newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

September 30, 2020

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Assessment of Options to Improve Holyrood Thermal Generating Station's Suitability as a Backup Facility

On February 25, 2020, Newfoundland and Labrador Hydro ("Hydro") advised the Board of Commissioners of Public Utilities ("Board") of its decision to forego a full condition assessment[1] of the Holyrood Thermal Generating Station ("Holyrood TGS") in 2020 pending the outcomes of the ongoing Labrador-Island Link ("LIL") reliability assessment. Hydro advised it would instead undertake a preliminary assessment of the potential to modify the Holyrood TGS to become a suitable backup generation facility and thus be considered as a potential long-term backup resource option, if required. In its March 17, 2020 correspondence,[2] Hydro outlined the scope of the preliminary assessment and committed to provide the results to the Board by September 30, 2020. The final report, prepared by Wood Canada Limited ("Wood"), is attached.

The preliminary assessment focused on identifying options for modifications at the plant to improve:

1) Minimum unit load;
2) Unit recall time; and
3) Conversion time of unit 3 from synchronous condenser to generation mode.

Minimum Unit Load

Wood's assessment involved four test methods, as detailed within the attached report, with the goal of determining which of the test conditions best suited both the boiler and the turbine while maintaining the ability to reload the unit quickly if requested by the Energy Control Centre. Tests were conducted for a minimal specified period of time under controlled circumstances.

---

[1] Estimated cost of the assessment is approximately $3 million, inclusive of internal labour, overheads, and contingency.
[2] "Reliability and Resource Adequacy Study Review – February 25, 2020 Update on Ongoing Work – Board's Request for Further Information – Reply," Newfoundland and Labrador Hydro, March 17, 2020.

Wood indicates that operating Holyrood TGS units at a sustained 30 MW[3] minimum unit load is acceptable if recommended procedures are followed and recommended plant upgrades are completed. Further trials at this new minimum load would need to be conducted for refining and confirmation purposes. As Wood has noted, further testing is required to discern the individual differences of each unit and account for currently unknown circumstances which may arise with running at a minimum unit load of 30 MW for a longer period of time.

Wood's findings did not identify any anticipated capital expenditures associated with reducing minimum load; however, further testing and investigation may identify a requirement for additional capital investment. From an operational perspective, one-time costs associated with boiler tuning and turbine logic adjustments would be required and the reduction in minimum unit load is not anticipated at this time to result in increased maintenance costs. Based on the findings of the assessment, Hydro is working with Wood to develop the required testing parameters. It is expected that the testing will take place in the latter part of spring/early summer 2021, depending on system requirements, with final analysis completed in the latter part of the summer of 2021. Hydro anticipates submitting the findings of this work to the Board in the fall of 2021.

Start Times

This area of the assessment focused on the ability of the first unit called to start to achieve a shorter start time than currently exists. Wood's assessment indicates that the 24–36 hours currently allotted[4] can be reduced to within 12 hours;[5] however, further testing is required to more fully understand the impact of an individual unit's differences on its recall time. Hydro has not yet tested a start to confirm this time frame under cold weather conditions (i.e., when a backup facility would be called for winter period).

Wood provided a number of recommendations related to engineering, investment, and testing that are required to support reliable fast starts of cold units. These recommended investments recognize the proposed operation of the Holyrood TGS as a backup facility. Wood has identified capital investment required to (i) provide auxiliary steam when the plant is not generating (but may be called upon); (ii) install flue gas temperature monitoring; (iii) install fuel tank recirculation and heating; and (iv) make additional modifications to prevent trips during the start process. The capital cost of this work is estimated to be approximately $1.5 million.

The most significant operating expenses related to reducing start times are associated with fuel and labour. The magnitude of these expenses, should the Holyrood TGS be required as a backup facility, will be determined by the required operating regime. The outcomes of the Assessment of Labrador-Island Link Reliability Considering Climatological Loads will further inform Hydro's understanding of the operating regime, if any.

---

[3] The target of 30 MW is based on start-up transfer requirements.
[4] Start from cold unit.
[5] On May 27, 2020, Unit 1 was recalled from cold to synchronized in approximately nine hours without external pre-warming measures.

Synchronous Condenser to Generation Conversion Time

The final area of assessment focused on the potential to reduce the time required to complete the changeover from synchronous condenser to generator. Hydro's current procedure to convert from synchronous condenser to generation mode requires that hydrogen be purged from the generator, which is a process that takes several days. Wood suggests that it is technically possible to reduce the conversion time by completing the uncoupling/recoupling of the generator and turbine without purging hydrogen from the generator and recommends Hydro investigate whether this can be completed safely.

Hydro engaged Emeric Solutions[6] to review the existing Holyrood TGS Unit 3 configuration and procedure to convert the unit from synchronous condenser to generator modes. If the risk associated with not purging the unit of hydrogen is deemed acceptable from a safety prospective, Emeric Solutions will prepare a procedure for the conversion of Unit 3 between synchronous condenser and generator modes while leaving the hydrogen in the generator.

The outcomes from Emeric Solutions' review are expected to be completed by November 15, 2020 at which time Hydro will review the findings to determine whether it is safe and operationally sound to implement such a procedure.

Conclusion

Wood's assessment determined that options exist to address three current specific limitations – minimum load, start times, and synchronous condenser to generation conversion time. The testing was carried out on a planned basis in a controlled environment rather than an emergency backup situation. As such, Wood has identified additional testing and analysis required to confirm that the modifications will result in the continued safe and reliable operation of the Holyrood TGS and it will indeed be able to be called upon in uncontrolled and emergency situations. Whether the Holyrood TGS should be considered as a long-term resource option will be informed by the outcomes of the ongoing Assessment of Labrador-Island Link Reliability Considering Climatological Loads. At that time, Hydro will determine whether it is necessary to undertake a full condition assessment of the Holyrood TGS.

Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
PUB Official Email

[6] Emeric Solutions has experience in the design, operation and maintenance of hydrogen cooled synchronous condensers with Canadian owned utilities.

Newfoundland Power
Gerard M. Hayes
Kelly C. Hopkins
Regulatory Email

Consumer Advocate
Dennis M. Browne, Q.C., Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Labrador Interconnected Group
Senwung Luk, Olthuis Kleer Townshend LLP
Julia Brown, Olthuis Kleer Townshend LLP

Attachment 1

Assessment of Viability of Continued Operation of Holyrood Thermal Generation Station as a Backup Facility

ASSESSMENT OF VIABILITY OF CONTINUED OPERATION OF HOLYROOD THERMAL GENERATION STATION AS A BACKUP FACILITY

August 2020

ASSESSMENT OF VIABILITY OF CONTINUED OPERATION OF HOLYROOD THERMAL GENERATION STATION AS A BACKUP FACILITY

Prepared for:

Newfoundland & Labrador Hydro
500 Columbus Drive
St. John's, NL A1B 3T5

Prepared by:

Wood Canada Limited
133 Crosbie Road
St. John's, NL AIA 3C1

REGISTERED PROFESSIONAL ENGINEER
BLAIR R. SECKINGTON
Blair Seckington
SIGNATURE
Sept 28/2020
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND AND LABRADOR
pegnl
ENGINEERING
PERMIT D0018
Wood Canada Limited
Signature or Member Number
(Member-in-Responsible Charge)

REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT
0	28-Sep-20	Issued for Use	IL	BS	RH	
E	18-Sep-20	Reissued for Client Review	IL	BS	RH	
D	28-Aug-20	Reissued for Client Review	IL	BS	RH	
C	26-Aug-20	Reissued for Client Review	IL	BS	RH	
B	21-Aug-20	Reissued for Client Review	IL	BS	RH	
A	7-Aug-20	Issued for Client Review	IL	BS	RH	

wood.	Assessment of Viability of Continued Operation of Holyrood Thermal Generation Station as a Backup Facility	Wood Canada Limited Job No. 205882	
		205882-001-CD10-RPT-002	REV. 0

Table of Contents

Appendices

Executive Summary

As part of its ongoing Reliability and Resource Adequacy study, Newfoundland and Labrador Hydro (NLH) is assessing the technical and economic viability of maintaining the Holyrood Thermal Generating Station (HTGS) as a backup facility for the Island Interconnected System. This report evaluated the following three issues that are currently considered limitations and makes recommendations to improve operational performance. Based on this evaluation, Wood recommends that HTGS can technically fulfil the role of backup facility.

NLH will use findings from this exercise as preliminary insight as to whether it is economically feasible to modify HTGS to become a suitable backup facility and thus be considered as a resource option in NLH assessments.

Minimum Load

An improvement to the historical minimum load of 70 MW per unit was demonstrated in June 2020 through a series of tests on Unit 2 that proved that a minimum load of 30 MW is achievable. Operational changes, further trials and optimization on all units and an observational minimum-load operating period are necessary prior to reliable operation at the new minimum load.

Faster Start Times

HTGS units are normally started from cold in two-to-three days. This can be, and has been demonstrated to be, shortened to under twelve hours. Engineering, investment and testing are required to ensure reliable fast starts of cold units. The essential recommendations are using Unit 3 boiler to provide auxiliary steam when the plant is not generating but may be called upon, installing Flue Gas Temperature (FGT) monitoring, and installing day fuel tank recirculation and heating. Additional recommendations are provided to prepare for cold starts and prevent trips during the start process. The capital cost (+100% / -25%) of the essential recommendations is estimated to be $0.4M and the remaining recommendations is estimated to be $1.1M.

Synchronous Condenser to Generation Conversion Time

Unit 3 can operate as a synchronous condenser by uncoupling the generator and turbine. The conversion from synchronous condenser to generator currently takes five-to-seven days, four days of which is a complex process of purging hydrogen from the generator. A new work procedure is currently being developed to safely complete this uncoupling/recoupling without purging in two-to-three days. Such procedures have been used elsewhere in Canada.

1. Introduction

As part of its ongoing Reliability and Resource Adequacy study, NLH is assessing the technical and economic viability of maintaining HTGS as a backup facility for the Island Interconnected System. Wood was contracted by NLH to assess the technical viability of HTGS to act as a reliable source of emergency power to the Newfoundland grid in the event of an outage to the Labrador Island Link (LIL). Three specific issues are addressed from a technical perspective in this assessment of viability:

- Can the minimum load at which the units operate be reduced?
- Can the units start from cold faster?
- Can the conversion time from synchronous condenser to generator be reduced?

In this report, the backgrounds of each of these issues are examined, recommendations are made to improve upon the current situation, and high-level cost implications are explained.

Wood is a global leader in the delivery of project, engineering and technical services to energy and industrial markets with operations in more than 60 countries. Wood is very familiar with operations at HTGS and has completed the following major assignments at the HTGS:

- 2010/11 Holyrood Level 1 Condition Assessment – Major EPRI Level 1 assessment of all HTGS equipment and systems which identified recommended remaining lives, suggested capital investments, and additional detailed EPRI Level 2 assessments.
- 2012-15 Holyrood Level 2 Condition Assessments – Carried out by Wood (AMEC NSS).
- 2017 Holyrood Condition Assessment Update – Major EPRI Level 1 assessment of all HTGS equipment and systems.
- 2019 Holyrood Thermal Generating Station Condition Assessment & Life Extension Study. An extensive review and confirmation of capital plans, operating costs and staffing levels necessary for the continued operations of the plant to March 2023 and standby operations of Unit 1 and Unit 2 to March 2027

2. Acronyms

The following acronyms have been used throughout this document:

ABNFS	Available But Not Fully Staffed
ABNO	Available But Not Operating
AC	Alternating Current
CO_2	Carbon Dioxide Gas
CV	Control Valve
DC	Direct Current
DCS	Distributed Control System
ECC	Energy Control Centre
EPRI	Electric Power Research Institute
FGT	Flue Gas Temperature
GE	General Electric
H_2	Hydrogen Gas
HP	High Pressure
HTGS	Holyrood Thermal Generating Station
IP	Intermediate Pressure
kPa	KiloPascals
LCP	Lower Churchill Project
LIL	Labrador Island Link
LP	Low Pressure
MPa	MegaPascals
MW	MegaWatts
NLSO	Newfoundland and Labrador System Operator
NLH	Newfoundland and Labrador Hydro
OEM	Original Equipment Manufacturer
RPM	Revolutions per Minute
RPP	Resource and Production Planning
TRO	Transmission and Rural Operations

3. References

The following documents have been referenced during the compilation of this report.

General Electric Start-up and Loading Manual

Combustion Fossil Power, 1991 Edition

4. Background

HTGS is a three-unit, heavy oil-fired steam cycle generating station on the south shore of Conception Bay in Newfoundland and Labrador. HTGS has a nominal capacity of 490 MW (net) and was constructed in two stages: Units 1 & 2 in the late 1960's and Unit 3 in 1977. Units 1 & 2 were modified in 1987 to increase their capacity to 170 MW (net) each; Unit 3 is 150 MW capacity. Typically, the units operate late Fall through Spring to support the Winter electrical demand peak. HTGS has served as a seasonal baseload station with hydroelectric generators elsewhere on the island of Newfoundland providing Winter peak capacity and most spinning reserve capacity. Given the proximity to the largest load centre, North-East Avalon, HTGS Unit 3 operates as a synchronous condenser for grid voltage support during the Summer season.

As a seasonal baseload generating station, the primary mandate was to provide high reliability during the Winter readiness season at minimal cost. Historically, the units did not operate below 70 MW capacity each due to concerns that long-term reliability would be affected. With the current interest in changing the HTGS mandate to backup power, there are opportunities and justification to further explore lower minimum loads. Similarly, it is desirable to reduce unit start-up time from the current two-to-three day time frame.

Conversion of Unit 3 from generator to synchronous condenser operation requires decoupling the turbine and generator, and reinstating generation requires recoupling turbine and generator. The current work method used requires five-to-seven days to transition from one state of operation to another. Unit 3 currently operates as a synchronous condenser during the Summer and will likely operate as such year-round to support the LIL electrical infeed to the island.

5. Viability of Reducing Minimum Load

NLH and Wood agreed that a target sustained minimum load of 30 MW should be achievable. It is not uncommon for turbines of similar vintage to be able to operate at 25% capacity. Four test procedures were developed by Wood and executed by HTGS operations staff in June 2020 with the goal of finding out which of the test conditions best suited both the boiler and the turbine while maintaining the ability to reload the unit quickly if requested by Energy Control Centre (ECC). Due to Summer outages, all tests were carried out on Unit 2. Since Unit 1 is of the same manufacturer and the same design, it can be assumed that outcomes will be similar to Unit 2. Individual units may have unique minimum loads and over time these loads may vary by a few megawatts due to the operational characteristics of the individual unit. Testing of Unit 3, which has different Original Equipment Manufacturers (OEM's) for the turbine/generator and the boiler than Units 1 & 2, should be undertaken at earliest opportunity to determine which setup method should be employed. Testing of Unit 3 is expected to result in similar results as Units 1 & 2, but this should be confirmed.

Several parameters (see Appendix A) were monitored and recorded during these tests to ensure that the unit operated safely and within OEM guidelines over extended periods of time. With the intent to operate these units at the safest lowest possible minimum load, Unit 2 was never placed in jeopardy. Any system alarm received during the test deemed to be a threat to the safety and security of the unit would have caused cancellation of the test; HTGS indicated that no such alarms were received.

A Wood Operations Specialist was unable to directly oversee the tests because of Covid-19 pandemic travel restrictions but was in regular communications with HTGS Operations during the tests. Based on the results obtained and previous operating knowledge, Wood Operations Specialist has determined operating HTGS units at a sustained 30 MW minimum load is acceptable if recommended procedures are followed, further trials conducted for refining purposes, and recommended upgrades implemented.

5.1 Minimum Load Test Plans

Four test plans were submitted to HTGS Operations to gradually reduce load on the unit from 70 MW to 30 MW while collecting operating information from the Distributed Control System (DCS). These tests were to be carried out with the understanding that if operating limits were being exceeded the test was to be terminated. Details of the test plans are included in Appendix B.

1. Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine
2. Partial Sliding Pressure Partial Control Valve (CV) Closure to Achieve Minimum Load of 30 MW
3. Total Variable Pressure Drop from Design Pressure to 30 MW
4. Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

5.2 Results of Minimum Load Tests

The following is an overview of the different tests conducted by HTGS Operational personnel:

Test Method 1: Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine

Results indicate that the unit could operate at 30 MW using this method. However, the results provided indicate that the unit was at that load for a very short time. If the unit had held 30 MW for the six-hour time frame, it is expected that the High Pressure (HP) Turbine 1st Stage Inner and Outer Metal Temperatures would have dropped significantly and subsequently caused high stress values when reloading the unit. This has been the experience of Wood Operations Specialist and is also stated in the General Electric (GE) Turbine Starting and Loading Manual.

Test Method 2: Partial Sliding Pressure Partial CV Closure to Achieve Minimum Load of 30 MW

Lowering the HP Turbine Throttle Pressure down to 11 MPa from the design pressure reduced the generator load to 61 MW. Using the CV's to lower the generator load to 30 MW and holding that load for six hours caused a slight but acceptable reduction of temperatures in the HP Turbine 1st Stage. The 1st Stage temperatures dropped from 432°C down to 383°C at 30 MW. Reloading the unit should not have caused any major heat stress event. However, one concern that was observed revolves around the Reheat Bowl Inner Metal Temperatures (likely due to a known probe accuracy issue). The inner metal temperature of the Reheat Bowl remained extremely low during the whole test. This was observed when the unit was at 70 MW at the design steam pressure and steam temperatures. Readings of 138°C were recorded and stayed at that level during the entire test. The Hot Reheat Steam temperature remained around 470°C and the Outer Reheat Bowl Metal Temperature indicated a temperature as high as 488°C at 30 MW. The outer temperature appears to be reasonable due to the overall thickness of this section along with the temperature of the Hot Reheat Steam as it will take a much longer time to cool. The anomaly with the Reheat Bowl Inner Metal temperature needs to be investigated further at the station to determine the cause. Lowering the unit load using this method caused some minor boiler control issues that could be addressed with boiler tuning and further trials.

Test Method 3: Total Variable Pressure Drop from Design Pressure to 30 MW

As expected, the HP Turbine 1st Stage Metal Temperatures and Reheat Bowl temperatures rose slightly from those at 70 MW as HP Turbine Throttle Pressure was reduced until 30 MW was reached. This was due to the fact the Main Steam Temperatures rose slightly along with the Hot Reheat Steam Temperature. Some concerns arose from this test.

- The turbine differential expansion increased from 4.35 millimetres to 7.72 millimetres which might be explained by the slightly higher metal temperatures.
- The boiler pressure must be lowered significantly to reach the desired load. Operating at these low pressures could create grid security issues if another generator on the island was to trip unexpectedly. HTGS units would attempt to restore the lost load which would cause the boiler steam drum pressure to drop even further and trip the unit due to high water levels in the steam drum.
- The Steam Drum Pressure is extremely low. Holding the new minimum load over long periods with just over 5 MPa pressure would result in the steam temperatures through the superheater and reheater tubes increasing to the point of requiring attemperation.

Test Method 4: Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

This test did not proceed as planned due to turbine control logic limitations. According to HTGS Operations, the transfer of load control to main steam stop valve bypass is much lower than the test plan during a normal shutdown and hence this part of the test could not be completed. Instead, a test was conducted during start-up from off-line using normal start-up procedure. The Main Steam Stop Valve and Bypass were used to run the unit up to synchronous speed, the unit synchronized to the grid, and HP Turbine Throttle pressure raised to 11.5 MPa to provide 30 MW. With the HP Throttle Pressure at 11.55 MPa, as time progressed, it was noted that the Turbine Metals temperatures improved, except for the Reheat Bowl Inner metal temperature. If the test had continued, it is expected that all of the temperatures would have stabilized near normal operating values. Concern still exists as to why the Reheat Bowl Inner metal temperature was not climbing like the rest of the unit and should be examined further. Whether this was due to a faulty thermocouple or reheat bowl drains being open unnecessarily is to be determined.

Test Method 4 sequence would have been GE normal operating procedure for coming down to minimum load when the station was first constructed. The reason GE has for this full arc admission type of operation was to ensure that chilling of the turbine metals did not occur thereby reducing the life cycle stress events the turbine would be subjected to. GE recommends the unit not be operated using the control valves below the transfer point for any longer than 5 minutes. The Main Stop Valve and Bypass are designed to deliver 20% of the total steam flow which equates to roughly 30 MW and the transfer point should be at a load slightly higher.

5.3 Recommendations to Reduce Minimum Load

Based on our review and recent testing conducted, the following actions are recommended.

1. Test Method 1, although feasible, is recommended by neither Wood nor the Turbine OEM. GE suggests that the unit should not be run in this manner for any longer than five minutes. What the definition of low loads is may be subject to interpretation but adding huge pressure differentials across the CVs and the turbine nozzle block may cause damage over time. Chilling of the HP Turbine metals would also occur over extended operating time at these loads. The pressure drop across the CVs would be increased such that the pressure downstream of the valves is reduced causing a cooling of the main steam and consequently the metal temperatures will drop.
2. Test Method 3 is not recommended for the reasons mentioned above with respect to grid security, higher than design reheat steam temperatures, and increased possibility of tube thinning and fractures of superheater, reheater, and economizer boiler tubes due to reduced cooling in these areas while operating at the lower steam flow rates.
3. A combination of Test Methods 2 & 4 should be further developed with the recommended upgrades and used to accomplish the 30 MW goal for minimum load. By reducing the HP Throttle Pressure to 11 MPa, transferring control from partial arc admission to full arc admission, and using the Main Steam Stop Valve and Bypass as the steam flow control, the unit is able to sit at or at least return to normal operating temperatures, therefore not risk high temperature stressing in the HP Turbine when the unit is requested to load. This is consistent with the GE Start-up and Loading Manual.
4. Further testing of all units should be conducted to optimize operating parameters and discern the differences of the individual units.
5. Logic changes are required in the turbine control system to change the transfer point from the Turbine Control Valves back to the Main Steam Stop Valve and Bypass. A higher value somewhere between 30 – 40 MW is necessary. The Boiler Control logic with respect to 3-element boiler feedwater control needs to be reconfigured to allow the controls to stay in automatic. The requirements to establish the 3-element control are a suitable feedwater flow, a suitable main steam flow input into the DCS, and a stable drum level. All these requirements can be met while operating below 30 MW therefore the controls should be tuned accordingly. Boiler tuning is also a necessity as the controls tuning needs to be tightened at the lower load. Controls Tuners tend not to worry about the tightness of the controls at loads where the unit is not expected to operate at for extended periods.

6. Wood recommends that NLH allow for a transition period between mandate of seasonal baseload generation and mandate of backup power during which HTGS units are operated at minimum load for a period while LIL is online. This will allow plant operators to learn the peculiarities of the new operating point, and plant engineering and maintenance personnel to identify any required changes to inspection and maintenance regimes or capital investment.

5.4 Budget Considerations

Operating Budget

Reducing minimum load from 70 MW to 30 MW reduces fuel consumption and greenhouse gas emissions while operating at that condition. A reduction of 65-75 bbl oil/hour/unit fuel consumption and 33-40 Mg/hour/unit CO_2 emissions is estimated. The costs to revise boiler and turbine control logic and re-tune boiler controls are a minimal one-time cost. Maintenance costs are not anticipated to increase noticeably due to the reduction in minimum load, but maintenance efforts will likely change areas of focus. Operating the plant during a transition period for observation purposes will consume fuel and require regular staffing even though there is no outage to LIL.

Capital Budget

There are no capital budget expenditures anticipated at this time. Investigation and engineering during the transition period may identify capital investment requirements to enhance reliability

6. Viability of Faster Starts

The target provided for fast starts was that the first unit called to start would synchronize in 8-12 hours, compared with 24-36 hours currently allotted. Common belief is that faster starts are achieved through external preheating of the turbines. However, through discussions with HTGS Operations, Wood holds the opinion that primary reasons for current long start times are boiler and fuel system related. On May 27, 2020 HTGS conducted a cold fast start test and synchronized the unit in just over nine hours without any additional turbine prewarming other than what is prescribed by the OEM. Industry standard for units of this size and vintage is eight-to-twelve hours, and Wood contend that should be regularly achievable for HTGS.

6.1 Definition of Faster Starts

Fast Starts can be defined differently depending on the condition of the Units Boiler, Turbine Generator and the associated equipment used in the operation of these major pieces of equipment. A start that is considered Cold is one where the boiler and turbine are at less than 100°C. This is considered as a Cold Start because the HP turbine requires to be prewarmed as prescribed by the OEM. Extreme stresses would be incurred if high temperature steam were introduced to a cold HP turbine therefore a slow heating procedure is followed before the unit is rolled on steam to reduce that concern. An achievable cold start time for a HTGS Unit with Nitrogen (N_2) filling of the boiler should be in the 6-12 hours range depending on the actual HP turbine metal temperature at the time of the start. For a turbine which is defined to be in a Warm Start condition, HP turbine inner metal temperatures between 100 - 325°C, a start time of 2.5 hours should be achievable. If the turbine HP turbine inner metal temperature is greater than 325°C (Hot Start) a start time of 1.5 hours can be achieved. All the above start times are based on the conditions of the unit boiler, turbine-generator, and the common systems necessary to run a unit.

- The auxiliary steam common header pressurized to 1.4 MPa from an auxiliary boiler or Unit 3 as an auxiliary steam source.
- The main fuel oil systems must be preheated and recirculated in order to be available to establish firing the boiler quickly and aggressively within the boiler manufacturers temperature limitations.
- The boiler temperature limitations along with a number of operational issues must be controlled during starts.
- The turbine-generator must be on turning gear for a minimum number of hours prior to rolling using steam. GE recommends 8 hours although shortening that time to as low as 4 hours has become an industry standard and is recommended by Wood. HTGS should conduct testing to determine the minimum time their units need to be on turning gear and adjust their procedures accordingly.

6.2 Unit Status

Available But Not Operating (ABNO)

ABNO may take on different meanings to different work groups. A unit that operated in the past three days and is still on turning gear, and a unit with boiler under layup procedure with N_2 filling can both be considered ABNO but will require different preparations for starting. Therefore, a strong understanding and a clear definition of an ABNO unit is required to ensure that the different work groups are all working to the same one when a fast start is requested. Because at least three different work groups are involved in this process, we believe that a definition needs to be developed by all interested parties: HTGS Operations; Newfoundland

and Labrador System Operator (NLSO); Resource and Production Planning (RPP); and Transmission and Rural Operations (TRO).

Available But Not Fully Staffed (ABNFS)

During extended non-operating times, a skeleton operating staff will be required in the plant 24/7 to ensure the equipment is in a state of readiness. A unit may be available to operate physically but if there is not sufficient experienced staff available to complete the start, then the start-up would be partially compromised until appropriate staff were present. This status was not previously used at HTGS but is particularly significant to whether the required start is an emergency or is planned.

6.3 Unit Pre-Conditions for a Cold Fast Start

A detailed listing of systems to be available and in service for a start is provided in Appendix C. This list assumes start up from a lay-up state and Wood is confident such a start can be accomplished safely and reliably within 12 hours provided the recommendations that follow are implemented. The lay-up state is intended to prevent corrosion and assumes N_2 filling of the steam spaces of the LP and HP Feedwater Heaters, including the Deaerator, and filling the water side of those heaters with treated demineralized water. Although the original equipment had capabilities for N_2 filling, Wood understands that some refurbishment will be required to ensure full functionality.

Three primary conditions must be met for fast cold starts to be realized:

- There can be no Outstanding Work Protection in place on the unit or in the switchyard that inhibits the start.
- Staff to operate the unit must be available in the plant or at least on call to respond if the start is of an emergency nature.
- Auxiliary steam must be available.

Provided all systems are available and primary conditions met, a cold start can commence. A generalized procedure for cold starts is provided in Appendix D.

6.4 Recommendations for Faster Starts

Wood recommends the following

1. Auxiliary Steam must be available to maintain the Auxiliary Steam Header Pressure. Without Auxiliary Steam Fast Starts are not viable. Auxiliary steam will allow for the Main Residual Fuel Oil Storage Tank and Day Tank Temperatures to be maintained at levels that will allow Main Oil firing earlier than what the present-day scenario dictates. Main burner Atomizing and Scavenging Steam pressure permissives required prior to firing any main oil gun would also be available immediately. The additional benefit of maintaining the powerhouse heating will also be satisfied. The primary alternatives for providing auxiliary steam are a dedicated auxiliary boiler (electric or fuel) or using an existing boiler at reduced output.
2. Our recommendation for providing Auxiliary Steam is that Unit 3 boiler, when not being used as a power generating source, be fitted with a limited number of smaller tipped interchangeable mechanically atomized main oil burners. This will allow the boiler to run at much lower operating

pressures and limits the amount of steam drum pressure cycling. These guns would be fitted into the same burner assemblies presently used. More detailed engineering and testing of this modification should be done to determine all necessary requirements. Within the DCS boiler controls, some additional logic will be necessary to allow the controls to work in the new environment. These burners and the boiler control logic can be switched back to the normal if Unit 3 is required as a power generator. Another advantage of using Unit 3 is, as of now, it is the only boiler with economizer recirculation which has benefits with respect to not having the economizer boil dry causing economizer tube failures and heavy fluctuations in drum level. This method does have drawbacks, as it is not an efficient mode of operating a boiler of this size. However, once one of the other unit boilers and turbine-generators are in operation, shutting down Unit 3 until required will reduce fuel consumption.

3. FGT Monitoring Equipment must be installed on all units. During a fast start, the unit boiler would be knowingly operated outside of the OEM limits. Without adequate FGT Monitoring, faster starts are not reliable and there is risk of damaging the superheater and reheater sections of the boiler. Controlling the firing rate and therefore the boiler FGT to maintain temperatures less than 538°C in the superheater / reheater sections of the boiler is critical to preventing overheating of the tube due to insufficient steam flows through them. (Reference "Combustion Fossil Power" 1991 edition Chapter 21 Pages 6-7 and also the General Electric Start-up and Loading Manual)
4. Optical FGT Monitoring is recommended. Retractable FGT probes are original to the unit but have not been used for many years; recommissioning them is not considered viable. Referencing the temperatures of the thermocouples located near to the headers of the superheater and reheater tubes is not satisfactory. These thermocouple locations are shielded from the actual flue gas and therefore do not provide satisfactory information during the starts.
5. Main Fuel Oil Day Tank recirculation and heating are recommended. This modification would maintain the Day Tank Oil temperature closer to that required to fire a main burner and reduce demand on the individual unit oil system heaters to raise the temperatures above 85°C. One of the observations made during the low load testing was the Day Tank temperature was as low as 36°C in the month of June. During the Winter months the Day Tank temperatures may even be lower with the current system. A suggested location for this system would be where the former Auxiliary Boiler Fuel oil pumps and heat exchangers were originally placed.
6. Permanent economizer recirculation should be installed on Units 1 & 2 (already on Unit 3 as part of original design). Keeping the economizer tubes that are exposed to higher FGT filled with water at all times provides the cooling necessary to prevent unnecessary damage. This recommendation was made in 2007 but not acted on at the time. Faster start times will be infringed upon and unit reliability diminished if these are not installed.
7. Lower waterwall header drain valves on all three units should be motorized. Operating limits must be installed in the DCS to prevent these valves from being opened above 3000 kPa as per the OEM's guidelines. Requirement for manual adjustment of these valves creates unnecessary boiler trips during the start process due to high or low drum levels. HTGS staff would be unable to stay in this one area until the request to open or close them is made as other duties are required.
8. Motorize the Steam Drum Continuous Blowdown Valves on Units 1 & 2 making them like Unit 3 and providing controls into the control room is recommended. The present situation requires that an

operator be dispatched to the 9th or 10th floor to manually operate these valves. The control room operator is required to make drum level adjustments quickly above 3000kPa and this system provides the optimum safe way for that to happen.

9. At least one main storage tank should be fitted with a recirculation pump to ensure the existing fuel heating system is effective and the stored volume of fuel remains accessible in Winter.
10. A lay-up procedure should be developed with objective of protecting the asset and facilitating quick response to an emergency request. If required for the procedure, the existing N_2 piping should be verified and repaired as necessary. Also, the addition of guillotine dampers on the flue gas outlet ducting of the rotary Lungstrom Air Heaters should be considered to prevent corrosion of the outer walls of the boiler tubes and ductwork
11. Staffing arrangements (numbers on shift, numbers on call, experience, etc.) for various scenarios should be developed so that costs are minimized but the assets are protected and the station is capable of responding as expected. These arrangements will correspond to the various states of readiness defined by NLH and NLSO.
12. Installation of piping from the individual Units 1 & 2 Auxiliary Steam Header to the turbine gland steam system should be considered. Some utilities have used this modification to heat the HP and Intermediate Pressure (IP) turbines and may be beneficial if faster start times are desired. Unit 3 is already equipped with this capability and the effects on that Unit could be tested before installing the piping on Units 1 & 2. To establish the warming condition, steam at approximately 180°C from the Auxiliary Steam header would be introduced to the HP, IP, and LP turbines through the Turbine Gland Steam system, and using the Condenser Air Extraction Pump to draw a minimal vacuum on the Condenser creating a warming steam flow through the unit from the glands into the main body of the Turbine casings.

6.5 Budget Considerations

Faster starts are desirable now but will be essential if HTGS were to serve as a backup facility. The following budget items should be implemented well before the transition to emergency power readiness so that the systems and procedures can be fully commissioned and HTGS staff gain experience with them.

Operating Budget

The most significant operating expenses will be fuel and labour. The magnitude of these expenses will be determined by the required state of readiness and duration of that state. Various levels of readiness can be envisioned; NLH and the NLSO must determine when such levels are required, if at all.

- A condition of no auxiliary steam production and no synchronous condenser operation may be considered during the Summer months when demand is reduced. At such times there will be no fuel consumption and only a skeleton staff will be necessary. However, fast starts will not be possible from such a condition.
- Producing auxiliary steam from Unit 3 boiler will require fuel consumption and modest amounts of additional staff. This would be desirable during the Winter months to provide fast starts and plant heat.

- Holding a unit online at minimum load when necessary for emergency or unplanned reasons will increase operating costs further but will provide spinning reserve capacity in addition to allowing fast starts of other units.

Other operating costs will be one-time expenses and are considered minor such as boiler tuning, logic programming, preparing procedures, and associated engineering.

Capital Budget

The recommendations considered essential, using Unit 3 boiler for auxiliary steam, installing Optical FGT monitoring and day tank recirculation and heating, will have a capital investment of approximately $400,000. Wood recommends these changes be implemented first or in conjunction with other improvements. The table below lists capital cost estimates (+100% / - 25%) for the recommendations. Except where noted, cost estimate is for all three units.

Recommendation	Priority	Estimated Cost
Use Unit 3 Boiler for Auxiliary Steam	Essential	$100,000
Optical FGT Monitoring	Essential	$100,000
Day Tank recirculation and heating	Essential	$200,000
Main storage tank recirculation	High	$300,000
Refurbish N_2 fill system	High	$50,000
Units 1 & 2 Economizer Recirculation	Moderate	$300,000
Motorize valves: lower waterwall header drains	Moderate	$200,000
Motorize valves: steam drum continuous blowdown	Moderate	$200,000
Units 1 & 2 Turbine gland seal auxiliary steam piping	Moderate	$50,000

7. Viability of Reducing Conversion Time on Unit 3 from Synchronous Condenser to Generator

The time required to complete the changeover from synchronous condenser to generator currently ranges five to seven days. The HTGS Procedure requires that the generator casing be purged of H_2 using CO_2 and then remove the CO_2 using air before the mechanical changeover can begin. The above procedure then needs to be done in reverse before the unit is started as a power generator after the conversion. The purging of gases is done as a safety precaution.

Maintaining this method but accelerating the process will require installing significantly larger diameter piping, enlarging tie-points on the generator, and possibly heating of the gases. A simpler solution is to leave the H_2 in the generator during the conversion, thereby reducing conversion time by four days and maintenance staff could then re-couple the generator to the steam turbine in three 10-hour days.

Wood was unable to locate any utilities that currently convert from synchronous condenser back to steam powered generator. Most utilities that have converted their generators leave them as condensers and dismantle the steam generator portion of the unit. One utility that routinely completed the conversion in the past did it with H_2 left in the generator.

Wood recommends leaving H_2 in the generator during conversion, possibly at a somewhat reduced pressure, and leaving the generator seal oil system in service. The seal oil system is a totally contained separate system that pumps oil to the generator shaft seals at a controlled differential pressure that is higher than the H_2 pressure. This ensures that H_2 does not leak into the atmosphere and therefore does not pose a risk to the work being done to complete the conversion.

Since commissioning this report, NLH engaged Emeric Solutions to review the existing HTGS Unit 3 configuration and existing procedure to convert HTGS Unit 3 from Generator to Synchronous Condenser modes. The final intent is to implement the unit conversion with H_2 in the vessel. If deemed feasible, Emeric Solutions shall prepare a procedure for HTGS to convert Unit 3 between synchronous condenser and generator modes while leaving H_2 in the generator.

Emeric Solutions are presently engaged to oversee the design, construction, commissioning, and maintenance programs for the synchronous condensers at the Soldier Pond Converter Station. They also have significant experience associated with the design, operation, and maintenance for a variety of Canadian utility owned H_2 cooled synchronous condensers.

Upon completion, we recommend this procedure be thoroughly reviewed with HTGS maintenance and safety personnel to ensure they have confidence in the methodology, and the procedure be used for all such conversions and not reserved only for emergency conditions.

7.1 Budget Considerations

The next opportunity to convert Unit 3 from synchronous condenser to generator will be the Fall of 2020. If the new procedure is completed and reviewed, it should be used for the next conversion.

Operating Budget

No additional costs are anticipated other than the one-time costs to develop the procedure. There is the possibility that the overall cost to complete the conversions may be reduced.

Capital Budget

There are no capital budget expenditures anticipated.

8. Conclusions

Wood studied three current operational performance limitations at HTGS and concludes that each of these can be significantly improved with modest investment. It is technically viable to change the mandate of HTGS from reliable baseload winter generation to backup power. The level of improvement possible to minimum load, start times, and synchronous condenser to generation conversion time warrant further consideration of the economic viability of HTGS as a backup facility when no longer required as a baseload resource.

Several recommendations are listed in previous sections. The following recommendations are considered essential.

- Revisions to control logic and boiler tuning are required for both lower minimum loads and faster starts.
- Auxiliary steam is available when HTGS is not generating but available. Without auxiliary steam, fast starts are not viable. Wood recommends using Unit 3 boiler to provide auxiliary steam.
- FGT monitoring equipment is installed to ensure the boilers are not inadvertently damaged during fast starts.

Appendix A

Minimum Load Testing Parameters Monitored

Unit Boiler and Associated Equipment

East and West Forced Draft fans discharge pressures

East and West FD fan bearing vibrations

East and West FD fan variable speed motor amperages

East and West FD fan speeds

Boiler Windbox Pressure

Boiler Air Flows (East and West)

Furnace Pressure

Boiler Opacity

Boiler Excess Oxygen (as a percentage)

Burner Tilt positions on ABCD elev. U1&U2

Main Fuel Oil Pressure Control Valve position (%)

Main Fuel Oil Filter Differential Pressures

Main Fuel Oil Pressure at the Burners

Main Fuel Oil Temperature

Main Fuel Oil Flow

Boiler Drum Level

Boiler Feedwater Pump East or West amperage

Boiler FW Pp East/ West bearing vibrations

Boiler FW Pp East/West discharge pressure

BFW Drum level Control Valve position

Boiler Steam Drum Pressure

Boiler Feedwater Flow

Boiler Main Steam Flow

Boiler Superheater tube Metal Temps

Boiler Reheater tube Metal Temperatures

Main Oil Day Tank Temperatures

Main Steam Turbine Generator and Associated Equipment:

Main Steam Temperatures at Turbine

HP Turbine 1st Stage Metal Temperatures (Inner & Outer)

HP Turbine Throttle Pressure

HP Turbine Control Valve Position in %

Hot Reheat Steam Temperatures

Cold Reheat Steam Temperatures

Reheat Bowl Inner and Outer Temperatures

Turbine Drain positions (open or closed)

Steam Turbine Differential Expansion

Steam Turbine Shaft Eccentricity

LP Turbine Exhaust Hood Temperatures

Turbine Condenser Vacuum Pressures

Generator Casing Hydrogen Pressure

Generator Hydrogen Temperatures

Generator MW Output

Generator MVAR Output

Steam Turbine/Gen. Bearing Shaft Vibrations

Appendix B

Minimum Load Test Procedures

Test Methods

1) Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine

a) Starting with the present-day minimum load of 70 MW's and the steam turbine throttle pressure at design of 12.9 MPa allow the unit to stabilize and take a full set of readings.

b) Closing the steam turbine control valves lower the unit loads to 60/50/40/30 MW's. Monitoring the selected points during each load reduction allowing the unit to stabilize for 30 minutes at each load. Take a full set of readings for each load value before moving to the next megawatt value.

c) Ensure that the turbine load limiter is set just above the load desired at each test load.

d) Depending on the condition of the unit i.e. turbine metal temperatures, turbine /generator vibrations, differential expansions and eccentricity, fuel oil filter differential pressures, main steam temperatures, burner tilt positions, and how the Boiler Feed Water is operating hold the unit at this load for at least six hours.

e) Release the unit to NLSO to load as required for system operations

2) Partial Sliding Pressure Partial Control Valve Closure to Achieve Minimum Load of 30MW

Reduce the boiler firing rates to lower the HP turbine throttle pressure from the design to a lower predetermined value ultimately causing the unit load to decrease to an unknown value. After reaching the unknown load continue lowering the load down to 30 MW using the unit Control Valves. Reducing the boiler pressure will allow the control valves to stay open longer and limits the throttling across these valves. Throttling causes the main steam to cool the HP Turbine metal temperatures creating excessive stress as the unit load is increased. Another advantage of using this method is by reducing the boiler pressure the risk of a secondary superheater outlet safety valve lifting is diminished. When these valves blow off high pressure steam into the atmosphere, high noise levels are generated

a) Starting with the present-day minimum load of 70 MW and the steam turbine throttle pressure at design of 12.9 MPa allow the unit to stabilize and take a full set of readings.

b) Reduce the boiler firing rate lowering the turbine throttle pressure to 11 MPa and determine what the unit load settles out at. When the load settles record the MW value and take a full set of readings. Allow the unit to stabilize for 2 hours and again take a full set of readings.

c) After determining what the load is, close the Control Valves and reduce the unit load to 30 MW while maintaining 11 MPa turbine throttle pressure. Allow the unit to settle out and take a full set of readings.

d) Depending on the condition of the unit i.e. turbine metal temperatures, turbine /generator vibrations, differential expansions and eccentricity, fuel oil filter differential pressures, main steam temperatures, burner tilt positions, and how the Boiler Feedwater system is operating hold the unit at this load for at least six hours.

e) Release the unit to NLSO (ECC) to load as required.

3) Total Variable Pressure Drop from Design Pressure to 30 MW

Reduce the Boiler Firing while leaving the turbine control valves either in position after reaching 70 MW or opening them to full open (full arc) after the HP turbine throttle pressure has decayed significantly. Continue to reduce the throttle pressure until the unit load reaches 30 MW. Operating in this manner prevents any throttling action across the Control Valves and therefore reduces the chilling effect that closing the control valves have on the turbine metals.

a) Reduce the firing rate allowing the throttle pressure to slide until 30 MW is obtained from todays present minimum load of 70 MW. (Note this test should only be performed after a full discussion with NLSO and what the ramifications might be if another generating unit on the grid was to trip.)

b) Operate the unit for a period of 2 hours at 30 MW while taking readings every 15 minutes.

c) Depending on how the Unit operates extending the test to an additional 6 hours to determine long term operating effect should be considered.

d) Release the unit to NLSO (ECC) for normal operating requirements.

4) Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

a) With the unit at the present day minimum load of 70 MW reduce the load down to 30 MW using the control valves and transfer the load control to main steam stop valve bypass (designed to supply 20% of the steam flow to the turbine which equates to approximately 30 MW based on the original design of the turbine before the uprating) Open the control valves to the full open position once it has been determined that they are no longer controlling the steam flow.

b) Operate the unit for a 3-hour period in this condition taking readings every 15 minutes.

c) Depending on how the unit is operating extending the test for an additional 6 hours should be considered.

d) Release the unit to NLSO (ECC) for normal operation.

Appendix C

Unit Pre-Conditions for a Cold Fast Start

Common Systems

- Auxiliary Steam Header 0-AS-03-300 must be fully pressurized to 1400 kPa and the 700 kPa 0-AS-03-301 line supplying the Main oil Tank Farm and the Main Oil Day Tank must be in service.
- The Common Water Treatment Plant must be available for supplying treated water to the unit boiler for makeup including the Reserve Feedwater Systems on the unit being started.
- The individual unit chemical dosing tanks and pumps are available in automatic or available with some Operator intervention with the appropriate chemicals to begin dosing as required.
- The units associated General Service Water and Turbine/Generator Auxiliary Service Water Systems along with the Raw Water Supply are in operation or available to operate.
- The associated units fire water system is in service. Note: This system should be available at all times or an appropriate fire watch is provided.
- The associated units Instrument and Service Air Systems are in service for at least the unit requested.
- The plant 4KV & 600VAC and the unit Uninterruptible Power electrical buses along with the 250V & 125V DC buses for the unit being started must be in service.
- The H_2 and CO_2 bulk supply systems must be available to the unit requested.
- Main Fuel Oil Storage Tanks (at least one tank) and its associated Suction Heater is in service and the steam tracing on the Main residual oil piping supplying the Residual Oil Day tank is in service.
- The Light Oil Storage Tanks (at least one) is available supplying the suction header common to all the units light oil pumps.
- All sumps and associated pumps along with the common wastewater treatment facility used with respect to the operation of the plant and specifically the unit being requested are available for service.

Unit Boiler Systems

- Unit Condenser hotwell, Condensate Extraction Pumps (at least one), Condensate Polishers and the remaining LP Feedwater System including the Gland Steam Condenser, LP heaters 1 & 2 with associated heater drips and vents, the Deaerator and Deaerator Storage Tank are available for service. All nitrogen connections on the LP Feedwater System including the Deaerator must be disconnected and heater venting re-established before starting the unit. Note that there is a safety concern when using Nitrogen to layup the equipment. Nitrogen does not support life and therefore monitoring should be installed and periodic atmospheric testing should be completed on the ground floor of the powerhouse to ensure nitrogen has not escaped from any of the above associated equipment.
- Unit HP Boiler Feedwater system is available for service including Boiler Feed Pumps (at least one) and the HP heaters 4, 5, and 6 are available for service. Included in this would be the HP heater drip system and HP heater vents. If an HP feedwater heater is unavailable due to any reason then depending on which heater and what the turbine OEM's limits are, a maximum unit load restriction may apply. The boiler economizer inlet manual valve must also be open. Nitrogen should be used to protect the heater shells from corrosion and oxidation if long term shutdowns are expected. Disconnection of the nitrogen would be necessary before starting the unit and heater venting re-established.
- Boiler waterwall circuits and the Steam Drum must be full of treated demineralized water and the Steam Drum maintained at the highest level possible without putting water into the primary superheater. If filling the superheaters and the main steam piping with demineralized water becomes part of the layup procedure, then all necessary hangar rod pins must be installed in the main steam lines from the boiler down to the turbine in order for

those lines to withstand the weight that the water would create. Unless the shutdown periods are excessively long this portion of the layup procedure should be thought through carefully before being carried out as all the steam piping would require draining and all hangar pins must be removed before starting the units boiler. All waterwall manual drains and vents must be closed to ensure no leakage or air ingress before the nitrogen blanketing is applied. All superheater manual drains and atmospheric vents must be closed along with the main steam boiler stop valve if available. (if BSV is not available then Turbine Main Stop Valves must be kept closed and any drain valves associated with these must be manually closed as nitrogen will migrate into these systems. This only applies if nitrogen blanketing is applied to the boiler through the connection at the Steam Drum and the Cold Reheat Piping. Disconnection of the nitrogen would be necessary before starting the unit and the manual vents to atmosphere must be opened prior to start.

- Boiler Combustion Air and Flue Gas Circuits including the boiler makeup air system, at least one FD fan, (as long as the discharge damper on the second fan is totally blocked to prevent a backflow of air and flue gas from entering the powerhouse) the combustion air heaters and the rotary Air Preheaters are in service or are ready for service, Auxiliary Air, Fuel Air Dampers, and Burner Tilts on Units 1 & 2 are available and in Automatic. The Boiler Temperature Probe or Optical Temperature measuring is available. If unit 3 is to be started as a power generator then the secondary air registers only are required to be in automatic (Unit 3 does not have burner tilts or Aux air and Fuel Air dampers as it is a different manufacturer). The flame scanner blower, the seal air fans, and aspirating air are available along with the Ignitor Booster Fans for units 1&2. All boiler and ductwork access doors along with flame viewing ports etc. should be closed and ready for boiler operation. As there is no isolation point between the boiler flue gas outlet and the Stack associated to the Unit, and due to the high salt content in the Newfoundland outdoor air, some form of protection should be considered for the outside of the boiler tubes and the inside of the boiler ductwork especially if extreme long- term shutdowns occur. A negative stack draft will occur while not in operation and a small air flow through the boiler to the atmosphere will take place. This airflow will cause some oxidation on the outside of all the boiler tubes and on the insides of the boiler ductwork. In order to prevent this draft from occurring ensure all dampers are closed and are tight shut off or one suggestion although not strongly recommended is placing tarpaulin's over the flue gas sides of the Lungstrom Air Preheaters to stop the flow of air created by the Stack draft effect. The other method to stop the flow of air is the addition of guillotine dampers in the ductwork at the FD fan discharges and on the flue gas outlets of the Lungstrom Air Preheaters. Neither of these recommendations are required immediately but might be considered after determining the critical role Holyrood has within the Newfoundland Power Grid. (Using tarpaulins and removing them would add a great deal of time and effort in starting up a unit)
- Boiler Fuel Systems including the Unit Main Residual Fuel Oil System including strainers, fuel oil heaters, and pumps up to the burner nozzles, the Unit Residual Fuel Oil Additive System, along with all of the piping and valving associated with these systems should be available. The Unit Light oil Ignition Fuel System up to the individual ignitor control boxes and ignitors while including the Common Light Oil Storage Tank and associated piping and pumps. Also required for the main burners is the Atomizing Steam and Scavenging Steam systems fed from the Auxiliary Steam system.
- The boilers DCS must be available

Turbine and Generator Systems

- Turbine Auxiliary Oil System including the associated lubricating oil tank filled to its normal working level with the oil tank vapour extractor in service along with at least one of the two AC oil pumps in service. The associated DC lube oil pump must be available and tested to ensure its operational ability in case there is a total loss of AC power to the unit. The lubricating oil filters must be in service to protect the integrity of the oil before being introduced to the turbine and generator bearings. Unit 3 requires the Turning Gear oil pump to be in service along with the Jacking oil pump to lift the turbine shaft before placing it on Turning Gear. (Units 1&2 do not have this requirement.)

- Turbine/Generator must be available to be put on Turning Gear for a period of at least 8 hours (or a determined reasonable time) if it is not already on turning gear. If the start required is not of an emergency nature then the turbine turning gear immediately should be placed in service to avoid any delays.
- The Turbine Hydraulic Oil system for the unit must be available for service on units 1&2 only. The Main Steam Stop valves, control valves, Reheat Stop Valves and Intercept Valves require this system as well additionally a number of other unit safety devices. Unit 3 requires that the Auxiliary Oil Pump be in service to operate the above listed valves. All of the above valves require to be tested prior to rolling the unit on steam to ensure they function correctly as they all perform a safety function if a premature trip occurs during unit operation.
- Turbine Extraction Steam Non-Return Valves should be tested to ensure they operate correctly. While in service if the unit trips prematurely during normal operation these valves close to prevent an uncontrolled overspeed situation on the unit turbine providing additional safety to the equipment and the staff within the plant.
- Turbine Gland Steam system along with the gland steam exhauster must be available.
- All of the necessary Turbine instrumentation such as vibration monitoring, differential expansion monitoring, eccentricity monitoring, and all other temperature monitoring must be available.
- The unit turbine Mark V control system is available for service.
- The Turbine's Steam Condenser Air Removal System is available.
- All of the Turbine and associated piping drains and blowdown tanks must be open and available for service.
- The Turbines Steam Condenser Circulating Water System is available for service.
- The Unit Generators associated Seal Oil System along with all associated equipment must be in service.
- The Unit Generator casing must be in a pure H_2 environment and pressurized with H_2 to the normal working pressure between 180-210 kPa.
- The Generator Hydrogen Cooling System is in service along with the associated cooling water temperature control valves availability.
- The Generator Field Excitation Transformer and all associated breakers are available for service.
- Generator Exciter Brushes are installed.
- All of the generator potential transformer and current transformer fusing is installed and the generator neutral ground switch is the proper position for unit operation.
- The Generator Main Output Transformer and the Unit Service transformer and their associated Cooling Systems are either in service or available for service.
- The Unit Generator Synchronizing Breaker and Disconnect Switches are available for operation.

Appendix D

Generalized Procedure for a Cold Start

Once it has been determined that all of the unit pre-conditions have either been satisfied or can be satisfied before being required and the unit has been checked over and ready for operation proceed with the following steps. Some of these steps may be done in conjunction with other activities.

1. If Nitrogen Blanketing has been used to Layup the equipment, disconnect the nitrogen connections and establish all vents and drains associated to that equipment. In parallel, open the boiler drum vents and use the lower waterwall header drains and begin draining the steam drum to a level just above the "low drum level trip setting. (Do this in the expectation of the drum level swell when heat is introduced into the boiler) Ensure the turbine / generator is on turning gear following the pre-established procedures if it has not yet been done. Start the rotary air heater drives. Make sure that auxiliary steam is available to the combustion air coils, fuel oil heaters, burner atomizing steam and scavenging steam systems. Start a Main Fuel Oil Pump and recirculate fuel oil back to the Main Oil Day Tank through the short recirculating valving supplied in an effort to raise the overall fuel oil temperature closer to the limit required for firing the boiler on Residual Oil.
2. Ensure that either the Boiler FGT Probe or the Optical FGT measuring equipment is available before lighting off any fuel source.
3. Start the boiler Forced Draft Fans and establish the boiler purge air flow for the time delay used at HTGS and controlled within the DCS.
4. Ensure that all the start permissives required within the DCS have been met.
5. Once these permissives have been satisfied and the Boiler Trip relay reset use the light oil ignitors to start warming the boiler setting. Establishing at least one full elevation of light oil ignitors to initially warm the boiler setting. (Using the bottom elevation of ignitors is preferable but not absolutely necessary for prewarming the whole boiler setting)
6. Fire the boiler in this manner until it is observed that the boiler drum level is beginning to swell. Using the lower waterwall header drains inch these slowly open to help maintain the level closer to the low drum level trip point.
7. Fire additional ignitors to continue raising the temperature in the boiler waterwall circuits and adjust the total air flow lower without causing a "low air flow boiler trip". (Doing this creates a better heat transfer into the boiler waterwall tubes.)
8. Open the Fuel Oil Trip Valve and ensuring the Long Recirculation Valve is open. Circulating the Main Fuel Oil through the entire units Fuel Oil System will aid in achieving the temperature limits required for burning Residual Fuel Oil.
9. Monitor all temperature points within the boiler to ensure none are being exceeded as prescribed by the OEM. This includes the inner and outer drum metal differential temperatures, any primary and secondary superheater limits and the FGT which must be kept below 538°C during the entire startup process.
10. Start the Condensate and Boiler Feedwater systems as necessary to provide feedwater to the boiler when required.
11. When the boiler drum pressure reaches 35 kPa or the value as defined by HTGS procedures close the steam drum vents and begin firing a Main oil gun preferably on "A" elevation and monitor the FGT probe to ensure that the FGT stay below 538°C . When the drum level is relatively stable and the FGT is under control aggressively increase the firing rate so as to not exceed these limits and raise the pressure and temperature of the steam throughout the entire unit down to the Main Steam Stop Valves using the boiler drains as necessary.
12. Start a Condenser Cooling Water Pump and establish the necessary systems i.e. Travelling Screens etc. etc.
13. Establish the Turbine Gland Steam system when the boiler pressure reaches approximately 1600 kPa.
14. Begin HP Turbine prewarm by following the GE recommended procedure and using HTGS operating guidelines.
15. When the HP Turbine 1st Stage Inner metal Temperature reaches 100°C close the main steam stop valve bypass while continuing to raise boiler pressure and temperature.

16. Continue drawing condenser vacuum down to normal operating values and proceed to roll the main turbine /generator on steam to 500 RPM. (full vacuum is not totally necessary before rolling the unit on steam however the values required will be HTGS specific)
17. Hold 500 RPM and physically check the turbine / generator to ensure it is operating normally. (GE recommends that the unit not be operated at speeds lower than this for long periods)
18. Continue raising the speed up towards Synchronous Speed moving quickly through the Critical Speed values up to 3000 RPM. Hold 3000 RPM and check the IP turbine to LP Turbine Crossover Temperatures and as well the IP Turbine Reheat Bowl Inner Metal Temperature to ensure the values are above 100°C before proceeding to the 3600 RPM Synchronous Speed. (GE recommended)
19. Apply the Generator Field and Synchronize the Unit in conjunction with the approval from the ECC.
20. Slowly raise the generator load and transfer the station service load to the Unit Service Transformer at the load specified by HTGS Procedures.
21. Raise the unit load to the minimum value of 30 MW's using the Main Seam Stop Valve Bypass and as conditions permit load the generator as per the ECC requests.