. Moreover, part of the heat harvested can be used to balance DHW loads.

# 5 Conclusions on FLEXYNETS-TRADING strategies

The business model scenarios analysed in the previous section, although far from being exhaustive, try to illustrate how economically viable (incentives are disregarded on purpose in these calculations) gathering waste heat and renewable energy into 5th generation DHC network is.

Depending on the temperature levels of energy source and network, the cost of energy made available can vary largely (factor 2). Moreover, better performance is obtained if the utility company managing the network also provides electricity to the single substations: in this case, customers handle only one contract covering their heating and cooling uses, while the specific electricity price is lower than what the single customer can negotiate.

As limited investments are involved in connecting substations to the network, business cases can be defined where private producers/prosumers invest. In principle, the utility company can be owner of the main network, while substations are all private owned. In these scenarios, when large waste heat providers (e.g. supermarkets, data centres, etc.) are accounted for, the cost of the heat exchanged with the network is higher and public incentives are needed to make waste heat as economically attractive as conventional technologies.

Heat costs in the range of 15 to 40 €/MWh are calculated in the most suitable cases of waste heat recovery. The same values are met with respect to renewable heating through geothermal/ground water and direct solar thermal energy integration.

The largest portion of heat cost to the final office or household customer is related to the substations connecting the network to the single buildings. Here additional costs in the range of 75 to 100 €/MWh can be achieved. Adding distribution costs of around 12 €/MWh on top results in overall final costs of energy between 100 and 150 €/MWh. The first value is competitive with traditional gas heating and conventional district heating networks.

Space cooling offered as a commodity or allowing to gather rejected heat for free during summertime is suitable both in northern and southern countries. Waste heat from single households is a viable solution to partially balance DHW loads, while heat rejection of the excess heat at central level is more convenient than with conventional, market solutions (e.g. split units).

This analysis can be repeated with respect to specific business cases as an easy-to-use tool during the decision-making phase, when profitability of a new substation connected and tariffs are decided. However, it can be used also to derive policies introducing incentives on renewable/waste thermal energy used in a district heating network. TRADING rules/tariffs have a strong connection with network control, therefore the same analysis can be used dynamically within a trading software to take timely decisions in terms of what temperature is best to be maintained, when electricity is to be used and thermal energy stored or deliver to users.

# 6 Literature references


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