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

August 8, 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 **$26.2M**. 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 – Glenannan Substation (GLN)

- Supply and install one dead tank 230kV circuit breaker.
- Supply and install two 230kV disconnect switches.
- Construct one 230kV line terminal with associated motorized disconnect switch, surge arrester and capacitor voltage transformer to connect the IPP's new transmission line.

Protection and Control

- Provide new protection at GLN for the IPP's new transmission line and modify the existing generation shedding Remedial Action Scheme (RAS) system at Skeena Substation (SKA).

Telecommunications

- Supply and install new [redacted] Passive Repeater.

Exclusions:

- GST
- Outage costs.
- Permits
- Cost change due to Currency Fluctuations.
- Book value of decommissioned equipment.
- Site-specific requirements for the new passive repeater site including but not limited to ground improvements, slope stabilization, etc. are not included.
- Cost of design, supply, and installation of the 230kV transmission line and the fibre optic cable from the IPP's Generating Station to BC Hydro's Glenannan substation.

Key Assumptions:

- Construction may be completed by either BC Hydro or its Contractor(s). It is assumed there is no major difference in construction costs between the two.
- 8 months of construction.
- Living out allowance is considered for the construction duration.
- No expansion of existing station or control building to accommodate new equipment.
- The IPP will design, supply, and install a new 230kV transmission line and a fibre optic cable from the IPP's Generating Station to BC Hydro's Glenannan substation.

Key Risks:

- Delays in receiving documentation or funding from the Interconnections Customer which may delay key milestones.
- Major Equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times.
- Additional right of way or acquisition may be required to accommodate equipment.
- No defined supply chain strategy at this stage.
- Project schedule may be longer than expected, leading to increased costs.
- Telecom scope presents high risk of change due to rapidly evolving technologies and standards.
- Cost of materials and major equipment 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 **Quarter 2, 2029** 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 report, BC Hydro can arrange for an optional SIS Review Meeting. After the SIS Review meeting, BC Hydro will provide you with a cost estimate for the Facilities Study and any additional data requirements. After being provided with the cost estimate, we ask that you provide written confirmation to proceed with the Facilities Study.

In addition to the confirmation, you will be required to provide additional data for the Facilities Study.

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: [redacted]

BC Hydro
Power smart

[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]
Subheader:	Interconnection System Impact Study
Title:	[Company Fax]
Subtitle:	[redacted]
Report Number:	832J-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Aug 08
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	
Title:	Sr. Engineer, Interconnection Planning
Checked by:	[redacted]
Title:	Sr. Engineer, Interconnection Planning
Reviewed by:	[redacted]
Title:	Manager, Interconnection Planning
Related Facilities:	Facility station code – NMW POI Station – Glenannan Substation (GLN)
Additional Metadata:	Transmission Planning 2025-023 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Aug	Initial release

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7 [redacted]

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Sr Engineer, Revenue Metering

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Acronyms

The following are acronyms used in this report.

BCH	British Columbia Hydro and Power Authority
COD	Commercial Operation Date
CT	Current Transformer
EMS	Energy management System
ERIS	Energy Resource Interconnection Service
FRT	Fault Ride-Through
FVO	Fraser Valley Office
GLN	Glenannan Substation
GNR	Glenannan Microwave Repeater
HS	Heavy Summer
HW	Heavy Winter
IC	Interconnection Customer
IP	Internet Protocol
IPO	Independent Pole Operated
ISD	In-Service Date
KMO	Kemano Generating Station
LS	Light Summer
MC	Measurement Canada or Canada federal regulations
NERC	North American Electric Reliability Corporation
NMW	[redacted]
NMWPx	[redacted] Passive Repeater (temporary site code)
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

RTA Rio Tinto Operations including KMO

SCC System Control Centre

SIS System Impact Study

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

TOV Temporary Overvoltage

VT Voltage Transformer

WSN Williston Substation

WECC Western Electricity Coordinating Council

Executive Summary

[redacted] the Interconnection Customer (IC), requests to connect a wind farm, [redacted] Project, into the BCH system in the North Coast Region.

The [redacted] Project will comprise [redacted] The total installed capacity of the project is 199.9 MW, with a maximum power injection of 191 MW at the proposed Point of Interconnection (POI).

The proposed POI is at the 230 kV bus of BC Hydro's Glenannan Substation (GLN). The IC originally proposed a Commercial Operation Date (COD) of October 1, 2030, and the IC later advanced the COD to November 5, 2029.

To interconnect the [redacted] Project to the BCH Transmission System at the POI, the System Impact Study (SIS) has concluded the following requirements and conclusions:

1. A new 230 kV line terminal at the Glenannan (GLN) substation is required to interconnect the IC's generating project to the BC Hydro system.

2. The proposed [redacted] project is capable of meeting 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). In addition, the turbine's "STATCOM" option is required so that each turbine can provide a partial of the required reactive power capability at zero MW output.

3. Fast Frequency Response, potentially implemented as Virtual Inertia Control (VIC) per the wind turbine manufacturer's documentation, is required at the [redacted] project. The proposed wind turbine generators, when equipped with the VIC function, will temporarily boost the MW output to limit the system frequency drop after a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

4. 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 will follow up on the ride-through settings during the pre-commissioning stage.

5. 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 loads forms. Anti-islanding protection can be implemented with a Power Quality (PQ) based protection scheme. It can be expected that the PQ protection settings will need to meet the relevant NERC PRC standard regarding the "no trip zone" requirements.

6. The [redacted] project is required to participate in the existing North Coast and GMS Area Generation Shedding Remedial Action Scheme (RAS).

7. The interconnection of the [redacted] Project in the North Coast Region does not cause any system performance violation (i.e. thermal overload, voltage violation, or voltage instability, etc.) under the normal and contingency system operating conditions. No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

8. Voltage sags caused by energization of entrance transformers are not expected to exceed the limits specified in BC Hydro's TIR. No mitigation measures are required for transformer energization.

9. The IC is required to install line differential protection using redundant SEL-411L-1 relays to provide protection for the transmission line connecting the plant. Additionally, the IC is required to install telecom systems for protection and SCADA purposes.

Note that the above requirements and 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 have [redacted] The total installed capacity of the project is 199.9 MW, with a maximum power injection of 191 MW at the proposed Point of Interconnection (POI). To compensate reactive losses in the facility and meet the reactive power capability requirement, the IC proposed [redacted]

The proposed POI is at the 230 kV bus of BC Hydro's Glenannan Substation (GLN). GLN is a major substation approximately 175 km from Williston Substation (WSN) located in BC Hydro's North Coast region. The IC's originally proposed Commercial Operation Date (COD) was October 1, 2030, and the IC later advanced the COD to November 5, 2029. 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	230 kV bus of GLN Substation	
IC Proposed COD	November 5, 2029 (1)	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	191 (Summer)	191 (Winter)
Number of Wind Turbines	[redacted]	
Plant Fuel	Wind	

Note 1: The IC advanced the COD from the originally proposed October 1, 2030 in the late SIS stage. However, the COD advancement is not expected to significantly impact the SIS conclusions.

There are [redacted] which is connected to BC Hydro's Glenannan Substation (GLN) via an IC-owned 24.2 km, 230 kV interconnection line. The IC's 230 kV main substation is referred to as "NMW" in this report.

Figure 1-1 illustrates the interconnection of [redacted] Project to North Coast Regional transmission system. Williston Substation (WSN) is a major substation in the Central Interior region with strong ties to 500 kV network.

Glenannan Substation (GLN) is a 500 kV substation in the North Coast region, which includes:

- Two 500/230 kV transformers (GLN T1 & T2)
- Two 230/138 kV transformers (GLN T5 & T11)
- Three 138/66 kV transformers (GLN T3, T4 & T6)

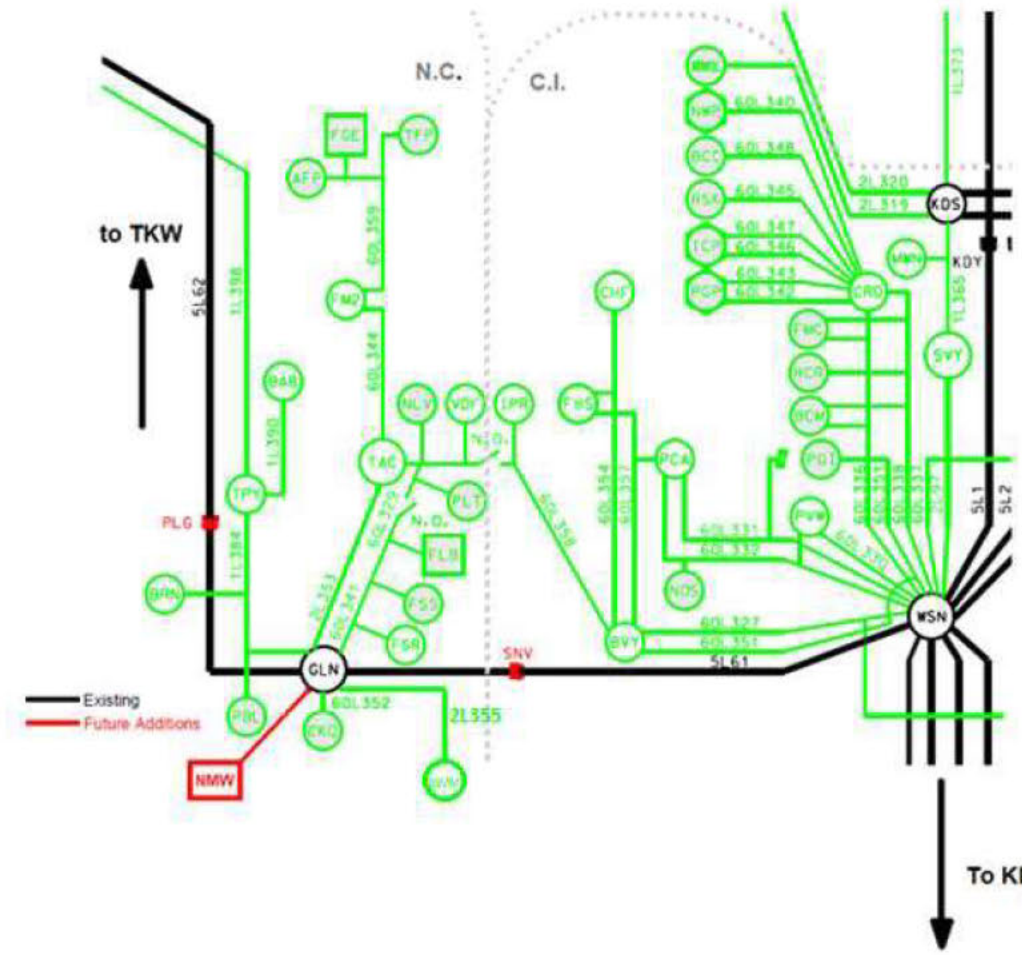


Figure 1-1: [redacted] Project and the Surrounding Area System

GLN Substation has two existing 230 kV line connections, line 2L353 to Tachick Substation (TAC), which further connects to the 66 kV system including a customer owned Fort St. James (FGE) generating station, and the other line 2L355 to a TVC load Blackwater Mine (BWM).

GLN Substation is connected to Williston Substation (WSN) via a 500 kV line 5L61, and to Telkwa Substation (TKW) via a 500 kV line 5L62, which is further connected to Skeena Substation (SKA) via a 500 kV line 5L63. The Williston-Glenannan-Telkwa-Skeena 500 kV transmission system is a radial system starting from Williston Substation (WSN), with various generating stations connected and customer loads served at different voltage levels, including major loads at Kitimat (KIT), and key regional generating resources such as Kemano (KMO) Generating Station, Forrest Kerr Generating Station (FKR), Volcano Creek Generating Station (VOL), and McLymont Creek Generating Station (MCY).

Appendix A 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 12, 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 2030 Heavy Winter (HW) and 2031 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, which are in effect at the time to start the study.

- The regional generations 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.

- There is a planned transmission line 5L64, which is in parallel with 5L61 connecting GLN and WSN with a preliminarily in-service date of September 30, 2030, however, due to the uncertainty of capital project plus for being conservative, this study is focused on the scenarios without the planned line 5L64.

5 System Studies and Results

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 2030 Heavy Winter (HW) load and 2031 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 in the studied regional system under system normal operating conditions and under the studied contingencies. Under system contingencies, it is observed that the addition of the 199.9 MW [redacted] Project will contribute to the increased power delivery on 5L61 into WSN substation. Appendix B contains the key results of power flow studies for the base scenario and the Additional Scenario studied in this SIS.

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 loads forms. Anti-islanding protection can be implemented with a Power Quality (PQ) based protection scheme. It can be expected that the PQ protection settings will need to meet the relevant NERC PRC standard regarding the "no trip zone" requirements.

Per BCH's TIR Section 6.4.2, the [redacted] plant shall be capable of injecting and absorbing reactive power of at least +/- 33% of MPO at the high-voltage side of the switchyard over the full MW operating range. Upon the received modeling information, the [redacted] Project can meet the reactive power 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 a partial reactive power capability at zero MW output.

5.2 Transient Stability Study

Transient stability studies have been performed using the 2031LS base case to assess the impact of 199.9 MW maximum power injections from [redacted] Project on the transmission network in the vicinity area, in accordance with the TPL-001-WECC-CRT- 4 Performance Criteria.

Besides, upon the IC's submission, the WTGs at [redacted] project can provide fast frequency response (FFR) if the turbine's optional Virtual Synchronous Machine Controller is enabled. The FFR function is required at [redacted] project to limit the system frequency drop during a major frequency event. The FFR 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 2031LS condition with the addition of [redacted] Project. No transient instability or transient voltage recovery violation has been observed under the study conditions and contingencies.

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] Project 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.
- Anti-islanding protection is required for the [redacted] Project. Given that the [redacted] Project is an IBR-based plant connected to a 230 kV substation with a [redacted] dedicated transmission line, the anti-islanding protection upon a Power Quality (PQ) based protection scheme is acceptable.
- Voltage disturbance resulting from energization of a [redacted] main power transformer was studied. Under system normal conditions, the voltage sags are not expected to exceed the limits specified in BC Hydro's 60-500 kV Generation Technical Interconnection Requirements for Power Generators (TIR). No mitigation measures are required for transformer energization.
- The harmonic current injection from the [redacted] Project shall not exceed the limits specified in TIR, which follow IEEE Std 519-2022. Harmonic studies will be conducted at a later stage when the detailed spectrum of harmonic current injection becomes available.

- The [redacted] Project's Electromagnetic Transient (EMT) model is parameterized with the voltage and frequency ride-through settings that meets TIR requirements. BC Hydro will follow up on this topic during the pre-commissioning stage.
- The electromagnetic transient response of the [redacted] Project, including the wind turbine generators (WTGs) active and reactive power outputs are in accordance with the facility's electrical and control requirements.
- The [redacted] Project demonstrated stable operation under reduced Short Circuit Ratios (SCRs), which were determined based on the credible contingencies selected for the study.

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

The North Coast region including the [redacted] project will form an island after loss of 5L61. The [redacted] project is required to participate in the existing North Coast Generation shedding RAS. Generation shedding shall be implemented at NMW with two independent blocks, which will provide more operational flexibility and has less impact on NMW operations.

Additionally, NMW project is required to participate in the existing GMS Area Generation Shedding RAS for contingencies occur in BC Hydro's south of WSN transmission system to provide operational flexibilities and reduce operational restrictions. The new generation shedding function is achieved by tripping [redacted] within IC's generating station.

5.7 Station Upgrade Requirements

To interconnect the [redacted] Project to the BC Hydro transmission system, following is the station work required at Glenannan (GLN) substation:

- Add one dead tank 230kV circuit breaker (2CB8) rated at 2000A continuous current, 40kA interrupting rating and shall be able to operate in the ambient temperature of -50ºC to +40ºC.

- Add two disconnect switches (2D1CB8 & 2D2CB7) rated 2000A.
- Add one 230kV line terminal (2LXXX) with associated motorized disconnect switch (2D24) rated 2000A, Surge Arrester (2SA24) and Capacitor Voltage Transformer (2CVT24). The line designation (2LXXX) will be finalized at a later stage.
- Other associated station work.

The draft of the GLN substation one line diagram is shown in Figure in Appendix H.

5.8 Transmission Line Upgrade Requirements

There is no required transmission line upgrade. However, the last span of the IC owned line 2LXXX into the GLN Substation (assuming the IC will design and build the last span into the substation for BC Hydro) will need to be reviewed by BCH for acceptance. Refer to the Sketch Diagram in Appendix D for assumed detail.

The demarcation point between IC owned and BC Hydro owned will be at the dead end structure before the gantry of GLN.

5.9 Protection, Control and Telecommunications

5.9.1 Protection

BCH will review the interconnecting customer's entrance protection documents and provide core protection settings for the new line 2LXXX between GLN and NMW. BCH will provide new protection at GLN station for the new line 2LXXX and modify the existing RAS system at SKA to incorporate the new IC.

NMW is required to participate in the North Coast RAS and GMS Area Gen Shed RAS. The IC is required to provide primary and standby WECC Level 1 telecom channels from SKA to NMW for RAS. The IC is also required to provide a WECC Level 3 telecom channel between GLN and NMW for digital teleprotection.

The IC is required to provide the following for the interconnection of [redacted] (NMW):

- Entrance protection that complies with the latest version of the "BC Hydro 60 kV to 500 kV Technical Interconnection Requirements for Power Generators".

- Provide two SEL-411L-1 line differential protection relays (firmware and options specified by BC Hydro) at the entrance of NMW to provide protection coverage for 2LXXX. BC Hydro P&C Planning will provide core protection settings for these relays to protect transmission line 2LXXX during a transmission line fault. Non-core protection such as local breaker failure, auto-reclosing, backup protection, NERC PRC related settings 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 PPIS equipment by BCH servers.
- Provide anti-islanding protection as per Section 5.1.
- The IC is required to participate in the North Coast RAS and the GMS Area Generation Shedding RAS as per Section 5.6. NMW generation shedding shall be implemented in two independent blocks at NMW [redacted] circuit breakers [redacted] 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 in the NMW [redacted] circuit breakers [redacted]

5.9.2 Control

To interconnect the [redacted] project, the IC is to provide a minimum 19.2 kbps SCADA channel to the closest BCH station with appropriate telecom facilities (station to be determined by BCH Telecom), which will then get routed internally via the BCH Telecom system to the FVO/SIO DCP sites.

The NMW generating plant 230 kV circuit breakers 2CBT1 and 2CBT2 are required to be equipped with dual trip coils.

Work is required at GLN for the provision of metering, remote access, and alarms. Work is required at SKA to update the North Coast RAS and GMS Area Generation Shedding RAS and their associated RTUs, and to add alarms for the new NMW RAS outputs.

5.9.3 Telecommunications

The detailed telecom work scopes and specs will be specified in detail at the later stage of Interconnection Studies.

To achieve Telecom WECC Level 1 for the RAS circuits, a new microwave link for the diverse path requirement (with the proposed NMW-GNR microwave link via a Passive Reflector site) will be installed. WECC Level 1 (SY) RAS circuits would take this new path in combination with existing BCH microwave system to carry the signal to SKA.

An intermediate passive repeater (temporarily referred to as 'NMWPx') will be employed, involving property acquisition, geotechnical investigation, and consultation. BC Hydro would be responsible for constructing the passive repeater site.

IC's Work Required at NMW

- Design to install 48 strands single-mode fibre optic cable along the new 230kV transmission lines 2LXXX and terminate to a Fiber Optic Terminal Rack in the control building.
- Install tower, two waveguides, and antenna facing NMWPx. Coordinate with BC Hydro telecom designer to confirm microwave path profile, frequency band, tower height, and antenna size.
- Install racks, dehydrator, and single two frequency microwave terminal facing NMWPx.
- Install two 7705 SAR-8 MPLS nodes equipped with 8p-Ethernet SFP, C37.94, OC3 and serial cards.
- Install a 48 VDC power system with 8-hour reserve.

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

a) NMW is assumed located at: [redacted] and GNR is assumed located at 54° 04' 4.85" N and 125° 00' 55" W.

b) WECC Level 1 (PY) RAS circuits will take the new NWM-GLN fiber in combination with the existing GNR-GLN fiber network and BCH microwave system to carry the PY RAS signal to SKA.

c) Initial calculation indicates that the microwave path between GNR and NMW is block 10.5 kms from NMW. A proposed Passive reflector site NMWPx with coordinates at 53° 59' 09.73" N and 124° 49' 40.74 W will clear the obstructions. BCH will further perform microwave path profile analysis to confirm the link.

d) BCH would perform a microwave link interference analysis for the NMW to GNR 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 would apply for radio licensing through Innovation, Science and Economic Development (ISED) Canada.

e) Assume good cellular data or satellite coverage at NMW for the revenue metering and PPIS circuits.

Appendix E summarizes the Telecom requirements for Teleprotection, RAS, Telecontrol, and other network additions along with the Telecom block diagram.

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 main meter will be leased by BCH to the IC. As per federal regulations, both meters will be periodically removed and re-verified in a MC authorized laboratory. The MC approved revenue class instrument transformers (CTs and VTs units) are supplied by IC (Stock items w/CAT ID provided by BC Hydro). All CTs and VTs must be pre-approved by BC Hydro Revenue Metering department before ordering by IC.
- 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)
Voltage Transformers	3 x VTs (L-Grd) – 138kV-115-115V - BCH Cat ID 96016229 (to be confirmed and supplied by the IC but model/maker subjected to approval by BCH Revenue Metering Department)
Current Transformers	3 x CTs- 300x600:5-5 A – Ratio (connected 600-5-5 A) – BCH Cat ID 96011039 (to be confirmed and supplied by the IC but model/maker subjected to approval by BCH Revenue Metering Department)

8 Conclusions

This System Impact Study has concluded the following requirements:

1. A new 230 kV line terminal at Glenannan (GLN) substation is required to interconnect the IC's generating project to the BC Hydro system.

2. The proposed [redacted] project is capable of meeting 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). In addition, the turbine's "STATCOM" option is required so that each turbine can provide a partial reactive power capability at zero MW output.

3. Fast Frequency Response, potentially implemented as Virtual Inertia Control (VIC) per the wind turbine manufacturer's documentation, is required at the [redacted] project. The proposed wind turbine generators, when equipped with the VIC function, will temporarily boost the MW output to limit the system frequency drop after a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

4. 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 will follow up on the ride-through settings during the pre-commissioning stage.

5. 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 loads forms. Anti-islanding protection can be implemented with a Power Quality (PQ) based protection scheme. It can be expected that the PQ protection settings will need to meet the relevant NERC PRC standard regarding "no trip zone" requirements.

6. The [redacted] project is required to participate in the existing North Coast and GMS Area Generation Shedding Remedial Action Scheme (RAS).

7. The interconnection of the [redacted] Project in the North Coast Region does not cause any system performance violation (i.e. thermal

overload, voltage violation, or voltage instability, etc.) under the normal and contingency system operating conditions. No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

8. Voltage sags caused by energization of entrance transformers are not expected to exceed the limits specified in BC Hydro's TIR. No mitigation measures are required for transformer energization.

9. The IC is required to install line differential protection using redundant SEL-411L-1 relays to provide protection for the transmission line connecting the plant. Additionally, the IC is required to install telecom systems for protection and SCADA purposes.

Appendix A
Schematic Diagram of the IC's Project

The following shows the plant schematic diagram for the IC's project:

[redacted]

Appendix B
Study-State Power Flow Study Results

Base Scenario

The base case scenario considered the addition of the 199.9 MW [redacted] Project, which will contribute to the power transfer from North Coast region to the WSN substation.

Table B-1 and Table B-2 contain the key results of power flow studies and bus voltages for the base scenario and additional scenario studied in this SIS.

Table B-1 Branch Overload Report and Selected Bus Voltages in Base Scenario

Case	IC's Plant Output	Contingency		Branch Loading			Bus Voltage (P.U.)
				5L61	5L62	2L353	GLN 230
		Cat.	Description	GLN-WSN	GLN-TKW	GLN-TAC	
Winter Rating (MVA)				2598	2598	119.5	
30HW	0 MW	P0	System Normal	3%	3%	16%	1.0
	Max	P0	System Normal	6%	2%	20%	1.0
	Max	P1	2L355	8%	1%	20%	1.01
	Max	P1	GLN T1 & T11 [1]	6%	2%	20%	1.0
	Max	P1	Loss of NMW	2%	3%	20%	1.0
	Max	P2	GLN 5CB23 [2]	6%	-	20%	1.01
Summer Rating (MVA)				1917	2099	119.5	
31LS	0 MW	P0	System Normal	9%	9%	28%	1.03
	Max	P0	System Normal	18%	9%	27%	1.02
	Max	P1	2L355	20%	9%	27%	1.02
	Max	P1	GLN T1 & T11 [1]	18%	9%	27%	1.02
	Max	P1	Loss of NMW	10%	9%	28%	1.03
	Max	P2	GLN 5CB23 [2]	9%	-	29%	1.03
31HS	0 MW	P0	System Normal	3%	4%	23%	1.0
	Max	P0	System Normal	12%	3%	22%	1.0
	Max	P1	2L355	14%	3%	22%	1.0
	Max	P1	GLN T1 & T11 [1]	12%	3%	22%	1.0
	Max	P1	Loss of NMW	3%	4%	23%	1.0

	Max	P2	GLN 5CB23 [2]	9%	-	22%	1.0

Note 1: GLN T1 and GLN T11 are in the same protection zone.
Note 2: Internal fault at GLN 5CB23 results in loss of 5L62, GLN T2 and GLN T5.

Additional Scenario

The Additional Scenario reflects a higher transfer from North Coast to WSN via 5L61, by setting higher KMO outputs. The power transfer to the WSN substation and further to the rest of the BCH system is higher compared to the Base Scenario.

Table B-2 Branch Overload Report and Selected Bus Voltages in Additional Scenario

Case	IC's Plant Output	Contingency		Branch Loading			Bus Voltage (P.U.)
				5L61	5L62	2L353	GLN 230
		Cat.	Description	GLN-WSN	GLN-TKW	GLN-TAC	
Summer Rating (MVA)				1917	2099	119.5	
31LS	0 MW	P0	System Normal	16%	15%	30%	1.02
	Max	P0	System Normal	23%	15%	29%	1.02
	Max	P1	2L355	25%	15%	28%	1.02
	Max	P1	GLN T1 & T11 [1]	23%	15%	28%	1.02
	Max	P1	Loss of NMW	16%	15%	30%	1.03
	Max	P2	GLN 5CB23 [2]	9%	-	30%	1.03
31HS	0 MW	P0	System Normal	9%	10%	25%	1.0
	Max	P0	System Normal	19%	10%	24%	1.0
	Max	P1	2L355	21%	10%	24%	1.0
	Max	P1	GLN T1 & T11 [1]	19%	10%	23%	1.0
	Max	P1	Loss of NMW	9%	10%	24%	1.0
	Max	P2	GLN 5CB23 [2]	9%	-	25%	1.01

Note 1: GLN T1 and GLN T11 are in the same protection zone.
Note 2: Internal fault at GLN 5CB23 results in loss of 5L62, GLN T2 and GLN T5.

Appendix C

Transient Stability Study Results

There is no transient instability or transient voltage recovery violation identified in the SIS. A summary of the transient stability study results for 2031LS load conditions with [redacted] project is provided in the table below.

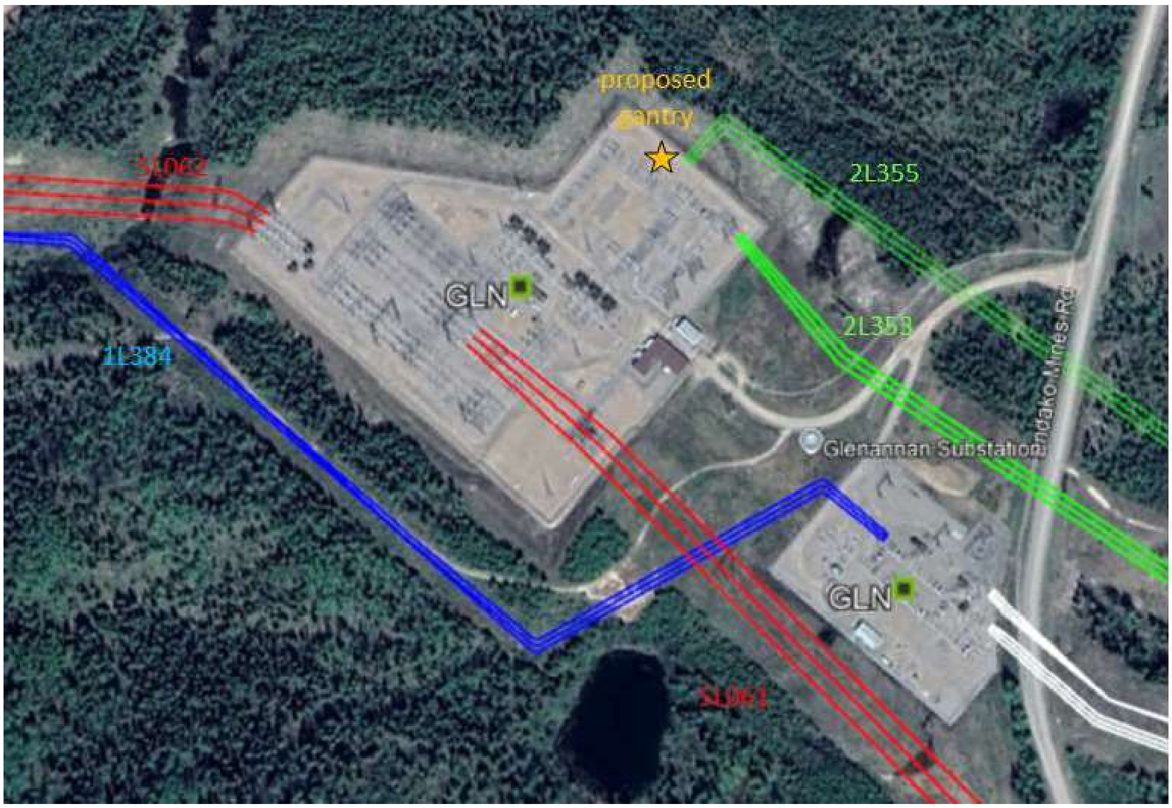
Table C-1: Transient Stability Study Results (2031LS Scenario)

Cat.	Contingency	3-Ph Fault Location	Fault Clearing Time (Cycles)		Dynamic Performance	
			Close End	Far End	[redacted] Wind Performance	Other Generators in Study Area *
P1.2	5L62	Close to GLN	4	4	Acceptable	N/A
P1.3	GLN T1 & GLN T11 [1]	GLN T1 230 kV	6	--	Acceptable	Acceptable
P1.2	2L353	Close to GLN	6	7	Acceptable	Acceptable
P1.2	2L353	Close to TAC	6	7	Acceptable	Acceptable
P1.2	2L355	Close to GLN	6	-	Acceptable	Acceptable
P1.2	1L384	Close to GLN	8	9	Acceptable	Acceptable
P1.2	60L341	Close to GLN	11	12	Acceptable	Acceptable
P2.3	GLN 5CB23 [2]	GLN 5CB23	4	12	Acceptable	N/A
P2.3	WSN 5CB13	WSN 5CB13	4	4	Acceptable	Acceptable

* Other key NC regional generators: FGE, FKR/VOL/MCY, KMO when operating in non-islanding mode
Note 1: GLN T1 and GLN T11 are in the same protection zone.
Note 2: Internal fault at GLN 5CB23 results in loss of 5L62, GLN T2 and GLN T5.

Appendix D
T-Line Diagram

The diagram below shows the suggested gantry for the proposed POI .



Appendix E
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 and RAS Requirements for Telecom

- Provide WECC Level 3 64 kbps synchronous circuits between GLN and NMW for “GLN-NMW 2LXXX PY/SY Digital Teleport”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 1 transfer trip facilities from SKA to NMW “SKA RAS PY G/S TT to NMW Block 1 and SKA RAS SY G/S TT to NMW Block 1.
- Provide WECC Level 1 transfer trip facilities from SKA to NMW “SKA RAS PY G/S TT to NMW Block 2 and SKA RAS SY G/S TT to NMW Block 2.

Telecontrol Requirements for Telecom

- NMW SCADA circuit off FVO & SIO.

Note: A recent disruption in the Passive Repeater supply chain would impact the cost and schedule for construction of the proposed ‘NMWPx’ passive repeater site. It is assumed that a suitable new passive solution could be procured to implement to this site.

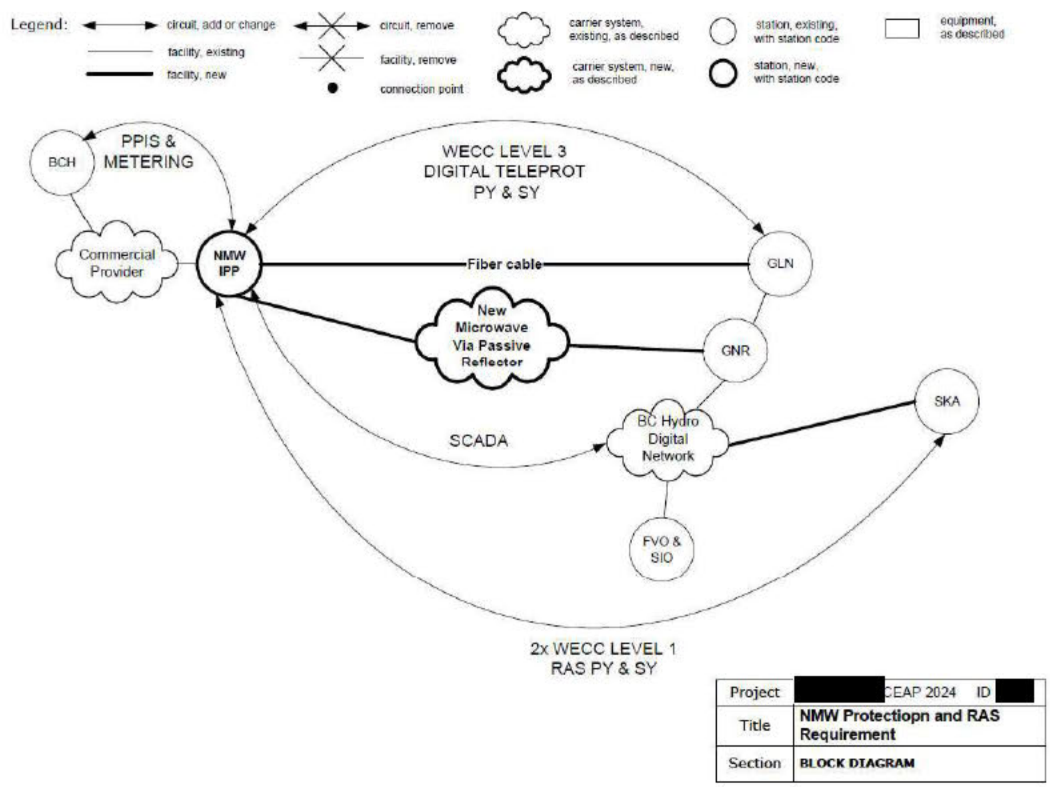


Figure E-1: The telecom block diagram identified in SIS of [redacted]Project.

Appendix F
Power Flow and Dynamic Models and Data

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

- G1: MBASE: [redacted]
- G2: MBASE:
- G3: MBASE:
- G4: MBASE:
- G5: MBASE:
- G6: MBASE:
- G7: MBASE:
- G8: MBASE:

[redacted]

[redacted]

Appendix G
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.

Appendix H

Station Work Required at Glenannan (GLN) Substation

The following diagram is the preliminary one-line sketch for the proposed work at Glenannan (GLN) Substation.