Q. **Reference: Volume II, Overhaul Turbine Valves – Unit 1 (2027) – Holyrood**

The estimated cost is $7,973,100. The Unit 1 overhaul was last performed in 2024, the 2022 Hatch assessment found the valves in good condition, and Hydro relies on an established three-year cycle for these safety-critical valves.

a) Please file the 2024 as-found report.

b) For each of the 17 major valves, please provide the 2024 as-found measurements, applicable original-equipment-manufacturer limits, and work performed.

c) For valves within those limits, please compare the engineering risk and cost of the fixed three-year cycle with a condition-based extension. Identify the minimum work required for safe operation through March 31, 2030.

A. **a)** The 2024 as-found report contains detailed inspection information developed by Newfoundland and Labrador Hydro's ("Hydro") contractor and is commercially sensitive and proprietary. In order to provide information that is responsive to the request, Hydro has summarized the information contained in the executive summary of that report, and included that summary as CA-NLH-062, Attachment 1. However, as Hydro notes in section 4.1.2 of its project proposal,[1] the condition of the turbine valves cannot be adequately determined through external inspection or monitoring instrumentation; as such, disassembly of the turbine valves would be required to determine overhaul timing based on condition. This could lead to unnecessary disassembly of the turbine valves and increased unit downtime. As such, condition-based refurbishment of the turbine valves is not a viable alternative.

Hydro recognizes that the cost of maintaining a three-year turbine valve overhaul cycle is very significant. However, the risk of not completing the work is also very significant. If the turbine valves are not overhauled per this schedule, they are at an elevated risk of not functioning as designed. From a safety perspective, the stop valves, blowdown valves, and non-return valves must function properly during an operational upset condition to prevent overspeed of the turbine and generator rotor. Overspeed can happen very

[1] "2027 Capital Budget Application", Newfoundland and Labrador Hydro, July 14, 2026, Vol. II, Project 3, Sec. 4.1.2.

quickly, and these valves must slam shut (or open, in the case of the blowdown valve) to avoid unsafe operating conditions. An overspeed failure has the potential to be catastrophic and can severely impact safe and reliable operations.

For these assets, a condition-based extension is not feasible as noted in Hydro's proposal for the project. The condition of the internal valve components cannot be determined through an external assessment or online instrumentation monitoring. It is necessary to disassemble the valves to identify conditions such as cracked seats, bent stems, excessive oxide scale buildup, steam erosion, and excessive clearances. All of these conditions, if not addressed during a planned overhaul, could lead to an in-service failure of a valve, which would result in an extended forced outage to correct, could liberate parts into the turbine that would cause further damage, and could lead to an overspeed event.

Operational experience confirms that the three-year overhaul cycle is appropriate. During each overhaul, issues with internal valve components are discovered and addressed, and this practice has resulted in reliable operation. Hatch Ltd., in their 2024 refresh of the Holyrood Thermal Generating Station ("Holyrood TGS") capital plan, recommended continuing with the three-year cycle which corresponds to completing a valve overhaul in 2027.[2]

As identified through the *Reliability and Resource Adequacy Study Review* proceeding (*"RRA Study Review"*),[3] the Holyrood TGS shall remain available for a "Bridging Period"[4] until 2030. Based on original equipment manufacturer ("OEM") recommendations, third-party assessments, and Hydro's operational experience, Hydro considers completion of the 2027 turbine valve overhaul to be the minimum planned capital work required to support the continued safe and reliable operation of Unit 1 through the Bridging Period.

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[2] "*Reliability and Resource Adequacy Study Review* – Holyrood Thermal Generating Station Capital Plan Refresh," Newfoundland and Labrador Hydro, March 7, 2025, att. 1.

[3] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).

[4] Hydro considers the Bridging Period to be from the present to 2030 or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link is proven, and generation reserves are met. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS, Stephenville Gas Turbine and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

Report Title: Holyrood Major Outage - Unit #1 Turbine Major and Generator Minor Outage and LSB Replacement

Report Prepared by: GE Vernova

Report Issued: 15 July, 2025

Executive Summary

- GE and APM mobilized to the Holyrood Thermal Generating Station on May 6, 2024 to perform a limited scope major inspection of the Unit 1 turbine, which included overhaul of the Unit 1 generator and 17 major turbine valves.
- Significant damage was observed throughout the steam path upon removal of the high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP) inner casings, which resulted in a scope increase to a full steam path inspection.
- Stage 2, 9, and 11 diaphragms were observed to have significant damage and were sent to the Atlanta Service Center to perform major repairs. Minor repairs were executed on-site on the remaining diaphragms by GE.
- The HP/IP and LP rotors were shipped to the Atlanta Service Center to perform scheduled L-0 and L-1 last stage blades ("LSB") replacements on the LP rotor. The rotors were separated in Atlanta, and the HP/IP rotor was sent to the Schenectady Service Center for unscheduled weld repairs on T1 and T2 journals from as-found damage.
- HP/IP journals restorations resulted in returning T1 and T2 bearings back to their original nominal dimensions and design, with the T2 bearing returned to an elliptical design and removed the modified liner. T3, T4, and T5 bearings were shipped to American Power Services for babbit restoration and sizing.
- Oil deflectors #1-#5 were visually and diametrically inspected, which found the oil deflectors to be out of GE specifications. New oil deflectors were fabricated to rotor dimensions. Journal restoration to T2 caused resizing of the #2 and #3 oil deflectors.
- Main control valves ("CV") were visually, diametrically, and non-destructive examination ("NDE") tested during disassembly and inspections, with multiple indications and issues observed with CV 1-6. The bodies of CV 1-6 were shipped to Atlanta Service Center for inspections and bushing replacements. NDE inspections on the seat of CV 2 showed numerous indications, requiring replacement and repairs to the seat on-site by GE. During the replacement, erosion was discovered, resulting in oversizing of the valve seat and seat bore.
- The main stop valve was visually, dimensionally, and NDE tested during disassembly and inspections. The pressure seal head body was shipped to the Atlanta Service center to undergo bushing replacement. Indications discovered by NDE testing on the valve seat

required replacement of the seat. During replacement of the valve seat, erosion was discovered in the bore of the steam chest, resulting in oversizing of the valve seat.

- Combined reheat and intercept valves were visually, diametrically, and NDE tested during disassembly and inspections, which showed intercept bypass lift out of GE specifications on both left and right assemblies. The assemblies were restored to their designed specification, with significant lapping required to achieve the required contact on both the left and right reheat valve seats.
- Emergency blow down valve was visually, diametrically, and NDE tested during disassembly, with no issues or indications observed.
- Steam seal packing was observed to be in overall fair condition, with some rubbing observed on multiple rows throughout the steam path.
- Visual inspections were performed on the inner and outer turbine casings, with no significant issues observed on the HP/IP inner casings, HP outer casing, or LP exhaust hood. Erosion was observed on the LP inner casing horizontal joint; however, there was no immediate cause for concern and repairs were declined.
- The generator field rotor and associated components was removed and visually, diametrically, and electrically tested as part of original base scope. Visual inspections found heavy greasing around the end windings, and a GE generator specialist performed repairs on-site. Significant lead contamination was found in the generator, and appropriate lead containment and control processes were established.
- Tops on, tops off steam path alignment was recommended by GE engineering due to a major water hammer event in 2021. Advanced Measurement Group came to site to assist with steam path alignment.
- Coupling alignment of turbine to generator was required after performing the steam path alignment; the generator was aligned within GE specifications.
- Unit commissioning started January 6, 2025, and was released to Operations on March 18, 2025.
- It was determined that steam was passing through the main stop valve ("MSV"), allowing the unit to run up with the MSV closed. The MSV was disassembled and it was discovered the main disc guide pin had been manufactured in the wrong location. This was corrected by Horizon Machining, and the MSV was reassembled utilizing plant labor and verified not to leak.
- A Mark VIe controls upgrade was performed this outage.
- The control valves were determined to be sticking under load at 56%. It was discovered the #4 knock down pin on the cam lobe was contacting the lever during operation. It was also discovered the upper rack guide was not in the correct position, further attributing

to binding. These issues were corrected and verified for operation, with plant labor utilized to perform these inspections.

- On April 17, 2025, sticking issues were reported at 59% load, and an investigation was opened.