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March 31, 2022

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: ***Reliability and Resource Adequacy Study Review*** **- Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station**

Through its *Reliability and Resource Adequacy Study Review* technical conference presentation on November 30, 2020, as well as subsequent correspondence to the Board of Commissioners of Public Utilities ("Board"), Newfoundland and Labrador Hydro ("Hydro") advised of its intention to undertake an assessment to determine the potential long-term viability of the Holyrood Thermal Generating Station ("Holyrood TGS"). The purpose of this assessment is to inform Hydro's options for incremental generation, should it be determined that additional backup generation is required to support the provision of least-cost, reliable service.

Hydro sought an in-depth independent assessment to ascertain the requirements (capital and operational) of the following options for the Holyrood TGS:

- Continued extension of the Holyrood TGS, whether online in full generation mode or standby mode, beyond the current retirement period, and;
- The viability and suitability of the Holyrood TGS to be used as a backup generating facility to support the Island Interconnected System in the event of a prolonged outage of the Labrador-Island Link ("LIL") until the End of Economically Feasible Life ("EEFL") of the plant.

As Hydro continues to assess the need for incremental generation resources and standby generation requirements to support the reliable operation of the Island Interconnected System, Hydro believes it is important to achieve a full understanding of the viability of the continued operation of the Holyrood TGS from the perspective of both asset reliability and total cost.

In March 2021, Hydro issued a request for proposals for the assessment of the Holyrood TGS. Hydro subsequently awarded the contract for the assessment to Hatch Ltd. ("Hatch"), an engineering consultant with expertise in the design, construction, and assessment of electrical power generating facilities.

A summary of Hatch's findings is provided in Attachment 1. The scope of the assessment consisted of two components:

1) A condition assessment as well as an assessment of the remaining life of the existing assets of the Holyrood TGS, provided as Attachment 2;[1] and

2) A study to determine the viability and costs associated with the continued operation of the Holyrood TGS, either in full generation mode or as a standby generating resource, provided as Attachment 3,[2] including:

  a. Determination of plant modifications required to reduce generation recall time under various scenarios ranging from 4 hours to the current recall time of 24–30 hours and associated capital costs;

  b. Determination of staffing requirements, environmental requirements, operating procedures, fuel storage requirements, and equipment layup requirements to support the operation of the Holyrood TGS as a standby facility with reduced recall time;

  c. Determination of sustaining capital, operating, and fuel costs to support continued reliable operation of the Holyrood TGS in full generation mode or as a stand-by generating facility through the EEFL; and

  d. Opportunities to reduce the time to convert Unit 3 from a synchronous condenser to a generating unit.

The outcomes of the assessment provide the necessary information to assess whether the Holyrood TGS can economically provide support to the system in the near term while incremental resources are constructed, or play a larger role in economically satisfying system requirements in future.

Holyrood Thermal Generating Station Condition Assessment

To assess the condition and remaining life of the Holyrood TGS, Hatch assessed all major systems and subsystems required for plant operation. This assessment consisted of a document review of all available maintenance records, inspection reports, equipment manuals, test results, operating history, and all other relevant documentation, supplemented by visual inspection of major systems and detailed inspection of those systems deemed necessary by Hatch. Asset condition was rated on a five-point scale, with "1" representing poor condition and "5" representing excellent condition.

Based on this assessment, Hatch concluded that the Holyrood TGS is generally in good operating condition. The majority of systems were assigned a condition rating of "3" or greater where "3" is defined as "Adequate: Moderately deteriorated or defective components; but has not exceeded useful life."[3] Particular areas of concern include the control systems and cooling water systems for each unit, and the wastewater treatment plant. A number of major systems such as unit turbines, boilers, condensers, and the fuel storage and fuel delivery system were assigned a condition rating of "3" and will require continued monitoring and potential capital intervention to ensure continued reliable operation to March 31, 2024, or beyond.

Details of the condition assessment can be found in Attachment 2.

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[1] "HTGS Condition Assessment and Life Extension Study – Project Report Volume I," Hatch Ltd.
[2] "HTGS Condition Assessment and Life Extension Study – Project Report Volume II," Hatch Ltd., March 30, 2022.
[3] "HTGS Condition Assessment and Life Extension Study – Project Report Volume I," Hatch Ltd., March 30, 2022, s 1.3.1, p. 3

Viability of the Holyrood Thermal Generating Station as a Standby Generating Resource

In consultation with Hydro, Hatch selected four recall time scenarios of Units 1 and 2 for study. The scenarios considered are outlined in Table 1.

Table 1: Recall Time Scenarios

Scenarios	1st Unit	2nd Unit
Scenario 1	24 Hours	30 Hours
Scenario 2	8 Hours	12 Hours
Scenario 3	6 Hours	8 Hours
Scenario 4	<4 Hours	4 Hours

For each scenario, Hatch determined the plant modifications required to achieve the target recall time and estimated the capital, operating, and fuel costs required. These costs are summarized in Table 2.[4]

Table 2: Summary of Costs by Recall Time Scenario through 2030 ($000)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
S1	Capital	25,044	39,651	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,155	566,150
	Operating	25,147	15,408	15,408	15,408	15,408	15,408	15,408	15,408	15,408	148,411	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S2	Capital	25,044	39,939	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,443	566,681
	Operating	25,174	15,435	15,435	15,435	15,435	15,435	15,435	15,435	15,435	148,654	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S3	Capital	25,044	41,379	26,317	22,299	27,104	17,750	14,011	24,728	12,251	210,883	585,302
	Operating	25,202	15,463	15,463	15,463	15,463	15,463	15,463	15,463	15,463	148,906	
	Fuel	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	225,513	
S4	Capital	25,044	46,275	26,317	22,299	27,104	17,750	14,011	24,728	12,251	215,779	612,275
	Operating	25,775	16,036	16,036	16,036	16,036	16,036	16,036	16,036	16,036	154,063	
	Fuel	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	242,433	

Hatch has provided recommendations on staffing and operating procedures such as unit test runs, fuel storage, environmental considerations, and equipment layup to support standby operation under each scenario. Based on their assessment, Hatch has concluded that the Holyrood TGS is a technically viable option for continued operation in full generation mode or as a standby generating resource under each recall time scenario through 2030 assuming the investments noted above are undertaken. Hatch notes that continued operation beyond 2030 may be viable, pending the results of a future condition assessment closer to 2030, should Hydro deem it necessary. Hatch also provided a range of capital costs for the period 2031–2040 based on the data available for the period to 2030.

The results of the life extension study are provided in Attachment 3.

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[4] Estimates developed by Hatch were Association for Advancement of Cost Engineering Class 4 estimates, with an expected accuracy of -30%/+50%.

Conclusion

The results of the Holyrood TGS condition assessment provide an indication of the capital asset renewal and maintenance investments that will be required for the continued operation of the Holyrood TGS in the near term. On the basis of the information provided, Hydro can expect the reasonable operation of the facility through the currently anticipated end-of-generation on March 31, 2024, with required human and maintenance investments.

Further, Hatch has concluded that the Holyrood TGS presents a technically viable option in full generation mode or as a standby generating resource under various recall scenarios in the near term and with the significant investments estimated. Hydro must now utilize the outcomes of this study to inform its analysis through the Reliability and Resource Adequacy Study of the options, should they be required, for standby generation and/or incremental generation. In determining the future role of the Holyrood TGS, Hydro must consider the economics and reliability of the continued use of the plant in comparison to other generation alternatives under consideration, including the expected reliability of other alternatives as well as current or anticipated legislative requirements regarding greenhouse gas emissions and other environmental considerations. Hydro will present the outcomes of this analysis and its recommendations in the Reliability and Resource Adequacy Study – Volume I and III Update, scheduled for filing with the Board by the end of August 2022.

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

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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Attachment 1

"HTGS Condition Assessment and Life Extension Study – Executive Summary" provided by Hatch Ltd.

Newfoundland and Labrador Hydro
HTGS Condition Assessment and Life Extension Study

Executive Summary

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1. Executive Summary

1.1 Holyrood Thermal Generated Station (HTGS)

Newfoundland and Labrador Hydro (NLH) is transitioning to lower emission power generation with its investment in additional hydroelectric capacity, clean energy technologies, and reinforced transmission systems. The additional planned generation is intended to replace Holyrood Thermal Generating Station (HTGS).

NLH is considering the role of the HTGS post-commissioning of the Muskrat Falls Project assets. Currently, the HTGS is planned for retirement as of March 31, 2023[1], with Unit 3 transitioning to a permanent synchronous condenser unit.

NLH is seeking an independent assessment to fully understand the requirements (capital and operational) should the following options be considered for the HTGS:

1. Continued extension of the Holyrood TGS, whether online in full generation mode or standby mode beyond the current retirement period.
2. The viability and suitability of the Holyrood TGS to be used as a backup generating facility to support the island system in the event of a prolonged outage of the Labrador-Island Link until the qualitative End of Economically Feasible Life ("EEFL") of the plant.

Hatch was engaged by NLH to review the condition of the asset and develop a capital plan with a view of extending the operation of the plant beyond 2023 that would permit comparison against other alternatives.

Reliability and quick recall are the most critical parameters when considering any power generation source for emergency backup power. Hatch has completed a condition assessment of the plant to determine the reliability of the units and to propose modifications to enable a 4 to 24 hours restart as defined in section 5 of Volume II report.

The condition assessment included:

- Onsite inspections of the fire water system, tank farm, marine terminal, and cooling water sumps by third party contractors and Hatch local team.
- Review of inspection reports and condition assessments of the power plant main equipment and systems, including the boiler, turbine and generator, cooling water system, condensate and feedwater system, fuel heating and supply system, and common systems.
- Visual inspection of the boiler, turbine, electrical systems, and balance of plant systems.

[1] This report was completed prior to Hydro's announcement on extension to March 31, 2024

Hatch has also developed the capital and operating cost estimates to operate the power plant beyond 2023 in a full generation mode or emergency standby mode as per RFP requirements.

1.2 HTGS Condition Assessment

The two oldest units have reported cumulative operating hours ranging from 212,000 to 220,000 hours with Unit 3 reporting 170,000 hours. The fuel oil supply and storage system, cooling water system, boiler stacks, and water treatment system require some repair and continued maintenance.

The three units have been inspected regularly by the OEMs and third-party specialists. The dates of the most recent boiler and turbine inspections are provided in Table 1-1.

Table 1-1: Boiler Inspection Dates

	Boiler Annual Inspection (GE)	Turbine Major Overhaul (GE)
Unit 1	2021	2021
Unit 2	2021	2014
Unit 3	2021	2016

The inspections revealed minor cracks and some signs of fatigue due to age of equipment, but there was no indication of end-of-life reported. This, together with continued O&M practices including inspections, predictive maintenance, reliability assessment programs, and ongoing life-cycle maintenance investment, supports evaluating the viability of continued use of the assets in full generation mode or emergency standby mode.

1.2.1 Assessment Methodology

A high-level description of the method used to determine the condition of each asset is described in the current section. The detailed methodology of this study is outlined in Volume I report.

1.2.1.1 Document Review

Hatch received from NLH the OEM and third-party service provider's inspection, maintenance, and overhaul reports for key plant equipment and systems. All documents received were reviewed by Hatch project team. A complete list of these documents is included in Appendix A of Volume I. In summary the documents reviewed can be categorized as:

- Operation and maintenance manuals
- Piping and instrument diagrams
- Equipment data sheets and performance curves
- Operational history of all three units

- Tripping log of all three units
- Maintenance record of critical equipment and valves
- Last major overhaul reports for turbine and generators
- High energy piping inspection records
- Past condition assessment reports

1.2.1.2 Detailed Inspection Plan

Hatch developed a detailed inspection plan for the project. The inspection's timeline and method, such as visual, borescope, thickness measurement, and non-destructive testing, were outlined in the plan. The latest main equipment inspection records were reviewed to determine their adequacy and to ensure periodic inspections were conducted using an appropriate method. Where records were deemed insufficient, Hatch recommended additional inspections. For example, Hatch recommended that visual inspections be conducted on the condenser shell and eddy current inspections conducted on the condenser tubes of all three units.

1.2.1.3 Inspections by Hatch Third Party Sub-Contractors

Hatch hired third party sub-contractors to conduct inspections of the cooling water system, fire water system, the paint on fuel oil tank No.3, and the marine facilities. The Hatch inspection supervisor and safety officer supervised the sub-contractor teams at site.

1.2.1.4 Site Visits

The local Hatch team from the St. John's office conducted visual inspections of key assets and had face to face meetings with plant staff when required. Two engineers from Hatch were stationed at site for the duration of the third-party inspections.

Hatch project team and subject matter experts visited the Holyrood facility in September 2021 and visually inspected the power plant.

1.3 Inspection Findings Summary

Hatch reviewed the condition of the plant and assigned a grade of 1 to 5 for each system as per the grading scale provided by NLH.

1.3.1 Grading

The NLH grading scale presented in Table 1-2 was used for grading of the power plant systems.

Table 1-2: Asset Grading Scale

Grade	Condition	Description
5	Excellent	No visible defects, new or near new condition, may still be under warranty if applicable.
4	Good	Good condition, but no longer new, may have some slightly defective or deteriorated component(s), but is overall functional.

Grade	Condition	Description
3	Adequate	Moderately deteriorated or defective components; but has not exceeded useful life.
2	Marginal	Defective or deteriorated component(s) in need of replacement; exceeded useful life
1	Poor	Critically damaged component(s) or in need of immediate repair; well past useful life

1.3.2 HTGS Systems Grading

A summary of the grades for each unit's critical assets is provided in Table 1-3.

Table 1-3: Summary of Asset Grades

Asset	Asset No.	Grade
Unit 1		
Turbine	6691	3
Generator	6691	4
Electrical	6723	4
Control Systems*	6723	2
Cooling Water System	8715	2
Boiler System	6699	3
Stack	6919	3
Condensate & Feedwater System	6708	4
Condenser	6708	3
Unit 2		
Turbine	7636	4
Generator	7636	4
Electrical	8152	4
Control Systems	8152	2
Cooling Water System	8093	2
Boiler System	7786	3
Stack	7900	3
Condensate & Feedwater System	7976	4
Condenser	7976	3
Unit 3		
Turbine	8194	3
Generator	8194	5
Electrical	8712	4
Control Systems*	8712	2
Cooling Water Systems	8645	2
Boiler System	8336	3
Stack	8448	3
Condensate & Feedwater System	8528	4
Condenser	8528	3

Asset	Asset No.	Grade
Balance of Plant		
Power Center and Excitation Transformers	-	4
Common Electrical and Control Assets	7199	4
Buildings and Building M and E System	7255	4
Hydrogen and Carbon Dioxide Supply Systems	7199	4
Compressed Air	7199	4
Fuel Systems (Light and Heavy Oil)	7199	4
Wastewater Treatment Plant (WWTP) Equalization Basin Building	9739	1
Water Treatment Plant (WTP) System	9739	4
Fire Water System	7251	3
Black Start Diesel Gensets	7199	4
Heavy Oil & Fuel Additive Systems (Tank Farm)	7204	3
Marine Terminal Structure (Jetty)	7133	3

1.4 Discussion of Findings

The plant, given its age, is generally in good running condition. Unit 1 last stage blades were inspected in 2021 and Units 2 and 3 will be inspected at the next turbine major overhaul scheduled in 2023 and in 2025 respectively. As per OEMs recommendation, the dovetails of the last stage blades are due for removal and thorough inspection. Considering the long lead time on the blades, the cost of inspection and the fact that the dovetail pins cannot be removed without a potential risk of damage to the pins, Hatch recommends conducting this inspection if considered necessary following visual and NDT inspections. Hatch also recommends that NLH procure a spare set of last stage blades.

1.4.1 Unit 1

The overall condition of Unit 1 was found to be adequate for continued operation beyond 2023.

Recent inspections carried out on Unit 1 by GE, B&W, and Team Industrial on the high energy piping, boiler, economizer, and air preheater showed that the boiler and its ancillary systems are generally in adequate condition. Some level of thermal fatigue, corrosion, pitting, and wall thinning was observed in some areas of the boiler, which is quite common for units of this age. The stack was last inspected in 2021, deterioration of the exterior coating was observed, and recoating of the stack is necessary.

The turbine vibration levels are slightly higher than the levels observed prior to 2013 repair, but they are within the permissible range of ISO20816-2.

In general, Hatch found the condition of Unit 1 to be adequate for operation as a baseload or back up unit through 2030 and beyond subject to ongoing inspections, maintenance, and repairs.

1.4.2 Unit 2

The overall condition of Unit 2 was found to be adequate for continued operation beyond 2023.

Recent inspections carried out on Unit 2 by GE, B&W, and Team Industrial on the high energy piping, boiler, economizer, and air preheater show that the boiler and its ancillary systems are generally in adequate condition. Some level of thermal fatigue, corrosion, pitting, and wall thinning was observed in some areas of the boiler, which is quite common for units of this age. The stack was last inspected in 2021, deterioration of the exterior coating and stainless-steel liner was observed, recoating and replacement of the liner are necessary.

In general, Hatch found the condition of Unit 2 to be adequate for operation as a baseload or back up unit to 2030 and beyond subject to ongoing inspections, maintenance, and repairs.

1.4.3 Unit 3

The overall condition of Unit 3 was found to be adequate for continued operation beyond 2023. The Unit 3 Steam Turbine is reported to have two cracks in the steam chest, these cracks have been monitored very closely since the 1990s. In general, Hatch found the condition of Unit 3 to be adequate for operation as a baseload or back up unit to 2030 and beyond subject to ongoing inspections, maintenance, and repairs. The stack was last inspected in 2021, deterioration of the exterior coating and stainless-steel liner was observed, recoating and replacement of the liner are necessary.

The plan going forward is to operate Unit 3 as a synchronous condenser. Considering the recent refurbishment of the Unit 3 generator, Hatch does not foresee any problematic operation of Unit 3 as a synchronous condenser.

1.4.4 Balance Of Plant

Most of the auxiliary systems of the plant were found in good condition.

Some areas of concern were identified on all condensers, exhaust stacks, and the cooling water system. Gradings were applied ranging from marginal to poor as shown in Table 1-3. It is therefore recommended to closely monitor and periodically inspect the equipment and systems.

The wastewater treatment plant and fire water system were found in poor condition and require major repairs. The cost of repairs has been included in the proposed capital plan.

1.4.5 Piping

The high energy piping and pipe support condition was assessed based on the NLH annual inspection reports as per ASME B31.1 guidelines. The piping systems and pipe supports were found in good condition.

1.4.6 Electrical and I&C

The electrical generator of Unit 1 and 2 were found in good condition, however, showed typical signs of aging. It is suggested that the electrical testing conducted in 2021 be repeated on a yearly basis going forward to support continued monitoring of the units for any signs of degradation. It is also recommended that a major inspection of Unit 2 be conducted in the year following the transition from normal to back up generation operation.

1.5 Hatch Third Party Site Inspections

Hatch conducted onsite inspections of the marine terminal, fuel tank farm, firewater hydrants and piping, and the cooling water pumphouse sumps. The findings of these inspections are summarized in the following sections.

1.5.1 Marine Terminal

The onsite inspection of the marine terminal consisted of a fender and piling inspection. Based on the conducted inspections, fender arms and pins on fenders #3 and #8 were replaced. The piling inspection indicated that the piles are in adequate to good condition. Corrosion on the piles was noted at the splash zone. Under the surface, the piles were covered in significant marine growth and coral, but any visible coating seemed to be in good condition. The degree of corrosion on the anode cathodic protection varies from pile to pile, ranging from 0 to 95% remaining. The marine terminal fenders and piles should continue to be inspected every 5 years.

1.5.2 Fire Water System

The exterior fire water system was inspected using visual inspection, static pressure testing, borescope testing, and acoustic testing. Twenty of the twenty-six hydrants passed inspection. The static pressure testing measurements ranged from 78-122 psi. There were no current leaks detected in the buried firewater line at the time of testing. Based on confirmation of past failures and leaks on the buried firewater line, it is recommended that the tank farm firewater buried pipe be replaced along with the balance of the buried firewater line during the planned 2022 upgrade. Hydrant inspection and testing is recommended to be conducted on an annual basis.

Note, Hatch was informed by NLH that currently the fire water and fire water pumping system is used as a source for water for auxiliary resources. Based on this information, Hatch recommends that a risk assessment study be conducted to investigate the requirement for a dedicated fire water system and a separate system for water for auxiliary resources.

1.5.3 Cooling Water Sumps

The powerhouse cooling water sumps were inspected using an ROV and a confined space drone. These sumps currently have restricted access, and personnel are no longer allowed entry. The sumps were last cleaned in 2014 and are no longer cleaned on an annual basis. There is significant marine growth covering most of the sump walls and floors. These inspections identified that there are significant cracks in the sump support beams in all four south sumps. It is recommended that these sumps undergo repair due to deteriorating conditions and the potential decreased strength of the interior beams. Furthermore, it is recommended that these areas be limited to foot traffic/small equipment and not used for laydown or staging areas for heavy equipment. These sumps should continue to be monitored with a drone/ROV (equivalent) on an annual basis.

1.5.4 Fuel Oil Tanks

Historical inspection information was reviewed for the main Heavy Fuel Oil (HFO) Storage Tanks 1, 2, 3, and 4, the HFO day tank, and a coating inspection was performed on Tank 3. The HFO storage tanks and day tank were found to be in adequate condition. A refurbishment program for the tanks was implemented in 2006. Tank 1 is targeted for decommissioning in 2022, and Tanks 2, 3, and 4 will undergo out of service inspections in 2024-2025 to determine if any refurbishment work will be required. NLH advises they have committed to performing annual in-service inspections of these tanks until the out of service inspections are performed. The HFO day tank is scheduled for an out of service inspection in 2023 to determine if any refurbishment work will be required.

1.6 Most Recent Failures

Holyrood power station experienced two failures, these failures occurred towards the end of the condition assessment and are summarized below.

- Unit 3 boiler waterwall failure
- Unit 1 Cold reheat piping support failure

Hatch notes that Transformer T2 failed in November 2021 and was replaced by the spare Transformer T4. Hatch has not reviewed any failure reports and therefore cannot comment on the nature of the failure.

1.6.1 Unit 3 Boiler Waterwall Failure

Hatch reviewed the TapRoot report prepared by NLH and Wayland on the causal factors leading to the tube failure and concurs with the findings. Namely, the failure is due to corrosion fatigue augmented by constraint on thermal expansion due to the original design of the windbox vestibule attachment.

1.6.2 Unit 1 Cold Reheat Piping Support Failure

Hatch reviewed the TapRoot report prepared by NLH which identified the causal factors that led to the incident and recommended actions to avoid recurrence. Hatch concurs with the findings of the TapRoot report and agrees that the incident was due to water leakage across a valve which is of a non-recurring nature based on implementing the recommended actions.

1.7 Starting Failure Forced Outage

The overall average number of starting failures is two per year up to 2013 and one per year after 2013. The outage data reviewed shows a pattern of higher restart failures prior to 2013 and an average of one restart failure per year post 2013. The total starting failure forced outages since 1993 are included in Table 1-4.

Table 1-4: Total Number of Starting Failures Since 1993

Unit	Total Number of Starting Failures Since 1993
1	24
2	17
3	15

To ensure high starting reliability, specific training with a focus on the standby operating scenarios and expectations for Plant Readiness to Serve as an Emergency Standby role should be developed.

1.8 Quick Recall Scenarios

The recall time is defined as the time between the call for power and synchronization with the grid. The recall time is of paramount importance for any power generation facility to be used as a backup generation facility. Starting a conventional steam power plant from a cold shutdown to synchronization is a lengthy process that requires start-up procedures to be followed in a sequential order. In addition to the recall time, high reliability is the second major requirement for a backup generation facility.

NLH has requested this assessment to determine the viability of the HTGS as a base-loaded or standby plant beyond 2023.

Hatch investigated the conversion of the existing power station from baseload operation to backup generation for emergency support of the grid. The time required for Unit 3 to transition from synchronous condenser to power generation mode was also assessed.

The four recall scenarios explored for Units 1 & 2 are summarized in Table 1-5.

Table 1-5: Summary of Scenarios

Scenarios	1st Unit	2nd Unit
Scenario 1	24 Hours	30 Hours
Scenario 2	8 Hours	12 Hours
Scenario 3	6 Hours	8 Hours
Scenario 4	<4 Hours	4 Hours

The capital plan and capital improvement cost estimates were developed for each scenario to an AACE Class-IV estimate. The operating and maintenance costs and costs associated with fuel and auxiliary power requirements were also developed. It is noted that the fuel costs for all scenarios are based on test runs with a duration of 24 hours at 100% maximum continuous rating (MCR). The loading can be varied to align with system grid limitations by using a longer duration to ensure a complete heat soak for the equipment. For Scenario 4, the plan includes maintaining the turbine's first stage inner metal shell temperature above the required level of 300°F to roll the turbine. This approach eliminates the prewarming time of 4 hours before rolling the turbine. The test runs, as proposed, and the associated turbine metal cool down period will result in a hybrid of Scenario 4 blended into Scenarios 1, 2, and 3 for the period when each turbine is above the pre-warming trigger level of 300°F. The fuel costs for test runs can be varied by changing the frequency of test runs, but this is limited by the maximum period of 8 weeks for dry storage of the reheater tubing without isolating the reheaters.

1.9 Capital and Operating Costs for Emergency Backup Operation

A capital plan to support emergency backup operation of the power station from 2022 to 2030 was developed. A summary of the modifications required to support power plant quick recall are provided in Table 1-6.

An auxiliary boiler is required to enable quick recall time of the facility. Steam from the auxiliary boiler will be used for building heating, deaerator water heating, boiler water heating, and for turbine pre-warming.

Table 1-6: Summary of Critical Improvements

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Auxiliary (Aux.) Boiler	Yes	Yes	Yes	Yes
Economizer Recirculation Line	N/A	No	Yes	Yes
Auxiliary Cooling Water Pump	N/A	Yes	Yes	No
Stack Damper	N/A	No	No	Yes
Auxiliary Steam System Modifications	N/A	Yes	Yes	No
Automation of Blowdown and Water Wall Headers Drain Valves	N/A	Yes	Yes	Yes
Fuel Oil Storage Recirculation to Day Tank	Yes	Yes	Yes	Yes

A capital plan to support major inspections, overhauls, upgrade of station assets, and operating cost from 2022 to 2030 was developed.

The detailed break down of costs associated with fuel consumption are included in Volume II report. The annual fuel costs shown in Table 1-7 cover the fuel used for each scenario plus the test runs for each unit. The plant is currently scheduled to continue in operating mode up to March 31, 2024, leading to nominally empty fuel tanks at that time. If it is decided that the plant is to either continue in current operating mode or to change to Emergency Standby mode, an additional cost to procure an inventory of fuel for potential consumption post March 31, 2024, will be incurred. To fill the fuel oil storage tanks at that time, the cost is estimated at CAD 22.1 million per storage tank. If the plant is to be used in Emergency Standby mode for a possible full load operating period of six weeks with no fuel oil delivery, then all four tanks will be needed. Alternatively, if operation for six weeks period at full load is required, three tanks may be adequate provided a fuel delivery can be scheduled during the fourth week.

Capital, Operating, and Fuel costs associated with each scenario are summarized in Table 1-7. A breakdown of the capital plan for each unit is provided in Table 1-8.

Table 1-7: Summary of Costs by Scenario ($1000's)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
S1	Capital	25,044	39,651	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,155	566,150
	Operating	25,147	15,408	15,408	15,408	15,408	15,408	15,408	15,408	15,408	148,411	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S2	Capital	25,044	39,939	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,443	566,681
	Operating	25,174	15,435	15,435	15,435	15,435	15,435	15,435	15,435	15,435	148,654	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S3	Capital	25,044	41,379	26,317	22,299	27,104	17,750	14,011	24,728	12,251	210,883	585,302
	Operating	25,202	15,463	15,463	15,463	15,463	15,463	15,463	15,463	15,463	148,906	
	Fuel	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	225,513	
S4	Capital	25,044	46,275	26,317	22,299	27,104	17,750	14,011	24,728	12,251	215,779	612,275
	Operating	25,775	16,036	16,036	16,036	16,036	16,036	16,036	16,036	16,036	154,063	
	Fuel	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	242,433	

Table 1-8: Capital Plan Breakdown by Unit, 2022-2030 ($1000's)

Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Unit 1	3,333	3,333	6,433	3,333	3,500	3,800	4,200	12,394	3,667	43,994
Unit 2	3,333	14,161	5,033	3,333	4,300	3,500	3,500	3,667	3,667	44,494
Unit 3	7,835	4,123	4,399	13,097	8,777	6,600	5,200	7,667	3,667	61,364
Common Facilities	10,543	11,378	10,452	6,109	2,500	3,850	1,111	1,000	1,250	48,193

1.10 Capital and Operating Costs for Continued Operation

Estimates for the capital, operating, and fuel costs for the continued operation of HTGS were developed and are shown in Table 1-9. Capital costs are based on the capital plan discussed in Section 1.9 and the operating costs include O&M costs based on the existing count of 101 employees. Fuel costs were developed based on the historical load data provided by NLH for each unit and an estimated cumulative four months of operation per year as indicated by NLH. Escalation is not included in the aforementioned cost estimates.

The following assumptions apply to the fuel cost estimates:

- The total operating time per year is 4 months based on historical power generation requirements.
- Average power generated (MW) per unit based on the historical plant data from 1997 – 2022, which indicates a range of 77 – 94 MW per unit.
- Fuel cost is based on the last delivery to HTGS ($104.22 CAD/barrel).

Table 1-9: Capital, Operating, and Fuel Costs for Continued Operation through 2030 ($1000's)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
Capital	25,044	32,995	26,317	25,872	19,077	17,750	14,011	24,728	12,251	198,045	1,325,387
Operating	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	226,325	
Fuel	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	901,017	

1.11 Capital Cost Projections Beyond 2030

The capital cost projections for 2031 to 2040 are based on the cost estimates for 2022 to 2030. The following assumptions apply to these projections:

a) The plant will run in either full generation or Emergency Standby mode.

b) The 2022 to 2030 capital cost estimates are used as the baseline for the projected costs.

c) Routine inspections and major overhauls of plant key equipment such as boilers, turbines, and pumps will be conducted as per existing plant practices. Years where the capital cost projection is higher than the preceding or following year is due to costs included for major turbine and boiler upgrades.

d) Refurbishment cost estimates for Fuel Tanks No.1 & 4 are included in the capital cost estimates for 2022 and 2023, respectively. Similarly, refurbishment of Fuel Tanks No. 2 & 3 is included in the capital cost estimate for 2031 and 2032, respectively.

e) An estimated minimum and maximum range for the capital cost for 2031 through 2040 is presented in Table 1-10. To establish this range, an adjustment of 20% to 50% is made to the capital cost estimates for 2022 through 2030. These adjustments are included to account for potential generator rotor rewinding, condenser retubing, major boiler tube repairs.

f) A refined capital plan is to be developed as part of the condition assessment program recommended in 2026 and 2027.

Table 1-10: Capital Cost for 2031 to 2040 ($1000's)

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Min	30,053	39,594	31,580	31,046	22,892	21,300	16,813	29,674	14,701	14,701	237,654
Max	37,566	49,493	39,476	38,808	28,616	26,625	21,017	37,092	18,377	18,377	297,068

1.12 Staffing Plan

A staffing plan was developed based on the recall time and corresponding staff requirements. The proposed staffing plan, with a total of 58 staff, and role descriptions are provided in Volume II of the report. Details regarding personnel competency and qualifications, as well as training requirements, are also included in Volume II.

1.13 Equipment Lay-up

To maintain the plant reliability for emergency recall, the lay-up requirements for each scenario vary depending on the state of readiness to be maintained for each recall option. The equipment lay-up requirements are summarized in Table 1-11. For Scenarios 1, 2, and 3, the boilers are stored using a Wet/Dry approach and steam turbines are maintained cold and placed on turning gear intermittently to keep rotor eccentricity within permissible limits. In the case of Scenario 4, a Wet/Warm approach is used for the boiler and the steam turbine is rotated continuously (on turning gear). Scenarios 2 to 4 have a recall time varying from 4 to 12 hours, for these scenarios the generators are maintained under hydrogen pressure. In scenario 1 a longer recall time, 24 to 30 hours, is considered, in this scenario the hydrogen is purged from the generator's first with CO_2 and then with air.

Table 1-11: Basis for Equipment Lay-Up

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Boiler	Wet/Dry	Wet/Dry	Wet/Dry/Cold	Wet/Warm
Turbine	Cold & On Turning Gear (fortnightly for 4 hrs.)	Cold & On Turning Gear (weekly for 4 hrs.)	Cold & On Turning Gear (twice in a week for 4 hrs.)	Warm & On Turning Gear (continuously)
Generator	Not Pressurized	H_2 Filled at 207 kPa	H_2 Filled at 207 kPa	H_2 Filled at 207 kPa

1.14 Summary of Inspection Frequency Recommendations

A summary of the recommendations for the inspection frequency as well as modifications to plant infrastructure, shutdown procedures, and the proposed staffing plan are provided in Table 1-12, Table 1-13 and Table 1-14.

Table 1-12: Summary of Recommendations for Inspections[2]

Equipment	2022	2023	2024	2025	2026	2027	2028	2029	2030
Turbine (Major Overhaul)		2		3					
Turbine (Routine Inspections)	3	1	2	3	1	2	3	1	2
Generator Inspection			1			2			
Valves Inspection	3	1	2	1	3	2	3	1	2
Feed Water Pump Major Overhaul (East)			2		3		1		
Feed Water Pump Major Overhaul (West)			2	3				1	
Deaerator Inspection					2	1	3		
Vacuum Pump Inspection (North)		2	1		3				
Vacuum Pump Inspection (South)	1			2		3			
Boiler Inspection (Minor for two and Major for one unit every year)	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3
Routine Fuel Tank Inspections	1	2	4	3	1	2	4	3	
API Fuel Tank Inspections	LFO Tank	1, 2	4, Day Tank	3					

Table 1-13: Summary of Suggested Modifications

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Installation of an Auxiliary Boiler	Yes	Yes	Yes	Yes
Piping Between Auxiliary Steam Header and Turbine Gland Steam System for all Units 1 & 2.	No	No	Yes	Yes
Economizer Recirculation	N/A	Yes	Yes	Yes

[2] Where the numbers refer to unit number or to tank number respectively

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Boiler Furnace Cameras with Monitors in Control Room	Yes	Yes	Yes	Yes
Motor Operated Boiler Blowdown Valves on all Three Units.	Yes	Yes	Yes	Yes
Motor Operated Lower Water Wall Header Drains on all Three Units.	Yes	Yes	Yes	Yes
Appropriate Heating of Fuel Oil Supply Lines	No	No	Yes	Yes
Fuel Oil Storage Recirculation to Day Tank	Yes	Yes	Yes	Yes
Damper in the Boiler Stack	Yes	Yes	Yes	Yes
Boiler Feedwater Pump to Support Economizer Circulation	No	No	No	Yes
Boiler Drains Modification to Support Economizer Circulation	No	No	No	Yes
Dehumidified Air Circulation Package	No	No	No	Yes
Fuel Oil Tank No.1 Refurbishment	Yes	Yes	Yes	Yes

Table 1-14: Proposed Staff

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
No. of Staff Proposed	58	58	58	58

1.15 Environmental Considerations and Recommended Changes to Certificate of Approval (COA)

An Environmental Management System (EMS) is in place in accordance with ISO 14001 and is operated in compliance with its existing environmental Certificate of Approval (COA). The environmental considerations for the emergency backup scenarios include the following:

- Additions to the COA for a new auxiliary boiler.
- Continued use of Quarry Brook to supply the Units 1 and 2 auxiliary cooling water and raw water systems.
- Noise emissions considerations for more frequent start/stop operations.
- In addition to the air emissions currently covered under the existing COA, it is noted that the introduction of GHG regulatory requirements and the federal carbon emissions program will need to be addressed for operation beyond 2021/2023. The carbon emissions program may impose additional costs in the form of a carbon tax or the acquisition of GHG credits. Potential carbon dioxide emissions were estimated based on an assumed operating profile given in Volume II of this report. The results are summarised in Table 1-15.

Table 1-15: Estimated CO_2 Emissions

	Description	Units*	Scenario			
			1	2	3	4
A)	Annual Plant Heating	Mg/yr	13,000	13,000	16,000	20,000
B)	All Units Standby Mode Test Runs	Mg/yr	79,000	79,000	79,000	79,000
C)	3 weeks Continuous Operation	Mg	162,000	162,000	162,000	162,000
D)	6 weeks Continuous Operation	Mg	323,000	323,000	323,000	323,000

*Mg: Million grams

1.16 End of Economically Feasible Life (EEFL) Assessment

The principal components that limit the useful life of utility boilers and steam turbines are: (a) damage to the high temperature heavy wall boiler headers and steam turbines, (b) significant damage to boiler drums, and (c) steam turbine rotor surface life. Industry experience has shown that the process of decision-making is a complex issue and is very site specific. For example, some utilities life extension programs have been based on target utilisation of assets for 60 years after first in-service date, however, there are also some power plants in North America with units which are still in service, primarily on a standby intermittent operation basis, after close to 70 years in service.

In the case of HTGS, the reported condition assessments and inspections of the boilers heavy wall components have not reported any indications that suggest limiting factors on their extended use to 2030 and beyond. Review of the boiler and turbine-generator condition assessments conducted over the period of 2017 to 2021, related inspection reports, and other inspection reports have recorded some issues in the heavy wall components on each of the boilers and Unit 3 turbine but no imminent end of life issues for the components operating in the creep range were indicated. Therefore, the steam turbine rotor surface life expended was assessed based on the available start-stop and load cycling operating history for each unit. The analysis indicated that the estimated cumulative steam turbine rotor life expended for each unit is moderate as summarized in Table 1-16. It is noted that this assessment is qualitative and not quantitative.

Table 1-16: Cumulative Rotor Life Expended for 2030

Unit 1	Unit 2	Unit 3
32%	34%	29%

Attachment 1

“HTGS Condition Assessment and Life Extension Study – Executive Summary” provided by Hatch Ltd.

Project Report

March 30, 2022

Newfoundland and Labrador Hydro

HTGS Condition Assessment and Life Extension Study

Distribution
Jessica McGrath

Project Report Volume I

PROVINCE OF NEWFOUNDLAND
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CLASS "A"
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which is valid for the year 2022

2022-03-30	4	Final	Rory Hynes Kamran Akhtar George Cooper Dayna Landry Saleha Habib Kevin King Ali Hazzouri Cesar Malaga	Scot DeYoung	Karim Meghari	
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**	**Approved By**
HATCH						**Client**

IMPORTANT NOTICE TO READER

This report, including the assessment contained herein, has been prepared by Hatch Ltd. ("Hatch") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to life extension of Holyrood Thermal Power Station (HTGS) and continued operation in full generation mode or conversion to emergency backup operation. Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person's use or reliance.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care based upon information available and conditions existing at the time of preparation of this report, and information made available to Hatch by the Client or by certain other parties on behalf of the Client (the "Client or Other Information").

The use of or reliance upon this report is subject to the following:

1. This report is to be read in the context of and is subject to the terms of the relevant Purchase Order 4769, dated 26 March 2021 between Hatch and the Client (the "Agreement"), including any methodologies, procedures, techniques, assumptions, and other relevant terms or conditions specified in the Hatch Agreement.
2. This report, including the assessment contained herein, is meant to be read as a whole, and sections of the report must not be read or relied upon out of context; and
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4. The condition, stability and safety of the facility has been assessed based on the data available on or before October 31st, 2021. This may change over time (or may have already changed) due to natural forces or human intervention, and Hatch does not accept any responsibility for the impact that such changes may have on the accuracy or validity of the opinions, conclusions, and recommendations set out in this report.

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1. Executive Summary

1.1 Holyrood Thermal Generated Station (HTGS)

Newfoundland and Labrador Hydro (NLH) is transitioning to lower emission power generation with its investment in additional hydroelectric capacity, clean energy technologies, and reinforced transmission systems. The additional planned generation is intended to replace Holyrood Thermal Generating Station (HTGS).

NLH is considering the role of the HTGS post-commissioning of the Muskrat Falls Project assets. Currently, the HTGS is planned for retirement as of March 31, 2023[1], with Unit 3 transitioning to a permanent synchronous condenser unit.[1]

NLH is seeking an independent assessment to fully understand the requirements (capital and operational) should the following options be considered for the HTGS:

1. Continued extension of the Holyrood TGS, whether online in full generation mode or standby mode beyond the current retirement period.
2. The viability and suitability of the HTGS to be used as a backup generating facility to support the island system in the event of a prolonged outage of the Labrador-Island Link until the qualitative End of Economically Feasible Life (EEFL) of the plant.

Hatch was engaged by NLH to review the condition of the asset and develop a capital plan with a view of extending the operation of the plant beyond 2023 that would permit comparison against other alternatives.

Reliability and quick recall are the most critical parameters when considering any power generation source for emergency backup power. Hatch has completed a condition assessment of the plant to determine the reliability of the units and to propose modifications to enable a 4 to 24 hours restart as defined in section 5 of Volume II report.

The condition assessment included:

- Onsite inspections of the fire water system, tank farm, marine terminal, and cooling water sumps by third party contractors and the Hatch local team.
- Review of inspection reports and condition assessments of the power plant main equipment and systems, including the boiler, turbine and generator, cooling water system, condensate and feedwater system, fuel heating and supply system, and common systems.
- Visual inspection of the boiler, turbine, electrical systems, and balance of plant systems.

[1] This report was completed prior to Hydro's announcement on extension to March 31, 2024

Hatch has also developed the capital and operating cost estimates to operate the power plant beyond 2023 in full generation mode or emergency standby mode as per RFP requirements.

1.2 HTGS Condition Assessment

The two oldest units have reported cumulative operating hours ranging from 212,000 to 220,000 hours with Unit 3 reporting 170,000 hours. The fuel oil supply and storage system, cooling water system, boiler stacks, and water treatment system require some repair and continued maintenance.

The three units have been inspected regularly by the OEMs and third-party specialists. The dates of the most recent boiler and turbine inspections are provided in Table 1-1.

Table 1-1: Boiler Inspection Dates

	Boiler Annual Inspection (GE)	Turbine Major Overhaul (GE)
Unit 1	2021	2021
Unit 2	2021	2014
Unit 3	2021	2016

The inspections revealed minor cracks and some signs of fatigue due to age of equipment, but there was no indication of end-of-life reported. This, together with continued O&M practices including inspections, predictive maintenance, reliability assessment programs, and ongoing life-cycle maintenance investment, supports the evaluating the viability of continued use of the assets in full generation mode or emergency standby mode.

1.2.1 Assessment Methodology

A high-level description of the method used to determine the condition of each asset is described in the current section. The detailed methodology for this study is outlined in Section 4.

1.2.1.1 Document Review

Hatch received from NLH the OEM and third-party service provider's inspection, maintenance, and overhaul reports for key plant equipment and systems. All documents received were reviewed by Hatch project team. A list of these documents is included in Appendix A. In summary, the documents reviewed can be categorized as:

- Operation and maintenance manuals
- Piping and instrument diagrams
- Equipment data sheets and performance curves
- Operational history of all three units
- Tripping log of all three units

- Maintenance record of critical equipment and valves
- Last major overhaul reports for turbine and generators
- High energy piping inspection records
- Past condition assessment reports

1.2.1.2 Detailed Inspection Plan

Hatch developed a detailed inspection plan for the project. The inspection's timeline and method, such as visual, borescope, thickness measurement, and non-destructive testing, were outlined in the plan. The latest main equipment inspection records were reviewed to determine their adequacy and to ensure periodic inspections were conducted using an appropriate method. Where records were deemed insufficient, Hatch recommended additional inspections. For example, Hatch recommended that visual inspections be conducted on the condenser shell and eddy current inspections conducted on the condenser tubes of all three units.

1.2.1.3 Inspections by Hatch Third Party Sub-Contractors

Hatch hired third party sub-contractors to conduct inspections of the cooling water system, fire water system, the paint on fuel oil tank No.3, and the marine facilities. The Hatch inspection supervisor and safety officer supervised the sub-contractor teams at site.

1.2.1.4 Site Visits

The local Hatch team from the St. John's office conducted visual inspections of key assets and had face to face meetings with plant staff when required. Two engineers from Hatch were stationed at site for the duration of the third-party inspections.

The Hatch project team and subject matter experts visited the Holyrood facility in September 2021 and visually inspected the power plant.

1.3 Inspection Findings Summary

Hatch reviewed the condition of the plant and assigned a grade of 1 to 5 for each system as per the grading scale provided by NLH.

1.3.1 Grading

The NLH grading scale presented in Table 1-2 was used for grading of the power plant systems.

Table 1-2: Asset Grading Scale

Grade	Condition	Description
5	Excellent	No visible defects, new or near new condition, may still be under warranty if applicable.
4	Good	Good condition, but no longer new, may have some slightly defective or deteriorated component(s), but is overall functional.
3	Adequate	Moderately deteriorated or defective components; but has not exceeded useful life.

Grade	Condition	Description
2	Marginal	Defective or deteriorated component(s) in need of replacement; exceeded useful life
1	Poor	Critically damaged component(s) or in need of immediate repair; well past useful life

1.3.2 HTGS Systems Grading

A summary of the grades for each unit's critical assets is provided in Table 1-3.

Table 1-3: Summary of Asset Grades

Asset	Asset No.	Grade
Unit 1		
Turbine	6691	3
Generator	6691	4
Electrical	6723	4
Control Systems*	6723	2
Cooling Water System	8715	2
Boiler System	6699	3
Stack	6919	3
Condensate & Feedwater System	6708	4
Condenser	6708	3
Unit 2		
Turbine	7636	4
Generator	7636	4
Electrical	8152	4
Control Systems	8152	2
Cooling Water System	8093	2
Boiler System	7786	3
Stack	7900	3
Condensate & Feedwater System	7976	4
Condenser	7976	3
Unit 3		
Turbine	8194	3
Generator	8194	5
Electrical	8712	4
Control Systems*	8712	2
Cooling Water Systems	8645	2
Boiler System	8336	3
Stack	8448	3
Condensate & Feedwater System	8528	4
Condenser	8528	3
Balance of Plant		
Power Center and Excitation Transformers	-	4

Asset	Asset No.	Grade
Common Electrical and Control Assets	7199	4
Buildings and Building M and E System	7255	4
Hydrogen and Carbon Dioxide Supply Systems	7199	4
Compressed Air	7199	4
Fuel Systems (Light and Heavy Oil)	7199	4
Wastewater Treatment Plant (WWTP) Equalization Basin Building	9739	1
Water Treatment Plant (WTP) System	9739	4
Fire Water System	7251	3
Black Start Diesel Gensets	7199	4
Heavy Oil & Fuel Additive Systems (Tank Farm)	7204	3
Marine Terminal Structure (Jetty)	7133	3

1.4 Discussion of Findings

The plant, given its age, is generally in good running condition. Unit 1 last stage blades were inspected in 2021 and Units 2 and 3 will be inspected at the next turbine major overhaul scheduled in 2023 and in 2025 respectively. As per OEMs recommendation, the dovetails of the last stage blades are due for removal and thorough inspection. Considering the long lead time on the blades, the cost of inspection and the fact that the dovetail pins cannot be removed without a potential risk of damage to the pins, Hatch recommends conducting this inspection if considered necessary following visual and NDT inspections. Hatch also recommends that NLH procure a spare set of last stage blades.

1.4.1 Unit 1

The overall condition of Unit 1 was found to be adequate for continued operation beyond 2023.

Recent inspections carried out on Unit 1 by GE, B&W, and Team Industrial on the high energy piping, boiler, economizer, and air preheater showed that the boiler and its ancillary systems are generally in adequate condition. Some level of thermal fatigue, corrosion, pitting, and wall thinning was observed in some areas of the boiler, which is quite common for units of this age. The stack was last inspected in 2021, deterioration of the exterior coating was observed, and recoating of the stack is necessary.

The turbine vibration levels are slightly higher than the levels observed prior to 2013 repair, but they are within the permissible range of ISO20816-2.

In general, Hatch found the condition of Unit 1 to be adequate for operation as a baseload or back up unit through 2030 and beyond subject to ongoing inspections, maintenance, and repairs.

1.4.2 Unit 2

The overall condition of Unit 2 was found to be adequate for continued operation beyond 2023.

Recent inspections carried out on Unit 2 by GE, B&W, and Team Industrial on the high energy piping, boiler, economizer, and air preheater show that the boiler and its ancillary systems are generally in adequate condition. Some level of thermal fatigue, corrosion, pitting, and wall thinning was observed in some areas of the boiler, which is quite common for units of this age. The stack was last inspected in 2021, deterioration of the exterior coating and stainless-steel liner was observed, recoating and replacement of the liner are necessary.

In general, Hatch found the condition of Unit 2 to be adequate for operation as a baseload or back up unit to 2030 and beyond subject to ongoing inspections, maintenance, and repairs.

1.4.3 Unit 3

The overall condition of Unit 3 was found to be adequate for continued operation beyond 2023. The Unit 3 Steam Turbine is reported to have two cracks in the steam chest, these cracks have been monitored very closely since the 1990s. In general, Hatch found the condition of Unit 3 to be adequate for operation as a baseload or back up unit to 2030 and beyond subject to ongoing inspections, maintenance, and repairs. The stack was last inspected in 2021, deterioration of the exterior coating and stainless-steel liner was observed, recoating and replacement of the liner are necessary.

The plan going forward is to operate Unit 3 as a synchronous condenser. Considering the recent refurbishment of the Unit 3 generator, Hatch does not foresee any problematic operation of Unit 3 as a synchronous condenser.

1.4.4 Balance Of Plant

Most of the auxiliary systems of the plant were found in good condition.

Some areas of concern were identified on all condensers, exhaust stacks, and the cooling water system. Gradings were applied ranging from marginal to poor as shown in Table 1-3. It is therefore recommended to closely monitor and periodically inspect the equipment and systems.

The wastewater treatment plant and fire water system were found in poor condition and require major repairs. The cost of repairs has been included in the proposed capital plan.

1.4.5 Piping

The high energy piping and pipe support condition was assessed based on the NLH annual inspection reports as per ASME B31.1 guidelines. The piping systems and pipe supports were found in good condition.

1.4.6 Electrical and I&C

The electrical generator of Unit 1 and 2 were found in good condition, however, showed typical signs of aging. It is suggested that the electrical testing conducted in 2021 be repeated on a yearly basis going forward to support continued monitoring of the units for any signs of degradation. It is also recommended that a major inspection of Unit 2 be conducted in the year following the transition from normal to back up generation operation.

1.5 Hatch Third Party Site Inspections

Hatch conducted onsite inspections of the marine terminal, fuel tank farm, firewater hydrants and piping, and the cooling water pumphouse sumps. The findings of these inspections are summarized in the following sections.

1.5.1 Marine Terminal

The onsite inspection of the marine terminal consisted of a fender and piling inspection. Based on the conducted inspections, fender arms and pins on fenders #3 and #8 were replaced. The piling inspection indicated that the piles are in adequate to good condition. Corrosion on the piles was noted at the splash zone. Under the surface, the piles were covered in significant marine growth and coral, but any visible coating seemed to be in good condition. The degree of corrosion on the anode cathodic protection varies from pile to pile, ranging from 0 to 95% remaining. The marine terminal fenders and piles should continue to be inspected every 5 years.

1.5.2 Fire Water System

The exterior fire water system was inspected using visual inspection, static pressure testing, borescope testing, and acoustic testing. Twenty of the twenty-six hydrants passed inspection. The static pressure testing measurements ranged from 78-122 psi. There were no current leaks detected in the buried firewater line at the time of testing. Based on confirmation of past failures and leaks on the buried firewater line, it is recommended that the tank farm firewater buried pipe be replaced along with the balance of the buried firewater line during the planned 2022 upgrade. Hydrant inspection and testing is recommended to be conducted on an annual basis.

Note, Hatch was informed by NLH that currently the fire water and fire water pumping system is used as a source for water for auxiliary resources. Based on this information, Hatch recommends that a risk assessment study be conducted to investigate the requirement for a dedicated fire water system and a separate system for water for auxiliary resources.

1.5.3 Cooling Water Sumps

The powerhouse cooling water sumps were inspected using an ROV and a confined space drone. These sumps currently have restricted access, and personnel are no longer allowed entry. The sumps were last cleaned in 2014 and are no longer cleaned on an annual basis. There is significant marine growth covering most of the sump walls and floors. These inspections identified that there are significant cracks in the sump support beams in all four south sumps. It is recommended that these sumps undergo repair due to deteriorating conditions and the potential decreased strength of the interior beams. Furthermore, it is recommended that these areas be limited to foot traffic/small equipment and not used for laydown or staging areas for heavy equipment. These sumps should continue to be monitored with a drone/ROV (equivalent) on an annual basis.

1.5.4 Fuel Oil Tanks

Historical inspection information was reviewed for the main Heavy Fuel Oil (HFO) Storage Tanks 1, 2, 3, and 4, the HFO day tank, and a coating inspection was performed on Tank 3.

The HFO storage tanks and day tank were found to be in adequate condition. A refurbishment program for the tanks was implemented in 2006. Tank 1 is targeted for decommissioning in 2022, and Tanks 2, 3, and 4 will undergo out of service inspections in 2024-2025 to determine if any refurbishment work will be required. NLH advises they have committed to performing annual in-service inspections of these tanks until the out of service inspections are performed. The HFO day tank is scheduled for an out of service inspection in 2023 to determine if any refurbishment work will be required.

1.6 Most Recent Failures

Holyrood power station experienced two failures, these failures occurred towards the end of the condition assessment and are summarized below.

- Unit 3 boiler waterwall failure
- Unit 1 Cold reheat piping support failure

Hatch notes that Transformer T2 failed in November 2021 and was replaced by the spare Transformer T4. Hatch has not reviewed any failure reports and therefore cannot comment on the nature of the failure.

1.6.1 Unit 3 boiler waterwall failure

Hatch reviewed the TapRoot report prepared by NLH and Wayland on the causal factors leading to the tube failure and concurs with the findings. Namely, the failure is due to corrosion fatigue augmented by constraint on thermal expansion due to the original design of the windbox vestibule attachment.

1.6.2 Unit 1 Cold reheat piping support failure

Hatch reviewed the TapRoot report prepared by NLH which identified the causal factors that led to the incident and recommended actions to avoid recurrence. Hatch concurs with the findings of the TapRoot report and agrees that the incident was due to water leakage across a valve which is considered to be of a non-recurring nature based on implementing the recommended actions.

1.7 Remaining Life Assessment

The principal components that limit the useful life of utility boilers and steam turbines are: (a) damage to the high temperature heavy wall boiler headers and steam turbines, (b) significant damage to boiler drums, and (c) steam turbine rotor surface life expended.

Review of the boiler and turbine generator condition assessments conducted over the period of 2017 to 2021, related inspection reports, and other inspection reports have recorded heavy wall component issues on each of the boilers but no imminent end of life issues for the components operating in the creep range were indicated.

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2. Introduction

Newfoundland and Labrador Hydro's (NLH) Holyrood Thermal Generation Station is comprised of three heavy fuel oil fired units generating a total of 500 MW. NLH is investing in additional hydroelectric capacity, clean energy technologies, and reinforcing the transmission systems. The additional planned generation will reduce NLH dependence on HTGS. Current plans call for Units 1 and 2 to be retired and Unit 3 to be converted to permanent synchronous condenser duty.

Deciding on the retirement of generating assets is a complex and difficult process. The technical requirements, environmental impacts, economic demands, social impact, staff knowledge retention and training, fuel supply, and environmental permitting are all factors to consider in the decision process to retire an asset. Ultimately, it is the unit's capability to serve a need that determines when and how the asset should be retired.

Hatch was selected by NLH to conduct the HTGS Life Extension Study with two main objectives. The first included a condition assessment of all major systems. The second was to determine the requirements for converting the facility from a prime power generating station to an emergency power generating station.

2.1 Background

HTGS consists of three units and can generate 500 MW. Units 1 and 2 were commissioned in 1969 with a capacity 150 MW. Unit 3 was commissioned in 1979 and can produce 150 MW. Units 1 and 2 were upgraded in 1988 and 1989 to 175 MW. Unit 3 is also capable of operating in synchronous condenser mode to provide voltage regulation.

When all three units are operating at the full maximum continuous rating (MCR), HTGS can supply approximately 20% of Newfoundland and Labrador's demand. Typically, the plant is only required to operate and supply power during the winter months, however, it is capable of supplying power to the grid at any time, 365 days a year, 24 hours a day.

With the introduction of the Muskrat Falls Project, HTGS is currently planned to continue operating until March 31, 2024.

2.2 HTGS General Description of the Facility

2.2.1 Unit 1

Unit 1 was designed to fire No. 6 fuel oil and had a rated capacity of 150 MW. The unit output was increased to 175 MW following the 1988 and 1989 upgrades.

2.2.1.1 Boiler

The Unit 1 boiler is a tangentially fired, natural circulation boiler manufactured by Combustion Engineering (CE). Originally, the boiler was designed for a steam flow of 132 kg/s at 541°C and 13,100 kPa(g). When Unit 1 was upgraded to 175 MW, the main steam flow capacity was increased to 147 kg/s at 541°C and 13,479 kPa(g).

Note that this boiler does not have any particulate capture systems, nor does it have low NOx burners or overfire air for low NOx operations. There is also no economizer recirculation or auxiliary steam flow to the steam turbines glands that could be used for unit preheating.

2.2.1.2 *Steam Turbine Generator*

The turbine generator is a 3600 rpm, three-cylinder (HP/IP/double flow LP) tandem compound General Electric (GE) turbine and has a hydrogen cooled GE generator. The HP throttle pressure is 13.1 MPa with the superheat temperature at 538°C.

2.2.1.3 *Condenser*

The condenser is a Foster Wheeler Double Flow Type M condenser which has two-pass flow with a divided water box. A pressure of 3.4 kPa is maintained at MCR using two vacuum pumps at 100% duty.

2.2.1.4 *Cooling Water System*

The Stage 1 pumphouse contains two cooling water (CW) pump systems (at 50% duty) which deliver seawater for cooling to the Unit 1 condenser. Two travelling screens are used to remove any debris that may be present in the incoming cooling water. Following the screens, the cooling water enters the CW pumps. Each pump can deliver cooling water at a rate of 2,252 L/s.

2.2.1.5 *Feedwater* System

Two feedwater pumps, a feedwater heating system, and reserve feedwater tanks comprise Unit 1's feedwater system. The feedwater heating system includes three high pressure (HP) heaters, one deaerator, and two low pressure (LP) heaters.

2.2.1.6 *Condensate System*

Condensate is pumped to the deaerator by means of two condensate pumps each rated for 100% duty. The water level in the condenser hotwell is controlled by the condensate pumps, along with the reserve feedwater tanks.

2.2.1.7 *Deaerator and HP System*

The deaerator system includes a storage tank with a capacity of 81,650 kg. This tank has sufficient capacity to provide the boiler feed pumps with water for 10 minutes at MCR.

The HP heater system, comprised of three feedwater heaters, receive feedwater from the deaerator. Feedwater entering the heaters is brought up to the temperature required for the economizer inlet.

There are two 50% capacity feedwater pumps, the pumps are a horizontal double casing design each rated for rated for a flowrate of 75 L/s at 1700 m of head. The pumps supply feedwater from the deaerator to the boiler via the HP heaters.

2.2.2 ***Unit 2***

Unit 2 was designed to fire No. 6 fuel oil and had a rated capacity of 150 MW similarly to Unit 1. The unit output was increased to 175 MW following the 1988 and 1989 upgrades.

Since Unit 1 and Unit 2 are identical to each other, the facility description provided for Unit 1 in Section 2.2.1 is applicable to Unit 2 as well.

2.2.3 Unit 3

Unit 3 is rated for 150 MW and was designed to use No. 6 fuel oil.

2.2.3.1 *Boiler*

The Unit 3 boiler is a reheat unit, front wall-fired, natural circulation boiler manufactured by Babcock and Wilcox. The boiler is designed for a superheated steam flow of 135 kg/s steam at 541.6°C and 13,020 kPa, and a reheat steam flow of 125.1 kg/s at 541.6°C and 3,716 kPa.

Note that this boiler does not have any particulate capture system, nor does it have low NOx burners or overfire air for low NOx operations. However, unlike the boilers for Units 1 and 2, it does have an economizer recirculation line and auxiliary steam flow to steam turbine glands to assist with unit preheating.

2.2.3.2 *Steam Turbine Generator*

The Unit 3 turbine generator is a 3600 rpm, three-cylinder (HP/IP/double flow LP) Hitachi turbine and has a hydrogen cooled Hitachi generator. The HP throttle pressure is 12.4 MPa with the superheat temperature at 538°C.

2.2.3.3 Condenser

Unit 3 is supplied with a Foster Wheeler condenser. A pressure of 3.4 kPa is maintained at MCR in the condenser by means of two vacuum pumps, each rated for 100% load.

2.2.3.4 *Cooling Water* System

The Stage 2 Pumphouse contains two cooling water (CW) pump systems (at 50% duty) which deliver seawater for cooling to the Unit 3 condenser. Two travelling screens (at 100% capacity) are used to remove any debris that may be present in the incoming cooling water. Following the screens, the cooling water enters the CW pumps. Depending on the tide, each pump can deliver cooling water at a rate between 2,250 and 3,785 L/s.

2.2.3.5 *Feedwate*r System

As with Units 1 and 2, two feedwater pumps, a feedwater heating system, and reserve feedwater tanks comprise Unit 3’s feedwater system. The feedwater heating system includes three high pressure (HP) heaters, one deaerator, and two low pressure (LP) heaters.

2.2.3.6 *Condensate System*

Condensate is pumped to the deaerator by means of two condensate pumps each rated for 100% duty. The water level in the condenser hotwell is controlled by the condensate pumps, along with the reserve feedwater tanks.

2.2.3.7 *Deaerator and HP Feedwate*r System

The deaerator system includes a storage tank with a capacity of 81,650 kg. This tank has sufficient capacity to provide the boiler feed pumps with water for 10 minutes at MCR.

The HP heater system, comprised of three feedwater heaters, receives the feedwater from the deaerator. Feedwater entering the heaters is brought up to the temperature required for the economizer inlet.

There are two 50% capacity feedwater pumps, the pumps are horizontal double casing design each rated for rated for a flowrate of 77 L/s at 1722 m of head. The pumps supply feedwater from the deaerator to the boiler via the HP heaters.

2.2.4 Balance of Plant

2.2.4.1 *Common Systems*

2.2.4.1.1 Lubricating Oil Supply

The lubricating oil supply pipes for all three units at HTGS are placed inside the common bearing oil return line to the lube oil storage tank. The bearings have “high bearing temperature” alarms to monitor the health of the bearings.

2.2.4.1.2 Fuel Oil Storage and Delivery

The unloading docks receive fuel oil from tankers, the fuel is then transported to the HTGS fuel oil storage tank farm via a heat traced pipeline. Four 33,710 m^3 tanks comprise the tank farm. Each tank’s oil discharge temperature is controlled using a steam suction heater, where the steam is supplied from the auxiliary steam system. Steam traps are used to capture the condensate which is then sent to drains.

Oil is transferred to the day tank from the tank farm by gravity flow. The day tank does not have any recirculation. Additionally, there is no recirculation from the powerhouse back to the tank farm. With all units operating at full load, approximately 120,000 to 130,000 barrels of fuel are consumed per week. Oil is supplied to the HTGS facility by tankers, it takes approximately 4 weeks from the time the order is placed to the time oil is delivered to site. The fuel delivery is dependent on weather as well as ship and fuel availability, as the tankers come from Texas.

The boiler fuel supply pumps on each unit receives oil from the day tank. Oil can also be supplied directly from the tank farm to the pumps suction through the day tank bypass line.

If atomizing steam is unavailable to support boiler firing with No. 6 oil, then light oil can be used to light off the steam generators from a black start. Light oil pumps receive the oil via a header from the station light oil tanks. Light oil is also used for purging the fuel lines from heavy fuel following boiler shutdown. This system has two positive displacement pumps (at 100% duty) which supply oil to the boiler at a pressure of approximately 1034 kPa. The system is also equipped with a recirculation line from the burner front header back to the day tank.

2.2.4.1.3 Compressed Air

The facility has three compressors which feed into a common header. Two compressors are fixed speed, and one is equipped with a variable speed mechanism. The compressors are not connected to the DCS but have a dedicated monitoring system that allows operators to switch on/off when needed. The system supplies both service and instrument air.

2.2.4.2 Buildings

Steam is required to prevent freezing of piping and for building heating. The building and fuel heating system consists of the following:

- Immersion and suction heaters for HFO day tank and storage tanks.
- Building unit heaters.
- Heat tracing (fuel system).

Steam is supplied to the heaters from the auxiliary steam header at 50 psig via a letdown station. The total auxiliary steam demand has been estimated by NLH to be 25,000 lb/hr.

3. Project Description

3.1 HTGS Project Overview

The decision to retire generating assets is a complex and difficult process. There are many components to take into consideration, including technical requirements, environmental impacts, economic demands, and the social impact. While there are several factors that need to be addressed related to staffing, knowledge retention and training, fuel supply, and environmental permitting, ultimately it is the unit's capability to serve a need that determines when and how the asset should be retired.

The best approach to making this decision is to develop a flexible plan with options that maximize the value the asset can provide. NLH has defined several potential scenarios for faster start-up of the station. The key to determining the cost impact of these options is a two-step process. First, is understanding the current state of the equipment and second, is determining the potential to modify the plant characteristics to meet the emerging needs.

This report is primarily focused on the condition assessment of all three units. The objective was to assess the major assets that comprise Units 1, 2, and 3 as well as the balance of plant equipment to determine whether the plant could be operated safely and reliably.

With HTGS potentially serving as an emergency generation source, there is a need for it to be available to generate electricity shortly after dispatch. There are several potential upgrades that were investigated as part of the assessment work, including pre-heating of the unit to allow faster start-up. In addition, options were explored to reduce the time required to convert Unit 3 from synchronous condenser to generation mode.

4. Methodology

The methodology described in this section was used to conduct the condition assessment of HTGS's critical assets.

4.1 Document Review

Plant documentation and historical records were reviewed. In summary, the documents reviewed can be categorized as:

- Operation and maintenance manuals of the units
- Piping and instrument diagrams
- Equipment data sheets and performance curves
- Operational history of all three units
- Tripping log of all three units
- Maintenance record of critical equipment and valves
- Last major overhaul reports for turbine and generators
- High energy piping inspection records
- Past condition assessment reports (2014 to 2021)

Appendix A contains the detailed list of documents provided by NLH to Hatch during the project execution.

This condition assessment was used as the primary input to validate the viability of the proposed scenarios for quick recall and to compute the O&M cost. Details regarding the quick recall scenarios and their O&M costs are provided in Volume II report.

4.2 Detailed Methodology and Site Inspection Plan

Hatch developed a detailed inspection plan for the project. The inspection timeline and method of inspection, such as visual inspection, borescope inspection, thickness measurement, and non-destructive testing, were outlined in the plan. The latest main equipment inspection reports were reviewed to determine the adequacy of inspections and to ensure periodic inspections were conducted on equipment and the method of inspections were appropriate. Where inspection records were deemed insufficient, Hatch recommended additional inspections. For example, Hatch recommended that visual inspections be conducted on the condenser shell and eddy current inspections conducted on the condenser tubes of all three units. A summary of the condition assessment methods are outlined in Table 4-1.

Table 4-1: Summary of Condition Assessment Method

Sr. No.	Equipment Description	Condition Assessment Method
1	**Cooling Water System**	
	CW Pump Sumps	ROV Inspection by Hatch Sub-Contractors in accordance with Hatch scope of work

Sr. No.	Equipment Description	Condition Assessment Method
	CW Pumps	ROV Inspection by Hatch Sub-Contractors in accordance with Hatch scope of work
2	**Power Generation Facilities**	
2.1	**Boiler & Auxiliaries**	
	Economizer to SH Outlet Header	Review of B&W Annual Inspection Reports and prior Condition Assessment reports and recommendations (by others)
	Main Steam, Hot & Cold RH Lines (HEP - High Energy Piping)	Review of B&W Annual Inspection Reports. Annual Inspection Data for Pipe Supports and prior Condition Assessment reports and recommendations (by others)
	Soot blowers	Review of Annual Maintenance Reports
	Safety Valves (General)	Review of Annual Maintenance Reports
	Casing, windbox, expansion joints, dampers & refractory - Includes Insulation	Review of B&W Annual Inspection Reports; B&W including B&W PSB and study on windbox wall tube failures for Unit 3; detailed root cause analysis reports and OEM assessment of risk on other boilers
	Auxiliary Steam Supply	Visual Inspection & Discussion with NLH Staff
	Forced Draft Fans	Visual Inspection & Discussion with NLH Staff
	Stack	Visual Inspection & Discussion with NLH Staff
	Burners	Review of Annual Maintenance Reports
2.2	**Turbine & Generator**	
	Steam Chests, Stop & Gov. Valves	Review of OEM Major Overhaul Reports Review of OEM Outage Reports Review of NDT Service Providers Inspection Reports
	Rotor	Review of OEM Outage and Maintenance Reports
	Governing System	Review of OEM Reports Review of NDT Service Providers Inspection Repots

Sr. No.	Equipment Description	Condition Assessment Method
	Pedestals - Bearings (Turbine)	Review of Vibration Analysis Reports
	Casing & Insulation	Visual Inspection & Discussion with NLH Staff
2.3	**Generator (General)**	
	Rotor and Stator	Review of Hi-Pot Test Reports Review of Major Overhaul/Refurbishment Reports for Unit-3
	Bearings	Review of Vibration Analysis Reports
	CO_2 System (Generator)	Visual Inspection & Discussion with NLH Staff
	H_2 System (Generator)	Visual Inspection & Discussion with NLH Staff
	Excitation System	Discussion with NLH Staff
	Voltage Regulation (Generator)	Discussion with NLH Staff
	Turbo/Generator - (Protection)	Discussion with NLH Staff
2.4	**Lube Oil System (Turbo/Gen)**	
	Lube Oil Pumps	Review of Maintenance Reports
	Coolers	Visual Inspection
	Vapor Extraction System	Visual Inspection
3	**Condenser**	
	Steam Side	Additional Inspections Requested. Reviewed Inspection Repots
	Water Boxes	Additional Inspections Requested. Reviewed Inspection Repots
	Condensed Tubes	Plugged Tubes Data Reviewed. Recommended Eddy Current Testing.
	Vacuum Pumps	Review of Maintenance and Major Overhaul Reports
	Condenser Ball Cleaning System	Not in Operation
4	**Feedwater System (General)**	
	Condensate Extraction Pump	Review of Maintenance and Major Overhaul Reports
	LP Feedwater Heaters	Review of Inspection Reports
	HP Feedwater Heaters	Review of Inspection Reports
	Heater Drain Pumps	Review of Maintenance and Major Overhaul Reports

Sr. No.	Equipment Description	Condition Assessment Method
	Deaerator	Review of Inspection Reports
	Boiler Feed Pumps	Review of Maintenance and Major Overhaul Reports
5	**Emergency Power Unit (General)**	
	Generator (EPU)	Visual Inspection & Discussion with NLH Staff
	Excitation & Syn (EPU)	Visual Inspection
	Fuel Supply (Diesel Tank)	Visual Inspection
6	**Electrical (General)**	
	Motors	Visual Inspection
	Starters	Visual Inspection
	Cable Trays	Visual Inspection
	Ducts	Visual Inspection
	Cables	Visual Inspection
	4.16 kV Switchgear Distribution	Visual Inspection & Discussion with NLH Staff
7	**Instrumentation & Controls (General)**	
	Turbine Control System (Mark-V)	OEM Inspection Reports Discussion with OEMs
	Plant DCS (Includes Boiler Controls)	OEM Inspection Reports Discussion with OEMs
	Controls Network	OEM Inspection Reports Discussion with OEMs
	Computers, Workstations & Switches	OEM Inspection Reports Discussion with OEMs
8	**Common Services**	
	General Service Water	Visual Inspection & Discussion with NLH Staff
	Compressed Air Systems	Visual Inspection & Discussion with NLH Staff
	Fire Water System	Hydrant Pressure Testing, Borescopic Testing and Acoustic Testing, Visual Inspection
	Buildings and Elevators (General)	Visual Inspection & Discussion with NLH Staff
	Communication System	Visual Inspection & Discussion with NLH Staff
	Heating, Ventilating & Air Conditioning	Assessment for an auxiliary boiler during winter shutdowns.
	Potable Water (General)	Discussion with NLH Staff
	Environmental Monitoring Equipment	Visual Inspection & Discussion with NLH Staff

The detailed inspection plan is attached in Appendix B.

4.3 Hatch Project Team Site Visit

The local Hatch team from the St. John's office conducted visual inspections of key assets and had face to face meetings with plant staff when required. Two engineers from Hatch were stationed at site for the duration of the third-party inspections.

Hatch project team and subject matter experts visited the Holyrood facility in September 2021 and visually inspected the the powerhouse, fuel receiving terminal, cooling water sumps, back up diesel gensets, and fuel tank farm.

4.4 Hatch Sub-Contractor's Inspections

Pumphouse 1 and 2 cooling water sump intake inspections were conducted by sub-contractors. The sump concrete floors, walls, and ceiling were inspected using a combination of remotely operated vehicle (ROV) and unmanned aerial vehicle (UAV) inspections. The ROV inspection of the floors and walls was limited to below the waterline due to lack of adequate lighting above the waterline and close distance to the ceiling. Therefore, the inspection of the ceiling and above the waterline (approx.10/12 ft) could not be completed. The cooling water intake sumps are a restricted, confined space area. To avoid personnel entering the sumps, a Confined Space UAV Drone was used to complete the wall and ceiling inspection. Photos of the inspection can be found in Section 5.7.

As part of the jetty inspection, jetty fender pin measurements were taken. Additionally, scaffolding was erected, and measurements of the jetty fender support arms were taken for comparison with inspection results from 2008 and 2013. Further details are available in Section 5.8.

An inspection of the jetty terminal piles and anodes was conducted. The piles were visually inspected above the splash zone and the piles and anodes were visually inspected at three locations below the water line. The results of the visual inspection were compared to the 2017 inspection results. Section 5.8 provides details regarding this inspection.

The coating inspection on Fuel Oil Tank 3 was conducted via rope access and measurements of the coating dry film thickness on the six (6) shell courses at the four quadrants of the tank were taken. A coating Adhesion Pull Test was also conducted via rope access on the six (6) shell courses at the four quadrants of Tank 3. Further information is available in Section 5.8.7.

Firewater service inspections consisted of static pressure testing on the fire hydrants, borescopic inspection on the hydrants, and acoustic leak testing on the hydrants. Acoustic correlation testing was attempted but was not successful due to interference from surrounding equipment and maintenance operations. Further details are available in Section 5.5.5.

4.5 Codes and Standards

The following codes, standards, and related guidelines are referenced in this report.

- ASME B31.1
- API 653
- NFPA
- ISO standard
- OEM manuals and recommendations

5. HTGS Condition Assessment

5.1 Unit 1

5.1.1 Unit 1 Boiler

The Unit 1 boiler was manufactured by Combustion Engineering (CE) and installed in 1969. This unit is over 50 years old and currently has over 220,000 operating hrs. The boiler and its ancillary equipment are inspected annually, the most recent inspection (2021) was conducted by GE. Other service providers are also contracted to provide specialized services, such as NDTs, to support OEMs inspections.

Overall, Hatch found the Unit 1 boiler in good condition. With continued periodic inspections and preventive maintenance as recommended, the Unit 1 boiler is considered suitable for continued use.

5.1.1.1 Boiler Drums

The boiler drums are generally in good condition. Four pressure boundary welds and 25 non-pressure boundary welds were identified on the drums and repaired between 2015 and 2020. The GE 2021 inspection did not find any significant concerns with the health of the Unit 1 boiler drum.

5.1.1.2 Super Heaters

In 2015 B&W identified some cracks near the super heater header outlet nozzles. The condition of these cracks was rechecked during the 2018 and 2019 B&W inspections and the subsequent 2021 GE inspection, no further crack propagations were observed.

5.1.1.3 Reheater

Thermal fatigue cracks were found during the 2018 inspection in the reheater outlet tube to the header welds. The subsequent B&W and GE 2019 and 2021 inspections did not reveal any growth in the size of the cracks.

5.1.1.4 Water Walls

In 2020, a wall thickness measurement was carried out by B&W on different sections of the boiler water wall tubes. Some evidence of wall thinning, and pitting was observed, however, the wall thickness of the tubes was found to be within the ASME permissible wall thickness.

5.1.1.5 *Economizer & Air Heater*

Pitting and wall thinning was reported during the 2020 and 2021 OEM inspections and was deemed not a concern. Fouling of the economizer tubes and air heater baskets was reported during earlier inspections, this fouling was found to be one of the main reasons of unit derating operation until 2018. In 2018, a new chemical cleaning solution was introduced at HTGS, and the new cleaning solution was a success. This cleaning is now performed annually and has significantly reduced the amount of fouling on the economiser tubing and air heater baskets.

5.1.1.6 *Forced Draft Fan*

The Unit 1 FD fan is reasonably in good condition. The VIV control for fan flow at partial load remained in place but was put out of service due to the introduction of variable frequency drives (VFD). The VFD controls have caused serious operational problems to the boiler unit. A plan is being put in place to decommission the VFD control and put the VIV control back in service. A visual inspection of the VIV wheels and actuators did not show any signs of wear; however, some mechanical linkages may be non-functional due to non-usage and may need replacement.

5.1.1.7 *Burners & Soot blowers*

There had been cleaning problems with the Unit 1 boiler burners and soot blowers. HTGS management, after discussion with OEMs, implemented an annual cleaning and maintenance program to fix these issues. Considering the condition of burners and soot blowers, Hatch agrees with the recommendation made by GE during the 2021 inspection to overhaul the full burner set and the soot blowers.

5.1.1.8 *Stack*

The stack exterior was last inspected in 2021, deterioration of the coating was observed, and recoating of the stack is necessary. The internals of the stack were inspected in 2018, concrete spalling was discovered during the inspection and repaired.

The stainless-steel liner is approaching the end of its 20-year life and need to be replaced. The Continuous Emission Monitoring System (CEMS) is in good condition. The aviation lights are old and will also need to be replaced.

5.1.2 *Unit 1 Steam Turbine*

The Unit 1 steam turbine was manufactured by GE and installed in 1969. The latest overhaul on this unit was carried out in 2021 by GE and showed that the turbine is in good condition.

The turbine experienced a problem with a lube oil system in 2013 resulting an interruption to supply of lubricating oil to the turbine bearings. This damaged the turbine bearings and journals. An overhaul was undertaken in 2013 to rectify the bearings and journals with some follow up work in 2014. It has been reported that the bearings and journals damage increased the sensitivity of the turbine to start-up vibrations, leading to a longer run-up time. GE conducted a vibration analysis in October 2021 with the support from Machinery Diagnostic Service Department of Bently Nevada and confirmed that the vibration levels are within the alarm range and are in accordance with ISO 20816-2. Hatch reviewed the vibration reports and confirmed that the vibration level for all turbine and generator bearings are within permissible limits, although on the higher end of standard industry practice.

In 2018, GE conducted a Turbine Valve Outage which included disassembly, cleaning, inspection, and repair as necessary of the turbine main stop valve plus all six control valves and the combined reheat valves. The work also included the turbine system non-return valves in addition to other valving and components.

The 2021 inspection report for the High Pressure and Intermediate Pressure (HPIP) and Low Pressure (LP) rotors have been reviewed and the following has been noted:

- HPIP Rotors Turbine #940310:
    - NDT tests performed in July 2021 included Periphery UT, Rotor dovetail UT, and Bucket to rotor gap measurements.
    - No indications detected by Periphery UT tests during recent tests.
    - Rotor dovetail UT tests were conducted on stages 1, 2, 3, 11, 12, and 13. No indications were identified. GE recommended that the HPIP rotor dovetails be re-inspected at next scheduled rotor NDT inspection.
    - The gap between the bucket to rotor wheel tangs was measured on stages 2, 3, 11, 12, and 13. Gaps identified are reported to be within the GE allowable gaps for this type of turbine.
- LP Rotor Turbine #940310:
    - NDT tests conducted included Periphery UT, Rotor dovetail UT, Bucket to rotor gap measurements and dovetail pins on stage L-0.
    - No indications were identified during the periphery UT during recent test.
    - Rotor dovetail UT was conducted on stages 3 and 4 on the turbine end and generator end of the rotor with some limitations due to geometry constraints. No further need for inspection at this time was identified. GE recommended that the LP rotor dovetails should be re-inspected, however, this has been postponed because of the non-availability of spares. Spare blades are recommended to be purchased and the cost for new set of last stage blades is considered in capital plan prepared by Hatch. Capital plan is covered in Volume II of this report.
    - The gap between the bucket and rotor wheel tangs was measured on stages 3 and 4 on both the turbine end and generator end of the rotor. Gaps identified are reported to be within the GE allowable gaps for this type of turbine.
    - No Indications were identified during the UT conducted on the dovetail pins on stage L-0.

- During the recent inspection of Last Stage Blades (LSBs), a crack was identified in one of the L-0 blades. The OEM has recommended annual LSB stage bucket inspections and has advised to keep a spare set of last stage blades in stock.
- Due to the lead time of the LSBs, the OEM has also recommended to purchase a spare set to reduce the downtime of the unit in case of a blade failure. Hatch agrees with this recommendation.

5.1.3 *Unit 1 Generator*

The Unit 1 generator is manufactured by GE and was installed in 1970. The generator produces 175 MVA of power at 16 kV and is hydrogen cooled. The most recent major inspection of Unit 1 was carried out in 2018.

A refurbishment of Unit 1 was performed in 2012/2013, however, the stator and rotor are original, and the unit has not been rewound. In May 2021, electrical testing was conducted on Unit 1. The tests included:

1. Insulation Resistance Measurement
2. FDS (Frequency Domain Spectroscopy) Measurement
3. PDC (Polarization Depolarization Current) Measurement
4. Power Factor and Capacitance Measurement
5. Partial Discharge Measurement.

The test results show that insulation resistance and polarization index values are adequate for operation for a unit of this age, however, power factor and capacitance values are high and indicate thermal aging and the presence of partial discharge. This partial discharge should be monitored closely going forward.

The generator shows typical signs of aging. Overall, the generator is in reasonably good condition for its age, but regular inspections and testing are required. It is suggested that the electrical testing carried out in 2021 be repeated on a yearly basis to monitor the unit for any signs of degradation. Regular planned maintenance on generator and auxiliaries should continue for the life of the generator. Assuming that there are no significant changes in electrical test results, the unit will not require a rewind until 2030.

5.1.4 *Unit 1 Condenser*

The condenser was inspected in 2014 by Alstom and significant damage was reported in the condenser. As a result, Hatch requested testing of the condenser tubes using non-destructive eddy current examination.

NLH hired GE to conduct this inspection. A total of 6.5% of tubes were tested with a focus on areas with higher damage potential. Indication of pitting and corrosion were found throughout the condenser at different tube lengths. The test results showed tube defects in the range of 20% to 40% of the tubes tested. Approximately 300 tubes were found plugged.

On the steam side, the tube bundles appeared in good condition. Some broken or eroded welds on supporting braces were observed which is not uncommon for an old unit. The magnitude of the erosion on braces is not of any major concern since the braces are welded on both sides and on the top and bottom.

Expansion joints and vacuum seal linings were also found in adequate condition.

The details of GE test report can be found in Appendix C.

5.1.5 Unit 1 Auxiliaries

Key plant auxiliaries are assessed based on the past inspection records available and their assessment status is summarized below.

5.1.5.1 Condenser Vacuum Pumps

Condenser vacuum pumps are overhauled every 12 years. The next overhaul on one of the two pumps is planned for 2022.

5.1.5.2 Condensate Extraction Pumps

Condensate extraction pumps (CEP) are overhauled every 12 years. The last inspection of Unit 1 CEPs was carried out in 2014 for the South side CEP and in 2015 for the north side CEP.

5.1.5.3 Boiler Feedwater Pumps

Boiler feedwater pumps (BFPs) are inspected every 6 years. In 2020, the suction valve of the West side BFP was closed, and the pump ran without water, damaging the pump impeller and bearing seals. This pump was then overhauled and put back in service. The east side BFP is overhauled in 2021.

5.1.5.4 Deaerator Shell

The deaerator shell is visually inspected every year and internals are inspected every 6 years. Unit 1 internals were last inspected in 2020. Cracking was observed in the steam coil inlet connection and is checked every year. NLH does not replace the deaerator internals on a periodic basis but only when needed.

5.1.5.5 Heater Drain Pump

The heater drain pump (HDP) is overhauled every 12 years. The last overhaul on the Unit 1 HDP was carried out in 2013. No major issues were found during this inspection.

5.1.5.6 Flash Box

The flash Box of Unit 1 is connected to the wall and can be separated. The flash box is inspected every 12 years. The last inspection on the Unit 1 flash box was carried out in 2012 and the condition of flash box was found adequate.

5.1.6 Unit 1 Asset Grading

Grades from the asset grading scale in Table 5-1 were assigned to Unit 1 assets as indicated in Table 5-2.

Table 5-1: Asset Grading Scale

Grade	Condition	Description
5	Excellent	No visible defects, new or near new condition, may still be under warranty if applicable.
4	Good	Good condition, but no longer new, may have some slightly defective or deteriorated component(s), but is overall functional.
3	Adequate	Moderately deteriorated or defective components; but has not exceeded useful life.
2	Marginal	Defective or deteriorated component(s) in need of replacement; exceeded useful life
1	Poor	Critically damaged component(s) or in need of immediate repair; well past useful life

Table 5-2: Unit 1 Asset Grading

Asset Class	Category	Asset No.	Description	Grade
Unit 1 Turbine & Generator		6691		
BU 1296 - Assets Generations	Sub-Systems	6696	#1 Generator Assembly	4
		6805	#1 Turbine Lubricating Oil	4
		6807	#1 Turbine Hydraulic Oil Systems	4
		6733	#1 Turbine Condenser System	3
		271309	#1 Steam turbine	3
	Components	6839	#1 Generator Rotor	4
		6840	#1 Generator Stator	4
		6850	#1 Hydrogen System	4
		6803	#1 Tank & Equipment	4
		6804	#1 Purification	4
		6829	#1 Pump South	4
		6830	#1 Pump North	4
		6833	#1 DC Pump	4
		6835	#1 Hydraulic Oil Pump North	4
		6838	#1 Hydraulic Oil Pump South	4
		271316	#1 Condenser	3
		6729	#1 Main Steam Chest	3
		6730	#1 HP Turbine	3
		6731	#1 IP Turbine	3
		6732	#1 LP Turbine	3
		6734	#1 Front Standard	4
Electrical & Control Systems		6723		
BU 1296 - Assets Generation	Sub-Systems	6723	#1 Electrical & System & Controls	3
	Components	6721	#1 Relay Room Protection & Control	3
		6722	#1 Main Controls	2
		6724	#1 Generator Bus-Duct and Connections	4

Asset Class	Category	Asset No.	Description	Grade
		6728	#1 Battery Chargers	4
		7184 / 7186 / 7187	MCCs, C2, C3, C4	4
		7193	#1 UPS1 Inverter	4
		270151	#1 Turbine Supervisory System	2
		270295	#1Switchgear, 4160V/600V	4
		7182	#1 Power Centre “A” UAB1, (600V)	4
		291668	#1 DCS	4
		7197	Common, Stage 1, 129VDC Supply System	4
		270297	Control Cables	4
		270298	Power Cables, 600V Metric Plugs	4
		6693	#1 Turbine Governor System	3
		270151	#1 Turbine Supervisory System	2
		7173	#1 Burner Management	4
		309897	#1 Boiler Protection & Control	4
Cooling Water Systems		8715		
BU 1296 - Assets Generations	Sub-Systems	270182	#1 CW System	2
	Components	7137	#1 CW Travelling Screens East	2
		7138	#1 CW Travelling Screens West	3
		7146	#1 CW Pump East	3
		7147	#1 CW Pump West	3
		7134	#1 CW Intake	2
		7138	#1 CW Discharge to Outfall	2
Unit 1 Boiler System		**6699**		
BU 1296 - Assets Generations	Sub-Systems	6700	#1 Boiler Structure	4
		6701	#1 Boiler F.W. & Sat. Steam	3
		6702	#1 Boiler Superheater and Reheater	3
		6703	#1 Boiler Air System	4
		6704	#1 Boiler Gas System	4
		6705	#1 Boiler Fuel Firing System	4
		6987	#1 Boiler Heavy Oil System	4
		6990	#1 Boiler Light Oil	4
	Components	6869	#1 Economizer, Tubing and Headers	3
		6871	#1 Linking Piping (Boiler Internal)	3
		6871	#1 Furnace Water Circuit	3
		6870	#1 Steam Drum	3
		6871	#1 Downcomers and Feeder Piping	4
		6871	#1 Lower Waterwall Headers	4
		6871	#1 Waterwall Tubing	3
		6871	#1 Upper Waterwall Headers, and Riser Piping	3

Asset Class	Category	Asset No.	Description	Grade
		6873 / 6878	#1 Superheater, Headers, and Tubing	3
		6878	#1 Reheater, Headers and Tubing	3
		6871	#1 Safety Valves	4
		6700	#1 Furnace structural, Hangers and Casing	4
		8777	#1 Boiler FD Fan System	4
		6943	#1 Boiler FD Fan East	4
		6944	#1 Boiler FD Fan West	4
		6954	#1 Boiler Steam Air Heater East	4
		6955	#1 Boiler Steam Air Heater West	4
		6914	#1 Boiler Main Air Heater East	4
		6915	#1 Boiler Main Air Heater West	4
		6917	#1 Boiler Gas Passes	4
		6920	#1 Boiler Sootblowing System	3
		6933	#1 Retractable Sootblowers	3
		6934	#1 Rotary Sootblowers	3
		8789	#1 Air Heater Sootblowers	3
		6988	#1 Boiler Heavy Oil Pump East	4
		6994	#1 Boiler Heavy Oil Pump West	4
		6995	#1 Boiler Heavy Oil Pump Steam, Valves, and Pipe	4
		6998	Boiler Heavy Oil Firing	4
		6999	#1 Boiler Light Oil Pump West	4
		8976	#1 Boiler Light Oil Pump East	4
		8977	#1 Boiler Light Oil Pump West	4
		6979	#1 Boiler Air Supply Seal Air	4
		6982	#1 Boiler Scanner Air System	4
		6919	#1 Boiler Stack	3
		270294	#1 Stack Breeching	4
Unit 1 Condensate & Feedwater System		6708		
BU 1296 - Assets Generations	Sub-Systems	6713	#1 High Pressure Feedwater	4
		6711	#1 Low Pressure Feedwater System	4
	Components	7112	#1 HP Heater 4	4
		7113	#1 HP Heater 5	4
		7114	#1 HP Heater 6	4
		7053	#1 Deaerator System (Deaerator and Deaerator Storage Tank)	4
		7059	#1 LP Heater 1	4
		7066	#1 LP Heater 2	4

5.2 Unit 2

5.2.1 Unit 2 Boiler

The Unit 2 boiler was manufactured by Combustion Engineering (CE) and installed in 1969. This unit is over 50 years old and currently has over 212,000 operating hours. The boiler and its ancillary equipment were previously inspected every year by Alstom and now it is inspected by GE or B&W. Other service providers are also contracted to provide specialized services such as NDTs to support OEMs inspections.

Overall, Hatch found the Unit 2 boiler in good condition. With continued periodic inspections and preventive maintenance as recommended, the Unit 2 boiler is considered suitable for continued use.

5.2.1.1 Boiler Drum

The boiler drum is in good condition. Some minor thermal fatigue and cracks were observed in the steam drum and downcomer nozzles during 2012 inspections. These cracks were inspected yearly, and a 2019 NDT inspection did not show any crack growth. The inspection carried out by GE in 2021 also found no evidence of crack growth.

5.2.1.2 Super Heaters

Earlier inspections identified some cracks near the header outlet nozzles and the secondary super heater outlet tube to header welds, these cracks have been repaired. Inspections carried out in 2019 and 2020 by B&W and by GE in 2021 have found no indications of any further cracks.

5.2.1.3 Reheater

Longitudinal welds on reheater 2 headers were found slightly damaged during the 2015 Phased Array Ultrasonic Testing (PAUT). This area was inspected in 2020 and the inspection confirmed the weld damage did not propagate further. The next inspection is scheduled for 2025.

5.2.1.4 Water Walls

The boiler floor tubes and waterwall tubes showed wall thinning and pitting both on the hot and cold side as reported by B&W during the 2019 inspection. Considering the remaining wall thickness, a plan was put in place to reinspect the hot side tubes in 2021 and cold side tubes in 2025. The hot side area tubes had already been reinspected during 2021 shutdown and no further wall thinning was observed. The cold side tubes are scheduled for reinspection in 2025.

The inspection carried out in 2021 by GE did not identify any further concerns with the damage on the cold side tubes. Therefore, it is recommended to replace the cold side tubes as per schedule.

5.2.1.5 Economizer & Air Heater

Economizer tubes have shown some pitting and wall thinning issues during the 2016 B&W inspection. The wall thickness is, however, found to be within ASME permissible limits.

Fouling of the economizer tubes and air heater baskets was reported during earlier inspections, this fouling was found to be one of the main reasons of unit derating operation until 2018. In 2018, a new chemical cleaning solution was introduced at HTGS. This new cleaning solution was a success and is now performed annually and has significantly reduced the amount of fouling on the economiser tubing and air heater baskets.

5.2.1.6 Forced Draft Fan

The Unit 2 FD fan is reasonably in good condition. The VIV control for fan flow at partial load remained in place but was put out of service due to the introduction of variable frequency drives (VFD). The VFD controls have caused serious operational problems to the boiler unit. A plan is being put in place to decommission the VFD control and put the VIV control back in service. A visual inspection of the VIV wheels and actuators did not show any signs of wear; however, some mechanical linkages may be non-functional due to non-usage and may need replacement.

5.2.1.7 Burners & Soot blowers

There had been cleaning problems with the Unit 2 boiler burners and soot blowers. HTGS management, after discussion with OEMs, implemented an annual cleaning and maintenance program to fix these issues. Considering the condition of burners and soot blowers, Hatch agrees with the recommendation made by GE during the 2021 inspection to overhaul the full burner set and soot blowers.

5.2.1.8 Stack

The stack exterior was last inspected in 2021, deterioration of the coating was observed, and recoating of the stack is necessary.

The stainless-steel liner is approaching the end of its 20-year life and need to be replaced. The Continuous Emission Monitoring System (CEMS) is in good condition. The aviation lights are old and will also need to be replaced.

5.2.2 Unit 2 Steam Turbine

The Unit 2 steam turbine is a GE turbine and is a sister machine to Unit 1 installed in 1970. The turbine is on a nine-year overhaul cycle and the turbine valves are on a three-year overhaul cycle.

The last major turbine overhaul was conducted in 2014 and the most recent valve overhaul was carried out in 2020. It is reported that the turbine vibration monitoring system was upgraded in 2013/2014.

The next scheduled turbine major overhaul is planned for 2023 in the same period as the next inspection on the turbine control valves.

The turbine control valves were the subject of an unplanned troubleshooting investigation and repair in 2019. The details of the incident, the results of the investigation, and the ongoing GE recommendations are reported in the GE Field Service Report - Unit 2 CV Troubleshooting issued in April 2019. With ongoing monitoring and implementation of GE recommendations, there is no concern regarding a recurrence.

5.2.3 Unit 2 Generator

The Unit 2 generator was manufactured by GE and installed in 1970. The generator produces 175 MVA of power at 16 kV and is hydrogen cooled. The most recent major inspection of Unit 2 was carried out in 2020.

A refurbishment of Unit 2 was performed in 2012/2013, however the stator and rotor are original, and the unit has not been rewound. In May 2021, electrical testing was conducted on Unit 2. The tests included:

1. Insulation Resistance Measurement
2. FDS (Frequency Domain Spectroscopy) Measurement
3. PDC (Polarization Depolarization Current) Measurement
4. Power Factor and Capacitance Measurement
5. Partial Discharge Measurement.

The test results show that insulation resistance and polarization index values are adequate for operation for a unit of this age, however, power factor and capacitance values are high and indicate thermal ageing and the presence of partial discharge. Moving forward, this partial discharge should be monitored closely.

The generator shows typical signs of aging. Overall, the generator is in reasonably good condition for its age, but regular inspections and testing are required. It is suggested that the electrical testing carried out in 2021 be repeated on a yearly basis to monitor the unit for any signs of degradation. Regular planned maintenance on the generator and auxiliaries should continue for the life of the generator. Assuming that there are no significant changes in electrical test results, the unit will not require a rewind until beyond 2030.

5.2.4 Unit 2 Condenser

The condenser was inspected in 2014 by Alstom and the report showed that significant damage was reported on the Unit 2 condenser, as a result, Hatch requested testing of condenser tubes using the eddy current method. NLH hired GE to conduct this inspection and Hatch reviewed GE report. Overall, the tube bundles appeared to be in good condition. Minor polishing and steam erosion was noted on the tubes as well as the bowing of isolated tubes. The test results showed tube defects in range of 20% to 50% of the total 280 tubes tested. A total of 381 tubes were mechanically plugged to avoid leakage and one tube was obstructed.

Broken/eroded welds were noted on the bundle supports on cross braces that extend horizontally between the tube support plates of the two bundles. These were noted in previous inspections as not being a significant finding since the braces are welded on both sides as well as the top and bottom. Break down of floor coating was noted in the Northeast, Northwest, and Southwest corners. The bottom welds were found to be adequate.

Erosion shields covering the extraction piping bellows expansion joints appeared to be in adequate condition. The casing expansion joint cover was in adequate condition and secure; however, noticeable signs of erosion/corrosion were observed on the cover with minor separation of attachment welds to the casing.

The details of the test report from the sub-contractor can be found in Appendix C.

5.2.5 Unit 2 Auxiliaries

Key plant auxiliaries are assessed based on the past inspection records available and their assessment status is summarized below.

5.2.5.1 Condenser Vacuum Pumps

Condenser vacuum pumps are overhauled every 12 years. The Unit 2 south side vacuum pump was overhauled in 2018 and the north side is scheduled for overhaul in 2023.

5.2.5.2 Condensate Extraction Pumps

Condensate extraction pumps (CEP) are overhauled every 12 years. The last inspections of the Unit 1 CEPs were carried out in 2014 for the South side and in 2016 for the North side.

5.2.5.3 Boiler Feedwater Pumps

Boiler feedwater pumps (BFPs) are overhauled every 6 years. The east side BFP was inspected and overhauled in 2018 and the west side BFP was overhauled in 2017.

5.2.5.4 Deaerator Shell

The deaerator shell is visually inspected every year and the internals are inspected every 6 years. Unit 2 internals were last inspected in 2019. Cracking is observed in the steam coil inlet connection and is checked every year. NLH does not replace the deaerator internals on a periodic basis but only when needed. The chemical dosing system is manual and dosing rates are manually adjusted based on sample results.

5.2.5.5 Heater Drain Pump

Heater drain pump (HDP) is overhauled every 12 years.

5.2.5.6 Flash Box

The flash Box of Unit 2 is connected to the wall and can be separated. The flash box is inspected every 12 years. The last inspection on the Unit 2 flash box was carried out in 2012. The condition of the flash box was found adequate in this inspection.

5.2.6 Unit 2 Asset Grading

Grades from the asset grading scale in Table 5-1 were assigned to Unit 2 assets as indicated in Table 5-3.

Table 5-3: Unit 2 Asset Grading

Asset Class	Category	Asset No.	Description	Grade
Unit 2 Turbine & Generator		7636		
	Sub-Systems	7753	#2 Generator Assembly	4

Asset Class	Category	Asset No.	Description	Grade
BU 1296 - Assets Generations		7711	#2 Turbine Lubricating Oil System (7719) and Turbine Hydraulic Oil System (7741)	4
		7664	#2 Turbine & Condenser	3
		271317	# 2 Steam turbine	4
	Components	7754	#2 Generator Rotor	4
		7759	#2 Generator Stator	4
		7768	#2 Hydrogen System	4
		7712	#2 Tank & Equipment	4
		7715	#2 Purification	4
		7720	#2 Pump South	4
		7721	#2 Pump North	4
		7725	#2 DC Pump	4
		7743	#2 Hydraulic Oil Pump North	4
		7744	#2 Hydraulic Oil Pump South	4
		271326	#2 Condenser	3
		7638	#2 Main Steam Chest	4
		7643	#2 HP Turbine	4
		7652	#2 IP Turbine	4
		7658	#2 LP Turbine	3
		7671	#2 Front Standard	4
Unit 2 Electrical & Control Systems		8152		
BU 1296 - Assets Generation	Sub-Systems	8152	#2 Electrical System & Controls	3
	Components	7677	#2 Turbine Governor System	4
		8138	#2 Relay Room Protection & Control	4
		8144	#2 Main Controls	2
		8153	#2 Generator Bus-Duct and Connections	4
		8173	#2 Battery Chargers	4
		8174	#2 UPS2 Inverter	4
		8186	#2 Battery Banks	4
		271478	#2 Switchgear 4160V/600V	4
		8162	Power Centre “B” UAB2, (600V)	4
		271479	#2 Turbine Supervisory System	2
		299451	#2 DCS	4
		7677	#2 Turbine Governor System	4
		8139	#2 Burner Management	4
		309898	#2 Boiler Protection & Control	4
Unit 2 Cooling Water System		8093		
BU 1296 - Assets Generations	Sub-Systems	271486	#2 CW System	2
	Components	8097	#2 CW Travelling Screens East	2
		8098	#2 CW Travelling Screens West	2

Asset Class	Category	Asset No.	Description	Grade
		8106	#2 CW Pump East	3
		8107	#2 CW Pump West	3
		8095	#2 CW Intake	2
		8120	#2 CW Discharge to Outfall	2
Unit 2 Boiler System		7786		
BU 1296 - Assets Generations	Sub-Systems	7787	#2 Boiler Structure	4
		7789	#2 Boiler F.W. & Sat. Steam	4
		7810	#2 Boiler Superheater and Reheater	3
		7838	# 2 Boiler Air System	4
		7890	# 2 Boiler Gas System	4
		7912	# 2 Boiler Fuel Firing	4
		7913	#2 Boiler Heavy Oil System	4
		7935	#2 Boiler Light Oil	4
	Components	7790	#2 Economizer, Tubing, and Headers	3
		7789	#2 Linking Piping (Boiler Internal)	3
		7789	#2 Furnace Water Circuit	3
		7794	#2 Steam Drum	3
		7789	#2 Downcomers and Feeder Piping as Required	4
		7789	#2 Lower Waterwall Headers	4
		7789	#2 Waterwall Tubing	3
		7789	#2 Upper Waterwall Headers, and Riser Piping as Required	3
		7811	#2 Superheater; Headers and Tubing	3
		7835	#2 Reheater; Headers and Tubing	3
		7789	#2 Safety Valves	4
		7787	#2 Furnace Structural, Hangers and Casing	4
		88781	#1 Boiler FD Fan System	4
		7843	# 2 Boiler FD Fan East	4
		7844	# 2 Boiler FD Fan West	4
		7855	# 2 Boiler Steam Air Heater East	4
		7856	# 2 Boiler Steam Air Heater West	4
		7883	# 2 Boiler Main Air Heater East	4
		7884	# 2 Boiler Main Air Heater West	4
		7916	#2 Boiler Heavy Oil Pump East	4
		7917	#2 Boiler Heavy Oil Pump West	4
		7920	#2 Boiler Heavy Oil Pump Steam, Valves, and Pipe	4
		7933	#2 Boiler Heavy Oil Firing	4
		8980	#2 Boiler Light Oil Pump East	4
		8981	#2 Boiler Light Oil Pump West	4

Asset Class	Category	Asset No.	Description	Grade
		7882	#2 Boiler Air Supply Seal Air	4
		7885	#2 Boiler Scanner Air System	4
		7900	#2 Boiler Stack	3
		271327	#2 Stack Breeching	4
Unit 2 Condensate & Feed Water System		7976		
BU 1296 - Assets Generations	Sub-Systems	8059	#2 High Pressure Feedwater	4
		7992	#2 Low Pressure Feedwater System	4
		7992	#2 Low pressure Feedwater	4
	Components	8066	#2 H.P. Heater 4	4
		8067	#2 H.P. Heater 5	4
		8068	#2 H.P. Heater 6	4
		8017	#2 Deaerator System (Deaerator and Deaerator Storage Tank)	4
		7997	#2 L.P. Heater 1	4
		7998	#2 L.P. Heater 2	4

5.3 Unit 3

5.3.1 Unit 3 Boiler

The Unit 3 boiler was manufactured by Babcock & Wilcox and installed in 1979. The unit is over 40 years old and currently has over 170,000 operating hours. The boiler and its ancillary equipment are inspected annually by Alstom and then by B&W. Other service providers are also contracted to provide specialist services such as NDT to support OEM inspections.

Overall, Hatch found the Unit 3 boiler in adequate condition. With continued periodic inspections and preventive maintenance as recommended, the Unit 3 boiler is considered suitable for continued use.

5.3.1.1 Boiler Drum

Boiler drum is in good condition with some minor thermal fatigue and cracks observed in the steam drum and downcomer nozzles during the 2012 inspection. Subsequent 2019 and 2020 NDT inspections did not show any further growth of the cracks. The recent (2021) GE inspection did not show any additional cracks or signs of fatigue.

5.3.1.2 Super Heaters

Cracks were observed in 2015 on the secondary super heater header outlet nozzles. These cracks on outlet nozzles were observed again in the 2018 inspection, and it was found that the cracks were not propagating. The inspection carried out by B&W in 2019 did not reveal any further crack growth.

5.3.1.3 Reheater

Welds on reheater headers to nozzles were found damaged during the 2015 Phased Array Ultrasonic Testing (PAUT). This area was inspected again in 2020, the inspection confirmed the weld damage did not propagate further and the next inspection is scheduled for 2025.

5.3.1.4 Water Walls

Some evidence of wall thinning, and pitting was found during the most recent inspections. Annual NDT to monitor the tubes internal conditions is recommended.

5.3.1.5 Economizer & Air Heater

Economizer tubes have shown some pitting and wall thinning issues over the years. The wall thickness is, however, found to be within ASME permissible limits. Some fouling issues were also found in the shell side of the economizer and air heater. This has been reported as one of the main causes of unit derating operation until 2018. In 2018, a new chemical cleaning solution was introduced at HTGS and was a success. This cleaning is now performed annually and has significantly reduced the amount of fouling on the economiser tubing and air heater baskets.

5.3.1.6 Forced Draft Fan

The Unit 3 FD fan is reasonably in good condition. The VIV control for fan flow at partial load remained in place but was put out of service due to the addition of variable frequency drives (VFD). The VFD controls have caused serious operational problems as a result HTSG has now restored the VIV operation.

5.3.1.7 Burners & Soot blowers

There had been cleaning problems with the Unit 3 boiler burners and soot blowers. HTGS management, after discussion with OEMs, implemented an annual cleaning and maintenance program to fix these issues. Considering the condition of burners and soot blowers, Hatch agrees with the recommendation made by GE during the 2021 inspection to overhaul the full burner set and soot blowers.

5.3.1.8 Stack

The stack exterior was last inspected in 2021, deterioration of the coating was observed, and recoating of the stack is necessary.

The stainless-steel liner is approaching the end of its 20-year life and need to be replaced. The Continuous Emission Monitoring System (CEMS) is in good condition. The aviation lights are old and will also need to be replaced.

5.3.2 Unit 3 Steam Turbine

The Unit 3 steam turbine was manufactured by Hitachi and was installed in 1979.

The steam chests have been the subject of ongoing Ultrasonic Testing (UT) inspections during planned outages to monitor cracks found in lower steam chest, identified as Crack A and B. Comparing reported crack sizes from 1999 to 2019 reveals little change in the crack depth dimensions. Some dimensions reported were smaller in the later inspections which can be attributed to improvements in UT process and technology. Two main changes are apparent, the depth of the crack on the generator right hand side has increased in depth from approximately 4 mm to 5 mm, and the depth of the crack on the turbine left hand side has increased from 2 mm to 4 mm and its length from 152.4 mm to 203.2 mm, this change occurred over a 20-year period.

During the recent inspection (2021), there was no change in Crack A from 2019 inspection and Crack B was reported as not accessible.

The inspection records indicated that both cracks had propagated from the 2013/2016 period to 2019. The OEM engineering recommendation in 2019 was to maintain ongoing monitoring of the cracks. Hatch concurs with this recommendation. Hatch also recommends that the OEM or service provider be requested to provide an assessment of the critical crack depth.

The turbine valves were overhauled in 2019.

5.3.3 Unit 3 Generator

Unit 3 generator was manufactured by Hitachi and was installed in 1980. Unit 3's rotor was rewound in 2016 and the stator was rewound in 2021. Having been recently rewound, the operation of the Unit 3 generator should pose no issues to 2030 and beyond.

5.3.4 Unit 3 Condenser

The Unit 3 condenser was inspected in 2014 by Alstom and the report highlighted significant damage, as a result, Hatch requested testing of condenser tubes using eddy current method. A total of 5% of tubes were tested with a focus on areas with higher damage potential. Indication of ID Pitting and corrosion were found throughout the condenser at different tube lengths. The test results showed tube defects up to 50% of tubes tested. Approximately 400 tubes were mechanically plugged to avoid leakage, and some were obstructed.

On the steam side, the tube bundles appeared in good condition. Mineral deposits were noted on the north side of the south LP outlet area. The amount of deposit is not significant enough to be of any concern. Broken and eroded welds were observed throughout. The amount of damage is not to the extent where an immediate repair is required, or operation of the unit needs to be restricted. An annual inspection, however, is to be carried out to check the condition of the condenser structural supports.

Expansion joints and vacuum measuring reference lines were also found extensively eroded and need close observation during future operation.

The details of the test report from the sub-contractor can be found in Appendix C.

5.3.5 Unit 3 Auxiliaries

Key plant auxiliaries are assessed based on the past inspection records available and their assessment status is summarized below.

5.3.5.1 *Condenser Vacuum Pumps*

Condenser Vacuum pumps are inspected every 12 years. Unit 3 vacuum pumps were refurbished in 2021 and no major concern was found.

5.3.5.2 *Condensate Extraction Pumps*

Condensate extraction pumps (CEP) are inspected every 12 years. The last major overhaul of Unit 3 CEPs was carried out in 2015 for both the South and the North side. No major issues were found after this major overhaul.

5.3.5.3 *Boiler Feedwater Pumps*

Boiler Feedwater Pumps (BFPs) are overhauled every 6 years. The west side BFP of Unit 3 was overhauled in 2020 under the regular pump overhaul and was overhauled again in 2021 because of thermal in-service failure. The east side BFP for Unit 3 was overhauled in 2021 as per routine overhaul.

5.3.5.4 *Deaerator Shell*

The deaerator Shell is visually inspected every year and internals are inspected every 6 years. Unit 3 internals were last inspected in 2020. Cracking was observed in the steam coil inlet connection and is checked every year. NLH does not replace the deaerator internals on a periodic basis, they are replaced as needed.

5.3.5.5 *Heater Drain Pump*

Heater drain pump (HDP) is overhauled every 12 years.

5.3.5.6 *Flash Box*

The flash Box of Unit 3 is rigidly connected to the condenser and cannot be separated. The flash box is inspected every 12 years. The last inspection on Unit 3 flash box was carried out in 2013 and it was found to be in adequate condition.

5.3.6 ***Unit 3 Asset Grading***

Grades from the asset grading scale in Table 5-1 were assigned to Unit 3 assets as indicated in Table 5-4.

Table 5-4: Unit 3 Asset Grading

Asset Class	Category	Asset No.	Description	Grade
Unit 3 Turbine & Generator		8194		
BU 1296 - Assets Generations	Sub-Systems	8298	#3 Generator Assembly	4
	Sub-Systems	8223	# 3 Turbine & Condenser	4
	Sub-Systems	271675	#3 Steam turbine	
		8270	Turbine Oil Systems - #3 Turbine Lubricating Oil (8275) and Jacking Oil Systems (8294)	4
	Components	8299	#3 Generator Rotor	4
		8304	#3 Generator Stator	4
		8313	#3 Hydrogen System	4
		8326	#3 Synchronous Condensing System	4

Asset Class	Category	Asset No.	Description	Grade
		8271	Tank & Equipment	4
		8274	Purification	4
		8276	Flushing Oil Pump	4
		8277	AC Pump South	4
		8281	DC Pump	4
		8546	Aux Oil Pump	4
		8285	Jacking Oil Pump	4
		271677	#3 Condenser	4
		8196	Main Steam Chest	3
		8201	HP Turbine	3
		8211	IP Turbine	3
		8217	LP Turbine	3
		8230	Front Standard	4
Unit 3 Electrical & Control Systems		8712		
BU 1296 - Assets Generation	Sub-Systems	8712	#3 Electrical Systems & Control	4
	Components	8698	Unit 3 Relay Room Protection & Control	4
		8704	Unit 3, Main Controls	2
		8713	Unit 3, Generator Bus-Duct and Connections	4
		8750	Unit 3, Battery Chargers	4
		8751	Unit 3, UPS3 Inverter	4
		8757	Unit 3, UPS4 Inverter	4
		8763	Unit 3, Battery Banks	4
		271766	Unit 3 Switchgear, 4160V/600V	4
		271767	Unit 3, Turbine Supervisory System	2
		301711	Unit 3 DCS	4
		271769	Unit 3 Static Exciter	4
		7197	Common, Stage 1, 129VDC Supply System	4
		271764	Common, Control Cables	4
		271765	Common, Control Cables	4
		309896	Common 600V Metric Plugs	4
		8699	#3 Burner Management	4
		309901	#3 Boiler Protection and Control	4
		8238	#3 Turbine Governor System	4
Unit 3 Cooling Water System		8645		
BU 1296 - Assets Generations	Sub-Systems	271678	#3 CW System	2
		8691	#3 T/gen Water Cooling	3
		8291	#3 Gen Service Cooling	3
	Components	8649	#3 CW Travelling Screens East	2
		8650	#3 CW Travelling Screens West	2
		8658	#3 CW Pump East	3

Asset Class	Category	Asset No.	Description	Grade
		8659	#3 CW Pump West	3
		8647	#3 CW Intake	2
		8676	#3 CW Discharge to Outfall	2
Unit 3 Boiler System		8336		
BU 1296 - Assets Generations	Sub-Systems	8337	#3 Boiler Structure	4
		8339	#3 Boiler F.W. & Sat. Steam	4
		8359	#3 Boiler Superheats Reheat	4
		8387	# 3 Boiler Air System	4
		8437	# 3 Boiler Gas System	4
		8460	# 3 Boiler Fuel Firing System	4
	Components	8340	Economizer, Tubing, and Headers	3
		8339	Linking Piping (Boiler Internals)	3
		8351	Furnace Water Circuit	3
		8344	Steam Drum	3
		8351	Downcomers and Feeder Piping as Required	4
		8351	Lower Waterwall Headers	4
		8351	Waterwall Tubing	3
		8351	Upper Waterwall Headers, and Riser Piping as Required	3
		8360	Superheater; Headers and Tubing	4
		8384	Reheater; Headers and Tubing	3
			Safety Valves	4
		8460	Furnace Combustion Systems; Burners, Fans, Air Heaters	4
		8337	Furnace Structural, Hangers and Casing	4
		8782	#3 Boiler FD Fan System	4
		8392	#3 Boiler FD Fan East	4
		8393	#3 Boiler FD Fan West	4
		8404	# 3Boiler Steam Air Heater East	4
		8405	# 3 Boiler Steam Air Heater West	4
		8410	# 3 Boiler Main Air Heater East	4
		8411	# 3 Boiler Main Air Heater West	4
		8438	# 3 Boiler Gas Passes	4
		8452	# 3 Boiler Sootblowing System	3
		8455	# 3 Retractable Sootblowers	3
		8791	# 3 Air Heater Sootblowers	3
		253030	# 3 Boiler Waterlances	4
		8448	#3 Boiler Stack	3
		271682	Stack Breeching	4
Unit 3 Condensate & Feed Water System		8528		
	Sub-Systems	8611	#3 High Pressure Feedwater	4

Asset Class	Category	Asset No.	Description	Grade
BU 1296 - Assets Generations		8546	#3 Low Pressure Feedwater	4
		8546	#3 Low Pressure Feedwater	4
		8801	#3 Condensate Extraction (Tables Only)	4
	Components	8818	#3 H.P. Heater 4	4
		8819	#3 H.P. Heater 5	4
		8820	#3 H.P. Heater 6	4
		8848	#3 Boiler Feed Pump East	4
		8849	#3 Boiler Feed Pump West	4
		8571	#3 Deaerator System (Deaerator and Deaerator Storage Tank)	4
		8551	#3 L.P. Heater 1	4
		8552	#3 L.P. Heater 2	4
		8586	#3 LP FW Reserve	4

5.4 Common Balance of Plant

5.4.1 Compressed Air

Compressor #1 was replaced in 2014/2015 and Compressor #2 was replaced in 2016.

Figure 5-1: Air Compressors

As required by government regulations, annual inspections are conducted on the service air pressure vessels and instrument air pressure vessels. Annual maintenance is also carried out on the instrument air filtration and drying systems. The annual inspection reports did not show any indications of significant degradation or regulatory/maintenance issues.

For a continued operation of HTGS or to be used a backup facility, Hatch envisions no additional work on top of the regular inspections and planned maintenance. Based on Hatch's assessment for the life extension, it is recommended that the current regular inspections, PMs, and maintenance systems continue to be implemented and no additional Level II inspections were identified or required. No capital works were identified or required at this time, although beyond 2023 it is possible that annual inspections may identify requirements for a receiver replacement or refurbishment considering the age of the pressure vessels and this should be considered in the capital budget planning.

5.4.2 *Water Treatment Plant (WTP)*

The water treatment plant supplies Units 1, 2, and 3 with demineralized water. This asset includes a clarifier system, flocculent chemical injection, sand filter, clear well system, sulfuric acid system, caustic system, brine system, and a mixed bed demineralized water production system. The Quarry Brook dam provides the fresh water for the WTP via a supply pipeline delivering freshwater from the dam to the pumphouse. Following the pumphouse, the water enters the raw water sump and is then pumped to the clarifier.

Another raw water supply line was added to the WTP in 2018, as reported in the 2020 Condition Assessment. As a result of this addition, this plant was no longer a single contingency failure asset, thus, increasing reliability. Other upgrades include improvements to the underground drainage system in 2017 and the domestic water supply line in 2018.

Following Hatch's condition assessment in 2021, it was found that regular PM work, inspections, and maintenance are done on this asset and that no additional replacements have been made since those reported in 2018 and earlier.

During Hatch's Condition Assessment in 2021, no notable issues with the water treatment system were observed, however, a detailed assessment of the water treatment plant was not part of this study's scope.

5.4.3 *Oily Water Separator*

The oily water separator, which consists of five oily water separation tanks, separates oil from the wastewater entering the basin ponds. The oily water tanks are passive, buried tanks installed in 1991. NLH advises that in 2017 there were major upgrades performed to the underground drainage system which included:

- Replacement of the underground drainage system on the North side of the plant.
- Installation of new (replacement) oil water separator tanks (No. 3 and 4) on the North side of the plant.
- Addition of isolation valves on the discharge side of oil water separator tanks (No. 1 and 2) located on the South side of the plant.

- Installation of a new section of outfall pipe from oil water separator tank 1.

The above works were performed to address recommendations made during several inspections leading up to 2017, which included inspections of the underground drainage lines, inspection of the cathodic protection, and inspection of a portion of the oily water separator.

No specific maintenance history was available for the oily water separator.

As per the 2020 condition assessment, it was indicated that the North tanks were inspected and replaced six years ago, and they are relatively new.

It is noted that the status of south tanks is uncertain due to the lack of inspection information available, therefore, a Level II inspection is recommended for south tanks.

A detailed assessment of the oily water separator is not part of this study's scope. The above assessment and recommendations were made based on the previous inspection reports provided by NLH to Hatch.

5.4.4 Black Start Diesel Generators

Black start and plant emergency power is provided to HTGS by 6 containerized Caterpillar (CAT) 3516B (mobile package XQ 2000 type) gensets each with a standby rating of 2 MW (or 1.825 MW prime) and a combined capacity of 12 MW. The units were initially leased by HTGS in 2015 and later purchased and fitted with permanent stacks in 2018 to reduce the impingement of exhaust on the surrounding facilities. Each generator enclosure contains a dedicated 1250 gal. (5682 L) fuel day tank and a transfer pump which draws fuel from a common 90,000 L main fuel tank installed adjacent to the black start diesel generators. Dedicated step-up transformers are installed outdoors for each black start diesel generator.

There is also a 635 kW CAT H-6-1F emergency genset located in the main powerhouse, which was installed in 2007 to replace the original genset in this area. Gensets from either location are designed to facilitate a safe shutdown of Unit 1, 2, and 3 in the event of a loss of power and plant wide trip.

Figure 5-2: HTGS Black Start Emergency Gensets

Figure 5-3: Emergency Genset in Powerhouse

The CAT 3516B gensets installed for the black start and emergency power services at HTGS are a common model which is well supported by the OEM in the province through the local dealer and service company Toromont.

Based on discussions with operators, only 5 of the 6 black start diesel generators are required to facilitate the black start of the HTGS facility. Thus, the installation is a N+1 design where one generator is available as a spare. The black start diesel generators are each tested at load weekly.

To maintain diesel generators of this type, an engine hours-based manufacturer specified maintenance program is required. Engine starts, cranks, and running hours data recorded by NLH operators on March 1st, 2022, for the black start diesel genset engine hours are summarized in the table below.

Table 5-5: Black Start Diesel Genset Engine Hours

Genset No.	Genset Starts	Engine Cranks	Engine Hours
1	223	245	178.9
2	401	425	485.7
3	351	365	447.5
4	347	370	391.0
5	408	439	431.4
6	350	432	294.4

As presented in Table 5-5, each black start diesel generator has less than 500 running hours. For diesel reciprocating engine generators of this type, in prime and continuous power applications, major overhauls are typically required at 8,000 hours when the engine would be due for a top end rebuild. For generators in emergency standby applications, some major service can be due as early as 500 hours due to the nature of automatic fast starting and type of engine loading. Based on discussions with the NLH operators and the method in which the black start generators are started and loaded Hatch does not view the service intervals of emergency standby operation to apply. Therefore, the black start diesel gensets are not considered to be due for any major service during the remaining life of HTGS based on their intended use. The engines are kept in hot standby using heaters and electric coolant circulation pumps which reduce the wear effects of fast starts.

Hatch reviewed maintenance records for the black start diesel generators that were provided from 2019 to 2022. The maintenance records included normal minor maintenance activities, generator megger tests, and the replacement of components due to age related deterioration, such as cooling hoses and rubber couplings which can become embrittled due to age. The maintenance records show a regular maintenance program in place being performed by local Toromont service technicians to ensure reliable operation.

The following observations were made during the assessment of the black start diesel generators, including recommended works for the life extension of HTGS:

1. Cables connecting the black start diesel generators to their step-up transformers and other services are run on the ground and sitting on the gravel under the genset enclosure, which is more typical of a temporary installation. For permanent installation, cables should be routed in cable trays or cable trenches.
2. Walkways over cables between the black start diesel generators and their step-up transformers were facilitated with stacked wood and plywood. These walkways / crossings should be improved for a permanent installation. There are modular cable trench sections with trench covers available that could be considered.
3. Rust and deterioration of the enclosures were noticed, and some water was seen to be present on the floor in some of the enclosures. Maintenance on the enclosures should be considered.

The above observations are shown below in the following photos:

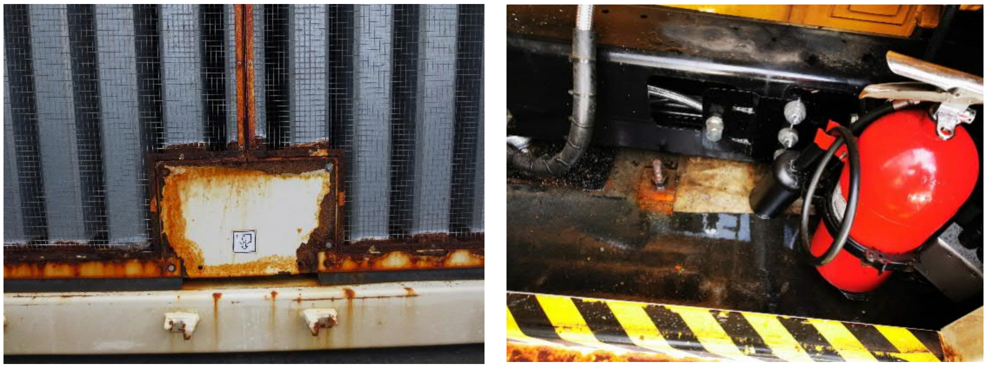

Figure 5-4: Black Start Diesel Generators Cable Connections to Transformers and Enclosures

The implementation of the noted improvements and suggested maintenance will protect the installation and improve safety for this asset which is critical to starting the HTGS in the event of a loss of power.

5.4.5 Balance of Plant (BOP) Asset Grading

Grades from the asset grading scale in Table 5-1 were assigned to BOP assets as indicated in Table 5-6.

Table 5-6: BOP Asset Grading

Asset Class	Category	Asset No.	Description	Grade
Power Center and Excitation Transformers				
BU 1325 – Assets Holyrood Switchyard	Components	5975	Unit 1, T1 Power Transformer	4
		5978	Unit 2, T2 Power Transformer (Newly Replaced with T4 spare transformer)	5
		5977	Unit 3 T3 Power Transformer	4
		5979	Transformer T5	4
		5980	Transformer T6	4
		5981	Transformer T7	4
		5982	Transformer T8	4
		5983	Transformer T9	4
		5984	Transformer T10	4
		6726	Unit 1 Service Power System, UST-1 Transformer	4
		8156	Unit 2 Service Power System, UST-2 Transformer	4
		8716	Unit 3, Unit Service Power System, UST-3 Transformer	4
		6727	Common, Stage 1, Station Service Power. SST-12 Trans	4
		5989	Common, Stage 2, Station Service Power, SST-34 Trans	4

Asset Class	Category	Asset No.	Description	Grade
BU 1296 – Assets Generation	Components	271311	RT1, Unit 1 Rectifying Transformer	4
		271324	RT2, Unit 2 Rectifying Transformer	4
		271680	RT3, Unit 3 Rectifying Transformer	4
Common Electrical and Control Assets		**7199 (**Common Systems**)**		
BU 1297 - Assets Commons	Components	6904	Common, Computers Foxboro	4
		7189	Common, Switchgear 4160V/600V (SB12)	4
		7190	Common, Diesel Bus, DB12	4
		7192	Power Centre C (SAB12, Diesel Bus DB12)	4
		7197	Common, Stage 1, 129VDC Supply System	4
		n/a	Common, Control Cables	4
		n/a	Common, Power Cables	4
		n/a	Common 600V Metric Plugs	4
Buildings and Building M and E System		**7255**		
BU 1297 - Assets Common	Sub-Systems	272255	Buildings	4
	Components	7283	Main Powerhouse	4
		7285	Stage 1 Pumphouse	4
		7286	Stage 2 Pumphouse	4
		7284	Training Centre	4
		7287	Guardhouse	4
		7288	H2 and CO2 Storage Building	4
		7302	Shawmont Building	4
		7303	Main Warehouse	4
		7307	Gas Turbine Building	4
		n/a	Six 2 MW Diesel Generators (Emergency/Black Start)	4
		n/a	One Siemens 120 MW Simple Cycle Gas Turbine Generator	4
Hydrogen and Carbon Dioxide Supply Systems		7199 (Common Systems)		
BU 1297 - Assets Commons	Sub-Systems	7205	Compressed Air Systems	4
	Components	7236	Hydrogen Storage & Supply	4
		7237	Carbon Dioxide Storage & Supply	4
Compressed Air		7199 (Common Systems)		
BU 1297 - Assets Commons	Sub-Systems	7205	Compressed Air Systems	4
	Components	7231	Compressors	4
		7234	Compressed Air Dryers Systems	4
		7235	Compressed Air Receivers	4
Fuel Systems (Light and Heavy Oil)		7199 (Common Systems)		
	Sub-Systems	7204	Heavy Oil & Fuel Additive	4

Asset Class	Category	Asset No.	Description	Grade
BU 1297 - Assets Commons		7209	Light Oil System	4
	Components	7223	Heavy oil Transfer to Storage	4
		7224	Heavy Oil Storage & Piping	4
		271814	Tank Farm Dykes & Liners	4
Wastewater Treatment Plant (WWTP)		9739		
BU 1297 - Assets Common	Sub-Systems	10038	Wastewater Treatment Plant	4
		272255	Buildings	4
	Components	286057	Wastewater Treatment Plant Systems	4
		7263	Oil/Water Separators	4
		7304	Wastewater Treatment Plant Building	4
		7305	Wastewater Treatment Basins Building	4
Water Treatment Plant (WTP) System		**9739** (Wastewater Treatment & Environment)		
BU 1297 - Assets Common	Sub-Systems	7203	Water Treatment Plant	4
			Waste Water Treatment Plant (WWTP) Equalization Basin Building*	1
	Components	286057	Water Treatment Plant Systems	4
		6802	WTP Brine System	4
		7185	WTP & MCC C5	4
		7212	WTP Sulphuric Acid System	4
		7213	WTP Flocculent Chem Injection	4
		7214	WTP Primary Train	4
		7220	WTP Mixed Bed	4
		7410	WT MCC C10	4
		7422	WTP Clarifier System	4
		8748	WTP & Aux Boiler MCC WTP-34	4
		9864	WTP Sand Filter	4
		9879	WTP Clearwell System	4
		9995	6400 Chem Injection	4
		10037	WTP Caustic System	4
Diesel Gensets		**7199**		
BU 1297 Assets Common Gas Turbine	Sub-Systems	6717	Auxiliary Diesel Generator	4
Heavy Oil & Fuel Additive Systems		**7204**		
-	Sub-Systems	7224	Heavy Oil Storage & Piping	3
	Components	7439	Heavy Oil Day Tank	3
		7441	Heavy OI - #1 Tank	3
		7442	Heavy Oil - #2 Tank	3

Asset Class	Category	Asset No.	Description	Grade
		7443	Heavy Ol - #3 Tank	3
		7444	Heavy Oil - #4 Tank	3
Marine Terminal Structure		**7133**		
-	Components	393825	Gravity Fenders	3
		99000019	Cathodic Protection for the Dock	3
		-	Jetty Pilings	3
Fire Water System		**7251**		
-		299429	Fire Suspension System	3
		-	Fire Hydrants	3

*Note that the Wastewater Treatment Plant (WWTP) Equalization Basin Building was not part of Hatch's scope. The graded assessment was based on information contained in earlier condition assessment reports and supported by information from NLH. NLH indicated a capital project is in place for 2022 to improve the condition of this asset.

5.5 Piping

5.5.1 *Main Steam and Reheat Steam*

The main steam and reheat steam piping and supports are inspected as per American Society of Mechanical Engineers (ASME) guidelines. Review of annual inspection records of the last 5 years confirm the stresses in the piping hangers are within permissible limits. The review found that support hangers (MS8-1 & 2) were added to the main steam piping following changes to piping system and stress analysis by third party contractor.

Following Hatch's condition assessment in 2021, it was found that regular inspections, and maintenance are done on this asset. No risks have been identified with continued operation of these piping systems if the current regular inspection, and maintenance continue to be implemented.

5.5.2 *Condensate and Feedwater*

The condensate and feedwater piping and supports are inspected as per ASME guidelines. Following Hatch's condition assessment in 2021, it was found that regular inspections, and maintenance are done on this asset. No risks have been identified with continued operation of these piping systems if the current regular inspection, and maintenance continue to be implemented.

5.5.3 *Blowdown*

Blowdown piping is not considered to be high energy piping and is not critical for this inspection. However, Hatch visually inspected the condition of the blowdown pipes, particularly those next to flash tanks, and found them to be adequate for continued operation.

5.5.4 *Heavy Fuel Oil Line*

The review of fuel oil piping during this study was limited to viewing systems during general site visits, and the review of HOIT (Historical Operating, Inspection and Test) data. Hatch conducted a walk down of the fuel tank farm and Jetty, day fuel tank area, and HFO fuel heater and pump areas within the HTGS powerhouse and discussed the recent maintenance history of the fuel piping systems with NLH.

Major large bore heavy fuel oil piping includes the 18-inch fuel unloading line from the fuel unloading jetty to the fuel tank farm, and a supply header from the 4 main heavy fuel oil storage tanks to the day tanks. There is also a 2.5-inch fuel pump out line from the jetty to the onshore piping that is used to drain the 18-inch unloading pipeline such that the pipeline section on the wharf is not filled with fuel when not in use. There is a quick closing nitrogen actuated valve that is pressurized in the open position during fuel offloading on the 18-inch line. If there is an event during offloading, the valve can be quickly closed to mitigate the environmental risk of a spill. The original 4-inch line, heat tracing, and insulation was replaced in 2019 with a smaller 2.5-inch line. This reduces the amount of oil stored over water between tanker offloads and a breakaway flange was installed between the pump out line connection into the 18-inch line near the shore arm 18-inch shut off valve. This will reduce the potential spill volume of a fuel release to the environment, particularly during the winter season in case an iceberg comes into contact with the jetty, and where the unloading pipeline is routed near to a public walking trail system (the Trailway) where there is public access. The breakaway flange and a concrete anchor block on the 18-inch line located just after the shore arm has been designed as a break point to separate the piping onshore from the piping on the jetty which is over the water.

During our review significant deterioration of pipe supports on the HFO pipeline header, which transfers fuel from the main tanks to the day tank by gravity feed, was identified. Evidence of previous patching works on this section of piping was also identified and NLH noted that leaks had developed previously and platework had been welded on to the affected areas to return the pipeline to service.

Figure 5-5: HTGS Tank Farm HFO Piping Observations

NLH advised that the pipe support issues had been noted previously and plans are being developed to replace and refurbish the affected supports. It is evident that this exterior piping system has been subject to greater deterioration than other areas of the plant, which is typical of outdoor piping and pipe supports subject to coastal climates. To ensure reliable operation, the deteriorated pipe supports at minimum will require replacement, and this system will require additional focus and monitoring under the HTGS piping inspection and maintenance program. It is noted that the failure occurred at a welded pipe shoe location where the pipe is subject to both support loads and residual stress from welding the pipe shoe.

Hatch recommends the following to prevent future pipe failures and ensure the necessary reliability of the HFO fuel distribution system for HTGS:

- Implement a fuel oil piping inspection and maintenance program in the far tank area with additional focus on wall thickness measurements in the areas of pipe supports. Consider increasing frequency of assessment in these areas where pipe walls are subject to additional point loads from supports.
- Where risk areas may be identified, increase resolution of the wall thickness measurement grid, and install welded plate reinforcement where needed in advance of running to failure.
- In the event cracked welds are discovered at support lugs and support saddles, they should not be welded again unless absolutely necessary. Pipe clamps and clamped pipe shoes should be used whenever possible as per industry standards to minimize welding of lugs, pipe shoes, and saddles to piping.
- Replace deteriorated pipe supports and ensure piping is properly supported to avoid load increases on individual supports. The pipe support replacements should be based on an engineering study of the piping system as a whole and its natural movements due to frost heave and thermal expansion etc.

The above actions will reduce the risk of future pipe failure. While the majority of the piping system is enclosed in a contained area to prevent the environmental impacts of a fuel spill, future failures would impact the reliability and availability of HTGS where they would affect the ability of HTGS to transfer HFO fuel from the main storage to the day tank.

5.5.5 Firewater Services

The exterior firewater service system consists of a 10inch ductile iron (Class 52) header pipe, with 26 hydrants surrounding the exterior of the thermal plant, support buildings, and fuel tank farm. The marine jetty terminal and pipeline from the jetty terminal to the fuel tank farm does not have fire protection. The Holyrood Generating Station Fire Protection System Schematic is shown on drawing A1-238004-0170-016 Rev 6. The current revision does not include the four hydrants installed around the Combustion Turbine (CT) Building and the four hydrants near the Diesel Pump House. During the inspection campaign hydrant H was isolated for nearby maintenance, so limited testing was conducted on this hydrant.

Fresh water is supplied from the nearby Quarry Brook and is pumped into the system by a diesel, electric, and jockey pump located in Pumphouse #1. Hatch oversaw static pressure testing, borescopic testing, and acoustic testing of the 26 hydrants on site.

The ROV inspection of the buried firewater piping was removed from the original inspection scope based on discussions with NLH representatives. During initial discussions, NLH representatives decided not to introduce a break in the firewater line to grant access for inspection so that the current integrity of the line would be maintained. Based on historical operating conditions and previous firewater line failures, NLH acknowledged they will be recommending upgrades to the firewater line as part of capital works projects for their 2022-2023 budget. Should NLH proceed with extending the life of the plant, the firewater line surrounding the tank farm should also be included in the 2022-2023 upgrade.

The firewater hydrant inspection was sub-contracted to Afonso Group Limited. A summary of their scope of work, methodology and results are noted in Appendix D. During the inspection and testing campaign, 6 of 26 hydrants failed to pass inspection: A, D, E, F, G, and P. Furthermore, 9 hydrants failed to properly drain water. These hydrants would need additional investigation to determine the cause of improper draining. Detailed comments and recommendations for each hydrant are noted in Appendix D. During the static pressure testing, the hydrants measured a range of 75 psi to 125 psi. Please see Appendix D for a detailed listed of static pressure results for each hydrant. During the inspection campaign, the emergency response team were assessing significant leakage at the electric firewater pump. This likely contributed to the lower static pressure results seen on August 24 – August 25, 2021. Static pressure testing results from the 2020 Tyco Hydrant testing campaign ranged from 90-117 psi. During two static hydrant tests, the hydrant static pressure test was read when a hydrant on the far side of the plant was fully flowing. This was to assess if the static pressure test was affected when there was a demand on the system. The static pressure at Hydrant E was determined to be 120 psi when Hydrant L was fully open flowing at a rate of 650 GPM. The static pressure at Hydrant L was determined to be 90 psi when Hydrant E was fully open flowing at a rate of 1130 GPM.

Acoustic hydrophone testing was conducted on each of the 26 hydrants/isolation valves. Based on the measured readings, there is potential for four hydrant leaks at A, B, G, and Southeast of CT building. It is believed that there is a low probability of leaks at these hydrants, and that the reading can likely be attributed to ambient noise from the surrounding equipment. NLH indicated that past leaks were quickly identified by the presence of significant surface flooding. Flooding was not identified at these locations. In attempt to determine if there were localized leaks present in the line, acoustic correlator testing was attempted at several locations around the firewater line. The correlator testing was unsuccessful due to interference from nearby equipment and ongoing maintenance operations. Regardless of localized acoustic correlator testing, any leaks present would have been seen at the surface at the hydrant locations.

Borescopic testing was conducted on each of the twenty-six hydrants. In general, the hydrants appeared to be in good condition but exhibit typical scale buildup. Hydrants A, B, C, D, E, F, GG, and NE of the CT Building did not fully drain. There is a (previously known) crack in Hydrant G Stem (south side), and the stem on hydrant J is showing signs of wear. Hydrant P and Q did not undergo borescopic testing as they are no longer maintained. Video files for each Hydrant are available for review.

NLH has recommended that portions of exterior firewater piping be replaced due to past failures in the line. It is also recommended that annual static pressure testing be conducted to verify the system can meet the demand requirements.

5.5.6 Auxiliary Steam and Other

The review of auxiliary steam system and other piping during this study was limited to viewing systems during general site visits, and the review of HOIT data. The auxiliary steam system is essential to providing heating to the HTGS powerhouse, offices, and other buildings and to the HFO storage and distribution facility where steam heat trace must be supplied to HFO fuel piping, and the tank suction heaters.

During our site visits to HTGS, Hatch viewed the auxiliary steam distribution system in the tank farm area and observed a section with insulation removed as depicted below in the photo.

Figure 5-6: Auxiliary Steam Line in Tank Farm Facility Observed with Insulation Removed

Previous condition assessment reports indicate an inspection by TEAM Industrial Services was completed in 2017 which identified significant corrosion on certain sections of this system in the tank farm area.

It is evident that this exterior piping system has been subject to greater deterioration than other areas of the plant, which is typical of outdoor piping and pipe supports in coastal climates. To ensure reliable operation, this system will require additional focus and monitoring under the HTGS piping inspection and maintenance program. To perform reliable wall thickness measurements, the areas of concern will need to be exposed by removing the jacket and insulation, and then be cleaned of corrosion. This is because a lot of corrosion under insulation (CUI) issues cannot be inspected without removal of the jacket and insulation.

HTGS should continue with their inspection program while considering increased frequency and resolution in areas of concern within the auxiliary steam system, such as in the tank farm area. Budget should be considered for potential repairs in Capital Budget Planning subject to the findings of ongoing wall thickness measurements and inspections.

5.6 Electrical Systems

5.6.1 UPS Systems

Unit 1, 258 V DC Battery Charger was installed in 2019. The charger has 600 V input, with 258 V DC output and is rated at a maximum output of 105 A.

Unit 2, 258 V DC Battery Charger was installed in 2019. The charger has 600 V input, with 258 V DC output and is rated at a maximum output of 105 A.

Unit 3, 258 V DC Battery Charger was installed in 2019. The charger has 600 V input, with 258 V DC output and is rated at a maximum output of 105 A.

Units 1/2, 129 V DC Battery Charger #1, was installed in 2006. The charger has a 575 V input, with 129 V DC output and is rated at a maximum output of 60 A.

Units 1/2, 129 V DC Battery Charger #2, was installed in 2010. The charger has a 575 V input, with 129 V DC output and is rated at a maximum output of 60 A.

Unit 3, 129 V DC Battery Chargers, were installed in 2011. The chargers have a 600 V input, with 129 V DC output and is rated at a maximum output of 60 A.

Unit 1 and Unit 2, 258 V DC Battery Banks were replaced in 2019.

Unit 3, 258 V DC Battery Bank was replaced in 2018.

129 V DC Battery Bank #1 was replaced in 2006.

129 V DC Battery Bank #2 was replaced in 2017.

Unit 1, Inverter UPS1 was installed in 1997. Unit 2, Inverter UPS2 was installed in 1998.

Unit 3 Inverters UPS3 and UPS 4 were scheduled for replacement in 2020.

Overall, the plant UPS system is in good condition with no major issues preventing it from operating to 2030 and beyond. The Unit 1/2 129 V DC battery chargers should be considered for replacement, having been installed in 2006 and nearing the end of their twenty-year useful life. The 129 V DC battery bank #1 should be considered for replacement, being installed in 2006 and having exceeded its fifteen-year useful life. Additionally, the Unit 1 and Unit 2 inverters should be considered for replacement, being installed in 1998 and having exceeded their twenty-year useful life.

5.6.2 Unit 1, 2, and 3 Main Distributed Control Systems (DCS)

Main Controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments, and an alarm annunciation. Modifications were made to adapt the generator, turbine, and boiler controls to the Distributed Control System (DCS), and some of the original controls, indications, and annunciation systems were replaced.

The main DCS was manufactured by Foxboro and is an Invensys system which was installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990’s, and new cabling installed at that time. The original system was hard-wired, but later updated to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004.

The process CPU → ZCP is set-up in the original enclosures (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following systems and programs being used are:

1. IA series – Version 8.4.2.

2. IACC, Version 2.3.1 (Configuration Program).
3. FoxView Version 10.2. Sept. 30, 2008 (Graphics Program).

There have been no major changes to the inspection and repair history of these systems since the 2017 and 2019 update Reports.

The main Foxboro DCS systems are in fair condition. Nothing changed since the 2019 Condition Assessment and 2017 update report work.

Foxboro has adopted five-tiered product lifecycle phases: **Preferred, Available, Mature, Lifetime, and Obsolete**. This phased lifecycle approach has been applied to the hardware and software products that comprise Foxboro system and solutions. Based on this:

- The Foxboro main DCS Control Processors FCP270 and ZCP270 are in **Mature Phase** until 2023, during this phase the product begins to be withdrawn from sale, and no more enhancements are provided. Before the product is withdrawn, the manufacturer is committed to ensure that a comprehensive, clearly defined support program is firmly in place.
- The Foxboro DCS Control Processors will start their **Lifetime Phase** in 2023. In this phase, products will be supported on a best-efforts basis for as long as the manufacturer can provide a quality repair or replacement. Most products transition to Lifetime Phase, while others may move directly to the Obsolete Phase sometime after Jan 2025 because, at some point, the manufacturer will no longer be able to repair or replace it. If the products are registered with Foxboro, the client will receive a Notification when the products reach their exact Obsolete date.
- Fieldbus Communication Modules FCM100ET are in **Mature Phase** and transitioning to **Lifetime Phase** in 2028.
- The FBM 200 family I/O modules are in **Preferred Phase**, which is considered ideal because Standard Hardware and Software products are currently available in their functional category. Products in this category are actively being promoted, enhanced, produced, and sold by the manufacturer.
- Most of the Plug-In Foxboro EVO DCS FBM modules, that provides migration from Westinghouse WDPF system, are in **Preferred Phase**. Although, some of them such as RTD (WRT03A-B), Digital Output (WTO09A, WRO09B), Analog Input (WAW01C), Digital Input (WID07G), Pulse Input (WPA06A), and Communication (FCM100Et) modules are already in **Mature Phase**.

With respect to actions that need to be taken, it is advised to maintain the existing systems with no major changes; supplement spares and secure ongoing maintenance agreements with DCS OEMs as much as possible. Evaluations should be followed given the remaining life.

After research, review, and study of the information obtained during the inspection and from the manufacturer, we recommend upgrading Foxboro DCS controllers, related communication, and Plug-In Foxboro EVO DCS FBM I/O modules before they approach Obsolete Phase expected in January 2025. A new assessment will be required close to that date to confirm the exact date of obsolescence by the manufacturer.

Recommendations with respect to the DCS Processor Upgrade Option are as follows:

- A fault-tolerant FCP280 may replace a fault-tolerant FCP270 or ZCP270. It may import the CP database from the CP270 it is replacing, for compatibility and minimal configuration time.
- The FCP280 provides an increase in performance and block processing capacity over the CP270s. When replacing FCP270s, the FCP280 eliminates the need for FEM100 expansion module hardware. For ease of replacement, the fault-tolerant or non-fault-tolerant FCP280 in its baseplate has the same dimensions as the fault-tolerant or non-fault-tolerant FCP270 in its baseplate. Refer to FCP280 Control Processor 280 User Manual: PSS 31H-1B11 B3.

5.6.3 Unit 1, 2, and 3 Turbine GE SpeedTronic Mark V System Controls

The electronic speed governor, GE SpeedTronic Mark V, manufactured by General Electric was installed in 1999. The governor is complete with protection and monitors speed, metal temperatures, vibration, and steam valve positions in the turbine. An HMI for operator use is provided in the control room.

The Turbine Supervisory System was manufactured by Bently Nevada and installed in 1994. It is a type 3300 System, c/w TDXnet Transient Data Interface and Delta Manager. Functionality of the Bently Nevada System has been transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevada and is transferred via a DDX link in the instrument shop. Machine protection is provided by the Mark V using information from the Bentley Nevada, and is part of the unit mechanical protection, except for the turbine vibration differential protection tripping, which is provided by the Bentley Nevada.

There has been no major change to the inspection and repair history of these systems since the 2017 and 2019 update reports.

The End of Life of the Mark V turbine control system was originally 2013. Its firmware (TSI upgrade in 2015/2016) was upgraded. Additional OEM support and spare cards were implemented. The Mark V controls continue to be an issue and are not scheduled for replacement before 2023 or in standby emergency use until 2027. OEM Smart Parts Agreement is in place for the next 3 years and is expected to be extended, although the manufacturer states it will be more complicated after this time.

Having an OEM Support Agreement with manufacturer and having spare parts available in-house may not be sufficient to assure proper functionality or response in a failure event.

Hatch recommends Holyrood to hire a specialist service provider on a retainership basis and work out a negotiation for performing services when needed until the end of the required period. Hatch also recommends Holyrood to budget a specific amount yearly for this purpose.

The actions recommended for these systems are as follows:

- Maintain existing systems – maintaining/supplementing spares and securing maintenance agreements with OEMs on Mark V governor. Replace as required.
- Continue inspections/testing.
- Investigate/re-examine the need for additional actions about every three years or so, and if the normal mode of plant operation should be modified to extend beyond 2024.

Mark V governor systems remain a medium risk area at this point in time, due to the sparing, system obsolescence, and management strategies undertaken by the plant. Ideally, once Smart Parts and Support Agreement expires, an upgrade to Mark VIe Control System would be desirable.

5.6.4 Unit 1, 2, and 3 Server, Operator Workstations, Network Switches

The plant's network architecture has (4) 24 Port Fiber Ethernet Switches, (2) 24 SPF Port Switches, and (6) 24-Port Fiber Managed Switches. In addition, it has (8) P92 Style M Workstations, (9) H92 Workstation for Windows, and (1) H90 Style F Windows Server.

There have been no major changes to the inspection and repair history of these systems since the 2017 and 2019 update Reports.

The switches SWC301, SWC302, SWC203, SWC204, SWC501, and SWC502 switches are in the Obsolete Phase. Moreover, several of the Windows Operator Workstations and Server are already in the Lifetime and Obsolete Phases.

The actions recommended for these systems are as follows:

Apparently, the plant is still preparing for Windows 7 and Server 2008 R2 upgrade to Windows 10 and Windows Server 2016 respectively. It is confirmed there are no more extended support, security updates, or technical support for Windows 7 or Server 2008 R2 since January 2020. This scenario can cause vulnerability, compliance, and cybersecurity issues putting the plant's applications at risk.

The use of Windows 10 and Windows Server 2016 will guarantee an up-to-date system with the latest fixes and updates. Windows as a Service (WaaS) assures a smooth transition between iterations of a single operating system. Windows 10 and Server 2016 may look completely different ten years from now, but incremental updates will happen behind the scenes without a major upheaval to business systems. Control Core Services V9.4 has been qualified to run on H92 Style G/A (HP Z420 Workstation), H92 Style J/A (HP Z440 Workstation), H90 Style G/A (HP DL380 Gen 9 Server), and V91 Style A/A (HP DL380 Gen9).

It is recommended to upgrade to the latest stations available which will be connected to the Mesh and will operate with the latest Foxboro Evo software version. Replacing the workstations and operating system before a failure will reduce costly downtime and will help maintain advanced security and performance. However, Holyrood will need to confirm if there are other applications running in Windows 7 and Server 2008 that could have compatibility issues with Windows 10 and/or Windows Server 2016.

5.6.5 Protection and Controls

The protection of the generating units utilizes the original GE electro-mechanical relays. Digital multi-functional generator protection relays have been added and are primarily used for extra ground fault protection of the stator windings.

Additionally, the unit transformers utilize the original GE electro-mechanical relays and blocking switches.

There have been upgrades to the G3, T3, UST3, and MWH meters and stator ground fault protection, by way of a multi-function relay added in 2008.

5.6.6 Generator Unit Transformers

Unit 1 Generation Transformer (T1) is by Trafo-Union and was manufactured in 1978. It is a 105/140/180 MVA, Star-Delta, 230kV to 16kV, ONAN/ONAF/OFAF transformer.

Unit 2 Generation Transformer (T2) was replaced by a spare transformer (T4). Generation Transformer (T4) is by General Electric. It is a 115/152/170 MVA, Star-Delta, 230kV to 16kV, oil cooled transformer.

Unit 3 Generation Transformer (T3) is by General Electric and was manufactured in 1969. It is a 170 MVA, Star-Delta, 230kV to 16kV, OFAF transformer.

The unit generation transformers are inspected and maintained by NL Hydro's Transmission group. Regularly scheduled preventative maintenance and testing of these transformers is performed and trend analysis conducted to ensure reliable operation. The current maintenance and testing regime for these transformers should be maintained in order to trend data and predict and manage end of life before failure occurs.

5.6.7 Excitation Transformers

Unit 1 Excitation Transformer (RT1) is by ABB and was manufactured in 2016.

Unit 2 Excitation Transformer (RT2) is by ABB and was manufactured in 2016.

Unit 3 Excitation Transformer (RT3) is by FPE and was manufactured in 1979.

It is a 1400 kVA, 16 kV to 575 V, dry-type transformer. There is an on-site spare for this transformer.

As the Unit 1 and Unit 2 excitation transformers were replaced in 2016, and there is a spare excitation transformer both for stage 1 and stage 2 units on-site, reliability of the excitation transformers should pose no issues to 2030 and beyond.

5.6.8 Exciters

Unit 1 and Unit 2 exciters were partially upgraded in 2017. The power section and breaker were reused, and the controls were upgraded to Unitrols 6080 with the excitation to the field supplied by an ABB Unitrol static thyristor excitation system.

Unit 3 exciter is an ABB Unitrol 6080 and was completely upgraded in 2013.

As the Unit 1 and Unit 2 Exciters were upgraded in 2017, and Unit 3 exciter upgraded in 2013, the reliability of the excitations systems should pose no issues to 2030 and beyond.

5.6.9 Unit Service Transformers

The UST-1 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer, +2@2.5%, -2@2.5%.

The UST-2 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%.

The UST-3 transformer was manufactured by General Electric, installed in 1978 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%.

The 2019/2020 preventative maintenance reports show no significant areas of concern for the Unit Service Transformers. The current maintenance and testing regime for these transformers should be maintained in order to trend data and predict and manage end of life before failure occurs. Additionally, due to the age of these transformers, purchase of a spare transformer should be considered to ensure reliable operation to 2030 and beyond.

5.6.10 Station Service Transformers

The SST-12 transformer was manufactured by Federal Pioneer, installed in 1969, and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69 kV:4160/2400 V, with primary tap-changer +2@2.5%, -2@2.5%.

The SST-34 transformer was manufactured by Westinghouse, installed in 1978 and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69 kV:4160/2400 V, with primary tap-changer +2@2.5%, -2@2.5%.

The 2019/2020 preventative maintenance reports and the 2021 dissolved gas analysis reports show no significant areas of concern for the Station Service Transformers. The current maintenance and testing regime for these transformers should be maintained in order to trend data and predict and manage end of life before failure occurs. Additionally, due to the age of these transformers, purchase of a spare transformer should be considered to ensure reliable operation to 2030 and beyond.

5.6.11 Variable Frequency Drives (VFDs)

Siemens 4160 V variable frequency drives (VFDs) are installed to operate the forced draft fans for the Unit 1, 2 and 3 boilers. The VFDs allow the fans to operate a variable speed for more efficient operation of the forced draft fans during lower loading of the units.

Forced outage data indicates that VFD issues have been reducing the reliability and availability of the generating station due to failures of the VFD cells which are long lead time items. The VFD issues may be caused by the installation of the VFDs in the turbine hall area instead of in an electrical room with a climate controlled environment.

Hatch was advised that the Unit 3 FD fan VFDs have been bypassed to use direct online operation of the fan motors and that the VFDs on the Unit 1 and 2 forced draft fans will be bypassed as well in the near future. With the forced draft fans operating at constant speed the variable inlet vanes on the fans will be used to control air flow through the fans. While there will be some reduction in efficiency Hatch views this to be an appropriate step to improve the reliability and availability of the generating station. It is however noted that the variable inlet vane actuators are the original actuators from when HTGS was first constructed. Replacement of the actuators will reduce potential issues with reliability and spare parts availability.

5.7 Cooling Water Intakes

Pumphouses 1 and 2 and Units 1, 2, 3, and 4 Cooling Water Intakes were inspected by subcontractors using a combination of underwater ROV and confined space UAV Drone to assess the condition of the concrete in the sumps. The Cooling Water sumps are restricted to personnel access. The underwater ROV inspection was conducted by Afonso Limited Group and the UAV inspection was conducted by Advanced Access Engineering. Units 1, 2, 3, and 4 have a Northwest, Northeast, and South Sump. The Northwest and Northeast sumps are fully separated by a concrete wall. The North Sumps have a trash screen on the north end and travelling screens on the south end. The South sump has a partial wall between the west and east side, allowing access between the two sides. The travel screens are at the north end of the South sumps, and the cooling water pump is located on the south end. Units 1, 2, and 3 have a Cooling Water Pump in operation, the synchronous condense pump is installed in Unit 4 south sump. Please see Figure 5-8 and Figure 5-9 for the Cooling Water Sump general layout. All ROV videos were recorded and provided to NLH. A summary of the ROV Cooling Water Sump Pit Inspections summary of work, methodology and results are shown in Appendix F. The UAV inspection reports prepared by Advanced Access Engineering are shown in Appendix G.

Pumphouses 1 and 2 Cooling Water Sumps were regularly cleaned (every 6 years) until (approximately) 2014. Due to concerns with ceiling concrete deterioration, personnel access has been restricted to the sumps and they have not been cleaned since. As a result of the lack of regular cleaning, there is extensive marine growth beneath the water line on the sump floors and walls. Areas under the waterline that were not covered in marine growth and were visible appeared to be in good condition. Video files of the ROV inspection were available for review. Photos from the Advanced Access Engineering 21-117-007 Pumphouse 1 Sump Inspections report and 21-114-007 Pumphouse 2 Sump Inspection report are referenced below.

Figure 5-7:Marine Growth Found in Cooling Water Sumps (typical to All 4 Units)

During the inspections several types of deterioration and damage was identified in the Cooling Water Sumps including, delaminated concrete, corroded rebar, spalled concrete, and cracks in the slabs and beams.

There are significant cracks in the interior beams of all four South Sumps. The general location of these cracks is shown in Figure 5-8 and Figure 5-9. Photos showing details of these cracks are shown in Figure 5-10 through Figure 5-22. Figure 5-23 shows an area with damage that has exposed several parallel rebar. Pump House 1 and Pump House 2 sumps have restricted personnel access. Due to the deteriorating conditions in the beams of the south sumps, it is recommended these areas be limited to foot traffic. These areas should not be used for laydown, storage, or staging of equipment. Going forward, if these areas are not restricted to foot traffic and are intended to be used per their original design, it is recommended that repairs should be made to the Pump House 1 and 2 south sump beams. These repairs would include dewatering the sumps, temporarily supporting the sump beams/ceiling, and removing and replacing the deteriorated concrete, all while giving consideration to the safety requirements for the confined space access. Due to the limited scope of the ROV and Drone inspection conducted in this assessment, it is not currently possible to determine the remaining strength capacity of these beams.

It is recommended that Pumphouse 1 and Pumphouse 2 sumps should be monitored and inspected (via drone or equivalent) on an annual basis going forward. Regarding the remaining areas (North and South Sumps) showing delaminated concrete, single corroded rebar, spalled concrete, and cracks, it is recommended that no immediate action is required at this time. These areas should continue to be monitored going forward to determine if further deterioration occurs, which may warrant future recommendations. Further details of these anomalies can be seen in Figure 5-23 through Figure 5-50. If repairs are done on the South Sumps, the additional highlighted deficient conditions noted here can be fixed at that time.

Figure 5-8: Pump House 1 South Sumps: Location of Significant Cracking in Interior Beams

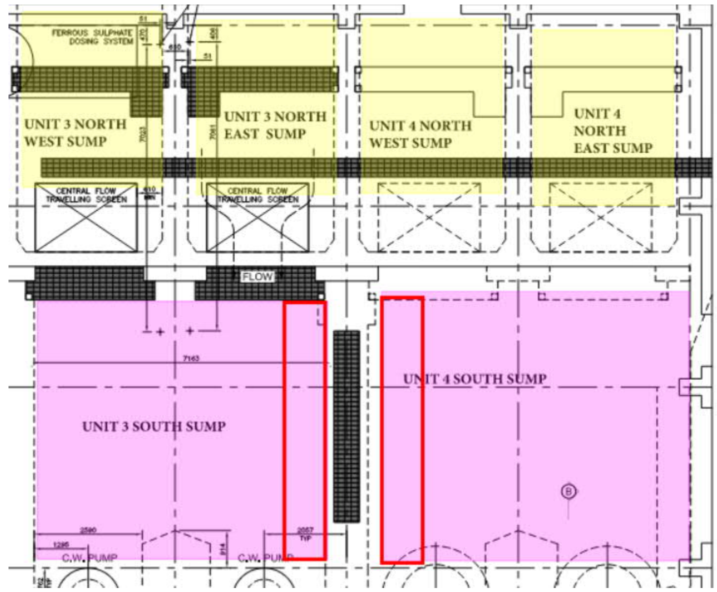

Figure 5-9: Pump House 2 South Sumps - Location of Significant Cracking in Interior Beams

Figure 5-10: Unit 1 South Sump East Crack Location

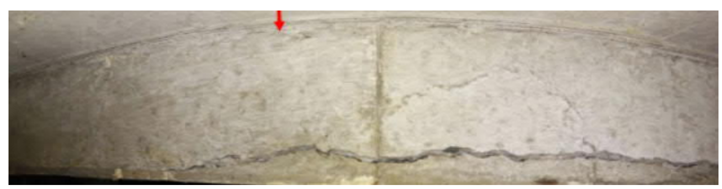

Figure 5-11: Unit 1 South Sump Crack in East Beam

Figure 5-12: Unit 2 South Sump in West Beam Crack Location

Figure 5-13: Unit 2 South Sump Crack in West Beam

Figure 5-14: Unit 3 South Sump Crack in East Beam

Figure 5-15: Unit 3 South Sump Crack in East Beam

Figure 5-16: Unit 3 South Sump Crack in East Beam

Figure 5-17: Unit 3 South Sump Crack in East Beam

Figure 5-18: Unit 3 South Sump Crack in East Beam

Figure 5-19: Unit 4 South Sump Crack in West Beam

Figure 5-20: Unit 4 South Sump Crack in West Beam

Figure 5-21: Unit 4 South Sump Crack in West Beam

Figure 5-22: Unit 4 South Sump Crack in West Beam

Figure 5-23: Unit 1 North East Sump: Exposed Rebar Near Access Point

5.7.1 Unit 1 and 2 Cooling Water Intake - Pumphouse 1

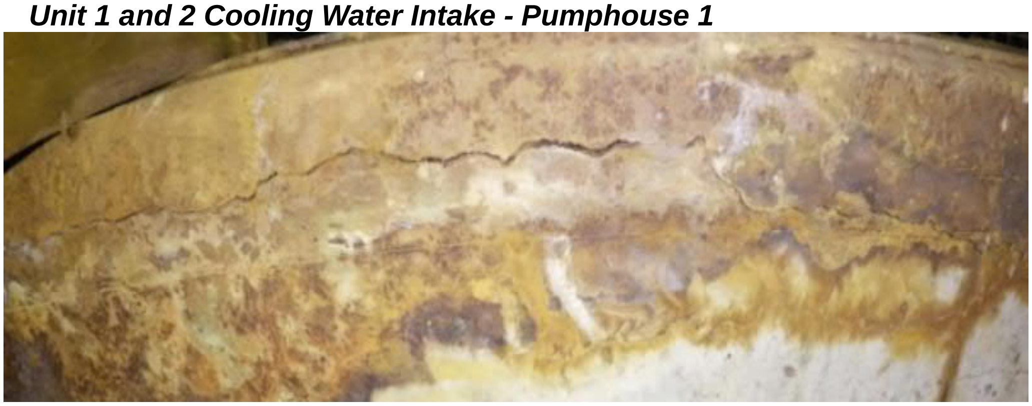

Figure 5-24: Unit 1 North West Sump – Crack on East Side

Figure 5-25: Unit 1 North West Sump - Ceiling near Traveling Screen

Figure 5-26: Unit 1 North West Sump - Crack in Southwest Corner

Figure 5-27: Unit 1 North East Sump - Exposed Rebar North End of Sump

Figure 5-28: Unit 1 North East Sump - Crack in Ceiling Along West Wall

Figure 5-29: Unit 1 North East Sump: Deterioration of Concrete in Ceiling Near Traveling Screens

Figure 5-30: Unit 1 South Sump - Crack in Ceiling Near Southwest Access Point

Figure 5-31: Unit 1 South Sump - Crack in Ceiling in Center of Sump

Figure 5-32: Unit 1 South Sump - Crack in North End Beam

Figure 5-33: Unit 2 North West Sump - Deterioration of Ceiling Near South End

Figure 5-34: Unit 2 North West Sump - Crack Near South Stop Log Guides

Figure 5-35: Unit 2 North West Sump: Deterioration of Concrete on Ceiling Near Travelling Screens

Figure 5-36: Unit 2 North East Sump - Crack in Ceiling Near Travelling Screen

Figure 5-37: Unit 2 North East Sump - Deterioration in Southwest Corner

Figure 5-38: Unit 2 South Sump Crack in North End

Figure 5-39: Unit 2 South Sump - Crack in Beam Near Southwest Access Point

5.7.2 Unit 3 and 4 Cooling Water Intake - Pumphouse 2

Figure 5-40: Unit 3 North West Sump - Deterioration in Ceiling Near Travelling Screen

Figure 5-41: Unit 3 North East Sump

Figure 5-42: North East Sump - Near South Access Grating

Figure 5-43: Unit 3 North East Sump - North End

Figure 5-44: Unit 3 South Sump - Crack in Ceiling Near North Access Grating

Figure 5-45: Unit 4 North West Sump West Side

Figure 5-46: Unit 4 North West Sump - Ceiling South End Near Traveling Screens

Figure 5-47: Unit 4 North West Sump - Crack Near South Access Grating

Figure 5-48: Unit 4 North East Sump Looking North

Figure 5-49: Unit 4 North East Looking South

Figure 5-50: Unit 4 South Sump Looking North

5.8 Marine Terminal

The Jetty Marine Terminal was built in 1969 and designed for Fuel Offload for 35,000 DWT tanker vessels. The structure is an a “L” shape configuration consisting of a shore link bridge and a berthing jetty. The shore link is approximately 410 ft in length and 20.6 ft wide concrete deck, the berthing jetty structure is 241.7 ft long by 39.4ft wide. The berthing jetting structure has eight (8) 70-Tonne swinging gravity concrete fenders. There are four shore mooring dolphins, each equipped with two bollards and one capstan.

Major Incidents requiring repairs to the Jetty Marine facility include:

- The north portion of the Jetty structure required a major repair in 1972 as a result of vessel impact.
- Several bridge-piled supports were bent and required major repair in 1983 as a result of heavy ice flow damage.

- In 2008, Gravity Fender #4 became disengaged from the Jetty structure and fell into the harbour. An investigation was conducted and the support arms of Fenders #3, #5 and #6 required temporary repairs. Permanent repairs and replacements were completed in 2013.
- Replacement of Fender #8 and #3 support arms were completed in Fall 2021.

5.8.1 Wharf Pilings

The Jetty Marine structure is supported by 600 mm diameter concrete filled steel piles. A diving visual inspection was conducted by Afonso Group Limited to review the condition of the piles and attached anodes. The inspection assessed the condition of the piles and anodes at the splash zone, middle and bottom of the pile. The Afonso Group Limited Dive Safety Plan, which includes a summary of work, methodology, and summary of results, is located in Appendix H. The inspection of each pile was recorded by Afonso Group Limited diving and has been provided to NLH for reference. A summary of the observations for the conditions of each pile and anode is located in. The checklist for Diving Contractors was reviewed and completed each day during the diving campaign and the records were confirmed as acceptable onboard the diving vessel. A copy of the completed diving checklists and the associated records are not included in this report.

A significant number of piles have corrosion present at the splash zone. Above the splash zone, near the upper portion of the piles, the coating is in generally good condition. There is significant marine growth (barnacles, coral, etc.) on the piles under the water surface. Visual inspection below the water line was limited due to the excessive growth. In areas where there was visible coating, the coating appears in generally good condition. Areas that were scraped clean for previous inspection are still visible and remained in good condition. The remaining life condition of the anodes at the surface, mid and bottom level of the pile were also assessed. The anodes condition varies, ranging from 0% remaining (anode completely gone) to 100% remaining (anode showing no deterioration). The remaining condition on adjacent anodes varied significantly in each location, there were several locations where one anode was completely consumed, and the adjacent was entirely intact. During the inspection it was noted that some anodes on the north end showed signs of damage due to ice contact in Winter 2017. It is recommended that the piles and anodes undergo a visual (diving) inspection again within a 5-year time frame.

Figure 5-51: Berthing Jetty Facing Southwest

Figure 5-52: Typical Pile Condition Above Water Line (Jetty South End)

Figure 5-53: Typical Corrosion Present at Water Line on Jetty Piles (Piles 29B, 29C, 29D Jetty South End)

Figure 5-54:Typical Pile Condition (Facing Northwest)

Figure 5-55: Typical Pile Condition (Facing Northwest)

Figure 5-56: Jetty Shore Arm (Facing Northeast)

Figure 5-57: Jetty Shore Arm (Facing East)

(Note: Pile S8 has Steel Cover and Concrete are Severely Deteriorated with Exposed Rebar. Pile S9 and P10 Concrete has Washed Away Below Water Line)

Figure 5-58: Pile P9 Concrete Jacket completely Deteriorated beneath the Water Line. Typical for Pile S8 and P9

Figure 5-59: Jetty Shore Arm (Pile P5)

5.8.2 *Fender Support Arms and Pins*

The Jetty was constructed with four gravity fenders aligned on a circular arc to ensure at least one fender (#1, #2, #7, #8) is engaged by the tanker's hull as it approaches and makes contact with the Jetty. The interior fenders (#3, #4, #5, #6) are the only fenders that are utilized during docking.

The Fender Pins and support arms have undergone several inspections and repairs since 2008. Support arm measurements have been previously taken in 2008, 2013, and 2016. During the 2021 inspection scaffolding was erected to provide access to the fender support arms and pins. Measurements were taken using vernier calipers and measuring tapes and compared against previous measurements. The location of the measurements is shown in Figure 5-60. Fenders #1 and #7 are stuck in the retracted position. Their measurements were not taken during inspections in previous years. The 2021 inspection measurement results are shown below in Table 5-7 and Table 5-8 below.

Based on the 2021 inspection results, it was recommended that #3 and #8 Fender Support Arms be immediately replaced before the next scheduled tanker arrival. The level of material wear since the last inspection is of concern. NL Hydro have proceeded with replacing the #3 and #8 fender arms and pins under a separate contract.

It is further recommended that the Support Arm and Fender Pin measurements continue to be inspected for wear within a 5-year period.

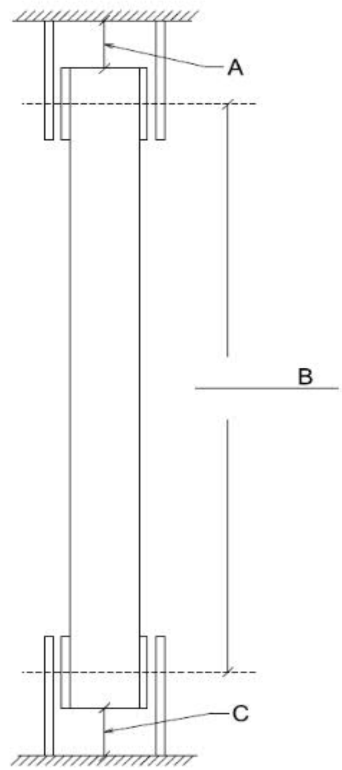

Figure 5-60: Jetty Fender Arm and Pin Measurement

Table 5-7: Jetty 1,2,3,4 (South) Fender Measurements

Dimension (in)	South Fender and Arm No.														
	Original Dimensions	South No (1) Not measured in 2008		South No (1) Not measured in 2016		South No (1) Not measured in 2021		Difference 2008-2016		Difference Original-2016		Difference 2016-2021		Difference Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0							N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
B	66.0	Stuck in the Retracted Position	Stuck in the Retracted Position	Stuck in the Retracted Position	Stuck in the Retracted Position	Stuck in the Retracted Position	Stuck in the Retracted Position	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	2.0							N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Dimension (in)	South Fender and Arm No.														
	Original Dimensions	South No (2) Measured in 2008		South No (2) Measured in 2016		South No (2) Measured in 2021 (mm/inch)		Difference 2008-2016		Difference Original-2016		Difference 2016-2021		Difference Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	2.25	2.375	2.375	2.25	67 2.638	67 2.638	-0.125	0.125	-0.375	-0.250	-0.263	-0.388	-0.638	-0.638
B	66.0	68.5	68.375	70.0	70.0	1770 69.685	1873 73.740	-1.500	-1.625	-4.000	-4.000	0.315	-3.740	-3.685	-7.740
C	2.0	2.5	2.75	2.0	2.0	154 6.063	124 4.882	0.500	0.750	0.000	0.000	-4.063	-2.882	-4.063	-2.882

Dimension (in)	South Fender and Arm No.														
	Original Dimensions	South No (3) Measured in 2008		South No (3) Measured in 2016		South No (3) Measured in 2021 (mm/inch)		Difference 2008-2016		Difference Original-2016		Difference 2016-2021		Difference Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	4.5	5.0	4.5	4.375	140 5.512	150 5.906	0.000	0.625	-2.500	-2.375	-1.012	-1.531	-3.512	-3.906
B	66.0	73.0	73.75	72.0	72.0	1936 76.220	1970 77.559	1.000	1.750	-6.000	-6.000	-4.220	-5.559	-10.220	-11.559
C	2.0	3.5	4.5	2.75	2.75	143 5.630	160 6.299	0.750	1.750	-0.750	-0.750	-2.880	-3.549	-3.630	-4.299

Dimension (in)	South Fender and Arm No.														
	Original Dimensions	South No (4)		South No (4) Not measured in 2016		South No (4) Measured in 2021 (mm/inch)		Difference 2008-2016		Difference Original-2016		Difference 2016-2021		Difference Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0					74 2.913	76 2.992	N/A	N/A	N/A	N/A	N/A	N/A	-0.913	-0.992
B	66.0	Missing Fender Completely Replaced 2013	Missing Fender Completely Replaced 2013	N/A	N/A	1820 71.654	1745 68.701	N/A	N/A	N/A	N/A	N/A	N/A	-5.654	-2.701
C	2.0					107 4.213	65 2.559	N/A	N/A	N/A	N/A	N/A	N/A	-2.213	-0.559

Table 5-8: Jetty 5,6,7,8 (North) Fender Measurements

Dimension (in)	North Fender and Arm No.														
	Original Dimensions	North No (5)		North No (5)		North No (5)		Difference		Difference		Difference		Difference	
				Not measured in 2016		Measured in 2021 (mm/inch)		2008-2016		Original-2016		2016-2021		Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	Arm Replaced 2013	Arm Replaced 2013	N/A	N/A	61 2.402	65 2.559	N/A	N/A	N/A	N/A	N/A	N/A	-0.402	-0.559
B	66.0					1735 68.307	1730 68.110	N/A	N/A	N/A	N/A	N/A	N/A	-2.307	-2.110
C	2.0					66 2.598	64 2.520	N/A	N/A	N/A	N/A	N/A	N/A	-0.598	-0.520

Dimension (in)	North Fender and Arm No.														
	Original Dimensions	North No (6)		North No (6)		North No (6)		Difference		Difference		Difference		Difference	
				Not measured in 2016		Measured in 2021 (mm/inch)		2008-2016		Original-2016		2016-2021		Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	Arm Replaced 2013	Arm Replaced 2013	N/A	N/A	43 1.693	58 2.283	N/A	N/A	N/A	N/A	N/A	N/A	0.307	-0.283
B	66.0					1725 67.913	1725 67.913	N/A	N/A	N/A	N/A	N/A	N/A	-1.913	-1.913
C	2.0					70 2.756	70 2.756	N/A	N/A	N/A	N/A	N/A	N/A	-0.756	-0.756

Dimension (in)	North Fender and Arm No.														
	Original Dimensions	North No (7)		North No (7)		South No (7)		Difference		Difference		Difference		Difference	
				Not measured in 2016		Not measured in 2021		2008-2016		Original-2016		2016-2021		Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	Stuck in the Retracted Position	Stuck in the Retracted Position	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
B	66.0					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	2.0					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Dimension (in)	North Fender and Arm No.														
	Original Dimensions	North No (8)		North No (8)		North No (8)		Difference		Difference		Difference		Difference	
		Measured in 2008		Measured in 2016		Measured in 2021 (mm/inch)		2008-20016		Original-20016		2016-2021		Original-2021	
		South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm	South Arm	North Arm
A	2.0	2.75	2.75	2.75	2.75	70 2.756	79 3.110	0.000	0.000	-0.750	-0.750	-0.006	-0.360	-0.756	-1.110
B	66.0	69.0	69.5	72.0	72.0	1815 71.457	1795 70.669	-3.000	-2.500	-6.000	-6.000	0.543	1.331	-5.457	-4.669
C	2.0	2.5	1.75	2.375	2.25	158 6.220	124 4.882	0.125	-0.500	-0.375	-0.250	-3.845	-2.632	-4.220	-2.882

5.8.3 Fuel Storage

The Scope of the condition assessment of the fuel storage facilities by Hatch has been comprised of a review of the available HOIT data, a site visit and general visual assessment, and engaging a subcontractor (Acuren) to complete a coating inspection on Tank 3. The fuel oil storage assets are comprised of four main storage tanks contained in a bermed area, advised by NLH to be of a clay lined dyke design, and one (1) day tank (North Side of plant) contained in a lined concreate containment. Our findings from the HOIT data review are summarized below in Table 5-9. In this table, the year + IS indicates the last in service (external) inspection performed and the year + OS indicates the last out of service (internal) inspection performed. In service inspections by an authorized inspector are required under API 653 every 5 years. NLH have committed to conducting an annual in service (external) inspection on HFO Tanks 2, 3, and 4 until reaching their out of service inspection, as listed below in Table 5-9

Table 5-9: Summary of Past Fuel Tank Inspection Based on HOIT Data Review

Asset	Last API 653 In Service (IS) or Out of Service (OS) Inspection	Next API 653 OS Inspection Due
HFO Tank 1	2005 OS 2016 IS	2021 OS (Not performed, not currently in service)
HFO Tank 2	2008 OS 2021 IS	2023 OS
HFO Tank 3	2013 OS 2021 IS	2025 OS
HFO Tank 4	2010 OS 2021 IS	2024 OS
HFO Day Tank	2013 OS 2018 IS	2023 OS 2028 IS

The HOIT data reviewed by Hatch indicates that a tank refurbishment program was implemented in 2006 with repairs performed on all 4 HFO storage tanks with the intention to provide each tank with at least 20 years of additional life. Tank 1 is scheduled to be decommissioned. Tank 2,3,4 2021 In Service Inspection reports indicate that the tanks are suitable for continued service for the following year. In Service Inspections will take place on an annual basis. The 2021 In Service Inspection reports indicated there were various degrees of paint failure on the tanks and recommend that paint failures be repaired and repainted. For Tanks 2,3,4 the reports indicated that further investigation be conducted on the tank stairs. These investigations are ongoing as of March 2022 and recommendations will be made based on the finding of these inspections. Recommended fixes will be implemented during the 2022 maintenance schedule. It is recommended to continue with the annual In-Service

Inspections and proceed with future recommendations as highlighted in the API 653 In Service Inspection reports.

5.8.4 Day Tank

HOIT data indicates that an out of service inspection of the HFO Day Tank is required to be completed in 2023 for continued operation. The most recent inspections include a 2013 API 653 out of service (internal) inspection and a 2018 API 653 in service (external) inspection.

5.8.5 Tank 1

HOIT data indicates that past inspections determined HFO Tank 1 would reach end of life this year in 2021 and that it had been decided that this tank will be decommissioned in 2022 as the fuel storage capacity of 3 tanks has been assessed to be sufficient to operate HTGS. NLH informed Hatch that this tank is currently no longer in service and noted that there are issues with leaks in the roof of the tank.

The last major refurbishment of Tank 1 was noted to be in 2005. A roof access platform was installed in 2015.The last API 653 in service inspection (external) was completed in 2016. TEAM industrial had been engaged to assess an extension of this next inspection and recommended that the out of service inspection could be delayed to 2021. Correspondence referenced in the WOOD report indicates that this deferral was accepted by the regulator.

To return this tank to service the required out of service inspection must be performed to determine the scope of repairs required.

5.8.6 Tank 2

HOIT data indicates that an out of service inspection of Tank 2 is required to be completed in 2023 for continued operation. During site visits performed by Hatch the coating on this tank was observed to have deteriorated. Painting has been deferred but the tank paint is recommended to be repaired as per the API 653 In Service Inspection. See Figure 5-61 below. As noted above, an investigation for the tank stairs is ongoing as of March 2022. Recommendations for repair from this investigation will be implemented during the 2022 maintenance season.

Figure 5-61: HFO Tank 2 with Deteriorating Coating

The last refurbishment of Tank 2 was noted to be in 2008. The most recent inspection was a 2021 API 653 in service (external) inspection and the next out of service inspection was due to be performed in 2018. A full floor replacement for Tank #2 has not been installed, but floor patch plates have been installed to meet the minimum thickness threshold identified during the previous inspection. Correspondence referenced in the HOIT data indicates that a deferral of this inspection to 2023 was accepted by the regulator. The next internal out of service inspection is scheduled for June 2023 during which the refurbishment scope required for Tank 2 will be determined.

5.8.7 Tank 3

HOIT data indicates that an out of service inspection of Tank 3 is required to be completed in 2025 for continued operation. The latest In-Service inspection occur in 2021. As noted above, an investigation for the tank stairs in ongoing as of March 2022. Recommendations for repair from this investigation will be implemented during the 2022 maintenance season.

As noted in the 2021 In Service inspection report, and during a site visit performed by Hatch coating issues were identified to the team by NLH where paint was seen to be bubbling and flaking off the tank. Hatch conducted a coating inspection as part of the condition assessment in August 2021.

Hatch oversaw the coating inspection on the #3 Fuel Tank conducted by Acuren. The inspection consisted of dry film thickness testing and adhesion testing, conducted on the six shell courses, at the North, South, East, and West quadrants of the tank. A summary of the dry film thickness readings is detailed in Appendix I. The #3 Fuel Tank had been painted in accordance with Specification 2003-24630 and the specified dry film thickness for the tank ranges from 16-20 mils. A summary of the actual measured dry film thicknesses is detailed in Table 5-10. Adhesion testing was conducted on the #2, 3, 4, 5, and 6 shell courses on the East and West sides of the #3 Fuel Tank. After an approximate 1 hour waiting period, all 10 test dollies were easy removed from the tank by hand, removing 3 layers of the paint coating at the local testing site. This can be seen in Figure 5-67.

Table 5-10: No. 3 Fuel Tank Dry Film Thickness Measurements

Location	Average DFT (mils)	Max DFT (mils)	Min DFT (mils)
North-Course 6	16.1	22.5	13.3
North-Course 5	16.7	20.4	12.2
North-Course 4	17.6	24.6	14.7
North-Course 3	17.9	24.1	10.5
North-Course 2	17.7	26.0	13.8
North-Course 1	18.5	27.8	12.1
South-Course 6	15.2	20.0	13.2
South-Course 5	14.9	23.8	9.5
South-Course 4	14.7	28.0	10.9
South-Course 3	15.0	21.7	9.7
South-Course 2	18.8	26.9	13.1
South-Course 1	18.7	22.2	16.5
East-Course 6	22.6	31.2	15.9
East-Course 5	23.4	30.8	15.2
East-Course 4	20.4	24.3	16.3
East-Course 3	20.9	29.7	13.1
East-Course 2	21.1	27.5	14.4
East-Course 1	23.1	26.0	19.1
West-Course 6	16.4	21.8	12.9
West-Course 5	15.4	19.2	11.9
West-Course 4	14.8	20.4	11.5
West-Course 3	16.0	24.0	8.5
West-Course 2	16.4	19.6	14.7
West-Course 1	17.3	26.0	11.6
West Roof	14.5	21.1	9.4
South Roof	17.3	32.9	9.7
East Roof	17.2	21.3	10.7
North Roof	13.9	16.4	10.1

Figure 5-62: Fuel Tank #3 North Quadrant Localized Paint Deterioration

Figure 5-63: Fuel Tank #3 East Quadrant – Localized Paint Deterioration

Figure 5-64: Fuel Tank #3 South Quadrant Localized Paint Deterioration

Figure 5-65: No. 3 Fuel Tank Southwest Quadrant Localized Paint Deterioration

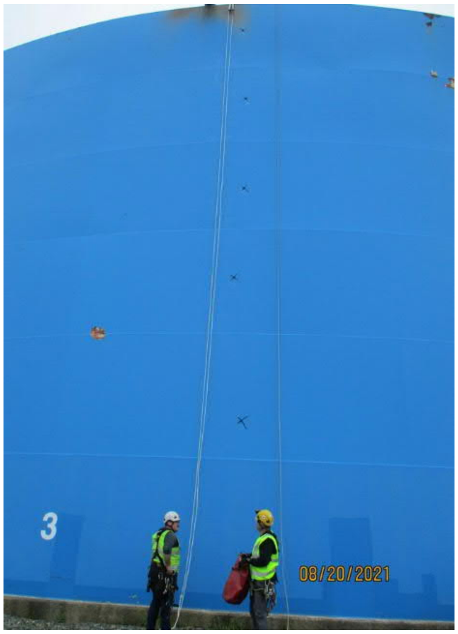

Figure 5-66: No. 3 Fuel Tank Location of Adhesion Test

Figure 5-67: Paint Adhesion Test Sample Results

The paint deterioration is consistent with the findings from the 2018 and 2021 API 653 In Service Inspection Report. Areas with coating failure should be properly cleaned and repainted to meet the specified dry film thicknesses per Specification 2003-24630.

The most recent inspections were a 2013 API 653 out of service (internal) inspection and 2021 API 653 in service (external) inspection. The tank floor was replaced as per the 2013 recommendations of previous inspection. NLH engaged TEAM industrial to determine if the next out of service inspection interval could be extended and TEAM recommended that the inspection could be extended to 2033. This needs to be approved by the regulator. The next internal out of service inspection is scheduled for June 2025 during which the refurbishment scope required for Tank 3 will be determined.

5.8.8 Tank 4

HOIT data indicates that that an out of service inspection of Tank 4 was required to be completed in 2020 for continued operation.

The last refurbishment of Tank 4 was noted to be in 2010 when a bottom replacement was completed. The most recent inspection was a 2021 API 653 in service (external) inspection. The next internal out of service inspection is scheduled for 2024 during which the refurbishment scope required for Tank 4 will be determined.

5.9 Recent Failures

During the execution of this study, some failure happened during plant operation. This section summarizes these failures and Hatch comments on these incidents.

- Unit 3 boiler waterwall failure
- Unit 1 Cold reheat piping support failure

Hatch notes that Transformer T2 failed in November 2021 and was replaced by the spare Transformer T4. Hatch has not reviewed any failure reports and therefore cannot comment on the nature of the failure.

5.9.1 Unit 3 boiler waterwall failure

Hatch reviewed the TapRoot report prepared by NLH and Wayland reports on the causal factors leading to the tube failure, we concur with the two reports finding, namely the failure is due to corrosion fatigue augmented by constraint on thermal expansion due to original design of the windbox vestibule attachment, refer to Hatch document H365408-0012-200-030-0003 for a detailed review of the incident.

5.9.2 Unit 1 Cold reheat piping support failure

Hatch reviewed the TapRoot report prepared by NLH which identified the causal factors that led to the incident and recommended actions to avoid recurrence. Hatch concurs with the findings of the TapRoot report and agrees that the incident was due to water leakage across a valve which is considered to be of a non-recurring nature based on implementing the recommended actions.

5.10 Review of HTGS Inspection Program

Hatch reviewed HTGS inspection program and find the program is quite comprehensive and online with applicable codes and regulatory requirements. Safety valves, pipe supports, and pressure parts are inspected as per ASME guidelines. The auxiliary equipment such as pumps, tanks, and heat exchangers are also inspected periodically as per good industry practices.

The boilers are inspected annually, and the turbines and electric generator are inspected annually and overhauled every 9 years.

6. Remaining Life Assessment

The principal components that limit the useful life of utility boilers and steam turbines are (a) damage to the high temperature heavy wall boiler headers and steam turbines (b) significant damage to boiler drums and (c) steam turbine rotor surface life expended. -

Review of the boiler and turbine generator condition assessments conducted over the period 2017 to 2021, related inspection reports and other inspection reports have recorded heavy wall component issues on each of the boilers, no imminent end of life issues for the components operating in the creep range were indicated. Therefore, steam turbine rotor surface life expended was assessed based on the operating history for each unit.

In the case of HTGS, the reported condition assessments and inspections of the boilers heavy wall components have not reported any indications that suggest limiting factors on their extended use to 2030 and beyond.

The remaining life of the turbine rotors was determined. From data received from NLH, the number of restarts for each unit was determined and a conservative approach was taken to calculate the number of load changes each unit has undergone. Hitachi steam turbine criteria was used as a basis along with the calculated values to predict the remaining life of the steam turbine rotor. For the year 2030, the units have an estimated remaining life in the range of 46% to 51%. The following section discusses the calculation methodology and summarizes data used.

6.1 Steam Turbine Rotor Life Expended

6.1.1 Criteria

To evaluate the steam turbine rotor life, Hitachi steam turbine criteria was used as a basis for calculations. The data breaks down damage done to the rotor in terms of restart type, or number of cycles, and major load changes which accumulates to 80% of rotor life expended. It is considered reasonable to use the Hitachi data because the Hitachi steam turbine for Unit 3 was a licenced design based on the GE design provided for Units 1 & 2.

There are four categories for restart type classified by the outage duration: very hot, hot, warm, and cold. The load swings are separated into major and minor. Classification of each criterion can be seen in Table 6-1 with the corresponding rotor life damage percentage.

Table 6-1: Hitachi Steam Turbine Rotor Assessment Data

	Description	Rotor Surface Life Used Up (%)	Cycle History 20 Year Basis (Total Unit Age)	Damage (%/cycle)
Very Hot Restart	≤ 2 hours	5	300	0.05
Hot Restart	2 < Duration ≤ 8 hours	20	500	0.01
Warm Restart	8 < Duration ≤ 48 hours	5	2,000	0.01
Cold Restart	≥ 48 hours	15	100	0.05
Major Load Swing	30-70% of rating	30	3,000	0.01
Minor Load Swing	15-30% of rating	5	20,000	0.00025
Total	-	80	-	-

6.1.2 Calculation

For this analysis, data provided covered restarts for the period from 1993 to 2021; this data was reviewed to determine the rotor life cycle expended. The results are summarized in Table 6-2 below.

Table 6-2: Restart Occurrences From 1993-2021

Restart Type	1993-2021 Restart Occurrences		
	Unit 1	Unit 2	Unit 3
Very Hot	186	198	167
Hot	79	79	53
Warm	29	37	23
Cold	32	31	33

To calculate the cumulative rotor life used, the number of restart types are required from first unit start. Restart occurrences obtained for the period from 1993 to 2021 were linearly extrapolated back to the first years of operation (Unit-1 and Unit-2 – 1969, Unit-3 – 1979) and the total restarts are used in the rotor life calculations, seen in Table 6-3.

Table 6-3: Lifetime Restart Occurrences from 1969-2021 for Units 1 and 2 and 1979-2021 for Unit 3

Restart Type	Lifetime Restart Occurrences		
	Unit 1	Unit 2	Unit 3
Very Hot	345	368	245
Hot	147	147	78
Warm	54	69	34
Cold	59	58	48

To determine the cumulative number of load swings, the hourly data provided by NLH was analyzed. It was assumed that any load swings would take place during a decrease in unit output and any increase would be a controlled load change. The hourly load decreases were then categorized into major load swings, 30-70% of rated output, and minor load swings, 15-30% of rated output. Calculations were completed for the data range provided, 1997-Present, and yearly average values were linearly extrapolated back to the unit beginning. Data is summarized in Table 6-4.

Table 6-4: Load Swings from 1997-Present and Lifetime

Restart Type	1997-Present Load Changes			Lifetime Load Changes		
	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3
Major Load Change	376	396	391	815	840	673
Minor Load Change	1,538	1,641	1,459	3,332	3,479	2,509

Therefore, with the lifetime restart occurrences, load swings, and the damage percentage per cycle, the cumulative rotor life expended was calculated. Table 6-5 lists the value for each unit. The table shows the rotors life consumed is low and rotor estimated remaining life is greater than 50%.

Table 6-5: Cumulative Rotor Life Used for Each Unit

	Unit 1	Unit 2	Unit 3
Cumulative Rotor Life Expended	31%	33%	23%

To determine the rotor life used for the next 10 years, an additional 110 restarts, representing an estimate of 11 restarts per year for the next 10 years, were added for each unit. Warm restarts were added for Unit-1 and 2 considering the units will be kept warm and ready for fast recall time and cold restarts were added for Unit-3 since the unit will be on Synchronous condenser mode. Utilizing the rotor damage percentage per cycle, the rotor life used in the year 2030 is estimated in Table 6-6. The table shows the rotor life cycle expended does not increase dramatically.

Table 6-6: Cumulative Rotor Life Expended for 2030

	Unit 1	Unit 2	Unit 3
Cumulative Rotor Life Expended Predicted for 2030	32%	34%	29%

7. Summary

7.1 HTGS

While HTGS is a relatively old facility, the overall plant condition was found to be good and functional with only a few items requiring attention. A summary of the grades for each unit's critical assets is provided in Table 7-1.

Table 7-1: Condition Assessment Summary

Asset	Asset No.	Grade
Unit 1		
Turbine	6691	3
Generator	6691	4
Electrical	6723	4
Control Systems*	6723	2
Cooling Water System	8715	2
Boiler System	6699	3
Stack	6919	3
Condensate & Feedwater System	6708	4
Condenser	6708	3
Unit 2		
Turbine	7636	4
Generator	7636	4
Electrical	8152	4
Control Systems	8152	2
Cooling Water System	8093	2
Boiler System	7786	3
Stack	7900	3
Condensate & Feedwater System	7976	4
Condenser	7976	3
Unit 3		
Turbine	8194	3

Asset	Asset No.	Grade
Generator	8194	5
Electrical	8712	4
Control Systems*	8712	2
Cooling Water Systems	8645	2
Boiler System	8336	3
Stack	8448	3
Condensate & Feedwater System	8528	4
Condenser	8528	3
Balance of Plant		
Power Center and Excitation Transformers	-	4
Common Electrical and Control Assets	7199	4
Buildings and Building M and E System	7255	4
Hydrogen and Carbon Dioxide Supply Systems	7199	4
Compressed Air	7199	4
Fuel Systems (Light and Heavy Oil)	7199	4
Wastewater Treatment Plant (WWTP) Equalization Basin Building	9739	1
Water Treatment Plant (WTP) System	9739	4
Fire Water System	7251	3
Black Start Diesel Gensets	7199	4
Heavy Oil & Fuel Additive Systems (Tank Farm)	7204	3
Marine Terminal Structure (Jetty)	7133	3

Appendix A
List of Documents Received from NLH

Documents for HTGS

Serial No.	Document Title
1	,Stage1drainage system(jessicamcgrath@nlh.nl.ca).pdf
2	01-Jan-1976_Plant Manual Vol 1 for Hydro Generating Station stage II - Unit No 3(jessicamcgrath@nlh.nl.ca).pdf
3	01-Jan-1976_Plant manual Vol 1A for Holyrood Generating Station Stage II Unit No3(jessicamcgrath@nlh.nl.ca).pdf
4	01-Jan-1980_Hitachi Steam Turbine(jessicamcgrath@nlh.nl.ca).pdf
5	092019 Tank 3 - Inspection Interval Extension Report.pdf
6	092019 Tank 4 - Inspection Interval Extension Report.pdf
7	1403-121-C001 SITE PLAN GENERAL ARRANGEMENT R9(jessicamcgrath@nlh.nl.ca).PDF
8	1403-147-M001 PLANT HEATING SYSTEM R8(jessicamcgrath@nlh.nl.ca).PDF
9	1403-150-M011 WTP CAUSTIC HEATER PIPING R0(jessicamcgrath@nlh.nl.ca).pdf
10	1403-211-M003 U3 SOOTBLOWERS SYSTEM R4(jessicamcgrath@nlh.nl.ca).pdf
11	1403-211-M004 U3 AIR & FLUE GAS SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
12	1403-223-M001 U3 WASH & RINSE WATER FOR AIRHEATERS(jessicamcgrath@nlh.nl.ca).PDF
13	1403-223-M001 U3 WASH & RINSE WATER FOR AIRHEATERS.pdf
14	1403-231-M001FUEL OIL DELIVERY SYSTEM R12(jessicamcgrath@nlh.nl.ca).pdf
15	1403-251-M001 U3 FO SYSTEM R11(jessicamcgrath@nlh.nl.ca).pdf
16	1403-251-M002 U3 FUEL ADDITIVE & LIGHT OIL FLUSHING R7(jessicamcgrath@nlh.nl.ca).pdf
17	1403-252-M001U3 IGNITOR LIGHT OIL & AIR SUPPLY R(jessicamcgrath@nlh.nl.ca).PDF
18	1403-271-M001QUARRY BROOK TEMPORARY WEIR(jessicamcgrath@nlh.nl.ca).PDF
19	1403-272-M001 WTP MIXED BEDS(jessicamcgrath@nlh.nl.ca).pdf
20	1403-280-M001 U3 ASPIRATING & SEAL AIR(jessicamcgrath@nlh.nl.ca).pdf
21	1403-281-M001U3 MAIN STEAM & REHEAT TURBINE DRAINS(jessicamcgrath@nlh.nl.ca).pdf
22	1403-282-M001 U3 AUX STREAM SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
23	1403-283-M001 U3 RFW SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
24	1403-284-M001U3 BOILER VENTS & BLOWDOWN SYSTEMS(jessicamcgrath@nlh.nl.ca).PDF
25	1403-285-M001U3 N2 BLANKETING PIPING(jessicamcgrath@nlh.nl.ca).PDF
26	1403-286-M002 U3 BOILER CHEMICAL CLEAN(jessicamcgrath@nlh.nl.ca).pdf
27	1403-287-M001 U3 CHEMICAL FEED SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
28	1403-310-M001U3 CONDENSER AIR EXTRACTION SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
29	1403-310-M002 U3 GENERATOR H2 & CO SUPPLY PIPING(jessicamcgrath@nlh.nl.ca).pdf
30	1403-310-M006 HYDROGEN COOLING AND CO2 FLOW UNIT 1(jessicamcgrath@nlh.nl.ca).pdf
31	1403-310-M006 U1 GENERATOR H2&CO SUPPLY PIPING(jessicamcgrath@nlh.nl.ca).pdf
32	1403-310-M007 U2 GENERATOR H2&CO SUPPLY PIPING(jessicamcgrath@nlh.nl.ca).pdf
33	1403-310-M008 U3 GENERATOR H2&CO SUPPLY PIPING(jessicamcgrath@nlh.nl.ca).pdf
34	1403-323-M001 U3 CW & SCREEN WASH SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
35	1403-340-M001 U3 FEEDWATER HTR DRAINS(jessicamcgrath@nlh.nl.ca).pdf
36	1403-340-M002 U3 FEEDWATER HEATER VENTS SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
37	1403-342-M001 U3 LP FW SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
38	1403-343-M001U3 HP FW SYTEM(jessicamcgrath@nlh.nl.ca).PDF
39	1403-345-M001U3 BFP GLAND SEALING WATER(jessicamcgrath@nlh.nl.ca).PDF
40	1403-351-M003 U3 BLED STEAM SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
41	1403-352-M001U3 TG SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
42	1403-431-M001 STAGE 11 SERVICE AIR SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
43	1403-431-M009 STAGE 11 INST & SERVICE AIR SUPPLY(jessicamcgrath@nlh.nl.ca).pdf
44	1403-442-M-001 (Plant Fire System Flow Diagram).pdf
45	1403-442-M001FIRE PROTECTION SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
46	1403-500-e001 PLANT SINGLE LINE DIAGRAM(jessicamcgrath@nlh.nl.ca).pdf
47	1403-500-E004 PLANT MCC SINGLE LINE DIAGRAM(jessicamcgrath@nlh.nl.ca).pdf
48	1403-550-E002 U3 LOGIC TRIPPING DIAGRAM(jessicamcgrath@nlh.nl.ca).pdf
49	1403-610-i-005 U3 AIR&COMBUSTION SIDE INSTRUEMENTATION(jessicamcgrath@nlh.nl.ca).PDF
50	1403-650-M001 U3 STEAM SAMPLING(jessicamcgrath@nlh.nl.ca).PDF
51	1403-V-311-E-054(jessicamcgrath@nlh.nl.ca).pdf
52	1403-V-311-M-143(jessicamcgrath@nlh.nl.ca).pdf
53	1403-V-311-M-320(jessicamcgrath@nlh.nl.ca).pdf
54	1403-V-311-M-322(jessicamcgrath@nlh.nl.ca).pdf
55	17-Aug-2012_Units 1 and 2 - GE Steam Turbine Manual Volume 1(jessicamcgrath@nlh.nl.ca).pdf
56	17-Aug-2012_Units 1 and 2 - GE Steam Turbine Manual Volume 2(jessicamcgrath@nlh.nl.ca).pdf
57	1998 Turbine Consultants, Inc - Report(jessicamcgrath@nlh.nl.ca).pdf
58	1999 NDE - U3 steam chest crack(jessicamcgrath@nlh.nl.ca).pdf
59	2000 U3 steam chest crack - repair application - Christians file(jessicamcgrath@nlh.nl.ca).pdf
60	2001 Unit 3 Major(jessicamcgrath@nlh.nl.ca).pdf
61	2003 Unit 1 Major(jessicamcgrath@nlh.nl.ca).pdf
62	2004 Unit 3 Valves(jessicamcgrath@nlh.nl.ca).pdf
63	2005 Unit 2 Generator(jessicamcgrath@nlh.nl.ca).pdf
64	2005 Unit 2 Major(jessicamcgrath@nlh.nl.ca).pdf
65	2007 Holyrood U#2 forced outage(jessicamcgrath@nlh.nl.ca).pdf
66	2007 Holyrood Unit 3 Generator(jessicamcgrath@nlh.nl.ca).pdf
67	2007 Holyrood Unit 3 Turbine(jessicamcgrath@nlh.nl.ca).pdf
68	2007 NDE - U3 steam chest crack(jessicamcgrath@nlh.nl.ca).pdf
69	2011 Unit 2 Valve(jessicamcgrath@nlh.nl.ca).pdf
70	2013 Steam Chest Crack Inspection - Acuren 2013(jessicamcgrath@nlh.nl.ca).pdf
71	2014 Unit 1 Bearings and Generator(jessicamcgrath@nlh.nl.ca).pdf
72	20140604-0600_VR164576 (#3 - 2014).pdf
73	2015 - Unit 1 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
74	2015 - Unit 2 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
75	2015 - Unit 3 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
76	20150408-0403_VR181343 (#3 - 2015).pdf
77	2015-2016 Condition Assessment Report
78	2016 - Unit 1 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
79	2016 - Unit 2 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
80	2016 - Unit 3 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
81	2016 GE Turbine Valve Major(jessicamcgrath@nlh.nl.ca).pdf
82	2016 Steam Chest Crack Inspection - UT-SS051916-001 R0(jessicamcgrath@nlh.nl.ca).pdf
83	2016 Unit 3 Valves - FSR_065909_Valve_Ken Roberts(jessicamcgrath@nlh.nl.ca).pdf
84	2017 Condition Assessment (Level 1 Refresh)

Serial No.	Document Title
85	2017 Condition Assessment Report
86	2017 Condition Assessment Report (Level 1 Refresh by Wood)
87	2018 Condition Assessment Report
88	2019 - Unit 1 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
89	2019 - Unit 2 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
90	2019 - Unit 3 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
91	2019 09 Duffs Road Hydro Communication Room Inergen.pdf
92	2019 09 Duffs Road NL Hydro INERGEN - GUARD HOUSE.pdf
93	2019 09 FA CERT HYDRO HOLYROOD GENERATING PLANT.pdf
94	2019 09 Hydro Holyrood FA Inspection.pdf
95	2019 Condition Assessment Report
96	2019 SP 09 Annual Report - NL Hydro Holyrood Generating plant.pdf
97	2019 Steam Chest Crack Inspection - PAUT-SS051319-001 R0(jessicamcgrath@nlh.nl.ca).pdf
98	2020 - Unit 1 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
99	2020 - Unit 2 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
100	2020 - Unit 3 - HEP Hangers(jessicamcgrath@nlh.nl.ca).xlsx
101	2020 02 Duffs Road Hydro Communication Room Inergen.pdf
102	2020 02 Duffs Road NL Hydro INERGEN - GUARD HOUSE.pdf
103	2020 Condition Assessment Report
104	2020 Diesel Fire Pump Test.jpg
105	2020 Electric Fire Pump Test.jpg
106	2021 Unit #1 Condenser Inspection Report.pdf
107	2021 Unit #3 Condenser Inspection Report.pdf
108	21490-001 as built report (jessicamcgrath@nlh.nl.ca).docx
109	21490-003 as built report (jessicamcgrath@nlh.nl.ca).docx
110	238-04-0170-016fire protection system(jessicamcgrath@nlh.nl.ca).pdf
111	238-05-0210-009 FUEL ADDITIVE SYSTEM R2(jessicamcgrath@nlh.nl.ca).pdf
112	238-06-0210-001 UNITS 1&2 CW SYSTEM R14(jessicamcgrath@nlh.nl.ca).pdf
113	238-06-0210-007 CHLORINE SYSTEM R3(jessicamcgrath@nlh.nl.ca).pdf
114	238-06-0210-011SCREEN WASH SYSTEM R5(jessicamcgrath@nlh.nl.ca).pdf
115	238-08-0210-013 DOMESTIC WATER R9(jessicamcgrath@nlh.nl.ca).pdf
116	238-08-0210-044 VACUUM SYSTEM R2(jessicamcgrath@nlh.nl.ca).pdf
117	238-10-0210-002 U1 MAIN&REHEAT SYS TURBINE DRAINS R11(jessicamcgrath@nlh.nl.ca).pdf
118	238-10-0210-003 HP FEEDWATER SYSTEM R16(jessicamcgrath@nlh.nl.ca).pdf
119	238-10-0210-009 GENERAL EQUIP LAYOUT R4(jessicamcgrath@nlh.nl.ca).pdf
120	238-10-0210-029 U1&2 LP FEEDWATER SYSTEM R22(jessicamcgrath@nlh.nl.ca).pdf
121	238-10-0210-045 U1&2 MAIN&REHEAT SYTEMTURBINE DRAINS R 0(jessicamcgrath@nlh.nl.ca).pdf
122	238-10-0210-063 U1&2 AIR FLUE GAS SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
123	238-10-0210-064 U1&2 SOOTBLOWER SYSTEM R4(jessicamcgrath@nlh.nl.ca).pdf
124	238-10-0210-065 U1&2 CONTINUOUS BLOWDOWN & SAMPLING R1(jessicamcgrath@nlh.nl.ca).PDF
125	238-10-0210-087 U1&2 RESERVE FEEDWATER R15(jessicamcgrath@nlh.nl.ca).pdf
126	238-10-0210-099 U1&2 BFP GLAND SEALING WATER SYS R11(jessicamcgrath@nlh.nl.ca).pdf
127	238-10-0210-106 U1&2 BLED STEAM & HEATER DRAINS R23(jessicamcgrath@nlh.nl.ca).pdf
128	238-10-0210-112 U1&2 FW HEATER VENTSR9(jessicamcgrath@nlh.nl.ca).pdf
129	238-10-0210-117 U1 BOILER VENTS,DRAINS&BLOWDOWN R14(jessicamcgrath@nlh.nl.ca).pdf
130	238-10-0210-121 (Stage I Wash and Rinse).pdf
131	238-10-0210-121 WASH&RINSEWATER FOR AIRHEATERS R6(jessicamcgrath@nlh.nl.ca).pdf
132	238-10-0210-124 U2 BOILER VENTS,DRAINS&BLOWDOWN(jessicamcgrath@nlh.nl.ca).pdf
133	238-10-0210-127 U1&2 FUEL OIL SYSTEM R20(jessicamcgrath@nlh.nl.ca).pdf
134	238-10-0210-134 U1&2 LIGHT OIL & iGNITOR AIR SUPPLY R 19(jessicamcgrath@nlh.nl.ca).pdf
135	238-10-0219-010 SAMPLE COOLING SYSTEM R4(jessicamcgrath@nlh.nl.ca).pdf
136	238-10-0219-013 STEAM & WATER ANALYIS R2(jessicamcgrath@nlh.nl.ca).pdf
137	238-12-0210-001 RAWWATER & MAKEUP SYSTEM R13(jessicamcgrath@nlh.nl.ca).pdf
138	238-12-0210-016 U1 AIRPREHEATER STEAM SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
139	238-12-0210-029 U1 AUX STEAM SYSTEM R27(jessicamcgrath@nlh.nl.ca).pdf
140	238-12-0210-030 U2 AUX STEAM SYSTEM R28(jessicamcgrath@nlh.nl.ca).pdf
141	238-12-0210-034 AUX BOILER AND CONDENSATE RETURN SYSTEM R9(jessicamcgrath@nlh.nl.ca).pdf
142	238-12-0210-041 U2 AIR PREHEATER SYSTEM R 5(jessicamcgrath@nlh.nl.ca).pdf
143	238-12-0210-043 U1&2 INSTRUEMENT AIR SYSTEM R11(jessicamcgrath@nlh.nl.ca).pdf
144	238-12-0210-046 VEHICLE WASH SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
145	238-12-0210-048 U1&2 SERVICE AIR SYSTEM R14(jessicamcgrath@nlh.nl.ca).pdf
146	238-12-0210-054 U1&2 TG SYSTEM R12(jessicamcgrath@nlh.nl.ca).pdf
147	238-12-0210-060 U1&2 GENERAL SERVICE COOLING SYSTEM R10(jessicamcgrath@nlh.nl.ca).pdf
148	238-12-0210-068 U1&2 GENERATOR HYDROGEN & CO2 SYTEMS R2(jessicamcgrath@nlh.nl.ca).pdf
149	238-12-0210-072 U1&2 N2 BLANKETING R2(jessicamcgrath@nlh.nl.ca).pdf
150	238-12-0210-077 U1&2 CHEMICAL FEED SYSTEM R8(jessicamcgrath@nlh.nl.ca).pdf
151	238-12-0210-084 U1&2 AISPIRATING AIR R9(jessicamcgrath@nlh.nl.ca).pdf
152	238-12-0210-090 U1&2 CONDENSER AIR EXTRACTION SYSTEM R8(jessicamcgrath@nlh.nl.ca).pdf
153	238-12-0210-114 WARM AIR MAKE-UP NORTH R3(jessicamcgrath@nlh.nl.ca).pdf
154	238-12-0210-115 WARM AIR MAKE-UP SOUTH(jessicamcgrath@nlh.nl.ca).pdf
155	238-12-0210-134 STG 1 GSCW SYSTEM R1(jessicamcgrath@nlh.nl.ca).pdf
156	238-13-0310-001 ELECTRICAL POWER SYSTEM SINGLE LINE R1(jessicamcgrath@nlh.nl.ca).pdf
157	238-13-0310-038 U1 BLOCK PROTECTION DIAGRAM R2(jessicamcgrath@nlh.nl.ca).pdf
158	3x2x9 Pump Curve Manual.pdf
159	3x2x9 Pump Curve.png
160	940310 HPIP Customer Report.pdf
161	940310 LP Customer Report.pdf
162	Alstom_ Holyrood_2012 TG Outage Reports_Dec 2012(jessicamcgrath@nlh.nl.ca).pdf
163	April Comp #1.pdf
164	April Comp #2.pdf
165	Atlas Copco Service Report 3-May-2021 visit.pdf
166	Attemperator supply to east - pin removed.JPG
167	Attemperator supply to west - gap at pin.JPG
168	Attemperator supply to west - pin removed.JPG
169	bf draft(jessicamcgrath@nlh.nl.ca).doc

Serial No.	Document Title
170	BF Pump - Final Report(jessicamcgrath@nlh.nl.ca).doc
171	BF Pump DCI Report(jessicamcgrath@nlh.nl.ca).pdf
172	CFRG033399_MHC and Oil pumps Overhaul_Guntner(jessicamcgrath@nlh.nl.ca).pdf
173	CFRG034145_Commissioning_160812_Scott(jessicamcgrath@nlh.nl.ca).pdf
174	CFRG034348_Warranty Repair_160903_Scott(jessicamcgrath@nlh.nl.ca).pdf
175	CFRG034522_warranty work East LHS SV_Scott(jessicamcgrath@nlh.nl.ca).pdf
176	Comment Log.xlsx
177	Compressor #2 oil analysis Sept 2020.pdf
178	Compressor #2 Oil Leak.docx
179	CONDENSER Inspection Plan.pdf
180	CW Pump - Service Report(jessicamcgrath@nlh.nl.ca).pdf
181	CW Pump - Service Report.pdf
182	Day Tank Out of Service 2013 - Complete Report.pdf
183	Day Tank Report - In-Service.pdf
184	Dec Comp #1.pdf
185	Dec Comp #2.pdf
186	EB0-004473 NFLDLH Holyrood #3 Condenser Final Report (3).pdf
187	Electric Fire Pump Manual.pdf
188	Elementary Drawings 1403-V-311-E-054(jessicamcgrath@nlh.nl.ca).pdf
189	EPS-RF-040 Nalcor WO 4002603, TS5104U14337, Compressor #1.pdf
190	EPS-RF-040 Nalcor WO 4002603, TS5582U16327, Compressor #2.pdf
191	event comp 1.pdf
192	event comp 2.pdf
193	Ext Pump - Service Report(jessicamcgrath@nlh.nl.ca).pdf
194	Field Service Report - Unit 2 CV Troubleshooting April 2019(jessicamcgrath@nlh.nl.ca).pdf
195	Fire Hydrant Report Hydrants A-D.pdf
196	Fire Hydrant Report Hydrants E-H.pdf
197	Fire Hydrant Report Hydrants I-L.pdf
198	Fire Hydrant Report Hydrants M-P.pdf
199	Fire Hydrant Report Hydrants Q-T.pdf
200	Fire Hydrant Report Hydrants U-W.pdf
201	Flow Diagram of Shaft Sealing System 1403-V-311-M-044(jessicamcgrath@nlh.nl.ca).pdf
202	FSR 065910 Generator_Ken Roberts(jessicamcgrath@nlh.nl.ca).pdf
203	FSR_065909_Valve_Ken Roberts(jessicamcgrath@nlh.nl.ca).pdf
204	Gen Operation-Cold Start up of Uni(jessicamcgrath@nlh.nl.ca).pdf
205	Gen(jessicamcgrath@nlh.nl.ca).pdf
206	Holyrood #2 EFSR 2014 Generator(jessicamcgrath@nlh.nl.ca).pdf
207	Holyrood Inspections.xlsx
208	Holyrood Rotor RSO FieldService Report CFSR28102017(jessicamcgrath@nlh.nl.ca).pdf
209	Holyrood S3-HST0004 Startup Valve outage 2019(jessicamcgrath@nlh.nl.ca).pdf
210	Holyrood Unit 1 East BF 26-Aug-2009(jessicamcgrath@nlh.nl.ca).pdf
211	Holyrood Unit 1 East BF 8-Sept-2015(jessicamcgrath@nlh.nl.ca).pdf
212	Holyrood Unit 1 Generator Report 2003(jessicamcgrath@nlh.nl.ca).pdf
213	Holyrood Unit 1 West and Unit 3 East CW Pumps 16-Sept-2010(jessicamcgrath@nlh.nl.ca).pdf
214	Holyrood Unit 1 West and Unit 3 East CW Pumps 16-Sept-2010.pdf
215	Holyrood Unit 1 West BF 10-Oct-2016(jessicamcgrath@nlh.nl.ca).pdf
216	Holyrood Unit 1 West BF 7-Sept-2010(jessicamcgrath@nlh.nl.ca).pdf
217	Holyrood Unit 2 East BF 19-July-2014(jessicamcgrath@nlh.nl.ca).pdf
218	Holyrood Unit 3 East and West BF 17-Jul-2016(jessicamcgrath@nlh.nl.ca).pdf
219	Holyrood Unit 3 East BF 12-May-2014(jessicamcgrath@nlh.nl.ca).pdf
220	Holyrood Unit 3 East BF 9-Sept-2013(jessicamcgrath@nlh.nl.ca).pdf
221	Holyrood Unit 3 West BF 8-July-2013(jessicamcgrath@nlh.nl.ca).pdf
222	HolyroodUnit1ValveOutage 2009(jessicamcgrath@nlh.nl.ca).pdf
223	HRD - Fire Protection System Description 1986.pdf
224	HRD 20 YEAR PLAN (2021).pdf
225	HRD RT1 fluid_report_pdf.pdf
226	HRD RT2 fluid_report_pdf.pdf
227	HTGS (Holyrood) P&ID Set.pdf
228	Jockey Pump Manufacturer and Model.png
229	Jockey Pump Name Plate.png
230	Low Load Test Unit#3 March 25th 2021 A1 Shift(jessicamcgrath@nlh.nl.ca).pdf
231	Low Load Test Unit#3 March 25th 2021 D Shift 2000-0800(jessicamcgrath@nlh.nl.ca).pdf
232	Low Load Test Unit#3 March 26th 2021 A Shift 0800-2000hrs(jessicamcgrath@nlh.nl.ca).pdf
233	Low Load Test Unit#3 March 27th 2021 A Shift 0800-2000hrs(jessicamcgrath@nlh.nl.ca).pdf
234	Low Load Test Unit#3 March 28th 2021 A Shift 0800-2000hrs(jessicamcgrath@nlh.nl.ca).pdf
235	Low Load Test Unit#3 March 28th 2021 A1 Shift 2000hrs-0800hrs(jessicamcgrath@nlh.nl.ca).pdf
236	Nalcor 1 -2017.pdf
237	Nalcor 2 -2017.pdf
238	Nalcor Compressor 1 Repairs - Nov 2020.pdf
239	Nalcor compressor 2 repair - Oct 2020.pdf
240	NALCOR Holyrood Unit #2 Minor Valve Inspection 2017(jessicamcgrath@nlh.nl.ca).pdf
241	Nalcor Holyrood, WO 4034537, Oct 2020 1.pdf
242	Nalcor Holyrood, WO 4034537, Oct 2020 2.pdf
243	Nalcor PM compressor 1 - Oct 2019.pdf
244	Nalcor PM compressor 2 - Oct 2019.pdf
245	Nalcor, Holyrood, WO 4066445, SN TS5104U14337 Nov 2020.pdf
246	NALCOR_ Holyrood_2012 TG Outage Reports_Dec 2012(jessicamcgrath@nlh.nl.ca).pdf
247	Nfld Lab Hydro BF Pump Service Report 20170526(jessicamcgrath@nlh.nl.ca).pdf
248	NFPA 20.PNG
249	NL Hydro Sprinkler Valves Zones page 2.pdf
250	NL Hydro Sprinkler Valve Zones page 3.pdf
251	NL Hydro Sprinkler Valve Zones page1.pdf
252	NL Hydro Tank 3 API 653 In Service Inspection Report.pdf
253	NL Hydro Tank 4 API 653 In Service Inspection Report.pdf
254	PAUT-SS072821-001 R0.pdf

Serial No.	Document Title
255	Penthouse - Desup inspection port.JPG
256	Pipe Shop sprinkler report.pdf
257	PMI-001-WW-U3 Steam Chest.pdf
258	Procedure_ 0326-POI-07 Boiler Operation - Starting Main Boiler(jessicamcgrath@nlh.nl.ca).pdf
259	Procedure_ 0541-POP-112 Safe, Efficient Start-up of Unit #1 Bo(jessicamcgrath@nlh.nl.ca).pdf
260	Procedure_ 0548-POP-001 Placing Turbine on Turning Gear - Unit(jessicamcgrath@nlh.nl.ca).pdf
261	Procedure_ 0550-POP-003 Filling Deaerator Using Condensate Ext(jessicamcgrath@nlh.nl.ca).pdf
262	Procedure_ 0554-POP-007 Prewarming Procedure for Units #1 & #2(jessicamcgrath@nlh.nl.ca).pdf
263	Procedure_ 0578-POP-013 Proper Establishment of Generator Seal(jessicamcgrath@nlh.nl.ca).pdf
264	Procedure_ 0580-POP-015 Start-up of the CW System on all Units(jessicamcgrath@nlh.nl.ca).pdf
265	Procedure_ 0581-POP-016 Start-up of Boiler Feed Pump on all Un(jessicamcgrath@nlh.nl.ca).pdf
266	Procedure_ 0598-POP-032 Start-up of Condensate Extraction Pump(jessicamcgrath@nlh.nl.ca).pdf
267	Procedure_ 0606-POP-040 Firing Boiler with Heavy Oil Burners -(jessicamcgrath@nlh.nl.ca).pdf
268	Procedure_ 0614-POP-043 Firing Boiler with Light Oil Igniters(jessicamcgrath@nlh.nl.ca).pdf
269	Procedure_ 0647-POP-075 Start-Up of Units #1 & #2 Hydraulic Fl(jessicamcgrath@nlh.nl.ca).pdf
270	Procedure_ 0681-POP-109 Roll Off and Synchronize Units #1 & #2(jessicamcgrath@nlh.nl.ca).pdf
271	Procedure_ 0991-POP-155 Safe, Efficient Start-up of Unit #2 Bo(jessicamcgrath@nlh.nl.ca).pdf
272	Pump Orientations.PNG
273	RFI 004 Reponse.zip
274	RFI-003 - HRD Inventory List - May 28, 2021.xlsx
275	Shawmont Bldg sprinkler report .pdf
276	Spray tube - supply to east.JPG
277	Spray tube - supply to west v2.JPG
278	Spray tube - supply to west v3.JPG
279	Spray tube - supply to west.JPG
280	stage 2 floor drains(jessicamcgrath@nlh.nl.ca).pdf
281	Start Up Report_Tony Ravnik_Holyrood GS U2(jessicamcgrath@nlh.nl.ca).pdf
282	Tank 1 - Inspection Interval Extension Report.pdf
283	Tank In-Service Inspection Report Nalcor Tank #1 Holyrrod Gen Stn r1.pdf
284	Title page(jessicamcgrath@nlh.nl.ca).pdf
285	Training Centre sprinkler report .pdf
286	trip comp 2.pdf
287	trip hist comp 1.pdf
288	U1 Outage Report - 2015(jessicamcgrath@nlh.nl.ca).pdf
289	U1 Turbine Valve Outage Report 2018(jessicamcgrath@nlh.nl.ca).pdf
290	U1 West BFP Incident Investigation Report - Rev5.pdf
291	U2 West BF Pump - Service Report May 26, 2017(jessicamcgrath@nlh.nl.ca).pdf
292	U3 Excitation Transformer Condition Assessment.docx
293	U3 Outage Report 2019(jessicamcgrath@nlh.nl.ca).pdf
294	Unit 1 - SH Attemperator - 2010 Report.pdf
295	Unit 1 2020.pdf
296	UNIT 1 Boiler Repair 2020.pdf
297	Unit 1 Condenser Report - 2014.pdf
298	Unit 1 Cooling Water Pump East Appendix A(jessicamcgrath@nlh.nl.ca).pdf
299	Unit 1 Cooling Water Pump East Appendix A.pdf
300	UNIT 1 EVT 2020.pdf
301	UNIT 1 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
302	UNIT 1 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
303	UNIT 1 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
304	UNIT 1 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
305	UNIT 1 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
306	UNIT 1 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
307	UNIT 1 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
308	UNIT 1 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
309	UNIT 1 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
310	Unit 2 - SH Attemperator - 2005 Report.pdf
311	Unit 2 2020.pdf
312	UNIT 2 Boiler Repair 2020.pdf
313	Unit 2 Condenser Report - 2014.pdf
314	Unit 2 EVT 2020.pdf
315	Unit 2 Extraction Pump Appendix A(jessicamcgrath@nlh.nl.ca).pdf
316	UNIT 2 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
317	UNIT 2 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
318	UNIT 2 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
319	UNIT 2 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
320	UNIT 2 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
321	UNIT 2 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
322	UNIT 2 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
323	UNIT 2 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
324	Unit 2 Repair and Bench Tests.pdf
325	UNIT 2 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
326	UNIT 2 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
327	UNIT 2 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
328	UNIT 2 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
329	UNIT 2 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
330	UNIT 2 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
331	UNIT 2 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
332	UNIT 2 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
333	Unit 3 2020.pdf
334	Unit 3 Boiler FWP West Appendix A(jessicamcgrath@nlh.nl.ca).pdf
335	UNIT 3 Boiler Repair 2020.pdf
336	Unit 3 Condenser Report - 2014.pdf
337	UNIT 3 EVT 2020.pdf
338	UNIT 3 NORTH RETURN B P #2 (2003)(jessicamcgrath@nlh.nl.ca).dwg
339	UNIT 3 NORTH RETURN B P (2003)(jessicamcgrath@nlh.nl.ca).dwg

Serial No.	Document Title
340	UNIT 3 NORTH RETURN T P # 2 (2003)(jessicamcgrath@nlh.nl.ca).dwg
341	UNIT 3 NORTH RETURN T P (2003)(jessicamcgrath@nlh.nl.ca).dwg
342	UNIT 3 NORTH RETURN (2003)(jessicamcgrath@nlh.nl.ca).dwg
343	Unit 3 North.MPG
344	Unit 3 North2.MPG
345	UNIT 3 SOUTH RETURN B P #4 (2003)(jessicamcgrath@nlh.nl.ca).dwg
346	UNIT 3 SOUTH RETURN B P (2003)(jessicamcgrath@nlh.nl.ca).dwg
347	UNIT 3 SOUTH RETURN T P #3 (2003)(jessicamcgrath@nlh.nl.ca).dwg
348	UNIT 3 SOUTH RETURN T P (2003)(jessicamcgrath@nlh.nl.ca).dwg
349	UNIT 3 SOUTH RETURN (2003)(jessicamcgrath@nlh.nl.ca).dwg
350	Unit 3 South.MPG
351	unit1 valve inspection report 2006(jessicamcgrath@nlh.nl.ca).pdf
352	vac draft(jessicamcgrath@nlh.nl.ca).doc
353	Vac Pump - Final Report(jessicamcgrath@nlh.nl.ca).doc
354	Vac Pump - Final Report.doc
355	Vacuum Pump DCI Report(jessicamcgrath@nlh.nl.ca).pdf
356	Vacuum Pump DCI Report.pdf
357	VR.121807 (#3 - 2012).pdf
358	VR_CA10_000401400468_APF138641_20190213 (#3 - 2019).pdf
359	VR_CA10_000401400468_APF138641_20190218 (#3 - 2019).pdf
360	VR_CA10_000401400468_APF138641_20190218_1 (#3 - 2019).pdf
361	VR_CA10_000401400468_APF138641_20190218_1 (#3 -2019).pdf
362	VR_CA10_000401733853_APF138641_20191105 (#3 - 2019).pdf
363	VR_report_247027_APF138641_20180313 (#3 - 2018).pdf
364	VR_report_247027_APF138641_20180315 (#3 - 2018).pdf
365	VR_report_260858_APF138641_20181025 (#3 - 2018).pdf
366	VR_report_260858_APF138641_20181029 (#3 - 2018).pdf
367	VR153147 (#3 - 2013).pdf
368	Warehouse sprinkler report.pdf
369	238-10-6022-041 HR81.pdf
370	238-10-6022-046 MS1.pdf
371	238-10-6022-047 HR1A.pdf
372	238-10-6022-048 HR2B.pdf
373	238-10-6022-049 HR61.pdf
374	238-10-6022-050 HR71.pdf
375	238-10-6022-051 HR11.pdf
376	238-10-6022-052 MS1A.pdf
377	238-10-6022-053 MS10.pdf
378	238-10-6022-084 CR2.pdf
379	238-10-6022-085 CR4.pdf
380	238-10-6022-086 CR10.pdf
381	238-10-6022-087 CR13-1.pdf
382	238-10-6022-088 CR18.pdf
383	238-10-6022-089 CR20.pdf
384	238-10-6022-128 MS11.pdf
385	238-10-6022-153 MS16.pdf
386	238-10-6022-154 MS14.pdf
387	238-10-6022-158 HR15.pdf
388	238-10-6022-327 MS13.pdf
389	238-10-6022-329 HR14.pdf
390	1403-V-281-M-090 HR1.pdf
391	1403-V-281-M-091 HR4.pdf
392	1403-V-281-M-092 HR6-1.pdf
393	1403-V-281-M-093 MS1-1.pdf
394	1403-V-281-M-094 MS2-1.pdf
395	1403-V-281-M-095 MS3-1.pdf
396	1403-V-281-M-096 MS6-1.pdf
397	1403-V-281-M-097 MS7.pdf
398	1403-V-281-M-100 CR6.pdf
399	1403-V-281-M-101 CR3.pdf
400	1403-V-281-M-102 CR1-1.pdf
401	1403-V-281-M-103 CR2-1.pdf
402	1403-V-281-M-152 HR7.pdf
403	2019 - Unit 1 - HEP Hangers.xlsx
404	2019 - Unit 2 - HEP Hangers.xlsx
405	2019 - Unit 3 - HEP Hangers.xlsx
406	2020 - Unit 1 - HEP Hangers.xlsx
407	2020 - Unit 2 - HEP Hangers.xlsx
408	2020 - Unit 3 - HEP Hangers.xlsx
409	U1-U2 CR Hangers.pdf
410	U1-U2 HR Hangers.pdf
411	U1-U2 MS Hangers.pdf
412	U3 CR Hangers.pdf
413	U3 HR Hangers.pdf
414	U3 MS Hangers.pdf
415	238-10-6022-023 MS Steelwork Loading.pdf
416	238-10-6022-024 HR Steelwork Loading.pdf
417	238-10-6022-025 CR Steelwork Loading.pdf
418	238-10-6022-028 HP Feedwater Steelwork Loading.pdf
419	238-10-6022-040 MS6.pdf
420	2021 - HRD U2 Test Report - Rev1 - Final.pdf
421	~$Unit 1 2021 PIR Log.xlsx
422	PIR #001 Crossover Pipe Lifting Lug Repair 210608.docx
423	PIR #002 N1 Labyrinth Packing 210609.docx
424	PIR #0023 T1 Bearing & Thrust Bearing Damage.pdf

Serial No.	Document Title
425	PIR #003 Main Stop Valve Cover 210612.docx
426	PIR #004 LPGEN Coupling Studs 210612.docx
427	PIR #005 NonReturn Valve 102 210614.docx
428	PIR #006 Control Valve No. 4 210615.docx
429	PIR #007 GE L0 Bucket Damage 210615.docx
430	PIR #007 MT6WW GE LP Blade With Impacted Damage.pdf
431	PIR #007 REV1 GE L0 Bucket Damage 210710.docx
432	PIR #008 Control Valve No. 5 210616.docx
433	PIR #009 N3 Labyrinth Packing 210616.docx
434	PIR #009 N3 Labyrinth Packing Rev1 210616.docx
435	PIR #010 Control Valve No. 6 210617.docx
436	PIR #011 HPIP Horizonal Joint Cuts 210619.docx
437	PIR #012 IP Inner Casing Peening Lip Restoration 210619.docx
438	PIR #013 IP Rotor Buckets and Diaphragms 210621.docx
439	PIR #014 NonReturn Valve 101 & 104B 210621.docx
440	PIR #015 Reheat Stop Valve Covers 210621.docx
441	PIR #016 Control Valve #2 & 3 Stem Replacement 230621.docx
442	PIR #017 Control Valve #2 & 3Stem Bushing Replacement 230621.docx
443	PIR #017 REV1 Control Valve #1, 3 & 5 Stem Bushing Replacement 210706.docx
444	PIR #018 MSV and RSV Steam Dam (Vortex Breakers) Repair 230621.docx
445	PIR #019 Main Stop Valve Stem Replacement 260621.docx
446	PIR #020 NRV 103 Actuator Piston Assembly Replacement 010721.docx
447	PIR #021 - Excessive Centre Pin Clearance (Sideslip) and Packing Radial Clearance
448	PIR #021 Centre Pin Side slips and Radial Clearances 62821.xls
449	PIR #022 HPIP Horizonal Joint Stud of Different Size 210703.docx
450	PIR #022 REV1 HPIP Horizonal Joint Stud of Different Size 210710.docx
451	PIR #024 Abnormal packing condition and bearing loadings 210709.docx
452	PIR #025 Control Valve #2 & 6 Disk Replacement 210706.docx
453	PIR #026 AsFound T2 and T3 Bearing Conditions.docx
454	PIR #027 Turbine End LP L0 Bucket Has Linear Indication 210710.docx
455	PIR #027 MT5WW TE LP Blade Has Linear Indication.pdf
456	PIR #028 HPIP Casing Stud Hole Thread Repair 210712.docx
457	PIR #028 (REVISED) HPIP Casing Stud Hole Thread Repair 210818.docx
458	PIR #029 CV Crosshead Runout and Bushing Replacement 210716.docx
459	PIR #030 LP Last Stage Bucket Erosion Shield Requires Repair 210719.docx
460	PIR #030 MT7WWLP Rotor Erosion Shield.pdf
461	PIR #031 RHS Reheat Valve Steam Strainer Rivets 210721.docx
462	PIR #031 PT21WWRHS CRV Steam Strainer.pdf
463	PIR #032 Steam Packing Alignment and Repair 210722.docx
464	PIR #033 T1 Bearing Ring Has Deformed 210727.docx
465	PIR #033 T1 Bearing Strong Back Bore Dimenions.pdf
466	PIR #034 Bearing Oil Deflectors Have Excessive Clearances 210803.docx
467	PIR #034 D309301 Oil Deflectors As Found.pdf
468	PIR #035 Axial Crush Pins Have Excessive Clearances 210818.docx
469	Unit 1 2021 PIR Log.xlsx
470	039 South Bottom J Pattern Data.xlsx
471	039 South Bottom U Pattern Det Data.xlsx
472	039 South Top Middle Det Data.xlsx
473	039 South Top U Pattern Det Data.xlsx
474	238-10-6002- 033 North Condenser Det Data.xlsx
475	238-10-6002- 033 South Condenser Det Data.xlsx
476	238-10-6002-033 North Condenser (2021825) ET Update TEAM Industrial Services.PDF
477	238-10-6002-033 North Condenser (2021830) ET Report TEAM Industrial Services.pdf
478	238-10-6002-033 South Condenser (2021825) ET Update TEAM Industrial Services.PDF
479	238-10-6002-033 South Condenser (2021830) ET Report TEAM Industrial Services.pdf
480	238-10-6002-039 North Bottom Candy Cane.PDF
481	238-10-6002-039 North Bottom Candy Cane_Det Data.xlsx
482	238-10-6002-039 North Bottom U Pattern.PDF
483	238-10-6002-039 North Bottom U Pattern_Det Data.xlsx
484	238-10-6002-039 North Top Middle.PDF
485	238-10-6002-039 North Top Middle_Det Data.xlsx
486	238-10-6002-039 North Top U Pattern.PDF
487	238-10-6002-039 North Top U Pattern_Det Data.xlsx
488	238-10-6002-039 North (2021917) ECT Report Team Industrial Services.pdf
489	238-10-6002-039 South (2021922) ECT Report Team Industrial Services.pdf
490	2007 Capital Expenditures & Carryover Report.pdf
491	2008 Capital Expenditures & Carryover Report.pdf
492	2009 Capital Expenditures & Carryover Report.pdf
493	2010 Capital Expenditures & Carryover Report.pdf
494	2011 Capital Expenditures & Carryover Report.pdf
495	2012 Capital Expenditures & Carryover Report.pdf
496	2013 Capital Expenditures & Carryover Report.pdf
497	2014 Capital Expenditures & Carryover Report.pdf
498	2015 Capital Expenditures & Carryover Report.pdf
499	2016 Capital Expenditures & Carryover Report.pdf
500	2017 Capital Expenditures & Carryover Report REVISED - 2018-04-02.pdf
501	2017 Capital Expenditures & Carryover Report.pdf
502	2018 Capital Expenditures & Carryover Report.pdf
503	2019 Capital Expenditures & Carryover Report.pdf
504	2021 Thermal Capital Expenditures.pdf
505	2021 Unite #2 Condenser Inspection Report.pdf
506	H365408-0000-210-066-0001, Vol. 1 Rev.0 JN Comments.pdf
507	HOLYROOD GS BOILER CONTRACT_2021 Year End Meeting - Final.pptx
508	HOLYROOD Thermal Station Tap Root Investigation (CRH 2021) Feb 21.docx
509	NLH CapEx and Carryover Report 2020.pdf

Serial No.	Document Title
510	rpt_rgm_20141222)Holyrood TGS_Fuel_Oil_Specification_Review_and_Mercantile Analysis_Final.pdf
511	Transactional Detail - Select Dept - with WO Desc - 10 year.xlsx
512	U1 Turbine Vibration Report - Final.pdf
513	U3 Boiler Tube Failure TapRooT Report Rev5 Stamped.pdf
514	Unit 1 MW Output 1997-Present.xlsx
515	Unit 2 MW Output 1997-Present.xlsx
516	Unit 3 MW Output 1997-Present.xlsx
517	Vol III, Att 12 - Bay d'Espoir Hydro Generating Unit 8 Summary Report.pdf
518	Vol III, Att 14 - Gas Turbine Alternatives Report.pdf
519	Volume III, Rev.1 - Long-Term Resource Plan.pdf

Appendix B
Hatch Inspection Plan

HTGS Unit 1

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Recommended Inspections / NDE		Execution date		Priority	CAPITAL		General Comments
The row on the right is for information purposes and will not be printed in final DBM	*Thermal Subject Index (TSI) Equipment or Area Description*	*High level concerns and condition assessments will be listed here. Information sources (references) will include TSI meeting minutes, Previous reports and studies, NDE results, and maintenance history when available.*		*Recommended workscope for life assessment. Workscope may include Remove and Replace (RR), Refurbish Existing (RE), or Operate and Monitor Existing (OME)*		*Recommended inspection or NDE requirements to further assess equipment condition.*		*Identify if workscope is to be executed during outage. Indicate the date workscope is to be carried out.*		*Identify Priority of the Workscope to be Executed.*	*Workscope currently identified as capital upgrade.*		
Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
100 100	**Building Structures - General**												
130	**Site Improvements (General)**												
143	Site Services - Sewers and Drainage System				*NLH to inform of License requirements*								
		Substation storm water storage tank condition is unknown. Also need to consider oily drains sumps and traps that may need consideration.	OME		One time inspection (VT) of underground tank / reservoir. Recommend repairs if necessary.	VT							
100	SUBTOTAL												
200 200	**Service Buildings -General**												
207													
220	**Cooling Water Supply and Storage - Cooling Water Supply and Storage - General**												
221	Canals												
222		Part of Hatch Sub-Contractor Insepection		OME	Need to wait till Inspection Results	Inspection with ROV				2021			
200	SUBTOTAL												
300	**Steam Generation Facilities**												
310	**Boiler & Auxiliaries**												
311.00	Economizer to SH Outlet Header												
311.10	Economizer & Links												
	Economizer Tubing, Tubes	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*	OME	Wall Thickness above refurbish/replace criteria. Last inspection 2016.	UT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
	Economizer Inlet Header, Header	Cracking	*BWL S20-030 CAMBTP9745*	OME	Borehole Cracking Unchanged; Reinspect in 3 years. Last inspection 2017.	Internal visual		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	FAC Site 1-1 Economizer Inlet Header Piping Bottom Bends, pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*	OME	Reinspect in 3 years. Last inspection 2020.	UT grid		*BWL S20-030 CAMBTP9745*		2023	Next Inspection		
311.20	Steam Drum	Good condition, overall functional		OME		Visual Inspection during next outage and SPOT NDE where requried.							
311.30	Lower Waterwall Drums (Mud drums)	Good condition, overall functional		OME		Visual Inspection during next outage and SPOT NDE where requried.							
	Steam Drum Downcomer Nozzle, Pipe	Thermal Fatigue Cracking	*BWL S20-030 CAMBTP9745*		No indications observed. Last inspection 2019.	MT		*BWL S20-030 CAMBTP9745*		2018	Next Inspection		
311.40	Waterwalls	Good condition, overall functional		OME		Visual Inspection during next outage and SPOT NDE where requried.							
311.50	Superheaters												
	SH-6 Header Outlet Nozzle Welds, Header	Creep Crack	*BWL S20-030 CAMBTP9745*		No active cracking. Last inspection 2019.	PAUT, MT, Replica		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
	SSH Inlet (SH5) Tube-to-Header Welds, Header	Cracks (2018)	*BWL S20-030 CAMBTP9745*		Cracks excavated, and weld refurbished. Last inspection 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021			
	SSH Outlet (SH6) Tube-to-Header Welds, Header	Cracks (2018)	*BWL S20-030 CAMBTP9745*		Cracks excavated, and weld refurbished. Last inspection 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021			
	Primary Superheater Tubing, Tubes	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*		Wall Thickness above refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		

HTGS Unit 1

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Recommended Inspections / NDE		Execution date		Priority	CAPITAL		General Comments
The row on the right is for information purposes and will not be printed in final DBM	*Thermal Subject Index (TSI) Equipment or Area Description*	*High level concerns and condition assessments will be listed here. Information sources (references) will include TSI meeting minutes, Previous reports and studies, NDE results, and maintenance history when available.*		*Recommended workscope for life assessment. Workscope may include Remove and Replace (RR), Refurbish Existing (RE), or Operate and Monitor Existing (OME)*		*Recommended inspection or NDE requirements to further assess equipment condition.*		*Identify if workscope is to be executed during outage. Indicate the date workscope is to be carried out.*		*Identify Priority of the Workscope to be Executed.*	*Workscope currently identified as capital upgrade.*		
Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
	Secondary Superheater Tubing	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*		Wall Thickness at some locations fell below refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
311.60	S.H. Attemperator	Check for Cracks and Erosion		OME	refurbish/replace criteria	UT							
311.70	Boiler Tubes												
312.00	Main Steam, Hot & Cold RH Lines (HEP - High Energy Piping)												
	Boiler Floor Tubes, Tubes	Wall Thinning	*BWL S20-030 CAMBTP9745*		one locations on hot side below recommended Refurbish/Replace thickness, others approaching this value. Last inspection 2019.	UT		*BWL S20-030 CAMBTP9745*		2021(hot side) 2025(cold side)	Next Inspection		
	Waterwall Tubes, Tubes	Wall Thinning/ Pitting	*BWL S20-030 CAMBTP9745*		some pitting and ID scale destabilization due to upset chemistry event. Last inspection 2019.	Metallurgical Assessment		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
	Lowe Vestibule Feeder Tubes	Pitting	*BWL S20-030 CAMBTP9745*		No Cracking, Minor pitting. Last inspection 2017.	PAUT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
312.10	Main Steam Lines	Good condition, overall functional			To be Inspectied this year	Replica, PAUT, MT				2021			
312.20	Cold Reheat Lines	Good condition, overall functional			To be Inspectied this year	Replica, PAUT, MT				2021			
312.30	RH Attemperator	Good condition, overall functional			To be Inspectied this year	UT				2021			
312.40	Reheater												
	RH Outlet (RH2) Tube-to-Header Welds, Header	Cracks (2018)	*BWL S20-030 CAMBTP9745*		Cracks excavated, and weld refurbished. Last inspection 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	RH Inlet (RH1) Tube-to-Header Welds, Header	No record	*BWL S20-030 CAMBTP9745*		no indication observed. Last inspection 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	Reheater Tubing, Tubes	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*		Wall Thickness at some locations fell below refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	East Hot Reheat Combined Stop Valve Weld, Pipe	No record	*BWL S20-030 CAMBTP9745*		no degradation at welds. Last inspection 2019.	PAUT, MT, Replica		*BWL S20-030 CAMBTP9745*		West Reheat CSV Weld 2022	Next Inspection		
312.50	Hot Reheat Lines	Good condition, overall functional			To be Inspectied this year	UT				2021			
313.00	Vents, Drains, Blowdown (Boiler General)												
313.10	Economizer Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.20	Drums Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.30	Downcomer Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.40	Superheater Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.50	Attemperator (Desuperheater) Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.60	Main Steam Line Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.70	Reheat & Desuperheater, Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.80	Blow Down Tank Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains				2021			
315.00	Sootblowers & Thermoprobes												
315.10	IK Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenance time evey year.	Visual Inspection				2021			
315.20	IR Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenance time evey year.	Visual Inspection				2021			

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316.00	Safety Valves (General)	Good condition, overall functional			NLH has a contract with New Valves to do inspection every three years. EBTs on all valves yearly.								
316.10	Drum (Safety Valves)	Good condition, overall functional			Alternate Year								
316.20	Super Heater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.30	Reheater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.40	Sootblower (Safety Valves)	Good condition, overall functional			Alternate Year								
316.50	Feedwater Heaters (Safety Valves)	Good condition, overall functional			Alternate Year								
317.00	Casing, windbox, expansion joints, dampers & refractory - Includes Insulation				Extensive inspection and modification on these equipment.								
318.00	Auxiliary Steam Supply	Good condition, overall functional											
320	**Drafting System (General)**												
321.00	Air Preheaters (General)	Good condition, overall functional			Every Year a lot of repair work is done on the folloiwng three equipment. a) Soot Blowers b) Burners c) Air Pre Heaters NLH informed that they prioritize these three components if they have limitation on maintenance budget.								
323.00	Forced Draft Fans	Good condition, overall functional			Equipped with Air Cooled VFDs in 2015. VFDs goes shut down with unit. Start up issues and cause trip. The temperature control during winter; goes out of operating limit. Power issues, Low switch power off. Vibration Issues in cooling fans for VFDs.								
325.00	Stack(Draft System)	Visual Inspection			Every three years. This year is in plan for exterior only. The 2018 inspection said internal was good. Problem is with concrete spalling issues. It was repaired in 2018 and needs to be done this year too. (For all three units) Issues with SS Liners. (All approaching to 20 years old and might need to be replaced) Monitoring system is installed and needs to be updated. CEMs are good. Aviation lights have some issues and need some attention.								
340	**Fuel Handling & Storage (General)**												
342.00	Fuel Tank Storage	Part of Hatch Sub-Contractor`s inspection for paint thickness			Paint Thickness Testing and Paint Chemical Analysis (if required)				2021				
350	**Fuel Burning (General)**												
354.00	Boiler Fuel Piping, Burners & Valves												
354.10	Main Oil Burners	Good condition, overall functional			Routine Maintenance, a lot of wear and tear. So have to clean it every year thorougly. Reliability issues arise if it is not done annualy.								
354.20	Pilot Oil Ignition	Good condition, overall functional											
390	**Boiler Water-External to Boiler (General)**												
391.00	Reserve Feed Water	Storage & pumping capacity is a problem when 2 or more units are down. Capital project is looking into the problem.	1								Reserve Feed Water Capacity planned in 2000 for 200 K (not released) (MA03.000.083)		
394.00	Chemical Injection (Boiler Water)	Being upgraded this year. Should be OK. Hydrazine system recently refurbished and should last with regular maintenance.	1 18								Phos dosing station replacement planned in 2004 for 50 K (P4)		
395.00	Boiler Steam & Water Sampling	New systems, should be OK, however water quality sampling panel is high maintenance and not designed for harsh environments.	1	RR	Replace water quality sampling panel. (High maintenance)				2004	4	Wab Gen Lab Int Upgrade for 75k in 2000 (over all units) (MA03.000.059)		
396.00	Boiler Acid Cleaning	OK	1										

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397.00	Nitrogen Blanketing	Capital project for next year if life extension proceeds. OEM Recommendation for performance improvement. The steam drum on this unit is riddled with cracks and may not last without nitrogen blanketing.	1, 18	RR	Install nitrogen blanketing system.			P	2002	2	Nitrogen capping project planned in 2001 for 750K (over all units) (GA03.000.003)		Need an economic analysis to justify this project on Wab 4.
300	SUBTOTAL												

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400	**Power Generation Facilities & (General)**												
410	**Turbine Generator & Ancillaries (General)**												
411.00	Turbine (General)	Unit Accumulated hours to July 2000: 237,312 IP rotor accumulated hours: 212,452. LP rotor accumulated hours: 205,168. HP rotor: 28,175 hrs since last inspection in 1996. IP rotor: 7,875 hrs since last inspection in 1999. LP rotors: 7,875 hrs since last inspection in 1999. Go to 4 year inspection schedule after 300,000 hours.			2013 Outage Report to be provided by NLH								
411.10	Steam Chests, Stop & Gov. Valves (Turbine)	Please provide the last steam turbine major and minor inspection report (s) with similar level of detail that was given for unit-3.											
	Main Steam Turbine Stop Valve Weld, Pipe	No record	*BWL S20-030 CAMBTP9745*		No defradation at welds. Last inspection 2019.	PAUT, MT, Replica		*BWL S20-030 CAMBTP9745*		West Main Stop Valve Weld 2022	Next Inspection		
411.20	M.S. Pipe, Flange Warming and Drain lines, Loop Pipes, Cross Under	Good condition, overall functional											
411.30	High Temperature Studs (Turbine)	Good condition, overall functional			NLH is planning to repalce unit-1 studs this year.								
411.40	Cylinders and Rotors (Turbine)	Good condition, overall functional											
411.50	Governing System - Relay Oil (Turbine)	Good condition, overall functional											
411.60	Pedestals - Bearings (Turbine)	Good condition, overall functional											
411.70	Gland & Drain System - Water Paddle Glands & LP Sprays (Turbine)	Good condition, overall functional											
411.80	Insulation, Thermal (Turbine)	Good condition, overall functional											
411.90	Misc. Pipes & Hangers, Flanges, Bailey Joints (Turbine)	Good condition, overall functional											
412.00	Generator (General)												
412.10	Steam Rotor, Brush Gear, Term., Buss DT	Good condition, overall functional			For 1 & 2: Some tests are being done to evaluate and will be determined if they need rewound. They are original so far.								
412.20	H_2 Seals - Bearings (Generator)	Good condition, overall functional											
412.30	Seal Oil System H_2 & CO_2 System (Generator)	Good condition, overall functional											
412.31	Seal Oil System (Generator) 2 x 100 % capacity coolers	Good condition, overall functional											
412.32	Bulk Hydrogen (Generator)	Good condition, overall functional											
412.33	CO_2 System (Generator)	Good condition, overall functional											
412.34	H_2 System (Generator)	Good condition, overall functional											
412.40	Generator Cooling Systems (General)	Good condition, overall functional											
412.41	Seal Oil Cooling (Generator)	Good condition, overall functional											
412.42	H_2 Coolers (Generator) 4 x 33 % capacity coolers	Good condition, overall functional											
412.50	Excitation System - Exciters - Fieldbreaker (Generator)	Good condition, overall functional											
412.60	Voltage Regulation (Generator)	Good condition, overall functional											
412.70	Turbo/Generator - (Protection)	Good condition, overall functional											
412.80	Generator AC Schematics and Metering	Good condition, overall functional											
413.00	Lube Oil System (Turbo/Gen) 2 x 100 % capacity coolers	Good condition, overall functional											
414.00	Foundations (Turbo/Gen)	Good condition, overall functional											
415.00	Turbovisory	Good condition, overall functional											
416.00	Barring Gear - T/G Coupling Alignment	Good condition, overall functional											
420	**Circulating Water System (General)**												
421.00	Inlet Canal - CW Screens/Sumps	Part of Hatch Inspection		OME	Hatch 3rd party sub-contractors will carry out the inspection.	ROV			2021				
422.00	Circulating Water Pumps	Good condition, overall functional											
423.00	CW Disch & Cond - In/Out Valves & Disch Pipe	Good condition, overall functional											
430	**Condensing System (General)**												
431.00	Main Condensor	Good condition, overall functional											
432.00	Condenser Shell & Water Boxes	Good condition, overall functional											
433.00	Condenser Tubes	Confirm tube material and maintenance history; manual Vol 1 Section 3.3 shows Al-Brass (90-10 Cu-Ni in air cooler zones)											
434.00	Air Extraction System	Good condition, overall functional											
436.00	Condenser Ball Cleaning System	Good condition, overall functional											
440	**Feedwater System (General)**												

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441.00	Extraction Pump	Good condition, overall functional											
442.00	LP Feedwater Hotwell to BFP Suction												
442.10	Condenser Hotwell	Good condition, overall functional											
442.20	Drain Coolers (Feedwater)	Good condition, overall functional											
442.30	No. 1 Low Pressure Feedwater Heater	Good condition, overall functional											
442.40	No.2 Low Pressure Feedwater Heater	Good condition, overall functional											
	FAC Site 1-4 Low Pressure Feedwater (Condensate Piping) U/S of Dearator	FAC (2012)	*BWL S20-030 CAMBTP9745*		Reinspect in 8 years. Last inspection 2015.	UT grid.		*BWL S20-030 CAMBTP9745*		2023	Next Inspection		
442.60	Deaerator	Internal inspection of dearating heater and of D/A storage tank should be conducted - establish condition of trays & supports in D/A heater plus all piping connections											
442.70	BFP Suction & Strainers	Internal inspection											
443.00	HP/Feedwater BFP to Economizer (General)												
	FAC Site 1-2 Boiler Feed Pump Flow Element 554, pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Reinspect in 6 years. Last inspection 2016.	UT grid		*BWL S20-030 CAMBTP9745*		2022	Next Inspection		
443.10	BFP Discharge												
	FAC Site 1-5 West Boiler Feed Pump Discharge Repair, Pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Pad Weld in 2015; Last inspection 2018.	UT grid		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	FAC Site 1-6 East Boiler Feed Pump Recirculation, Pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Last inspection 2015.	UT grid		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		

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443.20	No.4 High Pressure Feedwater Heater	Good condition, overall functional											
443.30	No.5 High Pressure Feedwater Heater	Good condition, overall functional											
	FAC Site 1-3 High Pressure Heater No. 6 Bypass Piping	FAC (2012)	*BWL S20-030 CAMBTP9745*		Last inspection 2016.	UT grid		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
443.40	No.6 High Pressure Feedwater Heater	Good condition, overall functional											
443.50	No.6 Feedwater Heater to Econ. Checkvalves	Good condition, overall functional											
444.00	Feedwater Heater Vents Drain - Flashboxes (Gen)	Good condition, overall functional											
444.10	Feedwater Heater - Vents & Drains	Good condition, overall functional											
444.20	Heater Drain Pumps	Good condition, overall functional											
444.30	Flashboxes (Feedwater)	Good condition, overall functional											
445.00	Turbine Bled Steam System	Good condition, overall functional											
446.00	Boiler Feed Pumps	Good condition, overall functional											
450	**Emergency Standby Diesel Generators 2x400 kW**	**01-Jan-1976_Plant manual Vol 1A for Holyrood Generating Station Stage II Unit No3(jessicamcgrath@nlh.nl.ca).pdf - Section 6.7.1 for Diesel Standby Generators. No information on the Gas Turbine Emergency Power Unit**	**1**										
451.00	Gas Turbine - (EPU)	Good condition, overall functional											
452.00	Generator (EPU)	Good condition, overall functional											
453.00	Excitation & Syn (EPU)	Good condition, overall functional											
454.00	Lubrication (EPU)	Good condition, overall functional											
455.00	Governing (EPU)	Good condition, overall functional											
456.00	Fuel Supply (Standby Generators and EPU)	Good condition, overall functional											
457.00	Fire Protection (Standby Generators and EPU)	Good condition, overall functional											
400	SUBTOTAL	Good condition, overall functional											
500	**Electrical (General)**												
501.00	Motors	Good condition, overall functional											
502.00	Starters	Good condition, overall functional											
503.00	Cable Trays	Good condition, overall functional											
504.00	Ducts	Good condition, overall functional											
505.00	Cables	Good condition, overall functional									-		
510	**Main Power Output (General)**												
511.00	Generator Transformer T1	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
512.00	Unit Service Transformer UST-1	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
513.00	Station Service Transformer SST-12	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
514.00	Excitation Transformer RT1	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
515.00	Generator CT,PT & Isolated Phase Buss	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								

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520	**4.16 kV Switchgear Distribution**												
521.00	Unit Boards UB1	Good condition, overall functional											
522.00	Station Boards SB12	Good condition, overall functional											
523.00	Unit Aux. Transformers AT-A	Good condition, overall functional											
524.00	Station Aux. Transformers AT-C	Good condition, overall functional											
530	**Conduit & Cable (General)**												
531.00	Power Cables	Good condition, overall functional			On turbine side, its Mark 5 which is obselete. NLH has good spare parts inventory and have a contract with B&H (now) to provide required spares. On DCS side, its FoxPro which is still available. On Unit-3, NLH is repalcing the hardware with the new one for DCS side.								
532.00	Control Cables	Good condition, overall functional											
533.00	Instrument Cables	Good condition, overall functional											
500	SUBTOTAL												
600	**Instrumentation & Controls (General)**												
620	**Instrumentation Tubing & Fittings**												
620.10	Electronic Components Instrumentation	Good condition, overall functional			Plant wide communication system was upgraded in 2012/2013. So no issues at this time.								
620.20	Fasteners & Connectors Instr. & Elect.	Good condition, overall functional											
621.00	Locally Mounted (Instruments)												
621.10	Indicators & Gauges	Good condition, overall functional											
621.20	Switches, Detectors, Sensors	Good condition, overall functional											
621.30	Transmitters	Good condition, overall functional											
621.40	Primary Elements (Wells)	Good condition, overall functional											
621.50	Controllers	Good condition, overall functional											
621.60	Valves,Regulators,Operators	Good condition, overall functional											
621.61	Instrumentation Isolators	Good condition, overall functional											
621.62	Solenoid Valve	Good condition, overall functional											
621.63	Control Valve & Regulator	Good condition, overall functional			Some of the critical breakers are not monitored by DCS.								
621.64	Operators Positioners	Good condition, overall functional			May be some tuning required for low loads.								
621.65	Motorized Valves	Good condition, overall functional											
621.70	Transducers	Good condition, overall functional			Stability of flame scanners is not issue above 40MW. 25 MW is being targetted on Unit-2. Other units are also being replaced.								
621.80	Relays & Coils	Good condition, overall functional											
630	**Process Controls Boiler (General)**												
631.00	Combustion & Draft Control	Good condition, overall functional											
632.00	Feedwater & Drum Level Control	Good condition, overall functional											
633.00	Steam Temperature Control (Sprays)	Good condition, overall functional											
634.00	Fuel Interlock (Safety)	Good condition, overall functional											
634.10	Flame Detectors	Good condition, overall functional											
636.00	Power Supplies & Change-Overs	Good condition, overall functional											
640	**Process Controls Turbine (General)**												
645.00	Turbo/Gen. Instrumentation and T/G Schedules	Good condition, overall functional											
650	**Process Controls Cooling Pond (General)**	Good condition, overall functional											
660	**Process Controls Water Treatment**	Good condition, overall functional											
690	**Operator Interfaces (General)**	Good condition, overall functional											
691.00	Main Control Room Panels & Desk	Good condition, overall functional											
692.00	Local Control Panels	Good condition, overall functional											
693.00	Annunciators	Good condition, overall functional											
694.00	Recorders	Good condition, overall functional											
695.00	Computers	Good condition, overall functional											
695.10	Data Logger Das (Computer)	Good condition, overall functional											
695.20	Turbine Run-Up (Computer)	Good condition, overall functional											
695.30	Lift Pumphouse (Computer)	Good condition, overall functional											

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695.40	Environmental (Computer)	Good condition, overall functional											
695.50	Programmable Controllers	Good condition, overall functional											
695.60	Sequence of Events (Computers)	Good condition, overall functional											
695.70	Process Control (Computers)	Good condition, overall functional											
600	SUBTOTAL												
700	**Common Services**												
710	**General Service Water (GSW) (General)**												
711.00	Pumps, Motors (General Service Water)	Good condition, overall functional											
712.00	Strainers, Valves, Piping (General Service Water)	Good condition, overall functional											
720	**Compressed Air Systems (General)**												
721.00	Plant Air				3 Compressor. All feed to common header. They are not connected to DCS, but have a dedicated monitoring system that allows operators to switch on/off when needed.								
722.00	Instrument Air												
723.00	Substation H.P. Air												
730	Fire Pumps & Motors												
731.00	Fire Pumps & Motors	Good condition, overall functional			Diesel pump has some suction issues. Twinning one more suction line is being investigated. (1500gpm to 2500gpm). Check with Greg S. This was Hatch study. [125MW GT is a new addition and is out of scope. Some resources including raw water is shared with this 125MW GT]. Some issues in udnerground piping. 75% underground fire water piping is being repalced. The existing plan is to replace the piping only need for sync. condenser operation for Unit-3. Hatch needs to investigate what segments needs to be repalced in addition based on our assessment.								
732.00	Fire Piping, Valves, Hydrants, Sprinkler	Underground fire piping inspection is in Hatch Scope. Hatch will arrange it via our sub-contractor		OME	To done by Hatch Sub-Contractor if required.				2021				
733.00	Fire Hoses	Good condition, overall functional											
733.10	Unit 1 Fire Hoses	Good condition, overall functional											
733.40	General Services Fire Hoses	Good condition, overall functional											

HTGS Unit 1

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Recommended Inspections / NDE		Execution date		Priority	CAPITAL		General Comments
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Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
740	**Cranes & Elevators (General)**												
741.00	Cranes (General)												
741.10	Turbine House (Cranes)	Good condition, overall functional											
741.30	Demin Plants (Cranes)	Good condition, overall functional											
741.40	Pump House (Cranes)	Good condition, overall functional											
741.50	Portable (Cranes)	Good condition, overall functional											
742.00	Elevators	Good condition, overall functional											
760	**Heating,Ventilating & Air Conditioning**	**HVAC Systems Are OK**	**1**										
770	**Potable Water (General)**												
771.00	Pump House (Potable Water)	Good condition, overall functional			Potable tank is filled on located at 11th F. No drinkable water at plant								
772.00	Distribution (Potable Water)	Good condition, overall functional											
780	**Plant Fuel Supply (General)**												
781.00	Plant Fuel Supply (General)	Good condition, overall functional			Steam heated lines. Electrical Heating tracing from Jetty to tank forms. Inside tank form, its all steam heat tracing. Condensate is not recovered back and is discharged to ground. Four fuel tanks. NLH is trying to get life extension. Tank-1 will be end of life this year. Need to see if it will de-commissioned or not. Tank 2; June 2023 Tank 3: 2025 Tank4: 2022 Day Tank: 2023 Management decided that plant is good with three tanks. So Tank-1 will be most likely decomissioned this year.								
781.10	Plant Fuel Lines & Metering	Good condition, overall functional											
781.11	Cathodic Protection System	Good condition, overall functional			No Underground piping. So No CP.								
790	**Miscellaneous (General)**												
791.00	Environmental Monitoring Equipment	Good condition, overall functional			6 monitoring sessions in the facility. SO2, CO2, Nox, PM								
791.10	Air Quality Monitoring Equipment	Good condition, overall functional											
791.20	Water Quality Monitoring Equipment	Good condition, overall functional											
791.23	Flue Gas Quality Monitoring Equipment	Good condition, overall functional											
791.30	Ground Temperature Probe Readings	Good condition, overall functional											
700	SUBTOTAL												

SUBTOTALS:		
100 - Structures and General Site		x 1000
200 - Service Buildings General		x 1000
300 - Steam Generation Facilities		x 1000
400 - Power Generation Facilities		x 1000
500 - Electrical General		x 1000
600 - Instrumentation & Controls		x 1000
700 - Common Services		x 1000
Subtotal:		**Million**
EPCM:	**8%**	**Million**
Spares:		**Million**
Remedial Repairs:		**Million**
RR EPCM:	**8%**	**Million**
Monte Carlo:	**8.18%**	**Million**
Design Risk:	**1%**	**Million**
Growth Allowance:		**Million**
Labour Risk:		**Million**
Unit #1 Grand Total:		**Million**

HTGS Unit 2

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Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
100	**Building Structures - General**												
130	**Site Improvements (General)**												
140	**Site Services**												
143	Site Services - Sewers and Drainage System				*NLH to inform of License requirements*								
		Substation storm water storage tank condition is unknown. Also need to consider oily drains sumps and traps that may need consideration.		OME	One time inspection (VT) of underground tank / reservoir. Recommend repairs if necessary.	VT							
100	SUBTOTAL												
200	**Service Buildings -General**												
207													
210	**Buildings and Structures - Buildings and Structures - General**												
220	**Cooling Water Supply and Storage - Cooling Water Supply and Storage - General**												
221	Canals												
222		Part of Hatch Sub-Contractor Insepction		OME	Need to wait till Inspection Results	Inspection with ROV				2021			
200	SUBTOTAL												
300	**Steam Generation Facilities**												
310	**Boiler & Auxiliaries**												
311.00	Economizer to SH Outlet Header												
311.10	Economizer & Links												
	Economizer Tubing, Tubes	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*	OME	Wall Thickness above Refurbish/replace criteria last inspection 2016.	UT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
311.20	Steam Drum	Good condition, overall functional		OME		Visual Inspection during next outage and SPOT NDE where requried.							
311.30	Lower Waterwall Drums (Mud drums)	Good condition, overall functional		OME		Visual Inspection during next outage and SPOT NDE where requried.							
	Downcomers	Good condition, overall functional		OME		UT in next insepction if no satisfactory details found for previous inspecion.							
311.40	Waterwalls	Good condition, overall functional		OME		UT in next insepction if no satisfactory details found for previous inspecion.							
311.50	Superheaters												
	Primary Superheatres Tubing, Tubes	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*	OME	Wall Thickness at some locations fell below refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	Secondary Superheater Tubing	Wall Thinning Creep	*BWL S20-030 CAMBTP9745*	OME	Wall Thickness at some locations fell below refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	SH-6 Header Outlet Nozzle Welds, Header	Creep crack (2015)	*BWL S20-030 CAMBTP9745*	OME	some active cracking observed; cracks were ground out. Last inspection 2019.	PAUT, MT, Replica		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	SSH Inlet (SH5) Tube-to-Header Welds, Header	No records.	*BWL S20-030 CAMBTP9745*	OME	No indications observed. Last inspections 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	SSH Outlet (SH6) Tube-to- Header Welds, Header	Cracks (2018)	*BWL S20-030 CAMBTP9745*	OME	Cracks excavated, and weld refurbished. Last inspection 2018.	MT, UT		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	Superheater Front Horizontal Spaced Outlet Heater SH-9	No records.	*BWL S20-030 CAMBTP9745*	OME	No cracking at long seam weld. Last inspection 2016.	PAUT		*BWL S20-030 CAMBTP9745*		2026	Next Inspection		
	RH2, Header	No records.	*BWL S20-030 CAMBTP9745*	OME	Longitudinal weld on the south side of the header was found. Last inspection 2015.	PAUT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
	Economizer Inlet Header	No records.	*BWL S20-030 CAMBTP9745*	OME	No degradation observed. Last inspection 2015.	Internal Visual		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	FAC Site 2-1 Economizer Inlet Header Piping Bottom Bends,pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*	OME	Reinspect in 3 years. Last inspection 2020.	UT grid		*BWL S20-030 CAMBTP9745*		2023	Next Inspection		
311.60	S.H. Attemperator												
	FAC Site 2-5 Inlet Blen of East Superheater Attemperator Station,pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Reinspect in 10 years. Last inspection 2016.	UT grid		*BWL S20-030 CAMBTP9745*		2026	Next Inspection		
311.70	Boiler Tubes												

HTGS Unit 2

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Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
	Boiler Floor Tubes, Tubes	Wall Thinning	*BWL S20-030 CAMBTP9745*	OME	Two locations on hot side below recommended Refurbish/Replace thickness, others approaching this valUe. Last inspection 2019.	UT		*BWL S20-030 CAMBTP9745*		2021(hot side) 2025(cold side)	Next Inspection		
	Waterwall Tubes, Tubes	Wall Thinning/ Pitting	*BWL S20-030 CAMBTP9745*	OME	some pitting and ID scale destabilization due to upset chemistry event. Last inspection 2019.	Metallurgical Assessment		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
	Lower Vestibule Feeder Tubes, Tubes	no record.	*BWL S20-030 CAMBTP9745*	OME	No fatigue cracking. Last inspection 2015.	PAUT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
312.00	Main Steam, Hot & Cold RH Lines (HEP - High Energy Piping)												
312.10	Main Steam Lines	Good condition, overall functional			To be Inspectied this year	Replica, PAUT, MT				2021			
312.20	Cold Reheat Lines	Good condition, overall functional			To be Inspectied this year	UT				2021			
312.30	RH Attemperator	Good condition, overall functional			To be Inspectied this year	UT							
312.40	Reheater												
	Reheater Tubing, Tubes	Wall thinning creep	*BWL S20-030 CAMBTP9745*	OME	Wall Thickness at some locations fell below refurbish/replace criteria. Last inspection 2016.	UT (NOTIS RLA)		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
312.50	Hot Reheat Lines												
313.00	Vents, Drains, Blowdown (Boiler General)												
313.10	Economizer Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.20	Drums Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.30	Downcomer Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.40	Superheater Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.50	Attemperator (Desuperheater) Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.60	Main Steam Line Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.70	Reheat & Desuperheater, Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains (close to blowdown tanks)				2021			
313.80	Blow Down Tank Vents and Drains	Good condition, overall functional			To be Inspectied this year	Visual On Vents and UT on drains				2021			
315.00	Sootblowers & Thermoprobes												
315.10	IK Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenace time every year.	Visual Inspection				2021			
315.20	IR Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenace time every year.	Visual Inspection				2021			
316.00	Safety Valves (General)	Good condition, overall functional			NLH has a contract with New Valves to do inspection every three years. EBTs on all valves yearly.								
316.10	Drum (Safety Valves)	Good condition, overall functional			Alternate Year								
316.20	Super Heater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.30	Reheater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.40	Sootblower (Safety Valves)	Good condition, overall functional			Alternate Year								
316.50	Feedwater Heaters (Safety Valves)	Good condition, overall functional			Alternate Year								
317.00	Casing, windbox, expansion joints, dampers & refractory - Includes Insulation				Extensive inspection and modification on these equipment.								
320	**Drafting System (General)**												
321.00	Air Preheaters (General)	Good condition, overall functional			Every Year a lot of repair work is done on the folloiwng three equipment. a) Soot Blowers b) Burners c) Air Pre Heaters NLH informed that they prioritize these three components if they have limitation on maintenance budget.								
323.00	Forced Draft Fans	Good condition, overall functional			Equipped with Air Cooled VFDs in 2015. VFDs goes shut down with unit. Start up issues and cause trip. The temperature control during winter; goes out of operating limit. Power issues, Low switch power off. Vibration Issues in cooling fans for VFDs.								

HTGS Unit 2

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Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
325.00	Stack(Draft System)	Visual Inspection			Every three years. This year is in plan for exterior only. The 2018 inspection said internal was good. Problem is with concrete spalling issues. It was repaired in 2018 and needs to be done this year too. (For all three units) Issues with SS Liners. (All approaching to 20 years old and might need to be replaced) Monitoring system is installed and needs to be updated. CEMs are good. Aviation lights have some issues and need some attention.								
340	**Fuel Handling & Storage (General)**												
342.00	Fuel Tank Storage	Part of Hatch Sub-Contractor's inspection for paint thickness			Paint Thickness Testing and Paint Chemical Analysis (if required)				2021				
350	**Fuel Burning (General)**												
354.00	Boiler Fuel Piping, Burners & Valves												
354.10	Main Oil Burners	Good condition, overall functional			Routine Maintenance, a lot of wear and tear. So have to clean it every year thorougly. Reliability issues arise if it is not done annualy.								
354.20	Pilot Oil Ignition	Good condition, overall functional											
360													
370	**Water Supply & Treatment (General)**												
390	**Boiler Water-External to Boiler (General)**												
391.00	Reserve Feed Water	Storage & pumping capacity is a problem when 2 or more units are down. Capital project is looking into the problem.	1			Need to be discused with Site Team for a mitigation Plan.					Reserve Feed Water Capacity planned in 2000 for 200 K (not released) (MA03.000.083)		
394.00	Chemical Injection (Boiler Water)	Being upgraded this year. Should be OK. Hydrazine system recently refurbished and should last with regular maintenance.	1 18		Refurbish and operate						Phos dosing station replacement planned in 2004 for 50 K (P4)		
395.00	Boiler Steam & Water Sampling	New systems, should be OK, however water quality sampling panel is high maintenance and not designed for harsh environments.	1	RR	Replace water quality sampling panel. (High maintenance)				2004	4	Wab Gen Lab Int Upgrade for 75k in 2000 (over all units) (MA03.000.059)		
396.00	Boiler Acid Cleaning	OK	1										
397.00	Nitrogen Blanketing	Capital project for next year if life extension proceeds. OEM Recommendation for performance improvement. The steam drum on this unit is riddled with cracks and may not last without nitrogen blanketing.	1, 18	RR	Install nitrogen blanketing system.			P	2002	2	Nitrogen capping project planned in 2001 for 750K (over all units) (GA03.000.003)		Need an economic analysis to justify this project on Wab 4.
300	SUBTOTAL												

HTGS Unit 2

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Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action** **RR RE OME**	**Description**	**Description**	**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
400	**Power Generation Facilities & (General)**												
410	**Turbine Generator & Ancillaries (General)**												
411.00	Turbine (General)	Unit Accumulated hours to July 2000: 237,312 IP rotor accumulated hours: 212,452. LP rotor accumulated hours: 205,168. HP rotor: 28,175 hrs since last inspection in 1996. IP rotor: 7,875 hrs since last inspection in 1999. LP rotors: 7,875 hrs since last inspection in 1999. Go to 4 year inspection schedule after 300,000 hours.			Unit 2014 Report to be provided by NLH								
411.10	Steam Chests, Stop & Gov. Valves (Turbine)	Please provide the last steam turbine major and minor inspection report (s) with similar level of detail that was given for unit-3.											
411.20	M.S. Pipe, Flange Warming and Drain lines, Loop Pipes, Cross	Good condition, overall functional											
	MS West Turbine Terminal	no record	*BWL S20-030 CAMBTP9745*		No creep damage observed. Last inspection 2015.	Replica, PAUT, MT		*BWL S20-030 CAMBTP9745*		2025	Next Inspection		
411.30	High Temperature Studs (Turbine)	Good condition, overall functional											
411.40	Cylinders and Rotors (Turbine)	Good condition, overall functional											
411.50	Governing System - Relay Oil (Turbine)	Good condition, overall functional											
411.60	Pedestals - Bearings (Turbine)	Good condition, overall functional											
411.70	Gland & Drain System - Water Paddle Glands & LP Sprays (Turbine)	Good condition, overall functional											
411.80	Insulation, Thermal (Turbine)	Good condition, overall functional											
411.90	Misc. Pipes & Hangers, Flanges, Bailey Joints (Turbine)	Good condition, overall functional											
412.00	Generator (General)												
412.10	Steam Rotor, Brush Gear, Term., Buss DT	Good condition, overall functional			For 1 & 2: Some tests are being done to evaluate and will be determined if they need rewound. They are original so far.								
412.20	H_2 Seals - Bearings (Generator)	Good condition, overall functional											
412.30	Seal Oil System H_2 & CO_2 System (Generator)	Good condition, overall functional											
412.31	Seal Oil System (Generator) 2 x 100 % capacity coolers	Good condition, overall functional											
412.32	Bulk Hydrogen (Generator)	Good condition, overall functional											
412.33	CO_2 System (Generator)	Good condition, overall functional											
412.34	H_2 System (Generator)	Good condition, overall functional											
412.40	Generator Cooling Systems (General)	Good condition, overall functional											
412.41	Seal Oil Cooling (Generator)	Good condition, overall functional											
412.42	H_2 Coolers (Generator) 4 x 33 % capacity coolers	Good condition, overall functional											
412.50	Excitation System - Exciters - Fieldbreaker (Generator)	Good condition, overall functional											
412.60	Voltage Regulation (Generator)	Good condition, overall functional											

HTGS Unit 2

newfoundland labrador hydro — a nalcor energy company

HATCH

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Work Breakdown Structure	Equipment or Area	Discussion	Reference	Action RR RE OME	Description	Description	Reference	Check if outage	Date (mm/yyyy)	Priority	Description, Cost, Date Planned	Included in Life Exten. Scope	
412.70	Turbo/Generator - (Protection)	Good condition, overall functional											
412.80	Generator AC Schematics and Metering	Good condition, overall functional											
413.00	Lube Oil System (Turbo/Gen) 2 x 100 % capacity coolers	Good condition, overall functional											
414.00	Foundations (Turbo/Gen)	Good condition, overall functional											
415.00	Turbovisory	Good condition, overall functional											
416.00	Barring Gear - T/G Coupling Alignment	Good condition, overall functional											
420	**Circulating Water System (General)**												
421.00	Inlet Canal - CW Screens/Sumps	Part of Hatch Inspection		OME	Hatch 3rd party sub-contractors will carry out the inspection.	ROV			2021				
422.00	Circulating Water Pumps	Good condition, overall functional											
423.00	CW Disch & Cond - In/Out Valves & Disch Pipe	Good condition, overall functional											
430	**Condensing System (General)**												
431.00	Main Condensor	Good condition, overall functional											
432.00	Condensed Shell & Water Boxes	Good condition, overall functional											
433.00	Condensed Tubes	Good condition, overall functional											
434.00	Air Extraction System	Good condition, overall functional											
435.00	Air Ejectors & Hoppers	Good condition, overall functional											
436.00	Condenser Ball Cleaning System	Good condition, overall functional											
440	**Feedwater System (General)**												
441.00	Extraction Pump	Good condition, overall functional											
442.00	LP Feedwater Hotwell to BFP Suction												
442.10	Condenser Hotwell	Good condition, overall functional											
442.20	Drain Coolers (Feedwater)	Good condition, overall functional											
442.30	No. 1 Low Pressure Feedwater Heater	Good condition, overall functional											
442.40	No.2 Low Pressure Feedwater Heater	Good condition, overall functional											
442.60	Deaerator	Internal inspection of dearating heater and of D/A storage tank should be conducted - establish condition of trays & supports in D/A heater plus all piping connections.											
442.70	BFP Suction & Strainers	Good condition, overall functional											
443.00	HP/Feedwater BFP to Economizer (General)	Good condition, overall functional											
443.10	BFP Discharge	Good condition, overall functional											
443.20	No.4 High Pressure Feedwater Heater	Good condition, overall functional											
443.30	No.5 High Pressure Feedwater Heater	Good condition, overall functional											
443.40	No.6 High Pressure Feedwater Heater	Good condition, overall functional											
443.50	No.6 Feedwater Heater to Econ. Checkvalves	Good condition, overall functional											
444.00	Feedwater Heater Vents Drain - Flashboxes (Gen)	Good condition, overall functional											
444.10	Feedwater Heater - Vents & Drains	Good condition, overall functional											
444.20	Heater Drain Pumps	Good condition, overall functional											
444.30	Flashboxes (Feedwater)	Good condition, overall functional											
445.00	Turbine Bled Steam System	Good condition, overall functional											
446.00	Boiler Feed Pumps												
	FAC Site 2-2 Boiler Feed Pump Flow Element 554, pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Reinspect in 5.0 years; to be replaced in 2017. last inspection 2016.	UT grid		*BWL S20-030 CAMBTP9745*		2021	Next Inspection		
	FAC Site 2-3 High Preasure Heater No. 6 Bypass Piping, pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Pad weld in 2016; no significant wall loss in past 3 years. Last inspection 2019.	UT grid		*BWL S20-030 CAMBTP9745*		2022	Next Inspection		
	FAC Site 2-4 Boiler Feed Pump Discharge Piping from East Pump and Y Connection, pipe	FAC (2012)	*BWL S20-030 CAMBTP9745*		Reinspect in 7 years. Last inspection 2016.	UT grid		*BWL S20-030 CAMBTP9745*		2023	Next Inspection		

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450	**Emergency Power Unit (General)**	**There is no information available on the Emergency Power Unit.**	1										
451.00	Gas Turbine - (EPU)	Good condition, overall functional											
452.00	Generator (EPU)	Good condition, overall functional											
453.00	Excitation & Syn (EPU)	Good condition, overall functional											
454.00	Lubrication (EPU)	Good condition, overall functional											
455.00	Governing (EPU)	Good condition, overall functional											
456.00	Fuel Supply (EPU)	Good condition, overall functional											
457.00	Fire Protection (EPU)	Good condition, overall functional											
400	SUBTOTAL	Good condition, overall functional											
500	**Electrical (General)**												
501.00	Motors	Good condition, overall functional											
502.00	Starters	Good condition, overall functional											
503.00	Cable Trays	Good condition, overall functional											
504.00	Ducts	Good condition, overall functional											
505.00	Cables	Good condition, overall functional									-		
510	**Main Power Output (General)**												
511.00	Generator Transformer T2	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
512.00	Unit Service Transformers UST-2	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
	Station Service Transformer				They are all original . NLH to share the last test reports to determine the remaining life of trans.								
513.00	Excitation Transformers RT2	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
514.00	Generator CT,PT & Isolated Phase Buss	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
520	**4.16 kV Switchgear Distribution**												
521.00	Unit Boards UB2	Good condition, overall functional											
522.00	Unit Aux. Transformers AT-B	Good condition, overall functional											
530	**Conduit & Cable (General)**												
531.00	Power Cables	Good condition, overall functional			On turbine side, its Mark 5 which is obselete. NLH has good spare parts inventory and have a contract with B&H (now) to provide required spares. On DCS side, its FoxPro which is still available. On Unit-3, NLH is repalcing the hardware with the new one for DCS side.								
532.00	Control Cables	Good condition, overall functional											
533.00	Instrument Cables	Good condition, overall functional											
500	SUBTOTAL												
600	**Instrumentation & Controls (General)**												
620	**Instrumentation Tubing & Fittings**												
620.10	Electronic Components Instrumentation	Good condition, overall functional			Plant wide communication system was upgraded in 2012/2013. So no issues at this time.								
620.20	Fasteners & Connectors Instr. & Elect.	Good condition, overall functional											
621.00	Locally Mounted (Instruments)												
621.10	Indicators & Gauges	Good condition, overall functional											
621.20	Switches, Detectors, Sensors	Good condition, overall functional											
621.30	Transmitters	Good condition, overall functional											
621.40	Primary Elements (Wells)	Good condition, overall functional											
621.50	Controllers	Good condition, overall functional											
621.60	Valves,Regulators,Operators	Good condition, overall functional											
621.61	Instrumentation Isolators	Good condition, overall functional											
621.62	Solenoid Valve	Good condition, overall functional											
621.63	Control Valve & Regulator	Good condition, overall functional			Some of the critical breakers are not monitored by DCS.								
621.64	Operators Positioners	Good condition, overall functional											
621.65	Motorized Valves	Good condition, overall functional											

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621.70	Transducers	Good condition, overall functional											
621.80	Relays & Coils	Good condition, overall functional											

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630	**Process Controls Boiler (General)**												
631.00	Combustion & Draft Control	Good condition, overall functional											
632.00	Feedwater & Drum Level Control	Good condition, overall functional			Unit-2: Level guage was changed in 2020.								
633.00	Steam Temperature Control (Sprays)	Good condition, overall functional			May be some tuning required for low loads.								
634.00	Fuel Interlock (Safety)	Good condition, overall functional											
634.10	Flame Detectors	Good condition, overall functional			Stability of flame scanners is not issue above 40MW. 25 MW is being targetted on Unit-2. Other units are also being replaced.								
636.00	Power Supplies & Change-Overs	Good condition, overall functional											
640	**Process Controls Turbine (General)**												
645.00	Turbo/Gen. Instrumentation and T/G Schedules	Good condition, overall functional											
650	**Process Controls Cooling Pond (General)**	**Good condition, overall functional**											
660	**Process Controls Water Treatment**	**Good condition, overall functional**											
690	**Operator Interfaces (General)**	**Good condition, overall functional**											
691.00	Main Control Room Panels & Desk	Good condition, overall functional											
692.00	Local Control Panels	Good condition, overall functional											
693.00	Annunciators	Good condition, overall functional											
694.00	Recorders	Good condition, overall functional											
695.00	Computers	Good condition, overall functional											
695.10	Data Logger Das (Computer)	Good condition, overall functional											
695.20	Turbine Run-Up (Computer)	Good condition, overall functional											
695.30	Lift Pumphouse (Computer)	Good condition, overall functional											
695.40	Environmental (Computer)	Good condition, overall functional											
695.50	Programmable Controllers	Good condition, overall functional											
695.60	Sequence of Events (Computers)	Good condition, overall functional											
695.70	Process Control (Computers)	Good condition, overall functional											
600	SUBTOTAL												
700	**Common Services**												
710	**General Service Water (GSW) (General)**												
711.00	Pumps, Motors (General Service Water)	Good condition, overall functional											
712.00	Strainers, Valves, Piping (General Service Water)	Good condition, overall functional											
720	**Compressed Air Systems (General)**												
721.00	Plant Air	Good condition, overall functional			3 Compressor. All feed to common header. They are not connected to DCS, but have a dedicated monitoring system that allows operators to switch on/off when needed.								
722.00	Instrument Air	Good condition, overall functional											
723.00	Substation H.P. Air	Good condition, overall functional											
730	**Fire Pumps & Motors**												
731.00	Fire Pumps & Motors	Good condition, overall functional				Diesel pump has some suction issues. Twinning one more suction line is being investigated. (1500gpm to 2500gpm). Check with Greg S. This was Hatch study. [125MW GT is a new addition and is out of scope. Some resources including raw water is shared with this 125MW GT]. Some issues in udnerground piping. 75% underground fire water piping is being repalced. The existing plan is to replace the piping only need for sync. condenser operation for Unit-3. Hatch needs to investigate what segments needs to be repalced in addition based on our assessment.							
732.00	Fire Piping, Valves, Hydrants, Sprinkler	Underground fire piping inspection is in Hatch Scope. Hatch will arrange it via our sub-contractor		OME	To done using ROV	To done by Hatch Sub-Contractor if required.			2021				
733.00	Fire Hoses	Good condition, overall functional											
733.10	Unit 2 Fire Hoses	Good condition, overall functional											
733.40	General Services Fire Hoses	Good condition, overall functional											
740	**Cranes & Elevators (General)**												
741.00	Cranes (General)												
741.10	Turbine House (Cranes)	Good condition, overall functional											
741.30	Demin Plants (Cranes)	Good condition, overall functional											
741.40	Pump House (Cranes)	Good condition, overall functional											
741.50	Portable (Cranes)	Good condition, overall functional											
742.00	Elevators	Good condition, overall functional											

HTGS Unit 2

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760	**Heating,Ventilating & Air Conditioning**	**HVAC systems are OK**	**1**										
770	**Potable Water (General)**												
771.00	Pump House (Potable Water)					Potable tank is filled on located at 11th F. No drinkable water at plant							
772.00	Distribution (Potable Water)												
780	**Plant Fuel Supply (General)**												
781.00	Plant Fuel Supply (General)	Good condition, overall functional				Steam heated lines. Electrical Heating tracing from Jetty to tank forms. Inside tank form, its all steam heat tracing. Condensate is not recovered back and is discharged to ground. Four fuel tanks. NLH is trying to get life extension. Tank-1 will be end of life this year. Need to see if it will de-commissioned or not. Tank 2; June 2023 Tank 3: 2025 Tank4: 2022 Day Tank: 2023 Management decided that plant is good with three tanks. So Tank-1 will be most likely decomissioned this year.							
781.10	Plant Fuel Lines & Metering	Good condition, overall functional											
781.11	Cathodic Protection System	Good condition, overall functional				No Underground piping. So No CP.							
790	**Miscellaneous (General)**												
791.00	Environmental Monitoring Equipment	Good condition, overall functional				6 monitoring sessions in the facility. SO2, CO2, Nox, PM							
791.10	Air Quality Monitoring Equipment	Good condition, overall functional											
791.20	Water Quality Monitoring Equipment	Good condition, overall functional											
791.23	Flue Gas Quality Monitoring Equipment	Good condition, overall functional											
791.30	Ground Temperature Probe Readings	Good condition, overall functional											
700	SUBTOTAL												

SUBTOTALS:		
100 - Structures and General Site		x 1000
200 - Service Buildings General		x 1000
300 - Steam Generation Facilities		x 1000
400 - Power Generation Facilities		x 1000
500 - Electrical General		x 1000
600 - Instrumentation & Controls		x 1000
700 - Common Services		x 1000
Subtotal:		**Million**
EPCM:	**8%**	**Million**
Spares:		**Million**
Remedial Repairs:		**Million**
RR EPCM:	**8%**	**Million**
Monte Carlo:	**8.18%**	**Million**
Design Risk:	**1%**	**Million**
Growth Allowance:		**Million**
Labour Risk:		**Million**
Unit #2 Grand Total:		**Million**

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HTGS Unit 3

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100	**Building Structures - General**												
130	**Site Improvements (General)**												
140	**Site Services**												
143	Site Services - Sewers and Drainage System				*NLH to inform of License requirements*								
		Substation storm water storage tank condition is unknown. Also need to consider oily drains sumps and traps that may need consideration.		OME	One time inspection (VT) of underground tank / reservoir. Recommend repairs if necessary.	VT							
100	SUBTOTAL												
200	**Service Buildings -General**												
207													
210	Buildings and Structures - Buildings and Structures - General	Not in Scope			Not in Scope	Not in Scope							
220	**Cooling Water Supply and Storage - Cooling Water Supply and Storage - General**												
221	Canals												
222		Part of Hatch Sub-Contractor Insepction		OME	Need to wait till Inspection Results	Inspection with ROV			2021				
200	SUBTOTAL												
300	**Steam Generation Facilities**												
310	**Boiler & Auxiliaries**												
311.00	Economizer to SH Outlet Header												
	Economizer Inlet Header	Cracking in Headers	*BWL S20-030 CAMBTP9745*	OME	No Thermal fatigue cracks but pitting on tube IDs. The last Inspection was done in 2018.	Visual (OAUT if cracks found)	*BWL S20-030 CAMBTP9745*		2022	Next inspection			
	SSH Outlet Header Tube Stubs	Fatigue	*BWL S20-030 CAMBTP9745*	OME	Early stage signs of fatigue damage, last inspection 2019.	MT	*BWL S20-030 CAMBTP9745*		2022	Next inspection			
	RH Inlet Header Tube Stubs	Cracks seen in 2018	*BWL S20-030 CAMBTP9745*	OME	No Indication observed in the last inspection that was done in 2019.	MT	*BWL S20-030 CAMBTP9745*		2022	Next inspection			
	SSH Outlet Header		*BWL S20-030 CAMBTP9745*	OME	No Indication observed in the last inspection that was done in 2019.	MT	*BWL S20-030 CAMBTP9745*		2022	Next inspection			
	RH Outlet Header	Thermal Fatigue Crack seen in 2014	*BWL S20-030 CAMBTP9745*	OME	No Indication observed in the last inspection that was done in 2019.	MT	*BWL S20-030 CAMBTP9745*		2022	Next inspection			
311.10	Economizer & Links	Wall thinning/ Creep	*BWL S20-030 CAMBTP9745*	OME	Wall thickness above refurbish/replace criteria last inspection 2016.	UT	*BWL S20-030 CAMBTP9745*		2025	Next inspection			
311.20	Steam Drum	Check for Cracking		OME	To be inspected this year.	Visual Inspection and Spot NDE where required.			2021	Next Inspection			
311.50	Superheaters			OME									
	Primary Superheater Tubing, Tubes	Wall thinning/ Creep	*BWL S20-030 CAMBTP9745*	OME	wall thickness above refurbish/replace criteria last inspection 2018.	UT (NOTIS RLA)	*BWL S20-030 CAMBTP9745*		2025	Next inspection			
	Secondary Superheater Tubing, Tubes	Wall thinning/ Creep	*BWL S20-030 CAMBTP9745*	OME	wall thickness above refurbish/replace criteria last inspection 2018.	UT (NOTIS RLA)	*BWL S20-030 CAMBTP9745*		2025	Next inspection			
311.60	S.H. Attemperator	Check for Cracks and Erosion		OME	refurbish/replace criteria	UT			2021				
311.70	Boiler Tubes												

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	Boiler Floor Tubes, Tubes	Wall Thinning	*BWL S20-030 CAMBTP9745*	OME	some bend extrados locations are approaching. Recommended refurbish/replace thickness. Last inspection 2019	UT	*BWL S20-030 CAMBTP9745*		2021	Next inspection			
	WW Tubes around Burner Openings, Tubes	Wall Thinning	*BWL S20-030 CAMBTP9745*	OME	Several locations pad welded and several more just avove the refurbish/replace thickness. Last inspection 2019	UT	*BWL S20-030 CAMBTP9745*		2021	Next inspection			
	Waterwall Tubes , Tubes	Wall Thinning / pitting	*BWL S20-030 CAMBTP9745*	OME	some pitting and ID scale destabilization due to upset chemistry event. Last inspection 2019.	Metallurgical Assessment	*BWL S20-030 CAMBTP9745*		2025	Next inspection			
	Lower Vestibule Waterwall Feeder Tubes, Tubes	Pitting	*BWL S20-030 CAMBTP9745*	OME	PAUT found pits but unknown if pits are active. Last inspection 2015.	Visual (PAUT if pits appear active).	*BWL S20-030 CAMBTP9745*		2021	Next inspection			
312.00	Main Steam, Hot & Cold RH Lines (HEP - High Energy Piping)												
312.10	Main Steam Lines	Degradation	*BWL S20-030 CAMBTP9745*	OME	Microstructrual degradation; Reinspection in 3 years. Last inspection 2020.	Replica, PAUT, MT	*BWL S20-030 CAMBTP9745*		2023	Next inspection			
312.20	Cold Reheat Lines	Good condition, overall functional			To be Inspected this year	Replica, PAUT, MT			2021				
312.30	RH Attemperator	Good condition, overall functional			To be Inspected this year	UT			2021				
312.40	Reheater			OME									
	Reheater Tubing, Tubes	Wall thinning/ Creep	*BWL S20-030 CAMBTP9745*	OME	Wall thickness in some locations fell below refurbish/replace criteria. Last inspection 2018.	UT (NOTIS RLA)	*BWL S20-030 CAMBTP9745*		2021	Next inspection			
312.50	Hot Reheat Lines	Good condition, overall functional			To be Inspected this year	UT			2021				As per ASME B31.1 Ch.7
313.00	Vents, Drains, Blowdown (Boiler General)												
313.10	Economizer Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.20	Drums Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.30	Downcomer Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.40	Superheater Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.50	Attemperator (Desuperheater) Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.60	Main Steam Line Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.70	Reheat & Desuperheater, Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains (close to blowdown tanks)			2021				
313.80	Blow Down Tank Vents and Drains	Good condition, overall functional			To be Inspected this year	Visual On Vents and UT on drains			2021				
315.00	Sootblowers & Thermoprobes												
315.10	IK Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenance time evey year.	Visual Inspection			2021				
315.20	IR Sootblower	Visual Inspection			Long retractable soot blowers pose different issues and take a lot of maintenance time evey year.	Visual Inspection			2021				
316.00	Safety Valves (General)	Good condition, overall functional			NLH has a contract with New Valves to do inspection every three years. EBTs on all valves yearly.								
316.10	Drum (Safety Valves)	Good condition, overall functional			Alternate Year								
316.20	Super Heater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.30	Reheater (Safety Valves)	Good condition, overall functional			Alternate Year								
316.40	Sootblower (Safety Valves)	Good condition, overall functional			Alternate Year								
316.50	Feedwater Heaters (Safety Valves)	Good condition, overall functional			Alternate Year								
317.00	Casing, windbox, expansion joints, dampers & refractory - Includes Insulation				Extensive inspection and modification on these equipment.								
318.00	Auxiliary Steam Supply	Good condition, overall functional											

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320	**Drafting System (General)**												
321.00	Air Preheaters (General)	Good condition, overall functional			Every Year a lot of repair work is done on the followng three equipment. a) Soot Blowers b) Burners c) Air Pre Heaters NLH informed that they prioritize these three components if they have limitation on maintenance budget.								
323.00	Forced Draft Fans				Equipped with Air Cooled VFDs in 2015. VFDs goes shut down with unit. Start up issues and cause trip. The temperature control during winter; goes out of operating limit. Power issues, Low switch power off. Vibration Issues in cooling fans for VFDs.								
325.00	Stack(Draft System)	Visual Inspection			Every three years. This year is in plan for exterior only. The 2018 inspection said internal was good. Problem is with concrete spalling issues. It was repaired in 2018 and needs to be done this year too. (For all three units) Issues with SS Liners. (All approaching to 20 years old and might need to be replaced) Monitoring system is installed and needs to be updated. CEMs are good. Aviation lights have some issues and need some attention.								
340	**Fuel Handling & Storage (General)**												
342.00	Fuel Tank Storage	Part of Hatch Sub-Contractor`s inspection for paint thickness				Paint Thickness Testing and Paint Chemical Analysis (if required)							
350	**Fuel Burning (General)**												
354.00	Boiler Fuel Piping, Burners & Valves												
354.10	Main Oil Burners	Good condition, overall functional			Routine Maintenance, a lot of wear and tear. So have to clean it every year thorougly. Reliability issues arise if it is not done annualy.								
354.20	Pilot Oil Ignition	Good condition, overall functional											
360													
370	Water Supply & Treatment (General)												
371.00	Not included in Hatch scope	Not included in Hatch scope											
390	**Boiler Water-External to Boiler (General)**												
391.00	Reserve Feed Water	Storage & pumping capacity is a problem when 2 or more units are down. Capital project is looking into the problem.	1			Need to be discussed with Site Team for a mitigation Plan.					Reserve Feed Water Capacity planned in 2000 for 200 K (not released) (MA03.000.083)		
394.00	Chemical Injection (Boiler Water)	Being upgraded this year. Should be OK. Hydrazine system recently refurbished and should last with regular maintenance.	1 18		Refurbish and operate						Phos dosing station replacement planned in 2004 for 50 K (P4)		
395.00	Boiler Steam & Water Sampling	New systems, should be OK, however water quality sampling panel is high maintenance and not designed for harsh environments.	1	RR	Replace water quality sampling panel. (High maintenance)				2004	4	Wab Gen Lab Int Upgrade for 75k in 2000 (over all units) (MA03.000.059)		
396.00	Boiler Acid Cleaning	OK	1										
397.00	Nitrogen Blanketing	Capital project for next year if life extension proceeds. OEM Recommendation for performance improvement. The steam drum on this unit is riddled with cracks and may not last without nitrogen blanketing.	1, 18	RR	Install nitrogen blanketing system.			P	2002	2	Nitrogen capping project planned in 2001 for 750K (over all units) (GA03.000.003)		Need an economic analysis to justify this project on Wab 4.
300	SUBTOTAL												
400	**Power Generation Facilities & (General)**												
410	**Turbine Generator & Ancillaries (General)**												

HTGS Unit 3

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411.00	Turbine (General)	Unit Accumulated hours to July 2000: 237,312 IP rotor accumulated hours: 212,452. LP rotor accumulated hours: 205,168. HP rotor: 28,175 hrs since last inspection in 1996. IP rotor: 7,875 hrs since last inspection in 1999. LP rotors: 7,875 hrs since last inspection in 1999. Go to 4 year inspection schedule after 300,000 hours.		NA									
411.10	Steam Chests, Stop & Gov. Valves (Turbine)	Last Inspection in 2016. Steam was again leaking so GE team re-opened the valve and changed the seal. Need to check with NLH if this problem appear again or not. Steam chest cracks to be re-checked next major outage; also check CRVs & MSVs stroking (unable to complete in 2019)	CFRG034522 U3 Outage Report 2019	OME	Check for Steam Chest Cracks in this year outage.				2021				
411.20	M.S. Pipe, Flange Warming and Drain lines, Loop Pipes, Cross Under Pipes	Good condition, overall functional		OME									
411.30	High Temperature Studs (Turbine)	Last Inspection in 2016. No issue Found.		OME	Operate and Monitor								
411.40	Cylinders and Rotors (Turbine)	Last Inspection in 2016. No issue Found.		OME	Operate and Monitor								
411.50	Governing System - Relay Oil (Turbine)	Last Inspection in 2016. No issue Found.		OME	Operate and Monitor								
411.60	Pedestals - Bearings (Turbine)	Last Inspection in 2016. No issue Found.		OME	Operate and Monitor								
411.70	Gland & Drain System - Water Paddle Glands & LP Sprays (Turbine)	Last Inspection in 2016. No issue Found.		OME	Operate and Monitor								
411.80	Insulation, Thermal (Turbine)	Good condition, overall functional											
411.90	Misc. Pipes & Hangers, Flanges, Bailey Joints (Turbine)	Good condition, overall functional											
412.00	Generator (General)												
412.10	Steam Rotor, Brush Gear, Term., Buss DT					Rotor was re-wound in 2016 and stator this year.							
412.20	H_2 Seals - Bearings (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.30	Seal Oil System H_2 & CO_2 System (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.31	Seal Oil System (Generator) 2 x 100 % capacity coolers	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.32	Bulk Hydrogen (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.33	CO_2 System (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.34	H_2 System (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.40	Generator Cooling Systems (General)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.41	Seal Oil Cooling (Generator)	Inspected and serviced in 2016.	FSR 065910	RR	Replace the parts recommended to be repalced in next outage in report. (Table-3)								
412.42	H_2 Coolers (Generator) 4 x 33 % capacity coolers	Good condition, overall functional											
412.50	Excitation System - Exciters - Fieldbreaker (Generator)	Good condition, overall functional											
412.60	Voltage Regulation (Generator)	Good condition, overall functional											
412.70	Turbo/Generator - (Protection)	Good condition, overall functional											
412.80	Generator AC Schematics and Metering	Good condition, overall functional											
413.00	Lube Oil System (Turbo/Gen) 2 x 100 % capacity coolers	Good condition, overall functional											
414.00	Foundations (Turbo/Gen)												
415.00	Turbovisory												
416.00	Barring Gear - T/G Coupling Alignment	Good condition, overall functional											
420	**Circulating Water System (General)**												

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421.00	Inlet Canal - CW Screens/Sumps	Part of Hatch Inspection		OME	Hatch 3rd party sub-contractors will carry out the inspection. Sump has falling concrete Issues. Replacement of screens will be needed.	ROV			2021				
422.00	Circulating Water Pumps	Good condition, overall functional											
423.00	CW Disch & Cond - In/Out Valves & Disch Pipe	Good condition, overall functional											
430	**Condensing System (General)**												
431.00	Main Condensor	Good condition, overall functional			NLH has inspection reports from past four years. NLH to share the reports for three units								
432.00	Condensed Shell & Water Boxes	Good condition, overall functional			Water Boxes are lined and are protected. NLH repaces annodes on regular basis.								
433.00	Condensed Tubes	Good condition, overall functional			Al/Brass Tubing for Unit-3 and NLH to confirm for other units. NLH to provide how many tubes have been plugged.								
434.00	Air Extraction System	Good condition, overall functional			Two Vaccum Pumps (Unit-3 has some issues and Unit-2 has some issues for one pump too.) No spares are available. Unit-3 Borescope was done and no issues found. For unit-1: in 2022, one pump is going to be overhauled as part of capital plan. Unit-2 North is comming 2023 for overhaul. Unit-2 South was overhauled in 2018.								
436.00	Condenser Ball Cleaning System	Good condition, overall functional			No Ball cleaning system is being used/not in service on all three units.								
440	**Feedwater System (General)**												
441.00	Extraction Pump	Good condition, overall functional			12 years frequecy for overhaul. Unit-3 North: 2017, South : 2015 Unit-2 Norh: 2016, South : 2014 Unit-1 Norh: 2015, South : 2014 Next Overhauls needs to be incldued in Capital Planning.								
442.00	LP Feedwater Hotwell to BFP Suction												
442.10	Condenser Hotwell	Good condition, overall functional											
442.20	Drain Coolers (Feedwater)	Good condition, overall functional											
442.30	No. 1 Low Pressure Feedwater Heater	Good condition, overall functional			Heaters are not original. NLH has to share the details of replacement of heaters.								
442.40	No.2 Low Pressure Feedwater Heater	Good condition, overall functional			HP Heater No.6 on Unit-1 has gasket leakage. So this is going to be open and can be used for additional inspection.								

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442.60	Deaerator	*Internal inspection of dearating heater and of D/A storage tank should be conducted - establish condition of trays & supports in D/A heater plus all piping connections.*			Unit:1 2020 Unit 2: 2019 Unit3 : 2020 NLH to share the inspection reports. Cracking is observed in steam coil inlet connection. So this is checked every year. Shell is visually inspected every year and internals are inspected every 6 years. On Unit-1, 2 Corrosion cracking was observed 15 yeards ago. Saddles were not sliding and some craks showed up due to accumulated stress. This was all addressed and fixed back then. NLH does not replace the deaerator internals on a periodic basis but only replace when needed. Chemical dosing system is mostly manul. NLH set the dosing rates based on sample results.								
442.70	BFP Suction & Strainers	Good condition, overall functional			Unit-1 East: 2021, West : 2021 Unit-2 East: 2014, West : 2017 Unit-3 East: 2016, West : 2016 Unit-1 West suction valve was closed and pump ran without water in Oct.2020, so impeller was worn out and bearing seals were damaged. So Unit-1 West was overhauled in 2021. NLH to share the report of failure and the overhaul report. So BFP`s are on 6 years interval for inspection and overhaul. Unit-1 East and Unit-3 East is being overhauled this year. No safety valve on BFP Discharge line. Pipe DP is more than dead end pressure. NLH to share the CP/BFP/BFBP curves for all three units.								
443.00	HP/Feedwater BFP to Economizer (General)												
443.10	BFP Discharge												
	FAC Site 3-1 West Discharge Pump 1, Pipe	FAC(2012)	*BWL S20-030 CAMBTP9745*	OME	Pad Weld in 2015. . Last inspection in 2018.	UT grid	*BWL S20-030 CAMBTP9745*		2023	Next Inspection			
	FAC Site 3-2 West BFP Discharge ECC. Reducer &Y, Pipe	FAC(2012)	*BWL S20-030 CAMBTP9745*	OME	Reinspect in 3 years. Last inspection 2020.	UT grid	*BWL S20-030 CAMBTP9745*		2023	Next Inspection			
	FAC Site 3-3 Low Flow Bypass & Attemp. Supply, Pipe	No record.	*BWL S20-030 CAMBTP9745*		Initial Inspection recommended (Site 3-3 in AM132-RP-001). No previouse inspection record.	UT grid	*BWL S20-030 CAMBTP9745*		2021	Next Inspection			
	FAC Site 3-4 Low Flow Line Connection to Main Run, pipe	FAC(2012)	*BWL S20-030 CAMBTP9745*	OME	Last inspection 2018.	UT grid	*BWL S20-030 CAMBTP9745*		2027	Next Inspection			
	FAC Site 3-5 BFP Discharge Eblow Upstream of Econ inlet, pipe	FAC(2012)	*BWL S20-030 CAMBTP9745*	OME	Last inspection 2019.	UT grid	*BWL S20-030 CAMBTP9745*		2022	Next Inspection			

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	FAC Site 3-6 LP FW piping Flow Meter South side of BFPs, pipe	FAC(2012)	*BWL S20-030 CAMBTP9745*	OME	Last inspection 2015.	UT grid	*BWL S20-030 CAMBTP9745*		2027	Next Inspection			
443.20	No.4 High Pressure Feedwater Heater	Good condition, overall functional											
443.30	No.5 High Pressure Feedwater Heater	Good condition, overall functional											
443.40	No.6 High Pressure Feedwater Heater	Good condition, overall functional											
	Element 554 HP Flow Element, pipe	FAC (2015)	*BWL S20-030 CAMBTP9745*	OME	Pad weld in 2018; Reinspect in 6 years. Last inspection 2018.	UT grid	*BWL S20-030 CAMBTP9745*		2024	Next Inspection			
	FAC Site 3-7 HP Heater No.6 Bypass Piping, pipe	FAC (2015)	*BWL S20-030 CAMBTP9745*	OME	Last inspection 2018.	UT grid	*BWL S20-030 CAMBTP9745*		2021	Next Inspection			
	FAC Site 3-8 HP Heater No.5 Inlet Piping, pipe	FAC (2015)	*BWL S20-030 CAMBTP9745*	OME	ASME min in 8 years. Last inspection 2019.	UT grid	*BWL S20-030 CAMBTP9745*		2023	Next Inspection			
	FAC Site 3-9 Discharge Full Flow/ Bypass Tee Double Elbow,pipe	FAC (2014)	*BWL S20-030 CAMBTP9745*	OME	Reinspect in 3.9 years. Last inspection 2017.	UT grid	*BWL S20-030 CAMBTP9745*		2021	Next Inspection			
	FAC Site 3-10 Flow Element Emergency RH Attempt. Refill Line, pipe.	No record.	*BWL S20-030 CAMBTP9745*	OME	Baseline inspection of new pipe recommended. Piping replaced in 2017.	UT (pipe too small for grid).	*BWL S20-030 CAMBTP9745*		2021	Next Inspection			
	FAC Site 3-11 HP Heater No. 6 Bypass Elbow Vert. to Hot Bend	FAC (2018)	*BWL S20-030 CAMBTP9745*	OME	Last inspection 2018.	UT grid.	*BWL S20-030 CAMBTP9745*		2027	Next Inspection			
	Main steam East Boiler Line, pipe	No record	*BWL S20-030 CAMBTP9745*	OME	Wall thickness was well above minimum wall. Last inspection 2015.	UT	*BWL S20-030 CAMBTP9745*		2025	Next Inspection			
	Cold Reheat Bleed Steam Line, pipe	No record	*BWL S20-030 CAMBTP9745*	OME	no indications obsereved. Last inspection 2015.	MT	*BWL S20-030 CAMBTP9745*		2025	Next Inspection			
	RH Leading Edge Bends, Tubes	Wall Thinning in 2017	*BWL S20-030 CAMBTP9745*	OME	Between 2017 and 2020, all 60 bends were pad welded. Last inspection 2020.	UT	*BWL S20-030 CAMBTP9745*		2023	Next Inspection			
443.50	No.6 Feedwater Heater to Econ. Checkvalves	Good condition, overall functional			NLH to share the HBD for all three units.								
444.00	Feedwater Heater Vents Drain - Flashboxes (Gen)												
444.10	Feedwater Heater - Vents & Drains	Good condition, overall functional											
444.20	Heater Drain Pumps	Good condition, overall functional			Overhaul frequency is 12 years. Unit-1 : 2013 Unit-2: Unit-3: NLH to share the last inspection/overhaul reports.								
444.30	Flashboxes (Feedwater)	Good condition, overall functional			Unit-3: 2013 (Rigidly connected to condenser). Unit-2: 2012 (Connected to wall so can be seperated) Unit-1: 2012 (Connected to wall so can be seperated) NLH to confirm the inspection dates and share the reports.								
445.00	Turbine Bled Steam System	Good condition, overall functional			NDE inspections are being done regularly. Nothing in particular. NRVs on extraction valves are overhauled every three years. Valve Laps are checked on valve seats.								
446.00	Boiler Feed Pumps	Good condition, overall functional											

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450	**Emergency Power Unit (General)**	**There is no information available on the Emergency Power Unit.**	**1**										
451.00	Gas Turbine - (EPU)	Good condition, overall functional											
452.00	Generator (EPU)	Good condition, overall functional											
453.00	Excitation & Syn (EPU)	Good condition, overall functional											
454.00	Lubrication (EPU)	Good condition, overall functional											
455.00	Governing (EPU)	Good condition, overall functional											
456.00	Fuel Supply (EPU)	Good condition, overall functional											
457.00	Fire Protection (EPU)	Good condition, overall functional											
400	SUBTOTAL	Good condition, overall functional											
500	**Electrical (General)**												
501.00	Motors	Good condition, overall functional											
502.00	Starters	Good condition, overall functional											
503.00	Cable Trays	Good condition, overall functional											
504.00	Ducts	Good condition, overall functional											
505.00	Cables	Good condition, overall functional								-			
510	**Main Power Output (General)**												
511.00	Generator Transformers T3, T4 (spare)	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
512.00	Unit Service Transformer UST-3	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
513.00	Station Service Transformer SST-34	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
514.00	Excitation Transformer RT3	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
515.00	Generator CT,PT & Isolated Phase Buss	Good condition, overall functional			They are all original . NLH to share the last test reports to determine the remaining life of trans.								
520	**4.16 kV Switchgear Distribution**												
521.00	Unit Boards UB3, UB4	Good condition, overall functional			They are all original. Need to get one spare to support during failure.								
522.00	Station Board SB34	Good condition, overall functional			Both 4160 and 600V switch gears will be replaced in 2023 as part of capital plan.								
528.00	Unit Aux. Transformer UAT-3	Good condition, overall functional			All batteries have been repalced in past. NLH will provide the details.								
529.00	Station Aux. Transformer SAT-34	Good condition, overall functional											
530	**Conduit & Cable (General)**												
531.00	Power Cables	Good condition, overall functional			On turbine side, its Mark 5 which is obselete. NLH has good spare parts inventory and have a contract with B&H (now) to provide required spares. On DCS side, its FoxPro which is still available. On Unit-3, NLH is repalcing the hardware with the new one for DCS side.								
532.00	Control Cables	Good condition, overall functional											
533.00	Instrument Cables	Good condition, overall functional											
500	SUBTOTAL												
600	**Instrumentation & Controls (General)**												
620	**Instrumentation Tubing & Fittings**												
620.10	Electronic Components Instrumentation	Good condition, overall functional			Plant wide communication system was upgraded in 2012/2013. So no issues at this time.								
620.20	Fasteners & Connectors Instr. & Elect.	Good condition, overall functional											
621.00	Locally Mounted (Instruments)												
621.10	Indicators & Gauges	Good condition, overall functional											
621.20	Switches, Detectors, Sensors	Good condition, overall functional											
621.30	Transmitters	Good condition, overall functional											
621.40	Primary Elements (Wells)	Good condition, overall functional											

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621.50	Controllers	Good condition, overall functional											
621.60	Valves,Regulators,Operators	Good condition, overall functional											
621.61	Instrumentation Isolators	Good condition, overall functional											
621.62	Solenoid Valve	Good condition, overall functional											
621.63	Control Valve & Regulator	Good condition, overall functional			Some of the critical breakers are not monitored by DCS.								
621.64	Operators Positioners	Good condition, overall functional											
621.65	Motorized Valves	Good condition, overall functional											
621.70	Transducers	Good condition, overall functional											
621.80	Relays & Coils	Good condition, overall functional											
630	**Process Controls Boiler (General)**												
631.00	Combustion & Draft Control	Good condition, overall functional											
632.00	Feedwater & Drum Level Control	Good condition, overall functional											
633.00	Steam Temperature Control (Sprays)	Good condition, overall functional			May be some tuning required for low loads.								
634.00	Fuel Interlock (Safety)	Good condition, overall functional											
634.10	Flame Detectors	Good condition, overall functional			Stability of flame scanners is not issue above 40MW. 25 MW is being targetted on Unit-2. Other units are also being replaced.								
636.00	Power Supplies & Change-Overs	Good condition, overall functional											
640	**Process Controls Turbine (General)**												
645.00	Turbo/Gen. Instrumentation and T/G Schedules	Good condition, overall functional											
650	**Process Controls Cooling Pond (General)**	Good condition, overall functional											
660	**Process Controls Water Treatment**	Good condition, overall functional											
690	**Operator Interfaces (General)**	Good condition, overall functional											
691.00	Main Control Room Panels & Desk	Good condition, overall functional											
692.00	Local Control Panels	Good condition, overall functional											
693.00	Annunciators	Good condition, overall functional											
694.00	Recorders	Good condition, overall functional											
695.00	Computers	Good condition, overall functional											
695.10	Data Logger Das (Computer)	Good condition, overall functional											
695.20	Turbine Run-Up (Computer)	Good condition, overall functional											
695.30	Lift Pumphouse (Computer)	Good condition, overall functional											
695.40	Environmental (Computer)	Good condition, overall functional											
695.50	Programmable Controllers	Good condition, overall functional											
695.60	Sequence of Events (Computers)	Good condition, overall functional											
695.70	Process Control (Computers)	Good condition, overall functional											
600	SUBTOTAL												

HTGS Unit 3

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Inspection Methodology	Recommended Inspections / NDE	Execution date		Priority	CAPITAL		General Comments
The row on the right is for information purposes and will not be printed in final DBM	*Thermal Subject Index (TSI) Equipment or Area Description*	*High level concerns and condition assessments will be listed here. Information sources (references) will include TSI meeting minutes, Previous reports and studies, NDE results, and maintenance history when available.*		*Recommended workscope for life assessment. Workscope may include Remove and Replace (RR), Refurbish Existing (RE), or Operate and Monitor Existing (OME)*				*Identify if workscope is to be executed during outage. Indicate the date workscope is to be carried out.*		*Identify Priority of the Workscope to be Executed.*	*Workscope currently identified as capital upgrade.*		
Work Breakdown Structure	Equipment or Area	Discussion	Reference	Action RR RE OME	Description		Reference	Check if outage	Date (mm/yyyy)	Priority	Description, Cost, Date Planned	Included in Life Exten. Scope	
700	**Common Services**												
710	**General Service Water (GSW) (General)**												
711.00	Pumps, Motors (General Service Water)	Good condition, overall functional											
712.00	Strainers, Valves, Piping (General Service Water)	Good condition, overall functional											
720	**Compressed Air Systems (General)**												
721.00	Plant Air	Good condition, overall functional			3 Compressor for all three units. All feed to common header. They are not connected to DCS, but have a dedicated monitoring system that allows operators to switch on/off when needed. All 3 compressor had issues in past and they were overhauled last year. Unit-1: 2015 Unit-2: 2016 Unit-3: 2008 No good drainage system to take care of moist. So a lot of moisture in air after the filters. A lot of salt resulting in plugging of coolers. No. 3 is a variable speed. No. 1,2 are fixed speed.								
722.00	Instrument Air	Good condition, overall functional			NLH opens the inst. Air to let moisture out as there are not many drip legs or moisture traps.								
723.00	Substation H.P. Air	Good condition, overall functional			Out of Scope from Holyrood PP.								
730	**Fire Pumps & Motors**												
731.00	Fire Pumps & Motors	Good condition, overall functional			Diesel pump has some suction issues. Twinning one more suction line is being investigated. (1500gpm to 2500gpm). Check with Greg S. This was Hatch study. [125MW GT is a new addition and is out of scope. Some resources including raw water is shared with this 125MW GT]. Some issues in udnerground piping. 75% underground fire water piping is being repalced. The existing plan is to replace the piping only need for sync. condenser operation for Unit-3. Hatch needs to investigate what segments needs to be repalced in addition based on our assessment.								
732.00	Fire Piping, Valves, Hydrants, Sprinkler	Underground fire piping inspection is in Hatch Scope. Hatch will arrange it via our sub-contractor		OME	To done by Hatch Sub-Contractor if required.								
733.00	Fire Hoses	Good condition, overall functional											
733.20	Unit 3 Fire Hoses	Good condition, overall functional											
733.40	General Services Fire Hoses	Good condition, overall functional											
740	**Cranes & Elevators (General)**												
741.00	Cranes (General)												
741.10	Turbine House (Cranes)	Good condition, overall functional											
741.30	Demin Plants (Cranes)	Good condition, overall functional											
741.40	Pump House (Cranes)	Good condition, overall functional											
741.50	Portable (Cranes)	Good condition, overall functional											
742.00	Elevators	Good condition, overall functional											
750	Communication System												
751.00	Phone Systems												
752.00	Company Phones												
753.00	Fax Equipment												
754.00	P.A. Systems - Public Address												

HTGS Unit 3

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Inspection Methodology	Recommended Inspections / NDE	Execution date		Priority	CAPITAL		General Comments
The row on the right is for information purposes and will not be printed in final DBM	*Thermal Subject Index (TSI) Equipment or Area Description*	*High level concerns and condition assessments will be listed here. Information sources (references) will include TSI meeting minutes, Previous reports and studies, NDE results, and maintenance history when available.*		*Recommended workscope for life assessment. Workscope may include Remove and Replace (RR), Refurbish Existing (RE), or Operate and Monitor Existing (OME)*				*Identify if workscope is to be executed during outage. Indicate the date workscope is to be carried out.*		*Identify Priority of the Workscope to be Executed.*	*Workscope currently identified as capital upgrade.*		
Work Breakdown Structure	**Equipment or Area**	**Discussion**	**Reference**	**Action RR RE OME**	**Description**		**Reference**	**Check if outage**	**Date (mm/yyyy)**	**Priority**	**Description, Cost, Date Planned**	**Included in Life Exten. Scope**	
755.00	Portable Radio Telephone												
756.00	Desktop Computer Communications												
760	**Heating,Ventilating & Air Conditioning**	**HVAC Systems Are OK**											
761.00	**Not in Hatch scope**												
761.10													
770	**Water (General)**												
771.00	Pump House (Potable Water)	Good condition, overall functional			Potable tank is filled on located at 11th F. No drinkable water at plant								
772.00	Distribution (Potable Water)	Good condition, overall functional											
773.00	Closed Cooling Water				NLH informed that the closed cooling water pumps are serviced/overhauled every 12 years. All units have 2x100% CCW pumps. Unit-3 has shell and tube type heat exchangers for CCW coolers and Unit 1,2 have plate type heat exchangers.								
780	**Plant Fuel Supply (General)**												
781.00	Plant Fuel Supply (General)	Good condition, overall functional			Steam heated lines. Electrical Heating tracing from Jetty to tank forms. Inside tank form, its all steam heat tracing. Condensate is not recovered back and is discharged to ground. Four fuel tanks. NLH is trying to get life extension. Tank-1 will be end of life this year. Need to see if it will de-commissioned or not. Tank 2; June 2023 Tank 3: 2025 Tank4: 2022 Day Tank: 2023 Management decided that plant is good with three tanks. So Tank-1 will be most likely decomissioned this year.								
781.10	Plant Fuel Lines & Metering	Good condition, overall functional											
781.11	Cathodic Protection System	Good condition, overall functional			No Underground piping. So No CP.								

HTGS Unit 3

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Inspection Methodology	Recommended Inspections / NDE	Execution date		Priority	CAPITAL		General Comments
The row on the right is for information purposes and will not be printed in final DBM	*Thermal Subject Index (TSI) Equipment or Area Description*	*High level concerns and condition assessments will be listed here. Information sources (references) will include TSI meeting minutes, Previous reports and studies, NDE results, and maintenance history when available.*		*Recommended workscope for life assessment. Workscope may include Remove and Replace (RR), Refurbish Existing (RE), or Operate and Monitor Existing (OME)*				*Identify if workscope is to be executed during outage. Indicate the date workscope is to be carried out.*		*Identify Priority of the Workscope to be Executed.*	*Workscope currently identified as capital upgrade.*		
Work Breakdown Structure	Equipment or Area	Discussion	Reference	Action RR RE OME	Description		Reference	Check if outage	Date (mm/yyyy)	Priority	Description, Cost, Date Planned	Included in Life Exten. Scope	
790	**Miscellaneous (General)**												
791.00	Environmental Monitoring Equipment	Good condition, overall functional			6 monitoring sessions in the facility. SO2, CO2, Nox, PM								
791.10	Air Quality Monitoring Equipment	Good condition, overall functional											
791.20	Water Quality Monitoring Equipment	Good condition, overall functional											
791.23	Flue Gas Quality Monitoring Equipment	Good condition, overall functional											
791.30	Ground Temperature Probe Readings	Good condition, overall functional											
700	SUBTOTAL												

SUBTOTALS:		
100 - Structures and General Site		x 1000
200 - Service Buildings General		x 1000
300 - Steam Generation Facilities		x 1000
400 - Power Generation Facilities		x 1000
500 - Electrical General		x 1000
600 - Instrumentation & Controls		x 1000
700 - Common Services		x 1000
Subtotal:		Million
EPCM:	8%	Million
Spares:		Million
Remedial Repairs:		Million
RR EPCM:	8%	Million
Monte Carlo:	8.18%	Million
Design Risk:	1%	Million
Growth Allowance:		Million
Labour Risk:		Million
Unit #3 Grand Total:		Million

newfoundland labrador hydro
a nalcor energy company

Substation

HATCH

WBS	Description	General Concerns and Condition Assessment		Recommended Workscope		Inspection Methodology	Recommended Inspections / NDE	Execution date		Priority	CAPITAL		General Comments
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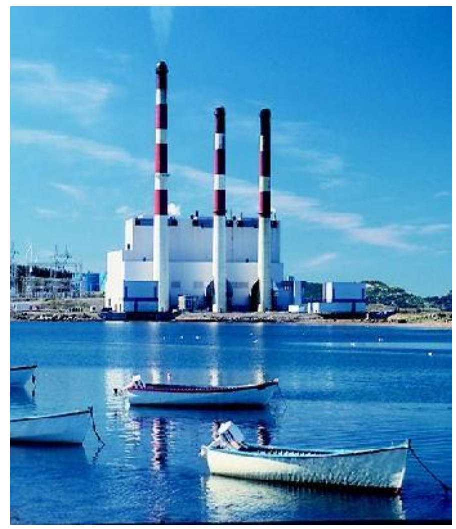
Work Breakdown Structure	Equipment or Area	Discussion	Reference	Action RR RE OME	Description		Reference	Check if outage	Date (mm/yyyy)	Priority	Description, Cost, Date Planned	Included in Life Exten. Scope	
100	**Substation (General)**												
101.00	Transformers												
101.10	Transformers (69 kV / 230 kV) T5, T10	Good condition, overall functional											
101.20	Transformers (230 kV / 138 kV) T6, T7, T8	Good condition, overall functional											
102.00	AC Distribution (Substation)	Good condition, overall functional											
103.00	DC Distribution (Substation)	Good condition, overall functional											
104.00	69 kV System (Substation)												
104.10	Structures	Good condition, overall functional											
104.20	Bus	Good condition, overall functional											
104.30	Breakers	Good condition, overall functional											
104.40	Disconnects	Good condition, overall functional											
104.50	Grounding System	Good condition, overall functional											
104.60	Metering, Relaying & Protection	Good condition, overall functional											
104.70	Breaker Control	Good condition, overall functional											
105.00	138 kV System (Substation)												
105.10	Structures	Good condition, overall functional											
105.20	Bus	Good condition, overall functional											
105.30	Breakers	Good condition, overall functional											
105.40	Disconnects	Good condition, overall functional											
105.50	Grounding System	Good condition, overall functional											
105.60	Metering, Relaying & Protection	Good condition, overall functional											
105.70	Breaker Control	Good condition, overall functional											
106.00	230 kV System (Substation)												
106.10	Structures	Good condition, overall functional											
106.20	Bus	Good condition, overall functional											
106.30	Breakers	Good condition, overall functional											
106.40	Disconnects	Good condition, overall functional											
106.50	Grounding System	Good condition, overall functional											
106.60	Metering, Relaying & Protection	Good condition, overall functional											
106.70	Breaker Control	Good condition, overall functional											
110	**Otherf Requirements**												
111.00	Coordination, Short Circuit, & Load Flow Study	Good condition, overall functional											
100	SUBTOTAL												
200	**Instrumentation & Controls (General)**												
210	**Instrumentation Tubing & Fittings**												
210.10	Electronic Components Instrumentation	Good condition, overall functional											
210.20	Fasteners & Connectors Instr. & Elect.	Good condition, overall functional											
220.00	Locally Mounted (Instruments)												
220.10	Indicators & Gauges	Good condition, overall functional											
220.20	Switches, Detectors, Sensors	Good condition, overall functional											
220.30	Transmitters	Good condition, overall functional											
220.40	Primary Elements (Wells)	Good condition, overall functional											
220.50	Controllers	Good condition, overall functional											
220.60	Valves,Regulators,Operators	Good condition, overall functional											
220.61	Instrumentation Isolators	Good condition, overall functional											
220.62	Solenoid Valve	Good condition, overall functional											
220.63	Control Valve & Regulator	Good condition, overall functional											
220.64	Operators Positioners	Good condition, overall functional											
220.65	Motorized Valves	Good condition, overall functional											
220.66	Transducers	Good condition, overall functional											
220.70	Relays & Coils	Good condition, overall functional											

	SUBTOTALS:		
100 -	Structures and General Site		x 1000
200 -	Service Buildings General		x 1000
300 -	Steam Generation Facilities		x 1000
400 -	Power Generation Facilities		x 1000
500 -	Electrical General		x 1000
600 -	Instrumentation & Controls		x 1000
700 -	Common Services		x 1000
	Subtotal:		Million
EPCM:		8%	Million
Spares:			Million
Remedial Repairs:			Million
RR EPCM:		8%	Million
Monte Carlo:		8.18%	Million
Design Risk:		1%	Million
Growth Allowance:			Million
Labour Risk:			Million
	Unit #3 Grand Total:		Million

Appendix C
Inspection Report

Technical Services
Report

2021 Condenser Inspection Report Unit # 1



NL Hydro - Holyrood TGS
Holyrood, NL

2021 AUGUST 04-05
GE Steam Power Contract #: EB0-018032
Customer PO #: 4618 OS
Report by Kristofer Jacobs

Imagination at work

REPORT DATA

Purpose of Visit:	Condenser Inspection		
Customer:	Nalcor - NL Hydro	GE Ref No.:	EB0-018032
Site Location:	Holyrood, NL	Customer P.O.:	4618 OS
GE TSA(s):	Kristofer Jacobs	Start Date:	2021 August 04
		End Date:	2021 August 05

EQUIPMENT INFORMATION

Equipment:	Steam Turbine Condenser
Equipment OEM:	CE
Original Ref No.:	CES 6819
Type:	RPR – 70 Steam Generator
Rating:	175MW
Primary Fuel:	No. 6 Fuel Oil
Aux. Fuel:	N/A
MCR Steam Flow:	1,050,000 lb/hr
Drum Des.Press:	2205 psig
SH Outlet Press:	2205 psig
SH/RH Out Temp:	1005 °F

CONTACT INFORMATION

GE TSA:	Kristofer Jacobs	Cust. Contact:	Jessica McGrath
Email:	Kristofer.Jacobs@ge.com	Email:	JessicaMcGrath@nlh.nl.ca
Phone (cell):	709-699-0386	Phone (bus):	709-229-2140
Phone (office):	709-229-2768	Phone (cell):	709-689-9732
GE Customer Service Manager:	Ghanshyam Patel		
Email:	Ghanshyam.Patel@ge.com		
Phone (cell):	1-289-244-3408		

TABLE OF CONTENTS

DISCLAIMER STATEMENT

1 INTRODUCTION

This report documents the results of the visual inspection carried out on the Unit #1 Condenser during the 2021 Maintenance Outage. The scope of the inspection was carried out by Kristofer Jacobs in both the steam side and the water side sections of the condenser.

2 NOTES AND OBSERVATIONS

2.1 Steam Side

At the time of inspection, steam side access was granted through the hotwell since the LP Hood had been removed for the turbine overhaul. No up-close inspections were achieved other than what was obtainable while standing on top of the bundles. Below is a summary and related pictures of the findings:

- Tube Bundles – Overall, the tube bundles appeared to be in good condition. Minor polishing and steam erosion was noted on the tubes **(Figures 6–8)**, as well as, bowing of isolated tubes **(Figures 1–3)**. One tube was also noted to be severed, however, upon further investigation, this tube has been plugged **(Figures 4–5)**.
- Structural Supports – Broken/eroded welds were noted on the bundle supports on cross braces that extend horizontally between the tube support plates of the two bundles. These were noted in previous inspections as not being a significant finding since the braces are welded on both sides, as well as, top and bottom. The bottom welds were found to be satisfactory **(Figures 9–11)**. Also, minor erosion was observed on additional supports throughout the cavity, however, there were no signs of significant material loss **(Figures 12–15)**.
- Expansion Joints
  - Extraction Piping – Two covers were noted to have discrepancies, the first having slipped from it's intended position to provide cover to the bellows expansion joint, the second having come loose posing a hazard if it were to be disturbed. Additional covers, as well as exposed bellows sections appeared to be in good condition, although a close-up inspection was not obtainable to due access restrictions **(Figures 16–19)**.
  - Casing Expansion Joint Cover – overall condition is satisfactory and secure; however, noticeable signs of erosion/corrosion were observed on the cover with minor separation of attachment welds to the casing **(Figures 20-23)**.
- Vacuum Measuring Reference Line – deemed satisfactory with minor erosion noted

FIGURE 1

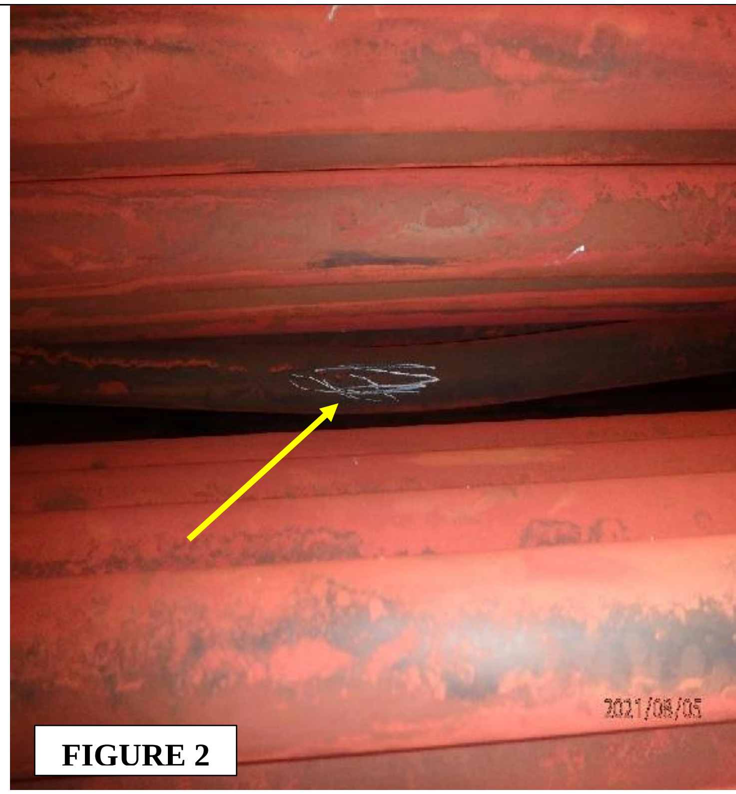


FIGURE 2

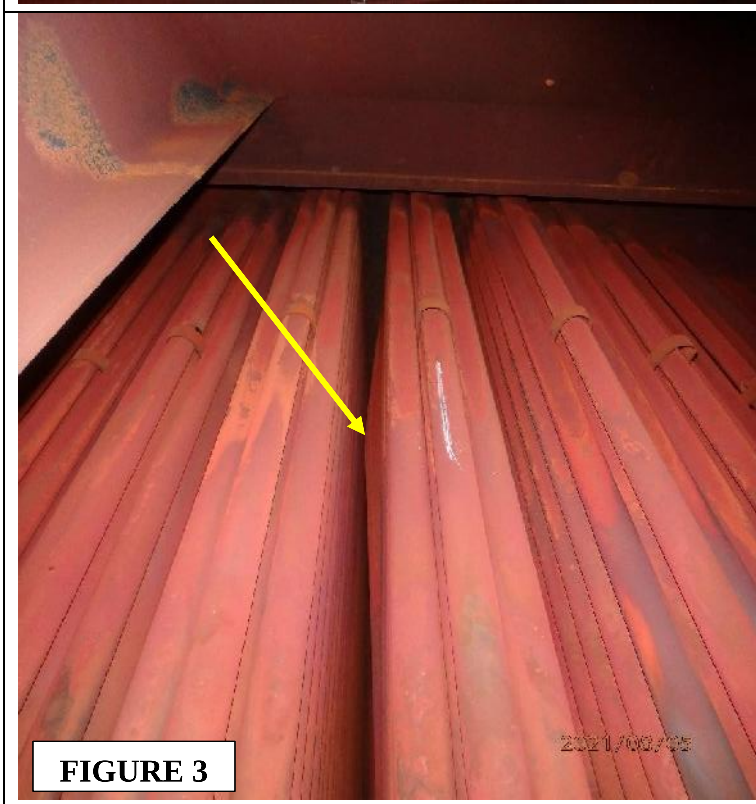


FIGURE 3

FIGURE 4

FIGURE 5

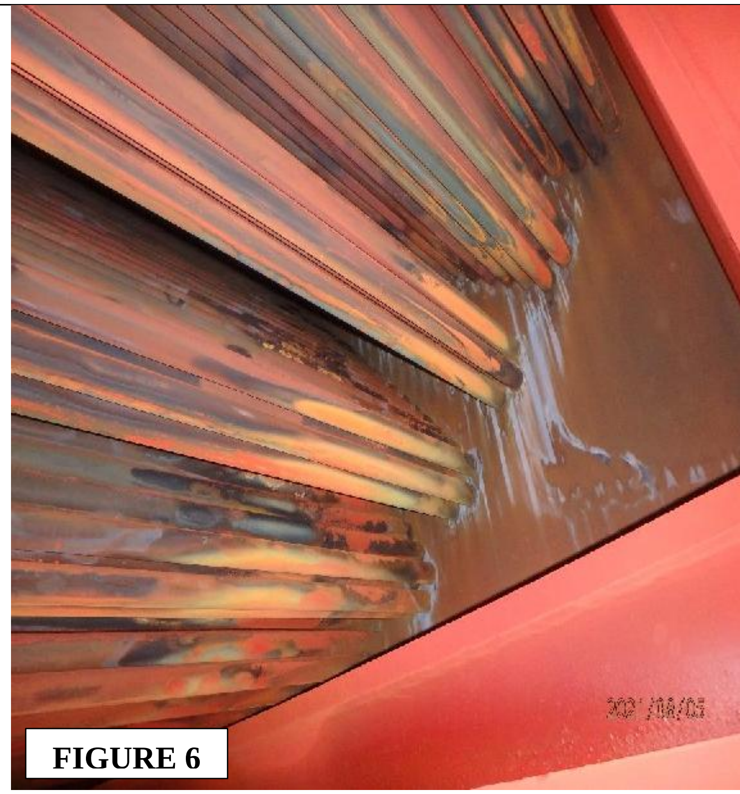


FIGURE 6

FIGURE 7


FIGURE 8

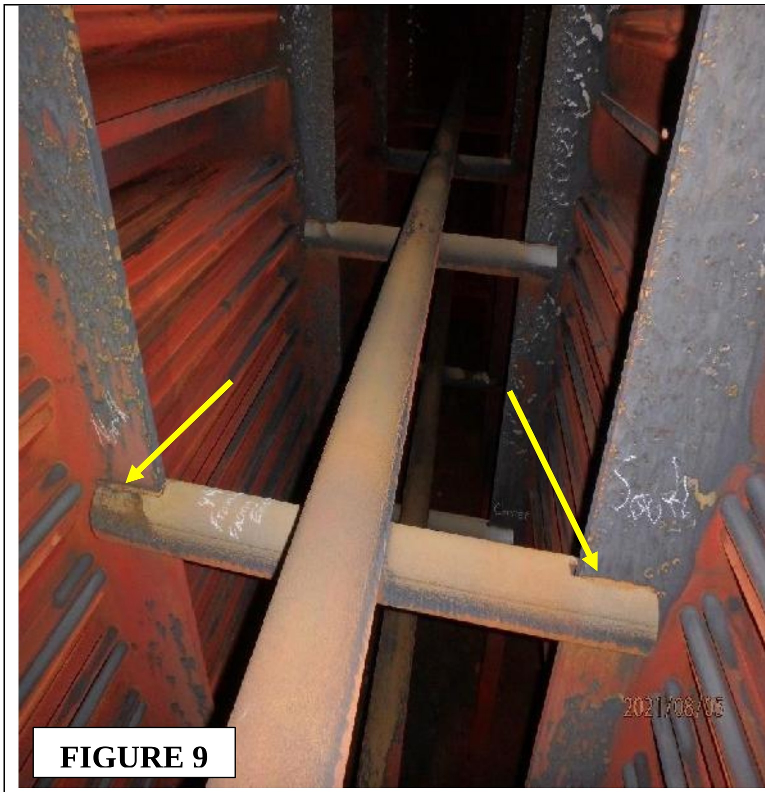


FIGURE 9

FIGURE 10

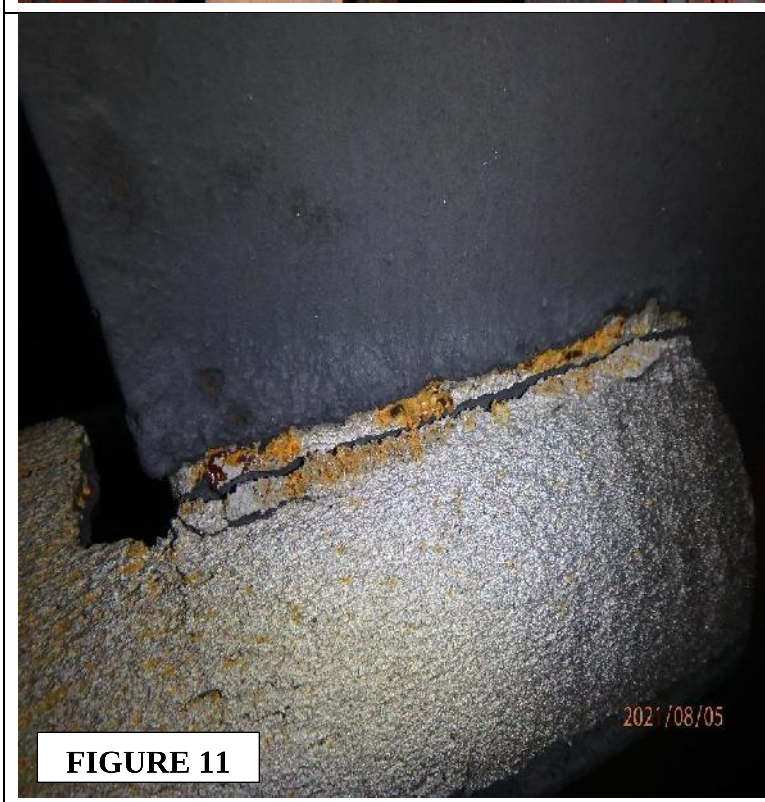


FIGURE 11

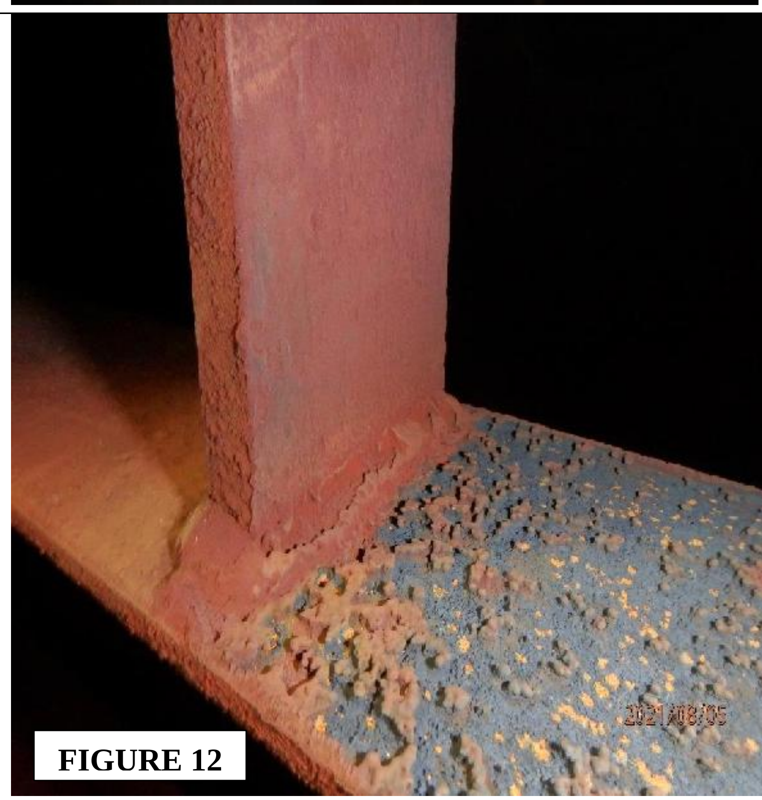


FIGURE 12

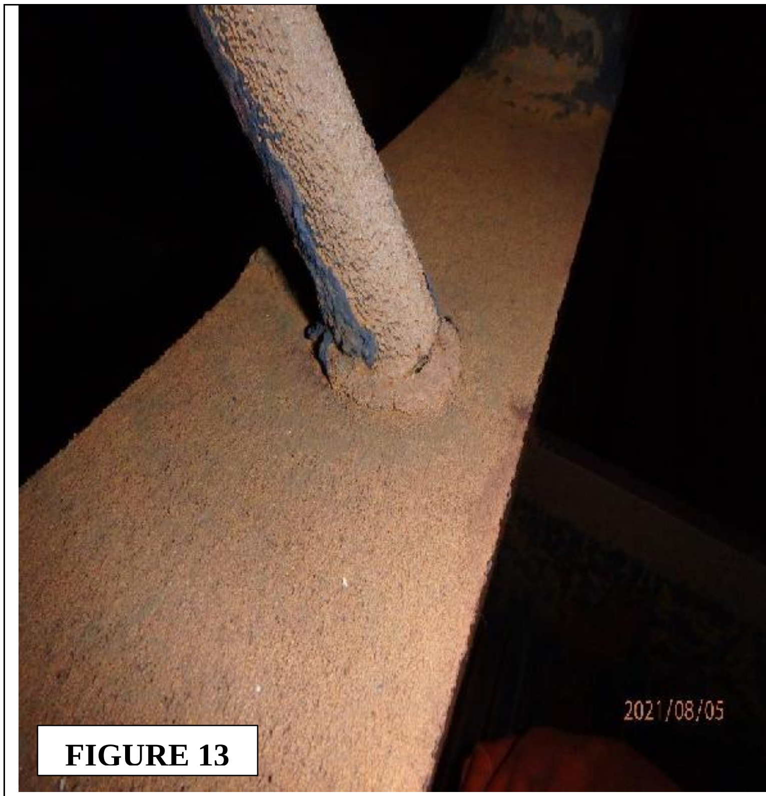


FIGURE 13

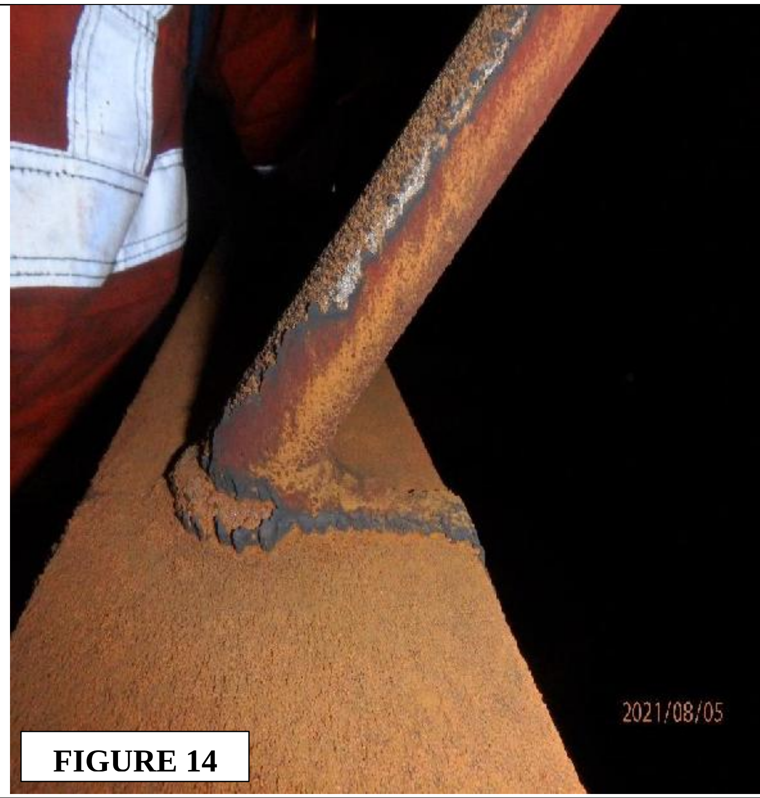


FIGURE 14

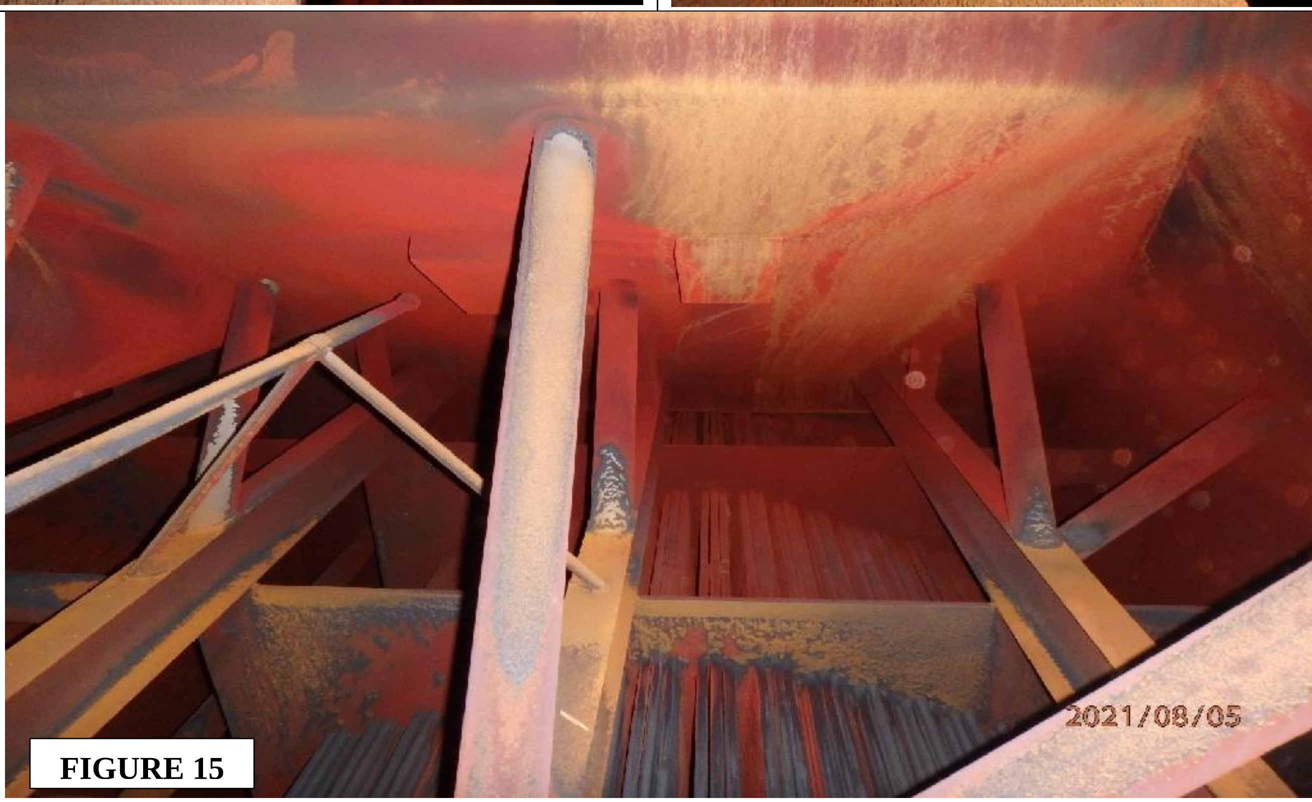


FIGURE 15

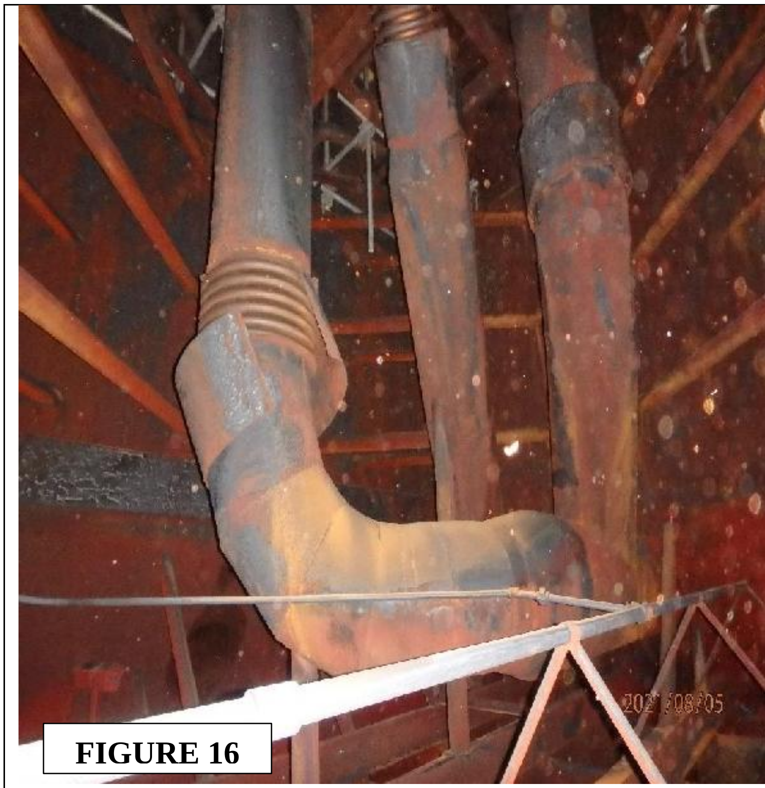


FIGURE 16

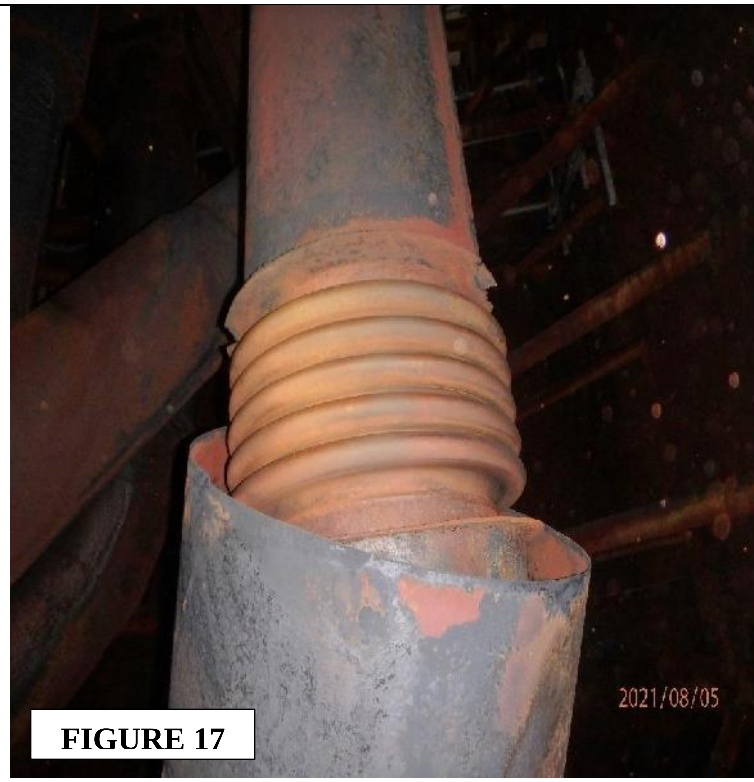


FIGURE 17

FIGURE 18

FIGURE 19

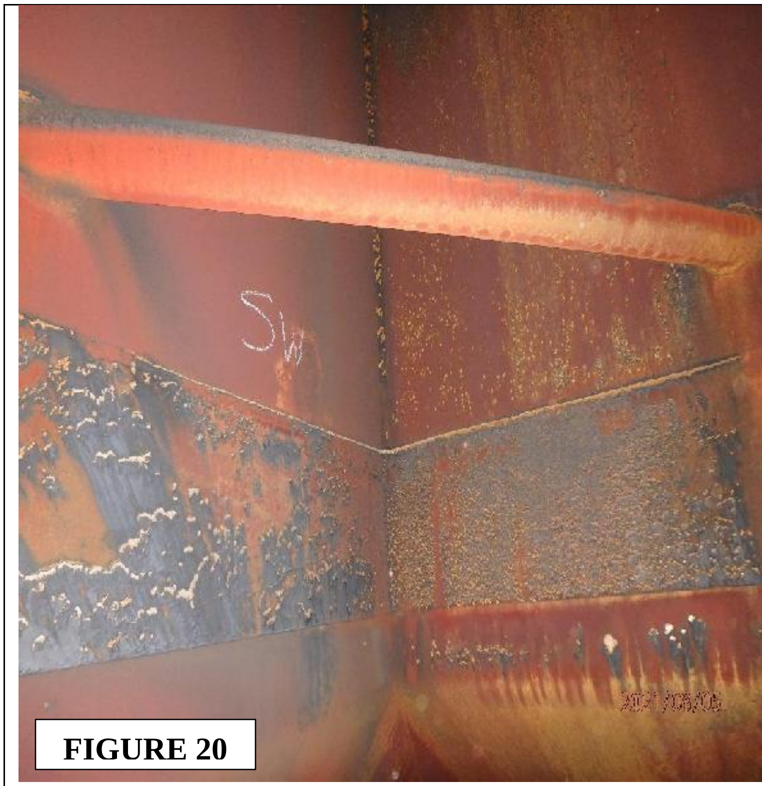


FIGURE 20

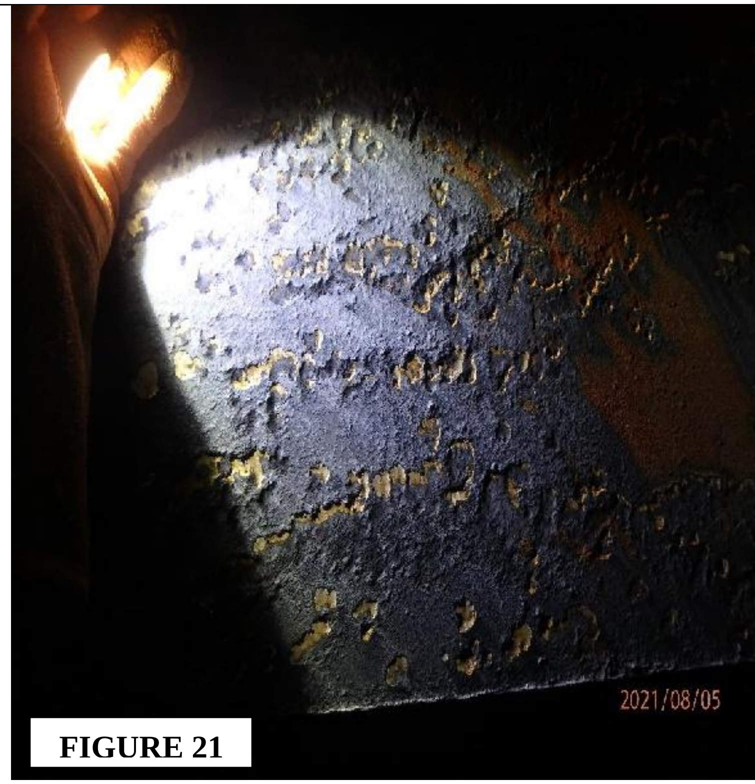


FIGURE 21

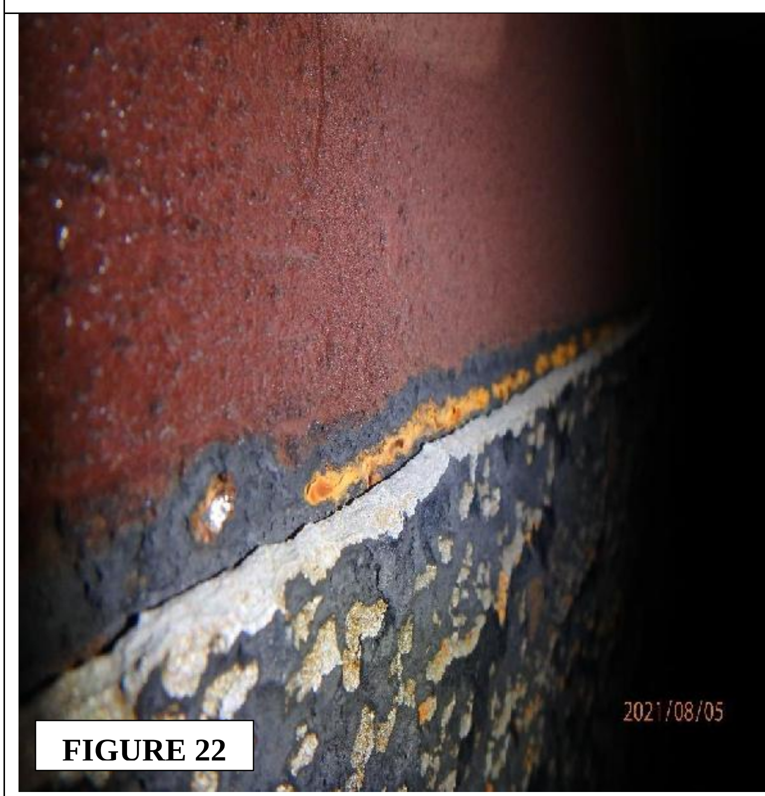


FIGURE 22


FIGURE 23

2.2 West Side – North Inlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout **(Figure 27)**
- Coating had mainly failed between the side walls and back walls as noted in previous inspections **(Figure 25)**
- Anodes in satisfactory condition
- No corrosion of tubesheet was observed
- Manway door recently refurbished with new anode installed **(Figure 24)**
- Corrosion was noted in drain pipe **(Figure 26)**
- Inspection of inlet piping not obtainable as valve was in closed position

FIGURE 24

FIGURE 25

FIGURE 26

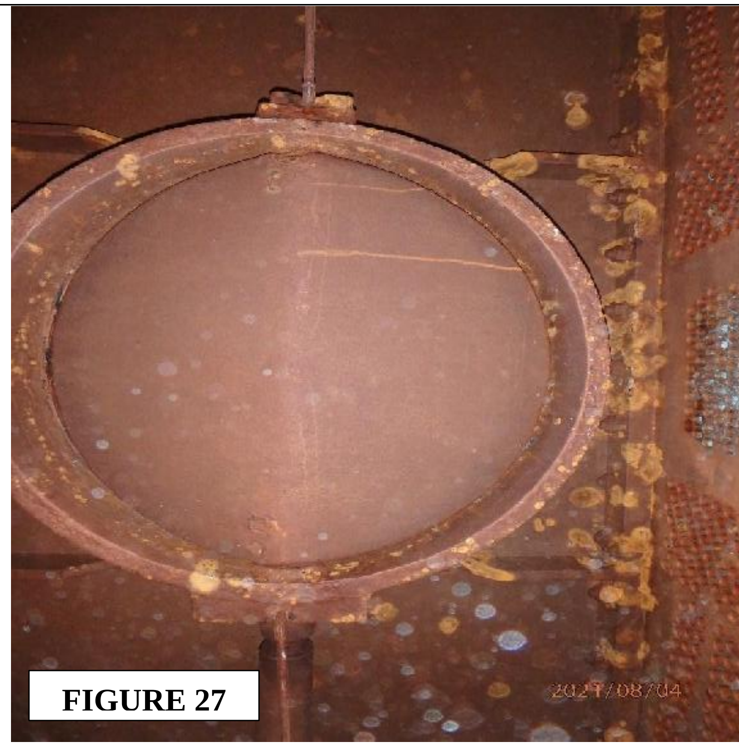


FIGURE 27

2.3 West Side – South Inlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout, especially in corners, however, a few deep pits were observed **(Figures 28, 29, 31-33)**
- Corrosion noted in drain pipe **(Figure 30)**
- Anodes in satisfactory condition
- No corrosion of tubesheet was observed
- Inspection of inlet piping not obtainable as valve was in closed position

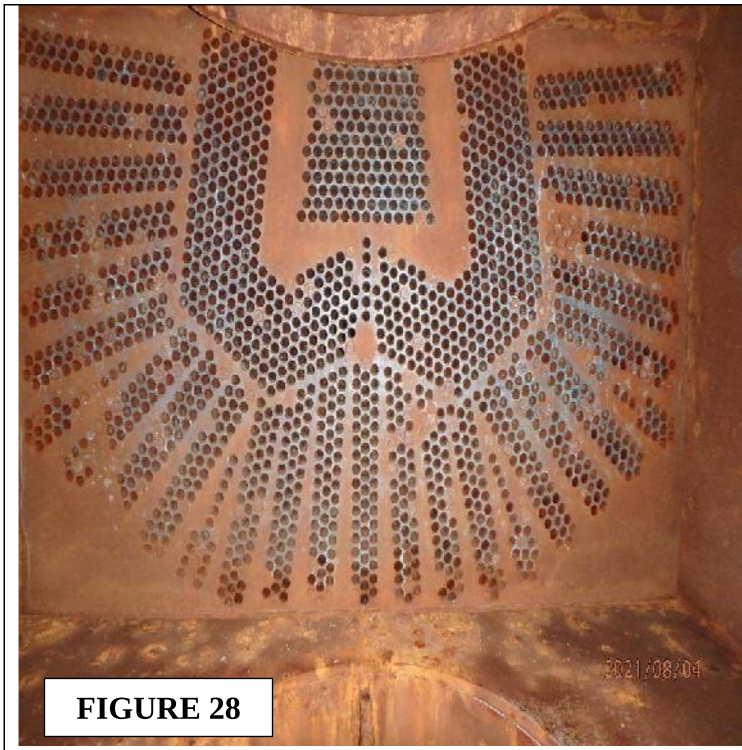


FIGURE 28

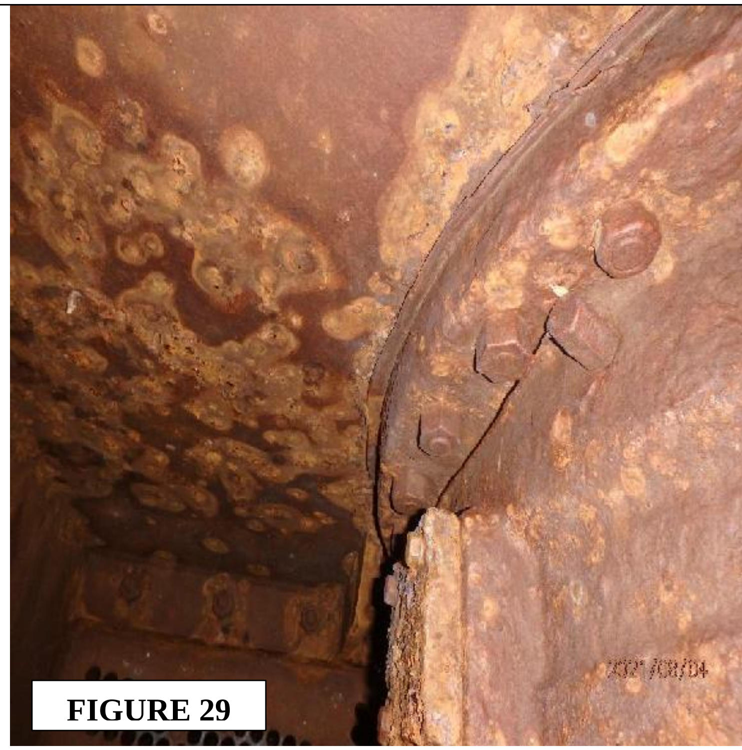


FIGURE 29

FIGURE 30

FIGURE 31

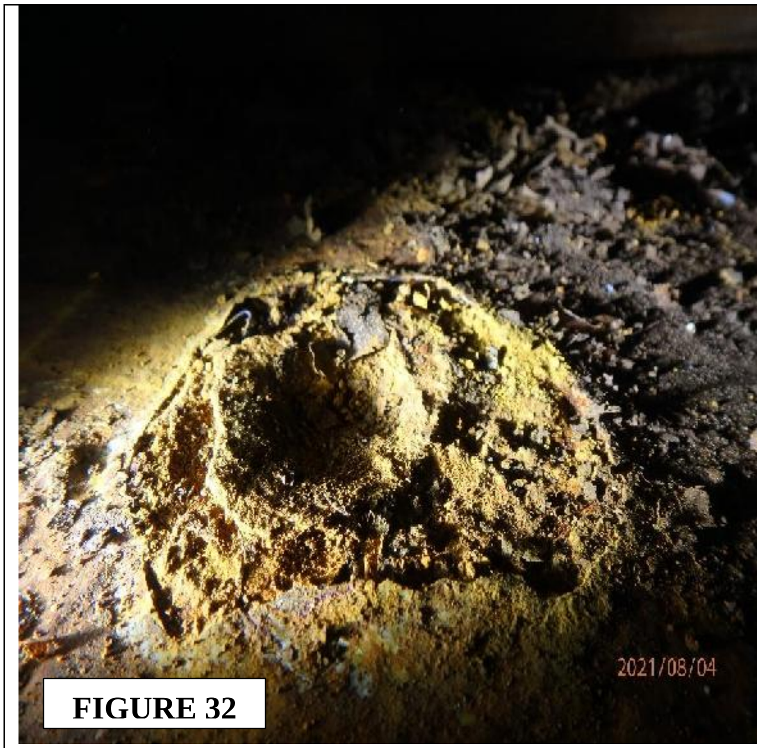


FIGURE 32

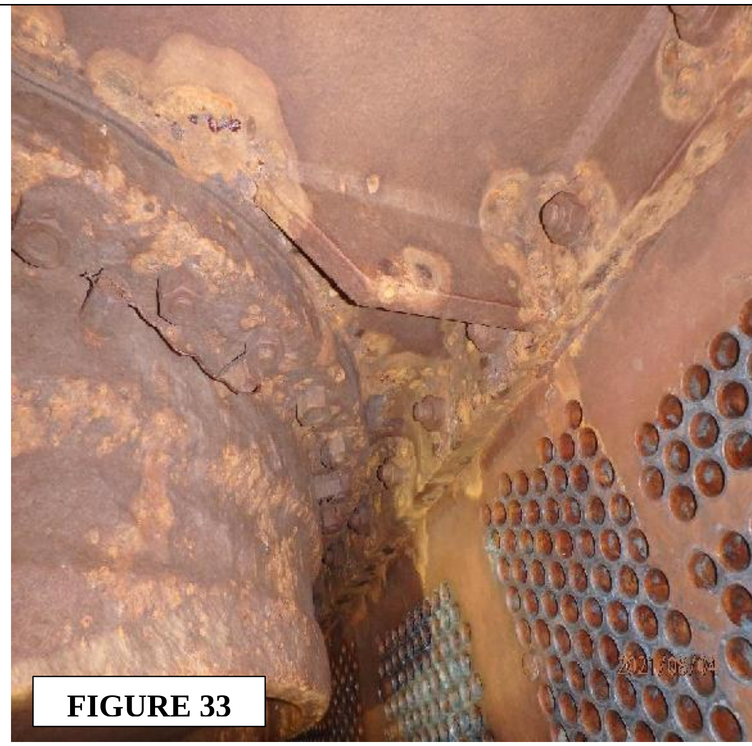


FIGURE 33

2.4 West Side – North Outlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout, especially in corners, as seen in adjacent boxes. As well, a few pits were observed **(Figures 36, 39-40)**
- Manway heavily corroded **(Figures 34, 41)**
- Butterfly valve disc coating failure and corrosion noted **(Figures 37, 38)**
- Anodes in satisfactory condition
- No corrosion of tubesheet was observed
- Minor corrosion noted in discharge piping **(Figure 35)**

FIGURE 34

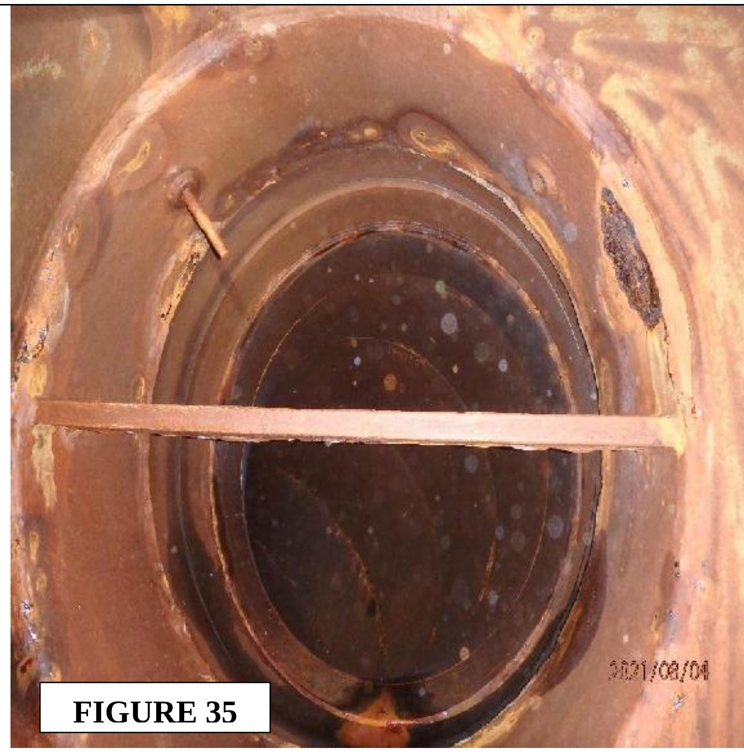


FIGURE 35

FIGURE 36

FIGURE 37

FIGURE 38

FIGURE 39

FIGURE 40

FIGURE 41

2.5 West Side – South Outlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout, especially in corners, as seen in adjacent boxes. As well, a few pits were observed **(Figure 47)**
- Manway heavily corroded **(Figure 42)**
- Butterfly valve disc coating failure and corrosion noted **(Figures 45-46)**
- Anodes – breakdown of door anode noted, internal anode found to be satisfactory **(Figure 42)**
- No corrosion of tubesheet was observed
- Minor corrosion noted in discharge piping
- Corrosion and blistering noted at inlet to discharge piping **(Figures 43-44)**

FIGURE 42

FIGURE 43


FIGURE 44


FIGURE 45

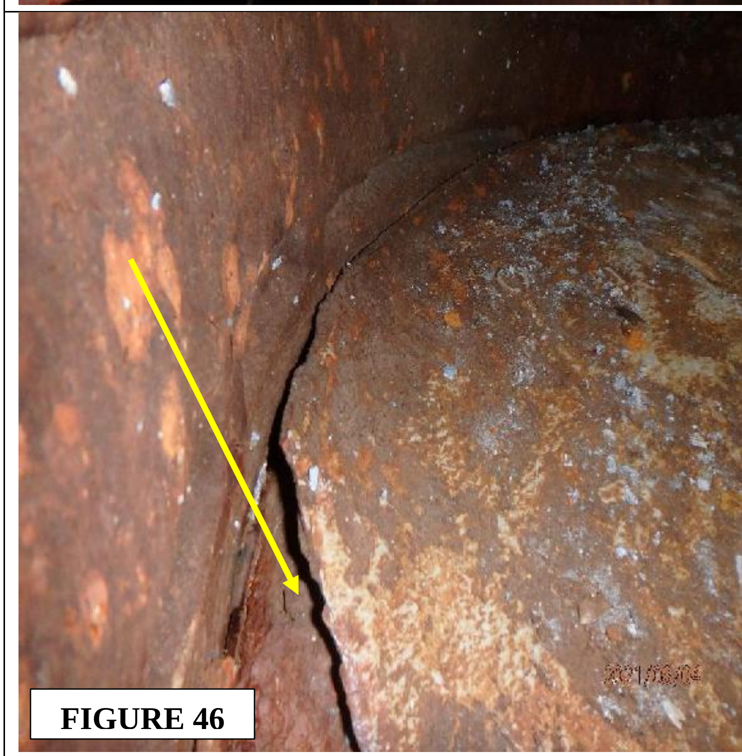


FIGURE 46

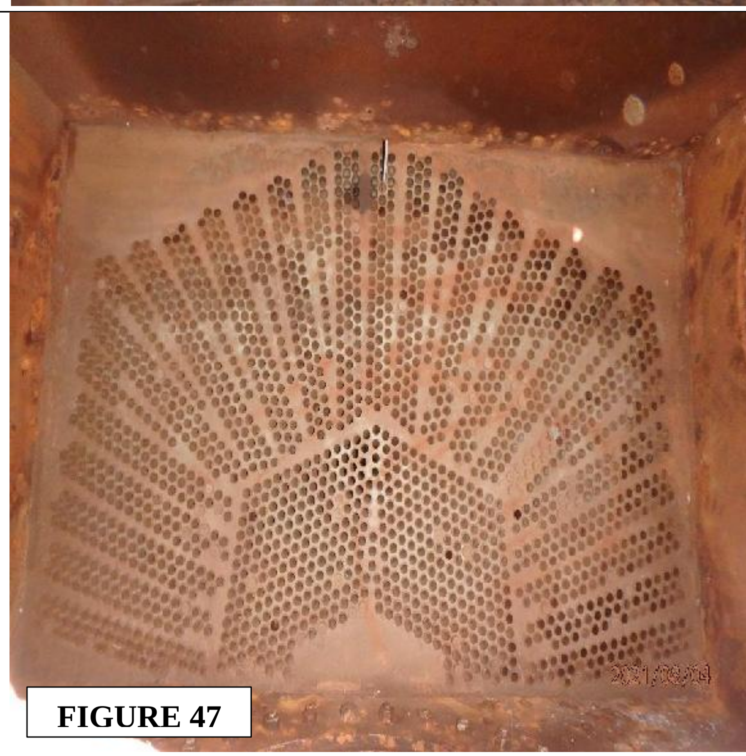


FIGURE 47

2.6 East Side – North Box

- The box was in poor condition with extensive coating breakdown and heavy corrosion throughout **(Figure 50-53)**
- Manways heavily corroded **(Figures 48-49)**
- Butterfly valve disc appeared to be in satisfactory condition
- Anodes in satisfactory condition
- No corrosion of tubesheet was observed
- Drain noted as being in good condition

FIGURE 48

FIGURE 49

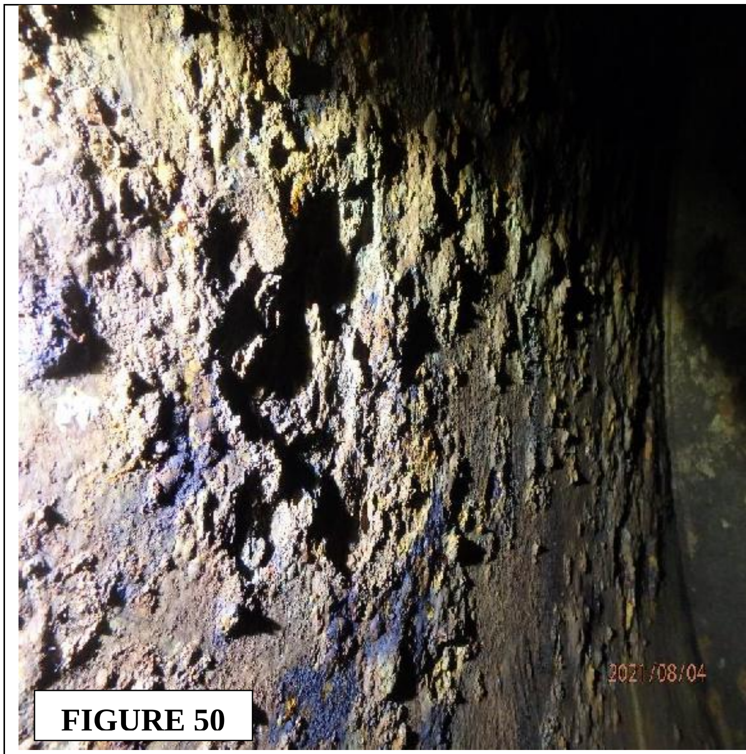


FIGURE 50

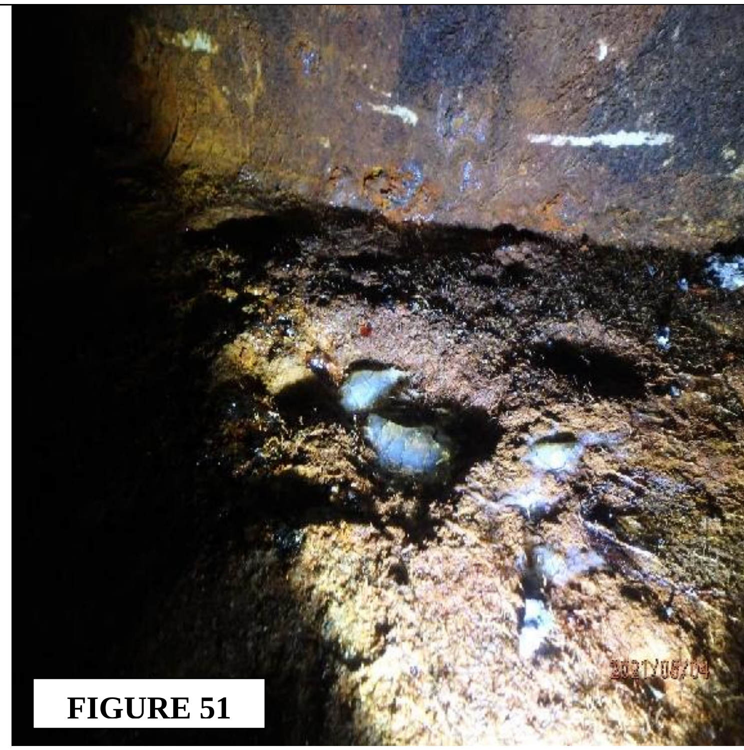


FIGURE 51

FIGURE 52


FIGURE 53

2.7 East Side – South Box

- The box was in poor condition with extensive coating breakdown and heavy corrosion throughout **(Figures 56-58)**
- Manways heavily corroded **(Figures 54, 55)**
- Butterfly valve appeared to be in satisfactory condition
- Anodes in satisfactory condition, 2 replaced (one inside and one on door)
- No corrosion of tubesheet was observed
- Drain noted as being in good condition

FIGURE 54

FIGURE 55

FIGURE 56

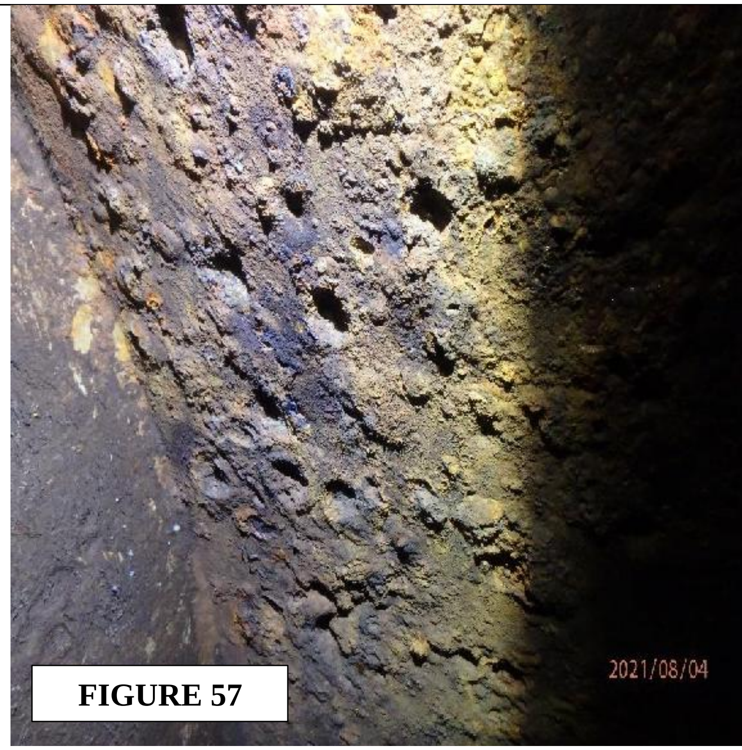


FIGURE 57

FIGURE 58

3 RECOMMENDATIONS

Steam Side

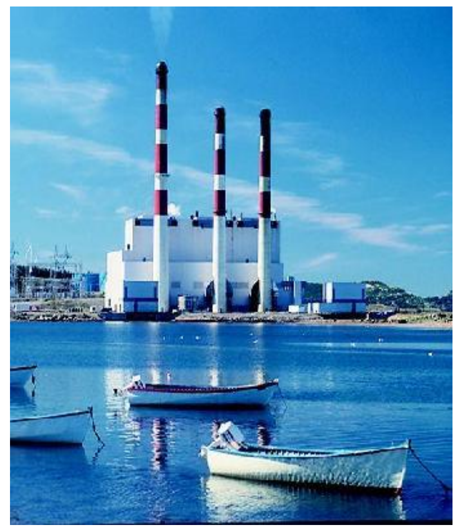
- Continue with regular inspections to monitor erosion of supports, especially the cross braces that extend horizontally between the tube support plate of the two tube bundles.
- Repair extraction piping expansion joint coverings. Monitor the corrosion of the shell expansion joint covering and erosion of the attachment welds.

Water Boxes

- Continue with inspections and regular maintenance of the water boxes, i.e., tube cleaning, debris removal, replacement of anodes
- Coating repairs should be considered in the West water boxes and due to the excessive pitting noted in the East boxes, these should be further assessed and repaired as necessary

Technical Services
Report

2021 Condenser Inspection Report Unit # 2



NL Hydro - Holyrood TGS
Holyrood, NL

2021 OCTOBER 03-06

GE Steam Power Contract #: EB0-018032
Customer PO #: 4618 OS
Report by Kristofer Jacobs

Imagination at work

REPORT DATA

Purpose of Visit:	Condenser Inspection		
Customer:	Nalcor - NL Hydro	GE Ref No.:	EB0-018032
Site Location:	Holyrood, NL	Customer P.O.:	4618 OS
GE TSA(s):	Kristofer Jacobs	Start Date:	2021 October 03
		End Date:	2021 October 06

EQUIPMENT INFORMATION

Equipment:	Steam Turbine Condenser
Equipment OEM:	CE
Original Ref No.:	CES 6819
Type:	RPR – 70 Steam Generator
Rating:	175MW
Primary Fuel:	No. 6 Fuel Oil
Aux. Fuel:	N/A
MCR Steam Flow:	1,050,000 lb/hr
Drum Des.Press:	2205 psig
SH Outlet Press:	2205 psig
SH/RH Out Temp:	1005 °F

CONTACT INFORMATION

GE TSA:	Kristofer Jacobs	Cust. Contact:	Jessica McGrath
Email:	Kristofer.Jacobs@ge.com	Email:	JessicaMcGrath@nlh.nl.ca
Phone (cell):	709-699-0386	Phone (bus):	709-229-2140
Phone (office):	709-229-2768	Phone (cell):	709-689-9732
GE Customer Service Manager:	Ghanshyam Patel		
Email:	Ghanshyam.Patel@ge.com		
Phone (cell):	1-289-244-3408		

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DISCLAIMER STATEMENT

1 INTRODUCTION

This report documents the results of the visual inspection carried out on the Unit #2 Condenser during the 2021 Maintenance Outage. The scope of the inspection was carried out by Kristofer Jacobs in both the steam side and the water side sections of the condenser.

2 NOTES AND OBSERVATIONS

2.1 Steam Side

At the time of inspection, steam side access was granted through the hotwell. No up-close inspections were achieved other than what was obtainable while standing on top of the bundles. Below is a summary and related pictures of the findings:

- Tube Bundles – Overall, the tube bundles appeared to be in good condition. Minor polishing and steam erosion was noted on the tubes, as well as, bowing of isolated tubes **(Figures 1–6)**.
- Structural Supports – Broken/eroded welds were noted on the bundle supports on cross braces that extend horizontally between the tube support plates of the two bundles. These were noted in previous inspections as not being a significant finding since the braces are welded on both sides, as well as, top and bottom. The bottom welds were found to be satisfactory **(Figures 7–14)**. Erosion was also observed on additional supports throughout the cavity **(Figures 15–18)**.
- Hot Well Floor – Break down of floor coating was noted in Northeast, Northwest & Southwest corners **(Figures 19–24)**.
- Expansion Joints
    - Extraction Piping – Erosion shields covering extraction piping bellows expansion joints appeared to be in satisfactory condition from point of assessment **(Figures 25–26)**.
    - Casing Expansion Joint Cover – overall condition is satisfactory and secure; however, noticeable signs of erosion/corrosion were observed on the cover with minor separation of attachment welds to the casing **(Figures 27-28)**.
- Vacuum Measuring Reference Line – excessive erosion noted on various sections of the piping, as well as support attachment welds **(Figures 29-34)**.
- Extraction Piping Erosion Shield – Minor hole noted in extraction piping erosion shield **(Figures 35-36)**.
- Heater Drain Spray Shield – right side of spray shield found to be damaged. Weld repaired during outage. **(Figures 37-40)**

FIGURE 1

FIGURE 2

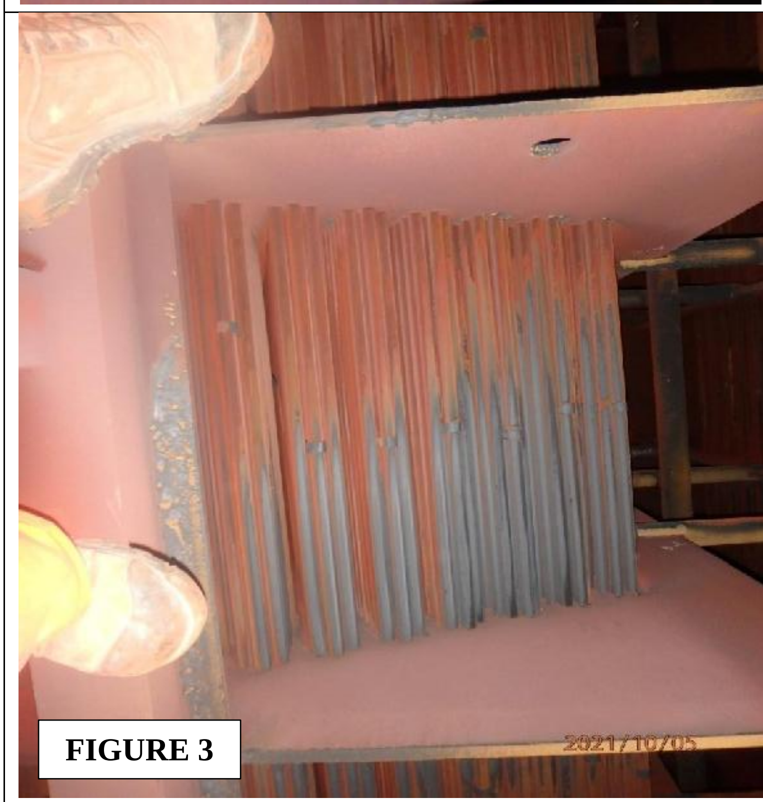


FIGURE 3

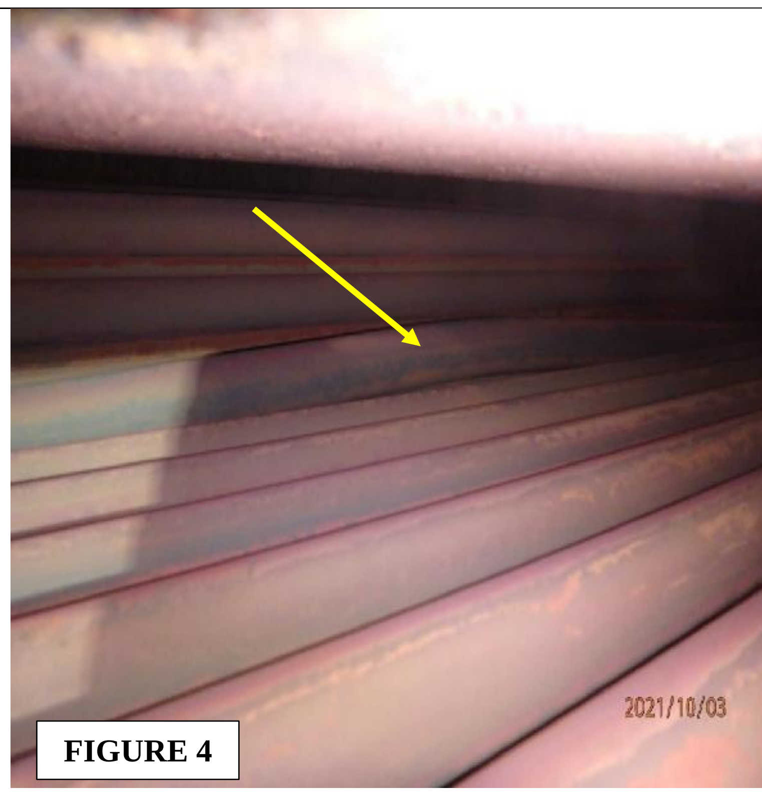


FIGURE 4

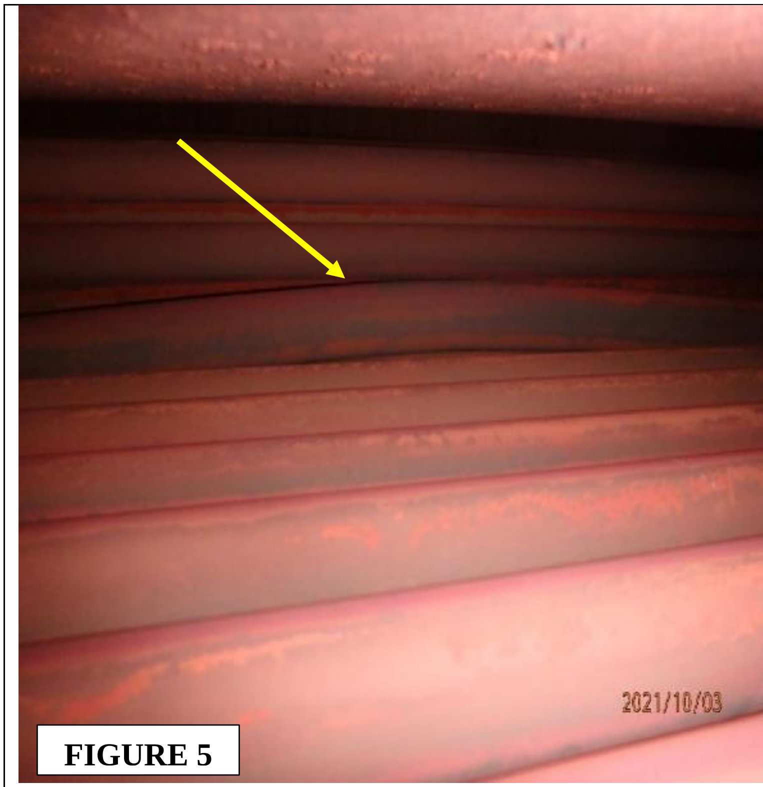


FIGURE 5

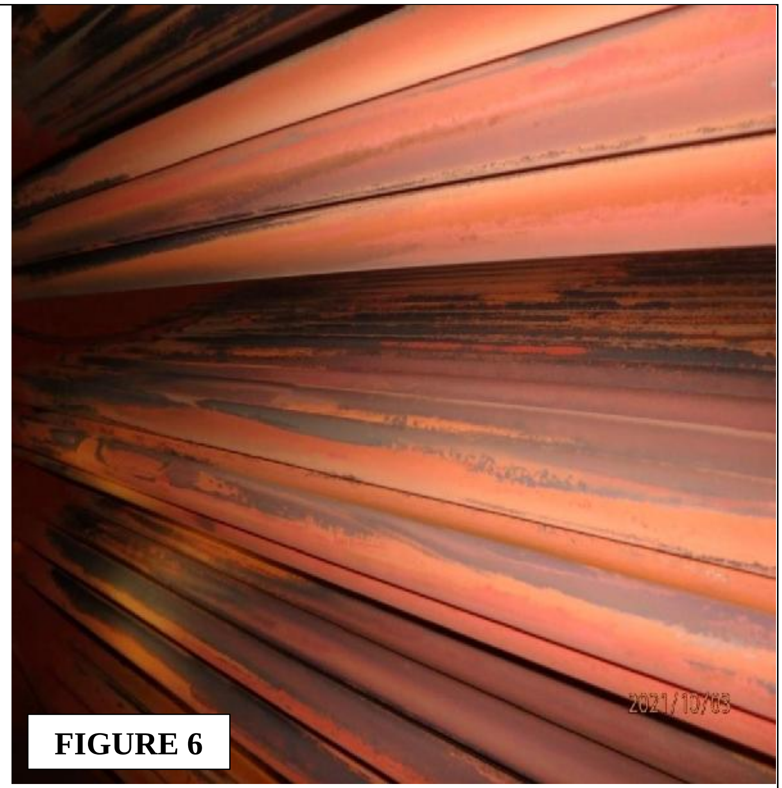
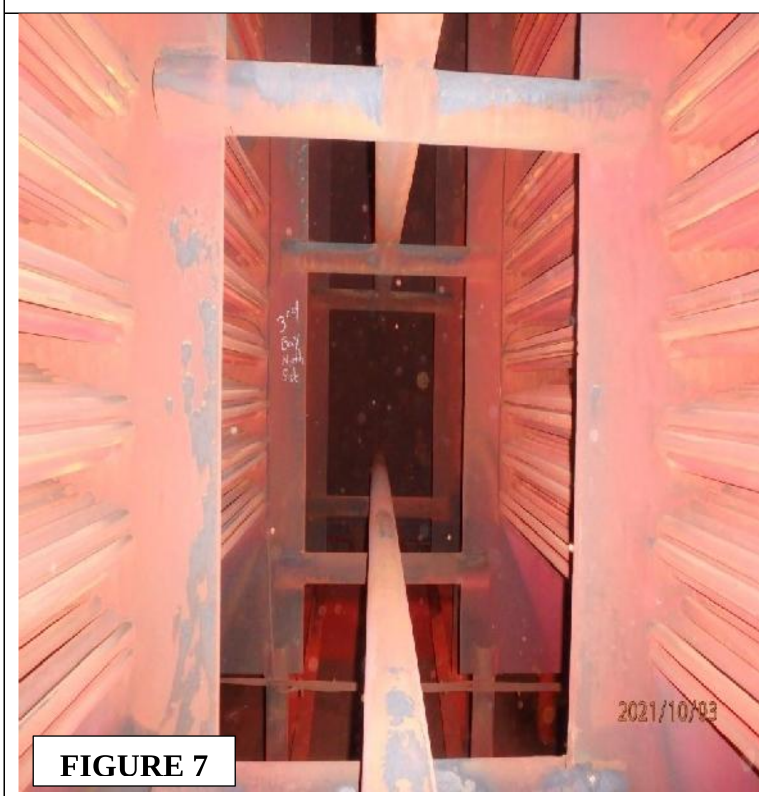


FIGURE 6



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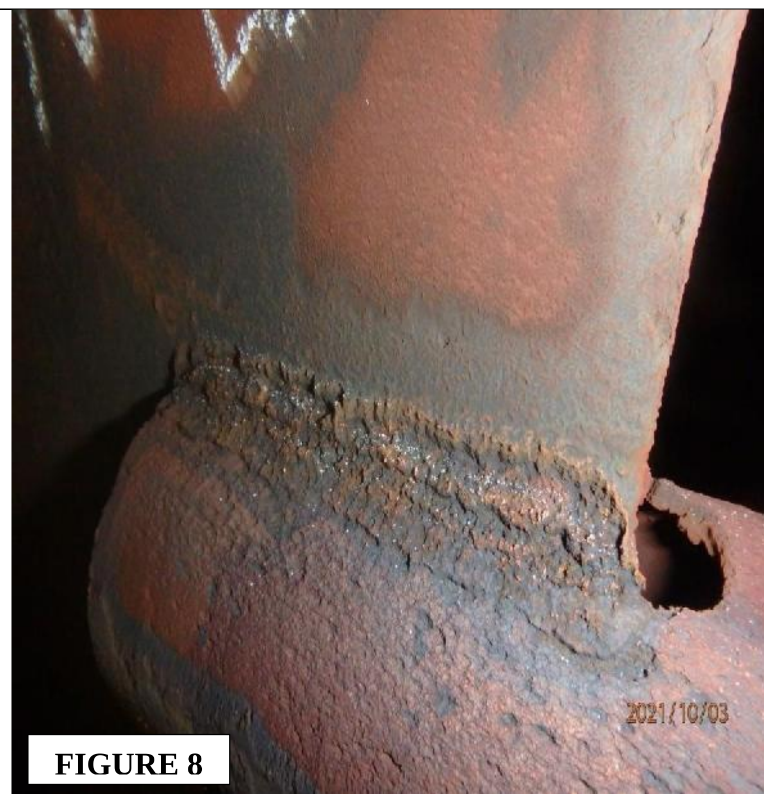


FIGURE 8

FIGURE 9

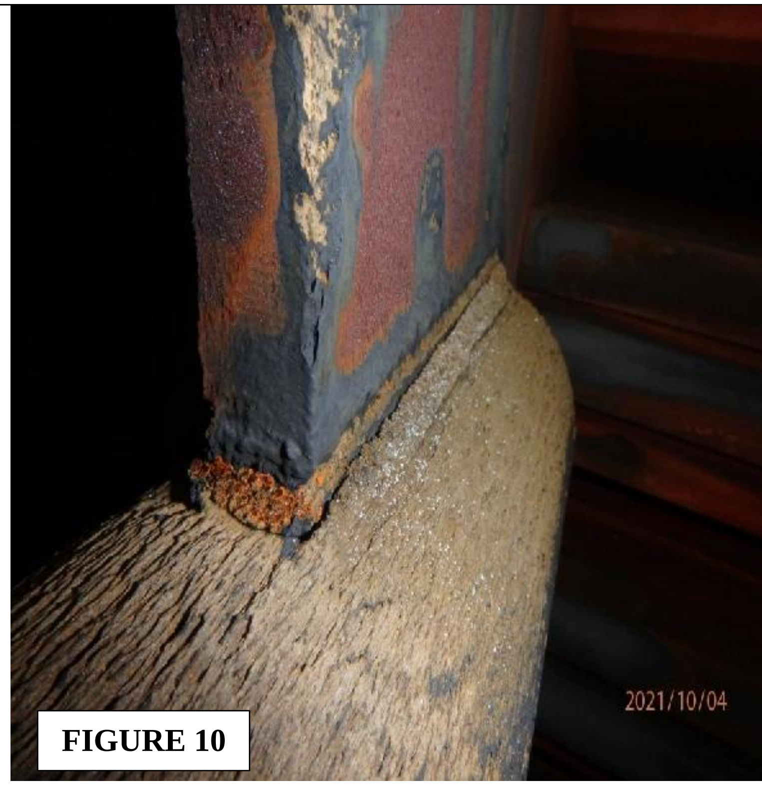
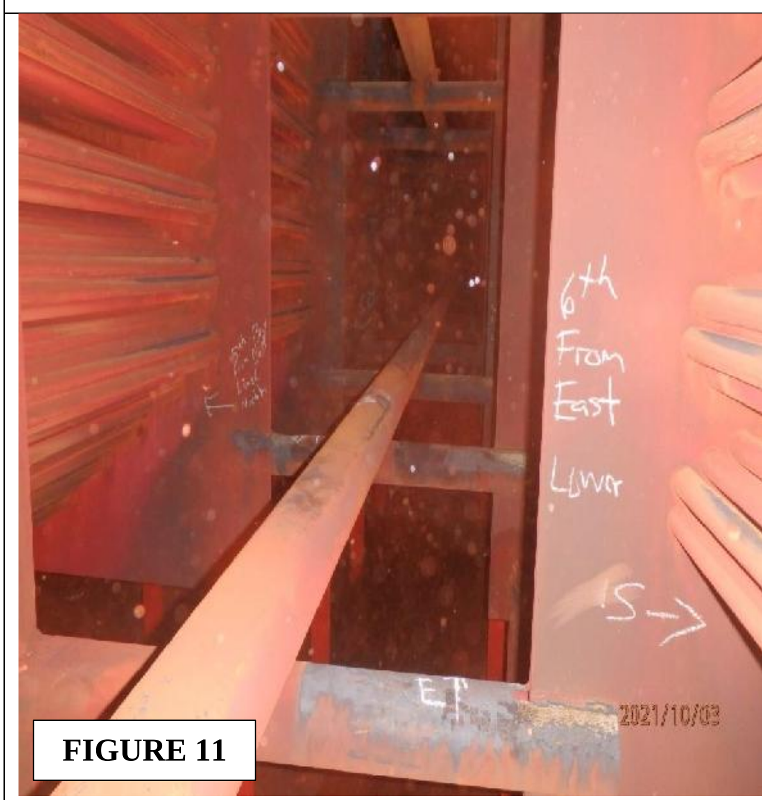


FIGURE 10



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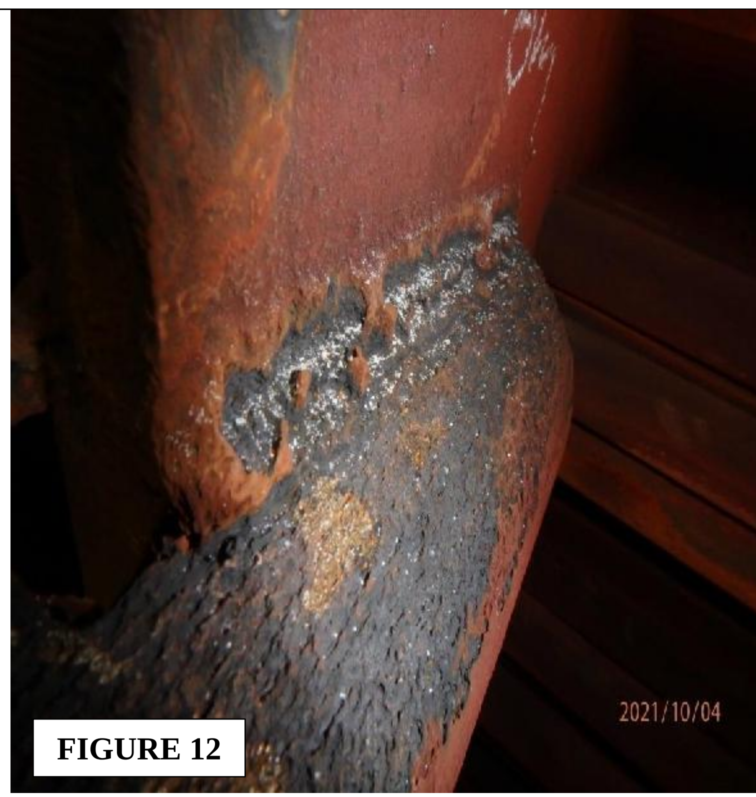


FIGURE 12

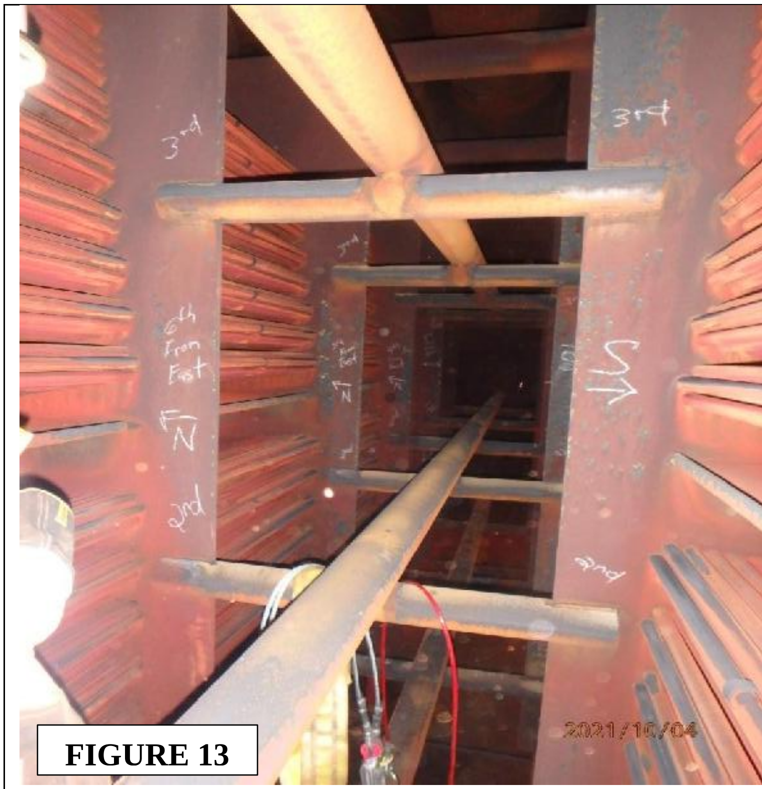


FIGURE 13

FIGURE 14

FIGURE 15

FIGURE 16

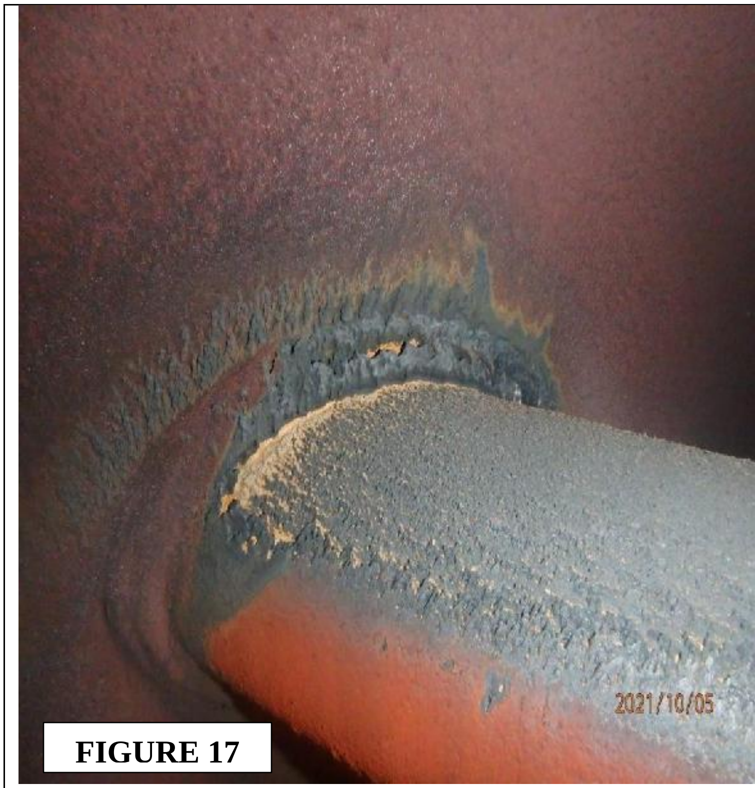


FIGURE 17

FIGURE 18

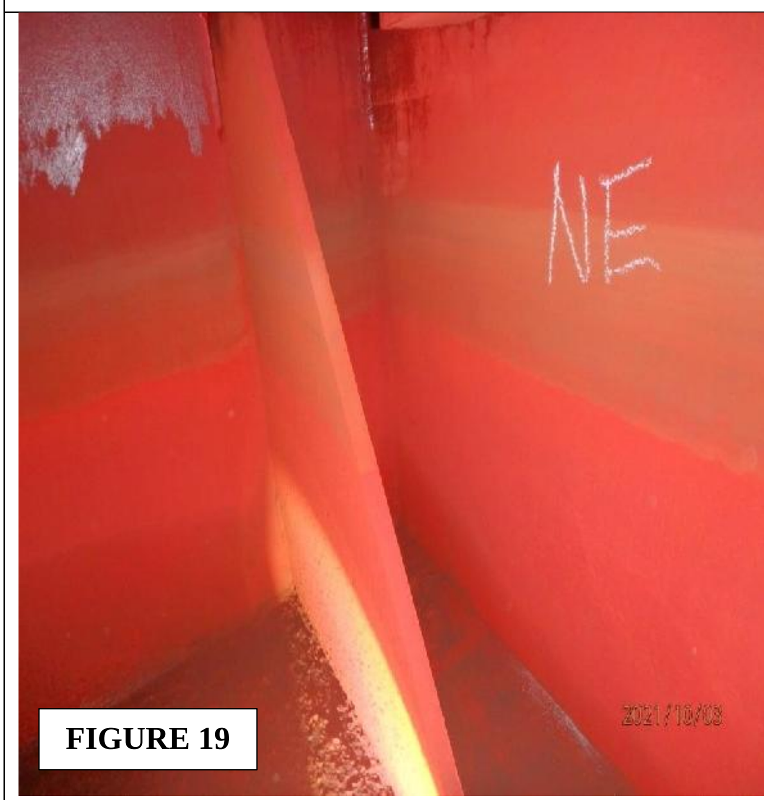


FIGURE 19

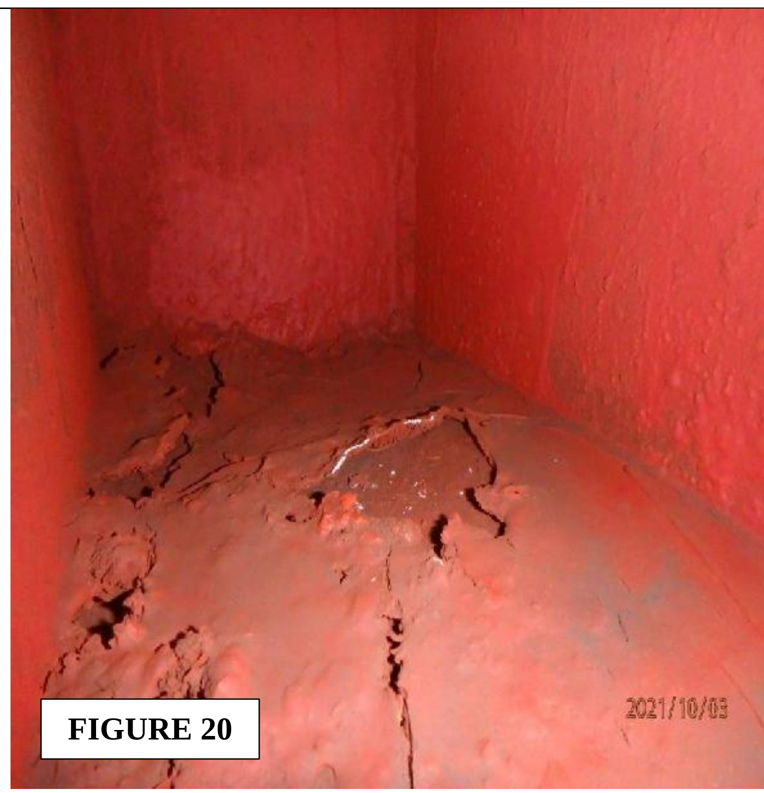
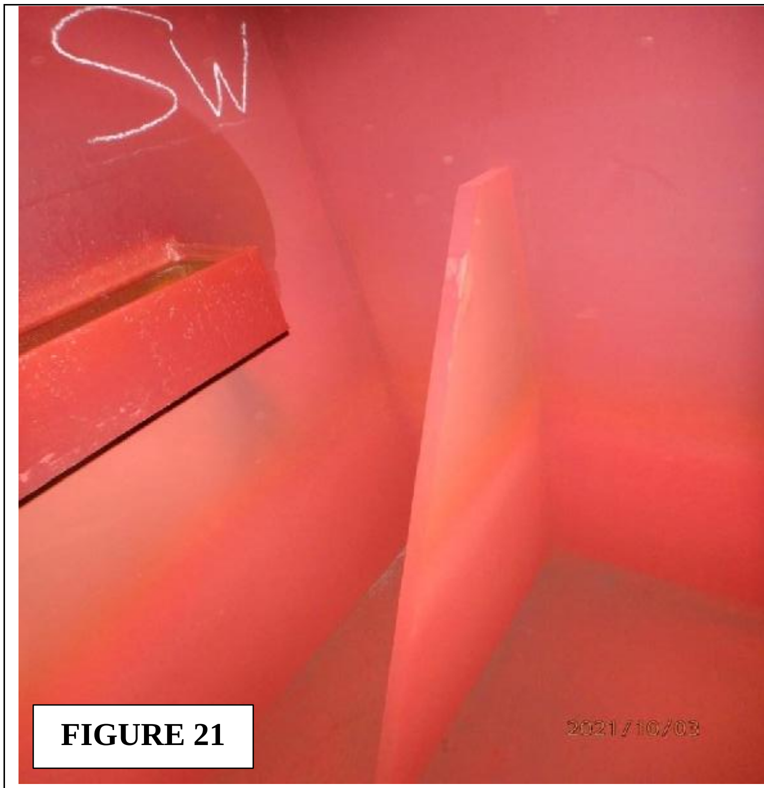


FIGURE 20



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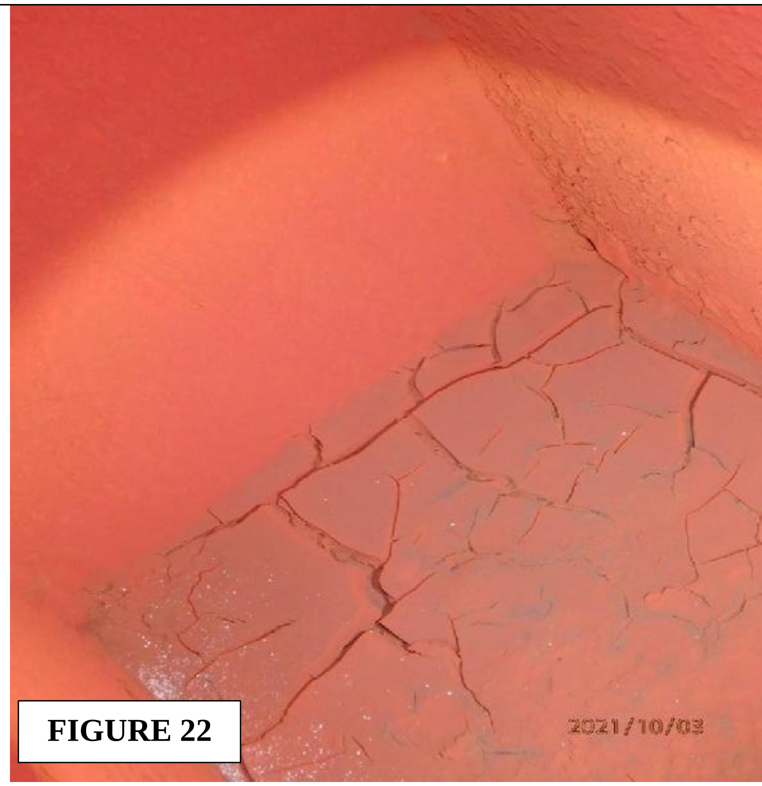
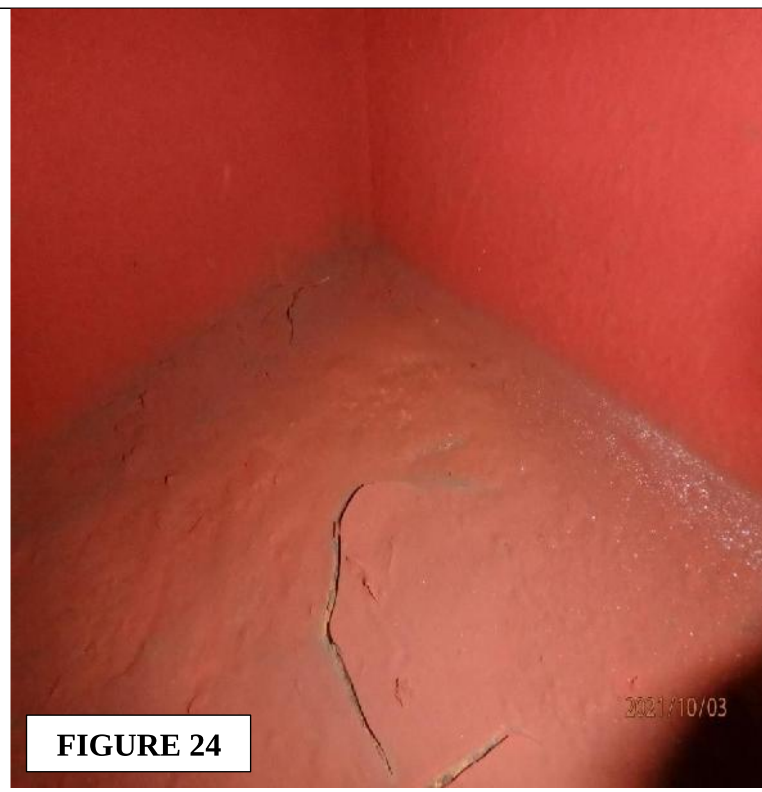


FIGURE 22

FIGURE 23



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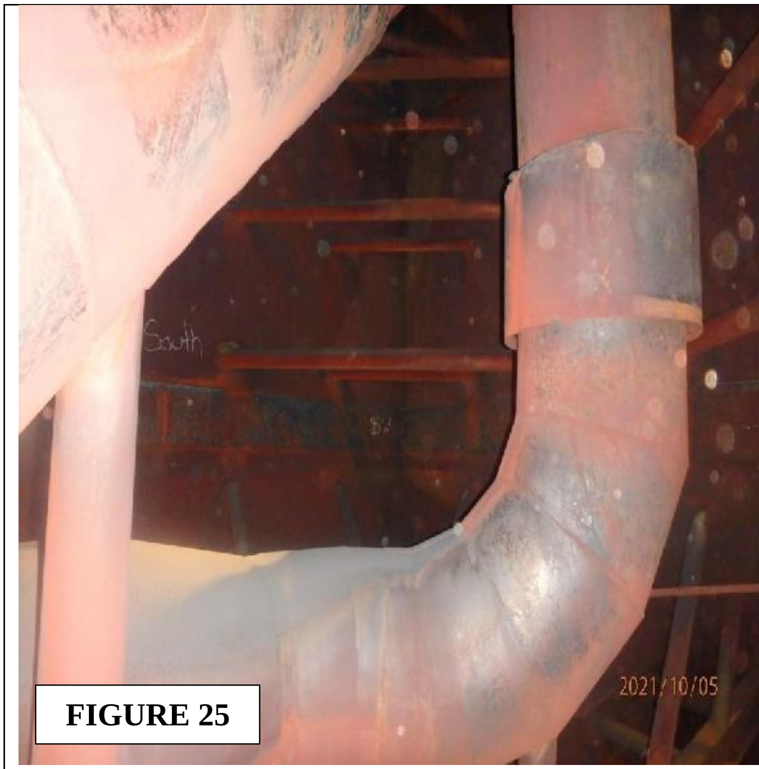


FIGURE 25

FIGURE 26

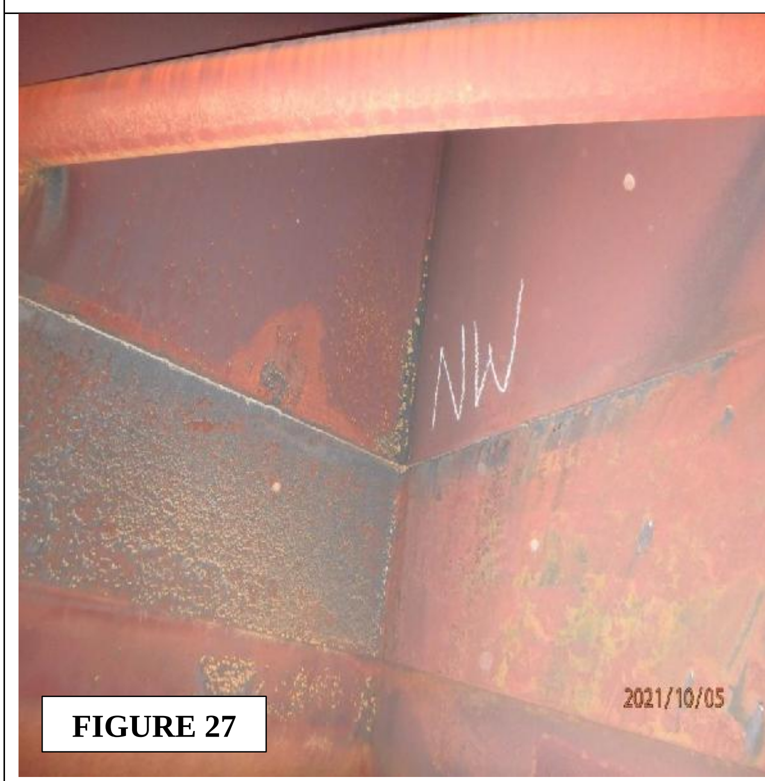


FIGURE 27

FIGURE 28

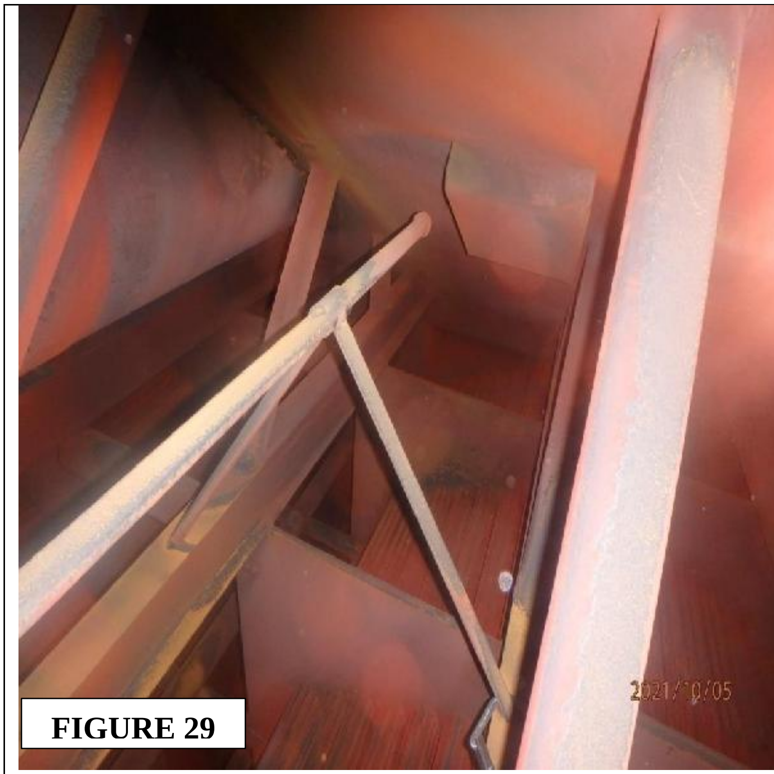
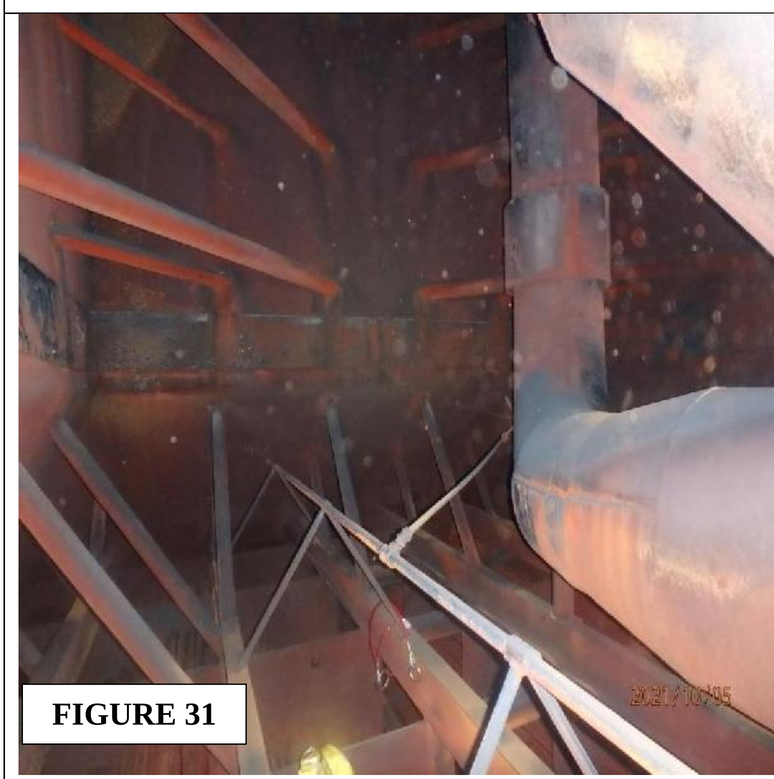


FIGURE 29

FIGURE 30



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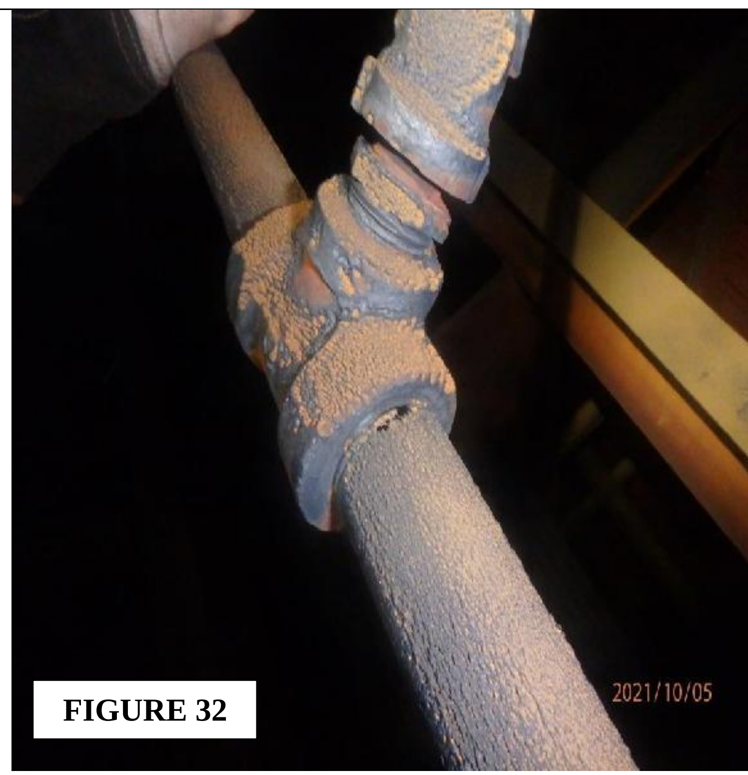


FIGURE 32

FIGURE 33

FIGURE 34

FIGURE 35

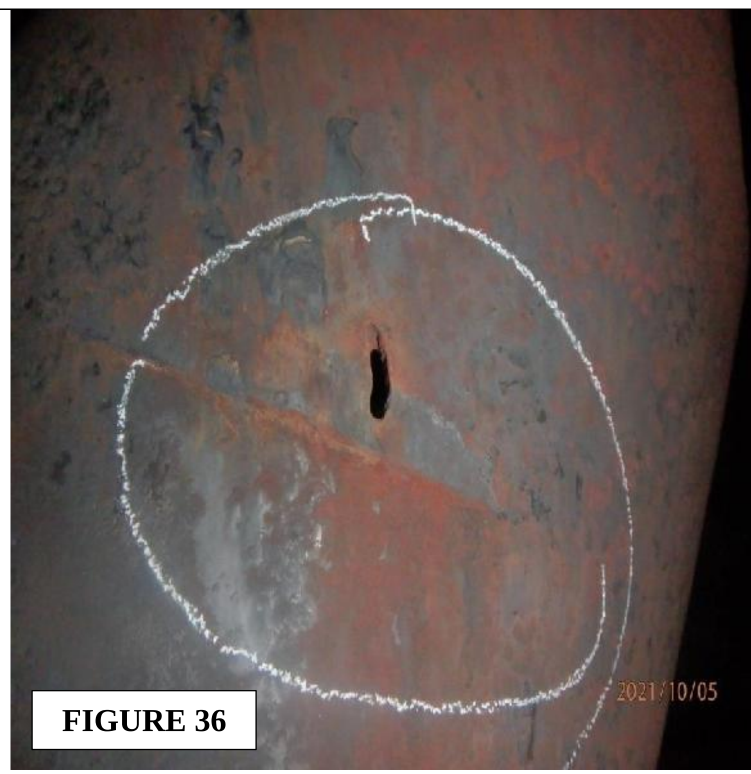
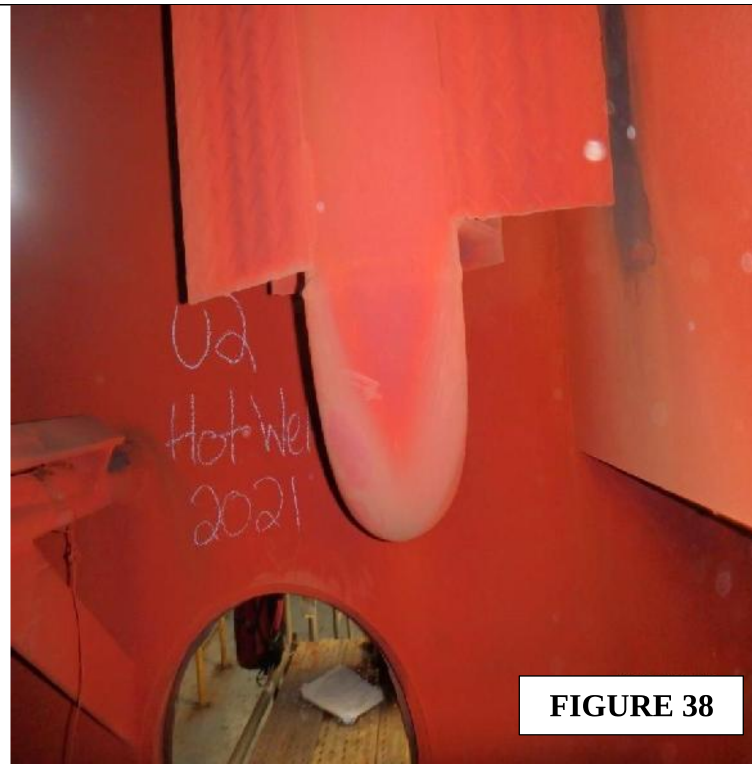


FIGURE 36

FIGURE 37



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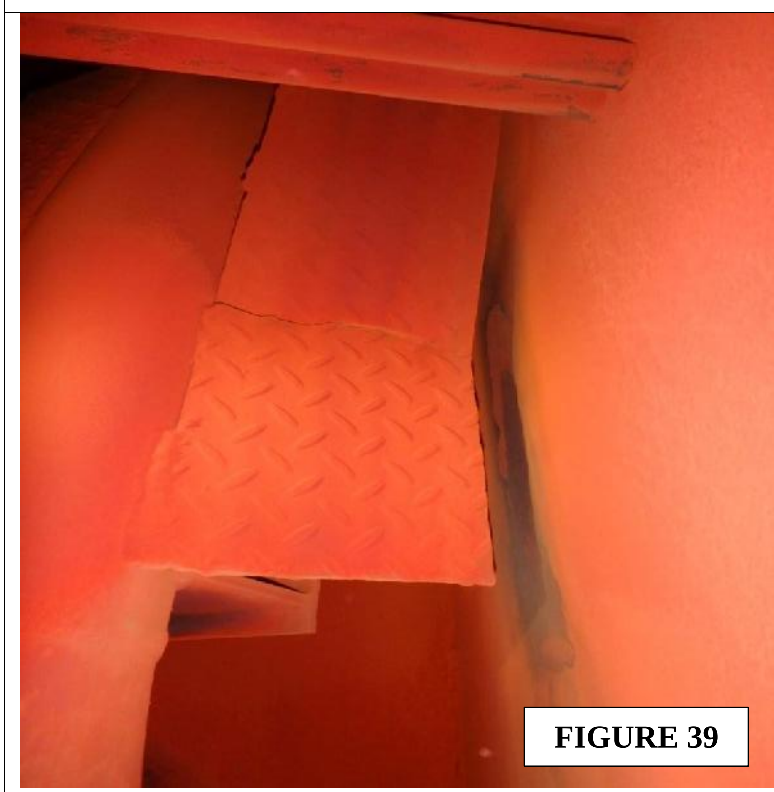


FIGURE 39


FIGURE 40

2.2 West Side – North Inlet Box

- The box was generally in satisfactory condition with coating breakdown and corrosion throughout **(Figures 42-48)**
- Anodes in satisfactory condition
- No corrosion of tubesheet was observed
- Corrosion was noted in drain pipe **(Figures 49-50)**
- Inspection of inlet piping not obtainable as valve was in closed position

FIGURE 41

FIGURE 42

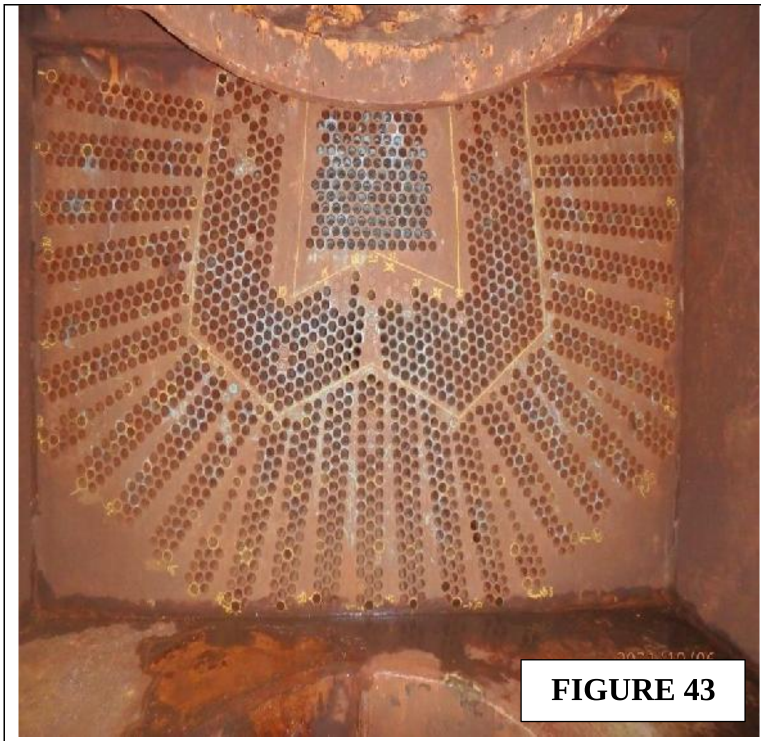


FIGURE 43

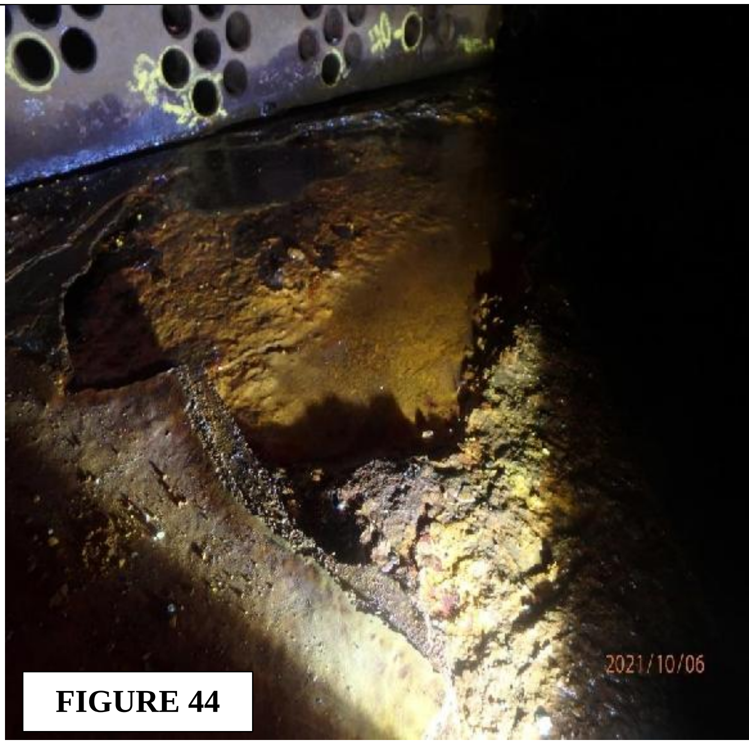


FIGURE 44

FIGURE 45

FIGURE 46

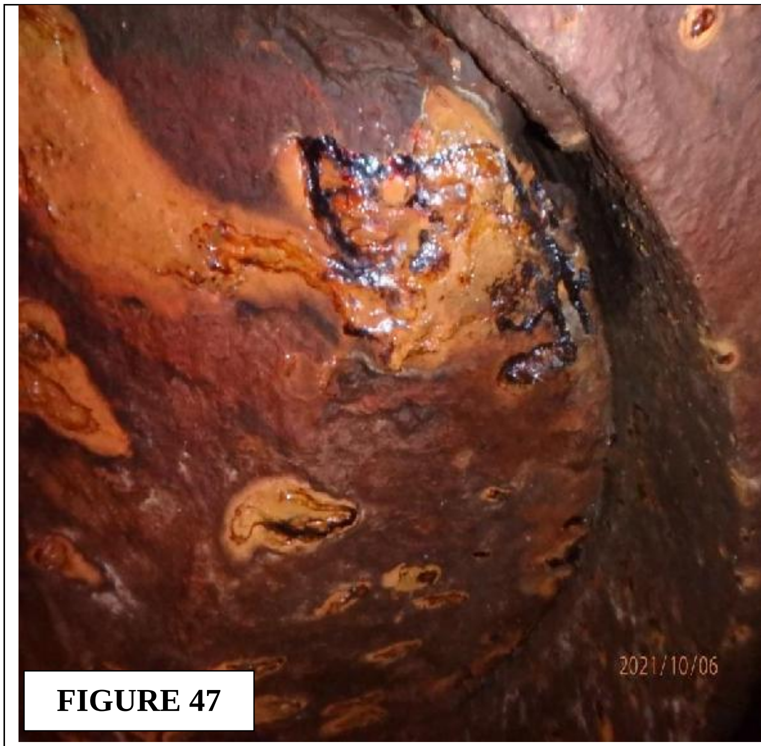


FIGURE 47

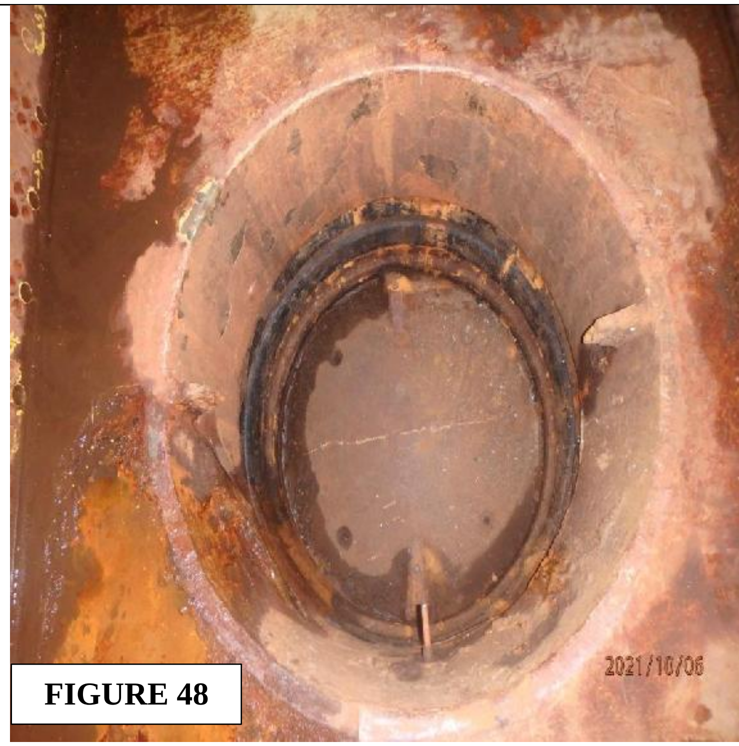


FIGURE 48

FIGURE 49

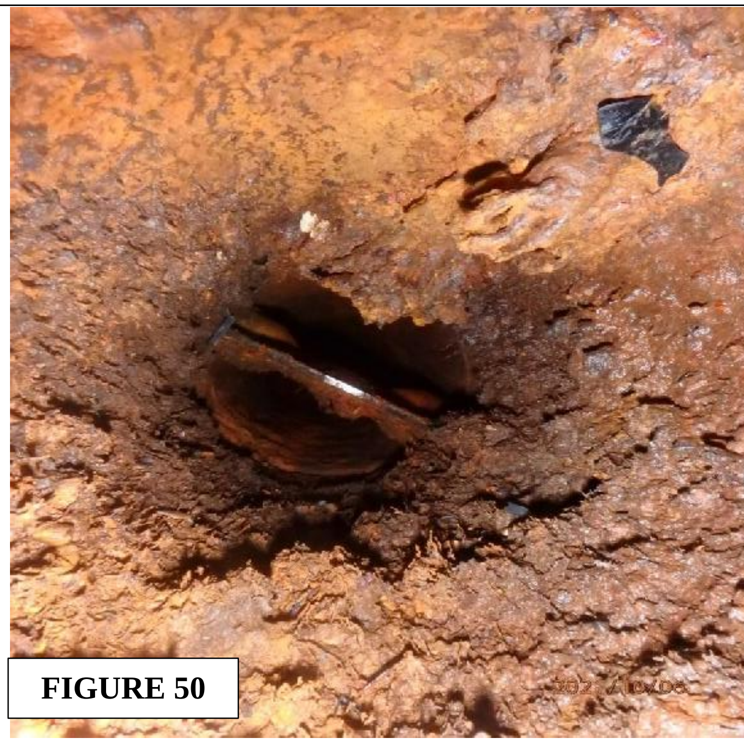


FIGURE 50

2.3 West Side – South Inlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout **(Figures 52-59)**
- Corrosion noted in drain pipe **(Figure 60)**
- Door anode requires replacement, others in satisfactory condition **(Figure 51)**
- No corrosion of tubesheet was observed
- Inspection of inlet piping not obtainable as valve was in closed position

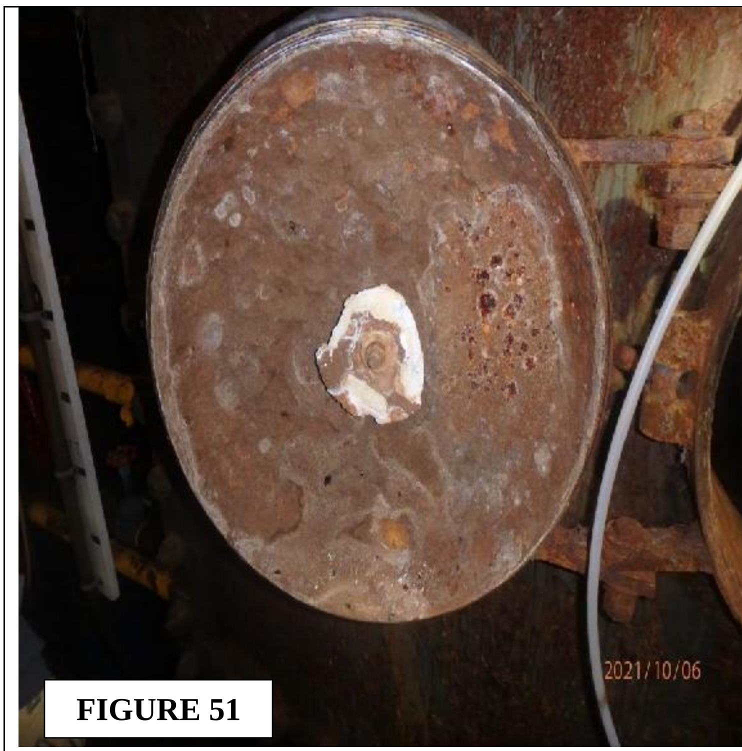


FIGURE 51

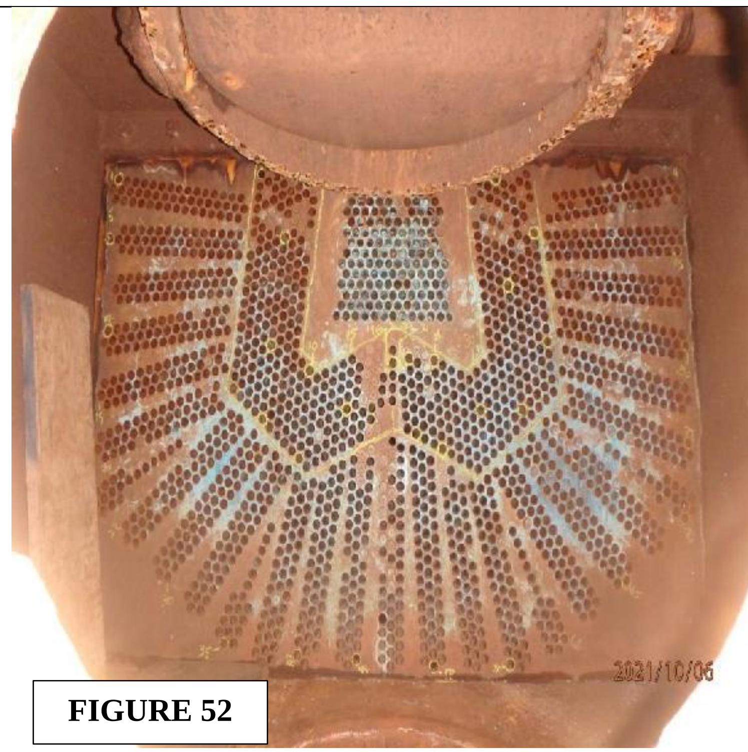


FIGURE 52

FIGURE 53

FIGURE 54

FIGURE 55

FIGURE 56

FIGURE 57

FIGURE 58

FIGURE 59

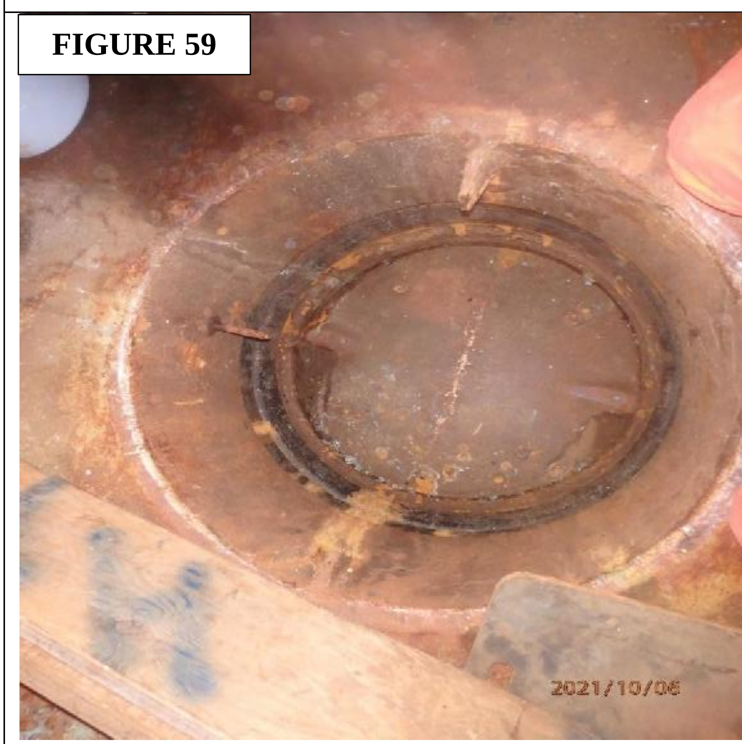


FIGURE 60

2.4 West Side – North Outlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout, especially in corners, as seen in adjacent boxes. As well, a few larger pits were observed **(Figures 64, 66, 69, 70)**
- Manway door appeared to be heavily corroded, however would require additional cleaning for further assessment **(Figure 61)**
- Butterfly valve disc coating noted as being satisfactory **(Figure 67)**
- Door anode requires replacement, others in satisfactory condition **(Figure 61)**
- No corrosion of tubesheet was observed **(Figures 62, 68)**
- Minor corrosion noted in discharge piping **(Figures 63, 64)**

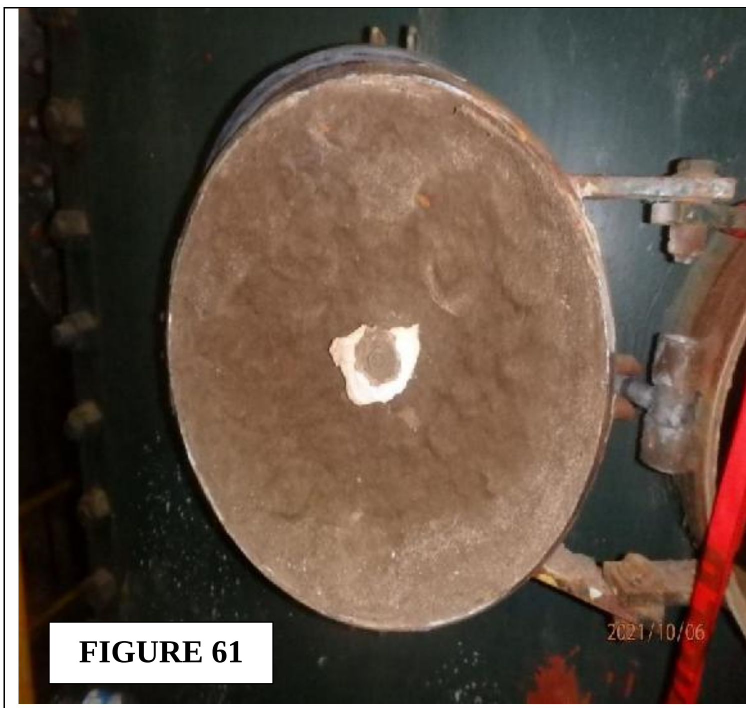


FIGURE 61

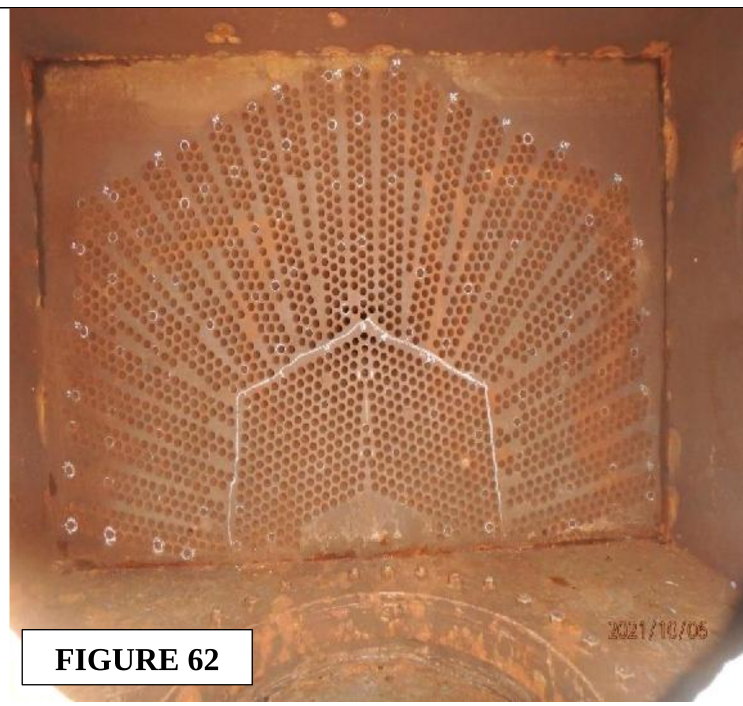


FIGURE 62

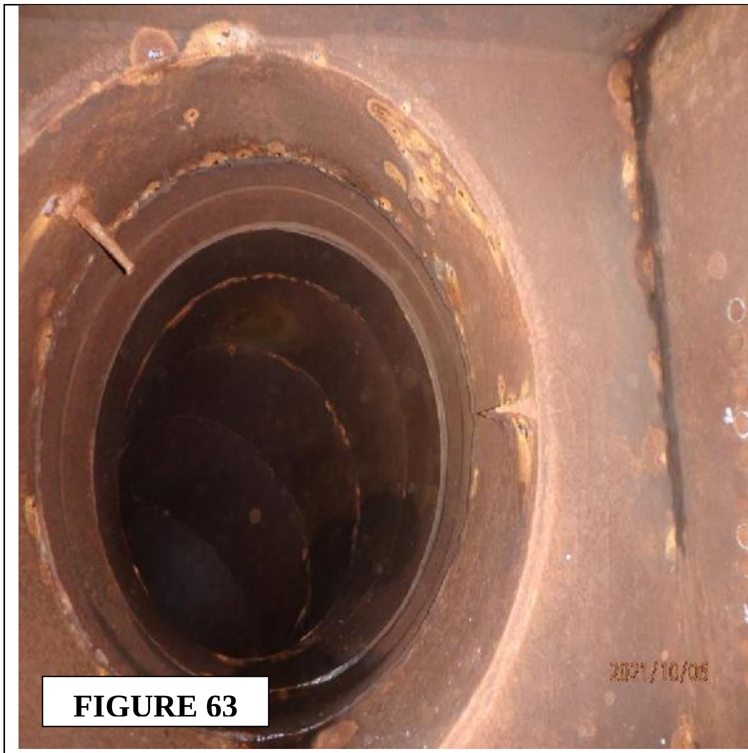


FIGURE 63


FIGURE 64


FIGURE 65

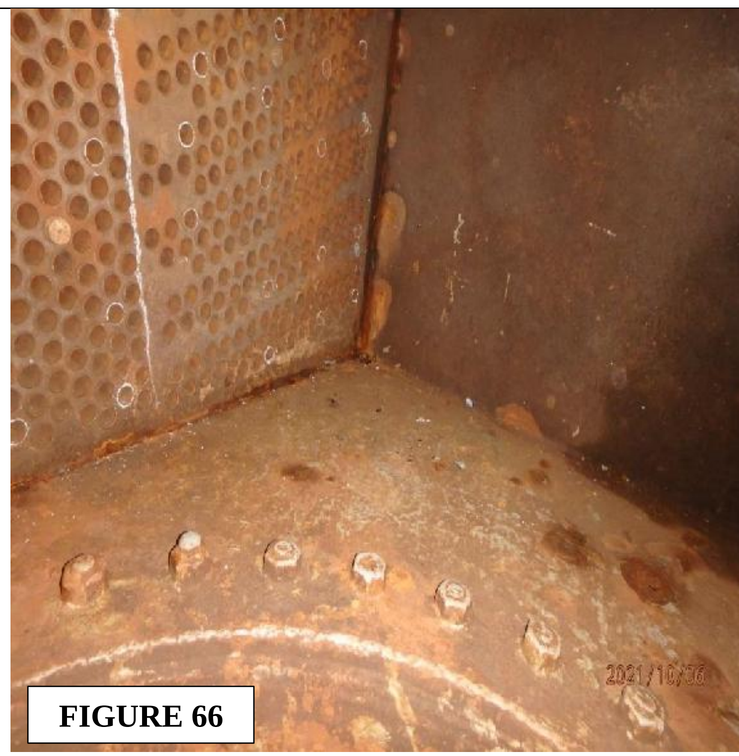


FIGURE 66

FIGURE 67

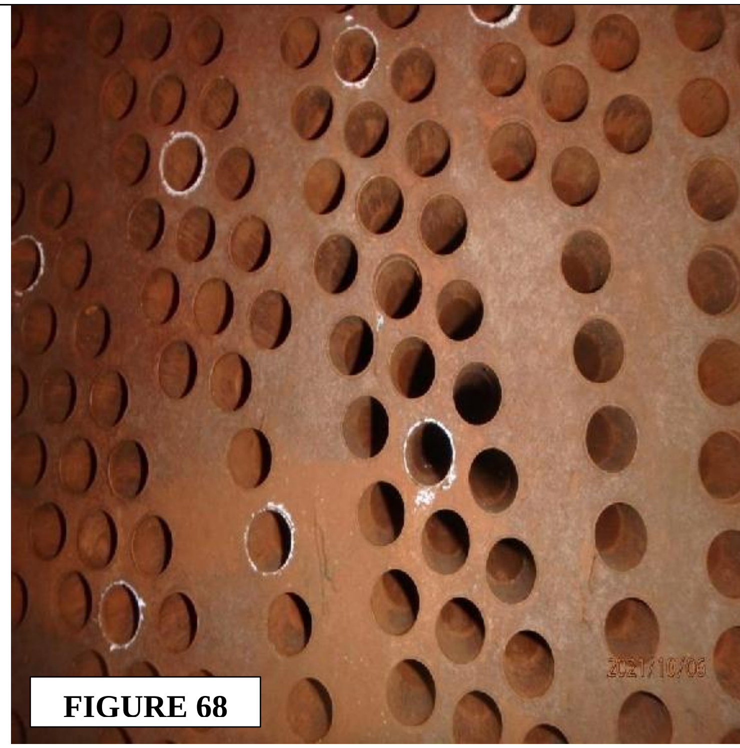


FIGURE 68

FIGURE 69

FIGURE 70

2.5 West Side – South Outlet Box

- The box was generally in good condition with minor coating breakdown and corrosion throughout, especially in corners, as seen in adjacent boxes. As well, a few larger pits were observed **(Figures 72, 79-82)**
- Manway door appeared to be heavily corroded, however would require additional cleaning for further assessment **(Figure 71)**
- Butterfly valve disc coating failure and corrosion noted **(Figures 83, 84)**
- Anodes – breakdown of door anode noted, internal anode found to be satisfactory **(Figure 71)**
- No corrosion of tubesheet was observed
- Corrosion and blistering noted at inlet to discharge piping **(Figures 73-78)**

FIGURE 71

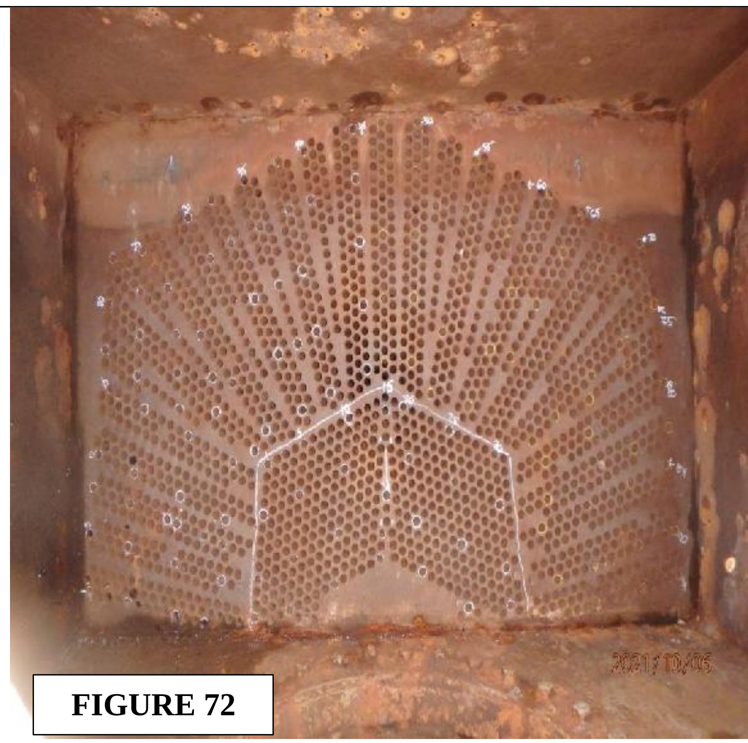


FIGURE 72

FIGURE 73

FIGURE 74

FIGURE 75

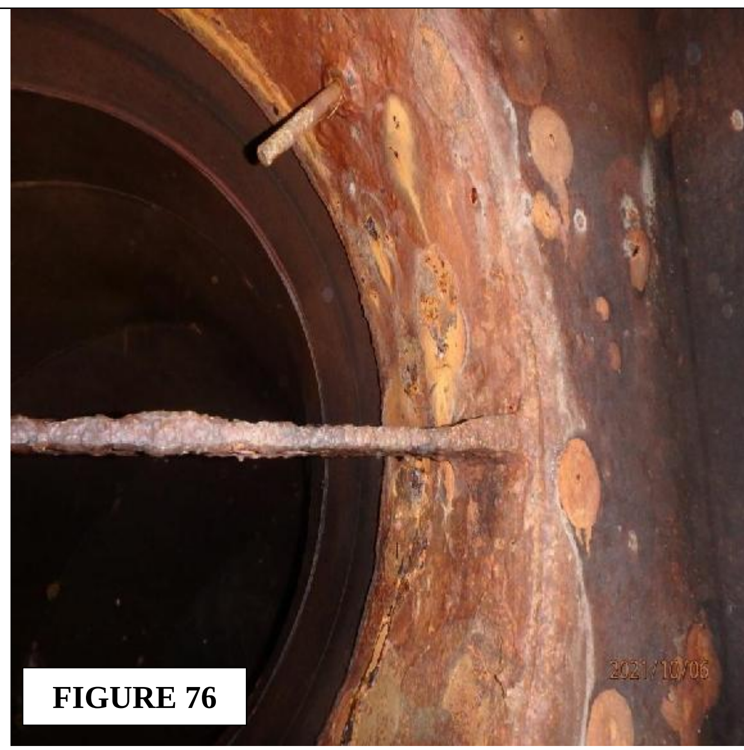


FIGURE 76

FIGURE 77

FIGURE 78

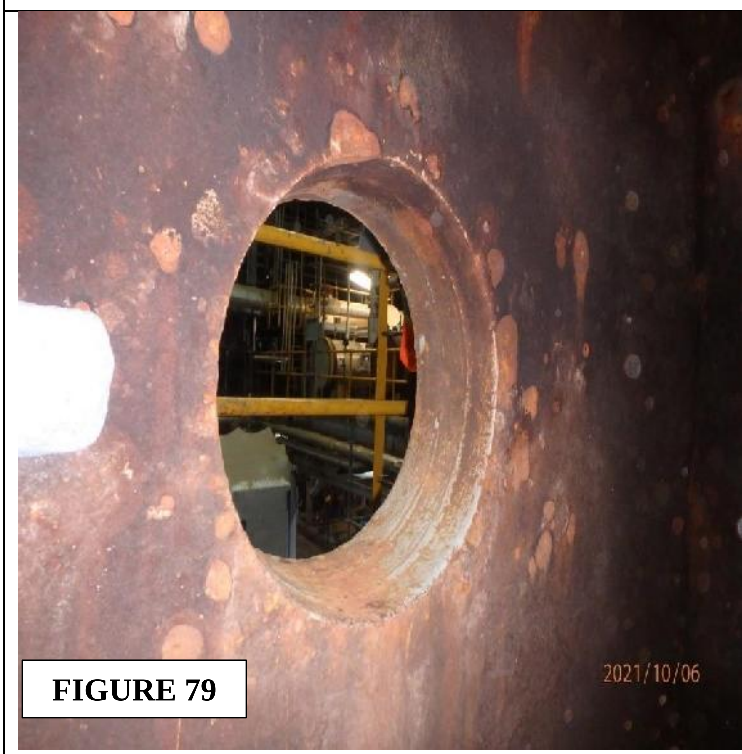


FIGURE 79

FIGURE 80

FIGURE 81

FIGURE 82

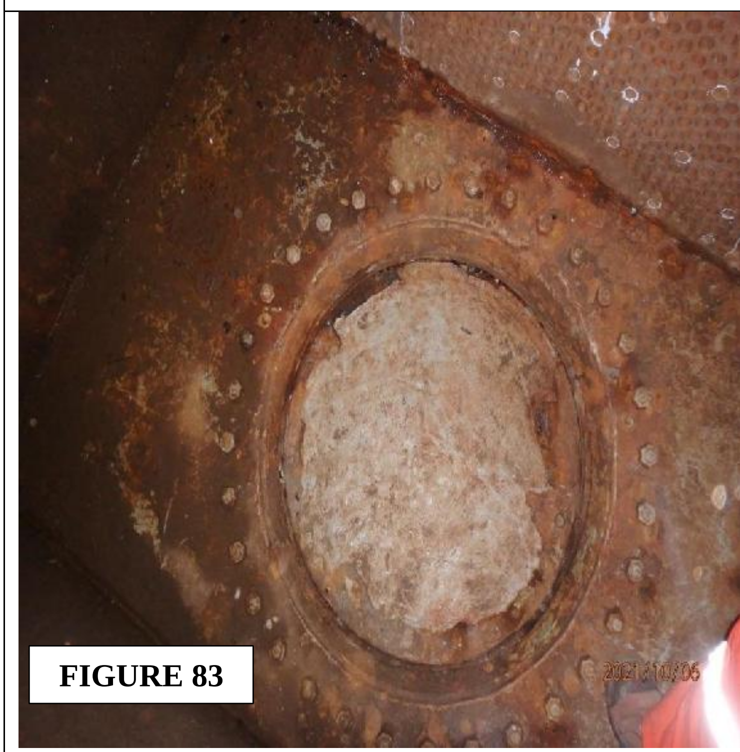


FIGURE 83

FIGURE 84

2.6 East Side – North Box

- Minor coating breakdown and corrosion noted throughout waterbox, difficult to assessment overall extent of corrosion and pitting due to lack of cleanliness **(Figures 86, 89, 91, 94-96)**
- Manway doors appeared to be heavily corroded, however would require additional cleaning for further assessment **(Figure 85)**
- Butterfly valve disc appeared to be in satisfactory condition **(Figure 88)**
- Anodes – breakdown of door and internal anode noted, one internal anode found to be satisfactory **(Figures 85, 87, 90)**
- No corrosion of tubesheet was observed **(Figure 93)**
- Drain - difficult to assess extent of corrosion due to lack of cleanliness **(Figure 92)**

FIGURE 85

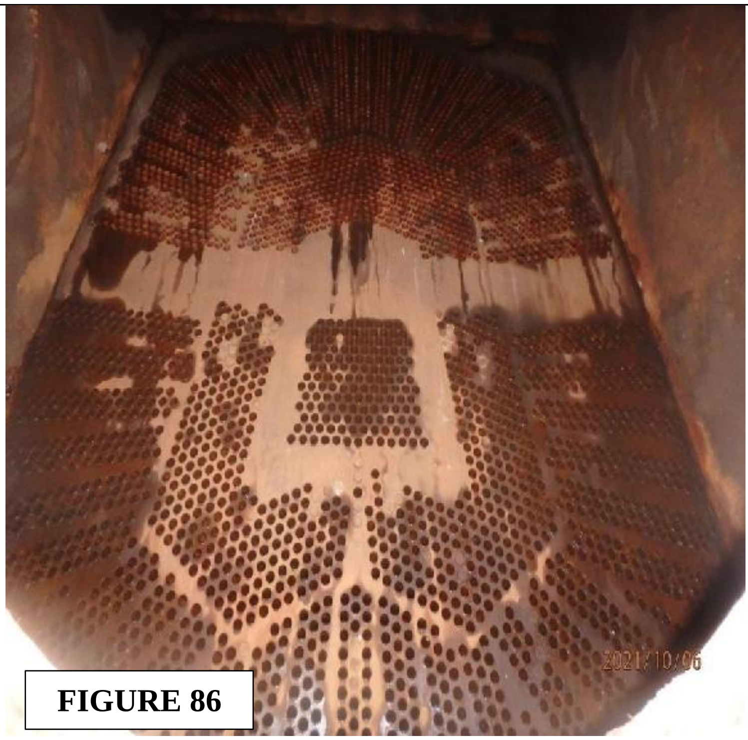


FIGURE 86

FIGURE 87

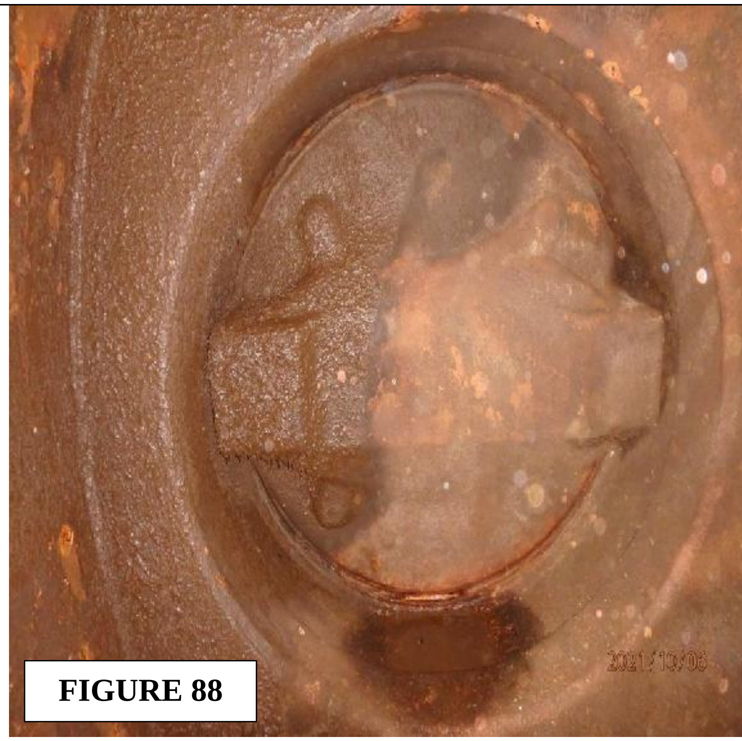


FIGURE 88

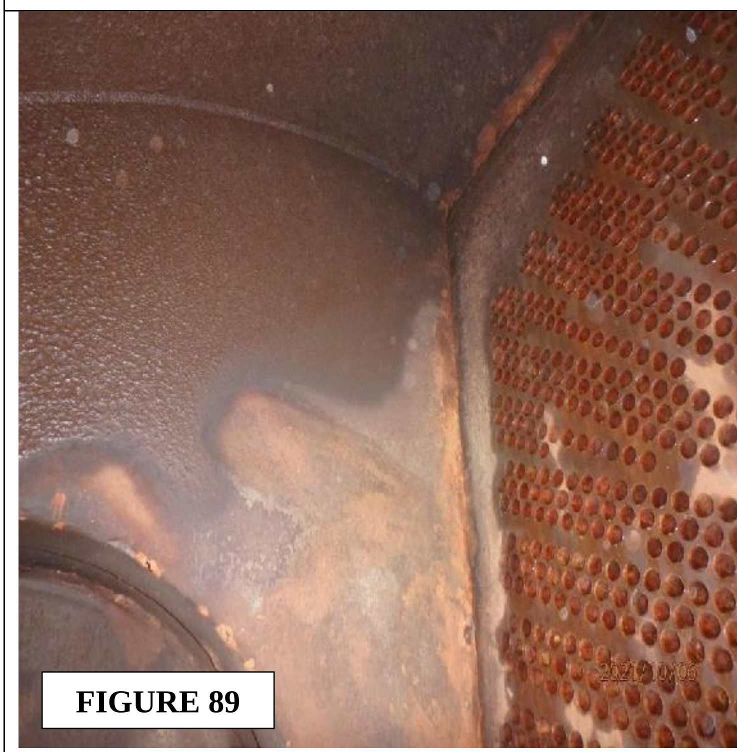


FIGURE 89

FIGURE 90

FIGURE 91

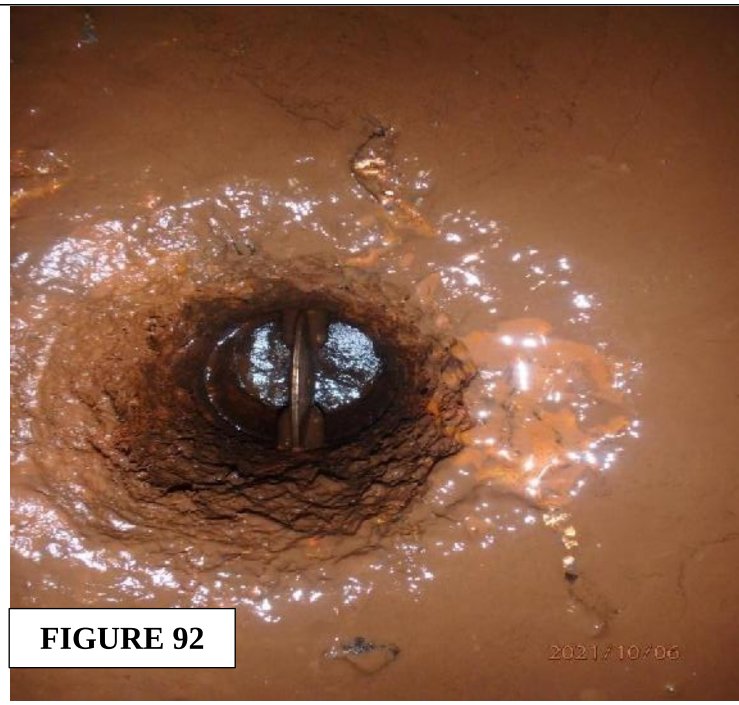


FIGURE 92

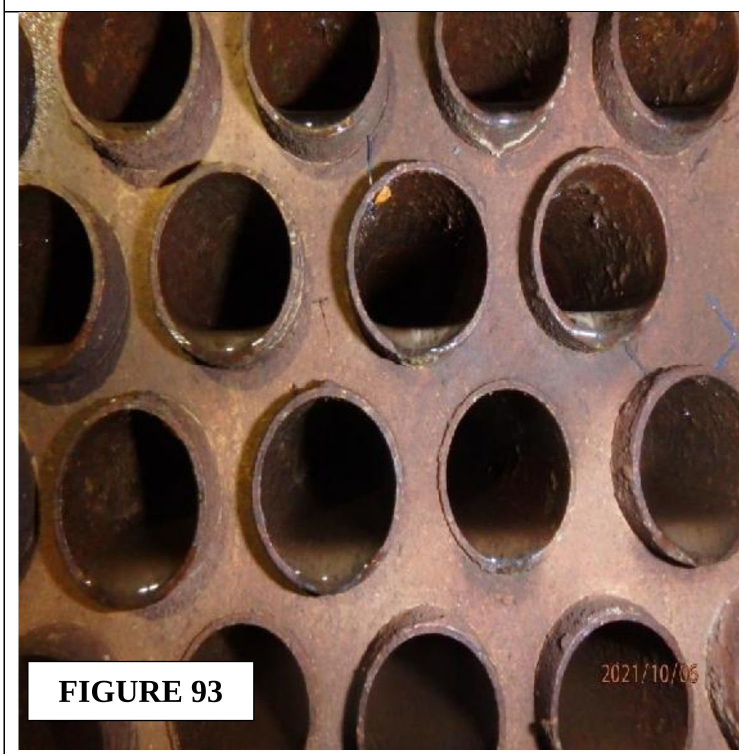


FIGURE 93

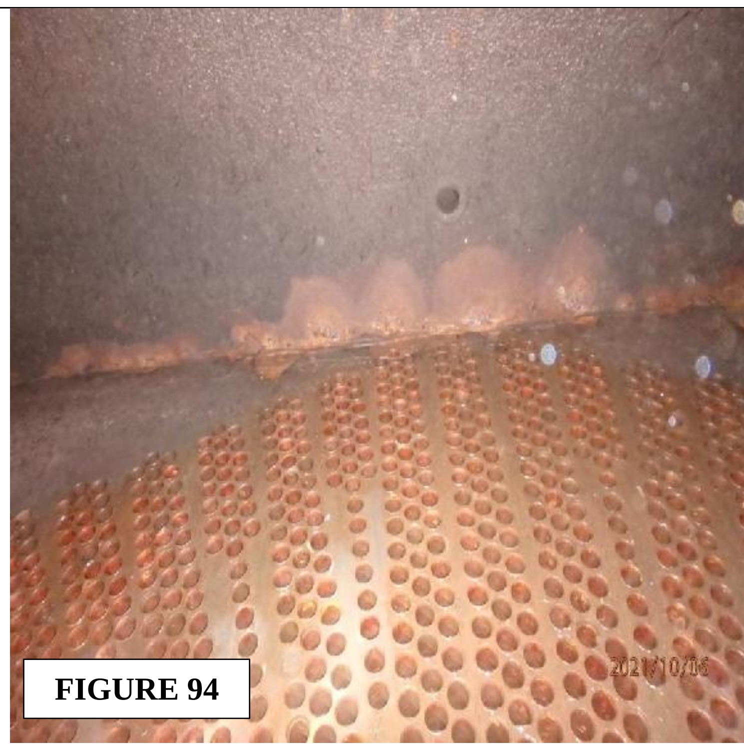


FIGURE 94

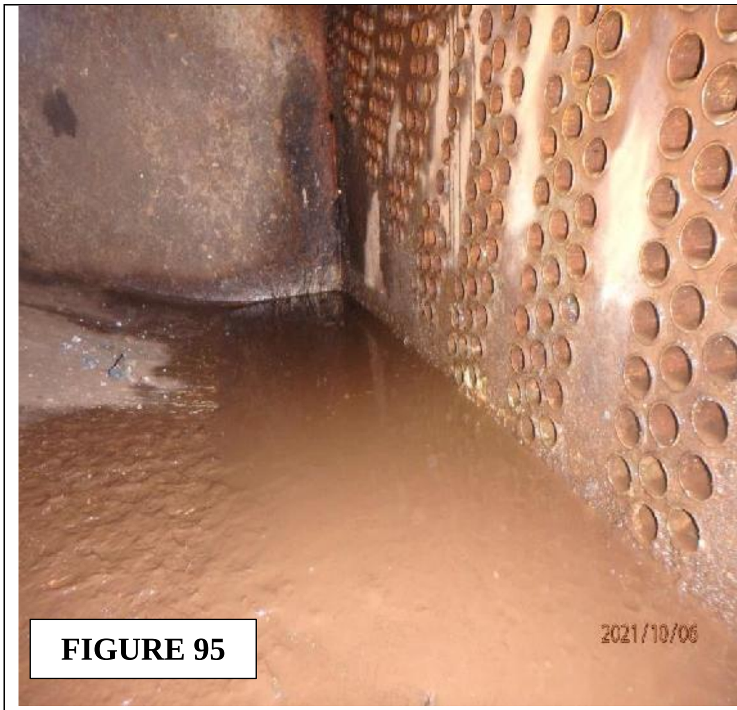


FIGURE 95

FIGURE 96

2.7 East Side – South Box

- The box was in poor condition with extensive coating breakdown and heavy corrosion throughout **(Figures 98-101, 105-109, 111, 112)**
- Manway doors appeared to be heavily corroded, however would require additional cleaning for further assessment **(Figure 97)**
- Butterfly valve appeared to be in satisfactory condition **(Figures 102-103)**
- Anodes found to be satisfactory **(Figures 97, 104, 111)**
- No corrosion of tubesheet was observed
- Drain - difficult to assess extent of corrosion due to lack of cleanliness **(Figure 110)**
- No corrosion of tubesheet was observed

FIGURE 97

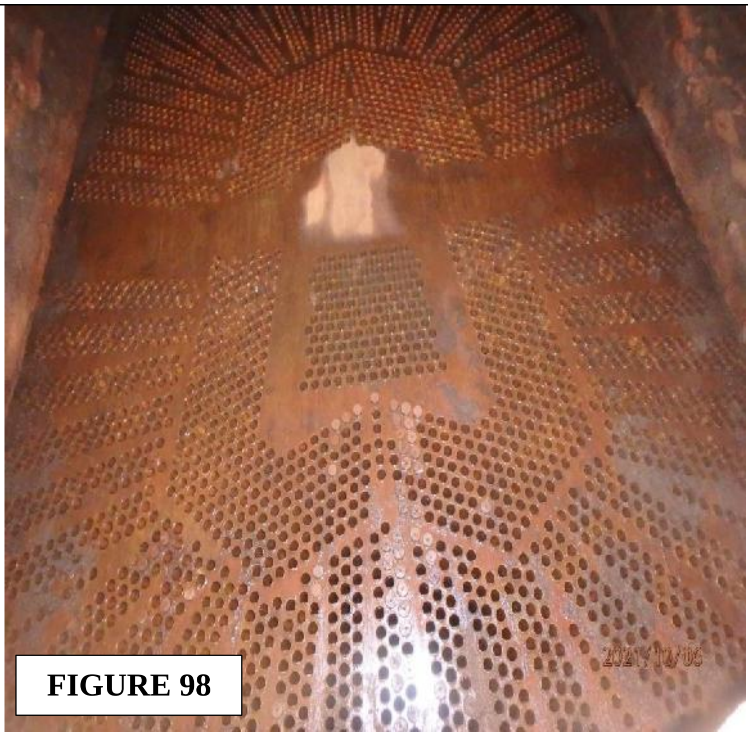


FIGURE 98

FIGURE 99

FIGURE 100

FIGURE 101

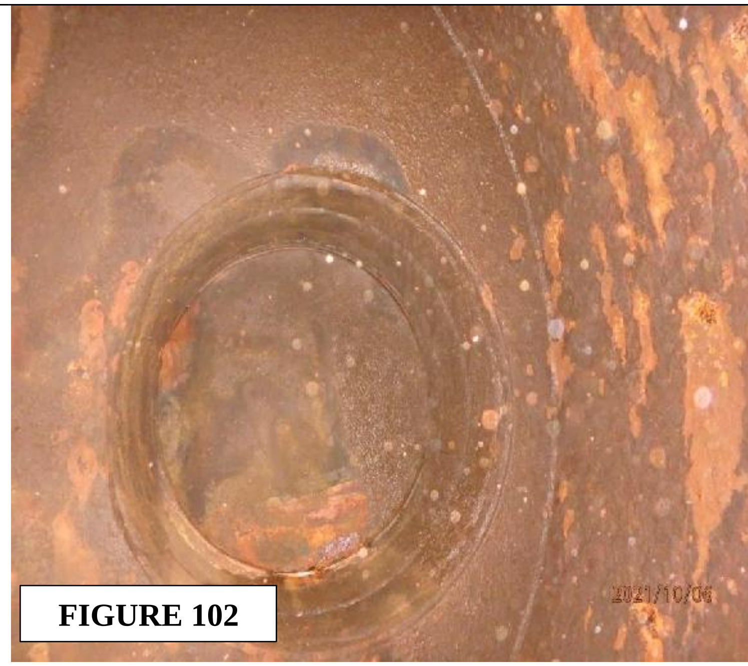


FIGURE 102

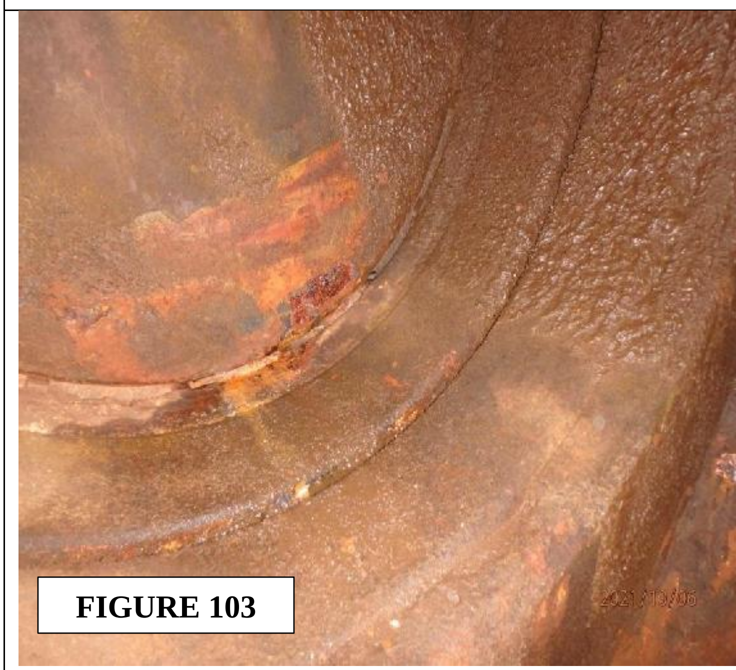


FIGURE 103

FIGURE 104

FIGURE 105

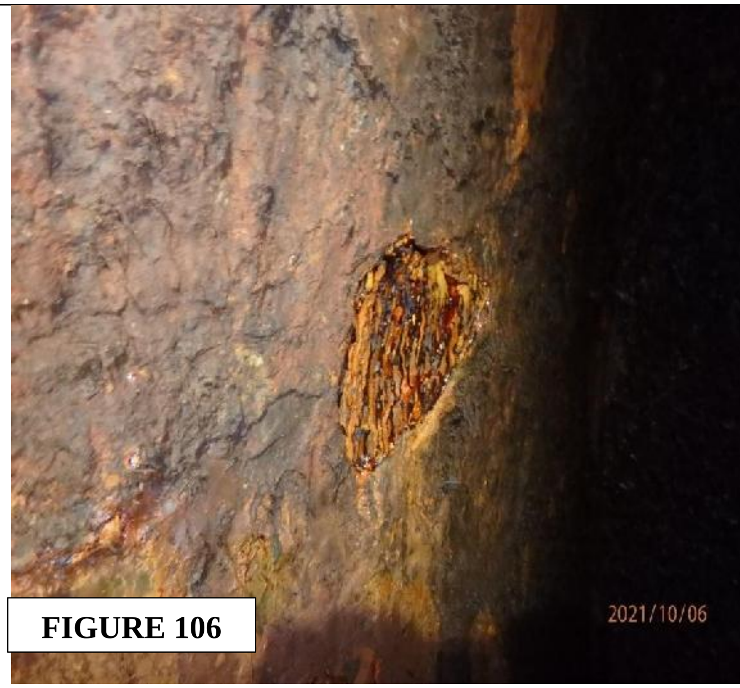


FIGURE 106

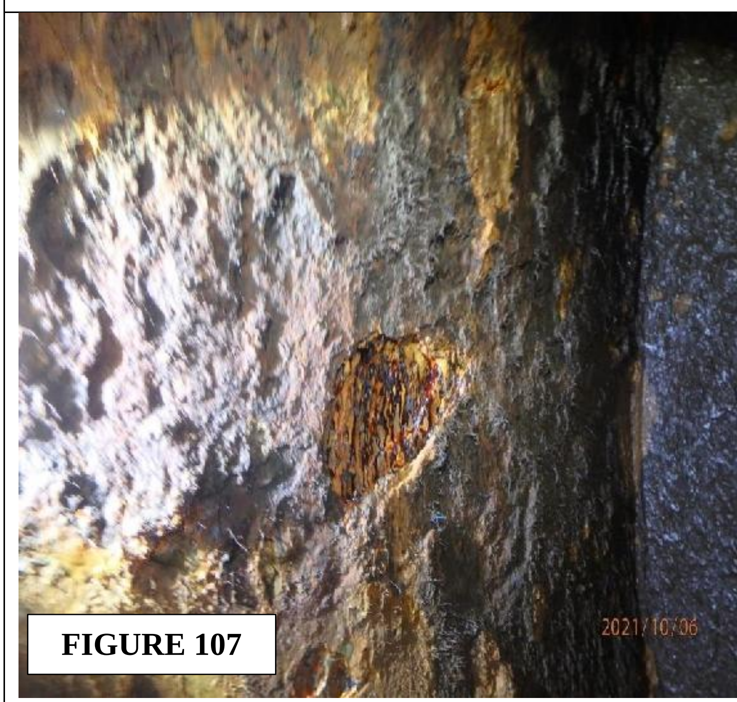


FIGURE 107

FIGURE 108

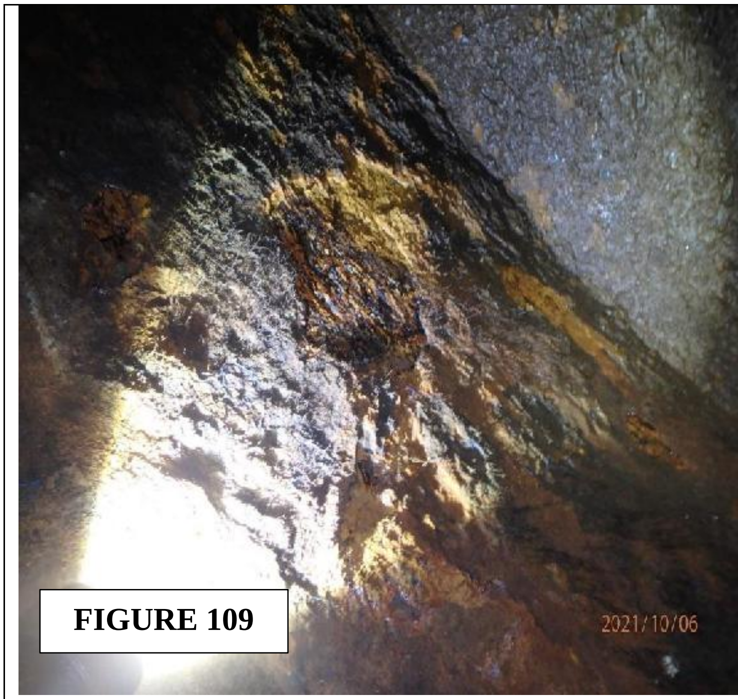


FIGURE 109

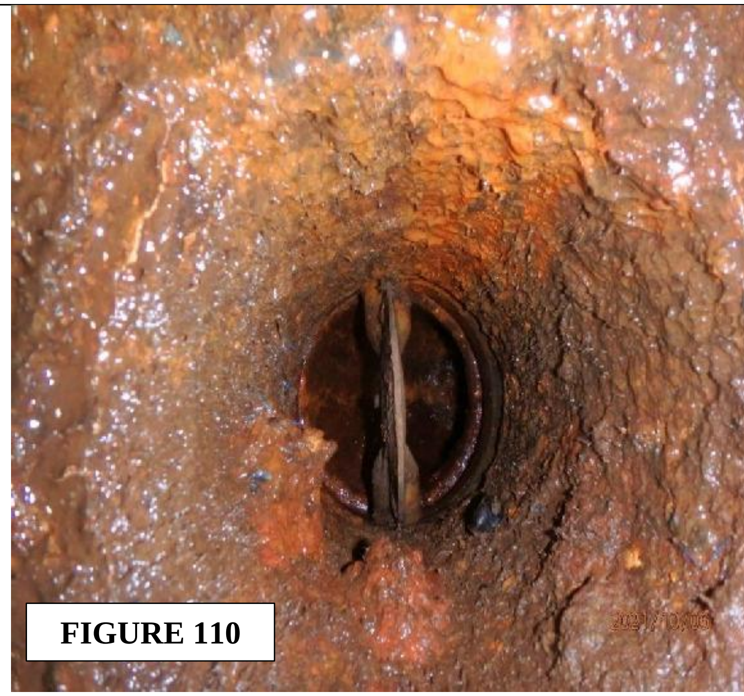


FIGURE 110

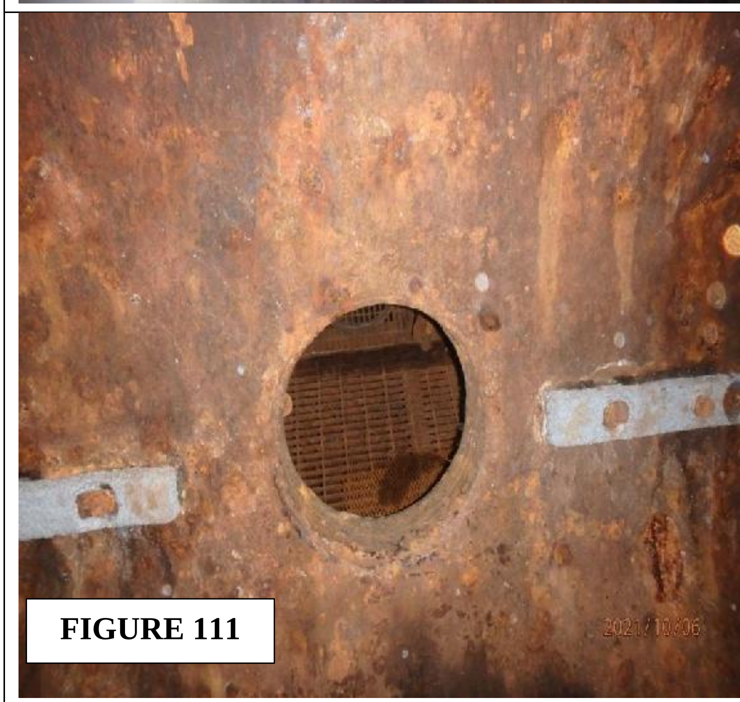


FIGURE 111

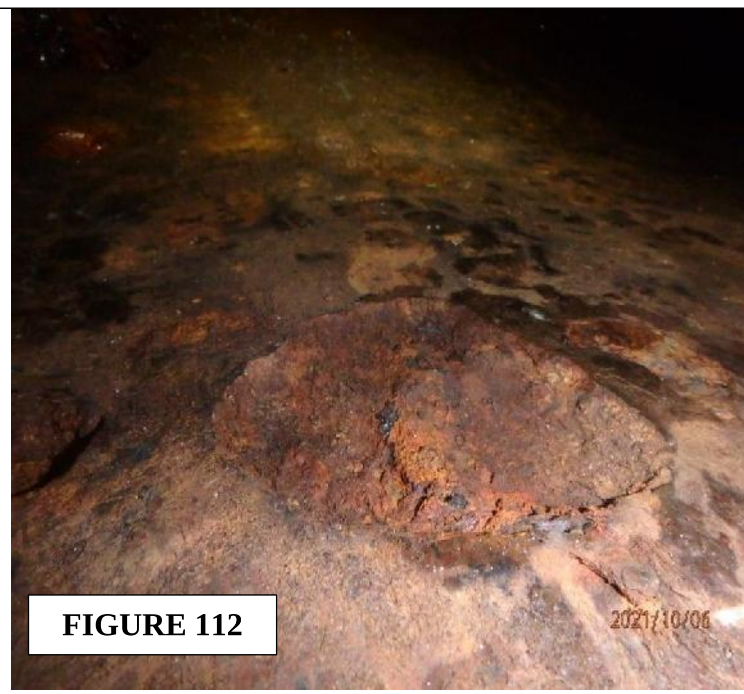


FIGURE 112

3 RECOMMENDATIONS

Steam Side

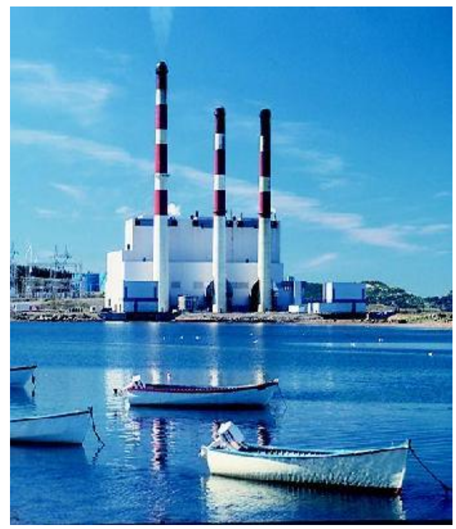
- Continue with regular inspections to monitor erosion of supports, especially the cross braces that extend horizontally between the tube support plate of the two tube bundles. Consider weld repairs in near future.
- Repair hole in extraction piping erosion shield
- Monitor the erosion of the shell expansion joint covering and attachment welds
- Consider replacement of vacuum measuring line and associated supports
- Continue monitoring stiffener erosion and shell attachment welds
- Repair floor coating in noted corners

Water Boxes

- Continue with inspections and regular maintenance of the water boxes, i.e., tube cleaning, debris removal, replacement of anodes
- Coating, plate and drain repairs should be considered in the near future, where necessary

Technical Services
Report

2021 Condenser Inspection Report Unit # 3



NL Hydro - Holyrood TGS
Holyrood, NL

2021 JUL 28-AUG 06
GE Steam Power Contract #: EB0-018032
Customer PO #: 4618 OS
Report by Kristofer Jacobs

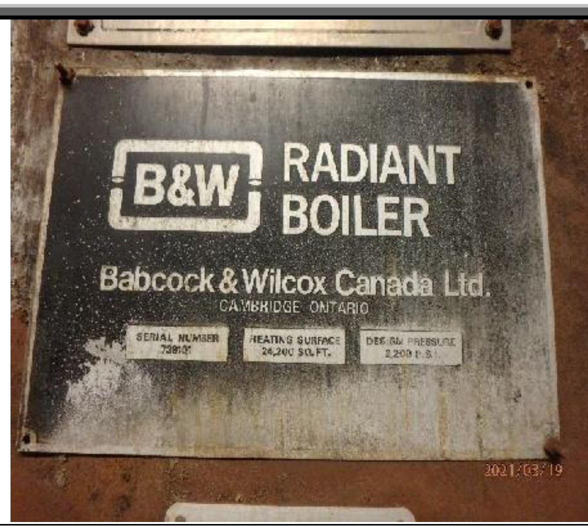
Imagination at work

REPORT DATA

Purpose of Visit:	Condenser Inspection		
Customer:	Nalcor - NL Hydro	GE Ref No.:	EB0-018032
Site Location:	Holyrood, NL	Customer P.O.:	4618 OS
GE TSA(s):	Kristofer Jacobs	Start Date:	2021 July 28
		End Date:	2021 August 06

EQUIPMENT INFORMATION

Equipment:	Steam Turbine Condenser
Equipment OEM:	B&W (Boiler)
Original Ref No.:	739101
Type:	Radiant
Rating:	150MW
Primary Fuel:	No. 6 Fuel Oil
Aux. Fuel:	N/A
MCR Steam Flow:	1,072,000 lb/hr
Drum Des.Press:	2200 psig
SH Outlet Press:	1895 psig
SH/RH Out Temp:	1005 °F



CONTACT INFORMATION

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Phone (office):	709-229-2768	Phone (cell):	709-689-9732
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Email:	Ghanshyam.Patel@ge.com		
Phone (cell):	1-289-244-3408		

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1 INTRODUCTION

This report documents the results of the visual inspection carried out on the Unit #3 Condenser during the 2021 Maintenance Outage. The scope of the inspection was carried out by Kristofer Jacobs in both the steam side and the water side sections of the condenser.

2 NOTES AND OBSERVATIONS

2.1 Steam Side

At the time of inspection, steam side access was granted through the hotwell, as well as the LP Hood. Below is a summary and related pictures of the findings:

- Tube Bundles – Overall, the tube bundles appeared to be in good condition. Minor polishing and steam erosion was noted on the tubes, as well as, bowing of particular tubes. Mineral deposits observed during a previous inspection on the North side of the South LP outlet area on the 8th row from the bottom was also noted. **(Figures 1-6)**
- Structural Supports – Erosion noted throughout. Also, broken welds were noted on various bundle supports on cross braces that extend horizontally between the tube support plates of the two bundles. The typical location of these broken welds is in the wrap of the fillet weld. Due to the amount of deposited weld metal, these are not deemed detrimental, however, should be monitored in future inspections. **(Figures 13-16)**
- Pipe Supports – Broken and eroded welds were noted on a total of 6 supports for the steam seal regulator piping. Upon discovery, these pipe supports were removed and repaired as necessary. **(Figures 7-12)**
- Steam seal regulator piping – In the SW corner of the LP section of the condenser, a hole was noted in an elbow of the steam seal regulator piping. This elbow was removed and replaced as necessary; however, extensive erosion was noted on the I.D. of the piping. **(Figures 29-34)**
- Expansion Joints
    - Extraction Piping – A discrepancy was noted on the erosion shield for the LP Heater extraction piping. **(Figures 25, 26)**
    - Casing Expansion Joint Cover – overall condition is satisfactory and secure; however, as noted in previous inspections, the expansion joint cover in all four corners is bent, giving susceptibility to exposure of the joint. **(Figures 27, 28)**
- Vacuum Measuring Reference Line – Extensive erosion/corrosion observed in various locations, no holes noted **(Figure 16-24)**

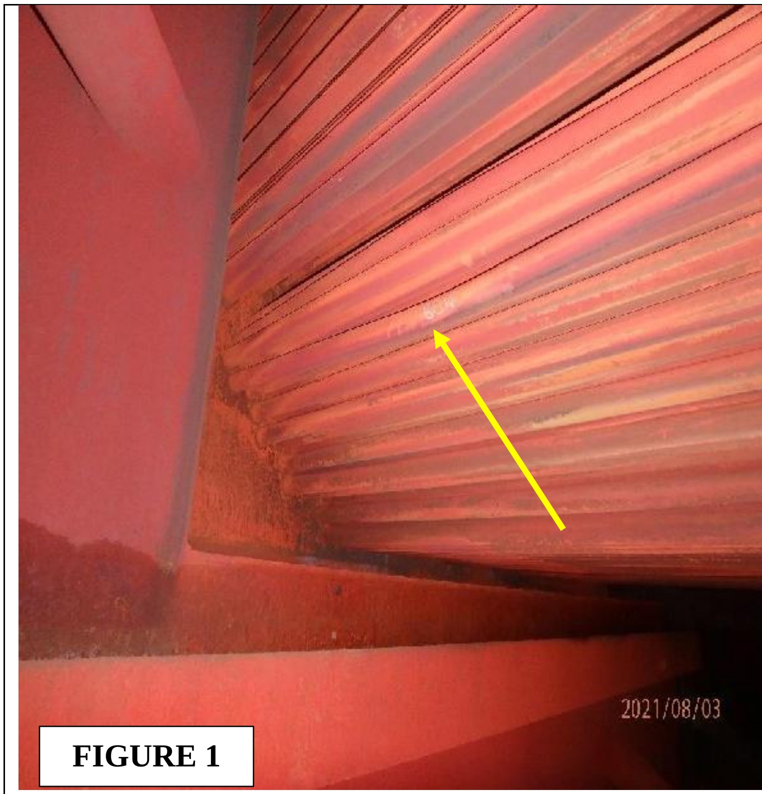


FIGURE 1

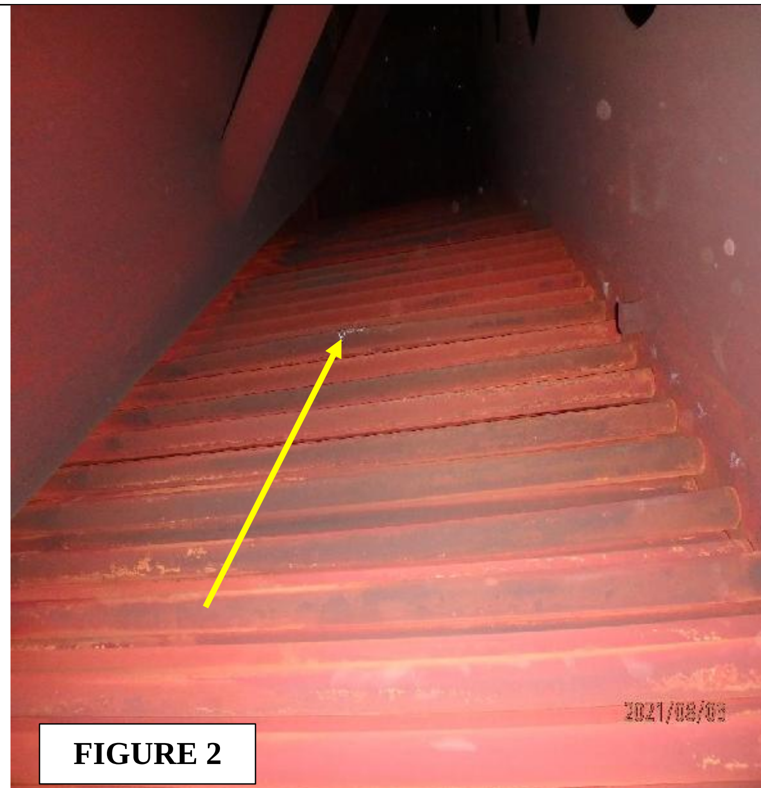
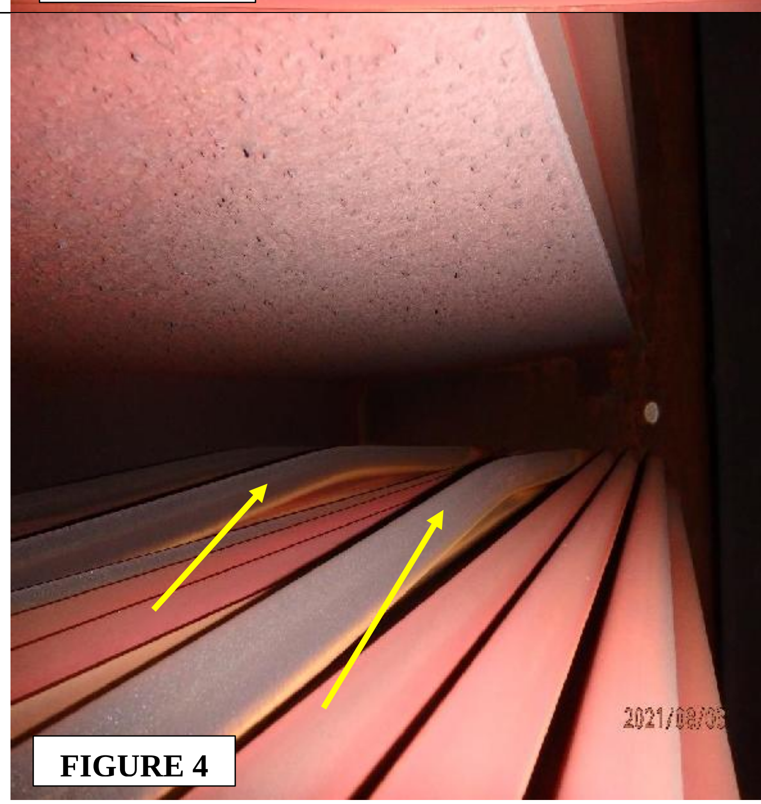


FIGURE 2

FIGURE 3



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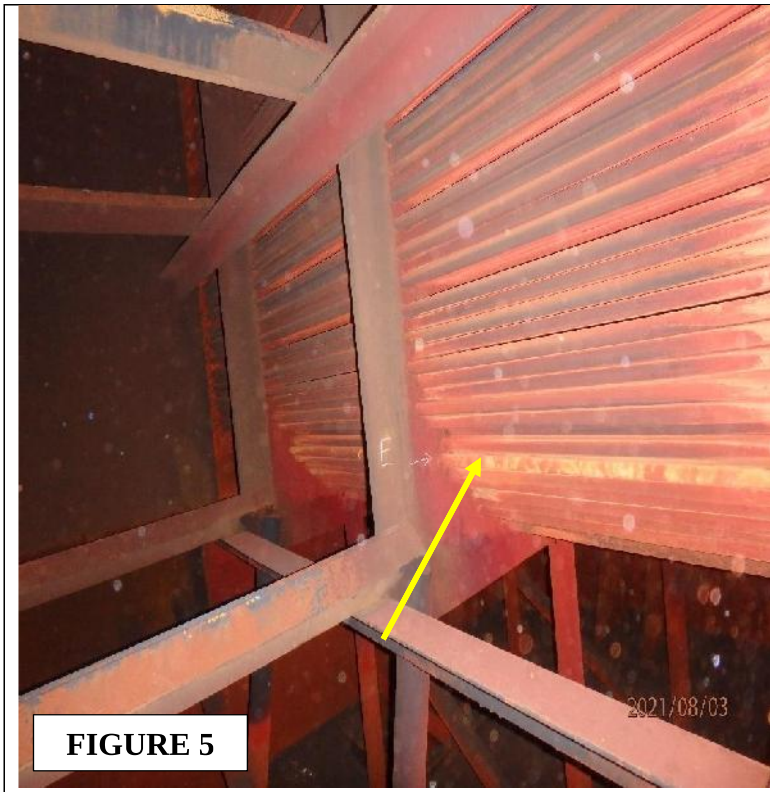


FIGURE 5

FIGURE 6

FIGURE 7

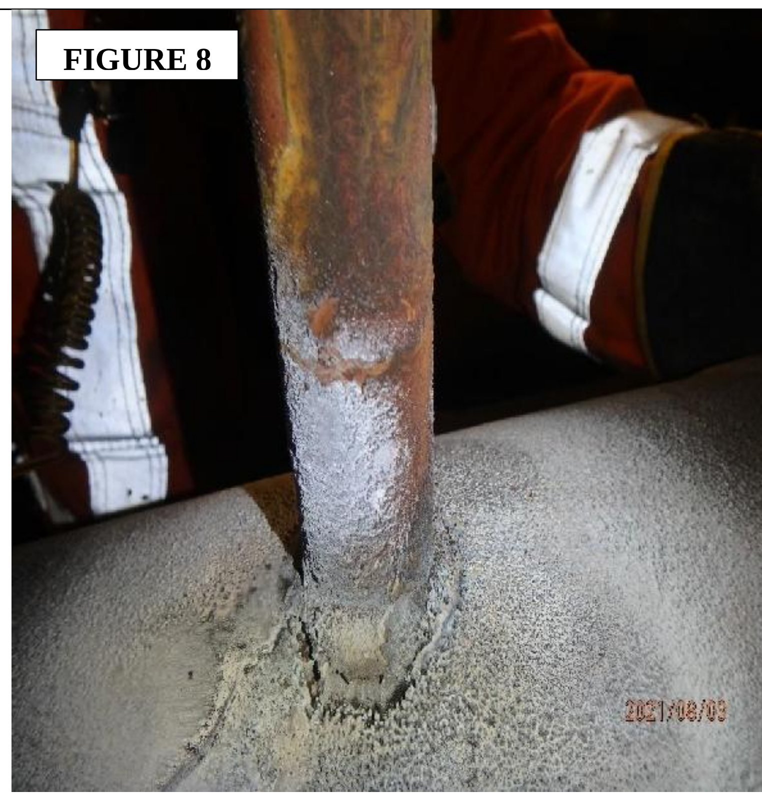


FIGURE 8

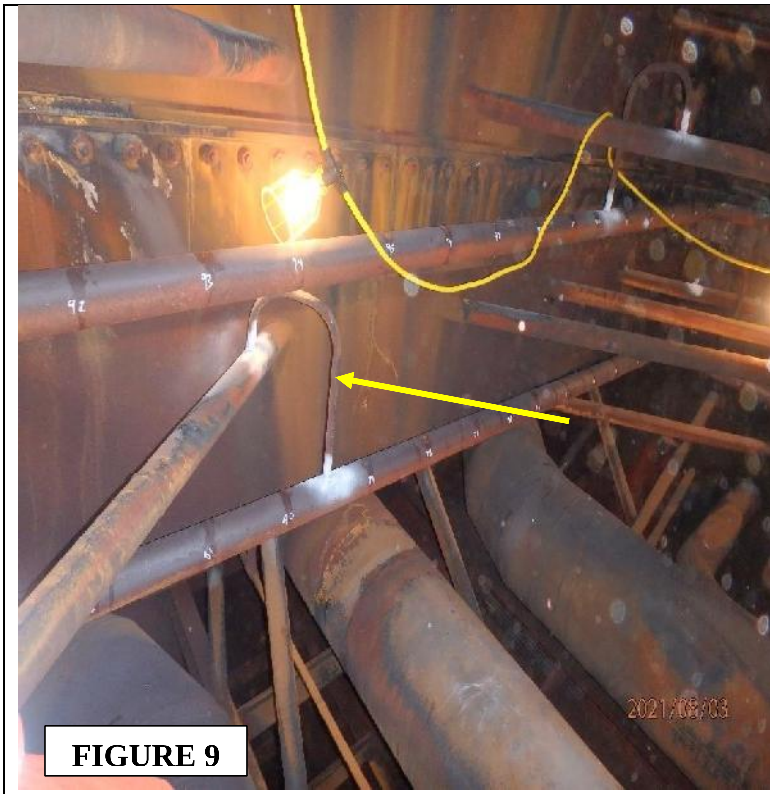


FIGURE 9

FIGURE 10


FIGURE 11

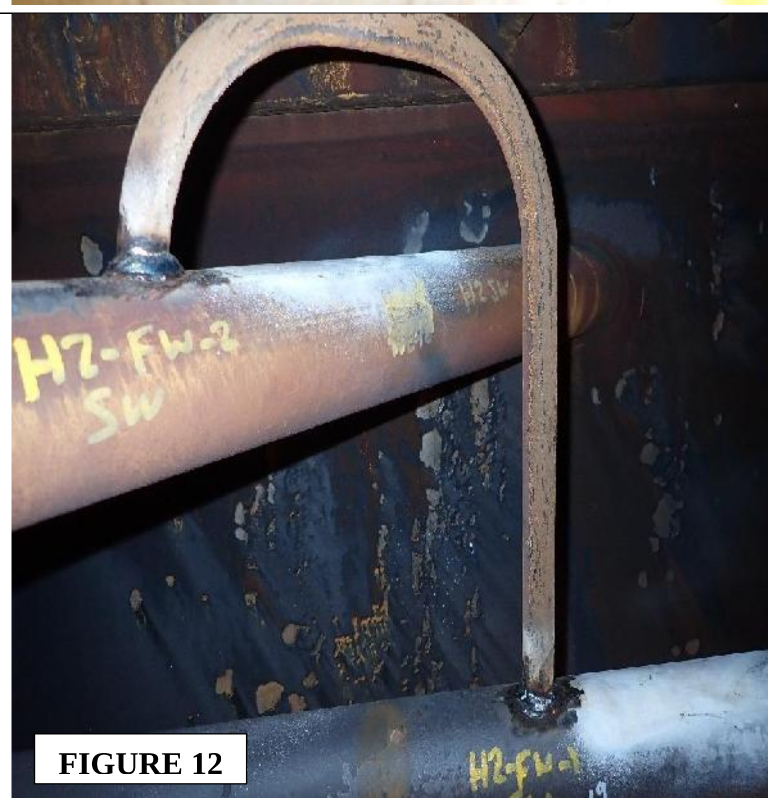


FIGURE 12

FIGURE 13

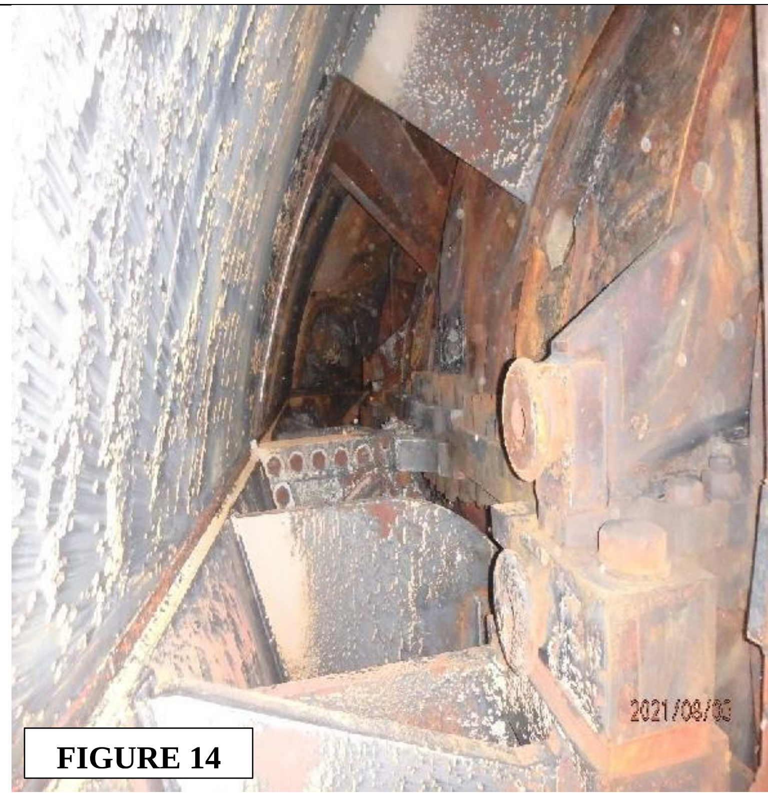


FIGURE 14

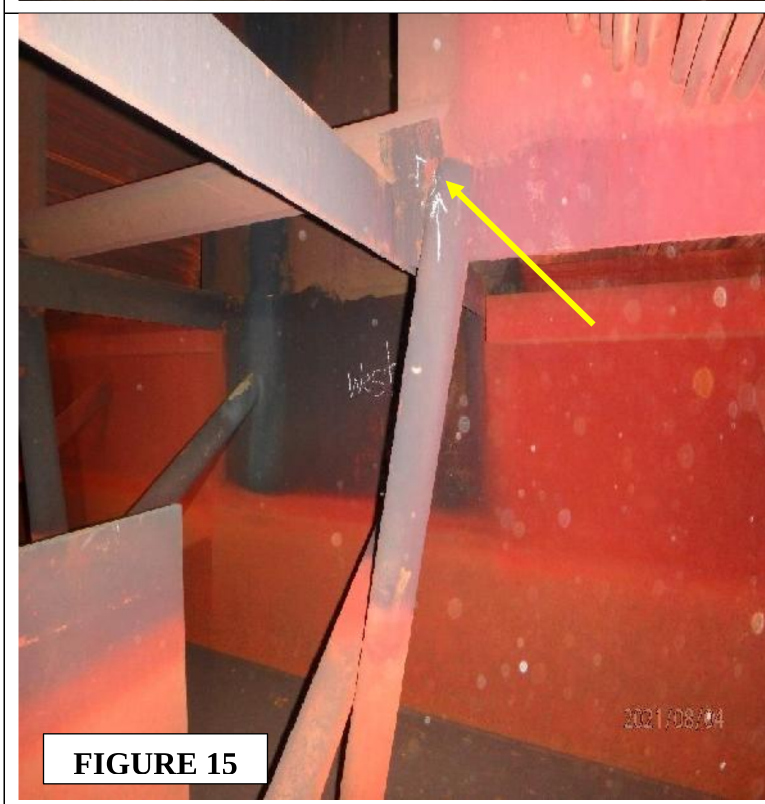
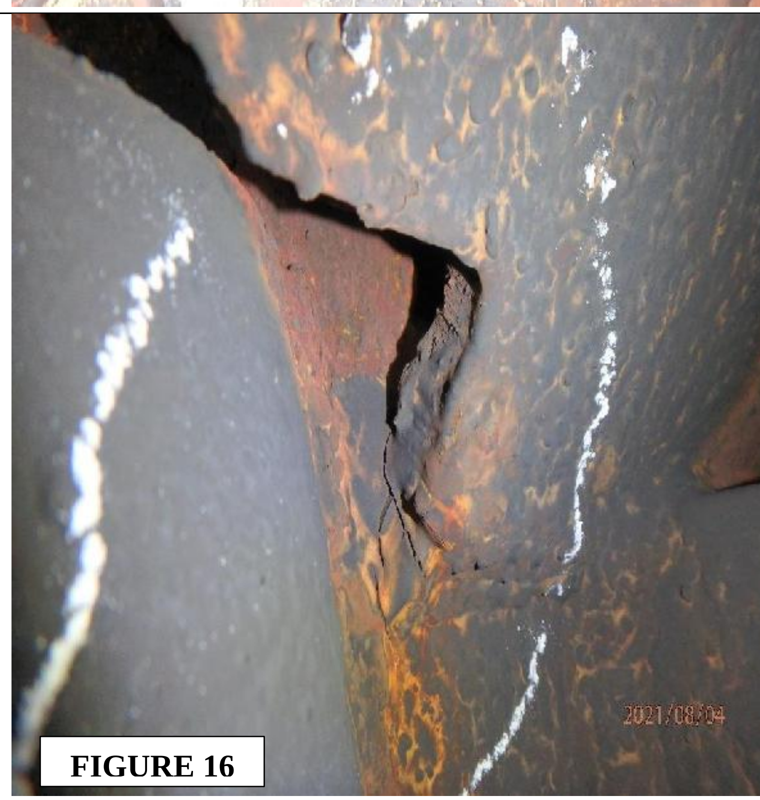


FIGURE 15



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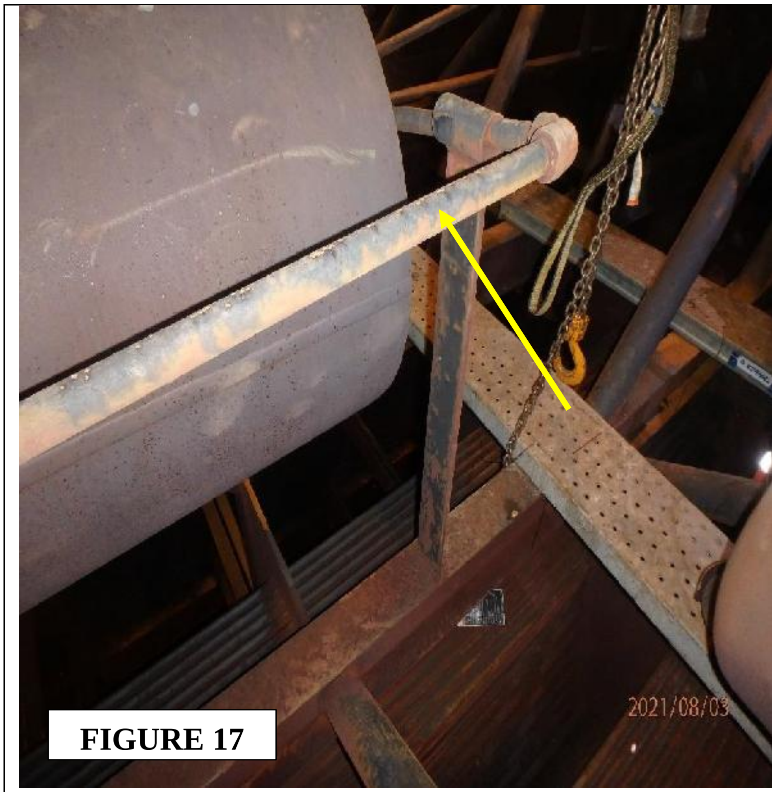

FIGURE 17

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FIGURE 19

FIGURE 20


FIGURE 21


FIGURE 22


FIGURE 23


FIGURE 24

FIGURE 25

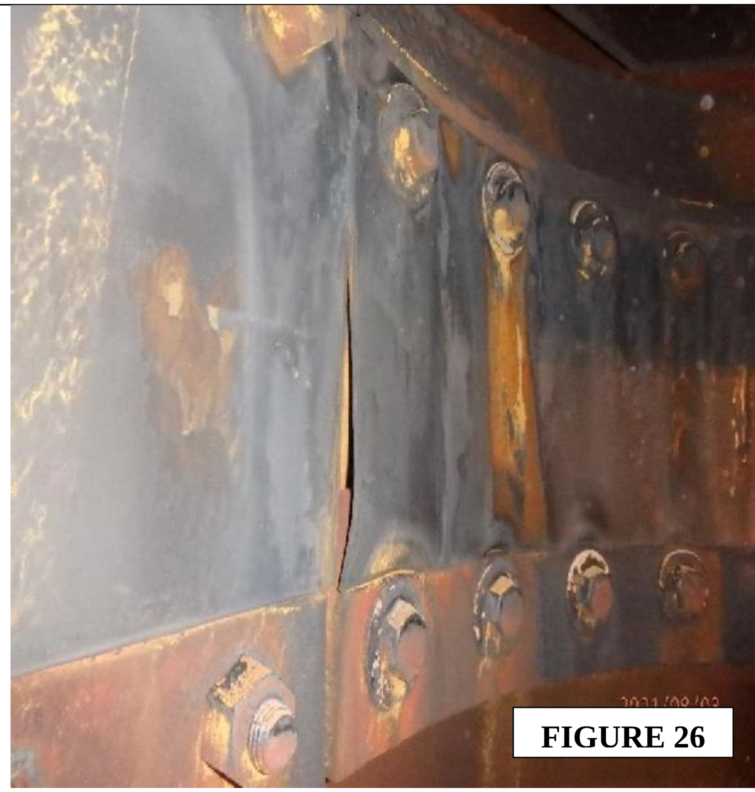
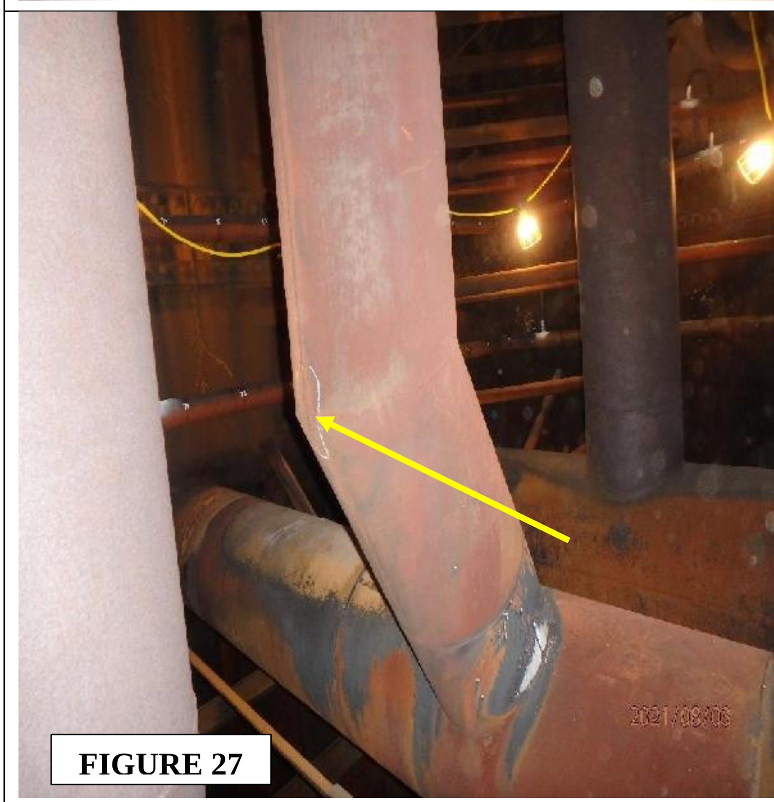


FIGURE 26



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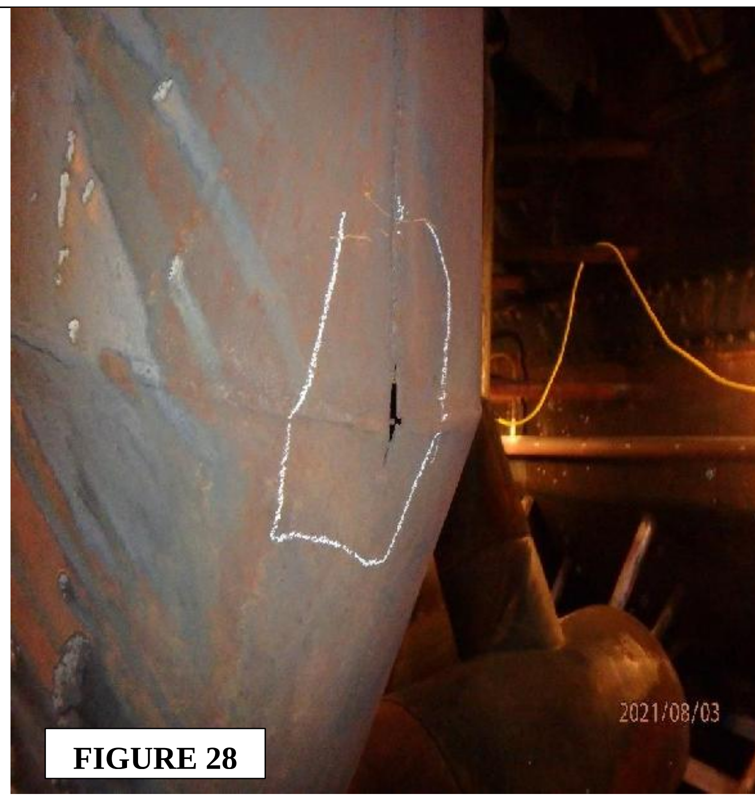

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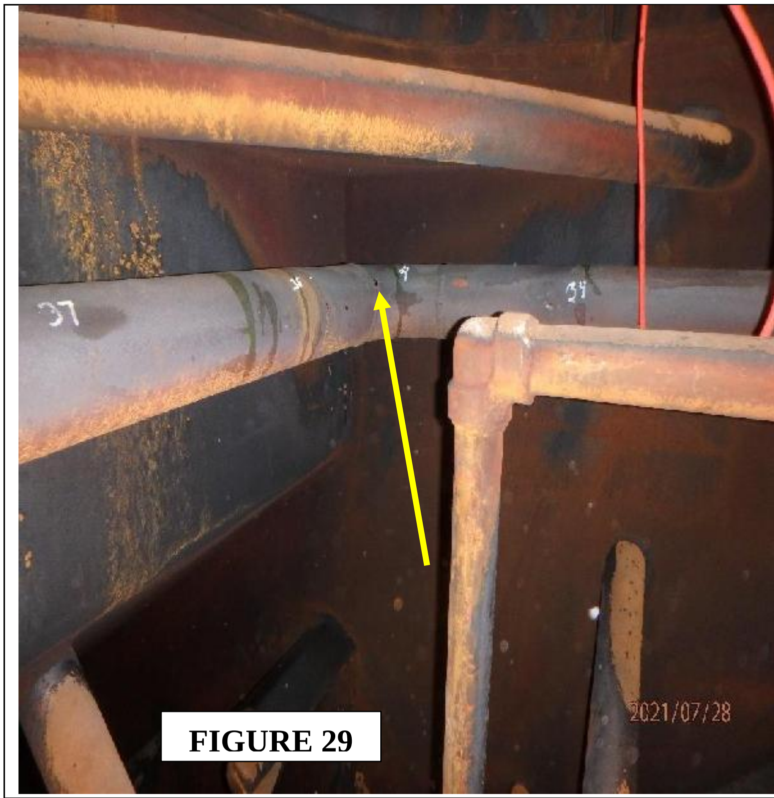
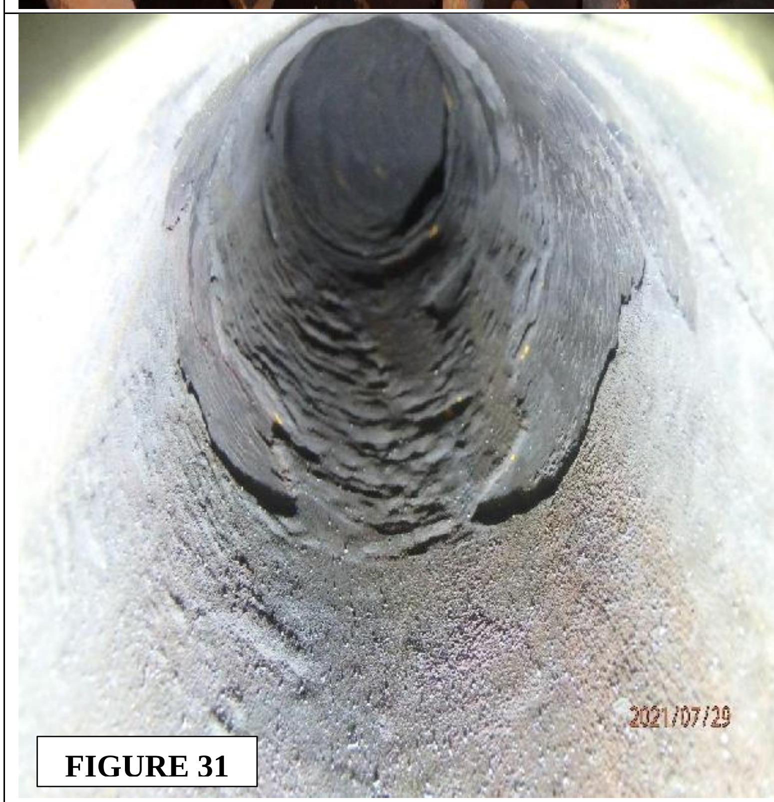


FIGURE 29

FIGURE 30



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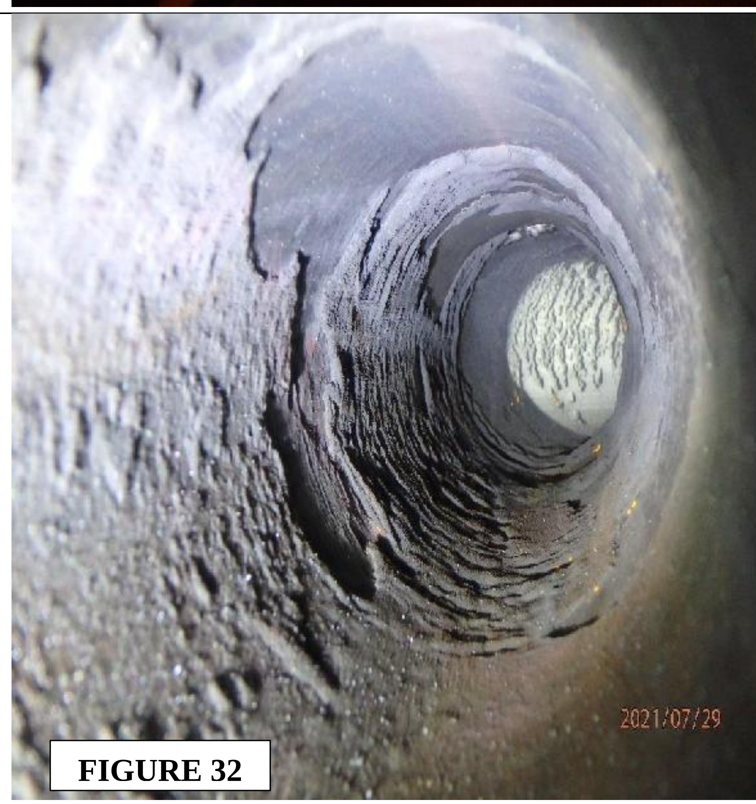


FIGURE 32

FIGURE 33

FIGURE 34

2.2 West Side – North Inlet Box

- The side walls of the box were generally in good condition with minor coating breakdown and corrosion noted, however, the floor and upper section coatings have failed more aggressively causing corrosion and erosion of structural components and casing **(Figure 37, 40-43)**
- Anodes in satisfactory condition
- Pitting of the tubesheet was observed **(Figure 38, 39)**
- Heavy corrosion and deep cavities were discovered around inside of manway due to coating breakdown **(Figures 35, 36)**
- Minor pitting noted in inlet piping
- Due to residual water, butterfly valve was not able to be inspected **(Figure 44)**
- Drain piping cover was intact and valve deemed satisfactory

FIGURE 35

FIGURE 36


FIGURE 37

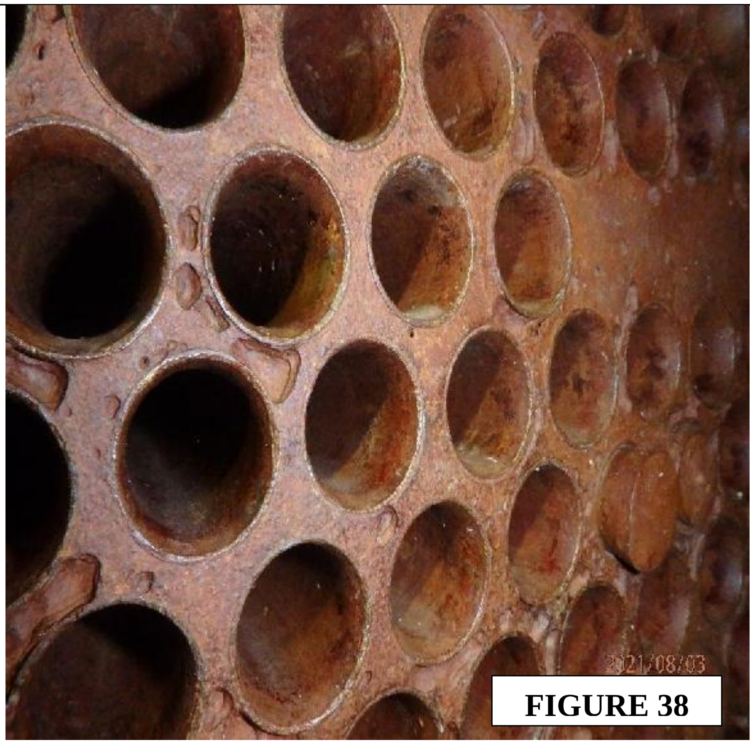


FIGURE 38

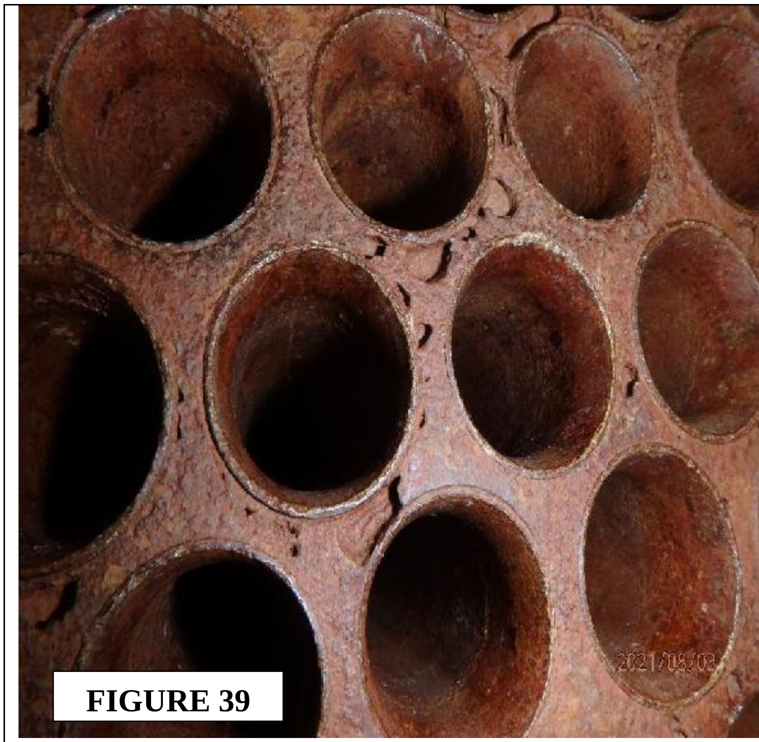
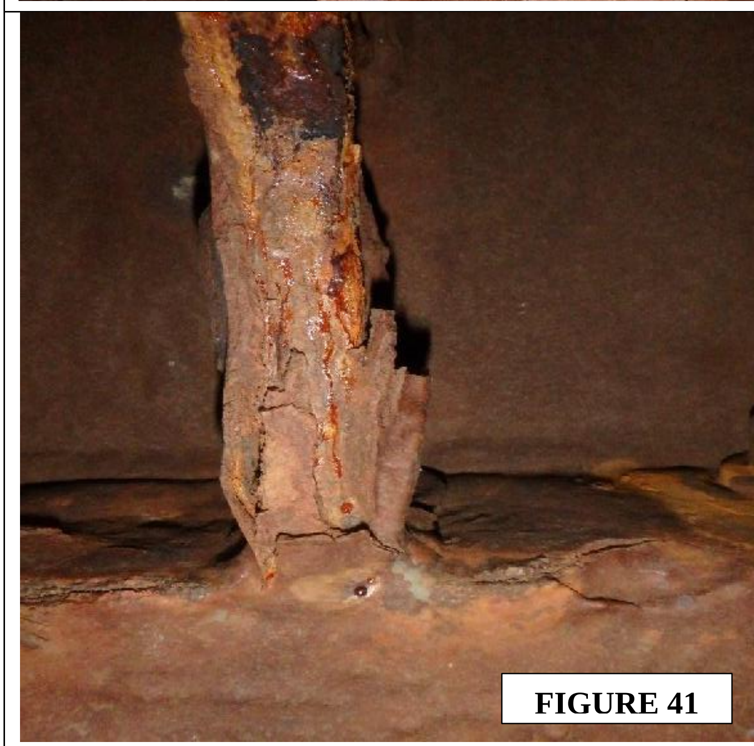


FIGURE 39

FIGURE 40



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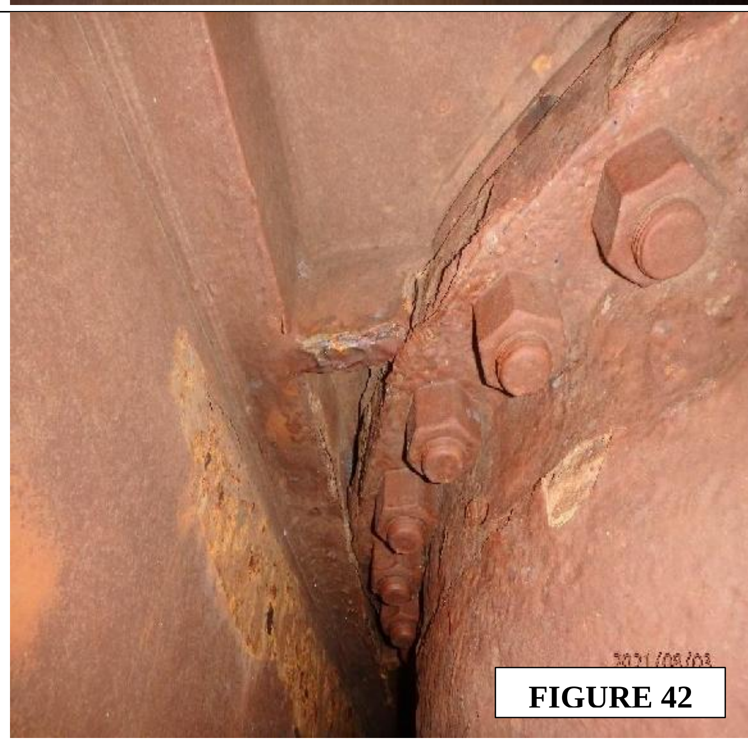


FIGURE 42


FIGURE 43

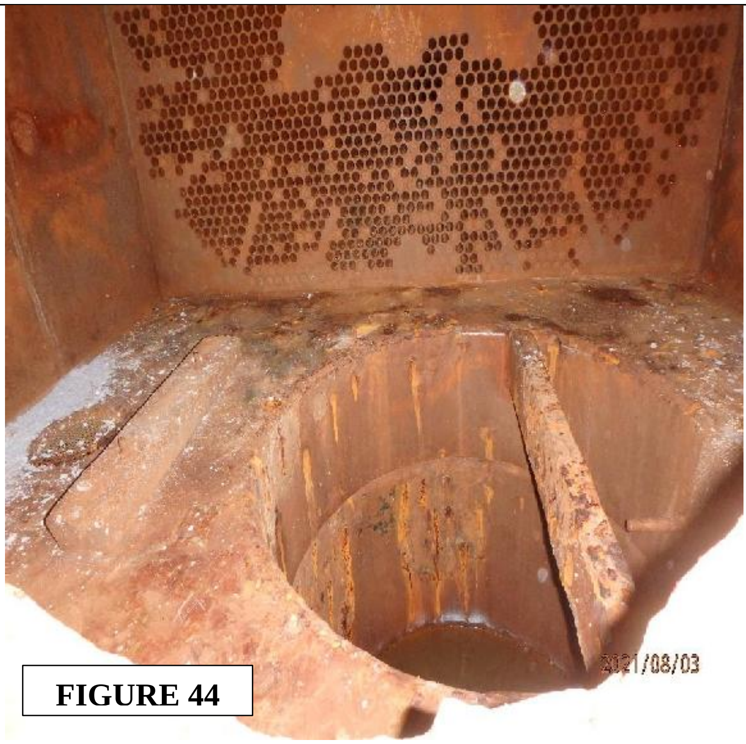


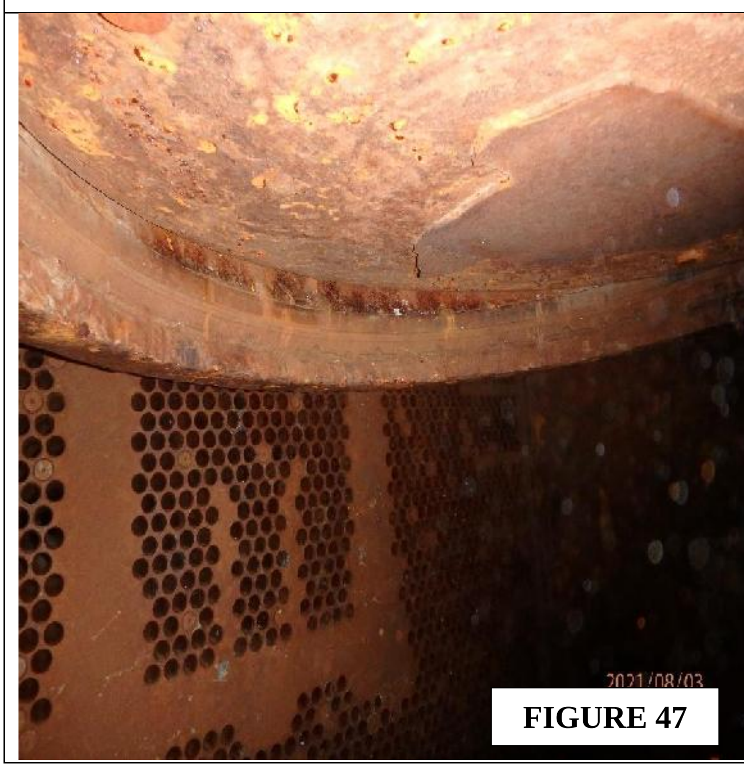
FIGURE 44

2.3 West Side – South Inlet Box

- The side walls of the box were generally in good condition with minor coating breakdown and corrosion noted, however, the floor and upper section coatings have failed more aggressively causing corrosion and pitting **(Figures 45, 48, 49)**
- Anodes in satisfactory condition
- No pitting of the tubesheet was observed
- Heavy corrosion and deep cavities were discovered around inside of manway due to coating breakdown **(Figure 50)**
- Minor pitting noted in inlet piping
- Due to residual water, inlet butterfly valve was not able to be inspected
- Drain found to be corroded with no cover installed. Valve noted as satisfactory **(Figure 46)**
- Outlet valve coating breakdown was observed causing corrosion **(Figure 47)**

FIGURE 45

FIGURE 46



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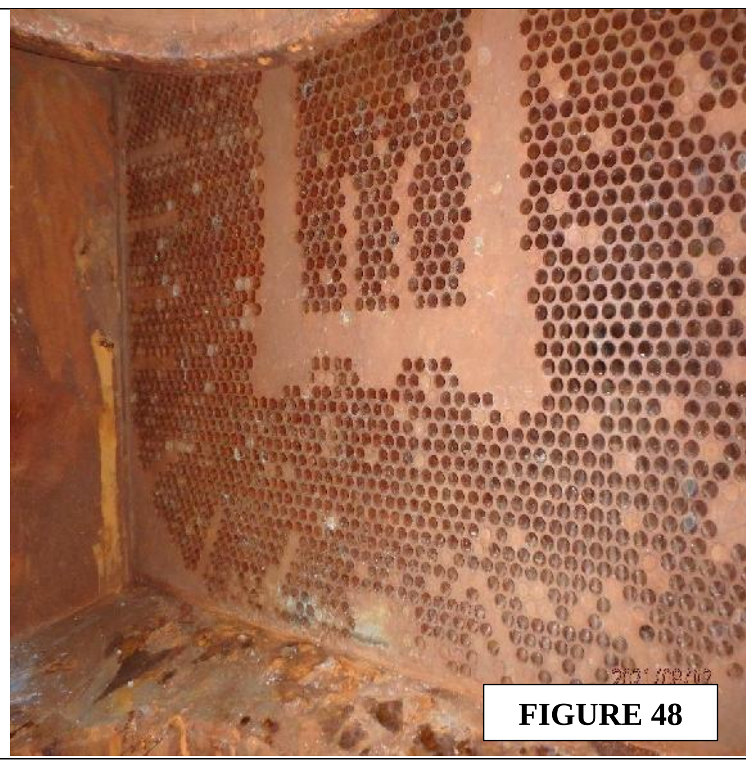


FIGURE 48

FIGURE 49

FIGURE 50

2.4 West Side – North Outlet Box

- The box was generally in poor condition with coating breakdown and corrosion throughout, especially of the floor and inlet to discharge piping **(Figures 54-58)**
- Manway heavily corroded **(Figure 51)**
- Butterfly valve disc coating failure and corrosion noted
- Anodes in satisfactory condition, one newly installed **(Figure 52, 53)**
- No corrosion of tubesheet was observed
- Minor corrosion noted in discharge piping

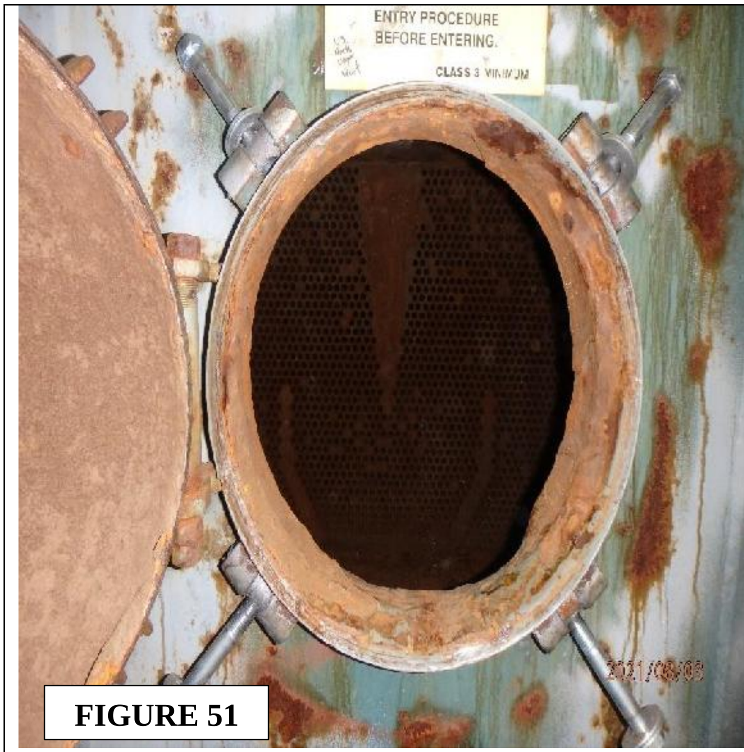


FIGURE 51

FIGURE 52

FIGURE 53

FIGURE 54

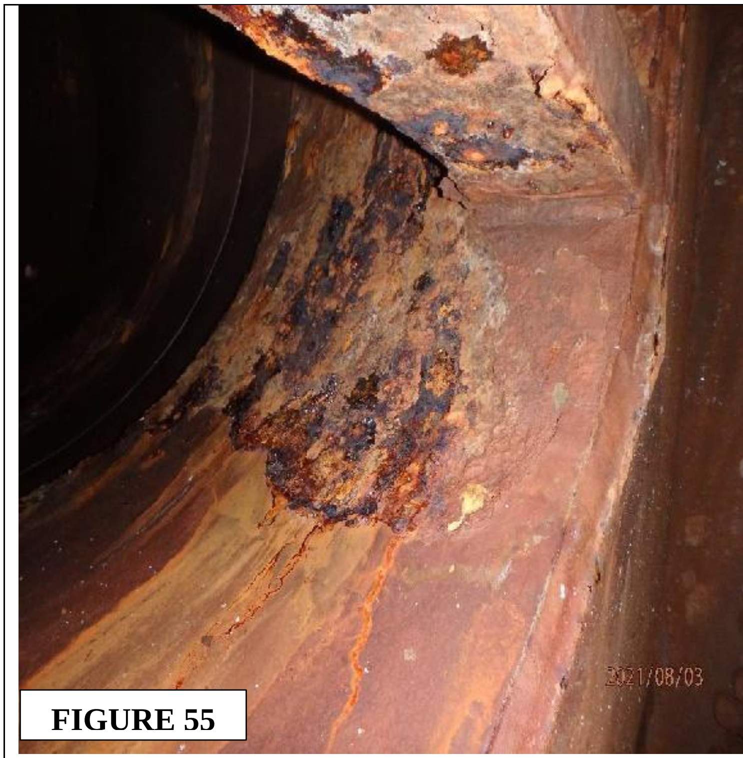


FIGURE 55

FIGURE 56

FIGURE 57

FIGURE 58

2.5 West Side – South Outlet Box

- The box was generally in poor condition with coating breakdown and corrosion throughout, especially of the floor and inlet to discharge piping **(Figures 61, 63-65)**
- Manway heavily corroded due to breakdown of coating
- Butterfly valve disc coating failure and corrosion noted **(Figure 66)**
- Minor breakdown of anodes, one newly installed **(Figure 59, 60)**
- No corrosion of tubesheet was observed
- Minor corrosion noted in discharge piping **(Figure 62)**

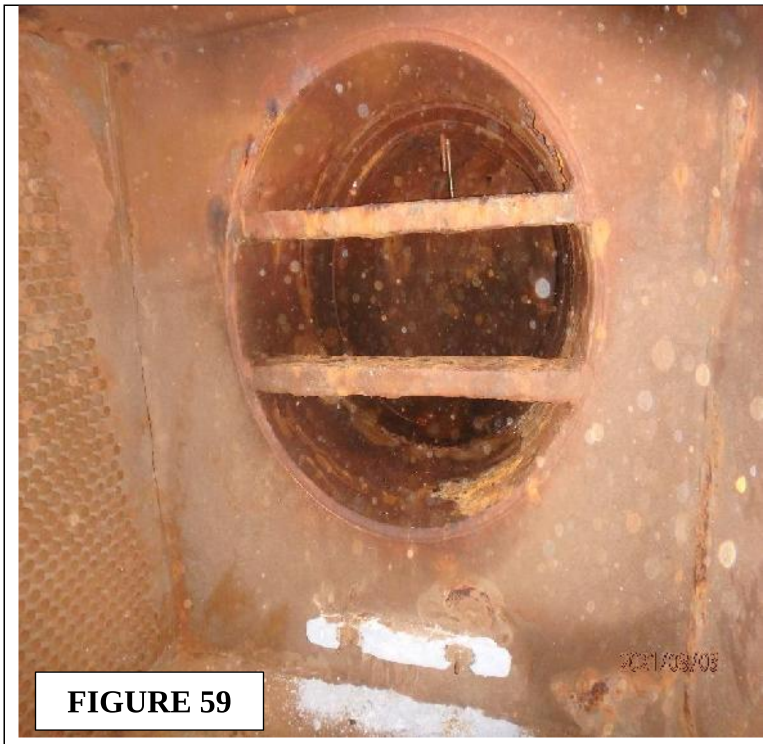


FIGURE 59

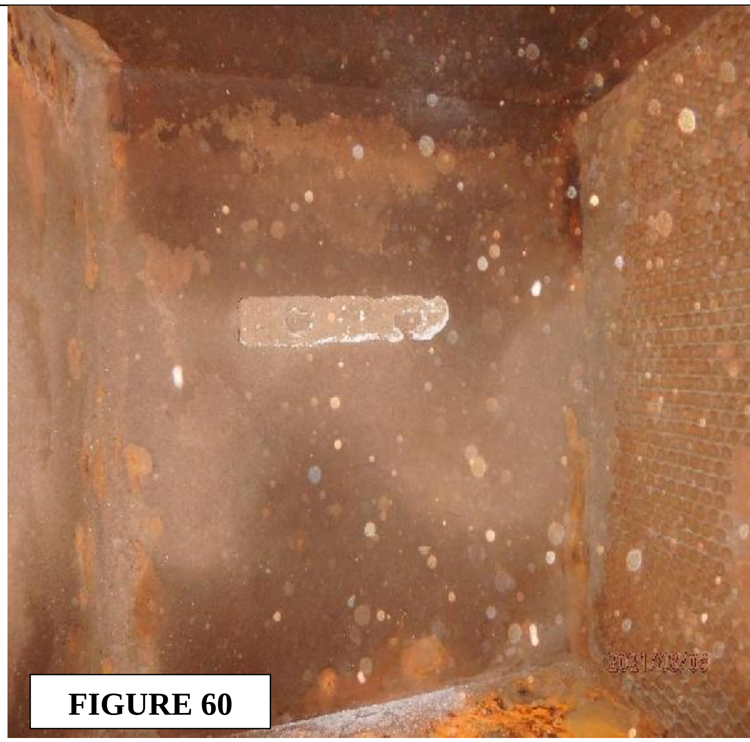


FIGURE 60

FIGURE 61

FIGURE 62

FIGURE 63

FIGURE 64

FIGURE 65

FIGURE 66

2.6 East Side – North Box

- The box was in poor condition with extensive coating breakdown and heavy corrosion throughout **(Figures 71-74)**
- Manways heavily corroded **(Figure 67)**
- Butterfly valve disc appeared to be in satisfactory condition
- One anode missing overhead, two newly installed, others deemed satisfactory **(Figure 68)**
- No corrosion of tubesheet was observed, with some debris noted in tubes
- Drain found to be corroded with no cover installed, valve satisfactory
- Debris from anode breakdown, as well, organic matter **(Figures 69, 70)**

FIGURE 67

FIGURE 68

FIGURE 69

FIGURE 70


FIGURE 71

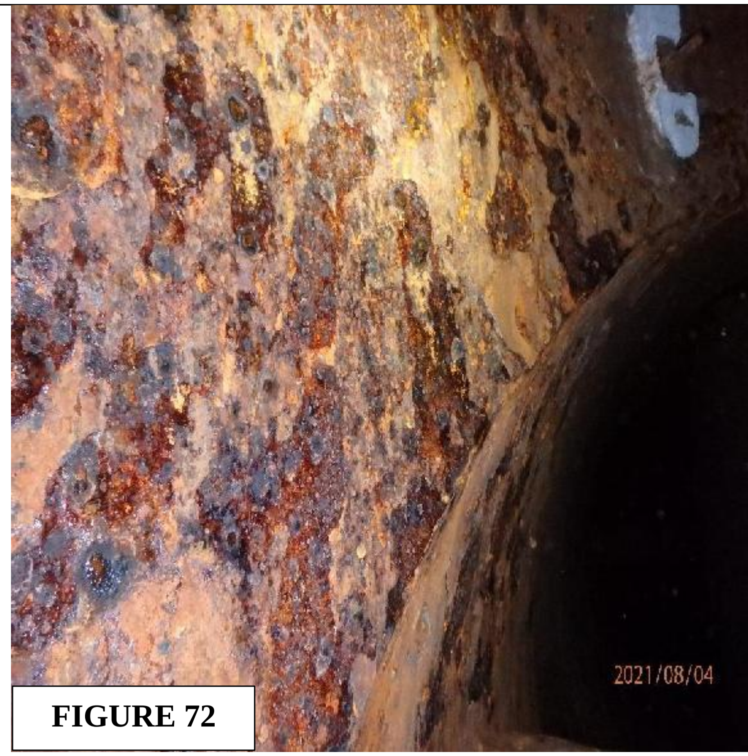


FIGURE 72

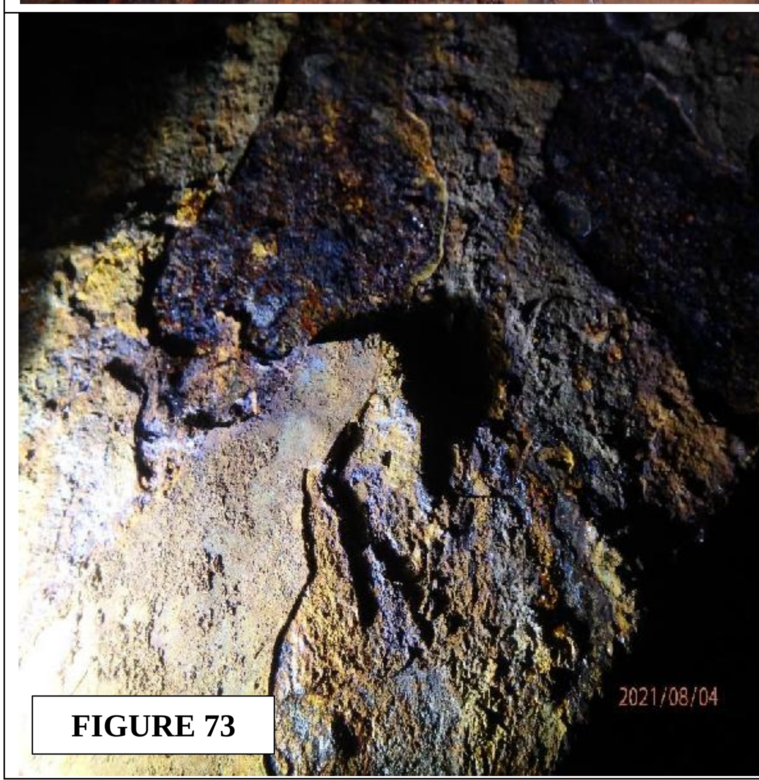


FIGURE 73

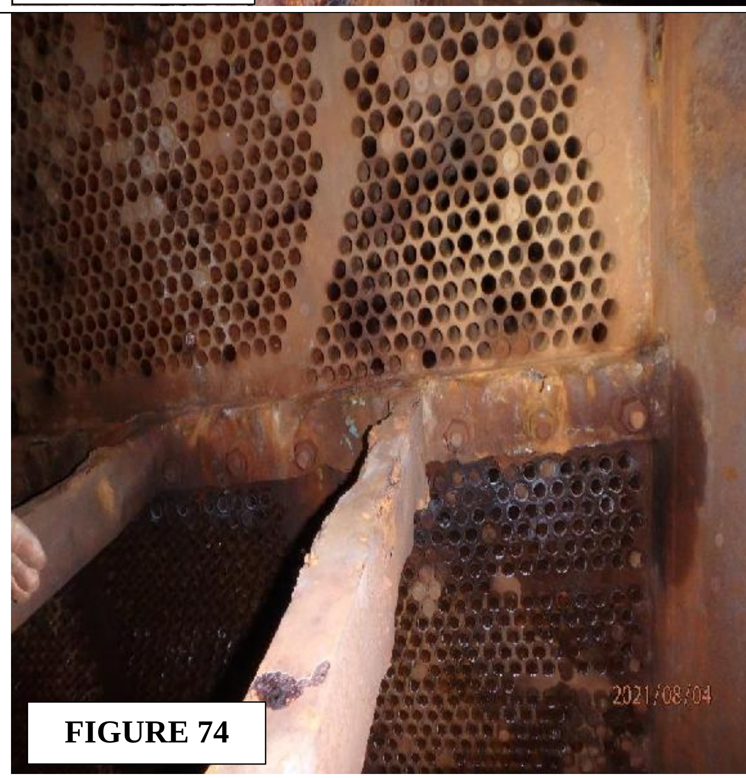


FIGURE 74

2.7 East Side – South Box

- The box was in poor condition with extensive coating breakdown and heavy corrosion throughout **(Figures 75, 76)**
- Manways heavily corroded **(Figure 82)**
- Butterfly valve disc appeared to be in satisfactory condition
- One anode missing overhead, two newly installed, others deemed satisfactory **(Figures 83, 84)**
- No corrosion of tubesheet was observed, however, some debris noted in tubes **(Figures 79, 81)**
- Drain found to be corroded with no cover installed, valve satisfactory **(Figure 80)**
- Debris from anode breakdown, as well, organic matter
- Extensive corrosion/erosion of supports **(Figures 77, 78)**

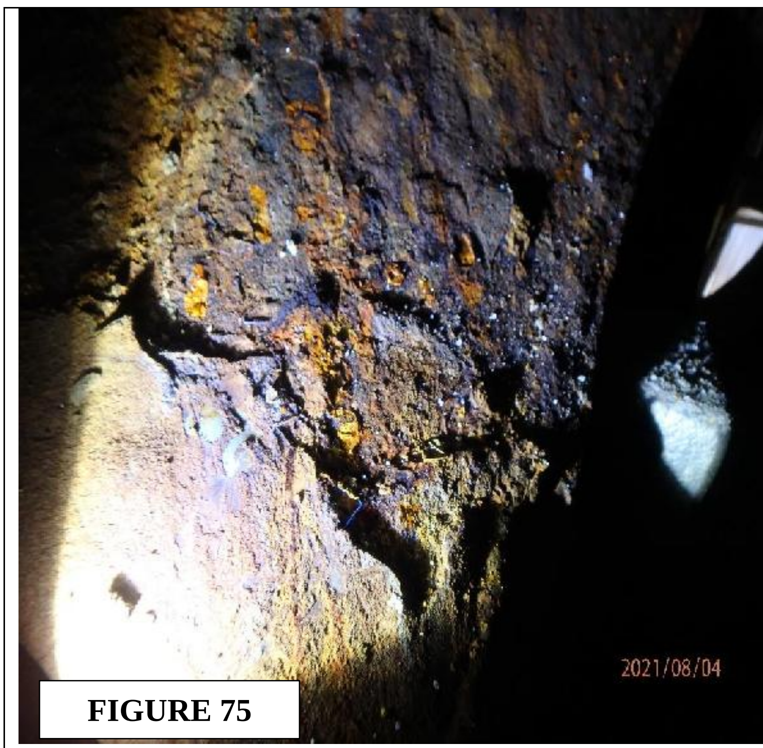
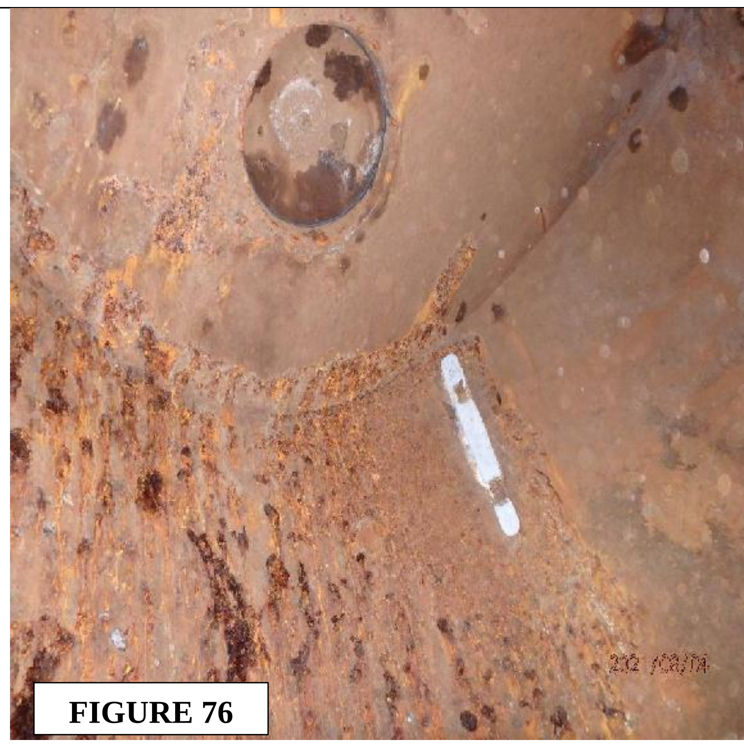


FIGURE 75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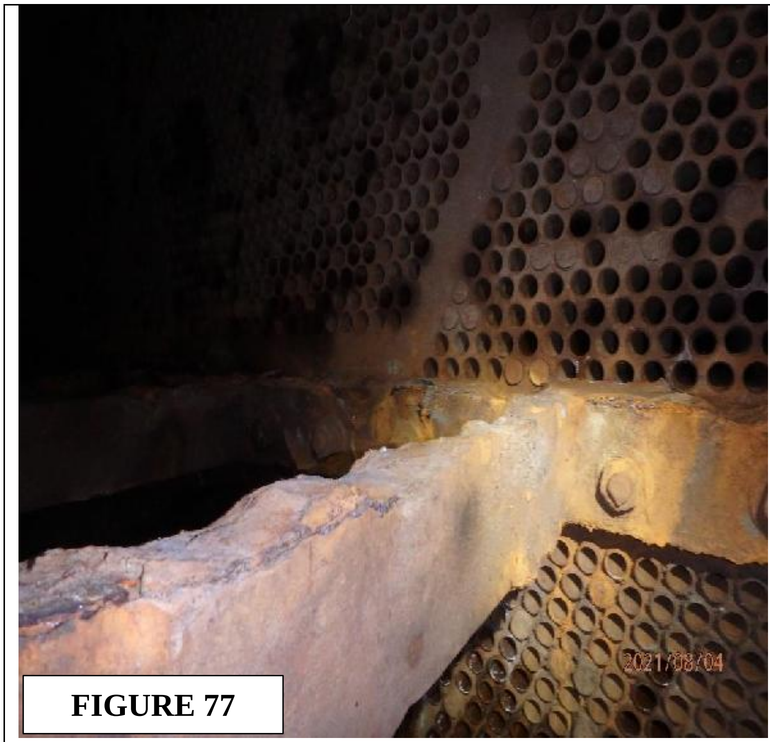


FIGURE 77


FIGURE 78

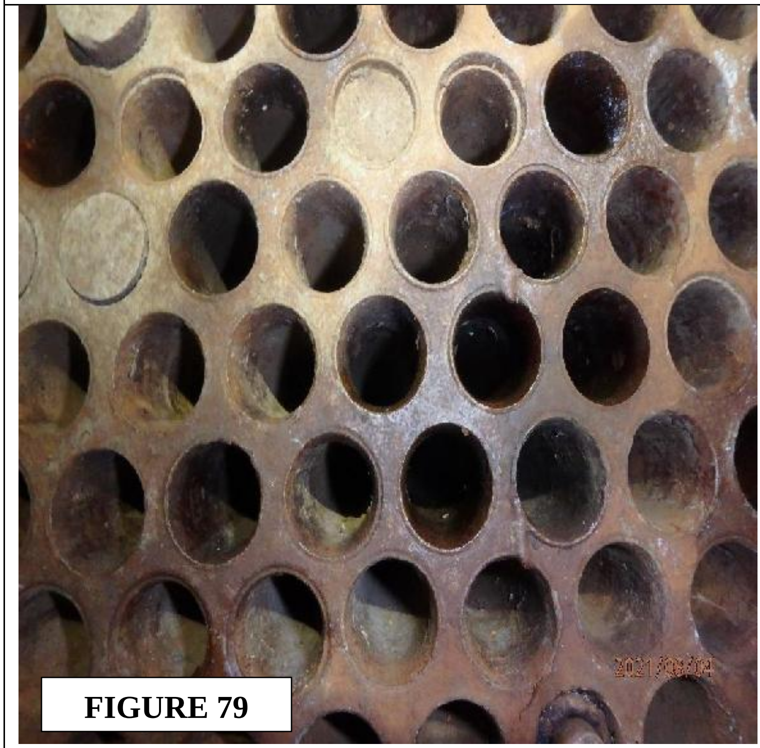


FIGURE 79


FIGURE 80

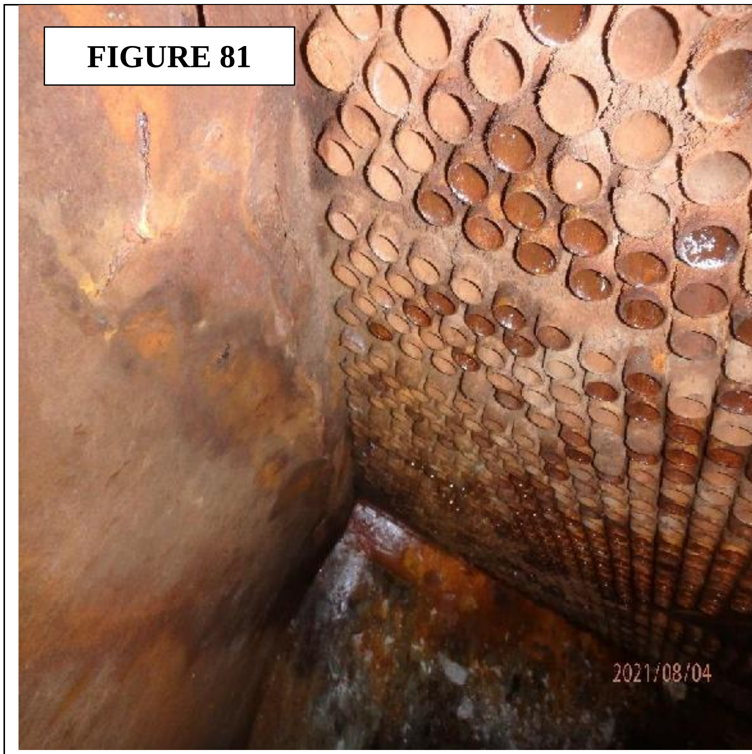


FIGURE 81

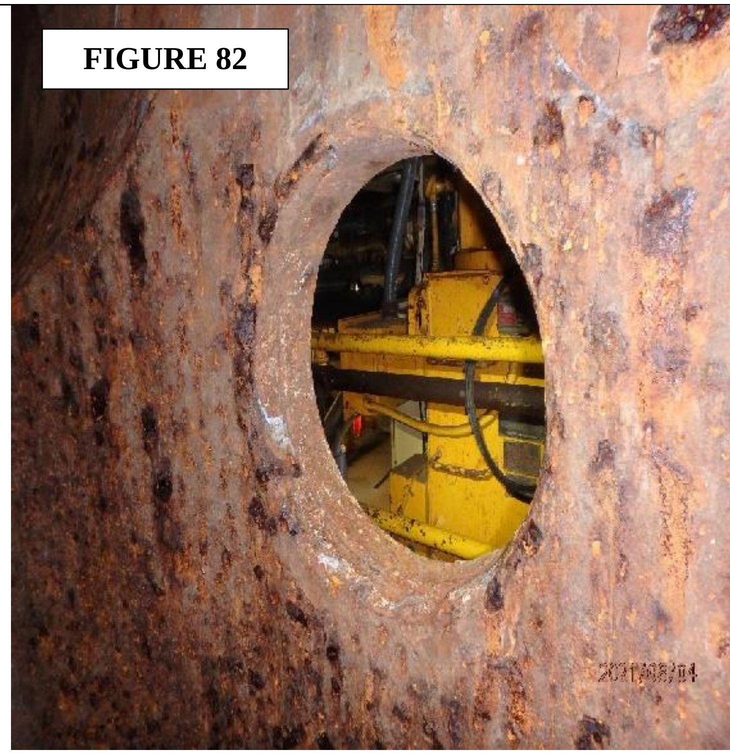


FIGURE 82

FIGURE 83

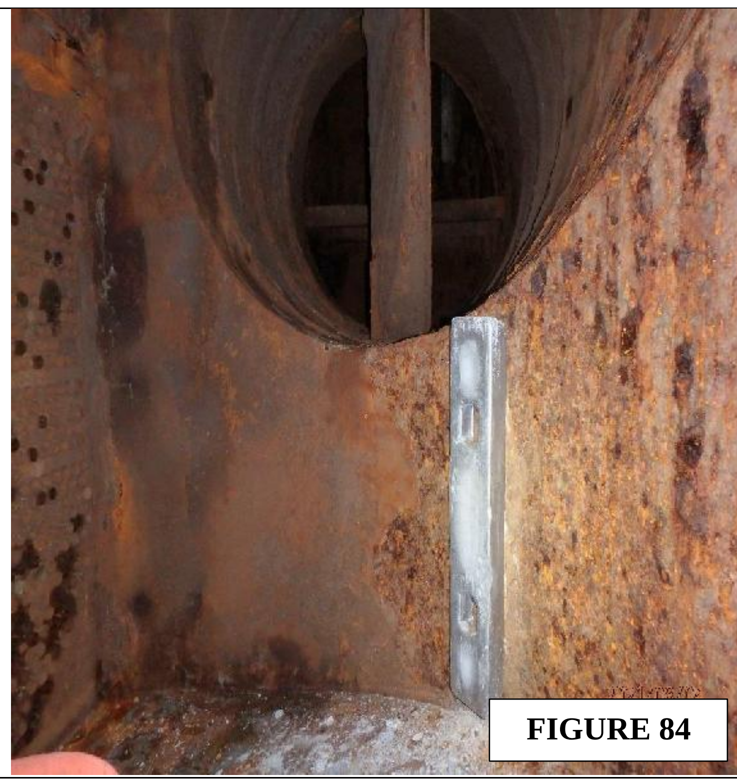


FIGURE 84

3 RECOMMENDATIONS

Steam Side

- Continue with regular inspections to monitor erosion of supports and the broken welds on the cross braces that extend horizontally between the two tube bundles, repair as necessary.
- Replace steam seal regulator piping next outage season due to the excessive erosion noted on the I.D. of the piping
- Replace corroded sections of vacuum reference line piping during next outage season to avoid failure
- During next outage season, repair discrepancy noted in the LP Heater extraction piping erosion shield

Water Boxes

- Continue with inspections and regular maintenance of the water boxes, i.e., tube cleaning, debris removal, replacement of anodes
- Coating repairs should be considered due to the excessive breakdown and corrosion noted. These should be further assessed and repaired as necessary

2020 and 2019 Condition Assessment Summary

Location	Year of Report	Years Left to reach minimum ASME Thickness	Comments
Unit 1 – Economizer Inlet Piping	2020	40.3	UT FAC Evaluation
Unit 2- Economizer Inlet	2020	11.3	UT FAC Evaluation. 11.3 years for section between weld 4 and header. 33 to 77 years for rest of the piping
Unit 3- Boiler Feed Pump Discharge Piping Eccentric Reducer and “Y”	2020	21.4	UT FAC performed. The other two original pipe sections are 36 years and 88 yrs.
Unit 3- Upper Reheater Tube	2020	None reported	As of May 2020, all 60 of leading-edge RH tubes in Unit 3 have been pad welded. The wall loss rates are very high, ranging from 12 mpy to 40 mpy. Because of these very high wall loss rates, it is recommended that the wall thickness of the Unit 3 leading edge RH tubes be re-evaluated within 3 years
Unit 3- Roof Tube	2020	None reported	The tube had not experienced appreciable wall thickness loss.
Unit 3 – Burner Windbox	2020	Not clear if this issue has been resolved.	In 2020, B&W performed an Engineering Study of this cracking phenomenon, and suggested mitigating strategies. Solution was adding expansion folds to the floor plate and side plate of the inner casing, and to the outer casing.
Unit 3 Main Steam Turbine Terminal	2020	None Reported	There is no evidence of creep voids or further microstructural degradation in the 2020 microstructures. It is recommended that this location be re-examined by PAUT, MT and metallographic replication within 3 years.
Unit 1 – SH6 Header Outlet Nozzle Welds	2019	None Reported	TEAM Industrial (NDE contractor) performed an MT evaluation of the nozzles and found that they were free of indications.

Unit 1- East Hot Reheat Combined Stop Valve	2019	None Reported	Applus RTD (NDE contractor) performed a phased array UT (PAUT) evaluation of the east hot reheat CS valve and found that it was free of indications.
Unit 1- Main Steam Turbine Stop Valve	2019	None Reported	Applus RTD (NDE contractor) performed a phased array UT (PAUT) evaluation of the main steam turbine stop valve east outlet piping and found that it was free of indications
Unit 1- Boiler Floor Tubes	2019	None Reported	None of the evaluated locations exhibited a wall thickness reading that was below 0.140", which is the thickness at which B&W recommends refurbishing/replacing furnace wall tubing.
Unit 1- Waterwall tube	2019	None Reported	Measurements at numerous points around the tube circumference showed the current wall thickness to be above the specified nominal value.
Unit 2- SH-6 Header Outlet Nozzle Welds	2019	None Reported	TEAM Industrial (NDE contractor) performed an MT evaluation of the nozzles and found that they were free of indications. This location should continue to be monitored for crack growth.
Unit 2- HP Heater #6 By-pass Piping	2019	None Reported	A comparison of the 2019 data with the 2016 data indicates that the wall has not experienced significant loss over the past 3 years.
Unit 2- Steam Drum Downcomer Nozzle	2019	None Reported	The MT evaluation on this nozzle in 2016 found no indications. This location should continue to be monitored to determine if the indications increase in size and/or number.
Unit 2- Boiler Floor Tubes	2019	None Reported	None of the evaluated locations exhibited a wall thickness reading that was below 0.140", which is the thickness at which B&W recommends refurbishing/replacing furnace wall tubing
Unit 2- Waterwall Tube	2019	None Reported	Isolated pits up to 0.014" deep were also observed, but no appreciable general wall loss.
Unit 3- HP Heater #5 Inlet Bend	2019	8	Considering the FAC rates and the minimum remaining wall thickness measured in 2019, the ASME minimum wall thickness will be reached within ~8 years.
Unit 3 – Economizer Inlet	2019	7	Considering the FAC rates and the minimum remaining wall thickness measured in 2019, the ASME minimum wall

			thickness will be reached within ~7 years.
Unit 3- RH Leading Edge Bends	2019	None Reported	
Unit 3- RH Outlet Header and SSH Outlet Header	2019	None Reported	The MPI evaluations revealed no defects at the tube-to-header welds.
Unit 3- RH Inlet Header and SSH Outlet Header	2019	None Reported	Continue monitoring.
Unit 3- Boiler Floor Tubes	2019	None Reported	The bend extrados wall thickness should be monitored in the future to ensure that the thickness remains at or above 0.147”. Additional pad weld will be required in the future.
Unit 3- Waterwall Tubes around Burner Openings	2019	None Reported	The wall thickness of the tubes surrounding the burners should continue to be monitored and pad welds should be applied at locations where wall thickness readings are <0.148”.
Unit 3- Waterwall Tube	2019	None Reported	Isolated pits up to 25 mils deep were also observed, but no appreciable general wall loss.

Table 3-1 Summary of Degradation Observed in HTGS Headers

Component	Degradation		
	Unit 1	Unit 2	Unit 3
Economizer Inlet Header	• ID thermal fatigue / ligament cracking • Wall thinning / FAC	• ID thermal fatigue / ligament cracking • Wall thinning / FAC	• ID thermal fatigue / ligament cracking
RH Inlet Header	NONE	NONE	NONE
RH Outlet Header	NONE	NONE	• Near minimum wall thickness • Thermal fatigue circumferential cracking (drain to header weld)
SSH Inlet Header	NONE	NONE	NONE
SSH Outlet Header	NONE	• Cracking in outlet nozzle and stub tube welds	NONE
WW Lower Header	NONE	NONE	• Pitting corrosion
WW Upper Header	NONE	NONE	NONE
High Pressure Feedwater Header	----	----	• Wall thinning / FAC
PSH Outlet Header	----	----	NONE

Table 3-2 Summary of Degradation Observed in HTGS Pipes

Component	Degradation		
	Unit 1	Unit 2	Unit 3
Economizer Inlet Header Piping	• Wall thinning / FAC	• Wall thinning / FAC	----
Feedwater Piping	• Wall thinning / FAC in some locations	• Wall thinning / FAC	• Wall thinning / FAC
Link Piping to Attemperator	NONE	• Wall thinning / FAC	• Wall thinning / FAC
Boiler Feed Pump Piping	----	• Wall thinning / FAC at several locations	• Wall thinning / FAC of Y
Cold Reheat Steam Piping	----	NONE	• Pitting
Hot Reheat Steam Piping	----	NONE	• Wall thinning
Main Steam Piping	----	NONE	• Wall thinning
RH Attemperator Refill Piping	----	----	• Wall thinning / FAC
SSH Attemperator Piping	----	----	NONE

Table 3-3 Summary of Degradation Observed in HTGS Steam Drums

Component	Degradation		
	Unit 1	Unit 2	Unit 3
Steam Drum	• Thermal fatigue cracking at downcomer nozzles	• Thermal fatigue cracking at downcomer nozzles	NONE

Table 3-4 Summary of Degradation Observed in HTGS Supports

Component	Degradation		
	Unit 1	Unit 2	Unit 3
Hangers and Supports	NONE	----	• RH inlet hanger collar failure due to temper embrittlement
Steam-cooled Roof Hangers	----	----	NONE

Table 3-5 Summary of Degradation Observed in HTGS Tubes

Component	Degradation		
	Unit 1	Unit 2	Unit 3
Economizer Tubes	• Wall thinning / FAC	• Wall thinning / FAC	• Near minimum wall thickness
Lower Vestibule Feeder Tubes	• Wall thinning / FAC • Internal Pitting	----	----
Lower WW Header Feeder Tubes	NONE	NONE	• Pitting corrosion
WW Tubes	NONE	NONE	• History of corrosion fatigue cracking
PSH Tubes	----	• Wall thinning	• Wall thinning
SSH Tubes	----	----	• Wall thinning
RH Tubes	----	----	• Wall thinning
Riser Tubes	----	----	NONE

2017 Condition Assessment

Table A1 Results and Recommendations from the 2017 NDE Inspections

Unit	Component/Location	Inspection	Findings	Recommendations
Unit 1	Economiser Inlet Header	Internal Visual	Borehole cracking unchanged. Discolouration of internal surface noted.	No re-inspection required to end of life. Or re-inspect in 3 years.
Unit 1	Lower Vestibule Feeder Tubes	Phased Array Ultrasonic Testing	No cracking found. Minor internal pitting noted	No re-inspection required to end of life.
Unit 2	Feedwater - BFP Discharge: Economizer Inlet Header Piping	UT Grid for Flow Accelerated Corrosion	Measurements below minimum wall thickness found. Assessed for continued operation. Bend replaced in fall 2017.	No re-inspection required to end of life.
Unit 2	Feedwater - BFP Discharge: Flow Element 554	UT Grid for Flow Accelerated Corrosion	Measurements below minimum wall thickness found. Pad weld applied. FE replaced in fall 2017.	No re-inspection required to end of life.
Unit 2	Feedwater – Heater No.6 Bypass Piping	UT Grid for Flow Accelerated Corrosion	Re-inspection of 2016 pad weld. All locations were above minimum wall thickness. Adjacent pipe is limiting.	Re-inspection of bend in 2 years.
Unit 3	Feedwater – Heater No.6 Discharge Piping	UT Grid for Flow Accelerated Corrosion	Re-inspection of 2014 pad weld. All locations were above minimum wall thickness. Adjacent pipe is limiting.	Re-inspection of bend in 4 years.
Unit 3	Main Steam Turbine Terminal	Replica, PAUT, UT, Magnetic Particle	No indications of creep found. Microstructure shows high-temperature creep damage consistent with previous findings. Wall thickness noted to be slightly lower than previously report.	Continue recommended monitoring in 3 years.

2015-2016 Condition Assessment

Table A1: Results and Recommendations from 2015 and 2016 NDE Inspections

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 1	Steam Drum Downcomer	MT for crack detection	2016: Magnetic Particle Examination was carried out as per scope on all accessible areas on the furthest West Downcomer located inside the Unit 1 steam drum. No relevant indications were found and the location was acceptable to code requirements [9].	Re-inspect in 2019.
	Feedwater - BFP Discharge: Economizer Inlet Header Piping	UT Grid for Flow Accelerated Corrosion	2015: All locations were above the minimum wall thickness. One area adjacent to a weld found a band of low wall thicknesses.	Replacement of the thinned section to be completed in 2017 outage.
			2016: All locations above the minimum wall thickness. Location immediately adjacent to lower weld on both sides had low wall thicknesses likely contributed to by counterbore [5][6].	
	Feedwater - BFP Discharge: Flow Element 554	UT Grid for Flow Accelerated Corrosion	2015: All locations were above the minimum wall thickness though some areas are near the minimum.	Re-inspection not required before planned end of life – recommended re-inspection interval of 6 years.
			2016: All locations above the calculated pressure based minimum wall thickness [5][6].	
	Feedwater - Heater No. 6 Bypass Piping	UT Grid for Flow Accelerated Corrosion	2016: All locations above calculated pressure based minimum wall thickness [5][6].	Re-inspection not required before planned end of life – recommended re-inspection interval of 17 years.
	Feedwater - BFP Discharge: West Pump Discharge Elbow and Reducer	UT Grid for Flow Accelerated Corrosion	2015: One point was below the pressure based ASME minimum wall thickness, and other low areas were found adjacent to the inlet weld of the reducer (on the 8" diameter side). Weld buildup was completed to increase the wall thickness. The re-inspection time will depend on the as-left wall thickness.	Re-inspection not required before planned end of life – recommended re-inspection interval of 7 years.
			2016: All locations above calculated pressure based minimum wall thickness. No locations with significantly low wall thicknesses [5][6].	

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 1	Feedwater – BFP Discharge Piping East Pump and Y Connection	UT Grid for Flow Accelerated Corrosion	2016: Removed from scope based on favourable results from 2016 Unit 2 inspection on similar area [5].	No immediate action is required.
	Hot Reheat Combined Stop Valve (CSV) Outlet welds	Phased Array Ultrasonic Testing (PAUT), Radiographic Testing(RT) after PAUT, Metallographic Replication for creep	2016: Weld locations were inspected by PAUT. West CSV Outlet Weld inspection results were acceptable with no relevant indications at the time of inspection. East Hot Reheat CSV Outlet (Valve to Pipe Butt) had one ID connected indication in the root area, approximately 30 mm long, centered 125 mm clockwise of 12 o' clock. Indication was suspected to be a lack of fusion defect formed during fabrication but could not be confirmed with only single sided scanning access 0. Radiographic testing (RT) was conducted on the indication location and no discontinuities were found [15]. Due to uncertainty as to the nature of the indication, it was ground out and repaired 0. Additionally, two replicas were taken, 90° apart at each of three circumferential weld locations. No appreciable damage was observed. Weld microstructures consisted of small spherical carbide particles evenly distributed throughout a ferrite matrix [11].	Conduct PAUT re-inspection on either the East or West weld location in 3 years as outlined in the Phase 2 Assessment [2]
	Main Steam Stop Valve Outlet Welds (East and West)	Phased Array Ultrasonic Testing (PAUT),	2016: Weld locations were inspected by PAUT. No relevant indications were found at time of inspection. Inspection results were acceptable.	Re-inspect either the East or West weld location in 3 years as outlined in the Phase 2 Assessment. [2]
	Feedwater - Low Pressure Elbow Upstream of Deaerator	UT Grid for Flow Accelerated Corrosion	2015: All locations were above the minimum wall thickness (70% of nominal wall thickness for low pressure piping). An unusual variation in the wall thickness was observed; this may be FAC but it is not an integrity concern.	2015: Re-inspection is recommended in 8 years
	Feedwater - BFP Discharge: East Attemperator Station	UT Grid for Flow Accelerated Corrosion	2015: All locations were above the calculated pressure based ASME minimum wall thickness. On the reducer immediately upstream of the inlet control valve, one band showed a large variation in the wall thickness and thus a higher wall loss rate. The date of installation of the attemperator piping could not be confirmed, thus there is some uncertainty in the wear rate and re-inspection time.	2015:The installation date for the piping needs be confirmed. Re-inspection is recommended in 6 years.

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 1	Feedwater - BFP Recirculation East: U/S and D/S of FV 544	UT Grid for Flow Accelerated Corrosion	2015: All points were well above the calculated pressure based ASME minimum wall thickness.	2015:Re-inspection is recommended in 21 years.
	SH6 Outlet Nozzles (East and West)	Phased Array Ultrasonic Testing (PAUT), Metallographic Replication, Magnetic Particle Inspection (MPI) (2013,2015)	In 2013, creep damage was reported at the toe of weld on the east nozzle. The damage was removed and weld repaired. MPI only was performed on the west nozzle; no damage was found.	Re-inspect in 6 years with PAUT, replication and MPI as recommended by the Level 2 Condition Assessment[2]
			In 2015, a small crack was found at the bottom of the east nozzle weld (~3 mm in length), about 20 mm from the previous repair. No microscopic creep damage was observed in the replicas. Replicas were taken at the bottom (6 o'clock position) of both nozzle welds. Microstructure showed spherical carbide particles in a matrix of ferrite grains. Assuming the original microstructure consisted of pearlite and ferrite, this microstructural transformation is not unexpected for the age of the component. PAUT found no mid-wall creep crack development. MPI inspection of the full circumference of the nozzles did not find any indications.	
			2016: East and West nozzle weld locations were inspected by PAUT. No relevant indications were found. Inspection results were acceptable. Metallographic replication was conducted on the East nozzles only (time and access constraints prevented replications on the West SH6 nozzle). No appreciable damage was observed. Weld microstructures consisted of small spherical carbide particles evenly distributed throughout a ferrite matrix [11].	
Unit 2	Feedwater - BFP Discharge: Economizer Inlet Header Piping	UT Grid for Flow Accelerated Corrosion	2016: All locations were above pressure based minimum wall thickness. One area of thinner wall thicknesses in the intrados of the upstream bend [5][7].	Weld build-up planned in 2017 to increase margin and extend re-inspection interval.
	Feedwater – BFP Discharge: Flow Element 554	UT Grid for Flow Accelerated Corrosion	2016: All locations were above the calculated pressure based minimum wall thickness. One area of thinner wall thickness on the underside of the straight pipe [5][7].	Weld build-up planned in 2017 to increase margin and extend re-inspection interval.

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 2	Feedwater – Heater No.6 Bypass Piping	UT Grid for Flow Accelerated Corrosion	2016: All locations above pressure based minimum wall thickness with evidence of significant FAC. One location was resampled due to unusual low point but this low value did not appear in resample. Weld build-up was conducted on the bend immediately upstream of the Heater 6 inlet to provide additional margin. The horizontal bend downstream of tee-connection also has a row of low thicknesses [5][7].	Recommend bend downstream of tee for re-inspection in 2 years.
	Feedwater – BFP Discharge: East Pump and Y Connection	UT Grid for Flow Accelerated Corrosion	2016: All locations above pressure based minimum wall thickness with minor to moderate FAC [5][7].	Re-inspection not required before planned end of life – recommended time of 7 years.
	Inlet Bends of East and West Superheater Attemperator Stations	UT Grid for Flow Accelerated Corrosion	2016: All locations above ASME minimum wall. Evidence of significant FAC but many bends show areas with wall thickness considerably greater than nominal which may have overestimated wear rates. Significant margin is still available [5][7].	Re-inspection not required before planned end of life – recommended time of 10 years
	Feedwater - BFP Discharge: Full Flow Tee D/S HP FW Heater 6	UT Grid for Flow Accelerated Corrosion	2015: All measured areas are above the ASME code calculated minimum wall. The region shows evidence of moderate wall loss due to FAC.	2015: Based on the calculated wear rate the next re-inspection is recommended in 5 years.
	Feedwater - BFP Discharge: Pump 1 (West) Discharge Piping	UT Grid for Flow Accelerated Corrosion	2015: All measured areas are above the ASME code calculated minimum wall. All segments of this piping show moderate evidence of wall loss due to FAC.	2015: Based on the calculated wear rate the next re-inspection is recommended in 8 years.
	Feedwater - BFP Discharge: East Attemperator Station	UT Grid for Flow Accelerated Corrosion	2015: All measured areas are above the ASME code calculated minimum wall. The apparent difference in the margin upstream of the valve is still evident.	2015: Re-inspection is recommended in 14 years.
	Boiler #2 – Superheater Front Horizontal Spaced Outlet Heater SH-6	Phased Array Ultrasonic Testing (PAUT)	2016: Long seam weldment was inspected. No major voids/cracking found [13].	No further inspection is required for this component.
	Lower Vestibule Feeder Tubes	Phased Array Ultrasonic Testing (PAUT)	2015: Inspection was conducted on six (6) bends. No fatigue crack or other degradation was found.	2015: No further inspection is required for this component.
	RH2	Metallographic Macro-Etch	2015: A longitudinal weld on the south side of the header was confirmed.	2015: No further inspection is required for this component at this time. If the recommended PAUT inspection of the SH6 header seam weld finds damage, the RH2 seam should also be inspected.

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 2	Boiler Stop Valve Inlet Weld	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	2015: PAUT found no evidence of mid-wall creep cracking. Replicas found no visible evidence of creep damage. Microstructure showed small, spherical carbide evenly distributed in ferrite matrix; this is not unexpected given the operating hours on the unit.	2015: Since there was no creep damage detected, no further inspection of this weld is necessary.
	MS West Turbine Terminal	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	2015: Replicas found no visible evidence of creep damage. Microstructure showed small, spherical carbide evenly distributed in ferrite matrix; this is not unexpected given the operating hours on the unit. PAUT found no evidence of mid-wall creep crack development	2015: No further inspection of this location is necessary.
	SH-6 Nozzle East/West	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	In 2012, multiple cracks were identified by MT in the weld on the east and west nozzles. The cracks were believed to be original fabrication defects. The majority of the damage was removed by grinding but small micro-cracks (not visible with MT) remained. A weld repair was applied to the bottom of the east nozzle to restore the wall thickness. In 2015, small cracks (intergranular and disjointed, ~2.5mm in length) were observed on the bottom of both the east and west nozzle welds. In the east nozzle, cracks were oriented in the weld material near the header fusion line. In the west nozzle, cracks were oriented within the heat affected zone (HAZ). The cracks were ground out; subsequent MPI found no reportable indications. PAUT found no evidence of mid-wall creep crack development. A longitudinal weld was located on the west end of the header, on the north side. Replication was performed 2 m inboard from the west end. No evidence of surface cracking or creep damage was found.	2015: The observed cracks are likely to be fabrication damage that was not removed during the previous repair. Since volumetric inspection found no evidence of cracking, inspections can return to the recommended 3 year inspection interval, alternating between Units 1 and 2 (for an overall 6 year inspection interval on each unit). The entire surface of the weld should be ground smooth, to improve the sensitivity of MPI. PAUT of the seam weld to look for sub-surface creep damage is recommended in the next outage.

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 2	Steam Drum East-most Downcomer	Wet Fluorescent Testing	2015: The inspection found no Indications.	2015: Periodic inspection should continue: one end (one downcomer) every 3 years, alternating ends for both Units 1 and 2.
Unit 3	Feedwater - BFP Discharge: HP Heater No. 6 Bypass	UT Grid for Flow Accelerated Corrosion	2015: Initial inspection found one measurement below the minimum wall thickness on an elbow. Re-inspection with a finer grid found several locations below the minimum. The elbow was replaced. FAC is evident in the bypass line.	2015: Re-inspection is recommended in 3 years.
	Feedwater - BFP Discharge: Full Flow Tee D/S HP FW Heater No. 6 and Bypass Tee Connection	UT Grid for Flow Accelerated Corrosion	Evidence of FAC was seen in the wall thickness data for the discharge bends, the tee and the bypass piping. There are a few thinned areas and a few isolated low points but they are all above the minimum required wall thickness.	2015: Re-inspection is recommended in 3 years.
	Feedwater - BFP Discharge Piping Eccentric Reducer and Y - Repairs	UT Grid for Flow Accelerated Corrosion	2015: The inspected piping shows evidence of FAC. One area had a measurement below the calculated minimum wall thickness. Three other areas had insufficient wall thickness for remaining life. Most of the low measurements were immediately adjacent to a weld so there is likely an effect of the counterbore contributing to the observed wall thinning. Weld repairs were applied.	Recommend replacement of piping at Y connection in 2 years.
			2016: The repair inspections showed evidence of moderate FAC. All were above ASME minimum wall thickness but 3 of the locations are near end of life [5][8].	
	Feedwater – BFP Discharge: Flow Element 3595 on Emergency Reheat Attemperator Refill Line	UT Scans for Minimum Wall Thickness	2016: All piping was above ASME minimum wall thickness with evidence of moderate FAC. Five of the fifteen scan locations require re-inspection before planned end of life [5].	Recommend re-inspection in 2017. Include both minimum and maximum wall thickness measurements at each location.
	Feedwater - Low Pressure (LP) Feedwater Flow Element	UT Grid for Flow Accelerated Corrosion	2015: The measurements show evidence of FAC but all the measurements were above the minimum.	2015: Re-inspection is recommended in 21 years.

	Component/Location	Inspection	Findings[1]	Recommendations
Unit 3	Feedwater - BFP Discharge: Bend U/S of Heater 5 Inlet	UT Grid for Flow Accelerated Corrosion	2015: All measured areas are above the minimum wall thickness. Both segments of this piping show evidence of wall loss due to FAC.	2015: Re-inspection is recommended in 4 years.
	Economizer Inlet Header	Remote Visual	2015: Inspection found the same cross ligament borehole cracking that was seen in 2014.	2015: Re-inspect visually in 3 years, and complete a sample crack depth measurement with PAUT. Mitigate occurrence of thermal transients.
	Lower Vestibule Waterwall Feeder Tubes	Phased Array Ultrasonic Testing (PAUT)	2015: PAUT of 10 tubes found no crack. Isolated pitting was noted in one tube. Average wall thickness was 11.4 mm; wall thickness at the pit was 10.4 mm.	2015: A visual inspection of the inside diameter of the pitted feeder tube is requested to determine if the pitting is active (i.e. if orange corrosion products are visible).
	Main Steam East Boiler Link	Ultrasonic Testing (UT)	2015: The minimum measured wall thickness (1.553) is greater than the minimum wall thickness (1.230").	2015: No further inspection is required for this location.
	Cold Reheat Bleed Steam Line	Magnetic Particle Inspection	2015: The inspection found no indications.	2015: No further inspection is required for this location.

Appendix D
Firewater Inspection

Hydrant	Static Pressure (psi)	Date of Test	Comment	Pass / Fail	Year of Manufacture
A	114	20-Aug-21	Hydrant leaked after it was fully closed and had to be drained via 2.5” connection. Recommend repair before temperature drops. Exterior paint in good condition.	F	1986
B	102	20-Aug-21	Exterior paint in good condition.	P	2020
C	106	20-Aug-21	Exterior paint in good condition. Could not get large cap off.	P	1994
D	108	20-Aug-21	Hydrant is located in heavy brush/growth making it difficult to locate. Growth should be cut back. Hydrant didn’t drain properly. Recommend repair before temperature drops. Exterior paint in good condition.	F	1969
E	120	19-Aug-21	Exterior paint in good condition. Water came up in the ground during the static test. Nut used to take off front cover is broken and would not come off. Recommend repair before temperature drops.	F	1967
F	121	19-Aug-21	Exterior paint in good condition. Water came up in the ground around the hydrant while conducting pressure test. Cover gasket needs to be replaced.	F	1967
G	104	19-Aug-21	Stem is deformed. When hydrant is turned on water shoots up out of top of hydrant. Gaskets in the covers are dry rotted and need to be replaced. Exterior paint in good condition.	F	1969
H	N/A	19-Aug-21	Hydrant H is isolated for nearby maintenance and was not static or leak tested. Exterior paint is in good	N/A	1969

Hydrant	Static Pressure (psi)	Date of Test	Comment	Pass / Fail	Year of Manufacture
			condition. Pass/ Fail inspection could not be completed at this time.		
I	106	20-Aug-21	Missing gaskets in the cap. Recommend replacing. Exterior paint in good condition.	P	1989
J	96	19-Aug-21	Signs of rust on hydrant, and stem shows sign of wear. Missing gasket on covers. Recommend replacing missing gaskets.	P	1989
K	94	19-Aug-21	Signs of rust on hydrant.	P	1988
L	90	20-Aug-21	Exterior paint in rough condition with signs of rust. Cap is missing a gasket. Recommend replacing missing gasket.	P	1969
M	104	20-Aug-21	Exterior paint in good condition.	P	2020
N	114	20-Aug-21	Exterior paint in good condition.	P	2019
O	116	20-Aug-21	Signs of rust on the hydrant. One of the nuts is broken and missing one cap gasket. Recommend replacing missing gasket and broken nut.	P	1969
P	N/A	19-Aug-21	Visual inspection only. Top cover is cracked. Nuts on two covers are broken and signs of rust showing. Hydrant used for previous training and has not been maintained. Exterior paint in poor condition. Passed but recommend repairs.	F	1988
Q	N/A	19-Aug-21	Visual inspection only. Nuts and covers are broken and could not get the big cover in front to open. Signs of rust all over hydrant. Hydrant used for previous training and has not	P	1988

Hydrant	Static Pressure (psi)	Date of Test	Comment	Pass / Fail	Year of Manufacture
			been maintained. Exterior paint in poor condition		
R	121	19-Aug-21	This hydrant is identified as Hydrant J on adjacent sign. This is Hydrant R according to drawing A1-238-04-0170-016. Signage to be updated accordingly. Exterior paint is in good condition.	P	2005
CT Building Northwest	121	19-Aug-21	Exterior paint in good condition.	P	2014
CT Building Southwest	122	19-Aug-21	Exterior paint in good condition.	P	2014
CT Building Southeast	121	19-Aug-21	Exterior paint in good condition.	P	2014
CT Building Northeast	122	19-Aug-21	Missing gasket on the 2.5”.		2014
North of Diesel Pump House	78	24-Aug-21	Exterior paint in good condition.	P	2014
Northeast of Diesel Pump House	86	24-Aug-21	Exterior paint in good condition.	P	2014
South of Diesel Pump House	84	25-Aug-21	Missing set screw on north side 2.5” connection. Recommend repairing cap.	P	2014
Far South of Diesel Pump House	78	25-Aug-21	Exterior paint in good condition.	P	2018

Appendix E
Hydrant Static Pressure Test Images

Figure 7-1: Static Testing on Firewater Hydrant Northeast of CT Building

Figure 7-2: Acoustic Testing on Hydrant Gp

Appendix F
Cooling Water Sumps ROV Inspection

Remote Operated Vehicle Survey
Cooling Water Sump Pit Inspections

1	July 6, 2021	Issued for Information/IFI	**Alex R. Afonso** VP & Operations Manager	**Steve Chafe** President & GM	**Alex R. Afonso** VP & Operations Manager	**Alex R. Afonso** VP & Operations Manager
Rev.	Issue Date	Description	Made by	Checked by	Discipline Approval	Project Approval

TABLE OF CONTENTS

1. INTRODUCTION

Located in the Town of Holyrood the Holyrood Thermal Generating Station is a thermal generating facility that was put in service in 1969 and consists of three turbines with a total generating capacity of 490 megawatts.

For 2021 Hatch has been contracted to perform a review of specific plant assets as part of the Holyrood Life Extension project. Afonso Group Limited have been contracted by Hatch to perform an ROV Survey of the three cooling water pits.

2. REVISION DETAILS

Revision	Location of Change	Brief description of Change
1		Issued for Information - IFI

3. PURPOSE AND SCOPE

The purpose of this procedure is to provide a detail description on the equipment required and methods to be used by the inspection team to carry out a detailed inspection of the condition of the concrete floor, walls, and ceiling in each pit. All information will be collected with supporting pictures and videos and handed over to the Primary Consultant for analysis.

4. DEFINITIONS AND ABBREVIATIONS

Client	Nalcor Energy
Primary Consultant	Hatch
Subcontractor	Afonso Group Limited
AGL	Afonso Group Limited
TBT	Toolbox Talks
JHRA	Job Hazard Risk Analysis
DRP	Daily Report Sheet
ISO	International Standards Organization

5. METHOD

Below is a list of equipment requirements and a step-by-step plan to execute this task:

Equipment List:

1. Wrenches, miscellaneous general tools
2. Barricades (supplied by other)
3. ROV
4. Recording Devices

Material List:

1. None

Step by Step Plan

Step	Description	Comments
A	Mobilisation to site	Day 1: St Johns to Holyrood
B	Pre job safety meeting	Day 1: At site and discuss plan, review JHRA, Perform TBT and WSSI. (Daily)
C	Function Test ROV	Day 1 and 2: Daily
D	Deploy and Inspect Cooling Water Pits	Day 1 and 2: Video survey and take measurements
E	Review findings with consultant	Day 1&2: Review field notes prior to demob
F	Demob	Day 2: Holyrood to St. John’s
G	Final Report	1 week estimate for deliverables

Times are estimates only and subject to change.

Details of Methodology

Step D Breakdown (Inspect cooling water pits)

1. Barricade must be set up around the manhole/access point perimeter.
2. No work will be performed inside the barricade. All work will be manageable from outside by lowering the small suitcase size ROV into the water. This ROV weighing approximately 5 KG can be lowered by one person. This will be communicated between the tether handler and ROV pilot.
3. Once the function test is completed the tether handler will lower a weighted hi vis rope in the water at the manway for Pilot to use as a reference point.
4. Once the ROV enters the water the pilot will dive to the bottom. From the reference rope the pilot will fly the ROV to the right covering two walls then return to the reference rope. This process will continue for a complete viewing of the walls and ceiling structure. Once the right side is completed the pilot will continue to survey the left side portion in the same manner.
5. Once the ROV is retrieved (daily) for the day the manways must be re installed prior to leaving.

For each survey, a live feed monitor will be set up at the surface for viewing and continuous monitoring. The team will document all finding for each sump pit.

Special note: 120-volt power is required for all inspection cameras. Client to provide otherwise contractor will supply generator.

Step E: Survey field notes will be reviewed by the consultant in the field to ensure all required data is collected. All video files will be backed up and closed off meeting completed prior to departure. Final report will follow and will be provided in an electronic format and video files transferred via the One Drive Cloud where the consultant can download and share with the client. Final report will include video, data tables and findings and images as required.

Special note: JHRA, WSSI and TBT must be reviewed in the field and before the start of the job. Review of these forms will be field level HA.

6. REFERENCES

Document Title	Document Number
Afonso Corporate Safety Manual	Manuals 1,2,3,4
OHS Act and Regulations	

7. HEALTH, SAFETY, ENVIRONMENT & QUALITY

Afonso Group Limited is an ISO 9001, 14001 and OHSAS 45001 certified company who aims to provide a safe environment for its employees, subcontractors, and client. Our goal is performing the work in a timely manner keeping safety and the forefront while ensuring our environment is protected.

To ensure that we maintain a safety culture it is critical that the team fully understand the safety plan, job hazard risk assessments, and fully comply with all local regulations and guidelines and our HSEQ Manual.

To ensure this is maintained the AGL Crew will be filling out daily status reports, time sheets and performing daily toolbox talks. For complete form list refer to the Appendix.

8. HAZARD RISK ASSESSMENT

RISK ASSESSMENT FORM

LOCATION: Holyrood Hydro	**DATE: July 2021**
TASKS: Remote inspection (ROV) Cooling water sump pits	**REFERENCE #: 24993-22**

Special Notes:

1. All personnel working or visiting the project site will be required to comply with all Safety regulations.
2. Proper personal protective equipment will be always worn. (Hard hat, safety glasses, safety boots, hi-vis Nomex coveralls, hearing protection.)
3. Toolbox meetings will be held every morning to discuss possible changes that might have occurred in the off shift.
4. Supervisors will assess sight conditions every morning before toolbox meeting to identify new hazards at the project site.
5. All work areas are to be barricaded and tagged to limit access to essential personnel only.
6. Pre check all equipment daily.
7. Review all procedures with parties involved in the task before starting tasks.
8. All personnel on the structure outside the railing must wear a PFD and be attached to the davit system.

STEP	TASK	INITIAL RISK RATE	HAZARDS / RISKS	CONTROL	FINAL RISK RATE	Accepted
0.	Mobilize to site	**2A**	• Driving incident collision • Faulty equipment	• Pre trip inspection, secure all equipment, be cautious and aware of traffic. Drive speed limit. Call office before leaving and when arrived.	**2D**	
1.	Set up inspection equipment.	**3C**	• Faulty Equipment • Fueling genset • Pinch Points • Awkward Lifting of heavy equipment • Slips trips and falls	• Proper pre checks and function tests to be performed by qualified personnel. • Use power from site if available. If not use gen set. Fuel up before arrival. • Two persons assist lift or use of mechanical advantage if any heavy objects are to be moved. • Wear gloves – be aware of pinch areas. • Be aware of surroundings and potential trip hazards on structure and equipment laydown	**4D**	
2.	Camera system to enter water and inspect systems	**4A**	• Delta P Risk - Gates or power and suction / discharge lines (if exist). • Low Visibility • Falling in water/working outside the rails • Active thrusters • Entanglement (stuck ROV)	• Ensure equipment is locked out tagged out. • Use of u/w lights – fitted on ROV. • Work outside the barricades • Hands free of rotating parts do not power up unless free from person and hands. Energize near waterline. • Good tether management, slow and methodical inspection. Be familiar with area and proceed with caution. If in the event ROV becomes stuck – diver intervention would be required if all other retrieval methods failed. .	**4D**	

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

3.	Breakdown system	**3B**	• Damaged equipment • shock	• Thoroughly inspect on breakdown and protect equipment in packaging or moving it. • Make sure all cables are not damaged with risk of shock. De energize at the source.	**4D**	

Signatures

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

UNIT 2 NORTH EAST SUMP
UNIT 2 NORTH WEST SUMP
UNIT 1 NORTH EAST SUMP
UNIT 1 NORTH WEST SUMP
UNIT 2 SOUTH SUMP
UNIT 1 SOUTH SUMP
AREA TO INSPECT
AREA TO INSPECT
AVAILABLE ACCESS POINTS
For details of Bases A to G incl. see Dwg. 238-06-0110-011 (B omitted)
NOTES:
1. Concrete in powerhouse shall be 3500 lb. Concrete in utilidor shall be 3000 lb.
2. Removable handrail: Rails: 1½"φ std. pipe. Posts: 1½"φ E.H. pipe
3. Waterproofing for utilidor: 3-Ply membrane waterproofing shall be applied as specified by the manufacturer. Material shall be the following type supplied by Domtar Constr. Material Ltd. or equal. Bitumen - Foundation coating fibrated. Membrane reinforcing - Glass fab.
4. Water stops: Water stops shall be B. F. Goodrich Koroseal 4500 Type 600-A.
5. Concrete cover: 3" for all formed surfaces, (Walls & base slab) 4" for base slab & unformed surfaces.
6. Concrete cover: 1" Clear for elevated slab, 1½" - beams & grade slabs.
7. For details of grounding cables to be incorporated in the slab see Grounding Plan - Dwg. 238-13-0310-115.
8. All embedded metal parts to be hot dipped galvanized.
9. All concrete surfaces shall receive a F3 finish.
10. Floors & Stairs: Master plate metallic aggregate or an approved equal shall be applied to the floors & stairs at a rate of .75 lb. per square foot in accordance with the manufacturers instructions.
11. Water stops are to be provided for construction joints up to El. 8.00'.
12. Floor loading: Floors designed for 300 lb/ft² L.L.
13. Paint to be in accordance with clause 4.12.03.03 of Specification. (Trash racks)
REFERENCES:
Dwg. 238-06-0110-004 - Excavation plan circulating water piping, pumphouse & utilidor, seal pit.
238-06-0110-005 - Pumphouse - Base slab & Sections - Conc. outline.
238-06-0110-009 - Pumphouse - Sections - conc. outline.
238-06-0110-011 - Pumphouse - Elevated floor plan - Reinforcement.
238-06-0110-012 - Pumphouse - Base slab & sections - Reinforcement.
238-06-0110-013 - Pumphouse - Sections - Reinforcement.
238-13-0310-115 - Pumphouse Grounding
REMOVABLE HANDRAIL DETAIL
ANCHOR BOLT - TYPE X3
ANCHOR BOLTS
CONSTRUCTION ISSUE
NEWFOUNDLAND AND LABRADOR POWER COMMISSION
HOLYROOD GENERATING STATION
PUMPHOUSE - ELEVATED FLOOR PLAN - CONC. OUTLINE.
SHAWMONT RESOURCES JOINT VENTURE
1047 YONGE STREET. TORONTO 5. ONTARIO
2. MAY 1969
J. K. RILEY
238-06
0110
010 - R6

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

HOLYROOD GENERATING STATION
CIRCULATING WATER PUMPHOUSE
GENERAL ARRANGEMENT - PLAN

ORIGINAL DRAWING SEALED BY V.M. PARRISH 1978

SCALE:	None
DESIGNED:	H.Hiscock
DRAWN:	F.Alonso
DATE:	3 FEB 1977
CHECKED:	
APPROVED:	

ELECT. / CIVIL / TRANS. / MECH. / P&C / TELC.

W.O. NO. | DWG. NO. B1 - 1403 - 323 - M002 | REV. 6

DWG.NO.	TITLE
1403-323-M011	NEW COOLING WATER DISCHARGE PLAN AND DETAILS
1403-323-M-10	NEW COOLING WATER DISCHARGE SECTIONS AND DETAILS
1403-323-M009	NEW COOLING WATER DISCHARGE PIPE ROUTING
B-FG-1403-025	PUMPHOUSE LOCATION OF BUBBLER PIPE SLEEVES
A-670-1033	BUBBLER DIP PIPE CIRCULATING WATER SCREENS
1403-322-E002	C.W. PUMPHOUSE UTILIDOR CABLE TRAY LAYOUT and DETAILS
1403-323-M005	C.W. PUMPHOUSE PIPING ARRANGEMENT – SECTION and DETAILS
1403-323-M004	C.W. PUMPHOUSE PIPING ARRANGEMENT – PLAN and FLOW DIAGRAM
1403-323-M003	C.W. PUMPHOUSE GENERAL ARRANGEMENT – SECTION

REFERENCE DRAWINGS

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
6	02-04-22	ISSUED FOR TENDER	K.B.R.			
5	05-10-01	REDRAWN WITH AUXILIARY COOLING WATER ADDED	K.B.R.			
4	16-03-99	FERROUS SULPHATE DOSING SYSTEM ADDED	D.O.			
3	27-3-80	REVISED AS BUILT	G.R.			
2	17-7-78	HOLD REMOVED FOR BUBBLER PIPES	R.G.			
1	26-5-78	GENERAL REVISION ISSUED FOR CONSTRUCTION	R.G.			
0	24-11-77	PRELIMINARY ISSUE	J.W.			

REVISIONS

02-04-19
2:40 PM

PLOT SCALE = 1 : 1 C.A.D.

10. APPENDIX

Project Details Details					
Client:		**Site:**		**Date:**	
Time Start:		**Time End:**		**Draft:**	

Environmental Conditions			
Wave Height:		**Current:**	
Wind :		**Temperature:**	

Dive Details			
Reference Location:		**Dive #:**	
Work Description:		**Video File:**	

Observations

Item	Location	Comments

Anomaly Report

Report Number		Raised by	
Installation		Company	
Space / Tank		Date	

Description of Defect:
Actions taken:
Extent of Defect:

Category *(select one)*					
Crack		General Corrosion		Missing Structure	
Buckle		Pitting Corrosion		Tripped Stiffener	
Coating		Coating Breakdown		Non-Structural	
Other (specify) X					

Location	
Observed from:	
Longitudinal Ref Dimension:	
Transverse Ref Dimension:	
Elevation Ref Dimension:	

References	
NDT Reports	
Drawings / Sketches	

Work Site Safety Inspection

Date:	**Time:**	**Inspection Team**
Location:		
Job Description:		
Job Number:		

√ X: Hazard : Safe/OK Blank: N/A	**Description**	**Hazard Severity (A, B, C)**	**Corrective Action**	**Responsible for Action (Who)**	**Date Completed**	**Initial when complete**
	First Aid Kits					
	Washroom Facilities					
	Kitchen Facilities-Cleanliness					
	Exits Signs					
	Lighting					
	Fire Extinguishers					
	Emergency Escape Plan					
	Potential Slips Trips and Falls					
	Proper use of equipment					
	Handrails					
	Spills					
	Pinch Points					
	Emergency Lighting					
	Proper PPE					
	Tagged NFG					
	Storage of Items					

Hazard Severity Legend: A:(Controls required immediately) B:(Two Days to put controls in place) C:(7 Days to put controls in place)

√ X: Hazard : Safe/OK Blank: N/A	Description	Hazard Severity (A, B, C)	Corrective Action	Responsible for Action (Who)	Date Completed	Initial when complete
	Walkways, Parking					
	Open Manholes					
	Traffic Control					
	Moving Equipment					
	Noise Levels					
	Ventilation					
	Sea State (if applicable)					
	Weather Conditions					
	Workspace Cleanliness					
	Emergency /Rescue Equipment					
	Ladders/Scaffold					
	Potential Strains, Sprains					
	Fire/Flammability Risks					
	Moving Debris					
	Powerline Hazards					
	Power cords					
	PFD (Marine)					
	Storage of compressed gases					
	House Keeping					
Completed **by (Print):**			Reviewed by Manager/Supervisor (Print):			
Completed **by (Sign):**			Reviewed by Manager/Supervisor (Sign)			

Hazard Severity Legend: A:(Controls required immediately) B:(Two Days to put controls in place) C:(7 Days to put controls in place)

Afonso Group Limited
14 Robin Hood Bay Rd
St.John's, NL. Canada A1A 5V3
T: 709.576.6070 F:709.576.1381
www.afonsogroup.com
ISO 9001:2008 Reg. #: 059.A

Oil & Gas *Pipe Inspection & Cleaning* *Diving*

Daily Report Details

Project Name:	*Project Description:*				
Location:	*Purchase Order/Work Order#:*			*Date:*	

Weather Conditions				*Personnel(Initials)*	
Temperature:	*Clear*	*Fair*	*Cloudy*		
Wind Direction:	*Rain*	*Snow*	*Other*		
Wind Speed:					

Description		
Time	*Task*	*Total Hours*

General Comments:

Prepared by:	*Signature:*

Daily Tool Box Talk

Project:	**Date:**
Crew Size:	**Supervisor:**
Task: Emergency Drill	

Review of Tasks:	
Review of JSA, HIRA:	
New Topics:	
Suggestions:	
Actions to be taken:	
Accident/Incident Review	
Other Comments	

Signatures:		

11. CERTIFICATIONS

Certificate of Registration

This is to certify that CWB Registration has registered the Occupational Health and Safety Management System of:

Afonso Group Limited

14 Robin Hood Bay Road St. John's, NF A1A 5V3

to the Occupational Health and Safety Specification:

ISO 45001:2018

Initial Registration	Date of Issue	Date of Expiry	Certificate Number
April 28, 2014	December 21, 2020	August 04, 2023	107792

Scope: Commercial diving services and ROV services (inshore, offshore). Cleaning and inspection of pipe systems, tanks and chambers using high pressure water and vacuum trucks. Inspect wellheads offshore, inspect valves offshore on drill rigs and FPSO's and pipe lining services.

CWB cwbregistration

SCC Accredited CB-MS
OCSM Accrédité CCN

Registrar

Registered by • Enregistré par
cwbregistration

Terms and Conditions governing registration and the use of this certificate are defined in the contract between CWB Registration and the Holder.
Contact the certificate holder for further information related to the scope and boundaries of the registration.

3400E-18-OHS/2018-11

CWB Registration, 8260 Park Hill Drive, Milton, Ontario, Canada, L9T 5V7, Tel: 1-800-844-6790 / (905)-542-1312, Fax: (905) 542-1318, Web: www.cwbgroup.org

Certificate of Registration

This is to certify that CWB Registration has registered the Quality Management System of:

Afonso Group Limited

14 Robin Hood Bay Road St. John's, NF A1A 5V3

to the Quality System Standard:

ISO 9001:2015

Initial Registration	Date of Issue	Date of Expiry	Certificate Number
March 25, 2014	December 21, 2020	August 04, 2023	Q103158-1

Scope: Commercial diving services and ROV services (inshore, offshore). Cleaning and inspection of pipe systems, tanks and chambers using high pressure water and vacuum trucks. Inspect wellheads offshore, inspect valves offshore on drill rigs and FPSO's and pipe lining services.

cwbregistration

SCC Accredited CB-MS
OCSM Accrédité CCN

Registrar

Registered by • Enregistré par • cwbregistration

Terms and Conditions governing registration and the use of this certificate are defined in the contract between CWB Registration and the Holder. Contact the certificate holder for further information related to the scope and boundaries of the registration.

 CWB Registration, 8260 Park Hill Drive, Milton, Ontario, Canada, L9T 5V7, Tel: 1-800-844-6790 / (905)-542-1312, Fax: (905) 542-1318, Web: www.cwbgroup.org

Certificate of Registration

This is to certify that CWB Registration has registered the Environmental Management System of:

Afonso Group Limited

14 Robin Hood Bay Road St. John's, NF A1A 5V3

to the Environmental System Standard:

ISO 14001:2015

Initial Registration	Date of Issue	Date of Expiry	Certificate Number
April 28, 2014	**December 21, 2020**	**August 04, 2023**	**Q103158-2**

Scope: Commercial diving services and ROV services (inshore, offshore). Cleaning and inspection of pipe systems, tanks and chambers using high pressure water and vacuum trucks. Inspect wellheads offshore, inspect valves offshore on drill rigs and FPSO's and pipe lining services.

cwbregistration

SCC Accredited CB-MS
OCSM Accrédité CCN

Registrar

Registered by · Enregistré par
cwbregistration

CWB Registration, 8260 Park Hill Drive, Milton, Ontario, Canada, L9T 5V7, Tel: 1-800-844-6790 / (905)-542-1312, Fax: (905) 542-1318, Web: www.cwbgroup.org

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1000 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #4: North West Sump	**Dive #:**	1
Work Description:	Survey wall and bottom concrete	**Video File:**	044Z and 0437Z

Observations

Item	Location	Comments
1	Unit 4	General swim of walls and bottom.
	NW	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.
		Two video files for this area.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1048 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #4: North East Sump	**Dive #:**	2
Work Description:	Survey wall and bottom concrete	**Video File:**	0454Z

Observations

Item	Location	Comments
1	Unit 4	General swim of walls and bottom.
	NE	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1130 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #4: South Sump	**Dive #:**	3
Work Description:	Survey wall and bottom concrete	**Video File:**	0608Z

Observations

Item	Location	Comments
1	Unit 4	General swim of walls and bottom.
	South	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.
		Note: Stop logs are installed in this unit.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1134 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #3: South West Sump	**Dive #:**	4
Work Description:	Survey wall and bottom concrete	**Video File:**	0422Z

Observations

Item	Location	Comments
1	Unit 3	General swim of walls and bottom.
	SW	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1242 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #3: North West Sump	**Dive #:**	5
Work Description:	Survey wall and bottom concrete	**Video File:**	0736Z

Observations

Item	Location	Comments
1	Unit 3	General swim of walls and bottom.
	NW	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1307 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit #3: North East Sump	**Dive #:**	6
Work Description:	Survey wall and bottom concrete	**Video File:**	0141Z

Observations

Item	Location	Comments
1	Unit 3	General swim of walls and bottom.
	NE	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Some marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1401 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit # 1: South Sump	**Dive #:**	7
Work Description:	Survey wall and bottom concrete	**Video File:**	0926Z

Observations

Item	Location	Comments
1	Unit 1	General swim of walls and bottom.
	South	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1420 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit # 1: North West Sump	**Dive #:**	8
Work Description:	Survey wall and bottom concrete	**Video File:**	014Z

Observations

Item	Location	Comments
1	Unit 1	General swim of walls and bottom.
	NW	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/8/2021
Time Start:	1435 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit # 1: North East Sump	**Dive #:**	9
Work Description:	Survey wall and bottom concrete	**Video File:**	0705Z

Observations

Item	Location	Comments
1	Unit 1	General swim of walls and bottom.
	NE	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/9/2021
Time Start:	853 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit # 2: North East Sump	**Dive #:**	10
Work Description:	Survey wall and bottom concrete	**Video File:**	0142Z

Observations

Item	Location	Comments
1	Unit 2	General swim of walls and bottom.
	NE	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/9/2021
Time Start:	903 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit 2 North East Sump	**Dive #:**	11
Work Description:	Survey wall and bottom concrete	**Video File:**	0859Z

Observations

Item	Location	Comments
1	Unit 2	General swim of walls and bottom.
	NE	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Project Details					
Client:	Hatch	**Site:**	Holyrood Hydro	**Date:**	7/9/2021
Time Start:	919 hrs	**Time End:**		**Draft:**	<5m

Environmental Conditions			
Wave Height:	nil	**Current:**	nil
Wind :	nil	**Temperature:**	>15 degree Celsius

Dive Details			
Reference Location:	Unit 2 South Sump	**Dive #:**	12
Work Description:	Survey wall and bottom concrete	**Video File:**	0919Z

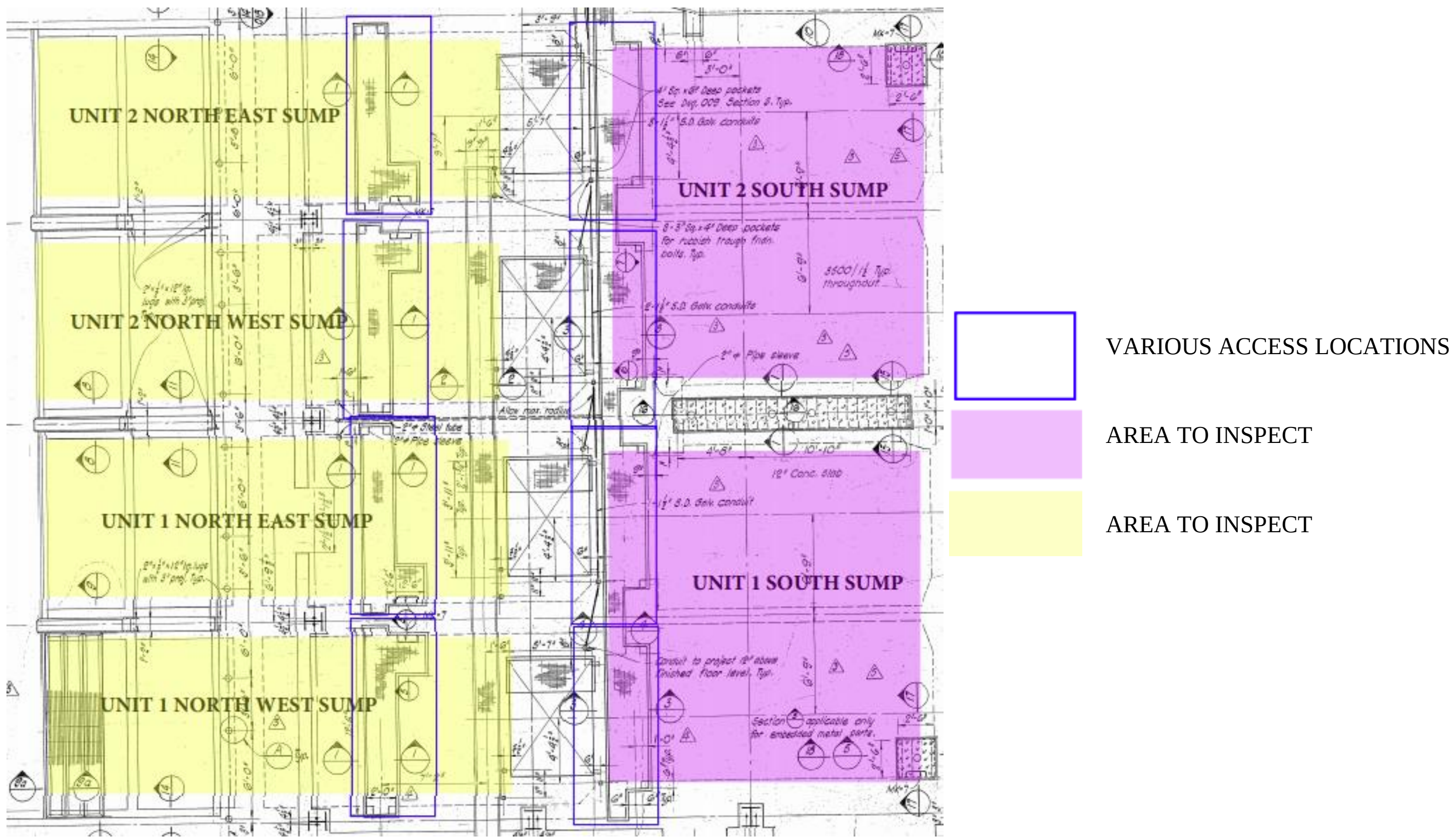
Observations

Item	Location	Comments
1	Unit 2	General swim of walls and bottom.
	South	No anomalies to report with respect to the concrete structure below
	Sump	water portion.
		Heavy marine growth build up on sump floor - can not assess condition.
		Very poor visibility in water - suspended particle.
		Marine growth on concrete walls but for portions visible
		concrete appeared to be in good condition.

Appendix G
Cooling Water Sumps Drone Inspection

Advanced Access
ENGINEERING

21-114-007 - Pumphouse 1 Sump Inspections



Concrete Slab Inspection – Pumphouse 1

Advanced Access Engineering

Conception Bay South

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Sign Off

Table of revisions			
Revision Number	**Revision Date**	**Nature of Revision**	**Approved**
Draft	Victoria Strickland – August 13th, 2021	Initial draft/reporting	SL
Review	Matt Sibley – August 14th, 2021	Reporting/Content review/QC	SL
Release	Shelly Leighton - August 16th, 2021	QC	

Acceptance								
Name	Joanne Norman	Shelly Leighton						
Signature	DocuSigned by: Joanne Norman C570524E6DAB4F2...	DocuSigned by: Shelly Leighton 05F379F857A145B...						
Title-Organization	NL Hydro	Advanced Access Engineering						
Date	8/16/2021	8/16/2021						

Other Endorsement		
Name		**Stamp, Seal, or other Endorsement**
Signature		
Title-Organization		
Date		

Introduction

Advanced Access Engineering were contracted to provide an internal UAV inspection of the sump pits located in Pumphouse One at the Holyrood Thermal Generating station.

The Inspection Shall:

- Capture meaningful data which can be used to determine the overall condition of the structure, i.e. equivalent to a “General Visual Inspection” (GVI).
- Determine the extent of additional close-up surveys if any.
- Collect visual data at specified locations for condition assessments of known anomalies, temporary repairs and/or product buildup.

Inspection Guidance:

The purpose of the GVI is to visually identify items such as gross deformation, gross damage, significant variance from "as-built" specification and breakdown of internal areas. All findings will be reported accordingly. This report will include photographs with accompanying text throughout.

Photographs should only be added where it will assist or add clarity to the reporting. Re-inspect areas that have a known anomaly and report findings accordingly.

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Contents

Inspection Summary

Notes:

Advanced Access Engineering were contracted to provide an internal UAV inspection of the sump pits located in Pumphouse one at the Holyrood Thermal Generating station. The inspection was carried out on 12 August 2021, with observations as described throughout this report.

Pre-Inspection Questions:

Y/N/NA/U (unsure)	
NA	1) Has a severe event (e.g.,) ship impact, severe storm, etc.) occurred since the previous inspection?
NA	2) Have significant changes occurred (e.g., significant load change or major modification, process/service, etc.) since the previous inspection?
NA	3) If response to question 2 is “Yes”, have any new degradation mechanisms been introduced? If so, update Inspection Scope section.
NA	4) If response to questions 1 or 2 is “Yes”, are there any damages as a result of the event/changes? If so, record details on Pictures section.
NA	5) Have all outstanding anomalies been incorporated into the work pack, if any exist? If not, record details on Pictures section.
NA	6) Have all resolved anomalies been incorporated into work pack, if any exist? If not, record details on Pictures section.
NA	7) Are there any ongoing operations that may affect inspection effort? If so, coordinate with operator and record details on Pictures section.

Inspection Requirements:

Y/N/Na	Resource(s)	Comments
Y	1) UAV Person In Control (PIC)	Jason Wade
Y	2) UAV Spotter	Matt Sibley
Y	3) Inspector – CWI/Marine Surveyor	Matt Sibley
N	4) Specialized NDT (UT, ECI, MPI, etc.)	N/A
N	5) Scaffolding	N/A
N	6) Insulation Support	N/A
N	7) Blasting/Surface Preparation	N/A
Y	8) Remote Access Technologies/Technicians	Internal UAV
N	9) Lighting	N/A
N/A	10) Other	N/A

Inspection Scope

Potential Deterioration Mechanisms:

N/A

Reference Documents:

-238-06-0110-010 Stage 1

Wall Thickness Information:

N/A

Location / Design Information:

Holyrood

Work Instruction:

1) Perform inspection using UAV in accordance with checklists and provided drawings.
2) Where applicable, a pre-cleaning visual check is required to note the tideline location, residue buildups, etc.
3) For all anomalies populate Pictures section to describe the location and type of anomaly.
4) The inspector should note in the comments section any additional features concerning vessel integrity.
5) Any significant SHE/Integrity anomalies or areas of concern should be brought to the immediate attention of the primary client contact.

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Existing Points of Interest

Existing Points of Interest (POI)			
No.	Name	Status	Comments

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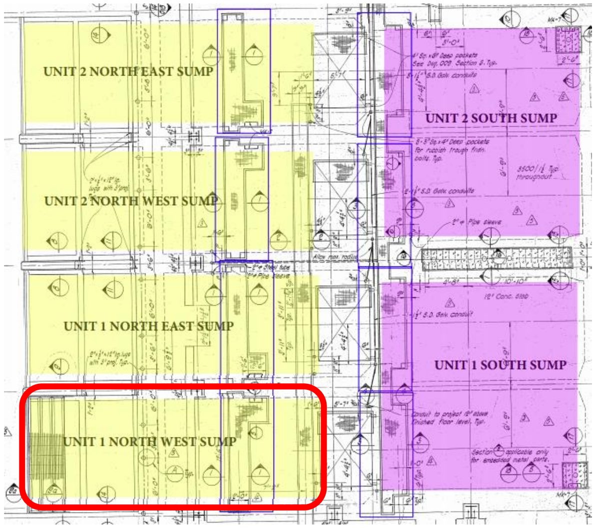

This section will cover
Unit 1 North West Sump

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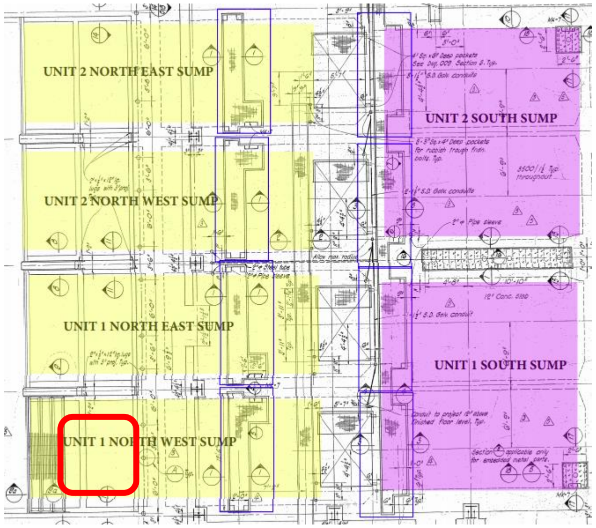
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 North West Sump	Equipment Description:		Code:	-

Reporting



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff of walls and top when first entering the space

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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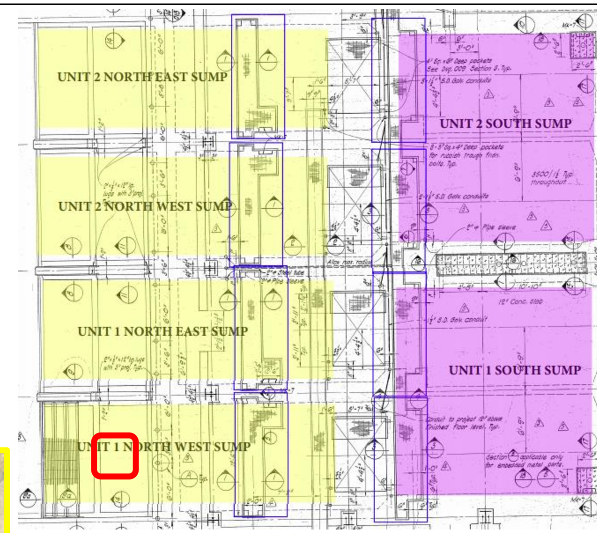

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration	-	-	-	-	Hole in the center area as seen in highlighted close-up picture

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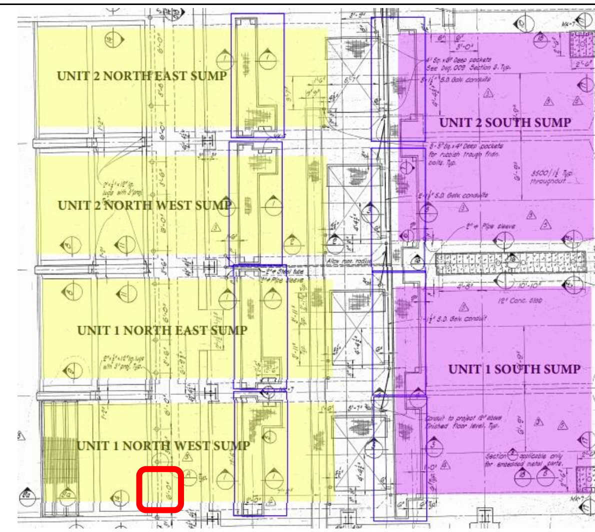
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Hole forming as seen in highlighted picture rebar visible through the concrete.

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Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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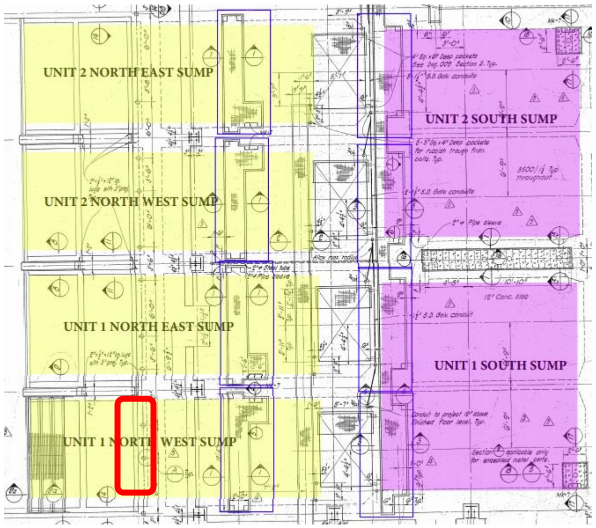

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Typical of what is seen throughout

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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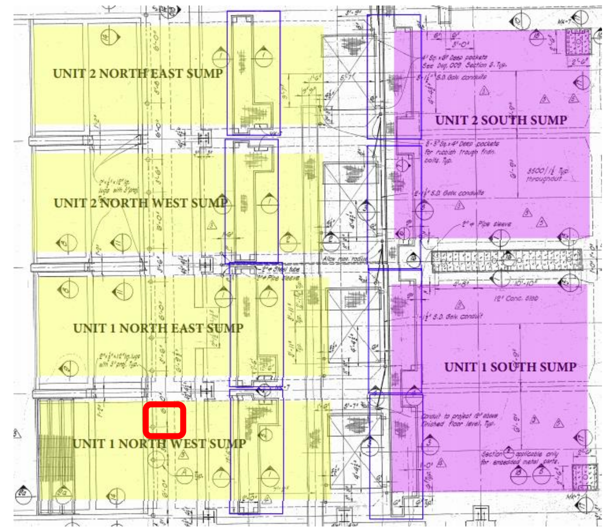
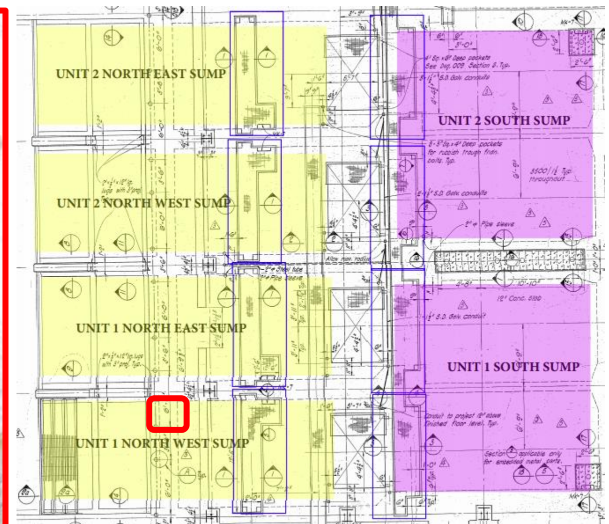


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Crack formed near an entry access point

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete and corrosion of rebar

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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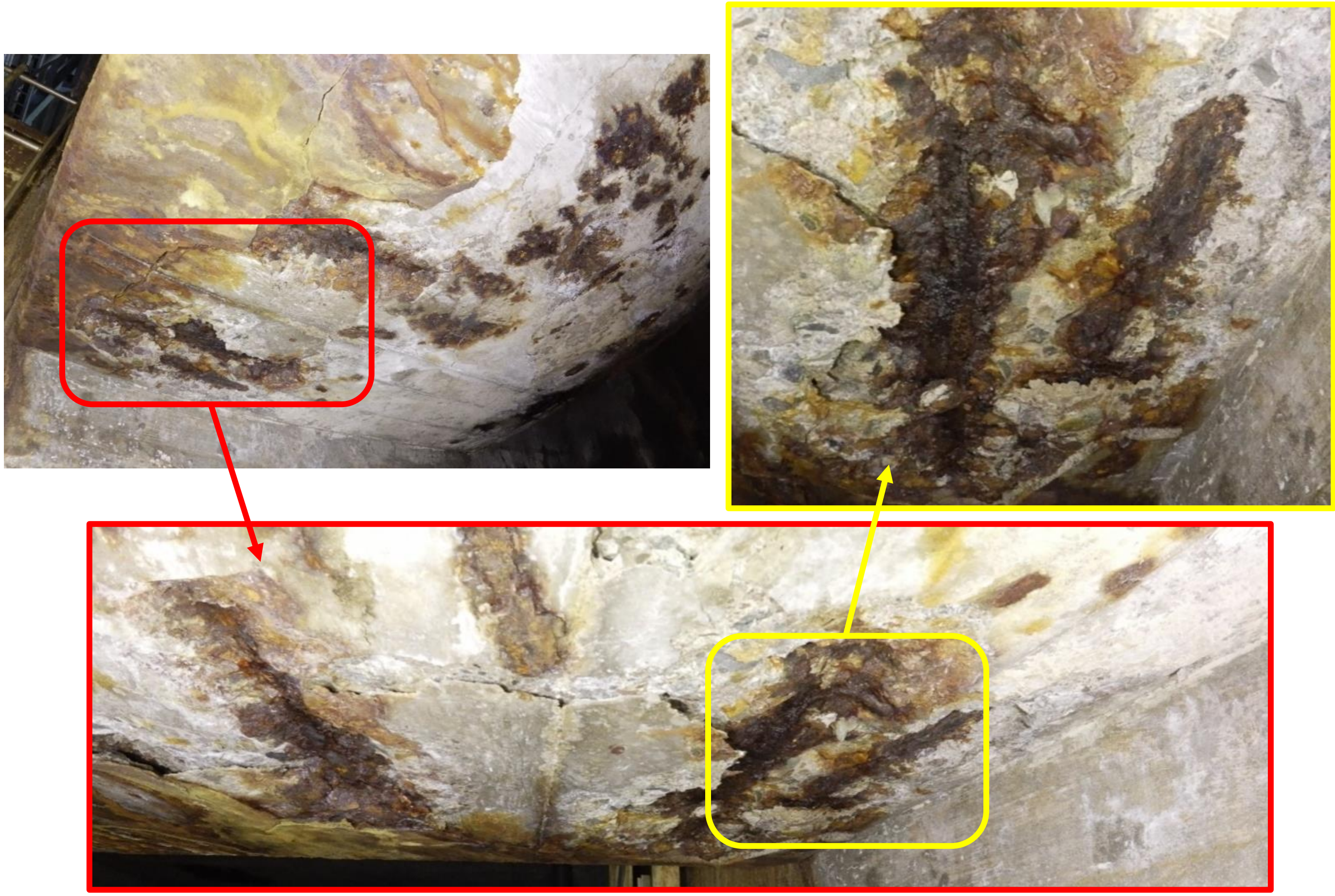

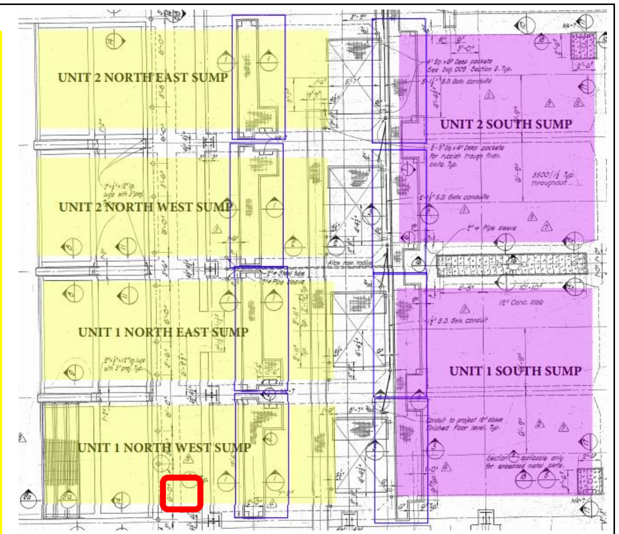

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete is deteriorating. Exposed rebar corrosion

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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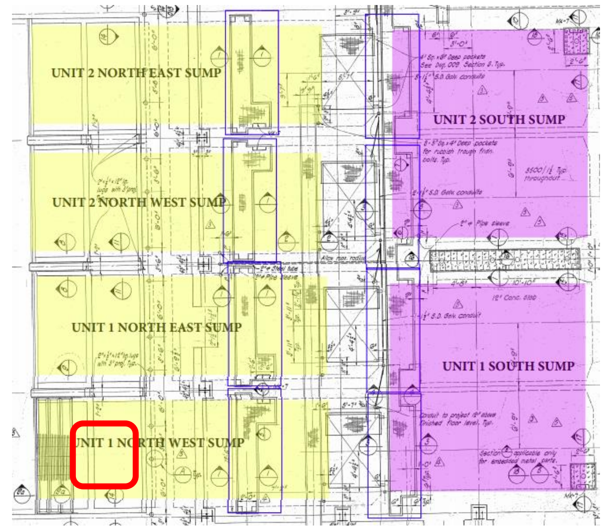

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff of north end of the tank

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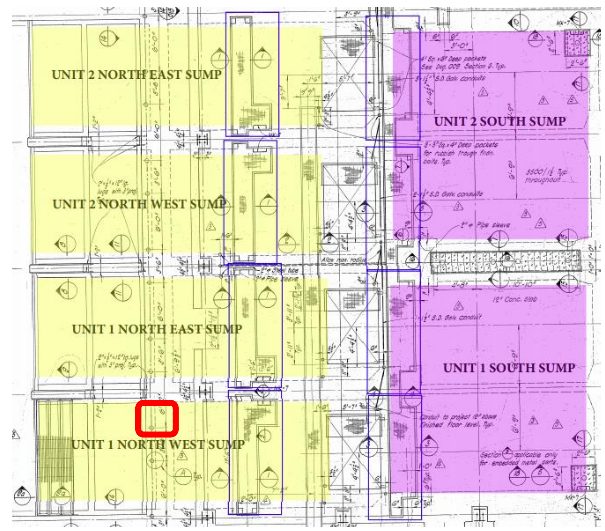
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	-	-	-	-	-	Standoff of entry access point. Deterioration of concrete present throughout

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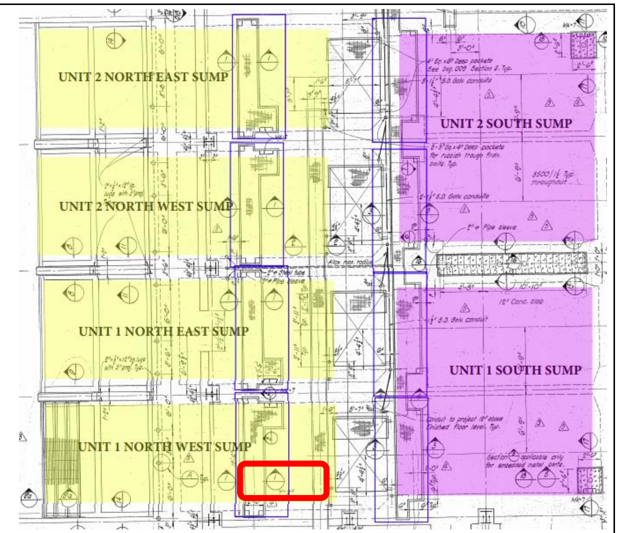
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete is deteriorating. Typical of what is seen throughout

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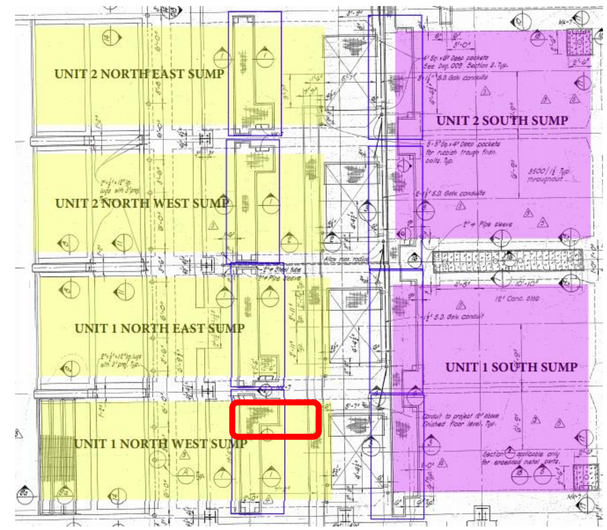
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff of travelling screens. Deterioration of concrete present throughout

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
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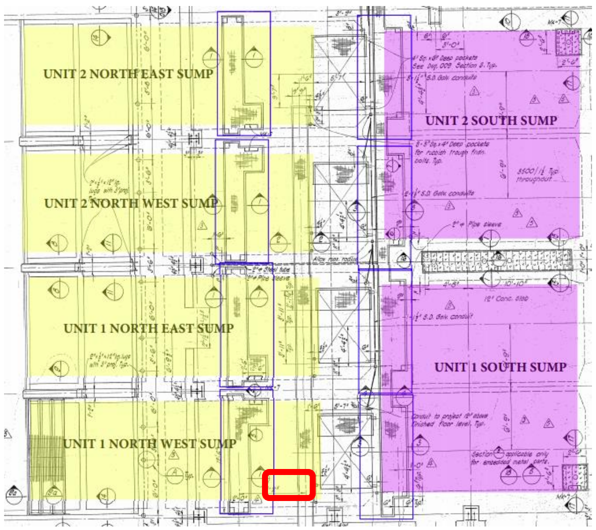

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Crack formed in corner of cross beam

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ENGINEERING

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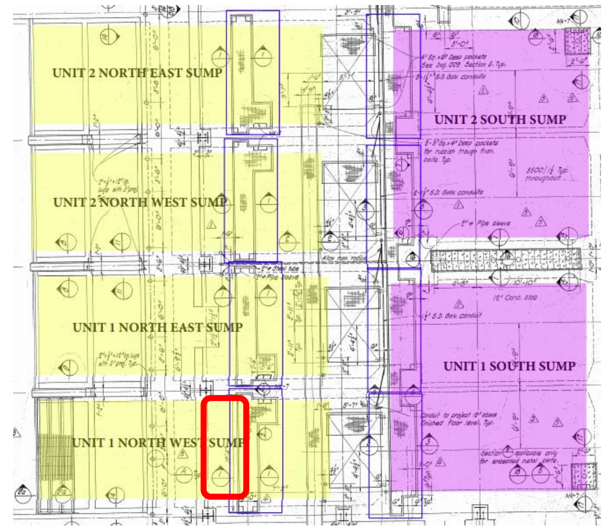

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	General overview of ceiling towards the south end Typical of what is seen throughout

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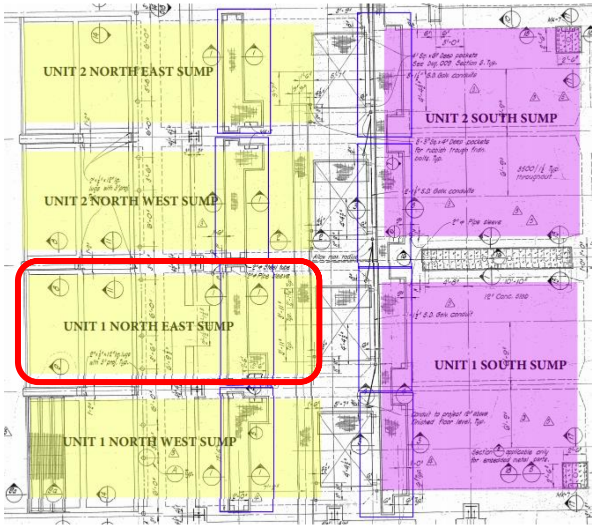
This section will cover
Unit 1 North East Sump



Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
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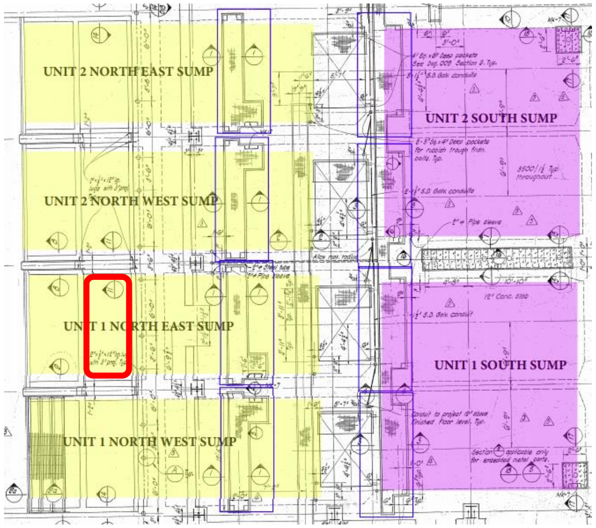

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off of North End of sump

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
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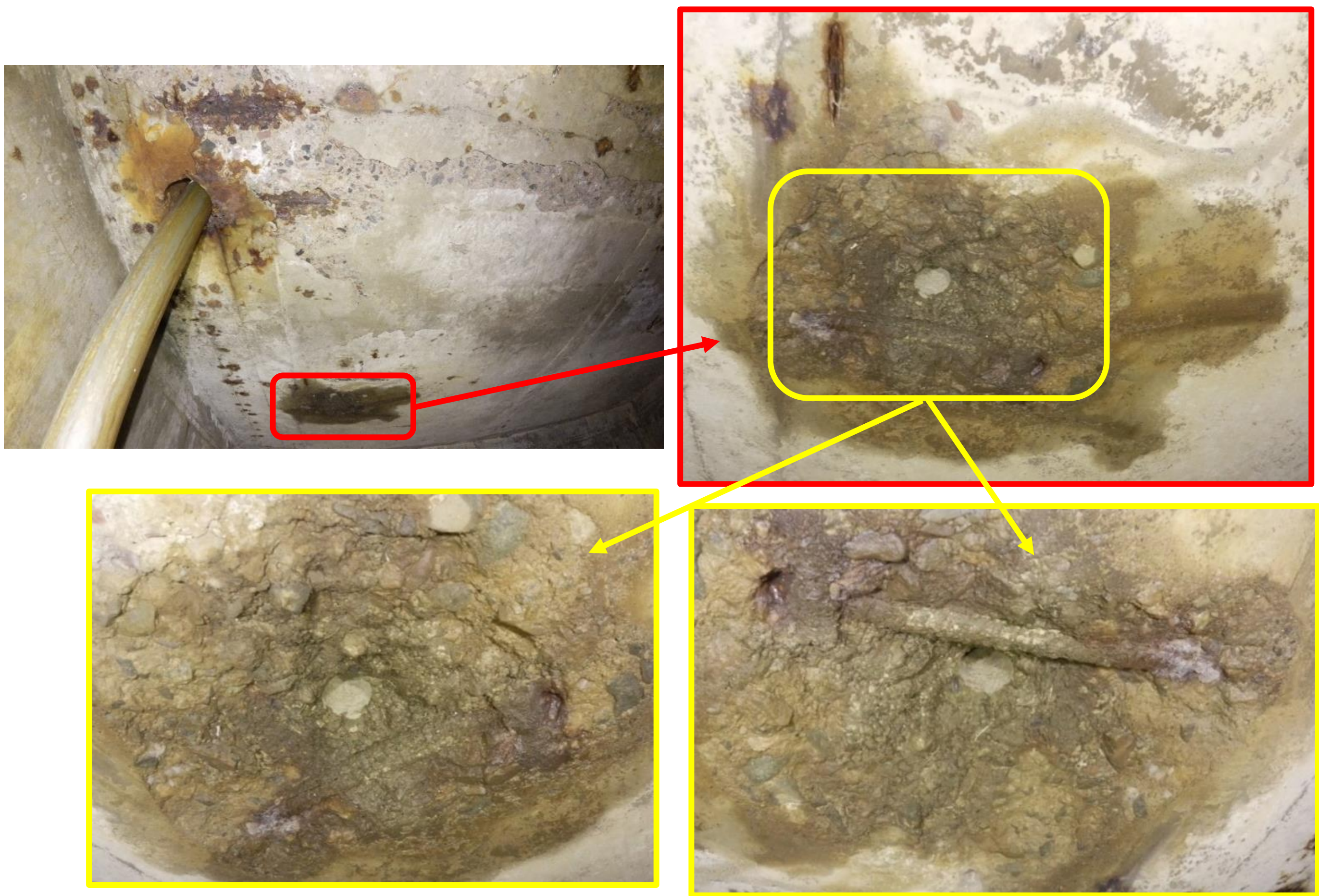

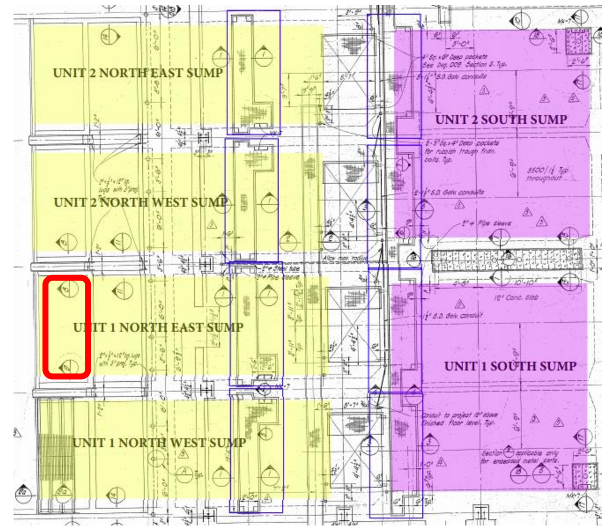

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Heavy deterioration of concrete in the north end.

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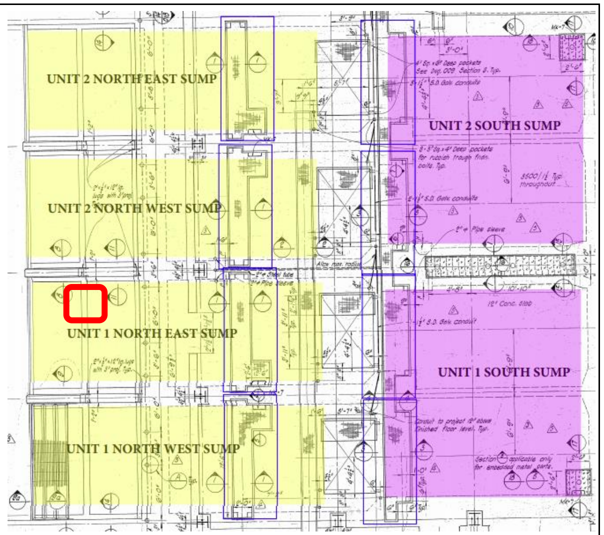
Equipment Tag:	Unit 1 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Severely corroded pipe

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
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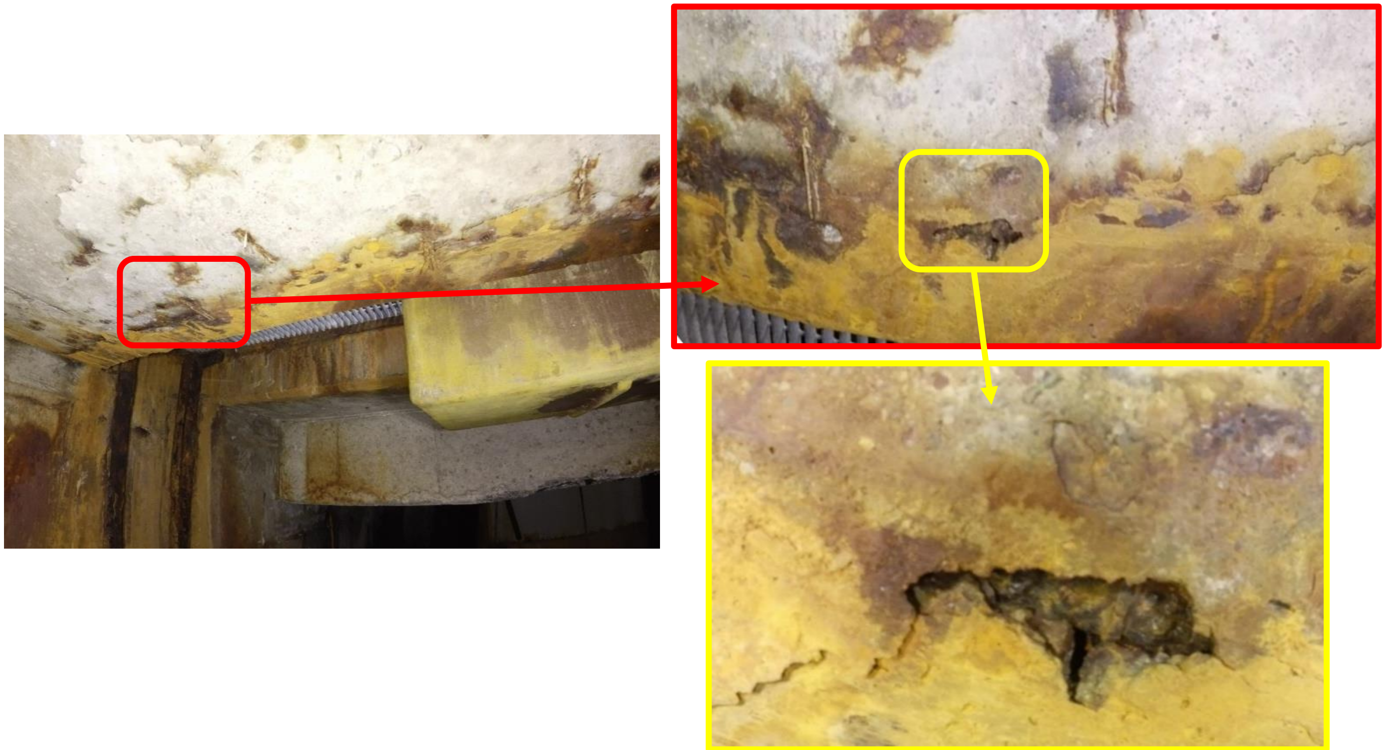

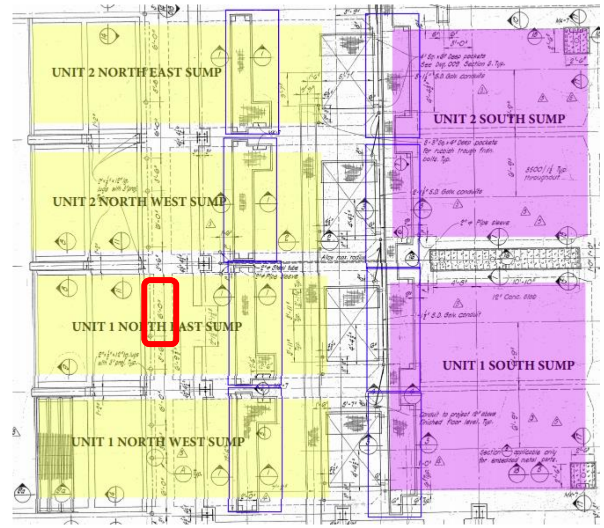

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration	-	-	-	-	Cracking of concrete near point of entry

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
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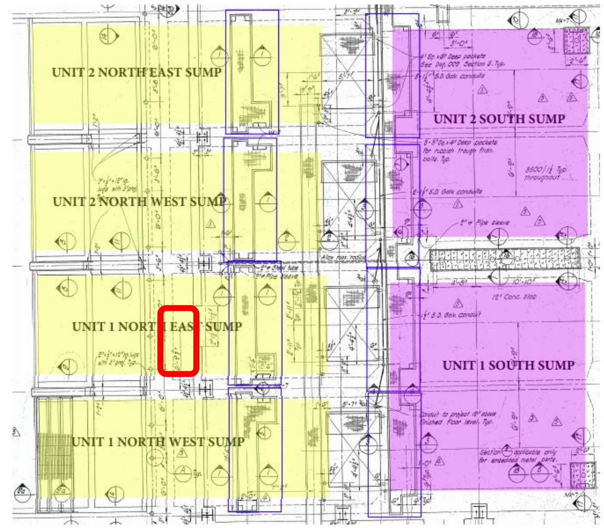

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

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UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
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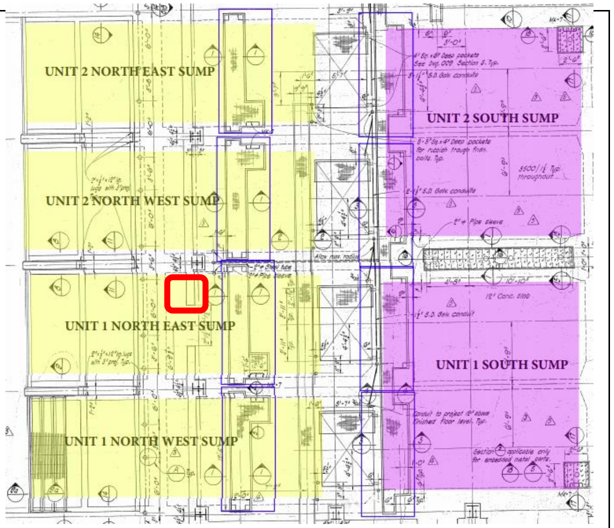

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Corrosion of steel and deterioration of concrete at edge

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
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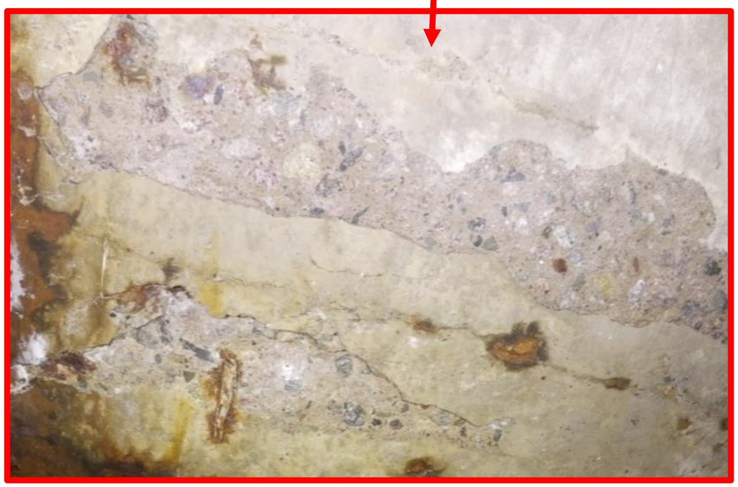

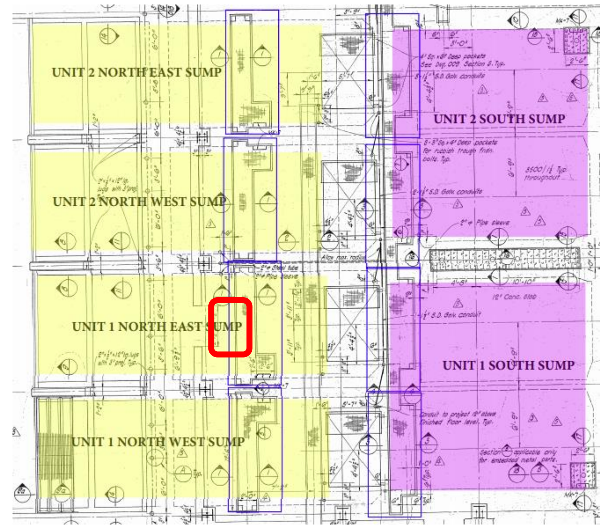

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of concrete towards south of tank

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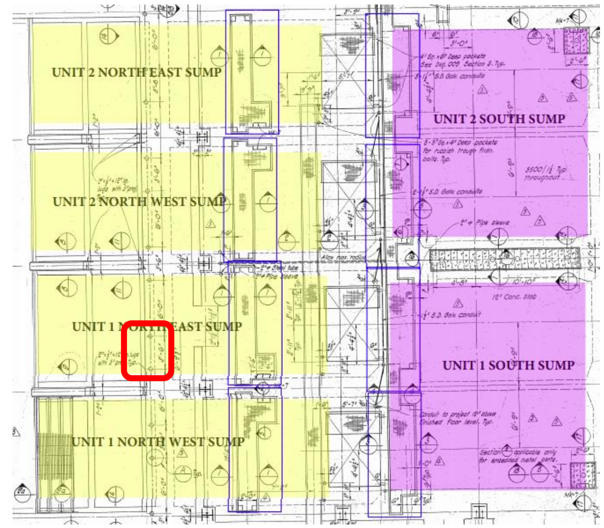

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of concrete around penetration along with corrosion of exposed rebar.

Advanced Access ENGINEERING

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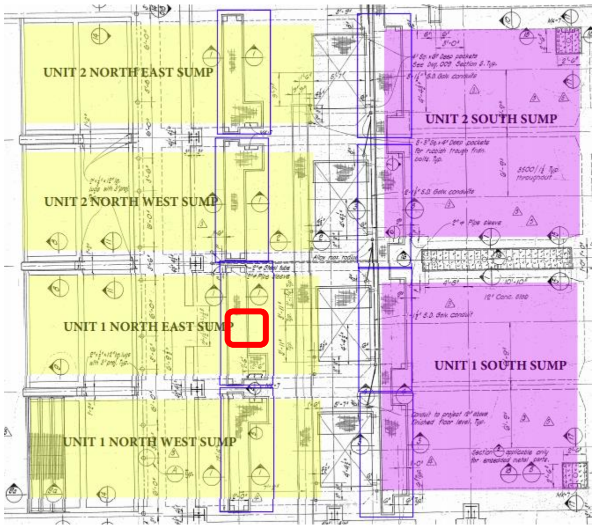

Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Cracking along west wall

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
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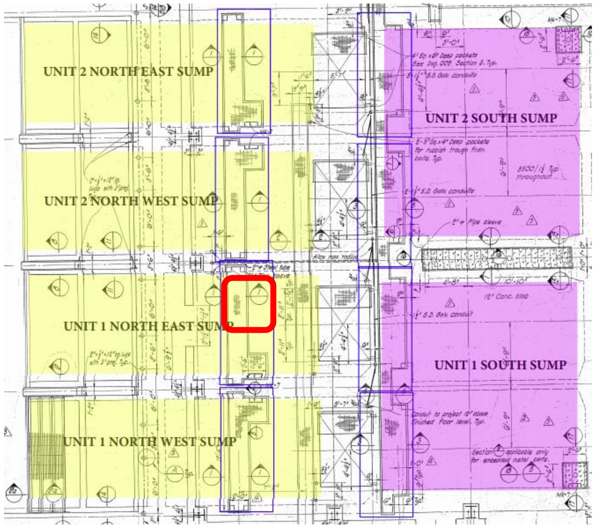
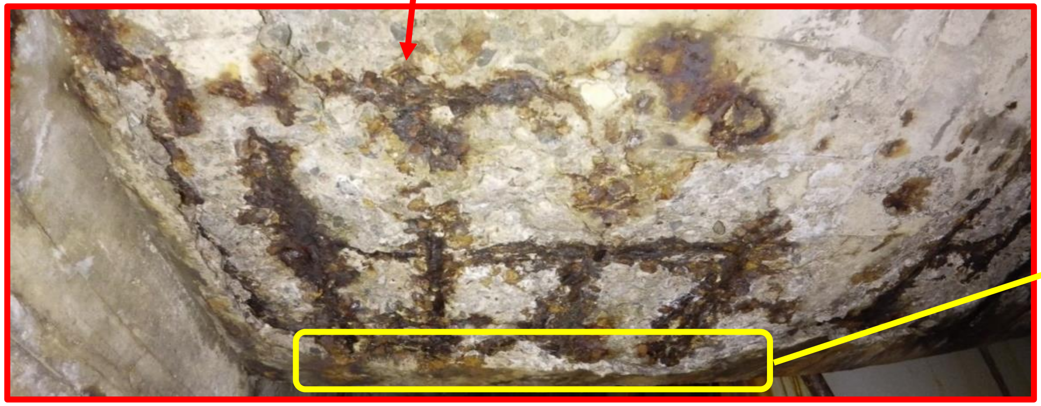
Equipment Tag:	Unit 1 North East Sump	Equipment Description:		Code:	-

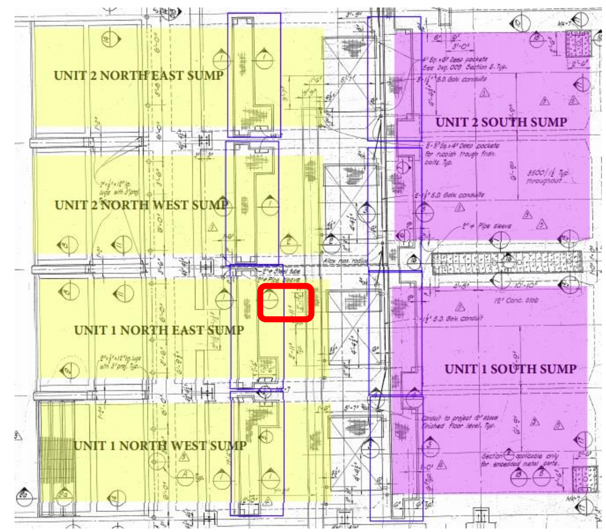




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of concrete and corrosion of exposed rebar

Advanced Access ENGINEERING

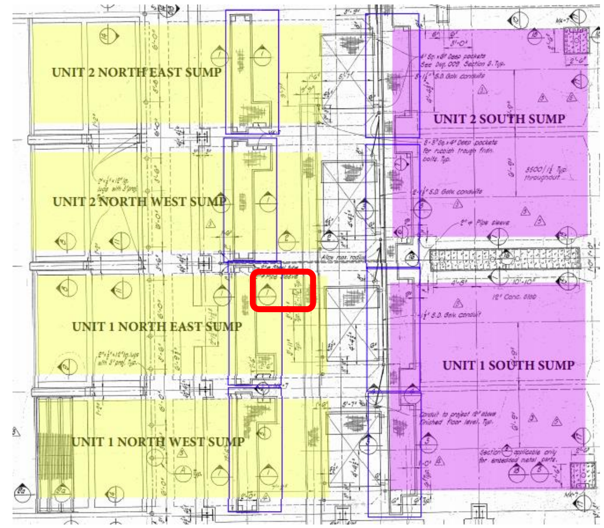
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	General poor condition.

Advanced Access ENGINEERING

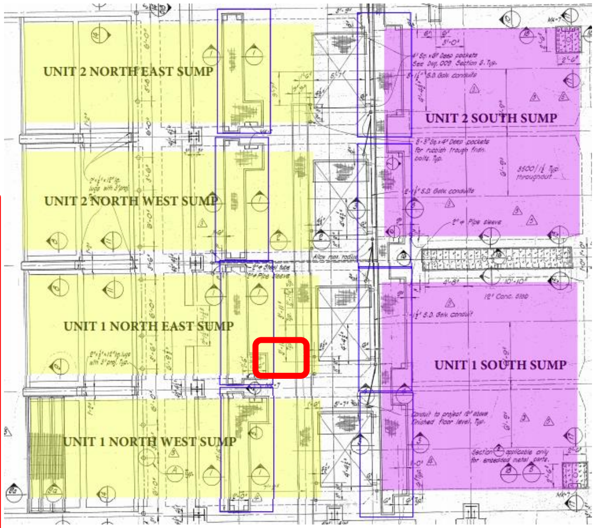
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete typical of what was seen

Advanced Access ENGINEERING

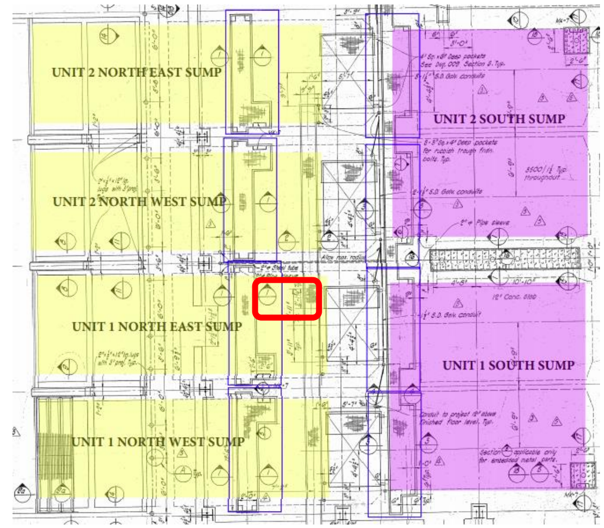
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete typical of what was seen

Advanced Access ENGINEERING

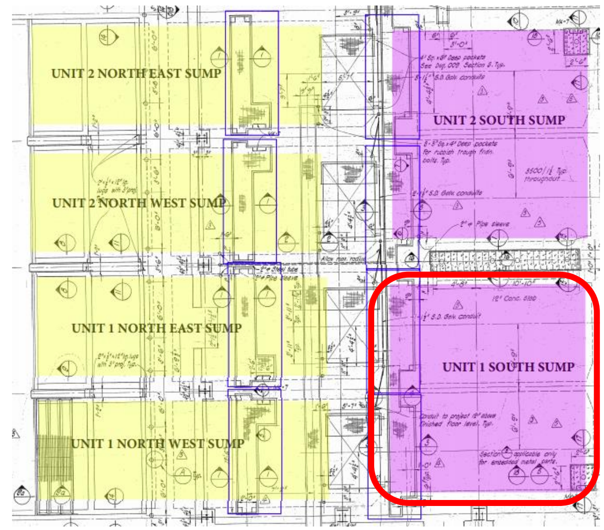
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of concrete and corrosion of exposed rebar

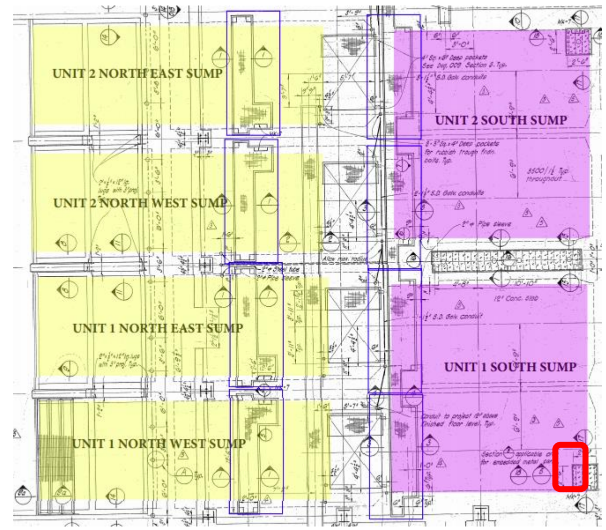
Advanced Access
ENGINEERING

This section will cover
Unit 1 South Sump



Advanced Access ENGINEERING

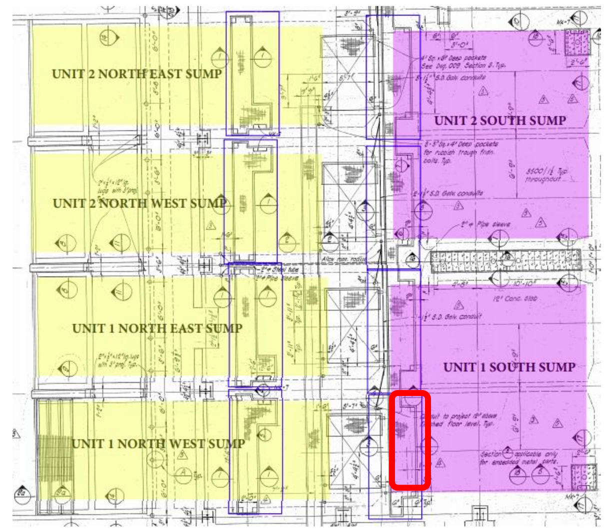
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Large crack and deterioration of concrete at entry point

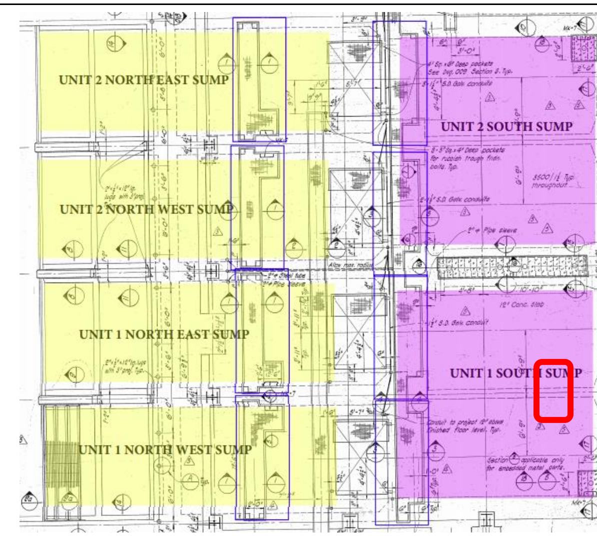
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off North End

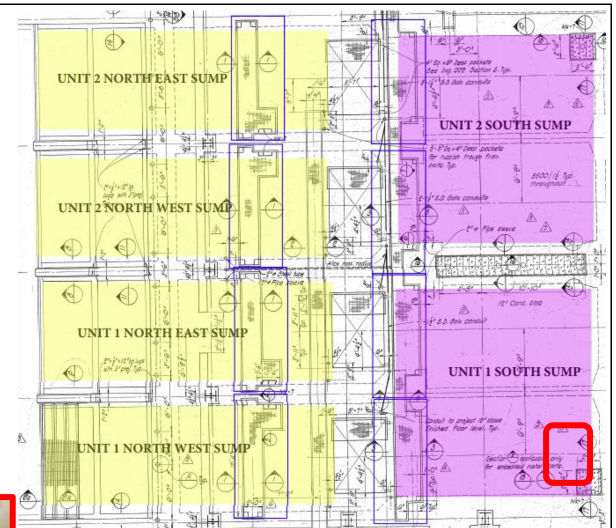
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete delamination

Advanced Access ENGINEERING

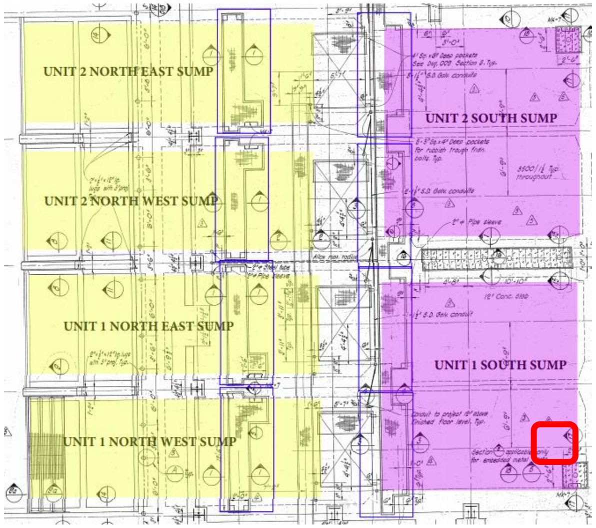
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview, Unit 1 intake area.

Advanced Access ENGINEERING

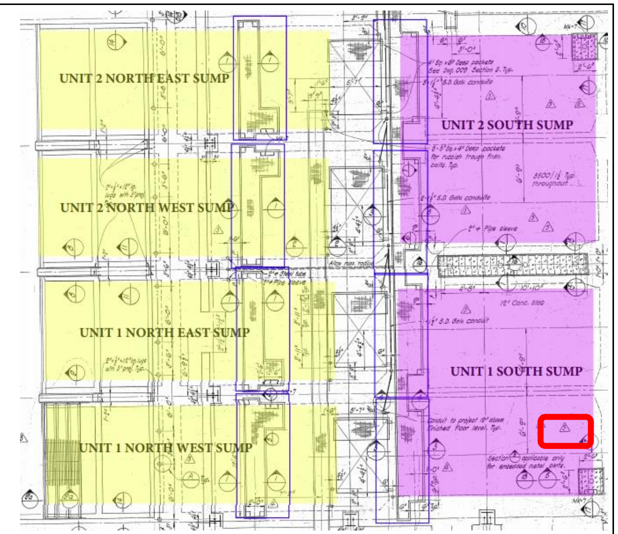
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview, Unit 1 Intake area.

Advanced Access ENGINEERING

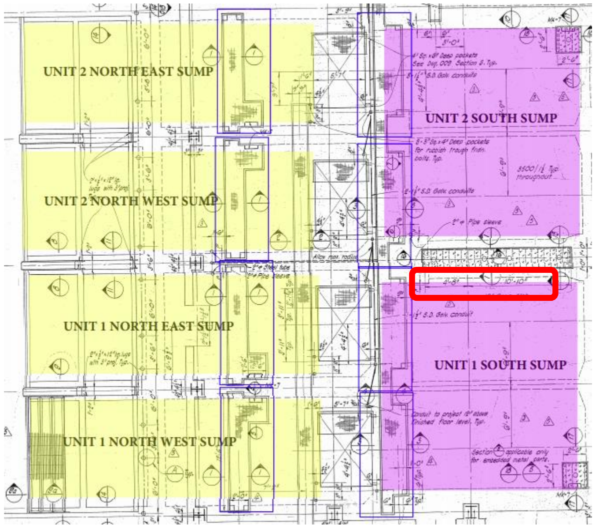
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Embedded plate left from repair or construction.

Advanced Access ENGINEERING

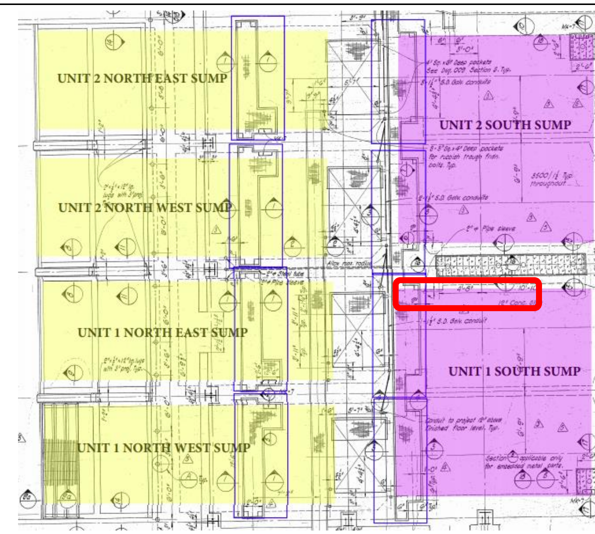
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off looking east

Advanced Access
ENGINEERING

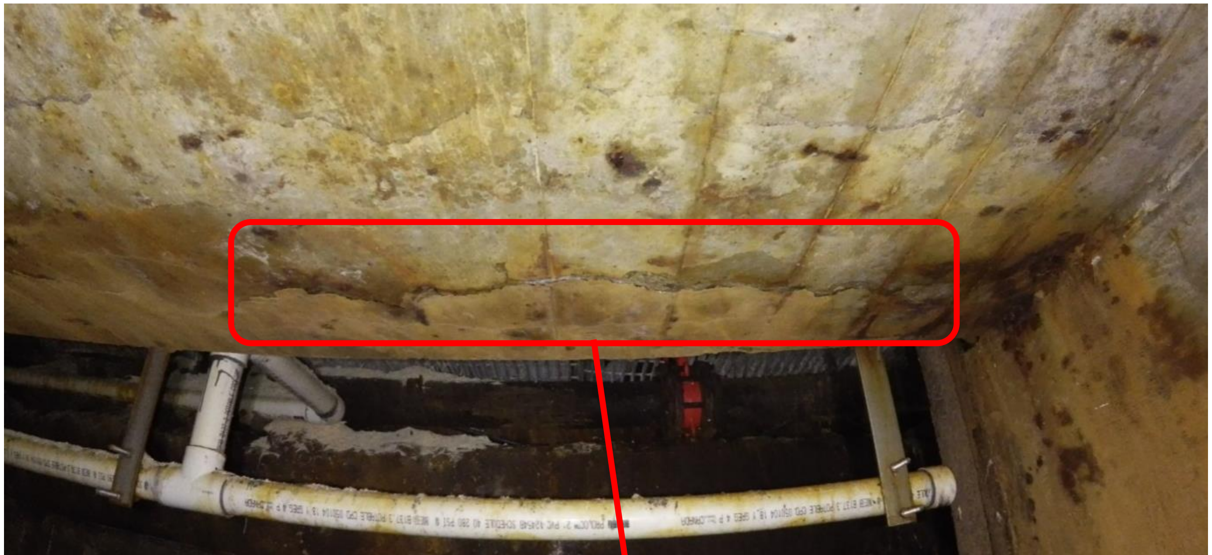
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 South Sump	Equipment Description:		Code:	-

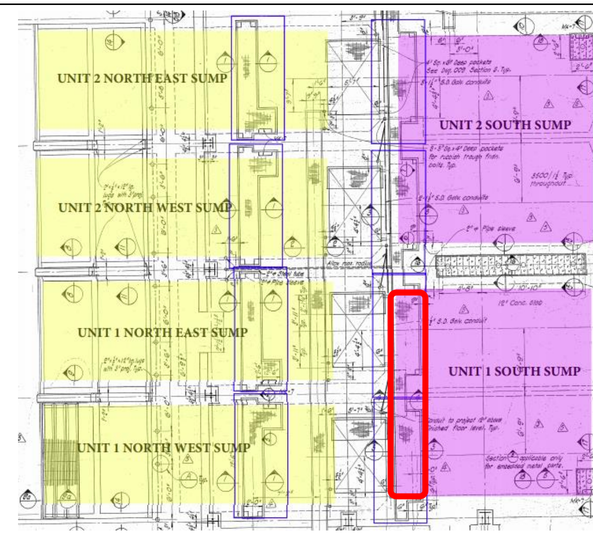


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Cracking of concrete beam

Advanced Access ENGINEERING

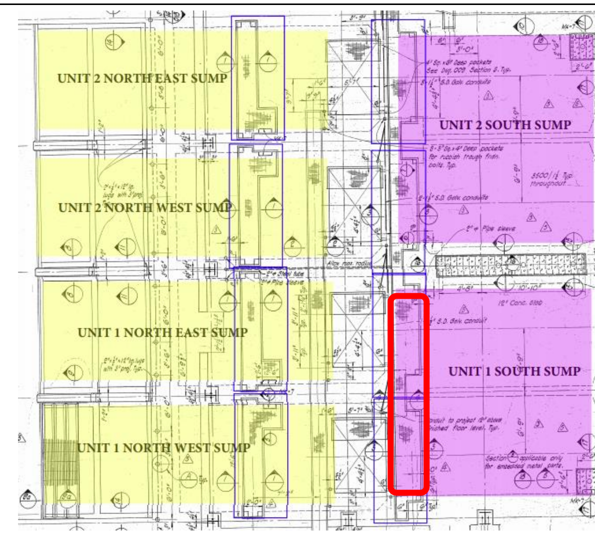
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 South Sump	Equipment Description:		Code:	-





Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete delamination

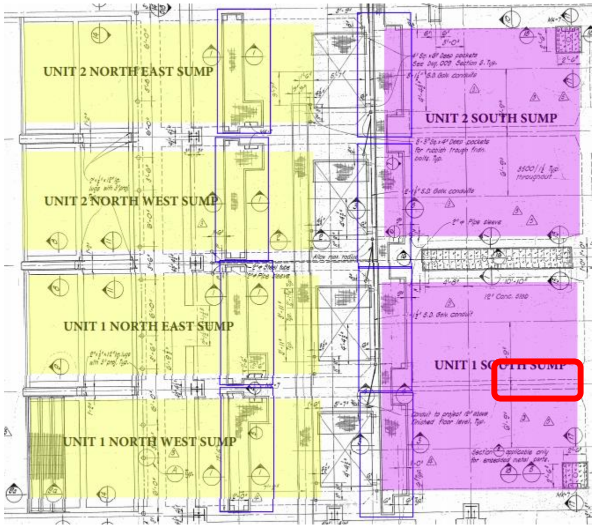
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete delamination

Advanced Access ENGINEERING

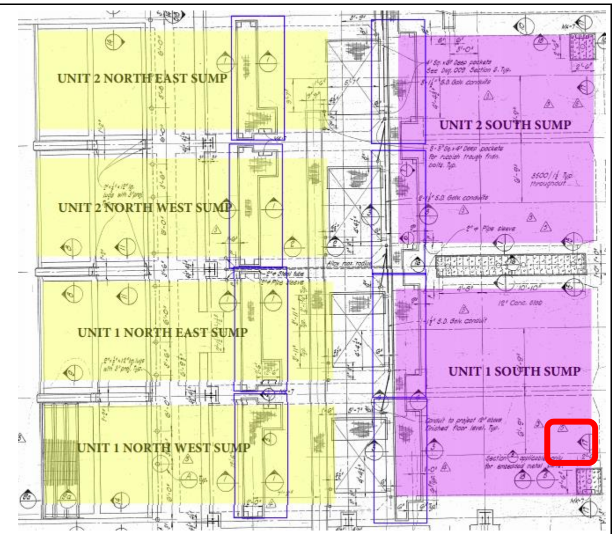
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Spalling of concrete and corrosion of exposed rebar

Advanced Access ENGINEERING

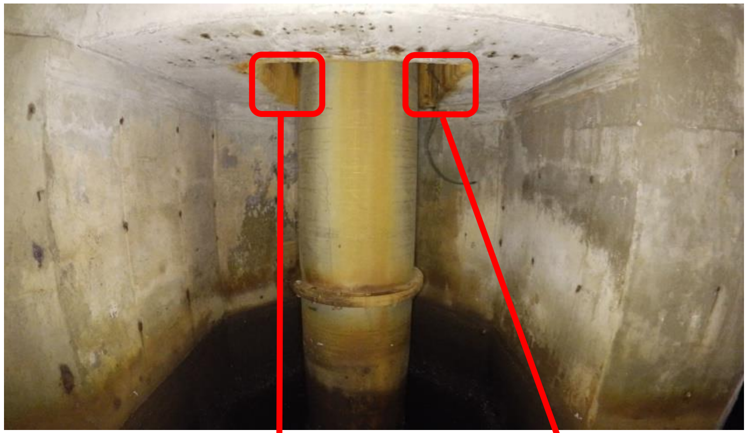
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 1 South Sump	**Equipment Description:**		**Code:**	-

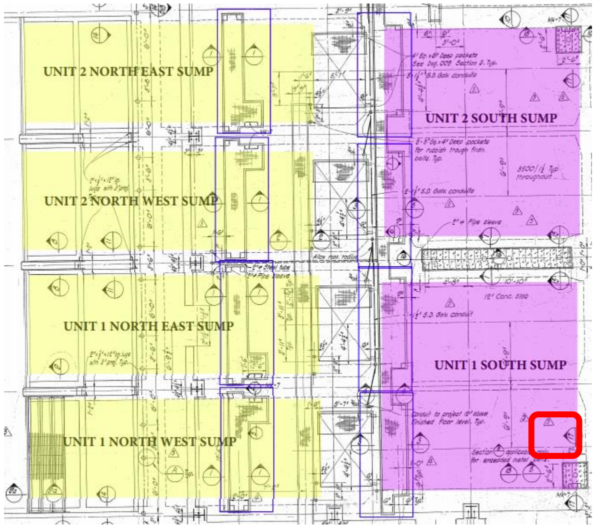


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion of exposed rebar.

Advanced Access ENGINEERING

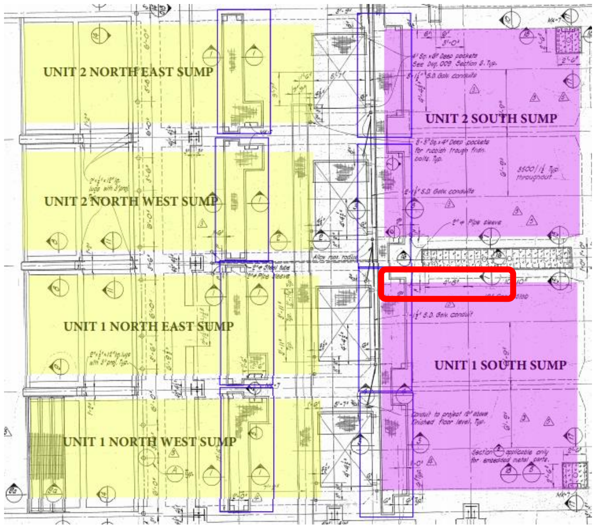
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 South Sump	Equipment Description:		Code:	-





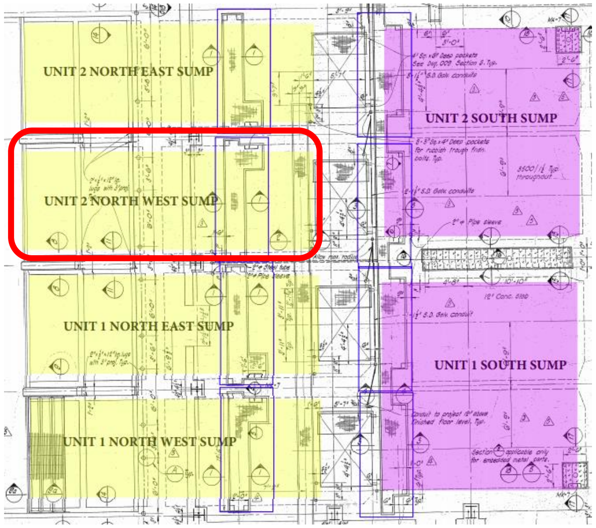
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of intake area.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 1 South Sump	Equipment Description:		Code:	-



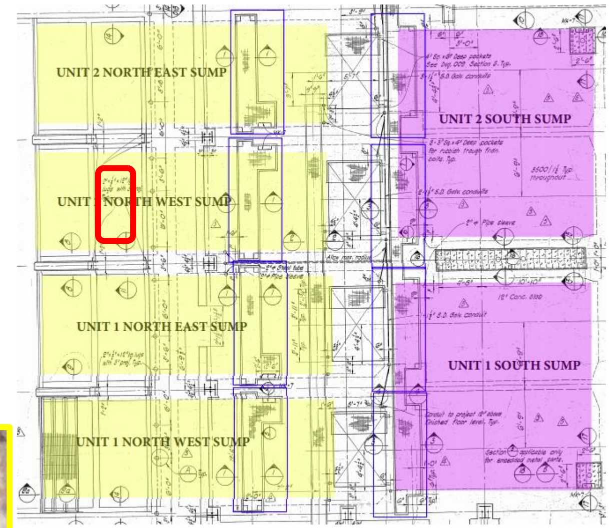
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of underside of central beam

This section will cover
Unit 2 North West Sump



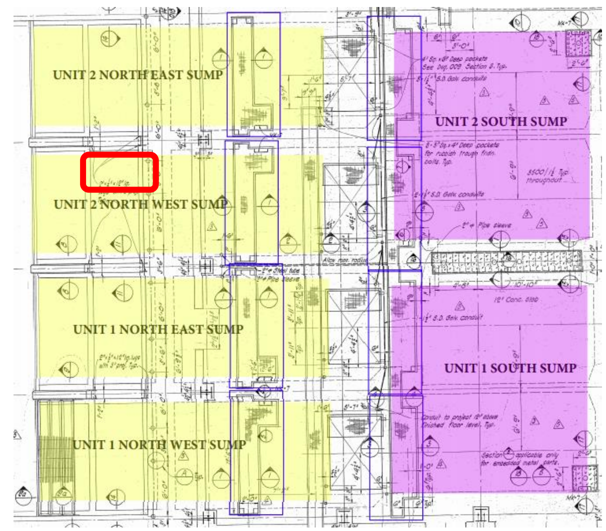
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



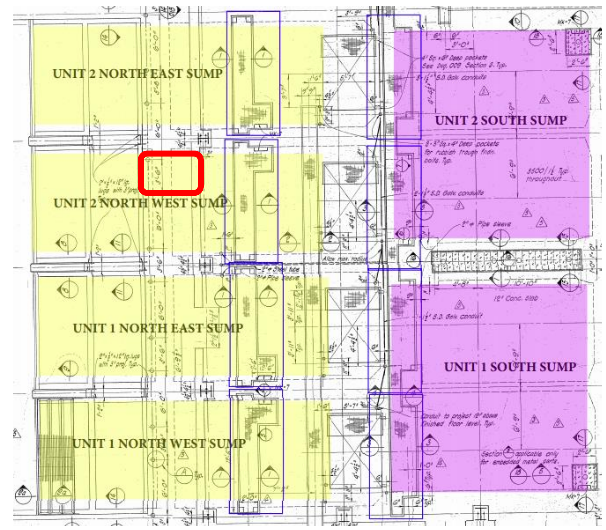
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion of exposed rebar

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

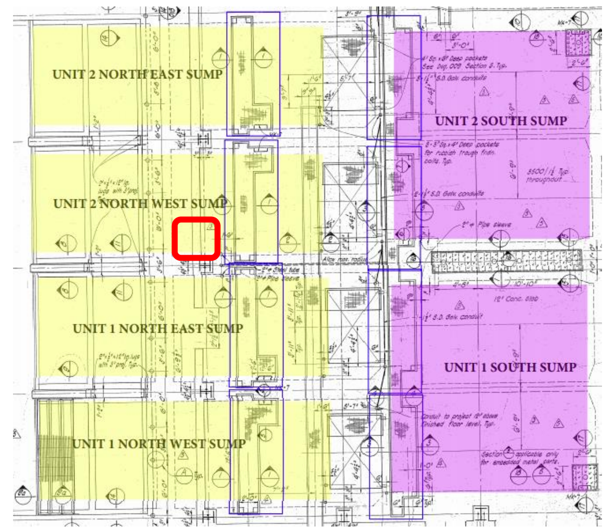
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Minor deterioration of concrete edge

Advanced Access ENGINEERING

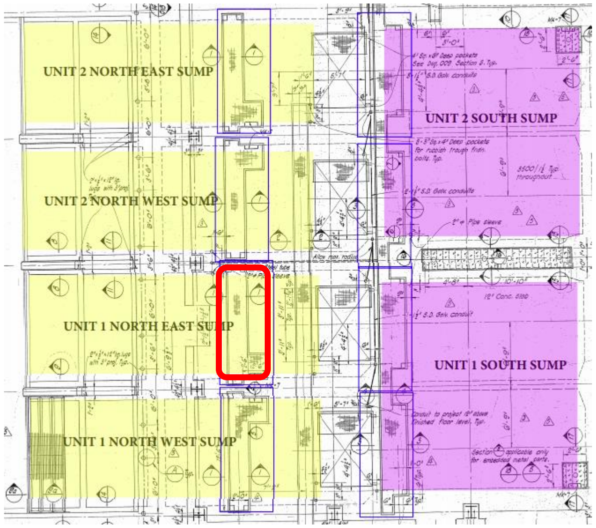
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete near grating

Advanced Access ENGINEERING

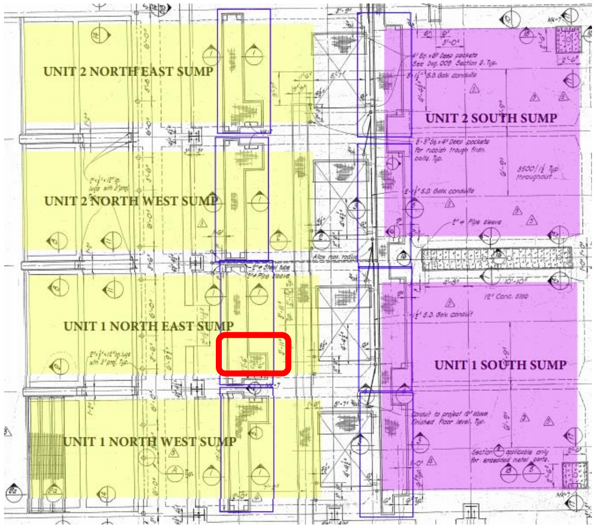
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off south end, typical of what was seen

Advanced Access ENGINEERING

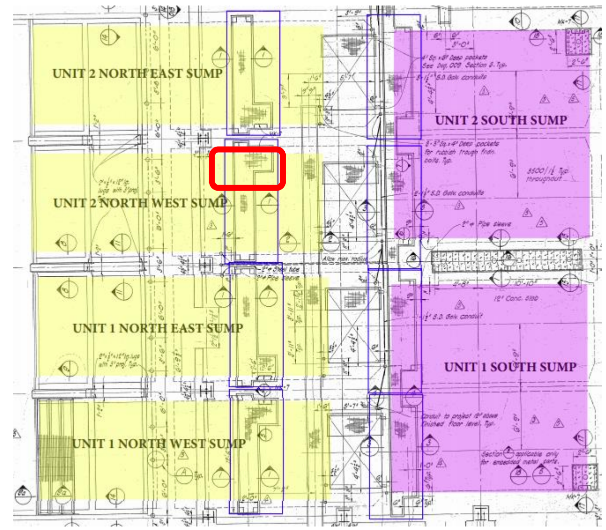
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling of concrete

Advanced Access ENGINEERING

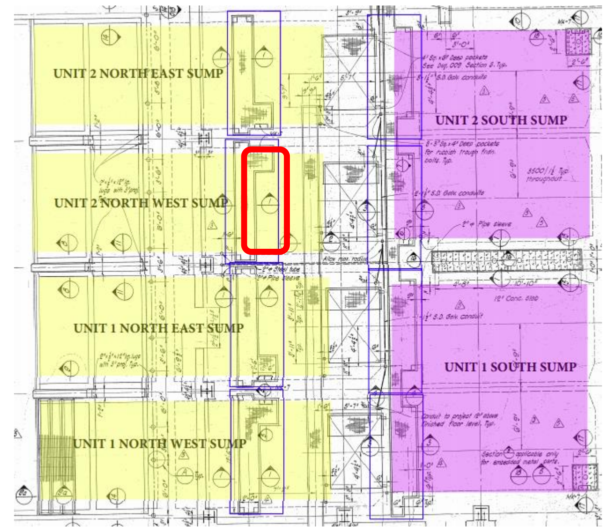
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and severe corrosion of exposed rebar

Advanced Access ENGINEERING

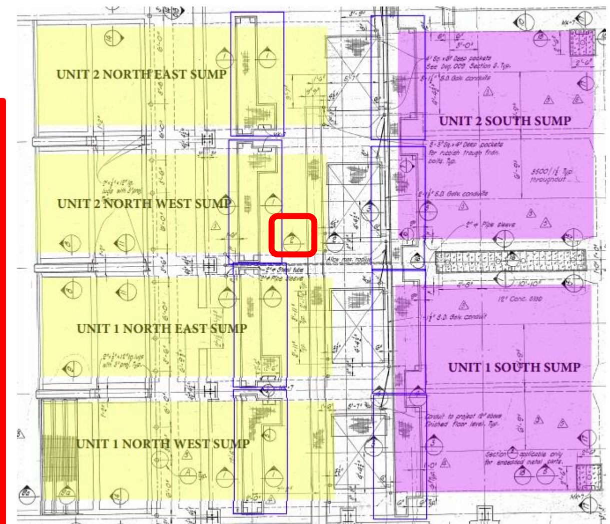
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete, typical of what was seen

Advanced Access ENGINEERING

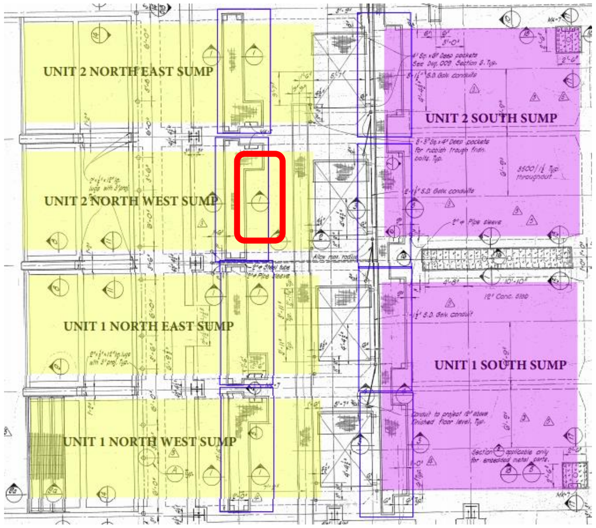
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion of rebar

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North West Sump	Equipment Description:		Code:	-

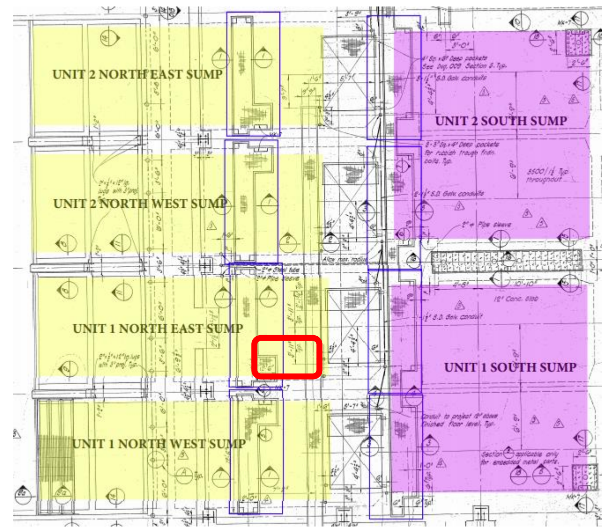


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete and corrosion of rebar

Advanced Access
ENGINEERING

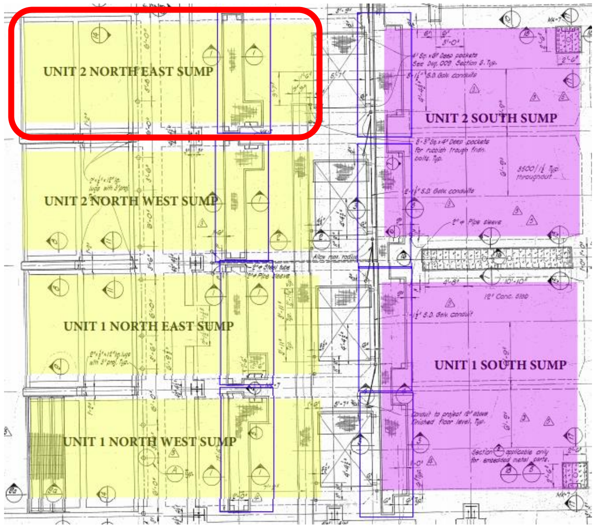
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North West Sump	**Equipment Description:**		**Code:**	-



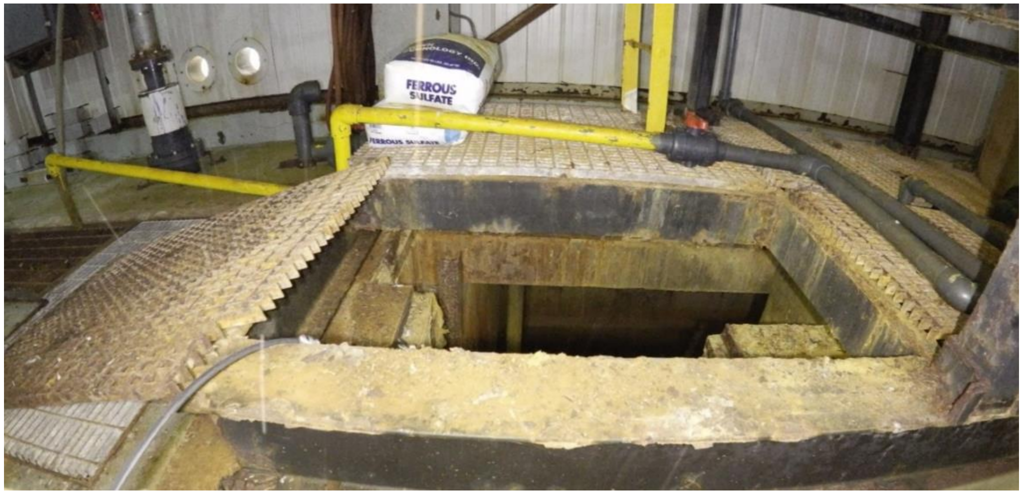



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion of rebar

Advanced Access ENGINEERING

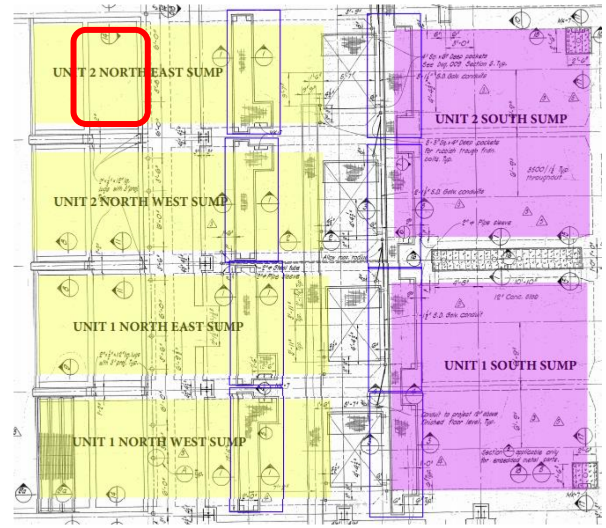


This section will cover
Unit 2 North East Sump



Advanced Access
ENGINEERING

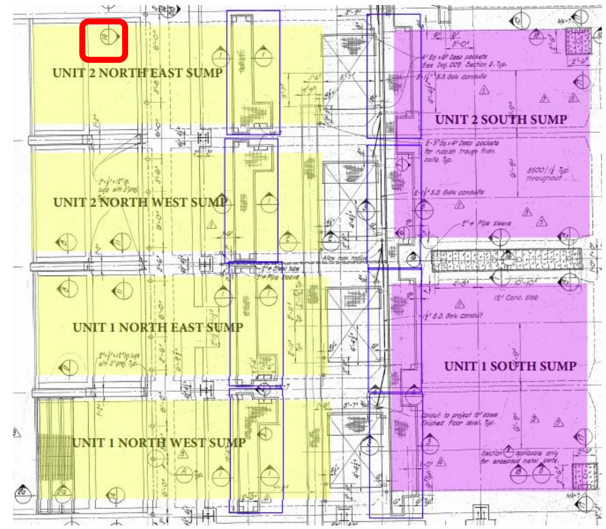
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion of exposed rebar

Advanced Access ENGINEERING

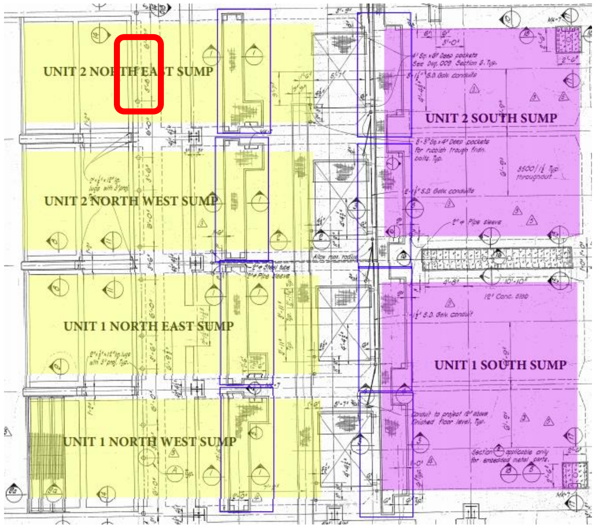
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff of Northeast Sump inlet.

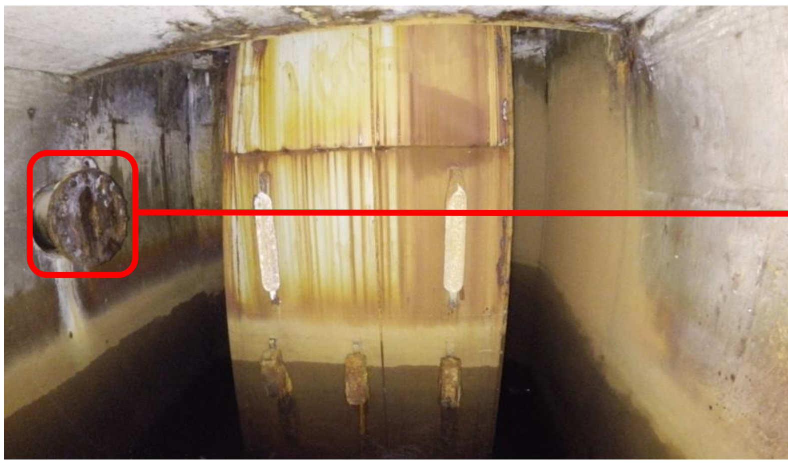
Advanced Access ENGINEERING

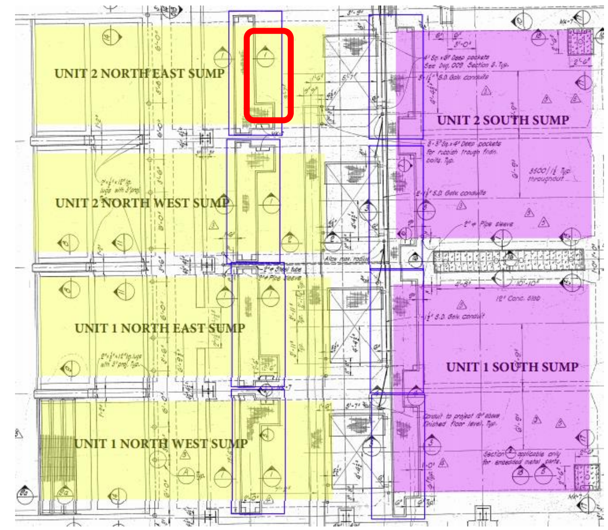
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Delamination of concrete	-	-	-	-	Delamination of concrete, unit 2 NE Sump.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-

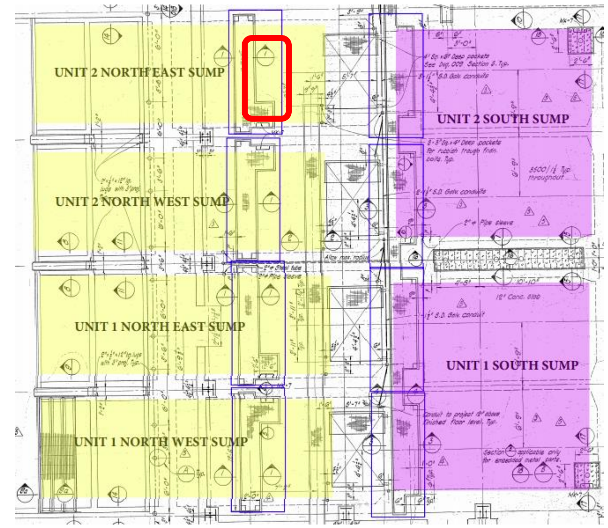




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Substantial corrosion of blind

Advanced Access ENGINEERING

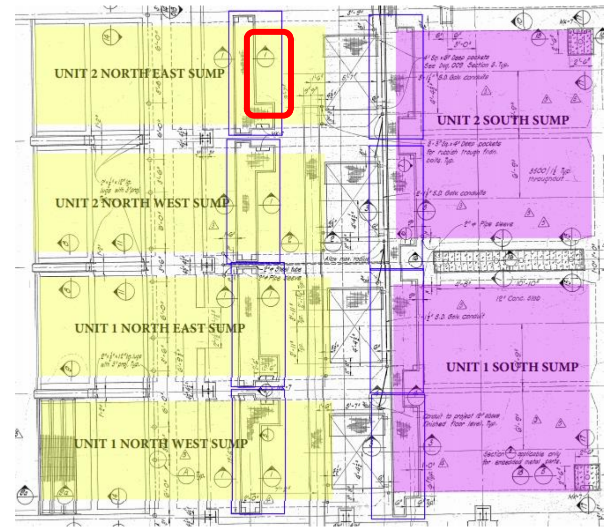
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

Advanced Access ENGINEERING

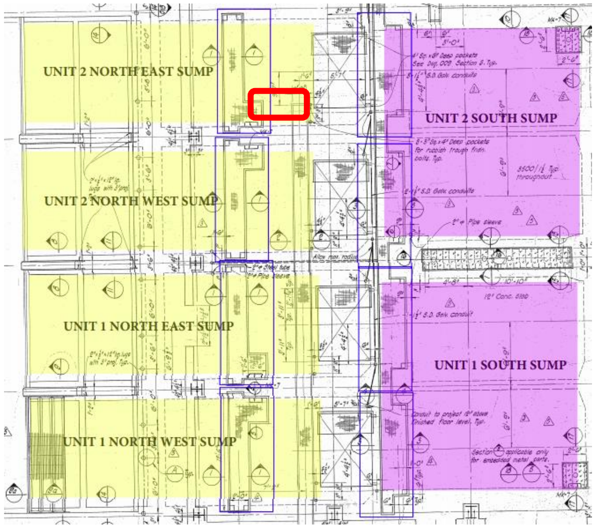
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

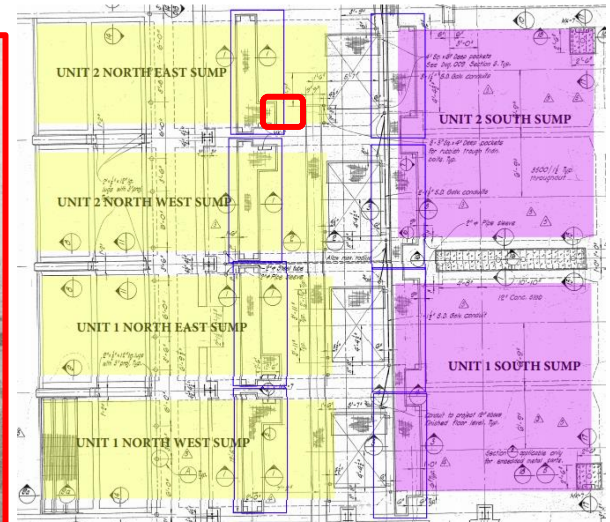
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete

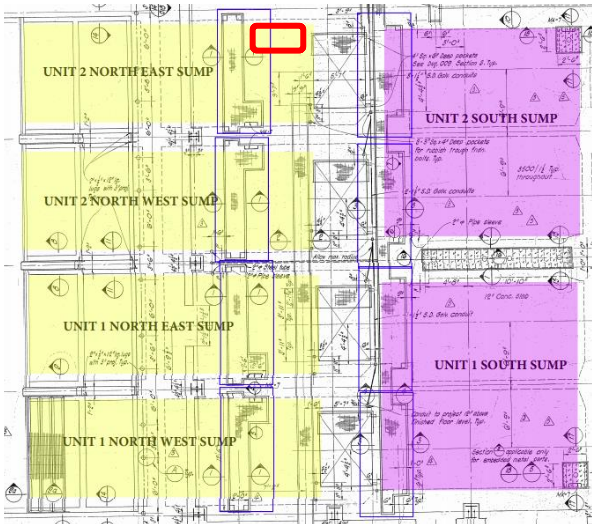
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete and corrosion of rebar

Advanced Access ENGINEERING

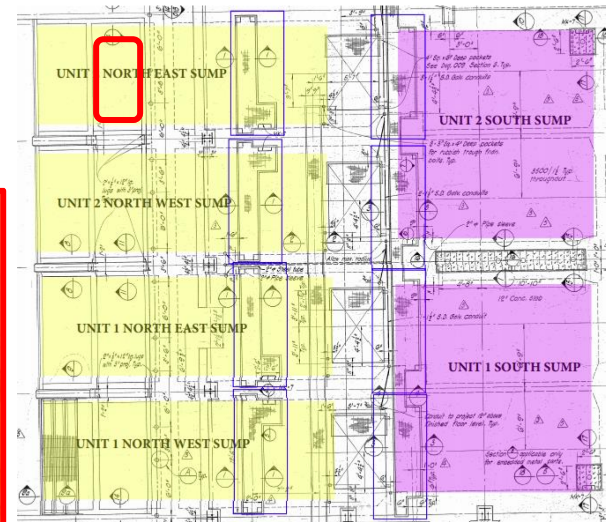
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete and corrosion to exposed rebar

Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Spalling around piping penetration

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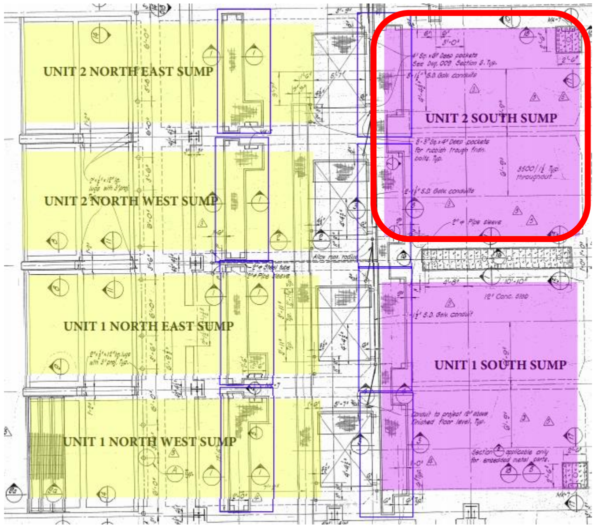

This section will cover
Unit 2 South Sump

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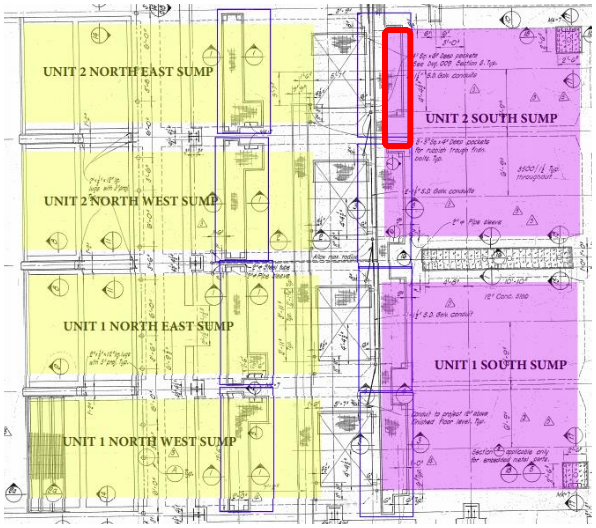
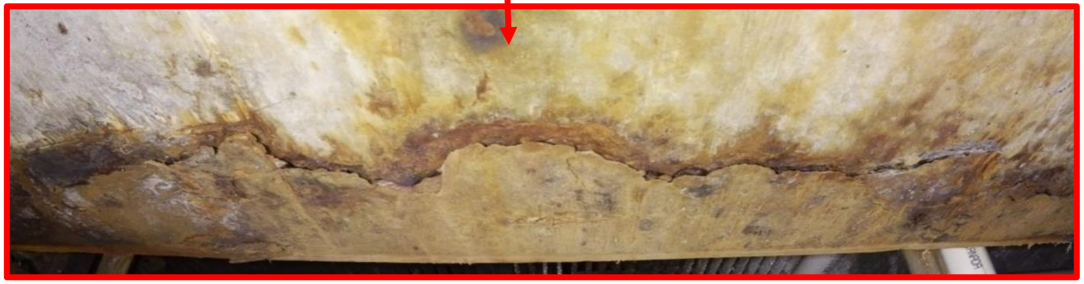
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 South Sump	**Equipment Description:**		**Code:**	-

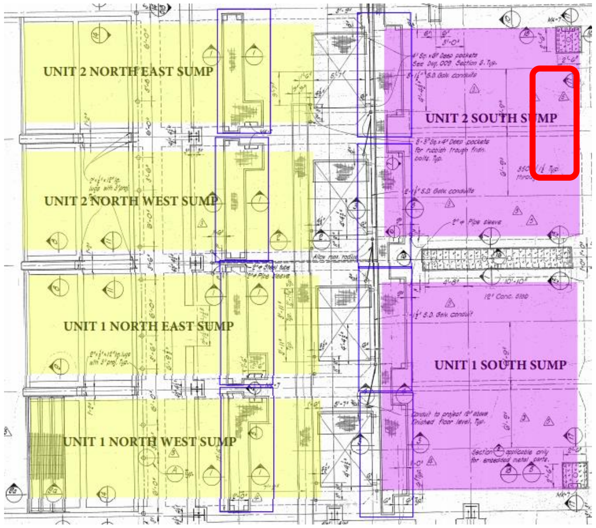




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete and corrosion of rebar

Advanced Access ENGINEERING

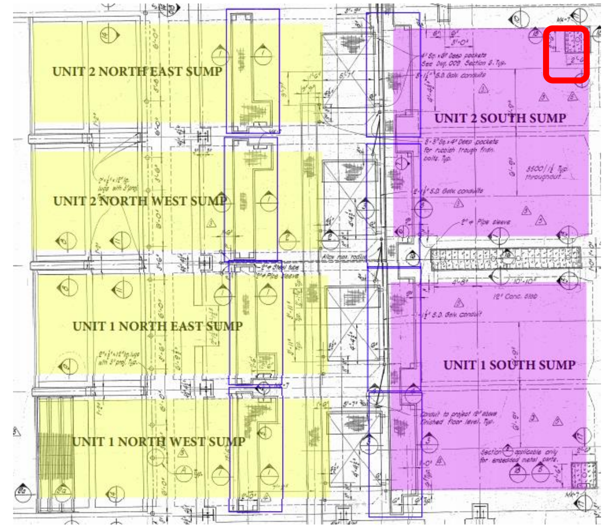
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off unit 2 south.

Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial cracking near entry point/intake area.

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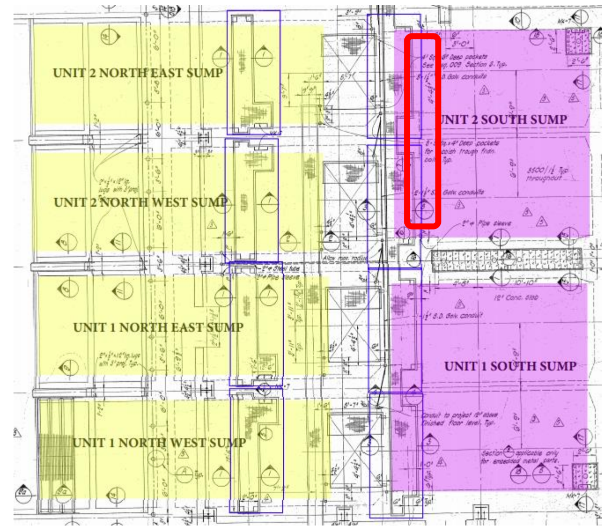
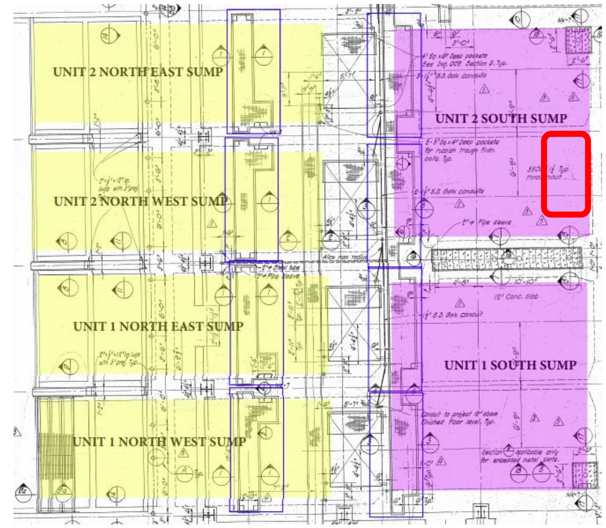
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 2 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Stand off south end intake area.

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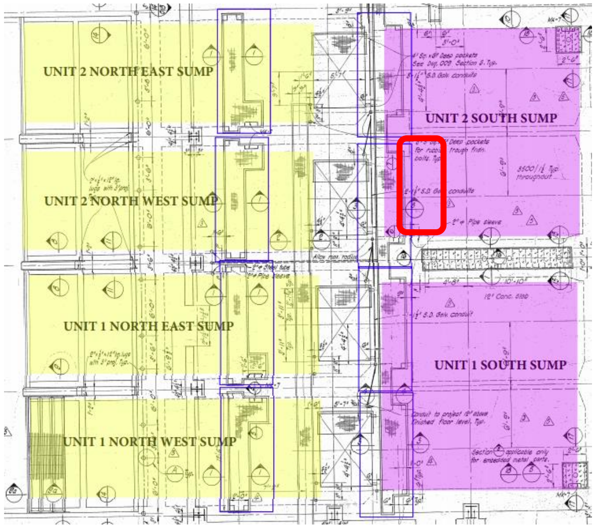
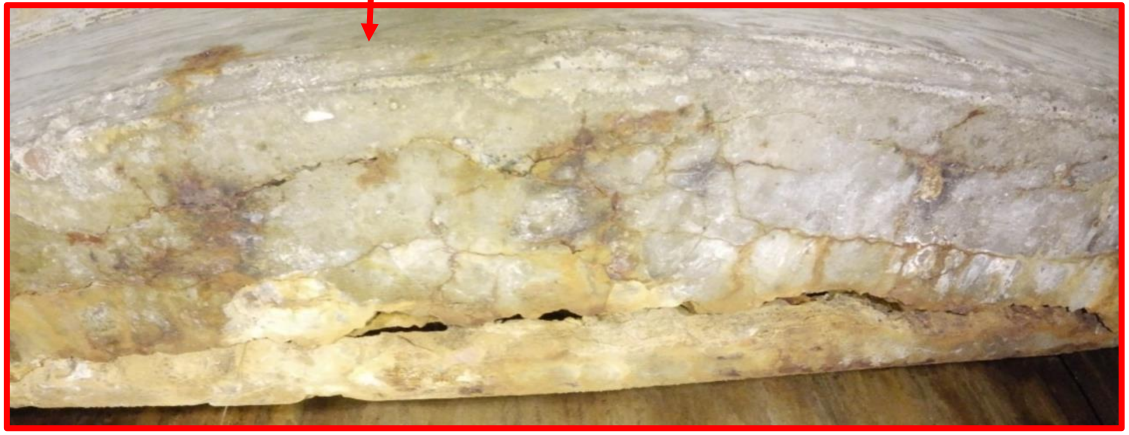
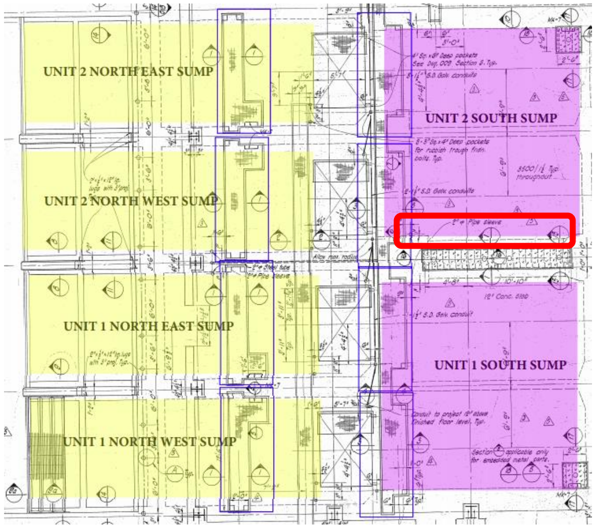
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Delamination of concrete

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 2 South Sump	**Equipment Description:**		**Code:**	-





Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Cracking and corrosion

Advanced Access ENGINEERING

Appendices and Recommendations

Appendices

238-06-0110-010 Stage 1

High Resolution Video and Images

Unedited high resolution project files of the inspection can be downloaded from the AAE Client Login Portal. A separate email will be sent providing those listed in the recipient table a username and login.

Recommendations

Recommendations from the inspection team would be to keeping monitoring the area at intervals identified in an asset integrity plan If one exists.

Appendices

UNIT 2 NORTH EAST SUMP
UNIT 2 NORTH WEST SUMP
UNIT 1 NORTH EAST SUMP
UNIT 1 NORTH WEST SUMP
UNIT 2 SOUTH SUMP
UNIT 1 SOUTH SUMP
AREA TO INSPECT
AREA TO INSPECT
AVAILABLE ACCESS POINTS
For details of Bases A to G incl. see Dwg. 238-06-0110-011 (B omitted)
NOTES:
1. Concrete in powerhouse shall be 3500 lb/in². Concrete in utilidor shall be 3000 lb/in².
2. Removable handrail: Rails: 1½" ø std. pipe. Posts: 1½" ø E.H. pipe
3. Waterproofing for utilidor: 3-Ply membrane waterproofing shall be applied as specified by the manufacturer. Material shall be the following type supplied by Domtar Constr. Material Ltd. or equal. Bitumen - Foundation coating fibrated. Membrane reinforcing - Glass fab.
4. Water stops: Water stops shall be B. F. Goodrich Koroseal 4500 Type 600-A.
5. Concrete cover: 3" for all formed surfaces, (walls & base slab) 4" for base slab & unformed surfaces.
6. Concrete cover: 1" clear for elevated slab. 1½" " - beams & grade slabs.
7. For details of grounding cables to be incorporated in the slab see Grounding Plan - Dwg. 238-13-0310-115.
8. All embedded metal parts to be hot dipped galvanized.
9. All concrete surfaces shall receive a F3 finish.
10. Floors & Stairs: Master plate metallic aggregate or an approved equal shall be applied to the floors & stairs at a rate of .75 lb. per square foot in accordance with the manufacturers instructions.
11. Water stops are to be provided for construction joints up to El. 8.00'.
12. Floor loading: Floors designed for 300 lb/ft² L.L.
13. Paint to be in accordance with clause 4.12.03.03 of Specification. (Trash racks)
REFERENCES:
Dwg. 238-06-0110-004 - Excavation plan circulating water piping, pumphouse & utilidor, seal pit.
238-06-0110-005 - Pumphouse - Base slab & Sections - Conc. outline.
238-06-0110-009 - Pumphouse - Sections - conc. outline.
238-06-0110-011 - Pumphouse - Elevated floor plan - Reinforcement.
238-06-0110-012 - Pumphouse - Base slab & sections - Reinforcement.
238-06-0110-013 - Pumphouse - Sections - Reinforcement.
238-13-0310-115 - Pumphouse Grounding
REMOVABLE HANDRAIL DETAIL
ANCHOR BOLT - TYPE X3
ANCHOR BOLTS
Utilidor
Concrete thrust block
C.W. pipe
For details of utilidor and associated stairs, see Dwg. 238-06-0110-021
For grounding det. see
Removable handrail
CONSTRUCTION ISSUE
NEWFOUNDLAND AND LABRADOR POWER COMMISSION
HOLYROOD GENERATING STATION
PUMPHOUSE - ELEVATED FLOOR PLAN - CONC. OUTLINE.
SHAWMONT RESOURCES JOINT VENTURE
1047 YONGE STREET. TORONTO 5. ONTARIO
scale ¼" = 1'-0"
date 2. MAY 1969
J. K. RILEY
238-06 0110
010 - R6
R6 Nov. 18.69 Bases A to H added
R5 30.10.69 Trash rack details, manhole cover & Stoplog cover details added.
R4 26 Sept. 69 Grade slab & details added
R3 12 Sept. 69 Details added
R2 26 Aug. 69 Released for wall construction
R1 1 Aug. 69 General Revision; Former Dwg. Nr. 238-06-0110-005 P.
238-06 0110
010 - R6

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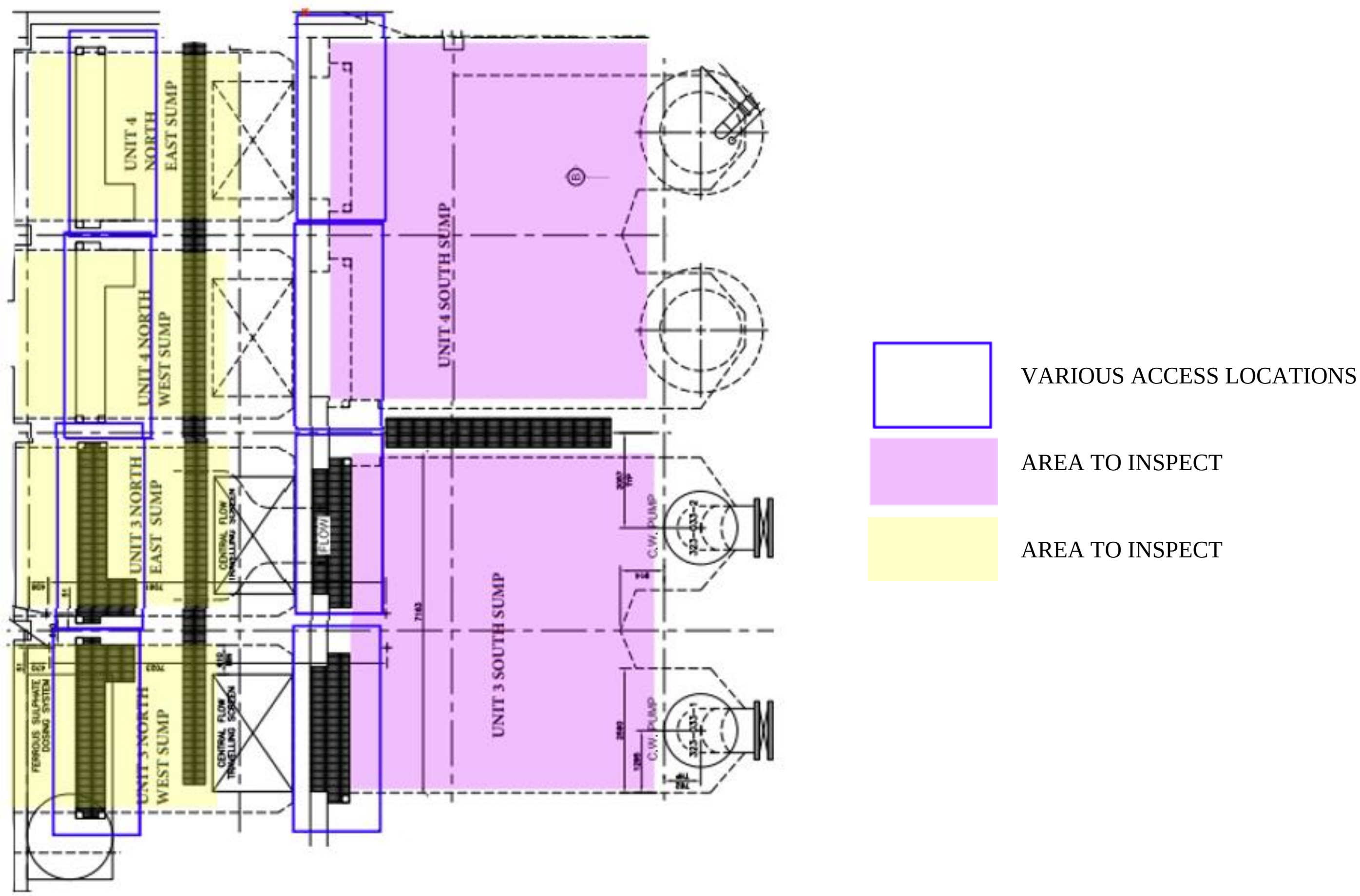
21-114-007 - Pumphouse 2 Sump Inspections



Concrete Slab Inspection – Pumphouse 2

Advanced Access Engineering

Conception Bay South

Advanced Access ENGINEERING

Sign Off

Table of revisions			
Revision Number	**Revision Date**	**Nature of Revision**	**Approved**
Draft	Victoria Strickland - 13 August 2021	Initial draft/reporting	SL
Review	Matt Sibley/ Jason Wade - 16 August 2021	Reporting/Content review/QC	SL
Release	Shelly Leighton - 16 August 2021	Release	

Acceptance								
Name	Joanne Norman	Shelly Leighton						
Signature	DocuSigned by: Joanne Norman C570524E6DAB4F2...	DocuSigned by: Shelly Leighton 05E379E8E7A145B...						
Title-Organization	NL Hydro	Advanced Access Engineering						
Date	8/16/2021	8/16/2021						

Other Endorsement		
Name		**Stamp, Seal, or other Endorsement**
Signature		
Title-Organization		
Date		

Introduction

Advanced Access Engineering were contracted to provide an internal UAV inspection of the sump pits located in Pumphouse Two at the Holyrood Thermal Generating station. The Inspection Shall:

- Capture meaningful data which can be used to determine the overall condition of the structure, i.e. equivalent to a “General Visual Inspection” (GVI).
- Determine the extent of additional close-up surveys if any.
- Collect visual data at specified locations for condition assessments of known anomalies, temporary repairs and/or product buildup.

Inspection Guidance:

The purpose of the GVI is to visually identify items such as gross deformation, gross damage, significant variance from "as-built" specification and breakdown of internal areas. All findings will be reported accordingly. This report will include photographs with accompanying text throughout.

Photographs should only be added where it will assist or add clarity to the reporting. Re-inspect areas that have a known anomaly and report findings accordingly.

Contents

Advanced Access
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Inspection Summary

Notes:

Advanced Access Engineering were contracted to provide an internal UAV inspection of the sump pits located in Pumphouse Two at the Holyrood Thermal Generating Station. The inspection was carried out on 12 August 2021, with observations as described throughout this report.

Pre-Inspection Questions:

Y/N/NA/U (unsure)	
NA	1) Has a severe event (e.g.,) ship impact, severe storm, etc.) occurred since the previous inspection?
NA	2) Have significant changes occurred (e.g., significant load change or major modification, process/service, etc.) since the previous inspection?
NA	3) If response to question 2 is “Yes”, have any new degradation mechanisms been introduced? If so, update Inspection Scope section.
NA	4) If response to questions 1 or 2 is “Yes”, are there any damages as a result of the event/changes? If so, record details on Pictures section.
NA	5) Have all outstanding anomalies been incorporated into the work pack, if any exist? If not, record details on Pictures section.
NA	6) Have all resolved anomalies been incorporated into work pack, if any exist? If not, record details on Pictures section.
NA	7) Are there any ongoing operations that may affect inspection effort? If so, coordinate with operator and record details on Pictures section.

Inspection Requirements:

Y/N/Na	Resource(s)	Comments
Y	1) UAV Person In Control (PIC)	Jason Wade
Y	2) UAV Spotter	Matt Sibley
Y	3) Inspector – CWI/Marine Surveyor	Matt Sibley
N	4) Specialized NDT (UT, ECI, MPI, etc.)	N/A
N	5) Scaffolding	N/A
N	6) Insulation Support	N/A
N	7) Blasting/Surface Preparation	N/A
Y	8) Remote Access Technologies/Technicians	Internal UAV
N	9) Lighting	N/A
N/A	10) Other	N/A

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Inspection Scope

Potential Deterioration Mechanisms:

N/A

Reference Documents:

- 1403-323-M-002 Stage 2

Wall Thickness Information:

N/A

Location / Design Information:

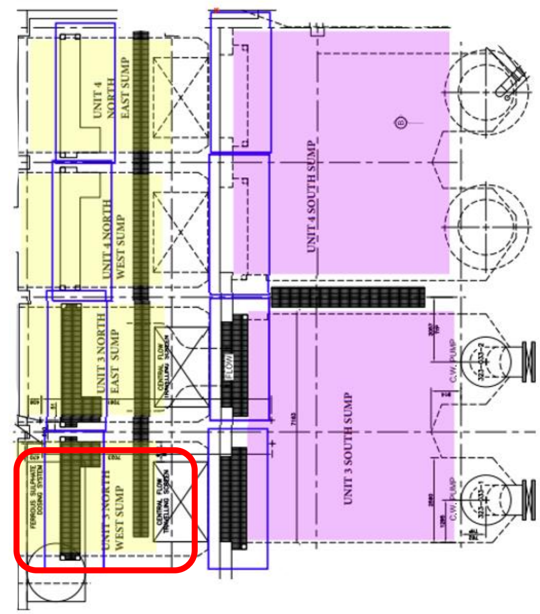
Holyrood

Work Instruction:

1) Perform inspection using UAV in accordance with checklist and provided drawings.
2) Where applicable, a pre-cleaning visual check is required to note the tideline location, residue buildups, etc.
3) For all anomalies populate Pictures section to describe the location and type of anomaly.
4) The inspector should note in the comments section any additional features concerning vessel integrity.
5) Any significant SHE/Integrity anomalies or areas of concern should be brought to the immediate attention of the primary client contact.

Existing Points of Interest

Existing Points of Interest (POI)			
No.	Name	Status	Comments

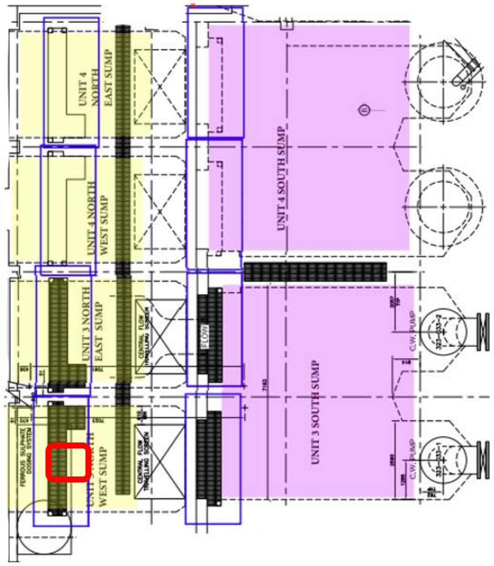


This section will cover
Unit 3 North West Sump

Advanced Access ENGINEERING

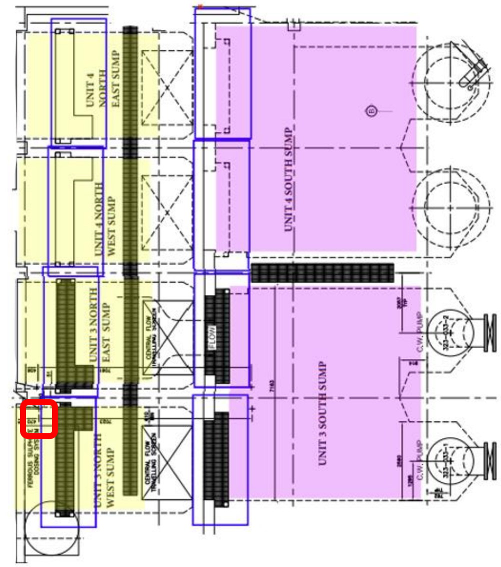
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North West Sump	**Equipment Description:**		**Code:**	-

Reporting



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff of walls and top.

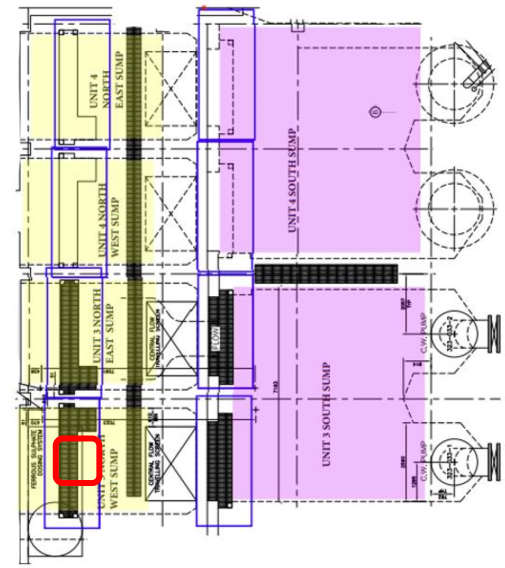
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Deterioration of concrete.

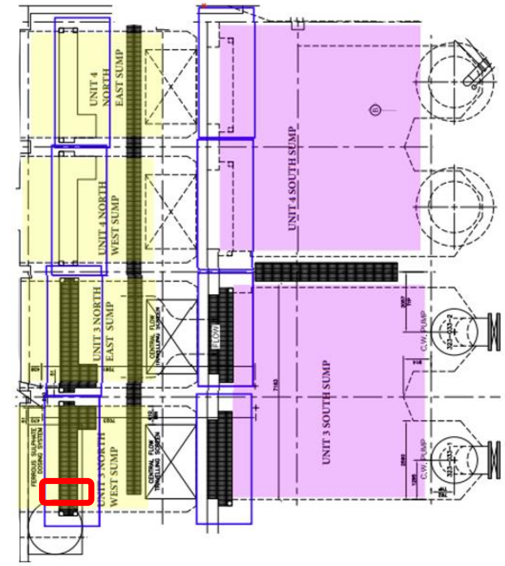
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North West Sump	**Equipment Description:**		**Code:**	-



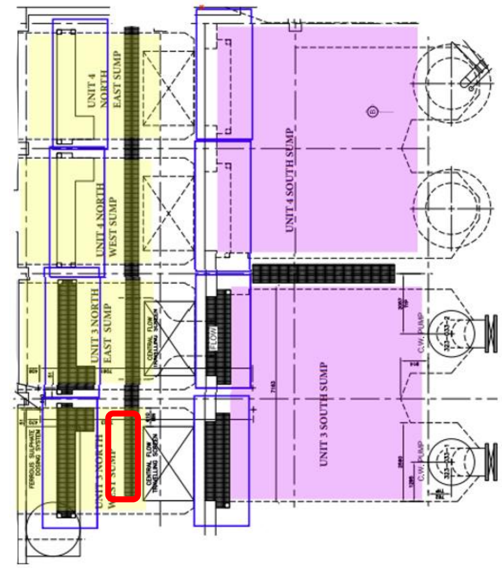
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview wall and ceiling and close up of corner seams.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Repair	-	-	-	-	Repairs to concrete noted throughout.

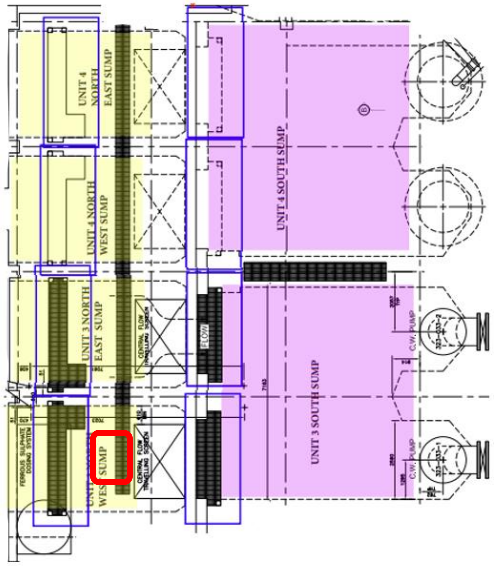
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete deterioration occurring on ceiling of sump/w corrosion of rebar.

Advanced Access ENGINEERING

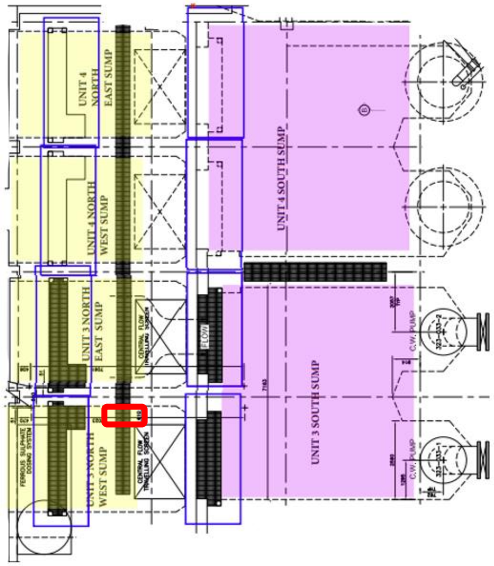
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete deteriorating and corrosion of rebar.

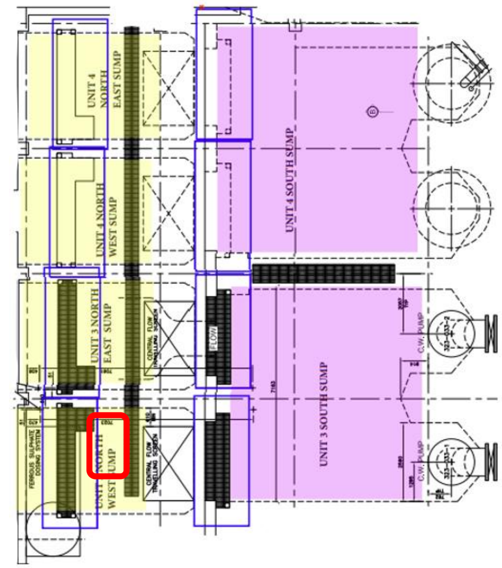
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	General overview of south end of sump, around the traveling screens. Noted throughout.

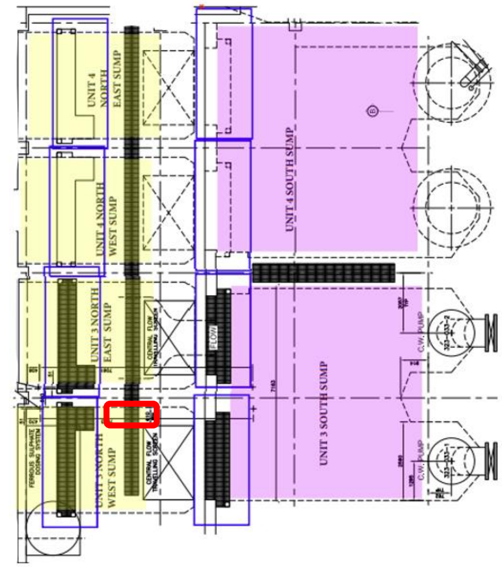
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North West Sump	**Equipment Description:**		**Code:**	-



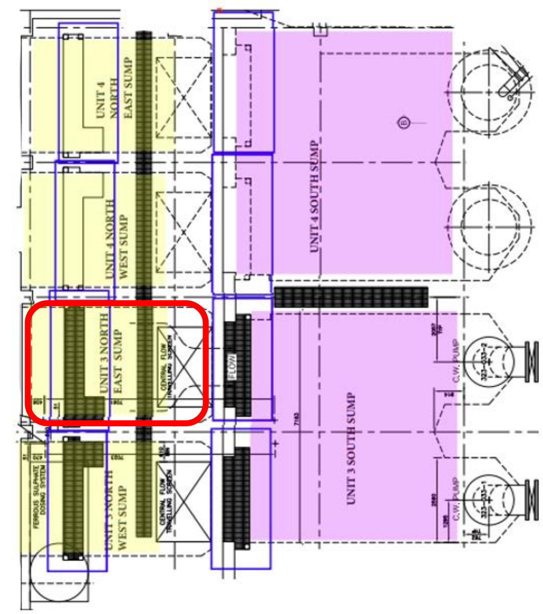
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of concrete	-	-	-	-	Concrete is deteriorating near the access points of the sump.

Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Corrosion on pipe located on ceiling of sump.

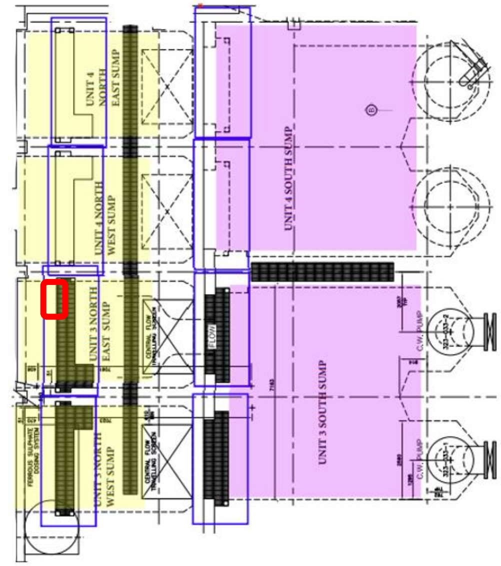


This section will cover

Unit 3 North East Sump

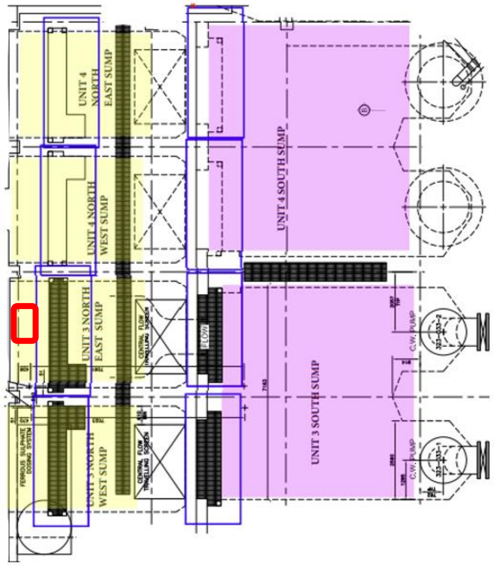
Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North East Sump	**Equipment Description:**		**Code:**	-



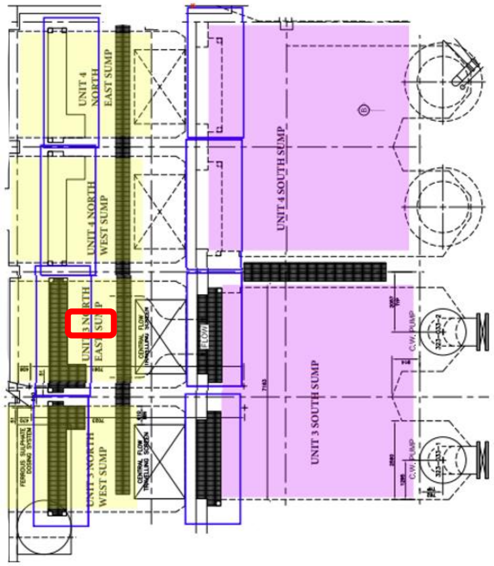
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	General overview of North end of sump Close up of pipe showing corrosion.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration around drainage holes.

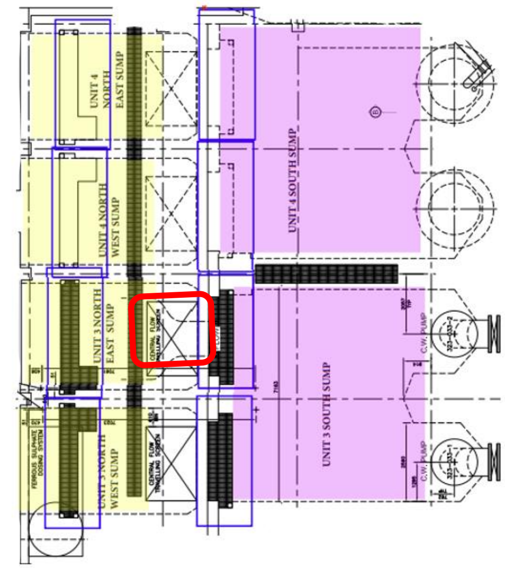
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of pipe looking towards the south end of the sump.

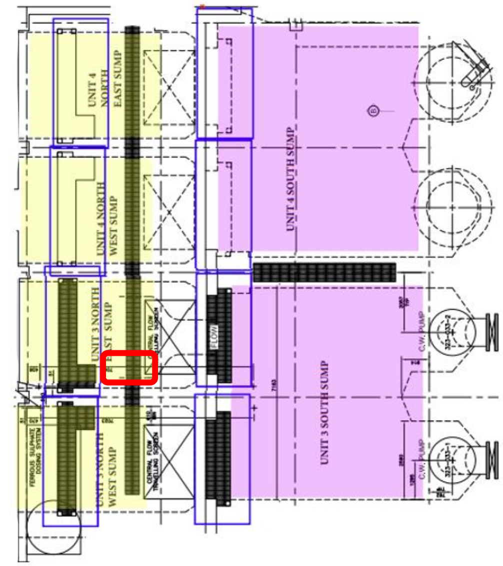
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North East Sump	**Equipment Description:**		**Code:**	-



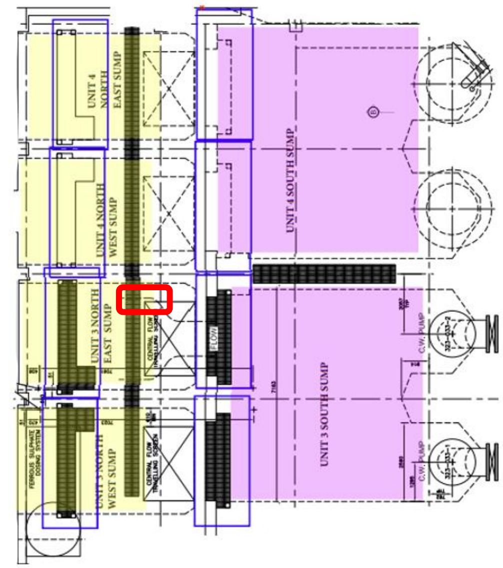
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete/ corrosion	-	-	-	-	General overview of south end of sump Deterioration is present throughout and corrosion of steelwork, noted throughout.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration noted throughout.

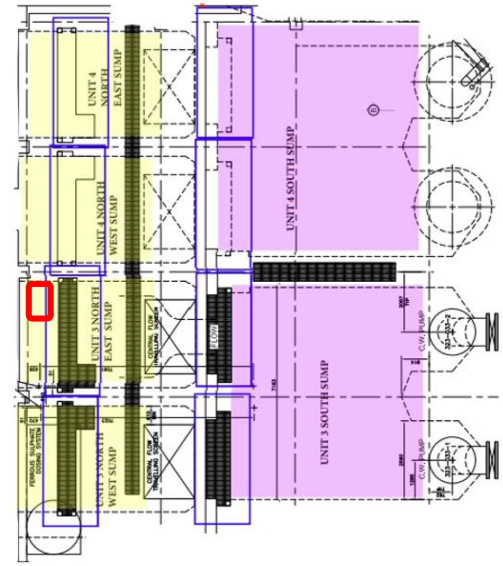
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Corrosion	-	-	-	-	General overview of south end of sump Deterioration and corrosion noted around traveling screens.

Advanced Access ENGINEERING

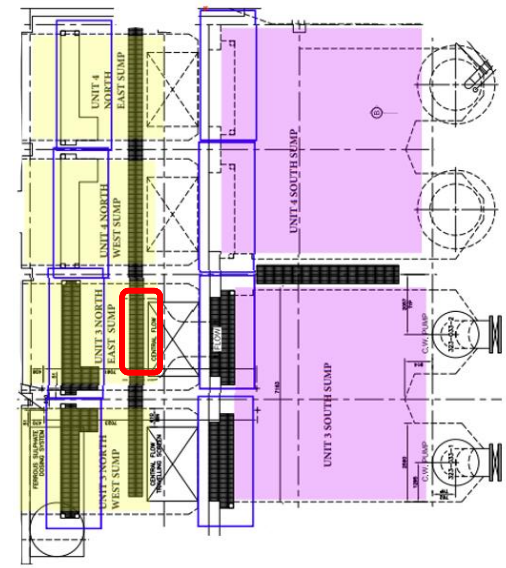
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Embedded object	-	-	-	-	Embedded object.

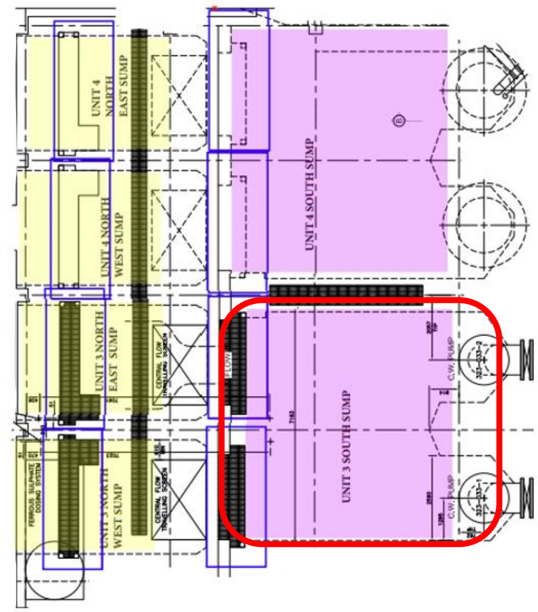
Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration noted throughout.

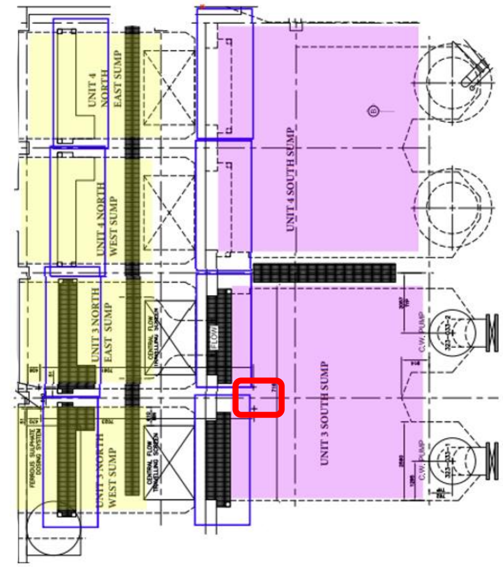
Advanced Access
ENGINEERING



This section will cover
Unit 3 South Sump

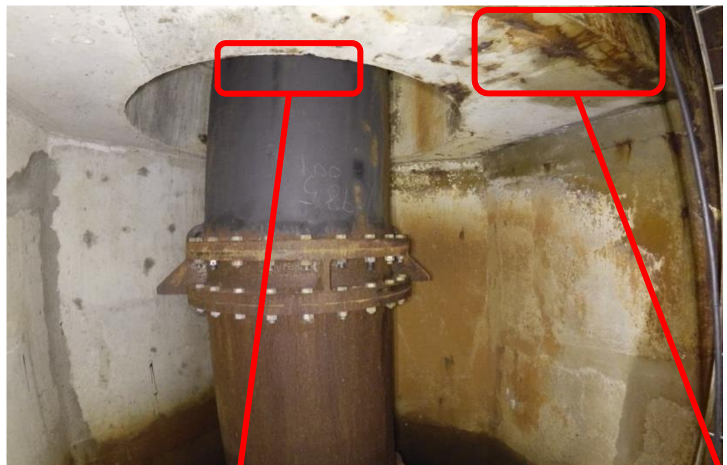
Advanced Access ENGINEERING

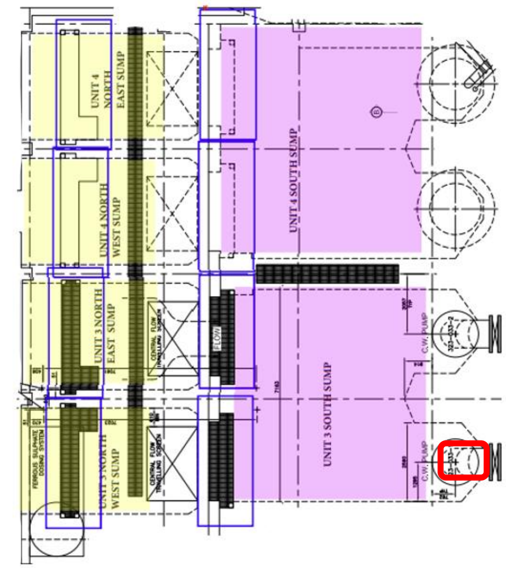
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Cracking and deterioration of concrete near access point of sump.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-

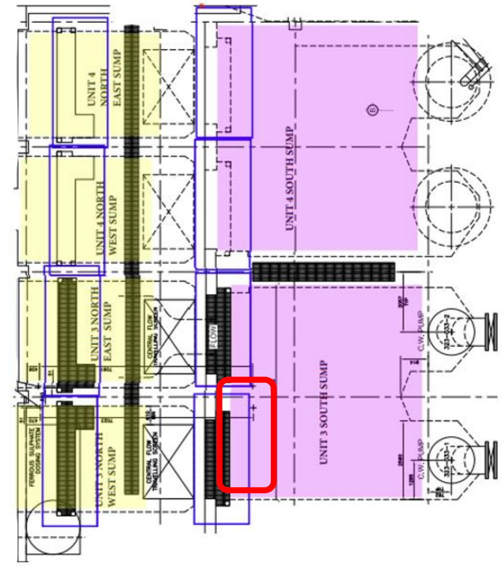




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration of concrete near pump.

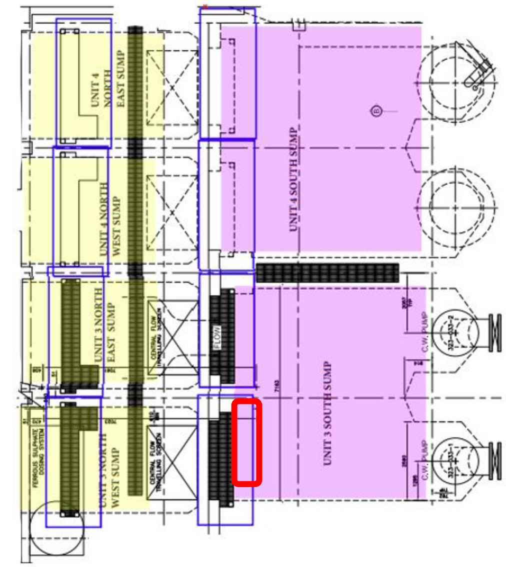
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration of concrete.

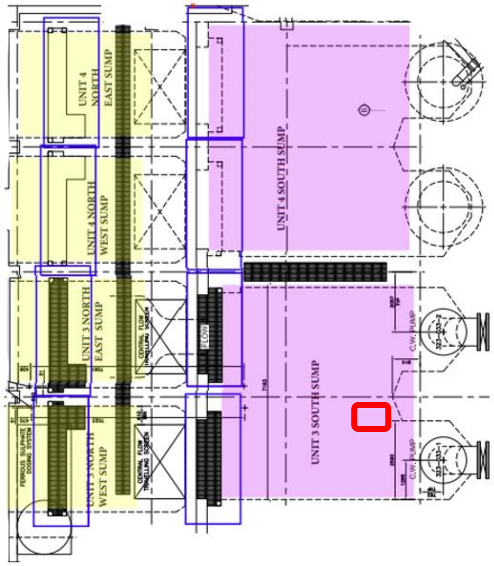
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Corrosion	-	-	-	-	Deterioration of concrete Corrosion of rebar.

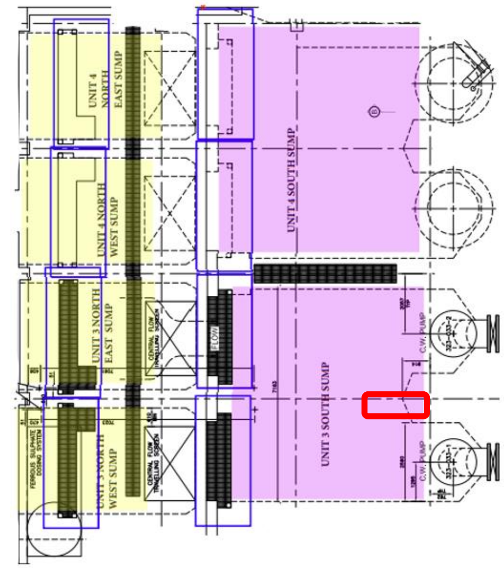
Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Spalling	-	-	-	-	Up close visual of spalling occurring near corner seams.

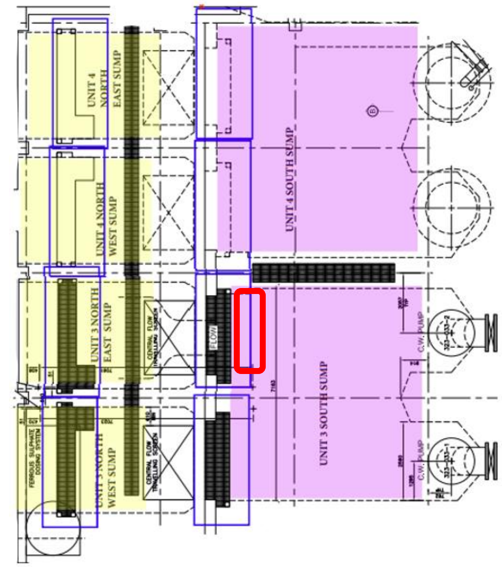
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Corrosion	-	-	-	-	Corrosion of pipe.

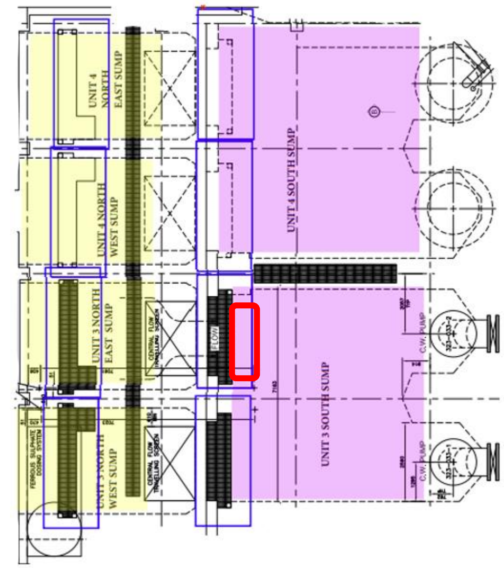
Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



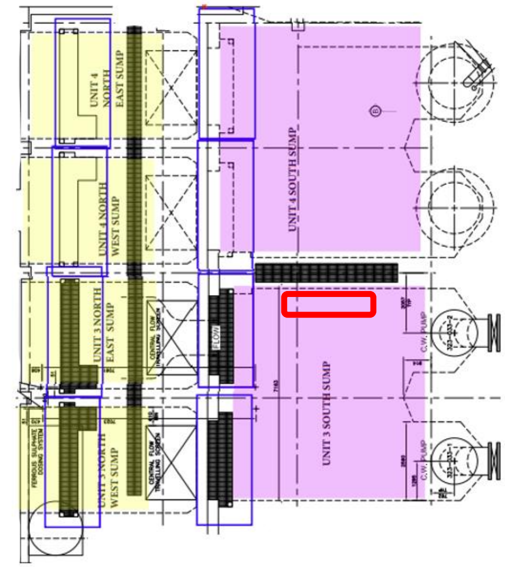
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Cracking	-	-	-	-	Cracking of concrete near access points.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Concrete is deteriorating and sheeting off/ delamination.

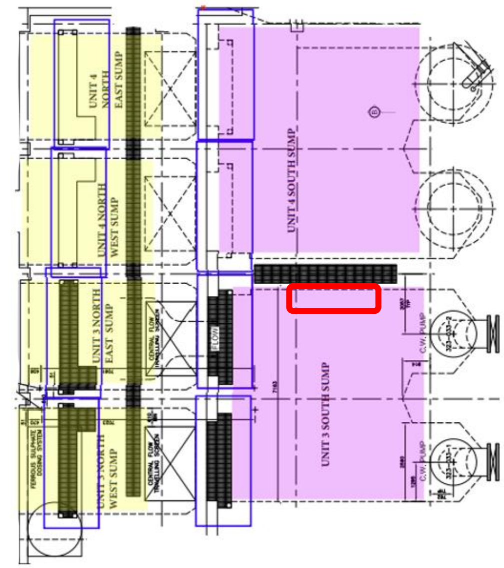
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack in concrete on center beam east side.

Advanced Access
ENGINEERING

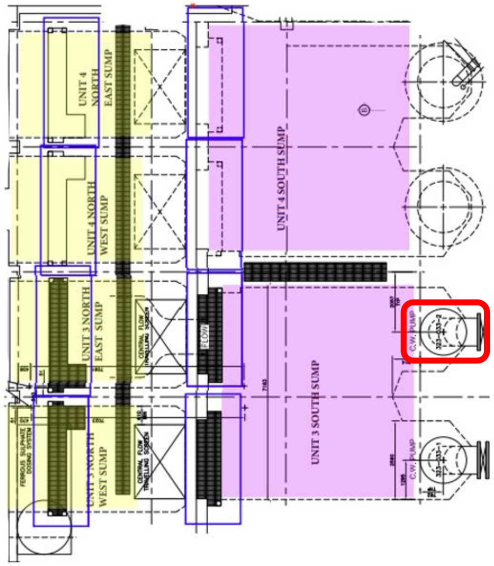
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 3 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack in concrete on center beam east side.

Advanced Access
ENGINEERING

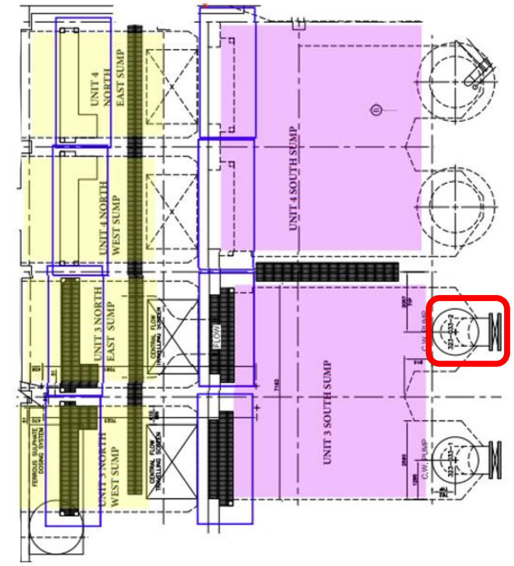
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



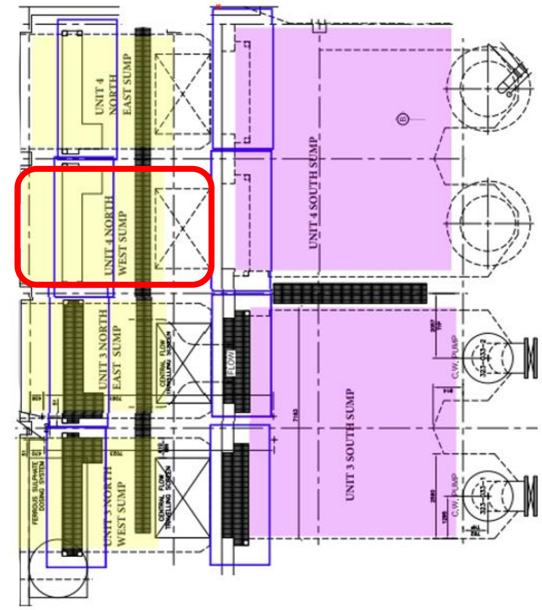
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of pump intake area.

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 3 South Sump	**Equipment Description:**		**Code:**	-



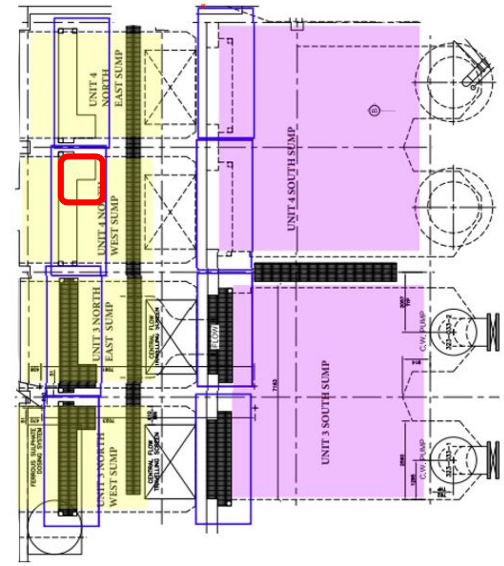
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack in concrete on the pump on the concrete cross member.



This section will cover
Unit 4 North West Sump

Advanced Access ENGINEERING

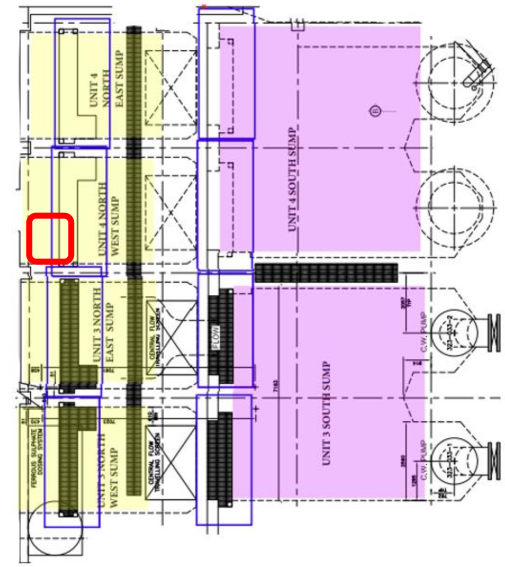
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of ceiling and walls of sump.

Advanced Access
ENGINEERING

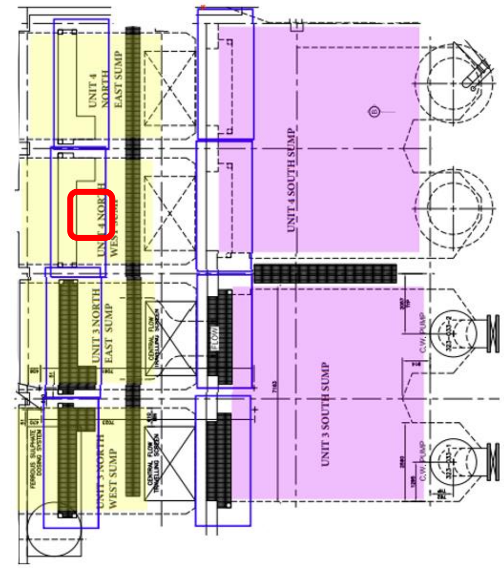
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of ceiling and walls of sump.

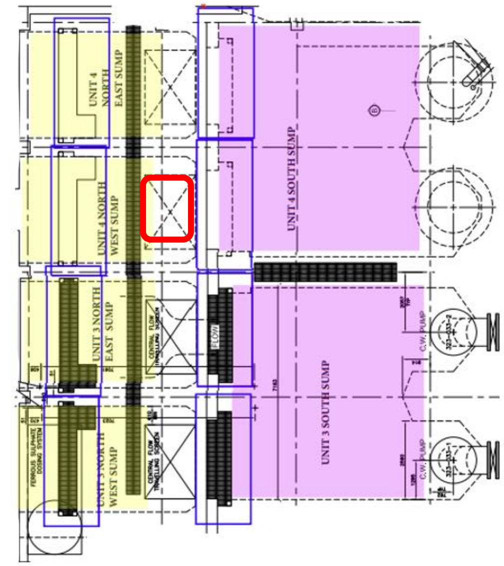
Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Near entry point, deterioration noted around grating.

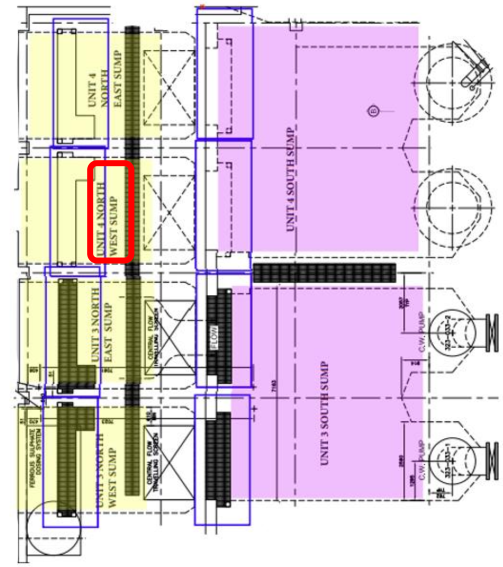
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North West Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Corrosion	-	-	-	-	Deterioration of concrete around hatch, corrosion of hatch

Advanced Access
ENGINEERING

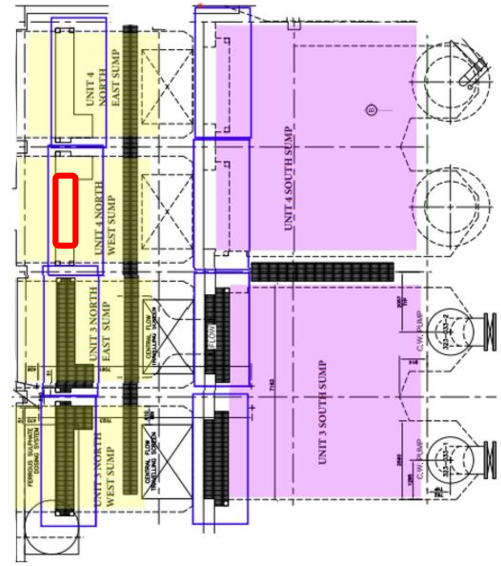
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Crack located towards south end of tank on the concrete cross member.

Advanced Access ENGINEERING

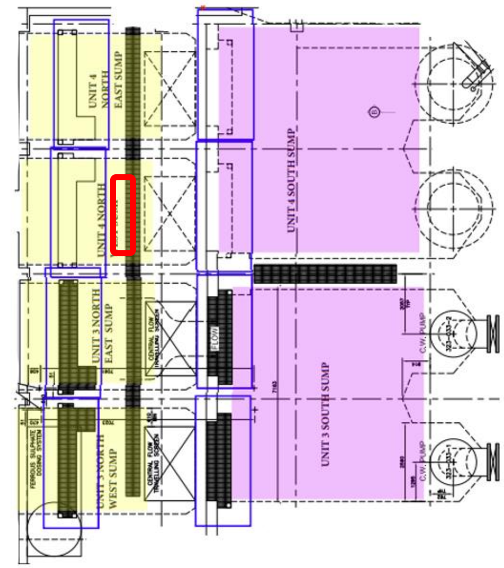
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Crack	-	-	-	-	Deterioration of concrete around hatch, crack formed that can be seen highlighted

Advanced Access
ENGINEERING

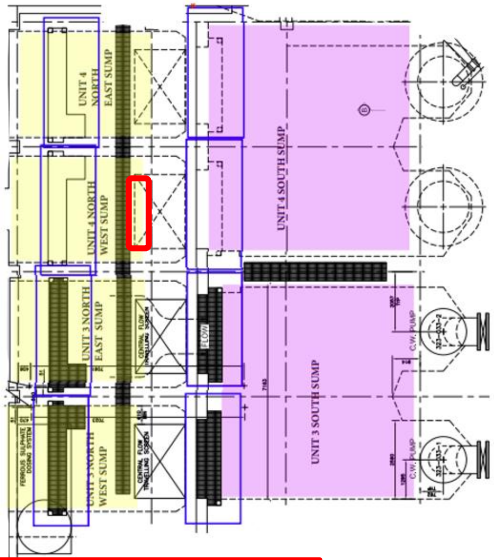
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Cracking of concrete.

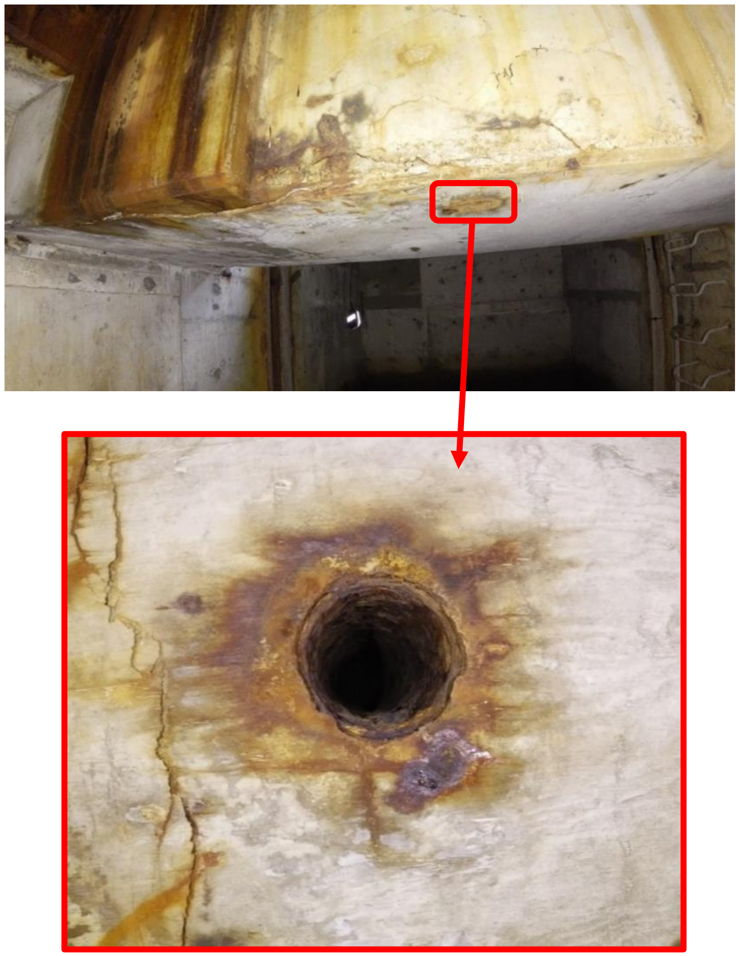
Advanced Access ENGINEERING

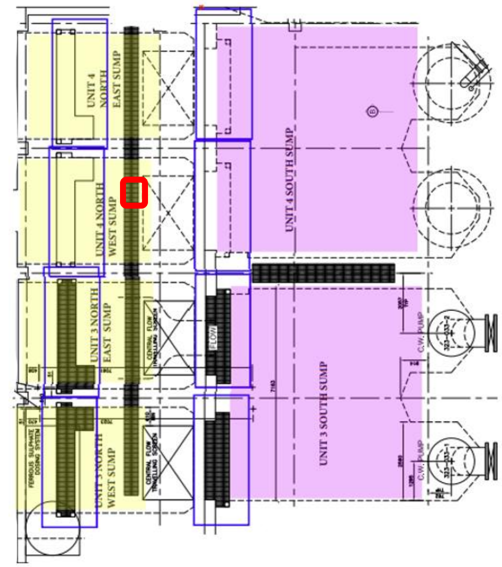
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Corrosion	-	-	-	-	Deterioration of concrete near hatch Corrosion occurring on hatch and supports.

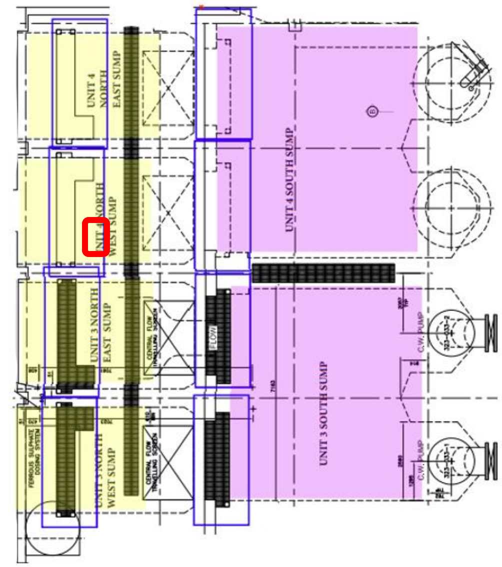
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North West Sump	**Equipment Description:**		**Code:**	-



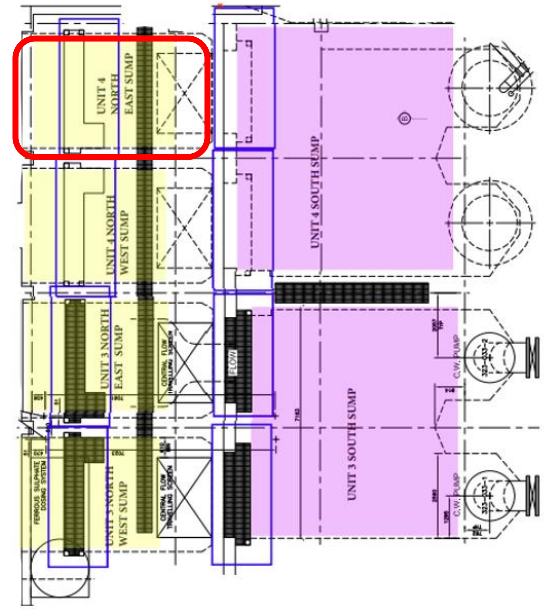


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration around opening/ piping.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North West Sump	Equipment Description:		Code:	-



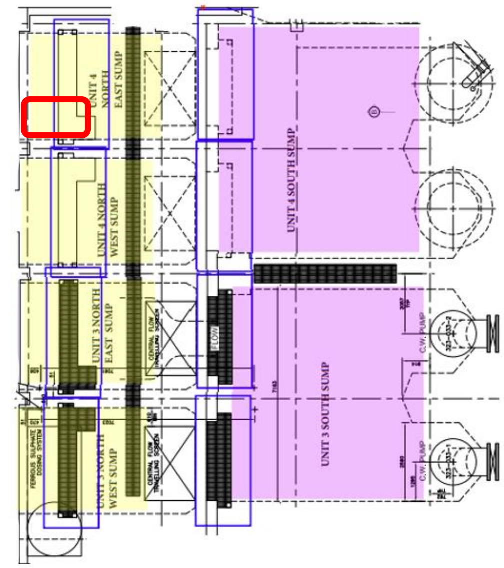
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Crack formed and concrete is sheeting off.



This section will cover
Unit 4 North East Sump

Advanced Access
ENGINEERING

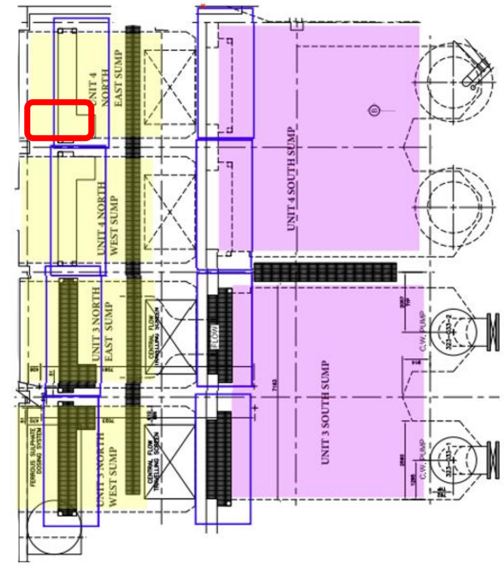
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Crack on ceiling near North end of tank.

Advanced Access
ENGINEERING

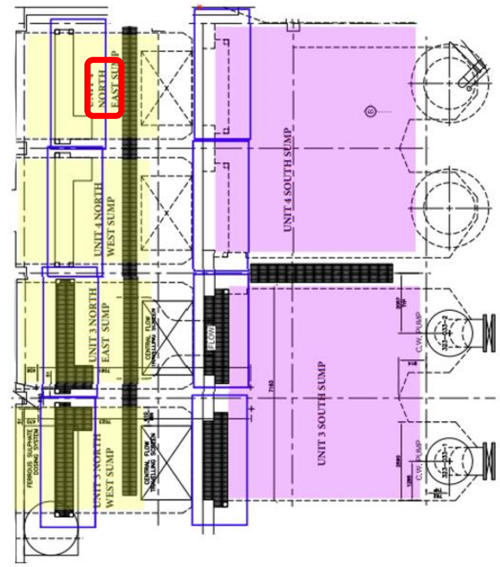
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Repair	-	-	-	-	Appearance of repairs throughout the sump.

Advanced Access
ENGINEERING

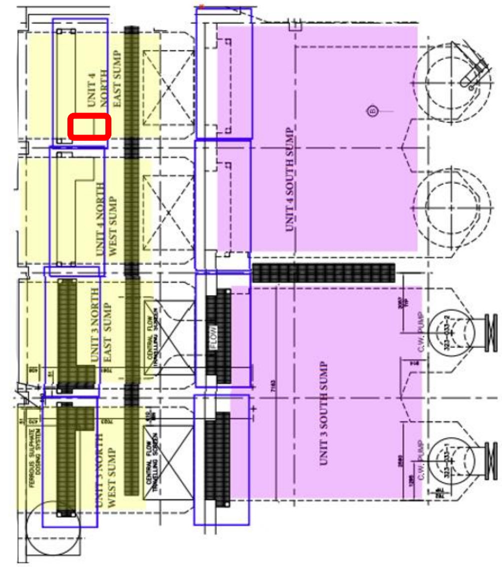
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North East Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Standoff looking north.

Advanced Access ENGINEERING

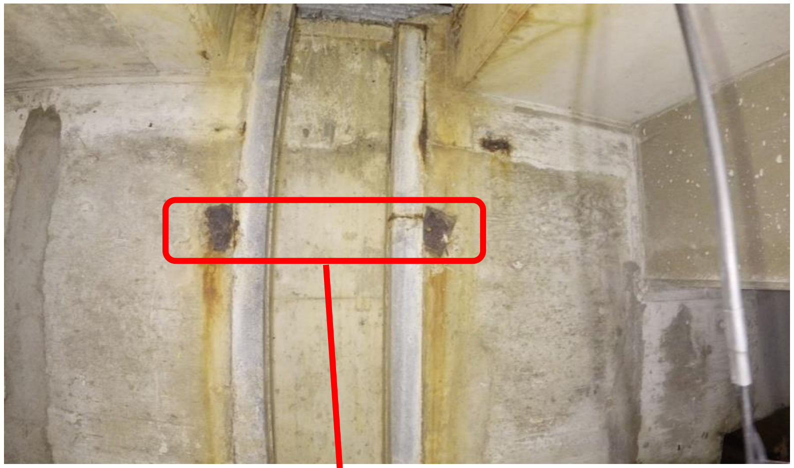
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-

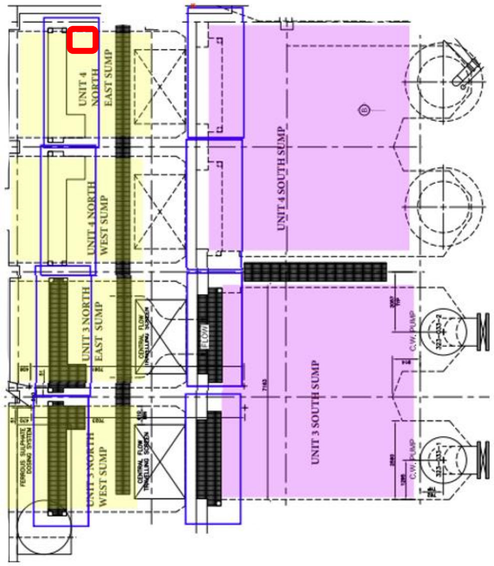


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Near ladder of entry point on stoplog slots.

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-

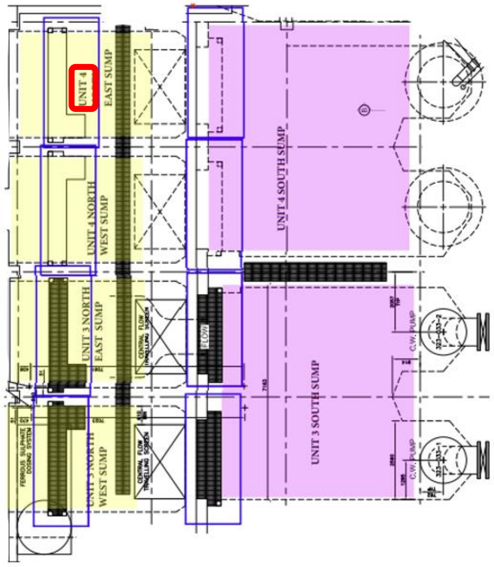




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration of spots Typical of what was seen throughout and along the stoplog slots.

Advanced Access ENGINEERING

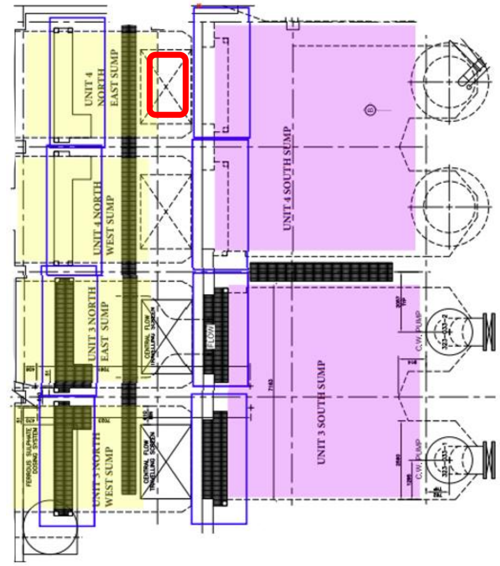
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Corrosion	-	-	-	-	Corrosion of rebar and deterioration of concrete occurring around it.

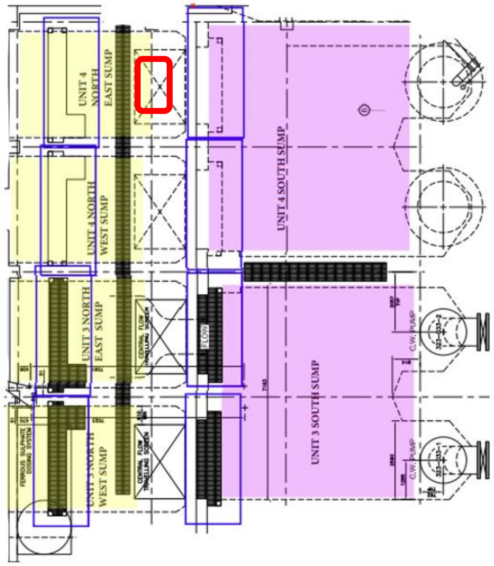
Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration on and around the hatch.

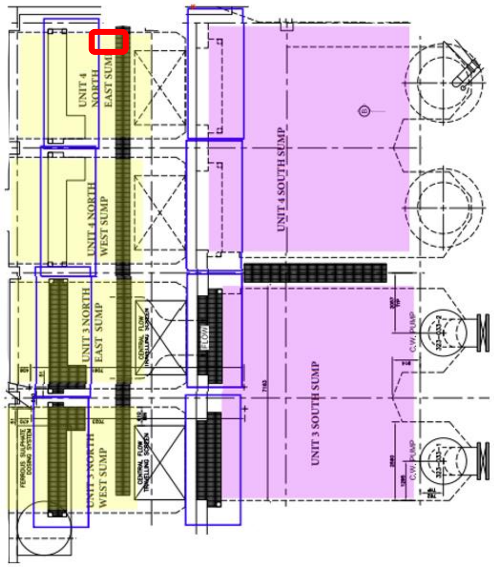
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Minor spalling and deterioration	-	-	-	-	Minor spalling and deterioration occurring near south end looking north

Advanced Access
ENGINEERING

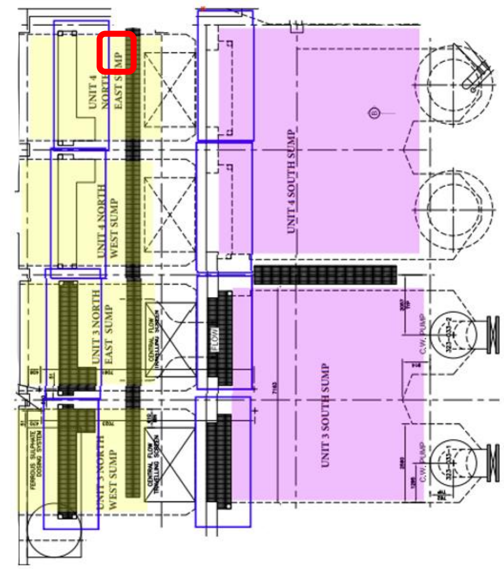
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 North East Sump	Equipment Description:		Code:	-



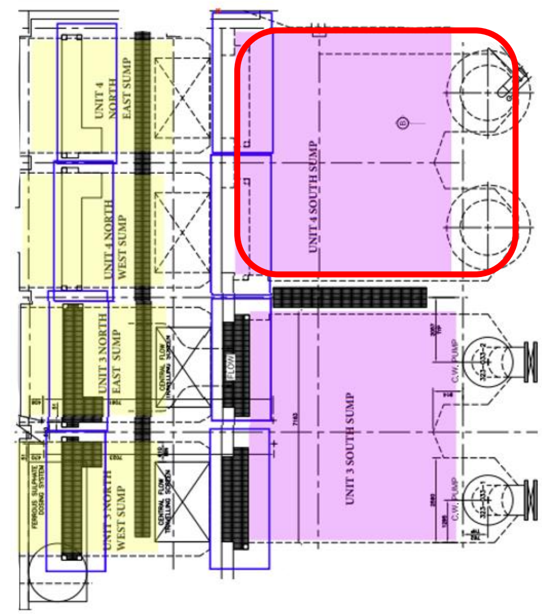
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration of concrete around opening.

Advanced Access ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 North East Sump	**Equipment Description:**		**Code:**	-

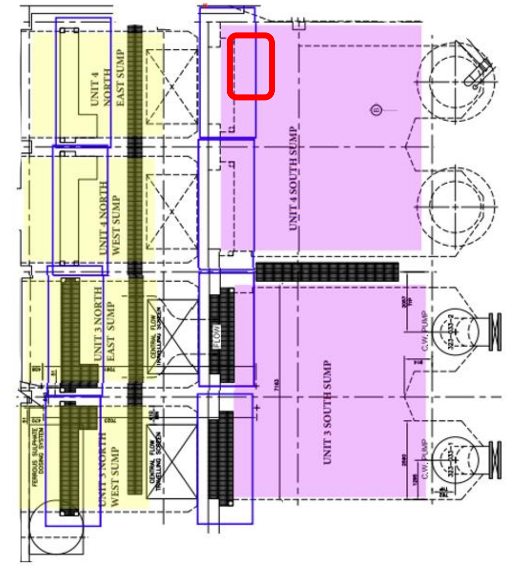


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of access point



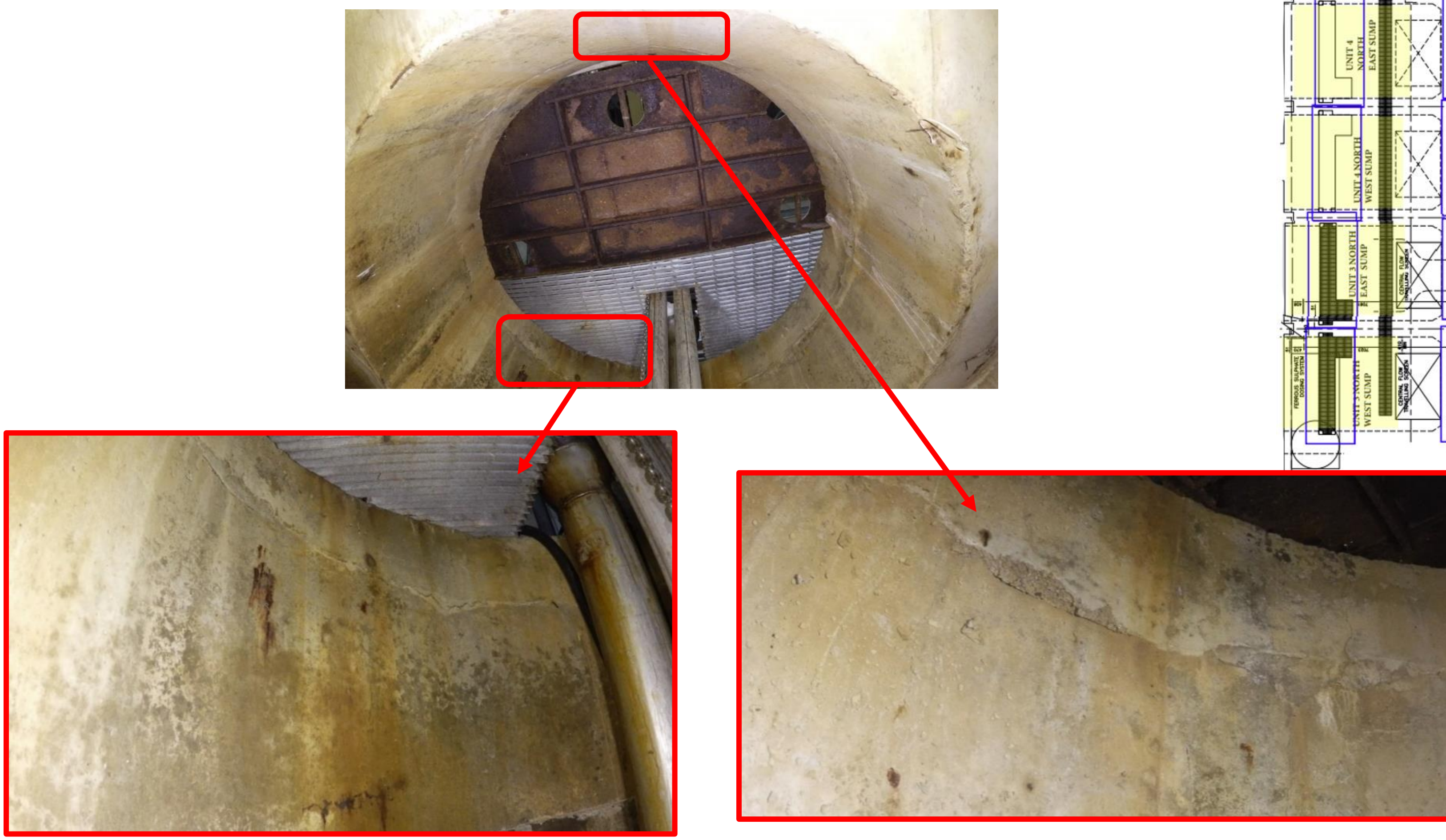
This section will cover
Unit 4 South Sump

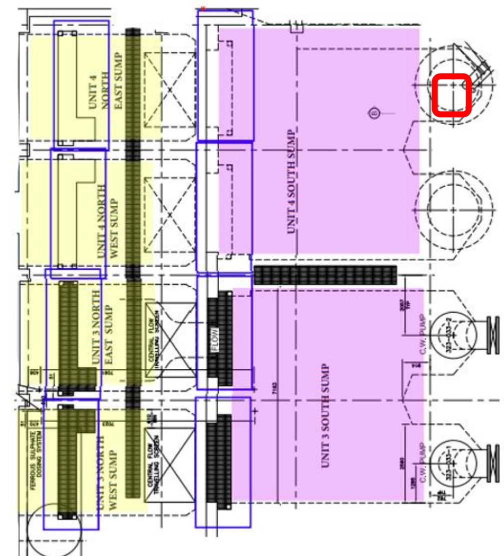
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack / Deterioration	-	-	-	-	Substantial crack formed and deterioration of concrete around crack.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-

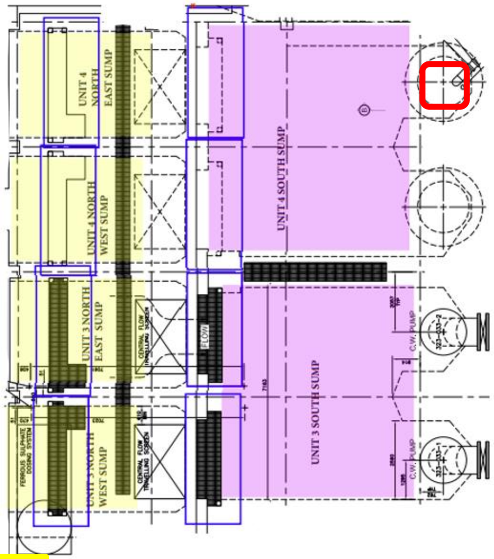


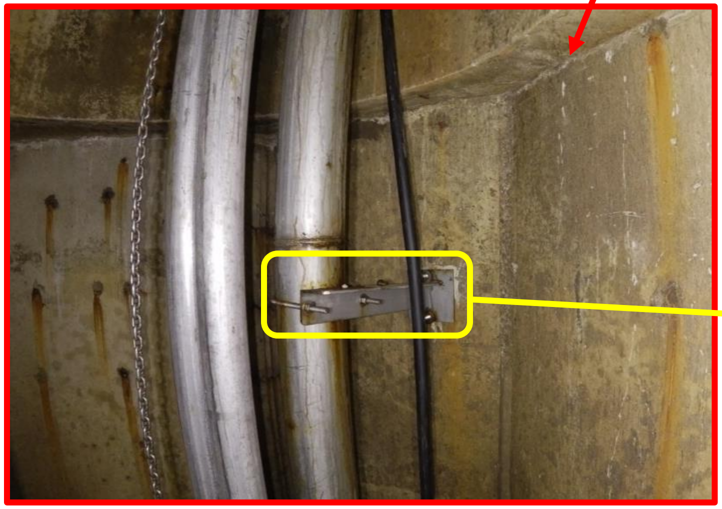


Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration / Minor Cracking	-	-	-	-	Some deterioration occurring and minor cracks forming.

Advanced Access
ENGINEERING

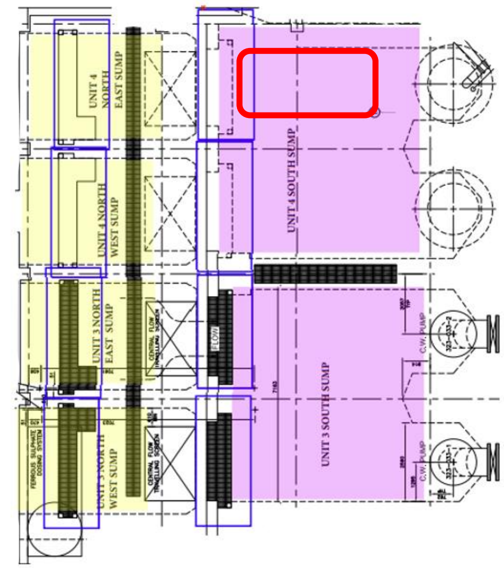
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-





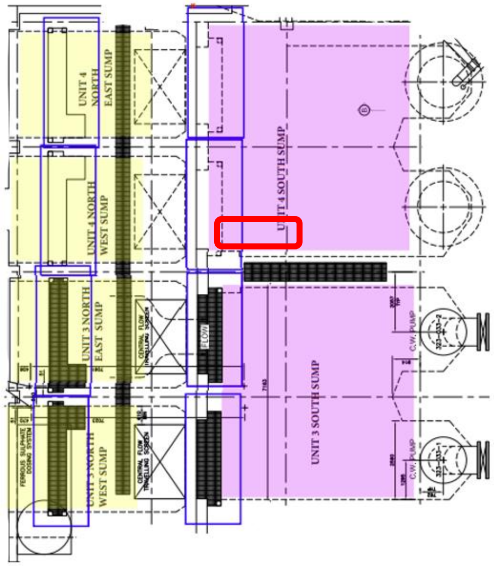
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	Piping is secure and bolted to the wall.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-



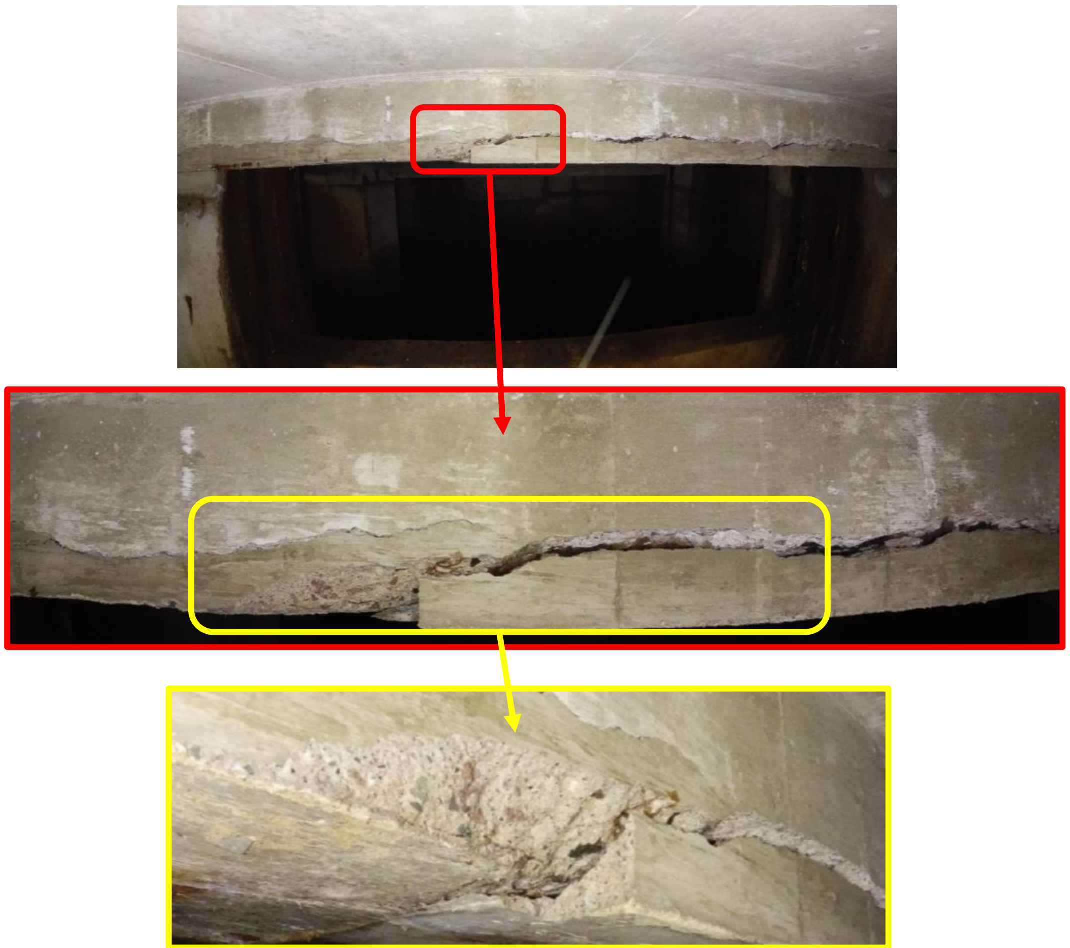
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration	-	-	-	-	Standoff shot and noted deterioration near access points.

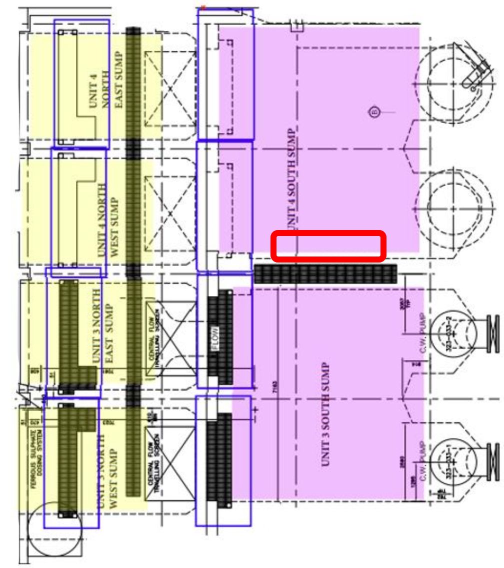
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack formed on the middle beam

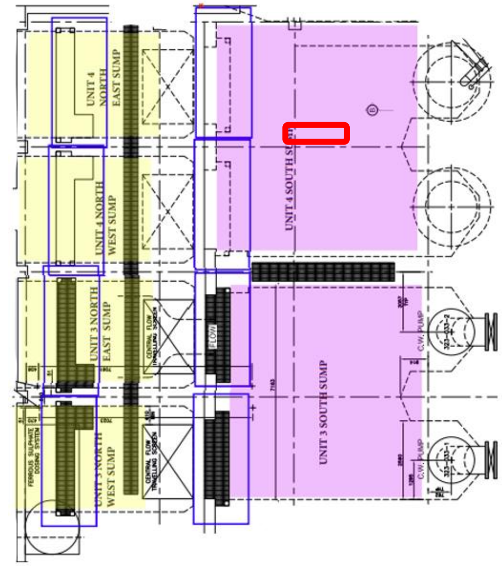
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-





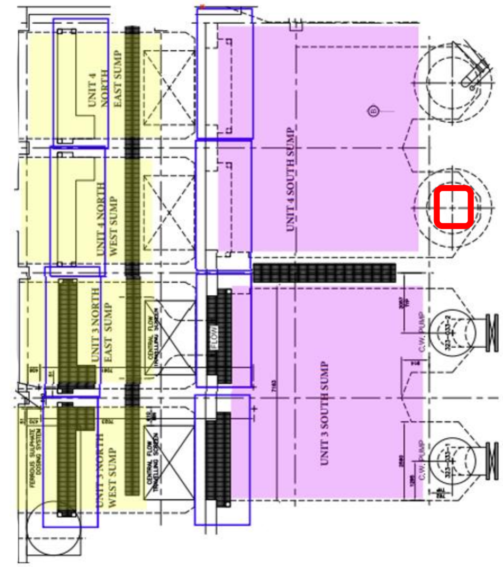
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack formed on the middle beam.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 South Sump	Equipment Description:		Code:	-



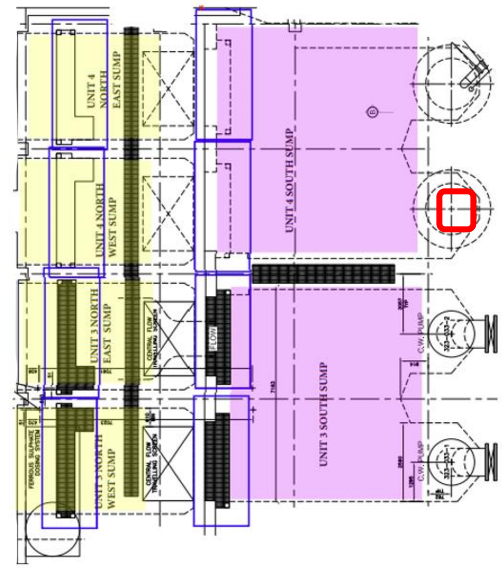
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack	-	-	-	-	Substantial crack formed on the middle beam.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 South Sump	Equipment Description:		Code:	-



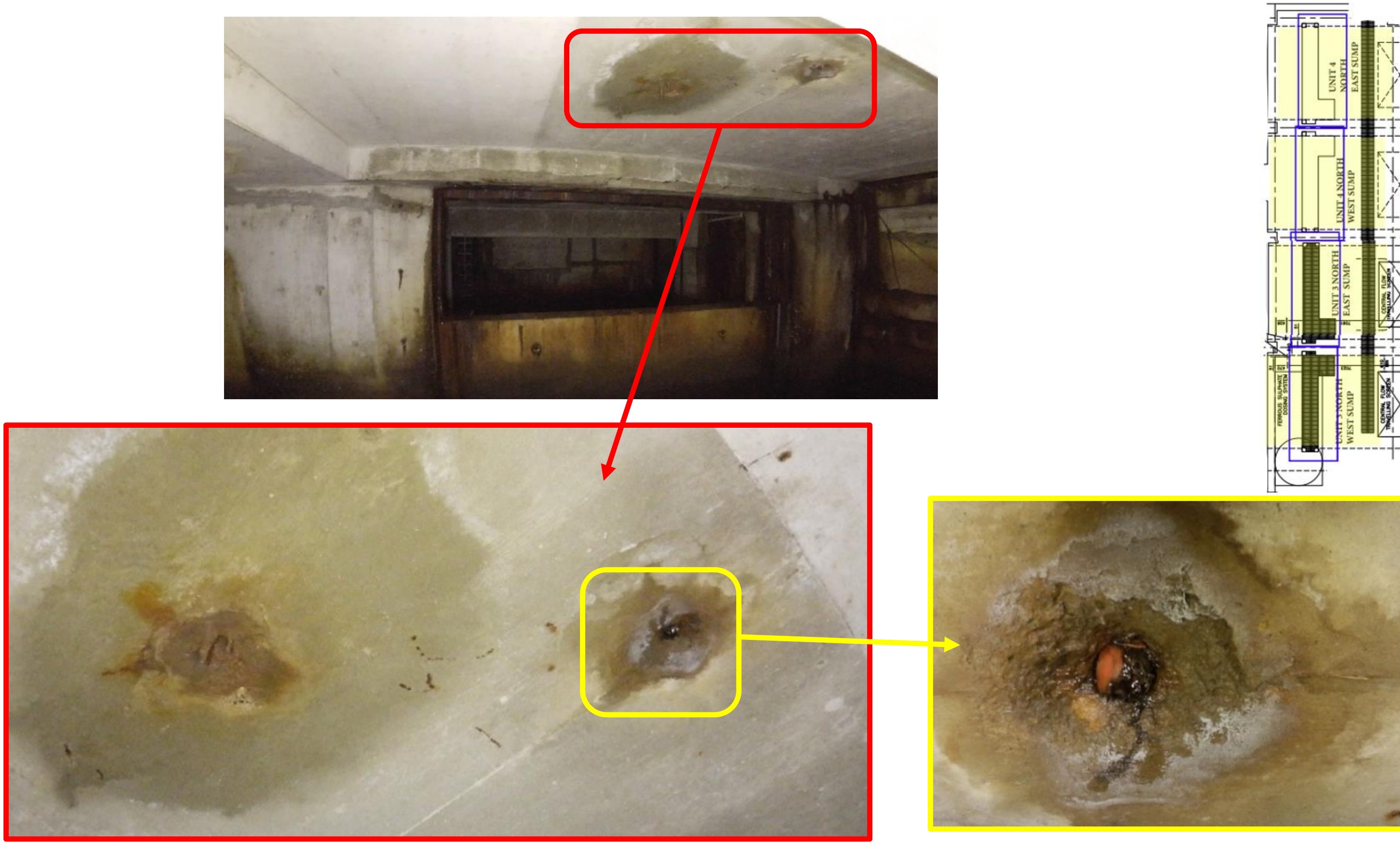
Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
N	-	-	-	-	-	-	-	-	General overview of ceiling and walls

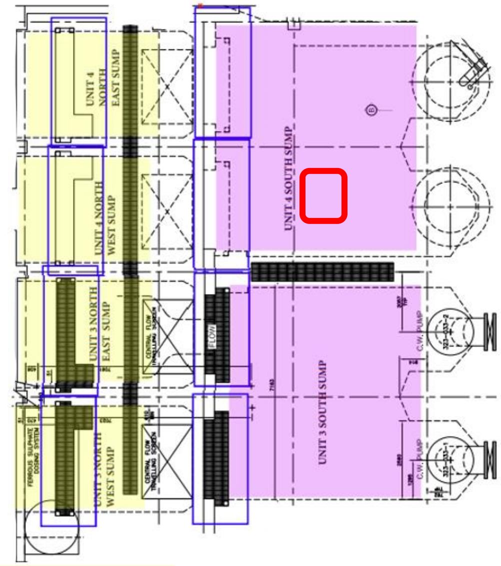
UAV Inspection team:	P: Jason Wade PI: Matt Sibley	**Certification & No.:**	CWI/Marine Survey	**Level:**	-
Date of Inspection:	12 August 2021	**Report Number:**	21-114-007	**Client:**	NL Hydro
Equipment Tag:	Unit 4 South Sump	**Equipment Description:**		**Code:**	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration	-	-	-	-	Deterioration around openings, Typical of what was seen throughout.

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 South Sump	Equipment Description:		Code:	-

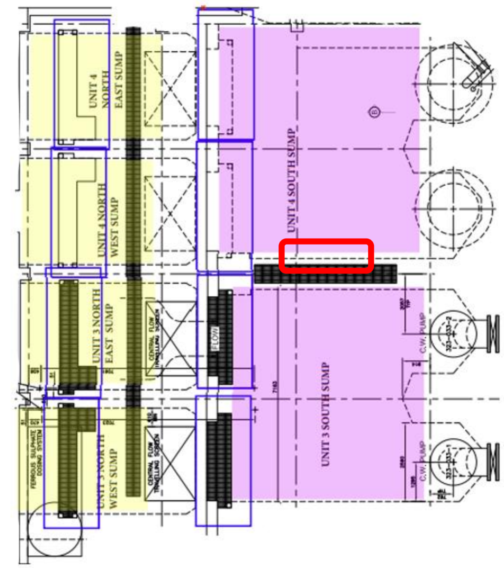




Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Deterioration of Concrete	-	-	-	-	Deterioration formed around drainage pipe.

Advanced Access
ENGINEERING

UAV Inspection team:	P: Jason Wade PI: Matt Sibley	Certification & No.:	CWI/Marine Survey	Level:	-
Date of Inspection:	12 August 2021	Report Number:	21-114-007	Client:	NL Hydro
Equipment Tag:	Unit 4 South Sump	Equipment Description:		Code:	-



Anomaly (Y/N)	ID	Component	Component Tag	Type of Anomaly	Deg of Corrosion	Module	Level	Heat Map	Comments
Y	-	-	-	Crack / Deterioration	-	-	-	-	Looking towards Unit 3 South Sump Substantial crack formed along the length of the beam and deterioration of concrete.

Appendices and Recommendations

Appendices

- 1403-323-M-002 Stage 2

High Resolution Video and Images

Unedited high resolution project files of the inspection can be downloaded from the AAE Client Login Portal. A separate email will be sent providing those listed in the recipient table a username and login.

Recommendations

Recommendations from the inspection team would be to keeping monitoring the area at intervals identified in the asset integrity plan if one exists.

DWG.NO.	TITLE
1403–323–M011	NEW COOLING WATER DISCHARGE PLAN AND DETAILS
1403–323–M–10	NEW COOLING WATER DISCHARGE SECTIONS AND DETAILS
1403–323–M009	NEW COOLING WATER DISCHARGE PIPE ROUTING
B–FG–1403–025	PUMPHOUSE LOCATION OF BUBBLER PIPE SLEEVES
A–670–I033	BUBBLER DIP PIPE CIRCULATING WATER SCREENS
1403–322–E002	C.W. PUMPHOUSE UTILIDOR CABLE TRAY LAYOUT and DETAILS
1403–323–M005	C.W. PUMPHOUSE PIPING ARRANGEMENT – SECTION and DETAILS
1403–323–M004	C.W. PUMPHOUSE PIPING ARRANGEMENT – PLAN and FLOW DIAGRAM
1403–323–M003	C.W. PUMPHOUSE GENERAL ARRANGEMENT – SECTION

REFERENCE DRAWINGS

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
6	02–04–22	ISSUED FOR TENDER	K.B.R.	B.S.	B.S.	M
5	05–10–01	REDRAWN WITH AUXILIARY COOLING WATER ADDED	K.B.R.			
4	16–03–99	FERROUS SULPHATE DOSING SYSTEM ADDED	D.O.			
3	27–3–80	REVISED AS BUILT	G.R.			
2	17–7–78	HOLD REMOVED FOR BUBBLER PIPES	R.G.			
1	26–5–78	GENERAL REVISION ISSUED FOR CONSTRUCTION	R.G.			
0	24–11–77	PRELIMINARY ISSUE	J.W.			

REVISIONS

HYDRO NEWFOUNDLAND AND LABRADOR HYDRO

ORIGINAL DRAWING SEALED BY V.M. PARRISH 1978

ELECT. CIVIL TRANS. MECH. P&C TELC.

SCALE:	None
DESIGNED:	H.Hiscock
DRAWN:	F.Alonso
DATE:	3 FEB 1977
CHECKED:	
APPROVED:	

HOLYROOD GENERATING STATION
CIRCULATING WATER PUMPHOUSE
GENERAL ARRANGEMENT - PLAN

W.O. NO.

DWG. NO. B1 - 1403 - 323 - M002

REV. 6

02-04-19
2:40 PM

PLOT SCALE = 1 : 1 C.A.D.

Appendix H
Marine Terminal Dive Inspection

DIVE SAFETY PLAN
Holyrood Hydro

1	2021/07/13	Issued for Information/IFI	**Alex Afonso** Project Manager	**T Griffin** Dive Supervisor	**Alex R. Afonso** VP & Operations Manager	**Alex R. Afonso** VP & Operations Manager
Rev.	Issue Date	Description	Made by	Checked by	Discipline Approval	Project Approval

TABLE OF CONTENTS

0. Revision Details

Revision	Location of Change	Brief description of Change
1		Issued for Information – IFI

1. Definitions & Abbreviations

CLIENT	NALCOR ENERGY
CONSULTANT	HATCH
SUBCONTRACTOR	AFONSO GROUP LIMITED
AGL	AFONSO GROUP LIMITED
ISO	INTERNATIONAL STANDARDS ORGANIZATION
DCBC	DIVER CERTIFICATION BOARD OF CANADA
DSP	DIVE SAFETY PLAN
DSV	DIVE SUPPORT VESSEL
MEDICOR	HYPERBARIC FACILITY (HEALTH SCIENCES CENTRE)

2. References

Document Title	Document No.
Afonso Diving Manual	2012 rev01
CSA	Z 275.2-11
CSA	Z 275.4-12
OHS Act and Regulations	
DCIEM Tables	
Guide to Safe Diving and Diving Emergencies (WHSCC)	
US Navy Treatment Tables	
AGL HSEQ Manuals	1,2,3 and 4

3. Purpose and Scope

Located in the Town of Holyrood the Holyrood Thermal Generating Station is a thermal generating facility that was put in service in 1969 and consists of three turbines with a total generating capacity of 490 megawatts.

For 2021 Hatch has been contracted to perform a review of specific plant assets as part of the Holyrood Life Extension project. Afonso Group Limited have been contracted by Hatch to perform a dive survey of the jetty structure.

The primary focus of our work will include 1) Surveying all piles with video and surface recording for real time viewing to be completed by the consultant representative. Piles will be surveyed at the tidal, midline and bottom (refer to figure 3.1) and 2) In addition to the pile survey the dive team will survey the hinge pins on the fendering system (refer to figure 3.2)

To ensure that this scope is completed in a safe manner all items will be addressed with in this document below.

Figure 3.1

Figure 3.2

4. Comprehensive Dive Plan

To have a detailed comprehensive plan the following items below must be addressed.

4.1 Contamination
Not Applicable

4.2 Competency
All Divers and Dive Supervisors must be certified to DCBC Standards and meet the competency standards set forth by *CSA guidelines.*

4.3 Medical Certifications
All divers must have completed a Commercial Diving Medical by an approved medical person. Certifications will be onsite.

4.4 Breathing Air
The diving air must be certified to CSA standards and tested every six months by an approved third-party testing laboratory. Bureau Veritas provides these services for Afonso Group Limited.

4.5 Work Recordings
The Dive Supervisor is responsible for ensuring that the diver logs are completed for each dive along with daily report sheets.

4.6 Work Site Identification
The location of the diver diving is a critical component to this plan. Holyrood Hydro's Jetty is in the Southwest boundaries of their facility as noted in figures 4.1 and 4.2 below. The area is active for boats or vessels therefore a diver flag must be raised during all dive operations and constant communication with marine traffic is imperative.

During all dive operations there will be continuous communication with the diver to topside diver supervisor and with the clients' operators and or representatives. Communication will be completed using cell phones and or portable radios.

A diver flag Alpha will be raised during all dive operations and removed daily when no diving is taking place.

This item will be further captured in the work permit, Hazard Assessments, work procedures and coordination of the work.

Figure 4.1

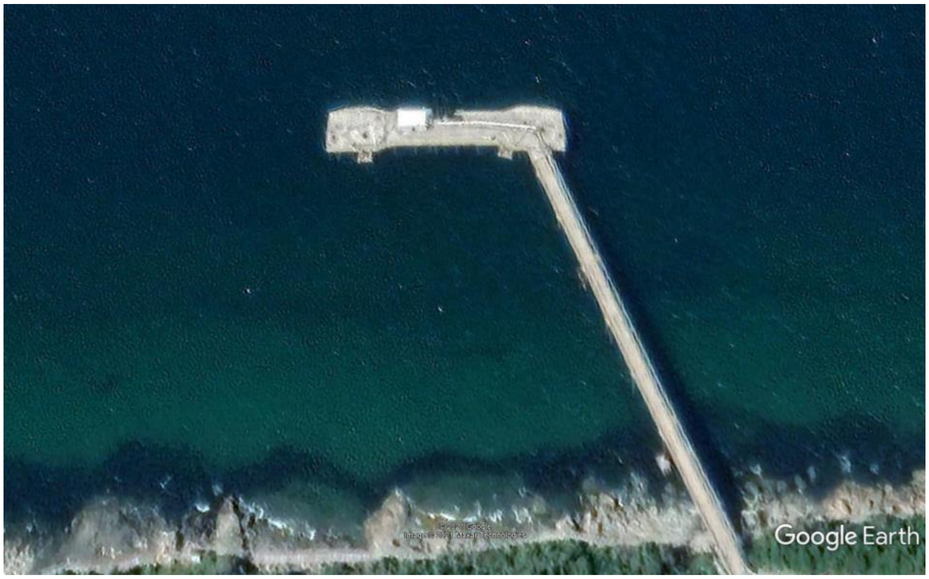


Figure 4.2

4.7 Diving Mode

The diver will be using KM 37 or 18. The diving program will be completed using surface supplied breathing air with an integrated umbilical to include communication rope, air hose and pneumo hose. Four 4500psi high pressure air cylinders will be regulated to a breathable pressure for the diver diving.

4.8 Communications

Communications are a vital part to all dive operations. The diver will have full communication with the Dive Supervisor. If at any time voice communications fail, (refer to section 7.1.2 of the AGL dive safety manual) pull signals will be used to warn each other and all dive operations will be aborted until communications are repaired.

Vessel traffic will be monitored by Cell/ Radio always during dive operations and continuous communication.

Tools for communication will include cell phones, marine radios and or personal radios with secure frequency. **Refer to cell numbers in the appendix section C.**

4.9 Decompression Procedures and Tables

The tables used for this dive operation will be DCIEM Standard Air Dive Tables. At no point is Decompression Diving to be considered. It is the intent to dive a *No Decompression Dive* each time.

4.10 Crew Size

The crew size will consist of the following:
Top Side Dive Supervisor (1)
Divers and Diver Tenders (+3)

4.11 Diving Cylinders

All diving cylinders are High Pressure 4500 PSI Cylinders.

4.12 Vessel Traffic

Vessel traffic will be advised of dive operations as well as with the client representatives on cell phone or radios.

4.13 Work Scope and Coordination of Work

To perform the tasks at hand various factors must be addressed to eliminate any risks. Details on the scope of work must be addressed, hazard assessments must be developed. For further details refer to the Appendix section A.

4.14 Contingency or Emergency Plan

In the event of an emergency whether it is an injured or unconscious diver at the dive location. Each event will be dealt differently and will have specific protocols.

A) For an injured diver in the water, we will have to consider the following factors.
- Is he or she unconscious?
- Can the diver be recovered from the water via the ladder, or to shore?
- Once the diver is recovered does he require first aid, medical aid, or hyperbaric treatment.
- If the diver or other person requires treatment, will he be brought to be treated by a first aider, paramedic/ hospital or to medicor. How will he be transported from the site?

B) For the Abort Dive Operations or could be for various reasons, Environmental conditions can affect the dive operations which will be monitored by the Dive Supervisor or contractor or client.

For Further details refer to the appendix section B.

APPENDIX

Appendix A- Scope of Work

The primary scope of work involved a visual and videorecording of all jetty piles from the splash zone, mid-line, and bottom. If there is heavy MG a small patch will be scraped clean for assessment. After the jetty piles are surveyed the fender system will me assessed too. The work will be coordinated in the following manner:

1. If a vessel is docked at the jetty, then Supervisor will be responsible for witnessing isolation certificate which has been completed by the vessel operators, or client representatives. Once the isolations are completed, the Dive Supervisor will sign the Permit to document that he has witnessed the lock outs.

   Once all isolations are in place and satisfied by the permit to work system and signatures of authorizations are in place and the client are notified and sanctions the dive area safe to dive then diving will commence.

2. During the process of step 1 above, the dive team on site will be performing all necessary checks on the diver equipment such as air supply, leaks, communication, emergency bail-out system, certifications. They will review the tasks at hand, risks and hazard assessments, roles and responsibilities of all parties and will discuss in detail the Emergency Plan. They will fill out, review, and sign all JSA'S, Hazard Risk Assessment and Permit and will have all dive team members do the same. Once all checks are satisfied the Supervisor will *record the permit number daily.*

3. The Dive Supervisor will then notify Operations and Medicor of diving operations location and company. For each dive day, this will be done and at the end of each day Medicor will be advised that diving operations are suspended until further notice.

   The Supervisor will document each time Medicor is called in his Daily report sheet or on the diver log sheet and complete the attached pre-dive checklist.

4. During the dive, the standby diver will be "dressed-in" always when diving operations are in progress. *The safety diver will be fully equipped to dive on surface air supply and ready to enter the water,* with all life support and communications equipment tested and at hand but, not necessarily with the helmet or face mask in place. The tenders will be standing by to look out to the needs of both the divers.

   The dive supervisor will be recording the activities of each individual diver, separate from the log owned and maintained by the diver. The daily records for each diver will be recorded on the daily record file sheet and filed for future reference.

Each individual diver is responsible for their own log which must be filled out daily and signed by the dive supervisor.

All aspects of the dive operation are to be controlled by and under the direction of the diving supervisor.

The air the divers will be breathing will be atmospheric gas and will be stored and supplied via a HP cylinder cascade system through a diver panel and umbilical c/w hard wire communication system. Each diver will be carrying a pony bottle bail-out cylinder with *2 ½ quantity* of air for the diver to abort the dive and surface in the event of a malfunction in the primary breathing supply system.

The dive team will be working from a DSV fitted specifically for dive operations with supplied heat and light.

When everyone is satisfied that all safety measures are in place and the diver is comfortable with his task, a final systems check will be made, and the diver may enter the water. Upon being submersed, during decent the diver will stop, and a systems check will again be performed. If the diving supervisor is satisfied, and the diver is comfortable with performing the task, the diver will be lowered to their maximum dive depth where work can begin. During the diving operation, the supervisor will, at regular intervals, ask the diver to confirm that he feels no discomfort and has no problem continuing the dive. Should, at any time, the diver wishes to abort or discontinue the operation, he is to stop work, let topside know the situation, and his assent is to begin under the direction of the diving supervisor.

The depth of the dive will be approximately 15-20 meters. The duration of any dive will not exceed the no-decompression dive limits as outlined in the DCIEM tables. When the diver has completed his task, he will, under the direction of the dive supervisor begin his assent and exit the water. When the dive operations have ended for the day the Supervisor will notify the harbour authority, medicor and contractor. *Once the dives have terminated for that day then* the permit will be closed off and all necessary lockouts will be removed. The dive supervisor will monitor the diver's time and depth to keep him well within the no decompression limits.

Remember: *No overhead lifting to take place above the diving area*

The safety of the public and our dive team is of the utmost importance to us, so any additional information regarding the safety of our divers will be welcomed and appreciated.

Note: In the event of any emergency refers to Emergency Protocol section 4.14

With respect to the two scopes these items will be addressed in the Hazard assessment.

Appendix B – Emergency

Prior to any diving operations the following items are required:

- Communication (Cell and radios)
- Ladder for Diver Entry (not required as diver can safely exit water from shoreline)
- Diver Davit recovery system or
- Secondary Rescue vessel for Diver recovery.
- Fire Extinguisher
- First Aid Kit
- O2 Emergency Kit
- Spill Kit
- Posted Emergency Contacts

All personnel must be fully aware of the item's locations and easily accessible.

In the event of an Injured Conscious diver the following steps must be followed. Supporting documentation on page 9 Section 76 of Afonso Dive Manual.

1. Dive Supervisor to determine if there is a response from the diver. If so, then assist the diver to the surface and if possible, have the diver climb the ladder to the wharf.

2. If the diver cannot climb out on his own, then the diver will be recovered using the primary or secondary diver recovery system.

3. Once the diver is recovered, the Dive Supervisor will assess the situation. Based on the seriousness of the injury the Supervisor will determine if it is a first aid response or if medical aid is required. In the event of Medical Aid being required the dive supervisor will designate a diver by name to call 911 providing them with details of the location to pick up the injured diver.

4. If required, Medicor will be notified too.
   Once the locations are delivered to the Emergency Response Team (911) the DSV or rescue craft will transfer the diver to the pickup point. Upon arrival Paramedics crew will take control of the situation.

In the event of an Unconscious diver the following steps must be followed.

1. Dive Supervisor will make every attempt to recover the diver to surface without using the standby diver. If the diver can be recovered to surface, then the use of the FRC or barge or diver recovery system or from the shoreline will be used and the following steps will take place. NOTE: If the standby diver must enter, he must take extreme caution upon entering the water and slowly follow the diver's umbilical to further assess the situation. The safety diver is not to approach the diver if there is an inherent danger to him too. He can only continue if and only if he is certain that there are no other risks to him. If the safety diver can retrieve the injured diver, then proceed to the next step.

2. Once the diver is recovered, the Dive Supervisor will assess the situation. Based on the seriousness of the injury the Supervisor will determine if it is a first aid response or if medical aid is required. In the event of Medical Aid being required the dive supervisor will designate a diver by name to call 911 providing them with details of the location to pick up the injured diver.

   Once the locations are delivered to the Emergency Response Team (911) the rescue craft will transfer the diver to the pick-up point. Upon arrival Paramedics crew will take control of the situation.

FOR AN INJURED DIVER REQUIRING MEDICAL TREATMENT FOLLOW THE PROTOCOL IN APPENDIX J OF THIS PLAN

In the event of an Abandon the Site (Environmental or Other) the following steps are to take place:

1. Dive Supervisor will notify the diver diving to abort all operations. He will be made aware of the situation and advised to return to the work site.

2. The diver will surface and exit the water via the ladder. If the diver requires assistance than the diver will exit via the shoreline.

3. Once all team members are onboard, they will make every effort to secure all tools and equipment if time permits.

4. Once they are in a designate safe zone they will contact the contractor of their location, condition and provide a head count.

5. They will stay at location until further notice or travel to the nearest and safest docking facility to wait further instructions.

For the unconscious diver:

1. Monitor the victim's vital signs (ABC). If possible, administer 100% oxygen with a flow of 15 litres / minute.
2. Initiate call to Medicor at the Health Sciences Centre or 911 to advise of location and situation. Inform paramedics of pick-up location and contact information.
3. Mobilise victim from rescue boat/barge to closest and safest port.
4. Continue to monitor victim until paramedics arrive.
5. Transfer the victim to ambulance and supervisor should accompany the victim.

Appendix C- Roles and Responsibilities:

Dive Operations Supervisor

The Dive Supervisor will be responsible for the following:

1. Planning the dive depth, no decompression diving plan, ensuring all personnel have the proper certifications in place and that all equipment is inspected, working properly and or certified.
2. Discussing the task at hand with all divers / team involved and the rescue boat crew.
3. Discuss the emergency plan, prepare a toolbox meeting, and prepare hazard assessments with the crew. Completing the Permit and signing it and returning it to the Supervisor.
4. Communicate with the Contractor on a continuous basis via phone and radios. Supervisor must be aware that no diving can start until given permission by the Contractor and or Harbour Authority
5. Anytime the supervisor feels the task or job is unsafe he has the authority to abort all dive operations.
6. Additional responsibilities are set forth in Afonso Dive Manual, Page 18 section 3.4.1.

Divers/Diver Tenders

The divers will be responsible for the following:

1. Ensuring that all their certifications are up to date.
2. Understanding their task at hand and to listen to the direction provided by the Dive Supervisor.
3. Responsible to review the Permit, understand it and then sign it.
4. The Diver has the responsibility to fully understand the task at hand and ask questions if he or she do not understand. If the diver feels that any task is unsafe, they shall raise it to the supervisor and all operations should be stopped until all risks are accurately assessed and mitigated.

Vessel Operator

1. Ensuring that all their certifications are up to date for operators and vessel.
2. Understanding their task at hand and to listen to the direction provided by the Dive Supervisor.
3. Responsible to review the Permit, understand it and then sign it.
4. Responsible to know the tasks at hand, monitor weather conditions and has the authority to abort if lose vessel power/control or any risks are present.
5. Responsible to maintain the vessel and at a minimum carry all TC requirements.

Appendix D - Pre-Dive Check Lists

AGL - AFONSO GROUP LIMITED			
MANUAL NAME:	STANDARD FORM FILES	REVISION #:	03
FORM #:	4SFF_D001	REVISION DATE:	December 18,2014
AUTHORIZED BY:	ALEX AFONSO	PAGE:	Page **1** of **2**

Client:______________________ Dive Site____________________ Job Reference #:____________________

Description:____

Date/Time:__________________________ Completed by:____________________________

PRE DIVE CHECKLIST (Y , N or N/A)

		Y,N or N/A
1	**Basics - Mission Safety**	
	: Dive Plan in accordance with appropriate federal and provincial regulations.	
	: Dive Plan approved by Dive Supervisor	
	: Emergency plan posted and Divers flag Alpha raised	
	: Dive team briefed on tasks involved.	
	: Hazard/Safety Assessment (JHRA) conducted and attached to dive plan.	
	: Lock Out/Tag Out (Mechanical Isolations) Y:Yes N:No and N/A: Not Applicable	
	Dive Manuals/Tables onsite	
2	**Diving & Support Personnel**	
	: All crew are authorized to perform their duties	
	: Certifications are valid (First Aid/Cpr, O2 providers, Medical and DCBC/equivalent)	
	: Verify divers are physically and mentally fit	
	: Ensure closest Hyperbaric chamber is available and functioning properly.	
	: Ensure all personnel are familiar with emergency hand signals or rope pull signalls	
	: Ensure Dive team are briefed	
3	**Diving Equipment**	
	: Ensure all equipment is authorized for use and or certified.	
	Communications	
	Chambers	
	Gauges	
	Dive Ladder/Recovery System	
	Umbilical's	
	Helmets	
	Harnesses	
	Bailouts/Regulators	
	General PPE (In compliance with corporate safety manual)	
	: Ensure equipment required is inspected and tested before each dive	
	: Ensure emergency protocols are in place (radio, cell, other_________________)	
	: Ensure there is a first aid kit, O2 kit, fire extinguisher on site	
	: Ensure dive site (van, platform, vessel) is outfitted with appropriate equipment	
	: Inspect dive recovery system(ladder/winch or other- specify:	
	: Ensure dive flag "A" is raised.	

See Reverse Side

POST DIVE CHECKLIST

4	Proper authorities notified when dive operation is complete	
	Flag “A" removed	
	Divers are monitored for a minimum of 2 hours post dive for symptoms.	
	Dive equipment is properly clean, stored, and checked for damages (Tag NFG for damaged items)	
	Refill air cylinders	
	Log all dives and topside activities (return to management for proper filing)	
	Conduct a dive debrief.	
	File a final dive report and submit to management	

COMMENTS

____

____

____

____

____

Dive Supervisor: ________________________

Signed: ________________________________

Date: ________________________________

CHECKLIST FOR DIVING CONTRACTORS

- ☐ Safe Diving Procedure Manual
- ☐ Diver Competence Certificates
- ☐ Diver Logbooks
- ☐ Basic First Aid / CPR / Oxygen Administration Certificates
- ☐ Diving Operations Logbook
- ☐ Diver Medical Certification
- ☐ Hyperbaric Chamber availability and operational status
- ☐ Diving Manual (i.e.: DCIEM) / Decompression Tables
- ☐ Medical First Aid Kit / Oxygen First Aid Kit
- ☐ Up-to-date verification of breathing air purification analysis
- ☐ Verify cylinders are hydrostatically tested and in date
- ☐ Copies of Diving Standards
- ☐ Dive Plan – Site Specific

______________________________	________________
Hydro Site Representative	Date
______________________________	________________
Diving Supervisor	Date

.

Appendix E - Signatures of all Members

NAME	SIGNATURE	POSITION	DATE

Appendix F- Afonso Crew Contact Information:

Name	Position	Contact Number
Alex Afonso	PM/Inshore Support	576 6070 / 687 0965
Terry Griffin	Sr. Dive Supervisor/Diver	709 764 1516
Trace Roberts	Sr. Dive Supervisor	709 685 6515
Robert Cox	Diver	709 728 7873
Mike Taylor	Diver and Diver Tender	
Greg Madden	Diver Tender	

Additional names may be added to this form. Crew size minimum will be 4, if names are changed prior to arrival then the Appendix F will be updated accordingly.

Qualified First Aiders:

Trace Roberts	Terry Griffin	Greg Madden
Mike Taylor		Robert Cox

Appendix G -Emergency Contacts (709 Area Code)

EMERGENCY PHONE NUMBERS	**Telephone Number**
Hospital..	911
Ambulance.......................................	911
Police...	911 or
Fire..	911
MEDICOR (Health Sciences Centre)	777-6433
O.H. & S...........................	729-4444
Nalcor Emergency Response	229 2754 2292739
Nalcor Control Room	229 2132

Appendix H – Hazard Assessments

AGL - AFONSO GROUP LIMITED			
Manual title:	Standard Operating Procedure	REVISION #:	00
Procedure #:	3SOP-JHRA-D019	REVISION DATE:	July 4 2017
AUTHORIZED BY:	ALEX AFONSO	PAGE:	Page **1** of **5**

RISK ASSESSMENT FORM

LOCATION: Holyrood Hydro	**DATE: July 2021**
TASKS: Diving Services -	**REFERENCE #: 24993-22**

Special Notes:

1. All personnel working or visiting the project site will be required to comply with all Safety regulations.
2. Proper personal protective equipment will be worn always. (Hard hat, safety glasses, safety boots, hi-vis Nomex coveralls, hearing protection.)
3. Toolbox meetings will be held every morning to discuss possible changes that might have occurred in the off shift.
4. Supervisors will assess sight conditions every morning before toolbox meeting to identify new hazards at the project site.
5. All work areas are to be barricaded and tagged to limit access to essential personnel only.
6. Pre-check all equipment daily.
7. Review all procedures with parties involved in the task before starting tasks.
8. All personnel on the structure outside the railing must wear a PFD and be attached to the davit system.
9. Working from the boat you must wear a PFD too.

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

STEP	TASK	INITIAL RISK RATE	HAZARDS / RISKS	CONTROL	FINAL RISK RATE	Accepted
1.0	Stem vessel to job site	1B	• Poor weather and visibility • Traffic • Falling in the water • Vessel power loss	• Monitor the weather and plan to complete scope of work on good weather days. • Radio communication to be monitored and good visibility to monitor traffic in area. • PFD and hold vessel to prevent falling. • Good maintenance and systems check prior to departure.	3D	
2.0	Set up dive spread	3C	• Faulty Equipment • Damaged hoses • Pinch Points • Awkward Lifting • Pneumo gauges are inaccurate. • Poor Air Supply • Slips trips and falls. • Generator- fueling spill risk	• Proper pre-checks and function tests to be performed by qualified personnel. • Replace damaged hoses or repair. • Two people assist lift or use of mechanical advantage. • Ensure gauges are certified and air supply. • Be aware of surroundings and potential trip hazards on structure and equipment laydown. • Use drip pan and have spill kit onsite. Gen set away from bodies of water- if possible	4D	

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

STEP	TASK	INITIAL RISK RATE	HAZARDS / RISKS	CONTROL	FINAL RISK RATE	Accepted
3.0	Dive to enter water and perform inspections	1A	• Other vessels in jetty (if applicable) • Slip trips and falls getting in water. • Low Visibility • Diver injury • Using sharp tools to scrape marine growth – cut hand. • Umbilical gets snagged. • Other vessel traffic in area • Loss of communication with diver	• Lock Out Tag Out-witness • Diver tender to assist diver entering water and hold umbilical snug. • Use of u/w lights if required/flashlight. • In the event of an injured diver there will be one of two recovery two methods available. Primary retrieval via dive support vessel from dive ladder or stage, retrieval from water from davit or to safety rescue vessel with a low free board (<18") • Divers to wear gloves and be aware of any sharp objects or potential pinch points. • Good tether management and continuous communication with the diver. • Monitor vessel traffic and raise diver flag. • Be familiar with rope signals to abort dive operations in the event of communication loss. • Full review of dive safety plan and sign off. • Divers' certificates are all valid. • Complete the pre dive checklists and TBT. • Avoid decompression dives- stay within the dive limits. Dive supervisor will be responsible for monitoring.	3D	

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

STEP	TASK	INITIAL RISK RATE	HAZARDS / RISKS	CONTROL	FINAL RISK RATE	Accepted
4.0	Exit water	3C	• Falling back in water exiting water and entering the vessel • Diver post dive condition	• Topside tenders to assist with diver existing. Take his fins and grab harness as climbing and remove helmet. • Assist diver undressing. • Monitor diver condition.	4D	
5.0	Breakdown dive system	3B	• Damaged equipment • Pressurized lines and cylinders	• Thoroughly inspect on breakdown and protect equipment in packaging or moving it. • Make sure all supply lines are shut off and de pressurize or bleed off prior to full disconnect.	4D	
6.0	Steam vessel back to wharf- demob	1B	• Poor weather and visibility • Traffic • Falling in the water • Vessel power loss	• Monitor the weather and plan to complete scope of work on good weather days. • Radio communication to be monitored and good visibility to monitor traffic in area. • PFD and hold vessel to prevent falling. • Good maintenance and systems check prior to departure.	3D	

1.Catastrophic 2. Critical 3. Marginal 4. Negligible // A Probable B. Reasonably Probable C. Remote D. Extreme Remote

Signatures

NAME	SIGNATURE	DATE

Appendix I – Equipment Info & Procedures

Appendix J – Emergency Protocol Steps

1. **Recover the Diver to Surface**

2. **Recover Diver to Shoreline**

3. **Dive Supervisor will assess the Divers condition.**

4. **The supervisor will designate a person by name to call 911. That person will provide his name, the injured persons name, nature of the injury and location to pick up the injured diver.**

5. **That same designate will notify the contractor.**

6. **Topside will mobilise to the rescue location; a minimum of two personnel will stay with the diver.**

7. **If necessary, the Supervisor will notify Medicor of the situation.**

8. **The dive team on site will abort all operations, and the dive supervisor will complete all accident/incident forms and necessary documentation.**

Appendix K – Daily Toolbox Talk

Project:	**Date:**
Crew Size:	**Supervisor:**
Task:	

Review of Tasks:	
Review of JSA, HIRA:	
New Topics:	
Suggestions:	
Actions to be taken:	
Accident/Incident Review	
Other Comments	

Signatures:		

Appendix L – Equipment Change Notice

If a specific piece of equipment or equipment part has malfunctioned or expired, it must be fully replaced or repaired prior to use. Depending on the equipment specific parts may be changed out to meet the standards.

To do so please complete the form below:

Equipment Change Notice	
Equipment Name:	
Serial Number:	
Defect/Concern Raised:	
Solution/Repair:	
Repair Comments: (Identify all serial numbers or markings)	
Permanent or Temporary Repair:	
Completed by:	
Date Completed:	

DIVE SAFETY PLAN REVIEW/SIGNATURES
To be signed daily

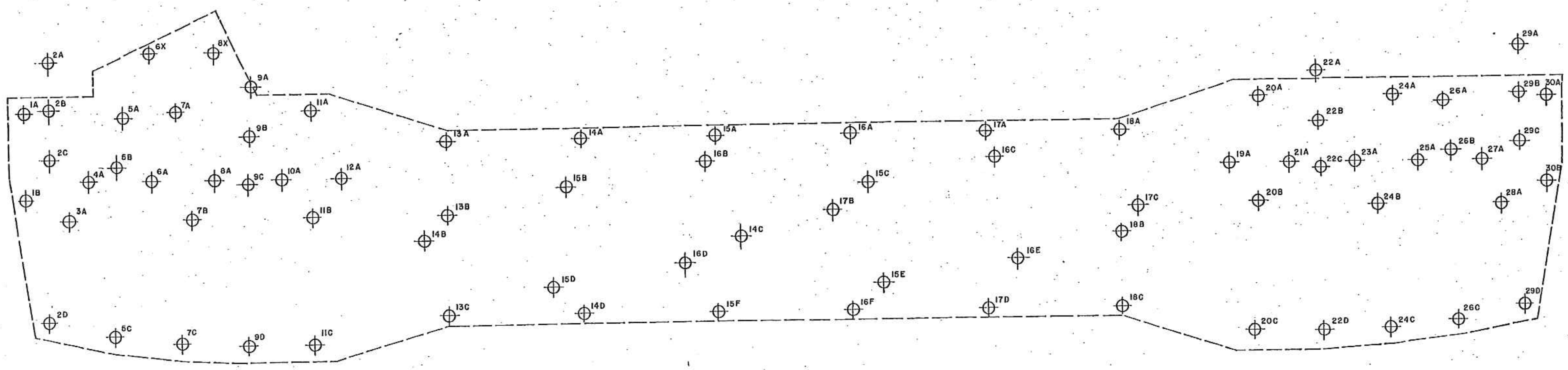
Date:			

Date:			

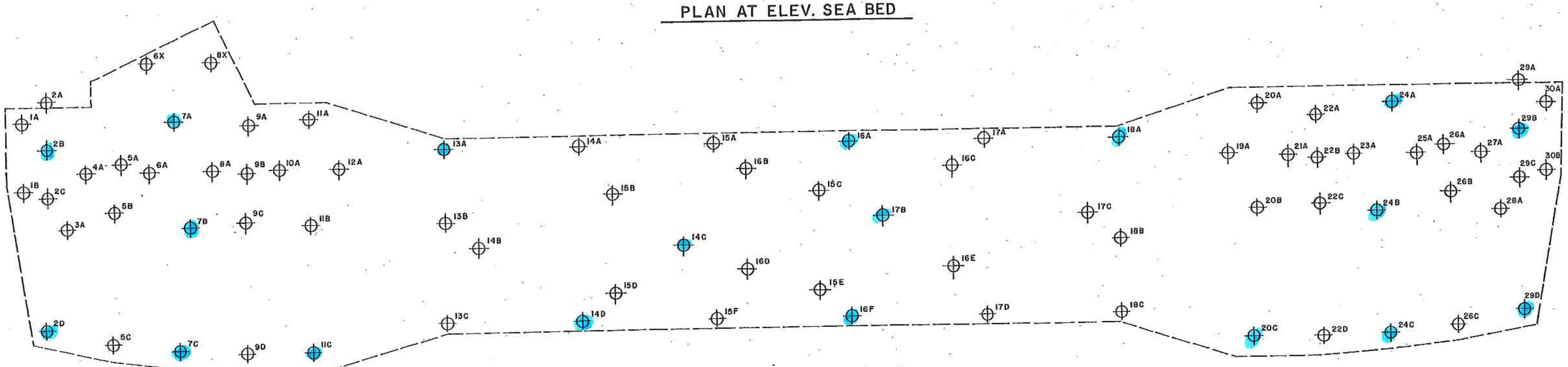
Date:			

Date:			

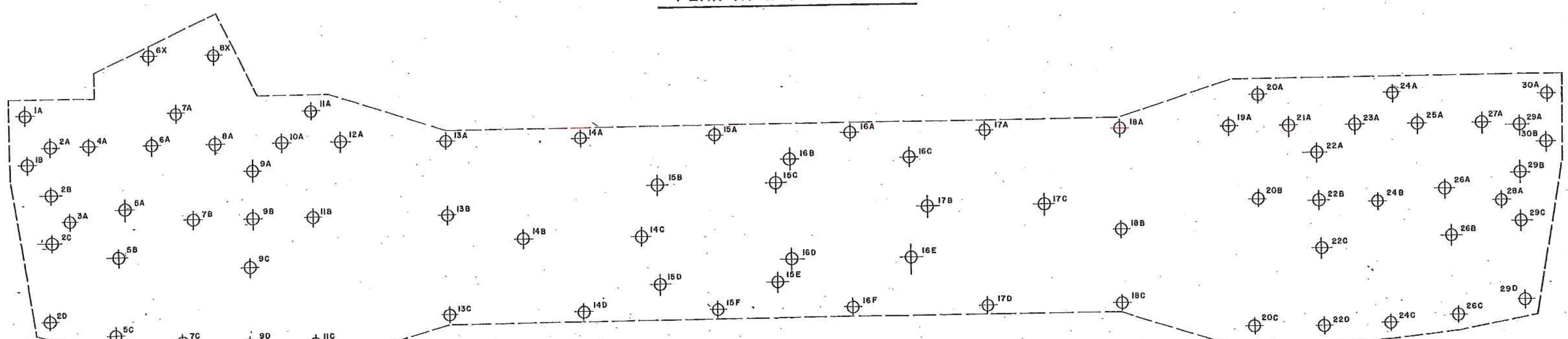
Date:			



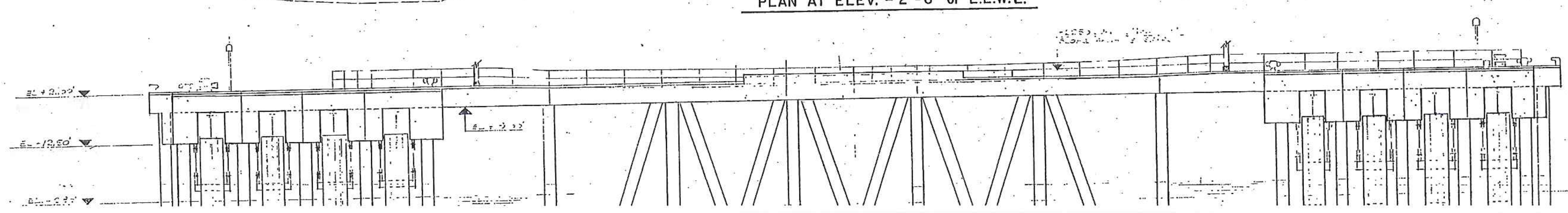
PLAN AT ELEV. SEA BED

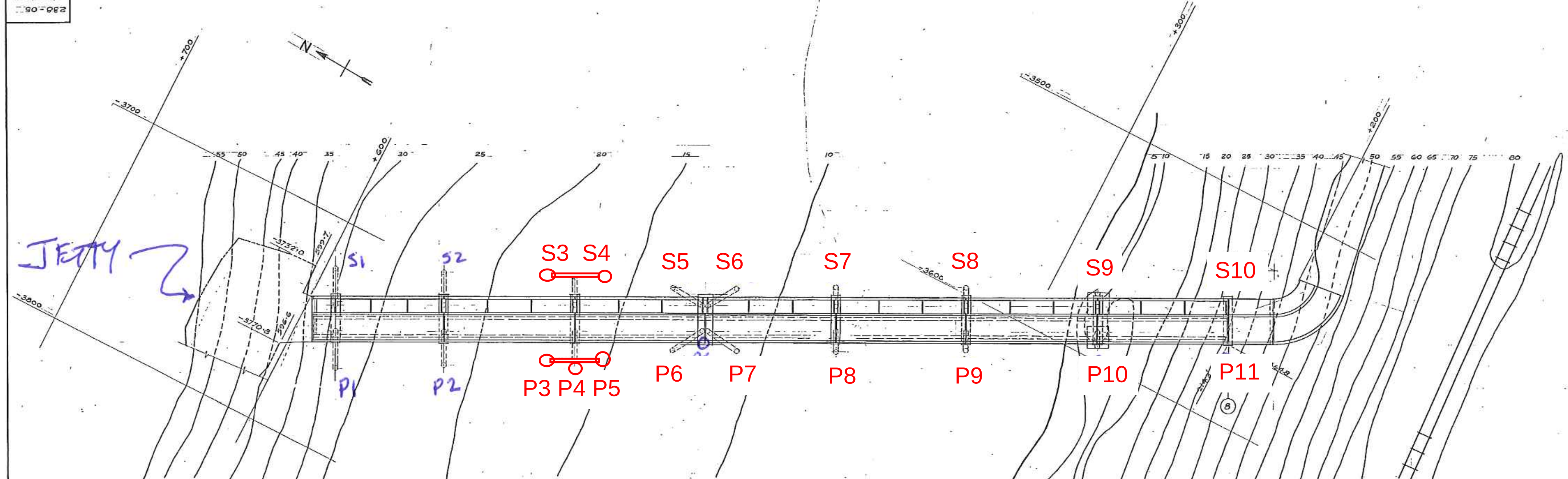


PLAN AT ELEV. - 23'-0"

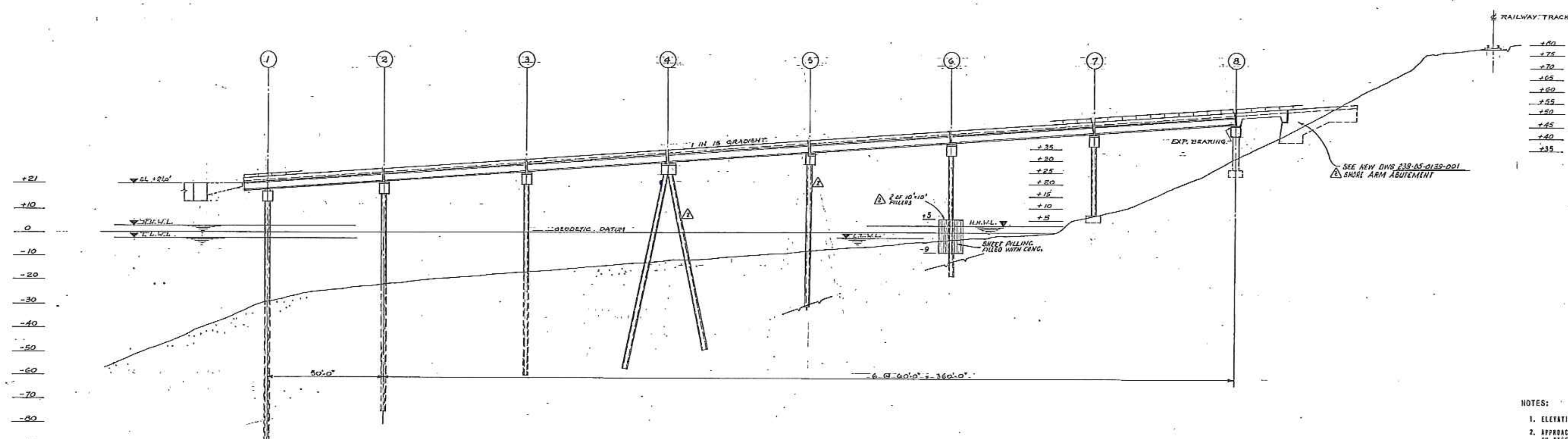


PLAN AT ELEV. - 2'-6" or L.L.W.L.

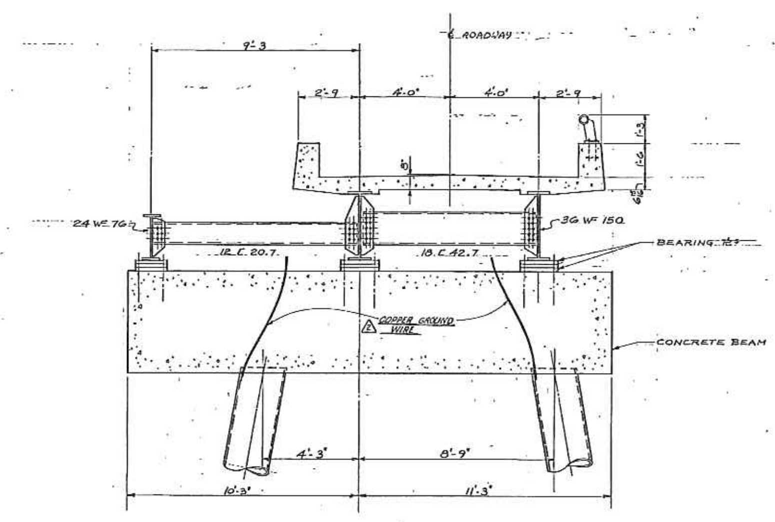




PLAN OF SHORE ARM



ELEVATION



TYPICAL SECTION ACROSS SHORE ARM

NOTES:

1. ELEVATIONS AND WATER LEVELS REFER TO GEODETIC DATUM.
2. APPROACH ROAD IS OF COMPOSITE CONSTRUCTION: REINFORCED CONCRETE DECK ON STEEL BEAMS. FOR DETAILS SEE DWGS Nos 14 & 15.
3. SUPPORTS ARE TUBULAR STEEL PILES FILLED WITH CONCRETE. FOR DETAILS SEE DWG. No 13
4. SUPPORT 6 AND SHORE ABUTMENT ARE OF REINFORCED CONCRETE CONSTRUCTION. FOR DETAILS SEE DWG. No. 16.

APPROVED FOR CONST.
1984-06-28

APPROVED FOR CONSTRUCTION
Date
Chief Civil Engineer

ASSOCIATION OF PROFESSIONAL ENGINEERS PROVINCE OF NEWFOUNDLAND
A. SPEARMAN
LICENCE TO PRACTICE

rev no	date	revision	by	chk	app
2	27-11-70	"AS BUILT"	BH		
1	4 FEB 70	AMENDED FOR CONSTRUCTION			

NEWFOUNDLAND AND LABRADOR POWER COMMISSION
HOLYROOD GENERATING STATION
MARINE TERMINAL
SHORE ARM
GENERAL ARRANGEMENT

SHAWMONT RESOURCES JOINT VENTURE
1047 YONGE STREET. TORONTO 5. ONTARIO

scale 1" = 20'-0" & 3/8" = 1'-0"
date AUG 5 - 1969
designed ESK
drawn
checked
approved

REGISTERED PROFESSIONAL ENGINEER E. S. KOMOROWSKI PROVINCE OF ONTARIO

238-05
4004
12-R2

CIVIL. ELECT. MECH.

W.O. No SME 1187-3
G-SME-41713

Video Catalogue Date and Order			
20-Jul	21-Jul	22-Jul	23-Jul
29D	26C	17D	9B
29C	24C	16E	9A
29B	22D	16F	7B
29A	20C	16D	5B
30B	18C	15E	5A
30A	26B	15F	2C
28A	26A	15D	3A
27A	24B	14D	2B
25A	22C	15A	1B
24A	22B	15B	2A
20A	22A	14C	1A
19A	20B	14A	8A
21A	18B	14B	7A
23A	18A	13C	6A
	17C	13B	4A
	17A	13A	6X
	17B	12A	8X
	16C	11A	S1
	16A	10A	P1
	16B	11B	P2
	15C	10A	S2
		11C	P3
		9D	P4
		7C	P5
		5C	S4
		2D	S3
		9C	P6
			P7
			S5
			S6
			S7
			P8
			S8

Client:					Location:
Dates:					Descrption:
Jetty Portion					
Pile #	**Location**	**Clock**	**# 1:Anode**	**# 2:Anode**	**Observations**
1A	Top	11:46	0%	75%	Pile coating good
	Mid	11:47		75%	Pile coating good
	Bottom	11:48	0%	35%	Pile coating good
1B	Top	11:32	5%	35%	Pile coating good
	Mid	11:33	0%	25%	Pile coating good
	Bottom	11:35	60%	0%	Pile coating good
2A	Top	11:39	0%	30%	Pile coating good
	Mid	11:40			Pile slight pitting
	Bottom	11:41	40%	0%	Pile coating good
2B	Top	11:20	15%	80%	Pile coating good
	Mid	11:21	25%	80%	Slight pitting on steel
	Bottom	11:24	80%	10%	Slight pitting on steel
2C	Top	11:04	70%	95%	Pile coating good
	Mid	11:05	85%	25%	Pile coating good
	Bottom	11:07	10%	95%	Pile coating good
2D	Top	16:09			Pile coating good
	Mid	16:10	15%		Pile coating good
	Bottom	16:12	0%	80%	Pile coating good
3A	Top	11:12	75%	20%	Pile coating good
	Mid	11:13	10%	75%	Pile coating good
	Bottom	11:14	25%	50%	Pile coating good
4A	Top	12:18	20%	30%	Pile coating good
	Mid	12:19	40%	40%	Pile coating good
	Bottom	12:21	25%	50%	Pile coating good
5A	Top	10:55	75%	25%	Pile coating good
	Mid	10:56	55%	90%	Pile coating good
	Bottom	10:58	45%	80%	Pile coating good
5B	Top	10:46	15%	10%	Pile coating good
	Mid	10:48	50%	95%	Pile coating good
	Bottom	10:49	85%	60%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
5C	Top	16:05	0%	30%	Pile coating good
	Mid	16:03	0%	10%	Pile coating good
	Bottom	16:01	0%	10%	Pile coating good
6A	Top	12:09	20%	80%	Pile coating good
	Mid	12:11	25%	35%	Pile coating good
	Bottom	12:12	30%	60%	Pile coating good
6X	Top	12:25			Pipe coating looks good
	Mid	12:26			Pipe coating looks good
	Bottom	12:27	5%	0%	Pile coating good
7A	Top	12:01	90%	95%	Pile coating good
	Mid	12:02			Pipe coating looks good
	Bottom	12:05	80%	25%	Pile coating good
7B	Top	10:35	80%	35%	Pile coating good
	Mid	10:37	90%	30%	Pile coating good
	Bottom	10:39	90%	45%	Pile coating good
7C	Top	15:54	0%	40%	Pile coating good
	Mid	15:56	0%	40%	Pile coating good
	Bottom	15:58	0%	15%	Pile coating good
8A	Top	11:55	30%	80%	Pile coating good
	Mid	11:56	80%	50%	Pile coating good
	Bottom	11:58	95%	25%	Pile coating good
8X	Top	12:21	0%	0%	Pile coating good
	Mid	12:25			Pipe coating looks good
	Bottom	12:29	0%	10%	Pile coating good
9A	Top	10:30	40%	95%	Pile coating good
	Mid	10:28			Pipe coating looks good
	Bottom	10:27	60%	50%	Pile coating good
9B	Top	10:21	80%	25%	Pile coating good
	Mid	10:23	80%	30%	Pile coating good
	Bottom	10:24	50%	95%	Pile coating good
9C	Top	16:16	15%	80%	Pile coating good
	Mid	16:17	45%	85%	Pile coating good
	Bottom	16:18	80%	35%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
9D	Top	15:51	0%	25%	Pile coating good
	Mid	15:50	0%	35%	Pile coating good
	Bottom	15:49	0%	50%	Pile coating good
10A	Top	14:13	50%	50%	Pile coating good
	Mid	14:13	50%	40%	Pile coating good
	Bottom	14:11	40%	80%	Pile coating good
11A	Top	13:59	0%	20%	Pile coating good
	Mid	14:00			Pipe coating looks good
	Bottom	14:02	80%	40%	Pile coating good
11B	Top	14:08	40%	80%	Pile coating good)
	Mid	14:09	40%	80%	Pile coating good
	Bottom	14:10	20%	80%	Pile coating good
11C	Top	15:38	40%	45%	Pile coating good
	Mid	15:40	35%	25%	Pile coating good
	Bottom	15:45	70%	35%	Pile coating good
12A	Top	13:53	20%	25%	Pile coating good
	Mid	13:52			Pipe coating looks good
	Bottom	13:55	80%	40%	Pile coating good
13A	Top	13:46	80%	10%	Pile coating good
	Mid	13:46			Pipe coating looks good
	Bottom	13:47	90%	20%	Pile coating good
13B	Top	13:40	30%	60%	Pile coating good
	Mid	13:41	30%	80%	Pile coating good
	Bottom	13:42	20%	80%	Pile coating good
13C	Top	13:38	50%	40%	Pile coating good
	Mid	13:37	20%	20%	Pile coating good
	Bottom	13:36	0%	30%	Pile coating good
14A	Top	13:24	80%	30%	Pile coating good
	Mid	13:25			Pipe coating looks good
	Bottom	13:27	80%	40%	Pile coating good
14B	Top	13:30	20%	10%	Pile coating good
	Mid	13:32	50%	50%	Pile coating good
	Bottom	13:35	80%	40%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
14C	Top	13:16	80%	40%	Pile coating good
	Mid	13:18	50%	40%	Pile coating good
	Bottom	13:20	90%	80%	Pile coating good
14D	Top	11:36	10%	80%	Pile coating good
	Mid	11:39	15%	15%	Pile coating good
	Bottom	11:40	90%	20%	Pile coating good
15E	Top	11:06	85%	25%	Pile coating good
	Mid	11:08	20%	30%	Pile coating good
	Bottom	11:10	35%	75%	Pile coating good
15B	Top	13:09	10%	50%	Pile coating good
	Mid	13:12	20%	40%	Pile coating good
	Bottom	13:13	40%	80%	Pile coating good
15C	Top	15:58	15%	85%	Pile coating good
	Mid	15:59	40%	95%	Pile coating good
	Bottom	16:01	75%	40%	Pile coating good
15D	Top	11:28	30%	85%	Pile coating good
	Mid	11:30	20%	90%	Pile coating good
	Bottom	11:32	45%	30%	Pile coating good
15A	Top	13:08			Pile coating good
	Mid	13:07			Pile coating good
	Bottom	13:06	40%	40%	Pile coating good
15F	Top	11:18	25%	25%	Pile coating good
	Mid	11:20	90%	20%	Pile coating good
	Bottom	11:23	50%	30%	Pile coating good
16A	Top	15:40			
	Mid	15:42	45%	25%	Pile coating good
	Bottom	15:44	25%	90%	Pile coating good
16B	Top	15:50	85%	20%	Pile coating good
	Mid	15:51	30%	30%	Pile coating good
	Bottom	15:52	25%	75%	Pile coating good
16C	Top	15:34	20%	25%	Pile coating good
	Mid	15:35	75%	50%	Pile coating good
	Bottom	15:37	65%	30%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
16D	Top	10:57	30%	40%	Pile coating good
	Mid	10:59	40%	70%	Pile coating good
	Bottom	11:00	65%	30%	Pile coating good
16E	Top	10:40	30%	20%	Pile coating good
	Mid	10:41	30%	50%	Pile coating good
	Bottom	10:43	30%	85%	Pile coating good
16F	Top	10:49	25%	50%	Pile coating good
	Mid	10:50	60%	30%	Pile coating good
	Bottom	10:52	15%	50%	Pile coating good
17A	Top	15:16			
	Mid	15:18	80%	30%	Pile coating good
	Bottom	15:20	25%	30%	Pile coating good
17B	Top	15:25	90%	25%	Pile coating good
	Mid	15:26	25%	80%	Pile coating good
	Bottom	15:28	95%	30%	Pile coating good
17C	Top	13:32	20%	80%	Pile coating good
	Mid	13:34	40%	50%	Pile coating good
	Bottom	13:36	50%	50%	Pile coating good
17D	Top	10:31	20%	75%	Pile coating good
	Mid	10:33	30%	45%	Pile coating good
	Bottom	10:34	90%	20%	Pile coating good
18A	Top	13:28			Pile coating good
	Mid	13:27	40%	60%	Pile coating good
	Bottom	13:26	80%	50%	Pile coating good
18B	Top	13:20	40%	40%	Pile coating good
	Mid	13:22	90%	50%	Pile coating good
	Bottom	13:23	90%	50%	Pile coating good
18C	Top	11:34	10%	85%	Pile coating good
	Mid	11:36	20%	35%	Pile coating good
	Bottom	11:37	10%	95%	Pile coating good
19A	Top	17:30			Pile coating good
	Mid	17:32	40%	10%	Pile coating good
	Bottom	17:35	20%	80%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
20A	Top	17:19			Pitting and scaling
	Mid	17:23	30%	60%	Coating chipped
	Bottom	17:27	10%	20%	Coating appears ok
20B	Top	13:12	60%	50%	Coating appears good
	Mid	13:13	5%	20%	Pile coating good
	Bottom	13:14	50%	80%	Pile coating good
20C	Top	11:24	0%	65%	Pile coating good
	Mid	11:25	5%	60%	Pile coating good
	Bottom	11:28	0%	55%	Pile coating good 11:28 40'corroded wood?
21A	Top	17:39			
	Mid	17:40	35%	80%	Pile coating good
	Bottom	17:43	30%	80%	Pile coating good -flaking but ok
22A	Top	13:02			
	Mid	13:04	80%	60%	Pile coating good
	Bottom	13:06	90%	50%	Pile coating good
22B	Top	13:00	60%	80%	Pile coating good
	Mid	12:59	50%	90%	Pile coating good
	Bottom	12:57	90%	80%	Pile coating good
22C	Top	12:52	60%	30%	Pile coating good
	Mid	12:55	60%	80%	Pile coating good
	Bottom	12:53	50%	80%	Pile coating good
22D	Top	11:17	25%	80%	Pile coating good
	Mid	11:18	5%	80%	Pile coating good
	Bottom	11:20	0%	85%	Pile coating good
23A	Top	17:48			
	Mid	17:50	17%	30%	Coating appears ok
	Bottom	17:52	40%	85%	Coating appears ok
24A	Top	17:10	30%	10%	Pile coating good
	Mid	17:12			
	Bottom	17:14	50%	90%	Pile coating good
24B	Top	12:43			
	Mid	12:45	70%	20%	Pile coating good
	Bottom	12:47	80%	20%	Pile coating good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
24C	Top	11:02	0%	70%	Pile coating good
	Mid	11:09	0%	80%	Pile coating good
	Bottom	11:12	0%	25%	Pile coating good
25A	Top	16:00	50%	50%	Pile coating good
	Mid	16:02	80%	50%	Pile coating good
	Bottom	16:04	80%	50%	Pile coating good
26A	Top	12:39	10%	20%	Pile minor pitting good
	Mid	12:40			
	Bottom	21:41	50%	50%	Pile coating good
26B	Top	12:32	20%	30%	Pile coating good
	Mid	12:33	30%	10%	Pile coating good
	Bottom	12:34	50%	40%	Pile coating good
26C	Top	10:56	0%	30%	Pile coating good
	Mid	10:59	0%	80%	Pile coating good
	Bottom	11:03	0%	55%	Pile coating good
27A	Top	15:49	30%	30%	Slight pitting
	Mid	15:53	80%	40%	Pile coating good
	Bottom	15:54	80%	40%	Pile coating good
28A	Top	15:41			Coating good
	Mid	15:42	50%	20%	Pile coating good
	Bottom	15:44	40%	40%	Pile coating good
29A	Top	15:11	0%	0%	Pile coating good
	Mid	15:13	50%		No Second Anode, Pile coating good
	Bottom	13:15	50%		No Second Anode, Pile coating good
29B	Top	14:00	30%	20%	Pile coating good
	Mid	14:03			No visible anode
	Bottom	14:06	90%		No Second Anode, Pile coating good
29C	Top	13:51	60%		Coating good
	Mid	13:53	60%	35%	Pile coating good
	Bottom	13:55	40%	10%	Pile coating good
29D	Top	13:30	1%		Pipe coating appears good
	Mid	13:35	60%	60,1%	2 anodes at mid one at 60% one at 1%
	Bottom	13:43	50%	0%	Pile coating appears good

Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
30A	Top	15:31			No Anode
	Mid	15:32			No Anode
	Bottom	15:34	50%		No Second Anode, Pile coating good
30B	Top	15:20	10%	20%	Pile coating good
	Mid	15:04	10%	50%	Pile coating good
	Bottom	15:25	30%	30%	Pile coating good
SHORE ARM					
Pile #	**Location**	**Clock**	**# 1:Anode**	**# 2:Anode**	**Observations**
P1	Top	14:10	30%	0%	Pile coating good
	Mid	14:08	30%	0%	Pile coating good
	Bottom	14:06	10%	30%	Pile coating good
P2	Top	14:13	0%	0%	Pile coating good
	Mid	14:15		0	Pile coating good
	Bottom	14:16		0	Pile coating good
P3	Top	14:21			Encased all good below water
	Mid	14:21			Encased all good below water
	Bottom	14:22			Encased all good below water
P5	Top	14:30			Encased all good below water
	Mid	14:31			Encased all good below water
	Bottom	14:32			Pipe coating looks good
P7	Top	14:45			
	Mid	14:47	30%	8%	Pile coating good
	Bottom	14:49			Pipe coating looks good
P4	Top	14:28			Encased on top pitting below
	Mid	14:29			Pipe coating looks good
	Nottom	14:31			Pipe coating looks good

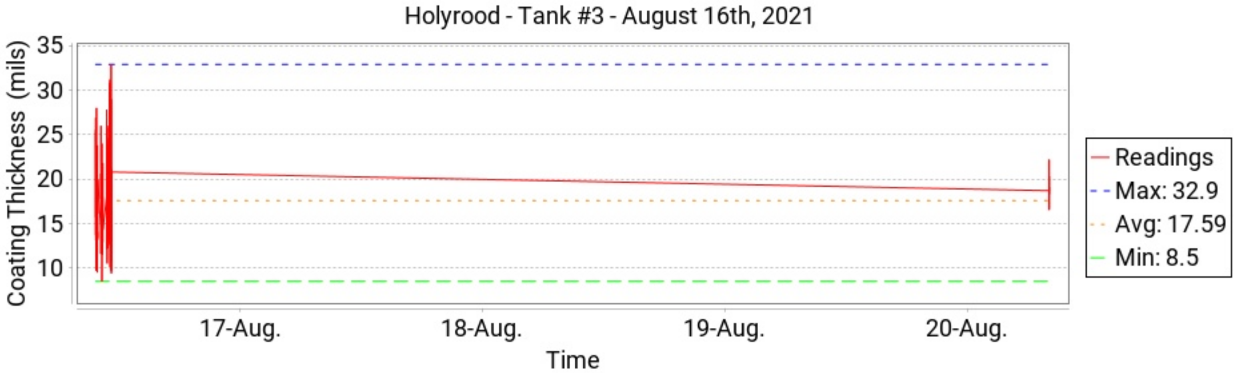
Pile #	Location	Clock	# 1:Anode	# 2:Anode	Observations
S1	Top	14:01			All good below waterline
	Mid				Encased to bottom
	Bottom				
S2	Top	14:19			
	Mid				All good below water line
	Bottom	14:17			Encased
S3	Top	14:37			Encased
	Mid				Encased to bottom
	Bottom	14:38			Slight rusting at encasement
S4	Top	14:36			Encased, Slight rusting of encasement at bottom
	Mid				Encased, Slight rusting of encasement at bottom
	Bottom	14:33			Encased, Slight rusting of encasement at bottom
P6	Top	14:45			Pile coating good
	Mid				Encased
	Bottom		0	0	
S5	Top	14:54			Encased pile coating good
	Mid				Encased pile coating good
	Bottom	14:51			Encased pile coating good
S6	Top	14:56			Encased pile coating good
	Mid				Encased pile coating good
	Bottom	14:58			Encased pile coating good
S7	Top	15:02			
	Mid				
	Bottom	15:01			Encased at mud line
P8	Top	15:03			Pile coating good
	Mid				Pile coating good
	Bottom	15:05			Pile coating good
S8	Top	15:09			One video S8 and P9 covered in marine growth steel sheet piling
	Mid				determined above and below water line
	Bottom				
P9	Top	15:09			
	Mid				
	Bottom				

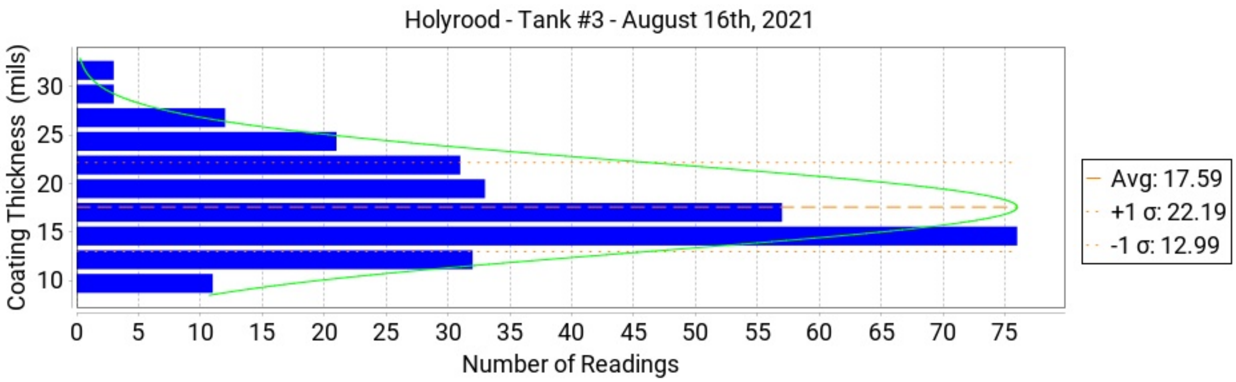
Pile #	Location		# 1:Anode	# 2:Anode	Observations
S9	Top				No Survey out of water
	Mid				No Survey out of water
	Bottom				No Survey out of water
P10	Top				No Survey out of water
	Mid				No Survey out of water
	Bottom				No survey out of water

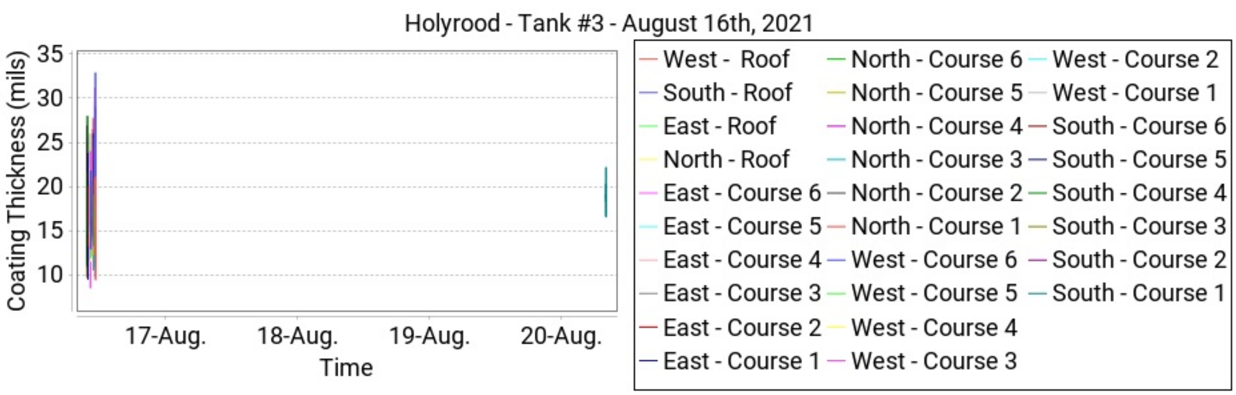
Appendix I
Fuel Tank #3 Paint Inspection

Holyrood - Tank #3 - August 16th, 2021 Summary

	#	x	σ	↓	↑
Coating Thickness (mils)	279	17.59	4.60	8.5	32.9







West - Roof

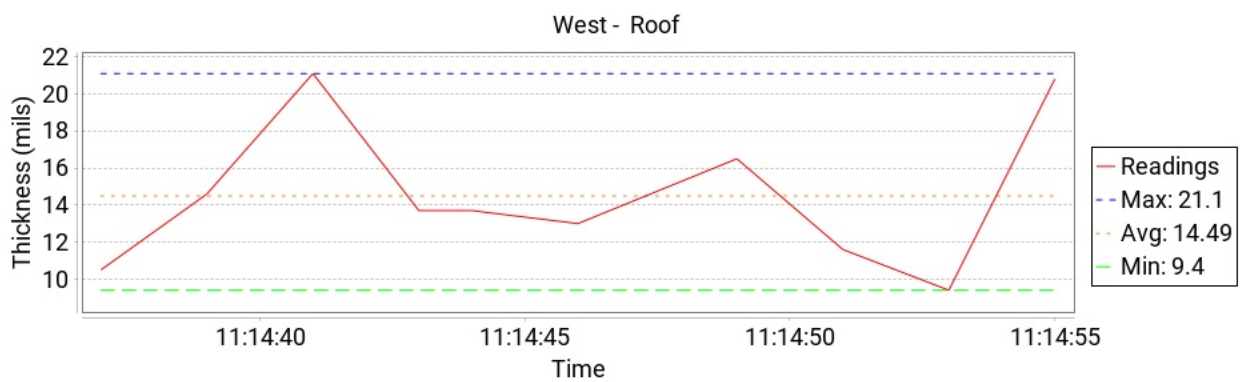
Created:	2021-08-16 11:14:34
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

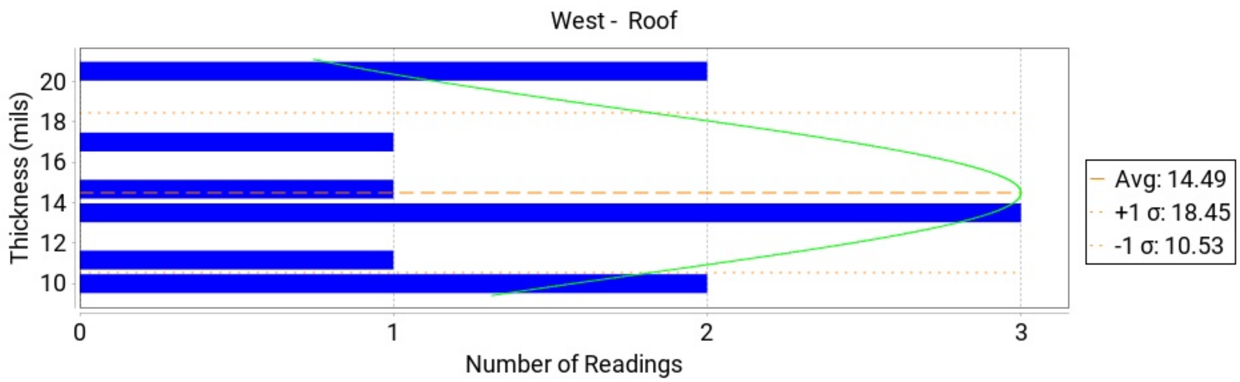
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	14.49	3.96	9.4	21.1

Readings

#	Thickness (mils)	Time
1	10.5	2021-08-16 11:14:37
2	14.6	11:14:39
3	21.1	11:14:41
4	13.7	11:14:43
5	13.7	11:14:44
6	13.0	11:14:46
7	16.5	11:14:49
8	11.6	11:14:51
9	9.4	11:14:53
10	20.8	11:14:55




West - Roof
Thickness (mils)
20
18
16
14
12
10
0
1
2
3
Number of Readings
Avg: 14.49
+1 σ: 18.45
-1 σ: 10.53

South - Roof

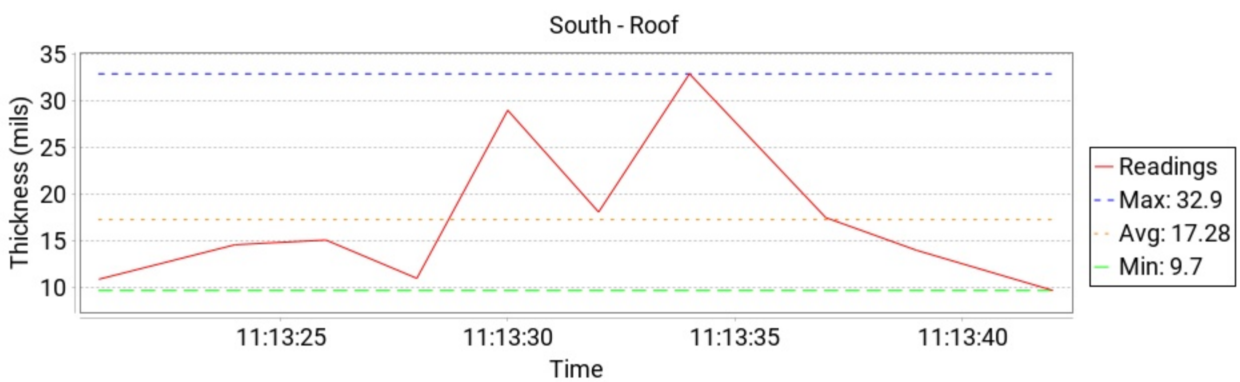
Created:	2021-08-16 11:11:23
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

Summary

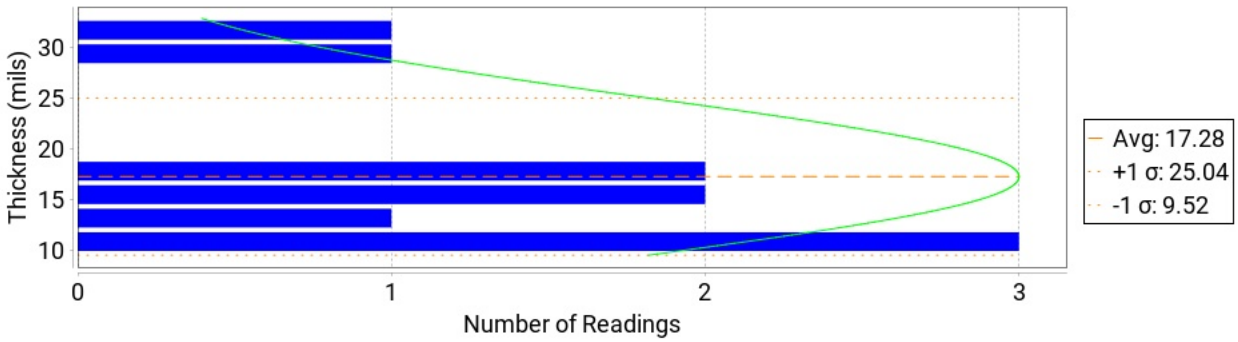
	#	x	σ	↓	↑
Thickness (mils)	10	17.28	7.76	9.7	32.9

Readings

#	Thickness (mils)	Time
1	10.9	2021-08-16 11:13:21
2	14.6	11:13:24
3	15.1	11:13:26
4	11.0	11:13:28
5	29.0	11:13:30
6	18.1	11:13:32
7	32.9	11:13:34
8	17.5	11:13:37
9	14.0	11:13:39
10	9.7	11:13:42



South - Roof



Thickness (mils)
30
25
20
15
10
0
1
2
3
Number of Readings
Avg: 17.28
+1 σ: 25.04
-1 σ: 9.52

East - Roof

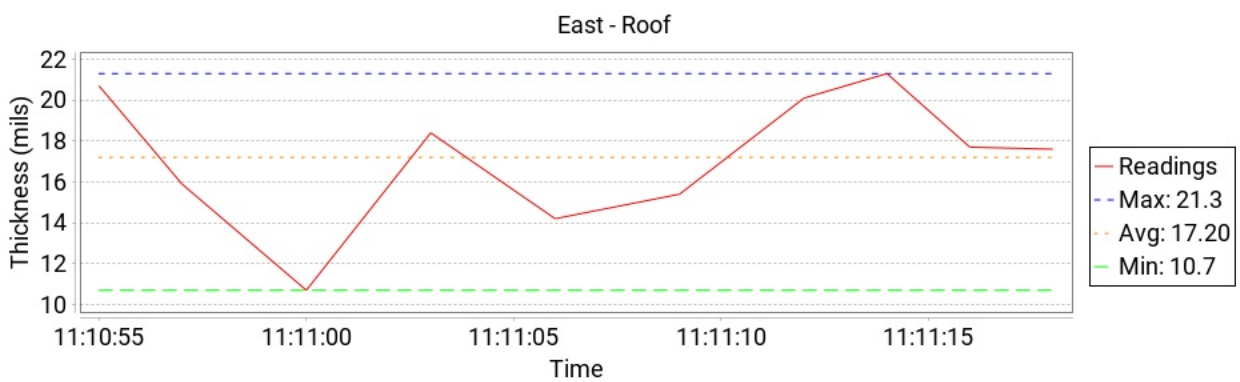
Created:	2021-08-16 11:07:38
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

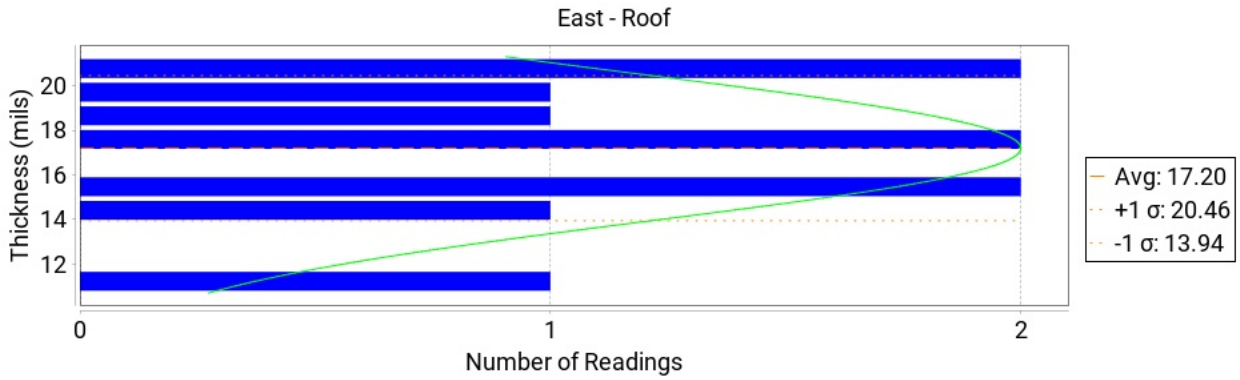
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	17.20	3.26	10.7	21.3

Readings

#	Thickness (mils)	Time
1	20.7	2021-08-16 11:10:55
2	15.9	11:10:57
3	10.7	11:11:00
4	18.4	11:11:03
5	14.2	11:11:06
6	15.4	11:11:09
7	20.1	11:11:12
8	21.3	11:11:14
9	17.7	11:11:16
10	17.6	11:11:18




East - Roof
Thickness (mils)
20
18
16
14
12
0
1
2
Number of Readings
Avg: 17.20
+1 σ: 20.46
-1 σ: 13.94

North - Roof

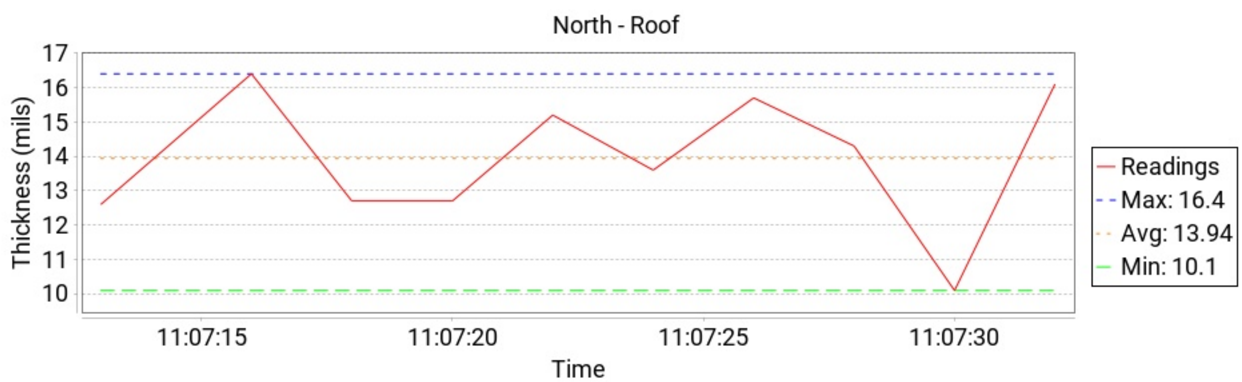
Created:	2021-08-16 11:06:28
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

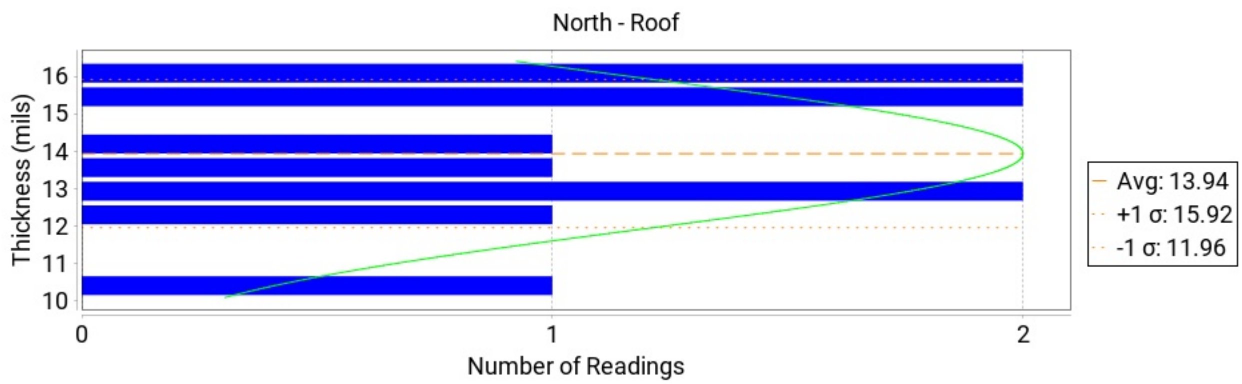
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	13.94	1.98	10.1	16.4

Readings

#	Thickness (mils)	Time
1	12.6	2021-08-16 11:07:13
2	16.4	11:07:16
3	12.7	11:07:18
4	12.7	11:07:20
5	15.2	11:07:22
6	13.6	11:07:24
7	15.7	11:07:26
8	14.3	11:07:28
9	10.1	11:07:30
10	16.1	11:07:32




North - Roof
Thickness (mils)
16
15
14
13
12
11
10
0
1
2
Number of Readings
Avg: 13.94
+1 σ: 15.92
-1 σ: 11.96

East - Course 6

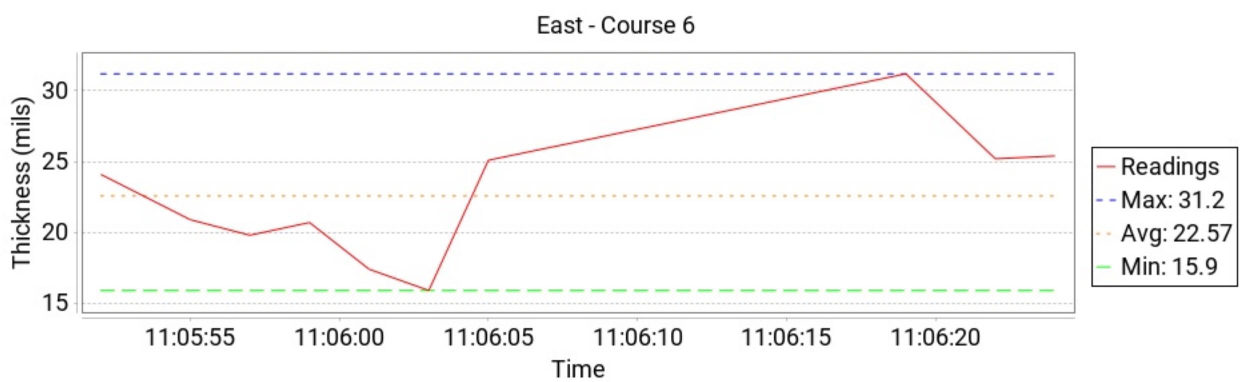
Created:	2021-08-16 11:05:42
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

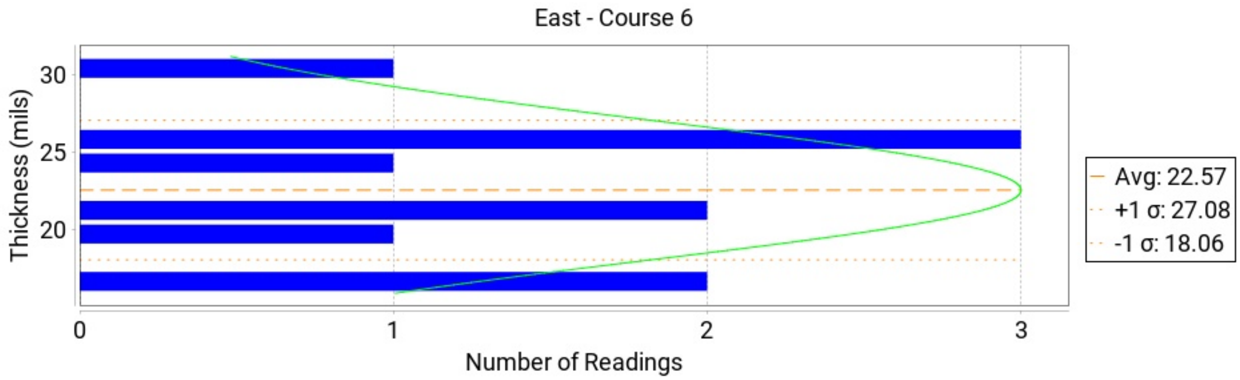
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	22.57	4.51	15.9	31.2

Readings

#	Thickness (mils)	Time
1	24.1	2021-08-16 11:05:52
2	20.9	11:05:55
3	19.8	11:05:57
4	20.7	11:05:59
5	17.4	11:06:01
6	15.9	11:06:03
7	25.1	11:06:05
8	31.2	11:06:19
9	25.2	11:06:22
10	25.4	11:06:24





East - Course 6
Thickness (mils)
30
25
20
0
1
2
3
Number of Readings
Avg: 22.57
+1 σ: 27.08
-1 σ: 18.06

East - Course 5

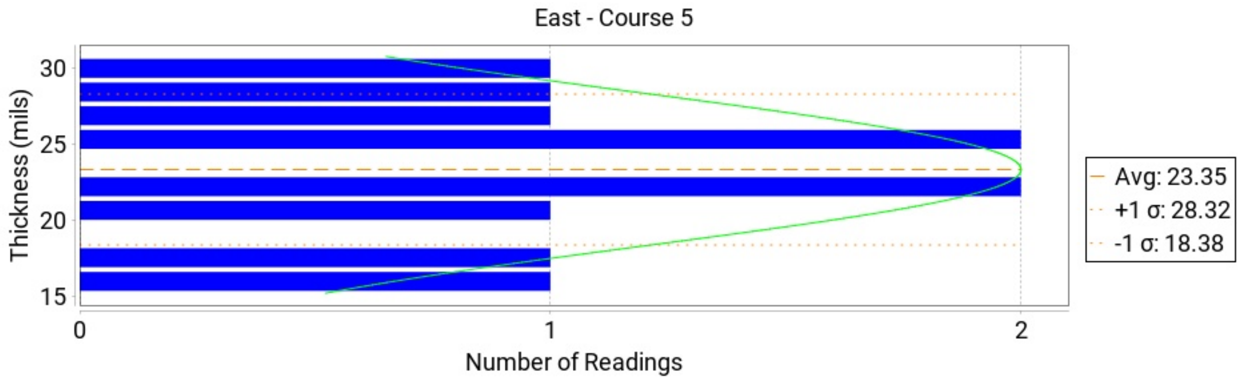
Created:	2021-08-16 11:05:04
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

Summary

	#	x	σ	↓	↑
Thickness (mils)	10	23.35	4.97	15.2	30.8

Readings

#	Thickness (mils)	Time
1	17.5	2021-08-16 11:05:16
2	30.8	11:05:19
3	22.0	11:05:21
4	25.1	11:05:24
5	28.4	11:05:26
6	27.3	11:05:29
7	19.9	11:05:31
8	21.6	11:05:33
9	25.7	11:05:35
10	15.2	11:05:38


East - Course 5
Thickness (mils)
30
25
20
15
0
1
2
Number of Readings
Avg: 23.35
+1 σ: 28.32
-1 σ: 18.38

East - Course 4

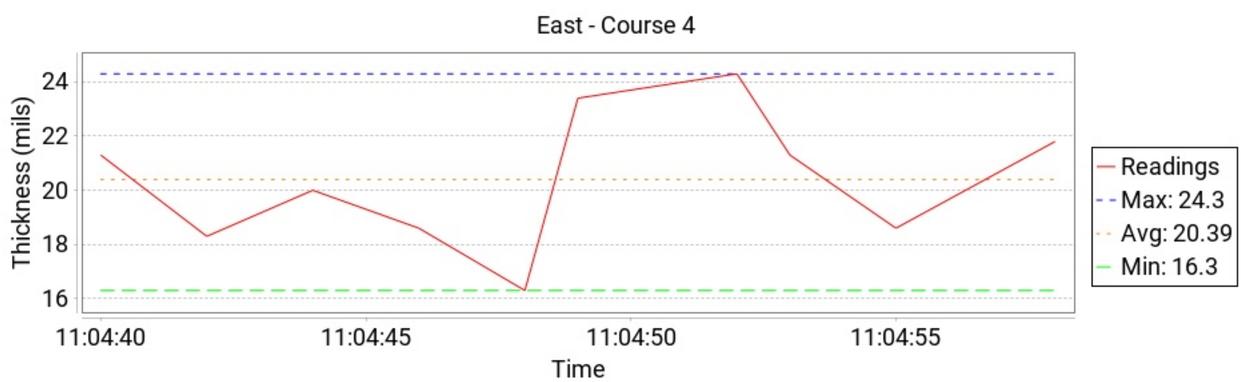
Created:	2021-08-16 11:04:25
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

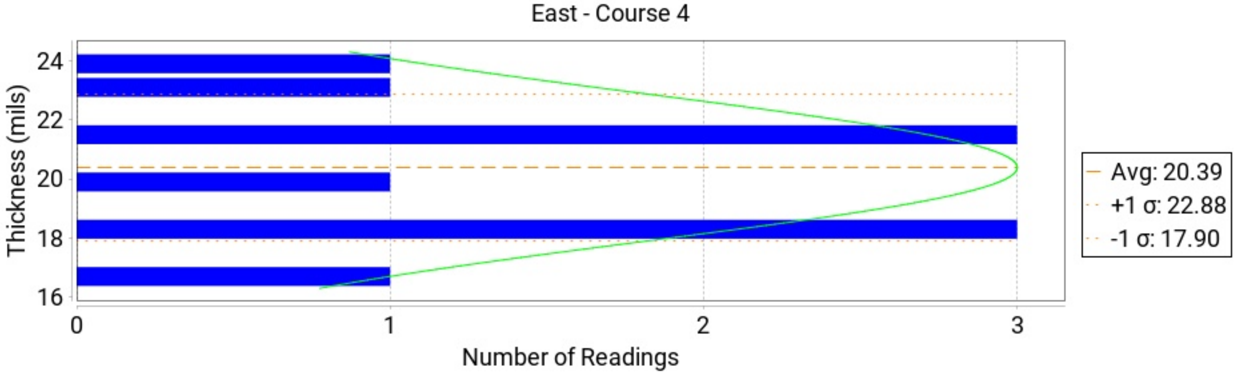
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	20.39	2.49	16.3	24.3

Readings

#	Thickness (mils)	Time
1	21.3	2021-08-16 11:04:40
2	18.3	11:04:42
3	20.0	11:04:44
4	18.6	11:04:46
5	16.3	11:04:48
6	23.4	11:04:49
7	24.3	11:04:52
8	21.3	11:04:53
9	18.6	11:04:55
10	21.8	11:04:58




East - Course 4
Thickness (mils)
24
22
20
18
16
0
1
2
3
Number of Readings
Avg: 20.39
+1 σ: 22.88
-1 σ: 17.90

East - Course 3

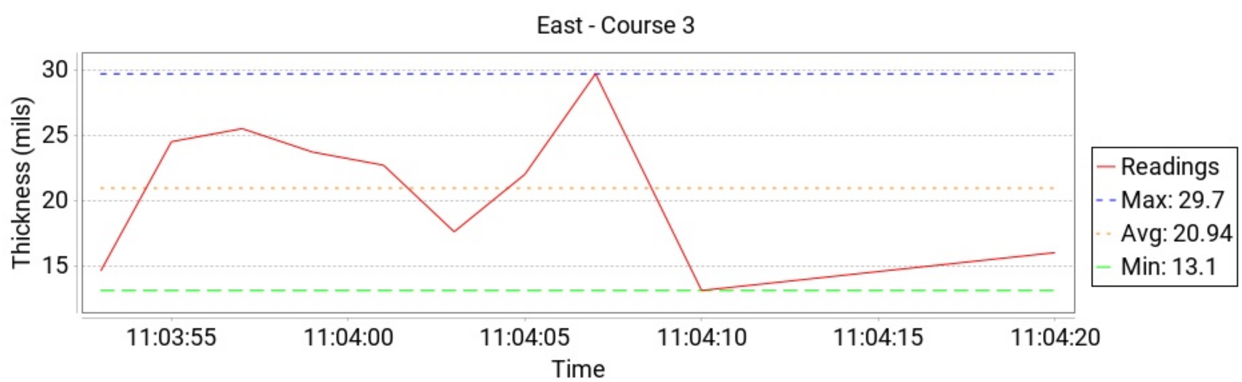
Created:	2021-08-16 11:03:41
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

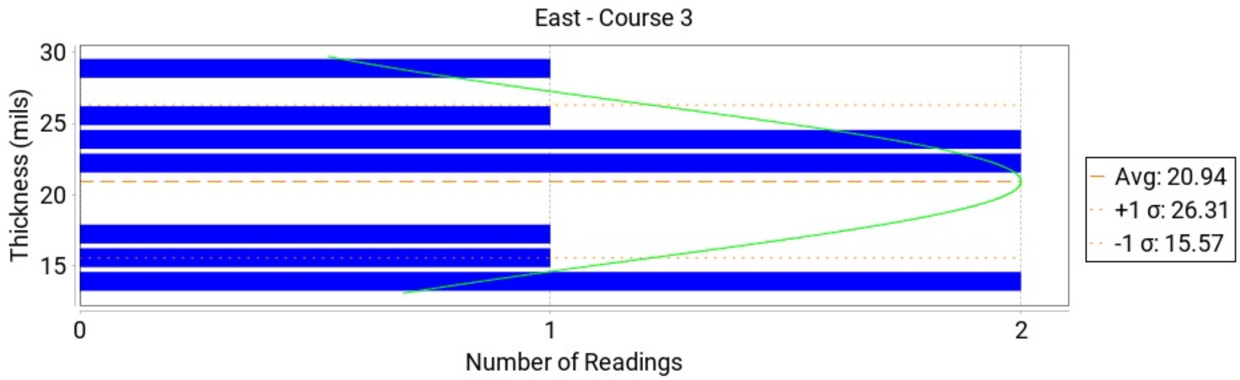
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	20.94	5.37	13.1	29.7

Readings

#	Thickness (mils)	Time
1	14.6	2021-08-16 11:03:53
2	24.5	11:03:55
3	25.5	11:03:57
4	23.7	11:03:59
5	22.7	11:04:01
6	17.6	11:04:03
7	22.0	11:04:05
8	29.7	11:04:07
9	13.1	11:04:10
10	16.0	11:04:20




East - Course 3
Thickness (mils)
30
25
20
15
0
1
2
Number of Readings
Avg: 20.94
+1 σ: 26.31
-1 σ: 15.57

East - Course 2

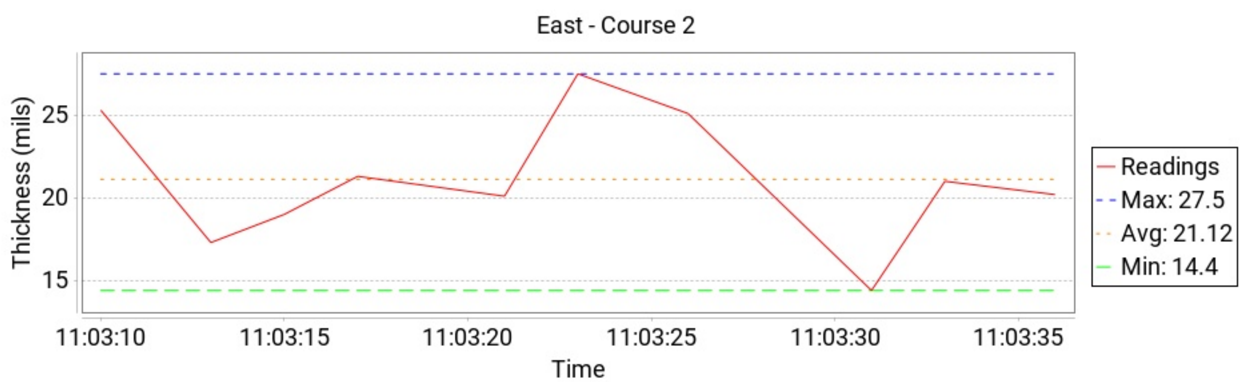
Created:	2021-08-16 11:00:13
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

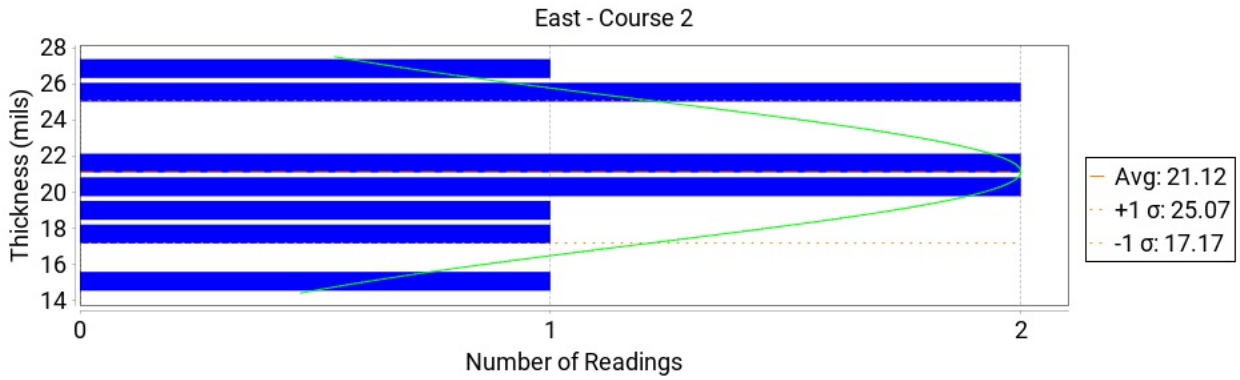
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	21.12	3.95	14.4	27.5

Readings

#	Thickness (mils)	Time
1	25.3	2021-08-16 11:03:10
2	17.3	11:03:13
3	19.0	11:03:15
4	21.3	11:03:17
5	20.1	11:03:21
6	27.5	11:03:23
7	25.1	11:03:26
8	14.4	11:03:31
9	21.0	11:03:33
10	20.2	11:03:36




East - Course 2
Thickness (mils)
28
26
24
22
20
18
16
14
0
1
2
Number of Readings
Avg: 21.12
+1 σ: 25.07
-1 σ: 17.17

East - Course 1

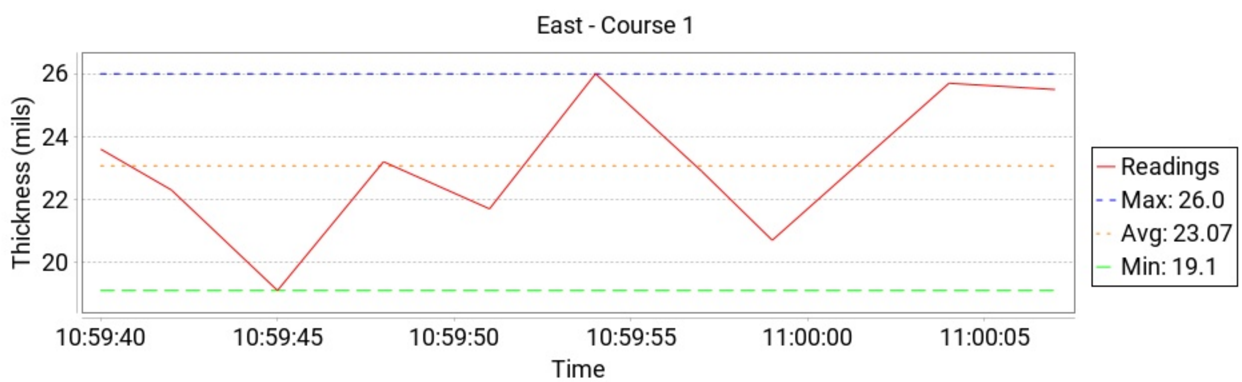
Created:	2021-08-16 10:59:28
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

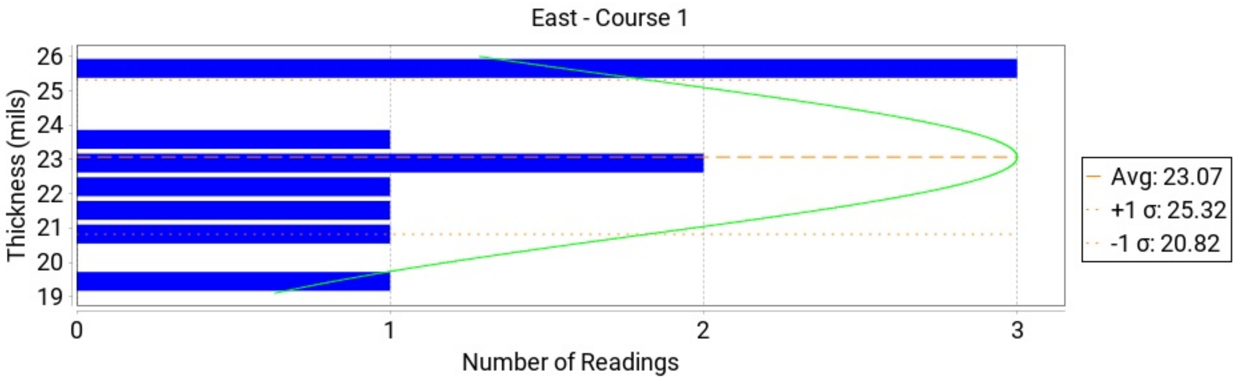
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	23.07	2.25	19.1	26.0

Readings

#	Thickness (mils)	Time
1	23.6	2021-08-16 10:59:40
2	22.3	10:59:42
3	19.1	10:59:45
4	23.2	10:59:48
5	21.7	10:59:51
6	26.0	10:59:54
7	22.9	10:59:57
8	20.7	10:59:59
9	25.7	11:00:04
10	25.5	11:00:07




East - Course 1
Thickness (mils)
26
25
24
23
22
21
20
19
0
1
2
3
Number of Readings
Avg: 23.07
+1 σ: 25.32
-1 σ: 20.82

North - Course 6

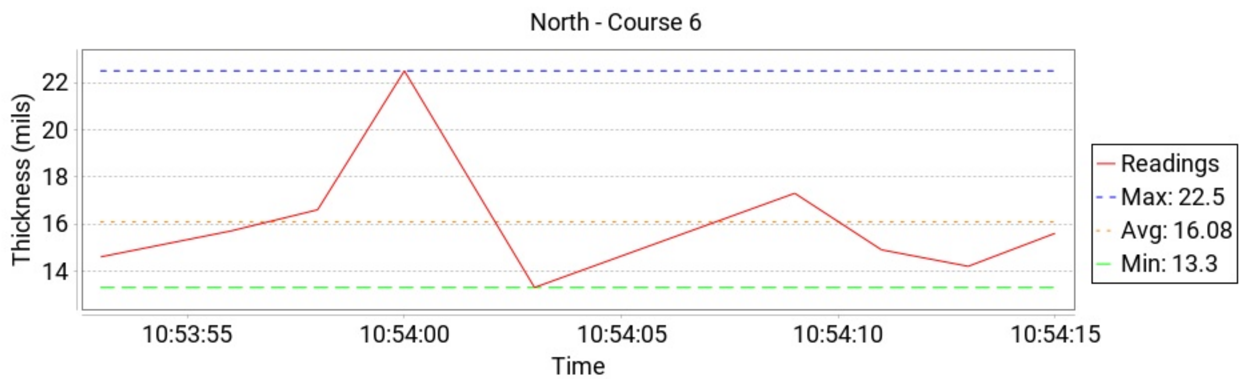
Created:	2021-08-16 10:52:59
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

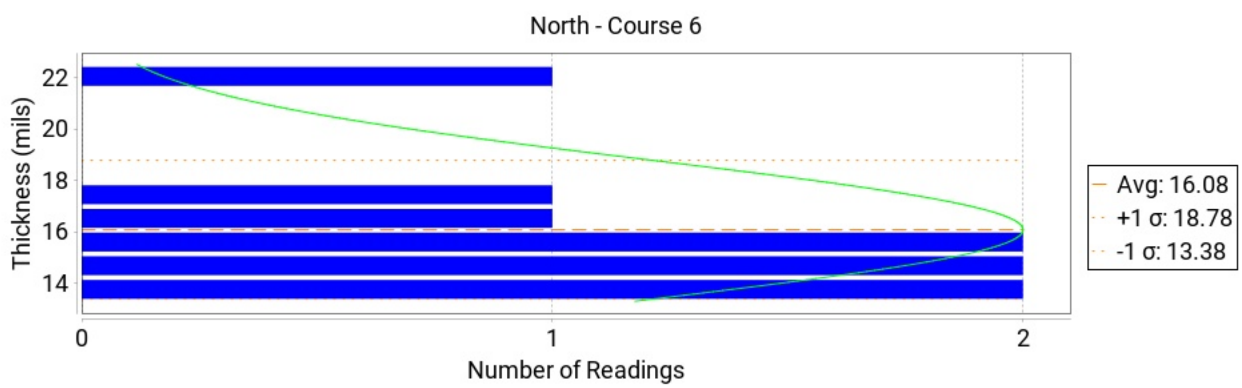
Summary

	#	x	σ	↓	↑
Thickness (mils)	9	16.08	2.70	13.3	22.5

Readings

#	Thickness (mils)	Time
1	14.6	2021-08-16 10:53:53
2	15.7	10:53:56
3	16.6	10:53:58
4	22.5	10:54:00
5	13.3	10:54:03
6	17.3	10:54:09
7	14.9	10:54:11
8	14.2	10:54:13
9	15.6	10:54:15





North - Course 5

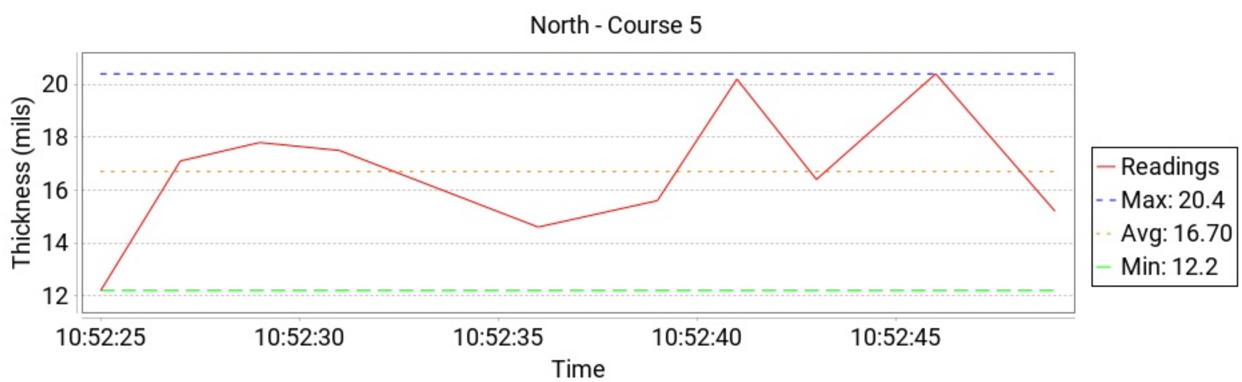
Created:	2021-08-16 10:51:20
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

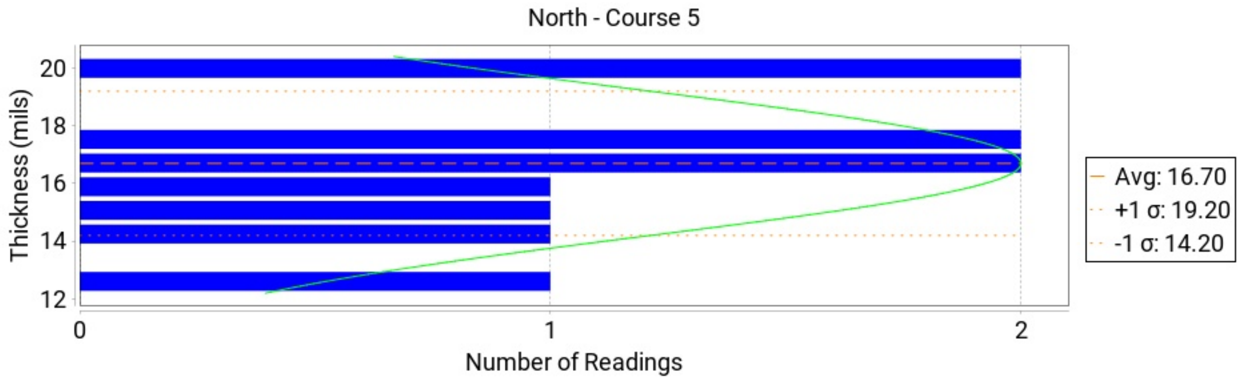
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	16.70	2.50	12.2	20.4

Readings

#	Thickness (mils)	Time
1	12.2	2021-08-16 10:52:25
2	17.1	10:52:27
3	17.8	10:52:29
4	17.5	10:52:31
5	14.6	10:52:36
6	15.6	10:52:39
7	20.2	10:52:41
8	16.4	10:52:43
9	20.4	10:52:46
10	15.2	10:52:49




North - Course 5
Thickness (mils)
20
18
16
14
12
0
1
2
Number of Readings
Avg: 16.70
+1 σ: 19.20
-1 σ: 14.20

North - Course 4

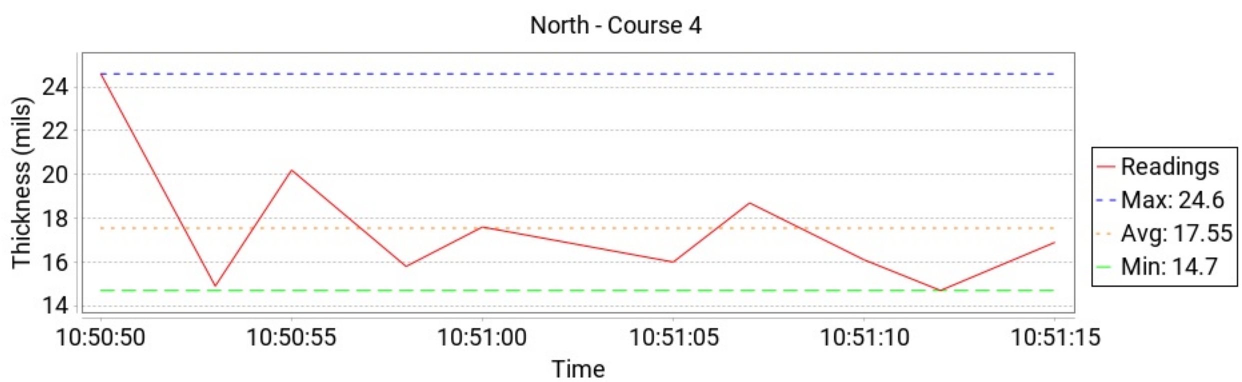
Created:	2021-08-16 10:49:55
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

Summary

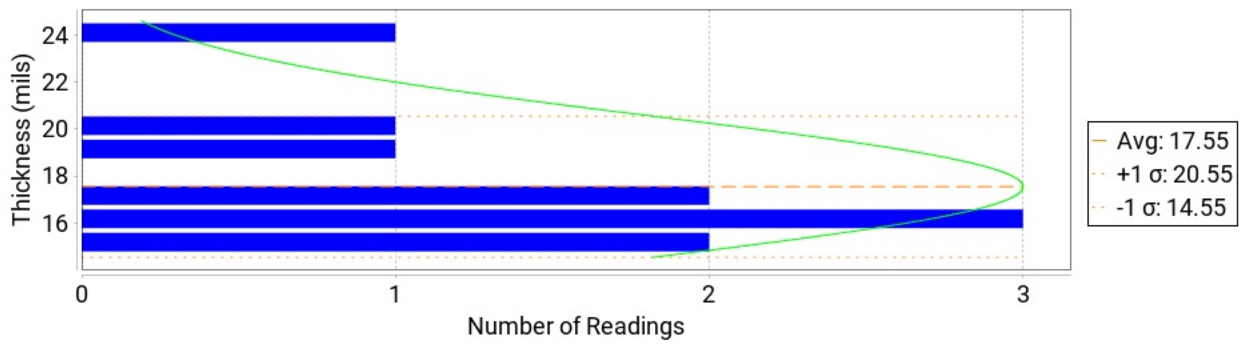
	#	x	σ	↓	↑
Thickness (mils)	10	17.55	3.00	14.7	24.6

Readings

#	Thickness (mils)	Time
1	24.6	2021-08-16 10:50:50
2	14.9	10:50:53
3	20.2	10:50:55
4	15.8	10:50:58
5	17.6	10:51:00
6	16.0	10:51:05
7	18.7	10:51:07
8	16.1	10:51:10
9	14.7	10:51:12
10	16.9	10:51:15



North - Course 4



North - Course 3

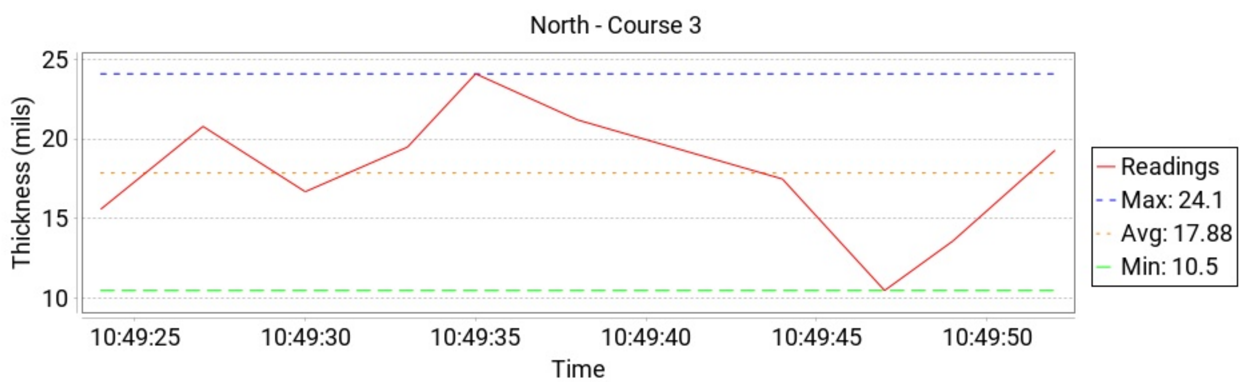
Created:	2021-08-16 10:48:28
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

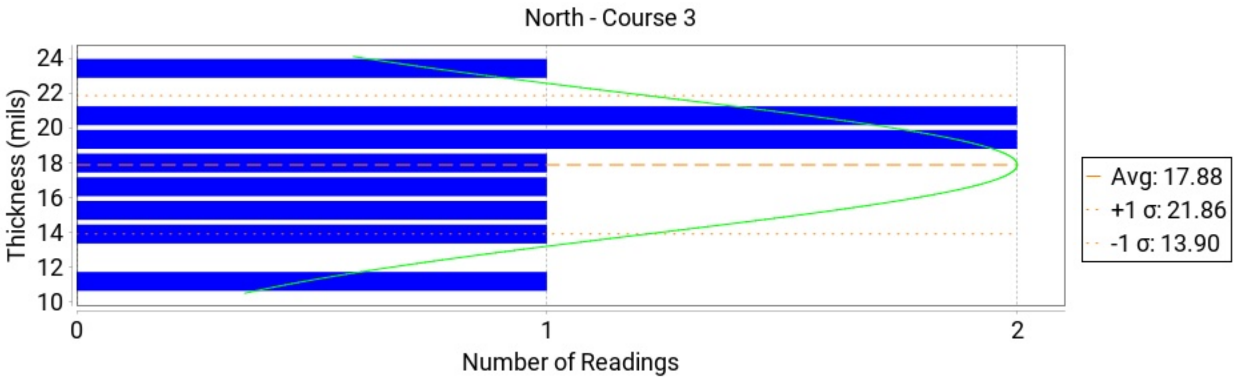
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	17.88	3.98	10.5	24.1

Readings

#	Thickness (mils)	Time
1	15.6	2021-08-16 10:49:24
2	20.8	10:49:27
3	16.7	10:49:30
4	19.5	10:49:33
5	24.1	10:49:35
6	21.2	10:49:38
7	17.5	10:49:44
8	10.5	10:49:47
9	13.6	10:49:49
10	19.3	10:49:52




North - Course 3
Thickness (mils)
24
22
20
18
16
14
12
10
0
1
2
Number of Readings
Avg: 17.88
+1 σ: 21.86
-1 σ: 13.90

North - Course 2

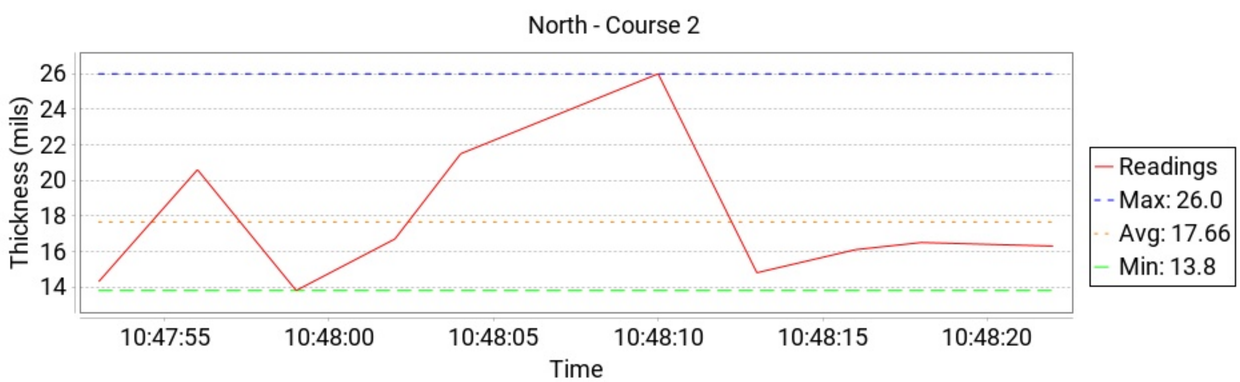
Created:	2021-08-16 10:47:01
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

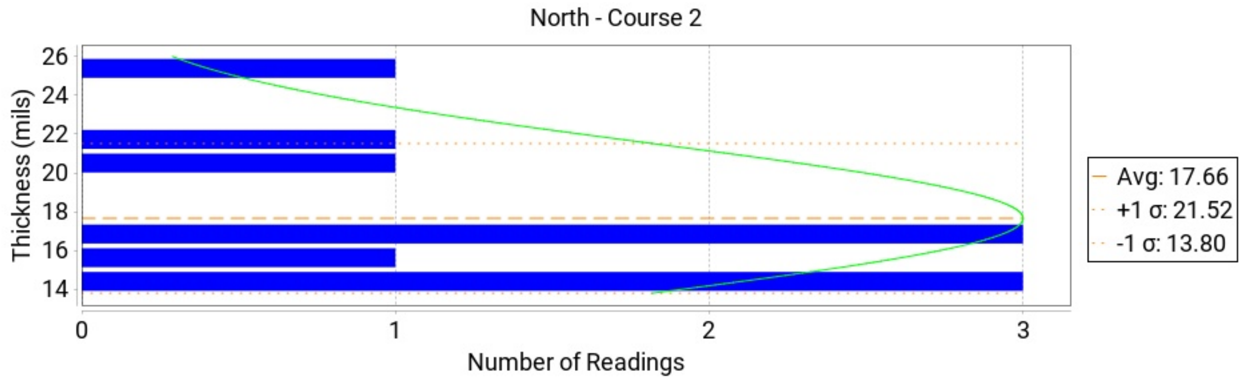
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	17.66	3.86	13.8	26.0

Readings

#	Thickness (mils)	Time
1	14.3	2021-08-16 10:47:53
2	20.6	10:47:56
3	13.8	10:47:59
4	16.7	10:48:02
5	21.5	10:48:04
6	26.0	10:48:10
7	14.8	10:48:13
8	16.1	10:48:16
9	16.5	10:48:18
10	16.3	10:48:22




North - Course 2
Thickness (mils)
26
24
22
20
18
16
14
0
1
2
3
Number of Readings
Avg: 17.66
+1 σ: 21.52
-1 σ: 13.80

North - Course 1

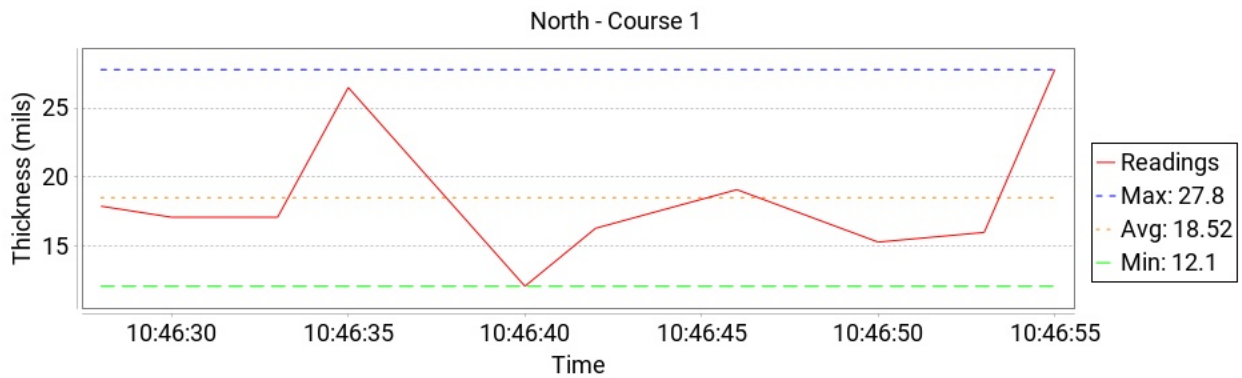
Created:	2021-08-16 10:46:21
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

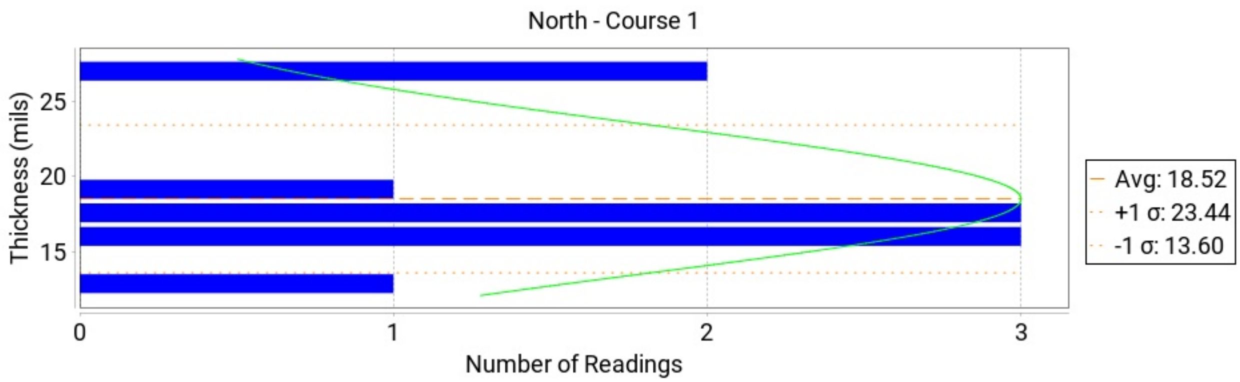
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	18.52	4.92	12.1	27.8

Readings

#	Thickness (mils)	Time
1	17.9	2021-08-16 10:46:28
2	17.1	10:46:30
3	17.1	10:46:33
4	26.5	10:46:35
5	12.1	10:46:40
6	16.3	10:46:42
7	19.1	10:46:46
8	15.3	10:46:50
9	16.0	10:46:53
10	27.8	10:46:55




North - Course 1
Thickness (mils)
25
20
15
0
1
2
3
Number of Readings
Avg: 18.52
+1 σ: 23.44
-1 σ: 13.60

West - Course 6

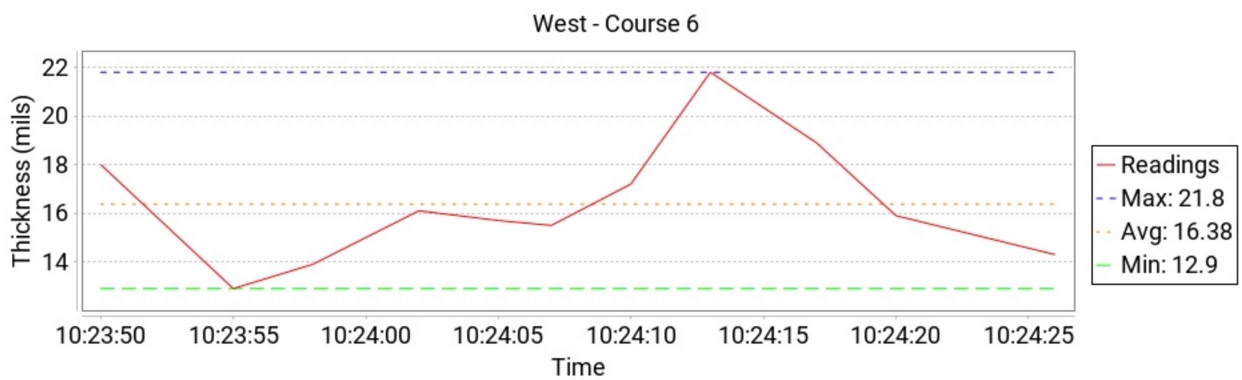
Created:	2021-08-16 10:22:55
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

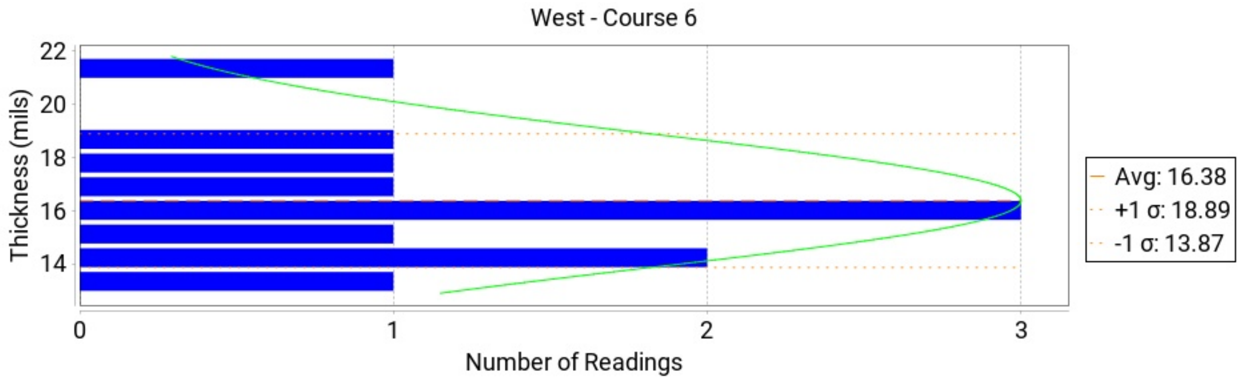
Summary

	#	x	σ	↓	↑
Thickness (mils)	11	16.38	2.51	12.9	21.8

Readings

#	Thickness (mils)	Time
1	18.0	2021-08-16 10:23:50
2	12.9	10:23:55
3	13.9	10:23:58
4	16.1	10:24:02
5	15.7	10:24:05
6	15.5	10:24:07
7	17.2	10:24:10
8	21.8	10:24:13
9	18.9	10:24:17
10	15.9	10:24:20
11	14.3	10:24:26




West - Course 6
22
20
18
16
14
Thickness (mils)
0
1
2
3
Number of Readings
Avg: 16.38
+1 σ: 18.89
-1 σ: 13.87

West - Course 5

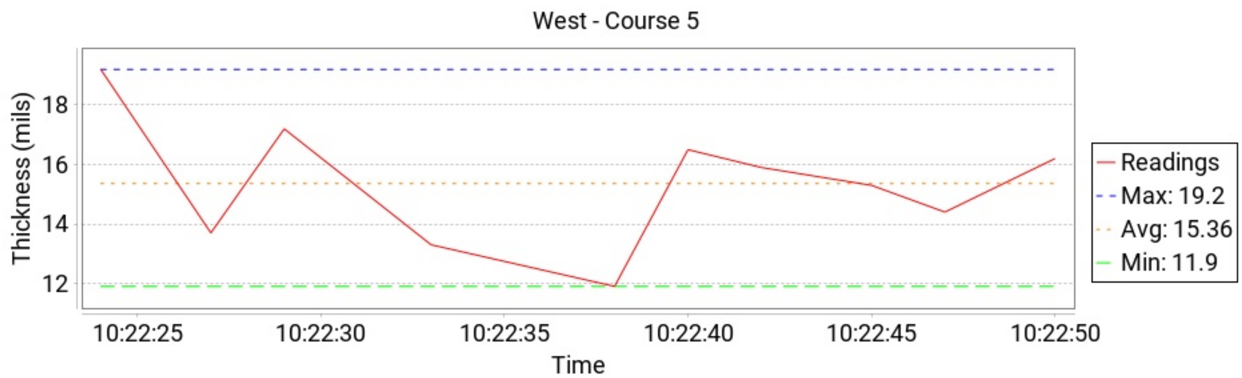
Created:	2021-08-16 10:21:30
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

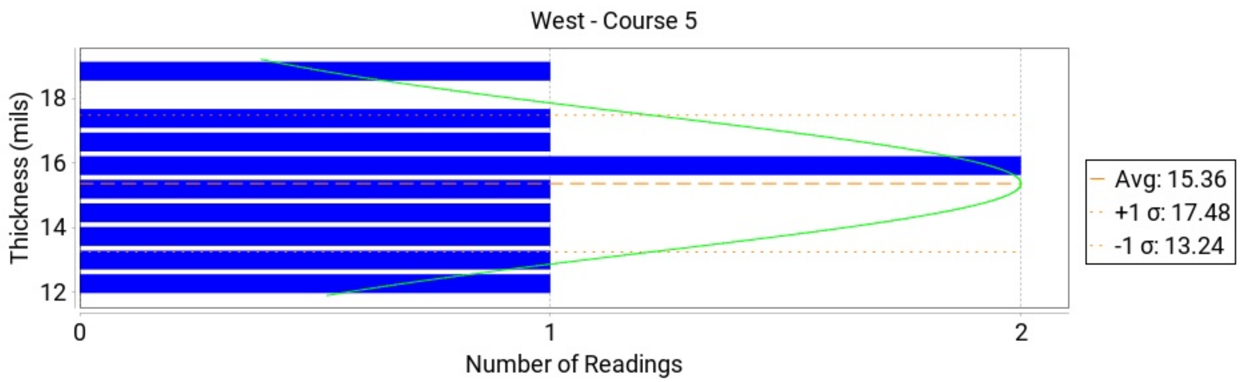
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	15.36	2.12	11.9	19.2

Readings

#	Thickness (mils)	Time
1	19.2	2021-08-16 10:22:24
2	13.7	10:22:27
3	17.2	10:22:29
4	13.3	10:22:33
5	11.9	10:22:38
6	16.5	10:22:40
7	15.9	10:22:42
8	15.3	10:22:45
9	14.4	10:22:47
10	16.2	10:22:50




West - Course 5
Thickness (mils)
18
16
14
12
0
1
2
Number of Readings
Avg: 15.36
+1 σ: 17.48
-1 σ: 13.24

West - Course 4

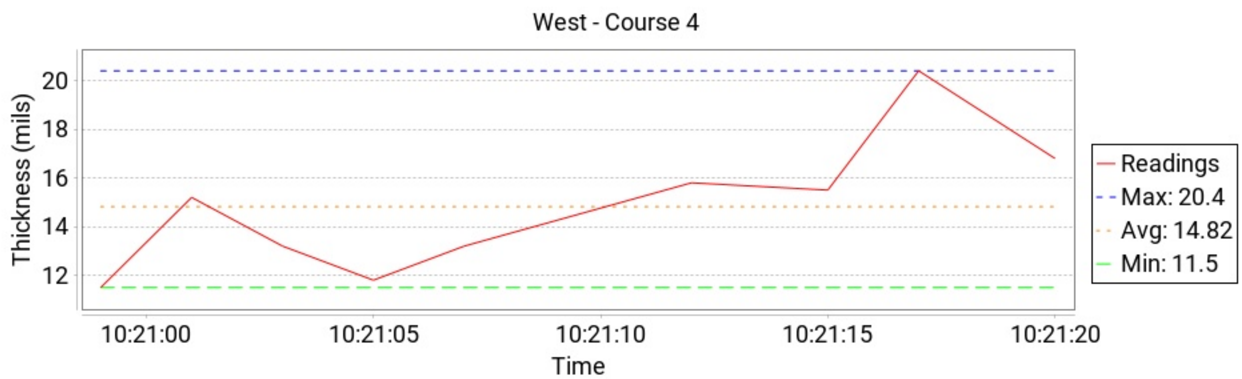
Created:	2021-08-16 10:19:21
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

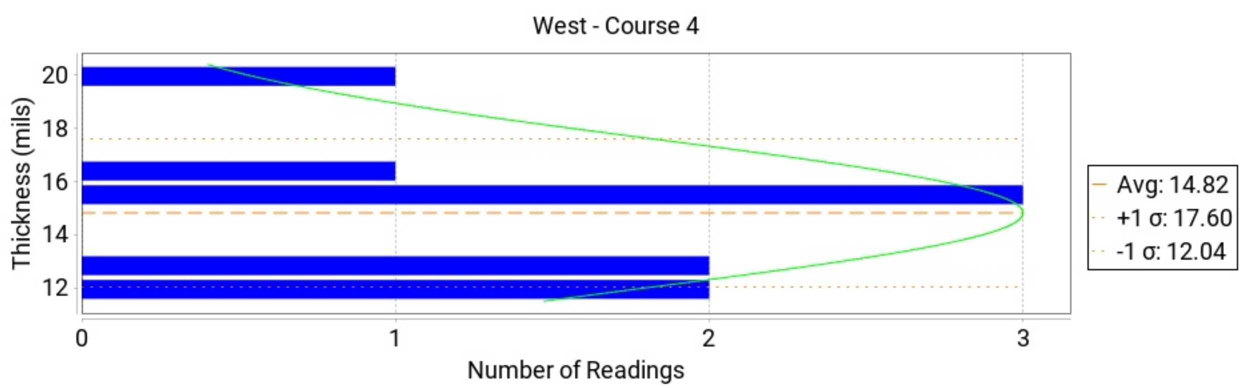
Summary

	#	x	σ	↓	↑
Thickness (mils)	9	14.82	2.78	11.5	20.4

Readings

#	Thickness (mils)	Time
1	11.5	2021-08-16 10:20:59
2	15.2	10:21:01
3	13.2	10:21:03
4	11.8	10:21:05
5	13.2	10:21:07
6	15.8	10:21:12
7	15.5	10:21:15
8	20.4	10:21:17
9	16.8	10:21:20





West - Course 3

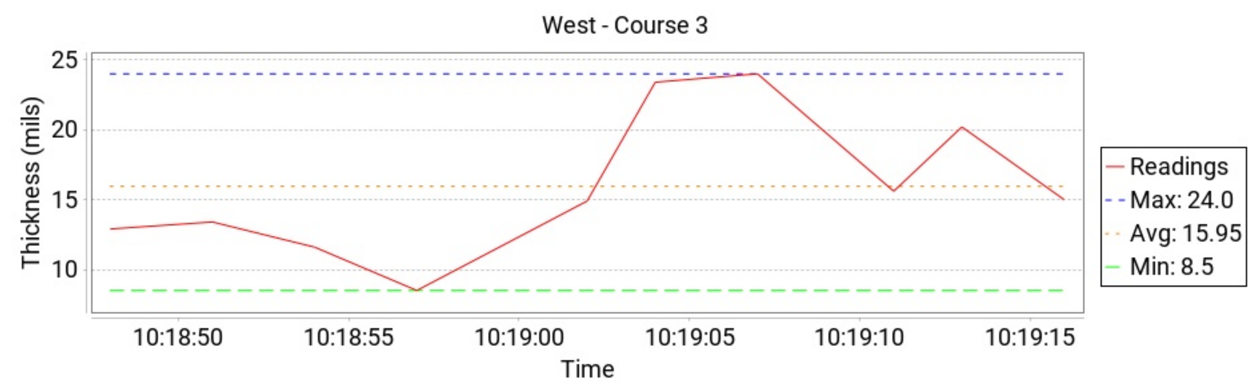
Created:	2021-08-16 10:17:31
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

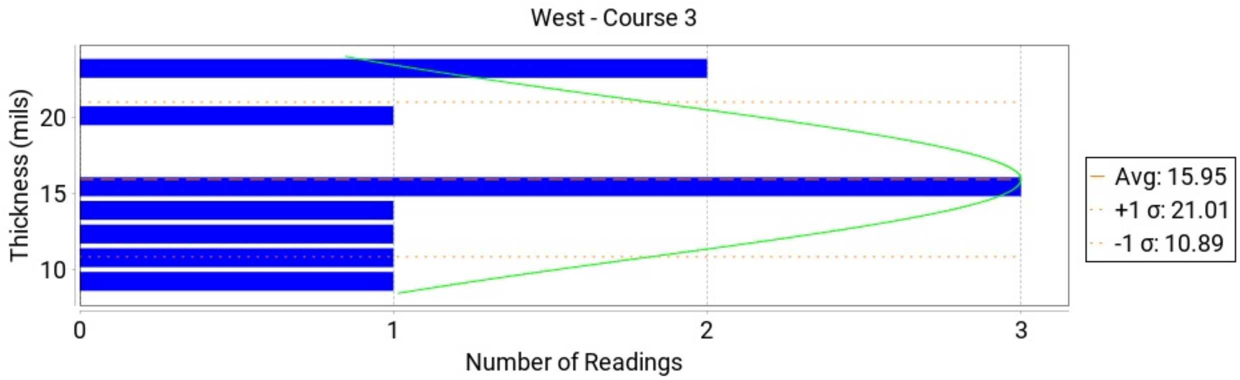
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	15.95	5.06	8.5	24.0

Readings

#	Thickness (mils)	Time
1	12.9	2021-08-16 10:18:48
2	13.4	10:18:51
3	11.6	10:18:54
4	8.5	10:18:57
5	14.9	10:19:02
6	23.4	10:19:04
7	24.0	10:19:07
8	15.6	10:19:11
9	20.2	10:19:13
10	15.0	10:19:16




West - Course 3
Thickness (mils)
20
15
10
0
1
2
3
Number of Readings
Avg: 15.95
+1 σ: 21.01
-1 σ: 10.89

West - Course 2

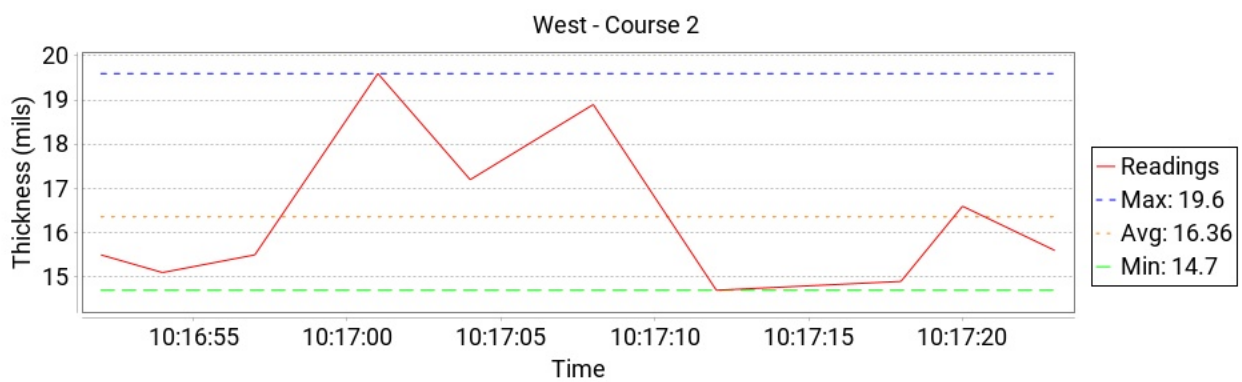
Created:	2021-08-16 10:13:17
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

Summary

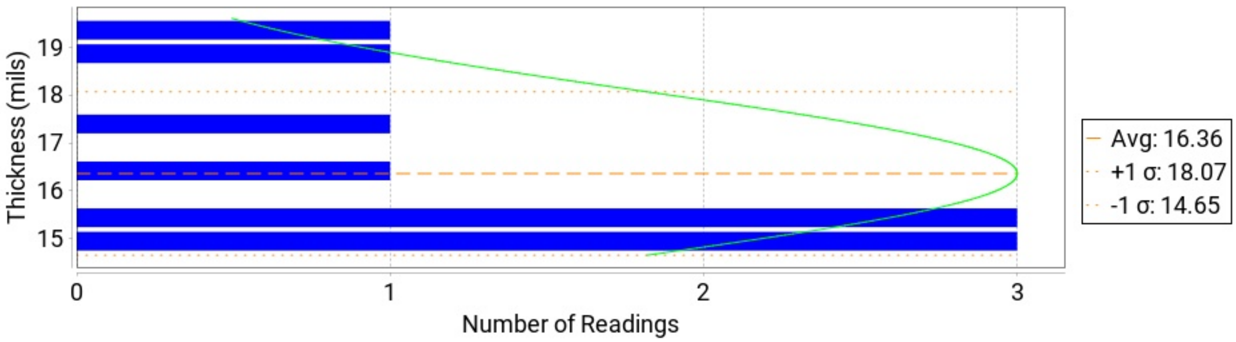
	#	x	σ	↓	↑
Thickness (mils)	10	16.36	1.71	14.7	19.6

Readings

#	Thickness (mils)	Time
1	15.5	2021-08-16 10:16:52
2	15.1	10:16:54
3	15.5	10:16:57
4	19.6	10:17:01
5	17.2	10:17:04
6	18.9	10:17:08
7	14.7	10:17:12
8	14.9	10:17:18
9	16.6	10:17:20
10	15.6	10:17:23



West - Course 2



West - Course 1

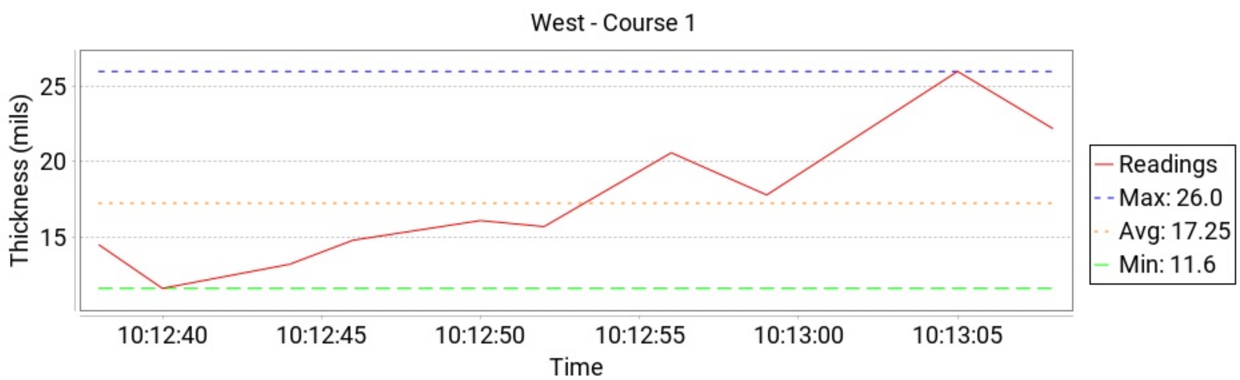
Created:	2021-08-16 10:12:31
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

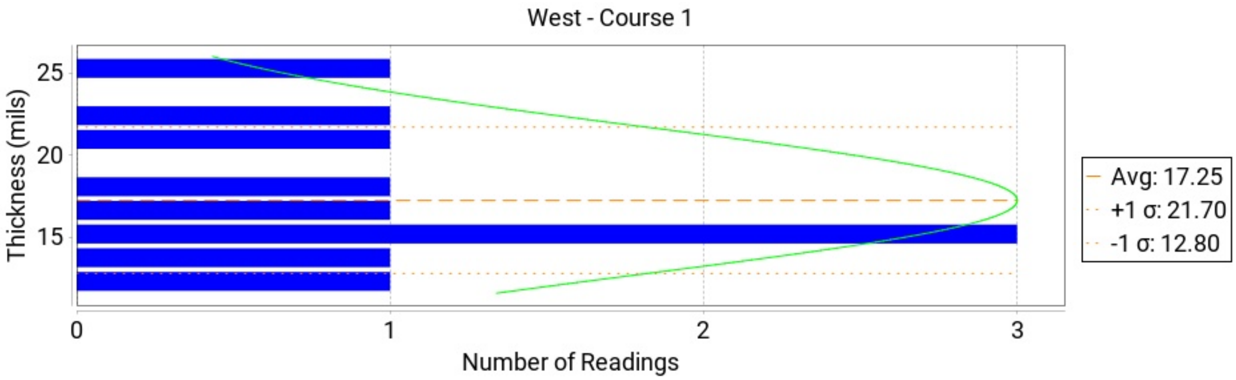
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	17.25	4.45	11.6	26.0

Readings

#	Thickness (mils)	Time
1	14.5	2021-08-16 10:12:38
2	11.6	10:12:40
3	13.2	10:12:44
4	14.8	10:12:46
5	16.1	10:12:50
6	15.7	10:12:52
7	20.6	10:12:56
8	17.8	10:12:59
9	26.0	10:13:05
10	22.2	10:13:08




West - Course 1
Thickness (mils)
25
20
15
0
1
2
3
Number of Readings
Avg: 17.25
+1 σ: 21.70
-1 σ: 12.80

South - Course 6

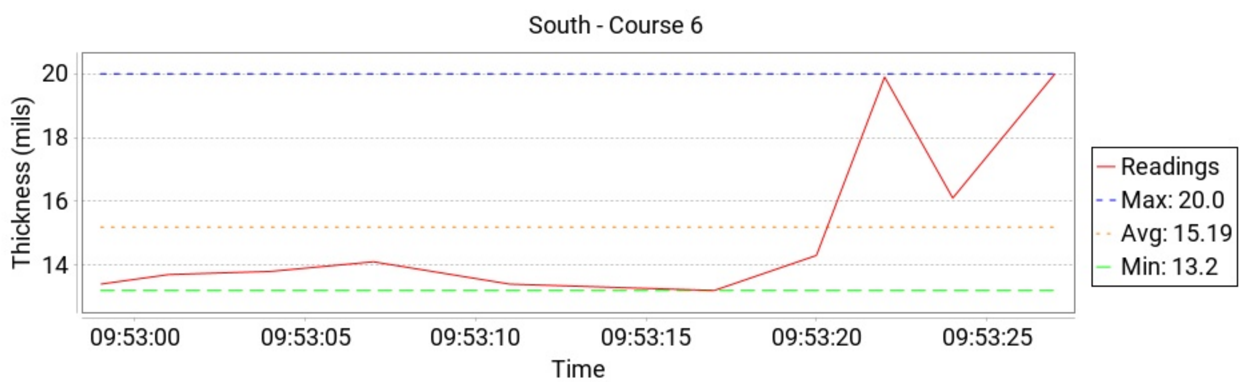
Created:	2021-08-16 09:51:59
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

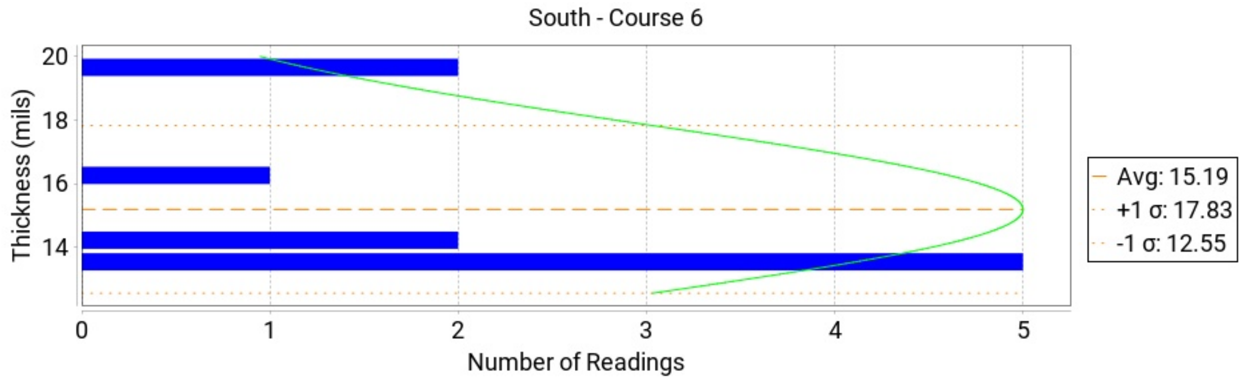
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	15.19	2.64	13.2	20.0

Readings

#	Thickness (mils)	Time
1	13.4	2021-08-16 09:52:59
2	13.7	09:53:01
3	13.8	09:53:04
4	14.1	09:53:07
5	13.4	09:53:11
6	13.2	09:53:17
7	14.3	09:53:20
8	19.9	09:53:22
9	16.1	09:53:24
10	20.0	09:53:27




South - Course 6
Thickness (mils)
20
18
16
14
0
1
2
3
4
5
Number of Readings
Avg: 15.19
+1 σ: 17.83
-1 σ: 12.55

South - Course 5

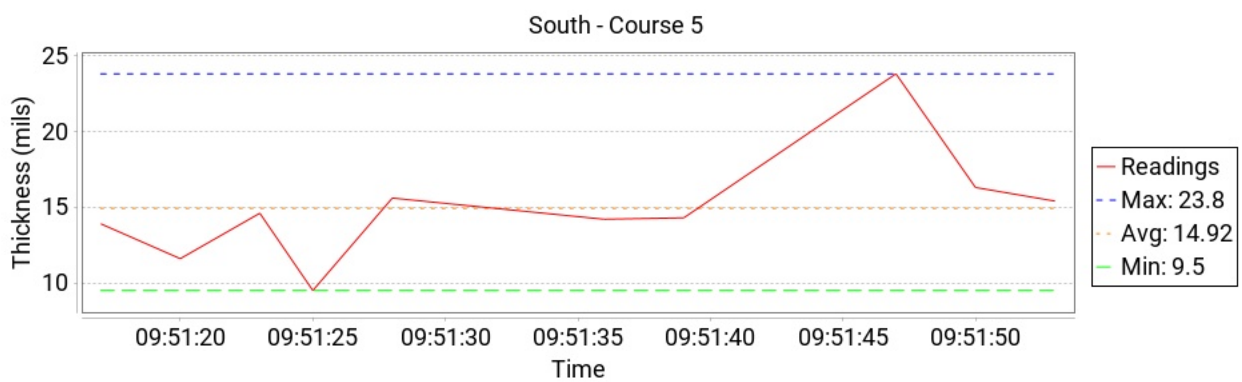
Created:	2021-08-16 09:46:43
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

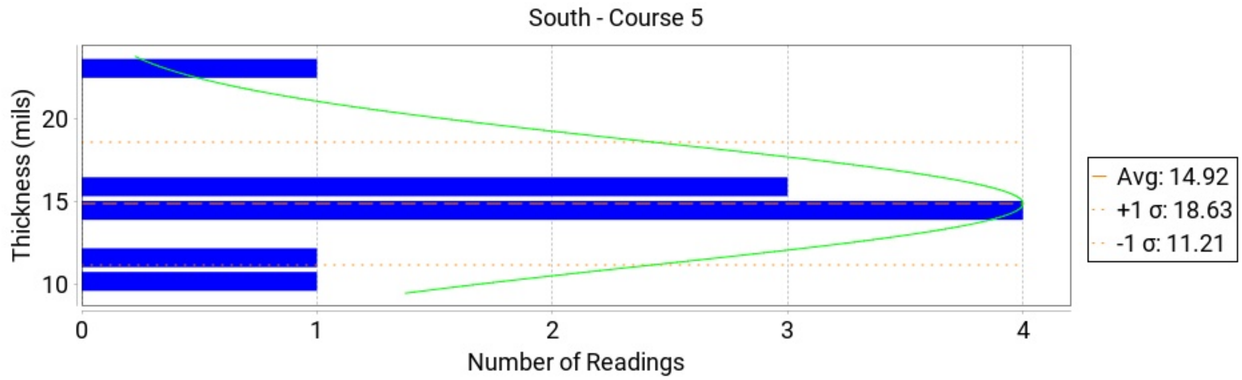
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	14.92	3.71	9.5	23.8

Readings

#	Thickness (mils)	Time
1	13.9	2021-08-16 09:51:17
2	11.6	09:51:20
3	14.6	09:51:23
4	9.5	09:51:25
5	15.6	09:51:28
6	14.2	09:51:36
7	14.3	09:51:39
8	23.8	09:51:47
9	16.3	09:51:50
10	15.4	09:51:53




South - Course 5
Thickness (mils)
20
15
10
0
1
2
3
4
Number of Readings
Avg: 14.92
+1 σ: 18.63
-1 σ: 11.21

South - Course 4

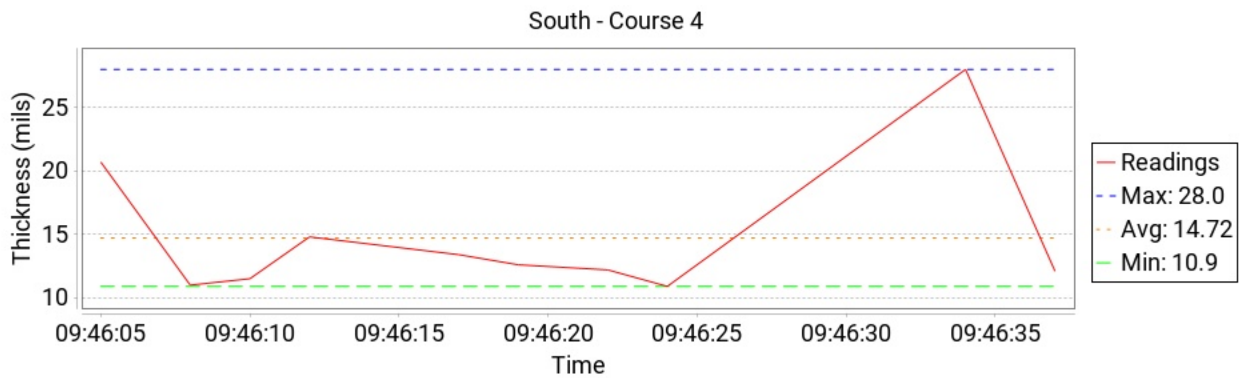
Created:	2021-08-16 09:45:04
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

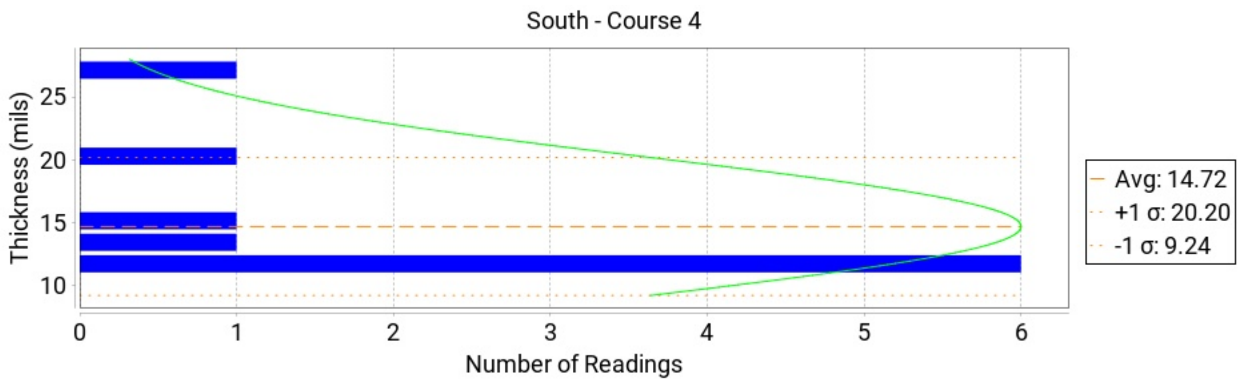
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	14.72	5.48	10.9	28.0

Readings

#	Thickness (mils)	Time
1	20.7	2021-08-16 09:46:05
2	11.0	09:46:08
3	11.5	09:46:10
4	14.8	09:46:12
5	13.4	09:46:17
6	12.6	09:46:19
7	12.2	09:46:22
8	10.9	09:46:24
9	28.0	09:46:34
10	12.1	09:46:37




South - Course 4
Thickness (mils)
25
20
15
10
0
1
2
3
4
5
6
Number of Readings
Avg: 14.72
+1 σ: 20.20
-1 σ: 9.24

South - Course 3

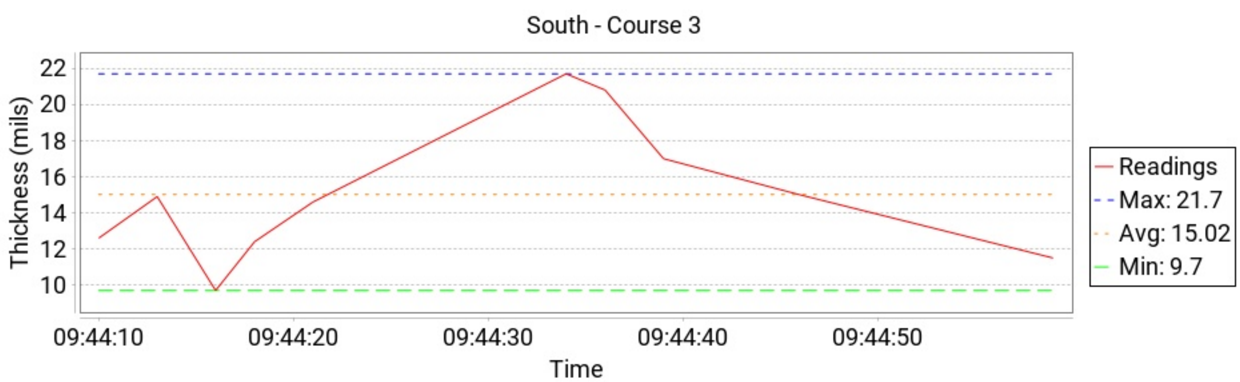
Created:	2021-08-16 09:42:32
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

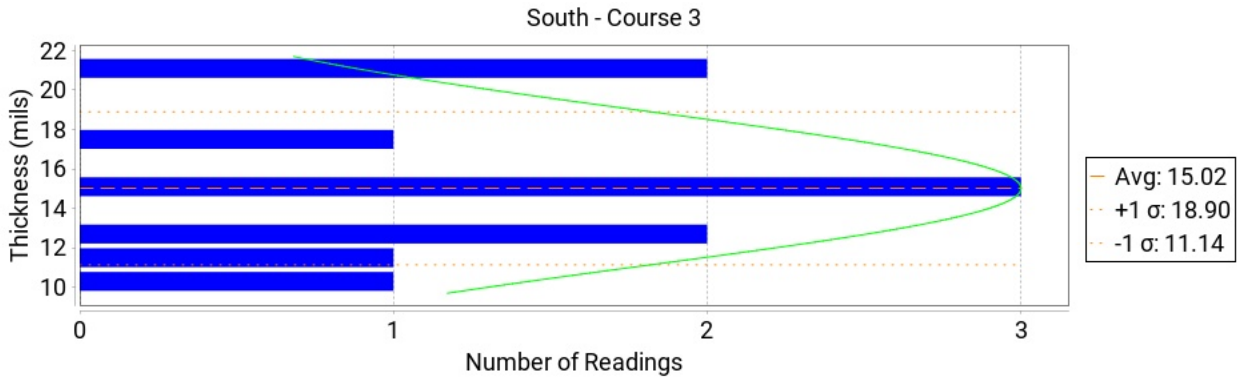
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	15.02	3.88	9.7	21.7

Readings

#	Thickness (mils)	Time
1	12.6	2021-08-16 09:44:10
2	14.9	09:44:13
3	9.7	09:44:16
4	12.4	09:44:18
5	14.6	09:44:21
6	21.7	09:44:34
7	20.8	09:44:36
8	17.0	09:44:39
9	15.0	09:44:46
10	11.5	09:44:59




South - Course 3
Thickness (mils)
22
20
18
16
14
12
10
0
1
2
3
Number of Readings
Avg: 15.02
+1 σ: 18.90
-1 σ: 11.14

South - Course 2

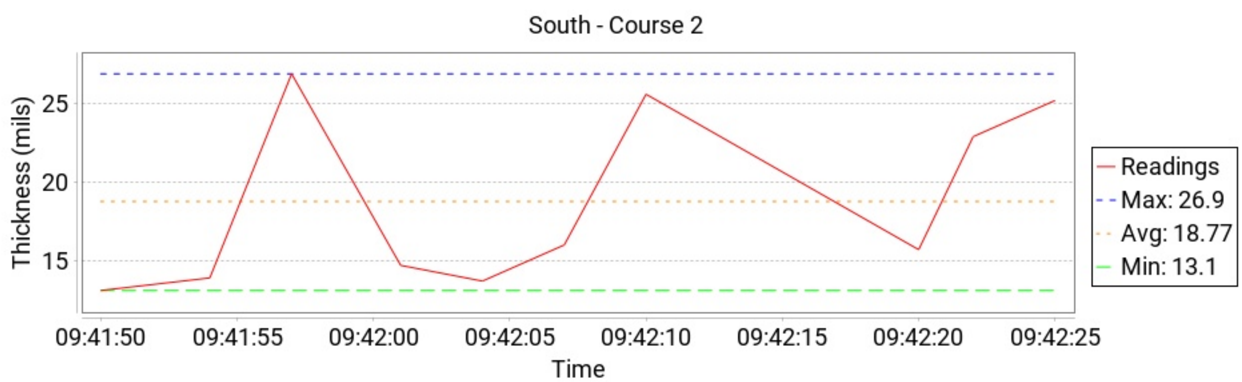
Created:	2021-08-16 09:38:36
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

Summary

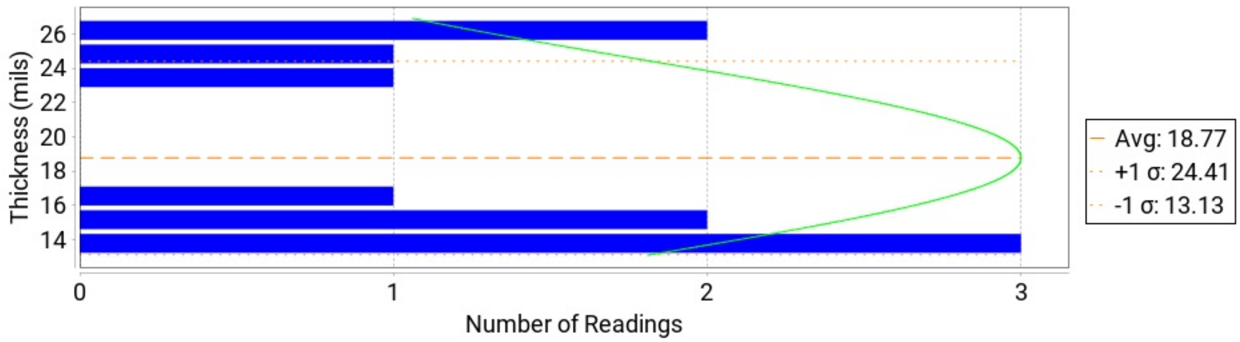
	#	x	σ	↓	↑
Thickness (mils)	10	18.77	5.64	13.1	26.9

Readings

#	Thickness (mils)	Time
1	13.1	2021-08-16 09:41:50
2	13.9	09:41:54
3	26.9	09:41:57
4	14.7	09:42:01
5	13.7	09:42:04
6	16.0	09:42:07
7	25.6	09:42:10
8	15.7	09:42:20
9	22.9	09:42:22
10	25.2	09:42:25



South - Course 2



South - Course 1

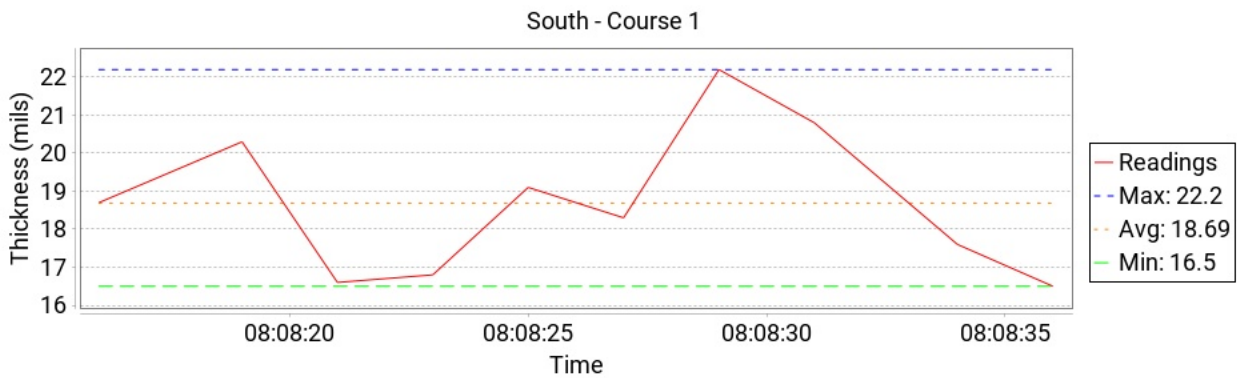
Created:	2021-08-20 08:08:08
PosiTector Body S/N:	764705
Probe Type:	PosiTector 6000 FS
Probe S/N:	242273
CAL:	Cal 1

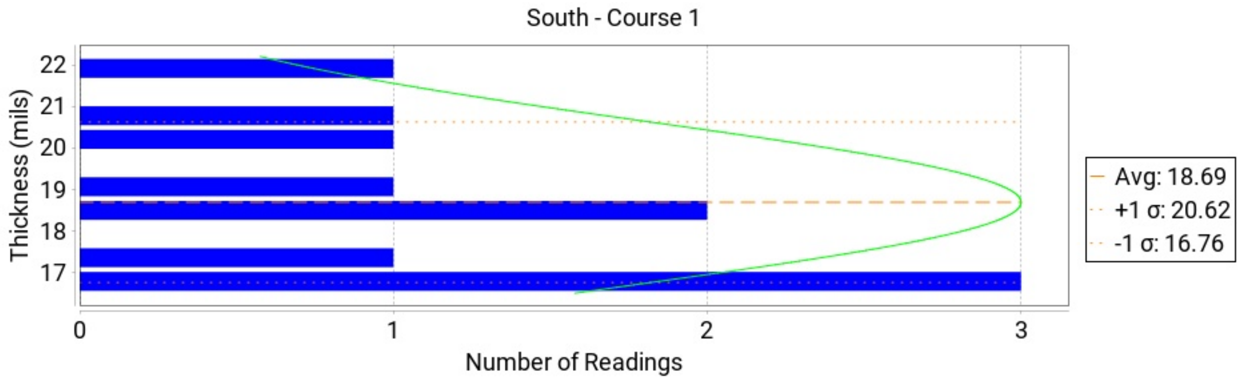
Summary

	#	x	σ	↓	↑
Thickness (mils)	10	18.69	1.93	16.5	22.2

Readings

#	Thickness (mils)	Time
1	18.7	2021-08-20 08:08:16
2	20.3	08:08:19
3	16.6	08:08:21
4	16.8	08:08:23
5	19.1	08:08:25
6	18.3	08:08:27
7	22.2	08:08:29
8	20.8	08:08:31
9	17.6	08:08:34
10	16.5	08:08:36




South - Course 1
Thickness (mils)
22
21
20
19
18
17
0
1
2
3
Number of Readings
Avg: 18.69
+1 σ: 20.62
-1 σ: 16.76

Attachment 3

“HTGS Condition Assessment and Life Extension Study – Project Report Volume II” provided by Hatch Ltd.

newfoundland labrador hydro

Project Report

March 30, 2022

Newfoundland and Labrador Hydro

HTGS Condition Assessment and Life Extension Study

Distribution
Jessica McGrath

Project Report Volume II

PROVINCE OF NEWFOUNDLAND
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
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which is valid for the year 2022

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HATCH						**Client**

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IMPORTANT NOTICE TO READER

This report, including the assessment contained herein, has been prepared by Hatch Ltd. ("Hatch") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to life extension of Holyrood Thermal Power Station (HTGS) and continued operation in full generation mode or conversion to emergency backup operation. Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person's use or reliance.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care based upon information available and conditions existing at the time of preparation of this report, and information made available to Hatch by the Client or by certain other parties on behalf of the Client (the "Client or Other Information").

The use of or reliance upon this report is subject to the following:

1. This report is to be read in the context of and is subject to the terms of the relevant Purchase Order 4769, dated 26 March 2021 between Hatch and the Client (the "Agreement"), including any methodologies, procedures, techniques, assumptions, and other relevant terms or conditions specified in the Hatch Agreement.
2. This report, including the assessment contained herein, is meant to be read as a whole, and sections of the report must not be read or relied upon out of context; and
3. Unless expressly stated otherwise in this report, Hatch has not verified the accuracy, completeness, or validity of any information provided to Hatch by or on behalf of the Client and Hatch does not accept any liability in connection with such information.
4. The condition, stability and safety of the facility has been assessed based on the data available on or before October 31st, 2021. This may change over time (or may have already changed) due to natural forces or human intervention, and Hatch does not accept any responsibility for the impact that such changes may have on the accuracy or validity of the opinions, conclusions, and recommendations set out in this report.

1. Executive Summary

1.1 Holyrood Thermal Generated Station

Newfoundland and Labrador Hydro (NLH) is transitioning to lower emission power generation with its investment in additional hydroelectric capacity, clean energy technologies, and reinforced transmission systems. The additional planned power generation is intended to replace Holyrood Thermal Generating Station (HTGS).

NLH is considering the role of the HTGS post-commissioning of the Muskrat Falls Project assets. Currently, the HTGS is planned for retirement as of March 31, 2023[1], with Unit 3 transitioning to a permanent synchronous condenser unit.[1]

Hydro is seeking an independent assessment to fully understand the requirements (capital and operational) should the following options be considered for the HTGS:

1. Continued extension of the Holyrood TGS, whether online in full generation mode or standby mode beyond the current retirement period.
1. The viability and suitability of the HTGS to be used as a backup generating facility to support the island system in the event of a prolonged outage of the Labrador-Island Link until the qualitative End of Economically Feasible Life (“EEFL”) of the plant.

Hatch was engaged by NLH to review the condition of the asset and develop a capital plan with a view of extending the operation of the plant beyond 2023 that would permit comparison against other alternatives.

Reliability and quick recall are the most critical parameters when considering any power generation source for emergency backup power. Hatch has completed a condition assessment of the plant to determine the reliability of the units and to propose modifications to enable a 4 to 24 hours restart as defined in section 5 of Volume II report.

The recall time is defined as the time between the call for power and synchronization with the grid. The recall time is of paramount importance for any power generation facility to be used as a backup generation facility. Starting a conventional steam power plant from a cold shutdown to synchronization is a lengthy process that requires start-up procedures to be followed in a sequential order. In addition to the recall time, high reliability is the second major requirement for a backup generation facility.

NLH has requested this assessment to determine the viability of the HTGS as a base-loaded or standby plant beyond 2023.

Hatch investigated the conversion of the existing power station from baseload operation to backup generation for emergency support of the grid. The time required for Unit 3 to transition from synchronous condenser to power generation mode was also assessed.

The four recall scenarios explored for Units 1 and 2 are summarized in Table 1-1.

[1] This report was completed prior to Hydro’s announcement on extension to March 31, 2024.

Table 1-1: Summary of Scenarios

Scenarios	1st Unit	2nd Unit
Scenario 1	24 Hours	30 Hours
Scenario 2	8 Hours	12 Hours
Scenario 3	6 Hours	8 Hours
Scenario 4	<4 Hours	4 Hours

The capital plan and capital improvement cost estimates were developed for each scenario to an AACE Class-IV estimate. The operating and maintenance costs and costs associated with fuel and auxiliary power requirements were also developed. It is noted that the fuel costs for all scenarios are based on test runs with a duration of 24 hours at 100% maximum continuous rating (MCR). The loading can be varied to align with system grid limitations by using a longer duration to ensure a complete heat soak for the equipment. For Scenario 4, the plan includes maintaining the turbine's first stage inner metal shell temperature above the required level of 300°F to roll the turbine. This approach eliminates the prewarming time of 4 hours before rolling the turbine. The test runs, as proposed, and the associated turbine metal cool down period will result in a hybrid of Scenario 4 blended into Scenarios 1, 2, and 3 for the period when each turbine is above the pre-warming trigger level of 300°F. The fuel costs for test runs can be varied by changing the frequency of test runs, but this is limited by the maximum period of 8 weeks for dry storage of the reheater tubing without isolating the reheaters.

1.2 Capital and Operating Costs for Emergency Backup Operation

A capital plan to support emergency backup operation of the power station from 2022 to 2030 was developed. A summary of the modifications required to support power plant quick recall are provided in Table 1-2.

An auxiliary boiler is required to enable quick recall time of the facility. Steam from the auxiliary boiler will be used for building heating, deaerator water heating, boiler water heating, and for turbine pre-warming.

Table 1-2: Summary of Critical Improvements

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Auxiliary (Aux.) Boiler	Yes	Yes	Yes	Yes
Economizer Recirculation Line	N/A	No	Yes	Yes
Auxiliary Cooling Water Pump	N/A	Yes	Yes	No
Stack Damper	N/A	No	No	Yes

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Auxiliary Steam System Modifications	N/A	Yes	Yes	No
Automation of Blowdown and Waterwall Headers Drain Valves	N/A	Yes	Yes	Yes
Fuel Oil Storage Recirculation to Day Tank	Yes	Yes	Yes	Yes

A capital plan to support the upgrade of station assets, major inspections, overhauls, and operating costs from 2022 to 2030 was developed. Capital, operating, and fuel costs associated with each scenario are summarized in Table 1-3. A breakdown of the capital plan for each unit is provided in Table 1-4. The detailed break down of costs associated with fuel consumption are included in Section 6.3.

The annual fuel costs shown in Table 1-3 cover the fuel used for each scenario plus the test runs for each unit. The plant is currently scheduled to continue in operating mode up to March 31, 2024, leading to nominally empty fuel tanks at that time. If it is decided that the plant is to either continue in current operating mode or to change to Emergency Standby mode, an additional cost to procure an inventory of fuel for potential consumption post March 31, 2024, will be incurred. To fill the fuel oil storage tanks during that time, the cost is estimated at CAD $22.1 Million per storage tank. If the plant is to be used in Emergency Standby mode for a possible full load operating period of six weeks with no fuel oil delivery, then all four tanks will be needed. Alternatively, if operation for a six-week period at full load is required, three tanks may be adequate provided a fuel delivery can be scheduled during the fourth week.

Table 1-3: Summary of Costs by Scenario ($1000's)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
S1	Capital	25,044	39,651	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,155	566,150
	Operating	25,147	15,408	15,408	15,408	15,408	15,408	15,408	15,408	15,408	148,411	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S2	Capital	25,044	39,939	26,317	22,299	27,104	17,750	14,011	24,728	12,251	209,443	566,681
	Operating	25,174	15,435	15,435	15,435	15,435	15,435	15,435	15,435	15,435	148,654	
	Fuel	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	23,176	208,584	
S3	Capital	25,044	41,379	26,317	22,299	27,104	17,750	14,011	24,728	12,251	210,883	585,302
	Operating	25,202	15,463	15,463	15,463	15,463	15,463	15,463	15,463	15,463	148,906	
	Fuel	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	25,057	225,513	
S4	Capital	25,044	46,275	26,317	22,299	27,104	17,750	14,011	24,728	12,251	215,779	612,275
	Operating	25,775	16,036	16,036	16,036	16,036	16,036	16,036	16,036	16,036	154,063	
	Fuel	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	26,937	242,433	

Table 1-4: Capital Plan Breakdown by Unit, 2022-2030 ($1000's)

Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Unit 1	3,333	3,333	6,433	3,333	3,500	3,800	4,200	12,394	3,667	43,994
Unit 2	3,333	14,161	5,033	3,333	4,300	3,500	3,500	3,667	3,667	44,494
Unit 3	7,835	4,123	4,399	13,097	8,777	6,600	5,200	7,667	3,667	61,364
Common Facilities	10,543	11,378	10,452	6,109	2,500	3,850	1,111	1,000	1,250	48,193

1.3 Capital and Operating Costs for Continued Operation

Estimates for the capital, operating, and fuel costs for the continued operation of HTGS were developed and are shown in Table 1-5. Capital costs are based on the capital plan discussed in Section 6.1.3 and the operating costs include O&M costs based on a count of 101 employees. Fuel costs were developed based on the historical load data provided by NLH for each unit and an estimated cumulative four months of operation per year as indicated by NLH. Escalation is not included in the aforementioned cost estimates.

The following assumptions apply to the fuel cost estimates:

- The total operating time per year is 4 months based on historical power generation requirements.
- Average power generated (MW) per unit based on the historical plant data from 1997 – 2022, which indicates a range of 77 – 94 MW per unit.
- Fuel cost is based on the last delivery to HTGS ($104.22 CAD/barrel).

Table 1-5: Capital, Operating, and Fuel Costs for Continued Operation through 2030 ($1000's)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
Capital	25,044	32,995	26,317	25,872	19,077	17,750	14,011	24,728	12,251	198,045	1,325,387
Operating	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	226,325	
Fuel	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	901,017	

1.4 Capital Cost Projections Beyond 2030

The capital cost projections for 2031 to 2040 are based on the cost estimates for 2022 to 2030. The following assumptions apply to these projections:

a) The plant will run in either full generation or Emergency Standby mode.

b) The 2022 to 2030 capital cost estimates are used as the baseline for the projected costs.

c) Routine inspections and major overhauls of plant key equipment such as boilers, turbines, and pumps will be conducted as per existing plant practices. Years where the capital cost projection is higher than the preceding or following year is due to costs included for major turbine and boiler upgrades.

d) Refurbishment cost estimates for Fuel Tanks No.1 and 4 are included in the capital cost estimates for 2022 and 2023, respectively. Similarly, refurbishment of Fuel Tanks No. 2 and 3 is included in the capital cost estimate for 2031 and 2032, respectively.

e) An estimated minimum and maximum range for the capital cost for 2031 through 2040 is presented in Table 1-6. To establish this range, an adjustment of 20% to 50% is made to the capital cost estimates for 2022 through 2030. These adjustments are included to account for potential generator rotor rewinding, condenser retubing, and major boiler tube repairs.

f) A refined capital plan is to be developed as part of the condition assessment program recommended in 2026 and 2027.

Table 1-6: Capital Cost for 2031 to 2040 ($1000's)

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Min	30,053	39,594	31,580	31,046	22,892	21,300	16,813	29,674	14,701	14,701	237,654
Max	37,566	49,493	39,476	38,808	28,616	26,625	21,017	37,092	18,377	18,377	297,068

1.5 Staffing Plan

A staffing plan was developed based on the recall time and corresponding staff requirements. The proposed staffing plan, with a total of 58 staff, and role descriptions are provided in Section 5.6.2. Details regarding personnel competency and qualifications, as well as training requirements, are provided in Sections 5.6.1 and 5.6.3, respectively.

1.6 Equipment Lay-up

To maintain the plant reliability for emergency recall, the lay-up requirements for each scenario vary depending on the state of readiness to be maintained for each recall option. The equipment lay-up requirements are summarized in Table 1-7. For Scenarios 1, 2, and 3, the boilers are stored using a Wet/Dry approach and steam turbines are maintained cold and placed on turning gear intermittently to keep rotor eccentricity within permissible limits. In Scenario 4, a Wet/Warm approach is used for the boiler and the steam turbine is rotated continuously (on turning gear). Scenarios 2 to 4 have a recall time varying from 4 to 12 hours, for these scenarios the generators are maintained under hydrogen pressure. In Scenario 1, a longer recall time of 24 to 30 hours is considered, in this scenario the hydrogen is purged from the generator's first with CO_2 and then with air. Further details for lay-up requirements are available in Section 5.4

Table 1-7: Basis for Equipment Lay-Up

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Boiler	Wet/Dry	Wet/Dry	Wet/Dry/Cold	Wet/Warm
Turbine	Cold & On Turning Gear (fortnightly for 4 hrs.)	Cold & On Turning Gear (weekly for 4 hrs.)	Cold & On Turning Gear (twice in a week for 4 hrs.)	Warm & On Turning Gear (continuously)

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Generator	Not Pressurized	H_2 Filled at 207 kPa	H_2 Filled at 207 kPa	H_2 Filled at 207 kPa

1.7 Starting Failure Forced Outage

The overall average number of starting failures is two per year up to 2013 and one per year after 2013. The outage data reviewed shows a pattern of higher restart failures prior to 2013 and an average of one restart failure per year post 2013. The total starting failure forced outages since 1993 are included in Table 1-8.

Table 1-8: Total Number of Starting Failures Since 1993

Unit	Total Number of Starting Failures Since 1993
1	24
2	17
3	15

To ensure high starting reliability, specific training with a focus on the standby operating scenarios and expectations for Plant Readiness to Serve as an Emergency Standby role should be developed.

1.8 Environmental Considerations and Recommended Changes to Certificate of Approval (COA)

An Environmental Management System (EMS) is in place in accordance with ISO 14001 and is operated in compliance with its existing environmental Certificate of Approval (COA). The environmental considerations for the emergency backup scenarios include the following:

- Additions to the COA for a new auxiliary boiler.
- Continued use of Quarry Brook to supply the Units 1 and 2 auxiliary cooling water and raw water systems.
- Noise emissions considerations for more frequent start/stop operations.
- In addition to the air emissions currently covered under the existing COA, it is noted that the introduction of GHG regulatory requirements and the federal carbon emissions program will need to be addressed for operation beyond 2021/2023. The carbon emissions program may impose additional costs in the form of a carbon tax or the acquisition of GHG credits. Potential carbon dioxide emissions were estimated based on an assumed operating profile as listed in Section 9. The results are summarized in Table 1-9.

Table 1-9: Estimated CO_2 Emissions

	Description	Units*	Scenario			
			1	2	3	4
A)	Annual Plant Heating	Mg/yr	13,000	13,000	16,000	20,000
B)	All Units Standby Mode Test Runs	Mg/yr	79,000	79,000	79,000	79,000
C)	3 weeks Continuous Operation	Mg	162,000	162,000	162,000	162,000
D)	6 weeks Continuous Operation	Mg	323,000	323,000	323,000	323,000

*Mg: Million grams

1.9 End of Economically Feasible Life (EEFL)

The principal components that limit the useful life of utility boilers and steam turbines are: (a) damage to the high temperature heavy wall boiler headers and steam turbines, (b) significant damage to boiler drums, and (c) steam turbine rotor surface life. Industry experience has shown that the process of decision-making is a complex issue and is very site specific. For example, some utilities life extension programs have been based on target utilisation of assets for 60 years after first in-service date, however, there are also some power plants in North America with units which are still in service, primarily on a standby intermittent operation basis, after close to 70 years in service.

In the case of HTGS, the reported condition assessments and inspections of the boilers heavy wall components have not reported any indications that suggest limiting factors on their extended use to 2030 and beyond. Review of the boiler and turbine-generator condition assessments conducted over the period of 2017 to 2021, related inspection reports, and other inspection reports have recorded some issues in the heavy wall components on each of the boilers and Unit 3 turbine but no imminent end of life issues for the components operating in the creep range were indicated. Therefore, the steam turbine rotor surface life expended was assessed based on the available start-stop and load cycling operating history for each unit. The analysis indicated that the estimated cumulative steam turbine rotor life expended for each unit is moderate as summarized in Table 1-10. It is noted that this assessment is qualitative and not quantitative.

Table 1-10: Cumulative Rotor Life Expended for 2030

	Unit 1	Unit 2	Unit 3
Cumulative Rotor Life Expended Predicted for 2030	32%	34%	29%

1.10 Summary of Recommendations for HTGS

A summary of the recommendations for the inspection frequency as well as modifications to plant infrastructure, shutdown procedures, and the current staffing plan is provided in Table 1-11, Table 1-12, Table 1-13, and Table 1-14.

Table 1-11: Summary of Recommendations for Inspections[2]

Equipment	2022	2023	2024	2025	2026	2027	2028	2029	2030
Turbine (Major Overhaul)		2		3					
Turbine (Routine Inspections)	3	1	2	3	1	2	3	1	2
Generator Inspection			1			2			
Valves Inspection	3	1	2	1	3	2	3	1	2
Feed Water Pump Major Overhaul (East)			2		3		1		
Feed Water Pump Major Overhaul (West)			2	3				1	
Deaerator Inspection					2	1	3		
Vacuum Pump Inspection (North)		2	1		3				
Vacuum Pump Inspection (South)	1			2		3			
Boiler Inspection (Minor for two and Major for one unit every year)	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3
Routine Fuel Tank Inspections	1	2	4	3	1	2	4	3	
API Fuel Tank Inspections	LFO Tank	1, 2	4, Day Tank	3					

Table 1-12: Summary of Suggested Modifications

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Installation of an Auxiliary Boiler	Yes	Yes	Yes	Yes
Piping Between Auxiliary Seam Header and Turbine Gland	No	No	Yes	Yes

[2] Where the numbers refer to unit number or to tank number respectively

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Steam System for all Units 1 and 2.				
Economizer Recirculation	N/A	Yes	Yes	Yes
Boiler Furnace Cameras with Monitors in Control Room	Yes	Yes	Yes	Yes
Motor Operated Boiler Blowdown Valves on all Three Units.	Yes	Yes	Yes	Yes
Motor Operated Lower Water Wall Header Drains on all Three Units.	Yes	Yes	Yes	Yes
Appropriate Heating of Fuel Oil Supply Lines	No	No	Yes	Yes
Fuel Oil Storage Recirculation to Day Tank	Yes	Yes	Yes	Yes
Damper in the Boiler Stack	Yes	Yes	Yes	Yes
Boiler Feedwater Pump to Support Economizer Circulation	No	No	No	Yes
Boiler Drains Modification to Support Economizer Circulation	No	No	No	Yes
Dehumidified Air Circulation Package	No	No	No	Yes
Fuel Oil Tank No.1 Refurbishment	Yes	Yes	Yes	Yes

Table 1-13: Proposed Modifications in Plant Operating Procedures

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cooling Water in Service	No	No	Yes	Yes
Boiler Wet Lay-Up	No	Yes	Yes	Yes
Auxiliary Boiler in Service	No	No	Yes	Yes
Air Pre-Heater in Service	No	Yes	Yes	Yes

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Condenser Vacuum Pump in Service	No	No	No	Yes
Boiler under Econ. Recirculation Mode	No	No	No	Yes
Turbine Chest Pre-Warming	No	No	No	Yes
Turbine on Turning Gear (Intermittent)	No	Yes	Yes	Yes
Generator Filled with H_2 at 30psig	No	Yes	Yes	Yes
Lubricating System in Service	No	Yes	Yes	Yes
Closed Cooling Water System in Service	No	Yes	Yes	Yes
General Service Cooling Water in Service	No	Yes	Yes	Yes

Table 1-14: Proposed Staff

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
No. of Staff Proposed	58	58	58	58

2. Introduction

Holyrood Thermal Generation Station is comprised of three heavy fuel oil fired units generating a total of 500 MW. NLH is investing in additional hydroelectric capacity, clean energy technologies, and reinforcing the transmission systems. The additional planned generation will reduce NLH dependence on HTGS. Current plans call for Units 1 and 2 to be retired and Unit 3 to be converted to permanent synchronous condenser duty.

Deciding on the retirement of generating assets is a complex and difficult process. The technical requirements, environmental impacts, economic demands, social impact, staff knowledge retention and training, fuel supply, and environmental permitting, are all factors to consider in the decision process to retire an asset. Ultimately, it is the unit’s capability to serve a need that determines when and how the asset should be retired.

Hatch was selected by NLH to conduct the HTGS Life Extension Study with two main objectives. The first included a condition assessment of all major systems. The second was to determine the requirements for converting the facility from a prime power generating station to an emergency power generating station.

2.1 Background

HTGS consists of three units and can generate 500 MW. Unit 1 and 2 were commissioned in 1969, with a capacity of 150 MW each. Unit 3 was commissioned in 1979 and can produce 150 MW. Units 1 and 2 were upgraded in 1988 and 1989 to 175 MW. Unit 3 is also capable of operating in synchronous condenser mode to provide voltage regulation.

When all three units are operating at the full maximum continuous rating (MCR), HTGS can supply approximately 20% of Newfoundland and Labrador's demand. Typically, the plant is only required to operate and supply power during the winter months, however, it is capable of supplying power to the grid at any time, 365-day a year, 24 hours a day.

With the introduction of the Muskrat Falls Project, HTGS is currently planned to continue operating until March 31, 2024. This report provides a summary of the condition assessments. The assessment was completed using a combination of site investigations, inspections, non-destructive testing, and documentation reviews.

2.2 General Description of the Facility

2.2.1 Unit 1

Unit 1 was designed to fire No. 6 fuel oil and had a rated capacity of 150 MW. The unit output was increased to 175 MW following the 1988 upgrades.

2.2.1.1 Boiler

The Unit 1 boiler is a tangentially fired, natural circulation boiler manufactured by Combustion Engineering (CE). Originally, the boiler was designed for a steam flow of 132 kg/s at 541°C and 13,100 kPa(g). When Unit 1 was upgraded to 175 MW, the main steam flow capacity was increased to 147 kg/s at 541°C and 13,479 kPa(g).

Note that this boiler does not have any particulate capture systems, nor does it have low NOx burners or overfire air for low NOx operations. There is also no economizer recirculation or auxiliary steam flow to the steam turbines glands that could be used for unit preheating.

2.2.1.2 *Steam Turbine Generator*

The turbine generator is a 3600 rpm, three-cylinder (HP/IP/double flow LP) tandem compound General Electric (GE) turbine and has a hydrogen cooled GE generator. The HP throttle pressure is 13.1 MPa with the superheat temperature at 538°C.

2.2.1.3 *Condenser*

The condenser is a Foster Wheeler Double Flow Type M condenser which has two-pass flow with a divided water box. A pressure of 3.4 kPa is maintained at MCR using two vacuum pumps at 100% duty.

2.2.1.4 *Cooling Water System*

The Stage 1 pumphouse contains two cooling water (CW) pump systems (at 50% duty) which deliver seawater for cooling to the Unit 1 condenser. Two travelling screens are used to remove any debris that may be present in the incoming cooling water. Following the screens, the cooling water enters the CW pumps. Each pump can deliver cooling water at a rate of 2,252 L/s.

2.2.1.5 *Feedwater* System

Unit 1 feedwater system includes two feedwater pumps, a feedwater heating system, and reserve feedwater tanks. The feedwater heating system includes three high pressure (HP) heaters, one deaerator, and two low pressure (LP) heaters.

2.2.1.6 *Condensate System*

Condensate is pumped to the deaerator by means of two condensate pumps each rated for 100% duty. The water level in the condenser hotwell is controlled by the condensate pumps, along with the reserve feedwater tanks.

2.2.1.7 *Deaerator and HP System*

The deaerator system includes a storage tank with a capacity of 81,650 kg. This tank has sufficient capacity to provide the boiler feed pumps with water for 10 minutes at MCR.

The HP heater system, comprised of three feedwater heaters, receive feedwater from the deaerator. Feedwater entering the heaters is brought up to the temperature required for the economizer inlet.

There are two 50% capacity feedwater pumps, the pumps are horizontal double casing design each rated for a flowrate of 75 L/s at 1700 m of head. The pumps supply feedwater from the deaerator to the boiler via the HP heaters.

2.2.2 ***Unit 2***

Unit 2 was designed to fire No. 6 fuel oil and had a rated capacity of 150 MW similarly to Unit 1. The unit output was increased to 175 MW following the 1988 upgrades.

Since Unit 1 and Unit 2 are identical to each other, the facility description provided for Unit 1 in Section 2.2.1 is applicable to Unit 2.

2.2.3 ***Unit 3***

Unit 3 is rated for 150 MW and was designed to use No. 6 fuel oil.

2.2.3.1 *Boiler*

The Unit 3 boiler is a reheat unit, front wall-fired, natural circulation boiler manufactured by Babcock and Wilcox. The boiler is designed for a superheated steam flow of 135 kg/s steam at 541.6°C and 13,020 kPa, and a reheat steam flow of 125.1 kg/s at 541.6°C and 3,716 kPa.

Note that this boiler does not have any particulate capture system, nor does it have low NOx burners or overfire air for low NOx operations. However, unlike the boilers for Units 1 and 2, it does have an economizer recirculation line and auxiliary steam supply to the steam turbine glands to assist with unit preheating.

2.2.3.2 *Steam Turbine Generator*

The Unit 3 turbine generator is a 3600 rpm, three-cylinder (HP/IP/double flow LP) Hitachi turbine and has a hydrogen cooled Hitachi generator. The HP throttle pressure is 12.4 MPa with the superheat temperature at 538°C.

2.2.3.3 Condenser

Unit 3 is supplied with a Foster Wheeler condenser. A pressure of 3.4 kPa is maintained at MCR in the condenser by means of two vacuum pumps, each rated for 100% load.

2.2.3.4 *Cooling Water* System

The Stage 2 Pumphouse contains two cooling water (CW) pump systems (at 50% duty) which deliver seawater for cooling to the Unit 3 condenser. Two travelling screens (at 100% capacity) are used to remove any debris that may be present in the incoming cooling water. Following the screens, the cooling water enters the CW pumps. Depending on the tide, each pump can deliver cooling water at a rate between 2,250 and 3,785 L/s.

2.2.3.5 *Feedwate*r System

Unit 3 feedwater system includes two feedwater pumps, a feedwater heating system, and reserve feedwater tanks. The feedwater heating system includes three high pressure (HP) heaters, one deaerator, and two low pressure (LP) heaters.

2.2.3.6 *Condensate System*

Condensate is pumped to the deaerator by means of two condensate pumps each rated for 100% duty. The water level in the condenser hotwell is controlled by the condensate pumps, along with the reserve feedwater tanks.

2.2.3.7 *Deaerator and HP Feedwate*r System

The deaerator system includes a storage tank with a capacity of 81,650 kg. This tank has sufficient capacity to provide the boiler feed pumps with water for 10 minutes at MCR.

The HP heater system, comprised of three feedwater heaters, receives the feedwater from the deaerator. Feedwater entering the heaters is brought up to the temperature required for the economizer inlet.

There are two 50% capacity feedwater pumps, the pumps are horizontal double casing design each rated for a flowrate of 77 L/s at 1722 m of head. The pumps supply feedwater from the deaerator to the boiler via the HP heaters.

2.2.4 Balance of Plant

2.2.4.1 *Common Systems*

2.2.4.1.1 Lubricating Oil Supply

The lubricating oil supply pipes for all three units at HTGS are placed inside the common bearing oil return line to the lube oil storage tank. The bearings have “high bearing temperature” alarms to monitor the health of the bearings.

2.2.4.1.2 Fuel Oil Storage and Delivery

The unloading docks receive fuel oil from tankers, the fuel is then transported to the HTGS fuel oil storage tank farm via a heat traced pipeline. The tank farm is comprised of four 33,710 m^3 tanks, each tank's oil discharge temperature is controlled using a steam suction heater. Steam is supplied from the auxiliary steam system. Steam traps are used to capture the condensate which is then sent to drains.

Oil is transferred to the day tank from the tank farm by gravity. The day tank does not have any recirculation. Additionally, there is no recirculation from the powerhouse back to the tank farm. With all units operating at full load, approximately 120,000 to 130,000 barrels of fuel are consumed per week. Oil is supplied to the HTGS facility by tankers. It takes approximately 4 weeks from the time the order is placed to the time oil is delivered to site. The fuel delivery is dependent on weather as well as ship and fuel availability, as the tankers come from Texas.

The boiler fuel supply pumps on each unit receive flow from the day tank. Oil can also be supplied directly from the tank farm through the day tank bypass line.

If atomizing steam is unavailable to support boiler firing with No. 6 oil, then light oil can be used to light off the steam generators from a black start. Light oil pumps receive the oil via a header from the station light oil tanks. Light oil is also used for purging the fuel lines from heavy fuel following boiler shutdown. This system has two positive displacement pumps (at 100% duty) which supply oil to the boiler at a pressure of approximately 1034 kPa. The system is also equipped with a recirculation line from the burner front header back to the day tank.

2.2.4.1.3 Compressed Air

The facility has three compressors which feed into a common header. Two compressors are fixed speed compressors, and one is equipped with a variable speed mechanism. The compressors are not connected to the DCS but have a dedicated monitoring system that allows operators to switch on/off when needed. The system supplies both service and instrument air.

2.2.4.2 Buildings

Steam is required to prevent freezing of piping and buildings heating. The buildings and fuel heating system consist of the following:

- Immersion and suction heaters for HFO day tank and storage tanks.
- Building unit heaters.
- Heat tracing (fuel system).

Steam is supplied to the heaters from the auxiliary steam header at 50 psig via a letdown station. The total auxiliary steam demand has been estimated by NLH to be 25,000 lb/hr.

3. Methodology

3.1 Document Review

Plant documentation and historical records were reviewed. In summary, the documents reviewed can be categorized as:

- Operation and Maintenance Manuals of the Units.
- Piping and Instrument Diagrams.
- Equipment Data Sheets and Performance Curves.
- Operational History of All Three Units.
- Tripping Log of All Three Units.
- Maintenance Record of Critical Equipment and Valves.
- Last Major Overhaul Reports for Turbine and Generators.
- High Energy Piping Inspection Records.
- Past condition Assessment Reports (2014 to 2021 reports).

Appendix A contains the detailed list of the documents provided by NLH to Hatch during the project execution.

3.2 HTGS Detailed Inspection Plan

Hatch developed a detailed inspection plan for the project. Inspection timeline, method of inspection such as visual inspection, borescope inspection, thickness measurement, and non-destructive testing were all outlined in the plan. The latest main equipment inspection reports were reviewed for adequacy of inspections and to ensure periodic inspections are conducted on equipment, and the method of inspections are appropriate. Where inspection records were deemed lacking Hatch recommended additional inspections. For example, Hatch recommended that visual inspections be conducted on condenser shell and eddy current inspections conducted on condenser tubes of all three units.

Details of the inspections and the condition assessment can be found in the Volume I report (H365408-00000-210-066-0001).

3.3 Inspections by Hatch Third Party Sub-Contractors

Hatch hired third party sub-contractors to conduct inspections of the cooling water system, fire water system, paint inspection for fuel oil tank No.3, and the marine facilities. The Hatch inspection supervisor and safety officer supervised the sub-contractor teams at site.

3.4 General Site Visits

The local Hatch team from the St. John’s office conducted visual inspections of key assets and had face to face meetings with plant staff when required. The team took photos and videos of the plant to allow the team located remotely to assess the condition of the assets and their viability to support the proposed operating scenarios. Two engineers from Hatch were stationed at site for the duration of the third-party inspections.

The site visits allowed the team to assess the actual condition of assets at HTGS, identify the capital upgrades required to convert the facility from a base load plant to a backup generation facility, and develop an operating and capital cost for future operations.

3.5 Hatch Project Team Site Visit

The Hatch project team and subject matter experts visited the plant in September 2021. The Hatch team visually inspected the powerhouse area, fuel receiving terminal, cooling water sumps, back up diesel gensets, and fuel tank farm.

3.6 Historical Plant Data

Hourly operating data and plant outage log data was used to compute the remaining life of the turbine.

Similarly, the past CAPEX reports from 2007 onwards were received and reviewed, the trend in CAPEX spent for HTGS was used to assess the suitability of the proposed capital plan until 2030.

4. HTGS Option Screening for Emergency Backup Scenarios

As a standard practice, the generating unit is in cold condition when it is down for more than a week. The cold condition implies that boiler and turbine metal temperatures are less than 50°C.

The start-up or recall time for a generation unit is the main consideration when operating a power plant as an emergency backup unit. Bringing a steam plant into service from cold condition is a lengthy process that involves several steps that need to be followed sequentially. In addition, several checks are required before powering up critical equipment such as pumps, boiler burners, and steam turbines to ensure equipment and personnel safety. Plant auxiliary systems such as the cooling water system and bearings lubrication system require time to be in place.

Rigorous checks may be required following a major boiler/turbine overhaul than typically required under normal plant cold start-up condition. The boiler will require initial filling, the turbine will require a full 8 hours turning gear rotation, and some additional start-up testing, such as a rub test, over speed test, etc., will be required as per the OEM's recommendation. This will result in an increased start-up time following a major overhaul than considered for Scenario 1.

Currently, Units 1 and 2 require 24 to 30 hours to start-up after a prolonged shutdown. This time is further increased for Unit 3 if it is in synchronous condenser mode. In this case, an additional 24 hours are required to decouple the generator from the motor and then attach it to the steam turbine.

In this study, the following four start-up scenarios were developed and investigated as part of future plant operation:

- **Scenario 1 (Base Case)**: Recall time of 24 hours for 1st Unit and 30 hours for 2nd Unit.
- **Scenario 2**: Recall time of 8 hours for 1st unit and 12 hours for 2nd Unit.
- **Scenario 3**: Recall time of 6 hours for 1st Unit and 8 hours for 2nd Unit.
- **Scenario 4**: Recall time of 4 hours for both Units.

Recall time can be defined as the duration between the “Call for Power” and the synchronization of Units 1 and 2.

In addition to the above operating scenarios for Unit 1 and 2, Unit 3 has been considered operating under synchronous condenser mode. Unit 3 can be converted into power generation mode if required.

The following sections explain the condition of critical power plant equipment after a prolonged shutdown (a month or so when the metal temperature of the turbine and boiler are close to ambient temperature) and expected prerequisites to start the power pant after such a shutdown. The subsequent sections of this chapter stipulate the modifications required for the existing processes, systems, and equipment to achieve the start-up scenarios. A Gantt chart showing the start-up sequences that run in parallel and those that run sequentially for each scenario are attached in Appendix B.

4.1 Cold Shutdown Condition

4.1.1 Description

For a baseload plant, the cold shutdown condition is considered only for a major overhaul of the power plant equipment (e.g., boiler, turbine, generator).

Table 4-1 summarizes the condition of each equipment during the normal shutdown process.

Table 4-1: Status of Key Equipment and System during Cold Shutdown Condition

Item	Equipment/System	Status Description
1	Cooling Water System	Drained and Turned Off
2	GSCW & Lubricating System	Turned Off
3	Turbine Rotor	Cold and intermittently on turning gear
4	Generator Sealing System	Not in place
5	Generator Hydrogen Cooling	Hydrogen Purged
6	Auxiliary Steam System	In service in winter for building heating Out of Service in Summer

Item	Equipment/System	Status Description
7	Boiler	Wet/Dry Lay-up
8	Water Treatment System	Not in Service
9	Low Pressure Feedwater System	Drained and Not in Service
10	Fuel Oil system (Light)	Not in Service
11	Boiler Feedwater Pump	Cold and Not in Service
12	Air Heaters	Not in Service
13	Main Burners	Turned Off
14	Heavy Fuel Oil System	Unit heaters out of service; circulation from/to tank farm out of service in summer and in service in winter
15	Turbine MSV, CV, Casing	Valves Closed, at ambient temperature

4.1.2 Boiler

The boiler drum and waterwalls can be wet/dry.

4.1.3 Turbine

The turbine is cold.

4.1.4 Generator

Hydrogen has been purged.

4.1.5 Condensate and Feedwater System

Both low pressure and high-pressure heaters are drained. The deaerator is filled with water.

4.1.6 Condenser and Cooling Water System

The vacuum sealing system and vacuum pumps are turned off. The cooling water from water boxes and the tubes are drained. The main cooling water pumps are drained.

4.1.7 Raw Water and Demineralized Water System

The raw water pumps, the demineralized water system, and water treatment plant are shutdown.

4.1.8 Auxiliary Steam System

The auxiliary steam system will be in service to support the building heating when required.

4.2 Scenario 1 (Baseline)

4.2.1 Description

Scenario 1 provides a start-up / recall time of 24 hrs for the fist unit and 30 hours for the second unit and represents the established process of starting up from the cold shutdown condition. During the shutdown, the plant operators will be doing all pre-start checks per shift to ensure plant readiness for quick recall.

The start-up steps and procedures that are on the critical path are summarized in Table 4-2. Further details are provided in the start-up Gantt charts in Appendix B.

Table 4-2: Plant Recall Time After a Prolonged Shutdown (Scenario 1, 1st Unit)

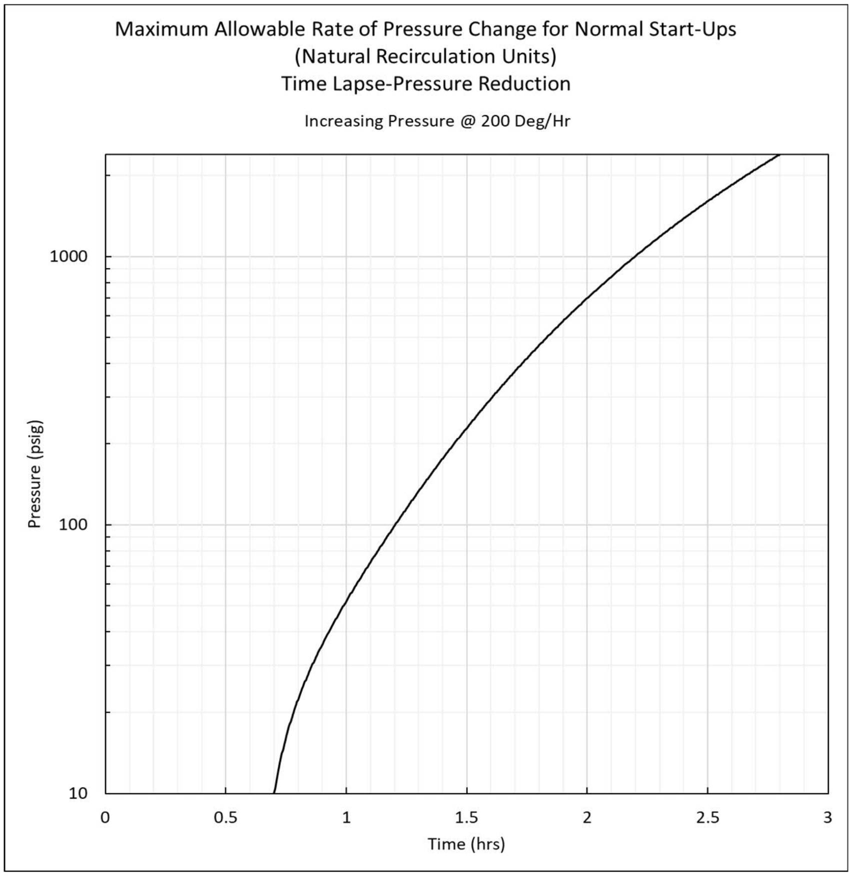
Item	Equipment/System	Description	Time (Hours)
1	Pre-start Checks	Pre-start checks to be completed	1.0
2	Cooling/Lubricating Systems	Put Cooling Water, Closed Cooling Water and Lubrication System in Service	1.0
3	Prepare TG for Start-up	Purge generator and purge with hydrogen	12.0
4		Turbine generator to be placed on turning gear	4.0
5	Turbine	Turbine MSV, CV and chest warming	4.0
6		Turbine rolling (including hold time and synchronization)	2.0
Total Recall Time			24.0

The operators in the control room and in the field will start with first unit pre-checks, opening/closing of manual valves, hydrogen filling in generator, and putting turbine on turning gear. The first unit will be synchronized in 24 hours. The second unit will follow and will be able to synchronize in 30 hours.

4.2.2 Boiler

Filling the boilers, preparing fans, initiating fires, and warming the furnace and steam drum requires 4 hours.

The allowable boiler drum water heating rate and respective maximum rate of pressure change during start-up are shown in Figure 4-1, extracted from the boiler OEM manual. The time required for the boiler to reach a pressure of 700 psig, where the main boiler steam can be used for turbine pre-warming, is approximately 2 hours.



Note: The curve above is based on the OEM Manual

Figure 4-1: Maximum Allowable Rate of Pressure Change for Drum Boilers

4.2.3 Steam Turbine

The turbine rotor will be placed on turning gear for 8 hours to ensure the eccentricity of the turbine rotor is within permissible limits to rotate the steam turbine at synchronous speed. Pre-warming of the turbine and main steam stop valve chest while on turning gear is recommended by the OEM when the first stage inner surface metal temperature is less than 150°C.

To avoid the thermal mismatch, the inner metal temperature should be within a reasonable limit before starting turbine rolling. More specifically, as per OEMs instructions for all three units, the inner metal temperature at the first stage of the turbine should be 150°C or more before turbine rolling. This pre-warming of the main steam valve and steam turbine chest is accomplished using steam from the auxiliary or main boiler and requires almost four hours to reach 150°C as shown in Figure 4-2.

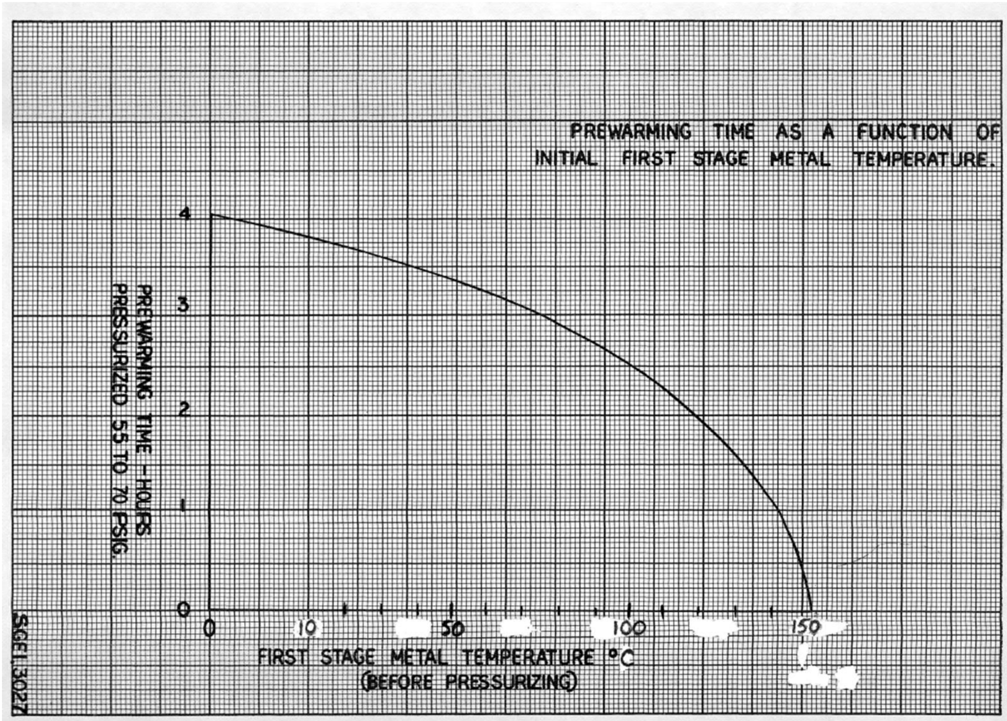


Figure 4-2: Pre-Warming Curve for Turbine Rotor

The manual gives Starting Times vs Steam Conditions for Full Arc admission shown in Figure 4-3. The figure indicates the following for a cold start based on a first stage steam temperature of 275°C:

- Pre-warming time of 4 hours for the turbine as show in Figure 4-2 above (Based on first stage metal temperature of 50°C).
- Acceleration rate 150 rpm/min.
- Length of hold at 3000 rpm of 45 minutes based on reheat metal temperature.
- Length of hold at 3600 rpm of 18 minutes.

This indicates a cumulative period of approximately 4 hours for pre-warming plus approximately 83 minutes for synchronizing and applying initial block load of about 2% of rated output.

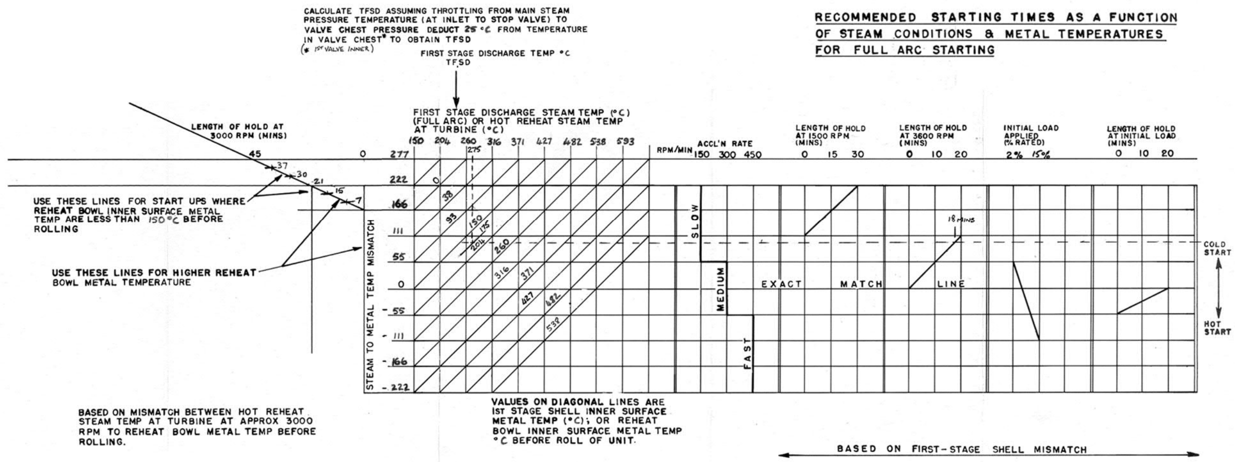


Figure 4-3: Turbine Start-up Curve

4.2.4 *Generator*

The electric generator winding is cooled using Hydrogen (H_2) and it requires approximately 12 hours to fill from empty. A minimum H_2 pressure of approximately 15 psig is required before putting the turbine rotor on turning gear, therefore, filling the generator and placing the turbine rotor on turning gear are required to take place in a sequential order.

4.2.5 *Condensate and Feedwater System*

Condensate extraction pumps will be primed. Both LP and HP heaters will be filled with fresh demineralized water. Water quality in the deaerator and the feedwater lines will be managed by injecting oxygen scavengers and other chemicals as per standard plant practices.

4.2.6 *Condenser and Cooling Water System*

The condenser steam side is filled with air which will be extracted using vacuum pumps, and the condenser pressure will be brought to 25” mercury or lower before starting the steam turbine pre-warming process. This is required to ensure the condenser is ready to accept the steam used for pre-warming of the steam turbine. The time required when using a 100% capacity vacuum pump is less than half an hour and can be accommodated while the generator is being filled with hydrogen.

Cooling water from the condenser water boxes and from the cooling water pumps is drained and will be primed/filled before starting any other process. This step of priming cooling water pumps and then filling the condenser water boxes and condenser tubes with cooling water is a pre-requisite before starting any other system. This is because all other systems either require cooling or sealing of bearings which directly or indirectly depends upon the cooling water system to dissipate the heat produced in bearings.

No empirical data is available for the facility to define the duration specific for priming the cooling water pumps and filling the condenser water side. Based on Hatch's experience for similar size power plants, this activity takes typically 2 hours.

4.2.7 Raw Water and Demineralized Water System

The raw water system, water treatment system, and demineralized water system will be made operational intermittently to ensure enough fresh demineralized water is supplied to the condenser hotwell.

4.2.8 Auxiliary Steam System

During complete shutdown of the units, the auxiliary boiler can be used to supply steam. Feedwater heating and turbine gland steam sealing will commence once the main boiler pressure is above 200 psig and is able to feed steam to the auxiliary steam header from the primary super heater.

4.3 Scenario 2

4.3.1 Description

Scenario 2 provides a start-up / recall time of 8 hours for the fist unit and 12 hours for the second unit. The plant operators will keep the plant in ready to start condition and will perform prestart checks during their shift. The time considered for prestart checks in this scenario is to review the check log and confirm the plant is ready to start. Start-up steps and procedures that are on the critical path are summarized in Table 4-3. The Gantt charts in Appendix B provides further details.

Table 4-3: Plant Recall Time (Scenario 2, 1st Unit)

Item	Equipment/System	Description	Time (Hours)
1	Pre-start Checks	Pre- Start Checks to be completed	0.5
2	Cooling/Lubricating Systems	Put Cooling Water, Closed Cooling Water and Lubrication System in Service.	0.5 (*1)
3	Prepare TG for Start-up	Turbine generator to be placed on turning gear	1.0
4	Turbine	Turbine MSV, CV and chest warming	4.0
5		Turbine rolling (including hold time and synchronization)	2.0
Total Recall Time			8.0
(*1): Some equipment starts in parallel with Pre-checks to reduce time.			

The operators in the control room and in the field will start with first unit pre-checks, checking turbine rotor eccentricity, and opening/closing of manual valves. The first unit will be synchronized in 8 hours. The second unit will follow and will be able to synchronize in 12 hours.

4.3.2 Boiler

The boiler will be in wet lay-up mode with the water side filled to the normal water drum level with chemically dosed water combined with the use of nitrogen gas to cap the upper area of the boiler drum plus the steam side (e.g., superheaters) to mitigate corrosion due to oxygen.

4.3.3 Steam Turbine

The turbine rotor will be placed on turning gear for approximately one to two hours per week based on OEM recommendation to ensure the eccentricity of the turbine rotor is within permissible limits during plant shutdown mode. The turbine bearings lubricating system and the lube oil cooling system will also be brought in service on a weekly basis. This will satisfy the OEM's requirement of putting the turbine rotor on turning gear for 8 hours after a long-term plant shutdown. The auxiliary power consumption for this weekly operation is added in the plant annual OPEX calculation and is given in Section 6 of this report.

The inner surface metal temperature, however, will still be slightly above the ambient condition (approximately 50°C) and the pre-warming of the main steam valves and turbine chest will still be required.

4.3.4 Generator

The generator will remain filled with H_2 at 30 psig. This is to avoid the time required for air and CO_2 purging and then filling the generator with H_2 before starting the unit. This will also require the following three systems to be in operation:

1. Shaft Seal Oil System
2. Bearing Oil System
3. Hydrogen Separation System (From Oil).

4.3.5 Condensate and Feedwater System

The condensate and feedwater system will be primed. The deaerator and the feedwater lines will be managed by injecting oxygen scavengers and other chemicals as per standard plant practices.

4.3.6 Condenser and Cooling Water System

Cooling water pumps will be primed, and the condenser water side will be filled with water.

4.3.7 Raw Water and Demineralized Water System

The raw water system, the water treatment system, and demineralized water system will be made operational intermittently to ensure enough fresh demineralized water is supplied to the condenser hotwell.

4.3.8 Auxiliary Steam System

When the units are in complete shutdown, the auxiliary boiler can be used to supply steam. Feedwater heating and turbine gland steam sealing will commence using auxiliary steam from the auxiliary boiler and will switch to the main boiler once the main boiler pressure is above 200 psig and is able to feed steam to the auxiliary steam header from the primary super heater.

4.4 Scenario 3

4.4.1 Description

Scenario 3 provides a plant recall time of 6 hours for the first unit and 8 hours for the second unit

Start-up steps and procedures that are on the critical path and contribute to the 6 hours of recall time are summarized in Table 4-4. One critical aspect of this scenario is to have a minimum time for pre-start checks. The start-up Gantt charts are provided in Appendix B for further details.

Table 4-4: Plant Recall Time (Scenario 3, 1st Unit)

Item	Equipment/System	Description	Time (Hours)
1	Pre-Start Checks	Pre-start checks to be completed	0.5*
2	TG Pre-Checks	Turbine Rotor eccentricity check, Generator H_2 check	0.5
3	Turbine	Turbine MSV, CV and chest warming	4.0
4		Turbine rolling and synchronization	1.0
Total Recall Time			6.0
*Time reduces as some systems will be already in service during plant shutdown.			

The operators in the control room and in the field will start with the first unit pre-checks, opening/closing of manual valves, checking turbine rotor eccentricity, and pre-warming of steam turbine. The first unit will be synchronized in 6-8 hours. The second unit will follow and will be able to synchronize in 8 hours.

4.4.2 Boiler

The boiler will be in wet lay-up mode with the water side filled to the normal water drum level with chemically dosed water combined with the use of nitrogen gas to cap the upper area of the boiler drum plus the steam side (e.g., superheaters) to mitigate corrosion due to oxygen. The recall time of 8 hours can be achieved by supplementing staff and increasing the frequency of plant readiness checks.

4.4.3 Steam Turbine

The turbine rotor will be placed on turning gear. However, to reduce the recall time further, the frequency of putting the turbine rotor on turning gears will be increased. The time for rotating the turbine rotor on turning gear is reduced to one hour. This means the eccentricity of the rotor will be approximately within the permissible limit at any given time and the one-hour allowance will ensure this is the case. To achieve this recall time, the turbine bearings lubricating system and the lube oil cooling system will be brought in service more frequently.

The inner surface metal temperature for this scenario, will still be slightly above the ambient condition (approximately 50°C) and the pre-warming of the main steam valves and turbine chest will still be required.

4.4.4 Generator

The generator will remain filled with H_2 at 30 psig. This is to avoid the time required for air and CO_2 purging and then filling the generator with H_2 before starting the unit. This will also require the following three systems to be in operation:

1. Shaft Seal Oil System
2. Bearing Oil System
3. Hydrogen Separation System (From Oil)

4.4.5 Condensate and Feedwater System

The LP heaters, HP heaters, and deaerator will not be drained during the shutdown period. Condensate extraction pumps, the heater drain lines, and feedwater pumps will be operated intermittently to keep the demineralized water quality to an acceptable limit at any given time. The feedwater in the deaerator will be heated using auxiliary steam.

4.4.6 Condenser and Cooling Water System

Cooling water pumps will be primed, and the condenser water side will be filled with water. The air from the condenser steam side will be extracted by vacuum pumps to establish condenser pressure at 25” mercury.

4.4.7 Raw Water and Demineralized Water System

The raw water pumps, the water treatment plant, and demineralized water system will be intermittently running during the plant shutdown period to ensure that system can be back to its normal operation within an hour.

4.4.8 Auxiliary Steam System

An auxiliary steam boiler is required to be sized to provide steam for:

a) Building Heating in Winter.

b) Auxiliary Steam for Deaerator Water Heating.

c) Turbine Gland Steam Sealing

d) Auxiliary Steam for Air Pre-Heater.

e) Fuel Heating System

4.5 Scenario 4

4.5.1 Description

Scenario 4 provides a start-up time of 4 hours.

The plant is required to be maintained in the following state to achieve a 4-hour recall time.

2. Water chemistry in boiler drum is correct.
3. Boiler drum will be hot at 100 psi and at 80°C.
4. Turbine metal temperature higher than 150°C.

If all the above conditions are met, steam can be fed to the steam turbine for turbine rolling and the plant can be synchronized in approximately 4 hours. Several key plant systems such as the condensate, feedwater, fuel oil systems, and several auxiliary systems, such as the cooling and lube oil systems, will be kept up and running during the plant shutdown period to ensure above three conditions are met. This condition will be referred to as "Hot Standby Mode".

Start-up steps and procedures that are on the critical path and contribute to the 4-hour recall time are summarized in Table 4-5. Please refer to the start-up Gantt charts for each scenario given in Appendix B for details.

Table 4-5: Start-Up Time After Prolonged Shutdown (Scenario 4, Both Units)

Item	Equipment/System	Description	Time (Hour)
1	Pre-start Checks	Pre-start checks to be completed	1.0
2	TG Pre-Checks	Turbine Rotor eccentricity check, Generator H_2 check	1.0
3	Turbine	Checks before Turbine Rolling and Grid Synchronization	1.0
4		Turbine rolling and synchronization)	1.0
Total Recall Time			4.0

4.5.2 Boiler

The boiler will be in hot standby mode. The drum water quality will be within an acceptable limit to light up the boiler at any given time. All the pre-requisite checks, that currently take approximately four hours before boiler firing, will be carried out as a part of the routine checks by all shift operators to ensure that the boiler is ready for light off as soon as the facility receives a call for dispatch.

4.5.3 Steam Turbine

The steam turbine will be in the following condition:

a) The steam turbine rotor will be on turning gear every day for two hours to ensure that the turbine rotor eccentricity is always within an acceptable range.

b) The turbine chest, stop valves, and control valves will be in continuous pre-warming condition.

4.5.4 Generator

The generator cooling system will be filled with H_2 at 30psig and will be maintained at this pressure during the plant hot standby mode. All the auxiliary systems required to keep this H_2 pressure will be up and running.

4.5.5 Condensate and Feedwater System

The condensate pumps, LP Heaters, Deaerator, and HP Heaters should all be filled with demineralized water with a water quality as per ASME guidelines. The boiler feedwater temperature in the deaerator and downstream to the economizer will be maintained at 85°C using auxiliary steam supply to the deaerator.

4.5.6 Condenser and Cooling Water System

The cooling water system will be operational at its minimum flow during the plant hot standby mode. The condenser vacuum pump will be operational, and the condenser vacuum pressure will be kept below 25” mercury.

4.5.7 Raw Water and Demineralized Water System

The raw water pump, water treatment plant, and demineralized water system will be operational to ensure adequate water supply to the plant as most of the plant systems will be operational and will require a supply of make-up water.

4.5.8 Auxiliary Steam System

An auxiliary steam boiler is required and should be sized to provide steam for:

a) Building Heating in Winter.

b) Auxiliary Steam for Deaerator Water Heating.

c) Auxiliary Steam for Air Pre-Heater.

d) Turbine Pre-Warming.

e) Fuel Heating System

4.6 Testing for Low Load Operation

NLH conducted a low load test in March 2021 and successfully operated Unit 3 at 30 MW (20% MCR) for several hours. The load was then fluctuated between 70 MW and 30 MW and no anomaly was noted. All critical valve positions, auxiliary equipment conditions, and variation in critical operating parameters were closely monitored during the test.

4.7 Test Runs

Hatch recommends carrying out the test runs on a monthly basis for both Unit 1 and Unit 2 and a 6-week interval for Unit 3 to support operating the plant as a backup generating plant. The test run can be carried out as per an agreed schedule with the grid operators. Hatch suggests operating each unit at maximum load for 24 hours each while testing the units. The loading can be varied to align with system grid limitations by using a longer duration to ensure a complete heat soak for the equipment.

These test runs will also ensure operating reliability for the major equipment and for auxiliary components, e.g., reducing the risk of control valves sticking or pump glands leaking. Such a program will feed into a predictive reliability-based maintenance program and will also serve to keep the operators familiar with all start-ups and shutdown procedures.

The cost for such test runs is included in the OPEX and the expected impact on emissions is considered in CO_2 emissions.

4.8 Modifications for Quick Recall of Units

Several modifications are required in the existing plant infrastructure, in plant existing start-up and shut-down procedures, and in maintenance intervals for key plant equipment to achieve a reliable recall time for each scenario.

Both units will require some permanent modifications in the plant infrastructure. The modifications required to reduce start-up time are listed below and Section 6 addresses the capital cost to implement the recommended modifications. The procedural changes during the plant shutdown period or during start-up will also result in an increased operating cost and additional staffing requirements. These additional costs are included in Section 5 .

4.8.1 Modifications in Plant Infrastructure

Table 4-6 summarizes the modifications suggested in existing plant infrastructure.

Table 4-6: Proposed Modifications in Plant Infrastructure

Sr. No.	Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1	Installation of an Auxiliary Boiler	Yes	Yes	Yes	Yes
2	Piping between auxiliary steam header and turbine gland steam system for Units 1 and 2	No	No	Yes	Yes
3	Economizer Recirculation	N/A	Yes	Yes	Yes

Sr. No.	Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
4	Boiler Furnace Cameras with Monitors in Control room	Yes	Yes	Yes	Yes
5	Motor Operated Boiler Blowdown valves on all three units	Yes	Yes	Yes	Yes
6	Motor Operated Lower Water Wall Header Drains on all three units	Yes	Yes	Yes	Yes
7	Appropriate Heating of Fuel Oil Supply Lines	No	No	Yes	Yes
8	Fuel Oil Storage Recirculation to Day Tank	Yes	Yes	Yes	Yes
9	Damper in the boiler stack	Yes	Yes	Yes	Yes
10	Boiler Feedwater Pump to support Economizer circulation	No	No	No	Yes
11	Boiler Drains Modification to support Economizer circulation	No	No	No	Yes
12	Dehumidified air circulation package	No	No	No	Yes
13	Fuel Oil Tank No.1 Refurbishment	Yes	Yes	Yes	Yes
14	Upgrade of Infrastructure for emergency diesel gensets for enhance safety	Yes	Yes	Yes	Yes

An auxiliary boiler will be required to support the quick recall of the units for each scenario. A new auxiliary boiler is recommended to be installed on the ground floor level, in the same area where the decommissioned auxiliary boiler was. There is a vacant space near the Unit #1 West VIV Fan where a new auxiliary boiler can be installed.

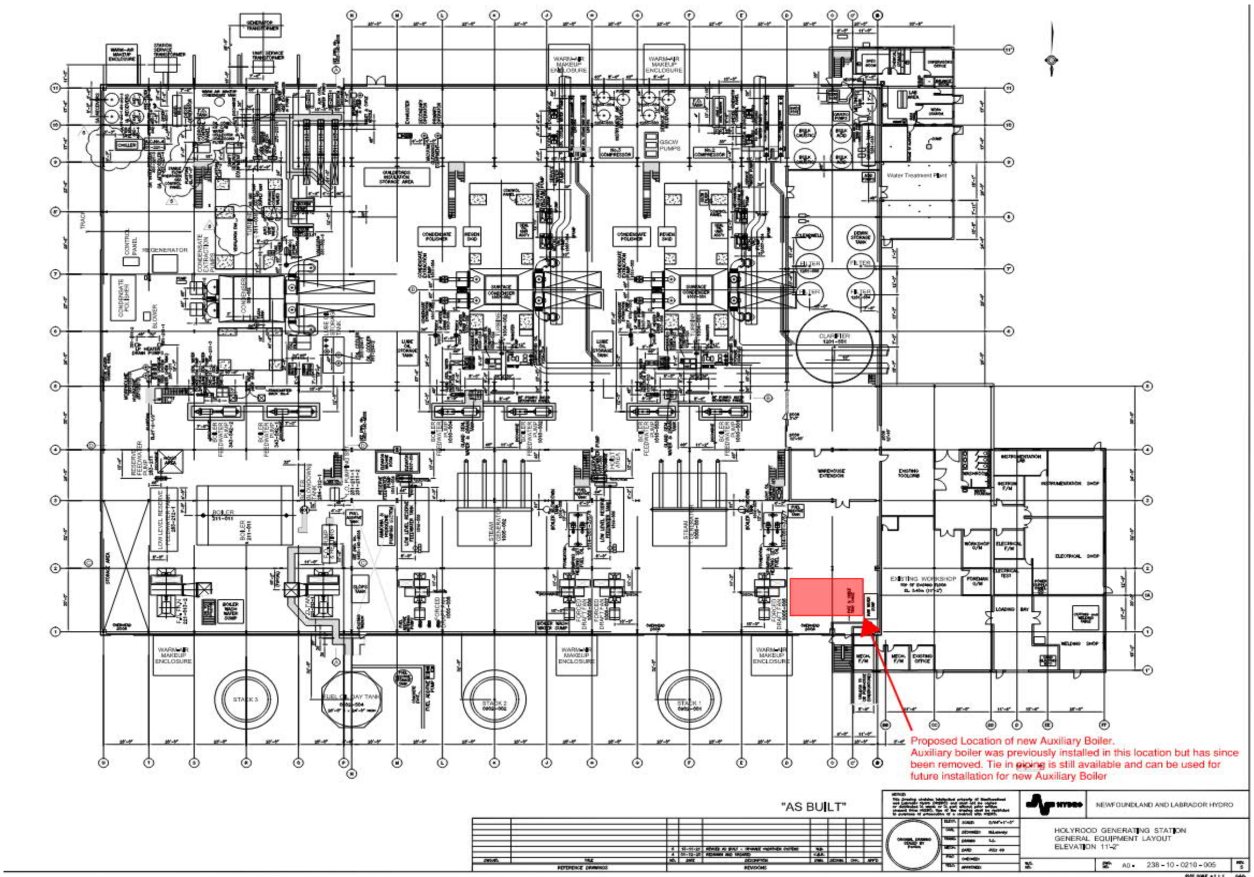


Figure 4-4: Proposed Location for New Auxiliary Boiler

Figure 4-5: Proposed location for New Auxiliary Boiler

Figure 4-6: Existing Tie In Location for New Auxiliary Boiler

Figure 4-7: Existing Auxiliary Boiler Piping

For Scenario 1, the auxiliary boiler steam will be used for plant building heating and for steam heat tracing where applicable.

For Scenario 2 and 3, in addition to plant building heating and steam heat tracing, the auxiliary boiler steam will also be used for initial feedwater heating in the deaerator and for turbine gland steam sealing at the start-up of the plant. This will eliminate the waiting time for the main boiler to reach 200 psig.

For Scenario 4, the auxiliary steam from the auxiliary boiler, in addition to the uses listed in the scenarios above, will also be used for turbine pre-warming.

To help retain heat in the boilers, it is recommended that dampers be installed on the inlet to the stacks on Unit 1 and Unit 2 to support the 4-hour recall scenario. No damper modifications are required for Unit 3. It is recommended that a double louver, seal fan and support structure be added to the duct work on the inlet to the stack on the exterior of the powerhouse. Please see Figure 4-8 and Figure 4-9 for the proposed location.

Figure 4-8: Recommended Damper Unit 1 and 2 Install Location

All other recommendations which require minor piping modifications can be field run based on the existing layout and space constraints.

Figure 4-9: Recommended Damper Unit 1 and 2 Install Location

4.8.2 Modifications in Plant Procedures

Table 4-7 summarizes the required changes to existing procedures.

Table 4-7: Proposed Modifications in Plant Shutdown Procedures

Sr. No.	Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1	Installation of an Auxiliary Boiler	Yes	Yes	Yes	Yes
2	Turbine on Turning Gear (Intermittent)	No	Yes	Yes	Yes
3	Generator Filled with H_2 at 30 psig	No	Yes	Yes	Yes

Sr. No.	Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
4	Lubricating System in Service	No	Yes	Yes	Yes
5	Closed Cooling Water System in Service	No	Yes	Yes	Yes
6	General Service Cooling Water in Service	No	Yes	Yes	Yes
7	Cooling Water in Service	No	No	Yes	Yes
8	Boiler Wet Lay-Up	No	Yes	Yes	Yes
9	Auxiliary Boiler in Service	No	No	Yes	Yes
10	Air Pre-Heater in Service	No	Yes	Yes	Yes
11	Condenser Vacuum Pump in Service	No	No	No	Yes
12	Boiler under Econ. Recirculation Mode	No	No	No	Yes
13	Turbine Chest Pre-Warming	No	No	No	Yes

4.8.2.1 Boiler Wet/Dry Lay Up

Large utility boilers are generally recommended to be stored under managed wet lay-up conditions to avoid corrosion. Typically, this would be achieved by flooding the superheaters and reheaters to the greatest extent possible with a demineralized condensate solution inhibited to prevent corrosion (i.e., buffered water) and pressurized with nitrogen to prevent air in-leakage. In colder climates where the risk of freezing is an issue, it is often necessary for boiler filling to be limited to partial wet filling and extending the use of nitrogen capping.

As was common industry practice at the time, Units 1 and 2 boilers, Figure 4-10: Drainable Boiler Superheaters at Units 1 and 2, were designed with horizontal superheaters and reheaters to reduce the risk of freezing. This also facilitates long term wet layup while minimizing the boil-out time required for pendant type heating sections but, in the case of the reheaters, it increases the consumption of nitrogen. Where the risk of freezing is high, e.g., due to loss of the plant heating system for extended periods, nitrogen capping may be used in the drainable sections in place of buffered water.

For Scenarios 1, 2, and 3, the boiler will be under wet/dry lay-up conditions and for Scenario 4 the boiler will be maintained warm and under steam pressure. For each of the former scenarios, the boiler drum, economizer, and waterwalls will be filled to the maximum water level in the drum with nitrogen capping to maintain the balance of the steam circuit in an inert atmosphere. For Scenario 1, 24 to 30-hour recall time, the boiler superheaters may also be flooded up to the closed main steam stop valve. It is recommended that the reheaters be nitrogen capped.

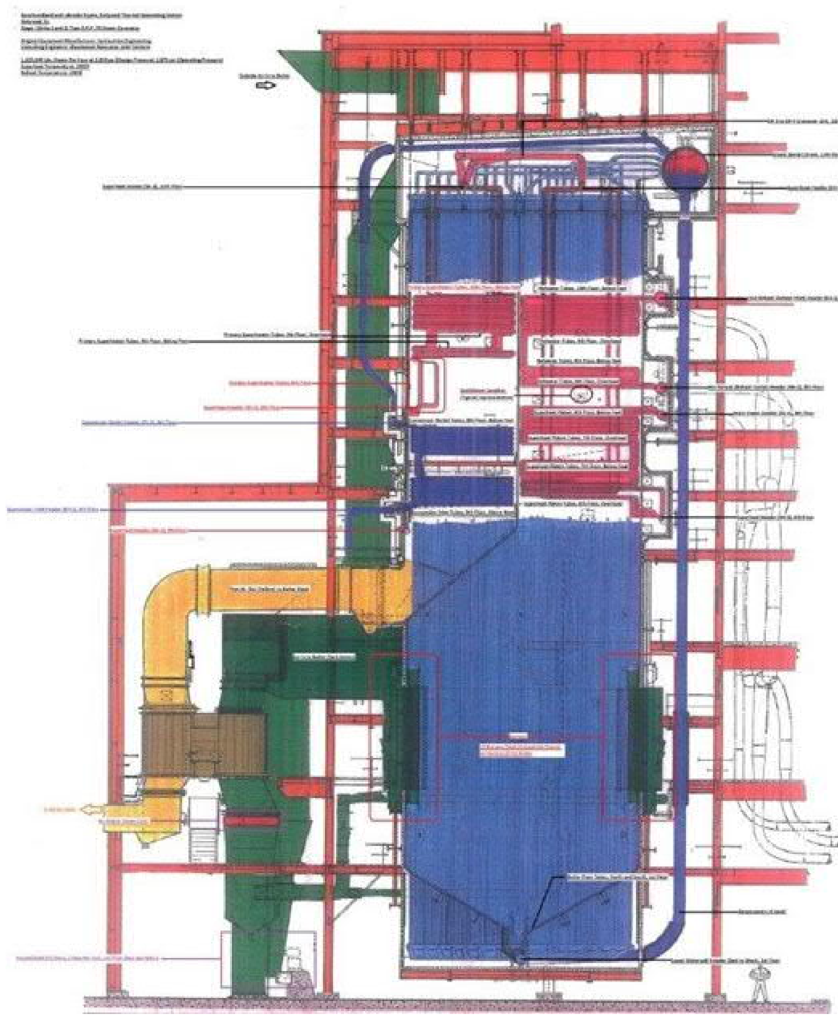


Figure 4-10: Drainable Boiler Superheaters at Units 1 and 2

4.9 Summary of Scenarios

Table 4-8 summarizes the start-up times of the first and second units for each scenario.

Table 4-8: Summary of Scenarios

Scenarios	1st Unit	2nd Unit
Scenario 1	24 Hours	30 Hours
Scenario 2	8 Hours	12 Hours
Scenario 3	6 Hours	8 Hours
Scenario 4	<4 Hours	4 Hours

5. HTGS Operation and Maintenance Requirements

This section refers to the option of operating in emergency backup generation mode.

5.1 Fuel Supply

The station will continue to operate on No. 4 Heavy Fuel Oil (HFO) as a primary fuel and No. 2 Light Fuel Oil (LFO, also referred to as diesel) as a start-up fuel, therefore, the following assets will remain in service:

- Fuel Unloading Wharf.
- Bulk HFO Storage including suction heaters.
- HFO Day Tank.
- Unit 1, 2, and 3 HFO Fuel Pumps and Final Stage Heaters.
- LFO Storage.
- HFO and LFO piping systems.

While the above assets and systems are required for all scenarios, the quantity of bulk storage tanks required and HFO storage volume differs between scenarios.

5.1.1 Fuel Specifications

No. 4 Heavy Fuel Oil (HFO) primary fuel and No. 2 Light Fuel Oil (LFO) start-up fuel specifications currently used in the plant are shown below in Table 5-1 and Table 5-3. The fuel in Table 5-1 is similar to the low sulphur fuel specifications adopted by the International Maritime Organization (IMO- 2020), reducing the sulfur specification for fuel oil to <0.5%. The IMO action caused a price increase for the low sulphur fuel oil in the short-term. However, in terms of future availability, it may not be an issue due to ongoing demand for shipping, industrial and utility plant users in the Americas and globally. Although refineries try to minimize heavy fuel oil production in favour of higher-grade products, it is not an easy transition especially for refineries designed to process heavy crude oil feedstocks (US Gulf Coast and US Midwest refineries are among such regions).

Table 5-1: Primary Fuel No. 4 Heavy Fuel Oil (HFO)

Fuel Oil Analysis	Grade No.4
Composition, weight %	
Sulfur	< 0.7
Hydrogen	(10.6 to 13.0) *
Carbon	(86.5 to 89.2)*
Nitrogen	-
Oxygen	-
Ash	0 to 0.1

Fuel Oil Analysis	Grade No.4
Gravity	
Deg API	15 to 30
Specific	0.966 to 0.876
Miscellaneous	
Density (lb/gal)	8.04 to 7.30
Pour Point (F)	- 10 to + 50
Water & Sediment, vol %	trace to 1.0
Viscosity	
Centistokes at 100F	10.5 to 65
SYS at 100F	60 to 300
SSF at 122F	-
Higher Heating Value, Btu/lb	18, 280 to 19,400
* Estimated: Source: Steam - Its Generation and Use, 40th Edition.	

Table 5-2: Startup Fuel No. 2 Light Fuel Oil (LFO)

Fuel Oil Analysis	Grade No.2
Composition, weight %	
Sulfur	0.05 to 1.0
Hydrogen	11.8 to 13.9
Carbon	86.1 to 88.2
Nitrogen	nil to 0.1
Oxygen	-
Ash	-
Gravity	
Deg API	28 to 40
Specific	0.887 to 0.825
Miscellaneous	
Density (lb/gal)	7.39 to 6.87
Pour Point (F)	0 to -40
Water & Sediment, vol %	0 to 0.1
Viscosity	
Centistokes at 100F	1.9 to 3.0
SYS at 100F	32 to 38
SSF at 122F	-

Fuel Oil Analysis	Grade No.2
Higher Heating Value, Btu/lb	19,170 to 19,750

The primary fuel was changed from No. 6 HFO to No. 4 HFO above for improved emissions performance. Since the change in fuel type, HTGS has experienced increased wear on the fuel pumps and final stage fuel oil heater tubing. Potential causes to the increased wear and maintenance requirements are thought to be related to the lower viscosity of the fuel and/or contamination in the fuel.

HFO fuel quality issues can be improved using new filters to remove contamination and reduce properties which have adverse effects on power generation equipment. However, considering the reduced operating hours expected in 2023 through 2030, and the fact that the current issues have been addressed through increased maintenance, Hatch does not recommend additional capital investment in new fuel treatment assets at this time and instead suggests that the fuel suppliers be engaged to address fuel quality issues.

In previous studies, concerns have been raised with the deposition and settling of sediment in the day tank when the facility is in cold recall or standby service due to a longer residence / storage time for the HFO fuel. To address this concern new and suitable filters may be added upstream of the tank to remove the particles that would otherwise settle.

5.1.2 *Fuel Supply, Delivery and Storage*

The operating scenarios assessed in this study consider the extension of the fuel supply, delivery, and storage systems to 2025, 2027, or 2030. The cost to extend the use of the HFO storage tanks and Day Tank are driven by the required API inspection intervals of every 5 years for external in-service inspections and every 10 years for internal out of service inspections and the findings and repairs required at each inspection interval. It has been determined that the station can be suitably operated with only 3 main HFO storage tanks, therefore, Tank 1 is scheduled to be decommissioned this year. Based on this, the tanks required for the new operating regimes, and their next inspection due dates are summarized below in Table 5-3.

Table 5-3: Fuel Tank Life Extension Requirements by Operating Scenario

Asset	Next API 653 Inspection Due	Full Operation	Emergency Standby Cold Recall
HFO Tank 1	2023	Required	Required
HFO Tank 2	2023 OS	Required	Required
HFO Tank 3	2025 OS*	Required	Required
HFO Tank 4	2024 OS	Required	Required
HFO Day Tank	2023*	Required	Required
LFO Tanks	2022	Required	Required

*Possibly later if extended, as noted by NLH.

As can be seen above, Tank 1, Tank 2, Tank 3, Tank 4, and the HFO Day Tank are required during all new operating regimes under consideration and have inspections due before 2025. HOIT data and discussions with NLH indicate that NLH has been applying for an extension of the inspection intervals based on the findings and remaining life forecast during past inspections.

5.1.3 *Fuel Tank Capacity Review*

The assessment of the fuel storage requirements considered in this study is based on the following key assumptions:

- Consider 3 weeks and 6 weeks operation reference cases.
- Each main storage tank has a nominal capacity of 33,710 m^3 (212,000 bbls).
- Fuel has been delivered by 200,000 bbl tankers every 3 weeks historically.
- Estimated 160,000 bbls required per year to exercise each of Units 1 and 2 monthly and Unit 3 on a six-week cycle, for 24 hours at loadings of approximately 150MW.
- Emergency use for all units at 150MW to 170 MW for 3 to 6 weeks is estimated to be 320,000 to 650,000 bbls.

Table 5-4: Fuel Storage Requirements by Operating Scenario

Scenario	Fuel Usage
All Units Test Runs Scenarios 1 to 4	160,000 bbls
Standby, 3 weeks operation	325,000 to 350,000 bbls
Standby, 6 weeks operation	650,000 to 700,000 bbls

Based on the above assumptions and criteria, the use of three HFO main storage tanks and one HFO day tank is considered manageable for most of the above operating scenarios. It is noted that the proposed test runs program is flexible and could be reduced to conserve fuel at the risk of increasing start-up reliability.

The HFO fuel usage during the case of Emergency Standby operation, for the duration of 6 weeks under continuous operation, exceeds the storage capacity of 3 tanks. In this scenario, all four tanks are required. Tank 1 may be refurbished to increase the on-site storage capacity to support continuous operation for a 6-week duration. An estimate for this is included in the Capital Plan. Alternative potential options for HTGS are:

- A tanker delivery at the 3-week mark would provide the additional fuel required to continue operation for the 6-week period and beyond. As the demand is based on an unplanned event, it may be necessary to pursue a spot market delivery with high uncertainty on availability and at a premium cost.

- Limit the operating availability of the plant to an average load profile to align with available HFO.

5.2 Environmental Considerations for Quick Recall

An Environmental Management System (EMS) is in place in accordance with ISO 14001 and is operated in compliance with its existing environmental Certificate of Approval (COA) which has been extended to a validity date of December 31, 2021. The current COA needs to be extended for the period of operation. It is understood that this process has been initiated.

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Municipal Affairs and Environment

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***October 31, 2016*** Approval No. AA16-105640A

Amendment: ***April 2, 2018***

Expiration: ***August 31, 2021*** File No. 716.008, 716.050.1

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

TERMS AND CONDITIONS FOR APPROVAL No. AA16-105640A
April 2, 2018

General

1. This Certificate of Approval is for the operation of a 123 MW Combustion Turbine, Six (6) Diesel Generating Units and a Thermal Generating Station, including power house, wastewater treatment plant, hazardous waste landfill and associated works located at Holyrood, Newfoundland. Extensive future expansion or change of activities will require a separate Certificate of Approval.

2. Certificate of Approval AA16-105640 is revoked and replaced by this Certificate of Approval.

Expiration

108. This Certificate of Approval expires ***August 31, 2021.***

109. Should HYDRO wish to continue to operate the Thermal Generating Station and the Combustion Turbine beyond this expiry date, a written request shall be submitted to the Director for the renewal of this Approval. Such request shall be made prior to ***March 1, 2021.***

Figure 5-1: Certificate of Environmental Approval[3]

[3] Note the expiry date shown has been extended to December 31, 2021.

The environmental considerations for the Emergency Backup scenarios include the following:

- Additions to the COA for a potential new auxiliary boiler.
- Continued use of Quarry Brook to supply the Units 1 and 2 auxiliary cooling water systems.
- Noise emissions considerations for more frequent start/stop operations associated with each of the Emergency Backup scenarios.

In addition to the air emissions currently covered under the existing COA, it is noted that the introduction of GHG regulatory requirements and the federal carbon emissions program will need to be addressed for operation beyond 2021/2023. The carbon emissions program may impose additional costs in the form of a carbon tax or the acquisition of GHG credits.

5.3 Spare Parts Inventory Requirements

NLH asset management practice includes an Asset Criticality and Critical Spares Framework, which implements the approach to identifying critical spares for each asset. Under this process, spares are assessed for a specific asset potential impact on safety, environment, asset integrity, and value to support the decision-making process for inventory management. The framework recognizes that assessing the criticality of spare parts is an ongoing process which may drive revisions to the critical spares list and may impact operating budgets.

Key elements of the process include:

- Identification of critical assets (Consequences and Probability of Failure)
- Spare part lead time
- Number of potential suppliers
- Availability of technical specifications and knowledge
- Type of maintenance whether corrective or preventive
- Decision diagram for spare part criticality classification

The criticality criteria are defined in the List of Critical Attributes below, which, from the perspective of this report, includes consideration of possible component obsolescence and differentiates between spares required for corrective maintenance and those required for planned maintenance; the latter category being considered less critical.

Table 5-5: Asset Criticality Criteria and Description

#	Criticality Criteria	Description
1	Asset Criticality	Evaluated as the probability of a failure of the asset and the consequence of that failure.
2	Lead Time	The total elapsed time from when a material need is communicated until the spare part has been received, checked and made available for use.
3	Number of potential suppliers	The number of potential suppliers (off site) who are able to deliver the specific spare part to the requestor.
4	Technical specifications	The availability of the technical specifications (drawings and text) and knowledge.
5	Maintenance Type*	The type of maintenance whether CM or PM done on the asset.

Existing electrical and instrumentation components are reported to be at or near end of life. The reliability of electrical switchgear is considered to be manageable using planned maintenance together with selective refurbishment.

Instrumentation components, e.g., turbine-generator controls and unit Distributed Control System (DCS) components, are of a more critical nature because of the single suppliers in each case. However, in these cases, sustaining an inventory of control systems electronic cards and other critical parts, coupled with OEM support agreements, will assist with addressing parts obsolescence and end of life deterioration. Other utility companies have also used reverse engineering in the past to obtain replacement electronic cards, e.g., for obsolete DCS systems.

It is considered that the Asset Criticality and Critical Spares Framework implemented by NLH reflects best industry practices.

5.4 Lay-Up

To maintain the plant reliability for emergency recall, the lay-up requirements for each scenario vary depending on the state of readiness to be maintained for each recall option.

Table 5-6: Equipment Lay-up Requirements

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Recall Time (hours)	30	12	8	4
Condition of Plant During Plant Shutdown				
Boiler	Wet/Dry	Wet/Dry	Wet/Dry/Cold	Wet/Warm
Turbine	Cold & On Turning Gear (Fortnightly)	Cold & On Turning Gear (Weekly)	Cold & On Turning Gear (Twice a week)	Warm & On Turning Gear (Daily)

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Generator	Not Pressurized	H_2 Filled at 30 psig	H_2 Filled at 30 psig	H_2 Filled at 30 psig

For each of the three scenarios, Scenario 1, Scenario 2, and Scenario 3, the boilers are stored using a Wet/Dry approach. That is, the boilers are maintained filled with feedwater to a drum level ranging from High level down to Low level. For the initial fill, the drum is filled to the highest level and as it falls over time down to a low level it is refilled to the upper level. The upper level of the drum and the superheaters are maintained under a nitrogen blanket to minimize oxygen absorption and tubing corrosion. Boiler water chemistry should be monitored to manage dissolved oxygen within the acceptable limits.

The reheaters can be stored dry under a nitrogen blanket which may lead to high nitrogen consumption, or alternatively, dry using an air dehumidification package to circulate dehumidified air through the headers and tubing using the headers drains and vents to achieve air flow.

The steam turbines are maintained cold or, in the case of Scenario 4, warm as described in Section 4.5 of this report. The turbine-generators are rotated as per Table 5-6 above to keep the shafts straight and to avoid bearing flat spots developing.

The generators are maintained under hydrogen pressure with seal oil supply in service for each of three shorter recall time scenarios as shown in Table 5-6. However, for Scenario 1, the generators hydrogen is purged with CO_2 and then air for storage. To limit the potential for moisture damage to the generator windings, it is recommended that a dehumidified air circulation package be used for the generators.

5.5 Recommended Inspection Frequency

The recommended inspection frequency for main equipment is outlined in Table 5-7. The inspection and major overhauls for critical equipment is recommended based on number of operating hours or accumulated years from previous overhaul, which ever comes first. Since this facility is going to be used as a backup generating station, Hatch suggests giving preference to the operating hours rather than the accumulated years, a review with the OEM is necessary to establish equivalent operating hours for each start-up/shutdown. Hatch, however, emphasizes to have a proper inspection to support any decision to delay an overhaul. Other peripheral equipment such as air compressors, air dryers, electrical system, and water treatment equipment should be inspected on an annual basis.

Table 5-7: Recommended Inspection and Overhaul Frequency for Units 1-3[4]

Equipment	2022	2023	2024	2025	2026	2027	2028	2029	2030
Turbine (Major Overhaul)		2			3				

[4] Where the numbers refer to unit number or to tank number respectively

Equipment	2022	2023	2024	2025	2026	2027	2028	2029	2030
Turbine (Routine Inspections)	3	1	2	3	1	2	3	1	2
Generator Inspection			1			2			
Valves Inspection	3	2	1	3	2	1	3	2	1
Feed Water Pump Major Overhaul (East)			2		3		1		
Feed Water Pump Major Overhaul (West)			2	3				1	
Deaerator Inspection					2	1	3		
Vacuum Pump Inspection (North)		2	1		3				
Vacuum Pump Inspection (South)	1			2		3			
Boiler Inspection (Minor for two and Major for one unit every year)	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3	1,2,3
Routine Fuel Tank Inspections	1	2	4	3	1	2	4	3	
API Fuel Tank Inspections	LFO Tank	1, 2	4,Day Tank	3					

5.6 Staffing Requirements

As of September 2, 2021, the station had 101 positions for staff. This staffing plan is shown in Figure 5-2.

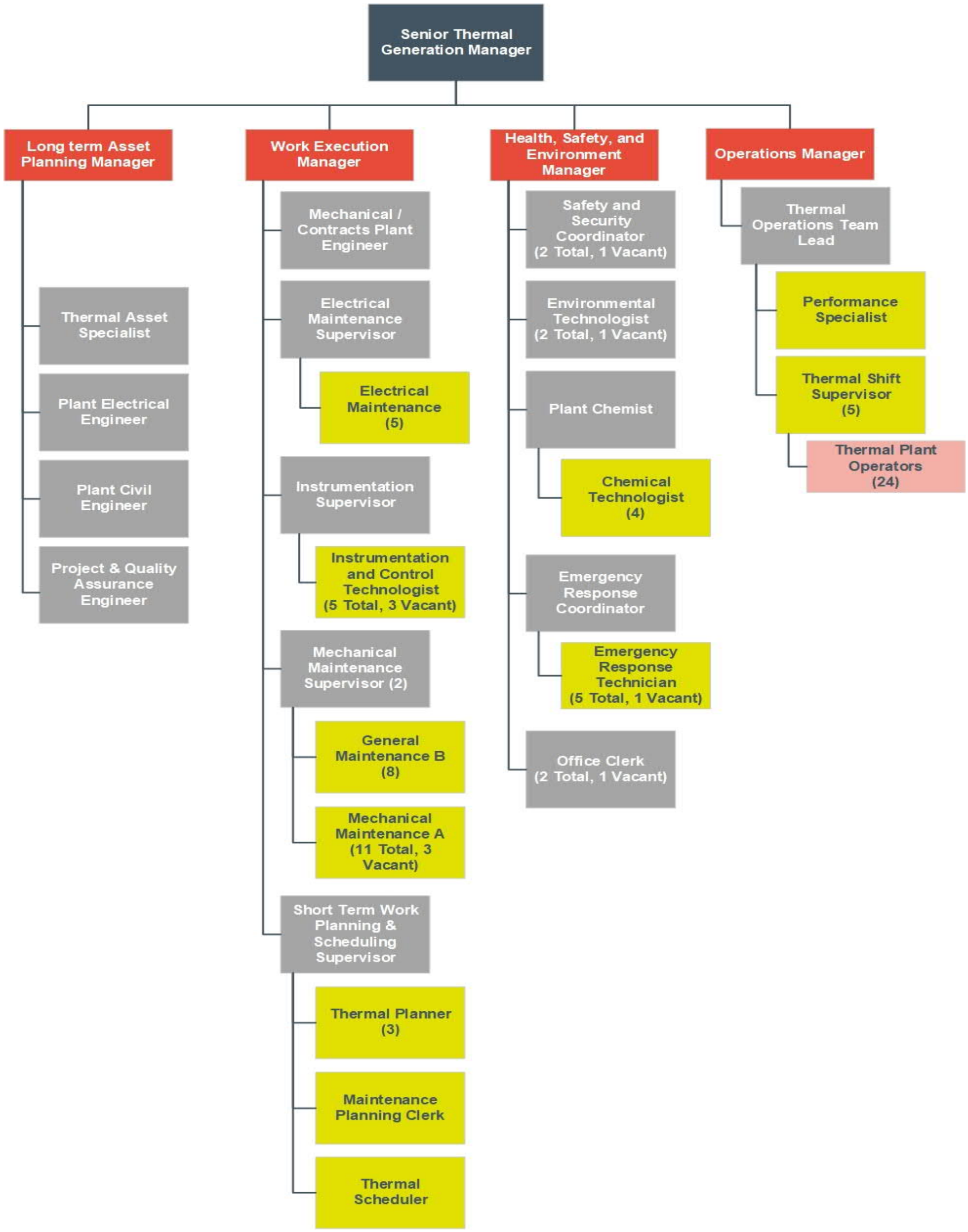


Figure 5-2: Current Staffing Plan

5.6.1 Personnel Competency and Qualifications

The current plant personnel have experience with the units and auxiliaries supporting a knowledge base equivalent to a significant number of person-years. The exact values of these years of experience and equivalent person-years of experience are to be determined based on discussions with NLH. In addition, NLH has additional staff, with HTGS operations and maintenance experience, who although currently assigned in other roles in the organization, can be called on to support HTGS. Therefore, as the role of the plant changes from base load or intermittent, but predictable, regular operation and moves to the emergency standby role, it will be important to ensure that the current knowledge base is not lost. However, it is also noted that the transition to the emergency standby role will lead to a plant that will require a smaller on-site day-to-day support team which could lead to options for developing an on-call roster for staff in other assignments and for out-sourcing specific support services on an as-needed basis. These considerations mean that the current plant systems documentation, in particular operations and maintenance materials and plant procedures and QA/QC processes, will need to be updated as necessary to ensure that the existing personnel knowledge base is not lost during any attrition or staff reductions. In addition, specific training with a focus on the standby scenarios and expectations for Plant Readiness to Serve mode required for an Emergency Standby role should be developed.

An essential part of the process to provide for future staffing needs includes a review of the current staff age, current grade of licenses, and length-of-service profiles to generate a look-ahead for the impact of routine attrition over the planned time frame in the emergency standby role.

The management and in-plant technical services teams' current knowledge base should be documented to avoid possible loss of plant or equipment specific knowledge and to ensure that the existing documentation is up to date with any ongoing modifications or improvements that have been planned or implemented. Subject to review of possible staff reductions due to attrition, the use of a Master Services Agreement (MSA) with selected qualified service providers should be considered to enable the reduction in the number of full-time positions over time.

Routine maintenance and specific equipment maintenance experience rests with the current complement of maintenance staff. The current personnel resources include licensed mechanics, electricians, and technologists (to be confirmed pending discussion with NLH). In addition, NLH will need to maintain the current contractor's license and related staff qualifications required for pressure parts repairs as per NLR 119/96 - Boiler, Pressure Vessel and Compressed Gas Regulations.

Therefore, in the near term, it is envisaged that the supervisory and technician staffing will remain as is pending the outcome of a review of probable staff attrition.

Similarly, the operations staff complement is envisaged to include personnel with various levels of steam tickets, including second class and third-class ticket holders. As with the maintenance personnel, the operations personnel complement should be reviewed to establish the age, current grade of steam tickets, and length-of-service profiles to look ahead at the future needs for training and replacement.

5.6.2 Proposed Staffing Plan

The staffing plan presented in Figure 5-3 was developed, in conjunction with NLH, as a proposed modified staffing plan based on the emergency standby power scenarios described in the earlier sections of this report.

Note the following regarding the proposed plan:

- Warehousing services and Work Execution and Engineering services are all shared across the thermal production assets (HTGS and gas turbines), this report is focused on HTGS only.
- It is also noted that NLH can share operators with the gas turbine plant and that there are other operators in various assignments across NLH with sufficient experience at HTGS with the capability to operate the units. This corporate wide resource pool should be able to be called on for additional support at site. Refresher training would be required periodically to ensure this staff is up to date with requirements.

5.6.2.1 Staffing Plan

The staffing plan proposed is shown in Figure 5-3 with a summary of each role listed in this section. Note that each block in the staffing plan represents one staff member unless otherwise noted in brackets. A total of 58 staff are recommended initially, pending implementation of capital programs. As the capital programs are completed in the near term, a future review of the number of positions required, e.g., under the Works Execution functions, may be justified.

Senior Management

- Thermal Production Senior Manager: There are no proposed changes to this role as it is continues to be necessary for providing overall direction, oversight, and management for Holyrood Thermal Generation Station and the gas turbine and reciprocating engine generating fleet throughout NLH. The responsibilities of this role may also include management functions of other thermal generating assets.

Work Execution and Engineering

- Work Execution and Engineering Manager: The proposed responsibility for this role is to manage and provide direction for the following staff: Mechanical Engineer, Contracts, Quality Assurance Engineer, Electrical Engineer, Asset Specialist, Instrumentation and Electrical Maintenance team, and Mechanical and General maintenance team. This role is required to provide direction to the staff under its supervision. While additions have been made to this role, it is expected that this combined role will be sufficient for leading work execution and engineering for operation in backup generation mode.
- Plant Mechanical Engineer: The mechanical engineer is responsible for all mechanical engineering issues related to HTGS. The scope of these responsibilities includes all boiler, turbine generator, common services, fuel supply and storage systems, service water, air compressors, combined generator oil and gas systems, and any other system with a mechanical component within the plant. This role is required to ensure mechanical equipment health monitoring for smooth backup generation operations. In addition, this role also provides support to other Thermal Generation facilities.

- Plant Electrical Engineer: The electrical engineer is responsible for all electrical engineering matters related to HTGS. The scope of these responsibilities includes electrical and control aspects of the boiler, turbine generator, common services, electrical switchgear, indoor and outdoor plant lighting, and electrical systems associated with any other plant components. This role is required to ensure electrical equipment health monitoring for smooth backup generation operations. In addition, this role also provides support to other Thermal Generation facilities.
- Civil Engineer: This position is responsible for all civil/structural engineering matters related to HTGS. The scope of these responsibilities includes the civil/structural matters pertaining to the integrity of the powerhouse, the administration building, other exterior buildings, the marine terminal, training center, warehouse building, fuel oil storage tanks, buried services, wastewater systems including oily water separators, basins, and all other containment structures. This role ensures compliance with regulatory requirements related to tank inspections, stack inspections, and stack lighting. In addition, this role also provides support to other Thermal Generation facilities.
- Asset Specialist: With the short-term asset role transferred to the corporate NLH office (as noted by NLH), this role is required to assist with long term asset planning for HTSG assets. As the plant will be operating in backup generation mode, the asset specialist is required to provide input into the asset management and planning for HTSG as well as ensuring consistent best practices for maintaining critical spares.
- Instrumentation and Electrical Supervisor: The roles of the instrumentation and electrical supervisors are combined. This role is required to provide the instrumentation and electrical maintenance teams with the supervision and direction necessary to ensure safe and effective operations. This supervisor is also essential for ensuring the instrumentation and electrical components are in good working condition. For operation in backup mode, this combined role would suffice for smooth operation.
  - Instrumentation Technician: Two technicians are recommended to provide sufficient support for backup generation mode.
  - Electrical Maintenance: Three electrical maintenance staff would be required to ensure that the unit(s) would be able to effectively ramp-up as needed during backup generation mode.
- Mechanical Supervisor: The mechanical maintenance supervisor role is not proposed to be changed as it is required to guide and direct the mechanical and general maintenance staff to ensure safety and efficiency. This supervisor is essential for ensuring the mechanical and general maintenance components are in good working condition. One supervisor is expected to be sufficient for supervising the maintenance staff team for backup generation operation.
  - Mechanical Maintenance: Four staff are proposed for the mechanical maintenance team to provide sufficient support for operation in backup generation mode.

- General Maintenance: Three staff are proposed for the general maintenance team to provide sufficient support for operation in backup generation mode.

Note that staffing for planning and scheduling is reduced and additional staff for short term work are based on the indication from NLH that this function can be effectively supported from the corporate office.

Safety, Health, Environment, Security, Emergency Response and Finance

- Support Services and Security: The manager in this role will be responsible for oversight and coordination of staff and support services for the functions listed below. This role is also responsible for managing site security related matters to ensure the safety of site staff.
  - HSE Coordinator: This role has the following responsibilities:
    a) Promote and ensure compliance with the Safety Management System and ensure maintenance and development of required standards, policies, and procedures.
    b) Promote and ensure compliance with other corporate policies related to Emergency Response, Fire Protection, and Safety.
    c) Assist in the identification of high-risk activities and ensuring that the appropriate work methods and/or procedures for mitigating the risk are developed, implemented, and maintained.
    d) Contractor Safety Management: ensuring that approved safety plans and reporting are in place.
    e) Assist in the completion of Incident and Near Miss Investigations and ensuring that remedial/corrective/preventative actions are implemented where required.
    f) Ensuring Safety Culture Action plan is developed, maintained, and effective.
    g) Ensure that the Industrial Hygiene program is monitored - would include air quality monitoring and noise monitoring.
    h) Ensure that the Emergency Response Plan and manual are implemented, maintained, and updated in compliance with Corporate and insurer requirements.
    i) Ensure that the Environmental Management System (EMS) is maintained in accordance with ISO 14001.
    j) Ensure that Document Control and record management systems satisfy the requirements of ISO 14001.

k) Ensure Regulatory Compliance according to Certificate of Approval (COA) for Provincial government reporting (environmental compliance monitoring, sampling information and reporting); and

l) Ensure compliance for Federal governing reporting with the completion of the National Pollutant Release Inventory (NPRI).

- Office Clerk: The office clerk's role includes document control and payroll coordination which is essential to the smooth operation and proper documentation of data for operation as a backup generation facility.
- Emergency Response Supervisor: This role is functionally responsible for ensuring safety orientation and training are provided, as needed, to all staff (term, contract, etc.). With the reduction in staff from the current operation to backup generation mode, emergency response coordination is critical to ensure the health and safety of all employees.
  - Emergency Response Team: Three Emergency Response Technicians (ERTs) are proposed to ensure all preventative measures pertaining to safety are taken and that the safety equipment is maintained in good operating condition. ERTs are essential for maintaining the following equipment:

    a) Fire Protection and Life Safety System Preventative Maintenance

    b) Safety Program and Emergency Response Training and Program Management

    c) Emergency Response and Standby Rescue (Confined Space/High Angle)
- Operational Readiness Supervisor: This role will provide supervision for the chemical and environmental technicians and ensure the requirements are met for ramping-up and being operational when requested by the grid.
  - Chemical / Environmental Technicians: Two technicians are recommended to operate the water treatment system, conduct boiler chemical analysis, chemical injection, monitor the continuous emissions monitoring system (CEMS), and monitor offsite environmental parameters, as needed.
- Planning/Scheduling: This role provides overall planning and scheduling for ongoing maintenance programs plus integration of the conversion and re-conversion of Unit 3 mode of operation. In addition, coordinates on fuel inventory with the Operations management and Operational Readiness functions.

Operations

- Operations Manager: In addition to being responsible for managing the operations staff, the operations manager will have a First Class Certification (applicable in Newfoundland).

The Operations Manager will be responsible to the Newfoundland and Labrador provincial regulator regarding all matters relating to operating safely.

- Shift Supervisor: Only three shifts are anticipated to be required for backup generation mode operation. Each shift will have experienced supervisors, with Second Class Certification, who will manage the operators and provide direction, in addition to maintaining contact with the Newfoundland and Labrador System Operator (NLSO). Shift coverage is provided for 24 hours a day, 7 days a week, 52 weeks per year.
  - Thermal Plant Operator: Each shift will be staffed with five experienced Thermal Plant Operators with at least Third Class Certification. These operators are essential in providing coverage for all units when running in standby mode and shifting into operation mode when requested by NLSO.

Additional Resources

- In addition to the full-time staffing complement proposed above, as noted, NLH has available several former operations personnel with extensive experience of the HTGS facilities. This group includes personnel who have operating experience within the past 2 to 6 years at HTGS who could be available on short notice. This group comprises about 16 people in total who were assigned in HTGS Operations Group with an average of 13 years of remaining service with NLH.

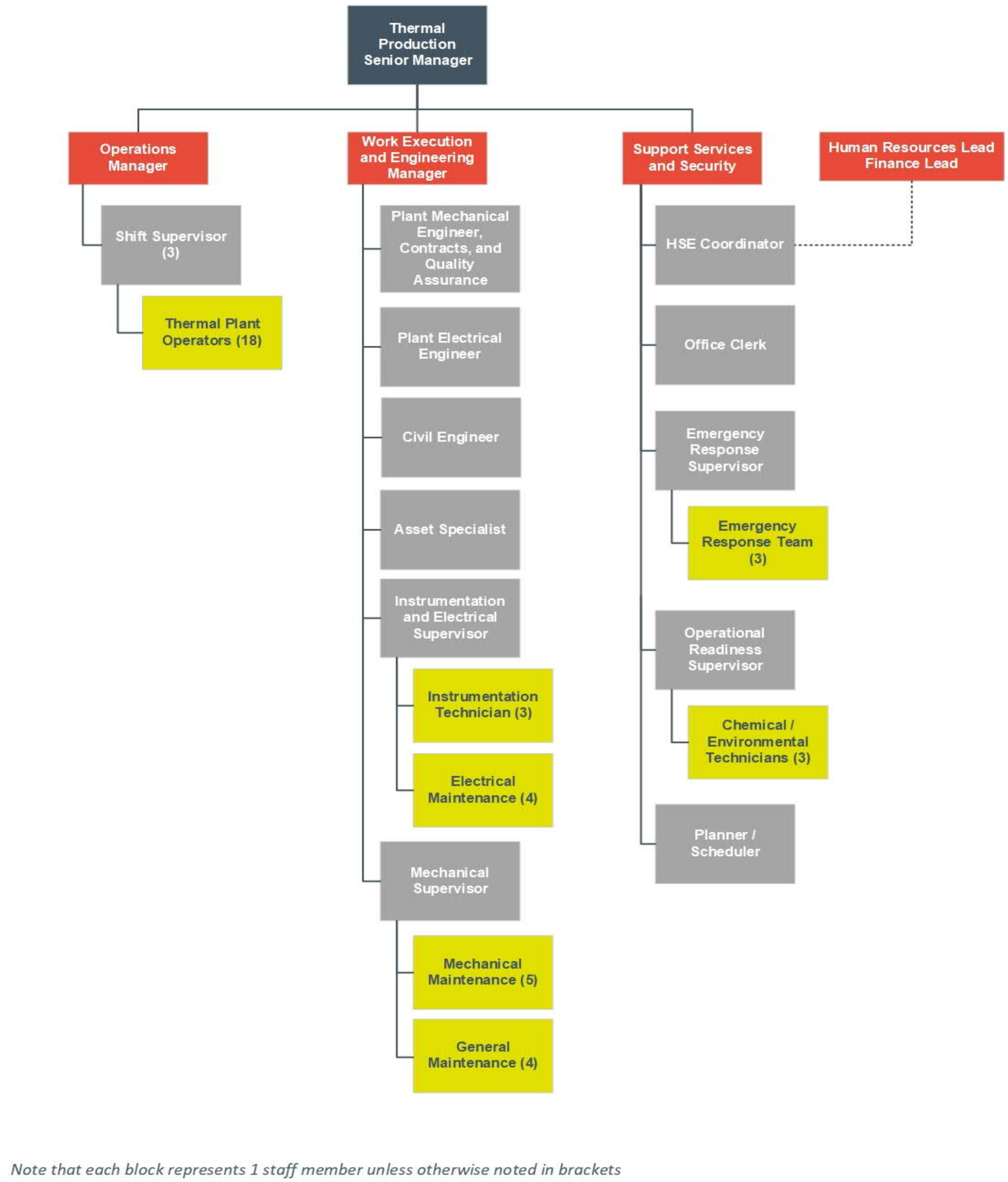


Figure 5-3: Proposed Staffing Plan

5.6.3 *Training Requirements*

Ongoing plant operation to 2030 in conjunction with the potential for staff losses due to attrition will drive a need for developing a comprehensive training program. The need for ongoing training and familiarisation in the operation requirements and specific characteristics of the plant equipment will be achieved by the proposed test runs program for each scenario.

In addition, essential training for existing and replacement personnel over the extended 10-year time frame should include:

- Safety and Emergency Response procedures plus ongoing safety training for refreshment and regulatory updates.
- Ongoing training of personnel in the areas of environmental matters related to plant specific issues and evolving regulatory requirements.
- Training support for all personnel as needed to support their functions and responsibilities, e.g., managerial, professional, and technical functions.
- Support for personnel development to upgrade their level of certification, e.g., master mechanic/master electrician/steam ticket holders from Level 3 to Level 1.

6. HTGS Capital and Operating Cost Estimates

6.1 Capital Costs

6.1.1 Capital Improvements

The following improvements are recommended for Units 1 and 2:

1. Extending the natural cool-down time of the boilers:

   For boilers operating on an intermittent basis, the natural cool down time is a function of the stack effect from a hot boiler through the stack. Inserting an improved shut-off damper arrangement between the air pre-heater outlet and the stack would reduce the stack effect and the associated loss of heat, thereby extending the cool down time. A typical damper arrangement for this purpose would be a double louvre damper set with a small fan to pressurize the volume between the double dampers; such damper arrangements have been used in conjunction with retrofit FGD systems on utility boiler's gas path to the stack.

   This approach may be beneficial if used in conjunction with providing a supply of auxiliary steam to an offline unit when operating one unit at minimum load.

   The limitations of this approach include the cool down time for Units 1 and 2 steam turbines to the metal temperature 150°C trigger level for pre-warming.

2. Supply of auxiliary steam:

   The procurement and installation of a new auxiliary boiler to supply auxiliary steam to the plant when all three units are offline is discussed in detail in document H365408-0012-200-030-0002. The supply of steam from the auxiliary boiler will also require the interconnection of Units 1 and 2 turbine gland steam systems.

   The use of an auxiliary boiler instead of one of the utility boilers to maintain steam turbine metal temperatures at levels that would limit turbine pre-warming raises a concern with steam quality from an auxiliary boiler with respect to drum carryover. This can be addressed by using demineralized water in the auxiliary boiler.

3. Boiler upgrades:

   Provision of economizer recirculation on Units 1 and 2.

   Installation of motorized valving on boiler drum continuous blowdown and boiler waterwall drains.

   Provide new boiler furnace cameras on each boiler with new monitors in the control room.

   Provide refurbished or replacement boiler furnace temperature probes on Units 1 and 2.

4. Main fuel oil system upgrades:

   The fuel oil system will require filtration and recirculation to support faster start-up and reduce the impact of high sludge content in the fuel.

6.1.2 Cost of Capital Improvements

A summary of the capital expenditure (CAPEX) expected for the proposed capital improvements, including those described above, is provided in Table 6-1.

Table 6-1: Summary of CAPEX for Capital Improvements ($)

Modification	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Modification Equipment Cost	$3,700,000	$3,800,000	$4,300,000	$6,000,000
Installation Cost	$2,960,000	$3,040,000	$3,440,000	$4,800,000
Sub-Total	$6,660,000	$6,840,000	$7,740,000	$10,800,000
Contingency	$1,998,000	$2,052,000	$2,322,000	$3,240,000
EPCM Cost	$1,998,000.0	$2,052,000.0	$2,322,000	$3,240,000
Total	$10,656,000	$10,944,000	$12,384,000	$17,280,000

Refer to Appendix C for the detailed CAPEX estimate breakdown

6.1.3 Capital Plan

The capital plan to support major inspections, overhauls, and upgrade of station assets from 2022 to 2030 was developed. A summary of the capital plan is shown in Table 6-2 and a breakdown of the plan by unit is provided in Table 6-3. Refer to Appendix D for a detailed breakdown of the capital plan

Table 6-2: Capital Plan Summary, 2022-2030 ($1000's)

2022	2023	2024	2025	2026	2027	2028	2029*	2030	Total
25,044	32,995	26,317	25,872	19,077	17,750	14,011	24,728	12,251	198,045

*Note that this includes an estimated allowance for generator #3 and transformer upgrades on the basis that synchronous condenser operation will continue beyond 2030.

Table 6-3: Capital Plan Breakdown by Unit, 2022-2030 ($1000's)

Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Unit 1	3,333	3,333	6,433	3,333	3,500	3,800	4,200	12,394	3,667	43,994
Unit 2	3,333	14,161	5,033	3,333	4,300	3,500	3,500	3,667	3,667	44,494
Unit 3	7,835	4,123	4,399	13,097	8,777	6,600	5,200	7,667	3,667	61,364
Common Facilities	10,543	11,378	10,452	6,109	2,500	3,850	1,111	1,000	1,250	48,193

1. The capital in year 2023 is relatively larger than other years. This is because the Unit 2 turbine major overhaul was scheduled for this year. Additionally, the refurbishment of fuel tank 1 was also proposed in this year.
2. A cost increase in 2029 occurs due to the proposed Unit 3 exciter and transformer upgrades to enable Unit 3 to run in synchronous condenser mode until 2043.
3. An annual capital cost of $3 Million is considered for boiler inspections and upgrades. This cost is increased to $3.5 Million for 2026 onwards and increased to $4 Million for year 2029 and 2030.
4. An allowance of $6 Million per year for all three units is added for unforeseen, in-service failures. This allowance is based on the following considerations.
   a) The routine inspection of boilers, turbines, generators, and all auxiliary equipment is carried out as per inspection program.
   b) The major overhauls for turbine and pumps are carried out as per recommendation in capital plan.
   c) All high energy pipes and supports are inspected regularly, and a record of inspection is maintained as per ongoing practice.

d) The cost is primarily to cover in service failures for assets in HTGS facility. The assets which do not fall in the scope of this study has not been considered and this allowance may or may not be sufficient to cover the failures on such assets.

e) Considering the age of the asset and the fact that some of the equipment falls in grade 3 or below as per asset grading in this study, an unforeseen failure may happen.

5. A total cost of $2 Million is reserved for an EPRI class 2 level condition assessment of the assets again in year 2026 and 2027. Hatch recommends conducting this condition assessment for the assets if NLH decides to extend the backup generation mode of these units beyond 2030.
6. The cost for capital upgrades or major overhauls of the turbine, valves, and remainder of plant equipment beyond 2027 is also considered as part of the capital plan.
7. No escalation has been considered in Capital and in Operating Cost Estimates.

This capital plan is compared with the actual CAPEX spent during last 15 years. The data is obtained from annual CAPEX reports and is summarized in Table 6-4.

Table 6-4: Actual Capital Spend for HTGS ($1000`s)

2007	2008	2009	2010	2011	2012	2013	2014
6,990	3,767	5,264	6,228	5,555	21,723	18,801	16,869
2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	
10,740	19,500	15,687	20,699	8,825	12,600	31,703	

6.1.4 *Capital Cost Projections Beyond 2030*

The capital cost projections for 2031 to 2040 are based on the cost estimates for 2022 to 2030. The following assumptions apply to these projections:

a) The plant will run in either full generation or Emergency Standby mode.

b) The 2022 to 2030 capital cost estimates are used as the baseline for the projected costs.

c) Routine inspections and major overhauls of plant key equipment such as boilers, turbines, and pumps will be conducted as per existing plant practices. Years where the capital cost projection is higher than the preceding or following year is due to costs included for major turbine and boiler upgrades.

d) Refurbishment cost estimates for Fuel Tanks No.1 and 4 are included in the capital cost estimates for 2022 and 2023, respectively. Similarly, refurbishment of Fuel Tanks No. 2 and 3 is included in the capital cost estimate for 2031 and 2032, respectively.

e) An estimated minimum and maximum range for the capital cost for 2031 through 2040 is presented in Table 6-5. To establish this range, an adjustment of 20 to 50% is made to the capital cost estimates for 2022 through 2030. These adjustments are included to account for potential generator rotor rewinding, condenser retubing, major boiler tube repairs.

f) A refined capital plan is to be developed as part of the condition assessment program recommended in 2026 and 2027.

Table 6-5: Capital Cost for 2031 to 2040 ($1000's)

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Min	30,053	39,594	31,580	31,046	22,892	21,300	16,813	29,674	14,701	14,701	237,654
Max	37,566	49,493	39,476	38,808	28,616	26,625	21,017	37,092	18,377	18,377	297,068

6.2 Operating Costs

The operating cost to support operation of steam generating assets from 2022 to 2030 was developed. The O&M Plan shown in Table 6-6 contains the forecasted full year O&M cost for 2022 through 2030 for all scenarios. To estimate the forecasted O&M costs for 2023 onwards, the 2022 costs were adjusted to reflect the reduced operating times as a result of transitioning to backup generation mode. Staffing and associated costs were reduced because of the decreased staff required at the facility in backup generation mode.

Table 6-6: O&M Plan ($1000's)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Salaries	9,459	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432
Other Salaries	514	295	295	295	295	295	295	295	295
Employee Future Benefits	795	457	457	457	457	457	457	457	457
Fringe Benefits	1,471	844	844	844	844	844	844	844	844
Overtime	1,237	300	300	300	300	300	300	300	300
Salaries and Benefits Total	13,476	7,328	7,328	7,328	7,328	7,328	7,328	7,328	7,328
Materials	2,903	1,887	1,887	1,887	1,887	1,887	1,887	1,887	1,887
Contract Labour	5,548	3,606	3,606	3,606	3,606	3,606	3,606	3,606	3,606
Tools	97	63	63	63	63	63	63	63	63
Chemicals	559	363	363	363	363	363	363	363	363
SEM (Supplies, Equipment, Materials) Total	9,107	5,920	5,920	5,920	5,920	5,920	5,920	5,920	5,920
Office Supplies & Expenses Total	59	59	59	59	59	59	59	59	59
Professional Services Total	420	168	168	168	168	168	168	168	168
Equipment Rentals Total	1,351	1,351	1,351	1,351	1,351	1,351	1,351	1,351	1,351
Travel Total	77	77	77	77	77	77	77	77	77

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Misc. Expenses Total	87	87	87	87	87	87	87	87	87
Building Rental and Maintenance Total	187	187	187	187	187	187	187	187	187
Transportation Total	24	24	24	24	24	24	24	24	24
Group Insurance	357	205	205	205	205	205	205	205	205
Total O&M Cost	25,147	15,408	15,408	15,408	15,408	15,408	15,408	15,408	15,408

The operating costs also include the auxiliary power consumption costs shown in Table 6-7.

Table 6-7: Auxiliary Power Consumption Costs ($1000'ss)

Scenario 1	Scenario 2	Scenario 3	Scenario 4
-	27	55	628

Refer to Appendix C for the detailed auxiliary power consumption and fuel cost estimate breakdown.

6.3 Fuel Costs

Fuel costs associated with fuel consumption for the deaerator, boiler, air preheater, test runs, and building heating were estimated and are shown in Table 6-8.

Table 6-8: Fuel Consumption Costs ($1000'ss)

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Fuel Consumption Cost for Deaerator, Boiler, & Air Preheater	-	-	1,881	3,761
Fuel Consumption Cost for Test Runs	16,544	16,544	16,544	16,544
Fuel Cost for building heating	6,632	6,632	6,632	6,632
Total	23,176	23,176	25,057	26,937

6.4 Capital, Operating, and Fuel Costs for Continued Operation

Estimates for the capital, operating, and fuel costs for the continued operation of HTGS were developed and are shown in Table 6-9. Capital costs are based on the capital plan discussed in Section 6.1.3 and the operating costs include O&M costs based on a count of 101 employees. Fuel costs were developed based on the historical load data provided by NLH for each unit and an estimated cumulative four months of operation per year as indicated by NLH. Escalation is not included in the aforementioned cost estimates.

The following assumptions apply to the fuel cost estimates:

- The total operating time per year is 4 months based on historical power generation requirements.
- Average power generated (MW) per unit based on the historical plant data from 1997 – 2022, which indicates a range of 77 – 94 MW per unit.
- Fuel cost is based on the last delivery to HTGS (104.22 CAD/barrel).

Table 6-9: Capital, Operating, and Fuel Costs for Continued Operation through 2030 ($1000's)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total by Category	Total
Capital	25,044	32,995	26,317	25,872	19,077	17,750	14,011	24,728	12,251	198,045	
Operating	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	226,325	1,325,387
Fuel	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	100,113	901,017	

7. End of Economically Feasible Life (EEFL)

In general, over the period of the recent decades, the utility industry has extended the operating life of steam power plants where baseload or significant load-cycling operation was required.

From an owner/investor perspective, the main drivers have included:

- Produced energy cost as a function of fuel cost, e.g., the cost of coal has been in the range of $2 - $3 per GJ as compared to pipeline natural gas at a range of $6 to $8 per GJ in the period from about 2001 to 2009, after which the price of natural gas fell to a range of $2 to $4 per GJ.
- Permitting delays for fossil fuel-based replacement generation widely experienced across North America. New bulk power transmission lines have also encountered permitting issues.
- The need to provide for recovery of the capital investments required to comply with emissions reduction programs; this provided justification for the extended use of existing facilities in production mode to allow for investment recovery.
- Locational strategic advantages, e.g., large oil-fired unis built in the early 1960's located in a major city in North America provided power and backup power capacity for periods over 60 years.

In general, HTGS is considered to have strategic advantages based on its location, existing assets, available useful remaining life. Extending the current environmental Certificate of

Approval to provide for extended operation does, however, require some additional considerations as noted in Section 1.5 and Section 5.2 to allow for

- Additions to the COA for a potential new auxiliary boiler.
- Continued use of Quarry Brook to supply the Units 1 and 2 auxiliary cooling water systems.
- Noise emissions considerations for more frequent start/stop operations associated with each of the Emergency Backup scenarios

In addition, there is a need to recognize the potential for more stringent stack emissions requirements such as further reduction in sulphur and NOx emissions as well as the carbon emissions program may impose additional costs in the form of a carbon tax or the acquisition of GHG credits.

7.1 Remaining Life Assessment

The principal components that limit the useful life of utility boilers and steam turbines are (a) damage to the high temperature heavy wall boiler headers and steam turbines, (b) significant damage to boiler drums, and (c) steam turbine rotor surface life expended.

Review of the boiler and turbine generator condition assessments conducted over the period 2017 to 2021, related inspection reports and other inspection reports have recorded heavy wall component issues on each of the boilers, no imminent end of life issues for the components operating in the creep range were indicated. Additionally, to determine the remaining life, the steam turbine rotor surface life expended was assessed based on the operating history for each unit. The assessment used the Hitachi calculation methodology with operating Very Hot/Hot/Warm/Cold starts using data records provided by NLH. It is noted that the Hitachi steam turbine for Unit 3 was a licenced design from GE who provided Units 1 and 2.

The remaining life assessment is then based on the difference between the cumulative life cycle expended to date and the total useful life cycle of the rotors as summarized in Table 7-1. It is noted that the Hitachi methodology assumes that units are base loaded at a load factor of approximately 90% over a twenty-year period. The loading history at HTGS is significantly lower over time and therefore the estimate of cumulative rotor life expended has been assessed based on operating data provided for HTGS. Prediction of future life expenditure has been assessed in these reports; however, it is noted that such predictions are based on the need for ongoing condition assessments to support the assumptions used.

While it is possible to extend the life of the high temperature boiler and turbine components as well as turbine rotors, industry experience has shown that economical justification for base load or load-cycling operating units has been based on relative fuel costs and locational advantages. For example, replacement costs of boiler heavy wall headers or drums is generally considered unjustifiable, given the additional capital costs of compliance with significant incremental emissions reduction requirements. However, the ongoing costs of inspections and condition assessments and related repairs for such components has supported their continued operation for periods over 60 years.

In the case of HTGS, the reported condition assessments and inspections of the boilers heavy wall components have not reported any indications that suggest limiting factors on their extended use to 2030 and beyond. An assessment of rotors surface life expended to date was also carried out. Table 7-1 indicates that the rotor useful life can extend beyond the next 10 years or more. It is noted that this assessment is qualitative and not quantitative.

Table 7-1: Estimated Rotor Life Used up to 2030

Unit 1	Unit 2	Unit 3
32%	34%	29%

7.2 Capital Program

The capital cost estimates for extending the utilization of the units to 2030 in an Emergency Standby role are presented in Section 6.1 of this report and amount to a cumulative CAPEX of $216 Million to 2030. For an emergency capability of 500 MW this ranges up to approximately $0.4 Million/MW.

It is noted that the total capital cost would be expended over the period to 2030.

In contrast, to provide an equivalent emergency power generation capacity, the current market estimated capital cost for an emergency standby plant, using simple cycle GT's fired with distillate oil, would be in the range of $2 Million (+/-)/MW amounting to a capital expenditure of about $980 Million to be expended over a time frame of approximately 2 years with associated carrying charges over time.

8. Starting Failure Forced Outage

For each unit, the outage data was reviewed and starting failure forced outage were identified. The list of starting failures is summarized below.

a) Unit 1 Starting Failure Forced Outage

Item	Year	Outage Description
1	1993	Main Steam Piping
2	1997	Boiler Blowdown System
3	1999	Generator
4	2002	Station Service Transformer
5	2006	Steam Turbine and Auxiliaries Instrumentation and Control
6	2006	Fuel Oil Boosting Systems
7	2006	Turbo-Supervisory

Item	Year	Outage Description
8	2007	Safety Valves
9	2007	Valve Gear
10	2007	Steam Generator
11	2009	Economizer
12	2010	Waterwalls
13	2010	Forced Draft Fans
14	2010	Turning Gear
15	2011	Steam Generating Tubes (between steam drum and mud drum) - Leakage
16	2011	Forced Draft Fan Motors
17	2011	Fuel Oil Boosting Systems
18	2011	Hydrogen Gas Cooling System
19	2012	Turning Gear
20	2013	Valve Gear
21	2015	Hydrogen Gas Cooling System
22	2016	Turbo-Supervisory
23	2018	Main Steam Piping
24	2021	Cold Reheat Piping

b) Unit 2 Starting Failure Forced Outage

Item	Year	Outage Description
1	1993	Boiler Blowdown System
2	1996	Turbine
3	1998	Valve Gear
4	2002	Forced Draft Fans
5	2004	Excitation Systems Equipment
6	2005	Waterwalls
7	2009	Economizer
8	2011	Steam Generating Tubes (between steam drum and mud drum) - Leakage
9	2012	Turbo-Supervisory
10	2013	Fuel Oil Heating Systems
11	2013	Air Extraction System Vacuum Pumps and Auxiliaries

Item	Year	Outage Description
12	2013	Air Heaters
13	2016	Governing System
14	2018	Circuit Breakers - Generator Voltage
15	2020	Governing System
16	2020	Fuel Oil Heating Systems
17	2020	Steam Generator

C) Unit 3 Starting Failure Forced Outage

Item	Year	Outage Description
1	1993	Igniters
2	1993	Computers
3	1997	Steam Generating Tubes (between steam drum and mud drum) - Leakage
4	2006	Computers
5	2007	Turbine
6	2008	Generator
7	2009	Waterwalls
8	2009	Gland Seal System - Steam
9	2010	Transmission Limitations
10	2014	Fuel Oil Heating Systems
11	2014	Excitation Systems Equipment
12	2014	Turbo-Supervisory
13	2017	Fuel Oil Boosting Systems
14	2018	Shaft Coupling Mechanism
15	2021	Steam Generator

For this analysis, data provided covered restart data for the period from 1993 to 2021; this data was reviewed to determine the starting failures forced outage. The results are summarized in the table below:

Table 8-1: Restart Data for The Period From 1993 to 2021

Unit	Total Number of starting Failures Since 1993
1	24

Unit	Total Number of starting Failures Since 1993
2	17
3	15

From the table above, the overall average starting failure is less than 1 per year. The tables show a pattern of higher restart failures prior to 2013 and an average of 1 restart failure per year after 2013. To ensure high starting reliability, a specific training with a focus on the standby scenarios and expectations for Plant Readiness to Serve mode required for an Emergency Standby role should be developed.

9. HTGS CO_2 Emissions

An estimate of potential carbon dioxide emissions was prepared for each operating scenario based on the following set of assumptions and input data.

It is noted that the test run program for each scenario is considered flexible and can be varied to suit specific conditions on an ongoing basis.

9.1 Inputs and Assumptions

- The Defined Timeframe for Emergency Standby Operating Mode commences 2023 and continues through 2030
- Units 1 and 2 will be operated intermittently as per defined recall scenarios; test runs for these units are tentatively scheduled for 24 hours per month per unit.
- Unit 3 generator will operate as a synchronous generator; however, Unit 3 is tentatively scheduled to be re-converted to generation mode once every 6 weeks for a 24-hour test run. The longer interval for Unit 3 is selected because the conversion and re-conversion from synchronous generator mode to generation mode will make it unavailable for a period of 5 to 7 days.
- The plant (all units) may be called on to operate at full output for nominal periods of (a) 3 weeks or (b) 6 weeks during the defined timeframe
- Fuel carbon 100% conversion is assumed; that is, there is no incomplete combustion
- Fuel quality used is as per NLH data
- All operation assumed at approx. 100% MCR
- Test runs for each scenario will have a duration of 24 hours
- All scenarios assume 11 test runs per year for Units 1 and 2 (allowing 1 month cumulatively per unit for inspections) and 9 test runs per year for Unit 3

9.2 Emissions

Table 9-1: CO_2 Emissions by Scenario

	Description	Units*	Scenario			
			1	2	3	4
A)	Annual Plant Heating	Mg/y	13,000	13,000	16,000	20,000
B)	All Units Standby Mode Test Runs	Mg/y	79,000	79,000	79,000	79,000
C)	3 weeks Continuous Operation	Mg	162,000	162,000	162,000	162,000
D)	6 weeks Continuous Operation	Mg	323,000	323,000	323,000	323,000

*Mg: Million grams

End of Technical Content

Appendix A
List of Documents Received from NLH

Documents for HTGS

Serial No.	Document Title
1	,Stage1drainage system(jessicamcgrath@nlh.nl.ca).pdf
2	01-Jan-1976_Plant Manual Vol 1 for Hydro Generating Station stage II - Unit No 3(jessicamcgrath@nlh.nl.ca).pdf
3	01-Jan-1976_Plant manual Vol 1A for Holyrood Generating Station Stage II Unit No3(jessicamcgrath@nlh.nl.ca).pdf
4	01-Jan-1980_Hitachi Steam Turbine(jessicamcgrath@nlh.nl.ca).pdf
5	092019 Tank 3 - Inspection Interval Extension Report.pdf
6	092019 Tank 4 - Inspection Interval Extension Report.pdf
7	1403-121-C001 SITE PLAN GENERAL ARRANGEMENT R9(jessicamcgrath@nlh.nl.ca).PDF
8	1403-147-M001 PLANT HEATING SYSTEM R8(jessicamcgrath@nlh.nl.ca).PDF
9	1403-150-M011 WTP CAUSTIC HEATER PIPING R0(jessicamcgrath@nlh.nl.ca).pdf
10	1403-211-M003 U3 SOOTBLOWERS SYSTEM R4(jessicamcgrath@nlh.nl.ca).pdf
11	1403-211-M004 U3 AIR & FLUE GAS SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
12	1403-223-M001 U3 WASH & RINSE WATER FOR AIRHEATERS(jessicamcgrath@nlh.nl.ca).PDF
13	1403-223-M001 U3 WASH & RINSE WATER FOR AIRHEATERS.pdf
14	1403-231-M001FUEL OIL DELIVERY SYSTEM R12(jessicamcgrath@nlh.nl.ca).pdf
15	1403-251-M001 U3 FO SYSTEM R11(jessicamcgrath@nlh.nl.ca).pdf
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19	1403-272-M001 WTP MIXED BEDS(jessicamcgrath@nlh.nl.ca).pdf
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22	1403-282-M001 U3 AUX STREAM SYSTEM(jessicamcgrath@nlh.nl.ca).pdf
23	1403-283-M001 U3 RFW SYSTEM(jessicamcgrath@nlh.nl.ca).PDF
24	1403-284-M001U3 BOILER VENTS & BLOWDOWN SYSTEMS(jessicamcgrath@nlh.nl.ca).PDF
25	1403-285-M001U3 N2 BLANKETING PIPING(jessicamcgrath@nlh.nl.ca).PDF
26	1403-286-M002 U3 BOILER CHEMICAL CLEAN(jessicamcgrath@nlh.nl.ca).pdf
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259	Procedure_ 0541-POP-112 Safe, Efficient Start-up of Unit #1 Bo(jessicamcgrath@nlh.nl.ca).pdf
260	Procedure_ 0548-POP-001 Placing Turbine on Turning Gear - Unit(jessicamcgrath@nlh.nl.ca).pdf
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262	Procedure_ 0554-POP-007 Prewarming Procedure for Units #1 & #2(jessicamcgrath@nlh.nl.ca).pdf
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265	Procedure_ 0581-POP-016 Start-up of Boiler Feed Pump on all Un(jessicamcgrath@nlh.nl.ca).pdf
266	Procedure_ 0598-POP-032 Start-up of Condensate Extraction Pump(jessicamcgrath@nlh.nl.ca).pdf
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268	Procedure_ 0614-POP-043 Firing Boiler with Light Oil Igniters(jessicamcgrath@nlh.nl.ca).pdf
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270	Procedure_ 0681-POP-109 Roll Off and Synchronize Units #1 & #2(jessicamcgrath@nlh.nl.ca).pdf
271	Procedure_ 0991-POP-155 Safe, Efficient Start-up of Unit #2 Bo(jessicamcgrath@nlh.nl.ca).pdf
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291	U2 West BF Pump - Service Report May 26, 2017(jessicamcgrath@nlh.nl.ca).pdf
292	U3 Excitation Transformer Condition Assessment.docx
293	U3 Outage Report 2019(jessicamcgrath@nlh.nl.ca).pdf
294	Unit 1 - SH Attemperator - 2010 Report.pdf
295	Unit 1 2020.pdf
296	UNIT 1 Boiler Repair 2020.pdf
297	Unit 1 Condenser Report - 2014.pdf
298	Unit 1 Cooling Water Pump East Appendix A(jessicamcgrath@nlh.nl.ca).pdf
299	Unit 1 Cooling Water Pump East Appendix A.pdf
300	UNIT 1 EVT 2020.pdf
301	UNIT 1 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
302	UNIT 1 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
303	UNIT 1 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
304	UNIT 1 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
305	UNIT 1 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
306	UNIT 1 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
307	UNIT 1 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
308	UNIT 1 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
309	UNIT 1 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
310	Unit 2 - SH Attemperator - 2005 Report.pdf
311	Unit 2 2020.pdf
312	UNIT 2 Boiler Repair 2020.pdf
313	Unit 2 Condenser Report - 2014.pdf
314	Unit 2 EVT 2020.pdf
315	Unit 2 Extraction Pump Appendix A(jessicamcgrath@nlh.nl.ca).pdf
316	UNIT 2 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
317	UNIT 2 NORTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
318	UNIT 2 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
319	UNIT 2 NORTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
320	UNIT 2 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
321	UNIT 2 NORTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
322	UNIT 2 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
323	UNIT 2 NORTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
324	Unit 2 Repair and Bench Tests.pdf
325	UNIT 2 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
326	UNIT 2 SOUTH INLET B P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
327	UNIT 2 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).bak
328	UNIT 2 SOUTH INLET T P (2003) - WEST LOOKING EAST(jessicamcgrath@nlh.nl.ca).dwg
329	UNIT 2 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
330	UNIT 2 SOUTH RETURN B P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
331	UNIT 2 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).bak
332	UNIT 2 SOUTH RETURN T P (2003) - EAST LOOKING WEST(jessicamcgrath@nlh.nl.ca).dwg
333	Unit 3 2020.pdf
334	Unit 3 Boiler FWP West Appendix A(jessicamcgrath@nlh.nl.ca).pdf
335	UNIT 3 Boiler Repair 2020.pdf
336	Unit 3 Condenser Report - 2014.pdf
337	UNIT 3 EVT 2020.pdf
338	UNIT 3 NORTH RETURN B P #2 (2003)(jessicamcgrath@nlh.nl.ca).dwg
339	UNIT 3 NORTH RETURN B P (2003)(jessicamcgrath@nlh.nl.ca).dwg

Serial No.	Document Title
340	UNIT 3 NORTH RETURN T P # 2 (2003)(jessicamcgrath@nlh.nl.ca).dwg
341	UNIT 3 NORTH RETURN T P (2003)(jessicamcgrath@nlh.nl.ca).dwg
342	UNIT 3 NORTH RETURN (2003)(jessicamcgrath@nlh.nl.ca).dwg
343	Unit 3 North.MPG
344	Unit 3 North2.MPG
345	UNIT 3 SOUTH RETURN B P #4 (2003)(jessicamcgrath@nlh.nl.ca).dwg
346	UNIT 3 SOUTH RETURN B P (2003)(jessicamcgrath@nlh.nl.ca).dwg
347	UNIT 3 SOUTH RETURN T P #3 (2003)(jessicamcgrath@nlh.nl.ca).dwg
348	UNIT 3 SOUTH RETURN T P (2003)(jessicamcgrath@nlh.nl.ca).dwg
349	UNIT 3 SOUTH RETURN (2003)(jessicamcgrath@nlh.nl.ca).dwg
350	Unit 3 South.MPG
351	unit1 valve inspection report 2006(jessicamcgrath@nlh.nl.ca).pdf
352	vac draft(jessicamcgrath@nlh.nl.ca).doc
353	Vac Pump - Final Report(jessicamcgrath@nlh.nl.ca).doc
354	Vac Pump - Final Report.doc
355	Vacuum Pump DCI Report(jessicamcgrath@nlh.nl.ca).pdf
356	Vacuum Pump DCI Report.pdf
357	VR.121807 (#3 - 2012).pdf
358	VR_CA10_000401400468_APF138641_20190213 (#3 - 2019).pdf
359	VR_CA10_000401400468_APF138641_20190218 (#3 - 2019).pdf
360	VR_CA10_000401400468_APF138641_20190218_1 (#3 - 2019).pdf
361	VR_CA10_000401400468_APF138641_20190218_1 (#3 -2019).pdf
362	VR_CA10_000401733853_APF138641_20191105 (#3 - 2019).pdf
363	VR_report_247027_APF138641_20180313 (#3 - 2018).pdf
364	VR_report_247027_APF138641_20180315 (#3 - 2018).pdf
365	VR_report_260858_APF138641_20181025 (#3 - 2018).pdf
366	VR_report_260858_APF138641_20181029 (#3 - 2018).pdf
367	VR153147 (#3 - 2013).pdf
368	Warehouse sprinkler report.pdf
369	238-10-6022-041 HR81.pdf
370	238-10-6022-046 MS1.pdf
371	238-10-6022-047 HR1A.pdf
372	238-10-6022-048 HR2B.pdf
373	238-10-6022-049 HR61.pdf
374	238-10-6022-050 HR71.pdf
375	238-10-6022-051 HR11.pdf
376	238-10-6022-052 MS1A.pdf
377	238-10-6022-053 MS10.pdf
378	238-10-6022-084 CR2.pdf
379	238-10-6022-085 CR4.pdf
380	238-10-6022-086 CR10.pdf
381	238-10-6022-087 CR13-1.pdf
382	238-10-6022-088 CR18.pdf
383	238-10-6022-089 CR20.pdf
384	238-10-6022-128 MS11.pdf
385	238-10-6022-153 MS16.pdf
386	238-10-6022-154 MS14.pdf
387	238-10-6022-158 HR15.pdf
388	238-10-6022-327 MS13.pdf
389	238-10-6022-329 HR14.pdf
390	1403-V-281-M-090 HR1.pdf
391	1403-V-281-M-091 HR4.pdf
392	1403-V-281-M-092 HR6-1.pdf
393	1403-V-281-M-093 MS1-1.pdf
394	1403-V-281-M-094 MS2-1.pdf
395	1403-V-281-M-095 MS3-1.pdf
396	1403-V-281-M-096 MS6-1.pdf
397	1403-V-281-M-097 MS7.pdf
398	1403-V-281-M-100 CR6.pdf
399	1403-V-281-M-101 CR3.pdf
400	1403-V-281-M-102 CR1-1.pdf
401	1403-V-281-M-103 CR2-1.pdf
402	1403-V-281-M-152 HR7.pdf
403	2019 - Unit 1 - HEP Hangers.xlsx
404	2019 - Unit 2 - HEP Hangers.xlsx
405	2019 - Unit 3 - HEP Hangers.xlsx
406	2020 - Unit 1 - HEP Hangers.xlsx
407	2020 - Unit 2 - HEP Hangers.xlsx
408	2020 - Unit 3 - HEP Hangers.xlsx
409	U1-U2 CR Hangers.pdf
410	U1-U2 HR Hangers.pdf
411	U1-U2 MS Hangers.pdf
412	U3 CR Hangers.pdf
413	U3 HR Hangers.pdf
414	U3 MS Hangers.pdf
415	238-10-6022-023 MS Steelwork Loading.pdf
416	238-10-6022-024 HR Steelwork Loading.pdf
417	238-10-6022-025 CR Steelwork Loading.pdf
418	238-10-6022-028 HP Feedwater Steelwork Loading.pdf
419	238-10-6022-040 MS6.pdf
420	2021 - HRD U2 Test Report - Rev1 - Final.pdf
421	~$Unit 1 2021 PIR Log.xlsx
422	PIR #001 Crossover Pipe Lifting Lug Repair 210608.docx
423	PIR #002 N1 Labyrinth Packing 210609.docx
424	PIR #0023 T1 Bearing & Thrust Bearing Damage.pdf

Serial No.	Document Title
425	PIR #003 Main Stop Valve Cover 210612.docx
426	PIR #004 LPGEN Coupling Studs 210612.docx
427	PIR #005 NonReturn Valve 102 210614.docx
428	PIR #006 Control Valve No. 4 210615.docx
429	PIR #007 GE L0 Bucket Damage 210615.docx
430	PIR #007 MT6WW GE LP Blade With Impacted Damage.pdf
431	PIR #007 REV1 GE L0 Bucket Damage 210710.docx
432	PIR #008 Control Valve No. 5 210616.docx
433	PIR #009 N3 Labyrinth Packing 210616.docx
434	PIR #009 N3 Labyrinth Packing Rev1 210616.docx
435	PIR #010 Control Valve No. 6 210617.docx
436	PIR #011 HPIP Horizonal Joint Cuts 210619.docx
437	PIR #012 IP Inner Casing Peening Lip Restoration 210619.docx
438	PIR #013 IP Rotor Buckets and Diaphragms 210621.docx
439	PIR #014 NonReturn Valve 101 & 104B 210621.docx
440	PIR #015 Reheat Stop Valve Covers 210621.docx
441	PIR #016 Control Valve #2 & 3 Stem Replacement 230621.docx
442	PIR #017 Control Valve #2 & 3Stem Bushing Replacement 230621.docx
443	PIR #017 REV1 Control Valve #1, 3 & 5 Stem Bushing Replacement 210706.docx
444	PIR #018 MSV and RSV Steam Dam (Vortex Breakers) Repair 230621.docx
445	PIR #019 Main Stop Valve Stem Replacement 260621.docx
446	PIR #020 NRV 103 Actuator Piston Assembly Replacement 010721.docx
447	PIR #021 - Excessive Centre Pin Clearance (Sideslip) and Packing Radial Clearance
448	PIR #021 Centre Pin Side slips and Radial Clearances 62821.xls
449	PIR #022 HPIP Horizonal Joint Stud of Different Size 210703.docx
450	PIR #022 REV1 HPIP Horizonal Joint Stud of Different Size 210710.docx
451	PIR #024 Abnormal packing condition and bearing loadings 210709.docx
452	PIR #025 Control Valve #2 & 6 Disk Replacement 210706.docx
453	PIR #026 AsFound T2 and T3 Bearing Conditions.docx
454	PIR #027 Turbine End LP L0 Bucket Has Linear Indication 210710.docx
455	PIR #027 MT5WW TE LP Blade Has Linear Indication.pdf
456	PIR #028 HPIP Casing Stud Hole Thread Repair 210712.docx
457	PIR #028 (REVISED) HPIP Casing Stud Hole Thread Repair 210818.docx
458	PIR #029 CV Crosshead Runout and Bushing Replacement 210716.docx
459	PIR #030 LP Last Stage Bucket Erosion Shield Requires Repair 210719.docx
460	PIR #030 MT7WWLP Rotor Erosion Shield.pdf
461	PIR #031 RHS Reheat Valve Steam Strainer Rivets 210721.docx
462	PIR #031 PT21WWRHS CRV Steam Strainer.pdf
463	PIR #032 Steam Packing Alignment and Repair 210722.docx
464	PIR #033 T1 Bearing Ring Has Deformed 210727.docx
465	PIR #033 T1 Bearing Strong Back Bore Dimenions.pdf
466	PIR #034 Bearing Oil Deflectors Have Excessive Clearances 210803.docx
467	PIR #034 D309301 Oil Deflectors As Found.pdf
468	PIR #035 Axial Crush Pins Have Excessive Clearances 210818.docx
469	Unit 1 2021 PIR Log.xlsx
470	039 South Bottom J Pattern Data.xlsx
471	039 South Bottom U Pattern Det Data.xlsx
472	039 South Top Middle Det Data.xlsx
473	039 South Top U Pattern Det Data.xlsx
474	238-10-6002- 033 North Condenser Det Data.xlsx
475	238-10-6002- 033 South Condenser Det Data.xlsx
476	238-10-6002-033 North Condenser (2021825) ET Update TEAM Industrial Services.PDF
477	238-10-6002-033 North Condenser (2021830) ET Report TEAM Industrial Services.pdf
478	238-10-6002-033 South Condenser (2021825) ET Update TEAM Industrial Services.PDF
479	238-10-6002-033 South Condenser (2021830) ET Report TEAM Industrial Services.pdf
480	238-10-6002-039 North Bottom Candy Cane.PDF
481	238-10-6002-039 North Bottom Candy Cane_Det Data.xlsx
482	238-10-6002-039 North Bottom U Pattern.PDF
483	238-10-6002-039 North Bottom U Pattern_Det Data.xlsx
484	238-10-6002-039 North Top Middle.PDF
485	238-10-6002-039 North Top Middle_Det Data.xlsx
486	238-10-6002-039 North Top U Pattern.PDF
487	238-10-6002-039 North Top U Pattern_Det Data.xlsx
488	238-10-6002-039 North (2021917) ECT Report Team Industrial Services.pdf
489	238-10-6002-039 South (2021922) ECT Report Team Industrial Services.pdf
490	2007 Capital Expenditures & Carryover Report.pdf
491	2008 Capital Expenditures & Carryover Report.pdf
492	2009 Capital Expenditures & Carryover Report.pdf
493	2010 Capital Expenditures & Carryover Report.pdf
494	2011 Capital Expenditures & Carryover Report.pdf
495	2012 Capital Expenditures & Carryover Report.pdf
496	2013 Capital Expenditures & Carryover Report.pdf
497	2014 Capital Expenditures & Carryover Report.pdf
498	2015 Capital Expenditures & Carryover Report.pdf
499	2016 Capital Expenditures & Carryover Report.pdf
500	2017 Capital Expenditures & Carryover Report REVISED - 2018-04-02.pdf
501	2017 Capital Expenditures & Carryover Report.pdf
502	2018 Capital Expenditures & Carryover Report.pdf
503	2019 Capital Expenditures & Carryover Report.pdf
504	2021 Thermal Capital Expenditures.pdf
505	2021 Unite #2 Condenser Inspection Report.pdf
506	H365408-0000-210-066-0001, Vol. 1 Rev.0 JN Comments.pdf
507	HOLYROOD GS BOILER CONTRACT_2021 Year End Meeting - Final.pptx
508	HOLYROOD Thermal Station Tap Root Investigation (CRH 2021) Feb 21.docx
509	NLH CapEx and Carryover Report 2020.pdf

Serial No.	Document Title
510	rpt_rgm_20141222)Holyrood TGS_Fuel_Oil_Specification_Review_and_Mercantile Analysis_Final.pdf
511	Transactional Detail - Select Dept - with WO Desc - 10 year.xlsx
512	U1 Turbine Vibration Report - Final.pdf
513	U3 Boiler Tube Failure TapRooT Report Rev5 Stamped.pdf
514	Unit 1 MW Output 1997-Present.xlsx
515	Unit 2 MW Output 1997-Present.xlsx
516	Unit 3 MW Output 1997-Present.xlsx
517	Vol III, Att 12 - Bay d'Espoir Hydro Generating Unit 8 Summary Report.pdf
518	Vol III, Att 14 - Gas Turbine Alternatives Report.pdf
519	Volume III, Rev.1 - Long-Term Resource Plan.pdf

Appendix B
Plant Start Up Scenarios (Gantt Chart)

HATCH

newfoundland labrador hydro
a nalcor energy company

CLIENT - PROJECT: Holyrood Life Extension
PROJECT No.: H365408 **REV:** A
AREA: ALL AREAS **DATE:** 29-Jul-21
Title: Plant Start Up Time (Scenario-1, 30 Hours)

ACTION REGISTER - OUTSTANDING ITEMS

Item	NLH Procedure	Equipment/System	Description	Time in Hrs	Remarks	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24	H25	H26	H27	H28	H29	H30
1	POI-57	Pre-Start Checks	Pre- Start Checks to be completed.	2																															
2	POP-015	Cooling water System	Cooling water Priming, Flush and Refill & prime U#1&2 condensers	2	2-4 hours																														
3	POP-139	GSCW In Service	General Service Cooling Water to be placed in Service.	0.5																															
4	POP-140	TG Cooling	Turbine and Generator Cooling Water to be placed in Service	0.5																															
5	POP-018	Prepare TG for start-up		-																															
6	POP-002.		Turbine Generator to be placed on Turning Gear	8																															
7	POP-135		Establish Generator Hydrogen Sealing system	1																															
8	POP-113		Purge Generator and purge with Hydrogen	12	Can be an opportunity to reduce time by using bulk storage vs bottle stroage?																														
9	POP-014	Lube Oil System	Start the Lube OIl Purifier and place the Purifier in service	0.5	Should precede activity #6;																														
10	POP-134	Aux. Boiler	Place the Aux. Boiler in Service	3	POP-134 is for aux steam using other units. POP for aux. boiler start-up needs to be developed.																														
11	POP-141	Boiler	Fill Boiler using Reserve Feedwater system	4	After 85°C in DTR, do not use Reserve Feedwater pump to put water in the Boiler. Use DTR instead.																														
12		Water Treatment System	Raw Water System (For Water Treatment Plant) In Service	0.5																															
13			Water Treatment Plant In service	2																															
14	POI-013	Low Pressure Feedwater System		-																															
15	POP-032/ POI-003.		Start Extraction Pump and fill Dearerator to approximately 65%	1																															
16			Deaerator Aux. Steam in Service	0.2																															
17			Use Steam Coils on Deaerator to heat Storage Tank Water to approximately 85°C. After this is achieved, do not use Reserve Feedwater pump to put water in the	0.8																															
18		Boiler	Boiler Water Side and Gas Side preparation for firing.	4	Includes all below steps (Unhide Rows to see)																														
19			Verify Yarway and drum level transmitters are in service.	-																															
20	POP-093,		Complete POP-093, Safe, Efficient Start-up of Unit #3 Boiler with	-																															
21			FD Fan start and Purge Air	-																															
22			All furnace doors and observation ports check closed and secured.	-																															
23			Check gas outlet dampers open and air heater doors closed.	-																															
24			Check that all burners and ignitors are installed and secured.	-	Total 4 horus, One hour overlap with boiler warm up.																														
25			Start Ljungstrom Air Pre heaters and open the air supply cock. Test for air drive operation by opening the air heater drive 600V breakers.	-	The air solenoids should be open on loss of power. Close 600V breakers and start motors again, the air solenoids should close.																														
26			Open the atomizing steam supply from the auxiliary steam system and slowly open the atomizing steam control valve to warm up header	-	When the pressure reaches 1140 kpa the control valve on the DCS station may be placed in "AUTO".																														
27			Check FD fans for operation-oil levels, damper positions, linkages, cooling water, doors or any obstructions. FD fans may now be started and air flow	-	(i) Start (1) Seal Air Booster Fans; (2) Scanner fan.																														
28	POP-055. POP-093	Fuel Oil system (Light)	(a) Start up Light Oil Pumps (b) Pressure should be stabilize around 800 kpa. Start Boiler Purge Five (5) minutes. When purge is completed - Open light oil trip valve; and - Start required igniters (air registers must be closed to get igniters to light to prevent flame out). Continue with POP-093 Safe, Efficient Start-up of Unit	0.5	During initial firing, do not let furnace exit gas exceed 530°C. Fire with igniters until air heater back end temperature is >100°C.																														
29	POP-063 POP-016	Boiler FeedWater Pump	(a) Deaerator temp must be 85°C+. (b) Fill and vent BFP discharge line on through the High Pressure Heaters (c) Ensure SH spray water drain valve is closed. 8th Floor RH spray water drain valve is closed, 5th floor, above #6 HP heater. Aux steam spray water drain valve is	4	Economizer recirc valve to be closed when water is being added to boiler drum and open when water is shut off.																														
30		Air Heaters	(a) At approximately 1200 kpa drum pressure the steam control valve to the air heaters can be opened. (b) At 1200 kpa all manhole doors and furnace doors should be snugged up.	1.5	Time taken to reach 1200 kpa pressure and then to close the manhole doors and furnace doors.																														
31	POP-049 POP-046 ED-061.	Main Burners	Place heavy oil set in service Fire Boiler using Heavy Oil Guns The Start up Firing sequence	0.5	Burner guns should be cleaned and installed. Advance/retract should have been previously tested as well as limit switch and valve operation. Someone must be standing by the burner before starting, to verify no leaks. As each burner is established-set up scanners.																														
32	POP-093	Boielr	Continue with POP-093, Safe, Efficient Start-up of Unit #3 Boiler with Acceptable Noise Levels , section E, F & G.Ensure Boiler Heating to right temp and pressure for steam induction to turbine	0.5	Time requried for Boiler Heating and High Energy Piping Heating.																														
33			Checks Before Steam Induction	1																															
34	POP-073	Turbine	Turbine MSV, CV and Chest Warming	4																															
35			Turbine Rolling including Hold Time	1.2	Up to 3600 RPMs																														
36			Generator Synchrnoization	0.5																															

HATCH

CLIENT - PROJECT: Holyrood Life Extension

PROJECT No.: H365408 REV: A

AREA: ALL AREAS DATE: 29-Jul-21

Title: Plant Start Up Time (Scenario-2, 12 Hours)

ACTION REGISTER - OUTSTANDING ITEMS

Item	NLH Procedure	Equipment/System	Description	Time in Hrs	Remarks	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
1	POI-57	Pre-Start Checks	Pre- Start Checks to be completed.	2																									
2	POP-015	Cooling water System	Cooling water Priming, Flush and Refill & prime U#1&2 condensers	2	Suggested to complete the pre-checks for CW system first and start it while other pre-checks are being carried out. Need to confirm if additonal staff would be required.																								
3	POP-139	GSCW In Service	General Service Cooling Water to be placed in Service.	0.5	Need to run in parallel with CW System. Need to check what modifications would be required (if any) and if additional staff will be required.																								
4	POP-140	TG Cooling	Turbine and Generator Cooling Water to be placed in Service	0.5																									
5	POP-018	Prepare TG for start-up		-																									
6	POP-002.		Turbine Generator to be placed on Turning Gear	2	Place Turbine Generator on turning gear every week for 2 hours to minimize this time. Staff requirements and Operating Cost needs to be included for Scenario-3.																								
7	POP-135		Establish Generator Hydrogen Sealing system	0	Considered in Service as Generator is being considered H2 filled.																								
8	POP-113		Purge Generator and purge with Hydrogen	1	Keep H2 filled. Check and top up H2 every week. Need to confirm if there is any safety issue. Cost to be included in OPEX.																								
9	POP-014	Lube Oil System	Start the Lube OIl Purifier and place the Purifier in service	0.5	Should precede activity #6;																								
10	POP-134	Aux. Boiler	Place the Aux. Boiler in Service	3	Aux. Boile is to be started after one hour of pre-checks. Additional staff may be required for this (Particularly in summer)																								
11	POP-141	Boiler	Fill Boiler using Reserve Feedwater system	4	Water filling in boiler needs to be started after first hour of checks. Additional Staff may be required.																								
12		Water Treatment System	Raw Water System (For Water Treatment Plant) In Service	0.5																									
13			Water Treatment Plant In service	2																									
14	POI-013	Low Pressure Feedwater System		-																									
15	POP-032/ POI-003.		Start Extraction Pump and fill Dearerator to approximately 65%	1																									
16			Deaerator Aux. Steam in Service	0.2																									
17			Use Steam Coils on Deaerator to heat Storage Tank Water to approximately 85°C. After this is achieved, do not use Reserve Feedwater pump to put water in the	0.8																									
18		Boiler	Boiler Water Side and Gas Side preparation for firing.	4	Includes all below steps. These checks needs to happen in parallel with general pre-start checks. Additional staff may be required.																								
19			Verify Yarway and drum level transmitters are in service.	-																									
20	POP-093,		Complete POP-093, Safe, Efficient Start-up of Unit #3 Boiler with	-																									
21			FD Fan start and Purge Air	-																									
22			All furnace doors and observation ports check closed and secured.	-																									
23			Check gas outlet dampers open and air heater doors closed.	-																									
24			Check that all burners and ignitors are installed and secured.	-	Total 4 horus, One hour overlap with boiler warm up.																								
25			Start Ljungstrom Air Pre heaters and open the air supply cock. Test for air drive operation by opening the air heater drive 600V breakers.	-	The air solenoids should be open on loss of power. Close 600V breakers and start motors again, the air solenoids should close.																								
26			Open the atomizing steam supply from the auxiliary steam system and slowly open the atomizing steam control valve to warm up header.	-	When the pressure reaches 1140 kpa the control valve on the DCS station may be placed in "AUTO".																								
27			Check FD fans for operation-oil levels, damper positions, linkages, cooling water, doors or any obstructions. FD fans may now be started and air flow increased to 35% to	-	(i) Start (1) Seal Air Booster Fans; (2) Scanner fan.																								
28	POP-055. POP-093	Fuel Oil system (Light)	(a) Start up Light Oil Pumps (b) Pressure should be stabilize around 800 kpa. Start Boiler Purge Five (5) minutes. When purge is completed - Open light oil trip valve; and - Start required igniters (air registers must be closed to get igniters to light to prevent flame out). Continue with POP-093 Safe, Efficient Start-up of Unit #3	0.5	During initial firing, do not let furnace exit gas exceed 530°C. Fire with igniters until air heater back end temperature is >100°C.																								
29	POP-063 POP-016	Boiler FeedWater Pump	(a) Deaerator temp must be 85°C+. (b) Fill and vent BFP discharge line on through the High Pressure Heaters (c) Ensure SH spray water drain valve is closed. 8th Floor RH spray water drain valve is closed, 5th floor, above #6 HP heater. Aux steam spray water drain valve is closed, 10th floor. (d) Start Boiler Feed Pump	4	Economizer recirc valve to be closed when water is being added to boiler drum and open when water is shut off.																								
30		Air Heaters	(a) At approximately 1200 kpa drum pressure the steam control valve to the air heaters can be opened. (b) At 1200 kpa all manhole doors and furnace doors should be snugged up.	1.5	Time taken to reach 1200 kpa pressure and then to close the manhole doors and furnace doors.																								
31	POP-049 POP-046 ED-061.	Main Burners	Place heavy oil set in service Fire Boiler using Heavy Oil Guns The Start up Firing sequence	0.5	Advance/retract should have been previously tested as well as limit switch and valve operation. Someone must be standing by the burner before starting, to verify no leaks. As each burner is established-set up scanners.																								

HATCH

newfoundland labrador hydro
a nalcor energy company

CLIENT - PROJECT: Holyrood Life Extension
PROJECT No.: H365408 **REV:** A
AREA: ALL AREAS **DATE:** 29-Jul-21
Title: **Plant Start Up Time (Scenario-2, 12 Hours)**

ACTION REGISTER - OUTSTANDING ITEMS

Item	NLH Procedure	Equipment/System	Description	Time in Hrs	Remarks	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
32	POP-093	Boielr	Continue with POP-093, Safe, Efficient Start-up of Unit #3 Boiler with Acceptable Noise Levels , section E, F & G. Ensure Boiler Heating to right temp and pressure for steam induction to turbine	0.5	Time requried for Boiler Heating and High Energy Piping Heating.																								
33			Checks Before Steam Induction	1																									
34	POP-073	Turbine	Turbine MSV, CV and Chest Warming	4																									
35			Turbine Rolling	0.5	Up to 3600 RPMs																								
36			Generator Synchrnoization	0.5																									

HATCH

newfoundland labrador hydro
a nalcor energy company

CLIENT - PROJECT: Holyrood Life Extension
PROJECT No.: H365408 **REV:** A
AREA: ALL AREAS **DATE:** 29-Jul-21
Title: Plant Start Up Time (Scenario-3, 8 Hours)

ACTION REGISTER - OUTSTANDING ITEMS

Item	NLH Procedure	Equipment/System	Description	Time in Hrs	Remarks	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
1	POI-57	Pre-Start Checks	Pre- Start Checks to be completed.	2																									
2	POP-015	Cooling water System	Cooling water Priming, Flush and Refill & prime U#1&2 condensers	2																									
3	POP-139	GSCW In Service	General Service Cooling Water to be placed in Service.	0.5	Modify the system if requried to start GSCW in parallel with main cooling water system.																								
4	POP-140	TG Cooling	Turbine and Generator Cooling Water to be placed in Service	0.5	Modify the system if requried to start TG Cooling in parallel with main cooling water system.																								
5	POP-018	Prepare TG for start-up		-																									
6	POP-002.		Turbine Generator to be placed on Turning Gear	1	Place Turbine Generator on turning gear every three days week for 1 hours to minimize this time.																								
7	POP-135		Establish Generator Hydrogen Sealing system	0	H2 Sealing System is in place																								
8	POP-113		Purge Generator and purge with Hydrogen	1	Keep H2 filled. Check and top up H2 every week.																								
9	POP-014	Lube Oil System	Start the Lube OIl Purifier and place the Purifier in service	0.5	Should precede activity #6;																								
10	POP-134	Aux. Boiler	Place the Aux. Boiler in Service	0	Aux. Boiler is considered in Service. Need to determine the OPEX for summer.																								
11	POP-141	Boiler	Fill Boiler using Reserve Feedwater system	0	Keep the boiler filled with N2 Blanket. Need to determine the OPEX and the additional staff requirements.																								
12		Water Treatment System	Raw Water System (For Water Treatment Plant) In Service	0	Considered in Service. Need to determine the OPEX and the additional staff requirements.																								
13			Water Treatment Plant In service	2																									
14	POI-013	Low Pressure Feedwater System		-																									
15	POP-032/ POI-003.		Start Extraction Pump and fill Dearerator to approximately 65%	0	Considered in Service. Need to determine the OPEX and the additional staff requirements.																								
16			Deaerator Aux. Steam in Service	0.2																									
17			Use Steam Coils on Deaerator to heat Storage Tank Water to approximately 85°C. After this is achieved, do not use Reserve Feedwater pump to put water in the	0.8																									
18		Boiler	Boiler Water Side and Gas Side preparation for firing.	2	Increase staff to complete these checks within two hours.																								
28	POP-055. POP-093	Fuel Oil system (Light)	(a) Start up Light Oil Pumps (b) Pressure should be stabilize around 800 kpa. Start Boiler Purge Five (5) minutes. When purge is completed - Open light oil trip valve; and - Start required igniters (air registers must be closed to get igniters to light to prevent flame out). Continue with POP-093 Safe, Efficient Start-up of Unit	0.5	During initial firing, do not let furnace exit gas exceed 530°C. Fire with igniters until air heater back end temperature is >100°C.																								
29	POP-063 POP-016	Boiler FeedWater Pump	(a) Deaerator temp must be 85°C+. (b) Fill and vent BFP discharge line on through the High Pressure Heaters (c) Ensure SH spray water drain valve is closed. 8th Floor RH spray water drain valve is closed, 5th floor, above #6 HP heater. Aux steam spray water drain valve is	0	All HP Heaters in Service. Modify the drainage to DTR/Condenser to avoid stalling of water in heaters. Need to determine the OPEX for running feedwater pump at minimum flow, modifications cost to heater drain system, and the additional staff requirements.																								
30		Air Heaters	(a) At approximately 1200 kpa drum pressure the steam control valve to the air heaters can be opened. (b) At 1200 kpa all manhole doors and furnace doors should be snugged up.	1.5	Time taken to reach 1200 kpa pressure and then to close the manhole doors and furnace doors.																								
31	POP-049 POP-046 ED-061.	Main Burners	Place heavy oil set in service Fire Boiler using Heavy Oil Guns The Start up Firing sequence	0.5	Advance/retract should have been previously tested as well as limit switch and valve operation. Someone must be standing by the burner before starting, to verify no leaks. As each burner is established-set up scanners.																								
32	POP-093	Boielr	Continue with POP-093, Safe, Efficient Start-up of Unit #3 Boiler with Acceptable Noise Levels , section E, F & G. Ensure Boiler Heating to right temp and pressure for steam induction to turbine	0.5	Time requried for Boiler Heating and High Energy Piping Heating.																								
33			Checks Before Steam Induction	1																									
34	POP-073	Turbine	Turbine MSV, CV and Chest Warming	4	Assuming aux steam can be used initially and then switched to main boiler when steam pressure is above 5 barg. Need to size the auxiliary boiler to account for steam requirements for Turbine warming in addition to building heating etc (For winter case). Need to determin the piping modifications with cost impact to supply aux. steam for turbine heating. Key Considerations are Steam Quality from Aux. boiler, DP of aux. steam header and reverse flow to aux. steam header during normal plant operation.																								
35			Turbine Rolling	0.5	Up to 3600 RPMs																								
36			Generator Synchrnoization	0.5																									

HATCH

CLIENT - PROJECT: Holyrood Life Extension

PROJECT No.: H365408 REV: A

AREA: ALL AREAS DATE: 29-Jul-21

newfoundland labrador hydro a nalcor energy company

Title: Plant Start Up Time (Scenario-4, 4 Hours)

ACTION REGISTER - OUTSTANDING ITEMS

Item	NLH Procedure	Equipment/System	Description	Time in Hrs	Remarks	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
1	POI-57	Pre-Start Checks	Pre- Start Checks to be completed.	1	Time for confirmation (not for Pre-Checks) before ramping up the boiler. As All Pre-checks should be done by each shift on regular basis.																								
2	POP-015	Cooling water System	Cooling water Priming, Flush and Refill & prime U#1&2 condensers	0	Considered in Service. Cost to be included in OPEX.																								
3	POP-139	GSCW In Service	General Service Cooling Water to be placed in Service.	0	Considered in Service. Cost to be included in OPEX.																								
4	POP-140	TG Cooling	Turbine and Generator Cooling Water to be placed in Service	0	Considered in Service. Cost to be included in OPEX.																								
5	POP-018	Prepare TG for start-up		-																									
6	POP-002.		Turbine Generator to be placed on Turning Gear	0	Place Turbine Generator on turning gear frequently (1-2 hours daily) to avoid any requirement.																								
7	POP-135		Establish Generator Hydrogen Sealing system	0	H2 Sealing System is in place																								
8	POP-113		Purge Generator and purge with Hydrogen	0	Check is part of the Pre-Check process																								
9	POP-014	Lube Oil System	Start the Lube Oil Purifier and place the Purifier in service	0	Already in Service. Cost to be included in OPEX.																								
10	POP-134	Aux. Boiler	Place the Aux. Boiler in Service	0	Aux. Boiler is considered in Service.																								
11	POP-141	Boiler	Fill Boiler using Reserve Feedwater system	0	Keep the boiler filled with N2 Blanket.																								
12		Water Treatment System	Raw Water System (For Water Treatment Plant) In Service	0	Considered in Service																								
13			Water Treatment Plant In service	0	Considered in Service																								
14	POI-013	Low Pressure Feedwater System		-																									
15	POP-032/ POI-003.		Start Extraction Pump and fill Dearerator to approximately 65%	0	Considered in Service																								
16			Deaerator Aux. Steam in Service	0	Considered in Service																								
17			Use Steam Coils on Deaerator to heat Storage Tank Water to approximately 85°C. After this is achieved, do not use Reserve Feedwater pump to put water in the Boiler.	0	Considered in Service																								
18		Boiler	Boiler Water Side and Gas Side preparation for firing.	0	Boiler already firing and in hot mode proucing enough steam at right steam conditions (at saturated condition of 200psig) for chest warming, pipes warming, facility heating, HFO heating etc.																								
28	POP-055. POP-093	Fuel Oil system (Light)	(a) Start up Light Oil Pumps (b) Pressure should be stabilize around 800 kpa. Start Boiler Purge Five (5) minutes. When purge is completed - Open light oil trip valve; and - Start required igniters (air registers must be closed to get igniters to light to prevent flame out). Continue with POP-093 Safe, Efficient Start-up of Unit #3 Boiler with Acceptable Noise Levels - section B & C.	0	Already in Service																								
29	POP-063 POP-016	Boiler FeedWater Pump	(a) Deaerator temp must be 85°C+. (b) Fill and vent BFP discharge line on through the High Pressure Heaters (c) Ensure SH spray water drain valve is closed. 8th Floor RH spray water drain valve is closed, 5th floor, above #6 HP heater. Aux steam spray water drain valve is closed, 10th floor. (d) Start Boiler Feed Pump	0	All HP Heaters in Service. Modify the drainage to DTR/Condenser to avoid stalling of water in heaters.																								
30		Air Heaters	(a) At approximately 1200 kpa drum pressure the steam control valve to the air heaters can be opened. (b) At 1200 kpa all manhole doors and furnace doors should be snugged up.	1.5	Time taken to reach 1200 kpa pressure and then to close the manhole doors and furnace doors.																								
31	POP-049 POP-046 ED-061.	Main Burners	Place heavy oil set in service Fire Boiler using Heavy Oil Guns The Start up Firing sequence	0.5	Advance/retract should have been previously tested as well as limit switch and valve operation. Someone must be standing by the burner before starting, to verify no leaks. As each burner is established-set up																								
32	POP-093	Boielr	Continue with POP-093, Safe, Efficient Start-up of Unit #3 Boiler with Acceptable Noise Levels , section E, F & G. Ensure Boiler Heating to right temp and pressure for steam induction to turbine	0.5	Time requried for Boiler Heating and High Energy Piping Heating.																								
33			Checks Before Steam Induction	1																									
34	POP-073	Turbine	Turbine MSV, CV and Chest Warming	0	Pre-Warming is being done on regular basis to keep metal temperature above 260F.																								
35			Turbine Rolling	0.5	Up to 3600 RPMs																								
36			Generator Synchrnoization	0.5																									
37			Initial Load Hold	0.5																									
			Total Time																										

Appendix C
Capital and Operating Costs

Holyrood Thermal Generating Station Condition Assessment Project

Title: Capital Modifications Cost

Modification Description	Scenario-1	Scenario-2	Scenario-3	Scenario-4	Remarks
Auxiliary Boiler Capital Cost	$2,000,000	$2,000,000	$2,000,000	$2,000,000	Assuming boiler stack is in good condition
Piping Modifications for Pre-Warming using Aux. Boiler			$600,000	$600,000	Considering Pneumatically Controlled actuators for Isolation of Main Steam Line
Economizer Recirculation on Unit-1 & 2		$100,000	$100,000	$100,000	
Boiler Furnace Cameras with Monitors in Control room	$50,000	$50,000	$50,000	$50,000	
Motor Operated Boiler Blowdown valves on all three units.	$200,000	$200,000	$200,000	$200,000	Including Control Modifications Cost
Motor Operated Lower Water Wall Header Drains on all three units.	$400,000	$400,000	$400,000	$400,000	Including Control Modifications Cost
Modifications to Fuel Oil Supply Lines	$100,000	$100,000			
Fuel Oil Storage Recirculation	$50,000	$50,000	$50,000	$50,000	
Damper in the Boiler Stack for all 3 units	$900,000	$900,000	$900,000	$900,000	
Capital Cost for Boiler Feedwater Pump and piping				$600,000	
Capital Cost for Boiler Drain Modifications				$300,000	
Dehumidified air circulation package				$800,000	
Modification Equipment Cost	$3,700,000	$3,800,000	$4,300,000	$6,000,000	
Installation Cost	$2,960,000	$3,040,000	$3,440,000	$4,800,000	80% of the equipment cost
Sub-Total	$6,660,000	$6,840,000	$7,740,000	$10,800,000	
Contingency	$1,998,000	$2,052,000	$2,322,000	$3,240,000	30% of Total Modification Cost
EPCM Cost	$1,998,000.0	$2,052,000.0	$2,322,000.0	$3,240,000	30% of Total Modification Cost
Grand Total	**$10,656,000**	**$10,944,000**	**$12,384,000**	**$17,280,000**	

Holyrood Thermal Generating Station Condition Assessement Project

Title: For Plant Heating (all scenarios)

Sr. No.	Description	Qty	Units	Remarks
1	**Energy Out from Boiler**			
	Total Steam Flow (Aux Boiler)	27000	lb/hr	25000lbs/hr for HVAC & Fuel Heating, 2000lbs/hr for Deaerator heating
	Pressure	200	psig	
	Temperature	388	F	
	Enthalpy	1199.8	btus/lb	
	Total Energy in Steam	32.3946	MMbtus/hr	
2	**Energy Into the Boiler**			
	Boielr Feedwater to the Boiler Inlet			
	Flow	28000	lb/hr	
	Pressure	250	psig	
	Temp	185	F	
	Enthalpy	154	btus/lb	
	Total Energy in Boiler	4.312	MMbtus/hr	
3	**Fuel Calculation**			
	Energy Input by Fuel	28.0826		
	Boiler Efficiency	85%		
	Energy Input by Fuel	33.03835294	mmbtu/hr	
	HHV of LFO	0.019604	Mmbtu/lb	
	Quantity of Fuel	1685.286316	lb/hr	
4	**Cost of Fuel for Building Heating**			
	Lb to Liters	1.87	lb/L	
	Liters per Hour	901.2226289	Litrs/hr	
	Cost of Diesel	1.4	$/Litres	
	Cost per hour	$1,261.71		
	Duration	5256	hrs	Considering 7 months for heating
	Cost of Fuel for Building Heating	**$6,631,557**		

Holyrood Thermal Generating Station Condition Assessement Project

Title: Additional Fuel/Auxiliary Power Consumption (Scenario-1)

The only cost associsated with Scenario -1 is the Test Run Cost.
Please refer to the test run fuel cost sheet for details.

Holyrood Thermal Generating Station Condition Assessement Project

Title: Additional Fuel/Auxiliary Power Consumption (Scenario-2)

Sr. No.	System/Equipment	Description	Qty	Unit	Remarks
1	Keeping Boiler under N2 Blanket	Power for compressor	7	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	56280	kWh	
2	Turning Gear Motor:	Power	20	kW	
		Duration	208	hrs	Once per week, for Four hours
		Consumption/year	**4160**	kWh	
3	H2 Sealing Pump	Power	7.5	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**60300**	kWh	
4	Lube Oil System Running	Power	315	kW	
		Duration/year	260	hrs	Once per week, for Five hours
		Consumption/year	**81900**	kWh	
5	Cooling Water Running	Power	291	kW	
		Duration	260	hrs	Once per week, for Five hours
		Consumption/year	**75660**	kWh	
6	Condenser Vacuum Pumps	Power	68	kW	
		Duration	52	hrs	Once per week, for One hour
		Consumption/year	**3536**	kWh	
7	Demineralized Water Pumps	Power	20	kW	
		Duration	52	hrs	Once per week, for One hour
		Consumption/year	**1040**	kWh	
8	Compressed Air System	Power	150	kW	
		Duration	104	hrs	Once per week, for Two hours
		Consumption/year	**15600**	kWh	
9	**Total Auxiliary Power Consumption**		**298476**	kWh	
10	Unit Cost		0.09	$/kWh	
11	**Total Cost for Aux. Power Consumption**		**26863**	**$**	

Total OPEX	**$26,863**

Holyrood Thermal Generating Station Condition Assessement Project

Title: Auxiliary Power Consumption (Scenario-3)

Sr. No.	System/Equipment	Description	Qty	Unit	Remarks
1	Keeping Boiler under N2 Blanket	Power for compressor	7	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	56280	kWh	
2	Turning Gear Motor:	Power	20	kW	
		Duration	416	hrs	Twice per week, for Four hours
		Consumption/year	**8320**	kWh	
3	H2 Sealing Pump	Power	7.5	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**60300**	kWh	
4	Lube Oil System Running	Power	315	kW	
		Duration/year	520	hrs	Twice per week, for Five hours
		Consumption/year	**163800**	kWh	
5	Cooling Water Running	Power	291	kW	
		Duration	520	hrs	Twice per week, for Five hours
		Consumption/year	**151320**	kWh	
6	Condenser Vacuum Pumps	Power	68	kW	
		Duration	104	hrs	Twice per week, for One hour
		Consumption/year	**7072**	kWh	
7	Demineralized Water Pumps	Power	20	kW	
		Duration	104	hrs	Twice per week, for One hour
		Consumption/year	**2080**	kWh	
8	Compressed Air System	Power	150	kW	
		Duration	208	hrs	Twice per week, for Two hours
		Consumption/year	**31200**	kWh	
9	Aux.boiler Power Consumption	Power	30	kW	For FWP and For FD Fan based on Hatch in-house simulation
		Duration	4320	hrs	
		Consumption/year	**129600**	kWh	
9	**Total Auxiliary Power Consumption**		**609972**	kWh	
10	Unit Cost		0.09	$/kWh	
11	**Total Cost for Aux. Power Consumption**		**54897**	**$**	

Title: Additional Fuel Consumption for Deaerator and Air Pre-Heater (Scenario-3)

Sr. No.	Description	Qty	Units	Remarks
1	**Energy Out from Boiler**			
	Total Steam Flow (Aux Boiler)	5000	lb/hr	Additional Steam for Dearator and Air Pre-heater (Excluding HVAC)
	Pressure	200	psig	
	Temperature	388	F	
	Enthalpy	1199.8	btus/lb	
	Total Energy in Steam	5.999	MMbtus/hr	
2	**Energy Into the Boiler**			
	Flow	5150	lb/hr	Considering 3% Blowdown
	Pressure	250	psig	
	Temp	185	F	
	Enthalpy	154	btus/lb	
	Total Energy in Boiler	0.7931	MMbtus/hr	
3	**Fuel Calculation**			
	Energy Input by Fuel	5.2059	mmbtu/hr	
	Boiler Efficiency	85%	%	
	Energy Input by Fuel	6.124588235	mmbtu/hr	
	HHV of LFO	0.019604	Mmbtu/lb	
	Quantity of Fuel	312.4152334	lb/hr	
4	**Cost of Fuel for Deaerator, Boiler, and Air Preheater**			
	Lb to Liters	1.87	lb/L	
	Liters per Hour	167.0669697	Litrs/hr	
	Cost of Diesel	1.4	$/Litres	
	Cost per hour	$233.89		
	Duration	8040	hrs	Excluding one month for Shutdown
5	**Cost of Fuel**	**$1,880,506**		

Total OPEX	**$1,935,403**

Holyrood Thermal Generating Station Condition Assessement Project

Title: Auxiliary Power Consumption (Scenario-4)

Sr. No.	System/Equipment	Description	Qty	Unit	Remarks
1	Keeping Boiler under N2 Blanket	Power for compressor	7	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	56280	kWh	
2	Turning Gear Motor:	Power	20	kW	
		Duration	832	hrs	Excluding one month for Shutdown
		Consumption/year	**16640**	kWh	
3	H2 Sealing Pump	Power	7.5	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**60300**	kWh	
4	Lube Oil System Running	Power	315	kW	
		Duration/year	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**2532600**	kWh	
5	Cooling Water Running	Power	291	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**2339640**	kWh	
6	Condenser Vacuum Pumps	Power	68	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**546720**	kWh	
7	Demineralized Water Pumps	Power	20	kW	
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**160800**	kWh	
8	Compressed Air System	Power	150	kW	
		Duration	416	hrs	Twice per week, for four hours
		Consumption/year	**62400**	kWh	
9	Aux.boiler Power Consumption	Power	150	kW	For FD Fan and for Boiler Feedwater Pump. Feedwater Pump will be large enough to support boiler circulation
		Duration	8040	hrs	Excluding one month for Shutdown
		Consumption/year	**1206000**	kWh	
9	**Total Auxiliary Power Consumption**		**6981380**	kWh	
10	Unit Cost		0.09	$/kWh	
11	**Total Cost for Aux. Power Consumption**		**628324**	**$**	

Title: Additional Fuel Consumption for Deaerator, Boiler, Air Pre-Heater and Turbine Pre-Warming(Scenario-4)

Sr. No.	Description	Qty	Units	Remarks
1	**Energy Out from Boiler**			
	Total Steam Flow (Aux Boiler)	10000	lb/hr	Additional Steam for Dearator and Air Pre-heater (Excluding HVAC)
	Pressure	200	psig	
	Temperature	388	F	
	Enthalpy	1199.8	btus/lb	
	Total Energy in Steam	11.998	MMbtus/hr	
2	**Energy Into the Boiler**			
	Flow	10300	lb/hr	Considering 3% Blowdown
	Pressure	250	psig	
	Temp	185	F	
	Enthalpy	154	btus/lb	
	Total Energy in Boiler	1.5862	MMbtus/hr	
3	**Fuel Calculation**			
	Energy Input by Fuel	10.4118	mmbtu/hr	
	Boiler Efficiency	85%	%	
	Energy Input by Fuel	12.24917647	mmbtu/hr	
	HHV of LFO	0.019604	Mmbtu/lb	
	Quantity of Fuel	624.8304668	lb/hr	
4	**Cost of Fuel for Deaerator, Boiler, Air Preheater, and Turbine Prewarming**			
	Lb to Liters	1.87	lb/L	
	Liters per Hour	334.1339394	Litrs/hr	
	Cost of Diesel	1.4	$/Litres	
	Cost per hour	$467.79		
	Duration	8040	hrs	Excluding one month for Shutdown
5	**Cost of Fuel**	**$3,761,012**		

Total OPEX	**$4,389,336**

Fuel Cost for Test Runs (1000 CAD)					
Description	**Units**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
HFO Consumed for Test Runs	kg/y	24,314,939	24,314,939	24,314,939	24,314,939
	barrel / y	158,746	158,746	158,746	158,746
Fuel Cost for Test Runs	CAD / y	16,544	16,544	16,544	16,544

Reference Data		
NLH HFO Cost	104	CAD / barrel
HFO Density from Fuel Data Sheet	8.04	lb/gal
	42	gal / barrel
	337.68	lb / barrel
	153.17	kg / barrel

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total auxiliary power consumption (kWh)	0	298,000	610,000	6,981,000
Unit Cost (CAD/kW)	0	0.09	0.09	0.09
Total aux. power consumption cost (1000 CAD)	0	27	55	628
Fuel Consumption Cost for Deaerator, Boiler, & Air Preheater(1000 CAD)	0	0	1,881	3,761
Fuel Consumption Cost for Test Runs (1000 CAD)	16,544	16,544	16,544	16,544
Fuel Cost for building heating (1000 CAD)	6,632	6,632	6,632	6,632

Holyrood Thermal Generating Station O&M Plan (1000 CAD)									
	Forecast Full Year								
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Salaries	9,459	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432
Other Salaries	514	295	295	295	295	295	295	295	295
Employee Future Benefits	795	457	457	457	457	457	457	457	457
Fringe Benefits	1,471	844	844	844	844	844	844	844	844
Overtime	1,237	300	300	300	300	300	300	300	300
Salaries and Benefits Total	**13,476**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**
Materials	2,903	1,887	1,887	1,887	1,887	1,887	1,887	1,887	1,887
Contract Labour	5,548	3,606	3,606	3,606	3,606	3,606	3,606	3,606	3,606
Tools	97	63	63	63	63	63	63	63	63
Chemicals	559	363	363	363	363	363	363	363	363
SEM (Supplies, Equipment, Materials) Total	**9,107**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**
Office Supplies & Expenses Total	**59**	**59**	**59**	**59**	**59**	**59**	**59**	**59**	**59**
Professional Services Total	**420**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**
Equipment Rentals Total	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**
Travel Total	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**
Misc. Expenses Total	**87**	**87**	**87**	**87**	**87**	**87**	**87**	**87**	**87**
Building Rental and Maintenance Total	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**
Transportation Total	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**
Group Insurance	**357**	**205**	**205**	**205**	**205**	**205**	**205**	**205**	**205**
Total O&M Cost	**25,147**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**

Appendix D
Capital Plan

HTGS Capital Plan (2022-2030) - Operation as a Back Up Unit until Dec 31, 2030 (1000 CAD): Unit 1										
Project	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total 2022-2030 Projects
Boiler Condition Assessment and Misc. Upgrades	1,000	1,000	1,000	1,000	1,167	1,167	1,167	1,333	1,333	**10,167**
Provisonal allowance for unforeseen failures and latent issues	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**18,000**
Routine Turbine and Valve Inspections	333	333	333	333	333	333	333	333	333	**3,000**
Allowance for LSB replacement: Unit 1 (completed at next majorhaul)			2,000							**2,000**
Overhaul Unit 3 Turbine and Valves								8,027		**8,027**
Inspect and Refurbish Stacks Unit-1			300							**300**
Upgrade Contriol System Unit 1			800							**800**
Dearators Major Inspections and Upgrades (Unit-1)						300				**300**
Major Overhaul Unit 1 Boiler Feed Pump East							700			**700**
Major Overhaul Unit 1 Boiler Feed Pump West								700		**700**
Total Capital Upgrades Cost (Unplanned)	**3,333**	**3,333**	**3,333**	**3,333**	**3,500**	**3,500**	**3,500**	**3,667**	**3,667**	**31,167**
Total Capital Upgrades Cost (Planned)			**3,100**			**300**	**700**	**8,727**		**12,827**
Total Capital Upgrades Cost (Unit-1)	**3,333**	**3,333**	**6,433**	**3,333**	**3,500**	**3,800**	**4,200**	**12,394**	**3,667**	**43,994**

HTGS Capital Plan (2022-2030) - Operation as a Back Up Unit until Dec 31, 2030 (1000 CAD): Unit 2										
Project	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total 2022-2030 Projects**
Boiler Condition Assessment and Misc. Upgrades	1,000	1,000	1,000	1,000	1,167	1,167	1,167	1,333	1,333	**10,167**
Provisonal allowance for unforeseen failures and latent issues	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**18,000**
Routine Turbine and Valve Inspections	333	333	333	333	333	333	333	333	333	**3,000**
Upgrade Contriol System Unit-2		800								**800**
Overhaul Unit 2 Turbine and Valves		8,027								**8,027**
Allowance for LSB replacement: Unit 2 (completed at next majorhaul)		2,000								**2,000**
Inspect and Refurbish Stack Unit-2			300							**300**
Major Overhaul Unit 2 Boiler Feed Pump East and West			1,400							**1,400**
Condenser Inspections and Repair					500					**500**
Dearators Major Inspections and Upgrades (Unit-2)					300					**300**
Total Capital Upgrades Cost (Planned)		**10,827**	**1,700**		**800**					**13,327**
Total Capital Upgrades Cost (Unplanned)	**3,333**	**3,333**	**3,333**	**3,333**	**3,500**	**3,500**	**3,500**	**3,667**	**3,667**	**31,167**
Total Capital Upgrades Cost (Unit-2)	**3,333**	**14,161**	**5,033**	**3,333**	**4,300**	**3,500**	**3,500**	**3,667**	**3,667**	**44,494**

HTGS Capital Plan (2022-2030) - Operation as a Back Up Unit until Dec 31, 2030 (1000 CAD): Unit 3										
Project	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total 2022-2030 Projects**
Units 3 Generator Upgrades - Slip Rings, Brush Gear, Bearings, Pony Motor and Starter, SSS Clutch, etc..	301	535								**836**
Boiler Condition Assessment and Misc. Upgrades	1,000	1,000	1,000	1,000	1,167	1,167	1,167	1,333	1,333	**10,167**
Provisonal allowance for unforeseen failures and latent issues	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**18,000**
Routine Turbine and Valve Inspections	333	333	333	333	333	333	333	333	333	**3,000**
Overhaul Unit 3 Turbine Valves	3,400									**3,400**
Upgrade Contriol System Uni-3	800									**800**
Install New Lube Oil / Seal Oil Systems Unit 3 (Inc. Assessment of LO Program)		255	766							**1,021**
Inspect and Refurbish Stacks Uni-3			300							**300**
Upgrade Vibration Monitoring Equipment Unit 3 Generator				337						**337**
Major Overhaul Unit 3 Boiler Feed Pump West				700						**700**
Replace parts of U3 - 129 VDC Battery Chargers, Batteries, Panels, Breakers					2,177					**2,177**
Overhaul Unit 3 Turbine and Valves				8,027						**8,027**
Major Overhaul Unit 3 Boiler Feed Pump East					700					**700**
Major Overhaul Unit 3 Boiler Feed Pump West				700						**700**
Synchronous Condenser Building Upgrades					100		900			**1,000**
Provisional Allowance for LSB replacement: Unit 3 (completed at next majorhaul)					2,000					**2,000**
Provisional Allowance for Unit 3 Steam Chest Overhaul (completed at next majorhaul)					300					**300**
Synchronous Condenser Cooling Water systems H2, Generator Lube Oil, Seal Oil, Upgrades Unit 3						1,500				**1,500**
Overhaul Unit 3 Generator						1,600				**1,600**
Dearators Major Inspections and Upgrades (Unit-3)							300			**300**
Condenser Inspections and Repair							500			**500**
Synchronous Condenser Unit 3 Exciter/Transformer Upgrades								4,000		**4,000**

Total Capital Upgrades Cost (Planned)	4,501	790	1,066	9,764	2,977	3,100	1,700	4,000		27,898
Total Capital Upgrades Cost (Unplanned)	3,333	3,333	3,333	3,333	5,800	3,500	3,500	3,667	3,667	33,467
Total Capital Upgrades Cost (Unit-3)	7,835	4,123	4,399	13,097	8,777	6,600	5,200	7,667	3,667	61,364

HTGS Capital Plan (2022-2030) - Operation as a Back Up Unit until Dec 31, 2030 (1000 CAD): Common Facilities										
Project	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total 2022-2030 Projects
Clean and Inspect Fuel Oil Storage Tank 4 (Supplemental if not extended)	6,500									**6,500**
Perform Level 2 Condition Assessment of Air Receivers	306									**306**
Fire System Upgrades	221	1,109				350				**1,680**
Upgrade 600V VFDs in Wastewater Treatment Plant	250									**250**
Enhancement Safety level around Emergency Back Generatros as per Hatch recommendations	150									**150**
Overhaul Major Pumps	700									**700**
Upgrade Waste Water Equilization System	548									**548**
Upgrade DCS Controllers / Hardware	368									**368**
Provisional Allowance for Sump Pump upgrades		500	500							**1,000**
Refurbish Cooling Water Pumphouse (stop logs in yr.1, new removable screens, 60 hp pump/motor, Insp. CW Pipes)		670	400							**1,070**
API Inspections for Fuel tanks	500	1,000	1,000	500						**3,000**
Refurbish the fuel tank No.1 and API Inspection		6,500								**6,500**
Refurbish Biogreen Waste System		100	100							**200**
Replace Stage II Electrical Distribution Equipment		299	4,967							**5,266**
Replace existing Stage 1 4160 V AC Breakers as Required		200	700							**900**
Upgrade Ambient Monitoring Stations			150	150						**300**
Install Energy Efficient High Bay Lighting System (Cost Benefit Analysis Required))			16	609						**625**
Install Plant Heating System			519	2,500						**3,019**
Water Treatment Plant Upgrades (if required for GSCW, Domestic)			1,000							**1,000**
Light Oil System Inspection and Upgrade			100	900						**1,000**
Out Building Upgrades Including Main Warehouse and Training Centre				450						**450**
Upgrade Cranes and Hoists					500					**500**

Waste Water Basin and Underground Drainage Upgrades						1,000				**1,000**
Upgrade On-Site & Access Roads						500				**500**
Revisit Condition Assessment - Level 2					1,000	1,000				**2,000**
Upgrade Powerhouse and Site Buildings Doors, Siding and Roofing							111			**111**
Upgrade Plant Heating System (5 Years)									250	**250**
Unforeseen failures	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	**9,000**
Total Capital Upgrades Cost (Planned)	**9,543**	**10,378**	**9,452**	**5,109**	**1,500**	**2,850**	**111**			**39,193**
Total Capital Upgrades Cost (Unplanned)	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**9,000**
Total Capital Upgrades Cost	**10,543**	**11,378**	**10,452**	**6,109**	**2,500**	**3,850**	**1,111**	**1,000**	**1,250**	**48,193**

Fuel Cost for Test Runs (1000 CAD)					
Description	**Units**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
HFO Consumed for Test Runs	kg/y	24,314,939	24,314,939	24,314,939	24,314,939
	barrel / y	158,746	158,746	158,746	158,746
Fuel Cost for Test Runs	CAD / y	16,544	16,544	16,544	16,544

Reference Data		
NLH HFO Cost	104	CAD / barrel
HFO Density from Fuel Data Sheet	8.04	lb/gal
	42	gal / barrel
	337.68	lb / barrel
	153.17	kg / barrel

Description	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total auxiliary power consumption (kWh)	0	298,000	610,000	6,981,000
Unit Cost (CAD/kW)	0	0.09	0.09	0.09
Total aux. power consumption cost (1000 CAD)	0	27	55	628
Fuel Consumption Cost for Deaerator, Boiler, & Air Preheater(1000 CAD)	0	0	1,881	3,761
Fuel Consumption Cost for Test Runs (1000 CAD)	16,544	16,544	16,544	16,544
Fuel Cost for building heating (1000 CAD)	6,632	6,632	6,632	6,632

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Holyrood Thermal Generating Station O&M Plan (1000 CAD)									
	Forecast Full Year								
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Salaries	9,459	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432
Other Salaries	514	295	295	295	295	295	295	295	295
Employee Future Benefits	795	457	457	457	457	457	457	457	457
Fringe Benefits	1,471	844	844	844	844	844	844	844	844
Overtime	1,237	300	300	300	300	300	300	300	300
Salaries and Benefits Total	**13,476**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**	**7,328**
Materials	2,903	1,887	1,887	1,887	1,887	1,887	1,887	1,887	1,887
Contract Labour	5,548	3,606	3,606	3,606	3,606	3,606	3,606	3,606	3,606
Tools	97	63	63	63	63	63	63	63	63
Chemicals	559	363	363	363	363	363	363	363	363
SEM (Supplies, Equipment, Materials) Total	**9,107**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**	**5,920**
Office Supplies & Expenses Total	**59**	**59**	**59**	**59**	**59**	**59**	**59**	**59**	**59**
Professional Services Total	**420**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**
Equipment Rentals Total	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**	**1,351**
Travel Total	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**
Misc. Expenses Total	**87**	**87**	**87**	**87**	**87**	**87**	**87**	**87**	**87**
Building Rental and Maintenance Total	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**
Transportation Total	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**
Group Insurance	**357**	**205**	**205**	**205**	**205**	**205**	**205**	**205**	**205**
Total O&M Cost	**25,147**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**	**15,408**

Appendix E
Unit 3 Synchronous Condenser Conversion

E.1 Unit 3 Synchronous Condenser Conversion

It has been reported that reassembling the turbine to generator coupling takes 24 to 30 hours to accomplish. As the spacing between the LP turbine and generator coupling is most likely insufficient to allow use of a SSS style (Synchronous-Self-Shifting) and which would require extensive shaft modifications, we will focus on opportunities to reduce assembly time via different style coupling bolts and opportunities to optimize generator purge and refill times.

E.1.1 Coupling Bolts

Assuming that standard coupling bolts which are typically torqued to a set elongation are being used, updated designs using hydraulic or other tightening means can reduce assembly/disassembly times and increase reliability. Two suppliers are highlighted here, but others exist as well.

E.1.1.1 Pilgrim International

Pilgrim's RadialFit Bolts (https://www.pilgrim-international.co.uk/product-range/bolts/rfb/) are re-usable, reduce maintenance downtimes, and are a direct retrofit replacement for conventional bolting systems. They are installed and removed faster than conventional bolts, less time is required to split and re-build couplings, reducing assembly/disassembly time. Hydraulic pressure generates the proper bolt stretch, the coupling nut is then seated against the coupling face thus maintaining stretch once hydraulic press is removed. Additional benefits are obtained by the self-centering nature of the taped sleeve and body.

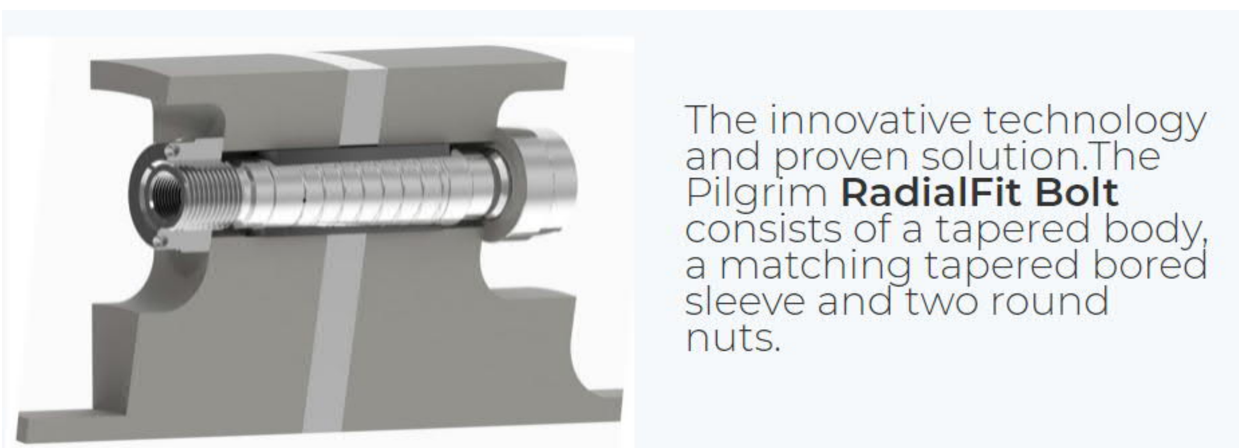

Figure 9-1: Sketch from the Pilgrim Website Showing Their Style Hydraulic Bolt

Advantages:

- Faster and easier to install and remove than conventional bolts.
- Reduce/eliminate delays caused by bolts getting stuck in-situ.
- Coupling slippage eliminated.
- Reusable, lower life cycle costs.
- Direct retrofit for conventional bolts.
- Reduce/eliminate the need for expensive re-machining.
- Concentricity easily re-established.
- OEM approved, safe and reliable.

Disadvantages:

- Higher initial cost of bolting hardware.
- Special tools and training required to use.
- Need to ensure spacing exists between coupling and bearing housing for special tooling.

E.1.2 Nord-Lock Group

Nord-Lock is another company employing a hydraulically stretched bolt as well as a unique mechanical stretch design ideal for couplings using bolt shear to transmit torque. First highlighted is the Superbolt HyFit (https://www.nord-lock.com/en-us/superbolt/products/hyfit/) which uses hydraulic pressure to create the bolt stretch much like the Pilgrim bolt. There is also the ability to use a split centering ring to accurately align coupling holes.

Figure 9-2: Photo from Nord-Lock Website Showing Hyfit Bolts and Stretching Tools

Advantages:

- Uses two separate dimensionally different heads and just one operating pressure, eliminating the risk of using the wrong pressure during operation.
- Uses heads that have a unique design so there is no way to use them incorrectly during assembly.
- New HyFit nut design can be retrofitted to any existing coupling bolt.
- Elimination of internally connected thread puller.
- Design does not use oil injection removal methods preventing a known mode of failure.
- Hole preparation costs are reduced as less demanding hole tolerances are required.
- Radial fit which allows for better coupling alignment and concentricity.
- Fully reusable, only requires sleeve replacement for rotor changes.
- Split sleeves allow greater expansion to accommodate hole tolerances more easily.

Disadvantages:

- Higher initial cost of bolting hardware.

- Special tools and training required to use.
- Need to ensure spacing exists between coupling and bearing housing for special tooling.

There is also a version called EZFit (https://www.nord-lock.com/en-us/superbolt/products/ezfit/) that utilizes a series of small cap screw to develop the required bolt stretch. This style is can also be used for coupling designs where the bolt body carries the torque load versus flange face friction. The key advantage here is that ordinary hand tools can be used to torque the small cap screws as well as specialized heads that actuate all the screws at the same time.

Figure 9-3: Photo from The Nord-Lock Website Showing the Mechanically Stretched Bolt

This design shares many of the same advantages and disadvantages except no hydraulic tooling is needed. A special multi-spindle head for the cap screws will increase the productivity of assembly and disassembly as all the cap screws are adjusted at once.

E.1.3 Generator Purging

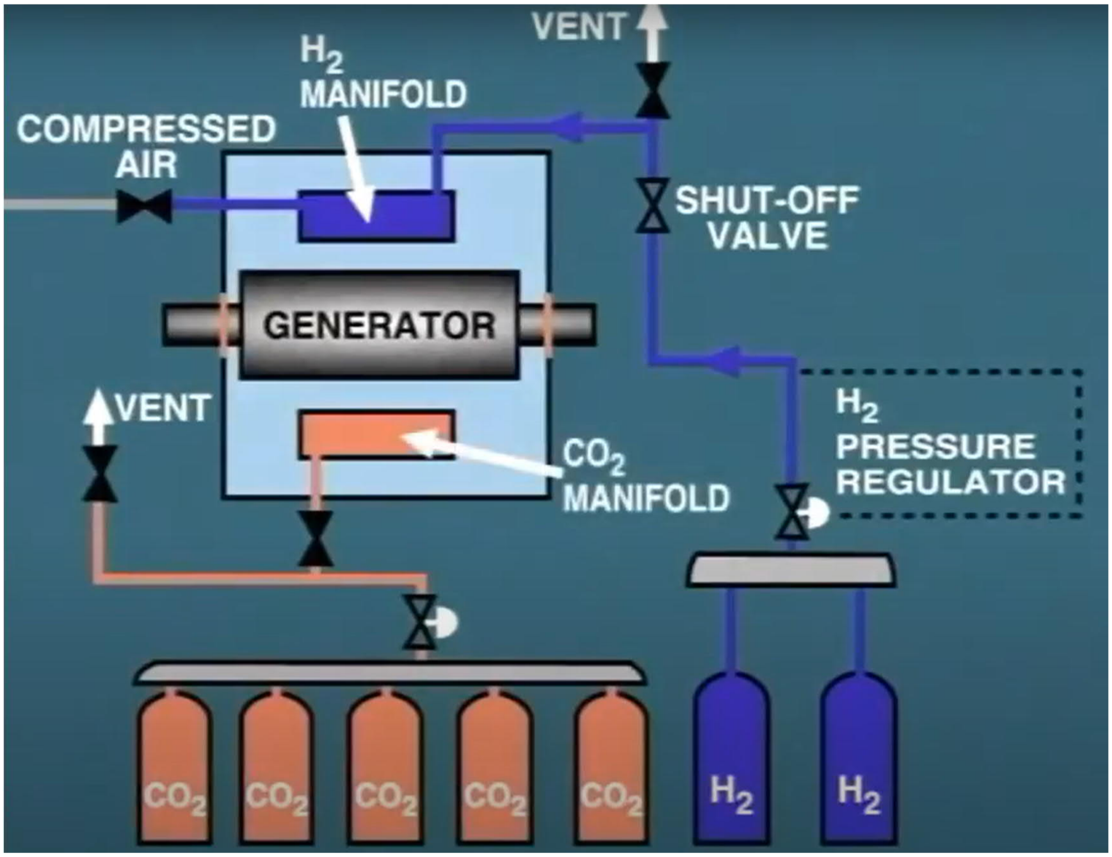

Figure 9-4: A Typical H_2 Purge and Fill System

Generator purging and filling is required when internal access to the generator is needed for maintenance. The H_2 is purged from the generator with CO_2 followed by purge with air. This is a lengthy process and provides an opportunity if the purge time can be reduced.

Purging is required when the unit is off turning gear as the leak rate through the seals can increase significantly and pose a danger to technicians working in close proximity to the generator bearing. H_2 is flammable at very low concentrations, 4% at room temperature, and has a very low ignition energy – 10% that of an air-gasoline mixture.

One possibility to shorten purging time is to not purge CO_2 with air. If the pressure boundary of the generator is not needing to be broken for other maintenance activities, it may be possible to leave the generator filled with CO_2 at a low positive pressure, 0.5 to 1.0 psig. It may be necessary to install a separate pressure regulator to maintain this low pressure while the vents are closed. With the rotor at standstill there is likely to be some leakage, however, CO_2 being non-flammable and in low concentrations on a well-ventilated turbine deck it is not perceived as a danger. It is assumed the seal oil and lube oil systems always remain active during this evolution. Low pressure of the CO_2 in the generator improves the safety profile in the event of a complete seal oil system failure. Not going to air in the purge process may save a quarter to a third the amount of the purge time necessary with minimal system changes.

Additionally, continuous air quality monitor specifically for CO_2 is recommended. In Canada, the Permissible Exposure Limit (PEL) for CO_2 is 5,000 parts per million (ppm) (0.5% CO_2 in air) averaged over an 8-hour workday (time-weighted average or TWA.

(https://www.labour.gov.on.ca/english/hs/pubs/oel_table.php).

Provided Unit 3's turbine deck is of a typical design with no enclosed areas CO_2 levels far below the permissible limit should be attainable.

E.1.4 Fast CO_2 systems

If funding is available, it is possible to purchase CO_2 systems specifically designed to speed the process of extracting CO_2 from bottles or bulk systems to make for higher CO_2 flow rates. One such system by Lectrodryer (https://lectrodryer.com/power-generation/) offers automated generator degas systems that can be actuated from the control room. An additional gas monitoring and control skid is also available to ensure proper CO_2 and H_2 gas purities.

Figure 9-5: A Fast Generator Purge System from Lectrodryer's Website

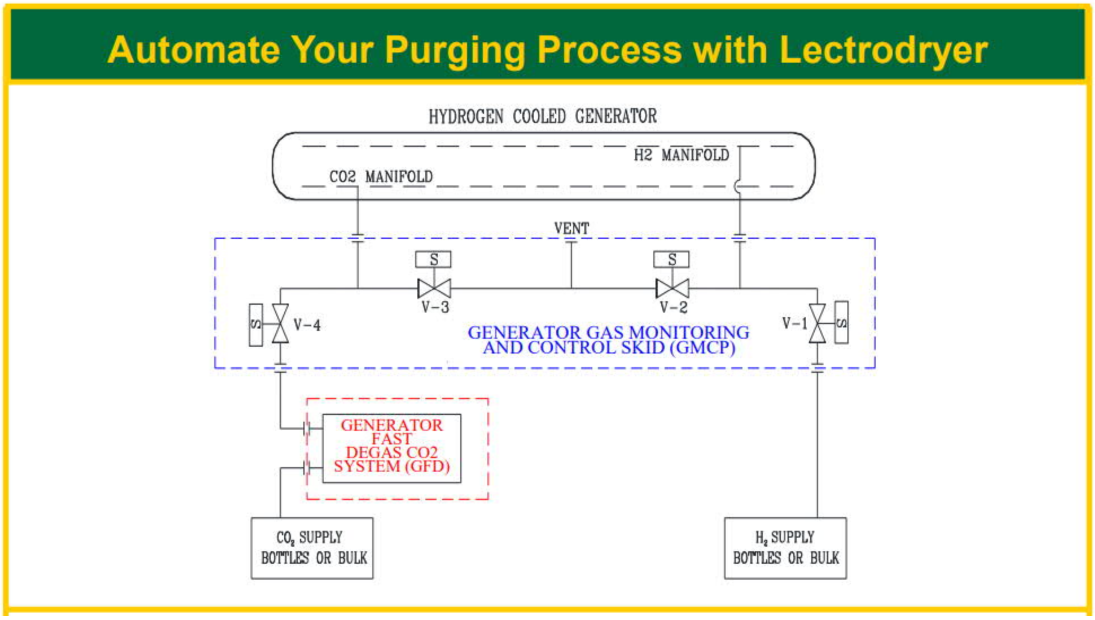

Figure 9-6: Schematic of Degas/Purge and Gas Monitoring and Control Skids

Lectrodryer further claims that purge times can reduced to 20 to 40 minutes from the typical 4 to 12 hours depending on site specifics. Other benefits listed include:

- Optional fully automated purging process with Lectrodryer's Generator Gas Monitoring and Control Skid (GMCP) – generator can be purged and brought to a safe condition from the control room.
- Safety - Complete automation minimizes the opportunity for human error.
- Dependability - Manual Bypass for every automated valve to ensure purge functionality even during complete power or instrument air black out.
- Efficiency / Unit Availability - Even faster purge times, resulting in even shorter outages.
- Automatic Hydrogen Make-up - Solenoid Valve and Regulator to maintain Generator Hydrogen Pressure due to leakage.
- Heater designed to provide consistent flow rate under extreme weather and operating conditions.

Depending on what is currently utilized on Unit 3 and choices for implementation of both bolting and purging options it is conceivable that the steam turbine can be recoupled to the generator within an 8-hour shift.