

# **EUSUSTEL**

## **European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply**

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### **WORK PACKAGE 3**

#### **Electricity Generation Technologies and System Integration**

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##### **Subtask 3.1.3**

##### **Combined heat & power**

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# **1 Introduction**

Early CHP was based on local initiative. The conversion efficiency of early electricity generation was very low in small units located near the final consumers, so using the large amount of waste heat was very attractive. When the power stations became larger, more efficient and located away from city centres, CHP became less attractive for the electricity supply industry.

However, promotion of CHP became a policy measure towards more rational use of energy and a means for reduction of emissions of pollutants from energy conversion, because (well-designed) cogeneration of electricity and heat is more efficient than separate production.

## **1.1 The EU CHP Directive**

In the Communication from the Commission to the Council and the European Parliament of October 1997 “A Community strategy to promote combined heat and power (CHP) and to dismantle barriers to its development” [13], it was stated that: “CHP is one of the very few technologies which can offer a significant short or medium term contribution to the energy efficiency issue in the European Union and can make a positive contribution to the environmental policies of the EU.”

After reiterating these principles in several formal EU documents over the following years, in 2004 the European Parliament and the Council adopted a Directive on the promotion of cogeneration based on a useful heat demand in the internal energy market [12]. The main purpose of the Directive is to create a framework for promotion and development of high efficiency cogeneration of heat and power based on useful heat demand. Member States shall bring into force the laws, regulations and administrative provisions necessary to comply with this Directive not later than 21 February 2006.

## **1.2 Principle of cogeneration: Heat, work and the Carnot efficiency**

*Combined heat and power (CHP) or cogeneration* is an energy conversion technique that tries to convert two useful energy (transfer) forms simultaneously: *work* and *heat*.

In contrast to *heat*, *work*, is more difficult to generate. E.g., starting from fossil fuels, two ways are possible. The first one, by electrochemical means in fuel cells, appears very promising, but cannot yet be seen as a routine technology. The other way goes through the thermal route and is based on the laws and concepts of classical thermodynamics. It concerns technologies of combustion engines and power stations.

Although the first law of thermodynamics dictates that energy is conserved, the second law dictates that not all energy types have the same value: work can be converted into heat without restriction; the reverse conversion cannot happen entirely.

Starting from a heat supply  $Q_1$  from a high temperature reservoir (at temperature  $T_1$ ), a quantity of work  $W$  is generated together with quantity of “lost heat”  $Q_2$  at low temperature  $T_2$ . The higher the

temperature of the high temperature reservoir, the greater the delivered work. In engines and power stations we are interested in the generated work, we define the efficiency of a thermal engine as<sup>1</sup>

$$\eta \equiv \frac{\text{useful work}}{\text{originally available heat}} = \frac{W}{Q_1} \quad (1)$$

The maximal efficiency theoretically feasible for thermal engines, is that of a Carnot cycle and is named the Carnot efficiency:

$$\eta \equiv 1 - \frac{T_0}{T_1} \quad (2)$$

where  $T_1$  is the temperature of the high temperature source, while the temperature of the low-temperature reservoir  $T_2$  is chosen equal to the ambient temperature  $T_0$ . Both temperatures are expressed in Kelvin ( $0^\circ\text{C} = 273 \text{ K}$ ). A high  $T_1$  and low  $T_0$  are favourable for a large Carnot efficiency.

In practice the efficiencies are lower and depending on the case, 40 to 60 % of the original energy is lost and “dumped” into the atmosphere.

If, however, in such optimal power station, the working fluid is prevented from cooling to just above the temperature of the environment, in order to use the heat at a higher temperature  $T_2$  (e.g., for process purposes) a price has to be paid: the efficiency for electric power generation is diminished. This efficiency decline occurs in all power stations with steam turbines where process heat is withdrawn from the thermodynamic cycle by turbine bleeding, or via a back-pressure turbine. This is the case in classical thermal power stations, but also in combined cycle power stations. The reason is that heat losses at high temperature in these plants are minimal because a lot has been done to use all the heat at high temperature. Although such power stations in the end drain a lot of heat to the environment (as mentioned above, 40 to 60 %) it is all heat at low temperature, just above the environmental temperature. The only way to become valuable process heat at high temperature is to intervene in the thermodynamic cycle, which results in a decrease of the electric power efficiency.

With reciprocating engines and (simple) gas turbines, on the other hand, it is possible to recuperate heat without diminishing the power efficiency: one simply tries to recuperate the heat at medium temperature instead of throwing it away. This can be done without intervening in the thermodynamic cycle. Examples of this kind of heat recovery is the energy of exhaust gasses of gas turbines and piston engines, as well as the heat of the oil cooling and the cylinder casing of piston engines.

### **1.3 Quality of energy and the concept of exergy**

Work and heat clearly have a different quality. Work is the most valuable type of energy. Work can be converted into heat completely, whereas heat can only be converted into work to a limited extent, given by the Carnot efficiency. This means that a heat reservoir of certain temperature  $T$  is more valuable when the temperature is higher (because in principle it can supply heat to a Carnot cycle with power efficiency equal to  $(1 - T_0/T)$ ). Therefore, the higher the temperature of the reservoir, the bigger the potential to deliver work. A high-T reservoir has therefore more quality

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<sup>1</sup> "thermal engine" is a collective noun for combustion engines and electric power stations.

than a low-T reservoir (with the same “heat content”); the *quality* of the energy content of a state is called the *exergy*, or *availability*. It is too bad that this concept is not mentioned in the Directive. This is not a reason why we should not use it.

More scientifically, *exergy* is defined as 'the maximal quantity of work that a system can deliver (on its way to equilibrium with the environment)'. Fuels before combustion, electricity and work itself have a high quality and therefore a relative exergy-content of 1; a body at temperature T has a relative exergy-content of  $(1 - T_0/T)$ .

The quality or exergy content of the heat dumped into the environment in an optimised power station is very low. The drained heat is almost worthless.

#### **1.4 Cogeneration, a clever way to produce heat**

At first sight, contemporary boilers for central heating are very efficient. We talk about *energetic* efficiencies of 90 - 95%. Nevertheless in their classical application for room heating, the quality of energy is poorly used. After all, one starts from fossil fuel with a “high quality”, with a relative exergy content of 1, while hot water is produced at a temperature of 80-90°C to finally heat a room to 22°C. The exergy of the fuel is drastically diminished to hardly 5% of the original exergy content. In other words, the *exergetic* efficiency of central heating system is merely 5%. This means that by this kind of space heating a lot the intrinsic quality of fuel has been lost. Space heating with central heating boilers is a very inefficient process. There are more clever ways to generate low-temperature heat.<sup>2</sup>

The exergetic efficiency of a common power station is approximately equal to the work efficiency. Taking that the heat drained to the environment has no exergy content anymore, the exergetic efficiency of, e.g., a combined cycle power station is 55 - 60%.<sup>3</sup> This shows that combined cycle technology is very efficient. Another quality index, the electric-power-loss-ratio, will be discussed in Section 3.5.

From the discussion above, one gathers that cogeneration has little to do with heat recovery in power stations. Cogeneration should rather be seen as a clever way to generate heat. Instead of degrading valuable fuel to heat at low temperature, it is better to insert some kind of power conversion equipment (like a turbine or an engine) during the degradation process to produce some work. According to this point of view, cogeneration is a method whereby electricity is a by-product, while heat is produced anyway (heat that otherwise would have been produced by a boiler).

In the case of reciprocating engines and (simple) gas turbines, it may be said that cogeneration is a way to recover heat next to mechanical-power generation. However, it must be stressed that *electricity generation* with engines is inferior to the combined cycle technology, and that it only

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<sup>2</sup> A thermodynamically speaking very good device is a heat pump. Here, environmental energy is “pumped up” to the required temperature for space heating.

<sup>3</sup> Strictly speaking, when the small exergy-content of the dumped heat is taken in account, the exergetic efficiency will be slightly larger than the work efficiency.

makes sense if the heat is also recuperated. Gas turbines<sup>4</sup> for *electricity generation* are only applied for peak shaving purposes (where short start-up time is important); heat recuperation is possible in principle, but that then restricts the flexibility of a peak shaving turbine.

From the above discussion it must be clear that cogeneration only makes sense energetically, where there is a demand for useful heat. Cogeneration is only justified if the produced heat is utilised; throwing away – or condensing – heat is to be discouraged and can only be allowed if the primary energy savings (integrated over e.g. a year) thanks to cogeneration remain positive compared to separate generation of electricity and heat. In some countries the existence of a market for heat or steam has been the primary criterion for the location of new electricity generating capacity with simultaneous heat production.

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<sup>4</sup> As stand-alone electricity production unit, not these of large CHP units.

## **2 Overview of used technologies**

### **2.1 Current technologies**

The prime movers used for cogeneration applications are of the following type:

- steam turbines (extraction-condensing or back-pressure)
- gas turbines
- reciprocating engines (especially gas- and diesel engines).

These prime movers are characterised by the type of fuel they use, the kind of combustion process and the power efficiency, the quantity and the temperature of the recoverable heat. An important characteristic of a cogeneration installation is the so-called heat/power ratio  $\dot{Q}/\dot{E}$  for a chosen working point; this is the ratio between the available heat-power  $\dot{Q}$  and the electric - work power  $\dot{E}$ .<sup>5</sup> Conversely, sometimes the power/heat ratio  $\dot{E}/\dot{Q}$  is used.

#### **2.1.1 Steam turbines**

Steam turbines are used to generate mechanical rotation power in a thermodynamic Rankine cycle. They are present in current power stations and consist of three major components: a heat source, a steam turbine and a heat sink (with or without improvements like steam reheating or regenerative water preheating).

The steam boilers, which deliver steam to the turbines, are systems based on external combustion. The furnace and the thermodynamic process fluid are physically separated. The big advantage of this type of systems is that nearly all fuels can be used in the steam boiler. The disadvantage is the (exergetic) efficiency drop due to the heat transfer process.

The higher the quality of the available process steam, the smaller the delivered mechanical power of the turbine. There are several configurations of steam turbine cogeneration systems and the operating conditions can vary in a wide range. Depending on the chosen pressures (from a few to about 100 bar) and temperatures for the process flows (up to about 600°C), the power/heat ratio can vary from 1 : 2 → 1 : 10.

There are three main configurations of steam turbine cogeneration systems. The first one, the simplest configuration, is the back-pressure turbine. Depending on the thermal load, steam exits the turbine at a pressure higher or equal to the atmospheric pressure or at an intermediate stage. The extracted steam is fed to the load, releases heat and condenses. The condensate returns to the boiler after addition of extra water, if necessary to compensate losses while using the steam. As the steam mass flow rate is depending on the thermal load, the electric output is depending on it as well. For back-pressure turbines the heat output is the most important, with  $\dot{E}/\dot{Q}$  ratios between 1 : 10 → 1 : 4-5.

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<sup>5</sup> Power (energy per time unit) is expressed with a point above the symbol. E is the electric energy;  $\dot{E}$  is the electric power.

A second configuration, which is more complicated and expensive than the first one, is the condensing steam turbine with steam bleeding. In this turbine, steam for the thermal load is extracted at one or more intermediate stages and the remaining steam expands to the condensing pressure, which can be as low as 0.05 bar. As it is not obvious to have a process application at the corresponding condensing temperature (33°C), the low temperature heat has to be rejected to the environment. In comparison with the first configuration, relatively less heat, but more electricity is delivered, resulting in a  $\dot{E}/\dot{Q}$  in the range 1 : 3-4.

A third configuration is the bottoming cycle steam turbine system. In this option, high temperature exhaust gases, which are the result of an industrial process, are used to produce steam by passing a heat recovery steam generator. So, fuel is first used to cover a thermal load and then to produce electricity by a steam turbine in a bottoming cycle. This configuration can be combined with the back-pressure or condensing bleeding turbine of options one or two. When the temperature of the bottoming cycle is in the range of 80-300°C, there is an option to use another working fluid in the Rankine cycle instead of water.

Historically, these three types of cogeneration have been widely used in industry. Most “auto generators” use(d) these kinds of cogeneration. One finds back-pressure installations in the electric power range of 50 kW<sub>e</sub> to above 100 MW<sub>e</sub>. Typical electric power efficiencies for back-pressure turbines come to 10-20 % (increasing for larger turbines).

### **2.1.2 Gas turbines**

The intention of this heat-recovery diagram is that the high-temperature exhaust gases of the gas turbine are recuperated in a recovery boiler, generating steam for process purposes.

A gas turbine is an internal combustion machine, where the thermodynamic fluid is composed of the reacting fuel-air mixture. The disadvantage is that the choice of the fuel is restricted to high value liquid fuels such as kerosene, or to gas, like natural gas or propane.

The gas turbines used for cogeneration purposes are mostly of the type with a simple cycle, without energy recuperation for power maximisation. This has as advantage that the gas turbine is less sophisticated and more robust. An additional advantage for cogeneration applications is that the recoverable heat in the exhaust gasses is of high quality. The price to pay is less mechanical work efficiency.

Turbines for cogeneration purposes are available and competitive in the range of 100 kW<sub>e</sub> to more than 100 MW<sub>e</sub>.<sup>6</sup> Depending on the specific design of the gas turbine / recuperation boiler combination, we have a typical  $\dot{E}/\dot{Q}$  ratio of approximately 1 : 1 → 1 : 3 (where the ratio of 1 : 2 is more usual).

Gas turbines are supposed to operate mostly at *full load*, as their efficiency at partial load decreases drastically. As rule of thumb a gas turbine should not be operated at a power level under 3/4 of full load.

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<sup>6</sup> Nowadays frequent use of gasturbines for cogeneration applications is mostly in the range of 1-100 MWe.

Because the exhaust gasses of a gas turbine contain still an excess of air, it is possible to have extra combustion in the recuperation boiler of the cogeneration unit: simple fuel injection suffices.

### **2.1.3 Reciprocating engines**

Typical piston engines used for cogeneration, are mostly diesel engines for large power (100 kW<sub>e</sub> - 60 MW<sub>e</sub>) while gas engines – mostly adapted versions of gas oil or petrol engines – are applied for smaller power levels (from 5 kW<sub>e</sub> up to 4 MW<sub>e</sub>).<sup>7</sup>

The typical temperatures of the recovered heat are situated around ± 50°C, ± 80°C and ± 100°C for the inter cooler, the oil cooler and the jacket cooler, respectively. The temperature of the exhaust gasses measures about 400-500°C. These temperature levels explain that the use of engines for cogeneration purposes is dependent upon the required temperature of the heat application (this is coupled with the return temperature). If the process returns the fluid flow at a temperature of more than 150°C, only the exhaust gasses can deliver heat. In that case, the thermal recoverable heat-power is rather limited.

At a return temperature of 70°C, the  $\dot{E}/\dot{Q}$  ratio of low-power gas engines (<1MWe) is in the range of ± 1 : 1.5. For high-power gas engines we have a ratio around 1 : 1 to 1 : 3. At return temperatures of 90°C, the  $\dot{E}/\dot{Q}$  ratio for gas engines is typical in range 1 : 0.5 to 1 : 1.

For diesel engines, the exhaust gasses cannot be cooled too far to avoid condensation of the exhaust gasses containing sulphur (avoiding corrosion). The typical power-heat ratio for diesel engines is in the range of 1 : 1 to 1 : 1.2 for a medium-power engine, and amount to typically 1 : 0.5 for higher power levels (with a return temperature of 70°C).

The *partial load* characteristics of reciprocating engines are more acceptable than for gas turbines. Both engines (gas and diesel) operate reasonably well up to half the rated power. The efficiency for electricity production in a gas engine does not decrease below 80 % of value at full load; for a diesel engine this value stays above 90 % of the full load value. The  $\dot{E}/\dot{Q}$  ratio of gas engines decreases slightly at partial load, while the  $\dot{E}/\dot{Q}$  ratio of diesel engines at partial load slightly increases in comparison to rated operation.

### **2.1.4 Combined cycle power stations**

A combined cycle power station is a system of a gas turbine with heat recovery boiler, whereby the steam leaving this boiler feeds a steam turbine to generate mechanical and electric power. When the system is optimised for electricity production, one obtains a high-value electricity power station with work efficiency around 55-60 %.

A common combined cycle power station recovers heat of the exhaust gasses of the gas turbine, thereby maximising the electricity production. Through steam bleeding, or via a back-pressure

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<sup>7</sup> Most diesel- and gas engines for cogeneration applications are situated in the categorie between 200 kW<sub>e</sub> and 2 MW<sub>e</sub>.

turbine, we can recover an amount of high-temperature heat coming from the heat recovery boiler. The price to pay is again a lower efficiency for electricity production. However, the overall primary energy consumption will be higher than for the separate production of electricity and heat.

## 2.1.5 Prospective technologies

### 2.1.5.1 Stirling engine

Stirling engines are based upon a thermodynamic cycle which has an efficiency equal to the Carnot efficiency, at least if considered as an *ideal* cycle. The Stirling cycle passes between two isotherms and two isochores. During the isothermal expansion, external heat is supplied; during the isothermal compression heat has to be removed towards the environment. What makes this cycle special, is the fact that the exchange of heat during the isochorous changes of state is compensated for internally: by storing the heat in a regenerator, the heat removed during one isochorous change of state is absorbed by the other. This thermodynamic cycle is represented in Figure 1<sup>8</sup> [1], [7].

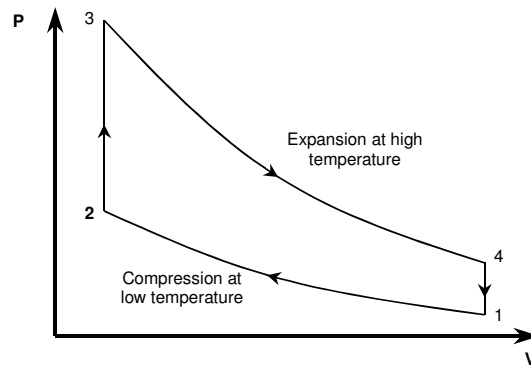


Figure 1 The Stirling cycle – two isochores and two isotherms [7]

In practice the Carnot efficiency is not reached due to various losses. Heat recovery in the regenerator is always incomplete because of heat losses and the isochorous transitions cannot be realised free from work because of friction. Schematically, the engine consists of a hot cylinder which is heated externally and a cold one which is cooled externally. The isochorous transitions  $2 \rightarrow 3$  and  $4 \rightarrow 1$  pass through a regenerator, which is some kind of ‘heat sponge’. The heat released during the isochorous cooling  $4 \rightarrow 1$  is stored and released again during the isochorous heating  $2 \rightarrow 3$ . The cold side of the engine is mostly cooled by tap water, while the hot side is heated by the exhausts of a combustion process. The Stirling engine is usually considered to be an external combustion engine, but may in principle be heated by other means such as concentrated solar heat.

Typically a Stirling engine is integrated into a boiler, where the Stirling engine itself produces electric power and the remaining heat of the boiler is used for heat applications. This combination of a Stirling engine and a traditional boiler is considered as a CHP facility. It is obvious that heat is

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<sup>8</sup> Besides the Stirling engine there exists another related cycle with similar properties, namely the Ericsson cycle; this cycle operates between two isotherms and two isobars

the primary product in this case and that the mechanical and electric power generated are thanks to the integration of the Stirling engine.

The practical realisable efficiencies of Stirling engines are quite low; electric efficiencies are situated between 10% and 30%. It is an open question whether Stirling engines will have a serious impact over the next twenty years.

#### 2.1.5.2 Fuel cells

A fuel cell is an electrochemical apparatus that converts chemical energy straight into electricity. Because the electrochemical reaction (the isothermal oxidation of hydrogen) is accompanied by several irreversibilities, heat is produced by the operation of the fuel cell. The fuel cell must be cooled adequately so that the stationary operational temperature is optimal for the ongoing electrochemical reactions. The heat delivered by this cooling circuit can be utilised for heating purposes; if the necessary provisions are provided to use the available heat, then one has a cogeneration unit.

Nowadays, research is done on five different types of fuel cells, all based on H<sub>2</sub> as cell fuel. A sixth type, that uses methanol directly - Direct Methanol Fuel Cell (DMFC) - is in a very early development stage. Depending on the fuel cell type, the temperature of the produced heat varies from 70°C to approximately 1000°C. The “Alkaline Fuel Cell” (AFC) and the “Polymer Electrolyte Membrane or Proton Exchange Membrane Fuel Cell” (PEMFC) are typically low temperature fuel cells with temperature from 70°C-80°C. The “Phosphoric Acid Fuel Cell” (PAFC) is a medium-T-cell, with about 200°C as operating temperature. The “Molten Carbonate Fuel Cell” (MCFC) and the “Solid Oxide Fuel Cell” (SOFC) are operational at temperatures of respectively 650°C and about 1000°C. It is also envisaged to combine these high-T cells with a recovery boiler and a steam turbine to produce electricity by way of a combined cycle.

Fuel cells are a potentially promising technology for the future of cogeneration applications. However, before the massive break-through, ample technological optimisation is needed. Also in economic terms, fuel cells have to make considerable advances before they will be competitive.

### 3 Cogeneration - miscellanea

#### 3.1 The energetic advantage of a CHP unit

##### 3.1.1 Energy savings of a CHP unit in comparison with separated production

Producing heat and electricity by means of a CHP unit is energetically very different compared to the separate production, by means of a traditional boiler and an electric power plant. This difference is mostly represented by the schematic depiction shown in Figure 2, whereby

$\alpha_E$  = electric efficiency of the CHP unit

$\alpha_Q$  = thermal efficiency of the CHP unit

$\eta_E$  = efficiency of the electric power plant

$\eta_Q$  = efficiency of the boiler

$\dot{E}$  = useful amount of electricity produced

$\dot{Q}$  = useful amount of heat produced

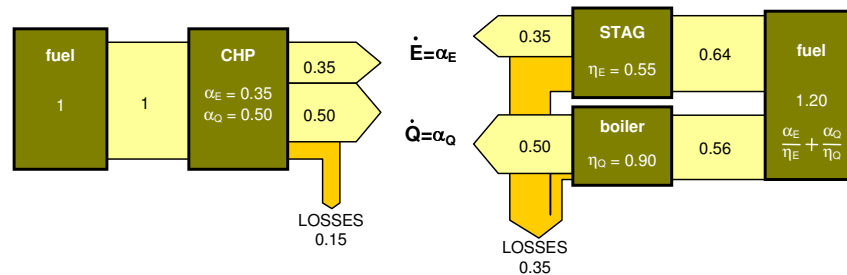


Figure 2 Schematic representation of the energetic balance between a CHP unit and separate production [1]

The values used in Figure 2 are merely examples. As electric power plant, a STAG-unit<sup>9</sup> is used. As the fuel input in Figure 2 equals 1, the thermal and electric efficiencies of the CHP unit are equal to the amount of electricity and heat that are produced, so  $\dot{E} = \alpha_E$  and  $\dot{Q} = \alpha_Q$ . To produce this same amount of electricity and heat, the electric plant needs  $\dot{E}/\eta_E$  units of fuel, while the boiler needs  $\dot{Q}/\eta_Q$  units. The sum of this electric and thermal efficiency is often unfortunately called the ‘overall efficiency’ of a CHP unit<sup>10</sup>. This is unfortunate from a thermodynamic viewpoint because two amounts of energy, heat and work, which are characterised by a totally different quality, are simply added. Therefore, it seems more appropriate to refer to this sum as the Fuel Utilisation Ratio (FUR),  $\alpha_{TOT}$ .

<sup>9</sup> STAG = Steam and Gas turbine plant; is synonym for CCGT (Combined Cycle Gas Turbine)

<sup>10</sup> Nevertheless, the EU CHP Directive referred to in Section 1.1, utilises this terminology.

On the basis of the simple scheme and formulas above, the main issue of interest when using CHP units, namely the amount of energy that can be saved, can easily be deduced. To produce  $\dot{E}$  units of electricity and  $\dot{Q}$  units of heat, the primary power<sup>11</sup> savings (PPS) can be written as follows:

$$PPS = \frac{\alpha_E}{\eta_E} + \frac{\alpha_Q}{\eta_Q} - 1 \quad (3)$$

The first two terms are the amount of fuel used for separate production; the CHP unit uses 1 unit of primary fuel. Then, using a CHP unit, the relative primary power saving (RPPS) in comparison to separate production is given by the following formula:

$$RPPS = 1 - \frac{1}{\frac{\alpha_E}{\eta_E} + \frac{\alpha_Q}{\eta_Q}} \quad (4)$$

The expression for RPPS is used to define a so-called Quality Index (QI) of a CHP installation. To label the CHP unit as “quality-CHP” – a requirement for the CHP unit to be qualified for subsidy support – a certain minimum value for the QI is imposed. Values of 0% for smaller CHP units (< 1 MW<sub>e</sub>), to 10% for larger units (> 1 MW<sub>e</sub>) are used. The CHP Directive (or at least the practical implementation of it) gives the following strategy. In a first step, one has to define which part of the installation can be considered as “real CHP” or as “ordinary heat production”<sup>12</sup>. In a next step, the electric and thermal efficiency of the CHP unit (calculated after the determination of the CHP and non-CHP part) has to be introduced in Eq. (4) to define the RPPS. As defined in the Directive (e.g. Article 12.2 of [12]), the member states can define other quality indices for the attribution of subsidies.

The reference values for the electricity and heat production in the case of separate production, to be used in Eq. (4), differ for the type of CHP unit used. Some reference efficiencies are shown in Table 1. The electric reference efficiencies depend on the date of commissioning and are based on operational data. This means that not only the *best available technologies* are taken into account (although not always logically – see also Section 3.1.2 of this report). Besides that, a grid loss correction and an ambient temperature correction have to be applied to the electric efficiencies.

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<sup>11</sup> “Power” here means energy per unit of time, and is not to be interpreted as a short for electric power.

<sup>12</sup> The methodology on how to break up the installation is still under discussion on the European level. In any case, the FUR of the CHP-unit ( $\alpha_E + \alpha_Q$ ) will play a role in it.

<b>Reference values for electricity (<math>\eta_E</math>)</b>	Hard coal/coke	Liquid biofuels	Natural gas	Biogas
1998 <sup>13</sup>	41.2%	41.2%	50.8%	37.5%
2005	44.0%	44.0%	52.4%	41.7%
<b>Reference values for heat (<math>\eta_Q</math>)</b>	Hard coal/coke	Liquid biofuels	Natural gas	Biogas
Steam/hot water	88%	89%	90%	70%
Direct use of exhaust gases	80%	81%	82%	62%

Table 1: Some reference efficiencies for different types of CHP installations.[5]<sup>14</sup>

Although the comparison between CHP and separate production is often made based on the schematic representation of Figure 2 and the equations derived from it, this approach is not entirely correct. This representation assumes implicitly that both the CHP unit and the separate-production units supply exactly and simultaneously the desired amount of electricity and heat. In reality this schematic representation is only correct if the CHP unit produces almost continuously a certain amount of heat during the entire year. This is rarely the case and as a result, the findings based on this approach can give a biased view of the real effects. The only way to make an exact comparison between CHP and separate production is to carry out a comparative simulation for a concrete situation, taking into account the specific heat and electricity demand, the time duration of operation of the CHP, the need for a back-up boiler, the dimensioning of the CHP unit and the interaction with the entire electricity system [1].

### 3.1.2 “Suitable” allocation of the energetic advantage; apparent efficiency

Apart from the considerations made, saying that cogeneration is an intelligent way of producing heat (see paragraph 1.4), we can wonder about the side to which the energetic saving of a cogeneration unit should be allocated: the heat side or the electricity side.

For the sake of simplicity we reconsider the "energetic equivalent" schematic of Figure 2. With the given numerical values, we have the following energetic balance to produce  $\dot{Q} = 0.5$  heat units and  $\dot{E} = 0.35$  electricity units:

<b>Cogeneration</b>		<b>Separated</b>	
<i>Total</i>	fuel input: 1	<i>STAG</i>	fuel input: 0.64
		<i>Boiler</i>	fuel input: 0.56
		<i>Total</i>	fuel input: 1.2

<sup>13</sup> Year of commissioning.

<sup>14</sup> The presented reference efficiencies are interim values. This is to be voted on February 1<sup>st</sup>, 2006.

The allocation of the advantage to the electricity side or to the heat side represents two extreme viewpoints. The reality is in between. It is not possible to give a unique location and the best one can do is to propose “meaningful” allocations.

The expression for primary fuel saving PFS (for a unit of fuel input in the cogeneration unit), Eq. (3), can also be written in an adapted form as follows:

$$PFS = \frac{\alpha_E}{\eta_E} + \frac{\alpha_Q}{\eta_Q} - 1 = \left(\frac{\alpha_E}{\eta_E} - X\right) + \left(\frac{\alpha_Q}{\eta_Q} - Y\right) \quad (5)$$

with  $X + Y = 1$

This expression suggests that the cogeneration unit needs  $X$  fuel units ( $X \leq 1$ ) to produce  $\alpha_E$  units of electricity. Analogously  $Y$  units ( $Y \leq 1$ ) are needed to produce  $\alpha_Q$  units of heat. From this it follows that the cogeneration unit is characterised by the “apparent” efficiencies  $\alpha_E^{app}$  and  $\alpha_Q^{app}$ :

$$\alpha_E^{app} \equiv \frac{\alpha_E}{X} \quad (6)$$

$$\alpha_Q^{app} \equiv \frac{\alpha_Q}{Y} \quad (7)$$

One viewpoint gives the advantage to the electricity side and assumes the heat production with the same efficiency as in a boiler. Therefore  $Y$  equals  $\alpha_Q / \eta_Q = 0.56$  and consequently  $X = 1 - \alpha_Q / \eta_Q = 0.44$ .

$$\alpha_E^{app} = \frac{\alpha_E}{1 - \frac{\alpha_Q}{\eta_Q}} = \alpha_E^{eff} \text{ and } \alpha_Q^{app} = \eta_Q \quad (8)$$

A different viewpoint gives the advantage to the heat side and assumes the electricity production with the same efficiency as in a STAG. Hence  $X$  equals  $\alpha_E / \eta_E = 0.64$  and consequently  $Y = 1 - \alpha_E / \eta_E = 0.36$ .

$$\alpha_E^{app} = \eta_E \text{ and } \alpha_Q^{app} = \frac{\alpha_Q}{1 - \frac{\alpha_E}{\eta_E}} = \alpha_Q^{eff} \quad (9)$$

If  $\alpha_Q^{eff} > 1$ , then a cogeneration unit could be considered to operate as an energy amplifier for the heat part; cogeneration seems to function as a kind of “heat pump”.

Although at first sight, it is logical to consider (8) and (9) as limits, the demand that  $0.44 < X < 0.64$  and  $0.36 < Y < 0.56$  (remember  $X + Y = 1$ ), is not necessary. Here, the numerical values to compare with separated production are based on a combined cycle power station efficiency  $\eta_E = 0.55$  and a heating boiler efficiency  $\eta_Q = 0.90$ . As a matter of fact, the cogeneration unit is not concerned about what exactly is taken as reference; the values for  $X$  and  $Y$  can vary over a larger range than what just is mentioned.

A “perhaps meaningful” assignment for fuel in a cogeneration unit can be done in an *exergetic way*. One way is to suppose that a “smart” cogeneration unit assigns via a “sensor” more fuel to the heat side in proportion to the quality (or exergy). In other words, the cogeneration unit is thought to waste less fuel on the heat side whenever low-temperature heat is made; only for high-temperature

heat, the cogeneration unit wishes to assign more fuel to the heat side. Instead of using a more energetically proportional allocation  $X = \alpha_E / (\alpha_E + \alpha_Q)$  and  $Y = \alpha_Q / (\alpha_E + \alpha_Q)$ , the preference is given to an exergetically weighted approach, Eq. (10) and (11).

$$X = \frac{\alpha_E}{\alpha_E + \alpha_Q (1-T_0/T)} = \frac{\alpha_E}{\alpha_{WKK}^{ex}} \quad (10)$$

and

$$Y = \frac{\alpha_Q (1-T_0/T)}{\alpha_E + \alpha_Q (1-T_0/T)} = \frac{\alpha_Q (1-T_0/T)}{\alpha_{WKK}^{ex}} \quad (11)$$

One recognises the relative exergy-factor  $(1-T_0/T)$  for heat; for electricity, the relative exergy factor is equal to 1.

The table below gives some numerical values for X and Y, based on Eq. (10) and (11), with  $T_0 = 15^\circ\text{C} = 288\text{K}$ .

T (°C)	15	100	150	200	250	300	400	500
X	1	0.75	0.69	0.64	0.61	0.58	0.55	0.53
Y	0	0.25	0.31	0.36	0.39	0.42	0.45	0.47

Table 2 Numerical values for X and Y according to Eq. (10) and (11) with  $T_0 = 288\text{ K}$ ,  $\alpha_E = 0.35$  and  $\alpha_Q = 0.50$ .

One extreme, with  $T = 15^\circ\text{C}$ , suggests that only electricity is produced, with simultaneous production of worthless heat. In this case (and as long as  $T < 200^\circ\text{C}$ ) the cogeneration unit requires more fuel than a combined cycle power station to produce  $\alpha_E$  units of electricity. The fuel saving for the cogeneration unit completely comes from the heat side (small values for Y). On the other hand, the cogeneration unit always uses less fuel than a boiler, being 0.56 units, to produce  $\alpha_Q$  units heat; which shows again the ability of a cogeneration unit to produce heat in a rational way.

It should be recognised that none of above mentioned allocations is more “correct” than the other. Each of them can have its merits according to particular viewpoints. However, the reader should be aware that those different allocation models exist, but he should be careful because some of the allocations can be misleading as they try to “amplify” particular aspects of CHP. In the end, the only things that really count are the *energetic, ecological and economic advantages compared to separate generation*. Depending on the CHP unit considered, the separate production-technologies to be compared with are the best-available technologies (based on the same – or a similar primary fuel) that the market would have invested in instead of CHP.

### 3.1.3 Energetic equivalence and influence of the overall system of power plants

As noticed in section 3.1.1, the set up of Figure 2 is only valid if the CHP unit and the combined cycle power station are delivering the same heat  $\dot{Q}$  and power  $\dot{E}$  simultaneously. Then, we have a "power-equivalent" comparison base. For simplicity, we will speak about the *energetic equivalence* between the CHP unit and the separated production.<sup>15</sup>

In reality, the situation of energetic equivalence depicted in Figure 2 only arises in the case that a cogeneration unit delivers heat continuously during almost the whole year (as for example in the process industry). For CHP units with limited operation times, the simple set up of Figure 2 is not correct, because the overall system of power stations is not taken into account.

For the further expansion of a system of power stations to replace decommissioned older units, on the one hand, and to cope with the expected increase in electricity demand, on the other hand, there are two possibilities. (Note that investors will base their decisions on the peak demand that the power plant system has to cover). Either the central power plant capacity is extended, and presently this would probably be with combined cycle (STAG) power stations, or there will be the installation of several cogeneration units, with the consequence that these cogeneration units have made the planned combined cycle power station "superfluous". They "prevent" or "avoid" the investment in new combined cycle plants.

If a new combined cycle power station is built (so, if no massive installation of cogeneration units takes place), then the new combined cycle power station pushes older power stations higher up in the merit order so these less efficient power stations (gas and older coal units) will operate less.<sup>16</sup>

If, on the other hand, a lot of cogeneration units with a limited operation time (< 4000 h) are installed that will operate during peaks of the electricity demand, then - as discussed before - this new combined cycle unit will be avoided. During the periods that the cogeneration units are not active, the electricity will be delivered by above-mentioned less performing gas- and coal power stations, which in the case of an investment in a combined cycle power station should have been 'pushed out'. According to this point of view, cogeneration units with limited operation time have caused the central system of power stations to operate less efficiently than would have been the case if the combined cycle power station had been built. A typical example of this situation could occur if one chooses to implement massive introduction of cogeneration units for space heating in the residential and the commercial sector.

This reasoning applies to gas-based CHP. For other fuel-based CHP, similar (albeit appropriately adjusted) arguments may be used.

To have a correct comparison between a cogeneration unit and separated production it is necessary to make a comparative simulation for the sector under consideration, the typical heat- and

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<sup>15</sup> In fact we have to speak about "simultaneously and integrated equivalence of the delivered end energy"; strictly speaking it is not enough that the units deliver the same end energy, they have to be delivered at the same time.

<sup>16</sup> This is due to the high efficiency of new CCGT's and because of the de-facto CO<sub>2</sub>-tax due to emission trading, even if gas prices are considerable.

electricity demand patterns, the dimensioning of the installation, the need for extra heating, and the behaviour of the assembly of power stations. The final result of such a simulation is that the energy saving at the end is usually less than what Figure 2 predicts [11]. For heating purposes with micro-CHP units in residential and tertiary sectors, the primary energy saving turns out to be very low so that it is not really justified to label these units as quality cogeneration units. Therefore, installation of micro-CHP units should not rely on environmental justification; it may be acceptable for different reasons like private economical reasons (whereby it has to be said that this economical decision should have no — or negligible — negative influence on the energy use or on the environmental impact of the country).

Especially if the ‘not-pushed-out’ (less performing) units are coal fired plants, the situation discussed above has large consequences for the CO<sub>2</sub>-emissions. The difference in CO<sub>2</sub>-emissions of the scenarios with or without cogeneration in the tertiary and the residential sector can turn out to be negligible.

### 3.2 Allocation of the CO<sub>2</sub>-emissions of CHP units

The reduction of CO<sub>2</sub>-emissions achieved by using a CHP facility is often referred to as the environmental benefit of such a facility. These avoided emissions depend on the primary energy savings and the type of fuel used. Each type of fuel has its own emission coefficient (CI), e.g. 209 g CO<sub>2</sub>/kWh<sub>prim</sub> for natural gas. This implies that the avoided CO<sub>2</sub>-emissions due to the use of a CHP installation equals the product of the primary energy savings and the emission coefficient of the fuel:

$$\text{Avoided emissions} = CI \cdot \left( \frac{\alpha_E}{\eta_E} + \frac{\alpha_Q}{\eta_Q} - 1 \right) \quad (12)$$

When the total inventory of CO<sub>2</sub>-emissions for a whole country is made, it can be useful to know which amount of emissions can be attributed to the generation of electricity and which amount to the production of heat. This attribution of emissions to the production of electricity and heat is called the *allocation* of CO<sub>2</sub>-emissions. Four different allocation methods can be distinguished, each of them having its own advantages and drawbacks. In this report, two of them will be explained in more detail: the *direct energetic allocation method* and the *direct exergetic allocation method*. More details and information about other allocation methods can be found in [1].

In order to explain the ‘*direct energetic allocation method*’, first two new emission coefficients CE and CQ have to be defined, representing the amount of CO<sub>2</sub>-emissions per kWh<sub>e</sub> and kWh<sub>th</sub> produced by the CHP unit, respectively. These coefficients have to be determined unambiguously and the following equation has to be fulfilled at any time:

$$CI = \alpha_E \cdot CE + \alpha_Q \cdot CQ \quad (13)$$

The ‘*direct energetic allocation method*’ distributes the amount of CO<sub>2</sub> emitted amongst the electric and heat side according to the amount of energy produced,  $\alpha_E$  and  $\alpha_Q$  for primary energy input equal to 1 as in Figure 2. The two equations

$$\alpha_E.CE \equiv \frac{\alpha_E}{\alpha_E + \alpha_Q}.CI \quad (14)$$

and

$$\alpha_Q.CQ \equiv \frac{\alpha_Q}{\alpha_E + \alpha_Q}.CI \quad (15)$$

then lead to the following expression for CE and CQ:

$$CE = CQ = \frac{CI}{\alpha_E + \alpha_Q} \quad (16)$$

For example, a CHP unit with an electric efficiency of 30% and a thermal efficiency of 50%, using natural gas as input fuel, would generate 261 g CO<sub>2</sub>/kWh<sub>e</sub> and 261 g CO<sub>2</sub>/kWh<sub>th</sub>. Therefore, according to this allocation scheme, if 1 kWh of natural gas is converted into electricity and heat, the electric side will emit 78.5 g CO<sub>2</sub> while the heat side will emit 130.5 g CO<sub>2</sub>. These figures, of course, are still based on the static comparison represented in Figure 2 and suffer from the same shortcomings as the static approach [1].

A more defensible allocation, the so-called ‘*direct exergetic allocation method*’, assumes that more primary energy is required for a unit of electrical energy than for a unit of heat. Hence, the electrical side should be responsible for a larger share of the CO<sub>2</sub>-emissions. When the quality of the heat is increasing, relatively more fuel shall be allocated to the heat side. The use of an exergetic quality factor (‘1’ for electricity and  $1 - \frac{T_0}{T}$  (= the Carnotfactor) for heat at a temperature T) results in the following allocation coefficients:

$$\alpha_E.CE \equiv \frac{\alpha_E}{\alpha_E + \alpha_Q \left(1 - \frac{T_0}{T}\right)} CI \quad (17)$$

and

$$\alpha_Q.CQ \equiv \frac{\alpha_Q \left(1 - \frac{T_0}{T}\right)}{\alpha_E + \alpha_Q \left(1 - \frac{T_0}{T}\right)} CI \quad (18)$$

which results in:

$$CE = \frac{CI}{\alpha_E + \alpha_Q \left(1 - \frac{T_0}{T}\right)} \quad \text{and} \quad CQ = \frac{CI \left(1 - \frac{T_0}{T}\right)}{\alpha_E + \alpha_Q \left(1 - \frac{T_0}{T}\right)} \quad (19) \text{ and } (20)$$

This direct exergetic allocation method is commensurate with the fuel-allocation method discussed in Section 3.1.2.

For completeness, we briefly mention the indirect allocation methods. The ‘*indirect energetically-weighted allocation method*’ allocates the *avoided CO<sub>2</sub>-emission* proportionally to the produced final energies, electricity and heat. The last allocation method, the ‘*indirect exergetically-weighted allocation method*’, allocates the *avoided CO<sub>2</sub>-emissions* proportionally to the exergy-content of the two produced secondary energy carriers. More details can be found in [1].

### **3.3 Electrical aspects of cogeneration units**

A cogeneration unit delivers electrical power by way of coupling the turbine- or engine axis to an electrical generator. For larger power values (about > 100 kW<sub>e</sub>) synchronous generators are used, for smaller power values (about < 100 kW<sub>e</sub>) mostly asynchronous generators are used.

An asynchronous or induction generator takes his magnetising current out of the stator. Usually, an asynchronous generator is coupled to the grid; then the grid delivers the magnetising current. It is also possible to operate an asynchronous generator in island mode, but then the terminals have to be coupled to a condensator battery to deliver the magnetising current. Island mode of asynchronous generators is reserved for small generators, because the condensator battery would be too large and too expensive otherwise. Even the grid coupled mode is restricted to powers smaller than 100 kVA since for larger values the inductive load would be too large and again a condensator battery for cos φ correction should be required.

That is the reason why from a specified power level it is best to switch to synchronous generators. The rotation speed of an asynchronous generator is slightly higher than the rotating magnetic field generated by the stator, which is rotating at the grid frequency or a fraction of the frequency (depending on the number of poles of the generator).

Synchronous generators are magnetised by a current through the rotor coils. The rotation speed of synchronous generators is exactly equal to a fraction of the grid frequency. It is common to have a four-pole generator, where the rotor rotates at 1500 rpm. A synchronous generator can work without problem in island mode; for the grid coupled mode, synchronisation equipment is required.

In island mode it is clearly impossible to deliver to the grid. If there is insufficient demand of electricity, the cogeneration unit must operate at partial load or must be switched off.<sup>17</sup> If delivery to the grid is desired, then operation in grid coupled mode is necessary.

A grid coupled *asynchronous* generator always takes up inductive reactive power. There is no intrinsic regulation of reactive power. By regulation of the excitation current on the rotor of a *synchronous* generator it is possible to manage the reactive power locally.

The large synchronous generators of electrical power stations are equipped with regulation apparatus for reactive power. Common cogeneration units do not foresee this regulation equipment. Such cogeneration units must be statically adjusted to deliver or consume reactive power, but dynamic regulation is not possible. Mostly cogeneration unit owners want to optimise their operation for active power production, so that no statical reactive power compensation is foreseen.

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<sup>17</sup> Consumption of produced electricity in resistances is not considered as a significant option, and storage of electricity is really not possible (for considerable amounts of electric energy).

It is important that the grid operator requires the suitable static-reactive-power when a CHP wants to hook up to the grid. Depending on the geographic location in the grid, there will be different requirements. In a region or territory with a lot of these decentralised power units (that are heat driven), it requires careful attention to manage unexpected grid perturbations. The rather extensive blackout in the region of Utrecht (NL) in July 1997 was the consequence of too many not adjustable production-units of the cogeneration type combined with too little adjustable “base-load” capacity.

Implantation of cogeneration units, dispersed over the grid, has the advantage that the central grid operator has to foresee less reserve power. When a large 1GW<sub>e</sub> power station suddenly shuts down, a 1GW<sub>e</sub> reserve power station should be available for back-up. In contrast, for 20 cogeneration units of 50 MW<sub>e</sub>, the probability that the 20 units are non-operational simultaneously is negligible. A few 100 MW<sub>e</sub> reserve power suffices in this case.

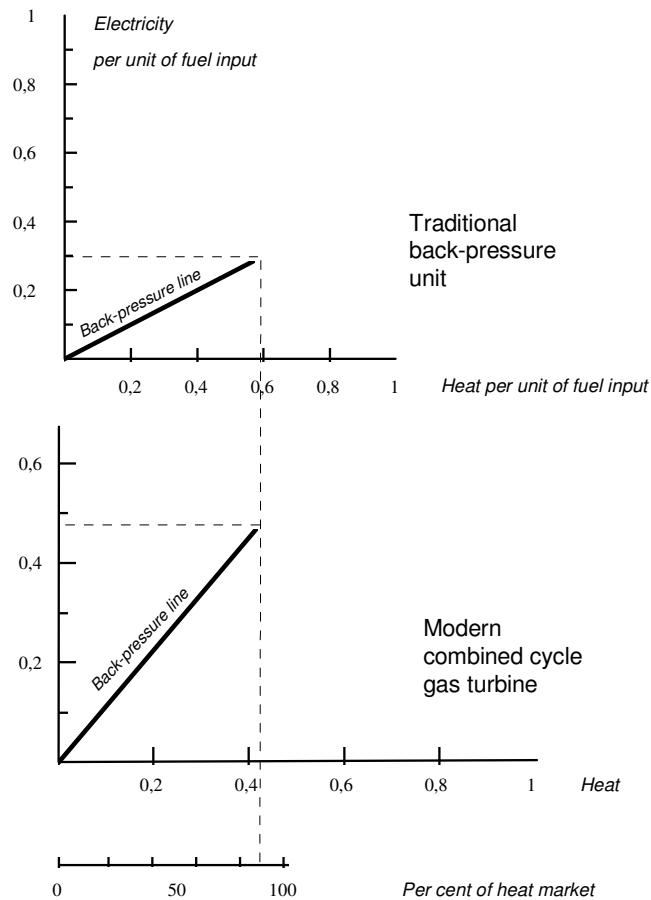
In principle, a well-chosen implantation of cogeneration units in the grid can help to decrease the congestion of transport lines. To influence a good implantation-configuration, the grid operator can give place-dependent grid coupling incentives or price signals. However, because well dimensioned cogeneration is always in the neighbourhood of large heat consumers, the site is fixed by the geographical location of (mostly industrial) heat consumers rather than by grid specification. A different question is whether place-dependent-price-signals will be accepted by society.

Likewise, by careful implantation, the cogeneration units will decrease the transmission- and distribution losses in the grid. Typically, the losses of the transport grid amount to approximately 2-3 %, the losses of the distribution grid are in the range of 5-7 %. Elementary papers claim that cogeneration can avoid about 7-10 % of the transport losses. However, this is not correct. The largest losses are in the distribution grid and more than half of these losses is due to zero-load loss in transformers (magnetic losses). Because most of cogeneration users want to rely on the distribution grid to buy power as the cogeneration unit is not operational or delivers insufficient power, or want to feed back to the grid, those same users require that the grid is sufficiently well established. This means that all transformers must be operational. Hence a large part of the distribution losses cannot be avoided by the use of cogeneration. It requires a detailed fiability study of the implantation configuration in the distribution grid to specify which transformers can be avoided. Cogeneration can save a few percent on transport losses, but probably no more than 3-5 %.

It is certainly not excluded that the grid operator makes contracts with the (industrial) owners of large cogeneration units to help in the case of an incident. (In some countries, e.g. Denmark, cogeneration has traditionally been fully integrated into the operation of the grid.) The grid operator will then by way of remote control and within the contractual scope influence the operation of the cogeneration unit. Technically it is certainly possible; the question is how far will a company allow intervention by the grid operator.

### 3.4 Improved power-to-heat ratio

If possible, both for energetic and economic reasons, one should try to improve the power-to-heat ratio or equivalently increase the slope of the back-pressure line. A straight forward way to do this is to use a CCGT – in CHP mode rather than a simple GT with heat recovery. An example from Denmark can illustrate the impact of this development. The first decentralised gas-fired CHP unit was a traditional gas turbine built in 1987. The power-to-heat ratio for this unit is about 0.5. The electric capacity is 17 MWe and its heat production covers most of the demand in a town with 25,000 inhabitants. The operation of the unit follows the heat demand, and the CHP unit covers the heat demand above the heat base load from a waste incineration plant. In 1996 a modern combined cycle gas turbine was commissioned in a neighbouring city with a heat market of nearly the same size. The power-to-heat ratio for this unit is about 1.0, and the maximum electric capacity is 60 MW. This CHP unit operate only during high and peak demand, and a heat accumulator to enable the unit to benefit from a time-of-day tariff or the operation on the spot market. Both cases are illustrated in *Figure 3*.



*Figure 3 Electricity and heat production from one unit of fuel input in old and new small-scale CHP units.*

*Case a:  $\alpha_E = 0.31$  and  $\alpha_Q = 0.61$ ; case b:  $\alpha_E = 0.47$  and  $\alpha_Q = 0.41$ .*

The improvement of the power-to-heat ratio is made at the expense of the total fuel utilisation ratio  $\alpha_E + \alpha_Q$ , which is reduced to 0.88 instead of 0.92, but this is energetically unimportant since the primary power saving (Eq. (3)) is larger in case (b). Indeed, PPS for case (a) equals 0.24 units, whereas PPS for case (b) equals 0.31 units. Another disadvantage is that the capital investment for a given heat market is much higher and, thus, the financial risk for the owners of the units. This is compensated, however, by a usually higher market value for electricity than for heat.

### 3.5 Extraction-condensing steam turbines

Extraction of heat or steam from large steam turbines is a very flexible way to produce heat in cogeneration. Instead of leading the steam to the low-pressure turbine it is sent to a heat exchanger to produce hot water for distribution in a district heating grid. See also Section 2.1.1. The operating area of these turbines is described in

Figure 4. The vertical axis represents condensing (electricity-only) capacity, and the back-pressure line shows the operation in full cogeneration mode (similar to Figure 3).

The efficiency for electricity generation in condensing mode is up to 47 % for modern coal-fired steam turbines with seawater cooling, and about 1.5 %-points lower for cooling towers, while the value of the power-to-heat ratio is a matter of both technology maturity and economic optimisation. The power-to-heat ratio for the most recent extraction-condensing units in Denmark is 0.7, which is significantly lower than the values selected for the decentralised units, see Section 3.4.

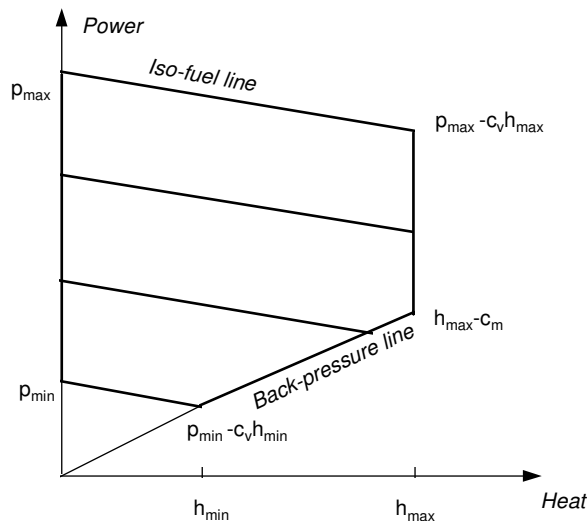


Figure 4. CHP parameters for extraction-condensing units.

The iso-fuel line describes the power-loss ratio, i.e. the percentage electric power loss per unit of extracted heat. A typical value of this parameter is 0.15 for both traditional and modern units. In practice neither the back-pressure line nor the iso-fuel line are straight lines, but this simplification is widely used in statistics and modelling.

When these units are operating in back-pressure mode with maximum heat extraction, there is a 'spinning reserve', which can be available for peak-load power supply at 15-20 per cent of the total capacity of the unit. The heat load may then be reduced for a short time, while the heat demand can

still be met, because the district heating mains have some heat storage capacity, or there are heat accumulators available for discharge, which have been built for this purpose. The benefit of this flexibility is particularly important in regions with a short-term regulation market, e.g. the Nord Pool electricity exchange area, or regions with a significant share of wind power. It should be noted that the discharge of heat is only justified in a system integrated picture (i.e., compensated for by other generation means) and considered over an extended period of time (e.g. on an annual basis). The main purpose of CHP should be kept in mind: to save primary energy, or to help other generation means reach the same goal.

### **3.6 Nuclear CHP**

Nuclear power plants are using steam turbines similar to those used by large fossil plants, but with poorer thermodynamic parameters. CHP applied to nuclear units has been used only on a smaller scale, e.g. heat supply for the town of Visagenas near the Ignalina nuclear power plant in Lithuania. In the late 1970s studies were made for CHP supply from planned new nuclear plants in Sweden and Denmark [18], but these units were never built. Because of the poor thermodynamic parameters in particular the power-loss ratio, which has been quoted as high as 0.24, large-scale heat supply from nuclear units may not be profitable. However, newer technologies and optimal dimensioning of all features could lead to a different conclusion, but no experience or recent studies are available.

### **3.7 Application of CHP**

#### **3.7.1 The CHP Directive**

The focus of the Directive [12] is the ‘useful heat’ demand. In the Explanatory Memorandum of the proposal for the Directive, three classes of cogeneration were created reflecting thermodynamic considerations as well as market segments facing different barriers to overcome:

- Industrial applications of heat, that usually require steam or hot water above 140° C;
- Central Heating applications that require warm water between 40°C and 140°C;
- Agricultural applications: for example for heating greenhouses.

In the final version of the Directive, which was adopted by the European Parliament and the Council 11 February 2004 the various types of useful energy were mentioned only in the recitals of the Preamble (Whereas ...(31)), but not in the legally binding enacting terms.

Annex I of the Directive lists 11 groups of cogeneration technologies:

- (a) Combined cycle gas turbine with heat recovery
- (b) Steam backpressure turbine
- (c) Steam condensing extraction turbine
- (d) Gas turbine with heat recovery
- (e) Internal combustion engine
- (f) Microturbines
- (g) Stirling engines
- (h) Fuel cells
- (i) Steam engines

- (j) Organic Rankine cycles
- (k) Any other type of technology or combination thereof falling under the definition laid down in Article 3(a)

The calculation of electricity from cogeneration is based on the formula:

$$\text{CHP electricity} = (\text{CHP useful heat}) \times (\text{electric power to heat ratio})$$

Thus, the electricity to heat ratio will reflect the various temperature levels and the cogeneration technologies. Annex II also specifies a set of default electricity to heat ratios for different cogeneration technologies.

Annex III specifies a methodology for determining the efficiency of cogeneration power. *High efficiency cogeneration* must provide primary energy savings of at least 10 % compared with the references for separate production of heat and electricity. However, production from small scale and micro cogeneration units providing primary energy savings (of at least  $\geq 0$ ) may qualify as high-efficiency cogeneration.

The purpose of this methodology has been to develop a set of rules for CHP to qualify for national support.

### **3.7.2 Industrial cogeneration**

Industrial CHP is one type of energy saving measure in process industries with an input of steam or heat and an electricity demand that may be generated on site or purchased from the electricity market. It will often require the infrastructure of the public grid for back-up or sale of excess electricity. Traditionally industrial CHP was an option for large energy consuming industries with a demand for both electricity and heat or steam, and in several countries a significant part of the electricity was generated outside the utilities by industrial generators. In most of the countries, where the electricity supply industry was nationalised, industrial generators did not become a part of the nationalised industry.

Industrial CHP has been promoted in many countries as a part of the public energy policy. The most consistent policy for promotion of industrial CHP has been in the Netherlands, where the share of CHP in the electricity market is among the highest among the EU member states, in spite of a very limited penetration of district heating. The recent availability of small-scale CHP units also expands the potential market for industrial CHP very considerably in all countries, because it is possible to install CHP capacity for much smaller heat loads, and the installed capacity can produce much more electricity for the electricity market.

### **3.7.3 Heating cogeneration**

Heating applications of cogeneration are mainly central heating applications that require warm water between 40°C and 140°C. Most often it requires a public distribution network in the form of district heating. Similar systems may be found for institutional building complexes, e.g. hospitals,

university campuses, or central heating systems for large residential buildings. In these last cases, decentralised CHP units are used.

Some district heating systems are using steam distribution systems at much higher temperature, notably Paris where steam at 19.5 bar and 230 °C is fed into the grid with water being condensed and returned at approximately 70 °C on average. However this system is not well suited for CHP, and the Paris system is supplied mainly from incineration of urban waste and coal (i.e., simply “boiler-fed”).

#### **3.7.4 Agricultural cogeneration**

In addition to the widely used industrial and heating applications the Directive also mentions agricultural applications: for example to heat greenhouses. The temperature of the warm water could be below 40° C, but in the case of heating pools in aquaculture the need is only of 15-25°C. However, the Explanatory Memorandum in the Commission’s proposal states that “justification of useful heat at this temperature level should be considered very careful in order not to increase fuel consumption.”

## **4 Cogeneration and district heating**

### **4.1 Introduction**

District heating (DH) is a widespread application of cogeneration. According to the Euroheat and Power Association [9], almost 25% of the European population makes use of DH. Like natural gas-fired local boilers, DH requires a water-based radiator system within buildings and a public distribution network. However, the investment cost of the DH distribution network is about four times that of natural gas. Thus, the regional climate is an important factor in the use of DH<sup>18</sup>, but it has never been the key driver. The historical and institutional background has been far more important. In Northern Europe, local influence on the utilities has been a key factor in promoting DH, in the former Communist Central and Eastern Europe the widespread building of large housing blocks was generally planned with heat supply from district heating.

District heating by means of CHP must be carefully studied on a case by case basis to evaluate the meaningfulness of such projects. The existence of a heat distribution grid is a surplus from an investment point of view. Also, the type of “prime mover” (classic coal-fired plant, CCGT unit, simple GT, gas or diesel engines) is important. For newly built districts, modern stringent insulation requirements minimises the heat demand, perhaps to such extent that investments in heat-distribution grids are not easily (if at all) paid back. District generation must very often be considered in the appropriate historic context of the region in question.

#### **4.1.1 Transmission and distribution technology**

Heat is provided through a “distance heating network” from the heat source to the primary or secondary users. The diameter of the pipelines is decreasing further away from the heat source. Both steam and water are possible heat carriers, but nowadays, steam (saturated or overheated) is only used when explicitly requested by a client: heat losses are high, pipelines have to resist the high temperatures and require a lot of maintenance and measures have to be taken to cope with the formed condensate. In modern networks, hot water (under pressure to avoid steam formation) at temperatures of about 130°C to 150°C and even lower (75°C to 90°C) is used. To reduce the heat losses, it is favourable to run the network at the lowest temperature regime possible. As a constraint, the temperature difference has to be large enough to avoid unnecessary large diameters and the departure temperature has to be high enough for space and tap water heating. Since the 1960's, rigid double lined pipelines in steel with an internal insulation are used. More and more, since the 1970's, the outer steel layer is replaced by a synthetic layer and flexible synthetic pipes are being introduced at the low temperature/pressure side of the distribution network.

As the heat source, one is not necessarily obliged to use a cogeneration unit for DH. A classical boiler can fulfil the heat demand as well, but a substantial part of the DH systems are cogeneration based. As only low temperature heat of 75°C to 150°C is requested for the heating of houses and

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<sup>18</sup> A good indication of the regional climate is the use of “degree days”. Although several countries have different definitions, they can give a good idea on the climate and the need for heat of a country in combination with the wind speed and the sunshine.

buildings, CHP units are ideal to minimise the exergetic losses. All technologies, mentioned above in Section 2, can be used.

#### **4.1.2 Historical notes on district heating**

The idea of district heating for urban heat supply is more than 150 years old. In 1834 a paper on “Suggestions for the Architectural Improvements of the Western Parts of London” contains a proposal “the practicability of laying on heat to a long range of these dwellings from one common source, a contrivance, which if perfected, would be of inestimable importance in London, where the high price of fuel is so great a burden upon the poor”. Fifty years later, in the 1880s, a systematic development of an urban network took place in New York. However, although the district heating network in New York became one of the largest in the world, it covers only a limited part of the city – in particular South Manhattan around Wall Street and Midtown around South Central Park.

In Europe the technology was used for some large institutions and prominent new buildings, e.g. the Technical University of Charlottenburg (Berlin) in 1884 and the Town Hall of Hamburg in 1893. The district heating system in Dresden, starting in 1900 with the aim of reducing the fire risk for Zwinger and the royal palaces, may be considered as the first urban system in Europe. Like in New York, it was based on CHP with steam distribution. From 1911 surplus steam was also used to heat a small water-based network in Dresden. Some larger urban systems were developed slowly after the First World War. Hamburg and Berlin were the leading cities in the 1920s, Copenhagen started in 1925 and Paris in 1930. Most of the development in European cities took place after the Second World War [21].

#### **4.1.3 Large-scale urban district heat systems**

The largest district heating system in the European Union is Berlin with sales of 11 TWh heat from the grid, followed by Copenhagen with 7 TWh. Cities in the range of 5 to 6 TWh are Helsinki, Hamburg Stockholm and Paris. The largest systems in the world are St. Petersburg, Moscow, Warsaw and Prague, while New York City, Seoul and Bucharest have systems with sales in the range of the largest within the EU<sup>19</sup>. There are several grids with sales between 1 and 4 TWh, e.g. Gothenburg, Sweden, Tampere, Finland, and five grids in Denmark.

None of the large-scale urban district heating systems in Europe has been developed over a short period according to a single initial plan. They were developed over decades for different reasons by adding new elements to the existing infrastructure, often taking advantage of temporary and unusual situations, e.g. the high oil prices in the period 1973-1985. The most constant elements have been local or national actors with a consistent interest in finding ways and means for expanding the district heating markets and networks. In addition, compulsion or long-term agreements were often a feature of their development.

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<sup>19</sup> [www.energy.rochester.edu/dh/largest.htm](http://www.energy.rochester.edu/dh/largest.htm)

#### **4.1.4 Small-scale heating cogeneration**

There is no consensus on labelling the scaling of CHP units. Compared to the large urban district heating systems that are supplied by several extraction-condensing power units up to some hundreds of MWe, a mid-sized town with a single CCGT up to 100 MW dedicated for district heating system in the town may be considered as ‘small-scale CHP’ or ‘decentralised CHP’. In other countries CHP units above a few MWe will be considered as ‘large-scale’.

However, apart from large existing urban district heating systems in the new member states, the largest potential for expansion of heating cogeneration must be based on units of a relatively small scale, which will supply heat distribution systems of a relatively modest size. In addition, there is a vast potential for micro-scale CHP, in particular in areas with natural gas supply.

## **4.2 Examples and energy analysis**

### **4.2.1 STAG-plant in combination with back-up boiler**

#### **4.2.1.1 Description of the system**

In the city of Gent (Belgium) a district heating network exists, which uses a small-scale STAG<sup>20</sup> as heat source. The gas turbine (LM6000PB) delivers a nominal electric output of 38.4 MWe. A heat recuperator produces steam at 30 bara and 450°C which can expand in a steam turbine (with an electric output of 12.8 MWe at maximal flow rate). Through intermediate steam bleedings (at 6 and 2.5 bara) and an additional heat recuperation of the exhaust gases, warm water can be produced. Depending on the season, the departure temperature of the warm water is 130°C or 90°C (respectively in winter and summer). The return temperature varies from 60 to 75°C. The maximal electric output of this installation is 51.2 MWe (electric efficiency of 50.7%) in combination with a thermal output of 9 MWth (thermal efficiency of 8.8%). With maximal steam bleeding, the electric output is 46.2 MWe (electric efficiency of 45.2%) with a thermal output of 27 MWth (thermal efficiency of 26.8%). As a back-up, additional boilers and gasoil engines are foreseen.

#### **4.2.1.2 Energetic analysis**

The annual heat demand shows a very small base demand - largely depending on the grid losses - and strong peaks, with large seasonal differences. This heat profile is typical for a distance heating network and makes a flexible CHP unit necessary. This is why two intermediate pressures for steam bleeding are foreseen.

Figure 5 shows the energy balance of the CHP-installation for the year 1998. The delivered heat (252TJ) represents only a small share of the overall energy output.

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<sup>20</sup> Recall that “STAG” is a synonymous of “CCGT”.

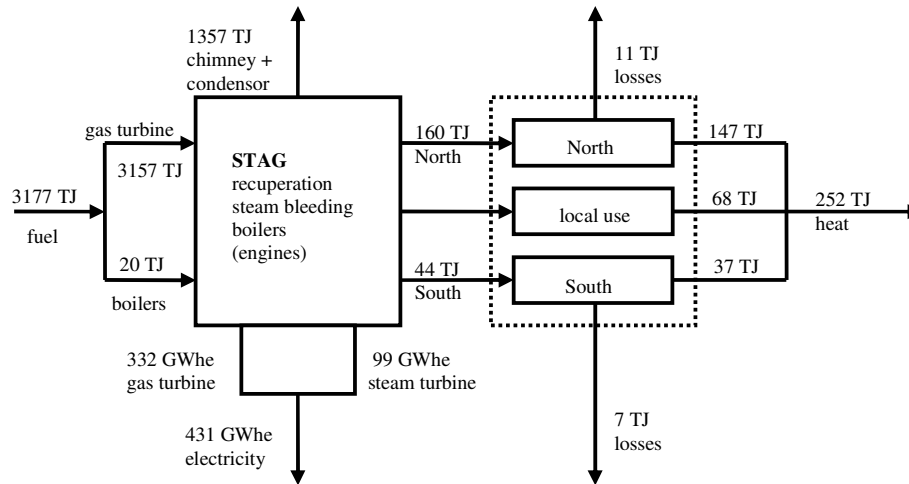


Figure 5 Energy flow chart of the CHP-installation in the city of Gent (Belgium) – 1998 [10]

#### 4.2.2 STAG-plants in combination with storage tanks

In the paragraph above a STAG-plant - in combination with a back-up boiler - is used to fulfil the DH demand. Other countries (e.g. Denmark and The Netherlands) make also use of STAG-plants to fulfil the DH demand, but instead of back-up boilers, they use large storage tanks to increase the systems flexibility.

In the town of Silkeborg (Denmark) two gas turbines of type LM6000PB are installed. These turbines are the same as in Gent and have a combined electric output of 78 MWe. The exhaust gases are used to produce steam, which is fed to a back-pressure steam turbine. Steam can be released at two pressure levels, to produce hot water at the condenser unit. The nominal output of the installation is 98.5 MWe and 71 MWth. Hot water can be fed directly to the heating network or can be stored in the two storage tanks (with a total capacity of 36000 m<sup>3</sup>). Storage capacity is enough to fulfil the peak heat demand during 11 hours.

Thanks to the use of storage tanks, the STAG-plant can be operated in a flexible way. The operational strategy is based on two pillars. First of all, heat demand has to be fulfilled at any time (although a sufficient capacity of old heat-only has been kept for back-up and peak load). The second pillar states that electricity (and as a consequence heat) has to be produced at that time when electricity tariffs are high<sup>21</sup>. Depending on the heat demand, hot water can be fed immediately to the network or can be fed to the storage tanks. Due to this flexible operation system, the STAG-plant does not work as a base load plant as it is only working for approximately 4600 hours per year<sup>22</sup>. (This annual operation time probably varies significantly over the year – with an increasing

<sup>21</sup> Since the early 1990s, a three level electricity pay back system (low, medium and high tariff) at fixed hours has been used in Denmark for ‘decentralised CHP units’ (<1 MWe to 100 MWe). This system has now been replaced by the Nord Pool spot and regulating power markets (CHP units above 10 MWe from 2005).

<sup>22</sup> The plant is shut down and started up approximately 200 times each year. In winter times, when temperature drops beneath -2°C, the power plant runs 24 hours a day.

trend due to expansion of the district heating grid.) In this working regime, the system obtains – on an annual base – an electric efficiency of 49% and a thermal efficiency of 36%.

This operational strategy is used in more than one-hundred towns and villages in Denmark for different sizes and types of CHP plants. In The Netherlands, the CHP-DH-units of the city of Purmerend and Almere have a comparable operational strategy.

#### 4.2.3 Gas engines in combination with boiler

At the university campus of Louvain-la-Neuve (Belgium), a distance heating system was installed during the building phase of the campus. Originally, four boilers (2 x 11.6 MWth; 1 x 5.8 MWth and 1 x 23.2 MWth - which is hardly used) produced the heat to deliver directly to the heating circuit, without the use of extra heat exchangers. To reduce costs and relieve the environment, the 23.2 MWth boiler was replaced by 3 identical Cummins-Wärtsilä gas engines, with a total electric output of 9.4 MWe. The total thermal output depends on the working regime: 9.9 MWth in combination with the 90/70°C<sup>23</sup> and 93/73°C regime and 8.2 MWth with the 103/83°C regime. Figure 6 shows the energy flow of the installation in the year 2000.

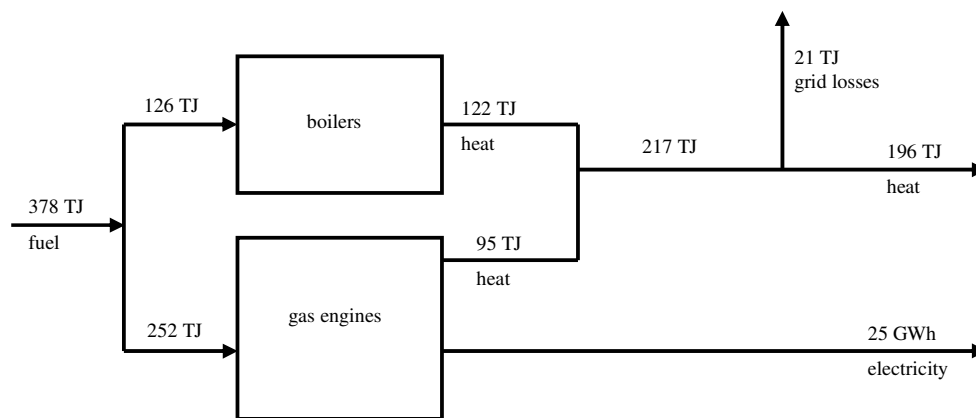


Figure 6 Energy flow chart of the distance heating installation in the university campus of Louvain-la-Neuve (Belgium) – 2000 [10]

#### 4.2.4 Static and dynamical energy analysis

The static analysis is the simplest way to calculate the energetic advantage and fuel saving of the abovementioned CHP-DH-systems. When using a valid reference<sup>24</sup> for the separate production and based on the known energy data, equation (3) results in a PPS of 9.4% for the installation in Gent<sup>25</sup> and 1.8% in Louvain-la-Neuve<sup>26</sup>.

<sup>23</sup> Departure temperature of 90°C and return temperature of 70°C.

<sup>24</sup> “...what would have been the option for separated production of a comparable amount of heat and electricity at the time of investment and depending on the country’s peculiarities.” This question is not so evident to answer as it is depending on the primary energy sources to fulfill the separated energy demands (gas, coal, RES...).

<sup>25</sup> Efficiencies for separate production: 48% (electric) and 90% (thermal).

<sup>26</sup> Efficiencies for separate production: 55% (electric) and 90% (thermal).

In the static analysis, we assume that the electricity, in case of not-building the CHP unit, would have been delivered by an electric power plant with the reference efficiency for separate production. But the static approach is not a realistic model as it neglects the dynamic character of the electricity production park. To bring this dynamism into account, more detailed models are necessary to cope with fluctuating efficiency, load factor, emissions, country-specific issues... As this is out of the scope of this *Work Package 3*, those kind of models will be discussed in *Work Package 5*.

#### **4.2.5 Utility integrated CHP**

The highest penetration of CHP in Western Europe is found in Denmark. This is explained mainly by the traditional organisation on the electricity supply industry, which was based on consumer co-operatives and municipally owned companies. These companies gradually merged as the thermal power plants became larger. The district heating industry was developed in the same tradition. Following the oil price shocks in the 1970s national regulation of the heat supply increased the penetration of CHP/DH mainly in the Copenhagen region during the 1980s, and introduced smaller CHP units for the existing DH grids in most towns and villages during the 1990s. The main criterion for the location of new electric power generating capacity became the existence of a heat market for CHP.

As the efficiency of large coal-fired units increased continuously, new efficient units (mainly 200-300 MWe extraction-condensing units) could be built to supply the base load of the large DH systems. A broad range of CHP units was used for the many smaller DH grids. At the same time existing and new DH networks were expanded and the introduction of natural gas was supported by creating a market for natural gas in the DH sector, first by the conversion of existing oil-fired boilers to natural gas, later by conversion of DH centralised plants to small-scale CHP units. Thus the possibility for further penetration of CHP in Denmark is now very limited, except for the conversion of the limited number of natural gas boilers in single-family houses into micro-scale CHP. However, the large number of CHP units of different scales and vintage is being used as a basis for the development of new technologies (e.g. biomass) and new operational strategies within a highly volatile electricity market.

The share of district heating in Sweden is similar to Denmark, but there is very little CHP, because electricity generation is dominated by hydro and nuclear power. In addition, the taxation system has discouraged CHP, and electrically driven heat pumps have been widely used for smaller district heating systems. Thus, there is a large potential for expansion of CHP for the future supply of the existing district heating systems, in particular if the natural gas supply is expanded to a larger part of Sweden.

District heating in Finland started late, but the development has been rapid. The country's first district heating power plant came on stream in 1952 in Helsinki. At the turn of the century, there were more than 200 district heating stations or power plants covering 46% of the heat market. In Helsinki the market share of district heating is over 90%. The fuels used for district heating depend on the location: coal is used in coastal regions, natural gas is used in areas covered by the gas grid, and peat is used in inland locations. Like in Denmark, a large quantity of new combined heat and

power capacity was added during the 1980s either by new plants or converting existing condensing (electricity-only) facilities. In addition to utility cogeneration, most district heating plants buy the base portion of heat from industry-run back-pressure facilities.

CHP operators in all the Nordic countries have full access to the electricity market. Since 2000 the Norwegian based Nordic power exchange, Nord Pool, has covered all four countries. However, the CHP operators are facing the same problems as other electricity generators; namely that electricity prices on both the spot and futures markets are too low to justify investment in new capacity.

The Nord Pool type spot market [22] has been copied in several other European countries, notably the Netherlands, Germany, Poland and Spain. The development of CHP and district heating in these countries is quite different. Industrial CHP was strongly promoted in the Netherlands during the 1980s, district heating, mainly supplied by CHP has been important in many cities in Germany. However, the municipal utilities in Germany (Stadtwerke) have faced severe competition from the large electricity-only generators following liberalisation. For this reason, CHP has now been supported by national legislation. In Spain, the warm climate does not justify any capital-intensive heating system.

#### **4.2.6 Nationalised industries and CHP**

The nationalised electricity supply industries in several Western European countries, notably France and the UK, did not support the development of CHP and DH, and the liberalisation in the 1990s has made little difference. Much effort has been devoted to the promotion of CHP/DH and several success stories can be found in all countries, but the penetration of CHP remains small. An important obstacle for the penetration of DH is the widespread use of natural gas in those areas that are most suited for DH.

Austria became an exception to this development. The Austrian electricity supply industry was nationalised in 1947 creating a hierarchical structure of 15 major utilities consisting of the Verbund and its subsidiaries. Austria has a hydro-thermal electricity system. The share of hydro power has been 70% since 1970 although the generation has increased significantly. The hydro power is mainly run-of-river; less than one-third is from hydro storage plants. Most of the thermal generation is gas-fired. Unfortunately, the availability of hydro power is lowest when demand is highest. The development of district heating systems came late. However, since the 1960s Vienna and five municipal utilities in the provincial capitals have systematically developed urban district heating systems, starting from existing central boilers for large building complexes and adding pieces to pieces.

In some countries, notably the UK, individual natural gas boilers are commonplace not only in single-family houses, but also in each flat in multi-family houses. This makes the introduction of DH nearly impossible. On the other hand, there is a vast potential for future individual gas-fired micro turbines for CHP.

#### **4.2.7 DH in the new member states in Central and Eastern Europe [14]**

In most of the new EU member states in Central and Eastern Europe, there is a high penetration of DH, and CHP is used in many large cities. In the Communist period, the widespread building of large housing blocks was generally planned with heat supply from district heating. However, at the time of transition, many of these systems were obsolete and highly inefficient. Much effort has been devoted to refurbishment and improvement of these systems with support from the World Bank and the 15 old EU Member States, focusing mainly on DH networks and house installations, rather than on CHP units.

Some features are typical for the DH systems in Central and Eastern Europe, which are very different from the systems in Western Europe. DH systems normally supply space heating only, and hot water is supplied separately. This means that DH systems operate only during the heating season. In addition, the radiator systems are often single pipe systems, so there is no technical possibility to regulate the space heating intensity in the individual flats; only regulation for whole buildings is possible. Metering is also made for the whole building, although bills are sent to each individual consumer on the basis of the floor area of each flat. The decision to start and finish a heating season is competence of municipality but not consumers.

Among the new member states, the energy sector in Lithuania has been studied most intensively, because approximately 80% of the electricity has been produced by one power plant, i.e. the Ignalina Nuclear Power Plant, which is now in the process of decommissioning. According to the agreement with the European Commission this power plant will be shut down by 2009. This has a huge impact on the electric power, district heating and natural gas supply sectors in Lithuania.

About 45% of the households are connected to DH systems. In urban areas, 73% of the buildings are connected to DH systems, while in rural zones only 1%. The heating season in Lithuanian is about 220 days and there are about 4000 degree days; a large share of household consumers live in multi-family houses. The average of heat losses in district heating networks is about 25%, and in some areas losses are as high as 45%. Thus, decrease in heat consumption will lead to significant overcapacity in district heating systems (boilers, pumping station, pipeline diameters, etc.). District heating companies have made investments into metering and renovation of substation buildings during the last few years. However, there are no sufficient long-term plans for pipelines renovation investment; pipelines are refurbished in emergency conditions only.

In 2002, the installed capacity of district heating boilers was 10.14 GW. The maximal demand at the winter peak was only 3.77 GW. Many of these boiler houses were located at industrial sites from the Soviet time, where energy-intensive industries have been closed down.

Lithuania has approximately 50 district heating companies of different size. In 1997 the ownership of the DH systems were transferred to the local municipalities, including the debt of the state owned company. By 2003, half of all municipalities did not have long-term development plans (including district heating development). To deal with large debts of municipal companies and lack of investments, municipalities are trying to transfer the management of district heating companies to private firms, e.g. the district heating company of the capital city Vilnius has been leased by the French company Dalkia for 15 years. The other major city, Kaunas, sold the main heat source, a

CHP plant to the Russian company Gazprom, which declared a plan to double the capacity of Kaunas CHP and export electricity to the neighbouring Kaliningrad region (Russia).

The new Lithuanian Heat Act came into force in July 2003. Each district heating company must prepare a long-term DH system development plan, zoning of cities will be introduced, the rights of consumers to disconnect from DH system is very limited, the vertical monopoly of DH companies will not be unbundled (including heat production, transportation through pipelines, distribution inside multi-family houses and billing), the municipality should be the owner of the transmission system (pipelines) and at least 30% of the generation capacity. Competition is allowed in two positions only: competition between independent producers and O&M service of heating equipment inside the building. However, secondary legislation made significant barriers for independent producers' entrance to a heat market.

Most of the multi-family houses were constructed before 1992 and have very poor thermal insulation. The average heat consumption in Lithuania is about 220 kWh/m<sup>2</sup> per year, whereas in the neighbouring Scandinavian countries it is 120 kWh/m<sup>2</sup> or less.

Up to 1991, the state was the owner of multi-family houses. The Soviet system legacy was problematic, since there was little motivation for inhabitants to keep houses in adequate quality. Therefore, privatisation of these houses was started in 1991. Now, 90% of the flats in multi-family houses are owned by individuals. However, one of the major issues is to upkeep a communal ownership of houses (e.g. roof, pipelines, etc.), because only 17% of multi-family houses have Home Owner Associations. The administration of communal ownership without associations is complicated. In addition, this is a barrier in the renovation process. There is a strong demand for the renovation of heating equipment inside buildings and insulation of these buildings.

### **4.3 Economic analysis**

To conclude this section on cogeneration and district heating, a short economic analysis is made, based on the results from [10]. Irrespective the used technology (gas engines, STAG with or without heat storage, back-up boilers...), but with the investment in a "distance heating network" included, economic results turn out in favour of separate production. A gas grid is assumed to exist in the cases analysed.

A sensitivity analysis on the results shows the impact of changing gas prices and efficiencies of central and individual boilers. The lower the gas prices, the higher the additional costs of DH compared to separate production, as the economic impact of the energetic advantage of DH decreases. Higher efficiencies of individual boilers make the additional costs of DH higher, and the influence of varying efficiencies of central boilers is rather small.

The largest impact on the economic analysis is caused by the investment in the heating network. The costs are depending on the specific circumstances of the grid - connection density, diameter of the pipelines, kind of subsoil... – but in any case, it has a large influence on the overall outline of the costs. By the operation of the heat network, the investment can be regained. The more heat is transported through the network – so the more heat is consumed by the users of the network – the sooner the investment is paid back. But this is in conflict with the aim to increase energy efficiency

in houses and reduce heat consumption without comfort losses. So there is a conflict of interests: more heat consumption to regain the investment costs of the network versus less heat consumption by better insulation of houses.

Many of the investments in the infrastructure may not have been cost-effective when they were decided for most of the criteria that are used for economic assessment. Later, however, in some countries (and after they had been built anyway) they became important elements of a more robust energy system that was necessary for the development of new opportunities or meeting the problems created by changing economic and political condition.

#### **4.4 The role of traditions and organisation**

Although the traditional organisation of the electricity industry has been monopolistic in all EU countries, there are many important differences in the organisation of the industry, which will survive the process of liberalisation:

A key issue is the *role of local government and local interests* in the electricity supply industry and other utilities. In some countries local government is directly or indirectly owner of utilities or has an important influence on physical planning and urban/regional development. In other countries the utilities have been either nationalised or privatised sector by sector (i.e. electricity, gas, water, etc.). In Scandinavia, Germany and the Netherlands there has been a strong involvement of local government and local interests in all types of public utilities. For these local utilities district heating is a business opportunity rather than a competitive threat.

*Different municipal structure and traditions.* The strength, financial sources, and responsibilities of the municipalities are very different. Municipalities in Denmark collect a significant part of the income, tax and the tax rates may vary by nearly 10% of the tax base. In Germany the utilities have been an important source of income for the municipalities, and cross-subsidies have been significant for providing municipal services to the public. In other countries significant areas of responsibilities were detached from the municipalities decades ago, in particular utilities. Although the structure of government is very centralised in both France and the UK, the number of local governmental units are very different, there are some 400 units in the UK compared to more than 30,000 in France. A key factor for the development of district heating has been the consistency between the structure of local government and the physical urban structure.

*The role of local industry:* In Finland, local industry has been very important for a fast development of district heating. In Denmark, industrial waste heat has been encouraged for the supply of large district heating systems. In other countries ‘embedded power generation’ has been a significant driver for industrial CHP, which was profitable only when the generated electricity was used on site.

*Early development of natural gas grids* has been a very important obstacle for the development of district heating in several countries. The Nordic countries, where natural gas came late are a significant exception. On the other hand, the existence of many small district heating systems in Denmark was important for the development of a market and infrastructure for natural gas. The

existence of a gas grid has recently become very important for the penetration of small-scale CHP based on the combined cycle gas turbine.

*Small-scale vs. large-scale systems:* The search for autonomy from nationalised or large public electric utilities has been an important driver for the development of many small-scale CHP applications both in industry and for district heating. A similar controversy between large-scale and small-scale application has been experienced for the district heating sector in countries with large urban networks for district heating, where local interest have argued for small local units rather than large-scale urban district heating networks. In this respect it is interesting to point to a social paradox: there seems to exist a social-drive towards decentralised electricity generation, whereas those same groups seems to advocate CHP-based centralised district heating.

*CHP vs. nuclear power:* CHP was often presented as an alternative to nuclear power, and opposed by nation-wide electricity-only utilities. Thus, CHP is virtually non-existent in France and the UK and far beyond the potential in Sweden and Germany. Large-scale nuclear CHP was studied in Sweden, Germany and Denmark in the late 1970s, but was never implemented in any of the countries in Western Europe. In Denmark, large-scale CHP was expanded based on coal, in Sweden, low electricity prices from hydro and nuclear lead to the use of heat pumps for district heating rather than CHP, and in Germany fossil fuel based CHP was expanded in a more limited scale.

*Climate and heat densities:* Cold climate is a necessary, but not sufficient condition for district heating based on CHP. High heat densities in urban areas are not necessary for district heating, provided that the infrastructure and organisation is available. District heating is also an option for an expanding market for single-family houses in new developments. But anyhow, the option of DH has to be carefully analysed when a gas grid is available and when a heat distribution grid is to be invested in.

## 5 Conclusions

If used properly, cogeneration is a very interesting technology to obtain primary energy savings and accompanying reductions in CO<sub>2</sub> when generating electricity and heat. Also, economically, this technology may be attractive, although market circumstances may necessitate subsidy schemes to promote a certain market penetration.

The European Commission believes that cogeneration can positively contribute to the EU environmental policies. Therefore, it has created a framework for the promotion and development of high efficiency cogeneration of heat and electric power. Within this framework, a good definition of *quality cogeneration* is essential. In this discussion, it is important that one does not lose sight of the fundamental thermodynamic concepts and backgrounds.

When the construction of a CHP unit is under consideration, it is important to realise that cogeneration is only justified if the produced heat is utilised. Throwing away – or condensing – heat is to be discouraged and can only be allowed if the primary energy savings (integrated over e.g. a year) thanks to cogeneration remain positive compared to separate generation of electricity and heat.

From a technical point of view, several mature CHP-options are available. Depending on the required power range, steam turbines, gas turbines, combined cycles or reciprocating engines are well-known solutions. New options for cogeneration applications, like the Stirling engines and fuel cells, are under development, but considerable advances have to be made before they will become competitive.

District heating is a widespread application of cogeneration. Several configurations, which make use of gas- or coal-fired technologies, are used. To increase the flexibility of the heating system, back-up boilers or heat storage tanks can be used. Although there are some examples where the use of district heating is advantageous, both from an energetic and economic point of view, one does not come to the same conclusion in every case. Especially the investment in a new heat-distribution grid may be precarious. Since newly built houses minimise the heat demand, due to the more stringent insulation requirements, and since the natural gas grid becomes more and more widespread, one needs to carefully analyse whether the centralised heating option is economically preferred over individual heating.

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