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Background report on best practices and informal guidance on installation level CBA for installations falling under Article 14(5) of the Energy Efficiency Directive

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Abstract
Background report on best practices and informal guidance on installation level CBA for installations falling under Article 14(5) of the Energy Efficiency Directive
This report provides guidelines how thermal electricity generation installations and industrial installations can carry out a cost-benefit analysis in order to assess whether the use of high-efficiency cogeneration, the connection to a district heating or cooling network or other means of waste heat recovery would be cost-effective.

Table of Contents

List of figures

List of tables

List of abbreviations and definitions

CA	comprehensive assessment of national heating and cooling potentials;
CBA	Cost Benefit Analysis;
CDD	cooling degree days;
CSWD	Commission Staff Working Document;
DH/DC	district heating and cooling;
CHP	Combined heat and power
EED	Energy Efficiency Directive;
HDD	heating degree days;
MS	member states;
NPV	Net Present Value

Introduction

The Energy Efficiency Directive (EED), adopted on 4 December 2012, establishes a set of binding measures to help the EU reach its 20% energy efficiency target by 2020. Under the Directive, all EU countries are required to use energy more efficiently at all stages of the energy chain from its production to its final consumption. Member States were required to translate the EED into national law by 5 June 2014. The EED repeals the existing Cogeneration Directive (2004/8/EC) and the Energy End-Use Efficiency and Energy Services Directive (2006/32/EC) as of 5 June 2014.

Article 14(5) of the EED requires Member States to ensure that thermal electricity generation installations and industrial installations exceeding 20 MW_{th}, carry out a cost-benefit analysis when they are planned or substantially refurbished to assess whether the use of high-efficiency cogeneration, the connection to a district heating or cooling network or other means of waste heat recovery would be cost-effective. The obligation to carry-out a cost-benefit analysis also applies to new district heating and cooling networks, when those are planned or when an energy production installation with a capacity exceeding 20 MW_{th} is planned or substantially refurbished within those networks, in order to assess whether the utilisation of waste heat from a nearby industrial installation is cost-effective. If the benefits exceed the costs, the options analysed in the cost-benefit analysis must be included in the authorisation or permit criteria.

The cost-benefit analysis has to be in accordance with the general methodological principles set out in Part 2 of Annex IX. A possible methodology for conducting a Cost Benefit-Analysis (CBA) in accordance with Article 14(5) and Part 2 of Annex IX of the Energy Efficiency Directive is presented here. The methodology takes into account the Guidance note prepared by the Commission for the implementation of Article 14, including the carrying out of the cost-benefit analysis by individual installations and district heating and cooling networks (SWD(2013) 449)[1].

Chapter 1 explains all concepts and methods available for the identification of necessary elements for the conduction of a Cost benefit analysis in the meaning of Part 2 of Annex IX for individual installations.

Chapter 2 provides generic informal guidance and case specific instructions on how to apply the described methodology for the various cases described.

Chapter 3 discusses similarities and differences of this study with the Comprehensive Assessment (Article 14(1-3)) and how the Comprehensive Assessment could establish exemptions for installations from the CBA obligation in the sense of the second sub-paragraph of Article 14(4).

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[1] Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52013SC0449&from=EN.

1 Overview and analysis of the methods and best practices on how to best carry out CBA for the cases described in Article 14(5)

1.1 Definition and description of cases where a CBA is required

The principles and requirements for the installation-level CBAs are given in Articles 14(5) and 14(7) and in Part 2 of Annex IX. According to the EED as of 5 June 2014, Member States must ensure that electricity generation and industry installations and district heating production installations will carry out an installation-level CBA on the use of high-efficiency cogeneration and/or the utilisation of waste heat when they plan to build or refurbish capacities above 20 MW_{th}. The outcome of the CBA must be taken into account in the criteria of authorisation and permit issued for new and refurbished installations and for district heating and cooling networks. The CBA obligation, or if an exemption from the CBA obligation is applied according to Article 14(4) second sub-paragraph, the exemption conditions must be defined in the procedure of issuing authorisations or permits.

Article 14(5) of the Directive requires that a CBA be carried out in four particular instances occurring after the 5th June 2014. These instances are:

- Article 14(5)(a), A new thermal electricity generation installation with a total thermal input exceeding 20 MW_{th}[2] is planned;
- Article 14(5)(b), An existing thermal electricity generation installation with a total thermal input exceeding 20 MW_{th} is substantially refurbished[3];
- Article 14(5)(c), An industrial installation with a total thermal input greater than 20MW_{th} generating waste heat at a useful temperature is either planned or is substantially refurbished. The purpose of the CBA is to assess the costs and benefits of utilising the waste heat to satisfy economically justified heat demand, including through cogeneration or connection of the installation to a district heating/cooling network;
- Article 14(5)(d), A new district heating/cooling network is planned, or an existing network has an energy production installation with total thermal input exceeding 20 MW_{th} that is planned or

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[2] Member States are allowed to follow their own national definitions of what total thermal input exceeding 20MW means, taking into account their definitions established under relevant European law, in particular the Industrial Emissions Directive (2010/75/EU), the EU Emissions Trading Directive (2003/87/EC) and the Electricity Directive (2009/72/EC).

[3] Article 2(44) of the Directive states that substantially refurbished means ‘a refurbishment whose cost exceeds 50 % of the investment cost for a new comparable unit.’

undergoing substantial refurbishment. The purpose of the CBA will be to assess the costs and benefits of utilising the waste heat from nearby industrial installations.

These cases are summarized in Figure 1. It can be seen that the CBA performed has a different purpose for each case. This CBA will be activated and performed by the operator of the plant when there is a plan for a new industry or for a substantial refurbishment (>50% of the original capital investment).

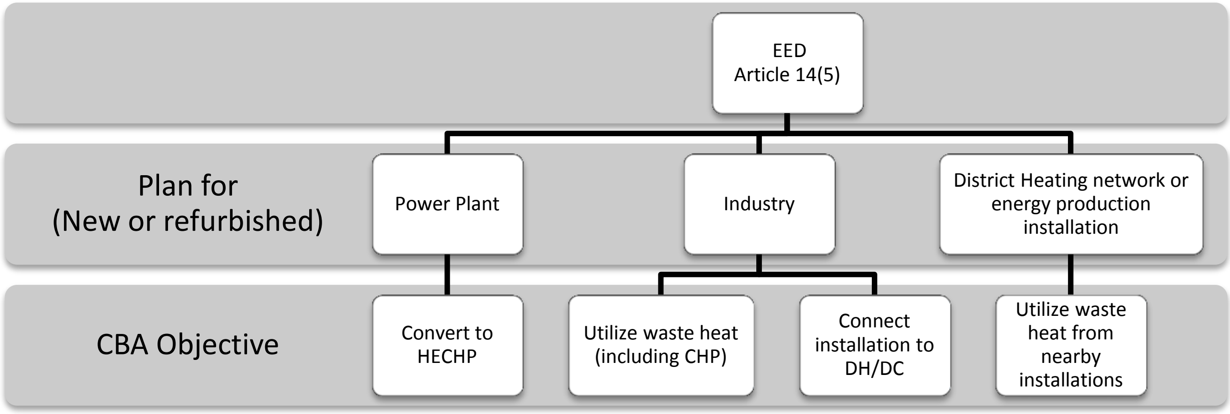

Figure 1. Summary of CBA obligations according to Article 14(5).

The directive further specified that Member States may exempt installations from carrying out a CBA in the following situations:

- those peak load and back-up electricity generating installations which are planned to operate under 1,500 operating hours per year as a rolling average over a period of five years, to be calculated using a verification procedure defined by the Member State[4];
- nuclear power installations[5];
- installations that need to be located close to a geological storage site approved under Directive 2009/31/EC[6];
- only for industrial installations or existing or planned district heating schemes, if a Member State defines 'thresholds, expressed in terms of the amount of available useful waste heat, the demand for heat or the distances between industrial installations and district heating networks'[7];

[4] Article 14(6) (a)

[5] Article 14(6) (b)

[6] Article 14(6) (c)

[7] Article 14(6) (d)

- if the national or regional/ local comprehensive assessment referred to in Article 14(1) determines certain areas of the country/ region/ locality that are not suitable for high-efficiency cogeneration and/or efficient district heating[8].

From a thermodynamic perspective Article 14(5) concerns two heat sources (power plant, industrial installations) and one heat sink (district heating). In the first two cases an "economically justifiable demand" (as defined in Article 2(31)) is necessary for the consideration of any alternative scenario that will improve energy efficiency.

Based on the above definition Article 14(5) differentiates the CBA between two broader categories that have to be analysed seperately. They can be generalized as follows:

- A: The CBA is for a heat source that recovers or transforms energy and transfers it to alternative sinks (14(5a-c));
- B: The CBA is for a heat sink (i.e. a distric heating network) that utilizes energy from alternative sources (14(5d)).

Despite the fact that both categories share many common elements (e.g. heat link) the scope is different ; the latter case is the inverse of the former. This explains that the methodology will consider certain factors as benefit in one case and as a cost in the other case

1.2 Identification of available waste heat

In this section a methodology for identifying and quantifying the potential waste heat is proposed for an individual power plant or industry installation (14(5a-c)). It is important to estimate this potential as it affects the results of the CBA as follows: Firstly, the waste heat recovered or transformed is effectively the 'product' that will cause the revenue flows. Secondly, the identification of this potential is necessary to determine the design and size of the necessary heat recovery equipment and consequently the capital costs.

At this point, it should be emphasized that the terms “excess” or “waste” heat are often misused. In particular, what is commonly regarded as waste heat could be often partially recovered by proper retrofit of the heat recovery systems [1]. For this report the term “waste heat” suggests that there is an excess of heat available from a process due to non-ideal heat recovery and that such heat is often at sufficiently high temperature to be used internally or to be exported as district heating. The feasibility and the selection of the above depend mainly on economic criteria. Internal vs

[8] Article 14(4) (a)

external recovery of heat is debated a couple of times in literature [2] and will be addressed in this section.

1.2.1 Power Plants

The main objective of the CBA in a new or substantially refurbished power plant is to assess the costs and benefits of converting it to high efficiency CHP, that is to meet the criteria laid down in EED Annex II[9]. According to those criteria, the cogeneration production should aim to achieve primary energy savings of at least 10 % compared with the separate production of heat and electricity reference technologies.

By design, thermal power plants try to maximize electricity production by utilizing as much energy content from the hot stream as possible (steam, gas). From a thermodynamic perspective this means that the only available waste heat is dissipated at near-ambient temperature levels as the rest of availability (also known as exergy) is converted to useful work and consequently to electricity. Potential applications for the direct use of this 'low value' heat (20 – 30 °C) could be the following [3]:

- greenhouses (~ 2 MWth/10000m^2);
- production of exotic fruits (2 MWth/10000m^2);
- Sport and leisure centers (0.2 MWth/facility);
- tropical greenhouses (2.5 MWth/facility);
- fish farms (0.2 MWth/400m^3);
- drying of scrap wood (10 MWth/(100,000 m^3 timber/year)).

Usually, it is uncommon to have sufficient demand for this type of waste heat nearby a power plant in order to exploit it economically. Some typical applications that cover a wide range of the temperature spectrum are presented in the so called Lindal diagram (see Figure 2) [4]. This diagram depicts the application temperature of several uses of heat ranging from fish farming and soil heating at low temperatures, through space heating and drying at intermediate temperatures, to industrial processes. The original Lindal diagram referred to direct use of geothermal heat but it can be generalized to illustrate the potential applications for any kind of waste heat.

For the utilization of the waste heat to higher temperature applications and consequently the conversion of the plant to high efficiency cogeneration, the heat has to be 'converted' to higher

[9] Article 2(34)

quality. In the following sections it is shown how this can be achieved and what the impact to the plant is.

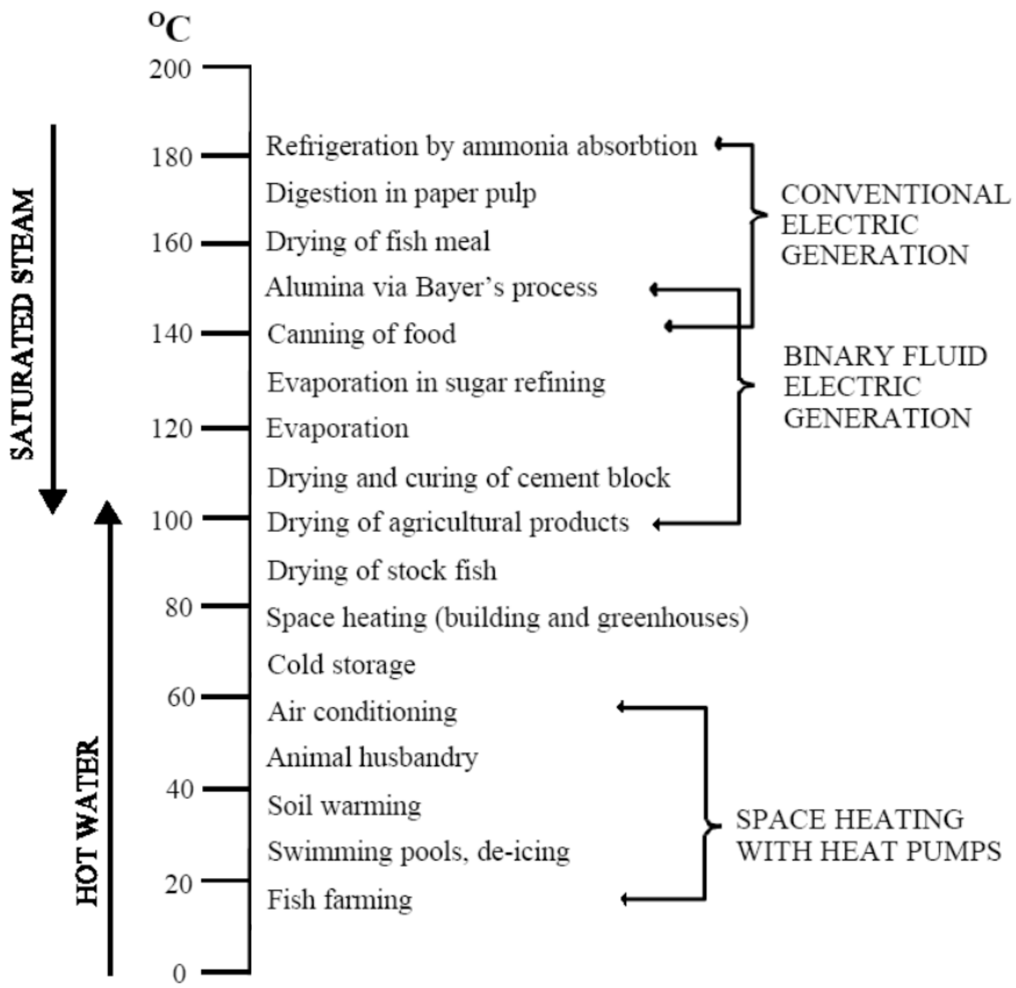

Figure 2. The Lindal diagram, showing the maximum required temperature of most common uses of heat.

1.2.1.1 Description of centralized cogeneration plants

The application of cogeneration technology and feasibility depends on the type of the plant. Among all cogeneration plant technologies that are described in Annex II of the EED the following technologies have been identified to be applicable for the scope of the Article 14(5).

- Steam cycle plant;
- Combined cycle plant;
- Open gas cycle plant.

Internal combustion engines, fuel cells, Stirling engines and other technologies described in Annex II of the EED usually are not commercially available at the defined threshold size (20 MWt). Open gas cycle plants are not used for base load and will fall most of the times in an exemption category of Article 14(6) due to low capacity factors (<1500 hours).

In the case of a steam-based cogeneration plant, the conversion of a power plant to combined heat and power plant is by proper modification of the steam turbine. Most piping and instruments (e.g. gearbox, electric generator, condenser, steam and condensate piping, lubrication and cooling systems, water-treatment system, electrical interconnection equipment and controls) will be similar to that of the reference plant with few modifications and with the addition of heat exchangers. The most common steam turbine configurations within a standard power generation cycle are the following:

- **Condensing steam turbines** (Figure 3a): Steam turbines used for non-CHP applications which condense the steam at sub-atmospheric pressure so as to gain the maximum amount of work from it ;
- **Extraction/condensing turbine** (Figure 3b)**:** Steam is extracted from the turbine at some intermediate pressure. This steam can be used to feed an external process. The remaining steam is expanded further and condensed like in a condensing turbine;
- **Non-condensing (back pressure) steam turbine** (Figure 3c): Steam is expanded over a turbine until a predefined pressure and the exhaust steam is used to meet the facilities steam needs. It is typically used in industry which often requires high temperature heat and continuous process steam and no need for flexible operation.

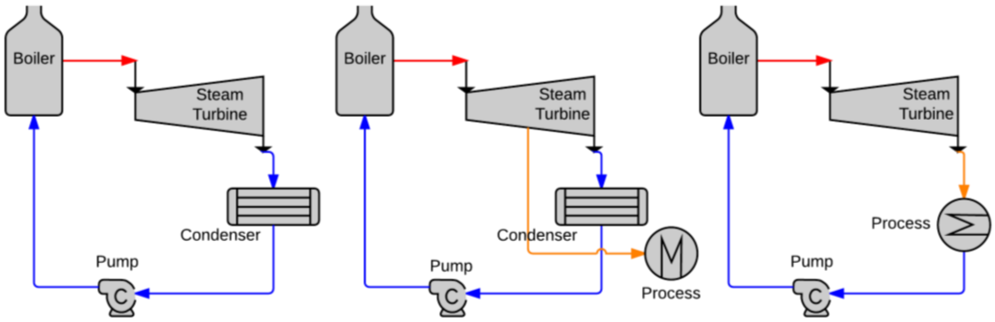

Figure 3. Simplified scheme for (a) power plant steam cycle (b) CHP with extraction-condensing turbine (c) CHP with backpressure turbine.

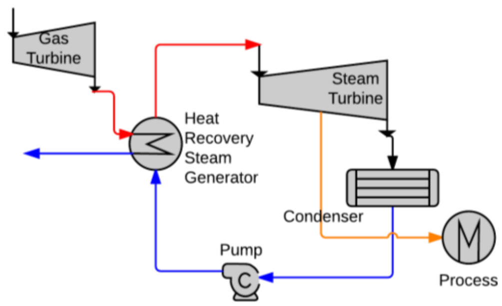

Figure 4 Simplified scheme for a CHP combined cycle plant with extraction condensing turbine

Waste heat from a steam turbine (either collected through the exhaust or from extraction), can be used for space heating or cooling or in any other industrial process.

In the case of a combined cycle cogeneration plant CHP is similar to simple steam cycle plants (Figure 4). Steam turbines are a part of a "combined cycle" process. In these processes, waste steam from an electricity producing process (i.e. waste steam produced by a gas turbine) is run through a steam turbine to produce more electricity. The latter can be modified in the ways described above in order to further utilize the heat available.

In the case of open cycle gas plants the exploitation of waste heat is done either by installing a waste heat recovery generator (heat exchanger) on the turbine exhaust. However the size and operation schedule of such plants do not fall into the required specifications of Article 14. Most of the times conversion of a gas cycle power to CHP will also involve the installation of a steam turbine converting it essentially to a combined cycle plant.

It is clear from the above that in most cases a CHP power plant falling in the categories of Article 14(5) will be based on steam turbines. Steam turbines can be used with a boiler firing any one or a combination of a large variety of fuel sources, or they can be used with a gas turbine in a combined cycle configuration. Typical techno-economic values of such plant are presented in Table 1.

Table 1. Typical techno economic data for a steam turbine cogeneration plant [5, 6].

Capacity range	50 kW – 500 MW
Fuel used	Any
Efficiency electrical (%)	7 – 20
Efficiency overall (%)	60 – 80
Power to heat ratio	0.1 – 0.5
Output heat temperature (°C)	Up to 540
Noise	Loud
CO_2, NOx emissions	Depend on fuel source of steam
Availability (%)	90 – 95
Part load performance	Poor
Life cycle (year)	25 – 35
Average cost investment (€/kW)	1000 – 2000
Operating and maintenance costs (€/kWh)	0.004

1.2.1.2 Thermodynamic estimation of CHP performance

The "waste heat" is a thermodynamic limit of any power station: for the power station to work and maximize its work output, this near-ambient-temperature heat must be delivered to a near-ambient temperature place (the heat sink). The higher the temperature difference between the top temperature and the sink temperature of the thermodynamic cycle, the more efficient the electricity production process will be. Converting a power plant to high efficiency CHP installation, from a thermodynamic point of view increases the overall efficiency or more accurately the thermal utilization. Some of the waste heat that is dissipated to the environment at almost ambient temperature is now converted to useful heat, substituting conventional generation plants.

However, the increased efficiency comes with a cost. The steam extracted from the turbine causes a drop in power generation which is strongly dependant on the extracted steam temperature, relative steam mass flow extracted and coupling configuration. The power lost is the difference between the power output of the reference plant (W_{ref}) and the power output of the cogeneration plant (W_{CHP}) by means of:

$$\Delta W = (W_{ref} - W_{CHP}) \approx \dot{m_{chp}}(h_{steam} - h_{cnd})$$

where m_{chp} (kg/s) is the massflow of steam entering the turbine, h_{steam} (kj/kg) and h_{cnd} (kj/kg) is the enthalpy of the extracted steam and the steam after the turbine exhaust respectively. The latter equation gives a very good approximation of the electricity production potential of the extracted steam. Figure 5 shows the energy balance of a typical power plant before and after the conversion to cogeneration.

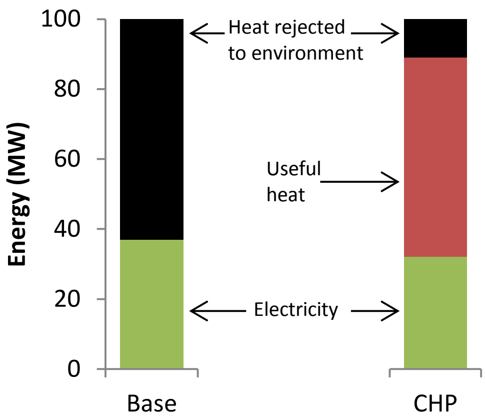

Figure 5. Energy balance of conventional and cogeneration power plant.

The described system can be seen as a virtual heat pump where heat is upgraded from low to high quality at the expense of electricity [7]. In order to simplify the preliminary economic evaluation of such plants it is usually common practice to adopt a metric which is similar to the coefficient of performance (*COP*) used in the evaluation of heat pumps. In the literature this is known as z-ratio and defined as follows [8]:

$$\mathrm{z-ratio(Temperature)} = \frac{\text{Heat extracted at the required temperature}(MW)}{\text{Electricity lost }(MW)}$$

This *z-ratio* is a function of the required temperature. The higher the temperature, the smaller the z-ratio is going to be since the potential of electricity production of the extracted steam will be higher. The temperature selection depends entirely on the requirements of the application that is going to be coupled with. Another expression of the z-ratio could be its reciprocal, sometimes called *power loss ratio;* it corresponds to the electric efficiency that the extracted heat would have if it was 'converted to electricity' e.g. a power loss ratio of 10 % implies that for each 100 MW(t) extracted the net nominal power output is decreased by 10 MW(e). For low extraction temperatures (~100 °C) this ratio is very close to the Carnot efficiency between the extraction and the ambient temperature. Figure 6 shows some typical values of this ratio for a conventional reheat steam cycle plant [9].

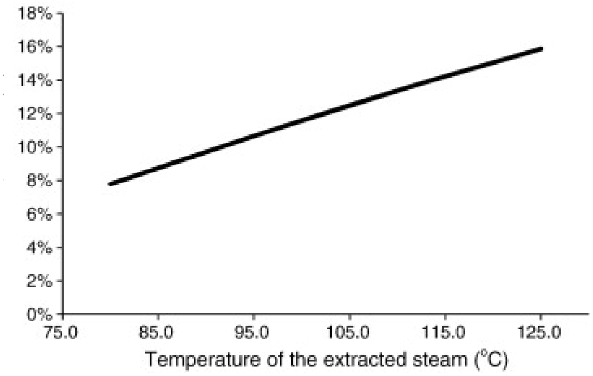

Figure 6. Typical values for the power loss ratio.

This ratio will be used to estimate the operating penalty to CHP performance and consequently the costs compared to the reference plant since the reduced electricity output will have an impact on the revenues of the power plant.

Depending on the temperature required the point of extraction from the steam turbine will be selected. The most suitable option to be examined in most cases in the context of Article 14(5a-b) is the use of extraction/condensing turbine. This is due to the fact that one of the most suitable applications to be coupled with a power plant is district heating or cooling networks. These networks require big amount of energy in relatively low temperatures with flexible operation due to high seasonality.

Contrary to industrial processes that usually require latent heat in a specific temperature a district heating network operates within a bigger range of sensible heat[10]. Common values of operation are: supply ~120–80 °C, return ~50°C[11] In this case an extraction of steam from multiple points of the low pressure turbine is usually recommended, see Figure 7. Thereby, the availability of steam is further exploited since lost electricity is reduced compared to a single extraction point.

[10] Sensible heat is the heat exchanged that causes a temperature rise or decline on the target fluid. Latent heat is the heat exchanged that causes a phase change (e.g. evaporation, condensation etc) on the target fluid.

[11] In the future with the development of more advanced systems lower supply temperatures (~50-60°C) can be considered [10].

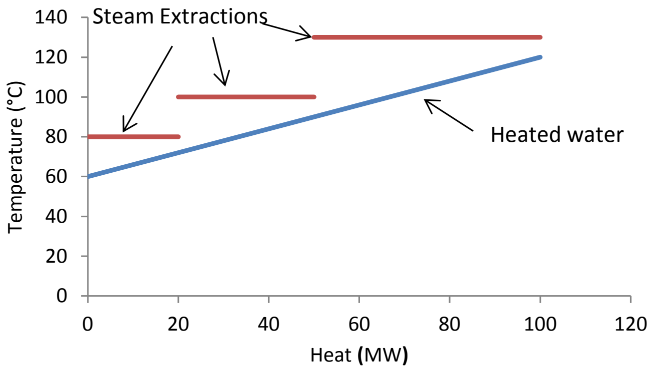

Figure 7. Example of coupling a steam turbine with DH network.

In some limited retrofitting cases and when the technical specifications of the power plant allow it, it is possible to design the plant to have the same electrical output with the reference case and 'balance' the electricity penalty by increasing the thermal output. However this usually involves some extra technical challenges since the plant will have to operate above the designed capacity. When comparing an imaginary single-purpose reference plant with a cogeneration plant in order to estimate its incremental cost and benefits, it is recommended to use the first approach, since it is less likely to be misapplied.

The z-ratio along with the part load operation curve describe the feasibility of the operation that constraints the amount of heat that can be extracted. Possible combinations of power and heat production are feasible inside this envelope which is shaped according to the design specifications. It can be seen that such CHP plant can have a flexible operation and a variable heat to power ratio according to the demand needs.

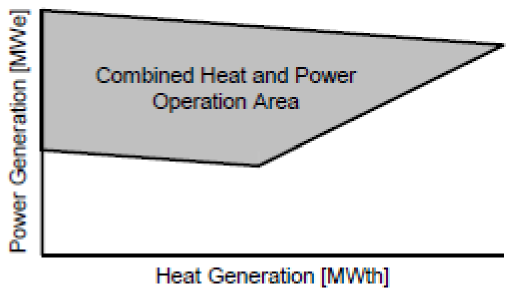

Figure 8. Operational feasibility envelope of a CHP plant with an extraction-condensing steam turbine.

1.2.2 Industrial Installations

The objective of the CBA according to 14(5c) is to identify waste heat available in industries and to assess the cost and benefits of:

- Utilizing the waste heat including CHP technologies if necessary
- Transferring waste heat to a DH network

The identification of the technical potential in industries contrary to the power plants described in the previous section is very site specific. In order to estimate the technical potential for heat recovery from industries on a national level the best available estimates for the fraction of total input energy contained in the exhaust gases have been used [11]. The investments for conversion of specific industrial processes to CHP depend not only on the type of the process but also on the technology applied. These investments cannot be defined without detailed descriptions of the processes [12].

Indicatively, energy efficiency investments in industries can be prioritized in the following order according to their capital costs [13]:

1. Direct use of heat (only requiring piping/ ducting, usually within the same process).
2. Onsite heat transfer using a heat exchanger.
3. Provide chilling using an absorption chiller, for use on-site.
4. Upgrade the heat, for use on-site, using a heat pump.
5. Generating electricity.
6. Export heat for use off-site.

However this does not imply that the order based on the net present value of such investments will be similar, since it is very much dependent on market conditions and relevant policies (prices of competing fuels, marginal prices of energy, feed-in tariffs and other incentives etc.). From this list it can be observed that any energy efficiency investment for internal recovery and utilization of waste heat (first 5 points of the above list) will be most of the times more economically efficient than any attempt of exporting the heat off-site. The economic efficiency also depends on the distance to the off-site demand point(s) and the amount of heat involved. However, in terms of energy efficiency, recovering and utilizing the energy onsite will be always better than using it off-site.

The nature of the above two categories of CBA will be completely different. In the first case (internal recovery), the energy savings are translated to reduced operational costs for the installation. In the second case there will be extra revenues from selling an extra "product" to a new market. In this report according to the objectives of Article 14(5c), it is necessary to focus on the latter while identifying the part of waste heat that is available for internal recovery.

1.2.2.1 Available waste heat sources

Many industries need high temperature heat for a variety of purposes, from melting metals, to making cement at the very high temperature end, ranging down to food processing, brewing and pharmaceuticals and calcium silicate brick/block manufacture which may require low temperature and pressure steam, i.e. temperatures just above the boiling point of water. Often the products – iron, cement, food, medicine etc. – will require cooling at some point, and this inevitably involves the rejection of this heat to the environment. This ultimately can be, for example, via a fan coil unit (a device similar to a very large car radiator), or heat exchangers placed in rivers or sea water, or cooling towers where water is evaporated to provide this cooling [8].

Evaluating the feasibility of waste heat recovery requires characterizing the waste heat source and the stream to which the heat will be transferred. This can be accomplished by reviewing the process flow sheets, layout diagrams, piping isometrics etc. Important waste stream parameters that must be determined include [14]:

- heat quantity;
- heat temperature;
- chemical composition, which could set other constraints, such as corrosion occurring in recovery devices etc.;
- minimum allowed temperature, and;
- operating schedules, availability of space, and other logistics.

Major industries that have individual processes with available waste heat in different qualities are presented in Table 2. However, this does not imply that all of there will be waste heat available on an industry level, since most of it is often already recuperated on site.

Table 2. Typical range of waste heat temperatures from different processes in the following industries.

Industry	Gas >250 °C	Liquid >90 °C	Steam/Vapour
Cement	X		
Glass	X		
Oil & Gas	X	X	X
Chemicals	X	X	X
Steel / Non Ferrous	X	X	X
Pulp & Paper			X
Food		X	X
Waste treatment	X	X	
Thermal Oxidizers	X		

More specifically, waste heat sources available in industries can be categorized as follows [14]:

- Combustion Exhausts:
    - Glass melting furnace;
    - Cement kiln;
    - Fume incinerator;
    - Aluminum reverberatory furnace;
    - Boiler.
- Process off-gases:
    - Steel electric arc furnace;
    - Aluminum reverberatory furnace;
    - Drying & baking ovens.
- Cooling water from:
    - Furnaces;
    - Air compressors;
    - Internal combustion engines.
- Conductive, convective, and radiative losses from equipment:
    - Hall-Hèroult cells (no commercially available recovery technique).

- Conductive, convective, and radiative losses from heated products:
    - Hot cokes;
    - Blast furnace slags (no commercially available recovery technique).

This report will only focus on the first three categories which incorporate a stream (air or liquid) coming out of a process. Other unconvential equipment that could be used in some processes to capture conductive, convective, and radiative losses is not expected to result in a big amount of waste heat recovery that could be used for the purposes of Article 14(5). A methodology for identifying the available heat source in an industry is presented in the following section.

1.2.2.2 Identification of useful waste heat

The first step is the identification and quantification of waste heat available that is of sufficient quality to supply the desired heat sink (i.e. a district heating network) and that cannot be utilized in any other on-site process. Identification of useful waste heat in industries usually depends on the type of the processes used in each sector and more specifically on the heat/temperature profile of any industrial plant/site. There are available best practices per sector but it would be useful to describe a systematic approach that can be used for the estimation of waste heat on an industry level.

Pinch Analysis can be used for quantifying the avoidable and unavoidable part of industrial waste heat [15]. It is based on thermodynamic principles examining an industrial site as an integrated energy system. It has already been used for the identification of the potential and economic feasibility of district heating delivery using industrial waste heat from a petrochemical industrial cluster [1].

Annex 5.1 summarizes the methodology and give advices for its application and references for further information. The main result of this method is a graph which corresponds to the temperature-energy profile of the whole industrial site after a system-level integration of all processes and streams based on their quality and quantity. Based on that, the following three aspects can be identified:

- Usable waste heat potential for off-site use
- Potential for installation of heat engines (CHP)
- Potential for installation of heat pumps for internal recovery of energy

1.3 Description of the system boundary

Heat recovery/transformation equipment installed in a power plant or an industry is used to offer energy products to satisfy a heat demand external of the site perimeter. A justifiable demand can be any individual consumer of thermal, electrical or cooling energy, a district heating/cooling network or the electricity grid.

On the same sense, a district heating network can receive heat or cooling energy by any means from a source that does not necesarilly belong in the distribution network. A supply can be a CHP plant, an industry or a dedicated heat plant.

The system boundary will be used to define the system and identify the costs and benefits. Since it will differ for each case it is presented in Figure 9. The system analysed will include the main plant with its modifications and the heat link. The remote supplier/receiver of the energy product interacts with the defined system but it is outside of the boundary and thus not analysed in the CBA.

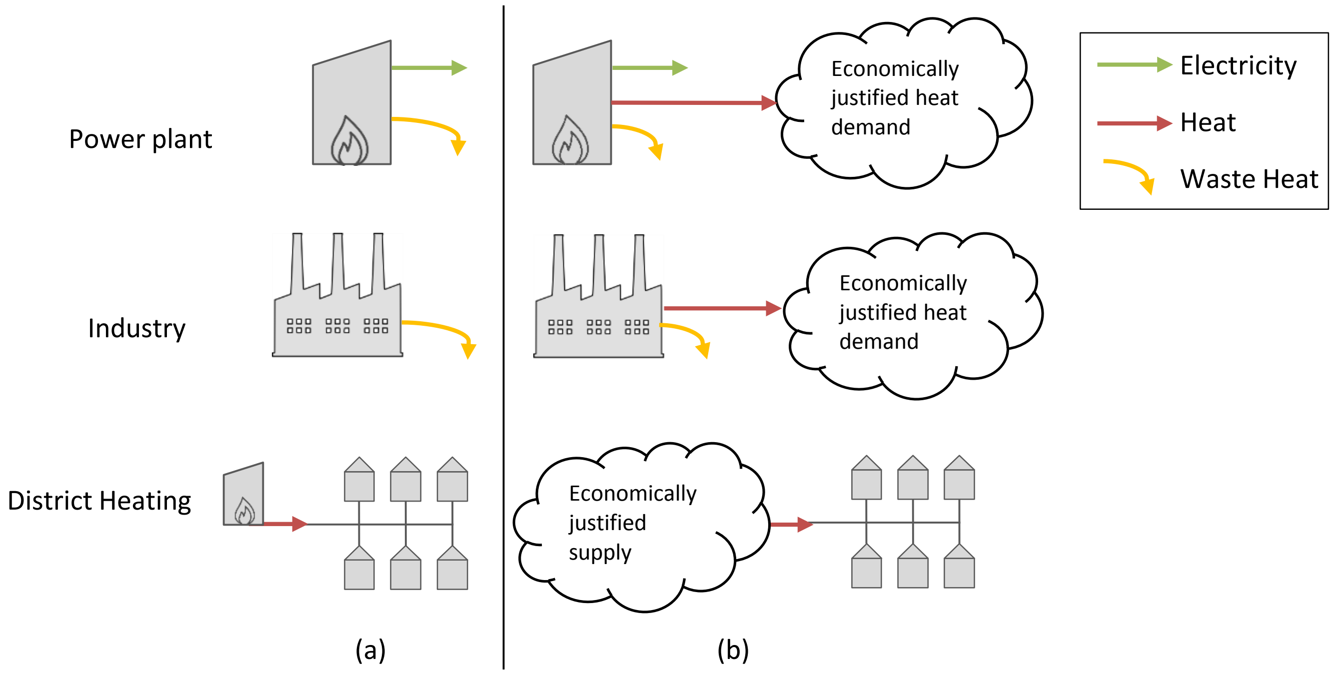

Figure 9. System boundaries for (a) Reference case and (b) Examined case.

1.4 Establishing the heat link

It should be prevalent from the previous sections that in all cases described in Article 14(5) there is a link between a source and a sink. This will be an important element of the CBA since the cost effectiveness of heat linking and consequently of the whole project will be dependent upon the quantity of heating/ cooling demanded and the distance over which the heating/ cooling will have to be supplied.

The search of an appropriate heat demand/supply will have to be done within a predefined threshold. This threshold will be based on the maximum feasible transfer distance which is a function of several factors: site-specific parameters (quantity and quality of heat), market conditions (electricity and heat price), climate data (ambient temperatures, heating season etc.) and design data (pipe material, diameter and efficiency of its insulation). According to Article 14(6), Member States can define exemption thresholds expressed in terms of the amount of available useful waste heat, the demand for heat or the distances from heat supply and heat demand, which identify which installations do not need to prepare CBAs. Where the installation is a planned or refurbished district heating/cooling network, this maximum distance should be measured from the nearest appropriate point on the planned or refurbished district heating/cooling network to the potential supplier of waste heat. A detailed methodology for defining a distance/energy threshold is explained in deliverable D2.2. It is the responsibility of the operator that performs the CBA to evaluate it. All points identified within this threshold should be considered as potential heat source/sink candidates and thus a separate CBA or at least a pre-screening carried out in qualitative terms based on multiple criteria will be needed for each one of them.

While the distance and the available heat are the most important criteria for the establishment of the heat link there are some other criteria that have to be also taken into consideration such as temperature level, load synchronicity [16].

Synchronicity refers to the match between supply and demand. The heat source will have to ensure that the availability of its heat will cover the sink's needs during any time of the day. The sink will have to declare whether flexible/seasonal operation or operation by shifts is possible. In any case it will be the sink's responsibility to install a storage vessel to act as a heat buffer in order to absorb any fluctuations of energy supply. Usually such buffer vessels are an integral part of all district heating networks but their design may need to be reconsidered in order to take into account the particularities of the linked source. If the sink is another consumer such as another industrial process it will be advisable to have an additional standby boiler in order to operate whenever there is a mismatch in the load synchronization.

Another important aspect is the consideration of the lifetime of the link. The expected life of the heat source and the consuming market should be sufficiently high and the availability of heat needs to be sufficiently secure.

1.5 Identification of costs and benefits

In this section the main components of costs and benefits that are applicable in all cases described in Article 14(5) are discussed. Contrary to the national level CBA, the CBA analysed here focuses mainly on the financial cash flows that will demonstrate the financial feasibility of the project and thus its implementation from the investor's perspective. However, some external benefits of the investment are also discussed here so that the relevant authority can evaluate the proposed investment with different criteria and apply specific measures, policies or financial incentives, if necessary.

1.5.1 Costs

Financial costs are seperated within the following two categories :

- Capital costs: incurred when a business spends money either to buy fixed assets or to add to the value of an existing asset with a useful life that extends beyond the current tax year. Best available practices for capital cost estimation if data is not available is presented in Annex 5.2;
- Operating costs: refers to expenses incurred in the course of ordinary business, such as sales, general and administrative expenses (and excluding cost of goods sold - or taxes, depreciation and interest).

1.5.1.1 Capital Costs

The major capital costs elements are summarized in the following categories. It should be noted that these costs do not refer to the existing costs of the reference case but to the incremental costs that will arise from the proposed investment.

Table 3. Capital costs (x: required; o: depending on the case).

Cost streams (€)	Power plant	Industry	District Network
Heat recovery equipment	x	x	
Heat pump	o	o	o
Heat transfer line	x	x	x
Standby boilers	o	o	o
Modifications to heat distribution network			x

1. **Heat recovery equipment:** This is the capital cost that must be incurred to make technically possible the recovery of heat at the heat generator side. It covers all capital costs related with the options described in Section Identification of available waste heat. The supply and installation of equipment such as heat exchangers, circulation pumps and associated controls and instrumentation is included in this category. For a retrofitted installation it also includes all costs related to turbine modification. If modifications are not possible the cost of a new optimized turbine for this purpose should be considered. The sizing and cost of heat recovery equipment is mainly a function of total heat surface area (for heat exchangers) or total load of heat recovery (for unconventional ways of heat recovery)

   Heat pump: The installation of a heat pump refers mainly to the case of a district cooling network. Most of the times it will be an one cycle absorption chiller cycle that produces cooling using low grade waste heat and can be installed in the side of the heat supplier. This is because it is likely that transmitting cooled water is more cost effective than transmitting heat to users that require cooling as these users would then need to chill the heat with their own distributed chillers.

   Another option is to consider heat pumps for upgrading the heat from a low quality heat source. In this case, with the use of electricity, waste heat can be upgraded in a higher temperature/quality that is suitable for a district heating network.

   Heat pumps in industries can be of different types depending on the scope of the investment. They mostly refer to internal transformation of energy and they can be either open cycle (thermal or mechanical compressions) or closed cycle (vapour compressions cycle or absorption chiller cycle).

   The sizing and costing of heat pumps is mainly done by identifying the separate components of a heat pump (compressor, evaporator, condenser etc.) or as an aggregated cost based on total cooling load which is most common in the case of absorption. A common range of capital costs of a one stage absorption chiller falls between the range of 500 – 700 EUR/kW.

2. **Heat transfer line**: This is the capital cost of purchasing, preparing the ground for, laying the necessary heat pipes and constructing the required pump stations. It can be assumed that two pipes are required per trench (supply/return). Overall capital costs will vary depending upon factors such as the heat carrying fluid (i.e. steam/water), pipeline length, terrain covered and any measures to traverse significant obstacles (e.g. major highways, rivers or rail-lines). Shortcut costing formulas can be found in the literature that correlate the pipeline's cost per meter as a function of its diameter. A common range for that cost is 1000 – 2000 EUR/meter

3. **Standby boilers**: This is the costs associated with stand-by boilers that the electricity generating or industrial installation may have to install in order to be able to honour heat supply contracts with heat users at times when the installation is unable to meet the demand profile of the heat user. A district heating network can also consider installing or upgrading such boilers to increase their availability of heat supply from other sources. A common range for that cost is 100 – 400 EUR/kW.
4. **Modifications to heat distribution network:** Depending on the distance and size of the new heat load source a new substation may need to be built along with a heat accumulator to alleviate any irregularities in the supply of thermal energy.

1.5.1.2 Operating costs

Table 4 summarizes the operating costs applicable to each case.

Table 4. Operating costs (x: required; o: depending on the case).

Cost streams (€)	Power plant	Industry	District Network
O&M Heat recovery equipment	x	x	
O&M Heat pump	o	o	o
O&M Heat transfer line	x	x	x
O&M Standby Boiler	o	o	o
Heat purchased			x
Lost revenue from power generation	x		
Additional fuel required for standby boiler	o	o	o
Additional carbon allowance costs for standby boilers	o	o	o

1. **Heat recovery equipment:** This is the on-going operation and maintenance costs falling on the heat source associated with any new equipment installed to make technically possible the recovery of waste heat. These costs should be priced at the date the project becomes

operational. It is typical for a major plant overhaul to be necessary after about 50,000-60,000 hours of operation. The CAPEX associated with this major overhaul may be either represented as one negative cash flow component in the middle of its lifetime or spread over the full lifespan of the cogeneration plant. To simplify the analysis it is recommended the cost of the major overhaul is presented as an annual OPEX equivalent amount over the lifetime.

2. **Heat pump:** This is the on-going operation and maintenance costs falling on the heat source associated with any new absorption chillers.
3. **Heat transfer line**: This is the on-going operation and maintenance costs falling on the heat source associated with the Heat transfer line. The electricity costs for circulating pumps are expected to be the major expense of this category but some expenses of periodic inspection and maintenance of pipeline can also be considered.
4. **Standby boilers**: This is the annual operation and maintenance costs associated with standby boilers that electricity generating and industrial installation may have to install in order to honour heat supply contracts with heat users.
5. **Heat purchased:** This parameter is used in the analysis where the Operator is a heat user. This will be calculated from the supplied values for:
   - Annual quantity of heat supplied from heat source(s) to heat user(s), and;
   - Heat purchase price.
6. **Lost revenue from power generation:** This parameter is used in the CBA where the Operator is a heat source that generates power. It is essentially the cost of recovering and transforming waste heat to useful heat. This will be calculated from values supplied for:
   - Electricity wholesale price (EUR / MWh);
   - Power generation lost (MWh).
7. **Additional fuel costs for standby boiler:** This is additional fuel consumed by standby boilers that electricity generating and industrial installations may have to install in order to honour their heat supply contracts with heat users. It will include the:
   - Fuel costs (EUR / MWh);
   - Additional fuel consumed (MWh).
8. **Carbon allowance costs:** Although Operators may be given some ‘free’ carbon allowances, there will often be a need for Operators to pay for additional carbon allowances. These will include:
   - Carbon costs (EUR / tonne);

- Additional tonnes of carbon allowances required.

1.5.2 Benefits

In this the benefits deriving from the proposed investments are discussed.

1.5.2.1 Financial benefits

Cash benefits belong in one of the following two categories:

- avoided cost (e.g. reduced fuel consumption);
- extra cash flow (e.g. extra revenues from heat sale).

The following cash benefits can be identified:

Table 5. Benefits (x: required; o: depending on the case).

Revenue streams (€)	Power plant	Industry	District Heating
Heat sales	x	o	
Electricity sales		o	
Fuel savings		o	x
Carbon savings		o	o
Financial incentives	o	o	o

1. **Heat sales**: This parameter is used in the CBA where the Operator is a heat source. This is the revenue from heat sales accruing to the Operator as a result of implementation of the heat linking project. This will be calculated from the supplied values for:
   - Heat sale price (EUR/MWh): It usually depends on the technology that it substitutes on the demand side (e.g. inefficient boilers) and it has to be competitive with market prices. Li et al. [17] describes in detail existing methods and models regarding heat pricing of District Heating which could be applied for regulated or deregulated markets;
   - Annual quantity of heat supplied from heat source(s) to heat user(s).
2. **Electricity sales (grid imports displaced/power sold)**: This is relevant for industries that are assessing the costs and benefits associated with its heat demand being met by on site

CHP. In this situation in exchange for more fuel being consumed than before electrical power will be generated, which could either be sold to another party (representing a source of revenue) or used to meet on site power demand, resulting in a reduction in purchased electricity (equivalent to a source of revenue). This will be calculated from the supplied values for:

- Electricity prices (EUR / MWh);
- Amount of electricity generated (MWh).

If the electricity from the CHP will be used onsite then the appropriate electricity price is the retail electricity price as the electricity generated will be able to offset electricity that would otherwise have to be purchased by the industrial installation. If the electricity will be sold to the grid the electricity price will be the wholesale electricity price. If some electricity will be sold to the grid and some used by the installation then it may be appropriate to use a 'blended' electricity price.

3. **Fuel savings**: This parameter is used if the CBA is conducted by a heat sink (DH network). This represents the avoided fuel costs associated with heat being provided from an external heat source, e.g. CHP, rather than from a conventional heat source, e.g. package boilers). It also applies for industries where the installation of a CHP will result in energy savings. This will be calculated from the supplied values for:

   - Fuel price (EUR / MWh);
   - The fuel avoided (MWh).

4. **Carbon savings**: If the network or energy production installation will need to purchase less fuel there will often be a reduction in the number of carbon allowances that need to be purchased. This value will be calculated from supplied values for:

   - Carbon costs (EUR / tonne);
   - Reduction in tonnes of carbon allowances purchased based on carbon emissions of substituted technology.

5. **Financial incentives**: The installation may generate revenue from financial incentives relative to the base case.

Financial incentives based on policies applied are usually given in one of the following forms:

- Capital subsidies: Reduces the capital costs;
- Tax exemptions: Reduces the operating expenses;
- Primary fuel subsidy: Reduces the operating expenses;
- Subsidy on sold energy products (Feed in Tariff) : Increases the revenues;

- Long term stability of prices: Reduce market risk by fixing prices to an index.

1.5.2.2 Socio-economic benefits

Socio-economic benefits are usually of no interest to the investor as they do not generate a real cash flow, but very important to the society. These benefits can be either internalized if the overall benefit to the society has to be estimated (full economic analysis) or used along the economic criteria to evaluate the impact of this investment on different dimensions (multi criteria analysis) during the pre-screening of alternatives. They can be categorized into two different groups: (a) direct which are the benefits where a positive impact can be identified specifically from a particular investment and (b) indirect which are the benefits that have a positive impact to the economy and society but they cannot be immediately identified.

The most important socio-economic benefits of such projects are based on the principle that the projects described in Article 14(5) will lead to a reduction of primary energy. Since the comparison between the two cases is based on the assumption that the same amount of electricity heat and/or cooling demand will be covered by the reference and the proposed project, the society will benefit with the following ways [18] (European Commission, 2008):

1. **Avoided GHG emissions through increased overall efficiency:** The specific GHG emissions per MWh of heat produced. This value will be calculated from supplied values for:
    - Fuel saved per year (MWh)
    - Specific GHG emission factor for the fuel (t CO_2/MWh);
    - Shadow price of CO_2 (EUR/t CO_2)
2. **Avoided emission of pollutants to air**
    - Pollutants avoided (kg)
    - Damage factor of pollutant (EUR/kg);
3. **Resource cost savings through improved efficiency.** The monetization of this benefit is based on the avoided cost of the next best alternative plant for producing the same amount of energy (heat/cooling). In the long term in Europe this would be a combined cycle plant. This will be values based on:
    - Long term marginal cost of electricity generation in CCGT (EUR/MWh)
    - Penalty cost for security of supply of substituted fuel i.e. gas (EUR/MWh)

Other Indirect benefits

Indirect benefits should be interpreted as changes in welfare that do not have a financial implication for the private investor. Nevertheless, its inclusion allows identifying projects that could be non-profitable in financial terms but turn to be profitable when positive social effects are taken into account. In the context of energy efficiency some of the main externalities are derived from the macro-economic impact but also others as energy dependency reduction and a more optimal operation of the electricity network [19-22]. The nature of the impacts is different in each case, so different valuation techniques would be applied to assess the value of those impacts for the society. For example, macro-economic impacts are assessed using Input-Output analysis or macro-economic models. The different valuation techniques are explained in more detail in the national CBA analysis Guidelines and if necessary they should be adapted from it.

1.6 List of important techno-economic parameters

The most important parameters needed for the conduction of the CBA are presented in this section.

1.6.1 Project lifetime

In the Discounted Cash Flow (DCF) analysis the period of time over which costs and benefits are collected up and discounted back to a present value needs to be defined. Assuming that the benefits in any year outweigh the costs, the longer the timeframe over which costs and benefits are evaluated, the greater the chance that the initial capital expenditure will be balanced by the future benefits, rendering the project cost effective, i.e. with a NPV greater than €0. It is important, therefore, that an appropriate project lifetime is selected for the DCF.

Table 6 mentions some indicative life times of most relevant equipment. If a piece of equipment has a smaller lifetime than the specified project time then it will need to be replaced. In the opposite case there will be some residual value to be accounted at the end of the project's lifetime.

Table 6. Lifetime of equipment.

Equipment	Lifetime (years)
Boiler	20-30
Absorption chiller	15
Heat transfer line	30

CHP (steam turbine)	20

1.6.2 Construction period (Lead time)

As the projects being evaluated will be significant in size, the project may be completed over a number of years. This means that costs may be staggered over a number of years. For this reason, the CBA should accommodate a spread of capital costs over an appropriate number of years.

Revenues associated with the project may also not flow at full steady state from the start of the project, but after a delayed period. In the interim period, revenues may flow at a fraction of the steady state value. The CBA should accommodate such a staggered revenue (and operating cost) profile allowing Operators to enter a percentage of full operations for relevant years. In any other case a uniform distribution of revenues (with a proper escalation factor if necessary) should be assumed.

A heat station and all related equipment (boiler, chiller etc) can be expected to be built within one year. A heat transfer line depending on the size/distance requires a construction period of 1 to 3 years.

1.6.3 Operation time (capacity factor)

Operation time is very important variable to identify for the conduction of the cost benefit analysis. From an economic point of view it shows at what extent the initial capital will be utilized. It is also common to use it as a factor representing the total energy produced/consumed in a year to the energy that could be produced/consumed throughout that year ($CF = \frac{Energy\ used\ (MWh)}{Maximum\ capacity\ (MW) \cdot 8760\ hrs}$). It is evident that for an investment that will fully operate only for an equivalent month per year (i.e. capacity factor 1/12 = 8%) it will be more difficult to pay it off.

For a CBA related to a power plant, the maximum capacity factor usually depends on the availability of the technology, i.e. total time minus the forced or unplanned outage time.

For a CBA related to an industry that sends waste heat off-site, the maximum capacity factor depends mainly on its production planning: how many shifts per day, days per week etc.. In this case, the remote sink's requirements will have to coincide with industries operating pattern.

For a CBA related to district heating, the operation time and consequently the capacity factor will often depend on the climate; the colder the climate the more hours a heating system will operate. For simple district heating systems it is common to expect a capacity factor in the range of 30–

60%. In case of installation of a heat pump (i.e. absorption chiller), the operation time can be extended to provide cooling during the summer months extending the capacity factor.

1.6.4 Financial and economic discount rate (Time value of money)

Companies are interested in acquiring money today to make a profit with it tomorrow. Thus, in the right hands USD 100 today is worth more than USD 100 tomorrow; money has a time-value component. To compare investment options with cash flows that occur at different times, it is useful to convert all cash flows to a common time. The most common way to do so is to convert all cash flows into their "present value", and then compare the present values to evaluate alternative investments. This conversion is called discounting and is done with the discount rate. This parameter is very important in the analysis as it assigns an appropriate time value of money and accommodates the effects of inflation, the cost of capital, opportunity costs, taxation and other allowances. In general, high discount rates reflect the belief that a large profit can be made from an alternative investment. A zero discount rate implies that the future is equally as important as the present. As a result, an increasing discount rate causes a reduction in the net present value. This affects mostly the capital-intensive investments. The proper selection of a discount rate will be analysed in the next sections.

1.6.5 Escalation

In energy economics, many calculations include fuel cost and heat tariffs, which frequently change over time. A forecast should be used as a data source. During the Comprehensive Assessment a forecast is going to be conducted and the same data can be provided by the authorities in order to be used in the individual installation CBAs.

If a price forecast is not available, a more simplistic assumption is to assume a constant value increase over time at some escalation rate e. In most cases, the rate of escalation of energy prices is different than the general rate of inflation. One way to estimate energy price escalation rates in the future is to consider past rates of energy price escalation. It should be noted that the effect of inflation has to be removed from this estimation as usually cash flow analysis uses nominal terms.

The 'real' energy price escalation rate, e', which represents the energy price escalation rate with the effect of inflation removed, can be determined by removing the effect of inflation, j, from the nominal energy escalation rate e using the following equation:

$$e' = \frac{e - j}{1 + j}$$

It is often assumed that the nominal escalation rate for fuels falls into the range of 2–4%

It is important to use either real rates or nominal rates in time-value of money calculations and to avoid mixing real and nominal rates in the same calculation. For example, either use nominal discount rate, i, and nominal energy price escalation rate, e, or use real discount rate, i', and real energy price escalation rates e'. When money is borrowed or invested at interest, the interest typically represents a nominal rate. Modelling in real terms is easier if all operating costs and revenues rise by an identical inflation rate. However, if there are different inflation rates on different cost and revenues streams then models should be calculated on a nominal basis. Modelling costs on a nominal basis is also the standard for project finance calculations, and therefore is the recommended approach. Typical variables to consider an escalation rate are mainly the heat sale/purchase price and the fuel costs.

1.7 Performing the cost/ benefit analysis

Cost-benefit analysis (CBA) is a way to systematically compare benefits and costs of a project or a government policy. It is used to determine whether a project is economically justifiable by comparing the total benefits (which go beyond purely financial benefits and revenues to include wider environmental, social and economic benefits) against the total costs (which again go beyond the financial construction and operating costs to include social, environmental and wider economic costs).

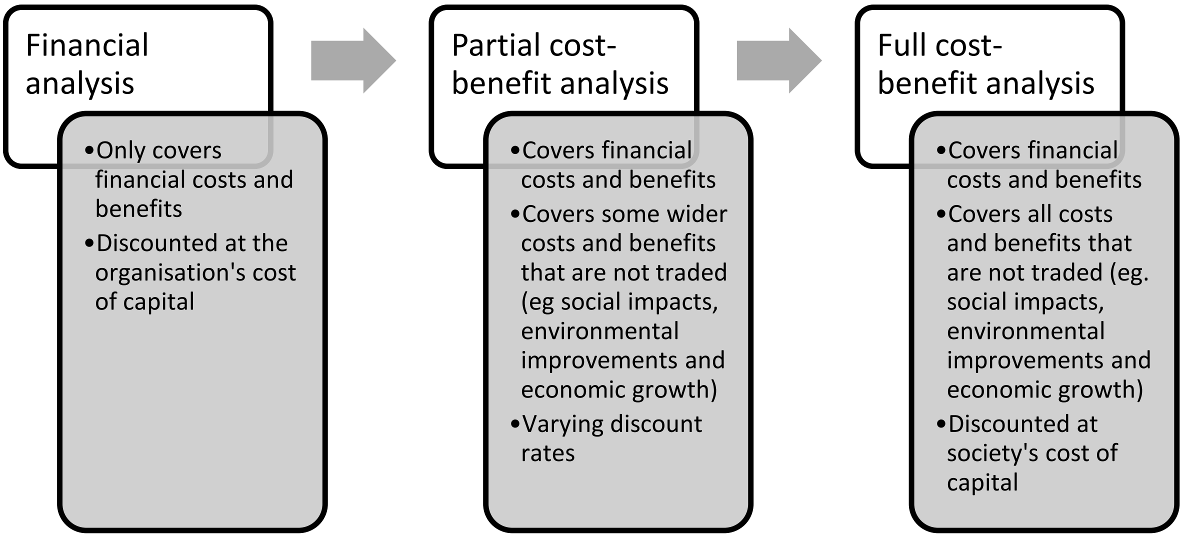

Figure 10. The spectrum of cost-benefit analysis. [12]

Figure 10 summarises this spectrum where at one end projects are evaluated by only considering those costs and revenues that are of concern to a commercial entity (this is sometimes called financial analysis, or financial evaluation, or investment appraisal) to the other end where all the costs and benefits of concern to society are considered, even those costs and benefits that would be very hard to monetise (this is often called an economic appraisal, or social cost-benefit analysis).

In contrast, an economics analysis appraises the project's contribution to the economic welfare of the region or country. It is made on behalf of the whole of society instead of just the owners of the infrastructure, as in the financial analysis [18]. An economic analysis treats taxes as transfers from one part of the economy to another, so these are not considered as net costs.

In Annex 5.4 a review of existing approaches and methodologies for quantifying the costs and benefits of efficient heating and cooling projects is provided. These studies assessed the costs and benefits of efficient heating and cooling projects and actions. The fields of the review template were designed to capture evidence on the different characteristics of the cost-benefit analysis methodologies, and the specific requirements of the EED.

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[12] Even the definitions used here mean different things to different organisations. For example, the European Commission's 'Impact Assessment Guidelines' (January 2009) defines a full CBA as being undertaken when the 'most significant part of both costs and benefits can be quantified and monetised, and when there is a certain degree of choice as regards the extent to which objectives should be met (as a function of the costs associated with the proposed measures).' It defines a partial cost-benefit analysis as being undertaken 'if only a part of the costs and benefits can be quantified and monetised.'

The following sub-sections outline the general approach and assumptions for carrying out investment appraisals of projects in industry and energy fields. Such assessments are widely used in order to support decision of whether or not an investment stands to be profitable.

1.7.1 Financial analysis methods

Since the project will normally be financed by a private entity, only costs and benefits that can be monetised and which would feature in the income statement and accounts of the private entity should be included in the financial CBA. For investments related with energy efficiency, the financial analysis (as part of a larger cost benefit analysis described above) can be placed into the two following categories [23]:

- Discounted cash flow forecast methodology (DCF): A discounted cash flow analysis is a method of calculating the NPV on a potential energy investment by estimating future cash flows on an annual (or even quarterly, or monthly) basis, taking into consideration the time value of money for a specified project life. A DCF analysis can be used to calculate a project's NPV both before and after tax. Cash flows are estimated using project-specific revenue and expense forecasts, depreciation schedules, and income tax assumptions (as applicable). A DCF analysis takes a project's operational and financing milestones—including evolving tax obligations—into account when estimating its NPV. The DCF method also is capable of considering time-sensitive operational events, such as major equipment repairs or replacements (e.g., overhaul for turbines, replacement for pumps etc.).
- Recovery factor analysis: This methodology relies upon a single factor to present capital costs into a stream of equal annual payments over a specified time. It replaces the year-by-year free cash flow estimates of the DCF method with a simplifying formula. Usually this methodology is used when the levelized cost of energy (LCOE) has to be estimated, capturing all related costs into a single value. Contrary to DCF which focuses directly on the profitability of a project instead of only its cost, the selling (market price) is omitted from the equation [24].

The appropriate method to be used for the analysis required by Article 14(5) is the discounted cash flow analysis, since it is more flexible, detailed and applicable to all cases described. Recovery factor analysis is complimentary and could be used to quantify the price of the energy products e.g. price of heat transferred.

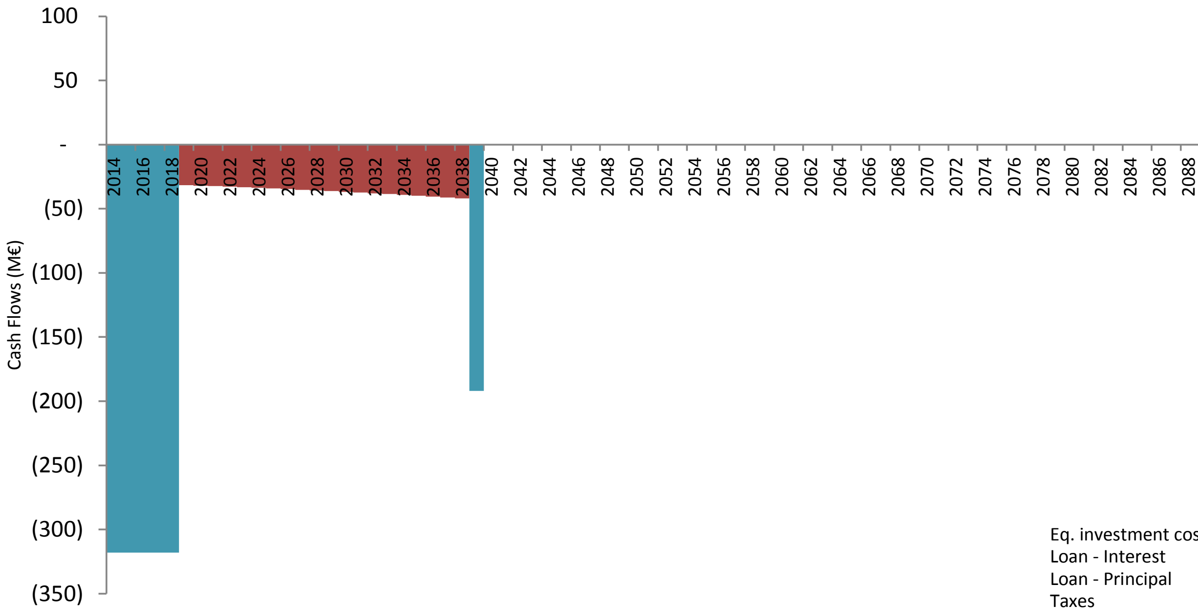

Figure 11. Comparison between (a) cash flow analysis considering only the costs and (b) recovery factor analysis.

1.7.2 Incremental accounting

If the decision for the base investment has already been taken, the determination of the project cash flows should be based on the incremental approach, i.e. on the basis of the differences in the costs and benefits between the scenario with the project (do-something alternative) and the counterfactual scenario without the project (BAU scenario) [18]. A general definition of the above can be the following: *"The incremental cash flows for project evaluation consist of any and all changes in the firm's future cash flows that are a direct consequence of taking the project"* [25]. Under this approach, it is only necessary to determine whether the balance of additional costs and benefits associated with the cogeneration/ heat linking project stands on its own financially, i.e. would give a positive cash flow to the installation, or in cases where grants or subsidies are necessary, reduce the amount of the additional support needed.

An important consequence of this approach is that the proposed project will be evaluated by the investors and the relevant authorities purely on its own merits, in isolation from any other activities or projects.

Some of the most common pitfalls that one should avoid while defining the project's incremental cash flows as identified by Ross et al. (2003) [25] are the following:

- **Sunk costs**: A cost that has already been incurred and cannot be removed, should not be considered in an investment decision. Only cash flows that arise because of the decision being made should be included; any cash flow that would have arisen anyway even if it concerns this investment should be ignored and any cash flow that exists regardless of whether or not a project is undertaken is not relevant. This could include the costs of performing this study or relevant infrastructure that will be built in any case.

- **Side Effects (Cannibalization)**: The cash flows of a new project that impacts the cash flows of a firm's existing projects. As an example it is mentioned for the power plant case, the reduced electricity sales due to the energy penalty caused by the heat extraction. In this case, a negative cash flow should be included representing the lost revenues;
- **Financing costs**: Interest paid or any other financing costs such as dividends or principal repaid will not be considered because we are interested in the cash flow generated by the project. However, all the above values are captured in the estimation of the proper discount rate has to be done based on financing arrangements and managerial decisions;
- **Other issues** like new working capital, opportunity costs, taxes etc. For the projects examined in this document it is not so common to have big differences in the abovementioned costs. Taxes are definitely a cash outflow and have to be considered in the installation level assessment, so all incremental cash flows described in this document refer to after-tax cash flows.

Within the Article 14(5) there will be some limited cases that the individual accounting will have to be used because the proposed and the alternative scenarios will be a mutual exclusive. For example in the case of a plan for new district heating network the CBA will examine whether the proposed energy production installation should be built or heat from other available sources should be utilized.

1.7.3 Cash flow model for financial CBA

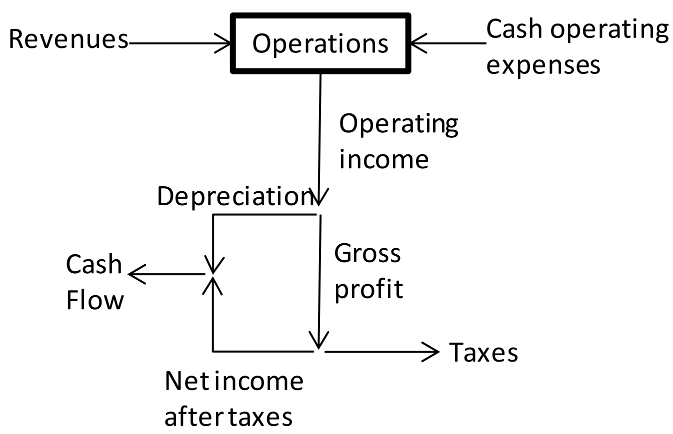

Figure 12. Yearly cash flow model for operation period [26].

For the scope of analysis described in this document, a cash flow analysis includes the elements presented in Section 1.5. In order to simplify the illustration of the model this Figure does not include the net capital spending that could arise from potential replacement of equipment during the investment period. Operating income comes from the normal operations, which is the profits from selling the energy product minus the cost of operation. After the estimation of taxable income (Gross profit) the tax can be estimated and deducted from the net operating cash flow.

Operating cash flow is an important figure because it shows, on a very basic level, whether or not a firm's cash inflows from its business operations are sufficient to cover its everyday cash outflows. Interest is considered a financing expense so it is not included here. This cash flow represents the viability of the inherent operations of the assets invested. It will be distributed to creditors (interest) and shareholders (dividend) depending on the capital structure. Interest paid, for example, is a component of cash flow to creditors and dependant on the sources of capital, not a cash flow from the project.

Future cash flows from the project will be discounted based on the described time value of money. In the present case, these are the costs and benefits to the firm, although the field of Cost-Benefit Analysis (CBA) attempts to measure wider, social impacts. The annual results of the above model can be used to estimate the net present value of the investment, which is the difference between an investment's market value and its cost. The net present value (*NPV*) is defined as the sum of all the discounted cash flows over the length of the project. The annual cash flow (*CF*) is summed over the lifetime of investment (*N* years) to get the cumulated cash flow by means of:

$$NPV = \sum_{t=0}^{N} \frac{CF_t}{(1+i)^t}$$

This NPV is known as the Financial Net Present Value (FNPV) [18]. For mutual exclusive investment decisions, NPV method gives the most accurate results and should be used to calculate the Cost-Benefit Surplus using a discounted cash flow (DCF) because it is less likely to be misapplied [26].

1.7.4 Economic analysis

Despite the fact that the installation level CBA focuses on financial CBA since it examines the proposed investment from an investor's point of view, it is necessary to describe the necessary elements that will turn a financial CBA into an economic one in order to examine the project from the perspective of the society.

According to European Commission [18] the following adjustments should be made in order to convert a financial CBA to an economic one:

- **Fiscal corrections**: Any fiscal figure used should not contain any direct or indirect taxes, VAT, or subsidies. These costs are instruments of social redistribution from a social group to another and not a net cost or benefit of this project to the society. Subsidies that are currently being used should be however considered at the end of the analysis when considering measures in order to support projects with a negative financial CBA but positive economic CBA.
- **Conversion from market to shadow prices**: Financial costs of the project are used as a basis to estimate its economic costs. This is achieved by the use of correction factors which effectively correct all market distortions capturing the real value to the society. These are defined as the factors at which market prices have to be multiplied to obtain inflows valued at shadow price. In principle, Conversion Factors should be made available by a planning office and not calculated on a project-by-project basis. When national parameters are not available, project-specific calculations can be made but these must then be consistent across projects. At least, corrections should be applied to depurate market prices from fiscal factors, e.g. an excise tax on import. In the absence of evidence of market failures, the correction factors should be set equal to 1.
- **Evaluation of non-market impacts and correction for externalities**: Due to their nature, some benefits are not captured with the evaluation of the projects' direct benefits and they need to be evaluated separately. The most important category of externalities that will be considered is environmental externalities (e.g. noise, air pollution, greenhouse gas emissions, landscape deterioration etc). Valuing of externalities may sometimes be difficult and subjective so it is recommended to use the same reference costs from literature studies like ExternE.

1.7.5 Selection of financial and economic discount rate

The discount rate that is related with investments and private projects is different than the social discount rate used in an economic cost benefit analysis. The concepts and the mathematics are identical but the nature of social project funding is different, because estimating the benefits of social projects relates to making ethically subtle choices about the benefits to others.

The discount rate used in corporate financing is also known as cost of capital or hurdle rate. This cost applies to both debt and equity. The cost of debt capital is the interest rate. The cost of equity capital is the investor's targeted rate of return. Returns can be calculated both before and after tax. Pre-tax returns are a useful comparison metric for an investor considering multiple potential uses for the same capital. This is especially true when each investment has a different tax consequence. For investments that are within a single industry and subject to the same tax obligations and incentives, an after-tax return provides insight that is more useful for the project's cash flow implications and it will be used throughout this document [23].

There are two levels of detail in estimating the cost of capital.

1 The simplified way captures all information related with the effects of capital structure, different types of return, tax shield effects, in a single value which is usually known as Weighted Average Cost of Capital (WACC). The two main sources a company has to raise money are equity and debt. WACC[13] is the average of the costs of these two sources of finance, and gives each one the appropriate weighting and is an indication of the overall firm's cost of financing. If the risk of the new project is considered to have similar risk to that of the overall firm it can be applied to discount the cash flows.

2 The complex way uses the percentage and cost of equity as well as the percentage and cost of debt along with relevant taxing schemes. For the estimation of the cost of equity usually the capital assets pricing model (CAPM[14]) is used which takes into consideration the risk free return (i.e. treasure bonds), the risk associated with the specific market, and the required premium. For the estimation of the cost of debt a value is given by the firm's bank. This is usually related with the interest of a central bank (e.g. European Central Bank) with the addition of a reasonable premium.

In the literature, there is great uncertainty about the amount of the cost of equity, but most of them are at very high levels, well over 15 %. The discount rate used in this type of cash flow analysis is effectively the required return on the funds spent, in this case to construct an energy efficiency project. The simplest solution will often be to quote the discount rate on a nominal, pre-financing basis (*WACC*) as that avoids the need to consider debt to equity ratios for different types and sizes of project.

On the other hand social discount rates are much lower while they vary greatly around the world: in the European countries discount rates are around 3-5 %. EC [18] proposes a reference value of 4 %. For the 2007–2013 period, the European Commission suggested using two benchmark social discount rates: 5.5 % for the Cohesion countries and 3.5% for the others.

1.8 Evaluation of results

Cash flow analysis will result to an after tax net present value. An investment option of cash flows that were based on the incremental method has to have a positive NPV in order to be viable which means that NPV of the alternative case is bigger than the BAU scenario. If NPV is less or equal to 0

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[13] WACC = (Percentage of finance that is equity x Cost of Equity) + (Percentage of finance that is debt x Cost of Debt) x (1 – Tax Rate)

[14] Expected return = Risk-free rate + Market premium x systematic risk → $E(R_i) = R_f + \left[E(R_M) - R_f\right] \cdot \beta_i$

then it means that the alternative investment does not produce any new benefit for the company and thus it should be rejected.

Sensitivity analysis

The results of the CBA refer to a basic reference point. However it is important to present the sensitivity of these results to the variation of basic data and assumptions. Sensitivity analysis is a statistical tool that determines how deviations from the expected value occur as it determines the sensitivity of the data and assumptions.

Sensitivity analysis can be performed by modifying key values for a specific amount, e.g. ±20 % and by observing the response of a result (in this case NPV). This can be for example presented in the form of a spider or tornado chart.

The following parameters usually have the biggest impact on the investment profitability:

- The annual operating time (break-even analysis), and the selling price of the product;
- The resources prices (raw materials, labour, utilities, equipment, energy prices);
- The economic environment (e.g. discount rate, tax and debt characteristics, subsidies and other policies).

Risk assessment

The results have usually a big amount of uncertainty due to uncertain assumptions. To overcome the uncertainty of the parameters, sometimes sensitivity analysis is used as described above, illustrating the cost changes for a range of parameters.

While conventional sensitivity analysis shows the expected estimation divergence between a maximum and a minimum value of a parameter, it does not take into account the frequency of this incident. This is especially useful when during the sensitivity analysis it has been identified that the investment is close to the feasibility region.

With the use of probabilistic analysis such as Monte Carlo, one can define with a known degree of confidence, the most possible results and the level of risk. A typical Monte Carlo analysis is based on the following steps:

- Extraction of inputs from a probability distribution according to the nature of the variable. If satisfying historical data, that could reproduce the behaviour of the variable in the future, are available then they can be used to fit an appropriate distribution function. Otherwise a more generic probability function, e.g. Normal, Lognormal, triangular etc. based on expert judgment is used to simulate the probability of such events;
- Calculation of desired outputs for many times according to the desired confidence degree;

- Illustration of the results in a probability distribution function and justification of the uncertainty.

Risk in the operation of such plants is usually divided in two generic categories: Operation and Maintenance Risks and Market, Regulatory and Finance Risks. The first category concerns operation characteristics of the plant and are based on the inherent characteristics of the technology selected. The latter category depends on the economic environment, energy prices and other geopolitical factors.

The assumptions about the possible and expected outcomes of the various cost factors will determine the possible and expected outcomes of NPV calculations. Monte Carlo simulations can be used to provide additional insights to investors and industry planners about the impact of technical, operational, and price risk.

2 Informal guidance on how to implement individual installations' CBA obligation

As it was mentioned in Section 1.1 the CBA required in Article 14(5) falls between the following two broad categories:

- A: The CBA for the a supply point that recovers or transforms energy and transfers it to alternative demand points (14(5a-c));
- B: The CBA for a demand point (i.e. a distric heating network) that utilizes energy from alternative supply points (14(5d)).

Although the Directive leave the freedom for Member States to decide who should carry out the CBA, a practical implementation approach is to assign this for the entity who is introducing the authorisation request in accordance with Article 14(7).

For the CBA under point a), b) and c) of Article 14(5), this would rest with the thermal electricity generation installation or the industrial installation.

For the second category of CBA under point d) of Article 14(5) the responsibility would be either with the district heating network or for installations within it. When planning a new district heating and cooling network an energy production installation will not yet exist, or in any case such energy potential is not exploited yet. Therefore, the responsibility for preparing the CBA would rest with the network itself. Where there is already a district heating network the energy production installation will also exist. Article 14(5)(d) would be triggered when this existing energy production installation is substaintially refurbished or rebuilt. When this happens it will be the responsibility of the existing energy production installation to prepare the CBA.

In many instances the district heating or cooling network will have the same operator as the energy production installation, but this need not always be the case. It may be that the district heating or cooling network purchases heat from a third party, with the third party being the operator of the energy production installation. If this third party energy production installation is refurbished or rebuilt, then the third party operator would be responsible for preparing the CBA.

2.1 Step 1: Data collection

As a first step all relevant data has to be collected. For this CBA, there is a variety of provisions in the EED that can facilitate the data collection procedure:

- All data for the reference plant should be available from the reference case study that could ideally already been conducted and proved feasible, since there is already an investment decision for the reference plant;

- Member states may require all companies or parties that are within the defined system boundary to contribute data[15];
- Data forecast and trends of consumption can come from the comprehensive assessment under Article 14(1). Possibly, the data on existing and potential heat/demand points would come from the comprehensive assessment too, but these data should be verified in order to enable a precise installation level assessment;
- Foreseen policies and measures that will be implemented in the country/region and will affect the viability of the investment during its lifetime would ideally also be adopted from the results of the comprehensive assessment.

In general, feasibility of heat-linking applications is highly dependent on local energy prices and regulatory conditions [27]. For a realistic CBA, costs and revenues have to be current and as representative and their forecast as accurate as possible.

Electricity selling prices depend on market conditions or special policies applied, e.g. Feed in Tariffs. Projections about energy prices can be found in relevant studies or in the results of the comprehensive assessment. In case of lack of sufficient projection data it is common to justify foreseeable trends in prices by a simple escalation factor.

Regarding the heat prices since often there is no heat market and heat is considered a local commodity that cannot be transferred for a long distance like electricity, the selling prices have to be competitive for the specific region. In the case of prices not being available, the following method could be used for the estimation of the heat selling price. It would have two components:

- The cost of the fuel that is typically used in the Member State to generate heat. For each unit of heat purchased, and assuming a boiler efficiency of 90 % it can be assumed that e.g. 1/90 % = 1.11 units of fuel are required to generate this heat. This allows the cost of fuel associated with heat to be calculated;
- A discount of the company in the business of supplying heat. A 10 % discount might be considered suitable. Hence, heat purchase price (EUR/MWh) = [Cost of fuel (EUR/MWh) x 1.11]*(1-.10).

The result of the abovementioned process can be summarized in a Table of the following form:

[15] Annex IX Part 2 last paragraph

Table 7. Simplified example of market energy prices and carbon allowances if a detailed forecast is not available

Name	**Price**	**Expected escalation**
Heat selling	0.06 EUR/kWh	3 %
Electricity selling	0.07 EUR/kWh	2 %
Fuel	0.03 EUR/kWh	3 %
Carbon allowances	4 EUR/tn	
…	…	…

This data should relate to demand for heat and cooling and sources of waste heat from industrial installations and thermal electricity generators, both existing and those associated with planned development.

Apart from market data there will be a need for equipment cost data. In general, a detailed estimation of capital expenditures will have to come from vendor quotations. In the absence of actual quotes, and if there is a need for less accurate data in the scope of prefeasibility analysis, operators could approach trade associations for generic data such as:

- Euroheat and Power - http://www.euroheat.org/
- Cogeneration Europe - http://www.cogeneurope.eu/
- National trade associations able to provide selections of recent technical studies for district heating/ cooling and cogeneration.
- Eurostat (http://epp.eurostat.ec.europa.eu/portal/page/portal/eurostat/home) also provides data on relevant fuel prices and degree day data for calculating heat demands.
- Spon's Mechanical and Electrical Services Price Book provides relevant data on capital and operating expenditures of heating and cooling plant.

Literature data and relevant estimation methods can be also used as described in Section 4.4.1.

Power plants and industries should also collect data related with identification of their technical potential. More specifically industries should collect data regarding process streams i.e. heat load, pressure and inlet/outlet temperature in order to apply the methodology described in Section 1.2.2.

The final step is to identify potential points to transfer and sell the waste heat, or buy the heat/cooling for district heating networks. In the interests of avoiding unnecessary burden on operators in situations where there is very little prospect of a technical opportunity being cost effective, it is advisable to define minimum threshold quantities of waste heat available/heat demand and maximum search distance, or combination of the above as foreseen in the directive. All candidate points within the predefined threshold should be identified and summarized in a Table that will contain at least the information presented in Table 8.

Table 8. Example of data collection results.

Name	**Distance**	**Current requirements /availability for demand/supply of heat/cooling**	**Load Factor (or operating hours)**
Point 1	5 km	2 MW at 120 °C	35%
Point 2	15 km	18 MW at 110 °C	40%
Point 3	8 km	20 MW 120 °C	35%
…	…	…	

The values in this Table are sensitive to the climatic conditions. The amount of heating demand and the operating hours as described by the load factor will be bigger the colder the climate is. The inverse relation applies for cooling, i.e. the hotter the climate is the bigger the amount of cooling demand. This Table should include only the points that do not exceed the specified heat/distance threshold. This minimum amount of necessary data should be collected in cooperation with the relevant authorities/parties responsible for these sites/networks. Expected trends in demand should also be considered where available. General demand projections could be given in the results of the comprehensive assessment.

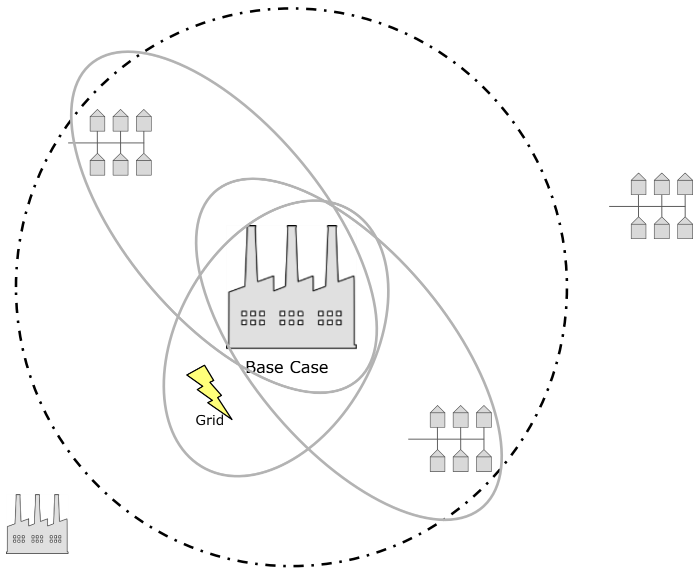

Figure 13. Illustration of different identification of different demand points within a specified threshold.

2.2 Step 2: Identification of available waste heat

The available waste heat to be sent off-site can be identified using the information from Step 1. For the energy sources (power plant, industries) this step will define how much heat is available to be delivered, according to the methodology described in Section 1.2.1, to the various consumers that were identified. The identified heat can be available at different quality levels and at different types (steam, water, flue gas etc.) and has to be indicated in the results of this step.

For district heating, there will be no actions needed for this step. These networks should have already identified the demand that they need to cover and the additional capacity that may be needed to install within the BAU scenario. Thus, their maximum capacity should be already in the reference design. The CBA will have to examine whether and at what extent this capacity will be covered by available external sources of heating and cooling. If there is a plan for a new electricity production installation inside the network, it should be examined whether this plant should be substituted with an external source.

This step will be identical for new and retrofitted plants, since the comparison will be done with the reference scenario.

2.3 Step 3: Definition of reference and alternative scenarios and assumptions

The total number of different alternative scenarios considered will depend on the available supply and demand points. Since the scope of the scenarios differ heavily it is necessary to examine the available scenarios on a case per case basis. It should be noted that the term 'scenario' is used to describe different cases of '*planned and comparison installations*' as mentioned in Annex 9 part 2 of the EED. As it will be discussed below, these scenarios are not necessarily mutually exclusive.

2.3.1 Scenarios for power plants and industries

For the energy supply cases as explained in Section 1.7.2, the decision for the reference scenario has already been taken, so it is reasonable to assume that the base case is already cost effective in its own right (i.e. the installation will make money from the scheme, or even if it cannot make a profit grants or subsidies are available to enable it to do so). If this assumption is made, then it is only necessary for the CBA to consider the additional costs and revenues arising from the project in question, e.g. the heat linking project. Under this approach, it is only necessary to compare it with the reference scenario using incremental cash flows as discussed in Section 2.6, i.e. if the heat linking would give a higher level of profit to the installation, or in cases where grants or subsidies are necessary, reduce the amount of the additional support needed.

These scenarios are not mutually exclusive; that means that a positive decision of more than one can be taken. In other words, connection to multiple sites may be possible assuming that the total energy delivered will not exceed the identified available waste heat. Since the heat recovery station is relatively a smaller investment than the heat transfer line, it is a good practice to design it to the maximum capacity i.e. utilizing all the identified waste heat, in order to be flexible for future expansions of nearby demands sites.

a) Power plants

The definition of alternative scenarios for power plants is relatively simple and it is based on one of the following assumptions:

- The new (or refurbished) installation uses the same amount of fuel, and thereby generating less electricity in order to supply heat to a nearby heat user, and;
- The new (or refurbished) installation generates the same amount of electricity but, in order to also supply heat to a nearby heat user, has to consume more fuel. In some cases this will also require a capacity expansion so that the power plant can handle the increase in thermal input.

The individual cost components are described in Table 9. In most cases it is reccommended that the comparison is based on the assumption of the first bullet. The second one, will be applicable mostly to existing plants that in the reference case are operating under nominal capacity and have to meet a specified electricity purchase per year.

Table 9 Major assumptions categories for defining a scenario for power plants (incremental approach)

	Same capacity – Reduced electricity	Increased capacity – Same electricity
Capital costs:	heat station + heat transfer line + standby boiler (if needed)	heat station + heat transfer line + standby boiler (if needed) + capacity expansion (if needed)
Operating costs:	operating costs of heat station + operating costs of heat transfer line + operating costs of standby boiler (if needed)	operating costs of heat station + operating costs of heat transfer line + operating costs of standby boiler (if needed) + additional fuel for electricity generator
Revenues:	sales of heat - lower electricity sales	sales of heat

b) Industry

The scope of alternative scenarios of an industry can differ based on the results of the waste heat identification. The following cases can be identified :

- Assess the costs and benefits of supplying waste heat to a district heating/cooling network or other heat user;
- Assess the costs and benefits of Combined Heat and Power (CHP) providing the installation's process heat and also generating electricity (topping cycle);
- Assess the costs and benefits of Combined Heat and Power (CHP) utilizing waste heat from an industry process and also generating electricity (bottoming cycle).

The main elements of these scenarios are summarized in

Table 10. One or more of these scenarios or even a combination of them, can be valid for a CBA depending on the identified potential.

Table 10 Alternative scenarios for an industry (incremental approach)

	Utilize and sell waste heat	Topping cycle cogeneration	Bottoming cycle cogeneration
Capital costs:	heat station + heat transfer line + standby boiler (if needed)	capital cost of cogeneration	capital cost of cogeneration
Operating costs:	operating costs of heat station + operating costs of heat transfer line + operating costs of standby boiler (if needed)	operating costs of cogeneration	operating costs of cogeneration
Revenues:	sales of heat	electricity sales (or reduced electricity purchase)	electricity sales (or reduced electricity purchase)

2.3.2 Scenarios for district heating/cooling networks

If a new district heating or cooling network is planned, then the way the heating or cooling will be generated may vary depending on each scenario. More specifically the operator will have the following options:

- build and operate its own energy production installation;
- it could contract with a third party energy production installation that will build the installation;
- or it could source its heat from industrial installations generating waste heat or thermal electricity generating installations.

For district heating networks the scenarios will not be considered incrementally with the reference scenario. The rationale behind that is that an alternative scenario will sometimes consists of a separate mutually exclusive investment. More specifically, considering that, the heat capacity of the district heating network is already specified in the reference scenario, there will be two main mutually exclusive scenarios:

- Cover the heat demand with a new or substantially refurbished energy production installation (reference);
- Cover the same heat demand (or a part of it) with waste heat from one or more identified heat sources.

This means that the identification of available heat sources that provide the required heat in a more cost efficient way can sometimes replace the energy production installation of the reference scenario. In some cases, depending on the availability of the remote heat source, it can be beneficial to even consider installing both options for increased redundancy.

Depending on the identified sources a new substation may need to be considered which will usually be constructed at the edge of the network and as close to the source as possible. In such case, design constraints should also apply in order to ensure that the heat distributed throughout the network will be of sufficient quality. Table 11 shows the most important elements of these scenarios.

Table 11 Reference and alternative scenarios for a district heating/cooling network (individual approach)

	Energy production installation	Supply from alternative sources
Capital costs:	New or substantially refurbished energy production installation	heat transfer line to industrial installation or thermal electricity generator + heat substation + other modifications to the network + eventual backup-boiler
Operating costs:	Costs of running the plant + fuel for energy production installation	operating costs of heat transfer line + cost of heat purchased from industrial installation or thermal electricity generator
Revenues:	Sales of heat / cooling to network or to properties in network	fuel savings due to the reduced need to use an energy production installation

In case only a part of the heat demand can be provided, a combination of elements from Energy production installation and Supply from alternative sources will be required.

2.3.3 Sub-scenarios applicable to the above cases

For each one of the abovementioned scenarios, there can be specific conditions that will have to include extra elements, such as:

- Installation of an auxiliary boiler to cover required loads when the main plant is not available. This will be mainly used when there is an agreed need for increased redundancy and in order to smooth the fluctuations from the supply side ;
- Installation of a thermal-driven heat pump (i.e. absorption chiller) to cover cooling load during summer season if the network allows it and there is an economically justifiable cooling demand.

One or more of these sub-scenarios can be incremental on the alternative scenario. This means that each alternative scenario based on the identified demand points can have sub-scenarios based on the specific requirements of the demand points. In this case the elements presented in Table 12 will have to be added in the relevant scenario.

Table 12 Important elements of sub-scenarios

	Installation of auxiliary boiler	Installation of absorption chiller
Capital costs:	auxiliary boiler	absorption chiller
Operating costs:	O&M of auxiliary boiler + fuel costs for auxiliary boiler	O&M of absorption chiller + fuel costs for absorption chiller
Revenues:	sales of heat form auxiliary boiler	sales of cooling form absorption chiller

Table 13 summarizes the described methods for performing the CBA.

Table 13. Accounting method for different cases of Article 14(5).

Type		CBA type
Power plant	New	Incremental
	Refurbished	Incremental
Industry	New	Incremental
	Refurbished	Incremental
DH network	New energy production installation	Individual
	Refurbished energy production installation	Individual

2.4 Step 4: Carry out the Cost Benefit Analysis

Summarizing what was said in previous sections, to conduct a detailed economic analysis several parameters must be specified and assumptions must be made for the entire life of the system being analysed. The CBA depending on the desired level of detail should have the following elements [28], as identified in the definition of alternative scenarios:

Table 14. Break down of costs to be considered in a financial analysis based on its complexity.

Preliminary	Detailed
▪ Estimated total capital investment (EUR /kW)	▪ Equipment ▪ Balance of plant ▪ Land costs ▪ Interconnection ▪ Development costs ▪ Financing costs ▪ Allocation of investment expenditures to the individual years of design and construction.
▪ Fixed operating costs (EUR /kW)	▪ Fixed O&M ▪ Insurance ▪ Project management ▪ Property taxes
▪ Variable operating costs (EUR /kWh)	▪ Variable O&M ▪ Royalties ▪ Emission allowances ▪ Fuel or other consumables (if applicable)
▪ Average load factors	
▪ Beginning and length of the design and construction period ▪ Beginning and length of operation period (investment lifetime)	
▪ Weighted average cost of capital	▪ Plant financing sources ▪ Associated required returns on capital ▪ Average general inflation rate ▪ Average nominal escalation rate of each expenditure.
▪ Tax rates (including depreciation method used)	

Table 15. Break down of benefits to be considered in a financial analysis based on its complexity.

▪ Selling prices (EUR /kWh) ▪ Fuel savings (EUR /kWh) ▪ Subsidies and other support instruments (EUR or EUR/kW or EUR/kWh)

Once the capital and operating costs for each case have been identified and estimated based on Section 4.4, the cash flow analysis can be performed. All costs and revenues are summed and discounted based on the presented cash flow model. This can be done with a simple spreadsheet software. Presentation of results should include a cash flow chart, and a breakdown of the main cost elements. Sensitivity on the most important variables should be also presented. In general, sensitivity analysis should be considered for uncertain estimates of: (i) energy prices; (ii) the discount rate; (iii) the different escalation rates; and (iv) load factors. An example of a sensitivity analysis chart is presented in Figure 14.

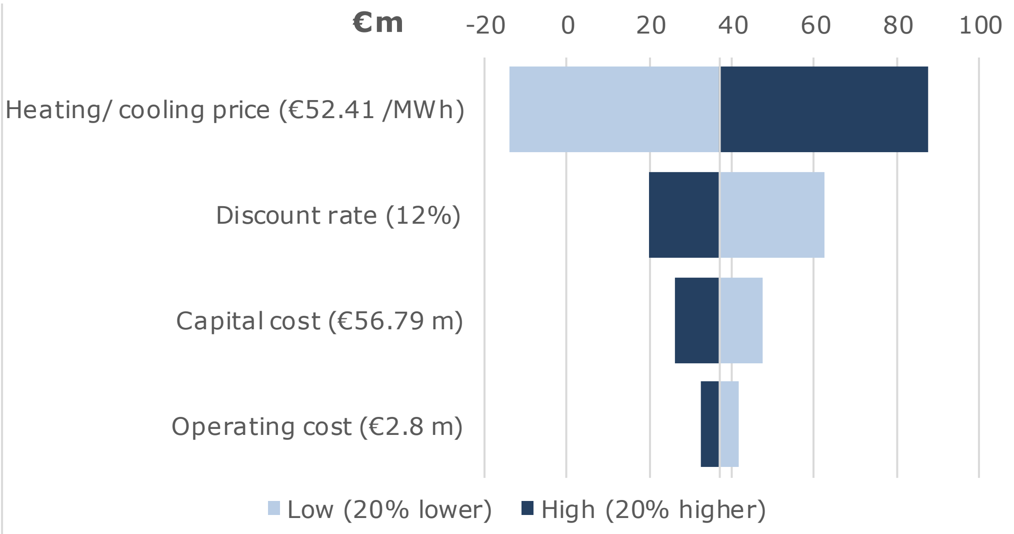

Figure 14. Effect upon NPV of independent variation (±20 %) of key parameters.

3 Link and synergies of country-wide CBA (Art 14(3)) with installation level CBA (Art 14(5))

Based on the EED, country-wide and installation level CBA have some fundamental differences in their scope and application that are summarized in Table 16.

Table 16 Comparison between national and installation level CBA

	National Level (Article 14(1-3))	Installation Level (Article 14(5))
Who ?	National authorities	3rd parties involved
When ?	Before Dec 2015 and every five years	When a new investment takes place
Main Goal	Identify technical and economic potential for efficiency in heating and cooling	Examine (and implement) related cost efficient investments that will result in a cost benefit surplus

The EED requires that cost-benefit analyses (CBA) are carried out at both national-level and installation-level. Whilst the principles are similar in both cases, the overall scope of the CBAs might be expected to vary. For the country-level CBA the emphasis is on the economic analysis which also covers socio-economic and environmental factors. The CBA under Article 14(5) for installations (according to Annex IX Part 2) should be an economic analysis focusing on the financial analysis reflecting actual cash flow transactions.

Despite the fact that the scope between the two CBA's is different, installation level CBA has a lot of synergies with the comprehensive assessment (CA).

More specifically, the comprehensive assessment (CA) will provide preliminary information about the demand trends for heating or cooling that can be utilised or the availability of waste heat that can be sourced. The Member State or competent authority may make available to installations and networks falling under its jurisdiction dynamic tools for sourcing the data mentioned above, such as a dynamic heat map of heat demand, both existing and planned, and industrial installations which could serve as sources of waste heat. Operators performing the installation level CBA may even identify potential heat load points mentioned in the CA that could not exist at the time the installation is commissioned.

Moreover strategies, policies and measures defined in the CA can be used as input for defining the energy prices and demand of the individual CBA. Similarly, Member States can allow exemptions from performing installation level CBA when the CA shows that there is no potential in that region[16]. Specific distance and energy threshold criteria can also be shared with the CA.

One example of a possible exemption from the obligation of an installation level CBA adapted from the CA is presented below. It is obvious that the feasibility of heat/cool linking investment between a supply and a demand point is very sensitive on the climatic conditions which determine the heat demand and the operation time of the supply line. Examining district heating solutions in a very hot climate — or district cooling in a cold climate — and preparing cost benefit analysis is usually not beneficial and will bear an extra licensing cost to the operators and the competent authorities. Figure 15 summarizes the current practice in EU-28. It is shown that for countries with less than 2500 heat degree days[17] district heating is not used today. After that point the energy consumed by DH network increases, with some countries underperforming other for various reasons (use better insulation materials in buildings, policies, incentives, relation with GDP etc.). Thus, for countries or regions that belong in the first category it can be expected that the CA will indicate an exemption from the obligation of heat linking. However, the current situation should not affect future decisions. If the low penetration of these networks is the result of special market conditions and unattractive policies, it has to be addressed within the CA and adapted from the installation level CBAs.

[16] Article 14(4)

[17] HDD is a measurement designed to reflect the heat demand defined relative to a base temperature

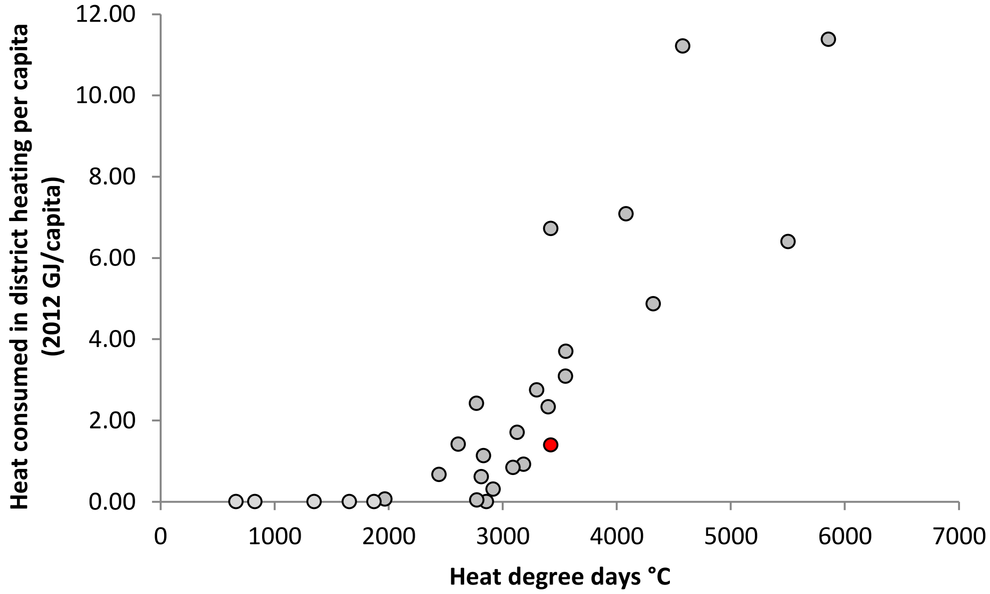

Figure 15 Relation between district heating consumption and climatic conditions. Red dot is the EU28 average (Data from Eurostat, 2012)

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ANNEX

A.1 Pinch analysis

Since the early 80's the systematic and structured approach that is used to solve to the difficult problem of overall system design is Pinch Analysis [29-33]. It is based on thermodynamic principles, and is especially useful in integrating energy intensive industries, designing optimal heat exchanger networks and identifying energy recovery opportunities. Its techniques have now been generally accepted (though more widely adopted in some countries than others), with widespread inclusion in undergraduate lecture courses, extensive academic research and practical application in industry [34]. However, as it will be described below, Pinch Analysis applies only on an industry level and does not identify heat recovery opportunities caused by modifications and improvements within a single process e.g. using a new catalyst or adding insulation in a specific process.

The basic steps of this analysis have been analysed extensively in the literature. They are summarized below but for a detailed guidance of implementing it goes beyond the scope of this report [34]:

1. Extraction of data : All process flows that are required to be heated or cooled are summarized in a Table (known as the "Problem Table") containing information about their quantity (heat load (kW)) and quality (temperatures (°C))
2. Construction of one cold and one hot composite curve for all stream within a single system/site
3. Estimation of minimum temperatures interval (ΔT_{min}) and identification of the pinch point (the point of the closest approach between the two composite curves.)
4. Construction of grand composite curve. This is the graphical representation of the "Problem Table" defined in step 1 and it can be considered as an accurate representation of the heat profile of an industry.
5. Analysis of the curve and optimal design of the required utility loads and heat exchanger network

Figure 16 presents an example of a Composite and a Grand Composite curve.

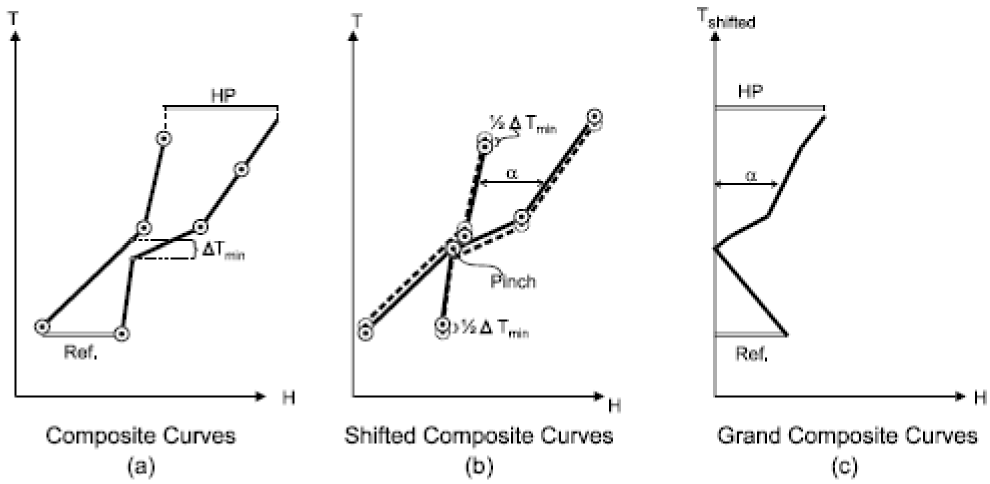

Figure 16. Construction of the Grand Composite Curve [34].

The benefit of the grand composite curve is that it shows a quick overview of the industries energy profile. More specifically it splits the system in two thermodynamically 'independent' sections:

- an energy sink which is above the pinch point and requires only external heat by a utility;
- an energy source which is below the pinch and requires only external cooling by a utility.

Both of these sections are energy integrated with specified heat recoveries when needed. This means that if a process needs cooling in the energy sink (temperatures above the pinch) then this is recovered by a hot stream. In other words, heat not used by a single process above the pinch is not considered waste heat of the industry (e.g. flue gases) since it can be recovered by another process. Similarly, if a process needs heating in the energy source (below the pinch) this is recovered by another process. As a result, the grand composite curve, acting as an illustration of the temperature profile of an industry, makes it easier to select the utilities that will meet the energy demand in the most economical way, because it shows where the heat demand and supply is 'located' within the temperature profile of the industry.

According to the above the identification of usable waste heat, potential and installation of CHP or heat pump in any industry is easily identified and simplified. In the following paragraphs this is further described and analysed.

The minimum temperature approach (ΔT_{min}) described in step 3 is needed to drive the heat transfer and is a necessary variable in the design of a heat exchanger. From a theoretical point of view it is an inherent limit of the second thermodynamic low. From a practical point of view if ΔT_{min}=0 then an infinite heat surface area would be needed. Its selection is the result of a design and optimization procedure of a heat exchanger. However there are some rules of thumbs that can be used within the scope of feasibility analysis, for approaches of steam flue gas and cooling water (CW); see Table 17.

Table 17. Common minimum temperature approaches for a variety of heat exchangers [34].

Match	DT_{min}	Comments
Steam against Process Stream	10-20°C	Good heat transfer coefficient for steam condensing or evaporation
Refrigeration against Process Stream	3-5°C	Refrigeration is expensive
Flue gas against Process Stream	40°C	Low heat transfer coefficient for flue gas
Flue gas against Steam Generation	25-40°C	Good heat transfer coefficient for steam
Flue gas against Air (e.g. air preheat)	50°C	Air on both sides. Depends on acid dew point temperature
CW against Process Stream	15-20°C	Depends on whether or not CW is competing against refrigeration. Summer/Winter operations should be considered

The type of heat recovery equipment depends on the temperature range, source of waste heat, type of heat exchange (gas-liquid, liquid-liquid etc.) and to other specific requirements, e.g. avoidance of cross-contamination. Some typical types of recovery equipment are presented below [14]:

- Radiation or convection recuperator;
- Metallic Hygroscopic or Ceramic Heat wheel;
- Plate heat exchanger;
- Shell-tube heat exchanger;
- Heat pipes.

The detailed sizing and design of the equipment that will enable the recovery of heat is beyond of the scope of this report. Critical variables include the selection of the minimum temperature difference (ΔT_{min}) of the heat exchanger, the estimation of the total heat transfer coefficient, and the total heat exchange area. Operating and capital costs of the equipment will depend on the pumping needs and the estimated heat surface area respectively. The proper selection of the design variables will be the result of the optimization procedure where an optimal trade-off between these two cost categories has to be identified.

A.1.1 Identifying the usable waste heat potential

A stream can be identified as 'waste stream' if there is no other use or potential for recuperation inside the site. In a grand composite curve, waste heat is equivalent to the energy load that needs external cooling by a utility in order to reject it to the environment. This is ensured by examining only the heat that is available in the source side of the industry; that is below the pinch point. Whether this heat can be utilized and has any economic value or not, depends entirely on the quality (temperature) requirements on the demand side. Waste heat in temperatures close to ambient is usually cooled away without having any other alternative uses similarly to the steam condensate in the power plants. If this waste heat is available at higher temperatures, it could be recovered and used for other processes like in a district heating network, or low-temperature drying etc. In that case the industry will not only benefit from the utilization or selling of this stream, but also from the reduced need for cooling this corresponding heat load (e.g. installation of a smaller cooling tower).

In the example of Figure 17, it was identified that the industry could supply 15 MW of sensible heat between the interval of 120 °C and 50 °C (marked with the dotted line). This amount of heat could be used to supply a conventional district heating network which operates within this temperature interval[18]. Apart from the benefit of selling the waste heat this industry will have also benefits from the reduced needs for cooling since now it needs only 15 MW instead of 30 MW of external cooling which will result in less pumping of water and cooling water withdrawal. On a similar way an absorption cooler could be placed at that point to supply a district cooling network.

To sum up, ideal industries that can be coupled with district heating networks are those that have any heat source at the temperature that the district heating allows (e.g. for a 3rd generation that is 130 °C) but below the pinch temperature. A more generic guideline could be defined as follows:

Depending on the design of the district heating system, this will require a heat source of 60 °C (future systems) to 120 °C (current systems) plus the minimum temperature interval (ΔT_{min}) plus the transfer heat losses.

This concept can be used for a quick estimation of the available heat to utilize both internally and externally. Recent studies in literature have used successfully this approach [1]. In this case the heat recovery station will be an appropriate heat exchanger suitable for this range of heat and fluid types.

Similarly, the installation of an absorption chiller can be identified. As an example, a conventional one stage LiBr/water absorption chiller needs heat at 80 – 110 °C and can provide cooling at 5 – 10 °C with a COP of 0.7 [6]. According to the above, for the case of the industry described in Figure

[18] Information about temperature requirements and other specifications of current and future district systems can be found in literature [8,10].

17, a district cooling network can be supplied with 10 MW (i.e. 15MW of heat multiplied by COP = 0.7) of cold water. Further technology improvements of heat-driven heat pumps will allow use of heat with lower temperature and/or higher COP, making the investments of waste-heat driven district cooling more feasible.

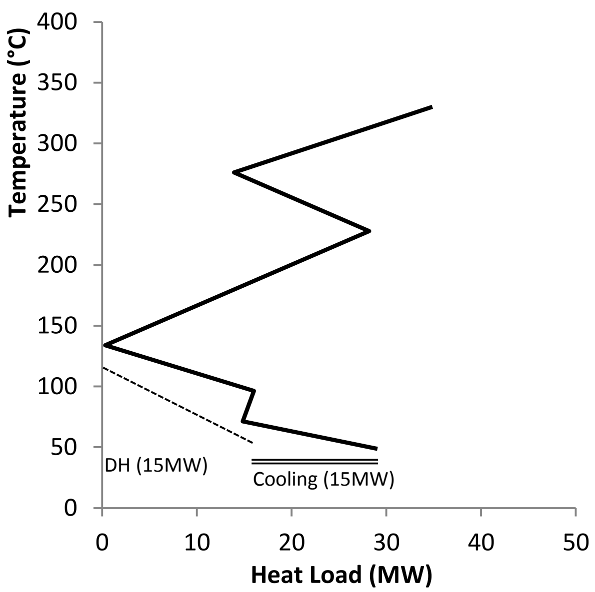

Figure 17. District heating fitted against the grand composite curve results in reduced cooling needs.

A.1.2 Identifying the potential for installation of heat engines (CHP)

Since all industries produce heat for its own uses an appropriate placement of a thermodynamic 'heat engine' will convert the installation to CHP. The 'heat engine' is used as a generic term to describe any thermodynamic cycle (e.g. Rankine, Brayton) that produces work and consequently electricity exploiting a temperature differential.

When introducing a CHP plant into an existing industrial energy system, the heat from the plant should be used where there is a deficit of heat in the process plant, i.e. above the pinch. Thus, the location of the pinch is of fundamental importance when integrating a cogeneration scheme into a process. Recall that the process is an overall heat sink above the pinch and an overall heat source below it. Therefore, the exhaust from a heat engine (e.g., steam turbine, gas turbine, gas engine) should be integrated totally above the pinch because the heat engine is then rejecting heat into the process heat sink. This is also known as topping cycle.

Alternatively, a heat engine which absorbs and rejects heat below the pinch is properly located because it converts surplus process heat, which would otherwise have been wasted to cold utility, into work. In that case, depending on the pinch temperature an alternative heat engine should be needed, such as an Organic Rankine Cycle. This is also known as bottoming cycle. In practice, bottoming cycle plants are much less common than topping cycle plants, since the number of processes that have an exhaust in high enough temperature to be utilized in a heat engine, is restricted.

The temperature level(s) at which this heat can be delivered to the process is of great importance, as is the total efficiency of the CHP plant. The possible temperature levels can be identified with the advanced composite curves above the pinch. The concept, based simply on overall energy balances, can be generalized and stated as the appropriate placement principle: the proper placement of a heat engine is either totally above or totally below the pinch [34]. If a heat engine is placed across the pinch, then no benefit is gained by the integration and it is better not to proceed with its installation.

Figure 18 shows the integration of (a) a Ranking cycle and (b) a combined cycle with a process. The key parameters for the thermodynamic system are set by starting from the target for steam demand. Minimizing the space between the grand composite curve and the utility line the thermodynamic efficiency is maximized. In the case of (a) Live steam is provided for the high temperature part and back-pressure steam from a steam turbine for the lower temperature part. The exact amount of electricity that can be produced can be identified by simple thermodynamic cycle calculations between the two temperature levels.

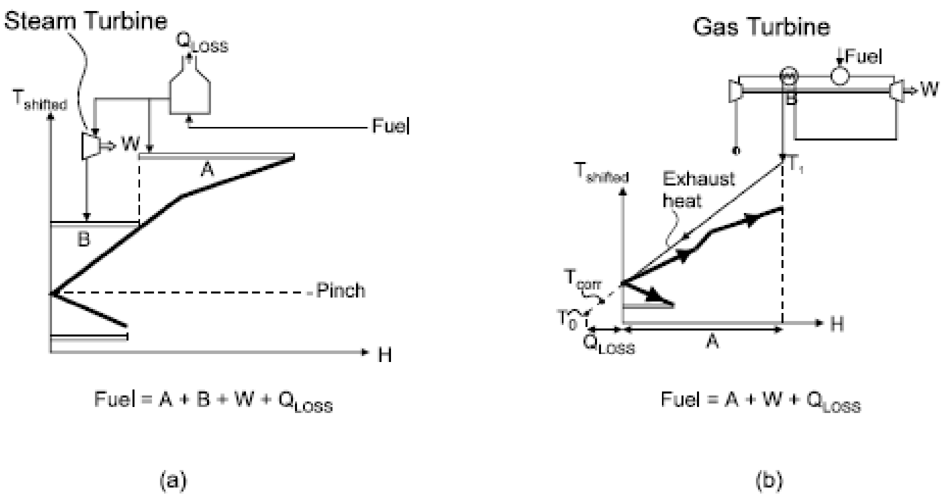

Figure 18. CHP (topping cycle) with (a) steam turbine or (b) gas turbine fitted against the grand composite curve.

Using this approach, a CHP system can be designed for industries and sized based on heat requirements (topping cycle). This makes sense since distribution of waste heat is much more difficult than distribution of excess electricity. Depending on the electricity requirements, electricity can either be used within the industry (autoproducer) or sold to the grid (producer).

A.1.3 Identifying the potential for installation of heat pumps

This paragraph refers only to heat pumps that can be used for the internal recovery and transformation of heat. Heat pumps, like absorption chillers, for the supply of cooling energy on an off-site destination is part of the analysis of the previous paragraph. In general, heat pumps should be integrated so that the evaporation takes place where there is a surplus of heat, and the condensation where there is a deficit of heat. In most industrial cases, this means around the pinch. There is also the possibility to integrate a HP around a "nose" in the GCC, but that is not discussed further here. Depending on the quantity of the heat available on the heat source or the heat sink size, the selection of the heat pump type is made (open cycle, closed cycle etc). In general the smaller the temperature interval between the heat source and the sink, the bigger the efficiency of the heat pumps.

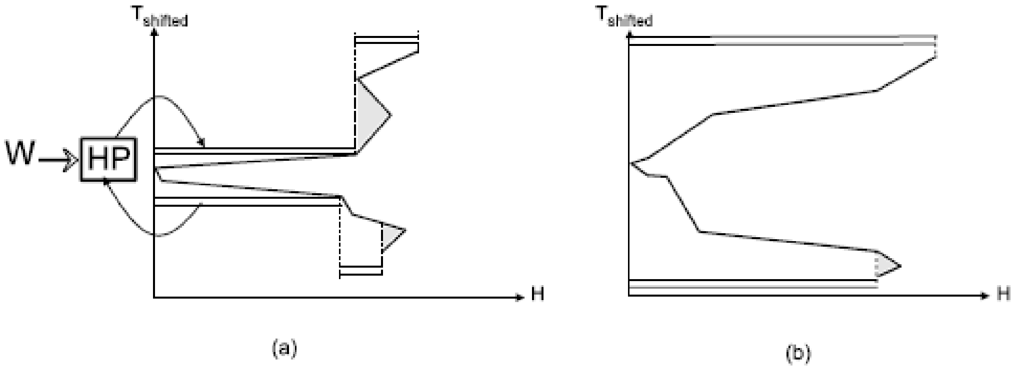

Figure 19. Proper placement of a heat pump around the pinch point minimizes the need for external utilities.

A.2 Capital cost estimation

Before equipment costs can be obtained it is necessary to determine equipment size based on the identified available waste heat of the previous section and the supply/demand of the off-site source/sink. Based on that size the capital costs can be estimated. The accuracy of the capital costs depends on the scope of the study. Through the various phases of the project the accuracy of estimates can been identified in Table 18 [35].

Table 18. Expected accuracy of estimates in various phases of project implementation.

Phase	Scope	Accuracy
Conception	Project evaluations, definition, and trade off studies	± 40 %
Feasibility	Demonstration of project economic viability	± 25 %
Definition	Control of a project that has been approved and financed	± 10 %

This type of study falls into the feasibility study category so an accuracy of ±25 % can be expected.

The capital needed to purchase the land, build all the necessary facilities, and purchase and install the required machinery and equipment for a system is called the fixed-capital investment. The fixed-capital investment represents the total system cost, assuming a zero-time design and construction period (overnight construction). The total capital investment is the sum of the fixed-capital investment and other outlays (e.g., start-up costs, working capital, costs of licensing, research and development, as well as interest during construction) [28].

The costs of all permanent equipment, materials, labour, and other resources involved in the fabrication, erection, and installation of the permanent facilities are the direct costs. The indirect costs (e.g., costs associated with engineering, supervision, and construction, including contractor's profit and contingencies) do not become a permanent part of the facilities but are required for the orderly completion of the project. The fixed-capital investment is the sum of all direct and indirect costs.

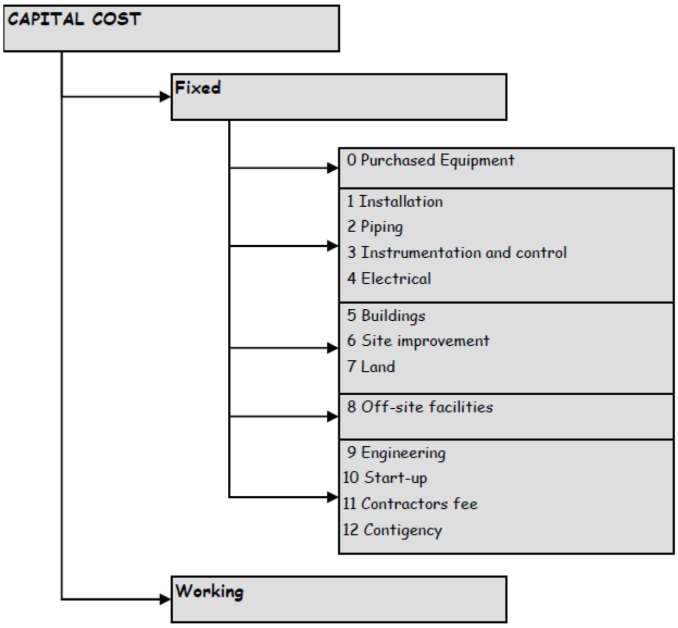

Figure 20. Summary of capital cost components.

Total capital costs can vary significantly depending on the scope of plant equipment, country, geographical area within a country, competitive market conditions, special site requirements, and availability of a trained labour force and prevailing labour rates. They are sensitive to a number of input factors such as manufacturing costs (e.g. steel), labour and other construction-related costs.

These costs can be estimated in many different ways. The purchased equipment costs are estimated with the aid of vendors' quotations, quotations from experienced professional cost estimators, calculations using extensive cost databases, or estimation charts. However the most important parameter is the capacity (size) which is defined differently for each piece of equipment. In literature it is very common to estimate capital costs like that. E.g. Boiler capital costs can be estimated as a function of their thermal output, turbines versus their pressure etc. [36]. For some purposes, the component-level detail is necessary but for the scope of the CBA, this approach is sufficient.

The equation below presents a useful method of cost estimation for equipment capacities at which costs are unknown, based on capacities at which the costs are known:

$$\frac{C_1}{C_2} = \left(\frac{A_1}{A_2}\right)^n \cdot f$$

where *C1*, *C2* are the costs and *A1*, *A2* are the capacities of the known and the unknown equipment respectively. When plotted in a log-log plot this line represent a straight curve.

The scaling exponent (*n*) is an empirical constant used to adjust the cost estimate for size expressing the influence of economies of scale; smaller systems will have a higher cost per capacity. Equipment that is completely modular where the economies of scale have no effect have a *n* closer to 1. Equipment with a bigger effect of economies of scale (vessels, boilers etc) can even reach *n* = 0.4. The average value for all equipment is about 0.6; that is why this method is known as the "six-tenth" method [35]. Based on this method rule of thumbs have been developed and used in case studies found in literature and can be used with sufficient accuracy for feasibility analysis if no other data is available. Indicatively CHP and absorption chiller capital costs are presented in the following chart:

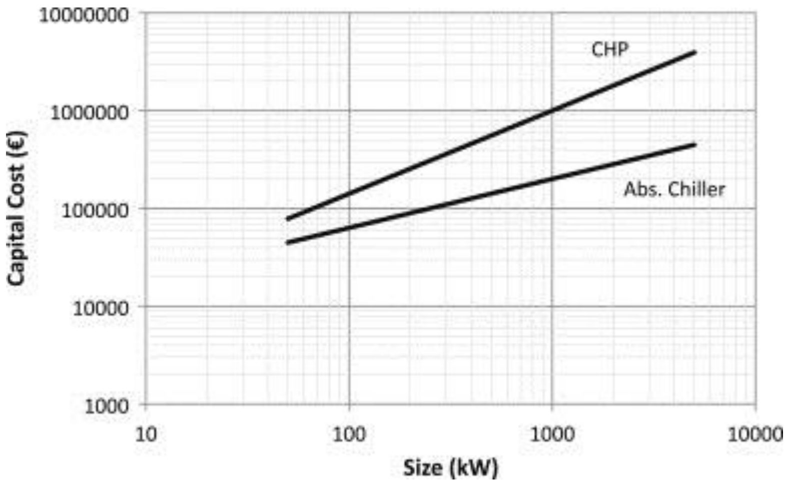

Figure 21. Typical capital cost curve for a cogeneration and absorption chiller equipment [37].

A correction factor (*f*), can be applied to the above in order to account differences in temperature, pressure, material of construction, equipment type, operating temperature etc. For example a heat exchanger that operates at around 50 bar will cost 2 times more from a similar sized heat exchanger that operates in atmospheric pressure. A stainless steel heat exchanger will cost 5 times more than a carbon steel one. Such correction factors and empirical equations can be found in literature [38].

If necessary, the cost estimates of purchased equipment can also be adjusted for time (with the aid of cost indices). Cost data given at a specific date can be converted to more recent costs through the use of cost indices. The most popular cost indices are the Marshall & Swift (for specific equipment) and the Chemical Engineering Plant index (for plants). They account for the general developments in costs since the estimate was made, related to labour, material, energy prices and product prices. Both of these indices are being published in an monthly basis by the Chemical Engineering magazine by Access Intelligence since 1967.

The remaining direct costs are associated with equipment installation, piping, instrumentation, controls, electrical equipment and materials, land, civil structural and architectural work, and service facilities. These direct costs, the indirect costs, and the other outlays, if they cannot be estimated directly, are calculated as a percentage of the purchased equipment costs or alternatively as a percentage of the fixed-capital investment.

The most popular empirical factor to estimate the fixed-capital investment of a project based on the purchase cost of equipment with a correlation invoking the empirical factor, is called Lang factor (f_L)

$$C_{installed} = f_L \cdot C_{equipment}$$

where $C_{installed}$ (EUR) is the total investment cost, f_L(-) and $C_{equipment}$ (EUR) are the Lang factor and the equipment capital cost respectively. The Lang factor accounts for project costs such as for installation, which are additional to the capital cost. The Lang factor can be applied to new plants, but not to projects where equipment is installed in existing plants. Usually this factor is characteristic per type of facility and varies from 3.5–5 depending on the type of the plant [39]. A similar factor that applies to main pieces of equipment rather than to the whole plant is the Hand factor. Indicatively the following relevant equipment is mentioned: Heat exchanger: 4.5; Pump: 4; Compressor: 2.5.

A.3 Evaluation of scenarios with multi criteria analysis

Multi – criteria analysis can be used in order to pre-select scenarios or evaluate the proposed investment from different perspectives if a full economic cost benefit analysis is not available. These criteria can be energetic and environmental benefits such primary energy savings and emission reduction. The financial result can be evaluated against these qualitative criteria.

Multi-criteria decision analysis is a qualitative tool for ranking alternative options against a given set of objectives and criteria. A global solution can be estimated but usually this solution will be based on subjective weighting of the above mentioned criteria. It is less rigorous than a full economic benefit cost analysis, but is more flexible since it enables the comparison of options involving both monetized and non-monetized impacts. Sometimes it performs better if there is no definitive and accurate methodology of converting non-monetizable benefits/costs to monetized ones, since the subjective/biased conversion is limited only in the weighting factors.

Figure 22 shows an illustrative example of different alternative scenarios comparing an financial (NPV) and an energy efficiency (PESR) criteria. It is clear that the non-dominated solutions which should be prefered are the solutions that are closer to the red dashed line. With this multidimensional overview it can be easily identified whether a positive financial outcome comes from a high energy savings (PESR) or from special market conditions.

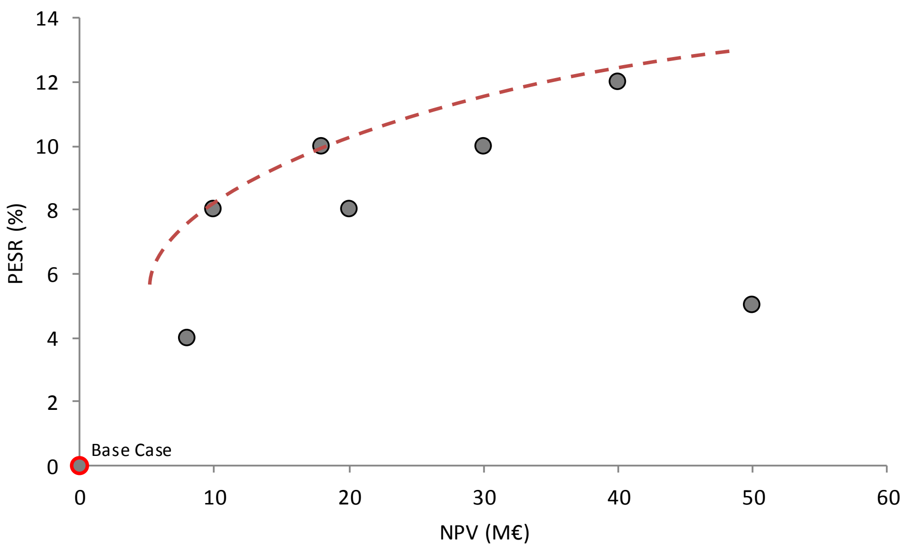

Figure 22. Multi objective evaluation of results.

A.3.1 Primary Energy Savings

All proposed investments should result in reduced primary energy used for the coverage of the same energy demand. The primary energy consumed between two cases (before and after the proposed investment) can be estimated by a simple indicator called Primary Energy Savings Ratio (PESR). The comparison should be done for the same amount of end-use energy (electricity, heat etc).

The generic equation of PESR which corresponds to the relative reduction of primary energy is as follows:

$$PESR = \frac{E_{before} - E_{after}}{E_{before}} = 1 - \frac{E_{after}}{E_{before}}$$

Where E is the primary energy consumed (e.g. fuel) and the subscripts (before, after) refer to the reference case and the proposed case respectively.

For a specific CHP plant the PESR can be estimated by means of:

$$PESR = 1 - \frac{E_{after}}{\frac{El}{\eta_{ref,El}} + \frac{Th}{\eta_{ref,Th}}} = 1 - \frac{1}{\frac{\eta_{CHP,El}}{\eta_{ref,El}} + \frac{\eta_{CHP,Th}}{\eta_{ref,Th}}}$$

where *El* is the electricity and *Th* the thermal energy produced (same amount before and after) and n_{ref} the reference efficiency of separate production technologies and n_{ref} the cogeneration efficiency.

A.3.2 Emissions/pollutant reduction

The energy efficiency investment should in principle result to the reduction of the emissions/pollutants linked to the reduction in primary energy due to more efficient technologies and the use of cleaner fuels.

Usually the value of the emissions for any end-use energy (i.e. grams emitted per kWh consumed) depends on the fuel and energy technology used.

Most common GHG emissions and pollutants that have to be considered are the following:

- carbon dioxide, CO_2;
- sulphur dioxide, SO_2;
- carbon monoxide, CO;
- nitrogen oxides, NOx;
- unburned hydrocarbons, HC;
- solid particle materials, PM.

On a similar rational with the primary energy savings, the relative reduction of emissions occurred by the installation of the new plant can be used as a criteria of 'environmental efficiency' of the proposed investment. More specifically as an environmental criterion, the Emission reduction ratio (ERR) is proposed to be the average relative reduction of all kind of pollutants as follows:

$$ERR = mean\left(1 - \frac{Emissions_{after,i}}{Emissions_{before,i}}\right)$$

A.4 CBA studies from literature

Small distributed generation versus centralised supply: a social cost–benefit analysis in the residential and service sectors [40]

a) System and geographic boundaries	Study examines several variants of centralised versus de-centralised heating, cooling and electricity for the case of a large residential building and for a hospital in two geographies: North ("Milan") and South ("Palermo"). The geographical distinction is relevant both for heating/cooling demand and the expected external costs.
b) Approach to demand and supply options	The model exogenously sets total demand for electricity, heating and cooling for the two building types in the two geographies for two six month periods (winter and summer). The issue of intermittency is not dealt with – As said, the model looks at how to meet total estimated energy requirements in either winter or summer.
c) Baseline construction	There is no defined baseline. The options being compared against each other all tend to be more efficient than the status quo. The idea is to compare different conceivable natural gas based options for supplying energy to buildings.
d) Identification of alternative scenarios	All options use natural gas as fuel. The aim is to compare conventional option A (centralised electricity generation, condensing boilers for heat, compression chiller for cooling) with option B (centralised generation, heat pumps for heating and cooling) and decentralised options C and D. Option C generates sufficient thermal energy for the building's energy requirements and feeds excess electricity into the grid whereas option D only generates enough electricity to cover the building's needs. In this case the thermal energy generated would be insufficient to cover the building's demand. Gaps in thermal energy demand are filled by a reversible heat pump using "cogenerated power" for additional heating and cooling.
e) Method for calculating the costs and benefits: ▪ Time horizon ▪ NPV	Minimum Payback 10 years. Typical payback 20-30 years The model will simulate the KWh for the different demands and investment to determine a competitive thermal KWh price.
f) Parameter assumptions ▪ Price assumptions	For the internal cost calculation a discount rate of 4% is chosen. This value would tend to correspond to a social discount rate. This is consistent with the aim of the article, namely to undertake social

▪ Discount rate ▪ External cost assumptions	CBA. For assessing the external costs of global warming discount rates between 1% and 3% are chosen (resulting in costs per t CO2 of 18-52€), following the suggestions of the ExternE report. Taxes not included in cost assessment. Assessment of real social value would be distorted by taxes, such as energy taxes. (p 806)
g) Costs and benefits covered ▪ Benefits ▪ Costs	Internal: ▪ Fuel costs ▪ Electricity costs ▪ O&M costs ▪ Investment costs External, based on estimates from ExternE, weighted by geography (e.g. population density), leading to higher pollutant costs for Milan than for Palermo. ▪ SO_x ▪ PM10 ▪ NO_x Global warming (18-52 €/t CO2)
h) Sensitivity analysis	Of structural conditions: Due to colder climate internal costs for CHP are more favourable in Milan while external costs are less favourable with higher damage costs from air pollutants. As sensitivities, internal costs from Milan are combined with external costs from Palermo (best case) and internal costs from Palermo are combined with external costs from Milan (worst case). Natural gas prices: high and low price cases examined based on observed price changes over the past 20 years. Reduced investment costs and increased efficiency of CHP plants Grid transportation costs for gas and electricity. Increase in power supply reliability from CHP

Feasibility study for a district heating system serving the primary school and leisure centre in La frazione di Lagaro, Italy

The scope of this feasibility study is to determine the best available technology to supply the heat demand of an existing school and leisure centre in the city La frazione di Lagaro, in Italy, utilizing woodchips from the Apennines. It compares the economic and environmental benefits of installing a boiler for only heat production or an engine for combine production of electricity and heat.

a) System and geographic boundaries	The selected geographical area is the city "la Frazione di Lagaro", in Italy. Two public buildings have been selected: the primary school and the leisure centre. These buildings are located close one to each other and currently supply hot water to the buildings burning conventional fuels in boilers with efficiencies 85-90%.
b) Approach to demand and supply options	The heat demand is based on the current existing demand for heating and hot water. If available, it's based on historic data; otherwise it's based on the demand of similar buildings or the energy analysis of the building. Currently the heat is supplied burning conventional fuels, and will be replaced by woodchips. The amount of conventional fuel currently used is known.
c) Baseline construction	Simultaneous hourly heat demand of the two buildings. Location of the central system and storage in the building with more available space. Technical details of the network: length, diameter, supply and return temperatures and insulation. Environmental analysis compared with the current situation
d) Identification of alternative scenarios	The study considers two options: District heating burning biomass with and without cogeneration and the utilisation of electronic management and a heat accumulator.
e) Method for calculating the costs and benefits: ▪ Time horizon	Results are presented in terms of payback, which is given as being 10-20 years

▪ NPV	
f) Parameter assumptions ▪ Price assumptions ▪ Discount rate ▪ External cost assumptions	
g) Costs and benefits covered ▪ Benefits ▪ Costs	The study provides a detailed analysis of the cost of the two options. The costs include investment, maintenance and operation. In case of the cogeneration mode, it includes the benefits obtained with green certificates and for sales of electricity.
h) Sensitivity analysis	No data available
i) Other: Valuing flexibility	The study only considers two technology options. Fuel considered is woodchips as available in the forest close by. The most feasible solution is determined as a result of comparing the technical, economic and environmental benefits and savings.

Determination of the potential for utilising combined heat and power and of the target reduction of CO2 emissions [41]

Chapter 5 of this report performs a set of simple financial analyses of the following CHP plants: Micro-CHP (0.8kW$_e$, 3kW$_{el}$, 9.5kW$_e$), CHP (50kW$_e$, 2MW$_e$), CCGT CHP (23.8MW$_e$, 100MW$_e$), Coal CHP (200MW$_e$), gas turbine CHP (simple cycle, 10MW$_e$). These are contrasted to 3 conventional generation options: CCGT (800MW), coal (700MW) and Lignite (800MW).

a) System and geographic boundaries	Financial assessment of several types of CHP plant compared to large-scale thermal generation. Comparison is made in terms of € cents per kWh.
b) Approach to demand and supply options	Not part of the analysis. Fixed output, amount of operating hours per year, revenues from electricity and heat generation assumed
c) Baseline construction	No baseline, not applicable
d) Identification of alternative scenarios	No options
e) Method for calculating the costs and benefits: ▪ Time horizon ▪ NPV	No time horizon given – all expresses as cents per kWh.
f)Parameter assumptions ▪ Price assumptions ▪ Discount rate ▪ External cost assumptions	Discount rate: Both ranges: calculations are performed using discount rates of 4%, 8% and 12% Fuel taxes included in the cost comparison
g) Costs and benefits covered ▪ Benefits ▪ Costs	Only commercial
h) Sensitivity analysis	Sensitivities performed for:

	▪ Discount rate (4%, 8% and 12%) ▪ Electricity prices (+2% p.a. vs -1% p.a.) ▪ Operating hours per year (1,500 h/y – 5,000 h/y in steps of 500 h) ▪ ETS price (€0/t, €10/t, €20/t)
i) Other: Valuing flexibility	

Guidelines for assessing techno-economic feasibility of a district heating network

The scope of this guideline is to demonstrate the profitability of a district heating Network compared to a conventional heating system in the region of Veneto. The guideline describes the determining technical and economic factors and considers different technical options. It compares different scenarios by analysing the economic benefits and environmental impacts. The decision of feasibility is a result of evaluating these factors.

a) System and geographic boundaries	The feasibility study describes the types of buildings that should be included within the boundaries of the selected geographical area and suggest criteria to include or exclude them based on demographic and socio-economic factors.
b) Approach to demand and supply options	Assessment of different methods to quantify the heat demand depending on the availability of information and the type of data that needs to be collected. This assessment should result in the determination of different parameters such as thermal demand, thermal capacity and required temperature and pressures to satisfy the demands. Supply will consider the available resources prioritising the utilisation of existing heat sources, excess heat from industries and renewable sources, however economic and technical feasibility factors will determine the best solution.
c) Baseline construction	Considering technical, economic and environmental conditions: ▪ Minimum distance from the heat plant to the user ▪ Minimum cost of supply of the energy source ▪ Minimum environmental impact per inhabitant
d) Identification of alternative scenarios	One main demand scenario and two additional scenarios considering minimum and maximum demands. Different configurations of the distribution network depending on technical and economic factors. Type of plant: only heat or CHP will depend on load variation and payback period. Type of technology (Engine, Gas turbine, Steam turbine, Combined

	cycle, fuel cells or micro turbines) and size will depend on: ▪ Final heat demand and losses ▪ Temperature required ▪ Economic priority attributed to the sale of heat. ▪ Load duration curve ▪ Monthly demand ▪ Guarantee 4000 operating hours to satisfy the demand Transport system: types of distribution networks depend on the length, diameter and material and have an important impact on the losses and cost. Type of operation: ▪ Only in cogeneration mode ▪ Either in cogeneration mode or as only power or only heat (more operating hours). Recommendable for plants with operating in a competitive heat or electric market and technologies with high power efficiencies and low maintenance costs.
e) Method for calculating the costs and benefits: ▪ Time horizon ▪ NPV	15-25 years' time horizon
f) Parameter assumptions ▪ Price assumptions ▪ Discount rate ▪ External cost assumptions	
g) Costs and benefits covered ▪ Benefits	Contains tables with the detailed information required : ▪ Cost of generation, distribution, control, regulation and auxiliary equipment.

▪ Costs	▪ Cost of operation and maintenance of equipment ▪ Sales of electricity and heat. Environmental analysis contains data required to evaluate the emissions. Energy and emissions of the district heating network should be compared with the system that will be substituted (decentralised system for heating and centralized power production in case of CHP) using average seasonal efficiency and type of fuel or the typical values for that sector. Emissions relative to power generation can be taken from the fuel mix of the national electric system
h) Sensitivity analysis	
i) Other: Valuing flexibility	Design flexibility is considered. Different options in technologies, operational modes, and transport and supply sources will be considered to achieve the best technical, economic and environmental solution.

After completion of heat mapping process it is advised to perform its revision. This is needed in order to eliminate possible errors and discrepancies. Some of them might be eliminated by mapping team itself after internal revision while others will have to be identified after external revision by competent persons. In order to make heat map as accurate as possible, organizers of CA might also consider gathering feedback from regional and especially municipal authorities and related organizations or persons.

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