10 Thermal Generation

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10.1 Introduction

Thermal generation is one of the key sources of energy production on the Island at present. As load grows, additional thermal generation sources are being considered to meet this demand, for base load in the Isolated Island Option and for peaking in both the Isolated Island and Infeed Options.

Within the current Isolated Island grid, Newfoundland and Labrador Hydro (NLH) operates one oil fired thermal generating station, three combustion turbines and two diesel plants. Holyrood Thermal Generating Station (HTGS) located on the south shore of Conception Bay, consists of three heavy fuel oil boilers for a combined net generating capacity of 466 MW. HTGS currently supplies approximately one third (up to 2,996 GWh annually) of the island's existing firm energy. The plant normally operates all three units during the highest customer demand periods of December through March. The plants energy production and operating factor can vary from year to year depending on the amount of hydraulic energy production, weather conditions, and industrial production requirements.

The Infeed Option includes the addition of 520 MW of thermal generation using combustion turbines (CT) and combined cycle combustion turbines (CCCT). This generation plan includes:

- Synchronous condenser conversion projects at HTGS for units 1 and 2 plus some life extension work to keep the plant running as a generation facility to 2021, after which all units operate as synchronous condensers to 2041.
- 7 – 50 MW new CTs.
- 1 – 170 MW new CCCT.

The Isolated Island Option is largely a thermal generation plan with the addition of 1,640 MW of CTs and CCCTs. The Isolated Island Option generation plan includes:

- Installation of environmental emissions controls at HTGS which includes electrostatic precipitators (ESP), flue gas desulphurization systems, also known as "scrubbers" and low NOx burners.
- Significant life extension projects at HTGS with eventual replacement of the units in 2033 and 2036 with 3 – 170 MW CCCTs.
- 9 – 50 MW new CTs.
- 7 – 170 MW new CCCTs.

The Infeed Option contains significantly less thermal generation than the Isolated Island Option.

As HTGS uses heavy fuel oil, it is a significant source of greenhouse emissions (GHGs) with the amount of emissions being proportional to energy production. Nalcor has stated that environmental stewardship is one of its guiding principles and this principle is documented within the Provincial Energy Plan (Focusing Our Energy: Newfoundland and Labrador Energy Plan)[204]. HTGS does not currently have any environmental equipment installed to control sulphur dioxide (SO_x) or particulate emissions.

Nalcor's Exhibit 16, page 27, states that "….the current Provincial Government 25,000 tons per year limitation on SO_X emissions from the HTGS, have traditionally been included in generation planning studies."[205] To date, the only year that annual emissions exceeded 25,000 tonnes was in 1989, when the SOx emissions at HTGS totaled 25,900 tonnes[206]. If 0.7% sulphur content fuel continues to be used at the facility, this target will not be exceeded in the future even with the units running at full load.

Even though Nalcor has projected a capital cost of $603 million for an environmental equipment upgrade, this investment will not reduce GHG emissions, which are expected to increase as the load factor of the plant increases. Should the GHG emission standard change through public policy to a lower target, there is the risk that a facility such as HTGS may not be able to operate in the long term. The proposed pollution control upgrades for HTGS under the Isolated Island Option meet the Newfoundland and Labrador Energy Plan's commitment to address environmental concerns at HTGS.

With pollution control equipment installed at HTGS, GHG will continue to present a challenge to its long term operation should emission standards change[207]. NLH is considering all current and impending environmental legislation in its decisions for generation expansion.

10.2 Thermal Generation Options

MHI's thermal specialists performed an assessment of the various options for HTGS and the planned CTs and CCCTs in meetings with Nalcor, with review of the available documentation, and responses to RFIs. The following outlines the various items under consideration for both generation expansion options:

Common to both options are:

- Life Extension
  - For the Infeed Option some life extension work to maintain the plant as a generating facility to 2021.
  - For the Isolated Island Option significant life extension upgrades.
- CTs
- CCCTs

Isolated Island Option:

- Installation of Pollution Control Equipment at HTGS
- HTGS Replacement in the 2033-2036 Timeframe

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[204] Government of Newfoundland and Labrador, Focusing Our Energy: Newfoundland and Labrador Energy Plan, 2007
[205] Exhibit 16, Nalcor, "Generation Planning Issues 2010 July Update", July 2010
[206] Response to RFI PUB-Nalcor-17
[207] Response to RFI PUB-Nalcor-141

Infeed Option:

- HTGS Synchronous Condenser Conversion (Units 1 and 2)
- HTGS decommissioning

10.3 Documents Reviewed

The following list outlines documents provided by Nalcor and reviewed by MHI as part of the thermal plant assessment study.

Table 22: Thermal Study Documents Reviewed

Exhibit	Title	Prepared by	Date
5	Summary – Capital Cost Estimates 2010	Nalcor	
5H	Holyrood Combined Cycle Plant Study– Final Report	Acres International	November 2001
5Li	Holyrood Thermal Generating Station Precipitator and Scrubber Installation Study	Stantec	November 2008
28	Board Letter – July 12th, 2011 Question 10 response	Nalcor	
44	Holyrood Thermal Generating Station Condition Assessment & Life Extension Study	AMEC	January 2011
65	Holyrood Marine Terminal 10 Year Life Extension Study	Hatch	April 2011
66	Newfoundland & Labrador Hydro Holyrood Generating Station, Phase 1 - Investigation of Methods to Improve Emissions on Units 1, 2 and 3	Alstom Canada	October 2002
67	Engineering Report Holyrood Generating Station MCC Assessment	Stantec	January 2009
68	Air Emissions Controls Assessment – Holyrood Thermal Generating Station Final Report	SGE Acres	February 2004
CE-39	MHI-Nalcor-1 CPWDetails	Nalcor	October 2011
CE-46 Rev. 2	PM0011 – CCGT Capital Cost Benchmark Study Final Report	Hatch	December 2008
CE-47 Rev.1 (Public)	Board Letter - July 12, 2011 Question 4b response on 50 MW Gas Turbine – Budget Estimate	Nalcor	June 2010
CE-56 Rev.1 (Public)	Feasibility Study Of HTGS Units 1&2 Conversion to Synchronous Condenser - An Evaluation of Run Up Options for Generators	SNC Lavalin	February 2011
	Board Letter – July 12th, 2011 Question 4 response	Nalcor	

10.4 Work Common to Both Generation Expansion Scenarios

10.4.1 Life Extension – Infeed Option

In the Holyrood Thermal Generating Station Condition Assessment & Life Extension Study[208] prepared by AMEC (the AMEC report), the operating basis for HTGS was noted as follows:

• 2010 to 2015 (now 2017)[209]	Continued operation as a generator
• 2017 to 2020 (now 2021)	Operation of plant in standby mode
• 2017 to 2041	Conversion of Units 1 and 2 in 2016/17 to synchronous condenser operation (Unit 3 has already been converted)

This life extension study applied only to the Infeed Option whereas the Isolated Island Option would have the plant operating as a generating facility until 2033/36.

Nalcor has investigated various options to upgrade or replace HTGS, which is approaching its end of service life. The initial screening study performed by AMEC concluded that HTGS life could be extended if capital investments were made for the refurbishment or replacement of critical plant equipment.

AMEC indicated in its report that the investigation was carried out generally in accordance with the EPRI Life Extension Condition Assessment methodology which is an industry practice for life extension for thermal plants. AMEC conducted only an initial condition assessment (Phase 1) which consisted of visual observations, interviews with operations and maintenance staff and document reviews, particularly related to previous inspection reports and plant studies.

The AMEC report covers the entire plant except for the marine terminal which is dealt with in a separate report prepared by Hatch.

The intent of the Phase 1 investigation was to assess the overall condition of the plant to provide an opinion on whether the plant is suitable for life extension based on a judgment of the remaining life of the plant and its general condition. In addition, the Phase 1 investigation developed a list of inspections and tests required to more firmly assess the condition of the main equipment, especially the boiler, steam turbine and generator, high energy piping, main step up transformer and other major equipment. The condition of plant systems, building etc. were assessed to develop a plan and timelines when upgrades and refurbishments would be required.

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[208] Exhibit 44, AMEC, "Newfoundland and Labrador Hydro - Holyrood Thermal Generating Station Condition Assessment & Life Extension Study", January 2011

[209] Exhibit 14 Rev 1, Nalcor, "2010 Strategic Generation Expansion Plans"

Several concerns were noted:

- AMEC indicated that although the units are 41, 40 and 31 years of age respectively (as of 2011) the units have been operated seasonally and at light load; therefore, the operational age of the majority of equipment and systems is estimated at 20, 19 and 16 years respectively.

  This is a simplification on the part of AMEC and MHI finds that it is somewhat inaccurate as starting and stopping units and low load operation can have as much or more impact than continuous operation. Lower load operation can be more detrimental on the boiler since cooler backend temperatures occur at lower loads which increases backend corrosion. Also, systems like the main steam and hot reheat piping would have the same pressure and temperature conditions regardless of the load, resulting in the same stress and creep rate. In addition, equipment that is sitting idle or has not been properly protected during down periods may actually have just as much or possibly more life used due to corrosion.

  Nalcor currently lays up their equipment in accordance with manufacturer recommendations. They indicated that they keep the boiler and steam turbine on hot standby when not operating during weekends and drain the boiler if the plant will not operate for more than five days.

  Although there have been efforts to quantify equivalent life used when a plant is down, no definitive conclusions have been reached since this is dependent on the surrounding environment i.e. salt water marine environment or dusty environment as well as the quality of the plant lay-up are crucial.

- There does not appear to have been any benchmarking of unit life in relation to other plants with similar designed equipment. For example, in the AMEC report, Unit 1 Generator (Figure 8-2, Life Cycle Curve – Unit 1 Generator) indicates a maximum life (without life extension) of 260,000 operating hours. The associated report indicates that the "ranges of equipment life is based on current and historical information and expert opinion". However, it does not indicate if there are similar units of a similar age that have operated without major refurbishment for up to 260,000 hours.

- The determination of remaining life of the equipment appears to be fundamentally based on operating hours and not total life. Again using the same AMEC Report Figure 8-2 the generator would be 71 years old at the end of life. When considering operating hours, there should still be an assumed upper life limit based on total installed years. It is widely accepted in industry that useable plant life is typically a maximum of 60 years including life extension work.

  Some of the conclusions for the capability of the boiler to operate until 2017 and then provide standby service in generation mode to 2021 are based on continuous use of low sulphur fuel oil (0.7%). AMEC indicated that the change to higher quality, lower sulphur fuel oil has significantly improved boiler reliability and efficiency and would have a positive impact on the life of the boiler systems. However, based on other reports, specifically the Stantec report on Electrostatic Precipitators (ESP) and Flue Gas Desulphurization (FGD), it is anticipated that HTGS may go back to higher sulphur oil, once the FGD is installed and this would have a negative impact on the life of the plant[210]. The response to RFI PUB-Nalcor 6 indicates that with the installation of pollution controls at HTGS, the use 2% sulphur fuel is acceptable for the remaining life of the plant.

However, as indicated in the AMEC life extension study, the boilers future life is significantly improved with low sulphur fuel and Nalcor staff confirmed improved boiler performance, lower maintenance requirements, and lower particulate levels of emissions using 0.7% sulphur fuel.

As indicated in the response to RFI PUB-Nalcor-17, the current Certificate of Approval for HTGS requires that the sulphur content of fuel used at the facility be no greater than 0.7% by weight.

- The number of starts can have a significant impact on unit life, especially the steam turbine, depending on the type of start i.e. cold, warm or hot and on the time taken for warm-up. The longer the start-up duration, the lower the temperature differentials and the lower the stresses incurred during start-up. However, the AMEC report only indicates the number of starts, not the type of start. This information was requested in MHI-Nalcor-108 and was subsequently provided for plant operation from 1991 to 2010. The number of starts, especially the number of cold starts is quite low alleviating this concern.

The report concluded that HTGS is a relatively modern design and in good condition employing materials and designs suitable for higher temperatures and pressures. HTGS does not appear to have any significant differences in requirements for life extension from those being faced by other utility plants of a similar vintage.

The plants' equipment was supplied by major industry vendors i.e., Babcock and Wilcox, Combustion Engineering (now Alstom), General Electric (GE), Foster Wheeler etc. Based on the investigation by AMEC, the plant appears to have been maintained well over the years with major inspections and refurbishments, when required.

During MHI's site visit, the plant was clean, appeared to be well maintained, and equipment and plant conditions were similar to those reported in the AMEC report.

The only "abnormal" condition noted was the corrosive impact of the marine environment (salt water) which would not be experienced by plants of that vintage built on fresh water lakes or rivers.

Costs

The AMEC report includes the costs for overhauls and inspections of the steam turbine, generator and boiler for Unit 1 in 2012, Unit 2 in 2014, and Unit 3 in 2016, as well as other inspections and tests for other plant components. However, it is unclear how much of the $22.58 million included in the Life Extension Study is actual life extension costs and how much is related to standard equipment overhauls i.e. the overhaul costs for the steam turbine which are incurred every 9 years and operating and maintenance costs related to keeping the plant running until 2021.

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[210] Exhibit 5Li, Stantec, "Holyrood Thermal Generating Station Precipitator and Scrubber Installation Study", November 2008

Meetings with Nalcor indicated that operating and maintenance costs planned for the plant have been considerably reduced based on the plant only operating until 2021. However, if the plant's life is extended to 2033/2036 as required by the Isolated Island Option, operating and maintenance costs would be considerably higher.

The cost carried in the Holyrood Marine Terminal 10 Year Life Extension Study prepared by Hatch was $5.5 million. Hatch indicated in its report that the cost estimates are based on similar work done in Atlantic Canada for similar generation plants and costs supplied by contractors familiar with this type of work. A more detailed study would be required in the future if Nalcor were to pursue the Isolated Island Option, as the generation equipment and marine terminal would be required to operate at least until 2036, by which time the plant would be replaced with CCCTs.

Summary and Conclusions

The AMEC report was detailed and addressed the main equipment and systems and developed a detailed list of requirements for the Phase 2 inspections and tests required and associated costs.

The AMEC Report met the study requirements documented in the report and was thorough, however, there are some issues noted:

- AMEC indicates in several locations including the Executive Summary that, although the units are 41, 40 and 31 years of age respectively (based on 2011) they have been operated seasonally and have been lightly loaded, therefore, the operational age of the majority of HTGS's equipment and systems is more like 20, 19 and 16 years respectively. This may be somewhat inaccurate as starting and stopping units and low load operation can have as much or more impact than continuous operation.
- The determination of remaining life of the equipment appears to be fundamentally based on operating hours and not total life. There does not appear to have been any benchmarking of unit life expectancy in relation to other plants with similarly designed equipment.
- Some of the conclusions for the capability of the boiler to operate until 2017 and then provide standby service to 2021 are based on using low sulphur fuel oil (0.7%). Based on other reports, specifically the Stantec report on ESPs and scrubbers, it is anticipated that HTGS may go back to higher sulphur oil once this equipment is installed. The Certificate of Approval would have to be amended by the Department of Environment and Conservation to allow the use of higher sulphur fuel.

Typically life extensions are done when the plant is approximately 30– 40 years old (end of typical original design life) and a life extension target would be to extend the plant operation for another 15 to 20 years. This would result in a total extended life of 45 to 60 years.

This would require the generator, switchgear, transformer etc. to operate for a total of 71 years (e.g. unit 1). A transformer typically has an operating life in the range of 40 years. As indicated in the AMEC report i.e. Fig. 11-7

> *"The curves indicate that the older transformers are in a critical period in their life where their reliability decreases and their likely susceptibility to system distance effects are higher. The remaining life of the transformers exceeds the end date for generation of 2020, but may not exceed the desired life of 2041 without refurbishment and replacement".*

It is likely that the transformers would not operate to 2041 without major refurbishment or replacement. This is also true of many of the components required for synchronous condenser operation as indicated in the AMEC report. It is not clear whether the costs for transformer replacements and other life extension costs are captured for the Infeed Option to maintain the plant as a synchronous condenser facility until 2041.

10.4.2 Life Extension – Isolated Island Option

In Exhibit 28, Nalcor indicated that life extension values for operation until 2033 / 2036 were included in its 2010 Capital Budget and 20 Year Plan but that, while the values in the plan are not based on detailed engineering, they do offer a conservative order of magnitude representative of the sustaining capital required for the plant.

In meetings with Nalcor, it was indicated that a cost estimate of $100 million was identified in the CPW analysis for the life extension work ($20 million per year from 2012 to 2016) and was based on comparisons with similar plants in the region, e.g. the Trenton Generating Station (Nova Scotia 1969) and the Coleson Cove Generating Station (New Brunswick 1976). MHI agrees that the $100 million estimate is conservative and appropriate for DG2.

10.4.3 Simple Cycle Combustion Turbines (CT) – 50 MW Additions

A CT consists of an air compressor, combustion chamber, turbine and generator. CTs can be operated using either natural gas or light fuel oil. Combustion turbine installations on the island system would have a nominal rating of 50 MW per unit and would be located either adjacent to existing NLH thermal operations or at greenfield sites near existing transmission system infrastructure. Due to their low efficiency, CTs are primarily deployed for system reliability and capacity support for peak demand.[211]

Combustion turbine technology is an integral part of the resource mix on the Isolated Island system today and is an appropriate supply resource for both Options.

Exhibit CE-47 Rev.1 (Public) and the response to the Board Letter July 12th, 2011 question 4 were both reviewed as part the assessment of combustion turbine simple cycle options. There was no comprehensive study report provided for the 50 MW CT.

Costs

The budget estimate for the 50 MW No. 2 oil-fired simple cycle gas turbine plant was based on an estimate documented in CE-47 Rev.1 (Public). In meetings with Nalcor, it was indicated that an additional $15 million was added by Nalcor for site preparation, fuel storage, electrical interconnection, engineering, project management etc. for a budget estimate of $55 million.[212]

[211] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011
[212] Exhibit CE-47 Rev.1 (Public), Nalcor, "50 MW Gas Turbine - Budget Estimate", July 2011

With the addition of overhead costs and contingency[213], an estimate of $65 million as shown in Exhibit 5 Summary-Capital Costs Estimates 2010 was used in the CPW analysis.

This value has then been escalated by approximately 2% per year to arrive at costs for various 50 MW installations in future years. Although the estimate was prepared based on very preliminary information, it is reasonable.

Summary and Conclusions

The estimate of $65 million assumed for a 50 MW simple cycle No. 2 oil fired CT installation is reasonable and comparable with industry estimates supplied by manufactures assuming a transmission line is in relative close proximity.

10.4.4 Combined Cycle Combustion Turbines (CCCT) – 170MW Additions

A CCCT is more efficient than a simple cycle combustion turbine. A CCCT plant is essentially an electrical power plant in which combustion turbine and steam turbine technologies are used in combination to achieve greater efficiency than would be possible independently. The higher efficiency makes it possible for CCCTs to be competitive and applicable for base load applications. CCCTs are typically configured using larger units such as the 170 MW units used in Nalcor's analysis.

The Isolated Island Option includes seven greenfield CCCT plant installations between 2022 and 2067. The CCCT Capital Cost Benchmark study prepared by Hatch in 2008 was used to develop the base cost estimate for a 170 MW greenfield installation[214]. This Benchmark Study was used to check against other studies done and to obtain an extrapolated value of the $/kW values for a 170 MW CCCT plant. The Benchmark Study report was not directly applicable to HTGS or a specific facility located in Newfoundland, but the study investigated the costs for a greenfield plant at three locations. The base cost estimate for the installations was escalated on average by approximately 2% per year to arrive at values used in the CPW analysis. MHI considers this estimate to be reasonable for the study purposes intended.

Technical Assessment

The work undertaken by Hatch was a benchmarking study. Options investigated were based on natural gas firing, local transmission and gas interconnections with wet cooling tower design. The plants also assumed that only low NOx combustors would be required with no additional Selective Catalytic Reduction (SCR) of nitrogen oxides. Although, some of these assumptions may not be suitable for a particular site in Newfoundland, the study was used as a guideline only.

The plant options considered were:

- 125 MW combined cycle plant.
- 275 MW combined cycle plant

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[213] RFI Responses – Batch 7, Nalcor, "Board Letter July 12th 2011- Question 4 response", August 2011
[214] Exhibit CE-46 Rev.2 (Public), Hatch, "PM0011 – CCGT Capital Cost Benchmark Study Final Report", December 2008

- 550 MW combined cycle plant.

These are all very typical selections of gas turbines for the size ranges investigated.

Costs

MHI reviewed the costs estimates used by Nalcor for CCCTs and found they compared well with the estimated values determined using GTPro/Peace software. This software is further described in sub-section 10.5.2.

Summary and Conclusions

The Isolated Island option includes a significant number of greenfield CCCT installations as indicated in Table 23.

Various studies and estimates, as well as the "CCGT Capital Cost Benchmark Study" report were used to come up with the base costs for a 170 MW greenfield CCCT installation. Figure 6.1 "CCGT Unit Cost to Plant Output Regressions Analysis" from the Benchmark Study was interpolated between the $/kW values determined for the various arrangements and sizes of plants reviewed in the report to provide an approximate value. The cost of $282 million in 2022 dollars for the first 170 MW CCCT plant for the Isolated Island Option is reasonable and in line with GTPro/Peace values for 2011. The base cost installation was escalated by 2% per year to arrive at values used in later years in the CPW analysis.

10.5 Isolated Island Option Thermal Plan

If the HTGS is required to continue operation past 2017, as is proposed under the Isolated Island Option, then extensive upgrades and remediation would be required. Typically a base-loaded thermal generating station has a life expectancy of approximately 30 years, but this can be extended when stations are operated continuously and are well maintained. As HTGS Units 1 and 2 are over 40 years old and Unit 3 has surpassed 30 years of service, a life extension program would be necessary to continue to operate the station safely and reliably to the end of 2033/36. Nalcor has completed Phase 1 of the condition assessment required for the life extension program, as described previously. The Phase 2 study would provide Nalcor with detailed information and costs on equipment and systems to be upgraded. After 2036 the HGTS would be replaced with CCCT technology.

Table 23: Isolated Option Thermal Plan

Isolated Island Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	**Description**	**Costs (millions)**	**Retirements**
2015	Holyrood ESP & Scrubbers	$582	
2016	Holyrood Life Extension (5-yr $20 M /yr)	$100	
2017	Holyrood Low NOx Burners	$20	
2019	Holyrood Upgrades	$121	
2022	170 MW CCCT (Greenfield)	$282	Hardwoods CT (50MW)
2024	50 MW CT (Greenfield) Holyrood Upgrades	$91 $9	Stephenville CT (50MW)
2027	50 MW CT (Greenfield)	$97	
2029	Holyrood Upgrades	$4	
2030	50 MW CT (Greenfield)	$103	
2033	Holyrood U1 Replacement - 170 MW CCCT Holyrood U2 Replacement - 170 MW CCCT	$465 $346	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW)
2036	Holyrood U3 Replacement - 170 MW CCCT	$492	Holyrood Unit 3 (142.5 MW)
2042	50 MW CT (Greenfield)	$130	
2046	50 MW CT (Greenfield)	$141	
2049	50 MW CT (Greenfield)	$149	50 MW CT
2050	170 MW CCCT (Greenfield)	$477	
2052	170 MW CCCT (Greenfield)	$665	50 MW CT & 170 MW CCCT
2056	170 MW CCCT (Greenfield)	$534	
2063	50 MW CT (Greenfield) - 2 Units 170 MW CCCT (Greenfield)	$395 $818	2 x 170 MW CCCT
2064	50 MW CT (Greenfield)	$201	
2066	170 MW CCCT (Greenfield)	$645	170 MW CT
2067	170 MW CCCT (Greenfield)	$882	50 MW CT

Based on Exhibit 7, Service Life – Retirements and other documents, the basis for operation of HTGS for the Isolated Island Option is as follows:

Table 24: Holyrood GS operating modes and key dates for the Isolated Island Option

Isolated Island Case Operation Mode / Activity	
HTGS ESP & FGD Systems Installation	2015
HTGS Upgrade	2016
HTGS Low NOx Burner Installation	2017
HTGS Upgrade	2019
HTGS Upgrade	2024
HTGS Replacement (Units 1 &2)	2033
HTGS Unit 3	2036

10.5.1 HTGS Pollution Control Equipment Upgrades

With the Isolated Island Option, Units 1 and 2 of the HTGS would continue operating until 2033, and Unit 3 until 2036, when the station would be replaced. The station would require various upgrades to continue operating as a generating plant, where most of these upgrades involve the addition of pollution control equipment including electrostatic precipitators, scrubbers, and low NOx burners required to meet the Government's directive.

The detailed report by Stantec covering the investigation of installation of electrostatic precipitators (ESP) and flue gas desulphurization (FGD) systems at HTGS is presented in Exhibit 5-L-i.

Nalcor indicated that emission control requirements are based mainly on ground level concentrations (GLC). Currently the plant meets the GLC requirements based on monitoring results at several test locations near the facility. There is also a limit on SOx emissions of 25,000 tonnes annually, but that level does not pose any problems when using low sulphur fuel.

Nalcor also stated that an earlier study showed that the plant would not be in compliance, based on modeling, with 2% or 1% sulphur fuel. The plant would need to reduce the sulphur content in the fuel to 0.7% in order to meet GLC requirements. The plant currently operates on 0.7% sulphur fuel and emissions are well below the 25,000 tons per annum.

In Exhibit 16 - Generation Planning Issues July 2010 Update report, pg. 28, Nalcor stated that:

> *"The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 866,000 tonnes per year of CO_2 (from footnote 6 of Exhibit 16 – Based on the 5-year average of 866,158 tonnes of CO_2 from 2005 through 2009). For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market.*

Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario."

CO_2 emission issues and/or costs have not been addressed in this report. Greenhouse gas emission standards are likely to be set by the Federal Government and as such pose a risk to the ongoing operation of HTGS as a generator.

Stantec selected removal efficiencies of 95% for the ESP and FGD systems. These efficiency values are considered low by industry standards but would be reasonable estimates for 2% sulfur fuel.[215]

The cost estimate in the 2008 Stantec study for the ESP and FGD systems was $450 million. In response to RFI MHI-Nalcor-101, Nalcor states that this estimate has been increased to $582 million with the additional costs attributed to corporate overheads, escalation and AFUDC. MHI finds this is a reasonable estimate to carry in the CPW analysis.

Low NOx Burners

There was no specific study provided for the addition of low NOx burners to HTGS. However, the Alstom Study on the investigation of methods to improve emissions on Units 1, 2 and 3 did investigate various potential NOx reduction technologies.[216]

The technologies investigated would be considered industry standard NOx emission reduction technologies for an oil-fired boiler and consisted of:

- burner tuning which would provide an approximate 12% reduction in NOx,
- windbox burner air modifications would provide approximately a 15 – 20% reduction in NOx,
- burner modifications plus the addition of an overfire air system that would provide 40 – 45% reduction in NOx
- and Selective Non-Catalytic Reduction (SNCR) which would provide an additional 25 – 30% reduction in NOx.

Nalcor indicated that low NOx burners have been under consideration for many years on the assumption that regulatory requirements would mandate the replacement of the present burners.

The capital cost estimate for low NOx burners outlined in Exhibit 5 is $19.8 million. The costs was prepared by Nalcor's Mechanical Engineering Department and is representative of the cost for this type of work in similar plants.

One manufacturer estimated that a low NOx burner conversion today would cost in the range of $5 to $6 million per 150 MW boiler assuming the pressure work is limited to that directly related to the

[215] Exhibit 5Li, Stantec, "Precipitator and Scrubber Installation Study Holyrood Thermal Generating Station", November 2008
[216] Exhibit 66, Alstom, "Newfoundland & Labrador Hydro Holyrood Generating Station, Phase 1 - Investigation of Methods to Improve Emissions on Units 1, 2 and 3", October 2002

burners and overfire air systems. MHI considers the $19.8 million estimate reasonable and in keeping with industry norms.

10.5.2 HTGS Replacement 2033/2036

The Holyrood Combined Cycle Plant Study report prepared by Acres International Ltd (November 2001)[217] considered two CCCT plant options located at the HTGS. The CCCT options are applicable today but the cost estimates would require updating. Three plant options were investigated in the 125 and 175 MW capacity ranges.

The technology for burning oil has not changed significantly since the study was done in 2001. The units proposed are now an older technology but are considered robust units suitable for firing oil.

The report concluded that firing on No. 6, 2% sulphur heavy fuel oil is difficult using a combustion turbine. Heavy fuel oil would be the preferred fuel since systems are in place at HTGS and heavy fuel oil is less expensive than No. 2, 0.7% sulfur oil. However, No. 6 oil tends to cause excessive erosion and corrosion of the blades. In discussions with manufacturers, both indicated that work is being done to mitigate the impacts of heavy fuel oil. From an environmental perspective, No. 2 oil would be the preferred fuel.

The report also indicated that NOx emissions could be an issue. Presently emission limits are met on CTs fired on No. 2 oil with water or steam injection. This requires a means of providing high quality demineralised water or superheated steam, increasing the cost of the CT installation significantly. Modern dry low NOx burners which do not require water or steam are not available for firing with No. 2 oil.

Costs

MHI prepared a comparison of the costs for the two options identified in the report using GTPro/Peace, a software tool used for industry benchmark cost estimating. The resultant costs for the 125 MW and 175 MW CCCTs are presented in Table 25.

[217] Exhibit 5h, Acres, "Holyrood Combined Cycle Plant Study – Combined Cycle Plant Study Update Supplementary Report - Final Report", November 2001

Table 25: Comparison of Two of the Thermal Options from the Report

Plant Size	Basis	Plant Output (MW)	Capital Cost Estimate ($millions)	Capital Cost ($ / kW)	Heat Rate (kJ/kWh) LHV[218]
125 MW	Exhibit 5H	131.2	136.4	1039.3	7528
	GTPro / Peace 2011	132.3	186.0	1407.5	7495
175 MW	Exhibit 5H	174.1	147.0	844.1	7452
	GTPro / Peace 2011	177.6	212.0	1193.8	7472

(Source: Exhibit 5H and GTPro/Peace by MHI)

GTPro / Peace is a combination of two interconnected programs, the heat balance program (GTPro) is specifically intended for the design of combustion turbine combined cycle power plants, cogeneration systems and simple cycle combustion turbine power plants. PEACE (Plant Engineering and Cost Estimator) in combination with GTPro provides engineering details and cost estimation. PEACE provides a database of installed plants and includes regional costs, provides graphic and tabular information about size, weight and cost of individual plant equipment and produces a detailed total plant cost estimate.

The values used in Exhibit 5 Summary-Capital Costs Estimates 2010 were checked against exhibit CE-46 Rev.2 (Public) CCGT Capital Cost Benchmark Study Final report Figure 6.1, "CCGT Unit Cost to Plant Output Regressions Analysis", and interpolated between the $/kW values determined in the report for an approximate value of $1,325 per kW or $225 million in 2008 dollars for a 170 MW CCGT plant.

The cost for the first unit would be higher since there would be significant costs incurred for transmission connection, fuel supply, black start capability, etc. which would not be required for the 2nd and 3rd units. The resulting base cost estimate for the first unit included in Exhibit 5 Summary-Capital Costs Estimates was $273.9 million.

The base value capital cost estimate for the second and third 170 MW units, with modifications applied for contingency and escalation was $206.2 million each. This matches up quite well to the GTPro / Peace estimate of $212 million.

The cost estimate values used in 2033 / 2036 are a combination of the $273.9 million and $206.2 million base costs escalated by approximately 2% per year. MHI finds that the values used for DG2 are reasonable.

[218] LHV is defined as Lower Heating Value and is applicable to heat rate.

Summary and Conclusions

The HTGS will require significant upgrades to continue operating as a generating plant. With the Isolated Island Option the plant would need to continue operating until 2033 for Units 1 and 2, and 2036 for Unit 3 when the plant would be replaced.

To provide a more accurate opinion on whether the generating plant could operate until 2036, the following would need to be addressed:

- What capacity will be required from the plant, and at what levels of availability and reliability?
- How long might the plant be down and what is the method / process for long term and short term layups that would be applied?

Also, the end of life would need to be defined. End-of-life may be the point at which damage has accumulated to the point where failures occur, or when the cost of inspection and repair exceed replacement cost. End-of-life may also be the point where the risk of failure is unacceptable due to hazards to plant personnel.

Smaller boiler plants have operated in many cases, in excess of 50 to 60 years; however, smaller boilers typically have much lower steam pressures and temperatures, lower heat flux rates etc. and the components are easier to replace. The end of life of these boilers typically occur when the drum's life is used up, repairs become too expensive, and emission control requirements are too restrictive.

In larger utility boilers it is unusual to find units that have been operating for more than 50 years even with life extension. Drums and other components are affected by corrosion and fatigue from flexing of the drums accumulates to the point where not only the boiler tubes require widespread replacement but so do major components. Note that even a small annual corrosion rate adds up to excessive wall and drum thinning over the years. The same is true for the steam turbine casing and other major pressure components.

Even with life extension, operation of the plant beyond 50 years, to a maximum of possibly 60 years, with reduced reliability, may not be practical. There may come a point well before 2036 when the plant becomes unsafe and unreliable to operate, not only for major components like the steam turbine rotor, boiler drum and critical piping, but also for other items such as wiring and non-critical piping.

The Holyrood replacement is anticipated to consist of 3 – 170 MW No. 2 oil-fired combined cycle combustion turbines installed in 2033 for Units 1 and 2 and 2036 for Unit 3.

The technology and the costs for the replacement plant appears to be reasonable.

10.6 Infeed Option Thermal Plan

Under the Infeed Island Option HTGS would be required to operate as is until at least 2016 then maintained in standby mode for power generation from 2017 to 2021. HTGS would primarily be operated in synchronous condenser mode from 2017 onwards. The schedule and costs for the thermal capital works and retirements are outlined in Table 26.

Table 26: Infeed Option Thermal Plan

Infeed Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	**Description**	**Costs (millions)**	**Retirements**
2014	50 MW CT	$75	
2017	Holyrood Units 1 & 2 Synchronous Condenser Conversion	$3	
2021	Holyrood decommissioning begins	$15	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW) Holyrood Unit 3 (142.5 MW)
2022			Hardwoods CT (50 MW)
2024			Stephenville CT (50 MW)
2025			
2029	Holyrood decommissioning complete	$12	
2037	170 MW CCCT (Greenfield)	$373	
2039			50 MW CT
2046	50 MW CT (Greenfield)	$141	
2050	50 MW CT (Greenfield)	$152	
2054	50 MW CT (Greenfield)	$165	
2058	50 MW CT (Greenfield)	$179	
2063	50 MW CT (Greenfield)	$197	
2066	50 MW CT (Greenfield)	$209	
2067			170 MW CCCT

10.6.1 HTGS Synchronous Condenser Conversion

Synchronous Condenser Conversion

The SNC Lavalin Feasibility Study for Units 1 and 2 conversions to synchronous condenser operation covers the main aspects of the required electronics, controls, and generator and steam turbine modifications required to allow operation of the generators as synchronous condensers[219]. Unit 3 already has the capability to operate as a synchronous condenser and therefore, conversion is not required.

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[219] Exhibit CE-56 Rev.1 (Public), SNC Lavalin, "Feasibility Study Of HTGS Units 1&2 Conversion to Synchronous Condenser - An Evaluation of Run Up Options for Generators", February 2011

SNC reviewed the various options available and recommended Static Frequency Converter (SFC) technology to be used for the conversion based on various factors including space availability, reliability, costs etc. The SFC is used to run the generation up to speed before connection to the grid.

The study only addresses the issues and costs directly related to the conversion to synchronous condenser operation and has not addressed a condition assessment of the generators, main step-up transformers, switchgear etc.

Costs

Costs for the synchronous condenser conversion were included in Exhibit 5 Summary-Capital Costs Estimates 2010 as $3.14 million with the work being done in 2016 and 2017. During the site visit on August 19, 2011 Nalcor did indicate that the SNC Study may have been too restrictive and only investigated the costs directly related to the synchronous conversion itself and did not appear to cover other costs such as building heating, cooling water modifications, etc. Therefore, a higher value, possibly in the $6.5 million – $7.0 million range could be expected for the synchronous conversion work.

Summary and Conclusion

The synchronous condenser feasibility study by SNC Lavalin was of sufficient depth to provide reasonable cost estimates for planning purposes. It is MHI's opinion that HTGS should be able to operate until 2041 as a synchronous condenser facility but reliability will likely degrade as the plant gets closer to end-of-life.

10.6.2 HTGS Decommissioning

Additional information was provided by Nalcor related to the development of the decommissioning costs of the HTGS (Responses to RFIs MHI-Nalcor-105 and 106).

In the absence of an in-depth study, Nalcor used engineering judgment to formulate the decommissioning program. This program was included in NLH's 2010 Capital Budget and 20 Year Plan as indicated in Exhibit 5 Summary Capital Cost Estimates 2010.

Costs

Details for the costs related to the decommissioning of HTGS were provided in response to MHI-Nalcor-105 and are summarized in the tables below.

Table 27: Holyrood Decommissioning Cost Estimates

Holyrood GS DCL1 Program		
Decommissioning Step	Year	Cost (1000's)
Remove and Decommission Common Electrical and Mechanical Equipment	2021	$ 1,242
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 1	2023	$2,555
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 2	2023	$2,555
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 3	2023	$2,555
Remove Fuel Storage Tanks	2025	$3,868
Remove Boiler House Building	2025	$2,678
Total DCL1 Costs		$15,452
Holyrood GS DCL2 Program		
Decommissioning Step	Year	Cost
Remove Boiler House Building	2027	$5,405
Secure Land Fill and Soil Remediation	2028	$4,308
Remove Marine Terminal	2029	$2,165
Total DCL2 Costs		$11,879

(Source: Response to RFI MHI-Nalcor-105)

The total cost for decommissioning HTGS is $27.33 million. MHI finds this estimate reasonable.

A report prepared by Stantec Consulting Ltd., Thermal Generating Station and Gas Turbine Site Remediation Study, available from the Nova Scotia Power website Appendix C includes fairly detailed cost estimates for site remediation for the following plants:

- Lingan Thermal G.S.
- Point Aconi Thermal G.S.
- Point Tupper Thermal G.S.
- Trenton Thermal G.S.
- Tuft's Cove Thermal G.S.

Although the report is not directly applicable to HTGS, it does provide estimates in 2010$ for site remediation of various thermal power plants with estimates ranging from $12.3 million to $25.3 million. The overall value estimated by Nalcor is in a similar range to the values from the Stantec report and is considered to be reasonable.

Nalcor indicated in the response MHI-Nalcor-106 that the costs associated with any asbestos removal have not been fully assessed within the context of site remediation. However, virtually all the asbestos at HTGS was removed during the 2005-2007 asbestos removal program. The relatively low amount remaining is being managed through the Holyrood Asbestos Management Plan (AMP).

The "Site Decommissioning and Restoration Plan" for HTGS is covered under Nalcor's Certificate of Approval issued by the Government of Newfoundland and states that "A plan to restore areas disturbed by the operation shall be submitted to the Director for review at least ten (10) months before the time that closure of the Thermal Generating Station is determined".

Appendix B of the Certificate of Approval "Industrial Site Decommissioning and Restoration Plan Guidelines" lists several objectives / requirements for the restoration.

It was noted, in the response to RFI MHI-Nalcor-106, that Nalcor would still be using the HTGS site for synchronous condenser operation until 2041, thus the site as a whole would not need to be remediated.

10.7 Conclusions and Key Findings

The costs associated with various thermal options have been estimated for the purposes of a DG2 screening study between the Isolated Island Option and the Infeed Option.

Key findings of MHI's review of thermal projects for both options are as follows:

- The thermal studies related solely to the Isolated Island Option were screening level studies, while there was a great deal more depth to studies of the Infeed Option. The level of detail of studies on upgrading the Holyrood Thermal Generating Station was found to be adequate, and the related upgrade costs are reasonable and in line with industry standards.
- Although the Holyrood Thermal Generating Station life extension costs for the Isolated Island Option are not based on detailed engineering studies, the estimates in the cumulative present worth analysis are conservative and representative of similar plants. This expenditure is needed to extend the life of the plant as a generating facility to 2033 for units 1 and 2, and 2036 for unit 3.
- Even with life extension under the Isolated Island Option, operating Holyrood Thermal Generating Station beyond 50 years, to a maximum of 60 years, with reduced reliability, may not be practical. There may come a point well before 2041 when the plant becomes unreliable to operate.[220] The life extension plan and requirements under the Infeed Option are as follows:
    - 2010 to 2017 Electricity Generation
    - 2017 to 2021 Electricity Generation, as-required primarily on a standby basis
    - 2017 to 2041 Synchronous Condenser Operation – Units 1 and 2 converted to synchronous condenser mode by 2017. Unit 3 is already synchronous condenser capable.
- The technology and base costs assumed for the 50 MW combustion turbine (CT) and the 170 MW combined cycle combustion turbine (CCCT) installations are reasonable. The technology and costs assumed for replacing Holyrood Thermal Generating Station using CCCTs under the

[220] Exhibit 44, AMEC, "Holyrood Thermal Generating Station Condition Assessment & Life Extension Study", January 2011.

Isolated Island Option are reasonable based on present utility plant retirements for plants built in the late 1960's and early 1970's.

- A detailed site assessment study for decommissioning the Holyrood Thermal Generating Station has not yet been completed by Nalcor. The costs of decommissioning the station are high level estimates, but they are considered reasonable when compared to similar recent projects.