Q. Has Hydro, within the last ten years, previously commissioned any studies to assess the condition of the Holyrood Generating Station and/or investigate redevelopment options for this site, including without limiting the foregoing, any studies on one or more of the 4 enumerated areas of study set out in the "Project Description" for the project at p. B-14?

A. Hydro has not commissioned any studies to assess the condition of the Holyrood Generating Station or to investigate the redevelopment option of the site. Attached are copies of the two studies Hydro commissioned to investigate the feasibility of installing emission control equipment:

- Air Emissions Controls Assessment – Holyrood Thermal Generating Station Final Report by SGE Acres, February 2004
- Newfoundland & Labrador Hydro Holyrood Generating Station Units 1, 2 & 3 Phase I – Engineering Study for Investigation of methods to Improve Emissions by Alstom Canada Inc., November 12, 2002

Prepared for

Newfoundland and Labrador Hydro
P.O. Box 12400, Hydro Place, Columbus Drive,
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Air Emissions Controls Assessment – Holyrood Thermal Generating Station Final Report

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
SGE ACRES LIMITED
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN X0185
which is valid for the year 2004

REGISTERED PROFESSIONAL ENGINEER
ROBERT J. GILL
SIGNATURE
Feb 13/04
DATE
PROVINCE OF NEWFOUNDLAND

Prepared by
SGE Acres Limited

February 2004
P15291.00

SGE Acres

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Appendix A – Fuel and Air Emissions Data (provided by Hydro)
Appendix B – Cost Analysis of FGD vs Low Sulphur Fuel Oil

1 Introduction

Newfoundland and Labrador Hydro (Hydro) operates a 500-MW heavy oil fired generating plant at Holyrood on Conception Bay. The plant consists of three units. Units 1 and 2 were commissioned as 150 MW units in 1969, and Unit 3 was commissioned as a 150 MW unit in 1980. In the late 1980s, Units 1 and 2 were uprated to 175 MW each, bringing the total capacity to 500 MW. No air emissions control equipment exists on any of the units.

In July 2003, Hydro called for proposals to assess emission controls technologies and to provide recommendations for the next 20 years of operation. In September 2003, Hydro awarded a contract to SGE Acres as a result of this call for proposal. The overall objective of this study is to provide Hydro with an independent evaluation for the reduction of plant air emissions to achieve the following emission targets.

- Reduce particulates by 20 percent from current levels, including fine particulate matter (PM_{10}).
- Maintain opacity at not more than 20 percent during normal operation, soot blowing or transients.
- Maintain oxides of sulphur at no more than that equivalent to burning 1 percent sulphur content fuel.

The study work involved the following activities.

- A review of emissions controls technologies used in similar heavy oil-fired plants.
- Identification of the current trends in air emissions controls and comment on the operating experience.
- An evaluation of such controls based on their advantages and disadvantages as well as capital and operating costs.
- Commentary on the direction and evolution of air emissions control regulations in Canada and the most likely application of controls to achieve compliance.

In determining the options for emission control for the plant, consideration was given to site constraints such as existing infrastructure, availability of space, water and reagent handling and storage, the impact of FGD (Flue Gas Desulphurization) on the existing stacks, plant auxiliary load consumption and electrical systems.

Based on the initial study meeting with Hydro, the study focused on the cost effectiveness and impact of the most likely emission controls options. Two basic approaches were considered, as follows.

A: Continuation of Current Fuel Type

Particulate emissions and opacity targets may be attained by

- electrostatic precipitation (ESP); or
- mechanical separation, possibly combined with emerging technologies that promote particle agglomeration to reduce the size fraction of PM_{10} .

Flue gas sulphur emissions targets may be reached by implementing FGD on one or more units including

- partial FGD on all three units with bypass of the balance of flue gas; or
- full FGD on selected units with no FGD on the balance.

B: Switch to Low Sulphur Oils

Switching to low sulphur oil would permit SO_2 levels to be reduced to acceptable levels. This may be achieved by a less costly partial switch in which low sulphur fuel would be used during heavy load periods and high sulphur fuel during light periods. Low sulphur (1% S) fuel oils typically have lower asphaltenes content and therefore will produce lower particulate emissions and may enable particulate targets to be met without capture equipment.

2 Review of Current Plant Operations

Plant History
Units 1 and 2 were commissioned in 1969 and Unit 3 was commissioned in 1980. Units 1 and 2 were uprated in the late 1980s and current ratings are as follows:

Unit	Original Nameplate Rating MW	Current Rating MW
Units 1 and 2	150	175
Unit 3	150	150

No particulate or SO_2 capture equipment is provided in the current installation. The boilers have pressurized furnaces. Hydro advised that fan margins were used when Units 1 and 2 were uprated. The limiting factor on output is air heater fouling.

Plant Operations
The plant operates on a daily load cycling basis with each unit typically running between 85 MW and full load. The plant avoids shift operation and has about 4 to 5 unit starts per year. The annual production profile showing actual and forecast annual production to 2020 is shown in Figure 2.1. The plant target fuel consumption per unit output is taken as 624 kWhr/bbl (net output).

Fuels and Fuel System
The existing fuel system includes

- Heated delivery pipeline about 0.75 km long from the ship unloading dock.
- Four 220,000 bbl storage tanks, un-insulated and unheated except for suction heaters. Storage tanks have about 15,000 bbl dead storage each. Each ship delivery is 275,000 bbl.
- Common day tank for all three units.
- Common magnesium oxide (MgO) injection system for all three units.

The existing fuel burners and combustion systems infrastructure is 1970s technology and has been optimized for combustion performance.

The specification of fuels delivered over a period of several years is included in Appendix A.

Present Emissions
Ambient air monitoring stations have been in service since 1994 in the region of the plant. The plant reports that complaints about air emissions from the local neighborhood are received depending on wind direction.

A summary of 2001 emissions tests is included in Appendix A.

Emissions Regulations

The plant emissions are currently regulated to limits on ground level concentrations (GLCs) plus maximum ambient air concentrations in the regional air shed. Hydro is also subject to an annual cap of 25,000 tonnes of SO_2 emissions.

Opacity is regulated to an allowable limit of 20 percent.

Site Constraints

The plant site has limited available space for new construction and significant buried services at the rear of each boiler. Maintaining truck access around the rear of the plant is necessary to provide service and maintenance access to the wastewater treatment plant, basins and pump houses. It is possible to fit particulate matter collection equipment behind the stacks; however, this requires re-routing the existing flue gas ductwork north of each stack to the new equipment and back to the existing stack inlets. The available space and other constraints do not permit retrofitting an FGD system to the north of the units.

The overall plant site includes space originally reserved for a possible Unit 4 with the assumption that it would be similar to the existing units. However, Hydro's current thinking is that future plans for expansion at the site would no longer include a Rankine cycle unit similar to the existing plant. Instead, Hydro has identified an alternate location at the site for a potential combined cycle development. As a result, the space reserved for a future Unit 4 can be made available for a potential FGD system.

Additional area would be required to provide for on-site landfill disposal for solid waste products (ash and/or gypsum) if the ESPs or FGD options are adopted. It is noted that if wet ESPs are adopted in conjunction with a wet FGD, that the gypsum waste from the FGD will not be suitable for commercial use. It is understood that Hydro has identified a potential site on the plant property for this purpose.

In the event that multi-cyclone collectors or ESPs are selected as the preferred option for PM mitigation, to maintain truck access it would be necessary to install the ESPs on elevated structures to provide space below the hoppers for an ash collection and handling system and for clear access underneath the complete assembly. For this reason, the site constraints impose an incremental cost impact on ESPs.

For cost comparison purposes, it has thus been assumed that particulate matter collection equipment would be located to the north of each unit on elevated structures and that an FGD system, common to all units sized at a nominal 500 MW, would be located in the space reserved for Unit 4.

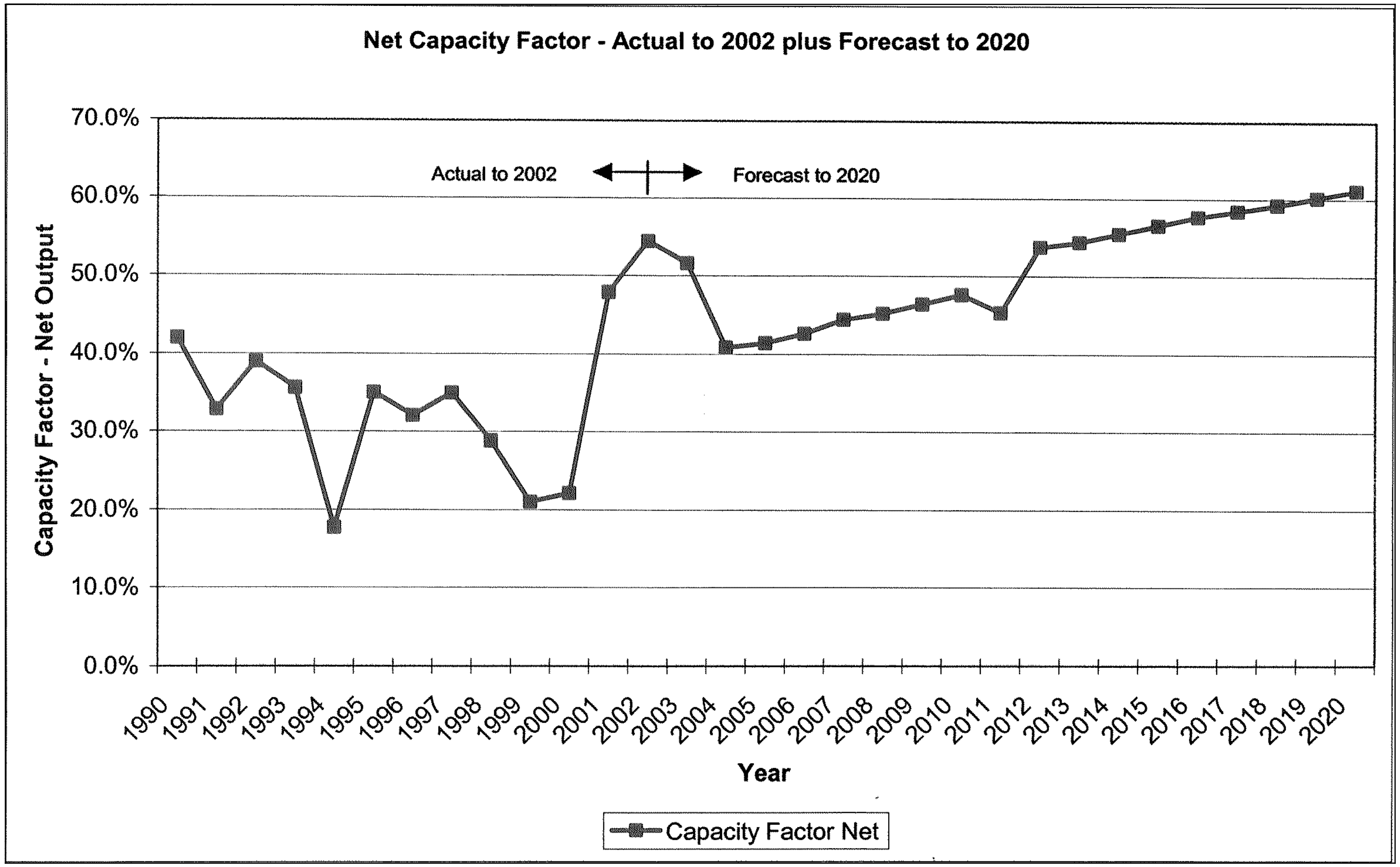

Figure 2.1
Actual and Forecast Annual Average Capacity Factor for Holyrood Plant

3 Experience with Other Heavy Oil-Fired Plants

Several heavy oil-fired plants in Canada and the eastern United States were identified for the purpose of determining how other similar facilities have approached the emissions control problem. These plants are as follows.

Tuft's Cove, N.S.	Courtenay Bay, N.B.
Dalhousie Unit 1, N.B.	Coleson Cove, N.B.
Tracy, P.Q.	Lennox, Ont.
Burrard, B.C.	Wyman, Maine
Newington, New Hampshire	Mystic, Mass.
Canal, Mass.	Yorktown, Virginia

In a number of instances, particularly in the case of the US plants, owners were reluctant to discuss the strategies they have developed for controlling emissions. In these cases, useful information was gleaned from public documents, such as licenses, which are available. In the case of a number of the Maritime plants, up-to-date information was available through prior contact and recent project experience. The results of the exercise are presented below and in the enclosed table, for US plants.

For additional background purposes, the following table[1] summarizes the target SO_2 emissions caps adopted by the provinces shown.

Province	Former Acid Rain Program Caps tonnes per year	New Targets and Percent Reduction		Target Achievement dates
		tonnes per year	Percent reduction	
Ontario	885,000	442,500	50%	2015[2]
Quebec	500,000	300,000 250,000	40% 50%	2002 2010
New Brunswick	175,000	122,500 87,500	30% 50%	2005 2010
Nova Scotia	189,000	142,000 94,500	25% 50%	2005 2010
Newfoundland and Labrador	45,000	-	-	-

This table reflects some of the regulatory objectives driving the strategies adopted to date in the Canadian plants referenced. New targets for Newfoundland and Labrador have not yet been negotiated.

[1] Source: Environment Canada
[2] Ontario is reported to be reviewing advancing this date to 2010.

Tuft's Cove, N.S.

Tuft's Cove Plant, which is owned by Nova Scotia Power Inc (NSPI), has three units.

Unit 1-100 MW - originally coal fired now dual fired capability HFO and natural gas (NG). It is provided with an ESP for particulate emissions control. The boiler is a cyclone firing type and was fitted with a precipitator for coal firing. Its annual capacity factor (CF) is 15-20 percent.

Unit 2 - 100 MW - originally oil fired now dual HFO & NG. It is fitted with a cyclone for particulate emissions control. Its annual capacity factor (CF) is in the range of 40 - 60 percent.

Unit 3 150 MW - originally oil fired now dual HFO & NG. It is also fitted with a cyclone for particulate emissions control and has an annual CF in the range of 45-80 percent.

The HFO used is in the 2 percent sulphur content range. It is anticipated that future federal regulations may reduce this. Based on recent experience, NSPI also monitor the ash content of HFO fuel purchased to manage particulate emissions.

NSPI operate to a regulated cap for SO_2 emissions on the generating fleet. This enables operation within the cap by varying the sulphur content of the coal used in the various coal plants to achieve compliance. The capacity factor on the coal plants and the impact of switching coals from local high sulphur to imported low sulphur coal provides NSPI with a sufficiently wide range of variation to enable them to maintain compliance with the SO_2 cap. NSPI have committed to a cap on SO_2 emissions of 142,000 tonnes in 2005.

NSPI advise that the drivers for use of fuel (HFO vs. NG) at Tuft's Cove include

- SO_2 cap compliance;
- Market cost of HFO vs. NG; and
- Unit cleanliness - if units or stacks are dirty, particulate emissions go up. This may drive the use of NG or require an outage to clean the units or wash the stacks.

Future SO_2 emissions compliance management options include the potential for purchase of power from lower SO_2 emission plants to displace the use of high sulphur fuels (oil and coal) at NSPI facilities. This option would also result in lower particulate emissions from the NSPI plants.

Courtenay Bay, N.B.

This plant, which is owned by NB Power, was originally developed to include 1x50 MW plus 1x12 MW backpressure units and 2x100 MW high sulphur HFO fired units. The initial development did not include any flue gas particulate capture or sulphur reduction facilities. In the period 1997 to 1999, one of the two 100 MW units (Unit 3) was repowered to a gas-fired combined cycle, cogeneration plant.

The 50 MW unit has been retired and the other 100 MW unit, (Unit 4) is in wet lay-up but may be used for peak demand periods. In the event that it is used, the operating permit for Unit 4 restricts the fuel to 1 percent, or lower, sulphur fuel.

Unit 2, the 12 MW backpressure unit, is used year round to provide steam to its steam host. The operating permit for this unit restricts the fuel sulphur content to 2 percent or lower.

Dalhousie Unit 1, N.B.

Dalhousie is a nominal 300 MW plant with two units; Unit 1 is rated at 100 MW and Unit 2 is rated at 200 MW. Unit 1 was originally heavy fuel oil fired using 2.2 percent sulphur oil, and Unit 2 was a coal-fired plant burning high sulphur coal blends, including a large portion of local coal with about 6 to 8 percent sulphur content. In the period 1992 to 1994, NB Power converted both units to burn Orimulsion™ as part of an overall strategy to reduce the cost of fuel at the plant and to satisfy a drive from the provincial DOE to reduce SO_2 emissions to meet an annual emissions cap set for the NB Power generating fleet. As part of the conversion program, a wet FGD system was added to reduce sulphur dioxide emissions by over 90 percent. Particulate emissions are controlled by ESPs, one retrofitted to Unit 1 in 1992 and one provided with the original coal fired unit. In 1998, a wet ESP was retrofitted to reduce SO_3 emissions in order to eliminate brown plume visibility under adverse weather conditions.

Coleson Cove, N.B.

The plant is a nominal 1050 MW plant developed in the early 1970s with three identical units each rated at 350 MW. In the past decade, the plant has been used as a swing plant running at high load factors in the late fall, early spring and winter peak periods with an overall annual average capacity factor of 65 percent; during the summer period, the plant plays either a standby role or is used to export to the interconnected markets, depending on market opportunities. In 2002, NB Power embarked on a project to convert the plant from HFO to Orimulsion™ and Unit 3, the first unit to be converted, is currently being returned to service after implementation of major modifications. The primary drivers for the conversion were forecast load demand, a need to provide for lost generation resulting from a planned refurbishment of Point Lepreau Nuclear Generating Station, a need to retrofit an FGD system to meet a decreasing fleet wide SO_2 emission cap, and the overall economic impact of forecast increases in HFO fuel costs together with the impact on power cost from the FGD retrofit.

The FGD retrofit program includes the provision of a wet ESP to reduce SO_3 content of the exhaust gases to eliminate the typical brown plume generated and to provide for potential future regulations on $PM_{2.5}$ emissions.

Each unit at Coleson Cove was originally fitted with an ESP and a fly ash system. In its early operating years, the plant had difficulty with the ash handling system and the ESPs were not functional. In the 1980s, a fly ash furnace reinjection system was added to recycle the carbon rich material captured by the ESP, and the ESPs were placed into continuous service.

Tracy, Quebec
Several attempts have been made to obtain information on this plant; however, none was available at the time of writing.

Lennox, Ontario
Originally developed as a HFO fired power plant, the plant was converted to dual fuel firing using natural gas in the early 1990s. The plant is used as a peaking facility only due to the cost of natural gas and the plant heat rate. The plant is registered under the guidelines set forth in the Ontario Emissions Trading Code of December, 2001 and uses SO_2 Emission Reduction Credits (ERCs) accrued from the standard method stipulated in that code for Fuel Switching at Electricity Generating Stations. The Lennox plant was originally designed to use fuel oils with a sulphur content of about 2.1 percent. Following a regulated SO_2 annual emissions cap in line with provincial regulations, the plant now uses fuel oils with a sulphur content ranging from 0.1 to 0.7 percent in conjunction with natural gas to achieve a reported SO_2 emissions rate of 1.64 kg/MWh.

Burrard, B.C.
Originally developed as a HFO fired power plant, the plant was converted to natural gas firing in the mid 1990s. The oil firing capability and oil storage facilities have been completely removed.

US Plants
The heavy fuel oil-fired fleet of US plants that remain in operation has been reduced to 54; of these plants, only a limited number have a significant capacity factor on fuel oil. A selection of these plants located along the eastern seaboard is listed in Table 3.1. Information on the quality of fuel oils used in a broader range of US plants is provided in Table 3.2.

Of the plants that currently use HFO in Rankine cycle generating units, the general trend has been driven by regulatory requirements, the advent of very competitive gas-fired generation in the 1990s and the age of the existing plants. These factors combined have resulted in the following emissions mitigation strategies.

Capacity Factor – in general, the duty of these plants has been largely standby or peaking duty with capacity factors ranging from negligible to less than 10 percent. There are a few plants that report capacity factors in the range of 20 to 40 percent with one plant reporting a capacity factor of 55 percent.

Particulate Emissions – a number of plants are equipped with particulate emissions controls including ESP or cyclone separators.

SO_2 Emissions – most of the units in service have dual fuel capability using natural gas and/or residual fuel oil. SO_2 emissions control is achieved by using low sulphur fuel oils and by purchasing SO_2 emissions credits to offset any extended SO_2 emissions from fuel oils or by firing with natural gas.

Of the US plants, the most directly comparable to Holyrood is Newington, NH. This plant has one 414 MW unit with an in-service date of 1974. It has a reported capacity factor of 37 percent. It was designed as a load cycling unit for peaking duty to provide a backstop power source during the delays in construction being experienced on a nuclear power station development at the time. As a result, the Newington plant was not fitted with a regenerative air preheater. A hot side ESP was originally provided in 1974 to control particulate emissions and opacity; fuel management is used to control SO2 emissions. The plant currently operates within a system wide SO2 emissions cap for emissions management and has natural gas co-firing capability to enable the plant to achieve its emissions limits.

Canal GS Units 1 and 2 are approximately 540 MW units with reported capacity factors of 55 percent and 23 percent. In response to environmental impact reports submitted by the owner, the state environmental regulator directed the owner to consider the use of fuel oils with sulphur contents of 0.7 percent to 0.3 percent for prior to final approval and issue of a permit. The status of final approval is not known.

Yorktown, GS is an 850 MW residual oil-fired utility boiler, which has historically operated as a peaking unit fitted with a custom designed multi-cyclone to reduce particulate emissions. PM_{10} emissions are reduced by 32.5 percent by the custom designed multi-cyclone as per the plant Title V Permit.

Table 3.1
Capacity and Emissions Information for Selected HFO Plants in the Eastern US

US States	Fuel Oil Power Plant Name	Total Installed Capacity	Net Generation	Capacity Factor	Opacity Factor	Emission Permits	SO2 Emission Control Technology used	Emission Permits			PM Emission Control Technology used
		[MW]	[MWh]	[%]	[%]	SO2		PM	PM2.5	PM10	
Maine											
	FPL Energy Wyman, LLC & Wyman IV LLC				20%	Limits emission to 0.80 lb/MMBTU and Licensed for annual emission of 45,901.6 tons/year		Licensed for annual emission of 4,964.8 tons/year		Licensed for annual emission of 4,964.8 tons/year	
New Hampshire											
	Newington GS	414	1,338,229	37%		Title V Permit not issued		Title V Permit not issued	Title V Permit not issued	Title V Permit not issued	
Massachusetts											
	Mystic 4, 5, & 6 GS	469	354,972	9%		Title V Permit not available		Title V Permit not available	Title V Permit not available	Title V Permit not available	

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Capacity and Emissions Information for Selected HFO Plants in the Eastern US

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		[MW]	[MWh]	[%]	[%]	SO2		PM	PM2.5	PM10	
	Canal GS Unit 1	543	2,594,406	55%		a) Shall not exceed 6.0 lbs/MWh calculated over any consecutive 12 month period, recalculated monthly. b) Shall not exceed 3.0 lbs/MWh calculated over any 12 month period, recalculated monthly. c) Shall not exceed 6.0 lbs/MWh calculated over any individual month.	Fuel Management for Lower Sulfur fuels				Electrostatic Precipitators

Table 3.1
Capacity and Emissions Information for Selected HFO Plants in the Eastern US

US States	Fuel Oil Power Plant Name	Total Installed Capacity	Net Generation	Capacity Factor	Opacity Factor	Emission Permits	SO2 Emission Control Technology used	Emission Permits			PM Emission Control Technology used
		[MW]	[MWh]	[%]	[%]	SO2		PM	PM2.5	PM10	
	Canal GS Unit 2	530	1,047,214	23%		a) Shall not exceed 6.0 lbs/MWh calculated over any consecutive 12 month period, recalculated monthly. b) Shall not exceed 3.0 lbs/MWh calculated over any 12 month period, recalculated monthly. c) Shall not exceed 6.0 lbs/MWh calculated over any individual month.	Fuel Management for Lower Sulfur fuels				Electrostatic Precipitators
Virginia											
	Yorktown Power Station, Unit 3	1,140	3,248,229	33%	20%	6303 tons/yr The capacity factor is limited to 8.5% based on 2% sulfur fuel oil.		8061 MMBTU/yr 806.1 lbs/yr		Particulate Matter/PM10 hourly is 25.0 lbs/hr, and annual 12.5 tons/yr	Universal Oil Products-Custom Design multiclone

Table 3.2
Average Quality of Fuel Oils Burned at US Electric Utilities by Census Division and State, 1999 and 2000

Census Division State	Petroleum			
	1999		2000	
	Average Btu per Gallon	Sulphur Percent by Weight	Average Btu per Gallon	Sulphur Percent by Weight
New England	151,244	0.99	151,633	0.95
Connecticut	151,783	.90	151,915	.84
Maine	150,653	1.03	151,415	.99
Massachusetts	151,055	.96	151,497	.98
New Hampshire	150,751	1.58	151,845	1.65
Rhode Island	--	--	--	--
Vermont	136,000	.05	136,000	.05
Middle Atlantic	149,848	.79	150,071	.75
New Jersey	150,210	.70	148,740	.55
New York	149,803	.83	150,155	.79
Pennsylvania	149,993	.61	149,886	.62
East North Central	144,449	.62	143,419	.46
Illinois	143,121	.46	148,032	.57
Indiana	137,202	.28	137,064	.30
Michigan	147,970	.83	143,196	.52
Ohio	138,008	.28	137,844	.26
Wisconsin	139,999	.22	139,648	.24
West North Central	144,187	.75	148,503	.97
Iowa	138,522	.44	138,523	.43
Kansas	147,939	1.00	152,885	1.25
Minnesota	137,792	.16	137,325	.16
Missouri	138,282	.34	138,365	.27
Nebraska	142,010	.69	147,037	1.00
North Dakota	139,722	.49	140,743	.46
South Dakota	139,958	.39	139,897	.38
South Atlantic	151,379	1.35	151,832	1.16
Delaware	150,201	.68	148,691	.66
District of Columbia	143,522	.87	143,132	.92
Florida	151,705	1.45	152,365	1.19
Georgia	147,423	1.95	147,302	2.11
Maryland	150,808	.99	150,405	.90
North Carolina	139,299	.20	139,562	.21
South Carolina	143,047	.77	145,650	1.23
Virginia	151,935	1.15	150,708	1.10
West Virginia	138,933	.34	139,340	.34
East South Central	147,099	2.20	142,119	2.38

Table 3.2
Average Quality of Fuel Oils Burned at US Electric Utilities by Census Division and State, 1999 and 2000

Census Division State	Petroleum			
	1999		2000	
	Average Btu per Gallon	Sulphur Percent by Weight	Average Btu per Gallon	Sulphur Percent by Weight
Alabama	139,111	.31	138,756	.30
Kentucky	138,106	.30	138,875	.29
Mississippi	148,129	2.43	142,569	2.65
Tennessee	138,039	.22	138,175	.25
West South Central	148,135	1.01	143,803	.58
Arkansas	148,484	1.16	149,421	1.44
Louisiana	150,954	1.17	149,335	.89
Oklahoma	138,834	.32	139,130	.41
Texas	138,038	.15	140,509	.30
Mountain	139,018	.23	141,163	.33
Arizona	139,549	.33	141,595	.36
Colorado	135,178	.22	135,151	.30
Idaho	--	--	--	--
Montana	141,000	.50	141,000	.50
Nevada	144,874	.40	146,844	.59
New Mexico	134,722	.10	135,999	.10
Utah	139,220	.12	137,187	.11
Wyoming	139,088	.17	140,104	.15
Pacific Contiguous	139,915	.31	139,153	.52
California	145,548	.25	139,059	.60
Oregon	138,800	.50	138,800	.50
Washington	139,900	.07	140,000	.05
Pacific				
Noncontiguous	149,425	.60	149,715	.63
Alaska	132,349	.29	135,310	.27
Hawaii	149,457	.61	149,716	.63
U.S. Average	150,528	1.12	150,494	1.01

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

4 Current Trends in Air Emissions Control

4.1 Technology Trends

Recent approaches to the control of air emissions from HFO fired power generation plants in North America have been driven by the following factors.

- Regulatory requirements that have imposed more stringent emissions limits.
- The use of emissions trading to enable credits to be purchased to offset emissions from peaking units.
- Emerging drive at the federal level to develop national standards for sulphur in fuel oils.
- The introduction of individual standards at the provincial level in Canada and state level in the northeastern US which regulate the amount of sulphur in heavy fuel oil.
- The availability of natural gas as a co-firing or alternate fuel for dual firing conversions in HFO fired plants.
- Alternate energy sources for power generation associated with clean air.
- Delivered power costs based on natural gas prices have crossed heavy oil prices in real terms and current market trends indicate ongoing volatility.
- The capital intensive cost associated with retrofitting emissions reduction systems.
- Low capacity factors forecast for the remaining life of HFO fired plants.

With reference to the plants described in Section 3, the following applies to the control of particulates and sulphur dioxide emissions.

a. Particulate Emissions:
   i. Fuel change over to a more benign fuel such as natural gas used as a single fuel (Burrard).
   ii. Repowering to combined cycle mode using natural gas (Courtenay Bay Unit 3).
   iii. Dual fuel firing using natural gas or residual fuel oil. The residual fuel oils used are typically low sulphur oils with sulphur contents ranging from 0.3 percent to 1 percent S (Lennox and US plants).
   iv. Cyclone separators or ESPs are used where historical capacity factors and regulatory requirements were the drivers (Primarily US plants and Coleson Cove).
   v. Some plants are effectively grandfathered with no emissions controls systems but they are subject to very limited use primarily for peaking in high demand periods (Courtenay Bay Unit 4 and US plants).

b. SO_2 Emissions

i. Fuel conversion to a single fuel firing using natural gas (Burrard) or Orimulsion™ fitted with a wet FGD system (Coleson Cove conversion).
ii. Fuel switching capability using either natural gas and/or low sulphur fuel oils coupled with the use of SO_2 emissions credits (Lennox and US plants).
iii. Dispatch regime to delegate the fuel oil fired plants to standby and peaking mode supplemented by the use of fuel sulphur content management to meet regulatory emission caps.

4.2 Technology Assessment

4.2.1 Particulate Emissions

Particulate emissions can be reduced by a variety of mechanisms. The practices most commonly used are removal systems as originally built with the plants, such as mechanical cyclone separators and electrostatic precipitators (ESPs), and combustion improvement modifications such as increasing the supply of steam atomizing. In some cases, proprietary additives for fuel oil systems are also used to promote carbon burnout; these have the effect of reducing total particulate emissions. However, although the total particulate emissions may be reduced, the improved combustion may have the effect of increasing the PM_{10} fraction of the total emissions.

4.2.1.1 Electrostatic Precipitators

ESPs include dry ESPs, which are used in either a hot side or cold side configuration, and wet ESPs.

Typical installations currently in use cannot in general meet the emerging requirements for reductions in fine particulate matter. To enhance the performance of existing installations, new technologies are being developed to promote fine particle agglomeration at the inlet side of ESPs that reduce the percentage of fine particulate by agglomeration to particle sizes of 10 micron. Preliminary tests on a 250 MW coal-fired plant indicate up to 70 percent reduction in opacity levels, a 45 percent reduction in outlet dust load, and a reduction in $PM_{2.5}$ fine particulate emissions of more than 50 percent. However, this technology is still considered in the development stage and is limited to enhancing the performance of existing particulate capture systems. Furthermore, due to the generally low forecast use of oil-fired generation, the development of this technology is focused on coal-fired plants.

Retrofitting dry ESPs to each of the units at Holyrood is a realistic option. However, it is not certain that ESPs can readily achieve longer term emergent reductions in fine particulate emissions ($PM_{2.5}$) in particular if the existing combustion system infrastructure is upgraded. Performance enhancements on a base installation of dry ESPs may be a consideration in the event of future requirements to reduce PM_{10} emissions by more than 20 percent. The ability of dry ESPs to provide significant reduction of $PM_{2.5}$ is questionable.

Wet ESPs are also potential solutions for particulate emissions control; however, these are typically more cost effective when combined with wet FGD systems.

4.2.1.2 Fabric Filters

Fabric filters are used in coal fired facilities and are not typically applied to oil fired plants. Their use is driven by a number of factors such as high pressure drop, reduced filter bag life and includes

- Reverse air
- Pulse jet
- Shake/deflate type

The ash produced in fuel oil fired plants is generally carbon rich. Experience in other installations indicates that the ash burns readily when collected in ESP hoppers; this characteristic would further limit the cost effectiveness of fabric filters due to the potential for very high filter bag failure rates.

4.2.1.3 Wet Scrubbers

Wet scrubbers include

- Venturi scrubbers
- Combined SO_2 and particulate collection using either wet lime or wet limestone scrubbing in conjunction with an integral wet ESP.

Unless combined with a wet FGD system for SO_2 removal, the use of scrubbers for particulate emissions control is not considered cost effective.

4.2.1.4 Fuel System Modifications

The particulate emissions report provided by Hydro shows that the emissions from Units 1 and 2 are significantly lower than Unit 3. Unit 3 burners are a steam assisted atomizing type with a reported steam consumption of 0.02 lbs per lb of fuel. It may be possible to improve the emissions from Unit 3 by changing the burners to a steam atomized type using a steam consumption of 0.20 lbs per lb of fuel. The impact of this significantly higher steam flow on the existing infrastructure has not been fully investigated as part of this review and the full impact of the ten-fold increase is unknown; however, it is clear that it would require significant piping changes in the steam supply system. The other impact of such a change would be an increase in the smaller fractions of particulate emissions from Unit 3 despite an overall reduction in total emissions. Thus this approach may not achieve the required objective.

4.2.1.5 Fuel Oil System Additives

A number of fuel additives are marketed for use in heavy fuel oils to reduce gaseous emissions. Such additives are typically proprietary mixes of water and chemicals and are provided in a variety of forms for injection either into the fuel feed or into the furnace. Vendors of such additives claim that they promote improved carbon utilization with reduced gaseous emissions. However, it is unlikely that any additives can achieve the targets set for SO_2 and particulate emissions. Moreover, additives may also have the impact of increasing the small particle fractions of the particulate emissions and thus may not meet the required objective. Potential impact on the existing fueling systems including the MgO injection system would also need to be quantified.

4.2.2 Sulphur Dioxide Emissions

The principal techniques and technologies available in the industry for sulphur dioxide emissions control are

- Fuel conversion from high sulphur HFO to alternate fuels. The bulk of current industry experience has been to convert to natural gas firing or dual fuel NG/HFO firing. However, natural gas is not yet available at Holyrood but could be in the 20-year horizon.

- Fuel switching or co-firing using dual fuel capability, HFO and natural gas. This practice has been adopted by many of the US based HFO fired plants that still have significant load factors. US based plants are generally located in areas where alternative fuels such as natural gas are available and emissions are regulated on a cap and trade basis. These strategies used separately or combined enable the owners to operate on a fleet wide basis within their permitted emissions cap.

- Fuel switching to lower sulphur HFO with a sulphur content in the range of 0.3 to 0.7 percent sulphur. A number of US based plants have been directed to lower sulphur fuel oils through the regulatory permitting process. In Canada, Ontario, Nova Scotia, Quebec and New Brunswick have introduced regulations to limit the maximum sulphur content of fuel oils. In addition, in Ontario, OPG have also adopted the use of fuel oils with sulphur contents in the range of 0.3 to 0.7 percent sulphur.

Other studies have shown that costs of desulphurization of fuel oils can vary widely, depending on the size of the refinery, the degree of desulphurization, the nature of the crude oil, and its cost. Study reports as recently as 1997 refer to estimates as follows in $U.S. (1985):

- Reducing heavy fuel oil from 2.15 to 1.0 percent S; $333/t of SO_2 removed.
- Reducing heavy fuel oil from 1.0 to 0.7 percent S; $722/t of SO_2 removed.

Processes commonly used in coal–fired plants for removing sulphur during combustion such as fluidized-bed combustion or limestone injection, as discussed in the following paragraph, require high-efficiency particulate cleanup systems.

Because the oil-fired plants in North America (Canada and the USA) were mostly developed prior to the mid-1970s, most of these plants were not provided with high efficiency particulate removal systems. Other factors affecting the emissions technology selection have been the forecast short life cycle of these plants coupled with the high capital costs of retrofitting current technologies. As a result, FGD systems are not typically utilized in oil-fired plants in North America. Post-combustion treatment for SO_2 reduction utilizing FGD systems has been reported to add 15 to 20 percent to the total cost of a new power plant, and operating costs for oil-fired plants are reported in the range of 610 to 720 $U.S./t of sulphur removed.

- Sorbent-Alkaline Injection (burners/in-furnace/boiler injection). The process involves direct injection of pulverized limestone, lime or dolomitic lime into the boiler. Reaction products and residual alkali are then removed. Auxiliary equipment similar to FGD systems both for injecting the alkali and removing reaction products is required. This type of system can offer up to 50 percent SO_2 reduction on coal-fired boilers when adequate furnace residence time is available. While it is difficult to predict any degree of success on HFO fired boilers due to the short reaction time available, it may achieve not more than about 25 percent reduction on retrofitted applications. The system is a combustion treatment system with the reaction products traveling through the air preheaters to a necessary back-end particulate removal system. It is not considered a reasonable candidate for Holyrood because of its low probability of achieving 50 percent SO_2 removal and its likely negative impact on air preheater fouling.

- Wet FGD systems retrofitted to existing HFO fired plants. This approach has been implemented in Europe but is not typical in North America due to the limited remaining life of the oil-fired fleet. The capital cost of an FGD system sized for reduction of the SO_2 content of part of the flue gas from all three units at Holyrood to achieve the equivalent of a 50 percent overall reduction is estimated to be approximately 75 percent of the capital cost of an FGD sized to treat all of the flue gas from the three units.

- Dry FGD – Spray Dryer Absorber (SDA) systems. These are commonly applied to low sulphur coal plants in North America. SDAs have a significant disadvantage compared to wet FGDs due to the higher flue gas inlet temperature required for SDAs. The Holyrood plant operates with flue gas exit temperatures from the air preheaters in the range of 290 ^{0}F to 250 ^{0}F. To efficiently use a SDA, an exit temperature of about 350 ^{0}F would be required. Because of the associated loss of heat rate, the potential capital and operating cost of an SDA system, and the lack of experience with such systems on high sulphur fuel oils, this option was not considered further.

4.2.3 Fuel Switching

4.2.3.1 Low Sulphur Fuel Oils

Switching to a lower sulphur fuel oil with one percent sulphur would be a move in the direction to achievement of the objectives of this review. Lower sulphur fuel oils have lower ash content, in the range of 0.06 percent for No. 6 HFO. The ash and asphaltenes content of HFO is source dependent and variations in the supply can directly impact the particulate emissions. Subject to such variations and based on work conducted by the US EPA, it is estimated that reducing fuel sulphur content to one percent would reduce total particulate emissions in the range of 40 percent to 60 percent. With no change to the current particle size distribution profile, the use of a lower sulphur content fuel oil could achieve the objective of 20 percent reduction in PM_{10} emissions.

Although not an objective of this review, it is considered likely that a change to lower sulphur HFO with one percent content maximum would also result in a reduction in $PM_{2.5}$ emissions. Environment Canada has reported that $PM_{2.5}$ emissions comprise a significant fraction, ranging from 30 percent to 50 percent, of the total particulate emissions from the combustion of HFO. Sulphate emissions condensing downstream of the stack are considered a major contributor to $PM_{2.5}$ emissions. On this basis, it is considered that a reduction in fuel sulphur content would also yield a reduction in $PM_{2.5}$ emissions in the range up to about 30 percent.

To achieve a reduction in particulate emissions with lower sulphur fuels, it would be prudent to consider the potential for combustion system improvements particularly for Unit 3 as noted above. This would promote improved carbon burnout and reduce overall particulate emissions. However, it would also have the impact of increasing the fine particle fraction of the total particulate.

4.2.3.2 Natural Gas

The option of switching to a natural gas dual firing configuration to enable Holyrood to adopt fuel strategies similar to those used in Nova Scotia, Ontario and in the US is not currently available. In the event that natural gas becomes available in the region in the next decade, then this option would be viable in the context of the regulatory framework that exists today. Due to the uncertainties in forecasting the potential environmental regulatory requirements over a decade, it seems prudent today to maintain this option for the future. However, it is noted that if the availability of natural gas for co-firing or replacement generation purposes is imminent, it would not be prudent to commit to a major capital expenditure to install emissions reduction technologies based on current fuel usage.

4.3 Comparison of Costs

Table 4.1 shows capital and operating costs for the various technologies/options for emission control. The detail of the capital costs is shown in the spreadsheets attached as Appendix B. The results of a comparative cost analysis of using an FGD with existing fuel type and switching to low sulphur fuel are included in Appendix B. The methodology was based on an evaluated estimate of the incremental cost on net output by using either one percent sulphur fuel oil or alternatively, retrofitting a wet FGD/ESP. Although the comparison is based on identical time periods for ease of relative cost comparison, it is noted that in real terms, a lead time of 2 years would be required to allow for design, procurement and construction of an FGD system. The incremental cost of one percent sulphur fuel oil was based on forecast price differential over the cost of 2.2 percent sulphur; the incremental cost in the case of wet FGD/ESP is based on the estimated capital cost plus the cost of reagent and waste product disposal. The incremental cost of low sulphur fuel is forecast to increase over the period.

The results show that because of the high capital cost of retrofitting an FGD unit, high plant capacity factors are required to make such a retrofit economical. Over the period of the review, it would be more cost effective to switch to low sulphur oil based on a Net Present Worth analysis; see Appendix B. At current capacity factors, the cost increase of net production with an FGD is \$16.65/MWh for 2004; as the capacity factor increases to about 60 percent, the cost impact of the FGD on net production in current dollars falls to about \$12.00/MWh near the end of the period. The net effect of using one percent sulphur oil increases the production cost from \$7.93/MWh in 2004 to \$10.82/MWh in 2020. The cost analysis assumes an operating cost for reagent and waste disposal based on 50 percent sulphur dioxide reduction.

Table 4.1
Summary of Estimated Costs

Technology	Estimated Costs		Comments
	Capital Cost Millions of Can 2003 $	O&M Costs	
Electrostatic Precipitators and Ash Handling system	$48.9	Aux. power 1.2 MW Maintenance $0.25 m per year	Based on in-house data
Wet FGD	$146.5	Aux. power 7 MW Reagent cost $0.86 m per year Waste Disposal $0.94 m per year Maintenance $1.0 m per year	Based on in-house data and recent industry bids. Reagent and waste disposal costs vary with Capacity Factor
Fuel Additives	$0.2 Estimated Allowance	Equipment Rental $36,000 per year Additive Cost $2.60 per tonne	Preliminary costs subject to clarification
Low Sulphur Fuel Oil (1%)	Assumed negligible	$4.95 per barrel (2004 $)	Based on sulphur content of 1% S and ash content < 0.5%

Note:

1. The project costs in the table above assume that the ESP and wet FGD are implemented as separate projects.

5 Anticipated Emissions Regulatory Direction in Canada

This section covers in broad terms the trend and possible direction that the environmental regulatory process may adopt. It is not the intent to provide an in-depth analysis of past and future policies but to focus on providing an overview of the process and paths followed in recent power industry developments.

From a Canadian perspective, air emissions are regulated at the provincial level. Recognizing the trans-boundary issues associated with air emissions, the Federal Government through the Federal Department of Environment, and the Canadian Environmental Protection Act, prepares and issues New Source Emission Guidelines for Thermal Electricity Generation and plays a role in the regulatory review process of any new source through co-operation with provincial regulators. The guidelines are used as a baseline reference for provincial regulators with each province applying the guidelines in accordance with its own policies as indicated by the following extract:

> "The Minister of the Environment recommends that the appropriate regulatory authorities adopt the annexed Guidelines as practical baseline standards for new fossil fuel-fired steam generating units within their jurisdiction. However, local conditions, such as density of industrial development, topography and other environmental considerations, may necessitate the adoption of more stringent requirements than those suggested in these Guidelines. The continual advancement in emission control technologies and strategies should also be taken into account."

From the perspective of Hydro and Holyrood, the most relevant feature of the guidelines is the reference to opportunities that may arise to reduce the emissions from existing facilities. This is highlighted in the scope of the guidelines and is reproduced as follows.

> "The Guidelines are intended to apply to new generating units only. However, it is recognized that opportunities to reduce emissions may arise during major alterations to an existing generating unit. It is therefore recommended that an assessment of the feasibility of emission reduction measures be completed prior to commencing such alterations. This assessment should be undertaken by the owner of the unit in close consultation with the appropriate regulatory authority, and improved emission control measures should be implemented wherever feasible."

The intent expressed in guidelines is that, in the event of any major alterations to a generating unit, the owner would conduct an in-depth assessment of retrofitting emissions reduction systems in conjunction with the provincial regulatory authority. For Holyrood, it is considered that this would include assessment of Best Available Control Technologies (BACT) for particulate and SO_2 emissions reduction. In the event that it is decided to retrofit a particulate reduction system, such an assessment would favour ESPs instead of multi-cyclone to provide for the highest efficiency in particulate removal in lieu of the target 20 percent reduction in PM_{10}. Similarly, in the case of retrofitting an FGD, such an assessment would tend to favour installation of an FGD system sized for up to 95 percent SO_2 reduction even though immediate requirements may be for 50 percent reduction.

Other initiatives driven by Environment Canada related to fuel oils are focused on removal of the sulphur content of the fuel in transportation and other light oils. Extensive feasibility studies have been conducted by Environment Canada leading to the preparation of a discussion paper on Setting Canadian Standards for Sulphur in Heavy and Light Fuel Oils.

Environment Canada has noted that while there is currently no regulated national standard for sulphur in heavy fuel oil, at the provincial and regional level, British Columbia, Ontario, Quebec, New Brunswick and the Montreal Urban Community regulate the sulphur content in heavy fuel oil at various levels ranging from 1.1 percent wt. up to 3.0 percent wt.

In the USA, for heavy fuel oil, the northeastern states have sulphur limits ranging from 0.2 to 2.8 percent wt. predominately 1 percent wt. in urban areas and 2 percent wt. in rural areas. Environment Canada also reports that in the United States, overall about 30 percent of HFO consumed is low sulphur HFO and in the northeastern states, about 40 percent of HFO consumed is low sulphur. In comparison, Canadian statistics indicate that the use of low sulphur HFO is less than 8 percent of all HFO used in Canada.

The Canadian Petroleum Products Institute (CPPI) recommends that Canadian and U.S. standards be consistent when setting sulphur requirements. CPPI are also reported to have stated that it would "*support aligning with standards that may emerge in the USA and Europe.*" It is noted that whereas the countries of the European Union have a pan-national standard, the U.S. does not have a national standard. The U.S. standards are set on a state-by state basis and each state generally has different requirements for fuel oil used in urban and rural areas. Because of this lack of U.S. national standard, Environment Canada has stated that it is focused on the standards of the European Union. These standards are also similar to many of the standards in the northeastern U.S.

The European Union issued a directive in 1999 requiring a reduction of sulphur in HFO to one percent wt. by January 1, 2003. Some countries such as Austria, Denmark and Finland already have in place a limit of one percent wt. sulphur (or less) for HFO.

Environment Canada has also issued a discussion paper presenting a target to achieve a Canadian standard for sulphur in fuel oils of 1.0 percent. Environment Canada has put forward the following issues for input from interested parties.

- Establish the appropriate sulphur level in Canadian fuel oils and the timing for reducing sulphur content
- Types of liquid fuels to be included in the initiative
- Identify any other (non-sulphur) parameters that should be controlled in fuel oils

- Identify which of the following instruments should be considered for use in Canada to reduce sulphur in fuel oils:

    - Tradable Permits
    - Emission trading
    - Product trading
    - Sulphur Taxes
    - Tax differential
    - Product tax
    - Sulphur emission tax
    - Fuel Quality Regulations
    - Combination of Instruments
    - Regulations and tax
    - Regulations and emission trading
    - Tax and emission trading

In summary, it is clear that Environment Canada's near term objective is to set a Canada-wide standard for a maximum of one percent sulphur in heavy fuel oils. It is also noted that some provincial jurisdictions have more stringent standards in place.

6 Summary, Conclusions and Recommendations

The scope of this study was to review, within the constraints identified and the potential future direction for the use of heavy fuel oils, the reasonable options available to Hydro to achieve the following.

- Reduce PM_{10} Particulate Emissions by 20 percent

- Reduce SO_2 Emissions by 50 percent

- Maintain opacity within the proposed permitted limits, i.e., 20 percent on a six minute running average basis not exceeding 25 percent for more than six minutes in any one hour period except for starting a new fire, in which event the limits are not exceeding 40 percent for one six minute period in the first 30 minutes after such new fire is started.

With respect to these parameters, the study indicates the following:

Particulate Emissions
The options considered include

- Fuel switching to 1 percent sulphur fuel oils which would result in lower ash and asphaltenes content. Lowering the sulphur content of fuel oils reduces the asphaltenes content and results in a reduction in particulate emissions. It is anticipated that using a lower sulphur fuel oil of one percent maximum could yield a reduction in total particulate emissions in the range of 40 percent to 60 percent. Assuming that there are no other changes that would impact the particle size distribution of the particulate, it is considered that this would achieve the target reduction of 20 percent in PM_{10} emissions. Depending on the fuel specifications adopted, this could enable the particulate objectives to be met at a lower capital cost. Operating costs would be higher due to the higher cost of fuel.

  Previous studies conducted by others for Environment Canada[3] concluded that reducing fuel oil sulphur content to one percent would lead to a reduction of about 28 percent in fine particulate matter in Atlantic Canada.

- Fuel switching to adopt a natural gas co-firing strategy to reduce emissions. This option may be an appropriate strategy for future consideration if natural gas becomes available in the region. However, if an FGD were installed in the near future to reduce sulphur emissions, this dual-firing option would become economically non-viable.

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[3] Environment Canada: Emissions-Scenario Simulations of Potential Sulphur-Content Reductions for Heavy Fuel Oils and Light Fuel Oils Using the Acid Deposition and Oxidant Model

- Retrofitting mechanical separators to reduce particulate emissions. The best available technology identified may provide up to 32 percent reduction in PM_{10} depending on further more detailed review. However, considering the letter and intent of the federal guidelines, it is considered that this option, if adopted, would trigger a regulatory drive to best available control technologies, such as an ESP.

- Retrofitting an ESP to achieve a minimum 98 percent particulate reduction.

- Proprietary fuel additives that may provide a reduction in total particulate emissions of about 50 to 60 percent. However, such additives may not achieve the required reduction in PM_{10} emissions.

SO_2 Emissions
Based on the current and forecast capacity factors over the time frame of the review, and a reduction in SO_2 levels of 50 percent, retrofitting FGD technology with the current fuel type would be less cost effective than switching to one percent sulphur fuel oil at an incremental cost of approximately $5 per barrel (in 2004) over 2.2 percent sulphur oil. It is also considered likely that a decision to retrofit a Wet FGD system would trigger a requirement to use a BACT approach to achieve the maximum benefit from the system. The potential for near term adoption of a Canada wide standard regulating fuel oil sulphur content to a maximum of 1 percent or lower would also impact on the economics of retrofitting an FGD system when the immediate objective can be achieved by utilizing one percent sulphur fuel oil without the capital cost. The capital cost of achieving 95 percent SO_2 reduction would be similar to that for the target reduction within the estimate accuracy. However, the reagent and waste disposal costs increase proportionately with the required SO_2 capture; as a result the total annual costs for an FGD at this higher reduction rate would be even greater.

Opacity
- Opacity is a function of fuel ash and asphaltene content, combustion efficiency and boiler/air preheater cleanliness. The latter are mitigated by boiler and air preheater cleaning; however, the frequency of cleaning required is also a function of the fuel and combustion characteristics. Managing opacity to the proposed limits may, in general, be achieved by fuel switching to lower sulphur fuel oils or by the adoption of co-firing natural gas in the event it becomes available. If switching to a lower sulphur fuel is adopted, the impact on opacity should be monitored as part of the follow-up operating permit emissions monitoring program to establish the magnitude of the benefit achieved on opacity.

- Retrofitting a Wet FGD system with a wet ESP at the outlet would provide assurance of achieving the opacity targets.

In general, switching to a lower sulphur oil reflects the industry trend in North America as evidenced by the review of a number of plants in Canada and the eastern US. Converting to dual firing with natural gas and oil, or natural gas alone, has also become more evident in recent years in areas where natural gas is available.

With respect to regulatory matters, initiatives currently driven by Environment Canada indicate that the federal regulatory objective is to develop a Canada wide standard for fuel oil sulphur content that is similar to that adopted in the European Union directive of 1999. This directive specifies the use of fuel oil with a maximum sulphur content of one percent except for plants that use best available control technology for sulphur reduction with FGD systems which typically were designed in the early 1990s for a minimum of 90 percent sulphur dioxide reduction. More recent experience has led to requirements for reduction rates of 95 percent as these have proven achievable.

Recommendations

Of the options reviewed and considering the relative costs over the forecast period, it is recommended that Hydro

- adopt the use of fuel oils with one percent sulphur content. This would achieve the objective of a 50 percent reduction in SO_2 emissions using the least cost option as determined by a Net Present Worth analysis as presented in Appendix B.

- review the available improvements in burners and combustion system technologies to optimize the fuel combustion within the existing furnaces.

- undertake follow up testing after the change of fuel is implemented to quantify the reduction in particulate emissions and opacity.

- conduct further investigation on the use of fuel additives for a trial program in the event that additional treatment for particulate reduction becomes necessary.

Appendix A
Fuel and Air Emissions Data
(provided by Hydro)

Fuel oil Deliveries from Tankers 1997-2001

		Vessel	Viscosty SFS	Pour Point F	Vanadiam PPM	Ashphaltenes % Weight	API	Sulphur % Weight	Sodium PPM	Sediment % Weight	Ash % Weight	Water % volume	Quantity bbls	Tanks 1	2	3	4	Btu/lb	density
Jan-97	22	M/T Hydramar			199			2.17					274053	*	*	*			
Feb	10	Nordic Laurta			176			2.18					273331			*	*		
Mar	2	Mehinik Slauter			85			2.17					277073			*	*		
April	16	United Sunrise	221	35	31	7	7.6	1.76	2	0.15	0.05	0.10	263917	*	*				
May	20	Kapitan E. Gorov			59			2.00					252793			*	*		
Oct	15	BT . Nautilus	216	37	71	9	7.8	1.87	10	0.08	0.065	0.57	246706	*			*		
Nov	17	Katitan V. Ivanov			264			1.70					249557	*	*				
Dec	3	Clement			83			2.16					260069			*	*		
Dec	28	MT. Providence			115			2.19					277943		*		*		
Jan-98	27	MT. Nester			103			2.20					272299	*		*			1.0277
Feb-98	3	United Triton			160			2.15					265219		*		*		1.0181
Feb-98	12	United Stella	263	37	222	11	5.8	1.46	17	0.052	0.090	0.30	289878	*	*	*			1.0310
Mar-98	4	M/T Levant	249		219	11	10	1.95	12	0.031	0.066	0.40	259794		*		*		1.0012
Apr-98	8	M/T Nestor			233			2.03					308656	*	*	*			0.979
Apr-98	23	B/T Paean			299			2.15					247684		*	*	*		0.9855
Dec-98	24	M/T Marshal Vavel	209	35	196	11	6.8	2.17	25	0.02	0.090	0.20	261067	*			*		1.0222
Jan-99	24	Vitoria	168	32	280	5	13.3	2.07	10	0.071	0.057	0.05	293824		*	*	*	18455	0.9766
Feb-99	1	Gerol Novarossia	244	27	79	5	11.5	1.80	12	0.039	0.036	0.20	225537		*		*	18360	0.9889
March	5	M/T Kestril	274	27	140	6	11.6	1.60	4	0.011	0.070	0.40	278920	*	*			18319	0.9882
Sep-99	21	M/T Mara	224	28	75	4	5.4	2.18	16	0.076	0.087	0.50	273566	*	*			18561	1.0330
Nov-99	3	M/T Levant	287	32	173	6	11	1.94	16	0.029	0.052	0.03	257270	*		*		18336	0.9924
Dec-99	2	M/T Fidelity	205	40	120	9	5.8	2.16	19	0.100	0.085	0.13	254951					17994	1.0300
Dec-99	21	Seamusic III	84	27	98	6	5.1	2.16	11	0.030	0.066	0.30	293368	160704	124800	7863		17857	1.0352
Feb-00	2	M/T vasileveski	71	18	85	7	5.1	2.01	7	0.055	0.068	0.18	285323			140239	144962	17913	1.0345
February	24	United Triton	175	37	74	5	5.9	1.95	12	0.040	0.060	0.23	240094		160278		79690	17956	1.0292
May	4	Dong Ting Hu	98	20	158	6	5.4	2.17	10	0.050	0.079	0.13	275185	169155			106031	17912	1.033
November	1	Daquing 92	215	37	150	9	5.2	2.18	10	0.090	0.083	0.28	280213		149790.01	130900		17840	1.0345
November	20	M/T Peregrine	254	35	136	8	6.4	2.19	17	0.105	0.080	0.45	275059		11047.9	77983	185905	17891	1.0255
1-Jan	3	M/T Galapagos	300	37	208	11	5.5	2.16	10	0.055	0.086	2.52	181046		135975	44949		17442	1.0322
January	26	M/T Pergerine	329	32	182	10	5.9	2.13	6	0.050	0.078	0.53	286368	181722	104409			17922	1.0292
February	24	Cabo de Hornos	300	26	231	11	9.7	2.01	17	0.040	0.080	0.50	279497		142425	136838		18229	1.0015
March	23	M/T Sea Navarin	234	32	163	11	8.5	1.54	16	0.060	0.065	0.58	**292216**	167288	124688			18111	1.0101
May	1	M/T Peregrine	265	16	277	8	11.1	2.08	8	0.055	0.076	0.50	**222612**		55299	167098		18236	0.9917
May	13	M/T Hobby	107	19	126	5	5.5	2.20	31	0.140	0.092	0.55	**267232**		108435		158565	17722	1.0322
July	31	M/T Egret	169	21	300	6	8.3	1.95	30	0.040	0.095	0.45	**197825**	191661		5958		18043	1.0116
Aug	24	M/T Alkman	97	27	70	4	7.5	2.06	16	0.060	0.060	0.08	**280211**		94886	185325		18128	1.0174
Oct	4	M/T Providence	125	24	45	5	5.8	2.18	24	0.100	0.056	0.90	**290956**	189220	40942		60556	17857	1.0300
Oct	29	Protank Orinico	253	38	42	6	7.2	2.17	25	0.090	0.075	0.52	**277867**			132769	144864	17979	1.0196
Nov	28	Hobby	304	40	55	6	7.3	1.98	14	0.090	0.067	0.20	**291044**	98896	191908			18068	1.0188
Dec	11	Elanora	336	32	90	6	6.0	2.18	24	0.080	0.076	0.12	**281999**			185526	96236	17961	1.0285

Dec	**25**	**Milagro**	292	24	96	5	6.8	2.17	24	0.090	0.083	0.43	**295492**	190372	104879			17987	1.0225
2-Jan	**9**	**Mekanik Slauta**	92	13	59	4	9.7	1.91	**21**	**0.060**	0.060	0.50	305525			140163	165118	18131	1.0020
2-Jan	**26**	**Providence**	101	23	46	8	5.0	1.97	**12**	**0.080**	0.100	0.55	282611	151082	131293			17830	1.0360
2-Feb	**26**	**Providence**	31	-15	22	1	6.0	1.66	4	**0.120**	0.100	0.40	215100			160508	54380	17966	1.0284

Table I Summary of Metals and Sulphate Emission Rates

Metal	Unit 1		Unit 2		Unit 3	
	Average µg/DSm3 c/o 3% O2	Average mg/s	Average µg/DSm3 c/o 3% O2	Average mg/s	Average µg/DSm3 c/o 3% O2	Average mg/s
Aluminum	1941	251	1536	198	1790	225
Antimony	31.6	4.1	26.7	3.4	25.0	3.1
Arsenic	4.2	0.5	3.2	0.4	3.1	0.4
Barium	53.2	6.9	42.1	5.4	48.1	6.0
Beryllium	1.0	0.1	0.9	0.1	0.9	0.1
Cadmium	4.6	0.6	1.7	0.2	1.6	0.2
Chromium	79.2	10.2	23.6	3.0	19.7	2.5
Cobalt	20.0	2.6	16.4	2.1	15.6	2.0
Copper	92.8	12.0	49.1	6.3	38.4	4.8
Iron	2229.1	288.1	1418.8	182.7	1522.6	191.0
Lead	39.7	5.1	24.9	3.2	21.9	2.7
Manganese	122.6	15.9	36.9	4.7	32.5	4.1
Mercury	0.6	0.1	0.6	0.1	0.5	0.1
Molybdenum	254.0	32.8	235.6	30.3	213.9	26.8
Nickel	1356.6	175.3	1131.2	145.6	1008.5	126.5
Phosphorus	506.6	65.5	460.4	59.3	444.7	55.8
Sulphur	1720033	222278	1730046	222740	1669087	222278
Sulphate	44901	5803	46316	5960	27701	3478
Sulphuric Acid Mist	54996	7107	56730	7300	33929	4260
Selenium	5.9	0.8	4.9	0.6	5.7	0.7
Titanium	54.5	7.0	44.6	5.7	44.8	5.6
Vanadium	5105.7	659.7	4724.5	608.3	4728.6	593.5
Total	**1831832**	**236725**	**1842873**	**237259**	**1737355**	**218125**

Table II Particulate Emission Data Summary

Parameter	Units	Unit 1	Unit 2	Unit 3
Date		25-27/10/2001	28-29/10/2001	02-03/11/2001
Particulate Concentration	gr/DScf	0.0593	0.0636	0.1129
	gr/DScf@ 3% O_2	0.0608	0.0666	0.1172
Particulate Concentration	mg/DSm^3	135.63	145.57	258.38
	mg/DSm^3 @ 3% O_2	138.96	152.44	268.30
Emission Rate	g/s	17.955	19.623	33.013
Cumulative % <10μm	g/s	7.898	12.954	14.526
Cumulative % <2.5μm	g/s	6.386	6.281	8.583
Volumetric Flowrate	DSm^3/hr	476743	485145	459707
Sample Volume	DSm^3	1.38	1.43	1.35
Particulate Gain	mg	187.8	207.9	241.5
Moisture	%	10.7	10.7	9.9
Temperature	deg. C	173	170	173
O_2 Concentration	%	3.4	3.8	3.7
CO_2 Concentration	%	14.2	13.9	13.9
Average Isokineticity	%	98.9	100.2	99.9

Table III Gaseous Emission Data Summary

Parameter	Units	Unit 1	Unit 2	Unit 3
Date		25-27/10/2001	28-29/10/2001	02-03/11/2001
O_2 Concentration	%	3.4	3.8	3.7
CO_2 Concentration	%	14.2	13.9	13.9
CO_2 Concentration	%@ 3% O_2	14.5	14.5	14.4
CO Concentration	ppm	1.9	1.7	92.4
CO Emission Rate	g/s	0.2820	0.2565	14.24
CO Concentration	ppm @ 3% O_2	1.9	1.7	96.1
SO_2 Concentration	ppm	1243.6	1208.1	1197.8
SO_2 Emission Rate	g/s	428.46	426.10	422.45
SO_2 Concentration	ppm @ 3% O_2	1274.4	1264.5	1244.2
NOx Concentration	ppm	210.1	227.0	375.9
NOx Emission Rate	g/s	51.96	57.50	95.22
NOx Concentration	ppm @ 3% O_2	214.9	236.3	388.9
Gas Flow	DSm^3/hr	473908	485145	485145

Appendix B
Cost Analysis of FGD vs Low Sulphur Fuel Oil

Holyrood Power Plant

Incremental Cost of Electricity Produced with FGD and 2% S Content in Fuel Oil

Existing Plant Parameters

Plant #1 (175*2) MW	350	MW
Plant #2 (150*1) MW	150	MW
Total Power - Combined	500	MW
Max Annual Energy - Combined @ 8760 Hrs	4,380,000	MWh
Fuel Oil Output/bbl	624	kWh/bbl
Fuel Oil Density	1.02	lb/ft3
One bbl of oil is equal to	42	Gallon
lbs of fuel per kWh	0.57	lbs/kWh

Plant Variable Parameters

% of S in Fuel Oil	2	%
SR Assumed	1.03	
Cost of Reagent Limestone	60	$/ton
Waste Disposal Cost	6	$/ton
SO2 Reduction	50%	
Incremental Station Service Load	1.50%	

Project Costs

EPC	$162,561,373
Owner's Costs	$15,026,074
IDC	$0
Contingency	$17,758,745
Total Project Costs	$195,346,192

Financial Parameters

Project Term (years)	16	years
Capital Spent In First Year	35%	
Capital Spent In Second Year	100%	
Inflation	2.50%	
Debt Interest Rate	8.5%	
Debt Term	16	years
Discount Rate	8.5%	

Operating Costs

Fixed Annum

Labour	$0	$/year
Maintenance	$0	$/year
Administration	$0	$/year
Property Tax	$0	$/year
Insurance	$0	$/year

Variable Annum

Variable Operating (Reagent $/yr @ 50% CF)	$2.50	$/year

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Actual Year		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Project Year			-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Plant Production																				
Maximum Electricity Produced (MWh)			4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000
Gross Capacity Factor (%)			51.6%	40.9%	41.4%	42.6%	44.4%	45.2%	46.4%	47.6%	45.3%	53.7%	54.4%	55.4%	56.6%	57.7%	58.4%	59.2%	60.2%	61.1%
Net Electricity Produced (MWh)			2,259,900	1,790,200	1,814,200	1,867,200	1,946,700	1,980,200	2,033,500	2,086,100	1,985,500	2,354,200	2,381,500	2,428,600	2,477,200	2,527,100	2,559,400	2,594,700	2,635,100	2,677,400
Gross Electricity Produced (MWh)			24,401	1,926,989	1,950,547	2,007,084	2,091,890	2,129,582	2,186,120	2,242,657	2,134,294	2,530,057	2,563,037	2,610,152	2,666,689	2,718,515	2,751,496	2,789,187	2,836,302	2,878,705
Fuel Cost for 2.2% S Fuel	per bbl.		$0.00	$29.20	$28.20	$28.95	$30.40	$31.45	$32.40	$32.90	$33.40	$33.90	$34.40	$34.90	$35.40	$35.95	$36.50	$37.05	$37.60	$38.15
Additional Energy - Station Service 1.5% (MWh)				26,871	27,200	27,988	29,171	29,696	30,485	31,273	29,762	35,281	35,741	36,398	37,186	37,909	38,369	38,894	39,551	40,143
Additional Fuel consumed for increased (1.5%) station service (bbl)				43,063	43,589	44,853	46,748	47,590	48,854	50,117	47,696	56,540	57,277	58,330	59,593	60,751	61,488	62,331	63,384	64,331
Additional Fuel Cost (2.2%S HFO)				$ 1,257,439	$ 1,229,222	$ 1,298,491	$ 1,421,142	$ 1,496,718	$ 1,582,865	$ 1,648,859	$ 1,593,035	$ 1,916,703	$ 1,970,326	$ 2,035,710	$ 2,109,602	$ 2,184,014	$ 2,244,329	$ 2,309,355	$ 2,383,225	$ 2,454,237
Based on Gross Electricity Produced																				
Tons of SO2 per year			279	22,040	22,310	22,956	23,926	24,358	25,004	25,651	24,411	28,938	29,315	29,854	30,501	31,094	31,471	31,902	32,441	32,926
Reagent Tons/year			144	11,351	11,490	11,823	12,322	12,544	12,877	13,210	12,572	14,903	15,097	15,375	15,708	16,013	16,207	16,430	16,707	16,957
O&M Expenses																				
Variable Cost																				
Reagent cost ($/yr)			$8,624	$698,074	$724,273	$763,898	$816,080	$851,554	$896,015	$942,168	$919,059	$1,116,718	$1,159,556	$1,210,394	$1,267,527	$1,324,465	$1,374,046	$1,427,690	$1,488,102	$1,548,108
Waste Disposal Cost ($/yr)			$2,250	$182,143	$188,979	$199,318	$212,934	$222,189	$233,790	$245,833	$239,803	$291,377	$302,554	$315,819	$330,726	$345,582	$358,519	$372,516	$388,279	$403,936
Additional Fuel Cost - Station Service				$1,257,439	$1,229,222	$1,298,491	$1,421,142	$1,496,718	$1,582,865	$1,648,859	$1,593,035	$1,916,703	$1,970,326	$2,035,710	$2,109,602	$2,184,014	$2,244,329	$2,309,355	$2,383,225	$2,454,237
Fixed Cost																				
Fixed Cost ($/yr)			$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655	$4,883,655
Total Operating Expenses			$4,894,529	$7,021,311	$7,026,129	$7,145,362	$7,333,810	$7,454,116	$7,596,325	$7,720,515	$7,635,552	$8,208,452	$8,316,091	$8,445,577	$8,591,509	$8,737,716	$8,860,549	$8,993,216	$9,143,261	$9,289,936
Depreciation - 30 year				$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540	$6,511,540
Interest				$16,604,426	$16,050,945	$15,497,465	$14,943,984	$14,390,503	$13,837,022	$13,283,541	$12,730,060	$12,176,579	$11,623,098	$11,069,618	$10,516,137	$9,962,656	$9,409,175	$8,855,694	$8,302,213	$7,748,732
Total Annual Cost				$30,137,277	$29,588,614	$29,154,366	$28,789,333	$28,356,158	$27,944,887	$27,515,596	$26,877,152	$26,896,571	$26,450,730	$26,026,735	$25,619,186	$25,211,912	$24,781,264	$24,360,450	$23,957,014	$23,550,208
CPW (Jan 2004$)				$27,776,292	$52,910,497	$75,735,686	$96,509,329	$115,367,462	$132,496,143	$148,040,428	$162,034,540	$174,941,658	$186,640,430	$197,249,873	$206,875,044	$215,605,143	$223,513,880	$230,679,260	$237,173,927	$243,058,151
				$243,058,151																
Capital Carrying Charge ($/yr)			$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012	$22,780,012
Incremental Cost of Electricity																				
Net Cost of Electricity ($/MWh)			12.25	16.65	16.43	16.03	15.47	15.27	14.94	14.62	15.32	13.16	13.06	12.86	12.66	12.47	12.36	12.25	12.11	11.98

Holyrood Power Plant

Incremental Cost of Electricity Produced, No FGD and 1% S Content in Fuel Oil

Existing Plant Parameters

Plant #1	(175*2) MW	350 MW
Plant #2	(150*1) MW	150 MW
Total Power - Combined		500 MW
Max Annual Energy - Combined @ 8760 Hrs		4,380,000 MWh
Fuel Oil Output/bbl		624 kWh/bbl
Fuel Oil Density		1.02 lb/ft3
One bbl of oil is equal to		42 Gallon
lbs of fuel per kWh		0.57 lbs/kWh

Plant Variable Parameters

% of S in Fuel Oil	1 %
SR Assumed	1.03
Cost of Reagent Limestone	0 $/ton
Waste Disposal Cost	0 $/ton
SO2 Reduction	0%
Incremental Station Service Load	0.0%

Project Costs

EPC	$0
Owner's Costs	$0
IDC	$0
Contingency	$0
Total Project Costs	$0

Financial Parameters

Project Term (years)	16 years
Capital Spent In First Year	35%
Capital Spent In Second Year	100%
Inflation	2.50%
Debt Interest Rate	8.5%
Debt Term	16 years
Discount Rate	8.5%

Operating Costs

Fixed Annum

Labour	$0 $/year
Maintenance	$0 $/year
Administration	$0 $/year
Property Tax	$0 $/year
Insurance	$0 $/year

Variable Annum

Variable Operating (Reagent $/yr @ 50% CF)	$2.50 $/year

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Incremental Fuel Cost for Low S (1%) Fuel per bbl.		$0.00	$4.95	$5.50	$5.80	$5.80	$5.90	$5.90	$5.80	$5.85
Fuel consumed (bbl)			2,868,910	2,907,372	2,992,308	3,119,712	3,173,397	3,258,814	3,343,109	3,181,891
Incremental Fuel Cost 1%S			$ 14,201,106	$ 15,990,545	$ 17,355,385	$ 18,094,327	$ 18,723,045	$ 19,227,003	$ 19,390,032	$ 18,614,063
Actual Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Project Year		-1	0	1	2	3	4	5	6	7
Plant Production										
Maximum Electricity Produced (MWh)		4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000
Gross Capacity Factor (%)		51.6	40.9	41.4	42.6	44.4	45.2	46.4	47.6	45.3
Net Electricity Produced (MWh)		2,259,900	1,790,200	1,814,200	1,867,200	1,946,700	1,980,200	2,033,500	2,086,100	1,985,500
Gross Electricity Produced (MWh)		2,397,215	1,900,118	1,923,347	1,979,096	2,062,720	2,099,886	2,155,635	2,211,384	2,104,532
Based on Gross Electricity Produced										
Tons of SO2 per year		13,709	10,867	10,999	11,318	11,796	12,009	12,328	12,647	12,036
Reagent Tons/year		0	0	0	0	0	0	0	0	0
O&M Expenses										
Variable Cost										
Reagent cost ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Waste Disposal Cost ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental Fuel Cost 1%S			$14,201,106	$15,990,545	$17,355,385	$18,094,327	$18,723,045	$19,227,003	$19,390,032	$18,614,063
Fixed Cost										
Fixed Cost ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Operating Expenses (1%S Fuel)		$0	$14,201,106	$15,990,545	$17,355,385	$18,094,327	$18,723,045	$19,227,003	$19,390,032	$18,614,063
CPW (Jan 2004$)			$13,088,577	$26,671,830	$40,259,501	$53,315,902	$65,767,577	$77,552,674	$88,506,614	$98,198,388
			$178,470,395							
Capital Carrying Charge ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental Cost of Electricity										
Net Incremental Cost of Electricity ($/MWh) for S=1%		0.00	7.93	8.81	9.29	9.29	9.46	9.46	9.29	9.38

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incremental Fuel Cost for Low S (1%) Fuel per bbl.	$5.95	$6.05	$6.15	$6.25	$6.35	$6.45	$6.55	$6.65	$6.75
Fuel consumed (bbl)	3,772,756	3,816,506	3,891,987	3,969,872	4,049,840	4,101,603	4,158,173	4,222,917	4,290,705
Incremental Fuel Cost 1%S	$ 22,447,901	$ 23,089,864	$ 23,935,721	$ 24,811,699	$ 25,716,482	$ 26,455,337	$ 27,236,034	$ 28,082,396	$ 28,962,260
Actual Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Project Year	8	9	10	11	12	13	14	15	16
Plant Production									
Maximum Electricity Produced (MWh)	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000	4,380,000
Gross Capacity Factor (%)	53.7	54.4	55.4	56.6	57.7	58.4	59.2	60.2	61.1
Net Electricity Produced (MWh)	2,354,200	2,381,500	2,428,600	2,477,200	2,527,100	2,559,400	2,594,700	2,635,100	2,677,400
Gross Electricity Produced (MWh)	2,494,776	2,527,296	2,573,754	2,629,503	2,680,606	2,713,127	2,750,293	2,796,751	2,838,562
Based on Gross Electricity Produced									
Tons of SO2 per year	14,267	14,453	14,719	15,038	15,330	15,516	15,729	15,994	16,233
Reagent Tons/year	0	0	0	0	0	0	0	0	0
O&M Expenses									
Variable Cost									
Reagent cost ($/yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Waste Disposal Cost ($/yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental Fuel Cost 1%S	$22,447,901	$23,089,864	$23,935,721	$24,811,699	$25,716,482	$26,455,337	$27,236,034	$28,082,396	$28,962,260
Fixed Cost									
Fixed Cost ($/yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Operating Expenses (1%S Fuel)	$22,447,901	$23,089,864	$23,935,721	$24,811,699	$25,716,482	$26,455,337	$27,236,034	$28,082,396	$28,962,260
CPW (Jan 2004$)	$108,970,679	$119,182,989	$128,940,059	$138,261,856	$147,166,672	$155,609,675	$163,620,879	$171,233,923	$178,470,395
Capital Carrying Charge ($/yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental Cost of Electricity									
Net Incremental Cost of Electricity ($/MWh) for S=1%	9.54	9.70	9.86	10.02	10.18	10.34	10.50	10.66	10.82

		#6 0.7%s ($Cdn/bbl)	Delta vs 2.2% ($Cdn/bbl)	#6 1.0%s ($Cdn/bbl)	Delta vs 2.2% ($Cdn/bbl)	#6 2.2%s ($Cdn/bbl)	Diesel ($Cdn/l)	Diesel ($Cdn/bbl)
2003						32.70	0.363	$57.76
2004	$6.15	35.35	$6.15	34.15	$4.95	29.20	0.333	$52.90
2005	$6.75	34.95	$6.75	33.70	$5.50	28.20	0.326	$51.84
2006	$7.10	36.05	$7.10	34.75	$5.80	28.95	0.326	$51.77
2007	$7.25	37.65	$7.25	36.20	$5.80	30.40	0.325	$51.63
2008	$7.30	38.75	$7.30	37.35	$5.90	31.45	0.334	$53.15
2009	$7.40	39.80	$7.40	38.30	$5.90	32.40	0.345	$54.85
2010	$7.15	40.05	$7.15	38.70	$5.80	32.90	0.354	$56.34
2011	$7.25	40.65	$7.25	39.25	$5.85	33.40	0.360	$57.20
2012	$7.35	41.25	$7.35	39.85	$5.95	33.90	0.365	$58.07
2013	$7.45	41.85	$7.45	40.45	$6.05	34.40	0.371	$58.96
2014	$7.55	42.45	$7.55	41.05	$6.15	34.90	0.377	$59.86
2015	$7.70	43.10	$7.70	41.65	$6.25	35.40	0.382	$60.78
2016	$7.80	43.75	$7.80	42.30	$6.35	35.95	0.388	$61.70
2017	$7.95	44.45	$7.95	42.95	$6.45	36.50	0.394	$62.64
2018	$8.05	45.10	$8.05	43.60	$6.55	37.05	0.400	$63.59
2019	$8.20	45.80	$8.20	44.25	$6.65	37.60	0.406	$64.56
2020	$8.30	46.45	$8.30	44.90	$6.75	38.15	0.412	$65.54
2021	$8.45	47.20	$8.45	45.60	$6.85	38.75	0.421	$66.92
2022	$8.55	47.95	$8.55	46.35	$6.95	39.40	0.430	$68.32
2023	$8.70	48.75	$8.70	47.10	$7.05	40.05	0.439	$69.76
2024	$8.85	49.60	$8.85	47.95	$7.20	40.75	0.448	$71.23
2025	$9.00	50.40	$9.00	48.70	$7.30	41.40	0.457	$72.72
2026	$9.15	51.25	$9.15	49.55	$7.45	42.10	0.467	$74.25
2027	$9.30	52.10	$9.30	50.35	$7.55	42.80	0.477	$75.81
2028	$9.45	52.95	$9.45	51.20	$7.70	43.50	0.487	$77.40
2029	$9.65	53.90	$9.65	52.05	$7.80	44.25	0.497	$79.03
2030	$9.80	54.80	$9.80	52.95	$7.95	45.00	0.508	$80.69
2031	$9.95	55.70	$9.95	53.85	$8.10	45.75	0.518	$82.39
2032	$10.15	56.70	$10.15	54.75	$8.20	46.55	0.529	$84.12

Note: 1. Product prices reflect landed values on Avalon Peninsula.
2. Diesel represents No. 2 distillate gas turbine fuel.

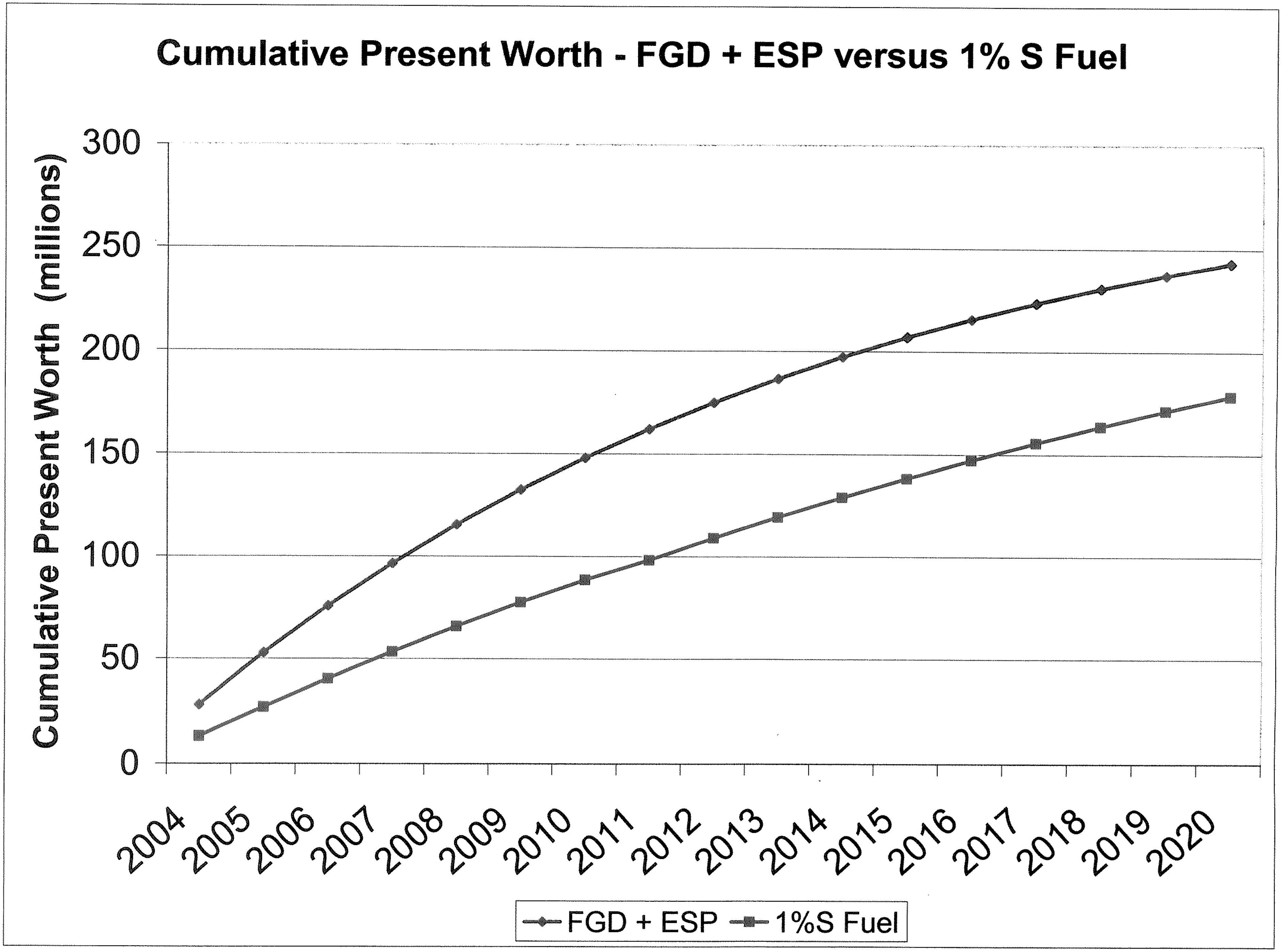
Source: 2002-2010 - PIRA Energy Group, Oil Price Forecasts, 12/23/02 & 01/08/03
2011-2032 - PIRA Energy Group and NLH Economic Analysis Section

27-Jan-03

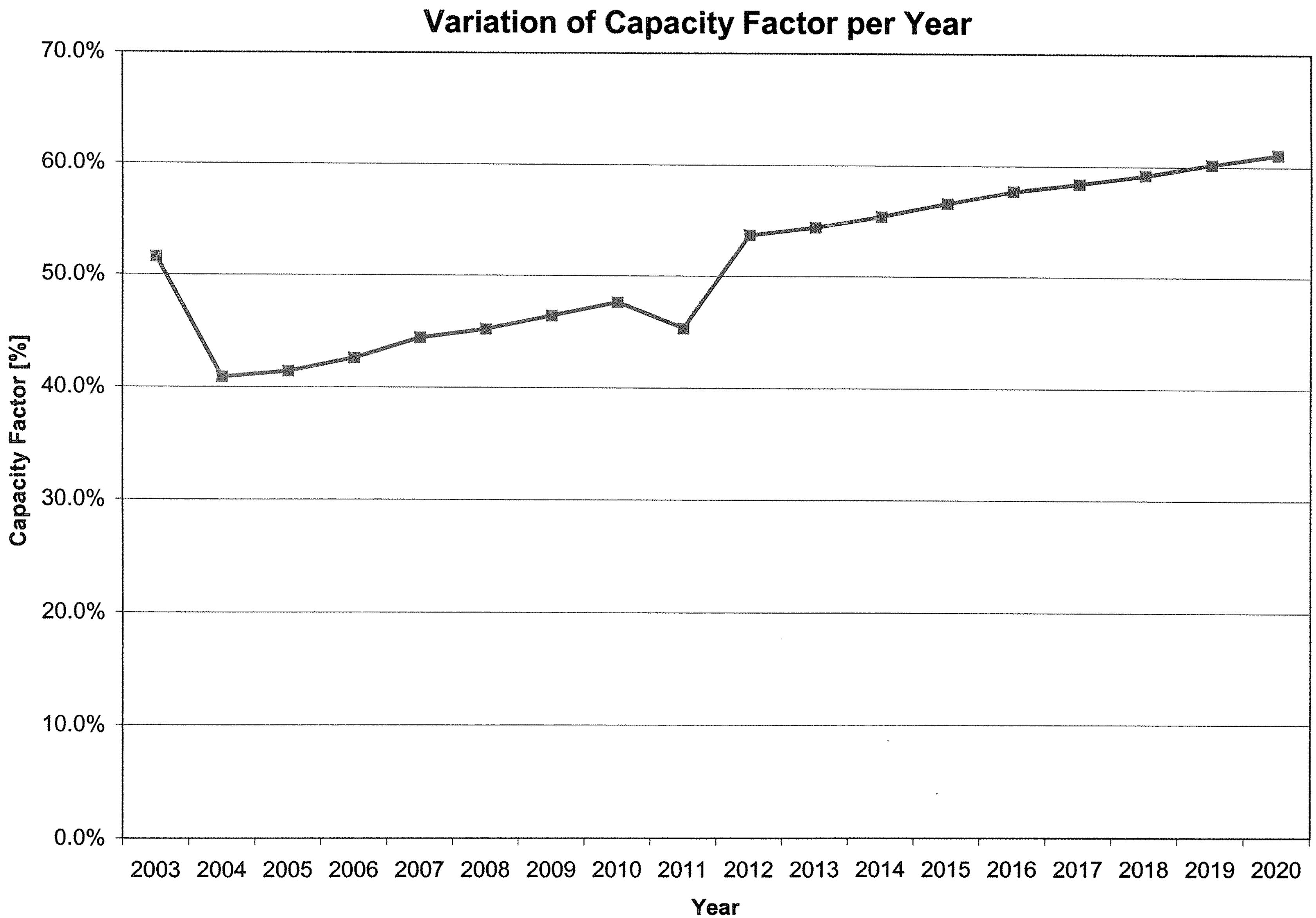
	Net Incremental Cost of Electricity ($/MWh)			
Year	2% S with FGD	1% S no FGD	0.7%S no FGD	Capacity Factor
2003	12.25	0.00	0.00	51.6%
2004	16.65	7.93	0.00	40.9%
2005	16.43	8.81	0.00	41.4%
2006	16.03	9.29	0.00	42.6%
2007	15.47	9.29	0.00	44.4%
2008	15.27	9.46	0.00	45.2%
2009	14.94	9.46	0.00	46.4%
2010	14.62	9.29	0.00	47.6%
2011	15.32	9.38	0.00	45.3%
2012	13.16	9.54	0.00	53.7%
2013	13.06	9.70	0.00	54.4%
2014	12.86	9.86	0.00	55.4%
2015	12.66	10.02	0.00	56.6%
2016	12.47	10.18	0.00	57.7%
2017	12.36	10.34	0.00	58.4%
2018	12.25	10.50	0.00	59.2%
2019	12.11	10.66	0.00	60.2%
2020	11.98	10.82	0.00	61.1%

Holyrood Annual Production (GWh)

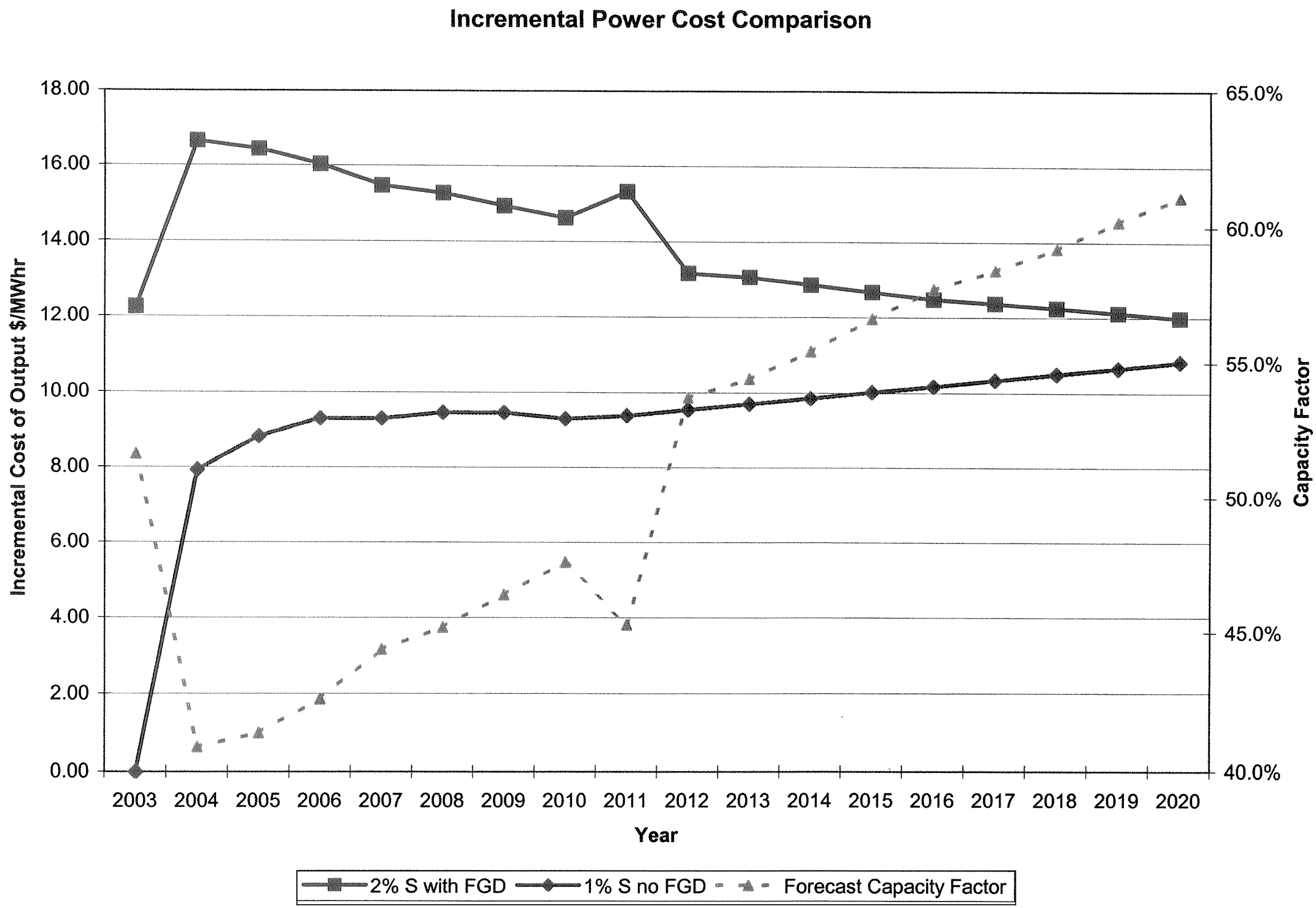
	Actual			Forecast		
	Net	Gross	Difference %		Net	Gross (est)
1990	1839.7	1947.1	5.52%	2003	2259.9	2378.6
1991	1436.2	1524.6	5.80%	2004	1790.2	1901.7
1992	1706.2	1812.5	5.86%	2005	1814.2	1927.2
1993	1558.9	1661.1	6.15%	2006	1867.2	1983.5
1994	776.9	839.8	7.49%	2007	1946.7	2067.9
1995	1533.1	1627.0	5.77%	2008	1980.2	2103.5
1996	1403.6	1493.1	5.99%	2009	2033.5	2160.1
1997	1531.3	1625.4	5.79%	2010	2086.1	2216.0
1998	1263.3	1343.5	5.97%	2011	1985.5	2109.2
1999	919.8	993.3	7.40%	2012	2354.2	2477.9
2000	970.3	1040.5	6.75%	2013	2381.5	2506.6
2001	2098.5	2218.6	5.41%	2014	2428.6	2556.2
2002	2385.3	2510.6	4.99%	2015	2477.2	2607.3
				2016	2527.1	2659.9
		Average =	6.07%	2017	2559.4	2693.8
				2018	2594.7	2731.0
				2019	2635.1	2773.5
				2020	2677.4	2818.1



Cumulative Present Worth - FGD + ESP versus 1% S Fuel
Cumulative Present Worth (millions)
300
250
200
150
100
50
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
FGD + ESP
1%S Fuel


Variation of Capacity Factor per Year
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Capacity Factor [%]
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Year

Incremental Cost per MWhr

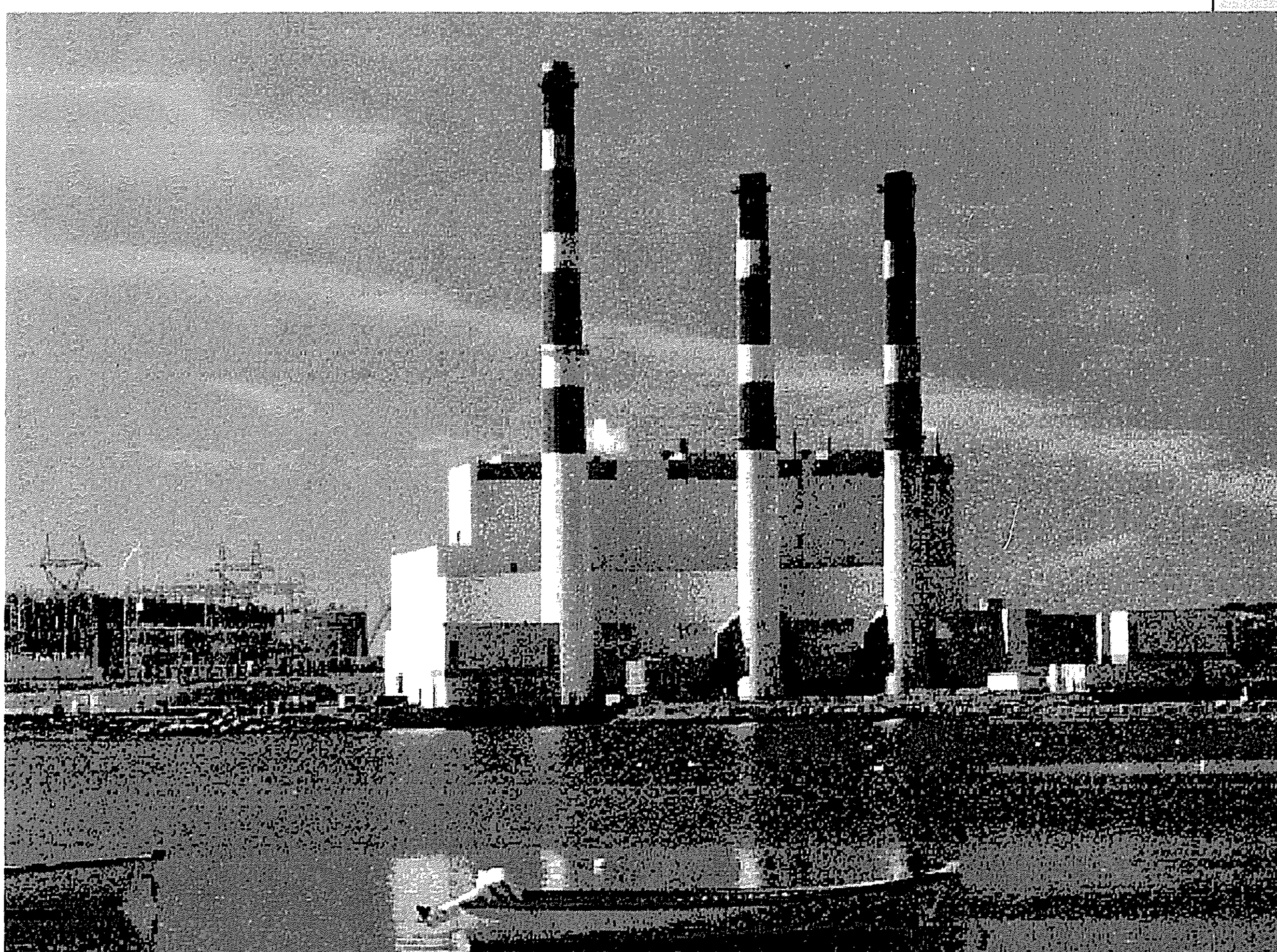


IC-28 NLH
Attachment 2
NLH 2007 CBA

Newfoundland & Labrador Hydro
Holyrood Generating Station Units 1, 2 & 3

PHASE I - Engineering Study for Investigation of Methods to Improve Emissions

ALSTOM Ref: 40233000
November 12, 2002



ALSTOM Canada Inc.

An Engineering Study for:

Newfoundland & Labrador Hydro
Holyrood Generating Station

For:

PHASE I - Investigation of Methods to Improve Emissions on Units 1, 2 and 3

Revision 1 November 12, 2002 *Study Number 40233000*

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1. INTRODUCTION

1.1. EXECUTIVE SUMMARY

ALSTOM Canada Inc. (ALSTOM) has completed this Phase I Report of an Engineering Study for Newfoundland and Labrador Hydro to evaluate alternative low emissions technologies for the three (3) units at Holyrood Generating Station.

In preparing this report ALSTOM considered a wide range of technologies, involving both the boilers, and potential backend equipment which were relevant to Newfoundland & Labrador Hydro's (N&L Hydro) Holyrood Generating Station. These various technologies also cover a wide band of cost options to consider.

ALSTOM has experience with, and confidence in all of the technologies discussed in the body of this report. The performance and environmental predictions presented in this study were calculated using ALSTOM's proprietary sizing and prediction models based on our global technology lead center standards and experience.

The report is separated into three (3) technical sections, specifically 1) fuel changes, 2) firing system technologies for the boiler, and 3) capture technologies through back end equipment. Each technology is discussed technically, followed by presentation of the predicted performance of the system, and then finally a scope description of the recommended equipment arrangement selected to achieve this performance.

Specifically, impacts on emissions for reduced sulfur and asphaltene oils have been included. Firing Systems modifications to reduce NOx emissions including, burner tuning, low NOx burners, low NOx burners with Overfire Air, and urea-based Selective Non-Catalytic Reduction (SNCR) have been evaluated. Particulate capture technologies including Mechanical Collectors, Electrostatic Precipitators (ESP's), as well as Dry & Wet Flue Gas Desulfurization (DFGD & WFGD) have been evaluated. The feasibility of applying each technology to the Holyrood site has been investigated, and in most cases, the physical limitations are presented.

Where possible, performance prediction tables present emission results in consistent units typical to those used in the stack testing reports (NOx, SOx in ppm & particulate in mg/DSm^3). In some cases the results are presented using more than one set of industry acceptable units. When multiple units are presented, those units identified above are highlighted in blue for clarity.

Finally, order of magnitude pricing and equipment delivery spans are presented for each of the equipment options, as well as a very general presentation on the impact these technologies would have on operating and maintenance costs at the station.

The study concentrates primarily on the impacts to NOx, SOx and Particulate, however the capture technologies also impact the removal efficiency of other emissions as shown in the following table, although these are not investigated in detail within this report.

	SOx	NOx	Particulate	CO	Metals	Acid Aerosols
Mechanical Collector	None	None	50%	None	Some	None
ESP	None	None	92.30%	None	Some	None
DFGD	95%	None	99% +	None	Some	Good
WFGD	98%	None	30 - 50% (max)	None	Some	Poor

Table 1-1: Capture Technology Removal Efficiencies

Of particular interest to N&L Hydro, is the comparative performance of each capture technology with respect to particulate fractioning. As a general rule:

- a mechanical collector will not collect particulate 2.5 microns or below
- a dry ESP will collect particles well at or above 10 microns, and will collect some particles at or below 2.5 microns, but not as efficiently as the larger particles (reference Appendix E for some relevant data on particle size distribution of particulate leaving a precipitator)
- a DFGD/Baghouse will be better at collecting particulate at or below 2.5 microns, and is the most efficient of the four capture technologies discussed at collecting fine particulate
- a WFGD is a poor particulate collector and will not do well with particulate at or below 2.5 microns

In recent years ALSTOM and N&L Hydro have reviewed in detail the operation of the 3 units at this site, and these reviews have confirmed that the units are operating very efficiently. Over the past few years improvements have been made to maintenance and outage work, equipment has been upgraded (such as the modifications to Unit 3 reheater surface in 2001), and engineering studies, completed and ongoing, continue to investigate opportunities to further improve the operation of the plant.

Some technologies have not been addressed in this report such as seawater scrubbers, or particulate screens. With respect to seawater scrubbers, it is our opinion that this is not a technology well suited to the Holyrood site due to permitting difficulties with the technology. To date, ALSTOM have not formally bid this technology to a North American customer. Presentations have been made to customers concerning the technology, but there is some concern on getting an environmental permit for the technology. It appears that the issue is more one of perception than fact. The perception is that with a sea water scrubber, waste gasses are being pumped into the sea, and this is an environmental problem. In reality, the waste gasses contain basically the same chemical components that are already in the sea, and so there is not the environmental hazard that people perceive. Despite the differences between perception and fact, to date no customer has felt comfortable with trying to permit the new technology.

With respect to particulate screens, which has been discussed between Alstom and N&L Hydro in the past, although the capital costs may not be significant, the reduction in particulate, although measurable, would not likely be visible out of the stacks. For this type of solution it is very difficult to predict the reduction efficiency without first looking at the feasibility from a physical standpoint (i.e. reviewing the existing ducting layout, and identifying the area best suited for flow directional changes and ash removal.) If an area exists which is suited, flow modeling would then be required to assist in predictions on particle fallout, possibly for more than one arrangement. This is beyond the scope of this study, and would be a separate study unto itself.

Some solutions such as converting the units to burn natural gas, or orimulsion fuels, or adding larger stacks for wider dispersal of emissions were not considered or discussed in the report. Conversion to natural gas is not feasible at this time since there is no gas supply infrastructure to support it. In consultation with the customer, it was decided not to include an assessment of the benefits of conversion to orimulsion fuel. N&L Hydro has already completed some economic analysis of this alternative. The option of using larger stacks for wider dispersion of the present emissions was not considered since this report deals specifically with the reduction of emissions exiting each unit. While higher stacks will offer better dispersion and ground level concentration profiles, they will not reduce the total emissions leaving the plant.

1.2. UNIT DESCRIPTION

1.2.1. Holyrood Units 1 and 2

Newfoundland & Labrador Hydro (N&L Hydro) Units #1 & #2 at Holyrood Generation Station are duplicate, 1970 vintage 150 MW, oil-fired boilers originally designed and built by Combustion Engineering (now ALSTOM). The boiler was designed to generate an MCR main steam flow of 1,050,000 lb/hr at an outlet temperature of 1005°F and a pressure of 1900 psig, with a feed-water inlet temperature of 468°F. The MCR design condition for the reheater was a flow of 921,000 lb/hr at an inlet temperature of 690°F and a pressure of 518 psig, with an outlet temperature of 1005°F. These two units were modified in approximately 1987 by ALSTOM to achieve an increased output of approximately 175 MW. The resulting revised steam conditions are an MCR main steam flow of 1,167,000 lb/hr at an outlet temperature of 1005°F and a pressure of 1955 psig, with a feed-water inlet temperature of 464°F, with a reheater flow of 1,045,000 lb/hr at an inlet temperature of 667°F and a pressure of 493 psig, with an outlet temperature of 1005°F.

1.2.2. Holyrood Unit 3

Unit #3 at Holyrood Generation Station is a 1980 vintage 150 MW, oil fired boiler originally designed and built by Babcock and Wilcox. Unit #3 was designed to generate an MCR main steam flow of 960,600 lb/hr at an outlet temperature of 1,005°F and a pressure of 1890 psig, with a feed-water inlet temperature of 464°F. The MCR design condition for the reheater was a flow of 865,700 lb/hr at an inlet temperature of 683°F and a pressure of 487 psig, with an outlet temperature of 1,005°F. ALSTOM has modified the reheater of unit #3 in 2001, but this modification has been done with the intent of achieving the originally intended boiler performance while providing improved reheater material protection.

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2. FUEL CHANGES

2.1. FUEL VARIATIONS AND SPECIFICATIONS

This section investigates the effect that sulphur and asphaltene content in the fuel has on the flue gas emissions from the Holyrood units. Generally fuel oil sourcing (pricing) information is a customer activity, and as such was not addressed in this report. However, ALSTOM would be able to comment on the impacts of different fuel specifications should they be provided by N&L Hydro. For example, evaluating the costs and effects of changing from a current fuel oil containing approximately 2.2 % Sulphur to one containing approximately 1.6 or 1.2 % Sulphur.

2.1.1. Fuel Oil Variations

The fuel specification used by N&L Hydro can have a significant impact on flue gas emissions from the Holyrood Units. The fuel sulfur level directly impacts flue gas SO_2 emissions. The oil ash level as well as oil asphaltene content directly impacts flue gas particulate emissions levels leaving the boiler. This boiler exit particulate level will then directly impact both the design and operations of any flue gas particulate removal equipment.

Table 2-1 below shows actual current and predicted sulfur emissions for several differing levels of fuel oil sulfur contents.

Holyrood Sulfur Emissions										
	BTU/lb ?? Oil HHV	Oil sulfur %	Asphaltenes %	Average Economizer Outlet O_2	Predicted SO_2 Emissions Lb/10^6 Btu	Predicted SO_2 Emissions mg/DSm^3 @3% O_2	Predicted SO_2 Emissions ppm @ 3% O_2	Predicted SO_3 Emissions ppm @ 3% O_2	Unit No. 1 Actual Average SO_2 Emissions ppm @ 3% O_2	Unit No. 2 Actual Average SO_2 Emissions ppm @ 3% O_2
Unit #1	17,824	2.184	3.7	0.7	2.4506	3,770.7	1,318.4	39.6	1,274.4	1,264.5
Alternate Oil 1	17,824	1.8	3.7		2.0197	3,107.7	1,086.6	32.6		
Alternate Oil 2	17,824	1.2	3.7		1.3465	2,071.8	724.4	21.7		

Table 2-1: Predicted Sulfur (SO_x) Emissions

Predicted particulate varies related to the fuel composition as well as to operating conditions. Low NOx operations can increase particulate emissions due to the processes required for low NOx combustion. These effects include low excess air operation, staged combustion, control of fuel and air mixing as well as flue gas re-circulation if so equipped. The effects of low NOx combustion on particulate emissions is reported on elsewhere in this report. This section describes the effects on particulates that changes in fuel composition and/or fuel specification can have on particulate emissions.

Next is Table 2-2, showing actual particulate emissions data from the Holyrood Units as well as predicted changes to particulate levels for a change in fuel asphaltene content.

		Holyrood Particulate Loading Oct. & Nov. 2001 test results Baseline "As Found"						
		Asphaltines %	Average Economizer Outlet O_2	Average gr/DScf	Average gr/DScf @3% O_2	Average mg/DSm^3	Average Lb/10^6 Btu	Average mg/DSm^3 @3% O_2
Actual	Unit #1	3.7	0.7	0.0593	0.0608	135.63	0.08830	138.96
Actual	Unit #2	3.7	1.2	0.0636	0.0666	145.57	0.09477	152.44
Actual	Unit #3	3.7	0.4-0.7	0.1129	0.1172	258.38	0.16821	268.3
Predicted Baseline	Unit #1	11	0.7		0.1781	373.73	0.24	385.63
Predicted Baseline	Unit #2	11	1.2		0.1951	409.38	0.27	422.42
Predicted Baseline	Unit #3	11	0.4-0.7		0.3434	720.42	0.47	743.35

Table 2-2: Predicted Particulate Emissions from Boiler with Varying Asphaltene Content

Figure 2-1 on the next page is a graph which shows the predicted impact and/or change in particulate loading due to fuel oil Asphaltene content.

For the purposes of sizing the Electrostatic Precipitator, an asphaltene content of approximately 8% was used since there was a concern over the relatively low actual asphaltene % measured (3.7%), compared to the contract limit in the current fuel spec (11%). As an example of the impact that asphaltene content has on equipment selection, if the sizing of the Electrostatic Precipitator selected in this report assumed an asphaltene content of 3.7% (instead of 8%), the ESP size would reduce to a size of 3*30M-152-135-A2 (compared to the size noted in Section 4.2.3 of this report). This would be a reduction of 26.7% and would reduce the ESP capital cost quoted in Section 5.1.1 of this report by approximately 10% (or $600,000.00 CDN per unit). Therefore in order to efficiently and cost effectively select final equipment sizes, it may be necessary to tighten up the fuel purchasing specification first to ensure equipment can handle the worst case scenario, but at the same time not result in overly conservative sizing of this equipment.

With respect to the Flue Gas Desulfurization equipment, a more in-depth study would have to be conducted to determine the size variation due to asphaltenes. This investigation is outside the scope of this study phase.

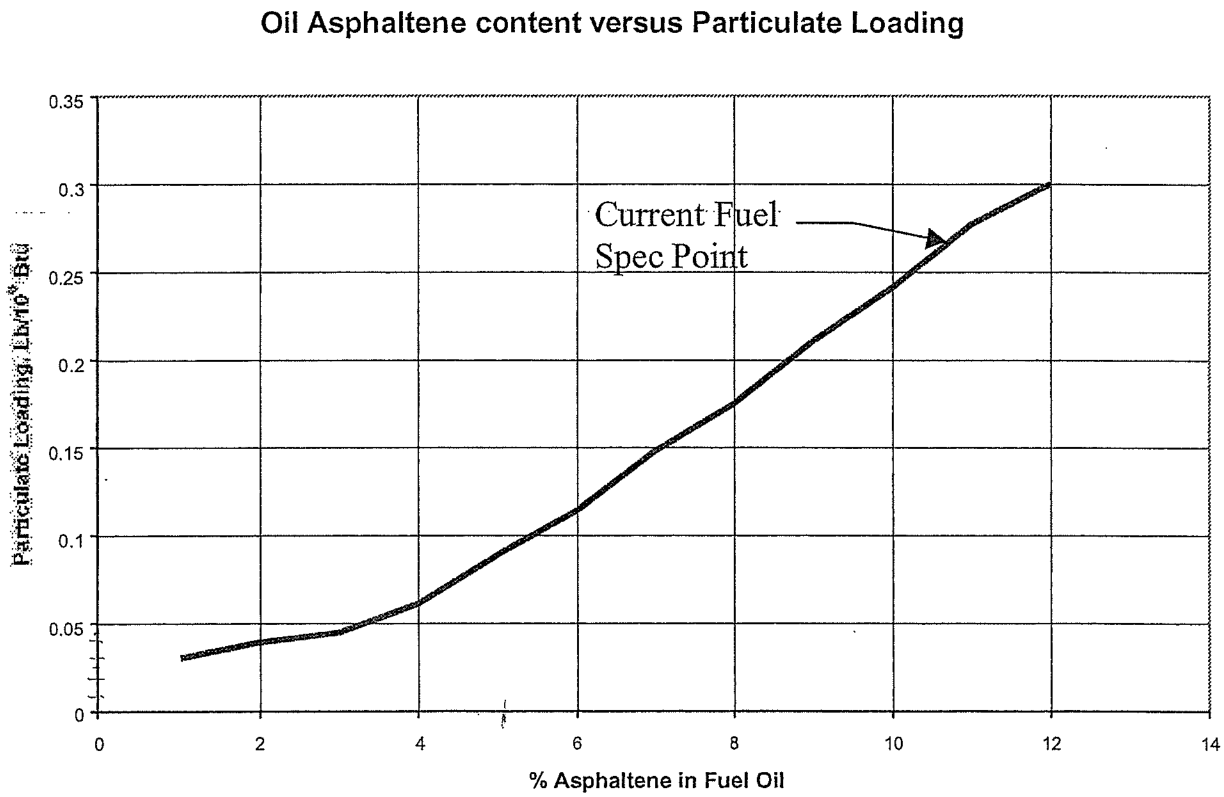


Figure 2-1: Predicted impact and/or change in particulate loading due to fuel oil Ashpaltene content

Sulphur content also has an impact on the boilers Average Cold End Temperature (ACET). Figure 2-2 shows this impact for a range of oil sulphur contents. As general rule of thumb, you typically see a 1% boiler efficiency change for every 40 degrees F change in airheater flue gas outlet temperature. Therefore, boiler efficiency improves as oil sulphur content is lowered, and this efficiency results in cost savings.

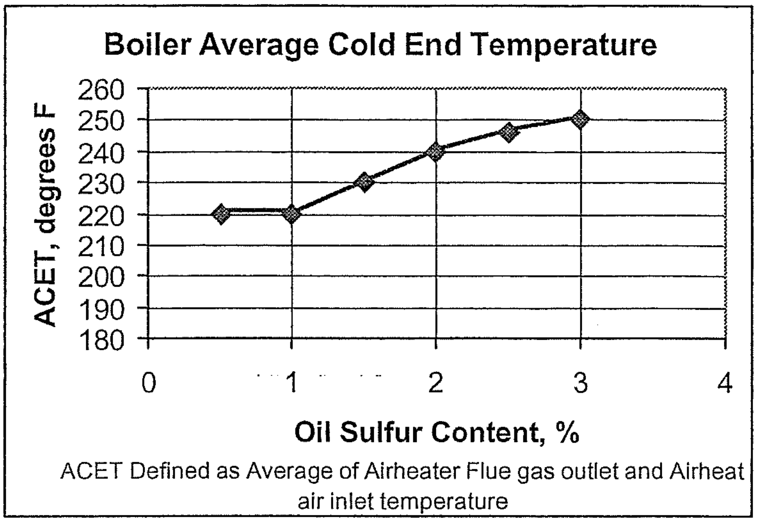


Figure 2-2: Predicted impact and/or change in ACET due to fuel oil sulphur content

Maintaining the flue gas temperature approximately 25 degrees F above the Acid dew point is the goal of the ACET limit. The Acid dew point is affected by the SO_3 level in the flue gas. The previous Table 2-1, included a column showing the predicted SO_3 level based upon changes in the % sulphur in the fuel oil. The following curve in Figure 2-3 shows the change in Acid dew point as a function of SO_3 level.

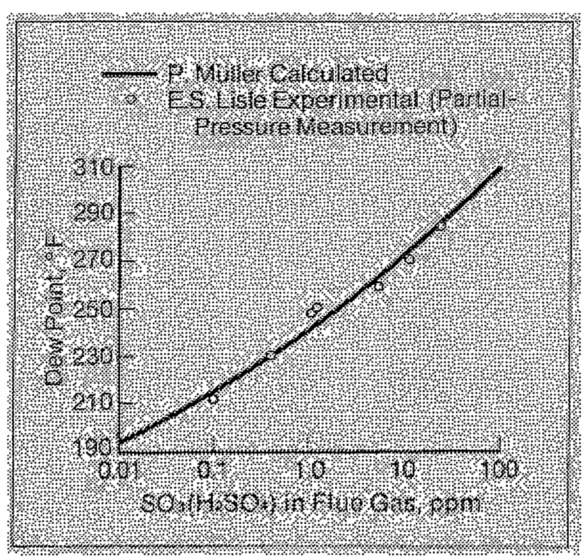


Figure 2-3: Dew point as a function of SO_3 concentration

There are other parameters in addition to the two main parameters (sulphur and asphaltenes) discussed earlier. The following is a general discussion on some of the others, however, no specific analysis was performed as part of this report.

Water: Lower sulfur oils typically contain lower water content on a raw basis, however, shipment method (e.g. barge shipment) will dominate and control final water content. Water content directly impacts boiler efficiency, but because of its low value is typically still a minor impact. More importantly, water content can dictate the design and operation of the fuel handling equipment due to freezing and corrosion.

Heating Value: More refined lower sulfur oil typically has a lower heating value due to lower specific gravity. Thus, additional low sulfur oil may be required for equivalent energy output. Heating values can change from about 150,000 Btu/gallon for high sulfur heavy residual Bunker "C" oil down to about 145,000 Btu/gallon for low sulfur light residual No. 4 or No. 5 oil.

Viscosity: Lower sulfur oils typically have lower viscosity and require lower storage, pumping and firing temperatures. Preheat temperature may decrease from about 220 degrees F to 180 degrees F depending on the viscosity change.

Vanadium: Vanadium in oil is a source for high temperature corrosion. Vanadium content in oil is strongly dependent on oil source, with South American oils typically having higher vanadium content. Oil additives may be necessary for high vanadium oils to control high temperature corrosion. More refined lower sulfur oils typically have lower vanadium content but the controlling variable is more likely the raw crude source.

3. FIRING SYSTEM TECHNOLOGIES

3.1. LOW NOx TANGENTIAL FIRING SYSTEM OPTIONS FOR UNITS 1 AND 2

3.1.1. Technical Discussion

3.1.1.1. Introduction

Holyrood Units No. 1 & 2 are tangentially fired units designed with three (3) oil elevations. ALSTOM discusses below the possibility of reducing NOx emissions through Low NOx Tuning of the existing system, as well as two (2) potential optional Low NOx configurations: an In-Windbox Low NOx firing system and a Separated Overfire Air (SOFA) based Low NOx Bulk Furnace Staging (LNBFS) Level II system to address N&L Hydro's request for assessing potential low NOx emissions on its units. Refer to Appendix C for an experience list of Tangentially-fired Low NOx retrofits supplied on oil and gas boilers. Note that the two system options are separate options and are not intended to be done in a phased approach.

It should be highlighted that Low NOx tuning is not the same as tuning the unit for efficiency. There can be a performance penalty when attempting to improve NOx emissions. For example, Low NOx tuning and/or the In-Windbox Low NOx option will have negligible impact on boiler efficiency. However, the SOFA based Low NOx option may decrease boiler efficiency by about 0.25% due to typical increase in excess O_2 of about 0.5-1.0% O_2.

3.1.1.2. Low NOx Tuning of Existing System

Based on a review of existing data and tests conducted at Holyrood #1 & #2, a reduction in NOx emissions to about 195-203 ppm (0.25-0.26 $Lb/10^6$ Btu), or about 12%, may be possible with tests/tuning efforts from a base current emissions level of 210-234 ppm (0.27-0.30 $Lb/10^6$ Btu) NOx.

The goals of these tuning efforts would be to maximize the amount of airflow to the upper portions of the existing windboxes and to minimize the amount of air near the fuel. This can be accomplished by increasing the boiler windbox pressure, to the extent possible without approaching fan limitations, while operating with the top end air compartments full open and the lower windbox compartments pinched closed. In addition, an assessment of decreasing the air near the oil fuel could be done by closing the secondary air dampers in the fuel compartments (reducing fuel air). Decreasing total unit excess oxygen levels is a typical method employed to reduce NOx emissions. At Holyrood Units #1 and #2 further reductions in unit excess oxygen and/or NOx emissions with this method would be slight if at all because the units currently operate at about 1% excess O_2.

To accomplish the above, a parametric tuning effort (varying different parameters in a test matrix) should be conducted with the following variables to be analyzed, to determine optimum NOx emissions with the existing equipment.

- Air bias to top (2 or 3 compartments) of windbox via opening upper compartment(s) dampers and closing lower compartment(s) dampers.
- Selectively closing Fuel Oil compartment dampers forcing additional air to upper compartments. (Note: Fuel compartment dampers maintain modulation, but the stroke is limited to "full open" being redefined as somewhere between 15 and 50% depending on ignition points and changes to emissions)
- Operate with the whole top tier of Burners-Out-of-Service (BOOS).
- Increase windbox-furnace pressure differential (up to FD fan limits) for the above conditions to force additional air to upper windbox.

Note that as part of a previous study (Ref ALSTOM Study No. 40133001), some boiler optimization tuning was performed on Units 1 and 2 in April of 2001. This tuning exercise did investigate, among other things, the effect of increased windbox delta-P, and burner tilt on opacity and efficiency, but it did not specifically address the redistribution of air vertically in the windbox, as discussed above.

3.1.1.3. In-Windbox Low NOx Option

The main windbox modifications will be limited to resizing the nozzle tips only. The top end air tips will be converted to operate as a Closed Coupled Overfire Air (CCOFA) elevation with a single, straight air nozzle tip. All three (3) oil compartments will be downsized with new oil and bulbous straight air nozzle tips. Each oil nozzle tip will come with a new extension cone. The auxiliary air and bottom end air compartments will also have the new bulbous style air nozzle tips. All nozzle tips will be fabricated from 309 stainless steel.

The Bulbous nozzle tip body incorporates design features to minimize uncontrolled air when tilting. Traditional air/oil nozzle tips allow a significant portion of air to bypass the tip when in full up or down tilt positions. In some cases, this can result in tip damage due to the reduced airflow through the tip. The Bulbous design includes a flared back bulbous shape to maintain similar air gaps over the entire tilt range. Controlling the air gaps and minimizing "uncontrolled" air, forces air into the tip as it tilts, resulting in improved tip life and improved emissions. Figure 3-1 illustrates the Bulbous features as applied to air and gas nozzle tips. The concept is similar when applied to oil nozzle tips.

The existing oil guns, ignitors, and scanners will be reused.

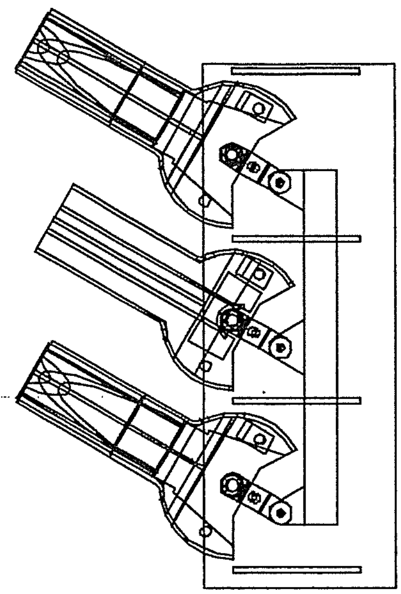


Figure 3-1: Example of Bulbous Air and Gas (similar for Oil) Nozzle tips.

Another important component of the LNBFS Low NOx Burner System is the Vaned Close-Coupled Overfire Air System (VCCOFA), which is installed in the top most air compartment of the main windbox (top end air compartment). The existing air nozzle tips are removed and a set of fixed vanes is installed into this compartment to optimize the amount and injection angle of the close-coupled air. An illustration of the new Vaned Close-Coupled Overfire Air (VCCOFA) arrangement is shown in Figure 3-2 below.

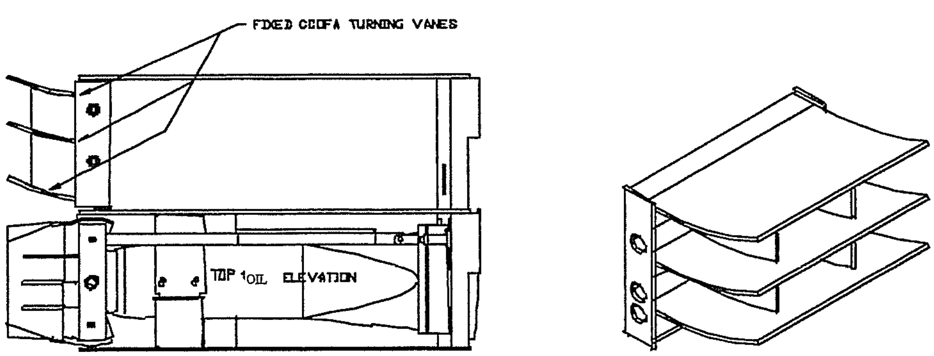


Figure 3-2: Vaned Close Coupled Overfire Air (VCCOFA™)
(conceptual - upper compartment only is applicable to Holyrood units)

Notes: There must be an independent damper drive installed to all of the VCCOFA compartments in order to for the system to function as intended. That is, the VCCOFA compartment damper drive typically operates as a function of boiler load instead of windbox-furnace differential.

NOx reductions of about 15-20%, to approximately 179-195 ppm (0.23-0.25 Lb/10^6 Btu) NOx, may be possible with the above In-Windbox NOx reduction option.

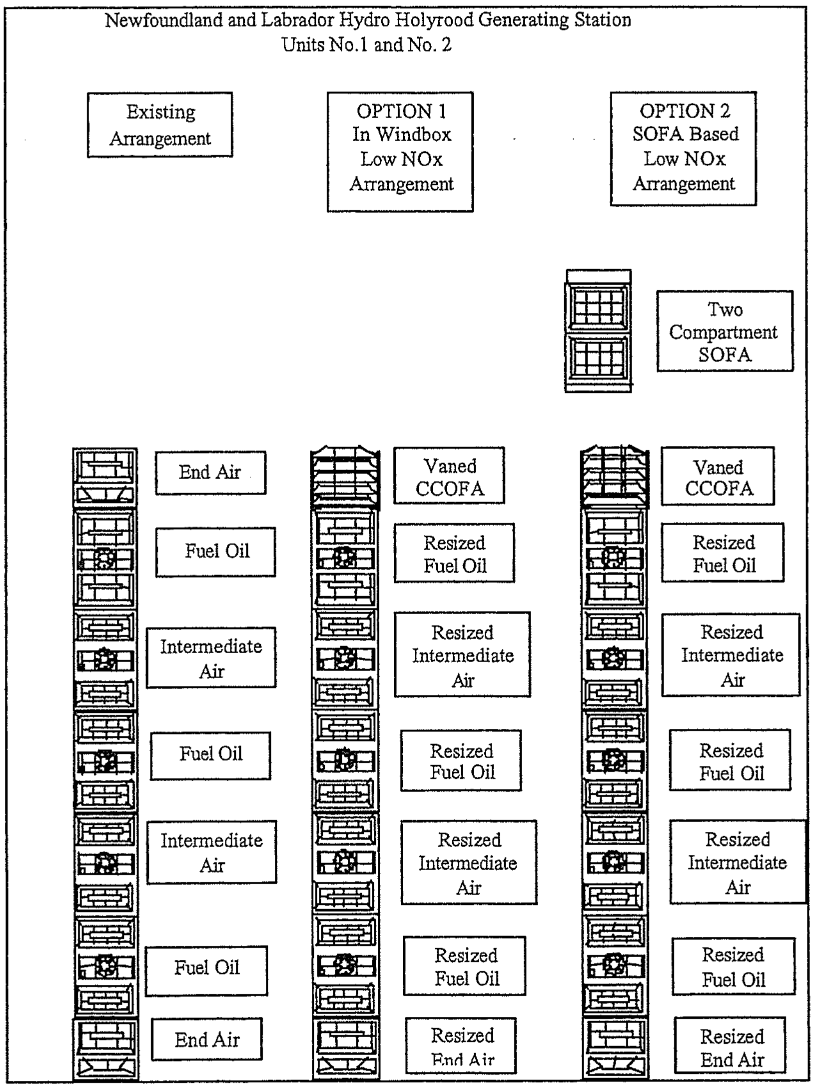


Figure 3-3: Schematics of Low NOx Options
(detail of compartments are typical and may not be representative of all units)

3.1.1.4. SOFA Based Low NOx Option

For the installation of a Separated Overfire Air (SOFA) System it is important to downsize the main windbox nozzle tips. This is necessary to ensure good jet velocities and mixing of the fuel and air from the main windbox is maintained upon the addition of about 20-25% additional nozzle area from the SOFA system. The main windbox modifications will be limited to resizing the nozzle tips only. The top end air tips will be converted to operate as a CCOFA elevation with a single, straight air nozzle tip. All three (3) oil compartments will be downsized with new oil and bulbous straight air nozzle tips. Each oil nozzle tip will come with a new extension cone. The auxiliary air and bottom end air compartments will also have the new bulbous style air nozzle tips. All nozzle tips will be fabricated from 309 stainless steel. A conceptual illustration of the new windbox arrangement is shown in Figure 3-4.

The existing oil guns, ignitors, and scanners will be reused.

The SOFA elevation will consist of ductwork and a total of four (4) registers located above the main windboxes. For Holyrood Units #1 & #2, due to limitations in space on the rear corners of the units, the SOFA registers will be located with two (2) SOFA windboxes on the front two corners of the unit and the remaining two (2) SOFA windboxes on the sidewalls near the rear of the unit partially up the rear wall arch. These four (4) SOFA windboxes will be at the same boiler elevation of approximately 65 feet. Each SOFA register will be 38.5" tall and 18" wide with two (2) distinct SOFA compartments. Each compartment (or elevation) will be equipped with its own set of airflow control dampers independently controlling airflow. The airflow will be controlled on an elevation basis via dampers equipped with pneumatic or electric drives (customer selection based on preference versus cost). The fabricated 309SS material SOFA nozzles normally have tilting capability via a tilt system actuated by independent drives.

The SOFA nozzle tips have adjustable horizontal (yaw) capability. This permits field setting of the nozzle tips to achieve the best mixing of the overfire air stream and furnace gasses, thus getting the best benefit of the staged combustion. Both laboratory and field testing has shown that the yaw capability is extremely valuable for maximizing NOx reduction while minimizing CO and carbon loss. The yaw mechanism allows for manual setting of the horizontal nozzle position, while the unit is online, to customize the most appropriate setting for NOx and boiler performance. Once the best setting is achieved, the yaw mechanism is locked in position. The intent of the yaw is that it is used during initial set-up only; it is not intended as a continuous control mechanism.

NOx reductions of about 40-45% to approximately 117-148 ppm (0.15-0.19 $Lb/10^6$ Btu) NOx may be possible with the above SOFA based Low NOx option.

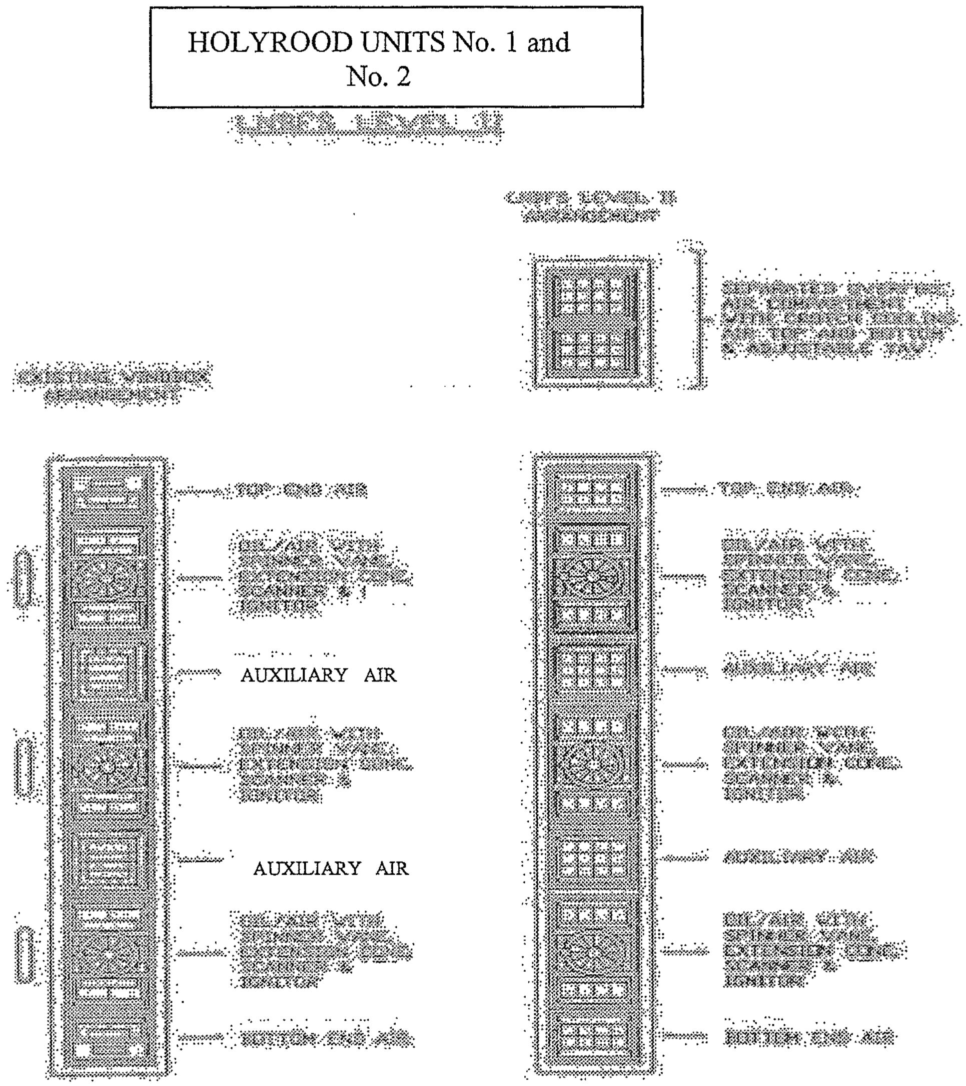


Figure 3-4: Conceptual Windbox Arrangement

The SOFA windboxes are connected to the existing secondary air system through the new ductwork arrangement. The overfire air connecting ductwork will be constructed of 3/16" A-36 carbon steel, externally stiffened. All duct bracing, hangers, and hardware is usually provided within the scope of SOFA system.

3.1.2. Performance

3.1.2.1. Performance Predictions

Following the completion of the installation of the equipment for the selected tangentially fired low NOx options ALSTOM predicts the following:

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 1: In-windbox NOx control (VCCOFA)		
	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3
Unit No.1	215	0.276	424	202.8	0.26	400	187.2	0.24	370
Unit No.2	236	0.303	466	202.8	0.26	400	187.2	0.24	370

Table 3-1: Predicted NOx Emissions for Low NOx Tuning followed by Option 1

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 2: SOFA & Burner NOx control		
	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3	ppm @ 3% O2	Lb/10^6btu	mg/Nm^3
Unit No.1	215	0.276	424	202.8	0.26	400	132.6	0.17	262
Unit No.2	236	0.303	466	202.8	0.26	400	132.6	0.17	262

Table 3-2: Predicted NOx Emissions for Low Nox Tuning followed by Option 2

		Holyrood Particulate Loading Oct. & Nov. 2001 test results							Predictions	
		Baseline "As Found"							NOx Control Option 1 In-Windbox	
		Asphaltenes %	Average Economizer Outlet O_2	Average gr/DScf	Average gr/DScf @3% O_2	Average mg/DSm^3	Average Lb/10^6 Btu	Average mg/DSm^3 @3% O_2	Predicted Average mg/DSm^3 @3% O_2	Predicted Average gr/DScf @3% O_2
Actual	Unit #1	3.7	0.7	0.0593	0.0608	135.63	0.088295	138.96	152.86	0.0669
Actual	Unit #2	3.7	1.2	0.0636	0.0666	145.57	0.094766	152.44	167.68	0.0733
Predicted Baseline	Unit #1	11	0.7		0.1781	373.73	0.24	385.63	424.19	0.1959
Predicted Baseline	Unit #2	11	1.2		0.1951	409.38	0.27	422.42	464.66	0.2146

Table 3-3: Predicted Particulate Emissions Leaving Boiler for Option 1
(Prior to any Flue Gas Cleanup Equipment)

		Holyrood Particulate Loading Oct. & Nov. 2001 test results							Predictions	
		Baseline "As Found"							NOx Control Option 2 SOFA	
		Asphaltenes %	Average Economizer Outlet O_2	Average gr/DScf	Average gr/DScf @3% O_2	Average mg/DSm^3	Average Lb/10^6 Btu	Average mg/DSm^3 @3% O_2	Predicted Average mg/DSm^3 @3% O_2	Predicted Average gr/DScf @3% O_2
Actual	Unit #1	3.7	0.7	0.0593	0.0608	135.63	0.088295	138.96	173.70	0.0760
Actual	Unit #2	3.7	1.2	0.0636	0.0666	145.57	0.094766	152.44	190.55	0.0833
Predicted Baseline	Unit #1	11	0.7		0.1781	373.73	0.24	385.63	482.04	0.2227
Predicted Baseline	Unit #2	11	1.2		0.1951	409.38	0.27	422.42	528.02	0.2439

Table 3-4: Predicted Particulate Emissions Leaving Boiler for Option 2 (Prior to any Flue Gas Cleanup Equipment)

Comments:

Unit No. 2, operating at a slightly higher excess oxygen level, and higher baseline existing NOx level served as the basis for the predicted NOx levels for both units No. 1 and No. 2.

Note that in respect to opacity, Low NOx technology can negatively increase opacity. Opacity is strongly related to the type and efficiency of back-end particulate removal equipment. Opacity also has so-called "dark" and "light" opacity consisting of particulates and SO_3 emissions, respectively. These "dark" and "light" opacity levels can change at different rates depending on the low NOx technology employed. However, all of ALSTOM's Low NOx projects have been able to maintain oil opacity levels to below 10%. Because opacity is a function of so many variables, changes in opacity have been difficult to quantify. Opacity is indirectly related to particulates and we have observed that opacity changes have been typically less than particulate changes, which have been predicted above.

3.1.3. *Materials and Services*

The following is a listing of the major equipment included within the scope of the Low NOx Firing for the Holyrood Units #1 & #2. *Note:* Quantities are for one (1) unit.

3.1.3.1. In-Windbox Low NOx Modifications – OPTION 1

Item	Quantity	Description
1.	Twelve (12)	Single piece oil nozzle tip with extension cone fabricated from 309 stainless steel.
2.	Twenty-four (24)	Single piece oil compartment straight air nozzle tip fabricated from 309 stainless steel.
3.	Sixteen (16)	Single piece auxiliary air nozzle tip fabricated from 309 stainless steel, complete with horizontal links and pivot pins and bearings. (Note that each existing compartment height requires 2 tips)
4.	Four (4)	Single piece bottom end air nozzle tip fabricated from 309 stainless steel, complete with horizontal links and pivot pins and bearings.
5.	Four (4)	Single piece VCCOFA nozzle tip (former top end air) fabricated from 309 stainless steel.
6.	N/A	Drawings and instruction manuals to incorporate the above equipment.

3.1.3.2. SOFA Based Low NOx Modifications – OPTION 2

Item	Quantity	Description
1.	Twelve (12)	Single piece oil nozzle tip with extension cone fabricated from 309 stainless steel
2.	Twenty-four (24)	Single piece oil compartment straight air nozzle tip fabricated from 309 stainless steel
3.	Sixteen (16)	Single piece auxiliary air nozzle tip fabricated from 309 stainless steel, complete with horizontal links and pivot pins and bearings. (Note that each existing compartment height requires 2 tips)
4.	Four (4)	Single piece bottom end air nozzle tip fabricated from 309 stainless steel, complete with horizontal links and pivot pins and bearings.
5.	Four (4)	Single piece VCCOFA nozzle tip (former top end air) fabricated from 309 stainless steel
6.	Four (4)	16" wide SOFA windboxes complete with tilt and damper components
7.	Eight (8)	Single piece SOFA horizontal adjustable offset nozzle tips fabricated from 309 stainless steel
8.	Eight (8)	Hagan 2 ½" x 5" SOFA damper drives
9.	Four (4)	SOFA tilt drive
10.	Four (4)	SOFA waterwall tube panels with casing
11.	Four (4)	SOFA ductwork including expansion joints and hanger rods to connect from secondary air duct
12.	N/A	Drawings and instruction manuals to incorporate the above equipment

3.1.4. Work Not Typically Included

Material Scope Not Included

1. Main windbox restoration materials including tilt mechanisms and drives, dampers and drives, etc.
2. Scanner or ignitor repair or upgrades
3. Gas or oil system repair or upgrade
4. Balance of Plant materials
5. Control system modifications
6. Airflow monitoring devices*
7. Asbestos Abatement
8. Insulation and Lagging

* Note that airflow monitoring devices have only shown to offer limited benefit. More important is a good indication (full grid) of O_2/CO and NOx at the economizer outlet.

3.2. LOW NOx WALL FIRED SYSTEM OPTIONS FOR UNIT 3

3.2.1. Technical Discussion

3.2.1.1. Introduction

Holyrood Unit No. 3 is a wall fired unit consisting of nine (9) burners. Two (2) Low NOx modification options have been discussed in this study in addition to NOx reductions via tuning of existing equipment. For the first Low NOx equipment option, ALSTOM would supply nine (9) new Radially Stratified Flame Core (RSFC™) burners per unit for Holyrood Unit No.3. For the second Low NOx equipment option ALSTOM would supply the above RSFC™ burners and in addition a Separated Overfire Air (SOFA) system would also be supplied in conjunction with the burners. Refer to Appendix C for an experience list of Wall-fired Low NOx retrofits we have supplied..

In reviewing the new burner selection, it appears the burners will fit into the existing windbox and waterwall openings, based on the advised 41-inch minimum pressure part opening. There also appears to be no interference internally in the windbox, such as buckstays, truss work, etc. that would inhibit the burner installation. Existing scanners and ignitors will be reused. Material would be included to allow mounting of these components on the new burners.

Note that it is feasible to perform the two system options discussed in a phased approach, and add a SOFA air system to the unit at a later date; however, it is important to understand that combustion performance may not be optimum. In order to burn a given quantity of fuel, a specific amount of air is needed to combust the fuel properly. Without overfire air the unit injects the air through the burners, which are designed to evenly distribute the required air throughout the furnace. This design philosophy is used to produce optimal velocity and pressure drop through each burner in order to achieve ideal fuel-to-air mixing ratios and unit turndown. When an overfire air system is installed, it takes a large percentage of the secondary air from the main windbox and redirects it to a different location. With this reduction of airflow through the burners, the velocity drastically decreases and combustion performance suffers. Keeping this in mind, should an overfire air system be installed at a later date, the equivalent area of the overfire air ports must be removed from the burner registers. Typically, the area is removed by installing block-off plates in the air registers; however, experience has shown that burners modified in this manner do not perform as well as those designed with a system approach. As such, if further NOx reduction is anticipated, ALSTOM strongly recommends designing the new burners in conjunction with overfire air as a system rather than modifying the registers and installing overfire air separately at a later date.

Similar to the comment in Section 3.1.1.1, for a wall fired unit, Low NOx tuning is not the same as tuning the unit for efficiency. And similarly, there can be a performance penalty when attempting to improve NOx emissions. For example, Low NOx tuning and/or the RSFC™ burner option will have negligible impact on boiler efficiency. However, the SOFA based Low NOx option may decrease boiler efficiency by about 0.25% due to typical increase in excess O_2 of about 0.5-1.0% O_2.

3.2.1.2. Low NOx Tuning of Existing System

Holyrood Unit No. 3 has 9 existing B&W burners arrayed in a 3x3 matrix on the front wall. Based on current NOx emissions levels of 389 ppm (0.5 Lb/10^6 Btu) NOx, it is predicted that parametric tuning and atomizer replacement could reduce NOx emissions to about 351 ppm (0.45 Lb/10^6 Btu), or about 11%. For wall fired boilers, the burner-to-burner mixing (just one parameter in the parametric tuning) is significantly less than for tangential firing. Thus, the matching and balancing of burner fuel and air flow distributions is more important for minimum particulate and NOx emissions as well as operating with minimum excess air. Also, as discussed in the previous sections on Units No 1 and No. 2, NOx can be reduced by biasing fuel to lower burners in the furnace while biasing the air to the top of the windboxes.

To accomplish the above a parametric tuning effort (varying different parameters in a test matrix) should be conducted with the following variables to be analyzed to determine optimum NOx emissions with the existing equipment.

- Burner-to-burner mixing Air Balance Assessment
- Air bias to top burner row of windbox via opening upper burner row dampers and closing lower burner rows dampers.
- Selectively closing Primary Air (inner swirl) dampers forcing additional air to Secondary Air (outer swirl).
- Operate with the whole top tier of burners out (BOOS).
- Increase windbox-furnace pressure differential (up to FD fan limits) for the above conditions to force additional air to upper burner row.

3.2.1.3. Wall Fired Burner Low NOx Option

The RSFC™ burner is an exciting new technology designed for low NOx emission and is proven successful in firing oil, gas, and coal on varying boiler designs around the world. The RSFC™ acronym stands for Radially Stratified Flame Core, which describes the unique flame structure that is at the heart of this burner design. The burner's three (3) air zones allows for a highly managed air/fuel mixing. The RSFC™ burner design allows it to be optimized to satisfy various drivers including emissions, efficiency, and turndown. Additionally, to reduce burner maintenance all movable linkage on the RSFC™ burner has been mounted externally, allowing operators to troubleshoot and maintain the burner while the unit is on line.

Description of the RSFC™ Burner Technology

The RSFC™ burner is designed primarily for low NOx emissions and also achieves reductions in CO and Opacity. Additionally, the RSFC™ burner design allows it to be optimized by the commissioning engineer to satisfy various other drivers including efficiency, flame stability, and turndown. To reduce burner maintenance, all movable linkage on the RSFC™ burner has been mounted externally, allowing operators to determine where problems exist while the unit is on line.

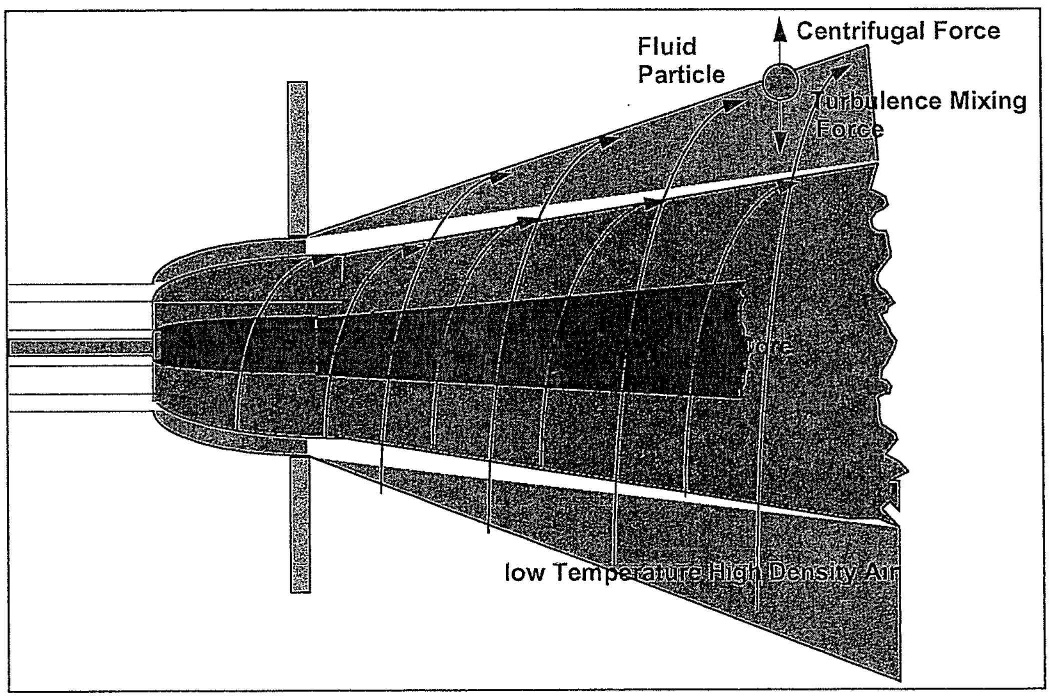


Figure 3-5: RSFC™ Radial Stratification

Many wall-fired burners employ swirling flows to enhance mixing in the near-burner flow region. The RSFC™ burner is different in that swirling flow is used to create the opposite effect, namely the delay of mixing in the near-burner zone. It is this combination of a near burner, high-temperature, fuel-rich core followed by a downstream, fuel-lean combustion zone that creates the low NOx combustion conditions generated by the RSFC™ burner. The conceptual Low NOx RSFC™ burner flow field is depicted in Figure 3-5.

The RSFC™ achieves this flame pattern in a unique manner. The delay in mixing is achieved through stratification between the fuel jet and the surrounding, swirling combustion air. The stratification of the flame depends on turbulence and turbulent mixing dampening at the flame/air interface. The fuel enters along the centerline of the burner and is surrounded by three (3) separate air annuli of strongly swirling air as shown in Figure 3-5. The fuel jet penetrates into the central fuel-rich recirculation zone where the centrifugal forces of the swirling air pull the fuel jet apart and begin to mix the fuel with hot recirculated flue gas.

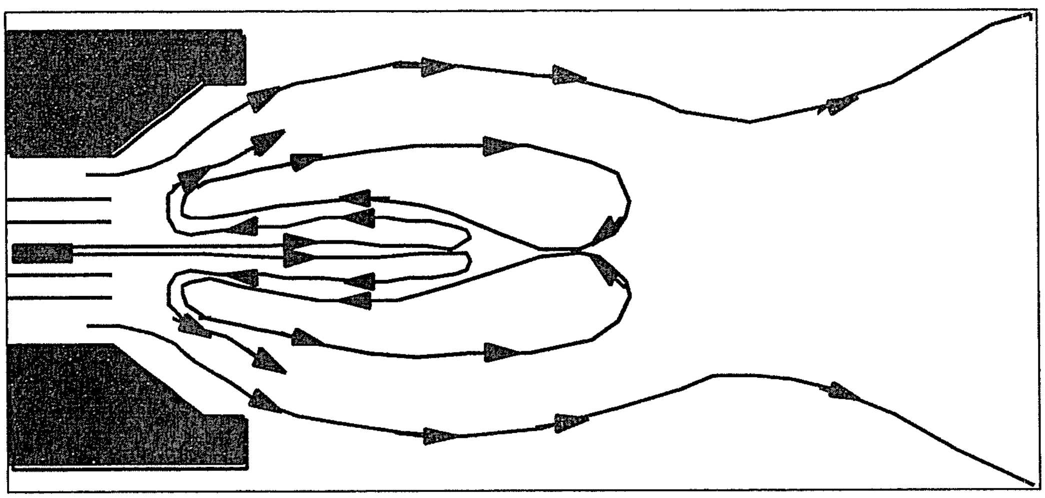


Figure 3-6: RSFC™ Flame Flow Field

The first flame region, in the fuel-rich, high-temperature recirculation zone, allows a large portion of the fuel nitrogen to be released in a low stoichiometric zone where it is easily converted to molecular nitrogen. The internal recirculation zone also helps stabilize the flame by providing adequate energy to the root of the flame. This higher temperature zone along the centerline of the burner, surrounded by the cooler, swirling combustion air, creates the stratification that is characteristic of the RSFC™ burner flame structure. After passing through this initial stratified, low stoichiometric, combustion zone, the fuel quickly mixes with the remainder of the combustion air to complete the combustion processes. This has the effect of achieving a low NOx configuration in a shorter flame length when compared with a conventional low NOx burner. The actual RSFC™ flame flow field is shown in Figure 3-6.

The RSFC™ burner register has three (3) separate air swirl generators to supply three (3) different air zones at the burner front, depicted pictorially in Figure 3-7. The variable swirl in the primary and tertiary air streams is generated through the use of moveable vane swirlers. The axial, fixed vane swirler in the secondary provides a consistent swirl and pressure drop over most conditions tested. The register also has a cylindrical slide damper. This damper, which covers the primary and tertiary swirler inlets, can be used to shut-off air to an idle burner. It can also alter the air distribution burner-to-burner or bias the mass flow between the primary and tertiary air zones. The secondary air zone is left open to ensure that sufficient cooling air is supplied to an out of service burner. This arrangement will protect burners even on very highly rated furnaces.

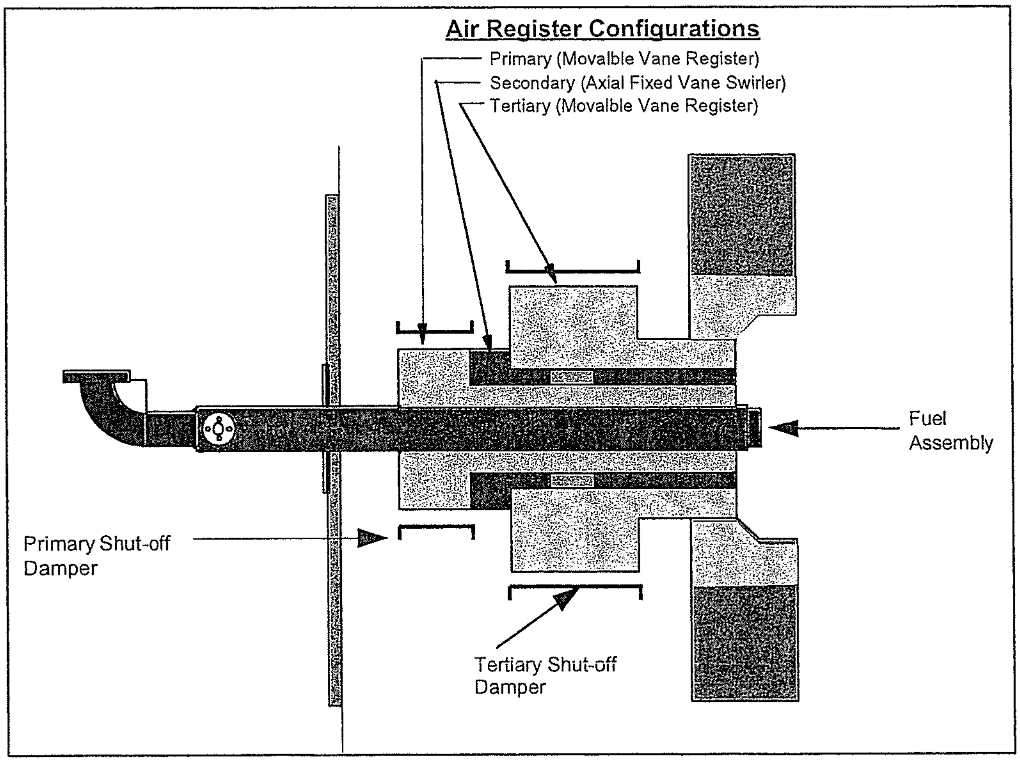


Figure 3-7: Graphical Representation of the RSFC™ Burner

This air swirl is the basis for the RSFC™ burner's operational flexibility including its flame shaping ability and low NOx performance. All swirl vanes in the primary air zone are connected with linkage mounted on the external surface of the burner front plate and controlled with a single manual gear drive. The tertiary zone swirl vanes are connected and controlled in a similar way. The RSFC™ burner's independent air zone swirl adjustment and shut-off damper adjustment allow for individual burner swirl adjustment without effecting burner mass flow. This feature provides an effective tuning tool for the subject unit to control flame shape and length while preventing flame impingement on side wall or rear wall tubes. Air entering the secondary air zone in is not regulated with a shut-off damper. A fixed swirl vane assembly imparts a high axial on the secondary air as it enters the burner throat.

The workings of the moveable vane damper are all hidden in the shadow of the throat inlet to minimize binding, ash deposition, and overheating. The primary and tertiary air zones can be isolated when the burner is out of service. When the shut off damper is closed, air leakage is designed to be a nominal fifteen to twenty percent (15% to 20%). Most of this leakage will occur through the secondary air zone where it will cool both the primary and secondary throats. The tertiary shut-off damper is "wheel & track" mounted, motor driven, and controlled by a linear actuator capable of three position control. The primary shut-off damper is manually controlled. Movement of the register swirl vanes is accomplished through manual gear-driven linkage mechanisms. These mechanisms are used to adjust the amount of swirl in the primary and tertiary airflows. The linkage mechanisms are mounted externally to allow for easy visual inspection of burner positions and configurations. The external mounting also allows for ease of maintenance and operability. If there were a problem with a damper linkage assembly, the burner would not need to be removed to complete the repairs. The linkages can be serviced with pliers and pin punch even when the burner is in service.

For oil and gas-fired RSFC™ burner applications, there is no diffuser or swirler required. This reduces the historical problems of overheating and associated maintenance of this equipment.

Another feature is a burner throat configuration unique to the RSFC™ burner. This design allows for the optimization of low NOx flame shaping and reduced furnace gas recirculation on the burner wall. The potential for wall slagging and overheating of the burner components is greatly reduced as a result of the design.

The RSFC™ burner support system will consist of an attachment to the windbox plate and to the existing water wall tube throat seal box. The burner front plate will be bolted to a frame type windbox extension that is welded to the existing windbox front plate. This arrangement will allow for localized enlargement of the windbox for the new burners and for centering of the burner. The burner to waterwall throat seal box connection is a seated type that allows for movement between the burner, windbox, and waterwall seal box. A new mounting adapter will be installed on the existing seal box. This mounting adapter will incorporate the RSFC™ burners' seated connection.

The Company's RSFC™ burner was initially developed as a low NOx burner. The design objectives resulted in a product that is well suited to perform as a high efficiency burner. RSFC™ burners have successfully operated with O_2 levels of one-half to one and one-half percent (1/2 to 1-1/2%), while also achieving reduced emission levels. The commissioning engineer typically does selection of the oxygen level. The engineer will optimize the excess O_2 during burner tuning while taking into consideration various drivers such as emissions, efficiency, turndown and flame stability. The RSFC™ burner's multiple air zones allows the Company to highly manage the air/fuel mixing, which is the feature that provides the benefit of great mixing and therefore, complete combustion.

Reliability of the RSFC™ is achieved through the many unique features incorporated into its basic design. The modular construction of the swirl block makes the RSFC™ burner very strong and rigid. Each of the blocks used in the construction of the burner becomes a stiffener in the swirler geometry. In addition, many of the parts in the RSFC™ burner have been constructed out of stainless steel to ensure that the burner will be functional over the long term. The use of stainless steel protects the RSFC™ burner from heat, corrosion, and rust on the critical moving parts, resulting in a more reliable design.

The RSFC™ burner's stable flame front is established with its unique exit profile. The existing burner refractory will be removed with the installation of the RSFC™ burner. A new burner refractory profile will be installed within the existing pressure part opening. No pressure part modifications are anticipated for this burner's installation. A drawing of the desired refractory profile is furnished during contract execution as well as dimensions for a profile sweep.

Electric linear actuators with three-position capability have been included for tertiary shut-off damper control. Manual actuators have been included for the primary air side control. Manual gear drives for both primary and tertiary vane damper adjustments are included. The intended use for these dampers is to optimize flame shape during burner commissioning. The Company's experience is that these vane dampers will not require adjustment over the unit's load range, with the exception of any significant change in fuel properties.

Burner Design Features

- Burner components that are exposed to furnace radiation are constructed of high-temperature 310 stainless steel.
- Primary and tertiary air zones swirl independent and have infinitely adjustable swirl capability from full radial flow to straight.
- Closing of the RSFC™ burner primary and/or tertiary shut-off or biasing dampers can be done when a burner is out of service. The secondary air zone is always open for cooling of burner furnace side components when a burner is out of service.
- RSFC™ burner primary and/or tertiary shut-off or biasing dampers can be modulated to balance airflow between burners on units with a common windbox.

- All moving parts (swirler vanes and air sleeve) are shaded from direct radiation eliminating binding due to overheating. Primary and tertiary swirler linkage is external for simple on-line maintenance and adjustment.
- RSFC™ burner has multiple view port options for scanners, or direct viewing for either center or offset ignitor locations.
- RSFC™ multi-fuel capability – Typical combinations are oil and gas or coal and gas. Installations have been designed for up to five (5) fuels.

Modular construction provides for a strong, yet lightweight burner.

3.2.1.4. SOFA Based Low NOx Option

There will be three (3) SOFA registers – one above each centerline of each burner column. The approximate height of the SOFA register centerline above the top burner centerlines is 12 feet. Three (3) individual ducts are included to supply combustion air to the three (3) SOFA registers.

The SOFA will be separated into two (2) compartments, stacked vertically. They will be equal areas, and the total size should be 18 inches wide by 24 inches high. Each compartment will be supplied with one (1) damper. The damper "box" and compartment assembly will be supplied with a bolted flange to the supply ductwork in lieu of a welded flange.

The ducting should be a standard duct, vertical from the top of the windbox to the SOFA register, with a 90-degree turn to the damper box. Turning vanes may be used to assist in the airflow in the 90-degree turn.

3.2.2. *Performance*

3.2.2.1. Performance Predictions

Following the completion of the installation of the equipment for the selected wall fired low NOx option ALSTOM predicts the following:

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 1: RSFC Burners			Predicted NOx Option 2: RSFC Burners with SOFA		
	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3
Unit No.3	389	0.499	768	351	0.45	693	218.4	0.28	431	171.6	0.22	339

Table 3-5: Predicted NOx Emissions

		Holyrood Particulate Loading Oct. & Nov. 2001 test results							Predictions			
		Baseline "As Found"							NOx Control Option 1: RSFC Burners		NOx Control Option 2 RSFC Burners w/ SOFA	
		Asphaltines %	Average Economizer Outlet O2	Average gr/DScf	Average gr/DScf @3% O2	Average mg/DSm3	Average Lb/106 Btu	Average mg/DSm3 @3% O2	Predicted Average mg/DSm3 @3% O2	Predicted Average gr/DScf @3% O2	Predicted Average mg/DSm3 @3% O2	Predicted Average gr/DScf @3% O2
Actual	Unit #3	3.7	0.4-0.7	0.1129	0.1172	258.38	0.1682054	268.30	295.13	0.1289	335.38	0.1465
Predicted Baseline	Unit #3	11	0.4-0.7		0.3434	720.42	0.47	743.35	817.69	0.3777	929.19	0.4292

Table 3-6: Predicted Particulate Emissions Leaving Boiler (Prior to any Flue Gas Cleanup Equipment)

Comments:
Unit No. 3, Actual Particulate Emissions from Unit No. 3 appear abnormally high. (Twice as high as either Units No. 1 or No. 2.) It is recommended that testing be conducted on Unit #3 to assess the cause of the high particulate loading. It may be necessary to modify the existing atomizers and/or balance the burner-burner airflow distribution to reduce particulate emissions. Lacking further information, this high particulate level for Unit No. 3 served as the basis for the low NOx and high Asphaltene predictions. With further information these predictions may be revised lower.

Note that in respect to opacity, Low NOx technology can negatively increase opacity. Opacity is strongly related to the type and efficiency of back-end particulate removal equipment. Opacity also has so-called "dark" and "light" opacity consisting of particulates and SO_3 emissions, respectively. These "dark" and "light" opacity levels can change at different rates depending on the low NOx technology employed. However, all of ALSTOM's Low NOx projects have been able to maintain oil opacity levels to below 10%. Because opacity is a function of so many variables, changes in opacity have been difficult to quantify. Opacity is indirectly related to particulates and we have observed that opacity changes have been typically less than particulate changes, which have been predicted above.

3.2.3. Materials and Services

The following is a listing of the major equipment included within the scope of the RSFC™ burner system for Holyrood Unit No.3. *Note:* Quantities are for one (1) unit.

3.2.3.1. Wall Fired Burner Low NOx Modifications – OPTION 1

Item	Quantity	Description
1.	Nine (9)	RSFC™ Low NOx venturi burners – nominally rated for approximately 165 MMBtu/hr equipped No. 6 fuel oil firing. Each burner will include two (2) view ports and one (1) scanner mount for the existing scanner. Each register will be shop assembled, including linkage and manual swirl damper actuators. The shut-off damper will be split with an electric linear actuator controlling the tertiary side, and the primary side controlled with a manual operator. The burner will also be equipped with an assembly to house the existing No. 2 fuel oil pilot assembly. Modifications to pressure parts are not required for burner installation (minimum 35-inch pressure part opening).
2.	Nine (9)	RSFC™ adapter flanges, to accept the new burner front plate into the existing windbox opening
3.	Eighteen (18)	Manual gearbox drives for operating the primary air and tertiary air swirl dampers
4.	Nine (9)	Electric linear actuators for control of tertiary air zone balance damper
5.	Nine (9)	Manual operators for control of primary air zone balance damper
6.	Ten (10)	WRHE steam atomized air-cooled oil gun for full load firing. Complete with guide pipe, stationary and removable union, spray plate and back plate, and oil and steam flex hose to interface with the existing supply piping - Includes three (3) spares. Note: Hose length provided is 6'.
7.	One (1)	Oil gun vise
8.	One lot	Material required to install the existing No. 2 fuel oil pilots onto the new RSFC™ burners
9.	One Lot	Material required to install the existing scanners onto the new RSFC™ burners

10.	Five (5)	Sets of the Company's standard instruction manuals and drawings

3.2.3.2. SOFA Based Low NOx Modifications – OPTION 2

Item	**Quantity**	**Description**
1.	Nine (9)	RSFC™ Low NOx venturi burners – nominally rated for approximately 165 MMBtu/hr equipped No. 6 fuel oil firing. Each burner will include two (2) view ports and one (1) scanner mount for the existing scanner. Each register will be shop assembled, including linkage and manual swirl damper actuators. The shut-off damper will be split with an electric linear actuator controlling the tertiary side, and the primary side controlled with a manual operator. The burner will also be equipped with an assembly to house the existing No. 2 fuel oil pilot assembly. Modifications to pressure parts are not required for burner installation (minimum 35-inch pressure part opening).
2.	Nine (9)	RSFC™ adapter flanges, to accept the new burner front plate into the existing windbox opening
3.	Eighteen (18)	Manual gearbox drives for operating the primary air and tertiary air swirl dampers
4.	Nine (9)	Electric linear actuators for control of tertiary air zone balance damper
5.	Nine (9)	Manual operators for control of primary air zone balance damper
6.	Ten (10)	WRHE steam atomized air-cooled oil gun for full load firing. Complete with guide pipe, stationary and removable union, spray plate and back plate, and oil and steam flex hose to interface with the existing supply piping - Includes three (3) spares. Note: Hose length provided is 6'.
7.	One (1)	Oil gun vise
8.	One lot	Material required to install the existing No. 2 fuel oil pilots onto the new RSFC™ burners
9.	One Lot	Material required to install the existing scanners onto the new RSFC™ burners
10.	Three (3)	Two-compartment SOFA registers; 18 inches wide by 24 inches high, arranged vertically; register equipped with required internal structural

		stiffeners, waterwall attachment flange (as required), expansion requirements, etc.
11.	Three (3)	Windbox to SOFA register connecting ducts; duct area to be 8.5 sq. ft. The duct design shall incorporate expansion joints and hangers as required.
12.	Three (3)	Two-compartment damper box; each box is equipped with a damper designed for shutoff of its respective compartment; each damper will modulate independently.
13.	Six (6)	Damper drive support mounts
14.	Six (6)	Electric rotary actuators for control of the dampers – Each drive will be capable for full range modulation.
15.	Three (3)	Sets of waterwall offset tubes; to allow for new SOFA opening
16.	Three (3)	SOFA seal boxes for new offset tubes and compartments
17.	One Lot	Miscellaneous steel for buckstay and platform steel modifications
18.	Five (5)	Sets of the Company's standard instruction manuals and drawings

3.2.4. Work Not Typically Included

Material Scope Not Included

1. Main windbox restoration materials
2. Scanner or ignitor repair or upgrades
3. Oil system repair or upgrade
4. Balance of Plant materials.
5. Control system modifications
6. Airflow monitoring devices*
7. Asbestos Abatement

* Note that airflow monitoring devices have only shown to offer limited benefit. More important is a good indication (full grid) of O_2/CO and NOx at the economizer outlet.

3.3. FUEL TECH NOXOUT SNCR PROCESS

3.3.1. Technical Discussion

In an effort to further reduce the NOx emissions from the Holyrood Units in addition to the burner and firing system modifications ALSTOM could, as an additional option, supply engineering, material, start-up and optimization of a urea-based Selective Non-Catalytic Reduction (SNCR) process such as the NOxOUT SNCR NOx Control Process supplied by Fuel Tech Inc. This option is predicted to reduce NOx emissions an additional 25-30% NOx reduction from the full load predicted levels achieved with the burner/firing system modifications while maintaining ammonia slip to less than 10 ppm as measured at the stack.

It is relevant to note that SNCR and other back-end NOx reduction technologies do not impact boiler efficiency, but they do increase heat rate due to auxiliary power usage.

If N&L Hydro desires, this Option can be exercised at a later date, after the Low NOx Bulk Furnace Staging (LNBFS) System (for Units #1 and #2) and/or the Radially Stratified Flame Core (RSFC™) burners (Unit #3) have been installed and operated for a period of time.

For this option, the Company has requested and received a proposal from Fuel Tech Inc. to supply the SNCR System for each unit using one (1) 30,000-gallon reagent storage tank per unit, as well as specific components for this boiler.

A Typical SNCR system would include a common heated and insulated reagent storage tank; a common Reagent Circulation Module enclosed in a heated building that is designed to supply reagent under constant pressure to the individual metering modules on the unit. Common dilution water pressure control modules will be utilized to feed and maintain dilution water to each of the metering modules.

Each boiler will have an Independent Zone Metering (IZM) module capable of automatically controlling the reagent and dilution water flow to various levels of injection, based on the demands of the system. The diluted reagent would be pumped to distribution modules on each level of injection where reagent and air flow is controlled to individual injectors.

The injectors for each unit will be a combination of wall injectors installed in the upper furnace and Multiple Nozzle Lances (MNL) installed through the side of the boiler in the superheat section. Both would come with automatic retract mechanisms. The MNLs would also require cooling water that is typically supplied from and returned to the hot well to retain heat in the cycle.

Continuous Furnace Temperature Monitors would also be supplied to provide additional control of the process. The control for Units would typically be through an Allen Bradley PLC with plant signal for load and furnace gas temperatures being used as a feed forward to determine which level of injection to use and the quantity of reagent feed. A NOx CEM measuring Unit stack emissions would be used as a feedback to fine-tune the process to maintain the target NOx level.

See Appendix B for the Fuel Tech brochure further describing this technology.

3.3.2. Performance Predictions

Following the completion of the installation of the equipment for the SNCR low NOx option ALSTOM predicts the following in combination with all of the previously discussed options:

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx SNCR		
	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3
Unit No.1	215	0.276	424	202.8	0.26	400	152.1	0.20	300
Unit No.2	236	0.303	466	202.8	0.26	400	152.1	0.20	300

Table 3-7: Predicted NOx Emissions for Low NOx Tuning& SNCR for Units 1&2

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 1: In-windbox NOx control (VCCOFA)			Predicted NOx SNCR		
	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3
Unit No.1	215	0.276	424	202.8	0.26	400	187.2	0.24	370	140.4	0.18	277
Unit No.2	236	0.303	466	202.8	0.26	400	187.2	0.24	370	140.4	0.18	277

Table 3-8: Predicted NOx Emissions for Low NOx Tuning, Option 1 & SNCR for Units 1&2

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 2: SOFA & Burner NOx control			Predicted NOx SNCR		
	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3
Unit No.1	215	0.276	424	202.8	0.26	400	132.6	0.17	262	99.45	0.13	196
Unit No.2	236	0.303	466	202.8	0.26	400	132.6	0.17	262	99.45	0.13	196

Table 3-9: Predicted NOx Emissions for Low NOx Tuning, Option 2 & SNCR for Units 1&2

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx SNCR		
	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3	ppm @ 3% O2	Lb/10^{6}btu	mg/Nm^3
Unit No.3	389	0.499	768	351	0.45	693	263.25	0.34	520

Table 3-10: Predicted NOx Emissions for Low NOx Tuning & SNCR for Unit 3

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 1: RSFC Burners			Predicted NOx SNCR		
	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3
Unit No.3	389	0.499	768	351	0.45	693	218.4	0.28	431	163.8	0.21	323

Table 3-11: Predicted NOx Emissions for Low NOx Tuning, Option 1 & SNCR for Unit 3

	Existing NOx			Predicted NOx w/ Tuning			Predicted NOx Option 1: RSFC Burners			Predicted NOx Option 2: RSFC Burners with SOFA			Predicted NOx SNCR		
	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3	ppm @ 3% O2	$Lb/10^6btu$	mg/Nm^3
Unit No.3	389	0.499	768	351	0.45	693	218.4	0.28	431	171.6	0.22	339	128.7	0.17	254

Table 3-12: Predicted NOx Emissions for Low NOx Tuning, Option 1&2 & SNCR for Unit 3

4. CAPTURE TECHNOLOGIES

4.1. MECHANICAL COLLECTORS

4.1.1. Technical Discussion

Mechanical dust collectors use cyclonic designs to remove particulate from the flue gas. Particulate-laden gas is set in rotation by the guide vanes located in each cyclone. Fully inserted guide vanes impart maximum rotation, i.e. the whole of the gas flow is caused to rotate along the same helical path as that formed by the guide vanes. Fully withdrawn guide vanes impart less rotation; the part of the gas passing outside the guide vanes reduces the rotation. The guide vane device can be set at any intermediate position. During rotation, the solid particles in the gas are forced out-wards towards the cyclone casing. The clean gas flows in towards the center of the cyclone, where additional separation takes place at the slots of the central tube, through which the gas must pass and be sharply deflected. The separation particulate is drawn out through the bottom of the cyclone, from where it is transported through the bottom of the unit to a secondary collector for final separation.

The type MJCD multicyclone is a controllable, dynamic dus collector designed for high-efficiency particulate collection. The gas flow is uniformly distributed across the entire peripheral area, and the cyclone is therefore well-suited for both fine-grained and highly abrasive particulate. To reach the desired efficiencies, multiple cyclones are connected in parallel and then multiple sections of cyclones are connected in series. The recommended arrangements includes the following:

4.1.2. Performance

4.1.2.1. Performance Predictions for Unit 1

Following the completion of the installation of the equipment for the recommended Mechanical Collector arrangement ALSTOM predicts the following:

Design Data		
Gas Flow Rate	Nm^3/hr	622,844
Flue Gas Temperature	°C	173
Excess Air, dry gas	(% vol.)	3.4
Particulate Inlet Loading* @ 3% O_2	mg/DSm^3, dry	519

*Worst case inlet loading based on Option 2 Low NOx Option

Design Parameters and Expected Performance		Primary	Secondary	Tertiary
Flue Gas Flow	m^3/hr	1,021,000	74,880	9600
Flue Gas Temperature	°C	173	173	173
Differential Pressure	kPa	1.4	1.2	0.7
Expected Particulate Emissions @ 3% O_2	mg/DSm^3, dry			262

4.1.2.2. Performance Predictions for Unit 2

Following the completion of the installation of the equipment for the recommended Mechanical Collector arrangement ALSTOM predicts the following:

Design Data		
Gas Flow Rate	Nm^3/hr	633,820
Flue Gas Temperature	°C	170
Excess Air, dry gas	(% vol.)	3.8
Particulate Inlet Loading* @ 3% O_2	mg/DSm^3, dry	568

*Worst case inlet loading based on Option 2 Low NOx Option

Design Parameters and Expected Performance		Primary	Secondary	Tertiary
Flue Gas Flow	m^3/hr	1,032,000	74,880	9600
Flue Gas Temperature	°C	173	173	173
Differential Pressure	kPa	1.4	1.2	0.7
Expected Particulate Emissions @ 3% O_2	mg/DSm^3, dry			262

4.1.2.3. Performance Predictions for Unit 3

Following the completion of the installation of the equipment for the recommended Mechanical Collector arrangement ALSTOM predicts the following:

Design Data		
Gas Flow Rate	Nm^3/hr	510,220
Flue Gas Temperature	°C	173
Excess Air, dry gas	(% vol.)	3.7
Particulate Inlet Loading* @ 3% O_2	mg/DSm^3, dry	1000

*Worst case inlet loading based on Option 2 Low NOx Option

Design Parameters and Expected Performance		Primary	Secondary	Tertiary
Flue Gas Flow	m^3/hr	835,840	62,400	9600
Flue Gas Temperature	°C	173	173	173
Differential Pressure	kPa	1.3	1.2	0.8
Expected Particulate Emissions @ 3% O_2	mg/DSm^3, dry			451

	SOx	NOx	Particulate	CO	Metals	Acid Aerosols
Removal Efficiencies	None	None	50%	None	Some	None

4.1.3. Materials and Services

To reach the desired efficiencies, multiple cyclones are connected in parallel and then multiple sections of cyclones are connected in series. The following is a listing of the major equipment included within the scope of the Mechanical Collecting system.

4.1.3.1. Recommended Equipment for Units 1 and 2

Item	Quantity	Description
1.0	Six (6)	Primary Collector MJCD Multicyclones consisting of 192 cyclones connected in parallel.
2.0	One (1)	Secondary Collector MJCD Multicyclones consisting of 96 unit cyclones connected in parallel.
3.0	Two (2)	Tertiary Collector MJCH high efficiency cyclones.
4.0	One (1)	Lot ductwork from air preheater to Collector inlet, from Collector outlet to gas fan, from gas fan outlet to exhaust stack.

4.1.3.2. Recommended Equipment for Unit 3

Item	Quantity	Description
1.0	Five (5)	Primary Collector MJCD Multicyclones consisting of 192 cyclones connected in parallel.
2.0	One (1)	Secondary Collector MJCD Multicyclones consisting of 96 unit cyclones connected in parallel.
3.0	Two (2)	Tertiary Collector MJCH high efficiency cyclones.
4.0	One (1)	Lot ductwork from air preheater to Collector inlet, from Collector outlet to gas fan, from gas fan outlet to exhaust stack.

Note that the Mechanical Collector Equipment layout is very similar in plan, to the recommended ESP equipment layout. For the ESP layout, the Holyrood Generating Station Master Site Plan Drawing B1-1403-121-C-003 Rev 8 was used to investigate the feasibility of locating the equipment arrangement at this site. Therefore for reference, the layout out sketch contained in Appendix A for the ESP, is representative of the location where the Mechanical Collectors would also be located.

4.1.4. Work Not Typically Included

Material Scope Not Included

1. Inlet and outlet ductwork access
2. Test ports and access thereto
3. Support for inlet and outlet ductwork
4. All foundations and anchor bolts
5. Gas ID Fans*
6. Dust evacuation system

* Given the relatively high pressure drop associated with this type of equipment, it is expected that new ID fans would likely be required.

4.2. ELECTROSTATIC PRECIPITATORS

4.2.1. Technical Discussion

The following is a general description of ALSTOM's Electrostatic Precipitators (ESP); please note that certain portions may not be directly applicable to the equipment offered in the Scope of Supply.

ALSTOM electrostatic precipitators are in use throughout the world in more than 1,200 installations. Refer to Appendix C for an experience list of ESP's supplied internationally on oil fired boilers.

The following describes the ALSTOM Rigid Frame Precipitator, which is a steel casing design for collecting many different types of particulates, such as fly ash, cement, lime, sodium sulfate and particulate containing iron metal oxides. The ALSTOM electrostatic precipitator embodies many unique design features that ensure high collecting efficiencies over an extended lifetime with the minimum of preventative maintenance.

4.2.1.1. Casing

The precipitator casing is made up of all welded construction utilizing shop prefabricated plate panels, thereby assuring close tolerances and quality control. The casing is designed for pressures, seismic, wind, live loads, and particulate loads as specified in the design section. The plate sections or panels are welded together for gas-tight construction with special care taken during welding to avoid porous welds which might invite corrosion. The roof of the precipitator casing supports both the internal discharge and collecting electrode systems. Loads are transmitted through columns to the support structures. The remainder of the precipitator internal components (drives, baffles, etc.) are supported by brackets welded to the precipitator casing. Inspection door frames are welded to the precipitator casing. In order to accommodate the effects of thermal expansion, the casing rests on anti-friction assemblies arranged in radial form emanating from a single welded fixed point on the supporting structural steel. Any external accessories, such as transformer-rectifiers, not permanently welded to the casing are equipped with permanent grounding lugs.

4.2.1.2. Gas Distribution Devices

It is essential that the precipitator be equipped with arrangements that will give an even gas distribution over the entire cross sectional area. This desirable gas distribution cannot be achieved solely through the design of the ducts, therefore, special gas distribution plates will be located in the inlet nozzles before the precipitator and at the outlet nozzle after the precipitator. The gas velocity within the precipitator is approximately 1/10 of the velocity in the ducting before the precipitator In order to prevent area of high gas velocities in the precipitator, the precipitator is equipped with a gas distribution arrangement which consists of three separate rows of perforated screens located in the inlet nozzles and one row of non perforated screens at the outlet of the casing.

The velocity distribution within the precipitator casing will be checked prior to start-up. During these gas distribution tests any necessary adjustments to the flow pattern will be made by the installation of deflector baffle plates attached to the perforated gas distribution screens.

For applications which are characterized by high inlet grain loadings and/or sticky particulates, rapping mechanisms, complete with geared motor, are provided for the two rows of inlet gas distribution screens located in the low velocity region of the inlet nozzles.

4.2.1.3. Collecting System

The ALSTOM designed collecting system is based on the concept of dimensional stability. The upper edges of the collecting plates are bolted to suspension angles, which in turn are connected to support members welded to the roof structure. The lower edge of each plate is similarly bolted to an alignment bar which is guided laterally across the gas flow. This results in a dimensionally stable collecting system compatible with the discharge system. In order to maintain the collecting efficiency at the design level, it is essential that the discharge electrode and collecting systems be dimensionally stable.

The collecting plates are made of 18 GA A366 CS (or equal) plate shaped in one 500 mm piece by roll forming. Rigidity is the main purpose for the special design of the collecting plate edges. The collecting plates are provided with tabs at the top and bottom edges which are bolted to the top suspension iron and lower alignment bar, respectively.

A series of 500 mm collecting plates form a row, or curtain, for each field. The separated module design allows each panel to respond individually to the rapping forces and minimizes shipping damage common with unitized plate designs. At 1/3 and 2/3 of the plate height a tab type device is furnished between each adjacent panel to interlock adjacent panels to each other.

4.2.1.4. Collecting Plate Rappers

The design of rapping mechanisms for the collecting system is an important factor to consider in the design of precipitator internals. It is essential that the collecting plates are thoroughly cleaned during rapping. The acceleration of the plate, which results from the rapping action, is the most important determinant of particulate removal and cleaning of the collector plates. In order to achieve efficient cleaning, the rapping system must be constructed so as to provide the required accelerations over all the plates.

Individual collecting plates in each row are bolted to and suspended from collector suspension angles. Each row of collector plates will receive a collector rapping anvil at the center field depth location attached to the suspension channel with tension control bolts. This arrangement ensures that the highest possible energy is transferred to the collecting plates when the tumbling hammer hits the corresponding rapping anvil.

The rapping system employs "tumbling hammers" that are mounted on a horizontal shaft in a staggered fashion with one hammer for each shock bar anvil. As a shaft rotates slowly, each of the hammers in turn overbalances and tumbles, hitting its associated shock bar anvil. The shock bar anvil transmits the blow simultaneously to all of the collecting plates in a row, because of their direct contact with the suspension channel and shock bar. A uniform rapping effect is, therefore, provided over the row of collecting plates.

It is of prime importance in any rapping system to avoid excessive re-entrainment of the particulate into the gas stream during the rapping procedure. With the ALSTOM rapping mechanism the electrodes are given an acceleration that causes the collected particulate to shear away from the collecting plates and fall down in large agglomerates. These large agglomerates, which result from the single shock shearing action, greatly reduce the possibility of particulate re-entrainment during rapping.

The rapping frequency should be as low as possible in order to minimize particulate re-entrainment from rapping. The frequency of the ALSTOM rapping system is adjustable within wide limits. All internal parts of the rapping mechanism are accessible for inspection, being placed in wide access passages before, between and after the collecting fields.

All physical data essential for designing plate suspension and rapping intensity for this type of particulate has been tested in ALSTOM 's laboratories. This type of "tumbling hammer" rapping mechanism has been used by ALSTOM for boiler plant precipitators for over 40 years as well as in all other ALSTOM precipitator applications. The acceleration at any point on a collecting system similar to the one recommended has been determined from full scale tests carried out in ALSTOM's laboratory.

When judging the effectiveness of the collecting and related rapping system, it is also essential to keep in mind the total collecting area being rapped at any one time. The higher the percentage of the total collecting area being rapped at any one time, the greater the re-entrainment of particulate into the gas. With the ALSTOM tumbling hammer rapping mechanism, a very small percentage of the collecting area for each precipitator is rapped at any one time. This improves the overall efficiency of the precipitator and avoids puffing at the stack outlet. The functional capabilities of the tumbling hammer system and its operational reliability have made it an ALSTOM standard, utilized in all installations noted in the reference lists in Appendix C of this report.

4.2.1.5. High Voltage System

An essential part of the precipitator is the high voltage discharge system. In the ALSTOM precipitator design, each individual discharge system is supported from four insulators. The discharge system is a frame structure that results in a stable configuration. The design is such that the discharge framework is supported at each upper corner and at the top of the collecting system. The discharge framework extends beyond the top and bottom edges of the collecting plates. These structural framework members consist of round or rectangular sections. The purpose of this design is to keep the field concentration at these points at a low level in order to avoid flashovers. The discharge frames are thoroughly braced above and below the collector plate system.. The discharge system can be adjusted to its final position inside the casing which makes it possible to obtain and maintain highly accurate spacing, without the need for anti-sway or lower stabilizing insulators.

4.2.1.6. Discharge Electrodes

The ALSTOM rigid discharge electrodes consist of 1 ¼" diameter 16 gauge and 1 3/8" diameter 10 gauge mechanical tubing with 16 gauge emitting tips. The electrodes are installed in three (3) vertical levels within a rigid frame for proper alignment and to prevent electrode swaying.

4.2.1.7. Insulator Compartments

Each electrical bus section is supported on four insulators located in insulator compartments. These compartments are provided with hinged door covers to allow access to the insulators for inspection and service. There is a special arrangement in each insulator compartment that makes it possible to suspend the discharge electrode system by means of a temporary jacking hook if the insulator must be exchanged.

A screen tube is installed immediately below the support insulator. The screen tube decreases back draft of gases and assists in maintaining cleanliness of the support insulator.

4.2.1.8. Discharge Electrode Rappers

During electrostatic precipitation a fraction of the particulate will be collected on the discharge electrodes; the corona will gradually be suppressed as the particulate layer grows. Therefore, it is necessary to rap the discharge electrodes occasionally. This rapping is done with a rapping system consisting of tumbling hammers that are mounted on a horizontal shaft in a staggered fashion. These hammers hit specifically designed shock anvil beams that are attached at the top of the discharge frame. In this manner the vibrations generated by the hammers are transmitted to the discharge electrodes.

One such rapping mechanism will be provided per electrical bus section. The drive of the rapping mechanism is via an insulator shaft that is installed on the top of the precipitator casing. The operation of the gear motor for the rapping mechanism is controlled by an ALSTOM EPIC-II, as described in Section 4.2.1.9, which is adjusted to optimum conditions at the time of commissioning. Subsequent adjustments can easily be carried out during operation, should operating conditions vary.

4.2.1.9. The ALSTOM Electrostatic Precipitator Control System

ALSTOM has offered a line of proprietary microprocessor controls for its electrostatic precipitator since 1982. These controls were developed exclusively for electrostatic precipitators by ALSTOM's R&D group in Vaxjo, Sweden. We now offers the next generation of electrostatic precipitator controllers EPIC-II (Electrostatic Precipitator Integrated Controller, Series II). This new microprocessor based automatic voltage controller provides the "state of the art" control for transformer - rectifiers and electrostatic precipitators.

EPIC-II

The EPIC-II main unit consists of a panel mounted control unit and a door mounted Remote Terminal Unit (RTU) display and terminal unit. The main unit contains one circuit board mounted in an enclosure. The one circuit board holds all the functions needed for the complete controller:

- One microprocessor for T/R control.
- One microprocessor for making computations and intelligence work such as communications and optimization routines.
- Data acquisition - analog and digital.
- Ignition circuits - for the Saturable Core Reactor (SCR).
- Non-volatile memory - EEPROM for storing the system parameters.
- Real time clock - capacitor backed, no battery needed.
- Field bus communication (Flakt Bus) - for communication with RTU, Preview, host computer, and other EPIC-II units.

There will be one EPIC-II supplied for each transformer rectifier. Each EPIC-II does not require a RTU and therefore APECS will provide a recommended number of RTU's.

Transformer Rectifier Control

The primary function of the EPIC-II is to monitor and control the level of power inside the precipitator. The principle output of the EPIC-II is a signal which determines the phase angle of the SCR's, which in turn regulates the power supplied to the transformer rectifiers. By measuring secondary voltage and current in the precipitator, sensing sparks, and utilizing its operating program, the EPIC-II is able to provide the optimum level of precipitator power over a wide range of gas conditions.

The EPIC-II also monitors many conditions of the transformer rectifier and SCR's to provide complete protection for the system. The EPIC-II presents alarms via the Flakt Bus which allows them to be viewed on the RTU, on Preview, or via the host computer. Certain alarm conditions will cause the transformer rectifier to trip.

Rapper Control

With the EPIC-II, there is no need for a separate rapper controller. Each EPIC-II can control up to four rapper motors. The various time settings are easily made using the RTU. These operating parameters are stored in the non-volatile memory of the EPIC-II. Alarm conditions for the rapper motors are presented on the Flakt Bus for operator presentation.

Optimization Routines

Several energy saving and system operation optimization routines are available in EPIC-II. These routines include patented Electrostatic Precipitator Optimization charge (EPOQ), semi-pulse optimization for performance and energy savings, opacity optimization for energy savings, and rapper operation optimization. Each EPIC-II includes an analog input (4-20mA) for use by the routines. The most common use of this input is for the opacity input. Note that this Information when input to one EPIC-II, can be shared with all other EPIC-II's via the Flakt Bus. These optimization routines offer best precipitator operation and energy savings for all operating conditions.

Remote Terminal Unit (RTU)

The RTU is a small operator interface with a keypad, for operator entry, and a display. The RTU is a general unit which collects its data and screen displays from the controller. The RTU's work over the Flakt Bus so that any RTU can access any EPIC-II on the Flakt Bus. The display provides easy to understand text display of information and alarms.

System Overview & TR Control

ALSTOM will supply standard EPIC II controllers for each Transformer & Rectifer set (T/R). In addition to controlling the T/R, each EPIC II is capable of controlling up to four rapper systems. The EPIC II controllers will be connected on a communications bus called Flakt Bus along with an EPIC II GATEWAY. All T/R functions are available across the FlaktBus.

Local access to the control system is via RTU's which are also connected to the communications bus. One per T/R control panel line-up is supplied. There will be one EPIC II GATEWAY for the precipitator to allow communication to the preview system or the boiler DCS.

Connection to a DCS System

The Gateways are network ports that can communicate directly with the DCS system; in fact, this is the normal use of these devices. The Gateways utilize Modbus protocol and act as slave devices. The Gateways can easily be connected to a new DCS system as long as that system has a compatible Modbus port. Any additional pertinent alarm information required can be routed through auxiliary I/O on the EPIC II's.

4.2.1.10. Hopper Heaters

ALSTOM will supply standard hopper heater control. A hopper heater control panel located under the hoppers and containing the fused power circuits for the heaters (one per hopper) will have individual H-O-A switches for each hopper power circuit. The automatic position allows a control thermostat to operate the heater as required to maintain the set point temperature. A second thermostat provides a low temperature alarm contact that illuminates an alarm light on the panel front. A common trouble alarm contact is provided. There is one hopper heater control panel per precipitator.

The hopper level switches are wired into the hopper heater panel and level alarm lights are located on the panel front. A common trouble alarm contact is provided. Please note that individual hopper information is not available at the control room. The philosophy is that any alarm from the hoppers needs to be investigated and individual hopper information is available at the local panel.

4.2.1.11. Insulator Heaters

To keep the insulators above the dew point of the gas during start up and operation, a special 1KW electrical resistance heater is provided for each insulator to supply heat to the insulators.

4.2.2. Performance

4.2.2.1. Performance Predictions

Following the completion of the installation of the equipment for the recommended Precipitator arrangement ALSTOM predicts the following:

ESP Predicted Performance				
		Unit 1	Unit 2	Unit 3
Fuel		Fuel Oil	Fuel Oil	Fuel Oil
Load		MCR	MCR	MCR
	MW	175	175	150
Gas Flow	Nm^3/hr (dry)	556,200	566,000	459,707
Gas Temp	°C	173	170	173
HHV	Btu/lb	17,857	17,857	17,857
Total Pressure @ ESP inlet	in.wg	-1.15	-1.15	-1.15
ESP Inlet Loading* @ 3% O_2	mg/DSm^3 (dry)	519	568	1000
Removal efficiency	%	90	90	92.0
Maximum Particulate Emission @ 3% O_2	mg/DSm^3 (dry)	51.86	56.80	76.85

*Worst case inlet loading based on Option 2 Low NOx Option

Flue Gas Analysis				
		Unit 1	Unit 2	Unit 3
Fuel		Fuel Oil	Fuel Oil	Fuel Oil
Load		MCR	MCR	MCR
Moisture	% vol.	10.7	10.7	9.9
Excess Air, dry gas	% vol.	3.4	3.8	3.7

	SOx	NOx	Particulate	CO	Metals	Acid Aerosols
Removal Efficiencies	None	None	92.30%	None	Some	None

4.2.3. Materials and Services

The following is a listing of the major equipment included within the scope of the Electrostatic Precipitator system.

4.2.3.1. Recommended Equipment for Units 1, 2 and 3

The recommended precipitator system per boiler is designated as:

1FTA 3*35.0M - 160 -150 - A2 - E131

The physical arrangement of each recommended precipitator for the boiler is summarized as follows:

Number of Precipitators	-	3
Number of Chambers / Precipitator	-	1
Number of Cells per Chamber	-	1
Number of Fields in Series	-	3
Field Height.	m	15.0
Field Depth, each.	m	3.5
Number Gas Passages/Precipitator	-	40
Plate to Plate spacing	mm	400
Number of Bus Sections/ Precipitator	-	3
Number of Transformer - Rectifiers	-	3
Gas Velocity through precipitator	m/s	1.09
Total gas treatment time	s	9.62
Aspect Ratio	-	0.70
SCA (Metric)	$m^2/m^3/s$	48
Total Installed Coll. Area/ Precipitator	m^2	12,600

Note that the Holyrood Generating Station Master Site Plan Drawing B1-1403-121-C-003 Rev 8 was used to investigate the feasibility of locating the above recommended equipment arrangement at this site. Although a more detailed investigation and discussion with site would have to take place, it appears as though it would be feasible. The equipment above has been superimposed onto a portion of this site plan, and for reference, this layout sketch is contained in Appendix A.

Mechanical Equipment

The following is a list of the major mechanical equipment (per boiler) typically supplied by ALSTOM:

Item	Quantity	Description
1.0	One (1)	Precipitator casings, consisting of inner roof (hot roof), side walls fabricated of 3/16 in A36, or equal, steel plate, adequately stiffened and braced to withstand differential pressures, stresses, and loads. The casing is complete with inspection doors in the side wall to allow access to internals.
2.0	One (1)	Outer roofs fabricated from 3/16 in A36, or equal, steel checkerplate, suitable for foot traffic.
3.0	Twelve (12)	Weathertight insulator compartments fabricated from 3/16 in A36, or equal, steel plate. The insulator compartments are provided with bolted doors for access to the supporting insulators.
4.0	One (1)	Set of inlet and outlet nozzles fabricated from 3/16 in A36, or equal, steel plate complete with flanges and bolts adequately stiffened and braced to withstand differential pressures.
5.0	Four (4)	24" X 24" hinged, interlocked, quick release access doors on the precipitator casing side wall, and inlet nozzle. Doors will be of double wall, shop insulated construction.
6.0	One (1)	Set of stub columns and slide plate bearing assemblies for the precipitator casing support, welded fixed point, to allow unrestricted thermal expansion in all directions.
7.0	One (1)	Set of support steel fabricated from A36, or equal, steel providing 26 ft. of clearance below the hopper discharge flanges to grade.
8.0	Six (6)	Pyramidal hoppers fabricated from 3/16 in A36, or equal, steel plate with external stiffeners. The hoppers will have minimum valley angle to the horizontal of 60°. Each hopper will be supplied with the following accessories: 1 Set of heaters 2 Hopper heater thermostats (one for control and one for alarm) 1 Access door, 24" X 24". 2 StrikePlates 2 Poke Holes

		2 Hopper Vibrator Mounts 1 Level Probe (high level alarm)
9.0	One (1)	Set of access facilities for ESP, consisting of platforms, walkways, and caged ladders as shown on the arrangement drawings. The floor grating and stairtreads shall be galvanized . Handrail, posts, ladders and other access steel will be prime painted .
10.0	One (1)	Gas distribution system at the inlet consisting of three (2) separate rows of perforated roll formed channels fabricated from 16 GA A366, or equal, steel sheet and one (1) row of plain roll formed channels for the outlet fabricated from 16 GA A366,or equal, steel.
11.0	One (1)	Gas distribution rapping systems, heavy duty tumbling hammer type complete with drive.
12.0	861	Collecting plates, 500 mm wide, fabricated from roll-formed 18 GA A366, or equal, steel sheet
13.0	123	Shock bar anvils, fabricated from carbon steel bar stock and angle, mounted on the suspension iron at the top of each row of collecting plates.
14.0	Three (3)	Collector plate rapping systems, heavy duty tumbling hammer type complete with drive.
15.0	Three (3)	Frames for discharge electrodes comprised of suitable braced vertical and horizontal structural members, complete with four-point suspension arrangement to avoid warping and misalignment (rigid type construction).
16.0	Three (3)	Sets of rigid type discharge systems comprising of framework with four-point suspension arrangement to avoid warping and misalignment and rigid discharging electrodes (RDEs) arranged in three (3) vertical levels in order to maintain proper alignment and to minimize electrode swaying.
17.0	Sixty (60)	Shock anvils fabricated from MS. bar stock mounted at the top of the discharge electrode frames.
18.0	Three (3)	Discharge electrode system heavy duty tumbling hammer type complete with drive.
19.0	One (1)	Temporary high voltage support frame lifting "J" hooks and electrode replacement tool.
20.0	One (1)	Set of portable grounding rods and "High Voltage" warning signs.

21.0	Three (3)	Sets of insulators, each set consisting of:	
		4	Support insulators for supporting the discharge electrode system (four point suspension).
		1	Shaft insulator for isolating the discharge electrode rapping drive shaft.
		1	High Voltage feed isolation Insulator
		1	T/R removal system consisting of a portable trolley and monorail beam.

Electrical Equipment

The following is a list of the major electrical equipment (per boiler) typically supplied by ALSTOM:

Item	Quantity	Description
1.0	Three (3)	Transformer-rectifiers with silicon diode or the R/C compensated or avalanche type rectifiers, enclosed in a weatherproof tank with a NEMA 3R low voltage junction box. The insulating liquid shall be mineral oil. Each unit will have one negative polarity high voltage bushing. Transformer-rectifier sets are rated for 65 KVDC average, 1100 MADC at modified resistive load. Transformer-rectifier tanks, and radiators shall be manufactured from ASTM-A36 (or equal) steel. Each transformer rectifier set will have an oil drip pan.
2.0	Three (3)	Transformer-rectifier power supply control panels, free standing with louvers, front access only, individual 480V - two pole power contactor, SCR-Thyristor and controls and air cooling fans. The following meters are provided: Primary voltage and current, secondary kilovolts and milliamps. Circuit breakers shall be furnished for each panel.
3.0	Three (3)	EPIC II microprocessor based electrostatic precipitator controller with field energizing optimizing, integrated rapper controller and high speed field bus communication.

4.0	One (1)	Remote Terminal Unit (RTU) operator interface with keyboard and display. One RTU will be installed in T/R line-up and one additional RTU is supplied as a handheld carry around unit.
5.0	One (1)	Key interlock system (Kirk or equal) for access doors and transformer rectifier control panel breakers.
6.0	One (1)	Set of 1 kW Heaters for the lead through support insulators and discharge rapper insulators.
7.0	One (1)	Gateway to interface with Owner's DCS.

4.2.4. Work Not Typically Included

Material Scope Not Included

1. Inlet and outlet ductwork access
2. Test ports and access thereto
3. Support for inlet and outlet ductwork
4. All foundations and anchor bolts
5. Gas ID Fans*
6. Motor Control Centers
7. Dust evacuation system
8. Control Building for ESP control system and MCC's (if required)

* Of the four capture technologies discussed in this report, this equipment results in the lowest added pressure drop. Therefore although it is likely that new fans would be required, there is still a possibility that after a more thorough evaluation, the system may be suitable without adding fans.

4.3. DRY FLUE GAS DESULFURIZATION

4.3.1. Technical Discussion

The Flue Gas Desulfurization System is designed to remove sulfur dioxide (SO_2) and particulate matter released from the steam generator. This is accomplished by intimately contacting a slurry of calcium hydroxide with the SO_2 laden gases while simultaneously allowing the hot flue gases to dry the reaction products. These dry reaction products are collected with the fly ash in the particulate collector.

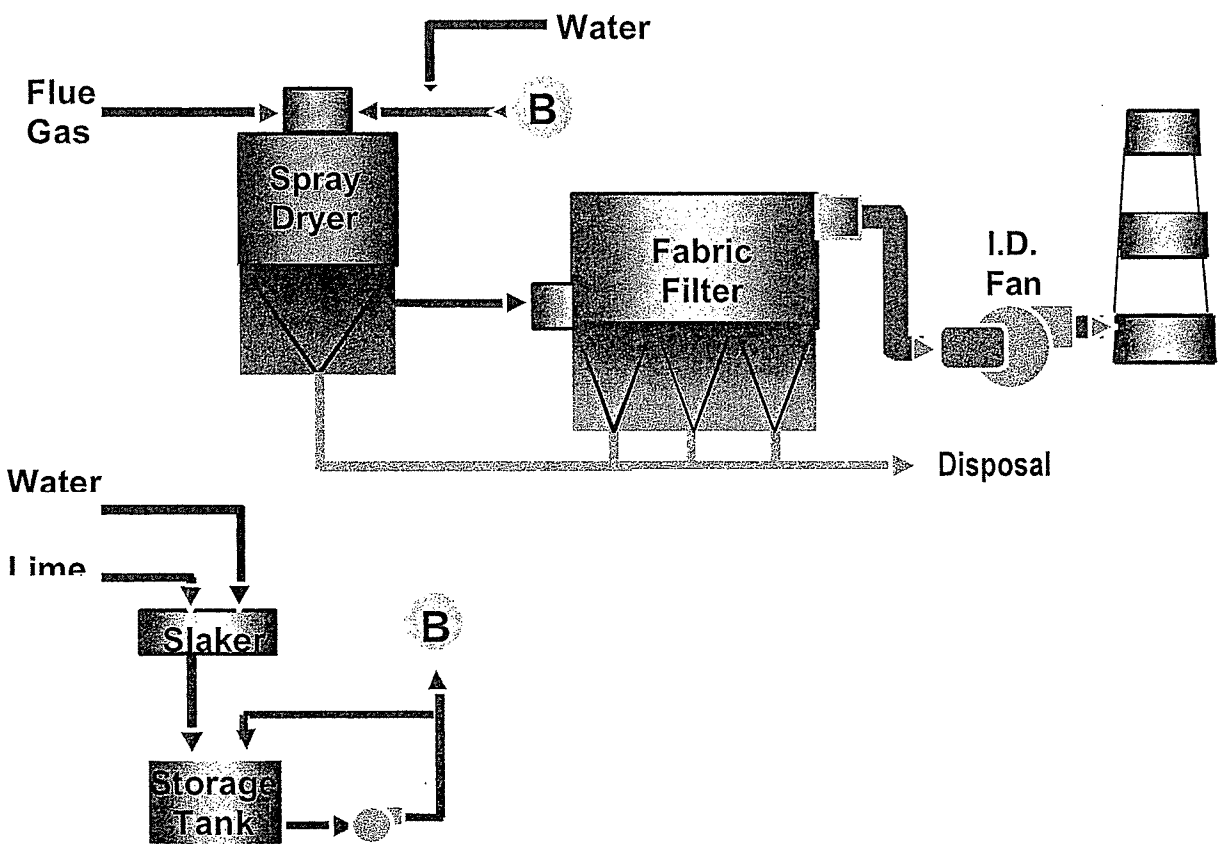


Figure 4-1: Spray Dryer Absorber (SDA)

The flue gas enters the top of the spray dryer absorber and accelerates as it passes through the disperser. At the discharge of the disperser the finely atomized spray of dilute lime slurry is introduced and the gas velocity is abruptly reduced. This produces a highly turbulent flow assuring the slurry droplets are intimately and thoroughly mixed with the gas.

As the gas exits the disperser and travels down the SDA chamber, the SO_2 reacts with the calcium hydroxide to form calcium sulfite and calcium sulfate reaction products. At the same time, the sensible heat of the gas causes the water in the droplets to evaporate, leaving a dry particulate residue suspended in the gas stream. Some of the dry reaction products and fly ash fall out of the gas stream into the absorber bottom and are re-entrained in the exiting flue gases by a constant influx of air from the bottom of the absorber cone. The gas stream carries the remaining products and fly ash to the particulate collector.

4.3.1.1. Process Design Parameters

The following is a summary of the process design parameters for the proposed DFGD:

Fuel	HHV	Ash	C	H	N	O	S	H2O
#6 Fuel Oil	17857 BTU/lb	0.1% (by wt)	87.84%	9.64%	0.49%	0.19%	2.2%	0.1%

Removals & Emissions

The DFGD system is designed to achieve an SO_2 absorbers outlet emission of 199 ppm (0.37 lb/MMBtu) while treating approximately 1,650,000 acfm @ 340 °F of boiler effluent flue gas containing a maximum absorbers inlet SO_2 loading of 12,120 lb/hr equivalent to 3,955 ppm (7.4 lb/MMBtu).

Flue Gas Reheat

Not provided.

Reagent

Lime containing 90% (dry basis) reactive calcium oxide.

By-Product

Disposable by-product

4.3.1.2. Atomization

The ALSTOM technology for slurry introduction into the hot flue gas is rotary centrifugal atomization. The atomizer feed slurry is fed to a rapidly rotating disk. The disk imparts centrifugal force to the slurry causing it to pass through openings in the circumference of the disk. As the slurry passes through these openings to leave the disk, it is sheered into very fine droplets. The disk is rotated (11,295 RPM) to achieve proper droplet size.

The absorption of SO_2 is enhanced because the small droplets, which are intimately mixed into the gas stream, have a large total surface area. This large interfacial area promotes the diffusion of gases into the liquid droplets. These gases (SO_2, SO_3, HCl, HF) then react with the calcium hydroxide to form the calcium sulfite/sulfate/chloride/fluoride reaction products.

ALSTOM takes care in the ensuring that the droplet dries neither too quickly, which can hinder and curtail the acid gas absorption reactions, nor too slowly, which can cause "wet bottom." The flue gas temperature at the spray dryer absorber outlet is maintained by controlling the dilution water addition rate to the atomizer.

The spray machine consists of an electric induction motor, a speed increaser gearbox, a flex shaft vibration absorber, and an atomizer wheel. The motor, flex shaft, and atomizer wheel are arranged in a vertical in-line assembly. The motor is coupled to the flex shaft with a spline coupling and the atomizer wheel is pressed onto the output of the flex shaft.

The speed increaser gearbox is conservatively designed to last the life of the plant. The gears are designed for 40,000 hours or more and comply with all applicable American Gear Manufacturers Association (AGMA) standards. Gear replacement is relatively easy and can be accomplished on site by the Customer's maintenance personnel following well-documented procedures. The gearbox is equipped with high-speed shaft bearings (tilting pad journal bearings). The low-speed and idler shaft bearings are rolling contact bearings. The journal bearings are designed for a three-year life at maximum load rating. Lube oil is supplied and cooled by the lubrication system.

4.3.1.3. Reagent Preparation

Lime is delivered pneumatically by self-unloading trucks that blow the lime through a four-inch line from grade to the top of the seven-day capacity lime silo. Pebble lime is fed from the lime bin at the desired rate by a bin activator and rotary or screw feeder to the lime slaker. The lime is mixed with a regulated amount of water to produce lime slurry of 20% solids. This slurry is passed through a vibrating screen to remove grit. The screened lime slurry flows directly to the lime slurry storage tank.

4.3.1.4. Transportation of Reagent

Centrifugal pumps transfer the lime slurry from the storage tank to the slurry control valves. Dilution water is delivered under line pressure to the water control valves.

The control valves are varied automatically, producing the correct flow rate to the atomizers for the desired degree of gas cooling and acid gas control.

4.3.1.5. Pulse Jet Fabric Filter

The fabric filter plant offered incorporates the OPTIPULSE bag pulse cleaning system. This design concept, which is unique to ALSTOM, was developed in the early nineteen seventy's (1970s), and is well-proven and reliable and has been utilized in hundreds of filter plants.

OPTIPULSE offers the following main exclusive features:

- Higher efficiency in converting medium pressure compressed air into pulse pressure in the filter bag than that of traditional high pressure (> 60 psi) designs. As a result, low-pressure oil free compressors can supply pulse air with consequential savings in capital cost, operating costs, and maintenance costs.

- Pulse air injected directly into the filter bags with only a limited amount of entrained secondary gas means less dispersion of the kinetic energy in the primary jet. This gives high propagation velocity of the pulse pressure along filter bags of up to 26 ½' in length. Importantly, the pulse overpressure over the length of the bag is higher than in high-pressure and low-pressure design baghouses.

- Cleaning energy consumption and specific air volume is low due to the fast mechanical action of the low pressure pulse valve which ALSTOM has developed to provide the required fast opening and closing actions. The essential cleaning action takes place when expanding the filter bag from its filtering position with little benefit from further extending the pulse length after the filter bag has been inflated.

- The pulses are accurately directed into the center of each filter bag. This alignment is established during construction and due to the static nature of the pulse pipes remains accurate. Therefore, cleaning remains at peak efficiency over the entire lifetime of the plant.

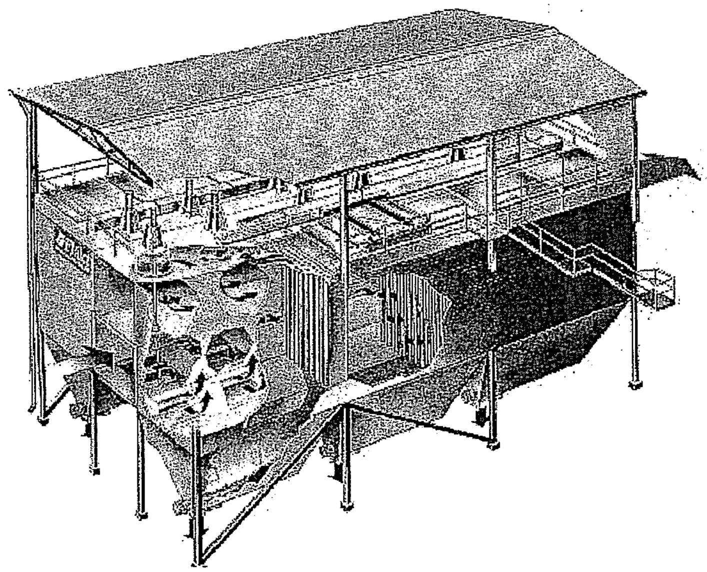


Figure 4-2: Typical LKP Baghouse

4.3.1.6. Fabric Filter Compartments

Each compartment casing is a gas-tight design to house the filter bags and their associated equipment. The fabric filter is designed to operate within guarantee limits at the design gas flow. The compartment casings are constructed of 3/16" A-36 steel or equivalent. Access to each compartment is achieved through top lift-off access doors. The doors are constructed of 3/16" A-36 or equivalent, and are sealed. The doors provide access to the nozzle tubes, bags and cages at the tubesheet level.

A penthouse-style enclosure frame with ventilation will be supplied.

4.3.1.6.1. Inlet and Outlet Plenums

Fabricated of 3/16" A-36 steel or equivalent, the inlet and outlet plenums distribute the gases into and out of each compartment, and provide a single flange for connecting to the inlet and outlet ductwork. The plenums are centrally located between the two (2) rows of compartments and connected to each by an isolation damper. The design of the plenums used in the fabric filter is based on years of field and flow model experience, and has been designed to optimize the following essential criteria:

1. Minimize system pressure drop.
2. Balance flow and particulate distribution between compartments and between filter bags within a compartment.
3. Minimize the potential for particulate dropout in the inlet plenum.

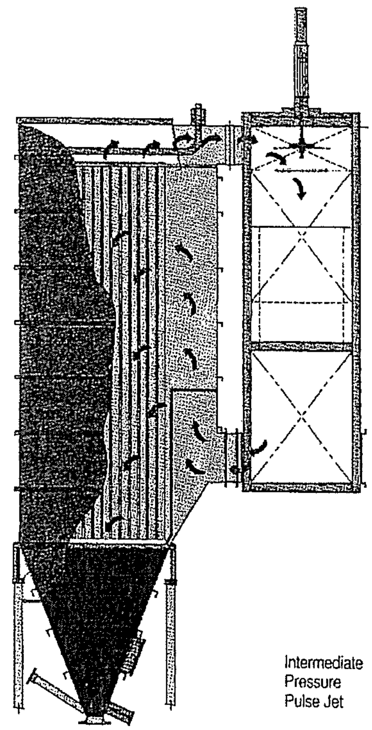


Figure 4-3: Typical LKP Plenum Arrangement

4.3.1.7. Tubesheet

The tubesheets are fabricated of 1/4" A-36 steel or equivalent with stiffening as necessary to support the imposed dead and live loads. Each tubesheet is seal welded to the housing and separates the clean and dirty sides of the compartment. It serves as a filter bag inspection platform inside the compartment. The filter bags are inserted through the tubesheet and held in place by a stainless steel snap band.

4.3.1.8. Filter Bags

Each of the filter bags is 5 1/8" in diameter and nominally 26'-6" long. A four-inch (4") cuff is sewn at the bottom and top of the bags. Also, a metal snap band is sewn into the top cuff of the bag. This seals the bag to the tubesheet.

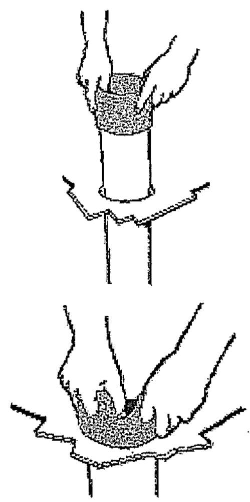


Figure 4-4: Snap-Band Installation of LKP Filter Bags

4.3.1.9. Bag Cages

All cage wires are 16 wire/ eight gauge to provide adequate cage strength for handling and transportation while also reducing the local internal stresses in the fabric along the fold lines. The cages incorporate a separate metal top-supporting ring to provide positive cage location, alignment, and support, and a separate metal bottom cap. These features of the ALSTOM filter bag cage accommodate thermal expansion of the cage / filter bag and tolerances on manufactured lengths of cage / filter bag. Cages are of a "split design" in two pieces each for ease of removal.

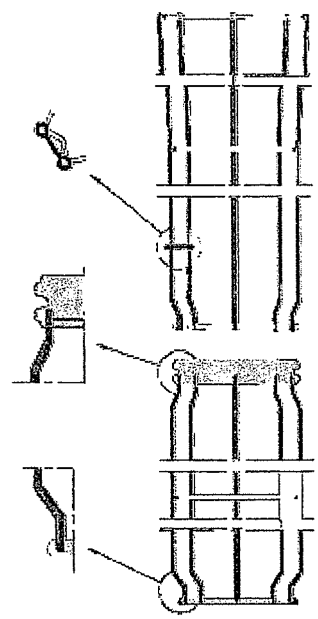


Figure 4-5: Typical LKP Filter Bag Cage (No Tools required for disassembly)

4.3.1.10. Pulse Air Cleaning System

The filter bags are cleaned by means of compressed air pulses that are directed down through the filter bag's opening. The compressed air expands the bag with such a strong acceleration that particulate on the outside of the bag are loosened when the bag later contracts. The compressed air is directed down into the bags via a pulse pipe provided with nozzles. The nozzles are specifically designed to reduce flow losses to a minimum. The compressed air pulse is extremely short (approximately 0.1 s) and adjustable. The entire cleaning operation, which occurs while the filter bags are in full operation, consumes little energy.

Distribution of air in short pulses is done by means of a patented valve. The pulse repetition frequency can either be constant or controlled by the resistance over the filter bags. Resistance-controlled cleaning by means of a PLC is especially suitable for varying operational conditions. The practical solution to the problem of pulse regulation involved, among other elements, a unique ALSTOM valve design OPTIPOW for which a patent has been applied for.

4.3.1.11. Pulse Air System Cleaning Cycle

Filter bag cleaning is controlled by a set pressure differential across the filter. The bandwidth of the variation in filter pressure differential can be selected arbitrarily narrow corresponding to the number of filter bag rows that are pulse cleaned (down to one (1) row or module respectively) when cleaning is initiated. The fluctuation in the flue gas pressure at the source's outlet terminal point can thus be minimized.

If the pressure differential set point is not reached within a set period of time after the previous cleaning pulse, due to reduced load or for some other reason, the cleaning will be carried out at constant intervals. This will limit the amount of particulate accumulated on the filter bags and limit the increase in differential pressure during a rapid load increase.

During the initial operating period and after commissioning, adjustment of the filter differential (or drag) set point as well as the pulse air pressure will take place. The settings are adjustable and each fabric filter installation should be set up for its own conditions. An optimum timing sequence should be determined by taking into account the minimum pressure loss vs. frequency of cleaning and filter bag life vs. outlet emissions.

4.3.1.12. OPTIPOW Pulse Valve

Proprietary valves have conventionally been used on most pulse jet filters. The maintenance requirements and lifetime of standard valves do not meet ALSTOM requirements.

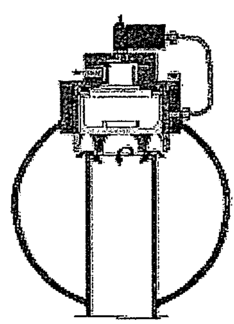


Figure 4-6: OPTIPOW Pulse Valve (open)

In 1975, ALSTOM, together with ASCO, developed an improved valve. This design has been extensively proven in the field on OPTIPULSE filters and refined in a number of ways to further extend the reliability. Following a thorough review of the development and operating history of the pulse valve, ALSTOM has continuously designed further improved versions, which incorporate state of the art plastic components specifically included to withstand corrosion, temperature, mechanical stresses, and shock loading. This design was subjected to extensive prototype testing and has been in service for several years.

4.3.1.13. Tanks and Nozzle Pipes

Pulse air for filter bag cleaning is evenly distributed by means of pipes arranged above each row of filter bags. These pipes have a nozzle for each filter bag, which is designed to direct the pulse air directly into the center of the filter bag.

Nozzle pipes are four inch (4") nominal mild steel plate assembled into fittings so that they may be easily lifted out and replaced during bag changing operation.

The pulse tanks with the pulse air solenoid valves integrally mounted are located on the outside of the compartment roof and pulse air is distributed to each filter bag via a distribution pipe which is an integrally welded part of the pulse tank assembly.

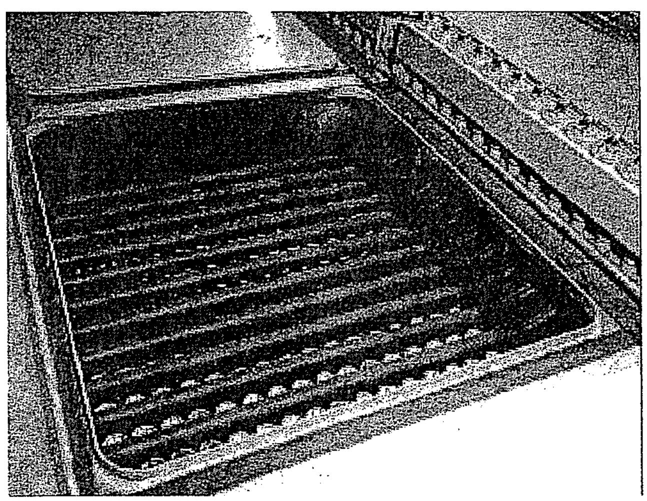


Figure 4-7: Typical LKP Nozzle Pipe Assembly

4.3.1.14. Dampers

All outlet and bleed-in dampers are pneumatically operated poppet type valves to ensure positive opening, closing, and sealing. The inlet damper is a manually operated butterfly damper.

4.3.2. Performance

4.3.2.1. Performance Predictions

Following the completion of the installation of the equipment for the DFGD system described ALSTOM predicts the following performance based upon the stated process design parameters:

Unit/Boiler Data			
No. Units:		3	
Gross Generation/Unit*:	MW	175	
Fuel		Oil	
Sulfur Content	%	2.2	
		Per Boiler	Total Plant
Fuel Firing Rate	lb/hr	91,827	275,480
Flue Gas Generation	acfm	551,950	1,655,850
SO_2 Production	lb/hr	4,040	12,121
SO_2 Production	ppm	1,318	3,955

* Approx only, Units 1 & 2 are 175 MW, Unit 3 is actually 150 MW

FGD Performance Data			
SO_2 Removal Efficiency	%	95	
SO_2 Outlet Emissions	ppm	199	
Lime Purity	%	90	
		Per Boiler	Total Plant
Lime Consumption	lb/hr	7,322	21,966
	ton/hr	3.7	11.0
Make-Up Water Consumption	gpm	142	425
Total DFGD Power Consumption	kW	656	1,969
% of Gross Generation	%	0.38	

	SOx	NOx	Particulate	CO	Metals	Acid Aerosols
Removal Efficiencies	95%	None	99% +	None	Some	Good

4.3.3. Materials and Services

The following is a listing of the major equipment included within the scope of the DFGD system.

Item	Quantity	Description
1.0	Two (2)	SDA towers
2.0	One (1)	Reagent handling/preparation (including two slaking systems)
3.0	One (1)	Fabric Filters (one LKPB type)
4.0	As Req'd	Ducts/dampers
5.0	As Req'd	Electrical (switchgear, MCCs, cable, raceway)
6.0	As Req'd	Piping and supports
7.0	As Req'd	Structural support/access steel
8.0	One (1)	DFGD building (control/electrical, pump, equipment)

Note that the Holyrood Generating Station Master Site Plan Drawing B1-1403-121-C-003 Rev 8 was used to investigate the feasibility of locating the above recommended equipment arrangement at this site. Although a more detailed investigation and discussion with site would have to take place, it appears as though it would be feasible. The equipment above has been superimposed onto a portion of this site plan, and for reference, this layout sketch is contained in Appendix A.

4.3.4. Work Not Typically Included

Material Scope Not Included

1. Gas ID Fans*
2. Ash Handling System
3. BOP Foundations / Civil Works
4. Reagents, Lubricants, and Precoats
5. Fire Protection
6. Communication System
7. Continuous Emission Monitor's
8. New Stack (may not be required, a cost analysis must be done vs. keeping old stack)

* Given the high pressure drop associated with this type of equipment, new ID fans would be required.

4.4. WET FLUE GAS DESULFURIZATION

4.4.1. Technical Discussion

Wet flue gas desulfurization (WFGD) systems are employed to remove sulfur dioxide (SO_2) produced during the combustion of coal or oil in utility power stations. Sulfur dioxide is believed to cause adverse health effects as well as contributing to the destruction of structures and damage to wildlife and vegetation through acid rain. The following is a general description of ALSTOM's limestone, forced oxidation WFGD system. These systems can remove up to 98% (however predicted values shown are based on 95% since this is typical guarantee level) of the acid constituents present in flue gas by scrubbing with limestone. Gypsum, which may be sold or landfilled is produced as a byproduct.

4.4.1.1. Process Design Parameters

The following is a summary of the process design parameters for the proposed WFGD:

Fuel	HHV	Ash	C	H	N	O	S	H2O
#6 Fuel Oil	17857 BTU/lb	0.1% (by wt)	87.84%	9.64%	0.49%	0.19%	2.2%	0.1%

Removals & Emissions

The WFGD system is designed to achieve an SO_2 absorbers outlet emission of 199 ppm (0.37 lb/MMBtu) while treating approximately 1,650,000 acfm @ 340 °F of boiler effluent flue gas containing a maximum absorbers inlet SO_2 loading of 12,120 lb/hr equivalent to 3,955 ppm (7.4 lb/MMBtu).

Flue Gas Reheat

Not provided.

Reagent

Limestone (100% < 18 mm) and ground limestone (90% < 44mm) containing 95% (dry basis) reactive calcium carbonate.

By-Product

The WFGD system will produce commercial grade gypsum containing approximately 95% $CaSO_4 \cdot 2H_2O$ at 90% solids content.

4.4.1.2. WFGD Process Flow Diagram

Flue Gas Path

For boiler capacities less than approximately 1,000 MWe, a single absorber is fitted to each boiler unit. The flue gas is combined downstream of the boiler and new ID fans and taken directly to the WFGD system. After being treated in the absorber tower, the flue gas is discharged through a wet stack. The entire gas stream is treated in the absorber. Induced draft (ID) fans provide the draft to overcome the pressure drop across the boiler, ESP, and FGD system. The absorber(s) discharge directly to the stack, without reheating. In most cases, absorber inlet or outlet dampers are not required unless a single absorber is coupled to multiple boilers. In that case, isolation dampers are generally provided to permit the boilers to operate independently of the WFGD system.

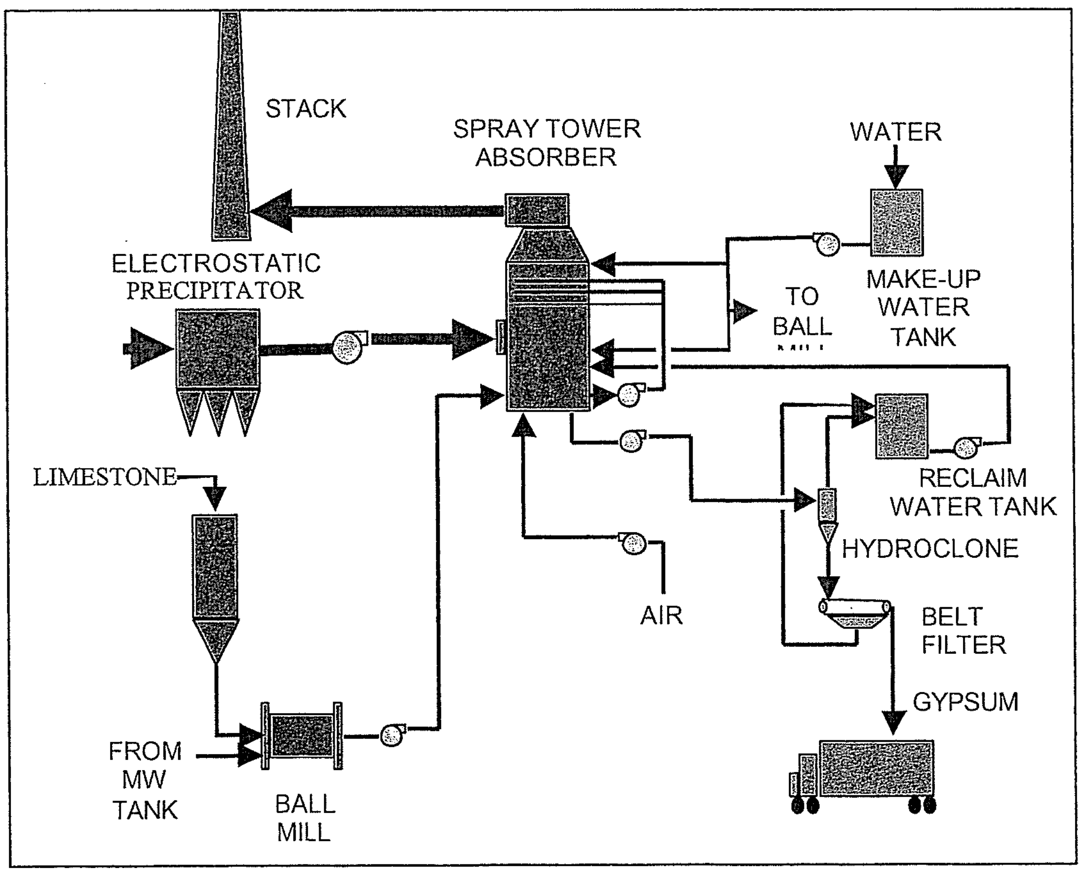


Figure 4-7: WFGD Process Flow Diagram

Flue Gas Path

For boiler capacities less than approximately 1,000 MWe, a single absorber is fitted to each boiler unit. The flue gas is combined downstream of the new ID fans and taken directly to the WFGD system. After being treated in the absorber tower, the flue gas is discharged through a wet stack. The entire gas stream is treated in the absorber. Induced draft (ID) fans provide the draft to overcome the pressure drop across the boiler, ESP, and FGD system. The absorber(s) discharge directly to the stack, without reheating. In most cases, absorber inlet or outlet dampers are not required unless a single absorber is coupled to multiple boilers. In that case, isolation dampers are generally provided to permit the boilers to operate independently of the WFGD system.

Alternatives

In the event that stack gas temperature requirements (e.g. 80 °C) are imposed by local regulations, reheat can be provided. Alternatives include gas-to-gas reheater (GGH), liquid couple heat exchangers, partial bypass, and heated air injection.

Materials

The WFGD system flue gas ductwork is fabricated of carbon steel. The absorber inlet duct (between the absorber expansion joint and the vessel wall) will be lined with C-276 alloy to prevent corrosion. The ductwork between the absorber outlet flange and the chimney breeching flange will also be protected against corrosion by metallic or organic linings.

4.4.1.3. Absorber

Absorption

Open spray tower absorbers that range in size from 20 to 65 feet in diameter, are used to provide intimate contact between the flue gas and the scrubbing liquid. These absorbers are constructed with various types of alloys, stainless steels, and mild steel with various corrosion/erosion resistant linings.

The flue gas enters the spray tower near the bottom through an inlet transition. Once in the absorber, the hot flue gas is immediately quenched as it travels upward countercurrent through a continuous spray of process (recycle) slurry produced by a series of independent spray banks. The recycle slurry, which is a suspension of limestone and gypsum, extracts the majority of the sulfur dioxide (SO_2) from the flue gas. Once in the liquid phase, the sulfur dioxide reacts with the dissolved calcium carbonate (limestone) alkali to form dissolved calcium sulfite. In addition to removing sulfur dioxide, other acid gases present, such as hydrogen chloride (HCl) and hydrogen fluoride (HF), are removed as well.

The quantity of recycle slurry needed to effectively remove the specified amount of SO_2 is determined by a parameter known as the liquid-to-gas ratio (L/G). The choice of the L/G is based on the supplier's experience in design and operation of full scale units in conjunction with an ongoing research and development effort in such areas as oxidation, process effects of dissolved chloride ion and reagent particle size.

The absorbers generally have 2 to 4 installed spray banks (levels). Each spray level is fed through an individual riser by a dedicated recycle pump. The requirement for spare spray pumps/levels is decided on a case-by-case basis depending on regulatory, customer, and availability requirements.

Each spray level consists of tangential-inlet, hollow cone spray nozzles manufactured of nitride-bonded silicon carbide. This nozzle type provides the proper sized droplets for optimum SO_2 absorption, typically a $d_{50} < 2{,}000$ µm.

When viewed from above, the pattern of spray cones produced by the spray nozzles appears as an array of overlapping circles. Great care is exercised in the layout of the nozzles to ensure overlap so that there are no voids through which flue gas can pass unscrubbed.

Reaction Tank

The recycle slurry falls from the spray zone into the reaction tank that forms the base of the absorber. This tank is sized to provide sufficient residence time for all of the WFGD chemical reactions to take place; for the design sulfur coal, the liquid turnover time is generally about 4 minutes and the solids residence time is 15-30 hours. Fresh reagent slurry is added to the reaction tank where it reaches equilibrium with the bulk of the recycle slurry prior to being returned to the spray banks by the recycle pumps.

Gypsum bleed pumps discharge slurry to the primary dewatering system to maintain the desired reaction tank slurry concentration and liquid level.

Forced Oxidation

Forced oxidation of the recycle slurry in a limestone wet FGD system produces byproduct that can be more easily handled and utilized than the byproduct from partially or non-oxidized systems. To produce fully oxidized byproduct, a centrifugal blower supplies compressed air to a sparging system in the reaction tank. The oxygen in the air converts the dissolved calcium sulfite ($CaSO_3$) to calcium sulfate ($CaSO_4$), which then crystallizes as $CaSO_4 \cdot 2H_2O$, gypsum.

The oxidation air, which has been heated in the compression process, is quenched and saturated with a stream of clean process water. This is done to prevent any scaling or buildup that could occur at the sparger tips due to localized evaporation of recycle slurry.

Mist Elimination: After leaving the spray zone, the scrubbed gas flows upward through a two-stage mist elimination system. The stages consist of multi-pass chevron baffles that remove entrained slurry droplets by inertial impaction. The first stage chevrons act as a barrier to keep the major portion of process slurry droplets entrained in the gas stream from leaving the absorption zone. The small fraction of entrained droplets that passes through the first stage mist eliminator is removed by the second stage.

The front face of the first stage mist eliminator is washed intermittently in zones with a stream of process water. The back face of the first stage mist eliminator and the front face of the second stage mist eliminator are washed simultaneously, also on an intermittent, zone basis, with a stream of fresh process water. The mist eliminator wash cycles, flux rates and pressures have been designed to provide effective rinsing of any solids or chemically reactive liquids.

Absorber Island Materials

The goal of the material selection strategy for the absorber island is to ensure continuous, reliable operation between maintenance outages at the lowest lifecycle cost. The absorber shell - from the reaction tank sidewall through the outlet cone – can be fabricated in a variety of materials, depending upon the absorber slurry steady state chloride concentration. Material selection includes mild carbon steel with corrosion and abrasion resistant lining, corrosion resistant stainless steel, alloys, FRP and concrete. Agitator shafts and impellers are manufactured of corrosion resistant stainless steel. Oxidation air sparge lances and recycle spray headers as well as the mist eliminator wash piping are made of fiberglass reinforced plastic (FRP). The mist eliminator blades are manufactured of polypropylene.

4.4.1.4. Reagent Preparation and Slurry Delivery

Limestone is generally delivered either as a crushed (3/4 x 0 in) stone or pre-ground (90-95% < 40 µ) powder. For large (>300 MWe) systems, economics usually favor the delivery of crushed stone and on-site grinding with wet ball mills.

Limestone Storage

Outdoor, uncovered, long-term on-site storage of crushed limestone is possible in most locations. In extreme climates, covered storage may be required. Limestone is conveyed from the long-term storage area to a day silo, which is sized to contain 16-24 hours supply.

Limestone Grinding

Limestone is fed from the day silo via a weigh belt feeder to a wet ball mill. The wet ball mill consists of a rubber-lined cylinder filled with hardened steel balls. In the ball mill, water is added and limestone is pulverized by the action of the balls as the mill rotates. Process make-up water is used for preparation of the limestone slurry, which is delivered to the reagent feed tanks for storage and use by the FGD system.

Slurry Feed

The reagent feed tank is sized to contain limestone slurry sufficient for 8 hours of operation of the entire plant at full load and design sulfur content. Reagent slurry is transported from the reagent feed tank to the FGD absorbers through the use of a recirculating feed loop.

Reagent slurry is added to the reaction tank in response to two control signals. The primary control is a feedforward loop driven by the SO_2 concentration in the flue gas entering the FGD system. The pH in the reaction tank drives a feedback loop that trims the feed valve. The pH-trimmed system responds rapidly, is essentially independent of plant load, and is therefore highly stable.

Materials

The day silo is fabricated of mild steel with a stainless steel or polymeric lining in the hopper. The ball mill is rubber lined steel. The reagent feed tank is fabricated of carbon steel with an abrasion- and corrosion-resistant flakeglass lining. The piping of the feed loop and stubs is manufactured of rubber-lined carbon steel, in order to ensure high resistance to abrasion during permanent operation at economic pipe velocities.

4.4.1.5. Dewatering and Product Handling

Primary Dewatering

Gypsum product slurry is pumped from the reaction tank by means of the gypsum bleed pumps to a cluster of hydrocyclone classifiers that separate the slurry into a low density stream of fines (the overflow) and a high density stream of coarse crystals (the underflow). In so doing, the hydrocyclones also classify the slurry chemically. Unreacted limestone is relatively fine and preferentially reports to the overflow; while the byproduct gypsum is a coarser material and it preferentially reports to the underflow. One dedicated set of hydrocyclones is provided for each absorber in a multi-unit application; the sets are combined in one hydrocyclone cluster assembly, if possible. Installing a spare cyclone in each set of hydrocyclones provides redundancy.

A gypsum bleed pump feeds each set of hydrocyclones whenever the solids content in the reaction tank reaches the upper value of the control range, and the feed is bypassed once the lower value of the control range is reached. The majority of the overflow from the hydrocyclone classifiers flows by gravity directly back to the respective reaction tanks. A portion of the overflow is available by gravity as blowdown stream to control and limit the chloride content in the reaction tanks, whenever the hydrocyclone is in operation.

The hydrocyclone underflow product flows by gravity directly onto the operating belt filter.

Secondary Dewatering

Horizontal belt vacuum filters are provided for secondary dewatering. The concentrated byproduct gypsum slurry flows from the primary dewatering hydrocyclone underflow to the belt filter. The gypsum slurry is vacuum-dewatered to produce a cake comprised of at least 90 percent byproduct gypsum solids and not more than 10 percent residual moisture. The belt filter includes equipment for washing of the gypsum cake during dewatering to reduce the concentration of soluble materials - particularly chloride ions - in the byproduct gypsum. Cooling tower blowdown is foreseen for washing of the cake as long as the concentration of soluble components are significantly lower than the corresponding values allowed in the final gypsum cake.

In the event that a drier byproduct is desired, centrifuges can produce moisture levels as low as 7-8%.

Byproduct Storage & Handling

Several alternatives are available for product transport and storage. In the simplest case, the belt filters are installed above ground level and the gypsum falls directly into a bunker or silo. In other cases, the gypsum is transferred from the filters to a storage building via belt conveyors. The building can be equipped with stackers and reclaimers for ease of handling.

4.4.1.6. Water Handling

Filtrate Water

Filtrate from the vacuum filters is collected in the FGD area sump, which is designed to accommodate this additional flow in addition to the runoff from all area trenches. Filtrate, along with the other sump contents, is pumped back to the reaction tank(s) as a function of the sump level.

Process Water

Process make up water for FGD systems is typically taken either from a nearby river/lake (clean water), or from the on-site waste water (cooling tower blowdown) supply. Other sources such as seawater, ash pond water, coal pile run-off, etc. can be considered. The need for pumps, storage tanks, and piping must be coordinated with the customer.

Process water will be boosted to a higher pressure by the mist eliminator wash pumps to satisfy the pressure requirements for the mist eliminator wash nozzles at their elevated location.

The majority of the process water will be used to maintain water balance in the absorber (reaction tank level control). Smaller amounts will be used for mist eliminator wash and secondary dewatering. All occasional equipment and pipe flushes will be performed with process water.

Chloride Bleed Stream

The absorber system is typically designed from a materials and performance standpoint for a dissolved chloride level in the absorbing slurry and related streams of 15,000 – 20,000 ppm. Due to the water balance requirements when producing wallboard quality gypsum, additional chloride ion and other dissolved solids must be bled from the system in another stream to prevent accumulation to excessively high levels. A controlled side-stream of hydrocyclone overflow is discharged by gravity as blowdown to a waste water treatment system or disposal pond in order to maintain the required maximum system chloride concentration.

4.4.2. Performance

4.4.2.1. Performance Predictions

Following the completion of the installation of the equipment for the WFGD system described ALSTOM predicts the following performance based upon the stated process design parameters:

Unit/Boiler Data			
No. Units:		3	
Gross Generation/Unit*:	MW	175	
Fuel		Oil	
Sulfur Content	%	2.2	
		Per Boiler	Total Plant
Fuel Firing Rate	lb/hr	91,827	275,480
Flue Gas Generation	acfm	551,950	1,655,850
SO_2 Production	lb/hr	4,040	12,121
SO_2 Production	ppm	1,318	3,955

* Approx only, Units 1 & 2 are 175 MW, Unit 3 is actually 150 MW

FGD Performance Data			
SO_2 Removal Efficiency	%	95	
SO_2 Outlet Emissions	ppm	199	
Limestone Purity	%	95	
Gypsum Purity	%	95	
Gypsum Moisture	%	10	
		Per Boiler	Total Plant
Limestone Consumption	lb/hr	6,502	19,507
	ton/hr	3.3	9.8
Gypsum Production	lb/hr @ 10% moisture	12,065	36,195
	ton/hr	6.0	18.1
Make-Up Water Consumption	gpm	315	945
WFGD Power Consumption	kW	2,600	7,800
ID Fan Power Consumption	kW	600	1,800
Total Power Consumption	kW	3,200	9,600
% of Gross Generation	%	1.8	

	SOx	NOx	Particulate	CO	Metals	Acid Aerosols
Removal Efficiencies	98%**	None	30 - 50% (max)	None	Some	Poor

** Although capable of 98%, the predicted values reflect 95% since this is typical of industry guarantees

4.4.3. Materials and Services

The following is a listing of the major equipment included within the scope of the WFGD system.

Item	Quantity	Description
1.0	One (1)	Absorber island (including one absorber, recycle pumps, spray levels and mist elimination system)
2.0	One (1)	Reagent handling/preparation (including one ball mill complete with accessories, limestone silo, powder limestone back-up system)
3.0	One (1)	Gypsum dewatering/storage (including one hydrocyclone and one horizontal vacuum belt filter with accessories)
4.0	As Req'd	Ducts/dampers
5.0	As Req'd	Booster fans
6.0	As Req'd	Foundations
7.0	As Req'd	Electrical (switchgear, MCCs, cable, raceway)
8.0	As Req'd	Piping and supports
9.0	As Req'd	Structural support/access steel
10.0	One (1)	WFGD building (control/electrical, pump, equipment)

Note that the Holyrood Generating Station Master Site Plan Drawing B1-1403-121-C-003 Rev 8 was used to investigate the feasibility of locating the above recommended equipment arrangement at this site. Although a more detailed investigation and discussion with site would have to take place, it appears as though it would be feasible. The equipment above has been superimposed onto a portion of this site plan, and for reference, this layout sketch is contained in Appendix A.

4.4.4. Work Not Typically Included

N/A The scope and pricing provided is for a complete turnkey WFGD island, including stack, fans, ducting etc. This includes a new stack. Since there is one gas train for all three units, and the existing stacks are probably steel lined, WFGD would be highly corrosive on a steel lined stack, a new stack would be necessary.

5. PRICE AND SCHEDULE

5.1. PRICING

5.1.1. Capital Costs

The following are order of magnitude capital costs (Design, Supply, and Installation) for the scope of equipment described in this report for each system:

	Unit 1	Unit 2	Unit 3
Firing System Technologies			
T-Fired Option 1 - In-Windbox Low NOx Mod's*	$700,000.00	$700,000.00	N/A
T-Fired Option 2 - SOFA Based Low NOx System*	$3,700,000.00	$3,700,000.00	N/A
Wall Fired Option 1 - Low NOx Burner**	N/A	N/A	$1,300,000.00
Wall Fired Option 2 - SOFA Based Low NOx System**	N/A	N/A	$2,700,000.00
SNCR Process***	$4,100,000.00	$4,100,000.00	$4,100,000.00
Capture Technologies			
Mechanical Collector	$2,000,000.00	$2,000,000.00	$2,000,000.00
Electrostatic Precipitator****	$6,000,000.00	$6,000,000.00	$6,000,000.00
Dry Flue Gas Desulfurization System	$60,000,000.00		
Wet Flue Gas Desulfurization System**** (Turnkey WFGD island)	$95,000,000.00		

* Option 1 & Option 2 for T-Fired are separate systems and cannot be installed in a phased approach

** Option 1 & Option 2 for Wall-Fired are priced as separate systems but can be installed in a phased approach. Note that the difference in pricing between options is the SOFA portion of the system in Option 2.

*** The SNCR Process can be installed in a phased approach in combination with any of the T-Fired or Wall Fired Low NOx Options.

****Only these two capture technologies are suited to be installed in combination.

All costs are in Canadian Dollars. The above prices are present day estimated prices only and are not given by ALSTOM Canada Inc. as an offer, nor as terms of any contract, nor as an undertaking that the estimated price shall be the final price.

Note that the above numbers are representative only of the scope of equipment discussed in the report. Specifically for the capture technologies (excluding WFGD since this is a Turnkey price), a typical assumed value for the "Balance of Plant" scope required to support the system is approximately 20% of the prices noted above. Note in this case that "Balance of Plant" refers to site, electrical, roads, civil, and does not cover all of the equipment listed in the Work Not Included scope sections. There is other capital equipment required for most of the options noted above, and this other equipment in some cases can have a significant impact on the total capital cost. This additional equipment was not sized or estimated as part of the scope of this report, but these issues could be investigated further if the study direction focuses on specific technologies in a later Phase.

Where new ID Fans are required, these fans (c/w motor, starter, support structure etc) can cost roughly between 1.0 to 2.0 MCAD depending on the size of fan required.

5.1.2. Operating & Maintenance Costs

5.1.2.1. Firing System Technologies

The Firing System Technologies do not have large operating costs associated with them since they do not require new equipment which has high power consumption, or the requirement for additional operating staff. Maintenance requirements do increase moderately since additional inspections should be performed during annual outages, and the new equipment and instruments require typical maintenance attention. In general the firing system technologies discussed do not have a significant affect on yearly operating and maintenance costs.

The SNCR NOx OUT system by Fuel Tech Inc is a relatively inexpensive NOx reduction technique when considering the capital costs compared with the predicted reductions in emissions, however, the technology comes with high operating costs. The system consumes approximately 140 gallons per unit, per hour (gph) of urea. The yearly consumption costs of urea could range between $1,000,000 to $1,500,000 CDN per unit depending upon the capacity factor of the unit.

5.1.2.2. Capture Technologies

The following table summarizes the typical maintenance and operating costs associated with the capture technologies discussed in this report. Note that although there is no specific power consumption associated with the Mechanical Collector, the pressure drop associated with this system would likely result in the requirement for a new fan, which would consume additional power. As noted in the specific sections, new ID fans are required for the DFGD and WFGD, and may be required for the ESP, so the same comment on power consumption applies. The selection and sizing of fans was not considered during this preliminary review of the different technologies.

	Maintenance Requirements	**Maintenance Costs**	**Power Consumption**
Capture Technologies	Yearly Outage Inspection	Yearly Estimate	Yearly Estimate
Mechanical Collector	(1-2 days)	$8,000*	≈600 kW**
Electrostatic Precipitator	(3-5 days)	$38,000*	≈400 kW**
Dry Flue Gas Desulfurization	(3-5 days)	3% Capital Cost	0.38% of Generation
Wet Flue Gas Desulfurization	(10 days)	No Data Available	1.2% - 1.8% of Generation

* Labour for inspection only
** Includes estimate of Fan Consumption
All costs are estimated in Canadian Dollars.

5.2. SCHEDULE

5.2.1. *Typical Lead Times*

The following are typical time spans from Notice to Proceed to Initial Operation for the scope of equipment described in this report for each system:

	Span
Firing System Technologies	
T-Fired In-Windbox Low NOx Mod's	< 12 months
T-Fired SOFA Based Low NOx System	< 12 months
Wall Fired Low NOx Burner	< 12 months
Wall Fired SOFA Based Low NOx System	< 12 months
SNCR Process	< 12 months
Capture Technologies	
Mechanical Collector	< 12 months
Electrostatic Precipitator	12-14 months
Dry Flue Gas Desulfurization	24 months
Wet Flue Gas Desulfurization	32 months

APPENDIX A – DRAWINGS

Capture Technology Drawings

Multicyclone Mechanical Collectors

20037-GA-200-002 Rev AA Mechanical Collector General Arrangement

Dry Electrostatic Precipitator

20037-GA-200-001 Rev AA Electrostatic Precipitator General Arrangement
Holyrood Site Plan ESP Location

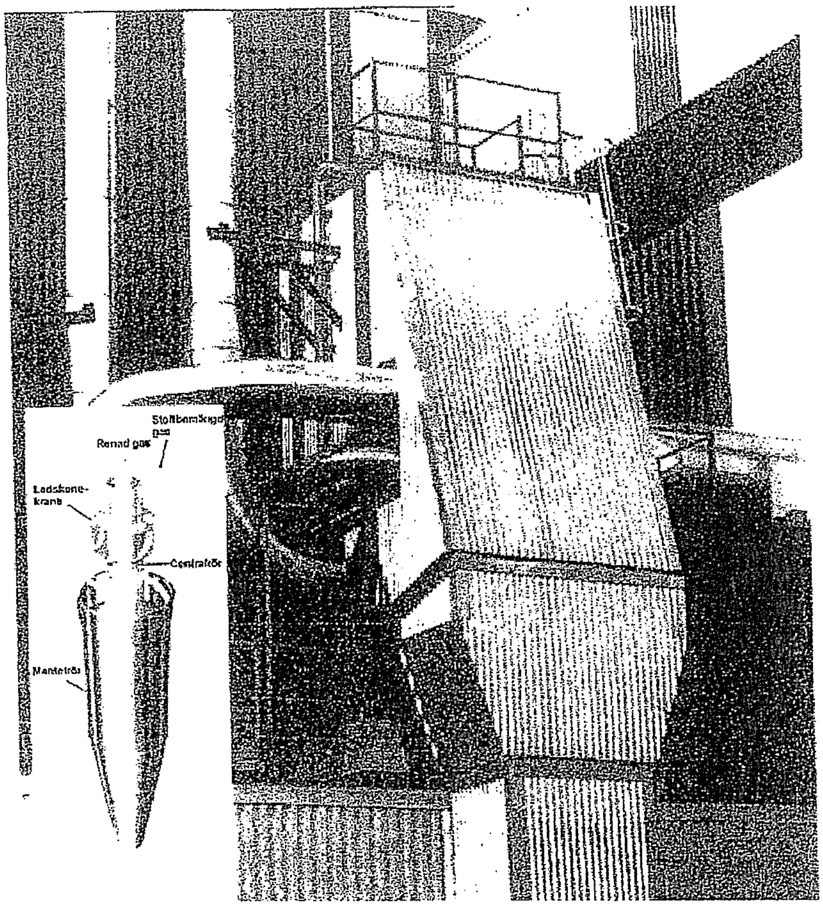
Dry Flue Gas Desulfurization

Typical Arrgt SDA and LKP Fabric Filter Side Elevation
Typical Arrgt SDA and LKP Fabric Filter Plan View
Holyrood Site Plan DFGD Location

Wet Flue Gas Desulfurization

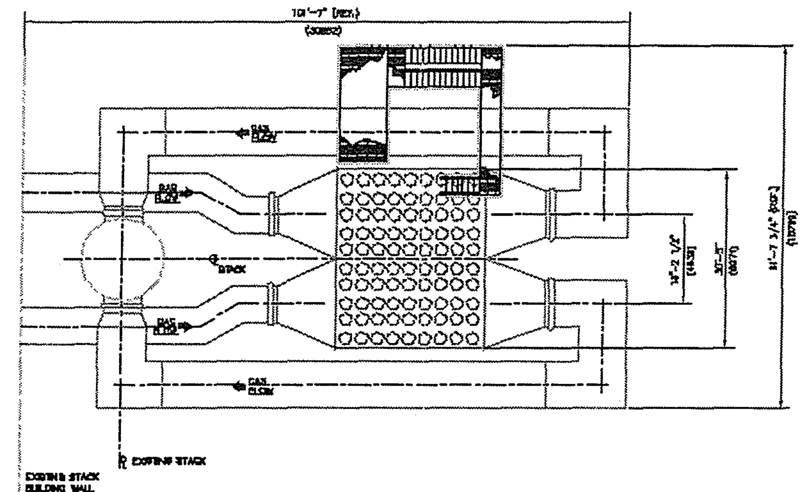
Typical Absorber Arrangement
Typical WFGD Arrangement
Holyrood Site Plan WFGD Location

MULTICYCLONE MECHANICAL COLLECTORS

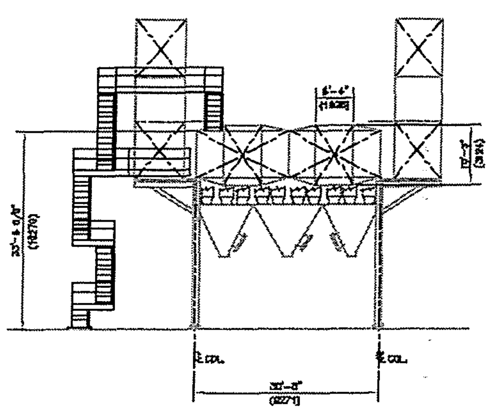


Clean air solutions from

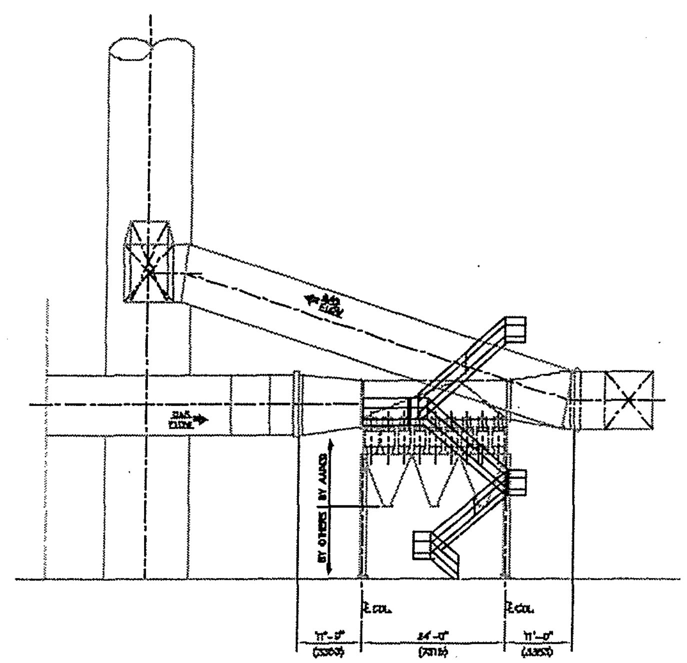
ALSTOM



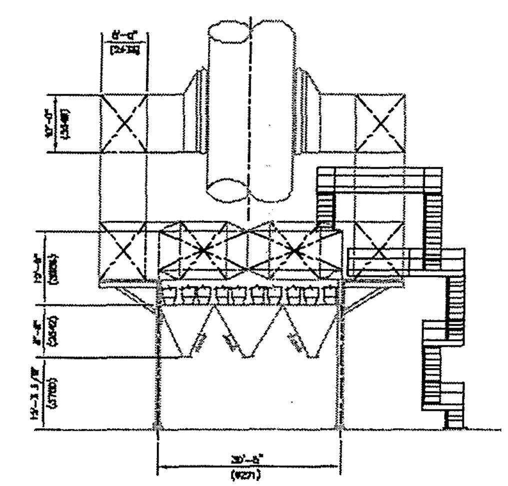
PLAN



INLET VIEW



SIDE ELEVATION



OUTLET VIEW

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ABB
ASEA BROWN BOVERI

ABB ENVIRONMENTAL SYSTEMS

SCALE NONE
ABB REFERENCE NUMBER 20037
DRAWN BY F.McPHERSON DATE 5/14/02

NEWFOUNDLAND AND LABRADOR HYDRO
HOLYROOD GENERATING STATION
OPTION 1 – MECHANICAL COLLECTOR

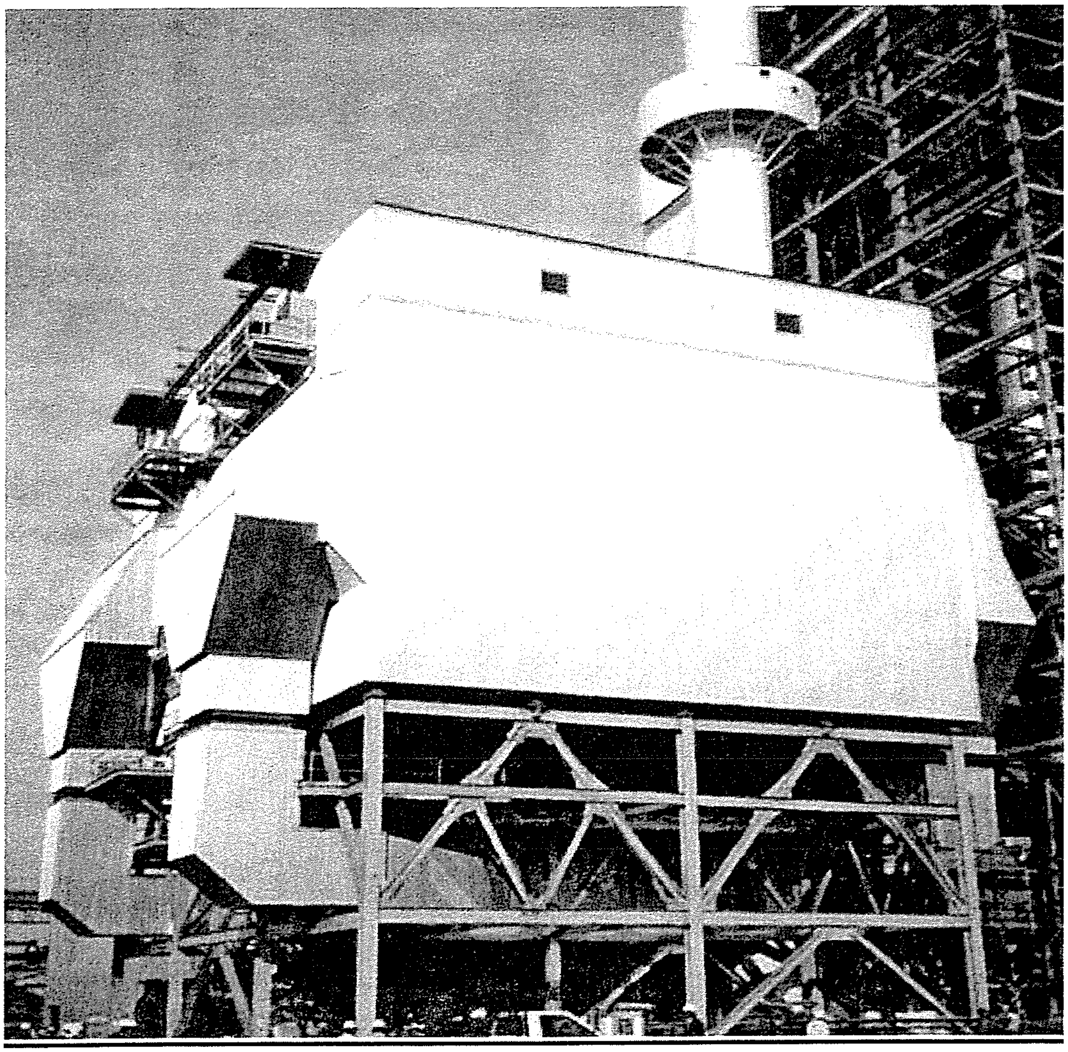
GENERAL ARRANGEMENT

DWG. NO. 20037-GA-200-002
REV. AA

FILE NO. 1110002-GA-200-002RAA

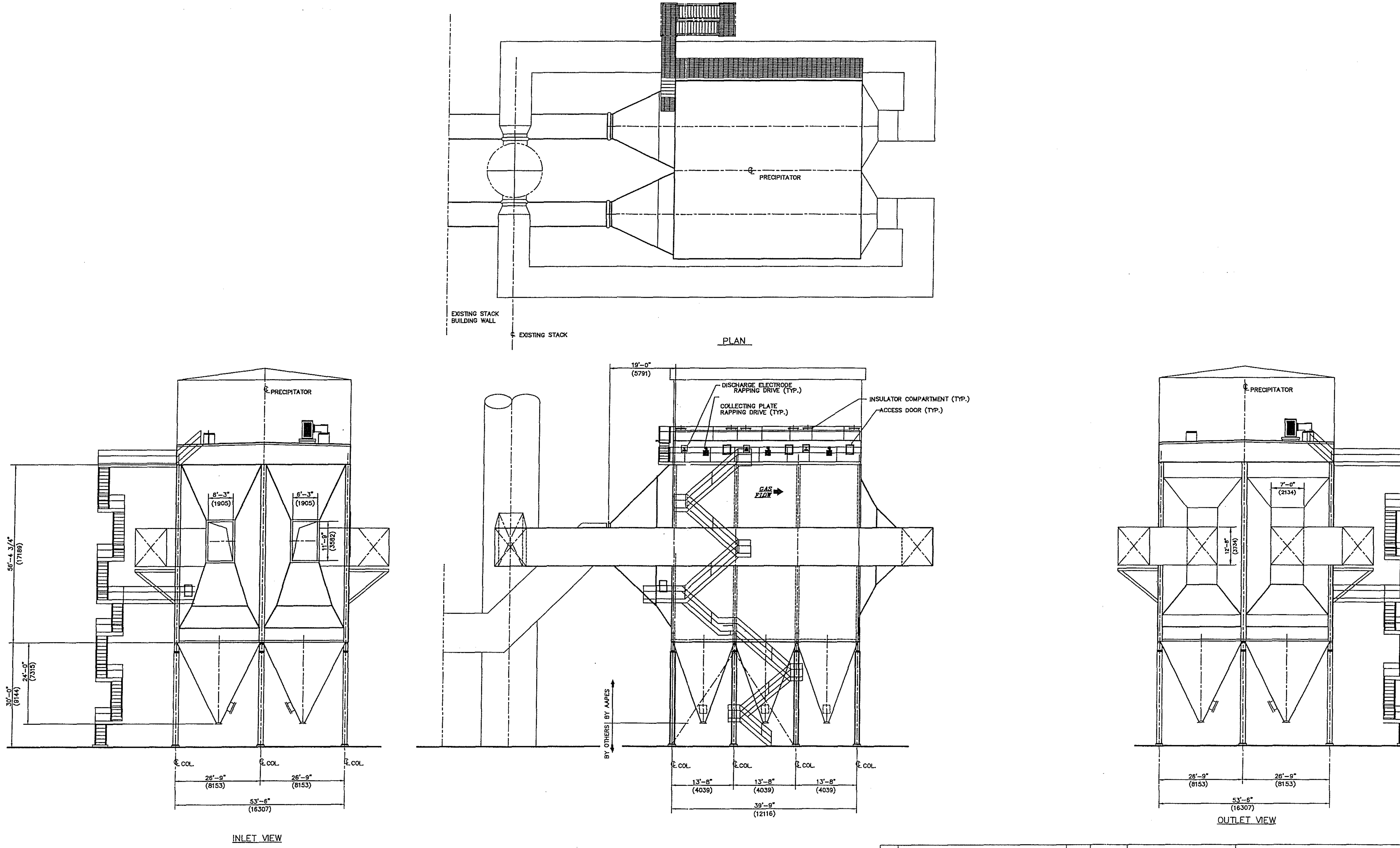
1/10"   1/8"-1/4"   3/8"-3/4"   1/2"-1"

DRY ELECTROSTATIC PRECIPITATOR



Clean air solutions from

ALSTOM



3 ONLY 1FTA-3x30.5M-160-150-A2-E131

	DESCRIPTION	APPR.	

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ABB REFERENCE NUMBER: 20037
CUSTOMER REFERENCE:
DRAWN BY: DATE:
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

NEWFOUNDLAND AND LABRADOR HYDRO
HOLYROOD
PROPOSED ELECTROSTATIC PRECIPITATOR

GENERAL ARRANGEMENT

DWG. NO. 20037-GA-200-001
REV. AA

FILE NO. GA2001AA

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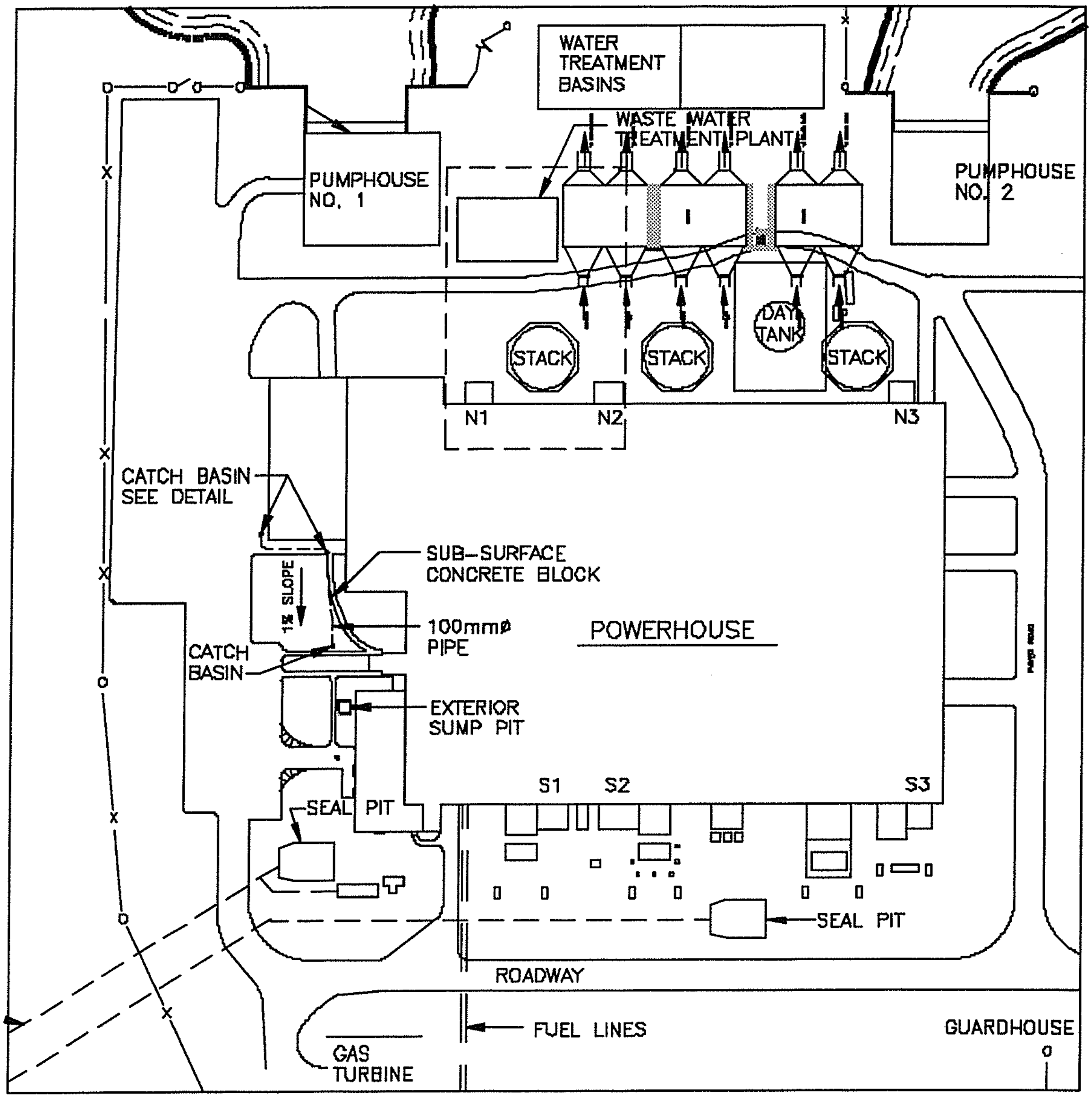
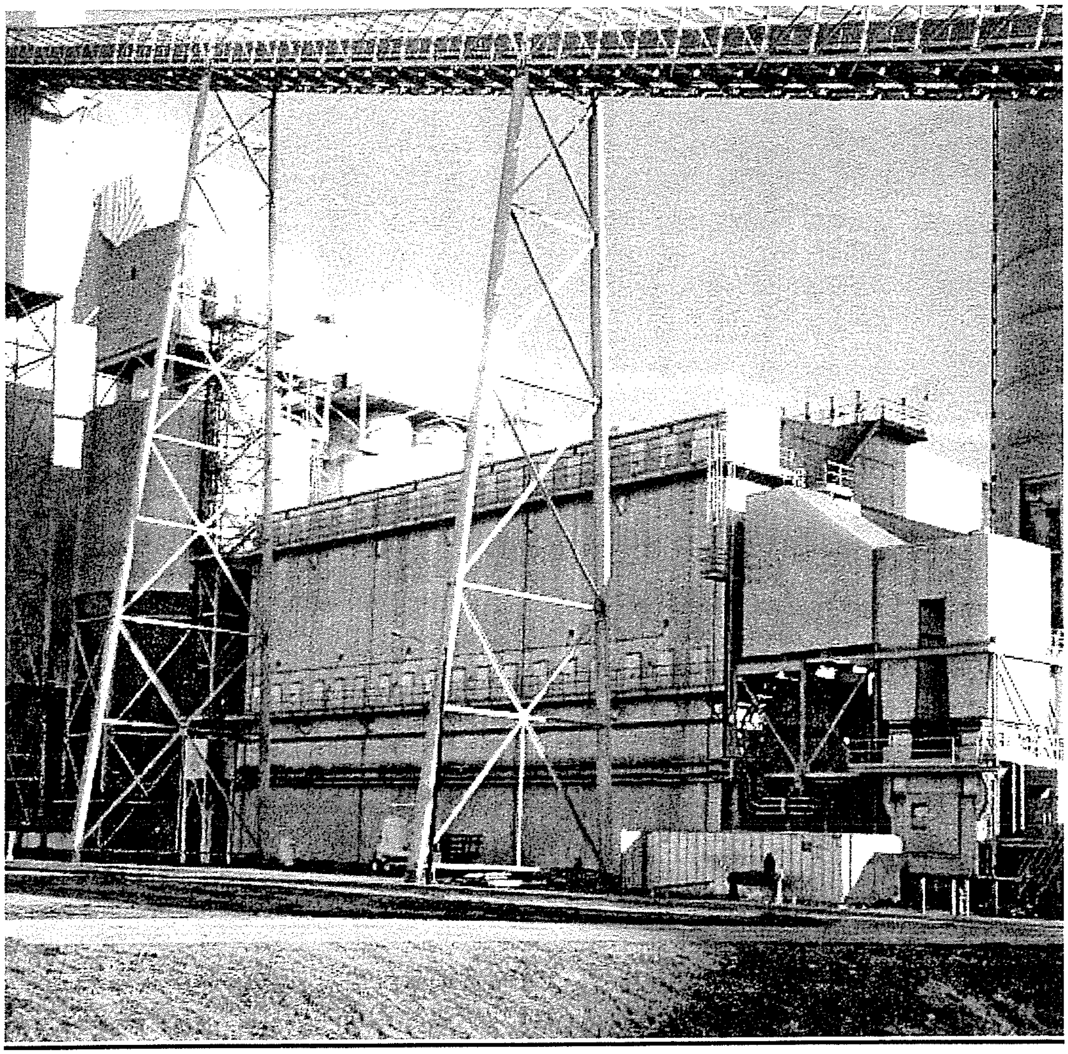


Holyrood Site Plan ESP Location

DRY FLUE GAS DESULFURIZATION



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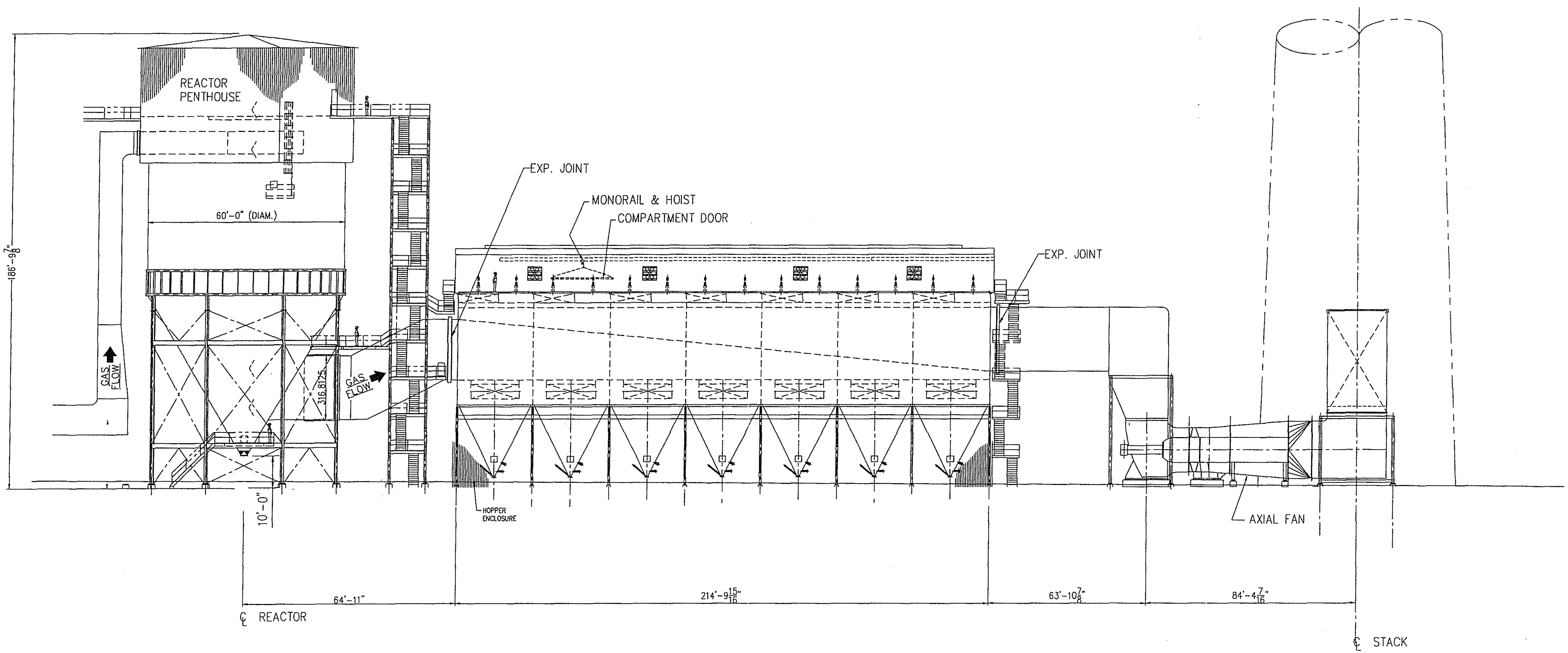

SIDE ELEVATION

TYPICAL

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ALSTOM
Power Inc.
Environmental Systems Division

SCALE: 1/8"=1'-0"
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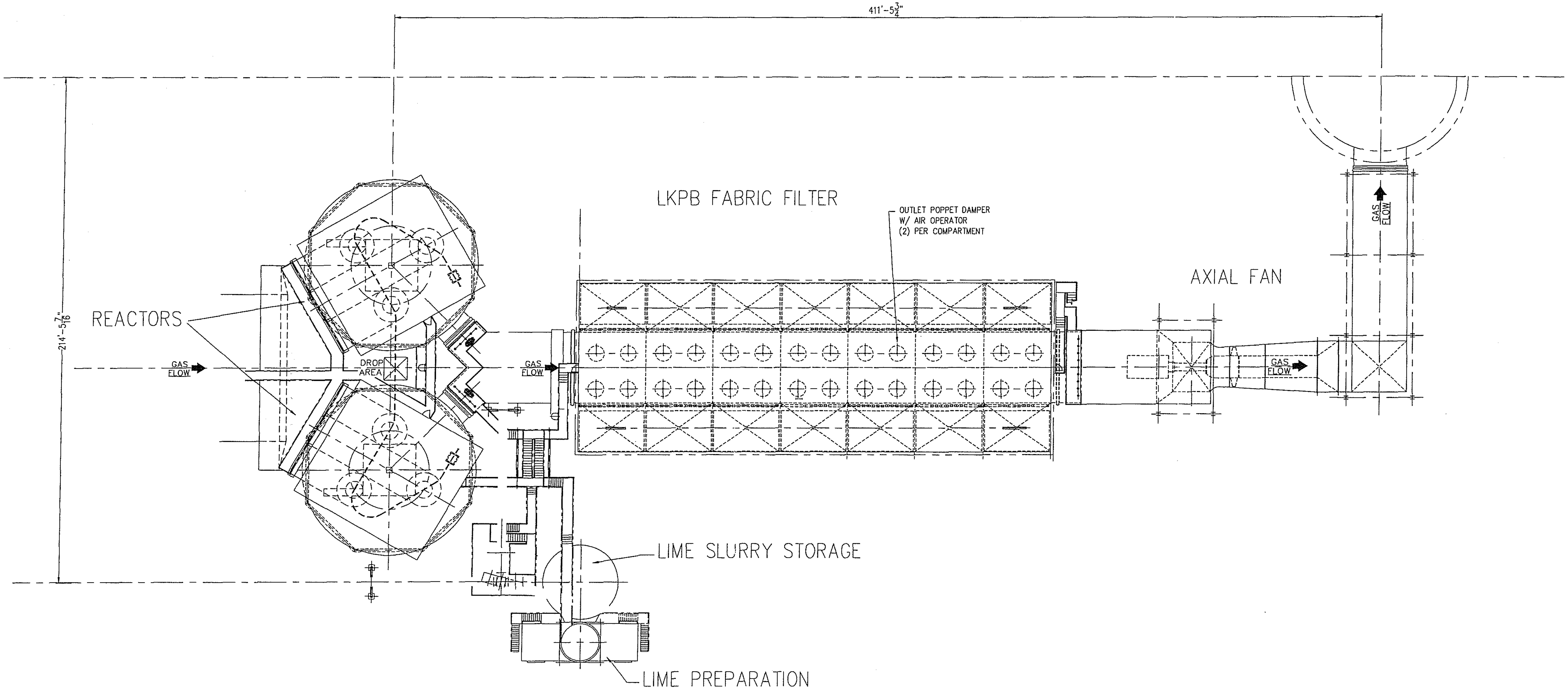
AP REFERENCE NUMBER:
CUSTOMER REFERENCE:
DRAWN BY: DATE:
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

HOLYROOD GENERATING STATION
TYPICAL ARRANGEMENT
SDA AND LKP FABRIC FILTER
SIDE ELEVATION

DWG. NO. REV.

FILE NO.

1/10" 1/8"-1/4" 3/8"-3/4" 1/2"-1"



PLAN VIEW

TYPICAL

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

ALSTOM
Power Inc.
Environmental Systems Division

SCALE: 1/8"=1'-0"
PCS NUMBER: 200
AP REFERENCE NUMBER:
CUSTOMER REFERENCE:
DRAWN BY: DATE:
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

HOLYROOD GENERATING STATION
TYPICAL ARRANGEMENT
SDA AND LKP FABRIC FILTER
PLAN VIEW

DWG. NO. | REV. | FILE NO.

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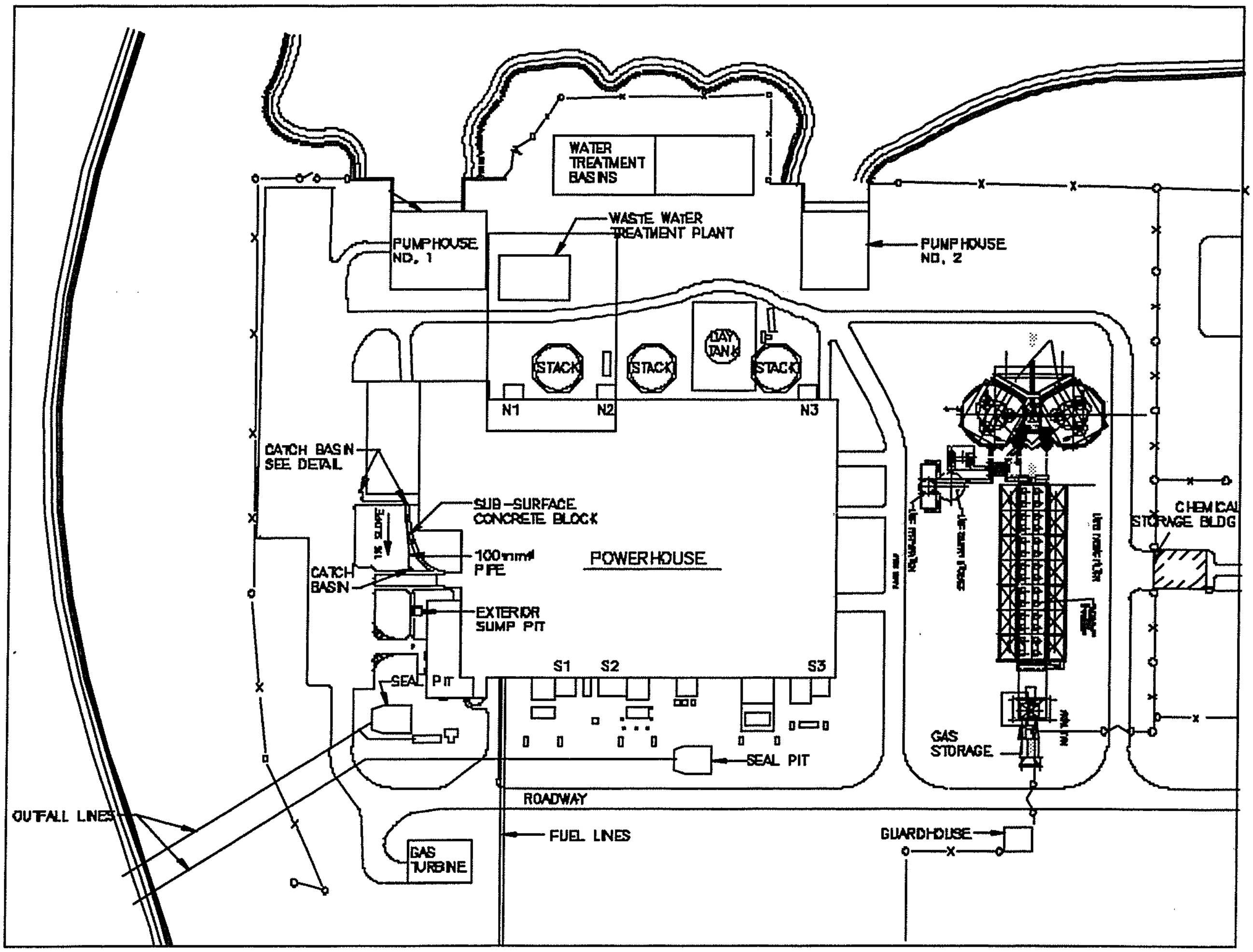
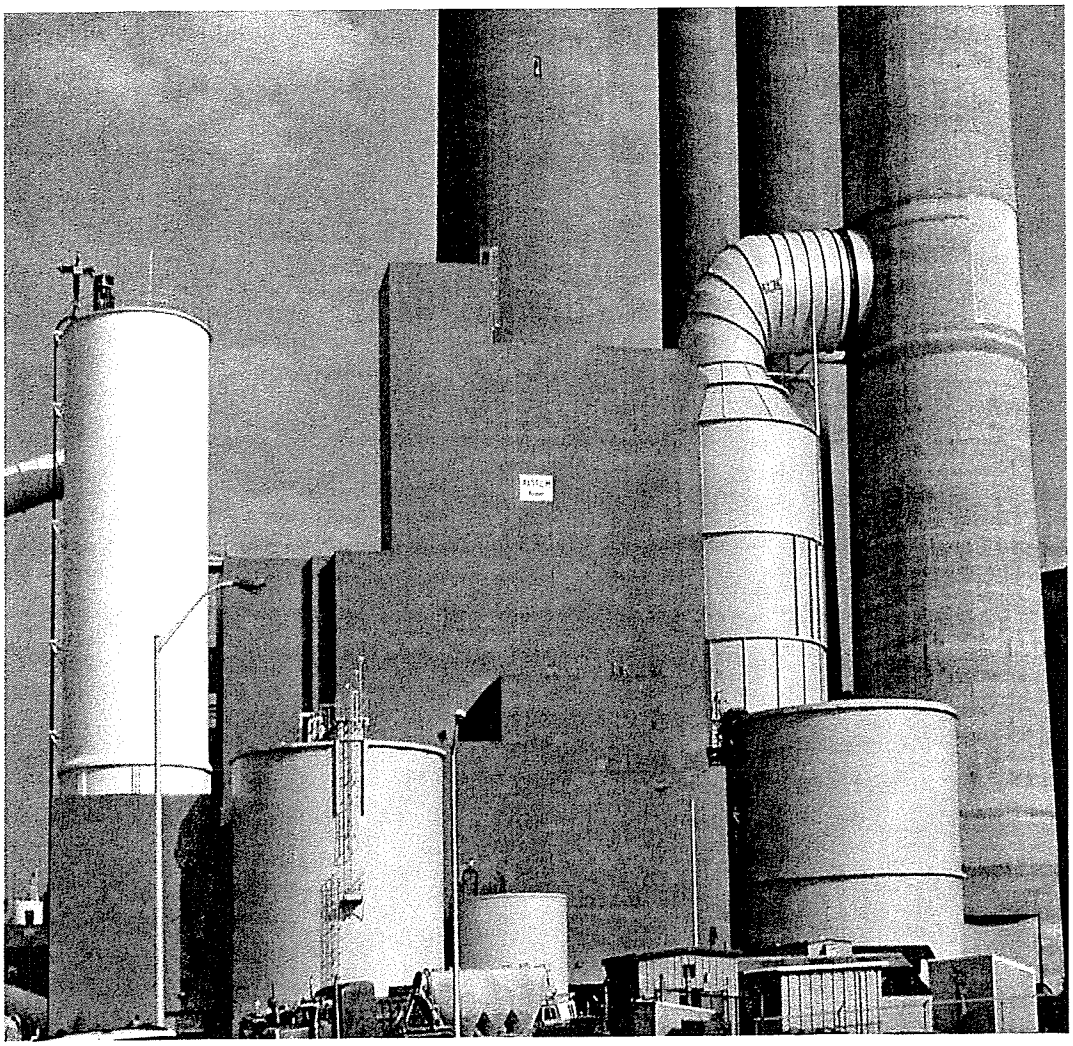


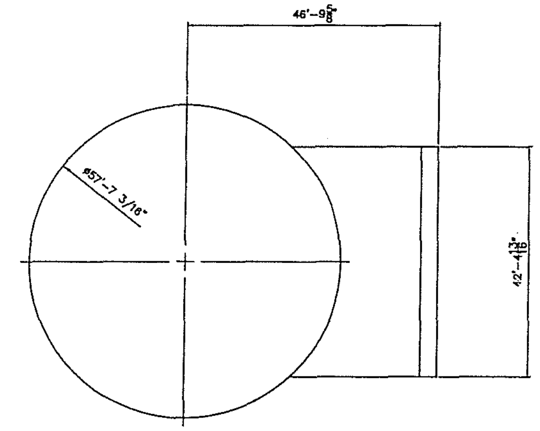
Holyrood Site Plan DFGD Location

WET FLUE GAS DESULFURIZATION

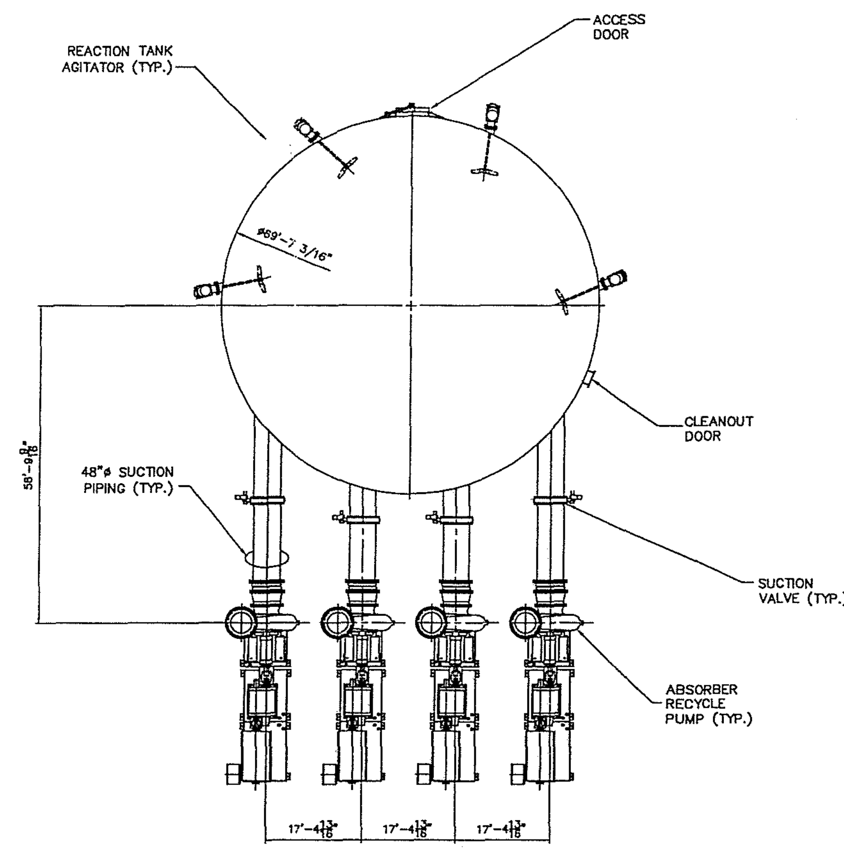


Clean air solutions from

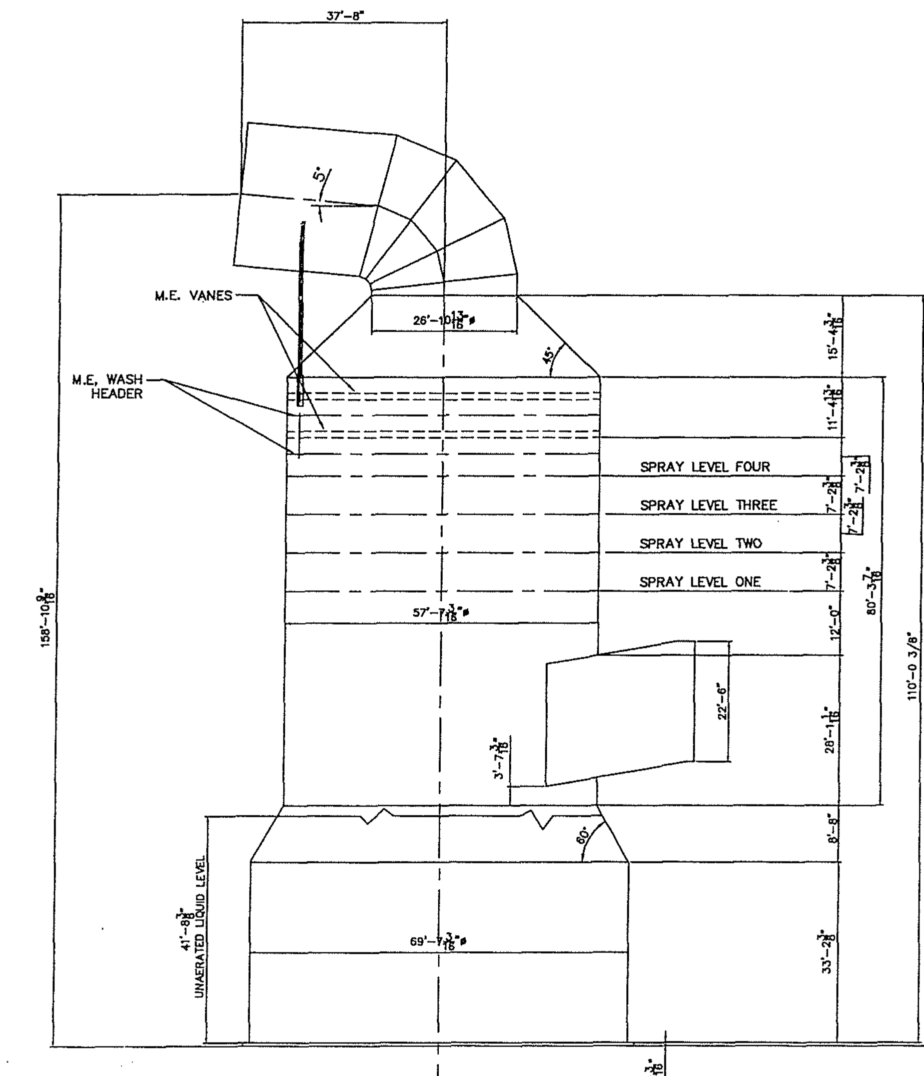
ALSTOM



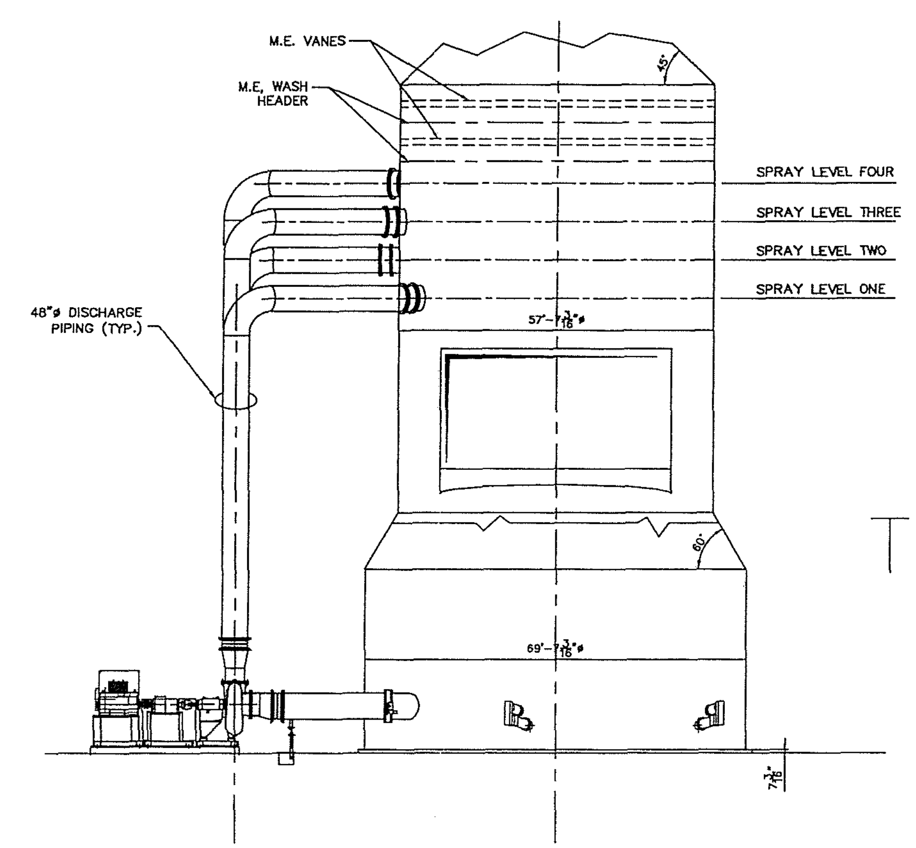
ABSORBER PLAN ABOVE INLET DUCT



ABSORBER PLAN ABOVE SUCTION PIPING



ABSORBER SIDE ELEVATION



ABSORBER FRONT ELEVATION

TYPICAL

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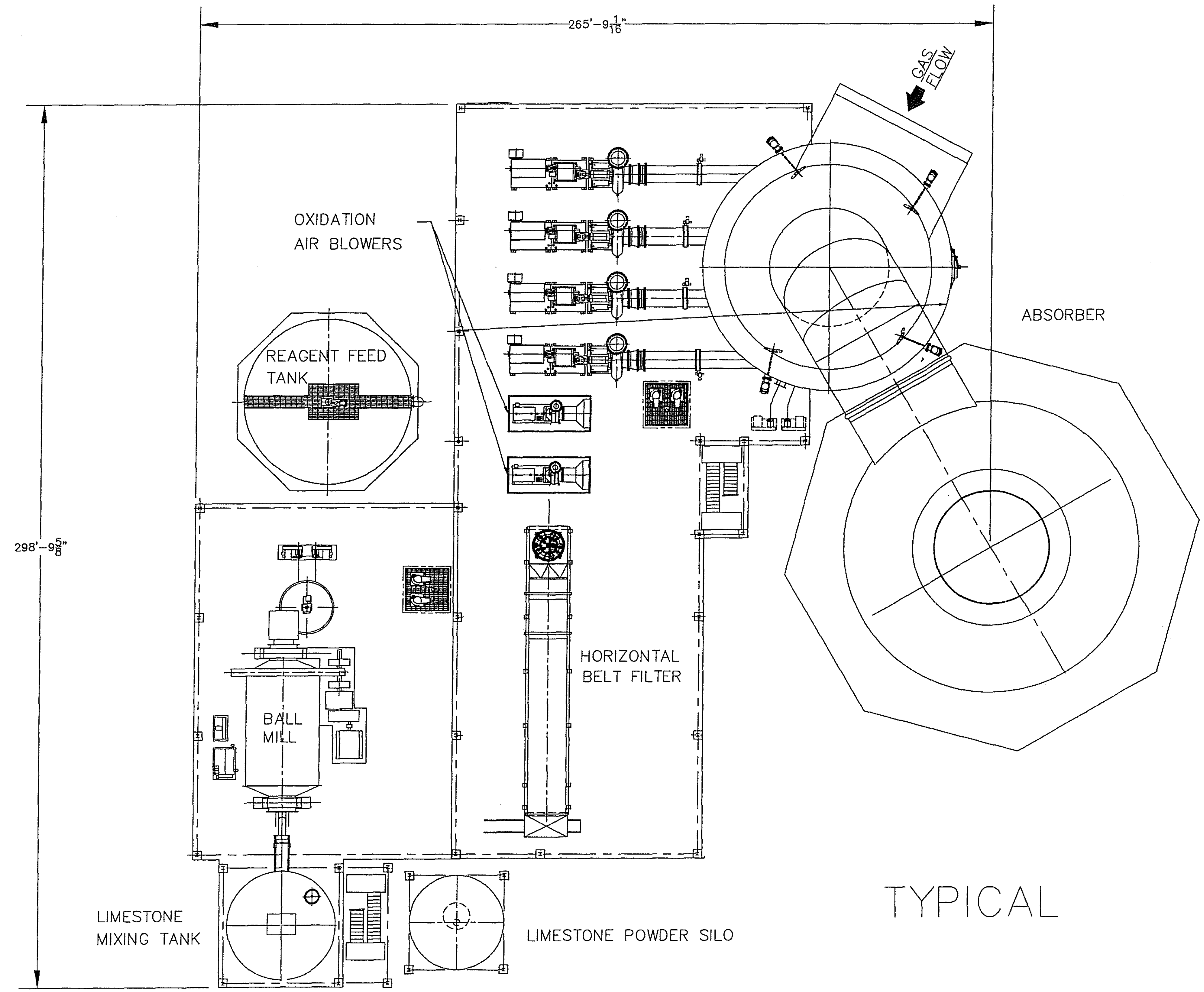
APPROVED BY: DATE:

HOLYROOD GENERATING STATION
TYPICAL ABSORBER ARRANGEMENT

DWG. NO. REV.

1/10" 1/8" - 1/4" 3/8" - 3/4" 1/2' - 1"



PLAN

ISO 9001
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SCALE: 1"=20'
PCS NUMBER: 200
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CUSTOMER REFERENCE:
DRAWN BY: DATE:
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

HOLYROOD GENERATING STATION
TYPICAL WFGD ARRANGEMENT

DWG. NO.

REV.

FILE NO.

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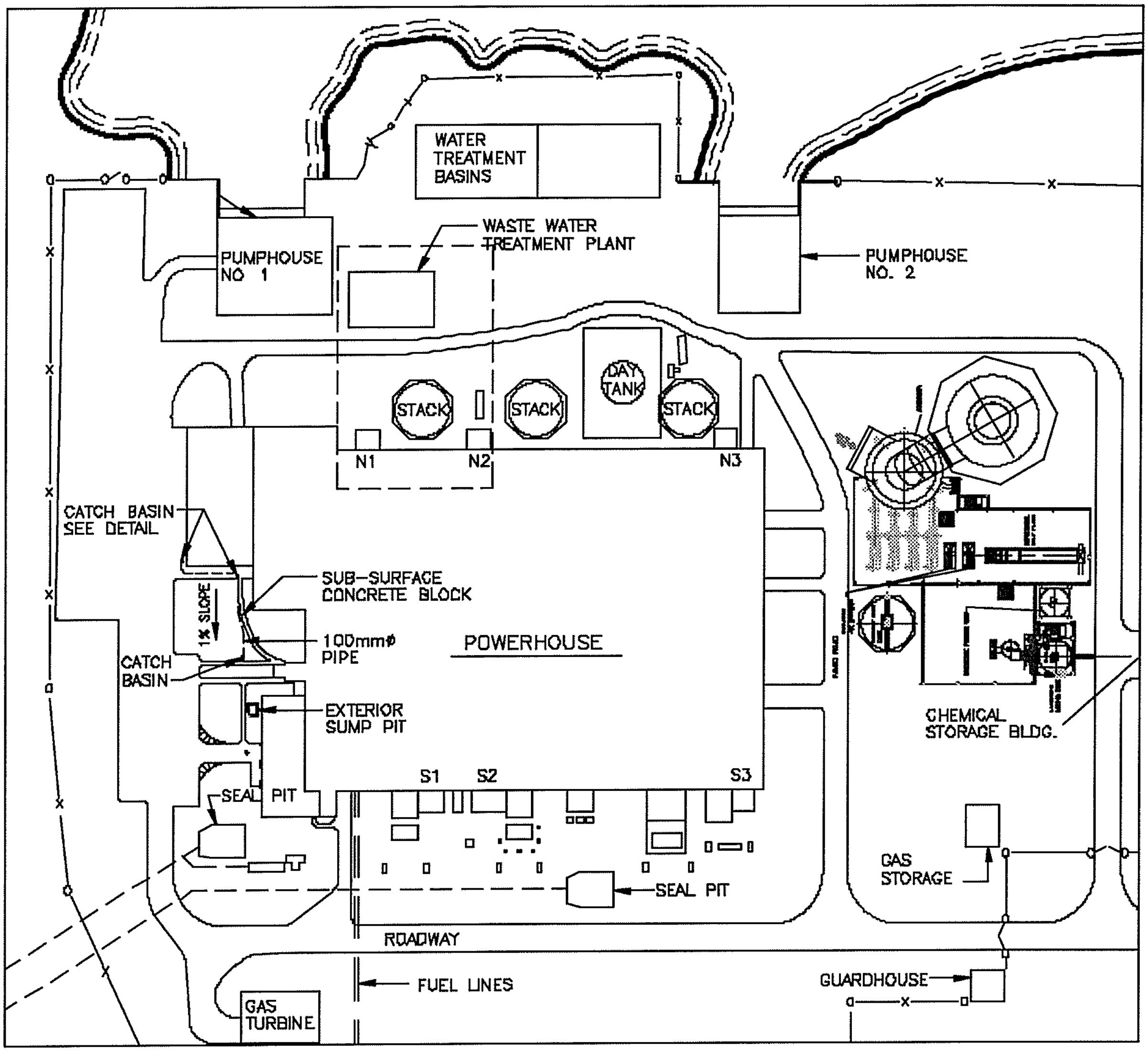


Holyrood Site Plan WFGD Location

APPENDIX B – SNCR BROCHURE

NO_xOUT

NO_x Reduction Process

TECHNICAL BENEFITS

- 30-80% NO_x reduction
- No liquid or solid by-product for disposal minimizes waste management
- Easy to retrofit – little downtime required
- Minimum space required
- Can be "hybridized" with other NO_x reduction technologies
- Is "Flexible" - can adjust NO_x reduction target
- Reagents not subject to SARA, Title III reporting

FUEL TECH™

Technology for a renewed environment™

The NO_xOUT process is a urea-based Selective Non-Catalytic Reduction (SNCR) process. It provides cost-effective NO_x reduction for fossil and waste-fueled stationary combustion sources.

Fuel Tech introduced the NO_xOUT process to provide an economical solution for meeting stringent requirements for NO_x reduction from fossil-fueled and waste-fueled combustion sources. The NO_xOUT process converts NO_x to harmless nitrogen and water.

From 1976 to 1981, research sponsored by the Electric Power Research Institute (EPRI) discovered that urea was an effective reagent for this conversion, and patented the chemical process.

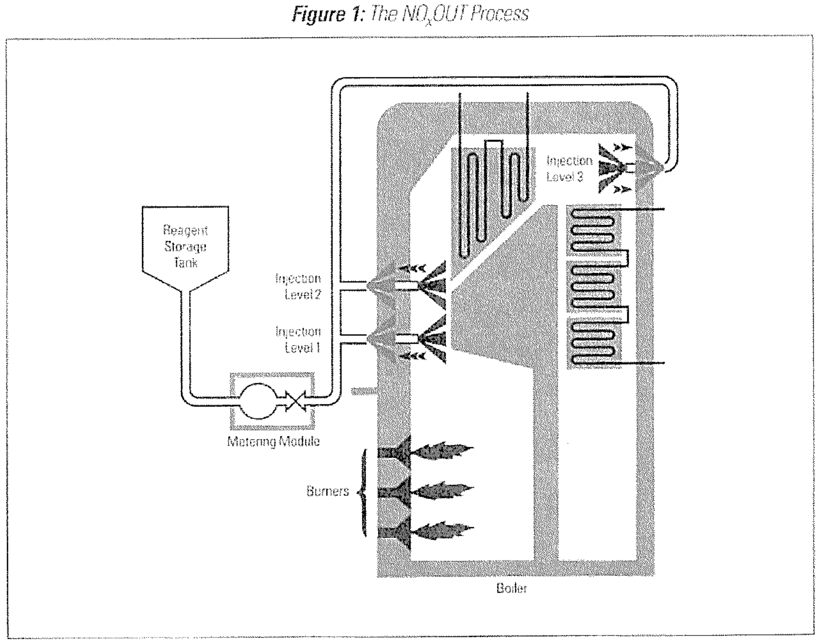
However, this reaction takes place only in a narrow temperature range, below which ammonia (NH_3) is formed and above which NO_x emission levels are compromised.

The NO_xOUT system uses process and mechanical modifications to significantly widen the temperature range over which the process is effective. Fuel Tech has developed this technology and commercially licenses it both directly and through selected licensing agents throughout the world.

What Makes the NO_xOUT Process Different?

Two of the most important features of the NO_xOUT process are its low energy consumption, typically 20-40 kW, and its ability to control ammonia slip, which may occur as a by-product of incomplete NO_x reduction. The NO_xOUT process uses particle momentum control technology instead of "brute force" (in the form of high volume mixing air or steam– 1 to 4% of flue gas volume) to achieve appropriate reagent distribution.

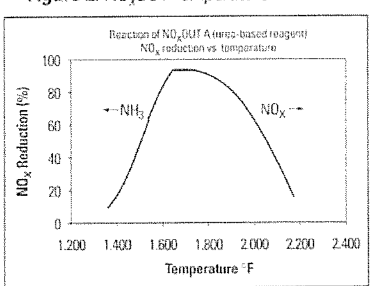
Figure 1: *The NO_xOUT Process*



Excessive ammonia slip adds another pollutant to the flue gas, can cause plugging of air preheaters through the formation of ammonium bisulfate, and also can cause contamination of fly ash and flue gas desulfurization waste water. Unlike other SNCR processes, the NO_XOUT technology is able to control ammonia slip to very low levels. (Refer to Figure 3.)

Combustion modification such as low NO_X burners and over-fire air are effective, yet normally only permit NO_X reductions up to 50% on liquid- or solid- fueled boilers. To date, there has been a sharp increase in cost when further NO_X reductions are required using selective catalytic reduction (SCR). SCR entails substantial capital cost and high operating costs associated with reactor construction and erection, catalyst replacement, pressure drop through the system, and ammonia consumption.

***Figure 2:** NO_XOUT Temperature Window*

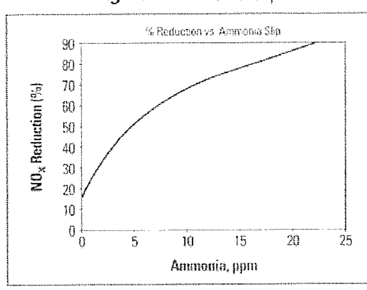


The NO_XOUT process can be used as a "stand-alone" technology to achieve up to 80% NO_X reduction, or it can be combined or "hybridized" with other NO_X reduction technologies to achieve SCR-type performance (>85% NO_X reduction) at a significantly lower cost.

The NO_XOUT process has been commercially installed on a wide range of combustion units burning such fuels as:

- Coal
- Sludge
- Lignite
- Wood
- Oil
- Fiber
- Gas
- Biomass
- Municipal solid waste
- Refinery/CO gas

***Figure 3:** Ammonia Slip*



Commercial combustion units include:

- Refinery crude heaters and CO boilers
- Sludge combustors
- Industrial power boilers
- Municipal waste combustors
- Incinerators
- Circulating fluidized bed boilers
- Stoker-fired boilers burning wood and coal
- Package boilers
- Tangentially-fired utility boilers
- Cyclone-fired utility boilers
- Wall-fired utility boilers (wet & dry)

The NO_XOUT process is also well suited to process combustion units, such as:

- Cement kilns
- Calciners
- Glass furnaces
- Coke ovens
- Ethylene furnaces

The NO_XOUT process can be easily retrofitted to most existing units. Fuel Tech can perform a NO_XOUT process demonstration, via mobile equipment, to predict and optimize the technology's operating results on a commercial application.

In the design phase of a NO_XOUT process application, Fuel Tech uses computational fluid dynamics (CFD) and chemical kinetic modeling (CKM) to aid in injector location selection, and determine the appropriate reagent droplet size distribution. Combustion unit temperature mapping and operating data are model inputs and are used to achieve high NO_X reduction and low by-product emissions, and prevent impingement on heat transfer surfaces.

***Figure 4:** CFD Model of Tangential Boiler*

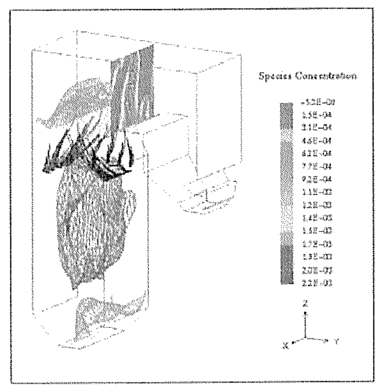


Figure 4 shows modeling results from a 750-MW tangentially-fired utility boiler burning coal. It shows 14 injectors placed at a certain elevation, spraying at a certain angle. The model then predicts the reagent concentration at various cross-sections and superimposes this information on flue gas temperatures and velocity. This modeling information is used to design a NO_XOUT process application to meet the needs for tightening pollution control restrictions in the Northeast United States.

Under Engineering Services Agreements, Fuel Tech performs CFD/CKM modeling studies on combustion units to predict NO_X reduction performance and by-product emissions. To optimize the NO_XOUT technology, Fuel Tech has developed equipment and components including:

- Specific injection equipment to ensure that the NO_XOUT reagents are distributed optimally in the combustion unit flue gases
- Control hardware and software to enable the NO_XOUT process to follow load changes and spikes in stack NO_X with the appropriate flow rates and mixtures of reagents
- Modular equipment for storing, mixing, metering, and pumping the NO_XOUT reagents to reduce retrofit costs

Figure 5: *Cost and Performance of the NO_XOUT Process on Various Units*

Electric Utility NO_XOUT Applications

	Boiler Type	MW	NOx REDUCTION %	CAPITAL $/kw	TOTAL ANNUALIZED USE COST $/Ton NOx REMOVED
Coal	Tangentially Fired	150	40%	$ 23.00	$ 1,775
	Wall Fired	600	25-30%	$ 10.50	$ 1,300 *
	Cyclone	160	36%	$ 12.50	$ 980
	Cell Fired	600	30%	$ 12.00	—
	Circulating Fluidized Bed	45	60%	$ 14.30	$ 1,380
	Wet Bottom, Wall Fired	320	30-35%	$ 13.00	$ 1,275 *
Oil	Tangentially Fired	160	40 %	$ 15.00	$ 1,200

* Ozone Season Only

Industrial Units

INDUSTRY TYPE	NO_X REDUCTION %	TOTAL ANNUALIZED USE COST $/Ton NO_X REMOVED
Refining Industry		
CO Boiler	65%	$712
GT HSRG	50%	$1,135
Package Boiler	60%	$1,900
Process Heaters	60 - 75%	$1200 - 1600
Pulp and Paper Industry		
Power Boiler	50%	$1,032
Recovery Boiler	60%	—
Sludge Combustor	50%	$1,424
Industrial Boilers	50%	$1,012
Municipal Waste Combustor Industry		
Municipal Waste Combustor	40 - 70%	$1040 - 1553
Wood Fired IPP / Cogen Industry		
Wood Fired IPP / Cogen	35 - 70%	$918 - 2222
Tire Burner Industry		
Tire Burners	50%	$1,418

Fuel Tech is an international company working at the forefront of combustion technology, with a particular objective to meet the increasing demands for cost-effective pollution control technologies and equipment.
In addition to the NO_xOUT process, Fuel Tech's products include:

- Enhanced fuel additive technologies
- Control programs for corrosion, particulate emissions, and fireside deposition
- The NO_xOUT Cascade® Process can remove up to 90% of NO_x using a compact SCR catalyst in conjunction with the NO_xOUT SNCR process.
- The AEFLGR™ Process (Amine-Enhanced Fuel Lean Gas Reburn) can provide an alternative to full SCR systems, but without the capital expense, catalyst replacement expense, or "stranded asset" potential of a SCR system.
- The NO_xOUT SCR® Process for industrial generators provides a cost-effective and safer alternative to ammonia-based SCR systems.

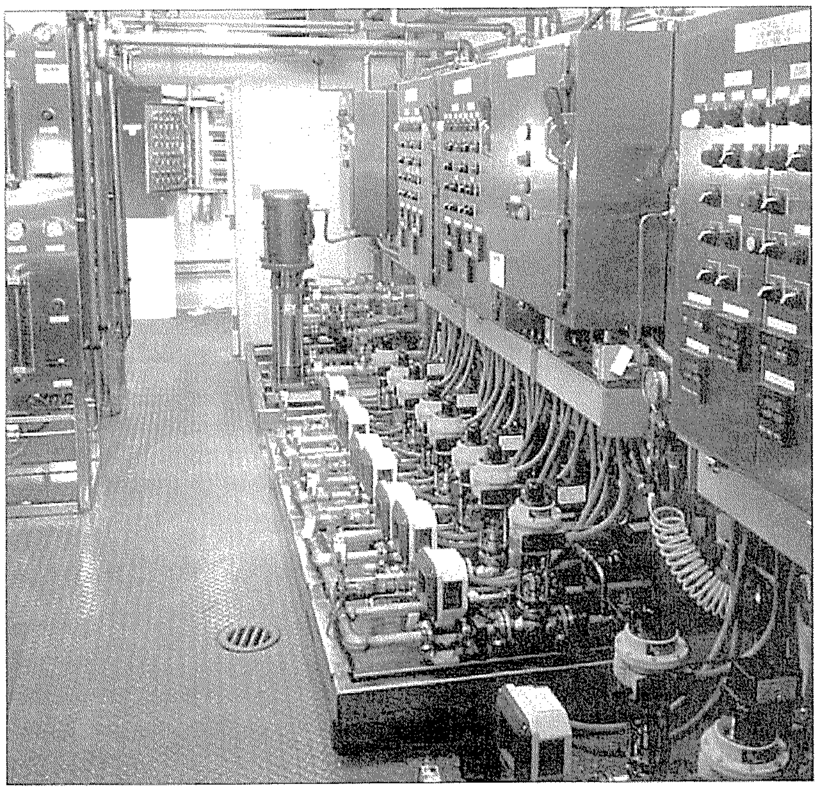


Figure 6: *Modular control and feed system delivered to site ready for hook-up*

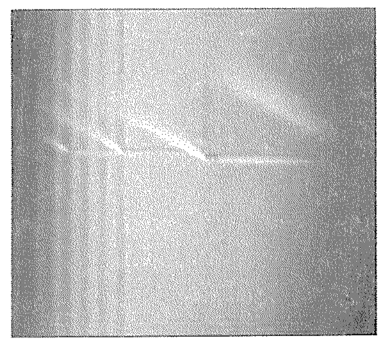


Figure 7: *Typical through-wall NO_xOUT injector*

For more information on NO_x reduction programs available from Fuel Tech, call, fax, or write us at:

Fuel Tech, Inc. • 512 Kingsland Drive • Batavia, IL 60510
Phone 800.666.9688 • 630.845.4500 • Fax 630.845.4501
www.fueltechnv.com • webmaster@fueltechnv.com

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APPENDIX C –EXPERIENCE LISTS

ALSTOM Power
Reference list: Electrostatic Precipitators for oil fired boilers

Country	Plant	End User	Start Up	Capacity	Unit	Process	Boiler Type	Gasflow (m^3/hr)	Temp. (°C)
Germany	Wesseling/Uk	Union-Kraftstoff	1978	220	TPH	Oil	Boiler	360000	210
Italy	Lamarmora	Asm Brescia	1990	35	MW	Oil	Boiler	262440	120
Italy	Lamarmora	Asm Brescia	1989	35	MW	Oil	Boiler	262440	120
Italy	Brescia	Asm Brescia	1993	90	MW	Oil	Boiler	351720	180
Italy	Ravenna	Enel	1966	170	MW	Oil	Boiler	894500	148
Italy	Civitavecchia	Enel	1989	240	MW	Oil	Boiler	1051000	154
Italy	Sermide	Enel	1982	320	MW	Oil	Boiler	1400000	145
Italy	Termini Imerese	Enel	1975	320	MW	Oil	Boiler	1416000	145
Italy	Tavazzano	Enel	1982	320	MW	Oil	Boiler	1400000	145
Italy	Sermide	Enel	1982	320	MW	Oil	Boiler	1400000	145
Italy	Melilli	Enel	1975	320	MW	Oil	Boiler	1416000	145
Italy	Termini Imerese	Enel	1975	320	MW	Oil	Boiler	1416000	145
Italy	Melilli	Enel	1975	320	MW	Oil	Boiler	1416000	145
Italy	Sermide	Enel	1983	320	MW	Oil	Boiler	1400000	145
Italy	Sermide	Enel	1982	320	MW	Oil	Boiler	1400000	145
Italy	Tavazzano	Enel	1982	320	MW	Oil	Boiler	1400000	145
Japan	Shingu Mill	Tomoegawa Seishi K.K.	1977	0		Oil	Boiler	33850	245
Japan	Toshiba Denki	Toshiba Denki Kk,Transistor Works	1974	0		Oil	Boiler	31700	300
Japan	Wakamatsu	Mitsui Alumina Seizo K.K.	1975	0		Oil	Boiler	131000	190
Japan	Kashima Pst	Kashima Minami Kyodo Hatsuden K.K.	1992	0		Oil	Boiler	439300	177
Japan	Shingu Mill	Tomoegawa Seishi K.K.	1977	0		Oil	Boiler	33850	245
Japan	Mie Mill	Yokohama Gomu K.K.	1974	7	MW	Oil	Boiler	168000	171
Japan	Fukuoka	Fukuoka Seishi K.K.	1973	39	TPH	Oil	Boiler	55450	200
Japan	Ikeda Mill	Daihatsu Kogyo K.K.	1974	39	TPH	Oil	Boiler	72800	250
Japan	Mie Power St.	Chubu Denryoku K.K.	1974	65	MW	Oil	Boiler	378200	140
Japan	Sakai	Sakai Kyodo Karyoku K.K.	1973	75	MW	Oil	Boiler	385600	147
Japan	Sakai	Sakai Kyodo Karyoku K.K.	1973	75	MW	Oil	Boiler	385600	147
Japan	Mie Power St.	Chubu Denryoku K.K.	1974	75	MW	Oil	Boiler	413000	140
Japan	Mie Power St.	Chubu Denryoku K.K.	1974	75	MW	Oil	Boiler	413000	140
Japan	Wakamatsu	Mitsui Alumina Seizo K.K.	1972	75	TPH	Oil	Boiler	132600	188
Japan	Nobeoka	Asahi Kasei Kogyo K.K.	1975	110	TPH	Oil	Boiler	190600	200
Japan	Chiba/Dai	Dai Nippon Inc K.K.	1976	114	TPH	Oil	Boiler	191500	250
Japan	Sofue Mill	Sanko Seishi K.K.	1975	120	TPH	Oil	Boiler	1782000	150
Japan	Ishikawa	Okinawa Denryoku K.K.	1974	125	MW	Oil	Boiler	531000	133
Japan	Ishikawa	Okinawa Denryoku K.K.	1978	125	MW	Oil	Boiler	541600	135
Japan	Toyama	Hokuriku Denryoku K.K.	1972	156	MW	Oil	Boiler	708000	142
Japan	Toyama	Hokuriku Denryoku K.K.	1972	156	MW	Oil	Boiler	708000	142
Japan	Yokkaichi Refinery	Daikyo Sekiyu K.K.	1972	170	TPH	Oil	Boiler	260000	200
Japan	Mizushima	Nippon Kogyo K.K.	1972	220	TPH	Oil	Boiler	44200	200
Japan	Tomakomai Kyodo	Tomakomai Kyodo Hatsuden K.K.	1972	250	MW	Oil	Boiler	1090000	140
Japan	Tomakomai Kyodo	Tomakomai Kyodo Hatsuden K.K.	1972	250	MW	Oil	Boiler	1096400	140
Japan	Date P.St	Hokkaido Denryoku K.K.	1975	350	MW	Oil	Boiler	1543000	140

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Reference list: Electrostatic Precipitators for oil fired boilers

Country	Plant	End User	Start Up	Capacity	Unit	Process	Boiler Type	Gasflow (m^3/hr)	Temp (°C)
Japan	Shiriuchi Pst	Hokkaido Electric Power	1997	350	MW	Oil	Boiler	1702800	165
Japan	Date P.St	Hokkaido Denryoku K.K.	1979	350	MW	Oil	Boiler	1543000	140
Japan	Taketoyo	Chubu Denryoku K.K.	1972	375	MW	Oil	Boiler	1613000	140
Japan	Taketoyo	Chubu Denryoku K.K.	1972	375	MW	Oil	Boiler	1613000	140
Japan	Taketoyo	Chubu Denryoku K.K.	1972	375	MW	Oil	Boiler	1607000	140
Japan	Taketoyo	Chubu Denryoku K.K.	1989	375	MW	Oil	Boiler	1785200	140
Japan	Taketoyo	Chubu Denryoku K.K.	1991	375	MW	Oil	Boiler	1598600	100
Japan	Makiminato	Okinawa Denryoku K.K.	1981	405	TPH	Oil	Boiler	604000	140
Japan	Shin Tokushima	Shikoku Denryoku K.K.	1973	435	TPH	Oil	Boiler	580000	135
Japan	Shin Tokushima	Shikoku Denryoku K.K.	1973	710	TPH	Oil	Boiler	900000	140
Korea	Vanguard	Kyungin Energy Co	1992	0		Oil	Boiler	121000	180
Korea	Ssangyong	Ssangyong Heavy Ind Co Ltd	1987	0		Oil	Boiler	428500	167
Korea	Vanguard	Kyungin Energy Co	1992	0		Oil	Boiler	69000	180
Korea	Gumi	Kolon Engineering Enc.	1992	65	TPH	Oil	Boiler	120000	200
Lithuania	Lithuania	Lithuanian Power Station	1996	0		Oil	Boiler	0	170
Netherlands	Dordrecht	Geb Dordrecht	1981	320	MW	Oil	Boiler	1470000	175
Saudi Arabia	Sceco Rabigh	Saudi National Co. Ltd	1985	250	MW	Oil	Boiler	1320000	164
Saudi Arabia	Sceco Rabigh	Saudi National Co. Ltd	1985	250	MW	Oil	Boiler	1320000	164
Saudi Arabia	Sceco Rabigh	Saudi National Co. Ltd	1984	250	MW	Oil	Boiler	1320000	164
Saudi Arabia	Sceco Rabigh	Saudi National Co. Ltd	1985	250	MW	Oil	Boiler	1320000	164
Singapore	Seraya Stage Iii	Public Utility Board, Singapore	1995	250	MW	Oil	Boiler	1062000	130
Singapore	Seraya Stage Ii	Public Utility Board, Singapore	1992	250	MW	Oil	Boiler	1024200	125
Singapore	Seraya Stage Iii	Public Utility Board, Singapore	1996	250	MW	Oil	Boiler	1062000	130
Singapore	Seraya Stage Ii	Public Utility Board, Singapore	1992	250	MW	Oil	Boiler	1024200	125
Singapore	Seraya Stage Ii	Public Utility Board, Singapore	1992	250	MW	Oil	Boiler	1024200	125
Singapore	Seraya Stage Iii	Public Utility Board, Singapore	1995	250	MW	Oil	Boiler	1062000	130
Spain	Granadilla	UNELCO	1995	80	MWE	Oil	Boiler	401760	170
Spain	Baranco D Tirajan	UNELCO	1995	80	MWE	Oil	Boiler	401760	170
Spain	Granadilla	UNELCO	1995	80	MWE	Oil	Boiler	401760	170
Spain	Baranco D Tirajan	UNELCO	1995	80	MWE	Oil	Boiler	401760	170
Sweden	Fyriskraft	Uppsala Energi AB	1973	0		Oil	Boiler	1015000	152
Sweden	Hammarby	Stockholms Energi Produktion AB	1987	80	MW	Oil	Boiler	155000	180
Sweden	Värtan	Stockholms Energi Produktion AB	1976	250	MW	Oil	Boiler	1105000	140
Sweden	Karlshamn	Kkab Karlshamn	1996	350	MWE	Oil	Boiler	0	130
Sweden	Hässelbyverket	Stockholms Energi Produktion AB	1967	490	TPD	Oil	Boiler	750000	150
Switzerland	Basel	Elektricitätswerk Basel	1975	0		Oil	Boiler	411200	210
Taiwan	Talinpu	Chinese Petroleum Corporation	1993	130	TPH	Oil	Boiler	192000	160
Taiwan	Hsieh Ho	Taiwan Power Co	1992	500	MW	Oil	Boiler	2391000	150
Taiwan	Hsieh Ho	Taiwan Power Co	1992	500	MW	Oil	Boiler	2391000	150
Taiwan	Hsieh Ho	Taiwan Power Co	1992	500	MW	Oil	Boiler	2481000	150
Taiwan	Talinpu	Chinese Petroleum Corporation	1995	130	TPH	Oil&gas	Boiler	193313	180

RETROFIT LOW NOX EXPERIENCE
OIL AND GAS FIRED UNITS (TANGENTIALLY FIRED)

Customer	Plant	Fuels	Contract Year
Keyspan	Ravenswood #20	Oil	1989
ENEL (Italy)	Fusina #2	Coal/Oil/Gas	1990
Philadelphia Electric Co.	Cromby #2	Gas/Oil	1991
Keyspan	Northport # 1	Oil	1992
NRG	Bridgeport Harbor #3	Coal/Oil	1993
Keyspan	Northport # 4	Oil/Gas	1993
Keyspan	Northport # 2	Oil/Gas	1994
Keyspan	Northport # 3	Oil	1995
Keyspan	Port Jefferson #3	Oil	1994
Keyspan	Barrett #2	Oil/Gas	1995
Iberdrola (Spain)	Santurce	Oil/Gas	1997
Keyspan	Yorktown #3	Oil	1999
Keyspan	Ravenswood #10	Oil	2000
Keyspan	Ravenswood #30	Oil/Gas	2001

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LOW NOx RETROFIT EXPERIENCE LIST – WALL-FIRED BURNER

ORDERED	CUSTOMER	PLANT	DESCRIPTION	FUEL	BURNERS	COMMISSIONED YEAR
1995	Pfizer	Groton	105,000 lb/hr CE VU40 Boiler	NG/#6	4 @ 40 MBtu/hr	1996
1996	Richmond Power & Light	Whitewater	Riley Stoker 300,000 lb/hr 32 MWe Utility Boiler 1	East. Bit. Coal	6 @ 70 MBtu/hr	1996
1996	ABB Site Services	Windsor Site	24 MBtu/hr Heating Boiler	NG/#6/#2	1 @ 30 MBtu/hr	1996
1996	ABB Alamsas	Tupras Refinery	330,000 lb/hr CE 37/VP18 Boiler	NG/RFO/PG	4 @ 119 MBtu/hr	1998
1997	Electricity Supply Board – Dublin, Eire	Poolbeg	120 MWe Foster Wheeler Reheat Boiler	NG/#6	12 @100 MBtu/hr	1998
1997	PLN Gresik, Indonesia	Gresik	100 MWe IHI – FW Utility Boiler	NG/RFO	12 @127 MBtu/Hr	1997
1997	Hoechst Celanese	Clear Lake	200,000 lb/hr CE 34-VP-18W Boiler	NG	1 @ 280 MBtu/hr	1998
1997	International Paper	Riegelwood	200,000 lb/hr CE 30-VP-14W Boiler	NG/#6	1 @ 280 MBtu/hr	1997
1997	Santee Cooper	Grainger	650,000 lb/hr Riley Stoker Utility Boiler	East. Bit. Coal	8 @ 130 MBtu/hr	1998
1997	Omaha Public Power District	North Omaha 5	1,600,000 lb/hr FW Utility Boiler	PRB Coal/Gas	12 @ 175 MBtu/hr	1999
1997	United Power Association	Stanton	172 MWe FW Utility Boiler	Lignite Coal	12 @ 125 MBtu/hr	1998
1998	ABB SA Portugal	C. N. P. Borealis	(3) FW Utility Boilers approx. 390,000 lb/hr	NG/#6	18 @ 80 MBtu/hr	1999

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LOW NOx RETROFIT EXPERIENCE LIST – WALL-FIRED BURNER

1998	ABB CE SpA Italy	ISE/Taranto	(3) B&W/Ansaldo Boilers @ 1,058,000 lb/hr	NG/COG BFG/#6 Other Wastes	20 @ 90 MBtu/hr 40 @ 90 MBtu/hr	1999
1998	Formosa Heavy Industries	Lung-Teh No. 1 (LT-1)	120 T/Hr (264,600 Lb/Hr) Kawasaki Heavy Industry Boiler RSFC™ Burners with OFA system	PC/Oil	6 @ 58 MBtu/hr	1999
1998	Formosa Heavy Industries	Lin – Yuan No. 1 (LP-1)	120 T/Hr (264,600 Lb/Hr) Hitachi Boiler RSFC™ Burners with OFA system	PC/Oil	4 @ 89 MBtu/hr	1999
1998	Virginia Power	Bremo No. 4	170 MWe B&W Utility Boiler	PC/Oil	16 @ 95 MBtu/Hr	1999
1998	Virginia Power	Chesapeake No. 3	170 MWe B&W Utility Boiler	PC/Oil	16 @ 95 MBtu/Hr	1999
1998	Western Farmers Electric Cooperative	Hugo No. 1	400 MWe B&W Utility Boiler – OFA Addition with modifications to existing burners	PRB Coal	35 @ 135 MBtu/Hr	2000
1998	CDE ITABO	Unit No. 1	880,000 Lb/Hr Foster Wheeler Boiler	Oil/PC	8 @ 148 MBtu/Hr	1999
1999	E. I. DuPont	Waynesboro No. 2	120,000 lb/hr C-E VU-40 Boiler	East Bit. Coal/ NG/Oil	4 @ 54 MBtu/Hr	2000
2000	Rock-Tenn	Lynchburg No. 3	90,000 Lb/Hr B&W Stirling	NG/Oil	1 @ 100 M Btu/Hr	2001
2000	Ameren	Mermac No. 4	360 MW FW Boiler	PRB Coal	18 @ 200 MBtu/Hr	2001
2001	E. I. DuPont	Waynesboro No. 1	120,000 lb/hr C-E VU-40 Boiler	East Bit. Coal/ NG/Oil	4 @ 54 MBtu/Hr	2001

APPENDIX D –STUDY PROPOSAL TERMS

A PROPOSAL TO

NEWFOUNDLAND & LABRADOR HYDRO

FOR AN

ENGINEERING STUDY

TO

INVESTIGATE METHODS TO IMPROVE EMISSIONS

ON

UNIT'S 1, 2 AND 3

AT

HOLYROOD GENERATING STATION

PREPARED BY ALSTOM

OTTAWA, ONTARIO

PROPOSAL NO. C0120267

DECEMBER 19, 2001

ALSTOM POWER

Alstom Canada Inc.

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STUDY OF METHODS TO IMPROVE EMISSIONS

Introduction

Newfoundland & Labrador Hydro (N&L Hydro) Units #1 & 2 at Holyrood Generation Station are duplicate, 1970 vintage 150 MW, oil-fired boilers originally designed and built by Combustion Engineering (now ALSTOM). The boiler was designed to generate an MCR main steam flow of 1,050,000 lb/hr at an outlet temperature of 1005°F and a pressure of 1900 psig, with a feed-water inlet temperature of 468°F. The MCR design condition for the reheater was a flow of 921,000 lb/hr at an inlet temperature of 690°F and a pressure of 518 psig, with an outlet temperature of 1005°F. These two units were modified in approximately 1987 by ALSTOM to achieve an increased output of approximately 175 MW. The resulting revised steam conditions are an MCR main steam flow of 1,167,000 lb/hr at an outlet temperature of 1005°F and a pressure of 1955 psig, with a feed-water inlet temperature of 464°F, with a reheater flow of 1,045,000 lb/hr at an inlet temperature of 667°F and a pressure of 493 psig, with an outlet temperature of 1005°F.

Unit #3 at Holyrood Generation Station is a 1980 vintage 150 MW, oil fired boiler originally designed and built by Babcock and Wilcox. Unit #3 was designed to generate an MCR main steam flow of 960,600 lb/hr at an outlet temperature of 1,005°F and a pressure of 1890 psig, with a feed-water inlet temperature of 464°F. The MCR design condition for the reheater was a flow of 865,700 lb/hr at an inlet temperature of 683°F and a pressure of 487 psig, with an outlet temperature of 1,005°F. ALSTOM has modified the reheater of unit #3 in 2001, but this modification has been done with the intent of achieving the originally intended boiler performance while providing improved reheater material protection.

N&L Hydro have expressed an interest in investigating methods to improve emissions from the three units at the Holyrood G.S. ALSTOM thus is providing a budget proposal for a paid study to address this request. The proposed study will focus on three areas of potential improvement:

1. Fuel changes
2. Firing equipment improvements
3. Capture technologies

STUDY OF METHODS TO IMPROVE EMISSIONS

Objective

ALSTOM will perform an engineering study evaluating potential to improve emissions from the three boilers at N&L Holyrood G.S. For the purposes of this study, Units #1 & 2 will be treated as duplicate units, with one design evaluation for the two units. Unit #3 will be treated as a separate unit. As Unit #3 was initially designed by others, ALSTOM will confer with N&L Hydro to ensure that the appropriate information is used for the evaluation.

For each design, ALSTOM will review the three areas of focus listed below.

> **Fuel Changes** – This will involve research into the effects of N&L Hydro purchasing better fuel to improve emissions. For example, evaluating the costs and effects of changing from a current fuel oil containing approximately 2.2 % Sulphur to one containing approximately 1.6 or 1.2 % Sulphur. In order to perform this evaluation, N&L Hydro will provide ALSTOM with some general fuel oil sourcing (pricing) information or contacts upon which to base the evaluation.
>
> **Firing Equipment Improvements** – ALSTOM will evaluate the firing systems for the two designs and advise potential operating or physical modifications that are likely to reduce the particulate and NO_x produced by the boilers.
>
> **Capture Technologies** – ALSTOM will review a number of options for improved capture of the particulate that is generated by the boilers.

ALSTOM will then generate a summary report discussing the findings of the study for each area of investigation.

STUDY OF METHODS TO IMPROVE EMISSIONS

Methodology

Each topic will be addressed by ALSTOM from a technical perspective, with a breakdown on a three tiered approach, generally starting with low cost changes and escalating to more costly options:

- Operational modifications – This involves potential improvements that may be obtained with operational modifications. For example, ALSTOM has been able to suggest changes to burner operations that have resulted in NO_x improvements just by re-directing air or changing windbox pressures. Discussion on this type of improvement will be presented in the report. Note: the suggested operational improvements would derive from an on-site Technical Services Representative upon conducting burner and boiler inspection, reviewing operations and operating data and performing a limited matrix of tuning tests.

- Minor equipment modification – This reflects the next level, where minor modifications may have a further reduction of emissions. This would be similar to changing out oil burner tips, as was suggested at a meeting by ALSTOM recently and carried out by N&L Hydro, apparently with improved operations. Similar options may involve changing oil burner buckets within the existing windbox pressure part openings to improve secondary air injection and thus reduce unburned carbon or improve NO_x reduction. For the Wall-fired boiler this would include change-out of the burner registers within the existing waterwall throat opening.

- Major equipment modifications – This is the more extensive effort. If it is perceived that the foregoing methods will not meet ultimate emission requirements, major modifications may be required. This may involve adding overfire air compartments for additional NO_x reduction or adding a precipitator for additional particulate collection. Particulate emission reduction techniques such as knockout boxes, mechanical collectors and precipitators together with the requirements for I.D.Fans will be considered and quantified. Basic feasibility arrangement drawings for the equipment alternatives would be made. Expectations will be presented as relative % reduction from baseline, and not in absolute terms. Note that some of the modifications discussed will likely result in the need for other changes to existing equipment, and may involve additional operating/maintenance costs. There will be a general discussion only around these potential affects. Any detailed review or analysis would be part of future work and extra to the contract scope if required. The range of reduction versus the cost of implementation and operation will be quantified.

- Sulphur Oxides and Sulphuric Acid – Alternatives for reduction of SO_2, SO_3 and H_2SO_4 aerosols will be reviewed and discussed as to their appropriateness for the Holyrood Plant and their relative costs. A more in depth study of the most applicable alternative(s) would be made. There will be a general discussion on the cost or system required to handle the by-products that are either produced or captured.

STUDY OF METHODS TO IMPROVE EMISSIONS

The study will evaluate options for each unit design and discuss likely improvements that may be attainable with the modifications discussed. In order to establish a meaningful evaluation, current operating data would be required. Unit drawings are also required including all General Arrangement drawings as well as site drawings for ESP option. At this point it is assumed that the data is presently available and N&L Hydro will provide such data to ALSTOM. ALSTOM will provide a list of data required to perform such an evaluation. (See Appendix for Typical Data Requirements- Data at full load with normal operations)

Design and operation of existing components will be reviewed and evaluated. Operational modifications will be discussed, briefly touching on the theory behind the suggestions. Anticipated potential improvements will be stated, with qualifying comments as appropriate. Modifications to design will similarly be discussed and where appropriate, design modifications will be outlined, again an explanation of the theory behind the suggestions. In addition the general affect this has on increasing existing operating costs or causing additional costs in other areas will be discussed.

Deliverables

ALSTOM will deliver a summary draft report as part of *Phase I* outlining the findings for each unit and making recommendations for the three tiered approach as defined above. Indicative pricing will be provided for equipment options discussed. It is understood that some options to be outlined by ALSTOM in this study may not be economically feasible in the foreseeable future, however, if required they can be discussed to provide N&L Hydro with as complete an overview as possible for the planning of the long term future of plant operations. The cost of Phase I will include the cost to produce the final report document.

If additional detailed engineering is required after review of the Phase I draft report, then the separate cost and duration for this additional work would be quoted as *Phase II*. At the end of Phase II a final report will be submitted.

Phase III will consist of a half day formal presentation of the final report at site.

STUDY OF METHODS TO IMPROVE EMISSIONS

Schedule for Study

ALSTOM anticipates schedule duration as indicated below, based on the execution of the subject engineering study as described in this proposal. The schedule of the study will be confirmed based on workload at the time of the receipt of the order.

	Deliverable	Schedule
Phase I	Submission of Draft Report (3 units)	6 weeks*
Phase II	Submission of Final Report (3 units)	To Be Determined
Phase III	Formal Presentation of Final Report	To Be Determined

*This duration is based upon having received:
- contract award
- unit operating data and corresponding stack testing data for all 3 Units

Engineering Study Fee

The price for this Engineering Study as outlined above is:

Phase I:	Draft Report (3 Units)	$62,755.00 CDN
Phase II:	Detailed Investigation on Selected Proposed Alternatives (scope and deliverables to be determined after review of Draft Report)	To be determined
Phase III:	Presentation of Final Report (3 Units)	$27,100.00 CDN**

**This cost is an estimate for Phase III is based on the following assumptions for the site presentation:

- Assumes 4 people travel to site (2 from Ottawa office, 1 from Windsor, Conn., and 1 from Knoxville Tenn.)
- Assumes individuals time is charged per hour ($125/hr for Canadian Rep's, $200/hr for US Rep's)
- Assumes 1 day travel to site, 1 day at site (1/2 day presentation), 1 day travel from site (3 x 8 hours per individual assumed)
- Assumes flights, hotel, meals, and car rentals are at cost.

The pricing for Phase I is firm and valid for sixty (60) days from the proposal submission date of December 19, 2001.

STUDY OF METHODS TO IMPROVE EMISSIONS

GENERAL CONDITIONS

1. TAXES

The prices provided for herein are exclusive of any present or future, Federal, Provincial, Municipal, or other sales, use, excise or similar tax with respect to any work performed hereunder.

If the Company is required by applicable law or regulation to pay or collect any such present or future, tax or taxes on account of this transaction or if any such taxes are assessed against the Company, no matter when such assessment is made, then such amount of tax or taxes shall be paid by the Purchaser to the Company in addition to the prices provided for herein.

2. FORCE MAJEURE

The Company shall not be liable for loss or damage resulting from any delay or failure to make delivery or complete the Work within the time specified due to Acts of God; War; Acts of the Public Enemy; Riot; Civil Commotion; Sabotage; Federal, Provincial or Municipal laws or regulations; strikes or other labour disputes; fire; flood; accidents; epidemics; quarantine restrictions; embargoes or other transportation delays; damage to or destruction in whole or in part to the Equipment or manufacturing plant; lack of or inability to obtain raw materials, labour, fuel or supplies for any reason including default of suppliers; or any failure on the part of the Purchaser or his representative to approve or comment on drawings or other technical documents within the period of time specified by the Company, or any other causes, contingencies, or circumstances beyond the Company's control, whether of a similar or dissimilar nature which prevents or hinders the manufacture, delivery or completion of the Work. Any such causes of delay, even though existing on the date of the contract or on the date of start of Work, shall extend the time of the Company's performance by the length of delays occasioned thereby, including delays reasonably incident to the resumption of the Work. Increased costs and expenses incurred by the Company in respect to the Force Majeure event shall be to the Purchaser's account.

3. WARRANTY

The Company disclaims all warranties in respect to services rendered in connection with this Contract whether express, statutory, oral, written or implied.

4. LIMITATION OF LIABILITY

The liability of the Company, its agents, employees, subcontractors and suppliers with respect to any and all claims arising out of the Company's performance or non-performance of Services pursuant to this Contract, whether based on Contract warranty, tort, negligence, strict liability or otherwise, shall in no event exceed the aggregate base Contract price. Upon expiration of 1 year following the completion of the Company's

services all such liability shall terminate in its entirety. In no event shall the Company be liable for damages for loss of profit or revenue, loss by reason of plant shutdown or increased expense of plant operation cost replacement power, increased cost of purchasing equipment materials, suppliers or services, claims of Purchasers customers, or incidental indirect or consequential damages of any nature whatsoever.
No claim shall be asserted against the Company, its agents, employees, sub-contractors or suppliers unless the alleged damage giving rise to the claim is sustained during the above-noted one (1) year period.
The Company disclaims any and all liability arising from damage or loss sustained by the Purchaser or by any third party in the event that the Company's recommendations, conclusions or opinions, as contained in the Study Contract, are implemented, acted upon or applied by any third party or by the Purchaser acting on its own without further involvement of the Company. The Purchaser shall indemnify the Company against all third party claims, damages and losses in this respect.
This article shall prevail over any conflicting provisions contained elsewhere in the Contract.

5. CANCELLATION

In the event of cancellation by the Purchaser, the Purchaser shall pay to the Company all incurred and committed costs, overhead and a share of profit prorated with the stage of completion of the work at the time of such cancellation.
The Company may cancel the Contract at any time upon written notice thereof to the Purchaser if a petition is filed by or against the Purchaser under the bankruptcy laws of Canada or if the Purchaser makes a general assignment for the benefit of his creditors or if a receiver is appointed for any property of the Purchaser. Such cancellation shall not prejudice the rights of the Company to any amounts due under the Contract.

6. PROPRIETARY INFORMATION

Information contained in the Proposal and the subsequent Study Contract includes proprietary information furnished to the Purchaser and its architect/engineer, consultant or agent for evaluation of the Company's Proposal and its performance under the Study Contract. Neither the Proposal the Contract nor any information contained therein nor any proprietary information furnished pursuant thereto, shall be disclosed to third parties without prior written approval of the Company.

7. RESPONSIBILITY FOR OPERATION OF PURCHASER'S EQUIPMENT

The operation of the Purchaser's equipment at the plant site is within the exclusive control of the Purchaser, and the Purchaser shall indemnify and save harmless the Company from and against all damages, loss, expense, or liability (including legal fees) incurred by or imposed upon the Company based upon injury to persons (including death) or damage to any property resulting from the operation of such equipment.

8. CHANGES AND EXTRAS

The Purchaser shall have the right, within the general scope of the Work to make changes in the Work, either by altering the nature of same or by adding to or deducting from it. All changes shall, except in the case of emergencies endangering the safety of persons or property, be made by written change order. The Company shall promptly comply with any and all written change orders. No such change shall be deemed to invalidate the Contract.

9. DURATION OF PROPOSAL

Unless otherwise stated, the Proposal shall remain in effect for a period of ninety days unless sooner withdrawn by the Company. Any Contract based on the Proposal, which is received by the Company within said period, is subject to approval in writing by the Company.

10. ENTIRE AGREEMENT

There are no understandings between the parties hereto as to the subject of the Proposal other than as herein set forth. All previous communications between the parties hereto, either verbal or written, are hereby abrogated and withdrawn, and the acceptance and approval of the Proposal with the specifications and drawings, if any, referred to herein constitutes the whole agreement between the parties hereto. The Contract cannot be assigned nor may any conditions be modified, except by a duly approved supplementary agreement signed by both parties. If the Proposal or this document is incorporated by reference in a purchase order or other document, any commercial terms and conditions printed on the purchase order or other document shall be null and void unless otherwise agreed to by the parties.

If any change order by the Purchaser causes an increase or decrease in the

Appendix- Typical Unit Data Requirements

Oil Analysis:

% ASH
% H
% C
% S
% N
% O
HHV
Asphaltine

Unit Data

Date
Test Time
Unit Load
Steam Drum Pressure
Turbine Throttle Pressure
Main Steam Flow K#/hr
Feedwater Flow K#/hr
S.H. Desup Spray Flow K#/hr
S.H. Outlet Stm Temp L/R
Average SH Stm Temp
SH Desup Valve Pos L/R
RH Outlet Steam Temp L/R
Average RH Stm Temp
RH Desup Valve Pos L/R
RH Steam Inlet Temp
Burner Tilt Position (+/-)avg for Units #1 &2
Burners In Service (Total and Location)
Oil Burner Pressure
Atomizing Steam Pressure (local)
Oil Burner Temp
Airflow (0 - 100%)/kpph
Airflow kpph
% O2 (Control Room Avg)
% O2 DRY Approx (Control Room Avg)
Windbox/Furnace dP
Auxiliary Air Damper Position Units #1 &2
Fuel Air Damper Position Units #1 &2
Register Swirl Position Unit #3
F D Fan Inlet Damp Pos. % open L/R
F D Fan Amps L/R

I D Fan Inlet Damp Pos. % open L/R
I D Fan Amps L/R
FD Fan Disch Press inches H2O L/R
Windbox Air Press inches w.c.
Furnace Draft inches w.c.
Economizer Gas Outlet Draft inches H2O
Airpreheater Gas Outlet Draft L/R
I D Fan Inlet Draft L/R
Airpreheater Gas Inlet Temp
Airpreheater Gas Outlt Temp L/R
Airpreheater Air Inlet Temp L/R
Airpreheater Air Outlet Temp L/R
Steam Drum Level inches
Economizer Wtr Inlet Temp
Economizer Wtr Outlet Temp L/R
Primary SH Outlet Temp
Secondary SH Inlet Temp
Primary SH Outlet Temp
Secondary SH Inlet Temp

EMISSION DATA (CEM)

Note: To evaluate Emissions reduction capability Unit operating conditions at conditions equivalent to the supplied emissions data must be supplied. Emissions data without operating conditions is of limited value.

% Opacity
% O2
% CO2
NOx #/MBtu

PARTICULATE RESULTS:

6 OIL Particulate Load Gr/DSCF
6 OIL Particulate Load Lb/MBtu

APPENDIX E –FRACTIONING DATA FOR PRECIPITATOR

Observations on 1976 Oil-Fired Boiler Data (attached)

To assist in interpreting the fractioning data provided on the next page, the following observations are noted:

- The data as presented in Power shows that the particle size of the flyash is relatively fine with about 60% < 2.5 micron. As the flyash passes through the precipitator the particles agglomerate so that material lost to atmosphere shows a smaller percentage < 2.5 micron. The precipitator that has been sized in the report will give 90% collection of the total mass entering the precipitator. Assuming more or less 100% collection of the material > 2.5 micron this would mean approximately 80% collection of the fine material < 2.5 micron.

- The data is from September 1976. The efficiency of the ESP measured on an oil-fired unit in 1976 may be lower than the 90% efficient ESP we have included in the study. So the ESP in the study may perform better than the data shown in the article with respect to fractioning.

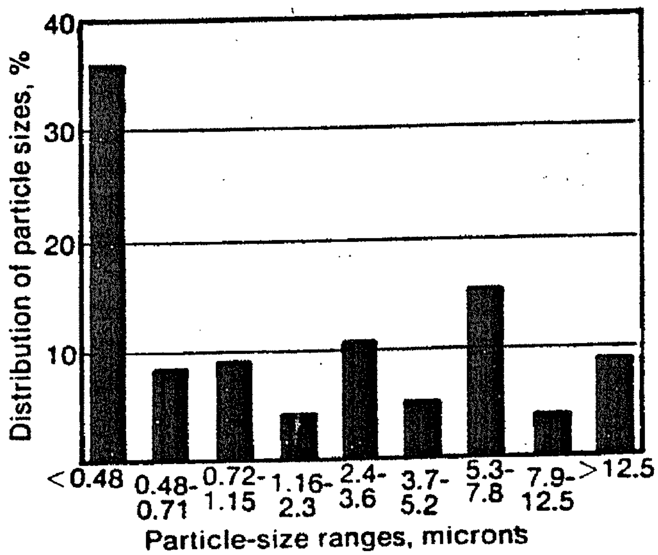
- The higher dust distribution shown on the ESP outlet of particulate above 2.5 microns is probably due to rapping losses. With the newer design ESP proposed in the study, rapper losses would be reduced, due to both the higher efficiency of the ESP, and improved rapper techniques over what was being done in 1976.

Observations on 1976 Oil-Fired Boiler Data (attached)

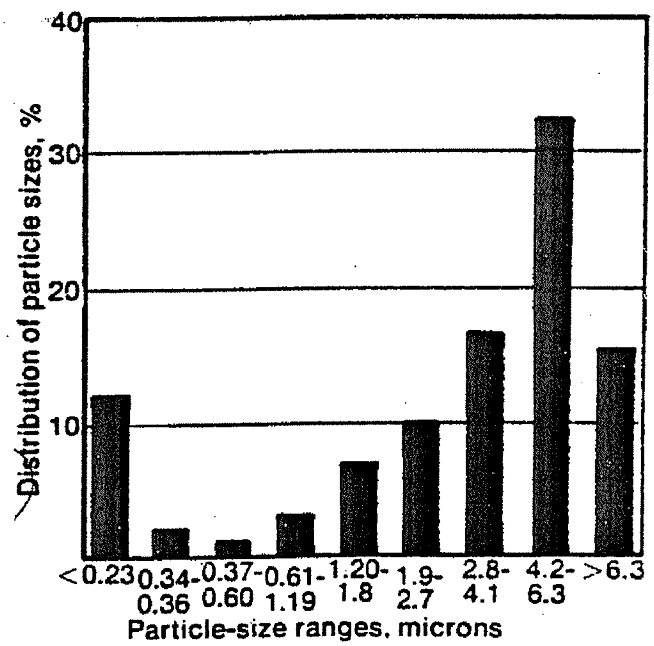
To assist in interpreting the fractioning data provided on the next page, the following observations are noted:

- The data shows that 60 % of the particulate that enters the Inlet to ESP is at or below 2.5 microns. About 35% of the particulate leaving the ESP is below 2.5 microns. The data suggests that the ESP collects about 40% of the particulate below 2.5 microns.
- The data is from September 1976. The efficiency of the ESP measured on an oil-fired unit in 1976 may be lower than the 90% efficient ESP we have included in the study. So the ESP in the study may perform better than the data shown in the article with respect to fractioning.
- The higher dust distribution shown on the ESP outlet of particulate above 2.5 microns is probably due to rapping losses. With the newer design ESP proposed in the study, rapper losses would be reduced, due to both the higher efficiency of the ESP, and improved rapper techniques over what was being done in 1976.

Controlling pollution from oil-fired boilers



23. Particle-size distribution of unagglomerated flyash often is finer than expected. This ash, measured *in situ*, shows a peak below 0.3 microns



26. Particle-size distribution of flyash escaping from the precipitator shows a more pronounced bimodal distribution than that for the inlet dust shown in Fig 23

11. Ultimate analysis of typical No. 6 fuel oils

	As-fired analysis, wt %	
Constituent	Dirty fuel	Clean fuel
Carbon	84.65	87.20
Hydrogen	11.09	12.01
Oxygen	1.10	0.28
Nitrogen	0.43	
Sulfur	2.45	0.50
Ash	0.28	0.01