7.3 Combustion Installations larger than 50 MW

7.3.1 Coverage

The combustion sector covers a range of different combustion techniques suited to different fuels: solid fuels, such as coal, lignite, peat, biomass, liquid and gaseous fuels, including low calorific and blast furnace gas. This section covers boilers (small: 50 - 100 MW_{th}, medium: 100 - 300 MW_{th}, and large: >300 MW_{th}) and gas turbines (>50 MW_{el}). In the following, the term “boilers” is meant in contrast to combustion engines or turbines and includes all kinds of boilers and process heaters. The given capacity classes in terms of rated thermal input refer to the lower heating value (LHV) of the respective fuel.

The following installations are not covered by this section:

- Plant in which the products of combustion are used for direct heating, drying, or any other treatment of objects or materials, e.g. reheating furnaces, furnaces for heat treatment;
- Post-combustion plant, i.e. any technical apparatus designed to purify the waste gases by combustion that is not operated as an independent combustion plant;
- Facilities for the regeneration of catalytic cracking catalysts;
- Facilities for the conversion of hydrogen sulphide into sulphur;
- Reactors used in the chemical industry;
- Coke battery furnaces;
- Cowpers;
- Waste incinerators; and
- Plant powered by diesel, petrol or gas engines, irrespective of the fuel used (For information about stationary engines see document "Stationary Engines" 7-45)

7.3.2 Emission sources

The combustion process leads to the generation of emissions to air, which are considered to be one of the major sources of air pollution. Depending on the type of the fuels, several combustion technologies are available which show considerably different NO_x, SO_x and dust emissions. This paragraph describes the main technologies used for the combustion of solid, liquid and gaseous fuels.

(a) Large boilers, process heaters and furnaces

Grate firing is used in comparatively small combustion plants with a thermal capacity of less than 100 MW_{th} sometimes grate firing is used for burning waste (not regarded in this section, cf. 7-18) and biomass [1]. The fuel on the grate will be first dried and pyrolysed. And then the char is burned on the grate. The conditions of combustion are not as well controlled as in other systems as the combustion chemistry and the temperature can vary considerably across the grate [**2**].

Pulverised fuel firing is well established for all sizes of boiler above 50 MW_{th} and is a solid fuel burning technique in which the fuel is pulverised before being ignited. Two general boilers types are distinguished:

Dry bottom boilers operate at lower temperatures so that the ash is not heated above its melting point during the combustion process.

Wet bottom boilers require high combustion temperatures in order to melt the ash, accordingly, comparatively high NOx emission levels are observed [1]. This technique is often used for fuels with poor combustion characteristics and involves recycling fly ash [3].

Fluidized bed combustion (FBC) is a combustion technology for burning hard coal and lignite, but also low-grade fuels such as waste, peat and wood, which are not regarded in this section. Fuel is injected into a hot turbulent bed of reactive or inert material while a flow of air passes up through the bed. Emissions can be further reduced via integrated combustion control in the system. Within the sector of energy conversion, atmospheric fluidized bed combustion is a well-established commercial technology. Depending on the velocity of the fluidisation air, two types of atmospheric fluidised bed combustion do exist, the atmospheric bubbling fluidised bed combustion (BFBC), and the atmospheric circulating fluidised bed combustion (CFBC). Pressurized fluidized bed combustion (PFBC) operates at elevated pressures and produce a high-pressure gas stream at temperatures that can drive a gas turbine.

(b) Turbines

Gas turbines are used for the transformation of thermal energy into mechanical energy. They use a steady flow of a gas (mostly air), compressed and fired with gaseous or liquid fuel. Gas turbines are increasingly used for electricity production in base and intermediate load but are also still used for peaking load in simple cycle (then fired with gas or light oil). In combined cycle power plants a gas turbine is combined with steam turbine to generate electricity.

Integrated gasification combined cycle (IGCC) process incorporates coal or biomass gasification and combined cycle plants. The gasified solid fuel is burned in the combustion chamber of the gas turbine. The technology also exists for heavy oil residue. However, this process is not yet fully commercialized, a small number of demonstration units, mainly around 250 MWe size are being operated in Europe and the USA.

BAT for the combustion of solid, liquid and gaseous fuels

Combustion of coal and lignite

Pulverized combustion, fluidized bed combustion as well as pressurized fluidized bed combustion and grate firing are all considered to be BAT for the combustion of coal and lignite for new and existing plants. Grate firing should preferably only be applied to new plants with a rated thermal input below 100 MW [3].

Combustion of biomass and peat

For the combustion of biomass and peat, pulverized combustion, fluidized bed combustion as well as the spreader stoker grate firing technique for wood and vibrating, water-cooler grate for straw-firing are BAT. Pulverized peat combustion plants are not BAT for new plants [3].

Combustion of liquid fuels

For liquid fuels, the use of pretreatment devices, such as diesel oil cleaning units used in gas turbines and engines, are BAT. Heavy fuel oil (HFO) treatment comprises devices such as electrical or steam coil type heaters, de-emulsifier dosing systems, etc.

Combustion of liquid and gaseous fuels in CHP plants

A combined cycle operation and cogeneration of heat and power is to be considered as the first BAT option, i.e. whenever the local heat demand is great enough to warrant the construction of such a system [3].

7.3.3 BAT, Associated Emission Levels (AEL)

7.3.3.1 SO_2

This section provides descriptions of the abatement options that are generally used to reduce emissions of sulphur oxides from combustion installations. Emissions of SO_2 are highly dependent on the sulphur content in coal burned and the emissions control system employed. In general, techniques to reduce sulphur oxides are divided into primary and secondary measures.

Primary measures

Use of low sulphur fuel, the SO_2 emissions during combustion are directly related to the sulphur content of the fuel used. Fuel switching (from high- to low-sulphur fuels) leads to lower sulphur emissions. This measure is widely applied. However there may be certain restrictions, such as the availability of low-sulphur fuels and the adaptability of existing combustion systems to different fuels. Fuel switching to natural gas can be sufficient for reducing SO_2, in case of other fuels depending on the fuel sulphur content it can be used as a supplementary technique.

Use of adsorbents in fluidised bed combustion systems.

FBC boilers can operate very efficiently in terms of SO_2 removal, for example sorbant injection into the FBC boiler is an inexpensive method for sulphur capture. Investment costs are low, because the desulphurisation is incorporated into the combustion process and separate reactor equipment is not needed [3]. However, the solid by-products composed of ash, sulphate containing reaction products and lime cannot be used for concrete making as fly ash from conventional PC combustion

Secondary measures

Flue gas desulphurization (FGD) processes. These processes aim at removing already formed sulphur oxides, and are also referred to as secondary measures. The state-of-the-art technologies for flue gas treatment are all based on the removal of sulphur by wet or dry processes.

In wet processes, wet slurry waste or by-product is produced, and flue gas leaving the absorber is saturated with moisture. Seawater scrubbing utilises seawater's inherent properties to absorb and neutralise sulphur dioxide in flue-gases. If a large amount of seawater is available near a power plant, it is most likely to be used as a cooling medium in the condensers. Wet scrubbers, especially the limestone-gypsum processes, are the leading FGD technologies. They have about 80% of the market share and are used in large utility boilers. The efficiency of sulphur dioxide removal may be increased up to 92-98%. In case of retrofitting the efficiencies are lower reaching up to 95%.

In semi-dry processes, a slurry of alkaline reagent is atomized and injected into a vessel where it reacts with the SO_2 in the flue gas to produce calcium sulphate or sulphite products [4]. Sulphur dioxide removal efficiencies of 80 to 95% have been achieved.

Table 1 Emission sources and selected BAT SOx control measures with associated emission levels in combustion installations (PM is for primary measures)

Emission source	Combination of control measures	SO_x emission level associated with BAT[1] (mg/Nm^3) [3]
boilers 50 - 100 MW_{th}		
Grate-firing, Fuel: coal and lignite	Low sulphur fuel or FGD	200 - 400
Boiler; Fuel: coal and lignite	Low sulphur fuel and FGD	200 - 400 (split view industry: 200 - 300)
Circulating FBC; Pressurised FBC; Fuel: coal, lignite	Low sulphur fuel Limestone injection	150 - 400 (split view industry: 150 - 300)
Bubbling FBC; Fuel: coal, lignite	Low sulphur fuel FGD	150 - 400 (split view industry: 150 - 300)
Boiler; Fuel: peat	Limestone injection Calcium hydroxide injection in dry form before the ESP or FF FGD	200 - 300 (new) 200 - 300 (existing)
Circulating FBC; Bubbling FBC; Fuel: peat	Co-combustion of biomass and peat Limestone injection Calcium hydroxide injection in dry form before the ESP or FF FGD	200 - 300 (new) 200 - 300 (existing)
Boiler; Fuel: oil	Low sulphur fuel oil Co-combustion of gas and oil FGD	100-350 (new) 100-350 (existing) (split view industry: new plants: 200-850, existing plants: 200-850)
Boilers 100 - 300 MW_{th}		
Boiler; Fuel: coal and lignite	Low sulphur fuel FGD Combined techniques for the reduction of NOx and SOx	100 - 200 (new) 100 - 250 (existing) (split view industry: existing plants 100-600)
Circulating FBC; Pressurised FBC; Fuel: coal, lignite	Low sulphur fuel Limestone injection	100 - 200 (new) 100 - 250 (existing (split view industry: existing plants: 100-300)
Bubbling FBC; Fuel: coal, lignite	Low sulphur fuel FGD	100 - 200 (new) 100 - 250 (existing (split view industry: existing plants 100-300)
Boiler; Fuel: peat	Limestone injection Calcium hydroxide injection in dry form before the ESP or FF FGD	200 - 300 (new) 200 - 300 (existing)
Circulating FBC; Bubbling FBC; Fuel: peat	Co-combustion of biomass and peat Limestone injection Calcium hydroxide injection in dry form before the ESP or FF, FGD	150 - 250 (new) 150 - 300 (existing)
Boiler; Fuel: oil	Low sulphur fuel oil Co-combustion of gas and oil and FGD FGD	100 - 200 (new) 100 - 250 (existing) (split view industry: new plants: 100-400, existing plants: 100-400)

	Combined techniques for the reduction of NOx and SOx	
Boilers >300 MW_{th}		
Boiler; Fuel: coal and lignite	Low sulphur fuel FGD Combined techniques for the reduction of NOx and SOx	20 - 150 (new) 20 - 200 (existing) (split view industry: new plants: 20-200, existing plants: 20-400)
Circulating FBC; Pressurized FBC, Fuel: coal, lignite	Low sulphur fuel Limestone injection	100 - 200 (new) 100 - 200 (existing) (split view industry: existing plants: 100-300)
Bubbling FBC, Fuel: coal, lignite	Low sulphur fuel FGD	20 - 150 (new) 20 - 200 (existing) (split view industry: existing plants: 20-300)
Boiler; Fuel: peat	FGD Combined techniques for the reduction of NOx and SO2	50 - 150 (new) 50 - 200 (existing)
Circulating FBC; Bubbling FBC Fuel: peat	Co-combustion of biomass and peat Limestone injection Calcium hydroxide injection in dry form before the ESP or FF FGD	50 - 200 (new) 50 - 200 (existing)
Boiler, Fuel: oil	Low sulphur fuel oil Co-combustion of gas and oil FGD Combined techniques for the reduction of NOx and SOx	50 - 150 (new) 50 - 200 (existing) (split view industry: new plants: 50-200, existing plants: 50-400)
[1] The BAT associated emission levels are based on a daily average, standard conditions and represents a typical load situation. For peak load, start up and shut down periods, as well as for operational problems of the flue gas cleaning systems, short-term peak values, which could be higher, have to be regarded. If not stated otherwise, values are daily averages assuming an oxygen content by volume in the waste gas of 3 % in the case of liquid and gaseous fuels, 6 % in the case of solid fuels.		

7.3.3.2 NO_x

The most important oxides of nitrogen with respect to releases from combustion processes are nitric oxide (NO), nitrogen dioxide (NO_2) and nitrous oxide (N_2O). NO and NO_2 are commonly referred to as NO_x. [2]. NO_x is formed during most combustion processes by one or more of three chemical mechanisms: “thermal” NO_x resulting form oxidation of atmospheric molecular nitrogen, “fuel” NO_x resulting from oxidation of chemically bound nitrogen in the fuel, and “prompt” NOx resulting from reaction between atmospheric molecular nitrogen and hydrocarbon radicals [4]. Only the first two mechanisms are of major importance in combustion plants.

This section provides descriptions of the abatement options that are generally used to reduce emissions of nitrogen oxides from combustion installations. In general, techniques to reduce nitrogen oxides are divided into primary and secondary measures. Primary measures have been developed to reduce NO_x emissions at source during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Secondary measures operate downstream of the combustion process and remove NO_x emissions from the flue gas.

The application of primary measures is limited by operational and fuel specific parameters that influence the safe operation. It is also limited by layout feasibility in existing installations.

Primary measures (combustion modifications):

Air staging consists of the introduction of combustion air into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. The primary combustion zone has a lack of oxygen and the secondary combustion zone an excess of oxygen. This technique is frequently used in conjunction with low NO_x burners, completes the combustion process at a lower temperature [1][5].

Fuel staging, also named **reburning** is a three-stage (zone) system. It is based on the creation of different zones in the furnace by staged injection of fuel and air. The aim is to reduce nitrogen oxides, which have already been formed back to nitrogen [1]. The reburning technique is capable of achieving relatively high NO_x reduction (50-75%) and can in principle be used at all types of fossil fuel fired boilers, and also in combination with low-NO_x combustion techniques for the primary fuel. This technique is not well adapted for retrofit due to space constraints.

Flue gas recirculation results in a reduction of available oxygen in the combustion zone and, since it directly cools the flame, in a decrease of the flame temperature: therefore, both fuel bound nitrogen conversion and thermal NO_x formation are reduced. The recirculation of flue gas into the combustion air has proven to be a successful method for NO_x abatement at high temperature combustion systems such as wet bottom boilers and oil or gas fired installations but is generally not effective on dry bottom pulverised coal boilers. NO_x emissions reduction of 30-60% can be observed by employing flue gas recirculation when burning natural gas. On heavy fuel oil NO_x reductions of 10-20% are observed but dust emissions may increase

Low NO_x Burners (LNB) are designed to control the mixing of fuel and air to achieve what amounts to staged combustion. An under-stoichiometric zone is created with a fuel/air mixture and primary air. Due to the swirl of primary air, internal recirculation occurs. Around the primary air nozzles, an arrangement of secondary nozzles feeds secondary air to the burnout zone. This staged combustion reduces both flame temperature and oxygen concentration during some phases of combustion, in turn, produces both lower thermal NO_x and fuel NO_x generation. Low NO_x Burners should be fitted to all new plant and retrofitting to existing plant should normally be expected. Low NO_x-Burners are effective in reducing NO_x emissions by 30-50% [1][5] and can be combined with other primary measures such as overfire air, reburning or flue gas recirculation.

Secondary measures (post combustion NO_x control technology)

Selective Catalytic Reduction (SCR) is the most mature and widely applied process for the reduction of nitrogen oxides in exhaust gases from combustion installations in Europe and other countries such as Japan and the U.S. The SCR process can be used for a wide range of fuels such as natural gas. The SCR process usually uses ammonia as a reducing agent, which is directly injected into the flue gas over a catalyst in the presence of sufficient oxygen. NO_x-conversion takes place on the catalyst surface at a temperature between 170 and 510°C (with a range between 300 and 400°C being more typical; the minimum flue gas temperature is dependent on the sulphur content of the fuel. At a too low flue gas temperature ammoniumbisulphate is formed which will clog the SCR element) [3] NO_x emission reductions over 80-90% are achieved and depend on the system design, catalyst activity and the concentration of reacting gases [2].

Selective Non-Catalytic Reduction (SNCR) reduces NO_x and operates without a catalyst at a temperature between 850 and 1100°C. This temperature window is strongly dependent on the reactant used, which can be: ammonia, urea or ammonia solution. The SNCR process has found application for various types of fossil fuels. The average achievable NO_x abatement efficiency is in the range of 30-50% [3]. SNCR is less costly than SCR because of the absence of catalyst and can be applied also at small installations. But SNCR is not well suited for plants, which are operated at variable load (risk of excessive ammonia slip and smell).

BAT for reducing nitrogen oxide emissions

Combustion of lignite and coal

For NO_x removal of off-gases from coal and lignite combustion plants, the use of a combination of primary and/or secondary measures is considered to be BAT. However according to the boiler technology and coal type (e.g. high primary NO_X for low volatile coals) a distinction of BAT has to be made.

The combination of primary measures in combination with secondary measures such a SCR is considered to be BAT for base load pulverized coal combustion plants.

The use of a combination of different primary measures for pulverized lignite-fired plants is considered to be BAT. Because of lower NO_x emissions in lignite-fired plants, the SCR technique is not considered to be BAT for the combustion of lignite.

The use of staged combustion for the fluidized bed combustion of coal and lignite is considered to be BAT.

Combustion of biomass and peat

For NO_x removal of off-gases from biomass and peat combustion plants, the use of a combination of primary and/or secondary measures is considered to be BAT. However according to the boiler technology a distinction of BAT has to be made.

Combustion of liquid fuels

For NO_x removal of off-gases from liquid-fuel fired combustion plants, the use of a combination of primary and/or secondary measures such as a SCR is considered to be BAT for over 50 MW_{th} and in particular for large baseload plants above 100$MW_{th.}$

The use of a combination of different primary measures is considered to be BAT for combustion plants with a capacity of less than 100 MW_{th}.

Combustion in Gas Turbines

For new gas turbines, dry low NO_x premix burners (DLN) are BAT. For existing gas turbines, water and steam injection as primary measure or conversion to the DLN technique is BAT. DLN burners are only BAT for new turbines where the technique is available on the market for the use in gas turbines burning liquid fuels.

Table 2 Emission sources and selected BAT NOx control measures with associated emission levels in combustion installation (PM is for primary measures)

Emission source	Combination of control measures	NO_x emission level associated with BAT[1] (mg/Nm^3) [3]
Boilers 50 - 100 MW_{th}		
Grate firing, Fuel: coal and lignite	PM and or SNCR	200 - 300 (split view industry: existing plants: 200-400)
Boiler; Fuel: coal	Combination of PM, SNCR or SCR	90 - 300 (split view industry: new plants: 90-450, existing plants: 90-500)
Boiler; Fuel: lignite	Combination of PM	200 - 450 (split view industry: existing plants: 200-500)
Circulating FBC; Pressurised FBC	Combination of PM	200 - 300

Bubbling FBC, Fuel: coal, lignite		
Grate firing, Fuel: biomass and peat	Spreader-stocker	170 - 250 (new) 200 - 300 (existing)
Boiler; Fuel: biomass and peat	Combination of PM or SCR	150 - 250 (new) 150 - 300 (existing)
Circulating FBC; Bubbling FBC, Fuel: biomass and peat	Combination of PM	150- 250 (new) 150 - 300 (existing)
Boiler, Fuel: oil	Combination of PM SCR SNCR in case of HFO firing	150- 300 (new) 150 - 450 (existing) (split view industry: new plants: 150-400)
Industrial boiler; fuel: gas	Low NO_x-Burners or SCR or SNCR	50 - 100 (new and existing) (split view industry: new and existing: 50-120)
Boilers 100 - 300 MW_{th}		
Boiler; Fuel: coal	Combination of PM in combination with SCR or combined techniques	90-200 (new) 90 - 200 (existing) (split view industry: new plants: 100-200, existing plants: 90-300)
Boiler; Fuel: lignite	Combination of PM	100 - 200 (new) 100 - 200 (existing) (split view industry: existing plants: 100-450)
Circulating FBC; Pressurized FBC Bubbling FBC, Fuel: coal, lignite	Combination of PM, if necessary, together with SNCR	100 - 200 (new) 100 - 200 (existing) (split view industry: existing plants: 100-300)
Boiler; Fuel: biomass and peat	Combination of PM, if necessary SNCR and/or SCR	150 - 200 (new) 150 - 250 (existing)
Circulating FBC; Bubbling FBC, Fuel: biomass and peat	Combination of PM	150 - 200 (new) 150 - 250 (existing)
Boiler, Fuel: oil	Combination of PM in combination with SNCR, SCR or combined technique	50 - 150 (new) 50 - 200 (existing) (split view industry: new plants: 50-200; existing plants: 50-450)
Industrial boiler; fuel: gas	Low NOx burners or SCR or SNCR	50 - ~~120~~ -100 (3% O2) (split view industry: 50-120)
Boilers >300 MW_{th}		
Boiler; Fuel: coal	Combination of PM in combination with SCR or combined techniques	90 - 150 (new) 90 - 200 (existing)
Boiler; Fuel: lignite	Combination of PM	50 - 200 (new) 50 - 200 (existing) (split view industry: new plants: 100-200; existing plants: 100-450)
Circulating FBC; Pressurized FBC Bubbling FBC, Fuel: coal, lignite	Combination of PM	50 - 150 (new) 50 - 200 (existing) (split view industry: existing plants: 100-200)
Boiler; Fuel: biomass and peat	Combination of PM, if necessary SCR or and SNCR	50 - 150 (new) 50 - 200 (existing)
Circulating FBC; Bubbling FBC, Fuel:	Combination of PM, if necessary	50 - 150 (new)

biomass and peat	SCR or and SNCR	50 - 200 (existing)
Boiler, Fuel: oil	Combination of PM in combination with SCR or combined techniques	50- 100 (new) 50 - 150 (existing) (split view industry: new plants: 50-200; existing plants: 50-400)
New CCGT without supplementary firing	Dry low-NOx premix burners or SCR	20-50
Existing CCGT without supplementary firing	Dry low-NOx premix burners or water and steam injection or SCR if required space	20-90 (split view industry existing plants: 80-120)
New CCGT with supplementary firing	Dry low-NOx premix burners and low-NOx burners for the boiler part or SCR or SNCR	20-50
Existing CCGT with supplementary firing	Dry low-NOx premix burners or water and steam injection and low-NOx burners for the boiler part or SCR if required space in the HRSG or SNCR	20-90 (split view industry existing plants: 80-140)
Industrial boiler; fuel: gas	Low NOx burners or SCR or SNCR	50 - 100 (3% O_2) (industry split view: 50-120)
Existing Gas-Turbines		
Fuel: natural gas	Water and steam injection or SCR	50-90 (industry split view: 80-120)
Fuel: diesel oil or process gas	Water and steam injection or SCR	
New Gas-Turbines		
Fuel: natural gas	Dry low-NO_x premix burner or SCR	20-50
Fuel: diesel oil or process gas	Wet controls SCR	
[1] The BAT associated emission levels are based on a daily average, standard conditions and represents a typical load situation. For peak load, start up and shut down periods, as well as for operational problems of the flue gas cleaning systems, short-term peak values, which could be higher, have to be regarded. If not stated otherwise, values are daily averages assuming an oxygen content by volume in the waste gas of 3 % in the case of liquid and gaseous fuels, 6 % in the case of solid fuels and 15 % in the case of gas turbines.		

7.3.3.3 Dust

Dust is emitted from the combustion process, especially from the use of heavy fuel oil and coal. The proven technologies for dust removal in power plants are fabric filters and electrostatic precipitators (ESPs) [6]

Electrostatic precipitators (ESPs) are the dust emissions control technology, which is most widely used in coal-fired power generating facilities [5]. They remove particles from a flowing gas using electrical forces. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the centre of the flow lane [7].

These control devices remove dust, including particulate matter less than or equal to 10 and 2.5 micrometers and hazardous air pollutants that are in particulate form, such as most metal oxides [7].

Electrostatic precipitators are used in both solid and liquid fired combustion plants and are available for small and large-scale combustion plants [1].

Fabric filters (Baghouses), are widely used worldwide for removing particles. A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle-laden gas passes up along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere [8]. This control devices remove dust, including particulate matter less than or equal to 10 and 2.5 micrometers and hazardous air pollutants that are in particulate form, such as most metal oxides [9]. The choice between ESP and fabric filtration generally depends on coal type, plant size, and boiler type and configuration [5].

Wet scrubbers, are air pollution control devices that remove dust and acid gases from waste gas streams of stationary point sources provided that the PM level is already within the right range to guarantee safe operation of the scrubber (if not another PM control technology is required upstream the FGD). The low capital cost of wet scrubbers compared to that for ESPs and baghouses makes them potentially attractive for industrial scale use, though this may be offset by a relatively high pressure drop and operating costs [3]. The pollutants are removed primarily through the absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers, which remove both acid gas and dust.

BAT for the removal of dust

Combustion of coal and lignite

For dust removal of off-gases from coal- and lignite-fired new and existing combustion plants, BAT is the use of an ESP or a FF, where a FF normally achieves emission below 5 mg/m^3. Cyclone and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage. BAT associated emission levels for dust are lower for combustion plants over 100 MWth, especially over 300MWth because the wet FGD techniques which are already a part of the BAT conclusion for desulphurization also reduce dust [10].

Combustion of biomass and peat

For dust removal from off-gases from biomass- and peat-fired new and existing combustion plants, BAT is the use of FF or an ESP. When using low sulphur fuels such as biomass, the potential for reduction performance of ESPs is reduced with low flue-gas sulphur dioxide concentrations. In this context, the FF, which leads to dust emissions around 5 mg/Nm^3, is the preferred technical option to reduce dust emissions. Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage [10].

Combustion of liquid fuels

For dust removal from off-gases from new and existing liquid fuel-fired combustion plants, BAT is the use of an ESP or a FF. Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage. BAT associated emission levels for dust are lower for combustion plants over 300 MWth because the FGD technique that is part of the BAT conclusion for desulphurisation also reduces dust [10].

Table 3 Emission sources and selected BAT dust control measures with associated emission levels in combustion installation (PM is for primary measures)

Emission source	Combination of control measures	Dust emission level associated with BAT[1] (mg/Nm^3) [3]
boilers 50 - 100 MW$_{th}$		
Boiler; Fuel: coal and lignite	ESP or FF	< 5 - 20 (new) (split view industry: new plants: 10-50) 5-30 (existing) (split view industry: existing plants: 20-

		100)
Circulating FBC, Fuel: coal, lignite	ESP or FF	
Boiler; Fuel: biomass and peat Circulating FBC; Bubbling FBC Fuel: biomass and peat	ESP or FF	< 5 - 20 (new) 5 - 30 (existing)
Boiler, Fuel: oil	ESP or FF	< 5 - 20 (new) 5 - 30 (existing) (split view industry: new and existing plants: 10-50 ESP)
Boilers 100 – 300 MW_{th}		
Boiler; Fuel: coal and lignite	ESP or FF in combination with FGD	< 5–20 (new) 5-25 (existing) (split view industry: new plants: 10-30; existing plants: 10-100 ESP/FF; 10-50 in combination with wet FGD)
Circulating FBC, Fuel: coal, lignite	ESP or FF	< 5–20 (new) 5-25 (existing) (split view: new plants: 10-30; existing plants: 10-100 ESP/FF; 10-50 in combination with wet FGD)
Boiler; Fuel: biomass and peat Circulating FBC; Bubbling FBC; Fuel: biomass and peat	ESP or FF	< 5 - 20 (new) 5 - 20 (existing)
Boiler, Fuel: oil	ESP or FF in combination with FGD	< 5 - 20 (new) 5 - 25 (existing) (split view industry: new plants: 5-30, existing plants: 5-50)
Boilers >300 MW_{th}		
Boiler; Fuel: coal and lignite	ESP or FF in combination with FGD	< 5 - 10 (new) 10 –20 (existing) (split view industry: new plants: 10-30, existing plants: 10-100; 10-50 comb. wet FGD)
Circulating FBC; Fuel: coal, lignite	ESP or FF	< 5 –20 (new) 5-20 (existing) (split view industry: new plants: 10-30, existing plants: 10-100; 10-50 comb. wet FGD)
Boiler; Fuel: biomass and peat Circulating FBC; Bubbling FBC Fuel: biomass and peat	ESP or FF	< 5 - 20 (new) 5 - 20 (existing)
Boiler; Fuel: oil	ESP or FF in combination with FGD	< 5 - 10 (new) 5 - 20 (existing) (split view industry: new plants: 5-30, existing plants: 5-50)

[1] The BAT associated emission levels are based on a daily average, standard conditions and represents a typical load situation. For peak load, start up and shut down periods, as well as for operational problems of the flue gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

If not stated otherwise, values are daily averages assuming an oxygen content by volume in the waste gas of 3 % in the case of liquid and gaseous fuels, 6 % in the case of solid fuels.

7.3.4 Cost data for emission reduction techniques

7.3.4.1 Cost data for NOx emission reductions

Table 4 Indicative costs of NO_x emissions abatement techniques for boiler plants (1999 Euros, Environment Agency)

Control options	**Typically achievable emission reduction**	**Process capacity (MWel)**	**Indicative capital cost € /kWel**	**Indicative operating cost€ /kWh**
SCR[1]	80-90%	Various	30-70 [2]	11-14 €/kW_{el}/a [2]
SNCR	30-50%	Various	14	0.0011
Reburning	50-75%	Various	42	0.0011
Flue gas recirculation	15-45%	Various	14	0.00014
Low NO_x Burner	30-50%	Various	14	0

[1] It should be noted that the design of SCR is highly site-specific and this makes definition of capital cost difficult

[2] J. Theloke, B. Calaminus, F. Dünnebeil, R. Friedrich, H. Helms, A. Kuhn, U. Lambrecht, D. Nicklaß, T. Pregger, S. Reis, S. Wenzel (2007): Maßnahmen zur Einhaltung der Emissionshöchstmengen der NEC Richtlinie, Umweltbundesamt, Texte 36/07, 498 pp. (cost data on p. 162)

7.3.4.2 Cost data for SOx emission reductions

Table 5 shows the indicative costs ranges for the sulphur abatement technologies described above. However, when applying these technologies to individual cases, it should be noted that investment costs of emission reduction measures will depend among other things on the particular technologies used, the required control systems, the plant size, the extent of the required reduction and the timescale of planned maintenance cycles. Operation and maintenance costs for SO_2 scrubbers for boiler plants increase with increasing sulphur content since more reagent is required to treat the same volume of gas [11].*Table 5 Indicative costs of SO_2 emissions abatement techniques for boiler plants (2001 Euros, EPA).*

Control option	**Process capacity MW_{th}**	**Capital cost € /kW**	**O&M Cost €/kW**	**Annual Cost** €/kW	**Cost per ton of Pollutant Removed** €/ton
Wet scrubber	>400	104 - 262	2 - 8	21 -52	210 -523
Wet scrubber	<400	262 - 1572	8- 21	52 - 210	523 - 5230
Dry Scrubber	>200	41- 157	4- 11	21 - 52	157 - 314
Dry Scrubber	<200	157 - 1572	11 - 314	52 - 523	523 - 4190

7.3.4.3 Cost data for dust emission reductions

Table 6 Indicative costs of dust emissions abatement techniques for boiler plants (1999 Euros, Environment Agency)

Control options	**Typically achievable emission reduction**	**Process capacity**	**Indicative capital cost** €/kW	**Indicative Operating cost** €/kWh
ESP	Reduction to below 25 mg/m3	various	35	0.00042
Fabric filters	Reduction to below 25 mg/m3	various	14	0.0015

7.3.5 References used in chapter 7.3

[1] Technical background documents for the actualisation and assessment of UN/ECE protocols related to the abatement of the Transboundary Transport of nitrogen oxides from stationary sources, DFIU, 1999

[2] Environment Agency, 2002: V2. 03 27.07.05, IPPC Sector Guidance Note Combustion Activities

[3] European Commission. 2006: Integrated Pollution Prevention and Control (IPPC) Reference Document on Best Available Techniques for Large Combustion Plants

[4] Multipollutant emission control technology options for coal fired power plants, US EPA 20005.

[5] http://www.iea-coal.org.uk/site/ieacoal/home

[6] IFC 2007. International Finance Corporation (World Bank Group): Environmental, Health, and Safety Guidelines for Thermal Power Plants

[7] US Environmental Protection Agency (US EPA). EPA-452/F-03-028, Air Pollution Control Technology Fact Sheet- Dry Electrostatic Precipitator (ESP)-Wire-Plate Type

[8] US Environmental Protection Agency (US EPA). EPA-452/B-02-001, Section 6, Chapter 2, Wet Scrubbers for Particulate Matter

[9] US Environmental Protection Agency (US EPA). EPA-452/F-03-026.025.024, Air Pollution Control Technology Fact Sheet-Fabric Filters

[10] UNECE 2006. Draft background document: Assessment of technological developments: Best Available Techniques (BAT) and limit values. Submitted to the Task Force on Heavy Metals of UNECE CLTRAP

[11] US Environmental Protection Agency (US EPA). EPA-452/F-03-034, Air Pollution Control Technology Fact Sheet-Flue Gas Desulphurization-Wet, Spray Dry, and Dry Scrubber