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June 20, 2025

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Re: Application for Capital Expenditures for the Life Extension of Bay d'Espoir Unit 7 – Redacted

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") application for the capital expenditures required for the life extension of Unit 7 of the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Unit 7").

Bay d'Espoir Unit 7, commissioned in 1977 and located in Powerhouse 2, currently provides 154 MW of generation capacity. The Bay d'Espoir Unit 7 Life Extension Project is a critical multi-year capital investment aimed at ensuring the continued safe, reliable, and efficient operation of Hydro's largest hydroelectric generating unit on the Island Interconnected System. A significant portion of the scope is based on a condition assessment performed by Hatch Ltd. in 2023,[1] with some additional portions identified by Hydro as being required for long-term reliability. Details of the project scope and its justification are provided in Schedule 1 to this application as well as the appendix and attachments thereto.

The schedule proposed by Hydro within this application considers the necessity of the work for long-term reliability, and the implications of the significant lead time for the turbine components. Additionally, as discussed in Section 5.2.1 of Schedule 1 to this application, it is important to align the Unit 7 Life Extension work with the planned start of Bay d'Espoir Unit 8 construction in 2028 to minimize potential interface impacts.

Hydro's application requests approval of the proposed Authorized Budget of approximately $85 million, which is inclusive of the Planned Project Budget and a Management Reserve as detailed in Attachment 1 of Schedule 1 to this application. The proposed capital expenditures detailed in the application are necessary to ensure that Hydro can continue to provide service that is safe and adequate and just and reasonable as required by Section 37 of the *Public Utilities Act*.

[1] Hatch's condition assessment report was received in 2024 and is provided within Attachment 1 of Schedule 1 to this application.

This application contains commercially sensitive information that, if made public, would undermine Hydro's ability to obtain goods and services at the lowest possible cost and therefore negatively impact Hydro's customers. Hydro has considered the practices of other utility regulators in Canada in determining the level of redaction to apply to the information. The information Hydro requests to be kept confidential is that which could be reasonably expected to:

i. Result in undue material financial loss or gain to a person or party directly affected by the hearing or other proceeding;
ii. Cause significant harm or prejudice to a party's competitive or negotiating position; or
iii. Interfere with the contractual obligations of a party.

Additionally, if any information is personal, financial, commercial, scientific, labour relations, or technical in nature and has consistently been treated as confidential, Hydro would propose to maintain that confidentiality.

In the application within, Hydro proposes to keep the following information confidential and not be made publicly available:

- Base Cost Estimate;
- Contingencies and Management Reserves;
- Escalation and Interest During Construction;
- Basis of Estimate;
- Escalation Factors;
- Basis of Schedule and Critical Path Schedule;
- Vendor quotes;
- Vendor information prepared specifically for Hydro; and
- Other third-party commercially sensitive information.

The reasoning for the confidential nature of these aspects of the application are as follows:

<u>Base Cost Estimate</u>

Base Cost Estimates, broken down by construction work package, are considered confidential and commercially sensitive, particularly during the early stages of the procurement process. Disclosing Hydro's forecasted cost for specific construction work packages could influence the pricing submitted by proponents. Further, knowledge of the budget available within a construction work package could incentivize contractors to seek claims to access known budget availability.

For projects with a low number of construction work packages, disclosing the total Base Cost Estimate would provide indicative information on the budget available in a construction work package and could negatively influence the cost of a project.

<u>Contingencies and Management Reserves</u>

Contingency is generally defined as a provision made for variations to the basis of an estimate of time or cost that are likely to occur but cannot be specifically identified at the time the estimate is prepared and/or the commitment amount is determined.

Management Reserve is generally defined as a provision held outside the baseline budget and is reserved for unforeseen costs that are within the project scope. It is usually available to senior management to address strategic risks that materialize outside of Hydro's control.

The amount of Contingency and Management Reserve is considered confidential and commercially sensitive. Disclosure of this information could impact the procurement process by revealing Hydro's estimate of the value of work and Hydro's assessment of the risk around project execution, both of which could influence bid pricing. Further, knowledge of the existence of Contingencies and Management Reserves can influence contractors to be more claims-focused and attempt to access these budget reserves, thereby increasing cost.

Escalation and Interest During Construction

Escalation and Interest During Construction is not commercially sensitive; however, owners would not normally provide an indication to the marketplace of the forecasted escalation assumptions during a bid phase. Additionally, providing the marketplace with this information may make it easier to extrapolate the budget that remains for other scopes of work or contingencies and management reserves, thereby increasing the risks noted above.

Basis of Estimate

The Basis of Estimate for a major project outlines the key inputs, assumptions, and exclusions used by Hydro to estimate not only the Base Cost Estimate, but also Contingencies and Management Reserves. This information is considered confidential and commercially sensitive, and these aspects of the Basis of Estimate continue to be redacted in the documentation. If the information were publicly available, it would provide insight into Hydro's assumptions, methodologies, and data used in determining a cost estimate and could influence proponents' bid pricing as well as contractors' claims. Disclosing Hydro's pricing strategies, cost structures, and internal processes could significantly impact bid pricing and claims.

Escalation Factors

The Escalation Factors provided in the Basis of Estimate for the project is not generally publicly available and would provide insight into elements of the project estimate that contractors could use to their advantage in bidding and negotiations.

Basis of Schedule and Critical Path Schedule

The Basis of Schedule documents the basis and assumptions underpinning the project schedules for the proposed project. That document and the Project Control Schedule are meant to be complementary and read together. The Basis of Schedule documents the current execution intent, sequence, assumptions, risks, and opportunities developed during the front-end planning phase of the project, and these aspects of the Basis of Schedule continue to be redacted in the documentation.

The Critical Path Schedule for a major project outlines the control schedule as well as various assumptions made by Hydro in developing the control schedule and planning the project execution strategy. It specifically outlines the critical path work and any schedule contingency that Hydro may have reserved for project execution.

The information described above would be considered confidential and commercially sensitive for reasons including the following:

- Having knowledge of Hydro's detailed assumptions around work execution timelines can negatively influence approaches to work and timeline optimization during the competitive bidding process, which can negatively influence the ability to realize opportunities in cost and schedule for Hydro and, ultimately, the ratepayers.

- Contractor's knowledge of Hydro's schedule contingency may influence work performance and hinder Hydro's ability to apply delay claims against contractors.
- Contractor's knowledge of other scheduled work and critical path activities may provide them with leverage when negotiating with Hydro.

Also confidential is vendor information prepared specifically for Hydro which includes commercially sensitive information as discussed above, as well as information that vendors deem to be proprietary or have commercial sensitivity for their operations.

An unredacted version of the application is being provided to the Board of Commissioners of Public Utilities ("Board") on a confidential basis; the parties will be provided with a version in which this information has been redacted. Hydro requests that the Board use the redacted version for posting to its website.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

ecc:

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Life Extension Application

Bay d'Espoir Unit 7

June 20, 2025

An application to the Board of Commissioners of Public Utilities

List of Contents

The components of the Life Extension Application include:

- Application
- Schedule 1: Overview
    - Appendix A: Project Scope Table
    - Attachment 1: Basis of Estimate
    - Attachment 2: Project Charter
    - Attachment 3: Basis of Schedule
    - Attachment 4: 2019 Voith Report

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures, pursuant to Subsection 41(3) of the *Act,* for the life extension of Unit 7 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir").

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro, a corporation continued and existing under the *Hydro Corporation Act, 2024*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *EPCA*.

2. Hydro is the primary generator of electricity in Newfoundland and Labrador. The largest of Hydro's hydroelectric generating facilities is Bay d'Espoir that consists of upstream storage reservoirs, a forebay, a spillway, and two powerhouses which together provide 613 MW of electrical capacity and 2,560 GWh of energy annually to the Island Interconnected System. Powerhouse 1 is equipped with six generating units, each with a capacity of 75 MW, providing a combined output of 450 MW. Powerhouse 2 houses a single unit with generation capacity of 154 MW ("Unit 7").

3. Bay d'Espoir Unit 7 was commissioned in 1977. As many critical components of the unit have a typical service life of 40–55 years, in 2023, Hydro arranged for a fulsome Level 2 Condition Assessment to be completed by Hatch Ltd. ("Hatch"). Hatch was also tasked with reviewing and validating the findings of the contractor from a previous inspection and providing an opinion as to the contractor's previous recommendations. Hatch's report was received in 2024 and is provided within Attachment 1 of Schedule 1 to this application.

4. Hatch's report concluded that various Unit 7 components are at, or approaching the end of their reliable service life and the unit requires significant refurbishment and component replacement within five years to preserve its operational integrity. The work is also necessary to extend the service life of Unit 7 and will do so by at least 25 years.

5. The recommendations made by Hatch for refurbishment and replacement will require full disassembly of Unit 7. Other work, identified by Hydro as necessary to ensure long-term reliability, would also require major outage windows to execute. Hydro's proposed project combines the work identified by Hatch in its condition assessment, as well as the work identified by Hydro, to minimize the costs and risks associated with multiple outages and disassembly. The scope of work, detailing the work identified in the condition assessment and the work identified by Hydro, is further described in Section 5.0 and Appendix A of Schedule 1 to this application.

6. The timing of the proposed scope of work for Unit 7 was developed with significant consideration of the lead time for the turbine components, but also of the planned construction schedule for the proposed Bay d'Espoir Unit 8 Project. As discussed in Section 5.2.1 of Schedule 1 to this application, it is important to align the Unit 7 Life Extension work with the planned start of Bay d'Espoir Unit 8 construction in 2028 to minimize potential interface impacts.

7. Hydro considered deferral of the work, as well as proceeding with part of the proposed scope. These considerations are described in Section 4.0 of Schedule 1. Hydro's proposal to proceed with the full scope proposed herein is the most efficient, least-cost solution to ensure the continued reliable operation of the unit for at least the next 25 years.

B. Application

8. Unit 7 provides 154 MW of generation capacity to the Island Interconnected System. The continued operation of Unit 7 without intervention within the recommended time period has the potential to result in equipment failure, leading to an extended forced outage and the loss of that capacity from the Island Interconnected System.

9. Project execution is expected to take four years. The project schedule is discussed in Section 5.2 of Schedule 1 and is included within the Basis of Schedule provided as Attachment 3 of Schedule 1 to this application.

10. The estimated Authorized Budget for the project is $85,346,227, which includes both the Planned Project Budget and a Management Reserve. Details regarding the calculation of this Authorized Cost as well as the Planned Project Budget are contained in Section 5.1 and Attachment 1 of Schedule 1 to this application. Discussion of the Management Reserve is provided in Section 5.1.8 of Schedule 1.

11. As Hydro's largest hydroelectric generating unit, Unit 7 is a critical component of the Island Interconnected System and is required to provide generation and synchronous condenser capability for the foreseeable future. Hydro submits that the proposed capital expenditures are necessary to ensure that Hydro can continue to provide service and facilities that are safe and adequate and just and reasonable as required by Section 37 of the *Act.*

C. Hydro's Request

12. Hydro requests that the Board make an Order approving the requested Authorized Budget in the amount of $85,346,227 for the capital expenditures necessary for the life extension of Bay d'Espoir Unit 7 as set out in Attachment 1 of Schedule 1, pursuant to Section 41(3) of the *Act*.

D. Communications

13. Communications with respect to this application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the province of Newfoundland and Labrador on this 20th day of June 2025.

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
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Schedule 1

Application Overview

Bay d’Espoir Unit 7 (2025–2028)

newfoundland labrador hydro

Executive Summary

The Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") Unit 7 ("Unit 7") Life Extension Project is a critical multi-year capital investment aimed at ensuring the continued safe, reliable, and efficient operation of Newfoundland and Labrador Hydro's ("Hydro") largest hydroelectric generating unit on the Island Interconnected System. Bay d'Espoir Unit 7 was commissioned in 1977. Located in Powerhouse 2, Unit 7 currently provides 154 MW of generation capacity and produces an average of 835 GWh annually. Many critical components of Unit 7 have typical service lives ranging from 40 to 55 years. After nearly 48 years in operation, a Level 2 Condition Assessment was conducted by Hatch Ltd. ("Hatch") in 2023 ("2023 Condition Assessment").[1] Hatch's final report, received by Hydro in the second quarter of 2024, concluded that components are at, or approaching, the end of their reliable service life and the unit requires significant refurbishment and component replacement within five years to preserve its operational integrity and extend its service life by at least 25 years.[2]

The unit remains in serviceable condition with above-average reliability metrics; however, critical components such as the runner, stator and rotor windings, and auxiliary systems have shown substantial signs of deterioration and obsolescence. Historical investments, including a 2019 turbine refurbishment and multiple modernization efforts, have contributed to maintaining operability; however, major life extension works are now required to mitigate the risk of forced outages and performance degradation.

The proposed project includes full disassembly of the unit, engineering, procurement, construction, installation, testing, and commissioning of all works required to refurbish or replace core components and modernize control and support systems. Key drivers include severe runner cavitation, aged electrical windings, and obsolete controls. The planned refurbishment will not only extend the life of Unit 7 but also optimize its efficiency within the current and forecasted operating regimes. A companion targeted condition assessment of Bay d'Espoir Intake 4 and the draft tube is scheduled for 2025, with any required refurbishment of these components to follow under a separate capital filing.

[1] Work for the condition assessment was completed throughout 2023. Hydro reviewed and verified the results in 2024 prior to Hatch providing the final report. The report is provided within Attachment 1 to this schedule.

[2] The 25-year timeframe was chosen as a reasonable goal to facilitate decision making while understanding that inspection findings during the course of this project may indicate the need for future major work in less than 25 years. Likewise, reference to a 25-year service life does not mean full unit replacement will be required in 25 years. Hydro will continue to monitor asset condition and evaluate options for life extension as required.

The primary justification for the project is the critical role Unit 7 plays in meeting provincial electricity demand and maintaining grid stability. Deferral of this project poses unacceptable risks to system reliability, given long lead times for key equipment and the risk of forced outages lasting up to two years. Hydro considered alternatives including project deferral; however, deferral was dismissed due to asset condition and risk. The chosen alternative is a like-for-like replacement and modernization strategy based on the findings from the 2023 Condition Assessment that were reviewed by Hydro and accepted as an accurate representation of the condition observed. The chosen alternative also includes scope items that were not explicitly contained in the 2023 Condition Assessment but support the safe and reliable operation of Bay d'Espoir Unit 7 and are required to achieve the desired 25-year life extension. These items are further detailed in Appendix A of this schedule.

If not executed, the consequences would include elevated risk of unit failure, significant capacity loss to the Island Interconnected System, and an increased probability of unplanned outages, particularly during peak winter periods. This work aligns with Hydro's legislated mandate to provide safe, reliable service at the lowest possible cost, in an environmentally responsible manner. Deferral of this work would impose interface issues with the construction of Unit 8, impacting the execution and schedule of that proposed project.

This project has a multi-year approach, with completion planned in 2028 at an Authorized Budget of $85,346,227. To support transparency and stakeholder confidence, Hydro proposes the implementation of a quarterly Major Projects report to the Board of Commissioners of Public Utilities ("Board") and intervenors. A quarterly schedule, over the estimated three-year timeline, will provide this information on a timely schedule while preventing repetition in more frequent reporting. These reports will provide updates on scope, cost, schedule, risks, and any emerging factors affecting execution. This regular reporting cadence will serve as a critical tool for maintaining alignment with project objectives, enabling early identification of issues, and supporting informed, proactive decision-making throughout the life of the project.

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Appendix A: Project Scope Table

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Attachment 1: Basis of Estimate

Attachment 2: Project Charter

Attachment 3: Basis of Schedule

Attachment 4: 2019 Voith Report

1.0 Introduction

Bay d'Espoir is located on the south coast of Newfoundland and Labrador. It lies within the island portion of the province and utilizes the natural geography of the bay and surrounding areas to produce electricity, making Bay d'Espoir critical to the provincial power grid. The facility consists of upstream storage reservoirs, a forebay, a spillway, and two powerhouses which together form an integral part of the hydroelectric system.

Powerhouse 1 is equipped with six generating units, each with a capacity of 75 MW, providing a combined output of 450 MW. The facility utilizes three water intakes, each connected to a penstock. A single headrace canal supplies water to the three intakes, optimizing flow and maintaining steady operations. The water is then discharged through a 4.5-kilometer-long tailrace channel, which directs the flow into Fortune Bay.

Powerhouse 2, shown on the right in Figure 1, houses Unit 7; a single unit with a capacity of 154 MW, it receives water through a dedicated headrace canal, intake, and penstock. Its tailrace channel connects to the tailrace channel of Powerhouse 1.[3] Unit 7 is a critical generating asset, supplied by water from the Long Pond Reservoir via Bay d'Espoir Intake 4 through a buried steel penstock, and exhausts water through the unit's draft tube. The unit is comprised of a generator and turbine assembly, complete with required auxiliary systems, that has the capability to generate as well as act as a synchronous condenser to meet system requirements. Unit 7 was commissioned in 1977 and has operated reliably for nearly 48 years. Critical components of Unit 7 have typical service lives ranging from 40 to 55 years[4] and targeted capital investments have been made over its operating life to refurbish and modernize the equipment, in order to reliably achieve the required service life and enabling comprehensive assessment of asset condition.

[3] Commissioned in 1977 during Phase 3, the powerhouse was built with provisions for adding a second unit in the future. To minimize disruptions to Unit 7 during eventual construction, rock excavation for the second unit was completed and the downstream portion of the draft tube, including the draft tube gate guides, was constructed. However, the headrace canal, intake, penstock, and downstream section of the tailrace channel were designed and built exclusively for Unit 7.
[4] Based on Hydro's depreciation study that considers 40 years for controls and relaying, 45 years for governors, 50 years for windings and 55 years for turbine and runner.

Figure 1: Bay d'Espoir and Powerhouse 2

In 2019, Hydro executed a turbine refurbishment project on Unit 7,[5] which provided an opportunity for detailed inspection and measurement of critical equipment as the unit was fully disassembled for the first time since commissioning. During these inspections, critical components of the unit, including the turbine, generator, and embedded parts were identified by the contractor, Voith Group ("Voith") as requiring intervention during the next major outage to ensure continued reliable operation of the unit. The contractor also presented alternatives for Hydro's consideration for the life extension of the unit. A 2023 Condition Assessment was carried out by Hatch,[6] with the latest condition information and operational data available intended to enable Hydro to plan for appropriately timed capital investment and provide Hydro with an independent, third-party review of the 2019 findings. The 2023 Condition Assessment is provided within the Basis of Estimate, as Attachment 1 to this schedule.[7] As outlined in Section 3.0 of the 2023 Condition Assessment,[8] Hatch generally accepted most findings by Voith;

[5] The scope was included within the Hydraulic Generation Refurbishment and Modernization Project, which was approved as part of Hydro's 2019 Capital Budget Application in Board Order No. P.U. 46(2018).
[6] The Unit 7 Condition Assessment (2023) – Bay d'Espoir Project was approved as part of Hydro's 2023 Capital Budget Application in Board Order No. P.U. 2(2023).
[7] In support of Attachment 1, Hydro has also provided the Project Charter as Attachment 2 to this schedule.
[8] Section 3.0 begins on page 7 of the 2023 Condition Assessment, or page 62 of 225 of Attachment 1 to this schedule.

however, Hatch determined that the timeline for required intervention could be extended by an additional five years, to 2029. The project schedule, with completion planned for 2028, is provided within the Basis of Schedule, as Attachment 3 to this schedule.

The proposed project involves the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the life extension of Unit 7.

2.0 Project Description and Justification

Unit 7 provides 154 MW of generation capacity to the Island Interconnected System and produces an average 835 GWh of energy annually. Hydro is proposing to complete life extension activities on Unit 7 to ensure the continued reliable operation of this critical generating asset. The purpose of the project is to extend the reliable service life of Unit 7 for at least 25 years through inspection, refurbishment, and replacement of components.

In 2019, Hydro executed a turbine refurbishment project that was justified primarily due to reliability concerns associated with the runner clearances. This project also provided an opportunity for detailed inspection and measurement of critical equipment as the unit was fully disassembled for the first time since commissioning in 1977. During these inspections critical components of the unit were identified as requiring future intervention[9] to ensure the continued long-term reliable operation of the unit, including but not limited to the turbine, generator stator and rotor and embedded parts. The unit was returned to service in 2019 with the runner clearances improved and additional improvements made to the turbine components, but with the knowledge that future assessment and investments would be required. Voith, who was the vendor for the turbine refurbishment project, documented their findings to inform Hydro of the as-found condition of Unit 7, details of remedial work completed to return the unit to service in 2019 and high-level recommendations for future capital expenditures. Voith's final report was received in 2020[10] and upon receipt of the report, Hydro determined that a third-party assessment was required to review the findings, to provide feedback on the recommendations, to include assessment of additional assets and operational data which were beyond the scope of the 2019 project and provide

[9] The timeline for the recommended interventions was within the next major outage, at that time anticipated to be within five years.
[10] Please refer to Attachment 4 of this schedule.

recommendations to extend the service life of Unit 7. The availability of on-site support from contractors was limited through 2020 and 2021 due to the COVID-19 pandemic, and access to Bay d'Espoir was restricted at times as operations were focused on the execution of business continuity activities. Following the resumption of normal operations, Hydro progressed its planning for a fulsome Level 2 Condition Assessment by an independent third party. The condition assessment would provide a more detailed review of the 2019 inspection findings to ensure prudency of the recommended timing of capital expenditures and prioritize the work with the significant capital scope planned for Bay d'Espoir for the next five years.

The 2023 Condition Assessment final report was delivered in 2024 and concluded that the unit requires major intervention within the next five years, including refurbishment and/or replacement of major components such as the runner, operating ring, and stator and rotor pole windings. The report also provides recommendations for refurbishment and replacement activities of other equipment and systems associated with the unit. In general, Hatch supported the Voith findings, and where the 2023 Condition Assessment provided more updated information, Hatch expanded upon the recommended scope for execution to ensure life extension, including the turbine shaft and embedded components. In circumstances where Voith presented long-term alternatives for either refurbishment or replacement of a component (i.e., head cover, wicket gates), at times, Hatch determined that replacement was not necessary, and that refurbishment would accomplish the life extension required by Hydro. A full synopsis of Hatch's 2023 Condition Assessment, including the 2019 findings by Voith, is presented in Section 3.0 of the report.

The proposed scope of work is based on the recommendations provided in the 2023 Condition Assessment, which identified the need for a lengthy outage and complete dismantling of the generating unit. The items identified in the 2023 Condition Assessment must be addressed in a timely manner, as failure to do so poses significant risk to the reliable operation of the unit. The continued operation of the unit without intervention within the recommended time period has the potential to result in equipment failure, leading to an extended forced outage and the loss of 154 MW of capacity from the Island Interconnected System.

Additionally, Hydro is proposing to cluster a number of additional capital works on Unit 7 which require major outage windows to execute. Given the requirement to fully dismantle the unit, Hydro is proposing to undertake additional activities beyond those explicitly identified in the assessment to ensure long-term reliability. These are additional scope items that were not included in the 2023 Condition Assessment but support the safe and reliable operation of Bay d'Espoir Unit 7 and are required to achieve the desired 25-year life extension.

Hydro is proposing the project over a four-year project timeline to allow for detailed engineering and planning activities and for the procurement of long-lead items, such as the turbine runner.

3.0 Asset Overview

3.1 Asset Background

Unit 7 was commissioned in 1977 and has provided nearly 48 years of generating capacity to the Island Interconnected System; it is currently the largest hydroelectric generating unit on the Island, with a generating capacity of 154 MW.

The unit is comprised of a generator and turbine assembly, Francis style design vertical runner configuration, complete with required auxiliary equipment and systems. It has performed reliably to support the Island Interconnected System. Figure 2 shows a cross-section of a typical hydroelectric generating unit including the major components such as turbine, wicket gates, shafts, stator, and rotor. Figure 3 and Figure 4 show pictures of major components of Unit 7, taken during the 2019 Turbine Refurbishment work.

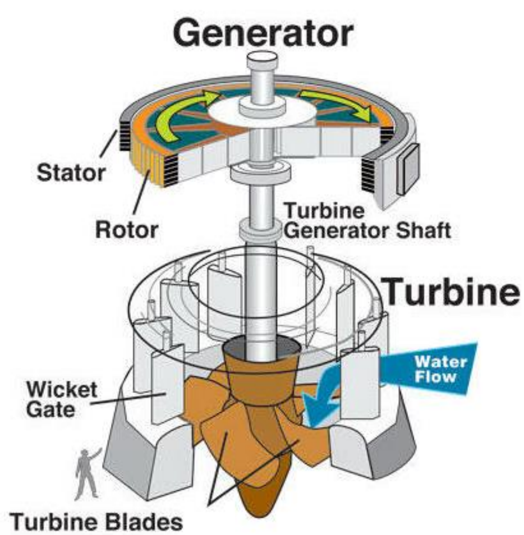

Figure 2: Hydraulic Generating Unit

Figure 3: Unit 7 Generator Rotor

Figure 4: Unit 7 Francis Runner

Unit 7 is operated according to system conditions to balance system load requirements, while maintaining efficient water management strategies and respecting necessary operating conditions as outlined by the asset design criteria. In addition, Unit 7 also provides synchronous condensing capability to provide the necessary voltage support to the system during periods when power generation from the unit is not required.

The unit is currently in operating condition and available for normal service with the exception of downtime associated with maintenance or forced outages. Since commissioning, the unit has operated continuously, with regular annual maintenance outages and periodic capital investments undertaken to refurbish and modernize the equipment in an effort to extend the reliable service life and ascertain an understanding of asset condition. Unit 7 undergoes an annual planned outage, which is typically three weeks in duration, to facilitate the completion of preventative and corrective maintenance activities. In addition, a more detailed inspection, referred to by Hydro as an "Overhaul" or "PM9" is completed at a six-year frequency.

Hydro is proposing the next PM9 for Unit 7 in its 2026 Capital Budget Application; the scope of this work will be expanded to include short-term remediation work to address deficiencies identified during the 2023 Condition Assessment as being urgent and unable to delay until 2028. It will also include necessary inspection work to ensure a fulsome understanding of up-to-date asset condition is known prior to critical design decisions in the life extension project. The execution of this PM9 is critical to ensure the reliable operation of the unit until the life extension work proposed in this project can be executed.

In addition to routine maintenance and PM9 activities, a list of past investments such as refurbishment, replacement, and condition assessment activities are provided in Table 1.

Table 1: Historical Investments

Year	Title of Investment
2023	Level 2 Condition Assessment
2020	Upgraded Protection
2019	Turbine Refurbishment
2015	Carbon Seal Replacement
2015	Turbine Base Plate Replacement
2014	Excitation Transformer Replacement
2009	Service Water Upgrades
2004	Field Breaker Replacement
2004	Exciter Replacement
1998	Synchronous Condense Compressor Replaced
1998	Air Gap Monitoring System Installed
1991	Synchronous Condense Blower Replaced
1990	Partial Discharge Monitoring Installed
1982	Rotor Brake Plate Replacement
1982	Guide Bearing Segments Replaced

3.2 Historical Reliability

Unit 7 has historically demonstrated above average levels of reliability performance when considering Electricity Canada standard measures. The five year derated adjusted forced outage rate ("DAFOR")[11] and capability factor ("CbF")[12] are shown in Chart 1 and Chart 2.

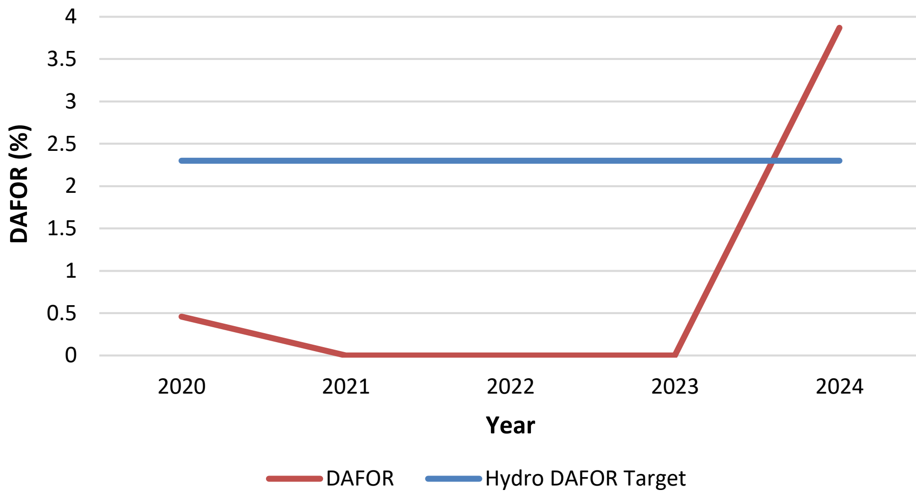

Chart 1: Five-Year DAFOR

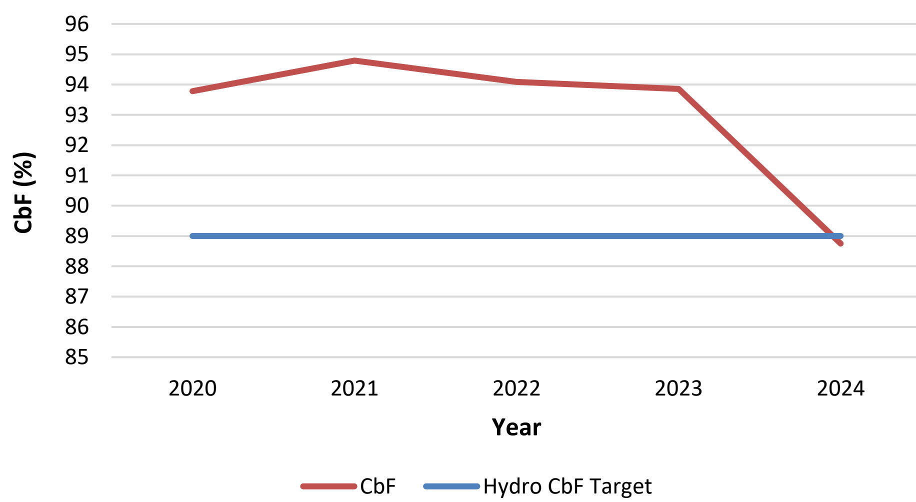

Chart 2: Five-Year CbF

[11] DAFOR measures the percentage of time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages or unit deratings. For DAFOR, a lower number is better.
[12] CbF measures the percentage of time that a unit or group of units is available to generate at its maximum continuous rating. It is impacted by both planned and forced outages. For CbF, a higher number is better.

Despite the above average performance, the unit has experienced a number of forced outage events associated with various equipment and systems; examples include generator bearing cooler failures, synchronous condenser system malfunctions, cooling water pressure reducing valve issues, generator bearing oil leaks and higher than normal bearing temperatures. Given the installed capacity of the unit, and the importance of its availability to the Island Interconnected System, Hydro has taken considerable efforts to reduce the number of forced outages and impacts associated with forced outages by ensuring issues are addressed in a timely manner and remedial actions are identified and implemented. In some cases, short-term repairs have been completed to allow the unit to return to operation with increased monitoring until a permanent solution can be implemented at the next scheduled outage.

The decline in performance in 2024 was the result of a forced outage, which occurred in August 2024 and lasted approximately two weeks, when leaks were discovered in the generator bearing coolers. Since this outage, all generator bearing coolers have since been replaced with new coolers.

3.3 Asset Condition

Unit 7 has operated reliably since commissioning in 1977; however, there are now major components of the unit that must be refurbished, replaced or modernized to achieve the desired 25-year life extension.[13]

The 2023 Condition Assessment identified varying levels of deterioration, particularly in critical components of the generator and turbine, which included:

- Dimensional irregularities of the stator core;
- Aged windings in both stator and rotor;
- Severe cavitation of runner;
- Accelerated wear of servomotors, wicket gates, operating ring, etc.; and
- Water leakage around the scroll case access door.

[13] Given the increased cost and risk resulting from full disassembly, Hydro considered replacement and refurbishment of other components to decrease the likelihood of another full disassembly for 25 years. The full condition of all components of Unit 7 will not be known until this project is complete. The 25-year life was chosen as a reasonable goal to facilitate decision making while understanding that inspection findings during the course of this project may indicate the need for future major work in less than 25 years.

In addition to identifying deterioration, the 2023 Condition Assessment also identified supporting systems of Unit 7 which are approaching obsolescence, including the governor and excitation system controls.

3.4 Condition-Based Remaining Life

Unit 7 is nearing the end of its reliable service life due to the age of major components and its current condition. Major components of a hydroelectric unit, such as the turbine runner, governor, protection and control panels, generator stator and rotor windings have a typical life span of 40 to 55 years. Approaching 48 years of age, critical components of Unit 7 such as the turbine runner, stator and rotor windings, and auxiliary systems, have shown substantial signs of deterioration and obsolescence. They require the execution of life extension activities in advance of reaching the end of their service life, to ensure 154 MW of reliable generation remains available to supply the Island Interconnected System.

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro has evaluated the following alternatives:

- Deferral;
- Like-for-Like Refurbishment/Replacement ("Partial Scope"); and
- Cluster Life Extension with Additional Required Work ("Full Scope").

4.1.1 Deferral

Full scope deferral is not a viable alternative for this project, as detailed inspections and measurements completed in 2019 and the follow up 2023 Condition Assessment have determined that the unit requires significant investment within the next five years to ensure the unit can continue to reliably operate. Deferral of this project presents an unacceptable risk to the operation of the 154 MW generating unit. Depending on the failure mode, a forced outage could last up to two years as a result of the current lead times for major components, such as stator windings or a runner.

4.1.2 Like-for-Like Refurbishment/Replacement

This alternative involves the refurbishment and like-for-like replacement of only the major components of Unit 7 identified by Hatch in the 2023 Condition Assessment report. Based on the findings of the 2023

Condition Assessment, major components will be refurbished or replaced in kind, or with modern equivalents where appropriate. The new turbine runner will be designed with a focus on improving efficiency across historical and forecasted operating ranges, thereby optimizing the use of available hydraulic resources within the Bay d'Espoir system.

4.1.3 Cluster Life Extension with Additional Required Work

This alternative includes implementation of all the recommendations from the 2023 Condition Assessment as well as additional items identified by Hydro through regular maintenance activities to achieve an additional 25-year life extension without a major intervention.

Projects requiring full disassembly require significant outages resulting in the unavailability of 154 MW for several months which can impact system reliability and the availability of outages for other critical work across the system. Both the life extension work and the additional scope of work proposed require disassembly and/or a major outage to complete; therefore, clustering these projects will optimize the outage window for Unit 7 and avoid further unit downtime.

The complete disassembly of Unit 7 is complex and requires significant resources. For this project, the disassembly and reassembly costs are estimated at approximately $5 million. Full disassembly also increases the risk of damage to the unit during lifting or by the introduction of foreign materials. Finally, executing this work in one outage will also result in design, contract and commissioning/start-up efficiencies. The total direct costs of all additional items identified by Hydro is approximately 15.7% of the direct construction costs for this project.

Given the increased cost and risk resulting from full disassembly, Hydro considered replacement and refurbishment of other components to decrease the likelihood of another full disassembly for 25 years. The full condition of all components of Unit 7 will not be known until this project is complete. The 25-year life was chosen as a reasonable goal to facilitate decision making while understanding that inspection findings during the course of this project may indicate the need for future major work in less than 25 years.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to the Partial Scope of the project to facilitate a least-cost evaluation. The execution of the Full Scope, which includes other work necessary to support long-term reliability, avoids incurring duplicate cost to fully disassemble the unit again in the future (estimated at approximately $5 million). Further, the clustering of these work scopes alleviates the requirement for further unit outages to accomplish the work, and supports Hydro's legislated mandate to provide safe, reliable service at the lowest possible cost, in an environmentally responsible manner.

4.3 Recommended Alternative

The recommended alternative is the Full Scope, including work required for the life extension of Unit 7 and the additional required work identified by Hydro, which requires the engineering, procurement, construction, installation, commissioning and testing of all works associated with the project scope detailed in Section 5.0.

Hydro believes that executing the Full Scope of the 25-year life extension at this time is the most efficient and responsible course of action. The items identified in the 2023 Condition Assessment which require intervention within five years require the full dismantling of the unit, which is not included in routine preventative maintenance tasks and is executed only when significant refurbishment or life extension work is necessary. This complete disassembly of Unit 7 is complex, requires significant outage time and resources, incurs significant cost and has the potential to introduce risk to the assets; therefore, completing the full recommended scope of work as a clustered project within a single outage results in design and contractual efficiencies and also saves customers the cost of the subsequent disassembly, reassembly and commissioning, that would be required if portions of the proposed scope were deferred.

Hydro recommends completing the proposed work to ensure the reliable operation of Unit 7 for at least the next 25 years. Discussion of the risk of asset stranding and the project risk score is provided in Section 6.0.

5.0 Scope of Work

A summary of the scope of work recommended by Hydro within this application, including the 2023 Condition Assessment recommendations from Hatch, is provided as Appendix A to this schedule.

The proposed scope of work includes the engineering, procurement, construction, installation, commissioning and testing of all works associated with Unit 7 which are required for life extension, including:

- Design and manufacture of a replacement turbine runner with a focus on optimizing the efficiency in the historical and forecast operating ranges. The design will be based on a computational fluid dynamics ("CFD")[14] model and an existing turbine design previously developed by the future original equipment manufacturer ("OEM");
- Finite element analysis and fatigue analysis on major components of the unit that are subjected to cyclic loading in order to confirm suitability for refurbishment and continued operation for a minimum of 25 years. This will include the head cover, turbine and generator shafts and the wicket gates;
- Site works including, but not limited to:
  - Complete dismantling of the unit;
  - Inspection of all components and necessary refurbishment or replacement based on the findings of inspections;
  - Replacement of the turbine bottom ring and runner and replacement and/or refurbishment of other key turbine components (i.e., operating ring, headcover, and wicket gates);
  - Replacement of generator stator windings and re-insulation of rotor field pole windings;
  - Procurement of spares such as bushings, bearing pads, coupling fasteners and hardware, brake pads, instrumentation, etc. required for unit reassembly;
  - Refurbishment or replacement of auxiliary equipment such as the tailwater depression system used during synchronous condenser operation and hydraulic lift system;
  - Site works to address leaks around embedded parts, scroll case and relief valve; and
  - Reassembly, testing and commissioning.

[14] CFD is a numerical simulation method that uses mathematical models to predict fluid flow patterns, pressure distribution and other related phenomena.

Additional scope necessary to support long-term reliability that Hydro proposes to be clustered with the life extension work to minimize future outage time and recommissioning activities are as follows:

- Install dust collection system;
- Design and install turbine pit monorail and hoist;
- Modernization of excitation system controls to address obsolescence;
- Conversion of turbine governor from mechanical to modern digital control; and
- Modernization of the unit control system to address obsolescence and improve asset monitoring.

To support overall project planning, Hydro has held lessons learned sessions with the project team currently executing similar refurbishment works in Churchill Falls. As a result of planning exercises and incorporation of lessons learned, Hydro intends to engage an OEM to lead the technical scope, given the specialized nature of the equipment and required expertise. In addition, Hydro plans to issue a Request for Proposals ("RFP") for a consultant to support overall project coordination and execution.

Replacement of Runner, Bottom Ring, Stator Windings and Re-Insulation of Rotor Poles

The replacement runner will be designed to reflect changes in reservoir levels and operating regime that have occurred since the unit was commissioned in 1977. The physical size and nameplate capacity of the runner will not change; however, improvements in materials and design methods should result in improved efficiency within the operating range and cavitation performance. The design is to be based on an existing design by Turbine-Generator suppliers and CFD modelling.

The generator stator windings will be replaced and the rotor pole windings re-insulated. The new windings will match the existing configuration and will be manufactured with modern methods and insulation systems. The stator core is to be cleaned and refurbished as necessary. Rotor pole bodies, rotor spider and rim are to be inspected and refurbished.

Refurbishment and/or Replacement of Other Turbine and Generator Components

Other turbine components are to be refurbished or replaced based on the results of the Turbine-Generator suppliers design and inspection activities. The replacement of the turbine guide bearing with water lubricated technology is being considered as it would eliminate the risk of an oil spill associated with the current bearing, pending technical feasibility.[15] Similarly, the supplier may suggest that the wicket gates be replaced with a design that better matches the new runner in order to maximize the turbine efficiency.[16]

Modernization of Control Systems

The modernization of the governor control system was recommended in the 2023 Condition Assessment, and it was identified that that excitation controls are currently obsolete. Hydro has proposed the inclusion of the excitation control system replacement in the life extension scope and has included similar replacements in their capital plan where required. To ensure the 25-year life extension can be achieved, Hydro has also proposed the modernization of the unit control system, as the most efficient and cost-effective time to complete this upgrade is concurrent to the planned upgrades to governor and exciter controls. All systems are to be modernized in accordance with the latest design philosophy to address obsolescence as well as to improve unit operation and monitoring capabilities. The modernized controls will interface with existing equipment and will provide provisions for interface with future installations and upgrades of other units at Bay d'Espoir.

Refurbishment of Auxiliary Systems

Auxiliary equipment such as draft tube water level controls system associated with the synchronous condenser operation of the unit as well as the high-pressure oil injection system will be refurbished based on original design requirements while employing modern technology.

Installation of Dust Collection System and Turbine Pit Hoist

In addition to the necessary life extension work, Hydro has proposed enhancements to be made which improve the operation and maintenance of Unit 7 going forward. These enhancements include the addition of dust collection systems and a turbine pit monorail and hoist. The dust collection systems will prevent conductive carbon dust from contaminating and adversely affecting the service life of the new stator and rotor windings. The turbine pit monorail and hoist will facilitate the safe and efficient

[15] The cost for this item has been included in the base cost estimate. Should the technical feasibility not be confirmed, and a traditional oil lubricated bearing is used, the base cost would be less.
[16] The costs for replacing the wicket gates have been included in the base cost. If the wicket gates can be refurbished, then the base cost would be less.

completion of maintenance activities in the turbine pit, saving both cost and time and reducing a safety risk when completing future maintenance activities.

Found Work

Due to the nature of turbine generator refurbishment projects, Hydro has adopted a proactive approach by including a dedicated "found work" scope item in the base estimate. This item is distinct from contingency and is informed by lessons learned from similar projects at the Churchill Falls Hydroelectric Generating Station.

Found Work refers to the scope of repair or replacement activities that are not specifically identified during the planning and engineering phases but are reasonably expected to arise once the unit is disassembled. Unlike contingency—which is calculated to account for uncertainty across the entire project—found work is anticipated discoveries based on historical evidence and engineering judgment. Including Found Work in the base estimate ensures transparency and realism in cost forecasting and avoids underestimating the true scope of work. The Found Work scope item is meant to cover a reasonable amount of repair and replacement activities. [redacted] For more information on how this item was included in the estimate for this project please refer to Attachment 1.

Excluded from Project Scope

Hydro will complete a targeted Level 2 Condition Assessment of Bay d'Espoir Intake 4 and the Unit 7 Draft Tube structure, including embedded parts and the draft tube gates in 2025.[18] Hydro will use the findings of the assessment to develop a refurbishment plan to inform the 2027 Capital Budget Application Hydraulic Unit Overhauls Program. Some known issues such as leaks in the downstream section of the draft tube liner are planned to be addressed during the same outage as the proposed Bay d'Espoir Unit 7 Life Extension Project, with execution aligned with the Unit 7 life extension in 2028. This

[redacted]

[18] The Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir project was approved as part of Hydro's 2025 Capital Budget Application in Board Order No. P.U. 28(2024).

approach maintains flexibility to coordinate refurbishment as needed and reflects Hydro’s commitment to responsible capital planning and long-term asset stewardship.

This recommended scope also excludes the uprating of the runner. It was determined that a runner with increased capacity has lower efficiency over the operating range of the unit, when compared to a runner with the same rating as is currently installed. If efficiency at typical operating conditions is sacrificed to provide a capacity uprate, the value of the turbine uprate is diminished. In addition, there is a finite amount of hydraulic capacity available in the Bay d'Espoir system to be utilized for the purposes of additional generating capacity, and Hydro’s most recent hydrological analysis confirmed that an additional 154 MW Unit (Unit 8) could be accommodated into the Bay d’Espoir system, alongside the seven existing units, and that there would be adequate water for the operation of this additional unit over a range of scenarios.[19] While uprating Unit 7 will not be pursued, there is an expectation that a modern design of the replacement runner will allow for improvements in efficiency in the operating range and therefore more effective use of the hydrological resource at Bay d’Espoir.

5.1 Project Cost and Assumptions

The cost estimating structure for this project is designed to ensure financial robustness and risk preparedness, and components are as defined within Basis of Estimate.

The project Capital Cost Estimate includes the following:

- Base Cost, which includes prices for direct costs, such as equipment, materials, etc., and indirect costs, such as Hydro’s management, project insurance, accommodations, and consultant services; and
- Contingency, to account for uncertainties outside of the Hydro’s control—they are the “known unknowns” that are within the project scope (e.g., higher than expected equipment costs).

The sum of these costs makes up the project capital cost estimate. To establish the Planned Project Budget, the following is also included:

- Interest during construction (“IDC”), to account for the cost of borrowing during project construction; and

[19] “2025 Build Application,” Newfoundland and Labrador Hydro, March 21, 2025, sch. 1, att. 2.

- Escalation, which accounts for anticipated increases in labour costs and material prices over the course of execution of a multi-year project.

The Authorized Budget, set at P85[20] confidence level in keeping with the Muskrat Falls Inquiry recommendation, encompasses the Planned Project Budget and Management Reserve.[21] This probabilistic estimating approach ensures proper risk assessment during budgeting exercises. The use of a P85 estimate is consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry.[22]

The following sections provide a detailed breakdown of each cost component, and Attachment 1 to this schedule provides a detailed breakdown.[23]

The cost estimate was developed by Hydro based upon estimated costs in the 2023 Condition Assessment report. Further detail on estimate development is contained within the Basis of Estimate, provided as Attachment 1 to this schedule.

5.1.1 Quantitative Risk Analysis

A Quantitative Risk Analysis ("QRA") is defined as a "risk analysis used to estimate a numerical value (usually probabilistic) on risk outcomes wherein risk probabilities of occurrence and impact values are used directly."[24] For the Bay d'Espoir Unit 7 Life Extension Project, a QRA was conducted by the Hydro Project Management team.

Through the process, various elements of the estimate were reviewed by the QRA team and consensus was reached about the amount of variability that might be encountered for each element. This variability range could be for the cost of an item, or for the element of cost for the item, such as the

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[20] A probabilistic cost estimate in which there is an 85% probability that the actual cost will be less than or equal to the budget**.**

[21] Management Reserve is an industry-standard tool that is used to manage strategic risk and to address issues that may arise that are outside of the control of Hydro. It serves as additional funds in a project budget that are set aside for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro's control. Considered "unknown unknowns" that are within the project scope (e.g., government policy changes).

[22] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Recommendation 5, pp. 61–62.

[23] A detailed cost breakdown is provided in Appendix A of Attachment 1 to this schedule.

[24] Association for the Advancement of Cost Engineering International ("AACE"). (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 104).

quantity or production rates. This variability defines the probabilistic ranges that are used in the model that is used for the Monte Carlo Simulation.

This Monte Carlo Simulation is done for a variety of items across the entire estimate, at the same time. The outcomes of all these calculations and analyses provide a statistical probability curve of outcomes for the overall project. Picking a point on this curve provides the probabilistic outcome at that point, also called the P-value.

These QRA sessions collected data for the execution of the work and was modelled using an industry-standard statistical modelling tool. The output of this tool provides a range of outcomes to inform the project management team on recommended values for contingency and Management Reserve.

5.1.2 Estimated Amount

The Capital Cost Estimate is based on the 2023 Condition Assessment performed by Hatch and a unit refurbishment completed in 2019. Components of the estimate have differing levels of definition. The overall estimate is deemed to be at a Class 3, as per as per the AACE Recommended Practice No. 69R-12. However, a total of 15% of the estimate, by value, is deemed to only have a maturity of Class 5, as the level of scope certainty of these items is lower.[25] Examples of items considered as Class 5 include spare parts, miscellaneous refits such as turbine and generator shafts, and upgrades such as cooling water piping and relief valve upgrades.

The Authorized Budget for the Bay d'Espoir Unit 7 Life Extension Project is $85.3 million including life-to-date costs as well as estimated direct construction costs, indirect construction costs, contingency, escalation, IDC, and Management Reserve. Attachment 1 to this schedule provides a breakdown of the project budget.[26] Further discussion of the underlying assumptions and individual cost estimate components are provided in the following sections.

[25] Having some elements of a cost estimate less known than other elements is not unusual, especially in refurbishment projects where the status/condition of some elements are not known. By identifying elements that are less certain, and which therefore has a greater likelihood of differing from the estimate, at the line-item level, provides transparency and identifies areas of cost risk that the project team can closely monitor.
[26] A detailed cost breakdown is provided in Appendix A of Attachment 1 to this schedule.

5.1.3 Assumptions

Assumptions underpinning project execution and estimating are contained in Attachment 1 and 3, the Basis of Estimate and Basis of Schedule, respectively, to this document. Some of the key assumptions include:

- An adequate labour supply is available;
- [redacted]
- The availability of the critical long lead Turbine-Generator items is not materially different from the assumptions contained in Attachment 3;
- [redacted]
- Critical OEM components can be delivered to the site within the timelines assumed, such that construction works can proceed unhindered; and
- Regulatory approvals will be generally granted as assumed in the project schedule.

5.1.4 Base Cost Estimate – Direct Construction Costs

The Base Cost was developed by Hatch subject matter experts ("SMEs") as part of the report on the 2023 Condition Assessment. This estimate was reviewed, and in some cases, updated by Hydro SMEs. Budgetary quotations were obtained from vendors by Hydro. Hydro also used historical information from similar works to inform the estimate.

The Base Cost encompasses all key project phases, including estimates for:

- Design;
- Procurement;
- Fabrication;
- Manufacturing;
- Transport;
- Equipment assembly;

- Equipment installation; and
- Testing and commissioning.

The estimate includes information from a variety of sources. The main scopes (i.e., runner replacement, stator rewind, and rotor pole re-insulation) were all informed by recent budgetary quotes from vendors.

5.1.5 Base Cost Estimate – Indirect Construction Costs

Hydro's indirect costs include the costs for the Owner's team, as well as for a consultant. The cost estimate includes labour costs as well as additional elements such as travel and accommodations, Hydro support during construction and commissioning, as well as various corporate costs, such as insurance. The estimate for the consultant was estimated by Hydro based on benchmarking of similar projects.

5.1.6 Project Contingency

Contingency was estimated as part of the QRA described in Section 5.1.1. Further information is provided in Attachment 3 to this schedule.

5.1.7 Escalations and Interest During Construction

Hydro has developed a standardized approach to escalation projections, which is utilized on all of its projects, including BDE Unit 7. The Management Reserve does provide a mechanism to deal with a certain level of unknown market volatility that may be encountered throughout the life of the project. Further information on some of the key risks that were considered as part of the QRA can be found in Section 6.0.

Hydro also has a standard method of calculating IDC, which is applied to capital expenditures. Further information on Hydro's IDC assumptions is provided in Attachment 1 to this schedule.

5.1.8 Management Reserve

Management Reserve is an amount that is held outside of the performance measurement baseline for management control purposes. It is reserved for unforeseen risks that are within the project scope (i.e., "unknown unknowns").[27] The Management Reserve equips Hydro to respond to strategic risks or unforeseen events quickly, consistent with recommendations from the Muskrat Falls Inquiry. Projects

[27] PMBOK Guide, p. 242.

can continue to progress and remain on schedule despite obstacles outside of Hydro's control. It is an industry standard practice to include management reserve in project estimates especially for large complex projects and was a key finding within the Muskrat Falls Inquiry. Commissioner LeBlanc noted that *"A reasonable reserve for strategic risk should have been included in the Project's cost estimate and made known to [the Government of Newfoundland and Labrador]."*[28] A well-managed Management Reserve is a crucial tool that increases the likelihood that the project will succeed.

During the strategic risk process, a number of strategic risks which are generally outside of the project teams' sphere of influence were considered. These include:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Another key consideration of the Management Reserve fund was the nature of the project. [redacted]

The Muskrat Falls Inquiry recommended that for large projects a range of cost estimates should be generated, and that funding should be based on a probability of not less than 85%. The Management Reserve for the Bay d'Espoir Unit 7 Life Extension Project was calculated by determining the budget at the 85% confidence level (based on the Monte Carlo Simulation conducted as part of the QRA) and subtracting the Base Cost. Further details are contained in Attachment 1 to this schedule.

Management Reserve is included within the Authorized Budget but remains outside of the project team's authorization to spend. The use of Management Reserve funds requires approval by Hydro's Chief Executive Officer.

[28] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Finding 41, p. 53.

5.1.9 Requested Authorization Amount

Hydro is requesting an Authorized Budget of $85.3 million for the project. This value is inclusive of direct construction costs, indirect construction costs, contingency, escalation, IDC, and Management Reserve, and represents a confidence level of P85.

5.2 Project Schedule

A detailed execution schedule, supported by a schedule basis, has been developed by Hydro. The life extension project is anticipated to take four years to execute. This project Control Schedule is provided within Attachment 3 to this schedule.

The anticipated construction timeframe for the Bay d'Espoir Unit 7 Life Extension Project is 2028, with a planned return to service in the fourth quarter of 2028. This is based on several assumptions, detailed below, including the timing of delivery of long-lead equipment.

[redacted] The project Critical Path Schedule is shown in Section 7.0 of Attachment 3 to this schedule.

The schedule for this project is shown in Table 2.

Table 2: Bay d'Espoir Unit 7 Major Milestones

Milestone Description	Date
Unit 7 Life Extension RFP Issued	Q2 2025
Supplemental Application Approval	Q4 2025
Unit 7 Life Extension Contract Awarded	Q4 2025
Runner Arrival at Site	Q2 2028
Stator Rewind Complete	Q3 2028
Rotor Reassembly Complete and Tested	Q3 2028
Unit Reassembly Complete	Q4 2028
Ready for Commercial Operation	Q4 2028

5.2.1 Scheduling Constraints and Considerations

The planned work for Bay d'Espoir Unit 7 is subject to several constraints including approvals, equipment lead times, coordination with other capital works and operational constraints within the winter period.

Approvals

There are a number of risks that could impact the execution schedule. The project schedule assumes time for a thorough review and evaluation of the project through a regulatory proceeding necessary to obtain Board approval that will allow award of contract by the end of the fourth quarter of 2025.

Equipment Lead Times

The project schedule is largely driven by the lead time for the turbine components, which sets the overarching timeline for the project execution. The timeline for this major component is based on budgetary quotation information. It is critical to proceed with initial vendor engagement concurrent with Board review to maintain the project schedule, as shown in Attachment 3. These specialized vendors commit to scheduling manufacturing of components as they accept orders. Engagement activities during this period will be limited to information gathering, scheduling discussions, and proposal refinement, and no contractual commitments or orders will be made until all necessary approvals are secured.

Coordination with other Capital Works

Certain portions of the proposed planned work for Bay d'Espoir Unit 7 require coordination with other facilities located in Bay d'Espoir, most notably the construction of Unit 8. The downstream tailrace widening works necessary for the BDE Unit 8 project must be executed during a period of no flow from Unit 7. While the timing of the tailrace widening work is flexible and can be adjusted to suit the timing of the outage associated with the planned Bay d'Espoir Unit 7 Life Extension Project, a more significant schedule concern exists with respect to coordinating the work at Powerhouse 2. To minimize potential productivity and schedule impacts, it is important to align the Unit 7 life extension work with the planned start of Bay d'Espoir Unit 8 construction in 2028. If the Unit 7 life extension work is completed prior to the end of 2028, the potential interface impacts would be minimized, [redacted]

[redacted]

For these reasons, it is important to coordinate the schedules for these planned works as described herein.

Outage Window

The work is planned to be executed during the 2028 non-winter season, running from April through to November. The planned schedule indicates an ability to execute the work during that timeframe; however, given the tight timeline for the delivery of critical equipment, there is a risk of equipment not being available as required to meet project schedule.

As the work involves the dismantling and replacement and refurbishment of components, the condition of some components may not be fully known until the unit is disassembled. Furthermore, some of the work involves remediation of non-mechanical turbine components, such as the portions of the turbine that are embedded in concrete. While there are plans for specific remediation and repair work, the full extent of the remediation and repair is unknown until the work is underway. To help mitigate this risk, Hydro has planned a discovery phase for the beginning of the outage to better understand the scope of remediation.

Electrical Grid Interactions

Certain portions of the commissioning work, post remediation, for Bay d'Espoir Unit 7 requires interaction with the electrical grid. The project schedule has this work occurring prior to the winter period.

6.0 Key Risks and Mitigations

A summary of key risks identified during the planning and execution of the project, as well as associated controls and risk status, provided in Table 3.

Table 3: Summary of Top Project Risks

[redacted]

[redacted]

[redacted]

6.1.1 Risk of Asset Stranding

As Hydro's largest hydroelectric generating unit, Unit 7 is a critical component of the Island Interconnected System and is required to provide generation and synchronous condenser capability for the foreseeable future. Hydro's *Reliability and Resource Adequacy Study Review* has identified the need for additional supply to meet Hydro's future generation needs, thus the risk of asset stranding is low.

6.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the proposed project in accordance with Hydro's Capital Risk Assessment process. The outcome of this assessment is provided in Table 4.

Table 4: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	4	**20**
Post-Implementation	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**5.7**

7.0 Conclusion

Bay d'Espoir Unit 7 is a critical hydroelectric generating asset that has provided reliable service for nearly five decades. However, a recent independent condition assessment has identified significant deterioration and obsolescence in key components, necessitating major refurbishment and modernization to preserve long-term operability. Without this investment, the risk of forced outage and loss of 154 MW of capacity to the Island Interconnected System would be substantial, with potential consequences for system reliability and resource adequacy.

Hydro recommends proceeding with the full project scope for the life extension of Unit 7. Critical components such as the runner, stator and rotor windings, and auxiliary systems have a normal service life ranging from 40 to 55 years and a recent condition assessment has shown substantial signs of deterioration and obsolescence. This approach represents the most cost effective, least-risk solution to extend the asset's useful life by at least 25 years while optimizing efficiency and supporting future system planning. The scope of work has been designed to align with Hydro's legislated mandate to provide least cost reliable service in an environmentally responsible manner.

The proposed life extension of Unit 7 represents a prudent, strategically timed investment to sustain critical generation capacity, mitigate reliability risks, and ensure continued alignment with Hydro's long-term system planning and operational goals.

Appendix A

Project Scope Table

Item No. (Hatch Report Appendix D)	Component/Topic	Status	Deficiency Description	Do-Nothing Consequence	Recommended Actions	Justification	References (Attachment 1)	Hydro Action (Life Extension Scope)
1	Stator Core	Good	Slightly oval circularity on lower plane. Circularity of the stator core as measured on three planes is reported to be more oval on the plane close to the bottom of the unit, matching the profile of the embedded structures. However, it is still within CEATI tolerances.	Progression of oval circularity can influence.	Adjust circularity during stator rewind.	Necessary for maximum life extension.	Section 3.4.2	Circularity to be adjusted during stator rewind.
2	Stator Core	Good	Air guide seal bend is recorded to have approximately 30% of the rivets loose which potentially can damage insulation of the bars behind if take off.	Detachments of the rivets can damage the bar insulation behind the insulating band or end up in the airgap.	Rewind the stator armature winding.	Necessary for maximum life extension.	Section 3.4.3	Rewind Stator Armature Winding. Air guide is to be replaced during the stator rewind and rivetted connections are to be replaced with cap screw, or approved alternative.
3	Stator Core	Good	Slight inwards conical verticality at the top. Verticality of the stator core is reported to be 85% within CEATI tolerances with remaining 15% out of the CEATI tolerance in direction of the bore, suggesting that the core is leaning inwards towards a conical shape.	Progression of oval circularity can influence magnetic pull balance. Increase in vibration and loss efficiency of the generator.	Adjust verticality after core clamping during stator rewind.	Necessary for maximum life extension.	Section 3.4.2	Verticality to be adjusted during stator rewind.
4	Stator Core	Good	Loose Core	Progression of looseness	Adjust verticality after core clamping during stator rewind.	Necessary for maximum life extension.	Section 3.4.2	Verticality to be adjusted during stator rewind. Core clamping bolts to be tightened, as required.
5	Stator Frame	Good	Metallic debris in frame and bottom end caps.	Serious in-service failure with damage to equipment and forced outage.	Clean and inspect to prevent accumulation. Perform during next planned outage or available opportunity.	Life extension.	Section 3.4.1	Stator frame to be cleaned and inspected.
6	Stator Armature Winding	Poor	Aged stator armature winding, including visual indications of localized high stress. Distributed cracks in the ground wall insulation close to the bar entrance to the cap and close to the lashing point which it is sign of movement and potentially vibration of the end-winding. End-winding caps at the bottom of the unit in slots from 194 to 200 have significant stress of ground wall insulation. It seems that a proper overlap of epoxy resin and cap compound (mixture of the mica powder and resin) was not achieved during installation. Online PD activity shows slot discharges that are not overt on offline tests. This suggests a potential looseness of the winding.	Serious in-service failure with damage to equipment and forced outage.	Rewind the stator armature winding.	An abnormal event (such as overspeed, single-phase trip, switching surge, etc.) striking an aged winding is more likely to drive it to electrical failure.	Section 3.4.3	Rewind stator armature winding.

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7	Stator Armature Winding	Poor	Significant bubbling of the paint over bars surface belonging to slot 196 in the area where the bar is going into the bottom cap is sign of possible cold joint of the two halves of the same coil being brazed inside the cap.	Serious in-service failure with damage to equipment and forced outage.	Monitor local temperature with thermal strips. See report for details.	Monitoring the development of the hot spot allows remedial action to be planned before an in-service failure happens.	Section 3.4.3	Recommendation Accepted. Area has been inspected annually since 2023 and no noted progression has occurred beyond what was identified in 2019. Another inspection is planned for 2025 and a detailed inspection will be completed during the 2026 PM9.
8	Rotor Field Coils	Fair	Missing additional turn tape over several outermost pole coil assembly turns.	Progression of additional turn tape can create turn to turn short.	Reinsulating the rotor field winding.	Presently, risk of mechanical failure in case of overspeed.	Section 3.4.7	Reinsulating the rotor field winding.
9	Rotor Field Coils	Fair	Flaking pole collars.	Degradation of the collars can short the creepage path to ground fault.	Reinsulating the rotor field winding.	Not urgent, but component is fully degraded and needs replacement.	Section 3.4.7	Reinsulating the rotor field winding.
10	Rotor Field Coils	Fair	Overall coil insulation completely degraded.	Serious in-service failure with damage to equipment and forced outage.	Reinsulating the rotor field winding.	Not urgent, but component is fully degraded and needs replacement.	Section 3.4.7	Reinsulating the rotor field winding.
11	Rotor Field Coils	Fair	Voltage pole drop test did not pass.	Turn to turn short creating unbalanced magnetic pull.	Reinsulating the rotor field winding.	Developing of additional turn-to-turn shorts will cause increased vibration.	Section 3.4.7	Reinsulating the rotor field winding.
12	Rotor	Fair	V block not installed as per OEM drawings.	Update OEM drawing to as-built condition, not u	Verify proper installation method.	n/a	Section 3.4.7	To be checked during unit reassembly. Rotor poles are to be reinstalled as per OEM drawings and procedures following reinsulation.
13	Pole Connectors	Fair	Broken lock tab on U shape connector of Pole #1.	If detached can end up in airgap.	Repair lock tab and adjust torque.	n/a	Section 3.4.7	This was inspected in 2024 and was found to be a non-issue. Locking tab is not broken, is just slightly "crooked". No risk to operation and will be inspected again during maintenance outages.
14	Pole Connectors	Fair	Frayed insulation between U shape connectors.		Reinsulate the field winding.	Not urgent, but component is fully degraded and needs replacement.	Section 3.4.7	Reinsulating the rotor field winding.
15	Pole Bodies	Fair	Rusted pole faces.	Can affect natural interlaminar insulation, so can created short during the transient condition due to tooth ripple effect.	Repair during field winding reinsulation.	Not urgent, but needed for maximum life extension.	Section 3.4.7	To be repaired during field winding reinsulation.
16	Pole Bodies	Fair	Minor dents and melt of pole laminations.	Due the location of the dent is more cosmetic than necessary functional correction.	Repair during field winding rewind.	Not urgent, but needed for maximum life extension.	Section 3.4.7	To be repaired during field winding reinsulation.
17	Rotor Field Winding	Poor	Aged and degraded insulation.	In-service failure with damage to equipment and forced outage.	Reinsulate rotor field winding.	Not urgent, but component is fully degraded and needs replacement.	Section 3.4.7	Reinsulating the rotor field winding.

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18	Runner Seal Clearance	Poor	Runner seal clearance is changing over time. Data tracked from 2006 by NL Hydro shows trending. Voith re-machined the wearing rings in 2019, recorded the as found and as-left condition, and provided analysis for estimated remaining life. Hatch took independent readings in 2023 and found the A2 location on the upper seal is above the "Upper Intervention / Critical" limit according to the Voith 2019 report.	The seal clearances are already near or exceeding the intervention limit recommended by Voith from 2019. More severe out of tolerance issues can cause vibration issues and increase in hydraulic thrust. High thrust load can decrease service life of thrust bearing or thrust bearing failure. Thrust bearing temperatures will provide indication of overloading. Do nothing analysis assumes continued monitoring and yearly measurements as currently performed.	Embedded component machining to ensure bottom ring and head covers have well-established seating surfaces and supply new wearing rings (bushings) on the head cover, bottom ring, and runner.	AAR may continue to pose a risk to embedded components and runner seal clearance. Expected life based on need to replace wearing rings and risk posed by large seal clearance. Costs included in other line items.	Section 3.13.4	Embedded components to be machined, new wearing rings to be installed. Continued vibration monitoring.
					Continue monitoring vibration and temperature of bearings with yearly runner seal clearance measurements.	Reduce risk of unplanned outages and sudden failure or issues.		
19	Runner Cavitation	Poor	Cavitation damage at several locations on the runner. The runner has been weld repaired several times and the cavitation damage is an ongoing problem.	Cavitation will continue and may cause structural damage to the runner. Cavitation can also cause poor hydraulic performance. If no action is taken, the runner will continue to cavitate. Hatch estimates that if NL Hydro operates the units within the known cavitation limits and performs regular inspections of the runner, the estimated service life is 5-10 years. Voith recommended to replace the runner within 5 years of 2019 report.	Supply a new stainless-steel runner.	A stainless-steel runner can be more cavitation resistant and not require painting like the current carbon steel runner. A new hydraulic profile and design can provide increased efficiency and reduce the likelihood of cavitation. Runner replacement with estimated 2% increase in efficiency is optimal solution according to Hatch Uprate Report (H371822-0000-2A1-066-0002). It is possible to perform cavitation repairs on runners, but this cannot be performed indefinitely. There is risk to weld deformations causing hydraulic tolerance issues and structural issues with layered weld repairs. Hatch does not recommend additional weld repairs beyond the extent currently performed. As NL Hydro does not have blade templates, the likelihood of performing extensive weld repairs within the hydraulic tolerance is very low.	Section 3.13.1	Runner to be replaced. Efficiency testing will be part of the runner replacement work.
					Perform an index test or an absolute efficiency test for a new runner (Dye Dilution Test).	Perform an index test or an absolute efficiency test for a new runner to ensure desired performance.		

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20	Runner Wearing Rings	Fair	Contact damage and minor cavitation. Contact damage believed to be from the 1970's based on inspection photos during that time.	There is little structural risk with the given damages as they are more of a consequence of other issues or events. However, significant cavitation or damage to the rings may cause an imbalanced seal that can lead to pulsing or vibrations. Cavitation damage likely to continue at an exponential rate if seal clearances continue to change.	Replace wearing rings along with new runner.	Costs included with runner replacement.	Section 3.13.2	Wearing rings to be replaced. Continued vibration monitoring and inspection.
					Monitor turbine vibration and annual inspection of runner seal clearances.	Reduce risk of unplanned outages and sudden failure or issues.		
21	Runner Cover Plate	Good	2019 outage found cracking and piece broken off the	There is a low risk of the cover plate failing again.	Replace Runner	Costs included with runner replacement. Risk of lead impact on environment is	Section 3.13.3	Runner to be replaced.
22	Wicket Gates	Good	Concentricity of trunnions were not verified during rehabilitation in 2019. Surface finish of gates stems above OEM tolerance. Wear and scoring on gate stems. Moderate scratches and dents on the gate leaves.	Out of concentricity tolerance can lead to binding of the wicket gates and pre-mature wear of the gate stem bushings. It can also impact the alignment of the wicket gate vertical seals when in the closed position. Scratches and scoring	Rehabilitate Existing Gates.	Hatch recommends that the base scope of supply to be rehabilitation of the existing gates with the option of new gates. New gates would need to be justified by a manufacturer to prove sufficient performance increase or by an outage schedule savings.	Section 3.9	Rehabilitation of existing wicket gates. Wicket gates may be replaced if replacement results in improved turbine efficiency - to be determined during runner design. Optional pricing and efficiency gain to be requested.
					FEA and Fatigue Life Calculation of existing gates.	Ensure life extension based on cyclical loading of gates.		
23	Turbine Shaft Seal Sleeve	Fair	2019 report by Voith showed wear of the shaft sleeve surface.	This seal surface will continue to wear. Increased wear will increase the leakage around the shaft seal. Too much leakage can cause water damage to other components in the turbine pit.	Replace shaft sleeve on turbine shaft and carbon seal rings. Inspect and rehabilitate the shaft seal housing assembly.	Cost of shaft sleeve included with turbine shaft recommendations. Cost of new carbon seals and rehabilitation shown in this row.	Section 3.7	Shaft sleeve to be replaced. Inspection and rehabilitation of shaft seal housing assembly.

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24	Turbine Shaft	Fair	There was no dimensional inspection or NDE performed in 2019. There was also no visual assessment of the turbine shaft coupling flange. The risk is associated with the unknown condition of the shaft and flanged connection to the runner. There were light scratches and dents on the turbine guide bearing journal reported in 2019.	If nothing is done, the expected shaft has an estimated remaining life of 10 years. Rough or damaged bearing journal surfaces can impact bearing life and operation. If a new runner is supplied, the shaft would require machining of the spigot and coupling bores to ensure a proper fit-up to the new runner.	Shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. A new shaft sleeve should be installed as well as new coupling hardware between the shaft and runner. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft. To adapt a new runner, the runner end spigot and runner end coupling bores should be re-machined.	Necessary for service life of 25 years or longer. Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new shaft for the turbine. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.	Section 3.9	Turbine shaft to be cleaned, inspected, rehabilitated, and painted. New shaft sleeve to be installed. FEA and fatigue analysis to be completed. An option to replace the existing oil filled turbine guide bearing with a water lubricated bearing will be investigated. If this option is selected the turbine shaft will need to be modified or replaced.
25	Generator Shaft	Fair	From visual inspection: Discoloration and scoring on the rotor coupling flange believed to be from the coupling hardware. There was no dimensional inspection or NDE performed in 2019. The risk is associated with the unknown condition of the shaft and flanged connection to the runner.	If nothing is done, the expected shaft has an estimated remaining life of 10 years.	Shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft.	Necessary for service life of 25 years or longer. Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new generator shaft. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.	Section 3.8	Generator shaft to be cleaned, inspected, rehabilitated, and painted. FEA and fatigue analysis to be completed.
26	Operating Ring and Bearings	Poor	Significant surface damage on the upper and lower operating ring bearing journal surfaces. Operating ring has deformed over time is now an oval shape. Issues with temporary bearing pads installed in 2019.	Bearing pads will continue to come out of place and cause damage to the operating ring and the head cover. Grease from the operating ring bearing is not contained and may contaminate turbine pit equipment. Sever damage may prevent gates from opening.	Inspection and Rehabilitation of Operating Ring and Supply of New Bearing Pads. As an option, a new operating ring with a split should be considered by NL Hydro as the bearing pads can be changed without major disassembly of the unit.	As the current bearing pads have already caused issues, regular maintenance and monitoring is required. Expected service life based on bearing pad life. Operating ring life expected to be 40 years.	Section 3.10.2	Based on the condition of the operating ring and its criticality in control of unit operation, it has been decided to replace the operating ring.
27	Gate Servomotor Scoring	Fair	NL Hydro believes that there was leaking in the servomotors prior to 2019. Scoring on the ID of the cylinder wall discover in 2019 and not addressed. Scoring on the piston.	Leakage around piston and loss of pressure.	Inspection, rehabilitation, and replace wear components. Recommend to complete work in parallel with operating ring.	Life extension.	Section 3.10.1.1	Inspection and rehabilitation of servomotor components. Replacement of wear components.
28	Wicket Gate Link Pins	Fair	Pins dropping out could cause damage to arms and links in addition to losing control of a wicket gate.	Pins dropping out could cause damage to arms and links in addition to losing control of a wicket gate.	Replace link pins.	Expected service life is based on new bushings. New pins expected service life is 50+ years.	Section 3.10.3	Link pin replacement.

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29	Spiral Case Access Door Leakage	Poor	Water leakage around the spiral case access door.	It's not possible to provide a confident outlook if nothing is done. If the condition has been in existence for 30+ years as reported by NL Hydro, it could continue as is for another 15 or 20 years. Or it could become a more urgent issue if the leakage rate increases rapidly. Exact consequences are unclear as the root cause is not identified. The current leakage rate does not appear to be causing other significant issues. NL Hydro could continue to monitor the flow rate.	Hatch recommends monitoring and collect leakage data. If the average flow rate increases month over month for more than three (3) consecutive months, or if there is a sustained average flow rate over 3.0 L/s over a given month, that NL Hydro investigate the problem further and perform the following recommended repairs.	Reduce risk of unplanned outages and sudden failure or issues.	Section 3.11.4.1	Leaks will be investigated during dismantling of unit and action taken to reduce or eliminate them. Cleaning and coating the embedded parts is part of the life extension work.
					Seal weld stay ring flange to discharge ring. This will likely cause distortion of the discharge ring surface where the bottom ring mounts to. Therefore, field machining of embedded components is required. This field machining would be recommended in either situation as to ensure proper alignment of the bottom ring to head cover, ensure level mounting surfaces, and ensure the bottom ring flange with the Oring has a proper mounting surface to seal.	This will resolve the most likely source of the water source. Not guaranteed to prevent all water leakage around spiral case access door.		
					Lead abate, blast, clean, NDE, and paint the spiral case, stay ring, stay vanes, discharge ring, and draft tube liner down to the maintenance platform. Perform local repairs as necessary.	Improve water passage surfaces and provide life extension to the embedded components. May reduce leakage if holes are present.		
					Remove spiral case baffle plate, inspect, repair as needed, and re-install baffle plate.	Less likely source of leakage but may improve leakage around access door.		
					Pressure tests all embedded piping.	Ensure embedded piping doesn't have leaks. Likely not the main source of the access door leakage, but may be a contributing factor if an embedded component has leakage.		
30	Relief Valve Leakage	Poor	Water leakage round the Relief Valve discharge piping and concrete. Water filling up the diffuser and valve when dewatered.	As the condition inside the pipe is unknown, it's difficult to provide a proper assessment.	Borescopic examination of outlet pipe and diffuser, valve rehabilitation, unknown repairs based on inspections.	Life extension of the relief valve.	Section 3.11.4.2	Borescopic examination of outlet pipe and diffuser, valve rehabilitation, repairs based on inspections. Overhaul of outlet gate. Overhauling outlet gate is not part of
					Overhaul of outlet gate.	Life extension and prevent leakage into valve when dewatering.		
31	Head Cover and Bottom Ring Gate Stem Bores	Fair	Gate stem bore alignment.	Gate stem bore wear, binding of wicket gates, and higher loading of operating mechanism.	The head cover and bottom ring gate stem bores should be either line bored or machined using matching templates.	Ensure proper alignment of the gate stem bores between the components and save on the outage schedule as to not have to line bore in the field.	Section 3.12.3	Boring and/or machining of gate stem bores.

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32	Head Cover and Bottom Ring Facing Plates and Gate End Seals	Fair	Facing plates are scratched and scored. Damage to rubber gate end seals.	Wicket gate end clearances would require continued monitoring to ensure no further damage is done to the facing plates. Gate end seals expected life is 5 years.	Replace gate end seals and facing plates.	Expected service life of new facing plates is 40+ years. Expected service life of new gate end seals is 15 years.	Section 3.12.4	Replacement of gate end seals and facing plates.
33	Head Cover	Poor	Wearing ring cavitation, scoring, scratches, and deformed shape. Cracks in stiffeners connecting to the outer flange of the head cover. Upper gate stem bushing damage. Debris from runner found in head cover with possible unknown damage.	Wearing ring damage, crack propagation, and wicket gate bushing issues (i.e. binding).	Rehabilitate existing head cover. Clean, blast, NDE, repair indications, dimensional inspection, machining of wearing ring mounting surface, water passage surface, mounting flanges, installation of new wearing ring, installation of new facing plate (or weld overlay), supply of new hardware, and paint. Gate stem bores should be line bored with bottom ring or bored with a template. Supply and install new gate stem bushings.	An assessment of the schedule and outage cost should be analyzed by NL Hydro to determine if a new head cover is justified. The head cover rehabilitation would be on or near the critical path. Any unforeseen issues or delays could cause an extended outage. Expected service life of rehabilitated head cover is 25-40 years. Expected service life of a new head cover is 50+ years.	Section 3.12.2	Rehabilitation of head cover. Cleaning. Option to replace head cover will be obtained . Replacement may ensure schedule can be achieved.
34	Bottom Ring	Poor	Cavitation damage under wearing ring. Out of tolerance water passage surface levelness.	Runner seal clearance issues and wearing damage. Wicket gate bushing issues and potential binding.	Replace	Hatch believes that the bottom ring would be able to be rehabilitated but agrees with Voith's 2019 assessment that the schedule risk may be too significant. The bottom ring is the last component out of the unit for rehabilitation and the first component needed back at site. It's also a relatively simple component that can be supplied as a forged ring or fabricated from plate steel.	Section 3.12.1	Replacement of bottom ring.
35	Thrust Collar, Keys, and Runner	Good	Thrust collar has light fretting and corrosion. Light scoring on the journal surface possibly from contact with guide bearing pads or debris. Mating surface of thrust runner to thrust collar had light signs of fretting and corrosion. Thrust keys have light fretting and corrosion.	These components being reported in good condition could remain as is for another 25+ years if the dimensional and geometric tolerances are within OEM design.	Dimensional inspection and surface finish measurements of running surfaces. Clean, machine, and polish surfaces in a rehabilitation facility to correct any dimensional, geometric, and surface finish out of tolerance issues.	Life extension of thrust collar and thrust runner.	Section 3.5.1.1	Inspection, measurement, and cleaning of running surfaces.

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36	Combined Thrust and Guide Bearing Pads	Good	Light scoring and Babbitt surface indications.	This surface is a critical surface. Given the current condition, it may be acceptable without intervention for another 5-10 years. Thrust bearing failure can be catastrophic. There is also a risk to wiping the bearing and damaging the thrust runner.	NDE inspection of the bearing pads, re-babbitt, and supply new thrust bed springs.	This will also help mitigate vibration issues by restoring the bearings and journal surfaces back to OEM condition	Section 3.5.1.2	NDE inspection of the bearing pads, re-babbitt, and supply of new thrust bed springs. Additional spare thrust bearing pads to be procured as a full set is not presently held in storage.
37	Wicket Gate Squeeze	Fair	Wicket gate squeeze is currently 0.5 inch. OEM design gate squeeze is 0.375 inch.	If nothing is done, the bearing pad failures on the operating ring are likely to continue. However, the recommendations for the operating ring bearings, the gate stem bore alignment and the gate servomotors are more critical to the long-term life extension of the turbine. Increased squeeze could cause the bearing pad screws to shear, oval the operating ring, and damage journal surfaces.	Adjust servomotor and wicket gate setting to re-establish OEM squeeze. Install upthrust clips where the OEM lip seal was.	Life extension of gate operating mechanism.	Section 3.10.4	Adjustment of servomotor and gate settings.
38	Generator and Turbine Cooling Water Strainer Pressure	Poor	Maintenance record Check sheets show consistently low water pressure in the strainer from 2020 to 2022.	Can impact cooling performance for the generator and bearings. Overheating of bearings can cause damage to the operating unit and force and outage to rebabbitt the bearings. Generator overheating can cause damage to insulation and other generator equipment.	Monitor generator and bearing temperatures. Replace strainer at end of service life.	Life extension.	Section 3.19.1	Not in scope of life extension. Routine maintenance and monitoring will continue as part of normal operation.
39	Wicket Gate Closing Time	Poor	Maintenance record Check sheets show consistently slow closing time for wicket gates.	Unit may not respond as quickly to changes. No likely damage to equipment.	Monitor closing times and servomotor pressures. Issue can be corrected with gate servomotor rehabilitation and operating ring overhaul.	Monitoring can prevent unplanned outages.	Section 3.19.2	Unit will be commissioned as part of this work, closing times and operating pressures will be adjusted and recorded to form the basis of maintenance check sheets going forward.
N/A- Hydro Proposed	Governor Control System	Fair	Workforce knowledge of this legacy governor is dwindling over time. In addition, system response testing has determined that this governor is not able to provide a faster response as-is.	Risk to operation and reliability in future.	Upgrade the governor to a digital head that can utilize the existing HPU, oil system, and gate servomotors.	Improves operation.	Section 3.15	Modernize the existing mechanical governor to a digitally controlled governor.
N/A- Hydro Proposed	Excitation Control System	Obsolete	ABB Unitrol F Excitation controls are obsolete. This was noted in the Hatch report.	Support and spares are limited, risk of unnecessary downtime.	Upgrade excitation controls to ABB Unitrol 6000 platform to match what has been completed for Units 1-6.	Obsolesce and risk to reliability.	Section 3.16.2	Upgrade excitation controls.

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N/A- Hydro Proposed	Turbine Guide Bearing	Fair	Eliminate the use of oil in the bearing by replacing the existing bearing with a water lubricated bearing. This reduces the amount of oil used in the equipment and reduces the risk of a spill.	No effect on the operation.	Obtain a proposal for replacement of the bearing.	Reduce environmental risk.	N/A	Through detailed engineering assess the technical viability, lifecycle cost and reliability impacts of the water lubricated bearing. Installation will be dependent on the outcome of this analysis.
N/A- Hydro Proposed	Dust Collection System	Not Currently Installed	Carbon brush wear from collector assembly during normal operation results in contamination to stator and rotor windings. To prevent contamination, a specifically designed dust collection system can be provided that removes the carbon from the area via vacuum process.	New stator and rotor windings are subject to more contamination and require more frequent cleaning to ensure reliable operation.	Procure dust collection system for installation during outage.	Prevent contamination to ensure reliable operation and to reduce the need for partial disassembly to clean and remove contamination.	N/A	Install dust collection system.
N/A- Hydro Proposed	Turbine Pit Monorail and Hoist	Not Currently Installed	Conducting maintenance in the turbine pit with the rotor installed is difficult and introduces potential safety hazards.	Continue to perform limited maintenance with the rotor installed, using temporary lifting devices. This may result in costly and time consuming disassembly if work cannot be completed with the rotor in place.	Design and install a turbine pit monorail and hoist to facilitate more efficient and safer maintenance operation in the turbine pit.	Maintenance efficiency and safety improvements.	N/A	Design and install turbine pit monorail and hoist.
N/A- Hydro Proposed	Unit Control System	Obsolete	Hardwired controls are original and are obsolete.	Components will continue to age and obsolescence has potential to result in unplanned downtime.	Modernize control system to integrate with all other control systems and unit protection. Allow integration with existing asset monitoring systems and the potential BDE Unit 8 system.	Maintain reliability.	N/A	Modernize unit control system at the same time as major electro-mechanical work, governor and exciter upgrades to minimize future outage time and recommissioning activities.

Schedule 1, Attachment 1

Basis of Estimate

newfoundland labrador hydro

Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

NLH Doc. No. BDE-NLH-40000-ES-BOE-0002-01

Comments: The Bay d'Espoir Unit 7 Life Extension Basis of Estimate presents the cost estimate and basis for the project, and methodologies used to estimate project elements, including direct costs, indirect costs, escalation and borrowing. This document has been prepared in alignment with AACE International Recommended Practices.	**Total # of Pages (including Cover): 225**
This document contains confidential and commercially sensitive information. Access to this document and the information contained within is restricted and should only be shared with the written approval of the Manager, Project Controls for Major Projects.	

B0	30-May-2025	Use	Doug Maloney	Tony Scott	Mark Howell	Marc Cullen
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Sr. Estimator, Major Projects	**Approved By** Manager, Project Controls, Major Projects	**Approved by** Project Manager, Bay d'Espoir Unit 7	**Approved by** Program Manager, Major Projects
These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.						

hydro	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
NLH Doc. No.	**BDE-NLH-40000-ES-BOE-0002-01**	**Revision**	**B0**	**Page**	**i**

Additional Approvals

Additional approvals are required for further authorization due to document contents, complexity, prescribed requirements, or multi-departmental involvement.

Position	Name	Signature	Date (DD-MMM-YYYY)
Director, Major Projects & Asset Management	Gail Randell		04-JUN-2025
Senior Manager, Major Projects PM & Engineering	John Walsh		4 JUN 2025
Senior Manager, Major Projects Commercial	John Skinner		4-Jun-2025

Endorsements

Endorsements indicate support or acknowledgement of this document's contents but do not imply formal approval. Endorsements are used to represent subject matter experts who have provided input but do not hold final decision-making authority for this document.

Position	Name	Signature	Date (DD-MMM-YYYY)
Sr. Cost Controller, Major Projects Project Controls	Brian Marsh		04 JUN 2025

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newfoundland labrador hydro	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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1.0 Executive Summary

Unit 7 at the Bay d'Espoir Hydroelectric Generating Facility (BDE) is a 154.4 MW vertical Francis hydroelectric unit located in Powerhouse 2. The unit is comprised of a generator and turbine assembly with the capability to generate as well as act as a synchronous condenser as required to meet system requirements.

In 2023, a condition assessment was conducted by Hatch Ltd. to develop a plan to correct issues identified during refurbishment work done in 2019. The assessment concluded that refurbishment and replacement work were necessary to ensure the reliable long-term operation of the unit. The report issued in 2024 included cost estimates for the recommended scopes of work.

The BDE Unit 7 Life Extension Project (BDE Unit 7 Project) has been proposed by Newfoundland and Labrador Hydro (Hydro) to complete the work required to address the recommendations in the condition assessment report, as well as recommendations from Hydro's Long-Term Asset Planning (LTAP) Team.

In addition to the estimated costs in the condition assessment, Hydro developed estimates for Hydro's project management and Owner's cost, Escalation, and Interest During Construction (IDC).

The project estimate includes:

- Refurbishment and replacements
- Equipment and materials
- Commissioning
- Engineering, Procurement, and Construction Management (EPCM)
- Owner's cost
- Camp construction
- Accommodations
- Escalation
- IDC
- Contingency
- Management Reserve

The base cost estimate for the project is [redacted] (2024 $CAD).[1] Components of the estimate have differing levels of definition. 85% of the estimate is considered commensurate with the requirements of a Class 3 estimate, as per the Association for the Advancement of Cost Engineering International (AACE)

[1] All costs referenced herein are expressed in Canadian dollars unless noted otherwise.

Recommended Practice (RP) No. 69R-12. The remaining 15% of the estimate is considered to be Class 5, using the same AACE RP. As a composite, the estimate is deemed to be a Class 3.

Escalation and IDC were calculated based on a cost profile developed from the project schedule.

Contingency and Management Reserve were calculated using a Monte Carlo Simulation (MCS) based on a Quantitative Risk Assessment (QRA) process.

A summary of the Total Installed Cost estimate is given in Table 1.

Table 1: Cost Estimate Summary ($2024)

Component	Estimated Cost
Direct Construction Costs	[redacted]
Hydro's Indirect Costs	
Found Work Allowance	
Subtotal Base Cost (Direct + Indirect) Estimate	
Project Contingency	
Subtotal Base Estimate (with Contingency)	
Escalation	
IDC	
Subtotal Planned Budget	
Management Reserve (P85 value)	
Total Cost Estimate (Authorized Budget)	**85,346,227**

2.0 Terms and Definitions

The following terms and definitions provide clarity on key terms and concepts used throughout the document.

Term	Definition
Agreement	Also referred to as a purchase order or commitment. Means a legal agreement that binds a party to a financial commitment and/or obligation with another party that provides goods, services, equipment, or materials with a desired delivery time and with specific quantities and processes.

Term	Definition
AACE	Association for the Advancement of Cost Engineering International. An international industry organization that publishes many Recommended Practices to aid in guiding project management professionals in many aspects of project execution. The AACE Recommended Practices provide useful guidance but are not standards.
Bay d'Espoir Facility (BDE)	Bay d'Espoir Hydroelectric Generating Facility
CAD	Canadian Dollar
Contingency	An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.[2]
Contractor	Any Vendor, Manufacturer, Supplier, or Consultant who enters into an Agreement with Hydro for the supply of goods or services.
EPCM	Engineering, Procurement, and Construction Management
Escalation	A provision in costs or prices for uncertain changes in technical, economic, and market conditions over time.[3]
FAT	Factory Acceptance Test
FEED	Front-End Engineering Design. A major part of FEP; It includes sufficient field investigations and engineering to establish a contracting strategy and Class 3 cost estimate.
FEP	Front-End Planning. A stage in project planning that includes project execution planning, environmental management planning, FEED, supply chain management planning, and construction planning.
Found Work	Unanticipated work that is discovered during the execution phase of a project.
GBP	British Pound Sterling
GDP	Gross Domestic Product
HPOIS	High Pressure Oil Injection System

[2] As per AACE RP 10S-90.
[3] As per AACE RP 10S-90.

Term	Definition
Hydro	Newfoundland and Labrador Hydro and/or a subsidiary.
IDC	Interest During Construction. The cost for the use of capital, sometimes referred to as the time value of money.[4]
LTAP	Long-Term Asset Planning
MCS	Monte Carlo Simulation
OEM	Original Equipment Manufacturer
PF	Productivity Factor
PUB	Public Utilities Board
PVP	Procurement Vendor Package
QRA	Quantitative Risk Analysis
RACI	Responsible, Accountable, Consulted, and Informed
RAS	Required at Site
RFP	Request for Proposals
SME	Subject Matter Expert
USD	United States Dollar
WBS	Work Breakdown Structure

3.0 References

The following is a list of documents that are either referenced in this Bay d'Espoir Unit 7 Basis of Estimate document or are relevant to the subject matter contained within.

Reference	Document Title
AACE RP 10S-90	Cost Engineering Terminology[5]

[4] As per AACE RP 10S-90.
[5] AACE International. (July 24, 2024) Recommended Practice 10S-90, *Cost Engineering Terminology*. <https://www.pathlms.com/aace/courses/2928/documents/3796>.

Reference	Document Title
AACE RP 31R-03	Reviewing, Validating, and Documenting the Estimate[6]
AACE RP 34R-05	Basis of Estimate[7]
AACE RP 69R-12	Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Hydropower Industry[8]
BDE-NLH-40000-EN-BOD-0002-01	Bay d'Espoir Unit 7 Life Extension Basis of Design
BDE-NLH-40000-PM-CHT-0002-01	Bay d'Espoir Unit 7 Life Extension Project Charter
BDE-NLH-40000-PL-BOS-0002-01	Bay d'Espoir Unit 7 Life Extension Basis of Schedule
BDES-2TFS70-0000-10066279	Unit 7 Refurbishment Report (2019)
BDE-HAT-00000-EN-REP-0001-01	Bay d'Espoir Unit 7 Condition Assessment Condition Report
BDE-NLH-40000-ES-EST-0002-01	Bay d'Espoir Unit 7 Life Extension Project Cost Estimate[9]
Muskrat Falls Inquiry Final Report	Muskrat Falls: A Misguided Project[10]

4.0 Introduction

BDE Unit 7 is a 154.4 MW vertical Francis hydroelectric unit located in Powerhouse 2. The unit was commissioned in 1977 and has operated reliably with periodic upgrades to individual components and auxiliary systems as needed.

A Level 2 Condition Assessment was carried out in 2023 to determine the remaining useful life of the generator/turbine. The condition assessment determined that the unit requires major intervention within the next five years to replace and refurbish major components such as the runner, stator, and rotor.

The BDE Unit 7 Project has been proposed to manage the work required to address the recommendations in the condition assessment report.

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[6] AACE International. (May 12, 2009) Recommended Practice 31R-03, *Reviewing, Validating, and Documenting the Estimate*. <https://www.pathlms.com/aace/courses/2928/documents/3815>.
[7] AACE International. (October 5, 2021) Recommended Practice 34R-05, *Basis of Estimate.* <https://www.pathlms.com/aace/courses/2928/documents/3819>.
[8] AACE International. (August 7, 2020) Recommended Practice 69R-12, *Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Hydropower Industry*. <https://www.pathlms.com/aace/courses/2928/documents/3852>.
[9] "Bay d'Espoir Unit 7 Life Extension Project Cost Estimate," Newfoundland and Labrador Hydro, Rev B0 (Excel support file).
[10] "Muskrat Falls: A Misguided Project," Commission of Inquiry Respecting the Muskrat Falls Project, March 5, 2020, vol. 1, p. 61, Key Recommendation 5. <https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf>.

The Level 2 Condition Assessment provided cost estimates for the identified scopes of work. Hydro assessed the provided estimates and obtained additional information, such as quotations from Suppliers, where warranted, to develop an overall contract estimate.

Hydro completed the Owner's cost estimate, which included Hydro's project management and overhead costs. The total estimated installed cost for the project is the sum of the contract cost estimate and the Owner's cost estimate. 85% of the cost estimate is considered commensurate with the requirements of a Class 3 cost estimate, according to AACE RP 69R-12. The remaining 15% of the estimate is considered to be Class 5. As a composite, the estimate is deemed to be within the bounds of a Class 3 estimate.

5.0 Purpose

The purpose of this document is to present the capital cost estimate and estimate basis for the BDE Unit 7 Project, for approval to commence project work, as well as to document the capital cost estimate preparation.

This document has been prepared using AACE RP 34R-05 and AACE RP 31R-03 as a general guide.

6.0 Project Scope

The project scope for BDE Unit 7 Life Extension consists of the following.

6.1 Direct Scope

The direct scope of work includes the refurbishment of the turbine and generator, the upgrade of some components, and the provision of spare parts.

- Turbine & Generator Major Refit:
  - Replacement of runner and bottom ring
  - Replacement of stator windings
  - Re-insulation of rotor poles

- Refurbishment and/or replacement based on the Turbine & Generator Supplier design and inspections:
  - Thrust collar and thrust ring
  - Head cover
  - Bottom ring
  - Facing plates
  - Turbine shaft
  - Generator shaft
  - Wicket gates

    - Servo motors and dashpot
    - Operating ring
    - Links, levers. and pins

- Refurbishment, replacement, modernization and/or installation:
    - Stator core (refurbish)
    - Rotor pole bodies, rotor spider and hub (refurbish)
    - Relief valve (refurbish)
    - Governor controls modernization
    - Exciter controls (modernization)
    - Unit controls (modernization)
    - Turbine bearing and shaft seal replacement
    - Synchronous condenser level controls (refurbish)
    - Turbine pit hoist (install)
    - Generator dust collector (install)
    - Cooling water piping (modernize)
    - High-pressure lift system (refurbish)

- Site Works
    - Address spiral case leakage
    - Line boring of head cover and bottom ring
    - Machining of stay ring flanges
    - Asbestos and lead abatement

- Spare Parts:
    - Brake shoes and seals
    - Bearing pads and springs
    - Set of seals
    - Slings
    - Miscellaneous tooling

6.2 Hydro's Indirect Costs

Hydro's indirect costs include:

- FEED: Up to May 2025
- Detailed Design and Procurement: June to December 2025
- Owner's Cost in Project Phase: January 2026 to [redacted]
- Powerhouse crane testing and certification
- Accommodations and turnarounds
- Emergency response
- Work Protection Team
- Camp construction
- EPCM

6.3 Allowances

- Found Work Allowance

7.0 Estimate Methodology

7.1 Direct Scope

The estimate for direct scope was initially developed by Hatch SMEs as part of the Level 2 Condition Assessment report issued in 2024. This estimate has been reviewed and, in some cases, updated as a result of review by Hydro SMEs.

For the major scopes (e.g., runner replacement, stator rewind, and rotor pole re-insulation), Hydro obtained budgetary quotes from Suppliers.

Estimates for other scopes are a combination of Hatch estimates and Hydro estimates, which are based on a combination of SME assessment, historical costs, and Supplier quotes.

Contractor indirect costs are not directly attributable to the completion of an activity or an asset and are not a part of the final installation; however, they are required for the orderly completion of the installation. These costs include various support facilities, activities, staff, and other miscellaneous costs.

For this estimate, it is assumed that Contractor Indirect Costs are considered and included in the Contractor direct costs.

7.2 Hydro's Indirect Costs

Components of Hydro's indirect costs are listed in Section 6.2.

Hydro's Owner's team costs are the costs that will be incurred by Hydro directly. These costs were estimated by the Hydro Major Projects estimator, in collaboration with the BDE Unit 7 Life Extension project team.

A major element of these costs is the Owner's team itself, the cost of which was developed using the roles required for the project, the estimated amount of time that these roles would be engaged by the project, and applicable labour rates.

Expenses, such as travel and accommodation costs, are also included.

Hydro's indirect cost estimate includes the following:

- Hydro's Major Projects Department Management Team
- Hydro's BDE Unit 7 Project Management Personnel
- Hydro's Major Projects Department Project Services Personnel
- Hydro's Engineering Personnel
- Hydro's Construction and Commissioning Site Personnel
- Hydro personnel expenses
- Sunk costs
- Insurance
- Camp construction
- Accommodation and turnaround costs
- Emergency response and work protection teams
- EPCM costs

Note that Hydro's Owner's team activities are divided into three phases:

- FEED: Up to May 2025
- Detailed Design and Procurement: June to December 2025
- Owner's Cost in Project Phase: January 2026 to [redacted]

7.2.1 Hydro's Major Projects Department Management Team

The Major Projects Department Management Team is responsible for managing and supporting all Major Projects and supporting BDE Unit 7 Project Management Personnel, as opposed to managing specific BDE Unit 7 Project activities.

The Project Manager developed the roster for Hydro's Major Projects Department Management Team and assigned hours for each position based on their expected engagement on the project.

Some Major Projects Department Management Team roles will not charge to the project because they are deemed to be operational charges, as per Hydro's finance direction. For example, the Director, Major Projects & Asset Management will primarily work at the Portfolio and Corporate level and will not charge directly to projects. No costs have been included for this position.

7.2.2 Hydro's BDE Unit 7 Project Management Personnel

The Project Manager developed the roster for Hydro's Unit 7 Project Management Personnel and assigned hours for each position based on their expected engagement on the project.

7.2.3 Hydro's Major Projects Department Project Services Personnel

While BDE Unit 7 Project Management Personnel are responsible for managing the project, the Major Projects Department Project Services Personnel are responsible for managing and providing services such as planning, estimating, cost control, procurement, financial services, and document control.

The hours for the Major Projects Department Project Services Personnel were estimated based on their expected engagement on the project.

7.2.4 Hydro's Engineering Personnel

The expected level of effort for engineering that will support the BDE Unit 7 Project is based on engineering performing the following tasks for the project:

- Reviewing engineering drawings and other technical documents from the EPCM Contractor[11] and other Contractors, for acceptance on behalf of Hydro
- Managing contracts for the procurement of components
- Answering technical queries
- Travelling out of province to Supplier facilities to participate in FAT, etc.

The hours for Hydro's Engineering Personnel were estimated based on their expected engagement on the project.

7.2.5 Hydro's Construction Oversight and Commissioning Site Personnel

The expected level of effort for Hydro's Construction Oversight and Commissioning Site Personnel is based on performing the following tasks at the Bay d'Espoir work site:

- Oversight of construction and commissioning work activities, including EPCM Contractor
- Provide authority for site decisions
- Answer site-related queries

[11] BDE Unit 8 Project EPCM Contractor selection process includes the opportunity to support (where needed) the various BDE facility Major Projects under consideration. For the BDE Unit 7 Project, utilizing a site-wide Construction Management Contractor would provide synergies.

- Manage the Turnover to Hydro Operations

The hours for the Construction Oversight and Commissioning Site Personnel were estimated based on their expected engagement on the project.

7.2.6 Hydro Personnel Expenses

Hydro personnel expenses include costs for business travel and safety events/incentives. Expenses for personal protective equipment, such as hard hats, steel-toed boots, gloves, safety glasses and hearing protection, are not included as a separate cost under expenses because it is built into the hourly rates for both Employees and Contractors.

Travel expenses, as applied to the Owner's estimated costs, include the following cost types:

- Modes of Transportation, such as flights, taxis, rental cars, fleet vehicles, and personal vehicles
- Meal per diems
- Accommodations, such as hotels

Travel expenses include costs for travelling outside the province, and to and from the construction site in Bay d'Espoir. The out-of-province travel expenses are for Hydro Engineering and Operations Personnel to check on Supplier progress, attend equipment FATs, and complete checkpoint inspections. The expenses for travelling to and from Bay d'Espoir are for the Hydro Construction and Commissioning Site Team, and periodic meetings and reviews performed by Hydro's Project Management and Engineering Personnel.

If in-province travel is required, other than travel to and from Bay d'Espoir, it will be due to some of the equipment being sourced within the province. If this is the case, some of the estimated costs for travelling outside the province will be reallocated to the costs for in-province travel expenses.

7.2.7 Sunk Costs

Sunk costs to the end of February 2025 are included in the estimate.

7.2.8 Insurance

An allowance for insurance is included in Owner's Cost in the estimate, based on input from Hydro's Commercial, Finance, and Risk Departments.

7.2.9 Accommodation and Turnaround Costs for Construction Personnel

The accommodations and turnaround costs for Construction Personnel are based on an estimated number of construction hours and shifts, with an accommodation allowance of [redacted].

7.2.10 Emergency Response and Work Protection Teams

The estimate for Emergency Response is based on an estimate developed for the BDE Unit 8 project, with 1 ambulance, 2 paramedics, 1 fire truck, and 5 dedicated firefighters. The cost is shared across the projects at the Bay d'Espoir Facility, with the cost for BDE Unit 7 prorated based on BDE Unit 7 duration and construction crew size.

The estimate for the Work Protection Program assumes 1 person dedicated to work protection activities for 9 months.

7.2.11 Camp Construction

The BDE Unit 7 estimate assumes a separate camp will be constructed for the project. The estimated cost is based on an estimate developed for BDE Unit 8, prorated for [redacted] instead of [redacted].

7.2.12 EPCM Costs

Engineering support, procurement support, and construction management for the project will be done by an EPCM Consultant chosen by Hydro through a competitive RFP procurement process. The EPCM Consultant's estimated cost is based on benchmarking of comparable projects.

7.3 Escalation and IDC

Hydro has a standard method of calculating IDC, which is applied to capital expenditures. This method was applied to this cost estimate.

The amount of applied Escalation and IDC depends on the cost profile and when project expenditures are incurred. The cost profile for each item in the estimate was developed based on the project schedule and distributed monthly across the project timeline.

Escalation was estimated by factoring the estimated costs in a given year by appropriate escalation factors, and IDC costs were estimated based on the cost profile and the applicable Hydro corporate interest rate, as described in Sections 10.4 and 10.5.

8.0 Design Basis

The objective of the BDE Unit 7 Project is to extend the life of the generating equipment by 25 years through the replacement or refurbishment of turbine and generator components and auxiliary equipment.

The project scope has been developed based on a condition assessment study issued in 2024 by Hatch. Input for the assessment came from inspections and measurements taken during the dismantling of BDE Unit 7 in 2019 and site inspections completed by Hatch in 2023.

The execution strategy is based on issuing a contract to a turbine and generator OEM to dismantle the turbine and generator, inspect and replace or refurbish the components, and reassemble and commission the unit. The successful OEM will be responsible for all engineering work associated with the replacement or refurbishment of equipment. Stress and fatigue analysis will be required on major components that have been identified for reuse to confirm suitability for an additional 25 years of service. Minor components will be inspected and refurbished or replaced as necessary.

Due to the condition of the existing runner, a replacement runner will be designed. Input to the runner design will reflect the changes in reservoir levels and operating regime that have occurred since the unit was commissioned in 1977. The physical size and shape of the runner will not change; however, improvements in materials and design methods should result in improved cavitation performance and efficiency. No increase in capacity is planned. The design will be based on an existing OEM runner design and Computational Fluid Dynamics modelling. The planned execution of the work in 2028 does not permit sufficient time to execute a turbine model test. Foregoing the turbine model test will not have a measurable effect on the turbine performance.

Stator windings will be replaced. The replacement will match the existing winding configuration and will be manufactured with modern methods and an insulation system. The design of the insulation system will be the responsibility of the successful OEM. The rotor poles, rotor spider, and hub will be inspected and refurbished. The rotor field windings will be reinsulated.

Other turbine components identified for replacement will match the existing design, with the possible exception of the turbine guide bearing. The replacement of the turbine guide bearing with water lubricated technology is being considered as an optional item, pending technical feasibility.

A significant design effort will be required to upgrade the unit control system. The specification under development dictates the main components and system configuration, with the technical requirements building on the experience developed through upgrades at Churchill Falls, the control system installed at Muskrat Falls, and preliminary work completed for BDE Unit 8.

Other control system elements identified for upgrade include the exciter and governor controls. The exciter control upgrade will match the upgrades completed on BDE Units 1 to 6, while the governor upgrade will be similar to the upgrades completed at Churchill Falls. A preliminary component list and installation scope have been received from [redacted] A specification for the governor upgrade is under development.

Auxiliary equipment, such as the draft tube water level controls and the HPOIS, will be updated based on matching the original design requirements and configurations.

Some enhancements to the installation will include the addition of a dust collection system and a turbine pit monorail to facilitate maintenance work.

The design basis document, Bay d'Espoir Unit 7 - Basis of Design, and specifications are scheduled for completion in Q2 and Q3 2025.

9.0 Planning Basis

The high-level preliminary project plan for BDE Unit 7 Project includes:

- Approval by the PUB in Q4 2025.
- Preliminary engineering in 2025, to support long lead equipment procurement.
- Detailed engineering starting in Q1 2026, following PUB approval.
- Mobilization, construction, and commissioning from Q1 to Q4 2028.

10.0 Cost Basis

This cost estimate is stated in 2024 dollars, with Escalation and IDC calculated based on a cost profile that follows the project plan. An estimate listing is included in Appendix A.

10.1 Direct Costs

The estimate for direct scope was primarily developed by Hatch SMEs as part of the condition assessment report issued in 2024.

For the major scopes (i.e., runner replacement, stator rewind, and rotor pole re-insulation), Hydro requested budgetary quotes from Suppliers, compared these to the Hatch numbers, and adjusted based on the assessment performed by the Hydro SME.

For the rest of the work scope, budget quotes were received for items such as Exciter Controls and incorporated into the estimate. The remaining scopes were reviewed by the Hydro SME and adjusted based on past Hydro experience.

Estimated costs have been broken out assuming [redacted] tools and equipment, [redacted] materials, and [redacted] labour, for the purpose of developing numbers such as labour hours and material costs.

10.1.1 Productivity

For the BDE Unit 7 Project replacement work, [redacted].

10.2 Hydro's Indirect Costs

Hydro's indirect costs are made up of components outlined in Section 7.2.

10.2.1 Hydro's Owner's Team

The Project Manager developed the roster for Hydro's Owner's Team and assigned hours for each position based on their expected engagement on the project.

10.2.2 Hourly Rates for Hydro Personnel

All-inclusive hourly rates were used to develop Hydro's project management cost:

- For Hydro employees, corporate rates were used.
- For Contractors, a rate of [redacted] was used for both regular time and overtime.
- For Hydro's Construction Consultant, a rate of [redacted] was used.

The totals for Hydro's owner's team wages are [redacted] and [redacted].

10.2.3 Hydro Personnel Expenses

For travel and accommodations, the following rates were used to estimate costs:

- For out-of-province trips, the following rates were applied:
  - Flight: [redacted]
  - Accommodations: [redacted]
  - Meals: [redacted]
  - Transportation: [redacted]
- For in-province trips, 2-, 3-, and 5-day trips were assumed, with costs as follows:
  - Accommodations: [redacted]
  - Meals: [redacted]
  - Transportation: [redacted]

A summary of Hydro's indirect costs is included in Appendix B.

10.2.4 EPCM Consultant Costs

The cost for EPCM was typically calculated as [redacted] of the Contractor's total direct and indirect cost, based on benchmarking of comparable projects. For the major refit scope (i.e., runner, stator, and rotor), EPCM [redacted]. For the miscellaneous refit scope, [redacted].

10.3 Exchange Rates

The corporate foreign exchange rates at [redacted] are shown in Table 2. These rates were applied in the estimate as necessary.

Table 2: Foreign Exchange Rates

Currency	Exchange Rate
[redacted]	

[redacted]

The project cost is estimated primarily in CAD. Foreign exchange exposure is considered to apply primarily to major equipment packages that may be procured in [redacted]. To account for foreign exchange risk, a line item was included in the strategic risk register for use in the MCS for Management Reserve.

10.4 Escalation

The estimated escalation cost for this project is approximately [redacted], which is the forecast increase in the estimated project costs beyond 2024.

To estimate cost escalation, an expected committed cost profile was developed, as shown in Table 3.

Table 3: Cost Profile for Escalation Calculation ($ Million)

	2024	2025	2026	2027	2028	2029
Cost	[redacted]					

As per normal Hydro practice, escalation factors provided by Hydro's Finance Department were then applied to the committed costs for the years 2025 to 2029 to predict future escalation.

The escalation factors from [redacted] Corporate assumptions are shown in Table 4.

Table 4: Escalation Factors

Year	GDP	Hydraulic Plant Construction
2024	[redacted]	[redacted]
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		

Year	GDP	Hydraulic Plant Construction
2038	[redacted]	[redacted]
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		

10.5 Interest During Construction

IDC is the cost of borrowing throughout the duration of the project. The expected annual borrowing rate, at the time of estimate preparation [redacted] Corporate rate. The estimated cost for IDC for the project is approximately [redacted].

To estimate the IDC, the above annual interest rate was applied to the expected annual cost profile as shown in Table 5.[12]

Table 5: Cost Profile for IDC Calculation ($ Million)

	2024	2025	2026	2027	2028	2029
Cost	[redacted]					

11.0 Allowances

As the BDE Unit 7 Project involves a life extension refit of a 50-year-old asset, there is a probability of finding components in need of repair that were not identified in the 2019 and 2023 condition assessments, as well as components that may have deteriorated since then.

It is considered prudent to include an allowance for Found Work in the base estimate to account for the likelihood of additional work when the unit is disassembled. [redacted]

[12] Note that the cost profile for escalation calculation in Table 3 includes base cost only, while the cost profile for IDC calculation in Table 5 includes base cost, escalation, and contingency.

[redacted]

12.0 Contingency

Hydro reviewed the project scope in detail and assigned potential low and high percentages to individual estimate items, as shown in Appendix A. These percentages were then used in a QRA using an MCS to develop a Contingency value. The results of the MCS are shown in the cumulative distribution curve for total cost in Figure 1.

[redacted]

Figure 1: Risk Results Summary for Total Cost

The contingency amount for the estimate is the P50 value – base estimate value:

$Contingency =$ [redacted]

13.0 Management Reserve

Hydro developed a strategic risk register of high-level risks and assigned low, expected, and high ranges of cost for each risk. These ranges were then used in a QRA using an MCS to develop a value for Management Reserve. The strategic risk register is included in Appendix C.

For this estimate, Management Reserve is calculated for a P85 probability, as per the recommendations of the Muskrat Falls Inquiry Final Report.

Management reserve consists of two components:

1) Management Reserve on base cost, which is calculated as the difference between the P85 and P50 values in the total cost MCS. (The P85 value is taken as the average of the P80 and P90 values shown in Figure 1.)
2) Management Reserve on strategic risks. (The P85 value is taken as the average of the P80 and P90 values shown in Figure 2.)

[redacted]

Figure 2: Risk Results Summary for Strategic Risk

A summary of Management Reserve is shown in Table 6.

Table 6: Management Reserve Summary

Component	Estimated Cost
Management Reserve on Base Cost: P85 - P50	[redacted]
Management Reserve on Strategic Risks: P85 = (P80 + P90) ÷ 2	
Total	

This cost estimate is stated in 2024 dollars, with Escalation and IDC calculated based on a cost profile, which follows the project plan. The estimated costs are contained in the Excel supporting document, BDE Unit 7 Life Extension Estimate. A summary of estimated costs is given in Table 7.

Table 7: Summary of Estimated Costs ($2024)

Component	Estimated Cost
Major Refit (Runner, Stator, and Rotor)	[redacted]
Miscellaneous Refit	
Upgrades	
Spare Parts	
Construction Labour	
Commissioning	
Subtotal Direct Costs	
EPCM Consultant	
Owner's Cost	
Subtotal Indirect Costs	
Found Work Allowance	
Subtotal Found Work Allowance	
Subtotal Base (Direct + Indirect + Found Work Allowance) Estimate	
Contingency	
Subtotal Base Estimate (with Contingency)	
Escalation	
Interest during Construction	
Subtotal Planned Project Budget	
Management Reserve	
Total Cost Estimate (Authorized Budget upon Approval)	**85,346,227**

14.0 Estimate Classification

Cost estimate classification and accuracy are considered to depend on the maturity level of the project definition deliverables. AACE RP 69R-12 provides guidance for cost estimation classification for new build Hydro Industry EPC projects. In AACE RP 69R-12, the maturity of the project deliverables is evaluated and used to determine the class of estimate that is applicable, as shown in Figure 3.

The BDE Unit 7 Project is a refurbishment project. The design element is significantly less than a new hydropower project, and the project deliverables are somewhat different. Developing an accurate estimate depends on the definition of the scope of the work, understanding the equipment condition, and the specifications used to execute the work. Therefore, the development of deliverables such as detailed condition assessments, and the detailed specifications for procurement and installation of parts, rather than studies and drawings, can improve estimate accuracy.

The input maturity of the BDE Unit 7 Project estimate was evaluated by adapting the deliverables table from the AACE RP to suit a refurbishment project. The maturity of the estimate inputs was evaluated and compared to the maturity level expected for a Class 3 estimate.

The maturity matrix of project deliverables is shown in Appendix D. The maturity level can be considered to meet the requirements of a Class 3 estimate, considering that, as previously stated, 85% or [redacted] of the direct plus indirect cost of estimated items was deemed to be Class 3, with the remaining 15% or [redacted] of the cost considered as Class 5. Examples of items considered as Class 5 include spare parts, miscellaneous refits such as turbine and generator shafts, and upgrades such as cooling water piping and relief valve upgrades. As a composite, the entire estimate is deemed to be a Class 3.

It should be noted that the estimate accuracy depends not only on the stage of the design but also on the estimating methods used. In this case, budget quotes were received for the larger elements and estimates for other elements were developed based on quotes for previous work. However, there is still an element of the estimate that is Class 5. A response to the RFP for OEM refurbishment services is necessary to improve the numbers.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Figure 3: Cost Estimate Classification Matrix

15.0 Assumptions, Exclusions and Opportunities

The following assumptions, exclusions, opportunities, and risks in Sections 15.1 to 15.4 are applicable to the cost estimate.

15.1 Assumptions

The following assumptions are applicable to the project:

- An adequate labour supply is available.
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- There are no delays due to Supplier constraints.
- There is an EPCM team dedicated to BDE Unit 7.
- The Construction Contractor will attract and retain a qualified workforce.
- No abnormal (i.e., outside of normal observed statistical history) weather events occur during construction.
- Commissioning does not identify issues with the reassembled unit that require rework.
- Commissioning tests and grid synchronization will be permitted to be performed once the work is completed, even if the work extends into the winter period.
- [redacted]
- [redacted]
- Hydro's indirect cost estimate includes the construction of a dedicated camp for BDE Unit 7.
- There will be no labour disruptions during the execution of the works.
- Regulatory approvals will be generally granted as assumed in the project schedule.
- [redacted]
- Work will be completed in the outage window.

[redacted]

15.2 Exclusions

The following items are excluded from the project estimate:

- Hydro corporate support that is not listed in Hydro's indirect costs.
- Draft Tube and Intake Structure inspection and refurbishment.
- Uprating of the unit capacity.
- Runner model testing.
- Purchase of new intake stoplogs.
- Unexpected macroeconomic factors outside the ranges considered in the Management Reserve analysis that could affect the work, including the onset of any pandemics, supply chain disruptions, hyperinflation, or difficulty in the movement of goods.

15.3 Opportunities

Opportunities that may occur include:

- Synergy and sharing of resources with other projects at Bay d'Espoir.
- Improved planning due to prior execution of similar scopes, such as previous work on BDE Unit 7 and other Hydro assets.
- [redacted]

15.4 Risks

Risks that may occur include:

- Late delivery of components.
- Found Work.
- [redacted]
- [redacted]
- Suppliers/OEMs experiencing a period of high demand for services.
- [redacted]
- An unplanned, forced outage of BDE Unit 7 prior to being ready to execute the work in a planned and orderly fashion.

16.0 Estimating Team

The estimating team consisted of members of Hydro's Major Projects Department, who reviewed the estimated costs in the "Bay D'Espoir Unit 7 Condition Assessment Report"; updated estimate components as required; estimated Hydro's indirect costs, escalation, and IDC; and prepared this Basis of Estimate.

Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

Appendix A: Estimate Summary

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
NLH Doc. No.	**BDE-NLH-40000-ES-BOE-0002-01**	**Revision**	**B0**	**Page**	**A-1**

Component	Estimated Cost ($2024)	Estimate Class	Potential Low Range for QRA	Potential High Range for QRA
Direct Costs				
Major Refit				
Runner Replacement	[redacted]	3	[redacted]	[redacted]
Stator Rewind	[redacted]	3	[redacted]	[redacted]
Rotor Re-insulate Poles	[redacted]	3	[redacted]	[redacted]
Subtotal Major Refit	[redacted]		[redacted]	[redacted]
Miscellaneous Refit				
Thrust Collar and Thrust Ring	[redacted]	5	[redacted]	[redacted]
Head Cover Replacement	[redacted]	3	[redacted]	[redacted]
Bottom Ring	[redacted]	5	[redacted]	[redacted]
Line Boring	[redacted]	5	[redacted]	[redacted]
Machining Stay Ring Flanges	[redacted]	3	[redacted]	[redacted]
Facing Plates	[redacted]	5	[redacted]	[redacted]
Turbine Shaft	[redacted]	5	[redacted]	[redacted]
Generator Shaft	[redacted]	5	[redacted]	[redacted]
Wicket Gates	[redacted]	3	[redacted]	[redacted]
Servo Motors and Dashpot	[redacted]	5	[redacted]	[redacted]
Operating Ring	[redacted]	3	[redacted]	[redacted]
Links, Levers, and Pins	[redacted]	5	[redacted]	[redacted]
Subtotal Miscellaneous Refit	[redacted]		[redacted]	[redacted]
Upgrades				
Spiral Case Leakage	[redacted]	5	[redacted]	[redacted]
Relief Valve	[redacted]	5	[redacted]	[redacted]
Governor Upgrade	[redacted]	3	[redacted]	[redacted]
Exciter Controls	[redacted]	3	[redacted]	[redacted]
Turbine Bearing Replacement	[redacted]	3	[redacted]	[redacted]
Synchronous Condenser Level Controls	[redacted]	5	[redacted]	[redacted]
Turbine Pit Hoist	[redacted]	3	[redacted]	[redacted]
Generator Dust Collector	[redacted]	3	[redacted]	[redacted]
Cooling Water Piping Mods	[redacted]	5	[redacted]	[redacted]
HP Lift System Refurbishment	[redacted]	5	[redacted]	[redacted]
Controls Upgrade Scope	[redacted]	3	[redacted]	[redacted]
Asbestos and Lead Abatement	[redacted]	5	[redacted]	[redacted]
Subtotal Upgrades	[redacted]		[redacted]	[redacted]
Spare Parts				
Brake shoes and seals	[redacted]	5	[redacted]	[redacted]
Bearing pads and springs	[redacted]	5	[redacted]	[redacted]

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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Component	Estimated Cost ($2024)	Estimate Class	Potential Low Range for QRA	Potential High Range for QRA
Set of seals	[redacted]	5	[redacted]	[redacted]
Slings	[redacted]	5	[redacted]	[redacted]
Miscellaneous Tooling	[redacted]	5	[redacted]	[redacted]
Subtotal Spare Parts	[redacted]		[redacted]	[redacted]
Construction Labour: Crane Operator & Labourer	[redacted]	3	[redacted]	[redacted]
Commissioning	[redacted]	3	[redacted]	[redacted]
Subtotal Direct Costs	[redacted]		[redacted]	[redacted]
Indirect Costs	[redacted]		[redacted]	[redacted]
Owner's Cost: FEED	[redacted]	3	[redacted]	[redacted]
Owner's Cost: Detailed Design and Procurement	[redacted]	3	[redacted]	[redacted]
Owner's Cost: Project Phase	[redacted]	3	[redacted]	[redacted]
Crane Testing and Certification	[redacted]	3	[redacted]	[redacted]
Accommodations & Turnarounds	[redacted]	3	[redacted]	[redacted]
Emergency Response	[redacted]	3	[redacted]	[redacted]
Work Protection Team	[redacted]	3	[redacted]	[redacted]
Camp Construction	[redacted]	3	[redacted]	[redacted]
EPCM	[redacted]	3	[redacted]	[redacted]
Subtotal Hydro's Indirect Costs	[redacted]		[redacted]	[redacted]
Found Work Allowance	[redacted]	5	[redacted]	[redacted]
Subtotal Base Cost Estimate	[redacted]			
Project Contingency	[redacted]			
Subtotal Base Estimate (with Contingency)	[redacted]			
Escalation	[redacted]			
Interest during Construction	[redacted]			
Subtotal Planned Project Budget	[redacted]			
Management Reserve, Base, P85	[redacted]			
Management Reserve, Strategic, P85	[redacted]			
Subtotal Management Reserve	[redacted]			
Total Cost Estimate (Authorized Budget)	**85,346,227**			

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Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

Appendix B: Hydro's Indirect Cost Estimate

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
NLH Doc. No.	**BDE-NLH-40000-ES-BOE-0002-01**	**Revision**	**B0**	**Page**	**B-1**

Phase	**Component**	**Hours**	**Estimated Cost ($2024)**
FEED	FEED Spent to Feb 2025		[redacted]
	FEED Team Hours March to May 2025	[redacted]	[redacted]
	Engineering Support		[redacted]
	Travel Allowance		[redacted]
	Subtotal FEED		[redacted]
Detailed Design and Procurement	Detailed Design and Procurement Team Hours	[redacted]	[redacted]
	Engineering Support		[redacted]
	EPCM		[redacted]
	Subtotal Detailed Design and Procurement		[redacted]
Project Phase	Hydro Major Projects Department Management Team & Project Management Personnel	[redacted]	[redacted]
	Hydro Engineering	[redacted]	[redacted]
	Hydro Construction & Commissioning	[redacted]	[redacted]
	Hydro Expenses (Travel & Accommodations)		[redacted]
	Insurance & Security		[redacted]
	Subtotal Owner's Costs in Project Phase		[redacted]
	Crane Testing and Certification		[redacted]
	Accommodations & Turnarounds		[redacted]
	Emergency Response		[redacted]
	Work Protection Team		[redacted]
	Camp Construction		[redacted]
	EPCM		[redacted]
	Total Hydro's Indirect Costs		[redacted]

Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

Appendix C: Strategic Risk Register

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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[redacted]

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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[redacted]

[redacted]

[redacted]

[redacted]

Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

Appendix D: Design Maturity Assessment

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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Design Maturity Assessment

Deliverables and Letter Codes are based on AACE 69R-12.

Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
Scope	Project Scope of Work Description	D	2	**Condition Assessment:** Detailed inspection and measurements were completed in 2019 during unit dismantling. Results documented in the Voith Report. Condition assessment completed by Hatch with recommended scope for life extension. Report issued in 2024. **Project Charter:** Signed/Approved. **Basis of Design:** In development. Information was originally included in the Project Charter. It was felt that some of the details in the Charter should be moved to a Basis of Design document. The document is in progress.	D	2	0	[redacted]
Scope	Site Infrastructure (Access, Construction Power, Camp, etc.)	D	2	Access for equipment deliveries is to be investigated. Camp under consideration with plans to share with BDE Unit 8.	D	2	0	[redacted]
Capacity	Facility Output/ Production Profile	D	2	Refurbished unit to have the same output as the existing unit. Increased capacity will not be pursued.	D	2	0	[redacted]
Capacity	Electrical Power Requirements (when not the primary capacity driver)	NR	2	Not required for this project.	NR	2	0	[redacted]
Project Location	Plant and Associated Facilities	D	2	The unit is located in the existing powerhouse.	D	2	0	[redacted]
Requirements	Codes and/or Standards	D	2	A list of applicable codes and standards has been developed	D	2	0	[redacted]

Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
				based on previous projects and is included in the specifications.				
Requirements	Communications Systems	D	2	Anticipated to use existing plant infrastructure.	D	2	0	[redacted]
Requirements	Fire Protection and Life Safety	D	2	Fire protection is available in the powerhouse.	P	1	-1	[redacted]
Requirements	Environmental Monitoring	P	1	Need to discuss further. There will be standard monitoring for a unit refurbishment project.	P	1	0	[redacted]
Strategy	Contracting/ Sourcing	D	2	Contract list developed and reviewed with Commercial Group. The Draft Contract Strategy has been developed.	P	1	-1	[redacted]
Strategy	Escalation	D	2	Escalation agreed and incorporated in the estimate.	D	2	0	[redacted]
Planning	Regulatory Approval & Permitting	D	2	PUB Application in development with plans for submittal in June 2025.	P	1	-1	[redacted]
Planning	Material Utilization (Borrow Source)	NR	2	Not required for this project.	NR	2	0	[redacted]
Planning	Logistics Plan	P	1	Components can be trucked by road. Bridge capacities to be checked. Final logistics plan to be developed by the Contractor	P	1	0	[redacted]
Planning	Work Breakdown Structure	P/D	1.5	Developed as part of the estimate. To be finalized during the start project execution phase.	P/D	1.5	0	[redacted]
Planning	Decommissioning Plan	NR	2	Not required for this project. The unit is being refurbished.	NR	2	0	[redacted]
Planning	Integrated Project Plan	D	2	The Major Project Department and required project-specific planning documents have been prepared.	D	2	0	[redacted]
Planning	Project Code of Accounts	D	2	Established in FEED.	D	2	0	[redacted]
Planning	Project Master Schedule	P/D	1.5	Class 3 schedule developed and reviewed by the Project Team.	P/D	1.5	0	[redacted]

Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
Planning	Risk Register	D	2	Risk register developed. Considered a "live" document to be updated and revised throughout the project.	D	2	0	[redacted]
Planning	Stakeholder Consultation/ Engagement/ Management Plan	D	2	It will be included in the engagement planned for Unit 8.	D	2	0	[redacted]
Planning	Startup and Commissioning Plan	P/D	1.5	List of commissioning tests included in technical specifications. The plan is to be developed by the Contractor.	P/D	1.5	0	[redacted]
Studies	Hydraulics	D	2	Using studies completed for Unit 8 for input to the runner design.	D	2	0	[redacted]
Studies	Topography and/or Bathymetry	NR	2	Not required for this project.	NR	2	0	[redacted]
Studies	Environmental Impact/ Sustainability Assessment	D	2	Confirmed with the Government of Newfoundland and Labrador Environmental Assessment Division that an Environmental Assessment is not required for the proposed work scope (letter dated August 29, 2024).	D	2	0	[redacted]
Studies	Environmental/ Existing Conditions	NR	2	Not required for this project.	NR	2	0	[redacted]
Studies	Soils and Hydrology	NR	2	Not required for this project.	NR	2	0	[redacted]
Studies	Geotechnical Investigation	NR	2	Not required for this project.	NR	2	0	[redacted]
Technical Deliverables	Block Flow Diagram	NR	3	Not required for this project.	NR	3	0	[redacted]
Technical Deliverables	Hydraulic Design and Probable Maximum Flood	C	3	Completed using existing information as well as studies completed as part of the Unit 8 project.	C	3	0	[redacted]
Technical Deliverables	Equipment Datasheets	C	3	Information is available for existing equipment.	C	3	0	[redacted]
Technical Deliverables	Equipment Lists: Electrical	C	3	Part of the specifications is under development.	C	3	0	[redacted]

hydro	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
Technical Deliverables	Equipment Lists: Process/Utility/Mechanical	C	3	Information on existing equipment is available. This will be updated if equipment is replaced as part of the life extension contract.	NR	3	0	[redacted]
Technical Deliverables	Electrical One-Line Drawings	C	3	The existing drawing is available.	C	3	0	[redacted]
Technical Deliverables	Design Specifications	C	3	In progress.	P/C	2.5	-0.5	[redacted]
Technical Deliverables	General Equipment Arrangement Drawings	C	3	Layouts will not change. Existing drawings are available.	C	3	0	[redacted]
Technical Deliverables	Instrument List	C	3	The existing instrument list is to be used and updated by the Contractor as a part of the Unit Life Extension contract.	C	3	0	[redacted]
Technical Deliverables	Construction Permits	NR	2	Not anticipated to be required for this project as construction will occur within the Hydro-owned Powerhouse. This will, however, be reviewed with the Contractor and Contractors when engaged as part of project execution.	NR	2	0	[redacted]
Technical Deliverables	Civil/Site/Structural/Architectural discipline drawings	NR	3	No change to existing facilities.	NR	3	0	[redacted]
Technical Deliverables	Demolition Plan and drawings	NR	3	No demolition is involved in this project.	NR	3	0	[redacted]
Technical Deliverables	Erosion Control Plan and Drawings	NR	3	No civil works.	NR	3	0	[redacted]
Technical Deliverables	Fire Protection and Life Safety drawings and details	C	3	No change to existing infrastructure.	C	3	0	[redacted]
Technical Deliverables	Mitigation measures (aquatic, terrestrial, avian, clearing, heritage etc.)	NR	3	Not required for this project.	NR	3	0	[redacted]

	Bay d'Espoir Unit 7 Life Extension Basis of Estimate					
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Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
Technical Deliverables	Dam Design & Drawings	NR	3	Not part of the project.	NR	3	0	[redacted]
Technical Deliverables	De-Silting Basins	NR	3	No civil works are included in the scope.	NR	3	0	[redacted]
Technical Deliverables	Gates and Cranes Design and Drawings	P	2	The existing crane will be used. No new equipment.	C	3	1	[redacted]
Technical Deliverables	Intake design and drawings	NR	3	Not part of this project.	NR	3	0	[redacted]
Technical Deliverables	Penstock design and drawings	NR	3	Not part of this project.	NR	3	0	[redacted]
Technical Deliverables	Powerhouse design and drawings	P	2	No new drawings required.	C	3	1	[redacted]
Technical Deliverables	Power Tunnel/Canal design and drawings	NR	3	Not applicable to this project.	NR	3	0	[redacted]
Technical Deliverables	Spillway design and drawings	NR	3	Not applicable to this project.	NR	0	-3	[redacted]
Technical Deliverables	Turbine-Generator design and drawings	P	2	Drawings for existing equipment are available. New drawings will be produced by Contractor for replacement parts.	P	2	0	[redacted]
Technical Deliverables	Electrical schedules	P	2	Drawings for existing installation are available. Drawings will be developed by Contractor for new equipment.	P	2	0	[redacted]
Technical Deliverables	Instrument and Control schedules	P	2	Existing documents to be updated by Contractor.	P	2	0	[redacted]
Technical Deliverables	Instrument datasheets	P	2	Existing documents to be updated by Contractor.	P	2	0	[redacted]
Technical Deliverables	Spare Parts listings	P	2	Preliminary list being developed for specifications. To be finalized on award of contract.	P	2	0	[redacted]

newfoundland labrador hydro	Bay d'Espoir Unit 7 Life Extension Basis of Estimate				
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Category	Deliverable Description	AACE Prescribed Maturity	AACE Prescribed Score Equivalent	Hydro Review Comments	Final Assessed Maturity	Hydro Final Assessed Score	Final Score Disparity	FEED Phase % Complete
Technical Deliverables	Electrical discipline drawings	S/P	1.5	Exiting drawings available. Updates maybe required by Contractor.	P	2	0.5	[redacted]
Technical Deliverables	Facility Emergency Communication plan and drawings	S/P	1.5	To be developed by EPCM Contractor.	-	0	-1.5	[redacted]
Technical Deliverables	Information Systems/Telecommunication drawings	NR	3	No changes to existing systems planned.	NR	3	0	[redacted]
Technical Deliverables	Instrumentation/Control system discipline drawings	S/P	1.5	To be produced by Contractor.	-	0	-1.5	[redacted]
Technical Deliverables	Mechanical discipline drawings	S/P	1.5	Existing documents available. To be updated by OEM.	S/P	1.5	0	[redacted]
Technical Deliverables	Auxiliary Electrical design and drawings	S	1	Existing drawings available. No changes planned.	S	1	0	[redacted]
Technical Deliverables	Auxiliary Mechanical design and drawings	S/P	1.5	Existing documents are available. To be updated by Contractor.	S/P	1.5	0	[redacted]
Technical Deliverables	Protection and Controls system design and drawings	S	1	Specification in progress. Design to be completed by Contractor.	S	1	0	[redacted]
Score			**141**			**134**	**-7**	[redacted]

Letter Code	Description
Technical Deliverables	
NR	Not required.
S	Started: Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
P	Preliminary: Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
C	Complete: The deliverable has been reviewed, approved, and issued for design, as appropriate.
General Project Data	
NR	Not required.
P	Preliminary: Project definition has begun and progressed to at least an intermediate level of completion.
D	Defined: Project definition is advanced, and reviews have been conducted. Development may be near completion.

Bay d'Espoir Unit 7 Life Extension

Basis of Estimate

Attachment 1: Bay D'Espoir Unit 7 Condition Assessment Condition Report

Document No.: BDE-HAT-00000-EN-REP-0001-01, Rev B0

Date: May 3, 2024

Report

Bay D'Espoir Unit 7 Condition Assessment Condition Report

H371822-0000-2A1-066-0001

BDE-HAT-00000-EN-REP-0001-01 Rev B0

[redacted]

			[redacted]		
2024-05-03	0	Approved for Use			
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**
	HATCH				

Disclaimer

This report has been prepared by Hatch Ltd. (Hatch) for the sole and exclusive use of Newfoundland Hydro Inc. (the "**Owner**) for the sole purpose of assisting the management of the Client in making decisions with respect to the Bay D'Espoir Unit # 7 Level II Condition Assessment (the "**Stucture**") and must not be used for any other purpose, or provided to, relied upon or used by any other person. 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 opinion of Hatch using its professional judgment and reasonable care based upon observations of the condition of the Structure made at the time of preparation of this report, and information made available to Hatch by the Owner.

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

(1) this report is to be read in the context of and subject to the terms of the relevant services agreement between Hatch and the Owner (the "**Hatch Agreement**"), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions specified in the Hatch Agreement;

(2) this report is meant to be read as a whole, and sections or parts of the report must not be read or relied upon out of context;

(3) unless expressly stated otherwise in this report, Hatch has not verified the accuracy, completeness or validity of the Owner or Other Information, makes no representation regarding the accuracy of such information and does not accept any responsibility or liability in connection with the Owner or Other Information; and

(4) the condition, stability and safety of the Structure 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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Appendix C : Mechanical Check Sheets

Appendix D : Deficiency Table and Recommendations

1. Executive Summary

NL Hydro retained Hatch to conduct a condition assessment review and uprate study for Bay d'Espoir GS unit 7.

As part of the review process, additional information was provided. The outage report in addition to the design, operation and maintenance information provided, helped build and inspection and testing procedure (ITP) for Generator and turbine components, including the excitation system.

Electrical and mechanical inspection were carried in accordance with a customized ITP that help to confirm several statements done in previous reports and analyze other conditions found during the site visit.

After data collection and findings were confirmed at the site visit, the analysis process was carried out. A do-nothing scenario was compared against further intervention. A cost estimate was provided for each recommendation.

An additional analysis was done to consider major components replacement like the turbine and the generator. These considerations and others in favor of a runner replacement can be found in Hatch, Bay d'Espoir Unit 7 Uprate Report, H371822-0000-2A1-066-0002, 2023-11-10.

A deficiency summary table (Appendix D) is provided in this report which includes a risk rating, urgency recommended action and cost estimate of each action.

1.1 Summary of Known Issues

From previous reports and discussions with NL Hydro, the following list summarizes the most significant or urgent issues. These issues are those verified during the site inspection as well those listed in the documentation provided.

1. Runner cavitation.
2. Runner seal clearances variances and wearing ring damage.
3. Water leakage around spiral case access door and relief valve.
4. Operating ring bearing issues.
5. Aged windings in stator and rotor.
6. Loose stator core.
7. Excess of debris in the stator frame.

1.2 Summary of Recommendations

1.2.1 Generator

The highest priority items for the generator are ranked as follows:

1. Debris in stator frame.
2. Aged stator winding.
3. Aged rotor winding.
4. Loose stator core.

These conditions put the machine at increased risk of an in-service failure that would remove the generator from service for several months. The debris in the stator frame needs to be cleaned as soon as possible. Both the stator winding and the rotor winding have components in risk of becoming lose due to age, and these repairs are not trivial.

To address the most significant issues, rewinding the armature and field windings is recommended. The mechanical structure of both stator core and rotor, including the pole bodies, can be reused.

Additionally, NL Hydro should replace the locking tab on U shape connector of pole # 1.

1.2.2 Turbine

The highest priority items for the turbine are ranked as follows:

1. Runner seal clearances.
2. Runner cavitation.
3. Operating ring bearing pads.

Hatch recommends replacing the runner and stationary wearing rings to address cavitation issues and the runner seal clearance issues. Restoring the runner seal clearances back to OEM design values will result in a minor increase in turbine efficiency and a minor decrease in downward thrust loads on the thrust bearing. Hatch recommends rehabilitation of the operating ring, including installation of stainless-steel journal surfaces, and supply of new bearing pads (head cover liners) to resolve the operating ring bearing pad issues.

1.2.3 Parameters to Monitor

Several critical parameters were identified as a risk of causing a potential in-service failure. Hatch recommends monitoring their status on a regular basis. These parameters are summarized here.

1. Wearing Rings: Radial Seal Clearance.
2. Runner: Cavitation Damage.

3. Spiral Case: Leakage around Access Door.
4. Relief Valve: Leakage around Discharge Pipe.
5. Operating Ring Bearing Pads: Position and Condition.
6. Wicket Gate Link Pins: Position.
7. Stator Winding: Ozone Levels.
8. Stator: Attach temperature sensitive stickers to the bars in slots 194 to 200 at the bottom of the unit close to the entrance of the bar to the cap and particularly monitor color change on bar that it is in slot 196.

2. Introduction

NL Hydro retained Hatch to perform the condition assessment of Bay d'Espoir Generating Station Unit 7. An initial approach to review current information was taken. This information was used to prepare and plan a visual inspection and several electrical test that could be executed with NL Hydro own resources.

A customized Inspection Test Plan was developed assessing the components covered in the scope of work. This was done evaluating past reports, design documents and operational data. The ITP was discussed and shared with NL Hydro to optimize the unit downtime inspection and coordinate resources required. The ITP was used as input to the HydroVantage software (uprate report) and based on risk of failure and replacement cost curves, a replacement strategy was established.

The conclusions and recommendations provided in this report aim to extend the service life of Unit 7 and prevent developing of existing failure mechanisms.

2.1 Facility Description

The Bay d'Espoir Generating Station located in Milltown-Head of Bay d'Espoir, Newfoundland and Labrador. The headwaters of the Bay d'Espoir system begin at Victoria Lake at an approximate elevation of 320 meters. Through a system of dams and canals, the water is connected to the Bay d'Espoir GS. Before the water reaches Bay d'Espoir GS it feeds Granite Canal GS and Upper Salmon GS. In addition, water from several drainage areas between Victoria Lake and Long Pond is collected at the forebay for the seven Bay d'Espoir units.

The seven generating units at Bay d'Espoir have rated head of 176 m to produce a rated output of 604 MW with a rated flow of 397 m3/s. The plant produces an average of 2,650 GWh annually, making it the largest hydroelectric plant on the Island of Newfoundland.

The two powerhouses were constructed in different phases. It began in 1964 with the first two units of the first powerhouse. The first powerhouse (units 1 to 6) comprises 6x80MW units.

The second powerhouse has 1x150MW unit with a provision for second unit. An arial view of the Generating Station complex can be seen in Figure 2-1.

Figure 2-1: Aerial View of Bay d'Espoir GS Powerhouses

2.2 Documents and References

As part of the scope of work, NL Hydro provided relevant documents for the review and analysis process. The following section outlines the documents and information provided by NL Hydro in addition to other reference documents or standards referenced during the condition assessment.

2.2.1 Drawings

1. Generator outline: 292D654 DA.
2. Stator winding diagram: 591E111CG.
3. Assembly of stator connections: 591E122BK.
4. Generator assembly and BoM: 591E106JE.
5. Foundation plan: 292D620DE.
6. Generator shaft: 704C693HT.
7. Shroud assembly: 591E121BB.
8. (1975). M-1337-02-055 - Wicket Gate. NLH-OEM Drawing.

9. (1976). M-1337-02-075. NLH OEM Drawing.
10. (1976). M-1337-02-085 - Main Shaft. NLH OEM Drawing.
11. (1976). M-1337-02-092 - Head Cover Liner. NLH OEM Drawing.
12. (1976). M-1337-02-096 - Head Cover Bushing. NLH OEM Drawing.
13. (1976). M-1337-02-098 -Head Cover Plan. NLH OEM Drawing.
14. (1976). M-1337-02-099 - Head Cover Section. NLH OEM Drawing.
15. (1976). M-1337-02-124 - Runner Band Wearing Rings. NLH OEM Drawing.
16. (1976). M-1337-02-203 - Runner Balance Plate. NLH OEM Drawing.
17. (1976). M-1337-03-003G - Generator Outline. NLH OEM Drawing.
18. (1976). M-1337-03-067G - Rotor Spider Details. NLH OEM Drawing.
19. (1976). M-1337-02-078 - Turbine Section.
20. (1976). M-1337-03-068G - Rotor Spider Fabrication. NLH OEM Drawing.
21. (1976). M-1337-03-069G - Bottom Bracket Details. NLH OEM Drawing.
22. (1976). M-1337-03-083 - Rotor Assembly. NLH OEM Drawing.
23. (1976). M-1337-03-087G - Spider Hub Fabrication. NLH OEM Drawing.
24. (1976). M-1337-03-091G - Spider Hub Details. NLH OEM Drawing.
25. (1976). M-1337-03-160G - Generator Assembly. NLH OEM Drawing.
26. (1976). M-1337-03-080G - Thrust Ring. NLH OEM Drawing.
27. (1976). M-1337-03-090G -Rotating Skirt. NLH OEM Drawing.
28. (1976). M-1337-03-116G. NLH OEM Drawing.
29. (1976). M-1337-03-118G - Rotating Ring. NLH OEM Drawing.
30. (1976). M-1337-03-111G - Generator Shaft. NLJ-OEM Drawing.
31. (1976). M-1337-03-119G - Stationary Ring. NLH OEM Drawing.
32. (1976). M-1337-02-061 - Turbine Guide Bearing. NLH OEM Drawing.
33. (1976). M-1337-02-125 - Wearing Rings. NLH OEM Drawing.
34. (1976). M-1337-02-043 - Operating Ring. NLH-OEM Drawing.

35. (1976). M-1337-02-092 - Head Cover Liner (Operating Ring Bushings). NLH-OEM Drawings.
36. (1976). M-1337-02-085 - Main Shaft. NLH-OEM Drawing.
37. (1976). M-1337-02-051 - Bushing. NLH OEM DRAWING.
38. (1976). M-1337-02-070 - Runner Machining. NLH OEM Drawing.
39. (1976). M-1337-02-071 - Runner. NLH OEM Drawing.
40. (1976). M-1337-02-034 – Piping for Draft Tube Aeration, Probe Tank, Runner Seal Lubrication, Air Admission to Runner Band. NLH OEM Drawing.
41. 1976). M-1337-02-151 – Upper Runner Seal Lubrication Piping. NLH OEM Drawing.
42. (2019). Wicket Gate Rehabilitation DMA, 2TFV04-0101-10042606. Voith Hydro Inc.
43. (2019). Runner Cover Balance Plate, 2TFV01-0155-10049134. Voith Hydro Inc.

2.2.2 Reports

1. Hydro Expertise USA, Newfoundland and Labrador Hydro Bay d'Espoir Unit 7 Vibration Assessment and Balance Report, 2014-11-13.
2. Voith Hydro, Bay d'Espoir Generating Station Unit 7 Refurbishment Report, 2019-08-07.
3. Generation Engineering, Bay d'Espoir Generating Station Generating Station Unit 7 Runner Replacement, 2001-04-06.
4. American Hydro, Hydraulic Performance Review for Bay d'Espoir Unit 7 Runner Upgrade, 2020-04-21.
5. Kestrel Power Engineering, Bay D'Espoir Unit 7 PSS Tuning, NERC MOD-026/027 Model Validation, and PRC-0179/024 Review, 2021-01-19.
6. Hatch, Bay D'Espoir Unit 7 Uprate Report, H371822-0000-2A1-066-0002, 2023-11-10.

2.2.3 Manuals and Procedures

1. Canadian General Electric, Special Maintenance Procedures.
2. Dominion Engineering Works Limited, Operating Instructions and Maintenance Recommendations for One – 207,000 H.P. Francis Turbine for Bay D'Espoir Power Station, Unit 7.
3. Hatch, Project Report, Disassembly Procedure Unit 7, December 13, 2018.
4. Dominion Engineering Works Limited, Field Erection Procedure for Bay D'Espoir Power Station.

2.2.4 Standards

1. CEATI. (2008). Hydroelectric Turbine - Generator Units Guide for Erection Tolerances and Shaft Alignment.

2.2.5 Maintenance and Operating Data

NL Hydro provided asset data logs and preventative maintenance checklists.

Daily reporting of asset data logs was provided from June 2020 until July 2023.

Preventative maintenance checklists were provided from 2013 until 2022. The checklists were separated into categories for electrical, mechanical, and protection and controls.

3. Condition Assessment

3.1 Site Visits

Hatch performed a limited inspection of Unit 7's components, as well as the governor, the excitation system, and the grounding system. The unit was fully assembled, and some minor elements were removed to allow access to the generator. All inspections were visual, with aid of a borescope for access of hard-to-reach areas. Hatch also witnessed electrical testing performed by NL Hydro Engineering Team. The generator, balance of plant, and turbine pit inspection took place on August 7-9, 2023.

A second visit took place on October 13-14, 2023, to inspect the water passage equipment of the turbine when the unit was dewatered. The runner, wicket gates, spiral case, stay ring, stay vanes, draft tube, and distributor facing plates were assessed. Hatch performed a visual assessment of the components in addition to gate end seal clearance measurements and runner seal clearance measurements.

The remainder of this condition assessment is based on the review of the documentation made available by NL Hydro (see Section 2.2 for list of documents).

Appendix A shows the inspection and test procedure document that was customized for Unit 7.

3.2 Limitations of Access

The generator was prepared for the inspection with three shroud segments removed on the top and one on the bottom of the unit. To have access to the back of the core where bars subjected to high voltage could be found, cooler # 6 was removed and one more top shroud segment was removed.

It was not possible to properly verify in person several deficiencies listed in the 2019 Outage Report as most of them require full access to the top and bottom end-windings, as well as removal of the rotor. Our commentary on these, as applicable, will be limited to the information available in the documentation provided by NL Hydro and the 2019 Outage Report.

Particularly, it was not possible to quantify the vibration of the end-windings. Visual indicators (cracks in the endcaps, frayed lashings, cracks in paint,) suggest high vibration, but full access to the end-windings arms is needed for the “bump” test. This access was requested, but not provided due to limitations in labor and outage time available.

Likewise, it was not possible to execute a pole drop test. The ones executed during the 2019 outage show a wide discrepancy between the results of each pole.

It was not possible to assess bearing and journal surfaces or seal surfaces as the unit was assembled. Nor was it possible to assess in detail the condition of the relief valve, valve dashpot, gate servomotors, shaft seal, shaft couplings, head cover, or bottom ring.

3.3 Review of the 2019 Outage Report

Unit 7 underwent a major overhaul in the summer of 2019. The work required full disassembly of the unit, including removal of the runner, to achieve restoration of clearances in the runner and to install greaseless bushings in the wicket gates. The generating unit had never been disassembled before to that extent. Therefore, it was opportunistic to conduct a thorough condition assessment of the other major power unit components.

Voith was retained by NL Hydro to carry out the work and part of the condition assessment inspections, as well as balancing and start-up support. Disassembly, reassembly, electrical testing, and inspection, as well as ordinary maintenance work in other components of the unit not in Voith’s scope were carried out by NL Hydro.

A final outage report was issued by Voith to document every aspect of all the work that happened during the outage. In this report, the remaining useful life of the unit is deemed to be 5 years, and an outage should be taken within this timeframe to address refurbishments required for life extension. These long-term recommendations have been reviewed in detail in this study as part of the current 2023 Hatch mandate.

3.4 Generator

The generator was inspected on August 7th to 9th, 2023. On the first day, the low voltage electrical testing was completed, and the exciter and the excitation transformer were inspected. Direction was provided to NL Hydro to remove cooler #6 in order to have access to a set of high voltage bars from behind the core.

A detailed inspection of the generator with the aid of a borescope was carried out on the second day.

On the third day, the high voltage electrical tests of the stator armature winding were executed by NL Hydro’s engineering, and Hatch team witnessed them.

The generator exhibits overall signs of aging consistent with the age of the machine, as well as widespread presence of oil and carbon dust soot contamination. The presence of the dirt made verification of tell-tale signs of incipient electrical issues difficult. The elements of the main electric circuit (stator armature windings, rotor field coils) have reached the end of their designed useful life, despite not displaying signs of a developing imminent failure. The elements of the magnetic circuit (stator core, pole bodies, rotor rim) are in better condition and do not require replacement at this point.

Refer to Section 3 and Appendix D for list of deficiencies, risk assessment, recommendations, and cost estimates.

3.4.1 Stator Frame

The frame structure is in good condition without visible cracks or other issues that could indicate fatigue or failure.

Figure 3-1: Example of Typical Magnetic Debris (Piece of Welding Rod) Found on the Shelves of the Stator Frame

Significant amount of steel chips and debris at the bottom and intermediate frame shelves were observed. Figure 3-1 shows an example of such debris. These were confirmed as being magnetic materials by picking them up with a magnet. It included fillings, chips, pieces of welding materials and small nuts and bolts. This debris could be brought from the back of the core into the bar slot by the flow of cooling air.

Despite being subjected to an AC magnetic field (meaning it would not be immediately dislodged by magnetic attraction alone), the shelving of the stator frame sees the ventilation airflow of the generator in full force. That movement of air is strong enough to drag these pieces from the shelving and into the air gap and other spaces. In fact, we found steel filing debris deposited on some of the bottom end caps we had access to.

It is not possible to infer how long it would take for one of these pieces to be dragged into a position of causing serious damage, or where that would happen. Such damage could range from a flash over to a bolted short circuit in the stator.

It is important to note that, despite fast actuation of protection systems in tripping circuit breakers, the fault current of a fault located inside the generator is not cleared even after the circuit breaker is open. This is because the energy stored in the electromagnetic circuit of the machine feeds the fault even as the connection to the system is open. Faults inside a generator may take up to 10 seconds to clear. Therefore, the risk of a serious in-service failure is not negligible.

During our inspection, NL Hydro's maintenance crews were informed that the shelving should be cleared during that outage.

3.4.1.1 *Recommended Repair*

Clean the stator shelving and verify that the bottom end caps are also clean. We recommend that an outage be taken for that purpose as soon as possible. An outage of one week should be sufficient for it, including the time for placement of permits and removal of all coolers.

3.4.1.2 *Do-Nothing Consequence*

A serious in-service failure may happen. It can range from increased partial discharges if the debris bridges an insulation path to air gap damage due to rubbing, or a short-circuit. All depends on the type, location, and duration of the foreign material issue.

3.4.1.3 *Estimated Cost*

The estimated direct cost for this activity is [redacted] Costs for removal and re-installation of the bottom shrouds are included, but not further disassembly and loss of revenue.

3.4.1.4 *Life Extension*

This work does not impact life extension of the unit, other than preventing the likelihood of an in-service failure. It amounts to the remediation of an unsafe condition, rather than improving operating parameters of the machine.

3.4.2 ***Stator Core***

Upon visual inspection, no visible structural issues could be verified. With the coolers in place, it was only possible to visualize certain segments of the core from the back, but it was sufficient to verify that the laminations are horizontal and properly stacked. No buckling or movement of the core is visible. The removal of cooler # 6 allowed a split section of the core to be verified and confirm no issues were present.

Hatch performed stator core knife test at the back of the core where cooler # 6 was removed. A 0.010" thick blade was inserted with very small resistance between adjacent core laminations for almost an inch. A core considered properly clamped would allow an insertion of no more than ¼ inch.

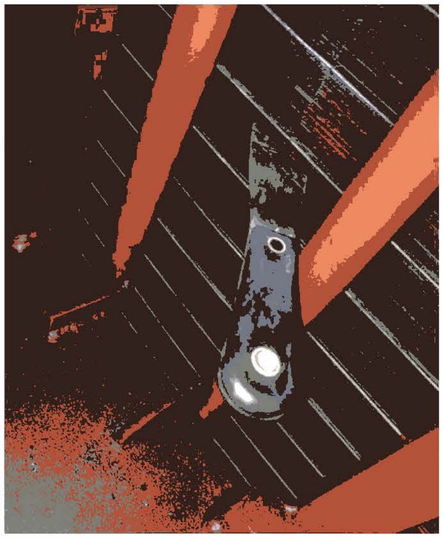


Figure 3-2: Blade Inserted Between Core Laminations

The result of the knife test indicates there is looseness on the core clamping. Documentation indicates movement of nuts on at least two core clamping studs, which corroborate the knife test result.

The core back was also rusted in its entirety. The brown color can be seen in Figure 3-2. Normally, even with age, the back of the laminations does not rust, unless due to a chemical reaction that happens when ozone is created as part of the partial discharge process or when the stator core is exposed to high humidity for prolonged periods out of service.

Monitoring of ozone presence inside the stator frame will allow to confirm if partial discharge activity is present during operation and causing the rust of the core back.

A loose core allows for increased movement of the lamination layers, and increased vibration overall. Such movement of the lamination advances aging and mechanically degrades the other corona protection on the bars first then ground-wall insulation over a long period of time. Degraded ground wall insulation will create space / voids in the slot that might create condition for corona activity in the slots. The rusted core back may indicate this is a process already in development. Electrical testing would not be able to indicate an advanced progression of this failure mechanism, as it is equally distributed through the armature winding.

3.4.2.1 *Recommended Repair*

There a few actions items required. All of them are low in priority and can wait until a reasonable time to be executed.

Check the torque on all core studs. If 10% or more of the nuts are loose, it will be necessary to retorque all of them to OEM values. Consultation with the OEM may be necessary if the information is not available. This exercise could be seized to adjust the verticality of the core stacking.

An El-CID test should be performed, if possible, ahead of the rewind to confirm the suitability of the core. The El-CID requires removal of the rotor.

The El-CID test done during the 2019 outage indicate no issues. Given that all other indicators point to a healthy structural integrity of the core and frame, it is possible to incorporate core checks (El-CID and Core Loop) in the rewind activities, as done for units 5 and 6.

The knife test is also a simple test that can be executed with barely any additional time during regular maintenance. We advise it to be incorporated in the yearly maintenance plan.

3.4.2.2 Do-Nothing Consequence

No immediate consequence is expected from this deficiency. It will progress overtime, but 10 or more years are expected before it develops into a significant issue.

3.4.2.3 Estimated Cost

The estimated direct cost for this activity is [redacted], travel, lodging and tooling. Costs for disassembly and loss of revenue are not included.

3.4.2.4 Life Extension

There are no short-term life extension benefits to be gained from addressing this deficiency. The effects it will have been on the availability of the unit is on the long term. Therefore, the verification and tightening of the core are required for any intended life extension beyond 15 years. The circularity and verticality would also need to be restored for a life extension of 15 years of more.

3.4.3 Stator Winding

The state of aging reported in the documentation was confirmed. This aging is common for machines of this vintage, so no indications of improper operation or significant events are visible.

Slot wedges seem to be intact when checked from the access point of top of the rotor between the adjacent poles. Stator winding lashing, tying and supports are intact, but a number of instances were verified where glass fibers are seen sticking out. Figure 3-3 shows an example. This is normally a result of poor workmanship at the time of installation. This can create conditions for tracking, bridging of insulating paths, and increased partial discharge over time. However, no visible evidence of such phenomena was seen at the locations inspected.

Figure 3-3: Fiberglass Sticking from Edge of Slot

Inspection of the winding on the bottom of the unit revealed some bars with cracks in the insulation right at the bar entrance into the cap compound (Figure 3-4). Such cracks are far from the active part of the bar, but they increase the likelihood that conductive dirt (like carbon dust mixed with oil) can be collected in the crack. This creates possible conductive paths closer to grounded elements, leading to increased partial discharge and possibly even a flashover.

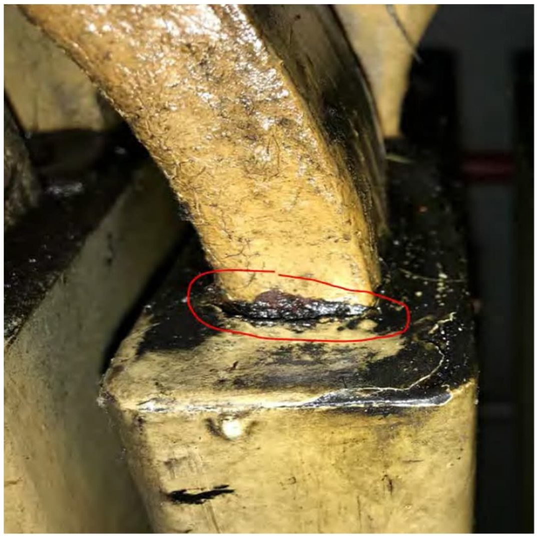


Figure 3-4: Example of Cracks at the Edges of End-Winding Caps

These cracks may become particularly troublesome in the presence of the metallic debris described in Section 3.4.1.1. Even in our limited inspection, we managed to collect a significant amount of magnetic metallic filings deposited on top of the bottom end-windings caps (Figure 3-5).

Figure 3-5: Example of Magnetic Metallic Debris Deposited on Top of the Bottom End-Winding Caps, Collected with a Magnet

Limitations of access prevented verification of possible partial discharge activity inside the slot, where critical areas like the interface of the inner and outer corona protection are located.

The 2019 outage report includes a detailed visual inspection account done by NL Hydro engineering. Several indicators, as described in detail in Section 3.4.3, show there is widespread aging signs of the winding. Of particular concern are the indications seen in the bottom end-winding arms of slots 194 to 200, and the state of the air guide.

End-winding caps at the bottom of the unit in slots from 194 to 200 have significant stress of the ground wall insulation. It seems that a proper overlap of epoxy resin and mica powder mixture with factory finished ground wall insulation was not achieved during installation. In addition, the significant bubbling of the paint on the back bars in slots 196 and 197 is a sign of possible cold joints inside the caps. The combination of those two workmanship issues during installation can create conditions for overheating. The apparent pitting of the insulation compound that fills the end cap of the top bar of slot 196 is a typical result of overheating at a defective brazing where the resin as organic material can gradually burn out. The fact that the damage seems to be symmetrical in relation to the top bar of slot 196 is also an indication of defective brazing of the end-winding arms. Figure 3-6 shows the paint bubbling and the cavity in the end cap of the top bar of slot 196.

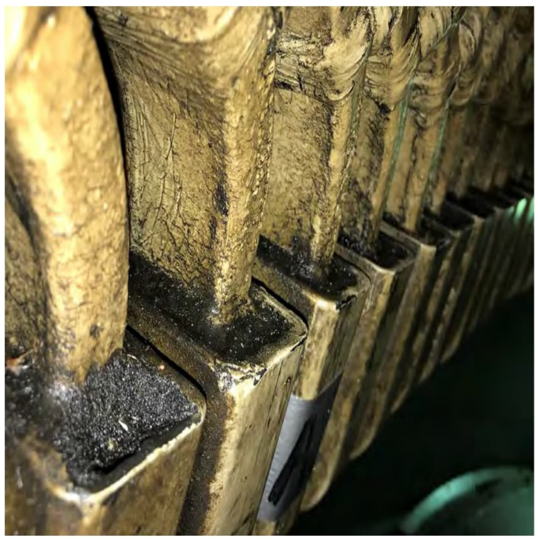


Figure 3-6: Bubbling of the Paint of Top Bars from Slots 196 and 197. Slot of Top Bar Closest to Observer is 196 (Source: NL Hydro Engineering Report, Part of the 2019 Outage Report)

Furthermore, the bars in this region are subjected to high voltage stress, including low and high voltage bars in proximity. The heavy collection of conductive soot of carbon dust and oil over creates a tracking path that can bridge insulation between phases and amplify the stress they experience. A phase-to-phase failure is a possible outcome if the area is not thoroughly cleaned, and the affected insulation repaired.

Because the highest degradation of the insulation in this area happens outside of the slot, in the extremity of the end-winding, it is unlikely to be captured by electrical testing done at the terminals. However, the issue is visible, and requires addressing with High urgency.

It is important to note that we could not access this particular portion of the bottom end-windings during our inspection, therefore it was not possible to verify if any progression of the issue happened since 2019. However, the state of the insulation seen in 2019 is already enough to warrant action.

3.4.3.1 Recommended Repair

The recommended repair is to rewind the stator armature windings in its entirety. There could be localized repairs done to the issues identified above, but the rewind is recommended for three main reasons.

First, any thorough cleaning or any repairs to the bars from slots 194 to 200 require a significant amount of disassembly and removal of the rotor. Bar removal without removal of the rotor (that is, pulling poles to make room for the work) is not practical due to limited space that would be made available. Other repairs recommended elsewhere in this report also require significant disassembly. Disassembly and reassembly are a significant component of the costs of a rewind, amounting to up to 20% of it.

Second, if just the bars from slots 194 to 200 were to be replaced, the remainder of the winding would be left in a condition of advanced aging, and an intervention for further repairs elsewhere is likely in the next 10 to 15 years. It is highly probable that the existing bars will fail before they reach 60 years of age. Therefore, diminished returns and life extension would be derived from a localized bar replacement.

Third, there is risk in adjusting circularity and verticality of the core with the windings in place. The stresses caused by the modification to the core structure can dislodge bars, crack insulation ground walls inside the slot and create condition for partial discharge in the slot. Despite the core issues not being a cause for concern at the moment, they will need to be addressed within 10 to 15 years.

Regardless of the path chosen, the situation in the bars of slots 194 to 200 needs to be monitored. At the first opportunity, thermal sensitive adhesive stickers (like ribbon RTD's) must be attached to the surface of those bars, so the total operating temperature can be recorded. The expected total temperature should not be above 80°C.

3.4.3.2 Do-Nothing Consequence

Stator windings like the ones installed in Unit 7 are usually manufactured with an intended service life of 40 years[1]. The state of the insulation in combination with the level of dirt contamination and the results of electrical testing show that widespread and evenly distributed aging has taken place. As there is no proven method to estimate or calculate the

[1] See Stone, G. C., & Culbert, I. (2010). Prediction of stator winding remaining life from diagnostic measurements. *2010 IEEE International Symposium on Electrical Insulation*. https://doi.org/10.1109/elinsl.2010.5549791. Also, an average of 30 years is given in Justification 52 of "Federal Replacements – Units, Service Lives, Factors – 2017, revision 1.1", by the U.S. Army Corps of Engineers

likelihood of an electrical failure to happen, it is not possible to affirm with certainty there is a guaranteed number of operating years left in the unit.

In addition, there is visual evidence that certain failure mechanisms are developing – particularly around the bottom end-windings of slot 194 to 200. The uniform rust on the back of the core may also be evidence of widespread, even if equally distributed, partial discharge activity.

The air guides are also in risk of an in-service failure due to poor fixation. It may cause an incident of lose metallic material, or excessive vibration that may wear off the insulation of the bars in the vicinity of the slot exit.

Therefore, doing nothing for the next few years yields a non-negligible chance of an in-service failure, and we recommend against it.

3.4.3.3 Estimated Cost

The estimated cost for the rewind of the stator is [redacted]. This is based on a turn-key project similar in execution strategy to Units 5 and 6. This cost is not inclusive of refurbishment to other unit components nor the rotor field winding. Lost revenue is also not included. There may be cost savings in combining all major refurbishments and replacements under one major contractor.

3.4.3.4 Life Extension

The life extension to be obtained by rewinding the stator armature winding is 40 years. This life extension covers only the stator and does not require replacement of the core. If circularity and verticality of the core are not addressed, this life extension is reduced to 15 years, as it is expected that circularity and verticality will progress beyond tolerance levels in that time frame.

3.4.4 Electrical Testing

NL Hydro engineering conducted the electrical testing of the stator, and Hatch witnessed the execution and reviewed the results. A detailed report by Omicron, the provider of the test equipment engaged by NL Hydro, with the results and connection diagrams is found in Appendix B - Electrical Check Sheets.

The electrical tests executed were:

1. Polarization index.
2. Frequency dielectric response.
3. Polarization – depolarization.
4. Power factor tip-up with hysteresis check.
5. Offline phase-resolved partial discharge.

The tests analyzed in detail the state of the insulation system of the machine and may indicate incipient failure mechanisms. However, on their own, they do not constitute a complete diagnostic suite and need to be complemented by a history of similar tests that allow a trend to be formed. Key indicators of failure mechanisms may be obtained from a single test battery, but these are only present on imminent failures.

These key indicators of failure mechanisms in advanced stage are:

1. The presence of hysteresis in the power factor tip-up test.
2. Specific distribution patterns of phase-resolved partial discharge graph.
3. A significant discrepancy between phases in any of the test results.

These tests were executed in 2019, however, at that opportunity, the machine had been offline and fully open for several weeks during the summer months. The results obtained in that opportunity were all affected by the presence of high humidity and therefore do not allow for trending.

The power factor tip-up results are within the limit of 1% indicated at IEEE 286-2000 and show no hysteresis. Measured partial discharge amplitudes are typical of advanced but uniform aging of the winding, without any graphical patterns that indicate incipient issues. All phases compare well with each other in all tests.

Therefore, considering the absence of trending results for comparison and none of the typical key indicators described above, no specific diagnostics can be derived from the electrical tests conducted. The results and signatures are common to machines of this size and this age. This does not indicate an abundance of useful life left. It simply shows that aging mechanisms are evenly present across the windings and phases.

It is important to note that there is no engineering method to guarantee an electrical in-service failure will or will not happen. The findings of the electrical tests must be taken in conjunction with the visual inspection, and one does not invalidate the other.

3.4.5 Cooling System

No issues were verified visually in the cooling system. No apparent leaks or damage were observed. Plant personnel informed all insulation was asbestos free. Records of operating temperatures of the stator show the cooling system works adequately. A significant collection of oil was observed at the bottom of cooler # 6 when it was removed.

3.4.6 Roter Rim and Hub

In 2019, Voith performed a visual inspection of the rotor rim and hub when the rotor was disassembled from the unit. The structural components of the rim and hub were reported to be in good condition.

During the 2023 site visits, the rotor was still assembled to the unit. Hatch was able to visually assess the accessible welds connecting the spider arms to the rotor hub. There were no signs of cracking or structural damage found. Rotor circularity, verticality and concentricity are within CEATI, Part 2 tolerances.

No fretting was found between rotor rim and rotor hub, or poles dovetail hammer heads and rotor rim.

3.4.7 Rotor Field Winding

The rotor exhibits key signs of degradation in the insulation of the coils in each pole, and most mechanical components that provide mechanical bracing are missing or in bad condition.

The pole faces experience significant rust, but they can be restored to a proper surface.

Due to the limited access, the insulation of the field winding was inspected in the vicinity of poles #12 and #13. The rest of the analysis is based on the existing documentation.

Figure 3-7: Dislodged Field Coil on Pole #20 (Source: 2019 Outage Report)

The insulation between each turn of each coil is still mostly intact, but all the rest that is exposed to air and not compressed between the turns is degraded and in advanced stage of deterioration. In Figure 3-7 it is possible to see the edges and fraying of the interturn insulation.

Minor signs of movement from the field coils in these two poles are also visible (Figure 3-7), although the extent of movement is minimal. It was not possible to verify dislodging to the extent of the one in Pole #20 (Figure), or to assess if the one in Pole #20 had progressed. It is likely that such dislodging would happen on the bottom of the poles, not on the top.

Insulation under and over the U shape connectors responsible for connections between poles is dry and brittle, which indicates degradation of the resin used. At one location, it was possible to easily lift a turn of glass tape by finger since the bonding of resin is lost. The field leads were reinsulated during the 2019 outage and are on good condition.

It was not possible, due to access limitation, to conduct a pole drop test. This test measured the voltage drop in each pole and, if they are similar, indicates few or no shorted turns exist. The pole drop test executed during the 2019 outage show a wide discrepancy between the results of each pole and seem to indicate several poles have shorted turns. However, due to degradation of the outer varnish layer that should coat the field winding as a whole, tracking due to conductive dirt (trapped between turns) is likely to have affected the results. Voltage source variation usually doesn't produce the results seen during the 2019 pole drop test.

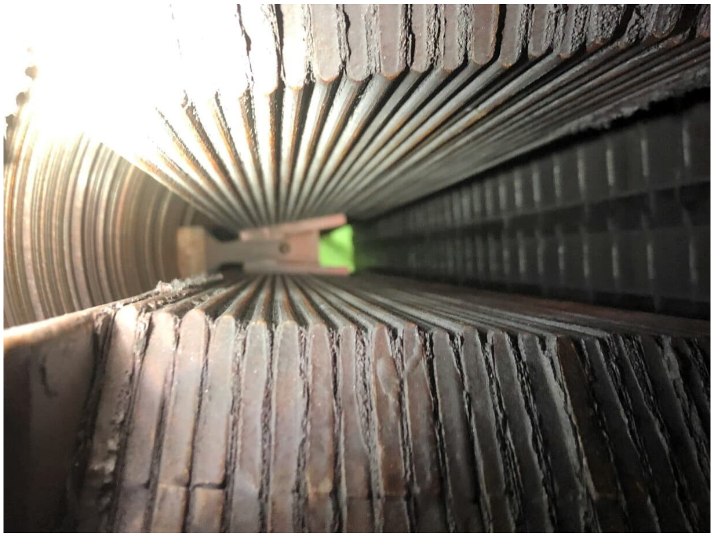


Figure 3-8: Typical state of pole coil Insulation seen from the top. In red are marked minor movement of a few coils.

The V blocks that restrain the field coil of the adjacent poles are intact but installed at a different height and in a different method than indicated in the OEM drawing. However, the drawing contains a note of a date more recent than the issue date stating that the coil V blocks (called "wedge" in the note) has been reviewed. No further information is available. An excerpt is show in Figure 3-9.

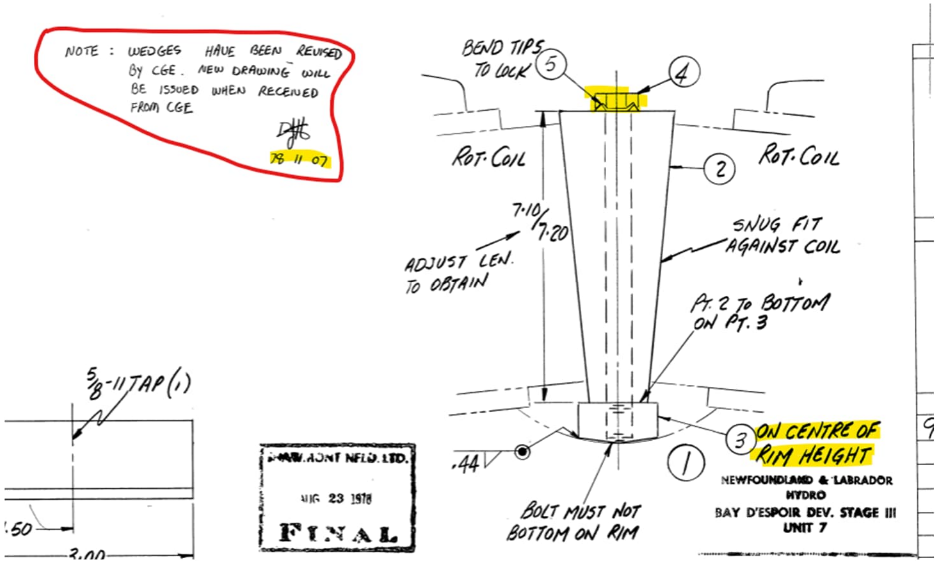


Figure 3-9: Excerpt from Coil Bracket Drawing (M-1337-03-213G) showing installation details not verified during the 2019 outage. Note mentions a further drawing to be issued.

The laminations in the rim and pole bodies are in good condition. The 2019 Outage report raised a concern about what seem to be melting of the rim laminations due to a significant electrical event. However, during the inspection it was verified that it was a mix of silicon and soot. The silicon was applied inside the ventilation duct to fixate spacers.

During a future outage, with all shrouds removed, it is necessary to verify that these spacers are present, and ensure they are properly fixated.

The dents on the laminations of the pole bodies can be repaired during the reinsulating of the rotor, and don't impair the machine's operation.

As the hub and rim are in a sound state, a large life extension can be obtained by reinsulating the field winding to class F insulation. The poles bodies also need repair, but their repair on its own will not achieve any extension of useful life. It is also necessary to confirm the proper installation method of the coil brackets / V blocks.

3.4.7.1 *Recommended Repair*

Reinsulating the field winding is the only repair possible, and there are no partial repairs to be considered. This repair must include all components of the field windings insulation, except for the field leads – these have been reinsulated during the 2019 outage. Therefore, the repair must include reinsulating pole coils, the pole bodies, and the U-shape connectors. A detailed inspection of the bolts, nuts and washers need to take place. Seen as it is a common practice for NL Hydro to regularly remove two poles to clean the core superficially, verification of the state of the keys is also required, and it is likely they will need to be replaced as well.

It is not required to replace the pole bodies damaged lamination, but rather simply to repair them. During the refurbishment, an assessment of the damper winding (embedded in the pole faces) should also be carried out.

A protective light coat of paint should be applied through the rotor at the end of the refurbishment, not just a layer of varnish as is the original design.

3.4.7.2 Do-Nothing Consequence

The rotor's insulation and winding bracing mechanisms are close to a state of failure. It seems to withstand normal operation and tripping events, but key components meant to provide resistance to an overspeed event are missing and damaged. We cannot be sure that a significant failure would not happen should an overspeed event ensue.

Do nothing about the rotor would mean accepting the risk of such a failure and we strongly recommend against it.

3.4.7.3 Estimated Cost

The estimated cost for the rewind of the rotor is [redacted]. This is based on a turn-key project similar in execution strategy to Hinds Lake's rotor rewind. A long outage would be required to remove the poles and ship them to a repair shop, refurbish them, ship them back, re-install and commission. Given that it is unlikely that this project would happen without other work on the unit, there are no schedule and loss revenue improvements to be had by buying new poles.

This cost is not inclusive of refurbishment to other unit components nor the stator armature winding. There may be cost savings in combining all major refurbishments and replacements under one major contractor.

3.4.7.4 Life Extension

The life extension to be obtained by reinsulating the rotor field winding is 40 years. This life extension covers only the rotor and does not require replacement of the hub and rim.

3.4.8 Slip Rings and Brush Rigging

The slip rings are in good condition. The brush marks (patina) observed are typical. Some very light pitting was verified on the bottom ring, which is usually the case with the positive polarity ring. The brushes that were removed from brush holders have smooth curvature surface which shows good contact with the slip rings. The four cables per sickle that connect the brush rigging to the excitation bridge have solid insulation without any signs of overheating. The insulation of the slip ring tested during the 2019 outage with acceptable results.

3.4.9 Maintenance recommendations

Other than the deficiencies requiring addressing as discussed in Section 3, the following recommendations concern monitoring and maintenance improvements that will allow NL Hydro to better control the progression of failure mechanisms.

1. Monitoring ozone inside the stator frame: regular ozone monitoring, either by portable machines at regular intervals, or continuous, would allow for verifications of evenly distributed partial discharge activity. It is also possible to clean the existing rust at the back of the stator core and verify if rust develops with the machine in service. That will not yield accurate measurements of ozone levels, but will provide a visual indication, over months, of the presence of ozone. The presence of ozone in service would be indicative of partial discharge activity inside the slots.
2. Bump test: verifying the vibration of the end windings with a calibrated hammer in accordance with IEEE will allow assessing whether the bars are securely lodged in the slots, of if excessive movement is present. These can be done at every major overhaul.
3. Off-line electrical testing: electrical tests with the same scope as those carried by NL Hydro during the inspection will create a tracking record that will allow for more precise trending and diagnostics. More details are discussed in Section 3.4.4. Executing the off-line partial discharge measurements with a device by Iris Power will allow for direct comparison with the online records, as Iris and Omicron use different computing quantities and strategies that are not directly correlatable[2].
4. On-line partial discharge verification and heat run: conduct a detailed heat run, in which the unit's output is incremented in certain intervals (25%, 50%, 75% and 100% load), with enough time for the machine to achieve thermal stability. At each output, record the on-line partial discharge levels. This will allow a better verification of how the partial discharge levels change with load and vibration and provide better diagnostic insight.
5. Wedge Tap: a calibrated wedge tap test can indicate whether wedges are loose because compression of the bars in the slot is no longer enough to prevent bar movement.
6. Winding resistance test: conduct a per phase winding resistance measurement. It may be able to indicate different ohmic resistance values of the windings, and therefore the presence of a cold joint as overheated hot spot.
7. Detailed visual inspection: a detailed visual inspection, with access to both endwinding sides, prior to cleaning, can provide a better understanding of the state of the stator, progression of issues identified in 2019, and identify telltale signs of insulation

[2] Iris Power's current offline testing device, the DeltaMaxx, uses the same measuring strategy as Omicron's MPD800. The MPD800 also allows for simultaneous measurement on both phase and neutral terminals of a phase and may be able to locate a cluster of discharges with precision. The DeltaMaxx doesn't have this feature as of April 2024. In case Iris doesn't have an instrument that measures discharges with the same method as the HydroGuardII (the existing online measurement device installed on U7), continuing to utilize the MPD800 from Omicron may be preferred.

degradation. It needs to be done prior to cleaning, as some of these signs can be wiped away (such as the white powder characteristic of partial discharges). A detailed visual inspection should be done at every major overhaul.

8. Add thermal strips on bars of slots 194 to 200: Add color changing strips to the bars of the affected slots to verify if they change color after operation in full load.
9. Fixate air deflectors where lose: one of the risks the machine faces is the air deflectors becoming lose during operation.
10. El-CID: carry out an El-CID test to verify the core has not develop hot spots and is suitable to be reutilized in the event of a rewind. An El-CID should be done at every major overhaul.
11. Rotor ventilation slot spacers: verify at every major overhaul that the spacers of the rotor ventilation ducts are properly fixated. The silicon in one of them was brittle and had come loose.

Some of these measures require increased access to the machine, including the face of the core (for example, wedge tap, or El-CID). If rotor removal is not viable, it may be achieved by removal of poles on both sides of the rotor (aligned by 180°). This would require engagement of the high pressure lift pump to allow rotation of the rotor as the work is performed as well as replacement of the pole keys for those two poles removed temporarily.

3.5 Bearings

Hatch did not have access to review the condition of the bearings during the 2023 site visits as the bearings were still assembled in the unit.

This unit consists of an oil-lubricated, combined thrust and guide bearing that sits below the generator and is supported by the main bearing bracket and an oil-lubricated babbitt shell-type turbine guide bearing located in the head cover.

3.5.1 Generator Combined Bearing

During the 2019 outage, Voith inspected the main bracket, thrust collar, thrust runner, thrust bearing pads, and guide bearing pads.

Voith visually inspected the thrust collar and determined the collar to be in good condition with limited signs of wear. Voith reported light fretting and corrosion. Additionally, there was light scoring on the journal surface possibly from contact with guide bearing pads or debris.

Voith visually inspected the thrust runner and determined the runner to be in good condition with limited signs of wear. The thrust bearing journal surface was found to be in good condition with no visual indications. The mating surface to thrust collar had light signs of fretting and corrosion.

Voith visually inspected the thrust collar keys and reported light fretting and corrosion.

Voith visually inspected the thrust and guide bearing pads. There was no NDE of the bearing pads or Babbitt material. Voith determined the thrust pads were in good condition with light scoring and surface imperfections on the Babbitt surface. Voith reported these types of imperfections are typical signs of debris or contaminates in the oil. The thrust bearing springs under two pads were checked to ensure none were broken and damaged. The springs were reported to be in good condition with no signs of damage.

The long-term recommendation by Voith in 2019 was to perform a more thorough inspection of the bracket including NDE along with a thorough inspection of the coolers and monitoring systems. Voith also recommended replacing all the thrust pads and springs. Voith recommends rehabilitating the thrust runner and thrust collar. Machining of both the running and collar mating surface is expected for the thrust runner. The guide bearing pads are recommended to be inspected and repaired as needed.

Hatch agrees that the bracket, coolers, and monitoring systems should be inspected during a major outage whenever repair work is being performed on the bearings. Hatch agrees with rehabilitating the thrust runner and thrust collar to ensure proper geometric tolerancing and surface finish. Hatch also agrees with inspecting (NDE) the guide bearing pads and recommends NL Hydro plan to re-babbitt the bearing pads. From Voith's report, there were no signs of damage to the thrust pads or spring beds. However, the thrust bearing pads and spring beds were considered 'delicate' and there was hesitancy to inspect and modify during the 2019 outage stating long lead times for the components and inability to repair damages. Therefore, Hatch recommends that they plan to be inspected (NDE), re-babbitted, and supplied with new spring beds. This will mitigate schedule and outage risks given a failure or issue with the bearings.

Refer to Appendix D, Item 35 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.5.1.1 Thrust Runner, Keys, and Collar

Light fretting and corrosion were identified on the thrust runner, keys, and collar. These are precision components that need to be level to a high degree of accuracy. There was no dimensional inspection of these components during the 2019 outage. Out of tolerance issues with the alignment of the thrust runner and bearing can cause unit alignment issues.

3.5.1.1.1 Do-Nothing Consequence

These components being reported in good condition could remain as is for another 25+ years if the dimensional and geometric tolerances are within OEM design.

3.5.1.1.2 Recommended Repair

Hatch recommends dimensional inspection and surface finish measurements of running surfaces. Clean, machine, and polish surfaces in a rehabilitation facility to correct any dimensional, geometric, and surface finish out of tolerance issues.

3.5.1.1.3 Estimated Cost

The estimate cost of repair work for the thrust collar and thrust runner is [redacted] (AACE Class 5 estimate).

3.5.1.1.4 Life Extension

After inspections and repairs, these components have an estimated life extension of 40+ years.

3.5.1.2 Thrust Bearing Pad

The thrust bearing pad had light scoring and surface indications on the babbitt surfaces. If the surface finish and condition is poor, the thrust bearing may become overheated and wiped; thus, causing a catastrophic failure and immediate shutdown / unplanned outage.

3.5.1.2.1 Do-Nothing Consequence

This surface is a critical surface. Given the current condition, it may be acceptable without intervention for another 5-10 years.

3.5.1.2.2 Recommended Repair

Replace the thrust pads and thoroughly inspect the other bearing components.

3.5.1.2.3 Estimated Cost

The estimated cost of new thrust pads and bearing inspection is [redacted] (AACE Class 5 estimate).

3.5.1.2.4 Life Extension

New thrust surface will allow an estimated life extension of 40+ years.

3.5.2 Turbine Guide Bearing

Voith inspected the bearing during the 2019 outage.

Voith recommended that the spare bearing be installed in 2019 and the original bearing be sent out for repairs and re-babbitting. NL Hydro proceeded with Voith's recommendations during the 2019 outage.

The long-term recommendation by Voith in 2019 was to perform a similar rehabilitation of the removed bearing as performed in 2019 for the spare bearing. Hatch agrees with Voith's recommendations so that NL Hydro will have a fully functional spare bearing that will reduce risks to extended unplanned outages related to the turbine guide bearing.

3.6 Main Bracket

During the 2023 site visits, Hatch had limited access to assess the main bracket condition but did not find any issues with the mounting plates, surrounding concrete, or bracket.

The main bracket supporting the generator thrust and guide bearings were visually inspected by Voith in 2019 and reported to be in good condition. There were no indications beyond limited signs of wear and deterioration.

3.7 Turbine Shaft

As the unit was not disassembled during the Hatch site visits in 2023, the turbine shaft was not able to be assessed beyond the shaft section above the turbine guide bearing to the generator shaft.

During the 2019 outage, Voith performed a visual inspection of the turbine shaft. The shaft was removed from the turbine pit but remained coupled to the runner. Voith reported light scratches and dents on the bearing journal surfaces, wear of the shaft seal sleeve, and discoloration and scoring on the generator end coupling flange. Voith did not perform any non-destructive examination (NDE) of the turbine shaft. Voith did not perform any dimensional inspections of the turbine shaft.

NL Hydro purchased multi-tensioner nuts to replace the OEM heat tension nuts. As the shaft and runner were not decoupled during the 2019 outage, the hardware was not replaced.

The long-term recommendation by Voith in 2019 was to rehabilitate the turbine shaft including non-destructive testing, dimensional inspection, spigot and coupling hole machining, painting, and repairs of issues found during inspection. Hatch agrees with Voith's recommendations. In addition, Hatch recommends installing a new shaft seal, re-establishing the OEM surface finishes for the bearing journal, and performing an FEA and fatigue analysis of the shaft. Hatch also recommends replacing the coupling hardware as multi-tensioner nuts have already been procured by NL Hydro.

Refer to Appendix D, Items 22 and 23 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.7.1 Do-Nothing Consequence

If nothing is done, the expected shaft has an estimated remaining life of 10 years. Longer life may be expected but cannot be assessed without further inspections beyond the limited inspections from 2019 and assessment in 2023.

If a new runner is supplied, the shaft would require machining of the spigot and coupling bores to ensure a proper fit-up to the new runner.

3.7.2 Recommended Repair

Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new shaft for the turbine. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.

To ensure an extended service life of 25 years or longer, the shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. A new shaft sleeve should be installed as well as new coupling hardware between the shaft and runner. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft.

To adapt a new runner, the runner end spigot and runner end coupling bores should be re-machined.

3.7.3 Estimated Cost

The estimated cost for rehabilitation of the turbine shaft is [redacted] (AACE Class 5 estimate) and a duration of [redacted].

3.7.4 Life Extension

Rehabilitation of the turbine shaft could provide a life extension of 50 years.

3.8 Generator Shaft

As the unit was not disassembled during the site visits in 2023, the generator shaft was not able to be assessed by Hatch.

During the 2019 outage, Voith performed a visual inspection of the generator shaft along with a high precision dimensional inspection using LIDAR. From the dimensional inspection (LIDAR), the critical dimensions, circularity, and flatness measurements were within OEM tolerances. There were no non-destructive examinations performed during the 2019 outage.

From the Voith 2019 report, the surface finishes were not verified or improved. However, there are no journal or thrust bearing surfaces on the shaft. Spigot and mating flanged have 63 RMS surface finish requirements per OEM drawing. Others are 125 or 250.

The long-term recommendation by Voith in 2019 was to rehabilitate the generator shaft. Hatch agrees with Voith's recommendations.

Refer to Appendix D, Item 24 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.8.1 Do-Nothing Consequence

If nothing is done, the expected shaft has an estimated remaining life of 10 years without interventions. Longer life may be expected but cannot be assessed without further inspections beyond the limited inspections from 2019 and assessment in 2023.

3.8.2 Recommended Repair

Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new generator shaft. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.

To ensure an extended service life of 25 years or longer, the shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft.

3.8.3 *Estimated Cost*

The estimated cost for rehabilitation of the generator shaft is [redacted] (AACE Class 5 estimate) and a duration of [redacted].

3.8.4 *Life Extension*

Rehabilitation of the generator shaft could provide a life extension of 50 years.

3.9 Wicket Gates

During the 2023 site visits, Hatch recorded gate end clearances for half of the gates in addition to a general visual assessment of the gates. Refer to Appendix C for Wicket Gate End Clearance Check Sheet. There were no obvious issues or damage to the gates. Hatch observed some minor surface finish issues but nothing of concern.

In 2019, the wicket gates were removed from the unit and shipped to Horizon Machining in St. John's, NL. The gates were visually inspected, dimensionally inspected, MT inspected, and partially refurbished.

Voith reported wicket gates trunnions showed signs of wear and light to moderate scoring. There was light to moderate scratches, dents, and small surface cracks on the main body of the gates. Gate end surfaces on some gates were damaged. As-left surface finish on gate stems were slightly above design tolerances but were accepted by Voith. The concentricity of the trunnions was not verified during the 2019 outage but was accepted by Voith and NL Hydro due to the measured runouts of the gates of the individual trunnions and increase gate stem bushing clearances.

Two long-term recommendation options were provided by Voith in 2019. Option 1 was to rehabilitate the existing gates. Option 2 was to supply 20 new wicket gates. Hatch recommends Option 1 as the gates are a solid construction made from stainless-steel. In addition to the recommendations by Voith, Hatch also recommends an FEA and fatigue analysis of the existing wicket gates. Hatch only recommends Option 2 as an alternative solution if a new runner is supplied, and the OEM can justify the need for new gates with sufficient performance increases or outage schedule savings.

Refer to Appendix D, Item 21 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.9.1 *Do-Nothing Consequence*

The wicket gates trunnion concentricity was not verified during the 2019 outage. This can lead to binding of the wicket gates and pre-mature wear of the gate stem bushings. It can also impact the alignment of the wicket gate vertical seals when in the closed position. However, as there are no reported issues due to any concentricity issues. The assessed risk to operation or failure of the wicket gates is low given the recent rehabilitation activities in 2019. If nothing is done, the estimated remaining life of the wicket gates is 25 years.

3.9.2 Recommended Repair

Hatch agrees with Voith's recommendations and assessment of the wicket gates. Rehabilitation of the gates is going to be the cheaper option as the wicket gates were inspected and refurbished in 2019. The condition is well known, and the gates are a well-constructed solid cast stainless-steel design. However, the outage schedule is critical as the wicket gates and bottom ring are the last two components to be removed from the unit during disassembly and one of the first components needed at site.

If re-using the existing wicket gates, an FEA and fatigue analysis is recommended to ensure proper life extension.

New wicket gates offer a potentially more efficient turbine as the hydraulic profile can complement a new runner hydraulic design. However, the effective gains in runner efficiency are likely small and need to be evaluated by the turbine manufacturer to determine if the cost of new gates is justified or offset by the performance increase. The schedule for new gates is more controlled as procurement can begin prior to the outage. However, if the head cover and bottom ring are being rehabilitated, the wicket gates would likely not be critical path and the schedule risk is low.

Hatch recommends that the base scope of supply to be rehabilitation of the existing gates with the option of new gates. New gates would need to be justified by a manufacturer to prove sufficient performance increase or by an outage schedule savings.

3.9.3 Estimated Cost

For rehabilitated gates, the estimated costs of engineering and rehabilitation is [redacted] (AACE Class 5 estimate). This would include shipping to a rehabilitation facility, cleaning, inspection, weld-overlay and machining of the vertical seal points, turning of the gate stem trunnions, and any repairs. The rehabilitation duration is estimated to take [redacted] at a rehabilitation facility.

If rehabilitating, it is advised to perform FEA and fatigue calculations to verify the life extension. The cost of the calculations is considered in the estimated cost provided.

Design and supply of new gates is estimated to cost [redacted] (AACE Class 5 estimate) and would take [redacted] for design and supply.

3.9.4 Life Extension

Both the rehabilitation and supply of new gates could provide a life extension of 50 years.

3.10 Wicket Gate Operating Mechanism

The gate operating mechanism includes the gate servomotors, servomotor links, operating ring, gate links, gate lever, shear pin, and link pins.

3.10.1 Wicket Gate Servomotors

During the 2023 site visits, Hatch was not able to assess the gate servomotors as they were assembled in the turbine pit and locked out for inspection. Visually, the exterior of the servomotors appeared in good condition.

During the 2019 outage, the wicket gate servomotors were removed from the turbine pit and disassembled. The components were cleaned and Voith performed a visual inspection of the components. There was no dimensional or NDE of the gate servomotor components during the 2019 outage and there was no pressure test performed in 2019. Overall, the servomotors were reported to be in good condition with typical wear. There was reported scoring on the cylinder wall bore and the piston. In addition, NL Hydro reported possible leaking in the servomotors prior to the 2019 outage.

In 2019, the servomotor cylinder walls were addressed with Scotch Brite to remove local high points from scoring, and new piston rings were installed. However, the refurbishment work did not fully correct the cylinder wall scoring issues. Voith concluded from their 2019 report that the new pistons are not as effective without properly addressing the cylinder walls scoring issues. Honing of the cylinder and new piston rings machined to suite the new diameter is required to properly address the issue.

The long-term recommendation by Voith in 2019 was to rehabilitate the gate servomotors. The expected scope of work for the gate servomotors include cleaning, NDE inspection, dimensional inspection, boring the cylinder, suppling new seals, and paint. Hatch agrees with Voith's recommended scope or work. If the governor and HPU are modified or replaced, consideration should be given to new gate servomotors, especially if a new operating pressure is chosen.

Refer to Appendix D, Items 26, 36, and 38 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.10.1.1 Gate Servomotor Scoring

The gate servomotor cylinder was found to have scoring in 2019 and the cylinder wall was addressed to remove sharp edges and high point, but the score is still present. Oil may seep past the pistons effecting the pressure and force generated by the servomotors. Seepage also can cause the jockey pumps to activate to maintain squeeze.

3.10.1.1.1 Do-Nothing Consequence

The gate servomotors are likely to function for another 10 years if nothing is done. However, it is important to address the issue for desired life extension of 25 or 50 years.

3.10.1.1.2 Recommended Repair

Hatch recommends rehabilitating the gate servomotors. The recommended scope of work includes cleaning, visual inspection, NDE inspection, and dimensional inspections of the components. Base scope of work should also include honing the cylinders, replacing piston seals, replacing wear components (bushings, seals, etc.), rehabilitation of the operating rod, and replacement of hardware under 1 inch. After rehabilitation, it is recommended to pressure test and leak test the assembled servomotors at the rehabilitation facility prior to shipping back to site.

There is a schedule risk when rehabilitating the servomotors if honing of the cylinder is not defined prior to shop rehabilitation. The piston seals are typically machined according to the cylinder bore diameter. This may extend the rehabilitation time based on the supplier and coordination.

If NL Hydro decides to replace the governor and HPU that is a different operating pressure than the existing system, new wicket gate servomotors would be required.

3.10.1.1.3 Estimated Cost

The estimated cost for the gate servomotor rehabilitation and supply of new components is [redacted] (AACE Class 5 estimate) and a rehabilitation duration of [redacted].

3.10.1.1.4 Life Extension

Hatch estimates that the life of the gate servomotors to be 50+ years after rehabilitation with periodic replacement of sealing components.

3.10.2 Operating Ring

During the 2023 site visits, Hatch was able to perform a visual assessment of the operating ring installed in the turbine pit.

During the 2019 outage, the operating ring was disassembled from the unit, visually inspected, and dimensionally inspected using LIDAR. There was no NDE of operating ring during 2019 outage.

Per Voith's recommendation, NL Hydro replaced the operating ring head cover liner (operating ring bearing pad) in 2019. The OEM head cover liner material was made from ASTM B171 Alloy 365. This material was unavailable due to long lead times to replace during the 2019 outage. After discussions between Voith and NL Hydro, new head cover liners made from Thordon SXL material were supplied and installed. Based on discussions between NL Hydro and Thordon, it was determined to increase the diametrical clearance between the journal and bearing to 0.085 inches from the OEM clearance of 0.020 – 0.030 inches to account for the oval shape of the operating ring. During a bump test after installation, it was revealed that the actual diametrical clearance was 0.150 inches. NL Hydro installed 0.030-inch shims behind the liners to reduce the clearance to approximately 0.100 inches.

The operating ring journal surface was in poor condition with significant damage to the surface. The journal surfaces were sanded down, removing high spots and rough areas.

NL Hydro has reported issues with the temporary bearing pads that were supplied and installed in 2019. There were reports that the replaced upper bearing has come out of position out the top of the operating ring. Hatch was able to review the 2019 designs and observe the condition at site. However, the operating ring was still installed during the Hatch 2023 site visits which limited the visibility of the components.

From discussions with NL Hydro and from the Hatch site visits, it was confirmed that the bearings are still greased. This is shown on the as-built drawing M-1337-02-165. NL Hydro reported that Thordon, the bearing manufacturer, advised grease would not harm the new material.

Drawing M-1337-02-092 indicates that the new Thordon SXL liners were made using the OEM drawings from Dominion Engineering. The drawing shows that the liners are secured to the head cover using 3/8-16 UNC button head screws. There are no dowels or other means to keep the liners fixed in place.

It is typical for a greaseless bearing material, like the Thordon SXL installed, run against a stainless-steel material with defined hardness and surface finish requirements. The current situation has the Thordon running against carbon steel with a poor surface condition.

From the 2023 site visit, it appears that modified liners were added that extend to the upper lip of the head cover to prevent them from moving, or the original pads have shifted out of position. Refer to Figure 3-10.

The OEM drawings indicate the bolts that are on top of the operating, as shown in Figure 3-10, are supposed to have a lip seal to contain the grease. There are no lip seals currently installed.

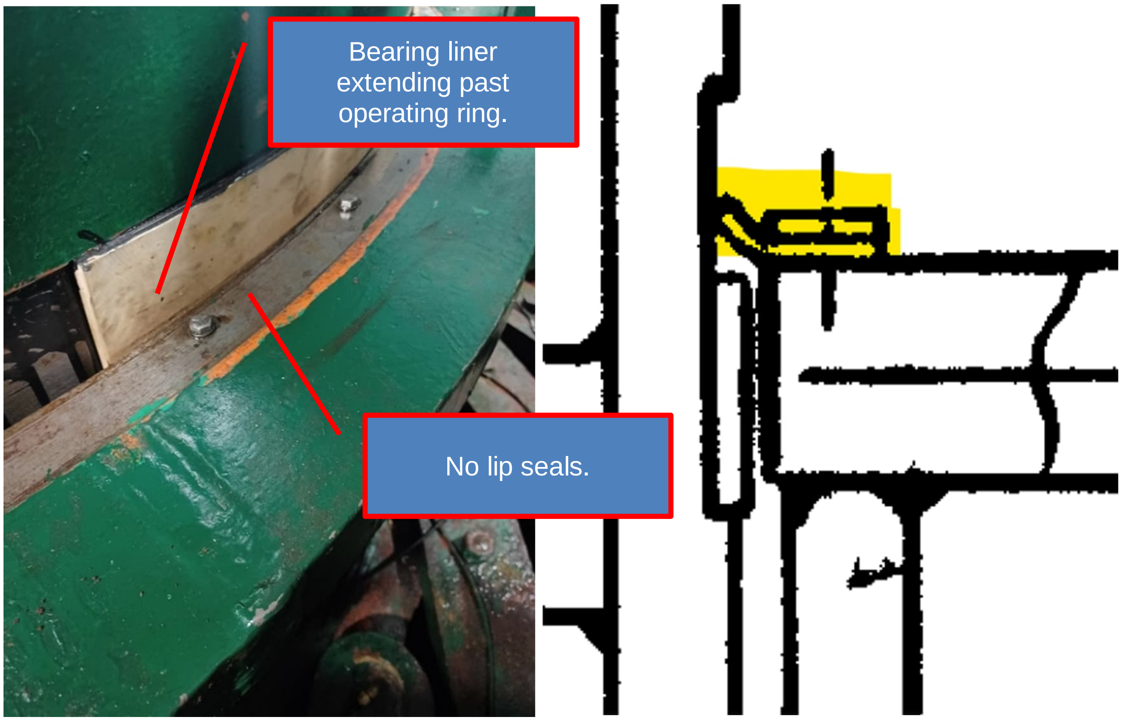


Figure 3-10: Operating Ring and Lip Seal

The long-term recommendation by Voith in 2019 was to rehabilitate the operating ring with new stainless-steel surfaces for the bearing journals. Hatch agrees with Voith's recommendations. However, the option of a new operating ring that can be split (two halves) should be considered by NL Hydro to improve access and ease of maintenance for the operating ring bearings, shaft seal, and head cover. Hatch recommends supplying new self-lubricating bearings that are metallic based and install upthrust clips to prevent the operating ring from shifting out of position.

Refer to Appendix D, Item 25 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.10.2.1 Operating Ring Bearings

There are two deficiencies with the operating ring guide bearings. The first is the general condition and design of the bearings and their running surfaces. The second is the lack of a lip seal to contain the grease pumped into the bearings.

1) Bearing Design and Condition:

There is significant surface damage on the upper and lower operating ring bearing journal surfaces. In addition to poor surface conditions, the operating ring has deformed over time is now an oval shape. The conditions were not fully addressed in 2019.

Regarding the design, there are issues with temporary bearing pads. First, the bearing clearance between the operating ring and the bearing pads is larger than the OEM design. Second, there are no dowels to hold the pads in place. The current bolts have some play between the bolt holes in the pads and rely on friction to keep the pads in place.

2) No Operating Ring Lip Seal:

The OEM design shows a lip seal above the operating ring to contain the grease injected to the bearing pads. This can cause a loss of lubrication between the bearings and journal surface. This is not a significant concern as the bearing material is considered a greaseless bearing material. There is an environmental risk of grease from the operating ring contaminating other turbine equipment in the pit.

3.10.2.1.1 Do-Nothing Consequence

The temporary solution provided by Voith in 2019 will be limited to a life of a few years. Regular assessments and maintenance should be performed to ensure the liners don't get dislodged out of position.

3.10.2.1.2 Recommended Repair

Hatch recommends that the operating ring be overhauled and rehabilitated in the next major outage.

The recommended scope of work is for the operating ring to be sent to a rehabilitation facility to be cleaned, visually inspected, MT or PT inspected, and dimensionally inspected.

Machining of the upper and lower bearing journals should be performed to re-establish roundness and surface finish. Gate servomotor pin bores and gate link pin bores should be oversized and machined concentric to the bearing journals.

Supply and installation of new stainless-steel wearing rings or pads welded or bolted to the operating ring to run against new greaseless head cover liners (bearing pads).

Supply new greaseless bearing pads (head cover liners). Preference towards metallic base material with self-contained lubricant that is machinable. It is recommended to secure the bearing pads to the head cover with a dowel to hold the pads in place. Refer to Figure 3-11 for a conceptual sketch.

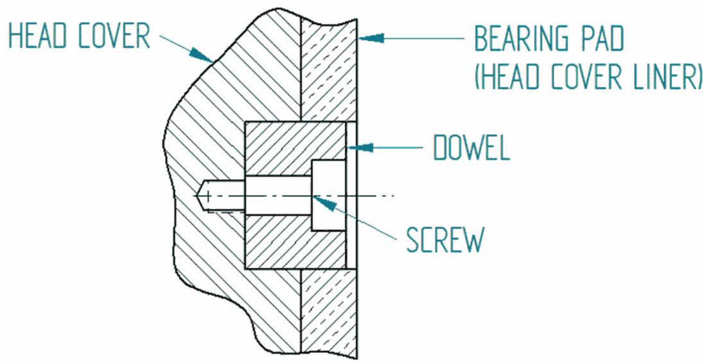


Figure 3-11: Example Dowel Concept Sketch to Secure Operating Ring Bearing Pads (NTS)

As an option, a new operating ring with a split may provide a benefit to NL Hydro as the bearing pads can be changed without major disassembly of the unit.

3.10.2.1.3 Estimated Cost

The cost to supply new bearing pads, new gate link pin bushings, new stainless-steel wearing pads, and perform the inspections, modifications, and machining of the operating ring is estimated to be [redacted] (AACE Class 5 estimate) and a rehabilitation duration of [redacted].

3.10.2.1.4 Life Extension

The greaseless bearing pads should be inspected or replaced periodically. Hatch estimates that the life expectancy of the bearings to be 15 years. Hatch estimates that the life of the operating ring to be 50+ years after rehabilitation.

3.10.3 Wicket Gate Arms and Linkages

During the 2023 site visits, there were no obvious defects or concerns with the gate arms and linkages observed by Hatch. However, NL Hydro reported that there are issues with the gate link pins dropping out of position.

The link pin is only held in place with a lock bar set into a groove on the pin. From the drawings and visual assessment, there is not a lot of overlap between the two. Lock bar is held in place by two ¼”-20 bolts. The lock bar has 9/32” clearance holes. That provides .0313” play for the lock bar to move within the bolt holes, assuming perfect alignment. However, the lock bar tapped holes in the link, the bore holes in the lock bar, and the dimensions of the lock bar were not given a machining tolerance on the drawing. It’s assumed that the freedom of movement and lack of tolerancing could lead to insufficient overlap between the lock bar and the groove on the pin causing the pin to drop out.

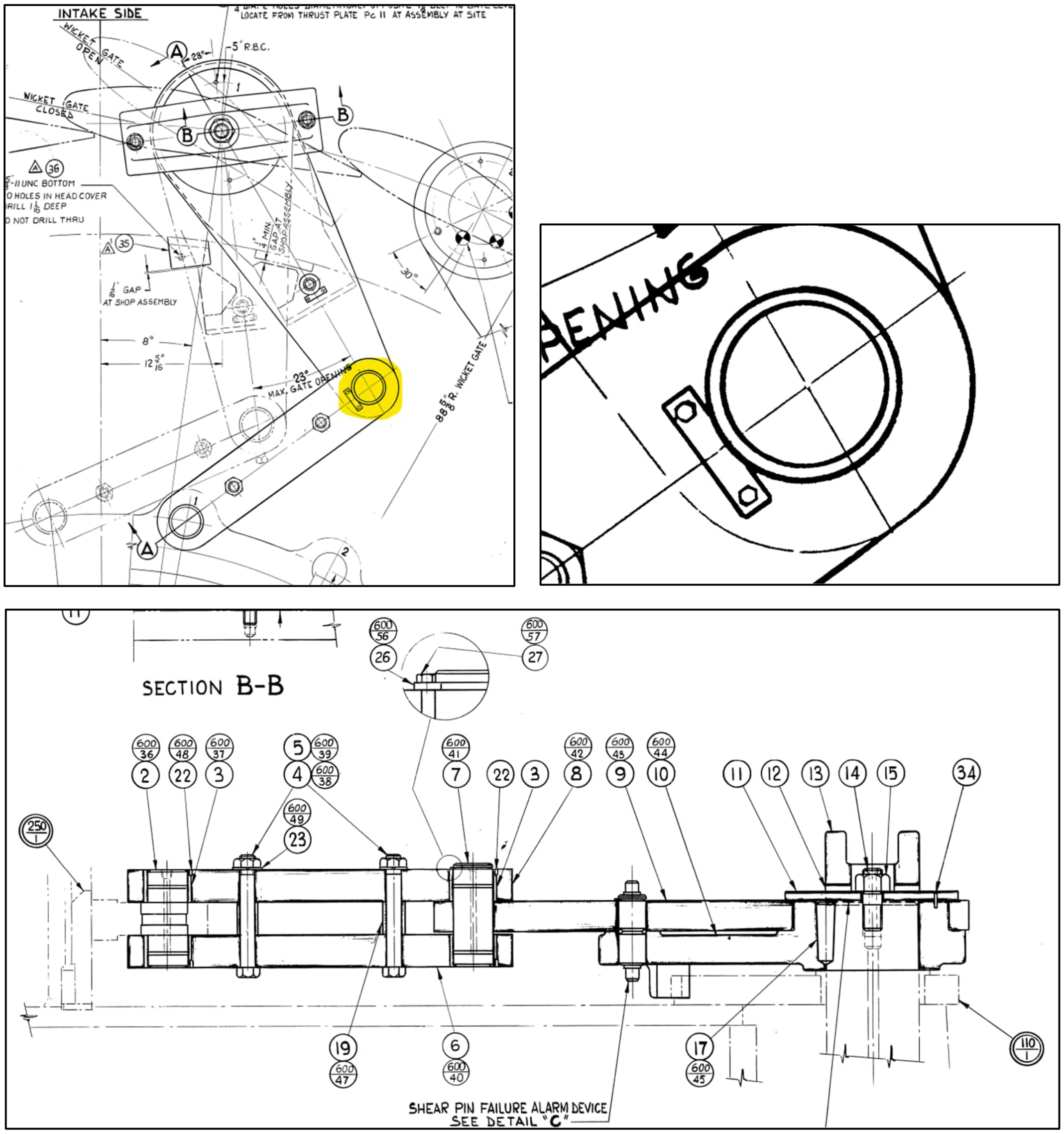


Figure 3-12: Gate Link Pin OEM Drawings

Figure 3-13: Gate Arms and Links (October 2023)

During the 2019 outage, the wicket gate arms and linkages were removed from the turbine pit and disassembled. The components were cleaned and Voith performed a visual assessment of the components. There was no NDE or dimensional inspection of the gate arms, linkages, or pins during the 2019 outage. Voith did not find any indications of concern and did not provide any formal recommendations during the outage.

The long-term recommendation by Voith in 2019 was to rehabilitate the gate arms and linkages including cleaning, NDE inspection, dimensional inspection, possible machining / repairs, and paint. Hatch agrees to rehabilitate the gate arms and linkages. Additionally, Hatch recommends suppling new stainless-steel pins and self-lubricated bushings.

Refer to Appendix D, Item 27 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.10.3.1 Do-Nothing Consequence

Pins dropping out could cause damage to arms and links in addition to losing control of a wicket gate.

3.10.3.2 Recommended Repair

Replace the gate link pins with a modified design that includes a flanged top to prevent pins from dropping. Recommended to replace with stainless-steel pins to allow use of self-lubricated bushings in the links.

Supply new greaseless gate link pin bushings. No preference towards metallic base materials or composite materials.

3.10.3.3 Estimated Cost

The estimated cost for new pins and bushings is [redacted] (AACE Class 5 estimate).

3.10.3.4 Life Extension

The expected life of the new pins is 50+ years; bushings is 25 years.

3.10.4 Wicket Gate Squeeze

NL Hydro reported that the wicket gates are currently operated with 0.5 inch of squeeze. The last documented measurements provided to Hatch were from 2022 Preventative Maintenance Check sheets with reported gate squeeze of 0.480”.

The OEM design squeeze is 0.375 inch according to OEM drawing 222F31628. The Unit 7 Commissioning Manual from October 24, 1977, reported the actual gate squeeze to be 0.360 inch. Site personnel suspects that the change in squeeze was made at some point to get the unit to stop reliably. Site personnel also reports that the operating ring is observed to lift slightly at maximum squeeze. There are currently no upthrust clips on the operating ring to control this.

2019 Pre-disassembly measurements on the unit show the vertical gap between the wicket gate seals were in good condition with only one gap at the bottom of the seal between gates 18 and 19 of 0.005 inch. All other seal points were recorded as 0 inch.

There were no squeeze measurements reported in the 2019 report by Voith. However, elevation and stroke measurements were taken and show the horizontality of the gate servomotors to be 0.238 inch and 0.168 inch. The stroke was recorded as 15.125 inch.

The wicket gate squeeze can be adjusted during the next major outage by adjusting the setting of the wicket gates and gate servomotors.

Refer to Appendix D, Item 36 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.10.4.1 Do-Nothing Consequence

If nothing is done, the bearing pad failures on the operating ring are likely to continue. However, the recommendations for the operating ring bearings, the gate stem bore alignment, and the gate servomotors are more critical to the long-term life extension of the turbine.

The increased squeeze may be causing the operating ring to oval and apply more pressure on the bearing pads resulting in bearing pad failures.

3.10.4.2 Recommended Repair

During the next major outage, adjust the wicket gate alignment, seal clearances, operating links / levers, and gate servomotor to re-establish the OEM design gate squeeze. This process is standard during the reassembly process.

Installation of upthrust clips is recommended where the OEM lip seal was. The lip seal is not necessary if converting to greaseless / self-lubricated bearing pads. Refer to Figure 3-14 for a conceptual sketch.

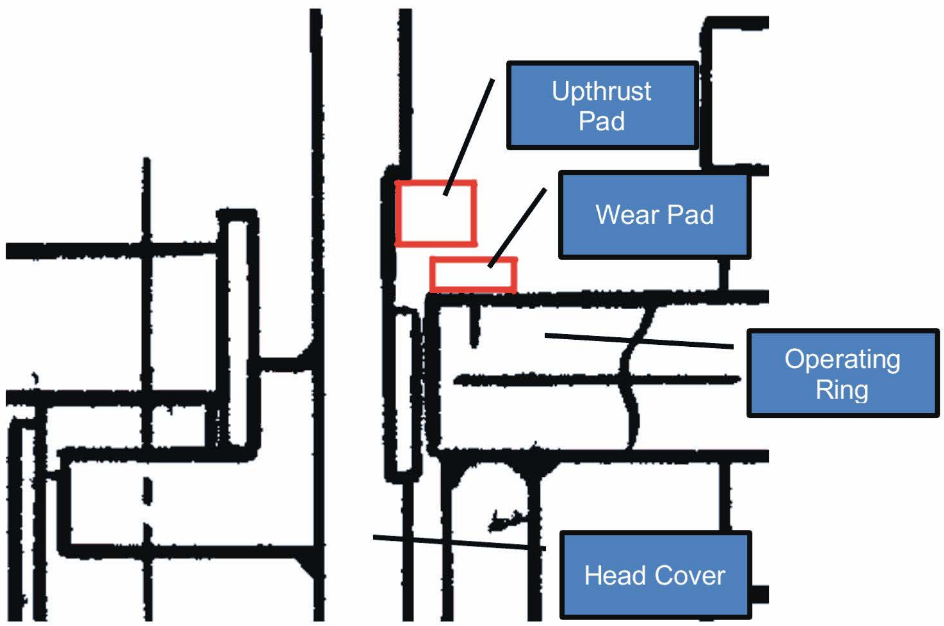


Figure 3-14: Example Upthrust Pad Concept Sketch (NTS)

3.10.4.3 Estimated Cost

The estimated cost to add an upthrust pad to the head cover and a wear pad to the operating ring is [redacted] (AACE Class 5 estimate).

3.10.4.4 Life Extension

Corrective actions have an estimated life extension of 40+ years.

3.11 Embedded Components

The embedded components assessed by Hatch were the spiral case, stay ring, stay vanes, and draft tube down to the draft tube maintenance platform.

Hatch was able to perform a visual assessment of the inside of the spiral case during a site visit in October of 2023. The unit was dewatered on October 12th and Hatch entered the spiral case and draft tube for inspections on October 13th and 14th with the assistance of NL Hydro personnel.

During the 2019 outage, Voith performed a visual inspection of the spiral case, stay ring, stay vanes, discharge ring, and draft tube.

3.11.1 Stay Ring and Vanes

During the 2023 site visits, Hatch was able assess the stay ring and stay vane water passage surfaces from the spiral case. The stay ring and vanes appeared to be in fair condition as areas of paint were starting to fade.

During the 2019 outage, Voith contracted Acuren to perform magnetic particle testing (MT) of the stay vane fillets. There were no relevant indications found during the MT or visual inspection of the stay vanes. Acuren was able to MT 97% of the stay vanes with no relevant indications, and it was decided to not MT the remaining 3% of the stay vane fillets as a new platform was needed to access.

The long-term recommendation by Voith in 2019 was for the stay ring and stay vanes to be blasted, NDE, possible machining of the stay ring flange, and paint. Hatch agrees with Voith's recommendations. In addition, a random MT inspection of 20% of the transition radii surfaces between the stay ring stay vanes and stay ring deck plates should also be performed to verify no changes or issues.

3.11.2 Discharge Ring and Draft Tube

During the 2023 site visits, Hatch was not able to inspect or assess the discharge ring. Hatch was able to verify the draft tube was absent of major Voids as this was checked by Mike Taylor of NL Hydro with the witness of Andrew Breighner of Hatch. There was minor deterioration of the welds connecting air admission vent covers to the draft tube, but nothing of structural concern. See Figure 3-15. There were also areas where the paint was eroded and areas of rust.

In 2019, Voith's report noted light rust and corrosion of the discharge ring but that the overall condition was good. Voith performed a void test with a hammer and concluded that there were no significant voids behind the discharge ring.

In 2019, Voith performed a void test with a hammer on the draft tube and found pockets that required grouting. In total, Voith drilled 25 holes and pumped 10 gallons of Prime Rex 1100 grout into the voids.

The long-term recommendation by Voith in 2019 was for the discharge ring and draft tube to be blasted, NDE, void checked, and painted. Hatch agrees with Voith's recommendations.

Figure 3-15: Aeration Pipe Injection Pipe to Draft Tube with Scoop / Cover

3.11.3 Spiral Case

During the 2023 site visits, Hatch was able to visually inspect the spiral case water passage surfaces. The paint was in fair condition with areas of degradation but limited base metal deterioration.

In the 2019 Voith report, the spiral case was reported to be in good condition given the age of the unit. Paint was in fair to poor condition. There were no clear signs of cracks or damage. Base metal in the middle of the spiral case was slightly worn with minor pitting and deterioration.

The long-term recommendation by Voith in 2019 was to blast, NDE, and paint the spiral case during the next major outage. Hatch agrees with Voith’s recommendation.

3.11.4 Leakage Around Embedded Components

NL Hydro reported water leakage between the spiral case and concrete near the spiral case access door. This has become a concern of NL Hydro as the issue appears to be becoming more significant. There was also observed leakage around the relief valve discharge pipe even when the unit is offline and dewatered. Figure 3-16 highlights the two areas of concern to be addressed in this report.

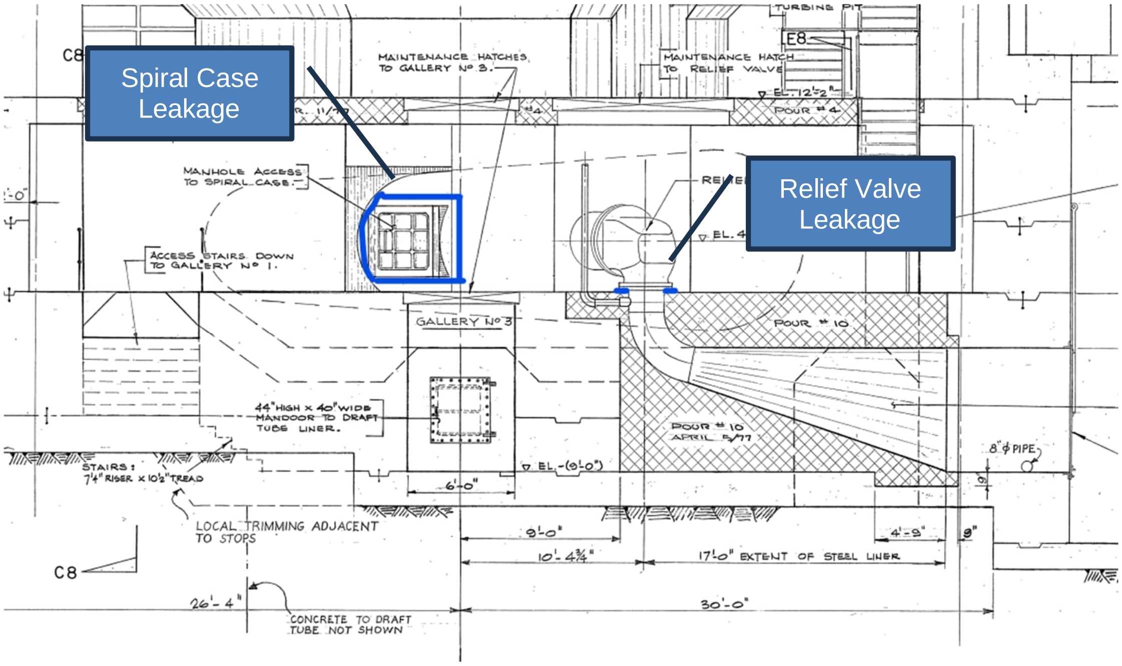


Figure 3-16: Powerhouse Layout Highlighting Concerning Leakage Areas in Blue

3.11.4.1 Spiral Case Leakage

3.11.4.1.1 Background and History

There is significant flow of water leaking around the spiral case access door between the concrete and the spiral case. NL Hydro reported that this leakage has existed in some form for at least 30 years (Customer Meeting November 6, 2023). A photo of the leakage is shown in Figure 3-17.

Figure 3-17: Scroll Case Leakage

NL Hydro operations began to raise safety concerns regarding the leakage around 2020. Even though the leakage had been an ongoing issue, it is believed that new staff raised the concern. There was no leakage data collected by the operations or engineering teams at NL Hydro until 2023.

There were anecdotal reports that the leakage seemed to increase after the 2019 outage where grout was injected behind the draft tube above the maintenance platform. However, without any data, these reports cannot be confirmed.

There were anecdotal reports that the leakage decreased in 2022 after installing a seal between the bottom ring and stay ring. This was suspected by site personnel due to reduced staining around the spiral case access door and around the exposed penstock near the spiral case intake.

3.11.4.1.2 Previous Work on Unit

The draft tube was void tested with a hammer and grouted in 2019. The grouting was checked by a hammer test for voids in October 2023 with evidence showing the grout is still in place with no voids behind the draft tube.

The spiral case piezometer ports were welded closed at various times between 1995 and 2005. It is believed by NL Hydro personnel that four (4) ports were not blocked off in the penstock.

As part of recent investigations by NL Hydro into the concerned leakage, NL Hydro opened the Winter Kennedy station valves, and no flow was reported.

In 2019, the cooling water supply line from the penstock was cleaned, inspected, and lined with a polyurethane sealer.

In the fall of 2022, an O-ring and silicone based Permetex product was placed between the bottom ring and stay ring. Refer to Figure 3-18 and Figure 3-19. This was inspected in October 2023 and appeared to be intact, but the effectiveness of the seal was not measured. The bottom ring was not removed in 2019 and therefore the O-ring seal under the bottom ring flange was not able to be inspected or replaced. The silicon was an attempt to re-establish this seal between the two components.

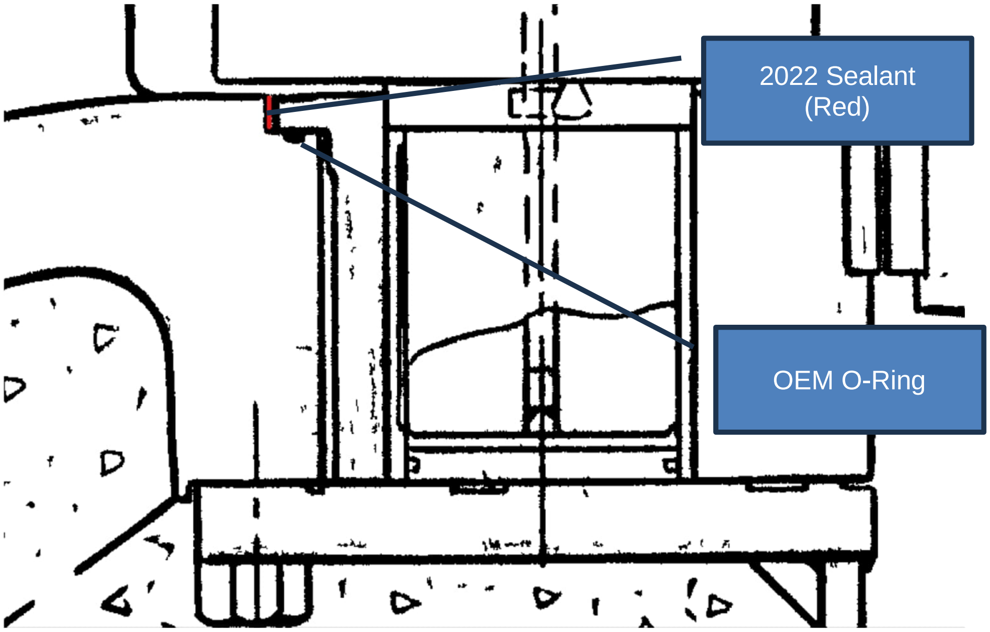
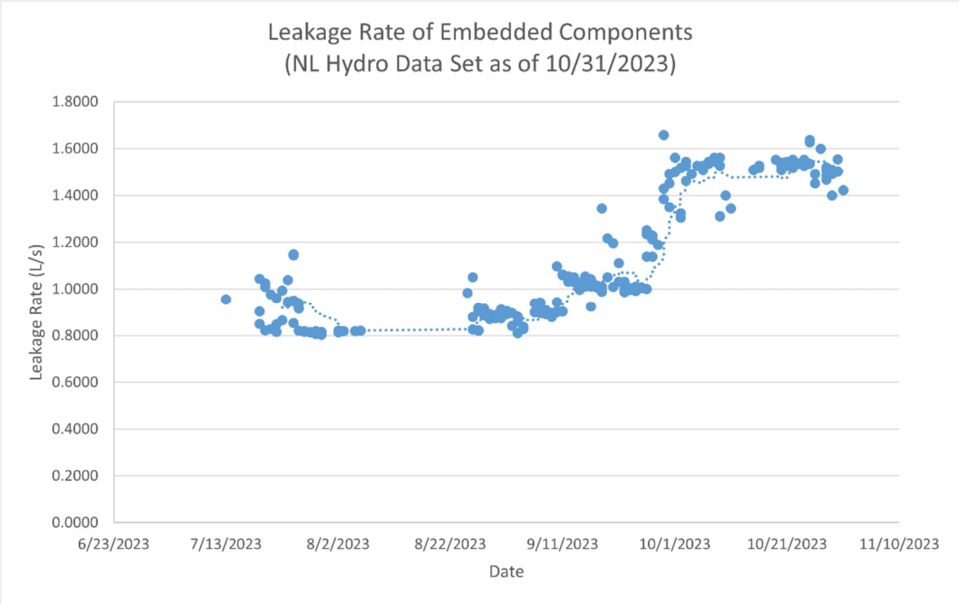


Figure 3-18: Location of Silicon Highlighted in Red (Turbine Cross Section)

Figure 3-19: Silicon Sealant between Bottom Ring and Stay Ring (October 2023)

3.11.4.1.3 Data and Analysis

NL Hydro provided Hatch flow information regarding the leakage around the spiral case in October 2023. Data was collected over 200 times from July through October of 2023 with three samples being taken each time. The leakage was measured by recording the time it took to fill a bucket of a known volume that flowed to the sump pit from the drainage canals. As part of the data collection, the date, time, weather, headwater elevation, tailwater elevation, unit output (MW), and unit status (ECON / Power Generation or Synchronous Condense Operation) was recorded. Figure 3-20 summarizes the flow rate data over time.



1) *Dotted line represents 14-day moving average.*

Figure 3-20: Leakage Rate of Spiral Case Over Time (NL Hydro Collected Data)

From the data, there was a notable increase in leakage at the beginning of October that appears to have leveled off. There was no correlation in the data found between the flow rate and the headwater elevation, tailwater elevation, weather, or unit output. There was a correlation between synchronous condense operation and ECON / power generation mode. Table 3-1 summarized the difference in average flow rates between the two modes of operation.

Table 3-1: Leakage Rate Data (NL Hydro Collected Data)

Unit Status	Average Flow (L/s) July - September 2023	Average Flow (L/s) October 2023
Synchronous Condense	0.8966	1.4472
Econ / Power Generation	1.0837	1.5211
% Difference from ECON to Synchronous Condense Operation	17%	5%

The data shows that the average leakage during synchronous condense operation is lower than the average leakage during ECON operation. However, the percentage difference is not consistent month to month. See Figure 3-21.

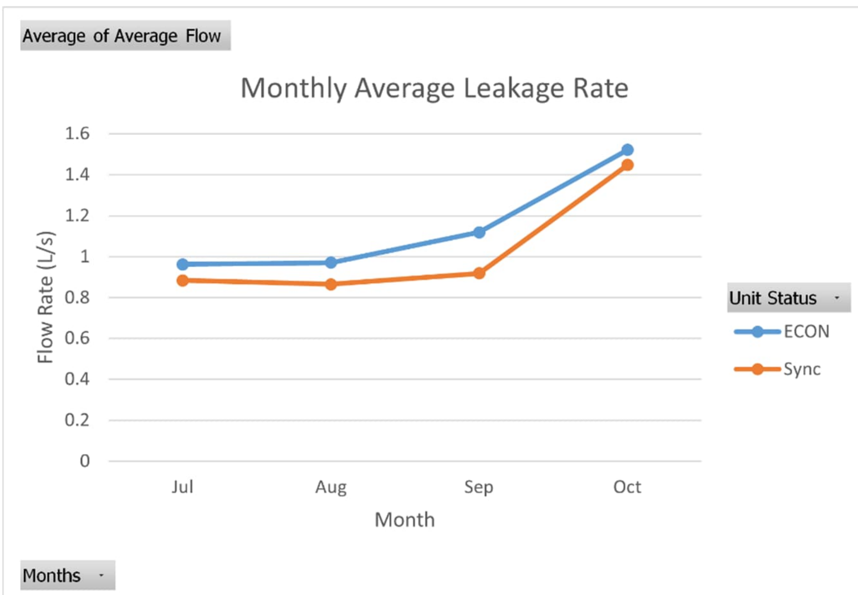


Figure 3-21: Average Leakage Rate of Spiral Case per Month (NL Hydro Collected Data)

NL Hydro reported the leakage ‘pulses’ when the draft tube aeration pipe check valve opens. It is not clear if the aeration system is causing a disruption to the flow of leaking water or if there is another phenomenon causing the check valve to open and the water leakage to pulse. There has been no formal study or recorded observations of the phenomenon or correlating data.

3.11.4.1.4 Potential Sources

There is no clear evidence or identification of the source of the leak. It is hypothesized that there are likely multiple sources contributing to the leakage as there is not a strong enough correlation between the flow rate, operating mode, or other measured conditions. This section discusses the possible leakage paths. Table 3-2 summarizes the potential sources.

Table 3-2: Spiral Case Potential Leakage Sources

No.	Source Description	Probability	Rationale	Inspection or Remedy
1	Penstock (General)	Low	There would be more water leaking at the exposed section in the powerhouse around the powerhouse drain.	NDE areas just upstream of the spiral case.
2	Spiral Case Water Passage Walls (General)	Low	Area was visually inspected. Only pinholes or small gaps would be leaking and likely not able to produce the flow observed.	NDE spiral case water passage. Visual inspection did not find any holes or cracks.
3	Spiral Case Drilled Holes	Moderate	Likely not able to produce amount of leakage observed. These holes were OEM design. This is closer to the exposed section of penstock than the access door. Would likely see linkage around exposed penstock in powerhouse.	Fill and cap if not needed. Investigate use and necessity of holes before capping.
4	Spiral Case behind the Baffle Plate	Moderate	This is closer to the exposed section of penstock than the access door. Would likely see linkage around exposed penstock in powerhouse.	Boroscopic inspection behind the baffle plate to identify leakage source.
5	Runner Seal Lubrication Piping	Low	Unlikely to have enough flow and pressure.	Pressure Test Piping; Borescope Inspection.

No.	Source Description	Probability	Rationale	Inspection or Remedy
6	Stay Ring to Discharge Ring Flange	High	Very likely to have corroded and would have a large area. Explains reduced leakage during synchronous condense operation.	Seal Weld between Stay Ring and Discharge Ring
7	Discharge Ring	Low	Unlikely to have corroded through the plates or welds.	NDE and local weld repair
8	Draft Tube Water Passage Walls	Low	Area was visually inspected. Only pinholes or small gaps would be leaking and likely not able to produce the flow observed.	NDE Inspection
9	Draft Tube Aeration Piping	Moderate	Explains reduced leakage during synchronous condense operation.	Pressure Test Piping; Borescope Inspection.
10	Piezometer Ports	Low	Unlikely to have enough flow through ports.	Inspect
11	Through Concrete	Moderate	Concrete around spiral case shows signs of water seepage between pours.	Volumetric test
12	Other Piping	Low	Unlikely to have enough flow and pressure.	Pressure Test

1. Penstock (General):

There is a low possibility there is corrosion or a leakage path in penstock. However, it would be nearly impossible to NDE the penstock, and the likelihood of any leakage coming from the penstock to the spiral case would be low. There is an exposed section of the penstock just upstream of the spiral case around the penstock drain. Any leakage from the penstock would more likely come out in this area and not around the spiral case access door.

A non-destructive examination (NDE) of the penstock from the spiral case to the penstock floor drain is recommended. This would be done at the same time as the spiral case NDE. This examination would look for any pinholes or cracks on the walls or weld seems of the penstock and spiral case.

2. Spiral Case Water Passage Walls (General):

Like the penstock, there may be corrosion, pinholes, or cracks not detectable by visual examination and would require NDE of the walls and weld joints.

3. Spiral Case Drilled Holes:

Another possible source of the water is from drilled holes in the weld seam of the spiral case inlet. From the original build, two 7/8-inch diameter holes were drilled 1 7/8 inch deep in the center of the weld. This could have opened a path between the walls of the spiral case and the stay ring casting.

Further investigation is needed as to the use of these holes. If deemed unnecessary, these holes could be filled and capped as to prevent any leakage.

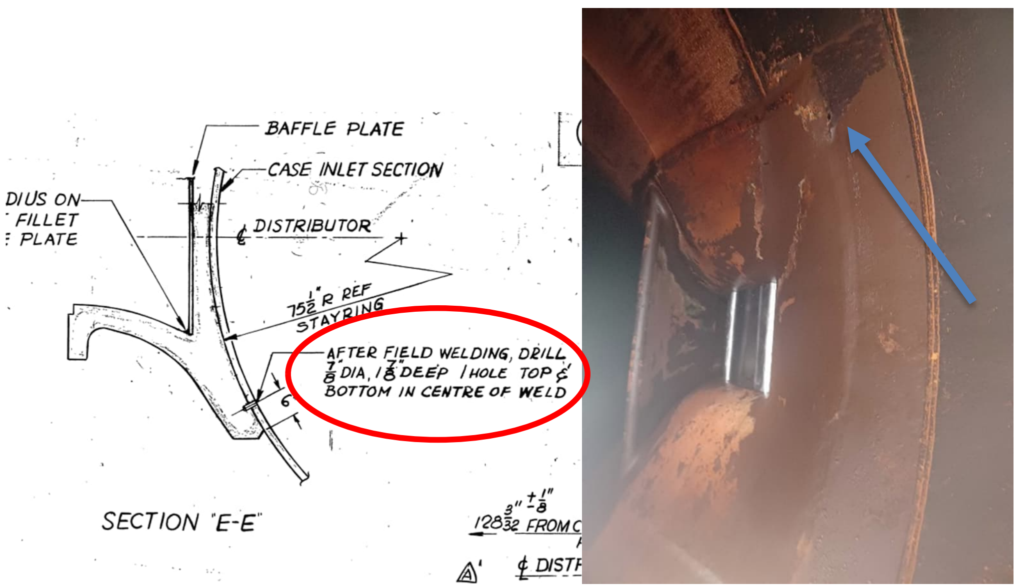


Figure 3-22: Spiral Case Drilled Holes in Weld Seam

4. Spiral Case behind the Baffle Plate:

On October 13th the bottom of the scroll case was slightly damp as the water hadn't fully drained and evaporated from dewatering. On October 14th, the spiral case was dry except for one stream of water still coming from behind the baffle plate at the end of the spiral and a stream of water coming from the pressure relief valve. The leakage behind the baffle could have been water dripping from debris built up behind it, but it was not possible for Hatch to fully inspect with the equipment available during the October 2023 site visit.

NL Hydro reported that a previous borescope inspection showed what could be interpreted as 'exposed concrete'.

Any recommended changes or repairs would require a better understanding of the location and extent of any discovered leakage path. Worst case scenario would be to remove the baffle plate, weld repair parts of the spiral case, then reinstall or replace the baffle plate.

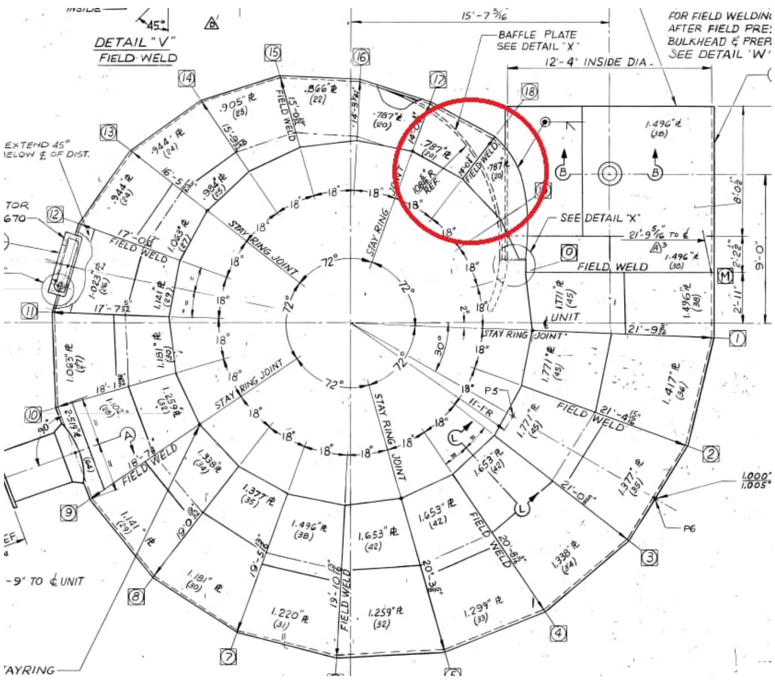


Figure 3-23: Spiral Case Location of Observed Possible Water Leakage

Figure 3-24: Spiral Case Location of Observed Water (October 14, 2023)

5. Runner Seal Lubrication Piping:

There is a 2-inch pipe takeoff from the stay ring for the runner seal lubrication piping. This piping has a header that runs around the turbine pit behind the head cover and is not embedded. It also feeds another header that is embedded and runs around the stay ring behind the discharge ring. Depending on the condition of the embedded piping below the stay ring, this could be leaking water behind the spiral case.

These lines can be inspected during an outage where the unit is disassembled, and pressure tested. However, it’s clear that the upper header that runs to the upper runner seal is not the source as it is not embedded and is visible from the turbine pit.

Figure 3-25: Runner Seal Lubrication Water Takeoff from Stay Ring

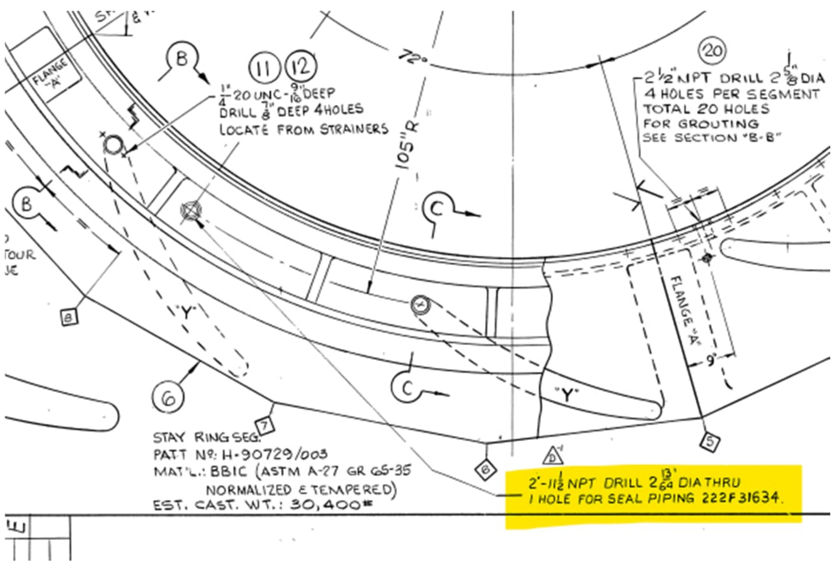


Figure 3-26: Runner Seal Lubrication Water Takeoff from Stay Ring

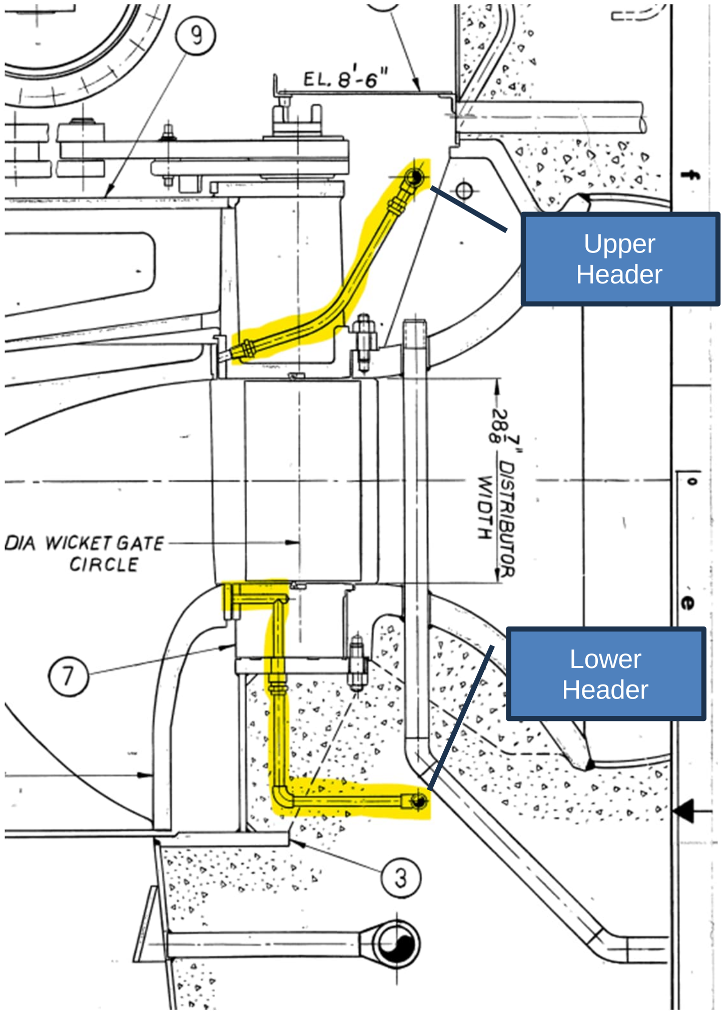


Figure 3-27: Runner Seal Lubrication Piping

6. Stay Ring to Discharge Ring Flange:

There are several possible paths of leakage through the bottom ring that all lead to a possible leakage area between the stay ring and discharge ring. This is a small surface area with a bolted connection between two carbon steel components that create very short leakage paths for water if there is any deterioration or erosion. This leakage path would correlate with the data as there would be less leakage during synchronous condense as water pressure from downstream of the wicket gates would not be a contributing factor. If the major of the water is leaking past the O-ring or through the gate stem bores, then only a small drop-off would be experienced between ECON and synchronous condense operation.

- Water could be leaking past the O-ring seal between the bottom ring and stay ring. This is the original seal and is likely well past its service life. A silicon seal was installed in

2022 as previously described. The effectiveness of this seal is not clear. But there is some evidence that this is a contributing source of leakage as some staff reported a noticeable decrease in leakage directly after the silicon seal was installed. However, no leakage data from before the seal was installed exists to verify this quantitatively. The type of seal used could easily loose function as there is no positive pressure to keep the seal functioning properly.

- It should be noted that part of penstock exposed at spiral case inlet shows signs of rust. NL Hydro reported leakage around this area of the penstock decreased after silicon was installed in 2022.
- Water could be leaking past the wicket gate stem bushing.
  - Water could be leaking between the bottom ring and discharge ring.

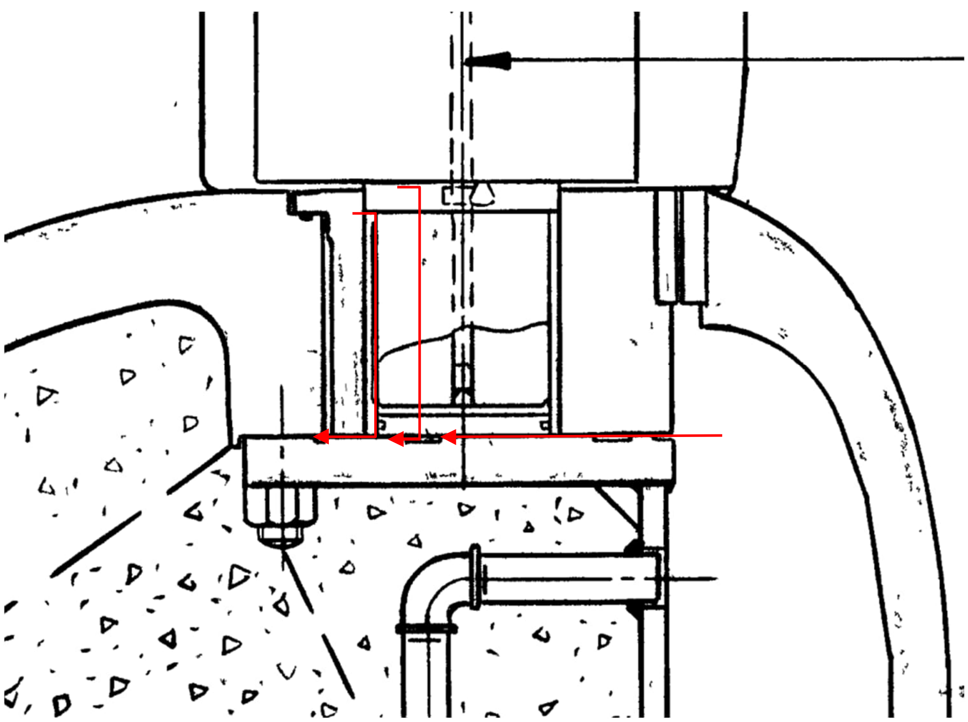


Figure 3-28: Leakage Paths to Stay Ring and Discharge Ring Flange

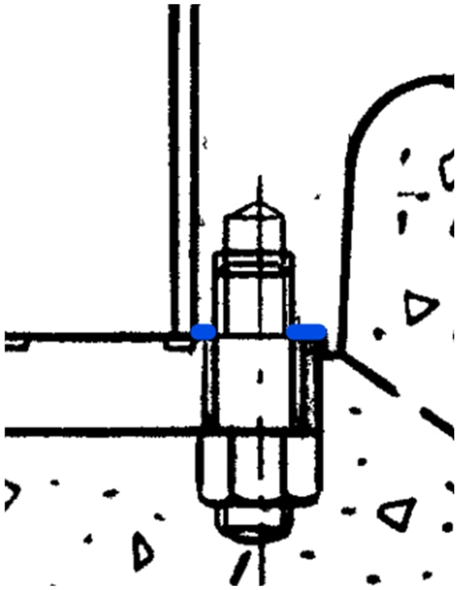


Figure 3-29: Stay Ring to Discharge Ring Bolted Connection

There is no means to inspect this connection without removing the discharge ring. To prevent leakage from any of these sources, a fillet weld should be added between the stay ring and discharge ring to seal the connection. A chamfer on the bottom ring would be required to ensure proper clearance.

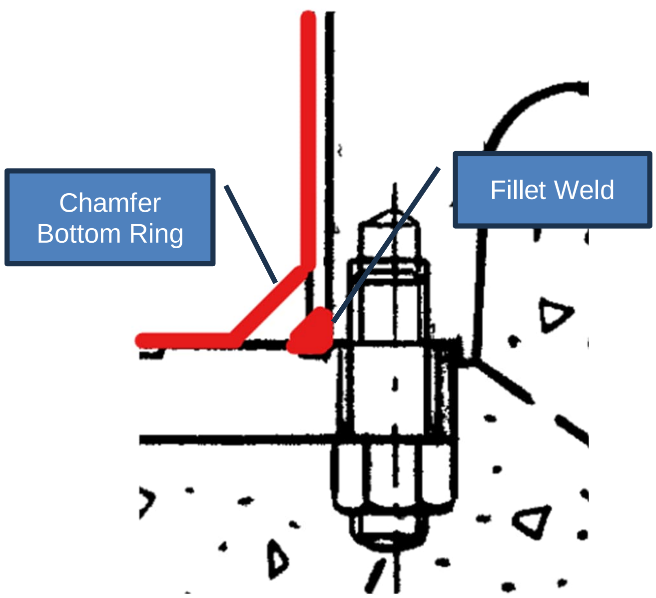


Figure 3-30: Stay Ring to Discharge Ring Recommended Modifications

7. Discharge Ring:

It's possible that weld defects in the discharge ring could create a possible leakage path. However, the leakage area in a weld defect would be small and unlikely contribute to the leakage around the spiral case access doors. However, during the next outage, it is recommended to NDE inspect the discharge ring welds and perform local repairs.

8. Draft Tube Water Passage Walls:

Like the penstock and spiral case, there may be corrosion, pinholes, or cracks that are not detected by visual inspection contributing to leakage. However, it's not a likely source of the amount of water currently leaking. It is recommended to NDE the draft tube above the maintenance platform similar to the penstock and spiral case.

9. Draft Tube Aeration Piping:

The draft tube aeration piping is embedded around the draft tube at an elevation just above the draft tube access door. It's possible that corroded pipes, cracks, or weld defects could cause the pipe to leak water into to the embedded area and work its way to the spiral case access door.

There is reported correlation between the aeration pipe check valve opening and pulsing of the leakage around the spiral case access door. There is no documentation or data collected and required further investigation to determine the causality between the two.

During the next major outage, it is recommended to inspect the piping with a borescope and pressure test the piping.

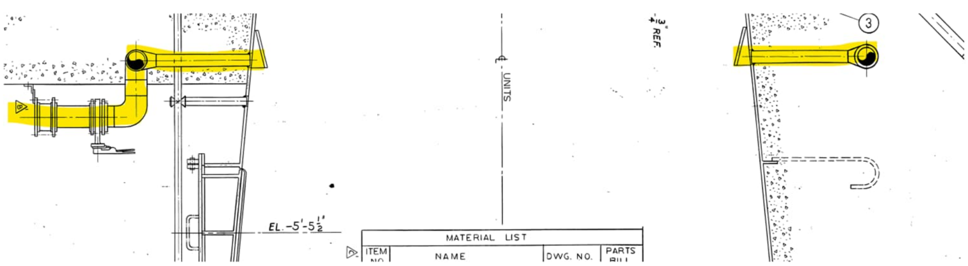


Figure 3-31: Draft Tube Aeration Piping

10. Piezometer Ports:

It's unlikely that the piezometer ports would create enough leakage as currently exists, but they may contribute if they are not properly sealed. The ports are recommended to be NDE inspected where sealed off.

11. Seepage through Concrete:

From the tailrace, there are possible seepage paths through the concrete that would align with the elevation of the spiral case access door. The area around the spiral case was poured in two stages. This would allow for cracks or gaps between the concrete pours. Evidence of water seeping through the two pours can be seen around the spiral case in the powerhouse. Refer to Figure 3-36.

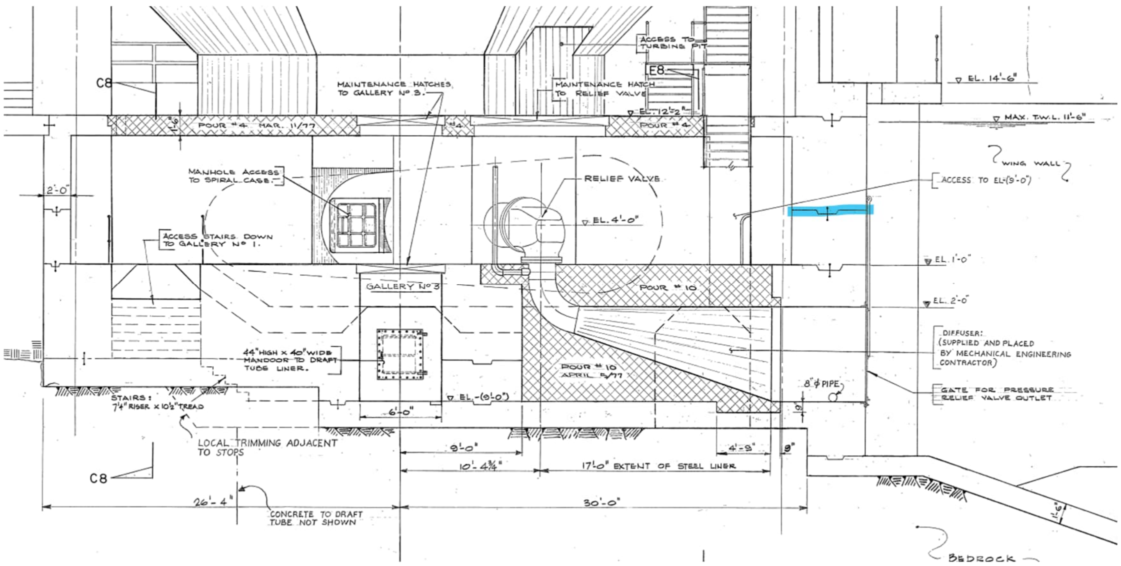


Figure 3-32: Powerhouse Layout and Embedment Details

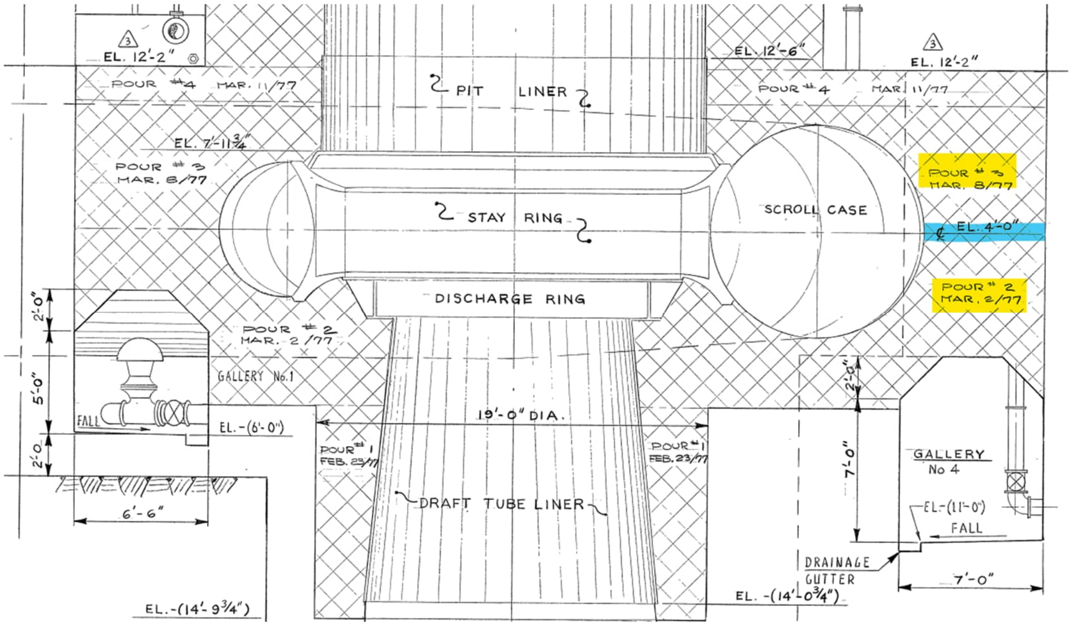


Figure 3-33: Spiral Case Embedment Details

Figure 3-34: Water Seepage Between Concrete Pours

12. Other Piping:

Other possible leakage paths are through embedded piping that passes through the concrete near the spiral case. Such piping should be pressure tested to see if there are any leaks. The following list are other possible water systems:

- Fire Protection Piping.
- Bearing Cooling Water Piping.
- Generator Cooling Water Piping.

3.11.4.1.5 Do-Nothing Consequence

It's not possible to provide a confident outlook if nothing is done. If the condition has been in existence for 30+ years as reported by NL Hydro, it could continue as is for another 15 or 20 years. Or it could become a more urgent issue if the leakage rate increases rapidly.

The leakage around the spiral case poses no immediate threat to the function of the turbine. There is a concern if the leakage rate continues to grow. Too much leakage or high velocity water can slowly erode concrete. It's more important at this point to be able to identify the source to monitor and further adverse conditions.

3.11.4.1.6 Recommended Repair

Table 3-2 summarizes some of the hypothesized leakage paths with possible inspections and remedies for each path.

The current leakage rate does not appear to be causing other significant issues. NL Hydro could continue to monitor the flow rate. Hatch recommends that if the average flow rate increases month over month for more than three (3) consecutive months, or if there is a sustained average flow rate over 3.0 L/s over a given month, that NL Hydro investigate the problem further and perform the following recommended repairs.

The following summarizes the general inspections and repairs recommended if intervention is needed.

1. Seal weld stay ring flange to discharge ring. This will likely cause distortion of the discharge ring surface where the bottom ring mounts to. Therefore, field machining of embedded components is required. This field machining would be recommended in either situation as to ensure proper alignment of the bottom ring to head cover, ensure level mounting surfaces, and ensure the bottom ring flange with the O-ring has a proper mounting surface to seal.
2. Lead abate, blast, clean, NDE, and paint the spiral case, stay ring, stay vanes, discharge ring, and draft tube liner down to the maintenance platform. Perform local repairs as necessary.

3. Remove spiral case baffle plate, inspect, repair as needed, and re-install baffle plate.

4. Pressure tests all embedded piping.

3.11.4.1.7 Estimated Cost

Table 3-3 provides an estimated cost breakdown to perform the various recommended actions to resolve the leakage issue.

Table 3-3: Estimate Cost for Spiral Case Leakage

Work Description	Estimate Cost (AACE Class 5 Estimate) [redacted]
Stay Ring Seal Weld and Embedded Parts Field Machining	[redacted]
Clean, NDE, and Paint Water Passage from Penstock Drain to Draft Tube Maintenance Platform	
Remove and Re-Install Baffle Plate in Spiral Case	
Pressure Test Embedded Piping	

3.11.4.1.8 Life Extension

If performing all the recommendations and correctly identifying the leakage path, this should resolve the issue for 50+ years. However, this is dependent on the confirmed source of the leakage.

3.11.4.2 Relief Pipe Leakage

There was observed leakage around the spiral case pressure relief valve outlet pipe connecting to the concrete as shown in Figure 3-35. There was also observed leakage in October 2023 inside the relief valve. A photo of the relief valve leakage is shown in Figure 3-36

Figure 3-35: Relief Valve Discharge Pipe Leakage (Unit Dewatered)

Figure 3-36: Leakage in Relief Valve as Seen from the Spiral Case

On October 13th, the pressure relief valve offtake from the spiral case and pressure relief valve were observed to be mostly dry with some residual moisture from the dewatering process. On October 14th, there was a noticeable stream of running water from the valve offtake on the spiral case and the valve was filled with water. There was also leakage on the outside of the pressure relief valve discharge piping between the pipe and concrete. There is a gate for the pressure relief valve outlet. It's possible that this gate was leaking causing the valve to fill up, but that leakage past the gate doesn't explain the leakage on the outside of the pipe. There is no evidence connecting the spiral case access door leakage, but this has not been ruled out.

During the next outage, it is recommended to examine the outlet pipe and diffuser of the relief valve for any signs of corrosion, cavitation, or other damage. The water velocities through the pipe could be very high and turbulent. Partial replacement or repair of the connecting flange and piping just downstream of the valve may be required depending on the results of an inspection. This would be considered the worst-case scenario.

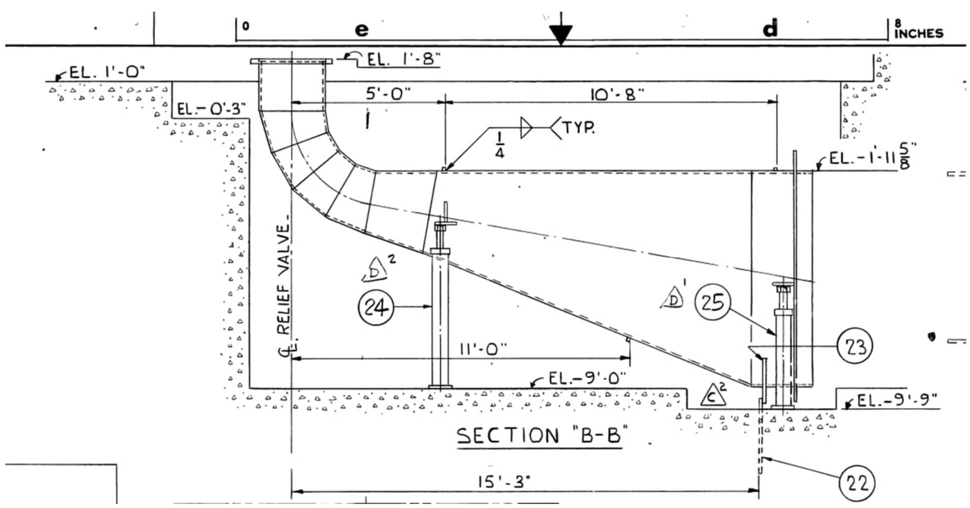


Figure 3-37: Relief Valve Outlet Pipe and Diffuser

3.11.4.2.1 Do-Nothing Consequence

If nothing is done, the piping around the valve would likely be acceptable for another 5-10 years. However, as the condition inside the pipe is unknown, it's difficult to provide a proper assessment.

The leakage around the concrete of the outlet pipe does not pose a serious risk to the operation of the valve at the current volume of leakage. However, if the leakage increases, this could pose a risk to the stability of the valve and outlet piping.

The leakage inside that filled up the diffuser and outlet pipe during the site visit is most likely caused by a leak in the outlet gate and is not a significant concern.

3.11.4.2.2 Recommended Repair

It is recommended to dewater the outlet pipe and diffuser and inspect the condition of the water passage surfaces with a borescope or visual inspection. If repairs are needed, the worst-case scenario would be to excavate part of the concrete, replace the upper section of the pipe and flange with stainless-steel pipe and re-embed the pipe.

The outlet gate should also be inspected and repaired.

3.11.4.2.3 Estimated Cost

The estimated cost to replace the upper section of pipe is [redacted] (AACE Class 5 estimate).

The estimated cost to inspect and repair the outlet gate is [redacted] (AACE Class 5 estimate).

3.11.4.2.4 Life Extension

If performing all the recommendations and correctly identifying the leakage path, this should resolve the issue for 50+ years. However, this is dependant on the condition of the diffuser and other sections of the outlet works.

3.12 Bottom Ring and Head Cover

During the 2023 outage, Hatch had limited view of the bottom ring and head cover as the unit was fully assembled. The facing plates, gate end seals, and top of the head cover were partially visible for assessment.

The seal clearance issues are discussed in detail in Section 3.13.4.

3.12.1 Bottom Ring

During the 2023 site visits, the bottom ring was not able to be assessed at site other than the facing plates and gate end seals. The gate end seals were partially damaged in some areas, but this is typically for the type of rubber seal used. The facing plates appeared to be in fair condition with some scratches and scoring. Some of the covers to the hold down hardware appeared to be missing or damaged. The gate end seal retaining plates appear to have a gap between the gate trunnion and the retaining plate. It's not certain if this is a design issue or is an intentional feature.

Figure 3-38: Bottom Ring Facing Plates and Gate End Seal

During the 2019 outage, Voith performed visual inspection, dimensional inspection (LIDAR), wearing ring machining, line boring, and replaced the greased lower gate stem bushings with greaseless bushings for the bottom ring. During the 2019 outage, the bottom ring was not removed and stayed mounted to the discharge ring.

The visual inspection found that the gate stem bushings were damaged and in poor condition. The bushings were scored, damaged, and elliptical. The retaining plates and rubber seals were damaged. There was cavitation on the water passage surface of the stainless-steel overlay near the gate stem bores and cavitation damage directly under the wearing rings. There was also damage to the wearing rings that indicated contact damage from either debris or the runner seal.

The LIDAR inspection found the wearing rings were out of tolerance, the gate stem bore circle deformed, and the water passages were out of tolerance.

During the 2019 outage, Voith recommended that the corroded area under the wearing ring be cleaned and filled with a high strength epoxy to fix the cavitation damage. NL Hydro performed the repairs as recommended by Voith.

During the 2019 outage, Voith recommended machining wearing ring to a known size to establish a larger runner seal clearance. NL Hydro approved and Voith machined the wearing ring to a diameter of 158.275 inch.

The long-term recommendation by Voith in 2019 was a new bottom ring to be supplied arguing that rehabilitation of the existing bottom ring would be expensive and labor intensive and that the bottom ring may not be able to be rehabilitated. Voith also highlights the schedule risk of rehabilitation as the bottom ring is the last component out of the unit and first required back at site. Hatch agrees with Voith’s recommendation. A new bottom ring is not significantly more expensive than to rehabilitate the bottom ring. This would avoid schedule and outage risks with rehabilitation as the bottom ring is the last component out of the unit and the first component required back at site for assembly.

Refer to Appendix D, Items 30, 31, and 33 for further information regarding deficiencies, risk, estimated service life, and recommendations.

Refer to Section 3.13.4 for runner seal clearance issues.

Refer to Section 3.12.3 for wicket gate stem bore alignment issues.

Refer to Section 3.12.4 for wicket gate end seal issues.

3.12.1.1 Do-Nothing Consequence

If nothing is done, the bottom ring may be acceptable for another 5-10 years. However, the runner seal clearances may drive remaining life of the wearing ring.

3.12.1.2 Recommended Repair

Hatch believes that the bottom ring would be able to be rehabilitated but agrees with Voith’s assessment that the schedule risk may be too significant. The bottom ring is the last component out of the unit for rehabilitation and the first component needed back at site. It’s also a relatively simple component that can be supplied as a forged ring or fabricated from plate steel.

Hatch recommends that a new bottom ring be supplied. The head cover and bottom ring gate stem bores should be either line bored or machined using matching templates. This will save on the outage schedule as to not have to line bore in the field.

A new bottom ring will eliminate out of tolerance issues and ensure a clean water passage surface with new facing plates.

3.12.1.3 Estimated Cost

The estimated cost of a completely new bottom ring is [redacted] (AACE Class 5 estimate).

The estimated cost to rehabilitate the bottom ring and supply with new facing plates, new wearing rings, and new lower gate stem bushings is [redacted] (AACE Class 5 estimate).

3.12.1.4 Life Extension

The expected life of a new bottom ring is 50+ years.

3.12.2 Head Cover

During the 2023 site visits, there was limited access to assess the head cover. The facing plates and gate end seals were visible from the spiral case and the top of the head cover was visible from the turbine pit. The condition of the facing plates and gate end seal are similar to that of the bottom ring. From the turbine pit, the top of the head cover had some standing water and some rusting.

Figure 3-39: Head Cover from Turbine Pit

During the 2019 outage, the head cover was removed from the unit for inspection and repairs. Voith performed visual inspection, non-destructive examinations, lead abatement, dimensional inspection (LIDAR), line boring of the gate stem bores, replaced the intermediate greased gate stem bushings with greaseless gate stem bushings, and painted the head cover. During the outage, the intermediate gate stem bushings were removed and replaced. The upper gate stem bushings were not removed from the head cover.

The visual inspection in 2019 found the operating ring liners were in poor condition, the gate stem bushings were in poor condition (scoring, damaged, elliptical), cavitation on the wearing ring near the cooling water supply ports, scoring on the wearing ring, damaged rubber gate end seals, damaged retaining plates for the gate end seals, missing retaining plate screws, and a piece of metal from the runner cover plate in the head cover. There was no conclusion if the metal debris from the runner cover plate caused damage to the head cover. However, Hatch believes there could have been damage caused given the potential speed at which the debris could have broken off. Assuming the center of mass of the metal piece was positioned at 55 inches radially from the unit centerline and rotating at 225 RPM, the metal piece would have had a tangential velocity of 107.9 ft / s. This would have been dampened by the water, but the velocity and energy could still be great enough to damage stationary components.

$$V_t = r * \omega = 55\,inch * (225\,RPM) * (2 * pi\,rad / 1\,rotation) * (1\,min / 60\,s) * (1\,ft / 12\,inch) = 107.9\,ft / s$$

Non-destructive examinations of the head cover found cracks in the stiffeners connecting to the outer flange of the head cover.

The LIDAR inspection found the upper and intermediate gate stem bores on the head cover were not concentric to each other in a range of 0.010 inch to 0.056 inch. The LIDAR inspection also found the head cover wearing ring was deformed into an elliptical shape.

During the 2019 outage, Voith recommended that the head cover be re-installed and bolted down to measure the gate stem bore alignment with the bottom ring. There was concern that the free state readings were not fully indicative of the installed shape and gate stem bore alignment. NL Hydro re-installed the head cover per Voith's recommendations. See Section 3.12.3 for further information.

Two long-term recommendation options were provided by Voith in 2019. The first is to rehabilitate the head cover. The second option is to provide a new head cover. Voith argues the advantage of rehabilitating the head is cost related and the ability to reuse existing components. The disadvantages of rehabilitating the head cover argued by Voith are transportation challenges and schedule risks leading to an extended outage. Voith argues the advantages of a new head cover are improved design, schedule control, shorten outage duration, less transportation activity, improved material properties, and new wearing rings. Voith argues the disadvantage of a new head cover is the expense. Voith expects that NDE, repairs, dimensional inspection, possible stainless-steel overlay, gate stem bore machining, and painting is required for the rehabilitation option.

Hatch recommends rehabilitating the head existing head cover. There are advantages to a new head cover as argued by Voith. In addition, a new head cover would have a longer expected service life. However, the complexity of designing and manufacturing a new head cover is a large capital investment. A thorough repair and rehabilitation of the existing head cover would provide the life extension desired by NL Hydro. However, there are risks associated with head cover rehabilitations that could increase the rehabilitation costs and schedule.

Refer to Appendix D, Items 30, 31, and 32 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.12.2.1 Do-Nothing Consequence

If nothing is done, the head cover may be acceptable for another 5-10 years.

There is a risk of further cracking of the stiffeners and further structural damage. The gate stem bore alignment and gate stem bushings damage are related and alignment issues are addressed in Section 3.12.3. Wearing ring issues can cause damage to the runner and increase hydraulic thrust potentially overloading the thrust bearing.

3.12.2.2 Recommended Repair

The head cover is recommended to be rehabilitated. However, an assessment of the schedule and outage cost should be analyzed by NL Hydro to determine if a new head cover is justified. The head cover rehabilitation would be on or near the critical path. Any unforeseen issues or delays could cause an extended outage.

If rehabilitating, the recommended scope of work would be to clean, blast, NDE, repair indications, dimensional inspection, machining of wearing ring mounting surface, water passage surface, mounting flanges, installation of new wearing ring, installation of new facing plate (or weld overlay), supply of new hardware, and paint. Gate stem bores should be line bored with bottom ring or bored with a template. New gate stem bushings are recommended.

3.12.2.3 Estimated Cost

The estimated cost to rehabilitate the head cover and supply new wearing rings, facing plates, and gate stem bushings is [redacted] (AACE Class 5 estimate).

The estimated cost of a completely new head cover is [redacted] (AACE Class 5 estimate).

3.12.2.4 Life Extension

The expected life of a rehabilitated head cover is 25-40 years.

The expected life of a new head cover is 50+ years.

3.12.3 Wicket Gate Stem Bores

During the 2019 outage, the head cover was installed back on the stay ring for gate stem bore alignment measurements.

After assembling the head cover the stay ring, a LIDAR inspection was performed to determine gate stem bore alignments for each gate. Voith determined the ideal tolerance range to be 0.006 inch to 0.010 inch with a recommended intervention or critical tolerance of 0.030 inch. Gate stem bore alignment was found to be in a range from 0.004 inch to 0.105 inch. Large deviations from design tolerance led Voith to question the validity of the findings and recommended another measurement method to validate.

After LIDAR measurements were not thought to be reliable, the head cover to bottom ring gate stem bores were measured with a wire micrometer. Gate stem bore alignment was found to be in a range from 0.003 inch to 0.035 inch.

Voith used a honing tool to bore a select number of upper gate stem bushings to increase the clearance and allow a better alignment of the bores for the wicket gates.

There was no binding or gate mechanism operating issues after the unit was aligned.

Refer to Appendix D, Item 30 further information regarding deficiencies, risk, estimated service life, and recommendations.

3.12.3.1 Do-Nothing Consequence

A misalignment of the gate stem bores can lead to premature wear of the gate stem bushings, binding of the wicket gates, and higher loading on the operating mechanism.

The current condition is likely to be acceptable for 2.5 - 5 years before corrective machining for replacement of the gate stem bushings is required.

3.12.3.2 Recommended Repair

The head cover and bottom ring gate stem bores should be either line bored or machined using matching templates. This will ensure proper alignment of the gate stem bores between the components and save on the outage schedule as to not have to line bore in the field.

3.12.3.3 Estimated Cost

The estimated cost to line bore the head cover and bottom ring in a rehabilitation facility is [redacted] (AACE Class 5 estimate). This assumes both components are being machined in the same facility.

The estimate cost of a set of templates and machining the head cover and bottom ring in different facilities is [redacted] (AACE Class 5 estimate).

3.12.3.4 Life Extension

This would allow resolve the gate stem alignment issue for 50+ years if no other external factors (i.e., concrete growth) impact the alignment.

3.12.4 Head Cover and Bottom Ring Facing Plates and Gate End Seals

Gate end seals allow the wicket gates to properly seal to allow better performance during synchronous condense operation. Facing plates, if in poor condition can cause rubbing or damage to the wicket gate ends or disrupt the flow into the unit. The risk of the facing plates causing damage is low, but not insignificant.

3.12.4.1 Do-Nothing Consequence

If nothing is done, the wicket gate end clearances would require continued monitoring to ensure no further damage is done to the facing plates and vice versa. The facing plates may last another 15 years if nothing is done.

The gate end seals may last another 5 years if nothing is done.

3.12.4.2 *Recommended Repair*

Replace the facing plates and gate end seals.

3.12.4.3 *Estimated Cost*

The estimated cost to replace the gate end seals and facing plates for both the head cover and bottom ring is [redacted] (AACE Class 5 estimate).

3.12.4.4 *Life Extension*

New facing plates would have a life extension of 40+ years. New gate end seals would have a life extension of 15+ years.

3.13 Runner

During the 2023 site visit, Hatch was able to confirm the cavitation at the inlet edge of the blade and band on the low-pressure side of the blade. Hatch also confirmed cavitation at the trailing edge of the blade on the crown. It was clear that previous repairs were performed on the blades as there is a combination of stainless-steel weld overlay and original paint on the low-pressure side of the blades. There was also rust on the runner blades on the low-pressure side where the stainless-steel weld repair transitioned to the OEM carbon steel painted surfaces. Hatch observed Belzona repairs on the band on the low-pressure side of blades 6 and 16. The wearing rings, top of the crown, and backside of the band were not accessible and were not assessed by Hatch.

In 2019, the runner was removed from the turbine pit for inspections but was not de-coupled from the turbine shaft. Voith performed a visual inspection, dimensional inspection using LIDAR, and local dye penetrant inspection (PT) of the runner cover plate after repairs were required. There was no inspection of the coupling hardware between the runner and turbine shaft, but new multi-tensioner hardware was purchased to be used later.

The 2019 visual inspection found minor corrosion under the lower wearing ring, moderate to heavy cavitation on the runner blades, cavitation on the upper wearing ring, damage to the balance cover plate (cracks and missing piece broken off), damage to the pressure relief holes, contact damage on the wearing rings, and minor damage on the runner cone. Cavitation on the runner blades observed at the entrance edge near the band on low pressure side, middle of the lower pressure side close to discharge edge, and top of the discharge edge near the crown.

The 2019 LIDAR inspection found the wearing rings were slightly smaller than the OEM, but no other significant findings.

During the 2019 outage, NL Hydro performed cavitation repairs per Voith Hydro instruction. Cavitation repairs of the thrust relief holes were excluded from repairs as they were regarded as a low risk prior to the next outage.

During the 2019 outage, NL Hydro repaired the runner balance cover plate per Voith Hydro instruction and design (2TFV01-0155-10049134).

The overall condition of the runner is poor due to the cavitation and structural issues. Voith recommended replacing the runner within the 5 years of 2019. The advantages proposed by Voith for supply of a new runner include increased efficiency, reduction or elimination of cavitation, possible environmental improvements, and possibility to increase power.

Hatch agrees that a new runner is needed. The runner itself may be able to operate for another 5-10 years given proper monitoring and maintenance of known issues. The runner seal clearance is the more critical issue. The cavitation issues will impact the efficiency of the runner, but there is little evidence that the runner will fail from a structural issue (i.e., blade cracking) within the next 5-10 years. However, it is not recommended to operate until failure with such a critical component.

Refer to Appendix D, Items 17, 18, 19, and 20 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.13.1 Runner Cavitation

The runner has been weld repaired several times and the cavitation damage is an ongoing problem.

The runner is currently constructed from ASTM A-27 Grade 65-35 carbon steel with stainless steel weld overlay in high-risk cavitation areas.

3.13.1.1 Do-Nothing Consequence

Cavitation will continue and may cause structural damage to the runner. Cavitation can also cause poor hydraulic performance. If no action is taken, the runner will continue to cavitate. Hatch estimates that if NL Hydro operates the units within the known cavitation limits and performs regular inspections of the runner, the estimated service life is 5-10 years. Voith recommended to replace the runner within 5 years of the 2019 report. Hatch believes this can be extended with yearly inspections and monitoring.

3.13.1.2 Recommended Repair

Hatch agrees with Voith's recommendation to supply a new stainless-steel runner. A stainless-steel runner can be more cavitation resistant and not require painting like the current carbon steel runner. A new hydraulic profile and design can provide increased efficiency and reduce the likelihood of cavitation.

It is possible to perform cavitation repairs on runners, but this cannot be performed indefinitely. There is risk to weld deformations causing hydraulic tolerance issues and structural issues with layered weld repairs. Hatch does not recommend additional weld repairs beyond the extent currently performed. As NL Hydro does not have blade templates, the likelihood of performing extensive weld repairs within the hydraulic tolerance is very low.

Without blade templates, there is an increased chance of reduced efficiency, hydraulic imbalance, increased cavitation, and increased stress in the blade.

Hatch also recommends performing an index test or an absolute efficiency test for a new runner to ensure desire performance.

3.13.1.3 Estimated Cost

Design and supply of a new stainless-steel runner from CA6NM or equivalent material is estimated to cost [redacted] (AACE Class 5 estimate) assuming global supply. It is estimated that the lead time for engineering and supply of a new runner is [redacted].

Cost of a dye dilution test and index testing is estimated to cost [redacted] (AACE Class 5 estimate).

3.13.1.4 Life Extension

A life extension of 50 years is expected for a new runner. This can be verified with FEA and fatigue calculations of the newly supplied runner. Depending on the cavitation performance and factor of safety in the stress and fatigue calculations, a life expectancy of greater than 50 years can also be achieved.

3.13.2 Runner Wearing Rings

The runner wearing rings were found to have minor cavitation and what appeared to be contact damage between the stationary wearing rings and the rotating wearing rings (runner wearing rings).

3.13.2.1 Do-Nothing Consequence

There is little structural risk with the given damages as they are more of a consequence of another issue. However, significant cavitation or damage to the rings may cause an imbalanced seal that can lead to pulsing or vibrations. Larger seal clearances will result in lower turbine efficiency performance and higher thrust bearing loads.

The wearing rings estimated service life is 5-10 years given the reported conditions.

3.13.2.2 Recommended Repair

Hatch recommends replacing the wearing rings along with a new runner.

3.13.2.3 Estimated Cost

Cost of new wearing rings is included in the cost of a new runner in Appendix D.

3.13.2.4 Life Extension

Estimated life of new wearing rings is 20 years before replacement.

3.13.3 Runner Cover Plate

3.13.3.1.1 Do-Nothing Consequence

There is a low risk of the cover plate failing again. However, the OEM drawings indicate that the balancing box was filled with lead. This poses an environmental risk of lead contamination or exposure.

The runner was not balanced after the installation of a new plate. There is a risk that the runner is out of balance and will cause undue vibration or instability.

3.13.3.2 Recommended Repair

Replace the runner. A new runner can be designed with a machined balance pad that eliminates the need for a welded cover plate.

3.13.3.3 Estimated Cost

Cost is included in the cost of a new runner in Appendix D.

3.13.3.4 Life Extension

Life extension is the same as new runner. See Section 4.2.

3.13.4 Runner Seal Clearance

A major concern with the turbine is the trending changes of the upper and lower runner seal clearances (RSC). Voith was contracted in 2019 to machine the stationary wearing rings to restore proper RSC in accordance with the OEM design and CEATI Part 5 standards. Based on the rate of change trends of the RSC from 2006 to 2019 recorded by NL Hydro and the machining by Voith projected that seals would require intervention again around 2025. Hatch took independent measurements of the RSC during the October 2023 site visit. The results are provided in Table 3-4. Aggregated data from NL Hydro, Voith, and Hatch are presented in Figure 3-40 and Figure 3-41.

Table 3-4: Runner Seal Clearance Measurements (October 14, 2023)

Location	Crown RSC (Upper Seal) [inches]	Band RSC (Lower Seal) [inches]
US	0.057	0.060
A2	0.077	0.065
DS	0.042	0.042
A1	0.052	0.057
Average	***0.057***	***0.056***

Note: Measurements by Andrew Breighner during site visit October 14, 2023, using feeler gauges. Measurements for indicative purposes only of the unit condition. NL Hydro should take independent measurements for their trending data.

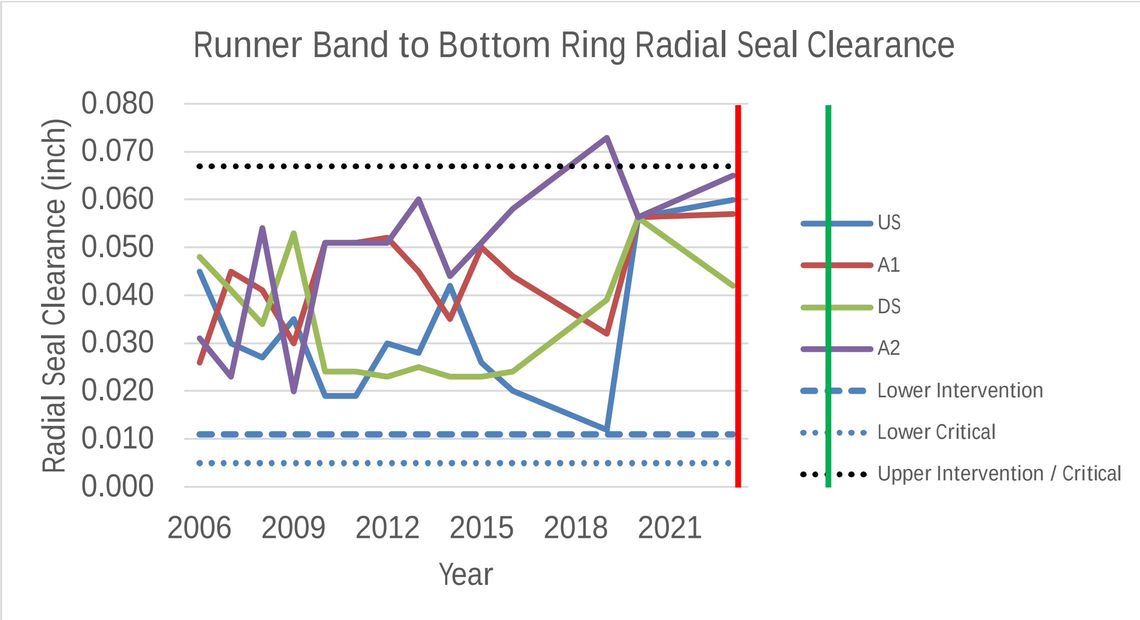


Figure 3-40: Runner Band Radial Seal Clearance

Note: Vertical red line indicates machining of the bottom ring by Voith Hydro. Vertical green line indicates independent measurements taken by Hatch during site visit.

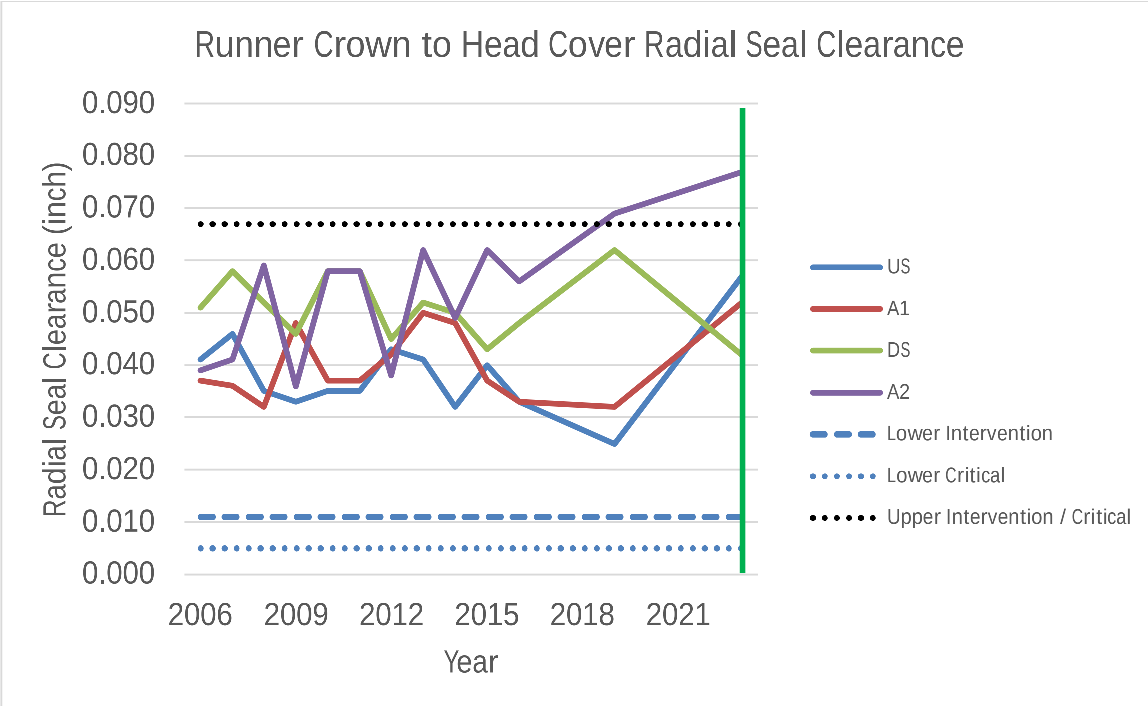


Figure 3-41: Runner Band Radial Seal Clearance

Note: Vertical green line indicates independent measurements taken by Hatch during site visit.

The intervention limits defined by Voith are 0.067 inch for the upper intervention limit and 0.011 inch for the lower intervention limit.

The A2 reading for the Crown RSC from the Hatch site visit is above the recommended “Upper Intervention / Critical” limit according to the VH 2019 report and the A2 reading for the Band RSC is approaching the VH 2019 report limit. There is a risk of increased cavitation and thrust loading. However, if the seal and runner are planned to be replaced, the existing wearing rings are likely to be suitable for another few years if the average RSC stays within the intervention limits.

Hatch recommends that corrective actions and interventions be taken in the next 3-5 years.

The runner seal clearance is a critical design feature. If the seal clearance is too small, contact between the rotating ring and station ring is possible and can cause damage. If the seal is too large, it can lead to high hydraulic thrust and less efficient operation. If the seal clearance is not uniform, it can lead to pressure pulsations and vibrations.

3.13.4.1 Do-Nothing Consequence

The seal clearances are already near the intervention limit recommended by Voith. If nothing is done, the current seal clearance may be operable for another 3-5 years before significant adverse impact on unit performance. Adverse impacts could include contact between stationary and rotating seals, increase vibration, and changes to hydraulic thrust loads.

3.13.4.2 Recommended Repair

Hatch recommends embedded component machining to ensure bottom ring and head covers have well-established seating surfaces and supply of new wearing rings on the head cover, bottom ring, and runner.

3.13.4.3 Estimated Cost

Refer to 3.11.4.1.7 for estimated cost of embedded component machining.

Refer to 3.12.1.3, 3.12.2.3, and 3.13.1.3 for estimated costs for wearing ring costs included in the repairs for the runner, head cover, and bottom ring.

3.13.4.4 Life Extension

Given the conditions at site with changing seal clearances over time, after field machining and supply of new wearing rings there is a possibility that the seals will continue to deform over time. However, with new components, the repair work recommended should provide a life expectancy of 25 years until replacement wearing rings are needed.

3.14 Spiral Case Relief Valve

The relief valve is a plunger type valve that comes off the spiral case near the spiral case access door and discharges through a diffuser directly to the tailrace. There is an outlet gate at the end of the diffuser that is used to dewater the valve and diffuser.

There was no scope for Voith during the 2019 outage regarding the spiral case pressure relief valve, operating servomotor, or dashpot. Voith recommended in their report that during the next major outage the valve be disassembled and sent to a qualified rehabilitation supplier. The scope of rehabilitation expected for the valve by Voith is shipping to a supplier, NDE, repairs, seal replacement, and paint. Similar scope of work was expected for the servomotor and dashpot.

During the 2023 site visits conducted while the unit was in outage, there was observed leakage around the relief valve discharge piping to the concrete and leakage in the diffuser that ingressed to the valve. When the pressure relief valve is removed, a blanking flange should be made available to cover the flange connecting to the outlet diffuser to prevent leakage into the powerhouse. If it is possible to fully dewater, it is recommended to use a borescope to look for any signs of material degradation, cavitation, cracks, or leakage in the piping and diffuser. The pressure relief valve outlet gate should also be inspected and assessed. This was not possible during the 2023 site visits by Hatch. See Section 3.11.4.1 for further details regarding leakage issues around the spiral case and relief valve piping.

During the 2023 site visits, there was reported concern with the inability to replace the dashpot seal as the component is no longer supplied. The seal will need to be reverse engineered, or a new solution is required. However, Hatch agrees with Voith's 2019 recommendations that the valve, servomotor, and dashpot should be rehabilitated, and the scope of work should include new wear components, small hardware, and seals. The components should be cleaned, lead abated if needed, inspected, and repainted.

Refer to Appendix D, Item 29 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.15 Governor

The existing governor is a Woodward Cabinet Actuator mechanical governor original from 1976. The governor was reported to be in good working condition. However, Hatch was not able to witness the governor in operation.

The system is still mechanically controlled. However it has been modified with power supplies and loop isolators for remote control and indication of the gate positions and limits. Raise and lower signals can be sent to the governor from the control room or the remote, control center. These modifications also provide necessary feedback and information.

NL Hydro reported from site interviews that the operations and maintenance staff has sufficient knowledge and understanding of the system. However, this vintage of mechanical governors is becoming rarer. Sourcing for spare parts will become more difficult over time and general workforce knowledge will diminish over time as most governors are now electrically controlled. Mechanical governors do offer a lower level of technology making it easier for maintenance and adjustment along with proven reliability of equipment.

Mechanical governors typically have a slow response time. In a report by Kestrel Power Engineering from 2021, the compensation settings for the governor were reported to be at their maximum given the governor design. The report concluded that the inertia and water starting time of the unit would not allow a 'faster response of the governor to frequency excursions or AGC commands without compromising the ability to provide stable control of frequency'.

During the next major unit overhaul, Hatch recommends upgrading the governor to a 'digital head' that can utilize the existing HPU, oil system, and gate servomotors. This will provide digital electronic control of the system while not requiring a complete overhaul of the governor and actuator system.

References:

- Kestrel Power Engineering, Bay D'Espoir Unit 7 PSS Tuning, NERC MOD-026/027 Model Validation, and PRC-0179/024 Review, 2021-01-19.

3.16 Excitation System

The excitation system is composed of an excitation transformer connected to the generator output, a redundant static exciter (complete with DC field breaker), a set of slip rings and brushes, and a permanent magnet generator. The overall state of the system is good, and there were no immediate issues verified. The majority of the system's components were replaced relatively recently.

3.16.1 Excitation Transformer

The excitation transformer was replaced in 2014 and is in very good state. It is an oil filled transformer coupled directly to the isophase bus. No issues were identified and upon visual inspection it seems to be in very good condition.

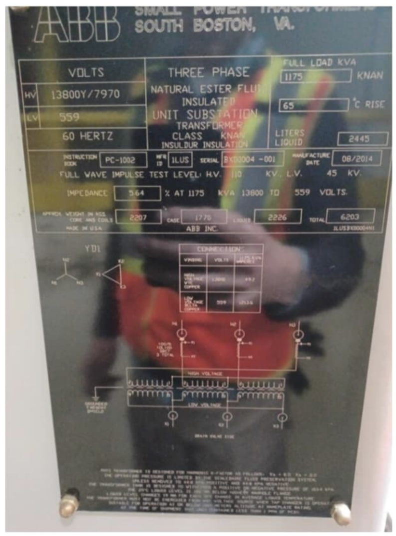


Figure 3-42: Nameplate of the Excitation Transformer

3.16.2 Exciter

The existing excitation system is a modern static type UNITROL installed by ABB in 2004 with two channel controls and redundant thyristor n+1 bridge. The bridge rating has 10% margin over typical field current requirements and its cooling system is forced air. The exciter, including bridges, controllers, and field breaker, was replaced in 2004. The exciter controller has entered its obsolescence period, with limited manufacturer support.

Figure 3-43: Nameplate of the Exciter

A Power System Stabilizer was installed and is enabled in the unit since 2022. The PSS is integrated into the control logic of the exciter.

3.16.3 Permanent Magnet Generator

The permanent magnet generator was disassembled for maintenance during our inspection. All its components were in good state, and nothing warranted action or attention.

3.16.4 Slip Rings

The slips rings are in good condition with standard patina due to use built on them and very light pitting on the bottom ring. This is common for the positive polarity ring. The contact surface of the brushes that were removed from brush holders were smooth and without tracks.

Figure 3-44: Typical condition of the Slip Rings (no concerns to note)

The cables that connect the brush rigging to the excitation bridge have solid insulation without any sign of overheating. The insulation resistance of the cables was tested during the 2019 outage with acceptable results.

3.17 Spare Parts

Hatch was given access to the spare stator armature winding bars. NL Hydro has 62 bottom and 52 top bars at site. Hatch was able to visually assess them during the site visit and their condition appeared to be acceptable. No electrical tests or further assessments were conducted on the spare bars. These bars should be sufficient to repair most possible bar-to-bar failures, provided other slot systems are available, such as slot fillers, wedges and ripple springs.

For the excitation system NL Hydro confirmed two bridges, a number of controller cards, a number of fans and one field breaker.

3.18 Significant Events

The only significant events reported to Hatch were a unit trip in 2022, and a flash over on the slip rings in 2017. Both were investigated in detail by NL Hydro.

The 2022 trip was due to a lightning strike in the proximity of the station.

The 2017 flash over was caused by spent brushes that caused the failure to occur. The slip rings were damaged and thus replaced as a result of that event.

- Known events: No significant events that could cause significant damage to the unit were reported, and no evidence of such an event was observed. Under review: Flash arc on the slip rings (2019).

Flash arc on the slip rings (2019)In July 2017 a flush over between the positive and negative slip rings resulting in damage of the collector ring brush rigging due wored out / short brush length, so the wire from the back of the brush got stacked in brush holder.

3.19 Review of Maintenance Records

NL Hydro provided 'Preventative Maintenance Check sheets' from 2013 to 2022. Hatch reviewed the maintenance checklists from 2019 to 2022 due to time constraints and the extensive outage activities performed in 2019.

3.19.1 Generator

The concerns from the 2019 through 2022 are listed below.

- 2019:
  - No pressure reducing valves pressures recorded.
  - Motorized ball valve on runner seal lubrication line not working.
- 2020:
  - Strainer on high pressure pump was filled with lint.
  - ACR1 and ACR2 pressure reducing valve for T&G cooling water pressure were higher than targets.
    - ACR1: 125-150 psi target | 203 psi actual.
    - ACR2: 45-50 psi target | 57 psi actual.
  - Rupture discs were ruptured.
  - Issue with transducers on cooling water system.
  - Generator and turbine cooling water strainer water pressure was low:
    - 1450 kpa target | 900 kpa actual.
- 2021:
  - ACR1 pressure reducing valve for T&G cooling water pressure was higher than targets.
    - ACR1: 125-150 psi target | 261 psi actual.
  - Generator and turbine cooling water strainer water pressure was low:
    - 1450 kpa target | 900 kpa actual.
- 2022:
  - Guide bearing oil level was approximately 1" too high.

- Rupture discs were ruptured.
- Motorized ball valve on runner seal lubrication line not working.
- Water pressure on SAC strainer was low:
  - 1450 kpa target | 900 kpa actual.

Refer to Appendix D, Item 37 for further information regarding deficiencies, risk, estimated service life, and recommendations.

3.19.2 Governor

The concerns from the 2019 through 2022 are listed below.

- 2020:
  - Wicket gate squeeze over design point:
    - Design = 0.360"
    - Actual = .450".
  - Wicket gate closing time 80%-30%:
    - Target = 13s
    - Actual = 17s.
- 2021:
  - Wicket gate squeeze over design point:
    - Design = 0.360"
    - Actual = .532".
  - Wicket gate closing time 80%-30%:
    - Target = 13s
    - Actual = 25.54s.
  - Wicket gate closing time 100%-0%:
    - Target = 32s
    - Actual = 49s.
- 2022:
  - Wicket gate squeeze over design point (2022):
    - Design = 0.360"

- Actual = 0.480".
- Wicket gate closing time 80%-30% (2022):
  - Target = 13s
  - Actual = 24s.
- Wicket gate closing time 100%-0% (2022):
  - Target = 32s
  - Actual = 38s.

Refer to Appendix D, Item 38 for further information regarding deficiencies, risk, estimated service life, and recommendations.

i) Pre-Start:

The concerns from the 2019 through 2022 are listed below.

- 2022
  - Brush gear assembly - 'cleaning required / several brushes not seated".

ii) Turbine:

There were no concerns from the 2019 through 2022 maintenance checklists.

3.20 Review of Operations Records

i) Vibration

NL Hydro provided asset data logs from June 2020 through July 2023. Hatch noticed a trend in the data that the generator bearing vibrations have been increasing over time. Hatch took sample data for one day each month from June 2020 through July 2023 and plotted the generator and turbine vibrations against NL Hydro alarm points and ISO 7919-5 operating zone limits. See Figure 3-45 and Figure 3-46. The alarm points are set by NL Hydro to be 50% of bearing clearance for warning and 75% bearing clearance for danger. ISO 7919-5 Zone A and B limits are considered acceptable for extended operation in normal operating conditions.

There is no concern with the current vibration levels. They are well within NL Hydro's alarm limits and industry standard operating ranges. The trend of the generator vibrations should be monitored by NL Hydro.

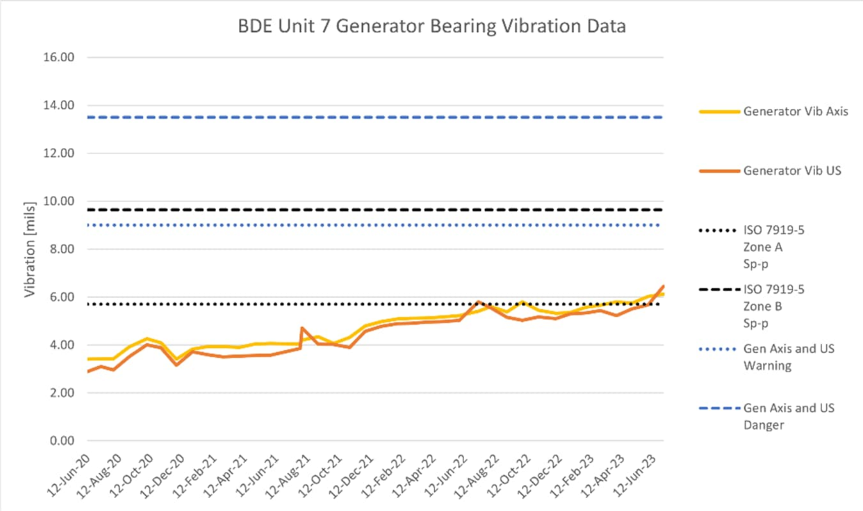


Figure 3-45: Generator Peak to Peak Vibration Trends Over Time

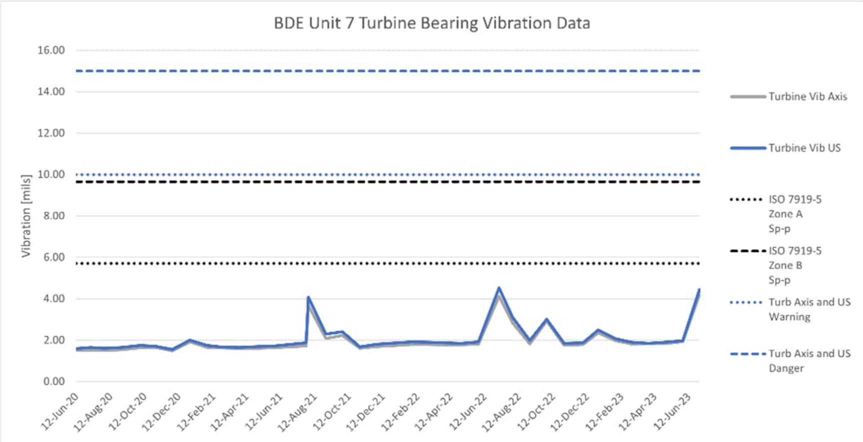


Figure 3-46: Turbine Peak to Peak Vibration Trends Over Time

ii) Bearing Temperature (oil & metal)

NL Hydro provided asset data logs from June 2020 through July 2023. Hatch reviewed bearing temperature data and observed the thrust bearing metal temperature exceeds 85 deg C which is the alarm limit. However, the maximum temperature observed in July 2023 was 86.36 deg C with an average temperature of 81.68 deg C. The bearing oil temperature consistently remains below the alarm values and does not have an issue.

Hatch is not concerned about the slightly high bearing temperatures. Rehabilitation of the thrust and guide bearings will likely resolve this issue. Hatch recommends that NL Hydro monitor the temperatures and take interventions when the bearing metal temperature is consistently above the alarm limit or when the bearing oil temperature is above the alarm limit.

iii) Generator Stator Temperature

NL Hydro provided asset data logs from June 2020 through July 2023. Hatch reviewed a sample of the stator temperature data and did not find temperatures that exceeded alarm values.

4. Deficiencies and Non-Conformities

This chapter describes and discusses the consolidated list of deficiencies identified in the previous chapters, as well as repair strategies and recommendations. The sections below are inclusive of the on-site findings during the 2023 inspection, the review of the 2019 Outage Report, and review of operations and maintenance records.

Appendix D provides a comprehensive summary table of the deficiencies, status, urgency, consequences, risk analysis, recommendations, and cost estimates. This section provides supplementary information and commentary on the major deficiencies that Hatch recommends for NL Hydro to address.

The statements of condition and urgency as described as follows:

1) Condition:

   1. Good – Component is in a good state and able for operation for the next 10 years. No or minor work is needed to maintain functionality. No or negligible chance of in-service failure.
   2. Fair – Component is in an acceptable state and able for operation for the next 5 years. Work is needed to maintain functionality. Negligible chance of in-service failure.
   3. Poor – Component has reached the end of its service life and requires replacement or refurbishment at the next opportunity. Major work is needed to maintain functionality safely. Low chance of in-service failure.
   4. Failed – Component has reached the end of its service life and requires an outage for urgent replacement. Major work is needed to maintain functionality safely. In-service failure imminent.

2) Urgency:

   5. Low – Recommended actions are needed for optimal functionality. It is possible to wait up to 10 years to execute the work without risk to safety or equipment.

6. Medium – Recommended actions are needed to maintain functionality. It is possible to wait up to 5 years to execute the work without risk to safety or equipment.
7. High – Recommended actions are needed as soon as possible. An intervention in the timespan of 3 years should be planned to execute the work.
8. Urgent – It is not safe to run the unit with the current condition, and it needs to be addressed right away or at the next available outage.

3) Life Extension:

This chapter summarizes the life extension scenarios to be achieved depending on the adoption of different recommendations of this report. Please see Chapter 4 for the detailed discussion about each deficiency and how life extension may be achieved.

It is important to note that several measures across the different components of the generating unit need to be taken to achieve a life extension scenario.

4.1 Immediate Actions

The following deficiencies carry a non-negligible chance of causing an in-service failure. Addressing them does not necessarily extend the life of the unit but prevents an immediate and unforeseen in-service failure.

- Cleaning stator frame.
- Rewind rotor field winding.

4.2 Life Extension Scenarios

The subsections below coalesce the different life extension measures in the various components required to achieve each of the life extension scenarios.

4.2.1 10 Years

1. Replace bars in slots 194 to 200 in the stator armature winding.
2. Replace air guides on the stator.
3. Rewind rotor field winding.
4. Replace wearing ring in head cover, bottom ring, and runner.
5. Replace operating ring bearings and wicket gate link pins.
6. Cavitation repairs on runner.

4.2.2 25 Years

1. Rewind stator armature winding.
2. Restore stator core clamping strength.

3. Restore stator core circularity and verticality.
4. Rewind rotor field winding.
5. Replace wearing ring in head cover, bottom ring, and runner.
6. Replace operating ring bearings and wicket gate link pins.
7. Replace runner.
8. Rehabilitate wicket gate servomotors, relief valve, relief valve dashpot, operating ring, head cover, bottom ring, wicket gates, shafts, bearings, shaft seal, and wicket gate arms.
9. Overhaul governor with digital head.
10. Blast, inspect, and paint water passage surfaces from penstock drain to draft tube maintenance platform.
11. Field machine embedded components and seal weld between stay ring and discharge ring.
12. Pressure test embedded piping and check for leaks.

4.2.3 40 Years

1. Rewind stator armature winding.
2. Restore stator core clamping strength.
3. Restore stator core circularity and verticality.
4. Rewind rotor field winding.
5. Replace head cover and bottom ring.
6. Replace runner.
7. Replace operating ring bearings and wicket gate link pins.
8. Rehabilitate wicket gate servomotors, relief valve, relief valve dashpot, operating ring, wicket gates, shafts, bearings, shaft seal, and wicket gate arms, links, and levers.
9. Overhaul governor with digital head.
10. Blast, inspect, and paint water passage surfaces from penstock drain to draft tube maintenance platform.
11. Field machine embedded components and seal weld between stay ring and discharge ring.
12. Pressure test embedded piping and check for leaks.

4.3 Cost Estimates

See Appendix D for cost estimate summary.

5. Conclusions

Overall, Bay D'Espoir Unit 7 is in fair condition. There are a few urgent conditions that need to be addressed, but Hatch expects there are a few more years remaining before major overhauls of the turbine and generator are required. Hatch recommends continued monitoring of known deficiencies and to consult the Hatch Uprate Report in addition to this Condition Assessment Report when planning future operations work, major maintenance, and capital improvements. Based on the Uprate Report and the assessed condition of the unit, Hatch recommends overhauling the generator, including a rewind of the stator, refurbish the rotor and to replace the runner with a more efficient and more cavitation resistant design.

Appendix A:
Test Plan

NL Hydro
Bay d'Espoir Unit 7 Condition Assessment

Inspection Test Plan - Turbine Generator

Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**	**Approved By**
HATCH						**Client**

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1. Introduction

This document contains the Inspection and test work plan to be carried out at Bay D'Espoir unit 7.

Inspection will be dependent on level of disassembly of the unit during the next outage. As well the electrical test will be revised and witnessed by Hatch and executed by NL Hydro.

1.1 Requirements

LIST Requirements from the client:

- Personal PPE
- Acknowledgement of Alcohol and Drug Program Requirements for Contractors
- Site safety orientation

1.2 Safety equipment

- Hard Hat
- Safety shoes
- Eye protection
- Ear protection
- Hugh Visible vest

1.3 Inspection and Test Plan

1.3.1 Generator Inspections

1.3.1.1 Electrical Inspections

Item	Inspection	Requirements	Notes
Stator			
Top and bottom end-winding areas	Winding insulation surface condition	Remove it. 1, 3, 81 top/ bottom of the unit per drawing 591E121BB	Two shroud segments were removed on the top (have access to poles 11, 12 and 13) and three shroud
	Corona dust between windings and at core exit surfaces	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar)	

		per drawing 591E121BB	
	Loose coil bracing and blocking	Remove top covers sections between upper brackets	
	Circuit ring bus and lead insulation surface condition, fretting at supports.	Remove top covers sections between upper brackets	
Stator core assembly	Corona stains along edges of slots	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB Remove cooler	Use borescope
	Loose wedges as per qualitative tapping test	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	Use 8 os boll head hummer by using space between poles
	Migration of top or bottom wedges and/or filler strips	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	
Rotor			
Rotor poles	Field winding assembly condition, insulation cracking and drying, pole collar looseness, migration of pole	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing	

	body insulation	591E121BB	
	Interpole connection condition, cracking, overheating, discoloration	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	
	Pole face discoloration, over heating around amortisseur bars, brazing cracks	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	

1.3.1.2 Mechanical Inspections

Item	Inspection	Requirements	Notes
stator	Deformed or damaged members		
	Cracks in welds on key bars, shelves and wrappers	Remove cooler	
	Signs of overheating and corrosion.	Remove cooler	
Stator core assembly	Displacement or deformation of top and bottom clamping fingers	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	
	Damaged welds or keeper plates on core stud nuts	Remove top covers sections between upper brackets	
	Chipped or fractured core teeth edges on	Remove it. 1, 3, 81 top/ bottom of the unit	

	core bore (as viewed between poles)	near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	
	Inadequate core compression as per knife test on core bore and core back.	Remove cooler	
	Core wave locations and amplitudes on core back	Remove cooler	
	Deformation, offsets and filler displacements at core splits, laminations.	Remove cooler near the frame / core split	
Rotor	Ventilation fan element cracking or deformation	Remove upper covers	
	Pole key, rim key and keeper plates fretting, deformation or displacement.	Remove it. 1, 3, 81 top/ bottom of the unit near the slot 393 (top bar), 29 (bottom bar) and 62 (bottom bar) per drawing 591E121BB	
	Rotor spider for signs of cracking at welds or other distress	Remove upper covers	
Rotor spider for	Component deformations or damage, weld cracks	Remove top covers	
	Hub bolt fretting or deformation	Remove top covers	
Collector rings & brush rigging	condition and cleanliness		accessible

	collector ring patina		accessible
	brush holder / brush type and number		accessible
Bearings	Signs of oil leaks and vapour problems at enclosures		accessible
Upper and lower brackets	Cracks in welds or deformations		accessible
Sole plates	Signs of concrete/grout cracking		accessible
Exciter TR + AVR	Type, age		accessible

1.3.1.3 Generator Test to be Witnessed

As per NLH schedule and testing procedure provided, Hatch would have an engineer witnessing the following tests:

a) On stator:

- Insulation resistance, polarization index (PI)
- Frequency domain spectroscopy with use of Omicron’s CPC100 and MPD800
- Polarization-depolarization currents
- Offline phase-resolved partial discharge (PRPD) with use of Omicron’s CPC100 and MPD800
- Power factor complete with hysteresis mapping with use of Omicron’s CPC100 and MPD800
- End-winding bump test

b) On Rotor:

- Insulation resistance, polarization index (PI)
- Pole drop test

1.3.2 Turbine Inspections

1.3.2.1 Requirements

For the turbine component inspection, access to the turbine will be required. The unit will need to meet the following conditions:

- Unit with intake service gate in closed position and draft tube stoplogs installed.
- Unit will be dewatered and with scroll case access open.
- Servomotors in fully closed or fully open position and locked with proper tag (open position will allow more access to the runner seal clearances and runner blade leading edge)
- Generator brakes applied and locked with proper tag.
- Lifeline installed in the stay vanes.
- Main interrupter open.

1.3.2.2 Turbine Mechanical Inspection

A visual assessment will be performed for the turbine, governor, and balance of plant mechanical components. A check sheet according to Appendix A will be recorded during the site visit.

The following table provides an outline of the components and inspections to be performed.

Item	Inspection	Requirements	Notes
Runner	Visual Assessment (Cracks at High Stress Regions)	Draft Tube Maintenance Platform Installed	
	Visual Assessment (Cavitation)	Draft Tube Maintenance Platform Installed	
	Dimensional Inspection of Seal Clearances	Draft Tube Maintenance Platform Installed or Access from Spiral Case	
Stay Ring	Visual Assessment	Scroll Case Access and Lifeline Installed	
Wicket Gates	Visual Assessment	Draft Tube Maintenance Platform Installed	

	Dimensional Inspection of Gate End Clearances	Scroll Case Access and Lifeline Installed	
Draft Tube	Visual Assessment	Draft Tube Maintenance Platform Installed	
	Void Check	Draft Tube Maintenance Platform Installed	
	Visual Assessment of Access Door		
Draft Tube Air Admission Piping	Visual Assessment of Valves, Piping, and Intake		
Relief Valve	Visual Assessment		
Gate Operating Mechanism	Visual Assessment of Gate Servomotors, Links, Levers, Operating Ring, Pins, and Bushings	Lock Servomotors	
Head Cover	Visual Assessment		
	Signs of standing water on head cover		
Turbine Guide Bearing	Visual Assessment		
	Signs of oil leaks and vapour problems at enclosures		
Shaft and Coupling	Visual Assessment		Limited view and access.
Turbine Pit	General Assessment of Piping and Auxiliary Equipment		
Governor	General Assessment of Condition and Operation		Collect feedback from operators and maintenance

			personnel
Balance of Plant Mechanical Systems	General Assessment of HVAC Equipment		
	General Assessment of Oil Systems		
	General Assessment of Water Systems		
	General Assessment of Compressed Air Systems		
	General Assessment of Crane		
	General Assessment of Sump and Pumps		

Appendix B:
Electrical Check Sheets

Generator Inspection Checklist	
Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Aug 8th to Aug 10th, 2023**
Weather	**Sunny or overcast**
Description of Item	**Response/Notes**
Station/Unit	U7
Last Rewind Date	n/a
Rating (MVA)	172
Manufacturer	GE
Voltage (V)	13800
Current (A)	7196
Frequency (Hz)	60
Power Factor	0.9
Rated Speed (rpm)	225
Runaway Speed (rpm)	380
Unit Cleanliness	☐ Excellent ☐ Normal Dust ☒ Severe Dust
Installation Date	1977
Evidence of Device Removal or Modification?	☐ Yes ☒ No
Issues with Rotor Field Poles?	☐ Yes ☒ No ☐ Not Visible
Issues with Rotor Winding?	☒ Yes ☐ No ☐ Not Visible
Issues with Rotor Spider?	☐ Yes ☒ No ☐ Not Visible
Issues with Rotor Rim?	☐ Yes ☒ No ☐ Not Visible
Issues with Stator Frame?	☐ Yes ☒ No ☐ Not Visible
Issues with Stator Core?	☒ Yes ☐ No ☐ Not Visible
Issues with Stator Winding/Interconnections?	☐ Yes ☒ No ☐ Not Visible
Issues with Stator Cooling?	☐ Yes ☒ No ☐ Not Visible
Issues with Stator Deluge System?	☐ Yes ☒ No ☐ Not Visible
Issues with Fire Detection System?	☐ Yes ☒ No ☐ Not Visible

Generator Inspection Checklist	
Type of Surge Protection	
Frequency Air Gap Testing	☐ Annual ☐ 2 to 5 years ☐ Greater than 5 ☒ None
Frequency PI Test	☐ Annual ☒ 2 to 5 years ☐ Greater than 5 ☐ None
Frequency Partial Discharge Reading	☒ Annual ☐ 2 to 5 years ☐ Greater than 5 ☐ None
Frequency Vibration Readings	☐ Annual ☐ 2 to 5 years ☐ Greater than 5 ☒ None
Other Tests	☐ Yes ☐ No
Type of Exciter	☐ Brushless ☐ Self Excited ☐ Common ☒ Static ☐ Other
Issues with Exciter Field Breaker?	☐ Yes ☒ No ☐ Not Visible
Issues with Exciter Brushgear?	☐ Yes ☒ No ☐ Not Visible
Issues with Exciter Rheostats?	☐ Yes ☒ No ☐ Not Visible
Type of Neutral Grounding?	☐ None ☒ Transformer ☒ Resistor ☐ Solid
Overall Condition of Generator	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Condition of Rotor	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Condition of Stator?	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
• Condition of Surge Protection	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Condition of Exciters	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Condition of Neutral Grounding?	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	Considering the unit age of 46 years, the generator is in good condition. No severe sign of corona was found at critical location of the stator winding, that was visually possible to observe like at high voltage bars interface of the OCP / ECP or at the bars lashing points. The attempt to observe condition of the bars in the slot from the back of the core, despite we had Borescope with 5 mm head (smallest on market) was not successful since vent spacing of the stator core was 5mm as well. Carbon dust mixed with oil residue are spread everywhere with various extend, more on the bottom of the unit. When inspecting condition of the stator core from the back where the

Generator Inspection Checklist	
	cooler # 6 was removed revealed collection of the steel cheeps / filing from the drilling on bottom shelf and intermediate frame reinforcing shelfs, on the top of the bar caps at the bottom of the unit. As per Inspection and testing plan we applied knife (by using Richard 0.010" thick blade) at the back of the core and found out that the stator core is loose. We inspect the condition of the rotor rim lamination between the poles and found out that previously reported melting by VH of the lamination due possible motoring of the unit because of CB malfunction was false, since that so called rim lamination 'melting' was a insert of nonmagnetic spacer kept in vent between 11^{th} and 12^{th} lamination layer with blip of silicon. Unpainted surfaces like back of the core or field winding copper strap have oxidation / rust on it. An air guide insulating band / seal (it. 81 per drawing 591 E 121 BB that is riveted to the face of the end finger) has some loose rivets that are about to go through the seal material. Last field coil strap turn on air gap side has peeling off or missing reinforcing insulation close to the pole end plate. It has been noticed that some turn insulation is sticking out either is that way from OEM assembly of the pole or migrated out but is not loos on touch. Damper winding rods when inspected with mirror on poles 12, 13 seems to be intact with no signs of over heating. The insulation on the U shape field coil to coil connections and collector leads are dry and crunchy. Due very limited access the inspection of the high voltage bars from the air gap side or back side with Borescope was not very successful.

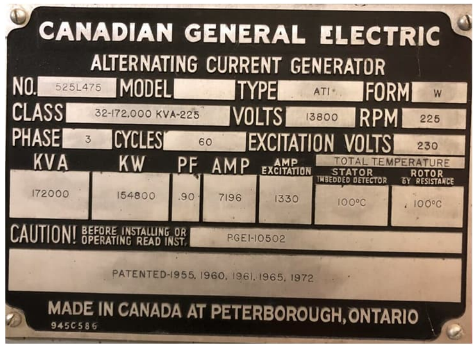
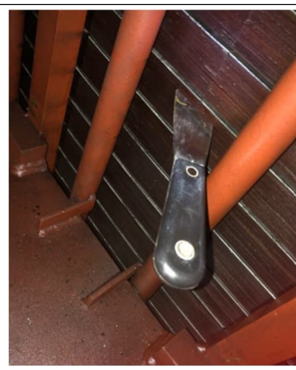
Generator Inspection Photographs	
Photo 1: Nameplate	
Photo 2: Knife test at the back of the core	
Photo 3: Turn tape peeling off	
Photo 4: Misaligned field coil turn	

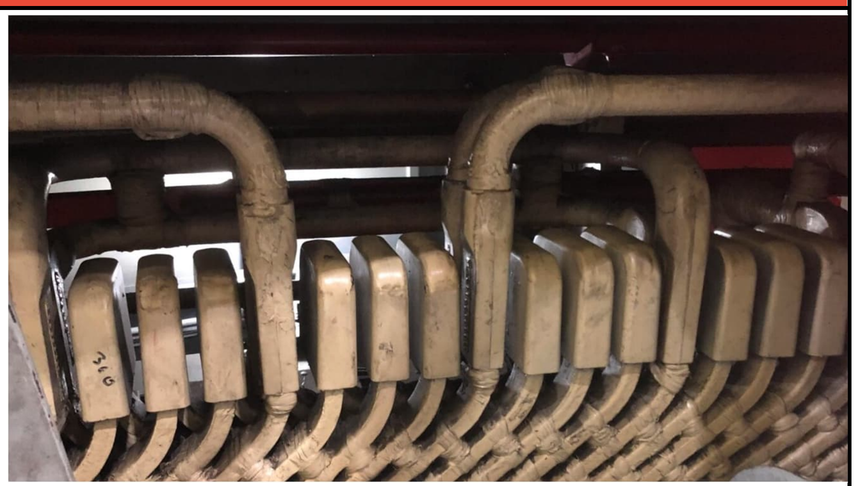
Photo 5: U shape connector insulation	
Photo 6: Debry found on the stator frame shelfs	 
Photo 7: Crack of the ground wall insulation close to the cap entrance at the bottom side of the unit	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Generator Conductors Checklist

Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Aug 8th to Aug 10th, 2023**
Weather	**sunny or overcast**
Description of Item	**Response/Notes**
Station/Unit	U7
Method?	☐ Cable ☒ Bus
Size in kcmil	,,,,,
Material?	☐ Aluminum ☒ Copper
Insulation	Mica tape and epoxy resin
Raceway	
Power Factor	0.9
Overall Condition of Generator Conductors	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	Circuit ring including main and neutral leads insulation is in tack, solid.

Generator Conductors Photographs

Photo 1: Stator winding connections	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Excitation System Checklist		
Parameters Description	**Static**	
Site Name	**Bay d'Espoir HPP**	
Date of Inspection	**Aug 8th to Aug 10th, 2023**	
Weather	**Sunny or overcast**	
Description of Item	**Excitation System**	
Station/Unit	Bay d'Espoir, U7	
Commissioning Year	2004	
Manufacturer	ABB	
Rated Output Voltage (V)	230	
Rated Output Current (A)	1457	1330 Amps per GE – generator name plate
Ceiling Voltage (V)		
Ceiling Current (A)	2120 for 30 sec	
Converter Redundancy (n+?)	n - 1	
Number *of Thyristors in Series	6	1 redundant set of 6
Number of Thyristors in Parallel	n/a	
Converter Cooling Method	air	
Control Modes (FCR, AVR, VAR, PF)	AVR / VAR	
Control System Redondance (n+ ?)	N - 1	
Type of Control System (Analog / Digital)	digital	
Includes PSS (Yes / No)	Yes	NLH start to use appx from 1 year ago
Includes PLC (Yes/ No)	Yes	from Allan Bradly
Includes HMI Screen (Yes / No)	yes	
Includes Communication Protocol for SCADA	yes	
Field Braker (AC / DC)	DC	
Includes O/V Protection (Yes / No)	yes	
De-excitation Method	Crow-bar	
Is there Electrical Braking	Mechanical braking	
Spare Parts Available (Yes / No)	yes	
Overall Condition	2	
Maintenance Period	every year	

Excitation System Checklist

Failure (Trip) Period	
If Static, Excitation Transformer	
Manufacturer	ABB
Type (Dry / Oil)	Oil
Rating (kVA)	1175
HV Rating (V)	13800 / 7970
LV Rating (V)	559
Uk (%)	5.64
No-Load Losses (kW)	
Load Losses (kW)	
Type of Cooling	Oil
Overall Condition	2
Maintenance Period	every year
Frequency of Failure	
Cleanliness	Very clean
Overall Condition of Excitation System	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	The static excitation system equipment was commissioned on 2004, while the excitation transformer was replaced on 2014. Both are in very good condition, so no refurbishment is required. There are the following spare parts on site: full bridge, fans, parts for field breaker and cards for controller.

Generator Conductors Photographs

Photo 1: Static Excitation Name plate

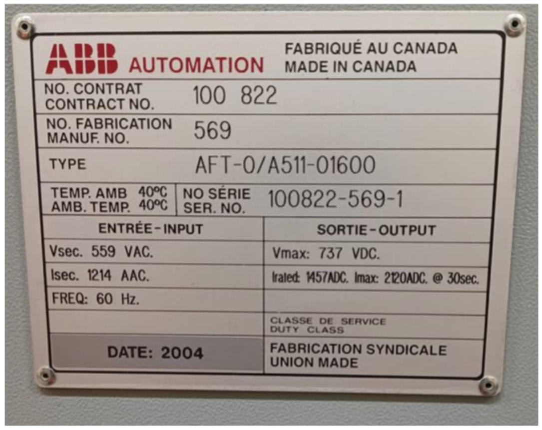
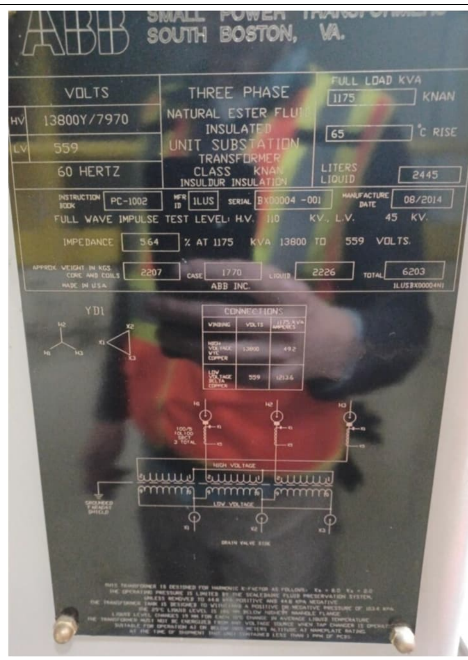


Photo 2: Name plate of the excitation transformer



Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Neutral Grounding Cubicle Checklist	
Parameters Description	**Neutral Grounding cubicle**
Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Aug 8th to Aug 10th, 2023**
Weather	**Sunny or overcast**
Description of Item	**Neutral Grounding Cubicle**
Station/Unit	Bay d'Espoir, U7
Commissioning Year	1992
Manufacturer	GE
Type (Metal-Clad or Metal – Enclosed)	Metal-Enclosed
Type of Grounding (Resistor, Transformer or ?)	Transformer / Resistor
Rated Voltage (kV)	18
Maximum Voltage (kV)	24.94
Rated Current (A)	
Insulation Disconnector	yes
Includes Protective Relays? (if so, type)	
Remote Control	
Local Control	
Voltage Transformer Ratio, Class, Power	n/a
Current transformer Ratio. Class, Power	n/a
Evidence (& Alarm) for Door Opening	No
Spare Parts Available (Yes / No)	yes
Overall Condition	2
Maintenance Period	every year
Frequency of Failure (Trip)	
Overall Condition of Neutral Grounding Cubicle	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	

Generator Conductors Photographs	
Photo 1: Name plate of the neutral grounding transformer	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Appendix C:
Mechanical Check Sheets

Hydro Turbine Checklist	
Site Name	**Bay d'Espoir HPP**
Date of Inspection	**October 13, 2023**
Weather	**Rainy, Mild**
Description of Item	**Turbine**
Station/Unit	Bay d'Espoir, U7
Commissioning Date	1977
Manufacturer	Dominion Engineering Works Limited
Orientation	☐ Horizontal ☒ Vertical
Type	☐ Propeller ☐ Kaplan ☒ Francis ☐ Pelton
Speed	225 RPM
Rated Head	566 ft
Rated Flow	
Rated Output	207 000 HP
Last Refurbishment Date	2019
Runner Install Date	1977
Last Internal Inspection	August 2022
Internal Inspection Now	☐ Yes ☒ No
Greaseless?	☐ Yes ☐ No ☒ Partial Wicket Gate Stems are Greaseless. Operating ring and pins are greased.
Overall Condition of Turbine	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Regulating Equipment	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ 7 Operating ring issues; Dashpot seal for PRV is obsolete; Gate servo cylinders need repaired and reported servo leakage; Gate pin issues with pins dropping out.
• Bearing	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 No visual assessment of current bearing. Spare is being used now when original was sent out in 2019. It is assumed that due to the short operating time, the bearing is in good working condition.
• Seal	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ 7 No visual assessment of current seals. In 2019, the stationary seals were machined as there were issues with the seal clearance changes

Hydro Turbine Checklist	
	over time that were of concern. NLH is monitoring the seal clearances but the machining done by Voith was predicted to be acceptable for 5 years.
• Covers	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ 7 Operating ring bearing and journal issues; Wearing ring seal clearance issues; NDE found cracks in weld between stiffener ribs and outer ring.
• Runner	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Balance cover issues; cavitation
• Vibration	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Cavitation	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
• Efficiency	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 No means to measure efficiency as the piezometers are not functional.

Hydro Turbine Checklist	
General Comments	August 2023 Site Visit Notes: • Critical leakage issues at wicket gates and in the scroll case. • Rob Wilcott & Matt Lambert (Mechanical Team at site). • During a load rejection event they split the base ring on the carbon seal (2018 or 2019), it was replaced. • Wicket gate bushings were all replaced in 2014. • Dashpot bushing for PRV in obsolete. • Servo shafts leak badly, the back of the piston in bolted directly to the wall (pit liner) with no seal/liner. No upthrust pads underneath? • Thordon Thoroplast (weird shape white material in turbine pit, in place one year) October 2023 Site Visit Noes: • General condition of turbine is fair with some rehabilitation and repairs necessary for extended life of the machine. • Cavitation is present on the blade and band on the low pressure inlet side of the blade. Cavitation and other weld repairs were performed the blades on the outlet edge. Weld repair appears to be stainless steel and there are areas of rust on the base material where there is no longer paint at the transition of the weld repair areas to the base metal. There were also areas where it appeared that Belzona was used for repairs. • Operating ring bearings should be addressed in the next 3-5 years. Replace in kind may be required as a short term solution if needed. • Issue with link pins dropping out was not able to be fully assessed at site as all the pins were installed. But there is likely an issue with the keeper plates and pin grooves. • Small amount of water pooling on top of head cover • Spare TGB is currently installed. Original was sent out for rehabilitation and is assumed to be in good working order as a spare back at site.

Hydro Turbine Photos	
Photo 1: Nameplate	
Photo 2: Turbine Pit	

Photo 3: Wicket Gates and Stay Ring	

Photo 4: Bottom Ring, Wicket Gates, and Runner Inlet	

Photo 5: Cavitation Repairs on Runner Band using Belzona	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Generator Checklist

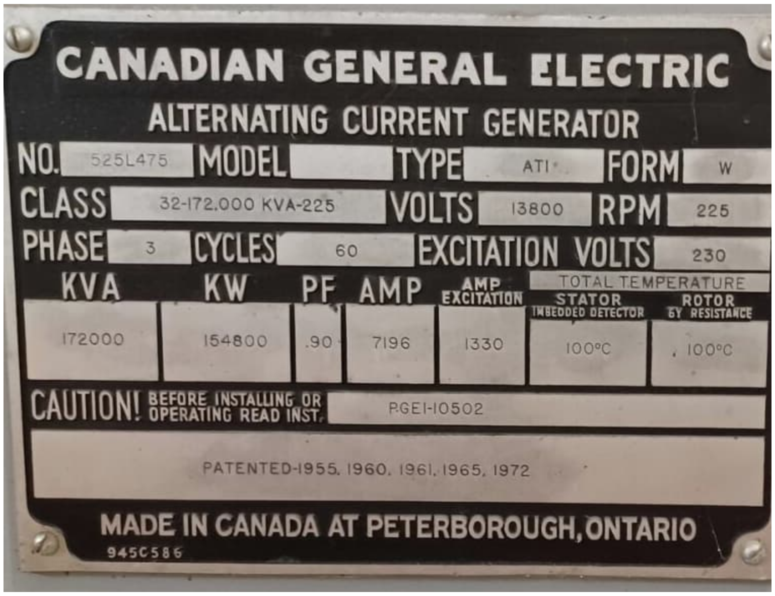
Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Oct 14, 2023**
Weather	**Rainy, Mild**
Description of Item	**Generator**
Station/Unit	Bay d'Espoir, U7
Commissioning Date	1977
Manufacturer	GE type: ATI-W
Orientation	☐ Horizontal ☒ Vertical
Generator Cooling	☒ Water ☐ Air
Thrust Bearing Cooling	☒ Water ☐ Air
Guide Bearing Cooling	☒ Water ☐ Air
Brakes	☐ Hydraulic ☒ Air
Fire Suppression	☐ Yes ☒ No
Speed	225 rpm
Rated Output	172
Last Rewind Date	
Age of Thrust Bearing	1977
Age of Guide Bearing	1977
Date of Last Oil Test	
Internal Inspection Now	☒ Yes ☐ No Performed in August 2023
Overall Condition of Generator	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Thrust Bearing	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Base on 2019 Voith inspection. Some minor indications and fretting.
• Rotor	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 Good to fair condition. Presence of oil should be evaluated.
• Stator	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 Good to fair condition. Debris and presence of oil should be evaluated and cleaned up.
• Guide Bearing	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Base on 2019 Voith inspection. Some minor indications and fretting.

Generator Checklist	
• Fire Suppression	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 n/a
• Brakes	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 No reported issues.
• Vibration	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 Need to analyze data provided by NHL. Waiting for unit of measure clarification.
• Noise	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7

Generator Checklist

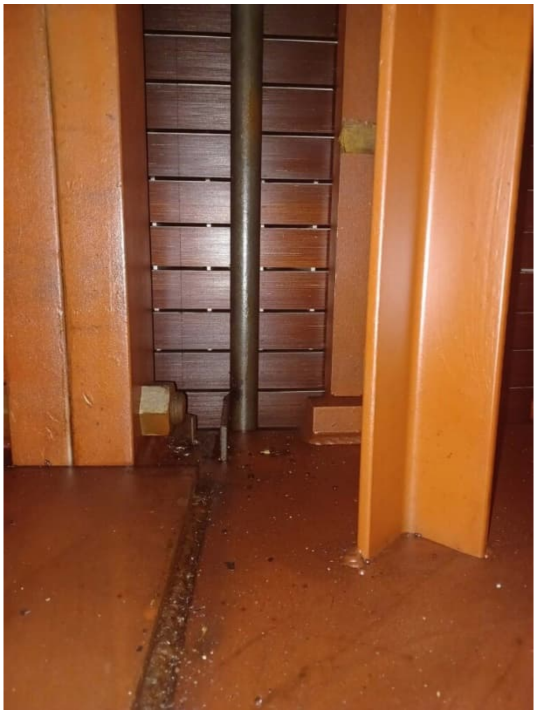
General Comments	Current= 7,196A, Voltage 13,800V **<u>General notes:</u>** **Rotor:** Rotor Hub • Minor fretting in coupling bores (VH report) • Oxidation on Coupling Face (VH report) • Rotor Hub had oil film present in some locations and dirt accumulation is some of the ribs (VH report verified by Hatch site visit). • Welds appeared to be in fair condition. No cracks found. Rotor Rim • Limited access during Hatch site visit. • Light rust present (VH report) • Light grease and dirt (VH report) Rotor Poles • Limited access during Hatch site visit. • Fair to poor condition (VH report) • Protective coating was peeling off (VH report) • Dislodged winding (VH report) • Correction to VH Report, no melting of rim laminations. Hatch inspection considers this to be a silicon or similar substance, not melting. Laser Inspection • Circularity of Rotor Poles were within CEATI tolerances (VH report) • Verticality of Rotor Poles were out of CEATI tolerances for three (3) poles (VH report) • Concentricity of the Rotor Poles to Hub was within CEATI tolerances (VH report) Other Notes: • NL Hydro replaced OEM heat tensioned nuts with Superbolt Nuts at the recommendation of Voith (VH report). **Stator** Stator Frame: • Limited access during Hatch site visit. • Sole plates and surrounding concrete were in good condition (VH report and verified by Hatch during site visit) • Overall stator frame was in good condition (VH report) • Debris, metal chips, and unused weld wire were found in the stator frame during the Hatch site visit. Laser Inspection: • Verticality and circularity are outside of CEATI tolerances for approximately 15% of the core (VH report)

Generator Checklist	

Generator Photos	
Photo 1: Nameplate	

Generator Photos	
Photo 2: Rotor Hub Weld (Typical Condition)	
Photo 3: Rim keys to the rotor spider attachement	

Generator Photos

Photo 4: Rust on the laminatinion at the back of the core	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Governor Checklist

Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Oct 14, 2023**
Weather	**Rainy, Mild**
Description of Item	**Governor**
Station/Unit	Bay d'Espoir, U7
Commissioning Date	1977
Manufacturer	Woodward
Last Refurbishment Date	
Original	☒ Yes ☐ Upgraded
Logic	☒ Mechanical ☐ Electro-Mechanical ☐ Electronic
Operating Pressure	350 psi (320-350 typical)
Number of Pumps	2 (lead / lag)
Fire Suppression	☒ Yes ☐ No Sprinklers overhead
Overall Condition of Governor	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Operating Condition	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Leakage	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Leakage observed around equipment. Rags on the floor.
• Operator Knowledge	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
• Maintenance Staff Knowledge	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Spare Part Availability	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ 7 Older vintage.
General Comments	Risk of obsolete spare parts given the vintage of the machine. Would recommend to upgrade to electro-mechanical or electronic governor and controls. There is also a risk of operator and maintenance staff knowledge transfer to new generation of workforce. New generation won't have access to training information as the vintage and type of governor are no longer common.

Governor Checklist	

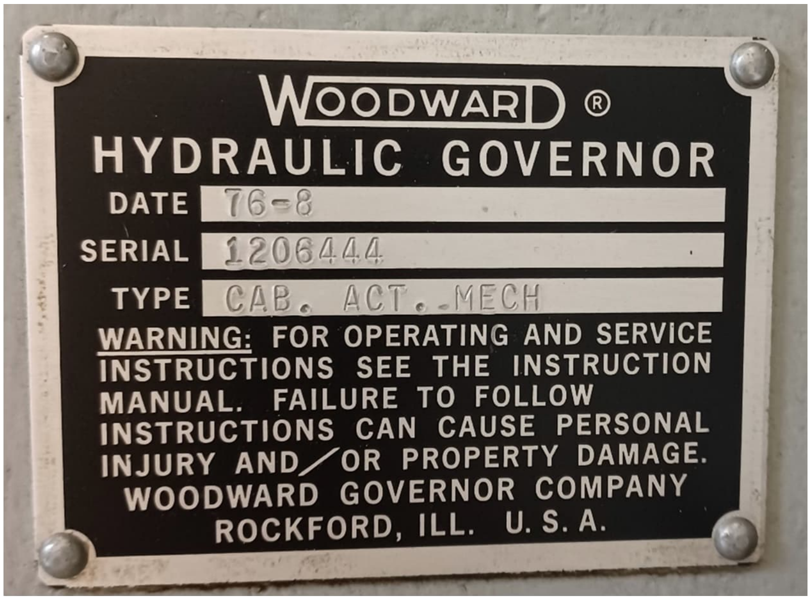
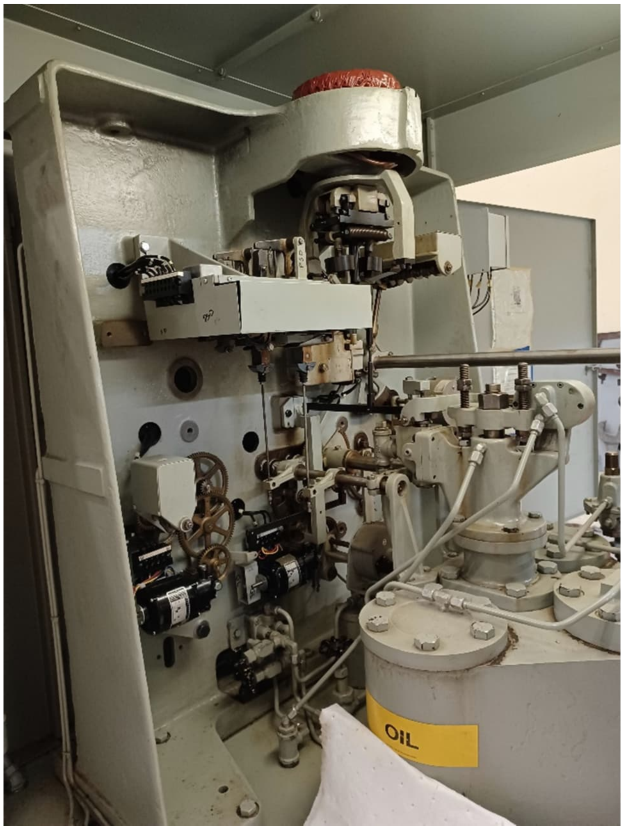
Governor Photographs	
Photo 1: Nameplate	
Photo 2: Governor	

Photo 3: Governor	

Photo 4: Guage Panel	

Photo 5: Leakage around Accumulator Tank and HPU	 

Photo 6: Governor Pump Control	

Photo 7: Accumulator Tank	

Photo 8: HPU	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Water System Checklist	
Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Oct 14, 2023**
Weather	**Rainy, Mild**
Description of Item	**Water Cooling System**
Station/Unit	Bay d'Espoir, U7
Purpose	☒ Cooling ☐ Service ☐ Domestic ☐ Fire
Commissioning Date	2018 re-commissioned. Some OME components still active.
Number of Pumps	n/a
Number of Strainers	2 (two lines off main supply)
Unit Specific	☒ Yes ☐ No
Treatment	☐ Chlorine ☐ Ozone ☐ Ultra Violet ☒ Filtration ☐ None
Main Source	☒ Penstock ☐ Tailrace ☐ Municipal ☐ None
Backup Source	☒ Penstock ☐ Tailrace ☐ Municipal ☐ None
Overall Condition of Water System	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Pumps	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 n/a
• Strainers	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Strainers are original and over 50 years old.
• Piping	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Instrumentation	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 OEM analog instrumentation. No digital readout or sensing.
• Treatment System	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 n/a
General Comments	Rupture disc on relief lines fail frequently. This was a complaint by the operating staff. There were reported water quality issues that would need further investigations.

Water System Photographs	
Photo 1: Main Line from Penstock	

Water System Photographs	
Photo 2: Line 1	
Photo 3: Line 2 Pressure Reducing Valve and Filter	

Water System Photographs

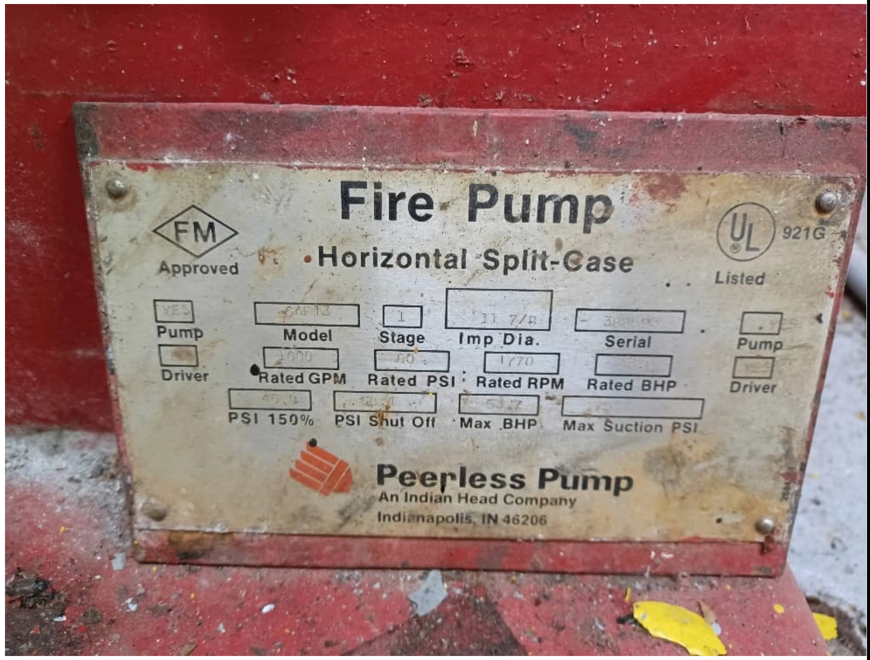
Photo 4: Line 2 Pressure Reducing Valves and Take-off	
Photo 5: Take-Off from Penstock	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.

3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Water System Checklist

Site Name	**Bay d'Espoir HPP**
Date of Inspection	**Oct 14, 2023**
Weather	**Rainy, Mild**
Description of Item	**Water Cooling System**
Station/Unit	Bay d'Espoir, U7
Purpose	☐ Cooling ☐ Service ☐ Domestic ☒ Fire
Commissioning Date	1977
Number of Pumps	1
Number of Strainers	1 on main line and 1 on relief line
Unit Specific	☒ Yes ☐ No
Treatment	☐ Chlorine ☐ Ozone ☐ Ultra Violet ☒ Filtration ☐ None
Main Source	☒ Penstock ☐ Tailrace ☐ Municipal ☐ None
Backup Source	☐ Penstock ☒ Tailrace ☐ Municipal ☐ None
Overall Condition of Water System	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	
• Pumps	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
• Strainers	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Piping	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 Paint chipping from take-off pipe near penstock.
• Instrumentation	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7 Analog OEM
• Treatment System	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7 n/a
General Comments	

Water System Photographs	
Photo 1: Pump Rating Plate	

Water System Photographs	
Photo 2: Pump	

Water System Photographs	
Photo 3: Piping (Penstock Take-off)	

Water System Photographs	
Photo 4: Piping (Penstock Take-off)	

Water System Photographs	
Photo 5: Piping (Drain Piping Take-off)	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Relief Valve Checklist	
Site Name	**Bay d'Espoir**
Date of Inspection	**Oct 14, 2023**
Weather	Rainy, Mild
Description of Item	**Main Relief Valve**
Station/Unit	Bay d'Espoir, U7
Commissioning Date	1977
Diameter	
Type	☐ Butterfly ☐ Spherical ☐ Gate ☒ Plunger
Date of Last Inspection	No known inspection.
Internal Inspection Now	☐ Yes ☒ No
Estimated Number of Cycles Per Year	
Overall Condition of Relief Valve	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	Leakage found inside of valve during Scroll Case inspection. Leakage during site visit on outlet piping and concrete.
• Operation	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
• Leakage	☐ 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ 7
General Comments	Was not able to view the disassembled valve. Condition assessment based solely on reported data and visual assessment from inside scroll case and gallery in powerhouse. October 13, 2023 inspection is scroll case did not show any leakage or water inside the valve. October 14, 2023 insepction in the scroll case showed leakage and water inside the valve.

Relief Valve Photographs	
Photo 1: Valve	

Relief Valve Photographs	
Photo 2: Dashpot in Turbine Pit	

Relief Valve Photographs	
Photo 3: Outlet Piping to Concrete (Leakage shown on right when unit was dewatered)	

Relief Valve Photographs	
Photo 4: Inlet from Spiral Case	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Compressed Air System Checklist	
Site Name	**Bay d'Espoir**
Date of Inspection	**Oct 14, 2023**
Weather	Rainy, Mild
Description of Item	**High Pressure Compressed Air System**
Station/Unit	Bay d'Espoir Unit 7
Commissioning Date	
Purpose	☒ Governor ☒ Service ☒ Brake ☐ Breaker ☒ Multipurpose
Number of Compressors	2
Max Pressure	425 PSI (Relief Valve Setting)
Operating Pressure	370 PSI
Capacity	
Accumulator Volume	Accumulator Tank for Compressor 1: 120 gal Accumulator Tank for Compressor 2: ??
Overall Condition of Compressed Air System	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	No clear visual signs of major deterioration or damage and no reported issues.
• Operating Condition	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Leakage	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Piping	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	

Compressed Air System Checklist	
Site Name	**Bay d'Espoir**
Date of Inspection	**Oct 14, 2023**
Weather	Rainy, Mild
Description of Item	**Low Pressure Compressed Air System**
Station/Unit	Bay d'Espoir Unit 7
Commissioning Date	1977
Purpose	☐ Governor ☐ Service ☐ Brake ☐ Breaker ☐ Multipurpose Blowdown air for sync condense operation.
Number of Compressors	1x Compressor 1x Blower
Max Pressure	110 PSI
Operating Pressure	90 PSI
Capacity	
Accumulator Volume	920 cu. Ft.
Overall Condition of Compressed Air System	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
Specific Notes for Condition of:	Piping could use some touch up paint and be inspected at some of the joints. No clear signs of any problems.
• Operating Condition	☐ 1 ☐ 2 ☒ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Leakage	☐ 1 ☒ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6 ☐ 7
• Piping	☐ 1 ☐ 2 ☐ 3 ☒ 4 ☐ 5 ☐ 6 ☐ 7
General Comments	

Compressed Air System Photographs

Photo 1: Compressor	
Photo 2: Blower	

Compressed Air System Photographs	
Photo 3: Air Tank	
Photo 4: Piping	

Compressed Air System Photographs	
Photo 5: Piping from Tank and Blower	

Compressed Air System Photographs	
Photo 6: Piping to Turbine Pit	

Rating	Condition Description	Details
1	Excellent	No noticeable defects. Some aging or wear may be visible.
2	Very Good	Only minor deterioration or defects are evident.
3	Good	Some deterioration or defects are evident but function is not significantly affected.
4	Fair	Moderate deterioration. Function is still adequate.
5	Poor	Serious deterioration in at least some portions of the structure. Function is inadequate.
6	Very Poor	Extensive deterioration. Barely Functional.
7	Failed	No longer functions. General failure or complete failure of a major structural component.

Appendix D:
Deficiency Table and Recommendations

Item No.	Component / Topic	Status	L_0 = Estimated Service Life (Do- Nothing) [Years]	Deficiency Description	Do-Nothing Consequence	Risk Category	C_0 = Consequence Rating (Do-Nothing)	P_0 = Likelihood of Consequence (Do-Nothing)	R_0 = Risk Rating (Do- Nothing) [R=C x P]	Priority	Recommended Actions	L_1 = Estimated Service Life (After Recommendations) [Years]	Justification	C_1 = Consequence Rating (After Recommendations)	P_1 = Likelihood of Consequence (After Recommendations)	R_1 = Risk Rating (After Recommendations) [R=C x P]	Estimated Cost AACE Class 5 [USD]	References
1.	Stator Core	Good	10	Slightly oval circularity on lower plane. Circularity of the stator core as measured on three planes is reported to be more oval on the plane close to the bottom of the unit, matching the profile of the embedded structures. However, it is still within CEATI tolerances.	Progression of oval circularity can influence magnetic pull balance	Production	2	5	10	Medium	Adjust circularity during stator rewind.	40	Necessary for maximum life extension	2	1	2	[redacted]	Section 3.4.2
2.	Stator Core	Good	5	Air guide seal bend is recorded to have approximately 30% of the rivets loose which potentially can damage insulation of the bars behind if take off.	Detachments of the rivets can damage the bar insulation behind the insulating band or end up in the airgap	Production	4	2	8	Medium	Rewind the stator armature winding.	40	Necessary for maximum life extension	4	1	4	See Item 11	Section 3.4.3
3.	Stator Core	Good	10	Slight inwards conical verticality at the top. Verticality of the stator core is reported to be 85% within CEATI tolerances with remaining 15% out of the CEATI tolerance in direction of the bore, suggesting that the core is leaning inwards towards a conical shape.	Progression of oval circularity can influence magnetic pull balance. Increase in vibration and loss efficiency of the generator	Production	2	5	10	Medium	Adjust verticality after core clamping during stator rewind.	40	Necessary for maximum life extension	2	1	2	Included in Item 1	Section 3.4.2
4.	Stator Core	Good	10	Loose Core	Progression of looseness	Production	2	5	10	Medium	Retorque core clamping during stator rewind.	40	Necessary for maximum life extension	2	1	2	Included in Item 1	Section 3.4.2
5.	Stator Frame	Good	3	Metallic debris in frame and bottom end caps.	Serious in-service failure with damage to equipment and forced outage.	Production	5	4	20	High	Clean and inspect to prevent accumulation. Perform during next planned outage or available opportunity.	5	Life extension.	5	1	5	[redacted]	Section 3.4.1

Priority:
Low – Recommended actions are needed for optimal functionality. It is possible to wait up to 10 years to execute the work without risk to safety or equipment.
Medium – Recommended actions are needed to maintain functionality. It is possible to wait up to 5 years to execute the work without risk to safety or equipment.
High – Recommended actions are needed as soon as possible. An intervention in the timespan of 3 years should be planned to execute the work.
Urgent – It is not safe to run the unit with the condition, and it needs to be addressed right away.

Risk Categories:
- Health and Safety
- Environment
- Financial
- Production
- Schedule
- Reputation
- Business Impact

Consequence Rating[1]:
1) Insignificant
2) Minor
3) Moderate
4) Major
5) Catastrophic

Likelihood of Consequence[2]:
1) Rare (<5% Chance of Occurrence)
2) Unlikely (20% Chance of Occurrence)
3) Moderate (50% Chance of Occurrence)
4) Likely (80% Chance of Occurrence)
5) Almost Certain (>95% Chance of Occurrence)

Risk Rating[2]:
≤ 6 Low
> 6, ≤ 13 Moderate
> 13, ≤ 19 High
> 19, Extreme

1. Definitions of consequences depend on risk category.
2. Risk likelihood and rating are based are scored based on the estimated service life. Example: If P0 = 4 and L0 = 10 years, then it is estimated that within 10 years there is an 80% chance of the consequence occurring.

Item No.	Component / Topic	Status	L_0 = Estimated Service Life (Do- Nothing) [Years]	Deficiency Description	Do-Nothing Consequence	Risk Category	C_0 = Consequence Rating (Do-Nothing)	P_0 = Likelihood of Consequence (Do-Nothing)	R_0 = Risk Rating (Do- Nothing) [R=C x P]	Priority	Recommended Actions	L_1 = Estimated Service Life (After Recommendations) [Years]	Justification	C_1 = Consequence Rating (After Recommendations)	P_1 = Likelihood of Consequence (After Recommendations)	R_1 = Risk Rating (After Recommendations) [R=C x P]	Estimated Cost AACE Class 5 [USD]	References
6.	Stator Armature Winding	Poor	5	Aged stator armature winding, including visual indications of localized high stress. Distributed cracks in the ground wall insulation close to the bar entrance to the cap and close to the lashing point which it is sign of movement and potentially vibration of the end-winding. End-winding caps at the bottom of the unit in slots from 194 to 200 have significant stress of ground wall insulation. It seems that a proper overlap of epoxy resin and cap compound (mixture of the mica powder and resin) was not achieved during installation. Online PD activity shows slot discharges that are not overt on offline tests. This suggests a potential looseness of the winding.	Serious in-service failure with damage to equipment and forced outage.	Production	5	3	15	High	Rewind the stator armature winding.	40	An abnormal event (such as overspeed, single-phase trip, switching surge, etc) striking an aged winding is more likely to drive it to electrical failure.	5	1	5	[redacted]	Section 3.4.3
7.	Stator Armature Winding	Poor	5	Significant bubbling of the paint over bars surface belonging to slot 196 in the area where the bar is going into the bottom cap is sign of possible cold joint of the two halves of the same coil being brazed inside the cap.	Serious in-service failure with damage to equipment and forced outage.	Production	5	3	15	High	Monitor local temperature with thermal strips. See report for details.	5	Monitoring the development of the hot spot allows remedial action to be planned before an in-service failure happens.	5	1	5	OPEX	Section 3.4.3
8.	Rotor Field Coils	Fair	10	Missing additional turn tape over several outermost pole coil assembly turns.	Progression of additional turn tape can create turn to turn short	Production	5	2	10	Medium	Reinsulating the rotor field winding.	40	Presently, risk of mechanical failure in case of overspeed.	5	1	5	Included in Item 17	Section 3.4.7
9.	Rotor Field Coils	Fair	10	Flaking pole collars.	Degradation of the collars can short the creepage path to ground fault	Production	2	1	2	Medium	Reinsulating the rotor field winding.	40	Not urgent, but component is fully degraded and need replacement.	2	1	2	Included in Item 17	Section 3.4.7
10.	Rotor Field Coils	Fair	10	Overall coil insulation completely degraded.	Serious in-service failure with damage to equipment and forced outage.	Production	3	1	3	Medium	Reinsulating the rotor field winding.	40	Not urgent, but component is fully degraded and need replacement.	3	1	3	Included in Item 17	Section 3.4.7
11.	Rotor Field Coils	Fair	10	Voltage pole drop test did not pass.	Turn to turn short creating unbalanced magnetic pull	Production	2	1	2	Medium	Reinsulating the rotor field winding.	40	Developing of additional turn-to-turn shorts will cause increased vibration.	2	1	2	Included in Item 17	Section 3.4.7

Item No.	Component / Topic	Status	L_0 = Estimated Service Life (Do- Nothing) [Years]	Deficiency Description	Do-Nothing Consequence	Risk Category	C_0 = Consequence Rating (Do-Nothing)	P_0 = Likelihood of Consequence (Do-Nothing)	R_0 = Risk Rating (Do- Nothing) [R=C x P]	Priority	Recommended Actions	L_1 = Estimated Service Life (After Recommendations) [Years]	Justification	C_1 = Consequence Rating (After Recommendations)	P_1 = Likelihood of Consequence (After Recommendations)	R_1 = Risk Rating (After Recommendations) [R=C x P]	Estimated Cost AACE Class 5 [USD]	References
12.	Rotor	Fair	10	V block not installed as per OEM drawings.	Update OEM drawing to as-built condition, not u	Production	2	1	2	Medium	Verify proper installation method.	10	n/a	2	1	2	[redacted]	Section 3.4.7
13.	Pole Connectors	Fair	10	Broken lock tab on U shape connector of Pole #1.	If detached can end up in airgap	Production	2	1	2	Medium	Repair lock tab and adjust torque.	10	n/a	2	1	2	OPEX	Section 3.4.7
14.	Pole Connectors	Fair	10	Frayed insulation between U shape connectors.		Production	1	1	1	Medium	Reinsulate the field winding.	40	Not urgent, but component is fully degraded and need replacement.	1	1	1	Included in Item 17	Section 3.4.7
15.	Pole Bodies	Fair	10	Rusted pole faces.	Can affect natural interlaminar insulation, so can created short during the transient condition due to tooth ripple effect.	Production	1	1	1	Medium	Repair during field winding re-insulation	10	Not urgent, but needed for maximum life extension	1	1	1	Included in Item 17	Section 3.4.7
16.	Pole Bodies	Fair	10	Minor dents and melt of pole laminations.	Due the location of the dent is more cosmetic than necessary functional correction	Production	1	1	1	Medium	Repair during field winding rewind.	10	Not urgent, but needed for maximum life extension	1	1	1	Included in Item 17	Section 3.4.7
17.	Rotor Field Winding	Poor	10	Aged and degraded insulation	In-service failure with damage to equipment and forced outage.	Production	3	1	3	Medium	Reinsulate rotor field winding.	40	Not urgent, but component is fully degraded and need replacement.	3	1	3	[redacted]	Section 3.4.7
18.	Runner Seal Clearance	Poor	5	Runner seal clearance is changing over time. Data tracked from 2006 by NL Hydro shows trending. Voith re-machined the wearing rings in 2019, recorded the as-found and as-left condition, and provided analysis for estimated remaining life. Hatch took independent readings in 2023 and found the A2 location on the upper seal is above the "Upper Intervention / Critical" limit according to the Voith 2019 report.	The seal clearances are already near or exceeding the intervention limit recommended by Voith from 2019. More severe out of tolerance issues can cause vibration issues and increase in hydraulic thrust. High thrust load can decrease service life of thrust bearing or thrust bearing failure. Thrust bearing temperatures will provide indication of overloading. Do nothing analysis assumes continued monitoring and yearly measurements as currently performed.	Production	4	3	12	Medium	Embedded component machining to ensure bottom ring and head covers have well-established seating surfaces and supply new wearing rings (bushings) on the head cover, bottom ring, and runner.	25	AAR may continue to pose a risk to embedded components and runner seal clearance. Expected life based on need to replace wearing rings and risk posed by large seal clearance. Costs included in other line items.	4	2	8	Included in Items 19, 33 and 34	Section 3.13.4
										High	Continue monitoring vibration and temperature of bearings with yearly runner seal clearance measurements.	5	Reduce risk of unplanned outages and sudden failure or issues.	3	3	9	OPEX	

Item No.	Component / Topic	Status	L_0 = Estimated Service Life (Do- Nothing) [Years]	Deficiency Description	Do-Nothing Consequence	Risk Category	C_0 = Consequence Rating (Do-Nothing)	P_0 = Likelihood of Consequence (Do-Nothing)	R_0 = Risk Rating (Do- Nothing) [R=C x P]	Priority	Recommended Actions	L_1 = Estimated Service Life (After Recommendations) [Years]	Justification	C_1 = Consequence Rating (After Recommendations)	P_1 = Likelihood of Consequence (After Recommendations)	R_1 = Risk Rating (After Recommendations) [R=C x P]	Estimated Cost AACE Class 5 [USD]	References
19.	Runner Cavitation	Poor	10	Cavitation damage at several locations on the runner. The runner has been weld repaired several times and the cavitation damage is an ongoing problem.	Cavitation will continue and may cause structural damage to the runner. Cavitation can also cause poor hydraulic performance. If no action is taken, the runner will continue to cavitate. Hatch estimates that if NL Hydro operates the units within the known cavitation limits and performs regular inspections of the runner, the estimated service life is 5-10 years. Voith recommended to replace the runner within 5 years of 2019 report.	Production	5	2	10	Medium	Supply a new stainless-steel runner.	50+	A stainless-steel runner can be more cavitation resistant and not require painting like the current carbon steel runner. A new hydraulic profile and design can provide increased efficiency and reduce the likelihood of cavitation. Runner replacement with estimated 2% increase in efficiency is optimal solution according to Hatch Uprate Report (H371822-0000-2A1-066-0002). It is possible to perform cavitation repairs on runners, but this cannot be performed indefinitely. There is risk to weld deformations causing hydraulic tolerance issues and structural issues with layered weld repairs. Hatch does not recommend additional weld repairs beyond the extent currently performed. As NL Hydro does not have blade templates, the likelihood of performing extensive weld repairs within the hydraulic tolerance is very low.	4	1	4	[redacted]	Section 3.13.1
											Perform an index test or an absolute efficiency test for a new runner (Dye Dilution Test).	n/a	Perform an index test or an absolute efficiency test for a new runner to ensure desired performance.	n/a	n/a	n/a	Dye Dilution Test [redacted]	
20.	Runner Wearing Rings	Fair	5	Contact damage and minor cavitation. Contact damage believed to be from the 1970's based on inspection photos during that time.	There is little structural risk with the given damages as they are more of a consequence of other issues or events. However, significant cavitation or damage to the rings may cause an imbalanced seal that can lead to pulsing or vibrations. Cavitation damage likely to continue at an exponential rate if seal clearances continue to change.	Production	4	3	12	Medium	Replace wearing rings along with new runner.	25	Costs included with runner replacement.	4	1	4	Included in Item 19	Section 3.13.2
										High	Monitor turbine vibration and annual inspection of runner seal clearances.	5	Reduce risk of unplanned outages and sudden failure or issues.	3	3	9	OPEX	

Item No.	Component / Topic	Status	L_0 = Estimated Service Life (Do- Nothing) [Years]	Deficiency Description	Do-Nothing Consequence	Risk Category	C_0 = Consequence Rating (Do- Nothing)	P_0 = Likelihood of Consequence (Do-Nothing)	R_0 = Risk Rating (Do- Nothing) [R=C x P]	Priority	Recommended Actions	L_1 = Estimated Service Life (After Recommendations) [Years]	Justification	C_1 = Consequence Rating (After Recommendations)	P_1 = Likelihood of Consequence (After Recommendations)	R_1 = Risk Rating (After Recommendations) [R=C x P]	Estimated Cost AACE Class 5 [USD]	References
21.	Runner Cover Plate	Good	10	2019 outage found cracking and piece broken off the balance cover plate on the crown. Voith designed a new cover plate that was installed in 2019 by NL Hydro.	There is a low risk of the cover plate failing again. However, the OEM drawings indicate that the balancing box was filled with lead. This possesses an environmental risk of lead contamination or exposure.	Production	4	2	8	Low	Replace Runner	50+	Costs included with runner replacement. Risk of lead impact on environment is based on OEM drawings.	1	1	1	Included in Item 19	Section 3.13.3
					The runner was not balanced after the installation of a new plate. There is a risk that the runner is out of balance and will cause undue vibration or instability.	Environme nt	3	1	3	Low		50+		1	1	1		
22.	Wicket Gates	Good	25	Concentricity of trunnions were not verified during rehabilitation in 2019. Surface finish of gates stems above OEM tolerance. Wear and scoring on gate stems. Moderate scratches and dents on the gate leaves.	Out of concentricity tolerance can lead to binding of the wicket gates and pre-mature wear of the gate stem bushings. It cam also impact the alignment of the wicket gate vertical seals when in the closed position. Scratches and scoring may damage gate stem bushings.	Production	3	2	6	Low	Rehabilitate Existing Gates.	50	Hatch recommends that the base scope of supply to be rehabilitation of the existing gates with the option of new gates. New gates would need to be justified by a manufacturer to prove sufficient performance increase or by an outage schedule savings.	3	1	3	[redacted]	Section 3.9
										Low	FEA and Fatigue Life Calculation of existing gates.	50	Ensure life extension based on cyclical loading of gates.	3	1	3	[redacted]	
23.	Turbine Shaft Seal Sleeve	Fair	10	2019 report by Voith showed wear of the shaft sleeve surface.	This seal surface will continue to wear. Increased wear will increase the leakage around the shaft seal. Too much leakage can cause water damage to other components in the turbine pit.	Production	4	1	4	Low	Replace shaft sleeve on turbine shaft and carbon seal rings. Inspect and rehabilitate the shaft seal housing assembly.	25	Cost of shaft sleeve included with turbine shaft recommendations. Cost of new carbon seals and rehabilitation shown in this row.	3	1	3	[redacted]	Section 3.7

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24.	Turbine Shaft	Fair	10	There was no dimensional inspection or NDE performed in 2019. There was also no visual assessment of the turbine shaft coupling flange. The risk is associated with the unknown condition of the shaft and flanged connection to the runner. There were light scratches and dents on the turbine guide bearing journal reported in 2019.	If nothing is done, the expected shaft has an estimated remaining life of 10 years. Rough or damaged bearing journal surfaces can impact bearing life and operation. If a new runner is supplied, the shaft would require machining of the spigot and coupling bores to ensure a proper fit-up to the new runner.	Production	5	1	5	Low	Shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. A new shaft sleeve should be installed as well as new coupling hardware between the shaft and runner. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft. To adapt a new runner, the runner end spigot and runner end coupling bores should be re-machined.	50	Necessary for service life of 25 years or longer. Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new shaft for the turbine. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.	5	1	5	[redacted]	Section 3.9
25.	Generator Shaft	Fair	15	From visual inspection: Discoloration and scoring on the rotor coupling flange believed to be from the coupling hardware. There was no dimensional inspection or NDE performed in 2019. The risk is associated with the unknown condition of the shaft and flanged connection to the runner.	If nothing is done, the expected shaft has an estimated remaining life of 10 years.	Production	5	1	5	Low	Shaft should be taken to a rehabilitation facility, cleaned, NDE inspected, dimensionally inspected, and painted. Surface finishes not to OEM specifications should be addressed during the rehabilitation. An FEA and fatigue analysis should be performed in addition to the general rehabilitation and reconditioning of the shaft.	50	Necessary for service life of 25 years or longer. Hatch agrees with Voith's recommendation to rehabilitate the shaft. There is no evidence to justify a new generator shaft. The only situation where a new shaft would be required is if the unit was uprated to a point that the current shaft is not suitable for static stresses, fatigue life, or shaft-line stability.	5	1	5	[redacted]	Section 3.8
26.	Operating Ring and Bearings	Poor	5	Significant surface damage on the upper and lower operating ring bearing journal surfaces. Operating ring has deformed over time is now an oval shape. Issues with temporary bearing pads installed in 2019.	Bearing pads will continue to come out of place and cause damage to the operating ring and the head cover.	Production	3	3	9	High	Inspection and Rehabilitation of Operating Ring and Supply of New Bearing Pads.	15	As the current bearing pads have already caused issues, regular maintenance and monitoring is required. Expected service life based on bearing pad life. Operating ring life expected to be 40 years.	4	1	4	Rehabilitation: [redacted]	Section 3.10.2
					Grease from the operating ring bearing is not contained and may contaminate turbine pit equipment.	Environment	1	5	5	Low	As an option, a new operating ring with a split should be considered by NL Hydro as the bearing pads can be changed without major disassembly oof the unit.	n/a		0	0	0	Option (New Operating Ring): [redacted]	
					Sever damage may prevent gates from opening.	Production and Business Impact	5	1	5	Medium		25		5	1	5		

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27.	Gate Servomotor Scoring	Fair	10	NL Hydro believes that there was leaking in the servomotors prior to 2019. Scoring on the ID of the cylinder wall discover in 2019 and not addressed. Scoring on the piston.	Leakage around piston and loss of pressure.	Production	4	2	8	Low	Inspection, rehabilitation, and replace wear components. Recommend to complete work in parallel with operating ring.	50	Life extension.	4	1	4	[redacted]	Section 3.10.1.1
28.	Wicket Gate Link Pins	Fair	10	Pins dropping out could cause damage to arms and links in addition to losing control of a wicket gate.	Pins dropping out could cause damage to arms and links in addition to losing control of a wicket gate.	Production	3	4	12	Medium	Replace link pins.	25	Expected service life is based on new bushings. New pins expected service life is 50+ years.	3	1	3	[redacted]	Section 3.10.3
29.	Spiral Case Access Door Leakage	Poor	15	Water leakage around the spiral case access door.	It's not possible to provide a confident outlook if nothing is done. If the condition has been in existence for 30+ years as reported by NL Hydro, it could continue as is for another 15 or 20 years. Or it could become a more urgent issue if the leakage rate increases rapidly. Exact consequences are unclear as the root cause is not identified. The current leakage rate does not appear to be causing other significant issues. NL Hydro could continue to monitor the flow rate.	Production	4	2	8	High	Hatch recommends monitoring and collect leakage data. If the average flow rate increases month over month for more than three (3) consecutive months, or if there is a sustained average flow rate over 3.0 L/s over a given month, that NL Hydro investigate the problem further and perform the following recommended repairs.	15	Reduce risk of unplanned outages and sudden failure or issues.	4	1	4	OPEX	Section 3.11.4.1
										Medium	Seal weld stay ring flange to discharge ring. This will likely cause distortion of the discharge ring surface where the bottom ring mounts to. Therefore, field machining of embedded components is required. This field machining would be recommended in either situation as to ensure proper alignment of the bottom ring to head cover, ensure level mounting surfaces, and ensure the bottom ring flange with the O-ring has a proper mounting surface to seal.	50	This will resolve the most likely source of the water source. Not guaranteed to prevent all water leakage around spiral case access door.	4	1	4	[redacted]	
										Medium	Lead abate, blast, clean, NDE, and paint the spiral case, stay ring, stay vanes, discharge ring, and draft tube liner down to the maintenance platform. Perform local repairs as necessary.	50	Improve water passage surfaces and provide life extension to the embedded components. May reduce leakage if holes are present.	4	1	4	[redacted]	

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										Low	Remove spiral case baffle plate, inspect, repair as needed, and re-install baffle plate.	50	Less likely source of leakage but may improve leakage around access door.	4	1	4	[redacted]	
										Medium	Pressure tests all embedded piping.	25	Ensure embedded piping doesn't have leaks. Likely not the main source of the access door leakage, but may be a contributing factor if an embedded component has leakage.	3	1	3	[redacted]	
30.	Relief Valve Leakage	Poor	10	Water leakage round the Relief Valve discharge piping and concrete. Water filling up the diffuser and valve when dewatered.	As the condition inside the pipe is unknown, it's difficult to provide a proper assessment.	Production	4	2	8	Medium	Borescopic examination of outlet pipe and diffuser, valve rehabilitation, unknown repairs based on inspections.	50	Life extension of the relief valve.	4	1	4	[redacted]	Section 3.11.4.2
											Overhaul of outlet gate.	40	Life extension and prevent leakage into valve when dewatering.	4	1	4	[redacted]	
31.	Head Cover and Bottom Ring Gate Stem Bores	Fair	5	Gate stem bore alignment.	Gate stem bore wear, binding of wicket gates, and higher loading of operating mechanism.	Production	5	2	10	Medium	The head cover and bottom ring gate stem bores should be either line bored or machined using matching templates.	50	Ensure proper alignment of the gate stem bores between the components and save on the outage schedule as to not have to line bore in the field.	5	1	5	Line Bore: [redacted] Template Bore: [redacted]	Section 3.12.3
32.	Head Cover and Bottom Ring Facing Plates and Gate End Seals	Fair	5	Facing plates are scratched and scored. Damage to rubber gate end seals.	Wicket gate end clearances would require continued monitoring to ensure no further damage is done to the facing plates. Gate end seals expected life is 5 years.	Production	3	3	9	Low	Replace gate end seals and facing plates.	15	Expected service life of new facing plates is 40+ years. Expected service life of new gate end seals is 15 years.	3	1	3	[redacted]	Section 3.12.4
33.	Head Cover	Poor	10	Wearing ring cavitation, scoring, scratches, and deformed shape. Cracks in stiffeners connecting to the outer flange of the head cover. Upper gate stem bushing damage. Debris from runner found in head cover with possible unknown damage.	Wearing ring damage, crack propagation, and wicket gate bushing issues (i.e. binding).	Production	5	2	10	Medium	Rehabilitate existing head cover. Clean, blast, NDE, repair indications, dimensional inspection, machining of wearing ring mounting surface, water passage surface, mounting flanges, installation of new wearing ring, installation of new facing plate (or weld overlay), supply of new hardware, and paint. Gate stem bores should be line bored with bottom ring or bored with a template. Supply and install new gate stem bushings.	25	An assessment of the schedule and outage cost should be analyzed by NL Hydro to determine if a new head cover is justified. The head cover rehabilitation would be on or near the critical path. Any unforeseen issues or delays could cause an extended outage. Expected service life of rehabilitated head cover is 25-40 years. Expected service life of a new head cover is 50+ years.	5	1	5	Rehabilitate: [redacted] Supply New: [redacted]	Section 3.12.2

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34.	Bottom Ring	Poor	10	Cavitation damage under wearing ring. Out of tolerance water passage surface levelness.	Runner seal clearance issues and wearing damage. Wicket gate bushing issues and potential binding.	Production	5	2	10	Medium	Replace	50	Hatch believes that the bottom ring would be able to be rehabilitated but agrees with Voith's 2019 assessment that the schedule risk may be too significant. The bottom ring is the last component out of the unit for rehabilitation and the first component needed back at site. It's also a relatively simple component that can be supplied as a forged ring or fabricated from plate steel.	5	1	5	Supply New: [redacted] Rehabilitate: [redacted]	Section 3.12.1
35.	Thrust Collar, Keys, and Runner	Good	25	Thrust collar has light fretting and corrosion. Light scoring on the journal surface possibly from contact with guide bearing pads or debris. Mating surface of thrust runner to thrust collar had light signs of fretting and corrosion. Thrust keys have Light fretting and corrosion.	These components being reported in good condition could remain as is for another 25+ years if the dimensional and geometric tolerances are within OEM design.	Production	5	2	10	Low	Dimensional inspection and surface finish measurements of running surfaces. Clean, machine, and polish surfaces in a rehabilitation facility to correct any dimensional, geometric, and surface finish out of tolerance issues.	40+	Life extension of thrust collar and thrust runner.	5	1	5	[redacted]	Section 3.5.1.1
36.	Combined Thrust and Guide Bearing Pads	Good	10	Light scoring and Babbitt surface indications.	This surface is a critical surface. Given the current condition, it may be acceptable without intervention for another 5-10 years. Thrust bearing failure can be catastrophic. There is also a risk to wiping the bearing and damaging the thrust runner.	Production	5	2	10	Low	NDE inspection of the bearing pads, re-babbitt, and supply new thrust bed springs.	40+	This will also help mitigate vibration issues by restoring the bearings and journal surfaces back to OEM condition.	5	1	5	[redacted]	Section 3.5.1.2

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37.	Wicket Gate Squeeze	Fair	5	Wicket gate squeeze is currently 0.5 inch. OEM design gate squeeze is 0.375 inch.	If nothing is done, the bearing pad failures on the operating ring are likely to continue. However, the recommendations for the operating ring bearings, the gate stem bore alignment and the gate servomotors are more critical to the long-term life extension of the turbine. Increased squeeze could cause the bearing pad screws to shear, oval the operating ring, and damage journal surfaces.	Production	4	2	8	Low	Adjust servomotor and wicket gate setting to re-establish OEM squeeze. Install upthrust clips where the OEM lip seal was.	40+	Life extension of gate operating mechanism.	4	1	4	[redacted]	Section 3.10.4
38.	Generator and Turbine Cooling Water Strainer Pressure	Poor	10	Maintenance record Checksheets show consistently low water pressure in the strainer from 2020 to 2022.	Can impact cooling performance for the generator and bearings. Overheating of bearings can cause damage to the operating unit and force and outage to re-babbitt the bearings. Generator overheating can cause damage to insulation and other generator equipment.	Production	3	2	6	Low	Monitor generator and bearing temperatures. Replace strainer at end of service life.	10	Life extension.	3	2	6	OPEX	Section 3.19.1
39.	Wicket Gate Closing Time	Poor	10	Maintenance record Checksheets show consistently slow closing time for wicket gates.	Unit may not respond as quickly to changes. No likely damage to equipment.	Production	3	1	3	Low	Monitor closing times and servomotor pressures. Issue can be corrected with gate servomotor rehabilitation and operating ring overhaul.	10	Monitoring can prevent unplanned outages.	3	1	3	OPEX Repairs included in Items 26 and 27	Section 3.19.2

Schedule 1, Attachment 2

Project Charter

newfoundland labrador hydro

Bay d'Espoir Unit 7 Life Extension

Project Charter

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These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

newfoundland labrador hydro	Bay d'Espoir Unit 7 Life Extension – Project Charter				
NLH Doc. No.	**BDE-NLH-40000-PM-CHT-0002-01**	**Revision**	**B1**	**Page**	**i**

Additional Approvals

Additional approvals are required for further authorization due to document contents, complexity, prescribed requirements, or multi-departmental involvement.

Position	Name	Signature	Date (DD-MMM-YYYY)
Project Manager, Bay d'Espoir Unit 7 Life Extension	Mark Howell	MHowell	12-JUN-2025

Endorsements

Endorsements indicate support or acknowledgement of this document's contents but do not imply formal approval. Endorsements are used to represent subject matter experts that have provided input but do not hold final decision-making authority for this document.

Position	Name	Signature	Date (DD-MMM-YYYY)
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1.0 Introduction

Bay d'Espoir Unit 7 is a 154.5 MW vertical Francis hydroelectric unit located in Powerhouse 2 of the Bay d'Espoir Generating Facility. The unit is comprised of a generator and turbine assembly with the capability to generate as well as act as a synchronous condenser as required to meet system requirements. The unit was commissioned in 1977 and has operated reliably with periodic upgrades to individual components and auxiliary systems as needed. A list of past Unit 7 replacement and upgrade projects is provided below:

Year	Year Major Work/Upgrade
2020	Upgraded Unit Protection
2019	Turbine Refurbishment
2015	Carbon Seal Replacement
2015	Turbine Base Plate Replacement
2014	Excitation Transformer Replacement
2009	Service Water Upgrades
2004	Generator Field Breaker Replacement
2004	Exciter Replacement
1998	Synchronous Condense Compressor Replaced
1998	Air Gap Monitoring System Installed
1991	Synchronous Condense Blower Replaced
1990	Partial Discharge Monitoring Installed
1982	Rotor Brake Plate Replacement
1982	Guide Bearing Segments Replaced

The turbine refurbishment work executed in 2019, driven primarily by issues with the runner clearances, provided an opportunity for detailed component inspections when the unit was fully disassembled for the first time since commissioning. Cavitation damage in the turbine, degradation of the generator stator windings and rotor field windings were noted along with distortion of embedded parts. These items could not be corrected at that time as replacement or repair required significant planning. The unit was put back in service with the runner clearances improved and other improvements made to the turbine but with the knowledge that additional work would be required in the future.

In 2023 a condition assessment was conducted by Hatch Engineering in order to develop a plan to correct the issues identified in 2019. The assessment concluded that major refurbishment and replacement work was necessary to ensure the unit's reliable long-term operation.

The Bay d'Espoir Unit 7 Life Extension Project ("Project") has been proposed to manage the work required to address the condition assessment report's recommendations.

The Project will be located at the Bay d'Espoir Facility in Bay d'Espoir, Newfoundland and Labrador, Canada.

2.0 Purpose and Scope

The Project Charter has been prepared for the Front-End Planning ("FEP") phase of the Project and will be updated, as appropriate, as the Project progresses through subsequent Decision Gates.

Management of Unit 7 scope may be integrated with the Unit 8 Project, if approved. Both Projects are in Powerhouse 2 with overlap in the execution timing which will require coordination between the teams and may provide opportunities for resource sharing.

The Project Charter defines why the Project exists and what the goals, objectives, and success criteria are. The Project scope, budget, schedule, constraints, assumptions, and risks are also described.

3.0 Abbreviations and Definitions

Term	Definition
Hydro	Newfoundland and Labrador Hydro
Bay d'Espoir or Bay d'Espoir Facility	Bay d'Espoir Hydroelectric Generating Facility
Project	Bay d'Espoir Unit 7 Life Extension Project
Decision Gate	Pre-defined moments in time where the Gatekeeper(s) make(s) appropriate decisions about whether to move to the next stage, make a temporary hold, or terminate the Project. The option to recycle to the current stage is considered an undesirable option unless caused by changes in business conditions.
FEED	Front-End Engineering Design, a major part of FEP, includes sufficient field investigations and engineering to establish a contracting strategy, Level 3 schedule, and Class 3 cost estimate.
FEP	Front-End Planning, also referred to as Feasibility Study, includes project execution planning, environmental management planning, FEED, supply chain management planning, and construction planning.
Gatekeeper	Responsible for making the decision at the Decision Gate of the Gateway Process.
OEM	Original Equipment Manufacturer
Project Sanction	When a project is formally given the go-ahead by management to move into the execution phase (typically making a commitment to construction).
Project Management Team	All Project Managers and their delegates who report directly to the Project Director.
Public Utilities Board	Board of Commissioners of Public Utilities
Risk	An uncertain event or condition that, if it occurs, has a positive or negative effect on a project's objectives.

Term	Definition
Shareholder	For Newfoundland and Labrador Hydro, the Shareholder is the Province of Newfoundland and Labrador.

4.0 Reference Documents

Reference	Document Title
NLH-MPM-00000-PM-STG-0001-01	Major Project Governance Framework;
BDE-VOH-00000-EN-REP-0001-01	Unit 7 Refurbishment Report, Voith, August 7, 2019;
BDE-HAT-00000-EN-REP-0001-01	Bay d'Espoir Unit 7 Condition Assessment, Hatch, May 3, 2024;
BDE-HAT-00000-EN-REP-0002-01	Bay d'Espoir Unit 7 Uprate Report, Hatch, June 21, 2024;
BDE-NLH-40000-EN-BOD-0002-01	Bay d'Espoir Unit 7 Life Extension Basis of Design
	We are Hydro: Strategic Plan 2023-2025, Newfoundland and Labrador Hydro. December, 2022.

5.0 Project Purpose

The purpose of the Unit 7 Life Extension Project is to overhaul Unit 7 through inspection, repair and replacement of components in order to extend the life of the generating unit and ensure continued reliable operation for at least the next 25 years.

The condition assessment completed by Hatch recommended that refurbishment be undertaken within 5 years as key components are at the end of their service life. Failure to complete the required work will most likely result in equipment failure, leading to an extended forced outage.

6.0 Description and Scope

This Project involves the life extension of Unit 7 through major refurbishment and replacement activities. The scope of work is based on the recommendations provided in the Hatch Condition Assessment Report along with input from the Long Term Asset Planning Team. Specifically, the Project will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the Project. The scope breakdown is as follows:

1. Design and manufacture a replacement turbine runner with a focus on optimizing the efficiency in the historical operating range. Increased output will not be pursued as the installation of an additional unit is planned for the powerhouse. The design will be based on a computer computational fluid dynamics model and an existing turbine design previously developed by the selected OEM. Turbine model testing is not included in the scope.

2. Finite element analysis and fatigue analysis will be performed on major components of the unit that are subjected to cyclic loading in order to confirm suitability for refurbishment and continued operation for a minimum of 25 years.

3. Site work will include:

- Complete dismantling of the turbine and generator;
- Inspection of all components;
- Replacement of turbine bottom ring and runner, generator stator armature windings and re-insulation of the rotor field coils;
- Repair or replacement of other components based on inspections after dismantling;
- Procurement of spares such as bushings, bearing pads, super bolts, brake pads, instrumentation, etc. required for reassembly of the unit;
- Replacement of exciter controls;
- Conversion of turbine governor from mechanical to digital controls;
- Refurbishment or replacement of auxiliary equipment such as air blow down system and hydraulic lift system;
- Updating unit control system;
- Repair leaks in draft tube liner, scroll case and relief valve; and
- Reassembly, testing and commissioning.

A more detailed scope description will be provided in the Basis of Design.

Inspections of the draft tube and intake gate slots are planned for 2025 and may result in additional scope proposed as a separate project.

The following is excluded from the scope:

- Any costs associated with the potential installation of Unit 8;
- Upgrades to other Powerhouse No. 2 facilities not associated with Unit 7; and
- Transmission system upgrades.

The contracting strategy, is under development, and is expected to include:

- Contract for engineering support during life extension RFP stage including development of technical specifications;
- Contract for engineering support during manufacturing and construction;

- Contract for unit life extension, including:
  - Refurbishment of the turbine and generator including supply of new parts, refurbishment of parts requiring repair and all site work required for assembly, disassembly, testing and commissioning;
  - Upgrading the governor; and
  - Upgrading the unit controls to match Unit 8, if approved.
- Contract for upgrading the exciter controls

7.0 Project Objectives

The execution of the Project will be conducted in a manner that supports the broader organizational objectives identified in Newfoundland and Labrador Hydro's Strategic Plan (2023 – 2025), including:

- Preparing for future system requirements through thorough analysis and prudent decision-making;
- Making measured and responsible capital investments;
- Operating a cost-conscious and accountable organization;
- Openly and regularly communicating with stakeholders regarding our operations;
- Strengthening the engagement process with Stakeholders; and
- Improving proactive identification and mitigation of safety risks, monitoring and trending.

The key objective of the Bay d'Espoir Unit 7 Life Extension project is to complete the required work scope by 2028 in order to ensure continued safe and reliable operation while providing the best value to stakeholders.

8.0 Project Success Criteria

The Project will support the 11 strategic goals outlined in Hydro's Strategic Plan (2023-2025); the Project success criteria that support these strategic goals are outlined as follows:

Strategic Goal	Project Success Criteria Supporting the Strategic Goal
Goal 1: Revitalize our Organization	• Execution of all project phases in a transparent and accountable manner that prioritizes information management, access to information, and the duty to document; • Application of corporate and project governance practices to ensure effective project oversight; and • Incorporation of applicable recommendations and/or lessons learned from previous large projects.

Strategic Goal	Project Success Criteria Supporting the Strategic Goal
Goal 2: Deliver Reliable Electricity to our Customers at the Lowest Possible Cost	• Implementation of a regulatory structure to support project success; • Use of a gated decision process to seek approval for all project phases, including Project Sanction; • Use of standard methodologies and good utility practice to determine the best value and justify and document decision-making; • Management of risk through all project phases; • Management of change to achieve an acceptable cost and schedule control; and • Management of quality and use of a Quality Management System to deliver a quality product and ensure future reliability.
Goal 3: Recognize Indigenous History and Strengthen Indigenous Relationships	• Indigenous engagement through all project phases as a part of overall engagement plan for all work scopes in Bay d'Espoir over the next 5-7 years; and • Building opportunities for Indigenous procurement into Hydro's processes.
Goal 4: Engage Who We Serve	• Open and regular communication with stakeholders during all project phases; and • Follow the Public Utilities Board's regulatory processes through all project phases.
Goal 5: Continue to Prioritize the Safety and Health of our Employees	• A Zero Lost-Time Injury Record; • A sustained world-class safety performance during the construction phase; • Incorporation of safety by design; and • Develop a strong safety culture throughout the Project through leadership commitment and employee and contractor engagement and involvement.
Goal 6: Foster Proud and Engaged Teams	• An empowered and skilled project team; and • Clearly defined roles and responsibilities.
Goal 7: Anticipate and Develop our Workforce Requirements	• Employees who are skilled and experienced in the management and execution of large projects, supported by external resources, as needed; and

Strategic Goal	Project Success Criteria Supporting the Strategic Goal
	• Create linkages between project personnel and other Hydro lines of business to build project expertise within the organization.
Goal 8: Support Growth of Renewable Energy Supply	• Life extension of the 150 MW hydro Unit at the Bay d'Espoir Facility.
Goal 9: Advance Electrification and Demand Management	• Life extension of the 150 MW hydro Unit at the Bay d'Espoir Facility.
Goal 10: Optimize the Value of Provincial Energy Resources	• Life extension of the 150 MW hydro Unit at the Bay d'Espoir Facility.
Goal 11: Integrate Renewable Energy Resources in Local Communities	• Employing environmental protection measures during all phases of the Project. • Life extension of the 150 MW hydro Unit at the Bay d'Espoir Facility

9.0 Key Stakeholders

Hydro's shareholders – the people of Newfoundland and Labrador – are the key stakeholder in the Project. Hydro is responsible to develop the Project on behalf of and in the best interest of the people of the Province.

Other stakeholders generally include, but are not limited to:

- Industrial/Commercial customers;
- Bay d'Espoir Operations Team;
- Long Term Asset Planning Team;
- Hydro's Board of Directors;
- Municipalities/communities in the Bay d'Espoir region;
- Indigenous communities;
- Public Utilities Board; and
- Regulatory/environmental agencies;

A robust stakeholder analysis and engagement plan will be completed as part of the planning process. This will be an ongoing process that will be maintained and updated over the Project lifecycle.

10.0 Summary Milestone Schedule

The following milestone schedule is based on preliminary work completed to date, but will be updated as the Project progresses.

- FEP (2024 – Q2 2025);
- FEED (Q1 – Q2 2025);
- Intake and draft tube slot Inspections (Q4 2025);
- Regulatory process and approval (2025);
- Detailed engineering (2026 to 2027);
- Unit inspections during PM9 (2026);
- Procurement (2026 to 2028);
- Construction (Q2 – Q4 2028); and
- Completion, commissioning and turnover to operations (Q4 2028).

A detailed project schedule has been developed and will be updated throughout the various stages of execution.

11.0 Budget

The Project budget has been developed as part of FEP. The budget provided below reflects the project estimate being submitted in the supplementary application to PUB in June 2025. The Base Cost was developed by Hatch subject matter experts ("SMEs") as part of the report on the 2023 Condition Assessment. This estimate was reviewed, and in some cases, updated by Hydro SMEs. Budgetary quotations were obtained from vendors by Hydro. Hydro also used historical information from similar works to inform the estimate. Owner's costs, FEED costs, contingency, escalation and management reserve were then added to calculate the total project cost. In addition, it has been decided to contract the labour for unit disassembly and assembly.

- Total Estimated Cost: $85,346,227

12.0 Constraints and Limitations

Project constraints and limitations have been identified during this phase of FEP. The following is a general list, which will be updated as the project moves into the execution phase:

- Internal and external governance processes (e.g., Board of Directors, Decision Gate approvals);
- Regulatory approval process with the Public Utilities Board;

- Public Procurement Act[1] followed for all procurement activities (e.g., goods and services);
- Internal staffing constraints for activities such as engineering support, permitting and commissioning;
- Availability of hydro turbine generator suppliers and experienced construction personnel;
- [redacted]
- [redacted]
- [redacted]

13.0 Assumptions

Project assumptions will be identified during the execution phase of the Project. The following is a general list, which will be updated as detailed design and planning progresses:

- Unit 7 continues to operate reliably until life extension activities;
- [redacted]
- Project scope and site conditions do not change substantially, leading to a requirement for an Environmental Assessment;
- [redacted]
- [redacted]
- An adequate labour supply is available;
- [redacted]
- The availability of the critical long lead Turbine-Generator items is not materially different from preliminary information provided by OEMs; and
- Critical OEM components can be delivered to the site within the timelines assumed, such that construction works can proceed unhindered.

[1] Public Procurement Act, SNL 2016, c P-41.001.

14.0 Key Risks

Risk	Description
Schedule Risks	• Delays due to demand for long-lead items (e.g., turbine runner, stator bars) [redacted] • [redacted] • Delays in approval to proceed from governing parties, such as Hydro Executive, Public Utilities Board, and regulatory agencies; • [redacted] • [redacted] • [redacted] • Shop availability for refurbishment work; • [redacted] • Unavailability of skilled trades workers; • Unavailability of engineering resources; • [redacted] • [redacted] labour disputes; and • [redacted]
Cost Risks	• [redacted] • [redacted] • Escalation, currency fluctuations, and interest rates exceed projected rates; • Interface issues [redacted] • [redacted] • Competition for skilled trades workers and engineering resources; and • [redacted] contract disputes.
Safety and Environmental Risks	• Safety incidents during construction;

Risk	Description
	• [redacted] • [redacted]
Organizational Risks	• [redacted] • [redacted] labour disputes; • [redacted] • [redacted] • Poorly defined roles and responsibilities; and • Lack of transparency and oversight.

15.0 Project Execution and Management

Hydro's Project Management Team will be responsible for project execution and management, with authorization as identified in the Major Projects Governance Charter. The Project Management Team will engage consultants and contractors via the appropriate contractual arrangements consistent with the selected project delivery model. The Project Management Team will maintain overall control of the Project—managing budget, schedule, risk, and changes in accordance with sound industry practice.

Schedule 1, Attachment 3

Basis of Schedule

newfoundland labrador hydro

Bay d'Espoir Unit 7 Life Extension

Basis of Schedule

NLH Doc. No. BDE-NLH-40000-PL-BOS-0002-01

Comments: The Bay d'Espoir Unit 7 Life Extension Project Basis of Schedule documents the basis and assumptions underpinning the Bay d'Espoir Unit 7 Life Extension Project Control Schedule. It documents the initial execution intent, sequence, and assumptions at a point in time.	**Total # of Pages (including Cover): 27**
This document contains confidential and commercially sensitive information. Access to this report and the information contained within is restricted and should only be shared with the written approval of the Manager of Project Controls for Major Projects.	

B0	2-Jun-2025	Use	Gary Davis	Tony Scott	Mark Howell	Marc Cullen
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Sr. Project Planner, Major Projects	**Approved By** Manager, Project Controls, Major Projects	**Approved by** Project Manager, BDE Unit 7 Project	**Approved by** Program Manager, Major Projects

These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

hydro (newfoundland labrador)	Bay d'Espoir Unit 7 Life Extension Basis of Schedule				
NLH Doc. No.	**BDE-NLH-40000-PL-BOS-0001-01**	**Revision**	**B0**	**Page**	**i**

Additional Approvals

Additional approvals are required for further authorization due to document contents, complexity, prescribed requirements, or multi-departmental involvement.

Position	Name	Signature	Date (DD-MMM-YYYY)
Director, Major Projects & Asset Management	Gail Randell	[signature]	04-JUN-2025
Senior Manager, Major Projects PM & Engineering	John Walsh	[signature]	4-JUN 2025
Senior Manager, Major Projects Commercial	John Skinner	[signature]	04-Jun-2025

Endorsements

Endorsements indicate support or acknowledgement of this document's contents but do not imply formal approval. Endorsements are used to represent subject matter experts who have provided input but do not hold final decision-making authority for this document.

Position	Name	Signature	Date (DD-MMM-YYYY)
Lead Engineer, BDE Unit 7 Life Extension Project	Richard Severs	[signature]	4-Jun-25
Team Lead Project Controls Major Projects Management	Bethany Cutler	[signature]	04-Jun-2025
Project Manager, BDE Unit 8 Project	Stephen Parsons	[signature]	4-JUN-2025

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Attachment 1: Bay d'Espoir Unit 7 Project – Project Control Schedule

Attachment 2: BDEU7 Project Control Schedule – WBS Structure

1.0 Executive Summary

Unit 7 at the Bay d'Espoir Hydroelectric Generating Facility (BDE) is a 154.5 MW vertical Francis hydroelectric unit located in Powerhouse 2. The unit is comprised of a generator and turbine assembly with the capability to generate as well as act as a synchronous condenser as required to meet system requirements.

In 2023, a condition assessment was conducted by Hatch Ltd. to develop a plan to correct issues identified during refurbishment work done in 2019. The assessment concluded that refurbishment and replacement work were necessary to ensure the reliable long-term operation of the unit.

The BDE Unit 7 Life Extension Project (BDE Unit 7 Project) has been proposed by Newfoundland and Labrador Hydro (Hydro) to complete the work required to address the recommendations in the condition assessment report, as well as recommendations from Hydro's Long-Term Asset Planning (LTAP) Team. To support this project, Hydro has assembled a Project Control Schedule (PCS) to validate and plan a successful life extension campaign that includes activities from the initial engineering, through procurement, construction, and final commissioning and unit energization. This document provides the basis for the full PCS.

2.0 Terms and Definitions

The following terms and definitions provide clarity on key terms and concepts used throughout the document.

Term	**Definition**
Agreement	Also referred to as a purchase order or commitment. Means a legal agreement that binds a party to a financial commitment and/or obligation with another party that provides goods, services, equipment, or materials with a desired delivery time and with specific quantities and processes.
AACE	Association for the Advancement of Cost Engineering International. An international industry organization that publishes many Recommended Practices to aid in guiding project management professionals in many aspects of project execution. The AACE Recommended Practices provide useful guidance but are not standards.
Basis of Schedule	A companion document to the Control Schedule that explains, in narrative form, the Control Schedule as well as the various assumptions made in developing the schedule and planning the project. The Basis of Schedule is sometimes called the Control Schedule Baseline Document or Schedule Basis Memorandum.
BDE	Bay d'Espoir Hydroelectric Generating Facility
Contractor	Any Vendor, Manufacturer, Supplier, or Consultant who enters into an Agreement with Hydro for the supply of goods or services.

Term	Definition
CS	Control Schedule. See Project Control Schedule (PCS).
CSBD	Control Schedule Baseline Document. See Basis of Schedule (BOS).
EA	Environmental Assessment.
FEP	Front-End Planning. A stage in project planning that includes project execution planning, environmental management planning, FEED, supply chain management planning, and construction planning.
FEED	Front-End Engineering and Design. A major part of FEP; It includes sufficient field investigations and engineering to establish a contracting strategy and Class 3 cost estimate.
FEP	Front-End Planning. A stage in project planning that includes project execution planning, environmental management planning, FEED, supply chain management planning, and construction planning.
Hydro	Newfoundland and Labrador Hydro and/or a subsidiary.
LTAP	Long-Term Asset Planning
MP	Major Projects Department of Hydro.
OEM	Original Equipment Manufacturer
P6	Oracle Primavera Project Planner Version 6. The preeminent project planning software application used in North America for large engineering and construction projects. Hydro currently uses Release 21 of this application.
PCS	Project Control Schedule. The project schedule, developed at a control level, is used to plan project execution, monitor its performance, and make execution decisions. Also called a Control Schedule (CS).
PUB	Public Utilities Board.
RFP	Request for Proposals.
SBM	Schedule Basis Memorandum. See Basis of Schedule (BOS).
TF	Total Float. A key component of the Critical Path Method schedule technique. Total Float is a measurement of how much an activity can be delayed without impacting project completion.
T&G	Turbine and Generator. A device that utilizes mechanical energy to generate electrical energy. The turbine is driven by water, causing it to rotate. This rotational motion is transferred to the generator, which uses electromagnetic induction to produce electricity.
WBS	Work Breakdown Structure

3.0 Reference Documents

The following is a list of documents that are either referenced in this Bay d'Espoir Unit 7 Basis of Schedule or are relevant to the subject matter contained within.

Document Reference	Title
AACE RP 38R-06	Documenting the Schedule Basis[1]
AACE RP 91R-16	Schedule Development[2]
COP-AWP-PBP-01-2016-v1	Advanced Work Packaging/WorkFace Planning: A Best Practices Guide[3]
BDE-NLH-00000-EN-REP-0001-01	Bay D'Espoir Unit 7 Condition Assessment Condition Report[4]
BDE-NLH-40000-ES-BOE-0002-01	Bay d'Espoir Unit 7 Life Extension Basis of Estimate

4.0 Purpose

The purpose of this Basis of Schedule is to document the basis and assumptions underpinning the BDE Unit 7 PCS. This document and the PCS are meant to be complementary and read together.

This Basis of Schedule documents the current execution intent, sequence, assumptions, risks, and opportunities developed during the FEP phase of the project. Further project execution maturity, including design development, authorization timeline changes, execution strategy changes, scope modification, or construction contractor execution optimizations, may require updates of the PCS as well as this Basis of Schedule.

5.0 Schedule Structure

5.1.1 Tools/Applications

The PCS is prepared in P6. Future Contractor tools and applications are unknown at this point; however, contractual arrangements will require the use of industry-typical applications, nominally P6 or equivalent. Exceptions to P6 have to be accepted by Hydro. This is a standard approach on Major Projects to ensure the quality of contractor schedule data.

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[1] AACE International. (June 18, 2009) Recommended Practice 38R-06, *Documenting the Schedule Basis*. <https://www.pathlms.com/aace/courses/2928/documents/3823>.
[2] AACE International. (August 13, 2020) Recommended Practice 91R-16, *Schedule Development*. <https://www.pathlms.com/aace/courses/2928/documents/9508>.
[3] "Advanced Work Packaging/WorkFace Planning: A Best Practices Guide," Construction Owners Association of Alberta, Version 1, July 2016. <https://coaa.ab.ca/wp-content/uploads/2022/09/COP-AWP-PBP-01-2016-v1-Advanced-Work-Packaging-Summary.pdf>.
[4] "Bay D'Espoir Unit 7 Condition Assessment Condition Report," Hatch Ltd, May 3, 2024.

5.1.2 Schedule Structure

The BDE Unit 7 PCS, provided as Attachment 1 to this Basis of Schedule, was built by incorporating supplier and OEM information, with historical data from other projects completed for Hydro (that were similar in scope). The PCS contains activities that develop a full project view of the scope, they are categorized as: deliverables for project management, procurement activities to secure vendor for the BDE Unit 7 Project scope, procurement/fabrication activities associated with new components to be installed, activities to secure a contractor to support the commissioning of the refurbished Turbine Generator, and construction activities to map out the construction steps required for successful project completion. The PCS also contains activities related to the regulatory process that are required to execute this project. These activities track and forecast the project's progression through phases structured to follow the Major Projects Approval Process, illustrated in Figure 1.

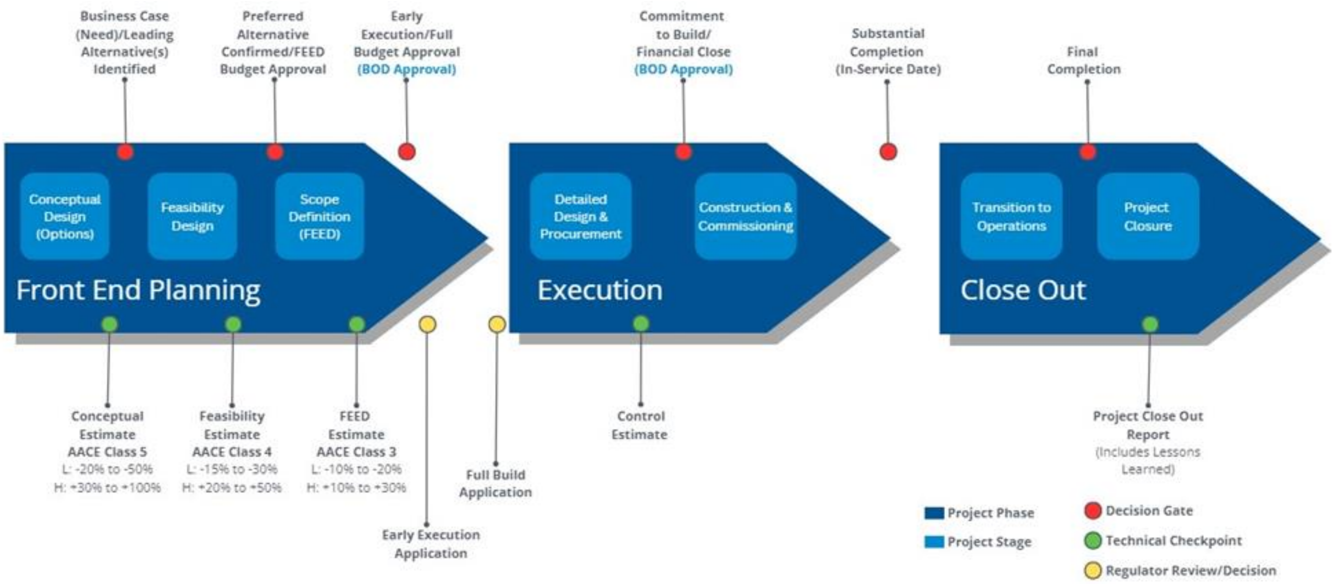

Figure 1: Major Projects Phased Approval Process

This phased definition of the BDE Unit 7 Project's life cycle has been summarized in the BDE Unit 7 PCS-WBS Structure, provided as Attachment 2 to this Basis of Schedule. Table 1 provides a summary of the Schedule Structure at the Level 1 and Level 2 WBS levels; Figure 2 shows the schedule summarized to the same levels. A full Schedule WBS listing is provided in Attachment 2.

Table 1: Schedule Structure

WBS Level 1	WBS Level 2	Items/Description
Milestones	Unit 7 Project Milestones	Start and finish milestones marking key project-specific activities from the schedule. These will be expanded to include select contractual dates.

WBS Level 1	WBS Level 2	Items/Description
	External Interface Milestones and Activities	Activities of interest to the BDE Unit 7 Project that are being executed by other projects. These activities/milestones will be monitored to ensure any opportunities are realized.
FEP	Hydro Project Management/Preparation for Execution	Activities related to the FEP stage of the project. Hydro documents and studies. Progressing the project towards Project Sanction and the Execution Phase.
Regulatory	PUB	Activities related to the PUB Application.
Execution	Procurement/Engineering	Activities associated with the procurement process of the project. These activities include Engineering support and Contractor Engineering post Contract Award. The activities under this heading are related to securing required material and/or services to support the Construction phase of the project.
	Construction	Activities to reflect the Construction phase of the project. This section includes activities for Contractor mobilization to site, Unit 7 disassembly, refurbishment, and reassembly. Logic links have been established with the procurement section of the schedule, as required.
	Commissioning	Activities to forecast the required steps and process for a successful Unit 7 restart / ready for Commercial Operation.
Closeout	Closeout	In this schedule, the Execution Phase ends with the "Unit 7 – READY FOR COMMERCIAL OPERATIONS." The Close-Out Phase contains the activities associated with documentation close-out (As-Built), lessons learned, and a final "Post Implementation Report."

[redacted]

Figure 2: BDE Unit 7 Schedule at Level 1 and Level 2 WBS Summary

5.1.3 Calendars

P6 allows for the creation of activity calendars to model various aspects of the work execution. P6 Calendars have several purposes. In the case of the BDE Unit 7 PCS, P6 Calendars are being used for activity scheduling. The calendars will define when work can take place for an activity; they identify working days and non-working days, such as weekends and statutory holidays. The non-working days can include holiday breaks or periods when work should be avoided, e.g., scheduling in-service commissioning work during the winter readiness period. For this example, a calendar would be used to restrict the work to occur outside of the winter readiness period, when system conditions would allow for such an activity to commence.

For the Bay d'Espoir Unit 7 PCS, the following calendars and their use are described in Table 2.

Table 2: Schedule Calendars

Schedule Calendar	Application
MP – 7 Day Calendar	Reflecting a 7-day work week, also referred to as "Calendar Days". This is the calendar used for procurement activities, regulatory activities, and milestones. The 7-day calendar ensures that the summary milestone directly reflects the date from the predecessor and is used in instances when an activity duration is referenced in calendar day durations (Procurement and Regulatory)
MP – Internal – 5D x 7.5 hrs	The Major Projects Internal (Hydro) office execution calendar reflects a 5-day work week, with a 7.5-hour working day. Statutory holidays are excluded from workdays, and a [redacted].
MP – Construction – [redacted]	The Construction execution calendar reflects a [redacted], exclusive of meals or breaks, and a [redacted]. Used for Construction and Commissioning activities.
MP – BDEU7 [redacted]	The BDEU7 Construction Specific Calendar reflects a working schedule of [redacted]. This is used for critical work that is time sensitive, [redacted].

5.1.4 Application-Specific Calculation Methods

The schedule uses the Retained Logic method of schedule calculation. The TF method is used to determine the project's Critical Path; the criteria used is the default method where TF <= 0 is considered critical. The TF is determined based on the activity predecessor calendar and is calculated as Finish Float.

These are the application's default settings and will be used for schedule management and reporting.

6.0 Schedule Development Basis

The Bay d'Espoir Unit 7 Project is a multi-year, multi-phase project that encompasses several large, discrete scopes of work that all combine to form the project. The construction schedule was developed in a manner that allows for a clear logic path to define the forecast date for "Acceptance for Commercial Operation." The high-level preliminary project plan for the BDE Unit 7 Project includes:

- Approval by the PUB in Q4 2025;
- Preliminary engineering in 2025, to support long lead equipment procurement;
- Detailed engineering and manufacturing for the components identified for replacement or refurbishment during the BDE Unit 7 Project; and

- Construction and commissioning from Q1 2028 to Q4 2028.

Completing the BDE Unit 7 Project in 2028 reduces the risk of unplanned outages to the unit and associated system impacts. Importantly, completion in 2028 aligns with the 5-year recommendation set out in Hatch's Bay d'Espoir Unit 7 Condition Assessment Condition Report, supporting responsible life cycle management and system reliability. If BDE Unit 8 is approved, there will be interdependencies with the construction of BDE Unit 8. The execution of the BDE Unit 7 Project must be completed by the end of 2028. Delays beyond this would introduce overlapping work in Powerhouse 2, leading to productivity and scheduling challenges, including shared access to the overhead crane, laydown space, and tailrace channel. The sections that follow provide an overview with a listing of assumptions, issues, risks, and opportunities by each Phase/Schedule WBS heading of the project.

6.1 Milestones

6.1.1 Overview

This section of the schedule is used to summarize key events and activities for quick reference. The milestones will reflect the dates from the detailed activities in the other phases of the schedule. As these summary milestones reflect the schedule logic, all milestones in this section of the schedule will utilize a 7-day calendar. The listing of milestones will be determined by the BDE Unit 7 Project Manager. They can be added/modified as required to ensure proper visibility of key events.

There is a heading for External Interfaces, to provide a reference to activities being completed by other planned projects that could present an opportunity for the BDEU7 Project. There is an Intake and Draft Tube Condition Assessment forecasted for completion in October of 2025. This activity is being completed as part of a capital project managed by Hydro's Regulated Engineering Department. This could lead to an independent project to be completed during the BDEU7 2028 outage.

A listing of the current milestones is shown in Figure 3.

[redacted]

Figure 3: BDE Unit 7 Schedule Milestone Listing

6.1.2 Assumptions

As the Milestone listing is a summary of details contained in the schedule, there are no schedule assumptions in this section of the schedule.

6.1.3 Risks/Opportunities

As the Milestone listing is a summary of details contained in the schedule, there are no Risks or Opportunities in this section of the schedule.

6.2 Front-End Planning

6.2.1 Overview

The FEP Phase contains the activities associated with the first stages of the project. For the BDE Unit 7 Project, the FEP phase contains activities that are used to track internal deliverables created by the

Major Projects Department. These deliverables are required to provide clarity of scope definition, increase cost and schedule certainty, and to progress the project through to the Execution Phase.

6.2.2 Assumptions

The project scope has been developed based on a condition assessment inspection completed by Hatch in 2023. Hydro reviewed the Condition Assessment Report as well as asset maintenance records to develop a Basis of Design, including a project scope statement and expectations for the life extension work to ensure the desired life extension of the unit is achieved.

6.2.3 Risks/Opportunities

As the FEP stage is essentially complete, with all deliverables well defined, there are no significant schedule issues, risks, or opportunities for this stage of work. If there were slight delays in issuing the final FEP deliverables, the schedule has the ability to absorb these changes without affecting overall project timelines.

6.3 Regulatory

6.3.1 Overview

The BDE Unit 7 project is subject to PUB Supplemental Application review and approval.

6.3.2 Assumptions

The assumptions of the Regulatory phase of the schedule related to the PUB review and approval process are:

- PUB Supplemental Application in Q2 2025
- PUB Approval in Q4 2025

As this project is within an existing Hydro facility, another assumption is that there are no external government permits associated with this project that would affect the start of construction. Any permits/approvals associated with material disposal will be the responsibility of the construction contractor and will not affect construction/project completion activities.

6.3.3 Risks/Opportunities

6.3.3.1 Risks

Regulatory approvals could take longer than assumed, which could negatively affect the project timeline, including impacting the planned seasonality of the construction work. This, in turn, could have a significant impact on project cost and schedule.

6.3.3.2 Opportunities

If regulatory approvals are granted more quickly than assumed, this may present opportunities. If this were to occur, there would need to be an evaluation as to the potential schedule opportunity that may be gained, as there is a necessary sequence and timeline for other elements of work (e.g., design and procurement). This means that any changes in the regulatory timelines may not directly translate into that exact change in the final project timelines.

6.4 Execution

6.4.1 Overview

The execution phase of the schedule contains activities for Procurement/Engineering, Construction, and Commissioning. These activities will be managed by Hydro or by the Contractor, with more detail to be added post-Contractor selection.

6.4.1.1 Procurement

The procurement activities reflect the strategy to develop the required technical specification and then engage with a T&G OEM to dismantle the turbine and generator, inspect, and replace or refurbish the components and reassemble, upgrade unit controls and governor controls, and commission the unit. In addition to the RFP process for securing the T&G OEM, there will also be a procurement process for upgrading Exciter Controls, consumables for the reassembly of existing equipment, and securing commissioning support to assist with the final commissioning and start-up.

Once the T&G OEM scope has been contracted, there are schedule headers and activities that outline the key items that will have to be progressed by the T&G OEM. These activities are currently placeholders and will be expanded with details and targets as outlined in the contract with the T&G OEM. The durations contained in the current PCS for T&G Engineering and Manufacturing are based on information provided by [redacted] and by professional experience from the BDE Unit 7 Project's Lead Engineer. PCS durations for the Exciter supply and installation, and the Governor and Unit Controls work are supported by the project team members' experience from the Churchill Falls and Muskrat Falls Projects.

6.4.1.2 Construction

The construction activities commence with the T&G OEM Contractor mobilization site to commence field work as soon as possible in 2028. The schedule is built using the basis that Unit 7 can only be taken off-line during the non-winter load period (April 1 to October 31). The existing Unit will be disassembled, and parts requiring refurbishment will be shipped off-site, with a standard assumed refurbishment and return shipment duration of [redacted]. The schedule for the rebuild of the unit, including the Stator rewind, has been logically linked to ensure that the delivery of the new equipment and refurbished pieces are received at site and installed in the correct sequential order.

As the Stator rewind will be the most time-intensive period, [redacted]. This is based on the Lead Engineer's experience with similar projects and accepted industry norms.

Durations for construction activities have been based off of actual recorded information obtained from daily reports from several recent Hydro projects: The BDE Unit 7 Turbine Refurbish (2019) for the Disassembly and Reassembly scopes; Refurbish Generator Rotor – Hinds Lake for the Rotor Pole durations (daily report durations were adjusted to reflect the difference in the number of poles between

Hinds Lake Generator and BDE Unit 7); and Rewind Unit 6 Stator – Bay d'Espoir for the stator rewind durations (daily report durations were adjusted to reflect the difference in size between Unit 6 (75 MW) and Unit 7 (150 MW)).

There are also placeholder activities for Auxiliary (potential) Work. These are activities that, if required, will be scheduled into the program at an appropriate time, but these activities are not critical / driving activities. This represents an opportune work scope that will be executed as it is practical to do so, but without jeopardizing the core planned scope.

6.4.1.3 Commissioning

Commissioning activities commence once the reassembly of Unit 7 has been completed. There will be mechanical tests, followed by tuning of the Exciter and Governor; after which, the load testing and protection test will be conducted. Durations for the commissioning phase are based on the previous experiences of the Lead Engineer.

6.4.2 Assumptions

Assumptions for the execution phase will be outlined by each heading of Procurement/Engineering, Construction, and Commissioning.

6.4.2.1 Procurement/Engineering

There are a number of key procurement/engineering assumptions that underpin the construction phase of the works. These include:

- Initial procurement activities can commence before full PUB Project release.
- The design will be based on an existing OEM runner design and Computational Fluid Dynamics modelling. The planned execution of the work in 2028 does not permit sufficient time to execute a turbine model test. Foregoing the turbine model test will not have a measurable effect on the turbine performance.
- Design and drawings for the runner will begin immediately after the successful OEM is selected, as will the fabrication/purchasing of material for the runner.
- Estimated durations provided by potential OEM Contractors remain valid; the duration used in the schedule is summarized in Table 3.

Table 3: Hydro Procurement Activity Lead Times for BDE Unit 7 Project Components

Item	Lead Time
Runner	[redacted]
Stator bars, circuit rings and installation materials	
Spare stator bars	
Spare rotor pole	
Bottom ring	
Operating ring	

Item	Lead Time
Turbine guide bearing and shaft seal	[redacted]
Turbine pit hoist	[redacted]
Brake dust collection system	[redacted]
Electronic governor	[redacted]
Unit Controls	[redacted]
Exciter Controls	[redacted]

6.4.2.2 Construction

There are a number of key assumptions that underpin the construction phase of the works. These include:

- All access roads and bridges necessary to bring the equipment to the site are, and will be, in acceptable condition, with no load deratings in place.
- The estimated durations are based on actual daily reports from previous projects. [redacted]
- [redacted]
- [redacted]
- Critical OEM components can be delivered to the site within the timelines assumed, such that construction works can proceed unhindered
- If the BDE Unit 8 Project is approved, there is an opportunity[6] [redacted]

6.4.2.3 Commissioning

There are a number of assumptions made with respect to the commissioning of Unit 7, as part of the BDE Unit 7 Project:

- The battery of commissioning tests, including load rejection tests, will be completed to test all equipment that is part of the BDE Unit 7 Project.
- It is assumed that all commissioning testing will be completed successfully, and there is no requirement for rework or retesting.

[5] This assumption will be removed when the OEM Contractor is selected and detailed construction schedules are provided.

[6] [redacted]

- Commissioning tests and grid synchronization will be permitted to be performed once the work is completed, even if the work extends into the winter period.

6.4.3 Risks/Opportunities

6.4.3.1 Risks

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- Unexpected issues in Hydro's system preventing the BDE Unit 7 shutdown required for executing the work in the required window.
- Suppliers/OEMs experiencing a period of high demand for services.

6.4.3.2 Opportunities

- Execution Strategy: [redacted]

7.0 Overarching Critical Path

The overarching critical path for the BDE Unit 7 Project is calculated to occur through the 2028 construction season, which has the basis that BDE Unit 7 can only be taken offline during the non-winter load period (April 1 to October 31). [redacted]

[redacted]

[redacted]

Figure 4: BDE Unit 7 Project Critical Path

8.0 Schedule Contingency/Schedule Reserve

[redacted] The PCS contains deterministic information, [redacted]

9.0 PCS Updates/Revisions

The PCS will be updated/revised at key points throughout the project life cycle. The following are known times when the PCS will be updated:

- [redacted]

There may be other instances when the PCS will have to be updated; however, these instances will only be allowed utilizing the project's change management process and with Senior Management approval.

Bay d'Espoir Unit 7

Basis of Schedule

Attachment 1: Bay d'Espoir Unit 7 Life Extension Project Control Schedule

REDACTED
IN FULL

Bay d'Espoir Unit 7

Basis of Schedule

Attachment 2: Bay d'Espoir Unit 7 Project Control Schedule – WBS Structure

BDE Unit 7 Project Control Schedule - WBS Structure

WBS Code	WBS Name	Total Activities
BDEU7_MP_PCS-BL	BDE Unit 7 Project Control Schedule - BASELINE	202
BDEU7_MP_PCS-BL.MS+KD	Milestones	19
BDEU7_MP_PCS-BL.MS+KD.1	Unit 7 Project Milestones	18
BDEU7_MP_PCS-BL.MS+KD.2	External Interface Milestones and Activities	1
BDEU7_MP_PCS-BL.FEED	Front End Planning (FEP)	15
BDEU7_MP_PCS-BL.FEED.FE Exec	Hydro Project Management / Preparation for Execution	15
BDEU7_MP_PCS-BL.Reg	Regulatory	3
BDEU7_MP_PCS-BL.Reg.Reg Prep	PUB	3
BDEU7_MP_PCS-BL.Exe	Execution	162
BDEU7_MP_PCS-BL.Exe.PROC	Procurement	50
BDEU7_MP_PCS-BL.Exe.PROC.Engr	Engr - Tech Spec Support	1
BDEU7_MP_PCS-BL.Exe.PROC.TGRef	Turbine & Generator Unit Life Extension RFP Development	7
BDEU7_MP_PCS-BL.Exe.PROC.TGRef.techspec	Technical Specification Development	3
BDEU7_MP_PCS-BL.Exe.PROC.TGRef.RFP	RFP - Bid, Evaluate, Award	4
BDEU7_MP_PCS-BL.Exe.PROC.RRS	Turbine and Generator Scope	29
BDEU7_MP_PCS-BL.Exe.PROC.RRS.Runner	Runner	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.Stator	Stator bars, circuit rings and installation materials	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.SSB	Spare Stator Bars	2
BDEU7_MP_PCS-BL.Exe.PROC.RRS.SSP	Spare Rotor Pole	2
BDEU7_MP_PCS-BL.Exe.PROC.RRS.BR	Bottom Ring	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.OR	Operator Ring	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.TGB	Turbine Guide Bearing and Shaft Seal	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.TPH	Turbine Pit Hoist	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.BDC	Brake Dust Collection System	3
BDEU7_MP_PCS-BL.Exe.PROC.RRS.EG	Electric Governor	2
BDEU7_MP_PCS-BL.Exe.PROC.RRS.CNTR	Unit Controls	2
BDEU7_MP_PCS-BL.Exe.PROC.ECP	Exciter Control Panels	5
BDEU7_MP_PCS-BL.Exe.PROC.POs	OEM Consumables (from Andritz)	4
BDEU7_MP_PCS-BL.Exe.PROC.POs.BP	Brake Pads	1
BDEU7_MP_PCS-BL.Exe.PROC.POs.GTGBPS	Generator Thrust & Guide Bearing Pads and Springs	1
BDEU7_MP_PCS-BL.Exe.PROC.POs.Seal	Seals for reassembly HC, BR, and WG's	1
BDEU7_MP_PCS-BL.Exe.PROC.Comm	Commissioning Support	4
BDEU7_MP_PCS-BL.Exe.Constr	Construction	106
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BDEU7_MP_PCS-BL.Exe.Constr.Co.Mob	Mobilization	1
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BDEU7_MP_PCS-BL.Exe.Constr.Co.Rot	Rotor Poles	10
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BDEU7_MP_PCS-BL.Exe.Commiss	Commissioning	6
BDEU7_MP_PCS-BL.CLOSE	CLOSE OUT	3

Schedule 1, Attachment 4

2019 Voith Report

newfoundland labrador hydro

VOITH

Bay d'Espoir – Newfoundland and Labrador Hydro		
Unit 7 Refurbishment Report Project Report	TFS7000	
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Bay d'Espoir

A Newfoundland and Labrador Hydro Power Station

Unit 7 Refurbishment Report

Final Project Report

Rev.	Page	Description	Created by	Released by	Date
A					
B					
C					
D					
E					
F					

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1 Revision

1.1 Revision History and Description

- Rev-
  - Original Release of Unit 7 Refurbishment Report: 2TFS70-0000-10066279
- Rev A **(N/A)**
  -
- Rev B **(N/A)**
  -
- Rev C **(N/A)**
  -
- Rev D **(N/A)**
  -
- Rev E **(N/A)**
  -
- Rev F **(N/A)**
  -

2 Bay d’Espoir Generating Station

2.1 Background

The Bay d’Espoir Generating Station resides in St. Veronica’s, Newfoundland, which is located in the central part of the province. The headwaters of the Bay d’Espoir system begin at Victoria Lake, which is approximately 150 km from the water’s final destination of Bay d’Espoir. From Victoria Lake the water is directed through a series of hydroelectric dams and canals. The water is collected, stored, and diverted from many reservoirs on its journey to the Bay d’Espoir Generating Station, at which point the powerhouse’s seven vertical turbines harness the energy of the water and convert it to electricity for all of Newfoundland and its surrounding areas to use. The Bay d’Espoir Generating Station is a part of a team of powerhouses with Granite Canal and Upper Salmon upstream. Combined, these three hydroelectric power plants provide nearly 75 percent of the hydroelectric power generated on the island (NLH, 2017).

The construction of the generation station began in 1964 with the first two of seven units coming online by 1968. The project took 12 years to complete. The generating station comprises of two powerhouses: one with six, 80 megawatt machines, and the second with the largest Bay d’Espoir generator, which produces 150 megawatts and was the last unit to be commissioned in 1977. The six smaller units in Powerhouse One have been rehabilitated over time, with major runner and generator upgrades. In Powerhouse Two, the much larger 150 MW machine has had routine and preventative maintenance performed on it, but no major outage or rehabilitation (NLH, 2017).

Figure 2-1: Bay d’Espoir Generating Station (NLH, 2017)

3 Introduction

3.1 Powerhouse Observations and History

Over the last two decades Newfoundland and Labrador Hydro (NLH) has been monitoring the reduction of the Radial Seal Clearance (RSC) between the rotating and stationary components. Specifically, the clearance between the Runner Wearing Rings (rotating) and both the Head Cover and Bottom Ring Wearing Rings (stationary). Over time NLH has recorded the clearances and the data reflects an increase in seal clearances in one axis and a decrease in the other perpendicular axis. In Powerhouse One, NLH observed and recorded an increase in radial seal clearance in the Upstream and Downstream axis, while a reduction in the seal clearance in the A2/A1 axis, which is perpendicular to the Upstream axis. NLH diligently monitored the changing seal clearance and started to plan for an intervention to remedy the issue. NLH planned to intervene to limit the risk of the damage to their machine if the seal clearance became critical enough to allow the Runner to contact the stationary Wearing Rings.

The exact reason the seal clearances changed can be hard to determine, but different hydroelectric agencies across North America have conducted research and concluded that the phenomenon can possibly be due to one of the following outlined in Part V of the Canadian Electricity Association's (CEATI) Guide for Erection Tolerances and Shaft System Alignment. In the Guide, CEATI reveals that the concrete of the powerhouse substructure and the foundation of the machine may not be perfectly stable over time. The instability effects include, but are not limited to, the following four causes: (1) Heat production during the curing of the concrete, which start the day the concrete is poured and can last for up to a year after the forms are removed. (2) Concrete growth due to a phenomenon called Alkali-Aggregate Reaction, which is related to the choices of aggregate, cement, and water content during construction of the powerhouse and machine foundation. The occurrence of this reaction may be long-term, lasting 30 to 60 years, and may cause the stationary embedded components to move and change shape, ultimately causing designed clearances and dimensions to change. (3) Seasonal substructure thermal impacts due to changes and fluctuations in the temperature of water passing through the turbine combined with cyclical changes of the ambient temperature. (4) Long term creep due to sustained loads applied to the powerhouse substructure and foundation by the machine's components, or the natural movement that may occur from the main dam (CEATI, 2008). All of the effects described by CEATI can lead to a change in the design tolerances of the machine, which requires intervention by the Owner to alleviate the issue(s).

In 2016 NLH removed Unit 4 in Powerhouse One from service, disassembled the unit, and Voith (VH) machined the Lower Wearing Ring of the Bottom Ring to increase the radial seal clearance between the stationary and rotating parts. Following the commissioning of Unit 4 in the summer 2017, NLH removed Unit 3 from service and performed similar tasks to remedy the clearance issues. NLH followed up the commissioning of the Unit 3 machine with the disassembly of Unit 2 in 2018. During the Unit 2 outage NLH employed similar repair and maintenance tasks that were performed on the Unit 3 and 4. After the successful assembly of Unit 2, the machine was commissioned later that year in 2018. During these outages, the work extended beyond the wearing ring issue that Voith was tasked with repairing, such as, performing preventative maintenance and inspections on wear parts. The additional work included some new and rehabbed components, such as: Laser Inspection, Head Cover and Bottom Ring Bushings, Turbine Guide Bearing, Wicket Gate machining, and cavitation repair. Upon completion of the 2017 outage, Voith submitted a Refurbishment Program Plan (VHY-1, 2017). This refurbishment report was created to assist NLH with future maintenance activities, highlighting and recommending components that will need attention over the next 25 years.

3.2 2019 - Unit 7 Planned Maintenance Outage Outline

Once Unit 3 was commissioned in 2017, NLH evaluated the Unit 7 machine, which is located in Powerhouse Two, and measured significant changes in the radial seal clearance between the stationary and rotating parts of the turbine. These changes in radial seal clearance varied depending upon which axis was being evaluated. The Upstream/Downstream axis showed a significant decrease in clearance, edging near the critical value of intervention that CEATI outlines in Part V of their maintenance guide (CEATI, 2008). However, the opposite was true for the axis perpendicular to Upstream (A2/A1), in which the radial seal clearance measured very high. According to CEATI’s maintenance guide, the measured radial seal clearance was higher than the maximum recommended, putting the state of their machine between the “required intervention” and “critical” values. With this information and using the 2017 recommendations provided in the Voith Refurbishment Program Plan, NLH developed a plan and determined the Unit 7 machine warranted attention and scheduled an outage for 2019.

3.3 Planned Project Activities

Based on the experience of past outages and using the recommendations Voith provided, NLH planned to perform the following activities:

- Take critical readings of the machine prior to dismantling (NLH);
- Disassemble the unit (NLH);
- Perform High-Precision Dimensional Surveys and Analyses (Voith) of the following systems/components:
  - Head Cover including:
    - Wearing Ring, Mating Stay Ring Flange, and Bushing Sockets;
  - Wicket Gates;
  - Turbine Shaft including Couplings;
  - Generator Shaft including Couplings;
  - Stator;
  - Rotor Poles and Coupling;
  - Runner including Wearing Rings;
  - Bottom Ring including:
    - Wearing Ring and Bushing Sockets;
- Lead abatement of preselected components to facilitate the planned work, such as NDE, grouting, and machining (Voith);
- Non-Destructive Examination (Voith) on the following components:
  - Head Cover;

- Wicket Gates;
- Stay Vane Connections to Upper and Lower Ring;
- Bearing Babbitts of:
  - Turbine Guide;
  - Thrust;
  - Generator Guide;
- Concrete Grouting Draft Tube (Voith);
- Wicket Gate Refurbishment (Voith):
  - Machining of Lower and Intermediate Gate Stems;
  - Grease Hole Plugging;
- In-place machining of Bottom Ring Wearing Ring (Voith);
- Line boring of Head Cover and Bottom Ring Bushing Sockets, if necessary (Voith);
- Replace Runner Band Wearing Ring, if necessary (Voith);
- Head Cover Wearing Ring machining, if necessary (Voith);
- Replacement of Lower and Intermediate Gate Stem Bushings with greaseless bushings (NLH);
- Reassembly of the Unit 7 machine (NLH);
- Mechanical Commissioning (Voith).

3.4 Project Objectives

The objectives of the project were:

- Restore the Lower Primary Ring Seal Clearance between the Runner Band Wearing Ring and Bottom Ring Wearing Ring to within OEM tolerance;
- Improve environmental friendliness of the unit by converting the Lower and Intermediate Wicket Gate Bearings from a greased brass bushing design to a greaseless design and;
- Extend the life of unit components to facilitate trouble-free operation.

4 Report

4.1 Scope of the Report

This report provides a complete summary of all of the activities described in the Voith contract, in detail. The report was formatted to describe the work as completed in chronological order. The report also takes into account the work performed by the Owner; however, the Owner's tasks are less detailed since Voith had limited involvement. Within the technical body of the report, each aspect of Voith's contractual obligation is described. The details of each task along with all of the dimensional/visual inspection results, NDE results, immediate recommendations, analysis/calculations, conclusion, and recommendation for future rehabilitation are provided within this report. NOTE: All dimensions are imperial units unless noted otherwise.

The typical section outline is:

- **Part-by-Part Assessment and Recommendations Format**
    - o Description of part and the work planned;
    - o High Precision Laser Inspection/Dimensional Inspection;
    - o Visual Inspection;
    - o Non-Destructive Examination, if applicable;
    - o Evaluation/In-progress Recommendation/Discussions/Owner Decision;
    - o Work Performed;
    - o Conclusion;
    - o Long term Recommendations (Separate Section)
    - o Appendix References

4.1.1 Recommendation Framework

All of the recommendations provided by Voith during the 2019 Bay d'Espoir outage were based upon the following understanding Voith agreed to with NLH. After the Unit 7 machine was disassembled, it was apparent that machine had mechanical issues and signs of severe wear beyond what was expected during the planning stages of the outage. After discussing matters internally within NLH, and reviewing the initial (as-found) condition of the machine with Voith, the following was agreed upon:

- *The recommendations Voith provides to Newfoundland and Labrador Hydro were now based upon what the customer needs to have the unit back in service by the scheduled completion date. The outage does not provide a long term fix for the unit. Another more comprehensive outage for refurbishment beyond the most immediate repairs will be required in 5 years.*

4.2 Abbreviations

The following abbreviations are often used in this report:

- A2/A1: Perpendicular Axis from US/DS
- BDES: Bay d'Espoir Generating Station
- CEATI: Canadian Electricity Association Technologies Inc.
- CL: Centerline
- DS: Downstream
- ESI: Epco Services Inc. - Laser Contractor
- GD&T: Geometric Dimensioning and Tolerances
- ITP: Inspection Test Procedure
- LIDAR: Light Detection and Ranging
- NLH: Newfoundland and Labrador Hydro (Owner)
- NTS: Not to Scale
- OEM: Original Equipment Manufacturer

- RSC: Radial Seal Clearance
- TGB: Turbine Guide Bearing
- US: Upstream
- VH: Voith Hydro
- WR: Wearing Ring

5 Outage Technical Assessment

5.1 Pre-disassembly Readings and Measurements

5.1.1 Context

Pre-outage readings including rotational check, guide bearing clearance, and runner seal clearance provide a baseline of the shaft line condition before dismantling in regards to standard tolerance. The readings also provide a state for comparison after reassembly. In summary, pre-outage readings allow personnel to:

- Know the verticality of the shaft line; should it be out of tolerance, a decision would made to move components or not;
- Know the runout at different levels, particularly at the Runner Wear Rings and Bearings. If runouts are excessive, the effective clearance is reduced, which could be detrimental for bearing behavior and create a high level of vibration. Runouts are the sum of square issue of the thrust versus the shaft line axis, the machining defects of the components and dogleg;
- Know the turbine guide bearings clearance for reference;
- Know the runner seal clearance for reference in dry condition, particularly for this Unit as it is the reason that the discharge ring machining program took place.

NLH millwrights preformed all of the pre-disassembly measurements and readings. All of the measurements and readings were recorded and compiled in a report. These measurements were used during the outage to determine recommended solutions and repairs to the machine. At the completion of reassembly of the machine, the initial (pre-disassembly) readings were used as a benchmark for comparison to gauge the new static and rotation measurements of the machine, along with CEATI Part 2 Standard for new machines. The pre-disassembly measurements were referenced when necessary throughout the individual part assessments, but were highlighted in detail in the assembly and commissioning sections of this report. A complete summary and list of all of the pre-disassembly readings and measurements are included in the Appendix of this report.

5.2 Unit 7 Disassembly

5.2.1 Description

On the week of May 27, 2019 NLH employees began the disassembly of the Unit 7 machine. Under the guidance of Hatch Engineering, a third engineering firm contracted to oversee the 2019 outage, the millwrights of NLH dismantled the machine from the top down. The millwrights followed a detailed procedure created by Hatch Engineering to guide them through the disassembly process. As components were disassembled they were placed in various locations throughout Powerhouse Two. To create more space in Powerhouse Two, some of the smaller components were stored in Powerhouse One or other areas of the BDES property. Voith engineering was onsite for two days to observe the disassembly and perform a preliminary site assessment to aid in the planning efforts for Voith to perform their contracted tasks. Refer to the Appendix for relative procedures, pictures, analysis, and other documentation.

5.3 High Precision Dimensional Survey

After the disassembly of the machine, Epco Services (ESI) was contracted by Voith to perform a high precision dimensional inspection of preselected components of the Unit 7 machine. ESI used a Voith supplied procedure to guide their LIDAR inspection of each component. The laser inspection guideline document (2TFS70-0000-10042146) is located in the Appendix in the Laser Inspection Results section. A comprehensive summary of the laser data is in this section as well, however, to aid the reader, the laser data analysis and recommendations are presented in each component section of this report to provide information as it happened, a complete summary in sequential order.

The preselected components for laser inspection were:

- Head Cover including:
    - Wearing Ring, Mating Stay Ring Flange, and Bushing Sockets;
- Wicket Gates;
- Turbine Shaft including Couplings;
- Generator Shaft including Couplings;
- Stator;
- Rotor Poles and Coupling;
- Runner including Wearing Rings;
- Bottom Ring including:
    - Wearing Ring and Bushing Sockets.

5.4 Wicket Gates

5.4.1 Description of Part and Work Planned

The Wicket Gates are the angularly adjustable streamlined components that control the flow of water into the turbine. As the gates are opened wider, more water is able to flow over the turbine blades which results in a higher output of power. The gates allow the unit to be adjusted and controlled to match the desired output power levels. The BDES Unit 7 machine's twenty Wicket Gates have been in service since the machine was first commissioned in 1977. Each gate has an Upper, Intermediate, and Lower Trunnion, consisting of bearing journals. These bearing journals interface with a bronze bushing and friction is controlled by grease. NLH planned to replace the intermediate and lower bushings to a plastic bushing, eliminating the need for grease on two of the three trunnions, thus improving the eco-friendliness of their turbine. The Upper Trunnion, the trunnion the gate arm mates with, will remain lubricated through grease. Ideally, NLH would have liked to replace these bushings as well, but the impact on the gate mechanism and subsequent tolerances and fit-up of existing components was too great to overcome during the timeline of the 2019 outage. Once the machine was disassembled, all of the gates were removed and prepared to ship to Horizon Machining in St. Johns, Newfoundland.

The following work was planned for each of the Wicket Gates:

- Visual Inspection;
- Laser Inspection (ESI, not performed);
- Dimensional Inspection (Horizon Machine Shop);
- Initial NDE (MT);
- VH Analysis and Recommendation;
- Plugging Lower Trunnion Grease Hole;
- Lower and Intermediate Trunnion Machining;
- Pressure Test;
- Final NDE (PT) and Post Machining Dimensional Inspection;
- VH and NLH Acceptance.

5.4.1.1 Visual and Initial Nondestructive Examination Inspection

Once the Wicket Gates arrived at Horizon Machining, all twenty gates were visually inspected for any signs of damage or wear. All of the gates showed similar signs of wear and damage. All of the trunnions showed signs of wear and light to moderate scoring. This scoring can be from poor lubrication, debris between the bushing and the gate stem, and/or misalignment issues between the Head Cover and Bottom Ring bores. Obvious indications were present at the ends of the gate. Light cavitation damage, scoring, and dents were present on the gate-ends during the inspection. These indications can be also be from misalignment issues between the Head Cover and Bottom Ring, failing seals/facing plates screws (threading out), debris, and/or material defects from manufacturing surfacing.

Light to moderate scratches, dents, and small surface cracks were also observed on the main body of the gates, all of which can be due to debris, rocks, and other hard material being forced through the turbine. Some of the gates had small surface cracks and imperfections, but it was difficult to determine when the cracks occurred; some of them could have been present during the commissioning of the machine. Of all the gates, Gate 18 showed the most significant signs of wear and damage (numerous scratches and moderate surfaces cracks were among the indications found). All of the Visual Inspection Reports and Voith Dispositions are located in the Wicket Gate Section of the Appendix. Below in Figures 5-2 through 5-4 are images of typical visual indications found.

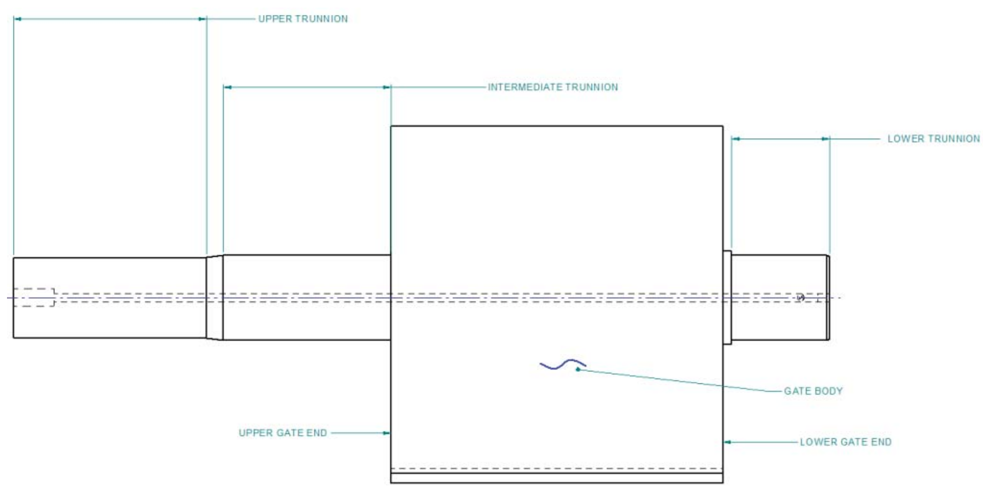

Figure 5-1: Wicket Gate Diagram

Bay d'Espoir – Newfoundland and Labrador Hydro		
Unit 7 Refurbishment Report	TFS7000	
Project Report	PDM Doc ID:	Doc. Revision:
	2-10066279	-

Figure 5-2: Visual Inspection - Typical Trunnion Indications

Figure 5-3: Visual Inspection - Typical Gate End Indications

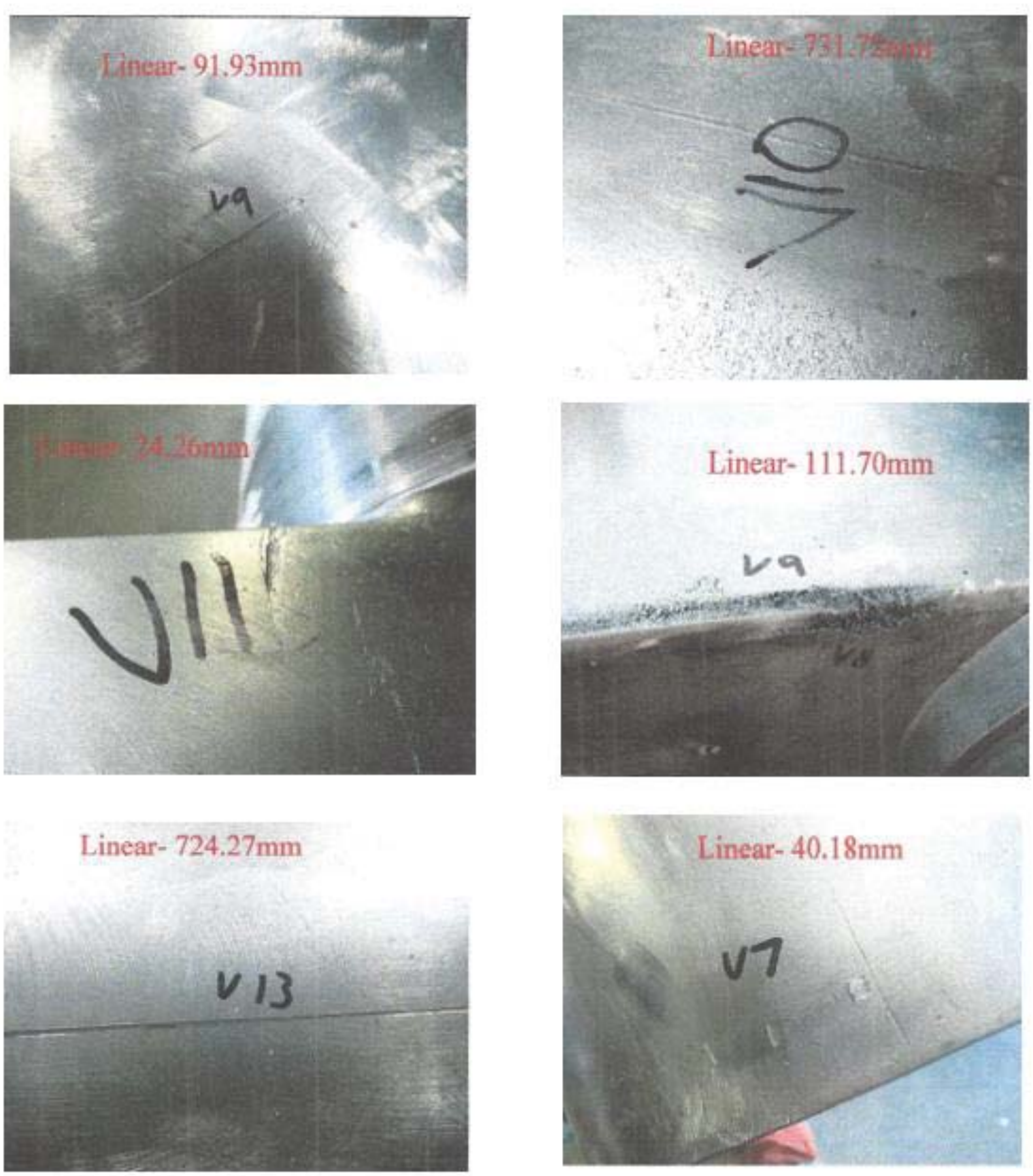

Figure 5-4: Typical Gate Body Damage

A magnetic particle test (MT) was performed on all gates. This method is used for the detection of surface and near-surface flaws and indications in ferromagnetic material and is primarily used for crack detection. The NDE inspector created individual reports for all gates and submitted to VH for disposition. In this case, the purpose of performing this test was to inspect for damage or possible failure indications that may lead to significant damage to the machine, causing unplanned repair outage. Another reason for the inspection was to assess the overall condition of the Wicket Gates for future rehabilitation planning. VH reviewed all of the indications found, focusing heavily on the indications near or in the high stress areas of the gate.

A complete list of the NDE reports are in Appendix. In general, the indications reported to VH were light to moderate surface damage, cracks, openings, or separation in base material and pitting. The cause or source of the indication could be anything from casting issues during manufacturing, debris hitting the gate, cavitation damage, misalignment of the gate stem bores, and even indications related to unplanned stress on the gate from abnormal loading. It should also be noted that not all of the gates showed significant signs of wear or indications; in fact, some of the gates only had light marks and scratches and no MT indications. Figures 5-6 through 5-7 are typical examples of the found MT indications. Figure 5-5 provides a diagram from document 2-10044792, NDE Instruction, of all of the areas in which the Visual and MT inspection were to be performed.

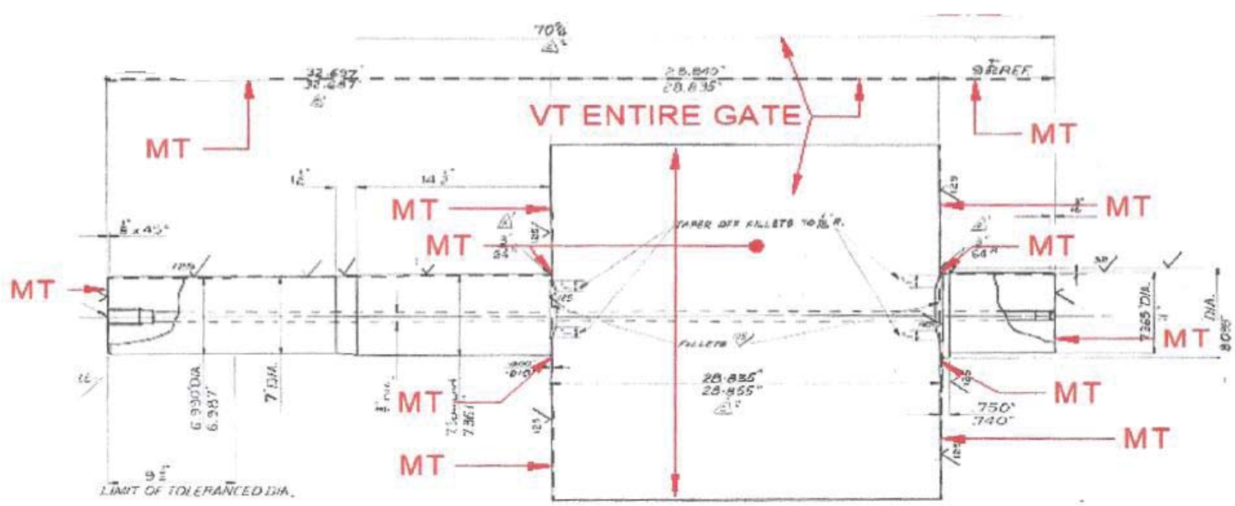

Figure 5-5: Wicket Gate NDE Diagram

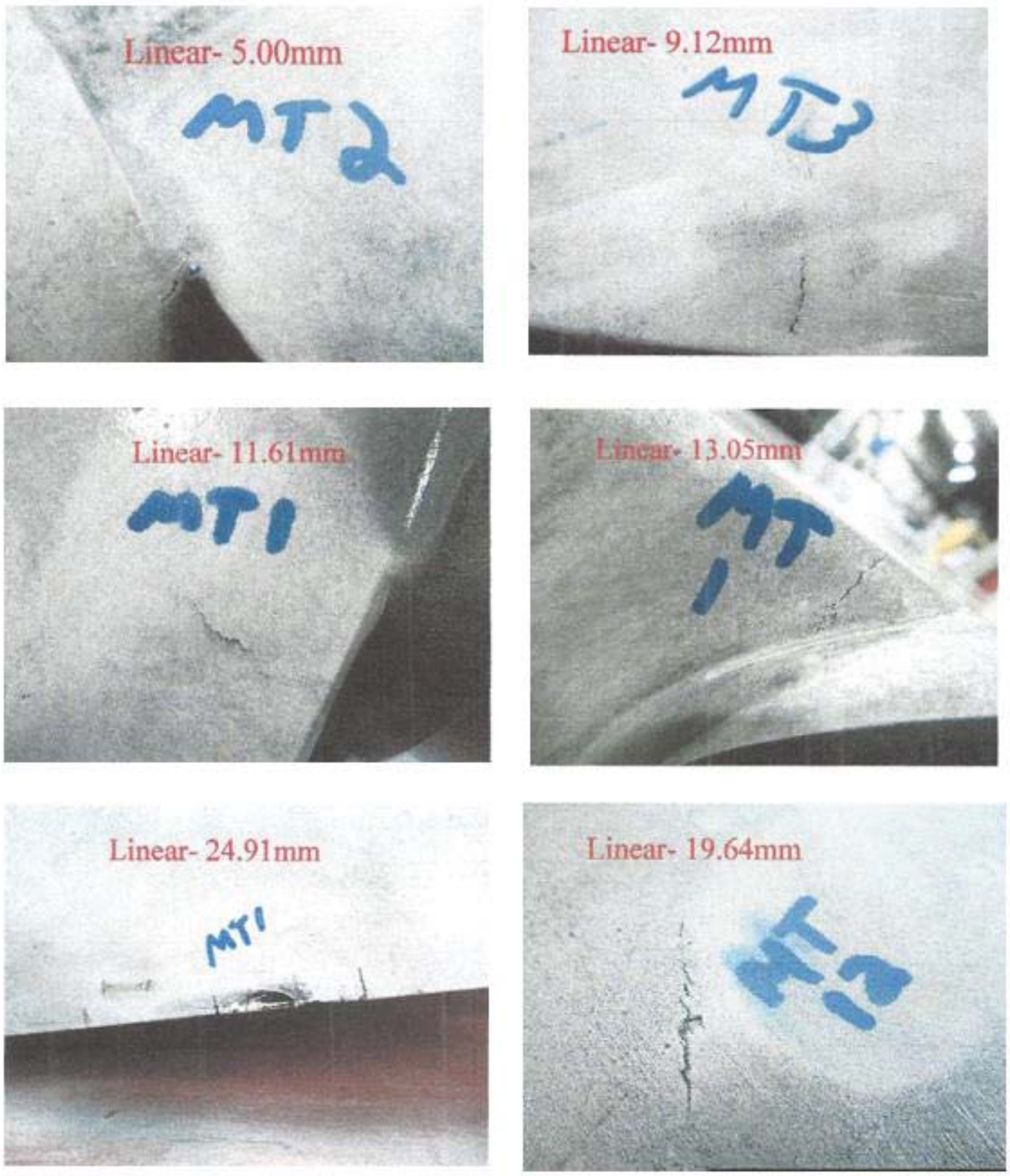

Figure 5-6: Typical Wicket Gate MT Indication

Figure 5-7: Wicket Gate #18 - MT Indications

5.4.2 High Precision Laser Inspection Analysis

During the planning stages of the outage, VH developed a High Precision Laser Inspection Recommendation document (2-10042146) to guide the laser inspector through the data that was required to be collected. This document was reviewed and approved by NLH prior to the start of the outage. Once the Wicket Gates were removed from the distributor assembly, they were immediately prepared to ship to Horizon Machining. At this time, and due to schedule time constraints, NLH decided to forgo the planned laser inspection and ship the gates to Horizon Machining. VH was not opposed to this decision because of the critical path nature of the gate machining, and the fact that all of the dimensions outlined in the Laser Inspection Recommendations document would still be collected, but by mechanical measurement means (calibrated micrometers, calipers and PI tapes) rather than LIDAR.

5.4.3 Dimensional Inspection (Performed by Horizon Machining Inc.)

All of the as-found dimensions and diameters required for determining the material removal amount to machine were reported to VH from Horizon Machining. With this information VH determined that the as-found diameters of the trunnions were close enough to OEM nominal to warrant limiting the material removal of the trunnions to 0.010 inch radially or 0.020 inch diametrically. This value of material removed was half the predetermined value allowed by NLH in the contract. Within the analysis of the dimensional inspection, VH determined that the proposed material removal was adequate in order to facilitate standardization of new wicket gate bushing and achieve a 32 micro-inch surface roughness consistently over the trunnion.

5.4.4 Lower Trunnion Grease Hole Plugging

To improve the eco-friendliness of their turbine, NLH planned to replace the Lower and Immediate greased Gate Stem Bushing with a self-lubricating plastic bushing. As mentioned in Section 5.4.1, the upper greased OEM Head Cover bushing will remain in-place. A plug was inserted in the grease hole and welded to prevent water entering the wicket gate through the grease hole and potentially leaking out the abandoned grease hole at the top of the wicket gate stem. Once approval was provided by VH, Horizon Machining machined the trunnions. After which, the gate grease system was pressure tested to 1.5 times the max head pressure the gate could experience and NDE (PT) was performed on the weld joint of the plug. The VH provided procedures and the drawing Horizon Machining used to guide their work on the grease hole plugging is in the Appendix.

5.4.5 VH Analysis and Recommendation

VH used the provided dimensional and NDE inspection information to analyze and determine the best course of action to recommend for the Wicket Gate rehabilitation. Section 5.4.5.1 includes a summary of the recommendations VH provided prior to machining being approved. Refer to Figures 5-1 to 5-7 for a visual representation of the indications. The complete list of documentation and dispositions from VH are located in the Appendix.

5.4.5.1 Visual and NDE Inspection

- Light to moderate cracks found during the MT inspection.
  - **Recommendation:** *Grind 0.125 inches deep, cap off with similar filler material to base metal. MT to ensure indication did not grow. PT after repair.*
- Moderate to heavy cracks found during the MT inspection.
  - **Recommendation:** *Grind 0.250 inches deep, cap off with similar filler material to base metal. MT to ensure indication did not grow. PT after repair.*
- Light scratches and dents found during the Visual Inspection.
  - **Recommendation:** *Minimal grinding to remove sharp edges and raised material. Ensure the indication is smooth once completed.*
- Moderate scratches and dents found during the Visual Inspection.
  - **Recommendation:** *Minimal grinding to remove sharp edges and raised material. Ensure the indication is smooth once completed.*
- Heavy scratches and dents found during the Visual Inspection.
  - **Recommendation:** *Minimal grinding to remove sharp edges and raised material. Ensure the indication is smooth once completed.*
- Scoring on Trunnions.
  - **Recommendation:** *No other repair required; scoring and surface finish will be improved during machining.*
- Indications on the nose and tail seal areas of the gate.
  - **Recommendation:** *Minimal grinding to remove sharp edges and raised material. Ensure the indication is smooth. Do not grind into the nose seal area.*
- Indications not repaired.
  - **Recommendation:** *Accept as is.*

5.4.5.2 Wicket Gate Machining

On June 28, 2019, VH completed their analysis and explained the dimensional data to NLH. Once all of the NDE inspection dispositions were satisfied, approval was given to Horizon Machining to proceed with the machining all of the Wicket Gates.

5.4.6 Pressure Test

Once machining of the Wicket Gate was completed and prior to shipping the gates back to BDES, Horizon Machining performed the required pressure test on the grease hole plug on the lower trunnion. The entire set of gates were pressure tested to 1.5 times the Penstock pressure, which is 250 psi. Prior to pressurizing the gates to 375 psi, each gate was filled with water or oil, which was the test medium. A fitting and measurement gauge was attached to the thread at the center of the upper trunnion. A pump was attached to the fitting to allow the grease passageway to be pressurized. The gates were pressurized to 375 psi for ten minutes. The pressure was recorded after five minutes. The pressure was allowed to drop ten percent from initial, but must have held a constant pressure after the initial drop for the remainder of the test. The pressure tests on all twenty Wicket Gates were completed and results provided to VH, all of which met the requirements stated above and outlined in the Wicket Gate Purchasing Specification (provided in the Appendix).

5.4.7 Final NDE (PT) and Post Machining Dimensional Inspection

Horizon Machining provided VH with all of the final documentation outlining the final NDE (PT) of machined surfaces, dimensional and GD&T, and final surface finish values. A comprehensive account of all of the documentation and data is located in the Appendix.

- **Trunnion Diameters:** All trunnion diameters were measured and machined within tolerance and in accordance with drawing 2TFV04-0101-10042606 (ER-2, ER-8, and ER-10).
- **Machined Surface Roughness Value:** All of the required surface roughness values were machined and measured within tolerance, and in accordance with drawing 2TFV04-0101-10042606 (ER-1, ER-4, ER-7).
- **GD&T – Runouts and Trunnion Concentricity:** All of the trunnion runouts were measured simultaneously with values recorded within tolerance and in accordance with drawing 2TFV04-0101-10042606, (ER-3, ER-6, ER-9). The concentricity checks were not performed. VH inquired as to why, and Horizon Machining explained that the runouts of all the trunnions were check simultaneously in the same setup and never exceeded the tolerance of the runout. Horizon Machining inferred that since the trunnions measured little to no runout that the concentricity must also be within tolerance. VH explained that the eccentricity of the gate body to stems and the natural linear deflection of the gate under its own weight could allow for balance issues to develop, which can lead to concentricity issues between the trunnions.
    - VH and NLH accepted the gates as-is without the concentricity being verified after discussions with Horizon Machining in which their balancing procedure and their experience with machining other eccentric Wicket Gates were explained. VH was also comfortable with accepting the gates as-is because of the increase in gate stem bushing clearance which was expected, ultimately allowing for misalignment of the bushings and gate trunnions.
- **Post Machining NDE (PT) of machined surfaces**: All of the machined surfaces were inspected using PT for surface imperfections and crack indications. The complete list of NDE reports for the post-machining inspection provide by Horizon Machining is located in the Appendix. Voith reviewed the reports and deemed all of the gates free and clear of post-machining defects.

5.4.8 VH and NLH Acceptance

On July 25, 2019, the Wicket Gate machining was accepted by the VH and NLH and the gates were released for shipment back to Bay d'Espoir Generating Station. The gates were prepared according to the document 2TFV04-0101-10042478 and shipped back to site, arriving on July 27, where the gate were stored outside the powerhouse until reassembly.

Figure 5-8: Finished Wicket Gates outside BDES Powerhouse 2

5.5 Lead Abatement

In order to detect for cracks, faults, and separation of materials, the existing lead paint on certain components of the Unit 7 machine had to be removed. Once the lead paint was removed, the detection of indications was found by using a variety of NDE methods, which are listed in Section 5.6. Voith subcontracted two contractors, Belor and Tacten, to perform the lead abatement tasks inside both Powerhouse One and Two. Both contractors removed the lead paint using industrial chemical remover. The lead abatement contractors were guided by a Voith-provided instruction (2TFS70-0000-10044792). Some of the challenges the lead abatement contractors faced were confined space limitations, tight work areas, and the need to construct an enclosure to perform the abatement activities around some of the parts. This enclosure was required to control the lead particles from contaminating the atmosphere of the powerhouse. These enclosures took valuable time to build and limited the amount of the floor space available in the powerhouse. Overall the lead paint abatement took more time than anticipated to complete due to the heavy layers of paint on the components and the requirement to use more applications of the chemical removal than planned for by the contractors. This document is included in the Appendix. Below is a list of the Unit 7 components that required lead paint abatement. A brief summary of the lead abatement work is provided within each component section requiring lead paint abatement. The final reports from the lead paint abatement contractors are also located in the Appendix.

5.5.1 List of Lead Abated Components

Components that required lead abatement were:

- Head Cover
- Stay Vanes
- Runner
- Draft Tube
- Turbine Guide Bearing

5.6 Non-Destructive Examination

The non-destructive examinations that occurred during the Unit 7 outage are listed in this section. These methods were chosen due to their effectiveness in locating indications that may lead to a component failing. Each examination method serves a different purpose depending upon the desired level of inspection. The visual inspections and examinations are more appropriate for high-level inspections, during which the human eye is used to observe and determine if any obvious signs of material failure are present. The Liquid Penetrant, Magnetic Particle, and Ultrasonic examinations are used based upon the material being examined, effectiveness, cost, and time. A comprehensive report of all of the NDE performed on the parts is located in the Appendix of this report. A summary of the NDE results and VH recommendations are located within each component section.

5.6.1 List of Non-Destructive Examination:

- Visual Examination – VT
- Liquid Penetrant Examination – PT
- Magnetic Particle Examination – MT
- Ultrasonic Examination – UT

5.6.2 List of Non-Destructive Examined Components:

- Head Cover (Planned)
- Wicket Gates (Planned)
- Stay Vanes (Planned)
- Turbine Guide Bearing (Planned)
- Generator Guide Bearing (Planned)
- Thrust Bearing (Planned)
- Runner Balance Plate (Not planned, but performed during outage, due to unforeseen repairs)

5.7 Laser Inspection Contractor

Epco Services Inc. (ESI) was contracted by VH to perform a dimensional inspection of the stationary parts, the Head Cover and the Runner-Turbine Shaft Assembly. The report, attached in the Appendix, was analyzed to assess the geometrical condition of those components for recommendations. The analysis and recommendations are found in each component's individual section within this report, when applicable.

Challenges the Laser Inspection contractor encountered were:

- Working in confined and tight spaces.
- Working from elevated surfaces that required fall protection.
- Limited space to maneuver and setup laser equipment, which can limit the data that can be collected.

Recommendation:

Future contractors should fully vet laser inspector contractors for their experience and expertise in working with hydroelectric turbines. Future contractors shall also use NLH as a reference and ask for recommendations and lessons learned from previous outages; however, contractors must also heed any recommendations provided by NLH.

5.8 Concrete Grouting

5.8.1 Background Information

Based on the experience of previous outages at BDES, grouting activity was planned for Unit 7 to fill voids that were expected to be found behind the Discharge Ring and Draft Tube. Typically, voids found behind the Draft Tube Liner are due to improper settling of the concrete during the initial construction of the powerhouse; consequently, small pockets of air and insufficient vibration of the concrete can lead to voids. The area in question can be seen in the OEM Turbine Cross-Section in Figure 5-9.

Once the unit was disassembled, the VH Field Services team began their concrete void inspection of the Draft Tube. The Draft Tube was inspected by tapping a hammer against the side wall of the Draft Tube and listening for different tones. The different tones would distinguish between void, a hollow location were grouting would be required, and a location where the original concrete was still intact and no voids were present. When voids were found, the inspectors marked the location with pink marking paint; this indication would help the inspector establish a map of the voids and help determine where the holes should be drilled to create a tapped port for pumping grout.

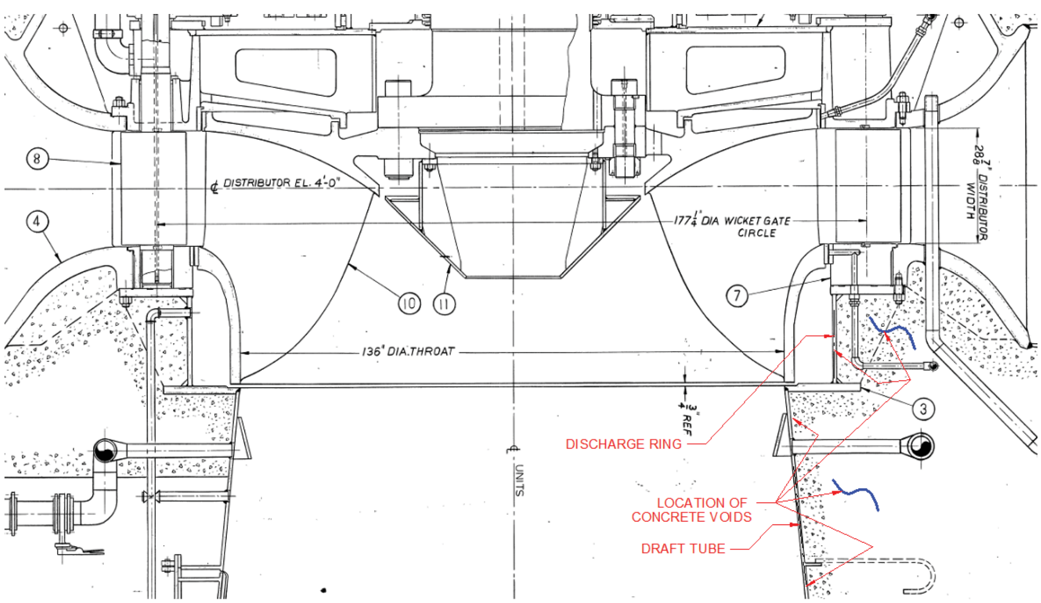

Figure 5-9: Turbine Cross-Section Grouting Diagram, (BDES-2, 1976)

5.8.2 Inspection Results and Draft Tube Grouting

Once a thorough inspection of the Draft Tube Liner was completed, VH's lead abatement contractor removed the paint in areas where the pumping was planned to occur. VH drilled 25 holes in the Draft Tube, generally, the center of the void, after which these holes were tapped to accept fittings for the attachment of the grout pump. The Discharge Ring was also inspected, but no signs of concrete voids were present. A total of ten gallons of the Prime Rex 1100 grout was pumped into the voids behind the Draft Tube and Discharge Ring. The fittings and pumped were removed after the grout was cured. A small non-malleable iron plug was used to fill the hole. The plug was welded into position and the surface was ground flush. On surfaces where VH removed the paint to perform grouting tasks, touch-up paint was applied to all exposed surfaces. According to the Refurbishment Report for the previous Unit 3 and 2 outages, the quantity of grout used for Unit 7 was three gallons less (VHY-9, 2017). This reveals that the voids found in the Unit 7 inspection are similar to those of the Unit 3 and are comparable NLH's plan. Due to the individual design of every turbine and powerhouse, it is difficult to quantify the amount of the voids found at BDES. In general, the voids found on the Unit 7 machine were somewhat small, but on average with the amount VH typically finds on Francis turbines of similar size and age. Figures 5-10 through 5-13 show the areas of the Draft Tube that had voids.

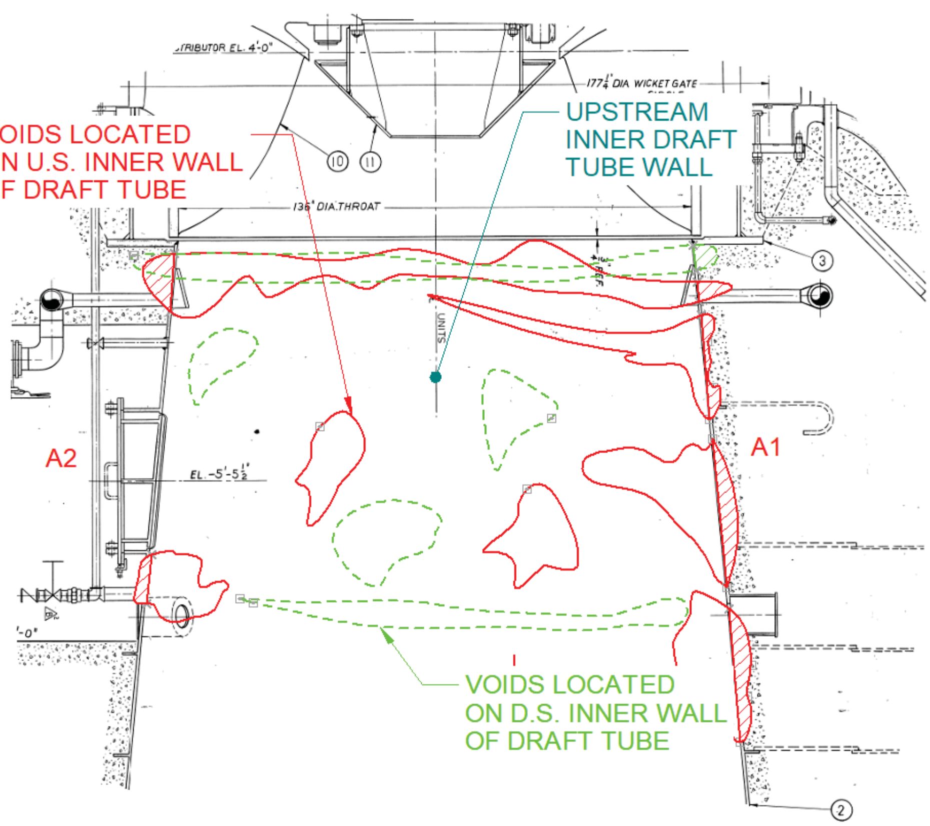

Figure 5-10: Draft Tube Void Mapping Overview

Figure 5-11: Draft Tube Void Mapping

Figure 5-12: Draft Tube Void Mapping

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Figure 5-13: Draft Tube Void Mapping

5.9 Turbine Runner

5.9.1 Background Information

The Runner is a rotating element of turbine that converts hydraulic energy into mechanical energy. This component is located between the Head Cover and Bottom Ring. The Runner is incased by the Spiral Case, a spiral-shaped water passage that completely surrounds the turbine to provide a uniform distribution of water flow to the turbine. The Bay d'Espoir Unit 7 Runner has been in service since the OEM commissioning with routine maintenance performed on the part. The focus to the routine maintenance would be monitoring for signs of cavitation, obvious damage, or wearing ring issues. Throughout the unit's history the Runner has had repairs performed on it for cavitation and the Wearing Rings have been closely monitored for damage and seal clearance gap concerns. Prior to the 2019 Unit 7 outage, NLH developed plans to repair any cavitation to the Runner using a cavitation repair procedure approved by Voith from previous outages. In order to evaluate the condition and life-remaining of the Runner, NLH contracted VH to perform the work below and provide recommendations.

Planned work:

- Visual Inspection (VH Scope).
- Laser Inspection (VH Scope).
- Cavitation Repair (NLH Scope).

5.9.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Runner and created a report defining the as-found condition of the Runner and associated features. The inspection report document (Bay d'Espoir Inspection Recommendations Rev- (VHY-10, 2019)) is included in the Appendix.

Figure 5-14: Turbine Runner Diagram

5.9.2.1 Runner Band

The Unit 7 Runner Band was found to be in average condition for the machine's age and usage. The lead base orange paint was still mainly intact with limited signs of deterioration on the outer and inner diameters. The Runner Band had minor debris impact scratches and scrapes. The only notable indication, Runner Band indication, noted VT-1 in Figures 5-15 and 5-16 from the inspection was underneath the Wearing Ring where minor cavitation and corrosion was present. Refer to the following inspection images.

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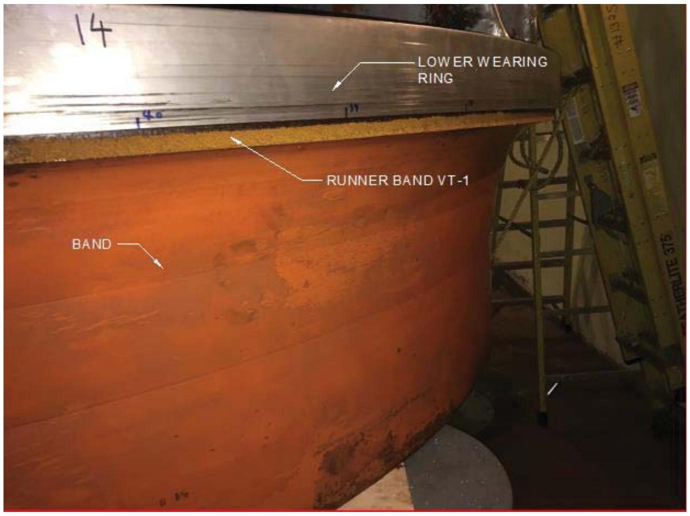

Figure 5-15: Runner Band Cavitation Damage

Figure 5-16: Runner Band Cavitation Damage

5.9.2.2 Runner Buckets

The fifteen Runner Buckets were in fair condition overall; however, they all show locations of moderate to heavy cavitation damage. The cavitation damage follows a pattern across the entire lot of buckets, presenting in the same general location on each individual bucket. The indication locations were typically found at: entrance edge where the bucket is attached to the band on the lower pressure side (VT-2), middle of the lower pressure side close to discharge edge (VT-3), and the top of the discharge edge where the bucket meets the crown (VT-4). Refer to the following inspection images.

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Figure 5-17: Runner Bucket Cavitation, VT-2

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Figure 5-18: Runner Bucket Cavitation, VT-2

Figure 5-19: Runner Cavitation Damage, VT-2

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Figure 5-20: Runner Cavitation Damage, VT-3

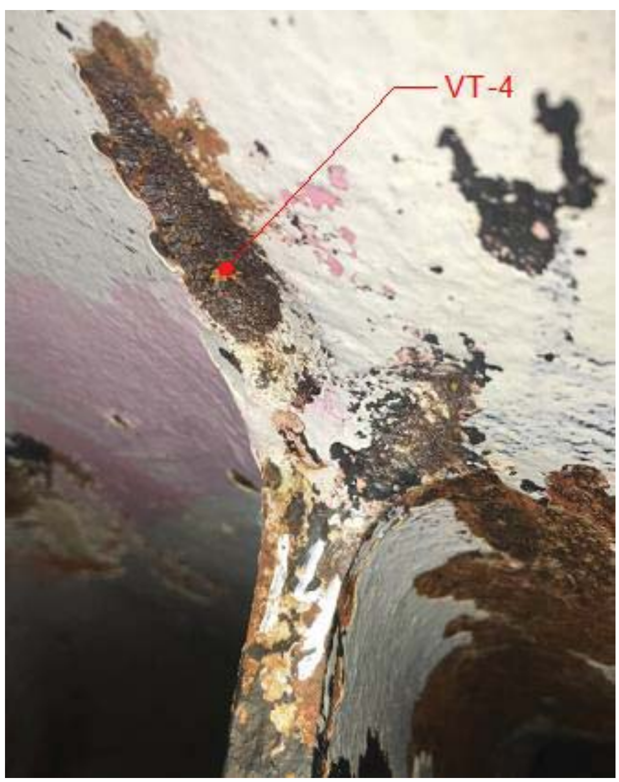

Figure 5-21: Runner Bucket Cavitation Damage, Discharge Edge near Crown, VT-4

5.9.2.3 Runner Crown

The Runner Crown was found to be in average condition; however, moderate corrosion and cavitation damage were found near the outer diameter of the Crown close to the Upper Wearing Ring mating surface (VT-5). One serious indication was found to the Balance Cover Plate located on the top of the Crown. Large cracks were present in the cover plate with large pieces missing (VT-6). Also, moderate to heavy cavitation damage was found around the pressure relief holes on top of the Crown (VT-7). Refer to the following inspection images.

Figure 5-22: Runner Crown Cavitation Damage, VT-5

Figure 5-23: Runner Crown Cavitation Damage, VT-5

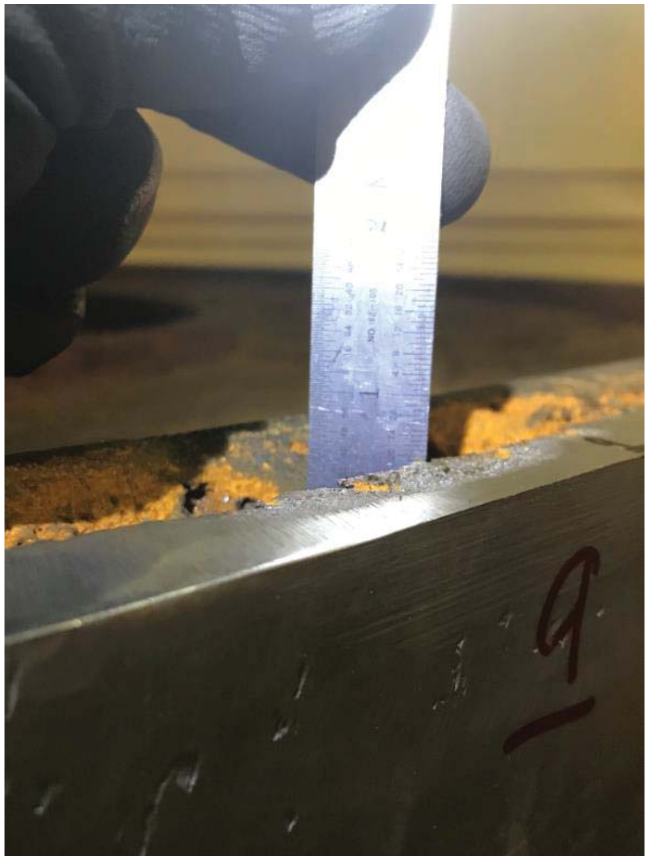

Figure 5-24: Runner Crown Cavitation Damage, VT-5

Figure 5-25: Runner Crown Cavitation Damage, VT-5

Figure 5-26: Runner Crown Balance Plate Damage, VT-6

Figure 5-27: Balance Plate Missing Piece, VT-6

Figure 5-28: Balance Plate Cracks, VT-6

Figure 5-29: Runner Crown Pressure Relief Holes Cavitation Damage, VT-7

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Figure 5-30: Runner Crown Pressure Relief Holes Cavitation Damage, VT-7

5.9.2.4 Runner Upper Wearing Ring

The inspection performed on the Upper Wearing Ring of the Runner showed light scratches, galling, dents, and some minor cavitation damage. The cause of scratches and physical damage on the outer diameter of the ring was difficult to determine with absolute certainty. Although the likely source is either from debris forcing its way between the rotating and stationary Wearing Rings, or the Runner came in contact with the Stationary Wearing Ring. This indication could be from several different sources, but the RSC issues described in Section 3.1 or shaft alignment (vertically) could easily explain the damage. Refer to the following inspection images.

Figure 5-31: Runner Upper Wearing Ring, Contact Damage

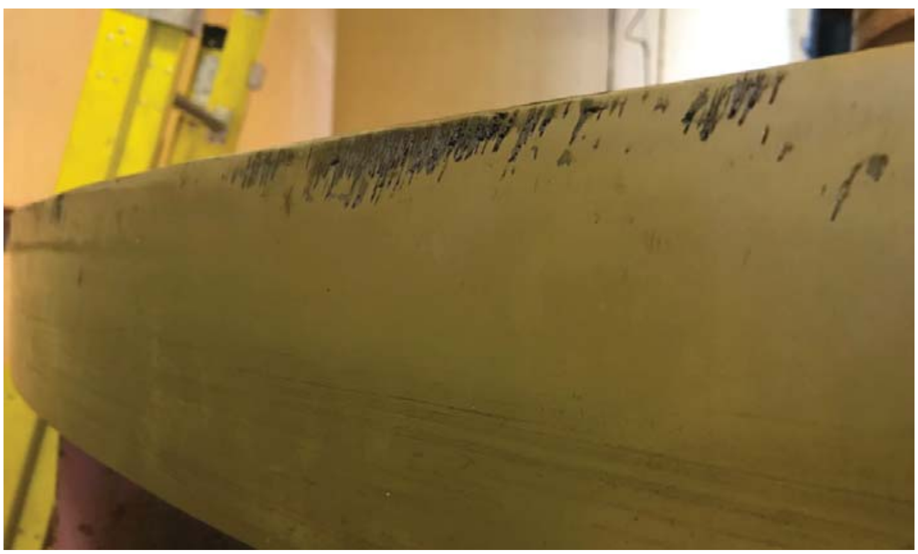

Figure 5-32: Runner Upper Wearing Ring, Cavitation Damage

5.9.2.5 Runner Lower Wearing Ring

The inspection performed on the Lower Wearing Ring of the Runner showed light scratches, galling, dents, and some minor cavitation damage. The cause of scratches and physical damage on the outer diameter of the ring was difficult to determine with absolute certainty. The likely the source damage is either from debris forcing its way between the Rotating and Stationary Wearing Rings, or the Runner came in contact with the Stationary Wearing Ring. This indication could be from several different sources, but the RSC issues describe in Section

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3.1 or shaft alignment (vertically) could easily explain the damage shown below; in fact, the as found conditions of the Bottom Ring Wearing Ring supported this causation. Refer to the following inspection images.

Note: Within the contract there was an option to replace the Runner Band Wearing Ring. This Wearing Ring was already purchased ahead of time by NLH in preparation for the possible replacement. Upon completion of the visual and laser inspection VH and NLH agreed that the condition of the Runner Band Wearing Ring was satisfactory and that there would be no significant net gain in replacing it.

Figure 5-33: Runner Lower Wearing Ring, Contact Damage

Figure 5-34: Runner Lower Wearing Ring, Contact Damage

5.9.2.6 Runner Deflector Cone

The Runner Deflector Cone and hardware was inspected for any visible signs of damage or deterioration. VH engineering found limited signs of damage, corrosion, or signs of cavitation deterioration. The surfaces had minor imperfections with some of the original paint still intact. The hardware appeared to be in good working order with no signs of damage or deterioration to the locking welds. Inspection images are shown in the following figure.

Figure 5-35: Runner Deflector Cone and Hardware

5.9.3 Laser Inspection Data and Results

The Turbine Runner was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The Runner dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The “reference only points” were recorded in case certain questions or information was needed outside of the planned scoped.

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The planned laser inspection data is shown in the Figure below.

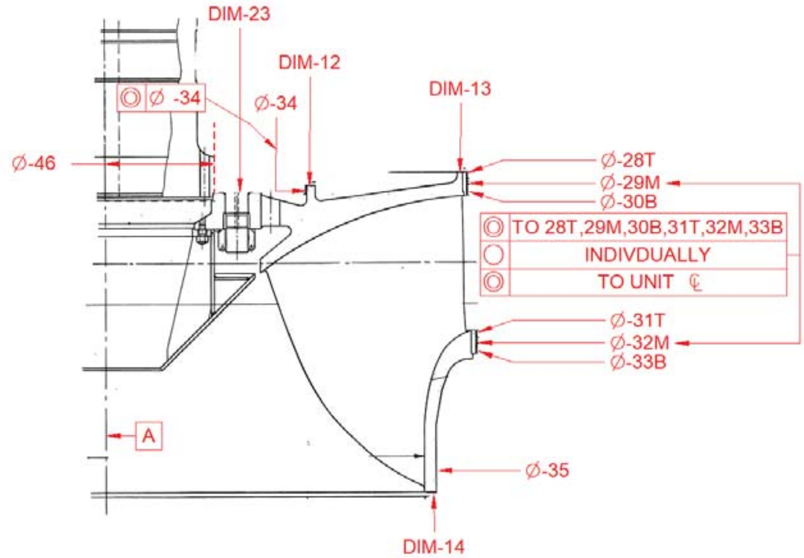

Figure 5-36: Runner Laser Inspection Diagram

ø-28T	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,29M, 30B,31T,32M,33B Circularity
ø-29M	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,28T, 30B,31T,32M,33B Circularity
ø-30B	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,28T,29M, 31T,32M,33B Circularity
ø-31T	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,28T,29M, 30B,32M,33B Circularity
ø-32M	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,28T,29M, 30B,31T,33B Circularity
ø-33B	Runner Crown WR (40 points minimum)	Concentricity to Unit CL,28T,29M, 30B,31T,32M Circularity
ø-34	Runner Crown	Concentricity to Unit CL,28T,29M, 30B,31T,32M,33B Circularity
ø-35	Runner Band	For Reference
DIM-12	Runner Crown	For Reference/Flatness/Runout
DIM-13	Runner Crown	For Reference/Flatness/Runout
DIM-14	Runner Band	For Reference/Flatness/Runout

Figure 5-37: Turbine Runner, Laser Inspection Data Points Collected

5.9.3.1 Runner Laser Inspection Analysis

The main purpose of the Runner laser inspection was to determine and evaluate the size and shape of certain features on the Runner and use the dimensions to aid in other aspects of the outage, such as how the OD of the Runner Wearing Ring diameters compare to the stationary Wearing Rings of the Head Cover and Bottom Ring. As shown in Figure 5-38, the as-found diameters of the Upper and Lower Runner Wearing Rings are slightly below the lower OEM tolerance values. The reduced size of the diameters was probably due to debris or wear from the Runner coming in contact with the Stationary Wearing Rings since commissioning. The Runner Wearing Ring reduction was not significant and in general did not pose a serious risk, but it does factor in to the overall RSC clearance of the Runner and the stationary Wearing Rings. The circularity (roundness) and concentricity of the Wearing Rings are all in an acceptable range, especially for the condition of the Runner and Wearing Ring surfaces.

Name	X	Y	Z	Concentricity	Diameter	Lower/Upper OEM Diameter		Roundness
Circle B: **Ø35**	0.0010	-0.0017	-28.4961	0.0020	-	-	-	-
Circle C: Ø**33B**	0.0000	0.0000	0.5591	0.0000	**158.152**	158.153	158.160	0.0084
Circle D: Ø**32M**	-0.0011	-0.0011	2.5588	0.0016	**158.145**	158.153	158.160	0.0119
Circle E: Ø**31T**	0.0003	0.0005	4.7471	0.0005	**158.119**	158.153	158.160	0.0118
Circle F: Ø**30B**	-0.0112	-0.0009	34.6826	0.0112	**154.092**	154.163	154.170	0.0462
Circle G: Ø**29M**	-0.0019	-0.0030	36.4409	0.0035	**154.131**	154.163	154.170	0.0376
Circle H: **Ø28T**	-0.0035	-0.0032	38.6298	0.0047	**154.132**	154.163	154.170	0.0197

Figure 5-38: Runner Diameters and GD&T

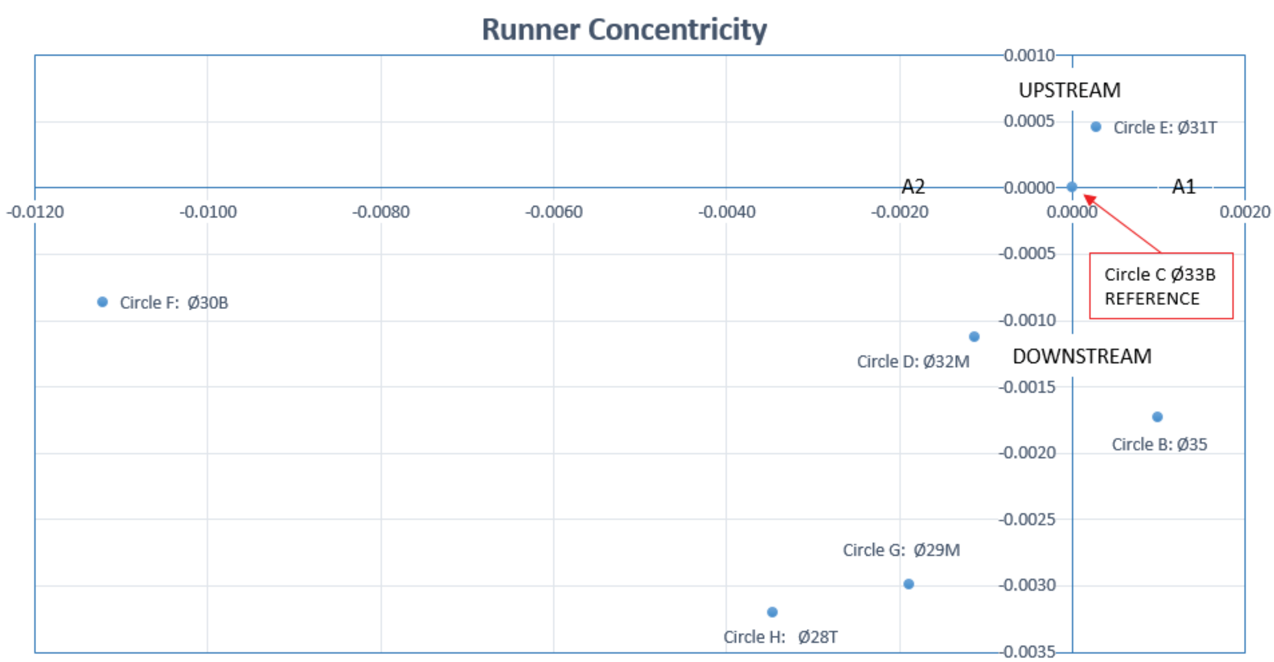

Figure 5-39: Runner Wearing Ring Concentricity

5.9.4 Non-Destructive Examination

There were no non-destructive examinations planned for the Runner for the 2019 maintenance outage; however, NDE was performed due to unexpected repairs required to the Runner Balance Plate. See section 5.9.5.2.

5.9.5 Outage Recommendations and Conclusion

Once the dimensional (Laser) and visual inspection were completed, Voith provided NLH with recommendations to repair the indications outlined in Section 5.9.2. A summary of the recommendations, with discussions, final decision are included in the following subsections. A comprehensive list of documents pertaining to the recommendations, discussions, and approvals are in the Appendix.

5.9.5.1 Runner Cavitation Repair

- Voith recommended repairing any and all cavitation damage.
  - **Reason:** As shown in Section 5.9.2, the cavitation the unit experiences caused structural damage to the Runner, which can lead to a catastrophic failure of the unit. Should the cavitation damage not be repaired, the Runner would continue to deteriorate to an unrecoverable state. Repairing the Runner during the 2019 outage would help improve the Runner's life expectancy and the likelihood that it could remain in service for five years after the 2019 commissioning, at which time a plan could be developed to perform a major rehabilitation on Unit 7.
  - **Recommendation Summary:** The location and severity of the cavitation damage determined the recommendation for repair methods. The smaller signs of damage could easily be addressed by lightly grinding and blending the surface flush with adjacent non-damaged surfaces. For moderate damage and pitting (deterioration), an epoxy was recommended to fill the impaired areas. Once the epoxy cures, an anti-cavitation paint can be applied over the epoxy. For heavy cavitation damage and deep pitting, mainly on the runner buckets, a filler metal was suggested to fill the deterioration, after which the welds would be ground flush. Using the filler metal method was not recommended for all of the cavitation damage due to the risk of heat distorting the shape of critically machined surfaces. While the thrust relief holes showed moderate cavitation damage VH believed there was no significant gain in repairing the damage, especially with the new five year plan for the unit.
  - **Outcome:** NLH decided to repair the cavitation damage to the Runner that Voith recommended using existing internal procedures and instruction documents created by VH. NLH conducted all of the repairs on the Runner cavitation. The cavitation repair on the crown is shown in Figure 5-45. The light gray ring on the top side of the Crown is the epoxy

and anti-cavitation paint. Voith was not requested to perform any inspection or quality documentation of the repairs.

- The cavitation damage in Figures 5-29 and 5-30 on the thrust relief holes was not repaired. While all cavitation should be repaired, there is a low risk of this posing a threat prior to the next major outage which is expected in five years.

- **Documents**
  - Voith Cavitation Instruction 2TFV04-0800-10052253 (VHY-7, 2019).

Figure 5-40: Runner Bucket Post Cavitation Repair

5.9.5.2 Runner Balance Cover Plate

- Voith recommended the Runner Balance Cover Plate be repaired prior to reassembly.
  - **Reason:** Not repairing the Runner Balance Cover Plate poses a risk to the Unit due to the extent of damage and the numerous cracks. The main concern was that the remainder of the Cover Plate would become dislodged from the rest of the Runner at some point and cause significant damage to the Runner and Head Cover, ultimately forcing NLH into an unplanned outage. Also, repairing the Cover Plate once the machine was assembled is impossible due to the location. Repair in place would require disassembling the entire machine. Repairing the Runner Balance Cover Plate during the 2019 outage would help improve the Runner's life expectancy and the likelihood that it could remain in service for five years after the 2019 commissioning, at which time a plan could be developed to perform a major rehabilitation on the Unit 7 machine.

- **Recommendation Summary:** Voith evaluated the repair options with the impacts to the outage schedule and NLH's five year plan in mind, and determined a solution to remedy the damaged Cover Plate. Voith recommended a steel plate be placed and welded directly over top of the existing Cover Plate. This annular shaped plate was of homogeneous in size and volume, which means no balance issues of the rotating Runner would be expected to develop. All of the lead paint in the proximity of the welds required removal to weld the plate to the Runner. Once the lead paint was removed, the new plate was lowered into position and centered over the existing plate. After centering, the circumferential welding on the ID and OD of the plate began. To aid in fusing the existing Cover Plate to the new one, Voith included equally spaced slots near the centerline of the plate. These slots would create a joint to weld the two plates together and limit the potential for the existing plate to vibrate under the new one. After welding the new Cover Plate the welds were to be inspected for quality (NDE-(PT)) and the surface was painted for protection.

    - **Alternative Options:** During the design phase VH investigated other options for the repair to the Cover Plate, such as simply repairing the existing Cover Plate in place (welding the cracks), or even removing the existing Cover Plate all together to eliminate the risk of the plate dislodging from the Runner; however, Voith determined the proposed recommendation was the best option that complimented the outage schedule and durability of the Unit for the next five years.

        - **Reasons alternative options were not recommended:**
            - Heat distortion.
            - Risk of disturbing lead balance weight, which could have impacted the overall balance of the machine.

- **Outcome:** NLH decided to repair the Runner Balance Cover Plate using the recommendation VH provided. NLH painted the entire crown, shaft hardware, and lower portion of the shaft (water side). NLH conducted all of the repairs on the Runner Balance Cover Plate. Voith was not requested to perform any inspection or quality documentation of the repairs. NLH performed all of the necessary NDE on the Runner Balance Plate repairs, including the VT and PT on the welds. Refer to the Appendix for all of the reports, discussions, and documents pertaining to the Runner.

- **Documents**
    - Runner Balance Cover Plate, 2TFV01-0155-10049134, (VHY-8, 2019)

- Note that NLH purchased three sets of Super Nuts to replace the existing OEM heat tensioned nuts, which required significant effort and time to remove during the disassembly of the machine in the 2019 Maintenance Outage. The Super Nuts only require manual hand torqueing to achieve the preload required. The Super Nuts also allow for a more simplistic disassembly and reassembly of the components during maintenance activities. They also do not require a heating source like the OEM nut. During the assembly of the unit in 2019 only two sets of Super Nuts were used. One set was used at the connection joint of the Rotor and Generator Shaft and the second set was used at the connection joint between the Turbine and Generator Shafts. The third set, which is intended for the connection joint between the Runner and Turbine Shaft, was not used during the assembly because the Runner and Turbine Shaft were not disassembled during the 2019 outage; therefore this set was saved and stored until required, which can during the next major outage.

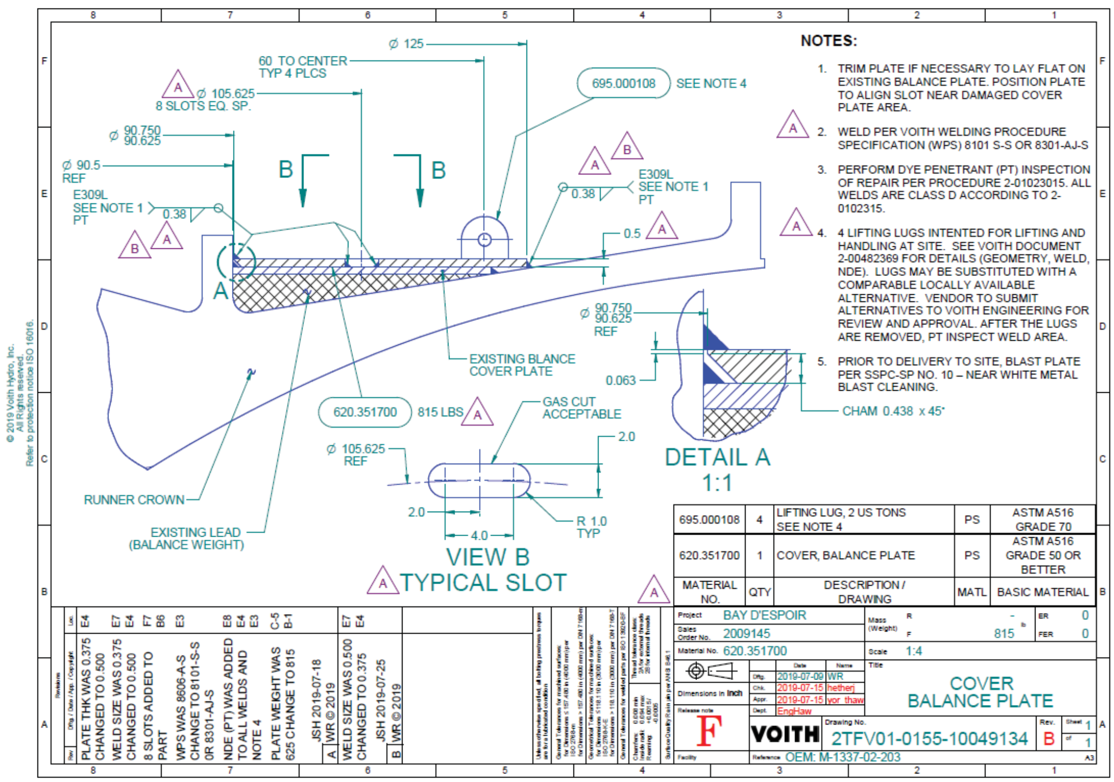

Figure 5-41: Runner Balance Cover Plate Repair

Figure 5-42: Lead Abatement (White Paste on Crown)

Figure 5-43: Runner Balance Cover Plate Welded

Figure 5-44: Runner Balance Cover Plate Repaired

Figure 5-45: Runner Repairs Completed

5.10 Turbine Shaft

5.10.1 Background Information

The Turbine Shaft is a rotating element that transmits torque from the Runner to the Generator Rotor. BDES Unit 7 uses two shafts, a Turbine Shaft and Generator Shaft, to transmit torque. The Turbine Shaft is connected to the Runner and the Generator Shaft connects to the Generator Rotor. The two shafts are mated through a bolted flange connection. Generally, the shaft(s) of the hydroelectric turbine are not in an environment where they experience conditions that would cause damage or deterioration over time, so only limited work activities were planned for the shaft(s). NLH did not remove the Turbine Shaft from the Runner, as shown in Figure 5-46. The tasks planned for the Turbine Shaft are described in this section.

Planned work:

- High Precision Dimension Inspection-LIDAR (VH Scope).
- Visual Inspection (VH Scope).

Figure 5-46: Turbine Shaft, Assembled to Runner

5.10.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Turbine Shaft and coupling bolts and created a report that defined the as-found condition. The inspection report document (Bay d'Espoir Inspection Recommendations Rev-, (VHY-10, 2019)) is included in the Appendix. In summary, while light scratches and small dents were present on the shaft and journal surfaces, no indications found required immediate attention.

The only noteworthy indication of the Turbine Shaft was on the Generator coupling flange where discoloration and scoring were present, which was more than likely from the removal of the coupling hardware. Due to the shaft still being connected to the Runner, the spigot joints and mating surfaces of the shaft and Runner were not inspected. Also, due to the location and height of the shaft, the mating surface of the Turbine and Generator Shafts were not inspected; however, NLH millwrights and Hatch Engineering informed VH that they did not see any visual indications of damage or deterioration on the mating flanges during the disassembly process. The nuts on the flange studs between the Runner Deflector Cone and Turbine Shaft, shown in Figure 5-49, were not easily accessible but appeared to be in good working order.

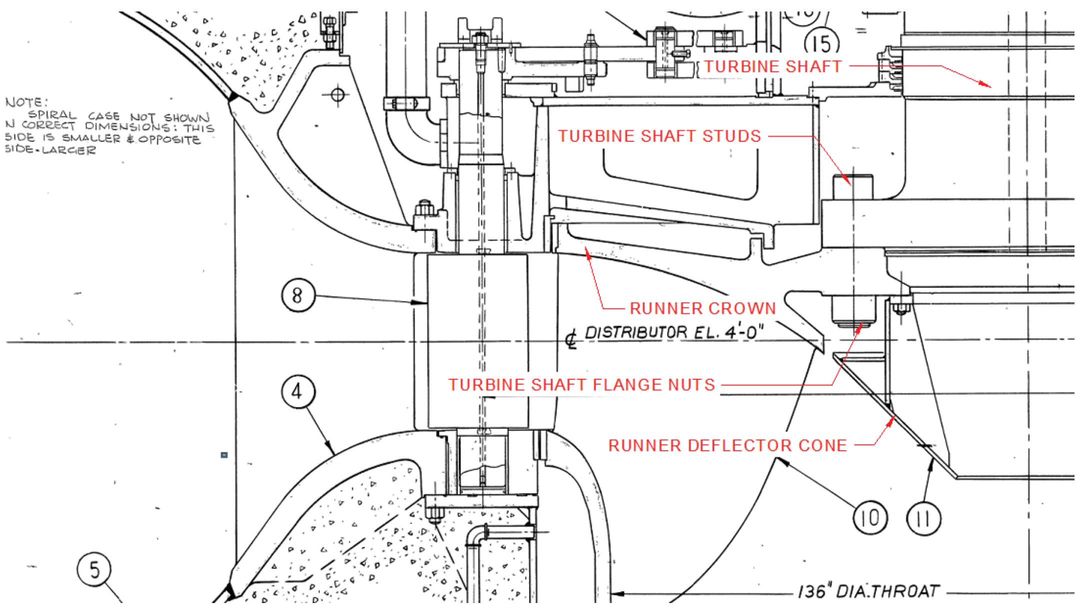

Figure 5-47: Turbine Shaft, from Unit Cross-Section

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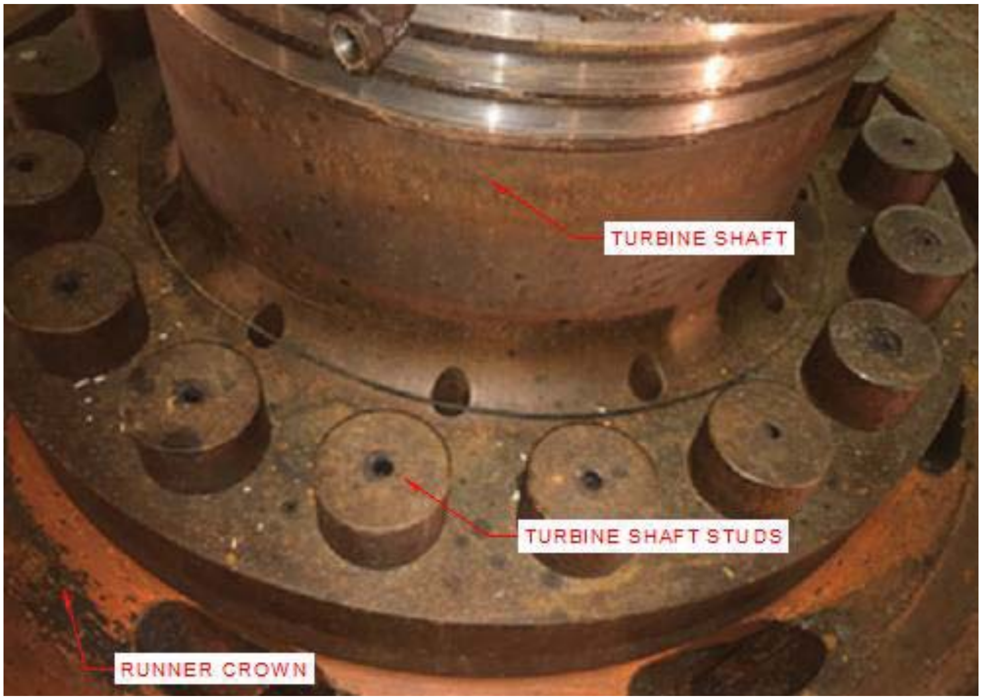

Figure 5-48: Turbine Shaft, Flange Hardware

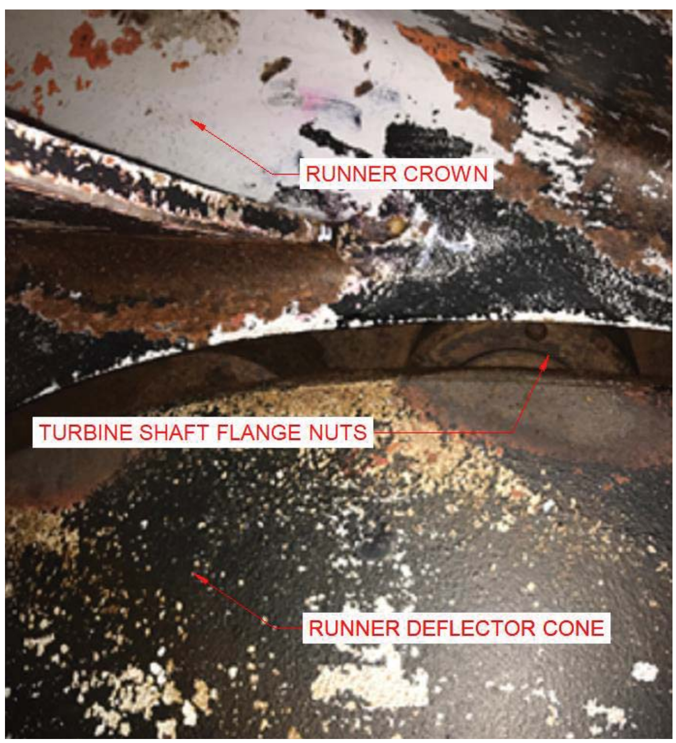

Figure 5-49: Turbine Shaft, Flange Hardware


Figure 5-50: Turbine Shaft Bearing Journal, Light scratches

Figure 5-51: Turbine Shaft Packing Seal Surface

5.10.3 Laser Inspection Data and Results

The high precision laser inspection of the Turbine Shaft was planned for by Voith, but not conducted by ESI. The decision not to perform the inspection was made after it was determined the Turbine Shaft was going to remain assembled to the Runner and that the effort to disassemble the two far outweighed the low risk of finding noteworthy indications. The good condition of the visible features of the Turbine Shaft was a driving factor in this decision.

5.10.4 Non-Destructive Examination

There was no non-destructive examinations planned or performed on the Turbine Shaft for the 2019 maintenance outage.

5.10.5 Outage Recommendations

Once the dimensional (laser) and visual inspections were completed, Voith provided NLH with recommendations to repair the indications outlined in Section 5.10.2. A summary of the recommendations, with discussions, final decision, and outcome are described in this section. A comprehensive list of documents pertaining to the recommendations, discussions, and approvals are located in the Appendix. Ideally, the Turbine Shaft would have been removed from the Runner, as this would have allowed for a complete inspection of the shaft and flange hardware. However, the risk of encountering indications requiring immediate attention was very low. The part of the shaft not inspected was the mating surface between the Runner and Turbine Shaft and the corresponding spigot joint. After visually inspecting the remainder of the shaft and considering the good condition of the critical surfaces and features, Voith was confident that the disassembly of the Runner/Shaft joint was not necessary.

- Voith recommended to smooth and blend any sharp edges or light scratches, to clean the shaft of dirt and debris, and to clean all bearing and flange mating surfaces. Voith recommended protecting the guide bearing journal surfaces until machine assembly.
    - **Reason:** Removing the dirt and debris eliminates the possibility for contamination issues in other systems of the machine. General cleaning and surface touch-up allows NLH to return the surfaces of the Turbine Shaft back to OEM condition, allowing parts to fit-up and mate in the manner in which they were designed. Note that this work was intended to be completed by manual labor, not by machine and therefore some forgiveness to the OEM surface finish requirements were allowed.
    - **Recommendation Summary:** Smooth and blend light scratches, clean the entire shaft of dirt and debris, and clean and restore critical surfaces and spigot joints by hand.
    - **Outcome:** NLH proceeded with the VH recommendation. Voith was not requested to perform any inspection or quality documentation of the repairs. Note that NLH purchased

three sets of Super Nuts to replace the existing OEM heat tensioned nuts, which required significant effort and time to remove during the disassembly of the machine in the 2019 Maintenance Outage. The Super Nuts only require manual hand torqueing to achieve the preload required. The Super Nuts also allow for a more simplistic disassembly and reassembly of the components during maintenance activities. They also do not require a heating source like the OEM nut. During the assembly of the unit in 2019 only two sets of Super Nuts were used. One set was used at the connection joint of the Rotor and Generator Shaft and the second set was used at the connection joint between the Turbine and Generator shafts. The third set, which is intended for the connection joint between the Runner and Turbine Shaft, was not used during the assembly because the Runner and Turbine Shaft were never disassembled during the 2019 outage; therefore this set was saved and stored until required, which can during the next major outage.

- Refer to Bay d'Espoir Unit 7 Inspection Recommendations document in the Appendix for additional pictures (VHY-10, 2019).

5.11 Generator Shaft

5.11.1 Background Information

Similar to the Turbine Shaft, the Generator Shaft is also a rotating element that transmits torque from the Runner to the Generator Rotor. The Generator Shaft is connected to the Turbine Shaft and the Generator Rotor. NLH removed the Generator Shaft from the Rotor and placed it on the powerhouse floor for inspection, as shown in Figure-5-52. The tasks planned for the Generator Shaft are described in this section.

Planned work:

- High Precision Dimension Inspection-LIDAR (VH Scope).
- Visual Inspection (VH Scope).

Figure 5-52: Generator Shaft

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5.11.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Generator Shaft and created a report describing its as-found condition and features. The inspection report document (Bay d'Espoir Inspection Recommendations Rev-, (VHY-10, 2019)) is located in the Appendix. While light scratches and small dents were present on the shaft, no indications requiring immediate attention were found. The only noteworthy indication of the Generator Shaft was on the Rotor coupling flange where discoloration and scoring were present, more than likely from the removal of the coupling hardware. Due to the shaft being placed on the floor the mating flange between the Generator Shaft and Turbine Shaft was not inspected; however, NLH millwrights and Hatch Engineering informed VH that they did not see any visual indications of damage or deterioration on the mating flanges during the disassembly process.

Figure 5-53: Generator Shaft, Rotor End

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Figure 5-54: Generator Shaft, Light Scratches

Figure 5-55: Generator Shaft, Coupling Hole


Figure 5-56: Generator Shaft, Rotor Flange Face

5.11.3 Laser Inspection Data and Results

The Generator Shaft was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The Runner dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The “reference only points” were recorded in case of certain questions or information was needed outside of the planned scoped. The planned laser inspection data is shown in Figure 5-57.

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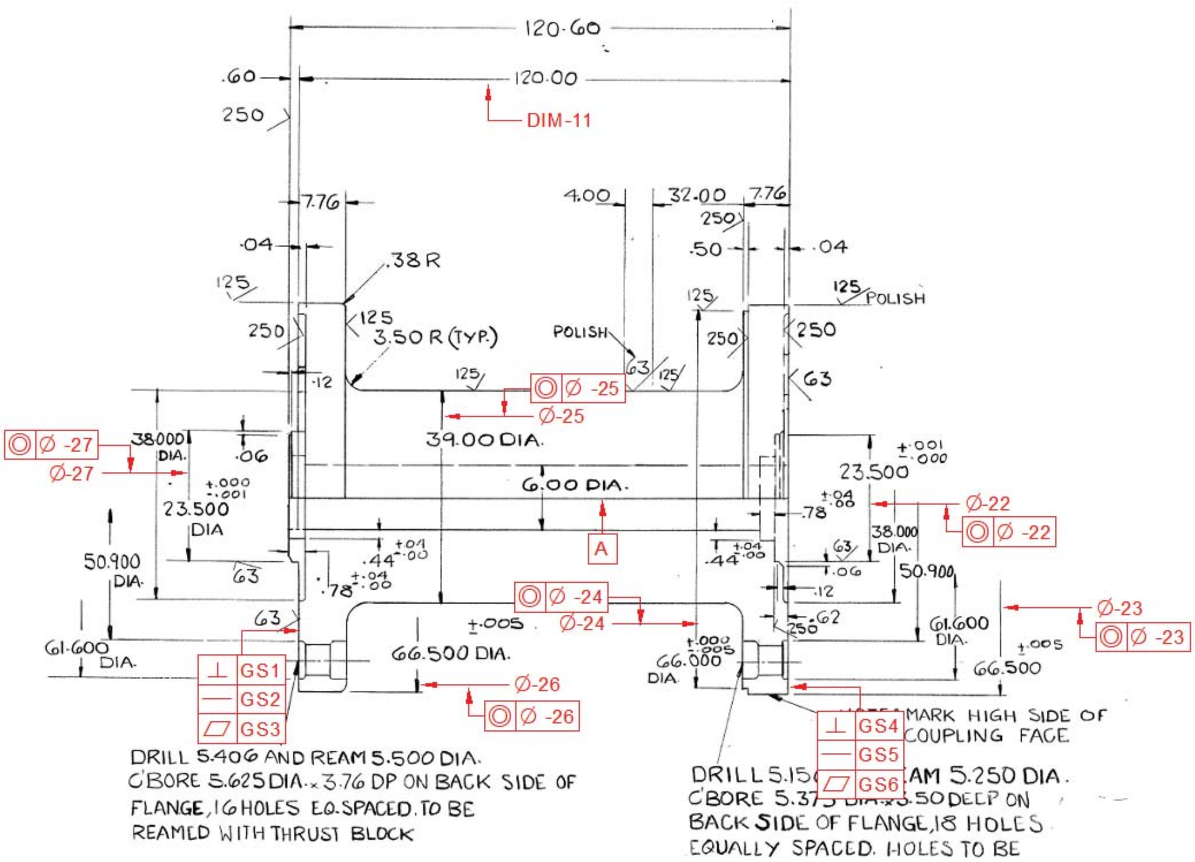

Figure 5-57: Generator Shaft Dimensional Inspection Plan

5.11.3.1 Generator Shaft Laser Inspection Conclusion

The main goal of the laser inspection of the Generator Shaft was to inspect specific diameters, flanges, features, and GD&T and then compare the data against the OEM planned drawing and check for any discrepancies with the shaft itself and possibly prepare for any machine alignment issues if found. In summary, all of the diameters and linear dimensions inspected on the Generator Shaft were within tolerance of the OEM design plan and the concentricity between the machined diameters was within 0.003 inch, which is acceptable for the features measured. The concentricity of diameters 23 and 24 were found to be slightly higher than the other diameters in Figures 5-57 and 5-58; however, these features had a larger OEM tolerance than the spigots and other features.

Figure 5-59 shows the flatness of both mating flanges of the Generator Shaft were found to be under 0.002 inch, which is acceptable. Overall, the Generator Shaft laser inspection was as expected and the data collected will be helpful for future planning activities with Unit 7. It should be noted that the laser inspector, ESI, noted in their report that the concentricity of the diameters collected could have been influenced by the movement of the shaft during the survey. This movement, which may or may not have occurred, would have been caused by the unevenness of the powerhouse floor. Voith believes ESI's comment had merit, but the concentricity values report were very low and consistent, indicating that large movements of the shaft probably did not occur.

Name	X	Y	Z	PolarAngle	Concentricity
CenterPoint Top spigot circle 27	0.0000	0.0000	122.2153	0.0000	0.0000
CenterPoint Outer top Circle 26	-0.0010	0.0009	122.5070	137.1239	0.0013
CenterPoint Circle 25	-0.0013	0.0027	84.0708	116.1373	0.0030
CenterPoint Circle 25	-0.0018	-0.0006	39.0669	199.7604	0.0019
CenterPoint Circle 25	-0.0006	-0.0034	15.0248	259.7387	0.0034
CenterPoint Bottom spigot 22	0.0000	0.0000	0.5428	0.0000	0.0000
CenterPoint Bottom Lip Circle 24	-0.0036	-0.0061	8.9844	239.3989	0.0071
CenterPoint Bottom Outer Flange 23	-0.0038	-0.0056	2.3692	235.7464	0.0068

Figure 5-58: Generator Shaft Concentricity Results

Name	X	Y	PolarAngle	PolarRadius	Elevation Z
CMP_1	14.8585	-12.6343	319.6252	19.5039	0.002
CMP_2	7.5877	-17.7928	293.0957	19.3432	0.001
CMP_3	2.0060	-19.2585	275.9466	19.3626	0.000
CMP_4	-5.7329	-18.4958	252.7787	19.3639	0.000
CMP_5	-12.6704	-14.5592	228.9680	19.3004	0.001
CMP_6	-17.5167	-8.4499	205.7522	19.4483	0.000
CMP_7	-19.6451	-0.4323	181.2605	19.6498	0.000
CMP_8	-18.3509	7.1602	158.6852	19.6983	0.000
CMP_9	-14.3533	13.0105	137.8093	19.3724	0.000
CMP_10	-7.4495	17.8978	112.5982	19.3863	-0.001
CMP_11	2.3459	19.9778	83.3027	20.1150	-0.002
CMP_12	10.8236	16.2044	56.2593	19.4868	-0.001
CMP_13	16.2409	11.1901	34.5670	19.7227	0.000
CMP_14	19.1465	5.8052	16.8673	20.0072	0.000
CMP_15	19.2918	-2.4050	352.8940	19.4411	0.001

Plane: "**Bottom Mid Plane 22**" (15) WCS: "Spigot Line 2"
Flatness: 0.0019
Center: X-0.2278 Y-0.1855 Z0.0000
Normal: I0.0000 J-0.0000 K-1.0000
Length: 43.9822 Width:41.9397

Total Points: 15 Used: 15 Unused: 0
MinDev: -0.0009 MaxDev: 0.0010 Range: 0.0019
AveDev: 0.0000 StdDev: 0.0006 RMS: 0.0005

Name	X	Y	PolarAngle	PolarRadius	Elevation Z
BMP_1	-2.1114	-20.3102	264.0650	20.4197	0.0011
BMP_2	-7.1698	-19.2117	249.5344	20.5060	0.0012
BMP_3	-11.8566	-16.2810	233.9360	20.1408	0.0012
BMP_4	-17.0898	-10.7473	212.1647	20.1882	0.0012
BMP_5	-19.4240	-3.7517	190.9318	19.7830	0.0007
BMP_6	-20.5026	0.1636	179.5429	20.5033	0.0008
BMP_7	-20.4122	3.8939	169.1997	20.7803	0.0003
BMP_8	1.3854	23.9817	86.6938	24.0217	-0.0008
BMP_9	5.5729	23.1305	76.4538	23.7923	-0.0010
BMP_10	12.3723	20.8218	59.2812	24.2203	-0.0009
BMP_11	13.5395	19.8995	55.7688	24.0688	-0.0010
BMP_12	15.3064	18.2176	49.9631	23.7942	-0.0014
BMP_13	23.0357	-1.6125	355.9959	23.0921	-0.0014
BMP_14	22.6917	-7.5371	341.6259	23.9107	-0.0003

Plane: "**Mid Top Plane 26**" (14) WCS: "Spigot Line 2"
Flatness: 0.0010
Center: X-0.3331 Y2.1898 Z121.5068
Normal: I0.0000 J0.0000 K1.0000
Length: 49.2648 Width:51.3550

Total Points: 14 Used: 14 Unused: 0
MinDev: -0.0006 MaxDev: 0.0003 Range: 0.0010
AveDev: -0.0000 StdDev: 0.0003 RMS: 0.0002

Figure 5-59: Generator Shaft Mating Flange Flatness

5.11.4 Non-Destructive Examination

There was no non-destructive examination planned or performed on the Generator Shaft for the 2019 maintenance outage.

5.11.5 Outage Recommendations

Once the dimensional (Laser) and visual inspection were completed, Voith provided NLH with recommendations to repair the indications outlined in Section 5.11.2. A summary of the recommendations, final decision, and outcome are included in this section. A comprehensive list of documents pertaining to the recommendations, discussions, and approvals are located in the Appendix.

- Voith recommended to smooth and blend any sharp edges or light scratches, to clean shaft of dirt and debris, and to clean flange mating surfaces.
  - **Reason:** Removing the dirt and debris eliminates the possibility for contamination issues in other systems of the machine. General cleaning and surface touch-up allows NLH to return the surfaces of the Generator Shaft back to OEM condition and allow parts to fit-up and mate in the manner they were designed. Note that this work was intended to be completed by manual labor, not by machine; therefore, the OEM surface finish requirements were not expected, but to be improved to acceptable operating range, if necessary.
  - **Recommendation Summary:** Smooth and blend light scratches, clean entire shaft of dirt and debris, clean and restore critical surfaces and spigot joints by hand.
  - **Outcome:** NLH proceeded with the VH recommendation. Voith was not requested to perform any inspection or quality documentation of the repairs. Note that NLH purchased three sets of Super Nuts to replace the existing OEM heat tensioned nuts, which required significant effort and time to remove during the disassembly of the machine in the 2019 Maintenance Outage. The Super Nuts only require manual hand torqueing to achieve the preload required. The Super Nuts also allow for a more simplistic disassembly and reassembly of the components during maintenance activities. They also do not require a heating source like the OEM nut. During the assembly of the unit in 2019 only two sets of Super Nuts were used. One set was used at the connection joint of the Rotor and Generator Shaft and the second set was used at the connection joint between the Turbine and Generator shafts. The third set, which is intended for the connection joint between the Runner and Turbine Shaft was not used during the assembly. This was due to the Runner and Turbine Shaft never being disassembled during the 2019 outage; therefore this set was saved and stored until required, which can be during the next major outage.
  - Refer to Bay d'Espoir Unit 7 Inspection Recommendations document in the Appendix for additional pictures (VHY-10, 2019).

5.12 Operating Ring

5.12.1 Background Information

The Wicket Gate Operating Ring is the ring rotated by the servomotors transmitting the force from the servomotors to all of the Wicket Gates simultaneously. The Operating Ring is located on the top of the Head Cover where it moves around the Head Cover Extension on a series of thrust and radial bearings (liners) fitted to the Head Cover Extension. There was no dimensional inspection planned for the Operating Ring.

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Planned work:

- Visual Inspection (VH Scope).

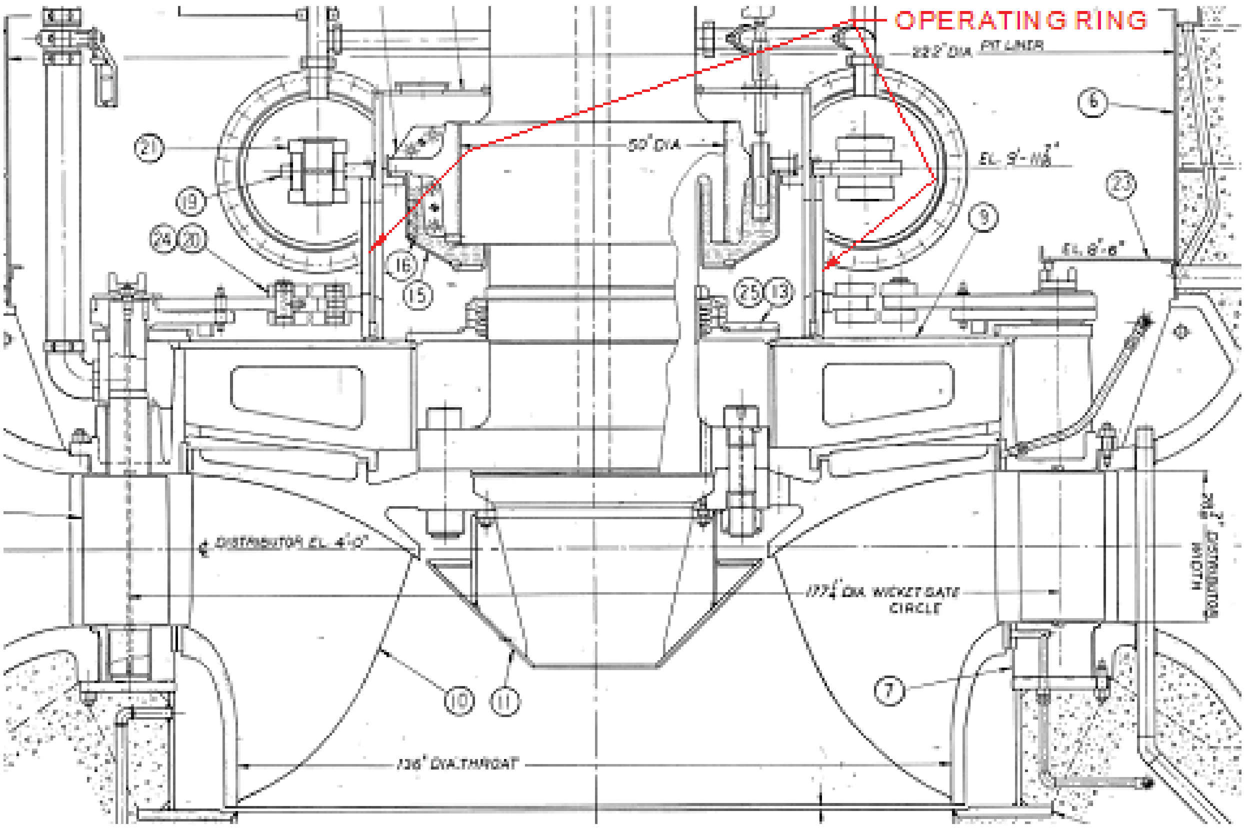

Figure 5-60: Operating Ring, Turbine Cross-Section View

Figure 5-61: Operating Ring

5.12.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Operating Ring and Head Cover Extensions and created a report defining the as-found condition and associated features. The inspection report document (Bay d'Espoir Inspection Recommendations Rev-, (VHY-10, 2019)) is located in the Appendix. In summary, the visual inspection revealed significant deterioration to the bearing surfaces of the ring. This damage was reflected on the Head Cover Liners, the pads the Operating Ring rides on during operation (Figures 5-65 and 5-66).

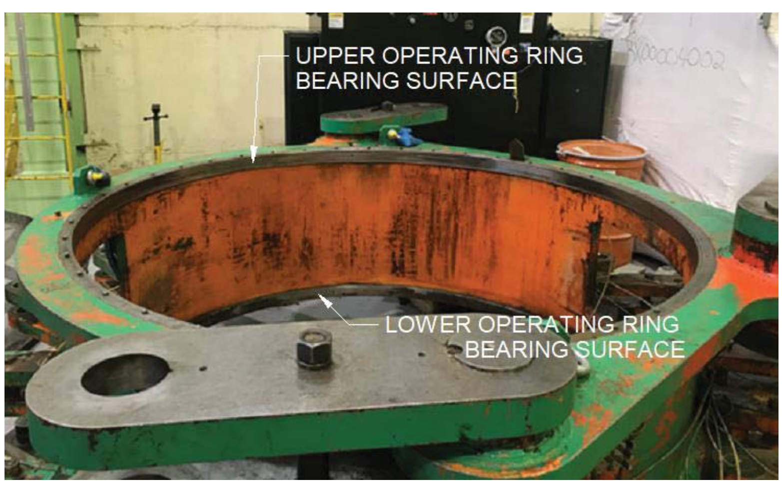

Figure 5-62: Operating Ring Bearing Surfaces

Figure 5-63: Operating Ring, Upper Bearing Surface Damage

Figure 5-64: Operating Ring, Lower Bearing Surface Damage

Figure 5-65: Lower Head Cover Liner

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Figure 5-66: Upper Head Cover Liner

5.12.3 Laser Inspection Data and Results

While there was no High Precision Dimensional Inspection (LIDAR) planned for the Operating Ring. NLH asked VH to take some measurements on the Operating Ring. The measurements were used during the investigation and analysis on how to repair the Operating Ring bearing surfaces and to help determine if the OEM Head Cover Liners could be used. Voith recorded diameter measurements of the bearing surfaces, which were required for the design of new Head Cover Liners. These measurements also showed the shape of the part and helped to determine if the Operating Ring deformed overtime.

The Operating Ring measurements in Figures 5-67 and 5-68 show the inside radii of the bearing surfaces compared to the OEM design (upper/lower tolerance). The measurements reveal that the Operating Ring, which is intended to be a circle, has slightly ovallized. This oval shape is clearly shown in Figures 5-69 and 5-70. Figure 5-71 shows the Operating Ring measurements compared to new OEM Head Cover Liner dimensions. Analysis of this data determined that the overall shape and critical dimensions of the Operating Ring were still within an acceptable range, although precautions would need to be taken to account for the deteriorated bearing surfaces of the ring.

OEM Upper Tolernace	Top Op. Ring As Founds	Delta
41.7450	41.7510	0.006
41.7450	41.7532	0.008
41.7450	41.7569	0.012
41.7450	41.7605	0.015
41.7450	41.7627	0.018
41.7450	41.7578	0.013
41.7450	41.7577	0.013
41.7450	41.7597	0.015
41.7450	41.7541	0.009
41.7450	41.7540	0.009
41.7450	41.7477	0.003
41.7450	41.7509	0.006
41.7450	41.7563	0.011
41.7450	41.7611	0.016
41.7450	41.7615	0.016
41.7450	41.7611	0.016
41.7450	41.7595	0.014
41.7450	41.7589	0.014
41.7450	41.7515	0.006
41.7450	41.7500	0.005
	Max	0.018
	Min	0.003
	Average	0.011

OEM Lower Tolerance	Top Op. Ring As Founds	Delta
41.7410	41.7510	0.010
41.7410	41.7532	0.012
41.7410	41.7569	0.016
41.7410	41.7605	0.019
41.7410	41.7627	0.022
41.7410	41.7578	0.017
41.7410	41.7577	0.017
41.7410	41.7597	0.019
41.7410	41.7541	0.013
41.7410	41.7540	0.013
41.7410	41.7477	0.007
41.7410	41.7509	0.010
41.7410	41.7563	0.015
41.7410	41.7611	0.020
41.7410	41.7615	0.020
41.7410	41.7611	0.020
41.7410	41.7595	0.018
41.7410	41.7589	0.018
41.7410	41.7515	0.010
41.7410	41.7500	0.009
	Max	0.022
	Min	0.007
	Average	0.015

Figure 5-67: As-found Dimensions compared to OEM Tolerances, Top Bearing Surface

OEM Lower Tolerance	Bottom OP. Ring As founds.	Delta
42.2410	42.2524	0.011
42.2410	42.2592	0.018
42.2410	42.2456	0.005
42.2410	42.2477	0.007
42.2410	42.2536	0.013
42.2410	42.2581	0.017
42.2410	42.2613	0.020
42.2410	42.2741	0.033
42.2410	42.2949	0.054
42.2410	42.2653	0.024
42.2410	42.2552	0.014
42.2410	42.2464	0.005
42.2410	42.2474	0.006
42.2410	42.2470	0.006
42.2410	42.2530	0.012
42.2410	42.2642	0.023
42.2410	42.2691	0.028
42.2410	42.2629	0.022
42.2410	42.2618	0.021
42.2410	42.2569	0.016
	Max	0.054
	Min	0.005
	Average	0.018

OEM Upper Tolernace	Bottom Op. Ring As founds.	Delta
42.2350	42.2524	0.017
42.2450	42.2592	0.014
42.2450	42.2456	0.001
42.2450	42.2477	0.003
42.2450	42.2536	0.009
42.2450	42.2581	0.013
42.2450	42.2613	0.016
42.2450	42.2741	0.029
42.2450	42.2949	0.050
42.2450	42.2653	0.020
42.2450	42.2552	0.010
42.2450	42.2464	0.001
42.2450	42.2474	0.002
42.2450	42.2470	0.002
42.2450	42.2530	0.008
42.2450	42.2642	0.019
42.2450	42.2691	0.024
42.2450	42.2629	0.018
42.2450	42.2618	0.017
42.2450	42.2569	0.012
	Max	0.050
	Min	0.001
	Average	0.014

Figure 5-68: As-found Dimensions compared to OEM Tolerances, Bottom Bearing Surface

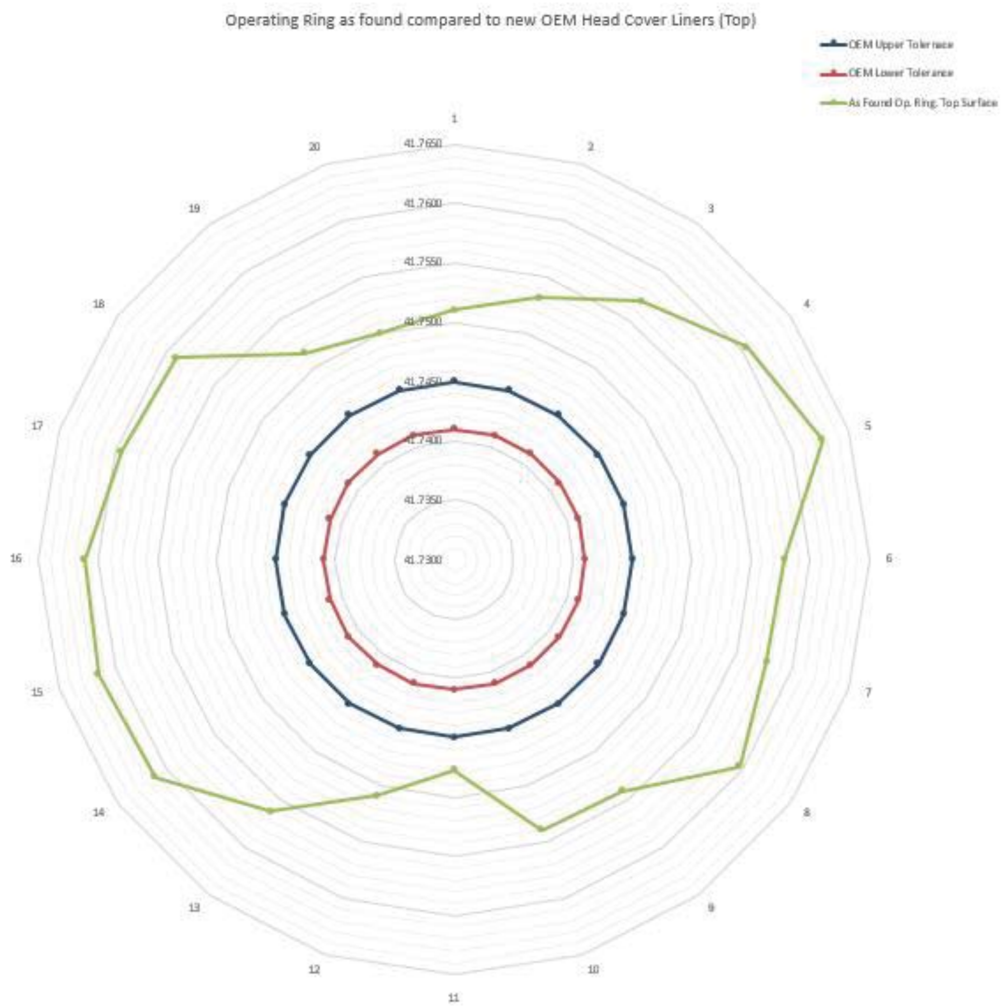

Figure 5-69: Operating Ring, Upper Bearing Surface (Green)

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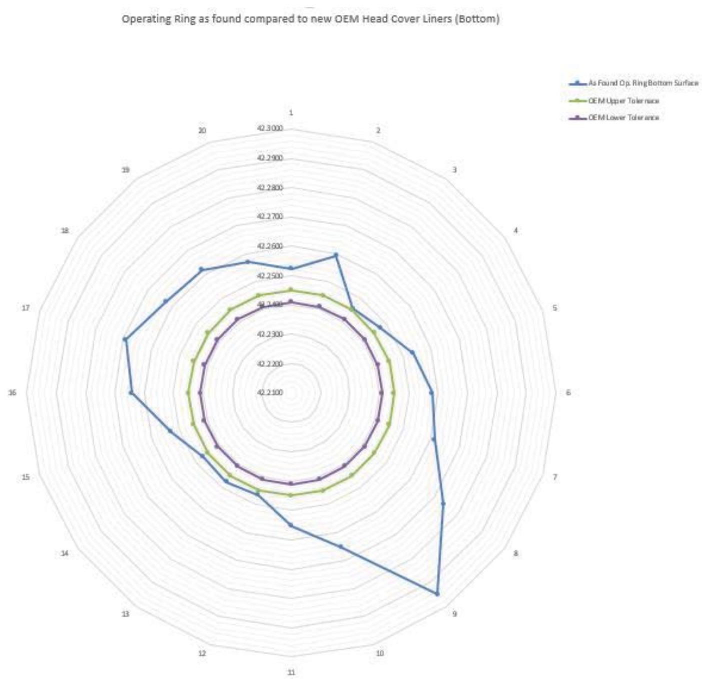

Figure 5-70: Operating Ring, Lower Bearing Surface (Blue)

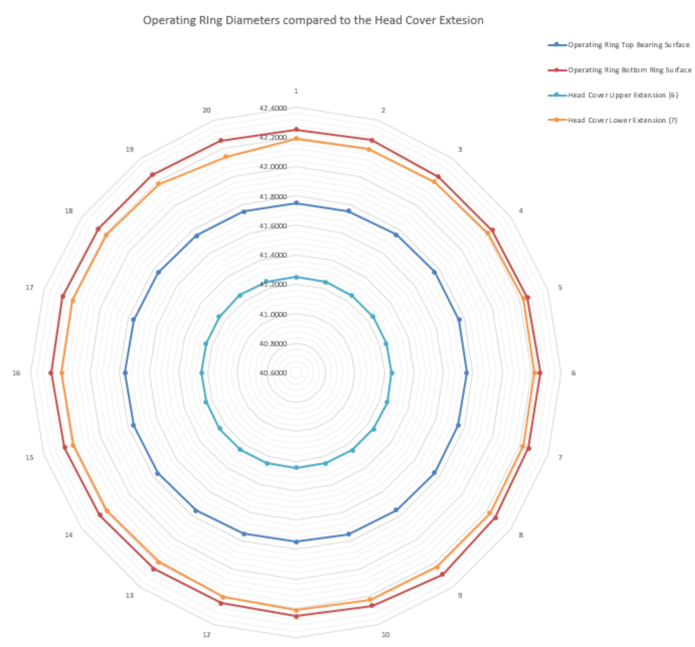

Figure 5-71: Operating Ring Clearance (As found) to Head Cover Liners (OEM)

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5.12.4 Non-Destructive Examination

There were no non-destructive examinations planned or performed on the Operating Ring for the 2019 maintenance outage.

5.12.5 Outage Recommendations

- **Recommendation Summary:**
  - Due to the condition of the Operating Ring bearing surfaces and the amount of wear on the Head Cover Liners, Voith recommended that the bearings surfaces be dressed and sanded; all of the high and rough locations should be sanded flush and blended into the surrounding material. The heavily pitted area should be filled with an epoxy and sanded flushed. The purpose for doing these activities is to improve the bearing surface roughness to as close to the OEM design as possible. The epoxy is a temporary repair for the pitted areas. This specific repair was an attempt to protect the new Head Cover Liners from being damaged by the rough surface. This improved surface finish would help extend the life of new OEM Head Cover Liners, which were required to be replaced due to the deterioration beyond repair of the liners. Ideally, the Operating Ring would have been sent to a machine shop and the bearing surfaces machined to the desired finished. This would have returned the shape of the ring to a circle, eliminate the elliptical shape, and ultimately improve the mechanical function and service life of the parts. The option of machining the ring was not feasible due to the time constraints of the 2019 NLH maintenance outage and the fact that the condition of the Operating Ring was unknown prior to the outage.

- **Outcome**
  - After VH presented their findings and discussed options with NLH, the decision was to follow VH's recommendation and repair the bearing surface of the Operating Ring and procure new OEM Head Cover Liners. Due to the time constraints of the 2019 outage, the OEM Head Cover Liner material, ASTM B171 Alloy 365, was unavailable and the lead time to obtain the raw material and manufacture the part was not parallel with maintaining the assembly schedule of the unit. To possibly remedy this issue, NLH contacted Thordon Bearing Inc. to investigate if a polymer material would be suitable alternative. After Thordon conducted their research of the application of the bearings, it was determined that the alternative SXL material was a viable candidate for replacing the OEM material.

    Prior to purchasing the Thordon bushings NLH discussed the material choice with VH and jointly evaluated the advantages and risks. While the polymer Thordon offer has many advantages, it would not be VH's first recommendation, but in the timeframe and limited resources available to NLH at the time of the outage, VH agreed that the Thordon material was the best option. At this time NLH worked directly with Thordon in the design and procurement of the liners, although VH offered input and recommendations as needed.

NLH amended VH's recommendation and moved forward. The Operating Ring bearing surface was sanded down, removing the high spots and rough areas that would cause damage to the new plastic liners Thordon provided for NLH; therefore, no epoxy was used to restore the surface finish. Voith was in agreement with this due to the unknown reaction between the epoxy and plastic liners. Thordon was also adamant that the epoxy was not required. To account for the condition of the bearing surface and the distorted shape of the Operating Ring, NLH and Thordon determined and agreed to adjust the diametrically clearance between the Operating Ring and Head Cover Liners to 0.085 inch, from the OEM ~0.020 – 0.030 inch. NLH discussed the increase in clearance with VH prior to committing and VH informed NLH that the risk was low and the increase in clearance should not impact the Wicket Gate Mechanism.

5.12.6 Conclusion

During the reassembly of the machine, NLH installed the Thordon SXL liners onto the Head Cover, lowered the Operating Ring into place, and performed a bump test to verify the actual installed clearance between the bearing surfaces. The bump test revealed that the actual clearance of 0.150 inch was much higher than the agreed upon 0.085 inch. To improve and decrease the clearance, NLH installed 0.030 inch shims behind the liners, improving the diametrically clearance globally to approximately 0.100 inch. NLH discussed the clearance with VH to determine if there were any adverse effects of the increased clearance.

Voith informed NLH that the increased clearance only affects the Operating Ring. During gate closure, the Operating Ring will flex more until all forces (externally applied from the Servomotor, reactions from the bearing pads, and from the wicket gates through the gate links) reach equilibrium. The risk of using the Operating Ring with the increased clearance is very small. It is recommended to not apply full servomotor pressure during commissioning. Instead gradually increase the pressure to make sure no adverse reactions on the Operating Ring occur. Voith did not expect any negative impact on the usability of the Operating Ring during the anticipated operating time of 5 years until the next major outage. At the time of this next outage, the indication maps should be compared to the maps obtained during this outage.

5.13 Servomotor

5.13.1 Background Information

The Wicket Gate Servomotor is a hydraulic cylinder that is actuated by oil pressure to supply the force necessary to operate the Wicket Gate though the Operating Ring. The BDES Unit 7 Servomotors are shown in the OEM Turbine Cross-Section drawing in Figure 5-72 (BDES-2, 1976). Voith was not tasked with performing any work on the Servomotors other than a visual inspection. During the outage NLH disassembled the Servomotors to inspect the internal parts and replace any wear components, if necessary. It is noteworthy to mention that NLH verbally informed VH engineering that the Servomotors were thought to be internally leaking prior to the 2019 maintenance outage.

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Planned Work:

- Visual Inspection (VH Scope).

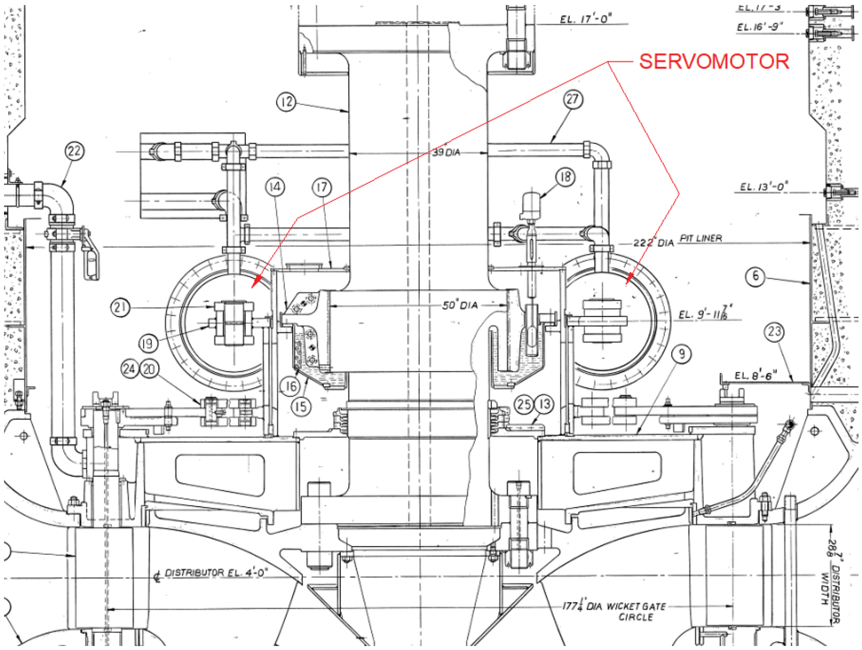

Figure 5-72: Servomotor Location

Figure 5-73: Bay d'Espoir Unit 7 Servomotors

5.13.2 Visual Inspection

In order to evaluate the condition of the Servomotors and determine a rehabilitation plan, Voith conducted a high level visual inspection of both pieces. Externally both of the Servomotors were in good condition. As shown in Figure 5-73, the Servomotors had at least three different colors of paint applied to them since commissioning. Overall, the paint and exterior features of each of the Servomotors were in good condition and no signs of leaks or damage were present. Some light scoring and damage were found once the Servomotors were disassembled. The indications were located on the piston head and main cylinder of the Servomotor. Shown in Figure 5-75, two types of the damage were found: light scorings on the piston head outer diameter and gouging to moderate scratches on the piston rings. Similar damage was found on the internal diameter of the Servomotor cylinders. Illustrated in Figure 5-76, abnormal wear, scratches, and gouges were present.

In both instances the indications found could be categorized as light damage with minimal impact to function, posing a low risk to the operation of the machine. However, these surfaces are intended to be sealing surfaces, which allows the Servomotors to maintain a constant design pressure. If these cylindrical surfaces are not smooth or concentric to each other, it can lead to oil seepage and affect the pressure. This constant change (leak) in pressure causes the secondary or jockey pumps to be activated to maintain squeeze pressure on the Wicket Gates. This squeeze occurs anytime the Wicket Gates are closed and are required to prevent the head water from entering the Runner. In general, the gates are closed for maintenance, when power generation is not required, or when the unit is operating as Synchronous Condenser, which is approximately 20 percent of the time. The Servomotors did not have any other notable signs of damage or alarming wear at the time of the inspection.

Figure 5-74: Servomotor, Piston Head

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Figure 5-75: Servomotor, Piston Scoring

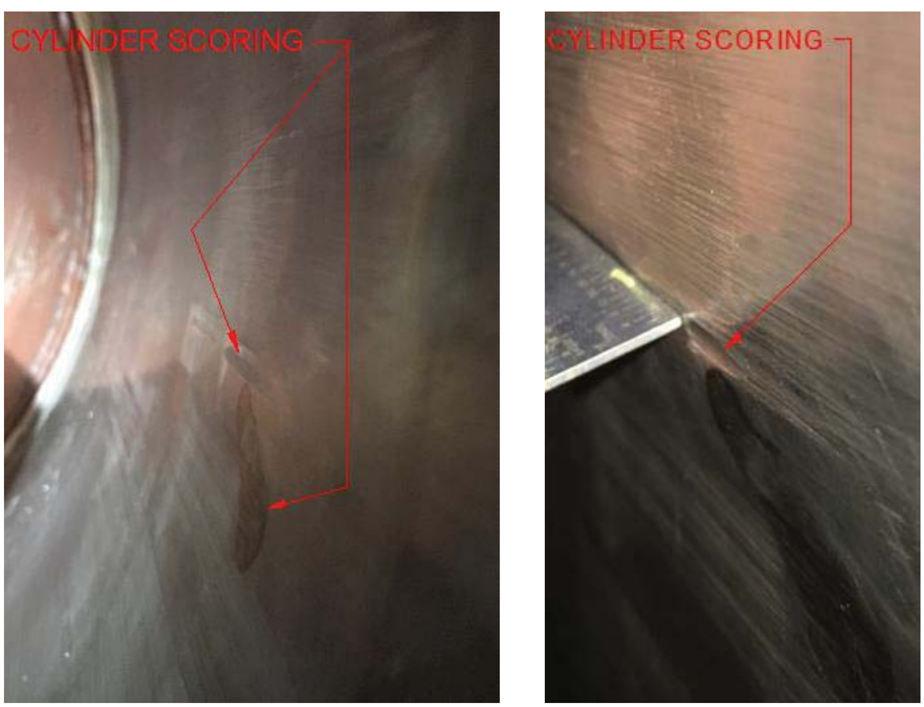

Figure 5-76: Servomotor, Cylinder Scoring

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5.13.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Servomotors during the 2019 maintenance outage.

5.13.4 Non-Destructive Examination

There was no Non-Destructive Examination planned for or performed on the Servomotors during the 2019 maintenance outage.

5.13.5 Outage Recommendations

Preferably, the Servomotor cylinder and piston would be rehabilitated to remedy all of the indications discussed in Section 5.13.2, but due to unforeseen nature of the issues and the lack of time and resources, a short-term solution was required.

- Voith informed NLH that ideally the Servomotors should be rehabilitated to OEM specification; however, to accommodate the circumstances and limitations during the 2019 outage, VH recommended that NLH clean and lightly sand (Scotch Brite) the rough spot inside the cylinders while being careful not to remove any more material than necessary. The piston head should also be cleaned and all rough spots mentioned during the Visual Inspection should be addressed. Voith recommended cleaning the remaining parts of the Servomotors, replacing all seals, and installing new piston rings. If new piston rings were not available, then the original rings could be used once cleaned and the high and rough spots were repaired. Voith was comfortable using the original piston rings because the net gain of using new piston rings on the highly worn cylinder walls was unknown and possibly have no positive impact. New piston rings are most effective if the cylinder wall of the Servomotors would be machined to a known size and rings manufactured to fit.
    - **Reason:** Prevent leaking inside the Servomotor, which causes secondary pumps to be activated unnecessarily.
    - **Recommendation Summary:** Clean all Servomotors components, repair visual indications, restore cylinder surfaces, and replace rings (if possible).
    - **Outcome:** NLH followed Voith's recommendation. The Servomotors components were cleaned prior to reassembly, the inside diameter wall of the Servomotor cylinders were addressed as recommended, and new rings were installed. No pressure test was performed on the Servomotors prior to reassembly of the unit.

5.14 Gate Arms and Linkages

5.14.1 Background Information

The Gate Mechanism consists of all of the components used to actuate the Wicket Gates, including the Servomotors, the Gate Operating Ring, and all of the Linkages. The Gate Arms and Linkages had very limited scope planned for the 2019 maintenance outage. The Gate Linkages consist of all of the parts that connect the Wicket Gate to the Operating Ring. The parts usually include a Gate Arm, Shear Pin, Shear Lever, Gate Link Pin, and Gate Link. A general layout of parts connecting the Wicket Gate to the Operating Ring is in Figure 5-77.

Planned Work:

- Visual Inspection (VH Scope).
- Clean and Paint Gate Mechanism Components (NLH).

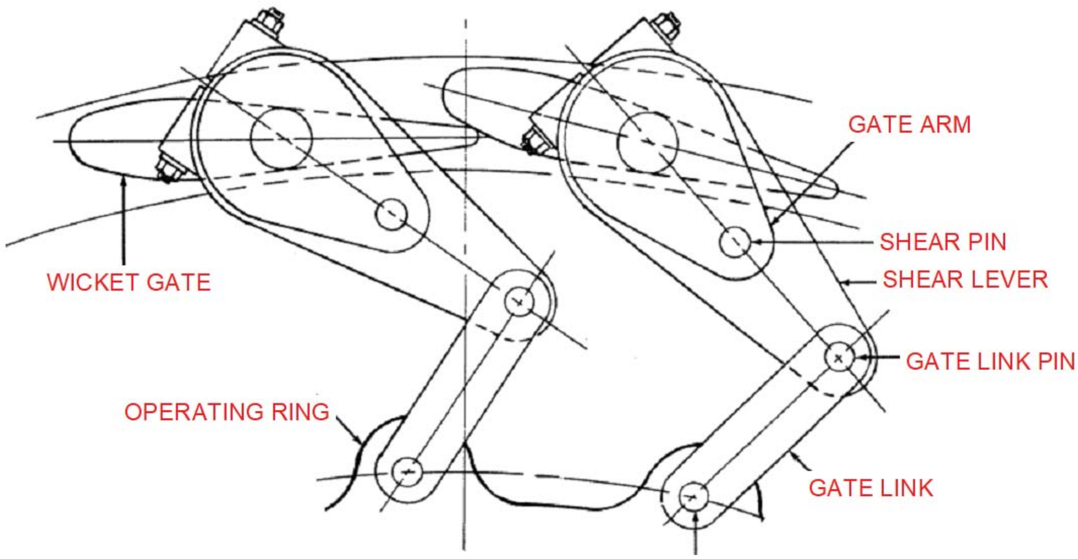

Figure 5-77: Typical Gate Mechanism Layout

5.14.2 Visual Inspection

The visual inspection performed on the Gate Mechanism Linkages did not yield any notable indications or areas of concern to report. At the time of disassembly, all of the components were heavily coated with grease and dirt. There were no signs of unexpected wear or damage once NLH removed the grease and cleaned each component.

Figure 5-78: Gate Linkages

Figure 5-79: Gate Arms and Shear Levers

Figure 5-80: Gate Arms and Shear Levers

5.14.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Linkages during the 2019 maintenance outage.

5.14.4 Non-Destructive Examination

There was no Non-Destructive Examination planned for or performed on the Linkages during the 2019 maintenance outage.

5.14.5 Outage Recommendations

Voith did not make any formal recommendations for any of the linkages for the BDES Unit 7 Gate Mechanism. NLH cleaned and painted all of the linkages. While doing so, NLH was able to perform their own high level visual inspection where no major signs of damage or wear were present.

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5.15 Rotor

5.15.1 Background Information

The Rotor is a rotating component of an electromagnetic system in the generator. Its rotation is due to the interaction between the windings and magnetic field which produces a torque around the Rotor's axis. The Rotor is made up of three main parts: Rotor Hub, Rotor Rim, and the Poles. These parts are assembled to create the Rotor assembly, which rotates inside the stationary Stator. The diameter of the Rotor is approximately 280.0 inches with an assembled weight of over 475,000 pounds. NLH established a detailed plan for the Rotor activities during the 2019 maintenance outage using the experience from previous outages at Bay d'Espoir Powerhouse One and from the recommendations outlined in a refurbishment plan (VHY-1, 2017) developed by VH.

Planned Work:

- Visual Inspection (VH Scope).
- Laser Inspection (VH Scope).

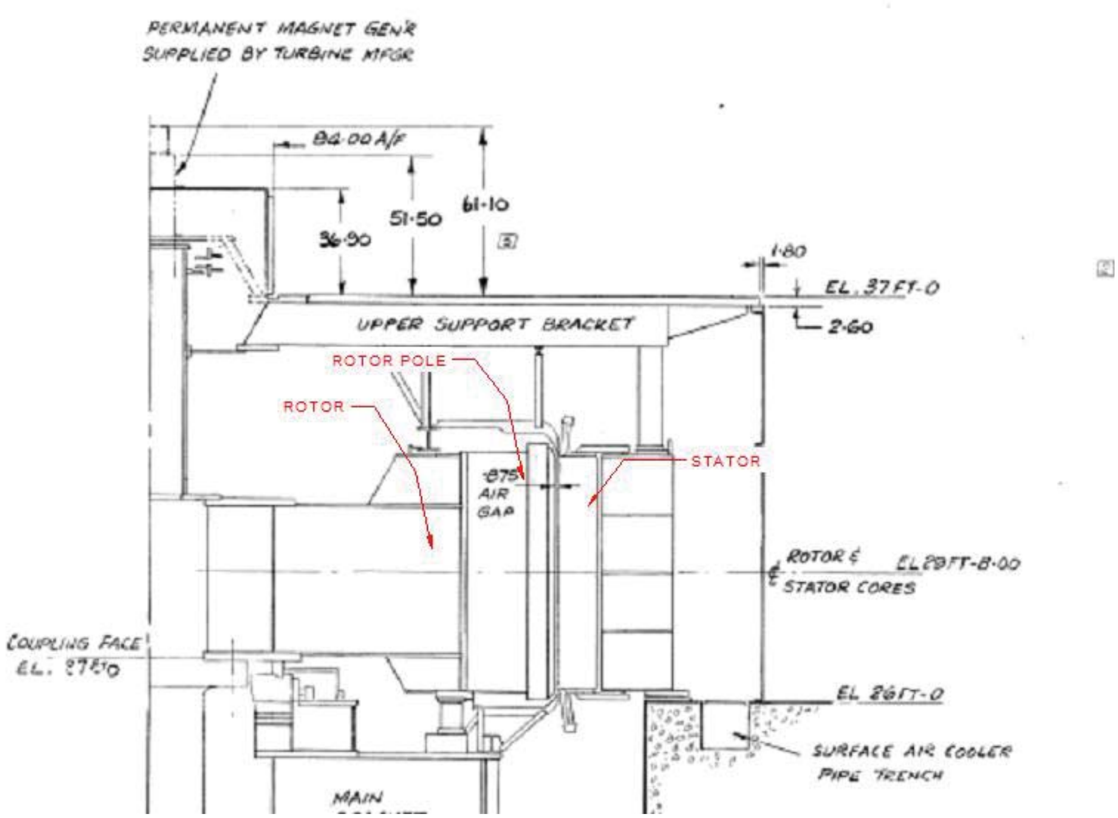

Figure 5-81: Rotor, Outline

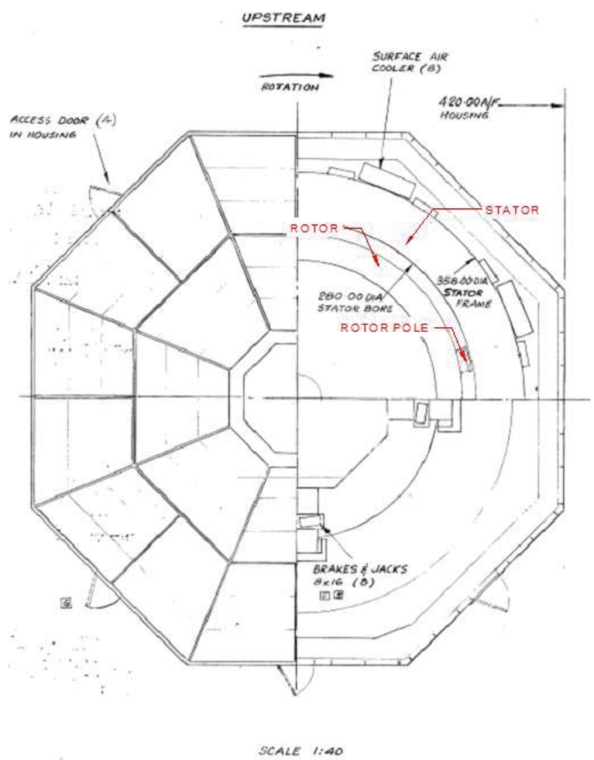

Figure 5-82: Rotor, Outline

Figure 5-83: Rotor, Removed from Stator

5.15.2 Visual Inspection

Voith engineering performed a visual inspection of the Rotor to look for any signs or indications of abnormal wear or damage. The overall condition of the Rotor was fair, but certain components were found to be in poor condition. The inspection of the Rotor can be segmented into parts based upon the different individual features of the part itself. The features are as follows: Rotor Hub, Rim and Poles. During the outage the Rotor was stored near the powerhouse door with the upper bracket placed delicately on top. This was due to the limited space available in the powerhouse. The rotor was supported by 12 equally spaced stands on the Brake Ring surface of the Hub.

5.15.2.1 Rotor Hub and Spider

The Rotor Hub's function is to support the Rotor Rim with the Poles, Fans, and Brake Ring assembly. Once installed into the Stator the Rotor Hub transmits the shaft torque to the Rotor Rim and Poles. The Rotor Hub also absorbs the forces due to the rim shrinkage during operation. During the inspection Voith was searching for indications of damage or failure around the higher stress locations of the Rotor Hub. The Shaft mating surface and spigot joints were found be in the fair condition with no signs of deformation or damages. The coupling holes appeared to have some signs of fretting and light corrosion, but they were light in nature and did not pose any concerns at the time of the 2019 maintenance outage. The keyways and threaded holes for that mate with the Thrust Collar were also in fair condition with no signs on wear or thread damage present.

The structural components were visually inspected for indications of wear or damage. The beams and ribs that are around the Rotor Hub were in good condition. The original OEM paint was still visible and for the most part in good condition; although, significant areas of dirt and grease were found in certain areas of the Hub. These areas were located in lower sections of the hub close to inner diameter of the Rim Laminations. There was a light film of oil over some of the sections, indicating a possible leak, but the source was not apparent.

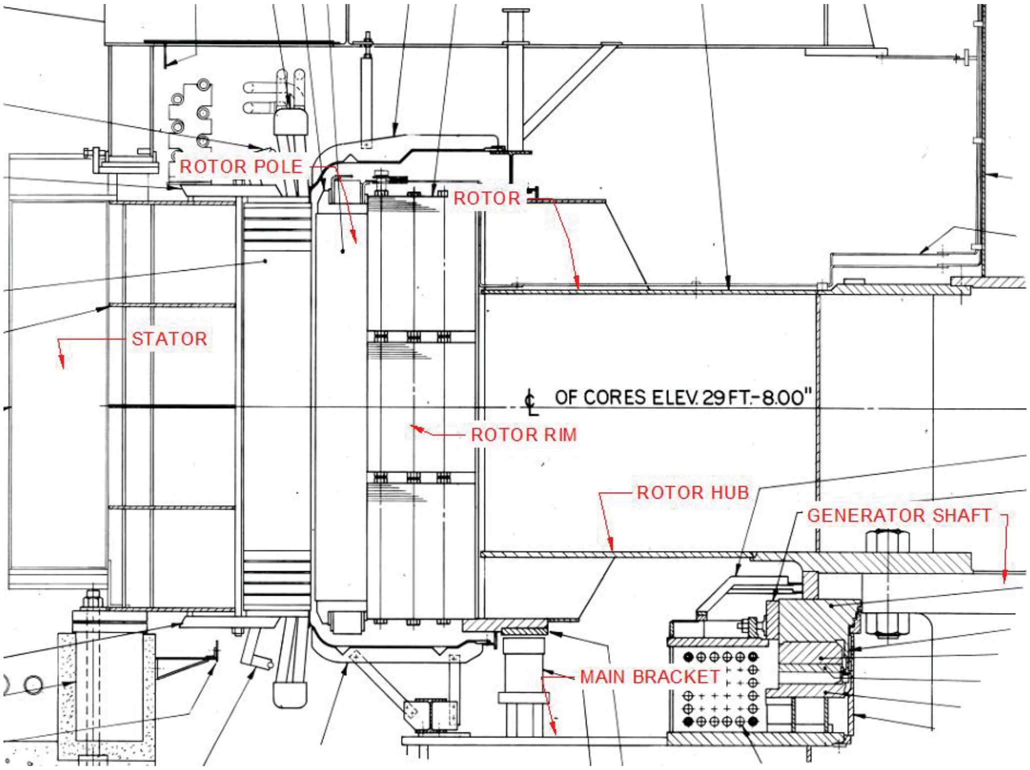

Figure 5-84: Rotor Hub, Outline

Figure 5-85: Rotor, Hub Coupling holes and Mating Surface

Figure 5-86: Rotor, Hub Lower Spigot Joint

Figure 5-87: Rotor Hub, Light Fretting and Oxidation on Coupling Flange

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Figure 5-88: Rotor Hub, Coupling Hole Fretting

Figure 5-89: Rotor Hub, Top View and Upper Spigot

Figure 5-90: Rotor Hub, Oil Film, Grease, and Dirt

5.15.2.2 Rotor Rim

The Rotor Rim is located between the Poles and main structure of the Hub. The Rim's principle construction is a stack of laminated steel alloy plates comprised of an alloy of high mechanical strength. The stack is radially shrunk-fit to the Rotor; tangentially, by means of a set of tangential and radial wedges. This attachment method ensures radial stability of the Rotor. The Rotor Rim serves as a means to close the magnetic circuit of the Rotor, a frame work to attach the poles, an inertia guarantee, and acts as a fan to generate air flow through the Rotor and Stator.

At the time of the inspection Voith engineering found the Rotor Rim to be in fair condition. Light surface rust was present on the individual Laminations during the inspection; however, more oxidation developed during the outage, consequently causing the laminations of the Rotor Rim to have a moderate coat of surface rust present when NLH started to perform electrical tests on the Rotor prior to assembly. The top and bottom surface of the Rotor Rim did not show any signs or indications of failure or fatigue. The red coating (paint) was still in good condition with light grease and dirt present.

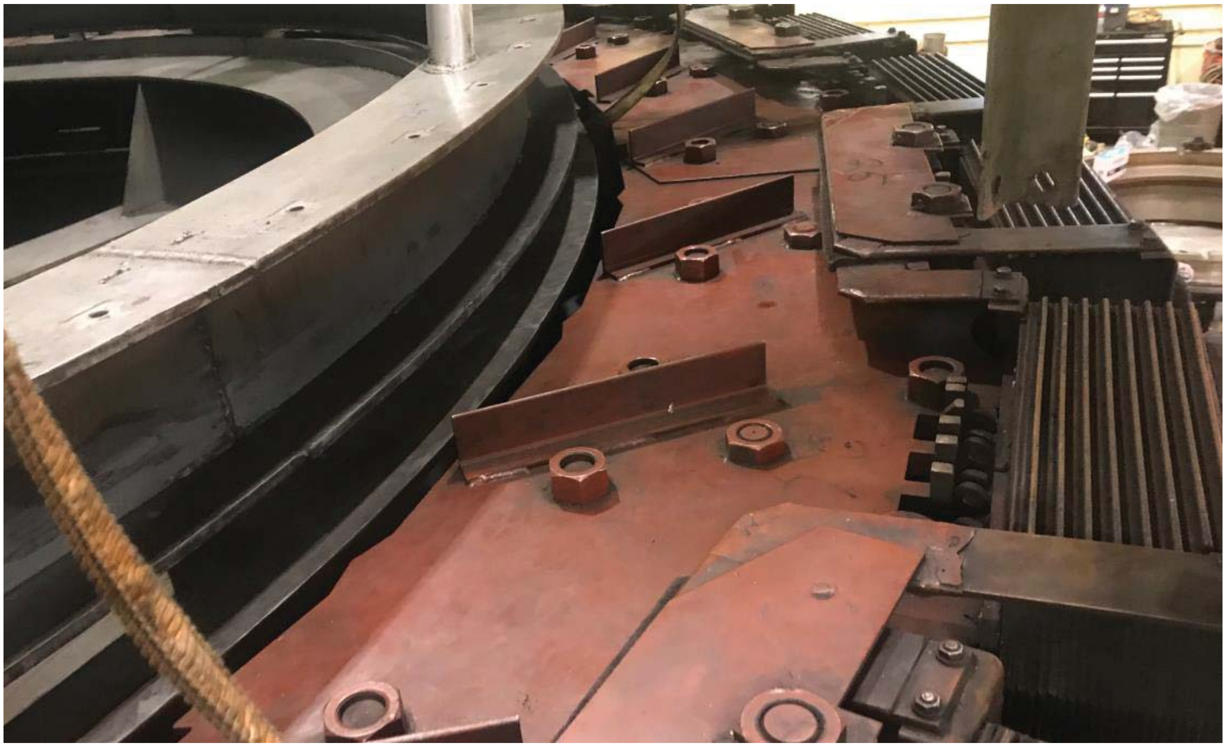

Figure 5-91: Rotor Rim, Top View 1

Figure 5-92: Rotor Rim, Top View 2

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Figure 5-93: Rotor Rim, Bottom View 1

Figure 5-94: Rotor Rim, Bottom View 2 - Brake Ring

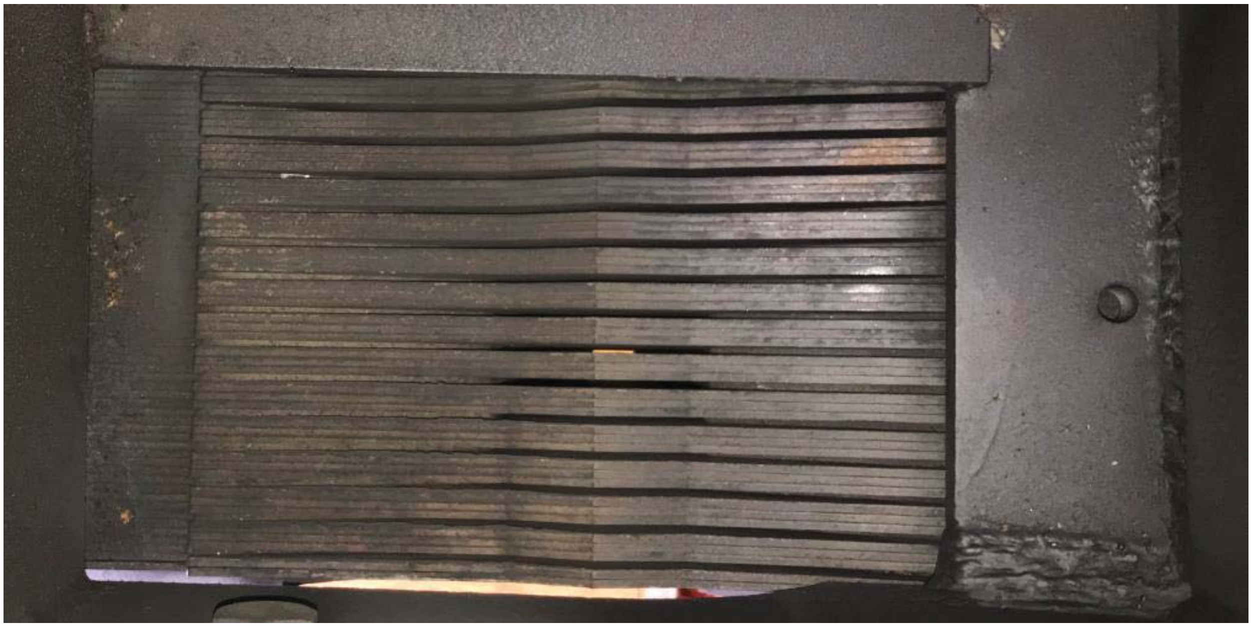

Figure 5-95: Rotor Rim, Back View through the Spider- Light Surface Rust

Figure 5-96: Rotor Rim, Outer condition of Rim Laminations (June 2019, Inspection)

Figure 5-97: Rotor Rim, Outer condition of Rim Laminations (August 2019, Preassembly Oxidation)

5.15.2.3 Rotor Poles

The Unit 7 machine consists of 32 Poles fixed radially on the outer diameter of the Rotor. Each Pole weighs approximately 3620 pounds. The outer diameter of the Poles when assembled on the Rotor is designed to measure 278.22 inches. During the inspection Voith was searching for indications of damage or failure on the all visible surfaces of the Poles. Overall, the Poles were found to be in fair to poor condition. Each Pole was equally covered with a film of dirt and grease. Some of the Poles' protective coating was peeling off of the cooper windings and exposing bare cooper. Also shown in this section is a comparison between what the Bay d'Espoir Unit 7 Pole condition was during the inspection versus a new Pole. The outer diameter of the laminations of the Poles showed signs of rust and oxidation; however, it was difficult to know the source or when the oxidation initiated.

On Pole number 20 it was obvious that one of the windings had become dislodged at one point. While there was a misalignment of one winding compared to the rest on Pole 20 it did not appear to be damaged or defective and it was unknown when this occurred. This could have occurred during the original manufacturing of the pole and thus it has been misaligned for 42 years. All of the clamping and connection hardware appeared to be in good working order. There were signs of melting Rim Laminations, which could be signs of a short in the Poles, in certain areas of the outer diameter of the Rim Plates. The impacted area was between the Poles at the top and bottom of the Rim, where plates seemed to have various states of degradation, mostly broken at the top and generally intact at the bottom. The tape on the outer pole winding was either damaged or absent on several of the Poles. This tape is typically used to keep the winding in place against the centrifugal forces of the Rotor.

In parallel with the Voith inspection of the Rotor, NLH's Electrical Engineering department performed their own detailed examination of the Unit 7 machine. This examination included many standard tests for generators including for power factor, resistance, visual inspection, and Pole drop test. The complete report is located in the Appendix of this report.

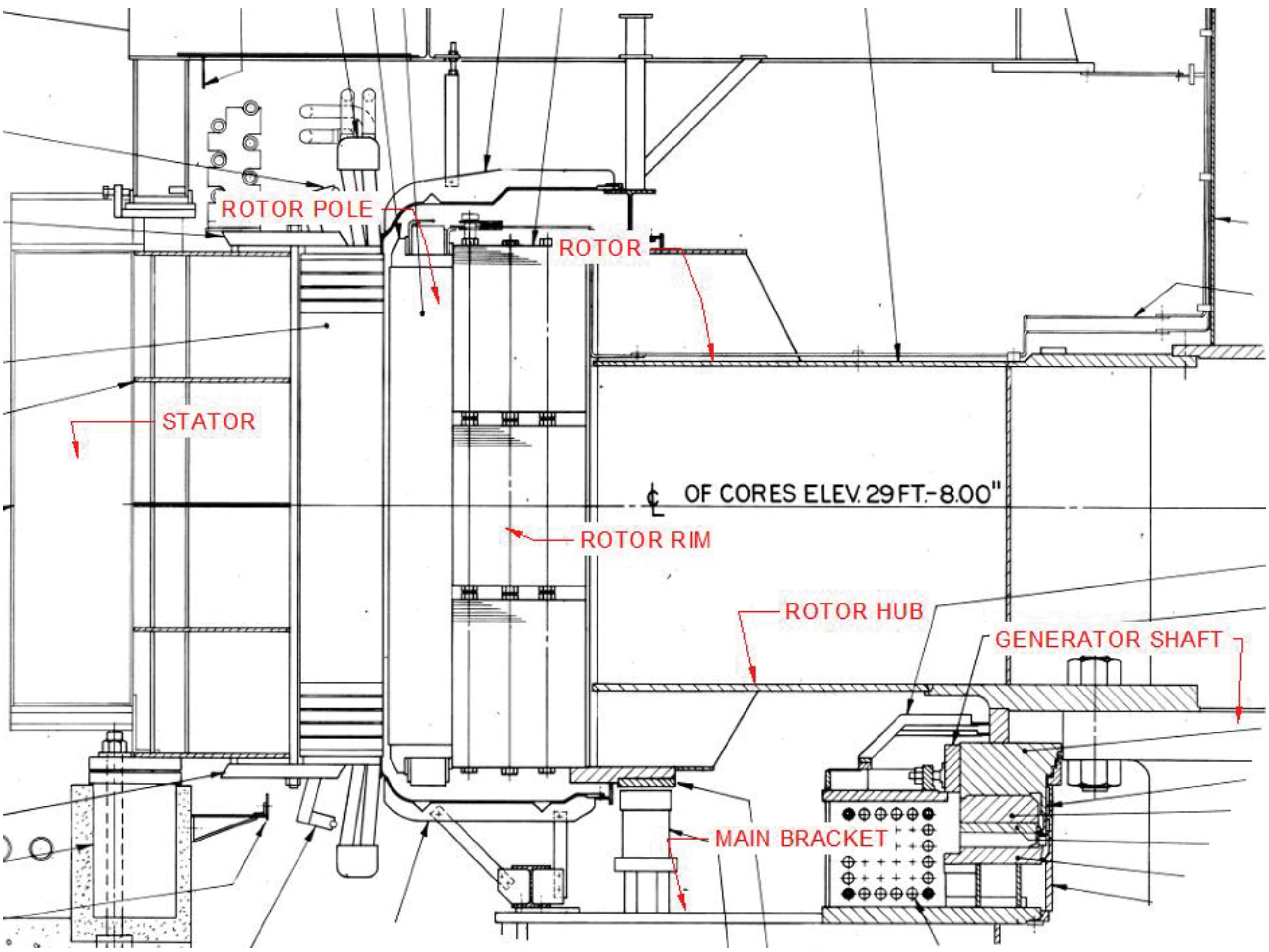

Figure 5-98: Rotor Pole, Outline 1

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Figure 5-99: Rotor Pole, Outline 2

Figure 5-100: Rotor Pole, Film of Dirt and Grease

Figure 5-101: Rotor Pole, (Left) Damaged Tape, (Right) Film of Dirt and Grease

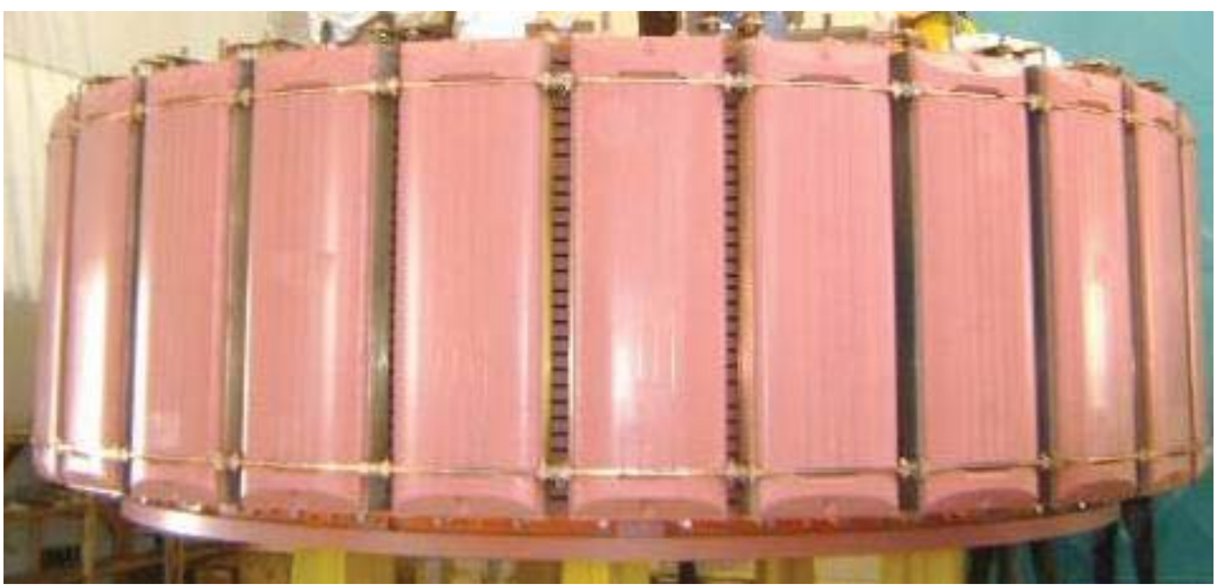

Figure 5-102: Rotor Example: Voith picture of a new rotor and poles.

Figure 5-103: Rotor Pole Example: Voith picture of a new poles.

Figure 5-104: Rotor Pole: Insulation Peeling or Absent

Figure 5-105: Rotor Pole: Dislodged Winding

Figure 5-106: Rotor Pole: Dislodged Winding

Figure 5-107: Rotor Pole: Evenly assembled Winding

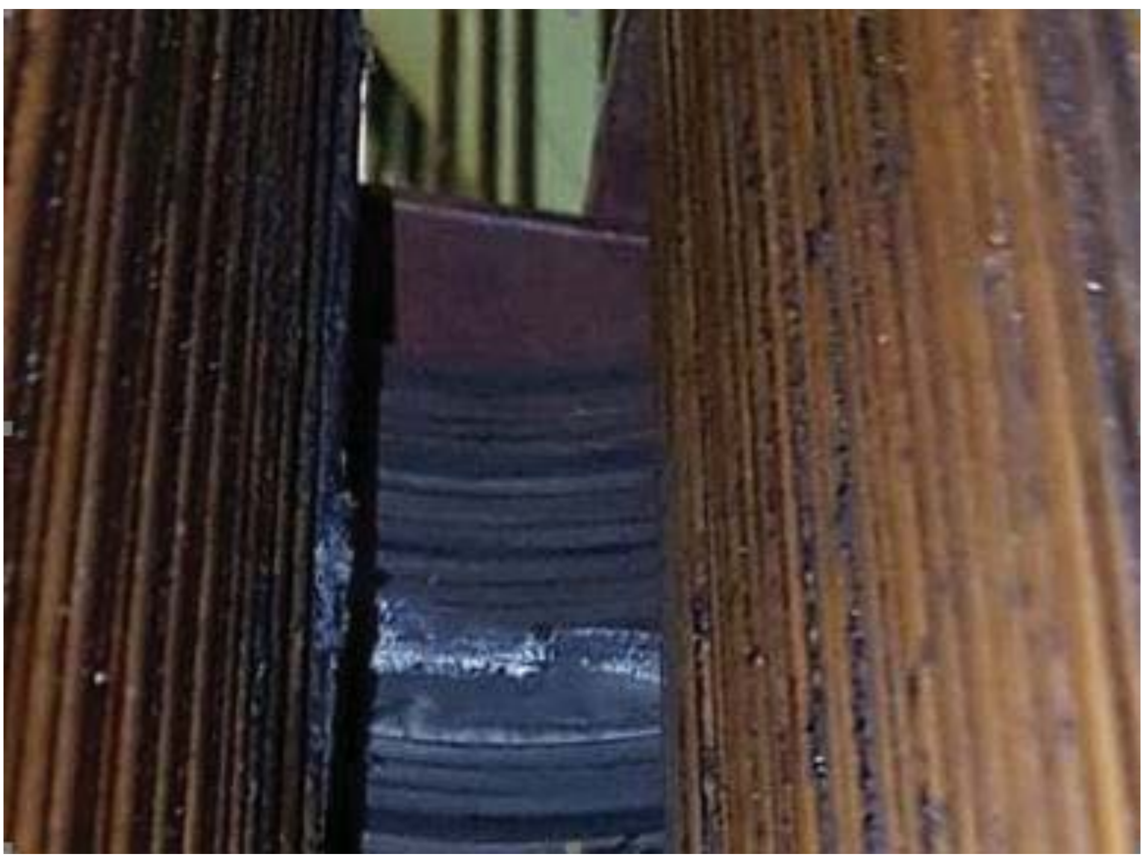

Figure 5-108: Rotor Pole: Melting Rim Laminations

Figure 5-109: Rotor Pole: Melting Rim Laminations

Figure 5-110: Rotor Pole: Melting Rim Laminations

Figure 5-111: Rotor Pole: Top of Poles and Connections

Figure 5-112: Rotor Pole: Rust and Oxidation

Figure 5-113: Unit 7 Rotor after Cleaning and Painting

Figure 5-114: Rotor Poles: Rim Rust and Oxidation

5.15.3 Laser Inspection Data and Results

The Rotor was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The Rotor dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The “reference only points” were recorded in case of certain questions or information was needed outside of the planned scoped. The main focus for the Rotor Laser Inspection was to measure and verify the circularity, concentricity, and verticality of the outer diameter of the Poles. The inspection also included the upper and lower spigot joints of the Rotor Hub and their concentricity to the relative the outer diameter of the poles.

5.15.3.1 Rotor Laser Inspection Analysis

To establish a clear understanding of the circularity of the Rotor Poles, data points were taken at three elevations on each of the Poles. The reason for doing this was not only to verify the circular shape of the Rotor but to also measure the verticality of each Pole. Typically, only two planes are required to achieve the results desired; however, Voith prefers a third middle plane. This plane provided a better average for the analysis of the data. The results in Figure 5-118 show the data points plotted on a circular graph. For the most part the three planes are consistent with each other. The circularity of the Rotor was found to within the CEATI Part 2 tolerance. The as-found average circularity of all the planes was 0.0389 inch. The CEATI tolerance is 8 percent of the OEM air gap; which calculates to 0.070 inch. The results of the circularity placed the Unit 7 machine in the middle of the CEATI range. Included in this section is a visual representation of the circularity within the CEATI Tolerance zone.

The verticality of the 32 Poles, which is also a CEATI requirement, was also checked during the 2019 maintenance outage. Figure 5-120 shows the results of the Pole verticality check. During the inspection two measurements were taken: one on the upper front face of the Pole and the other on the bottom face. Both measured points were taken roughly 150 mm from their respective ends. Poles 1 through 24 measured very good verticality; however the verticality started to increase clockwise from Pole 25 to Pole 30 and then improved for the remaining two poles.

While the verticality was increased from Pole 25 to 30, only three of the Poles measured out of the CEATI Part 2 tolerance range. This tolerance range, which is for a new machine, is a function of the OEM Air Gap. For BDES Unit 7, the verticality tolerance from CEATI Part 2 is 0.0525 inch. The three Poles found outside of this tolerance zone were in a range of 0.055 to 0.059, which is very close to the upper limit. While this could seem alarming, due to the delicate nature and function of the Poles, it was difficult to determine why and when these Poles verticality started to change; in fact, it is possible that the Poles were installed this way during the original commissioning in 1977.

The concentricity of the Rotor Poles compared to the Hub axis is shown in the table in Figure- 5-118. The measured diameters of the Rotor, at three elevations, were compared to the spigot holes in the center of the Rotor for concentricity. Similar to the verticality, the concentricity is also a function of the OEM Air Gap. The concentricity tolerance range used was from CEATI Part 2, in which the tolerance range was much finer than the verticality. The limit for BDES Unit 7 was 1.2% of the OEM Air Gap which was 0.011 inch. As shown in Figure 5-118, the average concentricity of the Rotor compared to the Hub axis was within the CEATI tolerance. Additional reference measurements and are located in the Appendix of this report, including Rotor level during inspection and other planes and elevations.

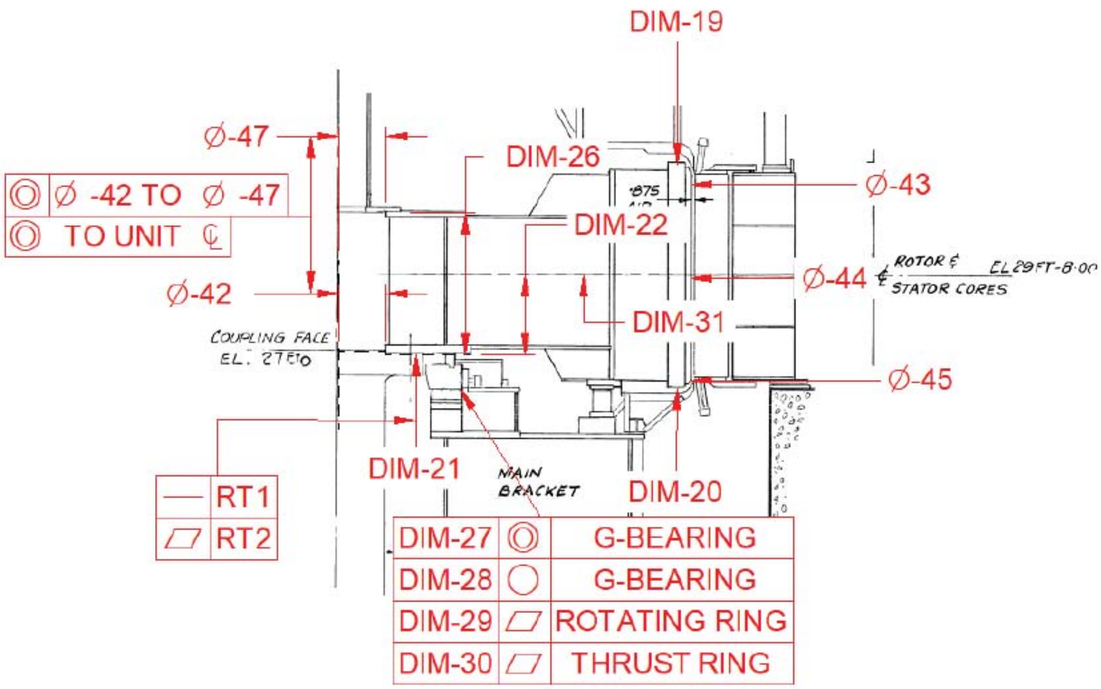

Figure 5-115: Rotor Laser Inspection Outline

Ø-42	Rotor	Concentricity to Unit CL
Ø-43	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-44	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-45	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-46	Runner Spigot	Concentricity to Datum A
Ø-47	Rotor Upper Spigot	Concentricity to Unit CL
DIM-26	Rotor Spigot Elevation	Overall Length
DIM-27	Guide Bearing	Concentricity
DIM-28	Guide Bearing	Circularity
DIM-29	Rotating Ring	Flatness
DIM-30	Thrust Block	Flatness
DIM-31	Theoretically Rotor Centerline	Best-fit center plane created from DIM-19 and DIM-20

Ø-42	Rotor	Concentricity to Unit CL
Ø-43	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-44	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-45	Rotor	Rotor Pole radii from Unit CL (Individually)
Ø-46	Runner Spigot	Concentricity to Datum A
Ø-47	Rotor Upper Spigot	Concentricity to Unit CL
DIM-26	Rotor Spigot Elevation	Overall Length
DIM-27	Guide Bearing	Concentricity
DIM-28	Guide Bearing	Circularity
DIM-29	Rotating Ring	Flatness
DIM-30	Thrust Block	Flatness
DIM-31	Theroactically Rotor Centerline	Best-fit center plane created from DIM-19 and DIM-20

Figure 5-116: Rotor Laser Inspection Dimensional Plan

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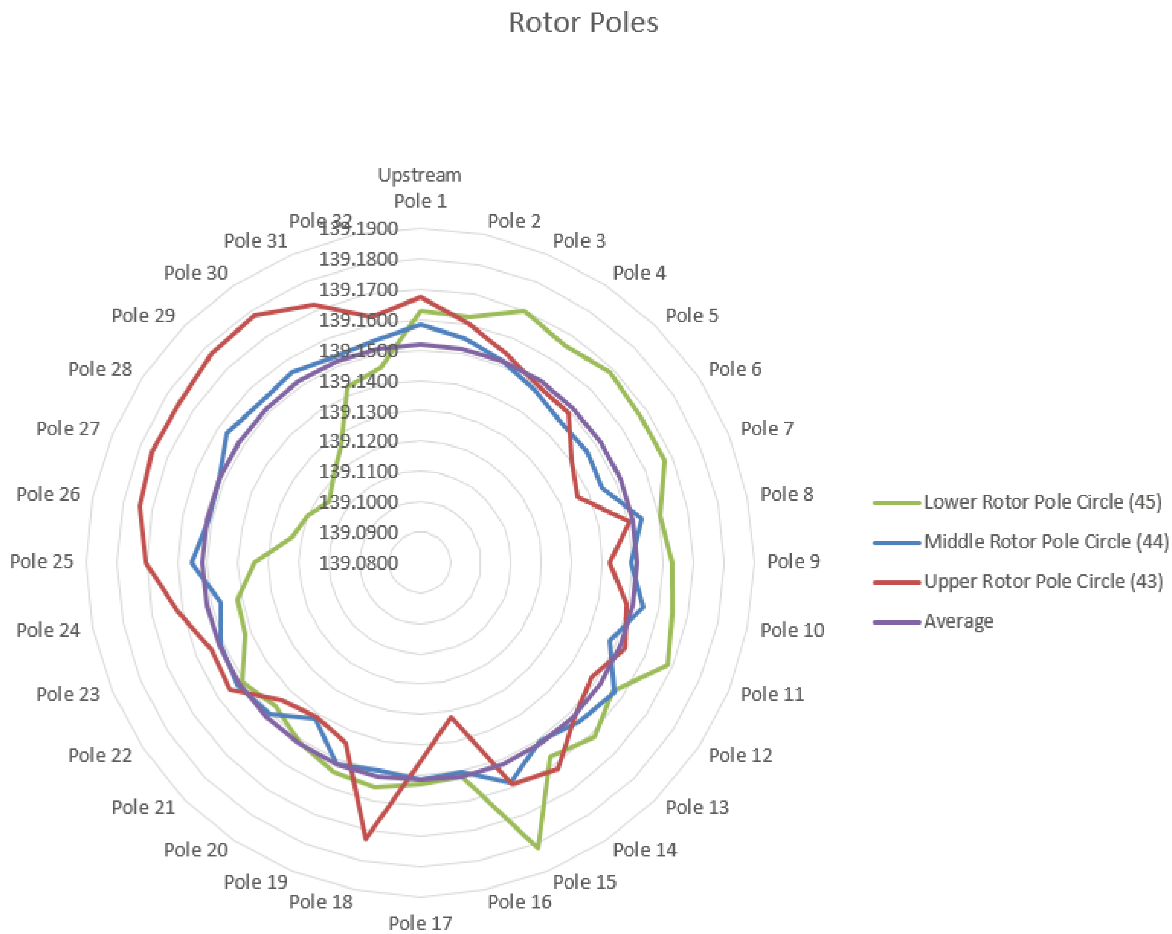

Figure 5-117: Rotor Pole Position, Top, Middle and Bottom Plane

Name	X	Y	Z	Polar Angle	Polar Radius
CenterPoint Spigot Top Circle **47**	0.0000	0.0000	57.0599	0.0000	0.0000
CenterPoint inner Spigot Circle **42**	0.0000	0.0000	1.7658	0.0000	0.0000
CenterPoint Outer Bottom Circle **27**	-0.0007	0.0001	1.5545	174.0221	0.0007
CenterPoint Lower Circle **45**	0.0184	-0.0041	-2.5023	347.5032	0.0189
CenterPoint Mid Circle **44**	-0.0004	0.0009	40.2907	116.9767	0.0010
CenterPoint Top Circle **43**	-0.0102	0.0072	68.7027	144.9483	0.0125
Average	-	-	-	-	0.0108
CEATI Part 2 Concentricity,(1.2% * N, where N is 0.875) =					0.0110

Figure 5-118: Rotor Pole Outer Diameter Concentricity

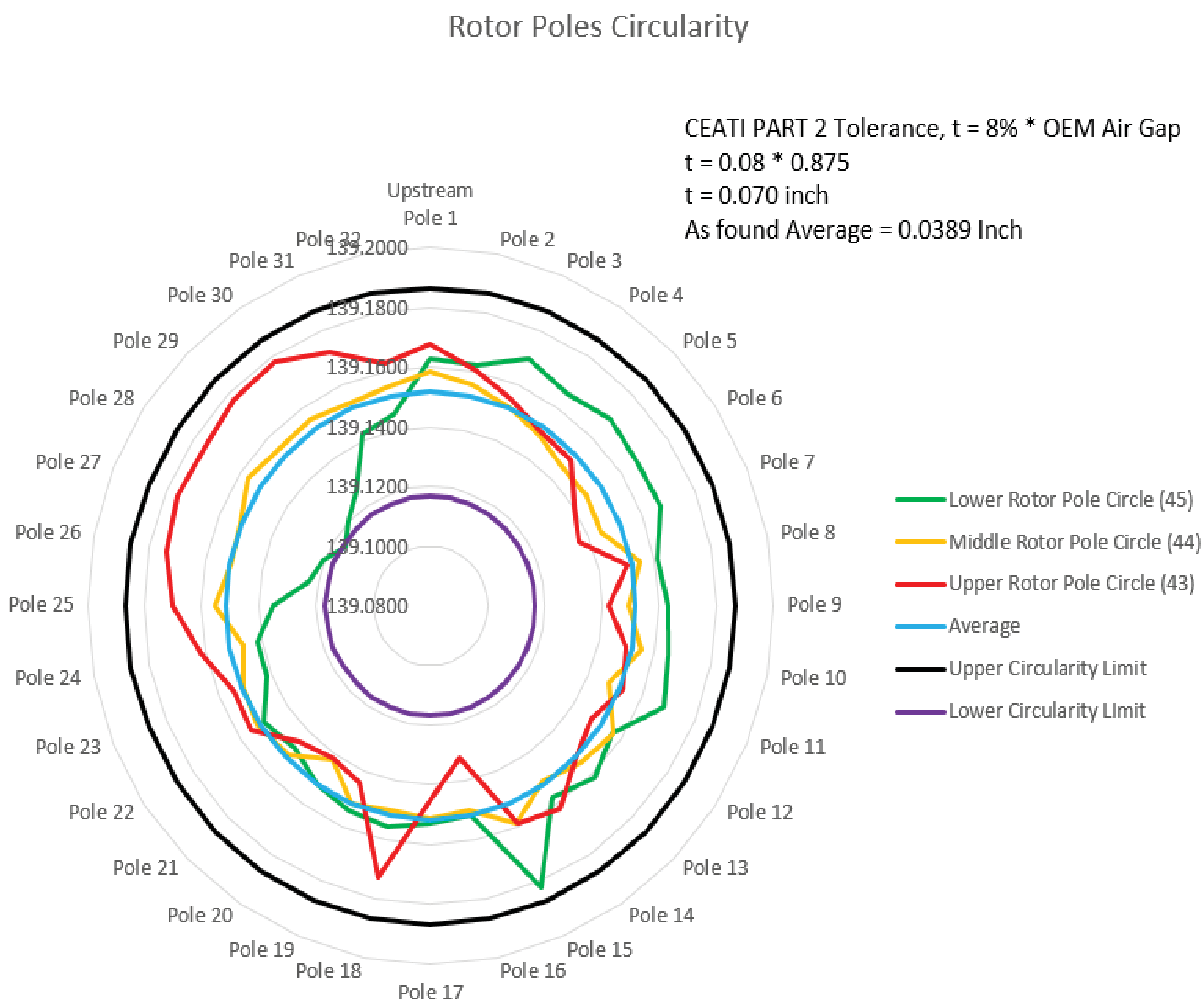

Figure 5-119: Rotor Outer Diameter Circularity

Pole Verticality

Pole 1	0.005	Pole 17	0.008
Pole 2	0.002	Pole 18	0.017
Pole 3	0.015	Pole 19	0.010
Pole 4	0.016	Pole 20	0.010
Pole 5	0.019	Pole 21	0.003
Pole 6	0.027	Pole 22	0.005
Pole 7	0.031	Pole 23	0.012
Pole 8	0.010	Pole 24	0.020
Pole 9	0.021	Pole 25	0.035
Pole 10	0.015	Pole 26	0.051
Pole 11	0.015	Pole 27	0.055
Pole 12	0.009	Pole 28	0.059
Pole 13	0.009	Pole 29	0.057
Pole 14	0.005	Pole 30	0.052
Pole 15	0.023	Pole 31	0.030
Pole 16	0.020	Pole 32	0.017

OEM Air Gap = 0.8750 inch
CEATI Part 2, t = 0.0525 inch

(CEATI Tolerance, t= 6% * OEM Air Gap)

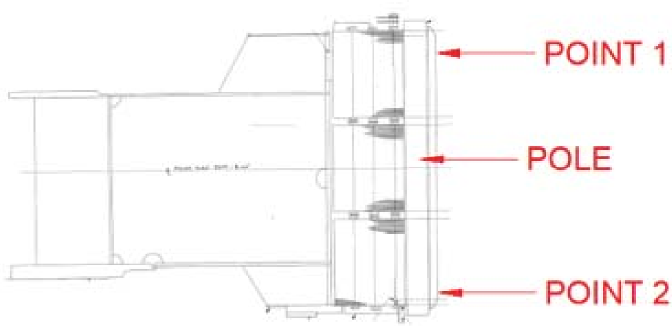

Figure 5-120: Rotor Pole Verticality

5.15.4 Non-Destructive Examination

There was no non-destructive examination planned for or performed on the Rotor during the 2019 maintenance outage.

5.15.5 Outage Recommendations

- **Voith Recommendation:**
  - Voith recommending that NLH clean the Rotor thoroughly, including the Hub, Rim, and Poles. The rotor was to be cleaned to remove all dirt, grease, and surface rust from the Rotor and then test using the following sequence:
    - Use rags and cleaning solutions to remove the rust, then paint the area.
    - Use extra caution to protect the coils and collect/contain all of the particles being removed.
    - Control the atmosphere (temperature, humidity, etc.).
    - Clean three or four poles at a time and paint immediately.
    - Clean all surfaces of the rotor prior to installation.
    - Perform tests (Megger, PI, IR, IEEE-43-2000, etc.) prior to commissioning.
- **Outcome:**
  - After further discussion, NLH followed Voith's recommendation and clean, paint, and test the Rotor prior to commissioning. All of the completed reports and data from electrical testing of the Rotor are provided in the Appendix.
  - Note that NLH purchased three sets of Super Nuts to replace the existing OEM heat tensioned nuts, which required significant effort and time to remove during the disassembly of the machine in the 2019 Maintenance Outage. The Super Nuts only require manual hand torqueing to achieve the preload required. The Super Nuts also allow for a more simplistic disassembly and reassembly of the components during maintenance activities. They also do not require a heating source like the OEM nut. During the assembly of the unit in 2019 only two sets of Super Nuts were used. One set was used at the connection joint of the Rotor and Generator Shaft and the second set was used at the connection joint between the Turbine and Generator shafts. The third set, which is intended for the connection joint between the Runner and Turbine Shaft was not used during the assembly. This was due to the Runner and Turbine Shaft never being disassembled during the 2019 outage; therefore this set was saved and stored until required, which can during the next major outage.

5.16 Stator

5.16.1 Background Information

The Stator is a stationary component of an electromagnetic system in the Generator. The Stator was fixed to the foundation of the powerhouse through the Stator Frame Soleplates, in which large threaded anchors imbedded in the concrete were used to secure the Stator in position. The Stator was constructed of the following main parts: Stator Frame, Core, and Windings. The main function of the Stator Frame is to fix the Stator Core, Upper Brackets, and air/water cooler elements. The frame also transmits the mechanical loads such as, torque, bearing, thermal expansion, and magnetic forces. The Stator Core provides a structure to secure the Stator Windings and also intensifies the magnetic flux. The Stator Windings create a stationary magnetic circuit, and voltage and current are induced as a reaction to the variable magnetic flux produced by the Rotor. Using the experience from previous outages at Bay d'Espoir Powerhouse One and from the recommendations outlined in a refurbishment plan (VHY-1, 2017) developed by VH, NLH established a detailed plan for the Stator activities during the 2019 maintenance outage.

Planned Work:

- Visual Inspection (VH Scope).
- Laser Inspection (VH Scope).

Figure 5-121: Stator, Bottom View

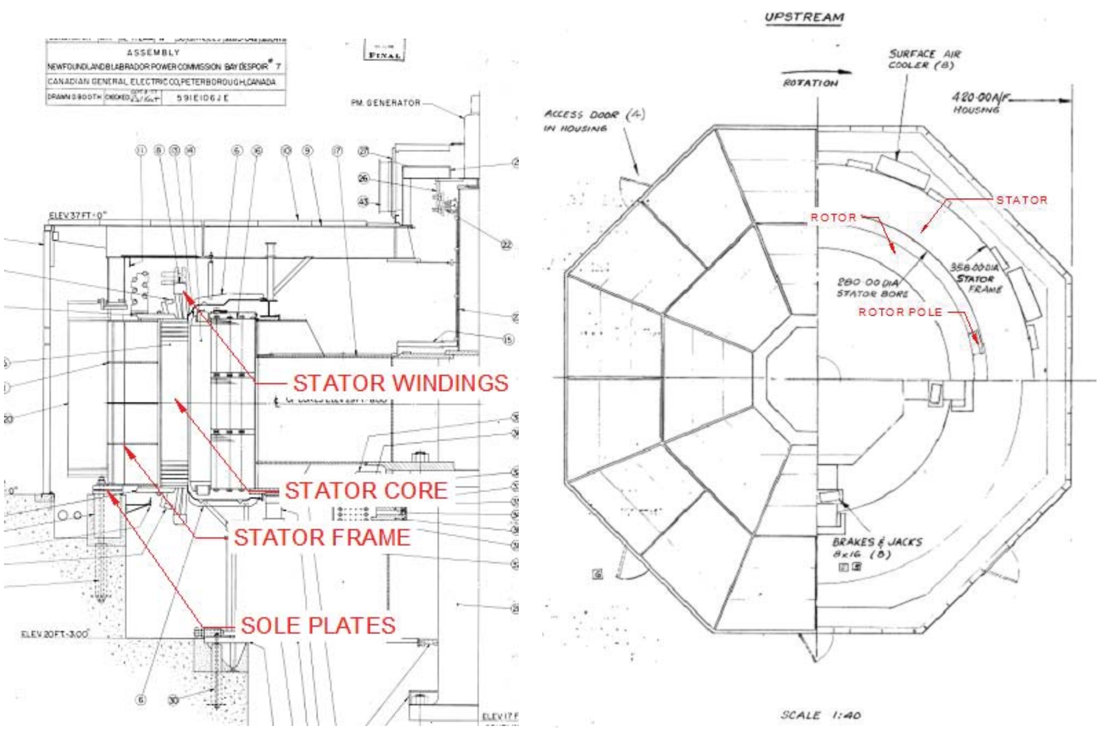

Figure 5-122: Stator, Outline

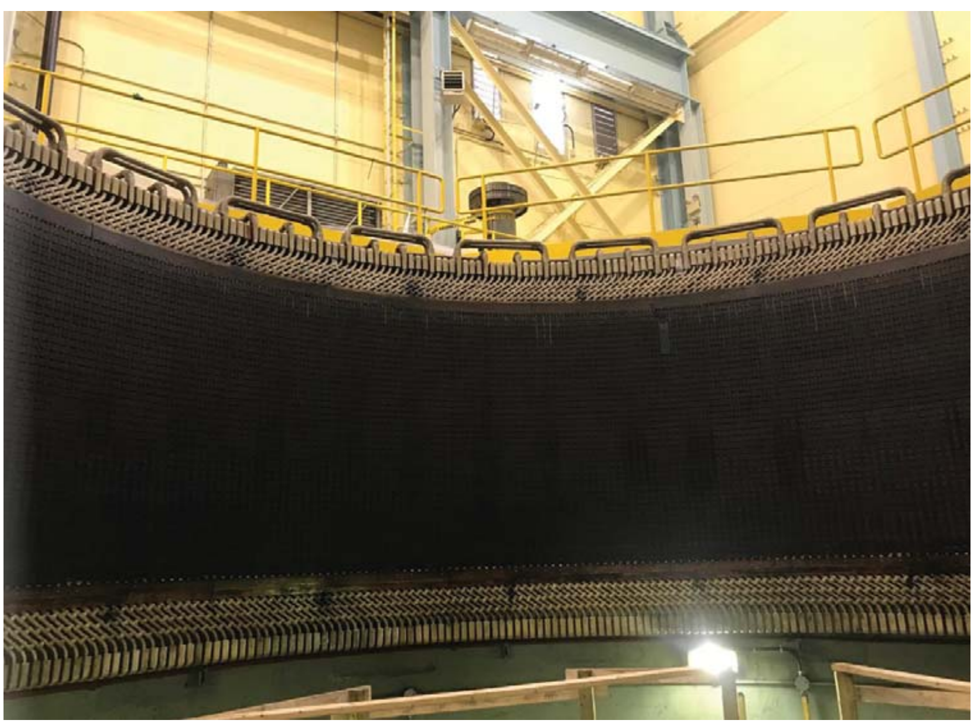

Figure 5-123: Stator, Bay d'Espoir Unit 7

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Figure 5-124: Stator, Bay d'Espoir Unit 7

5.16.2 Visual Inspection

Voith engineering performed a visual inspection of the Stator to look for any signs or indications of abnormal wear or damage. The overall condition of the Stator was fair, but certain components were found to in poor condition. The inspection of the Stator can be broken into parts based upon the different individual features of the part itself. The features are as follows: Stator Frame, Stator Core, and Stator Windings.

5.16.2.1 Stator Frame

The Stator Frame was inspected by Voith engineering during the 2019 maintenance outage. During the inspection VH was searching for signs of failure and fatigue. The areas of interest were the Sole Plates and foundation concrete around the securement points of the Stator Frame. The outer diameter or shell of the Stator Frame was also inspected, including the coolers. Overall the Frame was in good condition. The OEM gray paint was also found to be in good condition with limited signs of wear or damage. The Sole Plates and securement hardware were in good condition with no indications of damaged or loose hardware. The welds around the Sole Plates were also in good condition with no signs of cracking.

From what VH could visually inspect, the Sole Plate Keys were in place with no signs of movement. The concrete around the Sole Plates did not show any signs of cracking or damage; in fact all of the concrete in the area of the Stator appeared to be in good condition. The only notable finding was light grease and oil found on the coolers, concrete foundation, and shelf plates of the Frame. The sources of the oil film was unclear, but was consistent throughout the inspection of the entire generator.

Figure 5-125: Stator: Stator Frame Sole Plates

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Figure 5-126: Stator, Stator Frame Outer Diameter 1

Figure 5-127: Stator, Stator Frame Outer Diameter 2

Figure 5-128: Stator, Stator Frame Outer Diameter 3

5.16.2.2 Stator Core

The Stator Core was in fair to good condition with no signs or indications of major damage. The Core was very dirty with oil and grease, but the source of oil was unclear. During the inspection Voith found some Laminations that were bent or damaged, but this was random and no signs of buckling of the Core were present. The cause of the damage was unknown. Two nuts on the bottom Pressure Plates were not aligned with their original markings for torqueing, indicating movement during operation. The Air Guides were covered in grease and oil with approximately 30 percent of the fasteners loose, providing the Air Guide with the ability to move, which could possibly cause damage to the insulation behind the guide.

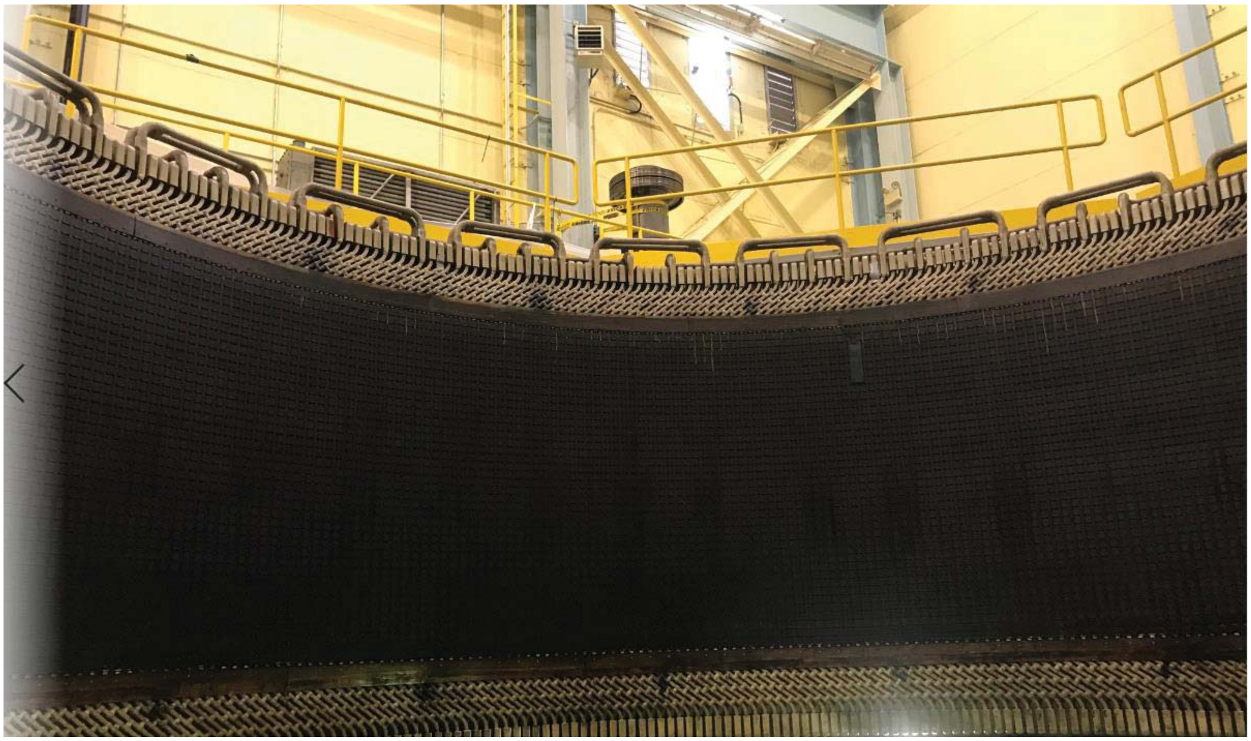

Figure 5-129: Stator Core, Overview

Figure 5-130: Stator Core, Bottom View looking towards the top of the core

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Figure 5-131: Stator Core, Lamination Close up

Figure 5-132: Stator Core, Pressure Plate Nut Movement

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Figure 5-133: Stator Core, Air Guide

Figure 5-134: Stator Core, Loose Rivet beginning to pull through Air Guide

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Figure 5-135: Stator Core, Air Guide Rubbing on Winding, due to Loose Hardware

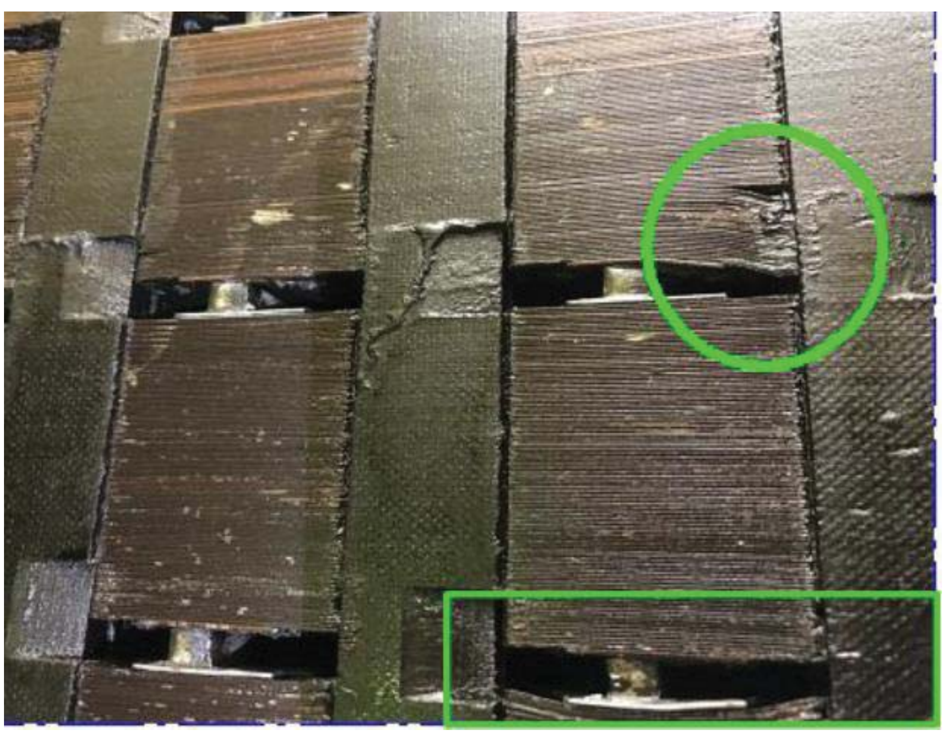

Figure 5-136: Stator Core, Bent Lamination Damage; the Cause was Unclear.

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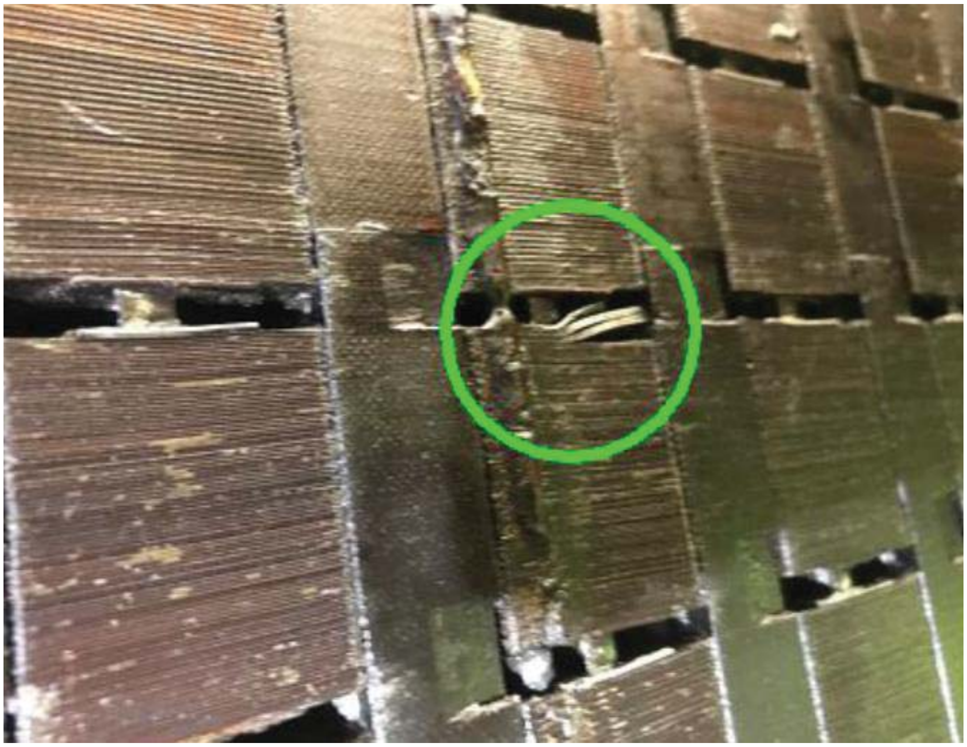

Figure 5-137: Stator Core, Bent Lamination Damage, the Cause was Unclear.

5.16.2.3 Stator Windings

Similar to the Stator Core, the Windings were dirty with significant oil and carbon dust from the exciter and brake pads on the surface of the Wedges and Punchings. The insulation tape around the Windings was cracked and dry. The ties between the Windings appeared to be fraying and brittle. The oil that covered the Core and Windings appeared to have run down the Core and collected in top of the bottom end caps. This was somewhat concerning because the insulation coating was in poor condition, and in some instances the insulation was missing from the end cap. In some locations the paint coating the Windings had severe bubbling and cracking present.

The top of the Windings appeared to be in good condition, with limited signs of oil and dust build up present. The top of the Core, Windings, and Stator Frame was not inspected in detail due to the inability to navigate around this area without proper safety tie-offs or without causing damage to the windings. Overall, no signs of the fretting, corona, or wedge displacement was present during the inspection, although the oil and dust film present on the Stator components may have hid some of these indications from the inspector. The following are images of the inspection points mentioned in this section. A comprehensive report of the inspection NLH's Electrical Engineering department performed is located in the Appendix of this report.

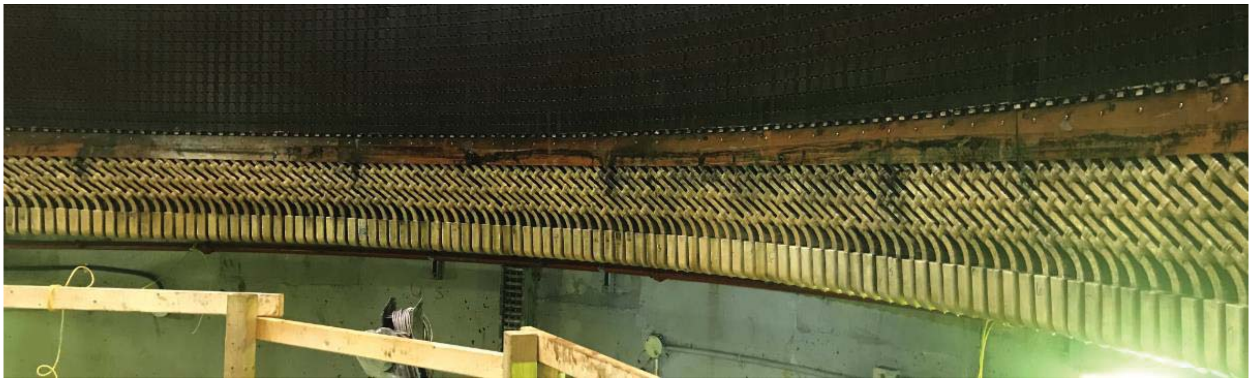

Figure 5-138: Stator Windings: Bottom Side Overview

Figure 5-139: Stator Windings: Typical Insulation Cracking Found

Figure 5-140: Stator Windings: Typical Condition of Bottom End of Windings

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Figure 5-141: Stator Windings: Typical Grease and Oil on Bottom End of Windings

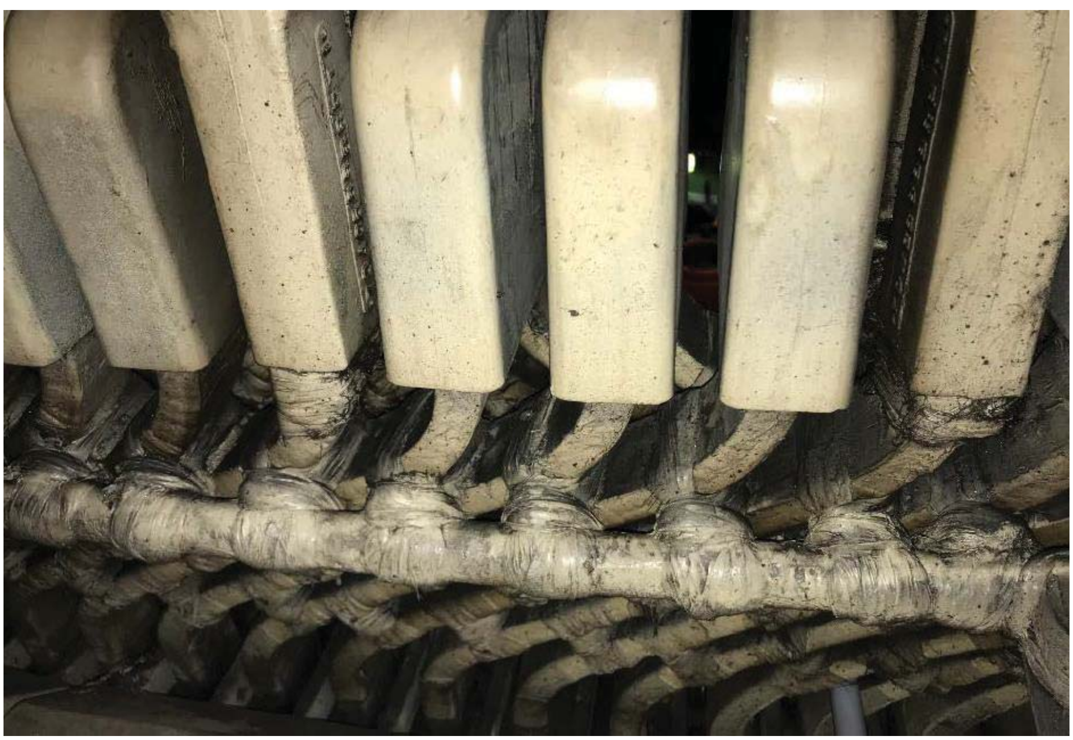

Figure 5-142: Stator Windings: Typical Top End View of the Windings

Figure 5-143: Stator Windings: Typical State of Lower End-Cap

Figure 5-144: Stator Windings: End-Cap Insulation Cracked

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Figure 5-145: Stator Windings: Damaged End-Cap

Figure 5-146: Stator Windings: Damaged End-Cap

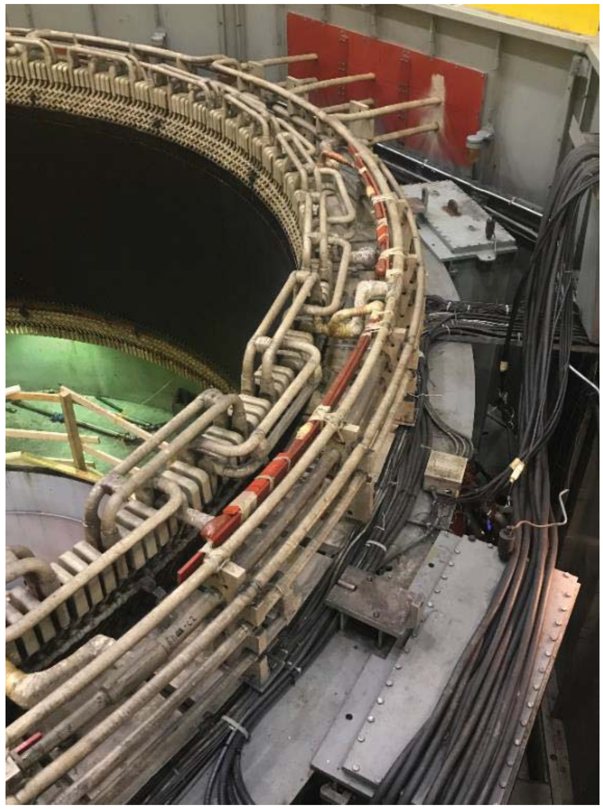

Figure 5-147: Stator Windings: Top End View of Stator Windings

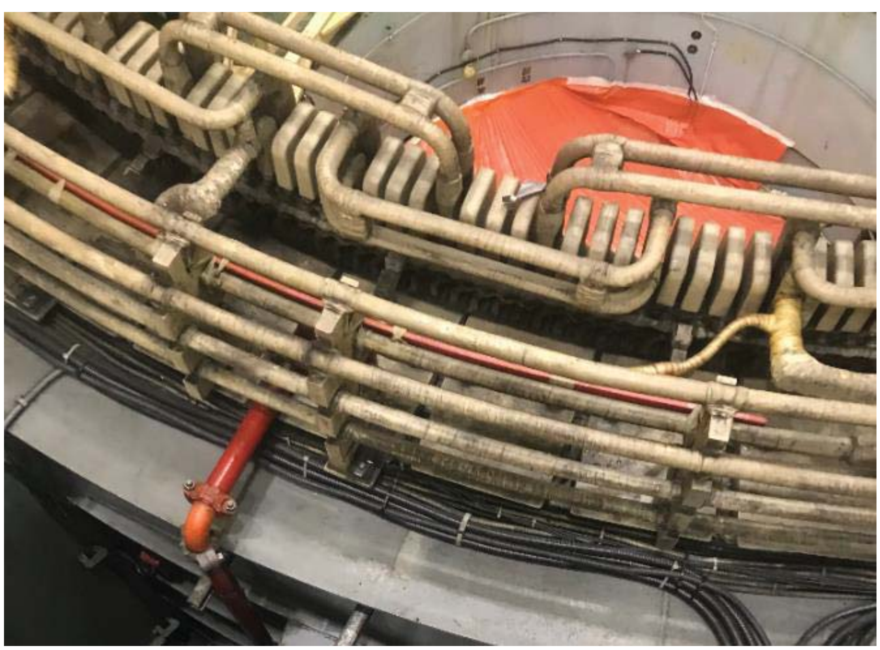

Figure 5-148: Stator Core, Top View of Windings

5.16.3 Laser Inspection Data and Results

The Stator was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The Stator dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The "reference only points" were only recorded in case of certain questions or if information was needed outside of the planned scoped. The main focus for the Stator Laser Inspection was to measure and verify the circularity, concentricity, and verticality of the outer diameter of the Core.

5.16.3.1 Stator Laser Inspection Analysis

The laser inspection of the Stator was performed to understand the as-found shape of the Core. This shape included the circularity and verticality of the Stator Core iron. This shape is important due to the delicate relationship between the Stator and Rotor. The shape of the Core can impact Generator performance, heat transfer, and the concentricity relative to other embedded components of the machine. The concentricity of the Stator relative to the unit centerline is crucial in ensuring bearing and Runner Seal clearances are maximized. Therefore, the data points recorded during the 2019 maintenance outage were used during the analysis of all of the embedded components.

The first data points taken on the Stator were on the inner diameter surface of the Core iron. These data points were recorded as circles on the three different planes: top, middle and bottom. The three planes were used to provide a complete perspective on the shape of the Core. The following figure shows the circle created by the data points on each plane of the core. For the most part the circles were concentric and had average circularity. However, the lower Stator plane showed a more oval shape whereas the middle and top planes circularity improved as the points got closer to the top of the Stator Core. The shape of the lower Stator plane was very similar to the shape of other embedded components. Also shown for reference is a plot of the data points taken on the inner diameter of the Stay Ring Flange. The plot reveals the same oval shape as the lower Stator plane and in the same direction towards the radial halfway point between the upstream and A1 axis. This suggests that the same phenomena impacting the shape of the Bottom Ring and Stay Ring is affecting the Stator. The shape of the Stator Core top to bottom was also found to be in a somewhat conical shape with the bottom plane slightly wider than the top plane, suggesting the Core could be leaning inward towards the centerline of the machine.

The circularity of the Stator Core of top, middle, and bottom is shown in Figure 5-153. The plot shows the three data point circles created during the inspection with the average shown in purple. The circularity tolerance is based upon the new machine standards set by CEATI (Part 2). The tolerance set by CEATI is a function of a percentage of the Air Gap. In this case, the circularity tolerance was 8 percent of the OEM Air Gap value of 0.875 inch, which was 0.070 inch. However, this calculated number was higher than the 0.059 inch (1.5 mm) limit established by CEATI, which was used during the analysis. As shown in the circularity graph, almost all of the data points are within the tolerance zone set by CEATI with the outliers falling just outside of the allowable range.

The verticality of the Stator Core was also recorded and analyzed and, similar to the circularity, the tolerance zone was a function of the Air Gap based upon CEATI standards. The points used for the verticality inspection were taken on the inner diameter of the top and bottom of the Core. The results of the verticality inspection showed that 85 percent of the Core was found to be within the tolerance zone of 0.053 inch. The 15 percent of the Core out of tolerance was in the location or direction where the elliptical (oval) shape had taken form over all of the embedded components.

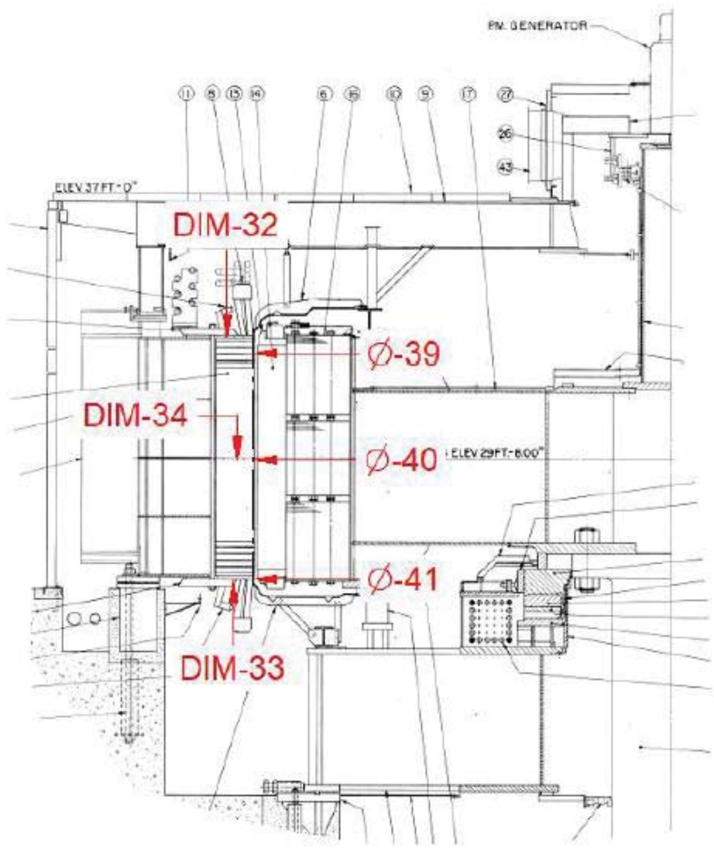

Figure 5-149: Stator Laser Inspection Outline

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Ø-39	Stator	For Reference
Ø-40	Stator	For Reference
Ø-41	Stator	For Reference
DIM-32	Stator Core Top	Record data points on top of the stator core at and between each soleplate.
DIM-33	Stator Core Bottom	Record data points on the bottom of the stator core at and between each soleplate.
DIM-34	Theoretically Stator Centerline	Best-fit center plane created from DIM-32 and DIM-33

Figure 5-150: Stator Laser Inspection Dimensional Plan

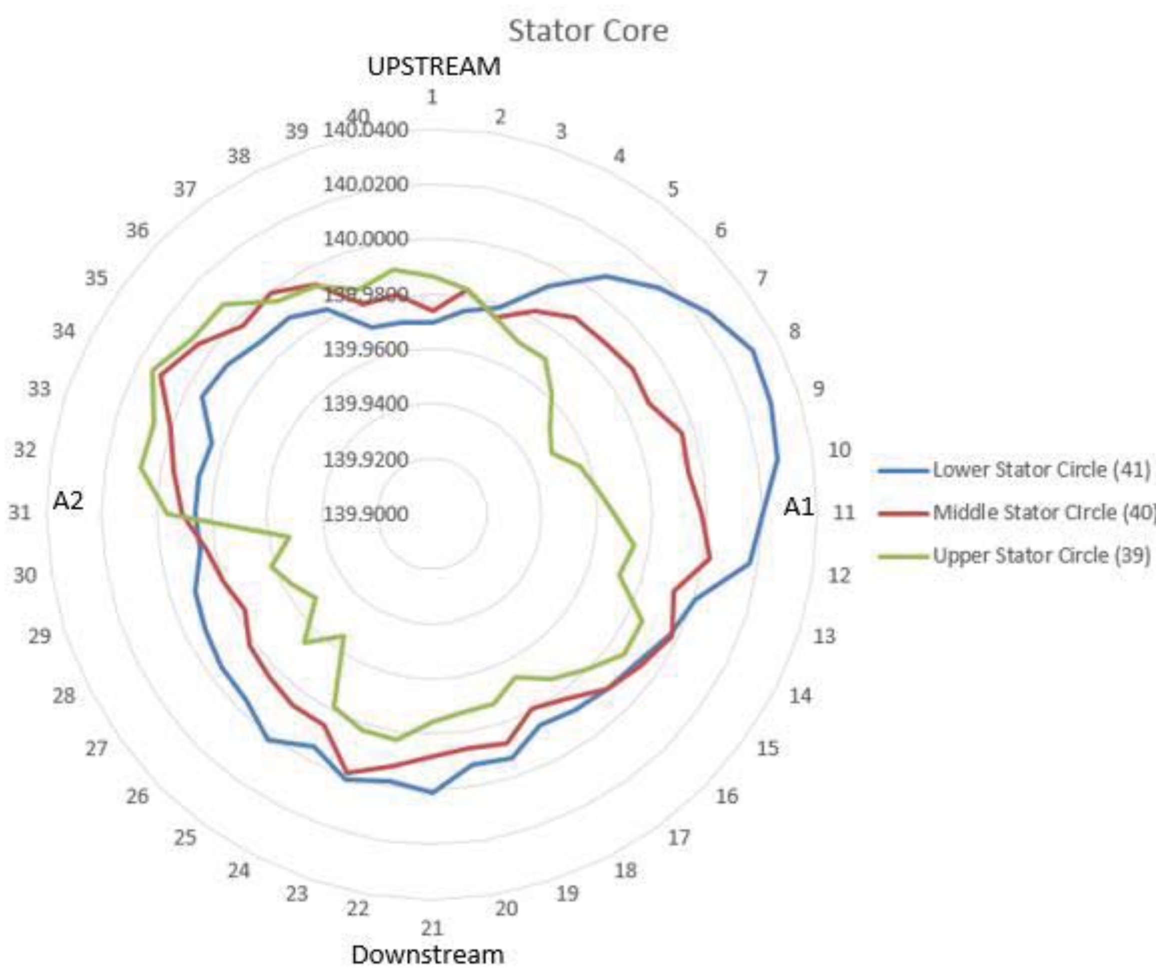

Figure 5-151: Stator, Top, Middle, and Bottom Plane

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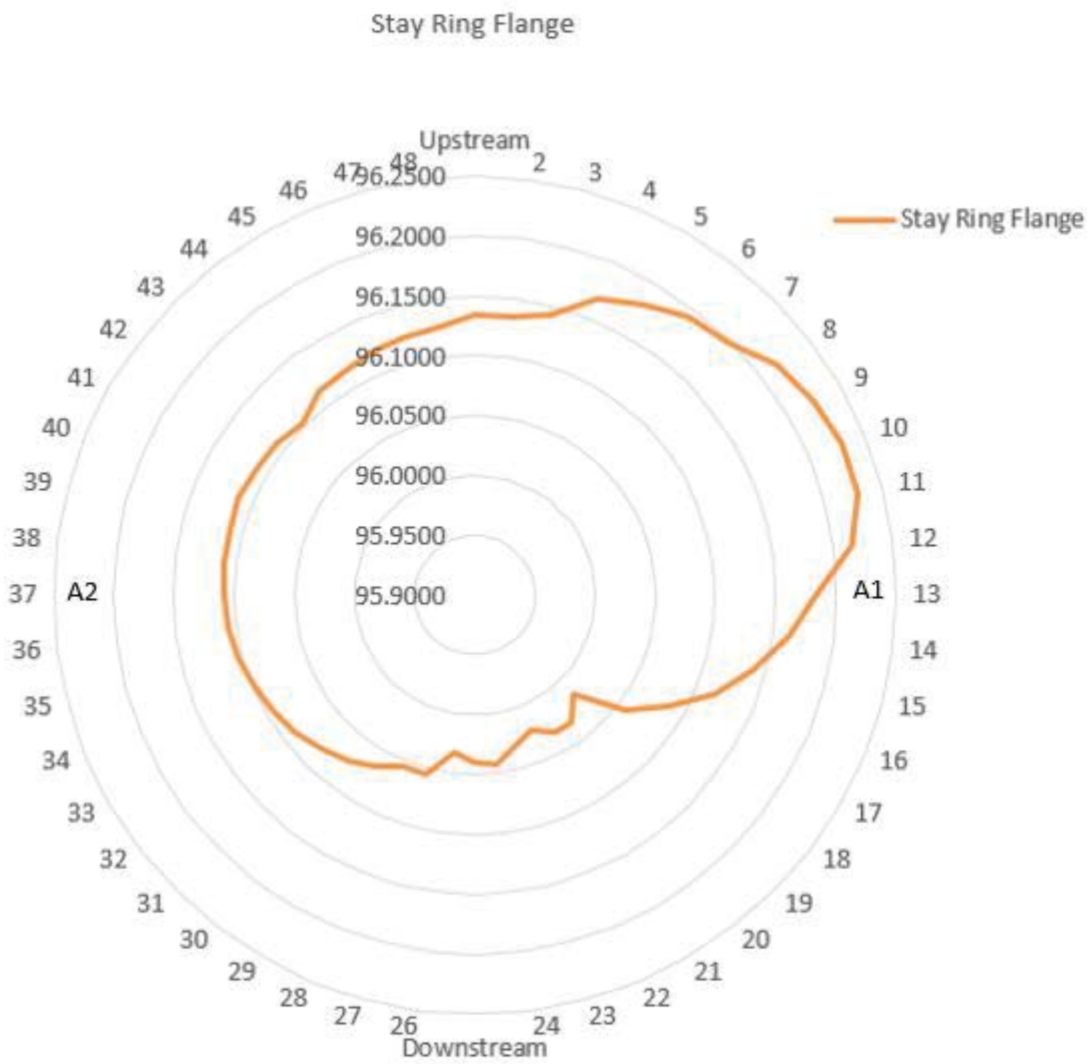

Figure 5-152: Stay Ring Reference

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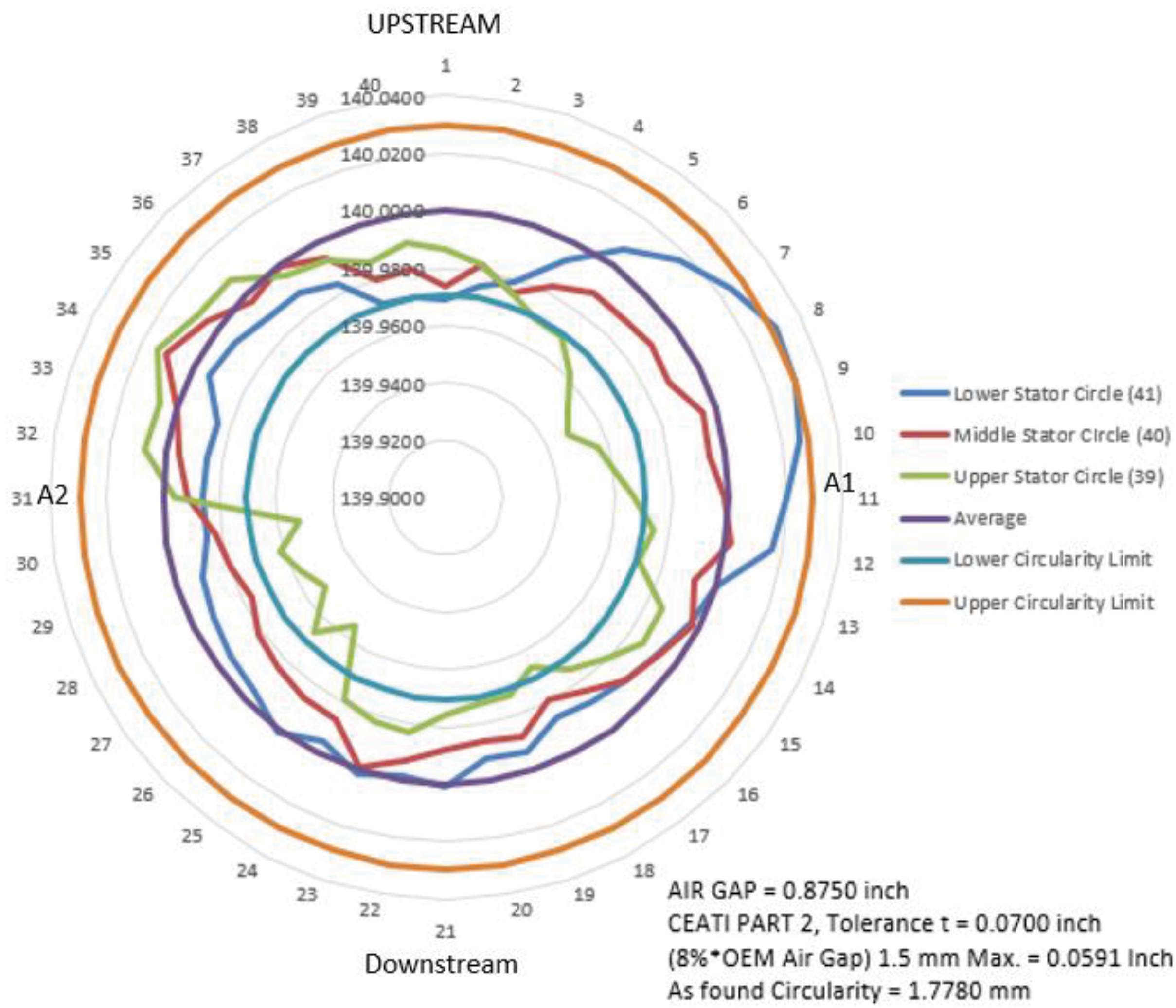

Figure 5-153: Stator Core, Inner Diameter Circularity

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<tr><td rowspan="3">Unit 7 Refurbishment Report
Project Report</td><td colspan="2">TFS7000</td></tr>
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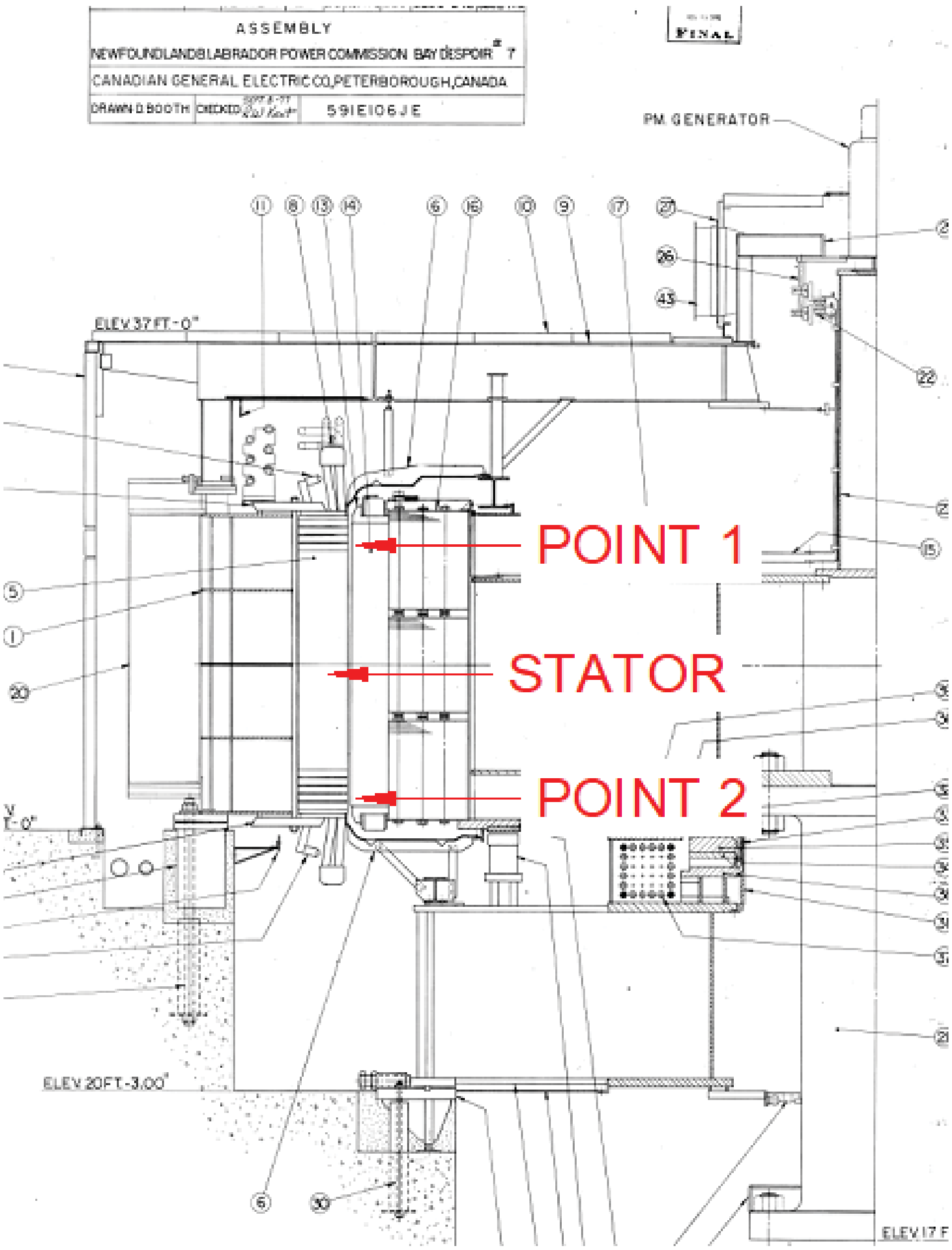

Figure 5-154: Stator Core, Verticality Measurement Description

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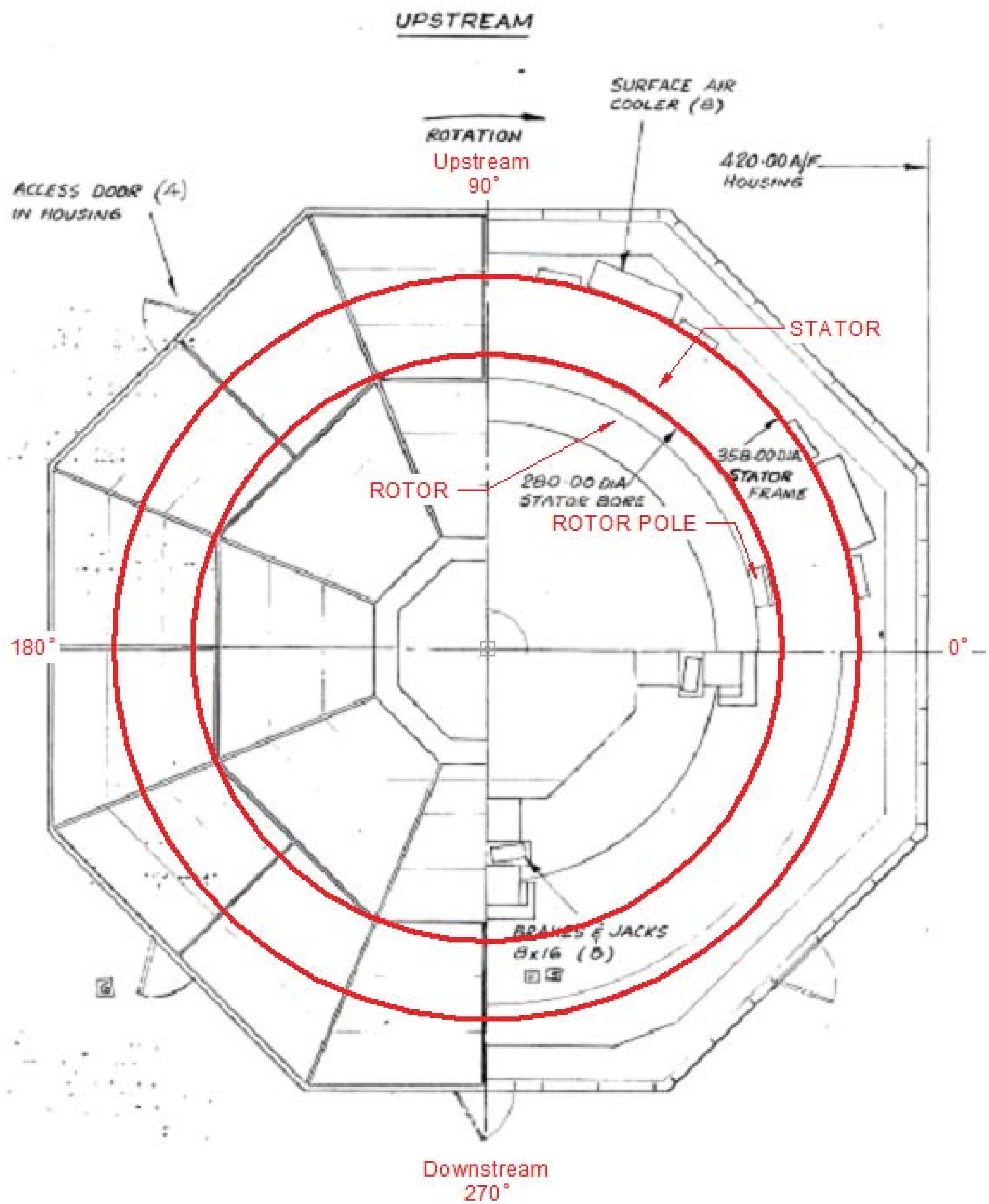

Figure 5-155: Stator Core, Description of Verticality Measurement Locations

Polar Angle Position	Verticality
Upstream	0.017
78	0.008
70	0.004
60	0.023
51	0.038
41	0.055
33	0.071
23	0.082
14	0.073
6	0.066
356	0.054
347	0.043
338	0.029
329	0.011
320	0.006
310	0.010
302	0.014
292	0.020
283	0.021
Downstream	0.020

Polar Angle Position	Verticality
266	0.025
257	0.016
247	0.019
238	0.016
228	0.047
218	0.030
209	0.042
210	0.035
201	0.029
201	0.033
171	0.010
162	0.022
156	0.022
147	0.020
139	0.016
130	0.019
119	0.008
110	0.009
102	0.015
Upstream	0.019

CEATI PART 2 Tolerance, t = 6% * OEM Air Gap or 1.5 mm max.
OEM Air Gap = 0.875 inch
CEATI Tolerance applied to OEM Air Gap = 0.0525

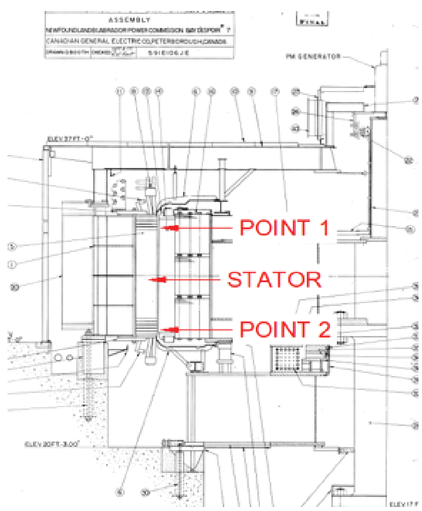

Figure 5-156: Stator Core, Verticality Results – Reference Figure 5-155 for Location

5.16.4 Non-Destructive Examination

There was no non-destructive examination planned for or performed on the Stator during the 2019 maintenance outage.

5.16.5 Outage Recommendations

- **Voith Recommendation:**
  - Voith recommended the Stator, especially the Core and Windings, be thoroughly cleaned. The heavy grease and oil prevented a more detailed inspection of the Stator components. Cleaning the Stator would allow NLH the opportunity to inspect for fretting, corona, and other physical damage not visible during the first inspection. Voith provided a procedure for cleaning, which is located in the Appendix of this report.

- **Outcome:**
    - After discussing with the NLH Maintenance department and developing a plan, NLH cleaned the Stator thoroughly and perform another visual inspection of the Stator. The results of this inspection are located in the Appendix of this report. Note that Voith was not contracted to perform a secondary inspection after cleaning; NLH internally performed another inspection.
- **Voith Recommendation:**
    - Voith recommended that NLH investigate the source of the oil and grease leak, which is apparent throughout the Stator. If found, the oil issues could be fixed, ultimately eliminating the collection of oil, dirt, and grease on the Core and Rotor.
- **Outcome:**
    - Throughout the 2019 maintenance outage, NLH investigated all leaks visible and fixed any and all seals; however, the exact source of the oil and dirt found on the Generator components was not determined. Moving forward, NLH planned to closely monitor the entire machine and fix leaks as they develop.
- **Voith Recommendation:**
    - Voith recommended a “Knife Test” be performed on the Stator Core. This is simple test to determine if the laminations can be easily separated by attempting to force a thin blade between the laminations. This is a simplistic method to determine if the core clamping pressure has decreased or become low enough to where a thin blade can get between the laminations.
- **Outcome:**
    - The knife test was performed by NLH and no negative results were reported. The results of the Knife Test are included in a NLH-supplied report in the Appendix.
- **Voith Recommendation:**
    - **Electromagnetic Core Imperfection Detection:** Due to the age and physical condition of the Stator, Voith recommended performing an ELCID. The ELCID identifies and locates existing damage to the Core, which will help determine and grade the condition of the Core more so than a visual inspection. Voith was requested to and provided a quote to NLH to perform the ELCID.
- **Outcome:**
    - After reviewing the options, NLH determined to performed the ELCID with internal means and not use Voith Fields Services. The results of the inspections are provided in a NLH-supplied report in the Appendix.

- **Voith Recommendation:**
    - Voith recommended repairing all of the Air Guides around the Stator. The movement of the Guide could be causing damage to the insulation behind it; however, it's difficult to know without removing the Air Guide. The recommendation was to verify that the insulation behind the Guide is not damaged and replace all of the Air Guides and rivets as needed. The risk is damage to the insulation or the Air Guide could fall off during operation.
- **Outcome:**
    - After reviewing Voith's recommendation NLH and due to project schedule restrictions, the repairs to the air guide baffles were not completed during this Unit outage. The repairs will be completed during the next major outage.
- **Voith Recommendations:**
    - Voith reported during the Visual Inspection that some of the laminations were bent and damaged in a few locations. While the source was unknown, it could be due to localized buckling (very unlikely), debris damage, or a clamping issues during assembly. NLH could straighten the laminations in place, but the net gain of straightening the laminations is low.
- **Outcome:**
    - Voith did not recommend any repair or task associated with the bent laminations found during the 2019 maintenance outage.
- **Voith Recommendation:**
    - Due to the condition of the electrical components with the Unit 7 machine, Voith recommended and offered to provide an expert Voith Electrical Engineer to perform a more thorough investigation of the components and conduct all of the necessary tests to ensure the machine was safe for operation.
- **Outcome:**
    - After discussing options internally, NLH determined they would use their already onsite team to investigate all of the issues and perform additional tests. At the time of Voith's inspection and recommendation report, NLH has already performed their own study of the machine and developed a plan to repair and test the machine using their own staff, which was parallel with Voith's recommended plan. All of the reports and conclusions provided to Voith concerning the generator from NLH are located in the Appendix of this report.

5.17 Stay Ring and Vanes

5.17.1 Background Information

The Stay Ring is a structural member surrounding the Wicket Gates. The Stay Ring is two annular rings connected by a number of fixed Stay Vanes in the water passages. Its function is to provide support and structural continuity between the upper and lower portions of the Turbine Distributor, while guiding the water as it enters or leaves the Spiral Case. The Stay Vane are streamlined stationary members that connect the upper and lower annular rings of the Stay Ring and provide a rigid connection for the top and bottom Turbine structures, and also help guide the water into the Runner. For the 2019 maintenance outage a non-destructive examination was planned for the larger fillet welds where the Stay Vanes connect to the Stay Ring, both at the top and bottom.

Planned Work:

- Lead Paint Removal, Welds only (VH Scope).
- NDE Stay Vane Welds (VH Scope).
- Paint as necessary (NLH Scope).

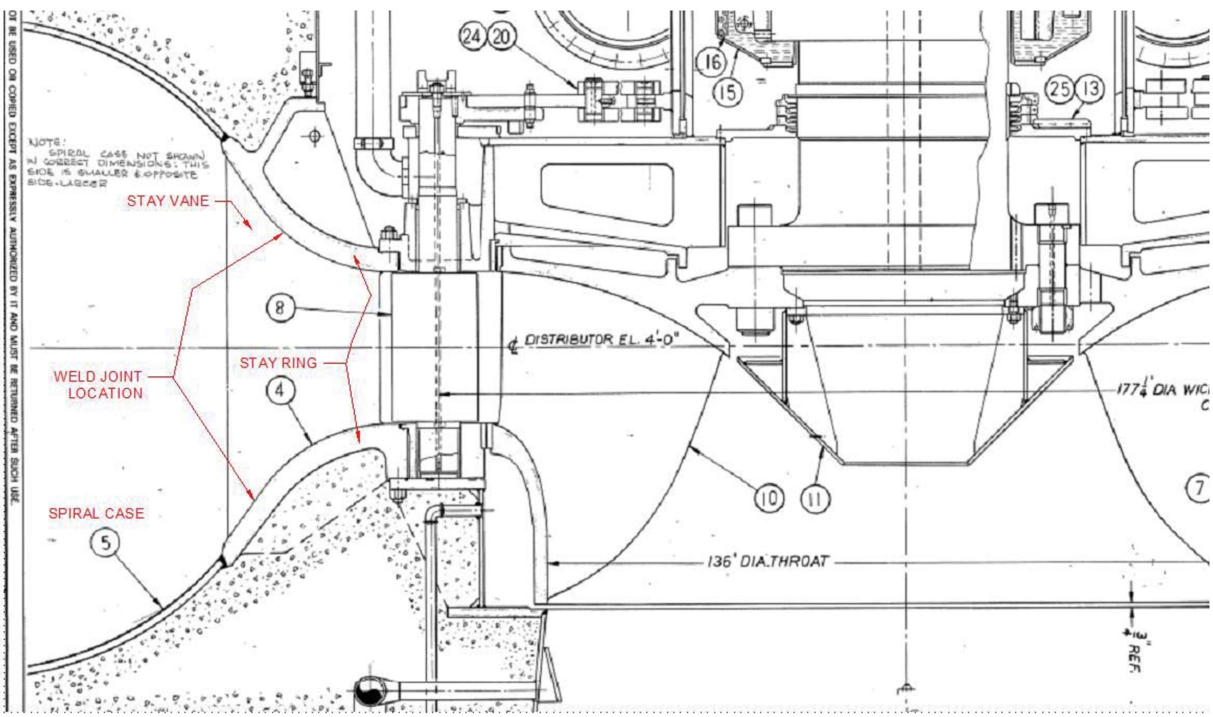

Figure 5-157: Stay Ring and Vanes, OEM Turbine Cross-Sectional View

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5.17.2 Visual Inspection

Voith performed a visual inspection of the Stay Ring and Vanes to detect any obvious signs of damage or failure. The Stay Ring and Vanes were in good condition considering the age and amount of time the Unit has been under operation. The orange paint (possibly OEM) was also in good condition with limited signs of deterioration. The leading entrance edge of the Stay Vane had some light scratches and signs of wear, but this is expected due to contact with high velocity water and possible impact from debris.

5.17.3 Laser Inspection Data and Results

Other than the Stay Ring Flange, there was no High Precision Dimensional inspection planned for or performed on the Stay Ring and Vanes during the 2019 maintenance outage. The Stay Ring Flange will be discussed in more detail in the Stationary Component Analysis section of this report. A table plot of the Stay Ring Level data points follows.

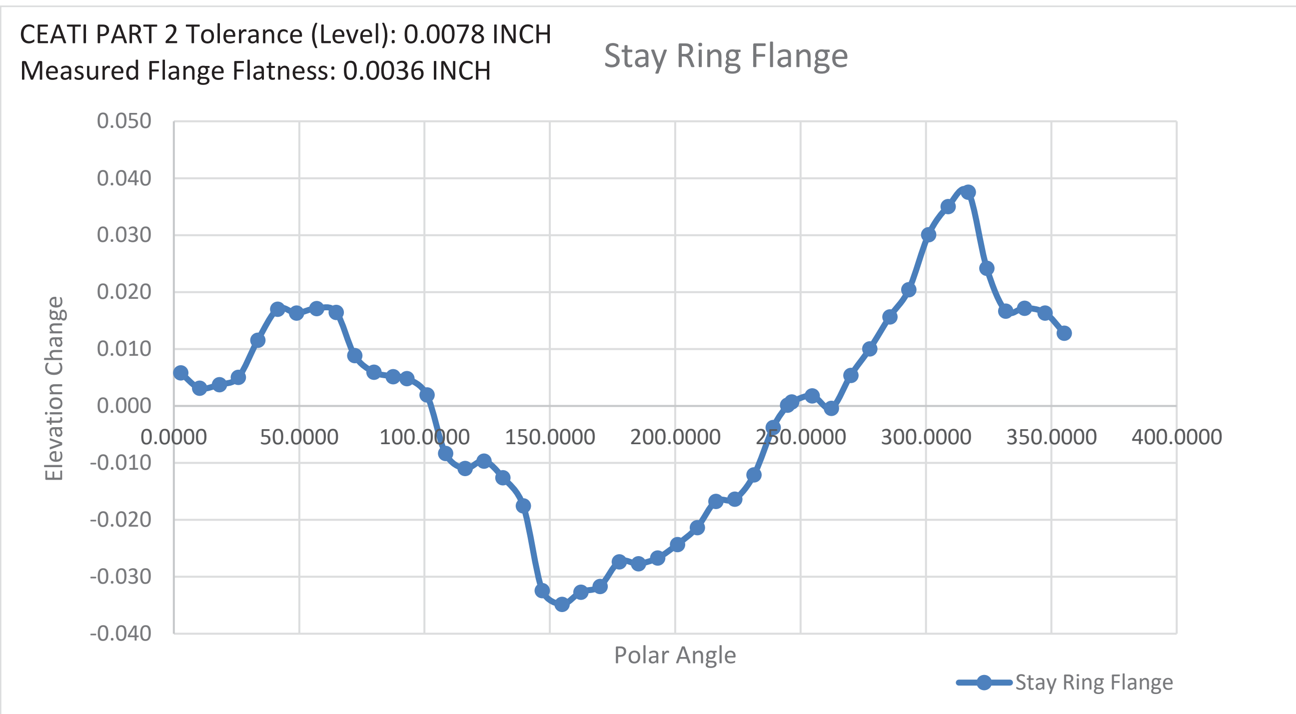

Figure 5-158: Stay Ring Level Readings

5.17.4 Non-Destructive Examination

A non-destructive examination was planned for the Stay Vane fillet welds for the 2019 maintenance outage. The NDE contractor, Acuren, performed the examination using the method of Magnetic Particle Test (MT). The contractor used a VH-provided document (2-10044792) to guide their inspection. Within this document the contractor was instructed to inspect all of the large fillet welds that connect the upper and lower rings of the Stay Ring assembly. Prior to doing so the lead paint was removed from the areas that were examined. Once the paint was removed, Acuren MT inspected all of the joints and reported that no relevant indications were found during the inspection.

Due to the temporary platform constructed during the 2019 maintenance outage, a small section close to the discharge edge of the Stay Vanes was not inspected. The platform was critical to other outage tasks and removing it to inspect the small area would not be conducive with maintaining the outage schedule. Since no indications were found on the Stay Vanes inspection, which was close to 97 percent, it was decided not to remove the platform for the remaining three percent. A comprehensive NDE report, with results and notes is located in the Appendix.

Figure 5-159: Stay Ring, Vane NDE

Figure 5-160: Stay Ring, Vane NDE

Figure 5-161: Stay Ring, Vane NDE

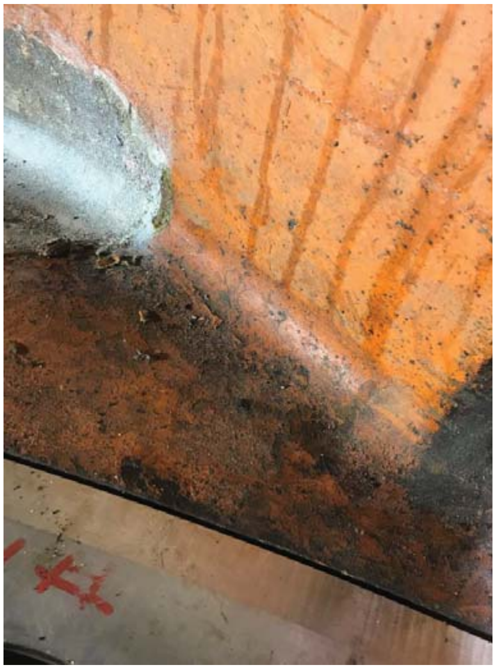


Figure 5-162: Turbine Pit Platform Interference

5.17.5 Outage Recommendations

The non-destructive examination did not produce any indications requiring attention; therefore VH was not required to recommend any repairs.

5.17.6 Conclusion

NLH was satisfied with the clear NDE inspection results and painted the joints where the inspection took place.

5.18 Spiral Case

5.18.1 Background Information

The Spiral Case is a spiral-shaped water passage that completely surrounds the Turbine to provide a uniform distribution of water flow to the Turbine. The upstream end of the Spiral Case connects to the pressure conduit or Penstock. A visual representation of the Spiral Case is included in this section of the report.

Worked Planned:

- Visual Inspection (VH Scope).

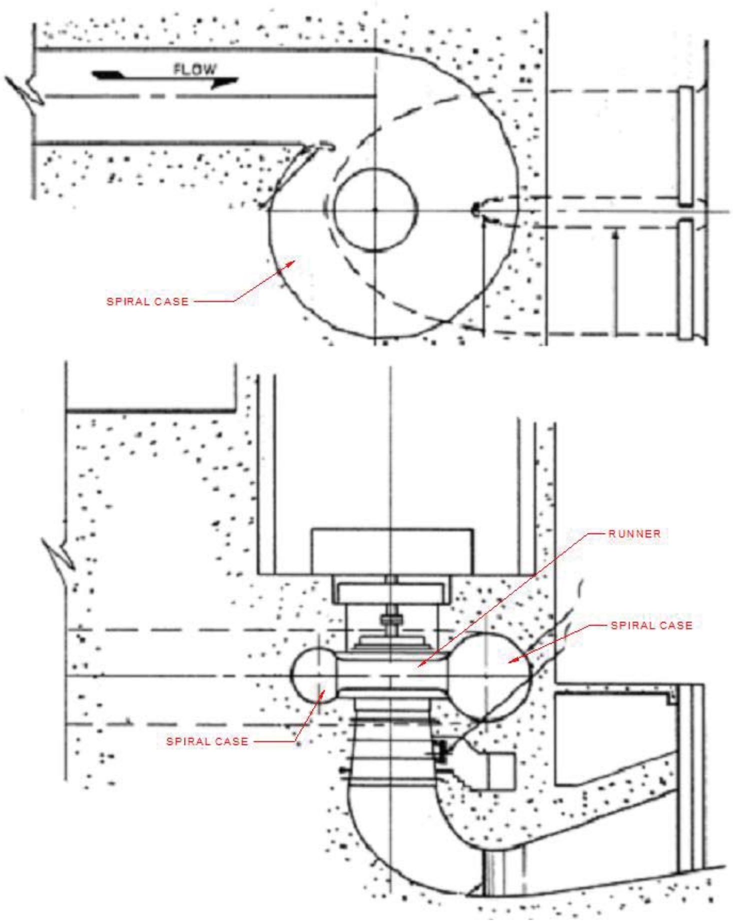

Figure 5-163: Typical Francis Turbine Spiral Case Layout, Top View (Top), Cross-Section (Bottom)

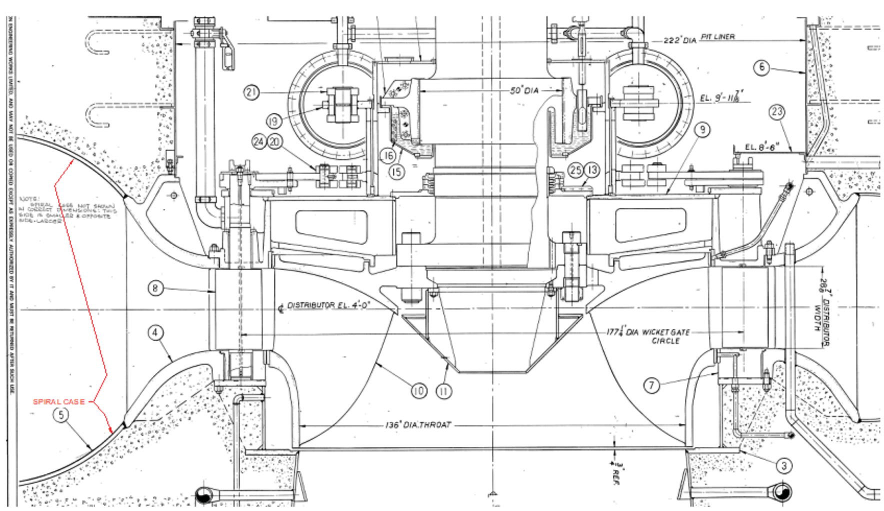

Figure 5-164: Spiral Case, OEM Turbine Cross-Sectional View

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5.18.2 Visual Inspection

Voith performed a visual inspection of the Spiral Case to look for any obvious signs of damage or failure. The Spiral Case was in good condition considering the age and amount of time the unit was under operation. The orange paint (possibly OEM) was in fair to poor condition with limited signs of base metal deterioration. As shown in the figures below, the paint was missing from the middle section of the Spiral Case; however a fair amount of paint was still present on the top and bottom sections. No signs of obvious damage or cracks were present at the time of the inspection. The base metal on the middle section of the Spiral Case was slightly worn and some pitting or deterioration was present.

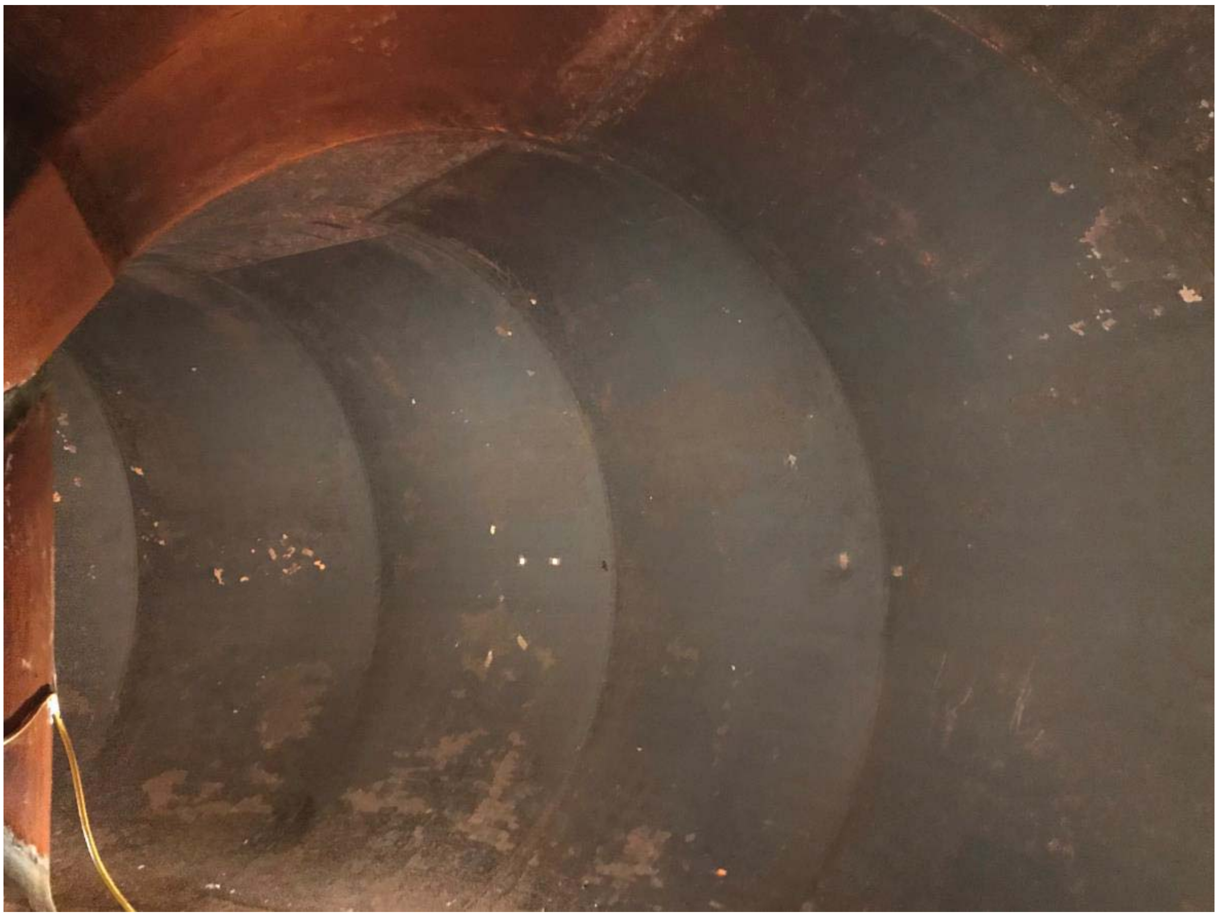

Figure 5-165: Spiral Case, Upstream

Figure 5-166: Spiral Case (Man-Door, and Pressure Relief Valve)

Figure 5-167: Spiral Case, Pressure Relief Valve

Figure 5-168: Spiral Case

5.18.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Spiral Case during the 2019 maintenance outage.

5.18.4 Non-Destructive Examination

There was no non-destructive examination planned for or performed on the Spiral Case during the 2019 maintenance outage.

5.18.5 Outage Recommendations

Voith did not provide any recommendations to NLH for the Spiral Case during the 2019 maintenance outage.

5.18.6 Conclusion

Prior to the 2019 commissioning, and once assembly was completed, NLH cleaned the Spiral Case thoroughly and ensured all debris and foreign material were removed.

5.19 Turbine Guide Bearing

5.19.1 Background Information

For vertical Francis Turbines the main function of the Turbine Guide Bearing (TGB) is to keep the shaft aligned vertically and support a radial force that can take place during operation. The TGB attempts to resist any mechanical imbalance and side loads from the Turbine Runner, thereby maintaining the Turbine Runner in its centered position in the Runner Seals. As shown in the figures included in this section, the TGB is located directly above the Head Cover and is encapsulated in an Oil Basin. The Turbine Shaft has a large journal on the lower end that the TGB surrounds. This journal surface rotates inside the TGB and is lubricated with pressurized oil. The inside diameter of the TGB, the bearing surface, is overlaid with a Babbitt material. This Babbitt material has a smooth, slick surface that is easily wetted by lubricants. This soft material is resistant to galling, but wears easily, and thus protecting the harder material of the shaft. When the machine begins to operate in an abnormal state, such as an over-speed, the oil film thickness can become thin, causing the shaft bearing journal to contact with the Babbitt material of the TGB. The bearing surface of the Babbitt material becomes the lubrication source and is sacrificed to preserve the harder material of the Turbine Shaft.

To account for possible wear of the Babbitt surfaces of the TGB, NLH planned for a visual inspection and non-destructive examination of the part.

Planned Work:

- Non-Destructive Examination (VH Scope).
- Visual Inspection (VH Scope).

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Project Report</td><td colspan="2">TFS7000</td></tr>
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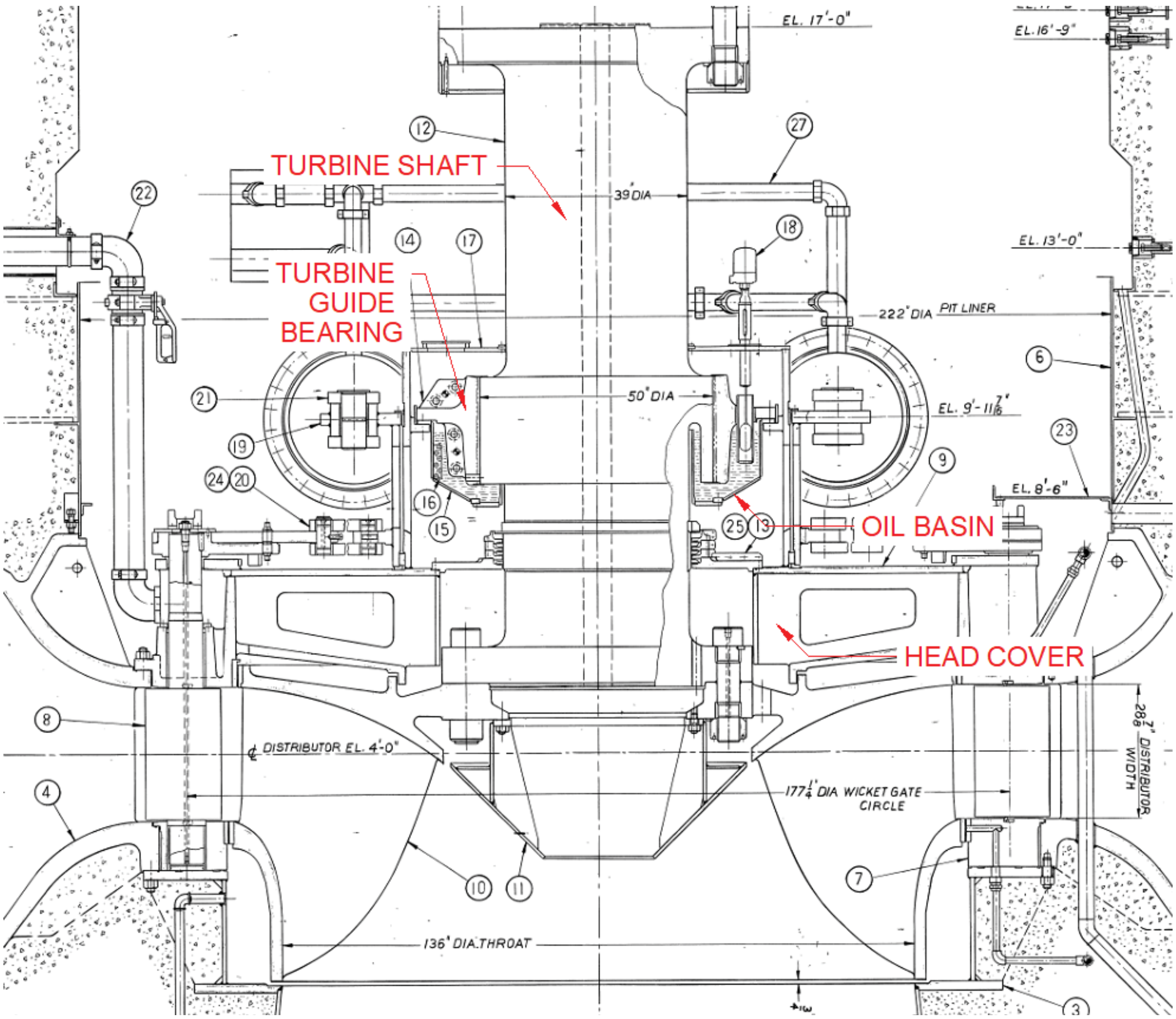

Figure 5-169: Turbine Guide Bearing, OEM Turbine Cross-Sectional View

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5.19.2 Visual Inspection

Voith performed a visual inspection of the Turbine Guide Bearing to look for any obvious signs of damage or failure. The Turbine Guide Bearing was in good condition considering the age and amount of time the unit has been under operation. The paint covering the outside of the TGB was in fair condition with limited signs of wear or deterioration. The split face surfaces had no signs of damage or fretting. The Babbitt surfaces of the TGB third sections had visible signs of wear, but no alarming damage was reported from the visual inspection.

Figure 5-170: Turbine Guide Bearing, Visual Inspection

5.19.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Turbine Guide Bearing during the 2019 maintenance outage.

5.19.4 Non-Destructive Examination

5.19.4.1 Examination Outline

A non-destructive examine was performed on the TGB during the 2019 maintenance outage. Voith subcontracted this work to the Acuren Group. To guide Acuren's examination, Voith created an instruction guideline document (2TFS70-0000-10044792), which is located in the Appendix. To summarize, the Turbine Guide Bearing NDE inspection consisted of: a Magnetic Particle Test (MT), which was used to find indications

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in high stress structural features and locations, and an Ultrasonic (UT) and Penetrant (PT) examination was used for the inspection of the Babbitt material. Prior to performing any inspections, lead paint abatement was required to be performed anywhere NDE was planned. Figure 5-171 is a diagram from the Voith NDE Instruction document, 2TFS70-0000-10044792, showing the areas to be inspected. Voith also supplied Acuren with their standard procedure, Babbitt Bearing Test Requirements, 2664-000300, to guide the UT inspection of the Babbitt surfaces.

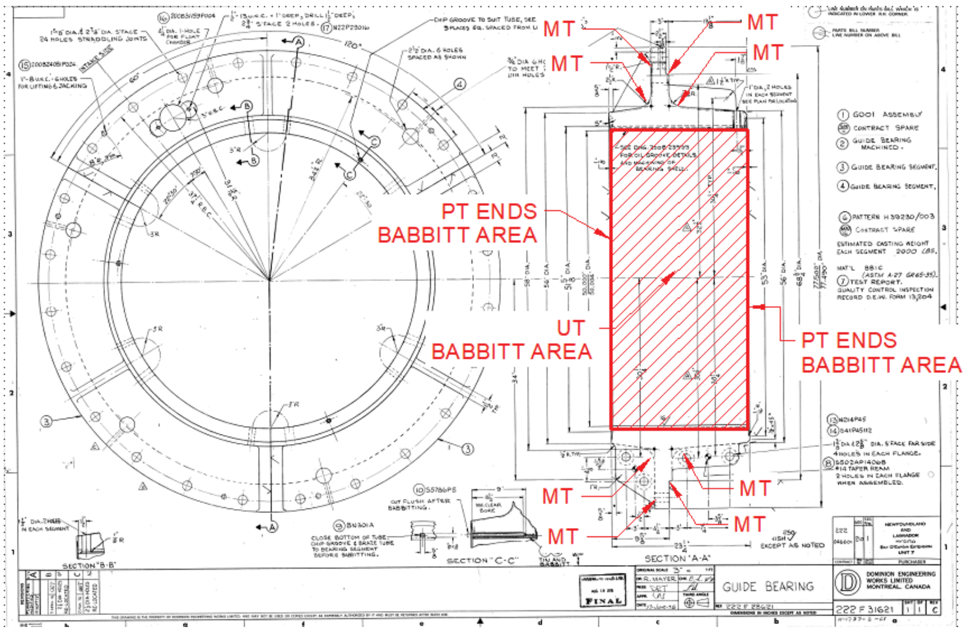

Figure 5-171: Turbine Guide Bearing Inspection Diagram

5.19.4.2 Non-Destructive Examination Results

- **Magnetic Particle Inspection**
  - Once the Magnetic Particle Inspection was completed, the Acuren Group reported that no relevant indications were found at the time of the inspection in all accessible areas where paint was removed. No cracks or defects were present. The comprehensive report for the MT inspection is located in the Appendix.
- **Liquid Penetrant Inspection**
  - The Liquid Penetrant Inspection of the Babbitt material revealed major linear indications. All of the PT indications are unacceptable per Voith's Babbitt Bearing Test Requirements 2664-000300 procedure.

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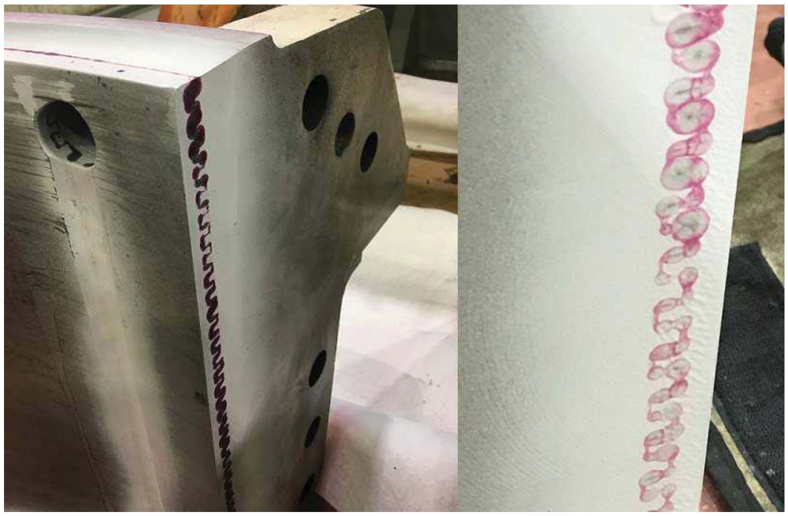

Figure 5-172: Turbine Guide Bearing, PT Section 1-3

1. **Section 1-3**: Unacceptable linear indications were found on the entire length of both mating sides. Across the top linear, indications were noted, the first starting at the edge stamped 1 for a length of 19" and the second starting at edge stamped 3 for a length of 22".

Figure 5-173: Turbine Guide Bearing, PT Section 1-2 and 2-3

2. **Section 2-3:** Unacceptable linear indications were found for the entire length of both mating sides. Across the top, linear indications were noted, the first starting at edge stamped 2 for a length of 13.5" and the second starting at edge stamped 3 for a length of 18.25".

3. **Section 1-2**: Unacceptable linear indications were found for the entire length of both mating sides. Across the top, linear indications were noted, the first starting at edge stamped 1 for a length of 13.5" and the second starting at edge stamped 2 for a length of 13".

- **Ultrasonic Examination**
  - The Ultrasonic Examination revealed significant delamination of the Babbitt material on all three sections of the Turbine Guide Bearing. Shown below and highlighted in red, the UT inspection located these areas of delamination. All of the UT indications are unacceptable per Voith's Babbitt Bearing Test Requirements 2664-000300 procedure.

Figure 5-174: Turbine Guide Bearing, Section 1-3

Figure 5-175: Turbine Guide Bearing, Section 2-3

Figure 5-176: Turbine Guide Bearing, Section 3-3

5.19.5 Outage Recommendations

Once Voith reviewed the reports provided by Acuren, Voith determined the condition of the Turbine Guide Bearing was unacceptable. This determination is a result of NDE indications and delamination of the Babbitt material listed in Section 5.19.4.2. Per Voith Standards, this bearing should be placed out of service and repaired.

- **Recommendation:** Voith provided a recommendation to NLH to use the spare Turbine Guide Bearing and to consider rehabilitating the bearing removed during the 2019 maintenance outage.

5.19.6 Conclusion

During reassembly of the Unit 7 machine NLH proceeded with the VH recommendation and installed the Spare Turbine Guide Bearing. The spare TGB was installed upon unit alignment and no issues or concerns were present prior to or during commissioning. The Turbine Guide Bearing taken out of service was sent to Canadian Babbitt Bearing for refurbishment.

5.20 Main Bracket - Thrust and Guide Bearing

5.20.1 Background Information

The Main Bracket of the BDES Unit 7 machine is located under the Generator and above the Turbine Shaft. The purpose of the Main Bracket is to provide a structural support for the unit in the vertical direction. In the case of Unit 7, the Main Bracket houses the Thrust Bearing assembly, where the vertical loads are transmitted, and the Upper Guide Bearing assembly, where lateral movement is controlled. During assembly the Generator Rotor is connected to a Thrust Collar and Thrust Runner. Both of these rotating components help transmit the radial and thrust loads of the unit. The radial forces are controlled through Guide Pads that are located around the circumference of the Thrust Collar.

Similar to the Turbine Guide Bearing, these pads are the sacrificial parts of the bearing assembly. A thin film of oil between the Guide Pads and Thrust Collar control the lubrication and heat transfer of the bearing assembly. Likewise, the Thrust Runner transmits the thrust forces of the machine through Thrust Pads. The friction between the Thrust Pads and Thrust Runner is also controlled by a hydrodynamic film of oil. During the 2019 maintenance outage, NLH planned to visually inspect the Main Bracket, along with the Thrust Collar and Runner. A more detailed NDE inspection was planned for all of the bearing pads and wear components.

Planned Work:
- Main Bracket Inspection (VH Scope).
- Bearing Component Inspection (VH Scope).
- Bearing Pads NDE Inspection (Babbitt Material, VH Scope).

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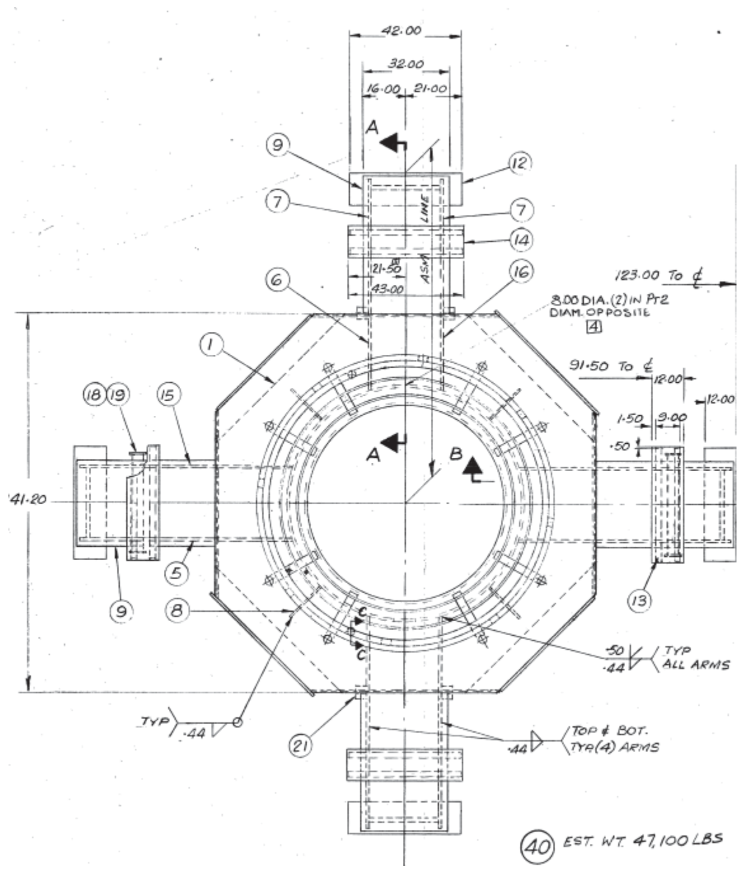

Figure 5-177: Main Bracket (Top View)

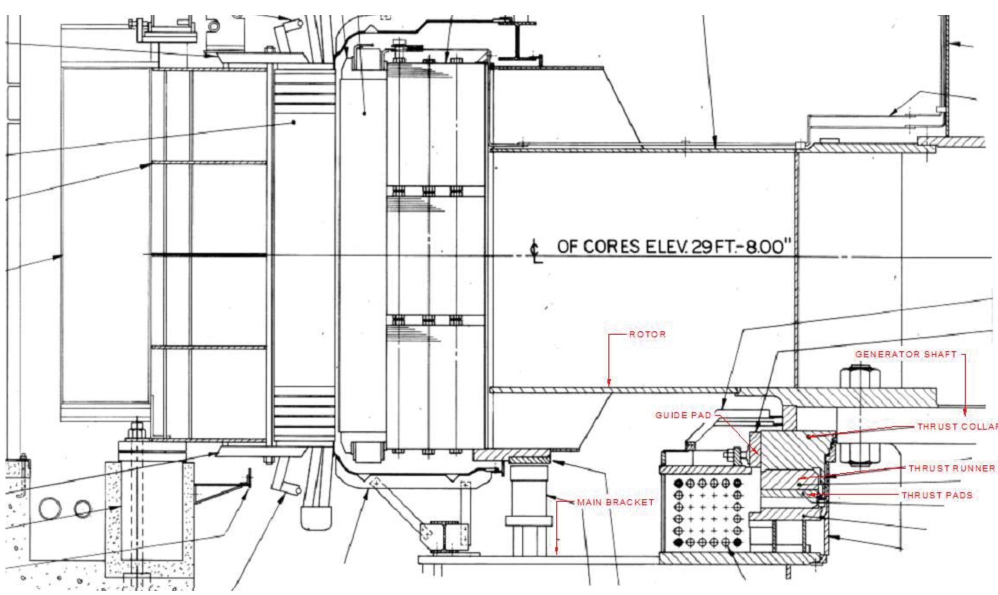

Figure 5-178: Main Bracket and Bearing Components

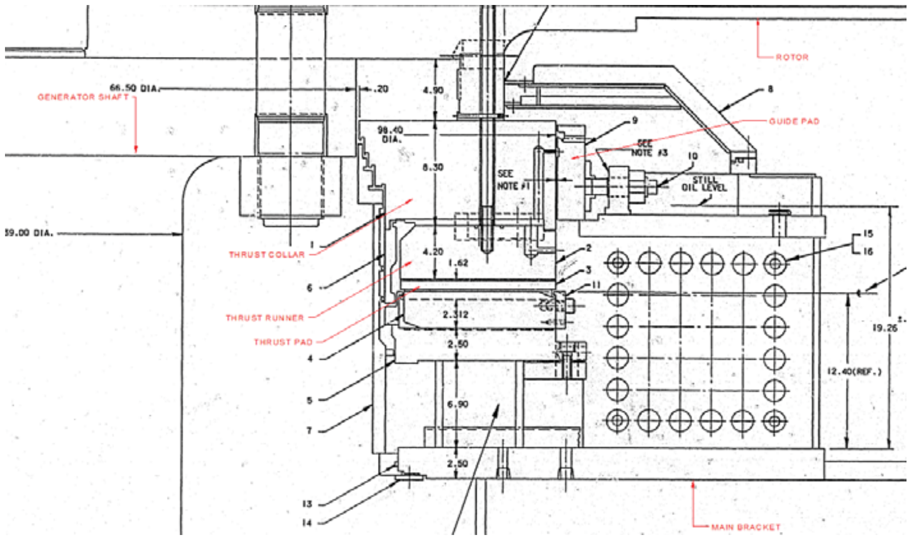

Figure 5-179: Combination Guide and Thrust Bearing Cross-Section

5.20.2 Visual Inspection

5.20.2.1 Main Bracket

The Main Bracket was visually inspected by Voith engineering for any obvious signs of damage, cracking, and any indications that the bracket may require repair prior to placing the unit back into to service. Overall the Main Bracket was found to be in good condition. No signs of major leaks or damage were present at the time of the inspection. The braking mechanism, piping, and electrical system were visually in good working order. The paint on the Main Bracket was in good condition with limited signs of wear and deterioration. During the 2019 maintenance outage, NLH covered the exposed internal components of the combined bearing to ensure the dust and debris did not enter the area.

Figure 5-180: Main Bracket

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Figure 5-181: Main Bracket

5.20.2.2 Thrust Collar and Thrust Runner

The Thrust Collar and Thrust Runner are bolted together to the Generator Rotor. These two rotating components transmit thrust forces from the machine through the Thrust Pads to Main Bracket and eventually to the foundation. Both of these parts are precision machined with extreme emphasis on the surfaces that interface with the Thrust and Guide Pads. Due to this interface, these surfaces should be machined with great care and the flatness, concavity, and surface roughness values should be controlled. To inspect the condition of these components and the Thrust Pads, which are located underneath the Thrust Runner, NLH unbolted the Thrust Collar from the Thrust Runner. Both components were lifted out of the Main Bracket and placed in the predetermined location in the powerhouse. From there the parts were visually inspected by Voith engineering.

Thrust Collar: The Thrust Collar was found to be in good visual conditional with limited signs of wear. The mating surface on the Thrust Collar that contacts the Thrust Runner had light signs of fretting and corrosion. No signs or indications of damage or failure were present during the time of inspection. The round keys, which mate with the Generator Rotor, were also found to be in good condition with some light fretting located on a few of the keys. The lower outer diameter of the Thrust Collar is the journal surface. The Guide Pads surround this surface, and with the use of oil a hydrodynamic environment is created. As shown below the outer diameter of the Thrust Collar had some wear and very light scoring, possibly from coming into contact with the Guide Bearing Pads or debris in the oil.

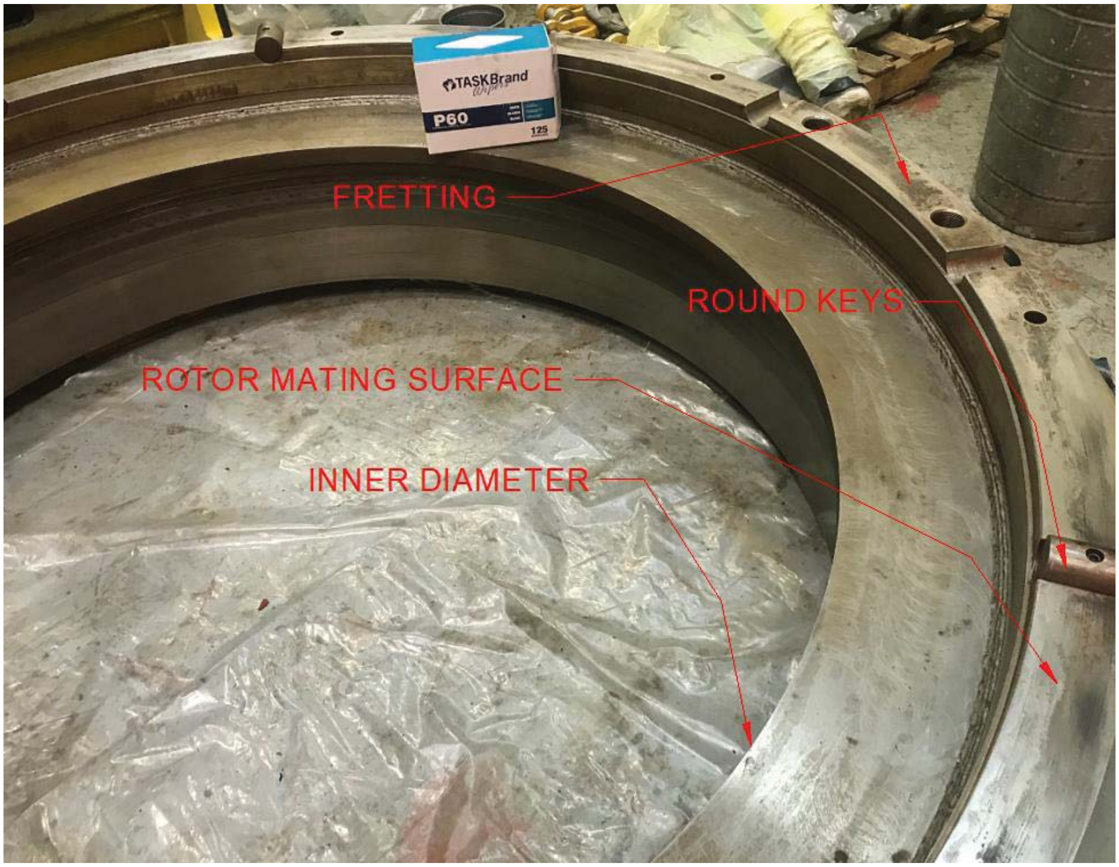
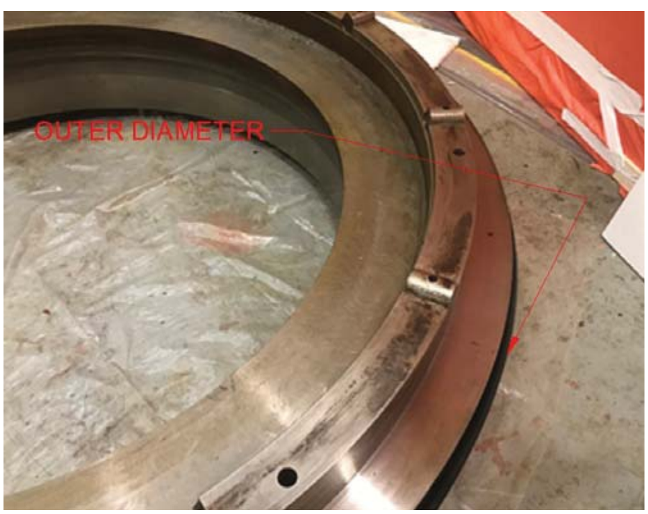


Figure 5-182: Thrust Collar Outline



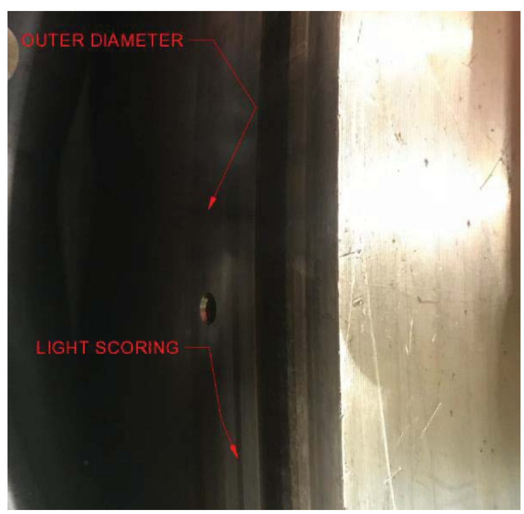


Figure 5-183: Thrust Collar, OD Light Scoring

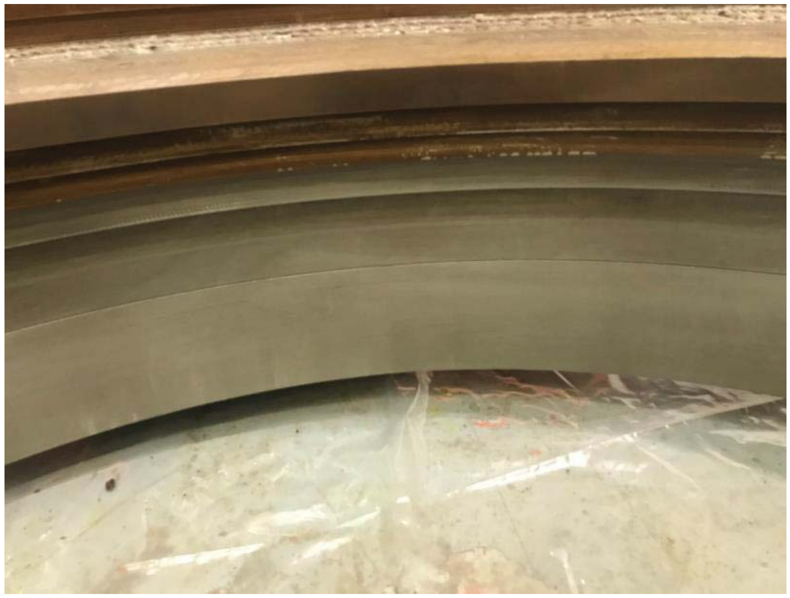


Figure 5-184: Thrust Collar Inner Diameter

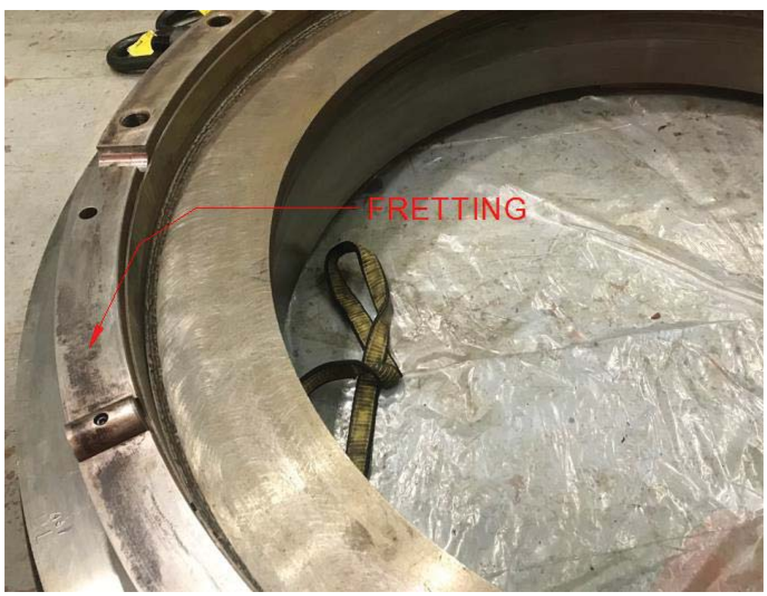


Figure 5-185: Thrust Collar, Fretting

Thrust Runner: The Thrust Runner was found to be in good visual condition with limited signs of wear. The mating surface on the Thrust Runner that contacts the Thrust Collar had light signs of fretting and corrosion. The fretting that was found between the Collar and Runner is not uncommon to find and in the case of Unit 7 was very light in nature. The fretting can be a result of high load vibrations, micro-debris between the contact surfaces, and/or repeated relative surface motion. It is difficult to determine the exact root cause of the fretting without performing a detailed inspections and analysis of the design and operation of the unit.

Overall the fretting was not deemed an immediate threat to the operation of the machine. On the opposite side of the Thrust Runner is the bearing journal of the thrust bearing assembly. This surface rotates on a thin film of oil. The Thrust Pad, which is located just below the Thrust Runner during operation is the sacrificial wear component made of softer material. The thin film of oil is located between the Pad and Runner and in theory, as long as the hydrodynamic condition exists the life of the bearing journal (Thrust Runner) is virtually limitless. In the case of the Unit 7 Thrust Runner the bearing journal was in good condition and no visual indications of damage or failure. All of the threaded holes and oil holes were also in good condition. The inner diameter and outer diameter surface did not show any indications or concerns.

Figure 5-186: Thrust Runner, after reassembly into Unit.

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Figure 5-187: Thrust Runner Removal

Figure 5-188: Thrust Runner Journal Surface

Figure 5-189: Thrust Runner, Fretting

Figure 5-190: Thrust Runner, Fretting

5.20.2.3 Thrust and Guide Pads

The Thrust Pads were exposed once the Thrust Runner was removed from the bearing assembly. The Thrust pads were not removed from the Main Bracket and were visually inspected in place by Voith engineering. The Thrust Pads were visually in good condition; however, nearly all of the pads had light scoring and surface imperfections on the Babbitt surface side of the pads. The source of the scoring is unknown, but typically these types of indications are sign that debris or contaminates are in the oil and are getting between the bearing surfaces, thus causing light damage to the Babbitt material. Visually it is difficult to determine how much of the Babbitt material is remaining on the pad; therefore a UT inspection of the each thrust pad was planned. The same UT inspection was planned for the Guide Pads of the Combined Bearing. The Guide Pads also had light scoring and surface imperfections. Similar to the Thrust Pads, the scoring or marks on the Guide Pads were more than likely from debris or dirt in the oil rather than the Thrust Collar contacting the Guide Pads.

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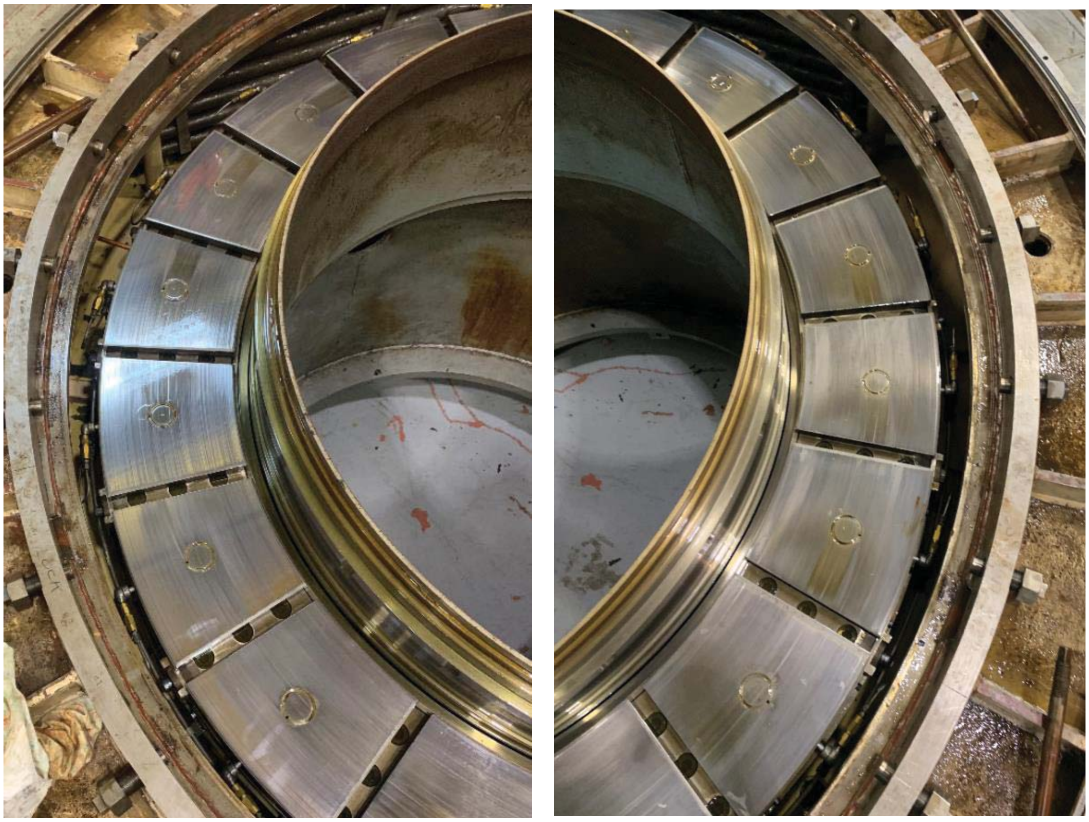

Figure 5-191: Thrust Pads

Figure 5-192: Thrust Pads

Figure 5-193: Guide Pads

Figure 5-194: Guide Pads

5.20.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Main Bracket and Combined Bearing components during the 2019 maintenance outage.

5.20.4 Non-Destructive Examination

A non-destructive examine was planned for the Thrust and Guide Pads of the Upper Combined Bearing during the 2019 maintenance outage. Voith subcontracted this work to the Acuren Group. To guide Acuren's examination Voith created an instruction guideline document (2TFS70-0000-10044792), which is located in the Appendix. To summarize, the NDE inspection of the Thrust and Guide Pads consisted of an Ultrasonic (UT) and Penetrant (PT) examination for the inspection of the Babbitt material. The results of the NDE inspection for each component is located in the Outage Recommendations of the section below.

5.20.5 Outage Recommendations

5.20.5.1 Thrust Collar

- **Voith Recommendation:**
    - Voith recommended cleaning the Thrust Collar and lightly removing any signs of fretting. The round keys should also be cleaned of dirt and any signs of fretting removed. Voith recommended the fretting be removed from the collar with a Scotch Brite pad and light oil. NLH was informed to only clean and blend those areas affected by fretting with minimal material removal. The surface of the outer diameter of the collar, where the Guide Pads are located, had very light scoring and marks present. Voith suggested that NLH could remove the high spots with a Scotch Brite pad, being careful not to remove excess material. After which, the Thrust Collar should be reinstalled in the Main Bracket and be protected from foreign matter entering the assembly and oxidation development until reassembly of the machine begins.
- **Outcome:**
    - All of the recommendations above were followed by NLH and the Thrust Collar was cleaned and all fretting surfaces were dressed, after which the collar was installed and protected in the Main Bracket.

5.20.5.2 Thrust Runner

- **Voith Recommendation:**
    - Voith recommended cleaning the Thrust Runner and lightly removing any signs of fretting. All of the threaded and non-threaded holes should be cleaned of dirt. Voith recommended the fretting be removed from the Runner with a Scotch Brite pad and light oil. NLH was informed to only clean and blend those areas impacted by fretting with minimal material removal. The

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bottom side or bearing side of the Thrust Runner showed no signs of wear or damage; therefore, no attention was required to this area.

- **Surface.** NLH was informed by VH to take extreme care of this surface during the outage. This is a critical surface and extra care and attention should be taken during lifting, handling, and storage operations. After which, the Thrust Runner should be reinstalled in the Main Bracket and protected from foreign matter entering the assembly and oxidation development until reassembly of the machine begins.

- **Outcome:**
  - All of the recommendations above were following by NLH and the Thrust Runner was cleaned and all fretting surfaces were dressed, and after which the Thrust Runner was installed and protected in the Main Bracket. NLH took extra precautions to ensure the critical surfaces of the Runner were protected during all operations of the 2019 maintenance outage.

5.20.5.3 Thrust and Guide Pads

- **Voith Recommendation:**
  - Voith recommended disassembly of the Thrust and Guide Pads from the unit and a complete NDE inspection should occur to verify the condition of the Babbitt surface of the pads. The individual springs that make up the spring beds under the Thrust Pads should be inspected while the Thrust Pads are removed from the Main Bracket. This inspection would help to determine if new springs were required; however, new springs should only be introduced into the unit only if all of the springs are replaced.

- **Outcome:**
  - The Guide Pads were removed from the unit and visually inspected and cleaned; however, NDE was not performed on the Guide Pads. The Thrust Pads remained installed in the Main Bracket where a visual inspection was performed. Due to delicate nature of the Thrust Pads and the risk of damaging the pads during the inspection, NLH decided not to perform the NDE inspection on the pads. The decision was reinforced by the long lead time to manufacture and replace any pads that might become damaged; therefore, the risk did not outweigh the reward for a detailed inspection of each pad. Moreover, a full lot of replacement springs for the spring beds was not available at the time of the outage, deeming the inspection of each spring bed futile. NLH compromised and removed two of the Thrust Pads briefly to visually inspect the condition of the springs to ensure none of the spring were broken. The springs were in good condition and no signs of damage were present. With this information and the overall good visual condition of all of the pads, NLH reassembled the bearing components into the Main Bracket.

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5.20.5.4 Main Bracket

- **Voith Recommendation:**
  - Voith recommended cleaning the exterior and interior of the Main Bracket and ensuring the unit was clean prior reassembly. VH recommended reassembling the bearing components back into the Main Bracket immediately following the inspection of the Thrust Runner, Thrust Pads, and Collar for the duration of the 2019 maintenance outage and protecting the opening of the Main Bracket with a cover to ensure foreign matter did not enter during the remainder of the outage. Also, all bearing parts should be coated with a light layer of oil to ensure that corrosion or oxidation did not develop.
- **Outcome:**
  - NLH followed Voith's recommendations and cleaned the Main Bracket and installed the bearing components back into the Main Bracket and protected all critical surfaces and openings as necessary to prevent foreign matter from entering the bearing assembly and oxidation development.

5.21 Head Cover

5.21.1 Background Information

The Head Cover is axisymmetric structural member in vertical machines that spans the top of the Distributor, provides the separation between the watered Runner chamber and the dry turbine pit, and supports the main shaft packing box and the main bearing. In Francis machines, and in the case the BDES Unit 7, the Head Cover also supports the upper Wicket Gate stems and is bolted to the Stay Ring. Using the experience from previous outages at Bay d'Espoir Powerhouse One and from the recommendations outlined in a refurbishment plan (VHY-1, 2017) developed by VH, NLH established a detailed plan for the Head Cover activities during the 2019 maintenance outage.

Planned Work:

- Visual Inspection (VH Scope).
- NDE Inspection (VH Scope).
- Lead Abatement (VH Scope).
- Laser Inspection (VH Scope).
- Machining of Wearing Ring (VH Scope, only if necessary).
- Line boring of the Gate Stem Bores (VH Scope, only if necessary).
- Eliminate Intermediate Gate Stem Bushing (greased) and replace with Greaseless Bushing (NLH Scope).

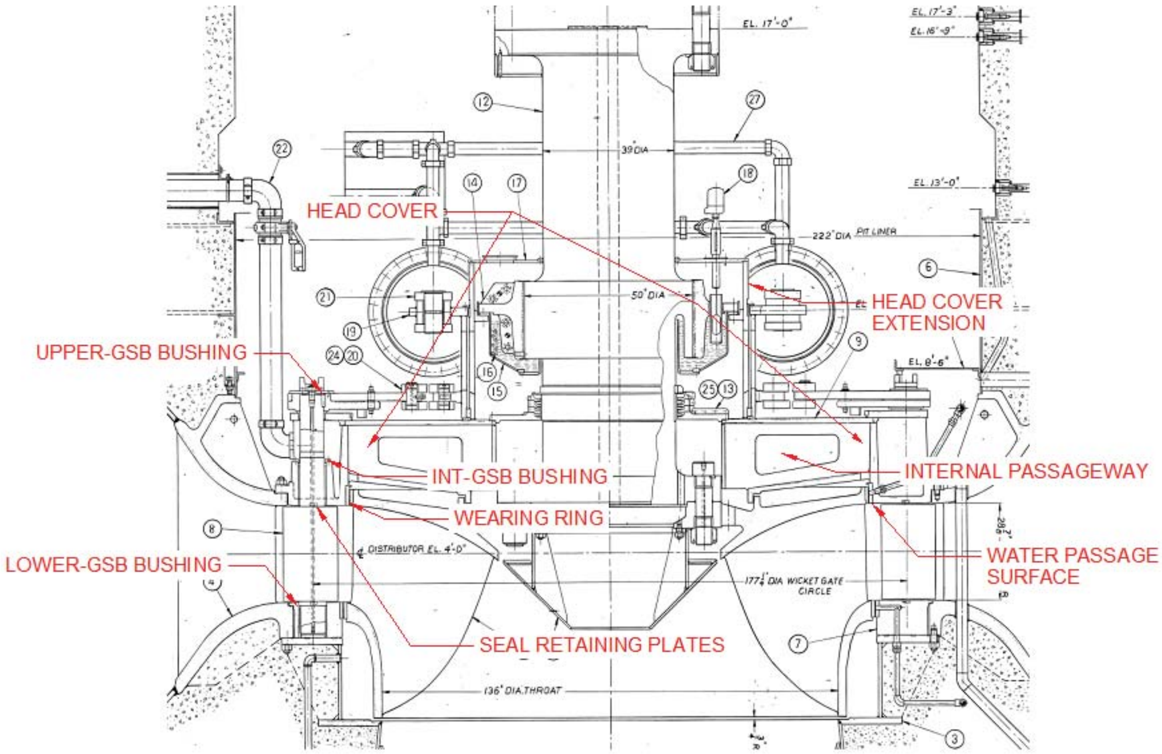

Figure 5-195: Head Cover Outline

Figure 5-196: Head Cover, Post Disassembly

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5.21.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Head Cover to look for any signs or indications of abnormal wear or damage. The overall condition of the Head Cover was fair considering the age of the unit and the fact that the 2019 maintenance outage was the first time the unit had been disassembled since commissioning in 1977. The inspection of the Head Cover can be broken in into parts based upon the different features of the part itself. The features are as follows: paint and overall appearance, Gate Stem Bores, Head Cover Extension, Water Passage Surface, Wearing Ring, and other found potential hazards.

5.21.2.1 Head Cover Paint – Overall Appearance

The condition of the paint was poor, especially on the flanges, top and bottom surface, and area in contact or near moving parts of the Gate Mechanism. Moderate rust, corrosion, and pitting was present on the top (dry side) and the bottom side (wet side) of the Head Cover.

Figure 5-197: Head Cover, Paint Condition and Overall Appearance

Figure 5-198: Head Cover, Paint Condition and Overall Appearance

Figure 5-199: Head Cover, Paint Condition and Pitting of Upper Surface

Figure 5-200: Head Cover, Paint Condition of Bolting Flange

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5.21.2.2 Head Cover Extension

The Head Cover Extension, which is the cylindrical part extending upward that houses the Turbine Guide Bearing, was also in fair condition. This part not only provides support for the TGB, but also acts as the framework on which the Operating Ring rotates. Specifically, the Operating Ring rotates on the greased copper alloy liners on the Head Cover Extension. Once the Operating Ring was removed, the liners were visible and revealed to be in a poor condition. The condition of the liners was so severe that they were not repairable and would require immediate invention from NLH to remedy the problem. This topic is discussed in more detail in the Operating Ring Section 5.12.

Figure 5-201: Head Cover, Extension and Liners

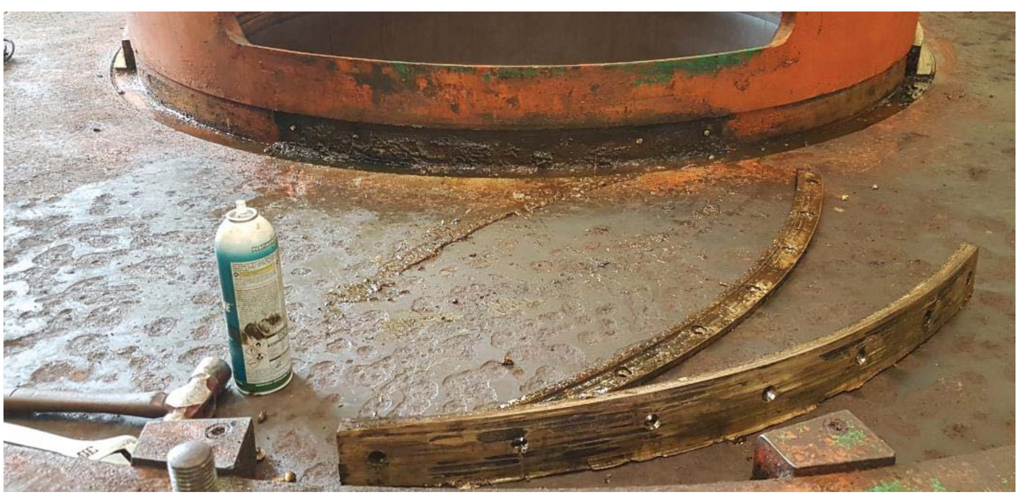

Figure 5-202: Head Cover, Extension and Liners

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Figure 5-203: Head Cover, Extension and Liners

Figure 5-204: Head Cover, Extension and Liner

5.21.2.3 Head Cover Gate Stem Bores

As part of the predefined work, NLH removed the Intermediate Gate Stem Bushing (IGSB) from the Head Cover in preparation of the installation of the greaseless Thordon bushing. Once the IGSB were removed the internal diameter of the bores was visible and showed to be in good condition. While the GSB concentricity was unknown at this time the surface finish and condition of the bores was suitable to accept the new Greaseless Bushing. However, the same was not the case for the Upper Gate Stem Bushings, which were not planned to be replaced due to impact this would have on other components. For the time being the Upper Gate Arm Bushing will remain greased until a major unit outage (six or more months) is planned.

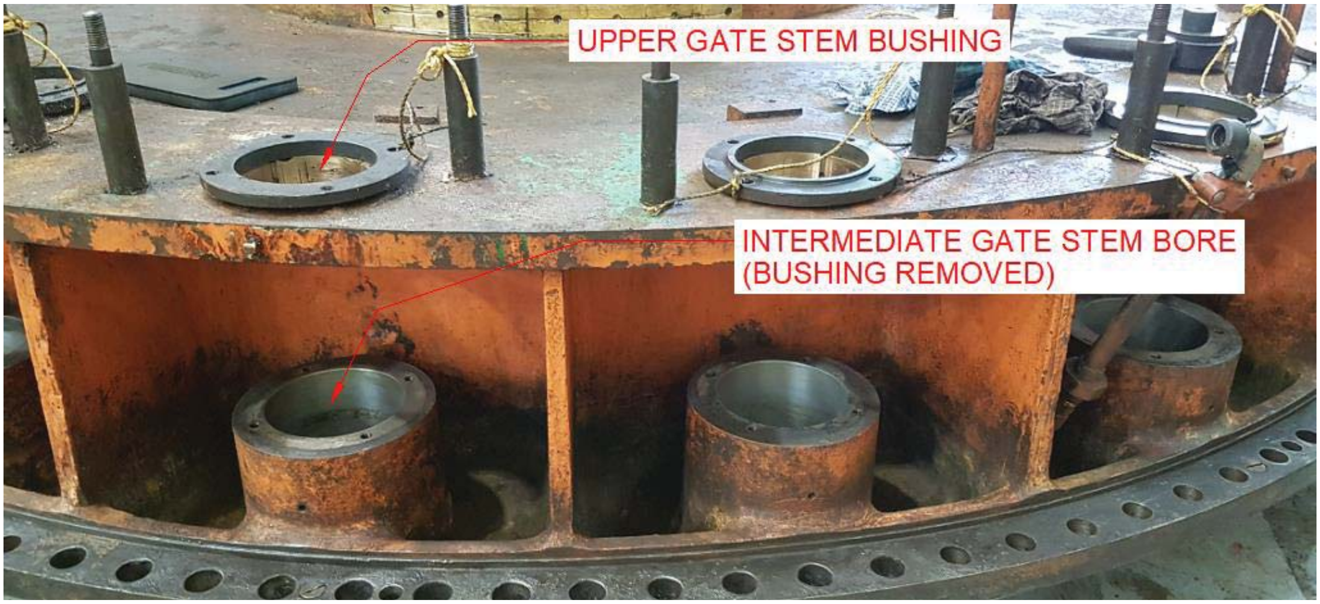

Figure 5-205: Head Cover, Gate Stem Bores

The condition of the Upper Gate Arm Bushings was poor; in fact, some of the bushings were scored and damaged enough to cause the bushing to take on an elliptical shape, rather than a circular one. This same wear pattern was found on the Intermediate Gate Stem Bushing and the Lower Gate Stem Bushing, which resides in the Bottom Ring. This pattern of wear and damage indicated that a misalignment or lack of concentricity between the Gate Stem Bores was present. The concentricity and alignment of all the Gate Stem Bores is discussed in Section 5.23.

Figure 5-206: Head Cover, Intermediate Gate Stem Bushing Removal

Figure 5-207: Head Cover, Intermediate Gate Stem Bushings

Figure 5-208: Head Cover, Upper Gate Stem Bushing

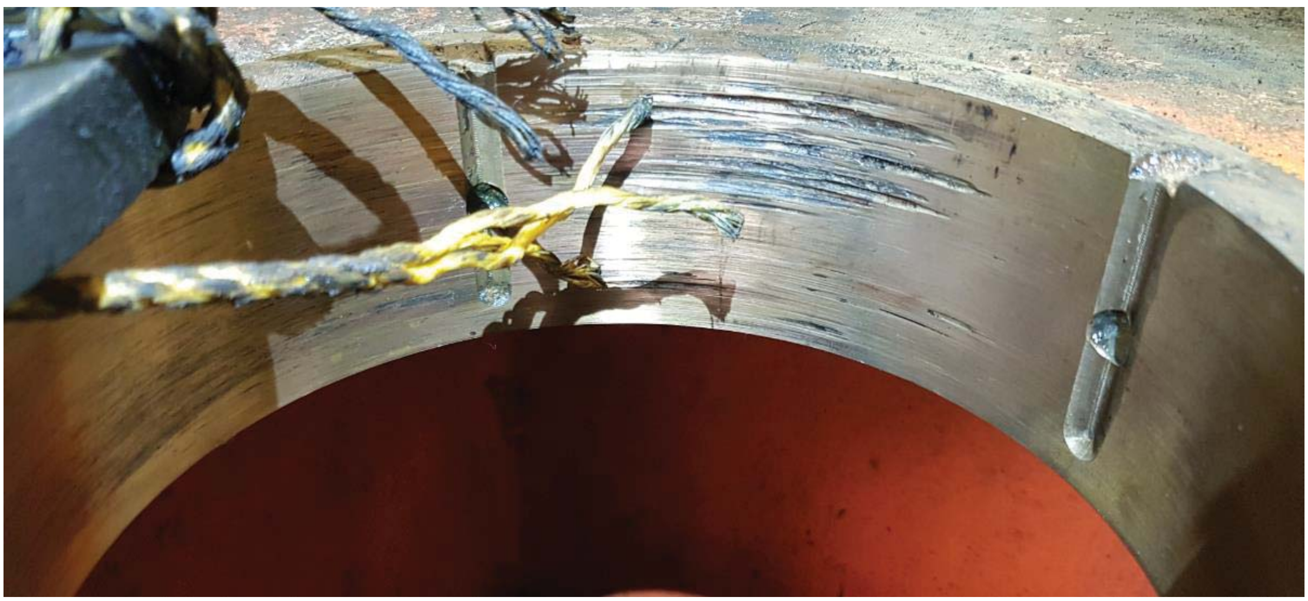

Figure 5-209: Head Cover, Upper Gate Stem Bushing

5.21.2.4 Head Cover Wearing Ring and Thrust Relief Holes

The Runner rotates between the Wearing Ring of the Head Cover on the bottom side or wet side of the Head Cover. As shown in the following pictures, light to moderate cavitation damage was present on the Wearing Ring, specifically around the cooling holes. These holes are used when the machine operates in Synchronous Condenser mode. It is unknown when this cavitation occurred, but cavitation evidently develops during normal operation when the water flow past the hole is interrupted, creating a turbulent zone. This turbulent zone creates a difference in pressure, causing the cavitation to develop, ultimately deteriorating the metal of the wearing ring.

Figure 5-210: Head Cover, Wearing Ring Cavitation

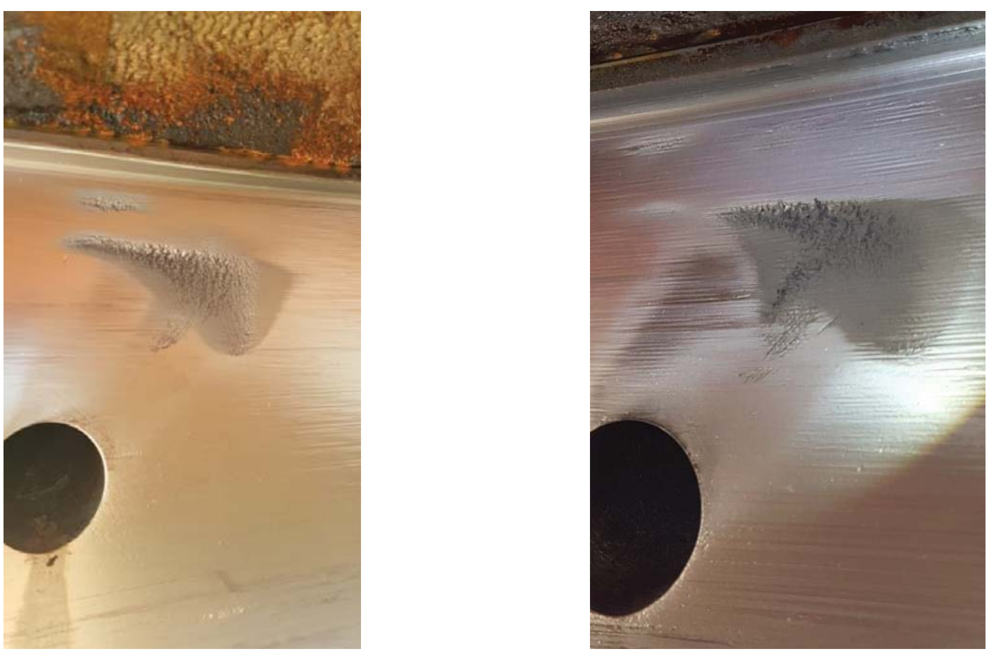

Figure 5-211: Head Cover, Wearing Ring Cavitation

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The Head Cover Wearing Ring also had scratches and scoring present during the inspection. The scratches can be sign of debris getting between the seal rings and causing damage or the Runner could possibly be contacting the ring. This is quite plausible due to the reduction of the radial seal clearance of the Runner the unit had been experiencing. Along with the cavitation found on the wearing ring there was also moderate to heavy signs of cavitation around all of the thrust relief holes on the Head Cover.

Figure 5-212: Head Cover, Wearing Ring Scratches and Scoring

Figure 5-213: Head Cover, Wearing Ring Scratches and Scoring

Figure 5-214: Head Cover, Wearing Ring Scratches and Scoring

5.21.2.5 Head Cover - Potential Debris Hazard Found

As mentioned in Section 5.9, a small piece of steel from the Runner Crown Balance Cover Plate broke free of the cover plate. The dislodged steel plate was able to move between the bottom side of the Head Cover and the Runner Crown and moved with the rotating motion of the Runner. This is very troublesome because the steel piece, now traveling a high velocity, had the opportunity to cause significant damage to Head Cover and Runner. The steel piece was found inside one of the internal Head Cover passageways during the inspection. After further investigation, it is unclear if the plate did any relevant damage to the Head Cover or Runner, but this is an example of how an aging machine can potentially cause significant damage to machine components of high precision, ultimately, causing an unplanned outage.

Figure 5-215: Runner Cover Balance Plate, Piece Missing

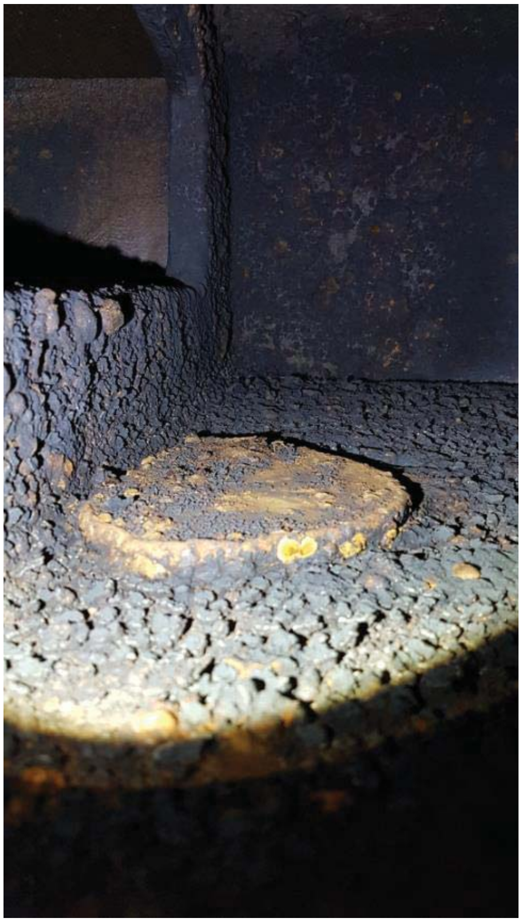


Figure 5-216: Head Cover, Runner Cover Balance Plate Steel Plate Found

5.21.2.6 Head Cover – Water Passageway and Seal Retaining Plates

The last part of the Head Cover to be inspected was the water passage surface. This is the very bottom surface of the Head Cover and where the top of each Wicket Gate meets the Head Cover. During manufacturing, this stainless steel surface was overlaid over the carbon steel Head Cover, then machined. This surface is important because it creates the seal between the top of the Wicket Gate and the bottom of the Head Cover. The seal is a hard rubber strip secured by a Seal Retaining Plate. As shown in the images in this section, these Seals and Retaining Plates reveal signs of wear and damage. The Retaining Plates are secured to the Head Cover by a series of socket head cap screws, many of which were missing. In fact, the missing screws would thread out of the Head Cover and rub against the end of the Wicket Gate, causing significant damage to the ends of the gates; this damage is discussed in more detail in the Wicket Gate section of this report.

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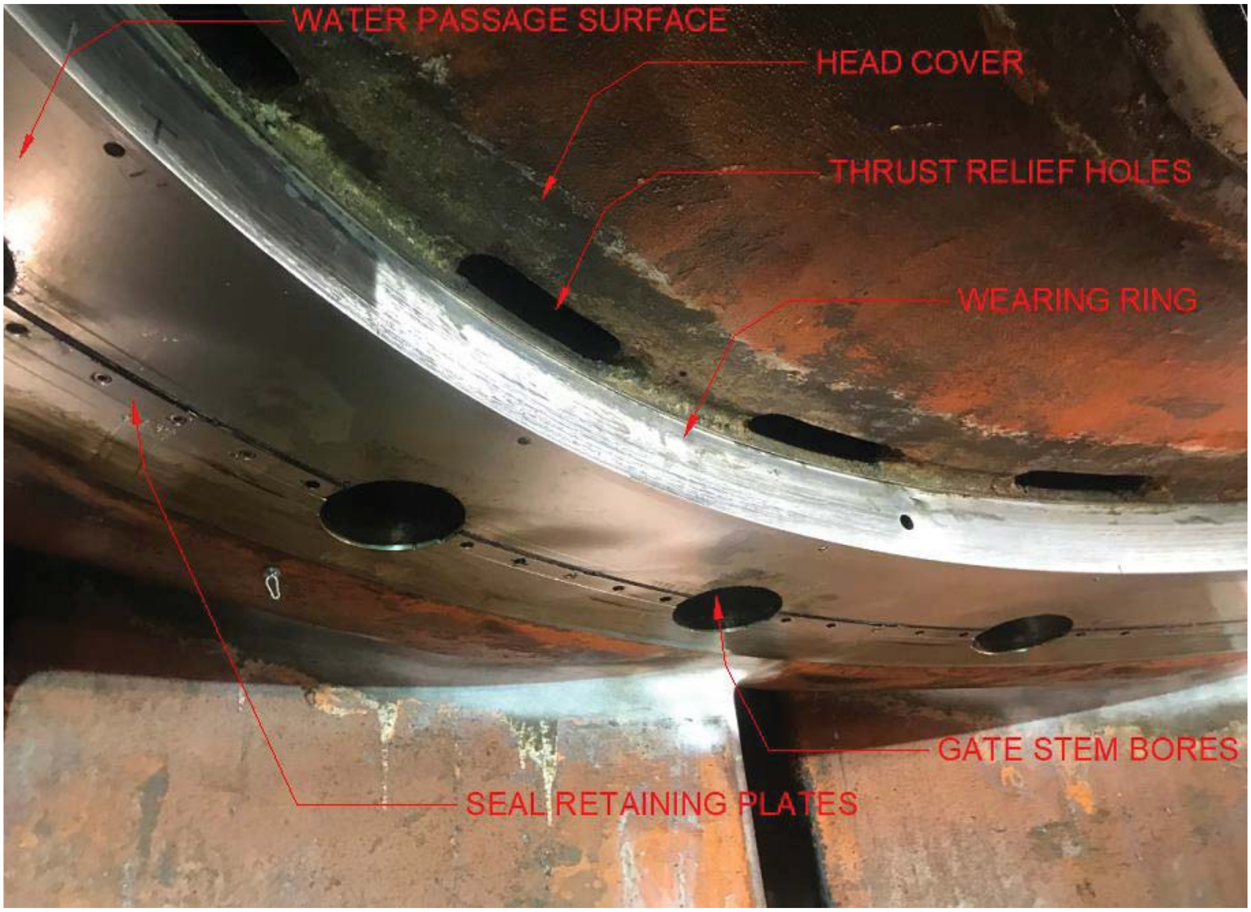

Figure 5-217: Head Cover, Water Side Outline of Components

Figure 5-218: Head Cover, Wicket Gate Seals and Seal Retaining Plates (Damage)

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The end seals were found to be highly deteriorated and in some cases damaged by debris or poor alignment of the Wicket Gates. The water passage surface of the Head Cover is overall in fair condition, but there were obvious signs of damage or abnormal wear. The lighter damage or imperfections were more than likely from the debris or maintenance over the years; however, in some locations it was apparent that the misalignment in the Wicket Gates caused the gates to contact the water passage surface, causing significant surface damage.

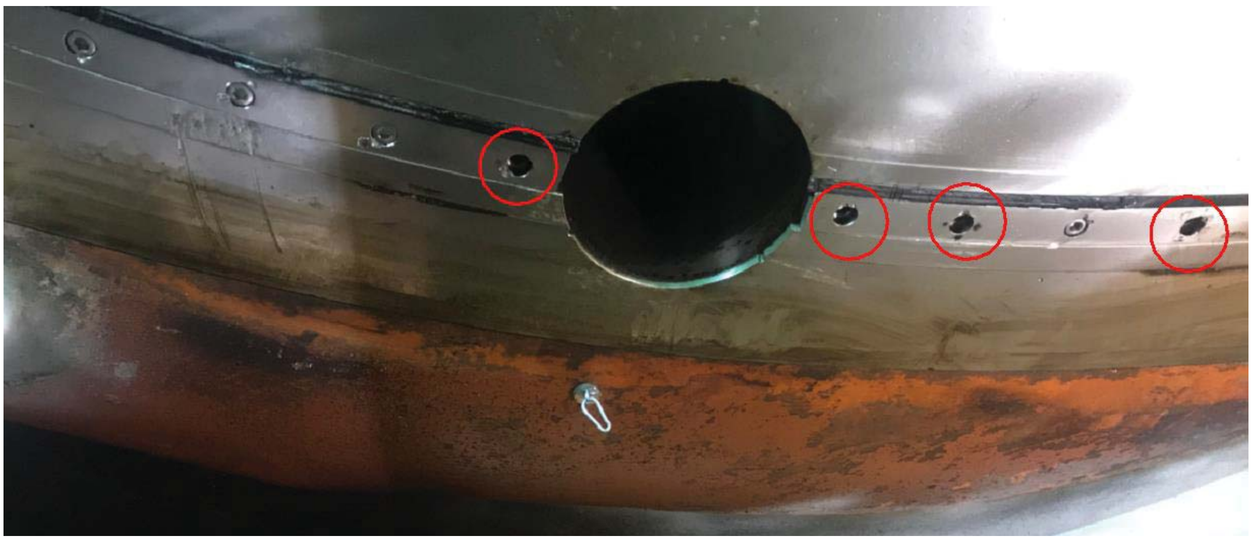

Figure 5-219: Head Cover, Seal Retaining Plates (Missing Screws)

Figure 5-220: Head Cover, Water Passage Surface Damage

5.21.3 Laser Inspection Data and Results

The Head Cover was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The Head Cover dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The "reference only points" were recorded in case of certain questions or if information was needed outside of the planned scoped. The three most sought after features during the laser inspection of the Head Cover are the Gate Stem Bore locations/concentricity, Wearing Ring, and the bolting flange. The Head Cover laser inspection was performed on the powerhouse floor when the Head Cover was in the "free state," i.e., not bolted down to the Stay Ring. The planned laser inspection data is shown in the figure below.

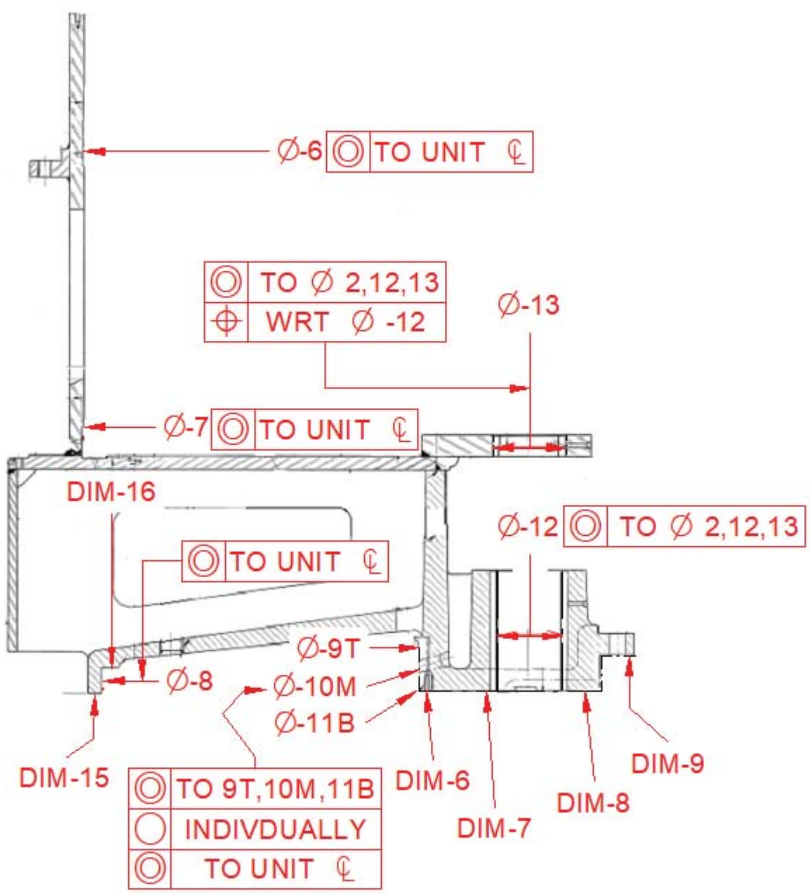

Figure 5-221: Head Cover, Laser Inspection Outline

Feature	Part/Component	General Comment/Information
Ø-6	Head Cover	Concentricity to Unit CL
Ø-7	Head Cover	Concentricity to Unit CL
Ø-8	Head Cover	Concentricity to Unit CL
Ø-9T	Head Cover Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-10M,ø-11B, Individually Circularity
Ø-10M	Head Cover Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-9T,ø-11B, Individually Circularity
Ø-11B	Head Cover Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-9T,ø-10M, Individually Circularity
Ø-12	Head Cover	Measure all bushing sockets at 3 elevations, recording 8 EQ. SP. PTS. at each. Concentricity to ø-2 and ø-13. ø-12 datum for all bushing sockets.
Ø-13	Head Cover	Measure all bushing sockets at 3 elevations, recording 8 EQ. SP. PTS. at each. Concentricity to ø-2 and ø-12. All bushing socket position measurements relative to ø-12
DIM-6	Head Cover	For Reference/Flatness/Runout, 16 EQ. SP. PTS
DIM-7	Head Cover	For Reference/Flatness/Runout, 16 EQ. SP. PTS
DIM-8	Head Cover	For Reference/Flatness/Runout, 16 EQ. SP. PTS
DIM-9	Head Cover	For Reference/Flatness/Runout, 16 EQ. SP. PTS

Figure 5-222: Head Cover, Laser Inspection Data Points Collected

5.21.3.1 Head Cover Laser Inspection Analysis

The main purpose of the Head Cover laser inspection was to determine and evaluate the size and shape of certain features on the part and use the dimensions to aid in other aspects of the outage. The Head Cover is comprised of many diameters and planes that are important for clearances, Wicket Gate alignment, Gate Mechanism function, and elevations of the Distributor parts. Figure 5-223 shows the concentricity of all of the large diameters of the Head Cover with respect to the best fit centerline from the Wearing Ring Circle, not the unit centerline. All of the values are within CEATI PART 2 erection tolerances and show that Head Cover is in the OEM shape in the free-state.

Shown in Figure 5-224 is a graph of the points taken on the bolting flange of the Head Cover. This feature is important because this surface mates with the Stay Ring Flange, which can influence the level reading of the Distributor assembly. Using the tolerance of the new machine standard set by CEATI Part 2, the data revealed

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that the Head Cover bolting flange is within the tolerance of 0.0078 inch; which is the zone used for the Stay Ring Flange. Figure 5-226 shows the points recorded on the Head Cover Extension. This is the reason the figure is somewhat irregular and not a perfect circle. These points were taken for reference purposes and were used to help predetermine the dimensions of the new Thordon SXL bushings for the Operating Ring.

The Gate Stem Bore alignment is shown in Figure 5-227. The plot revealed that the alignment of the Upper and Intermediate Bushings were not concentric to each other; however, the bores had to be compared to the Bottom Ring Gate Stem Bores for a complete analysis of the system. It was obvious from the data that the concentricity between the Upper and Intermediate Bores of the Head Cover were not concentric to each other individually in a range of 0.010 inch to 0.056 inch. This value was concerning because it indicated that line boring of the bores together was required. Line boring is a very tedious and time consuming operation, requiring large precision boring equipment to machine the upper bore the entire length of the Wicket Gate to the lower bushing of the Bottom Ring. A comprehensive summary of the Gate Stem Bore alignment and recommendations is in Section 5.23.

The Head Cover Wearing Ring data points are plotted in Figure 5-228. For the most part, the roundness of the ring data points recorded averages 0.0048 inch, which is somewhat expected considering the age and condition of the machine. A closer look at the plot reveals that the Wearing Ring has slightly changed into an elliptical shape, which is similar to the rest of the stationary components. This information was used and accounted for during the analysis of the Wearing Ring machining discussed in Section 5.25.

Name	X	Y	Z	Polar Angle	Concentricity
CenterPoint Wear Ring bottom Circle **11B**	0.0000	0.0000	2.0256	0.0000	0.000
CenterPoint Wear Ring Mid Circle **10M**	-0.0006	0.0000	4.1294	177.9849	0.001
CenterPoint Wear Ring Top Circle **9T**	-0.0011	-0.0008	6.3889	215.9604	0.001
CenterPoint Lower Extension Brass Circle **7**	0.0116	-0.0301	28.8807	291.0815	0.032
CenterPoint Upper extension circle **6**	-0.0022	0.0006	58.6806	165.8131	0.002
CenterPoint Inner Ring Circle **8**	0.0000	0.0014	1.8496	90.9815	0.001
CenterPoint Item **12 BFC**	0.0092	0.0002	1.5301	1.4820	0.009
CenterPoint Circle Item **13 BFC**	0.0105	0.0010	1.5176	5.3599	0.011
CEATI: PART 2 Concentricity, (0.05"*RSC") =					0.00225 inch
CEATI: PART 2 Concentricity, (MAX= 0.06 mm) =					0.00240 inch

Figure 5-223: Head Cover, Major Diameter Concentricity

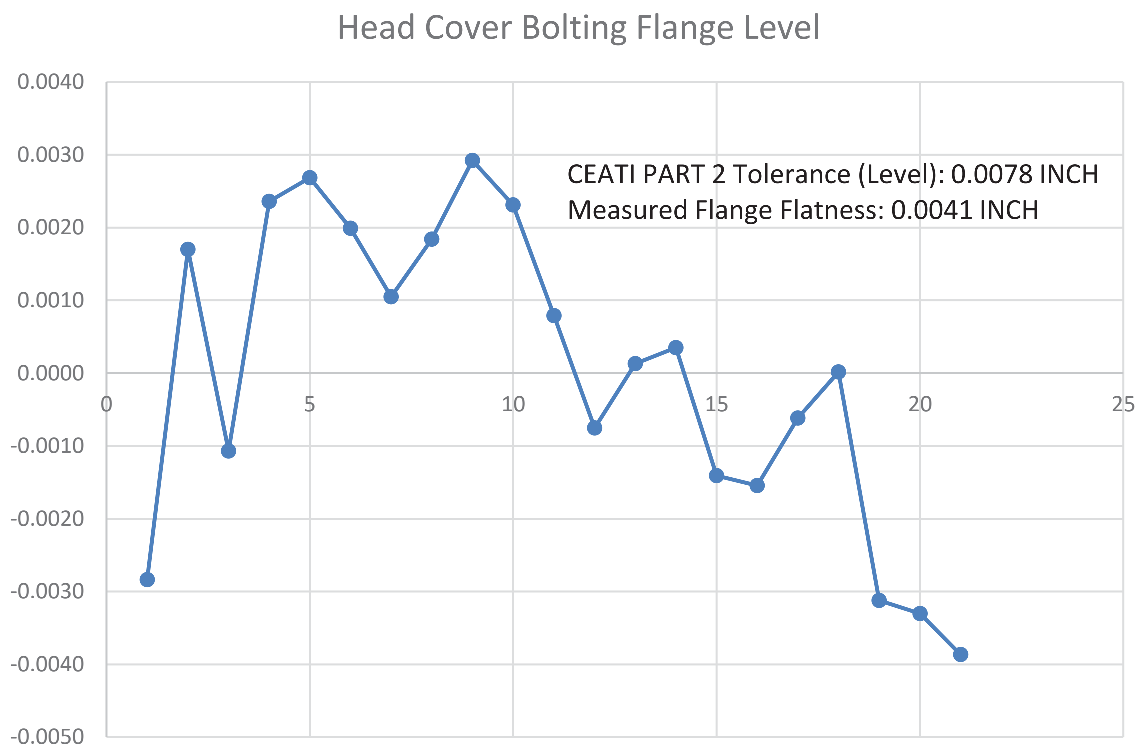

Figure 5-224: Head Cover, Bolting Flange Level/Flatness

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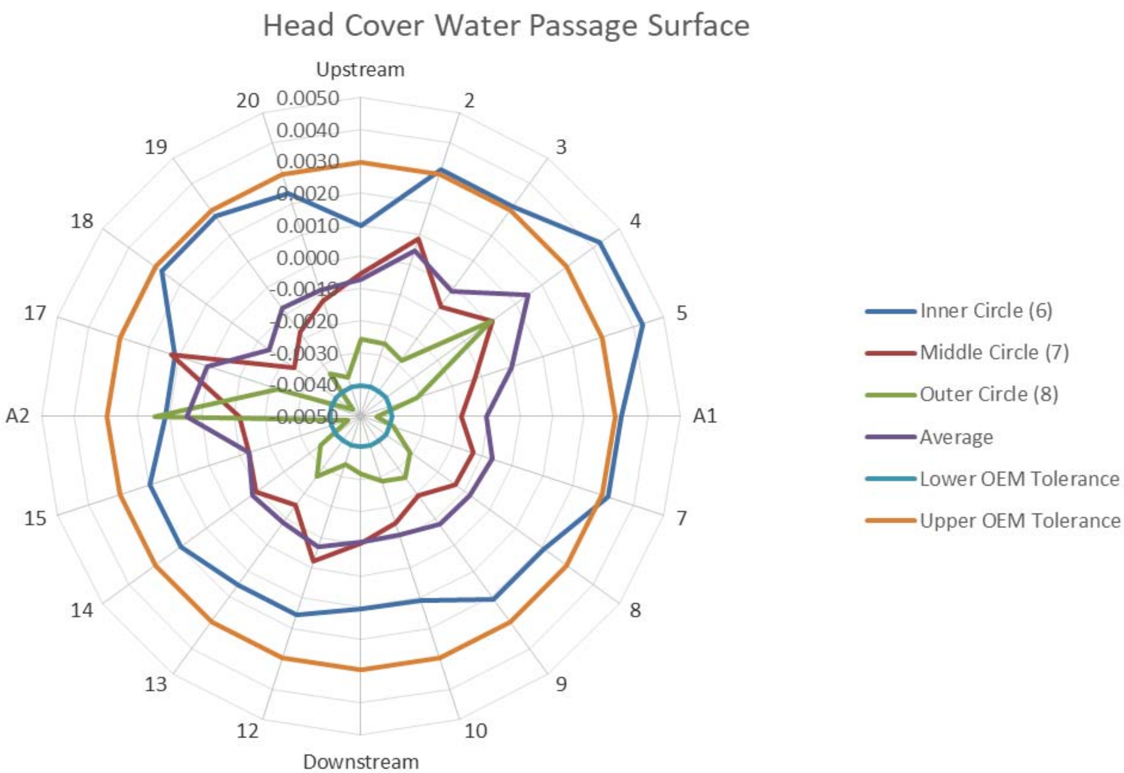

Figure 5-225: Head Cover, Water Passage Surface

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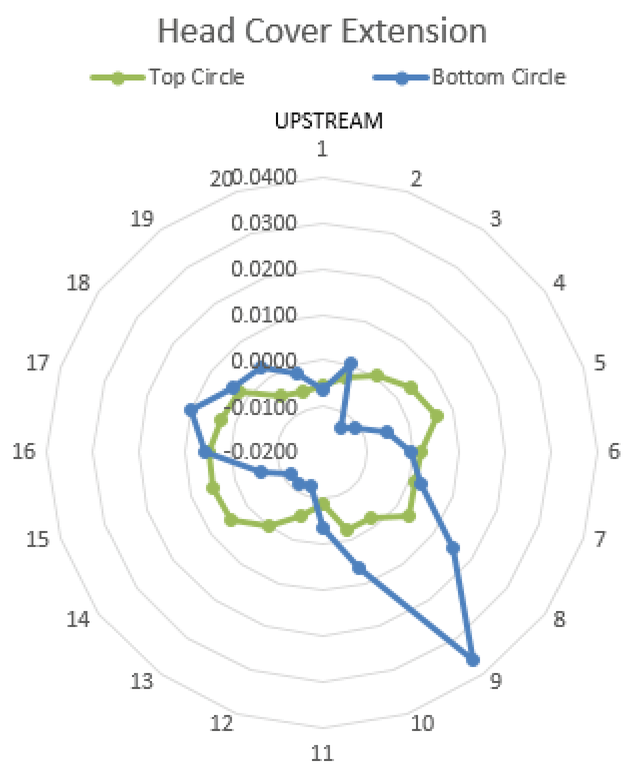

Circle: "Circle Top" (20) WCS: "Top plane"
Roundness: 0.0149
Diameter: 83.5126 Radius: 41.7563
Center: X0.0000 Y0.0000 Z0.0000

Circle: "Circle Bottom" (20) WCS: "Top plane"
Roundness: 0.0467

Diameter: 84.5176 Radius: 42.2588

Center: X0.0037 Y-0.0004 Z-29.3701

Figure 5-226: Head Cover, Bolting Flange Level/Flatness

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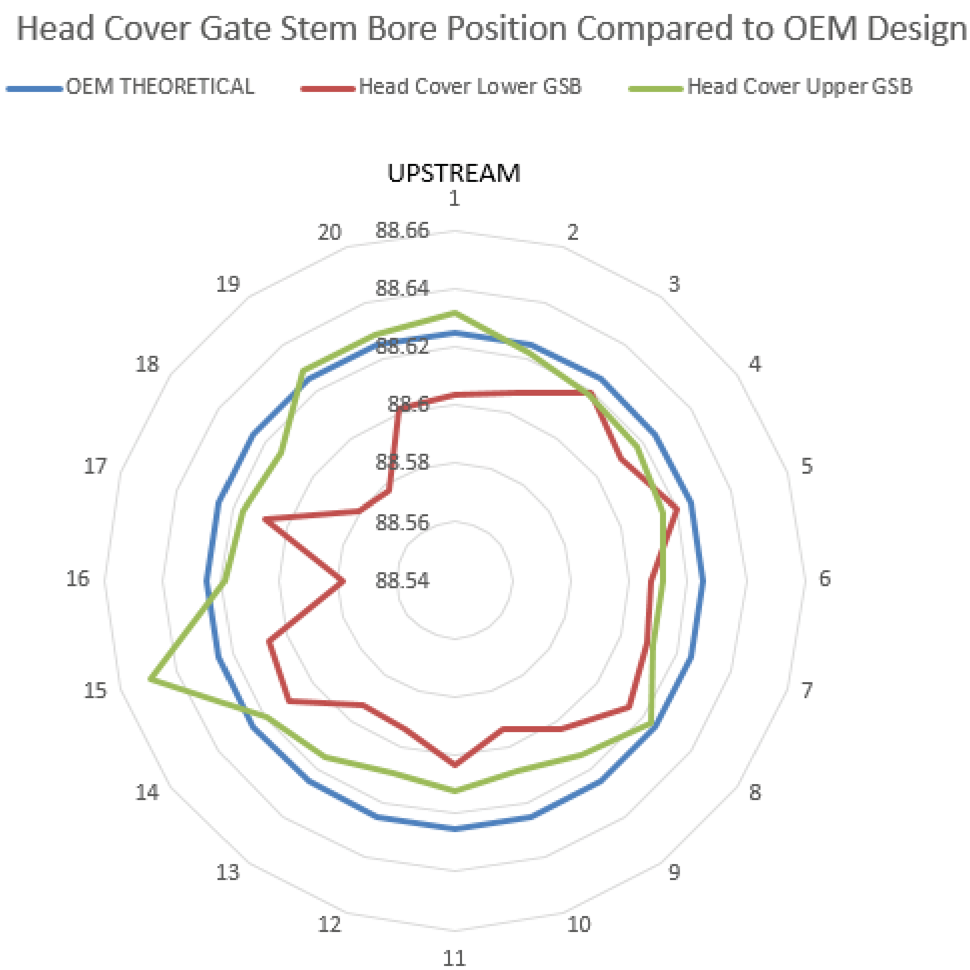

Figure 5-227: Head Cover, Gate Stem Bore Alignment

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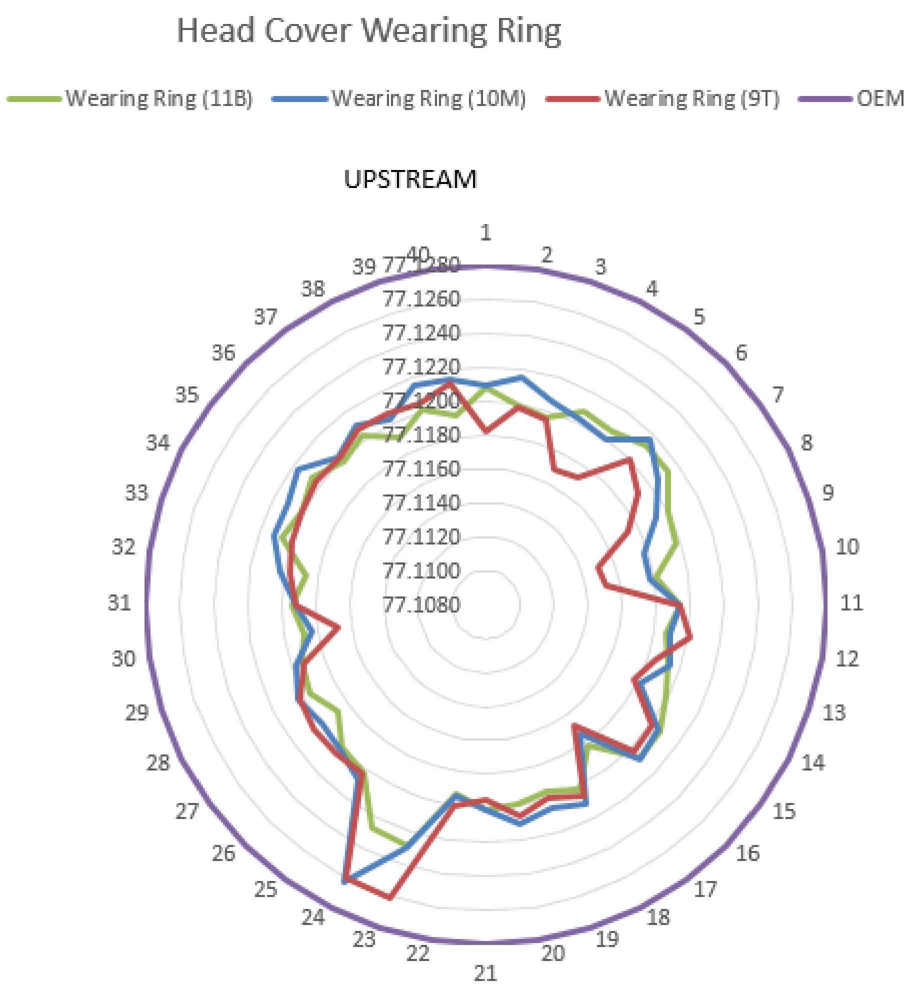

Figure 5-228: Head Cover, Wearing Ring

5.21.4 Non-Destructive Examination

A non-destructive examination was planned for the Head Cover fillet and joint welds for the 2019 maintenance outage. The NDE contractor, Acuren, performed the examination using the method of Magnetic Particle Test (MT). The contractor used a VH-provided document (2-10044792) to guide their inspection. Within the document the contractor was instructed to inspect all of the welds and surface areas that experience higher stress and fatigue during operation. The lead paint was removed from the areas that were examined prior to doing the inspection. Once the paint was removed Acuren MT inspected all of the joints and reported that no major indications were found during the inspection. The only notable indications were found on five stiffeners that connect the outer flange to the inner wall of the Head Cover. These were small cracks found around the ends of the joint. A comprehensive NDE report, with results and notes, is located in the Appendix.

Figure 5-229: Head Cover, NDE Overview

Figure 5-230: Head Cover, Small Stiffener Cracks

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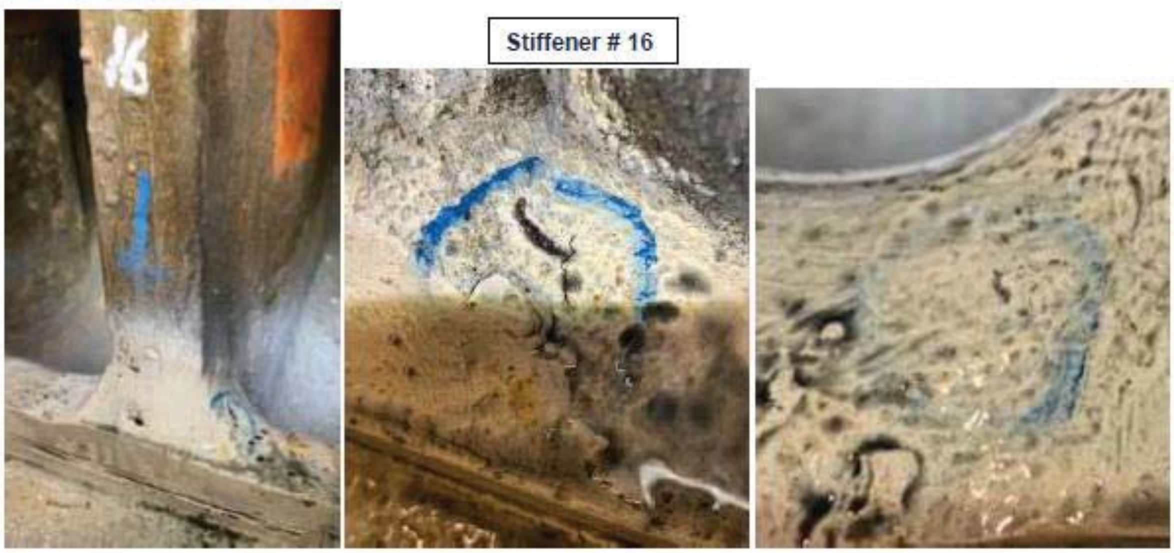

Figure 5-231: Head Cover, Small Stiffener Cracks

Figure 5-232: Head Cover, Small Stiffener Cracks

5.21.5 Outage Recommendations

- **Voith Recommendation:**
  - Voith recommended cleaning and repainting the Head Cover thoroughly prior to reassembly.
- **Outcome:**
  - NLH cleaned and painted the Head Cover. See figure below.

- **Voith Recommendation:**
  - The Gate Stem Bores alignment and concentricity were still in question after the laser inspection mainly due to the amount of misalignment the laser data was suggesting. At first Voith believed this could be due to the fact the Head Cover was measured in the free-state rather than in its operational state, in which it is bolted and doweled to the Stay Ring Flange. It was Voith's opinion that the GSB data points may have been somewhat misleading due to the Head Cover "springing" back into a normal, relaxed shape after being removed from the Stay Ring, causing the questionable data. Therefore, Voith recommended installing the Head Cover back into its position on the Stay Ring and bolting and doweling it into place. This would force the part back into the shape it has during operation. From there, Voith asked NLH to measure all of the GSB at once, using a wire micrometer, including the Bottom Ring GSB. This measurement would provide an improved data set and a complete view of all of the GSB together. This was critical for determining if line boring of the GSB was required.

- **Outcome:**
  - NLH installed the Head Cover as Voith recommended. The VH field machining team then proceeded to measure all of the GSB by means of wire micrometer. A detailed summary of the results of these measurements and outcome can be found in Section 5.23.
- **Voith Recommendation:**
  - The Wearing Ring of the Head Cover was in satisfactory condition and was deemed acceptable to reuse for the next five years. Therefore, Voith did not recommend any additional tasks for the Head Cover Wearing Ring.

5.22 Bottom Ring

5.22.1 Background Information

The Bottom Ring is a stationary ring located below the Head Cover that contains the lower Wicket Gate Bushing, provides the water surfaces leading to or from the Runner Band or Discharge Ring, and is bolted to the Stay Ring. In the case of the Bay d'Espoir Unit 7, the Bottom Ring is bolted to the Discharge Ring. Using the experience from previous outages at Bay d'Espoir Powerhouse One and from the recommendations outlined in a refurbishment plan (VHY-1, 2017) developed by VH, NLH established a detailed plan for the Bottom Ring activities during the 2019 maintenance outage. The Bottom Ring and its Wearing Ring are the main reason for the 2019 Maintenance outage, similar to previous Bay d'Espoir outages in the past few years with Units 2, 3, and 4. The radial seal clearance of the runner has been decreasing in one direction and increasing in another, suggesting the stationary Bottom Ring is changing shape. For more information and historical data review the introduction, Section 3, of this report.

Planned Work:

- Visual Inspection (VH Scope).
- Laser Inspection (VH Scope).
- Wearing Ring installation and machining (VH Scope, new ring only if necessary).
- Line Boring of the Gate Stem Bores (VH Scope, only if necessary).
- Remove Lower Gate Stem Bushing (greased) and replace with Greaseless Bushing (NLH Scope).

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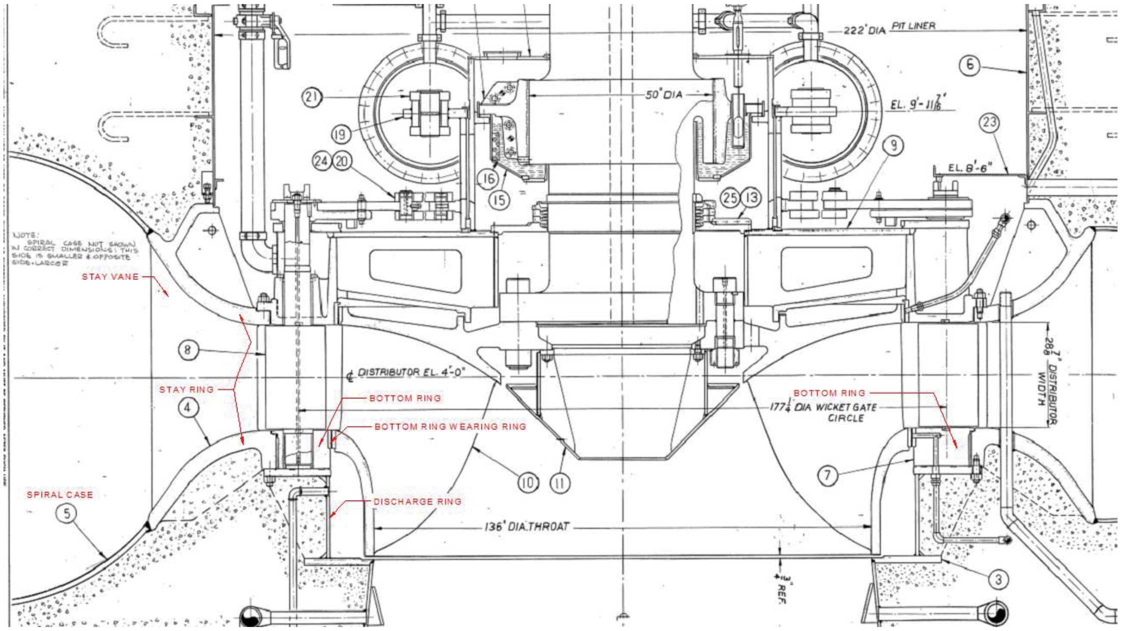

Figure 5-233: Bottom Ring, Outline 1

Figure 5-234: Bottom Ring, Outline 2

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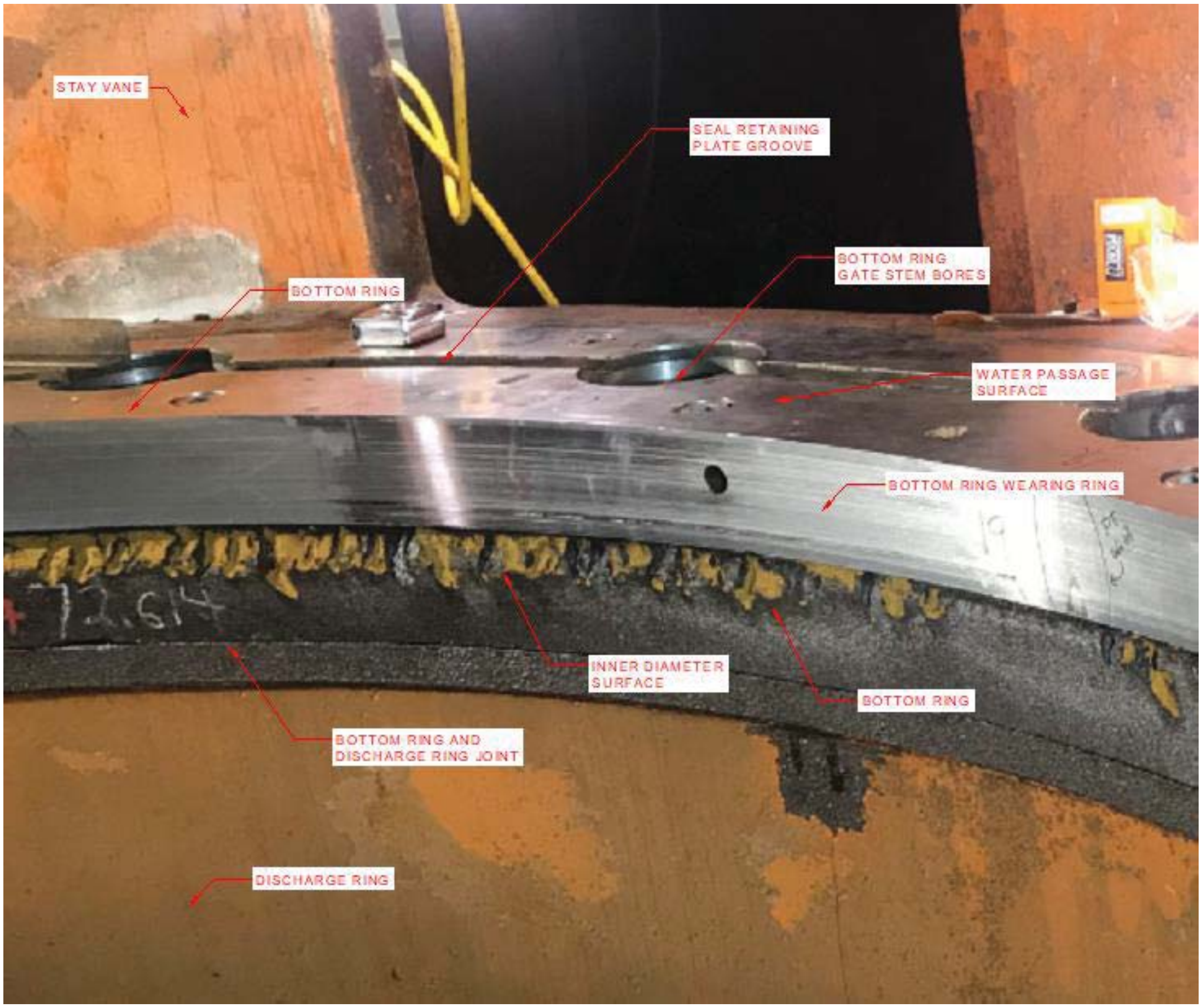

Figure 5-235: Bottom Ring, Outline 3

5.22.2 Visual Inspection

Voith engineering performed a visual inspection of the Unit 7 Bottom Ring to look for any signs or indications of abnormal wear or damage. The overall condition of the Bottom Ring was fair to poor considering the age of the unit and the fact that the 2019 maintenance outage was the first time the unit has been disassembled since commissioning in 1977. The inspection of the Bottom Ring can be broken in into parts based upon the different features of the part itself. The features are as follows: Gate Stem Bores and Seal Retaining Rings, Water Passage Surface, Wearing Ring, and the inner diameter surfaces.

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5.22.2.1 Gate Stem Bores – Seal Retaining Plates

The bushings for the Gate Stem Bores were already removed during the inspection, revealing the open bores of the Bottom Ring. The bushings of the Bottom Ring had the same wear pattern as those mentioned in Section 5.21.2.3 of the Head Cover. Within that section, Figure 5-227 provides proof of misalignment of the Wicket Gate Stem Bores between the Head Cover and the Bottom Ring. Overall the open Gate Stem Bores were found to be in good condition and no issue was foreseen by installing the planned upgraded greaseless bushing. The Seal Retaining Plates and Seals were also removed prior to the inspection, but like the bushing, the Seal Retaining Plates and Seals were found to be in similar condition as the Head Cover Seal Retaining Plates. Shown in Figure 5-220, the Head Cover Seal Retaining Plates showed signs of debris wear and damage from the Wicket Gate contact. The Bottom Ring Seal Retaining Plates also showed these same signs of damage. The groove where the Seal Retaining Plates and Seal are located was found to be dirty with debris and light corrosion was present, but there were no signs damage or indications that required attention at the time of the 2019 maintenance outage.


Figure 5-236: Bottom Ring, Gate Stem Bores

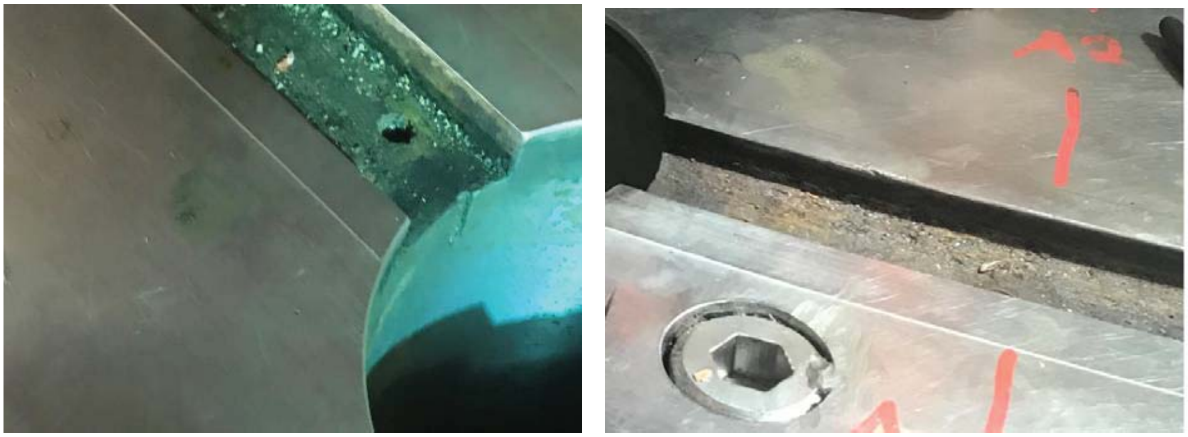

Figure 5-237: Bottom Ring, Seal Retaining Plate Groove

5.22.2.2 Water Passage Surface

The Water Passage Surface, which consists of a stainless steel overlay, was found to be in good condition considering the age and service hours on the machine. The surface had light to moderate scratches present with signs of cavitation located next to each GSB. The cavitation was light in the nature, but did occur in the same location around the Bottom Ring.

Figure 5-238: Bottom Ring, Water Passage Surface Cavitation

Figure 5-239: Bottom Ring, Water Passage Surface Cavitation

Figure 5-240: Bottom Ring, Water Passage Surface Cavitation

5.22.2.3 Wearing Ring

The Bottom Ring Wearing Ring condition was very similar to the Runner Band Wearing Ring discussed in Section 5.9.2.5. Both of these rings work in conjunction with one another during operation, creating the tight seal between the stationary wearing ring (Bottom Ring) and the rotating Wearing Ring of the Runner (Band). The Bottom Ring Wearing Ring had many visible scratches, dents, and some material missing. It is difficult to know what came into contact with the seal surface, and when it happened. Although, it is safe to assume that

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at some point in time small debris contacted the seal surfaces during operation; in fact, it is even possible that the rotating Runner came into contact with the stationary Wearing Ring of the Bottom Ring.

Figure 5-241: Bottom Ring, Wearing Ring Damage

Figure 5-242: Bottom Ring, Wearing Ring Damage

Figure 5-243: Bottom Ring, Wearing Ring Damage

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Figure 5-244: Bottom Ring, Wearing Ring Damage

5.22.2.4 Bottom Ring Inner Diameter Surface

The inner diameter surface directly under the Wearing Ring had significant cavitation damage in the axis perpendicular to the upstream/downstream axis. The source of this cavitation is more than likely a direct result of the change in RSC seal clearance in that area. The increased flow rate and velocity of water past the seal created an environment for cavitation to form, causing significant damage to the inner diameter surface of the Bottom Ring.

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Figure 5-245: Bottom Ring, Cavitation Damage

Figure 5-246: Bottom Ring, Cavitation Damage

Figure 5-247: Bottom Ring, Cavitation Damage

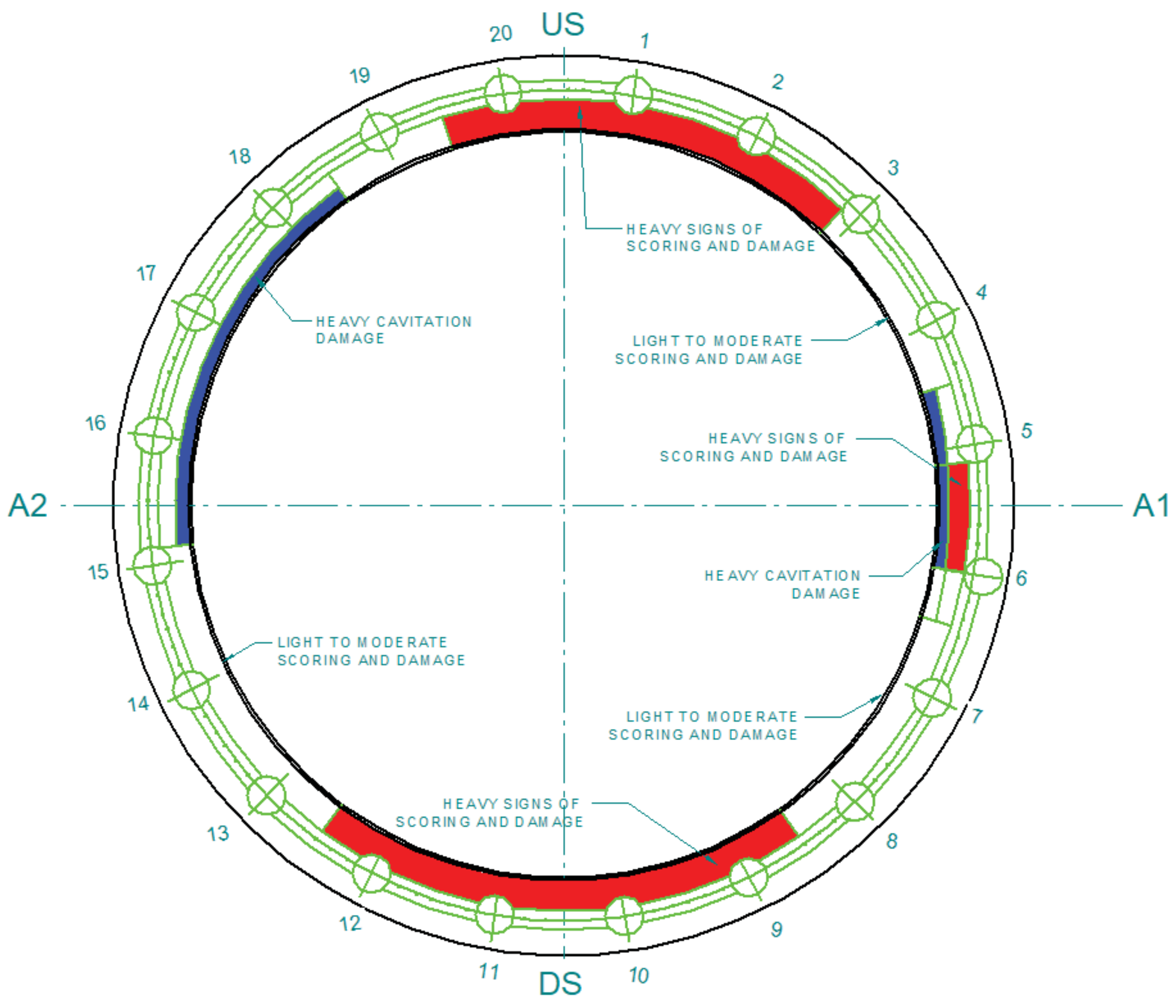

Figure 5-248: Bottom Ring, Overview of Cavitation and Scoring Damage

5.22.3 Laser Inspection Data and Results

The Bottom Ring was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix section. The Bottom Ring dimensions and data points collected during the inspection were an assortment of diameters and planes, some of which were required for the unit analysis and others were only recorded for information or reference. The “reference only points” were recorded in case of certain questions or if information was needed outside of the planned scoped. The three most sought after features during the laser inspection of the Bottom Ring are the Gate Stem Bore locations (for concentricity purposes), Wearing Ring (for improving RSC and machining), and Water Passage Surface.

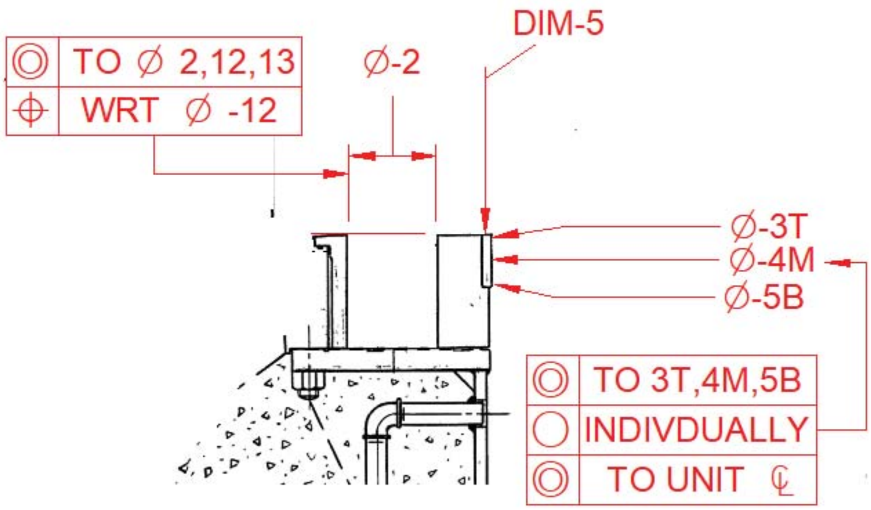

Figure 5-249: Bottom Ring, Laser Inspection Outline

Feature	Part/Component	General Comment/Information
Ø-2	Bottom Ring	Measure all bushing sockets at 3 elevations, recording 8 EQ. SP. PTS. at each. Concentricity to ø-12 and ø-13. All bushing socket position measurements relative to ø-12
Ø-3T	Bottom Ring Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-4M, and ø-5B Circularity
Ø-4M	Bottom Ring Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-3T, and ø-5B Circularity
Ø-5B	Bottom Ring Wearing Ring (40 points minimum)	Concentricity to Unit CL, ø-3T, and ø-4M Circularity

Figure 5-250: Bottom Ring, Laser Inspection Data Points Collected

5.22.3.1 Bottom Ring Laser Inspection Analysis

Figure 5-251 shows a circle graph representing the data points taken on the Wearing Ring during the laser inspection. The points are plotted starting in the upstream direction and going clockwise around the Wearing Ring. To provide an accurate representation of the Wearing Ring condition, three circles were created on the ring: top, middle, and bottom. The graph shows the OEM theoretical Wearing Ring design versus the as-found condition. As expected, and one of the main reasons for the 2019 maintenance outage, the Wearing Ring was found to be distorted in shape.

The Wearing Ring was originally machined as a perfect circle; however, the Wearing Ring has been forced into a different shape due to the movement/growth of the stationary components around the Bottom Ring. This change in shape has caused the RSC between the Runner and Wearing Ring to change. The circularity average found during the inspection was 0.052 inch. The standard set by CEATI is 5 percent of the RSC (0.045(RSC) * 0.05% = 0.00225 inch), not to exceed 0.06mm (0.0024 inch). Therefore, the as-found condition of the circularity was much higher than allowed by CEATI.

The Gate Pin Circle, which is the circle created by the center of all of the Gate Stem Bores, is shown in Figure 5-252. This circle was created by taking laser points on each of the individual GSB and defining a cylinder from each. From there the software used the mid-point of each cylinder to create a best fit circle.

The data revealed a significant shift in the position of the Bottom Ring GSB. The plot in Figure 5-252 shows that the GSB locations and Gate Pin Circle have taken on the same shape and shifted as to what was found in laser inspection of the Wearing Ring; this was visualized in Figure 5-253. The black circles of the plot represent the OEM intent for the Wearing Ring and Gate Pin circles. The orange and yellow circle reflect the as-found results of the laser inspection, which are distorted from OEM.

A comprehensive summary of the Gate Stem Bore alignment and recommendations is below in Section 5.23.

The water passage surface of the Bottom Ring was also measured during the laser inspection. This surface was measured for reference purposes to aid in the overall inspection of the machine. The laser inspector recorded three sets of the data points on the top surface of the Bottom Ring. These sets consisted of three circles of 40 points each: inner, middle, and outer circles on the water passage surface. The points collected were used to measure the change in elevation over the water passage surface and other machine features. This information allowed Voith to determine the flatness and profile of the surface that interfaces with the Wicket Gates. Figure 5-254 is a line graph of the data points taken during the laser inspection. The first point on the graph was recorded at the upstream location of the Bottom Ring and collected clockwise from there returning at the upstream location. The data revealed that the inner circle of points is lower in elevation from the middle and outer circle.

The data indicates a change in shape; however, the cause was difficult to determine. The surface was designed to be flat with zero elevation changes across the plane. The flat surface is critical for the gate end seals to function properly; however, there are no signs indicating that the as-found condition of the surface was impacting the seals. The Bottom Ring could have been mechanically deformed by the head pressure pushing on the closed gates, causing the ring to deform inward towards the unit centerline. A more likely reason for the change in shape could be from the same phenomena causing the Bottom Ring to oval, but it is difficult to know with 100 percent certainty.

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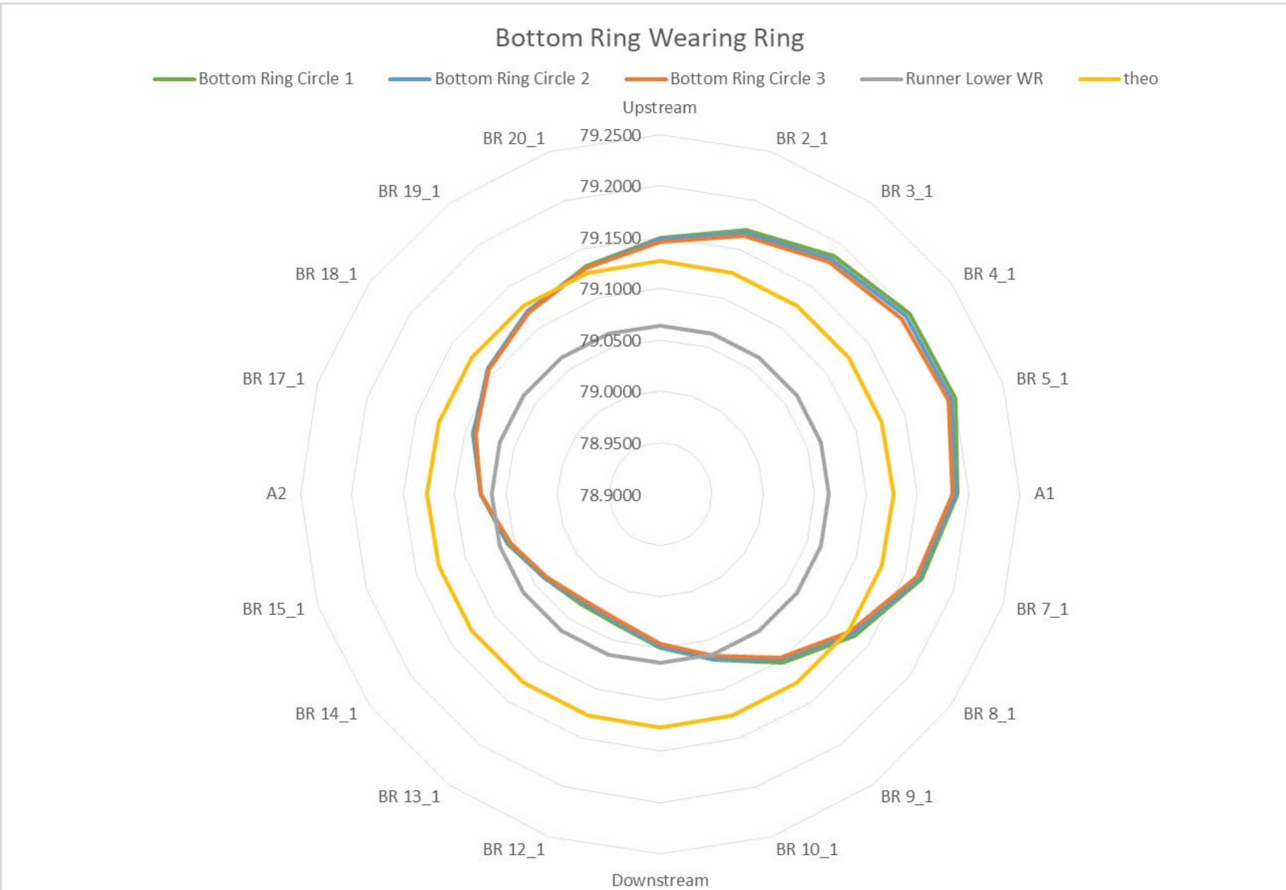

Figure 5-251: Bottom Ring, Wearing Ring Shape versus OEM

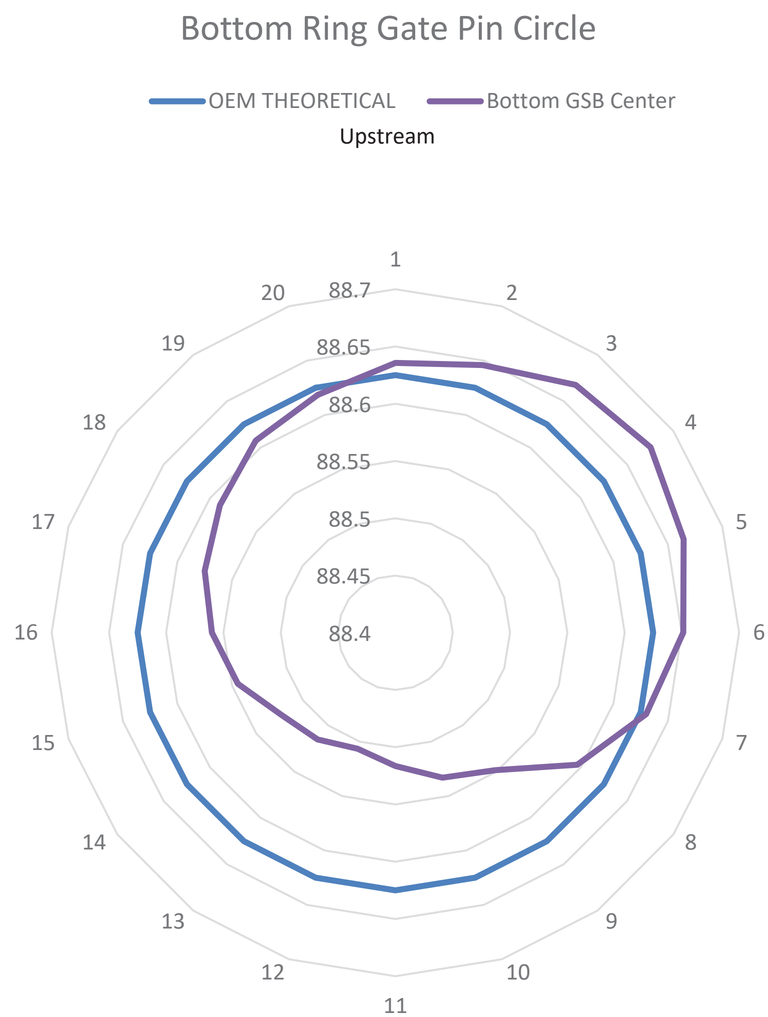

Figure 5-252: Bottom Ring, Wearing Ring Gate Pin Circle versus OEM

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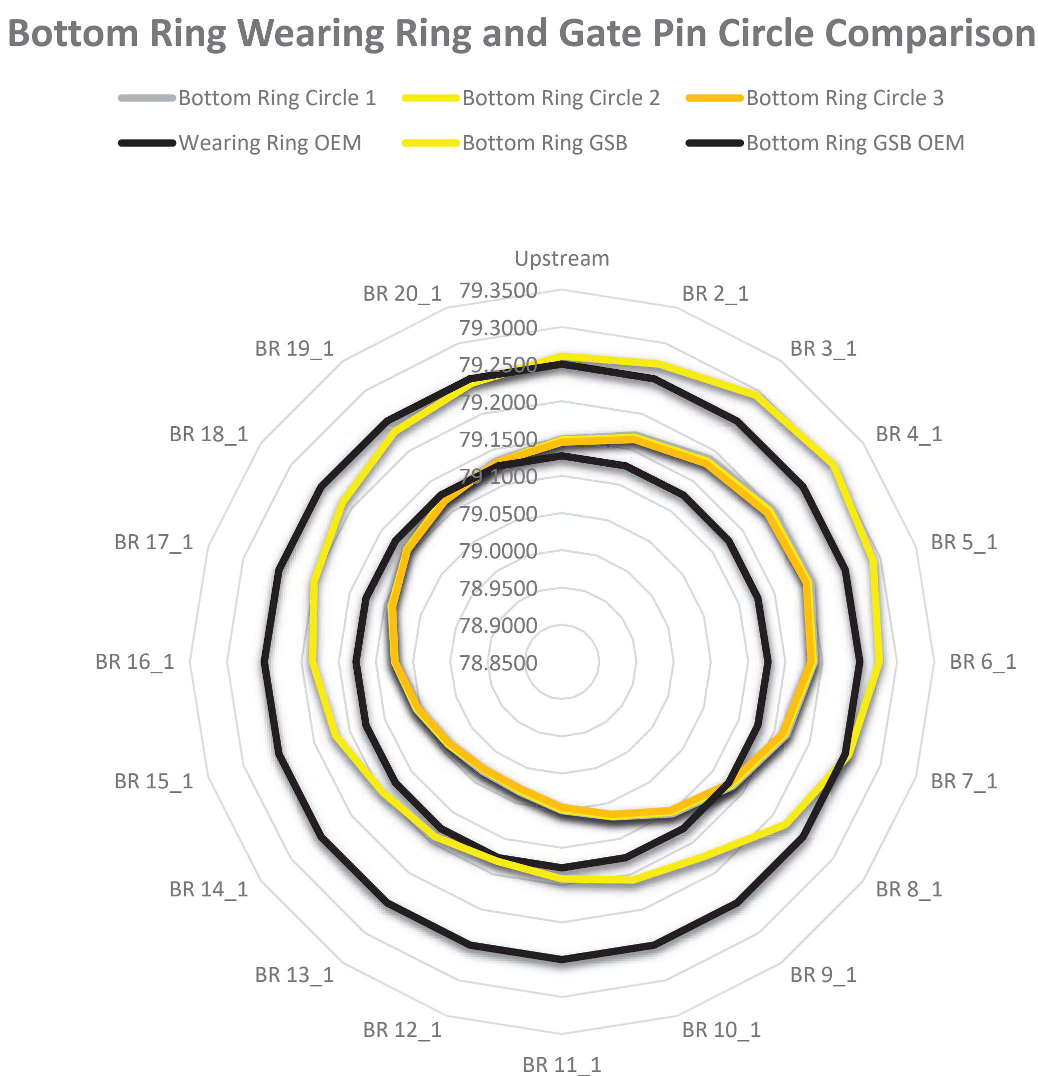

Figure 5-253: Bottom Ring, Wearing Ring Compared to Gate Pin Circle (Not to scale)

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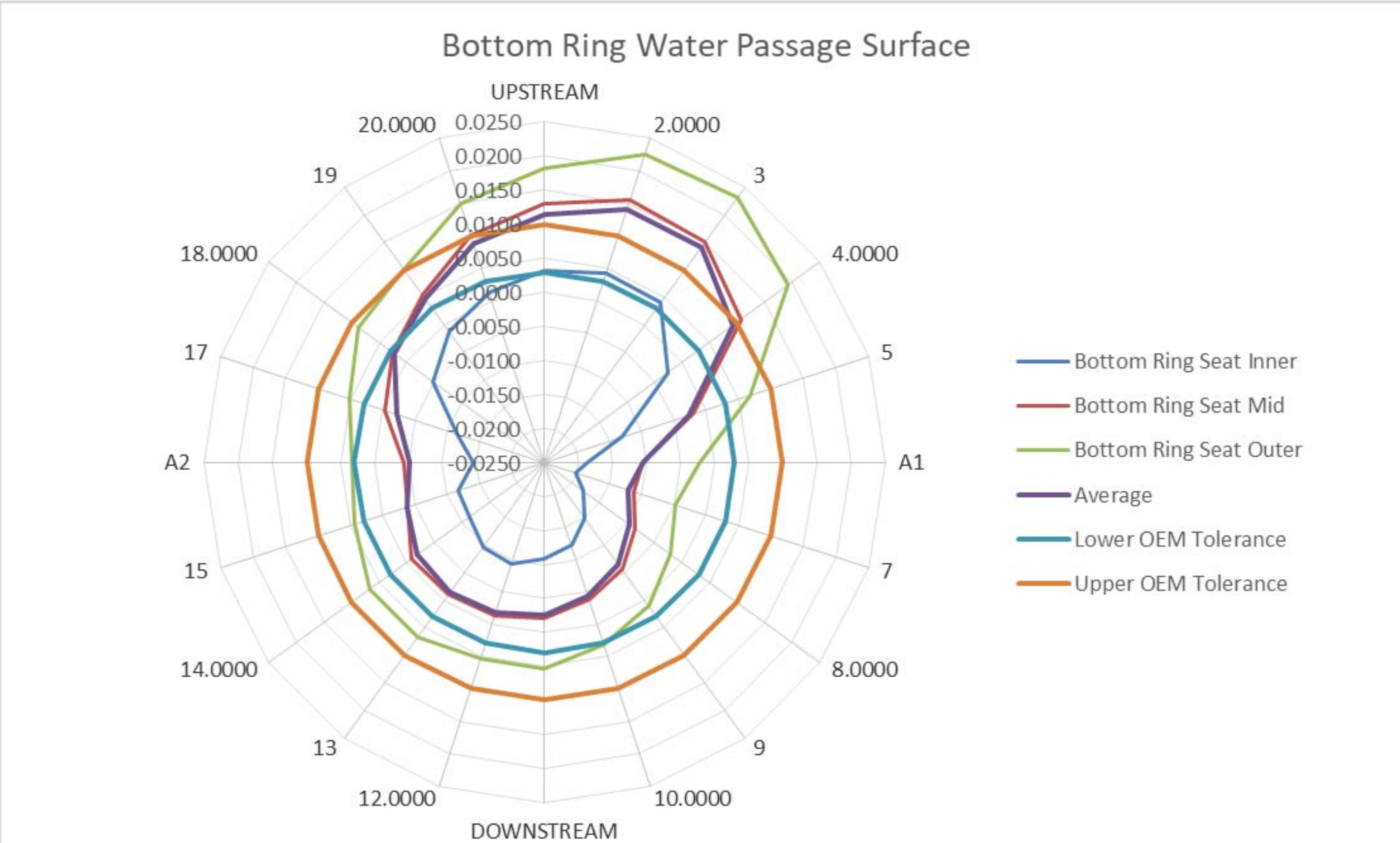

Figure 5-254: Bottom Ring, Wearing Ring versus OEM

5.22.4 Non-Destructive Examination

There was no Non-Destructive Examination planned for or performed on Bottom Ring during the 2019 maintenance outage.

5.22.5 Outage Recommendations

- **Voith Recommendation:**
  - Voith recommended cleaning and filling the eroded area found underneath the Bottom Ring Wearing Ring with a high strength epoxy to fix the cavitation damage. The area would be blasted to near white metal, then short pieces of a round steel bar would be added to the deeper area to create a framework to ensure the epoxy properly adheres. The Epoxy could be applied to the area once the framework is established until flush with the non-effected area, after which the epoxy was coated with a two-part, anti-cavitation paint. The complete repair procedure, BDES-2TFV04-0800-10052132-REV-, can be referenced in the Appendix.

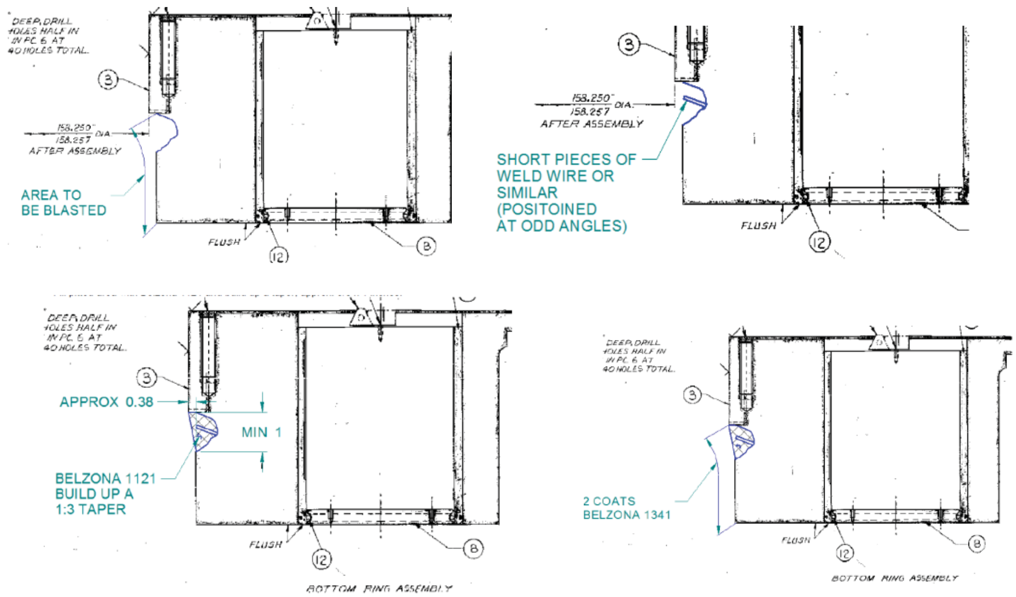

Figure 5-255: Bottom Ring, Cavitation Repair

- **Outcome:**
  - NLH performed the repairs recommended by Voith to prevent further cavitation damage and preserve the condition of the Bottom Ring.
- **Voith Recommendation:**
  - The as-found condition of Bottom Ring Gate Pin Circle was concerning to Voith because of the potential need for line boring all of the bores. The line boring procedure is very time consuming and expensive. Voith recommended installing the Head Cover back into position and measure the bores of the Bottom Ring in conjunction with the Head Cover GSB to determine if line boring was absolutely required. This method is the most accurate when determining the position of all of the bores relative to each other. Voith could determine if line boring is required with this information.
- **Outcome:**
  - NLH followed VH recommendation and reinstall the Head Cover and wire measure the Gate Stem Bores together to ensure the proper Gate Stem alignment and to potentially rule out line boring. The results of this recommendation are located in Section 5.23, Gate Stem Bore alignment.
- **Voith Recommendation:**
  - As expected the Wearing Ring of the Bottom Ring was going to require machining to improve the global roundness and clearance of the Runner radial seal clearance. Therefore, Voith recommended machining the Wearing Ring to a known size to establish a larger RSC.

- **Outcome:**
  - NLH followed the Voith recommendation to machine the Wearing Ring. A complete timeline, summary of events/discussions, and outcome is provided in Section 5.25, Wearing Ring Machining.

5.23 Gate Stem Bore Alignment

5.23.1 Background Information

The Gate Stem Bore (GSB) alignment is critical for proper mechanical function of the Wicket Gate operating mechanism. The Francis turbine Head Cover and Bottom Ring both have GSBs. The Head Cover had two bores, the upper and intermediate, and the Bottom Ring has one, the lower bore. If misalignment occurs between the bores, the Wicket Gates operating mechanism could be stressed above operating ranges. The GSB bushings, which are pressed into the bores and provide and bearing surface for the Wicket Gate trunnions, could prematurely wear, or, in the worst-case scenario, the misalignment could be so poor that the Wicket Gates could bind and hinder radial movement. NLH established a pre-outage plan to have Voith measure the Gate Stem Bores.

NLH learned about the importance of the Gate Stem Bore alignment during previous unit outages and applied lessons learned to the plan for Unit 7. The data was used to analyze concentricity and rule out or verify if line boring of all of the GSBs together was required. In this case, line boring is a machining process where a boring cutter is setup at one end of a bore, or multiple bores, and moves down through the bore(s), cutting the inner diameter uniformly through all of the material. The goal is to create a perfect cylinder where the diameter, concentricity, and cylindricality between the bore(s) is the same.

Many factors can lead to Gate Stem Bores being found out of concentricity, such as severe bushing wear, the level of the Head Cover and Bottom Ring being out of tolerance, or the Bottom Ring and Head Cover not being clocked (rotated or offset) correctly to each other. Another factor and one more parallel with Bay d'Espoir Unit 7 was the unknown phenomena causing the embedded components to change shape. As shown in the figures and plots in the individual part sections and below, all of the embedded components of Unit 7 have moved and changed to an oval shape. The Head Cover and Bottom Ring both suffered from this movement the most. This movement caused the Gate Pin Circle, the circle created by connecting all of the center points of the individual GSBs, to deform as well.

The following activities were preplanned and performed on the Bottom Ring and Head Cover to analyze the condition of the Gate Pin Circle and GSB alignment. This report presents the information in chronological order; some of the activities were additional based upon the results of the Voith analysis of the GSBs. It should also be noted that NLH planned to remove the greased bushing of the Lower and Intermediate bores and replace them with eco-friendly, self-lubricating (non-greased) Thorplas bushings supplied by Thordon. As discussed in the Head Cover section, the upper bushing remained greased due to the complexity of changing the bushing during the outage.

Work Planned and Performed:

- Post disassembly Laser Inspection of the Bottom Ring and Head Cover (NLH Preplanned, VH Scope).
- Data Analysis (NLH Preplanned, VH Scope).
- Rule out/verify if line boring was required with laser data (NLH Preplanned, VH Scope).
    - Laser data revealed significant GSB misalignment.
- Validate/disprove laser data results (Voith recommended) by measuring GSBs with a wire micrometer (Not planned).
- Wire micrometer measurements performed (Not Planned).
- Wire micrometer measurements analyzed (Second time, Not Planned).
- Adjustments to some of the bores (NLH Planned, VH Scope).

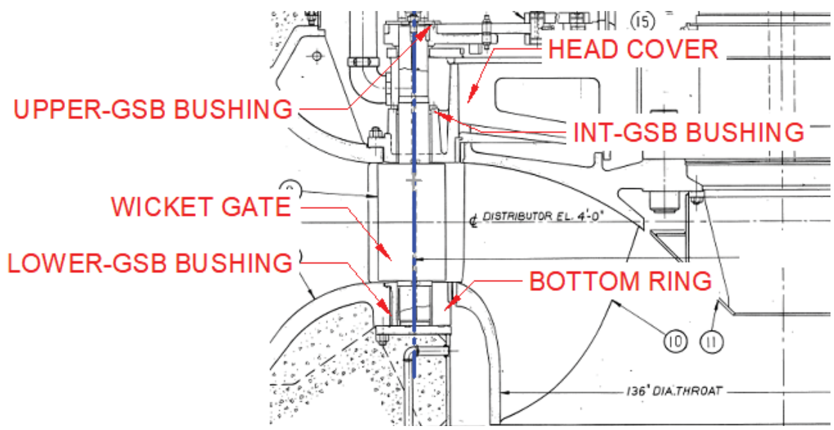

Figure 5-256: Gate Stem Bore Alignment Outline

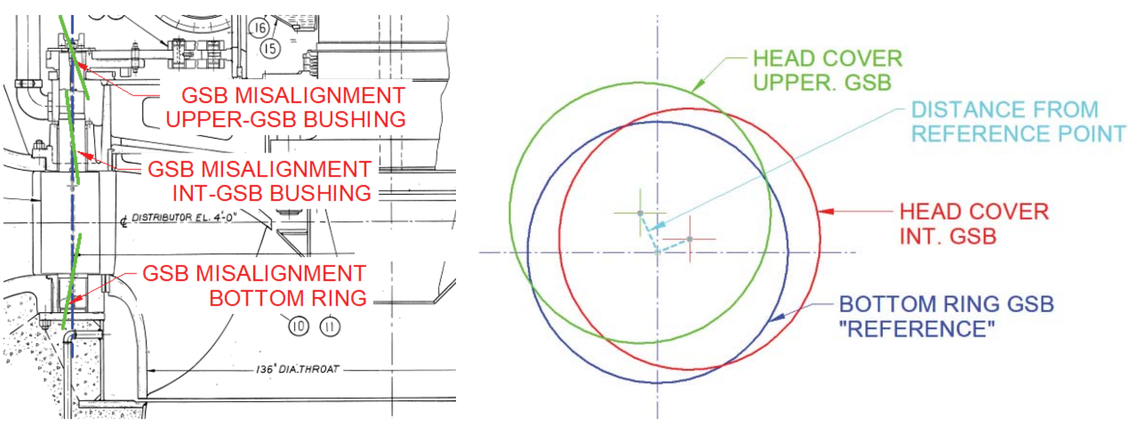

Figure 5-257: Example of Gate Stem Bore Axis Misalignment

5.23.2 Laser Inspection Data and Results

The entire unit was inspected by means of LIDAR using a laser tracker. The laser inspector, ESI, used a Voith-supplied document (VHY-2, 2019) to guide their inspection. A comprehensive report of the laser tracker data is located in the Appendix. The figure in this section shows the as-found condition of the both Head Cover Gate Stems Bores compared to the lower bore of the Bottom Ring. Also shown in the figure is the OEM Theoretical Gate Pin Circle, which was the planned design for Unit 7. In this section is an example of the shift of the embedded components' shape and position since the first commissioning. The Bottom Ring, the lowest component of the assembly, is represented by the yellow circle. The other components above the Bottom Ring, such as, the Head Cover, Stay Ring, and Stator, have deformed in the same manner and direction, but with different values of magnitude.

The planned concentricity tolerance zone is typically a function of the size of the Gate Stems, design bushing clearances, expected loads (forces), and overall size and dimensions of the other Distributor components. The design concentricity tolerance was unclear at the time of the 2019 maintenance outage from the drawings that were available; however, using modern design principles, which were not much different than the era of when Unit 7 what designed. This assembled tolerance range for concentricity was determined to be in a range 0.006 to 0.010 inch.

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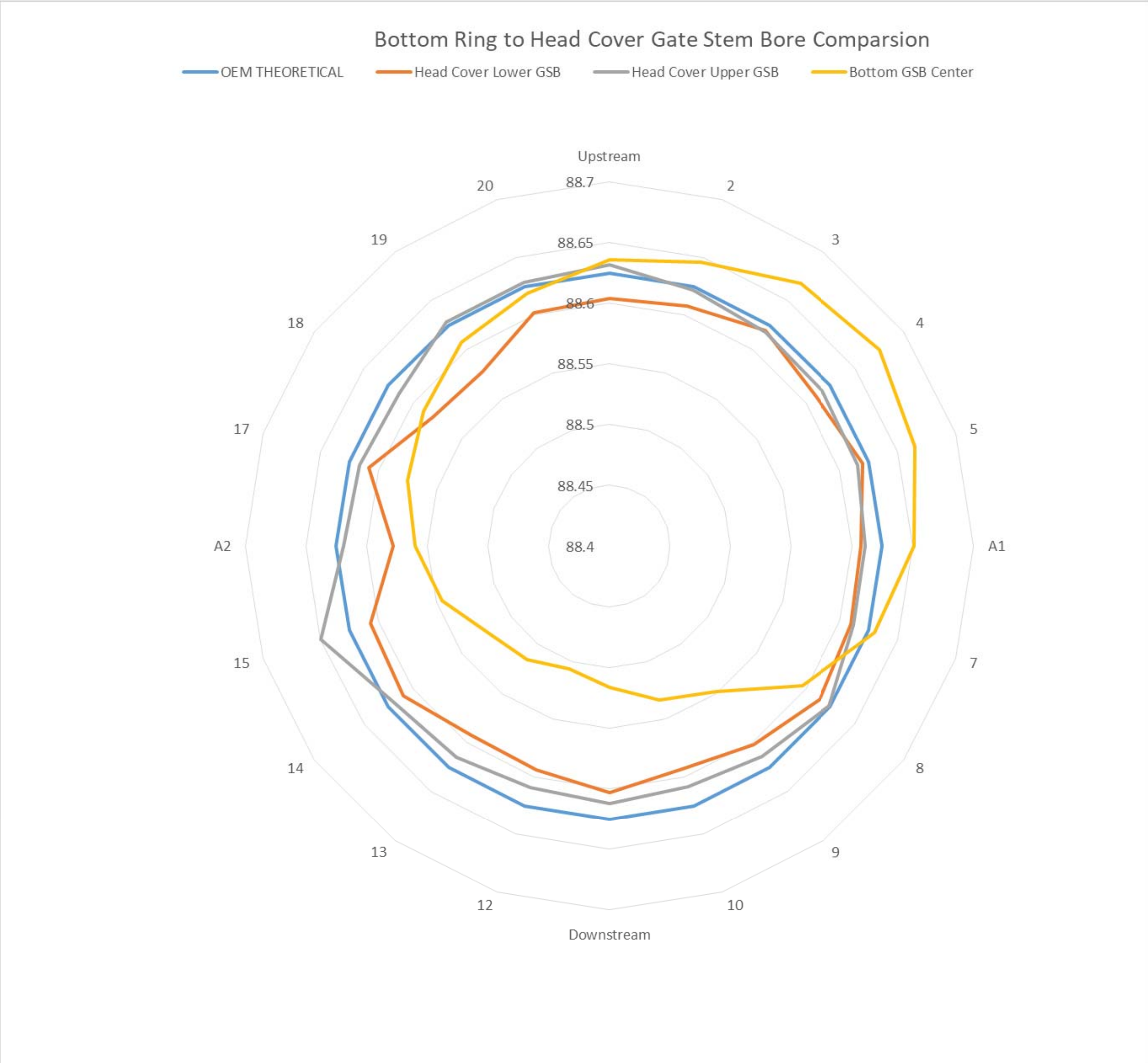

Figure 5-258: GSB Alignment: Laser Inspection Results Graph

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The disconcerting results of the laser inspection implicated misalignment between all of the GSBs. The reference point used during the inspection was the Bottom Ring Lower GSB. This was the zero-zero point to on which all other measurements were based. Figure 5-259 reflects the values found during the inspection. The data reveals that in some cases the misalignment between bores was in a range of 0.004 to 0.105 inch. The maximum value found of 0.105 inch was three to four times higher than what Voith deemed as critically high (0.030 inch, intervention required). The results of the laser inspection were high enough to where Voith started to question the validity of the data. The difference in position of the bores found by the laser data suggested that significant wear of the bores was possible, or severe misalignment of the Head Cover to Bottom Ring, or possibly a poor data set from the laser inspection. With the order of magnitude the concentricity was out, it was very plausible that the gate operating mechanism was not able to operate correctly or at all, but the gate mechanism was working as designed with no binding prior to the 2019 outage according to NLH.

Concentrictiy Results

	Polar Radius			Laser Data Results	
GATE	Bottom Ring GSB Center	Head Cover Int. GSB Center	Head Cover Upper GSB Center	Delta from Bottom Ring to Int. Bore	Delta from Bottom Ring to Upper Bore
GATE 1	88.636	88.632	88.604	0.004	0.032
GATE 2	88.646	88.622	88.608	0.024	0.038
GATE 3	88.668	88.618	88.619	0.049	0.049
GATE 4	88.675	88.618	88.611	0.058	0.065
GATE 5	88.665	88.615	88.620	0.049	0.045
GATE 6	88.651	88.611	88.608	0.040	0.044
GATE 7	88.630	88.612	88.610	0.019	0.021
GATE 8	88.596	88.624	88.614	0.027	0.018
GATE 9	88.549	88.614	88.603	0.065	0.054
GATE 10	88.533	88.609	88.593	0.076	0.060
GATE 11	88.516	88.612	88.603	0.096	0.087
GATE 12	88.506	88.609	88.594	0.103	0.087
GATE 13	88.515	88.615	88.593	0.100	0.078
GATE 14	88.523	88.619	88.610	0.097	0.087
GATE 15	88.545	88.650	88.607	0.105	0.062
GATE 16	88.560	88.619	88.578	0.059	0.018
GATE 17	88.575	88.616	88.609	0.041	0.034
GATE 18	88.589	88.614	88.580	0.024	0.009
GATE 19	88.607	88.628	88.578	0.021	0.030
GATE 20	88.618	88.628	88.602	0.010	0.017

Max =	0.105	0.087
Min =	0.004	0.009

Figure 5-259: GSB Alignment: Laser Inspection Results

This juncture was a critical moment in the 2019 maintenance outage because many of the present and future activities such as bushing bore machining, possible line-boring, Wearing Ring machining, and reassembly/commissioning of the entire unit, were based upon the decision about the Gate Stem Bore positions, which ultimately determined when the machine was able to be released to the grid.

After reviewing internally, Voith believed that the laser data points and results should be validated by another means of measurement. The logic VH used was simple: the Head Cover data points were collected when the Head Cover was in its free-state, i.e., not bolted, doweled, and clamped onto the Stay Ring flange. This freedom possibly allowed the Head Cover to "spring" back into its natural shape and not be in the shape it takes on when installed. This would explain the large misalignment the initial laser data revealed. All of the other possible scenarios were evaluated by Voith, but this option was the least invasive and the one with most benefit if proven true.

5.23.3 Wire Micrometer Recommendation

Voith recommended the following to NLH:

- Head Cover shall be bolted, torqued, and dowelled to the Stay Ring as per OEM guidelines.
    a. **Note:** Bolts were torqued 50% of OEM specified installation torque as discussed and agreed between NLH and VH.
- Use a wire micrometer and measure the concentricity between every other Gate Stem Bore.
- Report the numbers to Voith for review.

Outline of Wire Micrometer Measurement Procedure:

A thin wire is hung down through all of the Gate Stem Bores from an adjusted frame on top of the Head Cover. This setup shown below in the left image in Figure 5-261. The adjustable frame can move the wire in very fine increments for initial setup and centering into the lower GSB. The wire has a weight secured to it to ensure the wire is taught. The weight is placed in a small bucket of oil or detergent placed in the lower GSB. The oil dampens the movement of the wire, eliminating possible movements during measuring. The wire micrometer method can help establish three features between bores: the plumb, concentricity, and perpendicularity between the bores, shown from left to right in Figure 5-260.

The **plumb** is defined as the offset between a line passing through the center of the upper and lower bushing to the gravity vector.

The **concentricity** is defined as the offset between a line passing through the center of two holes to a parallel line passing through the center of the third hole.

The **perpendicularity** is defined as the offset between a line passing through the center of the upper and lower bushing to a line at a 90-degree angle to the Head Cover Facing Plates or water passage surface.

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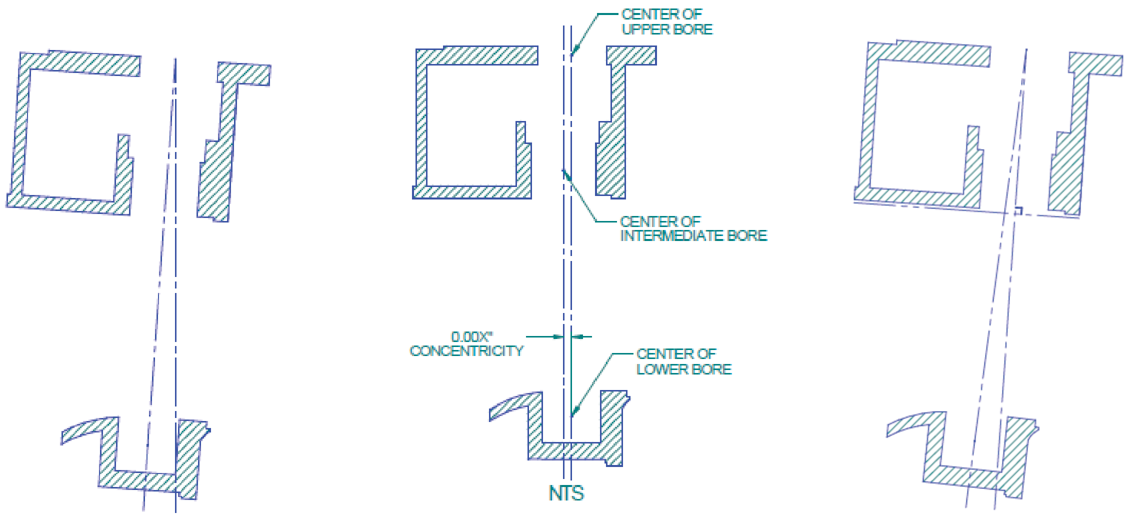


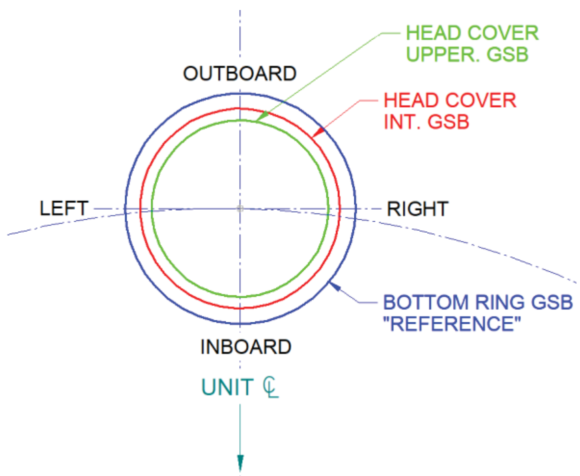
Figure 5-260: Wire Micrometer Outline

Figure 5-261: Wire Micrometer Example

5.23.4 Wire Micrometer Results and Analysis

After several conversations and presentations of the data, NLH determined to follow Voith's recommendation and installed the Head Cover and let Voith Field Services measure the Gate Stem Bores between the Head Cover and Bottom Ring using the wire micrometer method. Initially, Voith and NLH agreed that only a sample set of the half the GSB measurements were required to determine if line-boring was mandatory. However, the decision to line-bore and overall position of the bores relative to each other was still unclear after the data was provided to VH engineering, so Voith recommended that the remainder of the bores be measured for a complete analysis.

Once all the GSBs were measured, Voith analyzed that data and calculated concentricity between the three bushings for each gate individually. The Bottom Ring Lower Bore was the basis of comparison for the Head Cover Bores. Figure 5-262 is a description of where the measurements were taken from and a table of two of the Gate Stem Bores calculations Voith performed. Voith Field Services team measured each bore in four locations. This occurred after precision centering of the lower bores was achieved. The Head Cover Bores were measured at the inboard, outboard, left, and right locations, as highlighted in Figure 5-262. All of the results are in thousandths of an inch. A comprehensive collection of calculations and reports from the wire micrometer measurements are located in the Appendix.



	Bottom Bushing	Intermediate Bushing	Top Bushing
	Gate # 1		
Inside	180	153	297
Right	179	193	308
Out	181	209	322
Left	179	171	285
Radial	0	-28	-12.5
Tangential	0	11	12
Resultant	0	30	17
	Gate # 3		
Inside	183	168	309
Right	182	199	329
Out	184	195	306
Left	182	168	276
Radial	-1	-14	1.5
Tangential	0	16	27
Resultant	1	21	27

Figure 5-262: Wire Micrometer Results Example

Figure 5-263 summarizes the comparison of the wire micrometer results to the laser data inspection data. Overall the wire micrometer measurements taken on the Gate Stem Bores were calculated and revealed a much improved concentricity than the original laser measurements; however, many of the bores were still out of an acceptable range despite the wire measurements showing significant improvement and, in some cases, being four time better than the initial inspection. The maximum distance out of concentricity was 0.035 inch during wire measurements, compared to 0.105 during the laser inspection. The average concentricity found during laser measuring was 0.053 to 0.047 inch for the intermediate and upper bores of the Head Cover; whereas the wire method produced averages ranging from 0.019 to 0.018, which was a vast improvement.

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Concentrictiy Results

	Polar Radius			Laser Data Results		Wire Micrometer Results	
GATE	Bottom Ring GSB Center	Head Cover Int. GSB Center	Head Cover Upper GSB Center	Delta from Bottom Ring to Int. Bore	Delta from Bottom Ring to Upper Bore	Delta from Bottom Ring to Int. Bore	Delta from Bottom Ring to Upper Bore
GATE 1	88.636	88.632	88.604	0.004	0.032	0.030	0.017
GATE 2	88.646	88.622	88.608	0.024	0.038	0.027	0.023
GATE 3	88.668	88.618	88.619	0.049	0.049	0.021	0.027
GATE 4	88.675	88.618	88.611	0.058	0.065	0.015	0.019
GATE 5	88.665	88.615	88.620	0.049	0.045	0.015	0.019
GATE 6	88.651	88.611	88.608	0.040	0.044	0.010	0.020
GATE 7	88.630	88.612	88.610	0.019	0.021	0.003	0.010
GATE 8	88.596	88.624	88.614	0.027	0.018	0.011	0.006
GATE 9	88.549	88.614	88.603	0.065	0.054	0.022	0.014
GATE 10	88.533	88.609	88.593	0.076	0.060	0.028	0.022
GATE 11	88.516	88.612	88.603	0.096	0.087	0.034	0.026
GATE 12	88.506	88.609	88.594	0.103	0.087	0.035	0.029
GATE 13	88.515	88.615	88.593	0.100	0.078	0.027	0.022
GATE 14	88.523	88.619	88.610	0.097	0.087	0.021	0.016
GATE 15	88.545	88.650	88.607	0.105	0.062	0.016	0.015
GATE 16	88.560	88.619	88.578	0.059	0.018	0.013	0.010
GATE 17	88.575	88.616	88.609	0.041	0.034	0.007	0.007
GATE 18	88.589	88.614	88.580	0.024	0.009	0.004	0.006
GATE 19	88.607	88.628	88.578	0.021	0.030	0.018	0.016
GATE 20	88.618	88.628	88.602	0.010	0.017	0.031	0.026
			Max =	0.105	0.087	0.035	0.029
			Min =	0.004	0.009	0.003	0.006
			Average =	0.053	0.047	0.019	0.018

All dimensions are in inches.

Figure 5-263: Wire Micrometer versus Laser Data Results

With the concentricity results now available, Voith analyzed the data further and determined that line boring of all of the Gate Stem Bores was a valid option that NLH should consider. Line boring the bores would have established new centerlines through all of the bores, eliminating the risk of premature bearing wear or possible binding of the Gate Mechanism. Voith offered an alternative option to line boring that was less invasive and more in line with the five-year plan for the machine. Voith asked NLH to contact their bushing supplier (Avalon Bearings) and ask them what the permissible amount of clearance was allowed between the gate stems and the new plastic bushing. Voith's plan was to determine how much clearance and interference the new bushing can withstand while still performing as designed without premature wear occurring. The idea was to manipulate bushing clearances to account for the misalignment of the Gate Stem Bores.

The bushing supplier, Avalon Bearings, informed NLH that the supplied bushings would perform with as much clearance as desired. Thordon only stipulates the minimum clearance recommend for a particular shaft size. There was no concern with binding due to water absorption because the Thorplas is not a rigid material. There was no risk of galling as long as the bearings were operated in normal temperature ranges. Avalon provided more detail about bearing pressure, loading, and friction and described what the bushings experienced in the first few weeks of service. They even provided a description of what happens during "Edge Loading" of the bushing and provided supplementary material to support their claims. The data and support from Avalon Bearing provided Voith and NLH with the information to move forward with the second option of adjusting clearances of certain bushing to allow more clearance for the misalignment of the bores. All of the supplementary discussions, emails, and documentation of the bushing clearances information is in the Appendix.

5.23.1 Voith Discussion and Recommendation

Voith began evaluating the concentricity of the Gate Stem Bores while possibly increasing the clearance of certain bushings with honoring the agreed-upon clearance between VH, NLH and Thordon, of 0.015 to 0.020 inch. First Voith calculated the ideal position of the Upper Bushing based on the slope of a line connecting the Intermediate to the Lower Bushing. Voith then evaluated each Gate Stem Bore individually and established the required minimum bushing clearance at the Upper Bushing to avoid pinching of any bushing.

The calculation revealed that six upper bushings required machining to allow for the appropriate clearance. The gates affected were numbers one, two, ten, eleven, twelve, and twenty. Voith provided information to NLH for their review and approval prior to machining. Once the group collectively discussed the results and understood the calculations performed, NLH provided approval for Voith to machine the selected Upper Bushings. The calculation results of the impacted gates are shown in the table of Figure 5-264. A comprehensive collection of all of the measurements, discussions, and calculations are included in the Appendix.

Note that Voith used a honing tool to perform the adjustments to the selected Upper Bores of the Head Cover, not the large, full-scale size line-boring equipment typically used more invasive machining. Also note that only one of the six bushings required significant attention (number two bushing). The impact to other bores impacted were minor in comparison. The number two bushing was 0.0035 inch from the current center of the outside, thus making the bore eccentric. The other bushings machined were centered off of the existing inner diameter of the bore (concentric).

All values are in thousandths of inch		Bottom Bushing	Intermediate Bushing	Top Bushing	"Ideal" position of intermediate bushing based on slope upper to lower bushing	Difference to actual position of Intermediate Bushing	"Ideal" position of upper bushing based on slope intermediate to lower bushing	Difference to actual position of Upper Bushing	With 0.015 bushing clearance (intermediate and lower), the distance of upper bushing from the	Required min bushing clearance at upper bushing to avoid pinching of any bushing	Actual Bushing Diameter	Actual Gate stem diameter	Existing clearance	Lower Bushing Actual Clearance	Desired Clearance in upper bushing	Machine Bushing to	Remove (on the side)
1		Gate # 1				8											
Gate # 1	Inside	180	153	297													
	Right	179	193	308													
	Out	181	209	322													
	Left	179	171	285													
	Radial	0	-28	-12.5	-8.4	19.6	-41.9	-29.4	19.50	19.8	6.999	6.9875	0.011	0.0195	22.8	7.010	0.0057
	Tangential	0	11	12	7.7	-3.3	16.5	5.0		-29.1							
	Resultant	0	30	17													
10		Gate # 10															
Gate # 10	Inside	187	160	276													
	Right	187	185	296													
	Out	187	216	319													
	Left	187	190	299													
	Radial	0	-28	-21.5	-14.4	13.6	-41.9	-20.4	14.00	12.8	7.000	6.9875	0.012	0.014	15.8	7.003	0.0017
	Tangential	0	-3	-2	-1.0	1.5	-3.7	-2.2		-23.5							
	Resultant	0	28	22													
2		Gate # 2															
Gate # 2	Inside	186	166	313													
	Right	186	202	311													
	Out	186	209	282													
	Left	186	169	276													
	Radial	0	-22	15.5	10.4	31.9	-32.2	-47.7	16.50	62.4	6.999	6.989	0.010	0.0165	65.4	7.054	0.0350
	Tangential	0	17	18	11.7	-4.8	24.7	7.2		-18.6							
	Resultant	0	27	23													
11		Gate # 11															
Gate # 11	Inside	186	155	273													
	Right	187	190	297													
	Out	189	222	324													
	Left	187	187	295													
	Radial	-2	-34	-25.5	-17.0	16.5	-50.1	-24.6	15.00	19.3	7.003	6.988	0.015	0.015	22.3	7.010	0.0036
	Tangential	0	2	1	0.7	-0.8	2.2	1.2		-27.5							
	Resultant	2	34	26													
12		Gate # 12															
Gate # 12	Inside	187	154	271													
	Right	188	197	303													
	Out	187	221	327													
	Left	188	179	285													
	Radial	0	-34	-28.0	-18.7	14.8	-50.1	-22.1	15.00	14.3	7.000	6.9885	0.011	0.022	17.3	7.006	0.0031
	Tangential	0	9	9	6.0	-3.0	13.5	4.5		-21.1							
	Resultant	0	35	29													
20		Gate # 20															
Gate # 20	Inside	189	161	271													
	Right	189	190	292													
	Out	189	222	321													
	Left	188	181	305													
	Radial	0	-30	-25.0	-16.7	13.5	-45.3	-20.3	15.00	10.6	7.000	6.99	0.009	0.0175	13.6	7.004	0.0020
	Tangential	1	5	-7	-4.3	-8.8	6.7	13.2		-3.5							
	Resultant	1	31	26													

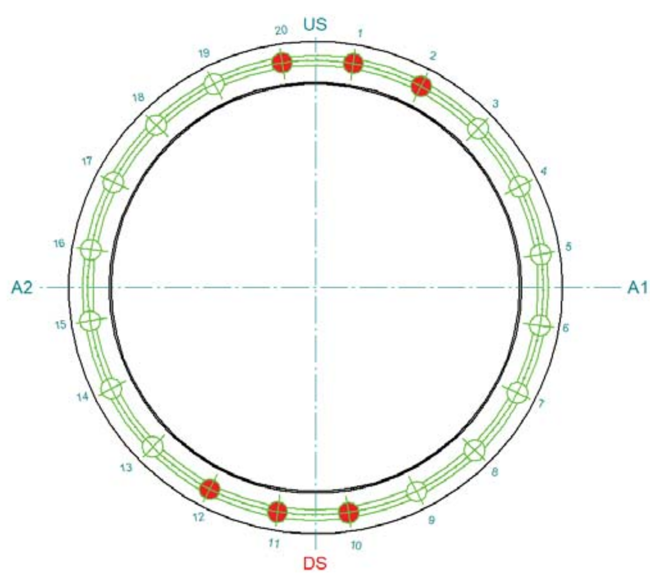

Figure 5-264: Bushing Clearance Evaluation (Affected Gate Stem Bores Only)

5.23.2 Outcome

The bores were measured after they were machined to ensure the desired diameter was achieved; after which, NLH was free to begin assembling the unit. The gate mechanism was monitored for any signs of binding or unexpected clearance issues during assembly and commissioning. Once in operation, the Wicket Gate Mechanism, which includes the Operating Ring, Linkages, Wicket Gates, and Servomotors performed as designed with no bindings or clearance issues. The wear patterns and effects of the larger bushing clearances on the Thordon bushings will not be known until the unit is disassembled during the next major outage.

Note: For future planning consideration, both laser tracker and wire micrometer metrology methods are acceptable means of measuring concentricity of components. However, both methods take a trained professional to conduct the inspection and collect the data. The laser tracker (LIDAR) method is highly sensitive to atmospheric and physical conditions of the parts being measured. Therefore, the measured data can be influenced by air movement, temperature, and surface conditions of the components. This method also requires the equipment to be calibrated frequently. The wire micrometer method is a mechanical means of measurement, which also requires calibrated equipment. Both types data collection can also be highly influenced by the inspector if attention to detail is not accounted for. As learned during the Unit 7 Maintenance Outage of 2019 the need to validate questionable measurements may be required; therefore being prepared to use both LIDAR and mechanical means of measurements collection would be preferred during an outage.

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5.24 Stationary Component Laser Inspection

5.24.1 Background Information

This section describes and summarizes the as-found condition of all of the stationary components of the Unit 7 machine. The data used for the figures below was collected from the laser inspection performed by ESI. This inspection occurred immediately following the conclusion of the disassembly activities. The figure reveals the stationary components as a whole were found to be out of concentricity. The detailed nature of each individual part has already been discussed throughout this report, but this image serves as a visual representation of the position of the stationary components. Further information and the raw data from the laser inspection is located in the Appendix of this report.

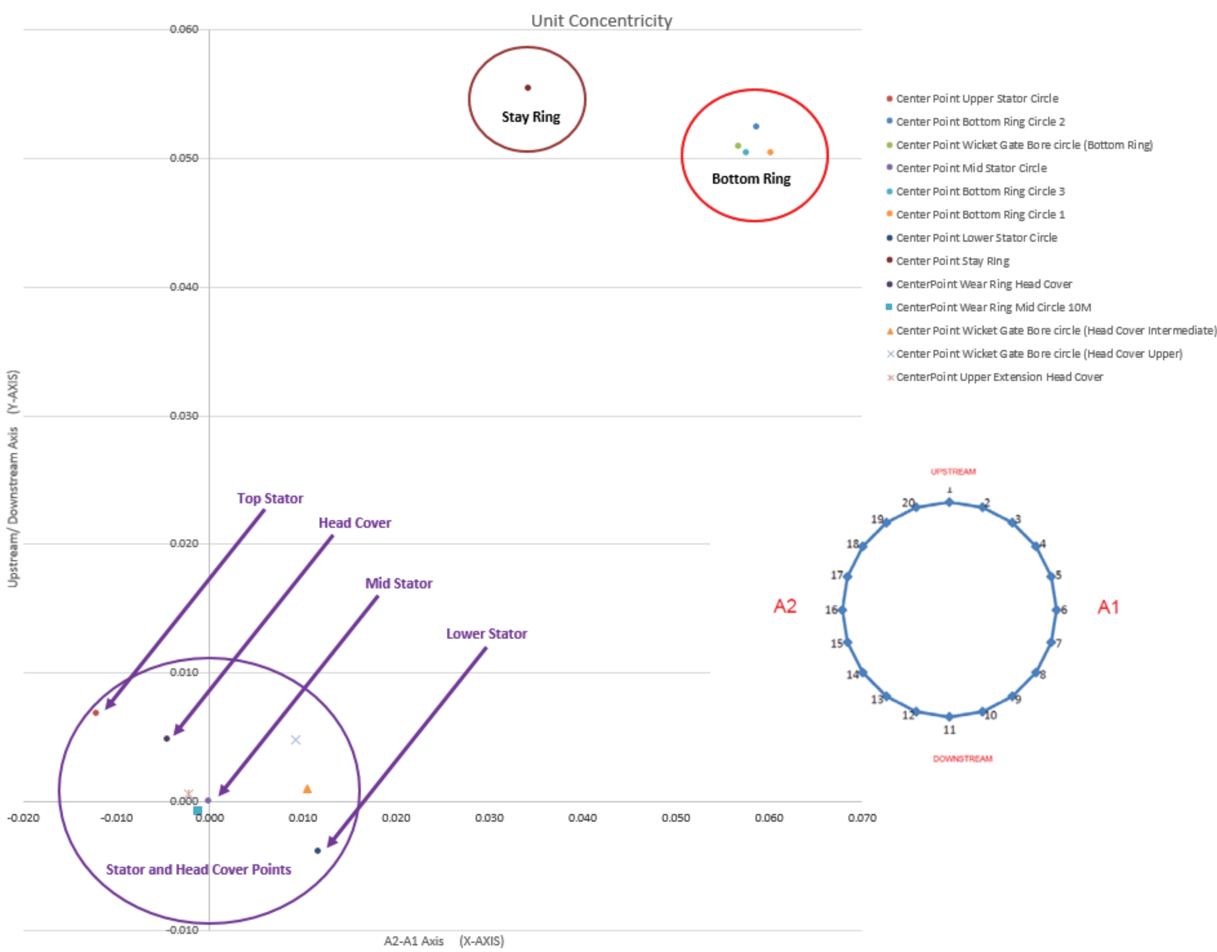

Figure 5-265: Unit Concentricity Overview

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Name	X	Y	Z
Center Point Lower Stator Circle	0.012	-0.004	253.452
Center Point Mid Stator Circle	0.000	0.000	287.019
Center Point Upper Stator Circle	-0.012	0.007	324.979
Center Point Bottom Ring Circle 1	0.060	0.050	-37.355
Center Point Bottom Ring Circle 2	0.059	0.052	-35.463
Center Point Bottom Ring Circle 3	0.058	0.050	-33.463
Center Point Wicket Gate Bore circle (Bottom Ring)	0.057	0.051	-31.918
Center Point Stay RIng	0.034	0.055	-1.481
Center Point Head Cover Upper GSB(Free State)	0.010	0.001	1.518
Center Point Head Cover Lower GSB(Free State)	-0.005	0.005	26.602
CenterPoint Wear Ring Head Cover	-0.005	0.005	2.026
CenterPoint Wear Ring Mid Circle **10M**	-0.001	0.005	4.129
CenterPoint Wear Ring Top Circle **9T**	-0.001	-0.001	6.389
CenterPoint Lower Extension Brass Circle **7**	0.012	-0.030	28.881
CenterPoint Upper Extension Head Cover	-0.002	0.001	58.681
CenterPoint Inner Ring Circle **8**	0.005	0.001	1.850
Center Point Wicket Gate Bore circle (Head Cover Upper)	0.009	0.005	1.530
Center Point Wicket Gate Bore circle (Head Cover Intermediate)	0.010	0.001	1.518

Figure 5-266: Unit Concentricity Overview

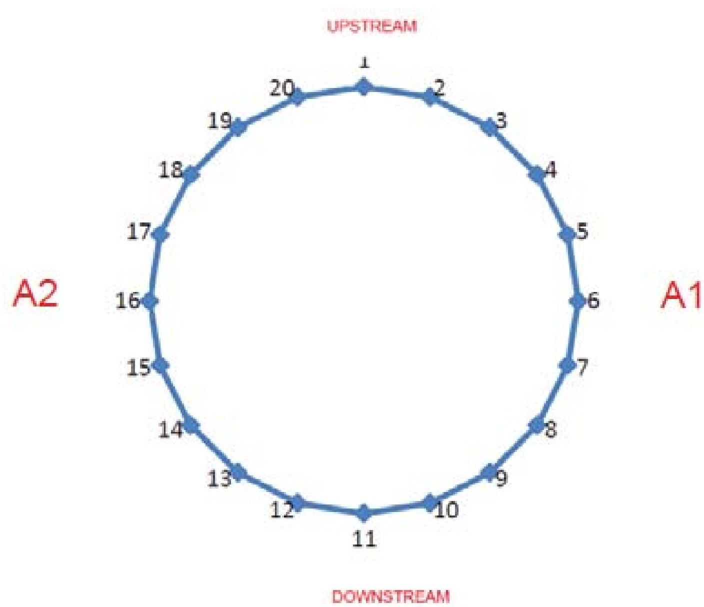

Figure 5-267: Reference used during laser inspection

5.25 Wearing Ring Machining

5.25.1 Background Information

The main reason and motivation for the 2019 maintenance outage was to restore the Lower Primary Seal Clearances between the Runner Band Wearing Ring and the Bottom Ring Wearing to OEM tolerance. Since 2006, NLH has measured significant changes in the radial seal clearance between the stationary and rotating parts of the turbine. Figure 5-269 and 5-270 show that the clearance was somewhat symmetrical in 2006 and, as time has passed, the clearances have changed. These radial seal clearance changes varied depending upon which axis was being evaluated.

The upstream/downstream axis showed a significant decrease in clearance, edging near the critical value of intervention that CEATI outlines in Part 5 of their Maintenance guide (CEATI, 2008). However, the opposite was true for the axis perpendicular to upstream (A2/A1), in which the radial seal clearance measured very high. According to CEATI's maintenance guide, the measured radial seal clearance was higher than the maximum recommended, putting the state of the machine between the "required intervention" and "critical" values. CEATI sets these guidelines to protect the machine in case it were operated outside normal conditions, such as an over-speed or load rejection. In such cases, the machine could contact the stationary components and possibly cause catastrophic damage and an unplanned outage. As small or reduced RSC can impact the operation of the machine it should be noted that larger RSC can also have significant effect on the machine. Larger radial seal clearance can allow cavitation to develop, which causes damage to the rotating and stationary components, and increases in thrust can also occur, which can lead to thrust bearing issues.

5.25.1.1 Summary of Scope

Voith was contracted to evaluate the data and measurements pertaining to improving the RSC of the Unit 7 Runner. The Voith team conducted a visual and metrology inspection on the Wearing Rings and Runner prior to machining the Wearing Ring. Voith engineers determined the best course of action for machining the Wearing Ring using this information and data. This analysis consisted of determining a best center to machine to, the effects of hydraulic losses, thrust concerns, and limiting increased cavitation; ultimately, the goal was to allow the machine to operate for another five more years. Voith presented their findings to NLH and explained the logic, consequently leading to a successful machining of the Bottom Ring Wearing Ring. Further explanations are included in subsequent sections with all of the reference material and measurements in the Appendix of this report. For more information about individual components mentioned in this section, refer back to the specific description within Section 5.

Equipment Used:

- Voith's Vertical Boring Machine
- Faro Tracker Laser

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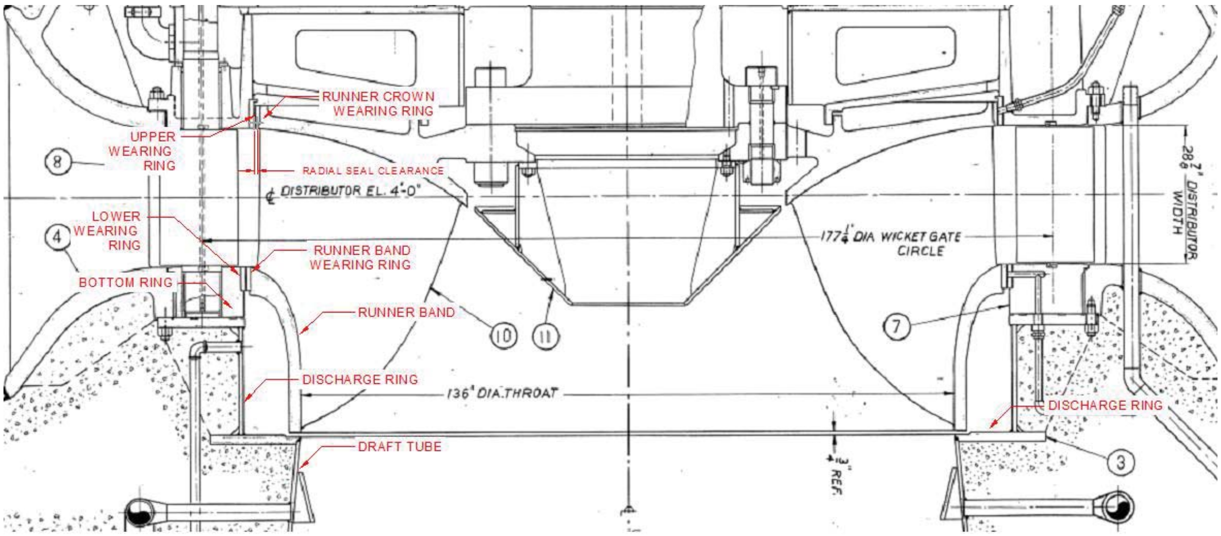

Figure 5-268: Wearing Ring Machining Outline

VOITH

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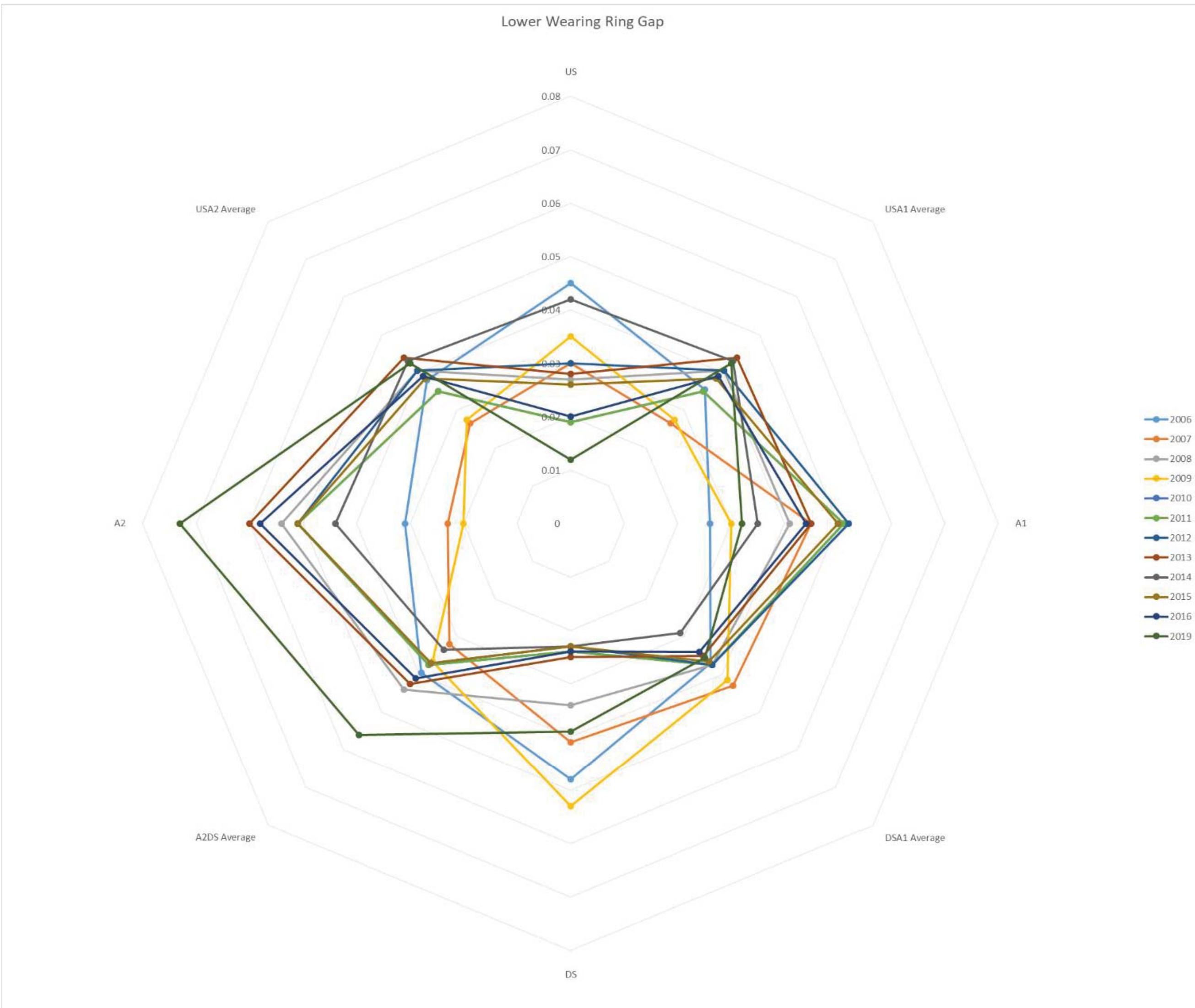

ACTUAL

Lower Wearing Ring Gap										
	Year	US	USA1 Ave	A1	DSA1 Ave	DS	A2DS Ave	A2	USA2 Ave	A1+A2	US+DS
1	2006	0.045	0.0355	0.026	0.037	0.048	0.0395	0.031	0.038	0.057	0.093
2	2007	0.03	0.0265	0.045	0.043	0.041	0.032	0.023	0.0265	0.068	0.071
3	2008	0.027	0.0405	0.041	0.0375	0.034	0.044	0.054	0.0405	0.095	0.061
4	2009	0.035	0.0275	0.03	0.0415	0.053	0.0365	0.02	0.0275	0.05	0.088
5	2010	0.019	0.035	0.051	0.0375	0.024	0.0375	0.051	0.035	0.102	0.043
6	2011	0.019	0.035	0.051	0.0375	0.024	0.0375	0.051	0.035	0.102	0.043
7	2012	0.03	0.0405	0.052	0.0375	0.023	0.037	0.051	0.0405	0.103	0.053
8	2013	0.028	0.044	0.045	0.035	0.025	0.0425	0.06	0.044	0.105	0.053
9	2014	0.042	0.043	0.035	0.029	0.023	0.0335	0.044	0.043	0.079	0.065
10	2015	0.026	0.0385	0.05	0.0365	0.023	0.037	0.051	0.0385	0.101	0.049
11	2016	0.02	0.039	0.044	0.034	0.024	0.041	0.058	0.039	0.102	0.044
12	2019	0.012	0.0425	0.032	0.0355	0.039	0.056	0.073	0.0425	0.105	0.051

Figure 5-269: NLH Lower Wearing Ring Radial Seal Clearance over 14 Years

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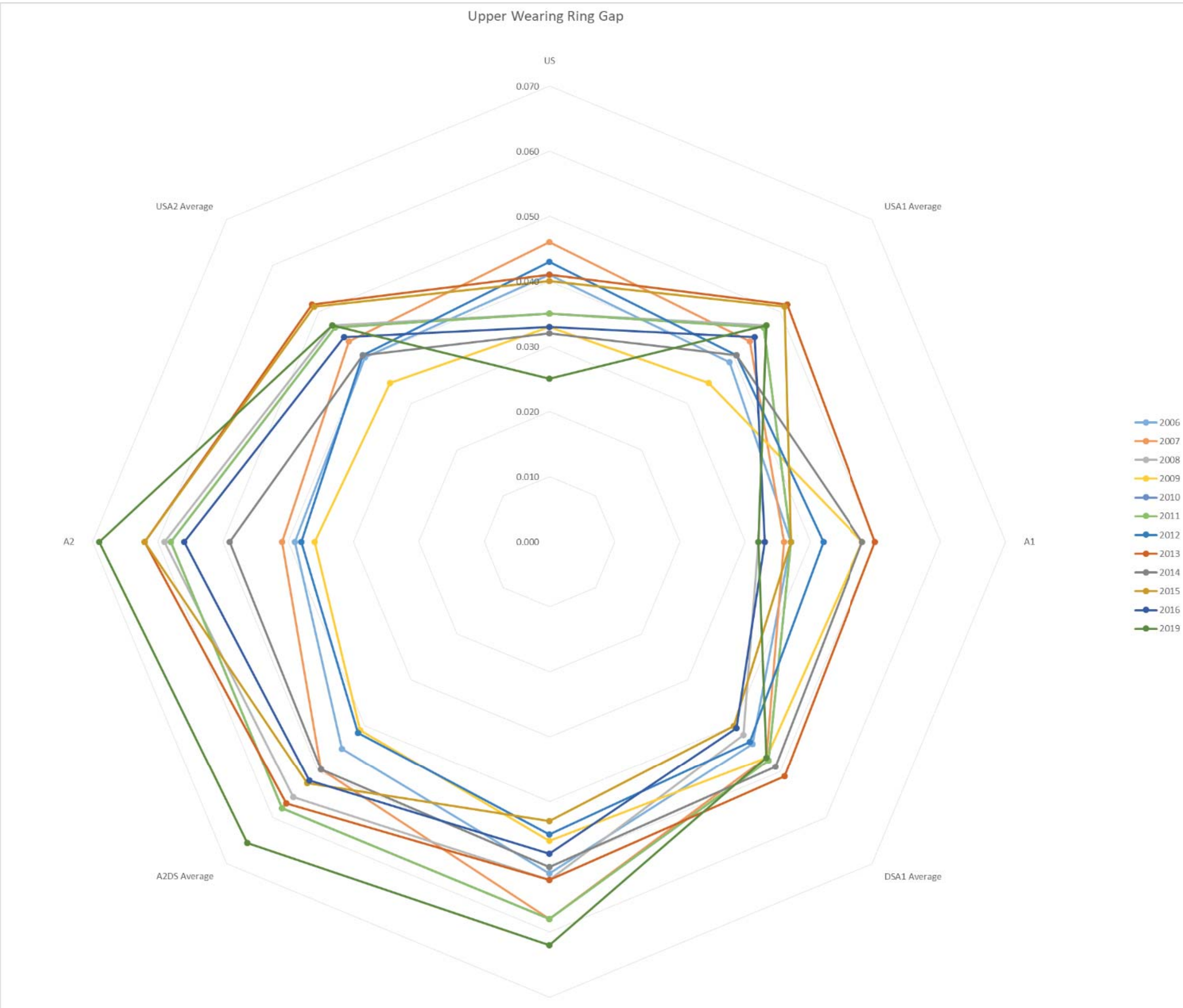

Upper Wearing Ring Gap												
ACTUAL		Year	US	USA1 Ave	A1	DSA1 Ave	DS	A2DS Ave	A2	USA2 Ave	A1+A2	US+DS
	1	2006	0.041	0.039	0.037	0.044	0.051	0.045	0.039	0.040	0.076	0.092
	2	2007	0.046	0.044	0.036	0.047	0.058	0.050	0.041	0.044	0.077	0.104
	3	2008	0.035	0.047	0.032	0.042	0.052	0.056	0.059	0.047	0.091	0.087
	4	2009	0.033	0.035	0.048	0.047	0.046	0.041	0.036	0.035	0.084	0.079
	5	2010	0.035	0.047	0.037	0.048	0.058	0.058	0.058	0.047	0.095	0.093
	6	2011	0.035	0.047	0.037	0.048	0.058	0.058	0.058	0.047	0.095	0.093
	7	2012	0.043	0.041	0.042	0.044	0.045	0.042	0.038	0.041	0.080	0.088
	8	2013	0.041	0.052	0.050	0.051	0.052	0.057	0.062	0.052	0.112	0.093
	9	2014	0.032	0.041	0.048	0.049	0.050	0.050	0.049	0.041	0.097	0.082
	10	2015	0.040	0.051	0.037	0.040	0.043	0.053	0.062	0.051	0.099	0.083
	11	2016	0.033	0.045	0.033	0.041	0.048	0.052	0.056	0.045	0.089	0.081
	12	2019	0.025	0.047	0.032	0.047	0.062	0.066	0.069	0.047	0.101	0.087

Figure 5-270: NLH Upper Wearing Ring Radial Seal Clearance over last 14 Years

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5.25.2 Visual Inspection

At the time of the Wearing Ring visual inspection, the entire Unit 7 machine was already disassembled and other tasks were being performed on all of the other components and subsystems of the machine. A thorough visual inspection had already been completed on all of the other components at this point. Each ring had varying levels of damage and deformation. The exact time and cause of damage is difficult to determine, but it was safe to assume the Runner contacted either debris or the stationary Wearing Rings at some point during its service life. Below are images of the condition of the Wearing Rings. While not critical to the machining process of the Wearing Ring, it is noteworthy to point out the cavitation damage again on the Bottom Ring. This damage is described in detail in Section 5.22, but is mentioned in this section and was considered during the analysis of the data and recommendations.

Figure 5-271: Bottom Ring Wearing Ring Condition (Lower)

Figure 5-272: Head Cover Wearing Ring Condition (Upper)

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Figure 5-273: Runner Wearing Ring Condition (Left – Crown, Right – Band)

Figure 5-274: Bottom Ring Cavitation Damage

5.25.3 Measurements and Analysis

Voith considered the following data to determine how much material to remove from the Bottom Ring Wearing Ring: unit best center, thrust issues, cavitation increases, hydraulic losses, and a consideration for future growth and shrinkage of the radial seal clearance. First Voith ruled out the replacement and machining of the Head Cover Wearing Ring. The visual inspection did reveal that the Head Cover Wearing Ring had signs of scoring and light damage; however, the laser inspection exposed the circularity and position of the Head Cover Wearing Ring compared to the Stator (centerline) was in CEATI Part 2 tolerance and in good condition. This information made it clear that the Head Cover Wearing Ring did not need to be replaced or machined to improve global roundness. Voith also performed runout and level checks on the Head Cover and Wearing Ring to verify the logic. The installed level and runout measurements were found to be acceptable and are located in the Appendix for reference.

5.25.3.1 Unit Best Center

The Unit Centerline is the axis around which the components are installed concentric to:

- The lower Wearing Ring, so the runner lower Wearing Ring clearance is well distributed all around.
- The upper Wearing Ring, so the Runner Band Wearing Ring clearances are well distributed all around.
- The Stator, so the Rotor air gap is well distributed all around.
- The Runner Band OD clearances to the Bottom Ring ID are well distributed all around; however, this clearance is often larger thus more tolerant to eccentricity.
- The Runner Crown OD clearances to the Head Cover ID are well distributed all around and like the Bottom Ring is more tolerant to having an eccentric position. Typically, the Head Cover ID is also concentric when the Head Cover Wearing Ring is concentric with the Runner.
- All bearings are around the axis to maintain the rotating parts within the stationary and embedded components.

Consequently:

- The Head Cover Wearing Ring must be concentric with the lower Wearing Ring,
- Both Wearing Rings must be concentric with the Stator, and
- The Head Cover Wicket Gate top and intermediate GSB axis should be concentric with the Bottom Ring Wicket Gate bores.

With the above information considered and based on the concentricity of all of the stationary components mentioned in Section 5.24 and throughout the individual part sections, Voith determined to use the Head Cover Wearing Ring as the best center for the machining of the Bottom Ring Wearing Ring. This decision was reinforced by the relative close distance between the Stator and Head Cover, which was revealed during the laser inspection, as shown in Figure 5-265. Many factors were considered during this determination. Voith's approach was to honor NLH's attempt to avoid moving the Stator and Bottom Ring, or machining the Stay Ring Flange or Bottom Ring seat. Also, the apparent movement of the concrete and embedded components caused concern when evaluating changing the physical position of parts because the movement could cause further damage or cause other parts of the machine fail to work properly. The overall goal was to determine a best center using the least invasive method possible with the understanding that the repairs made during the 2019 maintenance outage were to provide five more years of service.

5.25.3.2 Analysis of Future Radial Seal Clearance Reduction

Voith analyzed previous NLH-provided measurements of the RSC over the last 14 years (2006 to 2019) to ensure the machining of the Wearing Ring during the 2019 Maintenance considered future growth and reduction of seal clearance. Both linear and exponential models were created to determine the growth rate and attempt to predict when the RSC of the Wearing Ring would reach the intervention and critical limits of the CEATI Part 5 Maintenance Standard. In the case of Unit 7, the value was 0.25 of nominal (minimum) RSC and up to 1.5 times the nominal RSC for the maximum intervention limit. The critical limit set by CEATI Part 5 for the Unit 7 machine was 0.1 times the nominal RSC; this is the limit in which the machine should be placed out of service. Figures 5-275 and 5-276 show the actual growth and shrinkage of the clearance for both the Lower and Upper Wearing Rings from 2006 to 2019. Voith developed models to understand the change and predict intervention and critical moments in the future. The change in either axis was approximately 0.0015 to 0.004 inch per year regardless of which model was used, whether linear, exponential, or average.

The graph in Figure 5-277 shows that the upstream clearance of the Runner was approaching the intervention limit of CEATI Part 5; therefore, the 2019 maintenance outage timing was appropriate and in accordance with when the machine should be placed out of service prior to reaching the critical limit. With this analysis and timeline determined, Voith was able to propose a new diameter to machine the lower Wearing Ring to in order to safely operate the machine until the next major outage in five years.

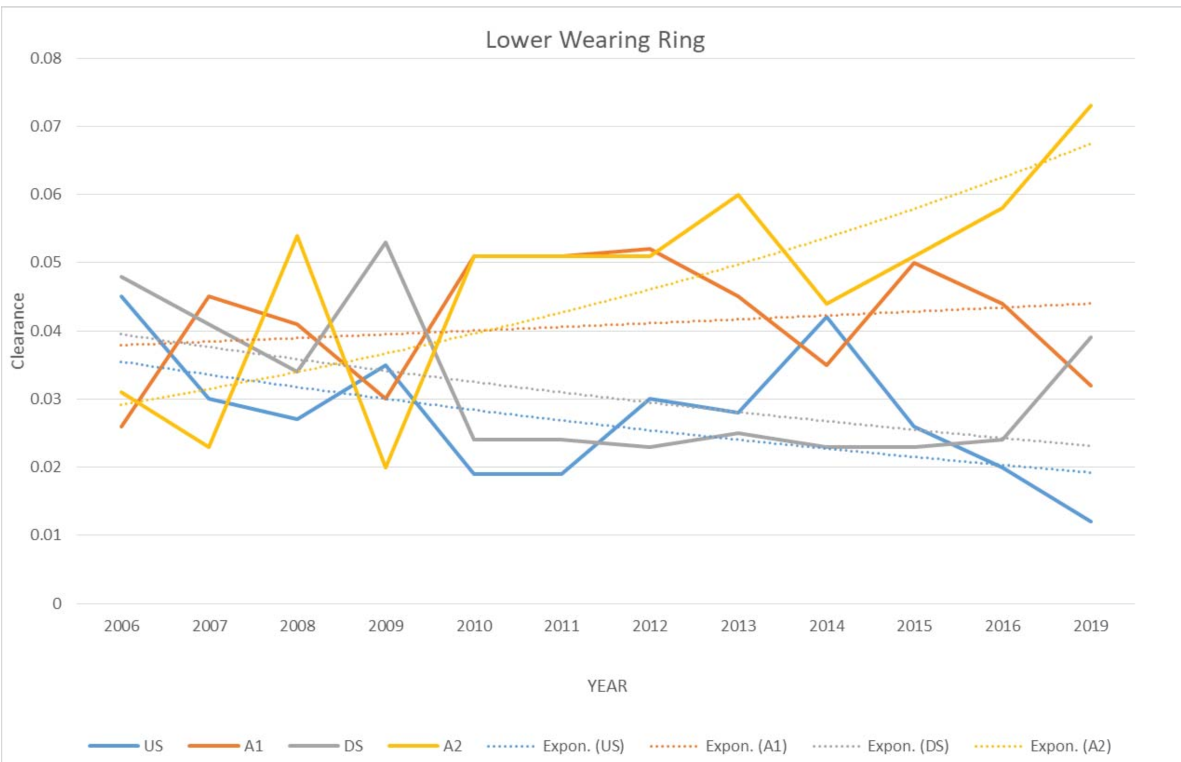

Figure 5-275: Lower Wearing Ring Radial Seal Clearance Change, (Clearance in Inches)

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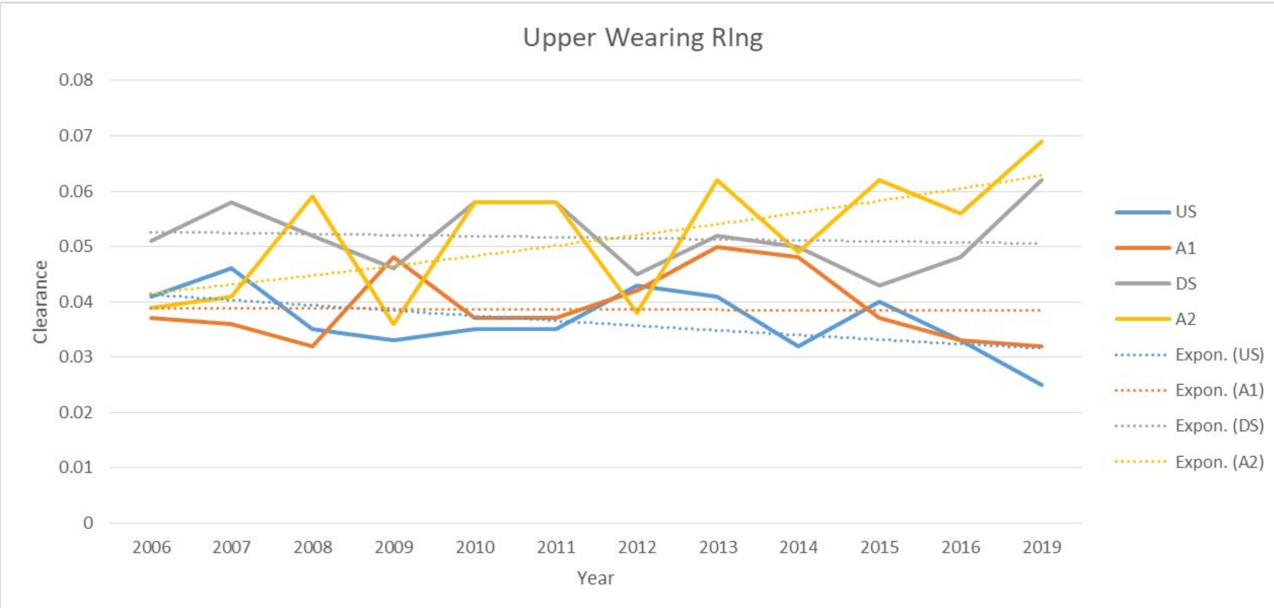


Figure 5-276: Upper Wearing Ring Radial Seal Clearance Change (Clearance in Inches)

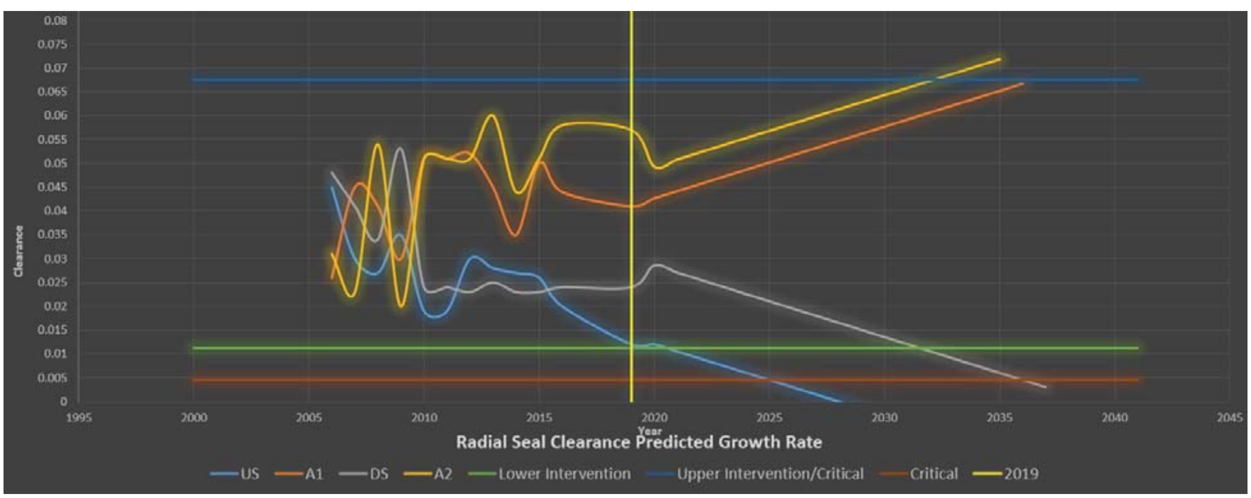


Figure 5-277: Predicted Growth Rate of Radial Seal Clearance (Clearance in Inches)

5.25.4 Voith Wearing Ring Machining Recommendation

On July 26, 2019, Voith determined and recommended that machining of the Bottom Ring Wearing Ring was indeed required and that NLH should allow the following tasks to be performed on the Unit 7 machine to improve the Radial Seal Clearances and global roundness.

- Recommendation Provided:

Prior to machining, the Voith Boring Machine should sweep the Head Cover and Bottom Ring Wearing Rings to determine concentricity relative to each other and the premeasured stator core offsets. The boring machine should also sweep the Head Cover and Bottom Ring to double check the level and parallelism to each other relative to the laser measurements already recorded. The level and parallelism of the Head Cover to the Bottom Ring is critical. Once these items are completed the machining of the Bottom Ring Wearing Ring should begin.

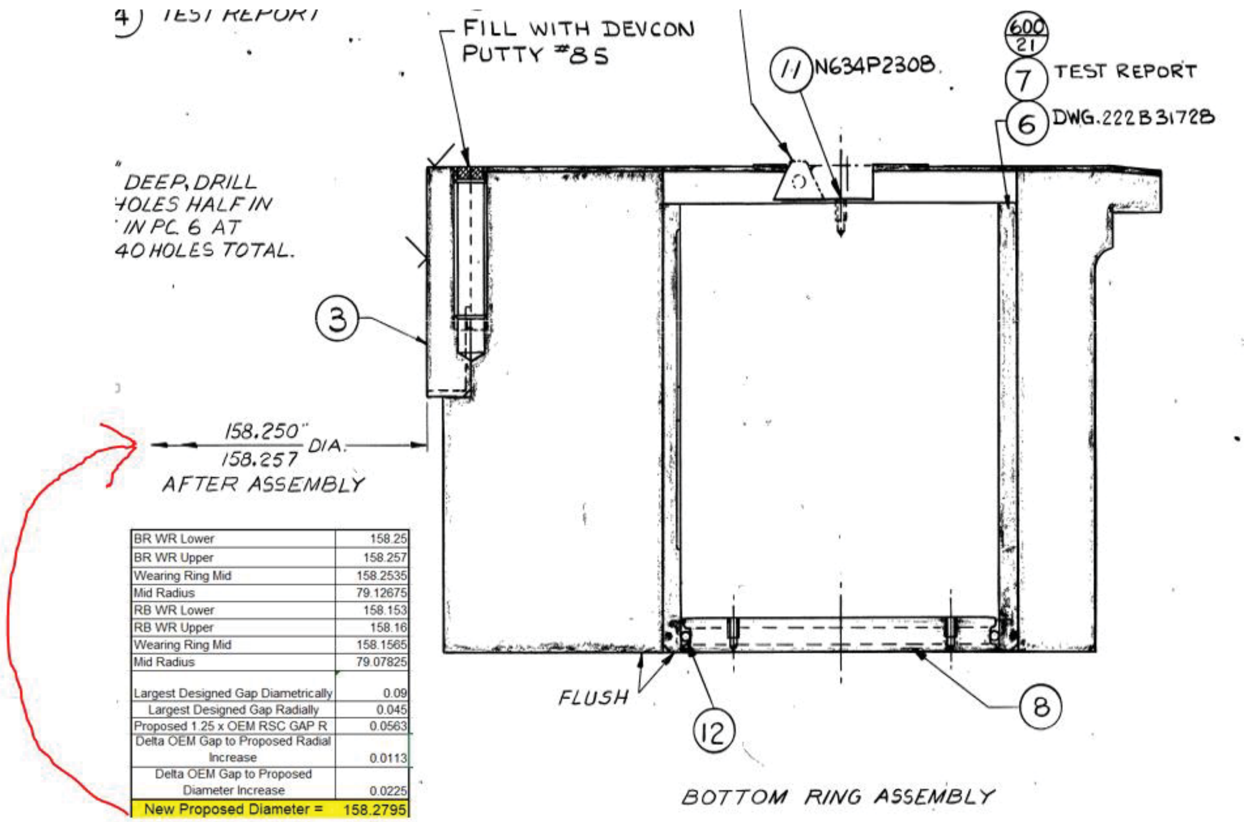
NLH should increase the radial seal clearance (RSC) to 1.25 times the OEM value, which is 0.05625 inch, rather than the OEM of 0.045 inch. This will improve the global roundness of the Lower Wearing Ring and increase the clearance between the Runner and Wearing Ring. Currently, the gap measures a minimum of 0.012 inch in the upstream direction and a maximum of 0.060 inch in the A2 direction. Machining the Wearing Ring to the proposed diameter will not "clean" or create a perfect circle, in fact, in the locations of the larger gap (A2), the boring bar will not even touch the surface, which is acceptable.

- Logic Used:

Continued deformation (elliptical shape) of the embedded components was highly likely. Voith used the data provide by NLH from 2006 to 2019 (years 2017 and 2018 were not provided) to determine the rate of change was approximately 0.002 inch (shrinkage) in the upstream/downstream axis and 0.003 inch (growth) across the A2/A1 axis per year. This data was only based upon a short window of time relative to the age of the machine. With the growth rate of deformation in mind, Voith's recommendation was a compromise between efficiency losses, creating more cavitation, and changing the thrust forces the machine experiences. As the radial seal clearance increases, the efficiency can decrease, heavy cavitation can develop, and increases in thrust can cause issues for the aging unit and its thrust bearing assembly. To machine the Wearing Ring to OEM size would be acceptable as well, but the increased size Voith recommended would improve the overall global roundness and provide the clearance for additional deformation, especially if the deformation rate were to increase rapidly. To quantify the logic in simple terms see below:

  - Machine to OEM size: Efficiency losses comparable to 2019 pre-outage, same to a slight increase in cavitation.
  - 1.5 times the OEM RSC: Efficiency loss could increase by 0.5%; moderate to heavy cavitation and thrust issues may start to develop.
  - 2.0 times the OEM RSC: Efficiency losses could increase by 1.2 %; heavy cavitation and thrust issues are expected.

The recommended 1.25 times the OEM RSC was a compromise between impacting the machine's performance and the rate of deformation of the embedded parts. If the Wearing Ring was machined to OEM RSC, the gap at certain locations could return to its current size in as little as five years on sooner. Increasing the RSC slightly past OEM would provide more clearance, especially if alignment issues develop with the machine over time or the rate of deformation increasing, and provide NLH more time to investigate the cause of the deformation and possible remedies.



BR WR Lower	158.25
BR WR Upper	158.257
Wearing Ring Mid	158.2535
Mid Radius	79.12675
RB WR Lower	158.153
RB WR Upper	158.16
Wearing Ring Mid	158.1565
Mid Radius	79.07825
Largest Designed Gap Diametrically	0.09
Largest Designed Gap Radially	0.045
Proposed 1.25 x OEM RSC GAP R	0.0563
Delta OEM Gap to Proposed Radial Increase	0.0113
Delta OEM Gap to Proposed Diameter Increase	0.0225
New Proposed Diameter =	158.2795

Figure 5-278: Voith Recommended New Diameter

To reiterate, this recommendation was a compromise between many factors that can impact the machine's performance and lifespan and that no standard guideline (e.g., CEATI) existed for this situation. Additionally, some of the same logic and principles were applied on previous Bay d'Espoir Wearing Ring issues; in fact, the diameters were increased even more than what Voith recommended for the Unit 7 machine in some previous cases.

After discussing internally with NLH maintenance and engineering staff, NLH agreed with Voith's logic and approved the machining of the Bottom Ring Wearing Ring of Unit 7 to the recommended value.

5.25.5 Wearing Ring Machining

Once approval was provided by NLH the Voith Field Machining crew performed final checks of their equipment and runouts prior to machining. All of these final checks and verifications were reviewed by VH engineering and were deemed acceptable. All of the check sheets and as-found runouts are located in the Appendix.

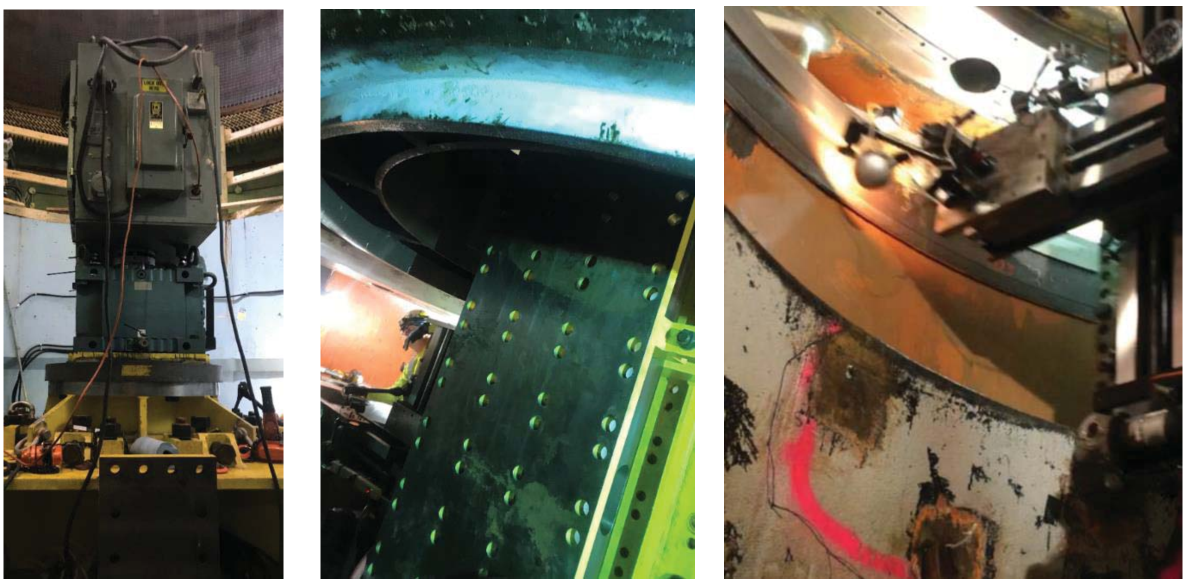


Figure 5-279: Voith Vertical Boring Machine

Figure 5-280: Bottom Ring Machined (Partial Clean)

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Figure 5-281: Bottom Ring Machined (Partial Clean)

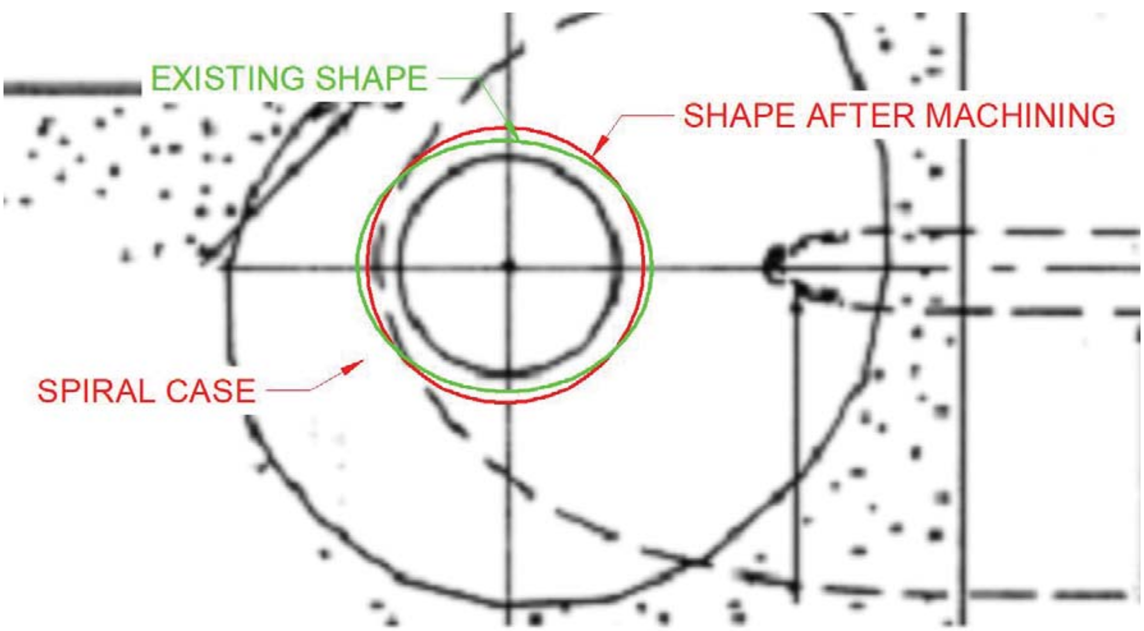

Figure 5-282: Bottom Ring Machined Example, (NTS)

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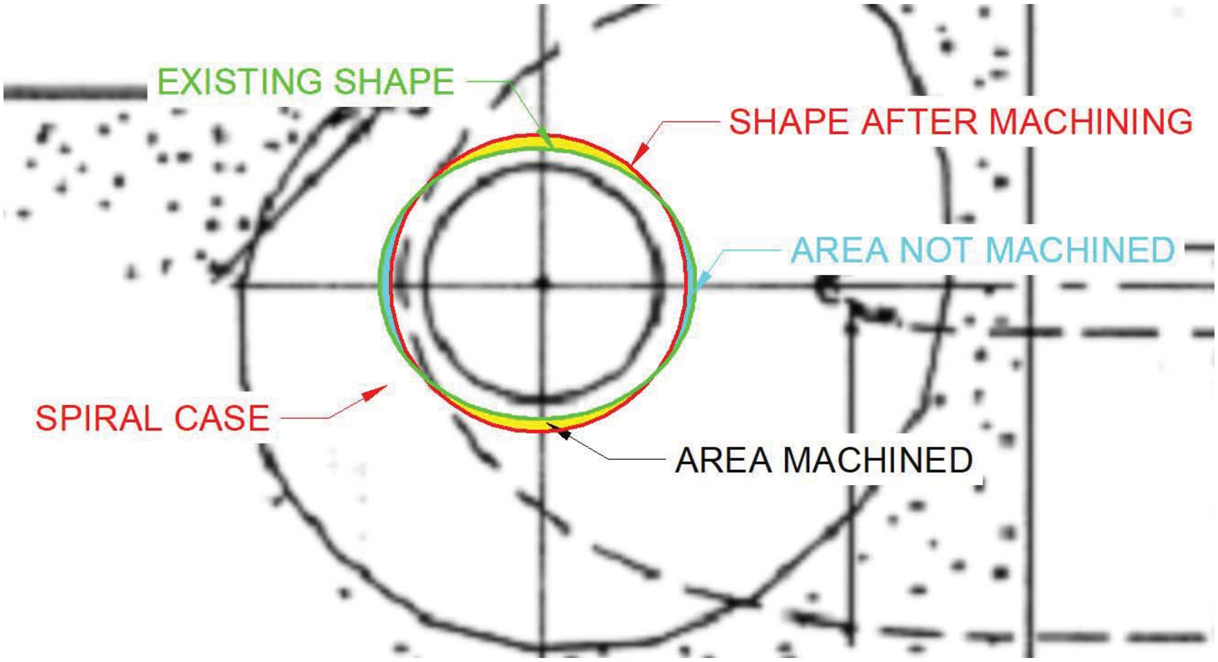

Figure 5-283: Bottom Ring Machined Example, (NTS)

5.25.6 Outcome

The machining of the Bay d'Espoir Bottom Ring Wearing Ring was completed on July 31, 2019. The final diameter shown in Figure 5-285 was recorded in four locations, top and bottom, on the Wearing Ring to 158.275 inches. The diameter is slightly less than the maximum Voith proposed, which was 158.2795 inches. With the slight risk going over proposed size, and with the logic that taking an additional cut would not net significant gain, Voith decided to remain a few thousandths of an inch under the max size. As the figures revealed, and as expected, the Wearing Ring did not machine clean; meaning, the final diameter was not large enough to cut the as-found elliptical shape of the Wearing Ring; however, Voith was confident that the new global roundness and runouts recorded would not have changed enough to warrant the additional cut. The machining of the Wearing Ring opened up new surface material of the OEM welds of the rings. These welds were located where the ring quarters were originally welded together. There were four welds. Of the four, three were easy to see visually and a 4th spot was NDE inspected assuming the welds were all equally spaced. To ensure the machining process did not reveal surface imperfection across the weld, Voith recommended NDE be performed on the welds. NLH performed the recommended examination on the welds after removal of the Voith Boring Machine; no indications were found. The NDE reports are located in the Appendix of this report.

Figure 5-284 is a graph that shows the 14-year change in the Radial Seal Clearance, the new 2019 RSC clearance, and the predicted rate of change of the next 15 years. This rate of change is using the 0.002 to 0.003 inch change per year used during the pre-machining analysis. While no absolute logic or mathematical model exists to predict the RSC phenomenon, the graph reveals that the RSC could be approaching, if not

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surpassing, the intervention limit referenced in the CEATI Part 5 maintenance standard in as little as five years. The change in RSC could also approach the critical limit after the ten year mark past the 2019 commissioning, if the growth rate continues at the same rate. Moving beyond the 2019 Maintenance Outage, NLH should plan to continue to monitor the RSC at appropriate intervals. The RSC should be measured and recorded at least once a year; however, if other opportunities present themselves NLH should take advantage and measure the RSC.

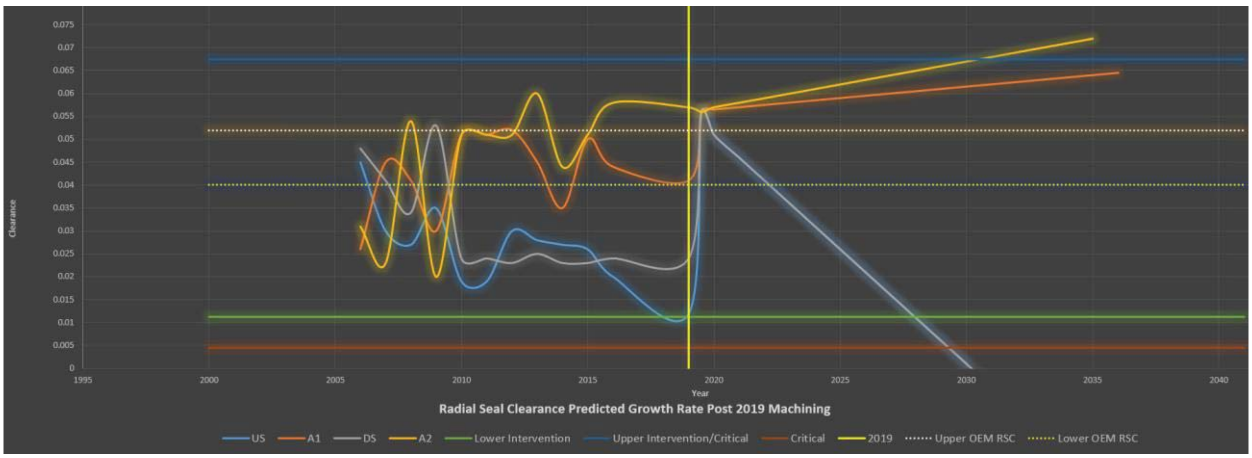

Figure 5-284: Predicted Growth Rate and Timeline of Radial Seal Clearance after Machining (Clearance in Inches)

Figure 5-285: Final Bottom Ring Wearing Dimension – (Two Location)

Figure 5-286: Bottom Ring Wearing Ring Split Welds

5.26 Discharge Ring

5.26.1 Background Information

The Discharge Ring is a stationary structural member on a Francis turbine that surrounds the Runner Band. It may or may not be integral with the Bottom Ring, but in the case of Unit 7, it is a separate piece. The Draft Tube Liner is attached to the downstream end of the Discharge Ring. NLH established a plan for the Discharge Ring and determined that only a visual inspection was required for the 2019 maintenance outage after reviewing their experience from previous outages at Bay d'Espoir Powerhouse One and the recommendations outlined in a refurbishment plan (VHY-1, 2017) developed by VH.

Planned Work:

- Visual Inspection (VH Scope).
- Inspection for Voids (VH Scope).

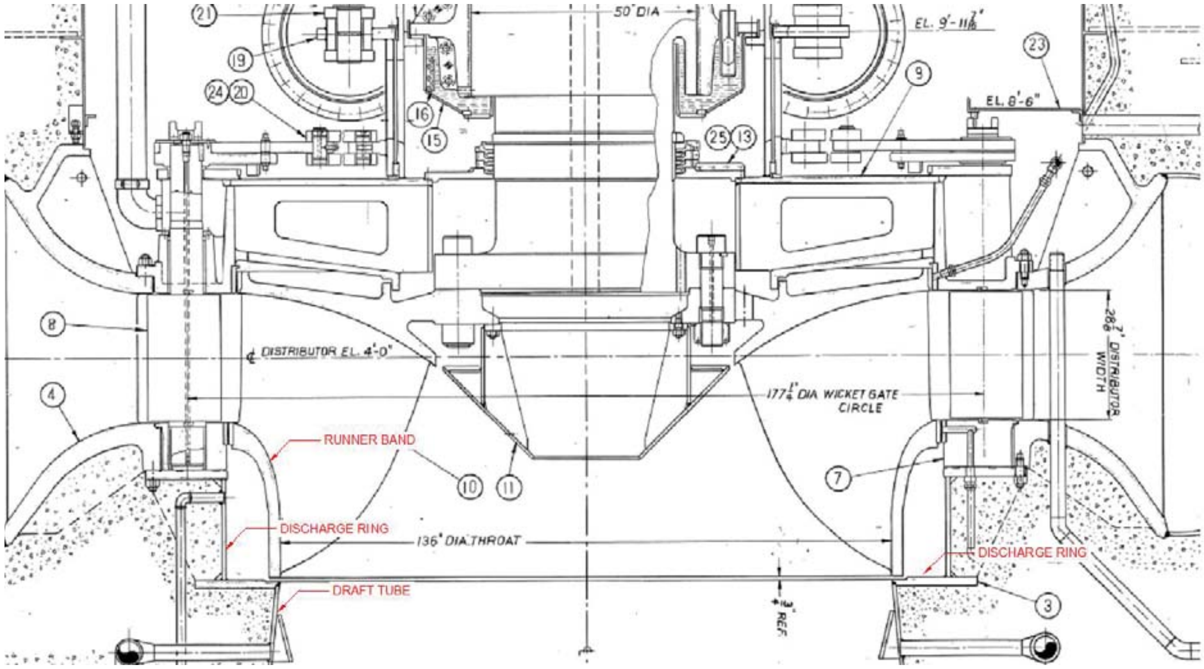

Figure 5-287: Discharge Ring, Outline

5.26.2 Visual Inspection

The Discharge Ring was visually inspected by Voith engineering for any obvious signs of damage, cracking, and any indications that the ring may require repair prior to placing the unit back into to service. The inspection of the Discharge Ring revealed that the ring was in good condition considering the age and service life of the machine. The original OEM orange paint was still present and in fair condition. There was some light rust and corrosion present, but this was limited to the upper and lower main plates of the Discharge Ring. There were no indications or signs of cracks or damage found on the Discharge Ring. The Voith Hydro Field Services team inspected the Discharge Ring by the means of tapping the structure of the Discharge Ring with a hammer and listening for different tones, indicating voids behind the steel. After a thorough inspection VH did not detect any voids behind the steel structure of the Discharge Ring.

Figure 5-288: Discharge Ring, Paint Condition

Figure 5-289: Discharge Ring, Upper Plate

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Figure 5-290: Discharge Ring, Rust and Corrosion

Figure 5-291: Discharge Ring, Lower Plate

Figure 5-292: Discharge Ring

5.26.3 Laser Inspection Data and Results

There was no High Precision Dimensional inspection planned for or performed on the Discharge Ring during the 2019 maintenance outage

5.26.4 Non-Destructive Examination

There was no non-destructive examinations planned or performed for the Discharge Ring for the 2019 maintenance outage.

5.26.5 Outage Recommendations

- **Outcome:**
    - Voith did not provide any recommendations for the Discharge Ring of the Unit 7 machine for the 2019 maintenance outage. Long time recommendations are provide in Section 8.1 of this report.

6 Unit 7 Reassembly

6.1 Unit 7 Reassembly

Voith disassembled and removed all of their machining equipment at the conclusion of Wearing Ring machining. The machine was released back to NLH once Voith Field Services concluded all of their activities to begin reassembly at the end of the second week in August 2019. Over the next five weeks NLH's maintenance staff and millwrights assembled the Unit 7 machine with the guidance and procedures created by a contracted engineering company, Hatch Engineering. Under their supervision, NLH was meticulously guided through every step of the assembly, ensuring that all of the components were correctly assembled. NLH performed the rotation measurements and checks outlined by the CEATI Part 2 standard for erection tolerance and shaft system alignment once the machine was reassembled.

On September 7, 2019, NLH and Hatch's onsite engineer performed the first rotation check where the shaft alignment, verticality, runout, and air gap measurements were recorded. Voith recommended to correct the verticality first, then correct the concentricity. Correcting the verticality of the machine was to maintain the same elevation of the Rotor as much as possible.

The first set of rotational readings indicated that:

- Unit verticality was 0.0929 mm/m compared to the CEATI tolerance of 0.0600 mm/m.
- Runout at the Turbine Guide Bearing was 0.002 inch in both the Upstream/Downstream and A2/A1 axis.
- Voith recommended moving the Main Bracket down 0.004 inch in US/DS direction and up 0.021 inch in the A2/A1 direction (NLH performed the recommended move).

Bay d'Espoir Unit 7 - First Verticality Check

Upstream	0.01	mm/m
A1	0.122	mm/m
Downstream	0.047	mm/m
A2	-0.06	mm/m
Main Bracket Dimensions	**INCH**	**FEET**
	234	**19.5**
	mm/m	**IN/FT**
US/DS	-0.0185	-0.000222
A2/A1	0.091	0.001092
Shaft Verticality	0.0929	mm/m
CEATI	0.0600	mm/m
Delta	0.0329	mm/m

Correction over Main Bracket Distance

-0.004329002
0.021294009

Figure 6-1: Unit 7 First Verticality Check

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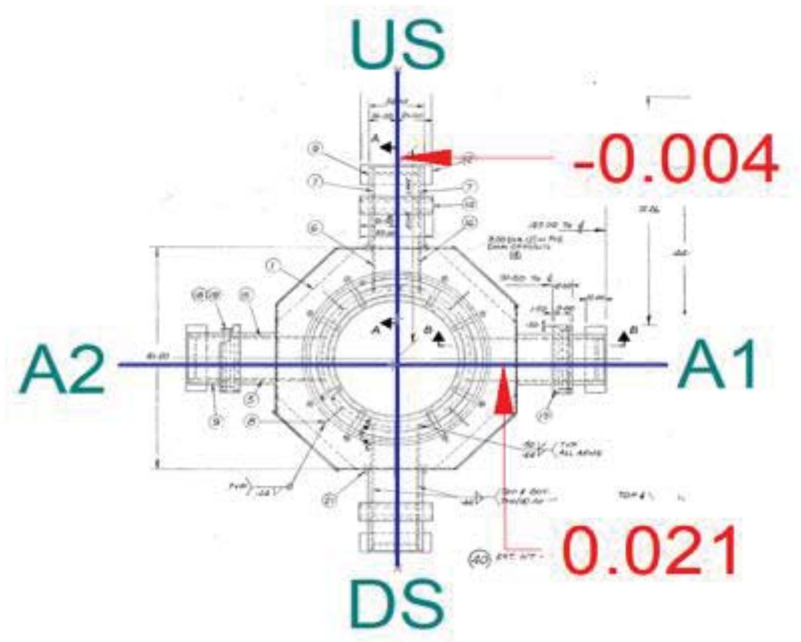

Figure 6-2: Unit 7 Verticality, First Move to Adjust Verticality

The second set of rotational readings indicated that:

- Unit verticality was 0.0106 mm/m compared to the CEATI tolerance of 0.0600 mm/m, which placed the machine well in the tolerance zone.
- Runout at the Turbine Guide Bearing was at 0.0025 inch in the upstream/downstream and 0.0035 inch A2/A1 axis.
- Voith recommended not to moving the main bracket any further. From this point NLH focused on the Air Gap and the concentricity.

Bay d'Espoir Unit 7 - Second Verticality Check

Upstream	0	mm/m
A1	0.005	mm/m
Downstream	0.02	mm/m
A2	0.012	mm/m
Main Bracket Dimensions	**INCH**	**FEET**
	234	**19.5**
	mm/m	**IN/FT**
US/DS	-0.01	-0.00012
A2/A1	-0.0035	-4.2E-05
Shaft Verticality	0.0106	mm/m
CEATI	0.0600	mm/m
Delta	-0.0494	mm/m
Correction over Main Bracket Distance		
-0.002340001		
-0.000819		

Bay d'Espoir Unit 7 - Second Runout Check(9-8-2019)

Position(Degrees)	Upstream/Downstream	A1/A2
0	0	0
90	-0.001	-0.003
180	-0.0025	0.0005
270	-0.002	-0.0015
360	-0.001	-0.0015
TIR =	0.0025	0.0035

	TGB Design Tolerance	Turbine Shaft Journal Design Tolerance
	50.000	49.975
	50.004	49.980
Average	50.002	49.978

Diametrical Design Clearance, DC = **0.024**
CEATI, Part 2

Figure 6-3: Unit 7 Verticality, Second Rotational Check

Once the verticality was within tolerance, Voith recommended moving the unit into a best center position with the stationary parts. Rather than move the entire Main Bracket, NLH used the Guide Pads to move the unit.

- The as-found concentricity of the upper and lower seal and the Air Gaps are shown in Figure 6-4. The table shows all concentricity values were in tolerance except for the lower seal of the Runner. The as-found measurements versus the CEATI tolerances are shown in the following tables.
- Voith recommended a move of -0.0048 in the X-direction and -0.0036 in the Y-direction (NLH performed the recommended move).

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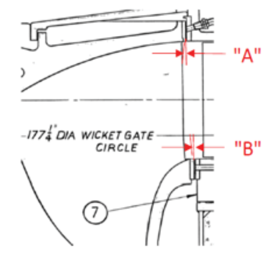

	Radial Design Clearance	Average RSC
"A"	0.040 to 0.047	0.044
"B"	0.045 to 0.052	0.049
	Nominal OEM Upper Seal Clearance =	0.044
	Nominal OEM Lower Seal Clearance =	0.049
	Upper Wear Ring Tolerance 10% of RSC, (Radial RSC CEATI Part 2)	0.004
	Lower Wear Ring Tolerance 5% of RSC, (Radial RSC CEATI Part 2)	0.002
	Average Air Gap from data above =	0.838
	5 percent average AIR Gap or 1 mm max =	0.042
	1 mm max =	0.039

X - MOVE =	-0.0048			
Y - MOVE =	-0.0036			
x-average	0.0020	-0.0008	-0.0134	-0.0087
y-average	-0.0025	0.0016	-0.0126	-0.0195
Concentricity	0.0032	0.0018	0.0184	0.0214
CEATI	0.0044	0.0024	0.0394	0.0394

Figure 6-4: Radial Design Clearance Measurements

Gap Measurements (09-08-19) (First Move)

Upper Seal

Position(Degrees)	0	90	180
Upstream	0.057	0.064	0.065
A1	0.047	0.043	0.056
Downstream	0.046	0.038	0.039
A2	0.053	0.053	0.043

Lower Seal

Position(Degrees)	0	90	180
Upstream	0.051	0.054	0.054
A1	0.063	0.066	0.07
Downstream	0.039	0.032	0.036
A2	0.055	0.056	0.048

Upper Air Gap

Position(Degrees)	0	90	180
Upstream	0.78	0.866	0.804
A1	0.78	0.82	0.818
Downstream	0.78	0.89	0.846
A2	0.78	0.861	0.863

Lower Air Gap

Position(Degrees)	0	90	180
Upstream	0.791	0.818	0.823
A1	0.841	0.859	0.863
Downstream	0.877	0.869	0.877
A2	0.877	0.862	0.863

Lower Air Gap					
Position(Degrees)	**0**	**90**	**180**	**270**	**360**
Upstream	0.791	0.818	0.823		
A1	0.841	0.859	0.863		
Downstream	0.877	0.869	0.877		
A2	0.877	0.862	0.863		

Concentricity Results(9-8-19)					
Best Center Position	**y =US/DS, X=A1/A2**	**Upper Seal**	**Lower Seal**	**Upper Air Gap**	**Lower Air Gap**
Best Center @ 0 Degrees	x	-0.003	0.004	0.000	-0.018
	y	0.006	0.006	-0.012	-0.027
Best Center @ 90 Degrees	x	-0.005	0.005	-0.021	-0.002
	y	0.013	0.011	-0.012	-0.026
Best Center @ 180 Degrees	x	-0.005	0.011	-0.023	0.000
	y	-0.013	0.009	-0.021	-0.027
Best Center @ 270 Degrees	x	0.000	0.000	0.000	0.000
	y	0.000	0.000	0.000	0.000
Best Center @ 360 Degrees	x	0.000	0.000	0.000	0.000
	y	0.000	0.000	0.000	0.000
	x-average	-0.003	0.004	-0.009	-0.004
	y-average	0.001	0.005	-0.009	-0.016
	Concentricity	0.003	0.007	0.012	0.016
	CEATI	0.004	0.002	0.039	0.039

Figure 6-5: Initial Gap Measurements and Concentricity

Results of the move for concentricity:

- The move to improve the concentricity was successful, resulting in Air Gap and Radial Seal Clearance within CEATI Part 2 Erection Standard. The results of the move are highlighted in green in Figure 6-6.
- With the rotation checks and measurements completed, NLH continued assembly of the final parts of the Unit 7 machine in preparation for commissioning.

Concentricity Results(9-9-19) (Second Move)					
Best Center Position	**y =US/DS, X=A1/A2**	**Upper Seal**	**Lower Seal**	**Upper Air Gap**	**Lower Air Gap**
Best Center @ 0 Degrees	x	-0.010	-0.003	0.000	-0.018
	y	-0.002	-0.001	-0.012	-0.027
Best Center @ 90 Degrees	x	0.000	0.000	-0.021	-0.002
	y	0.000	0.000	-0.012	-0.026
Best Center @ 180 Degrees	x	0.000	0.000	-0.023	0.000
	y	0.000	0.000	-0.021	-0.027
Best Center @ 270 Degrees	x	0.000	0.000	0.000	0.000
	y	0.000	0.000	0.000	0.000
Best Center @ 360 Degrees	x	0.000	0.000	0.000	0.000
	y	0.000	0.000	0.000	0.000
	x-average	-0.002	-0.001	-0.009	-0.004
	y-average	0.000	0.000	-0.009	-0.016
	Concentricity	0.002	0.001	0.012	0.016
	CEATI	0.004	0.002	0.039	0.039

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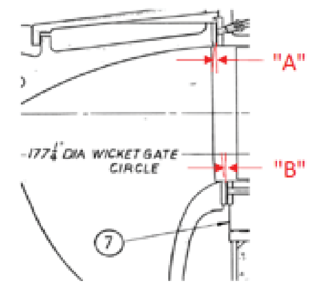

	Radial Design Clearance	Average RSC
"A"	0.040 to 0.047	0.044
"B"	0.045 to 0.052	0.049
	Nominal OEM Upper Seal Clearance =	0.044
	Nominal OEM Lower Seal Clearance =	0.049
	Upper Wear Ring Tolerance 10% of RSC, (Radial RSC CEATI Part 2)	0.004
	Lower Wear Ring Tolerance 5% of RSC, (Radial RSC CEATI Part 2)	0.002
	Average Air Gap from data above =	0.838
	5 percent average AIR Gap or 1 mm max =	0.042
	1 mm max =	0.039

X - MOVE =	0			
Y - MOVE =	0			
x-average	0.0020	-0.0006	-0.0086	-0.0039
y-average	-0.0004	-0.0002	-0.0090	-0.0159
Concentricity	0.0020	0.0006	0.0124	0.0164
CEATI	0.0044	0.0024	0.0394	0.0394

Figure 6-6: Final Results of Unit 7 Concentricity

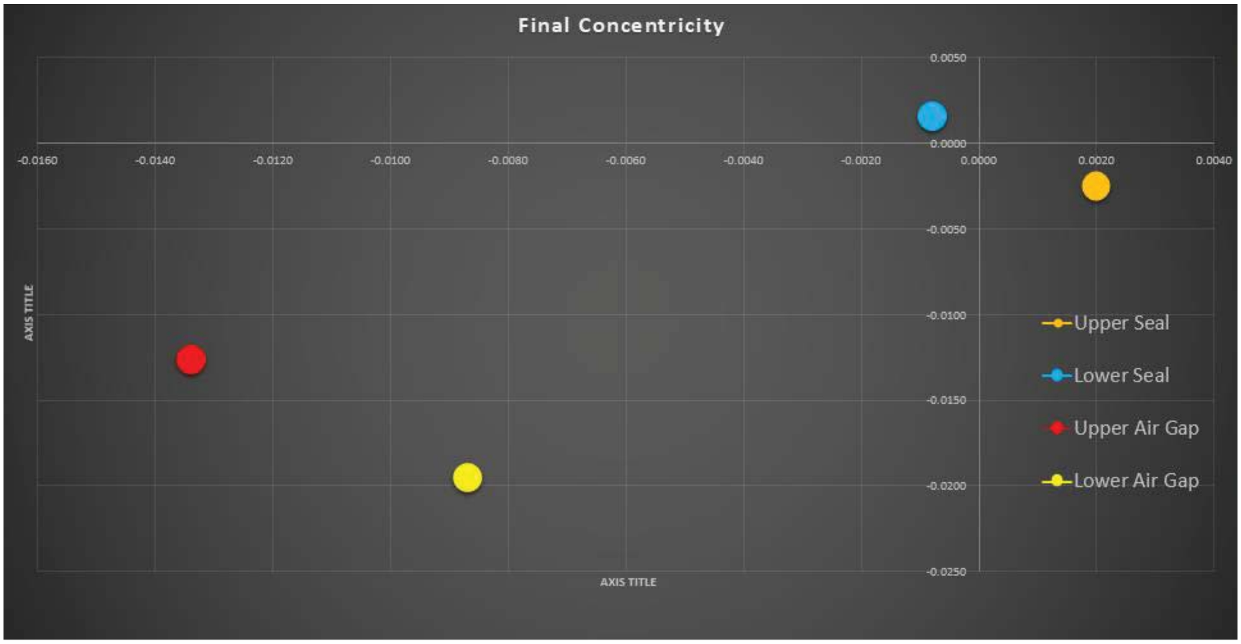

Figure 6-7: Final Concentricity Graph

7 Unit 7 Commissioning

7.1 Unit 7 Mechanical Commissioning

Voith and NLH conducted planning meetings in advance of commissioning to review Voith's plan and documentation. Some of the topics discussed were the first initial rotation, bearing runs, generator balancing, load tests, and over-speed procedures. The Voith Commissioning team provided details as to the events that were going to take place and what to expect during commissioning of the Unit 7 machine. Voith also provided a list of tools and equipment they shipped to site earlier in preparation for the commissioning activities. NLH approved all of Voith's documents and procedures for commissioning prior to the Voith Commissioning Team traveling to site. Below is a summary of the events that took place during the commissioning and acceptance of the Unit 7 machine. Voith created a separate, detailed commissioning report and released it to NLH; this document is included in the Appendix of this report.

Summary of commissioning:

- **2019-09-18:**
  - Voith Commissioning team traveled to site and met with NLH officials.
- **2019-09-19:**
  - NLH provided site introduction and safety training to Voith commissioning staff.
  - Voith installed all of the commissioning equipment and sensors to conduct the start-up and commissioning of the machine.
- **2019-09-20**
  - Penstock was watered up by NLH and unit was deemed ready for first rotation.
  - The first rotation and bearing run was conducted, after which the unit was brought up to 17 MW of power. No bearing temperature or vibration issues were observed at this point.
  - At the end of the day the unit was placed into Synchronous Condense mode were it remained over night until the next morning when the commissioning team arrive at site.
- **2019-09-21**
  - The unit remained in Synchronous Condense mode overnight until this morning of the 21st. There were no trips or alarms overnight. During the dayshift Voith performed intermittent tests and operated the machine up to full load, 150 MW, monitoring its performance along the way. Additionally Voith Hydro gradually increased the machine's power output from no load up to max output, which was 150 MW. Voith conducted this activity three times with full start and stop sequences at each occurrence. Once these test were completed, Voith performed a 25 MW load rejection. No bearing, oil, or air temperature issues during any of these tests.
  - No bearing or vibration issues was observed during normal operation or Synchronous Condenser mode. Adjustments for balance were not required.
  - The machine was deemed commissioned at the end of the day on 2019-09-21 and Voith and NLH were satisfied with the mechanical and electrical operation of the machine.

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Reference the Appendix for a complete report of the mechanical and electrical commissioning. Figures 7-1 and 7-2 are screenshots of the sensor panel during the 2019 commissioning at 75 and 150 MW. The sensor panel reveals the typical output at half (75MW) and full (150 MW) power.

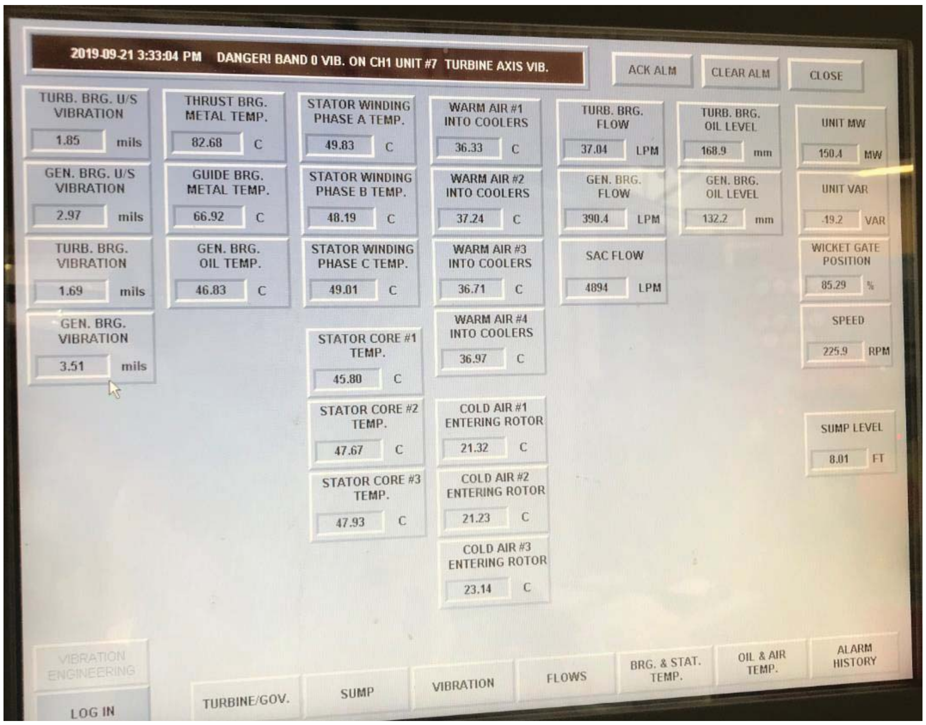

Figure 7-1: Commissioning, Typical Sensor Output, 150 MW

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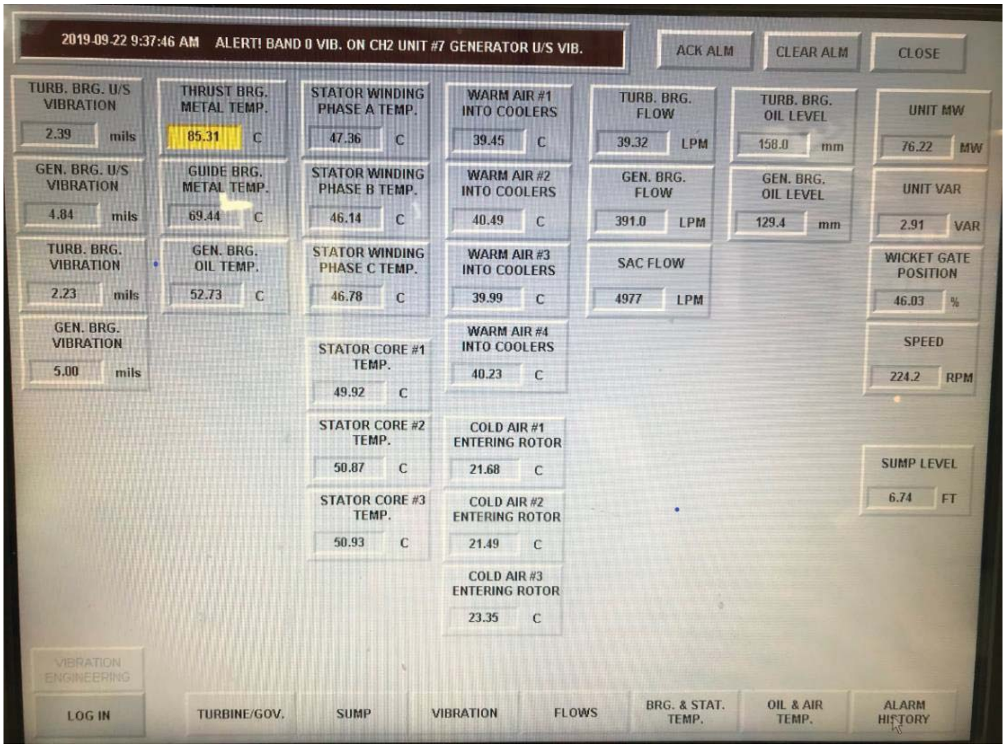

Figure 7-2: Commissioning, Typical Sensor Output, 75 MW

8 Conclusion

8.1 Long Term Recommendations

All of the recommendations in this section are based upon the information and data collected during the 2019 maintenance outage. Voith used this information to develop recommendations and establish the remaining life on the Unit 7 machine. The remaining useful life of the machine as of the 2019 commissioning is conservatively five years. While not all of the components would require attention in the five-year timeline, some of the major rotating and stationary components will require significant rehabilitation or complete replacement by 2025.

NLH should begin planning for a major (6-12 month duration) service outage to replace the major mechanical and electrical components listed below. The total length of the next outage can be adjusted by how many components NLH decides to replace (new) and how many are rehabilitated. New components can be manufactured while the existing unit is still operational, providing power to the grid and limiting the amount of time the unit is out of service. However, rehabilitated components require the unit to be placed out of service, disassembled, and those parts shipped to a supplier to be rehabilitated. This effort is time consuming and many delays can develop due to the unknown condition of the components prior to arrival to the supplier.

The unknown mechanical and material conditions typically are not found until all of the paint is removed and a trained inspector has time to perform detailed examination and develop a report. The logistics and shipping to and from the Bay d' Espoir Powerhouse in Newfoundland also has many challenges that NLH should take into account during the planning stages. To aid in the planning, Voith has developed a part-by-part list of the major components that will require attention in the next five years, including a brief explanation with a list of advantages, disadvantages, and different replacement options. The options will highlight schedule impacts and ultimately provide a budgetary estimate for planning purposes only.

IMPORTANT:

The rate of change described above in the Wearing Ring Machining Section 5.25.6 was a more linear approach to provide an estimate for planning purposes for NLH. There is no exact science or calculation to determine an absolute timeline for the change in Radial Seal Clearance. NLH should begin planning immediately for the next major outage and constantly monitor the Radial Seal Clearance to ensure the growth rate has increased and that the Runner is within a safe operator range.

8.1.1 Wicket Gates

Due to the assessment and condition outlined in Section 5.4, NLH should plan to employ one of the following recommendation(s) during the next major outage for the Wicket Gates of the Unit 7 machine.

Option 1: Rehabilitation of the existing 20 Wicket Gates

- **Rehabilitation Expected:**
  - Non-destructive examination
  - Unknown repairs
  - Gate stem machining
  - Gate-end machining/possible overlay
  - Gate seal overlay and machining
  - Possible replacement of individual gates
- **Advantages:**
  - Possibly less expensive than installing new gates, but this is not guaranteed.
- **Disadvantages:**
  - Major schedule impacts and time consuming work.
  - Expensive shipping to and from site.
  - OEM hydraulic profile will remain; lost opportunity to improve efficiency.

Option 2: Purchase 20 New Cast Wicket Gates

- **Purchase 20 new Wicket Gates prior to service outage**
- **Advantages:**
  - Control schedule.
  - Improve hydraulic profile and efficiency to match new runner design.
  - Less shipping.
  - Possibly improve material properties.
- **Disadvantages:**
  - Likely more expensive than rehab Wicket Gates, but less outage time would be required.

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8.1.2 Draft Tube and Discharge Ring

Due to the assessment and condition outlined in Section 5.26, NLH should plan to employ the following recommendation(s) during the next major outage for the Discharge Ring and Draft Tube of the Unit 7 machine.

Recommendation: Rehabilitate Draft Tube

- **Rehabilitation Expected:**
  - Abrasive blast.
  - Non-destructive examination.
  - Unknown repairs.
  - Inspect for voids.
  - Paint.
- **Advantages:**
  - Rehabilitate and prepare existing Draft Tube for the service life of a new machine.
  - Work tasks can be performed during other outage activities, not on critical path.

Recommendation: Rehabilitate Discharge Ring

- **Rehabilitation Expected:**
  - Abrasive blast.
  - Non-destructive examination.
  - Unknown repairs.
  - Inspect for voids.
  - Paint.
- **Advantages:**
  - Rehabilitate and prepare existing Discharge Ring for the service life of a new machine.
  - Work tasks can be performed during other outage activities, not on critical path.

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8.1.3 Turbine Runner

Due the cavitation and structural damage found in the 2019 maintenance outage, NLH should plan to replace their Turbine Runner in the next five years. A new Runner design will provide NLH the opportunity to improve the hydraulic design through model testing, ultimately increasing efficiency of the machine. An increase in efficiency at the designed operating limit and a flatter efficiency curve across flow range is also typical when modernizing the Turbine Runner. The new design and hydraulic profile would greatly reduce or eliminate the cavitation NLH currently experiences with the Unit 7 machine depending upon the range in which NLH operates. The new stainless steel Runner would have a service life similar to the original machine of 40-50 years, possibly longer.

Recommendation: New Stainless Steel Turbine Runner

- **Advantages:**
  - A new hydraulic profile would improve efficiency.
  - A possibility to install an aerating runner opportunity which controls oxygen levels downstream.
  - A possibility to install a fish-friendly designed Turbine.
  - Opportunity to increase power.

8.1.4 Turbine Shaft

Due to the assessment and condition outlined in Section 5.10, NLH should plan to employ the following recommendation(s) during the next major outage for the Turbine Shaft of the Unit 7 machine.

Recommendation: Rehabilitate Turbine Shaft

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Dimensional inspection.
  - Spigot and coupling hole machining to adapt to the new turbine runner (required).
  - Paint.
- **Advantages:**
  - Rehab and reuse existing component is a cost savings versus installing a new shaft.
- **Disadvantages:**
  - Possible schedule impacts. The shaft would be on or near the critical path.

8.1.5 Generator Shaft

Due to the assessment and condition outlined in Section 5.11, NLH should plan to employ the following recommendation(s) during the next major outage for the Generator Shaft of the Unit 7 machine.

Recommendation: Rehabilitate Generator Shaft

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Dimensional inspection.
  - Possibly spigot and coupling hole machining.
  - Paint.
- **Advantages:**
  - Rehab and reuse existing component is cost savings versus installing a new shaft.
- **Disadvantages:**
  - **IMPORTANT:** Shaft will possibly need to be shipped to a Runner supplier during outage.
  - Possible schedule impacts.

8.1.6 Head Cover

Due to the assessment and condition outlined in Section 5.21, NLH should plan to employ the following recommendation(s) during the next major outage for the Head Cover of the Unit 7 machine:

Recommendation: The existing Head Cover is a viable option for rehabilitation in five years, but significant time and rehab work should be expected. Another option to save time and possibly improve the design would be to have a new Head Cover manufactured and delivered to site prior the next outage.

Option 1: Rehab Existing Unit 7 Head Cover

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Complete dimensional inspection.
  - Possible stainless steel overlay.
  - Complete machining of all surfaces and gate stem bores.
  - New paint.
- **Advantages:**
  - Reuse of existing components and supplementary parts.

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- **Disadvantages:**
  - Transportation and logistical challenges/costs.
  - Possible unknown schedule impacts when rehabbing existing components. Rehabilitation of the Head Cover will be on or near the critical path.

Option 2: New Manufactured Head Cover

- **Rehabilitation Expected:**
  - New component
- **Advantages:**
  - Improved design.
  - Select new material with improved mechanical properties.
  - Predictable schedule.
  - Shorten outage time significantly.
  - Logistics and transportation are only one way.
  - New wearing ring design.
- **Disadvantages:**
  - Possibly more expensive, but the logistics and unknown condition of the rehab option might possibly offset the additional cost.

8.1.7 Bottom Ring

Due to the assessment and condition outlined in Section 5.22, NLH should plan to employ the following recommendation(s) during the next major outage for the Bottom Ring of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to completely replace the existing Unit 7 Bottom Ring with a newly manufactured component. Rehabilitation of the existing Bottom Ring would be expensive and labor intensive. The existing Bottom Ring may not be able to be rehabilitated.

- **Rehabilitation Expected:**
  - New component required.
- **Advantages:**
  - Improve design.
  - Select new material with improved mechanical properties.
  - New wearing ring design.
- **Disadvantages:**
  - ***Important to note the Critical path nature of Bottom Ring.*** The Bottom Ring is the last part to be disassembled and the first part to be installed in the unit; therefore, planning and procurement of a new Bottom Ring should start immediately.

8.1.8 Operating Ring

Due to the assessment and condition outlined in Section 5.12, NLH should plan to employ the following recommendation(s) during the next major outage for the Operating Ring of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehabilitate the existing Operating Ring of the Unit 7 machine; however, a newly-manufactured ring may be advantageous to the overall budget and schedule challenges of the project.

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Dimensional inspection.
  - Extensive machining to repair damaged and deformed existing bearing surfaces.
  - Possible stainless sleeve option for new bearing surface.
  - Paint.
- **Advantages:**
  - Rehab and reuse of an existing component.
- **Disadvantages:**
  - Possible unknown schedule impacts when rehabbing existing components due to unexpected as-found conditions.

8.1.9 Gate Arms and Linkages

Due to the assessment and condition outlined in Section 5.14, NLH should plan to employ the following recommendation(s) during the next major outage for the Gate Arms and Linkages of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehab the existing Gate Arms and Linkages.

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Possible machining.
  - Paint.

Note: If all new distributor components are chosen, as outlined in 8.1.6 to 8.1.9, a Distributor shop assembly can be performed to verify fit and function of the new components, which will greatly reduce the risk of surprises during site assembly.

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8.1.10 Servomotor

Due to the assessment and condition outlined in Section 5.13, NLH should plan to employ the following recommendation(s) during the next major outage for the Servomotors of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehabilitate all of the existing Servomotors of the Unit 7 machine.

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Dimensional inspection.
  - Bore machining likely
  - New seals.
  - Paint.

8.1.11 Rotor

Due to the assessment and condition outlined in Section 5.15, NLH should plan to employ the following recommendation(s) during the next major outage for the Rotor of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehab and/or replace the existing Rotor and supplementary components of the Unit 7 machine.

- **Rehabilitation Expected:**
  - **Poles**
    - 32 Pole rehabilitation should be a viable option for the next major outage, but new Poles design should be explored and evaluated by NLH
      1. **Advantages**
         - Reuse and recycle existing components.
         - Less expensive than new Poles, but requires valuable outage time.
      2. **Disadvantages**
         - Schedule can be impacted by rehabilitation of the Poles. New poles could be purchased to control schedule and reduce outage time.
         - Possible unknown schedule impacts can happen when rehabbing existing components.
  - **Hub/Spider**
    - **Rehabilitate Hub/Spider**
      1. Remove paint from high stress areas.
      2. Non-destructive examination.
      3. Unknown repairs.

4. Dimensional inspection.
5. Option: remove all paint and recoat the hub and spider (recommended).

- **Rim**
  - The Rim could possibly be rehabilitated and reused but only after further investigation due to the condition of the Rim Laminations during the 2019 maintenance outage. Note that it is very uncommon not to reuse the existing Rim, but some rehabilitation is would be expected.
    1. Cleaning, possible walnut shell blasting.
    2. Recoating.
    3. Possible unknown schedule impacts could happen when rehabbing existing components.

8.1.12 Stator

Due to the assessment and condition outlined in Section 5.16, NLH should plan to employ the following recommendation(s) during the next major outage for the Stator of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehab and/or replace the existing Stator and supplementary components of the Unit 7 machine.

- **Rehabilitation Expected:**
  - **Stator Frame**
    - Rehab of the Stator Frame is recommended.
    - Remove paint from high stress areas.
    - Non-destructive examination.
    - New Coolers and piping systems.
    - Perform dimensional inspection.
    - Concrete and Soleplate inspection.
    - Paint entire Frame.
      1. **Advantages**
         - Reuse and recycle existing components.
      2. **Disadvantages**
         - Time-consuming rehabilitation.
  - **Stator Core**
    - Two options:
      1. Rehabilitation:
         - Thoroughly inspect core prior to outage to detect mechanical and electrical defects. Rule out the requirement of a new Core.
         - During outage walnut shell blast and clean Stator Core.
         - Repair bent and damage Laminations.
         - Electrical Tests (ELCID).
         - Verify adequate clamping pressure of Core.
         - Moving Stator to improve circularity.

- Prepare for new windings.
- Paint.
  - Advantages:
    - Reuse existing components.
    - Possibly less time required compared to a new Core.
    - Potential cost savings compared to a new Core.
  - Disadvantages:
    - A reused Core may not be on the same life expectancy track as other major components; therefore attention may be required prior to a major outage.

2. New Stator Core
   - New design, and improved materials and heat transfer.
   - Extend life expectancy to be more parallel with other major components.

- **Stator Windings**
  - New Windings are required.

8.1.12.1 Overall Generator Recommendation Summary

Due to the important function Unit 7 serves the island of Newfoundland as a generating source and as a Synchronous Condenser, it is recommended that studies are conducted to evaluate the current machine operation (electrically) versus a new design. Therefore, prior to the next major outage, NLH should investigate significantly upgrading the Unit 7 Generator, which includes both the Stator and Rotor components. These upgrades would include overall power increases up ten to twenty percent of existing and improving the efficiency while decreasing losses. Improvements could also be designed and implemented to expand the capacity and efficiency of the heat transfer and cooling system. A new design would also take into account new maintenance improvements, reducing the costs of operation over time. NLH should investigate and determine the financial gains, mechanical/electrical advantages, and disadvantages of possibly replacing their entire Unit 7 Generator with a new state-of-the-art machine.

8.1.13 Stay Ring and Vanes

Due to the assessment and condition outlined in Section 5.17, NLH should plan to employ the following recommendation(s) during the next major outage for the Stay Ring and Vanes of the Unit 7 machine.

Recommendation: Rehabilitate Stay Ring and Vane

- **Rehabilitation Expected:**
  - Blast paint.
  - Non-destructive examination.
  - Unknown repairs.

- Possible (likely) machining of the stay ring flange required.
- Paint.

8.1.14 Scroll Case

Due to the assessment and condition outlined in Section 5.18, NLH should plan to employ the following recommendation(s) during the next major outage for the Scroll Case of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehabilitate the scroll case to extend the life possibly another 40-50 years of service and to minimize unplanned outages.

- **Rehabilitation Expected:**
  - Blast.
  - Non-destructive examination.
  - Unknown repairs.
  - Paint.

8.1.15 Turbine Guide Bearing

Due to the assessment and condition outlined in Section 5.19, NLH should plan to employ the following recommendation(s) during the next major outage for the Turbine Guide Bearing of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to rehab the Turbine Guide Bearing, including any spares.

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Paint.

8.1.16 Main Bracket and Thrust Bearing

Due to the assessment and condition outlined in Section 5.20, NLH should plan to employ the following recommendation(s) during the next major outage for the Main Bracket and Thrust Bearing of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to replace all of the Thrust Pads/Springs and thoroughly inspect the Main Bracket. Also, all of the coolers, monitoring systems and subsystems of the Main Bracket and Bearing assembly should be inspected.

- **Rehabilitation Expected:**
  - Replace existing Thrust Pads with new ones.
  - Main Bracket:
    - Blast.
    - Non-destructive examination.
    - Unknown repairs.
    - Inspect and replaces subsystems as necessary.
    - Paint.

8.1.17 Thrust Collar and Runner

Due to the assessment and condition outlined in Section 5.20, NLH should plan to employ the following recommendation(s) during the next major outage for the Thrust Collar and Runner of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to possibly rehab the Thrust Collar and Thrust Runner.

- **Rehabilitation Expected:**
  - Rehab Thrust Collar
  - Rehab Thrust Runner
    - Machining of both the running and Collar mating surfaces expected.
  - Inspect Generator Guide Pads' Babbitt condition. Rehab or replace as necessary.

8.1.18 Penstock

Due to the assessment and condition outlined in Section 5.18, NLH should plan to employ the following recommendation(s) during the next major outage for the Penstock of the Unit 7 machine.

Recommendation: During the next major outage, NLH should plan to thoroughly inspect, repair (if necessary), and paint the Penstock.

- **Rehabilitation Expected:**
  - Non-destructive examination.
  - Unknown repairs.
  - Paint.
  - Possible major schedule impacts.

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8.1.19 Miscellaneous Items

8.1.19.1 Pressure Relief Valve (PRV)

There was no Voith Hydro scope planned for the PRV for the 2019 Maintenance Outage.

Recommendation: During the next major outage, NLH should plan to thoroughly inspect, repair (if necessary), and paint the Pressure Relief Valve.

- **Rehabilitation Expected:**
    - Immediately ship the PRV to qualified rehabilitation supplier.
    - Non-destructive examination.
    - Unknown repairs.
    - New seals
    - Paint

Figure 8-1: Pressure Relief Valve and Operating Servomotor

8.1.19.2 PRV Dashpot and Operating Servomotor

There was no Voith Hydro scope planned for the Dashpot and Operating Servomotor (see Figure 8-1) for the 2019 Maintenance outage.

Recommendation: During the next major outage, NLH should plan to thoroughly inspect, repair (if necessary), and paint the Dashpot and Operating Servomotor.

- **Rehabilitation Expected:**
  - Immediately ship the components to qualified rehabilitation supplier.
  - Non-destructive examination.
  - Unknown repairs.
  - New seals.
  - Possible machining.
  - Paint.

Figure 8-2: Pressure Relief Valve Dashpot

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8.1.19.3 Hardware

Recommendation: During the next major outage, NLH should plan to thoroughly inspect and replace hardware. For planning purposes, NLH can use the following recommendation as a guide:

- Replace all fasteners size M20 (~0.7500 inch) or smaller on all turbine and generator components as necessary to facilitate the rehabilitation, excluding pumps, valves, and instrumentation.
- To possibly reuse specialty hardware, such as, Head Cover hardware, custom studs and bolts, NLH could inspect using Magnetic Particle Test.
    - Inspect 20% of the Head Cover hardware using MT.
    - Inspect 20% of the Head Cover to Stay Ring flange hardware using MT.
    - For remaining fasteners larger than M20, inspect 10% of the fasteners within each joint using MT.
- Shaft Coupling Studs should likely be able to be reused after a thorough NDE inspection, however this would depend on the following:
    - Runner to Turbine Shaft Coupling Hardware.
        - New Runner coupling holes would need reamed to the same size as the shaft. Typically, the Turbine Shaft and Runner are reamed together or by template. This new increased size would require new coupling hardware at the Runner end.
    - Turbine Shaft to Generator Shaft Coupling Hardware.
        - If the NDE inspection reveals the bolts are free and clear of indications and both shafts mating flanges and coupling holes do NOT require rehabilitation, then the bolts could possibly be reused.
    - Generator Shaft to Rotor Coupling Hardware.
        - If the NDE inspection reveals the bolts are free and clear of indications and both shafts' mating flanges and coupling holes do NOT require rehabilitation, then the bolts could possibly be reused.
        - For all other hardware larger than M20, replace as directed by the engineering department of the contractor.

Figure 8-3: Shaft Coupling Bolts

9 References

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Appendix A Pre-disassembly Readings and Measurements

Appendix B Laser Inspection Documents and Data

Appendix C Wicket Gate Data and Documents

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Appendix A - Pre-disassembly Readings and Measurements

Appendix B - Laser Inspection Documents and Data

<table>
<tr><td colspan="3">Bay d'Espoir – Newfoundland and Labrador Hydro</td></tr>
<tr><td rowspan="3">Unit 7 Refurbishment Report
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<tr><td>PDM Doc ID:</td><td>Doc. Revision:</td></tr>
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Appendix C - Wicket Gate Data and Documents

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Appendix D - Equipment Used

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Appendix E - Non Destructive Examination

Appendix F - Lead Abatement

Appendix G - Draft Tube Grouting

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Appendix H - Turbine Runner

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Appendix I - Turbine Shaft

Appendix J - Generator Shaft

Bay d'Espoir – Newfoundland and Labrador Hydro		
Unit 7 Refurbishment Report	TFS7000	
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Appendix K - Operating Ring

Appendix L - Rotor

Appendix M - Stator

Bay d'Espoir – Newfoundland and Labrador Hydro		
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Appendix N - Stay Ring and Vanes

Bay d'Espoir – Newfoundland and Labrador Hydro		
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Appendix O - Spiral Case

Bay d'Espoir – Newfoundland and Labrador Hydro		
Unit 7 Refurbishment Report Project Report	TFS7000	
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Appendix P - Turbine Guide Bearing

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Appendix Q - Thrust Bearing

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Appendix R – Head Cover

Bay d'Espoir – Newfoundland and Labrador Hydro		
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Appendix S - Bottom Ring

Bay d'Espoir – Newfoundland and Labrador Hydro		
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Appendix T - OEM Documents, Drawings, Miscellaneous Documents

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Bay d'Espoir – Newfoundland and Labrador Hydro		
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Appendix U - Commissioning

Affidavit

IN THE MATTER OF the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures, pursuant to Subsection 41(3) of the *Act,* for the life extension of Unit 7 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir").

AFFIDAVIT

I, Robert Collett, of St. John's in the province of Newfoundland and Labrador, make oath and say as follows:

1) I am Vice President, Engineering and Newfoundland and Labrador System Operator for Newfoundland and Labrador Hydro, the applicant named in the attached application.
2) I have read and understand the foregoing application.
3) To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this application are true.

SWORN at St. John's in the province of Newfoundland and Labrador this 20th day of June 2025, before me:

Kimberley Duggan
Commissioner for Oaths, Newfoundland and Labrador

R Collett
Robert Collett

KIMBERLEY DUGGAN
A Commissioner for Oaths in and for
the Province of Newfoundland and Labrador
My commission expires on December 31, 2027.