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POWER AND HEAT PRODUCTION: PLANTS AND GRID LOSSES

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Table of contents

1 Background

1.1 Introduction

RIVM has developed the global energy model TIMER (Targets Image Energy Regional model) to analyse the long-term dynamics of the energy-system within an integrated modelling framework. The model is mainly used to explore consequences of different scenarios for greenhouse gas emissions and emissions of atmospheric pollutants and to explore the possibilities to mitigate the emissions. In the TIMER-model, a combination of bottom-up engineering information and specific rules and mechanisms about investment behaviour and technology is used to simulate the structural dynamics of the energy system.

Until now, the fossil fuel electricity production sector is modelled based on a limited number of plants, classified on basis of fuel use. RIVM intends to improve the model by a more explicit definition of new fossil fuel power and heat supply plants. In addition, more explicit attention is needed to the losses in the electricity system related to transmission and distribution (T&D), malfunction of metering equipment, theft and meter tampering.

1.2 Approach power and heat plants

This report gives a short description for different types of power plant in order to derive functional relationships for future technology development of these plants For this purpose, a four step approach is used:.

- Firstly a description is given of the state-of-the-art power technology and possible opportunities are assessed for improving energy conversion efficiencies and reducing costs for the most common technology/fuel combination.
- Secondly differences are described when using other fuel-technology combinations.
- Thirdly differences are assessed when power technology is used in CHP mode.
- Fourthly an assessment is made for costs and efficiencies when the technology is combined with carbon dioxide capture.

The improvement of efficiency and development of investment costs and operation & maintenance costs are given for the view years 2020 and 2050. Furthermore a reasonable theoretical maximum efficiencies and costs are provided. These values can be considered as the efficiencies and cost level achievable up to 2100.

However, making any forecast for individual plant types in the period after 2050 is difficult and probably meaningless. It will therefore be assumed that from 2050 onwards an advanced plant will become operational. This type of plant can e.g. be based on fuel cell technology, but also on a technology not yet developed.

1.3 Approach grid losses

Worldwide, losses of electricity (after generation) amount to 5% to 30% (depending on the region). Obviously, reducing these losses represents an option to make future energy systems more efficient, and thus reduce emissions. If prices of electricity increase, e.g. induced by climate policies, pressure will be put on reducing losses in the grid. In this report an attempt is made to improve knowledge regarding level and composition of those losses, the potential for reduction and respective costs. As far as possible this information is processed that way in such a way it is applicable in the TIMER model.

1.4 Reading guide

Chapter 2 and chapter 3 present results of the analyses of the developments in conventional and combined cycle power plants. In chapter 4, we discuss the plant-of-the-future and in chapter 5 the boilers. Annex 1 holds the input tables for efficiency and costs for the various plants and annex 2 provides some background information on carbon dioxide capture. Chapter 6 provides information on types of grid losses, estimates of the grid losses per world region and costs to reduce these losses.

2 Conventional power plants

2.1 Introduction

The most widely used power plants are the conventional boiler plants based on the Rankine cycle. Fuel is combusted in a boiler and with the generated heat pressurised water is heated to steam. The steam drives a turbine and generates electricity. In principle any fuel can be used in this kind of plants. Most widely used is coal and natural gas, but also biomass can be used. In a few power plants, oil is used as fuel for such plants.

This section extensively describes the pulverised coal power plant. This type of plant is the most important of the conventional power plants and still in development. The significance of the conventional natural gas plant is decreasing as combined cycles are taking over the market. Biomass-fired plants may become more important, although large-scale plants have not been built yet. Biomass is currently mostly utilised in co-firing in coal-fired power plants. In this way, the fuel can profit from the relatively high efficiency obtained in large-scale coal-fired power plants compared to small-scale applications.

2.2 Pulverised coal power plant

The pulverised coal combustion was first developed in the 1920s. In this form of combustion, coal is first ground into fine particles. Fine coal particles are injected with a proportion of the combustion air (usually referred to as primary air) into the lower part of a combustion chamber using an array of injectors (i.e. burners) and ignited using oil or gas flames. The particles burn in suspension, creating flames and releasing heat into the combustion chamber. The temperature of the coal flame usually reaches around 1500°C. The rest of the combustion air (generally referred to as secondary air) is usually supplied around the injector, mixing with the burning coal particles further away from the chamber wall, to provide additional oxygen to complete combustion. The heat released into the combustion chamber is transferred, mainly by radiation and convection, to the water tubes that are located in the walls of the combustion chamber. Hot gases move upwards and superheater tubes located near the top of the combustion chamber extract heat. Finally, further heat is usually extracted in an economiser to heat the water before it enters the boiler tubes and the flue gases are vented to the atmosphere at around 130°C via a stack.

Both intensity of combustion (i.e. the heat released per unit volume of combustion chamber) and combustion efficiency achieved with pulverised combustion are well above those possible with other coal-firing appliances (e.g. stokers) and are comparable to those of oil and natural gas-fired systems. As a result, this form of combustion found widespread application in power generation soon after its introduction. In the early days, the unit size of pulverised combustors was small (typically 30 MWe). The pressure and temperature of the steam produced were also moderate, resulting in relatively low power generation efficiencies (typically 20%). Over time, with technological developments and experience, both the unit size of combustor, and steam pressure and temperature, have gradually increased over the years.

2.2.1 Efficiencies pulverised coal plants

In the development of conventional power plants there is a gradual shift from subcritical steam cycles, via supercritical steam cycles to ultra supercritical steam cycles. The theoretical thermal efficiency of a Rankine cycle is a function of both temperature and pressure, with the dependence on temperature being much stronger. Over the temperature range of 500 to 800°C efficiencies vary almost linearly with steam temperature. Thus, there is an incentive to boost steam temperature in order to achieve higher thermal efficiency [Ruth, 2003]. The temperature of steam increased 60°C over the last 30 years. It is expected that steam temperatures will rise another 50-100°C in the next 30 years [Viswanathan, 2000].

Pulverised coal-fired *sub-critical* steam power plants with steam pressure of around 18 MPa (critical pressure of steam is 22 MPa) and temperature of 540°C, with combustor unit size up to 1000 MWe, are commercially available and in use worldwide. These plants can achieve generation efficiencies of up to around $39\%_{LHV}$.

In the 1970s, pulverised coal-fired *supercritical* steam cycle plants, were developed and introduced, mainly in Europe and the USA. These plants use a steam pressure of around 24 MPa and temperature of around 560°C, and their unit sizes are in the range 400-900 MWe. Such plant can achieve generation efficiencies of up to around $42\%_{LHV}$. However, most of these units suffered problems regarding flexibility of operation (i.e. load changes), reliability and maintenance. More recently, however, supercritical plants built in the late 1980s and early 1990s, mainly in Europe (Germany and Denmark), have been able to operate with improved performance and reliability.

Of late, several *ultra supercritical* units, 400-600 MWe in unit size, have been ordered or are under construction in Denmark, Japan and China. These units are designed to operate at steam pressures up to about 30 MPa and temperature up to over 600°C to achieve a generation efficiency of up to $47\%_{LHV}$.

One of the first ultra supercritical plants was unit 3 at Nordjyllandsværket in Denmark, which is a double reheat unit with steam parameters 29 MPa and 3 x 580°C and an efficiency of 47%. The unit went into operation in 1998. This led to the start of the large European research project: The Advanced (700°C) PF Power Plant. The project receives funding from the EU and has 40 participants from the European power industry. The aim of the project is to raise steam temperatures to 700°C resulting in efficiencies in the range of 52 to 55% efficiency. The plant will have an output within the range 400-1000 MWe and therefore its output will be appropriate for utility-scale electricity generation. It is estimated that the total project duration will be 17 years including a two-year demonstration period, and the actual construction of the plant somewhere in Europe could start around year 2008. Commercial availability is not expected before the period 2010 to 2015. [Tech--wise A/S, 2003a]

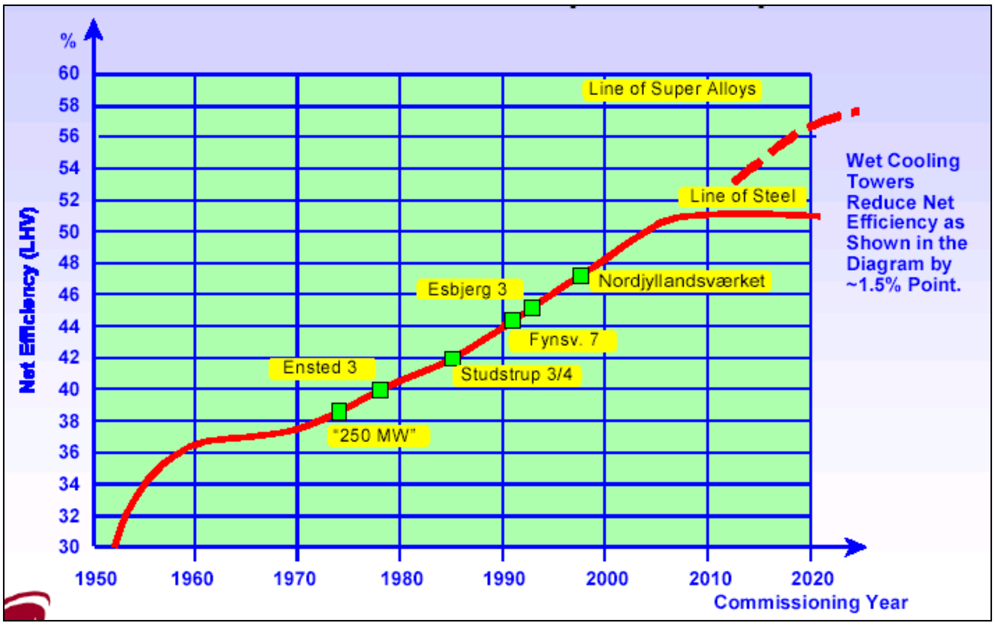

Figure 1. Past and projected future development in efficiency of Elsam's coal-fired power plant [Tech-wise A/S, 2003b]

In the United States a consortium of four major boiler manufacturers, EPRI and the Ohio Coal Development Office and ORNL is running a five-year project from 2003 to 2007 with the immediate goal to identify alloys for boiler tubes capable of operation with steam at temperature and pressures up to 760°C and 35 MPa [Ruth, 2003].

2.2.2 Costs pulverised coal plants

Investment costs for power plants are formed by

- Direct costs (site preparation, civil work, material, equipment, labour)
- Indirect costs (design, worksite administration)
- Owner's costs (general administration, R&D, spare parts, licensing, pr, taxes)
- Contingency

The quoted investment costs generally include all the aforementioned costs items. Based on a comparative study of the IEA [1998] with 22 running pulverised coal power plants, the average base costs amounted to 1000 $€_{2000}$/kWe. Including interest during construction and contingency (in total on average about 15%), total investment costs amount to 1150 $€_{2000}$/kWe.[1]. It must be noted that local, investment costs considerably can deviate from average costs, e.g. two plants in Portugal are 50% more expensive that average and twice as expensive as one plant in Finland.

In an earlier study by the IEA Greenhouse Gas R&D programme costs for pulverised coal power plants were estimated in the range of 1050 to 1300 $\$_{1991}$/kWe [IEA, 1991]. Converted to $€_{2000}$ and corrected for inflation this is equivalent to about 1000 and 1250 $€_{2000}$/kWe.

The tendency is that investment costs are decreasing. According to DoE [1999], dramatic improvements in the economics of the pulverized coal in the United States over the last decade have occurred. During the 1980s through the 1990s, commercially supplied pulverized coal plants with flue gas desulphurisation with nominal capacities of 500 MWe were priced 1,300$\$_{1995}$ per kWe. Presently (1999), the total plant costs for U.S. plants can be commercially offered for under $1,000 per kWe. Technology and economic advancements contributing to this reduction can be summarized by the following categories:

- Performance Improvements
- Plant Automation and Reliability Improvements
- Direct Equipment Cost Reductions

According to Torrens [1996], investment costs for ultra supercritical pulverised coal plants only marginally increase in costs while efficiencies might rise substantially. A detailed market study from DoE [1999] to 400/500 MWe sized coal-fired power plants indicated costs 1130 $\$_{1988}$/kWe (1185 $€_{2000}$/kWe) for sub critical, and 1170 $\$_{1988}$/kWe (1230 $€_{2000}$/kWe) for supercritical, and ultra supercritical power plants.

Projected O&M costs for coal-fired plants lie in the range of 20 and 65 $€_{2000}$/kWe capacity in OECD countries. In non-OECD countries, projected costs for coal-fired plants are generally lower, ranging from 15 to 35 $€_{2000}$/kWe [IEA, 1998].

The investment costs all include emission control systems, often flue gas desulphurisation, electrostatic precipitator and deNOx equipment. Desulphurization costs amount typically to about 200 $€_{2000}$/kWe and selective catalytic reduction equipment to 70 $€_{2000}$/kWe. According to Rubin [2002], costs of FGD and SCR are decreasing in relation to the installed capacity. Current costs are about 50% of the cost

[1] The 1996 dollar costs are converted to 2000 euro costs and corrected for inflation exchange rate of: euro (2000) to dollar (2000) = 0.95 dollar/euro; euro (1996) to dollar (1996) = 1.29 dollar/euro; euro (2003) to dollar (2003) = 1.15 euro/dollar

obtained in the seventies. Rubin [2002] estimates current investment costs for desulphurization at 130 $€_{2000}$/kWe and at 60 $€_{2000}$/kWe for DeNOx-SCR systems. IEA [1991] estimates costs for desulphization at 125 $€_{2000}$/kWe. The Asean Centre for Energy estimates costs for desulphurization at 200 $€_{2000}$ per kWe; DoE [1999] estimates costs for flue gas cleanup at about 155 to 165 €/kWe. Coal handling, preparation and feed costs are estimated at about 80 $€_{2000}$/kWe [DoE, 1999] or 60 $€_{2000}$/kWe [IEA, 1991].

2.3 Natural gas, oil and biomass fuelled conventional power plants

The principle of the conventional power plant fuelled by other fuels than pulverised coal is the same. Due to less required operations in natural gas-fired plants, e.g. grounding of coal and desulphurisation are not required, efficiencies of natural gas-fired conventional power plants are somewhat higher and investment and O&M costs somewhat lower. These arguments are to a lesser extend valid for oil-fired power plants. Usually heavy oil is used in oil-fired power plants. As heavy oil might contain as much or sometime more sulphur than coal, the desulphurisation unit will be comparable. Biomass plants are less efficient than coal-fired power plants. Biomass plants are typically smaller because of transport logistics of the fuel, the moisture content of the fuel is higher and the energy density lower. On the other hand, biomass has a higher reactivity than coal. New technologies, like torrefaction of the biomass to increase energy density and brittle the fuel, will increase fuel efficiency of the biomass.

2.4 Combined heat and power mode

The conventional power plant can easily be constructed as a combined heat and power generation unit. At the expense of the power output, extracting steam from the steam cycle can be used to produce heat. The additional investment costs and O&M costs of the plant are small. Lako [1998] estimates the extra costs at about 50 €/kWe. Overall energy-efficiency of the plant increases and might reach 70% or higher. It should be noted that considerable investment might be required to construct a district heating system to transport the heat of the CHP plant to the consumers.

2.5 CO_2 capture from conventional power plants

The post-combustion process is currently regarded as the best-suited technology to capture carbon dioxide from conventional power plants (see annex 2 and e.g. [GESTCO, 2003]). In a post-combustion process, the CO_2 is separated from the flue gases of a power plant or from the flue gases of an industrial process.

For post-combustion processes, the best-known and developed technology is separation of CO_2 from flue gases by an amine-based solvent. It is currently the most mature technology for capturing CO_2 from flue gases. Other ways to capture CO_2 is by using membranes (polymer- based, ceramic or metal-base) or in combinations of membranes and solvents. In the latter option, the membranes replace the absorption column and act as a gas-liquid contact facilitator. Also considered is to fractionate the carbon dioxide by solidifying it. These alternatives are at the moment less energy efficient and more expensive than chemical absorption. This can be attributed, in part, to the relative low CO_2 partial pressure in the flue gases. In this analysis, we assume à priori that the amine-based chemical absorption process is the preferred technology; our cost and energy consumption for post-combustion carbon dioxide capture are therefore based on this technology.

The amine-based systems are commercial proven technology on small scale, and are similar to other widespread used end-of-pipe environmental control systems as flue gas desulphurisation systems. The amine-based systems can cost-effective recover 85% to 95% of the CO_2 in the flue gas and produce CO_2 with purity of over 99.9%. Examples of current commercial available systems are the Econamine FG process of Fluor Daniel and the Amine Guard process licensed by UOP. The most commonly used absorbent is monoethanolamine (MEA). A method for reducing energy consumption is to use modified absorbents. Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries have been examining and testing a wide range of amines and developed new solvents (so-called KS-1, KS2, and KS-3). Compared to MEA, KS-1 has a lower circulation rate (due to its higher lean to rich CO_2 loading differential), lower regeneration temperature (110°C), and 10-15% lower heat of reaction with CO_2. KS-1 is commercialised and used in a commercial plant in Malaysia (the Petronas Fertiliser Kedah Sdn Bhd's fertiliser plant in Gurun Keday) and is operational since October 1999. In the early nineties Mariz [1991] and Sander [1992] reported that a heat consumption of 4.1 MJ/kg CO_2 can be obtained by the MEA-based Econamine process. According to Mimura [2000], the KS-1 solvent can reach less than 3.3 MJ/kg CO_2 for flue gases with 7% CO_2. They expect to obtain further improvements in the coming years.

2.5.1 Efficiency loss with carbon dioxide capture

The chemical absorption process is an energy intensive process, using high amounts of low-temperature heat. The efficiency loss of the power plant can be diminished when low-pressure steam of the steam cycle of the power plant is used. Due to the high carbon content, efficiency loss of coal-fired power plants by capturing carbon dioxide is considerably higher than for natural gas-fired plants.

Current research to carbon dioxide capture shows that substantial possibilities to improve the process exist. Improvements vary from better integration into the current power production plant to improved absorbent with higher loadings and lower energy consumption per kg carbon dioxide recovered. See [GESTCO, 2003] for an overview of capture technologies and research opportunities. Based on the early stage of development and on current knowledge of the technology, it is not unrealistic to assume that efficiency loss might be reduced by 50% in the year 2050 and 75% in the year 2100. Assuming gradual improvement this means that every year the efficiency loss due to the capture of the carbon dioxide is annually reduced by 1% towards 2050 and annually reduced by 0.5% from 2050 to 2100.

2.5.2 Costs of carbon dioxide capture

The direct capital costs of a chemical absorption capture plant are formed by the costs for flue gas blower, absorber, reboiler and regenerator, heat exchangers, reclaimer, pumps, piping, etc. In the case of flue gases containing sulphur, the cost of the SO_2 removal unit should be added. However, the extra capital costs for the SO_2 scrubber might more or less be offset by the elimination of the flue gas cooler. The capital costs depend mainly on the amount of carbon dioxide to be captured and the concentration of the carbon dioxide in the flue gas. The indirect costs comprises engineering costs, contingencies, interest during construction and possible royalty fees.

The operation and maintenance costs consist of labour costs and material costs. Variable material costs comprise

- Solvent consumption (make up of solvent losses resulting from degradation and spills). Can be about 2 – 4 kg per tonne CO_2 captured, assuming the presence of a desulphurisation unit.
- Water costs
- Additives (e.g. inhibitors) and activated carbon consumption.
- Disposal of waste streams (reclaimer waste, spent carbon and filter elements).

These costs depend on the composition of the flue gases and are generally higher for flue gas from coal-fired plants than for flue gas from natural gas-fired plants.

Carbon dioxide capture technologies are in an early stage of development. Commercially available systems are usually only used in small-scale applications. Considerable room for energy efficiency and costs improvements is still present. Cost reductions can be obtained in the future by

- Lower heat/steam consumption for the desorption process. Less heat demanding absorbents and better integration with in the plant has considerable potential to reduce energy use. Reduction of energy demand for the process lead to lower associated emission of CO_2 (thus less capture required) and to lower energy costs [Suda, 1993; Mariz, 1999; Chakma, 1998; Mimura, 2000]. In a Japanese programme, new solvents are tested and evaluated in a new bench scale test facility with a stripper of 1.8 m high and a maximum flow rate of 7 m^3/h [Mimura, 2002].

* Better absorbent columns leading to a lower pressure drop and higher recovery efficiency [Suda, 1992; Mimura, 2002]. The latest developments have been made in reducing amine consumption and pressure loss over the column. Mimura [2002] reports ten to twenty times reduced amine loss per kg of captured carbon dioxide than conventional MEA systems. Adjustments in packing have reduced pressure loss significantly.

In this respect also the use of membrane gas/liquid contactors to facilitate the contact with CO_2 and the solvent is being investigated In addition membrane contactors occupies less space what might be of interest offshore. Simulation predicted a reduction in weight of over 60% of the installation [Aboudheir, 2000; Falk-Pedersen, 2000a].

Rubin [2002] and Hendriks [2002] discuss the learning curve of carbon dioxide based on experiences in development of flue gas desulphurization systems and selective catalytic reduction systems to control NOx emission. Based on these findings, costs may decrease by 50% if the capture technology is implemented on large scale. The reliability of the estimate of the cost improvement following a learning curve is at this stage low. Although the technology is not completely new and in some form already applied for decades in the industry, large-scale application in power plants has not yet been applied. If we assume that costs indicated in the studies reflects costs when 2% of the potential has been implemented, investment costs can be halved compared to costs quoted in studies nowadays at large-scale implementation. We therefore assume that on the long term (2050) a 50% cost reduction is attainable.

The operation and maintenance cost (excluding fuel) for the capture process is assumed to be 6%, what is a usual figure for chemical installations.

2.6 Conclusion for input data TIMER

Pulverised coal power plants with an energy conversion net efficiency of 47%$_{LHV}$ can currently be built at costs of about 1100 €$_{2000}$/kWe. Improvement mainly in the steam cycle towards higher temperatures and pressure will lead to higher efficiencies. In 2020 efficiency of 52%$_{LHV}$ is foreseen and in 2050 this might increase to 55%$_{LHV}$. Due to material constrains, much higher efficiency are not expected on the longer run. Specific investment costs may slightly decrease over time, from the current 1150 €$_{2000}$/kWe to 900 €$_{2000}$/kWe in 2050.

It is not likely that many natural gas-fired conventional power plants will be built in the future. These plants are more expensive and lower in efficiency than combined cycles. Efficiency of conventional natural gas plants will be somewhat higher because desulphurisation (if applied), and coal handling are not required. Also, flue gases of natural gas-fired plants are cleaner than of coal-fired plants and the flue gases can be cooled down to lower temperatures.

The present share of oil-fired power plants is also low and it is not expected that a lot of additional oil-fired plants will be built in the near future. Locally, this might be different in situation of abundant available oil, like for instance some countries in the Middle East. Nevertheless, the natural gas and oil-fired conventional plant may profit from the developments in the pulverised coal plant. Efficiency of oil-fired conventional plants is approximately the same as of coal-fired plants.

In conventional steam power plants the main improvements will be in the steam cycle, i.e. to ultra supercritical conditions at higher temperatures and pressures. This technology can be applied in all types of conventional steam cycle power plant.

Equation (1) gives the relationship between the efficiencies of conventional coal-fired plant and the other conventional power plants:

$$\eta^{y}_{C-fuelx} = IF^{y}_{C-coal} \times \left(\eta^{2000}_{C\_coal} + \eta^{2000}_{coal-fuelx}\right) \qquad (1)$$

with:

$\eta^{y}_{c\text{-}fuelx}$ = efficiency of conventional power plant with fuel x in year y
$IF^{y}_{c\text{-}coal}$ = improvement factor efficiency of conventional coal-fired power plant in year y compared to year 2000
$\eta^{2000}_{c\text{-}coal}$ = efficiency of conventional coal-fired power plant in year 2000
$\eta^{2000}_{coal\text{-}fuelx}$ = difference of efficiency of conventional coal-fired power plant and power plant fired by fuel x in year 2000

[2]

The investment costs for power plants are the sum of the investment for the base plant, flue gas cleanup and fuel handling equipment.

$$I = I_{base} + I_{CU} + I_{FH} \qquad (2)$$

with:

I = Investment power plant (€/kWe)
I_{base} = Investment for base plant (€/kWe)
I_{CU} = Investment for desulphurisation, DeNOx, particulates, etc. (€/kWe)
I_{FH} = Investment for fuel handling (€/kWe)

The operation and maintenance costs (without fuel costs) for power plants are the sum of the O&M for the base plant, flue gas cleanup and fuel handling equipment.

$$OM = OM_{base} + OM_{CU} + OM_{FH} \qquad (3)$$

with:

OM = O&M costs power plant (€/kWe)

[2] Annex 1 summarizes the values for the parameters used in the equations, like plant efficiencies, investment costs, O&M costs, and improvement rates.

OM_{base} = O&M costs for base plant (€/kWe)
OM_{CU} = O&M costs for desulphurisation, DeNOx, particulates, etc. (€/kWe)
OM_{FH} = O&M for fuel handling (€/kWe)

The investment costs for future years (compared to costs in 2000) are given by equation (4)

$$I^{year\_x} = I^{2000} \times \frac{\eta_{2000}}{\eta_{year\_x}} \times IF_{year\_x} \tag{4}$$

with:
I^{year_x} = Investment costs power plant in year x (€/kWe)
I^{2000} = Investment costs power plant in year 2000 (€/kWe)
η^{2000} = efficiency of power plant in year 2000 (%)
η_{year_x} = efficiency of power plant in year x (%)
IF_{year_x} = Improvement rate (cost reduction) in year x compared to year 2000 (%)

To calculate the O&M costs the same approach is followed as elaborated for the investment costs.

Regarding the costs, the following assumptions are made:

- Investment of base plant (including boiler, steam turbine, cooling system, waste water treatment, control and instrumentation, miscellaneous (buildings etc.), land clearance) for all fuels is the same (in €/kWe)
- Investment of flue gas cleanup is the same for coal-fired and oil-fired power plants
- Investment of flue gas cleanup is the same for natural-fired and biomass-fired power plants
- Investment of fuel handling is the same for coal-fired and biomass-fired power plants

Conventional power plants may also be designed as combined heat and power generation units (CHP). Supply of heat will reduce electricity output. Assuming that the steam is extracted at a temperature of 150°C, the enthalpy of the steam amount to about 2885 kJ/kg. This would otherwise be expanded to steam with an enthalpy of 2294 kJ/kg. Neglecting some generation losses, the power loss is 2885-2294 = 591 kJ/kg steam. Neglecting possible heat losses and less reduced heat demand for heating boiler feed water, the useful amount of heat that can be extracted from the steam is 2885-450 (i.e. enthalpy of hot water of 150°C) = 2435 kJ/kg. This means that for 1 kJ of heat generated, the output of electricity is reduced with 591/2435 = 0.24 kJe. Equation (5) presents the relationship between the efficiency of conventional power plants and CHP plants.

$$\eta_e^{CHP} = \eta_e^{conv} - HF \times \eta_{th}^{CHP} \tag{5}$$

with:
$\eta^{CHP}{}_{e}$ = electric efficiency of conventional power plant in CHP mode
$\eta^{conv}{}_{e}$ = electric efficiency of conventional power plant
$\eta^{CHP}{}_{th}$ = thermal efficiency of conventional power plant in CHP mode (e.g. 30%)
HF = heat – electric ratio (=0.24 kJe/kJ steam extracted)

Carbon dioxide capture will decrease efficiency of the plant substantially. In conventional power plants, the amount of energy required to separate and compress carbon dioxide is approximately proportional to the amount of carbon dioxide recovered. As the heat is extracted at the low-pressure section of the steam turbine (and not in the high-pressure section where improvements can be expected), the reduction in power output is absolute and not relative to the efficiency of the plant, i.e. regardless of the efficiency of the plant causes implementation of carbon dioxide capture the same efficiency penalty in percentage-points. Departing from the estimate of efficiency loss of carbon dioxide capture from a conventional coal-fired power plant the following formula can be given

$$\eta_{C\_fuelx}^{Capt} = \eta_{C\_coal}^{Capt} \times \frac{EF_{fuelx}}{EF_{coal}} \times \frac{CR_{fuelx}}{CR_{C\_coal}} \qquad (9)$$

with:
$\eta^{Capt}{}_{C\_fuelx}$= efficiency loss by carbon dioxide capture of conventional power plant with fuelx
$\eta^{Capt}{}_{C\_coal}$ = efficiency loss by carbon dioxide capture of conventional power plant with fuel coal
EF_{fuelx} = emission factor fuelx (kgCO_2/GJ)
EF_{coal} = emision factor coal (kgCO_2/GJ)
CR_{fuelx} = carbon dioxide recovery factor conventional power plant with fuelx
CR_{coal} = carbon dioxide recovery factor conventional power plant with coal

It is expected that the energy efficiency of the process can substantially improve before the technology is mature. Assumed is a linear improvement of 1% per year in the next 50 years and 0.5% in the years 2050-2100.

For example, the efficiency of a power plant with CO_2 capture in a year between 2000 and 2050 can be calculated by:

$$\eta_{with}^{year} = \eta_{without}^{2000} - \eta_{loss} \times \left[1 - \left(year - 2000\right) \times \eta_{ann}\right] \qquad (10)$$

with:
η_{with} = efficiency of plant in a certain year with CO_2 capture [%];
$\eta_{without}$ = efficiency of plant in year 2000 without capture [%];
η_{loss} = efficiency loss of power plant due to capture of CO_2 in year 2000 [%];

year = year of interest between 2000 and 2050 [y];
η_{ann} = annual improvement rate of capture process [%/y]

The same pace is assumed for cost reductions

The results are presented in the tables in Annex 1.

3 Combined cycle power plants

3.1 Introduction

Next to the conventional type of power plants, another important type of power plant is the combined cycle power plant. In this type of plant fuel is combusted in a gas turbine to generate electricity, and the waste heat from the gas turbine is used to raise steam to generate additional electricity via a steam turbine. The most common used fuel is natural gas, but also gasified gases from coal or biomass. This type of plant is becoming increasingly important in the production of electricity and heat.

3.2 Natural gas combined cycle

The set-up of gas turbine, waste-heat boiler, steam turbine and generator(s) is called a combined cycle. This type of power plant is being installed in increasing numbers around the world where there is access to substantial quantities of natural gas. This type of power plant produces high power outputs at high efficiencies and with low emissions. A typical size of natural gas combined cycle (NGCC) plants is 250 to 360 MWe, with an availability of 90%. The construction time is typically 3 years. The plant has low emissions; about 0.16 g NO_x per kWh, and 350 g CO_2 per kWh and no significant sulphur or particulate emissions.

Developments needed for this type of energy conversion are only for the gas turbines. Both waste heat boilers and steam turbines are in common use and are well developed, without specific possibilities for further improvement. NGCC power plants are being installed in many parts of the world and the technology is considered reasonably well proven.

3.2.1 *Efficiency natural gas combined cycle*

Gas turbine is a technology, which is for decades widely deployed in the aviation sector. Since the seventies, this technology is increasingly implemented in the power generation sector. Since the 1980s the efficiency for the gas turbine in combination with a steam cycle has gradually improved. Were efficiencies in 1980s still well below $50\%_{LHV}$, currently the most modern combined cycles have efficiencies of about 60%. It should be noted that actual efficiencies are a few percent lower than design efficiencies because of part load and startup and shutdown of the plant. Although the pace of the improvement is expected to slow down, efficiencies improvement may still be obtained. Charpin [2000] forecasts efficiency of 60% in 2020 and 65% in the year 2050.

Gas turbine development is towards higher firing temperatures, which gives higher power outputs and efficiencies. This needs development of new materials, thermal barrier coatings and/or advanced blade-cooling techniques. Higher temperature may increase NOx formation. A number of ways of combating this are also under consideration, including the use of novel gas turbine cycles, e.g. sequential firing, intercooled regenerative cycles, and reheated gas turbines. Many gas turbine manufacturers are also investigating the possibility of staged combustion and catalytic combustion. Other research activities being pursued by manufacturers are centred on increasing component aerodynamic efficiencies to reduce the number of compressor and turbine stages, and improved turbine stator and blade cooling mechanisms.

Possible application (ultra)supercritical conditions in the steam cycle can only be applied by co-firing as gas turbine exhaust temperatures typically do not exceed 560 to 600°C. This will probably not improve total plant efficiency.

3.2.2 Costs of natural gas combined cycle

Generally, construction costs for natural gas-fired combined cycle power plants are much lower than e.g. those for conventional coal-fired plants. The quoted investment costs generally include all cost items as mentioned in the coal-fired section.[3] Based on a comparative study of the IEA [1998] with 18 running natural gas combined cycle power plants, the average base costs amounted to 700 $€_{2000}$/kWe. Including interest during construction and contingency (in total on average about 10%), total investment costs amount to 770 $€_{2000}$/kWe.[4] The investment costs are including emission control systems. Specific investment costs are sensitive to local circumstances and sizes of the installation. Charpin [2000] presents costs for new NGCC plants at 600 $€_{2000}$/kWe decreasing to 430 €/kWe in 2050.

3.3 Biomass and coal-fired IGCC

Gasification or partial oxidation makes it possible to produce a fuel gas from solid or liquid carbonaceous feedstocks, which can be cleaned and burned in a gas turbine. The resulting gas must be of such a quality that no damage (e.g. corrosion, erosion) is caused to the gas turbine whilst maintaining the high efficiency and low emissions of the combined cycle plant. Where the gas turbine is fired on a gas fuel derived from the gasification of liquid or solid carbonaceous materials, the cycle is known as an Integrated Gasification Combined Cycle (IGCC). IGCCs are able to convert “difficult” liquid and solid fuels to electricity at high efficiencies and with low emissions. The IGCC benefits from the continuous development effort being

[3] The 1996 dollar costs are converted to 2000 euro costs and corrected for inflation
[4] exchange rate of: euro (2000) to dollar (2000) = 0.95 dollar/euro; euro (1996) to dollar (1996) = 1.29 dollar/euro; euro (2003) to dollar (2003) = 1.15 euro/dollar

expended on gas turbines to raise their efficiency and performance. Gasification is identified as a crucial technology that may facilitate efficient, clean and cheap conversion of solid fuels (coal, biomass, residues) into electricity. In contrast to direct combustion the fuel gas produced during gasification is cleaned prior to combustion and thus a considerable smaller gas volume has to be cleaned. Furthermore, combined cycles offer high electrical efficiencies combined with low specific capital costs. In case of biomass, low-temperature heat present in the flue gas can be used to dry incoming biomass, making the system integration complete.

Current gasification technology can conserve over 80% of the chemical combustion energy in the feedstock material (the so-called cold gas efficiency). The exact percentages will depend on the type of gasification process, whether hot or cold gas treating is applied and on the feedstock properties.

Although several demonstrations of the technology have already been executed in the United States, Netherlands, and Spain the need for further development is high. The areas where these needs are the highest are the size of the gasifier, the heat transfer after the gasifier (syngas cooler), the gas cleanup, gas composition / burning in the gas turbine, waste water treatment and the air separation plant.

In future world markets IGCC-units will have to compete with advanced PF-boilers, pressurised fluidised bed combustion (PFBC) and other technologies. General Electric indicates that the viability of IGCC in various market segments depends on the gas turbine technology level and the specific fuel and that co-production of products such as hydrogen or methanol can enhance the economics.

The predominant type of large-scale gasifier is the entrained flow; however, some fluidized beds are also in use. Entrained bed flow systems, such as Texaco, Shell, and Lurgi systems, operate at high temperatures, 1040-1540°C. This technology is currently under demonstration. Examples are the Nuon/Buggenum plant in the Netherlands, the Puertollano plant in Spain, and the Wabash River plant in the United States. Fluidised bed systems operate at lower temperatures, 760-1040°C, depending on the properties of the coal. They have the potential advantage of being better matched to the operating temperatures of the cleanup systems. Operating pressures of up to several MPa are used, and are generally set to match the inlet pressures of the turbines located downstream.

3.3.1 Current development for improvement

With respect to IGCC gasification systems, research and development is directed towards cost reduction, efficiency improvement, system optimisation, mineral matter transformation in early stages of entrained flow gasification, slagging in entrained flow gasification, coal characterisation and blending and re-use of waste material.

In the United States, two different types of advanced gasifier are being developed. The first one is the so-called transport reactor, with the potential to process coal with a wide range of properties at high throughput and reduced costs. Its design is similar to that of a circulating fluidised bed except that it operates at considerably higher circulation rates, velocities, and riser densities than conventional circulating beds, resulting in higher throughput, better mixing, and higher mass and heat transfer rates.

The second type of gasifier under development is the partial gasifier, so-called because it gasifiers only a portion of the incoming carbonaceous feedstock, producing both syngas and char products. The syngas is intended for use in gas turbines and /or fuel cells to produce electricity and the char is combusted, either in a fluidized bed or entrained flow system, to raise steam for a steam cycle. The partial gasifier integrates well with high-efficiency combined cycles and it operates at lower temperatures (under 900°C) than most conventional gasifiers, potentially mitigating operational and reliability concerns associated with higher temperature conditions. Efficiency improvements can be reached taking advantage from the developments in improved combined cycles, which will occur independently of the gasification development. In addition, current turbines have been designed for use with natural gas. These designs need to be optimised for use of syngas.

Also introduction of possible hot cleanup systems will improve energy conversion efficiency in gasification systems. Conventional cold gas “wet” cleaning technologies, such as amine-based systems, are expensive and result in a thermal efficiency penalty of several percentage points when used in IGCC. The current trend is warm gas cleanup at temperatures of 150-400°C. Hot gas cleanup systems are more efficient but, although development has been ongoing for several decades, a satisfactory and reliable system has yet to be developed. Furthermore, in oxygen-blown gasification systems, the energy saving resulting from the use of hot rather than warm gas cleanup is on the order of only 1%.

Another possible way to reduce costs and improve efficiency is to improve the air separation process. The department of energy in the United States wants to decrease energy consumption by more than 50% compared to current levels. Technologies considered for oxygen separation include ion-electron conducting membranes using non-porous ceramic membranes, and advanced cryogenic processes. New inorganic membrane based systems may reduce the energy requirement from 235 kWh/t O_2 for cryogenic separation to under 150 kWh/t O_2 [Stein, 2001]. For an IGCC this implies an increase by over 3% percentage points.

Two developments are worthwhile to discuss in more detail; the humid air turbine cycle (HAT) and the high-temperature gas cleaning.

Humid air turbine cycle (HAT)
Converting the heat in a gas turbine exhaust into steam and then converting steam into electric power through a conventional steam cycle involves losses and inefficiencies, which reduce the overall cycle efficiency. One feature of a gas turbine is that it already has a turbine creating mechanical power from a flowing gas stream, and this power output can be increased (within limits) by increasing the mass flow of gas. In the case of an IGCC the fuel gas can be cooled by saturating it with steam, created by injecting water that evaporates as it cools the gas. This increases the mass flow of gas through the gas turbine's turbine. This effect can be taken further by injecting steam from the waste heat boiler into the gas turbine upstream or in the combustion chamber. Such cycles are known as Humid Air Cycles. This different conversion route can produce a rise in efficiency of about 3% points compared to a standard IGCC plant, depending on the precise cycle parameters. Needs for developments are still great: there are no commercially available gas turbine's suited to this application.

High-temperature gas cleaning
In an IGCC the highest cycle efficiency is achieved if the hot fuel gas from the gasifier can be fed directly into the gas turbine. In these circumstances no heat is lost and losses associated with heat exchangers are avoided. This would require the existence of gas cleaning technologies, which can operate at high temperatures of over 600°C. These technologies would have to cover dust separation, chemical clean up (sulphur, halogens, ammonia, etc.) and trace elements. In conventional gas clean up systems trace elements and alkalis are usually removed by wet scrubbing, but this is clearly not possible at these temperatures. The pressure to develop these technologies stems from the 2-3% potential efficiency gain identified in some studies. However, not all studies support this conclusion.

Biomass integrated gasifiers combined cycle (BIG/CC) systems have not been realised on a commercial scale yet, but a number of projects have been planned and are in various stages of development. The maximum gasification units are in the order of 150 MW_{input} [Foster Wheeler, 2003]. Biomass gasifiers operate with air. Increased size of the gasifier will make it more attractive to use oxygen.

3.3.2 Efficiencies of IGCC

Worldwide a number of IGCC plants have been built to demonstrate the technology to generate electricity on large scale.

Since 1994, a 253 MWe oxygen-blown IGCC (Shell/Siemens technology) operates in Buggenum, the Netherlands. The efficiency obtained at this plant is $43.2\%_{LHV}$. The demonstration period was closed in 1998 [Hannemann, 2002]. The plant currently produces power for the commercial market and operates without major difficulties [Kanaar, 2003].

Since 1996, a 252 MWe oxygen-blown IGCC (E-Gas™ /GE 7FA GT technology (E-Gas™ is the name given to the former Destec technology developed by Dow, Destec, and Dynegy) operates at Wabash River. The demonstration period was closed in 1999. The efficiency obtained is 38.3%$_{HHV}$ (40.2%$_{LHV}$) [Wabash, 2000]. The Wabash River project repowered a 1950s vintage pulverised coal-fired plant with a nominal 33% efficient 90 MWe unit.

Since 1996 a 250 MWe oxygen-blown IGCC (Texaco/GE technology) operates in Mulberry, Polk country, Florida, including full heat recovery, and conventional cold gas cleanup. The efficiency obtained is 36.5%$_{HHV}$ (38.3%$_{LHV}$) [Tampa, 2001].

Since 1997 a 335 MWe oxygen-blown IGCC (PERNFLO/Siemens V94.3 technology) operates at Puertollano in Spain. The efficiency obtained is 45%$_{LHV}$ [WEC, 1998].

The efficiency of biomass-fired IGCC (BIG/CC) plants will typically be somewhat lower than the same sized coal-fired plant, because of moisture and larger volumes (lower energy density). The expectation is that the efficiency difference will become smaller on the longer term. An important development is torrefaction. In this process the biomass is brittled and the energy density and reactivity is increased substantially. The biomass is heated up to about 220 to 260ºC. The biomass is left with a low moisture content and 98% of the energy can be recovered. This technology is being used in the Netherlands in a coal power plant with biomass co-firing.

3.3.3 Costs of IGCC

To date only few IGCC plants have been built and are operational. The plants often function (partly) as demonstration plant. It is expected that investment and O&M costs of these plants may reduce considerably when the technology is fully commercially available.

Plant	Investment costs
Buggenum	1600 €/kWe
Wabash	1650 €/kWe
Tampa	1700 €/kWe
Puertollano	na

The expectation based on Wabash River project is that for a new greenfield IGCC plant incorporating lessons learned and technology improvements, investment cost are around 1300 to 1400 €$_{2000}$/kWe. The department of energy of the United States estimates new IGCC plants at 1250 €$_{2000}$/kWe [DoE, 1999]. Projected costs for the transport reactor in 2010 are estimated at 1000 €$_{2000}$/kWe. Costs for hot gas cleanup are estimated at about 130 €/kWe [DoE, 1999].

O&M costs of currently operating IGCC plants are high and approximately around 70 $€_{2000}$/kWe. Costs may substantially reduce by operating larger plants and by experiences of first-of-its-kind plants. Efforts continue to further reduce operating and maintenance costs, including programs for operator cross-training, materials improvements in critical high cost areas such as refractory and char filtration, and general continuous improvement in O&M practices. Reduction of non-fuel operating and maintenance costs below 5% of total installed cost is achievable for the next generation of solid fuelled gasification facilities.

Reported investment costs of first generation BIG/CC systems are very high and range from 2500 to 5000 $€_{2000}$/kWe [Novem, 1998]. Investment costs are sensitive to plant size, and especially in the initiating phase small (demonstration) plants are or will be built. Costs may decrease substantially for this technology by increasing experience and by increasing system efficiencies. Increased efficiencies will be obtained by improved gas turbines and improved gasification. Increasing the scale of the conversion unit is another way of both obtaining efficiency and cost benefits. However, it should be kept in mind that when biomass is used as fuel, increasing scale will have a stronger influence on fuel transportation (costs and logistics) than for fossil-fuelled power plants, since biomass has a lower energy density and typically has to be collected from a large area. It has been estimated that over 50% cost reduction can be obtained by learning (i.e. after 10 plants have been realized) and increasing scale to about 200 MWe. For 2020 investment cost may be decrease to 1500 $€_{2000}$/kWe. In the longer term cost may decrease to 1100 $€_{2000}$/kWe.

3.4 Combined heat and power mode

A combined cycle power plant can easily be constructed as a combined heat and power generation unit. At the expense of the power output, heat can be produced by extracting steam from the steam cycle. Overall energy efficiency of the plant increases and might reach 75% or higher for IGCCs and 80% and higher for NGCCs. The additional investment costs and O&M costs of the plant are small. Lako [1998] estimates the extra costs at about 50 €/kWe. It should be noted that considerable investment might be required to construct a district heating system to transport the heat of the CHP plant to the consumers.

3.5 Carbon dioxide capture from combined cycle power plant

A combined cycle plant can be equipped both with post-combustion and pre-combustion carbon dioxide capture. In the case of IGCC the pre-combustion method is more attractive, because it leads to less efficiency loss and to less costs than the post-combustion process. The preference for natural gas combined cycle plants is not yet clear and current studies do not show significant advantage for either one of the technologies.

3.5.1 Efficiency loss capture process

Efficiency loss for the pre-combustion capture process for natural gas combined cycles is somewhat higher than for IGCCs, despite the higher amount of carbon in the fuel. This can be explained by the fact that in an IGCC the carbon dioxide needs to be recovered from the syngas (a mixture of mainly hydrogen and carbon monoxide), while for the NGCC the starting point natural gas is, involving an extra steam reforming step.

Based on a large set of studies to carbon dioxide capture from power plants an assessment has been made to costs and efficiency losses of a combined cycle plant with carbon dioxide capture and compression.

Efficiency improvement potentials are assumed to be the same as for carbon dioxide capture processes in the conventional power plants.

3.5.2 Costs of carbon dioxide capture

The costs per tonne of CO_2 captured is composed of total capital investment costs, operation & maintenance costs, and energy costs. The total capital investment costs comprises the direct capital costs plus various indirect investment costs, which are often expressed as a fraction of the direct capital costs.

Investment costs for NGCC per Mg of captured carbon dioxide are somewhat higher than for IGCC. Because of the much higher carbon content of the coal compared to natural gas, investment costs per kWe are considerably lower for capture equipment in an NGCC.

Cost figures are obtained from various studies. An overview of the results of these studies can be found in Hendriks [GESTCO, 2003].

The operation and maintenance cost (excluding fuel) for the capture process is assumed to be 6%, what is a usual figure for chemical installations.

3.6 Conclusion for input data TIMER

Current natural gas-fired combined cycle power plants reach efficiencies of $57\%_{LHV}$ and higher. Improvements should mainly be obtained in the gas turbine. Higher inlet temperatures and improved design could possibly lead to efficiencies up to 64% or somewhat higher.

Combined cycles on gasified fuels reach about 47%$_{LHV}$. Efficiencies improvements can be expected in the gas turbine section, gasification section, and processes like oxygen production and cleanup. It is not likely that substantial improvements will be made in the steam cycle. Based on these experiences and future optimisation potentials it is expected that efficiency of IGCC (without novel applications as integration in fuel cells) will reach in the longer term 57-58%. The short-term efficiency 2020 may reach about 52-53%. In 2050 this could reach 56%.

In principle it is possible to relate the efficiencies of natural gas-combined cycles and integrated gasifier combined cycle. The difference in efficiency is mainly due to the gasification efficiency, i.e. the amount of energy transferred from the solid fuel to the gaseous fuel ready to be fed into the gas turbine. Compared to NGCC, extra energy is used in an IGCC for oxygen production, coal handling, and gas cleanup. Furthermore there are heat losses. Current gasification efficiencies amount to about 80%. The efficiency of the plant is further determined by the combined cycle efficiency, currently about 58-60%$_{LHV}$. This leaves a total IGCC efficiency of about 47%$_{LHV}$. Future improvements will be obtained by improved combined cycles (same as in NGCCs) and improve gasification efficiencies.

$$\eta_{IGCC\_fuelx} = \eta_{NGCC} \times \eta_{Gasif\_fuelx} \quad (8)$$

with:
η_{IGCC_fuelx} = efficiency integrated gasifier combined cycle with fuelx
η_{NGCC} = efficiency natural gas-fired combined cycle
η_{Gasif_fuelx} = gasification efficiency fuelx

If we assume an IGCC plant equipped with a combined cycle with 57% (e.g. Siemens V94.3) and a gasification efficiency of 80% (this includes conversion losses, air separation and cleanup), the net efficiency of the IGCC plant is 45.6%. In the future, gasification efficiency will increase (e.g. due to improve air separation; hot gas cleanup) and the efficiency of the combined cycle. Assuming 88% gasification efficiency and 64% combined cycle efficiency, this will lead to 56% overall IGCC efficiency.

The investment costs for power plants are the sum of the investment for the combined cycle, the base plant (without combined cycle), flue gas cleanup and fuel handling equipment.

$$I = I_{base\_cc} + I_{base\_rest} + I_{CU} + I_{FH} \quad (9)$$

with:
I = Investment power plant (€/kWe)
I_{base_cc} = Investment for combined cycle (€/kWe)
I_{base_rest} = Investment for rest of the base plant (€/kWe)

I_{CU} = Investment for desulphurisation, DeNOx, particulates, etc. (€/kWe)
I_{FH} = Investment for fuel handling (€/kWe)

The calculation approach for the operation and maintenance costs for the combined cycle plants are the same as for the conventional power plants as explained in section 2.6.

CHP
Same conclusion as for conventional power plants

Capture of carbon dioxide
An essential difference between capture of carbon dioxide of an NGCC and IGCC is the need for steam reforming of natural gas prior to the water-gas shift reaction. The additional steps (i.e. the water-gas shift reaction, separation of carbon dioxide from the hydrogen and compression) can be regarded proportional to the flow of carbon dioxide. The following equation can be developed:

$$\eta^{Capt}_{CC\_fuelx} = \left(\eta^{Capt}_{SR-Gas} + \eta^{Capt}_{IGCC\_coal} \times \frac{EF_{fuelx}}{EF_{coal}} \right) \times \frac{CR_{fuelx}}{CR_{IGCC\_coal}} \qquad (10)$$

with:
$\eta^{Capt}_{CC\_fuelx}$ = efficiency loss by carbon dioxide capture of combined cycle power plant with fuelx
η^{Capt}_{SR-Gas} = efficiency loss by steam reforming or gasification of fuelx
$\eta^{Capt}_{IGCC\_coal}$ = efficiency loss by carbon dioxide capture of IGCC with coal
EF_{fuelx} = emission factor fuelx ($kgCO_2/GJ$)
EF_{coal} = emission factor coal ($kgCO_2/GJ$)
CR_{fuelx} = carbon dioxide recovery factor power plant with fuelx
CR_{IGCC_coal} = carbon dioxide recovery factor power plant with coal

Concerning pace of decrease in efficiency loss by capture process and cost of investment, the same approach as described under conventional power plants is followed.

The tables with results are presented in annex 1.

4 Plant-of-the-future

4.1 Introduction

The development in costs and efficiency of power plants in this report concerns existing and known technologies. It is not unlikely that plants may be developed which will operate on other technological principles than those known today, leading to higher conversion efficiencies and lower costs. These plants will gradually take over the conventional and combined cycles as we currently know them.

A concept with potential high efficiencies is fuel cells. In combination with other technologies, like a combined cycle, an energy efficient system may be developed. However, whether the plant of the future will be based on fuel cells is unknown. Nevertheless, we will use this plant as a representative of the plant-of-the-future; i.e. a plant with substantial higher efficiencies and lower costs than current known technologies. The integrated fuel cell plant is described for natural gas and solid fuels (coal and biomass).

4.2 NGCC-SOFC

A new development is the integration of a combined cycle with an solid oxide fuel cell (NGCC-SOFC). An SOFC operating at elevated pressure could function as the heat addition process in a Brayton cycle engine. This combined cycle would utilize the pressurized SOFC electrochemical engine as the topping cycle to a Brayton cycle gas turbine engine. Given that the SOFC can extract half of the fuel's heating value as electricity, and assuming that the Brayton cycle engine can operate at $40\%_{LHV}$ efficiency, then an overall cycle efficiency of 70% should be possible. This combination is expected to be commercially available at or shortly after 2010. On the longer term efficiencies may go up to 75 to 80%. Initially, costs are about 700 to 1000 $€_{2000}$/kWe, but will gradually decrease to 400 $€_{2000}$/kWe.

4.3 IGCC-SOFC

By adding a solid oxide fuel cell (SOFC) to the gasification system the efficiency of an IGCC might be further increased. Dijkstra [2002] presents such a novel concept, which integrates fuel cell, membrane technology and gas turbine technology in one concept. The working principle is depicted in Figure 2. Air is fed to a solid oxide fuel cell (SOFC) cathode; fuel is fed to the SOFC anode. The anode off-gas is fed to the feed side of the membrane reactor; the cathode off-gas is fed to the permeated side of a membrane reactor. On the feed side the watergas shift reaction takes place producing hydrogen and CO_2. The hydrogen permeates through the hydrogen selective membrane in the afterburner. The carbon dioxide is collected and prepared for transport and storage. At the permeate side (the afterburner) the hydrogen is burned with oxygen present in the off-gas from the cathode side of the SOFC. This result in a very low hydrogen partial pressure on the permeate side, resulting in a higher hydrogen permeation rate. The heated permeate stream passes an optional combustion chamber for additional firing to increase temperature. It is then expanded in a gas turbine. The expanded off-gas can be used for recuperation to heat the cathode feed steam or it can be used in a waste heat boiler.

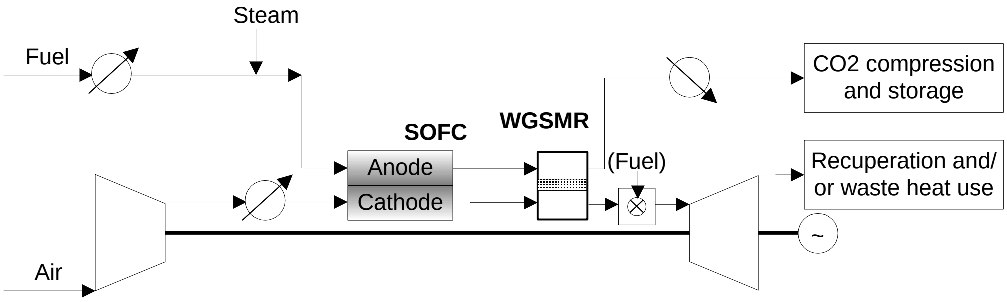

Figure 2. Working principle of the watergas shift membrane reactor afterburner, including CO_2 capture [Dijkstra, 2002]

The total efficiency of the IGCC-SOFC plant is expected to be high and might be up to 65%. Dijkstra [2002] aims at a fully developed system in 2010. On the longer term efficiencies might increase to70% - 75%. Initially, costs are high, about 1500 to 2000 €$_{2000}$/kWe, but will gradually decrease to 1000 €$_{2000}$/kWe.

4.4 Carbon dioxide capture

The principle of the fuel cell makes capture of dioxide relatively easy, as the air is not mixed with the fuel and relatively pure carbon dioxide is produced. Figure 2 shows already integration of carbon dioxide capture with this plant concept. Efficiency loss and costs are therefore moderate for these systems.

4.5 Combined heat and power and fuel cells

Although the application of combined heat and power is possible in the CC-SOFC systems, application is not very likely because of the high electric efficiency of the system. Use of heat of this plant will probably lead, at the best, to small energy savings.

4.6 Conclusion for input data Timer

The same approach for the input of data is followed as described in section 2.6 and section 3.6). Because these plants are not commercially available, there are no data given for the year 2000 (see Annex 1).

5 Large industrial boilers

Large boilers in the industry are used to produce steam and hot water for production processes. Current boiler efficiencies for steam production are approximately 92% LHV (84% HHV). No large improvements are expected in this field. As it is not possible to introduce condensing boilers because of temperature requirements steam, the room for improvement is small, and it can be assumed that efficiencies will stay in the range of 92% tot 95% (LHV).

Not much information on investment costs for boilers is available. Dril et al [1999] reports investment costs from 75 €/kWth for a 60 MWth boiler and 100 €/kWth for a 22 MWth boiler. When analysing data from IEA [1991] the costs for the boiler within a 500 MWe power plant are estimated at 124 $M\$_{1991}$ equivalent to 100 $/kWth (this exclude all kinds of additional cost).

Techniques to limit the emission of fine particles, SO_2 en NO_x are in principle the same as the ones applied with conventional power plants.

6 Grid losses and investments

6.1 Introduction

The *objective* of the work is to supply:

- Essential figures on electricity system losses and their composition in major world regions
- An estimate regarding potential improvements and respective costs.

The *research questions* related to the matter can be summarised as follows:

- In which way can electricity losses be categorised?
- Is it possible to classify the world regions with respect to electricity losses?
- Which countries may be considered as representative cases for those regions? What is the accessibility and quality of data?
- How can the particular losses be quantified or ranked?
- What are major explaining factors for the particular loss categories?
- What is the potential for improvement and reduction of losses?
- What are typical time spans and specific costs for the reduction of the particular loss categories?

6.2 Approach

Primary information was gathered in a brief literature survey and internet research. Many of the sources available (national statistics, company information, scientific papers) do not clearly define system borders and methods of data processing. Hence, direct comparison of data from different sources can be misleading. Nevertheless, these data were used as input for the review without any further validation. Interpretation and aggregation of the information to a large extent is based on existing experience and knowledge of the authors. The findings and conclusions are cross-checked with some known external experts in representative countries. The experts were asked to validate and comments on our theses and comments, the comments are incorporated in this report.

Given the brief character of the survey we were only able to collect incomplete and fragmented information. Furthermore part of the information desired simply does not exist. Because of these limitations a pragmatic approach was required. To this end a number of countries was selected and investigated in more detail. The selection of countries was based on three major criteria:

- Access of data should be better than average;

- It should be reasonable to consider the countries a good representative for at least one of the 17 regions
- Overlap should be avoided and as many regions should be covered by these representatives

6.3 Grid loss categories

In the context of this review different kind of losses in the electric power system have to be distinguished. The following drawing illustrates the losses considered.

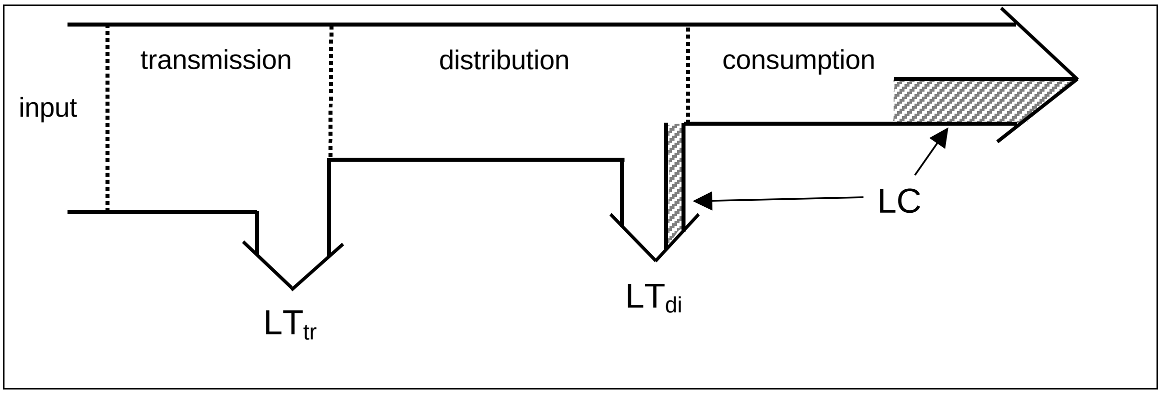

Figure 3: LT are Technical Losses, LC are Consumer losses.

In this paragraph the differences will be explained and reference values for state of the art power systems in industrialised countries will be given. All losses are related to consumption.

6.3.1 Technical losses (LT)

One major advantage of electrical energy is the ease of transport. However, transportation of electricity always causes losses. These losses are caused by the Ohmic resistance of the power lines but also associated with power conditioning and protection equipment (transformers, switchgears, supervisory devices, etc.). The level of the losses is directly related to the currents used and thus, considering a certain power level, reduces with increasing voltage.

In power systems different functions are distinguished using different voltage levels:

- Transmission, high voltage and extra high voltage
- Distribution, medium voltage and
- Distribution, low voltage

Exact voltages for these functions vary in the different power systems all over the world. In Europe for the respective functions the following indicative values may by used:

- Transmission: 220 kV or higher

- Distribution medium voltage: 10 - 110 kV
- Distribution low voltage: 0.23 / 0.4 kV

In the gaps between these ranges a function overlap exists.

According to a study carried out by Electric Power Research Institute (EPRI), the losses in various elements of the T&D system are usually of the order as indicated below:

Table 1: Composition of T&D losses

System element Power Losses (%)	Minimum	Maximum
Step-up transformers & EHV transmission system	0.5	1.0
Transformation to intermediate voltage level, transmission system & step down to sub-transmission voltage level	1.5	3.0
Sub-transmission system & step-down to distribution voltage level	2.0	4.5
Distribution lines and service connections	3.0	7.0
Total losses	7.0	15.5

[Bhalla, 2000]

As shown in the table, most of the technical losses are associated to the low voltage distribution level. In the following table the general figures are illustrated by indicative values for Germany and the Netherlands.

Table 2: T&D losses in Germany

	Germany
Transmission (HV)	~ 1 %
Distribution (MV)	~ 2 %
Distribution (LV)	~ 5 %

[VDEW, 2002]

In other regions the sum of those losses can be much higher and exceed 20%. However, simply adding the values does not give a reliable indication of the loss level of a region or country. Many large (industrial) customers are connected to MV or even HV networks directly.

6.3.2 Non-technical losses/Commercial losses (LC)

In addition to these physical losses, non-technical losses exist. Their common feature is that the energy is used but not accounted (and consequently nobody is paying for it). In literature these losses often also are indicated as commercial losses. The following types of commercial losses may be distinguished:

- Not accounted consumption: The power company just does not create preconditions for accounting the electricity supplied. Reasons may be low consumption or extremely low electricity prices not justifying costs for metering. Often these conditions have a political background. Electricity being considered as a basic commodity product should be available for everybody and availability should not be constrained seriously by lack of purchasing power.
- Malfunction of metering equipment: Reasons can be extremely old and / or defective metering equipment. Also intended tampering of metering equipment has to be considered here. In fact, the latter situation is a manner of electricity theft. In both cases metering equipment is installed but is not accounting the consumption correctly.
- Illegal tapping of power lines, i.e. theft without any metering facilities
- Theft and fraud with participation of corrupt metering staff of the power company
- Unpaid bills

In the world regions, commercial losses vary from less than 1% (e.g. most parts of western Europe) to more than 20% (e.g. parts of India).

It is important to be aware that commercial losses are not only theft or result of illegal practices. Also technical losses results in commercial losses if, for example, distribution losses are not accounted adequately and related costs are not passed to the customers. On the other hand, illegal practices use different approaches and may happen even in case of adequate technical equipment. Consequently, in these cases strictly technical countermeasures will not eliminate theft.

6.4 Grid losses for selected countries

In this paragraph different types of commercial losses described above are not processed separately. The reason is just lack of any reliable data sources at this detail level. Nevertheless, in the discussion of commercial losses, which can be reduced directly by technical measures (e.g. lacking or outdated metering equipment), will be distinguished from those caused by illegal practices. In general, reduction of the latter category will be less straightforward. The commercial losses with technical background will be added to the technical losses at low voltage level. Estimates of both shares of commercial losses will be based on indicators given in literature and comparison with reasonable reference values.

In many countries commercial losses (LC) are large, often larger than the strictly technical (LT) ones. They are not restricted to private / residential users but are relevant also in commercial and industrial sectors. Mostly they are related to low voltage level but occur at medium voltage too. For simplicity, in the drawing as well as in treatment of statistics export and import have been considered as being free of loss. Their balance is calculated and included in the category input directly.

6.4.1 Selection

The case countries were selected based on the criteria introduced in the methodology. Countries with more than average information are:

- Germany (TIMER Region 9)
- Lebanon (TIMER Region 12)
- India (TIMER Region 13)

6.4.2 Germany (region 9)

In Germany four Transmission System Operators do exist operating the high voltage system (220 / 380 kV) in different regions of the country. With respect to T&D losses, significant differences exist between the particular areas. Whereas in 1995 these losses in the zones of E-on, RWE and EnBW were below 5% of consumption, the same figure in the Vattenfall Europe Transmission (VE-T) zone was about 9%. The higher losses in the latter area have three major reasons:

1. Before reunification of Germany, the VE-T zone has been the area of the former German Democratic Republic. Equipment was much older and quality was lower then in the Western part of Germany and, hence, specific losses were higher.
2. The high voltage network with its lower specific losses was less dense than in Western Germany.
3. Population density in the Eastern part of the country is significant lower than in large parts of Western Germany. Consequently, specific transportation distances are longer and, combined with lower voltage levels, specific losses are even more increased.

[VE-T, 2003]

In the nineties massive investments have been done in the German power industry, in particular in the Eastern part. Between 1990 and 2000, the German network operators invested € 2.5 billion to 4 billion annually in upgrading of the grids and its components. No information is available regarding the geographical distribution of these investments. Also, certainly a significant part of these investments increased (economic) performance of the T&D system (automation, protection etc.) but not necessarily increased efficiency as well. [VDEW 2002}]

In 2002, the T&D losses in Germany as a whole were reduced to 4.3% of the consumption. However, this reduction of T&D losses has to be interpreted carefully. In the period considered the electricity consumption in the Eastern (less efficient) part of the country decreased dramatically due to economic restructuring. Even TSO representatives are not able to give a guess regarding the specific effectiveness of investments in terms of loss reduction achieved. Non-technical losses are of no practical importance in Germany. [VE-T, 2003]

Germany is considered being comparable to the countries in the same TIMER region (9, OECD Europe). In a first guess the figures are also considered being similar enough to the regions 1 (Canada), 2 (USA) and 17 (Japan).

6.4.3 Lebanon (region 12)

Electricite du Liban (EDL) figures show, that 'non-technical' waste, or electricity theft, reached 25,7 % of total electricity consumed in Lebanon and technical problems accounted for about 15 % of electricity consumption at the end of June 2003, resulting in nearly 40 % in revenue losses. EDL has lost about $600 million in uncollected bills since 1992 and another $230 million to illegal electricity connections and technical problems. [Saradar 2003]

In 2002 the Cabinet endorsed a series of measures to improve the performance of EDL. It granted security assistance from the Lebanese Army and Internal Security Forces to eliminate illegal connections to the electricity network, help with bill collection, and stop meter tampering. No reports could be found indicating the success of these measures. [Habib 2003]

6.4.4 India (region 13)

In India, average T & D losses have been officially indicated as 23 % of the electricity generated. However, as per sample studies carried out by independent agencies, these losses have been estimated to be as high as 50 % in some states [Bhalla, 2000]. In the last few years, especially after establishment of the independent state electricity regulatory commissions (SERCs), many state utilities are revising their T&D loss estimates from the earlier lower figures of around 18-20% to higher values in the range of 35% to 50%. This is a result of the installation of metering technologies (see Table 3). [Dixit, 2002]

Table 3: T&D loss estimates in India before and after reform of measuring and accounting system

State	**Reported T & D losses (%)**	
	Before reform	After reform
Orissa	23	51
Andhrs pradesh	25	45
Haryana	32	47
Rajasthan	26	43

[Blueprint, 2001]

The T&D losses assumed to 30 to 50 % consist of both technical losses (15 to 20 percent), and non-technical losses (20 to 25 percent). These losses translated into commercial losses make almost US $3 billion. This is equal to nearly 1% of the national GDP of India. [Eia, 2003]

Based on the assumed grid losses before the reform (Table 3) of the T & D losses of 22 % comprise about 13 % technical losses and 9 % commercial losses. Out of the above losses of 19 % at distribution level, non-technical commercial losses account for about 5 %, and thus the technical losses of 14 % are primarily due to inadequate investments for system improvement works, which has resulted in unplanned extensions of the distribution lines, overloading of the system elements like transformers and conductors, and lack of adequate reactive power support. By undertaking suitable system improvement schemes based on computer studies it should be possible to bring down the technical losses in the distribution system to the level of 9 %, which means a reduction of 5 %.

The following table shows an estimated break-up of T&D losses in Madhya Pradesh as an example:

Table 4: Composition of T&D losses in Madhya Pradesh

Energy input (MU)	27.000
T&D losses (as % Generation)	43,2%
Technical losses	15,3%
Total Commercial Losses	27,9%
HT Industry	5,4%
LT Industry	6,5%
Household	13,0%
LT Commercial	3,0%

[Dixit, 2002]

Table 5: Grid losses in the different States in India for the year 1991 – 2000.

State	1991/ 92	1992/ 93	1993/ 94	1994/ 95	1995/ 96	1996/ 97	1997/ 98a	1998/ 99b	1999/ 00c
Bihar	18.3	20.5	19.0	24.0	25.9	25.3	25.4	39.5	36.0
Goa	23.8	20.8	21.8	26.2	28.5	23.5	23.4	29.1	23.0
Jammu and Kashmir	50.1	45.3	47.7	46.9	48.6	50.0	47.5	43.8	46.5
Kerala	22.5	21.0	20.2	20.1	20.1	21.4	17.9	17.5	17.0
Madhya Pradesh	25.8	22.2	20.2	20.1	19.5	20.6	19.7	17.8	18.6
Meghalaya	11.7	12.2	10.7	18.7	17.8	19.5	17.9	18.9	19.0
Orissa	25.3	23.5	23.4	23.8	46.9	50.4	46.0	42.0	36.0
All-India (utili-ties)	22.8	19.8	20.2	20.3	22.2	24.5	23.9	23.2	22.0
a provisional; b revised; c estimate									

[Bhalla, 2000]

The central government is financially supporting distribution reform through the Accelerated Power Development Reforms Programme (APDRP). In 2002-2003 US $700 million was given to the APDRP for the implementation of the following measures:

- full metering,
- energy audits,
- management information systems,
- control of theft,
- increased transformation capacity,
- increases in the ratio of high-voltage to low-voltage transmission,
- reduction of technical losses.

Certain States where metering has been completed, have shown immediate gain in revenue ranging from 20 to 30%. [Eia, 2003]

6.4.5 Other countries, additional information and extrapolation of country results

As shown in the discussion above clustering of TIMER regions and even countries might be questionable because of the strong differences of losses between and within particular countries. Nevertheless it is a pragmatic and still reasonable approach to derive some figures for application in the TIMER model.

Annex 3 holds an arbitrary selection of additional countries with indicative information on losses. Quality of data sources obviously is differing but based on these references the following conclusions may be drawn:

- Theft is a problem in many developing countries;
- Related losses are high. However, no reliable data exist, even not within the companies affected.
- Theft behaviour includes large parts of the society and, one could say there is a certain level of public acceptance. In some cases simple and cheap measures may lead to a significant reduction of commercial losses (as in the Indian examples). In other regions any successful anti-theft policy may require political priority at high level, a long run and a broad range of measures with a very divers and facilitating character to achieve substantial success.

The table in annex 3 gives an overview of losses in large parts of the world. The table does not include all countries distinguished in the TIMER model but coverage of world electricity consumption probably is in the upper 90% range. No difference is made between technical and non-technical losses. The method of data treatment is not documented and probably is even not consistent for all countries, but still the table gives a rough impression of loss levels. Though in a number of cases the figures seem to be extremely optimistic, in general this impression is corresponding with the information in annex 3.

6.5 Explaining factors and potential for improvement

In order to assess the potential for improvement, specific factors determining or explaining the level of losses are discussed.

6.5.1 Technical losses

A key factor is the *age of equipment*. Electrical networks and their components have a rather extended technical life (20 years and longer). If service life is exceeded dramatically, losses increase because of material deterioration. This process is accelerated when maintenance is bad. One should realise, that a certain level of investment and upgrading is required just to maintain system efficiency. Hence, investments in networks do not automatically result in efficiency improvement.

In addition to old equipment in many regions of the world, existing networks are *operated far from their specifications*. Much more consumers with heavier equipment than anticipated in the planning phase are using the infrastructure. Often characteristics of the end user applications are poor (bad power factor, high harmonic emissions etc). Overloaded network components and high specific losses are consequences of this uncontrolled growth in consumption.

In addition to these technical characteristics of the power system some external factors influence the loss level. All of these factors hardly can be changed. The factors are:

- Low population density or natural resources far from the population centres mean long transportation distance.
- High ambient temperature levels and high humidity and / or salinity also tend to increase losses.
- Historically grown voltage levels and system frequencies (230 V / 50 Hz in Europe versus 110 V / 60 Hz) have a slight impact too.

In the TIMER model at least the variable aspects discussed first could be covered by investment figures of power companies (€ / customer, € / MWh delivered). However it is very difficult to give a generic and reliable relation between specific investments and the efficiency improvement to be expected. A new high voltage overhead line in Europe costs between 20 and 50 € per km and final consumer (assuming consumption is completely residential). At low voltage level the respective figures are 10 to 100 times higher. On the other hand, in developing countries with much lower labour costs both figures may be a factor 3 to 5 lower again.

A suitable indicator for the necessary investment level for efficient transport of electricity are the grid assess fees, e.g. as applied in the liberalised European market. As Europe has rather low losses and the fees even contain elements covering other aspects of power system operation these fees may be considered as an upper limit. At medium voltage level average fees in the different European countries vary between 10 and 25 € / MWh and at low voltage level between 25 and 65 € / MWh. As a rule of thumb, given moderate geographical conditions and similar consumption per user (3000 kWh/a), *specific costs for network access of 50 € / MWh consumption or 150 €/a per user should create sufficient revenues to avoid excessive technical transmission losses*. (To obtain end user prices, of course, costs of electricity have to be added. It may be clear that resulting prices are far from current conditions in many developing countries.)

Upgrading projects in (electrical) infrastructure take time. In industrialised countries, planning periods of 10 to 15 years are common. After construction a complete component life cycle is about 20 to 30 years. 20 years may be considered as theoretical upper level for achieving state of the art performance. [Matthes, 2002]

6.5.2 Commercial losses

To a large extend, the level of coverage and the quality of metering equipment determines commercial losses. Respective upgrading efforts have a clear technical character. As stated earlier, in the context of this study, those measures and related investments are associated with reduction of technical losses.

Fighting all kinds of theft is a political matter and so is the effectiveness of respective measures. It is nearly impossible to give general costs for the reduction of commercial losses. The specific investments range from some Euro per user (correcting tampered metering) to nearly indefinite amounts in case of ineffective instruments. Specific time spans for reduction of commercial losses vary in a similar way. Measures with immediate effect may coexist with efforts without any progress. An additional variable is the long-term effect of measures. In some cases an initial investment will achieve sustainable improvement whereas in other cases permanent effort will be necessary to avoid a fall back to the original situation.

For the purpose of this study, *the costs allowing elimination of theft in most of the cases are roughly estimated at 20 to 50 € / user.* For simplicity it may be assumed that this investment allows permanent improvement.

6.6 Conclusions for TIMER model

The countries in the table in annex 4 have been sorted according to the 17 regions. Consequently per region the arithmetic average of the losses has been calculated. The figures have been checked and partly corrected using additional information. Based on own estimates technical and non-technical losses have been ranked. The result is shown in Table 6. Of course, in reality the differences between the categories are smooth and the classification in the table is somewhat artificial.

Table 6 Ranking of TIMER regions according to technical and non-technical losses. Loss ranges used: **Moderate (0)** technical or non technical losses< 8%, **High($)** technical or non technical losses are between 8%-15%, **Extremely high ($$)** technical or non technical losses > 15%

<table>
<tr><th>Regions</th><th>Technical losses</th><th>Non-technical losses</th></tr>
<tr><td>1 Canada
2 USA
9 OECD Europe
17 Japan
14 East Asia</td><td>0
0
0
0
$</td><td>0</td></tr>
<tr><td>3 Central America
4 South America
8 Southern Africa
10 Eastern Europe
11 Former USSR
12 Middle East
15 South East Asia
16 Oceania</td><td>$
0
0
$
$
$
$
0</td><td>$…$$</td></tr>
<tr><td>5 Northern Africa
6 West Africa
7 East Africa
13 South Asia</td><td>$$</td><td>$$</td></tr>
<tr><td>Suggested improvement indicators[5]</td><td>In 20 years to state of the art levels with 50 € / MWh or 150 € per user and year</td><td>20 … 50 € per user leading to reduction of non-technical losses below 5% of consumption</td></tr>
</table>

Applying the improvement indicators one should be aware that improvement will not follow a linear function. Costs of initial measures may be very low and still may result in substantial improvement. Achieving state of the art levels after this initial phase will require higher specific costs. However, taking into account the limited accuracy of both, the estimated losses and the improvement indicators, it makes little sense to model complex dependencies for this process.

[5] Within the time span of the project it was not possible to obtain very detailed information on costs to reduce technical losses. Even the European TSO's contacted are not able to give respective figures. This effect is simply not evaluated. This has to do with the major objectives of the investments. In general, they are not driven by efficiency but by aspects as capacity for trading, security of supply etc. If efficiency is affected, this is a side effect.

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Annex 1: Input tables for TIMER

		Input TIMER Model			
Item	**Unit**	**2000**	**2020**	**2050**	**2100**
Type of plant	**conv. pf coal**				
Fuel (s)	**coal**				
Net electric efficiency	%	47%	52%	55%	55%
Net electric efficiency (CHP mode)	%	40%	45%	48%	48%
Net thermal efficiency (CHP mode)	%	30%	30%	30%	30%
Overall efficiency (CHP mode)	%	70%	75%	78%	78%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	175	134	105	97
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	18	16	12	12
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW	80	69	62	58
O&M costs Fuel handling	euro(2000)/kW	10	9	8	7
Investment costs plant (base)	euro(2000)/kW	870	865	818	743
O&M costs plant (base)	euro(2000)/kW	18	16	15	15
Total Investment costs	euro(2000)/kW	1125	1068	984	899
Total O&M costs	euro(2000)/kW	46	41	35	34
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	11.6%	9.3%	5.8%	2.9%
Net electric efficiency with CO2 capture	%	35.4%	42.7%	49.2%	52.1%
Investment costs capture	euro(2000)/kW	680	544	340	170
Investment costs (with capture)	euro(2000)/kW	1805	1612	1324	1069
O&M costs	euro(2000)/kW	41	33	20	10

		Input TIMER Model			
Item	**Unit**	**2000**	**2020**	**2050**	**2100**
Type of plant	**conv. natural gas**				
Fuel (s)	**natural gas**				
Net electric efficiency	%	48%	53%	56%	56%
Net electric efficiency (CHP mode)	%	41%	46%	49%	49%
Net thermal efficiency (CHP mode)	%	30%	30%	30%	30%
Overall efficiency (CHP mode)	%	71%	76%	79%	79%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	40	31	24	22
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	8	7	5	5
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW	870	865	818	743
O&M costs plant (base)	euro(2000)/kW	16	14	14	14
Total Investment costs	euro(2000)/kW	910	896	842	766
Total O&M costs	euro(2000)/kW	24	22	19	19
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	6.9%	5.5%	3.5%	1.7%
Net electric efficiency with CO2 capture	%	41.1%	47.6%	52.7%	54.4%
Investment costs capture	euro(2000)/kW	352	282	176	88
Investment costs (with capture)	euro(2000)/kW	1262	1177	1018	854
O&M costs	euro(2000)/kW	21	17	11	5

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**conv. oil**				
Fuel (s)	**oil**				
Net electric efficiency	%	48%	53%	56%	56%
Net electric efficiency (CHP mode)	%	40%	45%	48%	48%
Net thermal efficiency (CHP mode)	%	30%	30%	30%	30%
Overall efficiency (CHP mode)	%	70%	75%	78%	78%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	175	134	105	97
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	18	16	12	12
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW	870	865	818	743
O&M costs plant (base)	euro(2000)/kW	17	15	15	15
Total Investment costs	euro(2000)/kW	1045	999	922	841
Total O&M costs	euro(2000)/kW	35	31	27	26
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	9.4%	7.4%	4.6%	2.3%
Net electric efficiency with CO2 capture	%	38.1%	45.1%	50.9%	53.3%
Investment costs capture	euro(2000)/kW	516	413	258	129
Investment costs (with capture)	euro(2000)/kW	1561	1412	1180	970
O&M costs	euro(2000)/kW	31	25	15	8

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**conv. biomassa**				
Fuel (s)	**biomassa**				
Net electric efficiency	%	46%	51%	54%	54%
Net electric efficiency (CHP mode)	%	39%	44%	47%	47%
Net thermal efficiency (CHP mode)	%	30%	30%	30%	30%
Overall efficiency (CHP mode)	%	69%	74%	77%	77%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	40	31	24	22
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	8	7	5	5
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW	330	295	255	223
O&M costs Fuel handling	euro(2000)/kW	10	9	8	7
Investment costs plant (base)	euro(2000)/kW	870	865	818	743
O&M costs plant (base)	euro(2000)/kW	30	27	26	26
Total Investment costs	euro(2000)/kW	1240	1190	1096	989
Total O&M costs	euro(2000)/kW	48	43	39	38
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	8.1%	6.5%	4.1%	2.0%
Net electric efficiency with CO2 capture	%	37.9%	44.4%	49.8%	51.8%
Investment costs capture	euro(2000)/kW	680	544	340	170
Investment costs (with capture)	euro(2000)/kW	1920	1734	1436	1159
O&M costs	euro(2000)/kW	41	33	20	10

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**NGCC**				
Fuel (s)	**natural gas**				
Net electric efficiency	%	56%	60%	64%	66%
Net electric efficiency (CHP mode)	%	48%	51%	55%	57%
Net thermal efficiency (CHP mode)	%	36%	35%	33%	33%
Overall efficiency (CHP mode)	%	84%	86%	88%	90%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	34	26	21	19
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	7	6	5	4
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW	560	470	420	392
O&M costs plant (base)	euro(2000)/kW	16	14	12	12
Total Investment costs	euro(2000)/kW	594	497	441	411
Total O&M costs	euro(2000)/kW	23	20	17	16
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	7.1%	6.1%	4.6%	4.6%
Net electric efficiency with CO2 capture	%	48.9%	53.9%	59.4%	61.4%
Investment costs capture	euro(2000)/kW	360	288	180	180
Investment costs (with capture)	euro(2000)/kW	954	785	621	591
O&M costs	euro(2000)/kW	22	17	11	11

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**IGCC**				
Fuel (s)	**coal**				
Net electric efficiency	%	46%	52%	56%	58%
Net electric efficiency (CHP mode)	%	39%	44%	48%	50%
Net thermal efficiency (CHP mode)	%	35%	33%	32%	32%
Overall efficiency (CHP mode)	%	74%	78%	80%	82%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	130	98	74	67
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	18	16	12	11
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW	82	69	60	55
O&M costs Fuel handling	euro(2000)/kW	10	9	8	7
Investment costs plant (base)	euro(2000)/kW	1400	994	865	757
O&M costs plant (base)	euro(2000)/kW	42	26	22	18
Total Investment costs	euro(2000)/kW	1612	1161	999	879
Total O&M costs	euro(2000)/kW	71	51	42	36
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	8.2%	6.6%	4.1%	4.1%
Net electric efficiency with CO2 capture	%	37.7%	45.0%	52.2%	54.0%
Investment costs capture	euro(2000)/kW	620	496	310	155
Investment costs (with capture)	euro(2000)/kW	2232	1657	1309	1034
O&M costs	euro(2000)/kW	37	30	19	9

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**BGCC**				
Fuel (s)	**biomassa**				
Net electric efficiency	%	44%	50%	54%	57%
Net electric efficiency (CHP mode)	%	37%	43%	47%	49%
Net thermal efficiency (CHP mode)	%	36%	35%	34%	33%
Overall efficiency (CHP mode)	%	74%	78%	80%	82%
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW	44	32	24	22
O&M costs DeSulphurization/DeNOx	euro(2000)/kW	9	7	5	5
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW	86	72	62	56
O&M costs Fuel handling	euro(2000)/kW	11	9	8	7
Investment costs plant (base)	euro(2000)/kW	2850	1374	1064	921
O&M costs plant (base)	euro(2000)/kW	51	40	28	24
Total Investment costs	euro(2000)/kW	2980	1478	1150	999
Total O&M costs	euro(2000)/kW	70	56	41	36
Capture efficiency	%	85%	90%	95%	95%
Electric efficiency loss CO2 capture	%	5.8%	4.6%	2.9%	2.9%
Net electric efficiency with CO2 capture	%	37.9%	45.2%	51.5%	53.9%
Investment costs capture	euro(2000)/kW	620	496	310	155
Investment costs (with capture)	euro(2000)/kW	3600	1974	1460	1154
O&M costs	euro(2000)/kW	37	30	19	9

Item	Unit	Input TIMER Model 2000	2020	2050	2100
Type of plant	**NGCC-SOFC**				
Fuel (s)	**natural gas**				
Net electric efficiency	%		71%	75%	77%
Net electric efficiency (CHP mode)	%				
Net thermal efficiency (CHP mode)	%				
Overall efficiency (CHP mode)	%				
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW				
O&M costs DeSulphurization/DeNOx	euro(2000)/kW				
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW		850	485	394
O&M costs plant (base)	euro(2000)/kW		38	22	18
Total Investment costs	euro(2000)/kW		850	485	394
Total O&M costs	euro(2000)/kW		38	22	18
Capture efficiency	%		100%	100%	100%
Electric efficiency loss CO2 capture	%		3.0%	2%	1%
Net electric efficiency with CO2 capture	%		68%	73%	76%
Investment costs capture	euro(2000)/kW		200	100	50
Investment costs (with capture)	euro(2000)/kW		1050	585	444
O&M costs	euro(2000)/kW		12	6	3

		Input TIMER Model			
Item	**Unit**	**2000**	**2020**	**2050**	**2100**
Type of plant	**IGCC-SOFC**				
Fuel (s)	**coal**				
Net electric efficiency	%		65%	70%	72%
Net electric efficiency (CHP mode)	%				
Net thermal efficiency (CHP mode)	%				
Overall efficiency (CHP mode)	%				
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW		79	60	54
O&M costs DeSulphurization/DeNOx	euro(2000)/kW		13	10	9
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW		1700	1183	912
O&M costs plant (base)	euro(2000)/kW		42	29	23
Total Investment costs	euro(2000)/kW		1779	1243	965
Total O&M costs	euro(2000)/kW		55	39	31
Capture efficiency	%		100%	100%	100%
Electric efficiency loss CO2 capture	%		4.0%	2%	1%
Net electric efficiency with CO2 capture	%		61%	68%	71%
Investment costs capture	euro(2000)/kW		200	100	50
Investment costs (with capture)	euro(2000)/kW		1979	1343	1015
O&M costs	euro(2000)/kW		12	6	3

		Input TIMER Model			
Item	**Unit**	**2000**	**2020**	**2050**	**2100**
Type of plant	**BGCC-SOFC**				
Fuel (s)	**biomassa**				
Net electric efficiency	%		62%	66%	69%
Net electric efficiency (CHP mode)	%				
Net thermal efficiency (CHP mode)	%				
Overall efficiency (CHP mode)	%				
Net thermal efficiency	%				
Investment costs Cleanup (DeSulphurization/DeNOx/Precipitators)	euro(2000)/kW		25	20	18
O&M costs DeSulphurization/DeNOx	euro(2000)/kW		6	5	4
Investment costs Fuel handling (reception, storage, handling)	euro(2000)/kW				
O&M costs Fuel handling	euro(2000)/kW				
Investment costs plant (base)	euro(2000)/kW		1800	1268	977
O&M costs plant (base)	euro(2000)/kW		43	25	20
Total Investment costs	euro(2000)/kW		1825	1287	995
Total O&M costs	euro(2000)/kW		49	29	24
Capture efficiency	%		100%	100%	100%
Electric efficiency loss CO2 capture	%		4.0%	2%	1%
Net electric efficiency with CO2 capture	%		58%	64%	68%
Investment costs capture	euro(2000)/kW		200	100	50
Investment costs (with capture)	euro(2000)/kW		2025	1387	1045
O&M costs	euro(2000)/kW		12	6	3

Input data modelling

IFeff (2020, Conv_coal)	111%
IFeff (2050, Conv_coal)	117%
IFeff (2100, Conv_coal)	117%
eff(2000, Conv_coal)	47%
eff(2000, Conv_coal - Conv_NG)	1%
eff(2000, Conv_coal - Conv_oil)	0.5%
eff(2000, Conb_coal - Conv_BM)	-1%
HF	24%
eff(CHP, th)	30%
eff(Capt, Conv-coal)	11.6%
eff(Capt, IGCC)	8.2%
eff(Capt, SR-GasCoal)	0.0%
eff(Capt, SR-GasNG)	2.2%
eff(Capt, SR-GasBM)	0.0%
eff(Capt, NGCC-SOFC)	3.0%
eff(Capt, BGCC-SOFC)	4.0%
EFcoal (kgCO2/GJ)	94
EFNG (kgCO2/GJ)	56
EFoil (kgCO2/GJ)	76
EFbiomass (kgCO2/GJ)	66
eff(2000, combined cycle)	56%
eff(2020, combined cycle)	60%
eff(2050, combined cycle)	64%
eff(2100, combined cycle	66%
eff(2000, gasif-coal)	82%
eff(2020, gasif-coal)	86%
eff(2050, gasif-coal)	88%
eff(2100, gasif-coal)	88%
eff(2000, gasif-BM)	78%
eff(2020, gasif-BM)	83%
eff(2050, gasif-BM)	85%
eff(2100, gasif-BM)	86%

CR(2000, Conv_coal)	85%
CR(2020, Conv_coal)	90%
CR(2050, Conv_coal)	95%
CR(2100, Conv_coal)	95%
CR(2000, Conv_NG)	85%
CR(2020, Conv_NG)	90%
CR(2050, Conv_NG)	95%
CR(2100, Conv_NG)	95%
CR(2000, Conv_oil)	85%
CR(2020, Conv_oil)	90%
CR(2050, Conv_oil)	95%
CR(2100, Conv_oil)	95%
CR(2000, Conv_BM)	85%
CR(2020, Conv_BM)	90%
CR(2050, Conv_BM)	95%
CR(2100, Conv_BM)	95%
CR(2000, NGCC)	85%
CR(2020, NGCC)	90%
CR(2050, NGCC)	95%
CR(2100, NGCC)	95%
CR(2000, IGCC)	85%
CR(2020, IGCC)	90%
CR(2050, IGCC)	95%
CR(2100, IGCC)	95%
CR(2000, BGCC)	85%
CR(2020, BGCC)	90%
CR(2050, BGCC)	95%
CR(2100, BGCC)	95%
CR(2020, NGCC-SOFC)	100%
CR(2050, NGCC-SOFC)	100%
CR(2100, NGCC-SOFC)	100%
CR(2020, IGCC-SOFC)	100%
CR(2050, IGCC-SOFC)	100%
CR(2100, IGCC-SOFC)	100%
CR(2020, BGCC-SOFC)	100%
CR(2050, BGCC-SOFC)	100%
CR(2100, BGCC-SOFC)	100%

I_conv_base	870
I_conv_coal_CU	175
I_conv_NG_CU	40
I_conv_oil_CU	I_conv_coal_CU
I_conv_BM_CU	I_conv_NG_CU
I_conv_coal_FH	80
I_conv_NG_FH	0
I_conv_oil_FH	0
I_conv_BM_FH	I_conv_coal_FH
I_conv_coal_capt	680
I_conv_NG_capt	352
I_conv_oil_capt	516
I_conv_BM_capt	680
OM_conv_coal_base	18
OM_conv_NG_base	16
OM_conv_oil_base	17
OM_conv_BM_base	30
OM_conv_coal_CU	18
OM_conv_NG_CU	8
OM_conv_oil_CU	OM_conv_coal_CU
OM_conv_BM_CU	OM_conv_NG_CU
OM_conv_coal_FH	10
OM_conv_NG_FH	0
OM_conv_oil_FH	0
OM_conv_BM_FH	OM_conv_coal_FH
OM_capt	6% of I_capt
I_NGCC_base	560
I_NGCC_base (without CC)	0
I_IGCC_base (without CC)	840
I_BGCC_base (without CC)	2290
I_IGCC_CU	130
I_IGCC_capt	620
I_NGCC_capt	360
I_BGCC_capt	620
OM_NGCC_base	16
OM_IGCC_base	42
OM_BGCC_base	51
I_NGCC-SOFC	850
I_IGCC-SOFC	1700
I_BGCC-SOFC	1800
I_IGCC-SOFC_capt	200
I_NGCC-SOFC_capt	200
I_BGCC-SOFC_capt	200
OM_NGCC-SOFC	38

IFcosts_conv_NG_base_2020
IFcosts_conv_NG_base_2050
IFcosts_conv_NG_base_2100
IFcosts_conv_NG_CU_2020
IFcosts_conv_NG_CU_2050
IFcosts_conv_NG_CU_2100
IFcosts_conv_NG_FH_2020
IFcosts_conv_NG_FH_2050
IFcosts_conv_NG_FH_2100
IFcosts_conv_coal_base_2020
IFcosts_conv_coal_base_2050
IFcosts_conv_coal_base_2100
IFcosts_conv_coal_CU_2020
IFcosts_conv_coal_CU_2050
IFcosts_conv_coal_CU_2100
IFcosts_conv_coal_FH_2020
IFcosts_conv_coal_FH_2050
IFcosts_conv_coal_FH_2100
IFcosts_conv_oil_base_2020
IFcosts_conv_oil_base_2050
IFcosts_conv_oil_base_2100
IFcosts_conv_oil_CU_2020
IFcosts_conv_oil_CU_2050
IFcosts_conv_oil_CU_2100
IFcosts_conv_oil_FH_2020
IFcosts_conv_oil_FH_2050
IFcosts_conv_oil_FH_2100
IFcosts_conv_BM_base_2020
IFcosts_conv_BM_base_2050
IFcosts_conv_BM_base_2100
IFcosts_conv_BM_CU_2020
IFcosts_conv_BM_CU_2050
IFcosts_conv_BM_CU_2100
IFcosts_conv_BM_FH_2020
IFcosts_conv_BM_FH_2050
IFcosts_conv_BM_FH_2100
IFcosts_NGCC_base_2020
IFcosts_NGCC_base_2050
IFcosts_NGCC_base_2100
IFcosts_IGCC_base (without CC)_2020
IFcosts_IGCC_base (without CC)_2050
IFcosts_IGCC_base (without CC)_2100
IFcosts_BGCC_base (without CC)_2020
IFcosts_BGCC_base (without CC)_2050
IFcosts_BGCC_base (without CC)_2100

Annex 2. Capture processes

There are numerous ways to capture carbon dioxide from power plants. These CO_2 capture processes can conveniently be divided into three main categories:

1. Pre-combustion processes. The fossil fuel is converted to a hydrogen-rich stream and a carbon-rich stream.
2. Post-combustion processes. Carbon dioxide is recovered from a flue gas.
3. Denitrogenation processes. A concentrated CO_2 stream can be produced by the exclusion of N_2 before or during the combustion/conversion process.

Depending on the type of power plant, one or more types of capturing can be applied. In principle the post-combustion process is applicable to all types of power plant as it can be regarded as an add-on process, treating the flue gases of the power plant. The pre-combustion process is significantly more integrated in the total plant concept and is realistically seen only applicable to combined cycle plants. The denitrogenation process is also applicable to all types of power plants. It should be noted that for this process in combined cycles a gas turbine need to adapted or developed which can operate with carbon dioxide as the working medium instead of air.

On the longer term, carbon dioxide capture from the solid oxide fuel cell seems to be an attractive alternative. This type of power plant has the inherently advantage that the combustion air is not mixed with the fuel, resulting in a highly carbon dioxide concentrated exhaust gas.

Which of the capture processes will ultimately be the preferred ones is impossible to say at this moment of development. Nevertheless, the following processes are selected for this study because they are currently best-known, less expensive and provide good outlook for the future. These choices should be seen rather as an example than a prediction to future capture technologies.

- Conventional power plants (all fuels): post-combustion process based on chemical absorption process
- IGCC: pre-combustion process (all fuels)
- NGCC: pre-combustion process (all fuels) based on chemical absorption
- SOFC: adaptations in concept to facilitate CO_2 capture including compression

Natural gas-fired combined cycle power plant

A combined cycle plant can be equipped with pre-combustion carbon dioxide capture. In such a plant, the fuel is converted with steam in a reformer and shift reactor to hydrogen and carbon dioxide. External burners add heat for the reaction (most common design). When an authothermal reformer design is used, heat for the reaction is supplied by adding oxygen or air into the reformer. This process is also called *partial oxidation* [Rao, 2000; Stork, 2000].

The hydrogen is separated from the carbon dioxide by an absorption unit or a pressure swing adsorption unit (PSA). PSA separates gases by exploiting the ability of specially designed porous materials to selectively adsorb specific molecules at high pressure and desorb them at low pressure. PSA is able to recover over 97% of the hydrogen at very high purity. Modifications to the reformer process are e.g. using a part of the hydrogen-rich fuel to fire the reformer and recirculation of gas turbine exhaust gases and using it in the reformer furnace.
The produced hydrogen is combusted in (a slightly modified) gas turbine to produce electricity. In comparison to the plant without capture, additionally a steam reformer section, shift reactor and carbon dioxide separation section need to be added.

Integrated Gasifier Combined Cycle plant

IGCCs offer good possibilities to capture carbon dioxide through the pre-combustion route. An IGCC plant includes an oxygen-blown (or air-blown) gasifier, followed by a heat recovery steam generator and a steam turbine. Raw gas exiting the gasifier is cooled down and sulphur compounds are removed, e.g. by a Selexol absorption process and recovered as elemental sulphur from a Claus unit. An expander that reduces the gas pressure prior to entering the gas turbine combustor generates additional power. An air separation unit supplies the required oxygen. A gas turbine, capable of producing power on low heat content gas, converts the produced hydrogen-rich gas to electricity.
In case carbon dioxide is captured the raw fuel gas passes through high and low temperature shift reactors and a cleaning section for removing carbon dioxide. Heat for the reaction is supplied by adding air or oxygen into the gasifier. An extended gas treatment is required to remove particulates and other pollutants from the gas. The carbon dioxide is removed from the stream by a physical absorption process. Alternatively to coal also biomass can be used as feedstock for the IGCC. As a feedstock for gasification, biomass has some advantages relative to coal: it is more reactive and thus easier to gasify, and most biomass has sufficiently low sulphur content that costly sulphur removal systems are not required. On the other hand, the higher cost of transporting biomass will constrain biomass facilities to more modest sizes. IGCCs can be classified into two types: those equipped with oxygen-blown gasifier and those with air-blown gasifier. However, Parsons [1996] concluded that efficiency loss and capture costs for air-blown gasifiers are significantly higher than for oxygen-blown alternatives.

Conventional power plants

ECOFYS

In a post-combustion process, the CO_2 is separated from the flue gases of a power plant or from the flue gases of an industrial process. In few production facilities, e.g. from the production of ammonia and hydrogen, separation is not required as the CO_2 is already released in pure form.

For post-combustion processes, the best-known and developed technology is separation of CO_2 from flue gases by an amine-based solvent. It is currently the most mature technology for capturing CO_2 from flue gases. Other ways to capture CO_2 is by using membranes (polymer- based, ceramic or metal-base) or in combinations of membranes and solvents. In the latter option, the membranes replace the absorption column and act as a gas-liquid contact facilitator. Also considered is to fractionate the carbon dioxide by solidifying it. These alternatives are at the moment less energy efficient and more expensive than chemical absorption. This can be attributed, in part, to the relative low CO_2 partial pressure in the flue gases. In this analysis, we assume à priori that the amine-based chemical absorption process is the preferred technology; our cost and energy consumption for post-combustion carbon dioxide capture is therefore based on this technology.

The amine-based systems are proven technology on commercial scale, and are similar to other wide-spread used end-of-pipe environmental control systems as flue gas desulphurisation systems. The amine-based systems can recover 85% to 95% of the CO_2 in the flue gas and produce CO_2 with a purity of over 99.9%. Examples of current commercial available systems are the Econamine FG process of Fluor Daniel and the Amine Guard process licensed by UOP. The most commonly used absorbent is MEA. A method for reducing energy consumption is to use modified absorbents. Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries have been examining and testing a wide range of amines and developed new solvents (so-called KS-1, KS2, and KS-3). Compared to MEA, KS-1 has a lower circulation rate (due to its higher lean to rich CO_2 loading differential), lower regeneration temperature (110 °C), and 10-15% lower heat of reaction with CO_2. KS-1 is commercialised and used in a commercial plant in Malaysia (the Petronas Fertiliser Kedah Sdn Bhd’s fertiliser plant in Gurun Keday) and is operational since October 1999. In the early nineties Mariz [1991] and Sander [1992] reported that a heat consumption of 4.1 MJ/kg CO_2 can be obtained by the MEA-based Econamine process. According to Mimura [2000], the KS-1 solvent can reach less than 3.3 MJ/kg CO_2 for flue gases with 7% CO_2. They expect to obtain further improvements in the coming years.

Annex 3: Grid losses different countries

Bulgaria region 10:

"Bulgarian Energy sector: Assessment", C. Connors, I. Traugott, 2003
http://www.usaid.gov/locations/europe_eurasia/countries/bg/pdfs/assessments/energy_assessment_public.pdf :
T & D losses in electricity and heating are high ~20 %. In interviews with MEER, district heating, distribution company and NEK representatives, the Assessment Team learned repeatedly that the high rate of losses was attributable in part to old and inefficient technology, and in larger part due to corruption. Bills are based on reports made by individuals whose job it is to read meters. Corruption in this process (such as bribes to report lower usage than that recorded in the meter; and physical manipulation by the user of the metering system, which is most often located in the user's residence and thus entirely within the user's control) result in high loss rates. Corruption occurs in the reading and reporting process, not the collection process (with collection rates running in the 90 % range for electricity), as collections are handled through bank transfers for amounts based on billing, and do not involve reliance on human reporting or disclosure of information by the user.

"Electricity Distribution Companies", Ministery of Energy and Energy Resources – Republic of Bulgaria
http://www.doe.bg/download/default/BNP2.pdf :
The Government of Bulgaria is committed to implementing a far reaching energy sector restructoring and privatisation programme. The liberalisation is planned for 2003. 7 of the 8 distribution companies are state-owned, the 8th is already in private ownership.

Metering equipment is generally nearing the end or at the end of its useful operational lifespan. (40% installed before 1981, 30% installed between 1981 and 1985)

losses 2002:	5,322 GWh
consumption:	18,583 GWh
(=> supply:	23,905 GWh)
=> losses related to sale:	28,6 %
losses related to supply:	22,3 %

Nicaragua, region 3:

Nicaragua: Rehabilitation and Expansion of Power Distribution Systems II
http://www.kfw.de/EN/Entwicklungszusammenarbeit/Evaluation57/Ex-posteva43/nicaragua%20rehab%20and%20expansion%20of%20power.pdf :

In 2001 the losses amounted to 19 %, with non-technical losses accounting for the brunt of them (14 %).

Mexico, region 3:

Preliminary Cost Benefit Analysis - The Privatization of the Electric Sector in Mexico

http://unpan1.un.org/intradoc/groups/public/documents/other/unpan003516.pdf :

The Federal Electricity Commission (CFE) and *Luz y Fuerza Centro* (LFC) are Mexico's two state-owned electricity companies. The amount and cost of energy loss is not officially available and estimates vary dramatically. According to PRD (Democratic Party of the Revolution) Deputy Rosario Tapia, electricity theft for the LFC electric company alone is 13 % of its total electric production. Luis Felipe Lopez-Calva, a professor and researcher at El Colegio De Mexico, estimates that CFE "loses" 10.8 % of the energy it generates while at LFC energy losses from theft and inefficiency are a staggering 23.7 % of their total energy production. Even the President of the combative Mexican Union of Electricians (SME), Mr. Rosendo Flores, who is a staunch opponent of privatization, admits that electricity theft from LFC costs the company as much as U.S. $400 million dollars per year.

United Kingdom, region 9:

http://www.police999.com/stats/crime2002-18.html

For the UK the following data is puplished:

Abstracting electricity: recorded crimes:	1998/99: 2.454
	1999/00: 2.157
	2000/01: 1.451
	2001/02: 1.340

Pakistan, region 13:

"KESC sets up teams to curb power theft", the international news, 2003

http://www.jang.com.pk/thenews/oct2003-daily/18-10-2003/metro/k11.htm :

The managing director of Karachi Electric Supply Corporation (KESC) has set up special teams to curb power theft from the commercial buildings of city's posh shopping centres. Initial survey discloses that rampant theft of electricity is being committed and some of the consumers are repeatedly using electricity illegally. A KESC spokesman said that prominent business houses and commercial buildings of Zaibun Nisa Street were penalised by the teams for theft of electricity.

"The costs of corruption for the poor", L. Lovei, A. McKechnie, World Bank

http://www.worldbank.org/html/fpd/esmap/energy_report2000/ch8.pdf

Diversion of utility revenues had become such a problem in Pakistan that in 1999 the government mobilized the army to supervise meter reading and billing. The scale of theft surprised the authorities, especially the extent to which the affluent benefited; industries, shopping centers, and large residences accounted for a large share of the stolen electricity.

The following fragments are taken from [Smith, 2003]:

Bangladesh region 13:

~ 35 % losses, of which 21% technical losses and 14% non-technical losses (theft)

Malaysia region 15:

T&D losses 11 %, of which 4% theft

Budapest / Hungary region 10:

T&D losses 13%, of which ½ theft

Jakarta / Indonesia region 15:

In 1996 ~ 4 % theft

Pakistan region 13:

1999 gab es 100.993 Fälle von Energie-Diebstahl, die mit Geld- und Gefängnis-strafen bestraft wurden. In 2000 only 52 % of the 1,67 million customers paid their bills.

Armenia region 11:

T+D losses above 40%,
Non-Payment-Level of 80 – 90% in residential sector

Arizona region 2:

1% meter tampering rate

Annex 4: Grid losses

Country	Year	Electric power transmission and distribution losses (% of output)
Albania	1999	57.01 %
Algeria	1999	19.26 %
Angola	1999	14.53 %
Argentina	1999	14.78 %
Armenia	1999	25.14 %
Australia	1999	7.62 %
Austria	1999	7.67 %
Azerbaijan	1999	13.42 %
Bahrain	1999	6.60 %
Bangladesh	1999	15.82 %
Belarus	1999	13.37 %
Belgium	1999	4.96 %
Benin	1999	97.83 %
Bolivia	1999	17.85 %
Bosnia and Herzegovina	1999	22.07 %
Brazil	1999	17.29 %
Brunei Darussalam	1999	1.15 %
Bulgaria	1999	17.02 %
Cameroon	1999	20.56 %
Canada	1999	7.44 %
Chile	1999	5.48 %
China	1999	6.95 %
Colombia	1999	23.89 %
Congo, Dem. Rep.	1999	3.51 %
Congo, Republic of the	1999	90.72 %
Costa Rica	1999	7.67 %
Croatia	1999	16.83 %
Cuba	1999	18.30 %
Cyprus	1999	6.24 %
Czech Republic	1999	7.86 %
Denmark	1999	5.22 %
Dominican Republic	1999	27.10 %
Ecuador	1999	22.79 %
Egypt	1999	12.17 %

El Salvador	1999	13.19 %
Estonia	1999	17.78 %
Ethiopia	1999	10.00 %
Finland	1999	3.87 %
France	1999	5.94 %
Gabon	1999	10.05 %
Georgia	1999	18.79 %
Germany	1999	4.42 %
Ghana	1999	0.71 %
Greece	1999	6.75 %
Guatemala	1999	19.58 %
Haiti	1999	53.30 %
Honduras	1999	22.32 %
Hong Kong	1999	12.76 %
Hungary	1999	13.17 %
Iceland	1999	5.37 %
India	1999	21.01 %
Indonesia	1999	11.84 %
Iran	1999	15.33 %
Iraq	1991	5.77 %
Ireland	1999	8.47 %
Israel	1999	3.44 %
Italy	1999	7.16 %
Jamaica	1999	9.82 %
Japan	1999	3.41 %
Jordan	1999	11.06 %
Kazakhstan	1999	17.09 %
Kenya	1999	20.31 %
Korea, Republic of	1999	4.37 %
Kyrgyzstan	1999	26.98 %
Latvia	1999	27.01 %
Lebanon	1999	17.53 %
Lithuania	1999	10.16 %
Luxembourg	1999	35.20 %
Malaysia	1999	8.00 %
Malta	1999	12.22 %
Mexico	1999	14.36 %
Moldova	1999	26.14 %
Morocco	1999	4.03 %
Mozambique	1999	10.37 %
Myanmar	1999	24.96 %
Nepal	1999	22.69 %

Netherlands	1999	4.57 %
Netherlands Antilles	1999	12.30 %
New Zealand	1999	11.88 %
Nicaragua	1999	25.93 %
Nigeria	1999	31.82 %
Norway	1999	7.69 %
Oman	1999	17.37 %
Pakistan	1999	30.41 %
Panama	1999	19.34 %
Paraguay	1999	3.07 %
Peru	1999	12.05 %
Philippines	1999	14.81 %
Poland	1999	10.41 %
Portugal	1999	8.50 %
Qatar	1999	5.99 %
Romania	1999	12.59 %
Russian Federation	1999	11.38 %
Saudi Arabia	1999	8.28 %
Senegal	1999	16.73 %
Singapore	1999	4.16 %
Slovak Republic	1999	6.65 %
Slovenia	1999	5.04 %
South Africa	1999	8.39 %
Spain	1999	9.64 %
Sri Lanka	1999	20.63 %
Sudan	1999	31.12 %
Sweden	1999	6.95 %
Switzerland	1999	5.62 %
Syria	1992	26.27 %
Tajikistan	1999	13.43 %
Tanzania	1999	22.31 %
Thailand	1999	8.35 %
Trinidad and Tobago	1999	8.08 %
Tunisia	1999	10.40 %
Turkey	1999	18.50 %
Turkmenistan	1999	13.05 %
Ukraine	1999	17.56 %
United Arab Emirates	1999	9.00 %
United Kingdom	1999	8.21 %
United States	1999	7.60 %
Uruguay	1999	18.72 %
Uzbekistan	1999	9.14 %

Venezuela	1999	23.35 %
Viet Nam	1999	15.00 %
Yemen	1999	25.68 %
Zambia	1999	11.32 %
Zimbabwe	1999	16.57 %

[World Bank, 2002]