BEST AVAILABLE TECHNIQUES GUIDANCE DOCUMENT ON POWER GENERATION

FOREWORD

Best Available Techniques Economically Achievable (BAT) document had been prepared as a guidance notes for the nine (9) major industries in Malaysia and to support the implementation of the new Environmental Quality (Clean Air) Regulations 20xx. These documents were prepared based on the latest state-of-the-art technologies, internationally accepted limit values but had been adjusted and tailored to local requirements.

BAT is defined as the effective methods in preventing pollution and, where generally that is not practicable, to reduce emissions from industrial activities and their impact on the environment. This definition implies that BAT not only covers the technology used but also the way in which the installation is operated, to ensure a high level of environmental protection. Implementations of BAT in any specific industrial sectors are under economically and technically viable condition.

It is hope that the technical contents of these documents will prove beneficial to the industries in their endeavour to comply with the environmental regulations and standards through more cost-efficient means. In the identification of BAT, emphasis is placed on pollution prevention techniques rather than end-of-pipe treatment. These documents will be reviewed and updated from time to time.

These documents have been prepared in consultations with the University of Malaya Consultancy Unit (UPUM), Malaysia German Technical Cooperation (GTZ) and the relevant industries/stakeholders. The Department of Environment wishes to record appreciation to representatives of the relevant industrial sectors, government agencies and individuals for their invaluable input.

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LIST OF ABBREVIATIONS

BAT	-	Best Available Techniques
BFBC	-	Bubbling Fluidised Bed Combustion
BREF	-	Best Available Technique Reference Document
CAR	-	Clean Air Regulation
CCGT	-	Combined Cycle Generation
Cd	-	Cadmium
CFBC	-	Circulating Fluidised Bed Combustion
CO	-	Carbon Monoxide
DOE	-	Department of Environment
ESP	-	Electrostatic Precipitators
FBC	-	Fluidised Bed Combustion
FGD	-	Flue Gas Desulphurization
HCl	-	Hydrogen Chloride
HF	-	Hydrogen Flouride
HRSG	-	Heat Recovery Steam Generation
IPPC	-	Integrated Pollution Prevention Control
kg/h	-	kilogram per hour
mg/Nm^3	-	milligram per cubic metre at standard temperature (273K) and pressure (1atm)
N_2O	-	Nitrous Oxide
NMVOCs	-	Non Methane Volatile Organic Compounds
NO_x	-	Nitrogen Oxide
SO_x	-	Sulphur Oxide
TOC	-	Total Organic Compound
VOCs	-	Volatile Organic Compounds

1.0 PREFACE

1.1 Status of This Document

This document forms a part of a series presenting the guidance notes for selected industries in Malaysia (list given at the end of this preface) to apply best available techniques economically achievable (BAT), associated monitoring and developments in them. This series is published by the Department of Environment (DOE) in accordance to the Environmental Quality (Clean Air) Regulations 2014 (CAR 2014).

1.1 Definition of BAT

In order for the user of this document to understand the legal context of this document, the interpretation on the definition of BAT is taken from Regulation 2 – Interpretation of CAR 2014 and described as below:

“Best Available Techniques Economically Achievable” means the effective methods in preventing pollution and, where that is not practicable, generally to reduce emissions in the air from the industrial activities and their impact on the environment as a whole. In this regard:

“Techniques” includes both the technology used and the way in which the facility is designed, built, maintained, operated and decommissioned;

“Available Techniques” means those techniques that are accessible to the occupier and that are developed on a scale that allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages; and

“Best” means effective in achieving a high general level of protection of the environment as a whole;

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this document that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels “associated with best available techniques” are presented, this is to be understood to mean those levels representing the environmental performance that could be expected as a result of the application, of the techniques described, taking into account the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such.

In some cases it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of “levels associated with BAT” described above is to be distinguished from the term “achievable level” used elsewhere in this document. Where a level is described as “achievable” using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

The actual cost of applying a technique will depend strongly on the specific situation such as taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific economic viability of techniques drawn from observations on existing installations.

The purpose of CAR 2014 is to achieve prevention and control of pollution arising from activities listed in its First Schedule and Second Schedule. More specifically, it provides for a notification system for certain categories of industrial installations to conduct an integrated and comprehensive view of the pollution and consumption potential of their installation. The overall aim is to ensure a high level of protection of the environment as a whole based on appropriate preventative measures through the application of BAT.

1.2 Objective of This Document

The ‘emission minimization principle’ as cited in CAR 2014 requires that the goal of emission abatement is to achieve minimum emissions as a result of applying current BAT. Hence this guideline document is meant to provide the reference information for the permitting authorities to take into account when determining permit conditions. This document should serve as valuable input to achieve better environmental performance.

1.3 Information Sources

The information is mainly based on the European IPPC BREF document where the assessment was achieved through an iterative process involving the following steps:

- identification of the key environmental issues for the sector
- examination of the techniques most relevant to address those key issues;
- identification of the best environmental performance levels, on the basis of the available data world-wide;
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in Implementation of these techniques;

- selection of the BAT and the associate emission and/or consumption levels for this sector

1.5 How to Use This Document

It is intended that the general BAT in this document could be used to judge the current performance of an existing installation or to judge a proposal for a new installation and thereby assist in the determination of appropriate BAT based conditions for that installation. It is foreseen that new installations could be designed to perform at or even better than the general BAT levels presented here. It is also considered that many existing installations could reasonably be expected, over time, to move towards the general "BAT" levels or perform better. This reference document does not set legally binding standards, but they are meant to give information for the guidance of industry, the relevant government bodies and the public on achievable emission and consumption levels when using specified techniques.

The structure of the guideline document is as follows:

An overview of each particular sector in the Malaysian context is firstly covered briefly followed by process description, process optimization, sources of pollution, emission control options, recommended practices and emission values and finally emission monitoring and reporting. More often than not, trade-off judgements between different types of environmental impacts and specific site condition are the influencing factors.

Another important point to note is that BAT change over time and this guidance document needs to be reviewed and updated as appropriate.

2.0 OVERVIEW OF POWER GENERATION IN MALAYSIA

The three main electricity utilities in Malaysia are: Tenaga Nasional Berhad (TNB) which operates in Peninsular Malaysia, Sabah Elctricity Sendirian Berhad (SESB) in Sabah, and Sarawak Electricity Supply Corporation (SESCO) in Sarawak. In addition independent power producers (IPPs) contribute significantly to the supply of electricity in the country. The total installed generation capacity in the country at the end of 2011 was 28433 MW with a plant mix of 51.58% gas turbine and combined cycle, 27.01% coal, 10.60% hydro, 5.28% diesel, 2.85 % oil/gas thermal and the remaining others such as biomass and co-generation. In the year 2011, the total electricity generated was 127069 GWh with a generation mix of gas (43.86%), coal (41.18%), hydro (6.34%) and the rest diesel and biomass. (Source: *Electricity Supply Industry in Malaysia – Performance and Statistical Information, Energy Commission, 2011 Edition*).

The installed capacities of power plants in Malaysia and electricity generation according to fuel type are given in **Table 1.**

Table 1: Installed Capacity and Power Generation in Malaysia According to Fuel Type

Fuel type	Installed capacity		Energy generation	
	MW	%	GWh	%
Gas	14665.74	51.58	55732.46	43.86
Coal	7679.75	27.01	52327.01	41.18
Diesel	1501.26	5.28	5108.17	4.02
Oil	810.34	2.85	4294.93	3.38
Hydro	3013.90	10.60	8056.18	6.34
Biomass	739.26	2.60	1537.54	1.21
Others	19.90	0.07	38.12	0.03
Total	28433	100.0	127069	100.0

Source: *Electricity Supply Industry in Malaysia – Performance and Statistical Information, Energy Commission, 2011 Edition*

The Small Renewable Energy Programme (SREP) which was launched in year 2001 to encourage private sector to undertake small power generation project using renewable resources has not been progressing well due to number of factors such as uncertainty in long term fuel supply and challenges in securing loans for financing projects.

Table 2: Status of Approved SREP

Type of renewable energy	Number of approved applications	Capacity MW
Biomass	21	204 MW
Biogas	9	20.85 MW
Minihydro	13	61.3 MW
Wind and solar	0	0
Total	**43**	**286.15MW**

Source*: Energy Commission, March 2010*

3.0 PROCESS DESCRIPTION

In the fuel electric power generation, the thermal energy is transformed to electrical energy. There are six main processes:

3.1 Steam Boiler Turbine Power Plants

Heat for the system is provided by the combustion of coal, biomass, natural gas or oil. The fuel is pumped into the boiler's furnace. The boiler generates steam in the pressurized vessel in small boilers or in the water-wall tube system in modern utility and industrial boilers. High temperature, high-pressure steam generated in the boiler is fed to a turbine as shown schematically in **Figure 1**. At the outlet of the steam turbine there is a condenser, which is kept at low temperature and pressure. Steam rushing from the high-pressure boiler to the low-pressure condenser drives the turbine blades, which power the electric generator. There are three types of boilers commonly used: natural circulation, forced circulation, and once-through boilers.

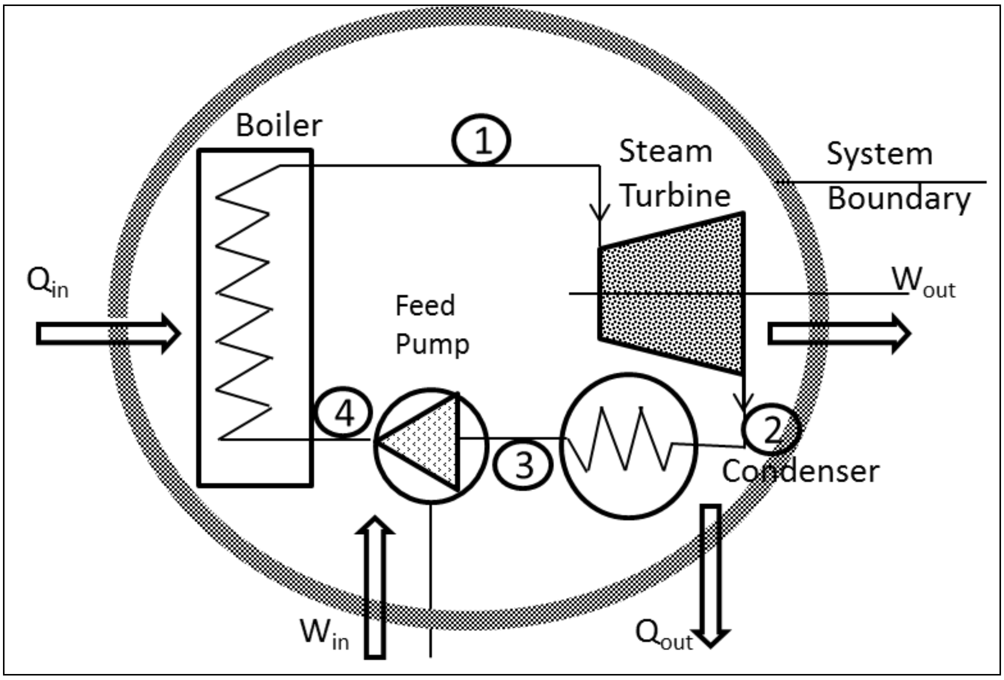

Figure 1: Schematic Diagram of Steam Turbine Power Plant

3.2 Fluidised Bed Combustion (FBC)

Fluidised bed combustion is mainly used for industrial applications where different solid fuels such as coal, lignite, peat, and particularly biomass are burned. There are two main types of FBC boilers:

Bubbling fluidised-bed combustion (BFBC) is a modern combustion technology especially suited for burning inhomogeneous biofuels: BFBC consists of a 0.5-1.0 m high bed on a fluidizing air distribution plate. The fluidising velocity is about 1 m/s. The density of the bubbling bed is about 1000 kg/m^3. Typical bed materials used are sand, ash, fuel, dolomite, limestone etc. The particle size distribution in the fluidising bed material is typically within 0.5-1.5 mm.

Circulating fluidized bed combustion (CFBC) in which a part of the bed material is carried out from the bed and transit through the furnace to the second pass of the boiler. The particles exiting the furnace are separated from the flue gas flow by a cyclone or by other separation methods and recirculated back to the fluidized bed. The separation can be done in the middle of the second pass and also at the outlet of the boiler. Electrostatic precipitators and fabric filters can be used as an emission control device for this process. As a rule of thumb, the bed material particle size is in the range of 0.1-0.6 mm, and fluidizing velocity is 4-6 m/s.

3.3 Internal Combustion Generation

Internal combustion generation units, also known as diesel engines, have one or more cylinders in which fuel combustion occurs. Internal combustion generating units convert the chemical energy of fuels into mechanical energy in a design similar to that of an automobile engine. The engine is attached to the shaft of the generator to produce electricity. Internal combustion generators are small and medium, ranging from 2 MW to greater than 50 MW capacities.

Mitigation measures given below can be considered to reduce pollution emitted from the process.

* **Catalytic converter** – typically a stainless steel box mounted in the exhaust system fitted with an autocatalyst (a ceramic or metallic substrate with an active coating incorporating alumina, ceria and other oxides and combinations of the precious metals - platinum, palladium and rhodium).

* **Diesel particulate trap filter (soot trap)** – consist of a filter material positioned in the exhaust designed to collect solid and liquid particulate matter emissions.

3.4 Open Cycle Gas Turbine Generation (OCGT)

Gas turbine systems operate in a manner similar to steam turbine systems except that combustion gases are used to turn the turbine blades instead of steam. In addition to the electric generator, the turbine also drives a rotating compressor to pressurize the combustion air, which is then mixed with either gas or liquid fuel in a combustion chamber. Unlike a steam turbine system, gas turbine systems do not have boilers and condensers. A schematic diagram of gas turbine generation system is given in **Figure 2**.

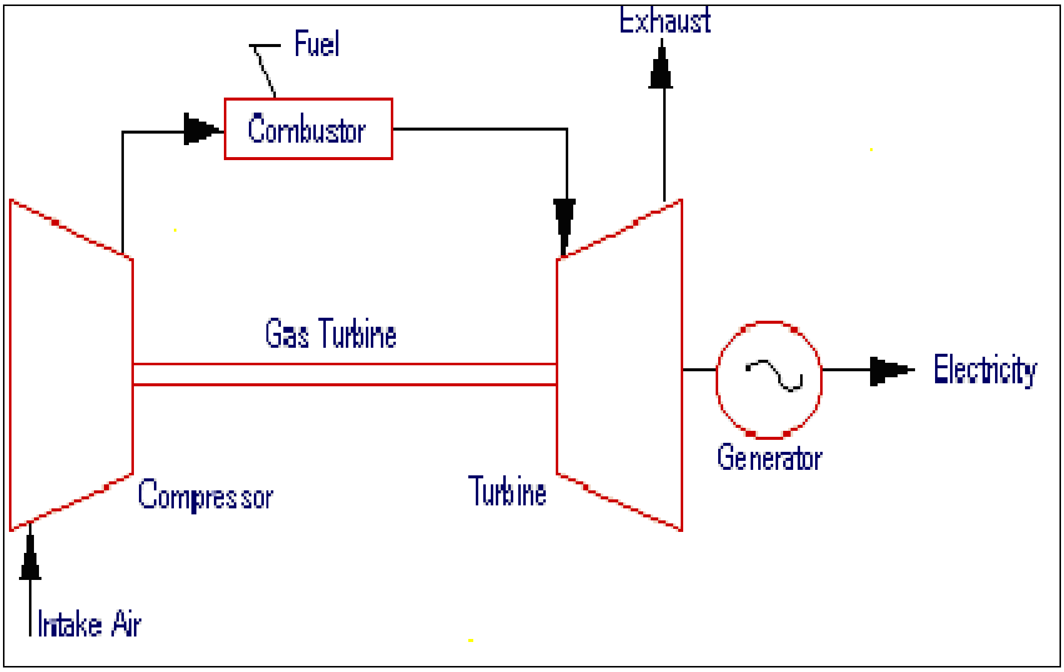

Figure 2: Schematic Diagram of a Open Cycle Gas Turbine

3.5 Combined-Cycle Gas Turbine (CCGT)

Combined-cycle generation is a configuration using both gas turbines and steam generators as shown in **Figure 3**. In a CCGT, the hot gases of a gas turbine are used to provide all, or a portion of, the heat source for the boiler, which produces steam for the steam generator turbine. This combination increases the thermal efficiency over that of a coal- or oil- fuelled steam generator.

There are four main configurations:

- *Gas Turbine plus Heat Recovery Steam Generator (HRSG):* The hot off-gases from the gas turbine are used to generate steam in a heat recovery steam generator downstream of the gas turbine.
- *Gas Turbine plus Supplementary-Fired Steam Generator:* A portion of the oxygen in the gas turbine exhaust is used to support further combustion in a supplementary firing system in the connecting duct between the gas turbine and the steam generator.

- *Gas Turbine plus Furnace-Fired Steam Generator:* this generator is the same as the gas turbine plus supplementary-fired steam generator, except that essentially all of the oxygen from the gas turbine exhaust is used to support further combustion.

- *Supercharged Furnace-Fired Steam Generator plus Gas Turbine:* A steam generator is placed between the air compressor and the gas turbine. The air compressor is used to pressurize the boiler where the fuel is fired. The products of combustion that have been cooled within the boiler are then discharged through a gas turbine.

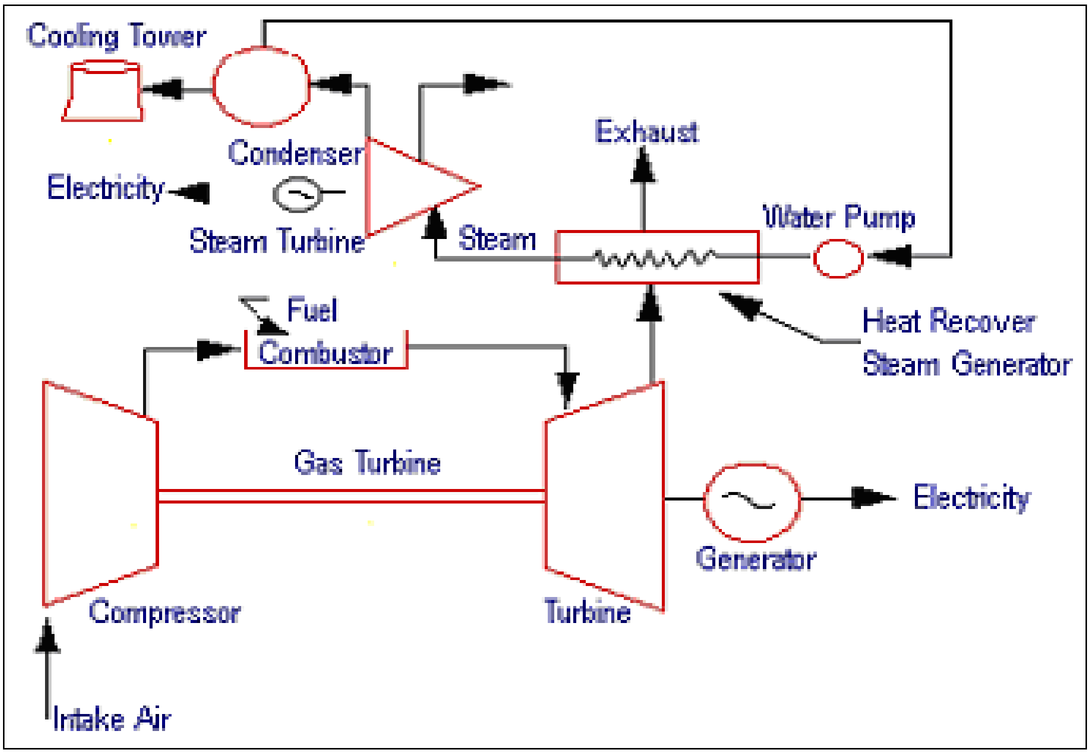

Figure 3: Schematic Diagram of a Combined Cycle Gas Turbine

3.6 Cogeneration

Cogeneration is a merging of a system designed to produce electric power and a system used for producing industrial heat and steam. A schematic diagram is given in **Figure 4**. This system is a more efficient way of using energy inputs and allows the recovery of otherwise wasted thermal energy for use in an industrial process. Cogeneration technologies are classified as “topping cycle” and “bottoming cycle” systems, depending on whether electrical (topping cycle) or thermal (bottoming cycle) energy is derived first.

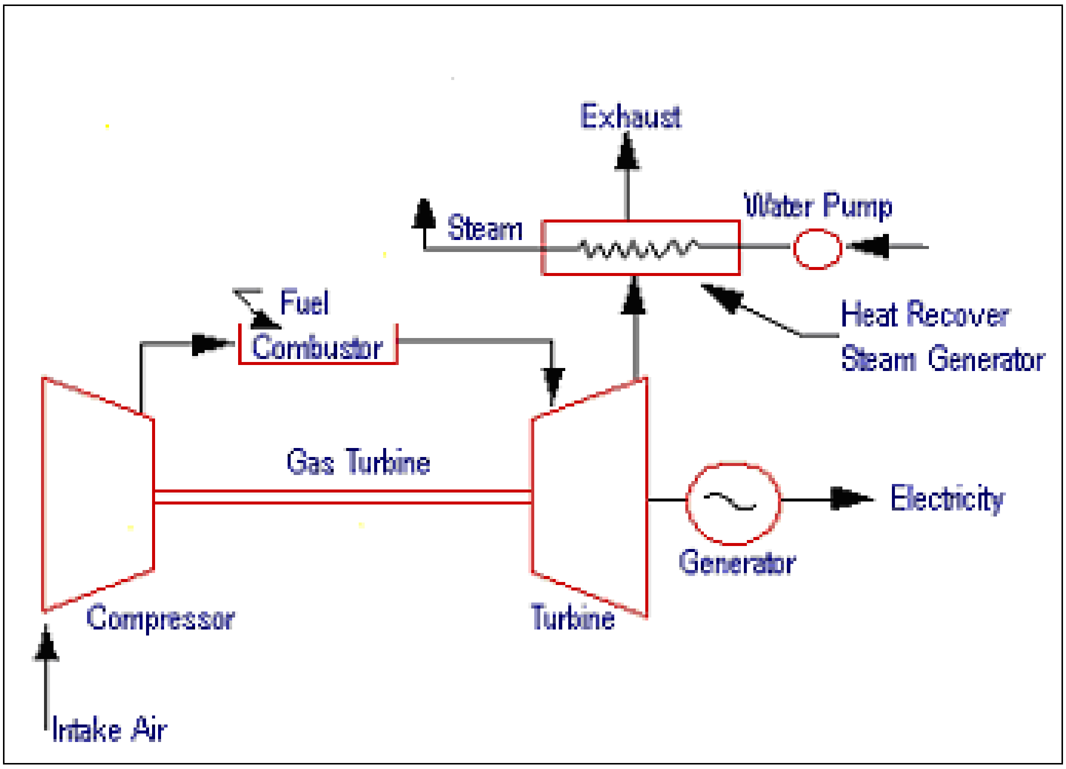

Figure 4: A Schematic Diagram of a Cogeneration System

4.0 PROCESS OPTIMIZATION

To increase the efficiency of electricity and heat generation, the first option is to replace or further optimize the main process items such as turbines, pumps and pollution control systems. Further measures to increase conventional power plant efficiency include lowering the condenser pressure, optimize the feed-water preheat system, utilization of waste heat and the use of supercritical steam cycle conditions.

The use of advanced computerized control system in order to achieve a high boiler efficiency with improve combustion conditions that support the reduction of emissions are considered as BAT.

5.0 SOURCES OF AIR POLLUTANT EMISSIONS

The major air pollutants released from the combustion of fossil fuels and biomass are SO_2, NO_x, particulate matter including emissions of particulate matter of aerodynamic diameters less than 10µm, called PM_{10}. Other substances such as heavy metals, HF, HCl, unburned hydrocarbons, non-methane volatile organic compounds (NMVOCs) and dioxins are emitted in smaller quantities.

5.1 Sulphur Oxides (SO_x)

Emissions of SO_x result mainly from the presence of organic and inorganic sulphur in the fuel. During combustion, by far the majority of sulphur oxides are produced in the form of sulphur dioxide SO_2. For solid and liquid fuels, 1 to 3 % of the sulphur is oxidized to sulphur trioxide (SO_3). This reaction is catalysed by transition metals. Biomass fuels are characterized by lower sulphur content than coal.

5.2 Nitrogen Oxides (NO_x)

The principal oxides of nitrogen emitted during combustion of fossil fuels are nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The first two of these form the mixture known as NO_x, which accounts for more than 90 % of the NO in the main types of large combustion installations.

The formation of NO_x is governed by three essential mechanisms:

- thermal NO_x results from the reaction between the oxygen and nitrogen from air (high a combustion temperature more than 1000 °C)
- fuel NO_x is formed from the nitrogen contained in the fuel (high contribution when combustion temperature less than 1000 °C).
- prompt NO_x is formed by the conversion of molecular nitrogen in the flame front in the presence of intermediate hydrocarbon compounds (low contribution to NO_x).

The formation mechanism of N_2O is not well understood. A possible mechanism is based on the formation of intermediate products (HCN, NH_3), which is comparable to the formation of NO. It has been found that lower combustion temperatures (below 1000 °C), cause higher N_2O emissions.

5.3 Dust and Particulate Matter

The dust emitted during the burning of coal, peat, and biomass arises almost from the mineral fraction of the fuel. A small proportion of the dust may consist of very small particles formed by the condensation of compounds volatilized during combustion.

The combustion of liquid fuels is also a source of particulate emissions, although to a lesser extent than coal. In particular, poor combustion conditions lead to the formation of soot, which is liable to produce acid agglomerates with corrosive properties in the presence of sulphur trioxide.

For many installations, there are also potential diffuse emissions (open-air handling and storage of coal, the crushing of the coal used in pulverized coal boilers, the handling of ash etc.)

5.4 Heavy Metals

The emission of heavy metals results from their presence as natural components in fossil fuels. Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Only Hg and Se are at least partly present in the vapour phase.

5.5 Carbon Monoxide

Carbon monoxide (CO) always appears as an intermediate product of the combustion process, particularly under incomplete combustion conditions.

5.6 Hydrochloric Acid

The emission of hydrochloric acid (HCl) is due to trace amounts of chloride present in fossil fuels such as coal and oil. Emission of HCl is significant in combustion plants without flue-gas desulphurization (FGD).

5.7 Hydrogen Fluoride

When using fossil fuels such as coal without FGD, fluoride is liberated and released to the flue gas. It combines with hydrogen to form hydrogen flouride, and with the moisture of the ambient air to form hydrofluoric acid. It has been observed that hydrogen flouride may be emitted by carry-over from the rotating heat-exchanger and combustion air preheater.

5.8 Ammonia (NH_3)

The emission of ammonia (NH_3) does not result from the combustion of fossil fuels, but rather the consequence of an incomplete reaction of ammonia in the denitrification process.

5.9 Volatile Organic Compounds (VOC)

Among the persistent organic compounds to be emitted during the combustion of fossil fuels are the polycyclic aromatic hydrocarbons (PAHs), the polychlorodibenzo-dioxins (PCDDs) and the polychlorodibenzo-furans (PCDFs).

6.0 EMISSION CONTROL OPTIONS

The reduction of emissions from large combustion plants should consider using both measures:

6.1 Primary measures: Integrated measures to reduce emissions at source or during combustion such as fuel switching (from solid to liquid or gas, liquid to gas), use of fuels with lower sulphur or nitrogen content, combustion modifications such as the use of additives to reduce emissions, capacity derating, burner modification, air and fuel modification (flue gas recycling, fuel air premix, fuel mixing, drying, finer grinding, gasification, pyrolysis). Possible measures to apply for combustion modification are given in **Table 3**.

6.2 Secondary measures: Control technologies used to reduce emissions before being released to air. They are pollutant specific measures that are described in the subsequent paragraph. A general schematic diagram for controlling emission as shown in **Figure 5**.

Table 3: Primary Measures for Emission Control

Combustion modification	Capacity derating	Air and fuel modification	Burner modification	In-furnace combustion modification
Solid fuels, PM control	Lower volume flow and higher oxygen surplus reduces temperature and slagging	Pre-drying gasification, pyrolysis of fuel, fuel additives. i.e low melting additives for slag tap furnace with liquid ash removal (tested for pressurized coal combustion for gas turbines)	Liquid ash removal, cyclone burner in slag tap furnace	Liquid ash removal, slag tap furnace; circulating fluidized bed combustion, coarse ash control.
Solid fuels, SO_2 control	Reduced temperature reduces sulphur volatilisation	Sorbent fuel additives, i.e lime and limestone for fluidized bed combustion	Burner with separate additive injection	Over fire air injection of absorbents, i.e limestone
Solid fuels, NO_x control (reduction of NO_x production)	Reduced temperature	Mixing and finer grinding of fuels, flue gas recycling reduces NO_x production	Low NO_x burners	Staged combustion and reburning
Liquid fuel, PM control	Reduced temperature reduces slagging	Gasification, pyrolysis of fuel, additives for low soot combustion	-	Optimised combustion

Combustion modification	**Capacity derating**	**Air and fuel modification**	**Burner modification**	**In-furnace combustion modification**
Liquid fuel, SO_2 control	-	Additive for absorption	-	-
Liquid fuel, NO_x control (reduction of NO_x production)	Reduced temperature	Flue-gas recycling	Low NOx burners	Staged combustion*, reburning water and steam injection.**
Gaseous fuel, PM control				Optimised combustion
Gaseous fuel, SO_2 control				
Gaseous fuel, NOx control (reduction of NOx production)	Reduced temperature	Flue gas recycling fuel air premixing**	Low NOx burner	Staged combustion* reburning, water and steam injection**

Notes:
* not applicable to gas turbines
** only practiced for gas turbines

6.2.1 Techniques to Reduce Particulate Emissions:

Different technologies such as electrostatic precipitators (ESP), fabric filters, and wet scrubbers are commonly used to remove particulate matter from the flue gas. The currently used particulate matter control devices are given in **Figure 5.**

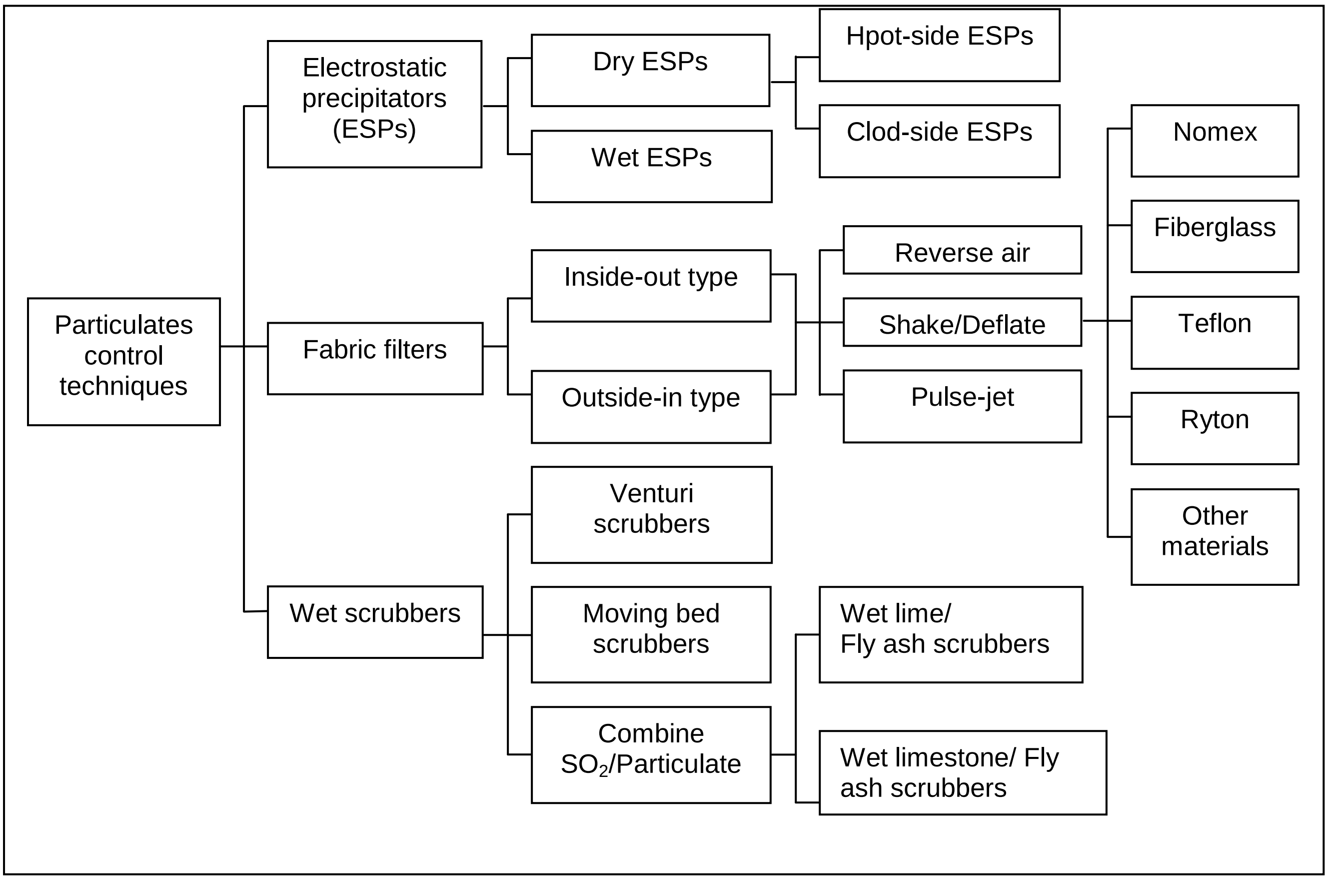

Figure 5: Overview of the Currently Used Particulate Matter Control Devices

ESPs with fixed/rigid electrodes are the most important technology currently used. Cold-side ESPs are located after the air preheater and operate over the temperature range of 130-180 °C. Hot-side ESPs are located before the air preheater and operate over the temperature range of 300-450 °C. Fabric filters which operate over the temperature range of 120-220 °C are becoming increasingly important. The choice between applying an ESP or fabric filtration generally depends on the fuel type, plant size, boiler type and the configuration. Both technologies are highly efficient devices. Wet scrubbers for dust control are used far less than ESPs and fabric filters. They are characterized by lower removal efficiencies, especially of fine particles, compared to ESPs and fabric filters.

Table 4 gives the performance of particulate matter cleaning devices.

Table 4: General Performance of Particulate Matter Cleaning Devices

Technology	**Removal efficiency % [35, ERM 1996]**				**Other performance parameters**		**Remarks**
	<1 µm	**2 µm**	**5 µm**	**>10 µm**	**Parameter**	**Value**	
Electrostatic precipitator (ESP)	>96.5	>98.3	>99.95	>99.95	Operating temperature	120 - 220 °C (cold ESP) 300 – 450 °C (hot ESP)	• the ESP has a very high efficiency, even for smaller particles • can handle very large gas volume with low pressure drop • low operating costs, except at very high removal rates • can operate at any positive pressure condition • the ESP is not very flexible, once installed, to changes in operating conditions • it might not work on particulates with very high electrical resistivity.
Fabric filter	>99.6	>99.6	>99.9	>99.95	Operating temperature	200 °C (polyester) 280 °C (fiberglass)	• filtration velocities generally lie in the range 0.01 to 0.04 m/s according to the application, the filter type and the cloth • typical values being used in power plant bag houses are 0.45 – 0.6 m/min for reverse-air, 0.75 -0.9m/min for shaker, and 0.9 -1.2m/min for pulse-jet applications • bag life decreases as coal sulphur content increases and as the filtering velocity increases • Individual bags fail at an average annual rate of about 1% of installed bags • the pressure drop increase as the particle size decreases for a given flue-gas throughput.
					Energy consumption	0.4 – 0.7 (kWh/1000m^3)	
					Pressure drop	5 -20 (10^2 Pa)	
					Residue	Fly ash	
					Off-gas flow rate	<1100000 m^3/h	
					Applicability	Solid and liquid fuels	

Cyclone	85 – 90 %. The smallest diameter of the dust trapped is 5 to 10 µm						• Limited performance, can therefore only be used with other techniques for dust control
Wet scrubber (high energy venturi)	98.5	99.5	99.9	>99.9	Operating temperature		• as a secondary effect, wet scrubbers contribute to the removal and absorption of gaseous heavy metals • waste water is produced, which needs treatment and further discharge.
					Energy consumption as % of electric capacity	Up to 3% (5-15 (kWh/1000m^3))	
					Liquid to gas ratio	0.8 – 2.01/m^3	
					Pressure drop	30 – 200(10^2 Pa)	
					Residue	Fly ash sludge/ slurry	

6.2.2 Techniques to Reduce Sulphur Oxide Emissions

Sulphure oxides are emitted from most fossil fuel combustion through oxidation of the sulphur contained in the fuel.

6.2.2.1 Primary Measures to Reduce Sulphur Oxide Emissions

Primary measures to reduce SOx emissions include the use of low sulphur content fuels and use of adsorbents in fluidized bed combustion. The adsorbents utilized are CaO, $Ca(OH)_2$ or $CaCO_3$ with a stoichiometric ratio (fuel/adsorbent) ranging from 1.5 to 7 depending on the fuel.

6.2.2.2 Secondary Measures to Reduce Sulphur Oxide Emissions

The common flue-gas desulphurization (FGD) technologies are given in **Figure 6**.

Wet scrubbers, especially the limestone-gypsum processes, are the leading FGD technologies (80 % of the market share) due to their high SO_2 removal efficiency and their high reliability. Limestone is used in most cases as the sorbents. Other sorbent used include sodium and magnesium which as used in small industrial boilers.

The performance of flue gas desulphurization techniques are given in **Tables 5a-5e**.

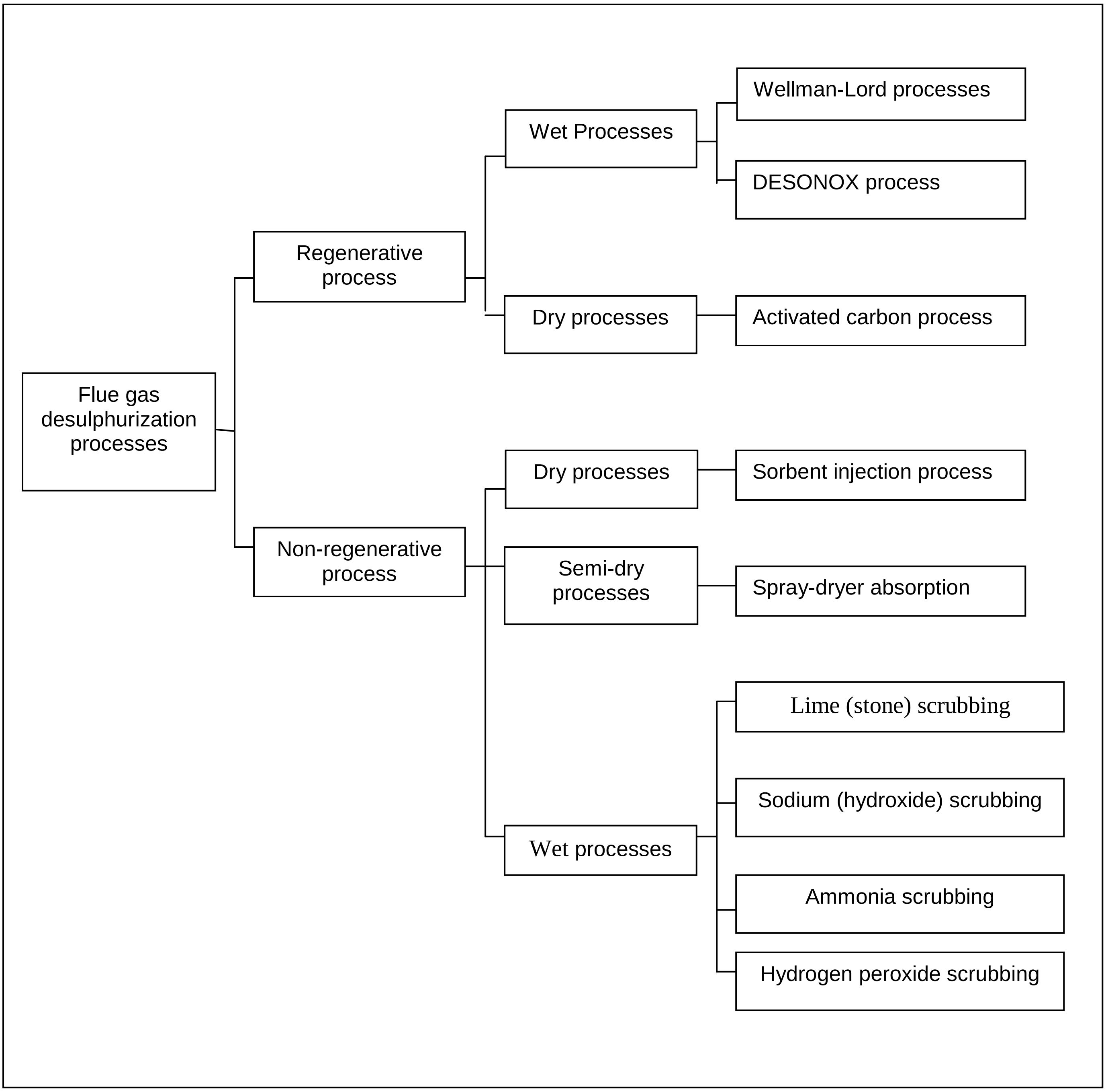

Figure 6: Overview of Technologies Used to Reduce Sulphur Oxide Emissions

Table 5a: General Performance of the Wet Lime/Limestone Scrubber for Reducing Sulphur Oxide Emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	**Value**	
Wet lime/ limestone scrubber	92 - 98 % (depending on the absorber type)	Operating temperature	45 - 80 °C	• of the total installed FGD capacity, 80% are wet scrubbers of which 72% use limestone as the reagent, 16 % use lime and 12 % use other reagents • the selection of limestone (high calcium carbonate content, low Al, F and Cl content) is an important issue to assure a good SO_2 removal rate • sometimes organic buffers are used to maintain the pH-value of the scrubbing solution • the energy loss due to the reheating of the flue gas is large compared to dry FGD systems and combined SO_2/NO_x removal systems, which do not generally require flue-gas reheating • the problem associated with the rotating gas-gas heat –exchanger operating at about 150°C is inherent internal flue gas leakage, with from 3-5 % of the raw flue gas going directly to the stack without reducing the SO_2 content • several plants use wet FGD systems with cooling tower discharge of cleaned flue-gas eliminate the need for costly reheating, save the reheating energy and result in significantly lower ground level concentrations of emissions • the production of waste water is a disadvantage of the wet limestone scrubber • high water consumption • loss in the overall plant efficiency because of the high energy consumption (in average, a suspension pump consumes about 1 MW)
		Sorbent	Limestone lime	
		Energy consumption as % of electrical capacity		
		Pressure drop	20 - 30 (10^2 Pa)	
		Ca/S molar ratio	1.02 - 1.1	
		Reliability	95 -99 % (of operating time)	
		Residue/by-product	Gypsum	
		Gypsum purity	90 - 95 %	
		Residence time	10 sec	
		Lifetime of rubber lining	>10 years (hard coal)	
		SO_3 removal rate	<70%	
		HCl removal rate	95 - 99 %	
		HF removal rate	95 - 99 % in the absorber	
		Particulate	>50 % depending on the particle size	

Table 5b: General Performance of Seawater Scrubbing for Reducing Sulphur Oxide Emissions.

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Seawater scrubbing	85 - 98 %	Operating temperature (example)	145 °C (flue gas inlet) 88 °C (flue gas outlet)	• seawater must be available • by applying a seawater scrubbing process to a combustion plant, the local conditions such as seawater conditions, tidal flows, the marine (aquatic) environment close to the scrubber water outlet, etc. needs to be carefully examined in order to avoid negative environmental and ecology effects. Effects may arise from the reduction of the pH level in the general vicinity of the power plants as well as from the input of remaining metals (heavy metals sometimes called trace elements) and fly ash. This is especially applicable to plants situated in an estuary • the applicability of the seawater scrubbing is very high as the process is simple and does not require slurry handling • the operating cost are low compared with a wet FGD system • the flue gas needs first to be dedusted • applicable only for high sulphur fuel
		Sorbent	Seawater/air	
		Residence time of seawater in aerator:	15 min	
		Max. flue-gas flow per absorber (example)	250000 m^3/h	
		Reliability	98 - 99 %	
		Residue/by-product	None	
		Energy consumption as % of electric capacity	.08 - 1.6 %	
		HCL removal rate	95 - 99 %	
		HF removal rate	95 - 99 % in the absorber	
		Water consumption (example)	15000 m^3/h	
		Waste water	None (but sulphate ions dissolved in seawater)	
		Pressure drop	1000 - 1100 Pa	

Table 5c: General Performance of the Spray Dry Scrubber for Reducing Sulphur Oxide Emissions

Technique	**General SO_2 reduction rate**	**Other performance parameters**		**Remarks**
		Parameter	**Value**	
Spray dry scrubber	85 - 92 %	Operating temperature	120 - 160 ^{o}C (flue gas inlet) 65 - 80 ^{o}C (flue gas outlet)	• it should be note that SO_3 is removed more effectively in spray dry scrubbers than in wet scrubbers • the tank slaker allows slaking of 2-11 mm pebble lime • use of tower mills for slaking can increase the reactivity of the slaked lime • as spray dry scrubbers can remove more SO_3 than wet scrubbers, there is likely to be less of a problem of H_2SO_4 in the environment close to the plant than with wet scrubbers • as power consumption in NO_x and particulate control devices usually amount to less than 0.1% the overall power consumption for pollution control is usually below 1.0% in a plant adopting the spray dry scrubbers which require a power consumption of 1.0% -1.5 % • the four to five times higher cost of the lime sorbent used in spray dry scrubbers in relation to limestone for the dominant wet scrubbers in relation to limestone for the dominant wet scrubbers is probably the greatest disadvantage of spray dry scrubbers • investigation showed that about 90% of the mercury present in the vapour phase upstream of the scrubbers is removed • spray dry absorption processes are currently operated at hard coal-fired combustion units. However, the process has proved to be applicable to other fossil fuels such as oil, lignite or peat in pilot studies • with sulphur contents exceeding 3 % the removal efficiency decreases slightly • the spray dry scrubber efficiency very much depends on the dedusting device used (e.g. Fabric filter or ESP), because desulphurization occurs to a certain extent, for instance, in the filter-cake of the fabric filter.
		Sorbent	Lime, calcium oxide	
		Residence time	10 sec	
		Ca/S molar time	1.1 - 2.0	
		Max. flue gas flow per absorber	500000 m^3	
		Removal range of SO_3 and HCL	95%	
		Recirculation rate of used sorbent	10 - 15	
		Solid content in injected liquid	20 - 50%	
		Reliability	97 - 99%	
		Residue/by-product	Mixture of fly ash, unreacted additive and $CaSO_3$	
		Energy consumption as % of electric capacity	0.5 - 3 %	
		Water consumption	20 - 40 1/1000 m^3 flue gas	
		Waste water	None	
		Pressure drop of the spray drier without the dedusting device	(100 Pa)	

Table 5d: General Performance of Different Sorbent Injection Techniques for Reducing Sulphur Oxide Emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Furnace sorbent injection	40 - 50 % 70 - 90% by recycling the reaction product	Operating temperature	980 ^{o}C -1230 ^{o}C (upper furnace) 540 ^{o}C (economizer)	• the efficiency of SO_2 control is primarily a function of the Ca/S molar ratio, the sorbent type, the degree of humidification, the additives available, the injection point and the boiler load. • to increase the SO_2 removal efficiency, water can be sprayed into the duct before the precipitator. This results in an improvement of the SO_2 removal efficiency of about 10 %. • problem of fouling, slagging and flame stability in the boiler • furnace sorbent injection can increase the amount of unburned carbon-in-ash
		Sorbent	Limestone, hydrated lime, dolomite	
		Reliability	99.9%	
		Boiler efficiency drop	2 %	
		Energy consumption as % of electric capacity	0.01 - 0.5 %	
		Residue	Ca salt mixture	
Duct sorbent injection (dry FGD)	50 - 90% (>90 % achieved at a power plant in the US)	Operating temperature	^{o}C	• low capital costs and extremely simple installation • easy to retrofit (small space and short construction period) • no waste water • ash handling is more difficult because the ash is enriched with non-reacted lime, which causes the ash to harden after wetting • the tendency for duct wall deposits is increased.
		Sorbent	Limestone, hydrated lime, dolomite	
		Reliability	99.9 %	
		Energy consumption as % of electric capacity	0.5 %	
		Residue	Ca salt mixture	
Hybrid sorbent injection	50 - 90% (90% by reactivation of the unreacted CaO by humidification)	Residence time	3 sec	• used in some plant in the US
CFB dry scrubber	90 - 95 %	Residence time	3 sec	• the CFB vessel is designed with an internal gas velocity range of 1.8 m/s to 6 m/s for boiler loads from 30% to 100 % • has only been applied a few times.

Table 5e: General Performance of Regenerative Techniques for Reducing Sulphur Oxide Emissions

Technique	**General SO_2 reduction rate**	**Other performance parameters**		**Remarks**
		Parameter	**Value**	
Sodium sulphite bisulphate process	95 - 98 %	Operating temperature in the absorber	55 – 90 °C	• the sodium sulphite bisulphate process is actually not applied anymore in Europe • as the process uses a solution to absorb SO_2, high efficiency contacting devices such as valve trays or packed beds can be used without scaling problems • in some cases, for example, where a power station is near, or in, a city centre, transport of a large amount of materials (limestone and gypsum) into and out of the power station may well create a nuisance due to noise and traffic movements. In contrast, for the sodium sulphite bisulphate process, there are less traffic movements for caustic soda and sulphur • the sodium sulphite bisulphate process requires high capital cost, and a high demand both in number and qualification of the operating staff and a high power consumption.
		Max S content in the fuel	3.5 %	
		Max. flue gas flow	600000 m^3/h	
		Solid content in injected liquid	20 - 50 %	
		Energy consumption as % of electric capacity	3 - 5.8 %	
		Water consumption	70 - 200 m^3/h (only pre-scrubber)	
		Reliability	> 95%	
Magnesium oxide process	n.a	Energy consumption as % of electric capacity	n.a	
		By product	Elemental sulphur, sulphuric acid or concentrated sulphur oxide	
		Reliability	n.a.	
Notes: n.a = not available				

6.2.3 Techniques to Reduce Nitrogen Oxide Emissions

6.2.3.1 Primary Measures to Reduce NO_x Emissions

There is a wide variety of primary emission reduction measures for nitrogen oxide formation. In these techniques the operational and design parameters of combustion installations are modified in order to minimize the formation of nitrogen oxide or to convert the formed nitrogen oxide inside the boiler prior to their release. An overview of the primary measures for reducing nitrogen oxide emissions are given in **Figure 7**. The performances of such measures are given in **Table 6**.

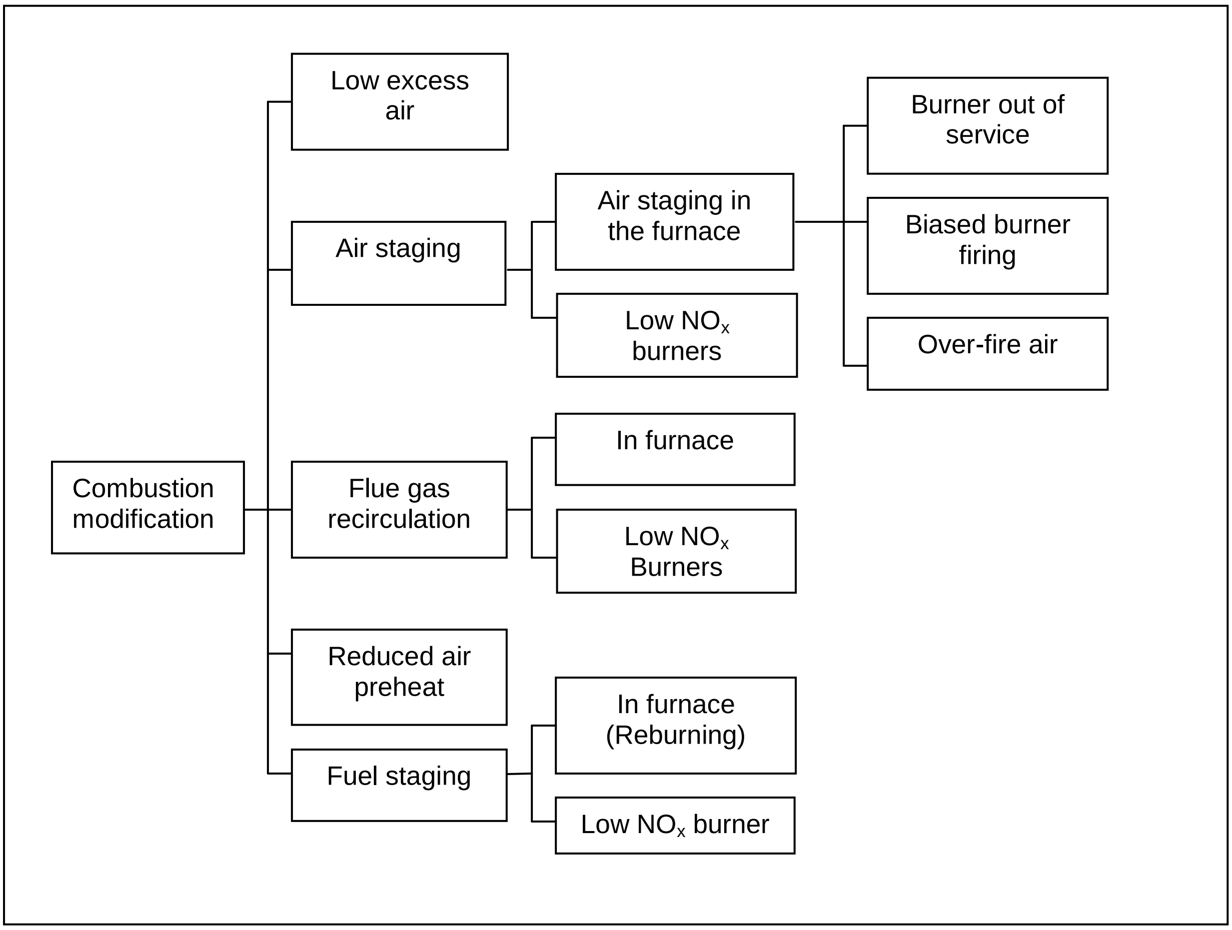

Figure 7: Overview of Primary Measures for Reducing Nitrogen Oxide Emissions

Table 6: General Performance of Primary Measures for Reducing NO_x Emissions

Primary measure		General NOx reduction rate*	General applicability	Applicability limitations	Remarks
Low excess air		10 - 44 %	All fuels	• incomplete burnout	• for NO_x reduction, it might be necessary to seal the furnace, the mills and the air preheater in order to allow application of low excess air firing
Air staging in the furnace	**Burner out of service (BOOS)**	10 - 65 % Maximum abatement levels for tangential-fired boilers of 40 % for coal, 45% for oil and 65 % for gas may be achieved [32, Rentz, 1999]	Generally restricted to gas and oil fired plants for retrofit only	Incomplete burn-out (and thus high CO and carbon levels)	• problems may arise maintaining the fuels input, because the same amount of thermal energy has to be supplied to the furnace with fewer operating burners.
	Biased burner firing (BBF)		All fuels for retrofit only		
	Overfire air (OFA)		All fuels		• retrofitting overfire air on an existing boiler involves water-wall tube modifications to create the ports for the secondary air • NO_x reduction of 10 % to 40 % is possible for wall-fired furnaces using OFA.
Flue-gas recirculation		20 - 50 % <20% for coal-fired boilers and from 30 - 50% for gas-fired plants combined with overfire air [33, [CIEMAT]	All fuels	• flame instability	• retrofitting an existing boiler with flue-gas recirculation presents some adaptation difficulties, mostly due to efficiency losses of both the boiler and the burners, except when recirculating very small amounts of flue gas. • this NO_x abatement measure can be used for retrofitting when combined with air staging • recirculation due to recirculation fan.
Reduced air preheating		20 - 30 %	Not suitable for coal-firing wet bottom boilers		• the amount of emission reduction achievable mainly depends on the initial air preheating temperature and on the temperature that is achieved after this measure has been implemented.

*Notes:

- if different primary measures to reduce nitrogen oxide emissions are combined the reduction rate can, in general, neither be added nor be multiplied. The combined reduction rate depends on a number of site-specific factors and needs to be validated on a plant-by-plant basis
- not all of the primary measures can be applied to all existing boilers, depending on the combustion configuration and the fuel
- new plants are already fitted with primary measures as part of their basic design.

Primary measure		**General NO_x reduction rate***	**General applicability**	**Applicability limitations**	**Remarks**
Fuel staging (Reburning)		50 - 60 % (70 - 80% of the NO_x formed in the primary combustion zone can be reduced)	all fuels		• reburning offers some advantages, such as compatibility with other primary NO_x emission reductions measures, simple installation of the technique, use of a standard fuel as reducing agent, and very small amounts of additional energy. The additional energy consumption by reburning coal over coal can be higher than using natural gas as a reburning fuel • combustion downstream of the primary zone also produces nitrogen oxides • when using natural gas as the reburning fuel, particulate matter, SO_2 and CO_2 are also reduced in direct proportion to the amount of coal replaced.
Low NO_x burner (LNB)	**Air-staged LNB**	25 - 35 %	all fuels	• flame instability • incomplete burn-out	• low NO_x burners can be used in combination with other primary measures such as overfire air and reburning of flue gas recirculation • low NO_x burners with overfire air can achieve reduction rates of 30-70% [33,Ciemat, 2000] • a drawback of first generation low-NOx burners is the space requirement of the flame separation: the diameter of low-NOx flames is about 30 to 50% larger than for conventional flames.
	Flue gas recirculation LNB	Up to 20 %	all fuels	• flame instability	
	Fuel-staged LNB	50 - 60 %	all fuels	• flame instability • incomplete burn-out	

* Notes:

- when combining different primary measures to reduce nitrogen oxide emissions the reduction rate can in general neither be added nor be multiplied. The combined reduction rate depends on a number of side specific factors and needs to be validated on a plants-by-plant basis
- not all of the primary measure can be applied to all existing boilers, their application depends on the combustion configuration and the fuel
- new plants are already fitted with primary measures as part of their basic design.

6.2.3.2 Secondary Measures to Reduce NO_x Emissions

These are end-of-pipe techniques to reduce nitrogen oxide (NO_x) already formed. Most of the techniques use the injection of ammonia, urea or other compounds, which reduce NO_x in the flue gas to molecular nitrogen. The reduction can be catalytic (selective catalytic reduction, SCR) or non-catalytic (Selective non-catalytic reduction, SNCR). The performances of these techniques are given in **Table 7**.

6.2.4 Combined Techniques to Reduce SO_2 and NO_x Emissions

Combined techniques for the simultaneous removal of SO_2 and NO_x are not widely used due commercial reasons. They can be classified as:

- solid adsorption/regeneration
- gas/solid catalytic operation
- electron beam irradiation
- alkali injection
- wet scrubbing

The performances of these techniques are given in **Table 8**.

Table 7: General Performance of Secondary Measures for Reducing No$_x$ Emissions

Secondary measure	General NO$_x$ reduction rate	Other performance parameters		Remarks
		Parameter	**Value**	
Selective catalytic reduction (SCR)	80 - 95 %	Operating temperature	320 - 420 ^{o}C (high-dust) 260 - 320 ^{o}C (tail-end)	• the ammonia slip increases with increasing NH_3/NO_x ratio, which may cause problems, e.g. with a too-high ammonia content in the fly ash. This is a problem which can be solved by using a larger catalyst volume and/or by improving the mixing of NH_3 and NO_x in the flue-gas • incomplete reaction of NH_3 with NO_x may result in the formation of ammonium sulphates, which are deposited on downstream facilities such as the catalyst and air preheater, increased amounts of NH_3 in flue gas desulphurization waste waters, the air heater cleaning water, and increased NH_3 concentration in the fly ash • catalyst lifetime is 4 -5 years for coal combustion, 7-10 years for oil combustion, and more than 10 years for gas combustion.
		Reducing agent	Ammonia, urea	
		NH_3/NO_x ratio	0.8 - 1.0	
		NH_3-slip	<20 mg Nm^{3}	
		Availability	>98 %	
		SO_2/SO_3 - conversion rate with catalyst	1.0 -1.5 % (tail gas)	
		Energy consumption as % of electric capacity	0.5 % (high-dust) 2 % (tail gas)	
		Pressure drop at the catalyst	4 -10 (10^{2} Pa)	
Selective non – catalytic reduction (SNCR)	30 - 50 (80) %	Operating temperature	850 - 1050 ^{0}C	• though some manufacturers report a NO_x reduction level of over 80 %, the common view is that SNCR processes are in general capable of 30 -50 % reduction as an average covering different operational conditions. Further NO_x reductions can be obtained on specific boilers where the conditions are good, as well as lower values where the conditions are bad, sometimes on existing plants [33, Ciemat. 2000] • SNCR cannot be used on gas turbines because of the residence time and temperature window required
		Reducing agent	Ammonia, urea	
		NH_3/NO_x ratio	1.5 - 2.5	
		Availability	> 97 %	
		Energy consumption as % of electric capacity	0.1 - 0.3 %	
		Residence time within temperature range	0.2 -0.5 sec	

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Table 8: General Performance of Different Sorbent Injection Techniques For Reducing SO_2 and NO_x

Technique	General SO_2/NO_x reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Activated Carbon Process	98-%/60 – 80%	Operating temperature	90 -150 %	• the activated carbon process also has a considerable potential for removing SO_3 and air-toxic substances such as mercury and dioxins • waste water is only produced in small amounts from the operation of the prescrubber • several commercial systems have been installed, mainly in Germany and Japan • the process is capable of cleaning flue gases from different fuel types such as coal and oil.
		Reagent	Activated carbon/ ammonia	
		Reliability	98 %	
		Other substances removed	HCI , HF, dioxin	
		Energy consumption as % of electric capacity	1.2 – 3.3 %	
		By-products	Elemental sulphur, or sulphuric acid	
NOXSO process	97 %/70 % (anticipated)	Reagent	Alumina beads impregnated with sodium carbonate	• the NOXSO process is in the demonstration stage and is scheduled to be tested in a 108 MW_e cyclone in the US under US DOE CCT -3 programme [33, Ciemat,2000]
		Energy consumption as % of electric capacity	4 %	
WSA-SNOX process	95 %/95 %	Reagent	Ammonia	• very low particulate emissions (below 5 mg/m^3)
		Energy consumption as % of electric capacity	0.2 %	
DESONOX process	95 %/95 %	Reagent	Ammonia	• waste water is generated by the use of a wet ESP for the removal of sulphuric acid area aerosols • in theory, liquid SO_2 sulphuric acid and elemental sulphur are possible to produce but plants commissioned to date have only produced sulphuric acid.
		Reliability	96 -98 %	
		Energy consumption as % of electric capacity	2.0 %	

7.0 RECOMMENDED PRACTICES AND EMISSION VALUES

7.1 Combustion of Solid Fuels

7.1.1 Unloading, Storage and Handling of Fuel and Additives

The BAT for preventing releases from the unloading, storage and handling of coal, and lignite and additives are given in **Table 9**.

7.1.2 Fuel Pretreatment

Blending and mixing of fuel to ensure stable combustion conditions and reduce peak emissions are considered as BAT. Switching from one type of coal to another with lower sulphur content can also be regarded as BAT.

Table 9: BAT for the Unloading, Storage and handling of Coal, Lignite, and Additives

Material	Pollutant	BAT
Coal and lignite	Dust	• the use of loading and unloading equipment that minimizes the height of coal drop to the stockpile, to reduce the generation of fugitive dust • using water spray systems to reduce the formation of fugitive dust from coal stockpiles • grassing over long-term storage areas of coal to prevent fugitive emissions of dust and fuel loss caused by oxidation in contact with the oxygen in the air • applying the direct transfer of lignite via belt conveyors from the mine to the on-site lignite storage area • placing transfer conveyors in safe, open areas above ground so that damage from vehicles and other equipment can be prevented • using cleaning devices for conveyor belts to minimize the generation of fugitive dust • using enclosed conveyors with well designed, robust extraction and filtration equipment on conveyor transfer points to prevent the emission of dust • rationalizing transport systems to minimize the generation and transport of dust within the site • the use of good design and construction practices and adequate maintenance.

	Fire prevention	• surveying storage areas for coal and lignite with automatic systems, to detect fires, caused by self-ignition and to identify risk points.
Lime and limestone	Dust	• having enclosed conveyors, pneumatic transfer systems and silos with well designed, robust extraction and filtration equipment on delivery and conveyor transfer points to prevent the emission of dust.

7.1.3 Combustion

For the combustion of coal and lignite, pulverized combustion (PC), fluidized bed combustion (CFBC and BFBC) as well as pressurized fluidized bed combustion (PFBC) are considered to be BAT.

For PC tangential- and cyclone-fired boilers are preferred, because NO_x and CO emissions are lower than in wall-fired boilers. Firing systems that assure a high boiler efficiency and which include primary measures to reduce the generation of NO_x emissions, such as air and fuel staging, advanced low NO_x burners etc. are considered as BAT.

7.1.4 Thermal Efficiency

The cogeneration of heat and power (CHP) is one the technically and economically most efficient means to increase the energy efficiency of an energy supply system.

The level of the thermal efficiency associated with the application of the BAT measures are given in **Table 10**.

Table 10: Levels of Thermal Efficiency Associated with the Application of the BAT Measures

Fuel	Comb. Tech.	Unit thermal efficiency (net) (%)	
		New plants	Retrofitted plants
Coal and lignite	Cogeneration (CHP)	75-90	75-90
Coal	PC (DBB and WBB)	43-47	The achievable improvement of the thermal efficiency depends on the specific plants, but as an indication a level of 36 – 40 % can be seen as associated with the use of BAT
	FBC	>41	
	PFBC	>42	
Lignite	PC (DBB)	42 – 45	
	FBC	>40	
	PFBC	>42	

7.1.5 Particulate Matter

The BAT for particulate matter removal is the use of electrostatic precipitator (ESP) or fabric filter.

Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue gas path.

The BAT associated emission levels are given in **Table 11**. These values are based on daily average, standard conditions and an O_2 level of 6 %.

Table 11: BAT for Dedusting Off – Gasses From Coal-Fired Combustion Plants

Capacity (MW_{th})	Dust-emission level (mg/Nm^3)		BAT to reach these levels	Monitoring	Applicability	Comments
	New plant	Retrofitted plants				
50 -100	10 - 20	10 - 20	ESP or FF	Continuous	New and existing plants	• the reduction rate associated with the use of an ESP is considered to be 99.5 % or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher.
100 -300	5 - 15	5 - 15	ESP or FF in combination FGD (wet, sd or dsi)	Continuous	New and existing plants	
>300	5 - 10	5 - 10	ESP or FF in combination with FGD (wet)	Continuous	New and existing plants	• the reduction rate associated with the use of an ESP is considered to be 99.5% or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95% or higher • a wet scrubber used for desulphurization also reduces dust.

Notes :
ESP (Electrostatic precipitator) **FF** (Fabric filter) **FGD (wet)** (Wet flue gas desulphurization)
FGD (sds) (Flue-gas desulphurization by using a spray dryer)
FGD (dsi) (Flue-gas desulphurization by dry sorbent injection)
For very high dust concentration in the raw gas, which might be the case when low calorific lignite is used as a fuel, the reduction rate of 99.95 % for the ESP or 99.99% for fabric filters is considered to be the BAT associated level, rather than the dust concentration levels mentioned in this table.

7.1.6 Heavy Metals

The BAT to reduce the emissions of heavy metals from the flue gases of coal- and lignite-fired combustion plants is to use a high performance ESP (reduction rate > 99.95 %) or a fabric filter (reduction rate > 99.99 %).

For the reduction of Hg emissions, the best levels of control are generally obtained by emission control systems that use FFs. An Hg emission level of less than 0.03 mg/Nm^3 is considered to be BAT.

7.1.7 SO_2 Emissions

The BAT for desulphurization and the associated emission levels are given in **Table 12**. The emission levels are based on a daily average, standard conditions and an O_2 level of 6 %.

7.1.8 NO_x Emissions

The BAT for the control of NO_x emissions and the associated emission levels are given in **Table 13.** The emission levels are based on a daily average, standard conditions and an O_2 level of 6 %.

7.1.9 Carbon Monoxide

BAT for the control of CO emissions is complete combustion, which can be achieved by good furnace design, the use high performance monitoring and process control techniques, and maintenance of the combustion system. A well-optimised system to reduce emissions of NO_x will also keep the CO level down.

CO level should not exceed 30 mg/Nm^3 for pulverized combustion and 100 mg/Nm^3 for fluidized bed combustion. For lignite-fired combustion plants the CO levels should be in the range of 100-200 mg/Nm^3.

Table 12: BAT for the Prevention and Control of Sulphur Dioxide from Coal- And Lignite-Fired Combustion Plants

Capacity (MW_{th})	Combustion technique	SO_2 emission level associated with BAT (mg/Nm^3)		BAT options to reach these levels	Applicability	Monitoring
		New plant	Retrofitted plants			
50 -100	PC	200-300	200-300	Low sulphur fuel and FGD (dsi) or FGD (sds)	New and retrofitted plants	Continuous
	CFBC and PFBC	150-300	200-300	Limestone injection	New and retrofitted plants	Continuous
	BFBC	150-300	200-300	Low sulphur fuel and FGD (dsi), FGD (sds)	New and retrofitted plants	Continuous
100-300	PC	100-200	100-250	FGD (wet) FGD (sds) FGD (dsi, up to about 200 MW_{th}), Seawater scrubbing Combined techniques for the reduction of NOx and SO_2	New and retrofitted plants	Continuous
	CFBC and PFBC	100-200	150-250	Limestone injection	New and retrofitted plants	Continuous
	BFBC	100-200	150-250	FGD (wet) FGD (sds)	New and retrofitted plants	Continuous
>300	PC	20 - 100	50 -150	FGD (wet) FGD (sds) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and retrofitted plants	Continuous
	CFBC and PFBC	100 - 200	100-200	Limestone injection	New and retrofitted plants	Continuous
	BFBC	20 - 100	50 -150	FGD (wet)	New and retrofitted plants	Continuous

Notes :
PC (Pulverised combustion)
BFBC (Bubbling fluidized bed combustion)
CFBC (Circulating fluidized bed combustion)
PFBC (Pressurized fluidized bed combustion)
FGD (wet) (wet flue gas desulphurization)
FGD (sds) (Flue gas desulphurization by using a spray drier)
FGD(dsi) (Flue gas desulphurization by dry sorbent injection)

Table 13: BAT for Nitrogen Oxide Prevention and Control in Coal- And Lignite-Fired Combustion Plants

Capacity ($MW_{th)}$)	Combustion technique	NO$_x$ emission level associated with BAT (mg/Nm^3)		Fuel	BAT options reach these levels	Applicability	Monitoring
		New plants	Retrofitted plants				
50 -100	PC	200-300 (N_2O:2-10)	200-300 (N_2):2-10)	Coal and Lignite	Combination of Pm (such as air and fuel staging, low NO$_x$ burner, etc), SNCR as an additional measure	New and retrofitted plants	Continuous
	BFBC,CFBC and PFBC	200 – 300 (N_2O:30 -120)	200 – 300 (N_2O:30 -120)		Combination of Pm (such as air and fuel-staging)	New and retrofitted plants	Continuous
100-300	PC	100 -200 (N_2O: 2 -10)	100 200 (N_2O: 2 -10)	Coal	Combine of Pm (such as air and fuel staging, low NO$_x$ burner, reburning, etc), in combination with SCR) or combined techniques	New and retrofitted plants	Continuous
	PC	100 -200 (N_2O: 2-10)	100 -200 (N_2O: 2 -10)	Lignite	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc)	New and retrofitted plants	Continuous
	BFBC,CFBC and PFBC	100 -200 (N_2O: 30-120)	100 -200 (N_2O: 30-120)	Coal	Combination of Pm (such as air and fuel-staging), if necessary, together with SNCR	New and retrofitted plants	Continuous
	BFBC,CFBC and PFBC	100 -200 (N_2O: 30-120)	100 -200 (N_2O: 30-120)	Coal and Lignite	Combination of Pm (such as air and fuel-staging)	New and retrofitted plants	Continuous
>300	PC	90-150 (N_2 O) :2-10)	100-200 (N_2O:2-10)	Coal	Combination of Pm(such as air and fuel-staging, low NOx burner, reburning, etc), in combination with SCR or Combined Techniques	New and retrofitted plants	Continuous
	PC	100-150 (N_2 O) :2-10)	100-200 (N_2O:2-10)	Lignite	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc)	New and retrofitted plants	Continuous
	BFBC,CFBC and PFBC	50-150 (N_2 O) :30-120	100-200 (N_2O:30-120)	Coal and Lignite	Combination of Pm (such as air and fuel-staging)	New and retrofitted plants	Continuous

Notes:

PC (Pelverised combustion) **BFBC** (Bubbling fluidized bed combustion) **CFBC** (Circulating fluidized bed combustion)

PFBC (Pressurised bed combustion) **Pm** (Primary measures …) **SCR** (Selective catalytic reduction of NO$_x$) **SNCR** (Selective non catalytic reduction of NO$_x$)

7.1.10 Hydrogen Fluoride and Hydrogen Chloride

The BAT for SO_2 emission reduction gives a high reduction rate for HF and HCl (98-99%). By using the wet scrubber or spray dryer, the associated emission level for HF and HCl is 1-5 mg/Nm^3.

In case of CFBC which uses the injection of limestone as BAT, the associated level of HCl is between 15-30 mg/Nm^3.

7.1.11 Ammonia (NH_3)

The ammonium concentration associated with the use of SNCR and SCR as BAT for NO_x reduction should be bellow 5 mg/N

7.2 Combustion of Liquid Fuels

7.2.1 Unloading, Storage and Handling of Fuel and Additives

The BAT for preventing releases from the unloading, storage and handling of liquid fuels and additives such as lime and limestone are given in **Table 14**.

Table 14: BAT for the Unloading, Storage and Handling of Liquid Fuel and Additives

Material	Pollutant	BAT (not exhaustive list)
Liquid fuel	Water contamination	• the use of liquid fuel storage system that are contained in impervious bunds that have a capacity capable of containing 75% of the maximum capacity of all tanks or at least the maximum volume of the biggest tank. Storage areas should be designed so that leaks from the upper portions of tanks and from delivery systems are intercepted and contained in the bund. Tank contents should be displayed and associated alarms used. The use of planned deliveries and automatic control systems can be applied to prevent the overfilling of storage tanks • pipelines placed in safe, open areas aboveground so that leaks can be detected quickly and damage from vehicles and other equipment can be prevented. If buried pipelines are used their course can be documented and marked and safe

		excavation systems adopted. For underground pipes, double walled type of pipes with automatic control of the spacing and special construction of piping (steel pipes, welded connections and no valves in underground section etc) are BAT • surface run-off (rainwater)that might be contaminated by any spillage of fuel from the storage and handling should be collected and treated before discharge.
Lime and limestone		• enclosed conveyors, pneumatic transfer systems and silos with well designed, robust extraction and filtration equipment on delivery and conveyor transfer points to prevent the emission of dust.

7.2.2 Fuel Pretreatment

Fuel pretreatment plants comprising diesel oil cleaning units such as centrifuge self-cleaning or electrostatic cleaning are considered as BAT. For heavy fuel oil (HFO) firing, the fuel treatment plant should comprise heaters for heating the HFO (electrical or steam coil type); de-emulsifier dosing systems, for breaking up the oil emulsion; separators (centrifugal or electrostatic type), for removing the solid impurities; and additive dosing systems, for rising the melting point of the vanadium oxidation products

7.2.3 Thermal Efficiency

The cogeneration of heat and power (CHP) is one the technically and economically most efficient means to increase the energy efficiency of an energy supply system.

For existing liquid-fuel-fired plants, a number of retrofit and repowering techniques can be applied to improve the thermal efficiency.

The uses of advanced computerized control system in order to achieve a high boiler performance with reduction of emissions are considered as BAT.

7.2.4 Particulate Matter and Heavy Metals

The BAT for particulate matter removal is the use of electrostatic precipitator (ESP) or fabric filter.

Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue gas path.

The BAT to reduce the emissions of heavy metals from the flue gases of coal- and lignite-fired combustion plants is to use a high performance ESP (reduction rate > 99.95 %) or a fabric filter (reduction rate > 99.99 %).

The BAT associated emission levels are given in **Table 15**. These values are based on daily average, standard conditions and an O_2 level of 3 %.

Table 15: BAT for Dedusting Off-Gases from Liquid Fuel Fired Combustion Plants

Capacity (MW$_{th}$)	**Dust emission level (mg/Nm^3)**		**BAT reach these levels**	**Monitoring**	**Applicability**	**Comments**
	New plants	**Retrofitted plants**				
50-100	10-20	10-20	ESP/FF	Continuous	New and existing plants	• the reduction rate associated with the use of an ESP is considered to be 99.5% or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher
100-300	5-15	5-15	ESP/FF/in combination FGD (wet) (depending on the specific plants size)	Continuous	New and existing plants	
>300	5-10	5-10	ESP/FF/in combination with FGD (wet)	Continuous		• the reduction rate associated with the use of an ESP is considered to be 99.5% or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher • a wet scrubber

						used for desulphurization also reduces dust
Notes : **ESP** (Electrostatic precipitator) **FF** (Fabric Filter) **FGD (wet)** (Wet flue gas desulphurization)						

7.2.5 SO_2 Emissions

For liquid-fuel-fired combustion plants, the use of low sulphur fuel and/or desulphurization is considered to be BAT.

The BAT is mainly the wet scrubber (reduction rate 92-98 %) and the spray dry scrubber (reduction rate 85-92%).

The BAT for desulphurization and the associated emission levels are given in **Table 16.** The emission levels are based on a daily average, standard conditions and an O_2 level of 3 %.

Table 16: BAT for the Prevention and Control Of Sulphur Dioxide from Liquid-Fuel-Fired Combustion Plants

Capacity (MW_{th})	**SO_2 emission level associated with BAT (mg/Nm^3)**		**BAT options to achieve these levels**	**Applicability**	**Monitoring**
	New plants	**Retrofitted plants**			
50-100	200-300	200-300	Low sulphur fuel oil FGD (dsi) or FGD (sds)	New and retrofitted plants	Continuous
100-300	100-200	100-250	Low sulphur fuel oil and FGD (dsi) or FGD (wet) (depending on the plant size) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and retrofitted plants	Continuous
>300	50-100	50-150	FGD (wet) FGD (sds) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and retrofitted plants	Continuous
Notes: **FGD (wet)** (Wet flue gas desulphurization) **FGD (sds)** (Flue gas desulphurization by using a spray drier) **FGD (dsi)** (Flue gas desulphurization by dry sorbent injection)					

7.2.6 NO_x Emissions

For liquid-fuel-fired combustion plants the BAT for the reduction of NO_x are combination of primary and/or secondary measures.

The BAT for the control of NO_x emissions and the associated emission levels are given in **Table 17**. The emission levels are based on a daily average, standard conditions and an O_2 level of 3 %.

Table.17: BAT for Nitrogen Oxide Prevention and Control in Liquid-Fuel-Fired Combustion Plants

Capacity (MW_{th})	NO_x emission level associated with BAT (mg/Nm^3)		BAT options to achieve these levels	Applicability	Monitoring
	New plants	Retrofitted plants			
50-100	150-250	200-300	Combination of Pm (such as air and fuel stagging, low-NO_x burner, etc.)	New and retrofitted plants	Continuous
100-300	50-150	100-200	Combination of Pm (such as air and fuel staging, low-NO_x burner, reburning, etc.) in combination with SNCR, SCR or combination techniques	New and retrofitted plants	Continuous
>300	50-100	50-150	Combination of Pm (such as air and fuel staging, low-NO_x burner, reburning, etc.) in combination with SCR or Combined techniques	New and retrofitted plants	Continuous

Pm – Primary measures

7.2.7 Carbon Monoxide

BAT for the control of CO emissions is complete combustion, which can be achieved by good furnace design, the use high performance monitoring and process control techniques, and maintenance of the combustion system. A well-optimised system to reduce emissions of NO_x will also keep the CO level between 30 and 50 mg/Nm^3.

7.2.8 Hydrogen Fluoride and Hydrogen Chloride

The BAT for SO_2 emission reduction gives a high reduction rate for HF and HCl (98-99%). By using the wet scrubber or spray dryer, the associated emission level for HF and HCl is 1-5 mg/Nm^3.

7.2.9 Ammonia (NH_3)

The ammonium concentration associated with the use of SNCR and SCR as BAT for NO_x reduction should be bellow 5 mg/Nm^3.

7.3 Liquid-Fuel-Fired (Diesel) Engines

7.3.1 Particulate Matter and Heavy Metals

BAT for the reduction of particulate emissions is the use of engine measures in combination with the use low ash and low sulphur fuel. The SCR system can also reduce the dust emission (soot particles) with an approximate reduction rate of 40 %.

The BAT associated emission levels are given in **Table 18**.

Table 18: BAT for Dedusting Off-Gases from Engines Plants by Primary Engine Measures

Engine Type	Dust-emission level (mg/Nm^3)	Monitoring	Comments
A dual fuel engine (in gas mode)	<5	Continuous	Steady state 85 to 100 % load of the engine. O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
Diesel engine	<30	Continuous	
A dual fuel engine in back-up fuel mode (diesel oil max. 0.02 wt-% ash)	<30	Continuous	

7.3.2 SO_2 Emissions

The use of low sulphur fuel is regarded as the first choice of BAT.

If low sulphur fuel is not available, the use of a secondary FGD system is the BAT for reducing SO_2 emissions.

7.3.3 NO_x Emissions

For liquid-fuel-fired combustion plants the BAT for the reduction of NO_x are combination of primary and/or secondary measures.

The BAT for the control of NO_x emissions and the associated emission levels are given in **Table 19.**

Table 19: BAT Associated NO_x Levels for Liquid-Fuel-Fired Engine Plants with SCR as BAT

Engine Type	NO_x emission level (mg/Nm^3)	Applicability	Monitoring	Comments
Diesel oil-fired engine plant	90 – 150	SCR can be applied to new plants and retrofitted to existing ones	Continuous	Miller-type engine, injection retard, water injection and/or SCR O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
A dual fuel engine in back-up mode	<150 (100% diesel oil as back-up fuel)	SCR can be applied also to dual fuel engines for the gas fuel mode and back-up mode	-	Miller-type engine, injection retard, water injection and/or SCR O -reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
Light fuel-fired engine plant	90 – 150	SCR can be applied to new plants and retrofitted to existing ones	Continuous	Miller-type engine, injection retard, water injection and/or SCR O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
Heavy fuel oil-fired engine plant	90 -150	SCR can be applied to new plants and retrofitted to existing ones	Continuous	Miller-type engine, injection retard, water injection and/or SCR O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa

7.3.4 Carbon Monoxide and Other Emissions

BAT for the control of CO emissions is the good maintenance of the engine. For spark-ignited engines, CO-catalysts can be considered as BAT.

7.4 Combustion of Gaseous Fuels

7.4.1 Supply and Handling of Gaseous Fuels

The BAT for preventing releases relating to supply of gaseous fuels are given in **Table 20.**

Table 20: BAT for the Supply and Handling of Gaseous Fuels

Material	Environmental effect	BAT
Natural gas	Fugitive emissions	• using fuel gas leak detection systems and alarms.
	Efficient use of natural resources	• using expansion turbines to recover the energy content of the pressurized fuel gases • preheating the fuel gas and the combustion air by using waste heat from the boiler or gas turbine.

7.4.2 Thermal Efficiency

The application of gas turbine combined cycles and the cogeneration of heat and power (CHP) is one the technically and economically most efficient means to increase the energy efficiency of an energy supply system. They are considered as the first BAT option.

The uses of advanced computerized control system in order to achieve a high boiler performance with reduction of emissions are considered as BAT.

Preheating the natural gas before it is fed to the burners can improve the efficiency.

Table 21 gives the efficiencies of gas-fired combustion plants associated to the use of BAT.

7.4.3 Particulate Matter and SO_2 Emissions

The emission levels of PM by using natural gas are normally bellow 5 mg/Nm^3 and SO_2 emissions are well below 10 mg/Nm^3.

If industrial gases are used in the process, pretreatment of the gas using fabric filters and desulphurization must be applied.

7.4.4 NO_x and CO Emissions

The BAT for the control of NO_x and CO emissions and the associated emission levels are given in **Table 22**. The emission levels are based on a daily average, standard conditions, and an O_2 level depending on the plant type.

Table 21: Efficiency of Gas-Fired Combustion Plants Associated to the Use of BAT

Plant type	**Electrical efficiency (%)**		**Energy efficiency (%)**	**Remarks**
	New plants	**Existing plants**	**New and Existing plants**	
Gas Turbine				
Gas turbine	38 - 40	32 - 35	**-**	
Gas engine				
Gas engine	40-45		**-**	
Gas engines with HRSG in CHP mode	>35	>35	75-90	The wide range of the energy efficiency of CHP plants is very much depends on the specific situation and the local demand of electricity and heat
Gas-fired boiler				
Gas-fired boiler	40 - 42	38 - 40		
CCGT				
Combined cycle with or without supplementary firing (HRSG) for electricity generation only	54 - 58	50 – 54	-	
Combined cycle without supplementary firing (HRSG) in CHP mode	< 38	< 35	75 – 85	The wide range of the electrical and energy efficiency of CHP plants very much depends on the specific local demand for electricity and heat. By operating the CCGT in thr CHP mode, the energy efficiency includes the amount of the electrical efficiency and should always be seen together to achieve the best overall exergetic efficiency.
Combined cycle with supplementary firing (Topping cycle) in CHP mode	< 40	<25	75 - 85	

Table 22: Reduction of NO_x And CO Emission from Gas Fired Combustion Plants

Plant type	Emission level associated with BAT (mg/Nm^3)		O_2 level (%)	BAT options to reach these levels	Monitoring
	NO_x	CO			
Gas Turbines					
New gas turbines	20-50	5-30	15	Dry low NO_x premix burners (standard equipment for new gas turbines) or SCR	Continuous
DLN retrofitted existing gas turbines	20-50	5-30	15	Dry low NO_x premix burners as retrofitting packages or SCR	Continuous
Existing gas turbines	50-75	30-50	15	Water and steam injection (only when DLN retrofitting packages are not available on the market or SCR)	Continuous
Gas engines					
Gas engines	20-50	30-50	15	Low-NO_x turned and SCR	Continuous
Gas engines with HRSG in CHP mode	20-50	30-50	15	Low-NO_x turned and SCR	Continuous
Gas-fired boilers					
New gas-fired boilers	<50	30-50	3	Low-NO_x burners	Continuous
Existing gas-fired boiler	50-80	<30	3	Low-NO_x burners	Continuous
CCGT					
New CCGT without supplementary firing (HRSG)	20-50	5-30	15	Dry low-NO_x premix burners or SCR	Continuous
Existing CCGT without supplementary firing (HRSG)	20-50 (75 for water and steam inj.)	5-30	15	Dry low-NO_x premix burners or water and steam injection or SCR	Continuous
New CCGT with supplementary firing (Topping cycle)	20-50	30-50	Plant spec.	Dry low-NO_x premix burners and low-NOx burners for the boiler part or SCR	Continuous
Existing CCGT with supplementary firing (Topping cycle)	20-50 (75 for water and steam inj)	30-50	Plant spec.	Dry low-NO_x premix burners or water and steam injection and low-NO_x burners for the boiler part or SCR	Continuous

7.5 Combustion of Biomass Fuels

7.5.1 Biomass Combustion Technologies

Table 23 shows typical thermal capacities and required fuel properties for different types of wood combustion techniques.

Table 23: Types of Biomass Furnaces with Typical Applications and Fuels

Application	Type	Typical size range	Fuels	Ash	Water content
Manual	wood stoves	2kW-10kW	dry wood logs	<2%	5%-20%
	log wood boilers	5 kW-50 kW	log wood, sticky wood residues	<2%	5%—30%
Pellets	pellet stoves and boilers	2 kW-25 kW	wood pellets	<2%	8%-10%
Automatic	understoker furnaces	20 kW-2.5 MW	wood chips, wood residues	<2%	5%—50%
	moving grate furnaces	150kW-15MW	all wood fuels and most biomass	<50%	5%-60%
	pre-oven with grate	20kW-1.5MW	dry wood (residues)	<5%	5%-35%
	understoker with rotating grate	2 MW-5 MW	wood chips, high water content	<50%	40%-65%
	cigar burner	3 MW-5 MW	straw bales	<5%	20%
	whole bale furnaces	3 MW-5 MW	whole bales	<5%	20%
	straw furnaces	100 kW-5 MW	straw bales with bale cutter	<5%	20%
	stationary fluidized bed	5MW-15MW	various biomass, $d <$ 10mm	<50%	5%-60%
	circulating fluidized bed	15MW-100MW	various biomass, $d <$ 10mm	<50%	5%-60%
	dust combustor, entrained flow	5MW-10MW	various biomass, $d < 5$ *mm*	<5%	<20%
co-firing [a]	stationary fluidized bed	total 50MW-150MW	various biomass, $d <$ 10mm	<50%	5%-60%

Application	Type	Typical size range	Fuels	Ash	Water content
	circulating fluidized bed	total 100-300 MW	various biomass, *d*< 10mm	<50%	5%-60%
	cigar burner	straw 5 MW-20 MW	straw bales	<5%	20%
	dust combustor in coal boilers	total 100MW-1 GW	various biomass, d< 2-5 mm	<5%	<20%

[a] Biomass covers typically less than 10% of the total fuel input

Source: *Draft Stockholm Guidelines*

7.5.2 Supply and Handling of Biomass Fuels

The BAT for preventing releases relating to supply of biomass fuels are given in **Table 24**

Table 24: Supply and Handling of Biomass Fuels

Material	Environmental and other effects	BAT
Biomass and peat	Fugitive dust emissions	• the use of loading and unloading equipment that minimises the height of the fuel drop to the stockpile, to reduce the generation of fugitive dust, especially when storing fine wood material and dry peat • water spray systems to reduce the formation of fugitive dust from storage areas • the moisture content of peat must be at least 40 % during transport to the plant. This eliminates fugitive dust arising from the fuel and reduces the speeding of fire, in the event of self-ignition • placing transfer conveyors in safe, open areas above ground so that damage from vehicles and other equipment can be prevented • using cleaning devices for conveyor belts to minimise the generation of fugitive dust • for dry peat and dusty biomass, enclosing conveyors with well designed, robust extraction and filtration equipment on conveyor transfer points, to prevent dust emissions • rationalising transport systems to minimise the generation and transport of dust within the site • using good design and construction practices and adequate maintenance.
	Water contamination	• having storage on sealed surfaces with drainage and drain collection,and water treatment by settling-out

		• collecting the surface run-off (rainwater) from biomass and peat storage areas that washes fuel particles away, and treating this collected stream (i.e. the settling-out portion) before discharge.
	Stable combustion	• carrying out quality checks of the delivered straw and subsequently storing the data on a central logistics computer. • ensuring that in the co-firing of several types of biomass, there are two or more storage systems so that the mixture of fed fuel can be controlled according to the quality of the fuels.
	Fire prevention	• surveying the biomass and peat storage areas, to detect fires, caused by self-ignition, and to identify risk points.

7.5.3 Fuel Pretreatment and Combustion

The BAT for biomass fuel pretreatment and combustion are given in **Table 25.**

Table 25: BAT for Biomass Fuel Pretreatment and Combustion

Activity	Effects	BAT
Pretreatment	• Stable combustion • Peak emissions reduction.	• classification based on the size and the contamination
	• Reduce water content • Increase thermal efficiency	• Drying of biomass fuel
Combustion	• High boiler performance • Reduction of emissions	• BFBC and CFBC for biomass and peat • spreader stoker grate-firing technique for wood • vibrating water-cooled grate for straw-firing • use of advanced computerized control system.

7.5.4 Emissions to Air

BAT and associated emission levels for large biomass-fired power plants are similar to those of coal-fired power plants. The details about this BAT can be found in the European BAT Reference Document. For small biomass-fired power plants, the use of ESP, fabric filter, Venturi scrubber could be considered as BAT.

Table 26 shows the PCDD/PCDF emission control measures for biomass firing installations.
For biomass-fired plants, in particular wood-fired installations, an emission level of 0.1 ng I-TEQ/m^3 shall be achievable.

Table 26: PCDD/PCDF Emission Control Measures for Biomass Firing Installations

Management options	**Emission level (%)**	**Estimated costs**	**Management risks**
Primary measures: • Control of fuel quality • Optimised burn-out (e.g. reduction of excess air) • Increased residence time of flue gases upstream the boiler	Resulting emission level not quantified	Higher fuel price No additional cost for new installations	High water content increases PCDD/PCDF formation
Secondary measures:			
• Efficient dust abatement	Medium efficiency		Filter temperature < 200 °C
• Dry sorbent injection	High efficiency		Disposal of used sorbents
• Selective non-catalytic reduction (SNCR)	Medium efficiency	Additional investment1): SNCR 50-60 %	not common in small plants
• Selective catalytic reduction (SCR)	High efficiency	SCR 110-180 %	not common in biomass combustion plants

1) Percentage related to the investment for furnace, boiler and dust collector of wood combustion plants with 1-10 MW thermal capacity

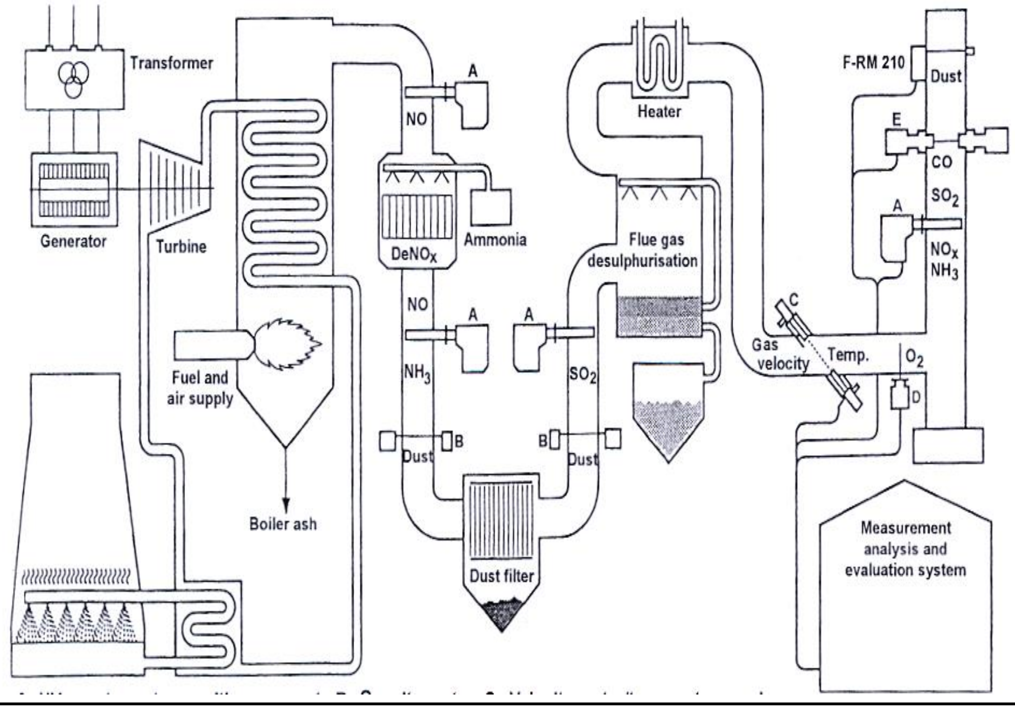
8.0 EMISSION MONITORING AND REPORTING

The emission monitoring should be carried out to determine the substances in the clean gas so that they can be reported. In order to control the combustion process and maintain optimum operation with minimum emissions to air, process parameters such temperature, pressure, fuel and air flow rates as well as key pollutants concentrations should be monitored on-line. Monitoring the sulfur and heavy metal content of the fuel is also important.

For measurement methods, see the chapter on Monitoring in Pollution Prevention and Abatement Handbook, WORLD BANK GROUP, 1998.

8.1 Online Monitoring:

The substances which need to be monitored on-line include PM, NO_x, NH_3 (in the case of SCR or SNCR installed), SO_2, CO, and O_2. A typical process control and air emission monitoring in power plants is shown in **Figure 8**.



A = UV Spectrometer **B = Opacity motor** **C = Velocity meter/ temperature probe**

D = O_2 Analyser **E = CO monitor** **F = Dust monitor**

Figure 8: Process Control and Air Emissions Monitoring in Power Plants

8.2 Stack Sampling:

Direct measurement of the concentrations of the following emissions in samples of flue gases should be performed regularly (for example, on an annual basis). At least three data sets should be used (ref: Pollution Prevention and Abatement Handbook, WORLD BANK GROUP, 1998)

- PM (including PM_{10} and $PM_{2.5}$) (not relevant for natural gas fuel)
- SO_2 (not relevant for natural gas fuel)
- NO_x
- CO
- Heavy metals (not relevant for natural gas fuel)
- HF
- HCl
- HC
- VOCs
- Dioxins and furans

The off-gas parameters that should be determined are:

- The volumetric off-gas flow
- The off-gas temperature
- The water vapour content of the gas
- The static pressure in the off-gas duct
- The atmospheric pressure
- Monitoring period

The stack dimensions should be also reported.

All emission concentrations should be reported under standard conditions, i.e. 273 K, 101.3 kPa and normalized 6 % O_2 content for solid fuel, 3 % for liquid fuels and 15 % O_2 content for gas turbine, and 3 % for gas-fired boiler.

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1. European Integrated Pollution Prevention and Control Bureau (EIPPCB), (July 2006). Best Available Techniques (BAT) Reference Document for Large Combustion Plants. Joint Research Centre, Institute of Prospective Technological Studies, EIPPCB

2. Hamdan Mokhtar (Sept 2-3 2002). Malaysian Energy Situation, COGEN3: A Business Facilitator. Shah Alam, Malaysia.