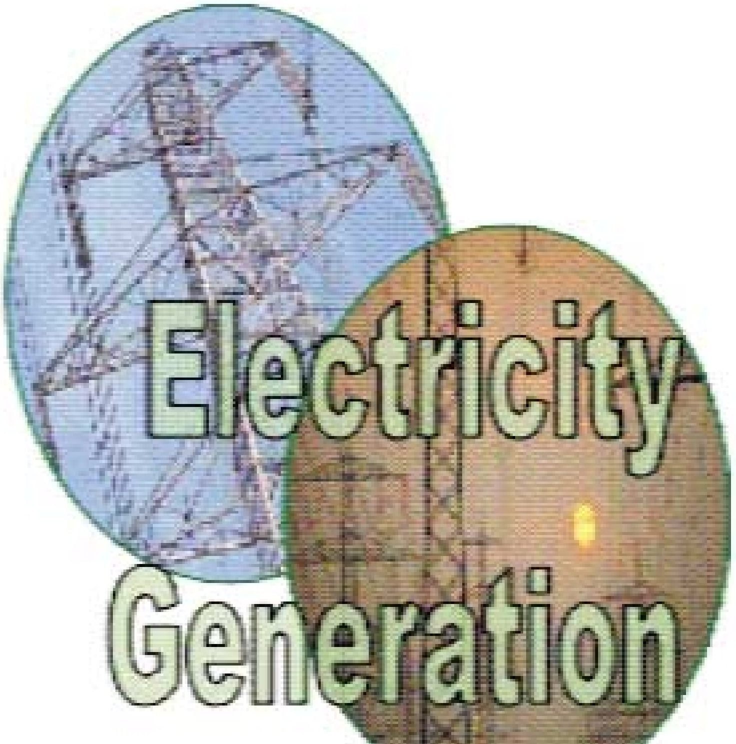
Electricity
Generation

5.1 INTRODUCTION

5.1.1 Industry Description

Electricity is an important contributor to the expansion of the Philippine economy. An internal study made by the National Power Corporation (NPC) has proven the direct correlation between economic growth and the increase in electricity demand. The 1995-2005 Philippine Power Development Program, thus, was made to address the expected increase in demand as the country pursues its industrialization thrust.

Generation of electricity in the country involves two types of power plants: the thermal power plants and the hydroelectric power plants. Hydroelectric power plants make use of water in generating electricity while thermal power plants make use of fossil fuel such as bunker oil, diesel oil, coal and geothermal to generate electricity. There were more than one hundred power plants in the country in 1995, including Independent Power Producers (IPPs). IPPs were fast-track solutions to the energy crisis experienced by the country in 1993. Owned by private business (local and foreign) groups, the IPPs were constructed under the build-operate-transfer (BOT), build-operate-own (BOO) and rehabilitate-operate-maintain (ROM) schemes. These IPPs sell their generated electricity to the NPC. The combined generating facilities of the NPC and the IPPs has an effective reserve power capacity of 1,000 MW.

5.1.2 Scope and Limitations of the Study

Emissions from the various power plants are estimated, and the services provided by the environment as receptacle of wastes generated by the power plants are quantified and assessed. An attempt was made to modify the emission factors used by ENRAP II and III for this sector by incorporating existing knowledge about combustion relations and actual Philippine data into the emission estimation system.

This study only assesses the emissions from fossil fuel-fired thermal power plants, particularly those that utilise oil and coal. The emissions of major pollutants, namely NOx, SOx, total suspended particulate or PM, CO, CO_2 and VOC, are estimated. The absence of necessary data inputs for valuation limited this study to the estimation of emissions in physical terms only.

5.1.3 Production Process

Although at the point of end use, electricity has relatively few environmental and health consequences, it is the generation of electricity which is one of the world's major environmentally damaging activities. While the energy sector contributes 49 percent of greenhouse gases, electricity generation alone produces more than 25 percent of energy-related carbon dioxide emissions (Munasinghe, 1995). The extent and nature of the impacts, however, differ among various types of fuel or energy sources.

5.1.3.1 To Air[1]

In the case of oil and coal-fired power plants, emissions include SO_2, CO, NOx, hydrocarbons, and polycyclic organic matter. In the case of coal-fired plants, additional pollutants include fly ash, trace metals, and radionuclides. The presence of these pollutants results in significant public health risks, and leads to increased incidence of respiratory diseases, toxicity and cancer.

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[1] The discussion in this section was based on Munasinghe, 1995.

The contribution of fossil fuels to carbon dioxide emissions depends on the carbon content of the fuel. Fuel oil emits 87.7 percent as much CO_2 as coal, while natural gas emits only 58 percent for the same thermal content.

Without control or treatment, coal emits more PM, SO_2, and NOX than any other fuel. While PM emissions in the case of natural gas are negligible, coal emits almost 10 percent of its oil equivalent in weight as ash and other matter.

Sulfur dioxide (SO_2) emissions depend on the sulfur content of the fuels while emissions of NOX are not significantly different between fuels, with natural gas emitting only two-thirds that of coal.

5.1.3.2 To Water

a. Thermal or waste heat [2]

The amount of cooling water required to carry away the waste heat from power plants already exceeds the amount withdrawn for any other purpose. In a once-through process, cooling water is extracted from some source, e.g., river, passed through the condenser where its temperature is increased by anywhere from 10 to 30°F, and returned to the source body of water at this higher temperature. Many of the adverse effects to aquatic life associated with thermal pollution stem from the increased rate of metabolism that occurs as temperature increases. This causes an increased demand for oxygen by the organisms. At the same time, the dissolved oxygen (DO) in the water decreases with increasing temperature. Thus, as the organisms' demand for oxygen increases, the amount of oxygen available decreases. A second factor that decreases the dissolved oxygen is the increased rate of decomposition of wastes that occurs at higher temperatures.

For a fossil-fired plant, 40 percent of the input energy is converted to electric energy, 10-15 percent is lost to the air by the stack gases and boiler, and the remaining 45-50 percent is removed by the cooling water. For a nuclear power plant, 33 percent is converted to electric energy, about 3-5 percent is lost to the air, and the remaining 62-64 percent ends up in the cooling water. While the nuclear plant is only 7 percent less efficient, its cooling water must remove about 60 percent more waste heat, and this is why thermal pollution is most often associated with nuclear plants.

b. Effluents [3]

The principal type of effluents from power plants are the mineralized liquors from water preparation plants, wastewater from hydro-ashing systems (where solid fuel is burnt), wash water from the heating surfaces (air heaters and economizers) of boilers operating on sulphuric fuel oil, water from chemical treatment or cleaning of thermal power plant and effluents contained with oil products. The quantity and quality of these effluents are determined by the type of power station, its capacity, the kind of fuel used, the composition of the original water, the types of water preparation in use, and various other factors. These pollutants to water and degradation to environment caused by the generation of electricity are not estimated in this study.

5.1.3.3 To Land

Solid waste (from the fly ash) disposal problem is not trivial, and the problem of disposal sites needs to be addressed. Disposal of solid wastes leads to health risks associated with leachate and groundwater contamination.

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[2] The information in this section was based on Masters, 1984.

[3] The discussion in this section was based on Abdullaev, *et al*., 1992.

5.1.4 Treatment Process [4]

5.1.4.1 Air Pollution Control Facilities

As of 1992, air pollution facilities installed in some of the power plants in the country were Electrostatic Precipitators (ESP), Dust Collectors and Tall Smokestack.

a. Electrostatic Precipitators (ESP)

The basic PM collection process taking place in an ESP is as follows: (1) suspended particles are given an electric charge; (2) the charged particles then migrate to a collecting electrode of opposite polarity while subjected to diverging electric field; and (3) the collected particles are then dislodged from the collection electrodes.

b. Dust Collectors

Dust collection devices collect dusts from flue gases. Most of these dusts are non-combustible residual particles from combustion processes. Dust collection equipment are mostly used in oil-based and coal-fired power plants.

c. Tall Smokestack

Tall smokestack is recommended for stationary sources of air pollution. Tall smokestack cause air pollutants contained in the flue gas to easily disperse in the atmosphere.

5. 2. SOURCES AND METHODS

5.2.1 Data Sources

In the absence of information on environmental protection costs, a questionnaire was designed by the TWG on Electricity and submitted to the NPC for validation. The questionnaires were distributed by the NPC to selected power plants under its supervision and to an IPP in September 1996. Responses from 15 power plants were collected in November 1996. The data compiled from the inquiry were used in the study. Emission factors were derived from Handbook of Emission Factors and OECD Secretariat. Annual reports of NPC were utilized for gross generation, installed capacity and date of operation of power plants.

5.2.2 Estimation Methodology [5]

5.2.2.1 Physical Estimation

For proper combustion, the fuel must be mixed rapidly and completely with sufficient combustion air, and must be burnt at a sufficiently high temperature. If not, part of the fuel will burn incompletely, and consequently, the flue gases will contain undesirable combustion products.

In this study, fossil fuel-fired thermal plants are grouped into bunker oil fuel-based, diesel oil fuel-based and coal-fired power plants. For 1995, 25 bunker fuel-based, 33 diesel-based and 5 coal-fired power plants are included in the study. Emissions from these plants consisting of SO_X, NO_X, PM, CO, CO_2 and VOC are estimated.

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[4] Other treatment processes and air pollution control facilities are discussed in Annex 5.1.2.

[5] This section was culled from the Handbook of Emission Factors, Part 3 (1988).

Total emissions (m) of SO_X, NO_X, and PM are calculated by multiplying the *emission rate* (in g/hr) by the number of operating hours of the plant (Eq. 1). The *emission rate* is estimated by multiplying the emission factors (*EF*, in g/GJ) by the *load* of the power plant expressed as N, in GJ/hr. (Eq. 2). Emission factors are given in Tables 5.1.2, 5.1.3, and 5.1.4. Load (*N*) is calculated as the product of net heat of combustion (H_c) and the actual average fuel consumption rate ($\frac{\Delta F}{\Delta t}$) (Eq. 3). An illustration of the procedure in formula form is given below.

a. Total emissions (m), in Metric Tons (MT)

$$m = \dot{m} * \text{operating hours} \qquad \textbf{Eq. 1}$$

where:

$\dot{m}$ = emission rates defined as the mass of pollutant emitted per unit of time. It is usually expressed as gram per hour, g/hr, (see Eq. 2).

operating hours = 7,680
= 365 - 45 days
= 320 days x 24 hours (45 days is the average number of days wherein a power plant undergoes rehabilitation)

b. Emission rate, $\dot{m}$, in g/hr

$$\dot{m} = EF * N \qquad \textbf{Eq. 2}$$

where:

EF = the emission factor in grams per gigajoules ($g \cdot GJ^{-1}$). It is the ratio between the quantity of a pollutant emitted and some units of the activity involved. For combustion processes the unit of activity is the energy input (see Tables 5.1.1 and 5.1.2 and Appendix Tables 5.1.1 and 5.1.2 for details of estimation).

N = the actual load or the amount of a fuel energy supplied per unit of time. It is expressed as GJ/hour (see Eq. 3).

c. Load (N): GJ/hour

$$N = H_c \times \frac{\Delta F}{\Delta t} \qquad \textbf{Eq. 3}$$

where:

H_c = the net heat of combustion - net heat value or the net calorific value of fuel.

$\frac{\Delta F}{\Delta t}$ = the actual average fuel consumption per unit time**.** *F* is the mass of fuel and *t* in hours. In this study, actual fuel consumption is calculated as gross generation multiplied by the fuel requirement per Megawatt Hour generated.

For NO_X and PM, some adjustments were made on the emission factors (see Eq. 2). These changes are given in the discussions for each pollutant.

5.2.2.1.1 Sulphur Oxides (SOx)

Many solid and liquid fuels contain sulphur, which is almost quantitatively oxidised during combustion. SO_2 is the major product (over 95 percent). In addition, some SO_3 (1-5 percent) and particulate sulphate (1-3 percent) may be formed. During coal combustion, a minor quantity of sulphur may remain in the bottom ash or may become part of the fly ash.

For the estimation of total emission of SOx, Eq's. 1, 2 and 3 as given above were used. The value of Hc used in Eq. 3 is given in Table 5.1.1. For bunker oil fuel, *Hc* for other distillate oil (41 MJ/kg) is used and for diesel oil emissions that of diesel oil (42.5 MJ/kg) is used. For coal, a combination of *Hc* for hard coal (27 MJ/kg) and brown coal (18 MJ/kg) is used. For an illustration on how the equations were applied, see Appendix Tables 5.1.1 and 5.1.2.

TABLE 5.1.1 FUEL CHARACTERISTICS

Fuel	H_c (MJ/kg of fuel)	X (g/kg of fuel)	ϕ	EF_{SO2} (g/GJ)
Hard coal	27 *	8	0.05	540
Anthracite	27 – 31			
Bituminous	24 – 31			
Subbituminous	18 –24			
brown coal	5 – 18			
(lignite)	20	4		
lignite briquettes	42.5	3		
diesel oil	42.5	4		
other distillate oil	41	15		730
residual oil				

*per kg standard coal equivalent: 29.3 MJ/kg
Source: Handbook of Emission Factors, Part III.

5.2.2.1.2 Nitrogen Oxides (NOx)

Contrary to SOx, emissions of NOx primarily depend on combustion conditions., hence some adjustments were introduced in the load and emission factor.

In Eq. 1, emission rate ($\dot{m}$) is derived using an adjusted emission factor (*AEF*) instead of EF. AEF refers to the emission factor by type of fuel, installation (e.g., boiler, burner) as given in Table 5.1.2, adjusted with a load correction factor.

$$AEF = EF \times \text{load correction factor} \qquad \textbf{Eq. 4}$$

TABLE 5.1.2 EMISSION FACTORS: NOx, PM, SOx

Fuel	Unit/Installation	Flue Gas Production (m^3/GJ)	NO_x (g/GJ)	PM (g/GJ)	PM [<10μg] (g/GJ)
Hard coal Lignite	Pulverized (pp)	380	300	15	100
Distillate Oil	Cylindrical boiler	280	85*	6	30
	Gas turbine	1,200	$450^{1/}$	20	
	Diesel engine	830	1,200	7	
Residual Oil	Water tube boiler (pp)	290	$230^{2/}$	20	
	Grate firing, overfeed stoker (pp, in U.S.A.)		110		
	Grate firing, underfeed stoker (pp, in U.S.A., Netherlands)		160		
Natural Gas	Water tube boiler (pp)	320	130*	0	

Note:
pp : power plant
* : applies to full load, and subject to load correction factors
1/ Used for Diesel Oil Fuel-based power plants
2/ Used for Bunker Oil Fuel-based power plants
Source : Handbook of Emission Factors, Part III (1988).

A load correction factor is defined as the load factor (Eq. 5) multiplied by the load correction factor given in Table 5.1.3. Load factor (*L*) is estimated as the ratio between actual fuel consumption rate and the nominal fuel consumption rate.

TABLE 5.1.3 LOAD CORRECTION FACTORS

Fuel Type	Load Correction Factor
solid fuels	$1 - 0.225 (1 - L)$
liquid fuels	$1 - 0.45 (1 – L)$
gaseous fuels	$0.16^{(1 - L)}$

Source: Handbook of Emission Factors Part III, 1988.

$$L = \frac{\text{actual fuel consumption rate}}{\text{nominal fuel consumption rate}} \qquad \textbf{\textit{Eq. 5}}$$

where:

Nominal Fuel Consumption rate = (*IC* * 1000) / 7680 (hours)

IC = Installed Capacity

Estimated Average Nominal Fuel Consumption per kilowatt:

- For bunker-fuel based plant:1,222.25 kg/hr (based on the Sucat Thermal Plant)
- For diesel-fuel based plant:7,130.67kg/hr (30MW diesel fuel-based power plant)

Actual fuel consumption rate is estimated in the same way as in the estimation of SOx. Load (N) is as in the general formula in SOx (Eq. 3). Hence, emission rate is calculated, as in Eq. 2, by replacing EF with AEF (calculated in Eq. 4). For an illustrative example on how the formulas were applied, refer to Appendix Table 5.1.2. The details of NOx emissions are found on Appendix Tables 5.1.3, 5.1.5 and 5.1.7.

5.2.2.1.3 Particulate Matter (PM)

The same procedure adopted in NOx (Eq's. 1, 4 and 5) is used for the calculation of the PM emissions. The only exception is the load correction factor (CF) which is fixed at 0.76 (Handbook of Emission Factors) for liquid fuels. For the emission factors refer to Table 5.1.2. The detailed emissions are tabulated on Appendix Tables 5.1.4, 5.1.6 and 5.1.7.

5.2.2.1.4 Carbon Monoxide (CO) and Carbon Dioxide (CO_2)

Carbon monoxide and organic compounds are products of incomplete combustion. This occurs if excess air is too low, e.g., during start-ups, temporary upsets, and with combustion conditions during which fuel particles (coal particles/oil droplets) leave the flame prematurely. Emissions of these substances can be reduced by combustion at a high temperature and/or on long residence times. The emission factors for CO are lower than those for CO_2 because the emission of CO is largely converted in the atmosphere into CO_2 within a short period of time. The heat value or net heat of combustion and carbon content of the fuels are key assumptions used to derive the emission factors.

Table 5.1.4 shows the emission factors for CO, CO_2 and methane (CH_4) by source or major end-use and fuel. The EF's are presented in grams of pollutant per giga-joule cf. energy use. The same procedure adopted for the estimation of SOx is used (Eq's. 1, 2 and 3. Appendix Tables 5.1.4, 5.1.6 and 5.1.7 provide the details of the estimation.

TABLE 5.1.4 EMISSION FACTORS FOR ORGANIC COMPOUNDS (IN G/GJ INPUT)

Fuel Type	Unit (Site/installation)	CO_2	CO	CH_4
Residual Oil [1/]	Utility / boiler	78,100	15	1
Distillate Oil [2/]	Utility / boiler	73,800	15	0
Hard Coal	Spreader stoker Pulverised coal Fluidized bed	94,200 94,200 94,200	105 10 NA	1 1 1
Brown Coal		105,400		

1/ Used for Bunker Fuel-based power plants
2/ Used for Diesel Fuel-based power plants
Source: OECD Secretariat (1994).

5.2.2.1.5 Volatile Organic Compounds (VOC)

For the estimation of VOC emissions the general formula used is:

Total emissions (in MT) = EFC * EF

Where EFC = Estimated Fuel Consumption, in kg.
EF = Emission Factor in kg/MT

To be more specific, for:

- Bunker-fuel based plant:

  Total emissions (in MT) = EFC (kg) * 0.04 gVOC/kg. oil / 1000

- Coal-fired power plants:

  Total emissions (in MT) = EFC (kg) * 0.15 kg/MT / 1000

The details of the estimation are shown in Appendix Table 5.1.8.

5. 3 RESULTS

5.3.1 Physical Estimates

5.3.1.1 Installed Capacity and Gross Generation

The gross energy generation of electricity from fossil fuel based power plants are given in Table 5.1.5. Most of the thermal power plants in the country are fuelled by bunker oil or residual oil. The gross energy generated by bunker oil-based plants was 8,789 GWh in 1988, and increased to 11,659 GWh in 1992, but decreased to 9,201 MWh in 1995 (see Figure 5.1.1). Diesel or distillate oil is used as fuel by some small island grids and power barges as well as for start-up of the other power plants. In response to the power crisis in the early 1990s, a number of these power barges have been installed. The gross generation of diesel oil-based power plants was only 352 GWh in 1988, and increased to 9,077 GWh in 1995. There are only five coal-fired power plants in the country: Calaca I and II in the Luzon Grid, and the Naga I and II and ACMDC in the Visayas Grid. Their gross generation averaged about 2,269 GWh for the period 1988-1995.

TABLE 5.1.5 GROSS ELECTRICITY GENERATION OF POWER PLANTS, IN GIGAWATTS, 1988-1995

Type of fuel	1988	1989	1990	1991	1992	1993	1994	1995
Bunker	8,789	8,933	9,609	11,288	11,359	9,714	9,587	9,326
Diesel	362	724	1,596	1,346	1,856	2,532	6,904	9,077
Coal	2,559	2,536	1,873	2,091	2,155	2,459	1,820	2,659
Hydro	6,212	6,473	6,047	5,077	4,274	4,987	5,768	6,239
Geothermal	4,842	5,316	5,470	5,761	5,693	5,644	6,350	6,102
TOTAL	**22,764**	**23,982**	**24,595**	**25,563**	**25,337**	**25,336**	**30,429**	**33,403**

In 1988, of the total electricity generated in the country, those fuelled by fossil fuels such as bunker oil, diesel and coal account for a little more than half. However, in 1995 the share increased to about 63 percent. Other major plants are fuelled by geothermal steam and hydropower.

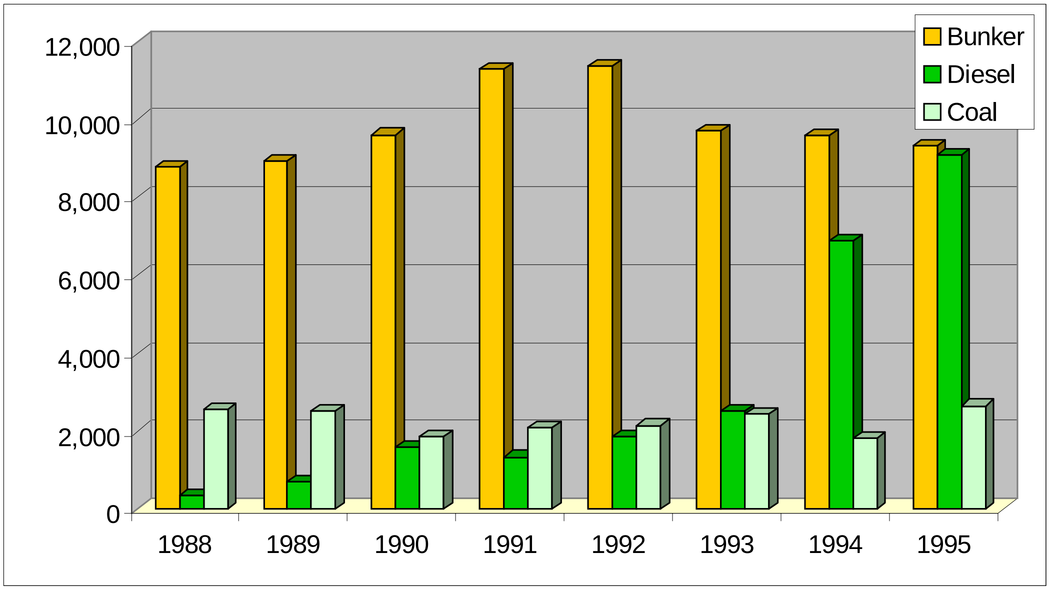

FIGURE 5.1.1 GROSS ELECTRICITY GENERATION OF POWER PLANTS, IN GIGAWATT HOURS, 1988-1995

5.3.1.2 Emissions From Bunker Oil Fuel-Based Power Plants

Table 5.1.6 provides the estimated fuel consumption used for the estimation of emissions of bunker oil fuel–based power plants. This is based on the average fuel consumption at the designed installed capacity of the plant, using the Sucat Thermal Plant as the basis. Since these power plants are fired by fossil fuels, they produce a high volume of CO_2 emissions. The other major pollutants are SOx and NOx. For bunker oil fuel-based power plants, next to CO_2, the biggest emission was estimated as SOx at about 55 million MT annually (see Table 5.1.7). Following SOx, is NOx at about 13 million MT every year. PM and CO each contributed a little over a million MT annually. VOC is small compared to other pollutants at about 80,000 MT every year (see Figure 5.1.2). The details of the computed emissions generated by Bunker Oil-Fuel Based Power Plants are shown in Appendix Tables 5.1.3, 5.1.4 and 5.1.8.

TABLE 5.1.6 ESTIMATED FUEL CONSUMPTION (EFC) OF POWER PLANTS, IN MILLION METRIC TONS, 1988-1995

Type of fuel	1988	1989	1990	1991	1992	1993	1994	1995
Bunker [1/]	1,821	1,847	1,819	2,102	2,208	1,910	1,727	1,676
Diesel [2/]	297	123	493	328	402	652	1,836	2,414
Coal	10,082	10,005	7,388	8,249	8,502	9,698	7,179	10,487

1/ EFC (bunker) = gross generation * annual fuel requirement per MW generated by the Sucat Thermal Plant (1,222,250 kg/hour)

2/ EFC (diesel) = gross generation * annual fuel requirement per MW generated

TABLE 5.1.7 TOTAL EMISSIONS FROM BUNKER OIL FUEL-BASED POWER PLANTS, IN THOUSAND METRIC TONS, 1988-1995

Year	NO_x	SO_x	PM	CO	CO_2	VOC
1988	15,244	54,642	1,135	1,120	5,832,262	73
1989	15,460	55,415	1,151	1,136	5,914,834	74
1990	15,143	54,558	1,133	1,118	5,823,280	73
1991	16,880	63,064	1,310	1,292	6,731,241	84
1992	17,915	66,232	1,376	1,358	7,069,313	88
1993	14,523	57,287	1,190	1,174	6,114,574	76
1994	12,696	51,814	1,076	1,062	5,530,469	69
1995	12,106	50,278	1,044	1,030	5,366,518	67

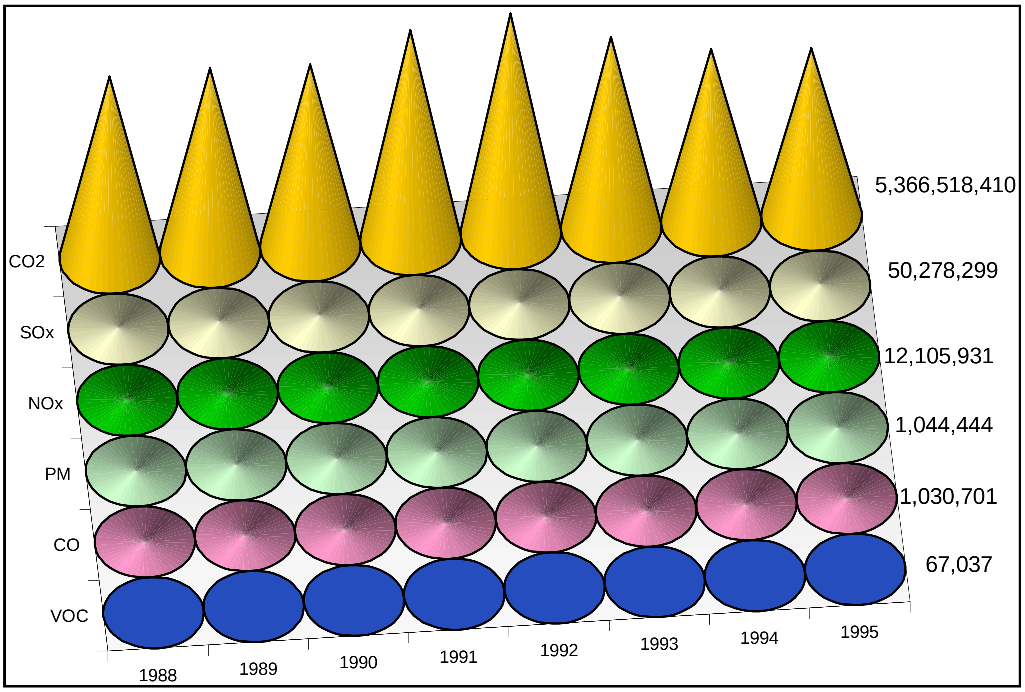

FIGURE 5.1.2 BUNKER OIL FUEL-BASED POWER PLANTS: EMISSIONS, 1988-1995

5.3.1.3 Emissions From Diesel Oil Fuel-Based Power Plants

The gross energy generation and the estimated average fuel consumption of the different diesel oil-fired power plants are shown in Table 5.1.6. The nominal load is based on the average fuel consumption at the designed installed capacity of the plant, using the Bataan Gas Turbine Power Plant as the basis. The detailed computed emissions generated by Diesel Oil-Based Power plants are shown in Appendix Tables 5.1.5 and 5.1.6. Table 5.1.8 presents the volume of major pollutants emitted by these power plants. Unlike the bunker oil fuel-based power plants, diesel oil fuel-based plants emit more NOx than SOx. The sudden fluctuations of the emissions of this type of power plant is closely related to the dramatic increases in the electricity generated from these plants (see Figure 5.1.1). As with bunker oil fuel-based plants CO2 emissions are of the highest magnitude, among the air pollutants (see Figure 5.1.3).

TABLE 5.1.8 TOTAL EMISSIONS FROM DIESEL OIL FUEL-BASED POWER PLANTS, IN THOUSAND METRIC TONS, 1988-1994

Year	NOx	SOx	PM	CO	CO2
1988	325	239	19	19	93,720
1989	1,409	983	79	78	385,489
1990	6,970	3,945	319	314	1,546,726
1991	4,214	2,625	212	209	1,029,177
1992	6,296	3,699	299	295	1,450,314
1993	8,150	5,217	421	416	2,045,470
1994	25,790	14,688	1,186	1,170	5,758,451
1995	36,609	19,312	1,559	1,539	7,571,158

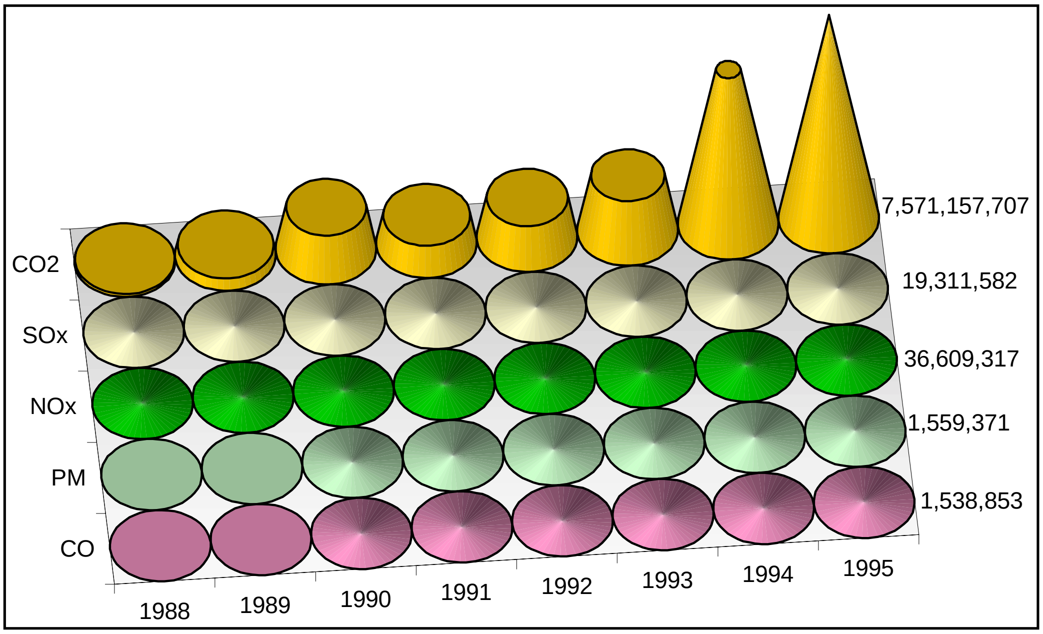

FIGURE 5.1. 3 DIESEL OIL FUEL-BASED POWER PLANTS: EMISSIONS, 1988-1995

5.3.1.4 Emissions From Coal-Fired Power Plants

Figures 5.1.1 and Table 5.1.6 show the gross electricity generation and the estimated fuel consumption of coal-fired power plants. The details of the computed emissions generated by Coal Fired Power Plants are shown in Appendices 5.1.7 and 5.1.8. The estimated average fuel consumption rate is 238 kg of coal per hour to generate 1 MW of energy (based on the Calaca Coal-Fired Power Plant).

TABLE 5.1.9 TOTAL EMISSIONS FROM COAL-FIRED POWER PLANTS, IN THOUSAND METRIC TONS, 1988-1995

Year	NO_x	SO_x	PM	CO	CO_2	VOC
1988	62,676	115,042	5,677	2,271	22,408,992	1,514
1989	62,130	114,039	5,628	2,251	22,213,600	1,501
1990	45,880	84,214	4,156	1,662	16,403,884	1,108
1991	51,223	94,021	4,640	1,856	18,314,176	1,237
1992	52,794	96,904	4,782	1,912	18,875,916	1,275
1993	60,227	110,547	5,455	2,182	21,533,277	1,455
1994	44,584	81,835	4,038	1,615	15,940,488	1,077
1995	65,124	119,536	5,899	2,360	23,284,357	1,573

Like the other power plants which utilized bunker oil for fuel, coal-fired plants' biggest emissions are SOx (90 million MT annually), followed by NOx (56 million MT annually). As with the other fossil fuel-based thermal plants, CO_2 emissions are also significant (see Figure 5.1.4).

5.3.2 Analysis of Results

Comparing the gross generation and the total emissions of the fossil fuel-based power plants (see Table 5.1.10 and Figures 5.1.4 and 5.1.5), the coal-fired power plants emitted more pollution by type of pollutant, followed by the bunker oil fuel-based power plants. Diesel oil fuel-based power plants had the least emissions. In 1995, although contributing the least to the generation of electricity, the coal-fired power plants had the most emissions of pollutants (ranging from 48 percent to 96 percent of the total emissions calculated in this study).

TABLE 5.1.10 SHARE OF GROSS GENERATION AND TOTAL EMISSIONS BY TYPE OF POWER PLANT (IN PERCENT), 1988 AND 1995

Year/ Type of Power Plant	Gross Generation	NO_X	SO_X	PM	CO	CO_2	VOC
1988	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Bunker Fuel-Based	75.1	19.5	32.2	16.6	32.8	20.6	406
Diesel Fuel-Based	3.1	0.4	0.1	0.3	0.6	0.3	0.0
Coal-Fired	21.9	80.1	67.7	83.1	66.6	79.1	95.4
1995	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Bunker Fuel-Based	44.3	10.6	26.6	12.3	20.9	14.8	4.1
Diesel Fuel-Based	43.1	32.2	10.2	18.3	31.2	20.9	0.0
Coal-Fired	12.6	57.2	63.2	69.4	47.9	64.3	95.9

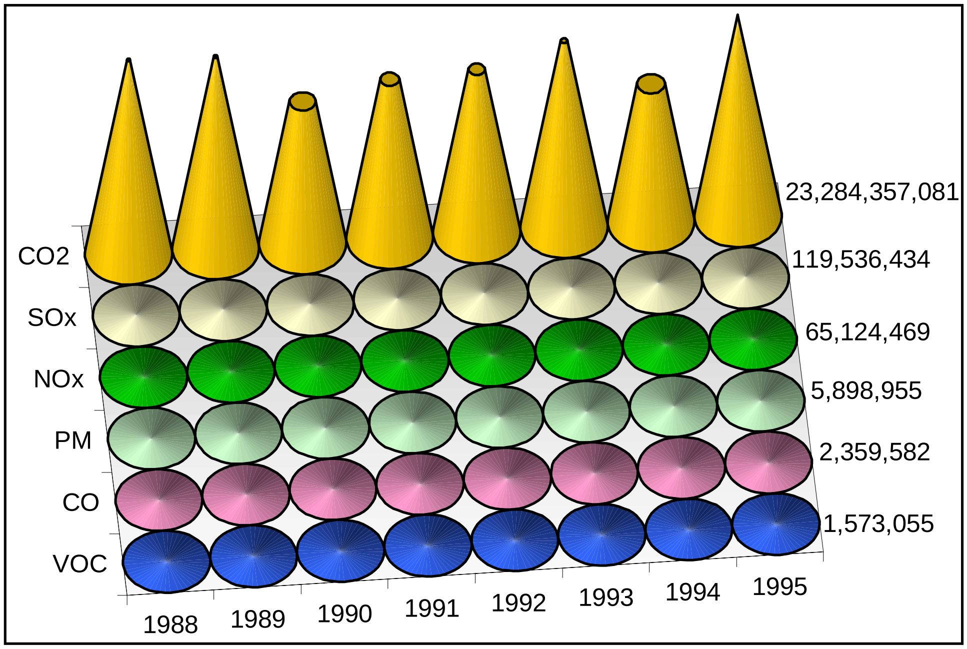

FIGURE 5.1.4 COAL-FIRED POWER PLANTS: EMISSIONS, 1988-1995

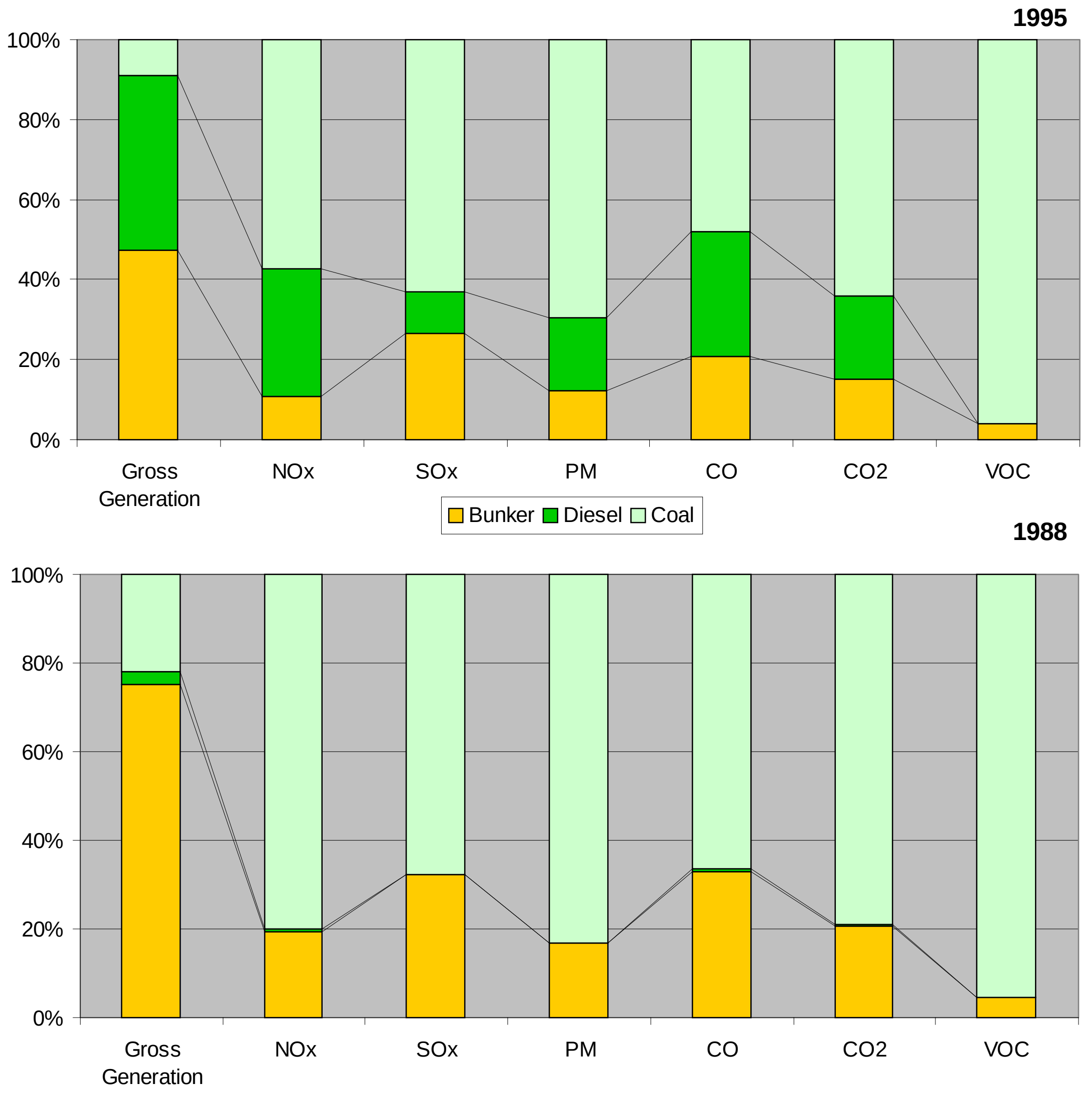

FIGURE 5.1.5 **GROSS GENERATION AND EMISSIONS BY TYPE OF POWER PLANT, 1988 AND 1995**

5.1.4 RECOMMENDATIONS

The emission factors used in this study represent uncontrolled emission rates by type of fuel, major end-use, and unit or installation. Standard assumptions used to derive the emission factors are based on the heat value or net heat of combustion of the fuel, the sulphur content (for SOx emission factor) and carbon content (for the CO and CO_2 emission factors). Data on these fuel properties are still based on measurements in North America and Europe, and therefore, should be used with caution, especially in our country where technology and operating characteristics differ significantly. The fuel properties of coal (Hc, x and 0) are based on the coal imported from Australia, which is the same source of our imported coal. About half of the total volume of coal used by the power plants, however, is from Semirara, and this local coal is more inferior. There is still no national information on average fuel properties for the fuel in use, technology and usage.

Assumptions regarding technology are important, particularly for non-CO_2 emissions. Many new technologies are more efficient and less polluting. Thus, if energy intensity is projected to alter over time, that change may also be accompanied with a change in the emission rate per unit of energy consumed or the emission factor. Another consideration is that emission control technologies may be installed over time, varying in the effective average efficiency of a given use of energy.

The location of the power plants should also be considered in coming up with degradation estimates. Most of the power plants are located in less populated areas. Another consideration is the absorptive capacity of the areas where the power plants are located.

The monetary valuation of the degradation to air caused by power generation is also still in the compilation process. Towards this end, a questionnaire had been designed and distributed to the different power plants to collect the required data inputs. Given that the data will become available, the following methodology is being proposed to be adopted in the estimation of the monetary valuation of the degradation caused by this economic activity:

1. identification of pollution control devices that have been installed

    - by type of pollutant that can be controlled
    - efficiency in terms of pollution reduction
    - estimation of the volume of pollutant controlled

2. segregation of expenditures for environmental protection

    2.1 fixed assets / capital cost of the pollution control facilities
    2.2 current operating and maintenance costs (current expenditures)

3. estimation of maintenance costing:

    abatement cost = [(capital cost, annualised) + (current expenditures)]
    - by type of pollutant that can be controlled

4. estimation of per unit cost of pollutant controlled

5. monetary valuation of degradation

    - cost per unit of controlling emission x uncontrolled emissions

APPENDIX 5.1.1

EMISSION FACTORS (EF) USED

1. For bunker oil fuel-based power plant

EF (SOx) = 2x/Hc

Where:

X = sulfur content of fuel (15) grams of SOx per kilogram of bunker fuel oil

Hc = net heat oc combustion (41 MJ/kg) (see Table 5.1.1 above)
= 2(15g/kg)/41MJ/kg
= .732 x 103 g/MJ x 103 MJ/GJ
= 732

2. For diesel oil fuel-based plant

EF = 2(4g/kg)/42.5MJ/kg
= 0.188 x 103 g/MJ x 103 MJ/GJ
= 188

3. For coal-based plant

- For hard coal

EF (SOx) = 2x x 8g/kg (1- 0.05) / 27 MJ/kg
= 0.563 g/MJ

Where:

x = 8 grams of sulphur per kilogram of hard coal

o = 0.05 (mass fraction of sulphur retained in ash)

Hc = 27 MJ/kg (net heat of combustion for hard coal)

- For lignite

EF(SOx) = 2x x 4 g/kg (1-0.05) / 18 MJ/kg
= 0.422 g/MJ

Where:

x = 4 grams of sulphur per kilogram of hard coal

o = 0.05 (mass fraction of sulphur retained in ash)

Hc = 18 MJ/kg (net heat of combustion for hard coal)

APPENDIX 5.1.2

SAMPLE COMPUTATION OF EMISSIONS

Estimation of SO_2

One way to estimate the emissions of sulphur dioxide (SO_2) from thermal power plants is to simply calculate the emission factor from the *sulphur content* and the fraction of the sulphur retained in ash by:

$$EF(SO_2) = \frac{x}{H_c} \cdot \frac{M(SO_2)}{M(S)} \cdot (1-\phi) = \boldsymbol{\frac{2x}{H_c} \cdot (1-\phi)}$$

where:

$EF(SO_2)$ = emission factor for SO_2 (in g × MJ^{-1})
Hc = net heat of combustion (in MJ × kg^{-1})
x = sulphur content of the fuel (in g/kg)
f = mass fraction of sulphur retained in ash
M(S) = molecular mass of sulphur (32 kMol × kg^{-1})
$M(SO_2)$ = molecular mass of sulphur dioxide (64 kMol × kg^{-1})

Estimation of NOx

Example

Given:

Fuel - residual oil
unit - water tube boiler, rotary cup burner
nominal fuel consumption rate - 6000 kg/hr
operating hours (of boiler) - 5000 hrs (per annum)
total fuel consumption - 24,000 tons

1. load factor (L) = 0.80

2. net heat of combustion (Hc): for residual oil = 41 MJ/kg (see Table 5.1.2)

3. load (N):

$$= H_c \times \frac{\Delta F}{\Delta t}$$

= 41 MJ/kg x 4800 kg/hr
= 197 x 10^3 MJ/hr
= 197 GJ/hr

4. emission factor (EF): installation/burner combination - residual oil (see Table 5.1.3)

5. correction for non-maximum load (load correction factor):

for liquid fuels = 1 - 0.45 (1 - L) (see Table 5.1.4)

load correction factor = 1 - 0.45 (1 - 0.80)
= 0.91

6. adjusted emission factor (AEF) = EF x load correction factor
= 210 g/GJ x 0.91
= 191 g/GJ

7. average emission rate during operating hours = AEF x N
= 191 g/GJ x 197 GJ/hr
= 37.6 x 10^3 g/hr
= 37.6 kg/hr

8. total emissions, m = average emission rate x operating hours
= 37.6 kg/hr x 5000 hrs
= 188 x 10^3 kg

Estimation of PM

1. emission factor (EF): installation/burner combination - residual oil = 15 g / GJ (see Table 5.1.3)

2. correction factor: 0.76

3. adjusted emission factor (AEF) = 15 g/GJ x 0.76
= 11.4 g/GJ

4. emission rate = 11.4 g/GJ x 197 GJ/hr
= 2,246 g/hr
= 2.25 kg/hr

5. total annual emissions, m = emission rate x operating hours):
= 2.25 kg/hr x 5,000 hrs
= 11.2 x 10^3 kg
= 11.2 mt

Estimation of SOx

1. emission factor, EF = 2 x (15g/kg) / (41 MJ/kg)
= .731707 g/MJ x 10^3 GJ
= 732 g/GJ

2. load, N = H_c x $\frac{\Delta F}{\Delta t}$
= 41 MJ/kg x 4,800 kg/hr
= 196,800 MJ/hr / 10^3 GJ/hr
= 197 GJ/hr

3. emission rate = 732 g/GJ x 197 GJ/hr
= 144,204 g/hr

4. total emissions = emission rate x operating hours
= 144,204 g/hr x 5,000 hrs
= 721,020,000 g
= 721 mt

APPENDIX TABLE 5.1.3

NOx EMISSIONS OF BUNKER OIL FUEL-BASED POWER PLANTS, 1988-1995

Year	Gross Energy Generation (MWh) 1	Estimated Total Fuel Consumption (m.t.) 2	Number of Hours in Operation (hr) 3	Estimated Fuel Consumption Rate (kg/hr) 4 (2*1000)/3	Estimated Nominal Fuel Consumption Rate (kg/hr) 5	Load Factor 6	Load (GJ/hr) 7 (4 * Hc)*0.001	Emission Factor (g/GJ) 8	Load Correction Factor 9	Adjusted Emission Factor (g/GJ) 10 (8 * 9)	Average Emission Rate (kg/hr) 11 (7 * 10) * 0.001	Total Emissions (kg) 12 (11 * 3)	Total Emissions (m.t.) 13 (12 / 1000)
1988	8,788,907	1,821,386,720	7,680	237,159,729	316,225,358	0.75	9,723,549	230	0.8875	204	1,984,868	15,243,786,547	15,243,787
1989	8,932,907	1,847,173,308	7,680	240,517,358	321,318,066	0.75	9,861,212	230	0.8875	204	2,012,969	15,459,602,995	15,459,603
1990	9,609,110	1,818,581,722	7,680	236,794,495	321,318,066	0.74	9,708,574	230	0.8830	203	1,971,714	15,142,766,208	15,142,766
1991	11,287,531	2,102,133,336	7,680	273,715,278	408,053,255	0.67	11,222,326	230	0.8515	196	2,197,893	16,879,815,398	16,879,815
1992	11,659,237	2,207,711,504	7,680	287,462,435	417,602,083	0.69	11,785,960	230	0.8605	198	2,332,677	17,914,960,666	17,914,961
1993	9,714,012	1,909,551,337	7,680	248,639,497	432,530,085	0.57	10,194,219	230	0.8065	186	1,891,028	14,523,092,659	14,523,093
1994	9,587,275	1,727,138,004	7,680	224,887,761	444,466,120	0.51	9,220,398	230	0.7795	179	1,653,125	12,696,001,459	12,696,001
1995	9,326,254	1,675,937,170	7,680	218,220,986	450,513,711	0.48	8,947,060	230	0.7660	176	1,576,293	12,105,931,008	12,105,931

Col. 2: Total Fuel Consumption: EFC = Gross Generation x Fuel Requirement Per Megawatthour Generated which is based on the Sucat Thermal Plant (see Appendix Table 2).
Col. 3: 365 days - 45 days (average number of days wherein a power plant undergoes annual rehabilitation) x 24 hours
Col. 4: Estimated Fuel Consumption Rate = Estimated Total Fuel Consumption (metric tons) / Number of Hours in Operation (hr) x 1,000
Col. 5: Estimated Nominal Fuel Consumption Rate (kg/hr): see Appendix Table 3.
Col. 6: Load Factor (L) = Estimated Fuel Consumption Rate (kg/hr) / Estimated Nominal Fuel Consumption Rate (kg/hr)
Col. 7: Net Heat of Combustion (Hc) for Residual Fuel Oil (which includes Bunker Fuel) is 41 MJ/kg (Handbook of Emission Factors, part III). This is applied to the Estimated Fuel Consumption Rate to derive the Load or the amount of fuel energy supplied per unit of time (e.g., 237,127 kg/hr x 41 MJ/kg = 9,722,207 MJ/hr/1,000 = 9,722 GJ/hr)
Col. 8: Emission Factor for Residual Fuel Oil used in Power Plants (Handbook of Emission Factors, part III).
Col. 9: Correction Factor for NOx emissions (corrected for non-maximum load): fL = 1 - 0.45 (1 - Load Factor); e.g., 1-0.45(1-0.75) = 1-0.45(0.25) = 1-0.1125 = 0.8875 or 0.89
Col. 10: Adjusted Emission Factor = Emission Factor (g/GJ) x Correction Factor
Col. 11: Average Emission Rate = Load (GJ/hr) x Adjusted Emission Factor (g/GJ)
Col. 12: Total NOx Emissions = Average Emission Rate (kg/hr) x Number of Hours in Operation (hr)
Col. 13: Total NOx Emissions (in metric tons) = Total NOx Emissions (kg) / 1,000

APPENDIX 5.1.4

NOx EMISSIONS OF DIESEL FUEL-BASED POWER PLANTS, 1988-1995

Year	SOx			PM		CO		CO_2	
	Load (GJ/hr)	Emission Rate (g/hr) EF*LOAD	Annual Emissions (MT) m*7680/106	Emission Rate (kg/hr) EF*LOAD	Annual Emission (MT) m*7680/106	Emission Rate (g/hr) EF*LOAD	Annual Emissions (MT) m*7680/106	Emission Rate (g/hr) EF*LOAD	Annual Emissions (MT) m*7680/106
1988	9,723,549	7,114,817,966	54,641,802	147,798	1,135,088	145,853,234	1,120,153	759,409,169,090	5,832,262,419
1989	9,861,212	7,215,547,191	5,541,540	149,890	1,151,158	147,918,175	1,136,012	770,160,631,427	5,914,833,649
1990	9,708,574	7,103,860,901	54,557,652	147,570	1,133,340	145,628,615	1,118,428	758,239,652,830	5,823,280,534
1991	11,222,326	8,211,488,450	63,064,231	170,579	1,310,049	168,334,896	1,292,812	876,463,691,840	6,731,241,153
1992	11,785,960	8,623,904,682	66,231,588	179,147	1,375,846	176,789,398	1,357,743	920,483,464,285	7,069,313,006
1993	10,194,219	7,459,212,263	57,286,750	154,952	1,190,032	152,913,291	1,174,374	796,168,533,578	6,114,574,338
1994	9,220,398	6,746,657,567	51,814,330	140,150	1,076,352	138,305,973	1,062,190	720,113,099,420	5,530,468,604
1995	8,947,060	6,546,653,573	50,278,299	135,995	1,044,444	134,205,906	1,030,701	698,765,418,021	5,366,518,410

APPENDIX TABLE 5.1.5

NOx EMISSIONS OF DIESEL FUEL-BASED POWER PLANTS, 1988-1995

Year	Gross Generation (MWh) 1	Estimated Fuel Consumption (m.t.) 2	Number of Hours in Operation (hr) 3	Estimated Fuel Consumption Rate (kg/hr) 4	Estimated Nominal Fuel Consumption Rate (kg/hr) 5	Load Factor 6	Load (GJ/hr) 7	Emission Factor (g/GJ) 8	Load Correction Factor 9	Adjusted Emission Factor (g/GJ) 10	Average Emission Rate (g/hr) 11	Total Emissions (mt) 13
1988	362,290	29,880,610	7,680	3,890,700	89,494,620	0.04	165,355	450	0.57	256	42,264,674	324,593
1989	723,910	122,904,260	7,680	16,003,160	147,015,332	0.11	680,134	450	0.60	270	183,486,631	1,409,177
1990	1,596,160	493,137,638	7,680	64,210,630	154,621,376	0.42	2,728,952	450	0.74	333	907,512,914	6,969,699
1991	1,346,430	328,129,246	7,680	42,725,160	158,044,096	0.27	1,815,819	450	0.67	302	548,704,276	4,214,049
1992	1,855,510	462,398,788	7,680	60,208,180	168,336,025	0.36	2,558,848	450	0.71	320	819,854,787	6,296,485
1993	2,531,900	652,150,623	7,680	84,915,450	370,894,496	0.23	3,608,907	450	0.65	294	1,061,307,262	8,150,840
1994	6,903,510	1,835,948,168	7,680	239,055,750	580,205,708	0.41	10,159,869	450	0.73	331	3,358,141,626	25,790,528
1995	9,076,670	2,413,887,379	7,680	314,308,250	587,336,375	0.54	13,358,101	450	0.79	357	4,766,838,210	36,609,317

Col. 2: Estimated Fuel Consumption = Gross Generation x Fuel Requirement Per Megawatthour Generated (for 1988 and 1989, the 1990 figure was adopted).
Col. 3: 365 days - 45 days (average number of days wherein a power plant undergoes annual rehabilitation) x 24 hours
Col. 4: Estimated Fuel Consumption Rate = Estimated Fuel Consumption (metric tons) / Number of Hours in Operation (hr) x 103 kg
Col. 5: Estimated Nominal Fuel Consumption Rate (kg/hr)
Col. 6: Load Factor (L) = Estimated Fuel Consumption Rate (kg/hr) / Estimated Nominal Fuel Consumption Rate (kg/hr)
Col. 7: Load (GJ/hr) = Estimated Fuel Consumption Rate (kg/hr) x Net Heat of Combustion (Hc) for Distillate Oil (gas turbine) which is equal to 42.5 MJ/kg
(e.g., 11,159 kg/hr x 42.5 MJ/kg = 474,268 MJ/hr / 103 GJ = 474 GJ/hr)
Col. 8: NOx Emission Factor for Distillate Oil (using gas turbines), (Handbook of Emission Factors, part III)
Col. 9: Correction Factor for NOx emissions (corrected for non-maximum load): fL = 1- 0.45 (1 - Load Factor);
e.g., fL = 1- 0.45(1 - 0.04) = 1- 0.45(0.96) = 1- 0.432 = 0.568 or .57
Col. 10: Adjusted Emission Factor = Emission Factor (g/GJ) x Load Correction Factor
Col 11: Average Emission Rate (g/hr) = Load (GJ/hr) x Adjusted Emission Factor (g/GJ)
Col. 12: Total Emissions (g) = Average Emission Rate (kg/hr) x Number of Operating Hours (hr)
Col. 13: Total Emissions (mt) = Total Emissions (g) / 106 m.t.

APPENDIX TABLE 5.1.6

SOx, PM, CO, AND CO2 EMISSIONS OF DIESEL FUEL-BASED POWER PLANTS, 1988-1995

Year	**Load (GJ/hr)**	**SOx**		**PM**		**CO**		**CO_2**	
		Emission Rate (g/hr) m = EF * LOAD (m)	**Annual Emissions (m.t.) m*7680/10^6**	**Emission Rate (kg/hr) m = EF * LOAD (m)**	**Annual Emission (Metric Tons) m*7680/10^6**	**Emission Rate (g/hr) m = EF * LOAD (m)**	**Annual Emissions (m.t.) m*7680/10^6**	**Emission Rate (g/hr) m = EF * LOAD (m)**	**Annual Emissions (m.t.) m*7680/10^6**
1988	165,355	2,514,528,863	19,311,582	2,513,392	19,303	2,480,321	19,049	12,203,180,550	93,720,427
1989	680,134	1,912,493,812	14,687,952	10,338,041	79,396	10,202,015	78,351	50,193,911,340	385,489,239
1990	2,728,952	679,340,584	5,217,336	41,480,067	318,567	40,934,277	314,375	201,396,641,364	1,546,726,206
1991	1,815,819	513,697,883	3,945,200	27,600,453	211,971	27,237,290	209,182	134,007,464,340	1,029,177,326
1992	2,558,848	481,677,482	3,699,283	38,894,484	298,710	38,382,715	294,779	188,842,956,570	1,450,313,906
1993	3,608,907	341,809,825	2,625,099	54,855,381	421,289	54,133,599	415,746	266,337,309,294	2,045,470,535
1994	10,159,869	128,028,481	983,259	154,430,015	1,186,023	152,398,041	1,170,417	749,798,360,244	5,758,451,407
1995	13,358,101	31,126,378	239,051	203,043,130	1,559,371	200,371,509	1,538,853	985,827,826,494	7,571,157,707

APPENDIX TABLE 5.1.7

NOx, SOx, PM, CO AND CO2 EMISSIONS OF COAL FIRED POWER PLANTS, 1988-1995

Year	Gross Generation (MWh) 1	Estimated Average Fuel Consumption Rate (AFCR) (kg/hr) 2	Load (N) (MJ/hr) 3	NOx		SOx		PM		CO		CO2	
				Emission Rate (g/hr) 4	Total Emissions m*7680/10^6 (mt) 5	Emission Rate (g/hr) 6	Total Emissions (mt) m*7680/10^6 7	Emission Rate (g/hr) 8	Total Emissions m*7680/10^6 (mt) 9	Emission Rate (g/hr) 10	Total Emissions (mt) m*7680/10^6 11	Emission Rate (g/hr) 12	Total Emissions (mt) m*7680/10^6 13
1988	2,558,680	1,314,163,635	29,568,681,783	8,160,956,172	62,676,143	14,979,494,191	115,042,515	739,217,045	5,677,187	295,686,818	2,270,875	2,917,837,518,346	22,408,992,141
1989	2,536,370	1,302,704,996	29,310,862,403	8,089,798,023	62,129,649	14,848,882,893	114,039,421	732,771,560	5,627,686	293,108,624	2,251,074	2,892,395,901,953	22,213,600,527
1990	1,873,011	961,997,180	21,644,936,543	5,974,002,486	45,880,339	10,965,324,853	84,213,695	541,123,414	4,155,828	216,449,365	1,662,331	2,135,922,338,110	16,403,883,557
1991	2,091,130	1,074,025,279	24,165,568,784	6,669,696,984	51,223,273	12,242,277,146	94,020,688	604,139,220	4,639,789	241,655,688	1,855,916	2,384,658,327,630	18,314,175,956
1992	2,155,270	1,106,968,225	24,906,785,056	6,874,272,675	52,794,414	12,617,777,309	96,904,530	622,669,626	4,782,103	249,067,851	1,912,841	2,457,801,549,301	18,875,915,899
1993	2,458,690	1,262,807,771	28,413,174,845	7,842,036,257	60,226,838	14,394,114,377	110,546,798	710,329,371	5,455,330	284,131,748	2,182,132	2,803,812,093,729	21,533,276,880
1994	1,820,100	934,821,561	21,033,485,123	5,805,241,894	44,584,258	10,655,563,563	81,834,728	525,837,128	4,038,429	210,334,851	1,615,372	2,075,584,311,888	15,940,487,515
1995	2,658,630	1,365,498,954	30,723,726,472	8,479,748,506	65,124,469	15,564,639,831	119,536,434	768,093,162	5,898,955	307,237,265	2,359,582	3,031,817,328,232	23,284,357,081

Col. 1: Gross Generation of Coal-Fired Power Plants.

Col. 2: Estimated Average Fuel Consumption Rate (kg/hr) = Gross Generation (MWh) x 154,083 (kg/hr), the average fuel consumption rate of Calaca Coal-Fired Power Plant / 300 (MW), installed capacity of Calaca Coal-Fired Power Plant

Col. 3: Load (MJ/hr) = [Estimated Average Fuel Consumption Rate (kg/hr) x 0.5 (percent blend of hard coal) x 27 MJ/kg (Hc or net heat of combustion for hard coal)] + [Estimated Average Fuel Consumption Rate (kg/hr) x 0.5 (percent blend of lignite) x 18 MJ/kg (Hc or net heat of combustion for lignite)]

Col. 4: Emission Rate (g/hr) = Load (MJ/hr) / 103 GJ/MJ x 300 g/GJ (NOx emission factor for hard coal **+** Load (MJ/hr) / 103 GJ/MJ x 240 g/GJ (NOx emission factor for lignites

Col. 5:: Total Emissions (MT) = Emission Rate (g/hr) x Number of Operating Hours - 7860 (hr)/10^6

Col. 6: Emission Rate = [Estimated Average Fuel Consumption Rate (kg/hr) x 0.5 (percent blend of hard coal) x 27 MJ/kg (Hc or net heat of combustion for hard coal) x 0.563 g/MJ (SOx emission factor for hard coal)] + [Estimated Average Fuel Consumption Rate (kg/hr) x 0.5 (percent blend of lignite) x 18 MJ/kg (Hc or net heat of combustion for lignite) x 0.422 g/MJ (SOx emission factor for lignite)]

Cols. 8, 10, 12 : For emission rates for PM, CO and CO2, use the same formula used for Col. 6 and replace the Emission factors with the respective emission factors , which is given above.

APPENDIX TABLE 5.1.8

VOC OF BUNKER OIL FUEL-BASED AND COAL FIRED POWER PLANTS, 1988-1995

Bunker Fuel-based					Coal-fired Power Plants						
Year	**Emission Factor (gVOC/kgoil) 1**	**Estimated Fuel Consumption (kg) 2**	**Annual Emission (kg) 3**	**Annual Emission (MT) 4**	**Year**	**Gross Generation (MWh or MJ) 1**	**Average Fuel Consumption Rate (kg/hr) 2**	**Number of Hours in Operation (hr) 3**	**Total Fuel Consumption MT 4**	**Emission Factor (kg/m.t.) 5**	**Total Emissions MT 6**
	0.03 g/li									0.07kg/li	
1988	0.04	1,821,386,719,960	72,855,469	72,855	1988	2,558,680	1,314,163,635	7,680	10,092,776,715.26	0.15	1,513,917
1989	0.04	1,847,173,308,180	73,886,932	73,887	1989	2,536,370	1,302,704,996	7,680	10,004,774,366.98	0.15	1,500,716
1990	0.04	1,818,581,722,160	72,743,269	72,743	1990	1,873,011	961,997,180	7,680	7,388,138,340.17	0.15	1,108,221
1991	0.04	2,102,133,335,790	84,085,333	84,085	1991	2,091,130	1,074,025,279	7,680	8,248,514,145.02	0.15	1,237,277
1992	0.04	2,207,711,503,660	88,308,460	88,308	1992	2,155,270	1,106,968,225	7,680	8,501,515,965.70	0.15	1,275,227
1993	0.04	1,909,551,336,920	76,382,053	76,382	1993	2,458,690	1,262,807,771	7,680	9,698,363,680.51	0.15	1,454,755
1994	0.04	1,727,138,003,980	69,085,520	69,086	1994	1,820,100	934,821,561	7,680	7,179,429,588.48	0.15	1,076,914
1995	0.04	1,675,937,170,050	67,037,487	67,037	1995	2,658,630	1,365,498,954	7,680	10,487,031,969.02	0.15	1,573,055

Col. 1: Emission Factor of VOC (ENRAP Study).

Col. 3: Annual Emission (kg) = Estimated Fuel Consumption (kg)
x Emission Factor (gvoc/kgoil)

Col. 4: Annual Emission (m. t.) = Annual Emission (kg) / 103 m.t.

Col. 4: Total Fuel Consumption (m.t.) = (Average Fuel Consumption Rate (kg/hr)
x Number of Hours in Operation (hr)) / 103 m.t.

Col. 5: 0.07 kg/li = Emission Factor of VOC per metric ton of coal (ENRAP study) converted to kg/m.t.

Col. 6: Total Emissions = (Total Fuel Consumption (m.t.) x Emission Factor (kg/m.t.)) / 103 m.t.

APPENDIX 5.1.9
TYPES OF POWER PLANTS [6]

1. INTRODUCTION

There are two types of plants that can be developed to generate electric power, namely, *hydro* and *thermal*. Hydroelectric plants and generators are propelled by water turbines while thermal or steam plants obtain energy from combustion of fuel, and driven by steam turbines. Thermal plants can utilize fossil fuel (oil, coal, or natural gas), nuclear fuel, or geothermal energy.

Comparison of thermal- and hydroelectric-power costs

Initial or capital cost. The initial investment or capital cost of a hydroelectric plant is generally higher than that of a comparable thermal plant.

Operating costs. The cost of operating a thermal plant is much higher than for a hydroelectric plant, mainly because of fuel costs. Hydroelectric power plants have low operating costs, are well suited to serve peak-load demands, and use a renewable resource as well. In contrast, the fuels used to run thermal power plants, e.g., oil, coal and natural gas, are non-renewable, and additional depletion costs have to be taken into account.

Environmental costs. Expensive air pollution-control systems are required for most thermal plants, and cooling towers or cooling ponds are needed to avoid thermal pollution of rivers or lakes. For hydroelectric plants, favorable sites have to be selected because of irreversible effects on land use.

Power systems and load

The unit of electrical power is the *kilowatt* (kW), which is equivalent to 1.34 horsepower. The unit of electrical energy is the *kilowatt-hour* (kWh), defined as 1 kW of power delivered for one hour.

Firm (or *primary*) *power* is the power that a plant can be expected to deliver 100 percent of the time. *Surplus* (or *secondary*) *power* is all power available in excess of firm power.

The load for the peak day of the year determines the required generating capacity, while the requirements of the peak week or month dictate the amount of energy storage required in the form of fuel or water. The key problem in the economics of electric power utilities is the variation in the demand for electric power during the day, each month, and throughout the year.

2. THERMAL POWER PLANTS

2.1 Fossil fuel-fired power plants

2.1.1 General layout and design considerations

For purposes of design and layout, thermal power stations can be classified by the number and ratings of the turbo sets, the number of boiler per set, the type of fuel, the methods of fuel delivery, and the method of cooling. Local weather conditions have an influence on the design of thermal power stations. The effective choice of the size and number of units will, in a given situation, be decided with due regard to total capacity and demand on the interconnected system, as well as the likely growth of future demand.

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[6] Lecture Notes of Ms. Maricor Ebarvia, Consultant, TWG on Electricity.

Fuel Supply

For coal-burning stations, the fuel supply could be delivered by road, rail or waterway. In the case where the power station is close to the sea or rivers, and fuel is transported by waterway, suitable berthing arrangements with jetties, cranes, etc. will have to be provided. In addition, adequate provision will have to be made for the storage of coal at the power plant to take care of possible unforeseen delays in the normal coal deliveries.

Oil fuel is handled, transported and stored more cheaply and easily. No ash handling is involved. Where natural gas is used, the supply is usually obtained over a pipe line, and no storage is required.

Plant design

The generally preferred modern practice is to adopt the unit type design in which the boiler, the turbo-generator and the transformer are tied together and operated as one unit.

The major inter-connections to be provided will include:

a) fuel supply line from the bunkers to the coal pulverizing mills, and then to the boiler burners;

b) combustion air supply ducts from the air intake to the forced-draft fans, and then to air pre-heater, and then to burners;

c) gas ducts from the super-heater to the economizer, then to the pre-heater, then to the dust precipitators, then to the induced fans, and then to the stacks for discharge into the atmosphere;

d) main steam and re-heater steam piping between the boiler and the turbine;

e) condensate and feed water line from the condenser through the feed heaters and de-aeration and feed pumps to the economizer and boiler;

Another important design consideration is the vacuum at the condenser. The performance of a steam turbine is highly sensitive to the backpressure or the exhaust. Intermediate feed water heating is an effective means of raising the efficiency of steam cycle.

f) electric cable connections between the generator and transformer;

g) electric cable network from the main transformers or auxiliary transformers through the switchboards to the various auxiliaries;

h) control and telemetering cables from the plant to the control center.

Cooling water supply

In the production of electricity, quantities of steam are generated and then condensed, driving the turbines in the expansion phase of the process. The condensation is achieved through rapid cooling with water, but carries away a great deal of waste heat due to thermodynamic inefficiencies. There are two systems of providing cooling water to a thermal power station. Where direct cooling is employed, cold water is drawn from the sea or river, pumped through the condenser, and then led back into the sea or river at a further location and at an elevated temperature. The difference in temperature may be 10-degrees Celsius. The second method is to adopt cooling towers in which water is pumped in a closed circuit consisting of the condenser and the cooling tower. The heat collected from the condenser by the circulating water is dissipated when it drops down the cooling tower against an upward draught of air.

The cooling towers are classified as wet or dry, and each of these may be forced-draught or natural-draught. In the wet tower. the cooling tower is in contact with the air, and cooling takes place by evaporation. A dry tower is basically a large radiator. The cooling water flows through finned tubes and is cooled by air passing over them. Dry towers are more expensive to construct than wet towers, but they do not have any water loss.

2.1.2 Environmental effects

a. Air pollution

Most of today's environmental discussions revolve around specific pollutants that influence the biosphere, such as sulfur dioxide, carbon monoxide, the oxides of nitrogen, and waste heat that cause temperature rise in water bodies. Coal and oil produce the most pollutants when burned. Coal accounts for about two-thirds of the SO_2 in the air. Thus, the primary strategies aim at controlling sulfur-oxide emissions, and limiting the sulfur content of the fuel, or limiting the SO_2 emitted at the stack.

Air pollution problems from fossil-fuel plants can be reduced somewhat by the use of tall stacks or the construction of mine-mouth generating plants. Tall stacks, about 150 meters high or more, can help disperse the pollutants, and thereby lower pollution concentrations at ground level, but they do not decrease the amount or air pollution, and may simply transfer the problem to a different area.

The most promising flue-gas desulphurization processes utilize scrubbing of flue gases with lime or limestone slurries, forming a sludge waste product. New plants install fluidized beds to control emissions of sulfur oxides and nitrogen oxides.

Electrostatic precipitators work well to control fly-ash problems. However, the solid waste (from the fly ash) disposal problem is not trivial.

b. Water pollution

Thermal power plants require substantial volumes of water for cooling purposes. The effect of thermal releases on the source of cooling water of a power plant depends upon the amount of water available, the ecology of the source water, and its desired use. Environmental effects result from the release of waste heat to the receiving water body. The oxygen content of water is critical for most marine life, and it is affected by temperature. Other than the impact caused by the warming of the cool water, the evaporation of about five pounds of water for each kWh produced is also a major environmental effect.

2.2 Geothermal power plants

2.2.1 Geothermal reservoirs

Below the earth's crust lies the mantle, the upper part of which is believed to be the source of magma, which is a mixture of molten rock and gases that penetrates the crust and erupts at the surface of volcanoes. Within the continental belts of recent volcanic action, heat flow is higher than the earth's average. The high-temperature geothermal areas are found in these belts of high heat flow.

Geothermal reservoirs consist of permeable and porous rock in which, by circulation of steam or hot water, a convection system can develop. Groundwater, which can percolate down to depths of several miles, is heated directly or indirectly by the underlying magmas, then expands. A cap rock traps the heat of the water until it is released by a well or a natural fracture, and ascends towards the surface.

2.2.2 Types of geothermal sources

a. Dry-steam geothermal fields

Little or no water remains with the superheated steam as it emerges. The steam is separated from water particles in the separator, and filtered to remove abrasive particles. The turbines for geothermal plants have a different design from those of modern fossil-fuel power plants which operate at much higher pressures and temperatures. The steam from the turbine is then condensed, and the resulting water is cooled in cooling towers. Most of the water is ultimately evaporated to the atmosphere in these towers, carrying with it the waste heat from the plant. About 20 percent of the condensed water, containing trace chemicals such as boron and ammonia, which would pollute local rivers if released, is reinjected into the ground through deep wells.

b. Wet-steam geothermal fields

Geothermal wells commonly produce a mixture of steam and hot water, rather than steam alone. Water-dominated sites are most commonly found in areas of volcanism. The water contained in wet-steam deposits, however, is often heavily contaminated by dissolved salts and minerals, which must be removed before the water enters the turbine, in order to avoid clogging and corrosion. A centrifugal separator is used to separate the steam and the water. Often, the water output of the separator is then allowed to flash at some suitable lower pressure, and the low-pressure steam is utilized while the water output is discarded. When the water is relatively saline, it is reinjected back into the earth. Two turbines can be used, one each for high- and low-pressure steam, respectively. The output of the low-pressure turbine is condensed and then cooled through the cooling tower (or through evaporative ponds which some plants use). Surplus condensate may be purified as desalted water. The additional components, such as the flash units and turbine sections, and the cost of disposal of wastewater raise the total cost to about twice the cost of the dry-steam plant, but still attractive in comparison to that of fossil-fuel plants.

c. Hot-brine geothermal fields

Many geothermal fields have reservoirs of water that has a salt content equal to or greater than that of sea water. These dissolved salts are extremely corrosive. Once the steam has been removed, the hot brine becomes a thick syrup. A distillation process can be employed to remove the salts from the hot brines. The primary problem is to design a corrosion-resistant turbine wheel to be able to use the hot brine directly.

The corrosive brine solution is used to heat secondary fluids, which have lower boiling points and are effective high-pressure heat carriers, in a series of heat exchangers. Then it is reinjected into the reservoir in order to avoid land subsidence and ground- and surface- water degradation.

d. Hot-rock geothermal fields

Underground water systems do not come in contact with most of the near-surface deposits of geothermal heat. High-porosity rocks, called hot-rock deposits, however, constitute an important source of heat. Utilizing these deposits requires the development of a technique for artificial fracture of the rock, the injection of water into the fractures, and subsequent recovery of steam for turbines.

2.2.3 Environmental impact of geothermal power plants

In many systems, towers must be erected to cool the surplus heat in the output steam. A plant's impact will vary widely with the quality of the steam or water that emerges from the condenser, and will be dependent upon whether subterranean pressures present obstacles in the way of returning the residues to the earth.

In the case of using hot dry rock, substantial quantities of surface water will be required for injection into the artificial fracture.

Steam coming from the earth may contain objectionable gaseous effluents. The steam used contains CO_2, H_2S, ammonia, methane, arsenic, mercury, and other non-condensable gases. Under current technologies, the toxins are re-injected into the reservoir.

The disposal of geothermal wastewater from hot-brine plants will be a problem because of the mineral content. Once through the turbines, the condensed water may be too full of contaminants to permit dumping into natural streams or lakes. Because the saline and siliceous solids precipitate out as the water temperature and pressure drop, re-injection into the ground also may be difficult. The solids may block the porosity of the underground rock.

3. HYDROELECTRIC POWER PLANTS

3.1 Definition of terms

The *gross head* for a hydroelectric plant is the difference in elevation between the water service in the stream at the diversion and the water surface in the stream at the point where the water is returned after having been used for power.

The *net* or *effective head* is the head available for energy production after deducting losses in friction, entrance, unrecovered velocity head in the draft tube, etc.

The *hydraulic efficiency* is equal to the ratio of net head to gross head.

The *overall efficiency* is equal to the hydraulic efficiency multiplied by the efficiency of the turbines and generators. If the plant is operating at optimum conditions, then the overall efficiency will usually be between 60 and 70 percent.

The *capacity* of a hydroelectric plant is the maximum power which can be developed by the generators at normal head with full flow.

3.2 Types of hydroelectric plants

Hydroelectric plants may be classified as *run-of-river*, *storage*, or *pumped-storage*. A run-of-river plant generally has very limited storage capacity, and can use water only as it comes. A storage type of plant is one with a reservoir of sufficient size to permit carry-over storage from the wet season to the dry season, and thus, to develop a firm flow substantially more than the minimum natural flow. A pumped-storage generates energy for peak load, but at off peak, water is pumped from the tailwater pool to the headwater pool for future use.

3.3 General arrangement of a hydroelectric project

A hydroelectric system includes a diversion structure, a conduit (penstock) to carry water to the turbines, turbines and governing mechanism, generators, control and switching apparatus, housing for equipment, transformers, and transmission lines to the distribution centers. In addition, trash racks at entrance to the conduit, canal and penstock gates, a forebay, or surge tank, and other appurtenances may be required.

The *forebay* serves as a regulating reservoir, temporarily storing water when the load on the plant is reduced and providing water for the initial increments of an increasing load while water in the canal is being accelerated. The forebay is provided with some type of *intake structure* to direct water to the penstock. Intakes should be provided with *trash racks* to prevent the entry of debris which might damage the wicket gates and turbine runners or choke the nozzle of impulse turbines. Moreover, a forebay must be provided with a *spillway*, or wasteway, so that excess water can be disposed of safely if the need arises.

Water is carried to the powerhouse from the dam and forebay through a canal, tunnel, or *penstock*. The structural design of a penstock is the same as for any other pipe.

A *powerhouse* consists of a *substructure* to support the hydraulic and electrical equipment, and a *superstructure* to house and protect this equipment. The details of the waterways in the substructure depend on the type of turbine and setting selected.

The *tailrace* is the channel into which the water is discharged after passing through the turbines. A tailrace, or waterway, from the powerhouse back to the river must be provided if the powerhouse is situated so that the draft tubes cannot discharge directly to the river.

3.4 Environmental problems

Hydroelectric power utilizes a renewable indigenous resource without producing air emissions and radioactive wastes. Moreover, there are many other advantages: longer service life, smaller staff requirements, operational flexibility, and fast response time to changes in demand. The problems associated are primarily local environmental and social consequences. The greatest effect of dam construction is on land use and its irreversibility after the completion of the hydroelectric power system. Undesirable effects include upstream flooding of river valleys, downstream water-flow reduction, impact on the area required for the lake (or forebays) such as the inundation of productive lands and forests, destruction of habititats and loss of the biodiversity of flora and fauna in the affected sites, siltation, relocation of human settlements, and the effects of long electric transmission line from the project site to the area where the electric power is used.

APPENDIX 5.1.10
TREATMENT PROCESS [7]

1. Air Pollution Control Facilities [8]

1.1 SO_2

For coal-fired boilers there are two Flue Gas Desulphurization (FGD) systems that are applicable to control SO_2 emissions: lime/limestone scrubbing process and sodium scrubbing.

For oil-fired boilers, most of the FGD units installed are sodium throwaway systems. The actual designs of the systems are very similar to coal-fired FGD system designs except that the oil-fired systems have lower flue gas flow rates for a given boiler size and because less excess air is used for combustion. Consequently, the oil-fired FGD systems are smaller.

1.2 NOx flue gas treatment (FGT)

<u>Examples of NOx FGT systems are the following (NOx - only processes)</u>:

- Fixed Packed Bed Selective Catalytic Reduction (SCR)
- Moving Bed SCR
- Parallel Flow SCR
- Absorption-Oxidation

<u>Simultaneous NOx/ SOx processes</u>:

Parallel Flow SCR
Adsorption
Electron Beam Radiation
Absorption-Reduction
Oxidation-Absorption-Reduction
Oxidation-Absorption

<u>Controls for coal-fired boilers</u>:

a. Control of NOx only

- Selective catalytic reduction (SCR)

Fixed packed bed systems for selective catalytic reduction of NOx are applicable only to flue gas streams containing particulate emissions of less than 20mg/Nm^3 while moving bed systems are applicable only to flue gas streams containing less than 1 g/Nm^3. Particulate emissions for all types of coal are higher. Although it is possible to install a hot electrostatic precipitator (ESP) to reduce the particulate level to 20mg/Nm^3 and 1 g/ Nm^3 for fixed packed bed systems and moving bed systems, respectively, this is expensive, and not always effective. For these reasons, both SCR systems are not considered for application to coal-fired boilers.

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[7] Ibid.

[8] The information in this section was based on Martin, ed. (1981) and the tables presented are culled from various EPA reports.

- Absorption-oxidation

The relative insolubility of NO in water presents a major obstacle to achieving the stringent level of control (90 percent NOx reduction) by this system. Another primary drawback of this system is the production of nitrate salts, a secondary pollutant. Trying to recover the nitrates as nitric acid for industrial use or potassium nitrate for fertilizer does not seem promising as the by-products are of low quality. Moreover, the use of expensive, liquid-phase oxidant requires stainless steel and other corrosion-resistant materials. High sulphur coals require an FGD system prior to the NOx absorber as it has been mentioned.

b. Simultaneous NOx/SOx removal

- Selective catalytic reduction

This process is similar to those discussed in the previous section on SCRs. The primary difference is the additional equipment necessary to collect and process SO_2. The main feature of the process is the reactor and the catalyst which remove both NOx and SO_2, a process developed by Shell. A uniquely designed parallel flow type of reactor is used to avoid problems with particulates. The Shell Flue Gas Treatment (SFGT) is a dry process with two or more reactors operating in a cyclic manner. The desulphurization aspect is regenerable, while NOx removal is accomplished by catalytic reduction with ammonia.

Controls for oil-fired boilers

a. Control of NOx only

Selective catalytic reduction

Since fixed packed bed systems are applicable only to flue gas streams containing less than 20 mg/Nm^3 of particulates, they are applicable to distillate oil-fired boilers (19 mg/Nm^3), but not to residual oil-fired boilers (330 mg/Nm^3).

The system of parallel flow reactor for SCR is similar to those designed for coal-fired boilers, and has been described in the previous section. The following variables associated with the boiler can also affect the performance of these SCR systems:

- flue gas flow rate
- NOx concentration
- boiler load variability

b. Simultaneous NOx/SOx removal

1.3 NOx combustion modification

- Decrease primary flame zone O_2 level by:
  - decrease overall O_2 level
  - controlled mixing of fuel and air
  - use of fuel-rich primary flame zone

- Decrease time of exposure at high temperature by:
  - decreased peak temperature
    - ➢ decreased adiabatic flame temperature through dilution
    - ➢ decreased combustion intensity
    - ➢ increased flame cooling

    - ➢ controlled mixing of fuel and air or use of fuel-rich primary flame zone

  - decreased primary flame zone residence time

- Chemically reduce NOx in post-flame residency by injection of reducing agent

- Applicable control techniques

  - staged combustion
  - flue gas recirculation
  - combined staged combustion and flue gas recirculation
  - low NOx burners
  - ammonia injection

2. Particulate collection

2.1 Electrostatic precipitators (ESP)

The basic collection processes taking place in an ESP are as follows: (1) suspended particles are given an electrical charge; (2) the charged particles then migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and (3) the collected material is then dislodged from the collection electrodes.

2.2 Fabric filtration

The basic mechanisms available for filtration are inertial impaction, diffusion, direct interception, and sieving. A *baghouse* consists of a number of filtering elements (bags) arranged in compartments, a cleaning mechanism or subsystem, and the main shell structure and hoppers. The bags used in coal-fired boiler applications are usually made of fiberglass with a coating of silicone, graphite, and/or Teflon. The bag material is most important since the bags are usually the highest maintenance cost component.

2.3 Wet scrubbers

The main advantages of using wet scrubbers are as follows:

- they collect both particulate matter and gases.
- they function in wet, corrosive, and/or explosive gas atmosphere.
- they may occupy less space than either fabric filter or ESP systems.

The main disadvantages are the following:

- the energy requirements associated with their operation
- possible high effluent opacity and the necessity for reheat
- exceptionally high pressure loss to attain equivalent (ESP or filter) efficiencies
- poor efficiency for fine particulates
- need for both water and solid waste disposal systems
- water availability and land requirements may also restrict the use of scrubbers in certain geographical areas.

2.4 Mechanical collectors - Multitube cyclones

Multitube cyclones, which represented the most common type of inertial collector used for fly ash collection before stricter emission regulations were enacted, depend on centrifugal forces. Due to efficiency limitations, they now function mainly as precleaning devices.

3. Fluidized-bed combustion (FBC)

The most important pollutants identified are SO_2, NO_x, particulates, and solid residue. Fluidized-bed combustion provides *in situ* retention of fuel sulphur, and consequently, lowers the concentration of SO_2 in the flue gas exhausted from the boiler. A suitable bed material such as limestone or dolomite is used to absorb the SO_2 formed during combustion.

By using FBC technology, SO_2 emissions can be reduced by up to 90 percent or more, depending upon the rate of sorbent addition to the bed and the FBC design and operating conditions. The SO_2 would be sent to a sulphur recovery system to generate elemental sulphur or sulphuric acid. NO_x emissions from FBC are inherently lower than uncontrolled emissions from conventional combustion due to the unique combustion chemistry that occurs in the fluidized bed.

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