File No. ______________

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO
Head Office: St. John's, Newfoundland P.O. Box 12400 A1B 4K7
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BY HAND

January 20, 2006

Board of Commissioners
of Public Utilities
P.O. Box 21040
St. John's, NF, A1A 5B2

Attention: Cheryl Blundon – Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Application for Approval of Recovery of Costs of 1% Sulphur Fuel through the Rate Stabilization Plan

Enclosed please find an original and ten copies of Hydro's application, supporting affidavit, engineering study and draft order pertaining to the recovery, as prudent operating expenditures, of the costs of purchasing 1% sulphur fuel for Hydro's Holyrood Thermal Generating Station. Hydro is requesting that these costs be recovered, in the usual fashion for these fuel expenses, through the Rate Stabilization Plan.

History

On November 3, 2004 Hydro wrote the Board to provide information as to its requirements to reduce the sulphur content in its fuel oil for the Holyrood Thermal Generating Station (HTGS) in response to the *Air Pollution Control Regulations, 2004* made under the Environmental Protection Act S.N.L. 2002, c. E-14.2. At that time, Hydro reduced the sulphur content in the No. 6 fuel purchased from 2.2% to 2%.

In that correspondence, Hydro informed the Board that there were a number of factors that required Hydro to take action to reduce its emissions at the HTGS, which factors could require Hydro to further reduce the level of sulphur in its No. 6 fuel.

Hydro has undertaken a number of means to reduce the air emissions environmental impact of the HTGS. It has strived to optimize the plant's generating efficiency by installing state-of-the-art control and performance monitoring software. This enables Hydro to reduce air emissions and while increasing the amount of electrical energy generated for each barrel of fuel that is consumed. Also, Hydro has strived to reduce its station services (auxiliary power requirements) so that it can generate energy more efficiently. The plant has a comprehensive Environmental Management System and is ISO 14001 certified.

In 2003 Hydro installed a fifth ambient air monitoring station, and in 2004, upgraded the instruments at the other air monitoring stations. These stations are located in the communities around the HTGS and provide data as to emissions in those areas. Hydro has recorded an incident where it exceeded acceptable levels of sulphur dioxide in the local environment. In addition, Hydro has installed a continuous opacity monitoring system to measure emissions density, and a continuous emissions monitoring system that directs new information to operators allowing them to diagnose problems sooner.

Environmental Regulatory Requirements

As the owner and operator of the HTGS, Hydro is required to adhere to the *Air Pollution Control Regulations, 2004* made under the Environmental Protection Act. Hydro can be charged under that Act or assessed administrative penalties if it emits pollutants in excess of the limits prescribed in the regulations. Hydro has determined that action to reduce emissions is required to better comply with these legal requirements.

Reducing the sulphur content of the fuel consumed at the HTGS is an effective means of significantly reducing the emissions from that facility. Sulphur dioxide (SO_2) levels will be reduced by 50% and total particulate emissions will be reduced by 40 to 60 percent. Opacity levels will be also significantly reduced.

Comparable Costs/Benefits of 1% Sulphur as a Remedy

Hydro retained the services of SGE Acres to assist it in the analysis of the HTGS emissions issue. That consultant provided a report (a copy of which is attached to the application, that, among other things, compared the costs of switching to 1% sulphur fuel to the very large capital costs and significant operating costs of retrofitting the HTGS with Flue Gas Desulphurization and Electrostatic Precipitation emissions control equipment. The attached report indicates that the 1% sulphur, fuel switching alternative is the least cost alternative. The fuel switching alternative has the additional benefit of being much less costly than a large capital improvement should circumstances change (e.g. reduced production from Holyrood or a conversion of the plant to burn natural gas).

We trust that you will find the enclosed application and supporting documentation to be in order. Should you have any questions or comments about any of the enclosed please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Wayne D. Chamberlain
General Counsel and
Corporate Secretary

Encl.

c.c. Mr. Peter Alteen - Newfoundland Power
Mr. Gordon Oldford - Abitibi-Consolidated Inc., Grand Falls

Mr. Mel Dean - Abitibi-Consolidated Inc., Stephenville
Mr. Patrick Corriveau - Corner Brook Pulp & Paper Co. Ltd.
Mr. Kevin Goulding - Deer Lake Power Ltd.
Mr. Glenn Mifflin - North Atlantic Refining Ltd.
Mr. Thomas Johnson - Consumer Advocate
Mr. Edmund Stuart - Aur Resources Inc.
Mr. Joseph S. Hutchings, Q.C., Poole Althouse

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the approval, pursuant to Section 71 of the Act, of the cost of Low Sulphur Fuel as a fuel cost component to be recovered through the Rate Stabilization Plan charged to Newfoundland Power Inc. and the Island Industrial Customers.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO ("Hydro") STATES THAT:

1. The Applicant is a corporation continued and existing under the *Hydro Corporation Act*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Order No. PU 40 (2003) sets out the manner by which the Rate Stabilization Plan ("RSP") is calculated and applied to the rates charged by Hydro to its Island Industrial Customers.

3. On November 3, 2004 Hydro wrote the Board to provide information as to its requirements to reduce the sulphur content in its fuel oil for the Holyrood Thermal Generating Station (HTGS) in response to the *Air Pollution Control Regulations, 2004* made under the <u>Environmental Protection Act</u>, S.N.L. 2002, c. E-14.2 (hereinafter the <u>EPA)</u>. At that time, Hydro reduced the sulphur content in the No. 6 fuel purchased

from 2.2% to 2%. Since that time, the cost incurred by Hydro to purchase 2% sulphur fuel has been used as its cost of fuel for RSP and rate setting purposes.

4. The environmental challenges facing Hydro arising from the operation of the HTGS remain formidable. In December of 2004 the HTGS was determined to be the worst emitter of air pollutants in the Province and the fifth worst in Canada. Were Hydro to seek to construct a facility like the Holyrood Thermal Generating Station today, pursuant to the *Air Pollution Control Regulations*, it would be required to install currently available emissions reducing equipment.

5. Hydro has already undertaken a number of means to reduce the air emissions environmental impact of the HTGS. It has strived to optimize the plant's generating efficiency by installing state-of-the-art control and performance monitoring software. This enables Hydro to reduce air emissions while increasing the amount of electrical energy generated for each barrel of fuel that is consumed. Also, Hydro has strived to reduce its station services (auxiliary power requirements) so that it can generate energy more efficiently. The plant has a comprehensive Environmental Management System and is ISO 14001 certified.

6. Hydro has, through approved capital budget expenses, installed monitoring equipment to provide data used to better define its emission characteristics which, along with other collected data, is used in modelling to determine Hydro's compliance with provincial regulations.

7. As an owner and operator of a facility that emits air contaminants in this Province, Hydro is subject to the *Air Pollution Control Regulations, 2004.* It is an offence under the EPA to emit substances into the environment at levels above those specified in the *Air Pollution Control Regulations,* 2004. The Minister of Environment and Conservation (hereinafter, the "Minister") has informed Hydro that there is reason to believe, based on the data and modeling, that Hydro is not in compliance with those regulations. Hydro can either be charged with offences under the EPA or be required to pay administrative penalties for exceeding the air contaminant limits prescribed in the *Air Pollution Control Regulations, 2004.*

8. Determining whether Hydro will be prosecuted or be assessed administrative penalties, requires the use of emission modeling that predicts the character and amount of emissions over a specified area under certain operating and climatic conditions. Through the application of these models, the Minister is of the belief that Hydro will exceed allowable emissions levels.

9. Hydro has considered its options as to the kinds of corrective actions that can be taken to comply with legislated requirements. The options include capital investments in the form of the installation of capture equipment, such as flue gas desulphurization (FGD) and electrostatic precipitation equipment (ESP). Also considered was the reduction of the sulphur content in the fuel to be burned.

10. Hydro has obtained an engineering report to assist in the analysis of its options. A copy of the Report from SGE Acres is attached. That report indicates that there are very large capital costs (approaching $200 million) associated with retrofitting the HTGS with emissions reducing equipment, such as FGD and ESP equipment, that would provide acceptable emissions levels. As well, there are increased operating and station service costs associated with these technologies which may advance the need for new generation sources to replace the significant power and energy used in this capture technology.

11. Large capital expenditures run the risk of becoming obsolete should certain circumstances change. For instance, were Hydro to obtain a transmission in-feed from the Lower Churchill project permitting a significant scaling back of production from the HTGS, or were the HTGS to be converted to burn natural gas instead of Bunker "C", these capital expenditures would be significant sunk costs. On the other

hand, if the environmental impacts can be mitigated or reduced through steps taken which result in additional operating expenses, as opposed to capital projects, Hydro's response to a change in circumstances can be more flexible and the potential for those large sunk costs associated with the capital improvements can be avoided.

12. After considering the available options, Hydro has decided to reduce the sulphur level of the fuel to be consumed at the HTGS. A number of emissions improvements will result from burning 1% sulphur fuel. Sulphur dioxide (SO_2) levels will be reduced by 50% and are anticipated to be within acceptable values, as determined by emissions modeling, with much greater frequency. Total particulate emissions will be reduced by 40 to 60 percent and, importantly, fine particulate emissions will also be significantly reduced. As well, opacity levels will be significantly reduced.

13. The HTGS emissions levels for the types of pollutants referred to in paragraph 12 hereof are in excess of levels permitted by emissions modeling under the <u>EPA</u> and the *Air Pollution Control Regulations, 2004.* Though reducing the sulphur content of the fuel to 1% will not deliver all of the benefits that would be achieved through the retrofitting of the HTGS with FGD and ESP technologies, it is the least cost option to achieve significant reductions in emission levels. The effectiveness

of this change in sulphur content of fuel will be assessed to determine the actual achieved levels.

14. There is an increase in fuel cost associated with lower sulphur fuels. All changes in HTGS fuel costs result in changes in the RSP. At present 1% sulphur fuel costs more than $6 more per barrel than 2% sulphur fuel but it is forecast that this incremental cost will be approximately $3.00 per barrel by the end of 2006 and less than $3.00 for 2007. Based on forecast fuel costs, and assuming normal hydrology, recovering the cost of 1% sulphur fuel would result in an approximate 1% increase in rates to Newfoundland Power's and Hydro's (non-Labrador Interconnected) residential and general service customers and an approximate 2% increase to Hydro's Island Industrial Customers.

15. Notwithstanding its higher price, switching to 1% sulphur fuel is the least cost option available to Hydro to reduce its emissions to levels more consistent with the modelling under the EPA and the *Air Pollution Control Regulations, 2004* and provides Hydro with the flexibility to assess future use of HTGS without committing substantial capital expenditures for retrofitting at this time.

16. **THE APPLICANT THEREFORE REQUESTS** that the Board grant an order approving as a prudent fuel purchase expenditure to be recovered through the RSP, Hydro's costs of purchasing 1% sulphur fuel in the same manner as Hydro has been recovering costs incurred for 2.2% sulphur fuel, and latterly, 2% sulphur fuel.

DATED AT St. John's in the Province of Newfoundland and Labrador this day of January 2006.

Wayne D. Chamberlain
General Counsel and Corporate Secretary

Solicitor for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's, Newfoundland, A1B 4K7

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the approval, pursuant to Section 71 of the Act, of the cost of Low Sulphur Fuel as a fuel cost component to be recovered through the Rate Stabilization Plan charged to Newfoundland Power Inc. and the Island Industrial Customers.

TO: The Board of Commissioners of Public Utilities (the "Board")

AFFIDAVIT

I, James R. Haynes, Professional Engineer of St. John's, in the Province of Newfoundland and Labrador, make oath and swear as follows:

1. THAT I am employed by Newfoundland and Labrador Hydro, the Applicant herein, in the capacity of Vice-President, Regulated Operations, and as such I have knowledge of the matters and things to which I have herein deposed, and make this affidavit in support of the Application.

2. THAT I have read the contents of the Application and they are correct and true to the best of my knowledge, information and belief.

SWORN TO BEFORE ME in the City of St. John's, in the Province of Newfoundland and Labrador, this 20th day of January 2006.

Barrister - Newfoundland and Labrador

James R. Haynes

(DRAFT ORDER)
NEWFOUNDLAND AND LABRADOR
AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO. P.U. __ (2006)

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the approval, pursuant to Section 71 of the Act, of the cost of Low Sulphur Fuel as a fuel cost component to be recovered through the Rate Stabilization Plan charged to Newfoundland Power Inc. and the Island Industrial Customers.

WHEREAS Hydro is a corporation continued and existing under the *Hydro Corporation Act*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994;* and

WHEREAS by Order No. PU 40 (2003) the Board set out the manner by which, through the Rate Stabilization Plan ("RSP"), Hydro's costs associated with the fuel it consumes at its Holyrood Thermal Generating Station to generate electricity are collected through rates charged by Hydro to Newfoundland Power and its Island Industrial Customers; and

WHEREAS Hydro is required through the *Air Pollution Control Regulations, 2004* made under Environmental Protection Act, S.N.L. 2002, c. E-14.2, to not exceed certain emissions limits and Hydro has considered the means available to it to adhere to those regulations; and

WHEREAS Hydro has determined that an effectual and cost effective means of reducing its limits with a view to adhering to the *Air Pollution Control Regulations, 2004* is to purchase and consume 1% sulphur No. 6 (Bunker C) fuel oil instead of 2% sulphur No. 6 fuel oil at that generating facility; and

WHEREAS 1% sulphur fuel oil has a higher cost and Hydro has applied to the Board for approval of the recovery of these higher forecast fuel purchase expenses through the RSP; and

WHEREAS the Board has considered the application and supporting affidavits and documentation.

IT IS THEREFORE ORDERED THAT:

1. The Board hereby approves the inclusion of the costs of Hydro's purchases of 1% sulphur fuel for the Holyrood Thermal Generating Station as prudent operating expenses which costs will be recovered by Hydro through the RSP.

Dated at St. John's, Newfoundland and Labrador, this day of 2006.

Prepared for

Newfoundland and Labrador Hydro

P.O. Box 12400, Hydro Place, Columbus Drive,
St. John's, Newfoundland A1B 4K7

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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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.

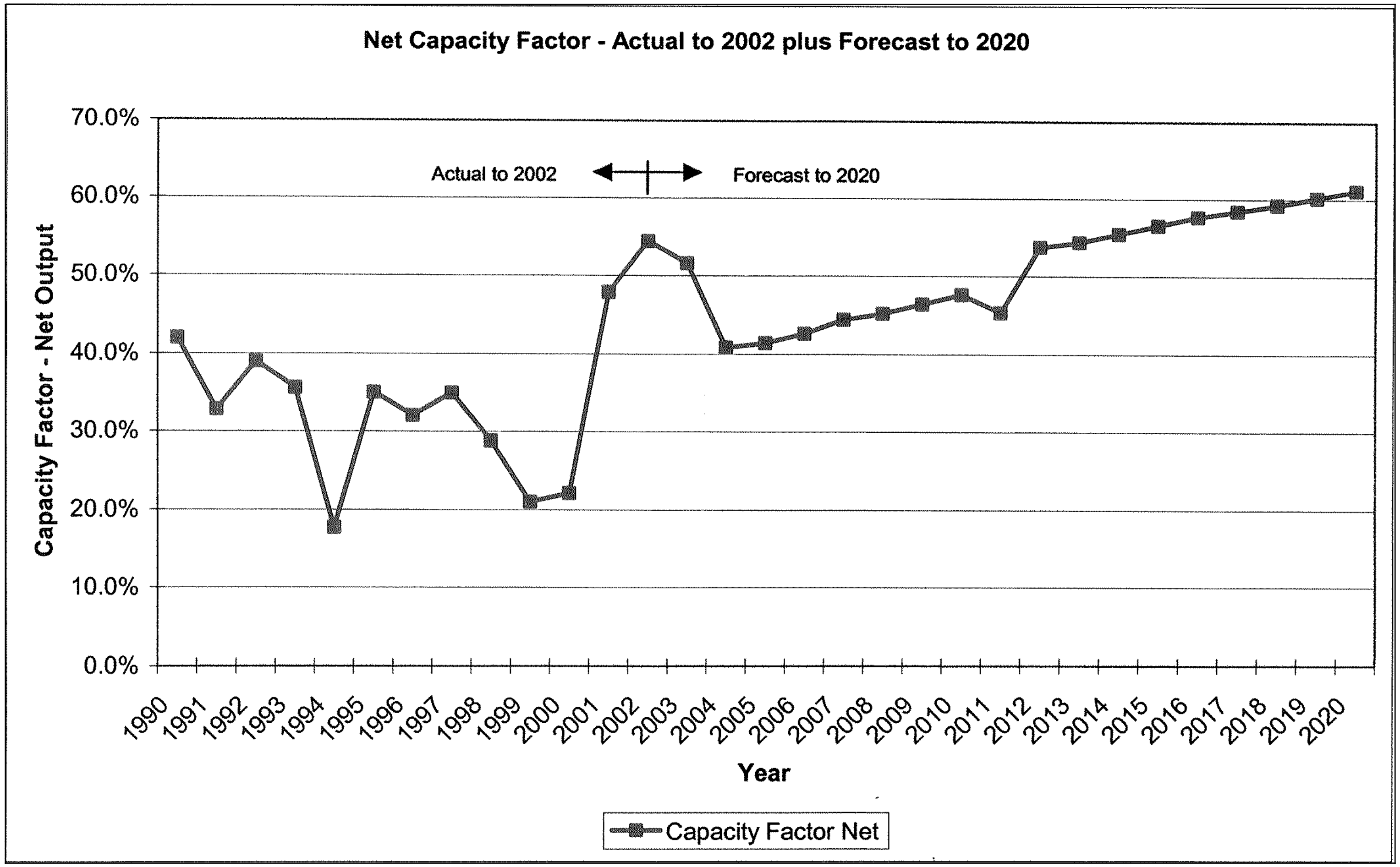

Figure 2.1
Actual and Forecast Annual Average Capacity Factor
for Holyrood Plant

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	

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 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				Financial Parameters		
Plant #1	(175*2) MW	350	MW	Project Term (years)	16	years
Plant #2	(150*1) MW	150	MW	Capital Spent In First Year	35%	
				Capital Spent In Second Year	100%	
Total Power - Combined		500	MW	Inflation	2.50%	
Max Annual Energy - Combined @ 8760 Hrs		4,380,000	MWh	Debt Interest Rate	8.5%	
				Debt Term	16	years
Fuel Oil Output/bbl		624	kWh/bbl	Discount Rate	8.5%	
Fuel Oil Density		1.02	lb/ft3			
One bbl of oil is equal to		42	Gallon	**Operating Costs**		
lbs of fuel per kWh		0.57	lbs/kWh	***Fixed Annum***		
				Labour	$0	$/year
Plant Variable Parameters				Maintenance	$0	$/year
% of S in Fuel Oil		2	%	Administration	$0	$/year
SR Assumed		1.03		Property Tax	$0	$/year
Cost of Reagent Limestone		60	$/ton	Insurance	$0	$/year
Waste Disposal Cost		6	$/ton			
SO2 Reduction		50%				
Incremental Station Service Load		1.50%				
				Variable Annum		
Project Costs				Variable Operating (Reagent $/yr @ 50% CF	$2.50	$/year
EPC		$162,561,373				
Owner's Costs		$15,026,074				
IDC		$0				
Contingency		$17,758,745				
Total Project Costs		$195,346,192				

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

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	$5.95	$6.05	$6.15	$6.25	$6.35	$6.45	$6.55	$6.65	$6.75
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	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			$ 14,201,106	$ 15,990,545	$ 17,355,385	$ 18,094,327	$ 18,723,045	$ 19,227,003	$ 19,390,032	$ 18,614,063	$ 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	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)		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	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		13,709	10,867	10,999	11,318	11,796	12,009	12,328	12,647	12,036	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	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	$0	$0	$0	$0	$0	$0	$0	$0	$0
Waste Disposal Cost ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	$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	$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	$22,447,901	$23,089,864	$23,935,721	$24,811,699	$25,716,482	$26,455,337	$27,236,034	$28,082,396	$28,962,260
CPW (Jan 2004$)			$13,088,577	$26,671,830	$40,259,501	$53,315,902	$65,767,577	$77,552,674	$88,506,614	$98,198,388	$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
			$178,470,395																
Capital Carrying Charge ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	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.

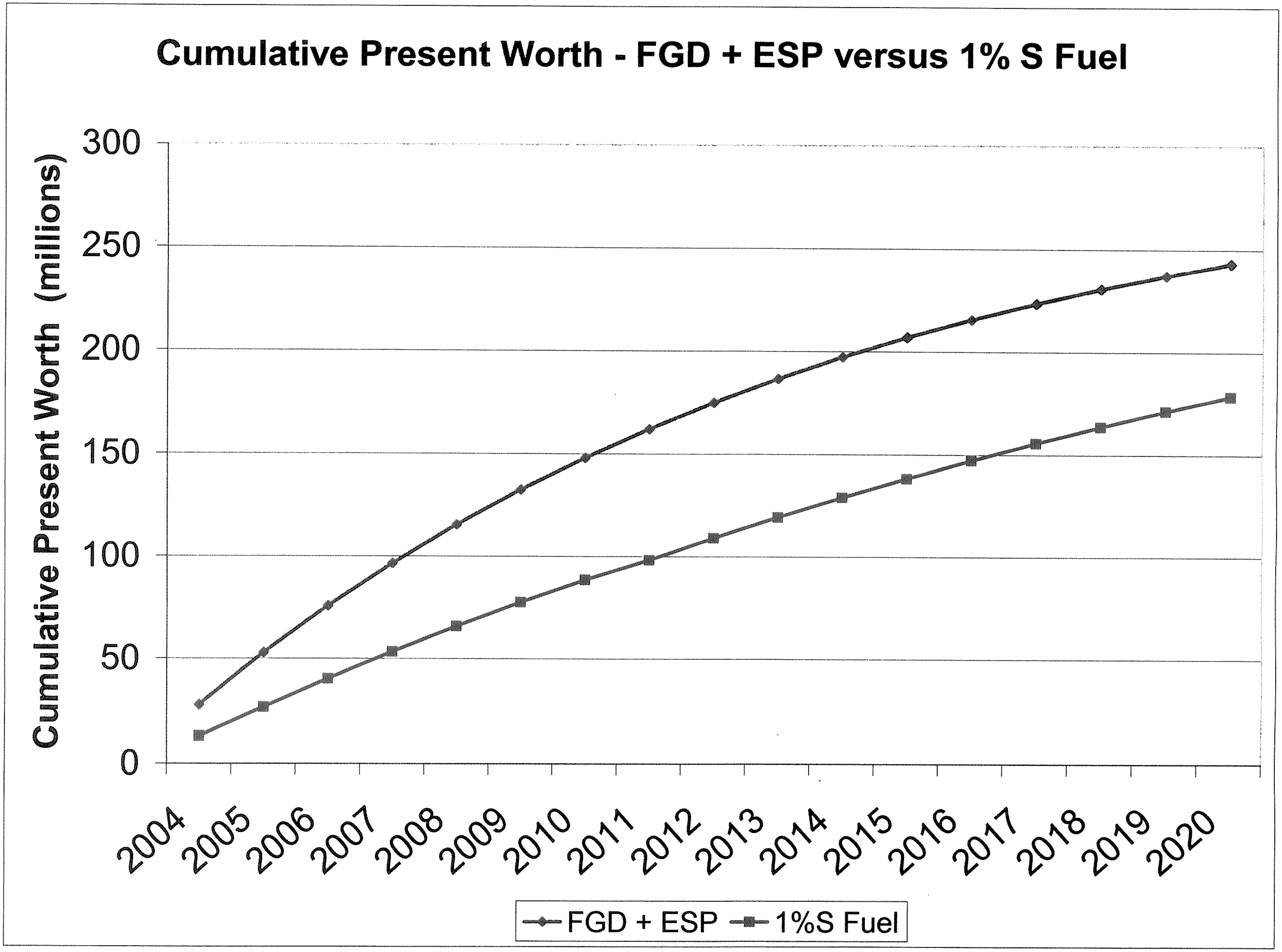
Source: 2002-2010 - PIRA Energy Group, Oil Price Forecasts, 12/23/02 & 01/08/03
2011-2032 - PIRA Energy Group and NLH Economic Analysis Section

27-Jan-03

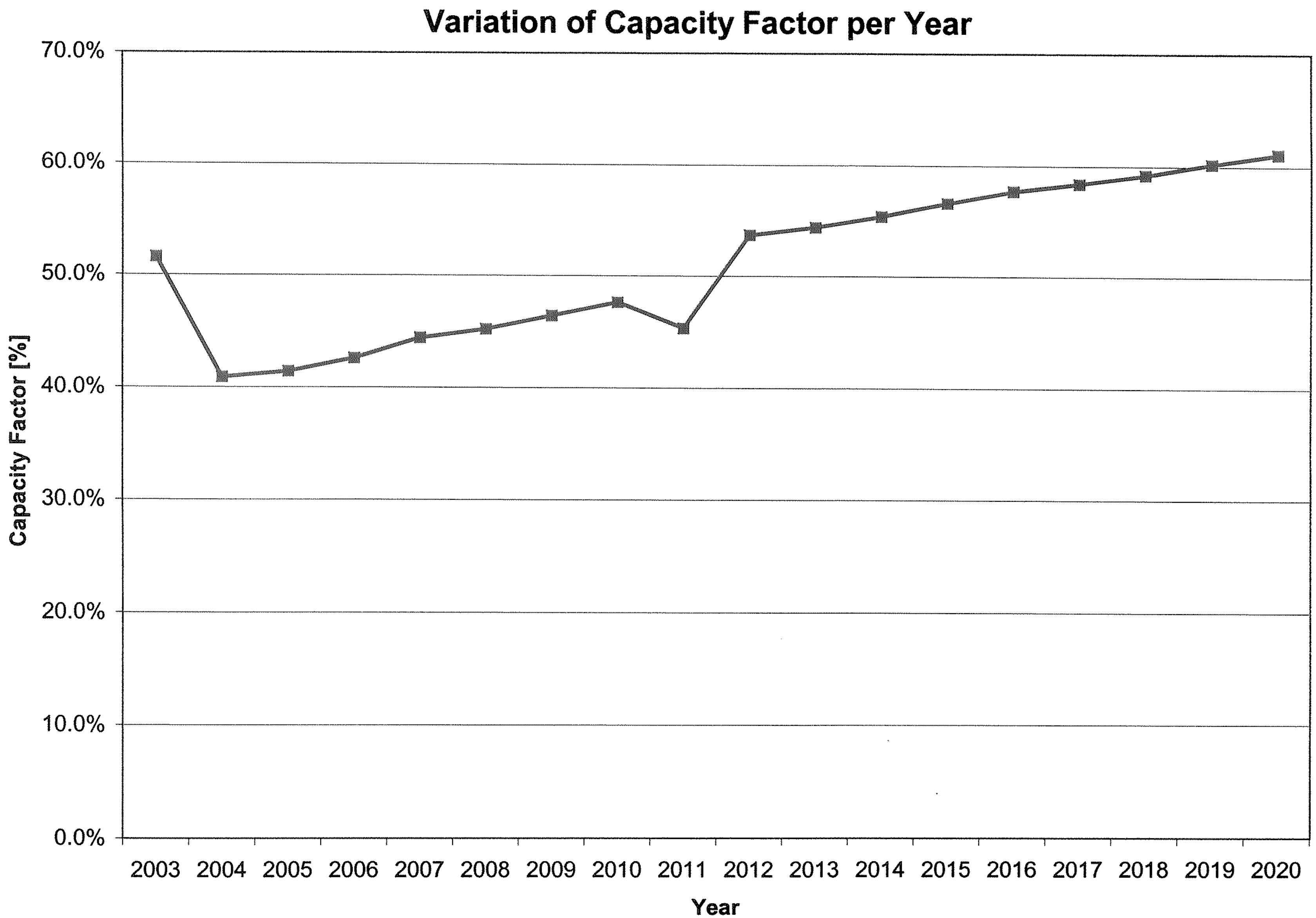
Year	Net Incremental Cost of Electricity ($/MWh) 2% S with FGD	1% S no FGD	0.7%S no FGD	Capacity Factor
2003	12.25	0.00	0.00	51.6%
2004	16.65	7.93	0.00	40.9%
2005	16.43	8.81	0.00	41.4%
2006	16.03	9.29	0.00	42.6%
2007	15.47	9.29	0.00	44.4%
2008	15.27	9.46	0.00	45.2%
2009	14.94	9.46	0.00	46.4%
2010	14.62	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