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How Can Environmental Regulations Promote Clean Coal Technology Adoption in APEC Developing Economies?

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1. INTRODUCTION

The objective of this study is to assess experience to date in developed Asia Pacific Economic Cooperation (APEC) economies regarding the interaction of environmental regulations with clean coal technology deployment and, based on this analysis, make recommendations on regulatory methods that promote investment in new commercial clean coal projects in developing APEC economies. Environmental regulations for coal-fired power are quite extensive and continue to evolve as new issues, such as water shortage, mercury emissions, and climate change have emerged. Particularly, the regulation of greenhouse gas emissions, such as carbon dioxide, promises to have a significant impact on the future use of coal for power generation. This study examines both existing and emerging regulatory frameworks in order to determine which type of regulations that would be most effective at promoting clean coal technology adoption in developing APEC economies and would be practical to implement.

The pollutants and environmental regulations examined in the study cover the entire project cycle from permitting, construction, and operation of coal-fired plants and are generally categorized into three major groups:

- Regulations targeting air emissions. These include regulations concerning local air pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_X), and coarse and fine particulate matter (PM_{10}, $PM_{2.5}$); mercury (Hg); and carbon dioxide (CO_2) which is the major greenhouse gas (GHG) attributed to coal-fired power generation.

- Regulations targeting water use. Relevant regulations or guidelines affecting coal-fired power plants include: 1) water temperature, 2) water intake, and 3) effluent standards for water released from the power plant.

- Regulations concerning coal combustion byproducts. These typically involve 1) classification as hazardous or non-hazardous wastes, which determines subsequent treatment and disposal; 2) allowable uses and disposal practices, such as recycling in other products; and 3) management practices of toxics in disposed and recycled combustion products.

When considering the potential effect of existing and new environmental regulations on the adoption of clean coal we organized the analysis of technologies into three categories. These include:

- Environmental control technologies. This typically includes flue gas desulfurization (FGD), selective catalytic or non-catalytic reduction (SCR/SNCR) systems, electrostatic precipitators (ESPs) or fabric filters)

- High efficiency coal combustion technologies such as supercritical, ultra-supercritical, pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC) technology)

- Carbon dioxide capture and storage. Capture technologies may include pre- and post-combustion capture and oxyfuel combustion. Storage of CO_2 can be done in geological formations such as oil or gas fields, saline formations, or coal beds.

To target the recommendations towards APEC economies that would benefit the most from this analysis, we focused on developing and transition APEC economies that are expected to rely on coal for a large part of their future generating capacity. These economies include China, Indonesia, the Philippines, the Russian Federation, Thailand, and Vietnam. Influenced by rising populations and increased standards of living, these APEC nations are turning to cheap energy sources to fulfill their energy demands and improve energy security. As illustrated in Tables 1 to 7, coal will provide the fastest growing source of energy in all of these economies, except in Russia, where natural gas and nuclear will continue to represent the greatest share of power generation.

The report is organized as follows. Chapter 2 provides an overview of the different types of regulations that developed and developing APEC economies have used to regulate air, waste, and water pollution from coal-fired power. The chapter draws extensively on individual economy summaries which are presented in Appendix 1. It also highlights emerging regulatory frameworks and mechanisms, focusing on emissions trading and other regulations for carbon dioxide, since these are having a large influence on the technologies used for coal-fired power. Chapter 2 concludes with a discussion of the future direction of environmental regulations.

Chapter 3 analyses the link between environmental regulations and technology adoption in several APEC economies, including Australia, Canada, China, South Korea, and the United States. Because the European Union's Emissions Trading Scheme is the only operating trading system for carbon dioxide, we also reviewed the technology impact of this program. The chapter concludes with a summary of technology trends in the target economies for this report: China, Indonesia, the Philippines, the Russian Federation, Thailand, and Vietnam. The analysis illustrates that while the existing environmental regulations have lead to increased and wide-spread adoption of environmental controls, they have not resulted in the uptake of more efficient coal combustion technologies or capture and storage technologies. It is only the prospect of emerging carbon dioxide regulations which have encouraged utilities to adopt these latter technologies.

Chapter 4 discusses the many barriers that may prevent the adoption of clean coal technologies, regardless of the introduction of more stringent environmental regulations. Barriers examined include regulatory, cost, infrastructure, and enforcement related challenges, as these are particularly relevant for developing APEC economies.

Finally, Chapter 5 provides recommendations for environmental regulations that will encourage the uptake of clean coal technologies. Drawing on the conclusions from Chapter 3, we focus on regulations for carbon dioxide as these appear to be the most effective at improving combustion efficiency and clean coal technology uptake. Recommended measures for developing APEC economies include technology standards and thermal efficiency targets in the short term, and emissions trading in the long term.

Table 1. APEC Projected Electricity Generation by Fuel Type, 2002 - 2030 (%)

Economy	Year	Electricity Source (%)					
		Oil	Coal	Natural Gas	Nuclear	Hydro	NRE
China	2002	3	75	-	2	19	-
	2030	-	73	5	6	14	1
Indonesia	2002	17	32	35	-	10	5
	2030	2	49	39	-	6	3
Malaysia	2002	9	6	74	-	11	-
	2030	-	50	45	-	4	1
Philippines	2002	4	41	18	-	12	25
	2030	3	54	28	-	7	8
Russia	2002	3	19	43	16	18	-
	2030	-	20	39	24	15	2
Thailand	2002	2	16	74	-	7	1
	2030	-	38	57	-	2	3
Vietnam	2002	12	14	23	-	51	-
	2030	-	32	23	16	26	3

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 140, 148, 160, 180, 184, 196, 204.

Table 2. China Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	164	1056	2324	3567	5202
Oil	78	49	32	24	28
Gas	1	5	33	106	360
Hydro	58	275	378	616	1027
NRE*	-	4	10	42	98
Nuclear	-	27	92	230	447
Total	301	1416	2869	4585	7162

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 140.

Table 3. Indonesia Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	-	30	69	118	159
Oil	6	16	16	7	7
Gas	-	34	45	83	127
Hydro	2	10	11	16	20
NRE*	-	5	9	8	11
Nuclear	-	-	-	-	-
Total	8	95	151	231	324

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 148.

Table 4. Philippines Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	-	21	35	69	113
Oil	12	2	4	5	6
Gas	-	9	27	37	57
Hydro	4	6	8	10	15
NRE*	2	13	14	15	16
Nuclear	-	-	-	-	-
Total	18	51	59	136	208

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 180.

Table 5. Russia Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	154	170	231	246	253
Oil	100	27	12	10	2
Gas	461	385	371	453	496
Hydro	172	162	185	193	197
NRE*	2	3	9	15	22
Nuclear	120	142	201	244	308
Total	1008	889	1009	1160	1280

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 184.

Table 6. Thailand Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	1	18	23	71	190
Oil	12	2	4	2	2
Gas	-	82	153	256	289
Hydro	1	8	11	11	10
NRE*	-	1	1	7	13
Nuclear	-	-	-	-	-
Total	14	111	192	347	504

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 196.

Table 7. Viet Nam Projected Electricity Generation to 2030 (TWh)

Source of Electricity Generation	Year				
	1980	2002	2010	2020	2030
Coal	1	5	20	36	85
Oil	1	4	-	-	-
Gas	-	8	23	37	62
Hydro	1	18	32	55	70
NRE*	-	-	1	6	7
Nuclear	-	-	-	14	42
Total	4	36	76	148	266

*NRE (Nonhydro Renewable Energy) includes biomass, bagasse, wind, solar, and geothermal.
Source: Asia Pacific Energy Research Center, *APEC Energy Demand and Supply Outlook 2006*, "Projections to 2030: Economy Review," Tokyo, Japan: APERC, 2006, 204.

2. ENVIRONMENTAL REGULATIONS FOR COAL-FIRED POWER IN THE APEC REGION

Coal-fired power results in several air, water, and waste pollutants that are covered by a range of regulations throughout the APEC region. The types of pollutants and environmental regulations that will be examined in this study cover the entire project cycle from permitting, construction, and operation of coal-fired plants and are generally categorized into three major groups:

- Regulations targeting air emissions;
- Regulations targeting water use and discharges; and
- Regulations concerning solid waste and byproducts.

Of the three topics, air emissions are considered the most important environmental issue related to coal-based power because they can affect large geographical areas. As a result, regulations in this area are substantial and vary significantly in approach and reach. Water consumption, aqueous discharges, and solid waste are regulated owing to their potentially large impact on the local environment. Regulations targeting these pollutants are often tailored towards local conditions and can vary greatly among and within economies. As a result, they are harder to assess in terms of their general impact on technology choice.

The following provides an overview of the types of environmental regulations introduced in developed, transition, and developing APEC economies. Detailed information about regulations in individual APEC economies, including Australia, Canada, China, Indonesia, Japan, Philippines, the Russian Federation, Thailand, United States, and Vietnam, is provided in Appendix A.

2.1 Air Emissions

In the past, regulatory approaches for air emissions have involved two types of legislation: legislation driven by environmental quality and legislation driven by available technologies. Legislation driven by environmental quality concerns is normally set such that the target is a measurable reduction in atmospheric concentrations of a specified pollutant. In the case of coal-fired power, the applicable legislation would typically be in the form of emission standards or caps for the affected units. These emission standards are developed to meet a country's GHG emission reduction target, ambient air quality standards or its critical load standards to protect ecosystems, human health, plants, or materials.

The technology-driven approach assumes that all sources, to which the legislation applies, have similar emission problems. This type of legislation involves specifying what technologies should be used or assessing available control technologies to derive an emission limit which plants must meet. The legislation would then be tightened over time as technologies advance. In many economies, particularly in the United States and the European Union, coal-fired power plants are covered by a combination of environmental- and technology-driven approaches.

The majority of air-related environmental legislation in APEC economies is aimed at conventional air pollutants, including particulate matter (PM), sulfur dioxide (SO_2) and nitrogen oxides (NO_X). However, in more recent years, new regulations are also being implemented for the control of emissions of mercury (Hg) and carbon dioxide (CO_2). The regulations fall under four possible legislative formats: 1) emission limits/standards; 2) best available technology/maximum achievable control technology; 3) fines, taxes, and levies; and 4) emissions trading. As described in Section 2.1.1, the legislative formats can overlap and can be combined across multiple sources through integrated pollution prevention. The specific legislative formats are described further in the following subsections.

2.1.1 Legislative Formats for Air Emissions

The following provides a list of possible legislative formats for regulating emissions of SO_2, NOx, PM, Hg, and CO_2.

Emission Limits/Caps

Emission limits are simple fixed limit values for a source or source type. Using this approach, if the level is set right, reductions can be achieved from many sources. Moreover, reductions are obtained without distortions because all sources are treated equally. In APEC economies with high coal use, emission limits is the most common type of regulation used for regulating SO_2, NO_X, and PM from power plants. In fact, in some developing and transition APEC economies (Indonesia, Philippines, Russia, Thailand, and Vietnam) it is the only method for controlling emissions. In China, the focus is also on emission limits, but in this case, the limits are augmented by guidelines on environmental controls and restrictions on the type (i.e., size) and location of new and existing capacity.

Typically, the SO_2, NO_X, and PM emission limits vary according to whether they apply to old or new plants, and whether the plants are located in areas with high existing pollution. In China, for example, the limits are more stringent for plants located in the Two Control Zones (TEC) where local air pollution is particularly high. The new Vietnamese emission standards are somewhat more complex and result in site-specific standards because they involve the use of an equation that is based on site-specific capacity and location inputs. Using this equation, larger plants located near ‘environmentally’ sensitive areas (i.e., urban and industrial zones) are assigned more stringent standards than smaller plants located in less sensitive areas (i.e., rural areas and mountain zones). Indonesia’s standards are the most simple, introducing the same limit for all fuel types and units, regardless of location. The emission limits in the United States are by far the most complex, incorporating a range of emission limits, caps, performance standards, and technology-based standards that make the emission standards highly site-specific.

Many developed and most developing APEC economies express emission limits for SO_2, NO_X, and PM in terms of mass concentration output (i.e., mg/m^3 of flue gas). Emission limits for CO_2 are typically set as a total cap on emissions from the power plant (i.e., the EU Emissions Trading Scheme or the Regional Greenhouse Gas Initiative on the U.S. East Coast) or as a percentage of total emissions. The U.S. state of Montana, for example, requires that 50 percent of all CO_2 emitted from new power plants must be captured and stored. The Canadian province of British Columbia requires that 100 percent of the CO_2 from new coal-fired power plants must be captured and stored while in Saskatchewan any new and replacement facilities at SaskPower must be emissions-free or fully offset by emission offsets.

Emissions Performance Standards

In Canada and the United States, regulations are beginning to incorporate output-based controls linked to electricity production. This is also known as performance standards and is typically expressed in terms of pounds (lbs) or kilograms (kg) of pollutant per megawatt-hour (MWh) of electricity production. For example, Canada's New Source Guidelines for Thermal Electricity Generation are based on the net energy output of the plant and are expressed in terms of kg of SO_2, NOx or PM_{10} per MWh. The reason for this output-based approach is to encourage sources to operate more efficiently by giving a price advantage to the most efficiently operated facilities.

The performance-based approach is also used in some of the emerging U.S. state programs for regulating GHG emissions. California initiated this approach because it imports significant amounts of coal-based electricity from neighboring states. Thus, if it were to set limits only on power generation within the state, purchases of cheaper out-of-state carbon intensive electricity may increase. To avoid such leakage, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) introduced a load-based performance standard that would prohibit long-term electricity contracts with in- and out-of-state generators that emit greenhouse gases in excess of a combined cycle natural gas turbine (or 1,100 lbs of CO_2/MWh).[i] This means that only coal-fired power plants that capture and store CO_2 would be able to enter into long-term contracts with California-based users. Although the state of Washington has also adopted this load-based approach, and Oregon is considering it, the performance standard approach is not likely to become a wide-spread means for regulating CO_2 emissions because it is envisioned as a temporary measure to spur federal legislation.

Efficiency Standards

Regulation of coal-fired power plants could also be accomplished by setting thermal efficiency standards for the coal-combustion process (i.e., the boiler and turbine). The standard could be set in terms of the power plant's thermal efficiency or heat rate and would likely differentiate between existing and new power plants, size, and fuel type. By improving power plant efficiency, several environmental goals could be reached at the same time because it would lead to a reduction in all air emissions, including CO_2. Efficiency-based standards would also help address waste and water pollution.

No APEC economy has yet to use this approach to regulate emissions from power plants, although China has a general goal of improving the efficiency of its power plants. In the past, energy efficiency was less of a priority because traditional air pollutants (NOx, SO_2, and particulates) could be removed by installing environmental controls. However, with rising concerns over energy security and climate change, economies are paying much more attention to how efficiently power plants use the coal. The state of New South Wales (NSW) in Australia tracks thermal efficiency to measure progress by power plants in meeting individual benchmarks under the

Greenhouse Gas Abatement Scheme (GGAS) and has developed a detailed guidance document for development of station-specific Performance Improvement Testing Regimes at coal-fired power plants.[ii] This document may be useful for developing and tracking economy-wide thermal efficiency targets.

Technology Standards: Best Available Technology (BAT)/Maximum Achievable Control Technology (MACT)

The technology-driven approach is progressive because it ensures that emissions are continually reduced as new and improved control technologies come onto the market. Best Available Technology (BAT) is the European term, while in the United States it is called Maximum Achievable Control Technology (MACT). The United States uses MACT in combination with emissions trading and emission limits to ensure reductions are achieved. Typical BAT or MACT includes electrostatic precipitators (ESPs) or fabric filters/baghouses for particulates; low-sulfur coal or the retrofitting of a flue gas desulfurization (FGD) system for SO_2; and low-NOx burners, selective catalytic reduction (SCR), or selective non-catalytic reduction (SCNR) for NOx. China also uses technology guidelines specifying the types of environmental controls that must be used for SO_2 removal at facilities that use medium- and high-sulfur content coal

So far, no national government has used a technology-based approach for the regulation of carbon dioxide from coal-fired power plants. However, it is possible that such national standards may be introduced in the future. One approach to the deployment of carbon capture and storage could be the adoption of international or national regulations that require participating economies to fit all new coal-fired, or other fossil fuel-fired, power plants with capture and storage from a specified date. An example of that is the EU's Revised Large Combustion Plant Directive (LCPD) which place Emission Limit Values (ELVs) on large combustion plants and specifies different treatment depending on the age of the facility. According to the influential Stern review, the early timing of such technology targets could be significant as overall mitigation costs will increase if significant near term investments are made in new capacity without, or precluding the addition of, carbon capture and storage technologies.[iii]

In April 2007, a new bill was introduced by U.S. Senator John Kerry proposing that new coal-fired capacity should only be permitted if it includes CO_2 capture and storage. However, this bill has not received much traction in the Senate. There is also some discussion within the EU to require all coal-fired power plants to be capture-ready by 2020.[iv] In the absence of federal regulation, some U.S. states and Canadian provinces have set technology standards for coal-fired power. The U.S. state of Montana, for example, requires that 50 percent of all CO_2 emitted from new power plants must be captured and stored while the Canadian province of British Columbia requires that 100 percent of the CO_2 from new coal-fired power plants must be captured and stored.

Fines, Taxes and Levies

Fines, taxes, and levies are a common way of penalizing sources for non-compliance and/or incentivizing adoption of costly control technologies. Levies and taxes have been used both for conventional air pollutants and for carbon dioxide. Part of China's strategy to control emissions, is to charge a levy on emissions of SO_2 and NOx. Through this levy, substantial funds have been raised for pollution prevention and control. Japan has a carbon tax that also applies to power plants and the Canadian province of Quebec is in the process of developing a tax on fuel sold to retailers which will be based on the carbon content of the fuel. Other economies which have imposed a tax on the CO_2 or carbon content of fuels include Norway, Sweden, and Switzerland.

Most economies combine their emission standards with fees for non-compliance. However, in the case of developing APEC economies, these fees are not always as effective as initially hoped for. In China and Vietnam, for example, the cost of investing in and operating control equipment or other abatement measures is generally higher than the emission charge for exceeding any pollution limit. As long as there is a cost difference, there is little incentive for the plant operators to reduce emissions.

Emissions Trading

Emissions trading is based on the principle that any increase in emissions must be offset by a decrease of an equivalent, or sometimes greater, quantity of emissions. Cap and trade, rate-based trading and project-based trading are three forms of emissions trading. Each trading program can create incentives to reduce emissions at lower costs than the traditional command and control approaches outlined above, because they give regulated entities the flexibility to adopt the lowest-cost option for complying with their emission limit or cap.

Cap and trade involves setting a cap on allowable emissions within a given industry, distributing the allowances among relevant emitters, and then allowing the buying and selling of allowances among the emitters based on whether it is more cost-effective to emit and purchase an allowance from someone else, or to reduce emissions and sell the excess allowances on the market. Sources covered by the program then receive "authorizations to emit" in the form of emissions allowances, with the total amount of allowances limited by the cap. Each source can design its own compliance strategy to meet the overall reduction requirement, including sale or purchase of allowances, installation of pollution controls, implementation of efficiency measures, among other options. The ability to trade allowances places a value on emission reductions and encourages sources to develop the most cost effective emission reduction strategies to achieve the overall required emission reduction. Individual control requirements are not specified under a cap and trade program, but each emissions source must surrender allowances equal to its actual emissions in order to comply.

Ultimately, abatement occurs as long as the regulated facilities believe it is more cost-effective to reduce emissions than to purchase allowances on the market. In this way, emission trading ensures that compliance occurs in the most cost-effective manner.

Under emissions trading, market prices will be determined by the stringency of the cap and whether any other mechanisms, such as a safety valve, are included to prevent prices from reaching a certain pre-specified level. To encourage the deployment of clean coal technology, the overall cap must therefore be stringent enough for prices to cover the additional capital cost of switching to clean coal. The new CO_2 emissions trading system in the US East Coast includes a safety valve of $7. At this price, efficiency improvements and other low-cost abatement options will be implemented. However, it is less likely that it will lead to substantial technology changes for coal-fired power.

The first cap and trade program was the EPA's Acid Rain Program, which has the goal of reducing emissions of SO_2 and NO_X from fossil fuel combustion. The first large CO_2 emission trading system is the EU-wide Emissions Trading Scheme (EU ETS). It covers six industrial sectors, including electricity generation.

In rate-based trading the regulating authority sets an emission rate performance standard (e.g., tonnes of emissions per MWh) that can be constant or gradually decline to provide greater incentives for improving efficiency over time. An emission source with an average below the performance standard earns credits that it can sell to other emission sources. Those sources with emission rates above the standard must either obtain credits to cover the excess or improve efficiency to remain in compliance. California’s CO_2 emissions performance standard for long-term power purchases and Australia’s Mandatory Renewable Energy Target (MRET) both use rate-based trading.

Offset trading or program-based trading allows sources flexibility to seek lower cost emission reductions from sources outside the underlying regulatory program. If a company wishes to increase the amount of air emissions coming out of an operating plant, the company may choose to offset the increases so that total air pollutant releases from the plant do not go up. Otherwise, they may choose to install pollution controls to keep pollutants at the required level.

An increase in emission can be offset with a reduction of the pollutant from some other stack at the same plant or at another plant owned by the same or by purchasing offsets from another company. The RGGI system on the U.S. East Coast allows offset trading.

In order for an emission trading system to work effectively, sources must measure and report all emissions completely, accurately, and in a timely manner to guarantee that the overall cap is achieved. For the power sector, this means that continuous emissions monitoring systems (CEMS) must be installed in order to accurately track emissions. Economies must also create institutions and data tracking systems for assigning, tracking, and registering allowances. As a result, developing APEC economies that do not yet have such systems in place, may find that emissions trading will be more costly to implement than the other legislative measures discussed above. Of the developing APEC economies examined in this report, China is the furthest ahead in this process, as it is already requiring large power plants to install CEMS. However, adoption of these CEMS is behind schedule.

Integrated Pollution Prevention and Control

Integrated pollution prevention and control (IPPC) is a more recent phenomenon. It involves the use of regulations that target several types of pollutants at the same time and enables power providers to integrate pollution prevention techniques, thereby meeting all requirements in a more cost-effective fashion. One example of the IPPC approach is the recent EPA introduction of the Clean Air Mercury Regulation and the Clean Air Intestate Rule, which target mercury together with NOx, SO_2, and fine particulates. The reasoning is that some mercury reductions can be achieved as co-benefits from setting a cap on NO_X and SO_2 because some of the technologies used for reducing the traditional criteria pollutants also lead to reductions in mercury.

If CO_2 regulations are put in place that lead to more efficient coal-combustion, it is likely to lead to significant co-benefits in terms of reducing NO_X, SO_2, Hg, and particulate emissions. Although technology standards requiring capture and storage of CO_2 does lead to some co-benefits in terms of significant removal of SO_2 and NOx during CO_2 capture, they may not have similar co-benefits as efficiency improvements, because CO_2 capture reduces the overall efficiency of the power plant, thereby increasing overall NOx emissions.[v]

Regulating all four emissions together would be beneficial in environmental terms as well as making it easier for plant operators to plan technology investment. With this in mind, several multi-pollutant bills have been proposed in the United States Congress targeting SO_2, NOx, Hg, and CO_2 from the power sector (See Appendix 1, Table 9.4). However, owing to the recent focus on adopting an economy-wide system for regulating GHG emissions in the U.S., it is more likely that a bill focusing solely on GHG emissions will be passed instead.

2.1.2 Local Air Pollutants – SO_2, NO_X, and Particulates

All of the APEC economies examined in this report have regulations in place to control SO_2, NO_X, and PM_{10}, except for Australia which regulates NOx and PM_{10} only (See Appendix 1). Regulations in developing APEC economies vary significantly in terms of stringency, and will require some adoption of environmental controls, although not the most efficient systems. In comparison, regulations in the United States and Europe have grown increasingly stringent and are having a significant impact on the use of environmental control technology. One reason for this is the movement to regulate fine particle ($PM_{2.5}$) emissions in addition to PM_{10}.

In Europe coal-fired power plants with a thermal capacity of >50MW must switch to low sulfur fuels, retrofit pollution reduction equipment such as flue gas desulfurization (FGD) for SO_2 control, install selective catalytic and non-catalytic reduction (SCR/SNCR) systems for NOx reduction, and upgrade electrostatic precipitators (ESPs) or install fabric filters to meet the new emission limits of the EU revised (2001) Large Combustion Plants Directive (LCPD).[vi] If they choose not to do this, they must either shut down or reduce output by operating less than 20,000 hours between January 1, 2008 and December 31, 2016. Similar technology improvements are required in the United States, although plants have greater flexibility owing to the use of emissions trading.

In the EU, the environmental regulations have also led to construction of coal-fired plants using the latest technology, such as supercritical boilers that are capable of achieving greater efficiencies than existing fleets. For example, in Germany, 43 percent efficiency has been achieved in lignite-fired power plants while facilities using hard coal have achieved 46 percent efficiency.[vii]

2.1.3 Mercury

In the case of mercury, regulation occurs through a mix of emissions trading and technology-based standards. For example, the US EPA's Clean Air Mercury Rule (CAMR), introduces a national trading system for mercury, while allowing states to set their own additional standards either by raising the individual state cap or by introducing specific technology-based requirements. Until recently, emissions of mercury from coal-fired power stations were not the subject of much regulatory attention. Several economies had set national guidelines for emissions of trace elements from large stationary sources in industry and the power sector that include standards for mercury (Table 8). However, because these standards apply across several industries, they are typically set at a level that is easily obtainable by coal-fired utilities. Certain economies, such as Germany, Flanders in Belgium, Italy, and Switzerland have mercury emission limits that focus specifically on utilities, but these can comfortably be met by existing control technologies.[viii]

Table 8. National Trace Element Guidelines and Legislation Targeting Mercury

Country or Region	Species Included	Limit (mg/m^3)	Applicable to
Australia			
National*	Hg and its compound	3	Any trade, industry or process
National*	Sb, As, Cd, Hg, Pb, V and compounds	10	Any trade, industry or process
Australian Capital Territory*	Hg and compounds	3	Any process
New South Wales	Hg and compounds (individually)		Any electricity generator using fuel other than coal, gas, oil, or wood:
		--	< July 1, 1986
		3	≥ Jul. 1, 1986 and ≤ Aug. 1, 1997
		1	≥ Aug. 1, 1997 and ≤ Sep. 1, 2005
		0.2	≥ Sep. 1, 2005
	Total of Sb, As, Cd, Pb, Hg and compounds		Any electricity generator using fuel other than coal, gas, oil, or wood:
		20	< July 1, 1986
		10	≥ Jul. 1, 1986 and ≤ Aug. 1, 1997
		--	≥ Aug. 1, 1997
Queensland	Total Hg, As, Cd, Pb and compounds	10	Utility plants (existing)
	Hg and compounds	3	Any trade, industry or process
South Australia	Hg and compounds	3	Fuel burning equipment
	Total of Hg, As, Cd, Pb, Se and compounds	10	Fuel burning equipment
Tasmania	Total of Hg, As, Cd, Pb, Se and compounds	10	Any installation operating after 1975
Victoria	Total of Hg, As, Cd, Pb, Se and compounds	10	Utility plants
Austria	Hg and compounds	0.5	Utility plants cofiring waste
Belgium (Flanders)	Hg and compounds	0.2	Combustion sources
Germany	Hg and compounds	0.3	Utility plants
Italy	Hg and compounds	0.3	Utility plants
Switzerland	Hg and compounds	0.3	Utility plants

Notes: *In this case, the limit is set in the form of a guideline instead of a mandatory standard.
Source: Lesley L. Sloss. "Trends in Emission Standards," IEA Clean Coal Centre, December 2003; updated as required

Canada and the United States are the only economies where legislation to control mercury emissions from coal-fired power stations is being implemented. No such legislation is currently planned in Europe, but there is increasing awareness of this whole issue. Both the United States and Canada set caps on mercury emissions from power generation. However, in the United States, state regulators can use a mix of market-based measures (emissions trading) and best available control technology to ensure compliance with the caps, while in Canada, the caps must be met through best available control technology.

2.1.4 Carbon Dioxide

Because of the rapid growth in carbon dioxide emissions from coal-fired power plants, regulation of this gas has become a priority in developing APEC economies within the past five years. Many of these economies are now considering, or developing, national emissions trading systems for electricity generation and other large sources, including Australia, Canada, New Zealand, and the United States. In the case of the power sector, emerging regulations focus on cap-and-trade and offsets because power plants are large sources and their emissions are fairly straightforward to monitor and track, both factors that lend themselves well to trading. However, some economies, such as Japan, Norway, Switzerland, and Sweden, also use a carbon tax to discourage the use of high carbon content fuels.

Many of the national systems regulating CO_2 are still under development, so there is less existing guidance to draw upon for examples. The largest existing emissions trading system for CO_2 is the European Union Emissions Trading Scheme (EU ETS) which began operation in January 2005. The scheme is based on Directive 2003/87/EC, which entered into force on 25 October 2003. Under the EU ETS, each participating country specifies caps on GHG emissions from individual power plants and other large point sources. The installations may then comply with their caps through on-site emission reductions or by purchasing emission allowances from the market. The first phase of EU ETS began in January 2005, covered CO_2 emissions only, and will continue through 2007. The second phase will cover all six GHGs and will run from 2008 to 2012, which is the end of the first commitment period of the Kyoto Protocol. Four non-EU economies will join the EU ETS in Phase II, including Norway, Iceland, Liechtenstein, and Switzerland.

In Phase I of EU ETS, the European Commission allocated 6.57 billion metric tons of CO_2 allowances and demanded cuts of over 290 million allowances, which represents about four percent of all the allowances requested by member economies.[ix] During Phase II, facilities must reduce overall emissions by seven percent compared to 2005. In both cases, the greatest reductions are required of the power sector, mainly because this sector is less affected by international competition than other industries. At the start of Phase I, nearly all of the emissions allowances for the EU ETS were awarded freely (as opposed to auction) to industry. Phase II allowances will also primarily be allocated for free. Section 3.7 includes a discussion of the early technology impacts of the EU ETS.

In the absence of national regulations for CO_2 in Australia, Canada, and the United States, several states and provinces have started implementing a mix of programs and regulations to reduce emissions, often focusing on the power sector. These regulations are summarized in Table 9 and described further in Appendix I in the individual APEC economy sections. Most of the regulations involve emissions trading covering several states and provinces. However, a mix of other emission control strategies are also being used to limit CO_2 emissions from coal-fired electricity, including technology and emissions performance standards, carbon taxes, emissions limit, energy efficiency goals, and limitations on permitting of new plants.

Table 9. Emerging GHG Regulations Directly Affecting Coal-fired Power

Region/Program	Type of Regulation
Emissions Trading	
EU Emissions Trading System (EU ETS)	- Cap on CO_2/GHG emissions from power generation and industrial processes - Entities can purchase emission allowances from other EU ETS installations or GHG offsets based on CDM/JI projects in other economies - 60% of covered entities have initiated internal abatement
RGGI –US East Coast	- Cap on CO_2 from power plants starting 2009
Western Climate Initiative	Emerging multi-sector GHG trading system in Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Oregon, Utah, Washington
Midwest GHG Reduction Program	- Emerging multi-sector GHG trading system for Illinois, Iowa, Kansas, Minnesota, Michigan, Wisconsin, and Manitoba to begin in 2010
Australia	- National cap and CO_2 trading for electricity and other sectors by 2012 - Possible link to emissions trading in New Zealand
New South Wales	- Electricity generators must meet average CO_2-equivalent emission intensity benchmarks
Tax	
Japan, Norway, Quebec, Sweden, Switzerland	- Carbon/ CO_2 tax on fuels
Technology/Fuel Standard	
British Columbia	- 100% carbon capture and storage at any new coal-fired electricity project
Manitoba	- Proposal to phase-down the province's coal-fired power plant
Montana	- New coal units must capture and sequester > 50% of CO_2 produced
Ontario	- Phasing out coal by 2014
Emissions Performance Standard	
California, Washington	- No long-term electricity contracts with generators that emit GHGs in excess of NGCC (or 1,100 lbs of CO_2/MWh)
Emissions Limit	
Alberta	- Existing industrial facilities that emit ≥ 100,000 tonnes of CO_2e must reduce their GHG emissions intensity by 12%
Saskatchewan	- New facilities must be GHG emissions free or offset emissions
Other	
Iowa	- New power plants must quantity expected GHG emissions in the application for a permit
Massachusetts	- All building projects required to undergo an EIA, or that are funded by the state, must estimate associated GHG emissions and propose measures to reduce these
New Mexico	- Electric utilities must consider the cost of GHG emissions in their long-term planning for power, starting 2008

The developing APEC economies examined in this report have yet to consider implementing regulations to limit CO_2 emissions from power generation. However, they all encourage entities within their borders to develop GHG emission reduction projects for inclusion in the Kyoto Protocol's Clean Development Mechanism (CDM). In 2007, the CDM Executive Board approved baseline and monitoring methodologies for increased efficiency at both new and existing coal-fired power plants.[x] If projects are implemented using these methodologies they could result in considerable emission reductions from coal-fired electricity generation in developing APEC economies.

2.2 Water Intake, Temperature and Effluents

Coal-fired power plants can impose three types of stresses on the water system. First, they consume vast quantities of water in order to make steam and to cool the equipment, which may result in the deaths of fish through entrainment in cooling water or impingement on intake screens. Water consumption may also conflict with other uses (i.e., agriculture, drinking water), if available water sources are limited. Second, the plants return heated water to lakes and rivers, potentially placing stress on aquatic life if the temperature differential is large. Third, the plants may result in the discharge of chemicals to nearby water bodies, thereby adversely affecting aquatic life and drinking water quality.

Most economies analyzed in this report have put in place an overall framework with a basic structure for regulating water use and discharges at the national level. This may include general water quality standards as well as safe drinking water standards that ultimately influence the amount of discharges individual sources can release into water bodies and soils. Expanding on this framework, some economies have then developed specific water-related regulations or guidelines affecting coal-fired power plants. These include: 1) standards for water temperature, 2) standards for water intake, and 3) effluent standards for water released from the power plant. Few economies regulate all three of these. All of these regulations are based on command and control measures and do not include market-based mechanisms for controlling pollutants.

All national governments surveyed in this report leave it up to individual regions and localities to implement the different standards. In some cases, such as Canada, the regulations are actually developed at the provincial level. Because water regulations are tailored towards local conditions they vary greatly among and within economies. The following provides a summary of the general types of regulations in place.

2.2.1 Water Intake

Cooling water intake structures can cause adverse environmental impact by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system. There, the organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. This is also known as entrainment. Larger organisms may be killed or injured through impingement when they are trapped against screens at the front of an intake structure. During drought conditions, plants can experience sedimentation and fouling of the intake system and water flows that are too low to meet thermal discharge permit requirements. Therefore, the location and design of proposed intake/discharge structures is an important consideration in the development and implementation of regulations, as well as the specific technologies used. Proposed regulations to regulate water intake in the United States include the following for new coal-fired facilities:

- Standards limiting intake capacity and velocity
- Requirements that facilities near fisheries are required to use additional fish protection measures including screens, nets, or other similar devices
- A limit for intake which must be relative to a defined proportion of the source water body

Moreover, for large existing facilities, EPA in 2004 proposed the use of performance standards for the reduction of impingement mortality and entrainment that are expressed in terms of ranges of reductions. These performance standards were determined to reflect the Best Technology Available (BAT) for minimizing adverse environmental impacts at covered facilities. However, the courts have since then challenged the ranges used in EPA's proposed rule and a new proposal is being developed by EPA.

Another issue that can be regulated is the type of cooling system used. The amount of water used to condense steam from steam-driven turbine generators (per unit electricity output) depends on the type of cooling system and the efficiency of the turbine. Turbine efficiency increases as the difference between the steam temperature and the condensing temperature increases. Plants with higher efficiencies require less cooling per unit energy produced.

More than half the power plants in the United States employ "once-through cooling" in which water is withdrawn from lakes or rivers, diverted through a condenser to absorb heat from the boilers, and then discharged back into the water body at elevated temperatures. Alternative and more efficient technologies exist. "Closed-cycle wet cooling" uses evaporative cooling towers, while "dry cooling" (or "air cooling") relies on water only for system maintenance and cleaning. Technology costs vary significantly between these technologies. As evidenced by the large use of once-through cooling in the United States this approach is considered economic and does not disrupt the generating system. Switching to dry cooling reduces water usage by as much as 98 percent, but operating costs are more than ten times higher, and air cooling requires more energy and, as a result, yields more air emissions. Table 10 presents comparative estimates of national annual energy penalties for three possible cooling system configurations (once-through, wet cooling tower, and dry cooling tower). The national energy penalty was determined as an average of annual energy penalties for facilities modeled for power plants located in four metropolitan areas in the United States (Boston, Chicago, Jacksonville, and Seattle) to represent a range of climate differences. The energy penalty was greatest in Jacksonville.[xi] Subsequently, air emissions would rise as a result of increased generation capacity needed to compensate for parasitic power losses.

Table 10. National Average Annual Energy Penalty for Cooling Systems in the United States

Cooling Type	67% Maximum Load		100% Maximum Load	
	Combined-Cycle Percent of Plant Output[a]	Fossil-Fuel Percent of Plant Output[b]	Combined-Cycle Percent of Plant Output[a]	Fossil-Fuel Percent of Plant Output[b]
Wet Tower vs. Once-Through	0.4	1.7	0.4	1.7
Dry Tower vs. Once-Through	2.1	8.6	2.8	10.0
Dry Tower vs. Wet Tower	1.7	6.9	2.4	8.4

[a] Energy penalty is applicable only to the energy output of the steam plant component
[b] Represents coal-fueled plants
Source: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann and Massood Ramezan. "Major Environmental Aspects of Gasification-Based Power Generation Technologies - Final Report. National Energy Technology Laboratory, December 2002

In its proposed rule for cooling water intake at new power plants, EPA had originally allowed the use of once-through technology. However, in 2004 the courts struck down this part of EPA's proposal while upholding EPA's mandate of closed-cycle cooling as the national minimum technology. EPA has not issued any new rules since then.

2.2.2 Water Temperature

At plants using open-loop cooling, essentially all of the water withdrawn for cooling is returned to the source. However, the water discharged is often warmer than the receiving water body, which can result in increased evaporation downstream of the discharge point and the need for large volumes of water to dilute the effluent to meet discharge water quality standards. Some economies therefore specify the maximum allowable temperature difference. In Indonesia, for example, the change in water temperature between inlet and outlet of the power plants must be less than or equal to 2˚Celsius.

2.2.3 Water Effluents

All of the APEC economies examined in this report have industrial effluent standards in place that also apply to thermal power plants.[1] In addition, some developed economies, such as Canada, Japan, and the United States, have developed effluent standards specifically for thermal electric plants. The standards differ according to the process stream coming from the power plant, such as the type of ash, cooling tower blowdown, or coal pile runoff. In the United States regulated parameters include pH, residual chlorine, total suspended solids (TSS), oil and grease, copper, iron, chromium and 126 pollutants contained in chemicals added for cooling tower maintenance. In Ontario, Canada regulated parameters include TSS, aluminum, iron, and oil and grease.

[1] Regulated constituents typically include biochemical and chemical oxygen demand, total suspended solids, ammonia, cyanide, phenols, sulfide, nitrate, fluoride, arsenic, barium, boron, cadmium, chromium, lead, mercury, selenium, silver, and zinc.

The World Bank recommends that the effluent levels presented in Table 11 (for the applicable parameters) must be achieved daily without dilution.

Table 11. World Bank Recommended Effluents from New Thermal Power Plants (milligrams per liter, except for pH and temperature)

Parameter	Maximum Value
pH	6-9
TSS	50
Oil and grease	10
Total residual chlorine[a]	0.2
Chromium (total)	0.5
Copper	0.5
Iron	1.0
Zinc	1.0
Temperature increase	≤ 3˚C[b]

Notes: [a]. "Chlorine shocking" may be preferable in certain circumstances. This involves using high chlorine levels for a few seconds rather than a continuous low-level release. The maximum value is 2 mg/l for up to 2 hours, not to be repeated more frequently than once in 24 hours, with a 24-hour average of 0.2 mg/l. (The same limits would apply to bromine and fluorine.)
[b]. The effluent should result in a temperature increase of no more than 3° C at the edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 meters from the point of discharge when there are no sensitive aquatic ecosystems within this distance.
Source: World Bank Group. "Pollution Prevention and Abatement Handbook. Thermal Power: Guidelines for New Plants," Effective July 1998
http://www.ifc.org/ifcext/enviro.nsf/AttachmentsByTitle/gui_thermnew_WB/$FILE/thermnew_PPAH.pdf

2.3 Regulations Concerning Coal Combustion Waste Products

Coal combustion products can include bottom ash, boiler slag, fly ash, flue gas desulfurization (FGD) sludge, wastes from fluidized-bed combustion (FBC) units, and coal combustion products codisposed with coal refuse.[2] These coal combustion products typically contain trace elements of toxic heavy metals. Regulation of coal combustion products can be organized into three major categories:

- Classification as hazardous or non-hazardous wastes
- Allowable uses and disposal practices
- Management practices

Similar to the regulation of water use and effluents, all of the regulations for coal combustion products are based on command and control measures. The specific measures are described further below.

2.3.1 Classification as Hazardous or Non-Hazardous Waste

A significant regulatory issue affecting waste products from coal-combustion is whether or not the by-products should be regulated as hazardous or non-hazardous wastes. Typically, economies impose stringent requirements on the generation,

[2] Coal refuse is the waste coal produced from coal handling, crushing, and sizing operations, and tends to have a high sulfur content and low pH from high amounts of sulfide minerals (like pyrite).

transportation, storage, treatment and disposal of hazardous wastes, which can be costly to implement.

Except for the United Kingdom, none of the economies examined for this report regulate coal combustion by products as hazardous waste. In the United States, for example, coal combustion products are classified as solid wastes and are subject to regulation by individual states as such. These regulations vary state by state, but are typically not as stringent as the hazardous waste requirements.

2.3.2 Allowable Uses and Disposal Practices

There are several options for using and disposing of coal combustion products. If economies have regulations in this area, they typically specify whether or not power plants are required to do anything with the coal combustion byproducts, such as storage in landfills or surface impoundments. The regulations may also specify which types of alternative uses that are permissible, and under what circumstances. For example, in the United States, federal regulations state that waste management alternatives are permissible, subject to demonstration that they are at least as effective as currently accepted control measures. The state of Indiana ads more guidance to the federal framework, by specifying the allowable uses of coal ash:

- Use of bottom ash as anti-skid material;
- Use of the waste as a raw material for manufacturing another product;
- Use in mine subsidence, mine fire control, and mine sealing;
- Use as structural fill when combined with cement, sand, or water to produce a controlled strength fill material;
- Use as a road-base in construction; and
- Extraction or recovery of materials and compounds from the coal ash.

The following provides examples of possible uses and regulations for coal combustion products:

Storage in Landfills or Surface Impoundments

At a minimum, most developed APEC economies require that coal combustion byproducts must be stored in landfills or surface impoundments. Beyond this, the type of regulation varies significantly among individual localities. Regulations could include fees charged for landfilling and/or standards for how the ash should be disposed of and how the landfills must be licensed. Wet ash disposal systems have been the norm, but this method of ash management is being reevaluated since there is some potential for contamination of surface and ground waters by trace elements leached from the ash. Over the past 10-15 years there has been an increasing trend to employ dry ash disposal in landfills, which when properly constructed are unlikely to produce leachate for many years. However, both dry and wet ash disposal systems may have an impact on surface and groundwater.

Storage in Active or Abandoned Coal Mines

In the United States, minefilling with coal waste has been shown to be inexpensive and successful in reducing water and acid drainage, increasing soil fertility, and filling mine pits and voids. Many states therefore employ this option as an alternative to landfilling coal combustion products. The U.S. Department of Interior is in the process of developing national standards for the placement of coal utilization by-products in mines, which include specific permit requirements and performance standards that would have to be satisfied before the products could be used in coal mines.

Reuse of Ash

Leaching rates of trace elements may determine the environmental suitability of using coal ash for reuse in other processes. An element of particular concern in this regard is selenium, which is a physiologically-essential trace element with only a relatively small margin between beneficial and potentially harmful effects. Coal-fired power plants have been identified as the single largest anthropogenic source of selenium to soil and water environments. Sample reuses of coal ash include:

- Cementitous Use for Construction. Regulations can include standards for the amount of carbon in the ash to be reused for cement. In some cases, if carbon content is high, modifications can be made at the plant to enable separation of finer ashes and reduction of the unburned carbon content, but this will increase cost.
- Horticultural Uses. Regulations can determine whether or not coal ash can be used as a soil supplement for the purpose of growing vegetation, and if so, whether there should be any standards for contaminants in the ash prior to land application.
- Gravel and Road-Based Uses. Coal ash can be blended with polymers to produce a product that has similar properties and strengths as quarry gravel. Regulations could determine whether use of this product is allowed in major road projects.

An issue that has received some attention in the United States is the negative impact the use of increased amounts of chemicals for removal of air pollutants (such as mercury) may have on the ability to recycle coal.[xii] The chemicals used for controlling air emissions include ammonia lime and calcium hydroxide. These and the removed air pollutants, including mercury, make the ash more toxic which then reduces the ability to use the ash in cement because the chemicals may prevent cement from hardening. The result may be increased use of landfilling instead of recycling, although no studies have quantified this potential trend yet.

2.3.3 Waste Management Practices

Regulations covering coal combustion products also include guidance on how the ash should be managed, which again depends on the different disposal practices. Coal ash naturally contains arsenic and mercury, and if the elements leach into groundwater they can contaminate drinking water supplies. Regulated management practices then typically consist of guidance for preventing these chemicals from getting into the surrounding environment. For example, in the United States, state permit requirements and siting control measures for landfills and surface impoundments usually include groundwater monitoring, leachate control systems, liners, and covering requirements, along with closure and fugitive dust controls. In Australia, utilities are now required to report on the any relevant substances contained in ash that is being 'transferred' to a storage site or another facility for recycling, reprocessing, or reuse.

2.4 Permitting

Environmental regulations for power plants are typically implemented through the process of permitting new power plants. It is during the permitting process that new and retrofit power plants must demonstrate that they have installed sufficient technologies to meet the various air, water, and waste regulations. Otherwise the facilities will not be permitted. For example, in November 2007, Washington state regulators rejected a proposed integrated gasification combined cycle (IGCC) power plant because the plant does not comply with Washington's new performance standard for long-term power purchase contracts.[xiii] According to the standard, plants must not emit more than a modern natural gas-fired facility (1,100 lbs of CO_2/MWh). The Washington Energy Facility Site Evaluation noted, however, that the firm would be allowed to operate the facility if it designed a plan for capturing and storing the associated CO_2 emissions.

In most cases, the permits reflect existing laws. But in some situations the permitting process can be used to reflect change in how existing and new laws are being interpreted by local governments and the courts. This is the case with CO_2 regulation in the United States, where in a landmark decision by the Ninth Circuit Court of Appeals held in November 2007 that federal agencies must assess the climate change impacts in environmental documents prepared under the National Environmental Policy Act (NEPA). The issue arose in the Court's review of new fuel economy standards for light trucks and SUVs issued by the National Highway Traffic Safety Administration (NHTSA). In its decision in *Center for Biological Diversity v. National Highway Traffic Safety Administration* __ F.3d ___, (9th Circuit, Nov. 15, 2007), the Court ordered the NHTSA to prepare an environmental impact statement (EIS) to assess the impact of newly-proposed fuel economy standards on global warming.

The decision's broadest impact may flow from the Court's holding that "the impact of greenhouse gas emissions on climate change is precisely the kind of cumulative impacts analysis that NEPA requires agencies to conduct." The decision means that project proponents, including both public and private developers and businesses, must evaluate GHG emissions for projects requiring federal approval or permits, such as new energy facilities and transmission lines, casinos, landfills, major land developments, telecommunication facilities, mines, road expansion and other transportation projects. While the Court's holding is limited to federal decisions subject to NEPA, it has the potential to also affect private development projects and other state-level projects under state environmental review statutes.

In addition to requiring the preparation of an EIS, the Court required NHSTA to "monetize" the impacts of both the proposed standards and alternative standards, and to quantify the potential benefits of those standards for reducing GHG emissions. Combined with the United State Supreme Court's landmark ruling in *Massachusetts v. EPA* that GHGs are regulated pollutants under the Clean Air Act (Section 9.2.2, Appendix 1), the Court's ruling mandates that environmental review under NEPA will include an assessment of the climate change impacts of federal agencies' planning and permitting decisions.

In addition to these legal developments at the national level, U.S. states such as California and Massachusetts are now requiring new building projects to assess associated GHG emissions and devise strategies for offsetting these as part of the Environmental Impact Assessment (EIA) (See Section 9.2.3 in Appendix 1). Moreover, in October 2007, the Kansas Department of Health and Environment became the first government agency in the United States to cite CO_2 emissions as the reason for rejecting an air permit for a proposed supercritical coal-fired power plant, saying that the plant's GHG emissions threaten public health and the environment.

The states responsible for these new EIA procedures argue that the existing state environmental policy frameworks extend to cover the impact of GHG emissions, because of the increasing scientific evidence linking rising anthropogenic GHG emissions with global warming. For example, in the decision to reject the coal-fired facility in Kansas, the Secretary of the Kansas Department of Health and Environment noted that "it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing." State regulators also refer to the April 2007 decision by the United States Supreme Court in the case of *Massachusetts v. the Environmental Protection Agency* stating that section 202(a)(1) of the Clean Air Act gives EPA the authority to regulate tailpipe emissions of greenhouse gases.[xiv] This ruling has significantly increased the likelihood that other sources of GHGs will be regulated under the Clean Air Act, including power plants, and the Kansas decision indicates that state approvers of new facilities have started to consider this in their permit decisions.

The permitting process for coal-fired power plants is quite lengthy and could take several years. One of the major factors is public involvement which could have a significant impact on technology choice, because local communities and environmental groups tend to put pressure on approving agencies to interpret environmental rules conservatively. China is not yet fully open to public review and, as a result, environmental objectives are sometimes overruled by other priorities such as cost, electricity demand growth, and employment opportunities, resulting in exemptions to some of the environmental regulations during the permitting process. However, Thailand and the Philippines allow public comment during the permitting process, which has led to significant pressure on applications for new coal-fired facilities. In fact, several proposed coal-fired power plants, using conventional pulverized coal, in Thailand and the Philippines have been cancelled owing to opposition by environmental groups and local communities.

2.5 Direction of Future Regulations

Perhaps the single most important near-term regulatory issue affecting coal-fired power plants and technology choice is the rapidly emerging regulations for GHG emissions. Not only is carbon dioxide a new environmental issue which must be incorporated into the existing environmental framework for air, water, and waste pollutants – thus, requiring significant adjustments to permitting, monitoring, reporting, and tracking institutions and procedures – but its' regulation is also likely to have a large influence on technology choice. The high carbon content of coal requires that significant improvements must be made to the average efficiency of coal combustion and CO_2 removal technologies to make coal competitive with other low- or zero-emission fuels.

Because of the new emphasis on avoiding catastrophic global warming, carbon dioxide regulations for coal-fired power will likely take priority in developed APEC economies in the near term and in all economies in the long term. Emissions trading will likely become the most commonly used measure for controlling CO_2 emissions from coal-fired power generation. However, technology standards such as combustion technology specifications (i.e., supercritical/ultra supercritical, IGCC) or carbon capture and storage targets will also be commonly used. For example, economies may require that all new and existing coal-fired power plants must be capture ready by a certain time period (i.e., 2020) and specific guidelines for the use of capture and storage technology will likely be incorporated into existing BAT/MACT standards in the United States and Europe.

The emerging CO_2 regulations are expected to have a dramatic effect on all pollutants from coal-fired plants. Many of the proposed GHG regulations aim at increasing efficiency, encouraging fuel switching to zero- or low-emission options, or deploying zero-emission technologies at coal-fired facilities. As a result, GHG regulations could contribute significantly to the reduction of other pollutants from coal-fired power, particularly air emissions. This will largely be the case, if the regulations lead to increases in the average efficiency of coal-fired power generation. However, if they mostly result in the use of CO_2 capture and storage without a shift towards more efficient coal combustion, the resulting efficiency penalty from capturing CO_2 may actually lead to increased emissions or discharges of pollutants from other sources. Given the consideration of such aggressive long-term targets of reducing GHG emissions by up to 80% below current levels by 2050, it is likely that emerging regulations for electricity generation will result in both an increase in average efficiency and the use of capture and storage at most new plants in order to adequately meet these goals.

In developing APEC economies, near term regulations will continue to focus on conventional air pollutants, and will not include mercury and carbon dioxide. Except for Russia, all of the developing economies examined have introduced new and much more stringent emission standards within the past five years and have indicated that it would be a while before new major regulatory changes would take place. In the short term, adjustments and companion legislation that serve to strengthen the mechanisms for implementing and enforcing the existing standards would be more likely. This could include more wide-spread use of technology standards for environmental controls, such as those adopted in China, or the introduction of average efficiency improvement targets existing and new coal-fired power plants. Developing APEC economies will also continue to be attractive markets for the generation of GHG emission reduction projects that can be used to offset emissions in developed economies. With the approval in 2007 of several CDM methodologies for efficiency improvements at existing and new coal-fired power plants there will be many opportunities for engaging in GHG reduction projects at coal-fired power plants. This is particularly so if the international community quickly agrees to an extension of the Kyoto Protocol framework beyond 2012, including a continuation of the procedures for approving CDM projects.

Other expected regulatory developments in the near future include:

- *Increased regulation of mercury and fine particulates,* using developments in the United States and Canada as an example. Considering that only the United States uses emissions trading for controlling non-CO_2 air emissions, it is likely that other economies will prefer to rely on technology standards and emission limits for the control of these emissions since they already have the infrastructure in place for this type of regulation.

- *Increased use of government-mandated technology standards to improve thermal efficiency and/or encourage CO_2 capture and storage*. This could be accomplished by requiring all new coal-fired power plants to be built to be capture ready and use supercritical or IGCC technology at large facilities.

- *Control of water will likely focus on water intake*. Regulations will continue to be developed based on local priorities, but will likely focus on measures related to water intake and water cooling. In the United States, Sections 316(a) and 316(b) of the Clean Water Act place restrictions on the impact of water cooling on the environment. Ongoing updates to these regulations means that permitting of open-loop cooling will likely be limited and that future electric power generation plants most likely will move to closed-loop cooling. This may limit future water withdrawals, but could significantly increase water consumption (i.e., less water will be re-released to the nearby water body). Economies, such as China, which face serious water shortages in many areas, will likely focus on regulations that discourage water consumption.

- *For coal ash, regulations will be strengthened in developing APEC economies to include improved guidance on how to prevent landfilled waste from impacting nearby water bodies and specifications for which alternative uses are permissible.* Regulation of coal wastes are typically not a priority in developing APEC economies, and are thus more likely to occur in the long-term.

Another general trend that will continue in the future is the growing use of market-based measures to control air emissions, mostly because of the cost-effectiveness of these approaches compared with traditional command-and-control regulation. In the United States, emissions trading is being used for the control of conventional air pollutants, mercury, and most recently, carbon dioxide at the regional level. Developing APEC economies are slowly turning towards emissions trading, but so far only for conventional air pollutants. China is developing a pilot program for SO_2 trading, and the Philippine's government has indicated that it has considered emissions trading for conventional air pollutants, although it likely would not be implemented in the near future due to the costs of developing and implementing such a program.[xv] For water and waste issues, regulations will continue to focus on command-and-control measures.

3. THE EFFECT OF ENVIRONMENTAL REGULATIONS ON THE CHOICE OF TECHNOLOGIES FOR NEW COAL-FIRED PROJECTS IN DEVELOPING AND DEVELOPED APEC ECONOMIES

Environmental regulations have fostered the uptake of clean coal technologies at different rates and to differing extents in a number of APEC economies. Regulations on conventional air pollutants - generally SO_2, NO_x, and particulate matter - have proven effective in stimulating the deployment of environmental controls, both pre- and post-combustion. This trend is has been evidenced most clearly by coal-fired generators' responses to government regulations on SO_2 and NO_x emissions in Japan in the 1960s and 1970s, in the United States in the 1970s and 1990s, and in China in the 1990s through the present. In general, the adoption of abatement technologies is a direct response to the development and enforcement of national regulations as these regulations, over time, appear to have lowered the cost of compliance by encouraging development of new low-cost technologies for meeting the standards.

Thus far, environmental regulations have had less direct influence on the adoption of advanced coal-fired combustion technologies that focus on improving efficiency and thus reduce CO_2 emissions. Adoption of these technologies appear to be more influenced by national energy policies that promote the efficient use of coal as a means to achieve greater energy security or as a response to volatile prices for natural gas and petroleum products. This trend is evidenced in the United States during the 1960s and 1970s, in Japan from the 1980s through the present, and in current day China. Government-funded demonstration projects have also contributed significantly to the growth of advanced coal-fired combustion and carbon capture and storage projects.

Regulations mandating GHG emission reductions through cap-and-trade programs are still in their early stages, and their overall influence on clean coal technologies is therefore still uncertain. Experience from the EU ETS suggests that regulations on greenhouse gas emissions, while they have historically been too low to encourage more efficient coal combustion technologies, carbon allowance prices have significant potential to stimulate major investment in advanced coal-fired combustion systems and carbon capture and storage projects. There is also some early evidence that the emerging regional and federal climate change regulations in the Australia, Canada, United States and other economies are beginning to have an influence on planning decisions for future coal-based capacity expansion projects by increasing investment in high-efficiency combustion systems and/or carbon capture and storage. However, the emerging GHG regulations tend to have a parallel impact on coal-fired capacity in terms of decreasing the overall use of coal for electricity generation. The emerging GHG regulations have increased the price of high carbon-content fuels relative to other fuels and thus in some cases encouraged closure of coal-fired plants or a switch away from coal to natural gas, nuclear, or renewables.

None of the water-related regulations appear to limit or encourage any particular coal combustion technology. However, the regulations do make it more costly for power plants to use water and thus may indirectly influence the use of more efficient combustion technology. In the United States, Sections 316(a) and 316(b) of the Clean Water Act place restrictions on the impact of water cooling on the environment.

Ongoing updates to these regulations, means that permitting of open-loop cooling will likely be limited and that future electric power generation plants will most likely move to closed-loop cooling. This may limit future water withdrawals, but could significantly increase water consumption (i.e., less water will be re-released to the nearby water body).

In general, there is a much more direct link between environmental regulations for air emissions and the deployment of more efficient clean coal technologies and carbon capture and storage than the introduction of regulations for wastewater and waste discharges and the use of clean coal combustion technology. In most of the APEC economies questioned, waste and water regulations had not influenced the use of environmental controls or clean coal combustion systems. However, it is possible that this type of regulation, if combined with other air regulations, can work to increase the cost of coal-fired power to such an extent that generators choose to use more efficient technology.

The following subsections outline technology trends in individual developed and developing APEC economies and the EU ETS.

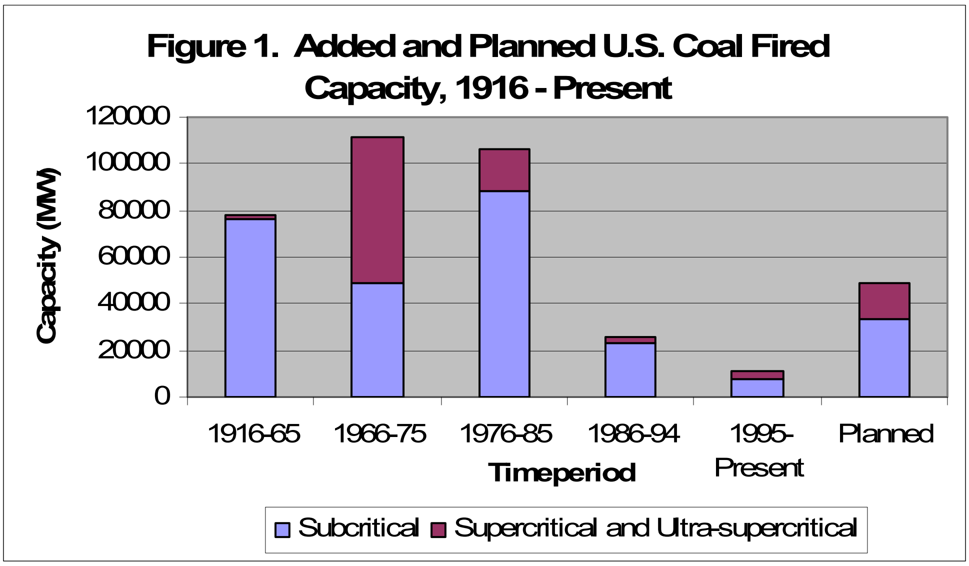
3.1 United States

Under the influence of government initiatives prioritizing the development of efficient utilization of indigenous resources, the United States experienced a period of growth in supercritical coal-fired capacity in the 1960s and 1970s. During the subsequent lowering of coal prices, and relatively low demand for additional coal-fired capacity, fewer plants were constructed, the overwhelming majority of which were subcritical units. During this period, federal regulations on air pollutants proved highly effective in promoting the development and deployment of pollutant controls in most new coal-fired capacity, as well as in many existing coal-fired plants. Environmental regulations do not appear to have had much influence on the adoption of advanced combustion technologies in the past, though there is evidence that the prospect of a mandatory greenhouse gas cap-and-trade program is generating renewed interest in more efficient advanced coal-fired combustion technologies and carbon sequestration and storage systems.

The first stringent requirements for SO_2 emissions from power plants were introduced by the Clean Air Act Amendments of 1970 and 1977. The most significant response from coal-fired generators was a dramatic shift to the use of lower sulfur coals from western coal mines. Many of the plants that continued to burn higher sulfur coals were retrofitted with flue gas desulphurization (FGD) units, and a shift to a technology-based standard in 1977 fostered the adoption of FGD systems in nearly all new coal-fired capacity. Currently, approximately 90,000 MW of existing coal-fired capacity in the United States utilizes FGD systems,[xvi] 25,000 MW of which was installed through the 1990s.[xvii]

NO_x emissions from coal-fired power generators were minimally regulated until the 1990 Amendments to the Clean Air Act. Prior to these Amendments, the only significant influence on generators were the 1971 New Source Performance Standards, which could be met by low-NO_x burners, and only affected new capacity. The 1990 Amendments specified emissions-rate limitations for specific abatement technologies for both new and existing facilities, many of whom also responded by adopting combustion modification devices such as low-NO_x burners.[xviii] Although the first selective catalytic reduction (SCR) system in the United States was adopted only in 1993,[xix] more stringent NO_x requirements for existing power plants established by the EPA in 1994 stimulated a significant growth in SCR utilization throughout the next decade. By 2005, over 100,000 MW of SCR-equipped coal-fired generators had been built in the United States.[xx]

Thus far, environmental regulations have had less of a direct impact on the adoption of advanced coal-fired combustion technologies in the United States. Other factors such as cost, government priorities and technology trends appear to have had an equally important influence on the rate of technology deployment, sometimes slowing the rate of deployment and sometimes increasing it (see Figure 1).



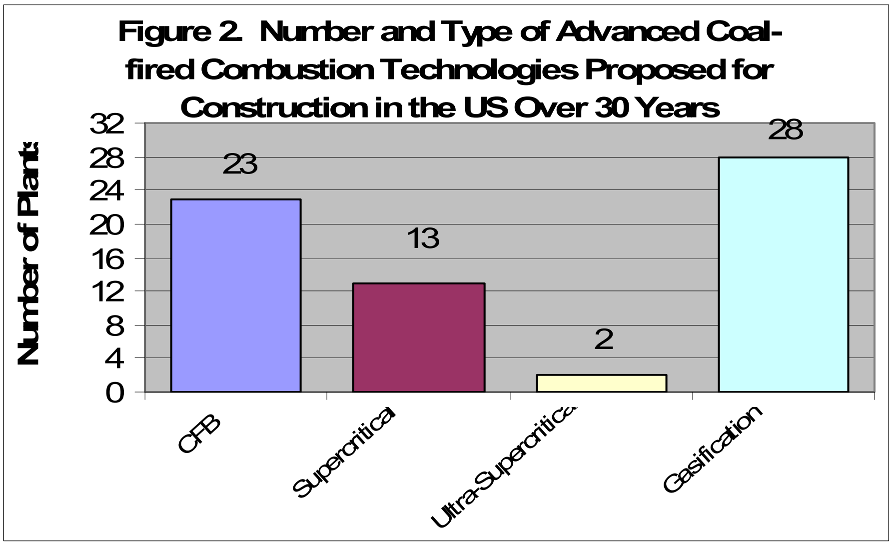
Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

Energy supply uncertainties following the 1973 oil embargo contributed to a period of increased fuel costs, high interest rates and inflation, and escalating electricity rates. In this environment, in conjunction with the recently enacted environmental regulations discussed above, the utility industry renewed its interest in increasing the productivity (efficiency) of coal-fired generating capacity and built more efficient, but generally smaller plants.

By the mid 1980s, however, generation demand was slowing and the need for new coal-fired plant capacity (not generation) greatly diminished well into the 1990s. New capacity demand in the late 1990s and into early 2000s was generally satisfied by natural gas combined cycle plants. Throughout this period, the greatest influence on the development of advanced coal-fired power generating technologies has been continued funding for RD&D projects like the Department of Energy's Clean Coal Technology Program, which focuses on the development and commercial demonstration of environmentally sound coal technologies.

There is evidence that impending legislation mandating GHG emission reductions in the United States may influence decisions on the part of utility investors regarding the use of advanced coal-fired combustion technologies. As discussed in the subsection on the European Union's Emissions Trading Scheme (Section 3.8), there is substantial evidence that costs imposed on carbon emissions can significantly drive investments in lower carbon alternatives, including more efficient advanced coal-fired combustion technologies. There are currently seven economy-wide GHG cap-and-trade proposals under consideration in Congress, all of which address the six "Kyoto" GHGs and include power generators (See Table 9.4, Appendix 1). There are also four bills which focus solely on the power sector, and include conventional pollutants as well.

The growing attractiveness of investment in more efficient coal-fired combustion technologies is reflected in the profile of proposed new coal-fired capacity in the United States. In early 2007, of the 159 coal plants (representing approximately 145 GW of capacity) proposed for construction over the next 30 years, 77 are advanced technologies- 23 CFB, 16 supercritical, 4 ultra-supercritical, and 34 IGCC systems (see Figure 2).[xxi]



Source: DOE/NETL. "Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation." April 2007

However, the emerging GHG regulations in the United States have also led to difficulties in permitting new coal-fired power plants, including those based on highly efficient technology, such as IGCC and supercritical technology. In October 2007, a new report by the U.S. Department of Energy indicated that at least 16 of the proposed coal-fired power plants listed in Figure 2 have been can cancelled or delayed while utilities wait for more certainty on emerging GHG regulations.[xxii] Other reasons for cancellations of planned coal-plants include rising plant costs due to increased competition for materials and shortage of skilled labor.

The following is a sampling of recent rejections or cancellations of coal-fired plants that have been directly linked to emerging GHG regulations:

- *Colorado:* In November 2007, Xcel Energy announced that it would close down two coal-fired power plants representing 229 MW and replace these with national gas and renewable energy sources.[xxiii] The announcement was part of the company's strategy for helping to meet the state's GHG reduction goal.

- *Florida:* In May 2007, the Florida Public Service Commission denied air permits to Florida Power and Light for two 980 MW coal-fired generators. Subsequently, Taylor Energy Center (consortium of Jacksonville Electric Authority, Florida Municipal Power Authority, City of Tallahassee and Walt Disney's Reedy Creek Improvement District) withdrew from consideration permit requests for an 800 MW coal-fired plant. Later in the year, the Orlando Utilities Commission and Southern Co. scrapped their plans for building a 285 MW IGCC facility and will convert it to a natural gas plant instead, and Tampa Electric Co. cancelled an even larger 630 IGCC facility. The developers cited the changing federal and state regulatory landscape for GHGs as the reason for the cancellations, arguing that IGCC is no longer an economically viable option in Florida.[xxiv]
- *Kansas:* In October 18, 2007 state regulators denied permits for two 700 MW supercritical coal-fired power plants proposed by Sunflower Electric based on the detrimental health effects of CO_2. The regulators cited an April 2007 Supreme Court ruling that EPA should consider CO_2 a pollutant as one of the major reasons for rejecting the permit.[xxv]
- *Texas:* Following environmental protests over 11 proposed coal-fired power plants in the state, TXU Corp. agreed in February 2007 to cancel eight of these plants as part of a deal to sell itself to two large private equity firms.
- *Washington:* In November 2007, Washington state regulators rejected a proposed IGCC power plant because the plant does not comply with Washington's new performance standard for long-term power purchase contracts.[xxvi] According to the standard, plants must not emit more than a modern natural gas-fired facility (1,100 lbs of CO_2/MWh).

Taken together, these recent developments indicate that the emerging GHG regulations may have a parallel affect of leading to less overall use of coal for power generation. This is particularly the case in the United States where GHG regulations are still emerging and the regulatory environment remains highly uncertain. It is possible that interest in coal-fired power will remain high, once a regulatory scheme has been firmly established, as long as the plants use highly efficient technology combined with some form of carbon capture and storage.

3.2 China

Regulation of air pollutants in China has historically been relatively lax, thereby limiting their effect on the uptake of clean coal technologies. In response to growth in the demand for power, and the accompanying growth in emissions from high-sulfur and high-ash indigenous coal, environmental regulations affecting coal-fired power plants have become both more stringent and more widespread. In recent years, these regulations have proved effective in promoting the adoption of pre- and post-combustion pollution controls, and promise to continue doing so into the future. While concerns regarding carbon dioxide emissions have taken less of a priority, the magnitude of projected growth in the Chinese power sector necessitates the efficient use of energy resources. In conjunction with China's significant coal reserves and government priorities to maximize energy independence, this has created an environment favorable to the use of advanced combustion coal-fired technologies. Between 2003 and 2010, supercritical units will potentially account for 40 percent of new coal capacity additions, and from 2010 to 2020, all new units of at least 600 MW will have supercritical or ultra-supercritical boilers.

Two of the major issues driving technology deployment in the Chinese power sector are dramatic projected demand growth and controlling emissions of pollutants, especially SO_2 and particulate matter. The importance of developing clean coal technologies is reflected in numerous State Policy directives in China, including the Coal Law of the People's Republic of China (PRC), the Energy Conservation Law of the PRC, and the Air Pollution Prevention and Control Law of the PRC.[xxvii] A prime example of China's commitment to adopt clean coal technologies over time is the "National High Technology Research and Development Program of China (863 Program), which funds RD&D activities in a number of areas pertaining to clean coal, including coal gasification technologies, ultra-supercritical power generation technologies, and SO_2 and NO_x control technologies. Government interest in advanced coal technologies stems from combined concerns over energy security, efficiency and air pollution.[xxviii]

Historically, environmental regulations have had mixed results in promoting clean coal technologies. Despite an extensive regulatory network, local enforcement efforts have sometimes proven ineffective and, in the past, the central government has had limited success in enforcing environmental regulations, especially outside the major cities, where funding is limited and most local environmental bureaus are understaffed. Moreover, environmental protection goals often conflict with local employment and economic goals, reducing the incentives for local governments to adhere with national pollution control.

In recent years, however, environmental regulations concerning pollutant emissions have grown increasingly stringent, particularly in areas with serious air pollution and high economic and population growth. Current policies focus on using low sulfur content coal, adding desulfurization technologies, burning coal more efficiently, and limiting the addition of new coal-fired capacity in highly polluted areas. The regulations vary significantly throughout China due to the government's focus on urban areas and environmental hot spots.

This trend is exemplified by the SO_2 Pollution Levy System. Throughout the early years of the program (which was expanded to include power generators in 1992) fines on excess SO_2 emissions imposed by the system were significantly lower than the marginal abatement cost of new control technologies.[xxix] Recent expansions to the program to include NO_x emissions and increases in levies have generated additional incentives for investment in emissions controls, particularly FGD systems.

China began installing FGD units on coal-fired power generators in 1991, and by 1999, had installed FGD systems on 2.4 GW of coal-fired power generating capacity.[xxx] It is worth noting, however, that most of these projects were financed as demonstration projects through bilateral funding mechanisms, most notably Japan's Green Aid Plan.[xxxi] Growth in the share of FGD-equipped coal-fired capacity has been exceptionally high in recent years, increasing to 200GW by the end of 2005, or approximately to 20 percent of total coal-fired capacity.[xxxii] The effect of environmental regulations on future FGD development is also clear, with some 300 new FGD systems scheduled to be installed under the 11th five year plant between 2006 and 2011.[xxxiii] The total capacity of coal-fired power plants equipped with wet FGD in China is estimated to reach 35 GW by 2010.[xxxiv]

As indicated in Table 12**,** the use of PM control equipment also increased throughout the nineties, with electrostatic precipitators showing the greatest growth in use. The growth of more effective PM controls is expected to continue rising, as all new coal-fired plants above 200 MW are required to have ESP systems installed, while smaller capacity plants will utilize Venturi and multi-tube scrubbers.[xxxv]

Table 12. Share of Boiler Capacity Installed with Different Particulate Removal Equipment, 1990-1997 (%)

Type	1990	1991	1992	1993	1994	1995	1996	1997
ESP (Electrostatic Precipitator	33.2	37.6	41.6	46.8	53.5	55.1	59.7	64.7
Venturi/ slant bar grating wet scrubber	30.1	29.4	28.4	26.6	23.9	22.6	21.8	19.5
Water film scrubber	17.2	15.6	14.2	12.8	11.9	11.9	9.4	7.9
Multi-tubular scrubber	5.9	5.8	5.2	4.6	3.5	3.4	3.0	2.1
Swirl scrubber	4.7	3.6	3.2	2.6	1.8	1.9	1.3	1.1
Other scrubber	0.4	0.3	0.3	0.2	0.4	0.3	0.4	0.2

Source: "Clean Coal Technology Assessment in China." The World Bank. 1999.

In addition to widespread efforts to close China's older, smaller, and less efficient generating plants the strengthening of environmental controls has led to a significant decrease in emissions (particularly SO_2), primarily through the increased use of emission control technologies. Policies that have directly promoted the adoption of emission controls include the following:

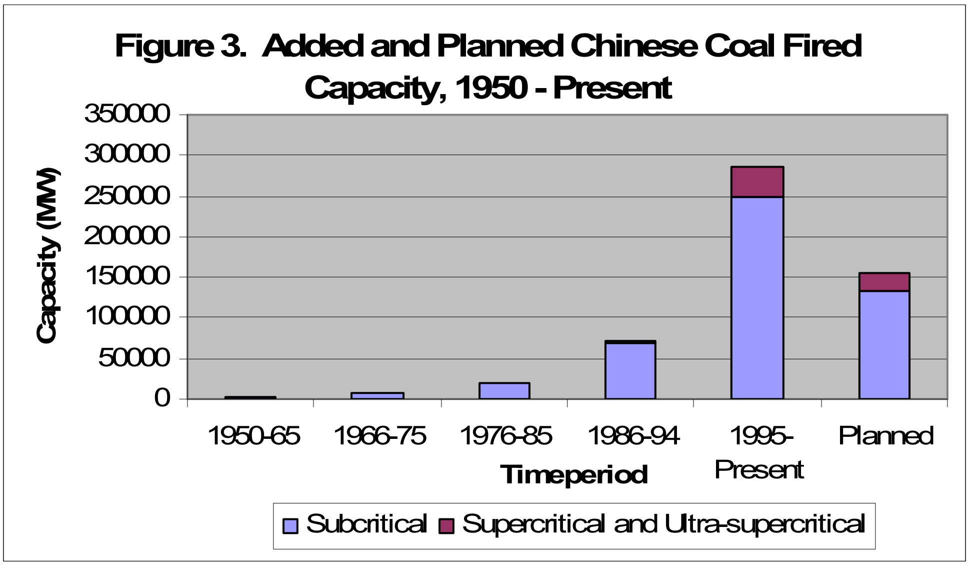
- *SO_2 Pollution Levy System:* A pollution levy system addressing a range of pollutants from industrial and power generation sources. Part of this levy is a financial penalty imposed on emissions exceeding the existing standard. Funds raised through the levy are then used to finance environmental projects, install pollution controls, and promote technology upgrades.

- *Three-Simultaneity Rule:* The rule requires that all new, replacement, or expansion projects must incorporate SO_2 controls simultaneously with the design, construction and operation of the new facilities.[xxxvi]

- *Two Control Zone Policy:* Mandates that areas most affected by acid rain and high SO_2 concentrations receive priority in terms of pollution control measures and investment.

- *Total Emissions Control:* Specifies a national SO_2 emission target, which is allocated within provinces and municipalities. The total target is set to decrease over time.

While environmental regulations in China have proven effective in increasing the use of emissions control technologies, they do not appear to have directly influenced the adoption of advanced coal-fired combustion technologies thus far. In conjunction with the government's objective to promote energy independence through the use of China's abundant coal resources, however, these factors have generated an environment that favors power generation technologies that optimize the use of coal while minimizing SO_2 and NO_x emissions. This is reflected in the increasing share of supercritical systems and advanced boiler systems in planned and under-construction capacity (Figure 3).[3]



Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

Historically, the price of coal has been artificially depressed by the central government, reducing incentives to invest in more expensive technologies to utilize coal more efficiently. Recent accounts, however, indicate that China has made major progress towards market pricing of energy commodities,[xxxvii] which will encourage more efficient use on the part of power generators. Between 2003 and 2010, supercritical units will potentially account for 40 percent of new builds, and from 2010 to 2020, all new units of at least 600 MW will have supercritical or ultra-supercritical boilers. Of the 460 GW of capacity anticipated to be installed between 2004 and 2020, some 50 percent is expected to be ultra-supercritical.[xxxviii] While cost is a major issue, PFBC or large-scale CFBC and IGCC technologies all have an excellent opportunity to penetrate China's power market over the next 20 years.

To date, there is little evidence that concerns regarding carbon dioxide emissions from power generation exert much influence on power sector development. Although emissions of CO_2 from fossil fuel combustion are growing rapidly, the government is paying less attention to the mitigation of climate change and has limited its GHG emission reduction activities to those that can be supported through the CDM. China has ratified the Kyoto Protocol and actively supports investment in GHG emission reduction projects through the CDM. As a major target for hosting energy-related CDM projects,[xxxix] numerous potential projects have been identified in China for

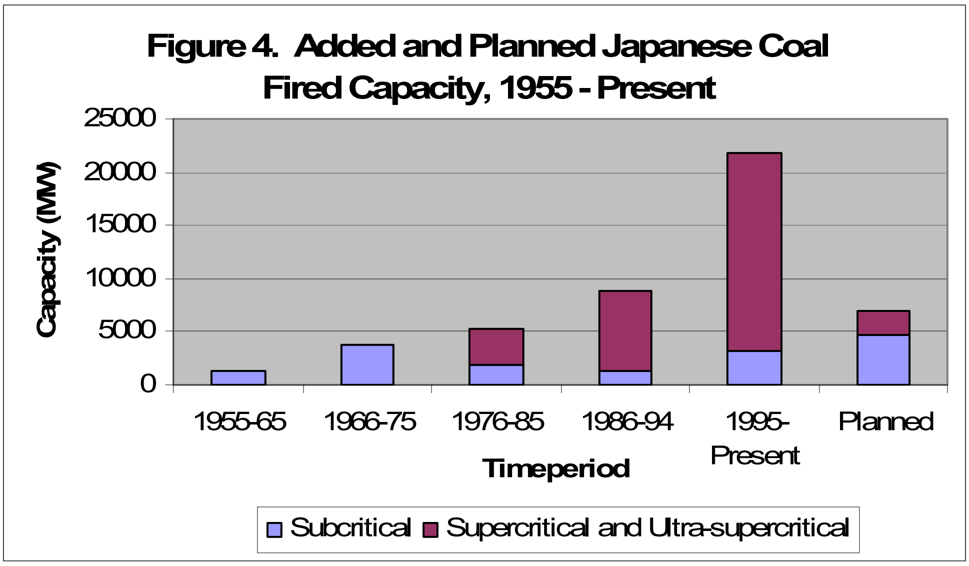
[3] It should be noted that the figures for the share of supercritical and ultra-supercritical plants in planned coal-fired capacity do not agree in the text and Figure 3. This is due partly to incompleteness of the Platts/UDI database. Where no data were given on the steam system of a unit, it was assumed to use subcritical technology.

improving the efficiency of existing coal-fired boilers and introducing advanced technologies such as supercritical coal-fired technology.[xl]

3.3 Japan

Japan was one of the first economies to enact a wide-ranging system of regulations governing emissions from power plants. The Air Pollution Control Law, enacted in 1968, laid the framework for the regulation of SO_x and NO_x emissions on a regional and local level and led to both pioneering of the development of many pollution control technologies, and their uptake by coal-fired generators in Japan. Japan commissioned the world's first utility-scaled FGD systems on coal-fired plants in the late 1960s. All Japanese coal-fired plants now are fitted with FGD.[xli] The first SCR systems were employed in the late 1970s; as of 2005, approximately two-thirds of Japanese coal-fired capacity was equipped with SCR systems.[xlii]

Although there are no specific environmental regulations mandating their development, advanced coal-fired combustion technologies, particularly supercritical and ultrasupercritical boilers, have enjoyed significant penetration in the Japanese power sector in recent years (Figure 4). The movement towards more efficient coal-fired power stems from the higher cost of coal in Japan.

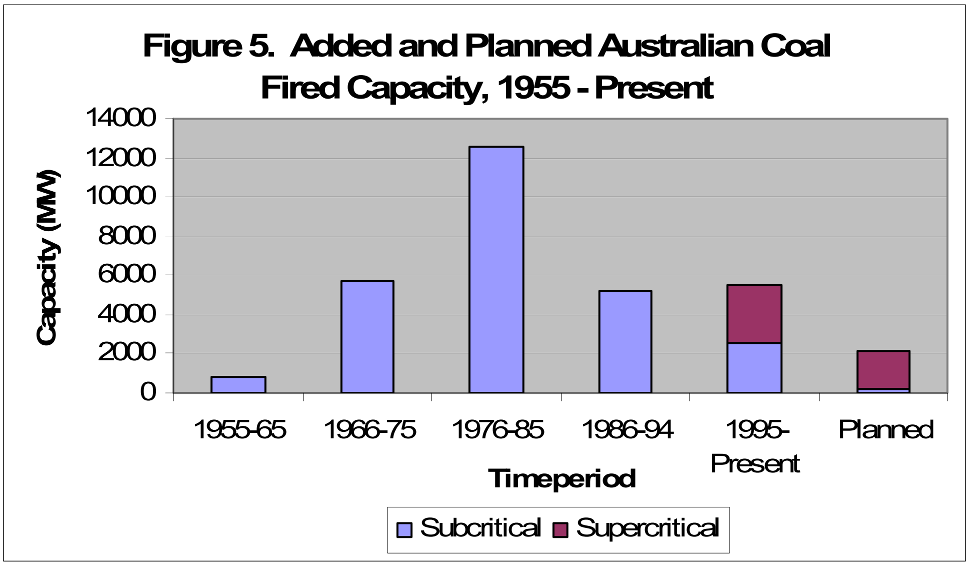


Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

High LNG cost, natural gas supply uncertainties, and Japan's limited indigenous energy resources have all contributed to the Japanese government's policy of retaining coal-fired capacity as a means of diversifying the power sector. However, in order to meet its GHG reduction obligations under the Kyoto Protocol, Japan has sought to increase the efficiency of coal-fired generators, largely through the increased use of highly efficient, advanced combustion technologies, including pressurized fluidized bed combustion units, ultra-supercritical boiler systems, and, eventually, integrated IGCC systems.[xliii] Many advanced coal-fired combustion systems in Japan have been aided by financial support from the government.

3.4 Australia

Thus far, environmental regulations have had little influence on the uptake of clean coal technologies in Australia. However, this trend is changing for planned plants. Australia's heavily coal-dependent power sector is comprised primarily of subcritical pulverized coal plants. The low sulfur content of Australian coal has precluded the need for stringent regulations governing sulfur emissions and FGD systems are minimally employed by coal-fired power plants. Generally, coal-fired generators have relied on efficiency improvements and environmental controls to meet environmental regulations. Commercially deployed advanced coal-fired combustion technologies are limited to three supercritical boilers in Queensland totaling 2.2 GW capacity,[xliv] and another 750 MW supercritical facility expected to come online in Queensland towards the end of 2007 (Figure 5). Numerous other advanced combustion technology demonstration projects are underway, mostly in response to the emerging concerns over GHG emissions.



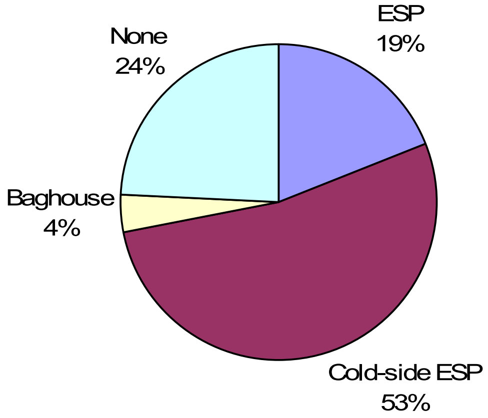
Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

The Australian coal industry has initiated Coal21, a collaborative partnership among governments, researchers, and industry, to develop advanced, near-zero-emission coal technologies and coal-based hydrogen fuel and technologies.[xlv] The Fund is expected to provide investment capital for CO_2 capture and storage, coal gasification, oxy-fuel combustion, advanced clean-coal preparation technologies, co-firing coal with biomass, and the integration of coal-fired power and solar energy, though it is unlikely that any of these technologies will be employed over the short term.

3.5 Canada

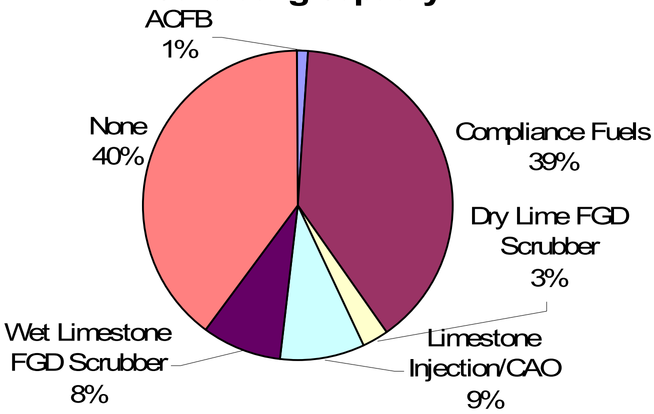
Environmental regulations in Canada have proven moderately effective in promoting the adoption of clean coal technologies. As indicated in Figure 6, some 76 percent of Canadian coal-fired generation capacity is equipped with particulate matter controls, primarily electrostatic precipitators. Figure 7 indicates that just over 20 percent of coal-fired facilities in Canada are equipped with SO_2 emissions controls; the remainder is uncontrolled, or meets emission requirements through the use of compliance fuels.

Figure 6. Particulate Matter Controls in Canadian Coal Plants by Share of Generating Capacity



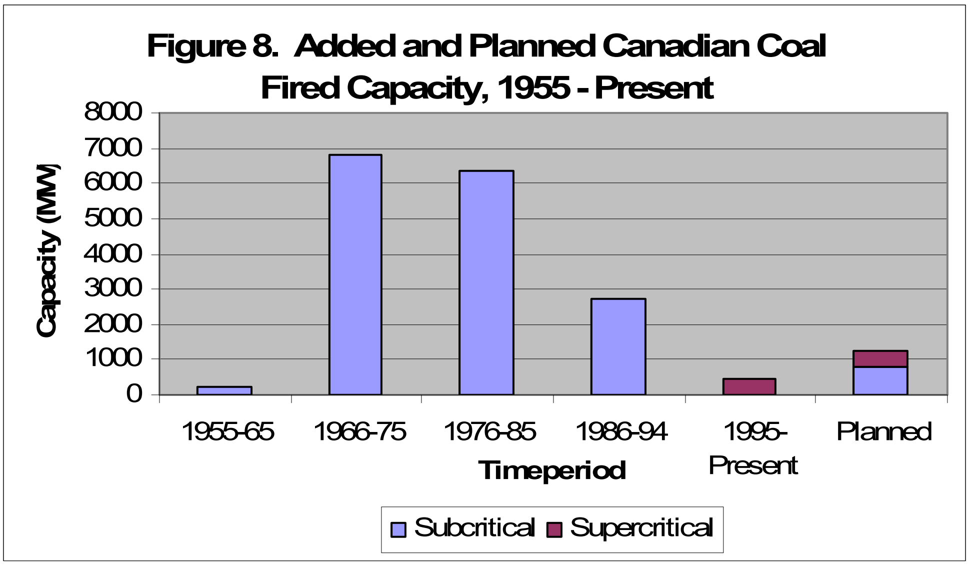
Source: Platts. UDI World Electric Power Plants Database, 2005 directories.

Figure 7. SO_2 Controls in Canadian Coal Plants by Share of Generating Capacity



Source: Platts. UDI World Electric Power Plants Database, 2005 directories.

Thus far, advanced coal-fired combustion technologies have had limited penetration in Canada (Figure 8), restricted to a 185 MW ACFB unit installed in 1995, and a 450 MW supercritical system installed in 2005.



Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

Coal-fired generation currently supplies approximately 18 percent of Canada's electrical generation, and given significant domestic coal reserves and projected high natural gas costs in Canada, it may continue to play a significant role in the future of Canada's power sector. In light of Canada's GHG reduction obligations under the Kyoto Protocol, Canada may incorporate more advanced coal-fired combustion technologies over time. Options for clean coal development have been investigated in a government-financed "Clean Coal Technology Roadmap."[xlvi] As part of its plan to reduce GHG emissions to 80% below 2004 levels by 2050, Saskatchewan requires that SaskPower's new and replacement generation facilities are emissions-free or fully offset emissions through other means (Table 2.5, Appendix 1). As a result, only coal-fired power plants with capture and storage would be economic. British Columbia also has a GHG reduction target and requires that 100 percent of the CO_2 produced from any new coal-fired power plant built in the province must be captured and stored.

However, it is also likely that many parts of Canada may switch away from coal entirely. Ontario has announced that it will switch away from coal by 2014 by phasing out its remaining coal-fired power plants. This is to meet its target of reducing GHG emissions by 80 percent below 1990 levels by 2050. Manitoba does not have a GHG target, but recently announced that it will phase down the only coal-fired power plant in the province. In short, measures to meet emerging GHG targets in Canada will lead to both a reduction of the use of coal for power and the adoption of technologies that reduce CO_2 emissions.

Likewise, the new regulations for mercury are expected to lead to a mix of fuel switching and adoption of increased environmental controls. For example, Nova Scotia will achieve its cap on mercury emissions for 2010, by Nova Scotia Power selecting among the following options to achieve the cap from its existing facilities:[xlvii]

- Use of fuels with low mercury content and other attributes that will reduce atmospheric mercury emissions;

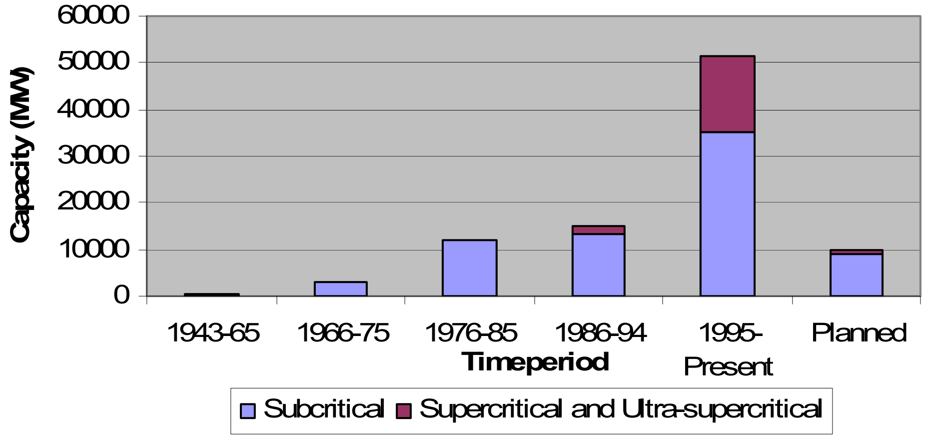
- Use of sorbents for mercury in flue gas streams to capture mercury with the various solids in the particulate collection equipment, including the modification of that equipment where necessary;
- Reduction in mercury emissions as co-benefits of the installation of air pollution control devices or modified management practices intended principally for reduction in atmospheric emissions of other substances; and
- Modification in production levels at existing coal plants from addition of lower-emitting new generation, including, but not limited to renewable energy.

3.6 South Korea

With limited indigenous energy resources, South Korea depends heavily on imports of foreign fuels. As is the case with Japan, coal provides fuel diversity, reliability, and prices that have remained relatively low and stable over time. Coal-fired power generation's share in the South Korean power sector is projected to grow to 34.4 percent (20.9 GW).[xlviii] South Korea has a long history of regulating pollutants, introducing regulations on SO_2, NO_x and particulate matter in 1977. Since then, regulations have steadily become more stringent, both in terms of allowable emissions and fines imposed. As a result, FGD and ESP systems are now installed on all new and existing coal plants in order to meet SO_2 and particulate matter emissions limits.[xlix] Low-NO_x burners are generally used by otherwise non-compliant plants in order to meet emissions standards.

The adoption of advanced coal-fired combustion technologies in South Korea is more influenced by government concerns about efficiency and energy supply than it is by environmental regulations. Since the mid-1980s, the South Korean government has been encouraging the adoption of supercritical systems, primarily through a program to develop and deploy a standardized, 500 MW supercritical boiler system. Growth in supercritical capacity is illustrated in Figure 9.

Figure 9. Added and Planned South Korean Coal Fired Capacity, 1943 - Present

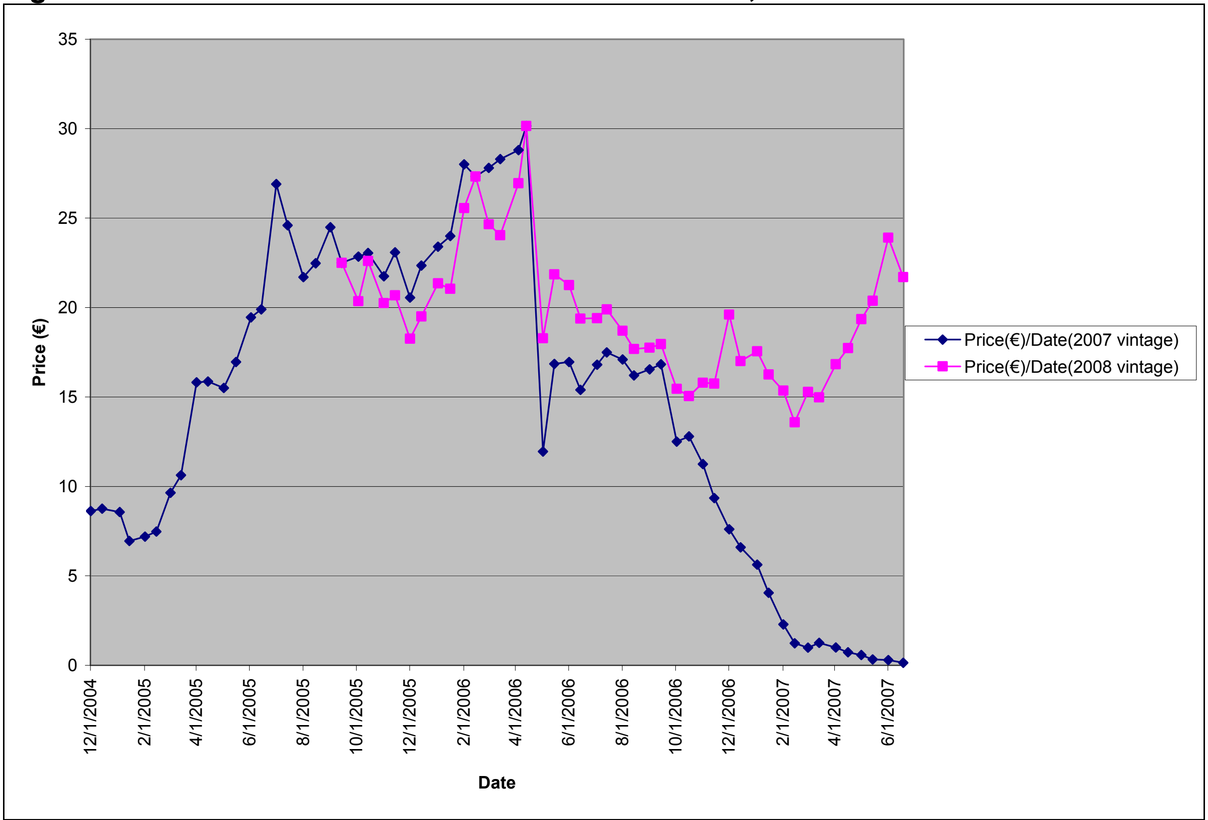


Source: Platts. UDI World Electric Power Plants Database, 2005 directories; and IEA. Coalpower5 Database. 2005

3.7 Europe and EU Emissions Trading Scheme

The EU ETS is a trading system for 25 European nations committed to emission reductions under the Kyoto Protocol. All participating economies have established a GHG cap for each installation covered by the scheme. The installations may then comply with its cap through on-site emission reductions or by purchasing emission allowances from the market. The carbon price is established from the supply and demand of emission allowances. As illustrated in Figure 10, below, the price of CO_2 allowances has fluctuated since the scheme was introduced, reaching a maximum of nearly US$ 38 (€ 30.5) per metric ton of CO_2. An analysis of verified emissions and allowance allocations performed in May of 2006 indicated an over-allocation of allowances of approximately four percent,[l] contributing to depressed prices for the remainder of the trading period. However, as indicated in Figure 10, Phase II allowances continue to trade higher given the European Commission's commitment to tighten caps during this phase.

Figure 10. EU ETS Allowance Prices for Phase I and II, 2004-2007



Source: Point Carbon. Historic EU Allowance Prices. 2007.

Because of the newness of the EU ETS, it is still too early to determine the full impact of the program on technology deployment. Over the past three years, coal prices have generally remained low and fairly stable, whereas natural gas prices have soared in tandem with oil prices. As a result, conventional coal-fired technologies have remained competitive despite increasingly stringent environmental regulations[li] and their relatively higher carbon emissions.

There are suggestions that the allowance price through Phase I was not consistently high enough to stimulate major investment in GHG-reducing technologies. For example, the International Energy Agency (IEA) suggests that CO_2 capture and storage project investment would require a carbon price of at least US$ 30 per metric ton over a sustained period of time.[lii] At prices below that, most entities are likely to focus on low cost efficiency improvements or purchase allowances on the market. It was not until the allowance price reached more than US$ 35 in April 2006 that the German utility RWI temporarily shut down two of its least efficient coal-fired units until the price dropped again.[liii]

The European Association for Coal and Lignite (Eurocoal) claims that the current structure of the EU ETS, specifically the short compliance periods, limits the development of clean coal technology. [liv] Instead, Eurocoal and other industrial interests have proposed compliance periods of 10 to 50 years, which would allow for the planning and construction of new facilities and achievement of their benefits within the commitment period.

A recent survey of companies in sectors ranging from energy to financial services in the United Kingdom reveals that business do not yet view the carbon price in the EU ETS as long-term enough to influence strategic decisions like investments into new technology.[lv] The study interviewed 14 UK-based utilities, energy companies, firms from the oil and gas sector, and financial services as to the way they address climate change in the long term. It concluded that national policies, particularly incentives frameworks for clean energy technologies, are seen as "the key drivers of low carbon investment." Many of these policies have been in place for several years and include specific standards for fuel switching or technology adoption, and their influence have therefore been more distinct in the short-term.

Nonetheless, since the onset of the scheme, participating companies have made a number of note-worthy announcements regarding clean coal technology investments, suggesting a growing influence of the role of carbon emissions on investments in coal-fired generators:[4]

<u>Carbon Dioxide Capture and Storage (CCS):</u>

- In the United Kingdom, plans are underway to retrofit an existing power station with a 500 MW supercritical coal technology plant with post-combustion CO_2 capture. The new plant will be the first CO_2 capture plant in the United Kingdom.[lvi]
- The German energy company Powergen is planning a 450 MW coal gasification plant for Killingholme, England, with the intention of sequestering 90 percent of the CO_2 emissions into the North Sea.[lvii]
- In Denmark, the utility Elsam plans to capture CO_2 from five large coal-fired power plants in western part of the country. The proposed CO_2 capture facilities can be phased into operation starting 2007 through to 2012.[lviii]

[4] The described technology investments and fuel switching are all undertaken by private companies and may or may not be used for compliance under the EU ETS. The potential compliance gains will to a large extent depend on how the respective national governments decide to allocate allowances for new entrants and specific fuel types in the next commitment period of 2008 to 2012.

Oxy-Fuel Combustion Combined with CCS:

- In Germany, construction of a new zero-emission coal-fired plant in Schwarze Pumpe began by Vattenfall in May 2006 and is scheduled to begin operation in 2008. The 30 MW test plant with CO_2 capture and storage will combine oxyfuel technology with a conventional pulverized coal plant. Upon successful completion of the test plant, Vattenfall is planning a 300 MW demonstration plant for 2015, and if successful, a 1,000 MW commercial plant for 2020.[lix]

Integrated Combined Cycle Gasification Combined with CCS:

- In March 2006, the German electricity generation company RWE announced plans to invest US$1.2 billion in a 400 to 450 MW IGCC plant to be operational by 2014. The proposed plant will sequester CO_2 in an onshore geologic storage site.[lx]

Integrated Combined Cycle Gasification

- The Dutch utility Nuon is planning to build its second IGCC plant at Eemshaven, Netherlands using Royal Dutch Shell coal gasification technology. Electricity production from the 1,200 MW plant, which will co-fire biomass, is scheduled to begin in 2011.[lxi]

Atmospheric Circulating Fluidized Bed Combustion:

- A 460 MWe supercritical CFBC unit is under construction in Poland was commissioned in 2006. This plant is expected to have a thermal efficiency of 43 percent (LHV).

Similar to the United States, the EU is witnessing a parallel trend of decreased reliance on coal due to the EU ETS, along with the shift towards adoption of advanced combustion technologies highlighted above. A 2007 study by the IEA indicates that the EU ETS has mainly led to fuel-switching away from coal; that is, switching to the building of new CCGT power plants and the moth-balling or shutting down of several coal-fired power units.[lxii] During high oil and gas prices, this trend was somewhat offset by reverse switching from natural gas to coal despite the need to then purchase allowances (EUAs) on the market. The upcoming reduction in EUAs during Phase II of EU ETS, and the resulting price increase in allowances, may result in making coal-firing less competitive compared with gas or oil. Moreover, the ability to use coal-fired capacity may be restricted because the revised LCPD directive limits the use of coal-fired plants without FGD controls. As a result, the overall use of coal-fired capacity in Europe is expected to decrease and there are few coal-fired power plants under construction or planned to be built in the near future.

3.8 Developing APEC Economies

In the developing APEC economies examined in this report, environmental controls have or will be introduced at some of the new plants while the older capacity remains largely uncontrolled. This is particularly the case in economies where the most stringent regulations apply only to new capacity. For example, none of Indonesia's power plants use SCR, while three have installed FGDs. In the Philippines, most of the plants use imported low sulfur (<1%) coal to meet the standards, two plants use FGD and almost all plants use ESPs (Table 13).

Table 13. Pollution Control Measures at Coal-Fired Power Plants in the Philippines

Measure	Power Plant						
	Sual 1152 MW	Masinloc 580 MW	Pagbilao 728 MW	Mauban 500 MW	Calaca 326 MW	Toledo 40 MW	Naga 100 MW
Air Pollution Control Technologies/Measures							
Electrostatic Precipitator	√	√	√	√	√		√
Bag Filter						√	
Low Sulfur Coal	√	√	√	√	√	√	√
Low NO_X Burner	√	√	√	√	√		
Tall Smoke Stack	√	√	√	√	√	√	√
Atmospheric Fluidized Bed Boiler						√	
Ash Pond	√	√	√	√	√	√	√
Coal Stockpile Water Spray System	√	√	√	√	√	√	√
Flue Gas $DeSO_X$	√			√			
Water Pollution Control Technologies/Measures							
Waster Water Treatment Facilities/Oil Water Separator	√	√	√	√	√	√	√
Sedimentation Basin	√	√	√	√	√	√	√
Neutralization Basin	√	√	√	√	√	√	√
Cooling Water Channel	√	√	√	√	√	√	√
Fly Ash Utilization	√	√	√	√	√	√	√

Source: Alternative Fuels and Energy Technology Division, Philippines Department of Energy, February 21, 2007

In Viet Nam, all new coal-fired power plants have flue gas $DeSO_X$. None of Electricity of Viet Nam's (EVN) planned units will use SCRs, but some of the units planned by independent power producers may.[lxiii] The proposed 300 MW capacity expansion project at EVN's Ninh Binh coal-fired power station that will begin operation in 2010 will be installed with a low NOx burner.

In Russia, anecdotal information indicates that the use of environmental controls has increased over the last decade, although at a slow rate. For example, in Moscow oblast,[5] low-cost measures are typically used for NOx control, including low-NOx burners (37 boilers), staged combustion (74 boilers), and recirculation of flue gas to the inlet of inducing draft fans (72 boilers). Particulate matter reduction is usually achieved by modernization of existing ESPs or wet scrubbers. The first two SCRs were recently installed at two boilers in Russia (at TEC-27 in Moscow).[lxiv] The otherwise slow implementation of SO_2 control technologies can be partially explained

[5] The OAO Mosenergo power system is a complex of 17 thermal power plants generating energy and power, having a common operation mode, relying on a shared capacity reserve, and a centralized operational and dispatching control system. The Company's installed electrical capacity totals 10.6 thousand MW, the installed heat capacity is 34.2 thousand Gcal/h (39.8 thousand MW). MOSENERGO's thermal plants operate 112 turbines (104 cogeneration turbines, 6 gas-turbine units, and 2 expansion generating units), 117 power boilers and 115 peak water heaters

by the small percentage of coal-fired boilers relative to other fuel-types, such as natural gas- or fuel oil-fired boilers, which has led authorities to focus on other environmental problems instead.

As part of the Moscow utility, OAO Mosenergo's, 2006-2008 program for environmental improvements, the utility will introduce a range of new environmental processes/technologies, including continuous wastewater quantity and quality control monitoring systems and new wastewater treatment facilities at five of its plants. It also plans to introduce a combustion process optimization system with continuous emissions control and metering, clean-burning combustion units, flue gas recycling, and staged fuel combustion technology. These projects are being financed, partly through assistance from the European Bank for Reconstruction and Development (EBRD). Examples of other pollution control projects in Russia are outlined in Table 14.

Table 14. Emissions Control Projects at Coal-fired Power Plants in Russia

Project Implementer	Measures	Technology/Process	Environmental/Economic Benefit
Novocherkasskaya GRES power plant	NOx reduction	Recirculation of smoke gases during the burning of natural gas and coal to decrease NOx content	At 10% gas in fuel balance of the boiler the NOx concentration drops 50-120mg/м^3
Berezovskaya GRES power plant - 1	NOx reduction	Suppression of NOx is stipulated through the burning of fuel at low temperatures with the recirculation of smoke gases	A decrease in NOx concentration of 100-150 mg/m^3
Berezovskaya GRES power plant - 1	Purification of gases from ash particles	2-level horizontal 4-floor electro-filters	Purification of leaving gases from ash particles
OAO «Kuzbassenergo» 9 boilers	NOx reduction	Staged combustion of Kuznetsk Basin coal	A double decrease in NOx emissions through steady burning of coal. Efficiency of the boiler is increased up to 91-91,8 %
Nazarovskaya GRES power plant	NOx reduction	Transfer of the boiler to "VIR-TECHNOLOGY" of coal burning in the mill variant	The boiler's production of steam and its efficiency is increased. NOx emissions are reduced from 370 to 345 mg/m^3
Heat-electric Generating Station OAO «Sverdlovenergo»	SO_2 and ash reduction	Introduction of a ring conic emulsifier, while submitting basic solutions	Ash gases purification at the rate of 99,2 %. SO2 purification at the rate of 4-21 %
OAO Krasnoyarskenergo 2 boilers	NOx reduction	Russian-developed WIR technology of staged combustion	NOx reduction from 800 mg/m3 to 550 mg/m3
Dzershinskaya TEC	NOx reduction	SCR process DENOX Haldor Topsoe, Denmark	90% reduction

Source: Y. Urinson. A Study on effective ecological projects implemented at enterprises of the OAO RAO "UES of Russia", 2005

None of the other developing APEC economies examined (Indonesia, Malaysia, Philippines, Thailand, Vietnam) plan to adopt advanced combustion technologies, such as supercritical or IGCC that also improve efficiency and reduce coal consumption. This is mainly due to the higher capital cost of these technologies, which is not expected to be sufficiently offset by the coal savings that could be achieved through improving efficiency. The only clean coal combustion technology that is or will be deployed at select new plants is fluidized bed combustion. For example, as illustrated in Table 13, an atmospheric fluidized bed combustion (AFB) system has been installed at the 40 MW Toledo power plant in the Philippines. Because of the Philippines' recent adoption of air emission standards for power generation, most of its new plants will include fluidized bed combustion so that low grade coal can be used to meet the standards.

In Vietnam, the proposed 1,000 MW Mong Duong 1 coal-fired plant, operated by EVN and scheduled to begin operation in 2012, will be the first Vietnamese power plant to use circulating fluidized bed combustion (CFB) technology.[lxv] This plant is still in the pre-planning stages. Russia will continue to focus on retrofitting and upgrading existing units, so there won't be many opportunities for deploying new advanced combustion technologies through capacity expansion. Many of the existing units already use early supercritical technology developed in Russia in the 1980s. To take advantage of existing engineering skills and control costs, new units added over the next 10 years will likely use the same Russian technology.

4. BARRIERS TO THE ADOPTION OF CLEAN COAL TECHNOLOGIES IN DEVELOPING APEC ECONOMIES

At present, barriers exist that make investment in technologies for high efficiency and zero-emission coal-based power generation rather difficult – regardless of the type of environmental regulations implemented. These barriers can lead power plant developers to opt for fuels other than coal when deciding on replacing or adding generating capacity, particularly, in the circumstances of increasing needs for reducing CO_2 emissions. Such fuel choices have the potential to affect the electricity mix long after the commercial viability of advanced combustion and zero emissions coal-fired power generation has been proven. This could occur through implementation of a specific infrastructure, such as an extensive network of gas pipelines or liquefied natural gas (LNG) terminals.[lxvi]

Future fuel choices would be influenced by the existence of an infrastructure that would reduce lead times and capital costs. For example, in the case of CO_2 capture and storage, without steady investment in coal transport infrastructure and planning for CO_2 transport, short-term attempts to introduce highly efficient and low-emission technologies may be frustrated, despite favorable life-cycle economics. Removing or lowering these barriers with well-designed policy measures and R&D support will be crucial to enabling widespread and rapid penetration of highly efficient coal-fired power plants and CO_2 capture and storage.

Monitoring, compliance, and enforcement of regulations. Existing and new environmental regulations will only be as effective as the overall framework economies have in place for monitoring, reporting, tracking, and enforcing their implementation. As discussed in Section 3, Appendix 1, China has adopted several environmental regulations that are not being fully enforced at the local and regional level. As a result, the implementation of environmental controls, efficient combustion technologies, and continuous emissions monitoring systems is not meeting the targets established at the national level. Improving the local and regional enforcement mechanisms would substantially improve technology adoption rates.

Infrastructure for emissions trading. A prerequisite for the effective implementation of emissions trading is the presence of the necessary infrastructure to implement such a system. This includes installation of continuous emissions monitoring systems (CEMS) at regulated entities to enable constant reporting of emissions, a registry for tracking and storing reported data, and availability of activity data (i.e., emissions, cost, and economic output data) to effectively determine and allocate allowances among covered entities. None of the developing APEC economies examined in this report have such infrastructure in place. China and Thailand have started requiring installation of CEMS at large facilities, but due to the high cost of these systems progress has been slower than expected, particularly in China. China is experimenting with emissions trading for SO_2 emissions at the regional level. This will assist the government in determining the remaining infrastructure requirements that must be developed in order to adequately support a large-scale trading system.

Technology experience. Except for China, which is building several supercritical and ultra-supercritical coal-fired power plants, there is little experience in developing

APEC with the construction and operation of highly efficient coal-combustion systems and capture and storage. Current R&D focus in most economies is on CFB systems, as these allow for combustion of low-grade coal. However, CFB systems do not necessarily lead to improved thermal efficiency. Thus, in anticipation of future GHG regulations in developing APEC economies, national governments in the region will need support in developing an encouraging the growth of indigenous expertise with clean coal technologies.

Public perception/acceptance of clean coal and CO_2 capture and storage. Reservations concerning coal's future in the electricity mix persist in many quarters.[lxvii] The benefits offered by coal and the realistic expectations of availability in the relatively near future of low or zero-emission power generation from coal have yet to be conveyed to the public in developing APEC economies. Wider public acceptance of the measures associated with advanced clean coal and capture and storage technologies is needed. Public debate will need to focus on the environmental and energy supply benefits considering in particular the feasibility of managing risks associated with transport and geological storage of CO2.

Moreover, as with other potential sources of low-CO_2 electricity, increased investment and operating costs may lead to concerns about possible higher electricity prices. It is important to consider the seriousness of public acceptability of carbon capture and storage. Wider public acceptance of the measures associated with advanced clean coal and carbon capture and storage technologies is thus needed. Public debate will need to focus on the environmental and energy supply benefits and the feasibility of managing risks associated with transport and geological storage of CO_2.

Cost. Clean and low CO_2 emissions coal technologies present high capital costs to investors in new power generation capacity. Capture and storage technologies only provide significant efficiency gains in large scale applications. Hence, the costs are prohibitive for smaller plants and for most developing APEC economies. For example, 300 MW of IGCC capacity costs around US$ 440 million without the additional expenditures for CO_2 capture and storage.[lxviii]

In addition, coal-fired power generation traditionally has a long investment cycle as plants operate for 40 years or even longer. The new generations of power plants are being commissioned for equally long time periods. The decision to invest in coal therefore requires investors' confidence in long-term persistence of conditions allowing for sufficient payback times. This becomes important especially when coal-based power generation is compared to the lower capital costs of a natural gas CCGT plant. The investment decision will also depend on the availability of capital to finance high-cost applications. In China, and other developing APEC economies, demand for electricity is growing rapidly every year thus limiting available resources to keep up with this growth. Because of the constraints on available resources, investors in these economies mostly choose low-cost options for meeting existing standards.

Besides capital costs, operating costs also present a barrier to uptake of the technology when comparing "capture ready" versions of power plant designs with existing coal technologies. Investors who wish to take advantage of the stable supply of coal fuel must also consider the profitability of investing in cleaner generating technologies. The risks and high costs of opting for best available high-efficiency processes that reduce CO_2 emissions compared to traditional coal technologies present an obstacle to the advancement of clean coal technologies. While existing technologies appear to make it possible to capture 80-90% of the CO_2 produced in plant flue gases, the impact of using such technologies could lead to significant increases in the cost of electricity generation and in electricity prices.[lxix] This indicates that both technological improvements that reduce capital and operating costs and so shorten payback times, and long-term stability of the market framework (i.e., emissions trading systems such as EU ETS), are vital conditions for the successful adoption of clean coal.

Regulatory framework for CO_2 capture and storage. The present regulatory environment in APEC and other economies does not provide sufficient incentives to invest in radical CO_2-reducing technologies, such as capture and storage. Current environmental legislation has been drawn up prior to the existence of capture and storage technology and may be creating unintentional and unwarranted barriers. The EU's Water Framework Directive[lxx] can be quoted as a case in point – its current text effectively disables storage of CO_2 in saline aquifers although these geological structures have little relation to underground water conditions. Planning regimes, regimes for disposal of gaseous waste and for geological surveys may need clarification to remove the obstacles to capture and storage. In addition, guidance must be established for the long-term storage of captured CO_2, including ownership, monitoring procedures, and delineation of liability for any future seepage from the permanent storage reservoirs.

CO_2 value chain. The absence of a value chain for carbon dioxide is a barrier to the rapid uptake of high efficiency combustion and capture and storage technologies. Emission trading systems such as the EU ETS and the emerging regional systems in the United States could provide the conditions to introduce such a value chain, but the EU ETS for example excludes CO_2 avoided through capture and storage from its permit trading system. A regulatory environment providing guarantees of long-term existence of a CO_2 value chain would enhance security of investment and encourage rapid development and deployment of clean coal combustion technologies and capture and storage. Refining the regulatory environment also includes satisfying the environmental requirements concerning carbon dioxide storage.

CO_2 infrastructure. Another issue to be resolved in the context of developing APEC economies is that of coordinating the build-up of a carbon dioxide infrastructure (pipelines, etc.) to ensure optimal network connections and transportation of the captured CO_2 to suitable storage sites.

Demonstrated commercial feasibility. A sufficient record of operational experience of the variety of clean coal technology options leading to low or zero emissions power plants is not available presently. An acceptable proof of the operational suitability of the technological solutions is necessary to provide confidence in their reliable performance and commercial viability. Competition in liberalized electricity markets will require that embarking upon high-risk or high-investment projects such as those that would be necessary for the demonstration of new methods on a commercial scale needs to be considered very carefully. Existing or announced projects for the demonstration of clean coal power generation indicate that some activities are underway in Australia, Canada, China, the United States and other APEC economies but these will need significant additional support at the international level to reach the necessary scale and to make progress quickly enough.

5. REGULATORY FEATURES THAT WOULD MOST LIKELY LEAD TO SELECTION OF CLEAN COAL TECHNOLOGIES AT NEW COAL-FIRED PLANTS IN APEC DEVELOPING ECONOMIES

Developing APEC economies rely mainly on emission limits to control pollution from their existing and new coal-fired power plants. Only China augments its regulations with specific technology standards for environmental controls and SO_2 removal. These limits are beginning to influence the use of environmental controls at new capacity, but except for China, they have not led to an improvement in the use of more efficient combustion technology that would reduce carbon dioxide emissions in addition to conventional air pollutants. As indicated in Section 3, China has already deployed supercritical technology and is in the process of building ultra-supercritical power plants. This switch has been initiated out of concern for energy security in addition to the concern for the environment. None of the developing APEC economies examined have adopted carbon dioxide capture and storage technology, except for a few research activities in China.

As indicated by the analysis in Section 3, regulations focusing on air emissions are likely to lead to the selection of clean coal technologies in developing APEC economies, particularly those focusing on carbon dioxide. None of the developing economies surveyed in this study indicated that solid waste or water regulations had influenced decisions regarding conventional or clean coal technologies. Mostly, solid waste and water regulations have worked in combination with regulations for air emissions to increase the cost of coal-fired power thereby adding incentives for more efficient combustion. As economies move to adopt more comprehensive regulations for waste and water pollutants, they will indirectly encourage the adoption of clean coal technology.

For reasons of practicality and cost, new regulatory features to encourage a switch to clean coal should build on the existing frameworks for emissions and pollution control, i.e., the existing emission limits. In doing so, the regulations should be designed in a way that encourages efficiency improvements at the plants, in addition to the installation of environmental controls. This could be done in three ways:

- Emissions trading, such as cap-and-trade or rate-based trading
- Technology-based standards
- Thermal efficiency standards

5.1 Emissions Trading

The use of emission trading would ensure that environmental goals are met in the most cost-effective manner. In general, policies that provide flexibility are more cost-effective than those obliging specific technologies or controls to be installed with all new fossil-fired plants. When superimposed on an existing regulatory structure, economic instruments have proven to be useful tools for meeting emission targets, particularly in securing those last incremental reductions that are most difficult and costly to attain. As the goals become more stringent, or as the nature of regional or local fuel condition imposes constraints, those tools become increasingly useful. The

United States and many European economies got most of their emission reductions by switching from coal to natural gas.[lxxi] China cannot do that as easily given the lack of gas resources and pipeline infrastructure. In this case, China would benefit from using economic instruments to deploy clean coal most cost-effectively.

Other developing APEC economies, such as Indonesia, Philippines, Thailand, and Vietnam may have more freedom to switch to natural gas (in terms of infrastructure), but are all constrained by the high cost of gas and a desire to maintain a diverse fuel mix. For these economies, although emissions trading will be effective at reducing emissions, it may be less beneficial in terms of meeting national energy security goals if these include continued reliance on coal. This is because market-based regulations leave it up to the individual utility to determine how to meet the imposed cap: the utility could invest in more efficient coal combustion technology; switch away from coal to natural gas, nuclear, hydro or renewable energy; or it could reduce electricity supply entirely. In this way, national governments cannot be entirely sure that their overall energy strategies will be met if the market is left to determine how the environmental goals are satisfied and which type of fuels are used.

To a large extent, the overall impact on the use of coal depends on general fuel prices. If natural gas prices are high, utilities tend to switch to coal for base load power. If natural gas prices are low, utilities will increase the use of this fuel. As long as the marginal cost of controlling emissions through coal-based technology remains below the marginal cost of using natural gas or other fuels, coal will remain in the electricity mix. Moreover, in economies such as China, where there is limited infrastructure for competitive fuels, it is likely that coal will continue to supply most of the needed electricity.

Nonetheless, if governments are concerned about the future of coal under emissions trading there are a few design issues which they may consider in the development of an emissions trading system. For example, the specific approach for allocating emission allowances is likely to have an impact on the future economics of coal-fired power plants. If allowances are allocated for free (often called "grandfathering") this may act as a subsidy on the fixed cost of a power plant, thereby increasing the profitability of coal-fired capacity compared to less CO_2 intensive plants. [lxxii] If the amount of allocated allowances remains the same, even for plants that install more efficient combustion technology or introduce capture and storage, the incentives for continuing in operation would remain. If plants using clean coal technologies were to receive fewer allowances, this would act as a disincentive. By that extension, regulators may choose to let clean coal technologies receive allowances based on the reference technology (i.e., conventional coal or average technology used in the individual APEC economy).

When using the grandfathering approach for existing plants, the issue of the base year is also important because it determines the level of emissions allocated; if the base year would be fixed for future trading periods, then this would provide an incentive to improve efficiency. If, however, the base year is updated for a new trading period, this will act as a distinctive, because any improvement in efficiency would be "punished" by reducing allowances. For new entrants, regulators may decide to reserve extra allowances for the introduction of a certain share of new coal-fired capacity. Of course, such considerations must be counterbalanced with the overall emission reduction goals of the trading system.

Finally, to provide utilities with the long-term certainty to facilitate investment in large-scale infrastructure changes, the trading system must be designed in such a way that it provides long-term signal to investors. One of the weaknesses identified with the EU ETS, is that it lacks of a long-term target beyond 2012. As a result, power planners have little incentive to undertake large technology improvements that will mostly result in emission reductions after the end of Phase II in 2012.

Although emissions trading would be the most cost-effective method for reducing emissions in developing APEC economies, it would also require the most effort in terms of developing a supporting infrastructure for operating the system. This is because it would require the installation of CEMS at the targeted facilities and the development of a system for assigning allowances and a registry for tracking and reporting on progress. In many developing APEC economies, there is still insufficient infrastructure and enforcement to support such efforts, and only China and Thailand have adopting CEMS.

5.2 Technology Standards

Economies may also choose to set technology-based targets for coal-fired power generation. These could include targets for when new coal-fired power plants should be built to be capture ready and when they must install capture and storage. Other technology standards could include the type of combustion technology to be used, such as supercritical and ultra supercritical technology, IGCC, or PFBC. The earlier these targets are introduced, the quicker the changes in overall infrastructure will take place, thus reducing overall mitigation costs.

The use of technology standards would be more straightforward to implement than emissions trading and may be more effective at meeting combined environmental and national security goals. However, they would be less cost-effective because they do not allow as much flexibility as emissions trading. For that reason, it may be preferable to use a combination of technology standards and emissions trading.

5.3 Thermal Efficiency Standards

Regulation of coal-fired power plants could also be accomplished by setting thermal efficiency standards for the coal-combustion process. The standard could be set in terms of the power plant's thermal efficiency or heat rate and would likely differentiate between existing and new power plants, size, and fuel type. By improving power plant efficiency, several environmental goals could be reached at the same time because it would lead to a combined reduction in air emissions, water use, and waste production.

Although economies may run into some difficulties in developing efficiency targets and standards for measurements (this has never been done) the use of efficiency target would likely be more straightforward to implement and would require less up-front implementation than emissions trading. However, the use of efficiency targets may not result in the same overall cost-effectiveness as emissions trading because they are inherently less flexible. Still, efficiency targets would allow more flexibility than technology standards.

5.4 Integrating Environmental Considerations

Regulations should also be designed to consider *both* local air pollutants and greenhouse gases in combination with any concerns regarding waste and water pollution. If regulations only encourage the adoption of environmental controls for NOx, SO_2, and PM reduction, the overall efficiency of coal-fired power plants will decrease. The installation of environmental controls typically leads to a slight derating of the plant. As a result, CO_2 emissions will increase. Similarly, technology that only target GHG emissions through capture and storage may ignore local air pollutions. This would be the case if the regulation results in the installation of CO_2 capture technology, with an associated efficiency loss, without encouraging further reduction of local air pollutants through other controls or efficiency improvements. This would be the case in the state of Montana, which has introduced a requirement that all new coal-fired power plants must capture at least 50 percent of the CO_2 emitted. Ideally, any new regulation to address either local air pollution or GHG emissions would be designed in such a way that it reduces all pollutants. The most effective way of doing so would be to introduce measures that lead to improved efficiency of the coal combustion process. Improved efficiency would have the added benefit of reducing water use and coal combustion byproducts.

5.5 Summary and Recommendations

In general, policies that provide flexibility in meeting environmental goals are more cost-effective than those obliging specific technologies or controls to be installed with all new fossil-fired plants. Therefore it is recommended to employ a mix of the possible regulatory options: emissions trading, technology standards, and thermal efficiency targets. Most likely, developing APEC economies would start with technology and/or efficiency standards, because these are more straightforward to implement. In the meantime, they could then begin preparing the infrastructure for emissions trading.

Other short-term options to strengthen environmental standards and encourage the adoption of clean coal technology in new coal-fired power plants include:

- In the case of Malaysia, Philippines, Indonesia, Russia, Thailand, and Vietnam strengthening the existing NO_X, SO_2, and particulate standards, particularly for new capacity. Russia is a special case, because the first step in improving its regulatory framework, should involve moving from a system based on dispersion modeling to actual measurements of stack emissions;
- For all economies, increase emission fees and levies to incentivize abatement. The fees must be set a such a level that it becomes more cost-effective to invest in environmental controls or efficient coal combustion rather than paying the fee;
- For all economies, encourage a switch from emission limits based on mass concentration output (i.e., mg/m^3) to performance standards based on energy

production (i.e., lb/kWh). This approach would provide incentives to operate sources more efficiently, thus encouraging the use of more efficient combustion technologies;
- For all economies, encourage the addition of limits for mercury;
- Building on ongoing efforts in China, implement government targets for the use of more efficient combustion systems in all economies, such as supercritical, ultra-supercritical, and IGCC technology. Activities should start with improving regional information and data repositories on power plant efficiencies and combustion technologies;
- To build capacity for emissions trading, require the use of continuous emissions monitoring, starting with large new facilities.

Long-term options include:

- Introduce a CO_2 emissions trading system for China in the near term, and at a regional basis for the remaining developing APEC economies in the long term. The system must be designed in such a way (i.e., long-term timeframe and stringent caps for the electricity sector) that the market price will support investment in capital intensive clean coal projects. This could be done by gradually lowering the cap to give economies some time to adapt to the trading system, but at the same time providing a long-term signal that increased efficiency will be required.

Although it may be expensive and difficult to implement upfront, the quick introduction of more stringent environmental regulations could be beneficial to developing economies that plan to continue expanding their coal capacity. Because of economic and population growth in these economies, and the subsequent rapid expansion of coal-fired power, a slow introduction of legislative improvements could result in further degradation in air quality in the long-term and a significant increase in CO_2 emissions. This is because of the long turn-over time for technology in the power sector.

Instead, 'technology leap' opportunities are possible by moving quickly towards efficient coal combustion and CO_2 control, which would allow developing nations to avoid projected increases in local air pollution and GHG emissions. Addressing both CO_2 and local air pollutants at the same time, would avoid costly technology retrofits and improvements at a later stage and would alleviate strains on water resources and landfills.

The expense of such systems would normally be prohibitive for developing nations. As a result, significant funding from international organizations would likely be required. Policies that attract such funding – either through the Kyoto Protocol or other technology transfer funds – would be beneficial.

APPENDIX I

Environmental Regulations for Coal-Fired Power in Select APEC Economies

1. Australia

1.1. Air Emissions

1.1.1 NO_X, SO_2, and PM

Through enactment of National Environmental Protection Measures (NEPMS), the National Environment Protection Council (NEPC) of Australia develops federal level regulations for coal-fired power and other industrial sources. Two national NEPMs are relevant for coal plants: the Ambient Air Quality NEPM and the National Pollutant Inventory (NPI) NEPM.

The Ambient Air Quality NEPM sets national ambient air quality standards that apply to urban air sheds in all Australian states and territories. These standards cover six criteria pollutants: PM, ozone, SO_2, NO_2, CO, and lead.[lxxiii] In May 2003, the NEPC adopted the Variation to the Ambient Air Quality NEPM which strengthened the framework by introducing reporting standards for $PM_{2.5}$ in addition to the existing PM_{10} standards.[lxxiv]

The NPI is an internet database which provides information on the types (90 substances) and amounts of pollutants emitted to air, land, and water.[lxxv] The NPI provides emissions estimates from facilities such as coal-fired power plants, and from other non-reporting facility sources (diffuse sources emissions). Facilities only report data when they exceed reporting thresholds related to the amount of different substances used, fuel or energy used, or emissions of nutrients.

The NEPC has not set federal emission standards for individual coal-fired power plants. Instead, emission standards for power stations are a matter of the environment protection agencies in each jurisdiction. These would normally be set as part of the licensing provisions associated with each facility, based on local conditions, and in the context of data available from the NEPMs described above.

The following outlines some of the air emission standards developed by individual states and territories.

New South Wales

The emission standards for coal-fired power plants in New South Wales (NSW) are contained in the Protection of the Environment Operation (Clean Air) Regulation 2002.[lxxvi] The standards, which are outlined in Table 1.1, target PM and NO_X. SO_2 is unregulated, because of the low-sulfur content of Australia's coal.

Table 1.1. Emission Standards for Electricity Generation in NSW, Australia

Pollutant	Plant Type	Applicable to installations in operation or with planning application for approval	mg/m^3
Solid particles (Total)	Plants using a liquid or solid standard fuel or a non-standard fuel	< Jan. 1, 1972 ≥ Jan. 1, 1972 and ≤ Aug. 1, 1997 ≥Aug. 1, 1997 and ≤ Sep. 1, 2005 ≥ Sep. 1, 2005	400 250 100 50
Nitrogen dioxide (NO_2) or nitric oxide (NO) or both, as NO_2 equivalent	Non-gas boilers >30 MW	< Aug. 1, 1997 ≥ Aug. 1, 1997 and ≤ Sep. 1, 2005 ≥ Sep. 1, 2005	2,500 800 500
	Gas turbines >30 MW	< Aug. 1, 1997 ≥ Aug. 1, 1997	2,500 70
	Non-gas turbines > 30 MW	< Aug. 1, 1997 ≥ Aug. 1, 1997 and ≤ Sep. 1, 2005 ≥ Sep. 1, 2005	2,500 150 90
Fluorine (F_2) and any compound containing fluorine, as total fluoride (HF) equivalent	Plants using a liquid or solid standard fuel or a non-standard fuel	< Jan. 1, 1972 ≥ Jan. 1, 1972	100 50
Type 1 substances (in aggregate)	Any plant using a non-standard fuel	< July 1, 1986 ≥ Jul. 1, 1986 and ≤ Aug. 1, 1997 ≥ Aug. 1, 1997	20 10 --
Type 1 and Type 2 substances (in aggregate)	Any plant using a non-standard fuel	> Aug 1, 1997 ≥ Aug. 1, 1997 and ≤ Sep. 1, 2005 ≥ Sep. 1, 2005	-- 5 1
Cadmium (Cd) or mercury (Hg) individually	Any plant using a non-standard fuel	< July 1, 1986 ≥ Jul. 1, 1986 and ≤ Aug. 1, 1997 ≥ Aug. 1, 1997 and ≤ Sep. 1, 2005 ≥ Sep. 1, 2005	-- 3 1 0.2
Dioxins or furans	Any plant using a non-standard fuel that contains precursors of dioxin or furan formation	≤ Sep. 1, 2005 ≥ Sep. 1, 2005	-- 0.1 ng/m^3
Volatile organic compounds (VOCs), as n-propane equivalent	Any plant using a non-standard fuel	≤ Sep. 1, 2005 ≥ Sep. 1, 2005	-- 40 VOCs or 125 CO
Smoke	Plants using a liquid or solid standard fuel or a non-standard fuel	< Jan. 1, 1972, in approved circumstances < Jan. 1, 1972, in other circumstances ≥ Jan. 1, 1972, in approved circumstances ≥ Jan. 1, 1972, in other circumstances	Ringelman 3 or 60% opacity Ringelman 2 or 40% opacity Ringelman 3 or 60% opacity Ringelman 2 or 20% opacity

Notes: Type 1 = Elements of antimony, arsenic, cadmium, lead, or mercury or any compound containing one or more of those elements
Type 2 = Elements of beryllium, chromium, manganese, nickel, selenium, tin or vanadium or any compound containing one or more of those elements
Standard fuel = any unused and uncontaminated solid, liquid or gaseous fuel that is: a) a coal or coal-derived fuel (other than any tar or tar residues), or b) a liquid or gaseous petroleum-derived fuel, or c) a wood or wood-derived fuel, or d) bagasse.
Source: Protection of the Environment Operations (Clean Air) Regulation 2002. Part 4 Emission of Air Impurities from Activities and Plant. www.legislation.nsw.gov.au

The 2002 Regulation establishes a framework for review of the suitability of the two oldest emission standard groups in the Regulation: Group 1 (pre-1972) and Group 2 (1972-1979). There are two stages to the review:

1. Equipment that is subject to Group 1 emission standards is required to meet Group 2 standards by 1 January 2008.
2. Equipment that is subject to Group 2 emission standards (including that previously in Group 1) is required to meet Group 5 standards by 1 January 2012.

In NSW, pollution is regarded as a criminal offense. Penalties for non-compliance with the emission standards include heavy fines and sometimes jail terms for offenders.

In addition to meeting the emission standards outlined in Table 1.1, stationary sources in NSW must undertake an air quality impact assessment. The purpose is to determine whether the impacts of the "sensitive receptors" surrounding the premises are acceptable, and whether further emission limits are required. The document *Approved Methods for the Modelling and Assessment of Air Pollutants in NSW* specifies the methods required by statute to be used to model and assess emissions of air pollutants from stationary sources in NSW.[lxxvii]

The NSW Department of Environment and Conservation has investigated the use of economic instruments, such as tradeable permits, "caps" on industrial NO_X emissions, and load-based licenses to reduce industrial emissions. Emissions of NO_X from power stations have been of particular concern because they account for most of NSW's industrial NO_X emissions. In July 1999, the Protection of Environment Operation (POEO) Regulation 1998 came into force which introduced a load-based licensing (LBL) scheme for power plants and industrial sources.[lxxviii] The LBL scheme sets limits on the loads of pollutants emitted by permit-holders and links license fees to emission loads. Table 1.2, outlines the pollutants from coal-fired electricity generation that are subject to these fees. The license fees are made up of an administrative fee and a load-based fee.

Table 1.2. Fee Rate Thresholds for Coal-Fired Electricity Generation under NSW Load-Based Licensing Scheme

Assessable Pollutants	Type	FRT Factor
Benzo(a)pyrene (equivalent)	Air	0.004
Coarse particulates	Air	80
Fine particulates	Air	54
Fluoride	Air	14
Nitrogen oxides	Air	2,700
Salt	Water	3.6
Selenium	Water	0.14
Sulfur oxides	Air	5,300
Total suspended solids	Water	0.18

Source: NSW Environment Protection Authority, "Load-based Licensing: A fairer system that rewards cleaner industry," April 2001. http://www.environment.nsw.gov.au/resources/lblbooklet.pdf

The load-based fee is determined by the pollutant, the amount emitted and the location of the activity. Weighted factors are used to increase the fee for targeted pollutants in sensitive areas. For example, NO_X emission fees are more expensive in western Sydney where ozone levels frequently exceed air quality standards. The goal is to create incentives for ongoing pollution reduction.

The fee formula for each assessable pollutant can be represented as:

Pollutant load fee = (AL x PW x CZ x PFU) / 10,000

or, where AL is greater than the FRT, the following equation should be used. In this case, the portion of the load that is in excess of the FRT (fee rate threshold) is charged double the rate:

Pollutant load fee = ((2AL - FRT) x PW x CZ x PFU) / 10,000

Where

AL = Assessable load. The pollutants for which load fees are payable for each type of licensed activity are called assessable pollutants. The fee is proportional to the assessable load (AL) of these pollutants, which is the least of the actual load (determined through the monitoring of emissions), the weighted load (where the actual load is discounted to reflect measures employed to reduce the harmfulness of discharges, such as effluent reuse), and the agreed load (a future load reduction committed to under a load reduction agreement with the EPA).

PW= pollutant weighting. Each assessable pollutant is given a pollutant weighting (PW), ranging from 0.5 to 930,000, to reflect its potential to inflict environmental damage. For water pollutants, weights vary depending on the type of receiving water (open coastal, estuarine or enclosed).

CZ - critical zone. A critical zone weighting (CZ) of between 1 and 7 applies for each assessable pollutant where there are excesses of pollutants in sensitive or overloaded environments.

PFU - pollutant fee unit. Pollutant fee units (PFUs) are the dollar value components of the load fee calculation formula which will gradually increase over the four-year phase-in period of the scheme.

FRT - fee rate threshold. Any portion of an assessable pollutant's load in excess of its fee rate threshold (FRT) is charged at double the rate. The FRT for coal-fired power is listed in Table 1.2. FRTs mark a level of performance readily achievable under Australian conditions, and provide a strong incentive for licensees to pursue early and easier gains in pollution reduction.

The LBL scheme has a relatively high threshold and emissions below this do not incur a fee. In its early years, the scheme did not generate enough economic drive to encourage emission reductions.[lxxix] NSW increased the fees in July 2004 because the Department of Environment and Conservation found that the fees did no have an impact on the bottom line of the regulated companies.[lxxx] The regulation covering the

LBL is currently being reviewed for its effectiveness. Depending on the findings of this review, the fees may be further increased.

In 1998, as part of the release of the *Action for Air* policy, NSW proposed a ceiling for industrial NO_X emissions which, if implemented, could have a significant impact on the operation of power stations the greater metropolitan area surrounding Sydney.[lxxxi] For example, a ceiling set at 1998 levels would have implications for coal-fired electricity generators by requiring investment in low NO_X burners or even in flue gas cleaning measures to reduce NO_X. Recent revisions to *Action for Air*, announced in 2006, modify the ceiling concept for industrial NO_X to focus on licensed sources within the three regions (Sydney, Hunter, and Illawarra) with the most critical air quality issues rather than the entire metropolitan region. The goal is to achieve cleaner air at a lower cost by targeting a smaller amount of polluters.[lxxxii]

Victoria

The Environmental Protection Authority (EPA) in Victoria requires approval and licenses for industries or operations under the Environment Protection (Scheduled Premises and Exemptions) Regulations of 1996. To get a license, coal-fired units must show that they are in compliance with the emission standards for stationary sources outlined in Tables 1.3 and 1.4. The 1996 regulations are due to expire in July 2007, and are currently under review. As a part of the review, the Draft Environment Protection (Scheduled Premises and Exemptions) Regulations 2007 and Regulatory Impact Statement for the Environment Protection (Scheduled Premises and Exemptions) Regulations 2007 have been posted on EPA's website, public comments have been collected, and final regulations are being prepared.[lxxxiii] The draft legislation includes a new section ordering premises with facilities for the capture, separation, or storage of waste carbon dioxide for the purpose of geological disposal to apply for a "works approval and license."

Table 1.3. Schedule D: Emission Limits for Existing Stationary Sources in Victoria

Pollutant	Applicable Sources	Emission Limit [1,2]	Notes
Particles	Solid fuel fired units All other units	$0.5\ g/m^3$ $0.25\ g/m^3$	Adjusted to 12 percent CO_2
Total particulate matter	All stationary sources	$0.5\ g/m^3$	
NOx	Fuel burning units (other than internal combustion engines and glass manufacturing plants) having a maximum heat input rate > 150 000 MJ/h gross	$1.0\ g/m^3$	Nitrogen calculated as NO_2 at a 7 per cent oxygen reference level[3] Emission limit = $\frac{CM\ (20.9 - \%\ O2\ reference)}{(20.9 - \%\ O2\ measured)}$
Lead and compounds	All stationary sources	$10\ mg/m^3$ expressed as lead	

1 Gas volumes are expressed dry at 0¡ C and an absolute pressure of one atmosphere (101.325 kPa).
2 Dilution of wastes to meet emission limits shall not be permitted except where noted.
3 CM is the measured concentration of NOx in g/m^3. Oxygen concentrations are expressed on a volumetric basis.
Source: Victoria Government Gazette. State Environment Protection Policy (Air Quality Management), No. S 240 Friday 21 December 2001 http://www.gazette.vic.gov.au/Gazettes2001/GG2001S240.pdf

Table 1.4. Schedule E: Emission Limits for New Stationary Sources in Victoria

Pollutant	Applicable Sources	Emission Limit [1,2]	Notes
Particles	a. All stationary sources except as described hereunder b. Incinerators with design burning rates of ≤300 kg/hr	$0.25\ g/m^3$ 0.5 g/m3	Adjusted to12 percent CO_2
Total particulate matter	All stationary sources except incinerators with design burning rates of ≤300 kg/ht	$0.25\ g/m^3$	
NOx	Fuel burning units (other than internal combustion engines and glass manufacturing plants) having a max. heat input rate > 150 000 MJ/h gross except as described hereunder	a. $0.35\ g/m^3$ for gaseous fuels b. $0.5\ g/m^3$ for liquid or solid fuels	Nitrogen calculated as NO_2 at a 7 percent oxygen reference level[3] Emission limit = $\frac{CM\ (20.9 - \%\ O_2\ \text{reference})}{(20.9 - \%\ O_2\ \text{measured})}$
	Boilers for electricity generation rated output ≥ 250 MW	0.7 g/m3 for solid fuels	This limit may be relaxed to 0.78 g/m^3 in cases where it can be shown that $0.7\ g/m^3$ is too restrictive in relation to the type of fuel being burned, existing emission control technology and factors of health and safety.
	Gas turbines for electricity generation: - Rated output ≥ 30 MW - Rated output < 30 MW	 $0.07\ g/m^3$ for gaseous fuels $0.15\ g/m^3$ for other fuels $0.09\ g/m^3$ for gaseous fuels	Calculated as NO_2 at a 15 percent oxygen reference level[3].
Carbon monoxide	All stationary sources except internal combustion engines and cold blast cupolas	$2.5\ g/m^3$	

1 Gas volumes are expressed dry at 0¡ C and an absolute pressure of one atmosphere (101.325 kPa).
2 Dilution of wastes to meet emission limits shall not be permitted except where noted.
3 CM is the measured concentration of NOx in g/m^3. Oxygen concentrations are expressed on a volumetric basis.
Source: Victoria Government Gazette. State Environment Protection Policy (Air Quality Management), No. S 240 Friday 21 December 2001 http://www.gazette.vic.gov.au/Gazettes2001/GG2001S240.pdf

South Australia

Emission legislation in South Australia is implemented on a license basis through the approval of Environment Improvement Plans to promote best practice environmental management. Emission limits are generally as follows:

Particulates	$250\ mg/m^3$ (12% CO_2 basis)
NO_X (>250 MWth)	$700\ mg/m^3$ (7% O_2 basis)

Tasmania

Tasmania's Environment Protection Policy (Air Quality) 2004 which came into effect on June 1, 2005 provides a framework for the management and regulation of both point and diffuse sources of emissions to the air. Relevant emission standards for electricity generation are outlined in Table 1.5.

Table 1.5 Emission Standards in Tasmania

Pollutant	Source	In-stack concentration (mg/m^3)
NOx	Any boiler operating on gas	350 (as NO_2)
	Any boiler operating on a fuel other than gas, other than a boiler used in connection with an electricity generator	500 (as NO_2)
	Any boiler operating on a fuel other than gas, being a boiler used in connection with an electricity generator of ≤ 30 MW	500 (as NO_2)
	Any boiler operating on a fuel other than gas, being a boiler used in connection with an electricity generator of ≥ 30 MW	800 (as NO_2)
	Any gas turbine operating on gas, being a turbine used in connection with an electricity generator of ≤ 10 MW	90 (as NO_2)
	Any gas turbine operating on gas, being a turbine used in connection with an electricity generator of ≥ 10 MW	70 (as NO_2)
Particulate matter	Any trade, industry or process and any fuel burning equipment or industrial plant	100

Source: Tasmania Department of Primary Industries, Water and Environment, *Environment Protection Policy (Air Quality) 2004* http://www.dpiw.tas.gov.au/inter.nsf/WebPages/CDAT-53M4U8#EPP

Other States and Territories

Western Australia is in the process of developing a State air environmental protection policy to implement the NEPM and adopt the Australian National Emission Standards.[lxxxiv] The Australian Capital Territory passed the Environment Protection Regulation 2005 under the Environment Protection Act 1997, but this regulation does not have emission standards for power generation.[lxxxv] Like most other Australian states, Queensland has its own requirements based on licenses and approvals.

1.1.2 Mercury

Australia does not regulate emissions of mercury from coal-fired power plants. In April 2004, Environment Australia adopted a new Air Toxics NEPM for industrial sources and power plants. It includes several organic compounds such as benzene, toluene, xylene and other polycyclic aromatic hydrocarbons. However, it does not cover mercury.[lxxxvi]

1.1.3 Carbon Dioxide

In Australia, there is no national regulatory requirement for the control of CO_2 from power stations. However, several measures to track emissions and encourage reductions are under development.

In June 2006, the National Environment Protection Council (NEPC) released a draft variation to the National Pollutant Inventory – the National Environment Protection Measure (NPI-NEPM) – that contains a proposal to include greenhouse gas emissions, such as CO_2, in the NPI. However, at its meeting on 14 July 2006, in relation to energy and greenhouse gas emissions reporting, the Council of Australian Governments (COAG) agreed that the National Pollutant Inventory (NPI) would not be used as a vehicle for reporting greenhouse gas emissions. Instead, COAG agreed to make every effort to reach agreement on a national purpose-built legislation on a

GHG reporting framework by December 2006. States and Territories reserved the right to use the NPI if the Commonwealth, States and Territories failed to reach agreement on national purpose-built legislation.

Since then, climate change has been high on the agendas of both COAG and the Council for the Australian Federation (CAF) and the design of a national emissions trading scheme has been prominent in these discussions. In April 2007, COAG decided to establish a mandatory national greenhouse gas emissions and energy reporting system, with the design to be settled after the release of the Prime Minister's task group on emissions trading reports at the end of May 2007. CAF resolved that robust emissions reporting is a fundamental pre-requisite of any emissions trading scheme and that, if the Commonwealth has not introduced legislation in time for the national greenhouse and energy reporting system to be activated by 1 July 2008, the State and Territories will require reporting from this date through the NPI as an interim measure.

As a consequence of these developments, the NEPC Committee (with the Commonwealth dissenting) has directed that greenhouse gas emissions reporting be included in the proposed NPI NEPM variation as an option for consideration by NEPC at its June 2007 meeting. The Committee noted that this should not change the commitment by all parties to work towards a new purpose-built system.

In early June 2007, the Prime Ministerial Task Group on Emissions Trading (the Task Group) released its final report. Immediately following this, the Prime Minister responded to the Task Group's report, announcing his intention to implement a domestic emissions trading scheme by 2012 at the latest. The key recommendations of the Prime Ministerial Task Group include:[lxxxvii]

- Trading must commence in 2011 and a mechanism to monitor, report and verify emissions data must be in operation before 2011.
- The government will set a long-term goal for emission reductions and a series of short-term annual caps for overall emissions, initially to 2020.
- Annual caps for overall emissions would be supplemented by ten-year gateways, which would provide upper and lower bounds for emissions caps for the years 2021 to 2030. The annual caps and gateways would be updated at five-yearly scheme reviews.
- The scheme is likely to cover stationary energy, fugitives, industrial processes and transport, where facility-level emissions exceed 25kt CO_2 equivalent. Coverage would be of direct emissions from large facilities, with some upstream coverage of fuel suppliers.
- Free permits would be issued to:
    - Existing businesses that are likely to suffer a disproportionate loss from the introduction of a carbon price (i.e., fossil fuel-fired generators). These free permits will only be available to firms that made investment decisions in advance of the announcement that an emissions trading scheme would be implemented. While there is no specific cut-off date for new generators in the Task Group's report, the relevant 'announcement' may have come on the day the Prime Minister declared his intention to proceed with emissions trading; and

- Trade-exposed, emissions-intensive industries, whose competitiveness may be affected by the cap. The report does not define what qualifies as a trade-exposed, emissions-intensive industry.
- Periodic auctioning of remaining permits for the period 2011 to 2020. A small number of future-dated permits beyond 2020 would also be periodically auctioned.
- An emissions fee would be imposed for non-compliance. The fee would be set low during early years and would increase over time.
- Payment of the emissions fee would effectively 'buy out' a firm's obligation to meet its cap. This is to provide a 'safety valve' against the possibility of excessively high permit prices.
- Banking of dated emission permits for use against future emissions liabilities would be permitted while borrowing of permits from future vintages would not.
- GHG offsets will be recognized, including early action measures undertaken starting 2008.

Australia's emissions trading system could eventually be linked with New Zealand's emerging system. In June 2007, Prime Ministers Helen Clark and John Howard announced that they plan to collaborate on a regional carbon trading system in Australia and New Zealand.[lxxxviii] The announcement is part of recent moves towards closer economic relations and a single economic market between the two economies.

In addition to the national developments, regulation of greenhouse gases has also occurred at the state and territorial level. Several states and territories have initiated programs to encourage greenhouse gas emission reductions in the energy sector, for example through renewable energy targets, but only New South Wales has developed a system that directly regulates coal-fired electricity generators. This program, which is based on emissions trading, is described below.

NSW Greenhouse Gas Reduction Scheme (GGAS)

The NSW Greenhouse Gas Reduction Scheme (GGAS) commenced on 1 January 2003 and aims to reduce greenhouse gas emissions[6] associated with the production and use of electricity. It achieves this by using project-based activities to offset the production of greenhouse gas emissions.

GGAS establishes annual statewide greenhouse gas reduction targets, and then requires individual electricity retailers and other parties who buy or sell electricity in NSW to meet mandatory benchmarks based on the size of their share of the electricity market. If these parties, known as benchmark participants, fail to meet their benchmarks, a penalty is assigned. The *Electricity Supply Amendment (Greenhouse Gas Emission Reduction) Act 2002* sets a State greenhouse gas benchmark expressed in tonnes of carbon dioxide equivalent (CO_2-equivalent) per capita.[lxxxix] The initial level was set at the commencement of GGAS in 2003 at 8.65 tonnes. The benchmark progressively dropped to 7.27 tonnes in 2007 which represents a reduction of five

[6] Regulated greenhouse gases include carbon dioxide, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons, and sulfur hexafluoride,

percent below the Kyoto Protocol baseline year of 1989-1990. The per capita amount continues at this level until 2021.

GGAS imposes mandatory greenhouse gas benchmarks on all holders of NSW electricity retail licenses, electricity generators prescribed by the regulations that supply directly to retail customers, and market customers which take their electricity supply directly from the National Electricity Market (NEM) and have an electricity load that is classified as a market load with the National Electricity Market Management Company (NEMMCO). GGAS also allows customers with electricity loads greater than 100 GWh (where at least one site consumes 50 GWh per year) or people carrying out State significant development as designated by the Minister for Planning under the NSW planning legislation, to elect to manage their own greenhouse gas benchmarks. At the time of writing, the scheme has 38 benchmark participants, 27 of which are mandatory.

Benchmark participants can reduce the average emissions intensity of the electricity they supply or use by purchasing abatement certificates and surrendering these to the Independent Pricing and Regulatory Tribunal (IPART) in its capacity as Compliance Regulator. Benchmark participants can also claim credit for the surrender of Renewable Energy Certificates (RECs) under the Commonwealth's Mandatory Renewable Energy Target (MRET). Accredited abatement certificate providers may carry out one or more of the following abatement activities:

- Low-emission generation of electricity and improved generator efficiency;
- Activities that result in reduced consumption of electricity, including on-site electricity generation;
- The capture of carbon from the atmosphere in forests; and
- Activities carried out by elective participants that reduce on-site emissions not directly related to electricity consumption.

Benchmark participants can choose to carry forward to the following year a greenhouse shortfall of up to 10 per cent of their benchmark without having to pay a penalty. Any shortfall carried forward must be abated the following year.

Benchmark participants incur a financial penalty of AUD$ 11.00 (US$ 9.2) per tCO_2 equivalent if they choose not to carry forward any shortfall or for any amount of shortfall in excess of the 10 percent allowable limit. Also if the amount carried forward is not abated in the following year, the benchmark participant will be subject to a penalty at the end of that year.

To date, the regulatory market for carbon credits created by the NSW scheme has been limited, in part because many companies have managed their emissions liabilities internally rather than through the purchase of offsets on the open market.[xc] The AUD$ 11 penalty provides some financial incentive for abatement activities in the power sector, but is insufficient to lead to significant investment in clean coal technology, which is more likely to occur at a price of US$ 30 and above. Most of the abatement generated in the scheme comes from efficiency improvements or low-emission electricity generation, such as renewables.[xci]

1.2 Water Consumption and Effluent Standards

Individual states and territories are generally responsible for the management, quality, and delivery of water, with the Australian Government playing a collaborative role in the Murray Darling Basin. The National Water Quality Management Strategy (NWQMS) has been jointly developed since 1992 by the Australian Government in cooperation with state and territory governments, currently under the Natural Resource Management Ministerial Council. Other ministerial councils have also been involved for some issues. The NWQMS is part of the Council of Australian Governments' (COAG) Water Reform Framework and provides part of the overall framework that states and territories follow to implement their water management strategies, set water consumption standards, and develop effluent targets. The NWQMS has three major elements: policies, process and guidelines. The NWQMS process involves community and government development and implementation of a management plan for each catchment, aquifer, estuary, coastal water or other water body. This includes use of high-status national guidelines with local implementation.[xcii]

Faced with critical water supply and water quality problems the government is taking a greater role in the management of water resources. A National Plan for Water Security was announced by the Prime Minister in January 2007 to accelerate the implementation of a National Water Initiative. Water that accrues to the Australian Government through the National Plan for Water Security will be managed to achieve environmental outcomes, such as restoring the health of rivers and wetlands in the Murray-Darling Basin.[xciii] States and territories will use the guiding principles from this Plan to develop standards for individual industries.

1.3 Waste Products

The specific regulations on coal combustion products and ash disposal vary from jurisdiction to jurisdiction (state by state) and are generally fixed with the expected life of the particular power station site.[xciv] Where sites seek an extension of operations, the required approvals are on a case by case basis.

A process to update the NPI NEPM to include ‘transfers’ is underway. A transfer is the transport or movement of an NPI substance contained within a waste for end use including containment, destruction, treatment, or energy recovery (e.g., in the case of transfer of ash from a power station to a storage site the plant would now have to report on any relevant substances contained in the ash). If the substance is removed from a facility for recycling, reprocessing or reuse it is also a transfer. The additional cost of reporting on these substances is not expected to be high because many facilities already report this information at the state and territorial level.[xcv] Documentation regarding the draft NIP NEPM change is available from the EPHC website.[xcvi] It is anticipated COAG will make a decision on this matter in June 2007.

The following discussion of New South Wales provides an example of waste regulation at the state level.

New South Wales

Coal combustion products (fly and bottom ash) and ash disposal in New South Wales is regulated under the framework of the Protection of the Environment Operations Act 1997 (POEO Act) which defines 'waste' for regulatory purposes and establishes management and licensing requirements along with offence provisions to deliver environmentally appropriate outcomes.

The Act requires regulation of the following electricity generators and their associated water storage, ash and waste management facilities: [xcvii]

(1) Facilities that supply or are capable of supplying more than 30 MW of electrical power from energy sources (including coal, gas, bio-material or hydro-electric stations), but not from solar powered generators, or
(2) Are within the metropolitan area of Sydney, Newcastle and Wollongong and are based on or use:
    (a) gas turbines, which are capable of burning fuel at a rate of more than 20 MW on a net thermal energy basis, or
    (b) internal combustion piston engines, which are capable of burning fuel at a rate of more than 3 MW on a net thermal energy basis.

Landfills that only receive ash from the electricity generators listed above or that receive non-hazardous ash generated from any power plant do not have to be licensed.[xcviii] However, this does not mean that coal ash is entirely unregulated. The *Protection of the Environment Operations (Waste) Regulation 2005* makes requirements relating to non-licensed landfills, non-licensed waste activities and non-licensed waste transportation. This includes the way in which waste must be stored or transported and requirements for reporting and record-keeping. For example, the Regulation requires that coal ash must be tracked when it is transported within New South Wales and to interstate destinations. It also provides a methodology for calculating the contributions to be paid by the occupiers of waste facilities for each tonne of waste received or generated in a particular area.

Finally, the Act specifies the types of waste that can and cannot be used for the purposes of growing vegetation. It mainly excludes industrial residues such as fly ash and bottom ash. However, in this case, a special exemption has been made for ash from the burning of New South Wales or Queensland coal if the in-ash contaminant of this product prior to blending, mixing, or processing does not exceed the concentrations listed in Column 2 of Table 1.6.[xcix]

Table 1.6 Maximum Contaminant Concentrations in Exempt Fly Ash and Bottom Ash

Contaminant	Maximum Concentration
Boron (mg/kg)	60
Electrical conductivity ECse (dS/m)	4

Source: Department of Environment and Conservation, "Protection of the Environment Operations (Waste) Regulation 2005—General Exemption Under Part 6: The Fly Ash and Bottom Ash From Burning NSW or Queensland Coal Exemption 2006.
http://www.environment.nsw.gov.au/resources/flyashnov2006.pdf

2. Canada

2.1 Air Emissions

2.1.1 NO_X, SO_2, and Particulates

Environment Canada's long-term goal for coal- and oil-fired plants is “clean as gas” for all pollutants. The term "clean as gas" is generally understood within Environment Canada to mean air emissions comparable to those of an efficient, natural gas-fired combined cycle generating unit.

Under the Canadian Environmental Protection Act 1999 (CEPA 1999), Environment Canada has published New Source Emission Guidelines for Thermal Electricity Generation. These Guidelines are intended to provide advice on emission standards to regulatory authorities for new coal, oil and gas-fired steam-electric plants. The suggested SO_2, NO_X, and PM_{10} emission standards are outlined in Table 2.1. There are no federal emission guidelines for $PM_{2.5}$. The guidelines are based on the energy output of the plant rather than an emission concentration. The guidelines will be revised over time to include mercury and to reflect new technology.

Table 2.1 Guidelines for National Emission Standards for New Thermal Electricity Generation

SO_2	NO_X	PM_{10}
Kg/MWh per net energy output **Based on the hourly mean rate of discharge of SO_2, NO_X, or PM_{10} emitted over successive 720 hour rolling average periods**		
4.24 (and 8% of the uncontrolled emission rate); or 2.65 (and 25% of the uncontrolled emission rate); or 0.53	0.69	0.095

Note: The uncontrolled emission rate of SO_2 from a generating unit in kg/MWh is calculated using the following formula:

(A/B) x C x (1000 MJ/1 GJ) x D

where:
A is the sulfur concentration in fuel expressed in the decimal form of a percentage, on a dry basis;
B is the higher heating value of fuel in MJ/kg;
C is a constant of 2, representing the ratio of molecular weight of SO_2 to molecular weight of sulfur;
D is a constant of 10.6 GJ/MWh, representing the reference net plant heat rate in GJ/MWh.
Source: Environment Canada, “New Source Emission Guidelines for Thermal Electricity Generation,” http://www.ec.gc.ca/CEPARegistry/documents/glines/thermal/gl.cfm

Also under CEPA, any facility (including coal-fired power plants) may be required to implement a pollution prevention plan which may then be used to develop further control measures (including regulations) if they are deemed necessary to achieve the desired environmental results.

Using the national standards outlined in Table 2.1, the provinces and territories are responsible for implementing regulatory requirements for power generation resulting in significant variation from region to region. Most emission standards for coal-fired plants in Canada are decided on a case by case basis. Emission limits for existing plants vary according to regional air quality considerations. In some cases, emission standards can take the form of emission caps for prescribed regions. This allows further variation in emission limits for different plants.[c]

In October 1998, federal, provincial and territorial Energy and Environment Ministers signed the Canada-Wide Acid Rain Strategy for Post 2000. The strategy laid the framework for how Canada would manage acid rain in the future. As part of this plan, the eastern provinces of Ontario, Quebec, New Brunswick and Nova Scotia were required to develop targets and timelines for achieving critical loads for wet sulphate deposition. At the time of the agreement, modeling suggested that, in order to reach this goal, SO_2 emissions in Ontario and Quebec would need to be reduced by 75 percent from their existing caps and by 30 to 50 percent from the existing caps in New Brunswick and Nova Scotia.[ci] Targets and schedules for these SO_2 emission reductions were established by each jurisdiction.

Environment Canada has also developed Environmental Codes of Practice for Steam Electric Power Generation (SEPG) which consists of a series of five reports that identify good environmental practices for various stages of a steam electric power project. The Codes of Practice encompass the siting, design, construction, operations and decommissioning phases of the power plant life cycle and deal with multi-media (air, water and land) considerations.[cii]

2.1.2 Mercury

Under the Canadian Council of Ministers of the Environment (CCME) the Government of Canada along with provincial and territorial governments—except Québec—entered a Canada-wide Standard (CWS) agreement to establish stringent mercury emission rates for new coal-fired units. The CWS agreement will also cap the emissions of mercury from existing plants; by 2010, this existing plant cap is set to reduce emissions by 45 percent relative to 2003. The CWS consist of two sets of targets:[ciii]

- provincial caps on mercury emissions from existing coal-fired electric power generation (EPG) plants, with the 2010 provincial caps representing a 60 percent national capture of mercury from coal burned, or 70 percent including recognition for early action; and
- capture rates or emission limits for new plants, based on best available control technology, effective immediately.

The percent capture rates used for the targets are based on best available technologies economically achievable. A second phase of the CWS may explore the capture of 80 pecent or more of mercury from coal burned in 2018 and beyond.

According to the agreement, existing coal-fired electricity generating plants must meet the provincial caps for annual mercury emissions outlined in Table 2.2. The 2010 national total represents mercury emission reductions from 2003/04 levels of approximately 52 percent, or 58 percent including recognition for early action. Each individual province and territory must develop an implementation plan for how these caps are implemented.

Table 2.2 Provincial Caps for Annual Mercury Emissions from Coal-fired Plants

Province	Estimated Emissions in 2002—2004 (kg/yr)	2010 Cap (kg/yr)
Alberta	1,180[1]	590
Saskatchewan	710	430[2]
Manitoba	20	20
Ontario	495	[3]
New Brunswick	140	25
Nova Scotia	150	65
Total	**2,695**	**1,130[4]**

Notes: [1] Alberta's commitment is through the implementation of the Clean Air Strategic Alliance Electricity Project Team recommendations. Alberta emissions are based on a 90% capacity factor.
[2] Saskatchewan's early actions, between 2004 and 2009, will be used to meet its provincial caps for the years 2010 to 2013. Examples of early actions include a mercury switch collection program and early mercury controls at the Poplar River Power Station.
[3] Ontario will help meet the CWS of 60% capture of mercury by 2010, and help exceed it in the near future with an ultimate Ontario goal of 0 mercury emissions from coal-fired power generation. The Lakeview coal-fired electricity generating station was closed in 2005. Ontario is committed to phasing out coal-fired electricity, and within 12 months Ontario will finalize its mercury emission plan for 2010.
[4] The percent capture rate is based on best available technologies economically achievable.
Source: Canadian Council of Ministers of the Environment, "Canada-wide Standards for Mercury Emissions from Coal-Fired Electric Power Generation Plants," October 2006 http://www.ccme.ca/assets/pdf/hg_epg_cws_w_annex.pdf

Mercury emissions from new facilities[7] are not included in the provincial caps for existing facilities. Instead, a new coal-fired unit must capture mercury from coal burned at no less than that specified in Table 2.3 or an average annual mercury emission rate no greater than that specified in Table 2.3.

Table 2.3 Provincial Mercury Emission/Capture Standards for Coal Coal-fired Plants

Coal type	Percent capture in coal burned* (%)	Emission rate* (kg/TWh)
Bituminous coal	85	3
Sub-bituminous coal	75	8
Lignite	75	15
Blends	85	3

Notes: * The capture/emission rate is based on best available technologies economically achievable.
Source: Canadian Council of Ministers of the Environment, "Canada-wide Standards for Mercury Emissions from Coal-Fired Electric Power Generation Plants," October 2006 http://www.ccme.ca/assets/pdf/hg_epg_cws_w_annex.pdf

[7] A new facility includes any coal-fired steam generating unit, including a unit which replaces an existing coal-fired steam generating unit with equivalent technology or with any other steam generating technology which is based on coal combustion, for which first permit approval occurs after October 2006.

2.1.3 Carbon Dioxide

Recently, the Canadian Government started moving towards integrated control of air pollutants and greenhouse gases. In October 2006, the Government of Canada issued a Notice of Intent in the Canada Gazette outlining the Government's plan to regulate the electricity and other sectors with respect to air emissions, defined as air pollutants (SO_2, NO_X, PM_{10}, and mercury) and greenhouse gases (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).[civ] The regulations, targets, and timelines will be developed through a consultative process involving provinces, territories, and other stakeholders and will take place throughout 2007 and 2008. The announcement also suggests the development of incentives or credits for investments in technology such as carbon capture and storage and the development of a technology investment fund to support the development of transformative technologies for emission reductions.

As outlined in Table 2.4, the announcement proposes a set of short, medium, and long-term targets designed to provide certainty for investors and encourage emitters to coordinate consideration of the air pollutant and GHG requirements in their capital stock investment decisions. Noteworthy for the proposed targets is the focus on greenhouse gas emissions intensity (greenhouse gas emissions per unit of economic output, or GDP) rather than absolute reductions during the first 20 years of the program. Greenhouse gas emissions could therefore continue to rise during these years, creating few near-term incentives for real reductions and technology investments.

Table 2.4 Proposed Targets and Time Tables for Regulating Air Emissions in Canada

Time Period	Type of Target	
	Air Pollutants	GHGs
Short-term (2010-2015)	Fixed cap	Emissions intensity
Medium-term (2020-2025)	Fixed cap	Emissions intensity Target must lead to absolute reductions and support establishment of a fixed cap
Long-term (2050)	Fixed cap	Fixed cap By 2050, reduction of 45-65 percent below 2003 levels

Source: Canada Gazette, "Government Notices: Notice of Intent to Develop and Implement Regulations and Other Measures to Reduce Air Emissions," Vol. 140, No. 42 — October 21, 2006 http://canadagazette.gc.ca/partI/2006/20061021/html/notice-e.html#i3

Several developments in early 2007 may eventually lead to further national regulation of Canada's coal-fired power sector. In April 2007, following extensive critique of the proposed emissions intensity targets, the Government announced an absolute national greenhouse emission reduction target of 20 percent below 2007 levels by 2020.[cv] The target would be reached partly by imposing stringent targets on industry so that air pollution is cut in half by 2015. The plan requires Canadian facilities to reduce greenhouse gas emissions - not in absolute terms, but per unit of production - by 18 per cent by 2010 and by 26 percent by 2015. This would result in an average yearly reduction of 6 percent for the next three years until 2010 and a further reduction of 2 percent thereafter. According to the plan, Canada will also set up a domestic emissions trading scheme with a baseline-and-credit approach. Each company's emissions intensity target is its baseline, and firms will be able to buy or sell credits depending on whether they meet it. Companies will also be able to buy credits from greenhouse gas emissions offsets projects to help comply with their emissions targets. However, the government has not yet defined what types of offsets will be eligible.[cvi]

Dissatisfied with the April 2007 announcement, Canada's parliament passed a bill in June 2007 requiring the government to develop a plan within 60 days for how it would comply with Canada's Kyoto Protocol target of reducing emissions by 6 percent below 1990 levels by 2012.[cvii]

In addition to the national developments outlined above, several Canadian provinces have developed GHG targets and emission reduction strategies that will have a direct influence on coal-fired power plants. These strategies, which were all introduced in late 2006 or early 2007, are outlined in Table 2.5. They represent a wide range of emission reduction measures affecting coal-fired power, including a carbon-based fuel tax in Quebec, a requirement that all new coal-fired plants in British Columbia must include CO_2 capture and storage, a phase-down of coal in Manitoba, and the complete phase-out of coal in Ontario by 2014. In addition, the Premiers of Canada's provinces and territories have agreed to start a national registry for reporting of entity emissions.

Table 2.5 Provincial GHG Regulations, Targets, and Emission Reduction Strategies Affecting Coal-fired Power

State	Target	Emission Reduction Strategies Affecting Coal-fired Power
Alberta	Emissions intensity 50% below 1990 levels by 2020.	Starting 2007, existing industrial facilities that emit ≥100,000 tonnes of CO_2e must reduce their GHG emissions intensity by 12%. New large facilities (in operation after 2000) have a 6-year graduated target that will evolve to 12%.
British Columbia	GHG emissions 33% below 2007 level by 2020	100% carbon capture and storage at any new coal-fired electricity project. Member of Western Regional Climate Action Initiative to set a common cap and introduce emission trading Member of multi-state The Climate Registry requiring emitters to submit annual GHG inventories
Manitoba	N/A	Member of Western Regional Climate Action Initiative to set a common cap and introduce emission trading Proposal to phase-down the province's coal-fired power plant
New Brunswick	GHG emissions at 1990 levels by 2012	
Ontario	GHG emissions 6% below 1990 level by 2014 15% below 1990 by 2020	Phase out coal-fired power by 2014

State	Target	Emission Reduction Strategies Affecting Coal-fired Power
	80% below 1990 by 2050	
Quebec	GHG emissions 6% below 1990 level by 2012	Tax based on carbon content of fuel sold to retailers to be developed by end 2007.
Saskatchewan	GHG emissions at 2004 level by 2010 32% below 2004 by 2020 80% below 2004 by 2050	Ensure SaskPower's new and replacement generation facilities are emissions-free or fully offset by emission credits. Develop a conservation program to reduce SaskPower's electricity load by 300 MW by 2017. Incentives for carbon capture and storage.

2.2 Water Consumption and Effluents

All provinces and territories in Canada have water pollution control regulations. For the most part, waters that are solely within a province's boundaries fall within the constitutional authority of that province and, as a result, it is also responsible for regulating water issues related to thermal and hydroelectric power development and operation.[cviii] This leads to some variation in effluent and water consumption standards across provinces, with each jurisdiction taking a slightly different approach. Ontario, for instance, views water as a public resource rather than a crown resource. The privilege to produce hydroelectricity is conveyed not by ownership of the water, but by ownership of the river bed and bank. Put another way, rather than paying for the water, hydroelectric firms pay for the occupation of land and the infrastructure that enables them to generate electricity. British Columbia, in contrast, takes a rights-based approach in which any stakeholder using water must compensate the rights of other affected parties. Moreover, as illustrated in the following description of Ontario’s water regulations for electricity generation, the standards also differ for individual power stations within individual provinces.

Ontario recently restructured its main utility. Until 2002, the integrated monopoly was a crown agency. Although the provincial government remains the shareholder, Ontario Power Generation (which own the generators) and Hydro One (which owns the transmission lines) are no longer provincial agencies, but are considered commercial enterprises. The transition required public officials to consider how to govern restructured utilities in ways that balance social, economic, and environmental goals. The key environmental assessment process is known as the water management plan, which will be reviewed every seven-to-ten years. The government promises a “rigorous public process” that focuses on sustainability. (Quebec Hydro remains a provincial agency and integrated monopoly.) Ontario also recently changed how it taxes power plants. For many years, the province imposed property charges as well as water rental charges. The new approach is a gross revenue charge. Revenue from such charges will continue to go to the general fund rather than any dedicated account for energy or environmental enhancements.

2.2.1 Ontario

Water regulations for coal-fired power plants in Ontario cover both water management and effluent standards. The Ministry of Environment is responsible for implementing both of these.

Water Management: In terms of water consumption, Section 4 of the Ontario Water Resources Act requires all operations that extract more than 50,000 liters of water per day to obtain Permits to Take Water (PTTW). In 2000, the Ministry of the Environment established a review process for obtaining these permits.[cix] If the water is taken from a groundwater source, a hydrogeological report is normally needed, including the results of a pump test on the well water to ensure that the amount to be taken is sustainable in the long term, will not interfere with adjacent properties, and will have no detrimental effect on the ecosystem. If the water is to be taken from a surface source (lake/stream/pond) the applicant must provide information such as available stream flow, use of the stream by other people for water, and the potential impact of the water-taking on other water uses. Based on this, the Ministry will make a determination regarding the amount of water that an entity may use according to a fair-share concept that takes into account how the water use will affect others along the watercourse.

Most PTTWs carry conditions that require the permit holder to perform certain monitoring functions and/or maintain a record of water use that the ministry can view upon request. For surface water takings, the permit holder may be limited to a percentage of available stream flow. Again, the ministry has the ability to impose special conditions to address issues unique to the individual application.

All applications are subject to public comment. Permit applications must be posted on the Environmental Bill of Rights (EBR) environmental registry for a 30-day public comment period. Comments received are noted and considered by the ministry in each decision. Should a decision on a permit be disputed, Ontario residents may appeal under the EBR and present arguments for overturning a ruling.

Penalties for non-compliance can range from cancellation of a permit, to a CAD$305 Provincial Offences ticket, and ultimately to court prosecution with fines upon conviction of up to CAD$20,000 for a first offence and CAD$200,000 for a subsequent conviction.

Effluent Standards: Ontario's Environmental Protection Act controls the discharge of pollutants to the natural environment, including Ontario's waters.[cx] Based on this, the Ministry of Environment has published a set of general policies and guidelines for water management in the document *Water Management - Policies, Guidelines, Provincial Water Quality Objectives of the Ministry of the Environment.*[cxi] All industry sectors are encouraged to produce pollution prevention strategies and environmental management systems to reduce pollution. These strategies are voluntary, except where they are used to achieve regulated standards.

The Municipal Industrial Strategy for Abatement (MISA) under the Environmental Protection Act sets emission limits for major industrial sectors, including electric power generation. The relevant monitoring and effluent standards for coal-fired power generation are spelled out in Ontario Regulation 240/07 and are listed in Tables 2.6 and Table 2.7 below.[cxii] The standards differ according to the process streams from the power plant. As outlined in Table 2.6, treated ash transport water, effluents from water treatment plants, boiler seal water, ash quench water, and effluent from an oily water separator have a mix of TSP, aluminum, iron, and oil and grease standards. Meanwhile, as illustrated in Table 2.7, effluents from a coal storage site and from cleaning and maintenance have a different set of TSP and iron standards, with one plant also being regulated for aluminum.

Table 2.6 Types of Non-Event Process Effluent Streams, Effluent Limits, and Monitoring Frequency Related to Coal-Fired Power Plants in Ontario

PLANT: Atikokan TGS					
ATG	Parameter	Types of NonEvent Process Effluent Streams	Monitoring Frequency	Daily Concentration Limit	Monthly Average Concentration Limit
				mg/L	mg/L
	Column 1	Column 2	Column 3	Column 4	Column 5
8	Total Suspended Solids	ATWE	D	70.0	25.0
		WTPE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		WTPE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		WTPE	W	2.50	1.0
25	Oil and grease	OWSE	W	29.0	13.0
PLANT: Lakeview TGS (Shut Down in 2005)					
8	Total Suspended Solids	ATWE	D	70.0	25.0
		BSWE	D	70.0	25.0
		AQWE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		BSWE	W	13.0	4.50
		AQWE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		BSWE	W	2.50	1.0
		AQWE	W	2.50	1.0
25	Oil and grease	OWSE	W	29.0	13.0
PLANT: Lambton TGS					
8	Total Suspended Solids	ATWE	D	70.0	25.0
		BSWE	D	70.0	25.0
		AQWE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		BSWE	W	13.0	4.50
		AQWE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		BSWE	W	2.50	1.0
		AQWE	W	2.50	1.0
PLANT: Nanticoke TGS					
8	Total Suspended Solids	ATWE	D	70.0	25.0
		BSWE	D	70.0	25.0
		AQWE	D	70.0	25.0
		ATLE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		BSWE	W	13.0	4.50
		AQWE	W	13.0	4.50
		ATLE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		BSWE	W	2.50	1.0

ATG	Parameter	Types of NonEvent Process Effluent Streams	Monitoring Frequency	Daily Concentration Limit	Monthly Average Concentration Limit
PLANT: Atikokan TGS					
				mg/L	mg/L
		AQWE	W	2.50	1.0
		ATLE	W	2.50	1.0
PLANT: R.L. Hearn TGS (Shut Down)					
8	Total Suspended Solids	ATWE	D	70.0	25.0
		WTPE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		WTPE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		WTPE	W	2.50	1.0
25	Oil and grease	OWSE	W	29.0	13.0
PLANT: Thunder Bay TGS					
8	Total Suspended Solids	ATWE	D	70.0	25.0
		WTPE	D	70.0	25.0
9	Aluminum	ATWE	W	13.0	4.50
		WTPE	W	13.0	4.50
9a	Iron	ATWE	W	2.50	1.0
		WTPE	W	2.50	1.0
25	Oil and grease	OWSE	W	29.0	13.0

Explanatory Notes:
Types of Non-Event Process Effluent Streams:
ATWE = Ash transport water that has received treatment, whether or not it is combined with cooling water or storm water effluent.
WTPE = Effluent that is discharged from a water treatment plant at a plant, whether or not it is combined with cooling water or storm water effluent.
BSWE = Boiler seal water, whether or not it is combined with cooling water or storm water effluent.
AQWE = Ash quench water, whether or not it is combined with cooling water or storm water effluent.
OWSE = Effluent that is discharged from an oily water separator on a continuous basis at a plant, whether or not it is combined with cooling water or storm water effluent.
ATLE = Ash transport water that has not received treatment, whether or not it is combined with cooling water or storm water effluent.
ATG Analytical Test Group
mg/L milligrams per liter
D Daily monitoring requirement
W Weekly monitoring requirement

Source: Environmental Protection Act, Ontario Regulation 215/95, Amended to O. Reg. 240/07 Effluent Monitoring and Effluent Limits — Electric Power Generation Sector http://www.e-laws.gov.on.ca/DBLaws/Regs/English/950215_e.htm

Table 2.7 Types of Event Process Effluent Streams, Effluent Limits, and Monitoring Frequency Related to Coal-Fired Power Plants in Ontario

ATG	Parameter	Types of Event Process Effluent Streams	Monitoring Frequency	Daily Concentration Limit mg/L	Monthly Average Concentration Limit mg/L
PLANT: Atikokan TGS					
	Column 1	Column 2	Column 3	Column 4	Column 5
8	Total Suspended Solids	CSSE	D	25.0	-
		ECE	D	25.0	-
9a	Iron	CSSE	D	1.0	-
		ECE	D	1.0	-
PLANT: Lakeview TGS (Shut down in April, 2005)					
8	Total Suspended Solids	CSSE	D	25.0	-
		ECE	D	25.0	-
9a	Iron	CSSE	D	1.0	-
		ECE	D	1.0	-
PLANT: Lambton TGS					
8	Total Suspended Solids	ECE	D	25.0	-
		CSSE	W	70.0	25.0
9	Aluminum	CSSE	W	13.0	4.50
9a	Iron	ECE	D	1.0	-
		CSSE	W	2.50	1.0
PLANT: Nanticoke TGS					
8	Total Suspended Solids	ECE	D	25.0	-
9a	Iron	ECE	D	1.0	-
PLANT: R. L. Hearn TGS (Shut down)					
8	Total Suspended Solids	ECE	D	25.0	-
9a	Iron	ECE	D	25.0	-
PLANT: Thunder Bay TGS					
8	Total Suspended Solids	ECE	D	25.0	-
9a	Iron	ECE	D	1.0	-

Explanatory Notes:
Types of Event Process Effluent Streams:
CSSE = Effluent that is discharged from a coal storage site at a plant, whether or not it is combined with cooling water or storm water effluent.
ECE = effluent that results from any cleaning or maintenance operations at a plant, whether or not it is combined with cooling water or storm water effluent
ATG Analytical Test Group
mg/L milligrams per litre
D Daily monitoring requirement

Source: Environmental Protection Act, Ontario Regulation 215/95, Amended to O. Reg. 240/07 Effluent Monitoring and Effluent Limits — Electric Power Generation Sector http://www.e-laws.gov.on.ca/DBLaws/Regs/English/950215_e.htm

3. China

3.1 Air Emissions

The Chinese government has developed a mix of regulations to control the growing SO_2, NO_X, and particulate matter emissions from coal-fired power generation. These policies span across the entire cycle of siting, constructing, and operating a power station and are focused on controlling the use of coal and improving the efficiency of the combustion process. The regulations represent a mix of emissions standards and technology requirements, such as desulfurization equipment.

The Law of the People's Republic of China on Prevention and Control of Atmospheric Pollution is the key legislation for preventing and controlling atmospheric pollution. It was updated in 2000 and includes provisions on controlling SO_2, NOx and PM, and encouraging desulfurization at coal-fired power plants.

Box 3.1 Environmental Policy Making in China

Responsibility for the development and implementation of environmental policy in China is divided between national and local levels. At the national level, the two major regulatory bodies are the State Council, which delivers broad policy guidance, and the State Environmental Protection Agency (SEPA), which is charged with developing this policy into specific regulations. The provincial, regional, and municipal Environmental Protection Bureaus (EPB) are responsible for designing, implementing, and enforcing environmental regulations at the local level. Typically, the regulations announced by the State Council and SEPA consist of general policy goals and targets that leave it up to the individual provinces and municipalities to develop specific rules and standards for their implementation.

Enforcement of Environmental Policies
Local governments are responsible for enforcing environmental regulations in China. Despite an extensive regulatory network, local enforcement efforts are sometimes not very effective and, in the past, the central government has had limited success in enforcing environmental regulations, especially outside the major cities. Funding is limited and most local environmental bureaus are understaffed. Moreover, environmental protection goals often conflict with local employment and economic goals, reducing the incentives for local governments to adhere with national pollution control standards.

SO_2, NO_X, and PM Emission Standards

Emission standards for coal-fired plants were introduced in 1991 and upgraded in 1996 and 2003. The 2003 standards were implemented on January 1, 2004, and specify much stricter SO_2, NO_x and particulate emission limits for all thermal plants, existing and new. The new standards apply to plants on a 'Period' basis – each of the three Periods encompasses all of the plants that were constructed or passed their environmental impact review within a given time frame.[8] Within each Period, implementation dates are specified for different emission limits. In general, emission limits are specified in terms of concentrations (i.e., mg pollutant/m^3 exhaust gas), but the State Environmental Protection Agency (SEPA) also sets limits for the total quantity of SO_2 emissions allowed from power plants in Period three (measured in kg pollutant/hour). Allowed quantities of SO_2 emissions are determined on a plant-by-

[8] One exception is that proposed plants that passed their environmental impact review between 01/01/99 and 01/01/04 are automatically "bumped" up to Period III if construction on the plant is not begun within five years of passing the impact review.

plant basis using a number of plant-specific parameters, including location (e.g., provincial location and proximity to urban areas), height of exhaust stacks and wind speed. Limits for allowable particulate emissions from coal plants are higher for rural areas than for urban ones.[9] The revised emission standards are provided in Table 3.1.

Local environmental agencies at the provincial and city level could enact stricter regulations than the ones identified in Table 2.1. Regional and local initiatives, implemented to improve existing emission standards, include output-based emission standards. In partnership with SEPA, three provinces – Shandong, Zhejiang, and Shanxi – have volunteered to test the use of an output-based approach to allocate their provincial SO_2 emissions cap.[cxiii] This approach limits emissions of SO_2, NO_x, and particulates in terms of grams per kilowatt-hour (g/kWh). This approach is encouraged by SEPA because it may encourage highly polluting facilities to improve their generation mix.

Two Control Zone Policy

In 1996, to address those areas most affected by acid rain and high SO_2 concentrations,[10] the government identified key acid rain and SO_2 pollution control areas, known as the "Two Control Zones" (TCZs), which would receive priority in terms of pollution control measures and investment. These TCZs include:

- *The Acid Rain Control Zone* – areas which receive precipitation with average annual pH values less than or equal to 4.5, sulfate deposition greater than the critical load, and high SO_2 emissions.
- *The SO_2 Pollution Control Zone* – includes cities with annual average ambient SO_2 concentrations exceeding Class II standards, daily average concentrations exceeding Class III standards, and high SO_2 emissions.[11]

As illustrated in Figure 3.1, most Acid Rain Control Zones are located in the South while most of the SO_2 Control Zones are located in the Northeast. Together, the TCZs cover 1.09 million square kilometers, or 11.4 percent of China's total land area[cxiv] and

[9] China's system of political divisions distinguishes between three types of cities. Municipal cities are the largest, and enjoy the same status as provinces. Prefecture-level cities are the next highest ranked type of city, and although they must have an urban population greater than 200,000, prefecture-level cities often include large tracts of rural land multiple times the size of the actual urban area. County-level cities are the smallest class of cities in China, and like prefectural-level cities, often consist of an urban area surrounded by much larger rural areas.

[10] Due to different quantifies and qualities (particularly sulfur and ash content) of coal, the alkalinity of soils, and the climatic conditions in China, SO_2 emissions and concentrations very widely between regions. Acid rain, for example, affects 30 percent of the total territory and occurs primarily in central and southwest China. The primary reasons for the regional differences are (1) the much higher sulfur content of coal in the south, and (2) the mostly alkaline soil in the north which neutralizes a portion of the SO_2 emitted in the northern part of the country.

[11] The National Ambient Air Quality Standards (NAAQS) were established in 1982 (Regulation GB 3095-82) and revised in 1996. The standards set maximum allowable ambient pollution concentrations for different types of areas in China and cover TSP, PM_{10}, SO_2, NO_X, carbon monoxide (CO), and ozone (O_3). Class I standards are the most stringent and apply to national nature reserves, tourist and historic areas, and conservation sites (20 $\mu g/m^3$ SO_2 annual average; 50 $\mu g/m^3$ SO_2 daily average). Class II standards apply to residential, commercial traffic, cultural, ordinary industrial and rural zones (60 $\mu g/m^3$ SO_2 annual average; 150 $\mu g/m^3$ SO_2 daily average). Class III standards apply to specific industrial areas (100 $\mu g/m^3$ SO_2 annual average; 250 $\mu g/m^3$ SO_2 daily average).

generate over 60 percent of China's total SO_2 emissions.[cxv] In total, 109 cities in 14 provinces have been identified for acid rain control, and 110 cities in 14 provinces have been identified for SO_2 control. Within the TCZs, certain municipalities are designated as "key," and therefore receive more stringent emission targets and are used as pilot tests for new environmental legislation.[cxvi] If proven successful, the experiments are often applied more broadly within the TCZs and then eventually in the non-TCZs as environmental priorities evolve.

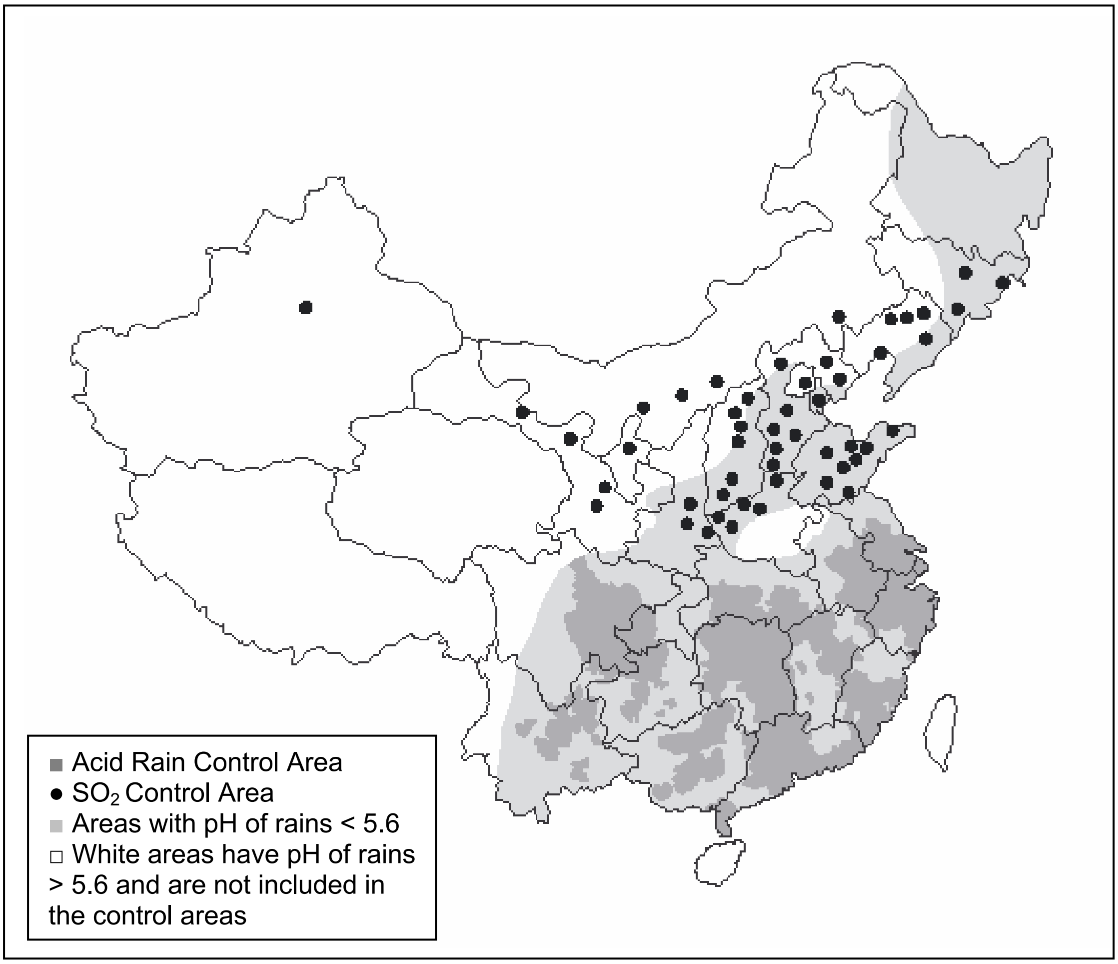
Table 3.1 SO_2, NO_X, and PM_{10} Emission Standards for Power Plants in China

Maximum Emission Levels (mg/m^3)							
Time Period (Power Plant Construction Date)			**Period I** (Pre-12/31/96)		**Period II** (1/1/97-1/1/04)		**Period III** (Post-1/1/04)
Date of Implementation			1/1/05	1/1/10	1/1/05	1/1/10	1/1/04
NO_X	Coal Fired	$V_{daf} < 10\%$	1,500	-	1300	-	1,100
		$10\% \leq V_{daf} \leq 20\%$	1,100	-	650	-	650
		$V_{daf} > 20\%$	1,100	-	650	-	450
	Oil Fired (Boiler)		650	-	400	-	200
	Oil Fired (Turbine)	All	-	-	-	-	150
	Gas Fired (Turbine)	All	-	-	-	-	80
SO_2	Coal/Oil Fired	General	2,100*	1,200*	2,100	400	400
		Approved / Non-TCZ	-	-	1,200	1,200	-
		Coal Mine Waste	-	-	-	-	800
		Mine Mouth					1,200
PM_{10}	Coal Fired	Urban Areas	300	200	200	50	50
		Rural Areas	600	200	600	50	50
		Approved / Non-TCZ	-	-	-	100	100
		Coal Mine Waste	-	-	-	200	200
	Oil Fired	All	200	100	100	50	50

Notes
V_{daf}: Volatiles content of dry, ash free coal
* Applies to the overall average emissions from boiler plants with more than one boiler system, Period one only
Approved/Non-TCZ: Applies to power plants whose environmental impact evaluation report had been approved before January 1, 2004, and to coal mine mouth power plants burning ultra-low sulfur coal (S < 0.5%) in the western portion of the non "Two Control Zone" areas (including Chongqing, Sichuan, Guizhou, Yunnan, Tibet, Shanx'I, Gansu, Qinghai, Ningxai, Xinjiang and Inner Mongolia).
Coal Mine Waste: Applies to resource comprehensive utilization power plants whose dominant fuel is coal mine waste (heating value < 12,550 kJ/kg).
Mine Mouth: Applies to coal mine mouth power plants burning ultra-low sulfur coal (S < 0.5%) in the western portion of the non "Control Zone" areas (including Chongqing, Sichuan, Guizhou, Yunnan, Tibet, Shanx'I, Gansu, Qinghai, Ningxai, Xinjiang and Inner Mongolia).
Urban Areas: Applies to thermal power plants located in the developed regions and the planning regions of cities at or above the county level
Rural Areas: Applies to thermal power plants located outside the developed regions and the planning regions of cities or above the county level
Source: PRC State Environmental Protection Administration. "Emission Standard of Air Pollutants for Thermal Power Plants," December 23, 2003. http://www.sepb.gov.cn/biaozhun/huodianchang.pdf

Because SO_2 emissions in China result mostly from coal combustion, the pollution control strategy of the TCZs focuses on the life-cycle control of sulfur in coal, coal mines and coal combustion facilities (See Table 3.2). For this reason, China's SO_2 control strategies encourage cleaner use of coal rather than a switch toward alternative, low-carbon fuel choices. As described in the Table 3.2, the SO_2 control policies of the TCZs are directed toward large industrial and power generation sources that are easy to target and where enforcement is relatively straightforward. Small dispersed sources, such as households, industrial boilers, and town and village enterprises receive less focus, although these usually produce higher emissions per ton of fuel used and release SO_2 closer to the ground.

Figure 3.1 Areas Covered by Acid Rain and SO_2 Control in China



Source: *Developing China's Natural Gas Market.* International Energy Agency, Paris, 2002.

To facilitate the implementation of control measures in the TCZs, SEPA formulated the 1998 Action Plan for the Two Controlled Areas.[cxvii] This Action Plan requires the governments at provincial, autonomous region, municipal, and city levels to formulate their own comprehensive plans for SO_2 control, which should build on the control measures outlined in Table 3.2. Provincial and municipal governments were also allowed to set more stringent rules than those applied to their jurisdictions by the central government. As a result, environmental regulations targeting power plants can vary significantly. In general, urban areas with high concentrations of atmospheric pollutants tend to institute more stringent controls.

Table 3.2. SO_2 Control Measures in China's Two Control Zones

<table>
<tr><th colspan="2">Target Area</th><th>Control Measures</th></tr>
<tr><td rowspan="2">Coal Mines</td><td>Existing</td><td>• Phase-out of mines with coal seam sulfur content > 4%, particularly small ones
• Limited production at mines with sulfur content > 3%
• Installation of coal washing and selection facilities at mines with sulfur content > 2%</td></tr>
<tr><td>New</td><td>• No construction of mines with coal seam sulfur content > 3%
• Installation of scaled coal washing equipment for new construction, retrofitting, or production expansion at mines with sulfur content > 1.5%</td></tr>
<tr><td colspan="2">Coal/Fuel type</td><td>• Prioritize low-sulfur coal in the planning and transportation of coal
• Movement of fine-washed coal to areas with high sulfur coal
• Ban on imports of fuels with sulfur content > 2% and coal with sulfur content > 1%
• By 2000, no burning of coal by households</td></tr>
<tr><td rowspan="2">Coal-fired Power Plants</td><td>Existing</td><td>• Plants that cannot use low sulfur coal must adopt other measures to control SO_2 emissions and remove particulates
• Closure of coal-fired facilities below 50 MW[cxviii]</td></tr>
<tr><td>New</td><td>• Ban on new plants in or around medium- to large-sized cities. Cogeneration plants are excluded.
• Desulfurization and particle control facilities must be installed for new construction, expansion or retrofitting of plants that use coal with sulfur content > 1%</td></tr>
</table>

Sources: *Developing China's Natural Gas Market.* International Energy Agency, Paris, 2002; and Finamore, B., *Taming the Dragon Heads: Controlling Air Emissions from Power Plants in China.* Natural Resources Defense Council, Washington DC, June 2000.

SO_2 Pollution Levy System

Since the early 1980s, China has implemented a pollution levy system on a range of pollutants from industrial and power generation sources. Part of this levy is a financial penalty imposed on emissions exceeding the existing standard. Funds raised through the levy are then used to finance environmental projects, install pollution controls, and promote technology upgrades. The levy was first applied to industrial sources in 1982 and was expanded to include SO_2 emissions from power generation in 1992, when SEPA introduced experimental SO_2 emission charges in 2 provinces and 9 cities with severe acid rain and high SO_2 emissions.[,cxix]

In 2000, the Chinese government extended the SO_2 levy to the entire area of the TCZs and set the levy at Yuan 0.20 (about 2.5 U.S. cents) per kg SO_2 emitted.[cxx] The new levy covers total emissions from each source, whereas the old levy only covered emissions that exceeded their standards.[cxxi] The SO_2 levy does not exempt polluters from legal liability for damages caused by the above-standard discharges and polluters are still required to undertake remediative measures to comply with existing standards.

The levy rates are supposed to exceed the marginal cost of abatement in order to encourage investment in pollution control technologies. However, the real marginal abatement cost of new control technology is estimated at five to six times the current SO_2 levy.[cxxii] As a result, power generators have little incentive to invest in new pollution controls and the levy has not stimulated significant pollution abatement. In 2002, the levy generated Yuan 1.15 billion (U.S. $140 million).[cxxiii] Moreover, as the current electricity tariffs set by the Chinese government do not enable coal-fired utilities to incorporate the cost of desulfurization equipment, the motivation for installing this type of equipment is low.

As part of a 1998 Notice of the Expansion of the Trial of SO_2 Levies in Acid Rain Control Areas and SO_2 Control Areas, some cities were allowed to use a higher levy fee as long as it had been approved by the State Council. Cities such as Hangzhou, Zhengzhou, and Jilin set the standard levy at 0.6 Yuan per kg SO_2 for select demonstration projects while levies in Beijing were set at 1.2 Yuan per kg SO_2 which is estimated to equal current treatment costs.[cxxiv]

To increase investment in pollution controls nation-wide, the government is gradually adjusting and enhancing the SO_2 emission charge in the TCZs, as well as the rest of the nation.[cxxv] In July 2003, the levy was increased to 0.6 Yuan/kg in some cities[cxxvi] and in July 2005 it was increased to 0.6 Yuan/kg nation-wide.[cxxvii]

An emissions charge has also been established for NO_X emissions. It took effect on July 1, 2004 and was set at 0.6 Yuan/kg nation-wide.[cxxviii]

Total Emissions Control (TEC)

Another cornerstone in Chinese air quality policy is the Total Emissions Control (TEC) program, which specifies a national SO_2 emission target, as well as provincial and municipal sub-targets. The TEC policy was first introduced by SEPA in the Ninth Five-Year Plan Period (1996 – 2000) when the State Council set the national limit for SO_2 emissions at 24.5 million metric tons. The plan assigns individual TEC targets to provinces, autonomous regions, and municipalities, which then assign TEC targets to local governments and/or individual emission sources in the industrial and power generation sectors. The goal is to reduce overall emissions and shifting emissions away from heavily polluted areas by influencing where new coal-fired power plants.

China's Tenth Five-Year Environmental Protection Plan (2001-2005) set the national TEC ceiling at 19 million tons of SO_2, with a reduction target of 10 percent below 2000 emission levels (See Table 3.3). The TEC limit for the TCZs was set at 20 percent below 2000 emissions levels.[cxxix] The TEC includes both industrial and power generation sources, with power plants contributing about 45 percent of all emissions covered.

In August 2006, SEPA issued the "Control Plan for Major Pollutants during the Eleventh Five-Year Plan"[cxxx] The Control Plan introduces a 10 percent reduction target for SO_2 emissions to be achieved by 2010, leading to a reduction of 22.94 million tons of SO_2. Table 3.4 shows the specific targets for each province, municipality and autonomous region.

Table 3.3 SO_2 TEC Targets for 2000 and 2005 in China's Tenth Five-Year Plan

Source / Area	Target (Thousand Tons SO_2)	
	2000	2005
All Industrial Sources[1]		
China	19,950	17,950
TCZs	13,164	10,536
SO_2 Control Zones	5,296	4,234
Acid Rain Control Zones	7,868	6,302
Power Generation[2]		
China	8,900	8,000
TCZs	6,400	5,100

Sources:
[1] *National Tenth Five-Year Environmental Protection Plan – Abstract,* State Environmental Protection Administration, January 2002. www.zhb.gov.cn/english/plan/Tenth.htm;
[2] Yang, Jintian, *et al. Air Pollution Control Strategy for China's Power Sector.* Chinese Academy for Environmental Planning, Beijing, China. December 2002.

Table 3.4 National SO_2 Emission Control Plan during the Eleventh Five-Year Plan

Province	Emission level in 2005 (in thousand tons)	Target for 2010 (in thousand tons)		Year 2010 required % reduction from year 2005
		Control level	From power generation	
Beijing	19.1	15.2	5.0	20.4
Tianjin	26.5	24.0	13.1	9.4
Hebei	149.6	127.1	48.1	15
Shanxi	151.6	130.4	59.3	14
Inner Mongolia	145.6	140.0	68.7	3.8
Liaoning	119.7	105.3	37.2	12
In Dalian	11.89	10.11	3.54	15
Jilin	38.2	36.4	18.2	4.7
Heilongjiang	50.8	49.8	33.3	2
Shanghai	51.3	38.0	13.4	25.9
Jiangsu	137.3	112.6	55.0	18
Zhejiang	86.0	73.1	41.9	15
In Ningbo	21.33	11.12	7.78	47.9
Anhui	57.1	54.8	35.7	4
Fujian	46.1	42.4	17.3	8
In Xiamen	6.77	4.93	2.17	27.2
Jiangxi	61.3	57.0	19.9	7
Shandong	200.3	160.2	75.7	20
In Qingdao	15.54	11.45	4.86	26.3
Henan	162.5	139.7	73.8	14
Hubei	71.7	66.1	31.0	7.8
Hunan	91.9	83.6	19.6	9
Guangdong	129.4	110.0	55.4	15

Province	Emission level in 2005 (in thousand tons)	Target for 2010 (in thousand tons)		Year 2010 required % reduction from year 2005
		Control level	From power generation	
In Shenzhen	4.35	3.48	2.78	20
Guangxi	102.3	92.2	21.0	9.9
Hainan	2.2	2.2	1.6	0
Chongqing	83.7	73.7	17.6	11.9
Sichuan	129.9	114.4	39.5	11.9
Guizhou	135.8	115.4	35.8	15
Yunan	52.2	50.1	25.3	4
Tibet	0.2	0.2	0.1	0
Shannxi	92.2	81.1	31.2	12
Gansu	56.3	56.3	19.0	0
Qinghai	12.4	12.4	6.2	0
Ningxia	34.3	31.1	16.2	9.3
Xinjiang In Xinjiang ShengChanJianSheBingTuan	51.9 1.66	51.9 1.66	16.6 0.66	0 0
Total	**2549.4**	**2246.7**	**951.7**	**11.9**

Notes: National SO_2 emissions must be reduced by 10% or 22.944 million tons. The actual distribution for the provinces is 22.467 million tons while the central government reserves 477 thousand tons for trial projects on SO_2 emission trading and discharge rights.
Source: The Central People's Government of the People's Republic of China "Control Plan for Major Pollutants during the Period of Eleventh Five-Year Plan," August 5, 2006. http://www.gov.cn/zwgk/2006-08/23/content_368354.htm

Starting in 2006, SEPA, the National Bureau of Statistics of China, and the National Development and Reform Commission will publish the amount of SO_2 emitted every six months and conduct inspections and audits with other relevant departments. In 2008 and 2010, mid-term and final assessments will be undertaken and the results will be issued for public access.

In addition to the short-term TEC targets, the State Council has set mid- and long-term goals for SO_2 emission reductions. Nation-wide, SO_2 emissions from the power sector must be reduced to 6.7 million tons by 2015.[cxxxi]

Although the TEC policy has the potential to reduce local air pollution significantly, there are some problems with its implementation, which may undermine the expected effects, including:

- Delayed approval of companion legislation on TEC pollutant management;
- Lack of integrated standards and instruments for implementing the TEC; and
- No method for identification of TEC targets; baseline development and monitoring; and verification and publication of TEC implementation results.[cxxxii]

Emission Discharge Permits and Emissions Trading

When China amended its 1987 Air Pollution Prevention Control Law (APPCL) and incorporated it into the Tenth Five-Year Plan along with the revised TCZ regulations in 2000, it also took the first steps toward emission trading through the introduction of the Discharge Permit System. The amended APPCL law requires facilities to have emission permits for SO_2 emissions. These permits are based on non-tradable emission limits for specific facilities that are allocated by local governments according to the TEC targets and other conditions set by the State Council.[cxxxiii] By changing the total emission quantity, this system allows the central and local governments to control the behavior of polluters through the number of emission permits allotted.

China had undertaken a few experiments with emission permitting prior to this. In 1991, for example, an SO_2 emission permit system was introduced, with 16 cities designated as the first experimental areas for controlling SO_2 emissions. During 1991 and 1994, 18 control zones were included and 999 emission permits were issued to 8,628 key pollution sources. In 2003, 115.3 million tons of SO_2 had been avoided and permit systems had been implemented in 20 provinces and 36 cities.[cxxxiv]

High-level Chinese officials have also expressed interest and support for developing the TEC and the Discharge Permit System into a full-fledged emission trading system.[cxxxv] In May 2002, SEPA launched a trial emissions trading regime for SO_2 that covers Shandong, Shanxi, Jiangsu, and Henan provinces; Shanghai, Tianjin, and Liuzhou municipalities; and the Huaneng Company (China Resources).[cxxxvi] Once the design of the system has been completed, permit trades will be conducted among firms that are required to comply with SO_2 emissions standards. Trades have already been initiated with the first one reported in 2003 and involving the Nanjing Power Plant and the Taicang Port Huanbao Power Company in Jiangsu Province (see Box 3.2).

The major challenge facing Chinese regulators in developing an emission trading system is the lack of air quality monitoring equipment in most of China's power plants. A mix of standards, first introduced in 1997 and strengthened in December 2001 through the Tenth National Environmental Action Plan, require the installation of continuous emission monitors (CEMs) for SO_2 on new or modified thermal power plants in the TCZs. However, because of the cost of CEMs and the large number of SO_2 emissions sources in China, it has been difficult to install CEMs at all large sources.

Box 3.2 Emission Trading in Jiangsu Province

In 2002, Jiangsu introduced a pilot emission trading program to help reduce its SO_2 emissions to the TEC provincial target of 1 million tons in 2005, down from 1.2 million tons in 2000. The system targets 196 power plants, and emission rights are allocated among them according to pre-specified emission performance standards. Emission goals have to be reached by 2005, the end of the Tenth Five-Year Plan period. Jiangsu has a relatively advanced economy and effective management institutions and uses a mix of CEMs, periodic source monitoring, and material balance estimation to ensure compliance.

In 2003, two power plants located in different cities participated in an allowance trade. Taicang Port Huanbao Power Company purchased SO_2 emissions rights to cover an expected increase in SO_2 emissions of 2,000 tons per year from meeting increased electricity demand. Nanjing Power Plant is producing 3,000 tons of SO_2 per year less than permitted due to its investment in state-of-the-art pollution control technology. To offset part of Taicang Port Huanbao Power Company's excess emissions, Nanjing will sell 1,700 tons of SO_2 over the next 3 years for the price of 1.7 million yuan ($204,800).

Sources: Jintian, Yang and Jeremy Schreifels. "Implementing SO_2 Emissions in China," OECD Global Forum on Sustainable Development: Emission Trading. Paris, March 2003; and "China's Emissions Trading Pilot Projects: A May 2003 Report from Embassy Beijing." U.S. Embassy in China, May 2003. www.usembassy-china.org.cn/sandt/Emissions-Trading.htm

Phase-Out of Small Power Generation Units

The Chinese government is actively shutting down small thermal power generation units as these units are typically inefficient and emit significant pollution. Beginning in 1997, the State Council and the State Economic and Trade Commission (SETC) required power enterprises to shut down units below 50 MW. By the end of 2000, small units representing a capacity of 10,000 MW were shut down.[cxxxvii] In 2002, SEPA introduced the "Prevention Technology Policy for SO_2 Emission from Coal Burning," which required all power generation units below and at 50MW to shut down by 2003. To promote overall efficiency even further, the Policy also required units below 100 MW that do not meet environmental standards to shut down by 2010. Also in 2002, the Bank of China announced that it would no longer provide funding to new, expansion, and retrofit projects at power plants smaller than 130 MW.

In 2005, the National Development and Reform Commission issued the "Index for Industrial Structure Adjustment Guidelines 2005." In the sections pertaining to electricity generation the following guidelines were issued:

- Clean coal technology, such as circulating fluidized bed combustion, pressurized fluidized bed combustion, and IGCC, is encouraged for units 300MW and above.
- Except for the small grids in Tibet, Xinjiang, and Hainan, installation of conventional single power generation units below 300MW is restricted.
- Except for the small grids in Tibet, Xinjiang, and Hainan, the use of power generation units with coal consumption (i.e., standard coal) above 300g/kWh is restricted.

- Within the large grid, single power generation units below 100MW, which have come to the end of their lifespan, must be phased out (the deadline is not specified).
- Single regular power generation units below 50MW must be phased out (the deadline is not specified).

Policies to Promote Installation of Desulfurization Equipment

The 2002 "Prevention Technology Policy for SO_2 Emission from Coal Burning[cxxxviii]" requires units using middle- and high-sulfur content coal to install desulfurization facilities. The following requirements were specified in the Policy:

- Newly built, renovated and expanded power plants must install desulfurization equipment at the time of construction to achieve their SO_2 standards.
- Existing units with a remaining lifespan of more than 10 years that have not yet met the SO_2 emission standard are required to install desulfurization equipment to meet the requirements.
- Existing units with a remaining lifespan of less than 10 years which have not yet met the SO_2 emission standard are required to use low sulfur content coal or other measures which can abate SO_2 emission and meet the SO_2 emission control requirements. Otherwise, the units must be shut down.
- Existing power generation units which have exceeded their designated period of services and cannot meet the SO_2 emission standard shall be shut down.

The policy recommends the following technical aspects when selecting desulfurization equipment:

- the equipment must have a lifespan of more than 15 years;
- the equipment must include self-control devices for the major parameters (i.e., PH value, liquid / gas ratio, SO_2 concentration levels);
- by-products from desulfurization should be stabilized or properly disposed to ensure there is no risk of SO_2 leakage;
- there should be no secondary pollution from the by-products and wastewater generated from the equipment;
- reasonable level of investment and operation cost; and
- the equipment must be able to be operated continually, especially during the winter season in Northern China.

In 2005, the "Technical Code for Designing Flue Gas Desulfurization Plants of Fossil Fuel Power Plants" was issued. The code is applicable to boilers of 400t/h and above. When selecting the desulfurization equipment, the following principles must be considered:

- For combustion using ≥2 percent sulfur content coal or large boilers (≥200MW), the use of lime stone & gypsum wet flue gas desulfurization is recommended, with a desulfurization rate of at least 90 percent.

- For small boilers (<200MW) using <2 percent sulfur content coal or for boilers with a remaining lifespan of less than 10 years, it is recommended to use semi-dry, dry process or other less expensive but mature desulfurization technology if it can fulfill the SO_2 emission control requirements and ensure the by-products from desulfurization are properly disposed of. The desulfurization rate must reach at least 75 percent.
- For coastal power plants using <1 percent sulfur content coal, the use of sea water desulfurization is recommended if it is approved under the environmental impact assessment. The desulfurization rate must reach at least 90 percent.
- Electron beam and ammonia absorption processes can be used if the sources of the ammargenum and the sale of the by-products from desulfurization can be ensured and agreed to by the government. The desulfurization rate must reach at least 90%.
- The operation of the desulfurization equipment must be greater than 95 percent during the operation of the power plant.

In 2003, SEPA published the "Notice for Enhancing the Prevention of SO_2 Emissions in Coal-fired Power Plants."[cxxxix] The notice included the following requirements related to desulfurization equipment.

- In eastern and central China and the TCZs in the western part of China, newly built, renovated and expanded power plants must strictly follow construction approval procedures and install desulfurization equipment.
- Power plants which are located outside the "Two Control Zones" in western China and do not fulfill their environmental requirements are required to install desulfurization equipment.
- If the plants already fulfill all environmental requirements they must reserve space for desulfurization equipment and install these gradually.
- Coal mine mouth plants using low sulfur content (<0.5 percent) coal do not have to install desulfurization facilities at present but are required to reserve space for such facilities.
- Plants which were approved and built before 2000 are required to install desulfurization facilities gradually if their SO_2 emissions exceed the standard.
- Newly built, renovated and expanded plants (except coal mine mouth plants using low sulfur content coal in western China) that were approved after 2000 are required to install desulfurization equipment by 2010.

Controls on the Siting and Planning of Power Plants

As it is very expensive to introduce environmental controls into existing power plants, the federal, provincial, and municipal governments in China have developed measures to control emissions and promote adoption of pollution controls at the planning stage of new capacity and expansion projects. The most important measures include:

Environmental Impact Assessments: Before new projects can be sited and the layout approved, they are required to undergo an environmental impact assessment (EIA), including an assessment of their effect on local concentrations of SO_2, NO_x, PM, and other pollutants. The EIA seeks to prevent the construction of plants with high emissions in areas with air pollution problems.[cxl]

- *Three-Simultaneity Rule:* The central government requires that all new, replacement, or expansion projects must incorporate SO_2 controls simultaneously with the design, construction and operation of the new facilities.[cxli] By incorporating environmental controls from the outset, the costs of environmental protection are minimized and the SO_2 emissions of new entrants are limited.

- *Removal and/or Ban on Coal-Fired Power Plants.* Over the past 5 years, a number of cities with serious air pollution problems banned the building of new coal-fired power plants completely. These cities, which include Shanghai and Beijing, will then have to build natural gas-fired units to meet new demand or rely on coal-fired electricity exported from utilities outside the controlled area. In September of 2003, SEPA announced a new regulation, which bans both the building of any new power plants and the expansion of any existing plants in large- and medium-sized cities and planning regions. Exceptions are given to thermal plants that meet national energy goals and current environmental standards. Moreover, to reduce SO_2 emissions from existing plants, some cities are also relocating urban power generation facilities to rural regions outside the cities to reduce emissions in heavily populated areas.

Although none of these measures will eliminate SO_2 emissions entirely, they do result in restricting the number of emission sources added to existing hotspots, particularly in urban areas. By banning the construction of new coal-fired capacity in major cities, it is possible that some new gas-fired generation will be built instead. However, this will only occur in areas connected to natural gas infrastructure and in places where natural gas is not already being used for other purposes, such as home heating or industrial processes. It is likely that many of the cities that have banned the construction of coal-fired facilities will continue to rely on electricity from coal, although this will now have to be transmitted from areas further away.

NOx and Particulate Matter

Unlike the control of SO_2 emissions, there are few implementation policies for meeting NOx and PM emission standards.

Requirements for controlling NOx are mentioned in the following regulations:

- The Law of the People's Republic of China on the Prevention and Control of Atmospheric Pollution. The law requires enterprises to gradually adopt measures to control any NO_X generated by the burning of fuel.
- The Tenth Five-Year Plan for Environmental Protection specifies that new coal-fired power plants are required to use low NOx burners.
- The Standard and Calculation Method for the Emissions Charge. This policy established a NOx emission charge of 0.6yuan / kg that took effect in July 1, 2004.

- The Emission Standard of Air Pollutants for Thermal Power Plants (GB13223-2003). The regulation provides an emission standard for NOx (Table 3.1), but no monitoring requirements were specified.

Similar to NOx, the control of particulates are broadly mentioned in the regulations and standards, but there are no specific regulations detailing their control.

2.2 Carbon Dioxide

China does not regulate CO_2 emissions from power plants or other sources, but in June 2007 it released a national climate change action plan that lists a number of general measures to reduce CO_2 and other GHG emissions from coal-fired power generation.[cxlii] These include:

- Amending the *Law on the Coal Industry* and the *Law on Electric Power of the People's Republic of China* to further develop and utilize clean and low carbon energy;
- Emphasizing research and development of efficient power generation technologies such as IGCC; high-pressure, high-temperature ultra supercritical units; large-scale supercritical circulating fluidized bed combustion boilers; and carbon capture, utilization, and storage.
- Phasing out small, old power plants;
- Developing ≥600MW supercritical and ultra-supercritical units;
- Developing other highly efficient and clean technologies; and
- Promoting cogeneration.

These measures are consistent with China's existing policies and measures to ensure energy security, improve efficiency of power generation, and minimize the environmental impacts of power generation. It is unclear whether the outlined measures will lead to additional incentives for clean coal technology adoption beyond those that are already planned.

3.3 Mercury, Wastewater, and Wastes

There are no specific regulations for controlling fine particulate, mercury, production of wastes (e.g., fly ash and slag), or water use from coal-fired power generation in China. The control of these pollutants is briefly mentioned in some of the regulations and standards reviewed above.

In the "Notice for Enhancing the Prevention of SO_2 Emissions in Coal-fired Power Plants," control of waste, waste water and mercury are required but not mandated. However, the Notice does include a requirement to consider the recycling and integrated use of by-products resulting from the desulfurization process, thereby reducing waste generation. Wastewater generated during the desulfurization process and dewatering is recommended to be kept in the processing loop. Wastewater discharged to water bodies must meet the relevant pollution standards, enhanced monitoring must be undertaken, and there should be control of substances containing mercury. The Tenth Five-Year Plan for Environmental Protection sets a target rate of 60% recycling of wastewater.

3.4 Future Developments

Several new policies and standards for coal-fired power will be developed in the near future. According to a government document describing the status of preparing and editing China's National Environmental Protection Standards during the eleventh five-year plan the following standards will be prepared before 2010:

- Emission Standards for Air Pollutants from Thermal Power Plants (GB13223-2003) (the third phase) - planning work is being undertaken in 2006 and 2007 by the Chinese Research Academy of Environmental Sciences;
- Emission Standards for Water Pollutants from Thermal Power Plants - planning work is being undertaken in 2007 by the Chinese Research Academy of Environmental Sciences;
- Technical Specification of Flue Gas Desulfurization at Thermal Power Plants - Ammonia Process, Selective Reduction Method, Non-Selective Reduction Method;
- Technical Specifications for Desulfurization and Denitrification at Thermal Power Plants; and
- Calculation Standards for the Discharge of Emissions from Thermal Power Plants - planning work is being undertaken by the Shanxi Environmental Monitoring Team.

3.5 Monitoring and Enforcement

Generally speaking, China is an executive-led nation. As a result, administrative rather than legal frameworks are used for enforcing policies or initiatives. In terms of air emissions, wastes and water use at coal-fired power plants, enforcement occurs mainly through administrative circulars (e.g., notices issued by SEPA or the State Council) which provide guidelines/requirements but do not provide a legal basis for execution.

Meanwhile, the Five-Year Plans provide a major tool for the Chinese government to set the direction and requirements for the development of the economy. In the Tenth and Eleventh Five-Year Plans, the control targets for SO_2 were included which required the local authorities to plan and take actions to reduce SO_2 emission. Therefore, government policies and the decisions of government officers are the key drivers in the enforcement of environmental regulations.

The government report "Results of Achieving the Indicator in the Tenth Five-Year Plan for Environmental Protection" shows that national emissions of SO_2 increased by 27 percent to 25.49 million tons in 2005 compared with 2000.[cxliii] Coal continues to be the major fuel used for energy (about 68.9 percent). In 2005, the total capacity of power generation units was 508 GW (compared with 238 GW in 2000). These units consumed almost twice the amount of coal consumed in 2000 (580 million tons versus 1,110 million tons in 2005). Meanwhile, desulfurization projects fell behind the plan during the Tenth Five-Year Plan. The plan was to reduce 1.05 million tons of SO_2 by requiring units representing about 35 GW to install desulfurization equipment. However, only about 70 percent of these projects were implemented.

Although there are requirements to phase-out small coal-fired plants and promote desulfurization projects, the results of the Tenth Five-Year Plan show that the implementation have not met the requirements. Barriers include deficiencies in the legal framework, lack of financial support, excess demand for electricity, time constraints, and differences in cost. Despite the fact that China has various policies to reduce emissions, it does not have a legal framework to guide and enforce policies. For example, the government introduced reduction targets for SO_2 emissions in each province / municipality / autonomous region, but there were no established requirements for how to distribute the targets locally. Local authorities are free to determine how to distribute the targets to their cities and electricity companies which may lead to arbitrary allocation and unfair competition. Other policies such as emissions trading and legal frameworks are not in place to support the implementation and provide overarching guidelines.

In cases where the government has introduced requirements for controlling certain pollutants, there are few corresponding legal requirements to monitor and audit their execution. For example, the Emission Standard of Air Pollutants for Thermal Power Plants (GB13223-2003) stipulated the emission standards for NOx but it included no legal requirements on monitoring for compliance.

Prevailing practices also show that enforcement of regulations is not widely established in China. For example, articles 35 and 36 of the "Due Diligence Guidelines for Commercial Bank Lending" [cxliv] require banks to deny loans to projects which are forbidden by the government or contravene its regulations and policies. Supporting documentation demonstrating project, environmental, and land approval is required for granting loans. However, according to the notice issued by the State Council on the clearance and recent construction of thermal power plants, units representing 125 GW had been constructed illegally.[cxlv] The illegal power plants did not obtain sufficient approvals from the relevant authorities. As a result, the State Council requested that commercial banks begin strict implementation of its guidelines to ensure that loan approvals are in line with government policies for the electricity industry.

The increased demand for electricity has also been a challenge for enforcing regulations. In 2005, national energy consumption increased 55.2 percent compared with 2000. Some of the big cities had banned the construction of new coal-fired capacity and new gas-fired generation was encouraged instead. However, in the case of Shanghai, the development of gas-fired capacity could not keep up with the rapid demand for energy. The initial target was to generate 1,200,000m^3 natural gas during the Tenth Five-Year Plan but Shanghai only achieved 200,000 m^3. This resulted in Shanghai re-investing into coal-fired generation to fulfill its energy demand.

Another barrier is the lack of financial policy support. Installation of desulfurization equipment involves a huge investment. It was found that some desulfurization projects could not secure sufficient financing from available sources, such as national bonds and environmental subsidies. Securing financial support is particular difficult in rural areas. For example, in Shanxi Province, the power supplied to 98 percent of the area outside Taiyuan city (the provincial capital) was provided by small-scale power plants without desulfurization equipment. The provincial government does not have enough financial capacity to change the situation although the government plans to build large-scale power plants with desulfurization equipment to replace these small-scale power plants.

The incentives for installing desulfurization facilities are also not well established. Most of the regions have not yet confirmed the fee for connecting to the national grid for existing power generation units with desulfurization equipment. This uncertainty leads to slow processing of investment into desulfurization methods.

Time is another constraint in installing desulfurization facilities. From preparation to installation it takes about 3 to 4 years for a desulfurization facility to operate. In the Tenth Five-Year Plan, the specific SO_2 emission reduction target was announced in the end of 2001. Subsequently, it took some time for the local authorities to plan and allocate the targets to different units. Thus, only 70 percent of the targeted desulfurization projects were implemented within the Tenth Five-Year Plan. Nevertheless, it is unknown if the problem will be eased in the future because the desulfurization market is not yet well-established. Although there has been a rapid expansion of the desulfurization market; quality control, operation and maintenance support have not yet caught up the development of the equipment.

Another barrier for enforcing the regulations stems from cost differences. The cost of investing and operating desulfurization equipment or other abatement measures is generally higher than the emission charge or penalty for exceeding any pollution limit. As long as there is a cost difference, there is no incentive for the power plant owners to reduce emissions.

Nevertheless, the situation is changing, particularly in big cities. Despite the fact that penalties are not enforced effectively, the administrative requirements for the phase-out of power plants play a significant role in forcing power plants to invest on desulfurization equipment. Meanwhile, financial support policies are gradually implemented and are spreading from bigger cities to rural areas.

To speed up reduction of SO_2 emissions from power generation, China has introduced several initiatives. In 2006, SEPA signed a mission statement with seven provincial governments which represent the major polluting areas and the six large power generation conglomerates to specify the desulfurization projects that should be completed or commenced in 2006.[cxlvi] In the near future, mission statements will also be negotiated with the remaining twenty-three governments of provinces, autonomous regions and municipalities directly under the Central Government. SEPA will monitor the status of installing the desulfurization equipment at both state- and privately-owned units and will consider reporting the results to the State Council and the public. Penalties will be increased for parties that do not achieve their targets.

In 2000, only 5,000 MW of desulfurization equipment had been installed in China, representing about 2 percent of the total power generation capacity. By the end of 2005, the installed desulfurization equipment exceeded 200 GW and represented about 20 percent of total capacity. This accounts for more than 2 million tons/year of potential emissions abatement. It is expected that the planned desulfurization facilities can be largely completed by 2009.

4. Indonesia

4.1 Air Emissions

Indonesia's emission standards for coal-fired units target SO_2, NO_X, and particulate matter.[cxlvii] As outlined in Table 4.1, the standards were strengthened significantly in 2000. The standards are the same for all units, regardless of fuel type. In addition to these emission standards, Indonesia also specifies the permitted level of opacity. All units in operation after 2000 must have opacity of 20 percent or below. So far, all units have been able to meet these standards.[cxlviii]

Table 4.1. Emission Standards for Power Plants in Indonesia – All Fuel Types

Pollutant	Year	
	1996-2000	2000 onward
	Emission Standard (Mg/m^3)	
Particulate Matter	300	150
Sulfur Dioxide	1500	750
Nitrogen Oxide	1700	850
	Other	
Opacity	40%	20%

Source: Decree of the State Minister for the Environment No. 13 of 1995 on Emission Standards for Stationary Sources (KEP-13/MENLH/3/1995)

4.2 Water Consumption and Aqueous Effluents

Indonesia regulates aqueous effluents from industry and power plants under the Regulation Concerning Control of Water Pollution passed in 1990. Applicable standards for coal-fired power plants are listed in Table 4.2.

Table 4.2. Criteria for Water Quality: Category D – Water that May be Used for Agricultural Purposes, Small Business in Cities, Industries, and Hydro-Electric Generation

No	Parameter	Unit	Max Concentration	Notes
	Physical			
1	Electrical Conductivity	umhos/cm (25ºC)	2250	Depending on species of vegetation. Maximum capacity is for tolerant species
2	Temperature	ºC	normal water temperature	According to local conditions.
3	Dissolved Solid Substances	mg/L	2000	Depending on species of vegetation. Maximum capacity is for tolerant species.
	Chemical a. Inorganic Chemical			
1	Mercury	mg/L	0,005	
2	Arsenic	mg/L	1	
3	Baron	mg/L	1	
4	Cadmium	mg/L	0,01	
5	Cobalt	mg/L	1	
6	Chromium	mg/L	0,003	

No	Parameter	Unit	Max Concentration	Notes
	(Hexavalen)			
7	Manganese	%	60	
8	Na (alkali salt)	mg/L	0,06	
9	Nickel			
10	pH			
11	Selenium			
12	Zinc			
13	Sodium Absorption Ratio (SAR)			Depending on species of vegetation. Maximum capacity is for tolerant species.
14	Copper			
15	Lead			
16	Residual Sodium Carbonate (RSC)			Maximum 1.25 for sensitive species; Maximum 2,50 for less sensitive species.
	Radio Activity			
1	Gross Alpha activity	Bq/L	0,1	
2	Gross Beta activity	Bq/L	1,0	

Source: Regulation Concerning Control of Water Pollution, Government Regulation Number 20 of 1990 http://law.nus.edu.sg/apcel/dbase/indonesia/regs/inrwat.html#Top

In addition to the standards outlined in Table 4.2, the change in water temperature between inlet and outlet of the power plants must be less than or equal to 2˚Celsius. None of the existing units have been able to meet this standard. [cxlix]

4.3 Coal Ash

Coal ash (fly ash and bottom ash) is regulated as a Hazardous and Toxic Material under Indonesia's Government Regulation No. 18 Jo 85/1999: Hazardous Waste Management. Power plants must write a letter to the State Ministry for the Environment describing how the ash is handled, including who is buying any of the ash. Beyond this, there are no specific regulations for ash disposal. The State Ministry is in the process of developing more guidance for fly and bottom ash management.[cl]

4.4 Monitoring and Compliance

Every three months, plants must report their emissions, production of fly and bottom ash, opacity, and water temperature to the State Ministry for the Environment. In principle power plants could have their operating license suspended if they fail to meet relevant standards. However, to date violators have simply been issued a warning letter from the State Ministry for the Environment and no further action has been taken.

Implementation of existing monitoring, enforcement, and compliance measures has been complicated by unclear division of authority between national, provincial, municipal, and local bodies.

5. Japan

5.1 Air Emissions

Emission limits in Japan vary depending on the size of the plant and its location. Japanese emission legislation for SO_2 is based on the 'K' value which is a practical emission target for companies to meet within a set time period. The K value takes into account the location of the source and best available technology (BAT) at the most reasonable cost. Emission limits are set and then future emission limits are gradually tightened over time. The SO_2 emission limit is calculated as follows:

Emission limit (mg/m^3) = $K * 10^{-3} * He^2$

Where:

K constant, determined for 100 areas by the national government based on air quality standards. Generally K is one of 16 values between 3.0 and 17.5. Special standards applied to new plants have K values of between 1.17 and 2.34.

He effective height of the stack in meters (sum of the actual stack height plus the average plume rise height).

For example, for a 1,000 MWth plant with a stack height of 260 m in a polluted and/or sensitive area the K value would be 1.17 which would give an emission limit of 60 ppm SO_2 (around 170 mg/m^3). The same plant in a less polluted area with a K value of 17.5 would have an emission limit of 1,250 ppm (3,600 mg/m^3).

In highly polluted areas the 'area-wide total pollutant load control system' applies. It is calculated with a more complex formula based on oil consumption, exhaust gas volume and various site-specific factors based on coefficients determined by the governor of the prefecture.

A system of levies on SO_2 emissions from sources >1.5 MWe also applies. The levy varies with the amount of SO_2 emitted and is used to compensate the residents of areas suffering from high pollution levels.

Emission standards for NO_X are outlined in Table 5.1.

Table 5.1. NO_X Emission Standards for Coal-Fired Power Plants in Japan

MWth	NO_X Limit (mg/m^3)
<32	720
32-560	515
>560	410
32-80, stoker boilers	655

Source: Lesley L. Sloss. "Trends in Emission Standards," International Energy Agency, December 2003

Fine Particulates

Fine particulate emissions from coal-fired power are not regulated in Japan.

Mercury

There are no emission limits for mercury on coal-fired power plants in Japan.

5.2 Water Consumption and Aqueous Effluents

Table 5.2. Effluent Limits for Trace Elements in Japan

Element		Effluent Limit (mg/L)	
		Japan Ministry of Environment	Individual Power Plants
Major Concern	Arsenic	0.1	0.14 - 0.3
	Boron	230	230
	Cadmium	0.1	0.3
	Lead	0.1	0.3
	Mercury	0.005	0.005
	Selenium	0.1	0.1 - 0.3
Moderate Concern	Chromium	0.5	1.5
	Flourine	16	15
Minor Concern	Manganese	-	1.1

Source: *http://www.ultrasys.com.au/bits.html*

5.3 Monitoring and Enforcement

Environmental policy in Japan is based on "administrative guidance" where the government gives advice and sets requirements for individual companies. These requirements are voluntary but include emission standards to be observed. Economic penalties are often set, however, these are not often used nor are they severe. In Japan, social responsibility is a high priority and a company violating regulations will lose their social reputation and public credibility which is regarded as worse than any fine or penalty.

6. The Philippines

6.1 Air Emissions

Philippines' air pollution control policy is outlined in the Philippine Clean Air Act (PCAA) and its Implementing Rules and Regulations (DAO 2000-81). [cli] The air quality guidelines and standards that apply to coal-fired power generation include standards for PM_{10}, SO_2, and NO_X. These are outlined in Tables 6.1 to 6.3. The emission standards outlined in Table 6.1 are not stringent enough to result in the use of advanced clean coal combustion technology, but they will require the use of low-NOx burners and SO_2 scrubbers at new plants. The PCAA includes emission limits for mercury that apply to any industrial source. The standard is 5 mg/nm^3, which is significantly higher than any possible emissions from coal-fired power plants.

Under the PCAA, emission permits will be issued for existing and new plants. Emissions quotas will be prescribed for each regional industrial center which then allocates emission allowances to pollution sources under their jurisdiction. However, there is no specific guidance on the process for how these allowances must be allocated.

For industrial sources, including coal-fired power plants, the PCAA introduced an emission charge system which includes fees proportional to the amount of pollutant emitted. However, this charge has not been implemented yet following a request by industry for a grace period while the necessary controls were implemented.[clii] The Philippine Clean Air Act also allows tax incentives such as total credits and/or accelerated depreciation deductions for plants installing or retrofitting pollution control equipment.

Table 6.1. National Emission Standards for Source Specific Air Pollutants

Pollutant	Plant Type	Maximum Permissible Limit (mg/nm^3)
Nitrogen Oxides (NO_x) as NO_2	Fuel Burning Steam Generators:	
	Existing Source	1,500
	New Source:	
	Coal-fired	1,000
	Oil-fired	500
Sulfur dioxide (SO_2)	Fuel Burning Equipment:	
	Existing Source	1,500
	New Source	700
Particulate Matter (PM_{10})	Fuel Burning Equipment:	
	Urban or Industrialized Area	150
	All other areas	200
Carbon Monoxide (CO)	Any industrial source	500
Mercury (Hg) as elemental Hg	Any source	5

Note: The Philippines did not have natural gas-fired electricity at the time the Clean Air Act was passed. Hence, it does not include NO_x emission standards for this fuel option.
Source: The Philippine Clean Air Act of 1999. Republic Act (RA) 8749. http://www.tanggol.org/environmental_laws/cleanair.html

The PCAA became effective in 2001 and its standards are to be reviewed and/or updated every two years. No review has been undertaken of the standards pertaining to coal-fired electricity, and it is not anticipated that they will be updated in the near future.[cliii] However, there has been some discussion that the PCAA should be revised to distinguish between small and large sources. At the moment the law applies equally to all sizes, which places a higher burden on small entities.

Table 6.2 National Ambient Air Quality Guidelines for Criteria Pollutants

Pollutants	Short Term			Long Term		
	μg/nm^3	ppm	Ave. Time	μg/nm^3	ppm	Ave. Time
Sulfur Dioxide (SO_2)	180	0.07	24 hrs	80	0.03	1 year
Nitrogen Dioxide (NO_2)	150	0.08	24 hrs			1 year
Suspended Particulate Matter:						
Total Suspended Particulate (TSP)	230		24 hrs	90		1 year
PM_{10}	150		24 hrs	60		1 year
Photochemical Oxidants	140	0.07	1 hr			
As Ozone	60	0.03	8 hrs			
As Carbon Monoxide (CO)	35	30	1 hr			
	10	9	8 hrs			

Source: The Philippine Clean Air Act of 1999. Republic Act (RA) 8749. http://www.tanggol.org/environmental_laws/cleanair.html

Table 6.3. National Ambient Air Quality Standards for Source Specific Air Pollutants from Industrial Sources/Operations

Pollutants	Concentration		Averaging Time
	μg/nm^3	ppm	(Minutes)
Sulfur Dioxide (SO_2)	470	0.18	30
	340	0.13	60
Nitrogen Dioxide (NO_2)	375	0.20	30
	260	0.14	60
Suspended Particulate Matter:			
Total Suspended Particulate (TSP)	150		60
PM_{10}	200		60

Source: The Philippine Clean Air Act of 1999. Republic Act (RA) 8749. http://www.tanggol.org/environmental_laws/cleanair.html

The government has considered introducing SO_2 and NO_X emissions trading for large sources because these would normally be run by large multinational corporations that are more experienced with the required continuous emissions monitoring systems.[cliv] However, before creating such as trading system, the government would have to determine the carrying capacity of each region, which would require extensive and costly modeling which the Philippine government currently cannot afford.

6.2 Water Consumption and Aqueous Effluents

The Clean Water Act of 2004 (RA 9275) includes effluent standards for water use (Table 6.4) that also apply to coal-fired power plants. There are no rules on the amount of water consumed by coal-fired plants as long as they are located near the coast and use sea water. Plants are not allowed to use ground water, and must certify this in the EIA.[clv]

Table 6.4 Effluent Standards: Toxic and Other Deleterious Substances (Maximum Limits for the Protection of Public Health)

Parameter	Unit	Protected Waters Category I Class AA & SA		Protected Waters Category II Class A, B, & SB		Inland Waters Class C		Marine Waters Class SC		Marine Waters Class SD	
		OEI	NPI	OEI	NPI	OEI	NPI	OEI	NPI	OEI	NPI
Arsenic	mg/L	(b)	(b)	0.2	0.1	0.5	0.2	1.0	0.5	1.0	0.5
Cadmium	mg/L	(b)	(b)	0.05	0.02	0.1	0.05	0.2	0.1	0.5	0.2
Chromium	mg/L	(b)	(b)	0.1	0.05	0.2	0.1	0.5	0.2	1.0	0.5
Cyanide	mg/L	(b)	(b)	0.2	0.1	0.3	0.2	0.5	0.2	-	-
Lead	mg/L	(b)	(b)	0.2	0.1	0.5	0.3	1.0	0.5	-	-
Total Mercury	mg/L	(b)	(b)	0.005	0.005	0.005	0.005	0.005	0.005	0.05	0.01
PCB	mg/L	(b)	(b)	0.003	0.003	0.003	0.003	0.003	0.003	-	-
Formaldehyde	mg/L	(b)	(b)	2.0	1.0	2.0	1.0	2.0	1.0	-	-

Notes: "NPI" means New/Proposed Industry or wastewater treatment plants to be constructed.
"OEI" means Old or Existing Industry.
Source: DENR Administrative Order No. 35, Series of 1990. “Revised Effluent Regulations of 1990, Revising and Amending the Effluent Regulations of 1982.” http://www.emb.gov.ph/laws/water%20quality%20management/dao90-35.html

6.3 Coal Ash

The Ecological Solid Waste Management Act of 2000 (RA 9003) sets guidelines and targets for solid waste avoidance and volume reduction through source reduction and waste minimization measures, including composting, recycling, re-use, recovery, green charcoal process, and others, before collection, treatment and disposal in appropriate and environmentally-sound solid waste management facilities. It places the primary enforcement and responsibility of solid waste management with local government units while encouraging cooperation among the national government, other local government units, non-government organizations, and the private sector for waste management.

Although coal ash is classified as a solid waste, the Act includes little guidance for its disposal, except for the requirement that the landfills used for fly ash must be lined.[clvi] All power plants have contracts to sell their fly ash for cement production, but the demand for fly ash in the cement industry is not enough to meet all the supply, so the remaining ash is dumped in landfills.

6.4 Monitoring and Enforcement

All government-owned and controlled corporations and private corporations, firms and entities must prepare an environmental impact statement for every proposed project and undertaking which significantly affects the quality of the environment.[clvii] The screening and categorization of projects is based on their type, location and scale of the proposed technology, sensitivity of the project site and the nature and magnitude of the potential impacts.

Environmental regulations are being enforced by a combination of measures, including:

- Monitoring by inspectors from the Department of Environment and Natural Resources;
- Inspection by local government units;
- Compliance monitoring of any "Special Conditions" listed in the Environmental Compliance Certificate (ECC);
- Submission of self-monitoring reports; and
- Multi-Partite/Stakeholder Monitoring

Challenges to the implementation of this monitoring system include insufficient funding for monitoring and inspections, lack of proper delineation of functions among agencies, different interpretation of environmental laws among regions, lack of funds for power plants to implement all environmental requirements (especially government owned power plants), and limited capacity and capability of monitoring agencies and its personnel to monitor and enforce regulations.[clviii]

For better monitoring, power plants must install continuous monitoring systems (CEMS). Only the major international power providers will install these.

7. The Russian Federation

7.1 Air Emissions

Air emission standards in Russia are plant-specific and based on estimates of maximum allowable point source pollution rather than measurements at the stack.[clix] The standards for particulate matter, sulfur dioxide, and nitrogen oxides therefore differ depending on the height of the smoke stack, the size of the power plant, and its location related to other emitters.

To develop the standards the Ministry of Public Health prepared an inventory of all air pollutants and characterized these by the volume, intensity, temperature, plant size, stack height, atmospheric dispersion, and source location. Second the maximum level of allowable pollution was calculated for each area, taking into account expected future growth and physical, geographic, and climatic conditions. This was done for each type of pollutant. The Ministry of Public Health of the Russian Federation then established a maximum emissions concentration (MEC) level for the area. Using the MEC, individual standards are established for industrial sources, including coal-fired power plants, using the following correlation:

$$\mathbf{C/MEC \leq 1}$$

where

C =	the estimated concentration of a pollutant (mg/m^3) in the atmosphere of the urban territory as measured near the boundary of the relevant sanitary-hygienic zone
Sanitary-hygienic zone =	designated zone surrounding the source (i.e., 500 m for a cogeneration plant, 50 m for a district heating boiler)

If several pollutants are present in the atmosphere, these must all be summed according to their estimated influence as established by the Ministry of Public Health. Table 7.1 provides samples of how relevant air pollutants are classified.

Table 7.1 Maximum Allowed One-Time Concentrations of Sample Air Pollutants

Ingredients	Code of substances	Class of hazard	MEC m.r.*, mg/m3
Carbon monoxide	0337	4	5.0
Nitrogen oxides	0301	3	0.2
Sulfur dioxide	0330	3	0.5
Soot	0328	3	0.15
Coal ash from cogeneration	2926	2	0.05
Mercury	0183	1	0.0003

Note: The maximum allowed one-time concentrations of pollutants refer to the maximum concentration of an impurity in the atmosphere referred to at the certain time of averaging.
Source: The classes of hazards, codes and MECs are established according to the hygienic regulations of the Ministry of Public health and are listed in the document "List and Codes of Substances Polluting the Atmospheric Air," St. Petersburg, 2005.

When determining the maximum allowed emissions for an industrial source, the background concentration of harmful substances created by other sources is also taken into account. This is done be using the following equation:

$$\mathbf{C = C_d + C_b}$$

where

Cd = the concentration of a pollutant (mg/m^3) in the designated location

C_b = the background concentration (mg/m^3) in the designated location

Using the equations outlined above, the classifications illustrated in Table 7.1, and data for coal-fired power plants in Russia it is possible to calculate the range of possible emission standards for coal-fired power plants. These ranges are provided in Table 7.2.

Table 7.2 Range of Emission Standards for Coal-fired Power Plants (2006)

Pollutant	mg/m3
Sulfur dioxide,	100-1000
Nitrogen dioxide	120-500
Nitrogen oxides	30-100
Particulate matter	30-130

Two outcomes are possible when determining the standards for existing plants:

- the current atmospheric pollution by the given plant (taking into account the background concentration) is less than the MEC
- the current atmospheric pollution by the given plant (taking into account the background concentration) is greater than the MEC

In the first case, determination of the maximum emissions concentration becomes simpler and the magnitude of actual emissions can be accepted as the given magnitude of the working plant. In the second case, the plant must introduce specific measures to reduce their emissions to the level of the MEC.

The emission standards have not changed significantly over the last 20 years. The only exception is the standard for NO_X emissions, which was raised from an MEC of 0.085 mg/m3 to 0.2 mg/m3. This change resulted in a *de facto* toughening of the requirements because of the high existing background concentrations in industrial cities.

Because all standards are determined using estimations and dispersion modeling rather than measurements, Russia does not have a national- or sector-based inventory system for tracking actual emissions. The government is working on developing an accounting and tracking system that will enable it to confirm with the general inventory procedures used in Europe.

Fine Particulate Matter

Russia does not regulate emissions of fine particulates from power generation.

Mercury

Control of mercury emissions is carried out according to the general framework for air pollution outlined above. The maximum allowed atmospheric concentration of mercury near urban areas is 0.0003 mg/m^3, but would have to be adjusted to each individual plant using the equations above. The penalty for exceeding the mercury limit is several times higher than for other types of emissions.

7.2 Water Consumption and Aqueous Effluents

On June 3, 2006, the Russian Federation adopted a new Water Code which entered into effect on January 1, 2007.[clx] The code does not include regulations for water use at coal-fired power plants, but it does introduce a framework for developing new 'water quality norms' for industrial effluents. Norms of allowable impacts will be based on maximum allowable concentrations of chemicals, nuclear substances, micro-organisms and other water quality indices. These norms will be adopted according to existing regulatory regimes defined by the government. The water quality norms will be developed by the federal executive authorities responsible for each water basin taking into account its natural and geographical conditions, as well as specific features of water uses within the basin.[clxi] A timeline for completing the guidelines has not been published.

7.3 Coal Ash

Solid wastes from coal-fired power stations are regulated under Russia's "National Legislation on Wastes of Manufacture and Consumption."[clxii] This regulation does not introduce any specific rules on the management and disposal of coal ash except that all electricity, cogeneration, and industrial facilities are required to develop a report describing any expected waste production, including a calculation of the amount of waste produced and a description of how the wasted is disposed of.[12] This relates to solid and liquid wastes, but not to wastewater.

Although there are no environmental regulations encouraging improved handling of coal ash, and there are few available technologies for recycling ash and slag wastes in Russia, there are some economic incentives for recycling coal wastes. This is because power plants are required to pay a fee for disposing of its waste in a landfill. Still, it is more common for enterprises to landfill their wastes rather than implement new technologies for ash disposal, and as a result there are few known cases of coal ash handling in Russia. Table 7.3 includes some of the few project activities to manage coal ash in Russia. In addition, there is some ongoing research in Russia to evaluate new avenues for ash and slag utilization, for example, by using ash and slag for road backing, construction of low-rise buildings, and as additives while manufacturing cement.

[12] "Methodical Instructions on the Development of the Pilot Regulations of Waste Formation and the Limits on their Accommodation (PNOOLR) authorized by the order Ministry of Natural Resources of Russia. 11.03.2002. # 115 of the Federal Law "On the Wastes of Manufacture and Consumption." And "Methodical Recommendations for Development of the Pilot Regulations of the Allowed Accommodation of Wastes for Thermal Power Stations, Co-generation, and Industrial and Heating Boiler-houses."

Table 7.3 Sample Measures for Reducing Solid Wastes from Coal-Fired Power Plants in Russia

Facility	Environmental Measure	Technology/Process	Environmental/Economic Result
Berezovskaya GRES - 1 Power Plant	Use of ash-and-slag wastes	- Joint system for removing ash and slags - Construction of protecting dams using level-by-level consolidation	- Maintains the environmental safety and serviceability of the ash dump - Reduces construction costs
Cheliabinskaya Heat-electric Generating Station -2	Recycling of ash-and-slag wastes	- The ash contains more than 80% aluminum silicate that allows for use as a secondary raw material in building materials, in particular lime-sand brick	- Ash recycling enables the release of the first section of the ash dump, reduces the area used for ash dumps, and reduces the payment for storing ash-and-slag wastes.

7.4 Monitoring, Enforcement, and Compliance

None of Russia's coal-fired power stations use continuous emissions monitoring. In 1991, a national emissions charge was introduced in Russia which applies to over 300 air and water pollutants from a large number of stationary sources. However, in the earlier years, monitoring and administrative capabilities were limited and the final charge was often open to negotiation between the source and the local authority. It was not uncommon for fees to be waived for sources experiencing financial problems. The collection rates for the fees were low and there was no coherent approach to spending any revenue raised. [clxiii]

However, during the last ten years, as the economic condition of many Russian enterprises improved, the enforcement system became more efficient and several improvements were made. All enterprises are now required to develop a Project for Maximum Permitted Emissions (MPE). The project includes establishment of MPEs and development of measures to fulfill these. The development of the projects must be coordinated with the relevant environmental enforcement organizations. During implementation, enforcement inspectors regularly inspect the enterprise and conduct emissions measurements. If an enterprise's emissions exceed the established norms, the penalties for being "caught" are 25 times higher than the fees for self-reported non-compliance. In addition, the managers and environmental specialists responsible for the enterprise are charged with administrative penalties.

If the enterprise exceeds emission limits on a systematic basis or does not carry out measures identified in the MPE project, inspectors from the enforcement organization report this to the prosecutor's office, which has the right to open a criminal liability case. The enforcement organization also has the authority to close the enterprise, if it does not meet its plan. If the enterprise cannot immediately implement the required environmental measures (for example, because of financial reasons) and/or cannot be closed due to social or labor concerns, a very strict plan of measures and schedules is to be developed, which is later controlled by the enforcement organizations and by the prosecutor's office.

8. Thailand

8.1 Air Emissions

Emission standards for coal-fired units in Thailand target SO_2, NO_X, and particulate matter (Table 8.1).

Table 8.1. Emission Standards for Power Plants in Thailand*

Type and Size of Power Plant	Emission Standard		
	Sulfur Dioxide (ppm)	Oxides of Nitrogen (ppm)	Particulates (mg/m^3)
New Power Plant (Permitted after January 31, 1996 or October 31, 2004 for Biomass)			
Coal			
<300 MWe	640	350	120
300-500 MWe	450	350	120
> 500 MWe	320	350	120
Oil			
<300 MWe	640	180	120
300-500 MWe	450	180	120
> 500 MWe	320	180	120
Natural Gas			
All sizes	20	120	60
Biomass			
All sizes	60	200	120
Old Power Plant (Permitted before January 31, 1996 or October 31, 2004 for Biomass)			
Coal	700	400	320
Oil	950	200	240
Natural Gas	60	200	60
Biomass	60	200	320
Existing Power Plant			
Bang Pakong			
Unit 1-4 (Thermal)	320	200	120
Unit 1-2 (Combined Cycle)	60	450	60
Unit 3-4 (Combined Cycle)	60	230	60
South Bangkok			
Thermal	320	180	120
Unit 1 (Combined Cycle)	60	250	60
Unit 2 (Combined Cycle)	60	175	60
North Bangkok	500	180	150
Surat Thani			
Gas Turbine	60	230	60
Combined Cycle	20	120	60
Lan Krabu	60	250	60
Nong Chok			
Gas Turbine	60	230	60
Wang Noi	60	175	60
Num Phong			
Combined Cycle	60	250	60
Mae Mohǂ			
Unit 1-3	1,300	500	180
Unit 4-13	320	500	180

* 25°C, 1 atm (760 mm Hg), 7% O_2 on a dry basis.

ǂ total SO_2 from Mae Moh plants 1-13 must not exceed 11 t/h (short tons)

Source: Notification of the Ministry of Industry B.E.2547 (2004), issued under Factory Act B.E.2535 (1992), dated September 28, B.E.2547 (2004). It was published in the Royal Government Gazette, Vol. 121, Part 113D, dated October 7, B.E.2547 (2004).

The limits differ, depending on whether they apply to units which acquired a permit of operation or expansion before or after 1996. They also differ depending on the size of the generating units. The standard for larger units (>500MWe) is twice as strict as that for smaller units (<300 MWe). The SO_2 emission standards for new coal-fired units are similar to those of Thailand's oil-fired capacity, but more lenient than for units using natural gas or biomass. The NO_X standards are more lenient than for any other fuel type.

The standards for existing lignite plants in the Mae Moh region are more lenient than for the rest of the nation. This is in spite of the high pollution in this region.

In addition to meeting the emission standards specified in Table 8.1, local authorities also consider the impact of a new coal-fired power plant on local air pollution before agreeing to a permissible emission level. For example, if NO_X concentrations are high in a specific region, a proposed plant could be asked to reduce NO_X emissions even further than specified in Table 8.1.[13] However, there are no general guidelines for how such a decision would be made.

Table 8.2 describes Thailand's air quality standards.

Table 8.2. Air Quality Standards – Thailand

Pollutant	1 Hour Average	8 Hours Average	24 Hours Average	1 Month Average	1 Year Average
CO (ppm)	30	9	-	-	-
NO_2 (ppm)	0.17	-	-	-	-
SO_2 (ppm)	0.3	-	0.12	-	0.04
TSP (mg/m^3)	-	-	0.33	-	0.1
PM-10 (mg/m^3)	-	-	0.12	-	0.05
O_3 (mg/m^3)	0.1	-	-	-	-
Pb (mg/m^3)	-	-	-	0.0015	-

8.2 Water Consumption and Aqueous Effluents

As part of the permitting process, power plants must obtain a license to consume water. The allowable volume is determined by local authorities and depends on other uses for water near the site. Specific rules for water discharge also depend on local priorities and site specific issues, such as whether the water is discharged into a river or the ocean.[clxiv]

Thailand's water quality standards are outlined in Table 8.3.

Table 8.3. Effluent Standards for Industrial Plants and Estates

Items	Unit	Standard Values
1. pH Value	-	5.5-9.0
2 Total Dissolved Solids (TDS)	mg/l	2.1) not more than 3,000 mg/l depending on receiving water or type of industry considered by Pollution Control Committee (PCC), but not to exceed 5,000 mg/l 2.2) not more than 5,000 mg/l exceed TDS of receiving water having salinity of > 2,000 mg/l or TDS of sea if discharge to sea
3. Suspended Solids (SS)	mg/l	≤ 50 mg/l depending on receiving water, type of industry, or type of waste water treatment system under consideration of PCC but not to exceed 150 mg/l
4. Temperature	˚C	≤ 40

[13] Dr. Boonrod Sajjakulnukit, Department of Alternative Energy Development and Efficiency, Ministry of Energy. Personal communication, December 14, 2006.

Items	Unit	Standard Values
5. Color and Odor	-	Not objectionable
6. Sulfide (as H_2S)	mg/l	≤ 1.0
7. Cyanide (as HCN)	mg/l	≤ 0.2
8. Heavy Metals		
8.1 Zinc (Zn)	mg/l	≤ 5
8.2 Chromium (Hexavalent)	mg/l	≤ 0.25
8.3 Chromium (Trivalent)	mg/l	≤ 0.75
8.4 Arsenic (As)	mg/l	≤ 0.25
8.5 Copper (Cu)	mg/l	≤ 2.0
8.6 Mercury (Hg)	mg/l	≤ 0.005
8.7 Cadmium (Cd)	mg/l	≤ 0.03
8.8 Barium (Ba)	mg/l	≤ 1.0
8.9 Selenium (Se)	mg/l	≤ 0.02
8.10 Lead (Pb)	mg/l	≤ 0.2
8.11 Nickel (Ni)	mg/l	≤ 1.0
8.12 Manganes (Mg)	mg/l	≤ 5.0
9. Formaldehyde	mg/l	≤ 1.0
10. Phenols	mg/l	≤ 1.0
11. Free Chlorine	mg/l	≤ 1.0

Source: Notification of Ministry of Science, Technology and Environment No.3, B.E. 2539 (1996), Dated January 3, B.E. 2539 (1996), published in the Royal Government Gazette, Vol. 113, Part 13 D, Dated February 13, B.E. 2539 (1996); Notification of Ministry of Industry, no.2, B.E. 2539 (1996), issued under Factory Act B.E. 2535 (1992), dated June 14, B.E. 2539 (1996), published in the Royal Government Gazette, Vol. 113, Part 52 D, dated June 27, B.E. 2539 (1996).

8.3 Coal Ash

As part of the Environmental Impact Assessment (EIA), coal-fired power plants must describe how solid waste, including fly ash, is disposed of. However, there are no specific guidelines for how fly and bottom ash must be handled.[clxv]

Some power plants sell their ash to cement manufacturing companies for recycling. Fly ash is collected from six Mae Moh units and supplied to such companies.[clxvi] The Thai Petrochemical Industry's (TPI) coal-fired plant in Rayong uses the ash in its own cement manufacturing facility. Most other coal-fired units in Thailand dump the ash in various places without any prior processing. For example, unused ash from Mae Moe is stored in a disused mine.

8.4 Monitoring and Compliance

Power plants report their emissions to the Department of Industrial Works (DIW). If they exceed the specified emission standards, DIW has the authority to stop power plants from operating for a given period. There have been cases in the past, where DIW has done so.[clxvii]

9. United States

In the United States, there is a large body of national and federal regulations which impact coal-fired power plants. Table 9.1 provides an overview of key elements of current regulatory policy impacting all fossil-based power plants in the U.S. The table identifies those media-specific regulations that have been developed to comply with federal and state laws, as well as the pollutants regulated.

Table 9.1 Key Regulatory Elements Impacting all Coal-Fired Power Plants in the U.S.

ENVIRONMENTAL MEDIA AND APPLICABLE REGULATIONS	POLLUTANTS REGULATED	REGULATORY BASIS
Air Pollution • National Ambient Air Quality Standards (NAAQS) • Federal New Source Performance Standards (NSPS) • Federal New Source Review (NSR) • Title IV, 1990 CAAA – Acid Deposition Control • Title III, 1990 CAAA – Hazardous Air Pollutants • Title I, 1990 CAAA – Attainment Maintenance of NAAQS, Regional Programs – NOx SIP Call • Acid Rain - Sulfur Dioxide Allowance System • Operating Permits (Major Sources) • State Implementation Plans (SIPs) • Clean Air Mercury Rule • Clean Air Interstate Rule • Local Standards (air quality, emission limits, control methods)	SO_2, NOx, PM10, PM2.5, Pb, Hg, O_3, CO, HAPs	Clean Air Act, Clean Air Act Amendments, State and local laws
Water Pollution • Federal Safe Drinking Water Standards (SDWS) • National Pollutant Discharge Elimination System Limits (NPDES) • State Pollutant Discharge Elimination System (SPDES) • Toxic and Hazardous Waste Regulations (Federal and State) • State and Local Standards (stream quality, effluent limits, treatment methods)	Priority Pollutants: arsenic, benzene, cyanide, mercury, naphthalene, selenium, other organics, and trace metals	Clean Water Act, Safe Drinking Water Act, Resource Conservation and Recovery Act (RCRA) State and local laws
Solid Waste Discharge • RCRA Subtitle C Toxic and Hazardous Waste	Fly Ash, Bottom Ash, Slag, Pollution	Solid Waste

ENVIRONMENTAL MEDIA AND APPLICABLE REGULATIONS	POLLUTANTS REGULATED	REGULATORY BASIS
Regulations • RCRA Subtitle D Non-Hazardous Waste Regulations • State and Local Standards (Classification, Disposal Methods)	Control Waste, By-products	Disposal Act as amended by the Resource Conservation and Recovery Act (RCRA)

Since inception, the environmental regulatory structure has been largely media-specific, with separate regulations covering air and water pollutants and solid waste/byproduct discharges. Regulations are based on health-related impacts to humans and wildlife, sustaining the national landscape, and the preservation of waterways to provide for both commercial and recreational use. Laws exist to provide public access to information on potentially hazardous substances that are produced or utilized at regulated facilities. The regulations also necessitate that proper siting procedures are carried out and that appropriate permits be obtained before any environmental compromise is likely to occur. Additionally, the major environmental laws call for investments and operating incentives to enhance current technology, develop new and innovative technology, and ensure that progress is made in improving the nation's air, water, and other natural resources.

The legal instrument used in the U.S. to ensure compliance with these environmental regulations is the environmental permit. A permit may specify in considerable detail how a facility may be constructed or operated and, therefore, must be obtained prior to commencement of any activity, including construction. Industrial and municipal facilities are required to obtain these permits to control their pollutant emissions to the air, land, and water. Various federal permitting programs have been established by EPA under the Clean Air Act, such as the New Source Review and Titles V of the 1990 Clean Air Act Amendments for air emissions, the National Pollutant Discharge Elimination System (NPDES) for discharges of pollutants into surface water, and the Resource Conservation and Recovery Act (RCRA) for waste management. In general, permit programs are defined in the regulations to ensure that the requirements of the original statute are properly implemented. Rather than issuing most permits itself, EPA generally has established programs to authorize state, tribal, and local permitting authorities to perform most permitting activities. Once EPA has delegated its authority for a permitting program to a state or tribe, they can then implement their own version of the permit program as long as it meets the minimum requirements stated in the governing statutes and regulations. EPA has delegated authority to most states for implementing part or all of the major permit programs. Some states have enacted provisions that are more stringent than federal requirements, while other states have adopted the federal requirements without revision.

The permitting process for coal fired power plants is a complex and lengthy process, especially due to the increasing number of applicable regulations and associated permits required. Permit applications may take several months to prepare and can take an additional twelve months for approval. The permit process usually includes air, water and solid waste impact assessments, assessment of need for additional generating capacity, and other impact analysis. In addition to the various state permitting agencies that are involved, there is also a public participation component that can significantly effect the time required to obtain the permit. Furthermore, National Environmental Policy Act (NEPA) analysis is required for facilities that have some degree of federal agency involvement. Many states are developing outlines for the siting process for power plants, including but not limited to the Florida Power Plant Siting Act, the Article X process of New York State, and the Ohio process overseen by the Ohio Power Siting Board.

9.1 Air Emissions

EPA has promulgated *National Ambient Air Quality Standards* (NAAQS) for criteria pollutants, including *carbon monoxide* (CO), *nitrogen oxides* (NOx as NO_2), *sulfur dioxide* (SO_2), *ozone* (O_3), *lead* (Pb), *particulate matter* with aerodynamic diameters less than 10 micrometers (PM_{10}), and extremely fine particulate matter ($PM_{2.5}$). These are listed in Table 9.2. To maintain the atmospheric concentrations of the criteria pollutants identified in Table 9.2, the Clean Air Act (CAA) introduced specific emission limits for fossil-fired facilities.

Table 9.2 National Ambient Air Quality Standards

POLLUTANT	PRIMARY STANDARDS	AVERAGING TIMES	SECONDARY STANDARDS
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour[1]	None
	35 ppm (40 mg/m^3)	1-hour[1]	None
Lead	1.5 µg/m^3	Quarterly Average	Same as Primary
Nitrogen Dioxide	0.053 ppm (100 µg/m^3)	Annual (Arithmetic Mean)	Same as Primary
Particulate Matter (PM_{10})	Revoked	Annual (Arith. Mean)	Revoked
	150 ug/m^3	24-hour	Same as Primary
Particulate Matter ($PM_{2.5}$)	15.0 µg/m^3	Annual (Arith. Mean)	Same as Primary
	35 ug/m^3	24-hour	Same as Primary
Ozone	0.08 ppm	8-hour	Same as Primary
	0.12 ppm	1-hour	Same as Primary
Sulfur Oxides	0.03 ppm	Annual (Arith. Mean)	-------
	0.14 ppm	24-hour	-------
	-------	3-hour	0.5 ppm (1300 ug/m^3)

Source: U.S. Environmental Protection Agency, "National Ambient Air Quality Standards (NAAQS)," Last updated Sunday November 25th, 2007 http://www.epa.gov/air/criteria.html#4#4

9.1 .1 Summary of Criteria Air Pollutant Regulations and Permitting

To achieve the NAAQS outlined in Table 9.2, air emissions from a coal-fueled plant are effectively required to comply with two major regulatory programs introduced by the Clean Air Act: New Source Performance Standards (NSPS) and New Source Review (NSR). NSPS specifies maximum emission limits on criteria air pollutants, but can be superseded by provisions of NSR that impose emission limits on individual sources, such as a coal-fired power plant. Other regulatory limits are based on Titles I, III and IV of the 1990 Clean Air Act Amendments (CAAA) covering ozone, PM_{10}, and $PM_{2.5}$ nonattainment, hazardous air pollutant emissions and aggregate emissions of acid rain precursors, respectively. These CAAA titles result in a national cap on SO_2 emissions and regional caps on NOx emissions.

The CAA mandates the ongoing promulgation of a variety of emission standards and controls; a rulemaking process that has been in progress for many years and is expected to extend well into the future. The HAPs, PM_{10} and ozone federal standards have been revised recently, and a new $PM_{2.5}$ particulate matter standard was promulgated. In March 2005, EPA announced new Clean Air regulations concerning power plant emissions of NOx, SO_2, and mercury. Under the Clean Air Interstate Rule, emissions of SO_2 and NOx will be reduced in 28 eastern states and Washington, DC. These new regulations are an attempt to successfully lower power plant emissions to levels that meet the federal standards set in the CAA. Both federal and state governments constrain sources of air emissions primarily based on the CAA regulations; however, state regulations may be even stricter than those promulgated in the CAA.

The NAAQS are achieved by each state through the implementation of a State Implementation Plan (SIP) that imposes emission limits on individual sources, such as a coal-fueled IGCC power plant. Although developed initially by state and local air pollution control officials, SIPs must be adopted by municipal and state governments and then approved by EPA. Once a SIP is fully approved, it is legally binding under both state and federal law, and may be enforced by either government. A geographic area that meets or does better than the NAAQS primary standard for a criteria pollutant is called an **attainment area**; areas that don't meet the primary standard are called **nonattainment** areas. In the New England region, for example, non-attainment areas are most likely due to ozone; emissions of VOCs and NOx are thus the primary focus in these areas since they are the precursor emissions that produce ozone.

The legal instrument used in the U.S. to ensure compliance with environmental regulations and SIPS is the environmental permit.[14] A permit may specify in considerable detail how a facility may be constructed or operated and, therefore, must be obtained prior to commencement of any activity, including construction. Utility, industrial and municipal facilities are required to obtain these permits to control their pollutant emissions to the air, land, and water.

Various federal permitting programs have been established by EPA under the Clean Air Act, such as the NSR and Title V of the 1990 Clean Air Act Amendments for air emissions. In general, permit programs are defined in the regulations to ensure that the requirements of the original statute are properly implemented. Rather than issuing permits itself, EPA generally has established programs to authorize state, tribal, and local permitting authorities to perform most permitting activities. Once EPA has delegated its authority for a permitting program to a state or tribe, they can then implement their own version of the permit program as long as it meets the minimum requirements stated in the governing statutes and regulations. EPA has delegated authority to most states for implementing part or all of the major permit programs. Some states have enacted provisions that are more stringent than federal requirements, while other states have adopted the federal requirements without revision. Air quality permitting is required if operational emissions are greater than the defined major source threshold; emissions threshold levels for major permit efforts are dependent upon the location of a facility <u>and</u> the existing air quality in that area; i.e. attainment or nonattainment area category.

[14] The permitting process for the siting of a fossil-based energy facility is a complex and lengthy process, especially due to the increasing number of applicable regulations and associated permits required. Permit applications may take several months to prepare and can take an additional twelve months for approval, as for a PSD permit. The permit process usually includes air, water and solid waste impact assessments, assessment of need for additional generating capacity, and other impact analysis. In addition to the various state permitting agencies that are involved, there is also a public participation component that can significantly effect the time required to obtain the permit.

New Source Performance Standards (NSPS, 40 CFR 60) outline performance requirements for new or modified source units,[clxviii] but other regulations may ultimately establish the actual performance level required. Subpart Da addresses requirements for fossil-fuel-fired electric utility steam generators greater than 73 MW (>250 million Btu/hr) for which construction commenced after September 18, 1978 (or an alternative date as modified). In addition, NSPS requirements for stationary gas turbines (that would be applicable for IGCC technology) are outlined by 40 CFR 60 Subpart GG. These requirements apply to all stationary gas turbines with a heat input (at peak load) equal to or greater than 10.7 gigajoules or 10 million Btu per hour. The language of the regulation includes combined cycle gas turbines defined as "any stationary gas turbine, which recovers heat from the gas turbine exhaust gases to heat water or steam" (40 CFR 60.331). Together, these regulations outline specific compliance requirements for SO_2, NOx, PM, and opacity.

New source review (NSR) requirements are outlined by 40 CFR 52.21(b)(1)(I)(a)-(b) and apply to all new major emission sources and may apply to expansions or modifications of existing facilities. Triggers for NSR compliance typically vary depending on the designated status of the location where the source will be located (i.e., whether the location is attainment or nonattainment). Areas classified as attainment or unclassifiable must comply with regulations outlined under the Prevention of Significant Deterioration (PSD) program. Because NOx is a precursor for ozone formation, area status of NAAQS for both NOx and VOC pollutants must be considered.

For areas that are designated as attainment or unclassifiable, the major source threshold for most sources is 250 tons per year of the applicable pollutant. For fossil-fueled steam electric plants, the trigger is 100 tons per year of the applicable pollutant. For areas designated as nonattainment, the compliance threshold ranges from 100 tons per year of the designated pollutant down to 10 tons per year, depending on the severity of the air quality compromise where the source is located. For companies that own or operate multiple sources within a single operating area, most often within a single plant site, the compliance thresholds can be interpreted with respect to total emission from all sources within the area or plant site. This allows the company to reduce emissions at another source and have a "net" emission increase within the operating area, including the new or modified source, of less than the NSR trigger. This process is known as "netting out."[clxix]

The NSR process is typically conducted on the state level in accordance with their SIP. Compliance plans for PSD include technological requirements such as Best Available Control Technology (BACT) and may include air quality dispersion modeling, using models such as EPA's CALPUFF non-steady-state modeling system.[clxx] Pre-startup air quality monitoring is required for new sources. BACT is an emissions limit based on the maximum degree of emissions reduction for a pollutant based on application of the best available control technology, and allows the consideration of energy, environmental, and economic impacts (42 U.S.C.A. §§ 7475, 7479(3)). Because BACT is a case-by-case decision, specific requirements may vary from one location to another. Sources subject to PSD are not typically required to offset emission increases.

In nonattainment areas, environmental permits may be issued requiring new sources to meet lowest achievable emission rate (LAER) standards (42 U.S.C.A. § 7503 (a)(2)) based on a numerical emission standard or a specific equipment design or operational requirement. These standards are based on technological factors and cannot consider energy or economic issues. In addition to LAER requirements, operators of facilities must obtain "emission offsets" of the same pollutant from other sources within the nonattainment area to ensure equivalent or lower total emissions in that area. These offsets typically are an equivalent 1:1 offset, but may require greater reductions depending on the severity of the air quality compromise.[clxxi] Thus, source control required under NSR can be significantly more stringent than required by the PSD rules.

The current requirements of the NSPS and NSR programs are summarized below in Table 9.3. As the table indicates, actual permitted emissions levels may be significantly less than required by NSPS based on a requirement to use BACT and LAER. BACT/LAER requirements are determined by a permitting agency on a case-by-case basis, considering the most stringent emission limits imposed on similar facilities and certain project-specific factors. Therefore, it is not possible to forecast precisely what BACT/LAER would require for any particular plant installation, but recent BACT/LAER determinations provide an indication of likely requirements. The air emission regulations that will likely have the biggest impact on the introduction of clean technology, such as IGCC, are those that limit NOx and mercury emissions. EPA's "top-down-approach" for determining BACT has resulted in the lowering of allowable natural gas-fired turbine NOx emission levels to values significantly less than NSPS. BACT levels as low as 9 ppm (equivalent to 0.04 lb/10^6 Btu) can be achieved using combustion controls, and flue gas treatment equipment, such as selective catalytic reduction (SCR), can further lower NOx levels. LAER may require emission levels as low as 2 or 3 ppm (equivalent to 0.01 lb/10^6 Btu) for natural gas-fired turbines in some states.

Table 9.3 NSPS and NSR Requirements for Air Pollutants from Coal-Fueled Power Plants

POLLUTANT	NEW SOURCE PERFORMANCE STANDARD (NSPS)	RECENT NSR BACT/LAER EMISSION LIMIT	RECENT BACT/LAER CONTROL TECHNOLOGY	RECENT BACT/LAER CONTROL EFFICIENCY
Sulfur Dioxide, SO_2	0.6 to 1.2 lb/10^6 Btu and 70% to 90%Removal	0.12 to 0.2 lb/10^6 Btu	Low to Medium Sulfur Coal, FGD	90 to 95%
Nitrogen Oxides, NOx as NO_2	1.6 lb/Megawatt-hour and 0.15 lb/10^6 Btu	0.05 to 0.1 lb/10^6 Btu	Selective Catalytic Technology with Low-NOx Burners	50 to 90%
Particulates, TSP or PM10	0.03 lb/10^6 Btu and 99% Removal	0.01 to 0.015 lb/10^6 Btu	ESP, Fabric Filter	>99.5%
Opacity	20% Opacity (6 minute average)[a]	10% opacity	ESP, Fabric Filter	99.9% TSP
Carbon Monoxide	None	0.1 to 0.15 lb/10^6 Btu	Combustion Control	--
Volatile Organic Compounds, VOCs	None	0.005 to 0.03 lb/10^6 Btu	Combustion Control	--

a May emit 27% opacity for one 6-minute period per hour

Title IV acid rain provisions of the 1990 Clean Air Act Amendments (CAAA Title IV – Acid Deposition Control, 42 U.S.C.A. § 7651) further regulate SO_2 and NOx emissions from electric utility plants and outline specific reduction targets for existing plants. The program includes traditional regulatory mechanisms along with an allowance trading system and a cap on future annual emissions of SO_2 of 8.9 million tons. In addition to SO_2 and NOx emission compliance, Title IV requires continuous emission monitoring (CEM) that includes measurement and recording of SO_2, NOx and CO_2 emissions, as well as volumetric flow, opacity and diluent gas levels.[clxxii]

Title I NAAQS attainment provisions of the 1990 Clean Air Act Amendments (CAAA Title I – Provisions for Attainment Maintenance of NAAQS, 42 U.S.C.A. § 7407d) requires reductions in ground-level ozone and its precursors, including NOx. Ground-level ozone is a major ingredient of smog. Since NOx is a major ozone precursor, it is necessary to control NOx to comply with ambient ozone standards. Effective July 16, 1997, the NAAQS for ozone is 0.08 ppm (8-hour average). At this level, many large- and medium-sized urban areas are classified as being in nonattainment, and many power plants are situated within these nonattainment areas. Nonattainment of ozone standards result not only from NOx emissions in a given locality, but also from significant amounts of NOx transported by winds over a wide geographical area. To account for the regional transport issue, the CAAA also provided for the establishment of ozone transport regions.

The Ozone Transport Assessment Group (OTAG), established in 1995 to undertake an assessment of regional pollutant transport problems in the eastern half of the United States, concluded that regional reductions in NOx emissions are needed to reduce the production and transport of ozone and its precursors. OTAG recommended that major sources of NOx emissions (utility and other stationary sources) be controlled. Based on OTAG's analysis, findings, and recommendations, EPA ultimately issued a rule under Title I on September 24, 1998, to establish a cap for NOx emissions. It is applicable to electric power generating units within an area covering 22 states east of the Mississippi River[15] plus the District of Columbia (EPA, 1998), although this area was later reduced to 19 states plus DC. These jurisdictions are required to submit SIPs to meet target emissions levels under the EPA NOx SIP Call. The cap applies to the five-month ozone season from May 1 through September 30. Both existing and new plants within the SIP Call region will be required to meet reduced NOx emissions levels that may be even more stringent than required by Title IV, NSPS or NSR.

Clean Air Interstate Rule. The Clean Air Interstate Rule (CAIR) is primarily designed to deal with regional air pollution control issues (i.e., ground-level ozone, fine particulates). It extends the CAA by permanently capping SO_2 and NOx emissions across 28 eastern states and the District of Columbia. EPA established more protective fine particle (PM2.5) and 8-hour ozone national air quality standards in 1997. Litigation and the need to establish a nationwide air monitoring system for fine particles delayed the implementation of these standards, but in 2006 the standards were further revised to include fine particles ($PM_{2.5}$), which are 2.5 micrometers in diameter and smaller, and inhalable coarse particles (PM_{10}) which are smaller than 10 micrometers and larger than 2.5 micrometers. Areas not meeting the new fine particle and ozone standards, known as "nonattainment" areas, were designated in 2004. EPA found that by limiting emissions of SO_2 and NOx on a regional scale, CAIR would help all areas in the eastern U.S. achieve air quality at lower costs than by using a strategy that relies solely on local controls.

States must achieve the required emission reductions using one of two compliance options: 1) meet the state's emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an

[15] The SIP Call area consists of Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

individual state emissions budget through measures of the state's choosing. Once implemented, EPA anticipates that states will achieve this primarily by reducing emissions from the power sector and by participating in the interstate cap and trade system.

SO_2

Federal NSPS for SO_2 compliance of fossil fuel-fired steam generators are based on the type of fuel burned and the potential combustion concentration[16] in the flue gas. For solid fuel or solid-derived fuel, sulfur dioxide limits are 520 nanograms per joule (ng/J) (1.20 lb/10^6 Btu) heat input and 10 percent of the potential combustion concentration (90 percent SO_2 reduction), or 30 percent of the potential combustion concentration (70 percent SO_2 reduction) when emissions are less than 260 ng/J (0.60 lb/10^6 Btu) heat input (40 CFR, Part 60 **§** 60.43a – standard for sulfur dioxide – 39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4, 1987). For combustion of combined fuels, the requirements are based on percentage contribution of solid, liquid and gaseous fuels.
CAAA Title IV acid rain compliance plans require that an affected unit hold enough allowances to cover annual SO_2 emissions and that it will comply with applicable Title IV SO_2 limits. Each sulfur dioxide allowance permits a unit to emit 1 ton annually. For each ton of SO_2 emitted in a given year, one allowance is permanently retired. The number of allowances an affected facility receives is based on past fuel consumption and relevant emission rate.

Additional allowances are allocated annually to units in high growth states (42 U.S.C.A. §7651d(i)) and certain municipally owned power plants. Also, for states with 1985 SO_2 emission rates below 0.8 lb/10^6 Btu, emission allowances are available upon the discretion of that State's Governor. Most important to plants that will be installed in coming years, any new fossil-fired plant will have to fall under the overall SO_2 cap of 8.9 million tons of SO_2 per year as well as the new CAIR cap. A utility will have to have either banked or purchased SO_2 allowances for the plant to operate. It is this cap on SO_2 emissions that most impacts construction of new plants and will likely require strict SO_2 emissions limits.

The CAAA provided special incentives for the "repowering" of a facility using specific clean coal technologies. The deadline for demonstrated intent was December 31, 1997. Utilities that underwent repowering were granted an extension of the deadline for emission limitation compliance and issued non-transferable SO_2 allowances specifically for the operation of the repowered unit.

NOx

Federal NSPS for fossil-fuel-fired steam generator NOx compliance were revised in September 1998. The change only applies to units for which construction, modification, or reconstruction began after July 9, 1997. The pollutant standard for newly constructed sources built after this date is quantified on a basis of energy output rather than the former heat input basis. The standard is 200 nanograms NOx (as NO_2) per joule (ng/J) or 1.6 lb/megawatt-hour (MWh) gross energy output on a 30-day rolling average, regardless of fuel type (40 CFR, Part 60 **§** 60.44a –standard for nitrogen oxides – 44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001). For existing sources that undergo a modification or reconstruction after the prescribed date, the standard remains on a heat input basis, but is lowered to 65 ng/J or 0.15 lb/10^6 Btu as NO_2.

[16] Potential combustion concentration is defined in the NSPS as the theoretical emissions that would result from the combustion of a fuel in an uncleaned state without emission control systems.

In December 1987, EPA's "top-down-approach" for determining BACT became a new Prevention of Significant Deterioration (PSD) requirement. The first step in this approach is to determine, for the power generation unit in question, the most stringent control available for a similar or identical unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The Title IV Acid Rain provisions for NOx reductions, like those for SO_2, required a two-phase program, but most importantly did not cap overall emission limits. Phase I began in 1996 and Phase II in 2000. Affected units have four compliance options.[clxxiii]

- *Standard Emission Limitations*: Specific units covered by Phase I include dry bottom-wall fired boilers and tangentially fired boilers with emission limits of 0.50 lb/10^6 Btu and 0.46 lb/10^6 Btu respectively, on a heat input basis. Phase II includes further restrictions on dry bottom-wall fired boilers (0.46 lb/10^6 Btu) and tangentially fired boilers (0.40 lb/10^6 Btu) while adding limits to cell burner boilers (0.68 lb/10^6 Btu), cyclone boilers (0.86 lb/10^6 Btu), vertically fired boilers (0.80 lb/10^6 Btu), and wet bottom boilers (0.84 lb/10^6 Btu).
- *NOx Emissions Averaging*: The owner or operator of two or more units subject to one or more of the applicable emission limitations may petition the permitting authority for alternate contemporaneous annual emission limits for such units that ensure that the actual annual emission rate in lb/10^6 Btu averaged over the units in question is less than or equal to the Btu-weighted average annual emission rate for the same units if they had been operated for the same time period in compliance with applicable emission limitations (42 U.S.C.A. § 7651f(e)).
- *Alternative Emission Limitations:* If a boiler is unable to meet its standard limits after proper installation and operation of appropriate NOx control technology, the owner and operator may petition EPA and the permitting authority for a less stringent NOx emission limit.
- *Early Election:* A Phase II affected unit with a dry bottom wall-fired or tangentially fired boiler that complied with Phase I emission limits by January 1, 1997 is exempt from Phase II limits until 2008.

In 1998 the Regional Transport of Ozone Rule, also known as the NOx SIP Call was passed. The NOx SIP call requires 22 eastern states and the District of Columbia to submit SIP revisions that address the regional transport of ground-level ozone. The SIP revisions must contain measures that will ensure that sources in their states will reduce their NOx emissions so that downwind states can meet the Federal ozone standards.

Since May 1999, 11 Northeastern states and the District of Columbia (the Ozone Transport Commission (OTC) region) have been subject to caps on their emissions of NOx between May 1 and September 30 in a bid to prevent summertime smog. Under a 2001 regulation, 13 Southern and Midwestern states were also asked to comply with similar restrictions. The EPA asked the 21 states to submit SIPs on how they plan to address NO_X pollution based on a model devised by the agency. The model suggested a cap-and-trade system which would be monitored by the US EPA. As with the current OTC market, one tradeable allowance will represent one ton of NOx emitted during the months of May through September. The plan caps emissions of NOx from the 21 states at a total of 3.3 million ton/year (3 Mt/y), down from a 1995 baseline of 4.4 million ton/y (4 Mt/y). The scheme will run through 2007, when an evaluation will be performed by the agency.

Ultimately, the NOx emission limit imposed on a specific power system depends upon its location and treatment by regulatory authorities. In the case of IGCC, it is possible that regulatory authorities could view a coal gasification-based power system as similar to a coal/solid fuel-based facility, a natural gas-fired unit (if a combustion turbine is part of the power cycle), or possibly as some unique gasification or syngas-fired unit. The location determines whether ozone attainment or nonattainment regulations apply, as well as conditions that could be imposed by the NOx SIP Call or other local requirements. Clearly, emission limits imposed on coal-fueled plants by Title IV are far less restrictive than the BACT or LAER regulations that are applied to natural gas-fired combustion turbines.

Particulates

Federal NSPS standards for PM10 for a fossil-fuel-fired steam generator are based on heat input and potential combustion concentration of the solid fuel. The particulate levels for fossil fuel fired steam generating units are 13 ng/J (0.03 lb/10^6 Btu) on a heat input basis and 1% of the potential combustion concentration. Opacity requirements are set at 20% for a six-minute average and an allowance of one 6-minute period per hour of no more than 27% opacity.

On March 29, 2007, EPA issued a rule defining requirements for state plans to clean the air in areas with levels of fine particle pollution that do not meet national air quality standards (see Section on CAIR above). State plans under this final rule, known as the Clean Air Fine Particle Implementation Rule, must be submitted to EPA by April 2008.

The Clean Air Fine Particle Implementation Rule describes the CAA framework and requirements that state, local, and tribal governments must meet in developing their $PM_{2.5}$ implementation plans. States must meet the PM2.5 standard by 2010. However, in their 2008 implementation plans, states may propose an attainment date extension for up to five years.
For each nonattainment area, the CAA requires the state to demonstrate that it has adopted all reasonably available control measures, considering economic and technical feasibility and other factors, that are needed to show that the area will attain the fine particle standards as expeditiously as practicable. This rule sets forth guidelines for making RACM and RACT determinations. The rule includes a presumption that for power plants subject to CAIR, compliance with CAIR would satisfy these requirements for SO_2 and NOx.[clxxiv]

This final rule does not include NSR requirements for the $PM_{2.5}$ standards. These requirements will be addressed in a separate rulemaking.

Mercury

Title III hazardous air pollutants provisions (HAPs) of the 1990 Clean Air Act Amendments (CAAA Title III – Hazardous Air Pollutants, 42 U.S.C.A. § 7412) identified 189 pollutants as potentially hazardous or toxic and required EPA to evaluate their emissions by source, health and environmental implications, and the need to control these emissions. These pollutants are collectively referred to as air toxics or hazardous air pollutants (HAPs). Control requirements are technology-based and established by the top performing existing sources.

Triggers for compliance are dependent on yearly emission quantities for one or more HAPs (10 tons/year for any one HAP or 25 tons/ year for any combination of HAPs).

The provisions in Title III specific to electric power generation units were comprehensively addressed by DOE's National Energy Technology Laboratory (NETL) and the Electric Power Research Institute (EPRI) in collaborative air toxic characterization programs conducted between 1990 and 1997. This work provided most of the data supporting the conclusions found in EPA's Congressionally mandated reports regarding air toxic emissions from coal-fueled utility boilers: the Mercury Study Report to Congress[clxxv] (1997) and the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress[clxxvi] (1998). The first report identified coal-fired power plants as the largest source of man-made or anthropogenic mercury emissions in the U.S., and the second concluded that mercury from coal-fired utilities was the HAP of "greatest potential concern" to the environment and human health that merited additional research and monitoring.

Subsequent to these findings, data were gathered during EPA's 1999/2000 Information Collection Request (ICR) to refine the total mercury emission inventory from coal-fueled plants and ascertain the mercury control capabilities of existing and potential emission control technologies. Results of this work, plus an independent evaluation of mercury health impacts by the NAS, culminated in EPA's regulatory determination, in December 2000, to regulate mercury emissions from coal-fueled power plants. In their regulatory determination, EPA concluded that there was a "plausible link" between emissions of mercury from coal-fired electric utility steam generating units and the bioaccumulation of methyl-mercury in fish and other animals that eat fish. Since human exposure to mercury occurs primarily through consumption of contaminated saltwater or freshwater fish, further control of coal- and oil-fired power plants was deemed necessary.

In 2005, the US EPA issued *the Clean Air Mercury Rule (CAMR),* which is based on a cap-and-trade system and new source performance standards for new units. A total national cap on annual mercury releases from coal-fired power plants is shared among the participating States and Tribes who decide on how their total number of allowances should be allocated to individual power plants. Facilities facing high emission reduction costs, due to their state of technology and other factors, can buy allowances from facilities that can reduce mercury releases at lower cost. Facilities that reduce their emissions below the number of allowances they hold for a given year can sell the "surplus" allowances in the market, or bank them for use in a later year. The Mercury Rule has two phases. The total mercury cap in Phase 1 is 38 short tons per year to be achieved by 2010, and in Phase 2 (from 2018) the cap is set at 15 short tons per year. The 38 tons cap is designed to be fulfilled solely by expected co-benefits of the new SO_2 and NO_x rules (*the Clean Air Interstate Rule*). That is, no specific mercury emission reduction equipment will be required. Some power plants would, however, probably invest in such measures – which would generate bankable permits that can be used once the total cap is reduced to 15 tons in 2018.

Some states fear that EPA's emissions trading system will not secure sufficient reductions on the local or regional level where specific facilities are major sources of mercury pollution. These concerns about "hot spots' were raised because of the local nature of mercury pollution. In response, the EPA has allowed all states to address local health-based concerns separate from the CAMR requirements.

Out of the 48 states that have coal-fired utilities, about two-thirds are planning to introduce mercury permit trading. Of these, three-fifths will implement the CAMR as-is. About one-fifth of the states with trading will have more stringent, direct local control requirements (i.e., permit limits) in addition to trading, whereas about one-fifth of these states will introduce trading but will hold back part of their state-wide emissions quota. About one-third of the 48 states with coal-fired utilities will either not participate in the trading program or have not provided clear indication of their plans. Those that have indicated that they will not participate in the trading program will likely introduce more stringent direct controls.

9.2. Carbon Dioxide

Regulations targeting CO2 emissions from the power sector are quickly emerging in the United States, particularly at the state and regional level. The following subsections describe developments in each area.

9.2.1 Federal Developments

There are no federal regulatory requirements in the United States for the reduction of greenhouse gases,[17] including CO_2. However, several national-level proposals are pending in congress that would regulate carbon dioxide and other greenhouse gases from the utility and other sectors. As outlined in Table 9.4, most of these bills are economy-wide and cover all six greenhouse gases, but there are also some that target just the power sector. Of the power sector bills, one regulates all six major GHGs while the other three include local air pollutants (sulfur dioxide, nitrogen oxides, and mercury) and CO_2.

Among the economy-wide bills in the Senate, the Sanders-Boxer proposal (S. 309) sets the most stringent target of 80 percent below 1990 level emissions by 2050, and is thus favored by many environmental groups. In the House, H.R. 1590, sponsored by Representative Waxman, has garnered similar environmental support. It sets similar targets for 2050 as the Sanders-Boxer bill, but would require earlier emission reductions. The target of the Lieberman-McCain bill (S. 280) falls more in the middle of the range of Senate bills (60 percent below 1990 by 2050), and has

[17] The six major greenhouse gases include carbon dioxide, methane (CH_4), nitrous oxide (N_20), hydro fluorocarbons (HFCs), per fluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These are also the ones covered by the Kyoto Protocol.

Table 9.4 GHG Emission Targets and Cap and Trade Legislation in the 110th Congress

Bill	Scope	Emissions Cap 2010-2012	Emissions Cap 2020	Emissions Cap 2050	Allocation versus Auction	Offsets
	Economy-wide Bills					
Bingaman-Specter (S. 1766) *Com. on EPW, 7/11/07.*	6 Major GHGs Economy-wide Upstream	2012 in 2012.	2006 by 2020.	1990 by 2030. President may set long-term target >60% below 2006 levels by 2050.	Increasing auction. Some sector allocations.	10% limit on international credits. 5% set-aside for bio sequestration $12/ton safety valve starting 2012; increasing 5%/year.
Lieberman-Warner (S. 2191) *Com. on EPW, 10/18/07*	6 Major GHGs Economy-wide "Hybrid" Up: transportation fuels Down: electric utilities, large sources	2005 by 2012	15% < 2005 in 2020	33% <2005 in 2030 52% <2005 in 2040 70% <2005 in 2050	Increasing auction. Some sector allocations.	15% limit on domestic offsets and international credits.
Kerry-Snowe (S. 485) *Finance Com., 2/1/07.*	6 Major GHGs Economy-wide Downstream	1.5% <2009 in 2010	1.5%/yr reduction 2010-2019	2.5%/yr reduction 2020-2029 3.5%/yr reduction 2030-2050	President determines.	Potential for offsets generated from biological sequestration.
Lieberman-McCain (S. 280) *Hearings, 7/24/07.*	6 Major GHGs Economy-wide "Hybrid" Up: transportation Down: electric utilities, large sources	2004 by 2012	1990 in 2020	20% <1990 in 2030 60% <1990 in 2050	Administrator determines.	30% limit on international credits and domestic reduction or sequestration offsets.
Olver (H.R. 620) *Energy and Commerce; Science and Technology, 1/22/07.*	6 Major GHGs Economy-wide "Hybrid" Up: transportation Down: electric utilities, large sources	2004 by 2012	1990 in 2020	20% <1990 in 2030 60% <1990 in 2050	Administrator determines.	30% limit on international credits and domestic reduction or sequestration offsets.
Sanders-Boxer (S. 309) *Intro Remarks, EPW, 6/13/06.*	6 Major GHGs Economy-wide Downstream	N/A	1990 in 2020	27% <1990 in 2030 53% <1990 in 2040 80% <1990 in 2050	Cap and trade not required.	Potential for offsets generated from biological sequestration.
Waxman (H.R. 1590) *Energy and Commerce 3/20/07.*	6 Major GHGs Economy-wide	2009 in 2010 2%/yr reduction 2011-2020	1990 in 2020 5%/yr reduction 2021-2050	5%/yr reduction 2021-2050 80%<1990 in 2050	President and Administrator determine.	N/A.

Bill	Scope	Emissions Cap 2010-2012	Emissions Cap 2020	Emissions Cap 2050	Allocation versus Auction	Offsets
	Bills Targeting the Electricity Sector					
Feinstein-Carper (S. 317) *Com. on EPW, 1/17/07.*	6 Major GHGs Electricity sector Downstream	2006 in 2011 2001 in 2015 1%/yr reduction 2016-2019	1.5%/yr reduction 2020- Administrator may adjust.	1.5%/yr reduction 2020- Administrator may adjust.	Increasing auction. Output-based allocation to generators.	Certain categories of bio sequestration and industrial offsets; 5% limit on forest management; 25% limit on international credits.
Alexander-Lieberman (S. 1168) *Com. on EPW, 4/19/07.*	CO_2, SO_2, NO_x, Hg Electricity sector	2300 MMT CO_2 2011-2014[18] 2100 MMT CO_2 2015-2019[19]	1800 MMT CO_2 2020-2024[20] 1500 MMT CO_2 2025-[21]	2500 MMT CO_2 2025-[22]	75% historical allocation; 25% auction. Input-based benchmarked allocation to generators.	Considering RGGI model rules.
Carper (S. 1177) *Com. on EPW, 4/20/07.*	CO_2, SO_2, NO_x, Hg Electricity sector	2006 in 2012-2014 2001 in 2015 1%/yr reduction 2016-2019	1.5%/yr reduction in 2020	1.5%/yr reduction in 2020 Administrator may adjust to 3%/yr reduction in 2030. 25%<1990 in 2050	Increasing auction. Output-based allocation to generators transitioning to 100% auction.	Agricultural sequestration allowances.
Sanders (S. 1201) *Com. on EPW, 4/24/07.*	CO_2, SO_2, NO_x, Hg Electricity sector	2300 MMT CO_2 by 2011[23] 2100 MMT CO_2 by 2015[24]	1803 MMT CO_2 by 2020[25] 1500 MMT CO_2 by 2025[26]	Goal: facilitate worldwide stabilization of atmospheric concentrations of GWP at 450ppm CO_2e by 2050.[27]	Increasing auction; administrator determines.	Potential for offsets generated from biological sequestration.

[18] This is approximately equivalent to 2006 level.
[19] This is approximately equivalent to 1997 level.
[20] This is approximately equivalent to 1990 level.
[21] This is approximately equivalent to 17% below 1990 level.
[22] This is approximately equivalent to 17% below 1990 level.
[23] This is approximately equivalent to 2006 level.
[24] This is approximately equivalent to 1997 level.
[25] This is approximately equivalent to 1990 level.
[26] This is approximately equivalent to 17% below 1990 level.
[27] If legislation to address 85% of GHG emissions economy-wide has not become law by 2012, increase reduction targets by 3%/yr until global GHG emissions reach 450ppm.

been dubbed the “Presidential Bill,” because of the large number of 2008 Presidential candidates who support it; John McCain, Hillary Clinton, and Barack Obama are all cosponsors.

The Bingaman-Specter bill (S. 1766) is one of the least stringent and is the only one to introduce a safety-valve as a means to limit the cost of the legislation. The safety-valve is set at \$12/MT-CO_2, which means that if the price of allowances exceeds this threshold, an entity can avoid submitting allowances by paying the “safety valve” price, starting at \$12/MT-CO_2 in 2010, with a nominal five percent annual increase. This would ensure an upper bound on costs, but also make it highly likely that emissions each year after 2015 would exceed the targeted caps. The Kerry-Snowe bill (S. 485) is advertised as a good first step toward reducing greenhouse gases, as it reduces GHGs more slowly than several of the other proposals. The Lieberman-Warner legislation (S. 2191), introduced October 18, 2007, combines many of the distinct features of the previously introduced economy-wide bills, and has already received significant support. It is widely anticipated as a strong compromise bill on climate change and includes a “Federal Reserve-style” board that would regulate the cost of GHG allowances.

In the House, representatives John Dingell (D-MI) and Rick Boucher (D-VA) are working on another economy-wide proposal. Their target would be set between 60 and 80 percent below current levels, and would be met through emissions trading and perhaps a mix of carbon taxes and increased funding for low-carbon technologies.

In addition to these proposed trading systems, one bill introduced by Senator John Kerry, would require that only new power plants that include CO_2 capture and storage would be allowed to operate in the United States. Another proposal introduces an economy-wide carbon tax instead of an emissions trading system.

A common feature of the proposals is their focus on incremental emission reductions over the next forty years to make significant reductions in GHGs and to encourage long-term transformation in capital investment toward a low-carbon economy. The expected influence of these bills on the uptake of clean coal technologies ultimately depends on the targets and mechanisms introduced. For example, Senator Bingamann’s proposed safety valve would mean that only reductions costing \$12, or less, would be implemented. Because of the higher cost of reducing emissions through the use of clean coal technology, such as CO_2 capture and storage, a safety valve at that price would likely not lead to significant deployment of clean coal in the power sector.

As outlined in Table 9.3, most of the proposed GHG bills have focused on emissions trading. However, a September 2007 carbon-tax proposal by Representative John Dingell, who chairs the House Committee on Energy and Commerce, is likely to increase the spotlight on taxes as a means of reducing emissions.[clxxvii] In its current form, Dingell's proposal would impose a \$50-per-ton tax on carbon[28] and a 50 cents per gallon (in addition to the current gas tax) on gasoline jet fuel and kerosene. Both taxes would be phased in over five years and then adjusted for inflation. The bill phases out tax deductions for homes over 3,000 square feet. Numerous lawmakers are skeptical of Dingell’s proposal because they believe he may be

[28] \$50-per-ton of carbon is equivalent to \$13.64-per-ton of carbon dioxide. According to a spokesman for John Dingell’s office (Personal Communication, Katie Murtha, October 24, 2007), the “ton” of carbon referred to is equivalent to 2,000 lbs, which is one “short ton.”

trying to avoid measures to improve auto fuel-economy standards that could adversely affect his Congressional district in Michigan.

In August 2007, another tax proposal (H.R. 3416) was introduced in the House by Rep. John Larson. This legislation would set a $15 tax on every short ton of carbon dioxide emitted from the oil, gas, and coal industries, with the tax rising 10 percent annually and adjusting for inflation. Larson estimates that the bill would lead to a 12.1 percent cut in GHG emissions every decade. Revenue from the tax would be invested in zero-carbon emissions energy production, transition assistance for affected industries, and a payroll tax. Companies that capture and store carbon dioxide would get a tax credit. Earlier in the year, representatives Peter Stark (D-CA) and Jim McDermott (D-WA) proposed a $10/short ton tax on the carbon content of extracted or imported fuel with a $10-per-year increase every year until U.S. carbon dioxide emissions have dropped to 80 percent below 1990 levels. While many industrial economies employ similar methods, carbon taxes as a mitigation option for the U.S. has yet to gain much support.

9.2.2 Legal Developments

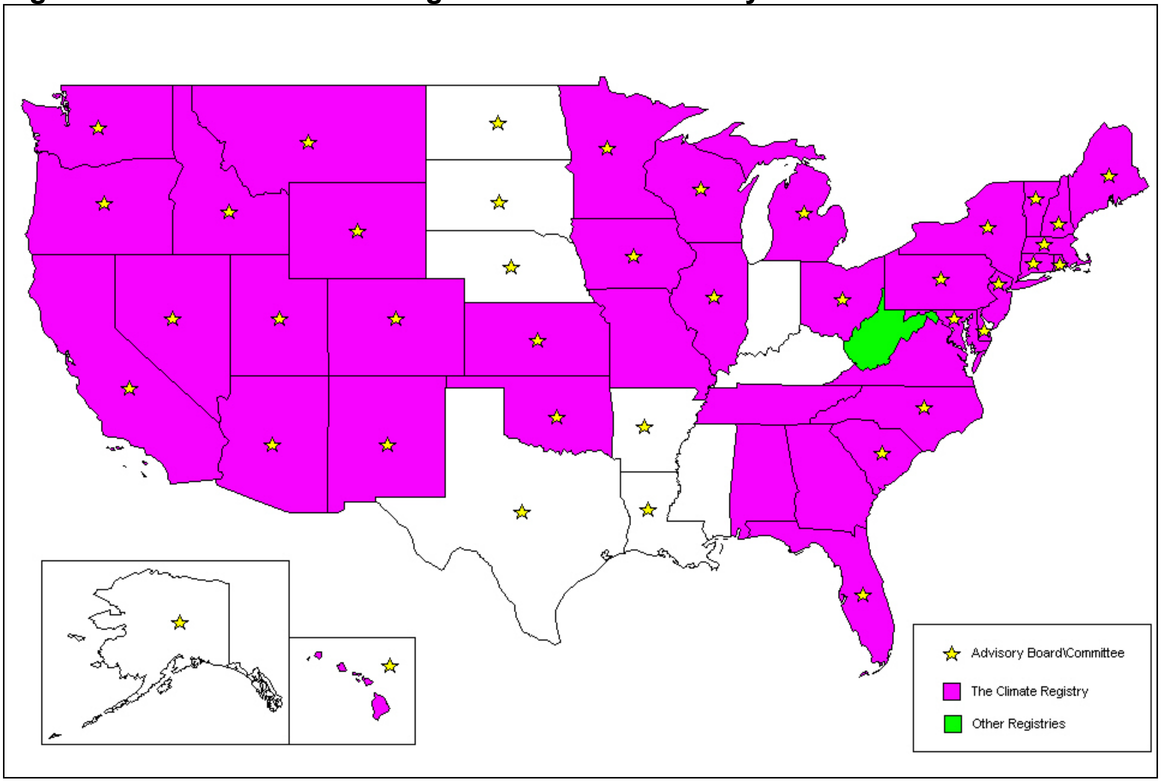
Federal and District Courts decided several cases in 2007 that will affect climate change policy in the U.S. Most notably, on April 2, 2007, the Supreme Court ruled in *Massachusetts v. the Environmental Protection Agency*, that section 202(a)(1) of the Clean Air Act gives EPA the authority to regulate tailpipe emissions of greenhouse gases. The decision states that "EPA can avoid promulgating regulations only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do."[clxxviii] This ruling significantly increases the likelihood that other sources of GHGs will be regulated under the Clean Air Act, including power plants.

Several 'public nuisance' lawsuits have also been filed against major GHG emitting companies, including power plants, in an effort to link their emissions to the perceived impacts and costs of climate change. However, so far, plaintiffs have had a hard time proving their cases. In September 2006, California filed a first-of-its-kind 'public nuisance' lawsuit against six of the world's largest automakers, charging that the GHG emissions from their vehicles have caused billions of dollars in damages. As noted in the lawsuit, California has spent millions to deal with the effects of climate change and the state is seeking monetary damages for past and ongoing contributions to global warming. On September 17, 2007, a U.S. District Court judge dismissed the case.[clxxix] Another 'public nuisance' suit, filed by Hurricane Katrina victims against Exxon Mobil Corp., Peabody Energy, American Electric Power Co., Dow Chemical Co. and others, claiming that these companies contributed to the global warming that caused the 2005 storm, was dismissed by a Federal Court on August 30, 2007. Katrina victims appealed the case to a federal appeals court on September 17, 2007, and plan to take the case all the way to the Supreme Court if this hearing is unsuccessful.[clxxx]

9.2.3 Individual States and Regions

Concerned with the lack of regulation at the federal level, several states and regions have introduced climate change legislation and emissions trading systems that will have significant impact on the power sector, particularly coal-fired power plants.

Figure 9.1 States with GHG Registries and/or Advisory Board Committees



The Climate Registry

Regional GHG reporting initiatives continued to grow in scope and expand their memberships over the past year, leading to the formation of a multi-state collaboration aimed at developing a voluntary, common system for entities to report GHG emissions known as the Climate Registry (see Figure 9.1).[clxxxi] The Registry will incorporate the California Climate Action Registry (CCAR), the Eastern Climate Registry, the Western Regional Air Partnership, and the Lake Michigan Air Directors Consortium (LADCO), making it the largest state- and province-based effort to date to track greenhouse gas emissions. On May 8, 2007, thirty-one U.S. states and one Tribal Nation signed on as charter members.[29] Since then, eight additional U.S. states, the District of Columbia, one Mexican state, two additional Tribal Nations and three Canadian provinces have become members.[30] The Registry will serve as a tool to measure, track, verify and publicly report GHG emissions consistently and transparently. Voluntary, market-based and regulatory GHG emissions reporting programs are all supported under the Registry.

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[29] The charter member states and tribes include: Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Illinois, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, New Hampshire, New Jersey New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, South Carolina, Utah, Vermont, Washington, Wisconsin, Wyoming and the Campo Kumeyaay Nation. The Canadian provinces of British Columbia and Manitoba also committed to participate.

[30] Additional members of the Climate Registry as of September 2007 are: U.S. States: Alabama, Georgia, Idaho, Iowa, Nevada, Oklahoma, Tennessee, and Virginia; District of Columbia (Washington, DC); Mexican State: Sonora; Tribal Nations: Pueblo of Acoma and the Southern Ute; and Canadian Provinces: British Columbia and Manitoba.

Regional Greenhouse Gas Initiative

In December 2005, seven Northeastern and Mid-Atlantic states (Connecticut, Delaware, New Hampshire, New Jersey, New York, Maine, and Vermont) issued a Memorandum of Understanding (MOU), implementing the Regional Greenhouse Gas Initiative (RGGI). The multi-state agreement establishes a cap-and-trade system that covers CO_2 emissions from power plants. RGGI aims to stabilize utilities' CO_2 emissions at current levels to 2015, and reduce emissions by 10 percent by 2019. The first compliance period under RGGI begins January 1, 2009. In April 2006, Maryland passed a law requiring the state to join RGGI by June 20, 2007. Massachusetts and Rhode Island had dropped out of RGGI, but in early 2007 both states announced that they would rejoin the process and become members by 2007. Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official observers to RGGI. Table 9.5 summarizes the main features of RGGI.

Table 9.5 Regional Greenhouse Gas Initiative (RGGI)

	RGGI
Sectors	Fossil fuel-fired electric generators ≥25 MW
Regulated sources	~810 units
Political jurisdiction	Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont
Emissions covered	CO2
Emissions cap	121.3 MMTCO2 through 2014 10% below this in 2018 (i.e., 2.5%/yr decline in emission budget)
Allocation	≥25% of each state's allowances must be auctioned for consumer benefit purposes, such as end-use energy efficiency
Offset types allowed	Landfill gas ♦ Sulfur hexafluoride (SF6) ♦ End-use energy efficiency ♦ Afforestation ♦ Farming operations ♦ Natural gas transmission and distribution (T&D)
Offset price < $7	Offsets capped at 3.3% of each generator's emissions RGGI offsets = 1:1 ton ratio; North America offsets = 2:1 ton ratio
Offset price > $7	5% offset cap and North America offsets = 1:1 ton ratio
Safety Valve **If price ≥ $10/ton**	Compliance period will be extended for one year, up to a total three-year extension
Implementation	1st phase 2009-2011; 2nd phase 2012-14; 3rd phase 2015-17

On August 15, 2006, after a period of public comment, the participating RGGI states released the final model rule for the RGGI program. The rule establishes a set of regulations regarding the structure and functions of the program. Each participating state must adopt this rule through legislation or regulation and determine how to allocate its emission allowances. Additional states can join RGGI with the agreement of the participating states. The model rule includes the following:

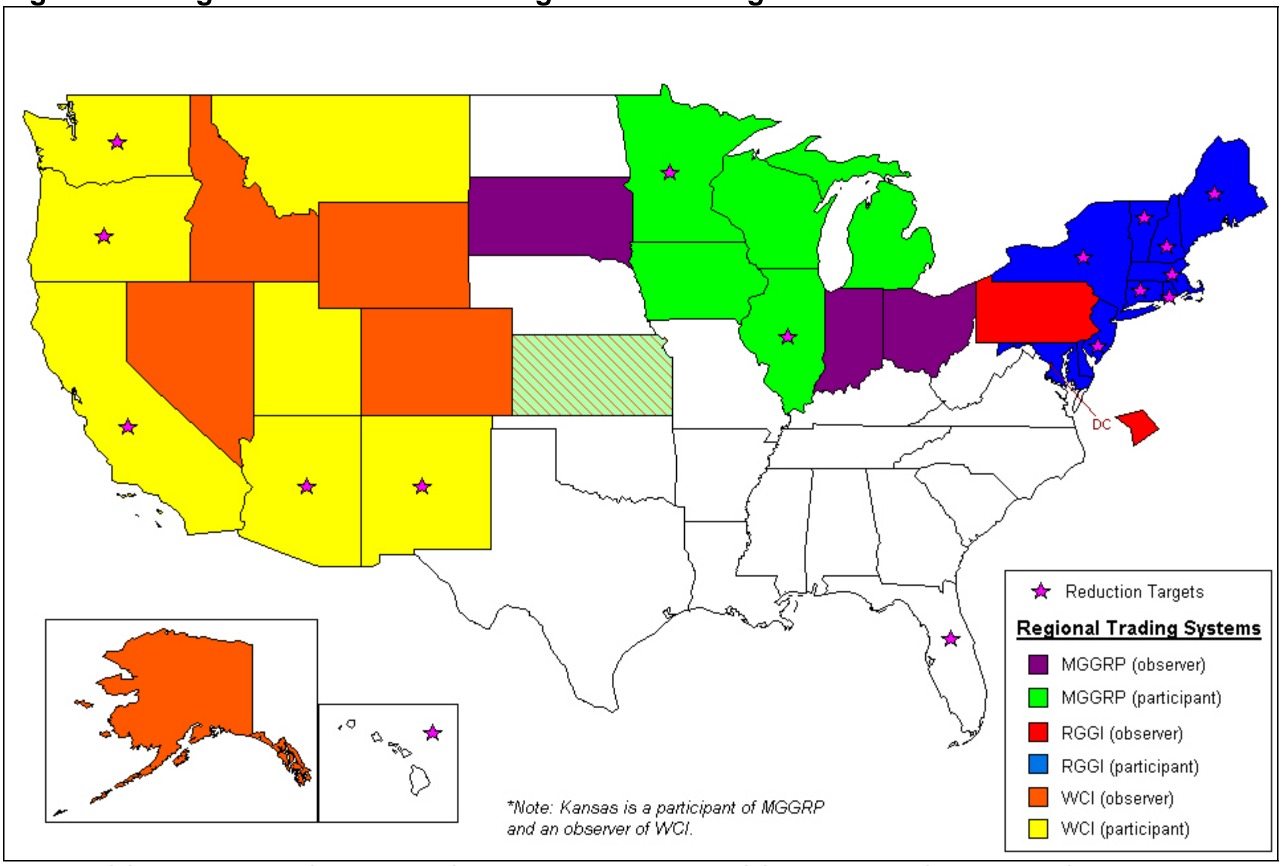
- Covered sources (stationary sources, i.e., electricity generator, with a capacity of 25 MW or more that burns more than 50 percent fossil fuel (other sources may be added in the future);
- How covered sources must demonstrate compliance; and
- Provisions for the allocation of allowances for public benefit purposes.

RGGI sets a cap on power plant emissions at approximately current levels of 120 million tons of CO_2 between 2009 and 2015, which is reduced a further 10 percent by 2019. RGGI estimates that 810 units will be affected in the participating states. Each state has received its share of allowances from the overall cap[1], and states can allocate 75 percent how they choose with the remaining 25 percent to be used for public benefit purposes, such as promoting renewable energy and energy efficiency or mitigating any increase in consumer energy prices. Most states have elected to allocate all allowances through auctioning, forcing utilities to bear the cost of participating in the scheme at the outset.

In addition to trading emission allowances, RGGI allows emissions offsets to ensure compliance with the emissions cap. RGGI offsets must come from sources outside of power plants, including the capture of landfill methane, implementation of end-use natural gas or heating oil energy efficiency, afforestation, and the capture of SF_6 emissions from electricity transmission and distribution equipment. Sources can use offset allowances to cover up to 3.3 percent of their emissions and offsets can come from anywhere in the United States. However, if the average allowance price rises to $7, the limit increases to 5 percent, and if it increases to $10 (safety valve price), the limit increases to 10 percent and offsets are allowed from international sources. If the average price exceeds the safety valve price for a year, the compliance period may be extended for up to three years in order to keep down costs to the power plants.

Participating RGGI states are in the process of developing a regional organization, located in New York, to help implement the program and develop future policies.

Figure 9.2 Regional Emissions Trading and State Targets



Notes: MGGRP = Midwest Greenhouse Gas Reporting Program; RGGI = Regional Greenhouse Gas Initiative; and WCI = Western Climate Initiative. A few other states, such as Colorado, have proposed greenhouse gas targets, but since these have not yet been adopted, they are not included here.

Western Climate Initiative[clxxxii]

On February 26, 2007, the Governors of Arizona, California, New Mexico, Oregon, and Washington signed an agreement establishing the Western Climate Initiative, a joint effort to reduce GHG emissions and address climate change. Since February 2007, Utah and the Canadian provinces of Manitoba and British Columbia have joined the initiative as full partners. U.S. member states are all listed in Figure 3. Five U.S. states, 3 Canadian provinces and one Mexican state are observers.[31] In November 2007, Montana announced that it would formally join the initiative.

In August 2007, the partners released their regional GHG emissions goal of 15 percent below 2005 levels by 2020, or approximately 33 percent below business-as-usual levels. By August 2008, they will establish a market-based system – such as a load-based cap-and-trade program covering multiple economic sectors – to aid in meeting the target. The states will also set up an emissions registry and tracking system using the rules developed by The Climate Registry as a foundation. The initiative builds on work already undertaken individually by the participating states, most of which have already set their own emissions reductions goals (Figure 3).

Midwest Greenhouse Gas Reduction Program

In November 2007, the governors of six Midwestern U.S. states announced the formation of the Midwest Greenhouse Gas Reduction Program.[clxxxiii] The Midwest agreement commits Illinois, Iowa, Kansas, Minnesota, Michigan, Wisconsin, and Manitoba to setting up a regional cap-and-trade system for trading emissions. Trading would begin in 2010, but no reduction goal has been established yet. The aim is to cut GHG emissions by 60 to 80 percent by 2050. Indiana, Ohio, and South Dakota also signed on, but only as observers.

During the November meeting, Midwest governors agreed to a host of other measures to reduce GHG emissions. Among these, the following will affect coal-fired power in the region:

- Generate more power from clean, renewable sources so at 10% of electricity consumed in the Midwest from wind power and other renewable energy sources to 10% by 2015, increasing to 30% by 2030.
- Cut pollution and utility bills by meeting at least 2% of Midwestern electricity and natural gas needs through use of energy-saving technologies by 2015.
- Capture and store carbon dioxide from all new power plants by 2020.
- Complete plans for a multi-state pipeline to transport carbon dioxide from coal gasification plants to oil fields suitable for enhanced oil recovery and underground storage of CO_2.

To support these shared goals, the Midwestern states launched new cooperative regional initiatives to address the following:

- Carbon dioxide management to create a regional transportation and storage infrastructure;

[31] Observer to the Western Climate Initiative are: Alaska, Colorado, Kansas, Nevada, Wyoming, the Canadian provinces of Ontario, Quebec, and Saskatchewan and the Mexican state of Sonora.

- Electricity transmission adequacy to support thousands of new megawatts of wind energy;
- Renewable fuels corridors and coordinated signage to promote renewable fuel usage across the Midwest; and
- Low-carbon energy transmission infrastructure that will provide a cost-effective way to supply the Midwest with sustainable and environmentally responsible energy.

California

California has taken a leadership role in policy development to limit future climate change in the United States, setting examples which a number of states have chosen to follow. The state has a GHG inventory, climate change action plan, highly comprehensive GHG registry, soon-to-be mandatory GHG targets, sector specific caps, sector specific minimum standards, and a renewable portfolio standard (RPS). GHG trading is under development.

Box 9.1. California AB32 – Global Warming Solutions Act

AB32 charges the California Air Resources Board (CARB) to:

- Adopt regulations to require reporting and verification of statewide GHG emissions and to monitor and enforce compliance;
- Adopt a statewide GHG emissions limit equivalent to 1990 level;
- Adopt rules and regulations in a public process to achieve the maximum technologically feasible and cost-effective GHG emission reductions;
- Adopt market-based compliance mechanisms, such as an emissions trading system;
- Monitor compliance and enforce any relevant rules, regulations, orders, emissions limits, emissions reduction measures, or market-based compliance mechanisms, a violation of which would be a crime; and
- Adopt a fee schedule for regulated sources of GHG emissions.

AB32 requires CARB to periodically review and update its emission reporting requirements if needed and to review existing and proposed international, Federal, and state GHG emission reporting programs to try to maintain some consistency among the programs and to streamline reporting requirements.

CARB will have authority over the cap-and-trade program, but the Governor has authority to suspend emissions cuts for up to a year in the event of an emergency, such as a natural disaster or energy shortage.

AB32 requires CARB to establish an environmental justice advisory committee to advise the Board on the establishment of a scoping plan to achieve the maximum technologically feasible and cost-effective reductions, which must consider total potential costs and economic and noneconomic benefits of a GHG emissions reduction plan.

In June 2005, Governor Schwarzenegger signed an executive order that established statewide targets for GHG emissions. In August 2006, the California legislature passed the ground-breaking Global Warming Solutions Act (AB 32) and on September 27, 2006 Governor Schwarzenegger signed it into law (see Box 9.1). It directs the California Air Resources Board (CARB) to develop and implement a mandatory statewide program by January 1, 2008 that would reduce the state's emissions to 1990 levels by the year 2020. AB 32 will be the first statewide program in the U.S. to mandate an economy-wide emissions cap that includes enforceable penalties.[clxxxiv] In order to meet these emission reductions, AB 32 includes, but does not require, an option for a cap-and-trade program for utilities and large industrial emitters in the state, as long as the overall emission cap is reached. However, in October 2006, Governor Schwarzenegger signed an executive order that, in effect, ensures that the goals of AB 32 will be met through emissions trading. On April 20, 2007, CARB released its analysis and recommendations for discrete, early action measures to reduce GHG emissions under AB 32.[clxxxv] As part of these recommendations, it suggested that CARB actively pursue 36 separate measures during Calendar Years 2007, 2008, and 2009. In February 2007, California state senators introduced a package of legislation that would reduce the state's GHG emissions even further than AB 32 by setting new regulations, requiring half of all passenger vehicles sold in the state to be alternative fuel-capable by 2020, mandating that a percentage of diesel fuel come from renewable resources, expanding the utilities renewable portfolio standard to 33 percent by 2021, and consolidating five state agency global warming efforts into the California Office of Climate Change Research and Assessment.

In October 2006, the Governor signed an Executive Order which instructed California's Environmental Protection Agency (CALEPA) to set up a committee of experts (Market Advisory Committee) that would make recommendations to CARB on the design of a market-based program by late June 2007. This Executive Order also directed CARB and CALEPA to develop a market-based program that permits trading with the EU and RGGI. In June 2007, the Market Advisory Committee (MAC) recommended that a trading program should be as broad as possible, including electricity providers, large industrial sources, and transportation. The MAC also recommended:

- Offsets should be high quality and should be based only on limited project types
- No safety valve should be used for cost containment
- The transportation sector should not be allowed to respond to price signals (8.8 cents/gallon for every \$10/ton CO_2)
- Four market scope programs are being considered:
  - <u>Program 1</u> - Medium and large point sources of emissions, and of some suppliers of high-GWP gases; coverage at point of combustion
  - <u>Program 2</u> - Program 1 plus upstream coverage of CO_2 emissions from transportation
  - <u>Program 3</u> - Program 2 plus upstream coverage of fossil fuel combustion by other sectors (small industrial, commercial, residential)
  - <u>Program 4</u> - Upstream coverage of CO_2 from fossil fuel combustion, and downstream coverage of large sources of non-CO_2 gases and some suppliers of high-GWP gases
- Two courses of action are proposed by the MAC – the #1-2-3 option and the #4 option

A second ground-breaking California law, which passed the legislature in September 2006, and, like AB 32, is likely to have a significant impact on long-term technology choices for power generation in the entire region, is Senate Bill (SB) 1368.[clxxxvi] The law prohibits load-serving entities (investor-owned utilities, energy service providers and community choice aggregators) from entering into long-term financial commitments for baseload generation unless they comply with a GHG emissions performance standard. It applies to all load-serving power plants, located in or out of the state, that supply energy to California and would be similar to the performance standard developed for state-utilities by the California Public Utilities Commission (CPUC). SB 1368 required the California Energy Commission

(CEC) and other regulatory agencies to set the emission standards for electricity used in California. On January 25, 2007, the CPUC adopted an interim Greenhouse Gas Emissions Performance Standard for public utilities.[clxxxvii] It is a facility-based emissions standard that requires that all new long-term commitments for baseload generation be with power plants that have emissions no greater than that of a combined cycle gas turbine plant (established at 1,100 pounds of CO_2 per megawatt-hour).

This standard is now in effect and affects all contracts with a term of 5 years or more for "baseload" power. Baseload power generation is defined as units with greater than 60% capacity factor - i.e. running at more than 60% of capacity on an annual basis. Consequently, SB 1368 does not affect contracts specifically aimed at addressing peak load generation capacity. The standard includes a R&D exemption for higher emitting facilities, such as an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions, and that has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide. In addition, the standard states that carbon dioxide which is injected into the ground should not be counted as a power plant emission when determining compliance with the performance standard.

The states of Oregon and Washington have announced that they will adopt similar performance standards, and the Canadian province of British Columbia announced that it will join the three states too.

As another measure affecting the power sector, on September 20, 2007, the CPUC approved a new framework planned to both achieve and exceed the state's aggressive energy efficiency goals.[clxxxviii] Under this framework, earnings to shareholders will accrue only when a utility produces positive net benefits (savings minus costs) for ratepayers. Earnings begin to accrue at a 9 percent sharing rate if the utility meets 85 percent of the CPUC savings goals. If performance achieves 100 percent of the goals, the earnings rate increases from 9 percent to 12 percent. The goal is to cause utility investors and managers to view energy efficiency as a core part of their operations that can generate "meaningful earnings" for their shareholders. At the same time, the new framework is set up to protect consumers' financial investment, verify program savings, and impose penalties for substandard performance. The framework is designed to assist the implementation of AB 2021, which requires all Load Serving Entities in the State to achieve a 1% per year energy efficiency target to reduce their projected load demand by 10% by 2017.

Other State Activities Affecting the Power Sector

There has been a significant amount of climate change-related activity occurring in other states across the United States in the past year. A number of states have set (by executive order) or proposed state-wide GHG emission targets, with varying degrees of stringency. States that have set targets include: *Arizona, Florida, Hawaii, Illinois, Minnesota, New Jersey, Oregon* and *Washington* (see Figure 9.2). States that have proposed targets include: *Colorado, Iowa, Pennsylvania, Virginia and Wisconsin*.

Other states have ordered specific entities to develop/assess GHG reduction strategies (see Figure 9.1). For example, on June 30, 2007, *Hawaii* established a GHG emission reduction task force which must prepare a work plan and regulatory mechanism for meeting the statewide GHG limit by December 1, 2009.[clxxxix] On April 27, 2007, *Iowa* Governor Chet Culver established a Climate Change Advisory Council that will be composed of a range of

Governor-appointed stakeholders, as well as members of the legislature.[cxc] The council is charged with developing a range of scenarios for reduction of statewide greenhouse gas emissions, including the possibility of cutting emissions 50 percent by 2050, and will submit its recommendations to the governor and the general assembly by January 1, 2008. On April 5, 2007, Governor Jim Doyle of *Wisconsin* signed a new executive order as part of the state's efforts to address climate change and energy issues.[cxci] The order created the Task Force on Global Warming, which will investigate the potential economic and environmental impacts of climate change on Wisconsin and recommend possible solutions and strategies for greenhouse gas emissions reductions. Other states that have recently taken similar actions to meet their mandatory or proposed emission reduction targets include: *Alaska*, *Arizona*, *Florida*, *Illinois, Minnesota, New Jersey, New Mexico South Carolina,* and *Washington*. *Colorado* has a similar organization, the Colorado Climate Project, which follows the model established by several state governments, but is the first such project undertaken as a private initiative.[cxcii]

A handful of states either already require or are in the process of developing mandatory GHG reporting, including for the power sector. As noted earlier, the *California* Global Warming Solutions Act of 2006 (AB32) requires CARB to adopt regulation to require the mandatory reporting and verification of GHG emissions. The mandatory reporting rules for significant sources of greenhouse gases must be completed by January 1, 2008.[cxciii] Other states, including *Wisconsin, New Jersey, Maine* and *Connecticut*, currently have mandatory reporting programs that, to varying degrees, track GHG emissions, and are not linked with emissions reduction requirements.[cxciv] *New Mexico* announced a mandatory reporting rule in November 2007, which covers power plants, refineries and cement manufacturing.

Several states have passed GHG performance standards for the power sector. In May 2007, *Washington* Governor Christine Gregoire signed Substitute Senate Bill 6001 (SSB 6001), which imposes a CO_2 emissions performance standard on baseload electric generation, similar to SB 1368 in California.[cxcv] *Oregon* is considering adopting a similar emission performance standard for long-term power purchase agreements. Also in May 2007, *Montana* adopted a technology performance standard for electric generating units in the state.[cxcvi] According to this standard, the state Public Utility Commission cannot approve electric generating units primarily fueled by coal unless a minimum of 50 percent of the carbon dioxide produced by the facility is captured and sequestered. This applies to units constructed after January 1, 2007.

There is also a growing trend to include a consideration of GHG emissions in the environmental impact assessments of new large infrastructure developments.[cxcvii] If this trend continues, it is likely to have a significant impact on the siting and approval of new coal-fired power plants in the U.S. In April 2007, *Iowa* began requiring the state to consider GHG emissions when reviewing proposals for new power plants,[cxcviii] and perhaps most notably, on October 18, 2007, the *Kansas* Department of Health and Environment became the first government agency in the United States to cite CO_2 emissions as the reason for rejecting an air permit for a proposed supercritical coal-fired power plant, saying that the plant's GHG emissions threaten public health and the environment.

In *Massachusetts*, "damage to the environment" is considered to include GHG emissions under the section of the Massachusetts Environmental Policy Act that pertains to approval for large development projects.[cxcix] As a result, all building projects in the state that are required to undergo an environmental impact assessment (EIA) or are partly funded by the state, must estimate the direct and indirect GHG emissions associated with these large development projects and propose measures to reduce them.

California has started experimenting with using the California Environmental Quality Act (CEQA) to enforce AB 32's mandate. Given the emerging status of climate change law there is a lack of standards for conducting analyses as to how a project may impact GHG emissions and for how to impose remedial actions. Two recent judicial settlements in California may set precedent for how other jurisdictions choose to address GHG emissions in new construction. In April 2007, the state Attorney General Edmund Brown filed a lawsuit against San Bernadino and other California counties, contending that development of land and infrastructure through 2030 must account for and compensate GHG emissions (for example through GHG offsets). The suit argued that unless development plans include GHG reduction measures, they violate the state's umbrella environmental code, the CEQA. San Bernadino settled the lawsuit in August 2007 and agreed to a package of measures to reduce GHG emissions.[cc] Second, in September 2007, California struck an agreement with ConocoPhillips compelling the oil company to offset GHG emissions related to the expansion of its San Francisco-based Rodeo oil refinery (see Box 9.2). ConocoPhillips must attain the estimated 500,000 metric tons of offsets by investing in projects involving energy efficiency, reforestation, and other activities spearheaded by the Bay Area Air Quality Management District.[cci]

Box 9.2. California Attorney General Agreement with ConocoPhillips

In May 2005, ConocoPhillips submitted an application to Contra Costa County (County) for a Project to increase the supply of cleaner burning fuels in California by approximately 1 million gallons per day. The Project would result in 1.25 million metric tons of annual CO_2 emissions. The Environmental Impact Report (EIR), prepared pursuant to the California Environmental Quality Act (CEQA), was certified and the corresponding land use permit was approved by the County Planning Commission on May 8, 2007. On May 18, 2007, the Attorney General (AG) appealed the County's approval of the Project alleging that the EIR failed to adequately address the Project's impacts on global warming. On September 11, 2007 the AG settled the case with ConocoPhillips requiring the company to comply with a comprehensive GHG reduction plan and making it the first oil company in the U.S. to offset GHG emissions from a refinery expansion project. ConocoPhillips agreed to take the following actions:

- Surrender the operating permit for its Santa Maria refinery calcining plant (registered with the California Climate Action Registry), which currently emits about 70,000 tons/year of CO_2;
- Conduct a GHG emissions audit of the Rodeo facility using an outside consultant;
- Complete a GHG emissions audit of all its California refineries and use the results to formulate a strategy for AB 32 compliance;
- Offset CO_2 emissions from the Project in excess of 500,000 metric tons per year, if any, for the period from the start-up of the Project's hydrogen plant until regulations are adopted for the implementation of AB 32; and
- Contingent upon obtaining a valid land use permit for the Project, ConocoPhillips agreed to make the following payments: (1) $7 million dollars to a carbon offset fund to be created by the Bay Area Air Quality Management District; (2) $200,000 to the Audubon Society for the restoration of the San Pablo Bay wetlands to offset Project emissions by sequestering carbon; and (3) $2.8 million dollars to California Wildfire ReLeaf to offset Project emissions by sequestering carbon.

Source: Office of the Attorney General, State of California, San Bernardino Settlement Agreement, September 17, 2007 http://ag.ca.gov/cms_pdfs/press/N1466_COP-AGSettlement_Agreement_Final.pdf

Finally, one state requires that power plants consider GHG costs in their long-term power plans. In June 2007, the New Mexico Public Utilities Commission passed a rule that requires electric utilities to factor in the cost of GHG emissions in their long-term planning for power, beginning in 2008. The companies must consider the cost impacts of three different carbon dioxide prices: $8, $20, and $40. These costs would kick in beginning in 2010 and rise by 2 percent a year. The wide price range is meant to force utilities to consider the range of possible carbon regimes in the future.

9.3. Water

The regulation of electric utility water use and effluents in the United States are primarily a state or local responsibility, but some guidance is also developed at the federal level. This is mostly done through the 1972 Federal Water Pollution Control Act which was amended in 1977 to become the Clean Water Act (CWA).

The Clean Water Act establishes the basic structure for regulating discharges of pollutants into the waters of the United States. It gives the Environmental Protection Agency the authority to implement pollution control programs such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters. The Act makes it unlawful for any person to discharge any pollutant from a point source into navigable waters, unless a permit is obtained under its provisions. Regulations targeting coal-fired power plants focus on water intake, thermal pollution, and water effluents.

Wastewater discharges normally are permitted under the CWA's National Pollutant Discharge Elimination System (NPDES) program and State Pollutant Discharge Elimination System (SPDES) programs, which may be more stringent than the NPDES. The design of cooling systems and wastewater treatment facilities must ensure that their discharges are permittable under the applicable program.

A particularly critical water issue that impacts all fossil-fueled plants deals with the construction of surface water intake and discharge structures. Issues such as the disturbance of shoreline and bottom habitats and the protection of fish and aquatic wildlife are often raised during the permitting process. Therefore, the location and design of proposed intake/discharge structures is an important consideration in the permitting process. As discussed in Section 9.3.1, EPA is developing federal regulations required by the CWA for fish protection at cooling water intake structures.

None of the water-related regulations appear to limit or encourage any particular coal combustion technology. However, the regulations do make it more costly for power plants to use water and thus may indirectly influence the use of more efficient combustion technology. Sections 316(a) and 316(b) of the Clean Water Act place restrictions on the impact of water cooling on the environment. Ongoing updates to these regulations, means that permitting of open-loop cooling will likely be limited and that future electric power generation plants will most likely move to closed-loop cooling. This may limit future water withdrawals, but could significantly increase water consumption (i.e., less water will be re-released to the nearby water body).

9.3.1 Water Consumption

Cooling water intake is regulated under 316(b) of the Clean Water Act and includes specific regulations for fish protection measures at cooling water intake structures. The 1972 CWA Amendments instructed EPA to regulate "the location, design, construction, and capacity of cooling water intake structures” so as to “minimize adverse environmental impacts.” 316(b) requires that the best technology available (BAT) be used to minimize adverse environmental impact and allows for economic considerations in the determination of appropriate implementation. The goal is to protect aquatic organisms from being killed or injured by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses). For several years, EPA avoided national uniform requirements, preferring instead to embrace *ad hoc* determinations based on fish-population models. Noting that this approach contradicted EPA’s approach with other sources of degradation to aquatic ecosystems controlled by the 1972 Amendments, several environmental groups in 1993 filed a lawsuit seeking national regulations. A federal district court in 2000 agreed with the environmentalists and required EPA to promulgate such regulations.

EPA divided its responding rulemaking into three phases: Phase I for new facilities; Phase II for existing electric generating plants that use large amounts of cooling water; and Phase III which will apply to electric generating plants using smaller amounts of cooling water and for other industrial sectors.

Phase I Rule: New Facilities

EPA issued final Phase I rules in November 2001 which allowed new facilities to use once-through cooling and deploy after-the-fact restoration measures. New facilities subject to this regulation include those that have a design intake flow of greater than two million gallons per day (MGD) and that use at least 25 percent of water withdrawn for cooling purposes. The ruling presents two options to new facilities. For certainty and fast permitting, a new facility can accept set standards that limit intake capacity and velocity. Facilities that are located near fisheries are required to use additional fish protection measures including screens, nets, or other similar devices. No reductions of intake capacity are required for facilities that withdraw less than 10 MGD but they must employ fish protection measures. Facilities also have the option of conducting site-specific studies that may allow for alternative fish protection measures so long as they provide comparable protection. All facilities must limit intake relative to a defined proportion of the source water body.[ccii] In June 2003, EPA published minor modifications to this rule which clarified three technical issues: 1) the requirements for monitoring intake velocity at facilities with shoreline intakes; 2) specified that only the Permit Director has the authority to require facilities to install additional design and construction technologies; and 3) clarified the procedures an applicant must follow when seeking less stringent alternative requirements. [cciii]

Critical of EPA’s phase I rule, environmental groups filed another lawsuit in January 2002. The court in February 2004 found that EPA had exceeded its authority by allowing industrial facilities to avoid the installation of technologies that prevent fish kills and, instead, to choose restoration of aquatic resources. The court, moreover, struck down EPA’s allowance of once-through technology but upheld EPA’s mandate of closed-cycle cooling as the national minimum technology for new power plants and factories. Since then, EPA has not issued any new rules related to Phase I.

Phase II Rule: Large Existing Facilities

On February 16, 2004, EPA issued the final Phase II rule which applies to existing power producing facilities that generate and transmit electric power; use cooling water intake structures with a total design intake flow of 50 MGD or more; and use at least 25 percent of the water withdrawn exclusively for cooling purposes.[ccv] Under the Phase II rule, EPA established performance standards for the reduction of impingement mortality and entrainment.[ccv] The performance standards consist of ranges of reductions in impingement mortality and/or entrainment. These performance standards were determined to reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts at facilities covered by the Phase II rule.

The Phase II regulations were challenged by industry and environmental stakeholders. The Second Circuit Court of Appeals sided with the environmental groups[ccvi] and remanded several provisions of the Phase II rule on various grounds. The provisions remanded to EPA include:

- EPA's determination of the BTA under section 316(b);
- The rule's performance standard ranges;
- The cost-cost and cost-benefit compliance alternatives;
- The Technology Installation and Operation Plan provision;
- The restoration provision; and
- The ``independent supplier'' provision.

With several significant provisions of the Phase II rule affected by the decision, EPA's Assistant Administrator for Water issued a memorandum on March 20, 2007, which announced EPA's intention to suspend the Phase II rule.[ccvii] Later in the year, in July 2007, EPA issued a Federal Register notice suspending the Phase II requirements pending further rulemaking and required that permits for cooling water intake structures at Phase II facilities must be granted on a case-by-case best professional judgment (BPJ) basis until EPA has considered and resolved the issues raised by the Second Circuit's decision.[ccviii]

Phase III Rule: Small Existing Facilities

In June 2006, EPA published the final Phase III rule which establishes requirements under section 316(b) of the Clean Water Act for new offshore oil and gas extraction facilities. Small existing power producers are not covered by this rule.

In the development of the rules for cooling water intake structures, EPA proposed the following three options that, based on design intake flow and source water body, define three different instances in which existing facilities would be subject to new requirements. Either:

- The facility has a total design intake flow of 50 MGD or more, and withdraws from any waterbody type; or
- The facility has a total design intake flow of 200 MGD or more, and withdraws from any waterbody type; or
- The facility has a total design intake flow of 100 MGD or more and withdraws water from an ocean, estuary, tidal river, or one of the Great Lakes.

Because the lowest proposed threshold is 50 MGD and EPA already is working on standards for power producers over 50 MGD in the Phase II rule, EPA only considered requirements for existing manufacturing facilities (not power producers) and new oil and gas extraction facilities under the Phase III rule.

9.3.2 Water Thermal Pollution

Section 316(a) of the Clean Water Act regulates heated discharges into waters of the United States. The current language allows EPA to vary a generator's heat-pollution standards depending upon the receiving water body's ability to dissipate the heat and preserve a "balanced, indigenous" wildlife population. As a result, there is no set standard, or maximum temperature, for thermal water discharge from coal-fired power plants. Instead, the required thermal properties of the discharged water will be determined in the individual NPDES permit. This approach is different from most Clean Water Act requirements that limit what a source can put into the water, not the ultimate effect of that discharge.

9.3.3 Water Chemical and Pollutant Discharges

The Clean Water Act[ccix] outlines the regulation of discharges into U.S. waters. The Act's National Pollutant Discharge Elimination System (NPDES) program limits the concentration of various pollutants in water discharges.[ccx] States may submit State Pollutant Discharge Elimination System (SPDES) plans to the Administrator of the EPA for approval. The SPDES may outline more stringent regulations but must be at least as stringent as the NPDES. NPDES plans differentiate between process wastewater and storm water runoff and regulate the two independently.[ccxi]

Process wastewater requirements for steam electric point sources are outlined by 40 CFR Part 423 (facilities "primarily engaged in the generation of electricity for distribution and sale"). Each discharge requires a separate NPDES permit with limitations based on industry specific control technologies, such as Best Practicable Control Technology Currently Available (BCT),
Best Technology Economically Achievable (BAT), or New Source Performance Standards (NSPS). Facilities that discharge to publicly owned treatment works (POTWs) must comply with Pretreatment Standards for Existing Sources (PSES) or Pretreatment Standards for New Sources (PSNS). Permits may also include water quality based limitations and pollution monitoring requirements. While the technology-based standards take into account economic impact of the implementation, water quality based standards typically do not.

Table 9.6 EPA Water Quality Standards

Constituent	Discharge Standard (mg/l, Average Monthly Limit)
Biochemical Oxygen Demand (BOD)	15
Chemical Oxygen Demand (COD)	50 to 200
Total Suspended Solids (TSS)	10
Ammonia	10
Cyanide	1.0
Phenols (4AAP)	0.025
Sulfide	0.1
Nitrate	100
Fluoride	100

Constituent	Discharge Standard (mg/l, Average Monthly Limit)
Arsenic	5.0
Barium	100
Boron	50
Cadmium	1.0
Chromium	5.0
Lead	5.0
Mercury	0.2
Selenium	1.0
Silver	5.0
Zinc	20

Sources: U.S. Environmental Protection Agency, "Quality Criteria for Water (the "Red" Book)," Office of Water and Hazardous Materials, Washington, D.C., GPO #055-001-01049-4, 1976; and U.S. Environmental Protection Agency, "Water Quality Standards Handbook-Second Edition," Office of Water (4305), Washington, D.C., EPA-823-8-94-005a, 1994.

Although water effluent standards vary significantly by application, industry, and location, the EPA Water Quality Standards presented in Table 9.6 are the most commonly used. Pollutants are grouped into three categories and designated as conventional, non-conventional, or priority pollutants.[ccxii] Particular water discharge criteria are outlined in NPDES permits generated by the state permitting authority. For existing sources, conventional pollutants are controlled using BCT standards, while priority and non-conventional pollutants are controlled by BAT standards. Federally mandated NSPS outline the baseline for minimum control requirements for new sources. Additionally, NSPS requires zero discharge for fly ash handling water. Furthermore, EPA reserved NPDES limitations for non-chemical metal cleaning wastes (Section 9.4) and FGD waters for future rulemaking.[ccxiii]

Conventional Pollutants

Conventional pollutants include but are not limited to five-day biochemical oxygen demand (BOD_5), total suspended solids (TSS), pH, fecal coliform, oil and grease.

Priority Pollutants

Section 307(a)(1) of the CWA required the establishment of a published list of priority pollutants considered to be toxic chemicals or compounds.[ccxiv] Included in this list are several elemental, organic and inorganic species that are present in wastes produced by steam electric generating plants. Among these are arsenic, benzene, cyanide, mercury, naphthalene and selenium.

Non-Conventional Pollutants

Pollutants that are neither conventional pollutants, nor toxics identified as priority pollutants, are considered "non-conventional." These include, but are not limited to, ammonia, nitrogen, trace metals, chemical oxygen demand (COD) and whole effluent toxicity (WET). Chemical oxygen demand is a measure of the oxygen required to oxidize all compounds, both organic and inorganic, in water.

Whole Effluent Toxicity is a term used to quantify the impact a discharge has on the water quality of the receiving body of water. WET is based on the aggregate toxic effect of an aqueous sample (e.g., whole effluent wastewater discharge or ambient receiving water) as measured according to an organism's response upon exposure to the sample (e.g., lethality and impairment to growth or reproduction).

Effluent Standards

Table 9.7 outlines national effluent standards for steam electric generating units.

Table 9.7 Effluent Standards – Steam Electric Power Generating Point Sources

Source	Parameter	Effluent Limitations	
Limitations based on best practicable control technology available (BPT)			
All discharges, except once through cooling water	pH	6.0 – 9.0	N/A
Any unit	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Unless otherwise permitted, only 1 unit in 1 plant may discharge at any one time
		Max for any 1 day (mg/l)	**Average of daily values for 30 consecutive days not to exceed (mg/l)**
Low volume wastes	TSS	100	30
	Oil and grease	20	15
Fly/bottom ash transport water	TSS	100	30
	Oil and grease	20	15
Metal cleaning wastes	TSS	100	30
	Oil and grease	20	15
	Copper, total	1	1
	Iron, total	1	1
		Max concentration (mg/l)	**Average concentration (mg/l)**
Once through cooling water/cooling tower blowdown	Free available chlorine	0.5	0.2
		Max concentration for any time (mg/l)	
Coal pile runoff[a]	TSS	50	N/A
Limitations based on best practicable control technology economically achievable (BAT)			
		Max concentration (mg/l)	
Plants ≥ 25MW once through cooling water from each discharge point	Total residual chlorine	0.20	N/A
Any unit in plant ≥ 25MW	Total residual chlorine	Maximum discharge of 2 hours any 1 day	Simultaneous multi-unit chlorination is permitted
Plants < 25MW, once through cooling water from each discharge point	Total residual chlorine	0.20	N/A
Any unit in plant < 25MW	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Unless otherwise permitted, only 1 unit in 1 plant may discharge at any one time
		Max concentration (mg/l)	**Average concentration (mg/l)**
Cooling tower blowdown	Free available chlorine	0.5	0.2
		Max for any 1 day (mg/l)	**Average of daily values for 30 consecutive days not to exceed =(mg/l)**
	126 priority pollutants contained in chemicals added for cooling tower maintenance, except:[b]	No detectable amount	No detectable amount

Source	Parameter	Effluent Limitations	
	Chromium, total	0.2	0.2
	Zinc, total	1.0	1.0
Any cooling tower blowdown unit	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Unless otherwise permitted, only 1 unit in 1 plant may discharge at any one time
		Max for any 1 day (mg/l)	**Average of daily values for 30 consecutive days not to exceed – (mg/l)**
Chemical metal cleaning wastes	Copper, total	1.0	1.0
	Iron, total	1.0	1.0
New Source Performance Standards (NSPS)			
All discharges, except once through cooling water	pH	6.0 – 9.0	N/A
		Max for any 1 day (mg/l)	**Average of daily values for 30 consecutive days not to exceed (mg/l)**
Low volume wastes	TSS	100	30
	Oil and grease	20	15
Metal cleaning wastes	TSS	100	30
	Oil and grease	20	15
	Copper, total	1	1
	Iron, total	1	1
Bottom ash transport water	TSS	100	30
	Oil and grease	20	15
		Max concentration (mg/l)	
Plants ≥ 25MW once through cooling water from each discharge point	Total residual chlorine	0.20	N/A
Any unit in plants ≥ 25MW	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Simultaneous multi-unit chlorination is permitted
		Max concentration (mg/l)	**Average concentration (mg/l)**
Plants < 25MW once through cooling water from each discharge point	Free available chlorine	0.5	0.2
Any unit in plants < 25MW	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Unless otherwise permitted, only 1 unit in 1 plant may discharge at any one time
		Max concentration (mg/l)	**Average concentration (mg/l)**
Cooling tower blowdown	Free available chlorine	0.5	0.2
		Max for any 1 day (mg/l)	**Average of daily values for 30 consecutive days not to exceed =(mg/l)**
	126 priority pollutants contained in chemicals added for cooling tower maintenance, except:[b]	No detectable amount	No detectable amount
	Chromium, total	0.2	0.2
	Zinc, total	1.0	1.0
Any cooling tower blowdown unit	Free available/total residual chlorine	Maximum discharge of 2 hours any 1 day	Unless otherwise permitted, only 1 unit in 1 plant may discharge at any one time
		NSPS limitation for any time	
Coal pile runoff[a]	TSS	Not to exceed 50 mg/l	N/A
Pretreatment Standards for Existing Sources (PSES)			

Source	Parameter	Effluent Limitations	
		Maximum for 1 day (mg/l)	
Chemical metal cleaning wastes	Copper, total	1.0	N/A
		Max for any 1 day (mg/l)	
Cooling tower blowdown	126 priority pollutants contained in chemicals added for cooling tower maintenance, except:[b]	No detectable amount	N/A
	Chromium, total	0.2	N/A
	Zinc, total	1.0	N/A
Pretreatment Standards for New Sources (PSNS)			
		Maximum for 1 day (mg/l)	
Chemical metal cleaning wastes	Copper, total	1.0	N/A
		Max for any 1 day (mg/l)	
Cooling tower blowdown	126 priority pollutants contained in chemicals added for cooling tower maintenance, except:[b]	No detectable amount	N/A
	Chromium, total	0.2	N/A
	Zinc, total	1.0	N/A

[a] Runoff associated with a 10 year, 24 hour rainfall event is excluded
[b] The list of 126 priority pollutants can be obtained in "Appendix A to Part 423—126 Priority Pollutants," Code of Federal Regulations, Title 40: Protection of Environment, Part 423—Steam Electric Power Generating Point Source Category.
Source: Code of Federal Regulations, Title 40: Protection of Environment, Part 423—Steam Electric Power Generating Point Source Category. http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div5&view=text&node=40:28.0.1.1.23&idno=40

9.3.4 Storm Water Discharges

The U.S. also has storm water discharge requirements for steam electric power generating facilities.[ccxv] Compliance with storm water requirements can be included within an individual NPDES permit or a Multi-Sector General Permit (MSGP) in areas where the EPA is the NPDES permitting authority. Requirements under individual NPDES permits request the facility to fulfill control and monitoring requirements subject to the judgment of the permit writer. Coverage under a general storm water permit requires the implementation of a storm water pollution prevention plan, "reasonable and appropriate" control measures, and one or two years of monitoring and reporting. General permit requirements include recommended best practices for storm water at steam electric facilities, landfills, treatment works, and construction areas greater than five acres. Requirements are additive across industrial sectors, requiring a facility with operations that fall under more than one category (i.e., a utility with onsite ash landfill) to comply with all requirements for each appropriate industry sector.[ccxvi]

9.3.5 Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) requires that EPA establish health-based regulations to protect humans from contaminants in national drinking water. The act requires EPA to set national drinking water standards and create a joint Federal-State system to ensure compliance. EPA is also required to protect underground drinking water sources by regulating and controlling the underground injection of liquid waste. The provisions of the SDWA apply directly to public water systems in each state.

Drinking water standards are included here because electric power generation results in waste streams that contain detectable levels of elements or compounds that have established drinking water standards. Regulations under the Resource Conservation and Recovery Act (RCRA) for ground water contamination resulting from the disposal of solid wastes are tied to the contaminant levels established under the SDWA. Furthermore, deposition of emissions from the atmosphere may result in increased ambient contaminant levels in surface waters. Together, these conditions may hinder the ability of a public water system to meet the Federal or State standards and may result in additional effluent regulations at point sources.

EPA has set primary and secondary drinking water standards. Primary drinking water standards are contaminant specific and consist of maximum contaminant level goals (MCLGs), which are non-enforceable health based goals, and maximum contaminant levels (MCLs), which are enforceable limits set as close to MCLGs as economically and feasibly possible. These are presented in 9.8.

Even properly operated cooling towers have the potential to breed microorganisms, therefore routinely requiring the addition of disinfectants. Measures to address water quality issues resulting from recycled cooling water include MCLs for common chlorinated water treatment chemicals, along with treatment requirements for *Legionella* and heterotrophic plate count (HPC), a quantitative measure of the amount of bacteria present in the water.

Table 9.8 Selected National Primary Drinking Water Standards

Contaminant	MCLG (mg/l)	MCL (mg/l)
Inorganic Chemicals		
Antimony	0.006	0.006
Arsenic	None	0.01
Barium	2	2
Beryllium	0.004	0.004
Cadmium	0.005	0.005
Chromium (total)	0.1	0.1
Cyanide	0.2	0.2
Fluoride	4.0	4.0
Lead[a] (treatment requirement)	Zero	0.015 (action level)
Mercury	0.002	0.002
Selenium	0.05	0.05
Organic Chemicals		
Benzene	Zero	0.005

[a] Lead is regulated by a treatment technique that requires systems to control the corrosiveness of the water. If more than 10% of tap water samples exceed the action level, water systems must take additional steps.

National Secondary Drinking Water Regulations (NSDWRs or secondary standards) are non-enforceable guidelines regulating contaminants that may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as taste, odor, or color) in drinking water. EPA recommends secondary standards to water systems but does not require systems to comply. However, states may choose to adopt them as enforceable standards.[ccxvii]

9.3.6 Federally-Mandated Water Permitting Requirements

Table 9.9 identifies many of the critical government water permit approvals that could be required by an electric generating facility. EPA implements two permit programs under the CWA, the objective of which is to restore and maintain the chemical, physical, and biological integrity of the Nation's waters: *Section 404* permits, and *National Pollution Discharge Elimination System (NPDES)* permits. Section 404 of the CWA establishes a program to regulate the discharge of dredged (or fill) materials into waters of the United States, including wetlands. Section 404 permits prohibit the discharge of dredged or fill material if there is a practicable alternative that is less damaging to the aquatic environment or if the discharge would result in significant degradation of waters of the United States.

Table 9.9 Probable Environmental Permit Approvals for Coal-fired Power Plants

Permit Type	Permit Approval Authority	Permit Approval Requirement
NPDES Wastewater Discharge Permit	State Environmental Agency	180 Days Prior to Discharge
Clean Water Act – Section 404 Wetlands Permit	U.S. Army Corps of Engineers	Prior to Construction/ Mobilization
NPDES – Storm Water Notice of Intent (NOI) for Construction General Permit	State Environmental Agency	Prior to Construction/ Mobilization
NPDES – Multi-Sector General Storm Water Notice of Intent Permit for Operations	State Environmental Agency	Prior to Operation
Storm Water Pollution Prevention Plan (SWPPP) for Construction Activities	State Environmental Agency	Prior to Construction/ Mobilization
Storm Water Pollution Prevention Plan (SWPPP) for Operations	State Environmental Agency	Prior to Operation
Beneficial Use Permits to Divert or Withdraw Groundwater	Permit Board/ State Environmental Agency	Prior to Installation of Wells

Source: Lockwood, D and T. Royer, "Permitting and Regulatory Issues Associated with Development of an IGCC Project," Proceedings of Gasification Technologies Conference 2001, San Francisco, CA. October 7-10, 2001.

NPDES permits regulate wastewater discharges with the goals of (1) protecting public health and aquatic life, and (2) assuring that every regulated point source complies with applicable technology based effluent limits and at a minimum treats wastewater. To achieve these ends, permits may include the following terms and conditions: site-specific discharge (or effluent) limits; standard and site-specific compliance monitoring and reporting requirements; and enforcement provisions in cases where the regulated facilities fail to comply with the provisions of their permits. Under the NPDES program, all facilities that discharge pollutants from any point source into waters of the United States are required to obtain a NPDES permit. The term "pollutant" is defined very broadly by the NPDES regulations and includes industrial, municipal, or agricultural waste discharged into water. Where such pollutants are discharged from a point source this discharge is subject to NPDES regulation.

The Safe Drinking Water Act (SDWA) provides for control of contaminants in public water systems and also provides authority to regulate underground injection wells. The SDWA uses Underground Injection Control (UIC) permits to regulate construction, operation, and closure of wells in order to protect public sources of drinking water. The UIC permit program regulates the underground injection of wastes or other fluids with the goal of protecting underground sources of drinking water (USDW) from endangerment. A USDW is defined as an aquifer capable of supplying a public water system now or in the future and containing water with a concentration of 10,000 mg/l of total dissolved solids or less.

The UIC program defines five classes of wells. For Class I-IV wells, all injection activities, including construction of an injection well, are prohibited until the owners or operators of these injection wells receive a permit. Most Class V wells are currently authorized by rule as long as they do not endanger underground sources of drinking water and the well owners submit basic inventory and assessment information (40 CFR 144.24). Existing Class II enhanced recovery wells and hydrocarbon storage wells are authorized by rule for the life of the field project or until a permit is issued (40 CFR 144.22). Class IV wells, those that inject hazardous waste into or above USDWs, are prohibited unless they are part of an aquifer cleanup operation (40 CFR 144.13).

9.4. Solid Waste Discharge

In the U.S. more than one-third of the waste generated by coal-fired power plants is recycled into cement or other products, while the rest is stored in surface impoundments, landfills or depleted strip mines. National level regulations governing these activities are outlined in the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (RCRA, 42 U.S.C.A. §§ 6901 to 6992k). Regulated wastes are characterized as either hazardous or non-hazardous wastes with regulations specific to the pertinent waste type. In addressing the regulatory status of fossil fuel combustion wastes,[32] EPA has divided the fossil fuel combustion wastes into two categories:

1. Large-volume coal combustion wastes generated at electric utility and independent power producing facilities that are managed separately
2. All remaining FFC wastes, including:
    a. Large-volume coal combustion waste generated at electric utility and independent power producing facilities that are co-managed with certain other coal combustion wastes (referred to as "co-managed wastes");
    b. Coal combustion wastes generated at non-utilities;
    c. Coal combustion wastes generated at facilities with fluidized bed combustion (FBC) technology;
    d. Petroleum coke combustion wastes;
    e. Waste from the combustion of mixtures of coal and other fuels;
    f. Waste from the combustion of oil; and
    g. Waste from the combustion of natural gas.

[32] Fossil fuel combustion (FFC) wastes are the wastes produced from the burning of fossil fuels (i.e., coal, oil, natural gas). This includes all ash, slag, and particulates removed from flue gas. FFC wastes are categorized by EPA as a "special waste" and have been exempted from federal hazardous waste regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA).

A significant policy issue affecting electric utilities that use coal has been the question of whether or not coal utilization by-products (CUBs) should be regulated at the Federal level as hazardous wastes under RCRA Subtitle C or under Subtitle D as solid waste. Subtitle C of RCRA imposes requirements on the generation, transportation, storage, treatment and disposal of "hazardous" wastes, and is thus more costly to utilities to implement. Wastes that are not considered hazardous under Subtitle C fall under Subtitle D of RCRA, and are subject to regulation by the states as solid waste. These regulations vary state by state, but are typically not as stringent as the hazardous waste requirements. For landfills and surface impoundments, state permit requirements and siting control measures usually include groundwater monitoring, leachate collection systems, liners, and covering requirements, along with closure and fugitive dust controls. Waste management alternatives are permissible, subject to demonstration that they are at least as effective as currently accepted control measures. Certain units may obtain exemption to specific control requirements provided it can be demonstrated that there is no danger to human health or environment.[ccxviii]

As originally drafted in 1976, RCRA did not specifically address whether CUBs fell under Subtitle C as a hazardous waste or Subtitle D as a solid waste. In 1980, Congress enacted the Solid Waste Disposal Act Amendments to RCRA. Under the amendments, certain wastes, including CUBs, were temporarily excluded from Subtitle C regulation. This regulatory exemption, introduced by Congressman Bevill of Alabama, is commonly referred to as the "Bevill Exemption." As a result, CUBs fell under Subtitle D and became subject to regulation under state law as solid waste. A total of 45 states, representing 96 percent of coal-fueled utility generating capacity, duplicate the federal exemption of coal combustion byproducts from being categorized as a hazardous waste.

On April 25, 2000, EPA issued a Regulatory Determination that concluded that FBC wastes and CUBs that are co-managed with other wastes (i.e., category 2 wastes) do not warrant regulation as hazardous wastes under Subtitle C of RCRA. EPA also concluded that, except for mine filling, no additional regulations are warranted for coal combustion wastes that are used beneficially (including agricultural applications). However, EPA determined that national regulations under Subtitle D of RCRA (i.e., the solid waste regulations) are warranted for coal combustion wastes when they are disposed in landfills[33] or surface impoundments,[34] and that a combination of regulations under Subtitle D of RCRA and

[33] Landfills are excavated or engineered sites where non-liquid hazardous waste is deposited for final disposal and covered. These units are selected and designed to minimize the chance of release of hazardous waste into the environment. Design standards for hazardous waste landfills require a double liner; double leachate collection and removal systems (LCRS); leak detection system; run on, runoff, and wind dispersal controls; construction quality assurance (CQA) program. Liquid wastes may not be placed in a hazardous waste landfill. Operators must also comply with inspection, monitoring, and release response requirements. Since landfills are permanent disposal sites and are closed with waste in place, closure and post-closure care requirements include installing and maintaining a final cover, continuing operation of the LCRS until leachate is no longer detected, maintaining and monitoring the leak detection system, maintaining ground water monitoring, preventing storm water run on and runoff, and installing and protecting surveyed benchmarks. (See 40 CFR Parts 264/265, Subpart N). Waste disposal landfills typically are regulated by state agencies, and in some states obtaining approval for the location and design of a landfill can be a very difficult and time-consuming process, but is typically easier than using hazardous waste material guidelines.

[34] Surface Impoundments are natural topographic depressions, man-made excavations, or diked areas formed primarily of earthen materials used for temporary storage or treatment of liquid hazardous waste. Examples include holding, storage, settling, aeration pits, ponds, and lagoons. Hazardous waste surface impoundments are required to be constructed with a double liner system, a leachate collection and removal systems (LCRS), and a leak detection system. To ensure proper installation and construction, regulations require the unit to have and

modifications to existing regulations established under the Surface Mining Control and Reclamation Act (SMCRA), are warranted when these wastes are used to fill surface or underground mines. So that coal combustion wastes are consistently regulated across all waste management scenarios, EPA intends to make these Subtitle D regulations applicable to large volume coal combustion wastes (i.e., category 1 wastes) that had previously been exempt.

The April 2000 regulatory determination is important in that it marks the first time EPA had stated its intent to develop nationwide regulations for disposal of CUBs; prior to this, all regulations governing CUB disposal and use had come from individual states. Even though the regulations are being developed under RCRA Subtitle D (rather than the more rigorous Subtitle C), the uncertainty caused by the possibility of having to comply with national regulations, which may not coincide with current disposal practices, is causing a great deal of concern within the utility industry. The possibility of a separate set of nationwide regulations regarding placement of CUBs in mines is also causing a great deal of uncertainty.

EPA is still working on developing these regulations. Specific developments are outlined in the following two subsections:

9.4.1 Management of Coal Utilization By-Products in Landfills and Surface Impoundments

On August 24, 2007, EPA issued a Notice of Data Availability (NODA) on the Disposal of Coal Combustion Waste in Landfills and Surface Impoundments and has requested comments on this by January 28, 2008.[ccxix] The NODA announces the availability of new information and data contained in three documents that EPA is requesting public comments on:

- A joint U.S. Department of Energy (DOE) and EPA report entitled, *Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004*;
- A draft risk assessment conducted by EPA on the management of coal combustion waste in landfills and surface impoundments; and
- EPA's damage case assessment.

EPA is soliciting comments on the extent to which the damage case information, the results of the risk assessment, and the new liner and ground water monitoring information from the DOE/EPA report should affect the Agency's decisions. EPA is also requesting comments on the draft risk assessment document to help inform a planned peer review. In addition, EPA has included a rulemaking petition submitted by a number of citizens' groups along with two approaches regarding the management of coal combustion waste, one prepared by the electric utility industry and the other prepared by a number of citizens' groups. EPA will use the submitted comments for finalizing its regulatory determination for coal combustion waste.

The data released by EPA shows that states have continued to strengthen regulatory practices related to landfills and surface impoundments. The joint DOE-EPA report, Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004, analyzed practices at 56 disposal units in the U.S.; compiled regulatory data for 11 states with high coal

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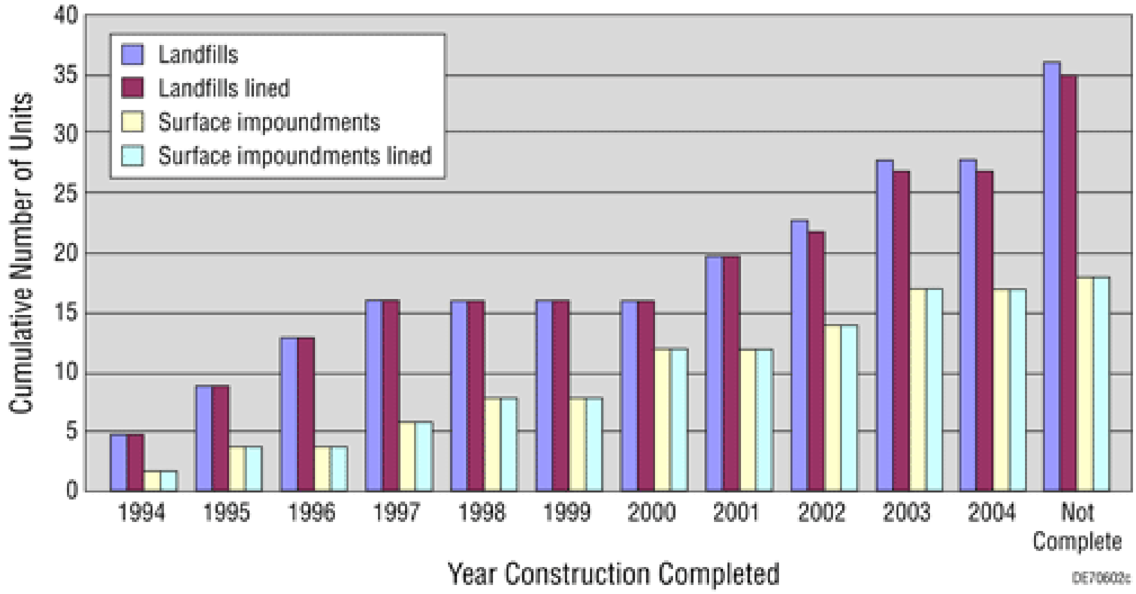
follow a construction quality assurance (CQA) program. The regulations also outline monitoring, inspection, response action, and closure requirements. (See 40 CFR Parts 264/265, Subpart K).

combustion rates; and reviewed 65 permits issued for CCW disposal units in 16 states.[ccxx] The study produced the following key findings:

- Disposal management practices and the enforcement of state requirements have resulted in liners for virtually all newly built or expanded units (97% of landfills and 100% of surface impoundments) and groundwater monitoring for the majority of units (97% of landfills and nearly 80% of surface impoundments) (See Figure 9.3).
- During the time period analyzed (, a majority of the 11 states reviewed tightened regulation of landfill liners, leachate-collection systems, and groundwater monitoring.
- A detailed analysis of variance requests (i.e., requests to obtain exceptions to relevant regulations) in 65 permits in 16 states indicates that state regulators have not issued variances without a sound scientific basis supporting the request.

Figure 9.3 Liners in Identified New or Expanded Disposal Units, 1994-2004 (cumulative yearly total numbers)



Liners in Identified New or Expanded Disposal Units since 1994 (cumulative yearly total numbers)

Source: Elcock, D., N. Ranek, 2006, *Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004,* DOE/PI-0004, ANL/EVS-06-4, Aug.

9.4.2 Placement of Coal Utilization By-Products in Mines

The EPA expressed serious concern over the use of CUB for mine filling in its 2000 Regulatory Determination on Wastes from the Combustion of Fossil Fuels.[ccxxi] EPA specifically noted that more information was needed on mine filling practices, impacts and "the ability of government oversight to ensure that human health and the environment are being adequately protected." The Agency stated:

> "We are aware of situations where coal combustion wastes are being placed in direct contact with ground water in both underground and surface mines. This could lead to increased releases of hazardous metal constituents as a result of mine filling. Thus if the complexities related to site-specific geology, hydrology, and waste chemistry are

> not taken into account when mine filling coal combustion wastes, we believe that certain mine filling practices have the potential to degrade, rather than improve, existing groundwater quality and can pose a threat to human health and the environment."[ccxxii]

Recognizing the importance of this debate, Congress in 2004 directed the National Research Council (NRC) of the National Academies of Science (NAS) to study the issue of coal placement in mines. The NAS Report, published in 2006, concluded that "that the presence of high contaminant levels in many CCR [coal combustion residue] leachates may create human health and ecological concerns at or near some mine sites over the long term."[ccxxiii] The National Research Council further concluded that placement of coal combustion waste in coal mines may be a viable option *only* if:

> "(1) CCR placement is properly planned and is carried out in a manner that avoids significant adverse environmental and health impacts and (2) the regulatory process for issuing permits includes clear provision for public involvement."[ccxxiv]

Lastly, the NRC concurred with USEPA that enforceable federal regulations were necessary to guarantee that state programs minimized such threats to health and the environment by implementing safeguards, such as sufficient monitoring, site and waste characterization, isolation measures, corrective action standards and public participation. As recommended in the NRC report, EPA is collaborating with the Department of Interior to develop such federal regulations.

In March 2007, the Office of Surface Mining (OSM) of the Department of Interior published an advance notice of proposed rulemaking concerning placement of coal ash in mines.[ccxxv] It came in response to the National Academies of Science 2006 Report. The proposal recommends only minimal changes to the Federal Surface Mining Control and Reclamation Acts.

The Federal Register notice explains how OSM thinks it could carry out the NCR's recommendation – specifically by adding language to existing Federal rules (30 Code of Federal Regulations VII) to include specific permit requirements and performance standards that would have to be satisfied before CUBs could be used in reclaiming coal mines. To address using CUBs at Federally-funded abandoned mine reclamation projects, OSM would propose changes to existing rules (Part 874) to require that appropriate data would have to be provided and evaluated before CUBs could be used for reclamation of these abandoned mines. In addition, consistent with the NRC recommendation emphasizing the need for public involvement in permitting decisions, OSM is considering modifying 30 CFR 774.13(b) to specify that permit revision applications proposing the placement of CUBs must be processed as significant revisions, which means that they would be subject to all the notice and public participation requirements that apply to applications for new permits.

9.4.3 State Waste Product Regulations and Permitting

As stated previously, individual states have the option to outline standards and regulations that are at least as stringent as federal standards, and may be more stringent, and they will sometimes permit individual counties to outline specific standards that are more stringent than both state and federal levels. Solid waste handling for Subtitle D non-hazardous waste materials is typically handled at the state level.

Currently 45 states duplicate the federal exemption of fossil fuel combustion wastes from hazardous wastes. Five states (California, Kentucky, Maine, Tennessee, and Washington) do not categorically exempt fossil fuel combustion wastes from hazardous waste requirements and either regulate as "special" waste or subject those wastes to hazardous waste characteristic tests and appropriate state handling and disposal procedures. For the handling of hazardous wastes, states may determine their own permitting and siting requirements but must be at least as stringent as those outlined by Subtitle C (42 U.S.C.A. § 6929).

Most states do not have specific regulations addressing the use of CUBs and requests for CUB uses are handled on a case-by-case basis or under generic state recycling laws or regulations. Many states have "generic" laws and regulations that authorize limited reuse and recycling of hazardous and/or solid wastes. These generic laws do not apply specifically to CUBs or any other materials. Classification of combustion wastes as CUBs and the allowable beneficial uses can vary widely from state to state. Some states include the same fossil fuel wastes as in the federal definition of CUBs while other states exclude a particular component or include co-burned wastes including tire derived fuels and/or wood. Often, regulation may fall under one or several state regulatory agencies, depending on the specific use or application of CUBs.

Florida

Florida regulations adopt the federal regulations which exempt fly ash, bottom ash, slag and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels from regulation as hazardous waste (40 CFR 261.49(b)(4), 62-730.030 F.A.C.). CUBs are regulated as solid waste if disposed of and may be regulated as industrial byproducts if the CUBs are utilized within one year, if there is no release or threat of release into the environment, and if the facility is registered with the Department of Environmental Protection to allow for such recovery of CUBs (FAC 62-701.220(2)(c) F.A.C.). Reuse of all CUBs is not specifically authorized under Florida law. However, ash residue from CUBs is specifically authorized for use in concrete under Florida statute 336.044(2)(b). Until national regulations are promulgated, Florida will continue to be responsible for implementation of Subtitle D disposal of CUBs.

Indiana

Indiana Code IC 13-11-2-109.5 defines industrial wastes as a solid waste that is not 1) a hazardous waste, 2) a municipal waste, 3) a construction/demolition waste or 4) an infectious waste as defined elsewhere in Indiana Code. The disposal of such wastes is subject to Federal Subtitle D regulations specified in 40 CFR §228, with certain provisions for small quantities and specially permitted disposal sites (IC 13-20-7.5-1). Any waste determination required for non-exempt wastes are the responsibility of the generator, and specific guidelines are outlined in 326 IAC 10.

Indiana Code (IC 13-19-3-3) specifically exempts coal combustion wastes from solid or hazardous waste regulations, if the waste is not included in the definition of hazardous wastes and meets the Federal exemption under 42 U.S.C.A. § 6921. In order to maintain the categorical exemption the waste must also be disposed of at a facility regulated as a surface coal mining facility. Additional exemptions from solid waste regulations are also provided for specific beneficial uses of coal combustion fly or bottom ash alone or in mixture with flue gas desulfurization byproducts generated by coal combustion units, or the use of boiler slag. The allowable uses include:

- Use of bottom ash as anti-skid material;
- Use of the waste as a raw material for manufacturing another product;
- Use in mine subsidence, mine fire control, and mine sealing;
- Use as structural fill when combined with cement, sand, or water to produce a controlled strength fill material;
- Use as a roadbase in construction; and
- Extraction or recovery of materials and compounds from the coal ash.

Louisiana

Under Louisiana regulations, fly ash, bottom ash, slag and flue gas emission control waste generated solely from the combustion of coal or other fossil fuels are exempt from regulation as hazardous waste (LAC 33:V.105(D)(2)(d)). Additionally, Louisiana specifically exempts from regulation as hazardous waste gasifier ash and process waste water resulting from coal gasification, categorizing this ash as solid waste resulting from the processing of ores and minerals (LAC 33:V.105(D)(2)(h)(ii)). These materials are, however, regulated as industrial solid wastes (LAC 33:VII.115). Louisiana does not specifically address the reuse of coal combustion by-products, but does require beneficial-use permits for land application of any solid waste (LAC 33:VII.1103(A)). Additional site analysis, disposal and record keeping requirements also exist. Louisiana code outlines recycling regulations (LAC 33:VII.Subpart 2) that may be applicable to the reuse of CUBs as raw material or product.

10. Viet Nam

10.1 Air Emissions

In December 2006, the Government of Viet Nam introduced new emissions standards for thermal power plants, which significantly increased controls on NO_X emissions. The standards, which are described in Table 10.1, include a site-specific formula for determining each unit's SO_2, NO_X, or PM limits. In this way, plants located near an urban or protected area will be required to use more efficient controls. The regulation also differentiates between plants that use coal with a high or low VOC content. Vietnam has some domestic coal with a VOC content of less than 10%. However, a majority of this low VOC-content coal is exported, making most new plants subject to the more stringent target of 650 mg/nm^3.

Until 2015, existing power plants, permitted before 2006, are allowed to use the old standards outlined in Table 10.3. After this, all plants will be subject to the new regulation. Plant operators will be charged a fee if the plants do not comply with the standards, but the fee is very low at about 10 percent of the cost of environmental clean-up. It will increase gradually over the next 10 years until it covers the full treatment cost.

The standards are most challenging for NO_X emissions. Power plant operators do not expect to have difficulties meeting the SO_2 standards.[ccxxvi]

Table 10.1. Emission Standards for Thermal Power Plants – Units Permitted in 2006 and Later

Parameter	Fuel Type (mg/nm^3)			Standard/Regulation Referenced
	Coal	Oil	Natural Gas	
Particulate matter	200	150	50	TCVN 5977: 1995
NO_X	650 (coal with VOC content > 10%) 1,000 (coal with VOC content ≤ 10%)	600	250	TCVN 7172: 2002
SO_2	500	500	300	TCVN 6750: 2000

Notes: The temperature of the boiler must be operated in standard condition. The oxygen concentration must be 6% at the boiler and 15% at the exhaust. The numbers in the table are invalid if diluting methods are applied.
Source: The Decision Requiring Use of Vietnamese Standards Regarding the Environment. Decision No 22/2006/QD-BTNMT, Ha Noi, Vietnam. December 18, 2006

Referring to Table 10.1 above, the emission standards for each individual unit should be calculated using the following equation:

$$C_{max} = C * K_q * K_v$$

Where

C = the specific emission limit listed in Table 10.1
Kq = 1 if the unit capacity is ≤ 300 MW

Kq = 0.8	if the unit capacity is >300 MW and ≤ 600 MW
Kq = 0.7	if the unit capacity is > 600 MW
Kv = 0.6	if located < 2km from a natural, cultural, or historic heritage site (urban area Type I)
Kv = 0.8	if located inside or < 2 km from urban areas Type II, III, and IV, and outside Type 1
Kv = 1.0	if located inside or < 2 km from an industrial zone or urban area Type V, and outside Types I, II, III, and IV
Kv = 1.2	if located in a valley
Kv = 1.4	if located in a mountain area

Table 10.2. Sample standards for new individual coal-fired plants, depending on location (mg/nm3)

	< 2 km from heritage site (Type 1)		Inside or < 2 km from industrial zone or urban area Type V		Mountain area	
	300 MW	600 MW	300 MW	600 MW	300 MW	600 MW
PM10	120	84	200	140	280	588
NOX > 10% VOC	390	273	650	455	910	637
NOX ≤ 10% VOC	600	420	1,000	700	1,400	980
SO2	300	210	500	350	700	490

Table 10.3. Industrial Emission Standards, Including Coal-fired Power – Units Permitted Before 2006

Parameter	Power Plants Permitted before 1995	Power Plants Permitted in 1995-2005
	(mg/nm^3)	
Particulate matter	600	400
NO_X	2500	1000
SO_2	1500	500

Source: Air Quality – Industrial Emission Standards – Inorganic Substances and Dust. TCVN 5939: 1995

10.2 Water Consumption and Aqueous Effluents

In the case of waste water regulations, there are 37 parameters that industrial sources have to comply with, some of which are applicable to water from coal-fired power plants (Table 10.4). The standards that plant operators may have difficulty meeting, include those for temperature, suspended solids, and heavy metals like mercury.

Table 10.4. Industrial Waster Water – Discharge Standards

Items	Unit	Implementation Period		
		A	B	C
Temperature	˚C	40	40	45
pH	-	6 – 9	5.5 – 9	5 – 9
Suspended Solids (TSS)	mg/l	50	100	200
Arsenic (As)	mg/l	0.05	0.1	0.5
Mercury (Hg)	mg/l	0.005	0.01	0.01
Lead (Pb)	mg/l	0.1	0.5	1
Cadmium (Cd)	mg/l	0.005	0.01	0.5
Chromium (VI)	mg/l	0.05	0.1	0.5
Chromium (III)	mg/l	0.2	1	2
Copper (Cu)	mg/l	2	2	5
Sulfide (as H_2S)	mg/l	0.2	0.5	1

Source: Industrial Waste Water – Discharge Standards. TCVN 5945: 2005

10.3 Coal Ash

There are no requirements for ash handling and all ash from coal-fired plants is deposited in open dumps. Viet Nam does not have the technology for ash recycling. The concentration of carbon in the ash is high (about 10%). As a result, specialized techniques for processing would be required, but the government has postponed investment in relevant research activities due to cost.[ccxxvii]

10.4 Monitoring and Enforcement

All thermal power projects with a capacity of more than 50 MW must prepare an EIA and address how each of the standards outlined above will be satisfied. The EIA is therefore the first step in ensuring that the power plants comply with the relevant environmental regulations.

Once operation has begun, it is much harder to ensure compliance because the monitoring system in Viet Nam is very weak. None of Viet Nam's power plants have CEMS in place. All monitoring takes place manually. Power plants self-monitor and every three to six months, depending on their size, report on their progress to the local authorities or the Ministry of Natural Resources and the Environment (MONRE). Only large plants (>300 MW) submit monitoring reports to MONRE. In a few cases, the EIA also specifies that smaller plants must report to MONRE. This depends on whether the plants are located inside or outside a sensitive area. From time to time, MONRE and the local authorities send out inspectors to monitor. However, this is not enough to ensure full compliance.[ccxxviii]

The system does include some incentives for compliance. For example, if plant operators do not comply with the specified standards and/or fail to install necessary pollution controls, they are not allowed to expand capacity at their existing sites. If, during the permitting process, it is found that the plant operator is out of compliance, the operator will not be granted a permit for new units until a remediation plan has been agreed upon.[ccxxix]

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