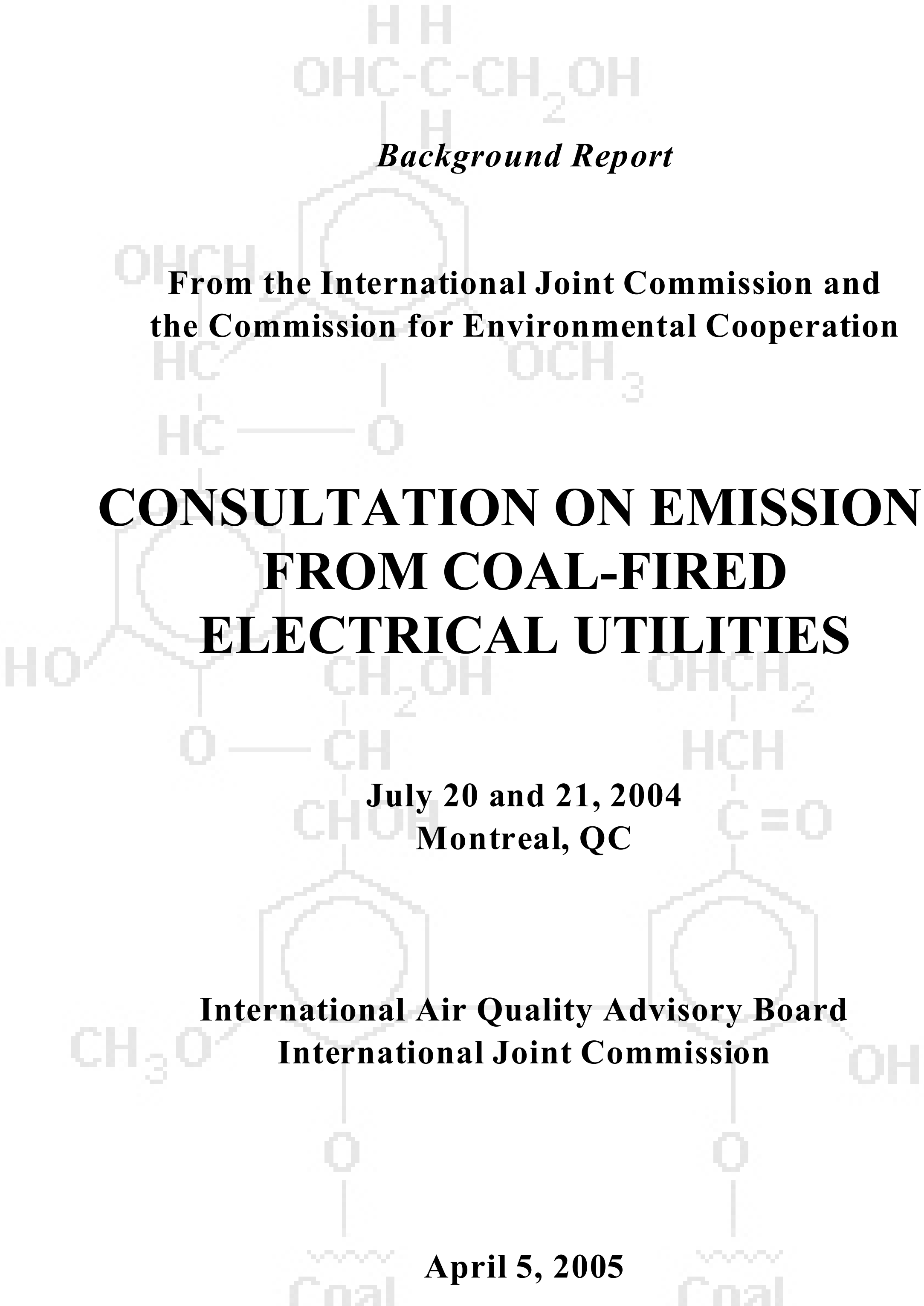

Background Report

From the International Joint Commission and the Commission for Environmental Cooperation

CONSULTATION ON EMISSIONS FROM COAL-FIRED ELECTRICAL UTILITIES

July 20 and 21, 2004
Montreal, QC

International Air Quality Advisory Board
International Joint Commission

April 5, 2005

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Executive Summary

On July 20 and 21, 2004, the International Air Quality Advisory Board and the Commission for Environmental Co-operation co-sponsored a one day Coal-Fired Consultation in Montreal, QC. This report augments the background material provided to participants prior to that event with some of the material provided by government, industry, and non-government organizations who were represented there.

A brief overview of current and future electricity generation in Canada and the United States, projected to the years 2010 and 2025, is provided. Electrical generation capacity and recent usage, and trends in prices and the extent of available reserves of the various fuels, including coal, natural gas, and uranium, are examined for both countries, as are government projections of supply and use under different economic and environmental scenarios. The price trend information is that presented at the Consultation; the prices of coal, oil, and natural gas have all risen substantially since that time, but their relative relationship remains largely as it was – coal remains the cheapest of the three.

Current emissions from coal-fired facilities, including mercury, particulate matter, SO_2, NO_x, *and their related detrimental impacts on the environment are examined, along with the performance and cost of related emission control technologies. To provide further context, limited data on the relative role of coal in the generation of electricity, and associated emissions control provisions are noted for selected other countries, including China, India, Japan, Germany, and the United Kingdom, all of which have different emission monitoring and control approaches.*

Emerging technologies for the measurement and control of emissions of mercury and other pollutants are described, including a brief discussion of some of the advantages, disadvantages, and costs of the various technologies in Canada and the United States. Evolving technologies are also described for China, India, Japan, Germany, and the United Kingdom.

The degenerative effects of emissions from coal-fired utilities are considered, including the imprecise but significant effect on human health from particulate releases, and the more subtle risk posed by mercury from these facilities.

Selected regulatory frameworks and jurisdictional approaches considered at the Consultation including those at the federal level and some at provincial or state jurisdictions, in Canada and the United States are outlined. In Canada, the development of the Canada Wide Standard for mercury emissions from this source sector is emphasized, while legislative proposals in the United States such as the Clear Skies Act, the Clean Air Planning Act, the Clean Air Interstate Rule, and the Clean Air Mercury Rule are discussed. Selected jurisdictional approaches to the *control of coal-fired utility emissions are also summarized, including those in Ontario and Alberta in Canada, and the New England States, particularly the state of Massachusetts and the western states in the United States.*

This report concludes that the price stability of coal, along with its relatively lower current cost and extensive reserves available in Canada and the United States, ensure that it will remain the fuel of choice for electrical generation in many regions of the two countries for several decades. Proven process and control technologies exist to further measure and reduce harmful emissions of acid gases, mercury, and particulate matter. Further aggressive application of these technologies is anticipated and encouraged. Prompt technology transfer to emerging economies, especially those in southeast Asia and India, is advocated to further control emissions from this sector on a global scale, and reduce the trans-Pacific transport of pollutants affecting North America.

1.0 INTRODUCTION

The International Joint Commission (IJC) has long recognized the robust link between energy sources and effects on the environment. In particular, coal-fired electrical generation has been a sector of interest for some time due to the magnitude of its environmental impacts, including those on human health.

The North American Commission for Environmental Cooperation (CEC) has also had a long standing interest in this sector and agreed to join the International Air Quality Advisory Board of the International Joint Commission in sponsoring a consultation related to this topic. The Coal-Fired Consultation was held on July 20 and 21, 2004 at the CEC offices in Montreal, with the intent of advising the Commissioners of the IJC on the current status and future of coal-fueled generation of electricity with an emphasis on its related environmental impacts. This report is an enhanced version of the background document used at that event, including portions of material presented at the Consultation.

Sources of electrical energy in North America currently include coal, natural gas, hydro power, oil, and renewables such as wind, solar, and biomass. The human health and environmental impacts of each of these sources of electrical energy vary substantially.

Hydroelectric facilities can have a significant impact on the watershed where they are situated and storage facilities, in particular, may affect the hydrology, geomorphology, wildlife, and aquatic life of the lakes, rivers, and shore lands. Smaller hydroelectric facilities have relatively minor environmental impacts as do facilities that generate power from wind. Nuclear power generation creates by-products including radioactive waste whose management has proved problematic. Efforts to address the long term storage and disposal options for radioactive waste continue in Canada and the United States. Should a long term disposal site be selected and approved, concerns about the secure transport of radioactive waste would remain.

Unlike nuclear power generation and renewables which emit no carbon dioxide or common air pollutants, the operation of fossil-fueled generation powered by natural gas, oil, and coal does contribute to impaired air quality. Natural gas is the cleanest burning hydrocarbon fuel and emits lower levels of pollutants and toxics including nitrogen oxides (NO_x), carbon dioxide (CO_2), sulphur dioxide (SO_2), and particulate matter (PM) and virtually no carbon monoxide (CO) or mercury. Oil, however, emits higher levels of these substances, and those associated with coal are higher still.

This report specifically focuses on the current and projected use of coal in the electrical generation sector. Coal-fired electrical generation is a major source of SO_2 and NO_x, as well as CO_2 and mercury and other harzardous air pollutants (HAPs) including cadmium, arsenic, vanadium, and various acid gases. Nitrogen oxides ($NO_{x)}$ and sulphur dioxide (SO_2) emissions, in particular, from this source sector have been found to contribute significantly to acid rain. In both years 2000 and 2001, coal-fired power plants have been confirmed as the leading source of anthropogenic atmospheric releases of mercury and its compounds in Canada and the United States combined (Commission for Environmental Cooperation, 2004).

Mercury emitted from coal-fired facilities can be deposited in surface water where, after chemical transformations, it bioaccumulates in fish. The result is an impairment of ecosystem quality, including the exposure of humans to mercury through the consumption of fish. The brain and developing neurological system of the fetus are particularly sensitive to mercury and can be damaged by fairly low levels of exposure. Based on recent data from the United States Centers for Disease Control, which measured mercury levels in the blood of women across the country, hundreds of thousands of newborns each year are at risk of mercury toxicity because of their mothers' exposure to mercury.

Mercury can also damage the kidneys and immunological system and new data also indicate that it may adversely impact the human cardiovascular system.

Coal as a fuel source for electrical generation maintains a substantial share of total generation in Canada at 18 percent (year 2000) and is associated with over half of the generation in the United States (54 percent) (year 2002). The quantity of future emissions of harmful pollutants as well as possible impairment of environmental and human health, are dependent in part on the forecasted generating capacity of coal. This report will explore the current and forecasted use of coal in Canada and the United States as raised at the IJC-CEC consultation, with a focus on the electrical generating capacity supplied by coal, the impact on human health and the ecosystem of continued coal combustion, available and emerging emission control technologies, and selected jurisdictional approaches related to possible future control of the coal-fired utility sector.

A relatively recent overview of current sources of electrical energy in North America is presented in this report, accompanied by projections from the governments of Canada and the United States for the quantity and distribution by fuel of generating capacity in the years 2010 and 2025. In addition, current and emerging emission control technologies in these countries is outlined. For comparative purposes, some consideration is also given to both current and emerging technologies in China, India, Japan, Germany, and the United Kingdom. Finally, an outline of the federal and selected state and provincial regulatory frameworks to further control coal-fired utilities in Canada and the United States is presented.

2.0 OVERVIEW OF CURRENT ENERGY SECTOR IN CANADA AND THE UNITED STATES AND COMPARISONS WITH CHINA, JAPAN, GERMANY AND THE UNITED KINGDOM

Figure 1 illustrates the contributions to the electrical generation sector in Canada, the United States, China, India, Japan, Germany and the United Kingdom by energy source. Approximately 56 percent of Canadian electrical power generation is from hydro power plants, which are not associated with atmospheric pollution. However, fossil fuel-fired utilities make up almost one third of total generation capacity and contribute significantly to atmospheric pollution. Coal-fired utilities account for over half of the fossil fuel-fired sector. A very small portion of electricity in Canada is produced by 'other' sources of energy; renewables, such as wind and solar generation, are in this category.

The United States produces slightly more than half of its electricity from coal-fired utilities with a concomitant contribution to air pollution. A further 20 percent is from other fossil fuel sources (principally natural gas). Less than 10 percent of electricity generation in the United States is from renewable or hydroelectric sources.

Of all of the countries considered in this report, China is the most heavily reliant on coal – 76 percent of electricity generation is from coal. China also generates 20 percent of its electricity from hydro sources. All other energy sources are relatively minor. Japan's energy sector has a broad spread of fuel sources. The main technology is nuclear, accounting for 31 percent of electricity generation. Coal and gas make up nearly equal proportions, accounting for 23 percent and 24 percent respectively. Oil produces 11 percent of Japan's electricity, and hydro and other sources make up 10 percent.

Germany is also very reliant on coal, as 51 percent of electricity is generated from this source. Nuclear fuel is the second most widely used energy source, accounting for 30 percent of the total energy generated and other fossil fuels make up 11 percent of generation. The United Kingdom burns slightly more gas than coal (37 percent and 35 percent respectively). Nuclear fuel accounts for nearly one quarter of total electricity generation there, with oil, hydro, and others accounting for less than five percent.

These data make clear that coal and other fossil fuel sources are important in many developed and developing countries around the world. Despite associated controversy, the use of nuclear fuel is widespread in the more economically developed countries. Hydropower is used in all six of these countries, notably in Canada, which perhaps suggests how the use of renewable sources will be tailored to the natural resources of specific countries. However, other renewable sources (in the 'Other' category) are currently only minor contributors in all countries.

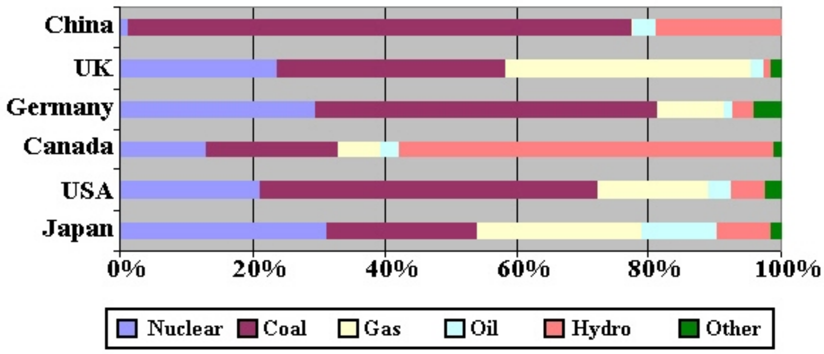


Figure 1. Electricity Generation by Percentage Energy Source (OECD 2000-2001)

2.1 Canada: Electrical Energy Sources

Table 1 presents a more detailed examination of the electrical energy sector in Canada. Some of the percentages are slightly different from Figure 1, as the data are from a different source. However, the distribution remains the same, with hydropower being the principal generation source.

Table 1. Canada's Electrical Generation and Percentage of generation by fuel type for the year 2000 (National Energy Board of Canada, 2003) (GW.hr - gigawatt hours)

Fuel Type	Electrical Generation (GW.hrs)	% share of generation
Hydroelectric	351,587	60.1
Nuclear	68,674	11.7
Coal	107,075	18.3
Natural Gas	33,015	5.6
Oil	8,519	1.5
Renewables	13,660	2.3
Diesel (Internal Combustion and Combustion Turbine)	544	0.1
Orimulsion*	2,129	0.4
Total	**585,203**	**100%**

*Note: Orimulsion involves the combustion of a mixture of bitumen (a tar-like substance) and water and is currently used for power generation in New Brunswick.

2.2 United States: Electrical Energy Sources

Table 2 provides details of the electricity sector in the year 2002, based on data from the U.S. Department of Energy, which again varies slightly from Figure 1. These data also highlight the large role of coal as a fuel for the generation of electricity in the United States.

Table 2. United States Electrical Generation and Percent of generation by fuel type for the year 2002 (U.S. Department of Energy (DOE) Energy Information Administration (EIA), Annual Energy Outlook 2004 (AEO2004), 2002)

Fuel Type	Electrical Generation (GW.hrs)	% share of generation
Coal	1,875,000	53.7
Nuclear	780,100	22.3
Natural Gas	450,000	12.9
Hydroelectric	255,780	7.3
Renewables	53,100	1.5
Oil	77,000	2.2
Total	**3,490,980**	**100%**

2.3 Coal Reserves in Canada and the United States

There are four different types of coal of commercial interest in North America: lignite; subbituminous; bituminous; and anthracite. In the progression from lignite to anthracite the carbon content increases, along with the geological age of the coal. The oldest, anthracite, or 'hard coal', has been exposed to increased heat and pressure and contains the greatest energy per unit mass. Lignite, or 'brown coal', is a geologically young coal that has the lowest carbon content and lowest energy per unit mass. Subbituminous coal generally has a lower sulphur content than other types of coal; its relatively low SO_2 emissions have lead to greater market penetration in some areas.

The national distribution of coal deposits in Canada is shown in Figure 2. In both Canada and the United States, anthracite, due to its limited availability and combustion characteristics, is not generally used for electrical power generation. Instead, it finds application in certain industrial and small commercial/residential uses. Bituminous, subbituminous, and lignite are the only types of coal commercially mined in Canada. Bituminous coal is used in the production of coke, an essential ingredient in the manufacturing of steel, as well as in energy applications, including the generation of electricity. Subbituminous coal and lignite are used only for electrical generation.

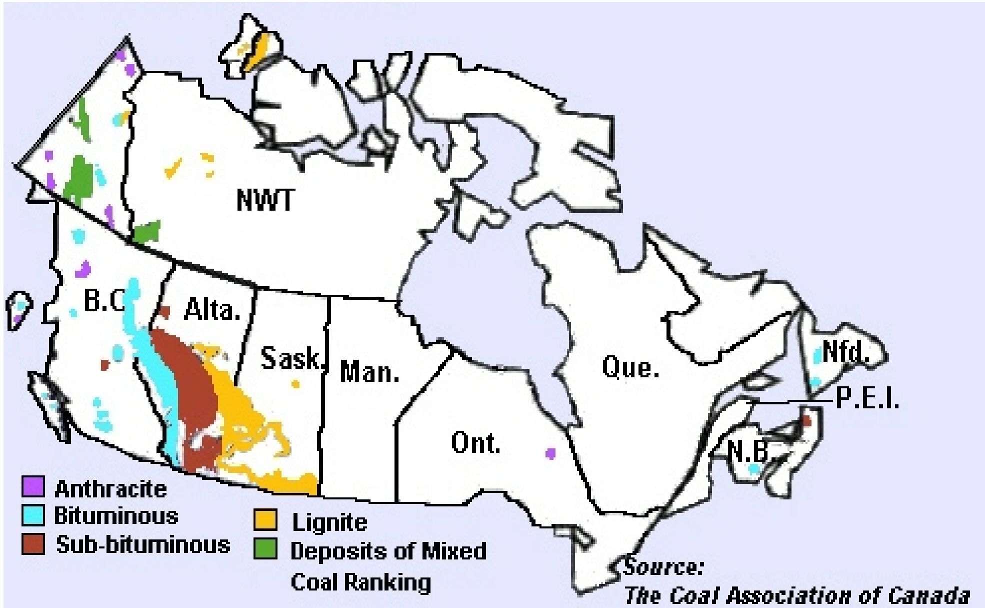


Figure 2. Canadian Coal Deposits by Type (http://www.climatechangecentral.com/ Info_centre/C3Views/c3views_mar03.html)

The province of Alberta has large deposits of subbituminous coal, which are heavily mined. Alberta also has smaller deposits of lignite and bituminous coal. Saskatchewan's coal resource is mainly lignite, and the Atlantic provinces of Nova Scotia and New Brunswick have quantities of bituminous coal which are also currently mined (Natural Resources Canada, 2000).

The distribution of coal deposits in the United States is illustrated in Figure 3. Anthracite constitutes a very small portion of the United States coal market, while bituminous and subbituminous are the most plentiful forms of coal. As in Canada, bituminous coal is used primarily to generate electricity and in the production of coke for the steel industry. Reserves of subbituminous coal in the United States are located primarily in half a dozen western states and Alaska. Texas is the principal source of extracted lignite coal in the United States. Large deposits of lignite are also found in Montana, North Dakota, South Dakota, and some Gulf Coast states (American Coal Foundation, 2004).

The governments in both the United States and Canada have developed estimates of the length of time coal could serve as a fuel source for future electrical power generation. The bases of these estimates are described below.

Coal ***resources*** are defined in both the Canadian and U.S. contexts as deposits whose extraction is currently or potentially economically feasible. Coal ***reserves*** are considered to be portions of measured and/or indicated resources of immediate interest that are anticipated to be mineable under current extraction technology now or in the immediate future.

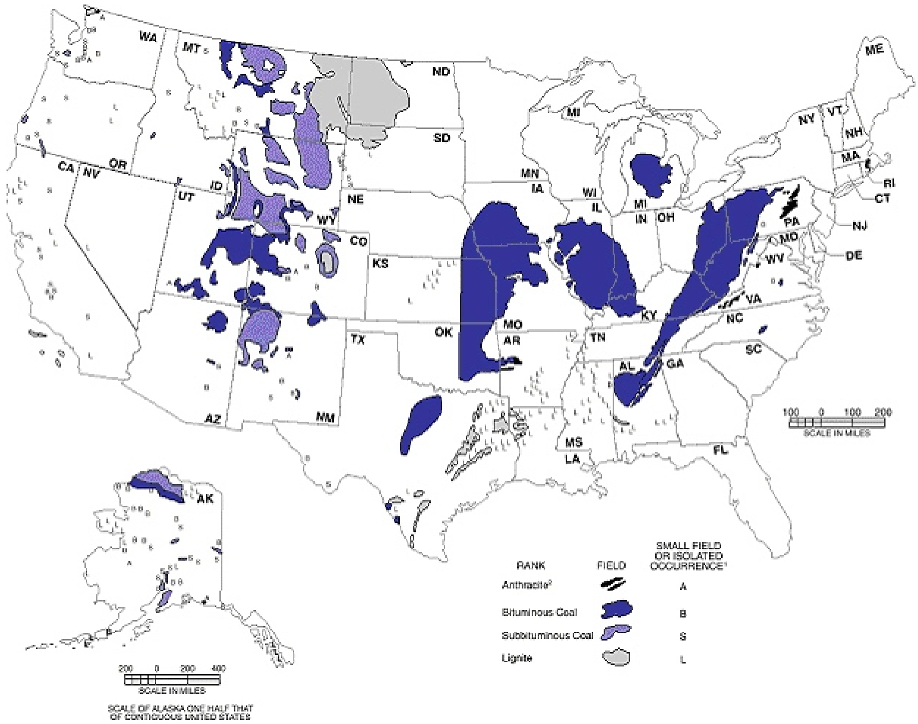


Figure 3. **National Distribution of American Coal Deposits (U.S. Department of Energy (DOE) Energy Information Administration (EIA) Coal Reserves: 1997 Update)**

Resources of coal may be classified as measured, indicated, or inferred resources. *Measured resources* refers to coal for which estimates of the rank and quantity have been determined to a high degree of geologic assurance from sample analyses obtained at well known sample sites. Coal for which estimates of rank, quality, and quantity have been estimated to a moderate degree of geologic assurance are referred to as *indicated resources*. Finally, *inferred resources* refers to coal of a low degree of geologic assurance in unexplored extensions of measured and indicated resources (U.S. Department of Energy (DOE) Energy Information Administration (EIA) Coal Reserves: 1997 Update).

Table 3 presents the quantity of coal reserves according to type for Canada and the United States. The quantity of Canadian coal reserves is based on the measured and/or indicated recoverable resources of coal of immediate interest only. United States' quantities of coal reserves displayed in Table 3 are based on the 'demonstrated reserve base' that includes those portions of identified resources that meet specified minimum physical and chemical criteria related to current mining and production practices.

Table 3. Canadian and American Coal Reserves (Million tonnes) (NRCan, 2000) (U.S. Department of Energy (DOE) Energy Information Administration (EIA) Coal Reserves: 1997 Update)

Country and Ref. Year	Anthracite	Bituminous Coal	Subbituminous Coal	Lignite	Total
Canada 1986		3,471	871	2,236	6,578
United States 1997	6,783	245,765	167,936	40,129	460,614

Note that Table 3 displays total reserves of coal, not all of which would be used for electrical generation. For example, of the 6,578 million tonnes of total coal reserves in Canada, only 4,660 million tonnes were designated for use in electrical generation.

The reserve life of the quantities of recoverable coal reserves has also been estimated for coal resources in Canada and the United States. The reserve life of the total 6,578 million tonnes of coal in Canada in 1986 was estimated to be 115 years based on 1998 production rates. The reserve life of the 4,660 million tonnes of coal designated for thermal purposes was anticipated to be in the vicinity of 100 years. The reserve life of coal in the United States can be determined based on the estimated recoverable reserve quantity of coal of 249.6 billion tonnes (275.1 billion short tons) as of January 1, 1997 (U.S. DOE EIA Coal Reserves: 1997 Update). The average coal production value for the years 2001 and 2002 was 1,007.9 million tonnes (1,111 million short tons) (U.S. DOE EIA Annual Coal Report 2002). The reserve life of recoverable reserves of coal in the United States can then be determined to be approximately 250 years at current rates of usage (Halvey, Personal Communication, 2004).

2.4 Historical Trends in Price Stability, Cost, and Reserve Life of Fuels for Electrical Generation

Price stability, along with fuel cost and the availability of the particular reserve of fuel, are all factors that influence the variability in usage of a particular fuel for electrical generation.

One indicator of the price stability of a particular fuel is the degree in fluctuation of cost over a specified period of time. Figure 4 illustrates the price stability of coal, natural gas, and oil in terms of the raw materials price index (RMPI) for Canada. The RMPI (y-axis in Figure 4) is a measure of the price changes for raw materials purchased by Canadian industries in relation to 1997 which is the base period (1997 = 100 on the y-axis). The RMPI attempts to account for all charges incurred by purchasers, such as transportation charges and custom duties, as well as the effect of subsidies.

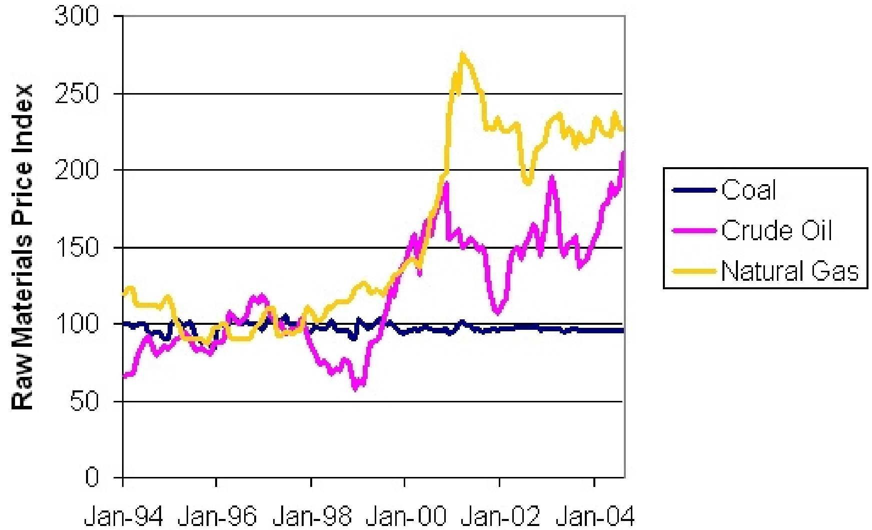


Figure 4. **Price Stability of Coal, Natural Gas, and Crude Oil in terms of the Raw materials Price Index (RMPI)(Statistics Canada 2004)**

As illustrated in Figure 4, until recently coal prices have remained relatively stable. The price of natural gas has become increasingly unstable largely as a result of natural gas supply, demand, and infrastructure issues (Trapmann, U.S. DOE EIA, 2003). Moderation of the recurrence and severity of 'boom and bust' cycles while meeting increasing demand at reasonable prices to consumers continues to be a major challenge for the natural gas industry (U.S. DOE EIA, 2001). The reserve life of a particular type of fuel for electrical generation applications provides a rough indication of the time period for which supplies of particular forms of energy may remain viable. Resource reserves are not absolute; reserve quantities increase as extraction technology improves, as higher prices justify including more difficult sources, or as regulatory requirements change. Figure 5 illustrates the energy reserve life of various types of fuel for Canada, based on current prices, technology, and rates of consumption. Reserve life estimates for conventional oil and gas have been stable or declining slowly. The introduction of new extraction technology for oilsands (a type of non-conventional crude oil resource) lowered the unit price of this energy source. The increased demand for oil from this source explains the dramatic decrease in the reserve life of non conventional crude oil in Figure 5.

The decline in coal reserve life since year 1975 is a reflection of the decreasing price for the resource rather than physical depletion of reserves. In addition, over the last few decades, the exploitation of various reserves of coal has been considered more closely and certain deposits have been removed from the overall count due to excessive exploitation costs. Reserves of uranium, a fuel used in nuclear reactors, have been judged to be stable.

Economically recoverable reserve lifetimes are sensitive to energy prices, thus reserve lifetimes, presented in Figure 5, reflect current and estimated future prices rather than the physical quantity of the resource. The comparative stability of the reserve life indices as production has grown illustrates the continued improvements in production technology (Natural Resources Canada (NRCan), 2003).

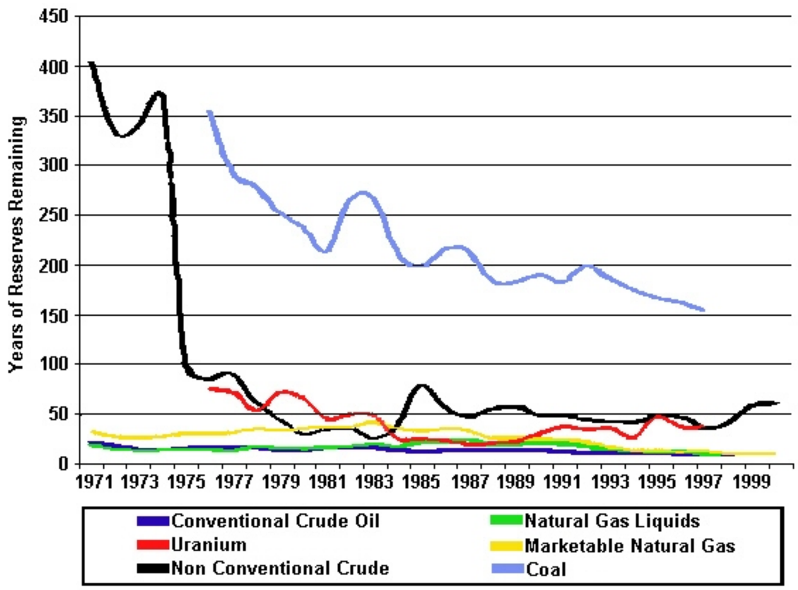


Figure 5. **Reserve Lives of Various Fuel Sources for Electrical Generation in Canada (Natural Resources Canada (NRCan), 2003)**

The production costs associated with electrical generation are a function of fuel prices, operating and maintenance expenses, and capital costs. For fossil-fired electrical generation, fuel costs make up the largest component of the operating expenses. Figure 6 illustrates the fuel prices to electricity generators with projections to the year 2025 (U.S. DOE EIA Annual Energy Outlook 2004 (AEO2004)). These prices are based on U.S. 2002 dollars per million British Thermal Unit (BTU) which is the scale on the *y* axis of Figure 6.

In these illustrations, as of a few years ago, decreasing prices for coal have reduced the fuel expense portion of operating costs for coal-fired generating plants while volatile natural gas prices along with rapidly increasing usage rates have raised the fuel portion of costs for natural gas-fired generating stations. In more recent years, the price of coal has increased, but this has been accompanied by a more dramatic and sustained increase in natural gas prices, continuing this difference in operating costs. Nuclear generating units have non-fuel operation costs such as maintenance which are a larger component of their total operating costs.

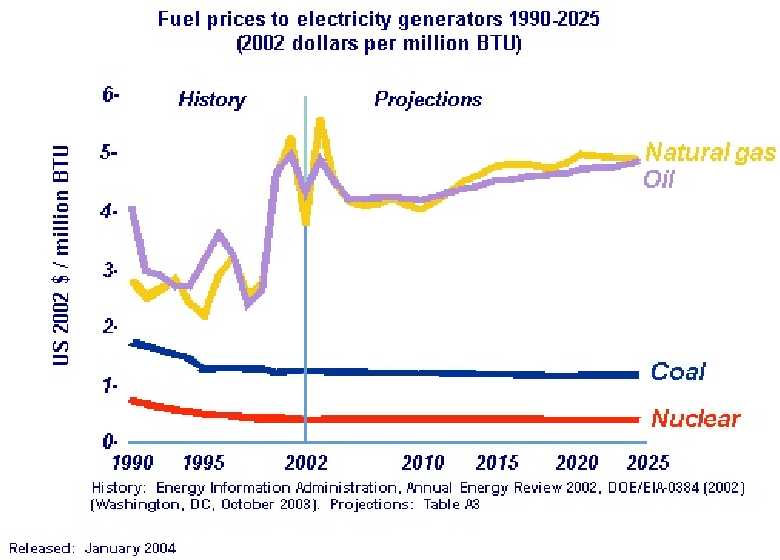


Figure 6. **Projections of the Prices for Various Fuel Sources for Electrical Generation (U.S. Department of Energy (DOE) Energy Information Administration (EIA) Annual Energy Outlook 2004 (AEO2004))**

The U.S. DOE EIA reference case projections assumed increased natural gas prices. The impact of these increased prices in the projections was offset by increased generation from coal-fired and nuclear power plants. Increased generation from these types of plants is evident in Figure 6 as the prices for these facilities remain relatively low and stable. The impact of high natural gas prices was also offset to some extent by the higher generation efficiencies of new plants using this fuel (U.S. DOE EIA AEO2004).

The price stability of coal, along with its relatively lower price due to its lengthy reserve life, are key factors influencing its continued use in the energy sector, particularly in the generation of electricity (Christie, 2004).

2.5 Efficiency of Electrical Generation in Canada and the United States

The conversion efficiency of thermal generation systems can vary depending on the fuel and type of combustion technology used. The average efficiency of existing infrastructure in Canada ranges from 30 – 40 percent. That is, only 30 – 40 percent of the potential energy in the original fuel source (i.e., coal, natural gas) is actually converted to electricity (NRCan, 2002). The balance, about two-thirds of energy in the consumed fuel, is wasted or lost. Additional energy losses occur when power is transmitted from the generation plants to electricity customers as electricity transmission lines have inherent resistive losses.

However, since 1990, the conversion efficiency of coal as a fuel for electrical generation has been improved by more than eight percent through introduction of several new technologies moving it closer to the 40 percent level. (NRCan, 2002).

Cogeneration, or combined heat and power generation, represents a significant opportunity to improve energy efficiency for many electricity generation applications. Cogeneration is the simultaneous production of electricity and useful heat from the same fuel source. Essentially, it involves the capture and use of waste heat or steam that is typically lost with conventional thermal electricity generation. Figure 7 compares a combined heat and power system to a system that generates electricity and steam heat separately. As illustrated by this figure, the separate electricity and heat generation facilities have a combined efficiency of only 45 percent while the combined heat and power system has an efficiency of 85 percent (American Council for an Energy-Efficient Economy (ACEEE, website accessed August 2004)).

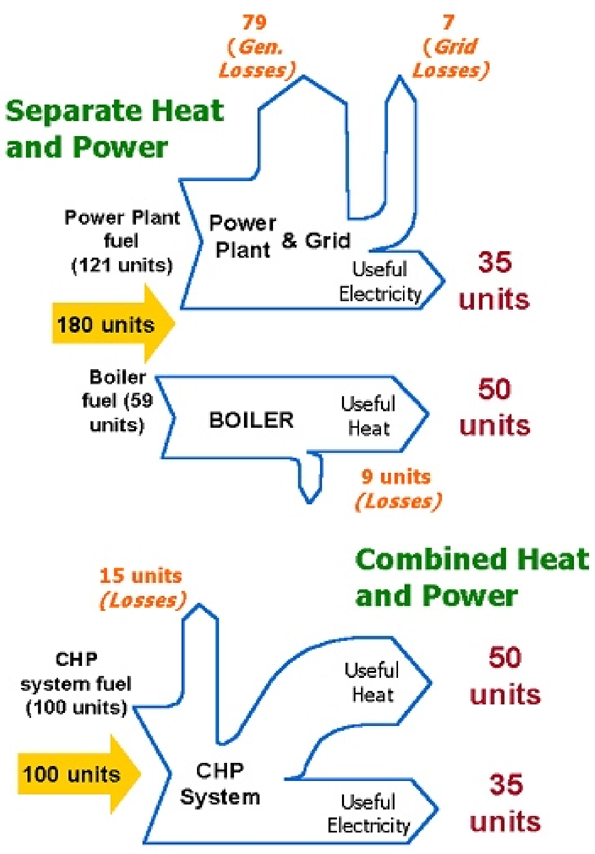


Figure 7. Comparison of Separate Heat and Power and Combined Heat and Power Generation
(American Council for an Energy-Efficient Economy (ACEEE, August 25, 2004)

In the United States, approximately 56,000 megawatts (MW) of combined heat and power electric generation is in operation, up from less than 10,000 MW in 1980. In 1999, cogeneration plants accounted for seven percent of the United States electricity generating capacity and had typical efficiencies of 68 percent, with some new systems exceeding 90 percent. Also, these plants emitted on average one-tenth of the nitrogen oxides (NO_x) per kWh of average utility grid electricity generation.

Cogeneration is not considered a feasible option for all electricity generation applications. Industrial generators, such as the pulp and paper industry, however, are often ideal candidates for such a system. Combined heat and power is also widely used and properly suited for chemical and petroleum refining industries. Applications such as 'district energy systems' where there is coincident demand for both heat and electricity in a small area, are also well suited for cogeneration. Countries such as Denmark and the Netherlands have employed combined heat and power-based district energy systems to meet a significantly large portion of their residential and commercial heating needs. In these countries 40 to 50 percent of the electrical generating capacity is estimated to be provided by cogeneration facilities (NRCan, 2002).

Currently seven percent of Canada's electricity generation capacity could be adapted for combined heat and power generation. This low figure is due to a variety of factors including numerous market and institutional barriers that favour large central generation facilities usually situated outside urban areas providing inexpensive electricity. The future of cogeneration is changing as it is now estimated that up to 30 percent of total Canadian future generation capacity could be compatible with cogeneration systems (NRCan, 2002).

The Environmental Protection Agency (EPA) set an ambitious goal to double U.S. cogeneration capacity between 1999 and 2010. If this goal is achieved, combined heat and power systems should represent 14 percent of the 2010 electric generating capacity in the United States. Various challenges exist in the United States to the widespread use of cogeneration. For example, national standards do not exist for the interconnection of distributed generation technologies to the electric utility grid and many facility managers are unaware of technology developments that have expanded the potential for cost-effective combined heat and power applications (ACEEE, 2004).

3.0 OVERVIEW OF PROJECTED ENERGY SECTOR SUPPLY IN CANADA AND THE UNITED STATES

Two different reports have been considered in order to determine the projected electrical generating capacity as well as fuel and electricity costs in both Canada and the United States. A report published by the National Energy Board (NEB) of Canada entitled "Canada's Energy Future – Scenarios for Supply and Demand to 2025" is used for the Canadian forecasts. The U.S. projections are based on the Annual Energy Outlook 2004 (AEO2004) report published by the U.S. Department of Energy (DOE) Energy Information Administration (EIA). These reports do not utilize the same baseline year; the NEB of Canada uses a baseline year of 2000 while the U.S. DOE EIA uses 2002. In both reports, however, projections are made to the years 2010 and 2025.

3.1 Projected Canada/United States Energy Supply by Sector/Fuel Type, for the years 2010 and 2025

This section outlines projections of electrical generating capacity by fuel type in Canada and the United States for the years 2010 and 2025. These respective reports also make various projections on the cost of fuel and electricity.

3.1.1 Canada

i) Overview of Report and Description of Energy Scenarios

The National Energy Board of Canada report entitled "Canada's Energy Future – Scenarios for Supply and Demand to 2025" includes projections of Canada's electricity sector based on two different scenarios. The *Supply Push* scenario considers the security of continental energy supply and the push to develop known conventional sources of energy. Technological breakthroughs related to sources of alternative energy are considered as beyond reach and application, as they are unfavourable under current economic circumstances. According to this scenario, in addition to gas-fired generation, there is a resurgence of coal-fired plants particularly in Ontario and the western provinces.

The *Techno-Vert* scenario represents rapid advance through emerging technologies. It assumes broad action with respect to the environment, with cleaner burning fuels and environmentally friendly products. There is also an improvement in efficiency of energy consumption and increased use of wind power and advanced nuclear reactors (NEB Canada, 2003).

ii) Assumptions Used to Develop Energy Projections

Certain assumptions underlie both scenarios. Energy demand is predominantly determined by economic growth and income levels along with the efficiency of energy use. Also, in each scenario the climate and living patterns in Canada as well as current provincial policies are assumed to remain unchanged for the most part over the projected period (years 2000 – 2025). Each scenario also assumes there is adequate oil and that world oil prices will average U.S. $22 per barrel which lies at the low end of the Organization of Petroleum Exporting Countries' (OPEC) target price range. The demand for natural gas increases in both scenarios as cleaner-burning fuels are favoured. In *Supply Push*, the price of natural gas grows from 83 percent to 90 percent of the equivalent crude oil price by year 2025. In the *Techno-Vert* scenario the natural gas price is assumed to reach that of crude oil by year 2010. The prices of oil and natural gas are reported in AEO2004 in terms of 2002 dollars per thousand cubic feet. In both scenarios, coal prices decline by one percent each year to 2015 and remain constant at these levels until year 2025 (NEB Canada, 2003).

The province of Ontario's announced intention to phase out the use of coal in Ontario Power Generation facilities, principally Lambton and Nanticoke generating stations, by year 2007 was not included in the assumptions of either the *Supply Push* or *Techno-Vert* scenario, as the announcement was made after these scenarios were developed.

iii) Distribution of Energy Source by Fuel for the Various Energy Scenarios

The following section outlines the changes in the energy sector that could occur under *Supply Push* and *Techno-Vert*, including projections to the year 2025. Table 4 indicates the projections for the year 2010 and Table 5 presents forecasted data for the year 2025 for the two energy scenarios. Figure 8 illustrates the percent share of generation supplied by each fuel for the years 2010 and 2025. The generating capacity increases by 42 GW and 45 GW for the *Supply Push* and the *Techno-Vert* scenarios, respectively (NEB Canada, 2003).

Hydro: Both the *Supply Push* and the *Techno-Vert* scenarios assume hydro power will remain a primary source of electricity generation, with four large-scale hydro developments at Gull Island (Labrador), Grand-Baleine (Québec), Peace Site C (British Columbia), and Gull Rapids (Manitoba). By year 2025, hydroelectricity accounts for about 50 percent of total generation in both national energy scenarios (NEB Canada, 2003).

Nuclear: In *Supply Push* and *Techno-Vert*, the operating lives of all nuclear units in Ontario are extended and all out-of-service units are returned to operation. Nuclear reactors at Point Lepreau (New Brunswick) and Gentilly-2 (Québec) facilities undergo renovations. No new facilities are constructed according to the *Supply Push* scenario, although new advanced nuclear reactors are constructed at existing facilities in Ontario and New Brunswick in *Techno-Vert*. The development of new nuclear reactors is assumed possible in the *Techno-Vert* energy situation due to favourable operating performance of the advanced CANDU reactor along with advancements in safety and waste disposal (NEB Canada, 2003).

Table 4. Projections of Generating Capacity and Electrical Generation for Canada for *Supply Push* and *Techno-Vert* scenarios to the year 2010 (NEB Canada, 2003)

	Generating Capacity (GW)		Electrical Generation (GW.hr)	
Fuel Type	*Supply Push*	Techno-Vert	*Supply Push*	Techno-Vert
Hydro	71.6	71.0	364,785	364,799
Nuclear	14.1	14.1	102,706	102,706
Coal	15.6	14.7	110,119	104,674
Orimulsion	1.3	1.3	8,851	8,867
Natural Gas	18.7	17.7	70,261	60,468
Oil	4.7	4.9	6,085	5,442
Diesel (Internal Combustion and Combustion Turbine)	1.3	1.3	2,381	2,216
Renewable Fuels				
-Wind	2.0	3.7	5,452	9,241
-Biomass	2.1	2.7	11,919	15,676
-Small Hydro	1.1	1.4	4,769	6,319
-Other	0.01	0.1	35	35
Total	**132.5**	**133.0**	**687,363**	**680,443**

Natural gas-fired: Assuming natural gas prices remain in the projected range outlined, both the *Supply Push* and the *Techno-Vert* scenarios result in natural gas fired capacity additions over the projected period. For the *Supply Push* scenario 17.6 GW is projected while 14.6 GW is projected in *Techno-Vert*, compared to the current 7.15 GW of generation. Natural gas generation is developed in both scenarios as it is relatively clean burning, efficient and requires relatively low capital investment over a short construction time. Cogeneration facilities are efficient and are considered a low cost source of energy. Significant development of this type of facility as part of continued exploitation of the oil sands and *in situ* bitumen projects are forecasted (NEB Canada, 2003).

Coal-fired: According to the *Supply Push* scenario for projections of electricity generation capacity, coal continues to be used in the long term with the emergence of new coal-fired power plants particularly in Alberta and Saskatchewan, where coal can successfully compete with natural gas. Coal-fired generation is built in British Columbia by year 2010. In the *Techno-Vert* scenario, after year 2010 *no new conventional coal plants are constructed*. Rather, conventional coal-fired units are replaced by Integrated Gasification Combined Cycle (IGCC) units mainly in

Alberta and Ontario where this newer technology is cost competitive. Clean coal technologies, according to the *Techno-Vert* energy situation, enable coal to remain in the overall fuel mix (NEB Canada, 2003).

Table 5. Projections of Generating Capacity and Electrical Generation for Canada for the year 2025 under *Supply Push* and *Techno-Vert* scenarios (National Energy Board of Canada, 2003)

	Generating Capacity (GW)		Electrical Generation (GW.hr)	
Fuel Type	*Supply Push*	Techno-Vert	*Supply Push*	Techno-Vert
Hydro	78.67	78.67	403,541	403,518
Nuclear	15.65	19.15	119,033	146,320
Coal	20.05	14.25	147,932	105,373
Orimulsion	2.05	1.30	14,444	8,864
Natural Gas	24.67	21.68	146,716	109,244
Oil	4.69	2.39	7,451	4,131
Diesel (Internal Combustion and Combustion Turbine)	1.35	1.33	2,898	2,768
Renewable Fuels				
-Wind	3.38	11.22	9,829	33,856
-Biomass	2.25	4.48	13,611	31,245
-Small Hydro	1.09	3.79	4,769	16,285
-Other	0.01	0.39	35	2,523
Total	**153.74**	**158.66**	**870,259**	**864,127**

Orimulsion: Orimulsion, a mixture of bitumen and water, is currently used for power generation in New Brunswick. In the *Supply Push* scenario the use of Orimulsion is expanded to Nova Scotia in addition to existing generation in New Brunswick. Alternatively, in the *Techno-Vert* scenario, electrical generation using Orimulsion does not expand beyond its existing and already-announced facilities in New Brunswick (NEB Canada, 2003).

Oil-fired: Similar to the *Supply Push* scenario, the *Techno-Vert* scenario also anticipates declining shares of oil-fired electrical power generation. *Techno-Vert* assumes a larger decline in the use of oil in order to reduce the undesirable environmental impacts of burning this fuel (NEB Canada, 2003).

Alternative Technologies and Renewable Fuels: Alternative technologies do not experience expansion in the *Supply Push* scenario since sufficient technological improvements have not been successful at reducing their costs. However, alternative technologies and renewable fuels experience an annual growth rate of about 10 percent over the projected period in *Techno-Vert*. By the year 2025, renewable fuels including wind, biomass, and small hydro would account for 10 percent of the total electricity generation in Canada. In both scenarios, wind power provides the greatest alternative energy capacity increase, rising from 0.2 GW in year 2001 to 3.3 GW by year 2025 in the *Supply Push* scenario and to 11.2 GW in the *Techno-Vert* scenario (NEB Canada, 2003).

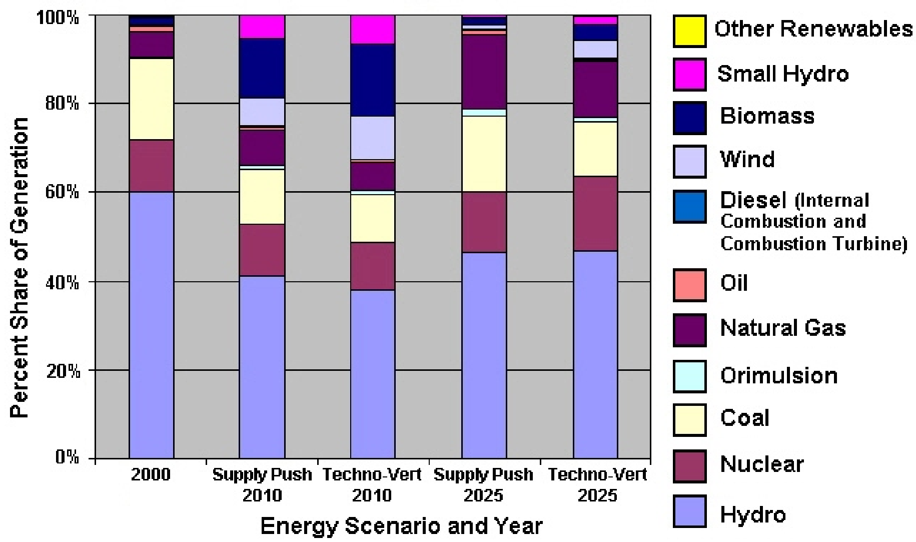


Figure 8. **Projected Canadian Electricity Generation by Fuel (% of GW.hr generation) for the years 2010, 2025 Using Two Energy Scenarios (National Energy Board of Canada, 2003)**

3.1.2 United States

i) Overview and Description of Energy Scenarios

The Annual Energy Outlook 2004 (AEO2004) report published by the U.S. Department of Energy (DOE) Energy Information Administration (EIA) presents a midterm forecast and analysis of United States energy supply, demand, and prices through year 2025 (Table 6 and Table 7). A reference case is defined in AEO2004 which uses cost and performance characteristics of different electrical generating technologies to select the distribution of new generating capacity over the projection period. Values of performance for different technology characteristics were determined by the U.S. DOE EIA through consultation with industry and government specialists. Cost characteristics of new technologies were based on estimates provided by government and industry analysts.

In addition to this reference case, a number of scenarios are considered in AEO2004 which reflect the sensitivity of cost and/or performance of various types of generation. A final scenario considers the impact of economic growth rate on the implementation of various technologies. In total, four scenarios are considered, including a low/high renewables scenario, a three-tiered fossil scenario (low fossil, high fossil and fossil goals), an advanced nuclear scenario involving two cases (advanced nuclear and nuclear goals), and a low/high economic growth rate scenario (U.S. DOE EIA, AEO2004).

ii) Assumptions Used to Develop Energy Projections

Assumptions are made to determine both the reference case over the projection period as well as to perform the sensitivity analysis of cost/performance of various electrical generating sources. For the reference case, energy generation technology alternatives for new generating capacity were selected to minimize cost while meeting emissions constraints under local, state and federal regulations. The choice of technology for the new capacity additions was determined, both in the reference case and in each of the four scenarios, based on the least expensive option available. Cost and performance values for the various technologies were assessed to determine the most appropriate technology option. Cost characteristics of new technologies are based on cost estimates provided by government and industry analysts. The reference case assumptions regarding cost and performance contain uncertainties associated with new, unproven designs (U.S. DOE EIA, AEO2004).

The reference case assumes a capital recovery period of 20 years and the cost of capital itself is based on competitive market rates, to account for the risks of constructing new units and facilities. The costs (non-fuel) and performance characteristics for new plants are assumed to improve over time at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward and the costs only decline once the project developers gain experience and more units are then built. As the capital costs decrease over time for the newer technologies the performance of these plants is also assumed to improve over time (U.S. DOE EIA, AEO2004).

The following section outlines the specific assumptions used in each of the four energy scenarios described.

Low/High Renewables Scenario: In this scenario, the influence of anticipated alterations in cost and performance on renewable sources of electrical generation is analyzed. The *low renewables* case assumes that the cost and performance characteristics for key non-hydropower renewable energy technologies remain fixed at current levels. The *high renewables* case assumes cost reductions of 10 percent on a site-specific basis. A third scenario referred to as *DOE goals* assumes lower capital costs, higher capacity factors, and lower operating costs, based on the U.S. DOE goals for renewable energy sources (U.S. DOE EIA, AEO2004).

Three-Tiered Fossil Scenario: In this scenario, the sensitivity of fossil fuel electrical generation sources to variation in heat rates and capital and operating costs is analyzed. The *low fossil fuel* case assumes that the capital costs and heat rates for advanced technologies remain fixed at their current year 2004 levels. The *high fossil fuel* case assumes a 10 percent reduction from year 2025 reference case levels of capital costs, heat rates, and operating costs for *advanced fossil-fired* generating technologies (such as integrated coal gasification combined cycle (IGCC), advanced combined cycle, and advanced combustion turbine). The *fossil goals* case assumes improved costs and efficiencies as a result of accelerated research and development efforts as specified by the DOE's Fossil Energy program goals (U.S. DOE EIA, AEO2004).

Advanced Nuclear Scenario: This scenario includes an analysis of the sensitivity of nuclear generation to variation in capital and operating costs due to various factors. The *advanced nuclear* case assumes capital and operating costs of 10 percent below the year 2025 reference case while the *nuclear goals* case assumes reductions of 38 percent relative to the reference case in year 2025. These costs were consistent with cost estimates for the manufacture of an advanced pressurized water reactor (AP1000) by British Nuclear Fuels Limited. The cost and performance associated with other technologies are assumed to be the same as in the reference case (U.S. DOE EIA, AEO2004).

Table 6. Forecasted Reference Case U.S. Electrical Generating Capacity for the Years 2010 and 2025 relative to 2002 (U.S. DOE EIA, AEO2004)

	Generating Capacity (GW)		
Fuel Type	2002	2010	2025
Hydroelectric (including pumped storage)	98.5	99.0	99.0
Nuclear	98.7	100.6	102.6
Coal	310.9	310.3	412.3
Natural Gas (Conventional Combined Cycle and Advanced Combined Cycle)	110.5	160	235.2
Conventional and Advanced Combustion Turbine (diesel, oil, or natural gas)	128.8	136.5	180.4
Oil and Gas Steam	133.6	106.1	96.5
Renewable Fuels			
-Wind	4.8	8.0	16.0
-Biomass	1.8	2.2	3.7
-Geothermal	2.9	4.0	6.8
-Municipal Solid Waste	3.5	3.9	4.0
-Solar Thermal	0.3	0.4	0.5
-Solar Photovoltaic	0.02	0.2	0.4
Fuel Cells	0	0.1	0.1
Total	**894.4**	**931.2**	**1157.1**

Low/High Economic Growth Rate Scenario: The sensitivity to variations in the annual growth rate of the Gross Domestic Product (GDP) is considered in this scenario. The *high economic growth* case assumes the annual growth rate of the GDP from years 2002 to 2025 is 3.5 percent while the *low economic growth* case assumes a GDP annual growth rate of 2.4 percent (U.S. DOE EIA, AEO2004).

iii) Distribution of Energy Sources by Fuel for the Energy Scenarios

Growth in electricity use is expected in all sectors and the historical relationship between demand for electricity and economic growth is also expected to continue. Table 6 and Table 7 indicate projected values of electrical generating capacity and generation for the years 2010 and 2025 based on the reference case. Figure 9 indicates the percent share of generation for each source of energy for the base year of 2002 and the forecasted years of 2010 and 2025. From years 2002 to 2025, new additional generating capacity of 356 GW is expected to be required. Most of the new generating capacity will be needed specifically after 2010, when the current excess energy supply situation has subsided. Between years 2002 and 2010, 88 GW of new capacity is projected to be needed (11 GW annually), while between years 2011 and 2025, 268 GW of new capacity is forecasted to be required (19 GW annually) (U.S. DOE EIA, AEO2004).

Table 7. Forecasted Reference Case U.S. Electrical Usage for Generation (GW.hr) for the Years 2010 and 2025 relative to 2002 (U.S. DOE EIA, AEO2004)

	Electrical Generation (GW.hr)		
Fuel Type	2002	2010	2025
Hydroelectric	255,780	304,370	304,800
Nuclear	780,100	794,300	816,500
Coal	1,875,000	2,201,000	2,975,000
Natural Gas	450,000	642,000	969,000
Oil	77,000	62,000	77,000
Renewable Fuels			
-Wind	10,510	24,070	53,160
-Biomass	8,670	23,530	29,160
-Geothermal	13,360	23,250	46,660
-Municipal Solid Waste	20,020	28,110	28,500
-Solar Thermal	540	840	1,100
-Solar Photovoltaic	0	360	1,020
Total	**3,490,980**	**4,103,830**	**5,301,910**

A large component of facility retirements between years 2002 and 2025 will be older natural gas- and oil-fired steam generating facilities. Also, smaller amounts of older natural gas- and oil-fired combustion turbines and coal-fired plants will be retired since they are not competitive with newer natural gas combustion turbine or combined cycle plants (U.S. DOE EIA, AEO2004).

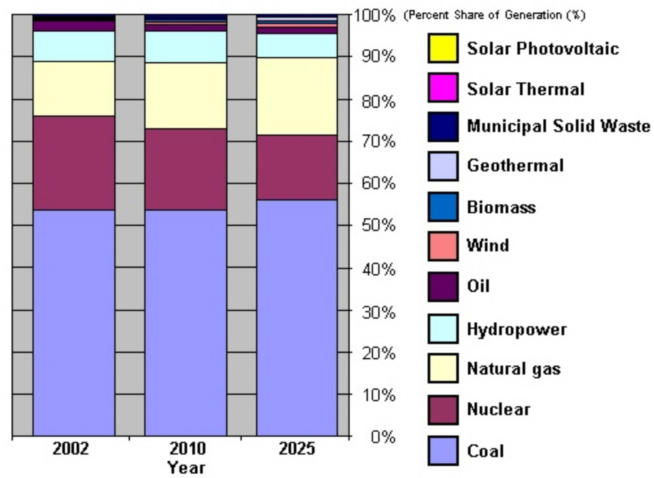


Figure 9. **Forecasted Percent Share of U.S. Electrical Generation (GW.hr) according to the Reference Case for the year 2010 and 2025 (U.S. DOE AEO2004)**

Hydro: Hydro-electric sources of energy generation are considered in the renewable technology category.

Nuclear: In the reference case, no nuclear units are expected to be retired between years 2002 and 2025. It is assumed that nuclear capacity increases at the existing units. The reference case assumes an increase of 3.9 GW in total nuclear capacity by year 2025. No nuclear units are expected to become operable during the projected period (years 2002-2025) because natural gas and coal-fired units are projected to be more favourable economically (U.S. DOE EIA, AEO2004).

In the *advanced nuclear cost* case the forecasted cost of generating electricity using nuclear power was not found to be competitive with the generating costs projected for new coal- and natural gas-fired units, until the end of the projection period (year 2025). No new nuclear generating capacity was added in the *advanced nuclear cost* case, although 26 GW of new nuclear capacity was added in the *nuclear goals* case due to the lower costs associated with this scenario. The addition of nuclear capacity in the *nuclear goals* case primarily displaced coal and a smaller portion of the natural gas capacity (U.S. DOE EIA, AEO2004).

Natural gas-fired: Natural gas-fired generation shows the largest percentage increase over the projected period. The share of electricity generated by natural gas increases from 18 percent of the total supply in year 2002 to 23 percent in year 2025. Additions of capacity for natural gas electrical generation are forecasted to occur early during the projection period. Of the new capacity projected to be needed, nearly 62 percent is projected to be natural gas-fired combined cycle, combustion turbine, or distributed generation technology. As the price of natural gas rises later in the forecast, new coal-fired generation is projected to become increasingly competitive with natural gas technologies (U.S. DOE EIA, AEO2004).

Natural gas technologies constitute the largest share of new capacity additions in each of the four *fossil fuel* cases including the reference case, *low fossil* case, *high fossil* case, and the *fossil goals* case. The distribution of the natural gas technology does vary depending on the case considered. In the *high fossil* and *fossil goals* case, advanced technologies are used for 78 percent and 75 percent of the projected gas-fired generation capacity additions, respectively. In comparison, in the *low fossil* case only 19 percent of the new gas-fired generation capacity additions are advanced natural gas technologies (U.S. DOE EIA, AEO2004). The *high economic growth* scenario leads to new capacity additions, more than half of which are expected to consist of new natural gas-fired plants (U.S. DOE EIA, AEO2004).

Coal-fired: Coal-fired power generation facilities are expected to remain the key source of electricity through 2025 according to the AEO2004. In the year 2002, coal as a fuel contributed to more than 50 percent of total generation (including output at combined heat and power plants). Coal-fired generation is expected to maintain an approximate 50 percent share through year 2010 and grow to 52 percent in year 2025. This type of generation is forecasted to be a capacity addition that is incorporated later in the considered projection period. Coal-fired capacity is expected to become increasingly competitive and increase its share of total electrical generation as natural gas prices rise. Coal-fired generation capacity accounted for nearly one-third (112 GW) of all the capacity expansion expected over the forecasted period. Most of the coal capacity is expected to be advanced pulverized coal. Integrated coal gasification additions are limited to only six gigawatts due to the higher capital costs of this technology (U.S. DOE EIA, AEO2004).

In the *low fossil* case, only a negligible amount of advanced coal-fired generating capacity is added. In the *high fossil* and *fossil goals* cases, however, advanced coal technologies are more competitive. These technologies make up almost half of the new capacity additions in the *high fossil* case and 95 percent in the *fossil goals* case (U.S. DOE EIA, AEO2004).

The *low economic growth* scenario leads to capacity reductions of 65 GW. Reductions in coal-fired generating capacity represent 61 percent of this capacity decrease (U.S. DOE EIA, AEO2004).

Oil-fired: Generation from oil-fired plants is projected to remain fairly low throughout the forecast. Oil-fired steam facilities are not forecasted to add any generating capacity besides some limited industrial cogeneration applications producing both heat and power. Oil-fired steam facilities are considered unfavourable due to their high fuel costs and lower efficiencies (U.S. DOE EIA, AEO2004).

Alternative Technologies and Renewable Fuels: Alternative technologies, primarily wind and biomass, account for slightly greater than five percent of expected capacity expansion by year 2025. Non-hydroelectric renewable sources of electrical generation capacity accounted for additions of 23 GW. Biomass is the largest source of non-hydroelectric renewable generation in the forecast (1.0 percent to 1.3 percent), including combined heat and power systems and biomass co-firing in coal-fired power plants.

Power generation involving biomass refers to the combustion of organic matter or vegetation such as wood, sewage sludge or crop and forest residues remaining following harvesting activities. AEO2004 also projects significant increases in electrical generation from both wind and geothermal power sources.

Total wind capacity is expected to increase from 8.0 GW in year 2010 to 16.0 GW in year 2025 (accounting for 0.3 percent of generation in year 2002 and 0.9 percent in year 2025). Output of geothermal generation sources, located solely in the western United States, is projected to increase from 0.3 percent of generation in year 2002 to 0.8 percent in year 2025. Generation of electricity from municipal solid waste and landfill gas is projected to increase to 0.5 percent of generation by year 2025. No new waste-burning capacity is expected to be added throughout the forecasted period. Solar technologies are not expected to contribute significantly to United States electrical supply. Grid-connected photovoltaic and solar thermal generation were projected to increase together from 0.02 percent of generation in year 2002 to 0.08 percent in year 2025 (U.S. DOE EIA, AEO2004).

Construction of new renewable capacity is considerably lower in the *low renewables* case than forecasted for the reference case. In the *high renewables* case, the capacity additions of geothermal, biomass, and wind capacity are substantially higher than projected in the reference case. This particular case forecasts most of the capacity additions between 2010 and 2025. In the *DOE goals* case a greater quantity of wind and geothermal electrical generating capacity is projected. Geothermal electricity generation is almost double the reference case projection in year 2025 and wind power generation is more than six times higher in year 2025 than in the reference case (U.S. DOE EIA, AEO2004).

3.2 Canada/United States Renewable Energy Sector Supply Outlook

This section provides an overview of various programs and initiatives currently in place in Canada and the United States that are advancing renewable energy technologies.

3.2.1 Canada

Natural Resources Canada (NRCan) developed the Renewable Energy Strategy (year 1996) in order to promote the use of renewable energies. The strategy is a plan for cooperative action with stakeholders to accelerate the development and commercialization of renewable energy technologies. NRCan promotes several initiatives to encourage the development and use of emerging energy sources and technologies including The Renewable Energy Deployment Initiative (REDI), The Wind Power Production Incentive (WPPI), and The Market Incentive Program for Distributors of Emerging Renewable Electricity Sources, and Government Purchases of Electricity from Renewable Resources (PERR). In addition, NRCan delivers several initiatives to increase the use of small-scale renewable energy in Canada including:

- Renewable Energy Information and Awareness Program;
- Renewable Energy Market Assessment Initiative;
- Green Power Initiative;
- Renewable Energy Deployment Initiative; and
- Renewable Energy Technologies Program.

The Canadian Renewable Energy Network (CanREN) was created through its efforts with NRCan and its stakeholders to increase the understanding of renewable energy and to accelerate the development and commercialization of renewable energy technologies. CanREN highlights the technologies and applications being developed to harness these sources (CanREN, 2000).

Natural Resources Canada's Bioenergy Development Program provides financial incentives for research and development in the areas of biomass handling, combustion, biochemical conversion, and thermochemical conversion. The Renewable Energy Deployment Initiative (REDI) promotes the use of high efficiency and low emission biomass combustion systems in the commercial and institutional sectors. The REDI offers incentives and undertakes marketing and infrastructure development activities. The REDI also encourages the adoption of earth energy systems in Canada through active market development and fostering the growth of the industry (CanREN, 2000).

In terms of hydroelectricity as a source of renewable energy, the government of Canada recognizes the valuable role that small scale hydroelectric facilities can play in meeting Canada's energy requirements (CanREN, 2000).

Natural Resources Canada supports various solar energy programs including an Active Solar Energy Program, a Passive Solar Energy Program, and a Photovoltaic Program. The Active Solar Energy Program works with industry to improve the cost and performance of these systems. Some of the current activities of this program include solar air heating and solar heating for residential swimming pools. The Passive Solar Energy Program is mainly aimed at the development and adoption of high-performance windows. The Photovoltaic Program is focused on the development and implementation of photovoltaic technologies where it is economically feasible, with the majority of projects conducted on cost-shared basis with other groups (CanREN, 2000).

There are several Canadian government programs that support field demonstrations and deployment of Canadian wind energy technologies. NRCan also provides cost-shared support for

Canadian companies to research and develop wind turbine systems and their components. The Wind Power Production Incentive (WPPI) will provide financial support for the installation of 1,000 MW of new capacity over the next five years (CanREN, 2000).

In August 2003, the province of Ontario announced that it would introduce a green power standard to require electrical generators to secure an additional one percent per year of their electrical needs for eight years from wind, solar, hydro, and biomass energy sources, beginning in 2006 (Canadian Electrical Association (CEA), 2002).

3.2.2 United States

The Electric Power Research Institute (EPRI) was formerly established in year 1973 as an independent, nonprofit organization designed to manage research on behalf of the electric utility industry, the industry's customers, and society at large. The EPRI's research and development work includes optimizing the performance of control technologies, developing new technologies related to pollutant control, performing modeling related to pollutant transport and deposition, and the advancement of renewable sources of energy.

In year 2003, the EPRI released an updated Renewable Energy Technical Assessment Guide examining low-impact and emerging hydro technologies and energy storage. The guide reviewed the technical status, cost, and performance of renewable technologies commercially available or on the threshold of commercialization and recommended that companies without a renewable component should determine which of these technologies would benefit their generation strategy.

Also, the EPRI, along with the U.S. DOE, U.S. EPA, and the Center for Resource Solutions organized a number of Green Power Marketing Conferences. The eighth conference (year 2003) noted that green power markets are continuing to expand in the United States, supporting more than 1,000 MW of new renewable energy capacity nationwide.

In year 2004, the EPRI published two reports on green options. The first considered biomass as an energy source and included descriptions of the nature and size of the resource, characteristics, performance and cost summaries for the various technologies, and identification and assessment of environmental impacts and benefits. The second report presented the results of four case studies on the availability of wind integration technology options. The EPRI reported that with a 20 to 30 percent annual growth of installed capacity worldwide, wind power had become the fastest growing source of electricity.

Also, in year 2004, the EPRI reported on case studies of grid-connected photovoltaic systems. The photovoltaics industry was growing rapidly (20 percent annually since the 1970s) and photovoltaic (PV) power would likely grow further as a portion of distributed generation as its cost declines over the next ten years. However, increases in inverter efficiency, reliability, and longevity were seen as particularly vital to the further application of this technology.

4.0 CANADA/UNITED STATES COAL-FIRED UTILITY SECTOR EMISSIONS AND CURRENT CONTROL TECHNOLOGIES

Electrical power generation by coal combustion technologies relies on the production of high pressure steam using heat produced by burning coal. The high pressure steam drives a turbine and electricity is produced by an electrical generator attached to that turbine. Exhaust gases from the combustion of coal contain particulate matter (PM), sulphur dioxide (SO_2), nitrogen oxides (NO_x), and other acidic species, as well as hazardous contaminants such as mercury. Many of the contaminants in the flue gas can be largely removed using downstream processes or emission control technologies. PM is removed by electrostatic precipitators (ESPs) or fabric filters (baghouses), while sulphur dioxide may be removed by a range of different flue gas desulphurization (FGD) (scrubbing) processes. The production of NO_x can be reduced by using in-furnace features such as low-NO_x burners. Selective Catalytic or Non-Catalytic Reduction emission control processes can further reduce NO_x emissions.

Co-beneficial technologies were designed to focus principally on certain pollutants providing incidental gains in control of other pollutants. The term *co-benefit* is usually used to describe the advantage an existing technology offers. Various control technologies currently in use, such as fabric filters (baghouses) and electrostatic precipitators, specifically aimed at reducing PM, can also achieve reductions in mercury emissions. Massachusetts data indicate that low NO_x burners may also facilitate mercury control, likely by lowering flue gas temperatures and increasing *de novo* carbon particulate levels (Smith, 2004). Multi-pollutant control technologies, on the other hand, are specifically designed to control a series of pollutants as opposed to only one.

The Electric Power Research Institute (EPRI) supports power producers in the application of Integrated Environmental Controls (IEC). IECs are emerging technologies that capture multiple pollutants in a single device or tightly integrated set of devices. The EPRI is evaluating integrated multi-pollutant processes through this program as they are developed and refined.

In preparing this overview, it should be noted that the type of coal used and the process of combustion influence the cost and the determination of the best configuration of emission control technologies in specific applications. Cost variations can be significant, and some of them can be associated with the achievement of equivalent pollution or emissions controls for the various types of coal fuel.

4.1 Combustion and Emission Control and Measurement Technology

4.1.1 Coal Combustion Techniques

The concentration of contaminants in the exhaust gas may vary depending on how the coal is combusted in the boiler. Different methods of coal combustion are outlined in thise following section.

i) Subcritical and Supercritical Pulverized Coal Combustion (PCC)

The most well established coal combustion applications have typically produced subcritical or lower pressure steam. Greater efficiencies in coal combustion have been found through use of higher steam pressures in what is referred to as the supercritical range. In both the subcritical and supercritical processes coal is initially ground into a fine powder. The powdered coal is blown with air into the boiler through a series of burner nozzles where combustion takes place at near-atmospheric pressure. The higher steam pressure in supercritical plants results in higher efficiency of energy conversation in the vicinity of 38 – 45 percent, compared with 33 percent for subcritical plants. Supercritical plants have been in commercial use for many years, despite their higher capital costs and the added risks associated with higher operational temperature and pressure (Winfield *et al.*, 2004).

ii) Atmospheric, and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used in the combustion of coals with a higher sulphur content. The FBC systems fall into essentially two major groups; atmospheric systems (AFBC) functioning at ambient pressure, and pressurized systems (PFBC). Systems are further differentiated by nature of their fluidization into those using a bubbling bed and those using circulating beds.

In an FBC facility, hot air blown up through the floor of the boiler suspends, or “fluidizes”, powdered coal mixed with a sorbent such as powdered limestone. The combustion of coal in the presence of a sorbent assists in the capture of sulphur dioxide (SO_2). The FBC plants can capture 98 percent of the SO_2 while burning coal more efficiently as the fuel stays in the combustion chamber for a longer period of time.

In both AFBC and PFBC plants the same process is used to fluidize the coal/sorbent mixtures and a similar granular material is formed by the reacted sorbent. The PFBC design is more efficient since additional energy is captured when the combustion gases are re-burned in a gas turbine after it passes through a gas cleaning system. A highly efficient combined cycle system is created when both a steam and gas turbine are used (Winfield *et al.*, 2004).

The operating temperatures of fluidized beds are approximately half the temperature of a conventional boiler and are below the temperature threshold where thermally induced NO_x forms. Fluidized bed designs have reduced SO_2 and NO_x emissions when compared with PCC systems. Additionally, FBC can use high ash coal while conventional PCC systems are limited to relatively low levels of ash (Winfield *et al.*, 2004).

The Electric Power Research Institute (EPRI) reported in year 2002 that atmospheric fluidized bed combustion (AFBC) boilers were well established as a mature power generation technology able to meet stringent environmental standards. Also, it was reported that AFBC units had inherent fuel flexibility which, in many instances, allowed these units to be designed to fire several different fuels. The EPRI noted that if AFBC technology is to make a contribution to CO_2 reduction, supercritical steam conditions should be pursued along with use of their fuel flexible characteristics to burn materials such as biomass that result in lower CO_2 emissions.

There are four plants currently using PFBC technology, in Ohio, Spain, Sweden, and Japan. The AFBC is much more wide-spread, with approximately 600 boilers in both North America and Europe. There are also around 2000 small bubbling AFBC boilers in China (World Bank, 2004).

iii) Integrated Gasification Combined Cycle (IGCC)

In IGCC plants, coal is converted into a hydrocarbon vapour (syngas) in a gasifier instead of being burned in a traditional boiler. The syngas is cleaned and stripped of impurities and used as a fuel instead of natural gas, in a conventional combined cycle plant. The IGCC configuration provides low emission levels and high system efficiencies in comparison to traditional coal-fired systems. Efficiency levels in IGCC systems can be as high as 45 percent. These plants were initially built on a demonstration basis and are now nearing commercial level of operation in the range of 200 – 300 MW (Winfield *et al*., 2004).

Two IGCC plants are in operation in the United States including a 262 MW IGCC unit at the Wabash River Plant in west Terra Haute, Indiana, which was a DOE cost-shared demonstration project, and a 250 MW IGCC facility at the Polk Power Station in Tampa, Florida. An additional IGCC plant has been proposed for Alabama (Halvey, 2004). There are no Canadian electric utility facilities that currently utilize the IGCC technology (Cummings, Environment Canada, 2004).

In year 2002, the Electric Power Research Institute (EPRI) published a report assessing clean coal technologies, including ultra supercritical pulverized coal, atmospheric and pressurized fluidized bed combustion (AFBC and PFBC), and integrated gasification combined cycle (IGCC) plants. At the time of this report, the EPRI estimated the costs of CO_2 removal from pulverized coal plants to be about double those from IGCC plants; if regulations are promulgated to require CO_2 removal to any major extent, then natural gas prices will likely rise and IGCC would most probably become the preferred coal technology. The U.S. Department of Energy's (DOE) Vision 21 program also identifies IGCC as a core technology for the future.

The characteristics of various coal-fired generating technologies were compared to the cleaner burning natural gas combined cycle system by the Pembina Institute in order to determine the optimal system in terms of cost and environmental performance. The coal-fired generating systems considered included PCC, supercritical PCC, AFBC, PFBC, and IGCC. The analysis determined that all coal-fired options, with the exception of perhaps IGCC, required both low NO_x burners and Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR) to meet a U.S. standard for NO_x, as well as a particulate control device such as a fabric filter or ESP. The IGCC option was the only coal-fired option that facilitated the capture of CO_2 and appeared to reduce, if not eliminate, emissions of mercury in flue gas. The IGCC system was, however, estimated to be generally 7 – 18 percent more expensive than the other coal-fired technology options considered. The Pembina Institute found that although none of the coal-fired options were as favourable as the natural gas fired option, the IGCC demonstrated the best environmental performance of all the coal-fired options considered. One concern raised with the IGCC was its commercial viability in larger scale operations. However, the large number of IGCC plants moving into or already in commercial operation suggests that this particular concern is being addressed (Winfield *et al*., 2004).

4.1.2 Emission Control Devices for Coal-fired Utilities

i) Low NO_x Process Burners (LNBs)

Low NO_x burners are used to control the combustion process to minimize the formation of nitrogen oxides (NO_x). Use of these burners for sub and supercritical pulverized coal combustion PCC plants has be demonstrated to yield is NO_x emission reductions of up to approximately 50 percent (Winfield *et al*., 2004). Low NO_x burners may also have the added benefit of facilitating mercury removal (Smith, 2004).

There are also a number of pollution control devices typically used at conventional coal-fired plants which enable such plants to achieve relatively very lower levels of emissions.

ii) Flue Gas Desulphurization (FGD)

Flue Gas Desulphurization (FGD) or scrubbing is a process during which lime or a similar material is added to the flue gas to absorb sulphur compounds and reduce SO_2 emissions. The process itself can be wet or dry, regenerable or non-regenerable. Often the recovered sulphur or reacted absorbent can be sold as an industrial process chemical. Dry systems can remove from 70 to over 90 percent of the sulphur dioxide while wet systems can remove 95 percent or more of this contaminant (Winfield *et al*., 2004, Amar Personal Communication).

In 2002, the Electric Power Research Institute (EPRI) released a technology evaluation of the potential market for fertilizer materials derived from coal combustion by-products of ammonia-based flue gas desulphurization (FGD) systems. In such a scrubber, ammonia combines with sulphate, and in some cases, nitrate, to remove SO_x and NO_x from the flue gas. Ammonium sulphate or ammonium sulphate-nitrate - the resulting by-product - if properly processed, can be readily accepted and marketed as a nitrogen based fertilizer. At the time of the EPRI publication, there were no ammonia-based FGD systems in the United States, although they are in place in other countries, including, for example, China (World Bank, 2004).

In 2004, the EPRI reported on the stability of mercury in FGD by-products. Results indicated that the potential for mercury reemission from such FGD products is small but measurable; however, further field investigations under actual reuse conditions were recommended.

iii) Selective Catalytic or Non-Catalytic Reduction (SCR or SNCR)

The SCR and SNCR are processes that have been applied to coal-fired facilities to remove NO_x formed in the exhaust gases from combustion. The SCR technology involves the injection of ammonia (NH_3) into the exhaust gas, which then passes through a catalyst bed where the ammonia and nitrogen oxides react to form harmless nitrogen and water vapour. The SNCR involves a similar process without the catalytic reaction. The SNCR reduces NO_x emissions by 40 – 60 percent, while SCR can achieve 90 percent reductions before the exhaust stack release of ammonia becomes problematic (Winfield *et al*., 2004). Between 105,000 to 200,000 MW of coal-fired generation capacity in the United States is expected to be retrofitted with SCR systems to meet the NO_x limits of various state implementation plans (SIPs) negotiated with the U.S. EPA as well as the requirements of pending federal regulation (Clean Air Interstate Rule or CAIR) or legislation (Clear Skies Act or other proposals).

iv) Electrostatic Precipitators (ESPs) and Fabric Filters (FF)

The ESPs and fabric filters (FFs) are emission control devices used to remove particulate matter (flyash) in the exhaust gases. Baghouses filter the PM from exhaust gases using a self-cleaning fabric filter process, while ESPs use an electrostatic charge to attract small particles. Baghouses are less sensitive to process variation than ESPs and are generally more efficient at removing most particulates (Winfield *et al*., 2004). Although both ESPs and baghouses have high efficiencies for total PM (>99 percent efficiency), the latter are more efficient (>99 percent) than ESPs (85 – 95 percent) at removing fine PM mass (Amar, 2003). Both ESPs and baghouses are able to remove some mercury, specifically the fraction associated with the flyash, if these control devices are used on cooled exhaust gases. Baghouses have been found to be more efficient than ESPs at capturing mercury in such applications (Winfield *et al*., 2004).

There is evidence that current emission control devices for coal-fired utilities can achieve co-benefits, as previously discussed, particularly in the reduction of mercury emissions. According to the Northeast States for Coordinated Air Use Management (NESCAUM), four bituminous coal-fired plants with dry scrubbers (FGD) and fabric filters (baghouses) have achieved more than a 95 percent mercury capture during emission tests. Also, some subbituminous coal burning plants equipped with fabric filters and other emission control devices achieved capture of 74 to 86 percent of mercury during testing. At the time of the emission testing it was reported that no attempts were made to optimize mercury removal (Northeast States for Coordinated Air Use Management (NESCAUM), 2003).

Although data for lignite-fired plants are more limited, pilot-scale testing has indicated that lignite and subbituminous coals are similar with respect to mercury speciation and control (NESCAUM), 2003). The University of North Dakota’s Energy and Environmental Research Center (EERC) conducted a two-phase project to develop and test sorbent injection technologies to capture mercury emitted by utilities that burn lignite coal. The project involved bench- and pilot-scale evaluations for screening of potential sorbents and then full-scale field tests of the selected sorbents at a lignite-fired power plant (Feeley *et al.* – U.S. Department of Energy (DOE), 2003). In the province of Saskatchewan, lignite is the type of coal burned at all coal-fired utilities due to the presence of deposits of that type of coal in the province. Along with the Canadian Clean Power Coalition (CCPC), SaskPower, Saskatchewan's provincial electric utility company, is conducting research related to the performance of various control technologies for lignite combustion (Christie, 2004).

Figure 10 includes U.S. EPA Information Collection Request (ICR) data based on 2001 and 2002 testing of various control technologies at different U.S. coal-fired utilities. The figure illustrates the differences in mercury removal for various control technologies burning bituminous and subbituminous coals. As indicated in Figure 10, for the same control technology or series of control technologies, higher mercury capture is achieved when bituminous coal is burned. Overall there is a wide variation in the ICR mercury capture data.

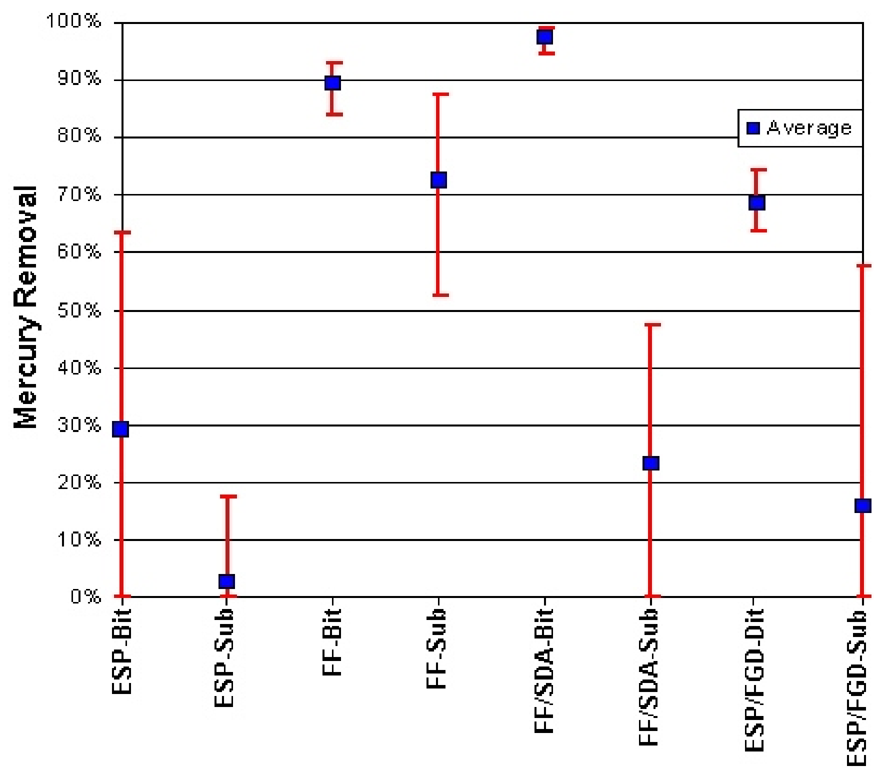


Figure 10. **U.S. EPA Information Collection Request (ICR) Data for Capture of Mercury with Existing Equipment (U.S. EPA ICR, 2001 and 2002)**

4.1.3 Continuous Emission Monitors

Continuous emission monitors (CEMs) offer an effective means to verify pollutant emissions compliance from combustion devices. These monitors can be used to directly measure a variety of pollutants. The use of CEMs provides several advantages including real (or near-real) time results, operational data for system optimization, and information concerning the temporal variations of emissions. In the United States, CEMs are used to verify emission rates and provide the data necessary for the application of market-based approaches such as cap-and-trade provisions for trading in the emissions of sulphur dioxide. This section will focus on the application of CEMs for monitoring mercury and NO_x emissions.

The U.S. Acid Rain Program requires units to continuously measure emissions of SO_2, NO_x, and CO_2 as well as the volumetric flow rate and opacity. In most cases, a continuous emission monitoring system is required to accomplish this. The accurate measurement of SO_2 emissions has made the trading of emission credits of this pollutant possible. In addition, the application of CEMs has facilitated the constant measurement of the concentration of NO_x along with the use of a diluent gas monitor to establish an emission rate (U.S. EPA Clean Air Markets – Programs and Regulations: Continuous Emission Monitoring Fact Sheet, 2002). The required use of CEMs has produced site-specific emissions estimates that have improved the quality of emission inventories for electrical generating power plants. These facilities previously relied upon more approximate emission factors to estimate their emissions. The Electric Power Research Institute (EPRI) reported in year 2002 that the enactment of the Acid Rain Regulations required by the Clean Air Act Amendments of 1990 had resulted in the electric utility sector installing and certifying over 1,500 new CEMs measuring sulphur dioxide emissions.

The U.S. DOE and the U.S. EPA co-sponsored a demonstration of several CEMs (Lemieux *et al*., 1998). This side-by-side testing involved the monitoring of six metals including arsenic, beryllium, cadmium, chromium, lead, and mercury. The appropriate EPA reference method was used as a benchmark in the testing. Each CEM was operated by the instrument's respective developer. An aqueous solution of the six metals, along with flyash from a coal-fired utility boiler, was injected into the afterburner of the EPA's rotary kiln incinerator simulator facility to generate a flue gas with realistic particulate loadings and target metals concentrations of approximately 15 and 75 $\mu g/m^{-3}$. The seven CEMs tested included two laser-induced breakdown spectroscopy systems, two inductively coupled plasma systems, a spark-induced breakdown spectroscopy system, a hazardous element sampling train with X-ray fluorescence, and a microwave plasma system. The EPA researchers involved in this testing found that none of the analyzers tested appeared ready for long-term evaluation. The CEMs evaluated did not demonstrate the capability to measure all six metals at or near the concentrations tested with the required relative accuracy of 20 percent (Lemieux *et al*., 1998).

Placet *et al*. (2000) considered the emissions of ozone precursors such as NO_x from stationary sources. Although the use of CEMs had increased the reliability of emission estimates of NO_x and other pollutants for power plants, further modification of the procedures involving the use of

CEMs would be necessary to refine their operation. They recommended that audits and other means to ensure CEMs are functioning as designed should be continued. Since CEMs generate a large volume of data through their operation, Placet *et al*. noted that a method of verifying CEM data is critical to the success of the instrument.

The real-time data provided by mercury CEMs have been compared to mercury emissions determined using the Ontario Hydro Method (OHM). Laudal *et al*. (2000) conducted a mercury sampling program at two North Dakota power plants - Milton R. Young Station and Coal Creek Station. At both plants, a portable Zeeman-modulated coal-vapour atomic adsorption (CVAA) CEM was used to measure total mercury emissions at the stack in real time. An objective of the study was to determine the ability of the mercury CEM to measure total mercury at the stack. Mercury stack emissions were also determined using the Ontario Hydro Method. The OHM is the standard (although unadopted) method of measuring and speciating mercury in the flue gas. The mercury CEM used gave mercury results that were highly comparable to those obtained using the Ontario Hydro speciation sampling method (Laudel *et al*., 2000).

Kellie *et al*. (2004) measured emissions using both a semicontinuous mercury emissions monitor (SCEM) and the Ontario Hydro Method (OHM). The SCEM utilized had an atomic fluorescence detector that analyzed the flue gas for mercury. The OHM and SCEM produced analogous results for the measurement of total mercury, but differed in their measurement of the individual mercury species (Kellie *et al*., 2004).

Laudal *et al*. (2004) considered the use of mercury CEMs at coal-fired utilities and concluded that additional work would be necessary to determine the reliability and durability of the instrument’s pretreatment/conversion systems before they could be used on a more routine basis. Based on their study, Laudal *et al*. found that the use of highly experienced personnel to perform on-site daily maintenance was necessary for long-term monitoring. Also, it was found that some modifications to the pretreatment/conversion unit could be made to allow their use in hot, wet, or high-dust locations.

There has been growing interest concerning predictive emission monitors (PEMs). The PEM is a mathematical model that does not directly measure emissions. Instead, it predicts emissions by developing a numerical relationship between a unit’s operating parameters and the particular pollutant being modeled. Chakravarthy *et al*. (2000) developed a PEM, based on data collected from a pilot plant furnace, to predict O_2, NO_x, CO, and CO_2 emissions. They found that the PEM developed predicted emissions of the specified gases with reasonable accuracy.

As of early 2004, the EPA had not yet determined what type of monitoring or testing requirements would be included in the upcoming mercury regulations for electric utilities.

4.2 Canada and United States Current Coal-Fired Utility Emissions

The electricity contribution to selected air pollutants in both Canada and the United States is shown in Table 8. The numbers in parenthesis are the contribution of coal combustion in the

Table 8. Electricity Sector Contribution to Total National Emissions (Contribution of the Coal-Fired Portion of the Electricity Sector is shown in parentheses) (Miller, 2004)

Country	SO_2	NO_x	Mercury	CO_2
Canada	20% (86%)	11% (81%)	25%	22% (?)
United States	69% (97%)	22% (93%)	40%	39% (87%)

Note: Mercury air emissions are currently only available from coal-powered plants. While the contribution to mercury air emissions from oil and natural gas plants is not known, they are believed to be minor so that mercury emissions are dominated by coal combustion.

electricity sector to national totals of emissions, based on year 2002 data. The numbers indicating the entire electricity sector's contribution are based on data from various years. For the Canadian national electricity sector percentages of total emissions, the SO_2 and NO_x data are from the year1995 emission inventories, while mercury is based on year 2000 data, and the CO_2 from year 1999 data. The U.S. percentages of electricity sector contribution to national pollution is based on year 2001 data for SO_2 and NO_x, while the mercury value corresponds to year 1999 data and the CO_2 percentage is based on year 2002 data. Table 9 shows the contribution in tonnes for these pollutants, with the exception of mercury which is in kilograms.

Table 9. Estimated Emissions of Selected Contaminants from the Coal-Fired Generation Sector in tonnes - mercury in kg (Miller, 2004)

Country	SO_2	NO_x	Mercury	CO_2
Canada	532,770	211,896	1,960	NA
United States	8,,913,330	3,745,110	44,200	1,894,860,000

The electricity sector in both Canada and the United States is also the single largest source of nationally reported emissions of toxics (including the contaminants discussed above) to the atmosphere. An analysis by the Commission for Environmental Co-operation of total pollutant release data for the year 2001 revealed that coal- and oil-fired facilities in the electric utilities sector accounted for the largest amount of toxic air releases (mainly stack emissions) in the United States with 322.4 million kg or 48 percent of total U.S. emissions. The facility in the United States with the largest toxic air releases in year 2001 was the CP&L Roxboro Steam

Electric Plant owned by Progress Energy in Semora, North Carolina. It reported 8.7 million kg of total toxic releases. Nine of the ten facilities with the largest toxic air releases in the United States in 2001 were electric utilities.

Coal- and oil-fired generation plants accounted for 22 percent (18.9 million kg) of toxic air releases in Canada. The Canadian facility with the largest toxic release (ranking fourth in North America) was Ontario Power Generation's Nanticoke Generating Station in Nanticoke, Ontario a coal-fired facility on the north shore of Lake Erie, with 6.9 million kg/year (Commission for Environmental Cooperation, 2004).

4.2.1 Coal-fired Utility Mercury Emissions

The electric utility sector's emissions of mercury in the United States and Canada of over 43,000 kilograms in 2001 represented 64 percent of the on-site air emissions reported by all industry sectors in 2001, a reduction of five percent from 2000. Among the coal-fired plants, the two power plants with the largest annual releases of mercury in the United States were Reliant Energies Inc's Keystone Power Plant in Shelocta, Pennsylvania with 819 kg and Mt. Storm, Dominion Resources Inc. in Mount Storm, West Virginia, with 635 kg. The largest air releases of mercury and its compounds by electric facilities in Canada were TransAlta Corporation's Sundance Thermal Generating Plant in Duffield, Alberta with 279 kg and Ontario Power Generation's Nanticoke Generating Station in Nanticoke, Ontario with 226 kg (Commission for Environmental Cooperation, 2004).

In 2000, an EPRI report assessed the transport and fate of mercury in the United States. Their model attempted to account for the global cycle of atmospheric mercury and generate estimations of the contribution of anthropogenic emission from the various continents to mercury deposition in the United States. The model appeared to reproduce measured concentrations on average as well as some of the spatial patterns that have been observed by others. The EPRI has maintained in some recent studies that non-U.S. industrial and background sources of mercury typically contribute 50 percent or more of the mercury deposition in much of the United States; however further consideration of the species of mercury and associated impacts on the environment is necessary to place this estimate in an appropriate context. In 2000, the U.S. EPA estimated 60 percent of the total mercury deposited in the United States came from U.S. anthropogenic emissions sources; the coal-fired utility sector emitted approximately 30 percent of current anthropogenic emissions (Federal Register, December 20, 2000). More recently, the total mercury deposition originating from U.S. sources was estimated at 50 percent; the extent of emissions from coal-fired utilities has increased to 40 percent of all domestic sources, with one third of these utility emissions being deposited in the contiguous United States and the balance being added to the global burden (U.S. EPA, February 2005).

There are two kinds of mercury released from coal-fired utilities: oxidized inorganic Hg^{2+}; and elemental mercury (Hg). The oxidized form of mercury, also called divalent mercury, is more likely to be deposited locally or regionally, whereas elemental mercury can remain airborne from one to two years, traveling thousands of kilometers before deposition occurs. The technology installed at facilities to lower mercury emissions decreases the emissions of reduced forms of mercury and, hence, lowers localized deposition. However, the control technologies do not all chemically reduced the oxidized fraction, so there is a limited effect on global deposition. There are differences of opinion as to the nature of the mercury contributing most to deposition, as the measurement of mercury ionic species can be unreliable. Mercury deposition is always a combination of local/regional and global deposition, from both natural and anthropogenic sources (Hanisch, 1998).

4.2.2 Coal-fired Utility Sulphur Dioxide and Nitrogen Oxide Emissions

Emissions of sulphur dioxide and nitrogen oxides contribute to acid rain, which remains one of the most serious threats to aquatic biodiversity, particularly in smaller waterbodies. Sources of sulphur dioxides and nitrogen oxides related to human activity, such as coal-fired utilities, release these gases into the atmosphere where they undergo chemical reactions to form acids or acidifying sulphates and nitrates. These sulphates and nitrates may be carried hundreds of kilometres before eventually falling to earth as dilute solutions of sulphuric acid and nitric acid in the form of rain, snow, or fog. This is termed wet deposition.

Figure 11 illustrates the atmospheric deposition of acidifying pollutants including sulphates and nitrates. The figure shows the regional-scale non-sea-salt wet sulphate (SO_4^{2-}) and wet nitrate (NO_3^-) deposition across eastern North America for the 1992-1994 and 1995-1997 periods. The decrease between the earlier and later periods was considerably greater for sulphate than nitrates, due largely to the significant reduction in SO_2 emissions achieved by year 1995 versus a minimal change in NO_x emissions. Wet sulphate deposition is considered the primary acidifying agent for lakes, although nitrogen-based acidification may become increasingly significant (Jeffries, 2004). Dry deposition is the fraction of acidic deposition deposited on dry surfaces, including buildings, cars and trees, when there is no precipitation. Dry deposition accounts for 20 to 60 percent of total acidic pollutant deposition of both particulate and gaseous forms (CASTNET, 2004). This includes particulate sulphate (SO_4) and nitrate (NO_3) and gaseous nitric acid (HNO_3), sulphur dioxide (SO_2) and ammonium (NH_4). It is usually more abundant near cities and industrial areas were the pollutants are emitted; however the particles and gases can travel into rural areas. Dry deposition can be washed off during precipitation events (CASTNET, 2004).

4.2.3 Human Health Related Impacts of Coal-fired Utility Fine Particulate Matter Emissions

Certain pollutants emitted from coal-fired combustion sources have been linked to various adverse health effects. Particulate matter (PM) contains many substances with potential environmental and health impacts such as metals, sulphates, nitrates, ammonium and some organic compounds. PM can be classified as either primary or secondary. Primary particles are those emitted directly into the atmosphere, while secondary particles are a product of chemical reactions that involve precursor gases. The predominate precursor gases are NO_x, SO_2, a large

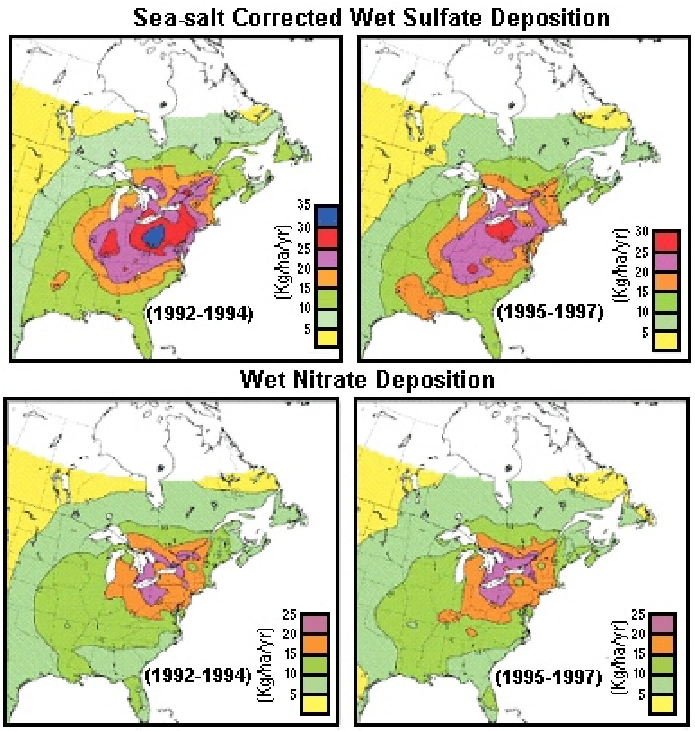


Figure 11. Wet Sulphate and Wet Nitrate Deposition for 1992 – 1994 and 1995 – 1997 (Jeffries *et al.*, 2003)

number of carbon-containing compounds known as volatile organic compounds (VOCs), and ammonia (NH_3). Particulate Matter (PM) is generally referred to as either coarse or fine. Coarse PM is between 2.5 microns (µm) and 10 microns (µm) in aerodynamic diameter while fine PM has an aerodynamic diameter of less than 2.5 µm ($PM_{2.5}$). Primary PM tends to be coarse while secondary PM is mainly fine in size.

Fine particulate matter ($PM_{2.5}$), which is primarily released from combustion sources has been associated with daily mortality in six eastern U.S. cities. Fine particulate matter ($PM_{2.5}$) consists mainly of combustion particles from motor vehicles and the burning of coal, fuel oil, and wood. Laden *et al*. (2000) conducted a study of samples collected from years 1977 – 1988 in an effort to identify several distinct source-related fractions of fine particles and to examine the association of these fractions with daily mortality in six American cities. The city-specific results were combined to derive overall relative risks for each source-related fraction of $PM_{2.5}$ and three sources of fine particles in the six cities were identified using factor analysis. These crucial factors included; a silicon factor classified as soil and crustal material; a lead factor classified as motor vehicle exhaust; and a selenium factor taken as representative of coal combustion sources.

Results indicated that the coal combustion (selenium) factor was positively associated with mortality in five of the six American cities considered. Figure 12 illustrates the findings of Laden *et al*. Each vertical bar illustrates the effect of a 10 µg/m^{-3} increase in mass concentration of $PM_{2.5}$ from a specific source. Lead and sulphur, also indicated in Figure 12, were considered markers for mobile and coal combustion sources, respectively. As shown, a 10µg/m^{-3} increase in $PM_{2.5}$ from coal combustion sources accounted for a 1.1 percent increase in daily mortality (confidence interval, 0.3 – 2.0 percent).

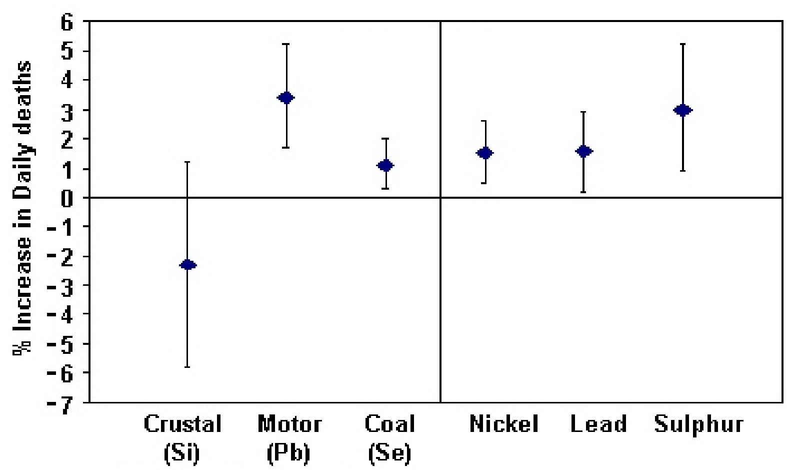


Figure 12. **Acute Effects - Daily Deaths in 6 U.S. Cities Associated with $PM_{2.5}$ from Major Sources (1979 - 1988)(Laden et al., 2000)**

Burnett *et al*. (2000) also considered the association between particulate matter components and daily mortality. Daily mortality rates and concurrent data on size-fractionated particulate mass and gaseous pollutants for eight Canadian cities were obtained for a period from years 1986 to 1996. It was determined that fine particulate ($PM_{2.5}$) mass was a stronger predictor of mortality than coarse PM. Results indicated that the four components of the fine fraction of PM that were most statistically significant and positively associated with mortality were sulphate, zinc, nickel, and iron. Sulphur or sulphate is known to be formed from emissions of SO_2. The main Canadian sources of SO_2 are coal- and oil-fired combustion, smelters, and the oil and gas extraction and refining industry. Selenium, as considered by Laden *et al*., is noted as a marker for coal. Mercury is known to be emitted from coal-fired generating stations. These three fractions of particulate matter are indicated in Figure 13. The figure illustrates the percent increase in (non-accidental) mortalities associated with an increase in $PM_{2.5}$ elemental concentration equal to the study mean (µg/m^{-3}).

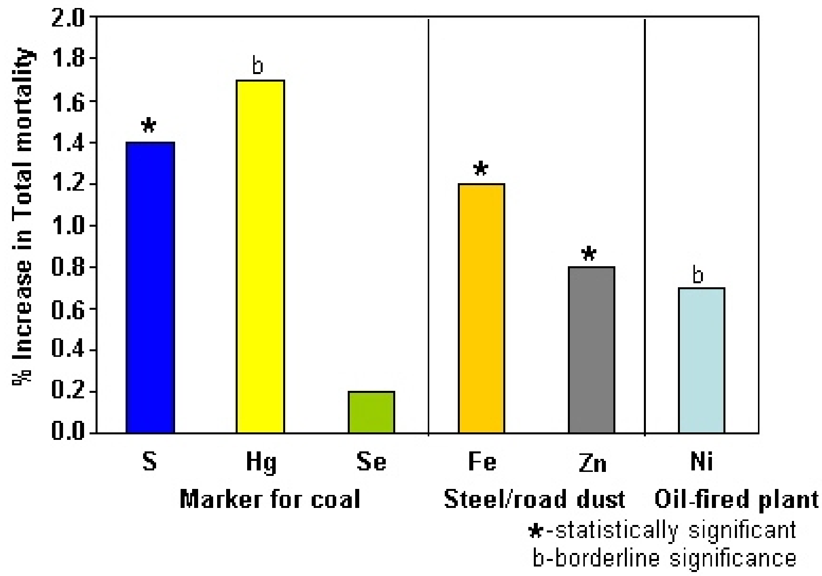


Figure 13. **Acute Effects - Daily Total Mortality in Eight Canadian Cities Associated with Elemental Components of $PM_{2.5}$ (1986 - 1996) (Burnette et al. 2000)**

The Electric Power Research Institute (EPRI) has also attempted to assess the contributions of power plant emissions to ozone, fine particulate matter ($PM_{2.5}$), and regional haze. The Institute has used models to predict how the application of emission controls to specific sources would affect air quality in particular regions. The primary goal of the program is to distinguish the fraction of $PM_{2.5}$ that is responsible for negative health outcomes found in the majority of epidemiology studies from other non lethal fractions of fine particulate.

Over 100 studies, producing different findings, have examined the links between $PM_{2.5}$ and health. Many, but not all, of the studies have found a link. The EPRI maintains that an important result from many of these studies is that carbon-containing pollutants, such as carbon monoxide and carbon dioxide, rather than particulate matter in general, are linked with negative health effects (EPRI, 2003).

The Aerosol Research Inhalation Epidemiology Study (ARIES) in metropolitan Atlanta has examined the relationship between various health indicators and the many different components of air pollution. The study included a detailed characterisation of particulate constituents. The ARIES found increased emergency room admissions for heart disease on days with high ambient concentrations of carbon containing particles or carbon monoxide gas in comparison to admissions on days with high atmospheric sulphate and nitrate levels. The EPRI also notes that a review of the toxicology of sulphates in The Netherlands *PM Criteria Document* (Annema, *et al*., 1996) concluded that, at realistic environmental concentrations, sulphates are unlikely to cause adverse health effects (EPRI, 2003).

4.3 Canada and United States Current Coal-Fired Utility Control Technologies

Table 10 gives a summary of the emission control technologies which are in place in United States and Canadian coal-fired utilities. More description follows in sections 4.3.1 and 4.3.2.

Table 10. Summary of Control Technologies in the United States and Canada. (For sources, see notes below)

Control Technology	Existing Capacity United States (MW)[1]	Existing Capacity Canada (MW)[2]
Particulate Matter Control - ESP	153,133	6,358
Particulate Matter Control - ESP and retrofit Fabric Filters	2,591	
Particulate Matter Control - Fabric Filters	11,018	216
Particulate Matter Control and Dry FGD	8,919	
Particulate Matter Control and Wet FGD	48,318	
Particulate Matter Control and LNB		5,842
Particulate Matter Control and OFA		1,885
Particulate Matter Control and CFB		165
Particulate Matter Control and Wet or Dry FGD and SCR	22,586	
Particulate Matter Control and Wet FGD and LNB		440
Particulate Matter Control and LNB and SCR		1,010
Particulate Matter Control and LNB and LIFAC		300
Particulate Matter Control and Wet FGD and LNB and SCR		1,020
Total	**246,565**	**17,236**
Total Generation	**310,900**[1]	**17,236**[2]

Particulate Matter -
ESP: electrostatic precipitator
NO_x Control -
SCR: selective catalytic reduction
LNB: low NO_x burner
OFA: overfire air
CFB: circulating fluidized bed
SO_2 Control -
FGD: flue gas desulphurisation
CFB: circulating fluidized bed
LIFAC: limestone injection into the furnace and reactivation of calcium

[1] 2002 US DOE EIA AEO2004
[2] Personal communication, Cummings, 2005

4.3.1 Canada

The following provides an overview of current emission control technologies at Canada's coal-fired electrical generating plants. In general, as illustrated in Table 10, emission control technologies to reduce PM, SO_2, and NO_x are currently deployed (Cummings, Environment Canada, 2004).

i) PM emission control technologies

In general, coal-fired utilities built in the 1980s and onward had ESPs installed since their in-service date. Plants built prior to this time typically did not include ESP or baghouse controls in their construction; however, many retrofitted PM control technologies in the 1980s. The particulate control technology of choice for Canadian coal-fired utilities is the electrostatic precipitator, although fabric filtration is used on a limited basis. (Cummings, Environment Canada, 2004).

ii) SO_2 emission control technologies

The majority of coal-fired utilities in Canada do not have any SO_2 emission controls, due mainly to the lower sulphur content coal burned at most plants. Where SO_2 emission control technologies have been deployed, wet FGD units (or scrubbers) are generally used. The Nova Scotia Power Point Aconi Plant has a CFBC system that, although it is not a control technology, reduces SO_2 by a modifications to combustion processes. The SaskPower Shand coal-fired power plant was constructed with an SO_2 control that injects limestone into the furnace and reactivates any calcium in order to reduce SO_2 in the flue gas. Ontario Power Generation's Lambton Generating Station added FGD units in the mid 1980s, while New Brunswick Power's Dalhousie Generation Station added their FGD unit when it switched to Orimulsion in 1994 (Cummings, Environment Canada, 2004).

iii) NO_x emission control technologies

In general, coal-fired utility plants built in Canada in the 1980s and onward have had Low NO_x Burners since inception. Plants built prior to this time later installed LNBs in the 1980s to reduce emissions of NO_x. Selective Catalytic Reactors (SCRs) were added to Ontario Power Generation's Lambton and Nanticoke Generating Stations between years 2003 and 2004 (Cummings, Environment Canada, 2004).

4.3.2 United States

Table 10 also provides an overview of current emission control technologies at coal-fired electrical generating plants in the United States. In general emission control technologies to reduce PM, SO_2, and NO_x are most prominent.

Most U.S. coal-fired utilities (about 86 percent) have ESPs installed, while the remaining 14 percent of facilities have the more efficient fabric filters (baghouses) in operation for particulate matter control (Amar, 2004).

The U.S. Environmental Protection Agency (EPA) eGrid reference (Emissions and Generation Resource Integrated Database -www.epa.gov/cleanenergy/egrid/
index.htm) is a comprehensive data source on the environmental characteristics of almost all electric power generating facilities in the United States. The database integrates data from the EPA, the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) to provide site specific emission and technology information on U.S. coal-fired utility facilities. It allows comparisons to be made by company, state or power grid region

The New Source Review (NSR) permitting program was established as part of the 1977 Clean Air Act Amendments. The NSR is a preconstruction permitting program specifying what construction is allowed, what emission limits must be met, and, in most cases, conditions under which the facility must be operated. The NSR is meant to ensure that air quality is not significantly degraded from the addition of new industrial facilities. In areas subjected to pre-existing poor air quality, the NSR is meant to ensure that any new emissions do not hamper progress towards cleaner air. In attainment areas, those with relatively clean air, for example many of the National Parks, the program aims to ensure that new emissions do not significantly degrade air quality. The NSR also attempts to ensure that technological advances in pollution control systems occur concurrently with industrial expansion. In most circumstances, NSR permits are issued by state and local air pollution control agencies, although the EPA issues these permits in some instances (EPA, 2004).

The Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Rate (LAER) Clearinghouse (RACT/BACT/LAER Clearinghouse)(RBLC)) website (www.epa.gov/ttn/catc/rblc/htm/welcome.html) and database contain information regarding emission control technologies in use at U.S. coal-fired electricity generating stations. Facilities designated as BACT and LAER (and sometimes RACT) are determined on a case-by-case basis usually by State or local permitting agencies. The RBLC database contains information condensed from past RACT, BACT, and LAER decisions associated with NSR permits from state and local air pollution control programs in the United States. The RBLC database also acts as a central database of air pollution technology information, thus allowing permitting agencies to share resources when case-by-case assessments are being carried out.

4.4 Current Coal-fired Utility Control Technologies in Selected Other Countries

The extent of available coal reserves, and application of coal combustion in the generation of electricity, as well as coal-fired utility control technologies currently in operation in China, India, Japan, Germany, and the United Kingdom (UK) are described in this section.

4.4.1 China

China is both the largest consumer and producer of coal in the world, and is now the fifth largest coal exporter. Coal makes up 64 percent of China's energy consumption, and in year 2001, China consumed 26 percent of the world's coal with electrical power generation stations accounting for approximately 50 percent of this consumption. Exports have more than doubled between years 1994 and 2000, when they exceeded 55 million tonnes per year.

The total proved recoverable reserves of coal in China are estimated to be 114,500 million tonnes, consisting of 62,200 million tonnes of bituminous and anthracite coal, 33,700 million tonnes of subbituminous and 18,600 million tonnes of lignite coal. Production peaked at 1400 million tonnes in year 1996, but fell to 1030 million tonnes in year 1999 (World Energy, 2004).

Coal deposits have been located in much of China, but three-quarters of proved recoverable reserves are in the north and north-west of the country, principally in the provinces of Shanxi, Shaanxi and Inner Mongolia. Most recently in China many small inefficient mines and plants have been shut down, in favour of technological improvements, including the development of coal-fired power plants co-located with large mines, called "coal by wire" projects (Mudway *et al*., 2003).

The International Energy Agency (IEA) described China's environmental protection legislation as extensive. Reduction of PM and SO_2 emissions from coal combustion has been a major priority for Chinese authorities according to the IEA (1999). The National People's Congress passed the Environmental Protection Law in 1989. Under this law, each plant pays a tax based on their total release of particulate matter and SO_2 each year, irrespective of whether they have met established emissions limits. However, if the plant has exceeded applicable standards, a fine is then imposed and the plant is given a fixed time period within which to reduce its emissions. The provincial environmental protection foundation fund receives 90 percent of this money which is to be put towards improving the environment (Mudway *et al*., 2003).

Particulate control systems are apparently being placed on 60 percent of the power plants in China to date; a target of 80 percent of the plants has been established (Attwood *et al*., 2003). In year 1997, most of the larger power plants in China had emission control devices for particulates although the efficiencies of these devices varied widely. There has been a widespread adoption of electrostatic precipitators (ESPs) in new large capacity utility plants and through retrofitting of selected older plants. The proportion of units equipped with ESPs increased from 16 percent in year 1986, to 34 percent in year 1990, and to 60 percent by the end of year 1996. In addition, by the end of year 1996, 22 percent of boilers had some rudimentary particulate control devices in use, such as a cyclone, with some limited capacity to reduce emissions of larger particulate matter (IEA, 1999).

New national emission standards were issued in December 1996 by Chinese authorities that required all new utilities burning coal with more than one percent sulphur content to add an SO_2

control technology in order to meet an emission concentration limit of 650 mg/m^{-3}. Local provincial and city regulations tend to be more stringent than these national standards in some areas of China, according to the IEA. These regulations encouraged the installation of flue gas desulphurizers (FGD) on plants that burn coals with relatively higher sulphur contents. The FGDs, or scrubbers, slowly began to be included into the design of new coal-fired power plants in order to comply with these national and state environmental regulations. However, in 1999, the bulk of power generation equipment operated without SO_2 control devices (International Energy Agency).

4.4.2 India

Coal is the most abundant fossil fuel resource in India, with proved recoverable reserves of 84,396 million tonnes, placing the country near the top of the world's producers. The principal deposits of anthracite coal are in the east and north-east of the country, and the Geological Survey of India states there is an additional 89,500 million tonnes of indicated reserves and 39,700 million tonnes of inferred reserves of bituminous coal in these areas. The southern state of Tamil Nadu has an indicated reserve of an additional 28,000 million tonnes of lignite coal. Despite these vast reserves, much of the coal in India has a high ash content and a low calorific value, limiting exportation. However, within India, coal is the most important source of energy for electrical generation, accounting for about 75 percent of the total power generated (World Energy, 2004).

The government of India has not set any limits on SO_2 and NO_x emissions from coal-fired utilities. According to the IEA, flue gas monitoring and cleaning systems generally have not been required. Installation of desulphurization systems is required where several power plants with more than 500 MW of total capacity are built at one location (International Energy Agency, 2002).

The Indian Central Board of Irrigation and Power collected statistics on air pollution control devices for various coal-fired utility plants. According to these statistics 73 percent of boilers had ESPs, 22 percent had an ESP with a combination of other devices, and three percent had multiple cyclones, with two percent not reporting (1997). Although flue gas conditioning is a commercially accepted and widely used technology, it is not currently used in India. Also, fabric filter collectors (baghouses) were not used in India until a boiler was retrofitted with a pulse-jet baghouse (Lookman and Rubin, 1998).

ESPs are considered the standard method for filtering out particulates from the flue gas to reach the Indian regulated limit value of 150 mg/m^{-3} for soot particles. This target is comparable to the U.S. EPA emission standards for particulate matter (PM_{10}) of 150 mg/m^{-3} in a 24-hour period, with an annual average of 50 mg/m^{-3} (SRMT, 2003). Highly-effective precipitators are currently manufactured in India and the installation of these control devices is now a legal requirement in new Indian power plants. The ESP fabrication industry is well developed in India and the conventional ESP is the most frequently used control device in India. It has also become compulsory to demonstrate that these devices are operating at ≥99.5 percent efficiency (Mishra, 2004). However, according to the IEA, it is unlikely that existing plants will be retrofitted with any emission control devices (2002).

Lookman and Rubin (1998) considered technologies such as ESPs, fabric filter collectors, flue gas conditioning (FGC), coal cleaning, and switching to imported coal in order to determine the least-cost control option for Indian power plants. The results of the study suggested that using flue gas conditioning reduces generation costs at all power plants burning Indian (un-cleaned) coal in meeting for an emission standards of 50 mg/nm^3. The FGC was also found to be cost-effective for new 500 MW units regardless of the coal used. It was noted that at the current time none of the least-cost measures identified in the study were widely used. According to Lookman and Rubin, particulate control system design practices that were optimal 10 – 20 years ago continue to be used today in India even though they no longer result in least-cost generation.

4.4.3 Japan

Japan has small coal reserves of 852 million tonnes, but the country ceased production in January 2002. Therefore, Japan is the world's largest importer of steam and coking coal, accounting for about 22 percent of world coal imports. In year 2002, 18 percent of Japan's electricity came from coal-fired power plants (Mudway *et al.*, 2003). Usually, coal burned in Japanese power plants has a mercury concentration of less than 0.1mg/kg (Yokoyama *et al.*, 2000).

Environmental policy in Japan is not based on prescriptive legislation, but instead on 'administrative guidance' where the government gives advice on standards for different sectors. These are voluntary requirements, but do include emission standards to be met, with proscribed fines when they are breached. Enforcement action is infrequent, as the high importance attached to social responsibility in Japan ensures that any company in breach of these requirements would lose its public credibility.

Emission concentration limits for particulates vary from 50 – 200 mg/m^{-3}, depending on plant size and location. The newest limits, set in year 1998, for SO_2 vary spatially and with the height of the exhaust stack, while NO_x limits vary with boiler/furnace type.

The most modern utility scale FGD systems were installed on Japanese power plants in the late 1960s, and served as benchmarks for early FGD adoptions in the United States and Germany. Japan was also a world leader in the use of selective catalytic reduction (SCR) in the 1970s. Widespread adoption of SCR then followed in Germany in the 1980s; the United States installed its first SCR units on coal-fired power plants in 1993.

The monitoring of mercury emissions is also among the required activities, and ambient levels of mercury are monitored for three years before construction of any new coal-fired facility can begin (Mudway *et al.*, 2003), allowing an ambient baseline to be established.

Yokoyama *et al*. (2000) conducted a study to characterize mercury emissions from a coal-fired power plant in Japan. The power plant under study was equipped with a low-NO_x burner, a two-staged combustion system, SCR with ammonia injection, a cold-side electrostatic precipitator (ESP) and a wet type flue gas desulphurization system in which limestone slurry was used to remove sulphur oxides. Mercury emissions were found to be 99.5 percent gaseous, with only a very small amount of particulate mercury present.

4.4.4 Germany and the United Kingdom under the European Union (EU)

In the EU, and many countries, the main market driver is compliance with regulatory emission limits. The relevant legislation within the EU are the Integrated Pollution and Prevention Control (IPPC) and the Pollution Prevention and Control (PPC) regulations. These regulations are EU directives, which means that the precise form and method of implementation is left to individual member states. The IPPC directive states that all industrial installations must obtain a permit from the authorities in the relevant country. This permit must be based on Best Available Techniques (BAT).

Facilities are allowed an eleven year transition period to comply with the permit conditions. Pollutants included in the IPPC Directive are: SO_2 and other sulphur compounds; NO_x and other nitrogen compounds; carbon monoxide; Volatile Organic Compounds (VOCs); metals and their compounds; particulate matter; asbestos; chlorine and its compounds; fluorine and its compounds; arsenic and its compounds; cyanides; and polychlorinated dibenzodioxins and dibenzofurans. For coal-fired power generation, the Large Combustion Plant Directive (LCPD) sets emission standards. There are variations in the standards depending on when the plant was built or licensed and how many hours the plant operates in one year. For plants licensed after July 1, 1987 and in operation after November 27, 2003, the limits are 200 mg/nm^{-3} for SO_2, 200 mg/nm^{-3} for NO_x and 30 mg/nm^{-3} for particulate matter (Mudway *et al*., 2003).

4.4.5 Germany

Germany is in the front rank for coal resources, reserves and production. The proven amount of coal in place is 122,000 million tonnes, including 44,000 million tonnes of bituminous coal and 78,000 million tonnes of lignite coal. The Ruhr coalfields produce over three-quarters of German anthracite and bituminous coals, and the Saar is the second largest coalfield, with significant amounts of bituminous coals. All German hard coals are deep-mined at depths of over 900 meters. The lignite deposit in the Rhine region is the largest such formation in Europe (World Energy, 2004).

Flue gas desulphurization systems cover more than 95 percent of the installed capacity of medium and large combustion facilities in Germany (International Energy Agency, 2002). Additionally, Germany is an active developer of clean coal technologies including coal gasification (IGCC), pressurized fluidized bed combustion (PFBC), and supercritical and ultra-supercritical pulverized combustion (SC and USC). The annual expenditure for these technologies is significant and it is exceeded only by Japan and the United States (International Energy Agency, 2002).

Thompson and Parker of the U.S. EPA (2000) completed a trip to France, Germany, Switzerland, and Belgium to investigate how facilities in these countries monitor mercury emissions. Thompson and Parker determined that while all four countries had a mercury emissions limit, only Germany had a continuous mercury emissions monitoring requirement. In addition Germany has the lowest daily mercury emissions limit. According to German regulations, only those mercury continuous emission monitors (CEMs) which have been approved by the country's Federal Environmental Agency may be installed in German facilities. The CEM is approved upon completion of a suitability testing procedure conducted by one of Germany's six approved independent laboratories. Thompson and Parker reported that mercury CEMs used at power plants typically have more rigorous requirements than those used at municipal waste incinerators. While in Germany, Thompson and Parker visited a power plant fired by a mixture of sewage sludge and coal (2000). Plant emission control devices at this co-combustion utility included fuel desulphurization, a wet scrubber, and an ESP. Controlled combustion technologies were also used at this facility.

4.4.6 United Kingdom

Due to the privatisation of the coal industry in the United Kingdom, and its subsequent decline, it is difficult to accurately quantify the coal resources and reserves in the country. However, World Energy reports proved recoverable reserves to be 1,500 million tonnes. Production in 1999 was just 37 million tonnes, mainly owing to competition from natural gas and higher quality, cheaper coal from overseas.

The United Kingdom restructured its energy supply sector by replacing 30 percent of coal-based generating capacity with gas-based generation between years 1990 and 2000. The United Kingdom's greenhouse gas emissions fell during this decade, according to the IEA, despite the strong economic growth the United Kingdom also experienced during this time. The reduction in greenhouse gas emissions may also be attributable to the promotion of greater energy efficiency and the introduction of pollution control measures in the industrial sector (International Energy Agency, 2002).

The United Kingdom's Electricity Association (EA) reported that between 1990 and 2001 the electric industry reduced its annual emissions of sulphur dioxide and oxides of nitrogen by 73 percent and 51 percent, respectively. These reductions were achieved through a range of measures including the retrofitting of plants with flue gas desulphurization (FGD) and low NO_x burners and further investment in high-efficiency natural gas-fired generation. The United Kingdom EA also reported plans to retrofit seven coal-fired power plants with FGD equipment (2003). In addition, one particular U.K. coal-fired power plant is investing in an innovative gas reburning technology to further reduce emissions of NO_x (United Kingdom's Electricity

Association (U.K. EA), 2003). The preferred approach in the United Kingdom to demonstrate compliance with the EU directives is the use of CEMs wherever possible (Mudway *et al.*, 2003).

4.5 Cost of Current Coal-Fired Utility Control Technologies

Costs are expressed in terms of cost to the ratepayer in units of mills per kWh of electricity. This unit of mills/kWh is commonly used to describe an annualized cost to a ratepayer where 10 mills = 1¢ and 1,000,000 mills = $1,000 (U.S. dollars). Table 11 provides a comparison of estimated costs associated with current control technologies including low-NO_x burners, selective catalytic reduction, and flue gas desulphurization units.

Table 11. Comparison of Current Control Technologies for Air Pollutants (NESCAUM, 2003).

Control Type	Total Annual Cost (mills/kWh)
Low-NO_x Burners (LNBs)	0.21 – 0.83
Selective Catalytic Reduction (SCR)	1.85 – 3.62
Flue Gas Desulphurization (FGD)	~ 3 – 5 *

* (Amar - personal communication, 2004)

When comparing the annual costs of different control technologies in Table 11 it is important to consider that the total annual cost of a mercury control technology such as activated carbon injection is estimated as between 0.18 – 1.15 mills/kWh which is comparable to the cost for control of NO_x. The overall cost of a baghouse would contribute an additional 0.5 to 1.5 mills per kWh to the values presented in Table 11. (Amar, 2004 Presentation or the NESCAUM Report “Mercury Emissions from Coal Fired Power Plants”)

5.0 EMERGING CONTROL TECHNOLOGIES

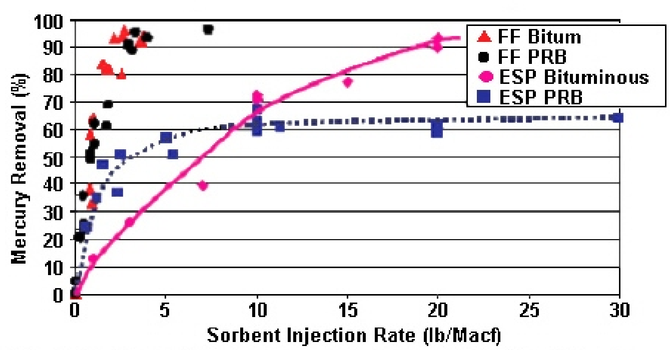
5.1 Evolving Coal-Fired Utility Control Technologies in Canada and the United States

Evolving control technologies in the coal-fired utility sector in Canada and the United States are outlined in this section. Five evolving control technologies specifically aimed at reducing mercury, as well as other pollutants, include Activated Carbon Injection, Other Sorbent Injection for Mercury Removal, Enhanced Wet-Scrubbing, K-Fuel® Technology, and Powerspan ECO Technology.

i) Activated Carbon Injection (ACI)

Activated carbon injection (ACI) refers to the injection of dry, powdered activated carbon as a sorbent into the flue gas duct between an air preheater and the ESP or fabric filter (baghouse). The ACI typically occurs in the temperature range of 250 to 350 degrees Fahrenheit. Mercury is adsorbed onto the activated carbon which is then collected in the ESP or baghouse where additional adsorption of mercury by the activated carbon continues to occur. ACI is now commercially available (Smith, 2005).

Research has been conducted in order to determine whether an ESP or a baghouse achieves better adsorption of mercury following ACI. This research has been conducted with different types of coal by ADA Environmental Solutions (ADA-ES), who have frequently worked with the U.S. Department of Energy (DOE). Figure 14 indicates that mercury removals in the 60 – 90 percent



"FF" stands for fabric filter, which is the same as a baghouse: "PRB" refers to Powder River Basin, which is a subbituminous coal; and "Macf" stands for million actual cubic feet.

Includes EPRI data on small-scale PRB/FF tests

Source: Durham, M. "Tools for Planning and Implementing Mercury Control Technology," American Coal Council, 2004, pp. 43-46.

Figure 14. Percent Mercury Removal vs. Activated Carbon Injection Rate

range can be achieved across the control devices for ESPs and FFs (baghouse), and for both bituminous and subbituminous coals. Higher capture of mercury at lower carbon injection rates is associated with the baghouse or fabric filter configuration according to this figure. This is due to the increased contact between the mercury and the flue gas and the activated carbon sorbent that occurs in a baghouse as opposed to an ESP. A carbon layer accumulates on the bag filters of a baghouse which encourages adsorption of mercury.

ADA-ES performed large-scale activated carbon injection technology testing at four different coal plants during 2001 and 2002, in partnership with the affiliated utility companies and with the support of the U.S. Department of Energy. The program sites included were testing at the Alabama Power E.C. Gaston Station, WEC Pleasant Prairie Power Plant, PG&E National Energy Group's Brayton Point Station, and PG&E National Energy Group's Salem Harbour Station. All sites had an ESP for particulate control (Bustard *et al*., 2003).

The first test site was Alabama Power's E.C. Gaston Electric Generating Plant in Wilsonville Alabama which fires low sulphur bituminous coal and has four 270 MW boilers and one 880 MW boiler. This plant has a Compact Hybrid Particulate Collector (COHPAC) which is a system consisting of a hybrid pulse-jet fabric filter (baghouse) situated downstream of an existing ESP.

The COHPAC system provides major reductions in total and fine particulate matter but was shown by itself to have no effect on removal of mercury from the flue gas at this particular facility (Bustard *et al*., 2002).

A technology known as TOXECON™ involves sorbent injection upstream of a fabric filter (baghouse) and downstream of a primary particulate collector. TOXECON™ and COHPAC are both Electric Power Research Institute (EPRI) patented processes that are currently commercially available. One of the disadvantages of ACI is that it can impact on the saleability or reuse of flyash – as the resultant higher levels of carbon in the ash can render it unsuitable for use in typical concrete applications. With the TOXECON™ configuration, however, a great majority of the flyash is collected upstream of the activated carbon injection stage (usually at an ESP) and remains acceptable for sale (Bustard *et al*., 2003). Figure 15 illustrates the TOXECON™ configuration which is the same as that used at the E.C. Gaston Electric Generating Plant. As illustrated by the figure, the majority of the flyash (99 percent) is collected at the ESP for possible commercial application and the remaining ash (one percent) would be disposed of appropriately.

The Gaston Plant (Unit 3 of 270 MW capacity) was the first full-scale installation of the TOXECON™ technology at a bituminous coal-fired power plant. Unit 3 had a hot-side ESP installed upstream of the COHPAC and then the TOXECON™ technology was incorporated with powdered activated carbon (PAC) used as the sorbent. The activated carbon was injected upstream of the COHPAC and downstream of the ESP. Results indicated that as much as 90 percent of all mercury was removed for short operating periods (8hrs) with the TOXECON™ technology implemented at Unit 3 of the Gaston Plant (Bustard *et al*., 2002).

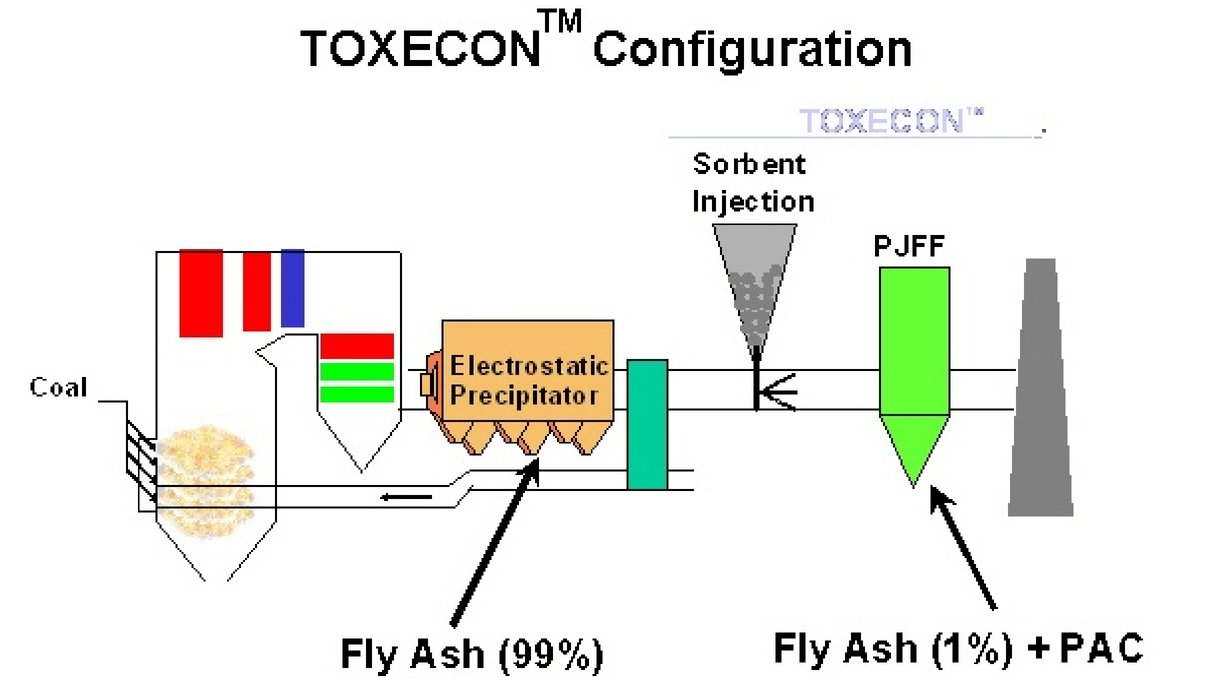


Figure 15. Configuration of the TOXECON™ Activated Carbon Injection Technology (Amar, 2004)

ii) Other Mercury Control Systems

Other sorbents may include sodium tetrasulphide, amended silicates, enhanced powdered activated carbon, and the gold-sorbent-coated plates of the EPRI-patented 'Mercury Control by Absorption Process' (MerCAP™). Sodium tetrasulphide is commercially used in Europe on waste incinerators and the use of amended silicates as a sorbent is being tested by Cinergy Corp. under a U.S. Department of Energy (DOE) program. An enhanced powdered activated carbon (PAC) -based sorbent has added chemicals which give this particular sorbent a higher effectiveness than ACI alone. The use of sodium tetrasulphide, amended silicates, and enhanced PAC preclude any issues associated with ash disposal, as the levels of mercury in the leachate of the ash are below detection limits (U.S. Environmental Protection Agency (EPA), 2003). Finally, the mercury control absorption process (MerCAP™) involves sorbent-coated (gold) metal plates suspended in flue gas to allow for the capture of mercury. Testing of this particular absorption process is underway in the United States (Babcock Power Mega Symposium, 2003).

The U.S. Department of Energy has sponsored several full-scale demonstrations of ACI technology. This type of mercury control is well on its way to widespread commercial availability.

iii) Enhanced Wet Scrubbing

Enhanced wet scrubbing technology promotes the oxidation of elemental mercury in the flue gas before it enters the scrubber to ensure that as high a fraction as possible of the total mercury is in the oxidized state. Mercury in its oxidized form is more easily removed in the scrubber vessel. Approaches to enhanced wet scrubbing under development include those using chemical reagents, fixed catalysts and high-energy oxidation (NESCAUM, 2003). This new technology is relatively cost-effective as it can easily be retro-fitted onto existing scrubbing systems, and Babcock & Wilcox (who are developing the technology) claim it should be cheaper than a similarly sized ACI-based application.

A U.S. Department of Energy sponsored program examined mercury oxidation technology for application in plants with scrubber systems (FGD). Major demonstrations were conducted at Michigan South Central Power Agency's Endicott and at Cinergy's Zimmer stations. A propriety chemical reagent was added to the scrubber system, so as to oxidize the elemental mercury present in the flue gas. Removal efficiencies varied between the two stations, with 75 to 80 percent at Endicott, and 50 percent at Zimmer. There are many possible explanations for this difference, including the different scrubber chemistries at the two sites (NESCAUM, 2003).

iv) K-Fuel® Technology

K-Fuel® is a pre-combustion technology capable of raising the BTU-value of western sub-bituminous and lignite coals while reducing the moisture and ash content. K-Fuel® has been found to remove more than 70 percent of the mercury and up to 30 percent of the sulphur dioxide and nitrogen oxide in coal that is already relatively low in mercury and sulphur content. K-Fuel® is the only pre-combustion commercial product to reduce mercury emissions from sub-bituminous coal and lignite (KFx, 2003).

K-Fuel® technology involves the following sequence of steps. Coal is crushed and screened to remove the large rock and rock material before being passed onto an intermediate storage facility. The coal is then transferred from the storage facility to a vessel where it is exposed to conditions of high temperature and pressure, which results in the fracturing of mineral inclusions and the subsequent removal of rock which contains some mercury. The coal then leaves this main vessel to another pressurized vessel that is vented into a water condenser to cool down the coal. After cooling, the coal is again screened to remove sulphur and mineral-containing matter liberated by the thermal process. K-Fuel® technology includes a water treatment system to process all the water removed at various stages in the process (KFx, 2003).

The company KFx has patented the K-Fuel® process. The first K-Fuel® plant is currently being constructed at the Buckskin Mine, north of Gillette, Wyoming. The plant is expected to produce between 750,000 and 1,000,000 tons of K-Fuel® per year and KFx expects production will begin early in 2005 (KFx, 2004).

v) Powerspan ECO

Powerspan ECO technology is an integrated air pollution control technology that can be installed in conventional coal-fired utility plants for the control of oxides of sulphur and nitrogen. The technology would be installed downstream of a facility's existing particulate control system such as dry ESP or a fabric filter (baghouse). Pilot tests have indicated the technology is capable of reducing SO_2 emissions by 98 percent, NO_x emissions by 90 percent, mercury emissions by 80 – 90 percent, and $PM_{2.5}$ (fine particulate matter) by 95 percent. The ECO system produces a commercial grade ammonium sulphate and nitrate fertilizer co-product that contributes to the economics of the ECO technology. High energy use (up to five percent of electricity generated at site) may affect the economics of this technology in field applications..

The ECO process involves a high-energy oxidation reactor followed by an ammonia-based scrubber and a wet ESP. Once the flue gas enters the ECO oxidation reactor, OH radicals and atomic oxygen are formed which then act to oxidize pollutants in the gas stream, resulting in soluble compounds and aerosols. The flue gas next enters an ammonia-based scrubber where the gas is saturated and cooled while being scrubbed of SO_2 and NO_2. The absorber vessel is similar to wet SO_2 scrubbers except that it operates at a high pH and utilizes a smaller tower. After exiting the absorber vessel, the flue gas then enters a wet ESP where the aerosols and fine PM are captured. The liquid layer created on the collection plate of wet ESPs prevents particle re-entrainment and improves overall collection efficiency (Powerspan Corporation, 2004).

The ECO system has been undergoing pilot testing in a 1 – 2 MW unit at FirstEnergy's R.E. Burger Plant since February of 2002. Currently, a 50 MW ECO commercial demonstration unit is under construction at the same plant with operational testing scheduled for 2004 (Powerspan Corporation, 2004).

vi) Technical Overview and Comparison

The evolving control technologies discussed above were mainly aimed at the capture of mercury. In year 2002 a report of the the Electric Power Research Institute (EPRI), the U.S. Environmental Protection Agency (EPA) and the Department of Energy – National Technology Laboratory (DOE-NETL) contained an outline of mercury removal options for power plants. The EPRI acted as a sponsor to assist power producers in evaluating the cost-benefits of various mercury reduction options.

Specific emphasis was given to activated carbon injection and wet scrubbing in the report. Five broad categories of mercury control options were explored including sorbent injection, wet and dry scrubbing, conversion of vapor mercury to particulate soluble forms, fixed or fluid beds, and coal cleaning. Emerging mercury control options discussed in the report included corona-induced plasma processes, circulating fluid bed adsorbers, mercury amalgamation, and mercury oxidation catalysts.

The report found that for most plants equipped with only an ESP or baghouse, activated carbon injection (ACI) is the most investigated option for mercury removal. The ACI seems to be the most effective for removal of all species of mercury from all coals. Options for supplemental capture of mercury where bituminous coal is fired include mercury oxidation across selective catalytic reduction (SCR), nitrogen oxides catalysts, and ACI before an ESP or baghouse.

5.2 Cost of Emerging Coal-Fired Utility Control Technologies

The ACI technology discussed can be compared in terms of price based on whether the activated carbon injection is followed by an ESP or a fabric filter (COHPAC FF as discussed in the TOXECON™ configuration). Figure 16 and Figure 17 show this cost comparison for low-sulphur bituminous coal and subbituminous coal, respectively. (See section 4.40 for an explanation of the units of mills/kWh). As indicated in the figures, the preliminary cost of the COHPAC (FF following the ACI) control device stabilizes at a constant cost to the ratepayer with increased capture of mercury for both low-sulphur bituminous and subbituminous coals.

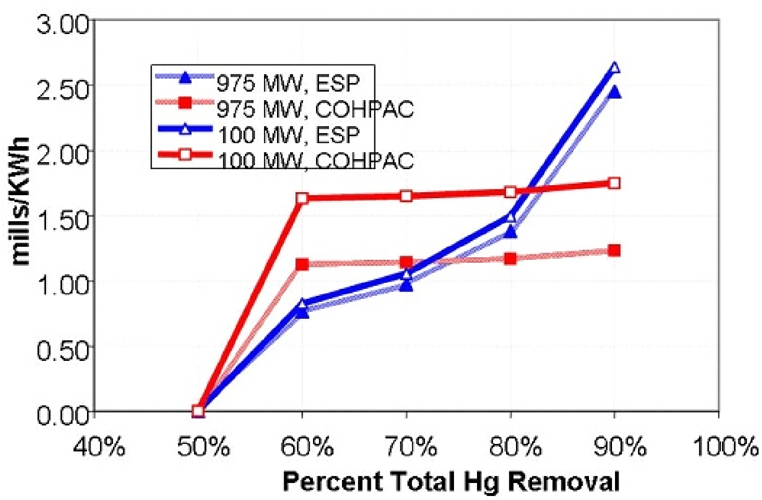


Figure 16. Preliminary Cost of Mercury Removal with ACI for Low-sulphur Bituminous Coal (Amar, 2004)

The cost of activated carbon varies depending on the quantity required. Differing quantities of activated carbon will be required for a system depending on whether the ACI in the configuration is followed by an ESP or a (COHPAC) fabric filter. The capital and operating costs for an ESP were compared to that for a COHPAC Fabric Filter (baghouse) in Table 12 for a 250 MW plant with an 80 percent capacity factor firing bituminous coal. Typical mercury capture percentages were assumed for both the ESP and COHPAC FF. It was also assumed that the capital cost of adding COHPAC FF treatment to the system under consideration would be approximately \$50/kW (\$12,500,000) (Amar, 2004).

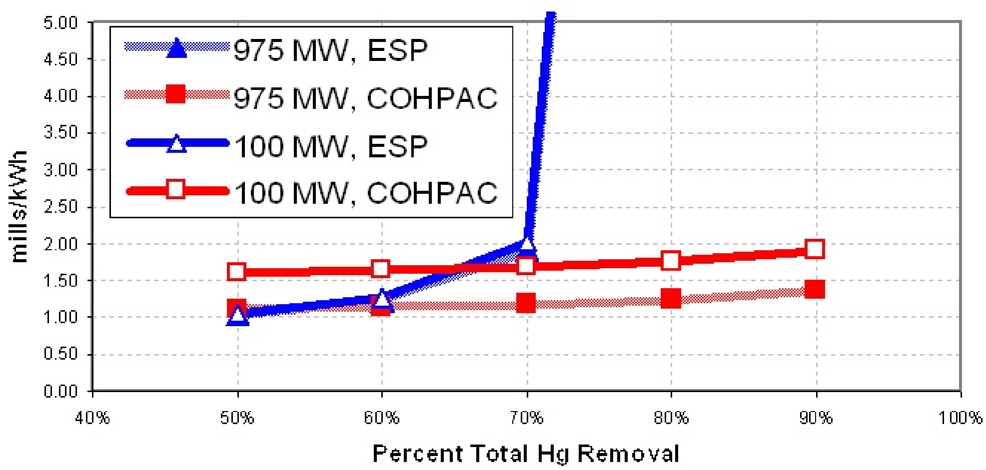


Figure 17. **Preliminary Cost of Mercury Removal with ACI for Subbituminous Coal (Amar, 2004)**

In regards to the other evolving control technologies described, no published costs were available for the KFx K-Fuel® technology. The ECO Powerspan technology has a published cost ranging from \$150 – 200/kW (Amar, 2004).

Table 12. Capital and Operating Costs for Activated Carbon Injection System Followed by Either an ESP or a COHPAC FF for Bituminous Coals (Amar, 2004)

	ESP	COHPAC FF
Percent of Mercury Removal	70%	90%
PAC Injection Rate	10 lb/Macf	3 lb/Macf
PAC Injection Cost	\$790,000	\$790,000
Activated Carbon Costs	\$2,562,000 / year	\$769,000 / year

PAC = powdered activated carbon

5.3 Other Emerging Coal-Fired Utility Control Technologies Outside Canada and the United States

This section outlines not only the emerging technologies for coal-fired utility plants in countries outside of Canada and the United States but also the regulatory drivers for developing these new technologies. Emerging requirements and accompanying technologies for the coal-fired power sector in China, India, Japan, Germany, and the United Kingdom are considered.

5.3.1 China

Clean coal technology is part of the 'Agenda 21' plan for sustainable development in China. China is planning a variety of actions including the closure of smaller scale, inefficient thermal plants and the development of super-critical coal-fired units. Research and development of clean coal technologies for power development were carried out for circulating fluidized bed combustion (CFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC). In addition research and development are targeted at SO_2 and NO_x removal technologies for conventional coal-fired plants. An additional action item for China in year 1999 was the retrofit of existing power plants with more efficient boilers and equipment as well as the addition of desulphurization equipment and ESPs (International Energy Agency).

Specifically, China attempted to develop the capability to manufacture FGD equipment through international cooperation projects. Also, a number of different institutions and manufacturing companies have been involved with developing circulating fluidized bed combustion (CFBC) system, which have been identified as particularly suitable for the southwestern China's coal given its sulphur/ash content and a low volatility/ash melting point. China is considering introducing IGCC-based power plants. In addition according to the IEA, China examined a range of options for NO_x control at their coal-fired power plants (International Energy Agency, 1999).

Minchener (2000) considered technology transfer issues in China. This researcher indicated that SO_x and NO_x control are almost non-existent while dust control is poor at the majority of coal-fired power plants in China. Minchener pointed out that although there is considerable technical interest in advanced systems such as PFBC and integrated gasification combined cycle (IGCC), these technologies are either not proven or at the commercial prototype stage. A major technology that began to be introduced in year 2000 at some utilities, according to Minchener, is CFBC.

Attwood *et al*. (2003) considered the prospects of IGCC technology in China and found this technology to be an option for the clean and efficient production of power. They pointed out that the current environmental policies of the Chinese government encourage the use of pollution control systems. Based on the estimated capital cost of IGCC plants there would need to be a 20 – 25 percent reduction in capital cost before the IGCC technology is competitive with conventional coal technology and control devices for NO_x, SO_2, and PM.

An additional clean coal technology, known as underground coal gasification, was studied by Yang *et al*. in a pilot project experiment (2003). They concluded that the technology considered could be adopted at old and unused Chinese coal mines.

5.3.2 India

A collaborative project developed in cooperation with the U.S. Agency for International Development and the National Energy Technology Laboratory is encouraging the adaptation of clean coal technologies suitable to Indian coal. Preferred options from a technical standpoint include CFBC and PFBC since these technologies permit more efficient use of coal with a low calorific value. The IEA views the use of these technologies in power plant operations as unlikely in year 2002, since at that time they were not yet ready for commercial operation and the financial conditions prevailing in the Indian electricity sector were not supportive.

The retrofit of existing coal-fired power plants is necessary in India to improve their overall efficiency. This normally requires major expenditure of capital. One approach to increase the thermal efficiency of a plant is to update and modernize the cooling system (International Energy Agency, 2002).

Using a modelling approach, Mathur *et al*. (2003) examined the economic attractiveness of setting up coal washeries and beneficiating (washing) indigenous coal. They concluded that if the data on coal quality published by the suppliers were credible, coal of good quality is available and the washery is therefore not advantageous.

5.3.3 Japan

The IEA identified Japan's research priorities related to coal as coal liquefaction, gasification, and fluidized bed combustion (FBC). In regard to coal liquefaction, the aim is to raise the yield of middle and light fractions from various kinds of bituminous coal. By early this century, Japan's goal is to develop a practical power generation system using gasification technology. Pressurized fluidized bed combustion (PFBC) technology is also being developed for application in Japan (1999).

Shinada *et al*. (2002) considered integrated coal gasification combined cycle (IGCC) power plants as a key technology in Japan for the 21st century. This study indicated that IGCC technology development in Japan is progressing from a an early feasibility study to a detailed study to allow for a final decision on demonstration plant construction. Unlike China and India, Japan is at a more advanced stage of development with the IGCC technology and will likely implement this technology much sooner.

In Japan, Ninomiya *et al*. (2004) are also considering the feasibility of co-combustion of coal with different fuels. A laboratory-scale study was carried out to determine the interaction between coal and sewage sludge and the resultant emissions.

5.3.4 Germany

As was the case in Japan, researchers in Germany have also studied co-combustion of coal with different fuels. Hartmann and Kaltschmitt (1999) analyzed the environmental effects of electricity production from hard coal in comparison to co-combustion of hard-coal and biomass. They found co-combustion to be a more environmentally sound alternative to electricity production than using coal alone. Campbell *et al*. (2000) also conducted a study involving the co-combustion of coal with an alternate fuel. This study considered the energy recovery of the co-combustion of textile wastes with coal in a circulating fluidized bed combustion (CFBC) system as well as the effects of different amounts of fuel blending.

5.3.5 United Kingdom

The United Kingdom government's policy has encouraged the development of cleaner coal technologies both at home and overseas. The United Kingdom implemented this policy through a program that commenced in year 1999 aimed at linking research and development with technology transfer and export promotion. The program is also designed to allow the UK to develop cleaner coal technologies and obtain an appropriate share of the growing world market for these particular technologies. Technology transfer to India and China is a main part of the focus. Much of the future research and development effort is expected to involve advanced power generation technologies, according to the IEA (2002). The potential for developing the United Kingdom coal bed methane resource and underground coal gasification technology is also under examination (International Energy Agency, 2002). Pressurized fluidized bed combustion (PFBC) research was initiated in the United Kingdom. It is commercially available within the EU, although the current cost and complexity of the technology may make it unattractive at the present time (BEO, 2004).

6.0 NATIONAL REGULATORY FRAMEWORK AND SELECTED JURISDICTIONAL APPROACHES RELATED TO THE COAL-FIRED UTILITY SECTOR IN CANADA AND THE UNITED STATES

6.1 Canadian Regulatory Framework and Selected Jurisdictional Approaches

In Canada, the environment is considered a shared jurisdiction bwetween federal and provincial governments and consequently emissions from coal-fired generating plants, such as mercury, are managed at both levels of government. Specifically, the federal government manages such toxic substances through the Canadian Environmental Protection Act (CEPA) and deals with international pollution issues, while the provincial government controls point and area industrial emissions. Mercury is a CEPA toxic and therefore requires specific management.

The Canadian Council of Ministers of the Environment (CCME) works to promote effective intergovernmental cooperation on interjurisdictional issues such as air pollution and toxic substances. The CCME collectively establishes nationally-consistent environmental standards, strategies, and objectives. The CCME works, in particular, to develop Canada Wide Standards (CWSs). The CCME has no authority to enforce legislation on its members. The federal government, however, may intervene if a province is not meeting a CWS. Each jurisdiction decides whether to adopt the CCME proposals. The CWSs are developed with participation of a variety of interests, including industry, municipal, environmental, health, and aboriginal groups that have an interest in the standards. The standards are developed using a firm scientific foundation and a risk-based approach. The provinces assist in the development of the CWSs and the province then determines individually how best to meet the particular CWS (CCME, 2004).

Currently, a CWS is under development for mercury emissions from the coal-fired electric power generation sector. The CCME has committed to develop a CWS by the year 2005 to reduce mercury emissions from coal-fired utilities by the year 2010, to explore the national capture in the range 60 – 90 percent for mercury from coal combusted, and to align with U.S. standards for mercury. This CWS would ensure that Canadian regulations align with U.S. standards for the control of mercury. The provincial application of the national target or standard may vary, depending on provincial willingness to aggressively pursue available control technologies for the different types of coal (CCME, 2003).

In Canada, the electrical generation sector is represented by the Canadian Electricity Association (CEA). The CEA members represent over 90 percent of the generation in Canada. Eight coal-fired generating companies that are either provincially or privately owned are members of CEA. A mercury program designed by the eight CEA coal-fired member companies was initiated in year 2002 with program completion expected by December 2005. The program, which is being implemented in cooperation with governments, is aimed at improving emission inventories through an intensive two year coal ash and stack sampling program. Effective stack testing is being promoted along with quality assurance programs to strengthen laboratory analytical capabilities. In addition, an information clearing house is being created in the CEA Mercury

Program to keep all involved parties informed on global mercury research and development projects (CEA, 2004). Finally, the CEA is considering the future of electrical generation in Canada and the new capacity additions and demand side management that would be required. The CEA's standpoint on Canada's electricity future is that coal will remain an important fuel for electrical generation due to its relatively stable and inexpensive price (Christie, 2004).

6.1.1 Jurisdictional Approaches – Ontario

The current Ontario government has re-affirmed its commitment to close all of the coal-fired power plants in the province, which are currently providing 22 percent or approximately 7,600 MW of the province's power, by the end of year 2007 if environmentally feasible. To accomplish this goal, 25,000 MW of the total provincial generating capacity must be refurbished, rebuilt, replaced or conserved by the year 2020 to meet increases in demand. A larger portion of the province's electricity would be supplied by hydroelectric and nuclear facilities. An Ontario Power Authority has been created to ensure the long term adequacy of the provincial power supply. Conservation programs will be established, including the deployment of smart meters in 800,000 homes by year 2007, to encourage power usage at off peak hours.

The Ontario Power Generation Review Committee report "Transforming Ontario's Power Generation Company" (Manley *et al*, March, 2004) recommended that 'OPG withdraw from non-core businesses (including wind-power, solar, biomass and small hydro projects) in an orderly fashion to allow room for others better suited to these businesses' (Recommendation II.4). The Report advocates rather that OPG should 'redevelop, enhance, and/or expand existing facilities that are part of its core assets' (Recommendation II.5) to meet its target of ceasing coal-fired electricity generation by the end of year 2007, including the refurbishment of nuclear power plants, and a proposed new tunnel under Niagara Falls to increase available hydroelectric capacity. This latter project was subsequently approved on June 25, 2004.

There were five nuclear units out of service (Pickering A Units 1, 2, & 3 (each with a capacity of 500 MW) and Bruce A Units 1 & 2 (750 MW units)) at the time of the Review Committee's report. On July 7, 2004, the Ontario Energy Minister announced an undertaking to refurbish the formerly out-of-service Pickering A Unit #1 reactor. Restoration is expected to take 15 months at a cost of $900 million; on completion and recommissioning, the unit will generate 515 MW of electricity. The government is to make a decision on whether to rebuild the remaining two nuclear units at the Pickering A plant after receipt of a report on the status of the Unit #1 project (Mackie – Globe and Mail, July 8 2004).

Renewal of these units is a complex, expensive, and demanding undertaking. The recently completed refurbishment of Pickering A Unit #4 cost $1.25 billion, three times the original estimate, and its completion took two years longer than projected. The only alternative to refurbishment of the Pickering unit considered in the OPG Report was construction of a combined cycle natural gas plant; the report authors suggested that this option would be $20 to $30 more expensive per MWh than the estimated costs of refurbishment of Pickering A Unit #1.

The Ontario Ministry of Energy has also announced ten new projects meant to generate 395 MW of renewable electricity. These projects include hydro, wind, and landfill gas generation; all are under 100 MW capacity and scattered across the province (Energy, 2004).

Consistent with the recommendations of the Manley Report, in November 2004, the government proceeded to request proposals from the private sector for the production of 'green power', including the identification of potential sites on Crown (government controlled) land for small scale hydro-power development. Proposals of over one MW generation would be subject to a competitive process, while a non-competitive process of Direct Site Release would be followed for smaller projects. Aboriginal communities may apply under the non-competitive process with projects up to 25 MW in some basins. In addition, there is a Request for Qualification on two MNR-owned dams on Crown land in southern Ontario which were decommissioned decades ago (Ontario MNR, 2004).

These steps are the first in the government's effort to provide five percent (1,350 MW) of capacity from renewable sources by year 2007, the year during which the province's coal-fired utilities are to be shuttered, and 10 percent by year 2010.

6.1.2 Jurisdictional Approaches – Alberta

In January 2002, the province of Alberta's Environment Minister asked the Clean Air Strategic Alliance (CASA), a non-profit organization established by the Government of Alberta in year 1994, to recommend an approach, including performance expectations, for new and existing power plants. The CASA is a multi-stakeholder group with participation by government, industry, and non-government organizations. The alliance published a report in November 2003 outlining an air emissions management framework and related recommendations. The provincial government then adopted the report as government policy in March 2004 (Letchford, 2004).

The CASA framework is aimed at significantly reducing releases of four priority air emissions – mercury, sulphur dioxide, nitrogen oxides, and primary particulate matter – to levels shown in Table 13. The new framework was recommended for implementation by January 1, 2006 (CASA, 2003).

In formulating their recommendations, CASA reviewed emission control technologies applied in other jurisdictions and capture rates for mercury achieved when combusting different types of coal. Fabric filters and activated carbon injection were considered to be the best option currently available to control mercury emissions. In year 2005, a technology review will consider new information and identify a BATEA (best available technology economically achievable) technology standard and associated emission limits for mercury.

Table 13. Expected Emission Reductions for the Province of Alberta Based on CASA Recommendations (Clean Air Strategic Alliance (CASA), 2003)

Contaminant	Annual Reductions	Reductions from 2003 levels	Target Year
Mercury	400 kg	50%	2009
Primary particulate matter (PM)	3,500 tonnes	51%	2025
Sulphur dioxide (SO_2)	52,000 tonnes	46%	2025
Nitrogen oxides (NO_2)	29,000 tonnes	32%	2025

The framework recommendations call for significant emission reductions for both new and existing units. The recommendations also utilize a multi-pollutant optimization as opposed to pollutant-by-pollutant approach. In addition, the CASA suggested the use of economic instruments such as emission trading of NO_x and SO_2, as well as continual stakeholder involvement and review. However, the Alliance elected not to pursue a mercury emissions trading option (Letchford, 2004). The report required a defined multi-stakeholder process to evaluate the performance of the framework at five year intervals starting in year 2008 (CASA, 2003).

The operating permits for Alberta coal-fired facilities will require renewal at various times between years 2005 and 2007. The requirement for mercury control will be included for the individual facilities at the time of their next permit renewal. With a few exceptions, including units approaching the end of their design life, facilities are to have installed mercury controls by the end of year 2009 (Letchford, 2004).

6.2 United States Regulatory Framework and Selected Jurisdictional Approaches

In the United States, the 1970 Clean Air Act and the 1990 Clean Air Act Amendments established a framework for reducing harmful emissions from several sources, including power generating plants. Cap and trade mechanisms act as approaches to managing emissions of SO_2 and, more recently NO_x, from coal-fired utilities in much of the proposed U.S. legislation.

Cap and trade is a policy approach for controlling large amounts of emissions from a group of similar sources on a regional or national basis. The approach first sets an overall cap, or a maximum amount of emissions per compliance period. The U.S. Acid Rain Program introduced an allowance trading system for SO_2. Under the system, affected utility units were allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year. For each ton of SO_2 emitted in a given year, one allowance is retired, that is, it can no longer be used. However, regardless of the number of allowances a particular source holds it may not emit at levels that would violate U.S. federal or state limits for sulphur dioxide set under Title I of the Clean Air Act to protect public health (U.S. EPA Clean Air Markets – Programs and Regulations: Acid Rain Program Overview, 2002).

As discussed, sources covered by a cap and trade program receive authorizations to emit in the form of emission allowances, with the total amount of allowances limited by national or regional caps. Allowances may be bought, sold, or banked. Each source involved in the cap and trade program can design its own compliance strategy to meet the overall reduction requirement including the sale or purchase of allowances, installation of pollution control technologies, along with other options. Sources must also completely and accurately record their emissions to ensure allowances in an equal quantity are submitted for compliance. Well designed cap and trade programs have characteristics including strict emission limits, high levels of compliance and complete accountability, and incentives for early pollution reduction and innovations in control technologies (U.S. EPA Clean Air Markets – Cap and Trade, 2004).

The suggestion of applying a cap and trade approach to control of mercury emissions has generated controversy as some believe that this method (and the Section 111 approach) is inappropriate for dealing with hazardous air pollutants deposited locally, regionally or globally. Others would be supportive of a cap and trade program for hazardous air pollutants but only as an interim step to a final more stringent goal of reducing emissions of the particular pollutant.

In March 2005, the EPA announced the Clean Air Interstate Rule (CAIR). The CAIR is an outgrowth of the Ozone Transport Commission initiative which focused on NO_x controls only for states largely east of the Mississippi River. In this region, NO_x and SO_2 controls are meant to lower or resolve PM and ozone non-attainment issues occurring over a great deal of the area as a result of long range transport of pollutants.

In year 2010, if enacted as proposed by the current U.S. administration, CAIR will reduce SO_2 emissions by 4.3 million tons, or 45 percent from year 2003 levels in the eastern 28 states and the District of Columbia, to which the rule applies. By year 2015, there is to be a reduction of 5.4 million tons, or 57 percent of the year 2003 SO_2 emissions. At full implementation, a reduction of 73 percent below the year 2003 benchmark emissions is to be achieved.

Nitrogen oxides emissions will also be reduced from year 2003 levels, by 53 percent in year 2009, and 61 percent by year 2015.

The program allows the 28 states involved the option of participating in a federal cap and trade program for electric utilities or requiring their own cuts on a breadth of facilities in individual states, not necessarily including power plants.

On March 15, 2005, the EPA was required to meet a court-ordered deadline to regulate hazardous air pollutants from power plants as a settlement with the Natural Resources Defense Council (NRDC). The NRDC sued the EPA 13 years ago for failing to regulate these pollutants.

To this end, the Clean Air Mercury Rule (CAMR), originally known as the Utility Mercury Reductions Rule, addresses emissions of mercury and the EPA has proposed two approaches to achieve reductions. In this rule, the U.S. EPA elected not to require a stringent application of a segment of the Clean Air Act (Section 112) which, in recognition of the hazardous nature of mercury, requires the installation of 'maximum achievable control technology' (MACT) at all coal-fired power plants.

Rather, the new rule will create a market-based 'cap and trade' program that, if implemented, should reduce nationwide utility emissions of mercury in two phases: an initial cap at the co-benefits level in year 2010; and a final cap in year 2018. The final cap in year 2018 is 13.6 tonnes (15 tons) for coal-fired facility emissions of mercury, a reduction of nearly 70 percent (Wehrum, 2004).

The State and Territorial Air Pollution Program Administrators have come out strongly against the Mercury Rule, as have several individual states and prominent non-government organizations. Their critiques center on the inappropriateness of trading in a neurotoxin, the failure to require state of the art controls at each facility and to address other toxicants, such as cadmium and arsenic, from these sources and concerns that the banking and trading of emissions will allow increases in mercury emissions in some states. Several states indicate they will continue to pursue their own, more stringent control programs and there is a strong likelihood of a court challenge to the U.S. EPA Rule.

Other current major legislative proposals to address the issue of emissions from a multi-pollutant standpoint which are in review include the Clean Air Planning Act (CAPA), the Clear Skies Act (CSA), and the Clean Power Act (CPA).

The Clean Air Planning Act (CAPA) establishes emissions caps for SO_2, NO_x, mercury and CO_2. The bill sets certain reforms for New Source Review (NSR). The four pollutant caps are established as cap and trade programs. The allocations of allowances for the caps of NO_x, mercury, and CO_2 are based on electrical generating output. The bill also includes allocations for renewable generators in the CO_2 program (U.S. EPA Output Based Regulations: A Handbook for Air Regulators, 2004).

The Clean Power Act (CPA) is a cap and trade program for SO_2, NO_x, and CO_2. Allocation of emission allowances is primarily accomplished through auctions. The bill does, however, create set-asides for renewables, clean combustion units, and end-use efficiency. These set-asides for renewable sources are to be allocated based in part on generation output. The bill does not allow trading for mercury (U.S. EPA Output Based Regulations: A Handbook for Air Regulators, 2004).

The *Clear Skies Act* (also referred to as the Clear Skies Initiative) is the legislation preferred by the current administration (Wehrum, 2004). The Clear Skies Initiative is a cap and trade program for SO_2, NO_x, and mercury. This initiative would create a mandatory program that would reduce emissions of SO_2, NO_x, and mercury by setting a national cap on each pollutant; the established targets are less ambitious than those in the preceding two bills. If implemented, it is expected to reduce emissions from electric power generation facilities to approximately 70 percent below year 2000 levels. This initiative has no provisions for CO_2 control; given the particularly toxic character of mercury, it is unclear if a market could be formed for trading emissions this contaminant.

During the first year of the trading program, 99 percent of the SO_2, NO_x, and mercury allowances are to be allocated to affected units with an auction for the remaining one percent. Each subsequent year for 20 years, an additional one percent of the allowances would be auctioned. The bill proposes revised New Source Performance Standards (NSPS) emission limits as a replacement for NSR permitting (U.S. EPA Output Based Regulations: A Handbook for Air Regulators, 2004).

The Electric Power Research Institute (EPRI), a facility funded by large electrical generation companies, assessed the cost-effectiveness of mercury emissions scenarios for electric utilities under two alternative policies including the Clear Skies Act (CSA) and an illustrative maximum achievable control technology (MACT) standard, another tool available in the U.S. Clean Air Act for this contaminant. The EPRI determined this to be approximately \$6 billion and \$19.3 billion for the CSA and the MACT approaches, respectively. According to this EPRI analysis, although significantly less expensive, the CSA produces greater mercury reductions than the illustrative MACT. By year 2020, the CSA could reduce continental U.S. mercury deposition by an average of 1.5 percent, compared to 1.2 percent by the MACT. However, MACT brings about the changes over a significantly shorter time span.

The Clean Energy Group is a coalition of electric generating and electric distribution companies in the United States that share a commitment to responsible environmental stewardship. This group used the ICF Consulting's Integrated Planning Model (IPM) to compare the Clean Air Planning Act, described earlier, and the CSA. This model is widely used by the U.S. EPA, industry, and non-government organizations for economic assessments of this kind. Any assumptions that were used to run the model replicated those used as inputs by the U.S. EPA in their analyses of these two acts (2000 IPM).

The modeling results obtained by the Clean Energy Group indicated that the CAPA provides substantially more emission reductions and public health benefits than CSA over a 20 year period. In comparison to the CSA, the CAPA was found to provide additional *cumulative* reductions of 23 million tonnes of SO_2, three million tonnes of NO_x, 136 tonnes of mercury, and 5.4 billion tonnes of CO_2. The CAPA was also found to provide various public health benefits over the CSA including roughly \$30 billion (\$US) in incremental public health benefits per year by 2020. Overall the Clean Energy Group favoured the proposed CAPA legislation as it provides conditions for the continued use of coal and a more certain investment environment (Berwick, 2004).

Other studies conducted by the EPRI compared year 2020 conditions under each of the EPA's two proposed mercury rules which include the MACT rule (Section 112) and the cap and trade rule (Section 111). The EPRI maintains that the cap and trade proposal (Section 111) would produce larger and more widespread reductions in mercury deposition than the MACT proposal, especially in regions currently having the highest deposition.

According to the results obtained by EPRI, reductions in mercury deposition would vary to some extent by location, with the greatest reductions in some of the mid-Atlantic and southeastern states, as the EPA proposed rules would incorporate greater incentives for power plants in these regions to install mercury controls. The reductions seen in the New England states are not as dramatic, which could leave concerns in these states largely unaddressed.

The EPRI has also suggested that much of the mercury deposited within the United States appears to be the result of trans-Pacific transport of emissions originating in Asia, which releases roughly half of the world's anthropogenic mercury. The bulk of this long range transport is in elemental form, which was thought to stay aloft for one to two years. However, there have been recent studies conducted by U.S. EPA and McGill University in Montreal, among others, suggesting a shorter life for elemental mercury in the atmosphere (EST, 2004). Other scientific research indicates that divalent mercury, which is the most bioavailable form, is deposited on a local and regional basis in the vicinity of the emitting source and significant local reductions in the mercury present in biota could accrue from further control of these emissions (Florida Department of Environmental Protection, 2003).

6.2.1 Selected Jurisdictional Approaches – New England and the State of Massachusetts

The New England Governors and the Eastern Canadian Premiers (NEG/ECP) is an organization of regional states and provinces focused on issues such as trade and the environment. States involved include Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Eastern Canadian provinces involved include Quebec, New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland. Beginning in the early 1980s the NEG/ECP became a leader in shared environmental issues. In year 1998 the Conference of NEG/ECP adopted two international environmental action plans including an Acid Rain Action Plan and a Mercury Action Plan (The Council of Atlantic Premiers, 2004). The mercury action plan set goals of 75 percent reduction in mercury releases by 2010, and virtual elimination of releases of mercury from human activities over the longer term (Massachusetts DEP, 2001).

All of the New England states have implemented regulations to addressing mercury emissions. These actions are consistent with the regional NEG/ECP Mercury Action Plan, but have not necessarily been adopted to address the plan. For example, Connecticut legislation calls for 90 percent control of mercury emissions from coal-fired power plants by year 2008 and review of this regulation in year 2012. In New Hampshire, the "Clean Power Strategy", which came into law in year 2002, gives the state's three fossil-fueled power plants (two of which are coal-fired) five years to reduce emissions of mercury by 70 percent. The state of Massachusetts has implemented progressive mercury regulations and this state's jurisdictional approach to the control of power plant emissions of mercury will be the focus of the following section.

The state of Massachusetts adopted a "Zero Mercury Strategy" in year 2000 to ensure that the State would meet the objectives of the regional mercury action plan set out by the NEG/ECP (Massachusetts DEP, 2004).

In May 2001, the state implemented emission caps for releases of NO_x, SO_2, mercury, CO_2 and fine PM ($PM_{2.5}$) from Massachusetts power plants. The regulation (310 CMR 7.29) established output-based emissions rates for NO_x, SO_2, and CO_2 and a cap on CO and mercury emissions from affected facilities (Massachusetts DEP, 2001).

Finally, on May 26, 2004, the state adopted new regulations to limit mercury emissions from four large coal-fired power plants. This regulation provided more specific requirements regarding the mercury cap that had been outlined in the May 2001 regulation. The year 2004 regulations limit mercury emission rates based on the capture of mercury or on the quantity of electricity generated by the facility. The limits are established in two phases. Phase 1 which takes effect January 1, 2008 affirms that each facility must capture at least 85 percent of the mercury in the coal burned by the facility or emit no more than 0.0075 pounds of mercury per net GW.hr of electricity generated. October 1, 2012 will see the implementation of Phase 2 which orders facilities to capture at least 95 percent of the mercury in the facility's coal or emit no more than 0.0025 pounds of mercury per net GW.hr of electricity generated. The net quantity of electricity generated is calculated as a rolling average in both Phases 1 and 2. The Phase 1 standards are already being partially met with existing air pollution control devices, with no optimization for mercury control, at several MA coal-fired units. Existing technologies, such as activated carbon injection, are necessary for the Phase 2 standards (Smith, 2005). These new mercury standards will ultimately result in the reduction of about 70.3 kg (155 lbs) annually of mercury emissions from the four coal-fired plants (Massachusetts DEP, 2004). The Massachusetts DEP believes that this approach will achieve more certain reductions in mercury emissions than those proposed by the U.S. EPA on January 30, 2004 at a modest cost (Massachusetts DEP, 2001).

6.2.2 Jurisdictional Approaches – Western States

The Western Regional Air Partnership (WRAP) is a collaborative alliance of tribal governments, state governments, and various federal agencies. The state governments participating in the WRAP include Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. The WRAP deals with the implementation of the Grand Canyon Visibility Transport Commission's recommendations and with the development of technical and policy tools needed by western states and tribes to comply with the U.S. EPA's Regional Haze Rule regulations. The WRAP is jointly administered by the Western Governors' Association and the National Tribal Environmental Council. Although the WRAP does not sponsor research, WRAP committees and forums interact with the research community to incorporate critical information into their strategic planning initiatives (WRAP, 2004).

The WRAP has developed a backstop trading program as an emissions reduction strategy to improve visibility in areas of the Colorado Plateau. The backstop trading program is aimed at reducing SO_2 emissions. The SO_2 milestones establish the environmental goals of this program. As long as regional emissions of SO_2 from major stationary sources remain below these milestones, all of the reductions called for by this program will remain voluntary. However, if SO_2 emissions from stationary sources are in excess of any of the milestones the backstop trading program will be initiated to achieve the reductions and ensure future milestones are attained. The set of recommended regional emission reduction measures in the backstop trading program are aimed at achieving a 40 percent reduction of SO_2 emissions by year 2018. The program includes SO_2 emission reduction milestones for each year between years 2003 and 2018 with most of the reductions required between years 2013 and 2018. The backstop trading program will be reviewed in 2013 to ensure the reduction targets are being met (Halvey, 2004). At the moment, there is no provision among those in the Western Governors' Association (WGA) to extend controls to NO_x and mercury, outside of the ongoing discussion at the federal level.

The WGA, one of the groups that manage the WRAP, has adopted a resolution for clean and diversified energy for the West based on a successful WGA North American Energy Summit that was held in April 2004. By June 2006, governors of the western states will determine the feasibility of adding 30,000 MW of new clean energy generating capacity by year 2015 and improving the efficiency of energy usage by 20 percent by year 2020. A working group will assist the governors in developing recommendations concerning these proposals. The clean energy resources currently being pursued to reach the 30 000 MW objective are solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies (WGA, 2004).

7.0 FINDINGS AND RECOMMENDATIONS

1. Significant reserves of coal remain available in the United States and Canada. The estimated 6,578 million tonnes of coal reserves in Canada are predicted to have a life of 115 years based on 1998 production rates. U.S. data from 1997 estimate a reserve life of 250 years at current rates of usage, based on a recoverable reserve quantity of 250 billion tonnes of coal.

2. Given the extent of coal reserves available in these two countries and the relatively high and more volatile price of some alternative fuels such as oil and natural gas, electricity production by the combustion of coal will continue in the United States and Canada for some decades. This will be the case despite the most recent fluctuations in energy prices, and anticipated expansion in renewable energy sources.

3. Proven process and control technologies can be applied to the coal-fired utility sector to better quantify and significantly reduce, in a cost effective manner, current emissions of pollutants, particularly acid species and mercury, harmful to the health of the ecosystem, including humans. Such options include modified coal combustion techniques, enhanced emission controls, and further application of continuous emission monitors to the measurement of emissions of sulphur dioxide, nitrogen oxides, mercury and other pollutants. Further aggressive application of these technologies and processes is encouraged in keeping with the national and bilateral commitments of the two governments to further reduce harmful air pollution.

4. Expanded transfer of emission measurement and control technologies to emerging economies should be supported. Such action is crucial in southeast Asia and India, where many current coal-fired facilities operate without adequate, much less advanced, pollution control equipment. Rapid economic growth continues in these areas, along with substantial increases in the number of coal-fired utilities. Greater control of these sources would have local, regional, continental and global benefits.

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GLOSSARY

Acid Deposition: A complex chemical and atmospheric phenomenon that occurs when emissions of sulphur and nitrogen compounds (SO_2 and NO_x) and other substances are transformed by chemical processes in the atmosphere, often far from the original sources, and then deposited on earth in either wet or dry form. The wet forms, popularly called 'acid rain,' can fall to earth as rain, snow, or fog. The dry forms are acidic gases or particulates.

Activated Carbon: A highly adsorbent form of carbon used to remove odors and toxic substances from liquid or gaseous emissions. It is produced by heating carbon-rich material such as bituminous coal, wood, peat, or coconut shell in the absence of air which creates a highly porous adsorbent material. Activated carbon is found in two general forms including granular activated carbon and powdered activated carbon (see Powdered Activated Carbon). Through the process of sorption activated carbon removes pollutants from liquid or gaseous streams. Sorption includes the adsorption of a solute to the solid surface of the activated carbon and absorption where the solute diffuses into the interior surfaces of the activated carbon.

Atmospheric Deposition: Pollution from the atmosphere associated with dry deposition in the form of dust, wet deposition in the form of rain and snow, or as a result of vapor exchanges.

Baghouse Filter: Large fabric bag, usually made of glass fibers, used to eliminate intermediate and large particles. This device operates like the bag of an electric vacuum cleaner, passing the air and smaller particles while entrapping the larger ones.

Biomass: All of the living material in a given area; often refers to vegetation.

Boiler: A sealed vessel where water is converted to steam.

British Thermal Unit (BTU): A measure of heat energy; the amount needed to raise the temperature of one pound of water by one degree Fahrenheit.

Canadian Environmental Protection Act (CEPA): An act (1999) respecting pollution prevention and protection of the environment and human health in order to contribute to sustainable development. The CEPA has a list of toxic substances (in Schedule 1 of the Act). Environment Canada and Health Canada must propose an instrument to establish preventive control actions for managing these toxic substances to reduce or eliminate the risk to human health and the environment.

Cap and Trade: Cap and trade is a policy approach for controlling large amounts of emissions from a group of similar sources on a regional or national basis. The approach first sets an overall cap (see Emission Cap), or a maximum amount of emissions per compliance period. Sources covered by the program receive authorizations to emit in the form of emission allowances, with the total amount of allowances limited by the cap. Emission trading of these allowances is then permitted between different facilities for which the cap applies.

Clean Coal Technology (American definition): Any technology not in widespread use prior to the Clean Air Act Amendments of 1990. This Act will achieve significant reductions in pollutants associated with the burning of coal.

Co-benefit: The achievement of reduced emission levels of a specific pollutant by the use of a certain emission control technology despite the fact that the technology was designed to capture an alternate pollutant or group of pollutants.

Coal: A fossil fuel composed mostly of carbon, with traces of hydrogen, nitrogen, sulphur and other elements. It was formed from the remains of living matter millions of years ago.

Coal Bed Methane Extraction: A method of extracting methane from a deposit of coal that requires the drilling of wells into the deposit, and then the pumping out of water followed by the extraction of methane. The methane is compressed and piped to market. Disposal of the water, which may contain impurities such as salt poses an environmental problem as does the resulting lowering of the water table.

Cogeneration: The simultaneous production of power and thermal energy. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Heat and Power: see Cogeneration

Confidence Interval: An interval that provides the estimated range of values (calculated from a given set of sample data) that has the specified probability of containing the parameter being estimated. The width of the confidence interval gives some indication about the uncertainty about the unknown population parameter.

Continuous Emission Monitor (CEM): A device that provides continuous measurement of pollutants emitted into the atmosphere in exhaust gases. Real-time CEMs can provide immediate feedback on how variations in combustion parameters affect pollutant formation and/or destruction.

Demand Side Management: Utility-sponsored programs to influence the time of use and amount of energy use by select customers.

Electrostatic Precipitator (ESP): A device that removes particles from a gas stream after combustion occurs. ESPs may be classified as either wet or dry. In a dry ESP an electrical charge is imparted to the particles, causing them to adhere to metal plates inside the precipitator. Rapping on the plates causes the particles to fall into a hopper for disposal. Wet ESPs contain tubes which are flushed periodically. In a dry ESP the particles are usually removed from the hopper by a rotary screw arrangement while in a wet ESP the hoppers are designed to gravity drain or pump the water used for flushing to a treatment facility.

Emission Inventory: A listing, by source, of the amount of air pollutants discharged into the atmosphere of a community; used to establish emission standards.

Emission Standard: The maximum amount of air polluting discharge legally allowed from a single source, mobile or stationary.

Fabric Filter: A cloth device that catches dust particles from industrial emissions.

Flue Gas: The air coming out of a chimney after combustion in the burner it is venting. It can include nitrogen oxides, carbon oxides, water vapor, sulphur oxides, particles and many chemical pollutants.

Flue Gas Desulphurization: A technology that employs a sorbent, usually lime or limestone, to remove sulphur dioxide (SO_2) from the gases produced by burning fossil fuels

Flyash: Non-combustible residual particles expelled by flue gas.

Fossil Fuel: Fuel derived from ancient organic remains; e.g. peat, coal, crude oil, and natural gas.

Fuel Cell: An electrochemical device that continuously changes the chemical energy of a fuel (hydrogen) and oxidant (oxygen) directly to electrical energy and heat, without combustion. The electrical process causes hydrogen atoms to give up their electrons. It is similar to a battery in that it has electrodes, an electrolyte, and positive and negative terminals. It does not, however, store energy as a battery does.

Fuel Efficiency: The proportion of energy released by fuel combustion that is converted into useful energy.

Gasification: Conversion of solid material such as coal into a gas for use as a fuel.

Generating Capacity: The greatest load that can be supplied by a generating unit, power facility, or entire provincial or state grid system.

Geothermal: Pertaining to heat energy extracted from reservoirs in the earth's interior, as in the use of geysers, molten rock and steam spouts.

Gigawatt (GW): An electric unit of power; one gigawatt equals one billion (1,000,000,000) watts and one million (1,000,000) kilowatts. The unit of gigawatts is useful for describing the capacity of large electrical energy systems.

Gigawatt hour (GW.hr): A unit of energy equal to one billion watts used per hour or one million kilowatts used per hour.

Gross Domestic Product (GDP): The total market value of goods and services produced by a nation within that nation in a single year.

Kilowatt (kW): An electric unit of power; one kilowatt equals 1,000 watts.

Kilowatt hour (kWh): The basic unit of energy equal to one kilowatt of power used for one hour. The amount of electricity sold or consumed is measured in kilowatt hours. The average Canadian household uses approximately 7,000 kilowatt hours per year.

Maximum Available Control Technology (MACT): The emission standard for sources of air pollution requiring the maximum reduction of hazardous emissions, taking cost and feasibility into account. Under the Clean Air Act Amendments of 1990, the MACT must not be less than the average emission level achieved by controls on the best performing 12 percent of existing sources, by category of industrial and utility sources.

Megawatt (MW): An electric unit of power, one megawatt equals one million (1,000,000) watts.

Municipal Solid Waste: Common garbage or trash generated by industries, businesses, institutions, and homes.

Ozone (O_3): A chemical oxidant and major component of photochemical smog. It can seriously impair the respiratory system. Ozone (in the troposphere) is produced through complex chemical reactions of nitrogen oxides (NO_x), which are among the primary pollutants emitted by combustion sources; hydrocarbons, released into the atmosphere through the combustion, handling and processing of petroleum products; and sunlight.

Pollutant: Generally, any substance introduced into the environment that adversely affects the usefulness of a resource or the health of humans, animals, or ecosystems.

Powdered Activated Carbon: One of the two forms of activated carbon (see Activated Carbon). Powdered activated carbon is composed of particles smaller than 0.8 mm in size.

Scrubber: An air pollution device that uses a spray of water or reactant or a dry process to trap pollutants in emissions.

Slurry: A watery mixture of insoluble matter resulting from some pollution control techniques.

Smelter: A facility that melts or fuses ore, often with an accompanying chemical change, to separate its metal content. Emissions cause pollution. "Smelting" is the process involved.

Solar Photovoltaic: Semiconducting materials are used to convert sunlight directly into electricity (direct current (dc)).

Sorbent: An insoluble material or mixture of materials used to recover liquids through the mechanism of absorption, or adsorption, or both.

Technology Transfer: The process of converting scientific findings from research into useful products by the commercial sector.

Turbine: A machine with propeller-like blades that are moved by the force of water or gas (including steam), thereby rotating a component in a generator to produce electricity.

Two-Staged Combustion: Also referred to as the method of air staging it involves part of the combustion air being introduced after the after the main combustion zone. This reduces the level of available oxygen in zones where it is critical for NO_x formation, thus achieving NO_x reductions. The primary combustion is operated in a fuel-rich zone and the secondary air of over-fire-air required to complete the combustion process is introduced downstream of the main firing zone.