

Thermal Power: Guidelines for New Plants

Industry Description and Practices

This document sets forth procedures for establishing maximum emissions levels for all fossil-fuel-based thermal power plants with a capacity of 50 or more megawatts of electricity (MWe) that use coal, fuel oil, or natural gas.¹

Conventional steam-producing thermal power plants generate electricity through a series of energy conversion stages: fuel is burned in boilers to convert water to high-pressure steam, which is then used to drive a turbine to generate electricity.

Combined-cycle units burn fuel in a combustion chamber, and the exhaust gases are used to drive a turbine. Waste heat boilers recover energy from the turbine exhaust gases for the production of steam, which is then used to drive another turbine. Generally, the total efficiency of a combined-cycle system in terms of the amount of electricity generated per unit of fuel is greater than for conventional thermal power systems, but the combined-cycle system may require fuels such as natural gas.

Advanced coal utilization technologies (e.g., fluidized-bed combustion and integrated gasification combined cycle) are becoming available, and other systems such as cogeneration offer improvements in thermal efficiency, environmental performance, or both, relative to conventional power plants. The economic and environmental costs and benefits of such advanced technologies need to be examined case by case, taking into account alternative fuel choices, demonstrated commercial viability, and plant location. The criteria spelled out in this document apply regardless of the particular technology chosen.

Engine-driven power plants are usually considered for power generation capacities of up to 150 MWe. They have the added advantages of shorter

building period, higher overall efficiency (low fuel consumption per unit of output), optimal matching of different load demands, and moderate investment costs, compared with conventional thermal power plants. Further information on engine-driven plants is given in Annex A.

Waste Characteristics

The wastes generated by thermal power plants are typical of those from combustion processes. The exhaust gases from burning coal and oil contain primarily particulates (including heavy metals, if they are present in significant concentrations in the fuel), sulfur and nitrogen oxides (SO_x and NO_x), and volatile organic compounds (VOCs). For example, a 500 MWe plant using coal with 2.5% sulfur (S), 16% ash, and 30,000 kilojoules per kilogram (kJ/kg) heat content will emit each day 200 metric tons of sulfur dioxide (SO₂), 70 tons of nitrogen dioxide (NO₂), and 500 tons of fly ash if no controls are present. In addition, the plant will generate about 500 tons of solid waste and about 17 gigawatt-hours (GWh) of thermal discharge.

This document focuses primarily on emissions of particulates less than 10 microns (µm) in size (PM₁₀, including sulfates), of sulfur dioxide, and of nitrogen oxides. Nitrogen oxides are of concern because of their direct effects and because they are precursors for the formation of ground-level ozone. Information concerning the health and other damage caused by these and other pollutants, as well as on alternative methods of emissions control, is provided in the relevant pollutant and pollutant control documents.

The concentrations of these pollutants in the exhaust gases are a function of firing configuration, operating practices, and fuel composition. Gas-fired plants generally produce negligible

quantities of particulates and sulfur oxides, and levels of nitrogen oxides are about 60% of those from plants using coal. Gas-fired plants also release lower quantities of carbon dioxide, a greenhouse gas.

Ash residues and the dust removed from exhaust gases may contain significant levels of heavy metals and some organic compounds, in addition to inert materials. Fly ash removed from exhaust gases makes up 60–85% of the coal ash residue in pulverized-coal boilers. Bottom ash includes slag and particles that are coarser and heavier than fly ash. The volume of solid wastes may be substantially higher if environmental measures such as flue gas desulfurization (FGD) are adopted and the residues are not reused in other industries.

Steam turbines and other equipment may require large quantities of water for cooling, including steam condensation. Water is also required for auxiliary station equipment, ash handling, and FGD systems. The characteristics of the wastewaters generated depend on the ways in which the water has been used. Contamination arises from demineralizers, lubricating and auxiliary fuel oils, and chlorine, biocides, and other chemicals used to manage the quality of water in cooling systems. Once-through cooling systems increase the temperature of the receiving water.

Policy Framework

The development of a set of environmental requirements for a new thermal power plant involves decisions of two distinct kinds. First, there are the specific requirements of the power plant itself. These are the responsibility of the project developer in collaboration with relevant local or other environmental authorities. This document focuses on the issues that should be addressed in arriving at project-specific emissions standards and other requirements.

Second, there are requirements that relate to the operation of the power system as a whole. These strategic issues must be the concern of national or regional authorities with the responsibility for setting the overall policy framework for the development of the power sector. Examples of such requirements include measures to promote energy conservation via better demand-side

management, to encourage the use of renewable sources of energy rather than fossil fuels, and to meet overall targets for the reduction of emissions of sulfur dioxide, nitrogen oxides, or greenhouse gases.

In the context of its regular country dialogue on energy and environmental issues, the World Bank is willing to assist its clients to develop the policy framework for implementing such environmental requirements for the power sector as a whole. One step in this process might be the preparation of a sectoral environmental assessment. This document assumes that the project is consistent with broad sectoral policies and requirements that have been promulgated by the relevant authorities in order to meet international obligations and other environmental goals affecting the power sector.

In some cases, strategies for meeting system-wide goals may be developed through a power-sector planning exercise that takes account of environmental and social factors. This would, for instance, be appropriate for a small country with a single integrated utility. In other cases, governments may decide to rely on a set of incentives and environmental standards designed to influence the decisions made by many independent operators.

Determining Site-Specific Requirements

This document spells out the process—starting from a set of maximum emissions levels acceptable to the World Bank Group—that should be followed in determining the site-specific emissions guidelines. The guidelines could encompass both controls on the plant and other measures, perhaps outside the plant, that may be necessary to mitigate the impact of the plant on the airshed or watershed in which it is located. The process outlines how the World Bank Group's policy on Environmental Assessment (OP 4.01) for thermal power plants can be implemented. The guidelines are designed to protect human health; reduce mass loading to the environment to acceptable levels; achieve emissions levels based on commercially proven and widely used technologies; follow current regulatory and technology trends; be cost-effective; and promote the use of cleaner fuels and good-management practices that increase energy efficiency and productivity.

It is important to stress that the results of the environmental assessment (EA) are critical to defining many of the design parameters and other assumptions, such as location, fuel choice, and the like, required to develop the detailed specification of a project. The assessment results must be integrated with economic analyses of the key design options. Thus, it is essential that the work of preparing an environmental assessment be initiated during the early stages of project conception and design so that the initial results of the study can be used in subsequent stages of project development. It is not acceptable to prepare an environmental assessment that considers a small number of options in order to justify a predetermined set of design choices.

Evaluation of Project Alternatives

The EA should include an analysis of reasonable alternatives that meet the ultimate objective of the project. The assessment may lead to alternatives that are sounder, from an environmental, sociocultural, and economic point of view, than the originally proposed project. Alternatives need to be considered for various aspects of the system, including:

- Fuels used
- Power generation technologies
- Heat rejection systems
- Water supply or intakes
- Solid waste disposal systems
- Plant and sanitary waste discharge
- Engineering and pollution control equipment (see Annex B for some examples)
- Management systems.

The alternatives should be evaluated as a part of the conceptual design process. Those alternatives that provide cost-effective environmental management are preferred.

Clean Development Mechanism (CDM)

The Kyoto Protocol provisions allow for the use of the clean development mechanism (CDM), under which, beginning in 2000, greenhouse gas emissions from projects in non-Annex I countries that are certified by designated operating entities can be acquired by Annex I countries and credited against their emissions binding commitments. The

availability of CDM financing may alter, in some cases, the choice of the least-cost project alternative. Once the CDM is enacted, it will be advisable to incorporate the following steps into the process of evaluating project alternatives:

- Identification and assessment of alternatives that are eligible for CDM-type financing (e.g., alternatives that are not economical without carbon offsets and whose incremental costs above the least-cost baseline alternative, taking account of local environmental externalities, are smaller than the costs of resulting carbon offsets).
- Negotiation with Annex I parties of possible offset arrangements, if CDM-eligible alternatives exist. The World Bank Group will be prepared to assist in the process of identifying the CDM-eligible alternatives and negotiating offset arrangements for projects that are partly financed or guaranteed by the World Bank Group.

Environmental Assessment

An EA should be carried out early in the project cycle in order to establish emissions requirements and other measures on a site-specific basis for a new thermal power plant or unit of 50 MWe or larger. The initial tasks in carrying out the EA should include:

- Collection of baseline data on ambient concentrations of PM₁₀ and sulfur oxides (for oil and coal-fired plants), nitrogen oxides, (and ground-level ozone, if levels of ambient exposure to ozone are thought to be a problem) within a defined airshed encompassing the proposed project.²
- Collection of similar baseline data for critical water quality indicators that might be affected by the plant.
- Use of appropriate air quality and dispersion models to estimate the impact of the project on the ambient concentrations of these pollutants, on the assumption that the maximum emissions levels described below apply. (See the chapters on airshed models in Part II of this *Handbook*.)

When there is a reasonable likelihood that in the medium or long term the power plant will be ex-

panded or other pollution sources will increase significantly, the analysis should take account of the impact of the proposed plant design both immediately and after any probable expansion in capacity or in other sources of pollution. The EA should also include impacts from construction work and other activities that normally occur, such as migration of workers when large facilities are built. Plant design should allow for future installation of additional pollution control equipment, should this prove desirable or necessary.

The EA should also address other project-specific environmental concerns, such as emissions of cadmium, mercury, and other heavy metals resulting from burning certain types of coal or heavy fuel oil. If emissions of this kind are a concern, the government (or the project sponsor) and the World Bank Group will agree on specific measures for mitigating the impact of such emissions and on the associated emissions guidelines.

The quality of the EA (including systematic cost estimates) is likely to have a major influence on the ease and speed of project preparation. A good EA prepared early in the project cycle should make a significant contribution to keeping the overall costs of the project down.

Emissions Guidelines

Emissions levels for the design and operation of each project must be established through the EA process on the basis of country legislation and the *Pollution Prevention and Abatement Handbook*, as applied to local conditions. The emissions levels selected must be justified in the EA and acceptable to the World Bank Group.

The following maximum emissions levels are normally acceptable to the World Bank Group in making decisions regarding the provision of World Bank Group assistance for new fossil-fuel-fired thermal power plants or units of 50 MWe or larger (using conventional fuels). The emissions levels have been set so they can be achieved by adopting a variety of cost-effective options or technologies, including the use of clean fuels or washed coal. For example, dust controls capable of over 99% removal efficiency, such as electrostatic precipitators (ESPs) or baghouses, should always be installed for coal-fired power plants. Similarly, the use of low-

NO_x burners with other combustion modifications such as low excess air (LEA) firing should be standard practice. The range of options for the control of sulfur oxides is greater because of large differences in the sulfur content of different fuels and in control costs. In general, for low-sulfur (less than 1% S), high-calorific-value fuels, specific controls may not be required, while coal cleaning, when feasible, or sorbent injection (in that order) may be adequate for medium-sulfur fuels (1–3% S). FGD may be considered for high-sulfur fuels (more than 3% S). Fluidized-bed combustion, when technically and economically feasible, has relatively low SO_x emissions. The choice of technology depends on a benefit-cost analysis of the environmental performance of different fuels and the cost of controls.

Any deviations from the following emissions levels must be described in the World Bank Group project documentation.

Air Emissions

The maximum emissions levels given here can be consistently achieved by well-designed, well-operated, and well-maintained pollution control systems. In contrast, poor operating or maintenance procedures affect actual pollutant removal efficiency and may reduce it to well below the design specification. The maximum emissions levels are expressed as concentrations to facilitate monitoring. Dilution of air emissions to achieve these guidelines is unacceptable. Compliance with ambient air quality guidelines should be assessed on the basis of good engineering practice (GEP) recommendations. See Annex C for ambient air quality guidelines to be applied if local standards have not been set.³ Plants should not use stack heights less than the GEP recommended values unless the air quality impact analysis has taken into account building downwash effects. All of the maximum emissions levels should be achieved for at least 95% of the time that the plant or unit is operating, to be calculated as a proportion of annual operating hours.⁴ The remaining 5% of annual operating hours is assumed to be for start-up, shutdown, emergency fuel use, and unexpected incidents. For peaking units where the start-up mode is expected to be longer than 5% of the annual operating hours,

exceedance should be justified by the EA with regard to air quality impacts.

Power plants in degraded airsheds. The following definitions apply in airsheds where there already exists a significant level of pollution.

An airshed will be classified as having *moderate air quality* with respect to particulates, sulfur dioxide, or nitrogen dioxide if either 1 or 2 applies:

1. (a) The annual mean value of PM_{10} exceeds 50 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) for the airshed ($80 \mu\text{g}/\text{m}^3$ for total suspended particulates, TSP); (b) the annual mean value of sulfur dioxide exceeds $50 \mu\text{g}/\text{m}^3$; or (c) the annual mean value of nitrogen dioxide exceeds $100 \mu\text{g}/\text{m}^3$ for the airshed.

2. The 98th percentile of 24-hour mean values of PM_{10} , sulfur dioxide, or nitrogen dioxide for the airshed over a period of a year exceeds $150 \mu\text{g}/\text{m}^3$ ($230 \mu\text{g}/\text{m}^3$ for TSP).

An airshed will be classified as having *poor air quality* with respect to particulates, sulfur dioxide, or nitrogen dioxide if either 1 or 2 applies:

1. (a) The annual mean of PM_{10} exceeds $100 \mu\text{g}/\text{m}^3$ for the airshed ($160 \mu\text{g}/\text{m}^3$ for TSP); (b) the annual mean of sulfur dioxide exceeds $100 \mu\text{g}/\text{m}^3$ for the airshed; or (c) the annual mean of nitrogen dioxide exceeds $200 \mu\text{g}/\text{m}^3$ for the airshed.

2. The 95th percentile of 24-hour mean values of PM_{10} , sulfur dioxide, or nitrogen dioxide for the airshed over a period of a year exceeds $150 \mu\text{g}/\text{m}^3$ ($230 \mu\text{g}/\text{m}^3$ for TSP).

Plants smaller than 500 MWe in airsheds with moderate air quality are subject to the maximum emissions levels indicated below, provided that the EA shows that the plan will not lead *either* to the airshed dropping into the “poor air quality” category *or* to an increase of more than $5 \mu\text{g}/\text{m}^3$ in the annual mean level of particulates (PM_{10} or TSP), sulfur dioxide, or nitrogen dioxide for the entire airshed. If either of these conditions is not satisfied, lower site-specific emissions levels should be established that would ensure that the conditions can be satisfied. The limit of a $5 \mu\text{g}/\text{m}^3$ increase in the annual mean will apply to the cumulative total impact of all power plants built in the airshed within any 10-year period beginning on or after the date at which the guidelines come into effect.

Plants larger than or equal to 500 MWe in airsheds with moderate air quality and all plants in airsheds with poor air quality are subject to site-specific requirements that include offset provisions to ensure that (a) there is no net increase in the total emissions of particulates or sulfur dioxide within the airshed and (b) the resultant ambient levels of nitrogen dioxide do not exceed the levels specified for moderately degraded airsheds.⁵ The measures agreed under the offset provisions must be implemented before the power plant comes fully on stream. Suitable offset measures could include reductions in emissions of particulates, sulfur dioxide, or nitrogen dioxide as a result of (a) the installation of new or more effective controls at other units within the same power plant or at other power plants in the same airshed, (b) the installation of new or more effective controls at other large sources, such as district heating plants or industrial plants, in the same airshed, or (c) investments in gas distribution or district heating systems designed to substitute for the use of coal for residential heating and other small boilers.⁶ The monitoring and enforcement of the offset provisions would be the responsibility of the local or national agency responsible for granting and supervising environmental permits. Such offset provisions would normally be described in detail in a specific covenant in the project loan agreement.

Project sponsors who do not wish to engage in the negotiations necessary to put together an offset agreement would have the option of relying on an appropriate combination of clean fuels, controls, or both.

Particulate matter. For all plants or units, PM emissions (all sizes) should not exceed $50 \text{ mg}/\text{Nm}^3$.⁷ The EA should pay specific attention to particulates smaller than $10 \mu\text{m}$ in aerodynamic diameter (PM_{10}) in the airshed, since these are inhaled into the lungs and are associated with the most serious effects on human health. Where possible, ambient levels of fine particulates (less than $2.5 \mu\text{m}$ in diameter) should be measured. Recent epidemiologic evidence suggests that much of the health damage caused by exposure to particulates is associated with these fine particles, which penetrate most deeply into the lungs. Emissions of PM_{10} and fine particulates include ash, soot, and carbon compounds (often

the results of incomplete combustion), acid condensates, sulfates, and nitrates, as well as lead, cadmium, and other metals. Fine particulates, including sulfates, nitrates, and carbon compounds, are also formed by chemical processes in the atmosphere, but they tend to disperse over the whole airshed.

Sulfur dioxide. Total sulfur dioxide emissions from the power plant or unit should be less than 0.20 metric tons per day (tpd) per MWe of capacity for the first 500 MWe, plus 0.10 tpd for each additional MWe of capacity over 500 MWe.⁸ In addition, the concentration of sulfur dioxide in flue gases should not exceed 2,000 mg/Nm³ (see note 4 for assumptions), with a maximum emissions level of 500 tpd. Construction of two or more separate plants in the same airshed to circumvent this cap is not acceptable.

Nitrogen oxides. The specific emissions limits for nitrogen oxides are 750 mg/Nm³, or 260 nanograms per joule (ng/J), or 365 parts per million parts (ppm) for a coal-fired power plant, and up to 1,500 mg/Nm³ for plants using coal with volatile matter less than 10%; 460 mg/Nm³ (or 130 ng/J, or 225 ppm) for an oil-fired power plant; and 320 mg/Nm³ (or 86 ng/J, or 155 ppm) for a gas-fired power plant.

For combustion turbine units, the maximum NO_x emissions levels are 125 mg/Nm³ (dry at 15% oxygen) for gas; 165 mg/Nm³ (dry at 15% oxygen) for diesel (No. 2 oil); and 300 mg/Nm³ (dry at 15% oxygen) for fuel oil (No. 6 and others).⁹ Where there are technical difficulties, such as scarcity of water available for water injection, an emissions variance allowing a maximum emissions level of up to 400 mg/Nm³ dry (at 15% oxygen) is considered acceptable, provided there are no significant environmental concerns associated with ambient levels of ozone or nitrogen dioxide.

For engine-driven power plants, the EA should pay particular attention to levels of nitrogen oxides before and after the completion of the project. Provided that the resultant maximum ambient levels of nitrogen dioxide are less than 150 µg/m³ (24-hour average), the specific emissions guidelines are as follows: (a) for funding applications received after July 1, 2000, the NO_x emissions levels should

be less than 2,000 mg/Nm³ (or 13 grams per kilowatt-hour, g/kWh dry at 15% oxygen); and (b) for funding applications received before July 1, 2000, the NO_x emissions levels should be less than 2,300 mg/Nm³ (or 17 g/kWh dry at 15% oxygen). In all other cases, the maximum emissions level of nitrogen oxides is 400 mg/Nm³ (dry at 15% oxygen).

Offsets and the role of the World Bank Group. Large power complexes should normally not be developed in airsheds with moderate or poor air quality, or, if they must be developed, then only with appropriate offset measures. The costs of identifying and negotiating offsets for large power complexes are not large in relation to the total cost of preparing such projects. In the context of its regular country dialogue on energy and environmental issues, the World Bank is prepared to assist the process of formulating and implementing offset agreements for projects that are partly financed or guaranteed by the World Bank Group. If the offsets for a particular power project that will be financed by a World Bank Group loan involve specific investments to reduce emissions of particulates, sulfur oxides, or nitrogen oxides, these may be included within the scope of the project and may thus be eligible for financing under the loan.¹⁰

Long-range transport of acid pollutants. Where ground-level ozone or acidification is or may in future be a significant problem, governments are encouraged to undertake regional or national studies of the impact of sulfur dioxide, nitrogen oxides, and other pollutants that damage sensitive ecosystems, with, in appropriate cases, support from the World Bank (see Policy Framework, above). The aim of such studies is to identify least-cost options for reducing total emissions of these pollutants from a region or a country so as to achieve load targets, as appropriate.¹¹

A possible (but not the only) approach to identifying sensitive ecosystems is to estimate critical loads for acid depositions and critical levels for ozone in different geographic areas. The analysis must, however, take into account the large degree of uncertainty involved in making such estimates.

In appropriate cases, governments should develop cost-effective strategies, as well as legal instruments, to protect sensitive ecosystems or to reduce transboundary flows of pollutants.

Where such regional studies have been carried out, the environmental assessment should take account of their results in assessing the overall impact of a proposed power plant.

The site-specific emissions requirements should be consistent with any strategy and applicable legal framework that have been adopted by the host country government to protect sensitive ecosystems or to reduce transboundary flows of pollutants.

Liquid Effluents

The effluent levels presented in Table 1 (for the applicable parameters) should be achieved daily without dilution.

Coal pile runoff and leachate may contain significant concentrations of toxics such as heavy metals. Where leaching of toxics to groundwater or their transport in surface runoff is a concern, suitable preventive and control measures such as protective liners and collection and treatment of runoff should be put in place.

Solid Wastes

Solid wastes, including ash and FGD sludges, that do not leach toxic substances or other con-

taminants of concern to the environment may be disposed in landfills or other disposal sites provided that they do not impact nearby water bodies. Where toxics or other contaminants are expected to leach out, they should be treated by, for example, stabilization before disposal.

Ambient Noise

Noise abatement measures should achieve either the levels given below or a maximum increase in background levels of 3 decibels (measured on the A scale) [dB(A)]. Measurements are to be taken at noise receptors located outside the project property boundary.

	Maximum allowable log equivalent (hourly measurements), in dB(A)	
	Day (07:00–22:00)	Night (22:00–07:00)
Receptor		
Residential, institutional, educational	55	45
Industrial, commercial	70	70

Monitoring and Reporting

For measurement methods, see the chapter on Monitoring in this *Handbook*.

Maintaining the combustion temperature and the excess oxygen level within the optimal band in which particulate matter and NO_x emissions are minimized simultaneously ensures the greatest energy efficiency and the most economic plant operation. Monitoring should therefore aim at achieving this optimal performance as consistently as possible. Systems for continuous monitoring of particulate matter, sulfur oxides, and nitrogen oxides in the stack exhaust can be installed and are desirable whenever their maintenance and calibration can be ensured. Alternatively, surrogate performance monitoring should be performed on the basis of initial calibration. The following surrogate parameters are relevant for assessing environmental performance. (They require no changes in plant design but do call for appropriate training of operating personnel.)

Table 1. Effluents from Thermal Power Plants
(milligrams per liter, except for pH and temperature)

Parameter	Maximum value
pH	6–9
TSS	50
Oil and grease	10
Total residual chlorine ^a	0.2
Chromium (total)	0.5
Copper	0.5
Iron	1.0
Zinc	1.0
Temperature increase	≤ 3°C ^b

a. “Chlorine shocking” may be preferable in certain circumstances. This involves using high chlorine levels for a few seconds rather than a continuous low-level release. The maximum value is 2 mg/l for up to 2 hours, not to be repeated more frequently than once in 24 hours, with a 24-hour average of 0.2 mg/l. (The same limits would apply to bromine and fluorine.)

b. The effluent should result in a temperature increase of no more than 3° C at the edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 meters from the point of discharge when there are no sensitive aquatic ecosystems within this distance.

- *Particulate matter.* Ash and heavy metal content of fuel; maximum flue gas flow rate; minimum power supply to the ESP or minimum pressure drop across the baghouse; minimum combustion temperature; and minimum excess oxygen level.
- *Sulfur dioxide.* Sulfur content of fuel.
- *Nitrogen oxides.* Maximum combustion temperature and maximum excess oxygen level.

Direct measurement of the concentrations of emissions in samples of flue gases should be performed regularly (for example, on an annual basis) to validate surrogate monitoring results or for the calibration of the continuous monitor (if used). The samples should be monitored for PM and nitrogen oxides and may be monitored for sulfur oxides and heavy metals, although monitoring the sulfur and heavy metal content of fuel is considered adequate. At least three data sets for direct emissions measurements should be used, based on an hourly rolling average.

Automatic air quality monitoring systems measuring ambient levels of PM₁₀, sulfur oxides, and nitrogen oxides outside the plant boundary should be installed where maximum ambient concentration is expected or where there are sensitive receptors such as protected areas and population centers. (PM₁₀ and SO_x measurements are, however, not required for gas-fired plants.) The number of air quality monitors should be greater if the area in which the power plant is located is prone to temperature inversions or other meteorological conditions that lead to high levels of air pollutants affecting nearby populations or sensitive ecosystems. The purpose of such ambient air quality monitoring is to help assess the possible need for changes in operating practices (including burning cleaner fuels to avoid high short-term exposures), especially during periods of adverse meteorological conditions. The pollutant guidelines specify short-term ambient air quality guideline values which, if exceeded, call for emergency measures such as burning cleaner fuels.

Any measures should be taken in close collaboration with local authorities. The specific design of the ambient monitoring system should be based on the findings of the EA. The frequency of ambient measurements depends on prevailing condi-

tions; ambient measurements, when taken, should normally be averaged daily.

The pH and temperature of the wastewater discharges should be monitored continuously. Levels of suspended solids, oil and grease, and residual chlorine should be measured daily, and heavy metals and other pollutants in wastewater discharges should be measured monthly if treatment is provided.

Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards so that any necessary corrective actions can be taken. Records of monitoring results should be kept in an acceptable format. The results should be reported in summary form, with notification of exceptions, if any, to the responsible government authorities and relevant parties, as required. In the absence of specific national or local government guidelines, actual monitoring or surrogate performance data should be reported at least annually. The government may require additional explanation and may take corrective action if plants are found to exceed maximum emissions levels for more than 5% of the operating time, or on the occasion of a plant audit. The objective is to ensure continuing compliance with the emissions limits agreed at the outset, based on sound operation and maintenance. Exceedances of the maximum emissions levels would normally be reviewed in light of the enterprise's good-faith efforts in this regard.

As part of the Framework Convention on Climate Change, countries will be asked to record their emissions of greenhouse gases (GHG). As an input to this, and to facilitate possible future activities implemented jointly with Annex I countries, the emissions of individual projects should be estimated on the basis of the chemical composition of the fuel or measured directly. Table 2 in the chapter on Greenhouse Gas Abatement and Climate Change in Part II of this *Handbook* provides relevant emissions factors.

In order to develop institutional capacity, training should be provided with adequate budgets to ensure satisfactory environmental performance. The training may include education on environmental assessment, environmental mitigation plans, and environmental monitoring. In some cases, it may be appropriate to include the staff from the environmental implementation agencies,

such as the state pollution control board, in the training program

Key Issues

The key production and emissions control practices that will lead to compliance with the above guidelines are summarized below. It is assumed that the proposed project represents a least-cost solution, taking into account environmental and social factors.

- Choose the cleanest fuel economically available (natural gas is preferable to oil, which is preferable to coal).
- Give preference to high-heat-content, low-ash, low-sulfur coal (or high-heat-content, high-sulfur coal, in that order) and consider beneficiation for high-ash, high-sulfur coal.
- Select the best power generation technology for the fuel chosen to balance the environmental and economic benefits. The choice of technology and pollution control systems will be based on the site-specific environmental assessment.

Keep in mind that particulates smaller than 10 microns in size are most important from a health perspective. Acceptable levels of particulate matter removal are achievable at relatively low cost.

Consider cost-effective technologies such as pre-ESP sorbent injection, along with coal washing, before in-stack removal of sulfur dioxide.

Use low-NO_x burners and other combustion modifications to reduce emissions of nitrogen oxides.

- Before adopting expensive control technologies, consider using offsetting reductions in emissions of critical pollutants at other sources within the airshed to achieve acceptable ambient levels.
- Use SO_x removal systems that generate less wastewater, if feasible; however, the environmental and cost characteristics of both inputs and wastes should be assessed case by case.
- Manage ash disposal and reclamation so as to minimize environmental impacts—especially the migration of toxic metals, if present, to nearby surface and groundwater bodies, in ad-

dition to the transport of suspended solids in surface runoff. Consider reusing ash for building materials.

- Consider recirculating cooling systems where thermal discharge to water bodies may be of concern.
- Note that a comprehensive monitoring and reporting system is required.

Annex A. Engine-Driven Power Plants

Engine-driven power plants use fuels such as diesel oil, fuel oil, gas, orimulsion, and crude oil. The two types of engines normally used are the medium-speed four-stroke trunk piston engine and the low-speed two-stroke crosshead engine. Both types of engine operate on the air-standard diesel thermodynamic cycle. Air is drawn or forced into a cylinder and is compressed by a piston. Fuel is injected into the cylinder and is ignited by the heat of the compression of the air. The burning mixture of fuel and air expands, pushing the piston. Finally the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of fuel is used to drive an engine, which rotates the shaft of an alternator to generate electricity. The combustion process typically includes preheating the fuel to the required viscosity, typically 16–20 centiStokes (cSt), for good fuel atomization at the nozzle. The fuel pressure is boosted to about 1,300 bar to achieve a droplet distribution small enough for fast combustion and low smoke values. The nozzle design is critical to the ignition and combustion process. Fuel spray penetrating to the liner can damage the liner and cause smoke formation. Spray in the vicinity of the valves may increase the valve temperature and contribute to hot corrosion and burned valves. If the fuel timing is too early, the cylinder pressure will increase, resulting in higher nitrogen oxide formation. If injection is timed too late, fuel consumption and turbocharger speed will increase. NO_x emissions can be reduced by later injection timing, but then particulate matter and the amount of unburned species will increase.

Ignition quality. For distillate fuels, methods for establishing ignition quality include cetane number and cetane index for diesel. The CCAI number,

based on fuel density and viscosity, gives a rough indication of the ignition behavior of heavy fuel oil.

Fuel quality. Fuel ash constituents may lead to abrasive wear, deposit formation, and high-temperature corrosion, in addition to emissions of particulate matter. The properties of fuel that may affect engine operation include viscosity, specific gravity, stability (poor stability results in the precipitation of sludge, which may block the filters), cetane number, asphaltene content, carbon residue, sulfur content, vanadium and sodium content (an indicator of corrosion, especially on exhaust valves), presence of solids such as rust, sand, and aluminum silicate, which may result in blockage of fuel pumps and liner wear, and water content.

Waste characteristics. The wastes generated are typical of those from combustion processes. The exhaust gases contain particulates (including heavy metals if present in the fuel), sulfur and nitrogen oxides, and, in some cases, VOCs. Nitrogen oxides are the main concern after particulate matter in the air emissions. NO_x emissions levels are (almost exponentially) dependent on the temperature of combustion, in addition to other factors. Most of the NO_x emissions are formed from the air used for combustion and typically range from 1,100 to 2,000 ppm at 15% oxygen. Carbon dioxide emissions are approximately 600 g/kWh of electricity, and total hydrocarbons (calculated as methane equivalent) are 0.5 g/kWh of electricity.

The exhaust gases from an engine are affected by (a) the load profile of the prime mover; (b) ambient conditions such as air humidity and temperature; (c) fuel oil quality, such as sulfur content, nitrogen content, viscosity, ignition ability, density, and ash content; and (d) site conditions and the auxiliary equipment associated with the prime mover, such as cooling properties and exhaust gas back pressure. The engine parameters that affect nitrogen oxide emissions are (a) fuel injection in terms of timing, duration, and atomization; (b) combustion air conditions, which are affected by valve timing, the charge air system, and charge air cooling before cylinders; and (c) the combustion process, which is affected by air and fuel mixing, combustion chamber design, and the compression ratio. The particulate matter emissions are dependent on the general conditions of the engine, especially the

fuel injection system and its maintenance, in addition to the ash content of the fuel, which is in the range 0.05–0.2%. SO_x emissions are directly dependent on the sulfur content of the fuel. Fuel oil may contain around 0.3% sulfur and, in some cases, up to 5%.

Annex B. Illustrative Pollution Prevention and Control Technologies

A wide variety of control technology options is available. As usual, these options should be considered after an adequate assessment of broader policy options, including pricing and institutional measures. Additional information is provided in the relevant documents on pollution control technologies.

Cleaner Fuels

The simplest and, in many circumstances, most cost-effective form of pollution prevention is to use cleaner fuels. For new power plants, combined-cycle plants burning natural gas currently have a decisive advantage in terms of their capital costs, thermal efficiency, and environmental performance. Natural gas is also the preferred fuel for minimizing GHG emissions because it produces lower carbon dioxide emissions per unit of energy and enhances energy efficiency.

If availability or price rule out natural gas as an option, the use of low-sulfur fuel oil or high-heat-content, low-sulfur, low-ash coal should be considered. Typically, such fuels command a premium price over their dirtier equivalents, but the reductions in operating or environmental costs that they permit are likely to outweigh this premium. In preparing projects, an evaluation of alternative fuel options should be conducted at the outset to establish the most cost-effective combination of fuel, technology, and environmental controls for meeting performance and environmental objectives.

If coal is used, optimal environmental performance and economic efficiency will be achieved through an integrated approach across the whole coal-energy chain, including the policy and investment aspects of mining, preparation, transport, power generation and heat conversion, and clean coal technologies. Coal washing, in particular, has

a beneficial impact in terms of reducing the ash content and ash variability of coal used in thermal power plants, which leads to consistent boiler performance, reduced emissions, and less maintenance.

Abatement of Particulate Matter

The options for removing particulates from exhaust gases are cyclones, baghouses (fabric filters), and ESPs. Cyclones may be adequate as precleaning devices; they have an overall removal efficiency of less than 90% for all particulate matter and considerably lower for PM₁₀. Baghouses can achieve removal efficiencies of 99.9% or better for particulate matter of all sizes, and they have the potential to enhance the removal of sulfur oxides when sorbent injection, dry-scrubbing, or spray dryer absorption systems are used. ESPs are available in a broad range of sizes for power plants and can achieve removal efficiencies of 99.9% or better for particulate matter of all sizes.

The choice between a baghouse and an ESP will depend on fuel and ash characteristics, as well as on operating and environmental factors. ESPs can be less sensitive to plant upsets than fabric filters because their operating effectiveness is not as sensitive to maximum temperatures and they have a low pressure drop. However, ESP performance can be affected by fuel characteristics. Modern baghouses can be designed to achieve very high removal efficiencies for PM₁₀ at a capital cost that is comparable to that for ESPs, but it is necessary to ensure appropriate training of operating and maintenance staff.

Abatement of Sulfur Oxides

The range of options and removal efficiencies for SO_x controls is wide. Pre-ESP sorbent injection can remove 30–70% of sulfur oxides, at a cost of US\$50–\$100 per kW. Post-ESP sorbent injection can achieve 70–90% SO_x removal, at a cost of US\$80–\$170 per kW. Wet and semidry FGD units consisting of dedicated SO_x absorbers can remove 70–95%, at a cost of US\$80–\$170 per kW (1997 prices). The operating costs of most FGDs are substantial because of the power consumed (of the order of 1–2% of the electricity generated), the chemicals used, and disposal of residues. Esti-

mates by the International Energy Agency (IEA) suggest that the extra levelized annual cost for adding to a coal-fired power plant an FGD designed to remove 90% of sulfur oxides amounts to 10–14% depending on capacity utilization.

An integrated pollution management approach should be adopted that does not involve switching from one form of pollution to another. For example, FGD scrubber wastes, when improperly managed, can lead to contamination of the water supply, and such SO_x removal systems could result in greater emissions of particulate matter from materials handling and windblown dust. This suggests the need for careful benefit-cost analysis of the types and extent of SO_x abatement.

Abatement of Nitrogen Oxides

The main options for controlling NO_x emissions are combustion modifications: low-NO_x burners with or without overfire air or reburning, water/steam injection, and selective catalytic or noncatalytic reduction (SCR/SNCR). Combustion modifications can remove 30–70% of nitrogen oxides, at a capital cost of less than US\$20 per kW and a small increase in operating costs. SNCR systems can remove 30–70% of nitrogen oxides, at a capital cost of US\$20–\$40 per kW and a moderate increase in operating cost. However, plugging of the preheater because of the formation of ammonium bisulfate may pose some problems. SCR units can remove 70–90% of nitrogen oxides but involve a much larger capital cost of US\$40–\$80 per kW and a significant increase in operating costs, especially for coal-fired plants. Moreover, SCR may require low-sulfur fuels (less than 1.5% sulfur content) because the catalyst elements are sensitive to the sulfur dioxide content in the flue gas.

Fly Ash Handling

Fly ash handling systems may be generally categorized as dry or wet, even though the dry handling system involves wetting the ash to 10–20% moisture to improve handling characteristics and to mitigate the dust generated during disposal. In wet systems, the ash is mixed with water to produce a liquid slurry containing 5–10% solids by weight. This is discharged to settling ponds, often with bottom ash and FGD sludges, as well. The ponds

may be used as the final disposal site, or the settled solids may be dredged and removed for final disposal in a landfill. Wherever feasible, decanted water from ash disposal ponds should be recycled to formulate ash slurry. Where heavy metals are pre-sent in ash residues or FGD sludges, care must be taken to monitor and treat leachates and overflows from settling ponds, in addition to disposing of them in lined places to avoid contamination of water bodies. In some cases, ash residues are being used for building materials and in road construction. Gradual reclamation of ash ponds should be practiced.

Water Use

It is possible to reduce the fresh water intake for cooling systems by installing evaporative recirculating cooling systems. Such systems require a greater capital investment, but they may use only 5% of the water volume required for once-through cooling systems. Where once-through cooling systems are used, the volume of water required and the impact of its discharge can be reduced by careful siting of intakes and outfalls, by minimizing the use of biocides and anticorrosion chemicals (effective nonchromium-based alternatives are available to inhibit scale and products of corrosion in cooling water systems), and by controlling discharge temperatures and thermal plumes. Wastewaters from other processes, including boiler blowdown, demineralizer backwash, and resin regenerator wastewater, can also be recycled, but again, this requires careful management and treatment for reuse. Water use can also be reduced in certain circumstances through the use of air-cooled condensers.

Annex C. Ambient Air Quality

The guidelines presented in Table C.1 are to be used only for carrying out an environment assessment in the absence of local ambient standards. They were constructed as consensus values taking particular account of WHO, USEPA, and EU standards and guidelines. *They do not in any way substitute for a country's own ambient air quality standards.*

Table C.1. Ambient Air Quality in Thermal Power Plants

(micrograms per cubic meter)

Pollutant	24-hour average	Annual average
PM ₁₀	150	50
TSP ^a	230	80
Nitrogen dioxide	150	100
Sulfur dioxide	150	80

a. Measurement of PM₁₀ is preferable to measurement of TSP.

Notes

1. For plants smaller than 50 MWe, including those burning nonfossil fuels, PM emissions levels may be as much as 100 mg/Nm³. If justified by the EA, PM emissions levels up to 150 mg/Nm³ may be acceptable in special circumstances. The maximum emissions levels for nitrogen oxides remain the same, while for sulfur dioxide, the maximum emissions level is 2,000 mg/Nm³.

2. *Airshed* refers to the local area around the plant whose ambient air quality is directly affected by emissions from the plant. The size of the relevant local airshed will depend on plant characteristics, such as stack height, as well as on local meteorological conditions and topography. In some cases, airsheds are defined in legislation or by the relevant environmental authorities. If not, the EA should clearly define the airshed on the basis of consultations with those responsible for local environmental management.

In collecting baseline data, qualitative assessments may suffice for plants proposed in greenfield sites. For nondegraded airsheds, quantitative assessment using models and representative monitoring data may suffice.

3. See, e.g., United States, 40 CFR, Part 51, 100 (ii). Normally, GEP stack height = $H + 1.5L$, where H is the height of nearby structures and L is the lesser dimension of either height or projected width of nearby structures.

4. The assumptions are as follows: for coal, flue gas dry 6% excess oxygen—assumes 350 Nm³/GJ. For oil, flue gas dry 3% excess oxygen—assumes 280 Nm³/GJ. For gas, flue gas dry 3% excess oxygen—assumes 270 Nm³/GJ (see annex D). The oxygen level in engine exhausts and combustion turbines is assumed to be 15%, dry. See the document on Monitoring for measurement methods.

5. Gas-fired plants (in which the backup fuel contains less than 0.3% sulfur) and other plants that achieve emissions levels of less than 400 mg/Nm³ for sulfur oxides and nitrogen oxides are exempt from the offset requirements, since their emissions are relatively lower.

Annex D. Conversion Chart

Table D.1. SO₂ and NO_x Emissions Conversion Chart for Steam-Based Thermal Power Plants

To convert From	To (multiply by):								
	Mg/Nm ³	ppm NO _x	ppm SO ₂	g/GJ			lb/10 ⁶ Btu		
				Coal ^a	Oil ^b	Gas ^c	Coal ^a	Oil ^b	Gas ^c
Mg/Nm ³	1	0.487	0.350	0.350	0.280	0.270	8.14 x 10 ⁻⁴	6.51 x 10 ⁻⁴	6.28 x 10 ⁻⁴
ppm NO _x	2.05	1		0.718	0.575	0.554	1.67 x 10 ⁻³	1.34 x 10 ⁻³	1.29 x 10 ⁻³
ppm SO ₂	2.86		1	1.00	0.801	0.771	2.33 x 10 ⁻³	1.86 x 10 ⁻³	1.79 x 10 ⁻³
G/GJ									
Coal ^a	2.86	1.39	1.00	1			2.33 x 10 ⁻³		
Oil ^b	3.57	1.74	1.25		1			2.33 x 10 ⁻³	
Gas ^c	3.70	1.80	1.30			1			2.33 x 10 ⁻³
lb/10 ⁶ Btu									
Coal ^a	1,230	598	430	430			1		
Oil ^b	1,540	748	538		430			1	
Gas ^c	1,590	775	557			430			1

Note: g/GJ, grams per gigajoule; lb/10⁶ Btu, pounds per 100,000 British thermal units; Mg/Nm³, megagrams per normal cubic meter; ppm, parts per million.

a. Flue gas dry 6% excess O₂; assumes 350 Nm³/GJ.

b. Flue gas dry 3% excess O₂; assumes 280 Nm³/GJ.

c. Flue gas dry 3% excess O₂; assumes 270 Nm³/GJ.

Source: International Combustion Ltd.; data for coal, oil, and gas based on IEA 1986.

6. Wherever possible, the offset provisions should be implemented within the framework of an overall air quality management strategy designed to ensure that air quality in the airshed is brought into compliance with ambient standards.

7. A normal cubic meter (Nm³) is measured at 1 atmosphere and 0° C. The additional cost of controls designed to meet the 50 mg/Nm³ requirement, rather than one of 150 mg/Nm³ (e.g., less than 0.5% of total investment costs for a 600 MW plant) is expected to be less than the benefits of reducing ambient exposure to particulates. The high overall removal rate is necessary to capture PM₁₀ and fine particulates that seriously affect human health. Typically about 40% of PM by mass is smaller than 10 µm, but the collection efficiency of ESPs drops considerably for smaller particles. A properly designed and well-operated plant can normally achieve the lower emissions levels as easily as it can achieve higher emissions levels.

An exception to the maximum PM emissions level may be granted to engine-driven power plants for which funding applications are received before January 1, 2001. PM emissions levels of up to 75 mg/Nm³ would be allowed, provided that the EA presents documentation to show that (a) lower-ash grades of fuel oil are not commercially available; (b) emissions control technologies are not commercially available; and (c) the resultant ambient levels for PM₁₀ (annual average of less than 50 µg/m³ and 24-hour mean of less than

150 µg/m³) will be maintained for the entire duration of the project.

8. The maximum SO_x emissions levels were back-calculated using the U.S. Environmental Protection Agency Industrial Source Complex (ISC) Model, with the objective of complying with the 1987 WHO Air Quality Guidelines for acceptable one-hour (peak) ambient concentration levels (350 µg/m³). The modeling results show that, in general, an emissions level of 2,000 mg/m³ (equivalent to 0.2 tpd per MWe) results in a one-hour level of 300 µg/m³, which, when added to a typical existing background level of 50 µg/m³ for greenfield sites, produces a one-hour level of 350 µg/m³ (see the discussion of degraded airsheds in the text). Compliance with the WHO one-hour level is normally the most significant, as short-term health impacts are considered to be the most important; compliance with this level also, in general, implies compliance with the WHO 24-hour and annual average guidelines. For large plants, the emissions guidelines for sulfur dioxide were further reduced to 0.1 tpd per MWe for capacities above 500 MWe to maintain acceptable mass loadings to the environment and thus address ecological concerns (acid rain). This results in a sulfur dioxide emissions level of 0.15 tpd/MWe (or 1.275 lb/mm Btu) for a 1,000 MWe plant.

9. Where the nitrogen content of the liquid fuel is greater than 0.015% and the selected equipment manufacturer cannot guarantee the emissions levels pro-

vided in the text, an NO_x emissions allowance (i.e., added to the maximum emissions level) can be computed based on the following data as exceptions:

Nitrogen content (percentage by weight)	Correction factor (NO _x percentage by volume)
0.015–0.1	0.04 N
0.1–0.25	0.004 + 0.0067 (N – 0.1)
> 0.25	0.005

Note: Correction factor, 0.004% = 40 ppm = 80 mg/ Nm³.

There may be cases in which cost-effective NO_x controls may not be technically feasible. Exceptions to the NO_x emissions requirements (including those given in this note) are acceptable provided it can be shown that (a) for the entire duration of the project, the alternative emissions level will not result in ambient conditions that have a significant impact on human health and the environment, and (b) cost-effective techniques such as low-NO_x burners, LEA, water or steam injection, and reburning are not feasible.

10. It should be noted that the offset requirement, which focuses on the level of total emissions, should result in an improvement in ambient air quality within the airshed, compared with the baseline scenario (as documented with ambient air monitoring data), if the offset measures are implemented for non-power-plant sources. Such sources typically emit from stacks of a lower average height than those for the new power plant.

11. Part II of this *Handbook* provides guidance on possible approaches for dealing with acid emissions. There is substantial scope for exploiting the synergies between the local and long-range benefits of emissions reductions.

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