Emission Inventory of Electricity Generation in Thailand

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Abstract: Using default emission factors might lead to both over and under estimates for evaluating the total emissions, because the emission factor is strongly affected by fuel properties, operation procedure, emission control etc. To decrease these errors, locally derived emission factors were developed by using site specific data, such as continuous emission monitoring system (CEMS), stack sampling and operation information data from the selected power plants. They were representative of each types of power plant in Thailand including thermal, gas turbine and combined cycle power plants. The locally derived emission factors, according to plant characteristics, were calculated from the annual gaseous emissions divided by either annual electricity generation or heat input in which unit were expressed in kg/MWh or kg/GJ. In order to compare, the locally derived emission factors might be different from the Intergovernmental Panel on Climate Change, IPCC emission factor from 1 to 4 times.
From the locally derived emission factors, the emissions inventory of the power generation sector and country-specific emission factors were evaluated. The average annual emissions inventory of electricity generation between 2001-2006 for CO_2, CO, NO_x, SO_2 and particulate matter were about 67, 0.03, 0.15, 0.04 and 0.005 million tons respectively. From the results of the nation grid emissions inventory between 2001-2006, the country-specific emission factors of the CO_2, NOx, SO_2 and particulate matters were approximately 563.52, 1.26, 0.41 and 0.06 g/kWh respectively.

Keywords: Emission inventory, power plant, emission factor.

1. Introduction

Total electricity generation in Thailand was 102,420 GWh in 2001 and increased continuously to 138,732 GWh in 2006 [1]. The sources of this generated power were mainly fossil fuels which accounted for 94 percent of electricity generation while the remaining came from hydro-electric energy and renewable energy sources [2]. As a result, the electricity generation sector is the major source of gaseous emissions such as carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), sulphur dioxide (SO_2) and particulate matter (PM). Particularly, CO_2 is a greenhouse gas (GHGs) which is a major cause of global warming. In addition, SO_2 and NOx gases are contributors to acid rain. Therefore, efficient environmental management and assessment plans are necessary to mitigate their adverse effects. In the light of this an emission inventory of data was necessary to evaluate the status of the existing situation or problems, and to assess effective policies to solve the problem. There have been some previous studies on the emission inventory of electricity generating sector in Thailand [3-5]. All of them were developed by a top-down approach and using default emission factors which were recommended in the IPCC Guidelines 1996; they were not country-specific or site-specific values [6]. This would lead to loss of accuracy due to the uncertainty associated with the representativeness of the information used. The results in this study were developed by using country- or site-specific emission factors, which were more accurate and directly related to local fuel properties and the nature of the power plant operation. One difficulty of locally derived emission factor preparation was insufficient raw data from CEMS, which directly related to plant characteristics such as efficiency of the power plant, emission control devices, operating mode, etc [7].

In this study, annual gaseous emissions from selected fossil fuel power plants were assessed and locally derived emission factors were developed from emission assessment, electricity generation and plant characteristics. Thereafter, locally derived emission factors were applied to all power plants in the national grid according to types of power plants for estimating gaseous emissions of the electricity generating sector in Thailand. In addition, the country-specific emission factors of 1 kWh of electricity generation for the whole national grid were calculated.

2. Experimental

2.1 The selected power plants in this study

The selected power plants were used to represent power plants in Thailand and investigate their emissions. The selected power plants used fossil fuel and were classified into 3 types: thermal, gas turbine and combined cycle power plants. Table 1 shows the comparison of installed capacity of selected power plants and the national grid with the same type.

Table 1. Installed capacity of selected power plants compared with the same type of power plant on the national grid [2].

Type of Power Plant	Fuel	in This Study	National Grid
Thermal (Steam Turbine)	Lignite	2,400 MW	2,400 MW
	Fuel oil and Natural gas	3,630 MW	5,517 MW
Gas Turbine	Natural gas	154 MW	778 MW
Combined Cycle	Natural gas	4,459 MW	6,069 MW

Thermal power plants use only steam turbines to generate electricity. In this study, they were sub-divided into 3 groups following the type of fuel used: lignite, fuel oil and co-firing of fuel oil, and natural gas. For lignite power plants, there are 10 units, which have a total installed capacity of 2,400 MW. All of these are pulverised coal combustors with a tangential firing configuration. Their gaseous emissions are controlled by using over fired air, an electrostatic precipitator (ESP) and wet limestone type of flue gas desulphurisation (FGD) for NO_x, PM and SO_2 emissions, respectively. The removal efficiency of PM and SO_2 are 99 and 95 percent, respectively [8]. For fuel oil thermal power plants and co-firing thermal power plants, there are a total of nine units; two units use only fuel oil while the rest use co-firing of fuel oil and natural gas. They accounted for 3,630 MW of installed capacity. There are only four units of co-firing thermal power plants which have ESP installation with 88 percent removal efficiency [9].

For gas turbine power cycles, 154 MW out of 778 MW total installation capacity are considered in this study. For combined cycle power plants, nine units are considered at a total installed capacity of 4,459 MW. For NO_x emission control, two techniques are used; low-NO_x burner and water/steam injection. The NO_x control techniques are described as follows: For low- NO_x burners, a lean premixed burner design, the air and fuel is premixed at very lean air/fuel ratios prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates [10]. For water/steam injection, the injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation [10].

2.2 Annual gaseous emission estimation methods

This study was concerned with the emissions of CO_2, CO, NO_x, SO_2 and particulate matter (PM) from fossil fuel power plants. The emissions from hydro-electric power plants and renewable energy power plants were excluded from this study, since their contributions in term of installed capacity to the national grid were very low. The installed capacity of hydro and renewable energy power plants in 2006 were 13.0% and 3.6% respectively [2]. In terms of electricity generation, hydro power plant contributed only 5.9% of the total grid generation. Considering total energy consumption, biomass and biogas were about 3.2% and 0.9% of the total energy consumption of the national grid, respectively.

There are several methodologies available for calculating the total weight of the emissions in a specific time. The method used is dependent upon available data, available resources, and the degree of accuracy required in the estimation [11]. Annual gaseous emissions in this study are emphasised on calculation using the measurement data of each power plant, which are preferable as representative of the normal operation of that power plant. In this study, we estimate the annual emissions by using three methods; calculation using continuous emission monitoring system (CEMS) data, using stack sampling data, and fuel analysis methods.

2.2.1 Continuous Emissions Monitoring System (CEMS) Data

Generally, the CEMS is installed at the stack for monitoring NO_x, SO_2 and CO emissions. The gas concentrations reported from CEMS is usually in units of ppm by volume at 25°C, 1 atm, dry basis and 50 percentage of excess air. The conditions of temperature, pressure, moisture and excess air are regulated by the emissions standards of Thailand [12]. The first step of calculation is a conversion unit from ppm to be mg/m^3. Then, the emission rate, kg/hr, is determined by multiplying flue gas flow rate, m^3/hr, with concentration, mg/m^3. Summation of emission rates of every operational hour in the year results in total annual emissions [13]. The accuracy of results from CEMS method is better than other methods because CEMS monitors in real time the variation of the emissions and continuously. However, this method is a very complicated calculation and quality control of raw data should be considered.

2.2.2 Stack sampling data

Stack sampling data is the preferable method of estimation of particulate matter emissions. Concentrations of particulate matter (PM) emissions in this study are measured following the United State Environmental Protection Agency methods 1 to 5 which are explained in 40 codes of federal regulations part 60 appendix A [14]. Concentrations of PM are usually reported in unit of mg/m^3 at 25°C, 1 atm, dry basis and 50 percentage of excess air, conforming to the emission standards of Thailand [12]. To estimate annual emissions, firstly average concentrations of PM, in unit of mg/m^3, is multiplied by total volume of flue gas flow in the year which is being calculated by summing the flue gas flow rate of every operation hour in the year [12]. The stack sampling cannot monitor the variation of the stack emissions therefore the results of this method might be over or under estimated.

2.2.3 Fuel analysis method

Due to the absence of CO_2 monitoring system, annual CO_2 emissions are calculated by using the fuel analysis method according to 1996 IPCC Guidelines [6]. The fuel properties such as composition and calorific values were received from EGAT.

2.3 Quality Assurance and Quality Control Processes

During calculation, quality assurance processes, such as reality check, computerised check and replication calculation check, are applied to obtain accurate results [15]. The reality check is used to check the quality of raw data from CEMS. For example, if the power plant is shut down, the emissions should be zero. On the other hand, while the boiler is operating, the emissions should be above zero. Suspicious data should be removed from raw data. The computerized check ensures that the formula will not be wrong from electronic error. The replicated calculations were done randomly to choose a result and calculate by hand or independent spread sheet for rechecking the formula.

2.4 Locally derived emission factors

Generally, an emission factor is the pollutant emission rate relative to the level of source activity. Emission factors are widely used to estimate the amount of emissions because few data are required. However, the estimation by using default or referenced emission factors can lead to greater error in the results. Therefore, locally derived or site-specific emission factors should be developed to decrease the error from local variation. For this study, the locally derived emission factors of CO_2, CO, NO_x, SO_2 and PM emissions from fossil fuel power plant have been developed by dividing annual emissions of selected power plants by their related activity, as shown below.

Locally derived emission factor = Annual emission / Related activity

Where: Related activity is electricity generation expressed in terms of either mega-watt-hours (MWh) or heat input (GJ). Then the locally derived emission factors are expressed in terms of mg of gaseous emission per unit of gross electricity produced (kg/MWh) and per unit of heat input (kg/GJ).

3. Results and Discussion

3.1 Locally derived emission factor of interested power plant

Locally derived emission factors were calculated from annual emission data assessed from selected power plants divided by related activity (electricity produced or heat input). The results of locally derived emission factors are shown in Table 2. They consist of emission factors of CO_2, CO, NO_x, SO_2 and PM from thermal power plant; with lignite, fuel oil and co-firing of fuel oil and natural gas, gas turbine power plant and combined cycle power plant. More details were reported in Krittayakasem (2008) [7].

3.2 Emission inventory of the electricity generating sector

Annual electricity generation from 2001 to 2006 is shown in Fig. 1. The generation steadily increased from 102,420 GWh in 2001 to 138,732 GWh in 2006. As mentioned earlier approximately

94% of electricity generation was from fossil fuel power plants and it could be seen that the largest contribution was from combined cycle power plants which accounted for 50% of the total production. Thermal power plants, which use steam turbines to generate electricity, and co-generation power plants, which used combined cycle power plant technology, accounted for 33 and 11%, respectively. The rest was from hydro-electric and gas turbine power plants, 6 and 1 respectively. Normally, gas turbine power plants were designed as a reserved capacity and start up for emergency case only.

The emission inventory of electricity generation during 2001 to 2006 was calculated as shown in Table 3. The amount of gaseous emissions released from power plants each year were only considered from fossil fuel power plants. In this study, gaseous emissions from hydro and renewable energy power plants during electricity generating were not included in this analysis. Gaseous emissions by type of power plants, such as combined cycle power plants, thermal power plants, etc., were the products of locally derived emission factor and gross electricity generation according plant characteristics. The total gaseous emissions from power plants were the summation of each gaseous emission by plant.

From the results, overall CO_2 emission was 59 million metric tonnes in year 2001 and steadily increased to 77 million metric tonnes in year 2006 due to increasing electricity generation and, hence, fuel consumption. It can be said that during the years 2001 to 2006, annual gaseous emissions increased: annual CO emissions increased from 23 to 30 thousand metric tonnes, annual NO_x emission increased from 126 to 170 thousand metric tonnes, annual SO_2 increased from 32 to 49 thousand metric tonnes, and annual PM increased from 4.4 to 6.0 thousand metric tonnes. Thermal power plants, using lignite, fuel oil and natural gas fired boilers, were the largest emission sources. From the results, roughly 50 percent of CO_2 and NO_x emissions came from thermal power plants whereas their production is approximately 30 percent of the total generation. Lignite power plants were the largest source of SO_2 emission due to the sulphur content in lignite meanwhile the emissions from other plants was lower due to lower sulphur content in the fuel oil. For PM emission, it can be seen that about 80 percent of the emission was from thermal power plants using lignite. Although, they have the more efficient PM emission control device such as ESP, that is because they have a larger consumption of lignite than the other types of fuel. About 50% of thermal power plant generation is from lignite fired boilers.

The gaseous inventory results showed the significant contribution from lignite powered plants. Even the total electricity generation increased resulting in increases of CO_2 emission due to increasing in fuel consumption, but NO_x, SO_2 and PM were decreased, comparing among years 2001 to 2003, since electricity generating share from lignite fuel was decreased.

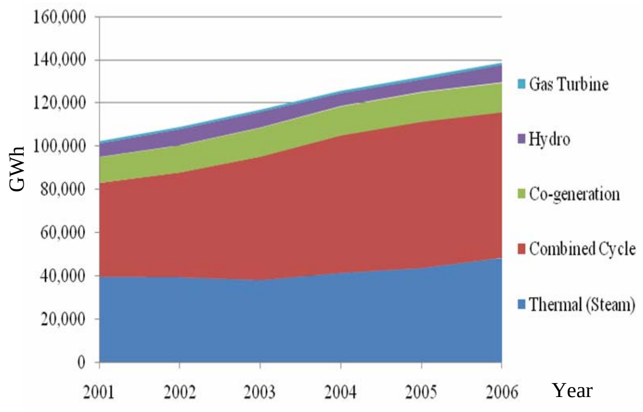

Figure 1. Total electricity generation in Thailand during year 2001 to 2006 [2].

3.3 Country-specific emission factor of electricity generation

Total gaseous emissions from fossil fuel combustion can be used as a representative of emissions from total electricity generation since the emissions from the other power plants such as hydro power plants and biomass power plants are negligible both in terms of gaseous emissions and contributions to the national grid. Country-specific emission factor is defined as the ratio of total gaseous emissions to total electricity generation

Table 2. Locally derived emission factors of tested power plants compare to IPCC emission factors [6].

Power Plant	Fuel	Gaseous emission	Locally Derived Emission Factor		IPCC Emission Factor [a]
Thermal (Steam Turbine)	Lignite	CO_2	101.3 kg/GJ	1,080 kg/MWh	99.18 kg/GJ
		CO	0.005 kg/GJ	0.05 kg/MWh	0.02 kg/GJ
		NOx	0.26 kg/GJ	2.83 kg/MWh	0.30 kg/GJ
		SO_2 (FGD controlled)	0.12 kg/GJ	1.26 kg/MWh	0.257 kg/GJ
		PM (ESP controlled)	10.24 g/GJ	0.09 kg/MWh	-
	Fuel Oil	CO_2	75 kg/GJ	765.16 kg/MWh	76.59 kg/GJ
		CO	0.03 kg/GJ	0.32 kg/MWh	0.015 kg/GJ
		NOx	0.06 kg/GJ	0.72 kg/MWh	0.20 kg/GJ
		SO_2	0.24 kg/GJ	2.40 kg/MWh	0.25 kg/GJ
		PM (Uncontrolled)	35.38 g/GJ	0.36 kg/MWh	-
	Co-firing Fuel oil and Natural gas	CO_2	59.65 kg/GJ	591.85 kg/MWh	-
		CO	0.03 kg/GJ	0.32 kg/MWh	-
		NOx	0.05 kg/GJ	0.51 kg/MWh	-
		SO_2	0.04 kg/GJ	0.53 kg/MWh	-
		PM (ESP controlled)	4.56 g/GJ	44.82 g/MWh	-
		PM (Uncontrolled)	11.66 g/GJ	114.22 g/MWh	-
Gas Turbine	Natural gas	CO_2	50.19 kg/GJ	822.22 kg/MWh	62.44 kg/GJ
		CO	0.03 kg/GJ	0.54 kg/MWh	0.02 kg/GJ
		NOx (Uncontrolled)	0.13 kg/GJ	2.03 kg/MWh	0.15 kg/GJ
		PM	0.80 g/GJ	13.12 g/MWh	-
Combined Cycle	Natural gas	CO_2	54.79 kg/GJ	451.64 kg/MWh	62.44 kg/GJ
		CO	0.02 kg/GJ	0.16 kg/MWh	0.02 kg/GJ
		NO_x (Water/Steam Injection)	0.12 kg/GJ	1.10 kg/MWh	0.15 kg/GJ (Default value)
		NO_x (Dry low NOx Burner)	0.11 kg/GJ	0.85 kg/MWh	
		PM	4.11 g/GJ	33.95 g/MWh	-

Table 3. Emission inventory of fossil fuel power plants.

Power Plant	Generation (GWh)	CO_2 (Ton)	CO (Ton)	NO_X (Ton)	SO_2 (Ton)	PM (Ton)
YEAR 2001						
Thermal	39,704	32,795,996	11,891	64,065	32,262	3,841
Combined Cycle	43,287	19,565,724	6,926	47,547	-	433
Gas Turbine	1,130	868,789	2,294	2,260	-	11
Co-generation	11,977	5,413,604	1,916	12,935	-	120
TOTAL	**96,098**	**58,644,113**	**23,027**	**126,807**	**32,262**	**4,405**
YEAR 2002						
Thermal	39,502	31,121,040	11,828	57,330	24,868	3,496
Combined Cycle	48,350	21,854,200	7,736	52,529	-	484
Gas Turbine	1,105	886,986	2,243	2,210	-	11
Co-generation	12,566	5,679,832	2,011	13,571	-	126
TOTAL	**101,523**	**59,542,058**	**23,818**	**125,641**	**24,868**	**4,116**
YEAR 2003						
Thermal	38,135	30,536,117	11,447	58,575	26,785	3,359
Combined Cycle	57,034	25,779,368	9,125	61,773	-	570
Gas Turbine	1,075	815,015	2,182	2,150	-	11
Co-generation	13,422	6,066,744	2,148	14,496	-	134
TOTAL	**109,666**	**63,197,244**	**24,902**	**136,993**	**26,785**	**4,074**
YEAR 2004						
Thermal	41,486	34,767,787	12,477	67,809	37,909	3,803
Combined Cycle	63,528	28,714,656	10,164	68,596	-	635
Gas Turbine	1,141	937,902	2,316	2,282	-	11
Co-generation	13,513	6,107,876	2,162	14,594	-	135
TOTAL	**119,668**	**70,160,372**	**27,120**	**153,281**	**37,909**	**4,584**
YEAR 2005						
Thermal	43,685	34,783,161	12,938	69,588	43,620	4,789
Combined Cycle	67,676	30,589,552	10,828	73,090	-	677
Gas Turbine	1,314	1,080,108	2,667	2,628	-	13
Co-generation	13,700	6,192,400	2,192	14,796	-	137
TOTAL	**126,375**	**72,645,221**	**28,626**	**160,102**	**43,620**	**5,616**
YEAR 2006						
Thermal	48,463	39,424,572	14,988	80,759	48,706	5,171
Combined Cycle	67,307	30,422,764	10,769	72,692	-	673
Gas Turbine	1,089	895,158	2,211	2,178	-	11
Co-generation	13,721	6,201,892	2,195	14,819	-	137
TOTAL	**130,580**	**76,944,386**	**30,163**	**170,448**	**48,706**	**5,992**

regardless of the plant type and fuel used. This refers to the amount of gases emitted when 1 kWh of electricity is generated as shown in Table 4. Averages over 6 years (2001-2006), for the generation of 1 kWh of electricity, CO_2, NO_x, SO_2 and PM emissions were 563.52, 1.26, 0.41 and 0.06 g, respectively. However, these results could be changed from year to year according to changing share of fuel type, plant characteristics and operating conditions. Using 2001 as a base line, country-specific emission factors, particularly CO_2 emissions, in 2002, 2003 and 2004 were lower because of increasing in operations of combined cycle power plants which used natural gas as fuel. After that, the usage of lignite was increased resulting in increases of emission factors (year 2005 and 2006). The variations of other emission factors were also affected by plant characteristics and operating conditions (Krittayakasem, 2008).

Table 4. Country-specific emission factors of electricity generation.

Items	Emission Factor (g/kWh)					
	2001	2002	2003	2004	2005	2006
CO_2	572.58	546.19	540.23	558.04	574.84	589.25
NO_x	1.36	1.2	1.21	1.25	1.24	1.28
SO_2	0.51	0.35	0.34	0.4	0.4	0.43
PM	0.11	0.08	0.08	0.07	0.02	0.02

3.4 Discussion

From the results of the locally derived emission factors, it can be seen that the lignite power plants are the major sources of gaseous emissions. Among these gaseous emissions, the largest emission is from CO_2. The CO_2 emitted from lignite combustion is about two times higher than that from natural gas combustion. This is not surprising since the carbon content of lignite is higher compared to unit of heat input. On the other hand, the calorific value of the lignite is lower, which means more lignite supply is needed.

In comparison with the IPCC emission factors, the results in this study are similar in many parameters. However there are some results that vary from 1-4 times from IPCC emission factors such as SO_2 emission from lignite power plants, and CO and NOx emissions from fuel oil power plants. There are two main reasons to explain the cause of wide variation of the both emission factors. Firstly, the chemical properties of fuel from IPCC data are different from the lignite in our study. The IPCC emission factor is an average value of lignite in the world, whereas the lignite in this study is only supplied from an internal source. Secondly, the IPCC emission factors do not consider the type of the furnace; some emissions, such as NOx and CO, are strongly affected by specific combustion conditions.

The country-specific emission factors of electricity generation, shown in Table 4, were derived from the emission inventory in Table 3, and they varied with contribution ratio of fuel type in use. When natural gas had a high consumption ratio, the factor would be decreased. In contrast, the factor would be increased, when lignite had a high consumption rate. That is because the emissions from a lignite power plant are generally higher than from a natural gas power plant. The factor was significant information for the decision of policy makers. They can use the factor for planning to control the emissions from power generation by using appropriate proportions of fuel type. Finally, the policy will be covered for all point of view both environment, economic and reliable of grid system as well.

4. Conclusion

In this study, annual emissions from selected fossil fuel power plants were assessed during 2001 to 2006, using 3 methods: CEMS, stack sampling and fuel analysis, depending on data sources available. Fuel analysis method was preferable for CO_2 emissions since it was directly related to the fuel's carbon content. Annual emissions of NO_x SO_2 and CO were calculated from CEMS and annual PM emission was estimated by using stack sampling data. Then locally derived emission factors, according to plant characteristics, were calculated from annual gaseous emissions divided by either annual electricity generation or heat input expressed in kg/MWh or kg/GJ.

Since, collecting data and information of all power plants in national grid were difficult and costly, in this study emission inventories of the electricity generating sector during year 2001 to 2006 were evaluated from locally derived emission factors and electricity generation at each plant characteristics, such as lignite power plant, combined cycle power plant or natural gas steam turbine power plant. From the results, it can be concluded that annual gaseous emissions increased due to increasing electricity generation, hence increased fuel consumption. Thermal (Steam turbine) power plants were the largest emission source accounting for 30 percent, especially the emissions from lignite power plants.

Finally, country-specific emission factor for electricity generated regardless to plant characteristics and fuel type was calculated. This could be used to study the affect of fuel mix and power plant technology to annual gaseous emissions.

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