Nova Scotia Energy Board Staff Interrogatory IR-1

Interrogatory:

Question(s):

Please compare the technical specifications of the existing transformer and the proposed new transformer.

Response:

The company that was conditionally awarded the contract for the new transformer is [redacted] Because it is a conditional award, we cannot share at this point their information to the public, to not alter the normal course of the RFP process. The RFP will be considered closed once the funds are secured, and the PO is issued with the contract information.

From a technical comparison standpoint, the principal improvements are the increased transformer rating from 600 kVA to 1000 kVA, the retention of the required 2.3 kV Delta / 12.47 kV grounded Wye step-up configuration, the continuation of ONAN pad-mounted outdoor service, and the inclusion of modern monitoring contacts and accessories for integration by BEC.

However, the proposal still requires clarification or final submittal confirmation on several technical items before the transformer can be considered fully closed for design and installation purposes. These include the guaranteed impedance percentage, guaranteed no-load and load losses, no-load/load currents, oil volume, total mass, center of gravity, terminal heights, bushing/termination details, fuse ratings and time-current curves, surge arrester/accessory scope, SCADA signal list, communication protocol availability, and final interface documentation required for BEC installation.

Capacity:
Existing: 600 kVA. Proposed: 1000 kVA. Evaluation Note: Clear capacity upgrades to support the higher-rated generating unit and provide operating margin.

Voltage / Connection:
Existing: 2.3 kV Delta on generator side / 12.47 kV Wye on grid side. Proposed: 2300 V Delta LV / 12470GRDY/7200 V Wye HV. Evaluation Note: Technically aligned with the required step-up configuration.

Vector Group:
Existing: Yd11. Proposed: Yd11. Evaluation Note: Compatible; no functional change in phase relationship expected.

Cooling / Temperature Rise:
Existing: ONAN, 65 °C rise. Proposed: ONAN, 65 °C rise. Evaluation Note: Equivalent cooling philosophy; acceptable for outdoor padmount service.

BIL:
Existing: LV 60 kV / HV 95 kV. Proposed: LV 60 kV / HV 95 kV. Evaluation Note: Insulation level remains aligned with the existing system and RFP expectations.

Impedance:
Existing: 4.3% at 85 °C. Proposed: stated as per CSA C227.4-21, with no final numeric % confirmed in the offer. Evaluation Note: Final guaranteed impedance must be confirmed for short-circuit studies and protection coordination.

Insulating Fluid:
Existing: mineral oil, 1,075 L, NON-PCB. Proposed: mineral oil Class B Type II; oil volume and total mass not stated. Evaluation Note: Oil volume and mass must be confirmed to verify sump/oil-trap containment, environmental compliance, handling and pad loading.

Winding Material:
Existing: not stated. Proposed: HV aluminum / LV aluminum. Evaluation Note: Acceptable if guaranteed losses, efficiency, thermal performance and impedance are confirmed by design submittals and FAT.

Primary Fusing / Protection:
Existing: CL fuse, bayonet fuse and CT 50/5 A. Proposed: STD CSA bayonets with CLF and one neutral CT. Evaluation Note: Conceptually aligned; fuse ratings, TCC curves and upstream coordination must be confirmed.

Surge Arresters / Overvoltage Protection:
Existing: surge protection devices are described at the transition pole. Proposed: provision for lightning arresters is not included; inserts, elbows and elbow lightning arresters are excluded. Evaluation Note: Scope must be clarified, so MOV arresters and required dead-front accessories are procured and installed by BEC or included as a defined adder.

SCADA / Relays:
Existing/RFP Requirement: Transformer monitoring and SCADA integration required. Proposed: instrument contacts terminated to a control box; relays not included. Evaluation Note: Acceptable only if BEC integrates the signals; vendor must provide point list, wiring diagrams and communication/interface data.

Nova Scotia Energy Board Staff Interrogatory IR-2

Interrogatory:

Question(s):

Please provide monthly generation records for the existing hydro plant for the last five years while in operation together with available records of water spillage, operating output, system availability, and outages (with the outage causes).

(a) Please provide the annual generator utilization rate, expressed as a percentage, for the last five years while in operation.

(b) Please compare the estimated annual generation of the proposed new system with the historical annual generation of the existing system

(c) If no records are available, please describe the reason why such information is not available.

Response:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Nova Scotia Energy Board Staff Interrogatory IR-3

Interrogatory:

Question(s):

(a) Please describe how Berwick Electric Commission currently manages the routine operation of the Factorydale facility.
   i. How many staff work at Factorydale, and what are their roles?
   ii. Are these staff dedicated to the site, or are they contractors?
   iii. What routine operation and maintenance tasks are performed by BEC staff and by contractors?

(b) Please describe whether there will be any changes to the routine operations following the installation of the new generating system, including:
   i. The number of staff required and their roles;
   ii. The routine operation and maintenance activities.

Response:

(a) BEC Employees complete daily operational checks on the generator at Factorydale while in service. They complete monthly visual checks on the backwoods dams and spill ways looking for signs of washout and general condition of the dams, structures, roadways etc.

   i. BEC has 4 employees (3 Power Line Technicians and 1 Electrician) that share the workload at BEC and all are qualified to work on the Factorydale river system and generating plant. They have shared duties between the BEC distribution work and the Hydro system.

   ii. These employees are FT employees of the BEC and BEC operates the Factorydale system.

   iii. They complete daily/weekly and monthly running checks while the unit is actively generating. These same 4 employees complete repairs and upgrades and anything that is outside of our abilities would go out to contract.

(b) In this case, the operations will be simplified, with a new modern design. We expect to have less maintenance hours applied to the entire system.

   i. The number of full-time staff required to maintain the operation of the Factorydale facility is 4 (the same as mentioned above in question a). The roles of these employees are also listed above and remain the same.

   ii. The maintenance plan has not been fully developed yet as it is part of the Phase 3 of this project (the Detailed Engineering package), once the funds are approved and the final design with all its components is completely defined and ready. Having said that, common activities that will be executed will be, based on best industry practices:
      - Visual inspection of governor system and manual readings, at least twice a week
      - Visual inspection of the exterior of the turbine system. In the current design, the operating ring is "exposed" so can be inspected without disassembling the unit. Once a week.
      - Manual readings of generator operating parameters. Review of alarms, if any.
      - Visual inspection of switchgear, review of operating parameters, if any.

- Visual inspection and registry of the batteries' condition. Once a week.
- Visual inspection of the transformer.

Then, at least once every year, when water levels are low enough to guarantee a 2-3 day outage:

- Visual inspection of the turbine, through the scroll case, including inspection of the wicket gates and all the turbine components.
- Visual inspection of the draftube.
- Insulation tests to the generator. This in fact can be done once every 2 years if no operating parameters show any issues that require an insulation test.

This is not a detailed maintenance program, and it is not the intention to provide one at this point. Once the final design is established, a proper maintenance program will be developed to include routine maintenance activities, people in charge, KPIs and recommendations.

Nova Scotia Energy Board Staff Interrogatory IR-4

Interrogatory:

Question(s):

On page 1 of the Application under introduction, BEC noted that there have been several major incidents that happened on the system that damaged the turbine and wicket gates, including incidents in 2006 and 2023. Paragraph 2 states: "…Hysovent concluded that an object large enough to break gates passed through and broke one or more wicket gates, creating a catastrophic event in the turbine leading to irreversible damage to the complete turbine, necessitating a replacement of the unit."

(a) Explain whether the proposed refurbishment will mitigate the likelihood of a similar incident occurring and if so, how?

(b) Please describe the protective devices, such as trash racks, screens, or other protective devices at the water intake or penstock to protect and block large objects from entering the system:

   i. Please explain why, with the protective devices, large objects were still able to enter the system;

   ii. If the protective devices are missing, please explain why such protective measures are not in place.

(c) Please describe BEC's routine inspection, maintenance, and cleaning procedures for these protective and control devices.

(d) Please describe the work BEC performed to identify the root cause of both incidents, especially for the 2006 incident, and were any corrective actions taken to prevent similar incidents in the future.

   i. If no investigation was performed, explain why.

Response:

a) BEC and the Owner's Engineers have selected vendors (HSV-2024-043-CA03) that have more durable wicket gate systems, and have proposed adding a log boom, replacing the trash rack with better protection than the existing system. The refinements include a cleaning process and an operation management system designed to minimize cleaning of the trash rack system and manual labor efforts. This helps to ensure the clean-up work gets done with a minimum of effort. The new screen sizes do not allow particulate to pass that would be larger than the replacement turbine system can handle.

b) The existing protection was a single vertical rack with bars that extended from top to bottom. The opening was less than 3", but objects were able to deflect these bars and pass through. Cleaning the racks was a manual task with manual tools. The process to clean the entrance was to contract an excavator and haul the large logs up on to the bank or drag them over the dam's edge.

The trash rack cleaning process involved inserting the stop logs, shutting down the turbine and generator, dewatering the penstock and trash rack areas, lowering men into the pit and manually scraping and pulling sediment and plant fibers from the screens. Ther is a long-handled rake that can be used to drag bigger objects out of the trash rack area without shutting the system down. The logbooks indicate this work was a common practice. Visibility and accessibility were restricted. It was hard for the operators to ensure the rack was in working order. There is evidence in the logbooks that the inspection and cleaning was carried out and any condition requiring maintenance or repair was done. The logbooks do not indicate at any time that the rack was not in service except during repairs. It was a risky process to clean the entrance to the intake. Tree root balls contained soil with rocks embedded. As the flow of water passed by these root balls, the soil and rocks were washed from the root balls. The shale rock in this area could have been large enough to damage the wicket gates and still be thin enough to pass through the trash rack grates. 3" diameter pieces of wood were found in the turbine casing.

c) To the best of our knowledge, the dam would have been inspected for log build-up within 10 days of a major storm. The operator could see on his panel the level of water in the pond and if the flow through the turbine was not matching the head pressure, an investigation would have been initiated. There was sufficient evidence in the logbooks to verify both of these procedures were followed.

d) In 2006, the investigating team found an axe head lodged into the broken wicket gates (HSV-2024-043-RCA01). This was established as the root cause. As the manufacturer was no longer in business, a local contractor made replacement gates for the site, and they were installed. The remedial action was to examine and repair the trash rack. It was considered an isolated incident and unlikely to re-occur. The root ball scenario was not considered at the time. In 2026, our report outlines the complete investigation, the root cause analysis, and the necessary remediations. To simplify this, a forensic evaluation of the mechanical failure was conducted and narrowed it down to obsolete design (new technologies are available), a long history of successful run time with little need to provide maintenance, and catastrophic set of events leading to failure.

Nova Scotia Energy Board Staff Interrogatory IR-5

Interrogatory:

Question(s):

On page 3 of the Application, in the table with project costs:

(a) Provide an updated table that includes the total cost and a line item for the net tax that BEC will have to pay.

(b) Provide a cost estimate/detailed breakdown of the installation and commissioning costs of $1,280,155, including personnel, hourly rates, hours, units, unit costs, number of units, works associated with turbine manufacture, and works not included in the turbine manufacturer's scope of supply.

(c) List all the items and their associated estimated costs included in electromechanical equipment under the item, spares

(d) Please describe the equipment and work included under the item, controls protection, switchgear and related commissioning.

(e) Please describe the equipment and associated work included under the item, decommissioning.

(f) Please describe in detail how BEC determined the rate of 5.5% for the item, spares.

(g) Why is the 20% contingency, which is stated to be for purposes of coping with unforeseen and unknown situations during commissioning, calculated as 20% of the total electromechanical equipment cost rather than 20% of the installation and commissioning cost?

(h) How was the 4% for "Interest during construction" determined? Is 4% reasonable and if so, why?

(i) For the full application for GMF funding cost of $5,000, who is being paid this cost and how was the amount determined?

(j) Explain the need for a financial audit of $20,000. Why is an audit required? Who will carry out the audit? Why is the cost estimated to be $20,000?

(k) Explain the need for an environmental results report. Why is an environmental report required? What will the report include? Who will prepare it? Why is it estimated to cost $20,000?

(l) Provide a cost estimate and detailed breakdown of costs of $300,000 under engineering consulting and on-site supervision, including personnel, hourly rates, hours, the associated works, etc.
   i. Please explain whether the engineering consultant was hired through the RFP process and provide the RFP and the accepted proposal for review.
   ii. If the engineering consultant was not hired through the RFP process, please explain why not.

(m) Provide a cost estimate and detailed breakdown of the $50,000 under-estimated payroll costs – staff remuneration, including personnel, hourly rates, hours, unit costs, number of units, etc.

(n) What were the costs for the following? Are they included in the project cost estimate, and if not, why?
   i. Condition assessment and costed option analysis (September 20, 2024);
   ii. Additional costed option analysis scenarios (October 11, 2024); and
   iii. Feasibility study (March 2025).

Response:

a) For transparency, BEC has identified a preliminary HST taxable base of $5,832,353. This amount is based on the $6,000,000 project estimate, excluding $117,647 for interest during construction and $50,000 for internal payroll/staff remuneration, which are not expected to generate HST in the same manner as third-party taxable supplies. Based on this preliminary taxable base, gross HST at 14% would be approximately $816,529. If applicable GST/HST on eligible project inputs is fully recoverable through Input Tax Credits, the estimated net GST/HST payable by BEC would be $0, and the total project cost including non-recoverable tax would remain $6,000,000.

b) This amount was indicated by the current conditionally awarded company on their proposal, but a detailed breakdown like the one requested on this IR was not requested during the RFP process, because it will involve an effort that no proponent would do when there is no detailed engineering developed yet. The cost would come, then, from their own cost estimation internal tools that we don't control or have access, which by industry practice, come from previous experience in similar projects. A detailed breakdown at this point is not available.

c) The amount included under spares is $134,018 (5% of new electromechanical equipment). This is a project allowance for spare parts associated with the new electromechanical equipment, not a final itemized OEM spare parts purchase order at this stage. It relates to [redacted] selected Option 2 – 750 mm Francis Turbine / 650 kW Package, including turbine ($[redacted]), generator ($[redacted]), hydraulic power unit ($[redacted]), controls, protection, switchgear, installation, commissioning, documentation, testing, and training. The final spare parts list, quantities, unit prices, and lead times will be confirmed with the selected OEM during final design and submittals.

d) The amount included for controls, protection, switchgear and related commissioning is $820,560. This item forms part of [redacted] selected 650 kW Francis turbine-generator package and covers the electrical, control, protection, monitoring, and commissioning systems required for operation of the new generating unit. The scope includes generator switchgear, control and protection panels, motor control equipment, auxiliary AC distribution, protection and control engineering, PLC/SCADA programming, communication configuration, protection coordination, relay settings, factory and site acceptance testing, commissioning support, as-built documentation, and operator training.

e) The Application includes $125,000 as a conservative budget allowance for decommissioning. Following the decommissioning RFP process, [redacted] was selected for Option 1 – Full Decommission, with a contract value of [redacted]. The scope covers the safe removal and disposal of existing obsolete and damaged powerhouse equipment to prepare the site for the new hydro-generation system. This includes removal of the existing turbine-generator equipment, governor-related equipment, switchgear, SCADA/control equipment, cabling, conduits, and associated mechanical and electrical components. The selected scope is based on full removal without intent to recover or reuse the existing components.

f) The rate came from common industry practice; it is a good practice to have a number between 5% to 6% of the total equipment cost as estimated costs for spares. The real cost will come after the detailed engineering is finalized.

g) The contingency, as a common industry practice, is estimated from the cost of the equipment, not the cost of the commissioning. The commissioning cost is more prone to change based on the selection of the equipment during the detailed engineering phase, but the equipment cost does not depend on project factors other than inflation and engineering decisions, so it is easier to estimate. That is why the contigency is taken from the estimated equipment cost.

h) It is also a common industry practice in projects developed under relatively low inflation economies, to add 2% to the current estimated inflation rate, which is 2% in this case.

i) The owner's engineer is being paid this cost. The cost is established under the eligible cost guidelines of the Green Municipal Fund for capital projects, here: https://media.fcm.ca/documents/programs/gmf/capital-projects-eligible-ineligible-costs-gmf.pdf

j) The financial audit is a requirement of the Green Municipal Fund to fund the project, requested directly by them during their first review of the application, and the estimate was agreed with them. At this point we haven't selected the auditor, this will be selected with or by the Green Municipal Fund when the time comes, during project execution.

k) It is part of the Green Municipal Fund requirements as well, requested directly by them during their first review of the application, and mentioned in their guidelines here: https://media.fcm.ca/documents/programs/gmf/ces-application-guide-gmf.pdf

l) At this point, this is a high-level estimate based on common industry practices of considering 5% of the total global project cost as the cost of engineering consulting, including companionship and supervision during commissioning. Once the commissioning plan is detailed, this cost will be properly updated and broken down. Commissioning plan will be detailed once the detailed engineering phase is completed, which is part of the project execution phase, which we will reach once the project gets NSUARB approval and funding approval through the Green Municipal Fund program.
   i. Consultant, in this case Hysovent, was selected by BEC through an RFP process in 2024, and it is the Owner's Engineer representative for this project, and, for now, there are no plans to do another RFP to select a different consultant until the project finishes. Hysovent Proposal is provided as IR-05 - Confidential Attachment 1. The RFP for that process is provided as IR-05 – Attachment 2.
   ii. Please refer to letter i. above.

m) This is a high-level estimate at this point in the project. We have not developed the full breakdown of the cost for the BEC internal resources costs. This will be developed once a full project execution plan is developed, and will be aligned with commissioning needs, QAQC needs, consultant level of involvement, and other factors. At this point we don't have those details, that's why it is a high-level estimate.

n) The costs of the items mentioned are not part of the application, the application covers cost after the initial assessment is determined, and the project is fully defined and ready for execution. The costs are as follows:
   i. Condition assessment and costed option analysis (September 20, 2024): $26,982.50 CAD before taxes.
   ii. Additional cost option analysis scenarios (October 11, 2024): $7,373 CAD before taxes.
   iii. Feasibility study (March 2025): $15,730 CAD before taxes.

Nova Scotia Energy Board Staff Interrogatory IR-6

Interrogatory:

Question(s):

(a) On page 3 of the application, how do the amounts of the application relate to the costs in 6.3 Summary – costed option analysis, on page 115 of the condition assessment and costed options analysis (September 20, 2024), and the costs in Table 4: Summary of costs, revenues, ROI and ROE for new units on page 22 of the additional costed options analysis scenarios (October 11, 2024)?

(b) Please develop a cost estimate for like-for-like options, consistent with the project cost estimation presented on page 3 of the capital work order application.

Response:

a) The amounts shown in the Capital Work Order Application are related to, but are not a direct duplication of, the earlier costed option analysis tables. The earlier reports were prepared as screening-level and feasibility-level comparisons to evaluate the available strategic options for Factorydale: like-for-like replacement, installation of a new modern unit, and full decommissioning. The Application amount of $6,000,000 is the later project-level capital estimate for the selected refurbishment path, developed after further scope definition, RFP development, and receipt of more detailed supplier pricing.

In Section 6.3 of September 20, 2024, Condition Assessment and Costed Option Analysis, the like-for-like options were shown as $2,472,500 for Norcan and $1,953,000 for Canyon. Those amounts represented high-level OEM replacement estimates used for financial comparison. The same table also showed new-unit options ranging from $3,500,000 (616 kW) to $5,883,466 (750kW), depending on the OEM and configuration, and full decommissioning at $18,800,000. These figures were used to determine the relative economics of each project path, not to establish the final capital work order budget.

In the October 11, 2024, Additional Costed Option Analysis Scenarios, the new-unit options were further tested under multiple hydrology scenarios. That analysis added $1,000,000 in total for a new draft tube and transformer to the new-unit options and confirmed that the new-unit path remained the preferred option when considering energy output, reliability, efficiency, funding eligibility, and long-term asset value.

The $6,000,000 amount in the Capital Work Order Application is therefore the current full project budget for the selected refurbishment approach. It includes not only the new turbine-generator package, but also installation and commissioning, controls/protection/switchgear, transformer, log boom, trash rack, intake gate, decommissioning, spares, contingency, interest during construction, engineering, financial audit, environmental reporting, and staff-related project costs. In this sense, the Application amount is a more complete project implementation budget, while the earlier costed option tables were comparative feasibility estimates.

b) For comparison purposes, BEC has developed like-for-like cost estimates using the same general cost structure applied in the Capital Work Order Application. These estimates are based on the original like-for-like replacement amounts identified in the Condition Assessment: $1,953,000 for the Canyon-based option and $2,472,500 for the Norcan-based option. These figures represent the OEM-level replacement estimates available at the time of the earlier assessment and are used here only to develop a comparable project-level estimate.

To make the like-for-like options consistent with the Application format, BEC added the same types of project implementation costs included in the current $6,000,000 capital estimate. These include installation and commissioning, decommissioning/removal, log boom, trash rack, intake gate, spares, contingency, interest during construction, engineering consulting and on-site supervision, financial audit, environmental results reporting, and estimated internal staff remuneration.

Using this approach, the Canyon-based like-for-like option would be approximately $5.21 million excluding tax. This estimate starts with the $1.953 million OEM replacement amount and adds project implementation allowances consistent with the Application, including $1.280 million for installation and commissioning, $125,000 for decommissioning/removal, $395,000 for intake protection and related works, a spare parts allowance of approximately $107,000, contingency, interest during construction, engineering, audit, environmental reporting, and staff-related project costs.

The Norcan-based like-for-like option would be approximately $5.89 million excluding tax. This estimate starts with the $2.473 million OEM replacement amount and applies the same Application-consistent allowances, including installation and commissioning, decommissioning/removal, intake protection and related works, spares, contingency, interest during construction, engineering, audit, environmental reporting, and staff-related project costs.

These like-for-like estimates are lower than, or close to, the $6,000,000 budget for the proposed new modern unit. However, they would generally restore the plant closer to its original generating capacity and would not provide the same long-term benefits as the selected refurbishment approach. The proposed new unit provides increased capacity, improved efficiency, modern controls and protection, better monitoring capability, improved reliability, and stronger long-term asset value. For these reasons, BEC considers the new modern unit to remain the preferred option despite the apparent proximity of the like-for-like cost estimates.

Nova Scotia Energy Board Staff Interrogatory IR-7

Interrogatory:

Question(s):

Provide a copy of the RFP and all addenda; all proposals received; and BEC's review, analysis and ranking of each proposal and which proponents it intends to retain for the work and why.

Response:

Please see Confidential Attachment 1 for the available RFP records, addenda, proposals received, evaluation reports, scoring/ranking records, and award recommendations for the Factorydale procurement packages.

For the main electromechanical contract, BEC received proposals from [redacted]

For the decommissioning / demobilization package, BEC received proposals from [redacted]

For the transformer upgrade package, BEC received proposals from [redacted]

For the intake system / trash rack and log boom scopes, BEC has [redacted]

The attached materials therefore provide the procurement record for each completed package, including the RFP documents, issued addenda, proposals received, evaluation methodology, ranking, and rationale for the selected proponent. BEC's intent is to ensure that the Board has a transparent and auditable record of the procurement process used to support the Factorydale refurbishment project.

Nova Scotia Energy Board Staff Interrogatory IR-8

Interrogatory:

Question(s):

Explain whether BEC is specifying the use of a particular turbine or leaving that to the successful proponents to determine based on their review of the studies completed.

Response:

BEC hired Hysovent as the owner's engineers to prepare a bid document (HSV-2024-043-CA03), which BEC reviewed and accepted prior to issuance. This document sets forth the operating conditions, the general type of equipment required, the quality control and assurance program to be followed, and the performance requirements along with the performance compliance. For this project, a Francis turbine was specified by the Owner’s Engineer in agreement with BEC. The resulting bids were evaluated for technical suitability, scheduling, performance guarantees, and any other advantages the new system would provide. The owner's engineers set up a review process acceptable to BEC and evaluated the bid documents. The owner's engineers reviewed their conclusion with BEC and the most beneficial supplier was selected. These documents are available for review in the bid document (HSV-2024-043-CA03).

Nova Scotia Energy Board Staff Interrogatory IR-9

Interrogatory:

Question(s):

Paragraph 9-10 say that the project has been split into four separate RFPs for (1) the main electromechanical contact, (2) demobilization, (3) transformer upgrade and (4) trash rack, and that the RFPs have been released, proposals received and BEC is in the process of notifying and working with the successful proponents. Please, break down the cost estimates on page 3 into the four separate RFPs showing both the original cost estimates and the actual bids.

Response:

BEC and the owner's engineers divided the Factorydale refurbishment procurement into targeted RFP packages to obtain more specialized proposals and improve cost competitiveness. The cost estimate shown on page 3 of the Application can be mapped to the RFP packages as follows. All amounts are in Canadian dollars and exclude tax.

Original Application Estimate and Actual Bid / Current Status:

1. Main Electromechanical Contract – New Power Generation Unit:
   The original Application estimate for this package is $3,716,845. This includes installation and commissioning ($1,280,155), new 650 kW turbine ($1,039,000), 650 kW generator at 600 RPM ($461,430), hydraulic power unit, servos and field piping ($115,700), and controls, protection, switchgear and related commissioning ($820,560). The selected [redacted] proposal is Option 2 – 750 mm Francis Turbine / 650 kW Package, with a total proposed package cost of $3,716,845.

2. Demobilization / Decommissioning:
   The original Application estimate for decommissioning is $125,000. Following the decommissioning RFP process, [redacted]. was selected for Option 1 – Full Decommission, with an actual bid / contract value of [redacted].

3. Transformer Upgrade:
   The original Application estimate includes $120,000 for the new transformer and $15,000 for transformer commissioning, for a combined allowance of $135,000. Following the transformer RFP process, [redacted] was selected with an evaluated bid of [redacted] for the transformer supply. The separate [redacted] commissioning allowance remains carried for transformer-related commissioning support, resulting in a current transformer-related estimate of [redacted].

4. Intake / Trash Rack / Log Boom Works:
   The original Application includes $150,000 for the new trash rack, $125,000 for the new intake gate, and $120,000 for the new log boom, for a combined estimate of $395,000. The procurement was later further organized into an Intake System Rehabilitation RFP, covering the intake gate, trash racks, access and controls, and a separate Dam Log Boom RFP. The current project record identifies $275,000 for the intake gate / trash rack / cleaning system scope and $120,000 for the log boom scope. At this stage, no final awarded bid amount for these two intake-related packages is reflected in the current record, so the original combined estimate of $395,000 remains in the control estimate pending final award.

The original Application estimate for the RFP-related scopes totals $4,371,845. Based on the actual awarded amounts currently available for the main electromechanical contract, decommissioning, and transformer supply, together with the retained transformer commissioning allowance and the retained intake/log boom estimate, the current known or retained amount for these RFP-related scopes is approximately $4,324,964.

The remaining items on page 3 of the Application are project allowances or owner-side costs rather than separate RFP awards. These include spares ($135,116), contingency ($980,392), interest during construction ($117,647), GMF application support ($5,000), financial audit ($20,000), environmental results report ($20,000), engineering consulting and on-site supervision ($300,000), and estimated payroll costs / staff remuneration ($50,000). These items total $1,628,155.

Accordingly, the original Application total remains $6,000,000 excluding tax. The current known awarded values are below the original allowances for decommissioning and transformer supply; however, the total project budget has not been reduced at this stage because the intake/log boom packages are not yet reflected as final awarded values in the current record, and because contingency, spares, engineering, owner-side costs, and commissioning-related allowances remain subject to final project execution and invoice-level confirmation.

Nova Scotia Energy Board Staff Interrogatory IR-10

Interrogatory:

Question(s):

Paragraph 11 of the Application says that the refurbishment project "…will significantly increase renewable energy production to help meet the Province's requirements for 80% renewable electricity and greatly improve reliability."

(a) What was BEC's i) current renewable energy production, and, ii) its renewable energy production when the Factorydale plant was operating, i.e., before the December 2023 incident?

(b) Explain how the refurbishment project will "significantly" increase renewable energy production.

(c) What percentage increase in renewable energy production does BEC expect from the refurbishment project?

Response:

(a) BEC's current renewable energy production is approximately 19,472 MWh/year based on 2025 data, consisting of 4,680 MWh from solar generation and 14,792 MWh from Ellershouse. Factorydale is currently producing 0 MWh/year because it has not generated electricity since the December 2023 incident.

In 2024, BEC's renewable energy production was approximately 19,859 MWh, consisting of 4,273 MWh from solar generation and 15,586 MWh from Ellershouse. Factorydale did not contribute generation in 2024.

BEC does not have measured historical generation records for Factorydale before the incident. For comparison purposes, BEC has relied on the RETScreen like-for-like model for the existing 416 kW unit, which estimates pre-incident Factorydale generation at approximately 1,556 MWh/year.

(b) The refurbishment project will significantly increase renewable energy production because it will return the currently non-operational Factorydale plant to service and replace the former 416 kW configuration with a modernized 650 kW unit. The final RETScreen model for the proposed refurbishment estimates annual generation of approximately 2,701 MWh/year.

Compared with the current condition of 0 MWh/year, the project restores approximately 2.7 GWh/year of local renewable generation. Compared with the RETScreen forecast for the former 416 kW unit of approximately 1,556 MWh/year, the proposed refurbishment increases annual renewable energy production by approximately 1,145 MWh/year.

The increase is also significant because the project does not simply repair the damaged unit. It modernizes the plant with a higher-capacity turbine/generator, improved efficiency, new controls, protection, SCADA, monitoring, and automation. These improvements are expected to increase output and improve reliability relative to the former unit.

(c) From the current post-incident production level of 0 MWh/year, the percentage increase is not mathematically meaningful because the baseline is zero. The practical result is that the project restores approximately 2,701 MWh/year of renewable generation to BEC's system.

Compared with the RETScreen forecast for the former 416 kW unit of approximately 1,556 MWh/year, the proposed 650 kW refurbishment at approximately 2,701 MWh/year represents an increase of approximately 1,145 MWh/year, or about 74%.

Accordingly, BEC expects the refurbishment project to increase Factorydale renewable energy production by approximately 74% compared with the modelled production of the former unit, and by approximately 2.7 GWh/year compared with the plant's current non-operational condition.

Nova Scotia Energy Board Staff Interrogatory IR-11

Interrogatory:

Question(s):

What is the expected useful lifespan of the following items listed in the cost estimate on page 3:

(a) turbine – 650 kW;
(b) 600 kW Generator, 600 RPM;
(c) hydraulic power unit, servos and field piping;
(d) controls protection and switchgear;
(e) transformer;
(f) log boom;
(g) trash rack; and
(h) intake gate.

Response:

The expected useful lives below are planning-level estimates for the major capital items listed in the cost estimate. They assume proper installation, normal operation within design conditions, routine inspection and maintenance, timely replacement of wear parts, and compliance with the manufacturers' operation and maintenance requirements. These useful lives should not be interpreted as warranty periods.

Expected Useful Lifespan:

(a) 750 mm Francis Turbine, embedment and Project support:
Approximately 50 years. The turbine is part of the main long-life electromechanical refurbishment and is expected to align with the overall 50-year design-life objective of the modernized plant, subject to routine inspection, alignment checks, coating maintenance, and replacement of wear components.

(b) 650 kW Generator, 600 RPM:
Approximately 40 to 50 years. The generator is expected to have a long service life with regular electrical testing, thermal monitoring, bearing maintenance, cleaning, and periodic overhaul or rewinding if required during its service life.

(c) Hydraulic power unit, servos and field piping:
Approximately 25 to 30 years. The hydraulic system includes more wear-prone components than the turbine or generator, including pumps, valves, seals, hoses, servos, filters, and instrumentation. Some components may require replacement within the useful life of the overall system.

(d) Controls, protection and switchgear:
Approximately 20 to 30 years. The switchgear structure and power components may last closer to 30 years with proper maintenance, while control, protection, communication and SCADA electronics are more likely to require refresh or replacement within approximately 15 to 20 years due to technology obsolescence and support availability.

(e) Transformer:
Approximately 40 years. The new padmount transformer is expected to provide long-term service if oil quality, loading, thermal performance, protection devices, grounding, bushings, terminations, and accessories are properly inspected and maintained.

(f) Log boom:
Approximately 20 years. The log boom is an outdoor, water-exposed debris protection system, and its actual life will depend on UV exposure, ice, storm debris impacts, anchoring performance, cable/floating component condition, and post-storm maintenance. Individual floats, cables, connectors, or netting may require replacement before the full system is replaced.

(g) Trash rack:
Approximately 25 to 30 years. The trash racks are specified as PE100 black HDPE, UV-stabilized, suitable for continuous immersion, outdoor exposure, low-temperature service, hydraulic loading, debris impact, and manual cleaning. Stainless steel frames and supports may last longer, while replaceable HDPE rack modules may require earlier replacement if damaged.

(h) Intake gate:
Approximately 40 to 50 years for the main stainless steel gate structure, frame and permanent metallic components. Mechanical drive components, seals, motors, position devices, and control accessories may require replacement or overhaul within approximately 15 to 25 years as part of normal maintenance.

Overall, the main civilly integrated and heavy electromechanical components are expected to support the long-term refurbishment objective, while auxiliary, electronic, hydraulic, floating, sealing, and wear components are expected to have shorter replacement cycles within the overall project life.

Nova Scotia Energy Board Staff Interrogatory IR-12

Interrogatory:

Question(s):

What are the estimated annual O&M costs for the new infrastructure? What is the source of this information? How do these costs compare to the annual O&M costs that were incurred prior to the December 2023 incident?

Response:

The estimated annual O&M value for the new infrastructure is approximately $58,852 per year. This value is the annual O&M cost/savings input used in the RETScreen financial analysis for the selected conservative 650 kW refurbishment scenario.

The source of this information is the Feasibility Study and associated RETScreen financial model for the 650 kW new-unit scenario. The estimate reflects a planning-level annual O&M value for the modernized hydroelectric facility, including routine inspection, preventive maintenance, minor service activities, consumables, monitoring, and normal upkeep of the new turbine-generator package, hydraulic system, controls/protection/switchgear, transformer, intake-related systems, and auxiliary equipment.

This amount is not a fixed vendor service contract and is not an audited historical O&M ledger value. It is a feasibility-stage modelling input used to evaluate the financial performance of the proposed refurbishment.

BEC does not have a complete standalone historical O&M record that isolates all annual Factorydale O&M costs by equipment category prior to the December 2023 incident. For comparison purposes, the closest available proxy is the like-for-like replacement model, which used $75,356 per year as the annual O&M cost/savings value for restoring the plant generally to its pre-incident 416 kW operating configuration.

On that basis, the estimated annual O&M value for the new infrastructure, $58,852 per year, is approximately $16,504 per year lower than the like-for-like / pre-incident proxy of $75,356 per year. This represents an estimated reduction of approximately 22%. The reduction is reasonable because the proposed project replaces obsolete and damaged equipment with modern equipment, improved monitoring, standardized controls and protection, OEM-supported components, and better preventive maintenance capability.

Nova Scotia Energy Board Staff Interrogatory IR-13

Interrogatory:

Question(s):

How were the amounts for O&M costs (savings) shown on the RETScreen – financial analysis determined for each of the options in the condition assessment and costed option analysis (September 30, 2024), and the additional costed option analysis scenarios (October 11, 2024)?

Response:

At the moment of preparing that analysis, the owner's engineers used the cost database from RETScreen Expert as a guide, to have a starting point to do the analysis. The RETScreen Expert cost database is in fact generally accurate when it is related to O&M costs for Canadian projects overall.

Nova Scotia Energy Board Staff Interrogatory IR-14

Interrogatory:

Question(s):

What are the O&M costs (savings) for the like-for-like replacement and how were they determined?

Response:

The O&M cost/savings value used for the like-for-like replacement is $75,356 per year. This value was applied consistently to the like-for-like replacement scenarios in the Condition Assessment and Costed Option Analysis and in the Additional Costed Option Analysis Scenarios.

The like-for-like replacement model assumes restoration of the plant generally to its original 416 kW configuration. The same annual O&M cost/savings value was used for both the Canyon and Norcan like-for-like options because the modelling assumption was tied to restoring the existing type of generating arrangement, not to a full modernization of the plant.

The $75,356 per year value was determined as a RETScreen financial modelling input for the like-for-like replacement option. It was used to represent the annual O&M burden or savings associated with returning the existing plant to service under a like-for-like configuration. It should not be interpreted as a vendor-quoted annual maintenance contract or as a fully audited historical O&M cost.

In the Additional Costed Option Analysis, the like-for-like cases were modelled using the same flow duration curve methodology applied to the new-unit options, but with key differences: no additional cost was added for a new draft tube or new penstock, no grant funding was assumed because the option does not increase renewable generation capacity, and the financing assumptions were modelled separately. The hydrology scenarios affect generation, revenue, ROI and payback; however, the annual O&M cost/savings input remained $75,356 per year across the like-for-like scenarios.

Nova Scotia Energy Board Staff Interrogatory IR-15

Interrogatory:

Question(s):

If this project is approved, will BEC need to file a rate application to increase rates to cover the costs of this project?

(a) If not, please explain why.

Response:

(a) As the Board is aware, BEC is facing significant increased costs associated with purchases from NS Power related to Fuel Adjustment Mechanism and Maritime Link Assessment Costs that are not included in its current charges under the Municipal Tariff. As noted in its response to IR-1(e) in Matter M12308 (An Application by the Town of Berwick for Approval of the Capital Costs of its Community Solar Garden), BEC continues to expect that it will need to file its next General Rate Application ("GRA") later in 2026. Whether or not a subsequent GRA would need to be filed to cover the costs of this project specifically would depend on the assumptions and timing of filing of the upcoming GRA and the outcome of the Board's decisions in this matter and the GRA.

Nova Scotia Energy Board Staff Interrogatory IR-16

Interrogatory:

Question(s):

Provide a list of all grants applied for, or intended to be applied for, with respect to this project, including:

(a) name of the grant;
(b) amount applied for;
(c) status of the application;
(d) when a decision is expected to be made; and,
(e) amount expected to be received.

Response:

[redacted]

Nova Scotia Energy Board Staff Interrogatory IR-17

Interrogatory:

Question(s):

Explain whether, if government funding is denied, a new unit still presents the most attractive option compared to the like-for-like replacement and if so, why?

Response:

It is the only way to go. Going back to try to repair the unit is not only uneconomical but does not offer the most reliable option for long term operations either. Please refer to the Application and documents HSV-2024-043-CA01 and HSV-2024-043-CA02.

Nova Scotia Energy Board Staff Interrogatory IR-18

Interrogatory:

Question(s):

[REQUIRES A CONFIDENTIAL RESPONSE].
With respect to the insurance claim:

(a) Provide a status update explaining what claims have been made and for what amounts, whether the insurer has denied or approved any claims and the status of negotiations.
(b) Why was the claim not resolved earlier given the incident leading to the claim occurred in December 2023?
(c) Has BEC retained anyone to help with the claim and if so, who?
(d) How much does BEC realistically estimate it will receive from its insurer and when?

Response:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Nova Scotia Energy Board Staff Interrogatory IR-19

Interrogatory:

Question(s):

With respect to the three dams:

(a) What is the expected remaining useful life of each of the three dams and how was this determined?

(b) When were the dams last assessed in accordance with the Canadian Dam Association Guidelines? Provide a copy of any reports.

(c) Explain whether it would be reasonable to wait until the dams are more thoroughly assessed before deciding whether to undertake the refurbishment project?

(d) Explain whether there is any concern that the dams could require such significant investment that it would not make financial sense to replace the damaged turbine.

Response:

From the most recent Dam Safety report produced by MECO Engineering in December 2024, page 4, states: "Factorydale Dam is regulated by the Nova Scotia Department of Environment and Climate Change (NSECC) through a water withdrawal agreement. With an estimated reservoir storage capacity of less than 30,000 m3, the dam as it is currently constructed does not meet the criteria of a dam, as defined by the CDA Guidelines, and compliance with the Guidelines is voluntary." In terms of the questions:

(a) There are no known deficiencies that would suggest that the other dams are on a shorter life cycle than the dam at Factorydale.

(b) The Factorydale Dam was assessed by MECO Engineering in December 2024, and in their report on page 4 we can read: "Factorydale Dam is regulated by the Nova Scotia Department of Environment and Climate Change (NSECC) through a water withdrawal agreement. With an estimated reservoir storage capacity of less than 30,000 m3, the dam as it is currently constructed does not meet the criteria of a dam, as defined by the CDA Guidelines, and compliance with the Guidelines is voluntary." A copy of the report is included as IR-19 - Attachment 1.

(c) The main dam was already assessed and shown as in good condition. We plan to assess the other dams in the next few months, budget permitting, but we are confident that, with the main one being in good condition, the other ones should not be different and should not stop continuing with the project.

(d) The concern does not exist at this point, because the dams had not shown the need for a significant investment.

Nova Scotia Energy Board Staff Interrogatory IR-20

Interrogatory:

Question(s):

In Condition Assessment section 3.1.1, page 13, Hysovent noted corrosion issues on turbine components.

(a) Please describe BEC's routine corrosion control practices and relevant standards.

Response:

BEC recognized that the runner blades were corroding and contracted out a coating system that was applied many years ago (HSV-2024-043-RCA01). This coating system was reaching the end of its life when the last failure occurred. Years prior to the incident, the BEC, reached out informally to some vendors to chat about potentially changing the runner and the unit as a whole. The incident occurred before any change could be implemented. Hysovent as the Owner's Engineers has proposed a maintenance program that will ensure inspections and re-application of corrosion systems occur with any new equipment being installed.

Nova Scotia Energy Board Staff Interrogatory IR-21

Interrogatory:

Question(s):

Explain the rationale for replacing the generator, circuit breakers, governor, and emergency closure gates and valves given that their Tier 1 condition index score does not indicate the need for replacement at this time.

Response:

The Tier 1 condition index was used as a screening tool to assess the apparent condition of the existing assets, but it was not the only criterion used to define the final project scope. The selected project is not a like-for-like repair of individual components; it is a complete modernization of the hydro-generation system. Therefore, replacement decisions were also based on capacity increase, equipment compatibility, safety, reliability, automation requirements, spare parts availability, OEM support, and long-term lifecycle risk.

The existing generator, circuit breakers, and Woodward governor were not all identified as requiring immediate replacement based only on their Tier 1 scores. However, they were designed for the original 1968 plant arrangement and the previous operating configuration. The new 650 kW unit requires a matched turbine-generator-governor-switchgear-control-protection package, with coordinated protection, modern monitoring, SCADA integration, guaranteed performance, commissioning support, and long-term maintainability. Reusing older equipment would increase interface, performance, protection coordination, and lifecycle risks.

Similarly, the intake gate, trash rack, and related intake works are included because the project must reduce the likelihood of another debris-ingress event, improve isolation capability, protect the new downstream equipment, and provide safer and more code-compliant operator access. In summary, these replacements are justified by the overall modernization strategy and system integration requirements, not by Tier 1 condition scores alone.

Nova Scotia Energy Board Staff Interrogatory IR-22

Interrogatory:

Question(s):

Has BEC considered whether any of the equipment being removed or replaced has value such that it can be salvaged and sold for reuse, scrap, or otherwise used to generate revenue to pay for the refurbishment project? If so, what revenue is expected from what equipment? If not, will BEC undertake this exercise prior to commencement of the project? If not, why?

Response:

Yes. Even though it is not considered in the financial model at this point, the current plan is that once the new unit is fully commissioned, BEC will sell the original generator on the power generation market. That's the only "recoverable" asset identified at this point. BEC does not currently have a value for it, as it is very difficult to estimate – hence why it was not included in the financial model of the project.

Nova Scotia Energy Board Staff Interrogatory IR-23

Interrogatory:

Question(s):

Will the project replace the batteries or cranes? If so, given their Tier 1 condition index score, why?

Response:

The current crane will not be replaced, it is in good condition and serves well the current and future systems in the plant. In fact, equipment selection criteria considered the maximum capacity of the current manual crane to lift and handle the new equipment. It is not expected that the crane will be used extensively during normal operations, other than if a major overhaul that requires the removal of the generator, the turbine or the governor is required.

The batteries were found in good condition, but the charging system may be updated if the new control system for the plant requires it. Because of the expected low dollar value of this item, if it is necessary, will be covered by the contingency budget.

Nova Scotia Energy Board Staff Interrogatory IR-24

Interrogatory:

Question(s):

Page 76 of Condition Assessment states: "…there is one global recommendation: a proper maintenance program for the entire facility and its assets." Will this program be prepared as part of the proposed project?

Response:

Yes, a detailed maintenance program tailored to the new assets will be developed, and it is part of the project deliverables.

Nova Scotia Energy Board Staff Interrogatory IR-25

Interrogatory:

Question(s):

In addition to the complete turbine replacement under Section 5.3.1 of Condition Assessment, identify any other recommendations listed in Sections 5.1 – 5.3 that are included in the proposed project.

Response:

Installing a new unit the way BEC is proposing covers all the recommendations listed in section 5.1, 5.2 and 5.3 of the Condition Assessment Report HSV-2024-043-CA01. Being a new asset, it will be commissioned and operated as such, with a more modern and simplified approach, focused on reliability, simplicity, and long-term usability.

Nova Scotia Energy Board Staff Interrogatory IR-26

Interrogatory:

Question(s):

On page 86 of Condition Assessment, Section 6.1.1, Hysovent noted the lack of studies and records needed to develop an accurate flow estimate, as quoted below:
Unfortunately, for the Factorydale reservoir, we don't have a hydrology study or historical records that allows us to build an accurate flow duration curve. So, we did an extrapolation, using hydrologic data from the Kelley River (Mill Creek) at Eight Mile Ford as a base.
…
We first established a flow of 3.39 m3/s as a design flow (120 cfs) assuming that will work 70% of the time.

(a) Will completing the project allow BEC to obtain this information on a go-forward basis?
   i. List and explain all parameters that the new project controls will allow monitoring for, noting which were previously monitored for and which were not.
(b) Please confirm whether any hydrology studies or related analyses were completed to determine the actual water flow at the site.
   i. If no, please explain how BEC determined that the proposed increase in generation capacity is reasonable.
   ii. If so, please provide the applicable studies or analysis for review.
(c) Please describe:
   i. How the design flow of 3.39 m3/s was determined and assess its accuracy in representing actual water flow conditions.
   ii. The basis for assuming that the design flow, 3.39 m3/s would be available for 10%, 30% and 70% of the time.
   iii. What data source(s) were used to estimate the water flow and what method was applied to derive the flow values?
   iv. What is the total dataset size, including both number of observations and length of record, and how was data quality verified?
   v. How was it determined that the dataset is sufficient for a reliable Flow Duration Curve (FDC)?
(d) Please explain whether BEC expects the estimated flow to vary by season or climatic conditions, and if so, describe the extent and duration of any expected variations.

Response:

(a) Yes. Completion of the project will allow BEC to obtain significantly better operating and performance information on a go-forward basis. The upgraded controls, protection, measurement, and SCADA systems will provide continuous data logging, historical records, event logs, alarms, and authorized monitoring capability that were not available in the same form from the existing plant.

The new system is expected to monitor and record key operating and electrical parameters, including generation output, voltage, current, frequency, power factor, active and reactive power, energy production, generator speed, unit operating status, breaker/switchgear status, protection alarms and trips, transformer alarms and operating status, temperature-related alarms, equipment events, and relevant control/protection system conditions. These parameters will support future analysis of plant performance, availability, operating trends, maintenance needs, and hydrology-related assumptions.

Some basic electrical and operating parameters were monitored previously through the existing protection, control, and metering equipment; however, the previous system did not provide the same level of integrated SCADA functionality, historical data storage, reporting, communications, and trend analysis expected from the new system.

(b) BEC confirms that no site-specific hydrology study or long-term historical flow record was available for the Factorydale site at the time of the Condition Assessment. The Condition Assessment noted that there was no hydrology study or historical record sufficient to build an accurate site-specific flow-duration curve. The Additional Costed Option Analysis also confirmed that there is no NRCan hydrometric station at Factorydale and that BEC did not historically register penstock flow.

(b) (i) In the absence of site-specific flow records, BEC determined that the proposed increase in generation capacity is reasonable by using a conservative engineering and sensitivity-analysis approach. The analysis used the existing plant's known design flow of 3.39 m³/s, or 120 cfs, as the reference design flow, and then tested that flow under multiple flow-duration scenarios.

The first analysis used Kelley River / Mill Creek at Eight Mile Ford data as an initial reference. The later Additional Costed Option Analysis improved the estimate by using Cornwallis River at Cambridge Station, which is geographically close to the Factorydale site, and Beaverbank River near Kinsac, which was selected as a secondary reference because it has similar expected hydrologic behaviour. The analysis then tested very pessimistic, pessimistic-to-realistic, and optimistic cases.

The proposed increase in capacity is also reasonable because the new turbine is not assumed to operate at maximum output all year. It is designed to operate under variable flow conditions and to use the available water more efficiently than the existing damaged unit. The final RETScreen model uses the Cornwallis River 30% exceedance case as the representative scenario, which provides a conservative basis for expected annual generation.

(b) (ii) No separate site-specific hydrology study is available. The applicable analyses are the Condition Assessment, the Additional Costed Option Analysis Scenarios report, and the final RETScreen Feasibility Report. Those documents provide the hydrology basis, reference stations, flow-duration methodology, scenario testing, and final selected modelling case.

(c) (i) The design flow of 3.39 m³/s was determined from the existing plant's historical design basis and operating configuration. It corresponds to 120 cfs, which is the design flow associated with the existing hydraulic infrastructure. The final RETScreen report also states that this design flow was selected because the existing hydraulic structures, including the intake, penstock, and spillway, remain unchanged.

The 3.39 m³/s value should not be interpreted as a continuously available year-round flow. Its accuracy as a representation of actual water conditions is limited by the lack of site-specific historical records. For that reason, it was used as a design-flow reference point and then evaluated under multiple exceedance scenarios.

(c) (ii) The 10%, 30%, and 70% assumptions were not measured Factorydale flow records. They were sensitivity scenarios used to test how the project would perform under different possible water-availability conditions. The 10% case represents a very pessimistic scenario, the 30% case represents a pessimistic-to-realistic scenario, and the 70% case represents an optimistic scenario.

(c) (iii) The data sources used were hydrology data from comparable Nova Scotia rivers. The initial Condition Assessment used Kelley River / Mill Creek at Eight Mile Ford as the first reference. The Additional Costed Option Analysis then used Cornwallis River at Cambridge Station and Beaverbank River near Kinsac. Flow-duration curves were generated from those reference datasets and then scaled so that 3.39 m^3/s aligned with the selected exceedance cases.

(c) (iv) The reports present the derived flow-duration curves as exceedance values in 5% increments from 0% to 100%. This results in 21 flow-duration points for each curve. The reports do not state the raw number of hydrometric observations or the full length of record used from the source hydrometric stations. Data quality was addressed by using active/current hydrometric stations and by comparing two independent reference rivers rather than relying on only one extrapolated dataset.

(c) (v) The dataset was considered sufficient for feasibility-level modelling because there were no local Factorydale flow records, the selected reference stations were current and active, one station was geographically close to the site, the other was selected for similar hydrologic behaviour, and the resulting scaled curves produced generally comparable results. The analysis was also made more conservative by selecting the 30% pessimistic-to-realistic case for detailed evaluation rather than relying on the optimistic 70% case.

d) Yes. BEC expects the available flow to vary by season and climatic conditions. Higher flows are expected during wetter periods, freshet conditions, snowmelt, and significant precipitation events. Lower flows are expected during dry summer periods and other low-runoff periods.

The modelling accounts for these variations by using flow-duration curves and by evaluating multiple exceedance scenarios, rather than assuming that the design flow is available continuously. Once the project is operating, the upgraded SCADA and monitoring systems will allow BEC to track actual generation, water-level conditions where instrumented, equipment performance, operating status, alarms, events, and trends over time. This will improve the accuracy of future operational and hydrology-related analysis.

Nova Scotia Energy Board Staff Interrogatory IR-27

Interrogatory:

Question(s):

On page 93 of Condition Assessment, in referring to the like-for-like replacement, it states, "There is no government aid on these scenarios, because we are not increasing the output." What is the least amount of output increase required to qualify for government aid, and what is the source of that information?

Response:

The minimum amount is not specified on any guideline directly. What is mentioned and required, in the case of the Green Municipal Fund's Community Energy Systems on their application guideline found here: https://media.fcm.ca/documents/programs/gmf/ces-application-guide-gmf.pdf on Page 17, is the following:

Your community energy project may lead to direct or indirect reduction of GHG emissions by:

- reducing reliance on fossil fuels to provide heating for a neighborhood area
- reducing infrastructure related to natural gas and its fugitive emissions in newly developing areas of your municipality
- reducing GHG emissions from your local grid through the implementation of larger solar arrays, wind farms, or other renewable sources

To be able to achieve GHG reduction on the current BEC grid, the reduction must be compared with the "business as usual" scenario with the current unit running (when it was running, before the incident in 2023). So, a like-for-like scenario does not reduce the GHG emissions; the only way is to increase the energy output of the unit, which, in this case, can be achieved only with a new unit with better design and higher reliability.

Nova Scotia Energy Board Staff Interrogatory IR-28

Interrogatory:

Question(s):

On the RETScreen – Financial Analysis, how are the “O&M costs (savings)” calculated? What were the O&M costs prior to the December 2023 incident when the turbine was operating and what are they expected to be after the refurbishment is complete?

Response:

In the RETScreen Financial Analysis, the “O&M costs (savings)” line represents the estimated annual routine operation and maintenance cost for the Factorydale plant. It is not calculated as a direct savings against the historical O&M cost of the former unit.

For the refurbished plant, annual routine O&M was estimated based on BEC’s expected staff allocation. Operation and maintenance activities are handled by a team of five personnel, each earning approximately $80,000 to $100,000 annually. Their responsibilities are distributed among several power plants and transmission lines. Assuming approximately 10% of their time is allocated to Factorydale, the annual O&M labour cost attributable to the facility is estimated at approximately $40,000 to $50,000 per year. The RETScreen model uses $40,000/year.

This estimate does not include periodic overhauls or major maintenance, which are accounted for separately in the Cost Analysis section of the RETScreen model.

BEC estimates that O&M costs for Factorydale prior to the December 2023 incident were approximately $115,000 to $150,000 in total for the 2015–2017 period. This equates to an average of approximately $38,000 to $50,000 per year over that period.

After the refurbishment is complete, BEC expects routine annual O&M costs to remain in approximately the same range, about $40,000 to $50,000 per year, with $40,000/year used in the RETScreen Financial Analysis. Periodic overhauls and major maintenance are treated separately.

Nova Scotia Energy Board Staff Interrogatory IR-29

Interrogatory:

Question(s):

Provide the RETScreen – Financial Analysis for the like-for-like replacement assuming debt financing of 4.5% (rather than the 8% assumed) over 20 years. Explain whether this changes the opinion that the proposed refurbishment is preferrable to the like-for-like replacement.

Response:

The original RETScreen analysis for the like-for-like replacement assumed that BEC would finance 50% of the project cost through a private lender at an 8% debt interest rate over a 20-year term. That assumption was used because the like-for-like option was evaluated as a conventional repair/replacement scenario, not as the GMF-supported refurbishment project.

BEC does not consider the 4.95% GMF preliminary rate to be an appropriate financing assumption for the like-for-like option. The 4.95% rate was used as a conservative preliminary estimate for GMF financing in the context of the proposed refurbishment project. That project involves a broader modernization of the facility, including a new higher-capacity unit, increased renewable generation, new controls, monitoring, protection systems, and related upgrades. By contrast, the like-for-like option would restore the facility to the previous 416 kW configuration and would not provide the same increase in renewable energy capacity or modernization benefits.

For that reason, the original RETScreen financial analysis for the like-for-like option reflects the financing terms BEC considered realistic for that type of investment: conventional private debt financing. Applying the GMF-style 4.95% rate to the like-for-like option would not reflect the financing structure BEC expects would be available or appropriate for that scenario.

BEC acknowledges that reducing the assumed debt interest rate from 8% to 4.5% would improve the financial results of the like-for-like option. However, that does not change BEC's conclusion that the proposed refurbishment remains preferable. The decision is not based solely on debt interest rate or simple payback. The like-for-like option would restore old equipment architecture, maintain the previous 416 kW capacity, and would not provide the same improvements in efficiency, reliability, generation output, automation, monitoring, or long-term asset condition.

There are also significant technical and execution risks associated with the like-for-like path. Further technical review has confirmed that repair/reuse would involve high uncertainty, including unknown damage to remaining components, high dismantling costs if components are removed with intent to reuse, limited salvage value, reliability risk, and the potential for cost overruns. The review also notes that repairing the unit carries a high risk of delivering an asset that is not fully reliable, and that replacement is the preferred approach where less than 65% of the equipment is repairable.

Accordingly, even if a lower debt interest rate improves the financial case for the like-for-like option, it does not change BEC's opinion. The proposed refurbishment remains the preferred option because it provides a modernized 650 kW unit, higher expected annual generation, improved reliability, updated controls and monitoring, and a stronger long-term solution for BEC and its customers.

Please see RETScreen financial model attached in IR-29 Appendix 1.

Nova Scotia Energy Board Staff Interrogatory IR-30

Interrogatory:

Question(s):

On page 90 of Condition Assessment, 6.2.1 Option A – Like for Like Replacement, states that “we will assume that 70% of the time, the flow of 3.39 m3/s (120 cfs) is available,” but page 12 of the Additional Costed Option Analysis Scenarios (October 11, 2024) states: “…we think that the pessimistic to realistic scenario [flow exceeds 3.39 m3/s only 30% of the time] is the one that will be the most probable one to occur during the life of the project.”

(a) Explain why the like-for-like replacement was not evaluated using the same pessimistic to realistic scenario used to evaluate the proposed refurbishment.

(b) Provide an evaluation of the like-for-like replacement using the pessimistic-to-realistic scenario. Explain whether this evaluation changes the opinion that the proposed refurbishment is preferrable to the like-for-like replacement.

Response:

(a) The like-for-like replacement was initially evaluated using the 70% flow scenario in the Condition Assessment because that report was a first-stage costed option analysis. At that stage, the purpose was to compare the available options under a common preliminary assumption, including the assumption that 3.39 m^3/s would be available 70% of the time.

Following that initial analysis, the Additional Costed Option Analysis Scenarios report was prepared to address the uncertainty in site-specific hydrology. Because there are no historical flow records for the Factorydale site, that follow-up report developed additional flow-duration curves using Cornwallis River and Beaverbank River data and evaluated both the new-unit and like-for-like options under 10%, 30%, and 70% flow-exceedance scenarios. Therefore, the like-for-like replacement was not excluded from the pessimistic-to-realistic analysis; it was evaluated in the subsequent sensitivity analysis.

(b) The like-for-like replacement under the pessimistic-to-realistic 30% scenario is evaluated in the Additional Costed Option Analysis Scenarios report, page 23, Table 5, “Summary of costs, revenue, ROI and ROE for like for like replacement.” That table includes the 30% cases for both the Canyon and Norcan like-for-like options, using both the Beaverbank and Cornwallis extrapolated flow-duration curves.

That evaluation does not change the conclusion that the proposed refurbishment is preferable. The like-for-like option has a lower initial capital cost and, under some 30% scenarios, produces payback results that are within a comparable range. However, it restores the plant only to the previous 416 kW configuration and does not increase renewable generation capacity. The Additional Costed Option Analysis also notes that the like-for-like option does not have access to the same grant funding because it does not increase renewable energy capacity.

By comparison, the proposed refurbishment provides a modernized unit with higher capacity, improved efficiency, increased generation, better monitoring and controls, improved reliability, and a longer-term asset renewal benefit. The final RETScreen model uses the Cornwallis 30% exceedance scenario as the representative case and estimates approximately 2,701 MWh/year of generation, with a simple payback of 17.1 years and an equity payback of 7.5 years.

Accordingly, even when the like-for-like replacement is evaluated under the same pessimistic-to-realistic 30% scenario, the proposed refurbishment remains the preferred option because it provides greater long-term value, higher energy output, improved reliability, and broader operational benefits to BEC.

Nova Scotia Energy Board Staff Interrogatory IR-31

Interrogatory:

Question(s):

On page 104 – Condition Assessment, CANYON Option – 750 kW - $4,883,466 CAD, states: "…CANYON estimates that if there is a flow of 4 m3/s through the pipe, the unit can reach 750 kW. This is something that we believe can be achieved during the freshet season."

(a) When and how long is the freshet season? Does it change annually?

Response:

For the Factorydale Hydropower Plant, "freshet season" refers to the spring runoff period when river flows are elevated due to winter thaw, snowmelt, spring rainfall, and saturated ground conditions. For the South Branch Annapolis River watershed in Kings County, Nova Scotia, this period would generally be expected to occur during the spring, typically from Late-March through Early-May, with the highest probability of elevated flow occurring in late March and April. The exact timing and duration vary from year to year.

The freshet season does change annually. Its timing, peak flow, and duration depend on annual snow accumulation, the rate of spring thaw, rainfall events, soil moisture, ice conditions, and reservoir operations. Warmer winters, rain-on-snow events, or early thaws can move the freshet earlier, while colder or drier winters can reduce or delay spring runoff.

Nova Scotia Energy Board Staff Interrogatory IR-32

Interrogatory:

Question(s):

Explain what items/equipment will be replaced in the like-for-like option compared to the refurbishment option.

Response:

The like-for-like option was developed as a restorative option intended to return the plant generally to its previous operating configuration and original output level, approximately 416 kW. Under that option, the replacement scope would focus primarily on the damaged turbine-related mechanical components required to put the existing generating arrangement back into service. This would include the damaged turbine runner, wicket gates, operating mechanism components, and related turbine hardware, together with any necessary repairs or replacements required to reconnect the turbine to the existing plant configuration.

The like-for-like option would not represent a full modernization of the plant. It would generally retain the existing generator, existing electrical configuration, existing transformer capacity, existing switchgear/protection philosophy, and existing control/governor architecture except where limited repairs, interfaces, adjustments, or commissioning work would be required to make the restored turbine operate. It would therefore restore generation but would not provide the same increase in capacity, efficiency, automation, monitoring, protection, or lifecycle support as the proposed refurbishment.

By contrast, the proposed refurbishment option replaces and upgrades the hydro-generation system as an integrated modern package. It includes a new 650 kW turbine-generator package, new hydraulic power unit, servos and field piping, new or upgraded governor/control functions, controls, protection, switchgear, commissioning, SCADA/monitoring integration, and a transformer upgrade suitable for the increased generating capacity. The refurbishment scope also includes related decommissioning, spares, installation and commissioning, and intake protection improvements such as the trash rack, intake gate, and log boom works. In short, the like-for-like option replaces only the minimum damaged equipment needed to restore the prior configuration, while the refurbishment option replaces the major electromechanical and protection/control systems required for a modernized, higher-capacity and more reliable plant.

Nova Scotia Energy Board Staff Interrogatory IR-33

Interrogatory:

Question(s):

On page 115 of the Condition Assessment and Costed Option Analysis (September 20, 2024) and page 22 of the Additional Costed Option Analysis Scenarios (October 11, 2024), explain why the cost of the 1013 kW unit is less than the cost of the 750 kW unit.

Response:

The apparent difference in cost between the approximately 1013 kW Norcan option and the 750 kW Canyon option is the result of using preliminary OEM quotations from different suppliers, with different technical approaches, currencies, contingency assumptions, and scope/pricing bases. The costs were not developed as a linear dollar-per-kW comparison.

For the Norcan new-unit option, the preliminary supplier estimate was CAD 3,625,000, and Hysovent as the Owner's Engineers applied a 15% allowance, resulting in CAD 4,168,750. For the Canyon new-unit option, the preliminary supplier estimate was provided in USD and carried a much higher uncertainty allowance of +50%, resulting in CAD 4,883,466 after conversion to Canadian dollars. In both cases, the Owner's Engineers then added CAD 1,000,000 for the new draft tube and transformer, resulting in total modelled initial costs of CAD 5,168,750 for Norcan and CAD 5,883,466 for Canyon.

Therefore, the 1013 kW option appears less expensive than the 750 kW option because the two estimates came from different OEMs and were based on different commercial and technical assumptions. The higher-output Norcan option was not inherently priced on the same basis as the Canyon option. The Canyon estimate included a larger uncertainty allowance and currency conversion impact, which made its modelled project cost higher despite the lower nominal capacity. These figures were high-level feasibility estimates used to compare strategic options. They were not final bid prices and were not intended to establish that a larger unit is generally less expensive than a smaller unit. The later RFP process refined the project scope and resulted in the current selected basis: a more conservative 650 kW Francis turbine-generator package aligned with the final project budget and site constraints.

Nova Scotia Energy Board Staff Interrogatory IR-34

Interrogatory:

Question(s):

Please explain the potential impact on water storage and reservoir levels if generating capacity is increased.

Response:

Increasing the generating capacity of the Factorydale Hydropower Plant does not increase or decrease the amount of water available in the watershed and does not, by itself, require the reservoir to be operated at a higher level. The available water remains governed by watershed inflow, precipitation, snowmelt, reservoir storage, required downstream flow, and spill. The refurbishment increases the plant's ability to convert available hydraulic energy into electricity when sufficient flow and head are available.

The principal operational effect of increased generating capacity is that, during periods of higher inflow, a larger portion of the available water may be passed through the turbine rather than spilled. During these periods, the project may reduce spill and increase renewable energy production without lowering reservoir levels, provided inflow is sufficient and reservoir level controls are maintained.

During lower-flow periods, the higher installed capacity would not be continuously used. The unit would operate below rated output, cycle as required, or be shut down if necessary to maintain reservoir operating levels and water management requirements. In other words, the plant's output would be limited by available flow and head, not simply by the nameplate capacity of the generator.

BEC's intended operating approach is to maintain the reservoir within its normal operating range and to use increased generating capacity only when water is available.

Nova Scotia Energy Board Staff Interrogatory IR-35

Interrogatory:

Question(s):

In several sections of Condition Assessment, Hysovent noted that consistent maintenance records and technical specifications for various equipment were not available.

(a) Please describe BEC's routine maintenance schedule and the applicable standards for generating facilities, electrical equipment, and electromechanical equipment.

(b) Please explain BEC's record-keeping methods for site operations, including but not limited to operating logs, maintenance records, incident logs, and incident investigation reports.

(c) Please provide a copy of the most recent maintenance report for all major electrical and mechanical equipment.
   i. If these records are not available, please explain why.

(d) Please explain BEC's record-keeping approach and operation and maintenance procedures for the proposed new generating system and provide copies of the relevant procedures for review.

Response:

[redacted]

[redacted]

[redacted]

[redacted]

Nova Scotia Energy Board Staff Interrogatory IR-36

Interrogatory:

Question(s):

In Condition Assessment, page 67, Hysovent referred to a structural engineering review of the plant. Further, in Appendix 2 of the condition assessment report, the structural engineer stated the following:
Cause of the cracking cannot be conclusively determined based on the visual site review but may have been initiated by machinery vibrations. A structural analysis is not recommended for the building unless the new machinery is heavier than the current equipment.
[B-1-i, Appendix 2, p.3]

(a) Please compare the weight of the new equipment and existing equipment and explain whether a structural analysis would be required if BEC proceeds with a like-for-like replacement or a new higher-capacity generating system.

Response:

a) Current equipment weight is not known with enough accuracy, but we know that it is below the 10,000 kg limit (to be exact, 9,996 kg) that the crane can lift safely, as per the most recent test conducted on it in 2025. With that in mind, we requested that the weight limit to all components should not be higher than 9,996 kg, and also recommended a scroll case with a snail shell design, which uses less water (and therefore be lighter on the slab of the second level itself) than the current cylindrical design to generate even more energy. With current materials and designs, the weight of the mechanical components was not a concern because we know they will be lighter. The main concern is the heaviest component of the system: the generator. In this case, the new generator weighs 8,410 kgs, which is below the limit of the crane, and considered safe for the structure.

b) This continues with the answer on a). We don't have the current weight of the generator, but we know is lower than 9,996 kG which is the lift weight limit of the crane. The new generator weighs 8,410 kg, which gives a healthy safety margin. A structural analysis was conducted, and simulations were performed that in fact shown that the structure can support loads way over the current ones, due to the design considerations of the time of the construction of the powerhouse and the location of beams and reinforcements.

Nova Scotia Energy Board Staff Interrogatory IR-37

Interrogatory:

Question(s):

Page 5 of Additional Costed Option Analysis Scenarios states that "BEC does not register the water flow through the penstock over the years". Why was BEC not measuring the water flow through the penstock?

Response:

At the moment of preparing the report HSV-2024-043-CA01 and HSV-2024-043-CA02, the records available were scarce. The current SCADA system shows information about the pond levels, but not about the water flows. An analog instrument is in place, but records were not kept with enough detail to build a flow duration curve from them, probably a system design decision at the time of building the current SCADA. Having said that, there were records of past tests performed to the unit that helped to understand its behavior under different flows and different loads. The new unit with updated and simplified SCADA corrects this issue.

Nova Scotia Energy Board Staff Interrogatory IR-38

Interrogatory:

Question(s):

Page 24 of Additional Costed Option Analysis Scenarios, Conclusion, states:
Once we see the numbers on different flow water duration scenarios, comparing it with the information available from the quotes received, it is even clearer than the best option is to go with a new unit.

(a) Explain in detail why comparing the number from the flow scenarios with the information available from the quotes led to the conclusion that “it is even clearer” that the best option is to go with a new unit.

Response:

The report HSV-2024-043-CA02 must be read in conjunction with the first report HSV-2024-043-CA01 to understand the full picture of the condition assessment and costed option analysis.

On the report HSV-2024-043-CA01, we explain in detail the different flow scenarios considered, and we compared them with the limited available performance data of the original machine. When compared, a new design is more efficient in terms of water usage and energy output, without changing elevations and without changing the diameter of the penstock. We studied more scenarios with different flows and in all cases the new unit with optimized design became the best approach. Another big factor, reliability, and simplicity of operations, played a big role in the recommendations.

Nova Scotia Energy Board Staff Interrogatory IR-39

Interrogatory:

Question(s):

On page 35 of Feasibility Study, financing from the green municipal fund is assumed to be 80% of the total capital cost; 15% of that financing portion as a grant; and an interest rate of 4.95%.

(a) Explain how the interest rate of 4.95% was determined and whether this is reasonable and if so why.

Response:

The 4.95% interest rate shown on page 35 of the Feasibility Study was used as a conservative preliminary estimate for GMF financing. At that stage, final GMF financing terms had not been established, and the study noted that the rate may vary at the time of final loan approval.

The assumption is reasonable because it was conservative and avoided overstating the project's financial performance before more detailed financing assumptions were available.

The financial model was later refined using the GMF funding guidance, which indicates that loan rates may be based on the Government of Canada bond rate for an equivalent term, up to 30 years, less 2%. Based on that methodology, page 42 of the Feasibility Study uses an estimated rate of 1.62% for the 30-year GMF loan.

This 1.62% rate is not a confirmed final financing term. It is a more refined estimate based on the GMF methodology and remains subject to GMF approval and the applicable rate at the time financing is finalized.

Nova Scotia Energy Board Staff Interrogatory IR-40

Interrogatory:

Question(s):

On page 37 of Feasibility Study, it states:
We think that the most conservative approach in terms of costs is the one where a unit of 750kW is using a water flow of 3.39 m3/s available 30% of the time. The cost is the highest of all three preliminary quotes received, but it is in fact the most realistic approach.

(a) Explain in detail why it is the most realistic option and is more realistic than all the other options explored.

Response:

The realism of the option is related to the overall cost of the system and the water availability to produce energy. At the time of conducting the study, we received very high-level quotes for the installation of a new unit. Of all the costs, at that time, and all the approaches, that was in fact the closest one to the simulations and calculations that we performed.

A key aspect of the study is the availability of water. A bigger machine can be installed (in fact, in one of the most "aggressive" models we were able to fit a 1MW unit on the plant) but the amount of energy that will be produced it is in fact significatively reduced, because the machine will use more water than the original one when the capacity is doubled. At that time, the 750 KW represented the best option, and subsequent analysis and once we received more detailed quotes and info from the market, we reached the consensus that a 650 KW unit was in fact the best fit.

Nova Scotia Energy Board Staff Interrogatory IR-41

Interrogatory:

Question(s):

On page 38 of Feasibility Study, it states:
Having said that, we are going to be even more conservative. We think that a unit on the lower end of the power output range, a 650 kW machine, will be closer to the final design approved (conservative scenario). With all the ancillary systems, including a new transformer, a new draft tube, and a new trash rack, including contingency, the financial models with the two flow duration curve scenarios, will be as follows:…

(a) Explain why are you being “more conservative” saying 650 kW?

Response:

The 650 kW scenario was described as “more conservative” because it uses the lower end of the expected output range, rather than assuming that the project would achieve the higher 750 kW output. This avoids overstating future generation, revenue, or project economics before final design, procurement confirmation, and validation of long-term operating data.

The 650 kW case is also technically more conservative because it better matches the known hydraulic conditions at Factorydale. The plant design flow is approximately 3.39 m³/s and the net head is approximately 22 m, which support an output near 650 kW when realistic turbine-generator efficiencies are applied. A 750 kW or higher-rated unit would require higher available flow, higher effective head, or more frequent operation near peak hydraulic conditions. Given the limited site-specific long-term flow records, using 750 kW as the base case would increase hydrology and utilization risk.

Therefore, the 650 kW option is not simply a lower-capacity assumption; it is a technically practical and financially conservative basis for the Application. It remains aligned with the selected [redacted] proposal, while still carrying the full project cost of approximately CAD 6,000,000. This tests the project under a lower-output, full-cost scenario rather than relying on the most optimistic generation case.

Nova Scotia Energy Board Staff Interrogatory IR-42

Interrogatory:

Question(s):

With respect to the Feasibility Study, Section 6, Table 5, Risk Evaluation, page 47:

(a) Under cybersecurity, please describe BEC's final plan and procedures for managing this risk.

(b) Please explain whether the listed risks apply only during the project stage, or whether any of them will also require long-term monitoring and management, for example cybersecurity, environmental, and operational risks.

  i. If yes, please list all risks require long-term monitoring and describe how BEC would continue to manage those risks.

  ii. If no, please explain why.

Response:

BEC will implement a high-level cybersecurity approach for the new control, protection, monitoring, and SCADA-related systems. The project will not enable general remote control of the generating unit or associated plant equipment. Control of the unit will be limited to authorized devices located on BEC premises, including one primary authorized control workstation and one backup authorized control workstation. Any monitoring access will also be limited to specifically authorized devices and users, with appropriate authentication, access control, and logging.

At this stage, the final cybersecurity architecture cannot be fully defined because the detailed design, final control philosophy, communication architecture, and complete list of control and monitoring variables have not yet been finalized. Once the final design is completed, BEC will engage a qualified cybersecurity specialist to develop and implement a detailed cybersecurity plan for the plant control and monitoring environment.

The detailed plan will address, as applicable, network segmentation, user access levels, password and authentication requirements, firewall/VPN rules if required, backup and recovery, software update practices, event logging, change management, vendor access control, incident response procedures, and cybersecurity checks during commissioning. The objective is to ensure that control functions remain restricted to authorized BEC-operated equipment while allowing secure monitoring of the plant by approved personnel and devices only.