BC Hydro
Power smart

6911 Southpoint Drive (B03)
Burnaby, BC
V3N 4X8

August 20, 2025

[redacted]

[redacted]

Dear [redacted],

RE: [redacted] Project - Interconnection System Impact Study Report

Enclosed is the Interconnection System Impact Study report for the proposed [redacted] project submitted under Attachment M-1: Standard Generator Interconnection Procedures (SGIP) including Standard Generator Interconnection Agreement (SGIA) of the Open Access Transmission Tariff (OATT).

This letter provides a non-binding good faith estimate of the cost and time to construct the facilities required to interconnect your project to BC Hydro's Transmission System, being the Network Upgrades, based on the findings of the Interconnection System Impact Study.

Open Access Transmission Tariff

The OATT defines Network Upgrades as additions, modifications, and upgrades to BC Hydro's Transmission System required at or beyond the Point of Interconnection (POI) to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Cost Estimate

Based on the Interconnection System Impact Study, the non-binding good faith estimated cost (typical accuracy range of +100%/-35%) for Network Upgrades required to interconnect your project is **$76.8M**. Please note that the cost estimate may be amended in the near future to reflect the SIS results of other Interconnection Requests (with the same queue position) in the same region.

Major Scope of Work Identified:

Stations Scope – [redacted] Terminal Switching Station (BTTX)

- Acquire adequate property close to the existing transmission line 2L154 and construct a new 230kV switching station.

Transmission Line Scope

- Re-terminate line 2L154 near the POI to the new switching station and install up to three 230kV 3-pole dead-end structures for each side of the re-termination.
- A dead-end structure should be installed as a demarcation point between Customer owned 230kV line and BC hydro owned portion of the line.

Protection and Control Scope at Strathconna Generating Station (SCA), John Hard Generating Station, Dunsmuir (DMR), Gold River (GLD), Tahsis Village (TSV), Port Hardy (PHY), Kokish (KTS), and the new BTTX Switching Station, including:

- Modifications/additions to the local Load Shedding Remedial Action Scheme (RAS) include updating protection relays, adding alarms, metering, and telemetry at DMR and GLD, and installing the complete control system suite at BTTX.

Telecom Scope at SCA, GLD, DMR, BTTX, and other microwave stations, repeater stations, and substations, including:

- Installing/adding routing nodes and equipment, towers, antennas, battery and charger requirements, microwave radio systems, routers and firewalls, and teleprotection terminals.

Exclusions:

- GST
- Outage costs
- Permits
- Book value of decommissioned equipment

Key Assumptions:

- Construction may be completed by BCH or its contractor(s)
- 27 months of construction
- No expansion of existing station or control building to accommodate new equipment
- Environmental assessment certificate not required for this project.
- Properties to be purchased are not known, an allowance of 1% of IMP cost has been included as an allowance to offset this cost.

Key Risks:

- Delays in receiving documentation from Interconnection Customer
- Telecom scopes present high risk of change due to rapidly evolving technologies and standards.
- Property acquisition cost may be higher than assumed
- No defined supply chain strategy, construction costs may increase depending on delivery method
- Cost of construction may increase based on geotechnical conditions at the actual project site.
- Project schedule may be longer than expected, leading to increased costs
- Costs may be affected by market conditions and escalation

Technical Interconnection Requirements and Revenue Metering Requirements

As part of our commitment to maintaining a reliable and responsive grid, BC Hydro maintains its Technical Interconnection Requirements (TIR) documentation (updated in February 2024). You will be required to meet the TIR as your project will be connecting to the BC Hydro Transmission system. Some of the revisions made in February 2024 include new provisions for Inverter-Based Resources (IBRs), which are required to participate in primary frequency regulation. BC Hydro looks forward to working closely with you so that you can meet the TIR and can assist with any technical questions you may have. For more details on the TIR, please refer to:

https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/transmission/tgi/60kV-500kV-TIR-for-power-generators-2024-feb.pdf

The Revenue Metering requirements to interconnect your project have been identified in the System Impact Study report. However, the Revenue Metering costs are not included in the above estimate as they are separate from the cost of Network Upgrades. Revenue Metering costs that are attributable to the Interconnection Customer are to be paid in cash. For more details on Revenue Metering requirements and responsibilities, please refer to:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/distribution/standards/ds-rmr-complex-revenue-metering.pdf.

Schedule

Based on the Interconnection System Impact Study, the non-binding good faith estimated in-service date for your project's Network Upgrades is **June 30, 2028** to align with the requested in-service date from your Interconnection Request. To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of equipment; the expediting of activities may result in increased costs.

Timely actions required from you for the rest of the interconnection process to minimize risks to the schedule:

- Submission of any additional required technical data
- Submission of any required information or documents such as demonstration of Site Control
- Execution of a Standard Generator Interconnection Agreement
- Providing Financial commitments and securities, as required

Please note that changes to your interconnection request, delays in data submission or financial commitments may also impact the target in-service date.

Next Steps

In Fall 2025, we are targeting to issue a final invoice for the System Impact Study costs. This invoice will reflect the total amount due or amount to be refunded, taking into account the System Impact Study deposits already paid.

Should you wish to discuss the contents of the SIS, BC Hydro can arrange for an optional SIS Review Meeting. Following the SIS Review meeting, BC Hydro will provide you with a cost estimate for the Facilities Study, which is being conducted concurrently with the SIS Study, along with any additional data requirements.

As the Facilities Study deposit has already been received, we kindly ask that you confirm your intention to continue with the Facility Study with the scope of work identified in the System Impact Study report following your review of the report. In the case we require more information from you, we will require the additional information to be provided in a timely fashion.

If you have any questions, please contact Transmission Generator Interconnections team at transmission.generators@bchydro.com.

Sincerely,

[redacted]

Interconnections Manager, Transmission Generator Interconnections

BC Hydro

Encl.: [redacted]_System Impact Study_Report.pdf

CC: As required

[redacted] Project

Interconnection System Impact Study

BC Hydro EGBC Permit to Practice No: 1002449

[redacted]

Prepared for: [redacted]

Prepared by: [redacted]

Sr. Engineer, Interconnection Planning

Reviewed by: [redacted]

Manager, Interconnection Planning

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

Header:	[redacted] Project
Subheader:	Interconnection System Impact Study
Title:	[redacted] Project
Subtitle:	[redacted]
Report Number:	524D-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Aug 15
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Sr. Engineer, Interconnection Planning
Checked by:	[redacted]
Title:	Specialist Engineer, Interconnection Planning
Reviewed by:	[redacted]
Title:	Manager, Interconnection Planning
Related Facilities:	Facility station code – BRW Line designation – 2L154
Additional Metadata:	Transmission Planning 2025-030 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Aug	Initial release

Disclaimer of Warranty, Limitation of Liability

This report was prepared solely for internal purposes. All parties other than BC Hydro are third parties.

BC Hydro does not represent, guarantee or warrant to any third party, either expressly or by implication:

any information, product or process disclosed, described or recommended in this report.

BC Hydro does not accept any liability of any kind arising in any way out of the use by a third party of any information, product or process disclosed, described or recommended in this report, nor does BC Hydro accept any liability arising out of reliance by a third party upon any information, statements or recommendations contained in this report. Should third parties use or rely on any information, product or process disclosed, described or recommended in this report, they do so entirely at their own risk.

This report was prepared by the British Columbia Hydro And Power Authority ("BCH") or, as the case may be, on behalf of BCH by persons or entities including, without limitation, persons or entities who are or were employees, agents, consultants, contractors, subcontractors, professional advisers or representatives of, or to, BCH (individually and collectively, "BCH Personnel").

This report is to be read in the context of the methodology, procedures and techniques used, BCH's or BCH's Personnel's assumptions, and the circumstances and constraints under which BCH's mandate to prepare this report was performed. This report is written solely for the purpose expressly stated in this report, and for the sole and exclusive benefit of the person or entity who directly engaged BCH to prepare this report. Accordingly, this report is suitable only for such purpose, and is subject to any changes arising after the date of this report. This report is meant to be read as a whole, and accordingly no section or part of it should be read or relied upon out of context.

Unless otherwise expressly agreed by BCH:

(a) any assumption, data or information (whether embodied in tangible or electronic form) supplied by, or gathered from, any source (including, without limitation, any consultant, contractor or subcontractor, testing laboratory and equipment suppliers, etc.) upon which BCH's opinion or conclusion as set out in this report is based (individually and collectively, "Information") has not been verified by BCH or BCH's Personnel; BCH makes no representation as to its accuracy or completeness and disclaims all liability with respect to the Information;

(b) except as expressly set out in this report, all terms, conditions, warranties, representations and statements (whether express, implied, written, oral, collateral, statutory or otherwise) are excluded to the maximum extent permitted by law and, to the extent they cannot be excluded, BCH disclaims all liability in relation to them to the maximum extent permitted by law;

(c) BCH does not represent or warrant the accuracy, completeness, merchantability, fitness for purpose or usefulness of this report, or any information contained in this report, for use or consideration by any person or entity. In addition, BCH does not accept any liability arising out of reliance by a person or entity on this report, or any information contained in this report, or for any errors or omissions in this report. Any use, reliance or publication by any person or entity of this report or any part of it is at their own risk; and

(d) In no event will BCH or BCH's Personnel be liable to any recipient of this report for any damage, loss, cost, expense, injury or other liability that arises out of or in connection with this report including, without limitation, any indirect, special, incidental, punitive or consequential loss, liability or damage of any kind.

Copyright Notice

Contributors

The following Professionals of Record (POR) accept responsibility for their technical content in the specified respective sections. Professionals apply their signature and/or seal for the technical or non-technical content as appropriate.

Section: Discipline:

The entire report except those listed below — Interconnection Planning

Contributed by: [redacted]

Sr. Engineer, Interconnection Planning

[redacted]

Section: Discipline:

5.7 — Stations Planning

Contributed by: [redacted]

Engineer, Substations Growth and Sustainment

[redacted]

Section: Discipline:

5.8 — Transmission Line Engineering

Contributed by: [redacted]

Sr. Engineer, Transmission Line Engineering

Section: Discipline:

5.9.1&5.9.2 P&C Planning

Contributed by [redacted]

Specialist Engineer, Transmission P&C Engineering [redacted]

Section: Discipline:

5.6 Transmission Operations Services

Contributed by: [redacted]

Specialist Engineer, Transmission Operations Services [redacted]

Section: Discipline:

5.4 Analytical Studies

Contributed by: [redacted]

Engineering Team Lead, Substations Growth and Sustainment [redacted]

Section: Discipline:

5.9.3 Telecom Planning

Contributed by: [redacted]

Specialist Engineer, Telecom Planning & Asset Management [redacted]

Section: Discipline:

7 Revenue Metering

Contributed by: [redacted]

Specialist Engineer, Revenue Metering [redacted]

Table of Contents

Tables

BC Hydro
Power smart

Figures

Appendices

Acronyms

The following are acronyms used in this report.

BCH British Columbia Hydro and Power Authority

BRW [redacted] Project

BTTX [redacted] Terminal Station

BWVx [redacted] Back-to-Back Repeater Site (Temporary site code)

COD Commercial Operation Date

CSS Cape Scott Wind Substation

CT Current Transformer

DMR Dunsmuir Substation

DTT Direct Transfer Trip

EFM Duncan Bay Substation

EMS Energy management System

ERIS Energy Resource Interconnection Service

FRT Fault Ride-Through

FVO Fraser Valley Office

GLD Gold River Substation

GRP West Coast Marine Terminals Substation

HS Heavy Summer

HW Heavy Winter

IC Interconnection Customer

ICG Island Generation Facility

IP Internet Protocol

ISD In-Service Date

JHS John Hart Substation

JHN John Hart Generating Station

KKS Kokish River Generating Station

KTS Kokish Terminal Station

LDR Ladore Falls Generating Station

LS Light Summer

MC Measurement Canada or Canada federal regulations

MPO Maximum Power Outputs

NERC North American Electric Reliability Corporation

NRIS Network Resource Interconnection Service

OOS Out of Service

PODR Point of Delivery Reference

POI Point of Interconnection

POM Point of Metering

PPIS Power Parameter Information System

RAS Remedial Action Scheme

SCA Strathcona Generating Station

SCC System Control Centre

SIS System Impact Study

STN Strathcona Microwave Repeater Site

TIR BC Hydro 60 kV to 500 kV Technical Interconnection requirements for Power Generators

TOV Temporary Overvoltage

TSV Tahsis Village Substation

VT Voltage Transformer

WECC Western Electricity Coordinating Council

Executive Summary

[redacted] the Interconnection Customer (IC), requests to connect the [redacted] into the BCH system, which locates in the North Vancouver Island, BC.

The [redacted] Project will feature [redacted] wind turbine generators, each with the rated capacity of 7.7 MVA. The total installed capacity of the project is 197.2 MW, with a maximum power injection of 189.3 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's 230 kV transmission line 2L154, approximately 47 km from Gold River Substation (GLD). The IC's proposed Commercial Operation Date (COD) is December 31, 2028.

To interconnect the [redacted] Project to the BCH Transmission System at the POI, the SIS has identified the following conclusions and requirements:

1. A new 230 kV switching station (temporarily referred to as "BTTX") on the BCH's existing circuit 2L154 is required at or close to the proposed POI for interconnecting the IC's generating project to the BCH system. With the new switching station BTTX, 2L154 will be segregated into two segments, temporarily referred as: 2L154_A (GLD-BTTX) and 2L154_B (BTTX-DMR). The 230 kV transmission line which is to be built by the IC for connecting the project is temporarily designated as 2L154_C (BTTX-BRW).

2. The connection of the [redacted] Project does not cause any performance violations (i.e. thermal overload, voltage violation, voltage stability) under system normal conditions. However, certain contingencies may result in thermal overloads, voltage violations and instability concerns in the system, which are attribute to the addition of [redacted] project. To address those concerns, the North Vancouver Island remedial action schemes (RAS) and JHN/ICG/EFM RAS need to be updated and the [redacted] Project is required to participate in the updated North Vancouver Island RAS and JHN/ICG/EFM RAS.

3. The proposed [redacted] project can meet the respective reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over most of the MW operating range (including full to lower MW output), and also provides a partial reactive capability at zero MW output provided that the turbine's optional "STATCOM" option is enabled. This

"STATCOM" mode shall be made available to each of the wind turbines at [redacted] project.

4. Virtual Inertia Control (VIC), a form of Fast Frequency Response, is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC function, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

5. A telecommunication-based Direct Transfer Trip (DTT) scheme is required to prevent the [redacted] Plant from operating under unstable conditions or forming a potential island. This DTT scheme will initiate a trip to the [redacted] plant for any protection tripping or manual opening of the line 2L154_B between the new switching station BTTX and DMR substation and is part of the updated North Vancouver Island RAS.

6. Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by the TIR. The [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.

7. BCH will provide line protections for 2L154_A, 2L154_B and the BTTX terminal of 2L154_C after the existing 2L154 being segregated as a part of this project interconnection. The IC is to provide entrance protection at IC's station BRW to comply with BCH's TIR. The IC is to provide two [redacted] relays at the entrance of BRW to provide protection coverage for 2L154_C.

8. The inverters of the [redacted] project are required to have fault ride-through (FRT) capabilities per BCH's TIR. Using the default settings provided, the fault ride-through performance of the inverters is satisfactory and does not result in unexpected tripping or momentary cessation in dynamic simulations. BC hydro may follow up on the ride-through settings during the pre-commissioning stage.

The above conclusions are made based on the IC's input data and study assumptions listed in Section 4, which represents the best available information for the study.

A non-binding good faith cost estimate and the estimated schedule of the Network Upgrades identified for the project interconnection are provided in a letter that accompanies this report. The identified Network Upgrades refer to the additions and modifications to the BC Hydro owned transmission facilities for interconnecting the proposed project.

1 Introduction

[redacted] the Interconnection Customer (IC), requests to connect its [redacted] Project to the BC Hydro (BCH) system. The project will feature [redacted] wind turbine generators, each with capacity of 7.7 MVA and rated active power output of 6.8 MW. The total installed capacity of the project will be approximately 197.2 MW, with a maximum power injection of 189.3 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's 230 kV transmission line 2L154, approximately 47 km from Gold River Substation (GLD). The IC's proposed Commercial Operation Date (COD) is December 31, 2028. The key information of the project reviewed in this SIS is summarized in Table 1-1 below.

Table 1-1: Summary of Project Information

Project Name	[redacted] Project	
Interconnection Customer	[redacted]	
Point of Interconnection	on 2L154, 47 km from GLD	
IC Proposed COD	December 31, 2028	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	189.3 (Summer)	189.3 (Winter)
Number of Wind Turbine Generators	29	
Plant Fuel	Wind	

The power generated from the wind turbines will be stepped up to 34.5 kV through step-up transformers, and further stepped up to 230 kV via two 208 MVA main power transformers. The IC's 230 kV substation is referred to as "BRW". The power will be transmitted through an IC owned [redacted] 230 kV transmission line to the BC Hydro system on line 2L154, which runs between Gold River Substation (GLD) and Dunsmuir Substation (DMR).

Figure 1-1 illustrates the North Vancouver Island (NVI) region 132/230 kV transmission system with the interconnection of [redacted] Project. NVI is a generation rich sub-area where most of the generation in Vancouver Island is located. Within the NVI 132/230 kV system, there are pre-existing system overload concerns under contingencies. The North Vancouver Island Remedial

Action Scheme (NVI RAS) has been implemented to specifically addresses thermal overloads on 1L120 (GLD-SCA) and other 132 kV lines in the event of a loss of the existing circuit 2L154 (GLD-DMR) during periods of high generation output. The NVI RAS will reduce the generation output of Cape Scott Wind (CSS) and Kokish River Generating Station (KKS) below their 50% maximum capacity in 50 seconds.

The NVI RAS also includes several direct transfer trips (DTT) schemes designed to prevent serious contingencies from affecting system stability. DTTs to isolate CSS and KKS are required following multi-phase faults on the existing circuit 2L154, 1L120, 1L131 and 1L134 during periods of high CSS and KKS generation.

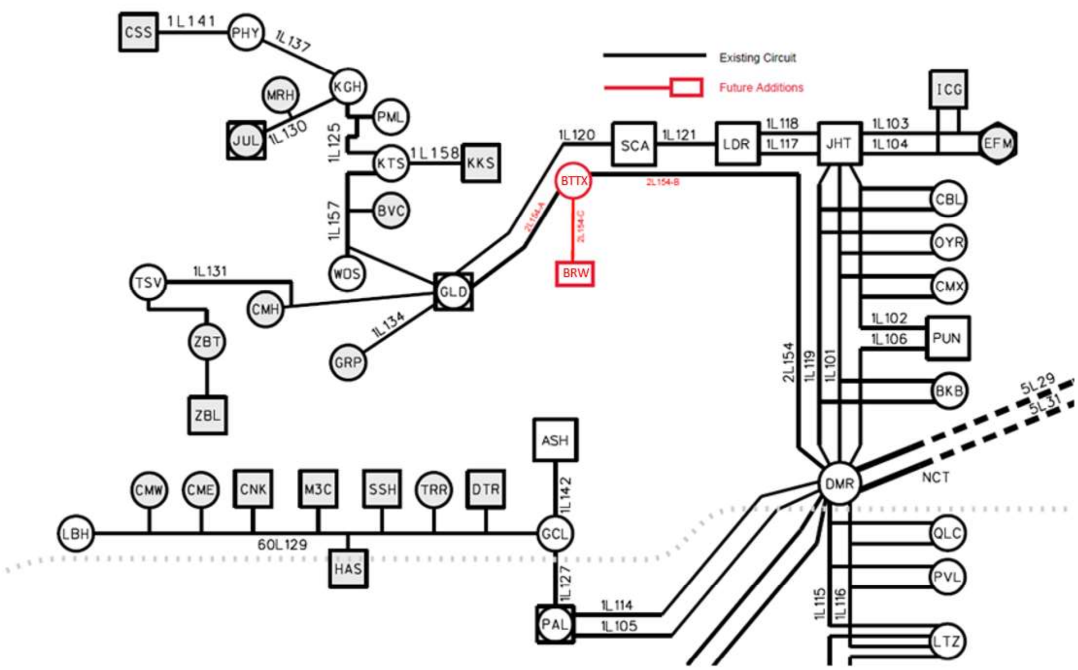

Figure 1-1: North Vancouver Island Transmission System with [redacted] Project Addition

Appendix A further shows the plant-level schematic diagram of the [redacted] Project.

2 Purpose of Study

The purpose of this System Impact Study (SIS) is to assess the impact to the BC Hydro transmission system of interconnecting the proposed Customer's facility, in accordance with the relevant BCH Open Access Transmission Tariff (OATT).

This study aims to identify transmission constraints and determine system reinforcement options, including the implementation of a Remedial Action Scheme (RAS) for generation shedding or generation runback, to ensure adequate performance and the reliable operation of the BC Hydro transmission system.

The SIS is performed in accordance with the North American Electric Reliability Corporation (NERC) reliability standards, Western Electricity Coordinating Council (WECC) performance criterion, and BC Hydro transmission planning requirements, specifically:

- NERC standards: FAC-002-3, TPL-001-4;
- WECC Performance Criterion: TPL-001-WECC-CRT-4;
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators per NERC Standard FAC-001-3; and
- BC Hydro's Transmission Asset Planning FAC-002-3 Study Guide.

3 Scopes of Study

This study investigates potential thermal overloading, voltage performance and stability constraints of the transmission system as a result of the proposed interconnection and identifies the requirements of the Network Upgrades in the BC Hydro transmission system to accommodate the IC's proposed interconnection.

This study is based on available information provided by the IC. Further studies or a study update may be required when additional data from the IC is available or key study assumptions are updated.

This study does not address the possible impact of the proposed interconnection on the adjacent systems that are neighboring with the BCH system. BC Hydro coordinates and cooperates with the neighboring systems per FAC-002-3 for them to assess the potential impact on the adjacent systems when needed.

4 Assumptions and Conditions

This SIS is performed based on the information in the IC's interconnection data form submitted on March 5, 2025.

The study assumptions and conditions used in the study cases include the forecasted load levels, generation resource plans, and facility ratings, etc. for the selected study years as appropriate. The key assumptions and study conditions used in this SIS are listed below:

- The 2028 Heavy Winter (HW) and 2029 Heavy/Light Summer (HS/LS) study cases are selected to study the proposed interconnection of the subject generating project.

- The generation dispatch in the study model represents both existing and future generators in BC Hydro's Base Resource Plan (BRP) that was available to start the SIS.

- Similarly, the forecasted loads in the study model represent the existing and future loads that were available at the time of preparing the SIS.

- The facility ratings used in this study are based on BC Hydro operating order 5T-10 dated May 12, 2025, and 5T-14 dated Dec 18, 2024.

- The regional generation are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the regional generations are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a three-circuit-breaker-ring switching station (referred to as "BTTX") at the proposed POI on 2L154 is required to interconnect the IC's generating project to the BCH system. The addition of the new switching station would maintain reliability and adequacy of system protection performance to serve the existing customers and the new addition.

With the new switching station BTTX, the existing 230 kV line 2L154 will be segregated into two new lines, temporarily referred to as: 2L154_A (GLD-BTTX), 2L154_B (BTTX-DMR). The proposed customer-built 230 kV line (BTTX-BRW) will be designated temporarily as 2L154_C. The temporary line designations will be replaced by permanent designations at a later stage of interconnection study.

5.1 Steady-State Power Flow Study

A series of pre- and post-contingency power flow analyses were performed to assess the impact of the subject project on the regional transmission system. The study was performed using the selected 2028 Heavy Winter (HW) load and 2029 Heavy/Light Summer (HS/LS) load conditions, based on the assumptions and considerations outlined in Section 4.

The power flow study finds no thermal overload or voltage violations under system normal conditions. Under various system contingencies, thermal overloads on the circuits 1L120 (GLD-SCA), 1L121 (SCA-LDR), 2L154_A (GLD-BTTX), 2L154_B (DMR-BTTX) and low voltage performance are observed. These overloads are driven or exacerbated by addition of the [redacted] project.

To address those thermal overload and low voltage violations under the contingencies, the [redacted] project will need to participate in the remedial action scheme (RAS) as stated in Section 5.6.

Appendix B contains the key results of power flow studies.

BCH TIR Section 6.4.2 requires Inverter Based Resource (IBR) power plant to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the IBR plant at the high-voltage side of the switchyard over the full MW operating range. The simulation results for the [redacted] Project indicate that the project meet the reactive capability requirements over most of the MW operating range (including full to lower MW output). No additional reactive resource is required at the facility. However, the turbine's "STATCOM" option is required so that each turbine can provide partial reactive power capability at zero MW output.

The IC is required to install anti-islanding protection within their facility to disconnect the wind farm from the grid when an inadvertent island with the local load forms. This anti-islanding protection shall be configured in the manner that does not compromise the required rid-through performance.

5.2 Transient Stability Study

Transient stability studies have been performed using the 2028 heavy winter and 2029 light summer base cases to assess the impact from [redacted] Project interconnection on the transmission network, in accordance with the TPL-001-WECC-CRT- 4 Performance Criteria.

Transient instability phenomenon has been observed in the area due to addition of [redacted] Project for a multi-phase fault on 2L154_B from BTTX to DMR. It is required to trip the [redacted] generators in a modified NVI RAS for this event as stated in Section 5.6.

In addition, upon the IC's submission, the WTGs at [redacted] project can provide fast frequency response (FFR) when the turbine's Virtual Inertia Control (VIC) function is enabled. The VIC function is required at [redacted] project to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

Appendix C shows a summary of the transient stability study results for 2029 light summer load conditions with the addition of [redacted] Project.

5.3 Reliability Impact to Adjacent Utilities

The study did not find any reliability impact of the proposed interconnection to adjacent systems. Therefore, it is not necessary to coordinate the study results with adjacent utilities in accordance with FAC-002-3.

5.4 Analytical Studies

Analytical studies identified the following key findings and recommendations:

- The risk of temporary overvoltages (TOVs) was assessed under the unintentional islanding contingency. Islanding occurs when the [redacted] and possibly a portion of loads become isolated from the main grid but remain energized. Based on the analysis, no risk of TOVs was identified.
- A telecommunication-based Direct Transfer Trip (DTT) scheme is required to prevent the [redacted] Plant from operating under unstable conditions or forming a potential island. This DTT scheme will initiate a trip to the [redacted] plant for any protection tripping or manual opening of the line 2L154_B between the new switching station BTTX and DMR substation and is part of the updated North Vancouver Island RAS as per Section 5.6.
- Voltage disturbance resulting from energization of a [redacted] main power transformer was studied under system normal and contingency conditions. The voltage sags exceeded the limit specified in BC Hydro's 60-500 kV Technical Interconnection Requirements for Power Generators (TIR). The [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.
- The harmonic current injection from the [redacted] Project shall not exceed the limit specified in TIR, which follows IEEE Std 519-2022. Harmonic studies will be conducted at a later stage when the spectrum of harmonic current injection from the solar farm becomes available.
- [redacted] Electromagnetic Transient (EMT) model is parameterized with the voltage and frequency ride-through settings that meets TIR requirements. BC hydro may follow up on this topic during the pre-commissioning stage.
- The electromagnetic transient responses of the [redacted] including the active power control, reactive power control, and dynamic active power support under abnormal frequency conditions, are in accordance with the facility's electrical and control requirements.
- The converter-driven stability of the [redacted] Plant was evaluated under reduced Short Circuit Ratios (SCRs). Simulations were conducted to analyze the dynamic interactions between the control systems of power electronic-based equipment and the transmission network. The [redacted] Plant demonstrated stable operation under these reduced SCR conditions, with SCR values determined based on credible operating scenarios selected for the study (except 2L154_B contingency that necessitate DTT tripping of BRW).

5.5 Short Circuit Analysis

The short circuit analysis for the System Impact Study is based upon the latest BC Hydro system model, which includes project equipment and impedances provided by the IC. Thevenin impedances for the near-term system conditions and the ultimate fault levels at POI are not included in this report but will be made available to the IC upon request.

5.6 Remedial Action Schemes

To maintain and meet the system reliability performance requirements under various operating conditions, the [redacted] project is required to participate in the existing North Vancouver Island RAS and the JHN/ICG/EFM RAS.

To mitigate thermal overloads of 1L120, 1L121, 2L154_B and transient instability identified for various system contingencies including single contingencies (P1, P2) and multiple contingencies (P4, P6), modification of the NVI RAS is required and BRW needs to be included as part of generation run back scheme for detected thermal overload and transfer trip scheme for contingencies that can cause transient instability.

The JHN/ICG/EFM RAS prevents thermal overloads of 1L101, 1L102, or 1L119. Modification of the RAS is required and BRW needs to be included as part of the generation run back scheme under critical system conditions.

5.7 Station Upgrade Requirements

The station upgrade requirements for [redacted] project are as follows:

- Acquire adequate property for the new [redacted] Terminal switching station (BTTX) close to the existing transmission line 2L154. The property shall be chosen considering ultimate stage of the BTTX switching station.
- Construct a new outdoor 230 kV, 3-circuit breaker ring bus switching station. Three circuit breakers (2CB1, 2CB2 and 2CB3) and associated disconnects shall be rated at 3000A.
- Install three 230 kV line terminals associated motorized disconnects, Surge Arresters and Capacitor Voltage Transformers for the transmission lines 2L154_A, 2L154_B and 2L154_C. The three line disconnects and associated bus works shall be rated at 2000 A.
- Install associated station service, P&C, telecom, SCADA, and mechanical equipment including fire detection/extinguishing devices.

- Install other necessary equipment and facilities required for new BTTX switching station, including 230 kV station service VTs, diesel generator for station service backup, a new control building and other required substation structure, and station ground system.
- Refer to draft one-line sketch (Appendix E) for details. The one-line sketch will be adjusted based on the size and orientation of the acquired property.

5.8 Transmission Line Upgrade Requirements

The transmission line scope of work for BC Hydro is to design, build and own the switching station (See Appendix F for details) that consists of the following:

- Re-terminate line 2L154 at approximately structure 101-02 (POI) to the new switching station BTTX forming section 2L154_A. And re-terminate the other portion of line 2L154 at approximately structure 101-01 (POI) to the new switching station BTTX, forming section 2L154_B. This may require up to six 230 kV 3-pole dead-end structures depending on the BTTX ‘s location. The exact circuit number will be determined at a later stage. (See Appendix F for details)
- Additional right of way may be required to accommodate the ingress and egress of the line.
- Some portion of the existing line may need to be decommissioned which will involve removing some conductor, hardware, and existing structure.
- A dead-end structure should be installed as a demarcation point between IC owned and BC Hydro owned. BC Hydro will design and build the last span into BTTX. If the IC would like to design and build the last span of 2L154_C into BTTX, BC Hydro will review for acceptance.
- A single-mode fibre optic cable may be installed on IC’s line 2L392_C, with BC Hydro designing its termination and transition to the control building; if the IC builds the last span to TYTX, BC Hydro will perform review.

5.9 Protection, Control and Telecommunications

5.9.1 Protection

BC Hydro will provide line protections for 2L154_A, 2L154_B and the BTTX terminal of 2L154_C. Protection work is also required at some BC Hydro substations in the area.

The IC is required to provide the following for the interconnection of its [redacted] project.

- Entrance protection that complies with the current version of the "60 kV to 500 kV BC Hydro Technical Interconnection Requirements for Power Generators."
- Provide two [redacted] relays (firmware and options specified by BC Hydro) relays at the entrance of [redacted] to provide protection coverage for 2L154_C. BC Hydro P&C Planning will provide core settings for these relays to protect transmission line 2L154_C during a transmission line fault. Non-core protection such as local breaker failure, auto-reclosing, backup protection for station elements will not be provided by BC Hydro P&C Planning.
- The IC is responsible for NERC PRC-related tasks, settings to compliance standards within their facilities.
- The IC is responsible for providing a communications link for remote interrogation of the line protection relays and Power Parameter Information System (PPIS) equipment by BCH servers.
- Provide anti-islanding protection as per Section 5.4.
- The IC is required to participate in the North Vancouver Island RAS and the JHN/ICG/EFM Generation Shedding RAS as per Section 5.4. The IC to provide provision to receive RAS signals and trip the breakers independently.
- The IC is required to provide and connect dual trip coils for 230 kV circuit breakers.

5.9.2 Control

The IC will provide SCADA data reporting to the control centers in accordance with the TIR, including required telemetry and status information, which should be available to the Energy Management System (EMS) at the nearest suitable BC Hydro site with appropriate telecom facilities. This data is supplied to BC Hydro Control Centers in DNP 3.0 format. All data provided in response to poll messages transmitted by BC Hydro must be completed in less than or equal to 2 seconds. Continuous communications using commercial lease or privately constructed connection from the IC to BC Hydro control centers is acceptable provided the performance objective stated in the TIR is met.

The IC's telemetry and status will be routed to the appropriate Data Collection Platform (DCP). BC Hydro control centers are required to reconfigure the existing equipment to accommodate the new IC, include the generator into the network model, and add the new telemetry and alarm points.

The IC is responsible for providing a communications link for remote interrogation of the PPIS equipment by BCH servers. Alternative communications include Internet Protocol (IP) cellular modem, IP satellite, BCH Wide Area Network (WAN) (where appropriate). The relay interrogation functionality should be provided by an [redacted] or equivalent. Communications and equipment selection is subject to BCH review and approval.

BRW 230 kV circuit breakers are required to be equipped with dual trip coils and to provide point-on-wave (POW) controller with independent pole operated (IPO) 230 kV circuit breakers.

BC Hydro Control work including control/indication, alarms, metering, etc will be required at GLD, BTTX, DMR, SCA, LDR, JHT/JHN, PHY, KTS, and TSV for the new equipment, protection relays, RAS IEDs, and telecom channels.

BC Hydro control centers are required to add BTTX and BRW in the EMS network model.

5.9.3 Telecommunications

A telecom solution has been identified to meet the requirements for teleprotection, telecontrol, RAS and other network additions (see these requirements in Appendix G). The detailed telecom work scopes and specs will be provided in detail at the later stage of Interconnection Studies.

A line-of-sight (LOS) microwave link from BTTX (and extended via fiber optic cable to BRW) to Stratchona Microwave Repeater (STN) is required to support WECC Level 3 Remedial Action Scheme (RAS)/teleprotection and operational circuits to interconnect [redacted] to the BC Hydro transmission network.

A Microwave back-to-back passive repeater (temporarily referred to as ‘BWVx’) will be employed, involving property acquisition, site clearing, and path surveys to BTTX and STN.

IC’s Work Required at BRW

- Install a 48 strands single-mode fibre optic cable along the new 230 kV transmission lines 2L154_C to BTTX and terminate to a Fiber Optic

Terminal Rack (FOTS Rack) in the control building; install a 48V DC power supply with 8-hour reserve; install redundant MPLS nodes.

BCH's Work Required at BTTX

- Construct tower and install antenna waveguides, dehydrator and two frequency single microwave terminals; install a 48V DC power supply with 8-hour reserve; install Telecom Management Router (TMS), Telecom Alarm Terminal and MPLS Rack.

The Telecom solution is developed based on the assumption as follows.

a) BTTX is assumed located at [redacted]
b) BRW is assumed located at 50° 05' 46" N, 125° 54' 02" W.
c) Assume that the location of BWVx at 50° 0' 0.32" N; 125° 35' 29.22" W would be suitable to construct a passive repeater sufficiently elevated above ground level. Geotechnical, field surveys, and path surveys would be necessary for confirmation and property rights would need to be acquired.
d) BCH would perform a microwave link interference analysis through Frequency Coordination and Spectrum Analysis (FCSA) for the BTTX to STN microwave radio link. Upon success of the interference analysis and upon receipt of required environmental information and other consultation related to new towers and antennas, BCH telecom Engineering would apply for radio licensing through Innovation, Science and Economic Development (ISED) Canada.
e) Assume good cellular data or satellite coverage at SHQ for the revenue metering and PPIS circuits.

6 Cost Estimate and Schedule

A non-binding good faith cost estimate and the estimated schedule of the Network Upgrades identified for the project interconnection are provided in a letter that accompanies this report. The identified Network Upgrades refer to the additions and modifications to the BC Hydro owned transmission facilities for interconnecting the proposed project.

7 Revenue Metering

- The remote read load profile revenue metering installation should be in accordance with Canada federal regulations (Measurement Canada or MC) and BC Hydro Requirements for Complex Revenue Metering. The latest version of this document is published at BC Hydro's external website. The revenue metering responsibilities and charges shall be in accordance with Section 10 (10.1 and 10.2). For details about the specific responsibilities, see table on pages.23-25.

- Primary Metering is required; 3-element metering scheme with 3 CTs and 3 VTs connected L-N (Grd) should be used.

- Main and backup load profile interval meters are required to measure the power delivered. The meters will be programmed for 5 minutes interval and will be remotely read each day by BCH Billing Group using MV-90 System; the POM shall have a dedicated communications link (BC Hydro's approved wireless IP solutions, landline or other approved alternative). The communications link should be used for revenue metering only. If there is IP digital cell phone coverage for data in the site, BCH can supply an IP Wireless Communications Modem equipment. BCH Transmission P&C Telecom/P&C Engineering Department should inform the connectivity options for complex metering at this specific site.

- The revenue class meters (main and backup) are Measurement Canada (MC) approved and will be supplied and maintained by BC Hydro.

- The MC approved revenue class instrument transformers (CTs and VTs units) are supplied by IC. The instrument transformers shall be metering class and have 115V (or 120V) and 5A on the secondary. The IC will also provide BC Hydro Revenue Metering department the transformer technical specifications and MC Notice of Approval (NOA) Number before ordering to ensure compatibility with the revenue meters.

- When the impedance and losses between the POM and the PODR are significant, the meters should be programmed to account for the line and/or transformer losses between the POM and PODR (usually at the POI). In this case, the customer or the consultant shall provide a letter with the line parameters (and/or power transformer) data signed and stamped by a professional engineer.

- Before definition phase, BCH Revenue Metering department should be contacted to discuss the specifics of the project. A complex metering designer responsible for the metering tasks will be assigned at this point.

- During the feasibility/definition phase, the applicant is to send drawings to the assigned project manager, for distribution to the BCH Revenue Metering Department showing the 1-line diagram (SLD) and informing the planned metering scheme, meter cabinet location, as well as any other metering related document for review and approval.

In order to finalize the metering option, the IC will work with BCH to determine the required Revenue Metering configuration in accordance with the Electricity Purchase Agreement and associated agreements. Specific metering information is provided in the table below.

Point-of-Metering	230 kV (voltage level), at BRW
Instrument Transformers	The CTs and VTs used on the metering scheme will be supplied by the IC and should have 115V (or 120V) and 5A on the secondary. The IC will also provide BC Hydro's Revenue Metering Department the transformer technical specifications and Measurement Canada Notice of Approval (NOA) Number before ordering to ensure compatibility with the revenue meters.

8 Conclusions

This System Impact Study has identified the following issues and requirements:

1. A new 230 kV switching station (temporarily referred to as "BTTX") on the BCH's existing circuit 2L154 is required at or close to the proposed POI for interconnecting the IC's generating project to the BCH system. With the new switching station BTTX, 2L154 will be segregated into two segments, temporarily referred as: 2L154_A (GLD-BTTX) and 2L154_B (BTTX-DMR). The 230 kV transmission line which is to be built by the IC for connecting the project is temporarily designated as 2L154_C (BTTX-BRW).

2. The connection of the [redacted] Project does not cause any performance violations (i.e. thermal overload, voltage violation, voltage stability) under system normal conditions. However, certain contingencies may result in thermal overloads and other performance concerns in the system, which are associated with the addition of [redacted] project. To address those concerns under contingencies, the [redacted] Project is required to participate in the existing North Vancouver Island remedial action schemes (RAS) and JHN/ICG/EFM RAS.

3. The proposed [redacted] project can meet the respective reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over most of the MW operating range (including full to lower MW output), and also provides a partial reactive capability at zero MW output provided that the turbine's optional "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at [redacted] project.

4. Virtual Inertia Control (VIC), a form of Fast Frequency Response, is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC function, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

5. A telecommunication-based Direct Transfer Trip (DTT) scheme is required to prevent the [redacted] from operating under unstable conditions or forming a potential island. This DTT scheme will initiate a trip to the [redacted] plant for any protection tripping or manual opening of the line 2L154_B between the new switching station

BTTX and DMR substation and is part of the updated North Vancouver Island RAS.

6. Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by the TIR. The [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.

7. BCH will provide line protections for 2L154_A, 2L154_B and the BTTX terminal of 2L154_C after the existing 2L154 being segregated as a part of this project interconnection. The IC is to provide entrance protection at IC's station BRW to comply with BCH's TIR. The IC is to provide two SEL-411L relays at the entrance of BRW to provide protection coverage for 2L154_C.

8. The inverters of the [redacted] project are required to have fault ride-through (FRT) capabilities per BCH's TIR. Using the default settings provided, the fault ride-through performance of the inverters is satisfactory and does not result in unexpected tripping or momentary cessation in dynamic simulations. BC hydro may follow up on the ride-through settings during the pre-commissioning stage.

Appendix A
Schematic Diagram of [redacted] Project

Figure A-1 shows the plant schematic diagram for the project based on IC submitted data.

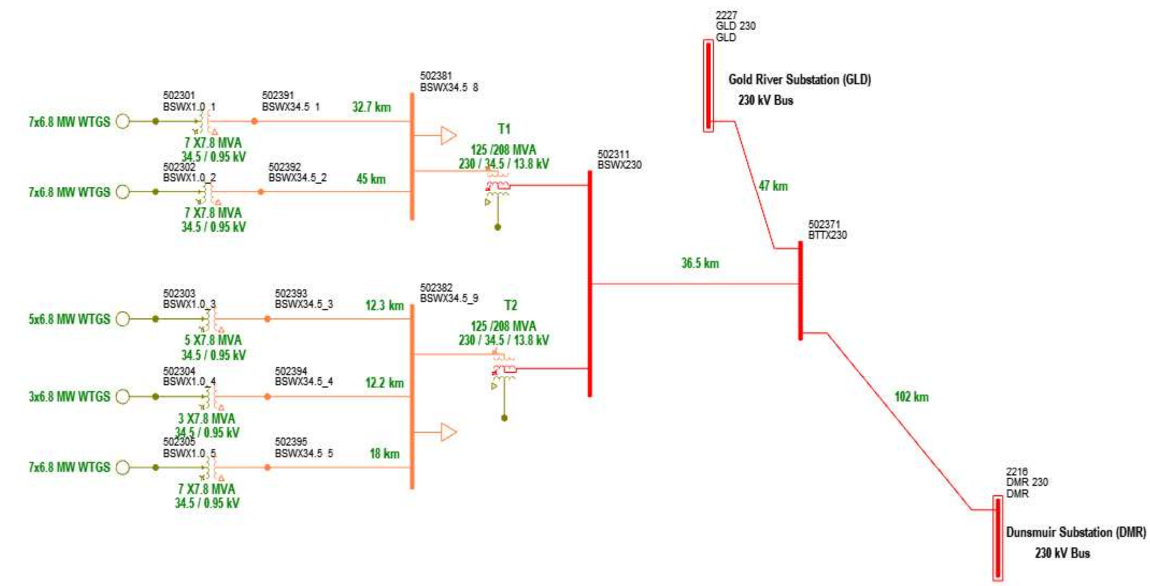

Figure A-1: Schematic Diagram of [redacted] Project

Appendix B
Power Flow Study Results

The key results of power flow studies for the study scenarios are shown in the table below.

Table B-1: Summary of Branch Loading and Voltage Performance Results in Study Scenarios

Case	IC's Plant Output	Contingency		Branch Loading				Bus Voltage (pu)			
				2L154_B	2L154_A	1L120	1L121	GLD	GLD	BTTX	DMR
		Cat.	Description	DMR-BTTX	GLD-BTTX	GLD-SCA	SCA-LDR	132	230	230	230
Summer Rating (Amp)				1009	844 [1]	635	639				
29LS	MAX	P0	System Normal	72 %	31 %	39 %	75 %	1.07	1.0	1.01	1.04
	MAX	P1	1L121 (LDR-SCA)	**103 %**	71 %	38 %	-	1.07	0.94	0.97	1.03
	MAX	P2	LDR Bus Section Fault	**103 %**	71 %	38 %	-	1.07	0.94	0.97	1.03
	MAX	P2	DMR 1CB15 Internal Fault [2]	**141 %**	**114 %**	**112 %**	75 %	0.99	**0.84**	**0.88**	1.03
	MAX	P1	2L154_B (DMR - POI) [3]	-	56 %	**135 %**	**169 %**	1.08	0.99	1.0	1.04
29HS	MAX	P0	System Normal	68 %	26 %	43 %	79 %	1.07	1.01	1.01	1.04
	MAX	P1	1L121 (LDR-SCA)	**101 %**	67 %	37%	-	1.07	0.95	0.97	1.03
	MAX	P2	LDR Bus Section Fault	**101 %**	67 %	37%	-	1.07	0.95	0.97	1.03
	MAX	P2	DMR 1CB15 Internal Fault[1]	**115 %**	88 %	73 %	38 %	1.06	**0.91**	0.94	1.03
	MAX	P1	2L154_B (BTTX-DMR) [2]	-	59 %	**129 %**	**163 %**	1.08	0.99	1.0	1.03
Winter Rating (Amp)				1224	844	768	740				
28HW	MAX	P0	System Normal	58 %	14 %	43 %	70 %	1.08	1.02	1.02	1.04
	MAX	P1	1L121 (LDR-SCA)	93 %	56 %	30 %	-	1.06	0.98	0.99	1.03
	MAX	P2	LDR Bus Section Fault	93 %	56 %	30 %	-	1.06	0.98	0.99	1.03
	MAX	P2	DMR 1CB15 Internal Fault	67 %	25 %	23 %	52 %	1.07	1.01	1.02	1.05
	MAX	P1	2L154 _B (BTTX-DMR) [2]	-	57 %	94 %	**119 %**	1.08	0.99	1.0	1.04

Note 1: The rating of 2L154_A (GLD-BTTX) is capped by ratings of transformer GLD T1 & T4.

Note 2: DMR 132 kV bus breaker 1CB15 fault results in tripping of 1L101, 1L106, 1L119, 1L105, 1L114, 1L115, 1L116.

Note 3: Existing DTTs isolate CSS and KKS following 2L154 zone 1 multi-phase faults during periods of high CSS and KKS generation.

Appendix C
Transient Stability Study Results

A summary of the transient stability studies for 2029LS load conditions with [redacted] project is provided in the table below.

Table C-1: Transient Stability Study Results (2029LS Scenario)

Cat.[1]	Contingency	3-Ph Fault Location	Fault Clearing Time (Cycles)		Dynamic Performance	
			Close End	Far End	[redacted]	Other Generators in Study Area
P1.2	2L154_A (GLD-BTTX)	Close to GLD	GLD 6	BTTX 7	Acceptable	Acceptable
P1.2	2L154_B (BTTX-DMR)	Close to DMR	DMR 6	BTTX 7	Unstable	Unstable
P1.2	2L154_C (BTTX-BRW)	Close to BRW	BRW 6	-	Acceptable	Acceptable
P1.2	1L120 (GLD-SCA)	Close to GLD	GLD 8	SCA 9	Acceptable	Acceptable
P1.2	1L121 (SCA-LDR)	Close to SCA	SCA 8	LDR 9	Acceptable	Acceptable
P1.2	1L131 (GLD-TSV)	Close to GLD	GLD 8	TSV 25	Acceptable	Acceptable
P1.2	1L134 (GLD-GRP)	Close to GLD	GLD 8	GRP 23	Acceptable	Acceptable
P1.2	1L157 (GLD-KTS)	Close to GLD	GLD 8	KTS 37	Acceptable	Acceptable

Note 1: P1.2 is the contingency categories defined in NERC TPL-001-4.

Appendix D
IC Provided Power Flow and Dynamic Models and Data

All WTGs connected to the same feeder are represented by one equivalent generator in power flow case with the following data:

- G1: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.95 kV
- G2: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.95 kV
- G3: MBASE: 38.5 MVA, P_{max}: 34.0 MW, V_{nom}: 0.95 kV
- G4: MBASE: 23.1 MVA, P_{max}: 20.4 MW, V_{nom}: 0.95 kV
- G5: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.95 kV

[redacted]

Appendix E

Preliminary One-Line Sketch for Future Proposed [redacted] Terminal Switching Station (BTTX)

The preliminary one-line sketch for the proposed switching station BTTX is provided below.

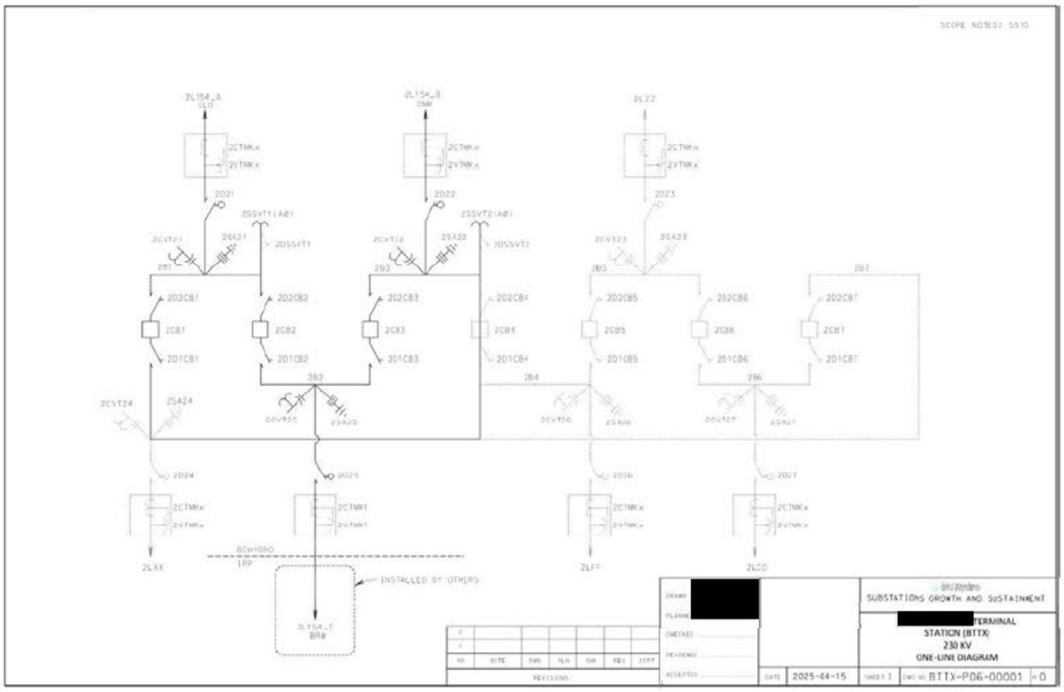

Figure E-1: Preliminary One-Line Sketch for the Proposed Switching Station BTTX

Appendix F
Transmission Line Diagrams

The POI location in F-1 and the conceptual Ingress and Egress of proposed switching station BTTX on 2L154 in F-2 are illustrated in this appendix.

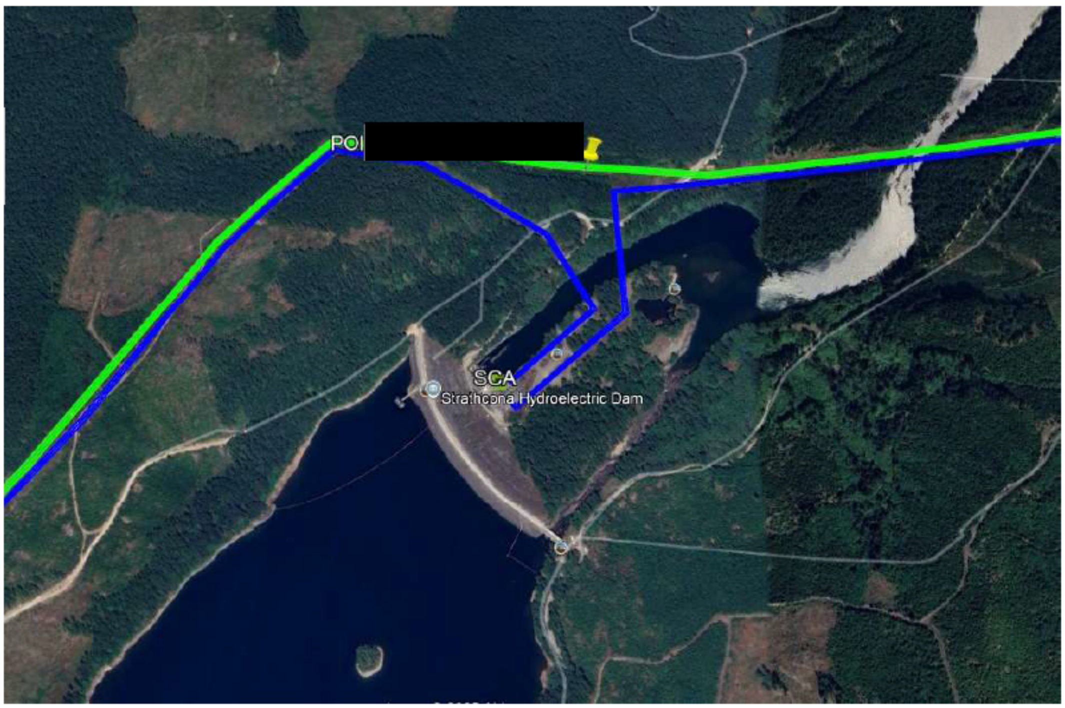

Figure F-1: POI Location Diagram

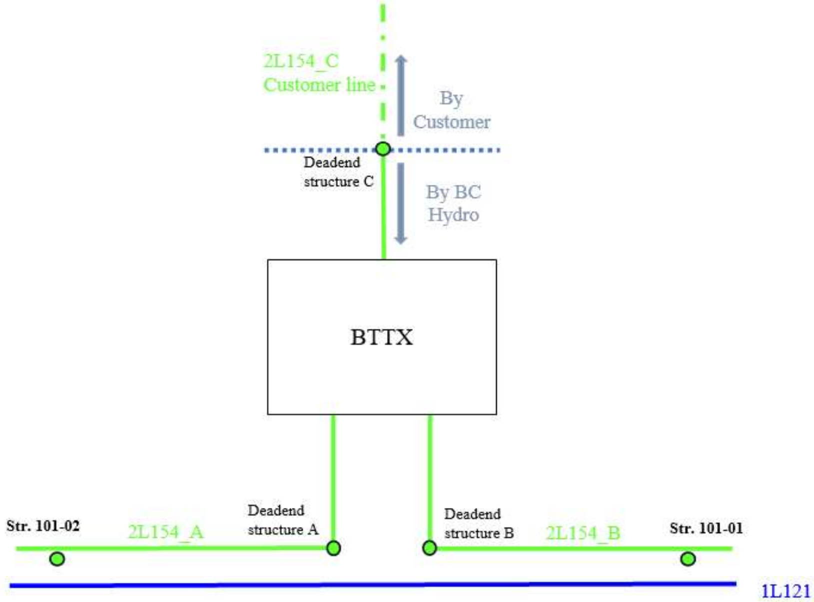

Figure F-2: Conceptual Ingress and Egress of Proposed Switching Station BTTX on 2L154

Appendix G
Telecom Requirements and Telecom Block Diagram

Below is a summary of Teleprotection, RAS and Telecontrol requirements for Telecom, along with the telecom block diagram that illustrates the telecom solution identified in this SIS.

Teleprotection Requirements for Telecom

- Provide WECC Level 3 64 kbps synchronous circuits between GLD and BTTX for “GLD-BTTX 2L154_A PY/SY Digital Teleprot”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 3 64 kbps synchronous circuits between BTTX and DMR for “BTTX-DMR 2L154_B PY/SY Digital Teleprot”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 3 64 kbps synchronous circuits between BTTX and BRW for “BTTX-BRW 2L154_C PY/SY Digital Teleport”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

RAS Requirements for Telecom

The final system architecture of RAS will be the result of an iterative optimization in a later stage of the project.

- Provide WECC Level 3 direct transfer trip facilities from DMR to GLD for “DMR 1CB15 BF G/S DTT PY/SY to GLD”.
- Provide WECC Level 3 direct transfer trip facilities from DMR to BTTX for “DMR 1CB15 BF G/S DTT PY/SY to BTTX”.
- Provide WECC Level 3 direct transfer trip facilities from GLD to BRW for “GLD RAS G/S (RUN BACK) DTT PY/SY to BRW”.
- Provide WECC Level 3 direct transfer trip facilities from GLD to JHN for “GLD RAS G/S (RUN BACK) DTT PY/SY to JHN”.

- Provide WECC Level 3 direct transfer trip facilities from GLD to ICG for "GLD RAS G/S (RUN BACK) DTT PY/SY to ICG".
- Provide WECC Level 3 direct transfer trip facilities from SCA to PHY (for CSS) for "SCA RAS G/S (RUN BACK) CSS DTT PY/SY to PHY".
- Provide WECC Level 3 direct transfer trip facilities from SCA to KTS (for KKS) for "SCA RAS G/S (RUN BACK) KKS DTT PY/SY to KTS".
- Provide WECC Level 3 direct transfer trip facilities from SCA to BRW for "SCA RAS G/S (RUN BACK) DTT PY/SY to BRW".
- Provide WECC Level 3 direct transfer trip facilities from SCA to GLD for "SCA RAS G/S (RUN BACK) BACKUP DTT GLD 1L157 PY/SY to GLD".
- Provide WECC Level 3 direct transfer trip facilities from BTTX to PHY (for CSS) for "BTTX RAS G/S (RUN BACK) CSS DTT PY/SY to PHY".
- Provide WECC Level 3 direct transfer trip facilities from BTTX to KTS (for KKS) for "BTTX RAS G/S (RUN BACK) KKS DTT PY/SY to KTS".
- Provide WECC Level 3 direct transfer trip facilities from BTTX to GLD for "BTTX RAS G/S (RUN BACK) BACKUP DTT GLD 1L157 PY/SY to GLD".
- Provide WECC Level 3 direct transfer trip facilities from BTTX to TSV (for ZBL) for "BTTX RAS DTT ZBL PY/SY to TSV".

Telecontrol Requirements for Telecom

- BRW SCADA circuit off FVO & SIO.
- BTTX SCADA circuit off FVO & SIO.
- REMACC circuit at BTTX.

Other Requirements for Telecom

- BTTX FWMTCE circuit off FVO.
- Corporate BPRN service at BTTX.

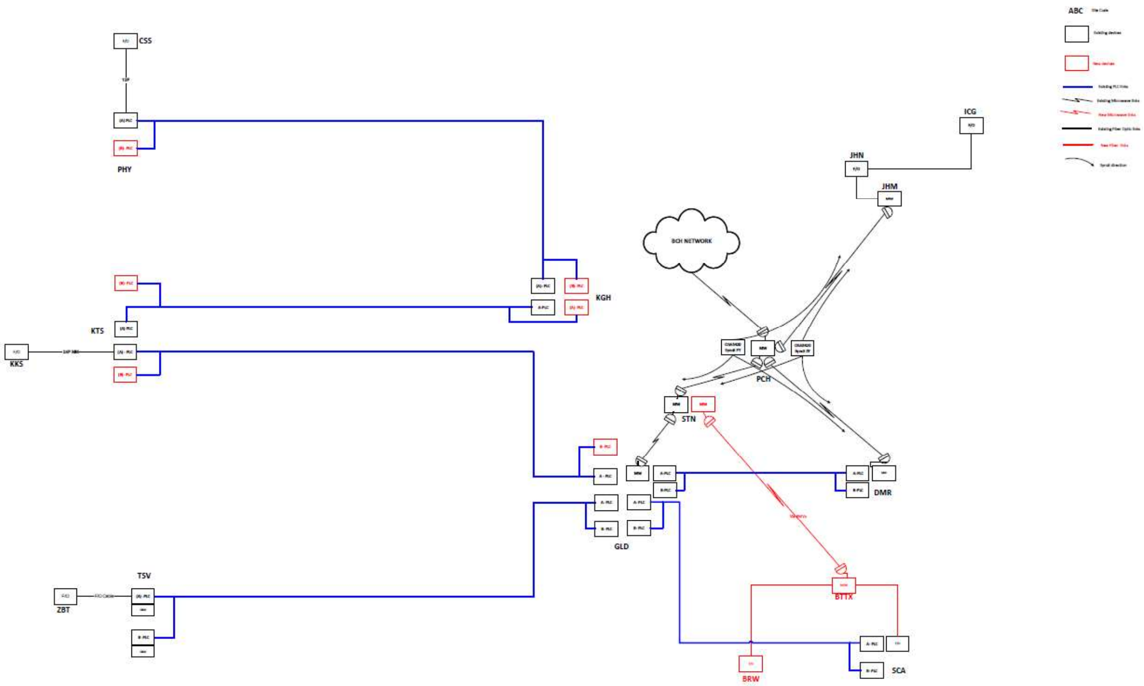

Figure G-1: The telecom block diagram identified for [redacted] Project

Appendix H
Revenue Metering Related Telecommunications Requirements

A telecommunications channel is required for remote read/download data from the main and the backup meters. The design, supply and installation of the communications equipment shall be coordinated between BCH Revenue Metering, BCH Telecom, the Power Generator and the Telecommunications Service Provider. The IC should provide a terminal / connector inside the BCH meter cabinet. Where the POI is on a 69 kV voltage class or higher BC Hydro transmission system and where a conventional wire-line telephone is installed, ground potential rise protection shall be provided. Alternative technologies may be used, e.g., cellular, fiber optic, microwave, satellite etc. however these solutions must be discussed and approved by BCH before installation. The bottom line is: - BCH MV-90 Server must be able to access and download data from the meters remotely as they do when they dial in a site using a standard phone line (wireless or landline). For more details, please, refer to Section 8 of BCH Revenue Metering Requirements for Complex Metering published at the Revenue Metering webpage and at the BC Hydro external website.