

FINAL REPORT

EVALUATION OF TECHNOLOGIES FOR REDUCING MERCURY EMISSIONS FROM THE ELECTRIC POWER GENERATION SECTOR

Prepared for:

The Canadian Council of Ministers of the Environment

Prepared by:

SENES Consultants Limited

121 Granton Drive, Unit 12

Richmond Hill, Ontario

L4B 3N4

February 2002

Printed on Recycled Paper Containing Post-Consumer Fibre



FINAL REPORT

EVALUATION OF TECHNOLOGIES FOR REDUCING MERCURY EMISSIONS FROM THE ELECTRIC POWER GENERATION SECTOR

Prepared for:

The Canadian Council of Ministers of the Environment

Prepared by:

SENES Consultants Limited

121 Granton Drive, Unit 12

Richmond Hill, Ontario

L4B 3N4



Paula T. Coutts, M.Eng., P.Eng.
Author



James W.S. Young, Ph.D., P.Eng
Reviewer

February 2002

Printed on Recycled Paper Containing Post-Consumer Fibre



DISCLAIMER

Working Paper Disclaimer:

This publication is a working paper only. It contains information which has been prepared for, but not approved by, the Canadian Council of Ministers of the Environment (CCME). CCME is committed to reflect the highest standards of research and analysis in its publications. Since CCME itself does not conduct research or author reports, it is not responsible for the accuracy of the data contained in the publications and does not warrant, or necessarily share or affirm, in any way, any opinions expressed therein.

Démenti:

La présente publication est un document de travail seulement. L'information qu'elle contient a été préparée à l'intention du Conseil canadien des ministres de l'environnement (CCME), mais n'a pas reçu son approbation. Le CCME exige l'application des normes de recherche les plus élevées qui soient dans ses publications. Comme le CCME ne poursuit aucuns travaux de recherche ni ne signe de rapports, il n'est pas responsable de l'exactitude des données contenues dans ses publications. Il ne se porte pas garant des opinions qui y sont exprimées, pas plus qu'il ne les partage ou ne les soutient nécessairement.

TABLE OF CONTENTS

	<u>Page No.</u>
DISCLAIMER	D-1
GLOSSARY	G-1
1.0 INTRODUCTION	1
1.1 Background	1
1.2 Scope of Work	1
1.3 Report Structure	2
2.0 MERCURY EMISSIONS AND REGULATIONS	3
2.1 Introduction.....	3
2.2 Mercury and Other Emissions from Coal-Fired Boilers	3
2.3 Current and Proposed Regulations	7
3.0 OPTIONS FOR ABATEMENT/REDUCTION OF MERCURY EMISSIONS	8
3.1 Introduction.....	8
3.2 Mercury Behaviour in Flue Gas.....	8
3.2.1 Measurement of Mercury Emissions and Speciation.....	9
3.2.2 Information Collection Request (ICR).....	10
3.3 Mercury Control Options	13
3.3.1 Pollution Prevention.....	16
3.3.2 Post-Combustion Technological Controls	19
3.3.3 Emerging Controls	30
3.4 Summary of Control Technologies Examined.....	38
3.5 Waste Disposal Issues	40
3.5.1 Solid Waste	40
3.5.2 Liquid Waste	40
4.0 CO-CONTROL.....	42
5.0 COST OF REDUCING MERCURY	46
5.1 Cost Estimating Methodology	46
5.2 Mercury Control Costs.....	51
5.3 Results of The Costing Analysis	51
5.4 Sensitivity Analysis	54
5.4.1 Retrofit Cost Factor.....	54
5.4.2 Sensitivity Analysis on Natural Gas Prices	55
6.0 CONCLUSIONS.....	57
REFERENCES	R-1
BIBLIOGRAPHY	B-1
APPENDIX A: INTRODUCTION TO COST ESTIMATING FUNCTIONS	

LIST OF TABLES

	<u>Page No.</u>
2.1	Compounds of Mercury3
2.2	1999 Canadian Mercury Emissions5
2.3	1999 Canadian Emissions from Coal-Fired Power Plants6
3.1	Examples of Measurement Variability: Mercury in Coal.....10
3.2	Summary of Mercury Speciation Data from U.S. Coals in 199911
3.3	Mercury Control Options for Current Air Pollution Control Devices in Coal-Fired Power Plants.....14
3.4	Summary of Mercury Control Efficiencies due to Coal Cleaning.....19
3.5	Summary of Mercury Control Efficiencies due to Wet Scrubbing22
3.6	Summary of Mercury Control Efficiencies due to Dry FGD Systems24
3.7	Potential Elemental Mercury Reduction by SCR26
3.8	Summary of Mercury Removal Efficiencies by Fabric Filters29
3.9	Summary of Mercury Control Technologies and Efficiencies39
4.1	Multi-Pollutant Control Benefits44
5.1	Summary of Mercury Control Costs and Co-Control for ATCOfollows 51
5.2	Summary of Mercury Control Costs and Co-Control for EPCORfollows 51
5.3	Summary of Mercury Control Costs and Co-Control for Manitoba Hydro.....follows 51
5.4	Summary of Mercury Control Costs and Co-Control for New Brunswick Power.... follows 51
5.5	Summary of Mercury Control Costs and Co-Control for Nova Scotia Power follows 51
5.6	Summary of Mercury Control Costs and Co-Control for OPG follows 51
5.7	Summary of Mercury Control Costs and Co-Control for SaskPowerfollows 51
5.8	Summary of Mercury Control Costs and Co-Control for TransAlta follows 51
5.9	Example Mercury Control Costs for U.S. Coal-Fired Boilers53
5.10	Sensitivity Analysis on Retrofit Cost Factor54
5.11	Effect of Increases in the Price of Natural Gas56
A.1	Conversion Factors for Yearly Cost Adjustments A-2
A.2	Costs of Inputs to the Algorithms A-4
A.3	Provincial Input Parameters A-5

LIST OF FIGURES

	<u>Follows Page No.</u>
5.1	Elements of Total Capital Investment48
5.2	Elements of Annual Cost50

GLOSSARY

ACC	-	Advanced Coal Cleaning
acf	-	actual cubic feet
ACI	-	Activated Carbon Injection
APCD	-	Air Pollution Control Device
B&W	-	Babcock & Wilcox
CAA	-	Clean Air Act
CAC	-	Criteria Air Contaminant
CaOH ₂	-	Hydrated Lime
CCR	-	Coal Combustion Residue
CCME	-	Canadian Council of Ministers of the Environment
CEA	-	Canadian Electricity Association
CEF	-	Cost Estimating Function
CEC	-	Commission for Environmental Co-operation
CEMS	-	Continuous Emissions Monitoring System
CEPA	-	Canadian Environmental Protection Act
CFB	-	Circulating Fluidized Bed
CI	-	Carbon Injection
Cl ₂	-	Chlorine
CO	-	Carbon Monoxide
COHPAC	-	Compact Hybrid Particulate Collector
CO ₂	-	Carbon Dioxide
CS-ESP	-	Cold-Side ESP
CWS	-	Canada-Wide Standards
U.S. DOE	-	United States Department of Energy
DC	-	Development Committee
DSI	-	Dry Sorbent Injection
dscm	-	dry standard cubic metre
ECO	-	Electro-Catalytic Oxidation
EPRI	-	Electric Power Research Institute
ESP	-	ElectroStatic Precipitator
FF	-	Fabric Filter
FGD	-	Flue Gas Desulphurization
FSW	-	Fuel Switching (to natural gas)
ft/hr	-	feet per hour
gal	-	gallons
H ₂ O	-	water
HRSG	-	Heat Recovery Steam Generator
H ₂ SO ₄	-	sulphuric acid

HAP	-	Hazardous Air Pollutant
HCl	-	hydrochloric acid
Hg	-	mercury
Hg ⁰	-	elemental or metallic mercury,
Hg ₂ ²⁺	-	mercurous ion (monovalent mercury)
Hg ²⁺	-	mercury II (mercuric ion, divalent mercury, oxidized/ionic form).
HgCl ₂	-	Mercuric Chloride
HgO	-	Mercuric Oxide
HgS	-	Mercuric Sulphide
HS-ESP	-	Hot-Side ESP
ICR	-	Information Collection Request
IGCC	-	Integrated Gasification Combined Cycle
KCl	-	Potassium Chloride
kg	-	kilogram (1000 grams)
kWh	-	kilowatt-hour
lb	-	pound
L/G	-	Liquid to Gas ratio
LSD	-	Lime Spray Drying
LSFO	-	Limestone Forced Oxidation (wet scrubbing)
MACT	-	Maximum Achievable Control Technology
MADEP	-	MAssachusetts Department of Environmental Protection
MBtu	-	Million British Thermal Units
MESA	-	MEcury Speciation Adsorption
mg	-	milligram (10 ⁻³ grams)
mmacf	-	million actual cubic feet
MW	-	Megawatt (million Watts)
MWe	-	Megawatt of electricity
MWh	-	Megawatt-hour
NAAQS	-	National Ambient Air Quality Standard
NAFTA	-	North American Free Trade Agreement
NEG/ECP	-	New England Governors / Eastern Canadian Premiers
NESCAUM	-	NorthEast States for Coordinated Air Use Management
NH ₃	-	Ammonia
NO	-	Nitric Oxide
NO _x	-	Nitrogen Oxides
OH	-	Ontario Hydro
OAQPS	-	Office of Air Quality Planning Standards
PC	-	Pulverized Coal
PCDD	-	Polychloro-dibenzo-p-dioxin
PCDF	-	Polychloro-dibenzofuran

pg	-	picogram (10^{-12} gram)
PJFF	-	Pulse-Jet Fabric Filter
PM	-	Particulate Matter
PM ₁₀	-	Particulate Matter less than 10 microns in diameter
PRB	-	Powder River Basin
RCRA	-	Resource Conservation and Recovery Act
RDIS	-	Residual Discharge Information System
S	-	sulphur
SC	-	spray cooling
scfm	-	standard cubic feet per minute
SCR	-	Selective Catalytic Reduction
SD	-	Spray Dryer
SDA	-	Spray Dry Absorber
SDS	-	Spray Dry Scrubbing
SO ₂	-	sulphur dioxide
SO ₃	-	sulphur trioxide
TAC	-	Total Annualized Cost
TCC	-	Total Capital Costs
TCLP	-	Toxicity Characteristic Leaching Procedure
TEQ	-	Toxic Equivalent
TWG	-	Technical Working Group
UNECE	-	United Nations Economic Commission for Europe
U.S.EPA	-	United States Environmental Protection Agency
WFGD	-	Wet FGD (also called LSFO)
WTE	-	Waste-To-Energy
µg/m ³	-	micrograms per cubic metre

1.0 INTRODUCTION

The purpose of this study is to assist the Development Committee (DC) on mercury, to set Canada-wide standards for mercury emissions from the coal-fired electric power generation sector, by providing cost information for technically feasible control technologies and pollution prevention strategies.

1.1 BACKGROUND

In October 1999, SENES Consultants Limited released a report entitled *Evaluation of Technologies for Reducing Mercury Emissions: Power Generation & Base Metal Smelting* (SENES 1999). In the 1999 study, the costs of mercury controls for the power generation sector were primarily based on 1995 facility data contained in Environment Canada's Residual Discharge Information System (RDIS II) database, in the absence of more accurate facility input data.

In September 2000, the Canadian Council of Ministers of the Environment (CCME) contracted SENES to update the 1999 study, using revised facility data and information on relevant technologies provided by the power generation sector. The Cost Estimating Functions have also been updated since the previous study, as have assumptions on control efficiencies of various air pollution control technologies, based on updated information received up to the end of August 2001 (data from the Canadian coal-fired electricity generating sector, personal communication with researchers, and information compiled from the literature, including Proceedings of the A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, held in Chicago on August 20-23, 2001).

1.2 SCOPE OF WORK

The objectives of this study are to:

- determine the technical capability of specific abatement technologies or fuel sources that can be applied to existing coal-fired facilities to reduce releases of mercury, and potentially other substances, to air (SO₂, NO_x, PM, CO₂ and dioxins/furans);
- revise the estimated costs and reduction efficiencies of specific technologies/fuels at each source in accordance with the finalized range of emission control technologies and updated source-specific data obtained through consultation with industry stakeholders. Report these costs and efficiencies for the various combinations as identified for each facility;

- produce a stand-alone report on the sector based on the updated technology and cost assessment; and
- work with government policy staff (Development Committee) and Technical Working Group (government and industry representatives) through the development, validation and finalization of the efficiencies, costs and implications of the evaluated technologies, through the period of approximately September 2000 – November 2001.

1.3 REPORT STRUCTURE

The report has the following structure:

Chapter 2 describes mercury emissions from the coal-fired power generation sector in general, and provides a summary of emissions from coal burned in Canada in 1999;

Chapter 3 describes current and emerging control technologies and pollution prevention options for reducing mercury from coal-fired utility boilers. The difficulties in measuring and reducing the different species and physical forms of mercury in the flue gas are discussed;

Chapter 4 discusses potential emission reductions that can be achieved for other pollutants such as SO₂, NO_x, CO₂, Particulate Matter and dioxins/furans;

Chapter 5 describes the principles of the costing analysis, as well as the results for each facility; and

Chapter 6 presents the conclusions of this study, and recommendations.

An introduction to the Cost Estimating Functions and inputs to the analysis are described in Appendix A.

2.0 MERCURY EMISSIONS AND REGULATIONS

2.1 INTRODUCTION

Mercury released to the environment can occur in various physical and chemical forms. Physically, mercury in the environment may exist as a gas or a liquid, or it may be associated with solid particles. Chemically, mercury can exist in three oxidation states:

- (1) Hg^0 - elemental or metallic mercury;
- (2) Hg_2^{2+} - mercurous ion (monovalent mercury); and
- (3) Hg^{2+} - mercury II (mercuric ion, divalent mercury, ionic/oxidized mercury).

Mercury also forms complexes with other chemicals to form inorganic compounds (such as HgCl_2 - mercuric chloride) and organic compounds (such as methyl mercury).

The physico-chemical properties of some mercury containing compounds are presented in Table 2.1. Both elemental Hg and mercuric chloride have high vapour pressures and as a result will be in the vapour phase at typical flue gas temperatures.

TABLE 2.1
COMPOUNDS OF MERCURY

COMPOUND	FORMULA	BOILING POINT (°C)	VAPOUR PRESSURE (Pa)	SOLUBILITY (PER 100 PARTS H_2O)
Mercury	Hg	356.6	0.26 @ 25°C 1000 @ 150°C	Insoluble
Mercuric Oxide	HgO	500 ¹		0.005
Mercurous Oxide	Hg_2O	100 ¹		Insoluble
Mercuric Chloride	HgCl_2	302	12.16 @ 25°C	6.9 @ 20°C 61.3 @ 100°C
Mercurous Chloride	Hg_2Cl_2	525 ¹		0.0002
Mercury Sulphide	HgS	583		insoluble

¹Decomposes at melting point

Source: Lerner 1993, U.S. EPA 1998b, Cooper and Alley 1994.

2.2 MERCURY AND OTHER EMISSIONS FROM COAL-FIRED BOILERS

Mercury is often found as a trace contaminant in fossil fuels. When these fuels are combusted, the combination of the elevated temperature and the volatility of mercury and its compounds result in the presence of mercury in the combustion gas exhaust stream. Due to extensive use, and

the relatively high mercury content of coal compared to fuel oil, coal-fired power plants account for the majority of mercury emissions from the power generation sector in Canada.

Coal is a complex combination of organic matter and inorganic ash found in geological formations from successive layers of fallen vegetation and other organic matter. Coal types are broadly classified as anthracite, bituminous, sub-bituminous or lignite. Classification is by heating value and amount of fixed carbon, volatile matter, ash, sulphur and moisture.

Important things to consider when dealing with mercury emission from coal-fired boilers include (NESCAUM, 2000a):

- the mercury content of different fossil fuels varies widely. Coal has the highest mercury content of conventional boiler fuels, natural gas has the lowest;
- mercury content can vary significantly among different samples of the same fossil fuel. For example, the mercury content of coal from different regions, or even from different coal seams at the same mine, can vary considerably;
- mercury in flue gas exists in different chemical forms or species. Mercury emitted from electricity generating boilers is emitted in ionic, elemental or particulate forms. The precise mix of species present depends on a number of factors and can vary from one source to another;
- the mix of mercury species present is critical because various control technologies are more effective at removing some species than others. Chemical speciation also affects the transport and deposition of emitted mercury;
- airborne mercury, especially when emitted in elemental form, can be transported over long distances; and
- the influence of individual power plants on local mercury deposition rates can be significant.

Brown et al. (1999) describe the following characteristics that most greatly influence mercury emissions:

- mercury content of the as-fired coal;
- type of burner(s) on the plant;
- boiler operating conditions;
- design and operation of particulate collection devices; and
- design and operation of flue gas treatment systems;

Table 2.2 summarizes total mercury emissions for each power generation company in Canada, as well as the amount of mercury in each species that is emitted (particulate, ionic or elemental).

TABLE 2.2

1999 CANADIAN MERCURY EMISSIONS

NOTE: The information in the Table below was calculated for a single-purpose study of costs and extent of possible mercury reduction from coal-fired power plants. The data are often taken from a single stack test, using a single coal, which means that the use of the data to estimate annual mercury emissions for any operating year or to define a speciation ratio for all operating periods produces a highly uncertain value for both. Even where measured results are reported, those measurements are made by methods which, themselves, have inherent uncertainty. Further, some of the data in the Table are produced from emission factors selected from a range of values available for the relevant coal types and may not necessarily apply fully to the specific application. The electricity generators are working to improve their estimations of both total annual mercury emissions, as well as the typical ratio of emitted forms of mercury¹ (Personal Communication with CEA, 2002).

Plant Name	Nameplate Capacity (MW)	Total Mercury Emissions (kg)	Species Ratio [%] [Elemental:Ionic]²
Brandon	105	<6	N/A
Selkirk	2 x 66	<5	N/A
Genesee	2 x 410 MW	106	Approx. 79:20
Boundary Dam	2 x 66, 3 x 150, 292	110	Approx. 85:15
Poplar River	2 x 300	111	Approx. 83:17
Shand Power	300	56	Approx. 85:15
Keephills	2 x 403	97	Approx. 71:29
Sundance	2 x 280, 3 x 355, 366	278	Approx. 85:15
Wabamun	2 x 64, 140, 280	79	N/A
H. R. Milner	150	5	N/A
Battle River	2 x 150, 375	140	Approx. 88:12
Sheerness	2 x 398	123	Approx. 81:19
Atikokan	215 (net)	70	Approx. 93:7
Lakeview	4 x 285 (net)	90	Approx. 33:65
Lambton	4 x 494 (net)	130	Approx. 72:27 (scrubbed) Approx. 33:64 (unscrubbed)
Nanticoke	8 x 490 (net)	260	Approx. 53:43
Thunder Bay	2 x 155 (net)	80	Approx. 96:4
Point Tupper	148	37	N/A
Point Aconi	165 (net)	6	Approx. 19:81
Trenton	150, 155	53	Approx. 50:50
Lingan	4 x 155	193	Approx. 53:47
Grand Lake	1 x 61	100	Approx. 40:57
Belledune	1 x 480	40 (Year 2000) Y1999 unavailable	N/A
Total		2,175 ³	

¹ The data from Year 1999 were retained for use in this study, even though lower values were measured in Year 2000 testing for some stacks.

² Updated speciation data were provided in February 2002. However, the information did not change the cost conclusions significantly, allowing the work to be accepted and stand in its reported form.

Table 2.3 lists the emissions for mercury and other pollutants used by SENES in this study. These estimates were obtained from the facilities in the fall of 2000 (with minor revisions from a few facilities in August 2001), together with process information, under specific confidentiality agreements signed with each company.

**TABLE 2.3
1999 CANADIAN EMISSIONS FROM COAL-FIRED POWER PLANTS⁴**

Plant	Coal Burned	Pollutant Emission (tonnes)				Total Mercury (kg)
		SO ₂	NO _x	PM	CO ₂	
Sheerness	Sub-bituminous	31,008	11,580	764	5,346,600	123
H.R. Milner	Bituminous	5,084	1,918	1,073	1,086,500	5
Battle River	Sub-bituminous	22,214	10,796	1,376	3,640,700	192
Genesee	Sub-bituminous	14,672	13,412	880	6,283,100	106
Selkirk	Sub-bituminous	501	450	771	217,750	5
Brandon	Sub-bituminous	887	602	4	325,750	6
Belledune	Bituminous	3,430	5,870	200	3,220,000	43
Grand Lake	Bituminous	21,210	830	70	353,000	97
Point Aconi	Bituminous	2,100	1,161	22	618,800	6
Point Tupper	Bituminous	16,525	3,002	228	1,067,000	37
Trenton	Bituminous	25,790	6,534	448	1,818,000	53
Lingan	Bituminous	73,952	11,332	395	3,564,300	193
Lambton	Bituminous	27,300	12,800	1,934	7,800,000	130
Nanticoke	Bit/PRB blend	81,800	24,300	7,758	17,000,000	260
Thunder Bay	Lignite/PRB blend	7,720	2,090	206	1,600,000	80
Atikokan	Lignite	5,560	1,310	30	1,100,000	70
Lakeview	Bituminous	18,100	8,740	259	3,000,000	90
Poplar River	Lignite	40,355	10,675	5,406	4,349,200	111
Shand Power	Lignite	15,000	6,000	150	2,200,000	56
Boundary Dam	Lignite	40,732	16,373	100,929	6,046,700	110
Sundance	Sub-bituminous	31,101	25,706	2,572	16,019,300	278
Keephills	Sub-bituminous	9,760	10,211	698	5,548,100	97
Wabamun	Sub-bituminous	11,683	7,412	1,924	3,919,800	79
Total*		506,400	193,100	128,100	96,130,000	2,225

* Total emissions are rounded.

Source: Personal Communication with Individual Companies.

³ Mercury emissions at some boilers are believed to be underestimated due to high particulate conditions at the sampling point. Total Canadian mercury emissions are estimated to be closer to 2,400 kg for 1999 (Smith 2001).

⁴ The mercury emissions reported in this table were used in the analysis that was conducted in the Fall of 2001, and do not reflect the updates reported by the CEA in February 2002, as listed in Table 2.2. However, the updated emissions data did not change the cost conclusions significantly, allowing the work to be accepted and stand in its reported form. Therefore, Tables 5.1 to 5.8 have not been updated to reflect the updated mercury emission and speciation data reported in Table 2.2.

2.3 CURRENT AND PROPOSED REGULATIONS

There are currently no existing standards for mercury emissions to air in North America for the utility sector. Austria is the only European country known to have a mercury limit specifically for coal-fired plants, which is 0.05 mg/m³ (Sloss 1998).

Maine, New Hampshire and Wisconsin have state level “programs” that require a percentage reduction from 1998/1999 emissions rates. In mid-2001, the U.S. EPA initiated development of a three-phased program that included streamlined and rationalized national standards/objectives for SO_x, NO_x and Hg. On 14 December 2000, the U.S. EPA announced that it will regulate mercury emissions from coal-fired boilers under Title III of the Clean Air Act Amendments of 1990. Under the hazardous air pollutant requirements of the Clean Air Act, the regulation will eventually lead to a control technology standard, Maximum Available Control Technology (MACT), based primarily on current control technology and practices. A proposed MACT rule is expected in 2003, and a Final MACT rule to implement the regulations will be issued by 15 December 2004. Compliance will be required by 2007.

President Bush’s announcement on the *Clear Skies Initiative* describes a national cap on mercury emissions, cutting them by 69 percent. Emissions will be cut from current emissions of 48 tons to a cap of 26 tons in 2010, and 15 tons in 2018. (Office of the Press Secretary, February 14, 2002).

The New England Governors/Eastern Canadian Premiers (NEG/ECP) have adopted the following emission reduction targets and timelines for coal-fired utility boilers (Resolution 25-11, adopted 18 July 2000):

- By January 2003, adopt appropriate control strategies for mercury to achieve the reductions specified below:
 - By January 2005, reduce the total annual emissions on a mass basis of mercury in the region from the coal-fired electric utility sector by 20-50% from 1995 levels⁵; and
 - By no later than January 2010, utilize the most stringent control measure(s), economically and technologically feasible, on a multi-pollutant basis, to ensure that the total annual emissions, on a mass basis of mercury in the region, from the coal-fired utility sector are reduced by 60 to 90 % from 1995 levels.

⁵ It is anticipated that this near-term goal can be achieved through currently available methods such as fuel switching.

3.0 OPTIONS FOR ABATEMENT/REDUCTION OF MERCURY EMISSIONS

3.1 INTRODUCTION

A variety of options have been evaluated for the reduction of mercury emissions to the atmosphere. These options range from add-on technological controls, which reduce end-of-pipe emissions, to pollution prevention options aimed at reducing emissions at the source. Many of these pollution prevention approaches are difficult to quantify and cost. For example switching to coals with higher heating values and the same mercury content can reduce Hg emissions as a function of electricity generation, assuming other attributes remain the same. Investment in energy efficiency can reduce the overall mercury emissions if it reduces coal burned within a facility (internal energy efficiency) or the net generation (external or end-use reductions).

Many technological and non-technological options were identified in this study. Where possible (i.e., if sufficient information was found), the costs of applying these controls to specific facilities were determined and are presented in Section 5.3.

3.2 MERCURY BEHAVIOUR IN FLUE GAS

In flue gas, mercury typically exists in two chemical forms: elemental (Hg^0) and ionic (Hg^{2+}). In its ionic form, mercury is usually found as mercuric oxide (HgO), mercuric chloride (HgCl_2), or mercury sulphide (HgS), depending upon the concentrations of the other ionic species required. The ratio of elemental to ionic species differs for each plant, depending upon (1) the process parameters, (2) the amount of chlorine or other ions in the stream and (3) the non-mercury attributes of the coal. Essentially, a high chlorine concentration in the flue gas stream usually results in a high proportion of ionic mercury, typically as HgCl_2 . Mercuric chloride is soluble in acidic water, and can adsorb onto particles. Thus, specially designed wet scrubbers, wet ESPs, and other particulate control devices can collect HgCl_2 . HgO and HgS are solids at typical air pollution control temperatures, and can be collected by standard particulate control equipment.

Elemental mercury cannot be easily removed at high temperatures. The key to successful Hg removal is therefore oxidation of the elemental species to an ionic species, or reducing flue gas temperatures. Low temperature is extremely important for effective removal (i.e., 250°C and below), as most technological controls tend to show decreasing efficiency with increasing temperature. However, moist, SO_2 -containing flue gases cannot be cooled too much, as corrosion problems can occur. If cooled too much, the gases may reach the dewpoint, which could result in excessive pressure drop and “blinding” in fabric filters. Also, the gases may need to be re-heated

in order to provide appropriate plume rise for dispersion, which requires additional energy, and thus may result in reduced efficiency, with increases in emissions of Hg and other pollutants.

Particulate mercury is usually adsorbed onto flyash rather than being a pure condensed mercury species, and can be captured by baghouses or ESPs. Baghouses typically provide higher capture effectiveness for mercury species than ESPs.

3.2.1 MEASUREMENT OF MERCURY EMISSIONS AND SPECIATION

Generally, there is limited speciation information in the literature, particularly in terms of control efficiency. U.S. EPA Methods 101B (does not allow speciation) and 29 have been used extensively in the past, and thus literature-reported speciation from the last several years is probably not accurate. Many reported results from flue gas collection studies do not specify the speciation, relying instead upon “total” mercury or requiring a “derived” collection efficiency by speciated mercury type. Also, the extremely low Hg concentrations in utility boiler flue gases present specific sampling and analytical challenges.

EPA Method 29 does not properly speciate Hg under certain coal combustion conditions, but is fully capable of measuring total Hg concentrations. Results from the DOE and EPRI characterization studies indicated that when utilizing EPA’s Draft Method 29 and the Mercury Speciation Adsorption (MESA) Method, the Hg⁰ concentration at the outlet of the scrubber was 10 to 40% higher than that measured at the inlet (concentrations expressed on the same basis). Dr. Keith Curtis of Ontario Hydro performed field studies using potassium chloride (KCl) as a replacement impinger solution for the acidified peroxide solutions (solutions for collecting the oxidized form of Hg), which were speculated to be oxidizing Hg⁰ in the flue gas. A comparison of EPA Method 29 versus the OH method (Bush et al. 1997 as cited by Brown et al. 1999) showed that EPA Method 29 overestimated the Hg²⁺ at the inlet of a wet FGD system by 36%. Bench and pilot scale studies showed that the MESA Method did not speciate Hg correctly. Other methods such as the Tris-Buffer Method (Radian International) and EPA Draft Method 101B (Research Triangle Institute) also did not compare favourably with the OH Method. Validation of the OH Method has provided researchers with a valuable tool to measure, within +/- 10%, the distribution between Hg⁰ and Hg²⁺, along with total Hg in flue gas from coal combustion. While the OH Method has been validated, it is a labour-intensive wet chemistry method requiring long sampling times. Real-time data on total and speciated Hg are needed to fully evaluate the control technologies under development (Brown et al. 1999).

Continuous emissions monitoring systems (CEMS) present several advantages over wet chemistry methods, including provision of real-time data, use as a feed-back for mercury control strategies and potentially lower costs. Although currently used in the incineration sector, CEMS

are not currently applicable to coal-fired boilers due to the lower emission rates from boilers. However, significant research efforts are being made to apply these analyzers to the utility sector.

The OH modified method is the only method that is currently recognized for the measurement of mercury speciation in the flue gas from coal-fired combustion (Kilgroe et al. 2000). However, the short-term nature of testing (typically less than 2 hours per sample) may not capture unit conditions which might affect the measurements (soot blowing, load changes, etc.). Stack measurements represent only a “snapshot” of mercury emissions over a period of a few hours. Table 3.1 shows an example of the variation in mercury content of coal, from sampling measurements at three Canadian plants.

TABLE 3.1
EXAMPLES OF MEASUREMENT VARIABILITY: MERCURY IN COAL

Utility	Example
New Brunswick Power	Multi-sample: Results range from 0.058 to 0.086 ppm
Nova Scotia Power	Same sample – multiple labs: Results range from 0.049 to 0.140 ppm
ATCO Power	Results for one plant range from 0.066 ppm for 1999 to 0.0274 ppm for 2000

Adapted from CEA Presentation on Mercury Strategy to EPG MAG on 4 June 2001.

The methods most commonly employed by the coal testing industry exhibit considerable measurement uncertainty at mercury levels below 0.06 ppm and chlorine levels below 200 ppm. New methods have been identified and are available for evaluation and use in routine laboratory analyses.

3.2.2 INFORMATION COLLECTION REQUEST (ICR)

The U.S.EPA initiated an Information Collection Request (ICR) which was aimed at getting additional mercury-in-coal data from each coal-fired utility in the U.S., and additional speciated mercury emissions data from a subset of these coal-fired utilities. The data-gathering effort for the mercury-in-coal analyses commenced January 1, 1999 and continued until December 31, 1999. The ICR data collection effort was conducted in three phases (Kilgroe et al. 2000):

- Phase I – information was collected on fuels, boiler types and air pollution control devices used at all coal-fired utility boilers in the U.S.;
- Phase II – coal data (mercury, chlorine, sulphur, moisture and ash content, and calorific value) were collected and analyzed by the utility industry for 1,140 coal-fired units; and
- Phase III – mercury stack measurements were made using the modified OH Method for total and speciated mercury.

Table 3.2 presents a summary of the speciation results for U.S. plants with similar control devices as those being evaluated in this study for Canadian utility boilers. Note that there are data quality issues in the Part III ICR stack gas database include poor material balance closures, significant variability from run-to-run and questionable data at the control device inlets (Chu et al. 2001), that may detract from the usefulness of some of this data. To date, the U.S.EPA and EPRI have evaluated mercury control efficiencies in the ICR data set based on total mercury and not on the individual species. Table 3.2 shows calculated removal efficiencies for particulate, ionic and elemental mercury, calculated where possible, by SENES, as well as total mercury reduction efficiencies reported by EPRI.

**TABLE 3.2
SUMMARY OF MERCURY SPECIATION DATA FROM U.S. COALS IN 1999**

Control	Coal Type	Boiler Type	Station	Mercury Removal Efficiencies (%)			
				particulate ^S	ionic ^S	elemental ^S	total ^E
Fabric Filter	Bituminous	PC	Sammis (avg)	99.9%	-6.0%	-3.6%	92.5%
			Shawnee (avg)	99.7%	14.1%	-11.8%	70.0%
			Valmont (avg)	100.0%	-40.0%	82.4%	86.9%
			Average	99.8%	0.0%	4.3%	83.1%
			Minimum				66.7%
	Maximum				93.0%		
	Sub-bit	PC	Boswell2 (avg)	98.4%	48.2%	91.4%	82.6%
			Comanche (avg)	100.0%	-58.1%	91.7%	62.3%
			Average	99.6%	-17.1%	91.6%	72.4%
			Minimum				52.7%
Maximum						87.5%	
CS-ESP AND FF (COHPAC)	Lignite	PC	Bigbrown (avg)	99.1%	-60.5%	9.6%	0.3%
			Monticello 1-2 (avg)	98.5%	-227.8%	64.7%	9.6%
			Average	98.5%	-168.7%	40.0%	4.9%
			Minimum				0.0%
			Maximum				28.7%
SDA/FF	Bit	PC	Logan (avg)	99.8%	98.3%	40.7%	98.5%
			Mecklenburg (avg)	100.0%	98.6%	91.3%	98.1%
			Average	99.9%	98.4%	85.5%	98.3%
			Minimum				97.7%
			Maximum				98.7%

TABLE 3.2 (Continued)

Control	Coal Type	Boiler Type	Station	Mercury Removal Efficiencies (%)			
				particulate ^S	ionic ^S	elemental ^S	total ^E
SDA/FF	Sub-bit	PC	Craig 3 (avg)	100.0%	91.3%	-443.8%	35.8%
			Rawhide (avg)	97.5%	9.0%	26.0%	32.2%
			Sherburne (avg)	-500.0%	37.5%	5.3%	8.3%
			Average	91.4%	37.5%	13.8%	25.4%
			Minimum				0.0%
			Maximum				47.3%
	Lignite	Cyclone	Coyote (avg)	91.5%	90.6%	-12.5%	9.3%
			Minimum	88.4%	97.5%	-2.1%	5.5%
			Maximum	91.7%	85.7%	-21.1%	11.8%
CS-ESP/SDA	Sub-bit	PC	GRDA (avg)	97.4%	80.3%	-23.0%	32.6%
			Laramie 3 (avg)	98.6%	84.6%	25.9%	40.0%
			Wyodak (avg)	98.1%	96.0%	7.3%	41.3%
			Average	98.2%	86.9%	4.4%	37.9%
			Minimum				0.0%
			Maximum				62.5%
CS-ESP/DSI	Bit	PC	Washington (avg)	n/a	-1.6%	71.9%	44.9%
			Minimum	n/a	-34.9%	69.4%	40.7%
			Maximum	n/a	15.9%	73.7%	52.6%
SCR and SDA/FF	Bit	PC	SEI (avg)	99.9%	34.6%	25.0%	97.6%
			Minimum	99.9%	68.0%	21.4%	96.6%
			Maximum	99.9%	-13.3%	27.8%	98.3%
CS-ESP and Wet FGD Scrubber	Bit	PC	Milliken 2 (avg)	n/a	96.0%	-9.3%	81.2%
			Minimum	n/a	96.8%	-20.5%	80.1%
			Maximum	n/a	94.4%	-4.4%	83.4%
	Bit	Cyclone	Bailly (avg)	100.0%	87.7%	-1.9%	56.3%
			Minimum	100.0%	86.9%	-1.9%	56.0%
			Maximum	100.0%	87.7%	3.4%	56.8%
	Sub-bit	PC	Bridger	73.7%	88.1%	-24.2%	21.4%
			Laramie 1	90.0%	94.6%	35.6%	57.8%
			Sam Seymour	-600.0%	93.0%	-10.1%	26.1%
			Average	60.0%	92.4%	1.6%	35.1%
			Minimum				10.0%
			Maximum				63.1%
	Lignite	PC	Monticello 3	-71.4%	77.1%	7.9%	0.0%
			Reliant	-750.0%	90.6%	-21.6%	51.0%
			Average	-150.0%	84.6%	-1.7%	37.5%
Minimum						0.0%	
Maximum						56.1%	

TABLE 3.2 (Continued)

Control	Coal Type	Boiler Type	Station	Mercury Removal Efficiencies (%)			
				Particulate ^S	ionic ^S	elemental ^S	total ^E
HS-ESP and Wet FGD Scrubber	Bit	PC	Morrow (avg)	-33.3%	81.0%	-18.8%	55.1%
			Minimum	-200.0%	84.0%	-35.5%	51.2%
			Maximum	0.0%	80.9%	-13.4%	58.9%
	Sub-bit	PC	Alabama	97.6%	48.3%	-60.8%	43.4%
			Coronado	-133.3%	91.7%	-43.1%	12.8%
			Craig 1	75.0%	57.7%	23.2%	32.1%
			Navajo	0.0%	97.0%	-2.5%	30.5%
			San Juan	-50.0%	92.2%	-21.3%	44.4%
			Average	90.7%	77.8%	-17.0%	32.6%
			Minimum				0.6%
Maximum				49.9%			
CS-FF and Wet FGD Scrubber	Bit	PC	Clover	33.3%	74.5%	80.2%	96.9%
			Intermountain	0.0%	94.8%	-68.2%	95.9%
			Average	0.0%	85.6%	56.3%	96.4%
			Minimum				94.6%
			Maximum				98.3%

^Scalculated by SENES from data.

^Etotal reduction efficiency calculated by EPRI.

The discrepancies in collection efficiencies of total mercury versus particulate/ionic/elemental mercury at some locations highlights the data quality issues raised by Chu et al. above.

Source of data: <http://www.epa.gov/ttn/uatw/combust/utiltox/control2.pdf> (December 2000).

3.3 MERCURY CONTROL OPTIONS

Mercury removal with wet processes is correlated with chloride and sulphur content of the fuel. Other important parameters include unburned carbon (or loss on ignition, LOI) in fly ash, flue gas temperature and trace metal constituents in coal and fly ash (Chu et al. 2001). For example, mercury removal efficiencies with dry processes such as carbon are a strong function of temperature, the particle size of the carbon, residence time and the chemical characteristics of the carbon. There is a confounding impact from sulphur, chloride and other elements that can bind to, and block, “mercury adsorption sites” on the carbon. The chemical species of mercury emitted from different sources varies significantly. Flue gas parameters such as temperature, volume and composition also vary considerably among sources, which may preclude the use of certain technological controls at certain facilities or in certain sectors. Other important parameters include the availability of physical space and other site specific constraints.

Flyash may oxidize elemental mercury to ionic mercury, which is readily removed by scrubbers, but the extent of this oxidation appears to vary both with the flyash and the contact time (i.e. more oxidation occurs in baghouses than ESPs) (Joint Boiler Workgroup 2000).

In most countries, control technologies have not been specifically developed for the power generation sector. Table 3.3 lists options that are currently available for this sector.

TABLE 3.3
MERCURY CONTROL OPTIONS FOR CURRENT
AIR POLLUTION CONTROL DEVICES IN COAL-FIRED POWER PLANTS

Current Control	Hg Control Options	Relative Cost
Electrostatic Precipitator (ESP)	Sorbent Injection (SI) Chloro-oxidation + SI Replace with FF + SI Add polishing FF + SI Add Wet Scrubber (WS) Add Carbon filter bed	Very high Moderately high Moderate to high Moderate to high Moderate to high Very high
Fabric Filter (FF) or FF + Dry Scrubber	SI or Oxidation + SI	Moderate to high
ESP (or FF) + Wet Scrubber	WS Chemistry modifications Add Selective Catalytic Reduction (SCR) + Chemistry modifications	Low to Moderate Moderate to High

Source: Kilgroe 1998.

Therefore, the coal composition (in terms of chlorine content and ash composition), the operation of the combustion system (in terms of unburned carbon in the ash), and temperature and residence time in the particulate control device will affect mercury speciation in the flue gas and the amount of mercury adsorbed on the particulate matter. Other components of the air pollution control system such as FGD and SCR systems have also been shown to affect both the speciation of mercury in the stack and the amount of mercury removed (Afonso and Senior 2001).

The following sections describe current and emerging control options that were evaluated in this study. The final list of technology options examined in this study, was developed in cooperation with the Technical Working Group (TWG) of the Mercury Development Committee. Recent literature sources were searched for information on potential mercury control efficiencies, with respect to particulate, ionic and elemental mercury. However, this information was not readily available for all of the control options examined in this study. This is because the importance of speciation, in determining mercury removal efficiencies, is a relatively new discovery, and the recent advancements in mercury speciation measurement mean that this information can now be collected on pilot and full-scale of control technology applications. Where sufficient information was found on speciated control efficiencies, summary tables have been included in the following

sections to summarize the range of control efficiencies expected, and the average value chosen for this analysis.

Each control efficiency that has been assigned by SENES has been given a rating from “A” through “E”, with “A” being the best (highest confidence level). The assigned rating is a general indication of the reliability, or robustness, of that parameter value. The rating has been assigned by SENES based on the estimated reliability of the method used to develop the parameter value and on both the amount and representative characteristics of the data that support that method. In general, estimates based on many observations, or on widely accepted procedures, were assigned higher rankings. On the other hand, a parameter value based on a single observation of questionable value, or one extrapolated from another source for a similar process, was given a much lower rating. The rankings used are subjective and should be interpreted as approximations. The factors do not imply statistical error bounds or confidence intervals about each parameter value. The reporting of literature sources is intended to give the reader a sense of the range of information, but not to imply that all sources necessarily have equal weight or that full acceptance of the information, particularly without caveat, is intended. At most, the rating should be considered to be an indicator of the accuracy of a given parameter value. The ratings are thus assigned as:

- A. **Excellent.** Control device has been proven at full scale for the utility sector, with several primary references to support the chosen control efficiency
- B. **Above Average.** Control device has been proven at full or pilot scale for the utility sector, with several primary references to support the chosen control efficiency. Although no specific bias is evident, it is not clear that the control device has been proven at enough facilities to be representative of them all.
- C. **Average.** Control device has been tested at pilot scale on a reasonable number of utility plants, with several primary and secondary references to support the chosen control efficiency. Although no apparent bias is evident, it is not clear if the plants tested represent a random sample over all industry.
- D. **Below Average.** Control device has been tested at pilot scale on a limited number of utility plants, with limited primary and secondary references to support the chosen control efficiency. There may be reason to suspect that the plants are not representative of the all industry.
- E. **Poor.** There may be reason to suspect that the control is not efficient for certain plant configurations or coal types.

3.3.1 POLLUTION PREVENTION

Fuel Switching (Repowering with Natural Gas)

The estimation of fuel switching costs depends on many assumptions, which can significantly affect the results. Variables such as coal and natural gas prices, installed air pollution controls and the proximity of gas pipelines (sources) to the plant can have a large influence on the total estimated costs. In general, coal tends to contain higher amounts of mercury than other fuels such as oil. Natural gas does not contain much mercury. One means of reducing mercury emissions is to switch from a high mercury content fuel (such as coal) to a fuel with insignificant amount of mercury (such as natural gas), or to another form of energy.

Generally, switching from coal to natural gas involves retrofitting or replacing the fuel burners, boiler re-surfacing, and installing a delivery system (i.e. natural gas pipeline), if one does not currently exist in the area. The power generation sector has indicated that in most cases, it would not be economical to retrofit existing coal-fired plants to natural gas. Retrofitting existing boiler burners to natural gas is a relatively inexpensive option in terms of capital costs. However, these burners are very inefficient and require large quantities of natural gas to produce the same amount of output as coal. As a result, fuel costs represent a large fraction of the generation costs, and emissions of CO₂ from this option can be higher than coal (Klein 2000). A more practical option is to replace the boilers with combined cycle gas turbines and steam turbines. These units are highly efficient, smaller than coal fired boilers in terms of space, and can produce similar outputs. However, re-powering units with combined cycle gas turbines is more complicated than designing a greenfield plant. As a result, the capital cost of re-powering can be the same, or greater than, the cost of a greenfield station (Stambler 1993).

For many facilities, adequate natural gas sources are not located nearby, requiring significant pipeline extensions, etc. As a result, if natural gas powering of thermal generators was required, most facilities indicated that they would start from a greenfield site that was close enough to significant natural gas sources to make the project feasible (personal communication with stakeholders, 23 October 2000). Therefore, replacing the existing capacity with a greenfield combined cycle plant was the option included in the cost analysis for this study.

A combined cycle, advanced combustion turbine power plant includes an advanced combustion natural gas turbine, a heat recovery steam generator (HRSG), a steam turbine/generator set, cooling system, switchyard, auxiliary power systems and related systems. The steam, condensate and boiler feedwater system includes the piping, pumps, de-aerator, controls and instrumentation required by the steam cycle to drive the steam generator. This system circulates the condenser water through the heat recovery steam generator (where it is heated to steam), to the steam

generator, and back to the condenser. Demineralized makeup water is provided to replenish the water used in blowdown of the HRSG.

Natural gas-fired combined cycle gas turbines are highly efficient (65 to 70%), compared to simple cycle coal-fired boilers (35 to 40% efficient). Therefore, emissions of CO₂ generated per kilowatt-hour of electricity generated are lower, not only due to the efficiency of the units, but because natural gas is not as carbon-intensive as coal. Natural gas also produces insignificant amounts of SO₂ and mercury, and about one tenth of NO_x emissions compared to well-controlled coal-fired boilers (Joint Boiler Workgroup 2000).

It should be noted that a large increase in the demand for natural gas resulting from the replacement of coal-fired stations with natural gas may lead to price increases as a result of supply and demand. The increased natural gas demand for energy production will also impact natural gas prices for other major users of natural gas. However, the size of that impact is beyond the scope of this study. It should also be noted that the increased demand generated by power plants will likely lead to additional exploration, with the potential to reduce costs for all users. Therefore, a sensitivity analyses has been conducted in Section 5.4.2 to address possible future gas costs by multiplying the base year (1999) costs by 2 and 5, as specified in the Terms of Reference.

Advanced Coal Cleaning

Coal cleaning (dry process) and coal washing (wet process) involve reducing the ash content of coal before it is crushed and combusted in the boiler. However, washed coal must first be dewatered and dried prior to use. Coal cleaning/washing is primarily focused on removing sulphur, as well as lowering shipping, storage and handling costs per unit of heating value, and improving boiler output per unit weight input of coal. For some coals, washing produces a loss in calorific value, requiring an increase in the amount of coal burned, which reduces the net gain in emissions reductions.

Conventional coal washing methods use jigs, concentrating tables and hydroclones, with water, to take advantage of the lower specific gravity of clean coal when compared to its impurities. Froth floatation is used to clean the fine fractions and consists of contaminant separation by using air bubbles to float the clean coal to the surface of the unit where they are skimmed off by mechanical means.

Various studies have indicated that the application of conventional coal cleaning processes has resulted in mercury removal of up to 64%, with overall average reductions of between 21 and 37%. Washability studies, which provide theoretical maximum separations, indicate that at high energy recoveries, mercury removals of between 30 and 50% can be easily achieved (Brown et al.

1999). Toole-O'Neil et al. 1999 (as cited by Brown et al. 1999) assume an average mercury reduction of 37% from conventional coal cleaning techniques).

The following mercury removal levels were reported by Smit et al. 1996 (as cited by Brown et al. 1999):

- Conventional cleaning and column froth flotation: 40 to >57% (average 55%) Hg removal from raw coal;
- Column froth flotation: 1 to >51% (average 26%) Hg removal from washed coals;
- Conventional cleaning and selective agglomeration: >63 to 82% (average 68%) Hg removal from raw coal; and
- Selective agglomeration: >8 to 38% (average 16%) Hg removal from washed coals.

Mercury removal by coal cleaning can range from 25 to 50%. The average removal reported at 6 commercial cleaning plants was around 30% (Sloss 1998). Moore 1994 (as cited by Kitto 1996) reports 30 – 40% Hg removal efficiency in a typical 500 MWe boiler system burning Pittsburgh-seam bituminous coal with average chemical species concentrations. Ferris et al. 1992 (as cited by Brown et al. 1999) report a 42-45% reduction in Hg from raw coal by conventional cleaning (heavy-media cyclone), and a further 21-23% reduction in remaining Hg by a water-only cyclone and column froth flotation system.

In practice, coal cleaning efficiencies are unpredictable and vary considerably with factors such as coal type, rank, ash content and mineral composition. Although these methods appear to reduce mercury, further research is needed to examine the potential impacts on the post-combustion form and control of the remaining mercury. Some additional benefits of coal cleaning include a reduction in the sulphur content, which translates into lower SO₂ emissions, as well as increased heating value which results from reduced ash formation (i.e., less coal must be burned to achieve the same output) and lower disposal costs.

Coal cleaning is widely used on Eastern U.S. coals to reduce ash and sulphur compounds in bituminous coals. There is less experience with cleaning in the Western U.S. on sub-bituminous coals and North Dakota lignites. According to a preliminary laboratory analysis conducted on PRB coal (Akers D.J., "Economics of Coal Cleaning for Control of Mercury Emissions" to be published in an EPRI report) intense conventional coal cleaning may be able to achieve an 11 percent reduction in mercury emissions.

This option has traditionally been applied to higher rank coals burned in the East, rather than lower rank Western coals. However, it is considered in this study as an option for reducing mercury.

Table 3.4 summarizes the Hg control efficiencies of coal cleaning, and the assumed efficiencies used in this study, which have been applied to all coal types.

TABLE 3.4
SUMMARY OF MERCURY CONTROL EFFICIENCIES DUE TO COAL CLEANING

Comments	Source	Reference Type	Total Hg Removal (%)		
			Minimum	Average	Maximum
500 MWe - bit coal	Kitto 1996	Secondary	30		40
average of 6 plants	Sloss 1998	Primary	25	30	50
conventional cleaning	Brown et al. 1999	Secondary		37	
Hg removal from raw coal	Brown et al. 1999	Secondary	40	55	>57
Hg removal from raw coal	Brown et al. 1999	Secondary	>63	68	82
Hg removal from raw coal	Brown et al. 1999	Secondary	42		45
SENES assumption for cleaning of raw coal (Rank = B)				55	
Hg removal from washed coal	Brown et al. 1999	Secondary	1	26	>51
Hg removal from washed coal	Brown et al. 1999	Secondary	>8	16	38
Hg removal from washed coal	Brown et al. 1999	Secondary	21		23
SENES assumption for cleaning of washed coal (Rank = C)				20	

There are no data currently available on the release of mercury from the coal-cleaning slurries and settling ponds, or on the altered distribution of mercury form in the flue gas, as a result of the coal cleaning process.

3.3.2 POST-COMBUSTION TECHNOLOGICAL CONTROLS

3.3.2.1 Existing Controls

A review of recent literature has shown that control technologies currently applied to control pollutants such as SO_x, NO_x, and particulate matter, may be effective in capturing mercury, with modifications to operating conditions and the application of sorbents effective at removing mercury. Although the data are limited at this time, and there are no full-scale applications of technologies aimed specifically at removing mercury, results are promising. The efficiencies of mercury removal for the technologies described below vary significantly from one pilot test to another. Therefore, conservative estimates of mercury removal efficiencies have been chosen for the cost analysis in this study, in order not to overestimate the potential for the removal of mercury and other pollutants. It should also be noted that, where information was available, control efficiencies were applied specifically to each mercury species, as opposed to total mercury, to account for the different types of coal used across facilities in Canada, and even among different units in one facility that may burn different types of coal.

Flue Gas Desulphurization Techniques (Wet and Dry)

Wet FGD

In wet FGD systems, the flue gas is sprayed with an aqueous slurry consisting of approximately 10% lime or limestone. This occurs in a large spray tower or absorber vessel, where the slurry reacts with the SO₂ in the flue gas to form calcium sulphite or calcium sulphate. Some of the reacted slurry from the tank is recycled into the stream, while the remainder is thickened and dewatered for disposal. Wet FGD technology has evolved from a typical 90% SO₂ removal capability in the 1970s to more reliable and lower cost systems that can achieve 95 to 98% in systems being installed today (Nolan et al. 1999). Three boilers in Canada have wet FGD scrubbers (two at Lambton and one at Belledune).

The U.S. EPA estimates that wet scrubbers designed for SO₂ removal are capable of reducing oxidized mercury by more than 90 percent, with elemental removal ranging from 0 – 70%. The liquid-to-gas ratio of a wet FGD system impacts the removal efficiency of oxidized mercury. In two separate studies, increasing the liquid-to-gas ratio from 40 gal/1000 acf to 125 gal/1000 acf increased the removal efficiency of oxidized mercury from 90% to 99% (U.S.EPA 1997a as cited by Ross & Associates 2000)⁶. Previous WFGD studies indicated that increasing the L/G ratio from 37 to 121 gal/1000 acf increased the removal efficiency of Hg²⁺ from 91 to 98%, and did not affect the removal of Hg⁰, which was close to 0% removal (Redinger et al. 1997 as cited by Brown et al. 1999).

Brown et al. report the removal of Hg²⁺ ranging from 86% to approximately 95% across WFGD systems during field sampling at five plants firing high sulphur bituminous coals. Corresponding SO₂ removal ranged from 82 to 96%.

The nominal Hg removal for WFGD systems on units firing bituminous coal(s) is approximately 55 +/- 10% of the total Hg, with an associated removal of 80 to 95% Hg²⁺, and no appreciable removal of Hg⁰ (Devito and Rosenhoover 1997, 1999; Kurz and Laudal 1999; Laudal and Kurz 1999, as cited by Brown et al. 1999).

Improvements in wet scrubber performance in capturing mercury depend primarily on the oxidation of Hg⁰ to Hg²⁺. This may be accomplished by the injection of appropriate oxidizing agents or the installation of fixed oxidizing catalysts upstream of the scrubber to promote oxidation of Hg⁰ (Kilgroe et al. 2000).

⁶ This may not be feasible in a retrofit situation, due to large efficiency losses on the unit.

Wet acid scrubbers generate large quantities of spent slurry. This waste is typically disposed of by (U.S.EPA 2001):

- ponding the spent slurry without dewatering. This is the simplest method but requires a large ponding area and the management of the site is expensive;
- a combination of dewatering, secondary dewatering and landfilling;
- mixing sulphite sludge with flyash and lime to yield a material suitable for landfilling;
- concentrating gypsum to a cake and selling it for use in wallboard or fertilizer manufacture.

Table 3.5 summarizes control efficiencies for ionic and elemental mercury found in the literature for wet scrubbing.

Tests performed by Babcock & Wilcox (B&W) to date indicate that the form of mercury is normally stable and re-release to the environment is not expected given the types of disposal practices, or by-product uses, for spent material from wet scrubber systems. The extremely low concentration of mercury contained in the gypsum is insoluble, thermally stable and not expected to adversely impact its use for wallboard or for disposal in a landfill. In general, the mercury concentration in the scrubber gypsum will be lower than the mercury levels in naturally occurring gypsum mined for commercial use (Bielawski et al. 2001).

TABLE 3.5
SUMMARY OF MERCURY CONTROL EFFICIENCIES FOR WET SCRUBBING

Comments	Source	Reference Type	Ionic Hg Removal (%)			Elemental Hg Removal (%)		
			Minimum	Average	Maximum	Minimum	Average	Maximum
Low rank coal	Afonso and Senior 2001	Primary		90			0	
	Afonso and Senior 2001	Primary		90			0	
	Ross & Associates 2000	Secondary	90		99	0		70
5 plants - High Sulphur coals	Brown et al. 1999	Secondary	86		95			
	Brown et al.1999	Secondary	80		95		0	
increasing L/G ratio increases Hg removal	Brown et al.1999	Secondary	91		98		0	
Bituminous coal	Afonso and Senior 2001	Primary		90			0	
Bit coal, CS-ESP, Milliken 2, PC Boiler	ICR 1999	Primary	94.4	96	96.8			
Bit coal, CS-ESP, Bailly, Cyclone Boiler	ICR 1999	Primary	86.9	87.7	87.7			3.4
Sub-bit coal, CS-ESP, average 3 stations, PC	ICR 1999	Primary	88.1	92.4	94.6		1.6	35.6
Lignite, CS-ESP, average 2 stations, PC	ICR 1999	Primary	77.1	84.6	90.6			7.9
Bit coal, HS-ESP, Morrow, PC Boiler	ICR 1999	Primary	80.9	81	84			
Sub-bit coal, HS-ESP, average 5 stations, PC	ICR 1999	Primary	48.3	77.8	97			23.2
Bit coal, CS-FF, average 2 stations, PC boiler	ICR 1999	Primary	74.5	85.6	94.8		56.3	80.2
SENES assumption for LSFO (Rank = A)				95			0	

Dry FGD (Spray Dry Absorbers)

Spray Dry Absorbers (SDAs) utilize calcium hydroxide slurry or dry sorbents to neutralize the SO₂ in the flue gas. These are sprayed into the flue gas in a spray dryer tower (lime spray drying), or directly into the duct upstream of a particulate control device (dry sorbent injection). Lime-based dry scrubbing systems, including the particulate removal equipment, routinely operate with SO₂ removal efficiencies from 70-90% on lower sulphur coals (<2.5%S) (Kitto 1996).

Dry Sorbent Injection (DSI) involves the addition of an alkaline material such as hydrated lime ($\text{Ca}(\text{OH})_2$) to the gas stream. This material reacts with the acid gases present, to produce a salt that must be removed with particulate control equipment, typically fabric filters. The gas stream or sodium based alkaline compounds are typically quenched prior to sorbent injection to reduce the temperature. Incidental mercury removal occurs through adsorption of soluble mercury species such as HgCl_2 onto the particles. Currently one plant in Canada is operating with furnace sorbent injection (Shand Power).

When used in isolation (with fabric filtration), dry sorbent injection (DSI) can achieve a total Hg removal efficiency of 50%. However, this technology is also applicable for use in combination with activated carbon injection (ACI).

Lime Spray Drying (LSD) is very similar to dry sorbent injection in that both controls use lime to neutralize acid gases in the stream. In the case of LSD, the gas stream is not quenched prior to the reagent addition, and the lime is added in the form of a slurry, sprayed at the top of an absorber tower. The moisture in the slurry is flashed off by the hot flue gas, and simultaneously reacts with the acid gas. Two studies showed mercury removal efficiencies for spray dry scrubber systems of 63-64% when oxidized mercury represented 68-73% of total mercury at the scrubber inlet (EPA 1997b, Redinger et al. 1997 as cited by NESCAUM 2000b).

The lower the spray dryer outlet temperature, the more efficient the acid gas absorption. In LSD, cooling occurs rapidly in a cloud of finely atomized droplets, which serve as condensation, or absorption, sites for soluble mercury compounds, such as mercuric chloride. The mercury is then removed downstream with the reaction products in the dust collector. However, significant mercury still remains in the vapour phase at LSD exit temperatures of 250°F. Similar to DSI, this control can be used alone or in combination with ACI.

Increasing coal chlorine content improves the mercury removal efficiency from dry scrubbers. Plants burning coals with less than 0.01 % chlorine show 6 – 23% removal efficiencies, whereas those burning high chlorine coal (0.1-0.3%) show 44-96% removal, which is likely a result of increased conversion of Hg^0 to more easily absorbed HgCl_2 .

SDAs remove similar amounts of oxidized mercury as FGDs (90%) but often remove a significant amount of Hg^0 as well, particularly those on boilers burning bituminous coal that are coupled with a fabric filter. SDAs reduce oxidized mercury by 20 to 60%, and elemental mercury is reduced by 20 to 40% (Afonso and Senior 2001).

Table 3.6 summarizes the removal efficiencies for ionic and elemental mercury, and the assumed efficiencies used in this study.

TABLE 3.6
SUMMARY OF MERCURY REMOVAL EFFICIENCIES DUE TO DRY FGD SYSTEMS

Comments	Source	Reference Type	Ionic Hg Removal (%)			Elemental Hg Removal (%)		
			Min	Ave	Max	Min	Ave	Max
Dry FGD	Afonso and Senior 2001	Primary	20		60	20		40
Bituminous coal - SDA/FF	Afonso and Senior 2001	Primary		60			40	
Low rank coal - SDA/FF	Afonso and Senior 2001	Primary		50			40	
Bit coal, SDA/FF, average 2 stations, PC	ICR 1999	Primary	98.3	98.4	98.6	40.7	85.5	91.3
Sub-bit coal, SDA/FF, average 3 stations, PC	ICR 1999	Primary	9.0	37.5	91.3	5.3	13.8	26
Lignite, SDA/FF, average 2 stations, PC	ICR 1999	Primary		15.8	55.8		11.4	34.2
Lignite, SDA/FF, Coyote station, cyclone boiler	ICR 1999	Primary	85.7	90.6	97.5			
Sub-bit, CS-ESP/SDA, average 3 stations, PC	ICR 1999	Primary	80.3	86.9	96		4.4	25.9
Bit, CS-ESP/DSI, Washington, PC boiler	ICR 1999	Primary			15.9	69.4	71.9	73.7
SENES assumption for DSI and LSD (Rank B)				60			40	

The end product of the LSD is a mixture of the various salts formed from the neutralization of the acid gases. It is usually tackier than fly ash and more difficult to convey and store. Waste disposal is usually accomplished via landfilling. Some concern has been expressed by industry that the use of such techniques would “harm” the sale of fly ash as a byproduct, thereby increasing costs for the facilities. However, it is beyond the scope of this study to evaluate whether markets for the LSD residues (dry wall, concrete) are feasible.

Mercury-containing products from spray dryers do not appear to re-enter the environment. Tests have shown that no mercury loss occurred from spray dryer absorber product or solidified fly ash-absorber product mixtures over three years, regardless of how the material was stored. Also, no mercury was leached from the product during the Toxicity Characteristic Leaching Procedure (TCLP) (NESCAUM 2000b).

Selective Catalytic Reduction (SCR)

SCR uses ammonia or other compounds, injected into the flue gas in the presence of a catalyst to convert NO_x emissions to elemental nitrogen and water. These systems operate at approximately 340-380°C and can remove 70-90% of NO_x emissions from boilers firing low sulphur coal.

Similar efficiencies are expected for units firing higher sulphur coals, but there are currently no demonstrated installations on utility boilers. Catalysts used include vanadium/titanium combinations and zeolites.

There is growing evidence that SCR can increase the relative amount of oxidized mercury downstream, thus improving the overall scrubber efficiency. Measurements from several European boilers confirm that SCR catalysts can oxidize elemental mercury, and thus can improve the mercury removal performance of downstream scrubbers. For example, for a 475 MW dry bottom boiler, the fraction of oxidized mercury increases from 77% after the boiler to 95% after the SCR. In a second European dry bottom boiler, the SCR system lowered the elemental mercury from 6-7 $\mu\text{g}/\text{m}^3$ (which represented 40-60% of the total) to less than 1 $\mu\text{g}/\text{m}^3$ (which represented 2 – 12% of the total) (Sloss 1995).

Dutch studies have confirmed that elemental mercury proportions dropped from 51% upstream of the SCR installation in the Gelderland power station to 28% downstream (Meij 1998 as cited by Sloss 1998).

Srivastava et al. (2000) assumed that SCR increases oxidized mercury content in the flue gas by 35% for both bituminous and sub-bituminous coal, for the cost analysis of mercury controls on electric utility boilers, based on limited results from the 1999 ICR analysis.

Almost all coal-fired boilers in Germany are equipped with both SCR systems and limestone-based wet scrubbers. Total mercury capture in these systems exceeds 80% across all plants (Meij 1994 as cited by Bielawski et al. 2001).

B&W tested the effectiveness of SCR catalyst in converting elemental mercury in flue-gas to the oxidized form for subsequent removal in a wet FGD system. The results of the study indicate that high levels of mercury removal (greater than 80 percent) can be repeatedly achieved adding small amounts of a proprietary agent and that SCR catalyst increased the percentage of oxidized mercury in flue-gas across the SCR (indicating that with FGD greater levels of total mercury could be achieved). At relatively high temperatures, flue-gas passed through SCR catalyst contained 92-94 percent oxidized mercury, compared to 48-54 percent in the untreated case. At lower temperatures, SCR treated flue-gas contained about 94 percent oxidized mercury compared to 80-84 percent in the untreated case (Milobowski et al. 2001).

Spent catalyst is typically reactivated for use as a reducing agent, or the components are recycled for other uses. When disposal is necessary, spent catalyst can be disposed of in approved landfills because EPA has determined that spent catalyst is not a hazardous waste (ICAC 1997 as cited in U.S. EPA 2001).

Table 3.7 lists the data collected on the oxidation potential for elemental mercury.

**TABLE 3.7
POTENTIAL ELEMENTAL MERCURY REDUCTION BY SCR**

Comment	% oxidation of Hg ⁰	Reference	Reference Type
European 475MW dry bottom boiler	78	NESCAUM 2000b	Secondary
assumption based on ICR	35	Srivastava et al. 2000	Secondary
B&W average of 3 tests at 750°F	82	Richardson et al. 2001	Secondary
Gelderland power station	45	Sloss 1998	Secondary
Hg ⁰ reduced from 6-7 µg/m ³ to less than 1 µg/m ³	85	NESCAUM 2000b	Secondary
Average used in this study (Rank=E)	60		

The performance of an SCR system is influenced by six factors (U.S.EPA 1994):

- Flue gas temperature – the optimum temperature depends on the type of catalyst material being used.
- Fuel sulphur content – approximately 1-4% of the sulphur in the fuel is converted to SO₃, which can then react with ammonia to form ammonium sulphate salts, which deposit and foul downstream equipment, resulting in additional maintenance costs. Applications of SCR with medium to high sulphur coals may need to incorporate ways to minimize the impacts of ammonium sulphate salt formation and deposition.
- NH₃/NO_x ratio – to achieve greater than 80% NO_x removal, it is necessary to inject NH₃ in excess of 1:1 stoichiometry ratio, which results in higher levels of NH₃ slip.
- NO_x concentration at the SCR inlet – at inlet concentrations below 150 ppm, the reduction efficiencies decrease with decreasing NO_x concentrations.
- gas flow rate and pressure drop across the catalyst, defined in terms of space and area velocity:
 - Space velocity (inverse of residence time, determined by the ratio of the amount of gas treated per hour to the catalyst bulk volume) – as space velocity increases, contact time between the gas and catalyst decreases, and so does NO_x reduction.
 - Area velocity (ft/hr, the ratio of volume of gas treated per hour to the apparent surface area of the catalyst) – at lower area velocities, NO_x in the flue gas has more time to react with NH₃ on the active sites of the catalyst.
- Catalyst condition – Catalyst can be deactivated from wear (attrition, cracking, breaking over time), from fouling by solid particle deposition in the catalyst pores or on the surface, or poisoned when certain compounds (e.g. arsenic, lead and alkali oxides) react with the active sites on the catalyst.

Disadvantages of SCR:

- High capital and operating costs
- Catalyst poisoning
- Increased pressure drop
- Possible water wash required
- Ammonia slip
- reduction of oxidized mercury may occur in the scrubber, leading to revolatilization of mercury in elemental form. Therefore, scrubber capture efficiencies for ionic mercury may overstate overall mercury removal efficiencies.

Particulate Control Devices

Electrostatic Precipitators (ESPs)

The most commonly installed particulate control devices on utility boilers are dry ESPs. These devices use wire electrodes to induce a charge on fly ash particles, which are subsequently collected by grounded plates. The accumulated particulate is removed from the plates by “rapping” in a dry ESP, or by a stream of water in a wet ESP. Wet ESPs produce a sludge that must be treated prior to disposal.

The collection efficiencies of ESPs depend on the flue gas and the particle characteristics. For example, high resistivity particles are more difficult to charge and remove, and can result in excessive sparking or back corona. Particle resistivity can be lowered by conditioning the flue gas with SO₃. However, this adds to the SO₂ loading of the flue gas, and thus additional treatment is usually required to remove acid gases if gas conditioning is employed. Alstom (2000) reports total Hg removal efficiencies ranging from 5 to 40%. The U.S. EPA (1997b) reports that cold-side ESPs reduce mercury emissions by a median of 15% and a mean of 24%, with a range of 0 to 82% for coal-fired boilers.

In cold-side ESP systems in Japan operating at 140°C, up to 33% Hg capture has been reported, whereas hot-side ESPs caught less than 2%. In lignite plants, the higher concentrations of unburnt carbon can lead to as much as 50% mercury capture in ESP systems (Maier 1990 as cited by Sloss 1995). ESPs appear to oxidize 25 to 40% of elemental mercury for bituminous coals, but not for low rank coals (Afonso and Senior 2001).

ESPs were not proposed as add-on control devices in the costing analysis performed as part of this study. Therefore, no mercury removal efficiency has been assumed for ESPs. Mercury emissions data supplied by the power plants are assumed to already take into account the mercury removal efficiency of existing ESPs.

Fabric Filters (Baghouses)

Fabric filters are more efficient at capturing smaller particles than ESPs, since the collected dust builds up on the filters, and this cake acts as a filter itself. Accumulated dust is removed by either shaking the bags, reversing the air-flow, or by pulsing the bags individually with compressed air. The dust falls off the bags and is collected in a hopper.

Compact Hybrid Particulate Collector (COHPAC) is an EPRI-patented concept that places a high air-to-cloth ratio baghouse downstream of an existing ESP to improve overall particulate collection efficiency. These units are particularly amenable to carbon injection downstream of an

ESP, which is then removed using the COHPAC unit. The advantages of this configuration are (Bustard et al. 2001):

- Sorbents are mixed with a small fraction of the ash, which reduces the impact on ash reuse and waste disposal;
- Pilot plant studies, and theory, indicate that compared to ESPs, baghouses require one-tenth the sorbent to achieve similar removal efficiencies; and
- Capital costs for COHPAC are less than other options such as replacing the ESP with a baghouse or a larger ESP.

Cooling the flue gas can improve ESP performance for Hg removal by reducing the flue gas volume and flyash resistivity. Similar to ESPs, baghouse mercury removal improves with decreasing temperatures as a result of increasing adsorption of Hg by the flyash. Flyash may continue to remove gas phase mercury once it has been trapped on filter bags, so that baghouses may be able to provide removals beyond the capture of particulate mercury. This effect strongly depends on the flyash composition and the baghouse temperature.

Hg⁰ removal from combustion of Powder River Basin (PRB) Belle Ayre coal (Haythornthwaite 1997, PSCo/ADA Technologies Inc. et al. 1997, Sjostrum et al. 1997, Haythornthwaite et al. 1998 as cited by Brown et al. 1999) is as follows:

Pilot-scale pulse-jet FF (air to cloth ratio of 4 ft/min):	10 and 17% at 275°F (135°C) 65% at 250°F (121°C)
Pilot-scale reverse-gas (RG) FF:	67% at 200F (93°C) <20% at 289F (143°C) 72-79% at 230F (110°C) 34-78% (average 66%) at 280°F (138°C) below 30% at 330-350°F (166-177°C)

Total mercury removal across the pulse-jet baghouse averaged 16%, indicating a small amount of mercury adsorption onto the baghouse filtercake. The primary mercury control mechanism for a conventionally operated baghouse appears to be the conversion of elemental mercury by the flyash filtercake (Evans et al. 1997).

FFs decrease elemental mercury by 40 to 85%, and oxidized mercury by 25% for bituminous coals. The large decrease in elemental mercury suggests that some of it is being adsorbed across the fabric filter (Afonso and Senior 2001).

Pulse-jet fabric filters (PJFFs) are capable of 99.9% removal of particulate matter, reducing particulate emissions to 0.015 lb/Mbtu (Bielawski et al. 2001).

Table 3.8 summarizes the control efficiencies found in the literature, and lists the average efficiencies chosen for this study.

TABLE 3.8
SUMMARY OF MERCURY REMOVAL EFFICIENCIES BY FABRIC FILTERS

Comments	Source	Reference Type	Hg Removal Efficiency (%)				
			Particulate			Ionic	Elemental
			Minimum	Average	Maximum	Average	Average
Bituminous coal	Afonso and Senior 2001	Primary				25	62.5
Other coals	Afonso and Senior 2001	Primary				72	58
PRB coal, 200°F, pilot RGFF	Brown et al. 1999	Secondary					67
PRB coal, 230°F, pilot RGFF	Brown et al. 1999	Secondary					66
PRB coal, 280°F, pilot RGFF	Brown et al. 1999	Secondary					75.5
PRB coal, 250°F, pilot, PJFF	Brown et al. 1999	Secondary					65
	Bielawski et al. 2001	Primary		99.9			
Bit coal, average 3 stations, PC	ICR 1999	Primary	99.7	99.8	100	14(max)	82(max)
Sub-bit coal, average 2 stations, PC	ICR 1999	Primary	98.4	99.6	100	48(max)	91.6
	EPA 2000a	Secondary		99			
Bit coal - PM ₁₀	EPA 2000a	Secondary	98.3		99.9		
SENES assumption for fabric filters (Rank in parentheses)				99.9 (A)		70 (C)	60 (B)

The Public Service Electric and Gas (PSE&G) Hudson Generating Station in New Jersey has a 620 MW Foster-Wheeler dry bottom boiler, which typically burns washed, eastern bituminous low sulphur coal (<1% sulphur, ~0.1% chlorine). The unit, which began service in 1968 and is equipped with an electrostatic precipitator for particulate control, low-NO_x burners with Advanced Overfire Air ("LNB/AOFA") and a newly installed SNCR system to control emissions of NO_x.

PSE&G, in partnership with EPRI, is currently conducting a pilot-scale evaluation of the capabilities of a polishing high air-to-cloth ratio pulse jet baghouse (COHPAC) with sorbent injection (TOXECON) as an effective particulate, mercury and acid aerosol emission-control technology. The pilot is a 4,000 actual cubic feet per minute (acfm) polishing pulse baghouse operated downstream of the electrostatic precipitator. The pilot test was conducted on a slipstream taken from Hudson Unit 2 and is roughly equivalent to the emissions from generating one megawatt of electricity.

The pilot demonstrated significant pollutant reduction levels. The pollutant reductions described below are the maximums achieved for a particular target pollutant. The full-scale installation will assist in determining how to optimize the system and sorbent(s) used to achieve the maximum, cost-effective, multi-pollutant control.

The results of the pilot indicate that the following reductions are possible:

- Particulate emissions (trace metals) reduced to better than New Source Performance Standards;
- HCl reduced up to 75%;
- SO₃ and HF reduced to near zero emissions;
- NO_x and SO₂ reduced by 10%; and
- Hg (Mercury) control up to 90 percent (with combined sorbent injection) (activated carbon w/alkaline sorbent).

The actual results of the full scale installation may vary significantly from the pilot results. These should be viewed as high end reductions.

3.3.3 EMERGING CONTROLS

Activated Carbon Injection (ACI)

Carbon injection is an emerging technology for power plants that has been tested at the pilot scale with several electricity generating boilers. This technology involves directly injecting activated carbon into the gas stream, upstream of a particulate control device (ESP or FF). Vapour phase mercury is then bound to the carbon, which is collected in the particulate control equipment. The U.S. EPA estimates removal efficiencies between 80 to 98%, depending on the temperature, mercury speciation, flue gas composition and the type of carbon used (U.S.EPA 1998a as cited in NESCAUM 2000b).

Recent laboratory and pilot scale evidence suggests that solids such as activated carbon and fly ash can not only adsorb Hg^{2+} , but can adsorb Hg^0 with the solids acting as catalysts to oxidize elemental mercury (Brown et al. 1999).

Mercury can be adsorbed or condensed on activated carbon. Both of these processes are favoured at lower temperatures. For example, in one test, mercury removal efficiency declined from 51% to 27% as the temperature increased from 205°F to 225°F. Also, at 190-205°F, 98% control was possible using 155 pounds of carbon per pound of Hg, but this dropped to 75-87% when the temperature was increased to 230-250°F, even though a much higher carbon:mercury ratio was used. Different activated carbons also have different mercury absorption capacities. As the contact time between the carbon and the flue gas increases, the amount of mercury that is adsorbed increases, as more can diffuse into the pore structure of the carbon. Collection in a baghouse as opposed to an ESP increases the contact time, as the flue gas passes through the filter cake on the bags.

Low mercury concentration in the flue gas increases mass transfer limitations, thus reducing the removal efficiency for a given carbon injection rate. Thermal generating stations have extremely high volumes of flue gas compared to incinerators, and therefore, higher carbon injection rates are required.

The concentration of mercury, chlorides and other flue gas components affect the mercury removal efficiency. The type of coal burned has a significant effect on the concentration of these components. Burning a low sulphur, high chlorine coal will likely increase the fraction of oxidized mercury present, over that of a high sulphur, low chlorine coal. For example, a pilot test of carbon injection at a facility burning low chlorine coal (0.019%), with an installed spray dryer and ESP showed that switching to a higher chlorine coal (0.094%) resulted in increased mercury removal from 57% to 78% in the spray dryer without carbon injection. Carbon injection resulted in approximately 90% removal in both cases, however, the high chlorine coal required approximately 1/5th of the carbon that the low chlorine coal needed (NESCAUM 2000b).

Increasing the amount of chlorine in the flue gas changes the oxidation state of mercury, making it more amenable to carbon uptake. However, increasing the amount of SO_2 decreases this capacity (since oxidized mercury is easier to adsorb, and the presence of high SO_2 helps to reduce oxidized mercury back to Hg^0). For a unit with a baseline Hg^0 fraction of 75%, the addition of 0.1 percent NaCl or 0.2 percent HCl (as chloride) to the flue gas increased the ionic mercury concentration to 65-75%. However, it is important to note that chlorides often react with alkaline flyash, thus reducing the efficiency.

The major factor affecting the cost of activated carbon injection based technologies is the rate of carbon injection needed for the required mercury removal efficiency. This rate depends on the

temperature of the flue gas and the type of coal fired in the boiler. Increasing the carbon injection rate increases the carbon:mercury ratio, and thus increases the number of active adsorption sites available for mercury. Also, the additional carbon decreases the average distance between mercury and carbon particles, which increases the rate at which mercury can diffuse to and be captured by the carbon. The carbon injection rate can often be lowered without sacrificing performance by decreasing the temperature, increasing the contact time, increasing the amount of chlorides present in the system or decreasing the particle size of the activated carbon. Carbon is typically not saturated with mercury after one pass through a system. Therefore, recycling a fraction of the carbon can lower carbon consumption without significantly affecting performance.

Potential Problems with ACI

Activated carbon technology may not be applicable to all coal fired boilers for several reasons Brown et al. 1999):

- Low concentrations of mercury present in the relatively high volumes of flue gas;
- Mercury speciation is highly variable across the boiler population;
- Higher concentrations of competing species occupying the active sites of carbon;
- Flue gas residence time upstream of an ESP is nominally one second or less with flue gas velocities in the range of 50 to 60 ft/s at 300°F (149°C);
- Compounding these factors are possible mass transfer limitations of the injected sorbents and the decrease in the carbon reactivity and equilibrium sorption capacity at this nominal temperature (149°C);
- High levels of sulphur dioxide (>1600 ppmv) with 50 ppmv HCl, have a profound negative impact on the equilibrium adsorption capacity of certain virgin activated carbons for both Hg^0 and Hg^{2+} ; and
- Significant interactions between SO_2 and NO_2 and activated carbon cause rapid breakthrough of mercury as well as conversion of the mercury to a volatile oxidized form. This effect occurred at both 225 and 325°F (107 and 163°C) and with, or without, the presence of HCl and NO.

While flue gas cooling (spray cooling or humidification) was demonstrated, during DOE and EPRI pilot-scale tests to increase mercury capture by ACI, it may have limited applicability in the utility industry, because of the short ducts and residence times upstream of utility ESPs (U.S.DOE 1988 and 1993 as cited by Brown et al. 1999). Spray cooling prior to a FF can be of concern because the increase in moisture content of the flue gas can lead to blinding (e.g. condensed sulphuric acid mist) and cake release problems within the FF.

Activated carbon can be impregnated with sulphur or iodide to increase the Hg removal efficiency. The impregnated compounds react with elemental mercury vapour, increasing the total removal efficiency by an additional 25 to 45% (U.S. EPA 1997b). However, these carbons are more expensive than traditional carbons, resulting in higher annual costs, and exhibit low Hg removal efficiencies at typical flue gas temperatures of coal-fired generators.

Sjostrom et al. (2001) report that activated carbon effectively removes elemental mercury (from the PRB derived flue gas) with no significant difference in carbon performance when injected into a COHPAC baghouse for temperatures from 260 to 350°F. The study reports 50% mercury removal at injection concentrations over 1 lb/Mmacf, and more than 90% removal at injection concentrations over 3.5 lb/Mmacf.

A full-scale evaluation of mercury control using activated carbon injection upstream of a COHPAC baghouse was conducted at Alabama Power Company's Gaston Plant Unit 3 (burning low-sulphur bituminous coal), showed up to 90% total mercury removal with Darco FGD powdered activated carbon (Bustard et al. 2001).

The mercury control efficiencies found in the literature, and summarized above, were reported for total mercury removal and not for the individual species. For this study, the combination of ACI/SC is assumed to remove 90% of ionic mercury (Rank = C) and 50% (Rank = D) of elemental mercury. It seems likely that finer grades of carbon, impregnated carbon and increased residence times will increase the collection rate for elemental Hg, however, this has not yet been proven at full scale. Since spray cooling (SC) of flue gas results in significantly reduced requirements for activated carbon, the cost of SC was included in the evaluation of ACI for this study.

Waste generated due to activated carbon injection through pilot testing (10,000:1 C:Hg ratio) was shown to be well below regulatory limits for leachate production. Based on the assumption that similarly high carbon:mercury ratios will be required for full-scale carbon injection, it is unlikely that wastes from carbon injection will be considered hazardous in Canada.

In pilot-scale carbon injection studies at the Public Service of Colorado's Commanche Station Unit 2, samples collected and analyzed under the TCLP during ESP, pulse-jet, reverse-gas and TOXECON testing showed levels well below all regulatory limits (Haythornthwaite 1997 as cited by NESCAUM 2000b).

ACI, coupled with other control technologies, provides a means of substantially reducing mercury emissions while keeping coal in the mix. This approach would also reduce SO₂ and fine particulate matter. However, mercury captured in the carbon results in solid waste disposal issues. Further research is needed, on ash and sorbent residue, to evaluate mercury retention and the potential for release into the environment.

Other Emerging Control Technologies

The technologies listed below are further away from commercialization, and were not examined in detail in this study. These types of controls are being considered in the context of the MERS

analysis (multi-pollutant emission reduction strategies) where single technologies are more cost-effective than putting together multiple technologies.

Electro-Catalytic Oxidation (ECO)

ECO technology (developed by Powerspan) breaks down gases that result from the combustion of coal into their basic elements. The ECO process treats coal combustion flue gas in three stages of multi-pollutant removal. In Stage 1, pollutants in the gas stream, particularly NO_x, SO₂ and elemental mercury, are oxidized by electro-chemical reduction in a gas reactor. In Stage 2, a condensing wet ESP removes acid mist from the gas stream and acts as a scrubber to remove additional NO₂ and SO₂. The wet ESP effluent, which includes sulphuric and nitric acids, and dissolved heavy metals such as mercury, are next directed to a By-product Recovery System (Stage 3) for further processing. Depending on the desired by-products, the process will include the production of concentrated acids, the production of gypsum for wall board manufacture, the production of ammonia to produce a high quality fertilizer, or the neutralization and disposal of collected material using normal disposal methods (Jones 2001).

ECO technology is expected to cost 25 % less to install and 50% less to operate than current NO_x control systems such as SCR. In pilot testing conducted since 1998 at FirstEnergy's R.E. Burger Plant near Shadyside, Ohio, two MW of flue-gas output were treated using ECO technology. NO_x emissions were reduced by an average of 76%, SO₂ emissions by an average of 44%, mercury by 68%, and other heavy metals by more than 90%. Hydrochloric acid was reduced by 88% and hydrofluoric acid was reduced to below detection (Business Wire via Newpage, Alexander's gas and oil connections, volume 5, issue #11, 23 June 2000).

Additional emerging technologies for mercury control include:

- Alstom Filsorption System (activated coke/carbon or sodium sulphide injection upstream of FF results in 95+% capture of ionic and elemental Hg) – currently employed on European WTE plants;
- Carbon filter beds;
- Chloric acid injection with Wet FGD (NO_xSorb) – oxidizes elemental Hg to HgCl₂ which is readily absorbed by wet FGD;
- WFGD additives (e.g. Na₂S – precipitates Hg as sulphides);
- Fluidized bed activated carbon;
- Condensing heat exchangers;
- Noble metal sorbents (e.g., gold forms an alloy with mercury);
- Corona discharge technologies (generation of intense corona discharge in duct upstream of wet scrubber results in oxidation of ionic mercury); and
- Enhanced limestone injection dry scrubbing.

Novel Process for Removal and Recovery of Vapour Phase Mercury (ADA Technologies Inc.)

The Mercu-RE process uses a regenerable noble metal as a sorbent, which allows for the recovery of liquid elemental mercury from the flue gas in the regeneration cycle. The major conclusions of laboratory tests conducted by ADA (Turchi et al. 1999 as cited by Brown et al. 1999) were:

- The metal monolith-supported sorbent (noble metal) could remove over 95% of total mercury from the inlet flue gas
- There was no discernible decrease in sorbent performance over 180 hr of sorption and 250 hr of regeneration.

Clean Coal Technologies

There are a number of clean coal technologies listed on the U.S. Department of Energy (DOE) and the International Energy Agency (IEA) websites. These technologies are described in terms of NO_x and SO_x controls. Although they have a potential to significantly reduce mercury emissions from coal combustion, these technologies are not addressed in this study due to the lack of available mercury control efficiency and costing data. Clean coal is also being examined as an option for reducing CO₂, especially when coupled with CO₂ separation and sequestration.

Integrated Gasification Combined Cycle (IGCC)

The basic Integrated Gasification Combined Cycle (IGCC) process for the production of electricity initially converts carbonaceous feedstock in a gasifier into a synthesis gas - a mixture of carbon monoxide and hydrogen. The synthesis gas is cleaned for particulates, sulphur and other contaminants and is then combusted in a high efficiency gas turbine/generator. The heat from the turbine exhaust gas is extracted to produce steam to drive a steam turbine/generator. Integrated gasifier technology and combined cycle offers high system efficiencies and low pollution levels, ultimately reaching efficiencies of 60%. In addition to steam and power, the clean synthesis gas can be catalytically converted into hydrogen, environmentally superior transportation fuels and a variety of chemicals in the co-production mode.

Gasification is mature, and can produce electricity where opportunity fuels are used, to produce a high value feedstock, usually in an integrated system. However, except in high subsidy situations, the IGCC, especially from coal, is not yet viable for electricity-only production.

The following IGCC base-load power production projects are a result of the U.S. DOE's Clean Coal Technology (CCT) Program:

- Wabash River Coal Gasification Repowering Project (262 MW);
- Tampa Electric Company Polk Power Station (250MW); and

- Pinon Pine IGCC Power Project (99 MW).

Wabash River Coal Gasification Repowering Project

The Wabash River Coal Gasification Project repowered a 1950s pulverized coal-fired plant, transforming the plant from a nominally 33% efficient, 90-MWe unit into a nominally 40% efficient, 262-MWe (net) unit. The overall combined cost of the gasification and power generation facilities was \$417 million at completion. This cost includes engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training) and startup. Escalation during the project is included. Startup includes the costs of construction and operations, excluding coal and power, up to the date of commercial operation in December 1995. Soft costs such as legal and financing fees and interest during construction are not included. Project participants project future costs of \$1,200/kW for dual-train repowered facilities, and greenfield costs under \$1,000/kW, with advances in turbine technology .

Source: Los Alamos National Laboratory, 1999. Operated by the University of California for the US Department of Energy.

Dakota Gasification Company

The Great Plains syngas plant at Beulah in North Dakota (owned and operated by the Dakota Gasification Company) was the first commercial-scale synthetic fuels project in the U.S. based on the conversion of coal. It is currently producing 125 million standard cubic feet per day (scfd) of pipeline quality synthetic natural gas (SNG), plus quantities of anhydrous ammonia and other chemical by-products. Daily coal consumption is 18,000 tonnes of lignite from local mines. The heart of the plant is the processing unit consisting of 14 Lurgi gasifiers, where coal is gasified by the action of steam and oxygen at high temperature. This gas is then cooled to condense the by-products, allowing their removal. About 30% of the synthesis gas is passed into a shift reactor to increase the proportion of hydrogen to carbon monoxide, appropriate for conversion to methane. After cooling, this stream is purified by a methanol wash which removes carbon dioxide, sulphur and naphtha. The main output from the plant is the mixture of hydrogen, carbon monoxide and methane, which is dispatched to gas users. The Rectisol waste gas from the methanol wash is 96% CO₂, which is a now source of CO₂ for an enhanced oil recovery (EOR) project at the Weyburn oil field in Southeastern Saskatchewan. Volatile trace metals such as mercury are vapourized almost completely during gasification and are carried downstream in the process. The SNG and CO₂ gas streams have no detectable levels of mercury. Analysis of precipitated deposits from the packing material within the syngas washing step showed the solids to be highly enriched in mercury.

Ongoing Research

The U.S. EPA's Office of Research and Development (ORD) *Mercury Research Strategy* guides ORD's mercury research program and covers the 2001– 2005 time frame. The key scientific questions cover: (1) transport, transformation, and fate, (2) risk management for combustion sources, (3) risk management for non-combustion sources, (4) ecological effects and exposure, (5) human health effects and exposure, and (6) risk communication. The goal in addressing the questions is to reduce scientific uncertainties limiting EPA's ability to assess and manage mercury and methylmercury risks.

The key scientific question for topic (2) above (combustion sources) is: “*How much can mercury emissions from coal-fired utility boilers and other combustion systems be reduced with innovative mercury and multi-pollutant control technologies; what is the relative performance and cost of these new approaches compared to currently available technologies?*” (U.S.EPA 2000c). The results of this research will provide data that informs the preparation of the U.S. EPA’s regulatory proposal for controlling mercury emissions from coal-fired utilities in 2003/2004.

In the U.S. and Canada, several projects are underway to evaluate the effectiveness of control technologies in reducing mercury as well as other pollutants. For example, to evaluate the potential effects of SCR catalysts and ammonia on mercury speciation and removal, EPRI, EPA, DOE and six power producers (American Electric Power, Cinergy, Ontario Power Generation, Southern Company, Tennessee Valley Authority and Wisconsin Electric Power) initiated a pilot-scale screening evaluation at the Energy and Environmental Research Center (EERC) (Chu et al. 2001).

Another example is the Advanced Emissions Control Development Program (AECDP), where activities are focused on maximizing the use of existing controls. Alternately, the Carbon-Based Sorbent Injection for Mercury Control Project is evaluating the mercury-capture effectiveness of various carbon-based sorbents under a joint effort by the DOE Coal & Power Systems Program, EPRI, and the Public Service Company of Colorado.

In May 2001, the DOE selected a second group of technology development projects, each proposing a more novel mercury control system than in an earlier phase of development. The projects were:

- The Energy & Environmental Research Center at the University of North Dakota, Grand, Forks, ND, will develop an advanced particulate collector that combines the best features of baghouses and electrostatic precipitators and offers the potential of removing 90 percent of all mercury emissions released by a coal-fired combustor.
- URS Group, Inc., Austin, TX, will test chemical catalysts that can convert mercury into an oxidized form that can be removed by the flue gas "wet scrubbers" and particulate collectors now commonplace on many power plants.
- CONSOL, Inc., Library, PA, will adapt a mercury control system now used on municipal waste incinerators to function on a coal-fired power plant and remove not only mercury but also sulphur pollutants that can create visible plumes and contaminate other pollution control devices.
- Southern Research Institute, Birmingham, AL, will test the effectiveness of calcium-based chemicals, such as lime and silica lime additives, that collect mercury and oxidize it into a form that can be separated from a power plant's flue gas. The calcium sorbents also remove sulphur dioxide.
- Powerspan Corp., Durham, NH, will test a multi-pollutant removal system that uses an electrical discharge to convert mercury to mercuric oxide, nitrogen oxides to nitric acid, and sulphur dioxide to sulphuric acid. In its oxidized form, mercury can be captured in an electrostatic precipitator along with other tiny solid particles.
- Apogee Scientific, Inc., Englewood, CO, will study the effectiveness of up to a dozen carbon-based and other chemicals that show promise in removing more than 90 percent of mercury and costing 40 to 75 percent less than commercial sorbents.

In a statement issued on 18 June 2001 on *Meeting Mercury Standards*, the U.S.DOE announced plans to develop a wide array of mercury control options for power plants that can reliably reduce emissions by 50 to 70% by 2005, and 90% by 2010. Many of the new technologies would tie in mercury controls with processes that reduce other air pollutants such as SO₂ and NO_x.

Source: Office of Fossil Energy, U.S. Department of Energy, Washington, DC

3.4 SUMMARY OF CONTROL TECHNOLOGIES EXAMINED

Table 3.9 summarizes the removal efficiencies for mercury, for the control technologies included in this study. The final list of technologies included in the cost analysis was based on the discussion held with the Technical Working Group during the project initiation meeting in September 2000, and the data available in the literature to develop Cost Estimating Functions.

TABLE 3.9
SUMMARY OF MERCURY CONTROL TECHNOLOGIES AND EFFICIENCIES

Control Option	Mercury Control Efficiency		
	Particulate	Ionic	Elemental
Pulse Jet Fabric Filter (PJFF)	99.9	70	60
Limestone Forced Oxidation/Wet FGD (LSFO)		95	0
Dry Sorbent Injection (DSI)		60	40
Lime Spray Drying (LSD)		60	40
Selective Catalytic Reduction (SCR)		oxidizes 60% elemental	
Natural Gas Turbines (Greenfield Site) (NGT)	Approximately 100% total		
Activated Carbon Injection w/ Spray Cooling (ACI/SC)		90	50
Advanced Coal Cleaning – 1 (ACC1)	55% total		
Advanced Coal Cleaning – 2 (ACC2)	20% total		

where: ACC1 = Efficiency over non-washed coals
ACC2 = Efficiency over washed coals

Combinations of the above technologies, as listed below, that could be used to reduce Hg emissions, were based on information identified in the recent literature:

- Limestone Forced Oxidation (LSFO) + Pulse Jet Fabric Filter (PJFF)
- Dry Sorbent Injection (DSI) + PJFF
- Lime Spray Drying (LSD) + PJFF
- Selective Catalytic Reduction (SCR) + PJFF
- Activated Carbon Injection (ACI) + Spray Cooling (SC)
- ACI + SC + PJFF
- SCR + LSFO
- SCR + ACI + SC + PJFF
- LSFO + ACI + SC + PJFF
- DSI + ACI+ SC+ PJFF
- SCR + DSI + FF
- SCR + ACI + SC
- LSFO + ACI + SC
- DSI + ACI + SC
- SCR + DSI

The list of control technology combinations applied to each plant varies, based on the existing controls. Efficiencies of the control technology combinations were calculated based on the cumulative efficiency of each control (e.g. for SCR + DSI - 60% of elemental is oxidized to ionic, 60% of the total ionic fraction is removed, and 40% of the remaining elemental Hg is oxidized and removed).

The suite of technologies chosen for this study reflect, to the degree possible, certain constraints indicated by members. However, the final set of options does not reflect all of the inputs that could be used to define the viable options for any specific generating station.

3.5 WASTE DISPOSAL ISSUES

3.5.1 SOLID WASTE

Solid discharges from coal-fired power plants include fly ash, bottom ash, boiler slag and FGD residues (scrubber sludge or gypsum). These coal combustion residues (CCRs) are typically landfilled or used in the manufacture of by-products (e.g. cement production, structural fill, mining applications). Mercury volatilization or leaching is possible during any phase of the CCR life cycle (production, usage or disposal). Flyash and FGD residues typically have higher mercury concentrations than bottom ash and boiler slag (U.S.EPA 2000a).

Examples of commercial uses of CCRs include:

- Cement production – mercury volatilization is a concern if fly ash is input to cement kilns in which temperatures reach 1500°C;
- Structural fill – mercury volatilization is not a concern, but leaching is possible, although the alkaline nature of fly ashes reduces this concern; and
- Mining applications – there is a concern that leaching may occur due to the acidic conditions occurring during mining applications.

Increased control of mercury emissions from coal-fired power plants may change the amount and composition of CCRs. Such changes may increase the potential for release of mercury to the environment from either landfilling or the use of CCRs.

Mercury volatilization from CCRs in landfills and/or surface impoundments is expected to be small because of the low temperatures involved and the existence of a relatively small surface area per unit volume of residue. Since the residues are typically alkaline and the mercury is adsorbed on alkaline particles, acid leaching potential is expected to be minimal. Based on the limited data available, mercury levels in the leachate are non-detectable (U.S.EPA 2000a).

3.5.2 LIQUID WASTE

Wet scrubbers create mercury-containing aqueous wastes, in the form of scrubber blowdown, or water discharge. However, wet scrubber liquor tends to contain little if any mercury because essentially all scrubber-captured mercury is entrained in the scrubber solids. If mercury is found

in the scrubber blowdown, precipitation of the mercury as an insoluble salt results in mercury-free wastewater before discharge from the plant.

4.0 CO-CONTROL

Over the past decade there has been increased interest in undertaking integrated environmental assessments. This is due in part to the fact that the cluster of current atmospheric environmental issues are inter-related, and attempts to solve them individually in the past have led, and may still lead, to conflicting policies and regulatory actions.

Control technology and pollution prevention alternatives for further reductions of mercury emissions to the air in Canada should focus on options that have the ability to achieve multiple emission reduction benefits simultaneously. This is vital to industry as they struggle with increased competition, more stringent controls on many more pollutants and the emergence of a global market.

It is important to note that many mercury control options also reduce other pollutant emissions. For example, fuel switching can dramatically reduce emissions of NO_x, SO₂, CO₂ and particulates, while scrubbers remove many other air toxics, in addition to mercury. However, a technology designed for removal of a single pollutant may either directly or indirectly increase emissions of another pollutant. For example, although the implementation of FGD as a control for SO₂ also removes particulates and air toxics, it creates more solid waste material. It also increases CO₂ via the chemical reactions that capture SO₂. Since FGD is energy intensive, it increases emissions of all pollutants to some degree on an output basis (Jones 2001).

In this study, an attempt was made to address the co-control benefits of reducing other pollutants when addressing the reduction of mercury from coal-fired power plants. The following discussion includes Criteria Air Contaminants (CACs, e.g. SO₂, NO_x, PM), CO₂ (a greenhouse gas) and dioxins/furans.

Airborne particles are microscopic solid and liquid particles that remain suspended in the air for varying lengths of time. Primary particles are predominantly produced by fuel combustion, industrial processes, as well as natural processes such as wind blown dust. Secondary particles are formed in the atmosphere by gas-to-particle conversion processes of the originally emitted gaseous compounds. Particulate emissions are typically controlled by cyclones and inertial separators, wet scrubbers, electrostatic precipitators and fabric filters.

Sulphur dioxide (SO₂) is a colourless gas that can be chemically transformed into acidic pollutants such as sulphuric acid and sulphates (sulphates are a major component of fine particles in the atmosphere). The main sources of airborne SO₂ are coal-fired power generating stations and non-ferrous ore smelters. Sulphur dioxide is also one of the main causes of acid rain, which can damage crops, forests and whole ecosystems. Typical SO₂ removal technologies include fuel switching, coal cleaning and flue gas desulphurization.

Nitrogen oxides (NO_x) are nitrogen-oxygen compounds that include nitric oxide (NO) and nitrogen dioxide (NO₂). NO₂ is a toxic, irritating gas emitted by all combustion processes. It is both a separate component of smog and a pollutant that contributes to the formation of ground-level ozone and particulate matter. In combination with water, NO₂ can form the nitric acid component of acid rain. Methods for controlling nitrogen oxides can be divided into (1) combustion control methods, in which operating conditions for combustion are modified to reduce the formation of NO_x, and (2) post-combustion control methods, in which NO_x is removed from the gas stream after formation. Examples of post-combustion NO_x controls are selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).

Greenhouse gases such as CO₂ heat the planet by absorbing and re-emitting solar radiation that is reflected by the earth's surface. The natural greenhouse effect is being enhanced by anthropogenic sources of greenhouse gas emissions such as from fossil fuel combustion in power generation, transportation and residential/commercial/industrial applications. The primary control option for CO₂ is fuel switching because end-of-pipe CO₂ removal options are generally very costly.

“Dioxins” is the collective name of polychlorodibenzo-p-dioxins (PCDDs) and “furans” are a group of polychloro-dibenzofurans (PCDFs). There are a total of 210 congeners (75 PCDDs and 135 PCDFs) formed by substitution of the number and/or location of chlorine and hydrogen atoms in the molecule. The most toxic congener is 2,3,7,8-TCDD, and only 17 of the congeners (the dirty 17) have significant toxicity. These have been substituted on the 2nd, 3rd, 7th and 8th positions. A toxicity equivalence factor (TEF) states a congener's toxicity in relation to 2,3,7,8-TCDD.

Dioxins exist naturally, and can also be formed as by-products from a number of processes involving combustion where chlorine, or a precursor, is present; or in sintering processes. Metals such as copper and iron are thought to act as catalysts in the formation of dioxins.

There are four important process conditions that make dioxin formation possible:

- temperatures between 200 and 800°C;
- the presence of chlorine;
- the presence of organic matter (specifically aromatics); and
- the presence of oxygen.

There are two methods available for reducing emissions of dioxins and furans:

- (1) technologies that avoid the formation of dioxins; and
- (2) technologies that collect and remove dioxins.

There was no information found in the current literature on the co-control of dioxins and furans, with respect to mercury control technologies, for the coal-fired electricity generating sector. The control efficiencies for dioxins and furans from a previous assessment for incinerators are not used quantitatively in this study, but qualitatively to suggest that there is a potential for reduction of dioxins and furans with the application of certain air pollution control devices.

Stack test results at several coal-fired electricity generating facilities indicate that levels of PCDD/Fs are in the 10 to 15 pg TEQ/m³ range. Canada currently uses 32 pg TEQ/m³ as the target for virtual elimination. Therefore, any additional reduction of dioxins/furans achieved by add-on mercury controls would be considered as a continuous improvement.

Table 4.1 lists the control efficiencies that were used in the analysis of co-control of other pollutants, based on the reduction of mercury. Control efficiencies assumed for the other pollutants are based on those reported in the literature for the coal-fired power generating sector.

**TABLE 4.1
MULTI-POLLUTANT CONTROL BENEFITS**

Control Technologies	NO_x	SO₂	PCDD/Fs¹	CO₂	TPM
Pulse Jet Fabric Filter	+	+	0	+	99.9%
Limestone Forced Oxidation (wet FGD)	+	95%	-	+	50%
Dry Sorbent Injection	+	70%	-	+	+
Lime Spray Drying	+	90%	-	+	+
Selective Catalytic Reduction	80%	+	-	+	25%
Natural Gas Turbines (Greenfield Site)	75%	100%	100% ²	53%	99.9%
Activated Carbon Injection w/ Spray Cooling (SC)	+	+	-	+	+
Advanced Coal Cleaning – 1 (ACC1)	+	85%	N/A	+	+
Advanced Coal Cleaning – 2 (ACC2)	+	50%	N/A	+	+

Where:

ACC1 = Efficiency over non-washed coals

ACC2 = Efficiency over washed coals

¹ PCDD/F reduction efficiencies based on the incinerator sector are not directly related to the power generation sector due to vast differences in flue gas volumes and mercury concentrations.

² Assumed no PCDD/Fs emitted from NGTs.

“+” indicates increases in CO₂ and Criteria Air Contaminants due to the increased energy requirements associated with the addition of pollution control devices.

“-” indicates reductions in PCDD/Fs (reduction efficiencies unknown).

“0” indicates no anticipated change.

CO₂ and CAC emissions increase with the addition of any air pollution control device, due to the increased energy required to overcome the power drag induced on the system by the pollution control device. The increased CO₂ requirement has been calculated in this report, based on the

equivalent amount of coal that needs to be burned to generate the electricity used by the control device. However, there are also indirect CO₂ and other pollutant emissions that result, based on the type of device that is added, such as the energy required to produce reagents such as activated carbon and lime), the CO₂ released in producing limestone, the energy required to stockpile and maintain lime, etc. Likewise, emissions of Criteria Air Contaminants will also increase. Therefore, Table 4.1 shows an increase “+” in these emissions. Since, the calculation for increases in other pollutant emissions (e.g., particulate matter, SO₂, NO_x) is very specific to the control device and operations at a particular plant, these increases have not been quantified in this study.

It should be noted that total CO₂ increases (direct and indirect) are expected to be in the order of 5 to 10%, for each control device that is added to a particular facility. Total CO₂ emissions from the coal-fired electricity sector in 1999 were 96.1 million tonnes. Total CO₂ emissions from all anthropogenic sources in Canada for 1998 (1999 not published yet) were 529.4 million tonnes (energy, industrial, agriculture and waste sectors). Therefore, the coal-fired electricity generating sector accounts for approximately 18% of Canada’s total anthropogenic CO₂ emissions, assuming total national emissions in 1998 were similar to 1999. Therefore, if additional control devices increase CO₂ emissions by up to 20% for this sector (conservatively high), the coal sector will account for approximately 21% (as opposed to 18%) of national anthropogenic CO₂ emissions.

5.0 COST OF REDUCING MERCURY

Cost analysis is an important input to the standard setting process, and can be used:

- to determine the level of control required (e.g. best economically available control versus maximum achievable control);
- to choose among alternative methods to achieve the same level of control (e.g. an ambient standard);
- to conduct a benefit-cost analysis that addresses the economic efficiency of alternative regulations; and
- to conduct an economic impact analysis to determine the consequences of the standard for industry, employment and competitiveness.

Since mercury is emitted in small quantities compared to other pollutants such as SO₂ and NO_x, the control cost effectiveness may seem unreasonably low compared to other pollutants. However, risk management decisions are complicated by the need to consider the total mass loading of mercury to the environment, long-range atmospheric transport, and persistence/bioaccumulation of mercury in the aquatic food web.

Regulators should also bear in mind that there are several different types of cost estimates that can be used to develop standards. The approach used here is based on a “study estimate”, which is based on preliminary sizes and material specifications for the equipment, estimates of utility consumption (power, water) and the approximate sizes of fans and motors (U.S. EPA 1995a). The U.S. EPA has found that study estimates are acceptable for the development of regulations. Study estimates are also used to assess the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys and acquisition.

5.1 COST ESTIMATING METHODOLOGY

The approach used in this study follows the method outlined in the OAQPS Cost Control Manual. Cost Estimating Functions (CEFs) are based on a “study” estimate of +/- 30% accuracy. However, this accuracy cannot be claimed in this study due to the various assumptions in the input parameters that have been made for this analysis. It should also be noted that the Cost Estimating Functions do not include site-specific costs such as:

- situations where there is insufficient room to install new equipment on existing ductwork;
- increases in operating and maintenance costs due to increased corrosion in exhaust gas ductwork (impact of gas cooling on the formation of SO₃ and downstream effects); and

- cost of ash disposal increases, if ash is currently utilized (e.g. as a concrete mix additive) and can no longer be used with the presence of carbon.

Elements of the cost calculations are briefly described below, with more details provided in Appendix A.

Total cost consists of two elements, total annualized capital investment (TCI) and total annual cost (TAC). Figure 5.1 presents all elements of total capital investment. TCI consists of Purchased Equipment Costs (PEC), Direct Installation Costs (DIC) and Indirect Installation Costs (IIC). TCI includes all costs required to purchase and ship the control system. These are described briefly below.

Purchased Equipment Costs

This category includes all costs associated with the purchase of the pollution control system, including fans, ductwork, system controls, freight and sales taxes. Purchased Equipment Costs (PEC) include:

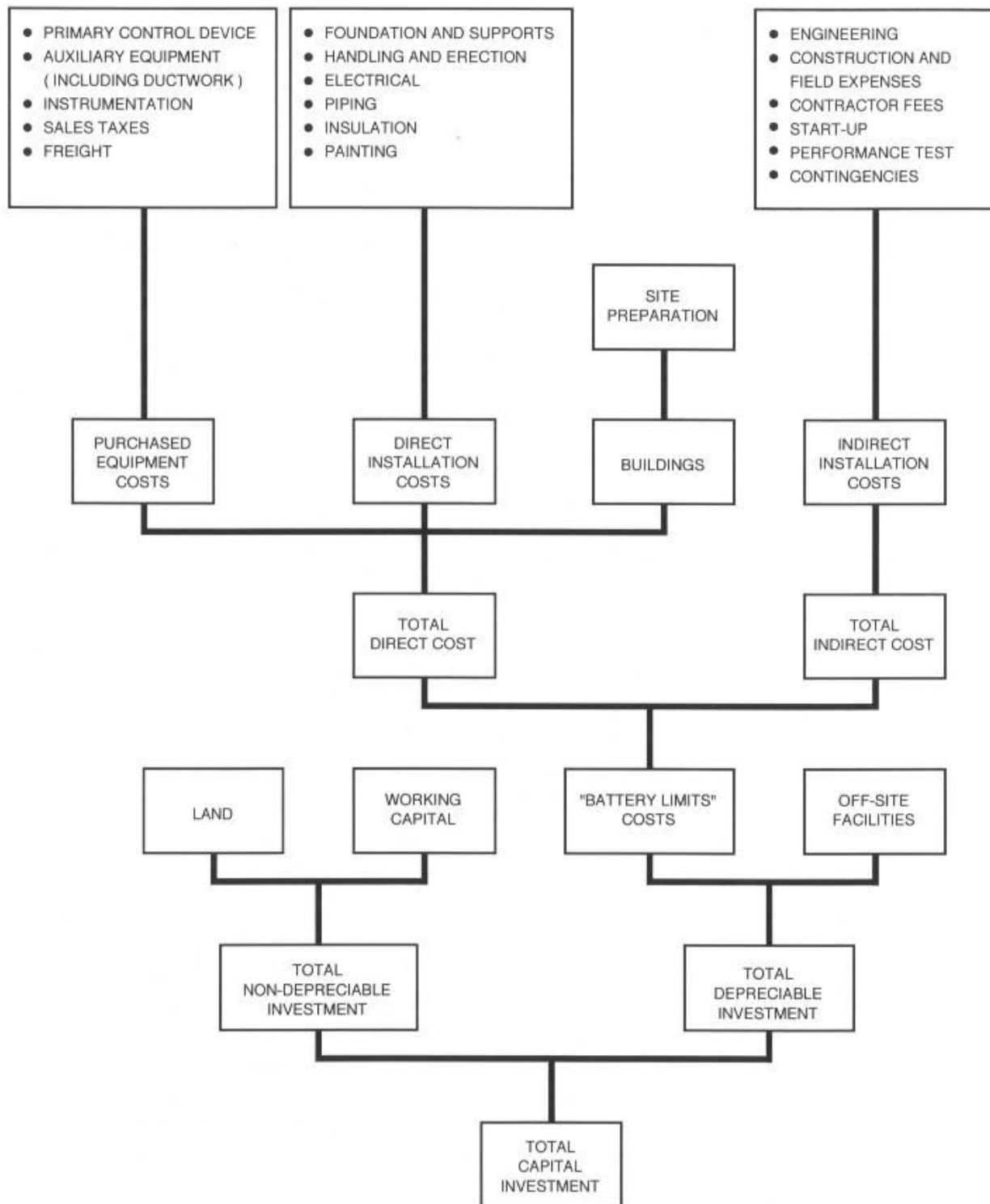
- labour and materials required for installation (direct installation costs DIC);
- site preparation and buildings, and indirect installation costs, IIC;
- “working capital”, which are funds set aside to cover the costs of fuel, chemicals and other materials, in addition to labour and maintenance. This cost, however, usually does not apply to control systems; and
- “off-site facilities” encompass facilities to produce steam, treated water or electricity, or laboratory facilities, etc. required by the pollution control system.

Installation Costs

The direct installation costs (DIC) include costs for foundations and supports, equipment erection and handling, electrical work, ducting, insulation and painting. This cost is usually estimated using a multiplier for the purchased equipment costs (PEC). Indirect installation costs (IIC) typically include the cost of engineering services, contractor fees, construction and field expenses (such as supervisory and office personnel), start-up and performance testing in addition to contingencies. Contingency costs are a built-in protection to cover all unforeseen costs such as possible equipment modifications and scheduling delays.

Elements from Figure 5.1 that were not included in this analysis are: site preparation, buildings, land, working capital, total non-depreciable investment and off-site facilities.

**FIGURE 5.1
ELEMENTS OF TOTAL CAPITAL INVESTMENT**



Source: U.S EPA OAQPS Control Cost Manual, 1995.

Annual Costs

There are three elements associated with the total annual costs (TAC) of pollution control systems. These are: direct costs (DC), indirect costs (IC) and recovery credits (RC), and are presented in Figure 5.2. Direct costs are those that tend to be proportional to the quantity of exhaust gas processed by the control equipment, and include costs for reagents, utilities (steam, electricity, process water, etc.), waste treatment and disposal, maintenance and replacement materials in addition to labour costs for operation, maintenance and supervision. Costs for reagents, utilities and waste handling are typically a direct function of the exhaust flow rate, such that when the flow rate is zero, the costs are zero and when it is at a maximum, the costs are maximized.

Indirect costs (IC), also known as fixed costs, vary independently of the flow rate and would be incurred even if the system were not operating. These include administration and overhead, property taxes, insurance and capital recovery. Indirect Costs are typically calculated using scaled factors of the Purchased Equipment Cost (PEC) and Maintenance Costs. For example, based on the OAQPS manual, overhead is calculated using 60% of the operating and maintenance costs. Property taxes, insurance and administration are 4% of the total Plant Cost.

Recovery credits are actually negative costs, in that they are revenues taken in or savings realized as a result of materials or energy recovered by the control system. They can be either sold or recycled, providing an economic benefit.

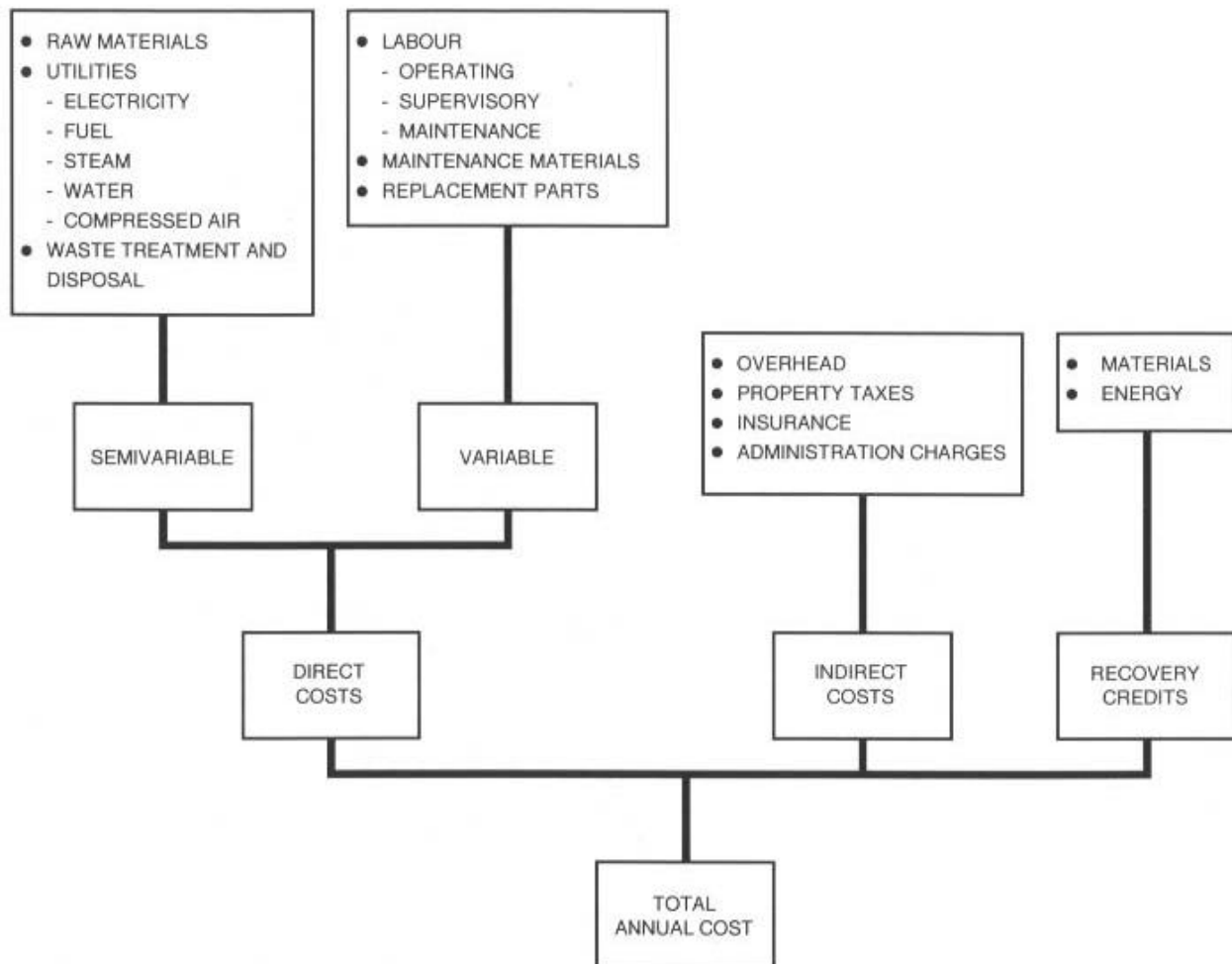
Payroll and plant overhead typically represent 50 – 70% of annual labour.

The maintenance labour rate is typically higher than the normal operating rate because more skilled personnel are required. A 10% wage premium is usually added. The cost of maintenance materials can be estimated using a factor of 100% of the maintenance labour.

Parts that must be replaced at distinct short intervals (e.g. fabric filter bags) should be annualized based on the cost of the part, the life of the part, and the labour required to install it.

Elements of Figure 5.2 that were not included in this analysis include: materials, energy and recovery credits.

FIGURE 5.2
ELEMENTS OF ANNUAL COSTS



Adapted from: U.S EPA OAQPS Control Cost Manual, 1995

Cost Amortization

In order to compare the costs of alternative control systems for a particular facility, the costs must be assessed on a uniform basis that allows unbiased comparisons. For example, some controls may require a relatively low capital expenditure, but may have very high annual operating and maintenance costs, while for others, the reverse may be true. In order to compare the overall costs of both controls, for example, to determine the most economical option, the differences in capital investment and annual costs for each control must be balanced. According to the OAQPS manual, this is best accomplished by using the equivalent uniform annual cost (EUAC), which is

also known as the total annualized cost. The EUAC is the sum of the annual costs and the capital recovery cost (CRC). The CRC is the total capital investment, equalized into annual payments over the design life of the control system. By annualizing the payments in this manner, the capital investment accrues interest, and thus the future value of the investment is used in the calculation. Design lives for control systems typically range from 10 to 30 years. An average value of 20 years was chosen for this study. However, since the coal-fired boilers across the country have varying retirement dates, costs were also amortized over the remaining life of each boiler within each facility included in this study. The remaining life of the boiler was calculated as the retirement date of the boiler minus 2010, which is the assumed implementation year of the mercury reduction program. Where retirement dates were not provided, SENES assumed a 50-year life for coal-fired boilers.

5.2 MERCURY CONTROL COSTS

All cost estimates were generated following the general approach outlined in the OAQPS Control Cost Manual (U.S. EPA 1995a). The cost estimates for the technological controls discussed in this report are based on mathematical Cost Estimating Functions (CEFs). The CEFs used in this study are based on documented algorithms and equations found in the literature or control costing models. Some were modified to suit the terms of reference of this study.

All CEFs were programmed in FORTRAN to allow sector cost estimates to be generated quickly and to permit repeated runs with varying inputs to refine the estimates. Each CEF program underwent a QA/QC check of test conditions to ensure that it and any subroutines were error-free.

CEFs are typically based on design information such as flow rate, temperature and emission rate. For this project, this information was provided by the facilities, upon signature of strict confidentiality agreements. In some cases, portions of the required information were missing and therefore were assumed or calculated, based on engineering judgement. The assumptions made by SENES have been reviewed and accepted by the CEA for this work (Cousens 2001).

5.3 RESULTS OF THE COSTING ANALYSIS

Tables 5.1 to 5.8 present the results of the cost analysis for each of the 8 power companies that operate the 23 coal-fired electricity generating plants across Canada. Costs are presented for each boiler within each plant. Control technologies applied to each boiler were selected based on the existing controls at each plant, as well as any specific information provided by plant contacts.

Each table presents the total capital cost and annual operating cost of the controls that are being examined. These costs were amortized over two periods:

TABLE 5.1
Summary of Mercury Control Costs and Co-control for ATCO Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Sheerness																
7: NGT	100%	540.59	289.63	331.77	331.77	122.47	2.71	5.34	2.71	5.34	31008	8685	+	2833698	763	0
Boiler: 1																
2: LSFO	18%	84.66	16.13	22.73	21.81	11.29	1.93	0.7	2.01	0.73	14792	0	+	-12069	192	16.18
17: DSI+PJFF	79%	36.76	7.16	10.03	9.63	48.44	0.2	0.31	0.21	0.32	10899	0	+	-10423	383	4.23
18: LSD+PJFF	79%	85.43	12.45	19.11	18.19	48.44	0.38	0.58	0.39	0.61	14013	0	+	-15452	383	4.23
20: ACI+SC+PJFF	84%	24.44	7.45	9.36	9.09	51.68	0.18	0.29	0.18	0.3	0	0	+	-11606	383	3.19
21: SCR+LSFO	58%	116.12	21.5	30.56	29.3	35.62	0.82	0.94	0.86	0.98	14792	4652	+	-22371	244	8.35
22: SCR+ACI+SC+PJFF	92%	55.9	12.83	17.19	16.58	56.48	0.29	0.53	0.3	0.55	0	4652	+	-21908	383	1.65
23: LSFO+ACI+SC+PJFF	87%	109.1	23.58	32.09	30.91	53.5	0.58	0.99	0.6	1.03	14792	0	+	-23676	383	2.6
24: DSI+ACI+SC+PJFF	91%	39.86	11.95	15.06	14.63	56.03	0.26	0.47	0.27	0.48	10899	0	+	-14624	383	1.79
25: SCR+DSI+PJFF	89%	68.21	12.54	17.86	17.12	54.8	0.31	0.55	0.33	0.57	10899	4652	+	-20724	383	2.19
Boiler: 2																
2: LSFO	18%	84.65	16.07	22.66	21.36	11.16	1.91	0.69	2.03	0.73	14666	0	+	-12029	190	16.04
17: DSI+PJFF	79%	36.72	7.13	9.99	9.42	47.86	0.2	0.3	0.21	0.32	10806	0	+	-10388	380	4.2
18: LSD+PJFF	79%	85.41	12.43	19.08	17.77	47.86	0.37	0.57	0.4	0.62	13894	0	+	-15400	380	4.2
20: ACI+SC+PJFF	84%	24.43	7.4	9.31	8.93	51.07	0.17	0.29	0.18	0.3	0	0	+	-11567	380	3.16
21: SCR+LSFO	58%	116.09	21.44	30.49	28.7	35.2	0.82	0.93	0.87	0.98	14666	4612	+	-22296	242	8.28
22: SCR+ACI+SC+PJFF	92%	55.88	12.78	17.13	16.27	55.81	0.29	0.52	0.31	0.55	0	4612	+	-21834	380	1.63
23: LSFO+ACI+SC+PJFF	87%	109.08	23.47	31.97	30.29	52.87	0.57	0.98	0.6	1.03	14666	0	+	-23596	380	2.58
24: DSI+ACI+SC+PJFF	91%	39.82	11.87	14.97	14.36	55.36	0.26	0.46	0.27	0.48	10806	0	+	-14575	380	1.78
25: SCR+DSI+PJFF	89%	68.17	12.5	17.81	16.76	54.15	0.31	0.54	0.33	0.57	10806	4612	+	-20655	380	2.17
H.R. Milner																
7: NGT	100%	230.99	88.19	106.2	106.2	4.83	21.99	13.18	21.99	13.18	5084	1439	+	575845	1072	0
Boiler: 1																
2: LSFO	5%	81.09	11.29	17.61	20.26	0.23	88.32	2.52	76.75	2.19	4830	0	+	-5430	537	5.71
4: DSI	41%	11.48	1.8	2.69	3.07	1.98	1.55	0.38	1.36	0.33	3559	0	+	-1358	0	3.54
5: LSD	41%	51.63	6.62	10.65	12.34	1.98	6.23	1.53	5.38	1.32	4576	0	+	-3620	0	3.54
15: ACI+SC	52%	2.46	0.77	0.96	1.04	2.51	0.41	0.13	0.38	0.12	0	0	+	-1899	0	2.88
21: SCR+LSFO	59%	111.44	16.31	25	28.64	2.85	10.04	3.56	8.77	3.1	4830	1534	+	-9994	681	2.46
26: SCR+ACI+SC	79%	32.82	5.79	8.35	9.42	3.83	2.46	1.17	2.18	1.04	0	1534	+	-6463	290	1.24
27: LSFO+ACI+SC	54%	83.55	12.05	18.57	21.3	2.62	8.13	2.64	7.08	2.31	4830	0	+	-7329	537	2.74
28: DSI+ACI+SC	72%	13.94	2.57	3.65	4.11	3.46	1.19	0.51	1.06	0.45	3559	0	+	-3257	0	1.7
28: SCR+DSI	75%	41.83	6.82	10.08	11.45	3.6	3.18	1.42	2.8	1.25	3559	1534	+	-5922	290	1.52
Battle River																
7: NGT	100%	511.73	257.82	297.71	297.71	191.8	1.55	6.15	1.55	6.15	22214	8097	+	1929597	1375	0
Boiler: 3																
2: LSFO	11%	98.67	12.9	20.59	26.58	4.32	6.15	2.77	4.76	2.15	4198	0	+	-16127	147	36.44
17: DSI+PJFF	77%	40.76	5.52	8.7	11.17	30.16	0.37	1.17	0.29	0.91	3093	0	+	-13396	294	9.47
18: LSD+PJFF	77%	90	11.34	18.36	23.81	30.16	0.79	2.49	0.61	1.92	3977	0	+	-20116	294	9.47
20: ACI+SC+PJFF	82%	34.55	7.28	9.97	12.06	31.98	0.38	1.26	0.31	1.04	0	0	+	-14883	294	7.57
21: SCR+LSFO	56%	137.43	20.35	31.06	39.39	21.94	1.8	4.11	1.42	3.24	4198	1701	+	-30645	187	18.05
22: SCR+ACI+SC+PJFF	91%	73.31	14.72	20.44	24.88	35.64	0.7	2.6	0.57	2.13	0	1701	+	-29401	294	3.75
23: LSFO+ACI+SC+PJFF	84%	133.21	20.18	30.56	38.64	32.77	1.18	4.03	0.93	3.19	4198	0	+	-31010	294	6.74
24: DSI+ACI+SC+PJFF	89%	44.9	8.97	12.47	15.19	34.92	0.44	1.59	0.36	1.3	3093	0	+	-18915	294	4.5
25: SCR+DSI+PJFF	89%	79.53	12.97	19.17	23.99	34.74	0.69	2.5	0.55	2	3093	1701	+	-27913	294	4.69

TABLE 5.1
Summary of Mercury Control Costs and Co-control for ATCO Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Battle River, continued																
Boiler: 4																
2: LSFO	11%	98.67	13.43	21.12	22.72	5.2	4.37	1.98	4.06	1.84	5051	0	+	-19357	177	36.54
17: DSI+PJFF	77%	40.77	5.85	9.03	9.69	36.3	0.27	0.84	0.25	0.79	3722	0	+	-16079	354	9.49
18: LSD+PJFF	77%	90	11.64	18.66	20.11	36.3	0.55	1.75	0.51	1.62	4785	0	+	-24144	354	9.49
20: ACI+SC+PJFF	82%	34.55	8	10.69	11.25	38.48	0.29	0.98	0.28	0.93	0	0	+	-17864	354	7.59
21: SCR+LSFO	56%	137.44	21.01	31.72	33.95	26.4	1.29	2.95	1.2	2.76	5051	2046	+	-36782	225	18.1
22: SCR+ACI+SC+PJFF	91%	73.31	15.58	21.29	22.48	42.89	0.52	1.96	0.5	1.85	0	2046	+	-35289	354	3.76
23: LSFO+ACI+SC+PJFF	84%	133.21	21.43	31.82	33.97	39.44	0.86	2.95	0.81	2.77	5051	0	+	-37221	354	6.76
24: DSI+ACI+SC+PJFF	89%	44.91	9.96	13.46	14.18	42.02	0.34	1.23	0.32	1.17	3722	0	+	-22703	354	4.51
25: SCR+DSI+PJFF	89%	79.54	13.43	19.63	20.92	41.8	0.5	1.82	0.47	1.71	3722	2046	+	-33504	354	4.7
Boiler: 5																
2: LSFO	11%	109.94	17.95	26.52	26.27	12.01	2.19	0.96	2.21	0.97	11854	0	+	-23729	364	34.11
17: DSI+PJFF	78%	50.81	8.53	12.5	12.38	81.81	0.15	0.45	0.15	0.46	8735	0	+	-19351	727	8.6
18: LSD+PJFF	78%	122.36	16.43	25.97	25.7	81.81	0.31	0.94	0.32	0.95	11230	0	+	-29238	727	8.6
20: ACI+SC+PJFF	82%	56.48	13.52	17.92	17.8	86.88	0.2	0.65	0.21	0.65	0	0	+	-21492	727	6.75
21: SCR+LSFO	58%	156.84	27.66	39.88	39.53	61.3	0.64	1.44	0.65	1.46	11854	4890	+	-45465	462	16.1
22: SCR+ACI+SC+PJFF	92%	103.38	23.23	31.29	31.05	96.64	0.32	1.13	0.32	1.14	0	4890	+	-43229	727	3.19
23: LSFO+ACI+SC+PJFF	84%	166.42	31.47	44.44	44.06	88.99	0.5	1.61	0.5	1.62	11854	0	+	-45222	728	5.98
24: DSI+ACI+SC+PJFF	90%	70.9	17.35	22.88	22.72	94.72	0.24	0.83	0.24	0.84	8735	0	+	-27425	727	3.89
25: SCR+DSI+PJFF	89%	97.72	18.24	25.86	25.64	94.25	0.27	0.94	0.27	0.95	8735	4890	+	-41087	727	4.06

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

COMMENTS FROM ATCO

Control Description	Comment (e.g. space constraints, loss revenue, etc)
Repowering with Natural Gas Turbines	None of the existing generating units would be considered for conversion from coal to natural gas. Instead, the stations would be decommissioned and the land reclaimed. If natural gas turbines were considered, they would be new units without all the ancillary equipment that a coal fired station would have. In all likelihood, the new units would be co-generation units.
Wet Flue Gas Desulphurization (FGD)	Since the sub-bituminous coal burned at Sheerness and Battle River, and the bituminous coal burned at HR Milner are low in sulphur and meet all regulatory requirements, this option would not be considered. We don't have an acid rain or sulphur problem in Alberta.
Dry Flue Gas Desulphurization (FGD)	See Wet Flue Gas Desulphurization above.
Selective Catalytic Reduction (SCR)	All the units presently meet all regulatory requirements. This is not an option that would be required or considered.
Wet FGD with Baghouse	See Wet FGD above.
Dry FGD with Baghouse	See Wet FGD above.
SCR with Baghouse	See SCR above.
Advanced Coal Washing	Coal washing won't work on the low pyrite coals that we burn at our stations. This is not an option.
Carbon Injection with each of the above	See all previous comments.

TABLE 5.2
Summary of Mercury Control Costs and Co-control for EPCOR
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Genesee																
7: NGT Boiler: 1	100%	578.1	327.37	372.43	372.43	106	3.51	5.44	3.51	5.44	14672	10059	+	3330096	879	0
2: LSFO	19%	90.81	14.45	21.52	20.22	10.27	1.97	0.59	2.1	0.63	6969	0	+	-15818	220	12.47
17: DSI+PJFF	79%	36.86	5.72	8.6	8.07	41.76	0.19	0.24	0.21	0.25	5135	0	+	-13379	440	3.28
18: LSD+PJFF	79%	96.19	12.4	19.9	18.51	41.76	0.44	0.54	0.48	0.58	6602	0	+	-19969	440	3.28
20: ACI+SC+PJFF	84%	29.52	9.89	12.19	11.77	44.58	0.26	0.34	0.27	0.36	0	0	+	-14876	440	2.46
23: LSFO+ACI+SC+PJFF	87%	120.33	24.34	33.72	31.99	46.21	0.69	0.93	0.73	0.98	6969	0	+	-30693	440	1.98
24: DSI+ACI+SC+PJFF	91%	40.71	12.34	15.51	14.93	48.28	0.31	0.44	0.32	0.45	5135	0	+	-18830	440	1.38
Boiler: 2																
2: LSFO	19%	90.81	14.45	21.52	19.82	10.27	1.93	0.58	2.1	0.63	6969	0	+	-15818	220	12.47
17: DSI+PJFF	79%	36.86	5.72	8.6	7.91	41.76	0.19	0.23	0.21	0.25	5135	0	+	-13379	440	3.28
18: LSD+PJFF	79%	96.19	12.4	19.9	18.09	41.76	0.43	0.53	0.48	0.58	6602	0	+	-19969	440	3.28
20: ACI+SC+PJFF	84%	29.52	9.89	12.19	11.64	44.58	0.26	0.34	0.27	0.36	0	0	+	-14876	440	2.46
23: LSFO+ACI+SC+PJFF	87%	120.33	24.34	33.72	31.46	46.21	0.68	0.92	0.73	0.98	6969	0	+	-30693	440	1.98
24: DSI+ACI+SC+PJFF	91%	40.71	12.34	15.51	14.75	48.28	0.31	0.43	0.32	0.45	5135	0	+	-18830	440	1.38

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

COMMENTS FROM EPCOR

Control Description	Comment (e.g. space constraints, loss revenue, etc)
repowering with natural gas turbines	To repower existing steam turbines to combined cycle implies a capacity increase of more than 2 times for each unit and would need 8+ gas turbines and HRSGs, located where existing boilers are. This is not within the bounds of practical or economic feasibility. Single cycle GT repowering on the site does not make sense and implies complete site abandonment with the GT sited elsewhere. Neither option can be sensibly considered.
wet flue gas desulphurization (FGD)	space restraints & outages assumed same as SCR
dry flue gas desulphurization (FGD)	space restraints & outages assumed same as SCR
selective catalytic reduction (SCR)	SCR could conceivably be installed above existing ducting at south wall of plant. Requires massive structural supports. Would require at least a 10 week outage. No evidence that it would reduce the predominately elemental Hg emissions. Not a sensible option.
wet FGD with baghouse	Implies removal of existing ESP & replacement with new equipment in same location.
dry FGD with baghouse	same as above
SCR with baghouse	same as above
advanced coal washing	Not applicable. Advice from federal NRC expert that coal washing will not only be ineffective but would likely significantly raise Hg emissions given existing capture being achieved in flyash.
carbon injection with each of the above	Understand from Wisconsin Power that activated carbon costs ~C\$1700/t and would make flyash unsaleable. Uncertain that this will significantly increase existing reduction of predominately elemental Hg in flyash.

TABLE 5.3
Summary of Mercury Control Costs and Co-control for Manitoba Hydro
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Selkirk																
7: NGT	100%	134.59	33.67	44.16	44.16	4.91	8.99	15.73	8.99	15.73	18501	338	+	115406	769	0
Brandon																
7: NGT	100%	100.43	29.41	37.24	37.24	6	6.21	7.62	6.21	7.62	9887	452	+	172645	4	0
Boiler: 1																
2: LSFO	20%	73.78	18.67	24.42	n/a	1.21	1.21	0.3	20.12	5	9393	0	+	-1823	2	9.8
17: DSI+PJFF	79%	25.74	4.16	6.16	n/a	4.73	n/a	n/a	1.3	1.26	6921	0	+	-1739	4	2.59
18: LSD+PJFF	79%	47.88	7.06	10.79	n/a	4.73	n/a	n/a	2.28	2.21	8898	0	+	-2499	4	2.59
20: ACI+SC+PJFF	84%	11.27	1.73	2.6	n/a	5.06	n/a	n/a	0.52	0.53	0	0	+	-1976	4	1.93
21: SCR+LSFO	58%	82.67	20	26.44	n/a	3.47	n/a	n/a	7.61	5.42	9393	482	+	-2553	3	5.17
22: SCR+ACI+SC+PJFF	92%	20.15	3.05	4.62	n/a	5.5	n/a	n/a	0.84	0.95	0	482	+	-2705	4	1.02
23: LSFO+ACI+SC+PJFF	87%	85.05	20.4	27.03	n/a	5.25	n/a	n/a	5.15	5.53	9393	0	+	-3799	4	1.54
24: DSI+ACI+SC+PJFF	91%	27.14	4.76	6.87	n/a	5.47	n/a	n/a	1.26	1.41	6921	0	+	-2432	4	1.08
25: SCR+DSI+PJFF	89%	34.63	5.48	8.18	n/a	5.33	n/a	n/a	1.53	1.68	6921	482	+	-2468	4	1.37

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

No other options were examined for Selkirk because this station is being converted to natural gas

TABLE 5.4
Summary of Mercury Control Costs and Co-control for New Brunswick Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Belledune																
7: NGT Boiler: 1	100%	340.54	170.2	196.74	196.74	43.2	4.55	5.04	4.55	5.04	3429	4406	+	1706600	200	0
20: ACI+SC+PJFF	85%	41.76	8.9	12.15	11.4	36.71	0.31	0.29	0.33	0.31	0	0	+	-16032	200	1.66
Grand Lake																
7: NGT Boiler: 1	100%	78.52	28.52	34.64	34.64	97	0.36	8.39	0.36	8.39	21210	623	+	187090	69	0
2: LSFO	56%	65.74	14.36	19.49	22.74	54.09	0.42	5.51	0.36	4.72	20150	0	+	-2241	35	103.98
17: DSI+PJFF	84%	29.58	7.09	9.4	10.86	81.12	0.13	2.63	0.12	2.28	14847	0	+	-2120	69	38.48
18: LSD+PJFF	84%	87.18	13.03	19.83	24.14	81.12	0.3	5.85	0.24	4.81	19089	0	+	-3054	69	38.48
20: ACI+SC+PJFF	91%	33.64	11.55	14.17	15.84	88.12	0.18	3.84	0.16	3.43	0	0	+	-2402	69	21.52
21: SCR+LSFO	66%	75.26	15.91	21.77	25.49	64.29	0.4	6.18	0.34	5.28	20150	664	+	-3506	44	79.27
22: SCR+ACI+SC+PJFF	93%	43.16	13.09	16.46	18.59	90.23	0.21	4.5	0.18	3.99	0	664	+	-3667	69	16.41
23: LSFO+ACI+SC+PJFF	96%	99.38	25.91	33.66	38.57	93.07	0.41	9.35	0.36	8.16	20150	0	+	-4643	69	9.52
24: DSI+ACI+SC+PJFF	96%	52.79	17.42	21.54	24.14	92.65	0.26	5.85	0.23	5.22	14847	0	+	-2962	69	10.53
25: SCR+DSI+PJFF	88%	39.1	8.63	11.68	13.62	84.89	0.16	3.3	0.14	2.83	14847	664	+	-3385	69	29.34

ACI - Activated Carbon Injection
 DSI - Dry Sorbent Injection
 LSD - Lime Spray Drying
 LSFO - Wet FGD (limestone forced oxidation)
 NGT - Natural Gas Turbines (Greenfield)
 PJFF - Pulse Jet Fabric Filter
 SC - Spray Cooling
 SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

TABLE 5.5
Summary of Mercury Control Costs and Co-control for Nova Scotia Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁵)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁹ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Point Aconi																
7: NGT Boiler: 1	100%	104.3	32.75	40.88	40.88	5.7	7.17	2.89	7.17	2.89	2100	871	+	327952	22	0
2: LSFO	77%	70.13	8.77	14.24	13.69	4.39	3.12	0.97	3.25	1.01	1995	0	+	-4655	11	0.93
4: DSI	56%	7.96	1	1.62	1.56	3.2	0.49	0.11	0.51	0.11	1470	0	+	-1164	0	1.77
5: LSD	56%	50.96	5.99	9.97	9.57	3.2	2.99	0.68	3.11	0.71	1890	0	+	-3103	0	1.77
15: ACI+SC	82%	1.85	0.83	0.98	0.96	4.7	0.2	0.07	0.21	0.07	0	0	+	-1673	0	0.71
21: SCR+LSFO	80%	90.8	11.71	18.79	18.08	4.54	3.99	1.28	4.14	1.33	1995	929	+	-6295	14	0.82
26: SCR+ACI+SC	84%	22.51	3.77	5.52	5.35	4.81	1.11	0.38	1.15	0.39	0	929	+	-3313	6	0.63
27: LSFO+ACI+SC	96%	71.99	9.61	15.22	14.65	5.47	2.68	1.04	2.78	1.08	1995	0	+	-6327	11	0.16
26: DSI+ACI+SC	92%	9.81	1.83	2.6	2.52	5.26	0.48	0.18	0.49	0.18	1470	0	+	-2836	0	0.31
26: SCR+DSI	61%	28.62	3.94	6.17	5.94	3.49	1.7	0.42	1.77	0.44	1470	929	+	-2804	6	1.57
Pont Tupper																
7: NGT Boiler: 2	100%	154.16	67.76	79.78	79.78	37.3	2.14	6.37	2.14	6.37	16525	2252	+	565486	228	0
2: LSFO	50%	70.88	13.88	19.4	39.74	18.6	2.14	3.17	1.04	1.55	15699	0	+	-4144	114	14.93
17: DSI+PJFF	83%	29.03	6.34	8.6	16.93	30.89	0.55	1.35	0.28	0.69	11568	0	+	-3776	228	5.12
18: LSD+PJFF	83%	60.32	9.7	14.4	31.71	30.89	1.03	2.53	0.47	1.15	14873	0	+	-5503	228	5.12
20: ACI+SC+PJFF	90%	15.85	4.63	5.86	10.41	33.54	0.31	0.83	0.17	0.47	0	0	+	-4238	228	3
21: SCR+LSFO	64%	91.85	16.9	24.06	50.41	23.92	2.11	4.03	1.01	1.92	15699	2402	+	-7054	145	10.68
22: SCR+ACI+SC+PJFF	93%	36.82	7.65	10.52	21.09	34.61	0.61	1.68	0.3	0.84	0	2402	+	-7148	228	2.15
23: LSFO+ACI+SC+PJFF	95%	86.73	18.51	25.27	50.15	35.41	1.42	4	0.71	2.02	15699	0	+	-8382	228	1.51
24: DSI+ACI+SC+PJFF	95%	31.13	9.3	11.72	20.66	35.44	0.58	1.65	0.33	0.94	11568	0	+	-5274	228	1.49
25: SCR+DSI+PJFF	88%	50	9.36	13.26	27.61	32.71	0.84	2.2	0.41	1.06	11568	2402	+	-6686	228	3.66
Trenton																
7: NGT Boiler: 5	100%	257.82	108.71	128.81	128.81	53.4	2.41	5.96	2.41	5.96	25790	4901	+	963525	448	0
2: LSFO	47%	65.82	11.08	16.21	n/a	10.23	n/a	n/a	1.58	1.62	9984	0	+	-2360	92	11.6
17: DSI+PJFF	82%	25.39	4.5	6.47	n/a	17.97	n/a	n/a	0.36	0.65	7357	0	+	-2204	183	3.84
18: LSD+PJFF	82%	54.95	7.96	12.25	n/a	17.97	n/a	n/a	0.68	1.23	9459	0	+	-3188	183	3.84
20: ACI+SC+PJFF	89%	13.32	3.15	4.19	n/a	19.49	n/a	n/a	0.21	0.42	0	0	+	-2489	183	2.32
21: SCR+LSFO	63%	84.64	13.56	20.16	n/a	13.74	n/a	n/a	1.47	2.02	9984	2130	+	-3741	116	8.08
22: SCR+ACI+SC+PJFF	93%	32.14	5.63	8.13	n/a	20.19	n/a	n/a	0.4	0.82	0	2130	+	-3870	183	1.62
23: LSFO+ACI+SC+PJFF	94%	79.14	14.23	20.4	n/a	20.57	n/a	n/a	0.99	2.04	9984	0	+	-4849	183	1.23
24: DSI+ACI+SC+PJFF	95%	27.27	6.3	8.42	n/a	20.64	n/a	n/a	0.41	0.84	7357	0	+	-3079	183	1.16
25: SCR+DSI+PJFF	88%	44.22	6.98	10.42	n/a	19.13	n/a	n/a	0.54	1.04	7357	2130	+	-3586	183	2.68
Boiler: 6																
2: LSFO	47%	67.12	12.96	18.19	18.04	14.83	1.22	1.55	1.23	1.57	14516	0	+	-3199	133	14.43
17: DSI+PJFF	82%	27.43	5.76	7.9	7.84	26.05	0.3	0.67	0.3	0.68	10696	0	+	-2973	265	4.78
18: LSD+PJFF	82%	55.01	8.83	13.12	13	26.05	0.5	1.12	0.5	1.13	13752	0	+	-4306	265	4.78
20: ACI+SC+PJFF	89%	13.83	3.93	5.01	4.98	28.25	0.18	0.43	0.18	0.43	0	0	+	-3352	265	2.88
21: SCR+LSFO	63%	87.61	15.8	22.63	22.43	19.91	1.13	1.93	1.14	1.95	14516	3097	+	-5280	168	10.06
22: SCR+ACI+SC+PJFF	93%	34.32	6.77	9.44	9.36	29.26	0.32	0.81	0.32	0.81	0	3097	+	-5433	265	2.01
23: LSFO+ACI+SC+PJFF	94%	80.95	16.89	23.2	23.02	29.82	0.77	1.98	0.78	2	14516	0	+	-6551	265	1.53
24: DSI+ACI+SC+PJFF	95%	29.4	8.29	10.58	10.51	29.92	0.35	0.9	0.35	0.91	10696	0	+	-4152	265	1.45
25: SCR+DSI+PJFF	88%	47.92	8.6	12.34	12.23	27.73	0.44	1.05	0.44	1.06	10696	3097	+	-5054	265	3.33

TABLE 5.5
Summary of Mercury Control Costs and Co-control for Nova Scotia Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁵)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Lingan																
7: NGT	100%	419.46	195.13	227.83	227.83	192.6	1.18	4.64	1.18	4.64	53952	8499	+	1889080	396	0
Boiler: 1																
2: LSFO	50%	70.03	14.46	19.91	20.09	24.49	0.82	1.57	0.81	1.55	17915	0	+	-3738	51	19.21
17: DSI+PJFF	83%	29.48	6.83	9.13	9.2	40.66	0.23	0.72	0.22	0.71	13200	0	+	-3429	101	6.59
18: LSD+PJFF	83%	60.65	10.1	14.82	14.98	40.66	0.37	1.17	0.36	1.16	16972	0	+	-4986	101	6.59
20: ACI+SC+PJFF	90%	15.25	5.33	6.51	6.55	44.15	0.15	0.51	0.15	0.51	0	0	+	-3854	101	3.87
21: SCR+LSFO	64%	90.11	17.26	24.28	24.51	31.49	0.78	1.91	0.77	1.9	17915	2312	+	-5973	64	13.75
22: SCR+ACI+SC+PJFF	93%	35.33	8.13	10.88	10.97	45.56	0.24	0.86	0.24	0.85	0	2312	+	-6088	101	2.77
23: LSFO+ACI+SC+PJFF	95%	85.28	19.78	26.43	26.64	46.62	0.57	2.08	0.57	2.06	17915	0	+	-7592	101	1.94
24: DSI+ACI+SC+PJFF	95%	31.65	10.58	13.04	13.12	46.65	0.28	1.02	0.28	1.02	13200	0	+	-4788	101	1.91
25: SCR+DSI+PJFF	88%	49.56	9.63	13.5	13.62	43.06	0.32	1.06	0.31	1.05	13200	2312	+	-5663	101	4.72
Boiler: 2																
2: LSFO	50%	69.99	14.18	19.64	19.64	23.54	0.83	1.57	0.83	1.57	17222	0	+	-3642	49	18.94
17: DSI+PJFF	83%	29.37	6.65	8.94	8.94	39.08	0.23	0.72	0.23	0.72	12690	0	+	-3340	97	6.5
18: LSD+PJFF	83%	60.62	9.96	14.68	14.68	39.08	0.38	1.18	0.38	1.18	16315	0	+	-4858	97	6.5
20: ACI+SC+PJFF	90%	15.25	5.2	6.39	6.39	42.44	0.15	0.51	0.15	0.51	0	0	+	-3754	97	3.81
21: SCR+LSFO	64%	90.05	16.98	23.99	23.99	30.27	0.79	1.92	0.79	1.92	17222	2222	+	-5854	62	13.56
22: SCR+ACI+SC+PJFF	93%	35.3	7.99	10.74	10.74	43.79	0.25	0.86	0.25	0.86	0	2222	+	-5967	97	2.73
23: LSFO+ACI+SC+PJFF	95%	85.24	19.38	26.02	26.02	44.81	0.58	2.08	0.58	2.08	17222	0	+	-7396	97	1.91
24: DSI+ACI+SC+PJFF	95%	31.54	10.27	12.73	12.73	44.84	0.28	1.02	0.28	1.02	12690	0	+	-4665	97	1.89
25: SCR+DSI+PJFF	88%	49.43	9.44	13.29	13.29	41.39	0.32	1.06	0.32	1.06	12690	2222	+	-5553	97	4.65

TABLE 5.5
Summary of Mercury Control Costs and Co-control for Nova Scotia Power
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Lingan, continued																
Boiler: 3																
2: LSFO	50%	67.52	10.2	15.46	15.05	22.04	0.68	1.36	0.7	1.4	6619	0	+	-3004	46	20.07
17: DSI+PJFF	83%	24.14	3.73	5.61	5.46	36.6	0.15	0.5	0.15	0.51	4877	0	+	-2771	91	6.88
18: LSD+PJFF	83%	57.75	7.69	12.19	11.84	36.6	0.32	1.07	0.33	1.1	6271	0	+	-4023	91	6.88
20: ACI+SC+PJFF	90%	14.69	4.84	5.98	5.89	39.74	0.15	0.53	0.15	0.54	0	0	+	-3119	91	4.04
21: SCR+LSFO	64%	87.68	12.97	19.8	19.26	28.35	0.68	1.74	0.7	1.79	6619	2080	+	-4865	58	14.36
22: SCR+ACI+SC+PJFF	93%	34.84	7.61	10.32	10.11	41.01	0.25	0.92	0.25	0.94	0	2080	+	-4980	91	2.89
23: LSFO+ACI+SC+PJFF	95%	82.21	15.04	21.45	20.94	41.97	0.5	1.9	0.51	1.94	6619	0	+	-6123	91	2.02
24: DSI+ACI+SC+PJFF	95%	26.3	7.08	9.13	8.97	41.99	0.21	0.81	0.22	0.83	4877	0	+	-3870	91	2
25: SCR+DSI+PJFF	88%	44.29	6.5	9.95	9.68	38.76	0.25	0.88	0.26	0.9	4877	2080	+	-4632	91	4.93
Boiler: 4																
2: LSFO	50%	67.81	11.37	16.65	16.12	25.98	0.62	1.27	0.64	1.31	9499	0	+	-3482	54	20.5
17: DSI+PJFF	83%	25.1	4.52	6.48	6.28	43.14	0.15	0.49	0.15	0.51	6999	0	+	-3212	107	7.03
18: LSD+PJFF	83%	58.01	8.27	12.8	12.34	43.14	0.29	0.97	0.3	1	8999	0	+	-4663	107	7.03
20: ACI+SC+PJFF	90%	14.7	5.46	6.61	6.49	46.85	0.14	0.51	0.14	0.52	0	0	+	-3615	107	4.12
21: SCR+LSFO	64%	88	14.18	21.04	20.35	33.41	0.61	1.6	0.63	1.65	9499	2451	+	-5647	68	14.67
22: SCR+ACI+SC+PJFF	93%	34.89	8.28	11	10.73	48.34	0.22	0.84	0.23	0.86	0	2451	+	-5781	107	2.95
23: LSFO+ACI+SC+PJFF	95%	82.51	16.82	23.26	22.61	49.47	0.46	1.78	0.47	1.83	9499	0	+	-7096	107	2.07
24: DSI+ACI+SC+PJFF	95%	27.28	8.48	10.6	10.39	49.5	0.21	0.82	0.21	0.83	6999	0	+	-4485	107	2.04
25: SCR+DSI+PJFF	88%	45.29	7.34	10.87	10.52	45.69	0.23	0.83	0.24	0.85	6999	2451	+	-5378	107	5.03

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

n/a - Costs were not amortized over the remaining life of boiler 5 because the retirement date is before 2010

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

Comments from NSPI

Control Description	Comment (e.g. space constraints, loss revenue, etc)
Point Aconi repowering with natural gas turbines	Unlikely for CFB boiler
Trenton wet flue gas desulphurization (FGD)	Trenton unit 5 age likely precludes scrubbers.

TABLE 5.6
Summary of Mercury Control Costs and Co-control for OPG
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Lambton																
7: NGT	100%	1167.01	515.46	606.43	606.43	134	4.53	6.74	4.53	6.74	27256	9599	+	4150960	1932	0
Boiler: 1																
2: LSFO	61%	107.81	16.7	25.1	30.43	27.19	1.12	1.35	0.92	1.12	10536	0	+	-7538	241	7.61
10: ACC2	20%	0	6.15	6.15	6.15	8.86	0.69	0.27	0.69	0.27	5545	0	+	0	0	15.75
17: DSI+PJFF	84%	51.25	7.71	11.71	14.24	37.37	0.38	0.63	0.31	0.52	7763	0	+	-6184	482	3.09
18: LSD+PJFF	84%	119.97	15.45	24.81	30.74	37.37	0.82	1.37	0.66	1.1	9981	0	+	-9325	482	3.09
20: ACI+SC+PJFF	92%	39.32	7.96	11.02	12.97	40.66	0.32	0.58	0.27	0.49	0	0	+	-6868	482	1.62
21: SCR+LSFO	69%	138.71	25.13	35.94	42.79	30.61	1.4	1.9	1.17	1.6	10536	3194	+	-14409	306	6.09
22: SCR+ACI+SC+PJFF	93%	70.22	16.38	21.86	25.33	41.39	0.61	1.13	0.53	0.97	0	3194	+	-13738	482	1.3
23: LSFO+ACI+SC+PJFF	97%	147.13	24.66	36.13	43.4	42.9	1.01	1.93	0.84	1.61	10536	0	+	-14406	482	0.63
24: DSI+ACI+SC+PJFF	96%	56.23	11.42	15.8	18.58	42.56	0.44	0.83	0.37	0.7	7763	0	+	-8753	482	0.78
25: SCR+DSI+PJFF	87%	82.14	16.14	22.54	26.6	38.75	0.69	1.18	0.58	1	7763	3194	+	-13054	482	2.47
Boiler: 2																
2: LSFO	61%	107.81	16.7	25.1	31.64	27.19	1.16	1.41	0.92	1.12	10536	0	+	-7538	241	7.61
10: ACC2	20%	0	6.15	6.15	6.15	8.86	0.69	0.27	0.69	0.27	5545	0	+	0	0	15.75
17: DSI+PJFF	84%	51.25	7.71	11.71	14.81	37.37	0.4	0.66	0.31	0.52	7763	0	+	-6184	482	3.09
18: LSD+PJFF	84%	119.97	15.45	24.81	32.08	37.37	0.86	1.43	0.66	1.1	9981	0	+	-9325	482	3.09
20: ACI+SC+PJFF	92%	39.32	7.96	11.02	13.41	40.66	0.33	0.6	0.27	0.49	0	0	+	-6868	482	1.62
21: SCR+LSFO	69%	138.71	25.13	35.94	44.35	30.61	1.45	1.97	1.17	1.6	10536	3194	+	-14409	306	6.09
22: SCR+ACI+SC+PJFF	93%	70.22	16.38	21.86	26.12	41.39	0.63	1.16	0.53	0.97	0	3194	+	-13738	482	1.3
23: LSFO+ACI+SC+PJFF	97%	147.13	24.66	36.13	45.05	42.9	1.05	2	0.84	1.61	10536	0	+	-14406	482	0.63
24: DSI+ACI+SC+PJFF	96%	56.23	11.42	15.8	19.21	42.56	0.45	0.85	0.37	0.7	7763	0	+	-8753	482	0.78
25: SCR+DSI+PJFF	87%	82.14	16.14	22.54	27.52	38.75	0.71	1.22	0.58	1	7763	3194	+	-13054	482	2.47
Boiler: 3																
19: SCR+PJFF	79%	59	11.61	16.21	19.13	18.01	1.06	0.85	0.9	0.72	0	1925	+	-9285	485	2.08
20: ACI+SC+PJFF	85%	33.23	5.75	8.34	9.98	19.28	0.52	0.44	0.43	0.37	0	0	+	-5813	485	1.52
22: SCR+ACI+SC+PJFF	92%	62.98	13.78	18.69	21.8	20.81	1.05	0.97	0.9	0.83	0	1925	+	-11435	485	0.84
26: SCR+ACI+SC	78%	33.73	10.2	12.83	14.49	17.64	0.82	0.64	0.73	0.57	0	1925	+	-7771	131	2.24
Boiler: 4																
19: SCR+PJFF	79%	59	11.61	16.21	19.13	18.01	1.06	0.85	0.9	0.72	0	1925	+	-9285	485	2.08
20: ACI+SC+PJFF	85%	33.23	5.75	8.34	9.98	19.28	0.52	0.44	0.43	0.37	0	0	+	-5813	485	1.52
22: SCR+ACI+SC+PJFF	92%	62.98	13.78	18.69	21.8	20.81	1.05	0.97	0.9	0.83	0	1925	+	-11435	485	0.84
26: SCR+ACI+SC	78%	33.73	10.2	12.83	14.49	17.64	0.82	0.64	0.73	0.57	0	1925	+	-7771	131	2.24

TABLE 5.6
Summary of Mercury Control Costs and Co-control for OPG
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Nanticoke																
7: NGT	100%	2027.14	1017.73	1175.75	1175.75	260	4.52	6.23	4.52	6.23	71792	18252	+	9004170	7752	0
Boiler: 1																
2: LSFO	40%	108.61	13.36	21.83	24.69	13.15	1.88	1.05	1.66	0.92	213	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	112	0	+	0	0	11.01
17: DSI+PJFF	82%	42.92	5.09	8.44	9.57	26.63	0.36	0.41	0.32	0.36	157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	122.38	13.97	23.51	26.73	26.63	1	1.13	0.88	1	202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	11.34	28.63	0.4	0.48	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	150.33	20.35	32.06	36.02	30.2	1.19	1.53	1.06	1.36	213	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	47.98	7.5	11.24	12.5	30.44	0.41	0.53	0.37	0.48	157	0	+	-6383	969	0.87
Boiler: 2																
2: LSFO	40%	111.13	16.93	25.59	28.52	13.15	2.17	1.21	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	13.29	26.63	0.5	0.56	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	28.94	26.63	1.09	1.23	0.96	1.09	9202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	11.34	28.63	0.4	0.48	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	39.86	30.2	1.32	1.69	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	16.23	30.44	0.53	0.69	0.48	0.62	7157	0	+	-6383	969	0.87
Boiler: 3																
2: LSFO	40%	111.13	16.93	25.59	28.52	13.15	2.17	1.21	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	13.29	26.63	0.5	0.56	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	28.94	26.63	1.09	1.23	0.96	1.09	9202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	11.34	28.63	0.4	0.48	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	39.86	30.2	1.32	1.69	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	16.23	30.44	0.53	0.69	0.48	0.62	7157	0	+	-6383	969	0.87

TABLE 5.6
Summary of Mercury Control Costs and Co-control for OPG
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁹ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁹ /kg Hg removed	Cost ¢/kWh						
Nanticoke, continued																
Boiler: 4																
2: LSFO	40%	111.13	16.93	25.59	27.92	13.15	2.12	1.18	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	13.01	26.63	0.49	0.55	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	28.26	26.63	1.06	1.2	0.96	1.09	9202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	11.11	28.63	0.39	0.47	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	39.03	30.2	1.29	1.65	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	15.91	30.44	0.52	0.67	0.48	0.62	7157	0	+	-6383	969	0.87
Boiler: 5																
2: LSFO	40%	111.13	16.93	25.59	27.39	13.15	2.08	1.16	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	12.76	26.63	0.48	0.54	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	27.67	26.63	1.04	1.17	0.96	1.09	9202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	10.91	28.63	0.38	0.46	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	38.31	30.2	1.27	1.62	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	15.64	30.44	0.51	0.66	0.48	0.62	7157	0	+	-6383	969	0.87
Boiler: 6																
2: LSFO	40%	111.13	16.93	25.59	26.54	13.15	2.02	1.12	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	12.36	26.63	0.46	0.52	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	26.71	26.63	1	1.13	0.96	1.09	9202	0	+	-6806	969	2.49
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	10.59	28.63	0.37	0.45	0.36	0.43	0	0	+	-5002	969	1.64
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	37.13	30.2	1.23	1.57	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	15.2	30.44	0.5	0.64	0.48	0.62	7157	0	+	-6383	969	0.87
Boiler: 7																
2: LSFO	40%	111.13	16.93	25.59	26.19	13.15	1.99	1.11	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	12.19	26.63	0.46	0.52	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	26.32	26.63	0.99	1.11	0.96	1.09	9202	0	+	-6806	969	2.49
19: SCR+PJFF	77%	66.56	12.8	17.98	18.34	24.99	0.73	0.78	0.72	0.76	0	2434	+	-8187	969	3.18
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	10.46	28.63	0.37	0.44	0.36	0.43	0	0	+	-5002	969	1.64
21: SCR+LSFO	59%	141.04	25.15	36.14	36.89	19.33	1.91	1.56	1.87	1.53	9713	2434	+	-10591	616	5.58
22: SCR+ACI+SC+PJFF	92%	71.62	15.2	20.78	21.17	29.87	0.71	0.9	0.7	0.88	0	2434	+	-10067	969	1.12
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	36.65	30.2	1.21	1.55	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	15.02	30.44	0.49	0.64	0.48	0.62	7157	0	+	-6383	969	0.87

TABLE 5.6
Summary of Mercury Control Costs and Co-control for OPG
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Nanticoke, continued																
Boiler: 8																
2: LSFO	40%	111.13	16.93	25.59	26.19	13.15	1.99	1.11	1.95	1.08	9713	0	+	-5526	485	8.2
10: ACC2	20%	0	7.37	7.37	7.37	6.5	1.13	0.31	1.13	0.31	5112	0	+	0	0	11.01
17: DSI+PJFF	82%	52.52	7.82	11.91	12.19	26.63	0.46	0.52	0.45	0.5	7157	0	+	-4503	969	2.49
18: LSD+PJFF	82%	124.74	15.93	25.65	26.32	26.63	0.99	1.11	0.96	1.09	9202	0	+	-6806	969	2.49
19: SCR+PJFF	77%	66.56	12.8	17.98	18.34	24.99	0.73	0.78	0.72	0.76	0	2434	+	-8187	969	3.18
20: ACI+SC+PJFF	88%	41.72	6.99	10.24	10.46	28.63	0.37	0.44	0.36	0.43	0	0	+	-5002	969	1.64
21: SCR+LSFO	59%	141.04	25.15	36.14	36.89	19.33	1.91	1.56	1.87	1.53	9713	2434	+	-10591	616	5.58
22: SCR+ACI+SC+PJFF	92%	71.62	15.2	20.78	21.17	29.87	0.71	0.9	0.7	0.88	0	2434	+	-10067	969	1.12
23: LSFO+ACI+SC+PJFF	93%	152.85	23.92	35.83	36.65	30.2	1.21	1.55	1.19	1.52	9713	0	+	-10528	970	0.98
24: DSI+ACI+SC+PJFF	94%	57.58	10.22	14.71	15.02	30.44	0.49	0.64	0.48	0.62	7157	0	+	-6383	969	0.87
Thunder Bay																
7: NGT	100%	322.51	126.29	151.43	151.43	80	1.89	9.45	1.89	9.45	7718	1565	+	830510	206	0
Boiler: 2																
2: LSFO	4%	79.57	10.44	16.64	16.46	1.41	11.71	2.06	11.84	2.08	3666	0	+	-4543	52	48.18
17: DSI+PJFF	77%	30.2	3.82	6.17	6.1	30.61	0.2	0.76	0.2	0.77	2701	0	+	-3962	103	11.72
18: LSD+PJFF	77%	70.08	8.62	14.08	13.92	30.61	0.45	1.74	0.46	1.76	3473	0	+	-5855	103	11.72
20: ACI+SC+PJFF	81%	22.79	6.57	8.34	8.29	32.31	0.26	1.04	0.26	1.04	0	0	+	-4416	103	9.6
21: SCR+LSFO	59%	95.97	13.89	21.37	21.15	23.66	0.89	2.64	0.9	2.67	3666	834	+	-8350	65	20.4
22: SCR+ACI+SC+PJFF	92%	39.2	10.01	13.07	12.98	36.74	0.35	1.62	0.36	1.63	0	834	+	-8224	103	4.07
23: LSFO+ACI+SC+PJFF	81%	102.36	17.01	24.99	24.76	32.58	0.76	3.09	0.77	3.12	3666	0	+	-8959	103	9.26
24: DSI+ACI+SC+PJFF	89%	33.4	8.03	10.63	10.56	35.44	0.3	1.32	0.3	1.33	2701	0	+	-5552	103	5.7
25: SCR+DSI+PJFF	90%	46.6	7.26	10.89	10.79	36.03	0.3	1.35	0.3	1.36	2701	834	+	-7769	103	4.96
Boiler: 3																
2: LSFO	4%	79.57	10.44	16.64	16.3	1.41	11.59	2.03	11.84	2.08	3666	0	+	-4543	52	48.18
17: DSI+PJFF	77%	30.2	3.82	6.17	6.04	30.61	0.2	0.75	0.2	0.77	2701	0	+	-3962	103	11.72
18: LSD+PJFF	77%	70.08	8.62	14.08	13.78	30.61	0.45	1.72	0.46	1.76	3473	0	+	-5855	103	11.72
20: ACI+SC+PJFF	81%	22.79	6.57	8.34	8.24	32.31	0.26	1.03	0.26	1.04	0	0	+	-4416	103	9.6
21: SCR+LSFO	59%	95.97	13.89	21.37	20.95	23.66	0.89	2.62	0.9	2.67	3666	834	+	-8350	65	20.4
22: SCR+ACI+SC+PJFF	92%	39.2	10.01	13.07	12.9	36.74	0.35	1.61	0.36	1.63	0	834	+	-8224	103	4.07
23: LSFO+ACI+SC+PJFF	81%	102.36	17.01	24.99	24.55	32.58	0.75	3.06	0.77	3.12	3666	0	+	-8959	103	9.26
24: DSI+ACI+SC+PJFF	89%	33.4	8.03	10.63	10.49	35.44	0.3	1.31	0.3	1.33	2701	0	+	-5552	103	5.7
25: SCR+DSI+PJFF	90%	46.6	7.26	10.89	10.69	36.03	0.3	1.33	0.3	1.36	2701	834	+	-7769	103	4.96
Atikokan																
7: NGT	100%	222.44	83.35	100.69	100.69	68	1.48	9.06	1.48	9.06	5556	983	+	599430	30	0
Boiler: 1																
2: LSFO	7%	88.11	12.08	18.95	18.12	4.46	4.06	1.63	4.25	1.71	5278	0	+	-9087	15	57.19
17: DSI+PJFF	77%	36.04	4.86	7.67	7.33	52.35	0.14	0.66	0.15	0.69	3889	0	+	-7742	30	14.08
18: LSD+PJFF	77%	80.42	10.14	16.4	15.65	52.35	0.3	1.41	0.31	1.48	5000	0	+	-11528	30	14.08
20: ACI+SC+PJFF	81%	41.54	8.75	11.99	11.6	55.37	0.21	1.04	0.22	1.08	0	0	+	-8612	30	11.37
21: SCR+LSFO	59%	107.61	16.53	24.92	23.91	39.8	0.6	2.15	0.63	2.24	5278	1049	+	-17011	19	25.38
22: SCR+ACI+SC+PJFF	92%	61.04	13.21	17.97	17.39	62.39	0.28	1.57	0.29	1.62	0	1049	+	-16536	30	5.04
23: LSFO+ACI+SC+PJFF	83%	129.65	20.83	30.94	29.72	56.2	0.53	2.67	0.55	2.78	5278	0	+	-17699	30	10.62
24: DSI+ACI+SC+PJFF	89%	53.55	10.69	14.86	14.36	60.58	0.24	1.29	0.25	1.34	3889	0	+	-10884	30	6.68
25: SCR+DSI+PJFF	90%	55.53	9.32	13.65	13.13	61.06	0.22	1.18	0.22	1.23	3889	1049	+	-15666	30	6.25

TABLE 5.6
Summary of Mercury Control Costs and Co-control for OPG
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Lakeview																
7: NGT	100%	810.82	269.33	332.53	332.53	87	3.82	10.41	3.82	10.41	18077	8196	+	1584700	259	0
Boiler: 1																
2: LSFO	61%	91.01	11.73	18.82	60.44	13.35	4.53	7.57	1.41	2.36	4293	0	+	-3217	32	10.52
17: DSI+PJFF	84%	39.32	4.69	7.75	25.73	18.34	1.4	3.22	0.42	0.97	3163	0	+	-2726	65	4.27
18: LSD+PJFF	84%	84.31	10.2	16.77	55.32	18.34	3.02	6.93	0.91	2.1	4067	0	+	-4067	65	4.27
20: ACI+SC+PJFF	92%	28.85	4.77	7.02	20.21	19.96	1.01	2.53	0.35	0.88	0	0	+	-3031	65	2.24
21: SCR+LSFO	69%	114.36	16.94	25.85	78.14	15.03	5.2	9.78	1.72	3.24	4293	2186	+	-6044	41	8.42
22: SCR+ACI+SC+PJFF	93%	52.19	9.98	14.05	37.92	20.32	1.87	4.75	0.69	1.76	0	2186	+	-5859	65	1.8
23: LSFO+ACI+SC+PJFF	97%	119.86	16.5	25.84	80.65	21.06	3.83	10.1	1.23	3.23	4293	0	+	-6249	65	0.87
24: DSI+ACI+SC+PJFF	96%	42.92	6.47	9.82	29.44	20.89	1.41	3.69	0.47	1.23	3163	0	+	-3836	65	1.08
25: SCR+DSI+PJFF	87%	62.66	9.9	14.79	43.44	19.02	2.28	5.44	0.78	1.85	3163	2186	+	-5553	65	3.41
Boiler: 2																
2: LSFO	61%	91.01	11.73	18.82	44.94	13.35	3.37	5.62	1.41	2.36	4293	0	+	-3217	32	10.52
17: DSI+PJFF	84%	39.32	4.69	7.75	19.04	18.34	1.04	2.38	0.42	0.97	3163	0	+	-2726	65	4.27
18: LSD+PJFF	84%	84.31	10.2	16.77	40.96	18.34	2.23	5.13	0.91	2.1	4067	0	+	-4067	65	4.27
20: ACI+SC+PJFF	92%	28.85	4.77	7.02	15.3	19.96	0.77	1.91	0.35	0.88	0	0	+	-3031	65	2.24
21: SCR+LSFO	69%	114.36	16.94	25.85	58.66	15.03	3.9	7.34	1.72	3.24	4293	2186	+	-6044	41	8.42
22: SCR+ACI+SC+PJFF	93%	52.19	9.98	14.05	29.02	20.32	1.43	3.63	0.69	1.76	0	2186	+	-5859	65	1.8
23: LSFO+ACI+SC+PJFF	97%	119.86	16.5	25.84	60.23	21.06	2.86	7.54	1.23	3.23	4293	0	+	-6249	65	0.87
24: DSI+ACI+SC+PJFF	96%	42.92	6.47	9.82	22.13	20.89	1.06	2.77	0.47	1.23	3163	0	+	-3836	65	1.08
25: SCR+DSI+PJFF	87%	62.66	9.9	14.79	32.76	19.02	1.72	4.1	0.78	1.85	3163	2186	+	-5553	65	3.41
Boiler: 5																
2: LSFO	61%	91.01	11.73	18.82	27.26	13.35	2.04	3.41	1.41	2.36	4293	0	+	-3217	32	10.52
17: DSI+PJFF	84%	39.32	4.69	7.75	11.4	18.34	0.62	1.43	0.42	0.97	3163	0	+	-2726	65	4.27
18: LSD+PJFF	84%	84.31	10.2	16.77	24.59	18.34	1.34	3.08	0.91	2.1	4067	0	+	-4067	65	4.27
20: ACI+SC+PJFF	92%	28.85	4.77	7.02	9.69	19.96	0.49	1.21	0.35	0.88	0	0	+	-3031	65	2.24
23: LSFO+ACI+SC+PJFF	97%	119.86	16.5	25.84	36.96	21.06	1.76	4.63	1.23	3.23	4293	0	+	-6249	65	0.87
24: DSI+ACI+SC+PJFF	96%	42.92	6.47	9.82	13.8	20.89	0.66	1.73	0.47	1.23	3163	0	+	-3836	65	1.08
Boiler: 6																
2: LSFO	61%	91.01	11.73	18.82	24.34	13.35	1.82	3.05	1.41	2.36	4293	0	+	-3217	32	10.52
17: DSI+PJFF	84%	39.32	4.69	7.75	10.14	18.34	0.55	1.27	0.42	0.97	3163	0	+	-2726	65	4.27
18: LSD+PJFF	84%	84.31	10.2	16.77	21.88	18.34	1.19	2.74	0.91	2.1	4067	0	+	-4067	65	4.27
20: ACI+SC+PJFF	92%	28.85	4.77	7.02	8.77	19.96	0.44	1.1	0.35	0.88	0	0	+	-3031	65	2.24
23: LSFO+ACI+SC+PJFF	97%	119.86	16.5	25.84	33.11	21.06	1.57	4.14	1.23	3.23	4293	0	+	-6249	65	0.87
24: DSI+ACI+SC+PJFF	96%	42.92	6.47	9.82	12.42	20.89	0.59	1.55	0.47	1.23	3163	0	+	-3836	65	1.08

ACI - Activated Carbon Injection
 DSI - Dry Sorbent Injection
 LSD - Lime Spray Drying
 LSFO - Wet FGD (limestone forced oxidation)
 NGT - Natural Gas Turbines (Greenfield)
 PJFF - Pulse Jet Fabric Filter
 SC - Spray Cooling
 SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)
² - Costs amortized over remaining life of boiler
 "+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

TABLE 5.7
Summary of Mercury Control Costs and Co-control for SaskPower
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Poplar River																
7: NGT	100%	582.28	300.35	345.74	345.74	111	3.11	8.06	3.11	8.06	40355	8006	+	2305061	5401	0
Boiler: 1																
2: LSFO	16%	103.51	19.75	27.82	27.18	8.83	3.08	1.22	3.15	1.24	18957	0	+	-22459	1337	20.64
17: DSI+PJFF	78%	49.6	9.77	13.64	13.33	43.07	0.31	0.6	0.32	0.61	13969	0	+	-18565	2670	5.33
18: LSD+PJFF	78%	95.34	14.76	22.2	21.61	43.07	0.5	0.97	0.52	0.99	17960	0	+	-27923	2670	5.33
20: ACI+SC+PJFF	83%	36.47	8.58	11.42	11.2	45.89	0.24	0.5	0.25	0.51	0	0	+	-20623	2670	4.07
21: SCR+LSFO	58%	144.05	27.65	38.88	37.99	31.82	1.19	1.7	1.22	1.74	18957	4223	+	-42779	1697	10.36
22: SCR+ACI+SC+PJFF	92%	77	16.48	22.48	22.01	50.43	0.44	0.98	0.45	1.01	0	4223	+	-40942	2671	2.05
23: LSFO+ACI+SC+PJFF	86%	139.98	28.33	39.24	38.38	47.35	0.81	1.72	0.83	1.75	18957	0	+	-43082	2672	3.42
24: DSI+ACI+SC+PJFF	91%	54.16	14.26	18.49	18.15	49.84	0.36	0.81	0.37	0.83	13969	0	+	-26238	2670	2.31
25: SCR+DSI+PJFF	89%	90.13	17.68	24.7	24.15	49.01	0.49	1.08	0.5	1.1	13969	4223	+	-38884	2671	2.68
Boiler: 2																
2: LSFO	16%	103.86	19.91	28.01	27.77	8.99	3.09	1.35	3.11	1.36	19380	0	+	-20613	1367	22.9
17: DSI+PJFF	78%	50.57	9.86	13.8	13.68	43.86	0.31	0.67	0.31	0.67	14280	0	+	-17038	2730	5.92
18: LSD+PJFF	78%	95.66	14.8	22.26	22.04	43.86	0.5	1.07	0.51	1.08	18360	0	+	-25627	2730	5.92
20: ACI+SC+PJFF	83%	36.47	8.19	11.03	10.95	46.72	0.23	0.53	0.24	0.54	0	0	+	-18927	2730	4.52
23: LSFO+ACI+SC+PJFF	86%	140.33	28.1	39.04	38.72	48.21	0.8	1.89	0.81	1.9	19380	0	+	-39540	2732	3.79
24: DSI+ACI+SC+PJFF	91%	55.13	13.99	18.29	18.17	50.74	0.36	0.88	0.36	0.89	14280	0	+	-24080	2730	2.56
COMMENTS FROM SASKPOWER																
Control Description		Comment (e.g. space constraints, loss revenue, etc)														
repowering with natural gas turbines		gas availability & cost														
wet flue gas desulphurization (FGD)		some space constraints, but not necessary since plant emissions do not result in exceedences of ambient limits; what to do with by-product														
dry flue gas desulphurization (FGD)		some space constraints, but not necessary since plant emissions do not result in exceedences of ambient limits; affect of byproduct on ash properties														
selective catalytic reduction (SCR)		space constraints; requirement of a reagent undergoing toxicity evaluation; not necessary since plant emissions do not result in exceedences of ambient limits; ash limits; ash contamination														
wet FGD with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
dry FGD with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
SCR with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
advanced coal washing		cost relative to the value of the coal being washed; water consumption in arid area; what to do with waste washings														
carbon injection with each of the above		contamination of fly ash with resulting loss of potential sales and threats to the integrity of existing ash placement system														

TABLE 5.7
Summary of Mercury Control Costs and Co-control for SaskPower
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Shand Power																
7: NGT	100%	309.87	148.82	172.97	172.97	56	3.09	7.57	3.09	7.57	15000	4500	+	1166000	150	0
Boiler: 1																
20: ACI+SC+PJFF	82%	54.24	14.84	19.07	18.14	45.95	0.39	0.79	0.42	0.83	0	0	+	-17556	150	4.4
COMMENTS FROM SASKPOWER																
Control Description		Comment (e.g. space constraints, loss revenue, etc)														
repowering with natural gas turbines		gas availability & cost														
wet flue gas desulphurization (FGD)		some space constraints, but not necessary since plant emissions do not result in exceedences of ambient limits; what to do with by-product														
dry flue gas desulphurization (FGD)		use LIFAC, but further controls not necessary since plant emissions do not result in exceedences of ambient limits; effect of by-product on ash properties														
selective catalytic reduction (SCR)		space constraints; requirement of a reagent undergoing toxicity evaluation; not necessary since plant emissions do not result in exceedences of ambient limits; ash contamination														
wet FGD with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
dry FGD with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
SCR with baghouse		space constraints; ESP already in place to remove particulates; existing particulate requirements are met.														
advanced coal washing		cost relative to the value of the coal being washed; water consumption in arid area; what to do with waste washings														
carbon injection with each of the above		contamination of fly ash with resulting loss of sales and threats to the integrity of existing ash placement system														

TABLE 5.7
Summary of Mercury Control Costs and Co-control for SaskPower
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Boundary Dam																
7: NGT	100%	733.67	376.45	433.64	433.64	110.1	3.94	7.46	3.94	7.46	40733	12279	+	3204741	86597	0
Boiler: 1																
1: PJFF	63%	10.91	1.26	2.11	4.31	6.11	0.71	1.15	0.35	0.56	0	0	+	-2040	13929	9.55
2: LSFO	9%	63.08	8.39	13.31	26.04	0.92	28.26	6.93	14.44	3.54	3422	0	+	-2941	6972	23.36
17: DSI+PJFF	78%	20.99	2.62	4.26	8.5	7.55	1.13	2.26	0.56	1.13	2521	0	+	-2775	13929	5.73
18: LSD+PJFF	78%	48.24	6.09	9.85	19.59	7.55	2.6	5.21	1.31	2.62	3242	0	+	-4001	13929	5.73
20: ACI+SC+PJFF	82%	12.58	1.98	2.96	5.5	7.96	0.69	1.46	0.37	0.79	0	0	+	-3143	13929	4.63
21: SCR+LSFO	56%	78.84	10.35	16.5	32.41	5.4	6	8.62	3.06	4.39	3422	1158	+	-4822	8854	11.45
22: SCR+ACI+SC+PJFF	91%	28.34	3.94	6.15	11.87	8.85	1.34	3.16	0.7	1.64	0	1158	+	-5024	13933	2.27
23: LSFO+ACI+SC+PJFF	84%	75.66	10.37	16.27	31.54	8.12	3.88	8.39	2	4.33	3422	0	+	-6083	13936	4.19
24: DSI+ACI+SC+PJFF	89%	22.66	3.35	5.11	9.69	8.66	1.12	2.58	0.59	1.36	2521	0	+	-3878	13929	2.78
25: SCR+DSI+PJFF	89%	36.75	4.58	7.45	14.87	8.64	1.72	3.96	0.86	1.98	2521	1158	+	-4657	13933	2.81
Boiler: 2																
1: PJFF	63%	10.62	1.25	2.08	3.32	6.17	0.54	0.7	0.34	0.44	0	0	+	-2589	14	7.6
2: LSFO	9%	62.91	8.41	13.32	20.68	0.93	22.21	4.33	14.31	2.79	3442	0	+	-3732	7	18.59
17: DSI+PJFF	78%	20.04	2.63	4.19	6.53	7.62	0.86	1.37	0.55	0.88	2536	0	+	-3523	14	4.56
18: LSD+PJFF	78%	47.79	6.09	9.81	15.4	7.62	2.02	3.23	1.29	2.06	3261	0	+	-5078	14	4.56
20: ACI+SC+PJFF	82%	12.28	2.15	3.11	4.55	8.04	0.57	0.95	0.39	0.65	0	0	+	-3989	14	3.69
21: SCR+LSFO	56%	78.35	10.38	16.48	25.65	5.45	4.7	5.38	3.02	3.46	3442	1165	+	-6120	9	9.11
22: SCR+ACI+SC+PJFF	91%	27.72	4.11	6.27	9.52	8.94	1.06	2	0.7	1.32	0	1165	+	-6377	14	1.81
23: LSFO+ACI+SC+PJFF	84%	75.2	10.57	16.43	25.22	8.21	3.07	5.29	2	3.44	3442	0	+	-7721	14	3.34
24: DSI+ACI+SC+PJFF	89%	21.71	3.53	5.22	7.76	8.74	0.89	1.63	0.6	1.09	2536	0	+	-4922	14	2.21
25: SCR+DSI+PJFF	89%	35.48	4.59	7.36	11.5	8.73	1.32	2.41	0.84	1.54	2536	1165	+	-5910	14	2.24
Boiler: 3																
2: LSFO	9%	76.62	11.36	17.34	18.94	1.78	10.66	1.81	9.76	1.65	6564	0	+	-7775	2678	16.14
17: DSI+PJFF	78%	29.47	4.44	6.74	7.35	14.55	0.51	0.7	0.46	0.64	4836	0	+	-6863	5350	3.96
18: LSD+PJFF	78%	66.17	8	13.95	15.34	14.55	1.05	1.46	0.96	1.33	6218	0	+	-10103	5350	3.96
20: ACI+SC+PJFF	82%	20.23	3.72	5.29	5.72	15.34	0.37	0.55	0.34	0.5	0	0	+	-7661	5350	3.2
21: SCR+LSFO	56%	99.89	14.88	22.66	24.75	10.41	2.38	2.36	2.18	2.16	6564	2222	+	-14130	3401	7.91
22: SCR+ACI+SC+PJFF	91%	43.5	7.23	10.62	11.53	17.06	0.68	1.1	0.62	1.01	0	2222	+	-14016	5351	1.57
23: LSFO+ACI+SC+PJFF	84%	96.85	15.08	22.63	24.65	15.66	1.57	2.35	1.44	2.16	6564	0	+	-15437	5353	2.9
24: DSI+ACI+SC+PJFF	89%	31.89	5.99	8.47	9.14	16.69	0.55	0.87	0.51	0.81	4836	0	+	-9605	5350	1.92
25: SCR+DSI+PJFF	89%	52.74	7.95	12.06	13.17	16.67	0.79	1.26	0.72	1.15	4836	2222	+	-13218	5351	1.94
Boiler: 4																
2: LSFO	9%	76.75	11.37	17.35	19.37	1.79	10.85	2	9.72	1.79	6597	0	+	-7171	2694	17.59
17: DSI+PJFF	78%	29.84	4.43	6.76	7.54	14.63	0.52	0.78	0.46	0.7	4861	0	+	-6330	5382	4.32
18: LSD+PJFF	78%	66.35	8.79	13.96	15.71	14.63	1.07	1.62	0.95	1.44	6250	0	+	-9318	5382	4.32
20: ACI+SC+PJFF	82%	20.25	3.61	5.19	5.72	15.43	0.37	0.59	0.34	0.54	0	0	+	-7066	5382	3.49
21: SCR+LSFO	56%	100.42	14.93	22.75	25.4	10.46	2.43	2.63	2.17	2.35	6597	2233	+	-13032	3421	8.62
22: SCR+ACI+SC+PJFF	91%	43.91	7.16	10.59	11.74	17.15	0.68	1.21	0.62	1.09	0	2233	+	-12927	5383	1.71
23: LSFO+ACI+SC+PJFF	84%	97	14.98	22.54	25.09	15.75	1.59	2.59	1.43	2.33	6597	0	+	-14238	5384	3.16
24: DSI+ACI+SC+PJFF	89%	32.26	5.89	8.4	9.25	16.78	0.55	0.96	0.5	0.87	4861	0	+	-8859	5382	2.09
25: SCR+DSI+PJFF	89%	53.51	7.99	12.16	13.57	16.75	0.81	1.4	0.73	1.26	4861	2233	+	-12191	5383	2.12

TABLE 5.7
Summary of Mercury Control Costs and Co-control for SaskPower
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Boundary Dam, continued																
Boiler: 5																
2: LSFO	9%	76.59	11.29	17.26	17.91	1.73	10.36	1.7	9.98	1.64	6395	0	+	-7824	25985	15.61
17: DSI+PJFF	78%	30.14	4.47	6.82	7.08	14.16	0.5	0.67	0.48	0.65	4712	0	+	-6906	51918	3.83
18: LSD+PJFF	78%	66.97	8.85	14.07	14.64	14.16	1.03	1.39	0.99	1.33	6059	0	+	-10167	51918	3.83
20: ACI+SC+PJFF	82%	21.04	3.82	5.45	5.63	14.93	0.38	0.53	0.37	0.52	0	0	+	-7709	51918	3.1
21: SCR+LSFO	56%	99.92	14.82	22.61	23.46	10.13	2.32	2.22	2.23	2.14	6395	2165	+	-14219	33001	7.65
22: SCR+ACI+SC+PJFF	91%	44.36	7.35	10.81	11.18	16.6	0.67	1.06	0.65	1.02	0	2165	+	-14104	51932	1.52
23: LSFO+ACI+SC+PJFF	84%	97.63	15.1	22.71	23.54	15.24	1.54	2.23	1.49	2.15	6395	0	+	-15534	51944	2.8
24: DSI+ACI+SC+PJFF	89%	32.56	6.04	8.58	8.85	16.24	0.55	0.84	0.53	0.81	4712	0	+	-9666	51918	1.86
25: SCR+DSI+PJFF	89%	53.47	8.01	12.17	12.63	16.22	0.78	1.2	0.75	1.15	4712	2165	+	-13301	51932	1.88
Boiler: 6																
2: LSFO	9%	99.69	16.57	24.34	23.91	3.32	7.21	1.26	7.34	1.29	12277	0	+	-15432	5007	16.71
17: DSI+PJFF	78%	45.72	7.7	11.27	11.07	27.15	0.41	0.59	0.41	0.6	9046	0	+	-12831	10004	4.1
18: LSD+PJFF	78%	91.85	12.99	20.15	19.75	27.15	0.73	1.04	0.74	1.07	11631	0	+	-19261	10004	4.1
20: ACI+SC+PJFF	82%	34.31	6.71	9.39	9.24	28.64	0.32	0.49	0.33	0.5	0	0	+	-14256	10004	3.31
21: SCR+LSFO	56%	137	23.45	34.12	33.53	19.42	1.73	1.77	1.76	1.81	12277	4155	+	-29307	6359	8.19
22: SCR+ACI+SC+PJFF	91%	71.62	13.59	19.17	18.86	31.83	0.59	1	0.6	1.01	0	4155	+	-28132	10006	1.62
23: LSFO+ACI+SC+PJFF	84%	134	23.28	33.73	33.15	29.23	1.13	1.75	1.15	1.78	12277	0	+	-29688	10009	3
24: DSI+ACI+SC+PJFF	89%	49.74	10.6	14.48	14.27	31.14	0.46	0.75	0.47	0.77	9046	0	+	-18114	10004	1.99
25: SCR+DSI+PJFF	89%	83.04	14.58	21.05	20.69	31.1	0.67	1.09	0.68	1.11	9046	4155	+	-26707	10006	2.01

COMMENTS FROM SASKPOWER

Control Description	Comment (e.g. space constraints, loss revenue, etc)
repowering with natural gas turbines	gas availability & cost
wet flue gas desulphurization (FGD)	considerable space constraints since any available space has been committed to ESP installation, but not necessary since plant emissions do not result in exceedences of ambient limits, how to deal with by-product
dry flue gas desulphurization (FGD)	considerable space constraints since any available space has been committed to ESP installation, but further controls not necessary since plant emissions do not result in exceedences of ambient limits, by-product may affect ash properties
selective catalytic reduction (SCR)	considerable space constraints since any available space has been committed to ESP installation; ash contamination; requirement of a reagent undergoing toxicity evaluation; not necessary since plant emissions do not result in exceedences of ambient limits
wet FGD with baghouse	considerable space constraints since any available space has been committed to ESP installation; ESP already in place or committed to remove particulates; existing particulate requirements are met.
dry FGD with baghouse	same as above
SCR with baghouse	same as above
advanced coal washing	cost relative to the value of the coal being washed; water consumption in arid area; what to do with waste washings
carbon injection with each of the above	contamination of fly ash with resulting loss of sales and increased amount that needs to be disposed

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

TABLE 5.8
Summary of Mercury Control Costs and Co-control for TransAlta
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Sundance																
7: NGT	100%	1279.43	795.7	895.44	895.44	278	3.22	5.89	3.22	5.89	31102	19280	+	8490221	2567	0
Boiler: 1																
2: LSFO	11%	81.59	11.69	18.05	22.08	4.21	5.25	1.03	4.29	0.84	3990	0	+	-10450	174	15.51
17: DSI+PJFF	78%	30.19	4.14	6.5	7.99	29.22	0.27	0.37	0.22	0.3	2940	0	+	-9065	347	3.87
18: LSD+PJFF	78%	72.92	9.18	14.87	18.47	29.22	0.63	0.86	0.51	0.69	3780	0	+	-13419	347	3.87
20: ACI+SC+PJFF	82%	23.29	5.33	7.14	8.29	30.93	0.27	0.39	0.23	0.33	0	0	+	-10098	347	3.07
21: SCR+LSFO	57%	100.04	15.82	23.62	28.57	21.33	1.34	1.33	1.11	1.1	3990	2777	+	-19298	220	7.55
22: SCR+ACI+SC+PJFF	91%	41.75	9.46	12.72	14.78	34.33	0.43	0.69	0.37	0.59	0	2777	+	-18947	347	1.5
23: LSFO+ACI+SC+PJFF	84%	104.88	17.01	25.19	30.37	31.67	0.96	1.41	0.8	1.17	3990	0	+	-20548	347	2.73
24: DSI+ACI+SC+PJFF	90%	32.95	6.92	9.49	11.12	33.66	0.33	0.52	0.28	0.44	2940	0	+	-12711	347	1.8
25: SCR+DSI+PJFF	89%	48.64	8.28	12.07	14.48	33.49	0.43	0.67	0.36	0.56	2940	2777	+	-17913	347	1.88
Boiler: 2																
2: LSFO	11%	81.59	11.69	18.05	20.2	4.21	4.8	0.94	4.29	0.84	3990	0	+	-10450	174	15.51
17: DSI+PJFF	78%	30.19	4.14	6.5	7.29	29.22	0.25	0.34	0.22	0.3	2940	0	+	-9065	347	3.87
18: LSD+PJFF	78%	72.92	9.18	14.87	16.79	29.22	0.57	0.78	0.51	0.69	3780	0	+	-13419	347	3.87
20: ACI+SC+PJFF	82%	23.29	5.33	7.14	7.75	30.93	0.25	0.36	0.23	0.33	0	0	+	-10098	347	3.07
21: SCR+LSFO	57%	100.04	15.82	23.62	26.26	21.33	1.23	1.22	1.11	1.1	3990	2777	+	-19298	220	7.55
22: SCR+ACI+SC+PJFF	91%	41.75	9.46	12.72	13.82	34.33	0.4	0.64	0.37	0.59	0	2777	+	-18947	347	1.5
23: LSFO+ACI+SC+PJFF	84%	104.88	17.01	25.19	27.95	31.67	0.88	1.3	0.8	1.17	3990	0	+	-20548	347	2.73
24: DSI+ACI+SC+PJFF	90%	32.95	6.92	9.49	10.36	33.66	0.31	0.48	0.28	0.44	2940	0	+	-12711	347	1.8
25: SCR+DSI+PJFF	89%	48.64	8.28	12.07	13.35	33.49	0.4	0.62	0.36	0.56	2940	2777	+	-17913	347	1.88
Boiler: 3																
2: LSFO	11%	87.66	13.43	20.26	21.33	5.8	3.68	0.76	3.5	0.73	5496	0	+	-13357	239	16.46
17: DSI+PJFF	78%	34.5	5.05	7.74	8.15	40.25	0.2	0.29	0.19	0.28	4050	0	+	-11385	478	4.11
18: LSD+PJFF	78%	90.92	11.46	18.55	19.65	40.25	0.49	0.7	0.46	0.66	5207	0	+	-16951	478	4.11
20: ACI+SC+PJFF	82%	27.29	6.63	8.76	9.09	42.61	0.21	0.33	0.21	0.31	0	0	+	-12665	478	3.26
21: SCR+LSFO	57%	109.24	18.66	27.18	28.5	29.38	0.97	1.02	0.93	0.97	5496	3826	+	-24997	304	8.01
22: SCR+ACI+SC+PJFF	91%	48.87	11.86	15.67	16.26	47.28	0.34	0.58	0.33	0.56	0	3826	+	-24305	478	1.59
23: LSFO+ACI+SC+PJFF	84%	114.94	20.07	29.03	30.42	43.63	0.7	1.09	0.67	1.04	5496	0	+	-26022	478	2.9
24: DSI+ACI+SC+PJFF	90%	37.84	8.67	11.62	12.07	46.37	0.26	0.43	0.25	0.42	4050	0	+	-16004	478	1.91
25: SCR+DSI+PJFF	89%	56.09	10.28	14.65	15.33	46.13	0.33	0.55	0.32	0.53	4050	3826	+	-23025	478	2

TABLE 5.8
Summary of Mercury Control Costs and Co-control for TransAlta
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Sundance, continued																
Boiler: 4																
2: LSFO	11%	87.66	13.43	20.26	21.01	5.8	3.62	0.75	3.5	0.73	5496	0	+	-13357	239	16.46
17: DSI+PJFF	78%	34.5	5.05	7.74	8.03	40.25	0.2	0.29	0.19	0.28	4050	0	+	-11385	478	4.11
18: LSD+PJFF	78%	90.92	11.46	18.55	19.32	40.25	0.48	0.69	0.46	0.66	5207	0	+	-16951	478	4.11
20: ACI+SC+PJFF	82%	27.29	6.63	8.76	8.99	42.61	0.21	0.32	0.21	0.31	0	0	+	-12665	478	3.26
21: SCR+LSFO	57%	109.24	18.66	27.18	28.11	29.38	0.96	1.01	0.93	0.97	5496	3826	+	-24997	304	8.01
22: SCR+ACI+SC+PJFF	91%	48.87	11.86	15.67	16.09	47.28	0.34	0.58	0.33	0.56	0	3826	+	-24305	478	1.59
23: LSFO+ACI+SC+PJFF	84%	114.94	20.07	29.03	30	43.63	0.69	1.08	0.67	1.04	5496	0	+	-26022	478	2.9
24: DSI+ACI+SC+PJFF	90%	37.84	8.67	11.62	11.94	46.37	0.26	0.43	0.25	0.42	4050	0	+	-16004	478	1.91
25: SCR+DSI+PJFF	89%	56.09	10.28	14.65	15.13	46.13	0.33	0.54	0.32	0.53	4050	3826	+	-23025	478	2
Boiler: 5																
2: LSFO	11%	87.08	13.2	19.99	20.45	5.58	3.67	0.77	3.58	0.75	5288	0	+	-12471	230	16.61
17: DSI+PJFF	78%	34.19	4.92	7.59	7.77	38.72	0.2	0.29	0.2	0.29	3896	0	+	-10647	460	4.15
18: LSD+PJFF	78%	89.97	11.28	18.29	18.77	38.72	0.48	0.71	0.47	0.69	5009	0	+	-15843	460	4.15
20: ACI+SC+PJFF	82%	26.88	6.17	8.26	8.41	40.99	0.21	0.32	0.2	0.31	0	0	+	-11845	460	3.29
21: SCR+LSFO	57%	107.7	18.06	26.46	27.03	28.26	0.96	1.02	0.94	1	5288	3680	+	-23312	292	8.08
22: SCR+ACI+SC+PJFF	91%	47.51	11.03	14.74	14.99	45.49	0.33	0.56	0.32	0.55	0	3680	+	-22687	460	1.6
23: LSFO+ACI+SC+PJFF	84%	113.96	19.37	28.25	28.86	41.98	0.69	1.09	0.67	1.06	5288	0	+	-24316	460	2.92
24: DSI+ACI+SC+PJFF	90%	37.47	8.14	11.06	11.26	44.61	0.25	0.42	0.25	0.42	3896	0	+	-14963	460	1.93
25: SCR+DSI+PJFF	89%	54.81	9.79	14.06	14.35	44.39	0.32	0.54	0.32	0.53	3896	3680	+	-21488	460	2.02
Boiler: 6																
2: LSFO	11%	87.11	13.19	19.98	19.98	5.58	3.58	0.75	3.58	0.75	5288	0	+	-12091	230	16.62
17: DSI+PJFF	78%	34.3	4.91	7.58	7.58	38.72	0.2	0.29	0.2	0.29	3896	0	+	-10323	460	4.15
18: LSD+PJFF	78%	90.06	11.27	18.29	18.29	38.72	0.47	0.69	0.47	0.69	5009	0	+	-15361	460	4.15
20: ACI+SC+PJFF	82%	26.88	6.07	8.16	8.16	40.99	0.2	0.31	0.2	0.31	0	0	+	-11485	460	3.29
21: SCR+LSFO	57%	107.79	18.04	26.45	26.45	28.26	0.94	1	0.94	1	5288	3680	+	-22603	292	8.08
22: SCR+ACI+SC+PJFF	91%	47.57	10.92	14.63	14.63	45.49	0.32	0.55	0.32	0.55	0	3680	+	-21996	460	1.6
23: LSFO+ACI+SC+PJFF	84%	113.99	19.25	28.14	28.14	41.98	0.67	1.06	0.67	1.06	5288	0	+	-23576	460	2.92
24: DSI+ACI+SC+PJFF	90%	37.58	8.03	10.96	10.96	44.61	0.25	0.41	0.25	0.41	3896	0	+	-14507	460	1.93
25: SCR+DSI+PJFF	89%	54.98	9.77	14.05	14.05	44.39	0.32	0.53	0.32	0.53	3896	3680	+	-20835	460	2.02

COMMENTS FROM TRANSALTA

Control Description	Comment (e.g. space constraints, loss revenue, etc)
repowering with natural gas turbines	please see comments for Wabamun plant: Sundance is a similar operation.
wet flue gas desulphurization (FGD)	please see comments for Wabamun plant
dry flue gas desulphurization (FGD)	please see comments for Wabamun plant
selective catalytic reduction (SCR)	please see comments for Wabamun plant
wet FGD with baghouse	please see comments for Wabamun plant
dry FGD with baghouse	please see comments for Wabamun plant + Sundance particulate emissions are very close to new source performance standards, therefore there is little rationale to improve particulate control at this time
SCR with baghouse	please see comments for Wabamun plant + Sundance particulate emissions are very close to new source performance standards, therefore there is little rationale to improve particulate control at this time
advanced coal washing	please see comments for Wabamun plant
carbon injection with each of the above	please see comments for Wabamun plant

TABLE 5.8
Summary of Mercury Control Costs and Co-control for TransAlta
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NOx Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Keephills																
7: NGT Boiler: 1	100%	591.9	303.94	350.08	350.08	98	3.57	6.11	3.57	6.11	9760	7659	+	2940481	697	0
2: LSFO	27%	89.33	13.11	20.08	19.53	13.41	1.46	0.72	1.5	0.74	4636	0	+	-12228	175	13.04
17: DSI+PJFF	80%	35.46	4.9	7.66	7.45	39.15	0.19	0.27	0.2	0.28	3416	0	+	-10374	349	3.61
18: LSD+PJFF	80%	93.78	11.56	18.87	18.29	39.15	0.47	0.67	0.48	0.69	4392	0	+	-15469	349	3.61
20: ACI+SC+PJFF	86%	28.41	6.35	8.57	8.39	41.99	0.2	0.31	0.2	0.31	0	0	+	-11537	349	2.57
21: SCR+LSFO	58%	111.41	18.4	27.08	26.39	28.48	0.93	0.97	0.95	0.99	4636	4085	+	-22956	222	7.52
22: SCR+ACI+SC+PJFF	92%	50.48	11.64	15.57	15.26	44.96	0.34	0.56	0.35	0.57	0	4085	+	-22265	349	1.48
23: LSFO+ACI+SC+PJFF	90%	117.74	19.47	28.65	27.92	43.91	0.64	1.02	0.65	1.05	4636	0	+	-23765	349	1.87
24: DSI+ACI+SC+PJFF	92%	38.9	8.14	11.17	10.93	45.18	0.24	0.4	0.25	0.41	3416	0	+	-14594	349	1.4
25: SCR+DSI+PJFF	88%	57.53	10.18	14.67	14.31	43.33	0.33	0.52	0.34	0.54	3416	4085	+	-21103	349	2.08
Boiler: 2																
2: LSFO	27%	89.25	13.15	20.11	19.41	13.41	1.45	0.65	1.5	0.67	4636	0	+	-13440	175	11.87
17: DSI+PJFF	80%	35.16	4.94	7.68	7.4	39.15	0.19	0.25	0.2	0.26	3416	0	+	-11402	349	3.28
18: LSD+PJFF	80%	93.71	11.6	18.91	18.17	39.15	0.46	0.61	0.48	0.63	4392	0	+	-17002	349	3.28
20: ACI+SC+PJFF	86%	28.41	6.69	8.9	8.68	41.99	0.21	0.29	0.21	0.3	0	0	+	-12680	349	2.34
21: SCR+LSFO	58%	111.18	18.47	27.13	26.26	28.48	0.92	0.88	0.95	0.9	4636	4085	+	-25237	222	6.84
22: SCR+ACI+SC+PJFF	92%	50.33	12	15.93	15.53	44.96	0.35	0.52	0.35	0.53	0	4085	+	-24477	349	1.35
23: LSFO+ACI+SC+PJFF	90%	117.66	19.84	29.01	28.09	43.91	0.64	0.94	0.66	0.97	4636	0	+	-26120	349	1.7
24: DSI+ACI+SC+PJFF	92%	38.59	8.49	11.49	11.19	45.18	0.25	0.37	0.25	0.38	3416	0	+	-16040	349	1.27
25: SCR+DSI+PJFF	88%	57.08	10.25	14.7	14.25	43.33	0.33	0.48	0.34	0.49	3416	4085	+	-23199	349	1.89
COMMENTS FROM TRANSALTA																
Control Description		Comment (e.g. space constraints, loss revenue, etc)														
repowering with natural gas turbines		please see comments for Wabamun - Keephills is a similar operation.														
wet flue gas desulphurization (FGD)		please see comments for Wabamun														
dry flue gas desulphurization (FGD)		please see comments for Wabamun														
selective catalytic reduction (SCR)		please see comments for Wabamun														
wet FGD with baghouse		please see comments for Wabamun														
dry FGD with baghouse		please see comments for Wabamun + Keephills particulate emissions are in line with new source performance standards so there is little rationale for installing a baghouse for particulate removal purposes.														
SCR with baghouse		please see comments for Wabamun + Keephills particulate emissions are in line with new source performance standards so there is little rationale for installing a baghouse for particulate removal purposes.														
advanced coal washing		please see comments for Wabamun														
carbon injection with each of the above		please see comments for Wabamun														

TABLE 5.8
Summary of Mercury Control Costs and Co-control for TransAlta
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Wabamun																
7: NGT Boiler: 1	100%	737.74	279.78	337.29	337.29	79.2	4.26	16.1	4.26	16.1	11683	5559	+	2077519	1922	-0.03216
2: LSFO	20%	63.86	8.46	13.44	-22.74	2.39	-9.52	-4.55	5.63	2.69	2646	0	+	-4624	29	18.84
4: DSI	44%	8.64	1.17	1.84	-3.06	5.22	-0.59	-0.61	0.35	0.37	1950	0	+	-1156	0	13.17
5: LSD	44%	37.84	4.78	7.73	-13.71	5.22	-2.62	-2.74	1.48	1.55	2507	0	+	-3083	0	13.17
15: ACI+SC	59%	1.73	1.2	1.34	0.36	6.91	0.05	0.07	0.19	0.27	0	0	+	-1718	0	9.8
21: SCR+LSFO	58%	73.54	10.06	15.8	-25.87	6.83	-3.79	-5.18	2.31	3.16	2646	1414	+	-7706	37	9.95
26: SCR+ACI+SC	78%	11.41	2.8	3.69	-2.77	9.22	-0.3	-0.56	0.4	0.74	0	1414	+	-4800	16	5.17
27: LSFO+ACI+SC	67%	65.59	9.66	14.78	-22.39	7.9	-2.84	-4.48	1.87	2.96	2646	0	+	-6343	29	7.82
26: DSI+ACI+SC	77%	10.37	2.37	3.18	-2.7	9.07	-0.3	-0.54	0.35	0.64	1950	0	+	-2874	0	5.46
26: SCR+DSI	71%	18.32	2.77	4.2	-6.18	8.33	-0.74	-1.24	0.5	0.84	1950	1414	+	-4238	16	6.95
Boiler: 2																
2: LSFO	20%	63.86	8.46	13.44	-6.43	4.27	-1.51	-1.29	3.15	2.69	2646	0	+	-4624	292	33.69
17: DSI+PJFF	79%	19.87	2.5	4.05	-2.13	16.65	-0.13	-0.43	0.24	0.81	1950	0	+	-4331	583	8.92
18: LSD+PJFF	79%	49.06	6.11	9.94	-5.33	16.65	-0.32	-1.07	0.6	1.99	2507	0	+	-6258	583	8.92
20: ACI+SC+PJFF	84%	13.05	3.18	4.19	0.13	17.79	0.01	0.03	0.24	0.84	0	0	+	-4893	583	6.64
21: SCR+LSFO	58%	73.54	10.06	15.8	-7.09	12.22	-0.58	-1.42	1.29	3.16	2646	1414	+	-7706	371	17.78
22: SCR+ACI+SC+PJFF	92%	22.73	4.78	6.55	-0.52	19.35	-0.03	-0.1	0.34	1.31	0	1414	+	-7975	583	3.5
23: LSFO+ACI+SC+PJFF	87%	76.91	11.64	17.63	-6.3	18.46	-0.34	-1.26	0.96	3.53	2646	0	+	-9517	584	5.29
24: DSI+ACI+SC+PJFF	91%	21.69	4.34	6.03	-0.72	19.25	-0.04	-0.14	0.31	1.21	1950	0	+	-6049	583	3.7
25: SCR+DSI+PJFF	89%	29.55	4.1	6.41	-2.79	18.75	-0.15	-0.56	0.34	1.28	1950	1414	+	-7413	583	4.71

TABLE 5.8
Summary of Mercury Control Costs and Co-control for TransAlta
(Costs in 1999 Canadian dollars)

Control	Hg Removal Efficiency	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Total Annual Cost (\$10 ⁶)-RL ²	Hg Removed kg	Remaining Life		Design Life		SO ₂ Removed tonnes	NO _x Removed tonnes	Dioxin Removed gTEQ	CO ₂ Removed tonnes	PM Removed tonnes	Hg emitted mg/MWh
							Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh	Cost \$10 ⁶ /kg Hg removed	Cost ¢/kWh						
Wabamun, continued																
Boiler: 3																
2: LSFO	20%	70.67	8.99	14.5	46.82	4.01	11.68	9.99	3.62	3.1	2481	0	+	-2903	274	33.72
17: DSI+PJFF	79%	25.23	2.78	4.74	16.28	15.62	1.04	3.48	0.3	1.01	1828	0	+	-2629	547	8.92
18: LSD+PJFF	79%	58.04	6.95	11.47	38.01	15.62	2.43	8.11	0.73	2.45	2351	0	+	-3838	547	8.92
20: ACI+SC+PJFF	84%	16.72	3.24	4.54	12.19	16.69	0.73	2.6	0.27	0.97	0	0	+	-2946	547	6.64
21: SCR+LSFO	58%	84.26	11.34	17.91	56.44	11.46	4.92	12.05	1.56	3.82	2481	1326	+	-5118	348	17.79
22: SCR+ACI+SC+PJFF	92%	30.31	5.59	7.95	21.81	18.16	1.2	4.66	0.44	1.7	0	1326	+	-5162	547	3.5
23: LSFO+ACI+SC+PJFF	87%	87.39	12.23	19.04	59	17.32	3.41	12.6	1.1	4.07	2481	0	+	-5849	547	5.3
24: DSI+ACI+SC+PJFF	91%	27.48	4.36	6.5	19.06	18.07	1.06	4.07	0.36	1.39	1828	0	+	-3672	547	3.7
25: SCR+DSI+PJFF	89%	38.82	5.13	8.15	25.9	17.59	1.47	5.53	0.46	1.74	1828	1326	+	-4844	547	4.71
Boiler: 4																
2: LSFO	20%	85.92	11.03	17.72	24.14	5.36	4.5	3.84	3.31	2.82	3326	0	+	-3688	367	33.66
17: DSI+PJFF	79%	36.28	4.04	6.87	9.58	20.91	0.46	1.53	0.33	1.09	2451	0	+	-3168	733	8.91
18: LSD+PJFF	79%	77.86	9.26	15.33	21.14	20.91	1.01	3.37	0.73	2.44	3151	0	+	-4705	733	8.91
20: ACI+SC+PJFF	84%	37.78	5.17	8.11	10.93	22.34	0.49	1.74	0.36	1.29	0	0	+	-3526	733	6.63
21: SCR+LSFO	58%	105.99	15.06	23.32	31.23	15.34	2.04	4.97	1.52	3.71	3326	1777	+	-6864	466	17.76
22: SCR+ACI+SC+PJFF	92%	57.85	9.19	13.7	18.02	24.3	0.74	2.87	0.56	2.18	0	1777	+	-6702	733	3.5
23: LSFO+ACI+SC+PJFF	87%	123.71	16.19	25.84	35.07	23.18	1.51	5.58	1.11	4.11	3326	0	+	-7214	734	5.29
24: DSI+ACI+SC+PJFF	91%	51.67	6.6	10.63	14.48	24.18	0.6	2.31	0.44	1.69	2451	0	+	-4448	733	3.69
25: SCR+DSI+PJFF	89%	56.35	8.07	12.46	16.67	23.55	0.71	2.65	0.53	1.98	2451	1777	+	-6344	733	4.7

COMMENTS FROM TRANSALTA

Control Description	Comment (e.g. space constraints, loss revenue, etc)
repowering with natural gas turbines	As Wabamun's fuel source is the adjacent Whitewood mine, is owned by TransAlta, and provides a fuel source that is much more economic than gas, there is no practical reason to repower with gas.
wet flue gas desulphurization (FGD)	this would not generally be used with low sulfur coal
dry flue gas desulphurization (FGD)	this would not generally be used with low sulfur coal
selective catalytic reduction (SCR)	as TransAlta's NO _x is relatively low and there are no smog or PM problems in the local airshed, TransAlta would likely choose different control technology for NO _x control, eg. low NO _x burners. Also, it is not clear from EPRI's September 2000 control technology review that there is any significant mercury control from SCR.
wet FGD with baghouse	would not use wet FGD for reasons outlined above
dry FGD with baghouse	as TA's Hg is largely elemental, not clear that baghouse would deliver significant Hg co-benefits
SCR with baghouse	see comments above
advanced coal washing	the mercury in TransAlta's coal is thought to be bound up in the organic components of coal. Unless "advanced coal washing" can effect mercury found in this form, it is unlikely to reduce the amount of mercury used for combustion.

ACI - Activated Carbon Injection

DSI - Dry Sorbent Injection

LSD - Lime Spray Drying

LSFO - Wet FGD (limestone forced oxidation)

NGT - Natural Gas Turbines (Greenfield)

PJFF - Pulse Jet Fabric Filter

SC - Spray Cooling

SCR - Selective Catalytic Reduction

¹ - Costs amortized over design life period (20 years)

² - Costs amortized over remaining life of boiler

"+" - dioxin emission reduction efficiencies were not quantified in this study (see Table 4.1)

1. The design life of the control device (20 years for all add-on devices and for a natural gas turbine); and
2. The remaining life of the boiler from the year 2010 to the retirement date of the boiler (if not provided, SENES added 50 years to the start date of each boiler, which was provided by all facilities).

The cost per kilogram of mercury removed, and cost per kilowatt-hour (kWh) are presented for each of the two amortization periods. For natural gas turbines, the cost per kWh is based on the total kWh generated in 1999 at each plant. Since some boilers are operating at low capacity, the cost per kWh for natural gas repowering is overestimated at some facilities (i.e. the total annualized cost is divided by a much lower generating rate (kWh) than it would really be operating at, if existing coal-fired boilers were replaced with new natural gas turbines).

The potential SO₂, NO_x, PM and CO₂ emission reductions are also presented in the tables. CO₂ emissions increase for all options except repowering with natural gas (reduced by 53%), due to increased energy required by the add-on control devices. The increase in CO₂ is calculated by converting the power consumption of the control device into an equivalent amount of coal (using the heating rate of the coal), and multiplying that amount of coal by the appropriate CO₂ emission factor. The increased energy requirements also increase criteria air contaminant emissions (such as SO₂, NO_x, PM). However, these increases are more difficult to quantify because the emission factors for these pollutants are not only based on the type of coal used, as is the case for CO₂.

A performance standard was also calculated in the form of µg mercury emitted, per kilowatt-hour of electricity generated. This value is 0 mg of mercury per Megawatt-hour (mg/MWh) for the fuel switching option (100% Hg removal), and varies significantly for the various control options examined, across all the coal-fired boilers in Canada, depending on the efficiency of the control examined, and the generating capacity of each boiler.

The range of costs are large for some control options, as a result of the very different operating parameters at each plant, such as:

- type of coal burned (and therefore the mercury speciation);
- existing controls at each plant; and
- boiler size and capacity factor (and therefore the calculation of Hg control costs in cents/kWh).

Table 5.9 summarizes costs presented in recent U.S. studies, for controlling mercury using activated carbon injection. The costs calculated for the Canadian plants fit within this range for most of the boilers. The U.S. costs were calculated based on model plants operating at high

capacities, therefore the costs per kilowatt-hour are generally lower when compared to some facilities in Canada that are operating at lower capacities.

**TABLE 5.9
EXAMPLE MERCURY CONTROL COSTS FOR U.S. COAL-FIRED BOILERS**

Coal		Existing Controls	Retrofit Control	Current US Cost		Equivalent 1999C\$	
Type	S%			cents/KWh		cents/KWh	
				Low	High	Low	High
Bituminous	3	CS-ESP + FGD	ACI	0.07	0.12	0.10	0.18
Bituminous	3	FF + FGD	ACI	0.03	0.05	0.05	0.08
Bituminous	3	HS-ESP + FGD	ACI+PFF	0.15	NA	0.22	NA
Bituminous	0.6	CS-ESP	ACI+SC	0.10	0.18	0.15	0.27
Bituminous	0.6	FF	ACI+SC	0.04	0.08	0.06	0.11
Bituminous	0.6	HS-ESP	ACI+SC+PFF	0.18	0.38	0.27	0.56
Sub-bituminous	0.5	CS-ESP	ACI+SC	0.12	0.19	0.17	0.29
Sub-bituminous	0.5	FF	ACI+SC	0.04	0.11	0.06	0.16
Sub-bituminous	0.5	HS-ESP	ACI+SC+PFF	0.14	0.27	0.21	0.40

ACI – Activated Carbon Injection

CS-ESP – Cold-side Electrostatic Precipitator

FF – Fabric Filter

FGD – Flue Gas Desulphurization

HS-ESP – Hot-side ESP

PFF – Polishing Fabric Filter

SC – Spray Cooler

Source: Srivastava et al. 2000.

A detailed discussion of the cost results is not included because the control options that are appropriate at each plant, and even within each plant (where there are multiple boilers), are very different for reasons such as:

- different ages of the boilers (controls would not be added to boilers which will not be operating for much longer);
- various types of coal burned and operating parameters (and therefore speciation of mercury emissions);
- availability of water and reagents required for control devices (e.g. water and lime for wet scrubbing);
- total emissions of all other pollutants from the plant and regional airshed issues (for example, NO_x controls would not be added to control mercury if there is no urgent need to reduce NO_x in a specific area); and
- site specific constraints (some control devices need more space and retrofit costs than others).

5.4 SENSITIVITY ANALYSIS

5.4.1 RETROFIT COST FACTOR

The equations in the U.S.EPA Cost Estimating Functions apply to control devices installed in new facilities, and must be adjusted when equipment is installed in existing facilities. This is accomplished by the retrofit cost factor. The retrofit factors for control systems are used to account for site-specific criteria, such as access and congestion, underground obstructions, ductwork tie-in difficulty, and distance between control system and waste handling system. EPRI has developed rough guidelines for capital adjustments that consider these factors. Suggested retrofit factors are 1.25 for 5-year old plants, 1.3 for 15-year old plants and 1.4 for plants 25 years or older (Brown et al. 1999). The EPA typically uses a factor of 1.3. Comments from reviewers suggest that actual retrofit costs at certain facilities may be much higher than 1.3.

The preparations for a retrofit installation are relatively expensive due to the costs of plant remodeling and modifications to the existing production process. Therefore, a sensitivity analysis was performed where the retrofit cost factor was altered to account for various levels of difficulty that may be experienced at different plants in dealing with issues such as scale effects, inexperience with installation of injection systems at power plants, possible retrofit difficulties and different operating practices.

Table 5.10 presents the results of this analysis, where the retrofit cost factor for installing an SCR was increased from the base case of 1.3, to 1.5, 1.75 and 2.0. In other words, the cost of retrofitting the plant is assumed to increase the total installed cost by 30%, 50%, 75% and 100%. Table 5.10 shows that when the retrofit cost factor is increased from 30% to 100%, the total annualized cost (amortized over a design life of 20 years) is 5% higher.

TABLE 5.10
SENSITIVITY ANALYSIS ON RETROFIT COST FACTOR
(Costs in 1999 Canadian dollars)

Retrofit Factor	Total Capital Cost (\$10⁶)	Annual Operating Cost (\$10⁶)	Total Annual Cost (\$10⁶)	Cost \$10⁶/kg Hg removed	Cost ¢/kWh
1.3 (Base Case)	105.11	20.89	29.08	0.82	0.94
1.5	108.25	21.06	29.50	0.83	0.95
1.75	112.19	21.28	30.03	0.84	0.97
2	116.12	21.5	30.56	0.86	0.98

Note: The sensitivity analysis was conducted for a generic 400 MW plant, burning PRB coal, with 80% of the mercury emissions in elemental form. The application on SCR in combination with wet scrubbing at this plant results in a 60% reduction in total mercury emissions.

The modifications required for each retrofit installation are specific to the facility, and may include the following:

- Auxiliaries – in addition to long duct runs, some retrofits require extra tees, elbows, dampers and other fittings;
- Handling and erection – due to lack of space, special care is required during unloading, transporting and placing of equipment (sometimes onto roofs and other inaccessible places);
- Piping, insulation and painting – large amounts of piping may be needed to tie in the control device to sources of process and cooling water, steam, etc.;
- Site preparation – sometimes may decrease for an existing facility (i.e. certain items that are included in the cost equations are already at an existing facility);
- Off-site facilities – e.g. preparation, crushing, storage of reagents (e.g. lime) and maintenance of stockpiles; and
- Lost production – when a retrofit control system cannot be tied into the process during normally scheduled maintenance periods, the revenue lost during the shutdown period can be a large retrofit expense.

5.4.2 SENSITIVITY ANALYSIS ON NATURAL GAS PRICES

Fuel switching is more expensive when all costs are assigned to mercury control. However, it substantially reduces a range of other pollutants. Key issues with respect to fuel switching are the availability of natural gas and the impact on natural gas prices of increased demand for use as a boiler fuel.

Table 5.11 shows the impact of increases in the price of natural gas on the cost of repowering with natural gas turbines. This analysis was based on replacing one 400 MW coal-fired boiler, operating at 95% capacity, with a natural gas turbine producing the same net power output. The annual operating costs are reported based on an amortization period of 20 years (the design life of a new natural gas turbine). The total capital cost remains the same in each case, but the annual operating cost increases due to the increase in fuel costs. When the price of natural gas doubles, the cost of Hg control (in cents per kilowatt-hour) is approximately 1.5 times higher than the base case. When the price of natural gas increases 5-fold, there is an approximate 3-fold increase in the cost per kilowatt-hour.

TABLE 5.11
EFFECT OF INCREASES IN THE PRICE OF NATURAL GAS

Reference Price	Natural Gas Price \$/MMBTU	Total Capital Cost (\$10 ⁶)	Annual Operating Cost (\$10 ⁶)	Total Annual Cost (\$10 ⁶)-DL ¹	Cost ¢/kWh
1999	3.78	317.31	161.09	185.83	5.58
1999 x2	7.55	317.31	257.71	282.44	8.48
1999 x5	18.88	317.31	547.55	572.29	17.19

It should be noted that the coal price varies significantly depending upon the source of coal. For example, Statistics Canada (2000) reports the following coal prices across Canada:

Nova Scotia	64.78 \$/tonne
New Brunswick	83.08 \$/tonne
Saskatchewan	10.98 \$/tonne
Alberta	12.65 \$/tonne
Canada	20.53 \$/tonne

Annual fuel costs are generally higher for natural gas turbines, compared to coal-fired boilers, when using the Canadian average or Western Canadian coal prices. On the other hand, if more expensive coals are used (e.g. Eastern Canadian), natural gas fuel costs become more attractive. However, the decision to switch to natural gas depends not only on the capital and annual costs, but also the remaining life of the coal-fired boilers, availability and price of natural gas versus coal, and various plant specific considerations.

The variation in the price of coal between Western and Eastern Canada suggests that with lower fuel costs in the west, additional funds (\$/kWh electricity generated) can be spent on Hg control to get equivalent Hg control as in the east, with the same overall price per kWh of power generation.

6.0 CONCLUSIONS

The main conclusions of this study are as follows:

- The selection of an optimum control technology is plant specific, depending on coal type, existing controls and boiler type. No single mercury control technology can be applied to the entire coal-fired electricity generating sector;
- In order for combinations of technologies to be commercially deployed, they must achieve high reliability, availability and capacity factors;
- The amount of mercury captured by a given control technology is better for bituminous coal than either sub-bituminous coal or lignite, due to the high fly ash carbon content and, generally the higher relative amounts of ionic Hg in the flue gas;
- Organized research efforts need to focus on bringing laboratory and pilot work on mercury control to full commercial status;
- Further research on the speciation of mercury is required, and how it is affected by fuel, combustion and flue gas conditions. It is necessary to target the controls with the highest efficiency for specific unit types;
- Increased control of mercury emissions may change the amount and composition of coal combustion residues (CCRs) from coal-fired power plants. Limited studies indicate that mercury captured onto fly ash and FGD by-products is relatively stable and that mercury is not released via leaching or volatilization in significant levels. Further research is required on the stability of mercury in CCRs and residue by-products;
- Regulatory approaches being considered (e.g. speciated versus total mercury) must be consistent with mercury measurement and monitoring capabilities;
- The cost data and models should be refined based on full-scale field experience;
- Accounting for multiple pollutant benefits reduces control costs for mercury alone; and
- Handling, treatment and disposal of air pollution control device residues are important for assessing the total environmental effects of mercury reduction strategies.

The sources of uncertainty associated with the results of this study include:

- consistency in speciation data on mercury emissions (e.g. costs are based on 1 or 2 series of tests conducted in one year and are very specific to the coal burned during the tests. They may not be representative of the actual emissions over the entire year because of differences in coal characteristics and operating conditions);
- differences in the mercury content of the fuels/materials combusted;
- differences in the effectiveness of installed air pollution control devices; and
- differences in retrofit/addition costs across facilities.

Implementation issues include:

- lack of current availability of the technology;
- uncertainty regarding achievable control efficiency;
- impacts on the ability to sell fly ash;
- increased corrosion at utility boilers that require flue gas cooling;
- carbon/sorbent injection may potentially impact on particulate collection efficiency of the ESP or baghouse performance, pressure and maintenance costs; and
- the cost of replacement energy during installation of new control equipment.

Control technology and pollution prevention alternatives for further reductions of mercury emissions to the air in Canada should focus on economically achievable options that have the ability to achieve multiple emission reduction benefits simultaneously. Regardless of the type of standard, or the method chosen to reduce mercury emissions, the following points will help to ensure success:

- allow flexibility in achieving emission reduction targets;
- avoid duplicative and onerous record keeping requirements; and
- integrate mercury control decisions with policies/actions taken by other groups to achieve the maximum potential reduction across all issues and all pollutants (through co-control).

REFERENCES

- Afonso, R. and C.L. Senior 2001. *Assessment of Mercury Removal by Existing Air Pollution Control Devices in Full Scale Power Plants*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.
- Alstom 2000. *Mercury Emissions Control*. PowerPoint Presentation, November. Personal Communication with David Henry.
- Bielawski, G.T., J.B. Rogan and D.K. McDonald 2001. *How Low Can We Go?* Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.
- Brown, T.D., D.N. Smith, R.A. Hargis, W.J. O'Dowd 1999. *1999 Critical Review, Mercury Measurement and its Control: What We Know, Have Learned, and Need to Further Investigate*. Journal of Air & Waste Management Association, June.
- Bush, P. et al 1997. *Test on a Coal Preparation Plant and the Associated Cyclone-Fired Unit Equipped with a Wet Venturi Scrubber*. Final Report, DOE Contract No.DE-AC-93PC93254. As cited by Brown et al. 1999.
- Bustard, C.J., M. Durham, C. Lindsey, T. Starns, K. Baldrey, C. Martin, S. Sjostrom, R. Slye, S. Renninger and L. Monroe 2001. *Full-Scale Evaluation of Mercury Control with Sorbent Injection and COHPAC at Alabama Power E.C. Gaston*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.
- Canadian Electricity Association (CEA) 2002. Personal Communication with Victoria Christie and Des Cousens, February.
- Chu, P., G. Behrens and D. Laudal 2001. *Estimating Total and Speciated Mercury Emissions from U.S. Coal-Fired Power Plants*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.
- Cooper, C.D. and F.C. Alley 1994. *Air Pollution Control: A Design Approach*. 2nd Edition. Waveland Press Inc.

- Cousens, D. 2001. Canadian Electricity Association. Personal Communication with Paula Coutts, SENES Consultants Limited. August.
- Devito, M.S. and W.A. Rosenhoover 1999. *Hg Flue Gas Measurements from Coal-Fired Utilities Equipped with wet scrubbers*. Presented at the 92nd AWMA Annual Meeting & Exhibition. St. Louis, MO, June. As cited by Brown et al. 1999.
- Devito, M.S. and W.A. Rosenhoover 1997. *Flue gas mercury and speciation studies at coal-fired utilities equipped with wet scrubbers*. Presented at the Fourth EPRI International Conference on Managing Hazardous Air Pollutants, Washington DC, November. As cited by Brown et al. 1999.
- Evans, A.P., K.E. Redinger, M.J. Holmes 1997. *Advanced Emissions Control Development Program: Mercury Control*. McDermott Technology Inc.
- Ferris, D.D. et al. 1992. *Engineering Development of Advanced Physical Fine Coal Cleaning Technologies – Froth Flotation*. ICF Kaiser Engineers Final Report for DOE Contract No. DE-AC22-88PC88881, December. As cited by Brown et al. 1999.
- Haythornthwaite, S., M. Fox, T. Hunt, J. Smith, G. Anderson, C. Grover 1998. *Investigation and Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control*. Quarterly Technical Report under DOE Contract No. DE-AC22-95PC95256. As cited by Brown et al. 1999.
- Haythornthwaite, S., S. Sjostrom, T. Ebner, J. Ruhl, R. Slye, J. Smith, T. Hunt, R. Chang and T.D. Brown 1997. *Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses*. Presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 25-29, Washington D.C. As cited by Brown et al. 1999.
- ICAC 1997. White Paper. Selective Catalytic Reduction (SCR) Control of NO_x Emissions. As cited by U.S. EPA 2000b.
- Joint Boiler Work Group 2000. *Technology Options and Recommendations for Reducing Mercury and Acid Rain Precursor Emissions from Boilers*. Conference of New England Governors and Eastern Canadian Premiers Committee on the Environment. July.
- Jones, B.M. 2001. Emissions Control Technology Review. M.J. Bradley & Associates Inc., Concord, MA

- Kilgroe, J.D., R.K. Srivastava, C.B. Sedman and S.A. Thorneloe 2000. *Technical Memorandum: Control of Mercury Emissions from Coal-fired Electric Utility Boilers*. U.S. EPA, 25 October.
- Kilgroe, J.D. 1998. *Control of Mercury from Coal Fired Utilities*. Presented at Science Experts Workshop on Mercury, U.S.EPA, Las Vegas, 6-8 October.
- Kitto, J.B. 1996. *Air Pollution Control for Industrial Boiler Systems*. Presented to ABMA Industrial Boiler Systems Conference November 6-7, Florida. BR-1624
- Klein, M. 2000. Environment Canada, Oil and Gas Division. Personal Communication with Abby Salb, 6 November.
- Kurz, M.D. and D.L. Laudal 1999. *Mercury Formation and Fate – Volume 2: Mercury Speciation Sampling at Cooperative and United Power Association’s Coal Creek Station*. DOE Report under Contract DE-FCCC21-93MC30098, April. As cited by Brown et al. 1999.
- Laudal, D.L. and M.D. Kurz 1999. *Mercury Formation and Fate – Volume 1: Mercury Speciation Sampling at Minnkota Power Cooperative’s Milton R. Young Station*. DOE Report under Contract DE-FC21-93 MC30098, January. As cited by Brown et al. 1999.
- Lerner, B.J. 1993. *Mercury Emission Control in Medical Waste Incineration*. Presented at AWMA Meeting & Exhibition. Denver, June.
- Maier, H. 1990. *Emission of volatile and filter-penetrating heavy metals in lignite-fired plants*. VGB Kratwerkstechnik; 69(8); 721-725. As cited by Sloss 1995.
- Meij, R. 1998. KEMA, The Netherlands. Personal Communication. As cited by Sloss 1998.
- Meij, R. 1994. *Trace Element Behaviour in Coal-Fired Power Plants*. Trace Element Transformations in Coal-Fired Power Systems, Fuel Processing Technology, August, pp. 199-217. As cited by Bielawski et al. 2001.
- Milobowski, M.G., G.T. Amrhein, G.A. Kudlac and D.Madden Yurchison 2001. *Wet FGD Enhanced Mercury Control for Coal-Fired Utility Boilers*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.

- Moore, T. 1994. "Hazardous Air Pollutants: Measuring in Micrograms" EPRI Journal January/February, pp.7-15. As cited by Kitto 1996.
- Nolan, P.S., G.A. Farthing, D. Madden Yurchison and M.J. Holmes 1999. *Development of Mercury Emissions Control Technologies for the Power Industry*. Presented to EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium. August 16-20, Atlanta.
- Northeast States for Coordinated Air Use Management (NESCAUM) 2000a. *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers*. September.
- Northeast States for Coordinated Air Use Management (NESCAUM) 2000b. *Assessment of Mercury Control Strategies for Electricity-Generating Boilers*. Prepared in cooperation with ESI International Inc. June.
- Public Service Company of Colorado/ADA Technologies Inc. 1997. *Investigation and Demonstration of Dry Carbon-Based Injection for Mercury Control*. Final Report under Phase 1 DOE/FETC Mega PRDA Program, September. As cited by Brown et al. 1999.
- Redinger, K.E., A. Evans, R. Bailey, P. Nolan 1997. *Mercury Emissions Control in FGD Systems*. Presented at the EPRI/DOE/EPA Combined Air Pollutant Control Symposium, Washington DC, August 25-29. As cited by Brown et al. 1999.
- Richardson, C., T. Machalek, S. Miller, C. Dene and R. Chang 2001. *Effect of NO_x Control Processes on Mercury Speciation in Utility Flue Gas*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.
- Ross & Associates Environmental Consulting Ltd. 2000. *Great Lakes Binational Toxics Strategy Draft Report for Mercury Reduction Options*. U.S.EPA GLNPO, September.
- SENES Consultants Limited 1999. *Final Report and Supporting Documentation for Evaluation of Technologies for Reducing Mercury Emissions – Detailed Facility Parameters and Costs*. Prepared for the CCME, 31 March.
- Sjostrom, S., J. Bustard, M. Durham and R. Chang 2001. *Mercury Removal Trends in Full-Scale ESPs and Fabric Filters*. Proceedings of the Mega Symposium and A&WMA Specialty Conference on Mercury Emissions: Fate, Effects and Control, August 20-23, Chicago.

- Sjostrom, S., J. et al. *Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses*. Presented at the 90th AWMA Annual Meeting & Exhibition, Toronto, Canada. June. As cited by Brown et al 1999
- Sloss, L. 1995. *Mercury Emissions and Effects – the Role of Coal*. IEA Paper 19, IEA Coal Research, London, U.K, August.
- Sloss, L.L. 1998. *Mercury Emissions and Control from Coal-Fired Power Stations in Countries Outside the USA*. Paper presented to the 1998 Science Experts Workshop on Mercury, Las Vegas, 6-8 October.
- Smit, F.J., N. Moro, G.L. Shields, M.C. Jha and T.J Feeley 1996. *Reduction of Toxic Trace Elements in Coal by Advanced Coal Cleaning*. Proceedings of the 13th Annual International Pittsburgh Coal Conference, Vol. 2, pp.879-884. As cited by Brown et al 1999.
- Smith, I. 2001. Co-Chair, Mercury Development Committee. Ontario Ministry of Environment. Personal Communication with Paula Coutts, SENES Consultants Limited. October.
- Srivastava, R.K., C.B. Sedman and J.D. Kilgroe 2000. *Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers*. U.S.EPA Office of Research and Development, September.
- Stambler, I., 1993. *Utilities Sold on Advantages of Gas Turbine Repowering*. Gas Turbine World. Pg 35-40. July-Aug. 1993.
- Statistics Canada 2000. Canada's Mineral Production, Preliminary Estimates 1999. Catalogue #26-202-X1B. Minister of Industry, September.
- Toole-O'Neill, B., S.J. Tewalt, R.B. Finkelman, D.J. Akers 1999. *Mercury Concentration in Coal – Unraveling the Puzzle*. Fuel, 78:47-74. As cited by Brown et al. 1999.
- Turchi, C.S., J. Albiston, T.E. Broderick and R.M. Stewart 1999. *Removal of Mercury from Coal-Combustion Flue Gas Using Regenerable Sorbents*. Presented at the 92nd Annual Meeting and Exhibition of the Air & Waste Management Association, St. Louis, MO, June. As cited by Brown et al. 1999.
- U.S.EPA 2001. *Preferred and Alternative Methods for Estimating Air Emissions from Boilers*. Emission Inventory Improvement Program (EIIP) Volume II: Chapter 2, Prepared by Eastern Research Group Inc., January.

- U.S. EPA 2000a. *Technical Memorandum: Control of Mercury Emissions from Coal-fired Electric Utility Boilers*. Research Triangle Park, 25 October.
- U.S. EPA 2000b. *How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates*. Emission Inventory Improvement Program (EIIP) Volume II: Chapter 12, Prepared by Eastern Research Group Inc., July.
- U.S. EPA 2000c. *Mercury Research Strategy*. Office of Research and Development. EPA/600/R-00/073. September.
- U.S.EPA 1999. *Analysis of Emissions Reduction Options for the Electric Power Industry*. March.
- U.S. EPA 1998a. *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units - Final Report to Congress*. February.
- U.S. EPA 1998b. *Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities VII*. Office of Solid Waste and Emergency Response. July.
- U.S. EPA 1997a. *Mercury Report to Congress - Volume I Executive Summary*, December.
- U.S. EPA 1997b. *Mercury Report to Congress - Volume VIII: An Evaluation of Mercury Control Technologies and Costs*. December.
- U.S. EPA, 1995a. *OAPQS Control Cost Manual*. Fifth Edition. December.
- U.S. EPA 1995b. *Integrated Air Pollution Control System (IAPCS) Version 5.1 - Model Source Code and Technical Documentation*. Volumes 1 to 3. Radian Corporation. November.
- U.S. EPA 1994. *Alternative Control Technologies Document : NO_x Emissions from Utility Boilers*. Emissions Standards Division. EPA-453/R-94-023. March.

BIBLIOGRAPHY

- Air and Waste Management Association (AWMA) 1992. *Air Pollution Engineering Manual*. Buonicore, A.J. and W.T. Davis, (Eds.). Van Nostrand Reinhold, N.Y. 918 pp.
- Akers, D.J. 1993. *Coal Cleaning: A Trace Element Control Option*. Managing Hazardous Air Pollutants – State of the Art. W. Chow and K.K. Connor, Eds. EPRI, Lewis Publishers.
- Bell, W., T.J. Selegue, M.B. Perry 1997. *Comparison of Mercury Uptake by Six Sorbents as Measured in Packed Bed and Sorbent Injection Tests*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- C.C. Doiron & Associates 1996. *Background Information Paper for a Heavy Metals Protocol Under the United Nations Economic Commission for Europe Convention on Long Range Transboundary Air Pollution*, March 31.
- Canadian Environmental Protection Act (CEPA) 1997. *Strategic Options for the Management of Toxic Substances Electric Power Generation (Fossil Fuel) Sector*. Report of Stakeholder Consultations.
- Centre for Clean Air Policy (CCAP) 1998. *Mercury Emissions from Coal-Fired Power Plants: Science, Technology and Policy Options*. November.
- Clarke, L.B. 1993. *The Behaviour of Trace Elements During Coal Combustion and Gasification: An Overview*. Managing Hazardous Air Pollutants – State of the Art. W. Chow and K.K. Connor, Eds. EPRI, Lewis Publishers.
- Commission for Environmental Co-operation, *North American Regional Action Plan on Mercury - Sound Management of Chemicals Initiative*, July 1997.
- Cummins, A.B. and I.A. Given (Eds) 1973. *SME Mining Handbook*. Volume 2. The American Institute of Mining, Metallurgical, and Petroleum Engineers Inc.
- Electric Power Generation (Fossil Fuel) Sector Issue Table 1997. *Technical Background Documents Volumes 1, 2 and 3*. Prepared by Issue Table Contractor Roderick Shaw. 15 April.
- Environment Canada and Natural Resources Canada 1996. *The Status of Mercury in Canada - A Background Report to the Commission for Environmental Co-operation North American Task Force on Mercury*, October 2.

- Electric Power Research Institute (EPRI) 2000. *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*.
- Felsvang, K., Gleiser, R., Juip, G. and Kragh-Nielsen, K. 1994. *Activated Carbon Injection in Spray Dryer/ESP/FF for Mercury and Toxics Control*. Fuel Processing Technology. Vol 39 no 1-3. pp. 417-430.
- Feeley, T.J. 1997. *An Overview of the U.S. Department of Energy's Electric Utility Mercury Emissions R&D Activities*. Presented at the Acid Rain and the Electric Utilities II Conference, Scottsdale AZ, January.
- Gullett, B.K., B. Ghorishi and F.E. Huggins 1997. *Mercuric Chloride Capture by Alkaline Sorbents*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- Gutberlet, H., A. Schluter and A. Licata 2000. *SCR Impacts on Mercury Emissions from Coal-Fired Boilers*. Presented at EPRI SCR Workshop, 18-21 April, Memphis, TN.
- Hagler Bailly Canada 2000. *Cost of Early Retirement of Coal Generation*. Prepared for Ontario Power Generation Inc., 27 March.
- ICF Consulting 2000. *Memorandum on Mercury Control Costs Calculations: Assumptions, Approach and Results*. EPA Contract No. 68-D7-0081, 30 September.
- Laudal, D.L., J.H. Pavlish, J. Graves and D. Stockdill 2000. *Mercury Mass Balances: A Case Study of Two North Dakota Power Plants*. J. Air & Waste Manage. Assoc., 50:1798-1804, October.
- Lee, C.W., J.D. Kilgroe, S.B. Ghorishi 1997. *Speciation of Mercury in the Presence of Coal and Waste Combustion Fly Ashes*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- Liu, W., J.A. Korpiel, R.D. Vidic 1997. *Effect of Impregnation Protocol on Physical Characteristics and Adsorptive Properties of Sulphur-Impregnated Carbon for Vapour Phase Mercury*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- Livengood, D.C. and M.H. Mendelsohn 1997. *Enhanced Control of Mercury Emissions Through Modified Speciation*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.

- Meserole, F.B., C.F. Richardson, S.D. Miller, K. Searcy, R. Chang 1997. *Estimating the Costs of Electric Utility Mercury Control Using Sorbent Injection*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- NAFTA North American Task Force on Mercury, 1996. *Draft North American Regional Action Plan on Mercury, Sound Management of Chemicals Project*, October 8.
- Nelson, S., J. Miller and D. Summanen 1997. *Innovative Mercury Emission Control*. Presented at AWMA 90th Annual Meeting & Exhibition. Toronto, June.
- New England Governors/Eastern Canadian Premiers (NEG/ECP) 1998. *Mercury Action Plan 1998*. Prepared by The Committee on the Environment of the Conference of the New England Governors and Eastern Canadian Premiers. Proposal, May.
- Norton, G.A., H. Yang, R.C. Brown, D.L. Laudal, G.E. Dunham, J.K. Okoh 1997. *Effects of Fly Ash on Mercury Oxidation in Simulated Flue Gas Environments*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- Noyes Publications 1993. *Pollution Prevention Technology Handbook*. Robert Noyes, ed. New Jersey.
- Ontario Clean Air Alliance 2000. *Countdown Coal: How Ontario can Improve Air Quality by Phasing Out Coal-Fired Electricity Generation*. October.
- Pacyna, J.M. and E.G. Pacyna 1998. *Cost Efficient Measures for Reduction of Anthropogenic Emissions of Mercury: Global Perspective*. Science Experts Workshop on Mercury, U.S.EPA, Las Vegas, 6-8 October.
- Resource Futures International (RFI), SNC-Lavalin, Informetrica, Globaltox, Marbek Resource Consultants and Sustainable Futures 1996a. *Evaluation of Technical Control Options and Management Options for Toxic Releases from the Fossil Fuel Fired Electric Power Sector*. Phase 1. Prepared for Environment Canada. July.
- Resource Futures International (RFI), SNC-Lavalin, Informetrica, Globaltox, Marbek Resource Consultants and Sustainable Futures 1996b. *Evaluation of Technical Control Options and Management Options for Toxic Releases from the Fossil Fuel Fired Electric Power Sector*. Phase 2-Final Report. Prepared for Environment Canada. August.

- Richardson, C., G.B. Blythe, R. Rhurdy and T. Brown 1997. *Enhanced Control of Mercury by Wet FGD Systems*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.
- Stiegel, G.J. n.d. *Gasification Technologies: Clean Energy for the Future*. U.S.DOE Federal Energy Technology Center (FETC).
- United Nations Economic Commission for Europe (UNECE) 1998. *Draft Protocol to the Convention on Long-Range Transboundary Air Pollution on Heavy Metals*. Economic and Social Council.
- U.S.EPA 1991. *Handbook of Control Technologies for Hazardous Air Pollutants*. ORD. June.
- Vatavuk, W.M. 1990. *Estimating Costs of Air Pollution Control*. Lewis Publishers, Chelsea, Michigan.
- Widmer, N.C., J. West and J.A. Cole 1997. *Thermochemical Study of Mercury Oxidation in Utility Boiler Flue Gases*. Proceedings of the 90th Annual AWMA Meeting. June 8-13, Toronto, Canada.

APPENDIX A

INTRODUCTION TO COST ESTIMATING FUNCTIONS

APPENDIX A: COST ESTIMATING FUNCTIONS

EQUATIONS USED IN COSTING METHODOLOGY

These equations refer to the methodology presented in Figures 5.1 and 5.2 for calculation of capital and annual costs, respectively. It should be noted that some CEFs deviate from this procedure. When only basic design/sizing information was available for certain controls, the following methods were used. However, in some instances, CEFs were found that provided fitted equations for the calculation of TCI and TAC based on flowrate. In these instances, only the conversions to 1999 CDN \$ were performed.

$$\text{Total Capital Investment (TCI)} = \text{Total Direct Cost (TDC)} + \text{Total Indirect Cost (TIC)}$$

$$\text{TDC} = \text{Purchased Equipment Cost (PEC)} + \text{Direct Installation Cost (DIC)} + \text{Retrofit Costs (RC)}$$

$$\begin{aligned} \text{PEC} &= \text{Unit Cost (UC)} + \text{Instruments} + \text{Controls} + \text{Freight} \\ &= \text{UC} * \text{PEC factor} \end{aligned}$$

$$\begin{aligned} \text{DIC} &= \text{Foundations} + \text{Electrical} + \text{Piping} + \text{Insulation} + \text{Painting} \\ &= \text{PEC} * \text{DIC factor} \end{aligned}$$

$$\begin{aligned} \text{RC} &= \text{Cost of adding control to existing facility} \\ &= \text{DIC} * \text{RC Factor} \end{aligned}$$

$$\text{TIC} = \text{IIC} + \text{CM}$$

$$\begin{aligned} \text{IIC} &= \text{Indirect Installation Cost} \\ &= \text{Engineering} + \text{General Facilities} + \text{Contingency Fees} \\ &= \text{RC} * (\text{E factor} + \text{GF factor} + \text{C factor}) \end{aligned}$$

$$\text{CM} = \text{Contractor Markup} = 3\% \text{ of IIC}$$

Example for PJFF:

$$\begin{aligned} \text{Instruments} + \text{Controls} &= 2\% \text{ of IIC} \\ \text{Freight} &= 5\% \text{ of IIC} \end{aligned}$$

$$\text{PEC} = \text{UC} * (1+0.07)$$

$$\text{Installation Factor} = 67\% \text{ of PEC}$$

$$\text{DIC} = 0.67 * \text{PEC}$$

Retrofit Factor = 30% of DIC

RC = DIC * 0.3

Indirect Costs:

General Facilities = 10% of RC

Engineering Fees = 10% of RC

Contingency Fees = 20% of RC

IIC = RC * 0.4

Contractor Markup = 0.03 * IIC

TCI = TDC + TIC

= PEC + DIC + RC + IIC + CM

All costs were converted to 1999 CDN \$ using an average exchange rate of \$1.486 CDN: \$1 U.S. and the following formula:

$$1999\ TCI = TCI \times \frac{1999\ Average\ CE\ Index}{Base\ Year\ CEF\ Average\ CE\ Index}$$

**TABLE A.1
CONVERSION FACTORS FOR YEARLY COST ADJUSTMENTS**

Year	CE Index
1980	263.6
1981	303.1
1982	314.0
1983	316.9
1984	322.7
1985	325.3
1986	318.4
1987	323.8
1988	342.5
1989	355.4
1990	357.6
1991	361.3
1992	358.2
1993	359.2
1994	368.1
1995	381.1
1996	381.7
1997	386.5
1998	388.5
1999	390.6

Annual Operating Costs

$$\text{Annual Operating Costs (OAC)} = \text{Direct Annual Costs (DAC)} + \text{Indirect Annual Costs (IAC)} \\ + \text{Recovery Credits (RC)}$$

Assuming that there are no recovery credits for mercury,

$$\text{OAC} = \text{DAC} + \text{IAC}$$

The breakdown of the direct annual costs (DAC) is as follows:

$$\text{DAC} = \text{Consumption Costs (CC)} + \text{Operating Costs (OC)} + \text{Maintenance Costs (MC)} \\ + \text{Disposal Costs (DC)}$$

$$\text{CC} = \text{Electricity Cost} + \text{Water Cost} + \text{Materials Costs (acid, solvents, carbon etc.)} \\ = (\text{Fp} * \text{EC}) + (\text{WU} * \text{WC}) + (\text{MU} * \text{CM})$$

where:

$$\begin{aligned} \text{Fp} &= \text{fan power (kWh)} \\ \text{EC} &= \text{power cost (\$/kWh)} \\ \text{WU} &= \text{water use (m}^3\text{/yr)} \\ \text{WC} &= \text{water cost (\$/m}^3\text{)} \\ \text{MU} &= \text{material use (tonne/yr, or m}^3\text{/yr)} \\ \text{MC} &= \text{materials cost (\$/tonne or \$/m}^3\text{)} \end{aligned}$$

If not provided in CEF,

$$\text{Fp} = 1.81 \times 10^{-4} * (\text{Q}_I) * (\text{P}) * (\text{HRS})$$

where:

$$\begin{aligned} \text{Q}_I &= \text{flow rate (acfm)} \\ \text{P} &= \text{pressure drop ("H}_2\text{O)} \\ (\text{HRS}) &= \text{operating hours (hrs/yr)} \end{aligned}$$

$$\text{OC} = \text{Operating Labour (OL)} * \text{Labour Hours (LH)} * 1.15$$

$$\text{MC} = \text{Maintenance Labour (ML)} * \text{Maintenance Labour Cost (MLC)} * 2 \\ \text{OR a percentage of PEC, DIC or IIC, depending on the CEF.}$$

The number of hours required for operation and maintenance (LH and ML respectively) differ for each control, depending on the amount of manpower required per year (i.e. some control technologies are more operator intensive while others are more maintenance intensive). Also, the hourly labour and maintenance rates used were province-specific, for individual facilities.

The factor of 1.15 in the *OC* accounts for supervisory labour, while the factor of 2 in the *MC* accounts for materials cost (U.S. EPA, 1995).

$$DC = \text{Mass Waste Generated (MW) [tonnes/yr]} * \text{Tipping Fees (TF) [$/tonne]}$$

All disposal costs in this study were based on municipal solid waste disposal tipping fees, with the exception of catalyst disposal of SCR, where a hazardous waste disposal tipping fee was used.

The final component of total annual cost (*TAC*) is the indirect annual cost (*IAC*). The breakdown of *IAC* is as follows:

$$IAC = \text{Overhead (OH)} + \text{Administration (A)} + \text{Insurance (I)} + \text{Property Taxes (P)}$$

$$OH = 0.6 * (OC + MC) \text{ (OC and MC as defined above)}$$

$$PIA = 0.04 * 1999 \text{ TCI}$$

Tables A.2 and A.3 outline the fixed costs used in the analysis:

**TABLE A.2
COSTS OF INPUTS TO THE ALGORITHMS**

Variable	Value	Year*	Currency/Units
Electricity	0.06	1994	C (\$/kWh)
Water	0.25	1980	C (\$/1000 gal.)
Carbon	4.36	1998	C (\$/kg.) converted from \$1.98/lb
HCl	0.167	1995	C (\$/kg.)
Sorbent	152.94	1999	C (\$/tonne)
Catalyst	400	1992	US (\$/ft ³)
Natural Gas	3.776	1999	C (\$/10 ⁶ BTU)
Ammonia	152	1994	C (\$/tonne)
Lime	92.84	1999	C (\$/tonne)
Limestone	44.11	1994	C (\$/tonne)
Steam	3.5	1998	US (\$/1000lb)
Tipping Fee (TF)	100	1999	C (\$/tonne)
HazWasteTF	250	1995	C (\$/tonne)

** All costs that were not in 1999 dollars were converted to 1999 Canadian \$ using the CE Index in Table A.1*

**TABLE A.3
PROVINCIAL INPUT PARAMETERS**

Province	1999 Labour Rates (\$/hr)		SalesTax
	Operating	Maintenance	
AB	24.53	30.87	0%
MN	22.76	26.23	7%
NB	23.18	30.09	7%
NF	27.64	33.91	12%
NS	21.51	28.32	10%
ON	23.45	27.76	8%
SK	22.52	29.59	9%

Total Annualized Costs

The 1999 TCI is annualized over the design life, which was assumed to be 20 years for all controls (except repowering with natural gas turbines = 40 years), by calculating the capital recovery. This was done in order to compute the Total Annualized cost (TAC).

Capital Recovery (CR) = 1999 TCI * Capital Recovery Factor (CRF)

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where:

n = equipment life = 20 years (design life)
 i = real discount rate

The real discount rate takes inflation into consideration, adjusting the market interest rate accordingly using the following formula: $i = \frac{(1+m)}{(1+I)} - 1$

where:

m = 1999 average market interest rate = 6.44%
 I = 1999 average inflation rate = 1.7%

Therefore,

$i = 0.047 = 4.7\%$
 $CRF = 0.078$

$CR = 1999\ TCI * 0.078$

The Total Annualized Cost (*TAC*) is calculated as follows:

$$TAC = AOC + CR$$

Sources of CEFs used in this study

In order to determine sector specific cost data, two primary sources of information were used, which are focussed on costs and emissions from the coal-fired generating sector. These are two existing control costing programs. The first is a recent program developed for the U.S.EPA called Coal Utility Environmental Cost (CUECost) version 1.3, which uses plant specific input data to size and cost various air pollution controls. The second is the Integrated Air Pollution Control System (IAPCS) Version 5a, which was developed by the U.S. EPA. This system also uses plant specific input data and allows the user to select full plant configurations of boiler type, size, control options, etc., to calculate costs associated with specific controls. It should be noted that these programs were not directly used to calculate the costs presented in this study. Instead, SENES examined the complete algorithms provided in these programs for individual control options and selected the basic sizing and costing equations found within the algorithms. SENES then followed the OAQPS approach to develop algorithms specifically targeted to this study. Consequently, the algorithms used in this study all follow the same basic pattern, and thus are directly comparable to one another, which yields more useful results than simply using the programs as found.

PJFF – CUECost modified
LSFO – CUECost modified
SC – Cooper & Alley 1994 modified
DSI – IAPCS modified
LSD - CUECost modified
SCR - CUECost modified
NGT – IAPCS modified
ACI – U.S.EPA 1999 modified
ACC – IAPCS modified