Environmental, Health, and Safety Guidelines for Thermal Power Plants

Introduction

The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP)[1]. When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the **General EHS Guidelines** document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry-sector guidelines may be necessary. A complete list of industry-sector guidelines can be found at: www.ifc.org/ifcext/sustainability.nsf/Content/EnvironmentalGuidelines

The EHS Guidelines contain the performance levels and measures that are generally considered to be achievable in new facilities by existing technology at reasonable costs. Application of the EHS Guidelines to existing facilities may involve the establishment of site-specific targets, based on environmental assessments and/or environmental audits as appropriate, with an appropriate timetable for achieving them. The applicability of the EHS Guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental assessment in which site-specific variables, such as host country context, assimilative capacity of the environment, and other project factors, are taken into account. The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons. When host country regulations differ from the levels and measures presented in the EHS Guidelines, projects are expected to achieve whichever is more stringent. If less stringent levels or measures than those provided in these EHS Guidelines are appropriate, in view of specific project circumstances, a full and detailed justification for any proposed alternatives is needed as part of the site-specific environmental assessment. This justification should demonstrate that the choice for any alternate performance levels is protective of human health and the environment.

Applicability

This document includes information relevant to combustion processes fueled by gaseous, liquid and solid fossil fuels and biomass and designed to deliver electrical or mechanical power, steam, heat, or any combination of these, regardless of the fuel type (except for solid waste which is covered under a separate Guideline for Waste Management Facilities), with a total rated heat input capacity above 50 Megawatt thermal input (MWth) on Higher Heating Value (HHV) basis.[2] It applies to boilers, reciprocating engines, and combustion turbines in new and existing facilities. Annex A contains a detailed description of industry activities for this sector, and Annex B contains guidance for Environmental Assessment (EA) of thermal power projects. Emissions guidelines applicable to facilities with a total heat input capacity of less than 50 MWth are presented in Section 1.1 of the **General EHS Guidelines.** Depending on the characteristics of the project and its associated activities (i.e., fuel sourcing and evacuation of generated electricity), readers should also consult

[1] Defined as the exercise of professional skill, diligence, prudence and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.

[2] Total capacity applicable to a facility with multiple units.

the EHS Guidelines for Mining and the EHS Guidelines for Electric Power Transmission and Distribution.

Decisions to invest in this sector by one or more members of the World Bank Group are made within the context of the World Bank Group strategy on climate change.

This document is organized according to the following sections:

Section 1.0 – Industry Specific Impacts and Management
Section 2.0 – Performance Indicators and Monitoring
Section 3.0 – References and Additional Sources
Annex A – General Description of Industry Activities
Annex B – Environmental Assessment Guidance for Thermal Power Projects.

1.0 Industry-Specific Impacts and Management

The following section provides a summary of the most significant EHS issues associated with thermal power plants, which occur during the operational phase, along with recommendations for their management.

As described in the introduction to the **General EHS Guidelines**, the general approach to the management of EHS issues in industrial development activities, including power plants, should consider potential impacts as early as possible in the project cycle, including the incorporation of EHS considerations into the site selection and plant design processes in order to maximize the range of options available to prevent and control potential negative impacts.

Recommendations for the management of EHS issues common to most large industrial and infrastructure facilities during the construction and decommissioning phases are provided in the **General EHS Guidelines**.

1.1 Environment

Environmental issues in thermal power plant projects primarily include the following:

- Air emissions
- Energy efficiency and Greenhouse Gas emissions
- Water consumption and aquatic habitat alteration
- Effluents
- Solid wastes
- Hazardous materials and oil
- Noise

Air Emissions

The primary emissions to air from the combustion of fossil fuels or biomass are sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), carbon monoxide (CO), and greenhouse gases, such as carbon dioxide (CO_2). Depending on the fuel type and quality, mainly waste fuels or solid fuels, other substances such as heavy metals (i.e., mercury, arsenic, cadmium, vanadium, nickel, etc), halide compounds (including hydrogen fluoride), unburned hydrocarbons and other volatile organic compounds (VOCs) may be emitted in smaller quantities, but may have a significant influence on the environment due to their toxicity and/or persistence. Sulfur dioxide and nitrogen oxide are also implicated in long-range and trans-boundary acid deposition.

The amount and nature of air emissions depends on factors such as the fuel (e.g., coal, fuel oil, natural gas, or biomass), the type and design of the combustion unit (e.g., reciprocating engines, combustion turbines, or boilers), operating practices, emission control measures (e.g., primary combustion control, secondary flue gas treatment), and the overall system efficiency. For example, gas-fired plants generally produce negligible quantities of particulate matter and sulfur oxides, and levels of nitrogen oxides are about 60% of those from plants using coal (without emission reduction measures). Natural gas-fired plants also release lower quantities of carbon dioxide, a greenhouse gas.

Some measures, such as choice of fuel and use of measures to increase energy conversion efficiency, will reduce emissions of multiple air pollutants, including CO_2, per unit of energy generation. Optimizing energy utilization efficiency of the generation process depends on a variety of factors, including the nature and quality of fuel, the type of combustion system, the operating temperature of the combustion turbines, the operating pressure and temperature of steam turbines, the local climate conditions, the type of cooling system used, etc. Recommended measures to prevent, minimize, and control air emissions include:

- Use of the cleanest fuel economically available (natural gas is preferable to oil, which is preferable to coal) if that is consistent with the overall energy and environmental policy of the country or the region where the plant is proposed. For most large power plants, fuel choice is often part of the national energy policy, and fuels, combustion technology and pollution control technology, which are all interrelated, should be evaluated very carefully upstream of the project to optimize the project's environmental performance;
- When burning coal, giving preference to high-heat-content, low-ash, and low-sulfur coal;
- Considering beneficiation to reduce ash content, especially for high ash coal;[3]
- Selection of 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 (some examples include the use of higher energy-efficient systems, such as combined cycle gas turbine system for natural gas and oil-fired units, and supercritical, ultra-supercritical or integrated coal gasification combined cycle (IGCC) technology for coal-fired units);
- Designing stack heights according to Good International Industry Practice (GIIP) to avoid excessive ground level concentrations and minimize impacts, including acid deposition;[4]
- Considering use of combined heat and power (CHP, or co-generation) facilities. By making use of otherwise wasted heat, CHP facilities can achieve thermal efficiencies of 70 – 90 percent, compared with 32 – 45 percent for conventional thermal power plants.

- As stated in the General EHS Guidelines, emissions from a single project should not contribute more than 25% of the applicable ambient air quality standards to allow additional, future sustainable development in the same airshed.[5]

Pollutant-specific control recommendations are provided below.

Sulfur Dioxide

The range of options for the control of sulfur oxides varies substantially because of large differences in the sulfur content of different fuels and in control costs as described in Table 1. The choice of technology depends on a benefit-cost analysis of the environmental performance of different fuels, the cost of controls, and the existence of a market for sulfur control by-products[6]. Recommended measures to prevent, minimize, and control SO_2 emissions include:

[3] If sulfur is inorganically bound to the ash, this will also reduce sulfur content.

[4] For specific guidance on calculating stack height see Annex 1.1.3 of the General EHS Guidelines. Raising stack height should not be used to allow more emissions. However, if the proposed emission rates result in significant incremental ambient air quality impacts to the attainment of the relevant ambient air quality standards, options to raise stack height and/or to further reduce emissions should be considered in the EA. Typical examples of GIIP stack heights are up to around 200m for large coal-fired power plants, up to around 80m for HFO-fueled diesel engine power plants, and up to 100m for gas-fired combined cycle gas turbine power plants. Final selection of the stack height will depend on the terrain of the surrounding areas, nearby buildings, meteorological conditions, predicted incremental impacts and the location of existing and future receptors.

[5] For example, the US EPA Prevention of Significant Deterioration Increments Limits applicable to non-degraded airsheds provide the following: SO_2 (91 μg/m^3 for 2nd highest 24-hour, 20 μg/m^3 for annual average), NO_2 (20 μg/m^3 for annual average), and PM_{10} (30 μg/m^3 for 2nd highest 24-hour, and 17 μg/m^3 for annual average).

- Use of fuels with a lower content of sulfur where economically feasible;
- Use of lime (CaO) or limestone ($CaCO_3$) in coal-fired fluidized bed combustion boilers to have integrated desulfurization which can achieve a removal efficiency of up to 80-90 % through use of Fluidized Bed Combustion[7, 8];
- Depending on the plant size, fuel quality, and potential for significant emissions of SO_2 , use of flue gas desulfurization (FGD) for large boilers using coal or oil and for large reciprocating engines . The optimal type of FGD system (e.g., wet FGD using limestone with 85 to 98% removal efficiency, dry FGD using lime with 70 to 94% removal efficiency, seawater FGD with up to 90% removal efficiency) depends on the capacity of the plant, fuel properties, site conditions, and the cost and availability of reagent as well as by-product disposal and utilization.[9]

Table 1 - Performance / Characteristics of FGDs

Type of FGD	Characteristics	Plant Capital Cost Increase
Wet FGD	• Flue gas is saturated with water • Limestone ($CaCO_3$) as reagent • Removal efficiency up to 98% • Use 1-1.5% of electricity generated • Most widely used • Distance to limestone source and the limestone reactivity to be considered • High water consumption • Need to treat wastewater • Gypsum as a saleable by-product or waste	11-14%
Semi-Dry FGD	• Also called "Dry Scrubbing" – under controlled humidification. • Lime (CaO) as reagent • Removal efficiency up to 94% • Can remove SO_3 as well at higher removal rate than Wet FGD • Use 0.5-1.0% of electricity generated, less than Wet FGD • Lime is more expensive than limestone • No wastewater • Waste – mixture of fly ash, unreacted additive and $CaSO_3$	9-12%
Seawater FGD	• Removal efficiency up to 90% • Not practical for high S coal (>1%S) • Impacts on marine environment need to be carefully examined (e.g., reduction of pH, inputs of remaining heavy metals, fly ash, temperature, sulfate, dissolved oxygen, and chemical oxygen demand) • Use 0.8-1.6% of electricity generated • Simple process, no wastewater or solid waste,	7-10%
Sources: EC (2006) and World Bank Group.		

Nitrogen Oxides

Formation of nitrogen oxides can be controlled by modifying operational and design parameters of the combustion process (primary measures). Additional treatment of NO_X from the flue gas (secondary measures; see Table 2) may be required in some cases depending on the ambient air quality objectives. Recommended measures to prevent, minimize, and control NO_X emissions include:

- Use of low NO_X burners with other combustion modifications, such as low excess air (LEA) firing, for boiler plants. Installation of additional NO_X controls for boilers may be necessary to meet emissions limits; a selective catalytic reduction (SCR) system can be used for pulverized coal-fired, oil-fired, and gas-fired boilers or a selective non-catalytic reduction (SNCR) system for a fluidized-bed boiler;
- Use of dry low-NO_X combustors for combustion turbines burning natural gas;
- Use of water injection or SCR for combustion turbines and

[6] Regenerative Flue Gas Desulfurization (FGD) options (either wet or semi-dray) may be considered under these conditions.
[7] EC (2006).
[8] The SO2 removal efficiency of FBC technologies depends on the sulfur and lime content of fuel, sorbent quantity, ratio, and quality.
[9] The use of wet scrubbers, in addition to dust control equipment (e.g. ESP or Fabric Filter), has the advantage of also reducing emissions of HCl, HF, heavy metals, and further dust remaining after ESP or Fabric Filter. Because of higher costs, the wet scrubbing process is generally not used at plants with a capacity of less than 100 MWth (EC 2006).

reciprocating engines burning liquid fuels;[10]

- Optimization of operational parameters for existing reciprocating engines burning natural gas to reduce NOx emissions;
- Use of lean-burn concept or SCR for new gas engines.

Table 2 - Performance / Characteristics of Secondary NOx Reduction Systems

Type	Characteristics	Plant Capital Cost Increase
SCR	• NOx emission reduction rate of 80 – 95% • Use 0.5% of electricity generated • Use ammonia or urea as reagent. • Ammonia slip increases with increasing NH_3/NOx ratio may cause a problem (e.g., too high ammonia in the fly ash). Larger catalyst volume / improving the mixing of NH_3 and NOx in the flue gas may be needed to avoid this problem. • Catalysts may contain heavy metals. Proper handling and disposal / recycle of spent catalysts is needed. • Life of catalysts has been 6-10 years (coal-fired), 8-12 years (oil-fired) and more than 10 years (gas-fired).	4-9% (coal-fired boiler) 1-2% (gas-fired combined cycle gas turbine) 20-30% (reciprocating engines)
SNCR	• NOx emission reduction rate of 30 – 50% • Use 0.1-0.3% of electricity generated • Use ammonia or urea as reagent. • Cannot be used on gas turbines or gas engines. • Operates without using catalysts.	1-2%
Source: EC (2006), World Bank Group		

Particulate Matter

Particulate matter[11] is emitted from the combustion process, especially from the use of heavy fuel oil, coal, and solid biomass. The proven technologies for particulate removal in power plants are fabric filters and electrostatic precipitators (ESPs), shown in Table 3. The choice between a fabric filter and an ESP depends on the fuel properties, type of FGD system if used for SO_2 control, and ambient air quality objectives. Particulate matter can also be released during transfer and storage of coal and additives, such as lime. Recommendations to prevent, minimize, and control particulate matter emissions include:

- Installation of dust controls capable of over 99% removal efficiency, such as ESPs or Fabric Filters (baghouses), for coal-fired power plants. The advanced control for particulates is a wet ESP, which further increases the removal efficiency and also collects condensables (e.g., sulfuric acid mist) that are not effectively captured by an ESP or a fabric filter;[12]
- Use of loading and unloading equipment that minimizes the height of fuel drop to the stockpile to reduce the generation of fugitive dust and installing of cyclone dust collectors;
- Use of water spray systems to reduce the formation of fugitive dust from solid fuel storage in arid environments;
- Use of enclosed conveyors with well designed, extraction and filtration equipment on conveyor transfer points to prevent the emission of dust;
- For solid fuels of which fine fugitive dust could contain vanadium, nickel and Polycyclic Aromatic Hydrocarbons (PAHs) (e.g., in coal and petroleum coke), use of full enclosure during transportation and covering stockpiles where necessary;
- Design and operate transport systems to minimize the generation and transport of dust on site;
- Storage of lime or limestone in silos with well designed, extraction and filtration equipment;
- Use of wind fences in open storage of coal or use of enclosed storage structures to minimize fugitive dust

[10] Water injection may not be practical for industrial combustion turbines in all cases. Even if water is available, the facilities for water treatment and the operating and maintenance costs of water injection may be costly and may complicate the operation of a small combustion turbine.

[11] Including all particle sizes (e.g. TSP, PM_{10}, and $PM_{2.5}$)

[12] Flue gas conditioning (FGC) is a recommended approach to address the issue of low gas conductivity and lower ESP collection performance which occurs when ESPs are used to collect dust from very low sulfur fuels. One particular FGC design involves introduction of sulfur trioxide (SO_3) gas into the flue gas upstream of the ESP, to increase the conductivity of the flue gas dramatically improve the ESP collection efficiency. There is typically no risk of increased SOx emissions as the SO_3 is highly reactive and adheres to the dust.

emissions where necessary, applying special ventilation systems in enclosed storage to avoid dust explosions (e.g., use of cyclone separators at coal transfer points).

See Annex 1.1.2 of the **General EHS Guidelines** for an additional illustrative presentation of point source emissions prevention and control technologies.

Table 3 – Performance / Characteristics of Dust Removal Systems	
Type	**Performance / Characteristics**
ESP	• Removal efficiency of >96.5% (<1 μm), >99.95% (>10 μm) • 0.1-1.8% of electricity generated is used • It might not work on particulates with very high electrical resistivity. In these cases, flue gas conditioning (FGC) may improve ESP performance. • Can handle very large gas volume with low pressure drops
Fabric Filter	• Removal efficiency of >99.6% (<1 μm), >99.95% (>10 μm). Removes smaller particles than ESPs. • 0.2-3% of electricity generated is used • Filter life decreases as coal S content increases • Operating costs go up considerably as the fabric filter becomes dense to remove more particles • If ash is particularly reactive, it can weaken the fabric and eventually it disintegrates.
Wet Scrubber	• Removal efficiency of >98.5% (<1 μm), >99.9% (>10 μm) • Up to 3% of electricity generated is used. • As a secondary effect, can remove and absorb gaseous heavy metals • Wastewater needs to be treated
Sources: EC (2006) and World Bank Group.	

Other Pollutants

Depending on the fuel type and quality, other air pollutants may be present in environmentally significant quantities requiring proper consideration in the evaluation of potential impacts to ambient air quality and in the design and implementation of management actions and environmental controls. Examples of additional pollutants include mercury in coal, vanadium in heavy fuel oil, and other heavy metals present in waste fuels such as petroleum coke (petcoke) and used lubricating oils[13]. Recommendations to prevent, minimize, and control emissions of other air pollutants such as mercury in particular from thermal power plants include the use of conventional secondary controls such as fabric filters or ESPs operated in combination with FGD techniques, such as limestone FGD, Dry Lime FGD, or sorbent injection.[14] Additional removal of metals such as mercury can be achieved in a high dust SCR system along with powered activated carbon, bromine-enhanced Powdered Activated Carbon (PAC) or other sorbents. Since mercury emissions from thermal power plants pose potentially significant local and transboundary impacts to ecosystems and public health and safety through bioaccumulation, particular consideration should be given to their minimization in the environmental assessment and accordingly in plant design.[15]

Emissions Offsets

Facilities in degraded airsheds should minimize incremental impacts by achieving emissions values outlined in Table 6. Where these emissions values result nonetheless in excessive ambient impacts relative to local regulatory standards (or in their absence, other international recognized standards or guidelines, including World Health Organization guidelines), the project should explore and implement site-specific offsets that result in no net increase in the total emissions of those pollutants (e.g., particulate matter, sulfur dioxide, or nitrogen dioxide) that are responsible for the degradation of the airshed. Offset provisions should be implemented before the power plant comes fully on stream. Suitable offset measures could include reductions in emissions of particulate matter, sulfur dioxide, or nitrogen dioxide, as necessary through (a) the installation of new or more effective controls at other units within the same power plant or at other power plants in

[13] In these cases, the EA should address potential impacts to ambient air quality for such heavy metals as mercury, nickel, vanadium, cadmium, lead, etc.

[14] For Fabric Filters or Electrostatic Precipitators operated in combination with FGD techniques, an average removal rate of 75% or 90 % in the additional presence of SCR can be obtained (EC, 2006).

[15] Although no major industrial country has formally adopted regulatory limits for mercury emissions from thermal power plants, such limitations where under consideration in the United States and European Union as of 2008. Future updates of these EHS Guidelines will reflect changes in the international state of

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. 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. The monitoring and enforcement of ambient air quality in the airshed to ensure that offset provisions are complied with would be the responsibility of the local or national agency responsible for granting and supervising environmental permits. Project sponsors who cannot engage in the negotiations necessary to put together an offset agreement (for example, due to the lack of the local or national air quality management framework) should consider the option of relying on an appropriate combination of using cleaner fuels, more effective pollution controls, or reconsidering the selection of the proposed project site. The overall objective is that the new thermal power plants should not contribute to deterioration of the already degraded airshed.

Energy Efficiency and GHG Emissions

Carbon dioxide, one of the major greenhouse gases (GHGs) under the UN Framework Convention on Climate Change, is emitted from the combustion of fossil fuels. Recommendations to avoid, minimize, and offset emissions of carbon dioxide from new and existing thermal power plants include, among others:

- Use of less carbon intensive fossil fuels (i.e., less carbon containing fuel per unit of calorific value -- gas is less than oil and oil is less than coal) or co-firing with carbon neutral fuels (i.e., biomass);
- Use of combined heat and power plants (CHP) where feasible;
- Use of higher energy conversion efficiency technology of the same fuel type / power plant size than that of the country/region average. New facilities should be aimed to be in top quartile of the country/region average of the same fuel type and power plant size. Rehabilitation of existing facilities must achieve significant improvements in efficiency. Typical CO_2 emissions performance of different fuels / technologies are presented below in Table 4;
- Consider efficiency-relevant trade-offs between capital and operating costs involved in the use of different technologies. For example, supercritical plants may have a higher capital cost than subcritical plants for the same capacity, but lower operating costs. On the other hand, characteristics of existing and future size of the grid may impose limitations in plant size and hence technological choice. These tradeoffs need to be fully examined in the EA;
- Use of high performance monitoring and process control techniques, good design and maintenance of the combustion system so that initially designed efficiency performance can be maintained;
- Where feasible, arrangement of emissions offsets (including the Kyoto Protocol's flexible mechanisms and the voluntary carbon market), including reforestation, afforestation, or capture and storage of CO_2 or other currently experimental options[16];
- Where feasible, include transmission and distribution loss reduction and demand side measures. For example, an investment in peak load management could reduce cycling requirements of the generation facility thereby improving its operating efficiency. The feasibility of these types of off-set options may vary depending on whether the facility is part of a vertically integrated utility or an independent power producer;
- Consider fuel cycle emissions and off-site factors (e.g., fuel

practice regarding mercury emissions prevention and control.

[16] The application of carbon capture and storage (CCS) from thermal power projects is still in experimental stages worldwide although consideration has started to be given to CCS-ready design. Several options are currently under evaluation including CO_2 storage in coal seams or deep aquifers and oil reservoir injection for enhanced oil recovery.

supply, proximity to load centers, potential for off-site use of waste heat, or use of nearby waste gases (blast furnace gases or coal bed methane) as fuel. etc).

Table 4 - Typical CO_2 Emissions Performance of New Thermal Power Plants

Fuel	Efficiency	CO_2 (gCO_2 / kWh – Gross)
Efficiency (% Net, HHV)		
Coal (*1, *2)	Ultra-Supercritical (*1): 37.6 – 42.7 Supercritical: 35.9-38.3 (*1) 39.1 (w/o CCS) (*2) 24.9 (with CCS) (*2) Subcritical: 33.1-35.9 (*1) 36.8 (w/o CCS) (*2) 24.9 (with CCS) (*2) IGCC: 39.2-41.8 (*1) 38.2–41.1 (w/o CCS) (*2) 31.7–32.5 (with CCS) (*2)	 676-795 756-836 763 95 807-907 808 102 654-719 640 – 662 68 – 86
Gas (*2)	Advanced CCGT (*2): 50.8 (w/o CCS) 43.7 (with CCS)	 355 39
Efficiency (% Net, LHV)		
Coal (*3)	42 (Ultra-Supercritical) 40 (Supercritical) 30 – 38 (Subcritical) 46 (IGCC) 38 (IGCC+CCS)	811 851 896-1,050 760 134
Coal and Lignite (*4, *7)	(*4) 43-47 (Coal-PC) >41(Coal-FBC) 42-45 (Lignite-PC) >40 (Lignite-FBC)	(*6) 725-792 (Net) <831 (Net) 808-866 (Net) <909 (Net)
Gas (*4, *7)	(*4) 36–40 (Simple Cycle GT) 38-45 (Gas Engine) 40-42 (Boiler) 54-58 (CCGT)	(*6) 505-561 (Net) 531-449 (Net) 481-505 (Net) 348-374 (Net)
Oil (*4, *7)	(*4) 40 – 45 (HFO/LFO Reciprocating Engine)	(*6) 449-505 (Net)
Efficiency (% Gross, LHV)		
Coal (*5, *7)	(*5) 47 (Ultra-supercritical) 44 (Supercritical) 41-42 (Subcritical) 47-48 (IGCC)	(*6) 725 774 811-831 710-725
Oil (*5, *7)	(*5) 43 (Reciprocating Engine) 41 (Boiler)	(*6) 648 680
Gas (*5)	(*5) 34 (Simple Cycle GT) 51 (CCGT)	(*6) 594 396

Source: (*1) US EPA 2006, (*2) US DOE/NETL 2007, (*3) World Bank, April 2006, (*4) European Commission 2006, (*5) World Bank Group, Sep 2006, (*6) World Bank Group estimates

Water Consumption and Aquatic Habitat Alteration

Steam turbines used with boilers and heat recovery steam generators(HRSG) used in combined cycle gas turbine units require a cooling system to condense steam used to generate electricity. Typical cooling systems used in thermal power plants include: (i) once-through cooling system where sufficient cooling water and receiving surface water are available; (ii) closed circuit wet cooling system; and (iii) closed circuit dry cooling system (e.g., air cooled condensers).

Combustion facilities using once-through cooling systems require large quantities of water which are discharged back to receiving surface water with elevated temperature. Water is also required for boiler makeup, auxiliary station equipment, ash handling, and FGD systems.[17] The withdrawal of such large quantities of water has the potential to compete with other important water uses such as agricultural irrigation or drinking water sources. Withdrawal and discharge with elevated temperature and chemical contaminants such as biocides or other additives, if used, may affect aquatic organisms, including phytoplankton, zooplankton, fish, crustaceans, shellfish, and many other forms of aquatic life. Aquatic organisms drawn into cooling water intake structures are either impinged on components of the cooling water intake structure or entrained in the cooling water system itself. In the case of either impingement or entrainment, aquatic organisms may be killed or subjected to significant harm. In some cases (e.g., sea turtles), organisms are entrapped in the intake canals. There may be special concerns about the potential impacts of cooling water intake structures located in or near habitat areas that support threatened, endangered, or other protected species or where local fishery is active.

Conventional intake structures include traveling screens with relative high through-screen velocities and no fish handling or

[17] The availability of water and impact of water use may affect the choice of FGD

return system.[18] Measures to prevent, minimize, and control environmental impacts associated with water withdrawal should be established based on the results of a project EA, considering the availability and use of water resources locally and the ecological characteristics of the project affected area. Recommended management measures to prevent or control impacts to water resources and aquatic habitats include[19]:

- Conserving water resources, particularly in areas with limited water resources, by:
  - Use of a closed-cycle, recirculating cooling water system (e.g., natural or forced draft cooling tower), or closed circuit dry cooling system (e.g., air cooled condensers) if necessary to prevent unacceptable adverse impacts. Cooling ponds or cooling towers are the primary technologies for a recirculating cooling water system. Once-through cooling water systems may be acceptable if compatible with the hydrology and ecology of the water source and the receiving water and may be the preferred or feasible alternative for certain pollution control technologies such as seawater scrubbers
  - Use of dry scrubbers in situations where these controls are also required or recycling of wastewater in coal-fired plants for use as FGD makeup
  - Use of air-cooled systems
- Reduction of maximum through-screen design intake velocity to 0.5 ft/s;
- Reduction of intake flow to the following levels:
  - For freshwater rivers or streams to a flow sufficient to maintain resource use (i.e., irrigation and fisheries) as well as biodiversity during annual mean low flow conditions[20]
  - For lakes or reservoirs, intake flow must not disrupt the thermal stratification or turnover pattern of the source water
  - For estuaries or tidal rivers, reduction of intake flow to 1% of the tidal excursion volume
- If there are threatened, endangered, or other protected species or if there are fisheries within the hydraulic zone of influence of the intake, reduction of impingement and entrainment of fish and shellfish by the installation of technologies such as barrier nets (seasonal or year-round), fish handling and return systems, fine mesh screens, wedgewire screens, and aquatic filter barrier systems. Examples of operational measures to reduce impingement and entrainment include seasonal shutdowns, if necessary, or reductions in flow or continuous use of screens. Designing the location of the intake structure in a different direction or further out into the water body may also reduce impingement and entrainment.

Effluents

Effluents from thermal power plants include thermal discharges, wastewater effluents, and sanitary wastewater.

Thermal Discharges

As noted above, thermal power plants with steam-powered generators and once-through cooling systems use significant volume of water to cool and condense the steam for return to the boiler. The heated water is normally discharged back to the source water (i.e., river, lake, estuary, or the ocean) or the nearest surface water body. In general, thermal discharge should be designed to ensure that discharge water temperature does not result in exceeding relevant ambient water quality temperature standards outside a scientifically established mixing zone. The mixing zone is typically defined as the zone where initial dilution of a discharge takes place within which relevant water quality

system used (i.e., wet vs. semi-dry).

18 The velocity generally considered suitable for the management of debris is 1 fps [0.30 m/s] with wide mesh screens; a standard mesh for power plants of 3/8 in (9.5 mm).

19 For additional information refer to Schimmoller (2004) and USEPA (2001).

20 Stream flow requirements may be based on mean annual flow or mean low flow. Regulatory requirements may be 5% or higher for mean annual flows and 10% to 25% for mean low flows. Their applicability should be verified on a site-specific

temperature standards are allowed to exceed and takes into account cumulative impact of seasonal variations, ambient water quality, receiving water use, potential receptors and assimilative capacity among other considerations. Establishment of such a mixing zone is project specific and may be established by local regulatory agencies and confirmed or updated through the project's environmental assessment process. Where no regulatory standard exists, the acceptable ambient water temperature change will be established through the environmental assessment process. Thermal discharges should be designed to prevent negative impacts to the receiving water taking into account the following criteria:

- The elevated temperature areas because of thermal discharge from the project should not impair the integrity of the water body as a whole or endanger sensitive areas (such as recreational areas, breeding grounds, or areas with sensitive biota);
- There should be no lethality or significant impact to breeding and feeding habits of organisms passing through the elevated temperature areas;
- There should be no significant risk to human health or the environment due to the elevated temperature or residual levels of water treatment chemicals.

If a once-through cooling system is used for large projects (i.e., a plant with > 1,200MWth steam generating capacity), impacts of thermal discharges should be evaluated in the EA with a mathematical or physical hydrodynamic plume model, which can be a relatively effective method for evaluating a thermal discharge to find the maximum discharge temperatures and flow rates that would meet the environmental objectives of the receiving water.[21]

Recommendations to prevent, minimize, and control thermal discharges include:

- Use of multi-port diffusers;
- Adjustment of the discharge temperature, flow, outfall location, and outfall design to minimize impacts to acceptable level (i.e., extend length of discharge channel before reaching the surface water body for pre-cooling or change location of discharge point to minimize the elevated temperature areas);
- Use of a closed-cycle, recirculating cooling water system as described above (e.g., natural or forced draft cooling tower), or closed circuit dry cooling system (e.g., air cooled condensers) if necessary to prevent unacceptable adverse impacts. Cooling ponds or cooling towers are the primary technologies for a recirculating cooling water system.

Liquid Waste

The wastewater streams in a thermal power plant include cooling tower blowdown; ash handling wastewater; wet FGD system discharges; material storage runoff; metal cleaning wastewater; and low-volume wastewater, such as air heater and precipitator wash water, boiler blowdown, boiler chemical cleaning waste, floor and yard drains and sumps, laboratory wastes, and backflush from ion exchange boiler water purification units. All of these wastewaters are usually present in plants burning coal or biomass; some of these streams (e.g., ash handling wastewater) may be present in reduced quantities or may not be present at all in oil-fired or gas-fired power plants. 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; trace contaminants in the fuel (introduced through the ash-handling wastewater and wet FGD system discharges); and chlorine, biocides, and other chemicals used to manage the quality of water in cooling systems. Cooling tower blowdown tends to be very high in total dissolved solids but is generally classified as non-contact cooling water and, as such,

basis taking into consideration resource use and biodiversity requirements.

[21] An example model is CORMIX (Cornell Mixing Zone Expert System) hydrodynamic mixing zone computer simulation, which has been developed by the U.S. Environmental Protection Agency. This model emphasizes predicting the site- and discharge-specific geometry and dilution characteristics to assess the environmental effects of a proposed discharge.

is typically subject to limits for pH, residual chlorine, and toxic chemicals that may be present in cooling tower additives (including corrosion inhibiting chemicals containing chromium and zinc whose use should be eliminated).

Recommended water treatment and wastewater conservation methods are discussed in Sections 1.3 and 1.4, respectively, of the **General EHS Guidelines**. In addition, recommended measures to prevent, minimize, and control wastewater effluents from thermal power plants include:

- Recycling of wastewater in coal-fired plants for use as FGD makeup. This practice conserves water and reduces the number of wastewater streams requiring treatment and discharge[22];
- In coal-fired power plants without FGD systems, treatment of process wastewater in conventional physical-chemical treatment systems for pH adjustment and removal of total suspended solids (TSS), and oil / grease, at a minimum. Depending on local regulations, these treatment systems can also be used to remove most heavy metals to part-per-billion (ppb) levels by chemical precipitation as either metal hydroxide or metal organosulfide compounds;
- Collection of fly ash in dry form and bottom ash in drag chain conveyor systems in new coal-fired power plants;
- Consider use of soot blowers or other dry methods to remove fireside wastes from heat transfer surfaces so as to minimize the frequency and amount of water used in fireside washes;
- Use of infiltration and runoff control measures such as compacted soils, protective liners, and sedimentation controls for runoff from coal piles;
- Spraying of coal piles with anionic detergents to inhibit bacterial growth and minimize acidity of leachate;[23]
- Use of SO_X removal systems that generate less wastewater, if feasible; however, the environmental and cost characteristics of both inputs and wastes should be assessed on a case-by-case basis;
- Treatment of low-volume wastewater streams that are typically collected in the boiler and turbine room sumps in conventional oil-water separators before discharge;
- Treatment of acidic low-volume wastewater streams, such as those associated with the regeneration of makeup demineralizer and deep-bed condensate polishing systems, by chemical neutralization in-situ before discharge;
- Pretreatment of cooling tower makeup water, installation of automated bleed/feed controllers, and use of inert construction materials to reduce chemical treatment requirements for cooling towers;
- Elimination of metals such as chromium and zinc from chemical additives used to control scaling and corrosion in cooling towers;
- Use the minimum required quantities of chlorinated biocides in place of brominated biocides or alternatively apply intermittent shock dosing of chlorine as opposed to continuous low level feed.

Sanitary Wastewater

Sewage and other wastewater generated from washrooms, etc. are similar to domestic wastewater. Impacts and management of sanitary wastewater is addressed in Section 1.3 of the **General EHS Guidelines.**

Solid Wastes

Coal-fired and biomass-fired thermal power plants generate the greatest amount of solid wastes due to the relatively high percentage of ash in the fuel.[24] The large-volume coal

[22] Suitable wastewater streams for reuse include gypsum wash water, which is a different wastewater stream than the FGD wastewater. In plants that produce marketable gypsum, the gypsum is rinsed to remove chloride and other undesirable trace elements.

[23] If coal pile runoff will be used as makeup to the FGD system, anionic detergents may increase or create foaming within the scrubber system. Therefore, use of anionic surfactants on coal piles should be evaluated on a case-by-case basis.

[24] 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 generate about 500 tons of

combustion wastes (CCW) are fly ash, bottom ash, boiler slag, and FGD sludge. Biomass contains less sulfur; therefore FGD may not be necessary. Fluidized-bed combustion (FBC) boilers generate fly ash and bottom ash, which is called bed ash. Fly ash removed from exhaust gases makes up 60–85% of the coal ash residue in pulverized-coal boilers and 20% in stoker boilers. Bottom ash includes slag and particles that are coarser and heavier than fly ash. Due to the presence of sorbent material, FBC wastes have a higher content of calcium and sulfate and a lower content of silica and alumina than conventional coal combustion wastes. Low-volume solid wastes from coal-fired thermal power plants and other plants include coal mill rejects/pyrites, cooling tower sludge, wastewater treatment sludge, and water treatment sludge.

Oil combustion wastes include fly ash and bottom ash and are normally only generated in significant quantities when residual fuel oil is burned in oil-fired steam electric boilers. Other technologies (e.g., combustion turbines and diesel engines) and fuels (e.g., distillate oil) generate little or no solid wastes. Overall, oil combustion wastes are generated in much smaller quantities than the large-volume CCW discussed above. Gas-fired thermal power plants generate essentially no solid waste because of the negligible ash content, regardless of the combustion technology.

Metals are constituents of concern in both CCW and low-volume solid wastes. For example, 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.

Ash residues are not typically classified as a hazardous waste due to their inert nature.[25] However, where ash residues are expected to contain potentially significant levels of heavy metals, radioactivity, or other potentially hazardous materials, they should be tested at the start of plant operations to verify their classification as hazardous or non-hazardous according to local regulations or internationally recognized standards. Additional information about the classification and management of hazardous and non-hazardous wastes is presented in Section 1.6 of the **General EHS Guidelines.**

The high-volume CCWs wastes are typically managed in landfills or surface impoundments or, increasingly, may be applied to a variety of beneficial uses. Low-volume wastes are also managed in landfills or surface impoundments, but are more frequently managed in surface impoundments. Many coal-fired plants co-manage large-volume and low-volume wastes.

Recommended measures to prevent, minimize, and control the volume of solid wastes from thermal power plants include:

- Dry handling of the coal combustion wastes, in particular fly ash. Dry handling methods do not involve surface impoundments and, therefore, do not present the ecological risks identified for impoundments (e.g., metal uptake by wildlife);
- Recycling of CCWs in uses such as cement and other concrete products, construction fills (including structural fill, flowable fill, and road base), agricultural uses such as calcium fertilizers (provided trace metals or other potentially hazardous materials levels are within accepted thresholds), waste management applications, mining applications, construction materials (e.g., synthetic gypsum for plasterboard), and incorporation into other products provided the residues (such as trace metals and radioactivity) are not considered hazardous. Ensuring consistent quality of fuels and additives helps to ensure the CCWs can be recycled. If beneficial reuse is not feasible, disposal of CCW in permitted landfills with environmental controls such as run-on/run-off controls, liners, leachate collection systems, ground-water monitoring, closure controls, daily (or other operational) cover, and fugitive dust controls is recommended;

solid waste per day.

25 Some countries may categorize fly ash as hazardous due to the presence of arsenic or radioactivity, precluding its use as a construction material.

- Dry collection of bottom ash and fly ash from power plants combusting heavy fuel oil if containing high levels of economically valuable metals such as vanadium and recycle for vanadium recovery (where economically viable) or disposal in a permitted landfill with environmental controls;
- Management of 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 addition to the transport of suspended solids in surface runoff due to seasonal precipitation and flooding. In particular, construction, operation, and maintenance of surface impoundments should be conducted in accordance with internationally recognized standards.[26, 27]
- Reuse of sludge from treatment of waste waters from FGD plants. This sludge may be re-used in the FGD plant due to the calcium components. It can also be used as an additive in coal-fired plant combustion to improve the ash melting behavior

Hazardous Materials and Oil

Hazardous materials stored and used at combustion facilities include solid, liquid, and gaseous waste-based fuels; air, water, and wastewater treatment chemicals; and equipment and facility maintenance chemicals (e.g., paint certain types of lubricants, and cleaners). Spill prevention and response guidance is addressed in Sections 1.5 and 3.7 of the **General EHS Guidelines**.

In addition, recommended measures to prevent, minimize, and control hazards associated with hazardous materials storage and handling at thermal power plants include the use of double-walled, underground pressurized tanks for storage of pure liquefied ammonia (e.g., for use as reagent for SCR) in quantities over 100 m^3; tanks of lesser capacity should be manufactured using annealing processes (EC 2006).

Noise

Principal sources of noise in thermal power plants include the turbine generators and auxiliaries; boilers and auxiliaries, such as coal pulverizers; reciprocating engines; fans and ductwork; pumps; compressors; condensers; precipitators, including rappers and plate vibrators; piping and valves; motors; transformers; circuit breakers; and cooling towers. Thermal power plants used for base load operation may operate continually while smaller plants may operate less frequently but still pose a significant source of noise if located in urban areas.

Noise impacts, control measures, and recommended ambient noise levels are presented in Section 1.7 of the **General EHS Guidelines**. Additional recommended measures to prevent, minimize, and control noise from thermal power plants include:

- Siting new facilities with consideration of distances from the noise sources to the receptors (e.g., residential receptors, schools, hospitals, religious places) to the extent possible. If the local land use is not controlled through zoning or is not effectively enforced, examine whether residential receptors could come outside the acquired plant boundary. In some cases, it could be more cost effective to acquire additional land as buffer zone than relying on technical noise control measures, where possible;
- Use of noise control techniques such as: using acoustic machine enclosures; selecting structures according to their noise isolation effect to envelop the building; using mufflers or silencers in intake and exhaust channels; using sound-absorptive materials in walls and ceilings; using vibration isolators and flexible connections (e.g., helical steel springs and rubber elements); applying a carefully detailed design to prevent possible noise leakage through openings or to minimize pressure variations in piping;

[26] See, for example, U.S. Department of Labor, Mine Safety and Health Administration regulations at 30 CFR §§ 77.214 - 77.216.

[27] Additional detailed guidance applicable to the prevention and control of impacts to soil and water resources from non-hazardous and hazardous solid waste disposal is presented in the World Bank Group EHS Guidelines for Waste Management Facilities.

- Modification of the plant configuration or use of noise barriers such as berms and vegetation to limit ambient noise at plant property lines, especially where sensitive noise receptors may be present.

Noise propagation models may be effective tools to help evaluate noise management options such as alternative plant locations, general arrangement of the plant and auxiliary equipment, building enclosure design, and, together with the results of a baseline noise assessment, expected compliance with the applicable community noise requirements.

1.2 Occupational Health and Safety

Occupational health and safety risks and mitigation measures during construction, operation, and decommissioning of thermal power plants are similar to those at other large industrial facilities, and are addressed in Section 2.0 of the **General EHS Guidelines**. In addition, the following health and safety impacts are of particular concern during operation of thermal power plants:

- Non-ionizing radiation
- Heat
- Noise
- Confined spaces
- Electrical hazards
- Fire and explosion hazards
- Chemical hazards
- Dust

Non-ionizing radiation

Combustion facility workers may have a higher exposure to electric and magnetic fields (EMF) than the general public due to working in proximity to electric power generators, equipment, and connecting high-voltage transmission lines. Occupational EMF exposure should be prevented or minimized through the preparation and implementation of an EMF safety program including the following components:

- Identification of potential exposure levels in the workplace, including surveys of exposure levels in new projects and the use of personal monitors during working activities;
- Training of workers in the identification of occupational EMF levels and hazards;
- Establishment and identification of safety zones to differentiate between work areas with expected elevated EMF levels compared to those acceptable for public exposure, limiting access to properly trained workers;
- Implementation of action plans to address potential or confirmed exposure levels that exceed reference occupational exposure levels developed by international organizations such as the International Commission on Non-Ionizing Radiation Protection (ICNIRP), the Institute of Electrical and Electronics Engineers (IEEE).[28] Personal exposure monitoring equipment should be set to warn of exposure levels that are below occupational exposure reference levels (e.g., 50 percent). Action plans to address occupational exposure may include limiting exposure time through work rotation, increasing the distance between the source and the worker, when feasible, or the use of shielding materials.

Heat

Occupational exposure to heat occurs during operation and maintenance of combustion units, pipes, and related hot equipment. Recommended prevention and control measures to address heat exposure at thermal power plants include:

- Regular inspection and maintenance of pressure vessels and piping;
- Provision of adequate ventilation in work areas to reduce heat and humidity;

[28] The ICNIRP exposure guidelines for Occupational Exposure are listed in Section 2.2 of this Guideline.

- Reducing the time required for work in elevated temperature environments and ensuring access to drinking water;
- Shielding surfaces where workers come in close contact with hot equipment, including generating equipment, pipes etc;
- Use of warning signs near high temperature surfaces and personal protective equipment (PPE) as appropriate, including insulated gloves and shoes.

Noise

Noise sources in combustion facilities include the turbine generators and auxiliaries; boilers and auxiliaries, such as pulverizers; diesel engines; fans and ductwork; pumps; compressors; condensers; precipitators, including rappers and plate vibrators; piping and valves; motors; transformers; circuit breakers; and cooling towers. Recommendations for reducing noise and vibration are discussed in Section 1.1, above. In addition, recommendations to prevent, minimize, and control occupational noise exposures in thermal power plants include:

- Provision of sound-insulated control rooms with noise levels below 60 dBA[29];
- Design of generators to meet applicable occupational noise levels;
- Identify and mark high noise areas and require that personal noise protecting gear is used all the time when working in such high noise areas (typically areas with noise levels >85 dBA).

Confined Spaces

Specific areas for confined space entry may include coal ash containers, turbines, condensers, and cooling water towers (during maintenance activities). Recommend confined space entry procedures are discussed in Section 2.8 of the **General EHS Guidelines**.

Electrical Hazards

Energized equipment and power lines can pose electrical hazards for workers at thermal power plants. Recommended measures to prevent, minimize, and control electrical hazards at thermal power plants include:

- Consider installation of hazard warning lights inside electrical equipment enclosures to warn of inadvertent energization;
- Use of voltage sensors prior to and during workers' entrance into enclosures containing electrical components;
- Deactivation and proper grounding of live power equipment and distribution lines according to applicable legislation and guidelines whenever possible before work is performed on or proximal to them;
- Provision of specialized electrical safety training to those workers working with or around exposed components of electric circuits. This training should include, but not be limited to, training in basic electrical theory, proper safe work procedures, hazard awareness and identification, proper use of PPE, proper lockout/tagout procedures, first aid including CPR, and proper rescue procedures. Provisions should be made for periodic retraining as necessary.

Fire and Explosion Hazards

Thermal power plants store, transfer, and use large quantities of fuels; therefore, careful handling is necessary to mitigate fire and explosion risks. In particular, fire and explosion hazards increase as the particle size of coal is reduced. Particle sizes of coal that can fuel a propagating explosion occur within thermal dryers, cyclones, baghouses, pulverized-fuel systems, grinding mills, and other process or conveyance equipment. Fire and explosion prevention management guidance is provided in Section 2.1 and

[29] Depending on the type and size of the thermal power plants, distance between control room and the noise emitting sources differs. CSA Z107.58 provides design guidelines for control rooms as 60 dBA. Large thermal power plants using steam boilers or combustion turbines tend to be quieter than 60 dBA. Reciprocating engine manufacturers recommend 65 to 70 dBA instead of 60 dBA (Euromot Position as of 9 May 2008). This guideline recommends 60 dBA as GIIP, with an understanding that up to 65 dBA can be accepted for reciprocating engine power plants if 60 dBA is economically difficult to achieve.

2.4 of the **General EHS Guidelines**. Recommended measures to prevent, minimize, and control physical hazards at thermal power plants include:

- Use of automated combustion and safety controls;
- Proper maintenance of boiler safety controls;
- Implementation of startup and shutdown procedures to minimize the risk of suspending hot coal particles (e.g., in the pulverizer, mill, and cyclone) during startup;
- Regular cleaning of the facility to prevent accumulation of coal dust (e.g., on floors, ledges, beams, and equipment);
- Removal of hot spots from the coal stockpile (caused by spontaneous combustion) and spread until cooled, never loading hot coal into the pulverized fuel system;
- Use of automated systems such as temperature gauges or carbon monoxide sensors to survey solid fuel storage areas to detect fires caused by self-ignition and to identify risk points.

Chemical Hazards

Thermal power plants utilize hazardous materials, including ammonia for NO_X control systems, and chlorine gas for treatment of cooling tower and boiler water. Guidance on chemical hazards management is provided in Section 2.4 of the **General EHS Guidelines.** Additional, recommended measures to prevent, minimize, and control physical hazards at thermal power plants include:

- Consider generation of ammonia on site from urea or use of aqueous ammonia in place of pure liquefied ammonia;
- Consider use of sodium hypochlorite in place of gaseous chlorine.

Dust

Dust is generated in handing solid fuels, additives, and solid wastes (e.g., ash). Dust may contain silica (associated with silicosis), arsenic (skin and lung cancer), coal dust (black lung), and other potentially harmful substances. Dust management guidance is provided in the Section 2.1 and 2.4 of the **General EHS Guidelines.** Recommended measures to prevent, minimize, and control occupational exposure to dust in thermal power plants include:

- Use of dust controls (e.g., exhaust ventilation) to keep dust below applicable guidelines (see Section 2) or wherever free silica levels in airborne dust exceed 1 percent;
- Regular inspection and maintenance of asbestos containing materials (e.g., insulation in older plants may contain asbestos) to prevent airborne asbestos particles.

1.3 Community Health and Safety

Many community health and safety impacts during the construction, operation, and decommissioning of thermal power plant projects are common to those of most infrastructure and industrial facilities and are discussed in Section 3.0 the **General EHS Guidelines**. In addition to these and other aspects covered in Section 1.1, the following community health and safety impacts may be of particular concern for thermal power plant projects:

- Water Consumption;
- Traffic Safety.

Water Consumption

Boiler units require large amounts of cooling water for steam condensation and efficient thermal operation. The cooling water flow rate through the condenser is by far the largest process water flow, normally equating to about 98 percent of the total process water flow for the entire unit. In a once-through cooling water system, water is usually taken into the plant from surface waters, but sometimes ground waters or municipal supplies are used. The potential effects of water use should be assessed, as discussed in Section 3.1 of the **General EHS Guidelines**, to ensure that the project does not compromise the availability of water for personal hygiene, agriculture, recreation, and other community needs.

Traffic Safety

Operation of a thermal power plant will increase traffic volume, in particular for facilities with fuels transported via land and sea, including heavy trucks carrying fuel, additives, etc. The increased traffic can be especially significant in sparsely populate areas where some thermal power plants are located. Prevention and control of traffic-related injuries are discussed in Section 3.4 of the **General EHS Guidelines**. Water transport safety is covered in the **EHS Guidelines for Shipping**.

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

Effluent guidelines are described in Table 5. Emissions guidelines are described in Table 6. Effluent guidelines are applicable for direct discharges of treated effluents to surface waters for general use. Site-specific discharge levels may be established based on the availability and conditions in the use of publicly operated sewage collection and treatment systems or, if discharged directly to surface waters, on the receiving water use classification as described in the **General EHS Guideline.** Guideline values for process emissions and effluents in this sector are indicative of good international industry practice as reflected in standards of countries with recognized regulatory frameworks. These levels should be achieved, without dilution, at least 95 percent of the time that the plant or unit is operating, to be calculated as a proportion of annual operating hours. Deviation from these levels due to specific local project conditions should be justified in the environmental assessment.

Table 5 - Effluent Guidelines
(To be applicable at relevant wastewater stream: e.g., from FGD system, wet ash transport, washing boiler / air preheater and precipitator, boiler acid washing, regeneration of demineralizers and condensate polishers, oil-separated water, site drainage, coal pile runoff, and cooling water)

Parameter	mg/L, except pH and temp
pH	6 – 9
TSS	50
Oil and grease	10
Total residual chlorine	0.2
Chromium - Total (Cr)	0.5
Copper (Cu)	0.5
Iron (Fe)	1.0
Zinc (Zn)	1.0
Lead (Pb)	0.5
Cadmium (Cd)	0.1
Mercury (Hg)	0.005
Arsenic (As)	0.5
Temperature increase by thermal discharge from cooling system	• Site specific requirement to be established by the EA. • Elevated temperature areas due to discharge of once-through cooling water (e.g., 1 Celsius above, 2 Celsius above, 3 Celsius above ambient water temperature) should be minimized by adjusting intake and outfall design through the project specific EA depending on the sensitive aquatic ecosystems around the discharge point.
Note: Applicability of heavy metals should be determined in the EA. Guideline limits in the Table are from various references of effluent performance by thermal power plants.	

Emissions levels for the design and operation of each project should be established through the EA process on the basis of country legislation and the recommendations provided in this guidance document, as applied to local conditions. The emissions levels selected should be justified in the EA.[30] 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

[30] For example, in cases where potential for acid deposition has been identified as a significant issue in the EA, plant design and operation should ensure that emissions mass loadings are effectively reduced to prevent or minimize such impacts.

below the design specification. Dilution of air emissions to achieve these guidelines is unacceptable. Compliance with ambient air quality guidelines should be assessed on the basis of good international industry practice (GIIP) recommendations.

As described in the General EHS Guidelines, emissions should not result in pollutant concentrations that reach or exceed relevant ambient quality guidelines and standards[31] by applying national legislated standards, or in their absence, the current WHO Air Quality Guidelines[32], or other internationally recognized sources[33]. Also, emissions from a single project should not contribute more than 25% of the applicable ambient air quality standards to allow additional, future sustainable development in the same airshed. [34]

As described in the General EHS Guidelines, facilities or projects located within poor quality airsheds[35], and within or next to areas established as ecologically sensitive (e.g., national parks), should ensure that any increase in pollution levels is as small as feasible, and amounts to a fraction of the applicable short-term and annual average air quality guidelines or standards as established in the project-specific environmental assessment.

Environmental Monitoring

Environmental monitoring programs for this sector are presented in Table 7. 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. Examples of emissions, stack testing, ambient air quality, and noise monitoring recommendations applicable to power plants are provided in Table 7. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the **General EHS Guidelines**.

31 Ambient air quality standards are ambient air quality levels established and published through national legislative and regulatory processes, and ambient quality guidelines refer to ambient quality levels primarily developed through clinical, toxicological, and epidemiological evidence (such as those published by the World Health Organization).

32 Available at World Health Organization (WHO). http://www.who.int/en

33 For example the United States National Ambient Air Quality Standards (NAAQS) (http://www.epa.gov/air/criteria.html) and the relevant European Council Directives (Council Directive 1999/30/EC of 22 April 1999 / Council Directive 2002/3/EC of February 12 2002).

34 US EPA Prevention of Significant Deterioration Increments Limits applicable to non-degraded airsheds.

35 An airshed should be considered as having poor air quality if nationally legislated air quality standards or WHO Air Quality Guidelines are exceeded significantly.

Table 6 (A) - Emissions Guidelines (in mg/Nm^3 or as indicated) for Reciprocating Engine

Note:

- **Guidelines are applicable for new facilities.**
- **EA may justify more stringent or less stringent limits due to ambient environment, technical and economic considerations provided there is compliance with applicable ambient air quality standards and incremental impacts are minimized.**
- **For projects to rehabilitate existing facilities, case-by-case emission requirements should be established by the EA considering (i) the existing emission levels and impacts on the environment and community health, and (ii) cost and technical feasibility of bringing the existing emission levels to meet these new facilities limits.**
- **EA should demonstrate that emissions do not contribute a significant portion to the attainment of relevant ambient air quality guidelines or standards, and more stringent limits may be required.**

Combustion Technology / Fuel	Particulate Matter (PM)		Sulfur Dioxide (SO_2)		Nitrogen Oxides (NOx)		Dry Gas, Excess O_2 Content (%)
Reciprocating Engine	NDA	DA	NDA	DA	NDA	DA	
Natural Gas	N/A	N/A	N/A	N/A	200 (Spark Ignition) 400 (Dual Fuel) (a)	200(SI) 400 (Dual Fuel / CI)	15%
Liquid Fuels (Plant >50 MWth to <300 MWth)	50	30	1,170 or use of 2% or less S fuel	0.5% S	1,460 (Compression Ignition, bore size diameter [mm] < 400) 1,850 (Compression Ignition, bore size diameter [mm] ≥ 400) 2,000 (Dual Fuel)	400	15%
Liquid Fuels (Plant >/=300 MWth)	50	30	585 or use of 1% or less S fuel	0.2% S	740 (contingent upon water availability for injection)	400	15%
Biofuels / Gaseous Fuels other than Natural Gas	50	30	N/A	N/A	30% higher limits than those provided above for Natural Gas and Liquid Fuels.	200 (SI, Natural Gas), 400 (other)	15%

General notes:

- MWth = Megawatt thermal input on HHV basis; N/A = not applicable; NDA = Non-degraded airshed; DA = Degraded airshed (poor air quality); Airshed should be considered as being degraded if nationally legislated air quality standards are exceeded or, in their absence, if WHO Air Quality Guidelines are exceeded significantly; S = sulfur content (expressed as a percent by mass); Nm^3 is at one atmospheric pressure, 0 degree Celsius; MWth category is to apply to the entire facility consisting of multiple units that are reasonably considered to be emitted from a common stack. Guideline limits apply to facilities operating more than 500 hours per year. Emission levels should be evaluated on a one hour average basis and be achieved 95% of annual operating hours.
- (a) Compression Ignition (CI) engines may require different emissions values which should be evaluated on a case-by-case basis through the EA process.

Comparison of the Guideline limits with standards of selected countries / region (as of August 2008):

- Natural Gas-fired Reciprocating Engine – NOx
  - Guideline limits: 200 (SI), 400 (DF)
  - UK: 100 (CI) , US: Reduce by 90% or more, or alternatively 1.6 g/kWh
- Liquid Fuels-fired Reciprocating Engine – NOx (Plant >50 MWth to <300 MWth)
  - Guideline limits: 1,460 (CI, bore size diameter < 400 mm), 1,850 (CI, bore size diameter ≥ 400 mm), 2,000 (DF)
  - UK: 300 (> 25 MWth), India: 1,460 (Urban area & ≤ 75 MWe (≈ 190 MWth), Rural area & ≤ 150 MWe (≈ 380 MWth))
- Liquid Fuels-fired Reciprocating Engine – NOx (Plant ≥300 MWth)
  - Guideline limits: 740 (contingent upon water availability for injection)
  - UK: 300 (> 25 MWth), India: 740 (Urban area & > 75MWe (≈ 190 MWth), Rural area & > 150 MWe (≈ 380 MWth))
- Liquid Fuels-fired Reciprocating Engine – SO2
  - Guideline limits: 1,170 or use of ≤ 2% S (Plant >50 MWth to <300 MWth), 585 or use of ≤ 1% S (Plant ≥300 MWth)
  - EU: Use of low S fuel oil or the secondary FGD (IPCC LCP BREF), HFO S content ≤ 1% (Liquid Fuel Quality Directive), US: Use of diesel fuel with max S of 500 ppm (0.05%); EU: Marine HFO S content ≤ 1.5% (Liquid Fuel Quality Directive) used in SOx Emission Control Areas; India: Urban (< 2% S), Rural (< 4%S), Only diesel fuels (HSD, LDO) should be used in Urban

Source: UK (S2 1.03 Combustion Processes: Compression Ignition Engines, 50 MWth and over), India (SOx/NOx Emission Standards for Diesel Engines ≥ 0.8 MW), EU (IPCC LCP BREF July 2006), EU (Liquid Fuel Quality Directive 1999/32/EC amended by 2005/33/EC), US (NSPS for Stationary Compression Ignition Internal Combustion Engine – Final Rule – July 11, 2006)

Table 6 (B) - Emissions Guidelines (in mg/Nm³ or as indicated) for Combustion Turbine

Note:

- **Guidelines are applicable for new facilities.**
- **EA may justify more stringent or less stringent limits due to ambient environment, technical and economic considerations provided there is compliance with applicable ambient air quality standards and incremental impacts are minimized.**
- **For projects to rehabilitate existing facilities, case-by-case emission requirements should be established by the EA considering (i) the existing emission levels and impacts on the environment and community health, and (ii) cost and technical feasibility of bringing the existing emission levels to meet these new facilities limits.**
- **EA should demonstrate that emissions do not contribute a significant portion to the attainment of relevant ambient air quality guidelines or standards, and more stringent limits may be required.**

Combustion Technology / Fuel	Particulate Matter (PM)		Sulfur Dioxide (SO_2)		Nitrogen Oxides (NOx)	Dry Gas, Excess O_2 Content (%)
Combustion Turbine			NDA/DA		NDA/DA	
Natural Gas (all turbine types of Unit > 50MWth)	N/A	N/A	N/A	N/A	51 (25 ppm)	15%
Fuels other than Natural Gas (Unit > > 50MWth)	50	30	Use of 1% or less S fuel	Use of 0.5% or less S fuel	152 (74 ppm)[a]	15%

General notes:

- MWth = Megawatt thermal input on HHV basis; N/A = not applicable; NDA = Non-degraded airshed; DA = Degraded airshed (poor air quality); Airshed should be considered as being degraded if nationally legislated air quality standards are exceeded or, in their absence, if WHO Air Quality Guidelines are exceeded significantly; S = sulfur content (expressed as a percent by mass); Nm³ is at one atmospheric pressure, 0 degree Celsius; MWth category is to apply to single units; Guideline limits apply to facilities operating more than 500 hours per year. Emission levels should be evaluated on a one hour average basis and be achieved 95% of annual operating hours.
- If supplemental firing is used in a combined cycle gas turbine mode, the relevant guideline limits for combustion turbines should be achieved including emissions from those supplemental firing units (e.g., duct burners).
- (a) Technological differences (for example the use of Aeroderivatives) may require different emissions values which should be evaluated on a cases-by-case basis through the EA process but which should not exceed 200 mg/Nm3.

Comparison of the Guideline limits with standards of selected countries / region (as of August 2008):

- Natural Gas-fired Combustion Turbine – NOx
  - Guideline limits: 51 (25 ppm)
  - EU: 50 (24 ppm), 75 (37 ppm) (if combined cycle efficiency > 55%), 50*η / 35 (where η = simple cycle efficiency)
  - US: 25 ppm (> 50 MMBtu/h (≈ 14.6 MWth) and ≤ 850 MMBtu/h (≈ 249MWth)), 15 ppm (> 850 MMBtu/h (≈ 249 MWth))
  - (Note: further reduced NOx ppm in the range of 2 to 9 ppm is typically required through air permit)
- Liquid Fuel-fired Combustion Turbine – NOx
  - Guideline limits: 152 (74 ppm) – Heavy Duty Frame Turbines & LFO/HFO, 300 (146 ppm) – Aeroderivatives & HFO, 200 (97 ppm) – Aeroderivatives & LFO
  - EU: 120 (58 ppm), US: 74 ppm (> 50 MMBtu/h (≈ 14.6 MWth) and ≤ 850 MMBtu/h (≈ 249MWth)), 42 ppm (> 850 MMBtu/h (≈ 249 MWth))
- Liquid Fuel-fired Combustion Turbine – SOx
  - Guideline limits: Use of 1% or less S fuel
  - EU: S content of light fuel oil used in gas turbines below 0.1% / US: S content of about 0.05% (continental area) and 0.4% (non-continental area)

Source: EU (LCP Directive 2001/80/EC October 23 2001), EU (Liquid Fuel Quality Directive 1999/32/EC, 2005/33/EC), US (NSPS for Stationary Combustion Turbines, Final Rule – July 6, 2006)

Table 6 (C) - Emissions Guidelines (in mg/Nm³ or as indicated) for Boiler

Note:

- **Guidelines are applicable for new facilities.**
- **EA may justify more stringent or less stringent limits due to ambient environment, technical and economic considerations provided there is compliance with applicable ambient air quality standards and incremental impacts are minimized.**
- **For projects to rehabilitate existing facilities, case-by-case emission requirements should be established by the EA considering (i) the existing emission levels and impacts on the environment and community health, and (ii) cost and technical feasibility of bringing the existing emission levels to meet these new facilities limits.**
- **EA should demonstrate that emissions do not contribute a significant portion to the attainment of relevant ambient air quality guidelines or standards, and more stringent limits may be required.**

Combustion Technology / Fuel	Particulate Matter (PM)		Sulfur Dioxide (SO_2)		Nitrogen Oxides (NOx)		Dry Gas, Excess O_2 Content (%)
Boiler	NDA	DA	NDA	DA	NDA	DA	
Natural Gas	N/A	N/A	N/A	N/A	240	240	3%
Other Gaseous Fuels	50	30	400	400	240	240	3%
Liquid Fuels (Plant >50 MWth to <600 MWth)	50	30	900 – 1,500[a]	400	400	200	3%
Liquid Fuels (Plant >/=600 MWth)	50	30	200 – 850[b]	200	400	200	3%
Solid Fuels (Plant >50 MWth to <600 MWth)	50	30	900 – 1,500[a]	400	510[c] Or up to 1,100 if volatile matter of fuel < 10%	200	6%
Solid Fuels (Plant >/=600 MWth)	50	30	200 – 850[b]	200			6%

General notes:

- MWth = Megawatt thermal input on HHV basis; N/A = not applicable; NDA = Non-degraded airshed; DA = Degraded airshed (poor air quality); Airshed should be considered as being degraded if nationally legislated air quality standards are exceeded or, in their absence, if WHO Air Quality Guidelines are exceeded significantly; CFB = circulating fluidized bed coal-fired; PC = pulverized coal-fired; Nm³ is at one atmospheric pressure, 0 degree Celsius; MWth category is to apply to the entire facility consisting of multiple units that are reasonably considered to be emitted from a common stack. Guideline limits apply to facilities operating more than 500 hours per year. Emission levels should be evaluated on a one hour average basis and be achieved 95% of annual operating hours.
- a. Targeting the lower guidelines values and recognizing issues related to quality of available fuel, cost effectiveness of controls on smaller units, and the potential for higher energy conversion efficiencies (FGD may consume between 0.5% and 1.6% of electricity generated by the plant). b. Targeting the lower guidelines values and recognizing variability in approaches to the management of SO_2 emissions (fuel quality vs. use of secondary controls) and the potential for higher energy conversion efficiencies (FGD may consume between 0.5% and 1.6% of electricity generated by the plant). Larger plants are expected to have additional emission control measures. Selection of the emission level in the range is to be determined by EA considering the project's sustainability, development impact, and cost-benefit of the pollution control performance. c. Stoker boilers may require different emissions values which should be evaluated on a case-by-case basis through the EA process.

Comparison of the Guideline limits with standards of selected countries / region (as of August 2008):

- Natural Gas-fired Boiler – NOx
  - Guideline limits: 240
  - EU: 150 (50 to 300 MWth), 200 (> 300 MWth)
- Solid Fuels-fired Boiler - PM
  - Guideline limits: 50
  - EU: 50 (50 to 100 MWth), 30 (> 100 MWth), China: 50, India: 100 - 150
- Solid Fuels-fired Boiler – SO_2
  - Guideline limits: 900 – 1,500 (Plant > 50 MWth to < 600 MWth), 200 – 850 (Plant ≥ 600 MWth)
  - EU: 850 (50 – 100 MWth), 200 (> 100 MWth)
  - US: 180 ng/J gross energy output OR 95% reduction (≈ 200 mg/Nm3 at 6%O_2 assuming 38% HHV efficiency)
  - China: 400 (general), 800 (if using coal < 12,550 kJ/kg), 1,200 (if mine-mouth plant located in non-double control area of western region and burning low S coal (<0.5%))

Source: EU (LCP Directive 2001/80/EC October 23 2001), US (NSPS for Electric Utility Steam Generating Units (Subpart Da), Final Rule – June 13, 2007), China (GB 13223-2003)

Table 7 – Typical Air Emission Monitoring Parameters / Frequency for Thermal Power Plants
(Note: Detailed monitoring programs should be determined based on EA)

Combustion Technology / Fuel	Emission Monitoring: Particulate Matter (PM)	Emission Monitoring: Sulfur Dioxide (SO_2)	Emission Monitoring: Nitrogen Oxides (NOx)	Stack Emission Testing: PM	Stack Emission Testing: SO_2	Stack Emission Testing: NOx	Stack Emission Testing: Heavy Metals	Ambient Air Quality	Noise
Reciprocating Engine								If incremental impacts predicted by EA >/= 25 % of relevant short-term ambient air quality standards or if the plant >/= 1,200 MWth: - Monitor parameters (e.g., $PM_{10}/PM_{2.5}/SO_2$/NOx to be consistent with the relevant ambient air quality standards) by continuous ambient air quality monitoring system (typically a minimum of 2 systems to cover predicted maximum ground level concentration point / sensitive receptor / background point). If incremental impacts predicted by EA < 25% of relevant short term ambient air quality standards and if the facility < 1,200 MWth but >/= 100 MWth - Monitor parameters either by passive samplers (monthly average) or by seasonal manual sampling (e.g., 1 weeks/season) for parameters consistent with the relevant air quality standards. Effectiveness of the ambient air quality monitoring program should be reviewed regularly. It could be simplified or reduced if alternative program is developed (e.g., local government's monitoring network). Continuation of the program is recommended during the life of the project if there are sensitive receptors or if monitored levels are not far below the relevant ambient air quality standards.	If EA predicts noise levels at residential receptors or other sensitive receptors are close to the relevant ambient noise standards / guidelines, or if there are such receptors close to the plant boundary (e.g., within 100m) then, conduct ambient noise monitoring every year to three years depending on the project circumstances. Elimination of noise monitoring can be considered acceptable if a comprehensive survey showed that there are no receptors affected by the project or affected noise levels are far below the relevant ambient noise standards / guidelines.
Natural Gas (Plant >50 MWth to <300 MWth)	N/A	N/A	Continuous or indicative	N/A	N/A	Annual	N/A		
Natural Gas (Plant >/= 300 MWth)	N/A	N/A	Continuous	N/A	N/A	Annual	N/A		
Liquid (Plant >50 MWth to <300 MWth)	Continuous or indicative	Continuous if FGD is used or monitor by S content.	Continuous or indicative	Annual	Annual	Annual	Annual		
Liquid (Plant >/=300 MWth)	Continuous or indicative	Continuous if FGD is used or monitor by S content.	Continuous	Annual	Annual	Annual	Annual		
Biomass	Continuous or indicative	N/A	Continuous or indicative	Annual	N/A	Annual	N/A		
Combustion Turbine									
Natural Gas (all turbine types of Unit > 50MWth)	N/A	N/A	Continuous or indicative	N/A	N/A	Annual	N/A		
Fuels other than Natural Gas (Unit > 50MWth)	Continuous or indicative	Continuous if FGD is used or monitor by S content.	Continuous or indicative	Annual	Annual	Annual	Annual		
Boiler									
Natural Gas	N/A	N/A	Continuous or indicative	N/A	N/A	Annual	N/A		
				Annual	Annual	Annual	N/A		
Other Gaseous fuels	Indicative	Indicative	Continuous or indicative	Annual	Annual	Annual	Annual		
Liquid (Plant >50 MWth to <600 MWth)	Continuous or indicative	Continuous if FGD is used or monitor by S content.	Continuous or indicative	Annual	Annual	Annual	Annual		
Liquid (Plant >=600 MWth)	Continuous or indicative	Continuous	Continuous	Annual	Annual	Annual	Annual		
Solid (Plant >50 MWth to <600 MWth)	Continuous or indicative	Continuous if FGD is used or monitor by S Content.	Continuous or indicative	Annual	Annual	Annual	Annual		
Solid (Plant >/=600 MWth)	Continuous or indicative	Continuous	Continuous	Annual	Annual	Annual	Annual		

Note: Continuous or indicative means "Continuously monitor emissions or continuously monitor indicative parameters". Stack emission testing is to have direct measurement of emission levels to counter check the emission monitoring system.

2.2 Occupational Health and Safety

Occupational Health and Safety Guidelines

Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH),[36] the Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),[37] Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),[38] Indicative Occupational Exposure Limit Values published by European Union member states,[39] or other similar sources.

Additional indicators specifically applicable to electric power sector activities include the ICNIRP exposure limits for occupational exposure to electric and magnetic fields listed in Table 8. Additional applicable indicators such as noise, electrical hazards, air quality, etc. are presented in Section 2.0 of the **General EHS Guidelines**.

Table 8 - ICNIRP exposure limits for occupational exposure to electric and magnetic fields.

Frequency	Electric Field (V/m)	Magnetic Field (µT)
50 Hz	10,000	500
60 Hz	8300	415

Source: ICNIRP (1998) : "Guidelines for limiting exposure to time-varying electric, magnetic, and electromagnetic fields (up to 300 GHz)

Accident and Fatality Rates

Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of disability, or even fatalities. The accident and fatality rates of the specific facility may be benchmarked against the performance of facilities in this sector in developed countries through consultation with published sources (e.g., US Bureau of Labor Statistics and UK Health and Safety Executive)[40].

Occupational Health and Safety Monitoring

The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals[41] as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases and dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the **General EHS Guidelines**.

[36] http://www.acgih.org/TLV/[36] Available at: http://www.acgih.org/TLV/ and http://www.acgih.org/store/
[37] Available at: http://www.cdc.gov/niosh/npg/
[38] Available at: http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9992
[39] Available at: http://europe.osha.eu.int/good_practice/risks/ds/oel/
[40] Available at: http://www.bls.gov/iif/ and http://www.hse.gov.uk/statistics/index.htm
[41] Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.

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Annex A: General Description of Industry Activities

Thermal power plants burn fossil fuels or biomass to generate electrical energy and heat. Mechanical power is produced by a heat engine, which transforms thermal energy from combustion of a fossil fuel into rotational energy. A generator converts that mechanical energy into electrical energy by creating relative motion between a magnetic field and a conductor. Figure A-1 is a generalized flow diagram of a boiler-based thermal power plant and its associated operations.

Not all thermal energy can be transformed to mechanical power, according to the second law of thermodynamics. Therefore, thermal power plants also produce low-temperature heat. If no use is found for the heat, it is lost to the environment. If reject heat is employed as useful heat (e.g., for industrial processes or district heating), the power plant is referred to as a cogeneration power plant or CHP (combined heat-and-power) plant.

Types of Thermal power plants

Thermal power plants can be divided based on the type of combustion or gasification: boilers, internal reciprocating engines, and combustion turbines. In addition, combined-cycle and cogeneration systems increase efficiency by utilizing heat lost by conventional combustion systems. The type of system is chosen based on the loads, the availability of fuels, and the energy requirements of the electric power generation facility. Other ancillary processes, such as coal processing and pollution control, must also be performed to support the generation of electricity. The following subsections describe each system and then discuss ancillary processes at the facility (USEPA 1997).

Boilers (Steam Turbines)

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 steam turbine to generate electricity. Heat for the system is usually provided by the combustion of coal, natural gas, oil, or biomass as well as other types of waste or recovered fuel. High-temperature, high-pressure steam is generated in the boiler and then enters the steam turbine. At the other end of the steam turbine is the condenser, which is maintained at a low temperature and pressure. Steam rushing from the high-pressure boiler to the low-pressure condenser drives the turbine blades, which powers the electric generator.

Low-pressure steam exiting the turbine enters the condenser shell and is condensed on the condenser tubes, which are maintained at a low temperature by the flow of cooling water. As the steam is cooled to condensate, the condensate is transported by the boiler feedwater system back to the boiler, where it is used again. A constant flow of low-temperature cooling water in the condenser tubes is required to keep the condenser shell (steam side) at proper pressure and to ensure efficient electricity generation. Through the condensing process, the cooling water is warmed. If the cooling system is an open or a once-through system, this warm water is released back to the source water body.[42] In a closed system, the warm water is cooled by recirculation through cooling towers, lakes, or ponds, where the heat is released into the air through evaporation and/or sensible heat transfer. If a recirculating cooling system is used, only a relatively small amount of make-up water is required to offset the evaporative losses and cooling tower blowdown that must be discharged periodically to control the build-up of solids. A recirculating system uses about one-twentieth the water of a once-through system.

Steam turbines typically have a thermal efficiency of about 35 percent, meaning that 35 percent of the heat of combustion is transformed into electricity. The remaining 65 percent of the heat either goes up the stack (typically 10 percent) or is

[42] If groundwater is used for cooling, the cooling water is usually discharged to a

discharged with the condenser cooling water (typically 55 percent).

Coal and lignite are the most common fuels in thermal power plants although heavy fuel oil is also used. Coal-fired steam generation systems are designed to use pulverized coal or crushed coal. Several types of coal-fired steam generators are in use, and are generally classified based on the characteristics of the coal fed to the burners and the mode of burning the coal. In fluidized-bed combustors, fuel materials are forced by gas into a state of buoyancy. The gas cushion between the solids allows the particles to move freely, thus flowing like a liquid. By using this technology, SO_2 and NO_X emissions are reduced because an SO_2 sorbent, such as limestone, can be used efficiently. Also, because the operating temperature is low, the amount of NO_X gases formed is lower than those produced using conventional technology.

Natural gas and liquid fuels are usually transported to thermal power plants via pipelines. Coal and biomass fuels can be transported by rail, barge, or truck. In some cases, coal is mixed with water to form slurry that can be pumped to the thermal power plant in a pipeline. Once coal arrives at the plant, it is unloaded to storage or directly to the stoker or hopper. In transporting coal during warmer months and in dry climates, dust suppression may be necessary.

Coal may be cleaned and prepared before being either crushed or pulverized. Impurities in coal such as ash, metals, silica, and sulfur can cause boiler fouling and slagging. Coal cleaning can be used to reduce sulfur in the coal to meet sulfur dioxide (SO_2) emissions regulations and also reduce ash content and the amount of heavy metals. Cleaning the coal is costly, but the cost can be at least partially offset by an increase in fuel efficiency, reduced emission control requirements, and lower waste management costs. Coal cleaning is typically performed at the mine by using gravity concentration, flotation, or dewatering methods.

Coal is transported from the coal bunker or silo to be crushed, ground, and dried further before it is fired in the burner or combustion system. Many mechanisms can be used to grind the coal and prepare it for firing. Pulverizers, cyclones, and stokers are all used to grind and dry the coal. Increasing the coal's particle surface area and decreasing its moisture content greatly boosting its heating capacity. Once prepared, the coal is transported within the plant to the combustion system. Devices at the bottom of the boilers catch ash and/or slag.

Reciprocating Engines

Internal combustion engines convert the chemical energy of fuels (typically diesel fuel or heavy fuel oil) into mechanical energy in a design similar to a truck engine, and the mechanical energy is used to turn a generator. Two types of engines normally used: 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. The products of combustion are then removed from the cylinder, completing the cycle.

The exhaust gases from an engine are affected by the load profile of the prime mover; ambient conditions such as air humidity and temperature; fuel oil quality, such as sulfur content, nitrogen content, viscosity, ignition ability, density, and ash content; and 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 NO_X emissions are fuel injection in terms of timing, duration, and atomization; combustion air conditions, which are affected by

surface water body.

valve timing, the charge air system, and charge air cooling before cylinders; and the combustion process, which is affected by air and fuel mixing, combustion chamber design, and the compression ratio.[43] 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%. SOx emissions are directly dependent on the sulfur content of the fuel. Fuel oil may contain as little as 0.3% sulfur and, in some cases, up to 5% sulfur.

Diesel engines are fuel flexible and can use fuels such as diesel oil, heavy fuel oil, natural gas, crude oil, bio-fuels (such as palm oil, etc.) and emulsified fuels (such as Orimulsion, etc.).

Typical electrical efficiencies in single mode are typically ranging from 40 % for the medium speed engines up to about 50 % for large engines and even higher efficiencies in combined cycle mode. Total efficiency in CHP (Combined Heat and Power) is typically in liquid operation up to 60 – 80 % and in gas mode even higher dependent on the application. The heat to power ratio is typically 0.5 to 1.3 in CHP applications, dependent on the application.

Lean Burn Gas Engines

Typical electrical efficiencies for bigger stationary medium speed engines in single mode are typically 40 – 47 % and up to close to 50 % in combined cycle mode. Total efficiency in CHP facilities is typically up to 90 % dependent on the application. The heat to power ratios are typically 0.5 to 1.3 in CHP-applications, dependent on the application.

Spark Ignition (SG)

Often a spark ignited gas-otto engine works according to the lean burn concept meaning that a lean mixture of combustion air and fuel is used in the cylinder (e.g., much more air than needed for the combustion). In order to stabilize the ignition and combustion of the lean mixture, in bigger engine types a prechamber with a richer air/fuel mixture is used. The ignition is initiated with a spark plug or some other device located in the prechamber, resulting in a high-energy ignition source for the main fuel charge in the cylinder. The most important parameter governing the rate of NOx formation in internal combustion engines is the combustion temperature; the higher the temperature the higher the NOx content of the exhaust gases. One method is to lower the fuel/air ratio, the same specific heat quantity released by the combustion of the fuel is then used to heat up a larger mass of exhaust gases, resulting in a lower maximum combustion temperature. This method low fuel/air ratio is called lean burn and it reduces NOx effectively. The spark-ignited lean-burn engine has therefore low NOx emissions. This is a pure gas engine; it operates only on gaseous fuels.

Dual fuel engines (DF)

Some DF engine types are fuel versatile, these can be run on low pressure natural gas or liquid fuels such as diesel oil (as back-up fuel, etc.), heavy fuel oil, etc. This engine type can operate at full load in both fuel modes. Dual Fuel (DF) engines can also be designed to work in gas mode only with a pilot liquid fuel used for ignition of the gas.

Combustion Turbines

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 air, which is then mixed with either gas or liquid

[43] 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.

fuel in a combustion chamber. The greater the compression, the higher the temperature and the efficiency that can be achieved in a gas turbine. Higher temperatures, however, typically lead to increases in NO_X emissions. Exhaust gases are emitted to the atmosphere from the turbine. Unlike a steam turbine system, gas turbine systems do not have boilers or a steam supply, condensers, or a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system.

In electrical power applications, gas turbines are often used for peaking duty, where rapid startup and short runs are needed. Most installed simple gas turbines with no controls have only a 20- to 30-percent efficiency.

Combined Cycle

Combined-cycle generation is a configuration using both gas turbines and steam generators. In a combined-cycle gas turbine (CCGT), the hot exhaust 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 to approximately 50 - 60 percent. Combined-cycle systems may have multiple gas turbines driving one steam turbine. Combined-cycle systems with diesel engines and steam generators are also sometimes used.

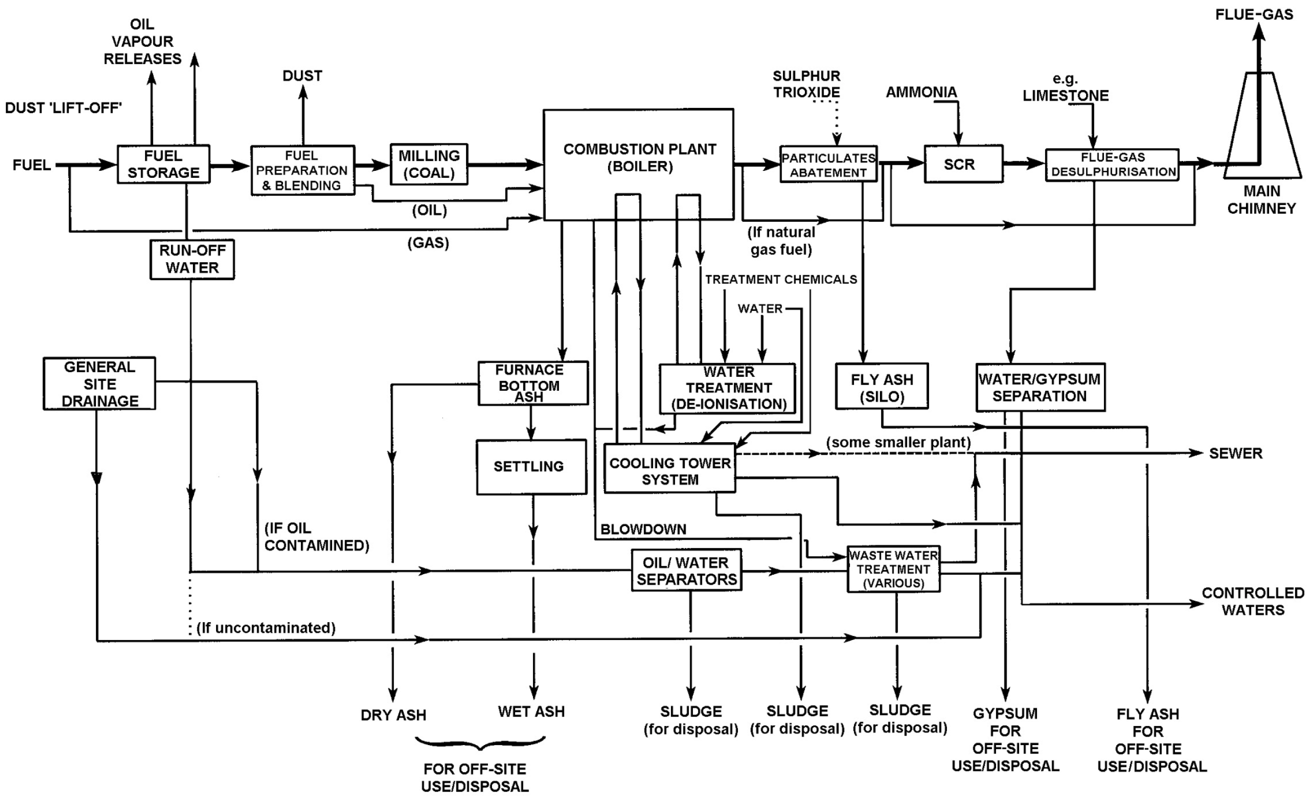
In addition, integrated coal gasification combined-cycle (IGCC) units are emerging technologies. In an IGCC system, coal gas is manufactured and cleaned in a "gasifier" under pressure, thereby reducing emissions and particulates.[44] The coal gas then is combusted in a CCGT generation system.

Cogeneration

Cogeneration is the merging of a system designed to produce electric power and a system used for producing industrial heat and steam and/or municipal heating. 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. Most cogeneration systems use a topping cycle.

[44] Gasification is a process in which coal is introduced to a reducing atmosphere with oxygen or air and steam.

Figure A-1
Generalized Flow Diagram of a Thermal power plant[45] and Associated Operations



Source: EC 2006

[45] Applicable to boiler plant with cooling tower only. Diagram does not apply to engines and turbines which have completely different configurations.

Annex B: Environmental Assessment Guidance for Thermal Power Projects

The development of an environmental assessment (EA) for a thermal power project should take into account any government energy and/or environmental policy or strategy including strategic aspects such as energy efficiency improvements in existing power generation, transmission, and distribution systems, demand side management, project siting, fuel choice, technology choice, and environmental performance.

New Facilities and Expansion of Existing Facilities

An (EA) for new facilities and a combined EA and environmental audit for existing facilities should be carried out early in the project cycle in order to establish site-specific emissions requirements and other measures for a new or expanded thermal power plant. Table B-1 provides suggested key elements of the EA, the scope of which will depend on project-specific circumstances.

Table B-1 Suggested Key EHS Elements for EA of New Thermal Power Project

Analysis of Alternatives	• Fuel selection including non-fossil fuel options (coal, oil, gas, biomass, other renewable options – wind, solar, geothermal, hydro), fuel supply sources
	• Power generation technology
	  ○ Thermal generating efficiency (HHV-gross, LHV-gross, HHV-net, LHV-net)
	  ○ Cost
	  ○ CO_2 emissions performance (gCO2/kWh)
	• GHG emissions reduction / offset options
	  ○ Energy conversion efficiency
	  ○ Offset arrangement
	  ○ Use of renewable energy sources, etc.
	• Baseline water quality of receiving water bodies
	• Water supply
	  ○ Surface water, underground water, desalination
	• Cooling system
	  ○ Once-through, wet closed circuit, dry closed circuit
	• Ash disposal system - wet disposal vs. dry disposal
	• Pollution control
	  ○ Air emission – primary vs. secondary flue gas treatment (cost, performance)
	  ○ Effluent (cost, performance)
	• Effluent discharge
	  ○ Surface water
	  ○ Evaporation
	  ○ Recycling – zero discharge
	• Siting
	  ○ Land acquisition consideration
	  ○ Access to fuel / electricity grid
	  ○ Existing and future land use zoning
	  ○ Existing and predicted environmental baseline (air, water, noise)

Impact Assessment	• Estimation of GHG emissions (tCO_2/year, gCO_2/kWh)
	• Air quality impact
	  ○ SO_2, NO_2, PM_{10}, $PM_{2.5}$, Heavy metals as appropriate, Acid deposition if relevant
	  ○ Incremental impacts to the attainment of relevant air quality standards
	  ○ Isopleth concentration lines (short-term, annual average, as appropriate) overlaid with land use and topographic map
	  ○ Cumulative impacts of existing sources / future projects if known
	  ○ Stack height determination
	  ○ Health impact consideration
	• Water quality / intake impact
	  ○ thermal discharge if once-through cooling system is used
	  ○ other key contaminants as appropriate
	  ○ water intake impact
	• Noise impact
	  ○ Noise contour lines overlaid with land use and locations of receptors
	• Determination of pollution prevention and abatement measures

Mitigation Measures /	• Air (Stack height, pollution control measures, cost)

Management Program	• Effluent (wastewater treatment measures, cost) • Noise (noise control measures, cost) • Waste utilization / disposal (e.g., ash, FGD by-product, used oil) ○ Ash management plan (quantitative balance of ash generation, disposal, utilization, size of ash disposal site, ash transportation arrangement) • Fuel supply arrangement • Emergency preparedness and response plan • Industrial risk assessment if relevant
Monitoring Program	• Parameters • Sampling Frequency • Evaluation Criteria • Sampling points overlaid with relevant site layout / surrounding maps • Cost

Tasks related to carrying out the quality impact analysis for the EA should include:

- Collection of baseline data ranging from relatively simple qualitative information (for smaller projects) to more comprehensive quantitative data (for larger projects) on ambient concentrations of parameters and averaging time consistent with relevant host country air quality standards (e.g., parameters such as PM_{10}, $PM_{2.5}$, SO_2 (for oil and coal-fired plants), NO_X, and ground-level ozone; and averaging time such as 1-hour maximum, 24-hour maximum, annual average), within a defined airshed encompassing the proposed project;[46]
- Evaluation of the baseline airshed quality (e.g., degraded or non-degraded);
- Evaluation of baseline water quality, where relevant;
- Use of appropriate mathematical or physical air quality dispersion models to estimate the impact of the project on the ambient concentrations of these pollutants;
- If acid deposition is considered a potentially significant impact, use of appropriate air quality models to evaluate long-range and trans-boundary acid deposition;
- The scope of baseline data collection and air quality impact assessment will depend on the project circumstances (e.g., project size, amount of air emissions and the potential impacts on the airshed). Examples of suggested practices are presented in Table B-2.

Table B-2 - Suggested Air Quality Impact Assessment Approach	
Baseline air quality collection	• Qualitative information (for small projects e.g., < 100MWth) • Seasonal manual sampling (for mid-sized projects e.g., < 1,200MWth) • Continuous automatic sampling (for large projects e.g., >= 1,200MWth) • Modeling existing sources
Baseline meteorological data collection	• Continuous one-year data for dispersion modeling from nearby existing meteorological station (e.g., airport, meteorological station) or site-specific station, if installed, for mid-sized and large projects
Evaluation of airshed quality	• Determining if the airshed is degraded (i.e., ambient air quality standards are not attained) or non-degraded (i.e., ambient air quality standards are attained)
Air quality impact assessment	• Assess incremental and resultant levels by screening models (for small projects) • Assess incremental and resultant levels by refined models (for mid-sized and large projects, or for small projects if determined necessary after using screening models)[47] • Modify emission levels, if needed, to ensure that incremental impacts are small (e.g., 25% of relevant ambient air quality standard levels) and that the airshed will not become degraded.

[46] The term "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.

[47] For further guidance on refined / screening models, see Appendix W to Part 51 – Guidelines on Air Quality Models by US EPA (Final Rule, November 9, 2005)

When there is a reasonable likelihood that in the medium or long term the power plant will be expanded 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 formally planned expansion in capacity or in other sources of pollution. Plant design should allow for future installation of additional pollution control equipment, should this prove desirable or necessary based upon predicted air quality impacts and/or anticipated changes in emission standards (i.e., impending membership into the EU). The EA should also address other project-specific environmental concerns, such as fuel and emissions from fuel impurities. In cases where fuel impurities lead to known hazardous emissions, the EA should estimate the emission amount, assess impacts and propose mitigations to reduce emissions.[48] Examples of compounds which may be present in certain types of coal, heavy fuel oil, petroleum coke, etc. include cadmium, mercury, and other heavy metals.

Rehabilitation of Existing Facilities

An environmental assessment of the proposed rehabilitation should be carried out early in the process of preparing the project in order to allow an opportunity to evaluate alternative rehabilitation options before key design decisions are finalized. The assessment should include an environmental audit that examines the impacts of the existing plant's operations on nearby populations and ecosystems, supplemented by an EA that examines the changes in these impacts that would result under alternative specifications for the rehabilitation, and the estimated capital and operating costs associated with each option. Depending on the scale and nature of the rehabilitation, the audit/environmental assessment may be relatively narrow in scope, focusing on only a small number of specific concerns that would be affected by the project, or it may be as extensive as would be appropriate for the construction of a new unit at the same site. Normally, it should cover the following points:

- Ambient environmental quality in the airshed or water basin affected by the plant, together with approximate estimates of the contribution of the plant to total emissions loads of the main pollutants of concern
- The impact of the plant, under existing operating conditions and under alternative scenarios for rehabilitation, on ambient air and water quality affecting neighboring populations and sensitive ecosystems
- The likely costs of achieving alternative emissions standards or other environmental targets for the plant as a whole or for specific aspects of its operations
- Recommendations concerning a range of cost effective measures for improving the environmental performance of the plant within the framework of the rehabilitation project and any associated emissions standards or other requirements implied by the adoption of specific measures.

These issues should be covered at a level of detail appropriate to the nature and scale of the proposed project. If the plant is located in an airshed or water basin that is polluted as a result of emissions from a range of sources, including the plant itself, comparisons should be made of the relative costs of improving ambient air or water quality by reducing emissions from the plant or by reducing emissions from other sources.

[48] Several U.S. states have adopted regulations that give coal-fired power plants the option to meet either a mercury emissions standard based on electricity output or a control-based standard. For instance, Illinois requires all coal-fired power plants of 25 MW electrical capacity or greater to meet either an emissions standard of 0.0080 lbs mercury per gigawatt hour (GWh) gross electrical output or an emissions control requirement of 90 percent relative to mercury input.