

2.0 Canada's Coal-fired Power Industry

2.1 Canadian Mercury control regulations and policies

The Canadian Council for Ministers of Environment (CCME) is committed to reduction in mercury emission from coal-fired power stations. In October 2006 the CCME endorsed the *Canada wide standards for Mercury Emissions from Coal-fired Power Stations* (the "CCME Standards"). These standards include numerical targets and timeframes for mercury reduction, schedules for implementation by province, as well as schedules for reporting and review. Targets include a national 60% reduction in mercury emissions by 2010, and emission limits on new plants based on best available technology. 2010 Emission caps by province are identified in Table 2-1 (from CCME 2009).

Table 2-1. CCME Standards mercury emissions caps for 2010.

Province	2008 Mercury Emissions	2010 cap
Alberta	481 kg	590 kg
Saskatchewan	648 kg	430 kg (early actions to be used to meet cap)
Manitoba	9.6 kg	20 kg
Ontario	191 kg	Under discussion*
New Brunswick	41 kg	25 kg
Nova Scotia	161 kg	65 kg
Total	1532 kg	1130*

*Ontario cap to be added to total

Source: CCME 2009

A second phase of the CCME Standards may explore a further reduction to 80% reduction in mercury emissions from 2018 onwards.

In addition to the CWS, the CCME published the *Monitoring Protocol in Support of the Canada wide standards for Mercury Emissions from Coal-Fired Power Stations* (CCME July 2007). The CCME Monitoring Protocol outlines acceptable methods for monitoring mercury emissions, as well as requirements for record keeping, reporting, and QA/QC. Appendix A of the CCME Monitoring Protocol provides calculations for calculating mercury emissions from either continuous mercury emissions monitoring systems (CMMS) data or based on the mass balance approach.

2.2 Alberta

Alberta Regulation 34/2006 *Mercury Emissions from Coal-Fired Power Plants Regulation* requires that approval holders (coal-fired power plants) must, by January 1, 2010, have installed mercury control equipment to achieve a minimum capture of 70%. The Alberta regulation applies to all existing power plants except the Keephills 3 power plant (under construction) that has to capture 75% of the Hg or a limit of 8kg/TWh.

2.2.1 ATCO Power

2.2.1.1 Battle River Generating Station

ATCO Power's Battle River Generating Station has three units totalling 730 MWs. Unit 3 commissioned in 1969 is 160 MW, Unit 4 commissioned in 1975 is 165 MW and Unit 5 commissioned in 1981 is 405 MW (Table 2-1).. All units have cold-side ESPs and burn subbituminous coal from the Paintearth Mine at a rate of about 400 tonnes coal per hour at full load on all three units. There is no NO_x or SO₂ control on any of the units. Fly ash is handled dry and land-filled or sold. Bottom ash is handled wet and land-filled. The annual mercury emissions from 2008 were 66.91 kg, and the rate of capture was 27.1% (CCME, 2008). The Battle River Generating Station sells its flyash to ASHCOR technologies for reuse in the cement industry and unsold flyash and all bottom ash are disposed of at designated ash disposal sites (CCME, 2008).

2.2.1.2 Sheerness Generating Station

The Sheerness Generating Station has two units totalling 816 MWs. Unit 1 was commissioned in 1985 and unit 2 commissioned in 1990. Both are 408 MW and have cold-side ESPs. The Sheerness plant burns subbituminous coal from the Sheerness mine. Fly ash is handled dry and land-filled or sold. Bottom ash is handled wet and land-filled. There is no NO_x or SO₂ control on the units. The station burns 480 tonnes of coal per hour when operating at full load. Historically 24% of the Hg in the coal is captured in the ash. The annual mercury emissions from 2008 were 89.7 kg, with a rate of capture of 29.4% (CCME, 2008). CCME (2008) report 80,192 tonnes of fly ash was sold for use in concrete manufacturing with the remaining ash sent to the ash management site.

2.2.2 Capital Power

2.2.2.1 Genesse Generating Station

The Genesse generating station has two 410 MW Units, Unit 1 built in 1994 and Unit 2 built in 1989. A third unit owned jointly by Capital Power and TransAlta Utilities Corp will be discussed separate from these units. Both have cold-side ESPs and burn subbituminous coal from the Genesse mine. The annual mercury emissions from 2008 were 75.11 kg, and the rate of capture was 40.6% (CCME, 2008). Fly ash is handled dry and land-filled or sold and bottom ash is handled wet and land-filled. Approximately 25 – 30 % of the Hg is removed naturally in the

ESP. CCME (2008) report 184,242 tonnes of fly ash and 14,442 tonnes of bottom ash were sold with the remaining ash returned to the mine.

2.2.2.2 Genesse Unit 3 Generating Station

Genesse Unit 3 Generating Station jointly owned by Capital Power and TransAlta Utilities Corporation is a 495 MW unit built in 2005. It has a super critical boiler which provides enhanced thermal efficiency, state of the art low NO_x burners, lime spray-dryer absorbers for SO₂ control and a fabric filter baghouse for particulates. Testing on Genesse Unit 3 showed 98% of the Hg emitted was in the elemental form. The annual mercury emissions from 2008 were 29.72 kg, and the rate of capture was 52.7% (CCME, 2008). A full scale activated Carbon Injection Demonstration run July 26 to September 2 was conducted at the station (CCME, 2008). Fly ash is handled dry and land-filled while bottom ash is handled wet and land-filled. CCME (2008) report both fly ash and bottom ash are returned to the mine.

2.2.3 Milner Power

The Milner Power generating station has a 150 MW unit commissioned in 1972. It has a fabric filter baghouse for particulate collection and does not have NO_x or SO₂ control. Fly ash is handled dry and land-filled or sold and bottom ash is handled wet and land-filled. The station burns cleaned bituminous coal from Coal Valley and raw bituminous coal from the Grande Cache mine. Mercury emissions for the 2005 to 2008 period range are estimated at 5.1 kg or less (Triton 2009).

2.2.4 TransAlta Utilities

2.2.4.1 Sundance Generating Station

The Sundance Generating Station consists of six units totalling 2152 MW. The first unit was built in 1970 and the final unit in 1980. Unit six was ungraded from 387 to 427 MW. The station burns low sulphur subbituminous coal from the Highvale mine. All units have cold-side ESPs and no NO_x or SO₂ control. Fly ash is handled dry and land-filled or sold and bottom ash is handled wet and land-filled. Test results indicated that the speciation of Hg in the flue gas is approximately 80% elemental Hg. The station burned 8,986,208 tonnes of coal in 2006. Approximately 75% of the ash is fly ash and 25% bottom ash. Mercury emissions from 2008 were 153.9 kg, with a capture rate of 43.2% (CCME, 2008). CCME (2008) report 328,871 tonnes of fly ash was sold with the remaining ash returned to the mine. Units built as follows:

- Unit 1 built in 1970 - 300 MW
- Unit 2 built in 1973 – 300 MW
- Unit 3 built in 1976 – 375 MW
- Unit 4 built in 1977 – 375 MW
- Unit 5 built in 1978 – 375 MW
- Unit 6 built in 1980 – 387 MW – unit upgraded by 40 MW

2.2.4.2 Keephills Generating Station

Keephills 1 and 2

Keephills Generating Station consists of two units (403 MW each) totally 806 MWs. Unit 1 was built in 1983 and Unit 2 in 1984. Both units have cold-side ESPs and no NO_x or SO₂ control. The station burns subbituminous coal from the Highvale mine. Sundance units 5 & 6 were used as a proxy for the Keephills generating station and all coal and fly ash data is as per the Sundance plant. Fly ash and bottom ash are handled wet and land-filled. CCME (2008) report the bottom ash and fly ash is slurried to the ash lagoon. The station burned approximately 3,442,519 tonnes of coal in 2006 and the average Hg in the coal was 47 ppb. CCME (2008) report the mercury emissions from 2008 was 22.2 kg, with a capture rate of 79.0%. An enhanced activated carbon injection for mercury removal was installed at Keephills Unit 2 from August 2007 to October 2008 (CCME, 2008).

Keephills 3

Keephills Unit 3 Generating Station under construction is scheduled for commissioning in 2011. It is jointly owned by TransAlta Utilities Corporation and Capital Power. The Unit is a 495 MW super critical boiler with high thermal efficiency. It has low NO_x burners for NO_x control, a Spray-Dry Absorber (SDA) for SO₂ control and a fabric filter baghouse. Fly ash will be handled dry and land-filled and bottom ash will be handled wet and land-filled. Brominated AC will be injected into the flue gas stream between the boiler and the spray-dry absorber, likely at the inlet to the air heater before the SDA.

2.2.4.3 Wabamun Generating Station

The last unit at the Wabamun generating station, Unit 4, a 300 MW unit was shutdown on March 31, 2010.

2.3 New Brunswick

New Brunswick, through the Canada Wide Standards (CWS) has committed to reducing mercury emissions from its coal-fired power plants to 25 kg per year by 2010 (CCME, 2010).

2.3.1 New Brunswick Power

2.3.1.1 Grand Lake

Ceased operation February 28, 2010,

2.3.1.2 Belledune

The 457 MW (name plate capacity) Belledune Generating Station began operation in 1993 is the only operating coal-fired thermal plant in the province. Belledune Unit 2 burns primarily

subbituminous coal, with Pet Coke as a secondary fuel (Table 2-2). The station has low NO_x burners, wet FGD and CS-ESP. It burns low mercury subbituminous coal (82% - 2002) with Pet Coke (18% - 2002) as a secondary fuel. CCME (2008) report annual mercury emissions from the combined Grand Lake and Belledune units at 41 kg for 2008. Fly ash generated by the plant is collected dry and either land-filled or sold. Bottom ash is collected wet and land-filled.

Table 2-2. Mercury emissions for Canadian coal-fired generation units.

Power station	Gross cap. MW	Coal type	AP Controls			Ash Sale	Stack test data				Avg % Hg capture
			NO _x	SO ₂	PM		Coal Hg, dppm	Hg Emissions Speciation %			
								Hg ⁰	Hg ²⁺	Hg (p)	
Alberta											
H.R. Milner											
Unit 1	150	sub-bit			FF	YES	0.018	21.4%	77.4%	1.2%	87%
Battle River											
Unit 3	160	sub-bit			CS-ESP	YES	0.394	73.5%	26.2%	0.13%	27.1%
Unit 4	165	sub-bit			CS-ESP	YES	0.394	73.5%	26.2%	0.13%	27.1%
Unit 5	405	sub-bit			CS-ESP	YES	0.394	79.7%	20.1%	0.28%	27.1%
Sheerness											
Unit 1	408	sub-bit			CS-ESP	YES	0.061	69.7%	30.0%	0.30%	29.4%
Unit 2	408	sub-bit			CS-ESP	YES	0.061	69.7%	30.0%	0.30%	29.4%
Genesee											
Unit 1	410	sub-bit	LNB		CS-ESP	YES	0.045	67.9%	31.1%	0.05%*	40.6%
Unit 2	410	sub-bit	LNB		CS-ESP	YES	0.045	67.9%	31.1%	0.05%	40.6%
Unit 3	495	sub-bit	LNB	d-FGD	FF	YES	0.042	99.3%	47.0%	0.3%*	52.7%
Sundance											
Unit 1	300	sub-bit			CS-ESP	YES	0.039	77.2%	22.6%	0.26%	35.6%
Unit 2	300	sub-bit			CS-ESP	YES	0.039				
Unit 3	375	sub-bit			CS-ESP	YES	0.039				
Unit 4	375	sub-bit			CS-ESP	YES	0.039	86.0%	11.5%	3.0%**	52.6%
Unit 5	375	sub-bit			CS-ESP	YES	0.039	94.9%	5.1%	0.3%*	44.2%
Unit 6	427	sub-bit			CS-ESP	YES	0.039				
Wabamun											
Unit 4	300	sub-bit			HS-ESP	YES	0.000	decommissioned			
Keephills											
Unit 1	403	sub-bit			CS-ESP	NO	0.039	76.0%	23.8%	0.12%**	79.0%
Unit 2	403	sub-bit			CS-ESP	NO	0.039	86.2%	13.3%	0.46%*	79.0%
Saskatchewan											
Boundary Dam											
Unit 1	66	lig.	OFA		CS-ESP		NO	83.6%	16.7%	<0.1%	7.5%
Unit 2	66	lig.	OFA		CS-ESP		NO	83.6%	16.7%	<0.1%	12.5%
Unit 3	150	lig.	OFA		CS-ESP		NO				2.8%
Unit 4	150	lig.	OFA		CS-ESP		NO				2.5%
Unit 5	150	lig.	OFA		CS-ESP		NO	83.3%	16.7%	<0.1%	5.6%
Unit 6	293	lig.	OFA		CS-ESP		NO	80.1%	18.1%	1.80%	6.8%
Poplar River											
Unit 1	310	lig.	OFA		CS-ESP		NO	60.4%	39.2%	0.40%	35.2%
Unit 2	305	lig.	OFA		CS-ESP		NO	93.0%	6.9%	0.06%	3.8%
Shand											
Unit 1	305	lig.	LNB	LIFAC	CS-ESP		YES	83.6%	16.7%	<0.1%	12.5%

Power station	Gross cap. MW	Coal type	AP Controls			Ash Sale	Stack test data				Avg % Hg capture
			NO _x	SO ₂	PM		Coal Hg, dppm	Hg Emissions Speciation %			
								Hg ⁰	Hg ²⁺	Hg (p)	
Manitoba											
Brandon											
Unit 5	105	sub-bit			CS-ESP	NO	0.063	89.0%	11.0%		9.7%
Ontario											
Atikokan											
Unit 1	230	lig.	LNB		CS-ESP	YES	0.082				
Lambton											
Unit 1	505	bit	LNB		CS-ESP	NO	0.052	71.0%	20.0%	1.00%	
Unit 2	505	bit	LNB		CS-ESP	NO	0.052	75.0%	24.0%	0.04%	
Unit 3	505	bit	LNB, SCR	w-FGD	CS-ESP	NO	0.052	64.0%	34.0%	3.00%	
Unit 4	505	bit	LNB, SCR	w-FGD	CS-ESP	NO	0.052	84.0%	15.0%	1.00%	
Nanticoke											
Unit 1	564	sub-bit/bit	LNB	LS-Coal	CS-ESP	YES	0.062				
Unit 2	564	sub-bit/bit	LNB	LS-Coal	CS-ESP	YES	0.000	54.3%	45.6%	1.00%	
Unit 3	564	sub-bit/bit	LNB	LS-Coal	CS-ESP	YES	0.000	36.7%	50.8%	12.50%	
Unit 4	564	sub-bit/bit	LNB	LS-Coal	CS-ESP	YES	0.000				
Unit 5	564	sub-bit/bit	LNB	LS-Coal	CS-ESP, FGC	YES	0.067	36.3%	44.5%	19.20%	
Unit 6	564	sub-bit/bit	LNB	LS-Coal	CS-ESP	YES	0.000	52.9%	43.0%	4.10%	
Unit 7	564	sub-bit/bit	LNB, SCR	LS-Coal	CS-ESP	YES	0.000	23.6%	76.0%	0.40%	
Unit 8	564	sub-bit/bit	LNB, SCR	LS-Coal	CS-ESP, FGC	YES	0.000				
Thunder Bay											
Unit 2	163	sub-bit/ lig.			HS-ESP	YES	0.085	91.0%	9.0%	0.00%	
Unit 3	163	sub-bit/ lig.			HS-ESP	YES	0.062	96.0%	4.0%	0.00%	
New Brunswick											
Belledune											
Unit 2	457	sub-bit	LNB	w-FGD	CS-ESP	YES	0.000				
Grand Lake											
Unit 8	Decommissioned										
Nova Scotia											

Power station	Gross cap. MW	Coal type	AP Controls			Ash Sale	Stack test data				Avg % Hg capture
			NO _x	SO ₂	PM		Coal Hg, dppm	Hg Emissions Speciation %			
								Hg ⁰	Hg ²⁺	Hg (p)	
Lingan											
Unit 1	150	bit	OFA		CS-ESP	YES	0.057				
Unit 2	150	bit	OFA		CS-ESP	YES	0.057				
Unit 3	150	bit	OFA		CS-ESP	YES	0.057				
Unit 4	150	bit	OFA		CS-ESP	YES	0.057				
Point Aconi											
Unit 1	186	bit	inherent	inherent	FF	YES	0.020				
Point Tupper											
Unit 2	150	bit	OFA		CS-ESP	YES	0.064				
Trenton											
Unit 5	150	bit	-		CS-ESP	YES	0.109				
Unit 6	160	bit	LNB		CS-ESP	YES	0.109				

*2009 data; **2008 data

2.4 Nova Scotia

There are four coal-fired power generation plants in Nova Scotia, which are regulated under the Air Quality Regulations through a fleet-wide cap. The CWS target for mercury emissions set the cap at 65 kg for 2010 (CCME, 2008).

2.4.1 Nova Scotia Power Inc.

2.4.1.1 Lingan Generating Station

The Lingan Generating Station consists of four 150 MW units commissioned between 1979 and 1984. They all have over-fire air and cold-side ESPs. There is no SO₂ control. In addition Nova Scotia Power recently installed activated carbon injection on all the units. The station burns bituminous coal and small amounts of petroleum coke in a variety of blends at each unit. The majority of the coal is imported from South America and the United States. Fly ash is handled dry and bottom ash is handled wet. The annual mercury emissions from 2008 were 95 kg (CCME, 2008).

2.4.1.2 Point Aconi Generating Station

The Point Aconi Generating Station has one 165 MW unit (name plate capacity 186 MW). Built in 1994, it is a fluidized bed combustor built for NO_x and SO₂ control. The station has a fabric filter baghouse for particulate control. Point Aconi station is the only one without activated carbon injection system as it is considered a low mass emitter. The station burns bituminous coal and small amounts of petroleum coke in a variety of blends. Fly ash and bottom ash is handled dry and land-filled. The annual mercury emissions from 2008 were 2.9 kg (CCME, 2008).

2.4.1.3 Point Tupper Generating Station

The Point Tupper generating station has one 150 MW unit built in 1973 that was converted to coal in 1986. It has a cold-side ESP, over fire air for NO_x control and no SO₂ control. The station burns bituminous coal and some small amounts of petroleum coke in a variety of blends. The majority of the coal is imported from South America and the United States, as well as some domestic coal. Fly ash and bottom ash are land-filled. The annual mercury emissions from 2008 were 24 kg (CCME, 2008).

2.4.1.4 Trenton Generating Station

The Trenton generating station has two units, Unit 5 is 150 MWs built in 1969 and Unit 6 is 160 MWs built in 1991. Both units have cold-side ESPs and Unit 6 has low NO_x burners. There is no SO₂ control on either unit. The station burns bituminous coal with some petroleum coke similar to the rest of the stations. Fly ash is handled dry for both units however no information on how the fly ash is disposed of has been found. Bottom ash for Unit 5 is handled dry and for Unit 6 is handled wet, however again no information has been provided on how the bottom ash is

disposed of. Mercury emissions are approximately 52.0 kg per year based on data provide to the CEA program. The annual mercury emissions from 2008 were 40 kg (CCME, 2008).

2.5 Manitoba

Section 16 of the *Climate Change and Emissions Reductions Act* (enacted June 2008) phased out the use of coal-fired generation by Manitoba Hydro, except in “support of emergency operations.” The *Coal-Fired Emergency Operations Regulation MR 186/2009* restricts Brandon Unit 5 operations to “support of emergency operations” or when Manitoba is experiencing drought conditions.

2.5.1 Manitoba Hydro

2.5.1.1 Brandon Generating Station Unit 5

With the conversion of the Selkirk Generating Station to natural gas in 2002, Unit 5 of Manitoba Hydro’s Brandon Generating Station is the only operating coal-fired power unit in Manitoba. Commissioned Oct 1, 1970, the 105 MW Brandon plant is slated to be operational until 2019. Brandon Unit 5 burns subbituminous PRB coal, sourced from southern Montana (Spring Creek Mine). The unit does not employ NO_x or SO₂ control. Particulate matter (PM) control is via a cold-side electrostatic precipitator (Table 2-1). Fly ash is handled wet and land-filled. Bottom ash is handled wet and land-filled. Mercury emissions in 2001 were 8.9 kg annually.

CCME (2008) report annual emissions of total mercury from 2008 were 9.575 kg via the air and 0.750 kg in the ash. The capture rate in 2008 was 9.68%, however this is not a requirement of the Manitoba facility as it is not a new generating unit (CCME, 2008). Coal combustion residues are sent to an ash lagoon for storage (CCME, 2008).

2.5.1.2 Selkirk Generating Station

The Selkirk Generating Station was converted to natural gas in July 2002.

2.6 Ontario

Ontario has four operating coal-fired electric generating stations and is legally required by Ontario Regulation 496/07 *Cessation of Coal Use – Atikokan, Lambton, Nanticoke and Thunder Bay Generating Stations*. to phase out coal use at all four stations by the end of 2014 (CCME, 2008). In order to achieve this, a series of measures have been initiated and include the phasing out of the four units in 2010 (CCME, 2008). Ontario Power Generation (OPG) is planning to convert some units to burn biomass provided they secure board and government approval.

CCME (2008) report that since the 2003 baseline year, Ontario has reduced is mercury emissions from coal-fired electric power generation plants by 60%. The Lakeview unit was closed in 2005 and Ontario will not be initiating any new coal-fired electric power generation stations (CCME, 2008).

2.6.1 Ontario Power Generation

2.6.1.1 **Atikokan Generating Station**

The Atikokan Generating Station has one 230 MW unit built in 1985 at a cost of \$742 million. The station burns a low sulphur lignite coal from Western Canada. Fly ash is handled dry and either land-filled or sold. Bottom ash is handled dry and land-filled. The station has a cold-side ESP and low NO_x burners but there is no SO₂ control. Mercury emissions from 2008 were 18 kg (CCME, 2008). Ontario Power Generation is conducting some testing of biomass fuel (which is carbon neutral) to replace coal at the station. Fly ash was sold to the cement making and concrete industries, and the remainder was land filled on site (CCME, 2008).

2.6.1.2 **Lambton Generating Station**

The Lambton Generating Station has four 505 MW units for a total of 2020 MW capacity. Unit 2 was built in 1969 and Units 1, 3 and 4 were built in 1970. The station burns a low sulphur bituminous coal from Western Canada or the Eastern US (approximately 99%) and Petroleum Coke from Western Canada (less than 1%). All units have cold-side ESPs and low NO_x burners. Flue Gas Desulphurization (FGD) and selective catalyst reduction (SCR) was installed on Units 3 & 4 at a cost of \$500 million. Both fly ash and bottom ash are handled dry and land-filled. Units 1 & 2 are scheduled for decommissioning in late 2010, as per OPG statement Sept. 3, 2009*. The annual mercury emission from 2008 was 58 kg (CCME, 2008). CCME (2008) report that bottom ash was sold as a gravel substitute and gypsum was sold into the wallboard industry, and fly ash was land filled on site in 2008.

* <http://www.news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html>

2.6.1.3 **Nanticoke Generating Station**

The Nanticoke Generating Station consists of eight 564 MW units totalling 4512 MW. The units were built between March 1973 and December 1978. All units have cold-side ESPs and low NO_x burners. In addition Unit 5 has over fire air (OFA) and Units 7 and 8 has selective catalyst reduction (SCR) installed in 2003. Initial cost of the station was \$800 million and the upgrades have cost an additional \$900 million. The station burns both bituminous coal and Powder River Basin subbituminous coal. Fly ash is handled dry and either land-filled or sold. Bottom ash is handled wet and either land-filled or sold. Units 3 & 4 are scheduled for decommissioning in late 2010 as per OPG announcement Sept 3, 2009*. Annual mercury emissions from 2008 were 84 kg which is lower than from previous years due to a decrease in mercury concentration in subbituminous coal (CCME, 2008). The fly ash and bottom ash was sold to the cement making and concrete industries, and the remainder was land filled on site in 2008 (CCME, 2008).

* <http://www.news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html>

2.6.1.4 Thunder Bay Generating Station

With the retirement of Unit 1 at the Thunder Bay Generating Station has two remaining units totalling 326 MW. Unit 1 built in 1963 at a cost of \$27 million, was a 100 MW unit that was retired in 1984. In 1981 Unit 2 was built followed by Unit 3 in 1982. Both Units 2 and 3 are 163 MW units for a total plant capacity of 326 MW and cost \$345.4 million. The station burns both a low sulphur lignite coal (0.6% S) and a low sulphur PRB coal (0.4% S) from the Western United States. The split is 75 % lignite coal to 25 % PRB coal. Fly ash is handled dry and goes to land-fill or sales. Bottom ash is handled wet and goes to land-fill. The station has hot-side ESPs but no NO_x or SO₂, controls. The annual mercury emissions from 2008 were 31 kg (CCME, 2008). The fly ash was sold to the cement making and concrete industries, and the remainder was land filled on site in 2008 (CCME, 2008).

2.7 Saskatchewan

Saskatchewan's approach to mercury emission management is to incorporate Canada Wide Standards into operating permits issued pursuant to its *Clean Air Act* and *Clean Air Regulations*. As well, Saskatchewan Environment and SaskPower have entered into a memorandum of understanding with the general objective of achieving "harmony between the environment and industrial operations of SaskPower (CCME 2006)."

2.7.1 SaskPower

2.7.1.1 Mercury control research and development

SaskPower has carried out significant research and development on mercury over the years, some of the mercury control activities include (CCME, 2008):

- SaskPower's Emission Control Research Facility, which has established a mercury capture rate of 75% at Poplar River Power Station, received a national stewardship award in 2008;
- A commercial system including full-scale injection of enhanced activated carbon into the electrostatic precipitator was installed for both the Poplar River units and handed over to the plant on June 5, 2009 making it the first permanent utility mercury control system in Canada;
- 43 kg of mercury was recovered from mercury switches and thermostats in 2008 with 29.5 kg eligible as an offset toward the CWS for mercury emissions requirement. Additional credits have been achieved as a result of mercury captured from Poplar River Power Station.
- Collaboration with lignite burning facilities in North Dakota to get various tests done on coal; and
- Investigation of several coal treatment approaches in order to remove significant amounts of mercury and other pollutants from lignite coal.

2.7.1.2 Poplar River Generating Station

The Poplar River Generating Station began with the construction of the 305 MW Unit 2 in 1981. That was followed in 1983 with Unit 1 at 310 MW. The station burns Saskatchewan lignite coal and is the location of the SaskPower Mercury Project. Both units have cold-side ESPs and some NO_x control. Both fly ash and bottom ash are handled wet and land-filled. Full scale mercury control has been installed on both units. It consists of brominated activated carbon injection (BACI). CCME (2008) report mercury emissions from 2008 at 239.13, with a capture rate from Unit 1 at 2.24% and Unit 2 at 35.18%.

SaskPower has conducted an extensive research and development program to improve the technologies used to control the mercury emissions from their units. The work conducted has applications to other Canadian utilities that emit mainly elemental mercury, which is in contrast to US coal plants where flue gas mercury can have a significant fraction of oxidized mercury (CCME, 2008). At the Poplar River Generating Station, SaskPower commissioned an Emissions Control Research Facility (ECRF) where selected technologies are assessed for their capability to remove mercury from a slipstream of Poplar River's flue gas (CCME, 2008).

2.7.1.3 Shand Generating Station

The Shand Generating Station began operation in 1992 and is a single 305 MW unit. The station burns a Saskatchewan lignite coal and at the time of construction installed an advanced SO₂ control system (LIFAC). The station has a cold-side ESP and low NO_x burners. Fly ash is handled dry and goes to land-fill or sales. Bottom ash is also handled dry and goes to land-fill. Although it has no mercury control, it is likely the next SaskPower station to install mercury control. CCME (2008) report mercury emissions from 2008 at 115 kg, with a capture rate of 3.8%.

2.7.1.4 Boundary Dam Generating Station

The Boundary Dam Generating Station was the first coal-fired power plant built by SaskPower. The first unit went commercial in 1959 and the last unit in 1978 for a total of 875 MW. Units 1 & 2 are 66 MW each, Units 3, 4 and 5 are 150 MW each and Unit 6 is 293 MW. The station burns Saskatchewan lignite coal. All the units have cold-side ESPs. There is no SO₂ control. The literature indicates that there is some type of NO_x control on units 2 to 6 but it has not been identified. Fly ash is handled wet and goes to land-fill or sales. Bottom ash is handled wet and goes to land-fill. CCME (2008) reports mercury emissions and capture rates from 2008 for all 6 units, which includes the following:

<u>Unit No.</u>	<u>Emission (kg)</u>	<u>Capture (%)</u>
1	25	7.48
2	23	12.47
3	50	2.82
4	48	2.51
5	54	5.55
6	93	6.81

3.0 Mercury Control Technology

3.1 Technical Considerations

3.1.1 Coal types and mercury speciation

Coal is a composite of organic and inorganic matter formed over time through deposition of vegetation and other organic matter. Coal is broadly classified into four types with anthracite ranking highest in energy content, followed by bituminous, subbituminous, then lignite. Other physical properties of coal include: carbon content, ash content, chlorine content, sulphur content, and moisture content. Table 3-1 summarizes general physical properties of the four major coal types.

Table 3-1. Characteristics of coal used by Canadian utilities.

Type	HHV, MJ/kg (range)	% Ash (range)	% Moisture (range)	%S (range)	Cl PPM (range)	Hg in Coal, PPM (range)
Bituminous	31.283 (27.814-33.726)	9.38% (2.74%- 18.44%)	8.95% (7.84%- 10.51%)	2.51% (1.06%- 5.11%)	478.3 (335- 870)	0.0615 (0.02 – 0.109)
Sub-bituminous	22.307 (13.025- 30.142)	18.51%?? (5.50%- 31.3%)	19.94% (10.84%- 24.60%)	0.42% (0.02%- 2.15%)	104.1 (19- 297)	0.1015 (0.018- 0.3935)
Lignite	15.953 (13.284- 24.25)	13.66% (13.47%- 14.99%)	33.53% (32.13%- 37.58%)	0.57% (0.56%- 0.60%)	23 (“low” – 23)	0.1847 (0.066- 1.092)
Sub-bit./bit.	27.715 (27.715)	8.61% (7.12%- 10.09%)	18.20% (7.94%- 28.46%)	0.69% (0.34%- 1.04%)	67.5 (62- 73)	0.0645 (0.062- 0.067)
Sub-bit./lignite	24.861 (24.861)	9.72% (5.36%- 14.08%)	18.76% (4.59%- 32.92%)	0.55% (0.45%- 0.65%)	18.5 (18- 19)	0.0735 (0.062- 0.085)

Source: Canadian Electricity Association, Mercury Program, 2002 - 2004

3.1.1.1 Mercury in coal

Mercury exists in a number of physical and chemical forms in the environment. Physically, mercury can occur as a liquid, gas, or bound physically to particles. Chemically, mercury exists in three oxidation states: elemental (Hg^0), mercurous ion (Hg_2^{2+}), and mercuric ion (Hg^{2+}). Ionic mercury forms complexes with other compounds, such as oxygen (mercuric oxide, HgO).

Mercury is found in trace quantities in coal and some other fossil fuels. Common forms of mercury in coal include elemental mercury (Hg^0), mercuric oxide (HgO) mercuric chloride (HgCl_2), and mercury sulphide (HgS). Upon combustion, elemental mercury and its compounds are volatilized into the gas exhaust stream. The extent and nature of mercury emissions depends on a number of characteristics including the content of mercury, sulphur, and chlorine in the coal; the burner type, plant operating conditions; and design and type of criteria air contaminant treatment systems (SO_2 , NO_x , and particulate matter) (Brown *et. al* 1999 from SENES 2002).

3.1.1.2 Mercury speciation in flue gas

The distribution of mercury speciation in the flue gas influences the extent by which mercury can be removed using criteria air contaminate control equipment or specialized mercury removal technologies. During combustion, mercury in coal is volatilized to elemental mercury. As the flue gas cools the mercury is converted into three general species: elemental (Hg^0), gaseous oxidised (Hg^{2+}), and particle-bound (Hg^p). Gaseous oxidized species (or ionic) species, such as mercuric chloride (HgCl_2) dissolve in water and can be collected through wet desulphurization equipment and by particle control devices, such as electrostatic precipitators or fabric filters (Yang et. al 2007). Particle-bound mercury, including HgO and HgS , are solids at flue gas temperature, and are collected using particulate control devices (SENES 2002).

Elemental mercury (Hg^0) is difficult to capture by conventional air contaminate control devices both because it does not dissolve in water and it remains in a vapour state at typical flue gas operating temperatures. The reduction in flue gas temperatures and conversion of elemental mercury to an ionic form are effective strategies for capturing elemental mercury. As SENES (2002) points out, the balance of plant issues associated with reducing flue gas temperature include potential for corrosion, fabric filter blinding, and possible need for subsequent re-heating of the exhaust to allow for a sufficient dispersal plume.

The oxidation state of coal is influenced by its chemical composition. Coals having higher chlorine levels tend to have a higher proportion of oxidized versus elemental mercury in flue gases, resulting in higher levels of mercury capture by conventional air contaminate control devices. High sulphur levels, by contrast has a positive influence on elemental mercury formation (Yang et. al 2007). Sulphur in coal is oxidized to sulphur oxides (SO_x), which can reduce native mercury capture by 40% and effectiveness of active carbon injection methods by 25% to 35% (Presto and Granite 2007).

3.2 Mercury control technology development

3.2.1 Canadian Electricity Association

The Canadian Electricity Association (CEA) is a non-profit organization whose membership is comprised of most Canadian electricity generation, transmission, and distribution utilities. CEA has participated in a number of initiatives and programs related to the measurement and control of mercury emissions from coal-fired power plants. In 2002, CEA organized the Mercury Program, which included extensive measurement of mercury levels in coal, ash, and flue gas, by member utilities. The data generated under the CEA Mercury Program provided the foundation for the development of mercury emissions targets, as outlined in the *Canada wide standards for Mercury Emissions from Coal-fired Power Stations* (CCME 2006). Data from the participating utilities is found on the CEA website (www.ceamercuryprogram.ca).

3.2.2 U.S. Environmental Protection Agency

Amendments to the U.S. Clean Air Act in 1990 required the U.S. Environmental Protection Agency (EPA) to determine whether mercury emissions from coal-fired power plants posed an unacceptable public health risk. In reports submitted to the U.S. Congress, the EPA indicated that mercury emitted by coal-fired electric power plants was potential threat to human health. The EPA also indicated that additional information was required before a definitive statement on the potential human health risk posed by mercury from coal-fired power plants.

The EPA issued an information collection request in 1998, requiring coal-fired utilities to analyze their coal for mercury and submit results on a quarterly basis. The EPA also selected 85 power plants on the basis of plant configuration and coal type and required that they measure speciated mercury concentration in flue gas.

In December 2000, under the Clinton Administration, the U.S. EPA made a regulatory determination that the Maximum Achievable Control Technology (MACT) standard, was the best approach for controlling mercury and other hazardous air pollutants (HAPs) such as arsenic, lead, nickel, chromium and hydrochloric acid. The same determination added coal and oil fired power plants to the list of HAP sources, subject to the MACT standard.

The MACT standard requires new power plants to adopt, at a minimum, control technologies in use at “best-controlled similar source.” Existing plants are required to adopt controls achieved by the best-performing 12% of the fleet of similar plants. As applied to mercury emissions, the MACT standard would require most plants to reduce their emissions by 85% to 90% within three years of the date of the final MACT rule..

In 2005, under the Bush Administration, the EPA delisted coal and oil fired power plants from the HAP source list, and issued the *Clean Air Mercury Rule* (CAMR). CAMR set a cap of mercury emissions from the coal fired utility level at 70% of 1999 levels by 2018, and allowed utilities to trade mercury credits as a means of reducing their compliance cost.

A coalition of environmental and public health groups challenged CAMR, and in February 2008 the U.S. Court of Appeals for the District of Columbia Circuit vacated both CAMR and the rule that delisted coal and oil fired plants from the HAP source list. A subsequent consent decree has fast tracked the EPA’s timeline for proposing new mercury control regulations, and in November 2009 it announced that rules would be finalized by November 16, 2011 to reduce mercury and other HAPs from coal and oil fired power plants. On December 24, 2009 the EPA issued an Information Collection Request requiring all plants with coal or oil fired generating units to provide emissions information that will be used to develop the new emissions standard..

3.2.3 U.S. Department of Energy National Energy Technology Laboratory

Since the early 1990’s the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL), along with various partner institutions, has been conducting comprehensive

research and development program to develop low-cost mercury control programs for coal-fired power plants. Beginning with laboratory and bench-scale testing, DOE/NETL commenced Phase I pilot and field testing of sorbent injection at four sites and liquid reagent at two sites (Feely et. al 2003). In 2004 DOE/NETL commenced long term field testing (Phase II) and expanded both the number of participating plants and organizations and the scope of mercury control technologies under review (Table 3-2). DOE/NETL has recently selected 12 projects for Phase III of its program. Seven of those projects involve continuation of full scale field tests while five involve bench or pilot scale testing of advanced mercury reduction technologies (U.S. DOE/NETL website).

Table 3-2. Summary of Mercury technology control development projects under DOE/NETL.

Project Title	Lead Company	Test Location	Coal Rank	APCD Configuration
Evaluation of Sorbent Injection for Mercury Control	ADA-ES	Sunflower Electric's Holcomb Unit 1	Subbituminous	SDA/FF
		AmerenUE's Meramec Unit 2	Subbituminous	CS-ESP (320 SCA)
		Missouri Basin Power Project's Laramie River Unit 3	Subbituminous	SDA & CS-ESP (599 SCA)
		Detroit Edison's Monroe Unit 4	Subbit. / Bit. Blend	SCR & CS-ESP (258 SCA)
		American Electric Power's Conesville Unit 6	Bituminous	CS-ESP (301 SCA) & Wet FGD
Sorbent Injection for Small ESP Mercury Control	URS Group	Southern Company's Plant Yates Unit 1	Bituminous	CS-ESP (173 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 2	Bituminous	CS-ESP (144 SCA)
Enhancing Carbon Reactivity in Mercury Control in Lignite-Fired Systems	UNDEERC	Basin Electric's Leland Olds Unit 1	ND Lignite	CS-ESP (320 SCA)
		Great River Energy's Stanton Unit 10	ND Lignite	SDA/FF
		Basin Electric's Antelope Valley Unit 1	ND Lignite	SDA/FF
		Great River Energy's Stanton Unit 1	Subbituminous	CS-ESP (470 SCA)
Advanced Utility Mercury Sorbent Field-Testing Program	Sorbent Technologies	Detroit Edison's St. Clair Unit 1	Subbit. / Bit. Blend	CS-ESP (SCA 467)
		Duke Energy's Buck Unit 6	Bituminous	HS-ESP (240 SCA)
Demonstration of Amended Silicates for Mercury Control	Amended Silicates	Cinergy's Miami Fort Unit 6	Bituminous	CS-ESP (353 SCA)
Pilot Testing of Mercury Oxidation Catalysts for Upstream of Wet FGD Systems	URS Group	TXU's Monticello Unit 3	TX Lignite	CS-ESP (452 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 1	Bituminous	CS-ESP (173 SCA) & Wet FGD
Evaluation of MerCAP™ for Power Plant Mercury Control	URS Group	Great River Energy's Stanton Unit 10	ND Lignite	SDA/FF
		Southern Company's Plant Yates Unit 1	Bituminous	CS-ESP (173 SCA) & Wet FGD
Mercury Oxidation Upstream of an ESP and Wet FGD	UNDEERC	Minnkota Power's Milton R. Young Unit 2	ND Lignite	CS-ESP (375 SCA) & Wet FGD
		TXU's Monticello Unit 3	TX Lignite	CS-ESP (452 SCA) & Wet FGD

Source: Jones et. al. 2006

Table 3-2 (cont.) Summary of Mercury technology control development projects under DOE/NETL Phase II-2 Field Testing

Project Title	Lead Company	Test Location	Coal Rank	APCD Configuration
Field Testing of Activated Carbon Injection Options for Mercury Control	UNDEERC	TXU's Big Brown Unit 2	TX Lignite / Subbit. Blend	CS-ESP (162 SCA) & COHPAC® FF
Field Demonstration of Enhanced Sorbent Injection for Mercury Control	ALSTOM Power	PacifiCorp's Dave Johnston Unit 3	Subbituminous	CS-ESP (600 SCA)
		Basin Electric's Leland Olds Unit 1	ND Lignite	CS-ESP (320 SCA)
		Reliant Energy's Portland Unit 1	Bituminous	CS-ESP (284 SCA)
Low Cost Options for Moderate Levels of Mercury Control	ADA-ES	Entergy's Independence Unit 1	Subbituminous	CS-ESP (542 SCA)
		MidAmerican's Louisa Unit 1	Subbituminous	HS-ESP (459 SCA)
		MidAmerican's Council Bluffs Unit 2	Subbituminous	HS-ESP (224 SCA)
		AEP's Gavin Station	Bituminous	CS-ESP (430 SCA) & Wet FGD
Brominated Sorbents for Small Cold-Side ESPs, Hot-Side ESPs, and Fly Ash use in Concrete	Sorbent Technologies	Progress Energy's Lee Unit 1	Bituminous	CS-ESP (300 SCA)
		Midwestern Generation's Crawford Unit 7	Subbituminous	CS-ESP (112 SCA)
		Midwestern Generation's Will County Unit 3	Subbituminous	HS-ESP (173 SCA)
Field Testing of a Wet FGD Additive for Enhanced Mercury Control	URS Group	TXU's Monticello Unit 3	TX Lignite	CS-ESP (452 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 1	Bituminous	CS-ESP (173 SCA) & Wet FGD
Demonstration of Integrated Approach to Mercury Control	GE-EERC	Progress Energy's Lee Unit 3	Bituminous	CS-ESP (300 SCA)

Source: Jones et. al. 2006

3.2.4 Energy and Environment Research Centre

The Energy and Environment Research Centre (EERC) is a non-profit branch of the University of North Dakota that focuses on the development and commercialization of cleaner and more efficient energy and environmental technologies. One of ten centres of excellence organized under EERC, the Center for Air Toxic Metals® (CATM®) coordinates research into prevention and control of potentially toxic trace element emissions from energy-producing and incineration

systems. The EERC and CATM[®] have worked with the DOE/NETL and partner research organizations and industry on development and testing of mercury control technologies.

In 2005 EERC prepared the report entitled *Technical Review of Mercury Technology Options for Canadian Utilities – A Report to the Canadian Council of Ministers of the Environment*. This document includes a comprehensive review of mercury control options and estimate of cost of applying mercury control technology to the fleet of Canadian coal-fired utilities, assuming 50% to 60% and 70% to 80% mercury capture.

3.2.5 Emissions Control Research Facility (ECRF)

The Emission Control Research Facility (ECRF) at SaskPower's Poplar River Power Station was built to evaluate ACI effectiveness on lignite coal. The ECRF features an ACI unit installed between an electrostatic precipitator and a fabric filter baghouse (Pavlish 2007). Testing at ECRF has been conducted under a joint funding agreement, and is managed by the Energy & Environment Research Centre (EERC) of the University of North Dakota. Since 2007, research at the ECRF facility has focused on balance of plant issues associated with ACI use for lignite coals (Pavlish 2007).

3.2.6 Electric Power Research Institute

The Electric Power Research Institute (EPRI) is an independent non profit organization that conducts research and development relating to the delivery and use of electricity. EPRI manages a portfolio of 100 research programs focused on challenges of electricity delivery, including reliability, health, safety, and the environment. In cooperation with the U.S. Department of Energy and the power industry, EPRI has conducted extensive mercury control research and has developed some of the most promising technologies for reducing mercury emissions from coal-fired power plants, such as TOXECON.

3.3 **Mercury reduction technologies**

3.3.1 Fuel switching

Fuel switching involves reconfiguring a coal-fired thermal plant to use natural gas or fuel oil as an energy source. The general drivers behind switching away from coal are reduction in greenhouse emissions and/or criteria air contaminants such as SO₂ and NO_x (EERC 2005). In April 2010 Environment Canada proposed that major electricity firms gradually replace their coal-fired plants with cleaner sources of power after those plants. Under the proposal, utilities would not be allowed to re-furbish their coal-fired plants once they had reached the end of their commercial lives, unless they include technology to capture and store carbon (Globe and Mail, April 25, 2010).

3.3.1.1 Natural Gas

Natural gas combustion produces almost 45 percent fewer carbon dioxide emissions than coal, emits lower levels of nitrogen oxides and particulates, and produces virtually no SO₂ and mercury emissions. The lower levels of these emissions mean that the use of natural gas does not contribute significantly to smog or acid rain formation.

Capital costs for natural gas conversion may include either retrofitting existing boilers or replacing existing boilers with combined cycle gas turbines and steam turbines, and installing a gas delivery system. Operating costs may change, due to the relative cost of coal versus gas per usable quantity of heat generated. Due to the costs involved, utilities are unlikely to switch to natural gas for mercury control alone. Mercury emissions would benefit, however, from a broader regulatory package that encouraged switching from coal to natural gas.

3.3.1.2 Fuel oil

Fuel oil contains lower levels of mercury than coal (EERC 2005). However, oil fuelled plants have higher emissions relative to natural gas, and may have higher operating costs due to the relative cost of oil versus natural gas for equivalent thermal units. For these reasons, plants considering repowering would likely favour natural gas over fuel oil.

3.3.1.3 Biomass

The drive towards sustainable energy generation and climate change policies and commitments has motivated a number of utilities in Canada and the U.S. to consider biomass conversion. Ontario Power Generation (OPG) has tested biomass burns and blends at all four of its coal-fired plants. The 200 MW Atikokan facility has been tested with 100% biomass pellets, and OPG has targeted 2012 to begin permanent biomass generation at this facility (Ontario Ministry of Agriculture Food and Rural affair website). The Nanticoke facility has been co-fired with blends of wood pellets and wheat shorts.

The major constraint to biomass conversion is fuel availability. OPG has sponsored a number of studies with the Ontario Ministry of Agriculture Food & Rural Affairs to evaluate the biomass availability of a number of crops, including sorghum, millet, and switchgrass. In February 2009, OPG issued a Request for Expression of Interest (RFEI) for the supply and transport of solid biomass fuel. The RFEI indicates that OPG is investigating "...full and partial replacement of coal at its power plants..." and that it anticipates that 2,000,000 MT or more of solid biomass fuel will be consumed annually in power production (OPG 2009).

3.3.2 Coal switching/blending

Mercury emissions can be reduced if coals with favourable characteristics, including lower levels of mercury and sulphur, and higher levels of chlorine are used. In Canada, coal blending is conducted for the purpose of reducing sulphur levels as a means of addressing SO₂ emission objectives. An example is the production of a sulphur compliant control by blending high sulphur bituminous coals with low sulphur PRB subbituminous coals.

Operational constraints make coal blending expensive for many power plants in Canada. Particularly in western Canada, power plants tend to be geographically proximate to a coal mine, and transportation of coals from distance sources may be uneconomical. Coal blending, however, may be a practical solution in Nova Scotia, which imports the majority of coal it burns from U.S. and South American sources.

Mercury levels in coals used in Nova Scotia range from 0.020 PPM (Point Aconi) to 0.109 Trenton (data year). Therefore, assuming sufficient lower mercury coal is available, and that other characteristics are also conducive to lower emissions (i.e. chlorine and sulphur levels) then some reduction in emissions due to coal blending may be achieved.

3.3.3 Coal cleaning

Bituminous coals are typically cleaned to remove non-combustible materials, including sulphur and ash and to improve the heating value. Conventional coal cleaning technology involves gravimetric methods that take advantage of differences in specific density between the organic and inorganic constituents of coal (i.e. pyrites and ash). As some mercury is bound to the pyrite and ash particulates, removal of those components reduces the overall mercury level of the coal combusted (EERC 2005).

3.3.4 Standard plant components (Criteria Air Contaminates)

Air pollution control devices (APCD) designed from control of SO₂, NO_x, and particulate matter have demonstrated a degree of co-benefit mercury control. The extent by which APCD equipment confers mercury control co-benefit depends on the plant configuration and fuel type burned. Particle bound mercury is readily captured by particulate control devices, such as electro-static precipitators and fabric filter baghouses. Oxidized mercury is water soluble, and can be captured by wet flue gas desulphurization systems and to a lesser degree by particulate matter control devices (Jones et. al 2006).

3.3.4.1 **SO₂ control**

The principle objective of SO₂ control technology, including wet and dry flue gas desulphurization (FGD) and spray dry absorbers (SDA) is removal of SO₂ from flue gas. Wet scrubbers remove a high proportion (>75%) of oxidized mercury in flue gas but do not remove elemental mercury (Senior 2009). Therefore, native mercury removal potential depends on coal characteristics. Mercury removal in units burning low grade coal ranges from 0% to 40%, and averages 30% , while mercury removal in units burning bituminous blends averages over 50% (Pavlish et al. 2005, Senior 2009).

Spray dry absorbers absorb mercury onto sorbent and fly ash. Spray dry absorbers are coupled with a particulate control device, usually a fabric filter. The resulting SDA/FF combination removes most oxidized mercury, while its effectiveness at removal of elemental mercury depends on the coal halogen content. Overall mercury removal of the mercury via the SDA/FF combination has been reported at over 90% (Senior 2009).

In Canada, SO₂ control equipment is installed at 5 of the 53 operating units: Genesee Unit 3 (d-FGD), Shand Unit 1 (LIFAC), Lambton Units 3 and 4 (w-FGD) and Belledune Unit 2 (w-FGD). Other units achieve SO₂ emission control objectives through the use of low sulphur coals.

Scrubber technology is expensive to install and operate. Figures provided by Pavlish *et. al* 2005 indicate the cost to retrofit a 400 MW plant with wet or dry scrubber technology would range from \$40 million to nearly \$90 million with total operating costs in the order of \$6.6/MWh to \$12.0/MWh (figures in 2005 USD). ¹By comparison, activated carbon injection (ACI) and enhanced activated carbon injection can achieve mercury control in the range of 70% to 90% for many coal types, at a levelized cost of \$1.00/MWh to \$2.0/MWh.

3.3.4.2 NO_x control

Selective catalytic reduction (SCR) systems can oxidize elemental mercury. Senior (2009) reports that observed mercury oxidation across SCR systems ranges from less than 10% to over 90%. Coupled with a wet scrubber a SCR can result in high levels of mercury removal (EERC 2005).

Based on a 400 MW plant, the capital cost of SCR equipment would range from \$16 to \$40 million, with total annual operating cost ranging from \$4.0/MWh to \$8.0/MWh (2005 USD), which is about four times higher than the cost of implementing an ACI system. Thus, NO_x control technologies are cost prohibitive if deployed with the principle objective of mercury control.

3.3.4.3 Particulate matter control

Particulate matter (PM) control devices removing particle bound mercury from flue gas streams, with units equipped with fabric filter baghouses generally achieving higher levels of mercury removal than those equipped with electrostatic precipitators (Table 3-3).

Table 3-3. Average co-benefit mercury capture by APCD in Canada.

APCD Configuration	Average % Mercury Capture			
	Bituminous	Sub-bit/Bit blend	Subbituminous	Lignite
Cs-ESP	36%	21%	3%	-4%
SDA/FF	98%	N/A	24%	0%

From EERC 2005.

□

¹ Cost data cited in Section 3 are quoted from a number of literature sources. They have not been adjusted for inflation or currency exchange

3.3.5 Activated Carbon Injection

Activated carbon injection (ACI) has been tested extensively in the U.S. and Canada at the pilot and commercial scales over a wide range of plant configurations and coal types. ACI involves the injection of powdered activated carbon (PAC) sorbent upstream of the particulate control device (fabric filter or electro-static precipitator). The PAC absorbs vapour phase mercury by providing catalyst sites for elemental mercury to be oxidized. The oxidized mercury then binds to the carbon particle, which is collected in the particulate control device.

The removal efficiency of ACI depends on a number of variables including the coal type, nature of sorbent, unit emission control configuration, flue gas operating temperature, and sorbent injection rate. The sulphur and chlorine content of coal affect the SO_x and HCl ratio in the flue gas, which in turn affect the absorption rate of mercury on both carbon sorbents and ash particles. Higher chlorine levels promote oxidation of elemental mercury and binding onto the carbon particles. ACI system performance can thus be improved through the use of coals with high chlorine content, by treating the coal with halogenated compounds prior to combustion, or by treating the sorbent with a halogenated substance (usually bromine).

High SO₂ levels in flue gas decreases the effectiveness of the activated carbon to absorb mercury, as the activated carbon catalyses SO₂ to H₂SO₄ which in turn occupy the active sites on the carbon catalyst (Sjostrom 2008). High flue gas SO₂ levels may result from burning high sulphur coal, through the use of selective catalytic reduction systems, or by injecting SO₃ as a flue gas conditioning agent (Sjostrom 2008). Mercury absorption onto activated carbon improves with lower flue gas temperatures, as this facilitates oxidation of elemental mercury (SENES 2003).

The nature and configuration of emission control devices affects the performance of ACI systems. Systems equipped with filter fabric (baghouse) particulate control devices tend to perform better than those with electrostatic precipitators. The baghouse filter allows for greater contact time between the flue gas and carbon particle resulting in a higher rate of absorption. Mercury removal by ACI systems generally increases at higher sorbent injection rates. Commercial field tests conducted for DOE/NETL have demonstrated that mercury removal by ACI systems generally increases at higher sorbent injection rates (Figure 3-1)

3.3.5.1 Brominated activated carbon

The ability of powdered activated carbon (PAC) to remove flue gas mercury is generally enhanced when it has been impregnated with a halogen (usually bromine). Impregnating with the halogen increases the oxidative capability of the PAC, resulting in marked improvement in maximum mercury capture rates (over untreated PAC) for high sulphur fuels (Feeley and Jones 2008). While brominated PACs are more costly than untreated PACs, a comparable level of mercury capture can be achieved at a lower PAC injection rate, potentially resulting in a lower overall levelized cost to the unit.

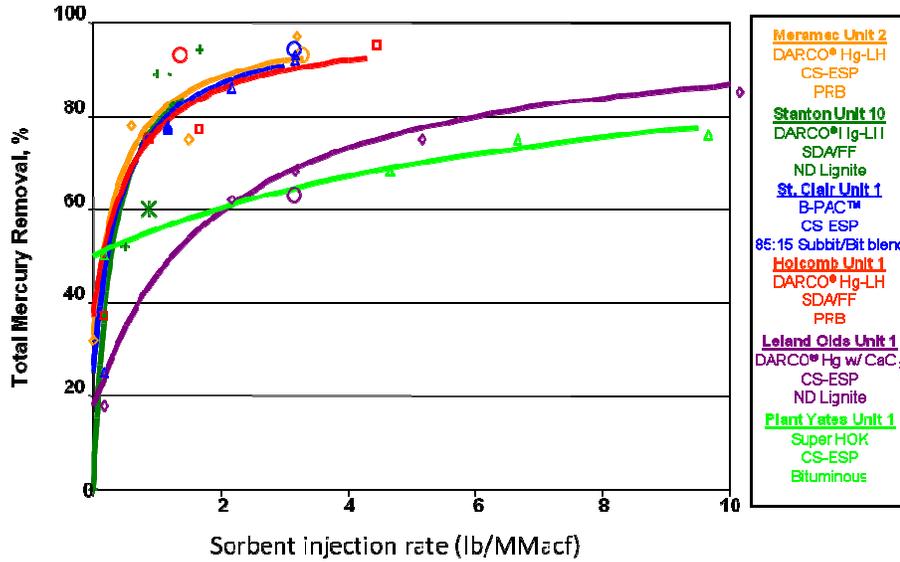
3.3.5.2 Performance

Both untreated and brominated PACs have been field-tested for a wide variety of coal types (Table 3-4, Figure 3-1). Total Hg capture of up to 90% has been reported from ACI systems using untreated PAC in units burning bituminous and powder basin subbituminous coals (Table 3-4). Mercury recover rates of over 90% were reported at the PRB-burning Holcomb-1 and Meremec-2 units, using brominated PAC (Jones et. al 2008). Field tests at SaskPower's lignite-burning Poplar River Station indicated mercury capture of 60% to 80% using 2 – 2.5 lb/MMacf enhanced PAC (Pavlish 2007). By comparison, the lignite-burning Stanton 10 unit equipped with ACI and using brominated PAC achieved mercury capture of over 90% (Pavlish 2007).

Table 3-4. Full scale field tests results of activated carbon injection.

Sorbent	Test lead	Station	Coal	APCD configuration	Injection Rate (lb/MMacf)	% Hg capture
Untreated PAC						
DARCO [®] Hg		Gaston	Bit.	COHPAC		90%
		Pleasant Prairie	PRB	ESP		67%
		Brayton Point	Bit.	ESP		90%
		Laramie River	Subbit	ESP		90%
		Monroe	PRB/Bit.	ESP		80%
		Conesville	Bit. (HS)	ESP		35%
Enhanced PAC						
DARCO [®] Hg-LH	ADA-ES	Holcomb 1	PRB	SDA/FF	1.03	93%
	ADA-ES	Meremec 2	PRB	CS-ESP	3.3	93%
	UNDEERC	Stanton 10	Lignite	SDA/FF	0.7- 1.15	56% - 70%
		Labadie	PRB	ESP/FGC (5.2 ppm SO ₃)		75%
	EERC	Poplar River	Lignite	ESP	2 – 2.5	60% - 80%
DARCO [®] Hg-LH + B-PAC [™]	UNDEERC	Stanton 10	Lignite	SDA/FF	1.5	>90%
B-PAC [™]	URS	Stanton 1	PRB	CS-ESP	1.7	85%
MC-PLUS		Labadie	PRB	ESP/FGC (5.2 ppm SO ₃)		85%
Sources: Pavlish (2007), Feeley and Jones (2008), Jones et. al (2008), Sjostrom (2008)						

Figure 3-1. Phase II raw data regression.



(Source: Jones et. al 2006)

3.3.5.3 Economic considerations

Jones et. al (2006) and Sjostrom (2008) present economic analyses of activated carbon injection for mercury control. Sjostrom (2008) presents estimated costs associated with sorbent injection at five of nine stations evaluated by ADA-ES over the 2004 to 2007 period (Table 3-5). In this analysis, the cost of mercury removal is calculated on a % of total removal basis. This analysis included the cost of additional landfill and lost ash sales where relevant.

Table 3-5. Cost analysis summary of plants tested for ACI by ADA-ES.

Sorbent	Station (MW)	Coal	APCD	% Hg capture (total)	20 year levelized cost		Notes (Year)
					Annual	\$/MWh	
Untreated PAC							
DARCO® Hg	Holcomb 1	PRB	SDA/F F	>90%	\$ 857,000	\$0.32	(2004)
	Monroe	PRB/Bit. (LS/MS)	ESP/FGC	80%	\$7,317,000	\$1.17	(2005)
Enhanced PAC							
DARCO® Hg-LH	Meramec 2	PRB	CS-ESP	90%	\$2,610,000	\$2.50	(2004) Includes \$1,070,000 annual landfill charge + lost ash sales

MC -Plus	Labadie	PRB (LS/MS)	FGC	75%	\$5,832,000	\$1.57	(2007) Includes \$500,000 annual landfill charge
Milled MC-Plus	Labadie	PRB (LS/MS)	FGC	85%	\$4,794,000	\$1.30	2007) Includes \$500,000 annual landfill charge
Source: Sjostrom (2008). Costs unadjusted for inflation							

Jones et. al (2006) present a preliminary economic analysis of tests for activated carbon injection systems undertaken six stations as part of DOE/NETL's Phase II mercury control technology field testing program (Table 3-6). In this evaluation, mercury control costs were calculated on the basis of mercury removed due to the ACI rather than total mercury removal. The methodology involves developing non-linear regression algorithms based on parametric tests of mercury removal at different PAC injection rates, and then adjusting the algorithms to account for baseline mercury capture and long-term field tests. This method accounts that baseline mercury removal declines asymptotically to zero as the level of PAC injection increases, as an increasing proportion of mercury is taken up by the PAC as opposed to fly ash.

Table 3-6. Cost analysis summary of DOE/NETL's Phase II Mercury Control Program Field Testing Program .

Sorbent	Station (MW)	Coal	APCD	% Hg capture (by ACI)	20 year levelized cost	20 year levelized cost (with by-product impact)
					\$/MWh	\$/MWh
DARCO [®] Hg & CaCl ₂	Leland Olds 1	Lignite		50%	0.82	2.57
				70%	1.02	2.77
DARCO [®] Hg-LH	Meremec 2	Sub-bit	CS- ESP	70%	0.47	1.85
				90%	0.99	2.37
DARCO [®] Hg-LH	Holcomb 1	SDA/FF	SDA/ FF	70%	0.18	0.90
				90%	0.37	1.09
B-PAC TM	St. Clair 1	85% sub-bit. /15% bit.	CS- ESP	70%	0.48	1.47
				90%	1.06	2.05
Super HOK	Yates 1	Bit.	CS- ESP	70%	0.97	2.94
				90%	1.72	3.69
Source: Jones et. al (2006) All figures in 2005 US Dollars						

3.3.5.4 Activated Carbon Injection – Use in Canada

ACI was field tested at OPG's Nantikoke Station and ACI testing has taken place at the Emission Control Research Facility (ECRF) at SaskPower's Poplar River Power Station since 2005. In 2009, ACI systems were installed at Nova Scotia Power Inc.'s Trenton, Point Tupper, and Lignan generating stations. Brominated ACI (BACI) is currently being installed at the ATCO Power, Capital Power and TransAlta generating stations.

3.3.5.5 Balance of plant

With the exception of Toxecon[®] ACI systems are generally located upstream of the particle control device, allowing for simultaneous capture of fly ash and spent PAC. Fly ash generated from typical ACI processes contain carbon levels that may be unacceptable for cement manufacturer since carbon absorbs air entrainment agent (AEA) which imparts foam properties needed for concrete workability and strength.. A plant otherwise able to sell its fly ash would thus suffer a double financial penalty from using ACI or BACI. It would no longer enjoy revenue from ash sales, and it would incur extra ash disposal cost.

3.3.5.6 Mercury fate and disposal

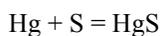
Fly ash not sold for commercial use is either dry stored in landfills or wet stored in storage lagoons. ACI or BACI systems results in ash having higher levels of mercury. The mercury levels in the ash can affect the concentration of mercury with the storage lagoon's leachate. While storage lagoons are designed with impermeable barriers to prevent the introduction of leachate into groundwater or surrounding surface waters, there is potential for failure of lagoon containment structures.

3.3.5.7 Iodine impregnated activated carbon

Activated carbon impregnated with 2% Potassium Iodide (KI) removed over 90% of mercury in dynamic tests conducted at velocity flow of 0.3 m/s and temperature at 298 °C (Henning and Schaffer 2005). Further, KI impregnated PAC maintained its catalytic activity (over 50% Hg removal) for approximately 1000 hours, versus 100 hours for non-iodated activated carbon.

3.3.5.8 Sulphur impregnated activated carbon

Henning and Schaffer (2005) report the absorptive ability of sulphur impregnated activated carbon is superior to both un-enhanced and iodine impregnated activated carbon. Elemental mercury in flue gas diffuses through the pores of the activated carbon where it is absorbed at the activated sites, and then chemi-absorbed by sulphur to form mercury sulphide through the mechanism:



Under laboratory test conditions, activated carbon catalysts impregnated with 1.1 % sulphur maintained mercury removal of over 90% for 3000 hours, versus about 20 hours for unenhanced activated carbon.

In a project conducted by Idaho National Laboratory and Thor Treatment Technologies LLC, Soelberg et. al (2007) report that fixed bed activated carbon catalyst impregnated with 13% S (MERSORB[®]) removed up to 99.999% of mercury in pilot tests conducted at very low flow conditions (10 litres/hour).

Most testing of mercury removal by sulphur impregnated activated carbon has been conducted at flow rates that are orders of magnitude less than those experienced within a coal-fired power plant. As well, the effectiveness of sulphur impregnated activated carbon reportedly decreases when operating temperatures exceed the 112 °C melting point of sulphur (Korpiel 1997), which is lower than the typical ESP or baghouse operating temperatures (135 ° to 177° C).

Sulphur impregnated activated carbon is more costly than straight activated carbon. EERC (2005) reports that MERSORB® costs about \$3.00/lb versus \$0.50/lb for DARCO® brand unenhanced PAC. This price differential may render it uneconomical at mercury removal rates required by coal-fired power plants.

3.3.5.9 Concrete friendly carbon sorbents

C-PAC™ is a PAC sorbent that has been passivated during production to limit AEA absorption. C-PAC™ has been tested at Midwestern Generation's Crawford Station Unit 7, which burns PRB coal and is equipped with CS-ESP. At an injection rate of 4.6 lb/MMacf the sorbent achieved an average of 81% mercury capture (Feely and Jones 2008). As well, ash samples collected from the station are suitable for cement production.

3.3.6 TOXECON™ process

The Toxecon™ process was developed and patented by the Electric Power Research Institute (EPRI). In the Toxecon system, activated carbon sorbent is injected into exhaust gases downstream of the existing particulate control device. The carbon particles are then collecting on a second particulate control device, a pulse-jet fabric filter (i.e. COHPAC). An advantage of the Toxecon™ systems is that the fly ash collected in the primary particle collection device has not been contaminated by carbon, and can thus be sold for use in cement manufacture (Derenne 2006). Thus plant considering the use of Toxecon™ over conventional ACI systems must weigh the added capital cost of installing the pulse-jet fabric filter (also known as a polishing baghouse) with the revenue realized from fly ash sales.

Since 2006, a Toxecon™ system has been operational at WeEnergie's Presque Island Power Plant in Marquette, Michigan, which burns Powder River Basin subbituminous coal. The system has achieved over 90% mercury capture using both untreated and brominated activated carbon sorbent (Feely and Jones 2008).

3.3.7 TOXECON II™

EPRI developed the Toxecon II™ configuration to eliminate the need of the polishing baghouse for a plant equipped with an electrostatic precipitator. In Toxecon II™ activated carbon sorbent is injected into the downstream collection fields of the ESP. As over 90% of the fly ash is collected in the upstream fields (Feely and Jones 2008), the Toxecon II™ configuration appears suitable for operations that can sell their fly ash while avoiding the capital expenditure of a polishing baghouse. The Toxecon II™ process has been tested at Entergy's PRB fuelled Independence Station Unit 1. Sorenson (2008) reports that the unit achieved total mercury

removal of 90% using 5.5 lb/MMAcf of DARCO® Hg-LH (brominated activated carbon sorbent). The estimated capital cost of installing a Toxecon II™ system at the 700 MW Independence Station Unit 1 was \$4.7 million +/- 25%, with annual levelized cost to achieve 80% capture estimated at \$9.07 million +/- 15% (Sorenson 2008, figures are in 2007 US\$).

3.3.8 In-situ carbon sorbent production

3.3.8.1 **Partial coal gasification**

General Electric Energy (GEE) and Environmental Research Corporation (ERC) developed a technology for producing a sorbent for mercury removal from gasification of some of the coal used by a coal burning power plant. Development of this technology was funded under Phase III of DOE/NETL's mercury emission control technology development program. Parametric testing at ERC's Boiler Simulation Furnace found sorbents generated by bituminous coals achieved 70% incremental mercury removal at loading rates of about 50% higher than a commercial powdered activated carbon sorbent. Mercury capture rates of up to 95% were demonstrated at sorbent loading rates of about 32 lb/MMAcf (Samuelson *et. al* 2008). While detailed economic analysis has not been conducted for partial coal gasification preliminary estimates suggest the technology may result in 80% to 85% reduction in the cost of mercury reduction (based on bituminous coals) since the cost of the sorbent (the largest operating cost component of ACI) is avoided (Samuelson *et. al* 2008).

Potential balance of plant issues associated with the technology were not factored into Samuelson *et. al* (2008) preliminary economic analysis. For instance, higher carbon loading required by the PCG process could result in resistivity issues and lower performance within an ESP, and result in higher solid waste disposal costs.

3.3.8.2 **Thief process**

Developed by the U.S. Department of Energy, National Energy Technology Laboratory, the Thief process is similar to partial coal gasification. In the Thief process partially combusted coal is extracted by lance from the combustion chamber of a coal-fired power plant, and then re-injected into the ductwork downstream of the air pre-heater (Granite *et. al* undated). The partially combusted coal acts as a sorbent similar to powdered activated carbon. The Thief process requires extraction of 0.1% to 0.5 % of combustion gas depending on the level of sorbent loading required

Pilot testing at a 500 lb/hour combustion facility indicate that Thief produced sorbents prepared from Powder River basin coal resulted in mercury capture up to 80% at loading of about 1.2 lbs/MMAcf and up to 90% at loadings of 2.0 to 4.5 lbs/MMAcf (Granite *et. al* undated). These tests suggest the Thief sorbents removed mercury at comparable levels and loading rates as a commercially available sorbent.

The Thief system results in a system energy loss of up to 0.5%, which is the largest operational cost associated with the technology (Granite et. al.). However, this loss may be modest in comparison with the expenditure require to purchase equivalent amounts of commercial grade sorbent.

The Thief process is still at a developmental stage, and no commercial scale tests have been completed. As well, balance of plant costs, which could include higher levels of carbon loading within particulate control devices, has not been quantified.

3.3.9 Mer-Cure™

Mer-Cure™ is a patented process, developed by Alstom Power Systems. It involves a proprietary sorbent injected upstream into the high temperature region of the flue gas, upstream of the air pre-heater. A third component of the technology is a delivery system that avoids injection of agglomerated PAC, thus avoiding clogging of the pre-heater. Advantages of injecting before the pre-heater include improved mercury oxidation kinetics, extended sorbent-mercury contact time, and avoidance of sulphuric acid poisoning of sorbent, which can occur when sorbent is injected in cooler regions of the flue gas. Alstom has pilot tested the Mer-Cure™ system at several power plants, burning a range of coal types. Test results suggest the technology can achieve high levels of mercury capture at loading rates lower than straight or brominated PAC. At a sorbent cost range of \$0.75 to \$2.00/lb, Kang *et. al* (2008) estimate the levelized annualized cost of applying Mer-Cure to low grade coals is less than \$1.00/MWh (Table 3-7). The cost is higher for medium sulphur bituminous coals due to higher loading rates required.

It is noted that while Mer-Cure™ is a patented combinations of technologies, individual process components are not covered by Alstrom's patent. Plant operators are now experimenting with ACI configurations to optimize mercury removal and lower sorbent costs. For example, Nova Scotia Power is installing PAC injectors upstream of the air pre-heaters to improve performance at its Trenton, Point Tupper, and Lignan stations (D. Cousens pers. comm. 2010).

Table 3-7. Cost analysis summary of Mer-Cure™

Sorbent	Test lead	Station	Coal	Injection Rate (lb/MMacf)	% Hg capture	Levelized operating cost (\$/MWh)
	Alstrom	Dave Johnston-3 (220 MW)	PRB	0.63	90%	\$0.25 – 0.50
		Leland Olds-1 (220 MW)	ND lignite	1.4	90%	\$0.35 – 0.85
		Portland-1 (170 MW)	Eastern bituminous	8.5	90%	\$1.40 – 3.75
		Fayette-3 (480 MW)	PRB	0.9	90%	\$0.25 – 0.50

Sources: Kang et. al. (2008)

3.3.10 Fixed carbon sorbents

3.3.10.1 **MerScreen™**

Developed by the Electric Power Research Institute (EPRI), MerScreen™ is a fixed sorbent bed structure intended to be installed downstream of a plant's particulate control device. The MerScreen™ apparatus consists of one bed of quartz wool and three beds of granular activated carbon pellets or granules placed perpendicular to the flue gas flow. The quartz wool bed eliminates some of the incoming fly ash while the carbon bed oxidizes and absorbs mercury Machalek *et. al* (2008).

MerScreen™ was pilot tested (slipstream) at Southern Company's low sulphur eastern bituminous fuelled Plant Yates Unit 1. The tests involved four sorbent grades and a number of bed depth configurations. Total mercury removal by most configurations was 90% to 99% at accumulated exposure time of less than 25 hours, falling to 50% at 70 to 100 hours, then to 20% or less by 100 to 120 hours. Pressure drop was experienced across all configurations due to ash build-up, with beds containing granules experiencing higher pressure drop than those containing pellets.

Machalek *et. al* (2008) suggests that the advantage of using fixed structure technology over technologies such as ACI is that fly ash quality is preserved. While the costs of implementing MerScreen™ have not been developed, Machalek *et. al* (2008) notes that the capital cost is likely higher than for ACI. In 2008 full pilot scale of MerScreen™ was installed in Plant Miller Unit 3, downstream of the pilot COHPAC II unit. Test data from this facility was not available at the time of this review.

3.3.10.2 **MerCAP™**

EPRI's MerCAP™ process uses fixed gold coated sorbent structures placed downstream of wet or dry scrubbers, within fabric filters (Table 3-8). The sorbent plates capture mercury particles in the flue gas stream. Once the plate is saturated it is regenerated and the sorbent is recovered. Tests of MerCAP™ at Georgia Power's eastern bituminous fuelled Plant Yates Unit 1 and Great River Energy's Stanton Station Unit 10, which tested the technology using both North Dakota lignite and PRB coals. At Stanton Station, initial mercury capture was in the 70% to 90% range, but this declined to 35% to 40% after three months of operation, burning lignite. Kyle and Fisher (2006) suggest declining performance may be attributable to the gold plates and steel used at the Stanton Plant were affected by acidic conditions, and material build up on the gold plates. Performance at Yates was lower, with initial capture estimated at 15%, declining to about 6% after one month.

Table 3-8. MerCAP™ Performance.

Technology	Test type (year)	Test lead	Plant	Coal	APCD configuration (baseline Hg removal)	% Hg removal
MerCAP™	Long term	URS	Stanton 10		SDA/FF, dFGD	70% to 90% (initial), 35% to 40% long term
MerCAP™	Long Term	URS	Yates 1		csESB, wFGD, LNB	

3.3.11 Non carbon sorbents

3.3.11.1 **Amended Silicates™**

Sorbents based on chemically amended silicates have been developed as a “concrete friendly” alternative to carbon sorbents, for use in sorbent injection systems. Amended Silicates™ brand silicate sorbent was tested at Duke Energy’s Miami Fort Unit 6, which burns medium sulphur bituminous coal and is equipped with CS-ESP. Over a 30 day trial, the sorbent achieved an average 40% mercury capture at an injection rate of 5 to 6 lb/MMacf (Feely and Jones 2008).

3.3.11.2 **Calcium based sorbents**

Mercury absorption through the use of calcium based sorbents and oxidizing agents was tested at the Southern Research Institute’s Combustion Research Facility (CRF) in Birmingham, Alabama. When firing a low-chlorine bituminous coal (Choctaw American coal), injecting 15 lb/hour of hydrated lime (Ca(OH)₂) into the baghouse inlet increased total mercury removal from 25% to nearly 80% (Gale and Merritt 2003).

In another experiment, the ash from Choctaw American coal, along with hydrated lime, was injected into the baghouse of the CRF while it was burning PRB subbituminous coal. Mercury removal increased from 30% (baseline), to about 37% at 20% ash/80% hydrated lime, to about 60% with 100% injected ash. Gale and Merritt (2003) conclude that the effectiveness of calcium sorbents depends on the qualities of the coal combusted. In the case of high calcium coals, such as PRB, added unburned carbon (UBC) from the injected ash provides the catalytic sites for enhanced mercury capture.

3.3.11.3 **Sodium tetrasulphide sorbents**

Sodium tetrasulphide (Na₂S₄) sorbent was pilot tested at SRI’s Combustion Research Facility. Mercury removal was nearly 100% with 12 PPMV Na₂S₄ injected at the baghouse inlet, when the CRF was burning PRB subbituminous coal, and 90% when 14 PPM Na₂S₄ injected at the baghouse outlet with the CRF burning Choctaw American Coal (Gale 2005). Na₂S₄ effectiveness declined linearly with chlorine injected into the flue gas. As well, the effectiveness dropped

from over 90% to less than 40% as flue gas temperature was increased from 300 °F to 380°F (Gale 2005).

3.3.11.4 Metal-oxide based sorbents

Pilot scale work on the Pahlman process, which features manganese oxide (MnO₂) sorbent, is discussed in Section 3.4.15.1. Other metal-oxide sorbents evaluated at lab scale only (EERC 2005).

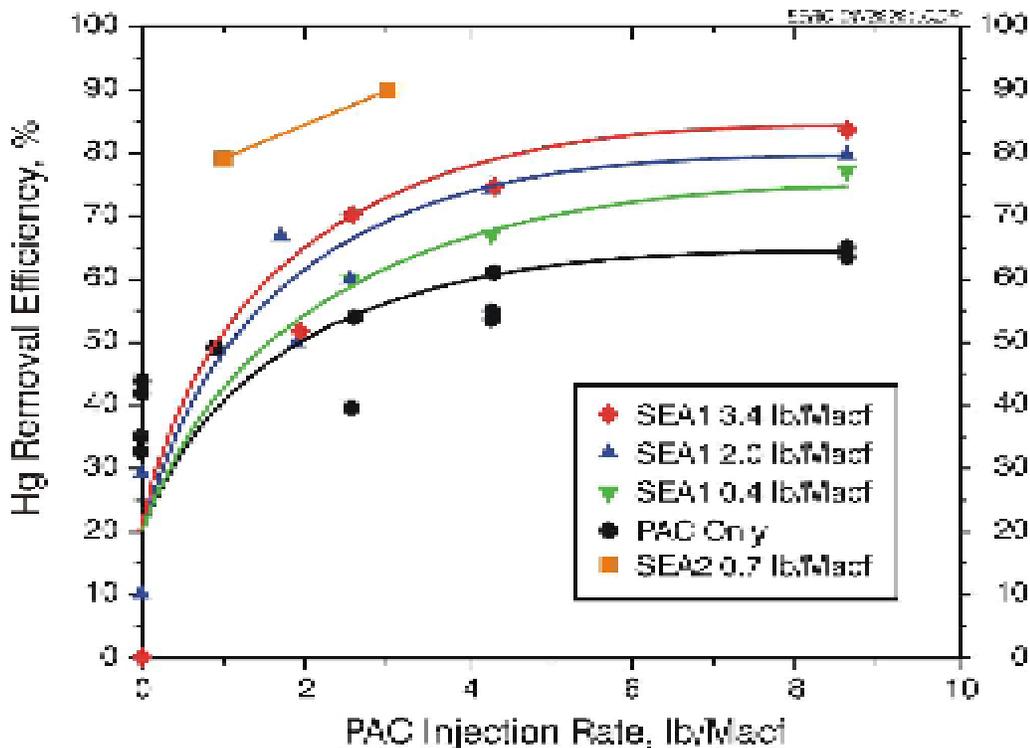
3.3.12 Sorbent Enhancement Additives

Sorbent enhancement additives (SEA) are coal additives that promote oxidation of elemental mercury and subsequent absorption either on fly ash or carbon sorbents. SEA may be particularly effective in removing mercury from low grade coals, such as North Dakota and Saskatchewan lignites, characterized by low chlorine levels and high levels of elemental mercury in emissions (Crocker et. al 2004). Pilot tests conducted at EERC's Particulate Control Combustor (PCC) demonstrated that an SEA oxidant in combination with a powdered activated carbon (PAC) sorbent was capable of removing up to 90% of total mercury in a combination of particular control configurations, including ESP, ESP-FF (ToxeconTM), and Advanced Hybrid FilterTM (Crocker et. al 2004).

EERC undertook commercial scale tests of SEAs at the 550 MW PRB burning Hawthorn-5 unit, which is equipped with FF for particulate control; SDA for SO_x control; and LNB, OFA, and SCR for NO_x control. In earlier tests, EERC achieved 80% mercury capture at this unit by adding 1000 ppm of Calcium Chloride (CaCl₂) with no sorbent. EERC achieved total mercury capture of 88.3% with SEA-1 additive added at 1200 PPM and PAC Hg (un-enhanced PAC) added at 3.9 lbs/MMacf. Mercury capture was increased to 91.1% through the use of SEA-1 (1200 PPM) and PAC Hg LH (un-enhanced PAC) at 3.0 lbs/MMacf (Laumb et. al 2007).

Parametric testing at three plants – Leland Olds, Stanton, and Antelope Valley - burning low grade coals demonstrated that sorbent enhancement additives can result in substantial improvement of mercury capture over PAC only (Holmes 2006). Parametric results in Figure 3-2 show the addition of SEA-1 additive results in up to 20% additional mercury removal from the bituminous burning Leland Olds Station Unit-1. The use of 0.7 lb/MMacf of SEA2 additive resulted in 90% mercury capture at PAC injection rate of 3.0 lb/MMacf (Holmes 2006).

Figure 3-2. Leland Olds-1 Parametric Results.



Source: Holmes, 2006 (note: Macf is the same as MMacf)

3.3.13 Oxidation additives

Mercury removal through the use of chemical oxidizing agents has been field tested in stations burning low grade lignite coals, with an ESP-wFGD air pollution control configuration (Benson et. al 2006, Benson et. al 2007). In this process, chemical oxidants, such as Calcium Chloride (CaCl_2), Magnesium Chloride (MgCl_2), Calcium Bromide (CaBr_2), and SEA2 (a proprietary sorbent) are injected into the coal feed prior to combustion. The heat of combustion converts the chlorine or bromine compound into atomic and molecular components (Benson et. al 2007). The oxidant then promotes the conversion of elemental mercury (Hg^0) to ionic mercury (Hg^{2+}) in the flue gas, enabling it to be removed in either the ESP or the scrubber.

Benson et. al (2007) reports full scale tests of oxidation additives, conducted at TXU Energy's Monticello Steam Engine Station (MoSES) Unit 3 and Minnkota Power Cooperatives Milton R. Young Station (MRY) Unit 2. The objective of these tests was to achieve mercury removal of over 55% on a sustained basis, and evaluate the cost and balance of plant issues associated with the use of oxidation additives in plants burning lignite coals.

Tests at the MRY-2 demonstrated that SEA2 sorbent was far more effective at removing mercury than either CaCl_2 and MgCl_2 for lignite coal (Table 3-9). Combining chemical oxidation with powdered activated carbon resulted in an improvement in total mercury capture from 35% to 65% at a PAC addition rate of 1 lb/MMAcf. Tests at the MoSES-3 indicate CaBr_2 is more effective at removing mercury from lignite/PRB blend, achieving up to 92% removal at 330 PPM (Table 3-9).

Table 3-9. Chemical oxidation of lignite coals with wet flue gas desulphurization.

Technology	Test type (year)	Test lead	Plant	Coal	APCD configuration (baseline Hg removal)	Oxidant (PPM)	% Hg removal
Oxidation	Full scale (2003-2007)	EERC/URS	MRY-2	Lignite	ESP-wFGD	CaCl_2 (100 – 500)	-5% to 12%
						MgCl_2 (500)	11%
						SEA2 (25 – 75)	18% to 45%
Oxidation	Full scale (2004-2007)	EERC/URS	MoSES-3	Lignite/PRB	ESP-wFGD	CaCl_2 (400 – 800)	40% to 45%
						CaBr_2 (55 - 330)	65% to 92%

Sources: Benson *et. al* (2006), Benson *et. al* (2007)

3.3.13.1 Economic considerations

Benson *et. al* (2007) estimate the cost associated with operated oxidation treatment systems. For the 450 MW MRY-3 unit operating at 85% capacity and burning lignite coal, capital and operating costs were estimated for eight mercury control operating configurations. The highest level of mercury capture (60%) was achieved with SEA2 added at 50 ppm and PAC added at 1.3 lb/MMAcf. The levelized annual cost for this configuration was estimated at about \$1.9 million, equivalent to \$0.50/MWh or \$10,424 per pound of mercury removed (all figures in 2007 US dollars).

For the 793 MoSES-2 unit operating at an assumed 85% capacity and burning a lignite/PRB blend, capital and operating costs were estimated at three levels of mercury removal using a CaBr_2 injection system. Levelized annual cost ranged from about \$2.9 million for 59% mercury removal (\$0.5/MWh) up to \$7.9 million for 90% mercury removal (\$1.34/MWh) (all figures in 2007 USD).

3.3.14 Fixed Oxidation catalysts

Fixed oxidation catalysts have been tested at the pilot and commercial scale on units equipped with wet flue gas desulphurization (wFGD) systems (Table 3-10). The fixed bed catalyst is installed downstream of the particulate control device and upstream of the wet scrubber. Flue gas passes through the catalyst bed where elemental mercury is oxidized. The oxidized mercury is then removed in the scrubber.

URS conducted pilot scale tests of fixed oxidation catalysts for wFGD at two facilities (Coal Creek and Spruce) from 2002 to 2005, and commenced full scale tests at three sites (Monticello, Plant Yates, Coronado) beginning in 2005. Pilot tests at lignite-burning Coal Creek, equipped with palladium catalysts resulted in Hg⁰ oxidation of up to 95%, based on lignite coals, with fresh catalysts, declining to 60% to 70% after 20 months of tests. Elemental mercury oxidation was 90% in palladium catalyst regenerated with 600 °F air (Blythe et. al 2007). Pilot tests at the PRB-burning FF equipped Spruce unit, resulted in 93% Hg⁰ capture in the scrubber.

Full scale testing at Monticello 3 and Plant Yates 1 have revealed several technical challenges associated with use of fixed bed catalysts. At the lignite/PRB burning Monticello 3, ash build up caused pressure drop across the catalysts, resulting in decreased performance (Blythe et. al. 2007). Catalyst performance at PRB-burning Coronada also suffered from ash build up. The use of sonic horns reduced ash build up at both Monticello 3 and Coronado. Preliminary economic assessments conducted by Blythe and Brasfield (2006) and Blythe et. al 2007 indicate that fixed bed catalysts have similar economics as ACI systems, when ash sales is not important. However, when ash sales are a consideration, fixed bed oxidation catalysts may be economically attractive (relative to ACI) in units equipped with ESP/FGD.

Table 3-10. Fixed oxidation catalysts.

Technology	Test type (year)	Test lead	Plant	Coal	APCD configuration	Catalyst type	% Hg⁰ oxidation
Fixed catalyst bed (Pd)	Pilot (2004)	URS/EP RI	Coal Creek	Lignite	csESP/wFGD	Pd	95% (fresh), 67% (20 months)
Fixed catalyst bed	Pilot (2004)	URS/EP RI	Coal Creek	Lignite	csESP, wFGD	AC	79% (13 months)
Fixed catalyst bed	Full scale (2005/06)	URS	Monticello 3	Lignite/PRB	csESP, LSFO, wFGD	Au	66% (17 months)
						Regen. Pd	72% (17 months)
Fixed catalyst bed	Full scale (2005/06)	URS	Coronado	PRB	hsESP, wFGD		88%
Fixed catalyst bed	Full scale (2008)	URS	Plant Yates 1	Bit(LS)	csESP, wFGD	Au	58% (11 months)
						Pd	38% (11 months)
						Regen. SCR	32% (11 months)
						Regen. Au	26% (11 months)

Source: Feely and Jones (2008)

3.3.15 Low temperature mercury capture

Consol Energy Inc. has developed method for low cost control of mercury emissions from coal-fired power plants. The Low Temperature Mercury Control Process (LTMC) involves cooling the flue gas to about 220 °F with an air heater or water spray and absorbing mercury onto carbon inherent in the flue gas. Magnesium Hydroxide $Mg(OH)_2$ is introduced into the flue gas upstream of the heater to protect components from SO_2 corrosion (Winschel et. al 2004). At a slip stream pilot tested conducted at Allegheny Energy's 288 MW bituminous powered Mitchell Station Unit 3, equipped with FGD and ESP the LTMC process reduced mercury emissions by 50% versus 25% in baseline conditions (Winschel et. al 2004). The LTMC process is currently undergoing field trials at Unit 4 of AER Paul Smith Station.

3.3.16 Multi-pollutant control technologies

3.3.16.1 **Pahlman™ Process**

The Pahlman™ process is a multi-pollutant control technology developed by EnviroScrub Technology Corporation. The process uses a patent-pending manganese oxide (MnO_2) sorbent (Pahlmanite™) injected into the flue gas downstream of the primary particle control device (Wocken 2004). The sorbent collects in a baghouse reactor chamber. Once gas-sorbent contact is completed the sorbent can be pulsed off and either re-injected into the flue gas stream or regenerated. The technology was slipstream pilot tested at Minnesota Power's PRB subbituminous burning Boswell Energy Centre. Total mercury removal ranged between 64% and 94%, with up to 99% removal of elemental mercury. SO_2 removal averaged nearly 99% while NO_x removal ranged from 53% to 96% depending on sorbent loading (Wocken 2004).

Pahlman™ is touted as a lower cost alternative to a SCR/wFGD set up for SO_2 , and NO_x control, with the additional benefit of mercury removal. While detailed cost data on the Pahlman™ process was unavailable for this review, information provided by EnviroScrub suggest the technology could be installed at a capital cost of \$150/kW for a 500 MW plant, and incur annual operating costs of \$1.45/Mh (Power Engineering 2002). No commercial scale installations of the Pahlman™ process were identified in this review.

3.3.16.2 **Electro-catalytic oxidation**

Electro-catalytic oxidation (ECO) is a patented technology developed by Powerspan for simultaneous removal of sulphur dioxide (SO_2), nitrogen oxides (NO_x), fine particulate matter ($PM_{2.5}$), and mercury from the flue gas of coal-fired power plants (McLarnon 2004). ECO is a four step system designed to be installed downstream of a plant's particulate treatment device. The first stage is a barrier discharge reactor, which oxidizes flue gas constituents into higher oxides. At this stage, nitrogen oxides are oxidize to nitrogen dioxide and nitric acid while mercury is oxidized to mercuric oxide (McLarnon 2004). The second stage consists of an ammonium based scrubber, which converts the nitrogen dioxide and sulphur dioxide from the discharge reactor into ammonium sulphate/ammonium nitrate. The third phase is a wet electrostatic precipitator (wESP), which captures mercuric oxide, acidic aerosols and particulate matter (McLarnon 2004). Liquid effluent from the scrubber is sent to a recovery system that

includes fine filters, to remove ash, and sulphur impregnated activated carbon, to remove oxidized mercury.

Powerspan pilot tested the ECO system at First Energy's Burger Plant Units 4 and 5. Pilot results indicate the technology was successful at removing 80% to 90% of mercury, while also removing 90% of NO_x, 98% of SO₂, and 99.9% of fine particulates (McLarnon 2004). It should be noted that during pilot testing, due to ash contamination of the discharge reactor by the flue gas stream, an elemental mercury gas was added to the reactor to test its mercury oxidation effectiveness. Thus the pilot test did not in this respect mimic plant operating conditions. Other potential benefits of ECO are a smaller footprint relative to other multi-pollutant technology combinations. As well, the system produces ammonium-nitrate/sulphate, which can be commercially sold as a fertilizer. McLarnon (2004) estimates that an ECO system can be installed for \$250 per kW of capacity operated at a levelized cost of \$2.0 to \$2.5/MWh.

3.3.16.3 GE EER multi-pollutant control process

Combustion modification involves optimizing combustion conditions to maximize mercury and NO_x removal from existing air pollution control equipment. The process involves creating a secondary (reburning) combustion area in the boiler, above the primary combustion zone by injecting reburning fuel and overfire air. NO_x in the reburning zone is reduced to elemental nitrogen (N₂). Pilot and full scale tests of the technology were undertaken at the 250 MW bituminous fueled Green Station Unit 2, which is equipped with an ESP and wet scrubber. At pilot scale, up to 95% mercury removal was recorded across the ESP. Mercury removal was lower at full scale tests, with only 30% - 50% removal across the ESP and 70% to 80% removal across the ESP and wet scrubber (GE and EER 2004).

3.3.16.4 Mobotec Furnace Sorbent Injection (FSI) with ROFA™ and ROTAMIX™

The Mobotec Furnace Sorbent Injection (FSI) with ROFA™ and ROTAMIX™ is a patented technology developed by NALCO Mobotec. This method includes injection of an oxidizing agent, such as limestone and trona directly into the furnace. It is developed for SO₂ control and touted as a lower capital cost alternative to wFGD.

The technology has been commercially tested at Cape Fear Station with further testing to be conducted at RPL Whitewater Station. (EERC 2005). Total mercury reduction from limestone injection was 90% and trona² injection was 67%. The capital cost of the system was estimated at \$40 – 50/kW which may be too expensive for mercury removal only.

□

² Trisodium hydrogencarbonate dehydrate, a natural source of sodium carbonate.

3.3.17 Combustion modification

3.3.17.1 **Lehigh University – increased LOI (loss on ignition) process**

The increased loss on ignition (LOI) process developed by Lehigh University, achieves higher levels of mercury capture by manipulating process controls. It has been field tested at a 250 MW plant, burning eastern bituminous coal (See Romero *et. al* 2006). The native mercury removal increased from 20% to 36%. The technology is still in an early state of development.

3.3.17.2 **Airborne Process - Sodium bicarbonate scrubbing**

The sodium bicarbonate scrubbing methodology is a patented process by Airborne Pollution Control Inc. The process combines SO₂, NO_x, and a PM control. Sodium bicarbonate is injected upstream of the scrubber and in the scrubber. The process results in 99.9% SO₂ removal and NO_x removal > 80%. It has been tested (5 MW scale) at Ghent Generating Station with high sulphur coal, ESP, wFGD (see Johnson *et. al* 2003).

3.3.18 Advanced coal cleaning/pre-treatment

3.3.18.1 **Western Research Institute (WRI) thermal treatment of coal**

The University of Wyoming's Western Research Institute (WRI) has patented a process for mercury removal from coal via pre-combustion thermal treatment. The two step process involves heating the coal to first remove moisture and then, in the presence of an inert gas, remove mercury. Bench-scale tests undertaken by WRI indicate the technology can remove up to 80% of mercury in PRB subbituminous and lignite coals. In general, higher levels of mercury removal were experienced at higher temperatures and residency times within the reactor (Bland *et. al* undated). Higher levels of mercury removal are anticipated when thermal pre-treatment is combined with ACI. Another benefit of thermal pre-treatment is the capture of water, which can be used in the plant.

The technology is currently undergoing pilot scale testing by WRI and partner organizations as part of Phase III of DOE/NETL's mercury emission control development program. Objectives of the pilot scale tests include validation the technology over a number of coal types, integrate the technology with operating plants burning PRB and lignite coals, and conduct an economic analysis of the benefits of pre-combustion thermal treatment.

3.3.18.2 **K-fuel[®]**

The K-fuel[®] process, developed by Evergreen Energy Inc., is a form of coal pre-treatment of that removes moisture and impurities through the use of heat and pressure. One of the principle objectives of the K-fuel[®] process is to refine lower rank coals, such as subbituminous and lignite grades, by driving out moisture and raising the heat content. On its website, Evergreen Energy claims the K-fuel process has achieved up to 76.2% mercury removal from PRB subbituminous coals and 76.1% mercury removal from Louisiana lignite coal. In 2005 Evergreen Energy Inc. constructed a full scale coal refinery near Gillette, Wyoming. The Gillette plant has since been

idled and Evergreen Energy has teamed up with Bectel to promote the commercialization of its K-fuel[®] technology (Evergreen Energy website).

3.3.18.3 Magnetic separation

Dry magnetic separation has been developed as an alternative to gravimetric methods now used for cleaning bituminous coals. MagMill[™], a technology developed by MagMill LLC, combines coal pulverizing and magnetic separation of mineral components. Mineral laden pyritic components become concentrated on the grinding table are withdrawn from the pulverizer and passed through a series of mechanical and magnetic separators. The separators remove the mineral components while recycling carbon components back into the mill (Oder et al. 2008). Since MagMill[™] removes sulphur, mercury, and other mineral components, it is a form of multi-pollutant control. A commercial scale MagMill[™] demonstration unit has been installed at the DTE Energy SERvices Petcoke Grinding Facility in Vicksburg, Mississippi.

A beta prototype MagMill[™] unit was installed at the Bradley Pulverizer Company pilot test facility in Allentown, Pennsylvania in 1999. Tests based on Pennsylvanian bituminous coal with 2.95% S and 0.15 ppm mercury yielded mercury separation by the MagMill (Oder 2004). Oder estimates that over 90% mercury removal would be achieved by combining MagMill with a LSFO flue gas scrubber.

Preliminary cost figures presented in Oder 2004 indicate the cost of installing a MagMill[™] range from \$65 million to \$85 million depending on the level of sulphur removal required and whether or not the plant is equipped with a scrubber, based on a 500 MW plant burning Appalachian bituminous coal (figures in 2004 USD). The capital cost of MagMill[™] likely render it cost prohibitive for mercury reduction only, though it may be economical for use by plants requiring both sulphur and mercury control.

3.3.18.4 Chemical separation

CQ Inc. developed the HAPs-Rx[™] process for removing mercury from coal, in the late 1990's. Unlike other coal cleaning techniques, the HAPs-Rx[™] was developed specifically for mercury capture. The technology involved use of mild solvents and heat to volatilize mercury components. Using a variety of solvents, the technique achieve up to 38% mercury capture from PRB subbituminous coals and 50% capture from eastern bituminous coals (Akers 1998). While Akers 1998 provides some preliminary cost figures, detailed information was not available for this review.

3.3.18.5 Advanced froth flotation

In advanced froth flotation, fine coal slurry and air bubbles are fed into a mechanically agitated separation column. The air bubbles separate coal particles, which have hydrophobic properties, from mineral refuse particles, which are hydrophilic (EERC 2005). Water added above the coal feed creates downward pressure within the column, and flushes out mineral refuse particles. Bench-scale testing of advanced froth flotation of bituminous coals yielded mercury removal in the 50% to 55% range. EERC (2005) reports initial cost estimates for bituminous coals was

\$5.60 to \$8.70 per ton (1997 US\$) but the technique would be cost-prohibitive for subbituminous and lignite coals.

3.3.18.6 Selective agglomeration

Selective agglomeration involves the use of an oil-based bridging solution, which causes agglomeration of coal particles (EERC 2005). Mineral refuse particles remain entrained in the liquid phase, and are separated using flotation or screening. EERC (2005) reports selective agglomeration resulted in 39% mercury removal based on tests of five bituminous coals. Costs were estimated at about 30% higher than advanced froth flotation.

3.3.18.7 Biological separation

Laboratory testing on coal treatment through use of bacteria and fungi has been conducted at the Idaho National Engineering and Environmental Laboratory, as well as several universities in Europe (EERC 2005). One potential method involves use of microbes that consume sulphur, to which metals including mercury is attached. A two stage approach involves first physical separation of pyrite and other minerals within the coal, and then biological treatment to oxidize the sulphur, mercury, and other components of the pyrite (EERC 2005). Biological separation methods are experimental and have not been commercially tested.

3.3.19 Other developing technologies

3.3.19.1 Photochemical Oxidation

Photochemical oxidation uses ultraviolet light to excite mercury in flue gas, resulting in oxidation. This process is a potential low cost mercury capture method. It results in oxidation rates up to 90% at bench-scale. There has been no larger scale testing or economic assessment of this technology (McLarnon et. al 2005, EERC 2005).

3.3.19.2 GRE fluid-bed drying process (Lignite Fuel Enhancement System)

The GRE fluid-bed drying process is a method which uses waste heat in lignite burning units to pre-heat the coal. The pre-heating removes boiler efficiency, reduces NO_x and SO₂, and mercury emissions (in small amounts). This process has been tested at Great River Energy, Coke Creek Station in North Dakota and resulted in a decrease in mercury emissions of only 0.5% (see Gollakata 2007).

3.3.19.3 Membrane based wet Electrostatic Precipitation

Membrane based w-ESP is a multi-pollutant control technology used to capture particulate matter, sulphuric acid, as well as mercury. The technology has been developed as a lower cost alternative to metallic ESP. Pilot testing at Penn Power's Bruce Mansfield Plant indicate that membrane based w-ESP provides similar multi-pollutant capability as conventional wESP. The membrane based w-ESP removed higher levels of particle based and oxidized mercury compared to the metallic w-ESP (Reynolds 2004). However, the level of elemental mercury capture was

lower (33% vs. 36%) suggesting that w-ESP may not be effective as a stand-alone technology for coals that result in high levels of elemental mercury in the flue gas.

3.3.19.4 Advanced Hybrid Filter™

The advanced Hybrid Filter™ was developed by EERC and is licensed to W.R. Gore. It is a hybrid particulate control device which combines the features of ESP and baghouse. The system uses GORETEX membrane filter bags and has been tested at Big Stone Power Plant, and it burns PRB. The principle market is for particulate removal with over 90% Hg removal (Gerbert *et. al* 2001, EERC 2005.) This system is a possible alternative to TOXECON.

3.3.19.5 W.R. Gore promoted felt filter bag inserts

The W.R. Gore promoted felt filter bag insert technology is added to the baghouse to achieve higher levels of mercury removal (Durante *et. al* 2003). Pavlish *et. al.* (2005) reports nearly a 100% mercury removal from bench-scale testing.

3.3.19.6 LoTox™

LoTox™ is a method for oxidizing lower nitrogen oxides into higher nitrogen oxides, which are water soluble and can be removed with a wet scrubber. It is a multi-pollutant control and treats SO₂, NO_x and mercury. It is licensed to BOC Gases by Gannon Technology and has been tested at SRI. Pavlish (2005) suggests a mercury removal of over 90% is possible with the scrubber. There is no commercial validation and the current status of the technology is uncertain.

3.3.19.7 Condensing heat exchanger (McDermott Technologies)

The condensing heat exchanger has a similar performance as the wet scrubber (Pavlish *et. al* 2005). It was developed primarily for SO₂ removal however, Ohio Coals reported 62% mercury removal. There are no recent test results or economic data available.

3.3.20 Next Generation Coal Combustion Technologies

3.3.20.1 Fluidized bed combustion

The fluidized bed combustion technology is used at Point Aconi. This technology has the potential for higher levels of mercury removal than pc and cyclone fired systems because of its lower operating temp (Pavlish *et. al* 2005). FBC units sampled at ICR Phase III saw a mercury removal from 48% to 99%, lignites at 54% to 58% and bituminous at 99%. Point Aconi use a pet coke (75%)/bit/sub bit (25%) blend, and see a mercury removal above 90%. The R.M. Heskett Station in North Dakota reports a mercury removal of 53%.

3.3.20.2 Integrated Gasification Combined Cycle Systems (IGCC)

The Integrated Gasification Combined Cycle (IGCC) system technology has been around for a many years and comes with a high capital cost. It reports a native mercury removal of 33% to 42%. Mercury removal would be increased with the use of fixed AC bed (Pavlish *et. al* 2005).

The Polk Power 250 MW, HS bit coal, can also take petroleum coke with a 42% native mercury removal. The Wabash Power 262 MW, bit coal sees a 33% mercury removal.

The cost of mercury removal would be low (but would not implement technology for mercury removal only) for this technology. Pavlish (2005) makes an economic case for low cost mercury removal with a fixed carbon bed (\$3412/lb) based on sulphur impregnated carbon.

3.3.20.3 Indirectly fired combined cycle (IFCC) systems

There is no Indirectly Fired Combined Cycle (IFCC) system in the U.S. or Canada. The IFCC systems may replace supercritical boilers now operating in North America. The EERC pilot scale SFS reports a 20% mercury capture from lignite (Pavlish *et. al* 2005).

3.3.21 U.S. Government Accountability Office

The United States Government Accountability Office (U.S. GAO) has completed two reports regarding the technologies and costs associated with mercury control. The first report, was completed in May 2005 in response to requests from the U.S. Congress, was based on a literature review and interviews with key stakeholders, including technology vendors, representatives of the coal fired power industry, as well as government and academic researchers. The report found sorbent injection methods the most promising method for mercury control. GAO (2005) provides capital and operating cost estimates for installing sorbent injection technology under a number of operational configurations. It also acknowledged that cost estimates depend on a number of site-specific factors, including coal type and existing air pollution control equipment.

In its 2009 report to the U.S. Senate entitled *Mercury Control Technologies at Coal-Fired Power Plants Achieved Substantial Emissions Reductions* the GAO provided an update on the effectiveness and cost of mercury control technologies. In this report, the GAO focussed on sorbent injection systems. In addition to a literature review, the report based its findings on structured interviews with representatives from 13 coal-fired power plants that were operating mercury control technologies (all using activated carbon injection systems) and with six plants that were using existing air pollution controls to meet mercury emission reduction requirements (GAO 2009).

Based on its survey, GAO (2009) found that operating utilities used either a form of activated carbon injection or activated carbon injection coupled with a polishing fabric filter baghouse for mercury control. Average reduction in emitted mercury was 80% to 90%, with plants reporting higher levels of mercury removal through the use of chemically treated carbon sorbents.

GAO (2009) identified several examples where total mercury reduction was 90% or more, including:

- a bituminous-fired 164 MW plant equipped with cs-ESP, using chemically treated carbon sorbent (95% mercury reduction),
- a subbituminous fired 400 MW plant equipped with cs-ESP and a fabric filter, using untreated carbon sorbent (99% mercury reduction),