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

August 14, 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 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 to accommodate the interconnection of the Generating Facility to the BC Hydro 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 (SIS), the non-binding good faith estimated cost (typical accuracy range of +100%/-35%) for Network Upgrades required to interconnect your project is **$17.9 M.** 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:

- **Transmission Design – POI:**
  Design and build:
  - A new BC Hydro standard 138kV tap structure and up to three 138 kV disconnect switch structures.
  - Two existing structures will need to be replaced by 3-pole dead-end structures. These structures may need to be relocated to accommodate the tap/switch structures.
  - A new BC Hydro standard 138kV 3 pole dead-end structure will be installed as a demarcation point between BC Hydro and the Customer.
  - New right of way will be required to accommodate the tap connection.

- **Protection and Control Planning scope** at Nicola (NIC), Savona (SVA) and Highland (HLD) substations, including:
    - New SEL protection relays, thermal overload protection relay additions and revisions, RAS modifications, update telemetry.
    - Anti-islanding Direct Transfer Tripp (DTT) for protection/manual opening of 1L243.

- **Telecom Planning scope** at multiple microwave stations, repeater stations and substations:
    - Installing/adding routing nodes and equipment, towers, waveguides, antennas, battery and charger requirements, microwave radio systems, routers and firewalls, and tele-protection terminals.

Exclusions:

- GST
- Book value of decommissioned equipment
- Outage costs (lost revenue)
- Cost change due to currency fluctuations.
- Permits
- Potential property impacts (see Key Assumptions below for more information).
- As the exact project location is unknown, site-specific requirements including but not limited to dewatering, ground improvements, slope stabilization, etc. are not included.

Key Assumptions:

- Project is considered greenfield, outside of work around existing Transmission lines (taps, in-out reconfigurations, etc.).
- 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.
- Multiple outages on 1L243 may be required to accommodate the tap and switch structures construction.
- BC Hydro's Contractor to assume Prime Contractor responsibility.
- Telecom estimates are included in this estimate as a lump sum and it is assumed that some costs will be shared with other Interconnection Requests.
- Properties to be purchased are not known.
- Environmental Assessment Certificate will not be required for this project.
- Temporary camp for construction will not be required.
- Station and Control room expansions are not triggered by this Interconnection Request.

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.
- No defined supply chain strategy at this stage.
- Cost of construction may increase based on geotechnical conditions and environmental issues at the actual project site.

- Project schedule may be longer than expected, leading to increased costs.
- Cost of materials and major equipment may be affected by market conditions and escalation.
- Telecom scope presents high risk of change due to rapidly evolving technologies and standards. This project shares Telecom scope with other Interconnection Requests which adds additional complexity to these risks.
- Additional right of way or acquisition may be required to accommodate equipment.

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 Network Upgrades is Quarter 2, 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 System Impact Study, BC Hydro can arrange for an optional SIS review meeting. After the SIS review meeting, BC Hydro will provide you with an updated cost estimate for the Facilities Study and any additional data requirements.

As the Facility Study is currently in progress, we kindly request 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.

If you have any questions, please contact [redacted] at [redacted]

Sincerely,

[redacted]

Interconnections Manager, Transmission Generator Interconnections

BC Hydro

Encl.: [redacted]**_System Impact Study.pdf**

CC: [redacted]

BC Hydro
Power smart

[redacted]

Interconnection System Impact Study

BC Hydro EGBC Permit to Practice No: 1002449

[redacted]

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]
Sr. Engineer, Interconnection Planning

[redacted]

Reviewed by: [redacted]

[redacted]
Manager, Interconnection Planning

Accepted by: [redacted]

[redacted]
Manager, Transmission Planning

Report Metadata

Header:	[redacted]
Subheader:	Interconnection System Impact Study
Title:	[Company Fax]
Subtitle:	[redacted]
Report Number:	601G-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Aug 12
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 – [redacted] Line designation – 1L243
Additional Metadata:	Transmission Planning 2025-026 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Aug	Initial release

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7 Revenue Metering

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Sr Engineer, Revenue Metering

2025-08-13

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Acronyms

The following are acronyms used in this report.

BCH	British Columbia Hydro and Power Authority
[redacted]	[redacted] Project
COD	Commercial Operation Date
CT	Current Transformer
DTT	Direct Transfer Trip
EMS	Energy management System
ERIS	Energy Resource Interconnection Service
FRT	Fault Ride-Through
FVO	Fraser Valley Office
G/S	Generation Shed
HAM	Hamilton Microwave Repeater
HLD	Highland Substation
HS	Heavy Summer
HVC	Highland Valley Copper Substation
HVW	[redacted] Project
HW	Heavy Winter
IC	Interconnection Customer
ILM	Interior to Lower Mainland
IP	Internet Protocol
IPO	Independent Pole Operated
ISD	In-Service Date
K2W	[redacted] Project
KLY	Kelly Lake Substation
LS	Light Summer
MC	Measurement Canada or Canada federal regulations
[redacted]	[redacted]

MSV Mount Savona Microwave Repeater Station

NERC North American Electric Reliability Corporation

NIC Nicola Substation

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

PV Photovoltaic

PY/SY Primary/standby

QYS [redacted]

RAS Remedial Action Scheme

SCC System Control Centre

SIS System Impact Study

STL Spatsum Substation

STM Stump Pumping Station

SVA Savona Substation

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

TOV Temporary Overvoltage

TT Transfer Trip

VT Voltage Transformer

WECC Western Electricity Coordinating Council

WKTP West Kelowna Transmission Project

Executive Summary

[redacted]., the Interconnection Customer (IC), requests to connect a wind farm, [redacted], to the BC Hydro (BCH) system.

The [redacted] has [redacted], each with the rated capacity of 7.7 MVA. The total installed capacity of the project is 142.8 MW, with a maximum power injection of 138.2 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's 138 kV transmission line 1L243, approximately 22 km from Nicola Substation (NIC). The IC's proposed Commercial Operation Date (COD) is December 31, 2028.

To interconnect the [redacted] to the BCH Transmission System at the proposed POI, the SIS has concluded the following requirements:

1. The T-tap connection on the BCH's existing circuit 1L243 is acceptable for interconnecting the IC's generating project to the BCH system.

2. The proposed [redacted] is capable to meet the dynamic 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 provide a partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at the [redacted].

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

4. BCH will design and build the transmission tap assembly that will include tap structures and a disconnect switch structure. The exact type, number and location of the switches will be decided in a later stage.

5. BC Hydro will replace the existing 1L243 line protections at Highland Substation (HLD) and Nicola Substation (NIC) to accommodate the tap

connection. As part of the line protection & control, telecommunication facilities will be required to accommodate the new protection schemes. The IC shall provide required relays, telecom facility and associated equipment at its facilities as BC Hydro specifies to accommodate the new protection schemes.

6. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

7. A telecommunication-based Direct Transfer Trip (DTT) anti-islanding scheme is required in accordance with IEEE Std 2800-2022. This DTT scheme will initiate a trip to the [redacted] for any protection tripping or manual opening of the line 1L243.

8. The connection of the [redacted]t together with other 2024 Call for Power projects in the area does not cause any system performance violations (i.e. thermal overload, voltage violation, voltage instability, etc.) 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]. To address those concerns under contingencies, the [redacted] is required to participate in generation runback remedial action schemes (RAS). No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

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

Note that 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] to the BC Hydro (BCH) system. The project has [redacted]) [redacted], each with capacity of 7.7 MVA. Each turbine will have a maximum active power output of 6.8 MW. The total installed capacity of the project will be approximately 142.8 MW, with a maximum power injection of 138.2 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's 138 kV transmission line 1L243, approximately 22 km from Nicola Substation (NIC). The IC's proposed Commercial Operation Date (COD) is December 31, 2028. The project reviewed in this SIS is summarized in Table 1-1 below.

Table 1-1: Summary of Project Information

Project Name	[redacted]	
Interconnection Customer	[redacted]	
Point of Interconnection	A point on 1L243, 22 km from NIC	
IC Proposed COD	December 31, 2028	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	138.2 (Summer)	138.2 (Winter)
Number of Wind Turbines	[redacted]	
Plant Fuel	[redacted]	

The power generated from the [redacted] site will first be stepped up to 34.5 kV through step-up transformers, and then further stepped up to 138 kV via [redacted] main power transformers. The power will be transmitted through an IC-owned 4 km, 138 kV transmission line to BC Hydro's line 1L243, which runs between Highland Substation (HLD) and Nicola Substation (NIC).

Figure 1-1 illustrates the Nicola-Highland-Savana region transmission system. Nicola Substation (NIC) is a major hub in this region with a strong tie to 500 kV network, which includes:

- Two 500/230 kV transformers (NIC T2 & T3)
- Two existing 230/138 kV transformers (NIC T5 & T6)
- A new 230/138 kV transformer (NIC T7) to be added

Additionally, Savona Substation (SVA) is a BC Hydro owned 230/138 kV substation, which connects to Kelly Lake Substation (KLY) via two 230 kV transmission lines, 2L92 and 2L93.

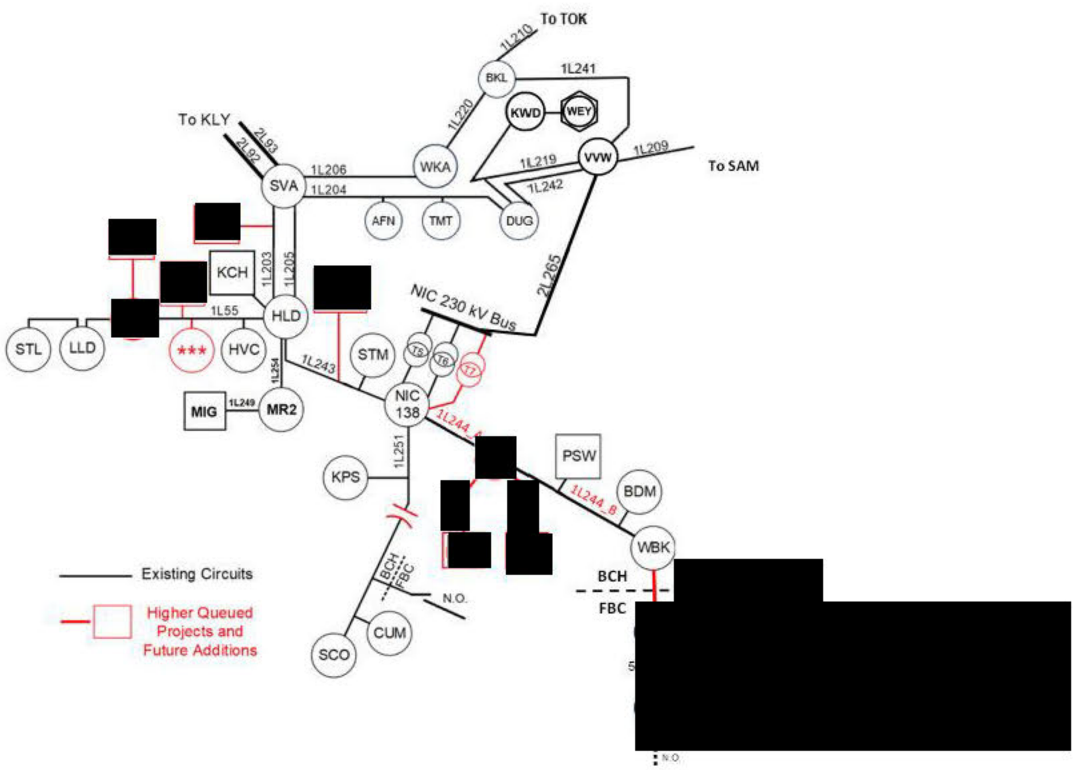


Figure 1-1: [redacted] and the Surrounding Area System

The [redacted] and the surrounding 138 kV transmission system are connected to SVA Substation via 1L203 and 1L205, and to NIC substation via 1L243.

The HLD Substation serves several industrial facilities and interconnects multiple generating stations owned by third parties—including the proposed HVC Load Increase and newly commissioned QYS Solar farm—via its transmission network, supporting growing energy demands in the area.

To support regional load growth, BC Hydro is planning several priority interconnection and network reinforcement projects—including upgrades at Nicola substation, reconductoring of 1L243, and series compensation on 1L251. Further details can be found in Section 4.

For the 2024 power call, there are four additional projects in the same SIW area, which are listed below.

- [redacted] ([redacted]) Proposed COD: 9/30/2030
- [redacted] ([redacted]) Proposed COD: 12/31/2028
- [redacted] ([redacted]) Proposed COD: 10/1/2031
- [redacted] ([redacted]) Proposed COD: 9/30/2028

The four projects above have been considered in the [redacted] SIS. The cumulative impact of those projects would contribute to the transmission constraints in the SIW area.

Appendix A shows the plant schematic diagram of the [redacted].

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 03, 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 2032 Heavy Winter (HW) and 2033 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. Specifically, the 2024 power call projects in the study area ([redacted], [redacted], [redacted], [redacted]) and other higher-queue generator interconnection projects (e.g. [redacted]) are included in the study model.

- 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.

- West Kelowna Transmission Project (WKTP) Alterative 3e[1] which will build a new 138 kV line from BC Hydro's West Bank substation (WBK) to Fortis BC's Recreation substation (REC) is included in the study model after F2032.

- Nicola Substation Transformation Capacity Reinforcement will add a new 230/138 kV transformer at NIC (i.e. NIC T7) to mitigate the possible transformer overload associated with the industrial load increase in the Highland region.

- 1L243 Line Reconductoring project will accommodate an industrial load increase in the Highland region.

---

[1] BC Hydro, West Kelowna Transmission Project, see details in https://www.bchydro.com/energy-in-bc/projects/wktp.html

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 2032 Heavy Winter (HW) load and 2033 Heavy/Light Summer (HS/LS) load conditions, based on the assumptions and considerations outlined in Section 4.

Table 5-1 shows a summary of stead-state performance concerns and the identified solutions associated with the interconnection of the subject project.

The Base Scenario reflects the high generation outputs from the Columbia River generating system while the Additional Scenario reflects the high generation outputs from the Peace River system. The two generation dispatch scenarios could result in different power flow distributions on 1L203 and 1L205.

The power flow study finds no thermal overload or voltage violations under system normal conditions. Under system contingencies, thermal overloads on the circuits 1L203, 1L205, 1L204 and 1L206 are observed under various contingencies. These overloads are driven by the addition of [redacted] together with other neighbouring power call projects. The detailed study results are listed in Appendix B.

To address those thermal overload concerns under the contingencies, the [redacted] will need to participate in generator runback remedial action schemes (RAS), as stated in Section 5.6 and detailed in Table 5-2. In addition to those listed in Table 5-1, 500 kV system contingencies may result in a mild overload on some of the 138 kV circuits, which can be also managed by the local RAS described in Table 5-2.

Table 5-1: Steady-State Performance Concerns and Proposed Solutions

Performance Concern	Conditions Observed	Contingencies that Result in the Facility Overload	Proposed Solution
1L203 Overload	LS, HS, HW	P1.2: 1L205 P2.1: Opening 1L243 at NIC P2.3: HLD 1CB2, HLD 1CB3, SVA 1CB2, and SVA 1CB4	Generation Runback RAS at MMW (See Section 5.6 for Details)

1L205 Overload	LS, HS, HW	P1.2: 1L203 P2.1: Opening 1L203 at SVA, Opening 1L243 at NIC P2.3: HLD_1CB5, SVA_1CB5, SVA_1CB6	Generation Runback RAS at [redacted] (See Section 5.6 for Details)
1L204 Overload	HS, HW with a higher flow on 5L87 southbound (KLY to NIC)	P1.2: 1L206, 1L220, 2L265 P1.3: VVW_T2 or T3 P2.1: Opening 1L243 at NIC P2.3: SVA_1CB10, SVA_1CB8	Generation Runback RAS at [redacted] (See Section 5.6 for Details)
1L206 Overload	HS with a higher flow on 5L87 southbound (KLY to NIC)	P2.1: Opening 1L204 at SVA	Generation Runback RAS at [redacted] HQ (See Section 5.6 for Details)

Note: P1.2, P2.1 and etc. are the contingency categories defined in NERC TPL-001-4.

The proposed [redacted] is capable to meet the dynamic 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 provide a partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at the [redacted].

5.2 Transient Stability Study

Transient stability studies have been performed using the 2032 heavy winter and 2033 light summer base cases to assess the impact of a maximum power injection of 138.2 MW from the [redacted] and other call projects on the transmission network in the vicinity area, in accordance with the TPL-001-WECC-CRT- 4 Performance Criteria.

Appendix C shows a summary of the transient stability study results for 2033LS condition with the addition of [redacted] No transient instability or transient voltage violation has been observed under the study conditions and contingencies.

In addition, upon the IC's submission, the WTG at [redacted] can provide fast frequency response (FFR) if the turbine's optional [redacted] is enabled. The FFR function is required at [redacted] 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.

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.
- Anti-islanding protection is required for the [redacted]. A telecommunication-based Direct Transfer Trip (DTT) scheme has been identified in accordance with IEEE Std 2800-2022. This DTT scheme will initiate a trip to the [redacted] for any protection tripping or manual opening of the 1L243 line.
- Voltage disturbance resulting from energization of two [redacted] main power transformers 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] 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] 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.
- 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 responses of the [redacted] turbine generator 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 [redacted] 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 thermal overload issues have been identified for various P1 or P2 contingencies in Table 5-1.
In addition, thermal overload issue on various sections of 1L243 is observed for the following P6 multiple contingencies:

- 1L203 SVA-[redacted] POI OOS and 1L205 contingency
- 1L205 OOS and 1L203 open end at SVA

A RAS based on local detection is proposed to mitigate the overload issues identified in Table 5-2.

Table 5-2: Proposed RAS for Regional System Contingencies

No.	Overload protection (Note 1)	Generation Runback at [redacted] (Note 2)	Speed Requirement (Note 3)
1	Install overload protection at SVA on 1L203, which operates if 1L203 is overloaded and the MW flow is flowing into SVA	Yes	5 to 10 seconds
2	Install overload protection at SVA on 1L204, which operates if 1L204 is overloaded and the MW flow is flowing out from SVA	Yes	
3	Install overload protection at SVA on 1L205, which operates if 1L205 is overload and the MW flow is flowing into SVA	Yes	
4	Install overload protection at SVA on 1L206, which operates if 1L206 is overloaded and the MW flow is flowing out from SVA	Yes	
5	Install overload protection at NIC on 1L243, which operates if 1L243 flow is larger than (1L243 MW rating – X MW) and the MW flow is flowing into NIC, where the X is the maximum load at STM.	Yes	
Note 1: Ambient temperature and line load dependent overload protection shall be used.			

Note 2: The run back signal shall be sent to [redacted] station to reduce the generation to a pre-determined value. This value will be provided in an operational planning study later before the IC connecting to BC Hydro system. Note 3: The speed requirement is defined as the time from the detection of the overload to the runback signal being sent out.

It is noted that the integration of the [redacted] will also implement runback schemes to manage increased generation injection during certain 500 kV contingency events via the Energy Management System (EMS) based RAS.

5.7 Station Upgrade Requirements

No station equipment upgrade is required for this project.

5.8 Transmission Line Upgrade Requirements

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

- A new BCH standard 138 kV tap structure between Str 13-01 and 13-02 of 1L243.
- Existing two structures Str 13-01 and 13-02 will need to be replaced to 3-pole dead-end structures with 65 ft C1 pole at minimum.
- Up to three new 138 kV disconnect switch structures as per BCH standard. The exact type, number and location of the switches will be decided in a later stage.
- A new BCH standard 138 kV 3 pole Dead-End structure will be installed as a demarcation point between BC hydro and the customer.
- Relocation of 1L243 Str 13-01 and/or 13-02 may be required to accommodate the tap and switch structures.
- New right of way may be required to accommodate the tap connection.
- Multiple outages on 1L243 maybe required to accommodate the tap and switch structures construction.

5.9 Protection, Control and Telecommunications

5.9.1 Protection

For successful integration of [redacted] project, as a tap on transmission line 1L243, the line protection relays at BC Hydro's HLD and NIC substations associated with 1L243 will be upgraded to convert from a two terminal line protection to a three terminal line protection. As part of the line protection upgrade, telecommunication facilities will be required for each of the three substations.

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 [redacted] relays (firmware and options specified by BC Hydro) relays at the entrance of [redacted] to provide protection coverage for 1L243. BC Hydro P&C Planning will provide settings for these relays.
- Provide instantaneous protections for transformers, buses, and lines between its 138 kV entrance breakers to unit step-up transformer HV buses.
- Main transformer T1 and T2 should not operate in parallel at 34.5 kV, the tie breaker of 34.5 kV buses should be normally open.
- The IC is responsible for implementing RAS requirements at their facility with no single point of failure.
- The IC is responsible for NERC PRC-related tasks, settings to compliance standards within their facilities.
- Provide anti-islanding protection as per Section 5.4.
- The IC is to provide the telecom facilities to receive the three runs back RAS signals from BCH stations.
- The IC is to provide the facilities to receive the DTT from 1L243 protection and manual opening of 1L243.

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 EMS at the nearest 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 leased 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 an appropriate Power Parameter Information System (PPIS) meter per the TIR requirements, connected to a suitable high voltage source for harmonics and power quality metering.

The IC is responsible for providing a communications link for remote interrogation of the PPIS equipment by BCH servers. Communication options include IP cellular modem, IP satellite, BCH WAN (where appropriate) and is subject to BCH review and approval.

Minor work will be required by BC Hydro to recommission telemetry, alarms, and remote access at NIC, HLD and SVA for the new protection relays. Additional work is required at NIC for Digital Fault Recorder (DFR) changes.

5.9.3 Telecommunications

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

The IC's Work Required at [redacted]

- Install tower, two waveguides, and antenna facing Hamilton Microwave Repeater (HAM). BC Hydro telecom designer to confirm frequency band, tower heights, and antenna sizes.

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

a) Assume that the location of [redacted] at [redacted] would be suitable for a passive reflector sufficiently elevated above ground level. Geotechnical, field surveys, and path surveys would be necessary for confirmation and property rights would need to be acquired.
b) Vegetation clearing at [redacted] would provide a suitable line-of-sight path to MSV.

c) BCH would perform a microwave link interference analysis through FCSA for the [redacted] to MSV 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 ISED Canada.

d) Assume good cellular data or satellite coverage at [redacted] for the revenue metering and PPIS circuits.

e) New towers at HAM, MSV could be added near an existing tower at each of those sites. And at Tuktakamin Microwave Repeater Station (TUK), it would be possible to use an expansion port on the existing waveguide facing HAM, if required.

f) A recent disruption in the supply chain for passive repeater components would impact the cost and schedule for construction of a passive repeater site at [redacted]. It is assumed that a suitable new passive solution could be developed and implemented at that site.

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 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	138 kV (voltage level), on the primary side of customer's main power transformer.
Voltage Transformers	3 x VTs (L-Grd) – 138/80.5 kV-115-115V - BCH Cat ID 3624351 (to be confirmed and supplied by the IC)
Current Transformers	3 x CTs- 300x600x1200:5-5 A – Ratio (connected 600:5-) – BCH Cat ID 96004282 (to be confirmed and supplied by the IC)

8 Conclusions

This System Impact Study has concluded the following requirements:

1. The T-tap connection on the BCH's existing circuit 1L243 is acceptable for interconnecting the IC's generating project to the BCH system.

2. The proposed [redacted] is capable to meet the dynamic 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 provide a partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at the [redacted]

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

4. BCH will design and build the transmission tap assembly that will include tap structures and a disconnect switch structure. The exact type, number and location of the switches will be decided in a later stage.

5. BC Hydro will replace the existing 1L243 line protections at Highland Substation (HLD) and Nicola Substation (NIC) to accommodate the tap connection. As part of the line protection & control, telecommunication facilities will be required to accommodate the new protection schemes. The IC shall provide required relays, telecom facility and associated equipment at its facilities as BC Hydro specifies to accommodate the new protection schemes.

6. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

7. A telecommunication-based Direct Transfer Trip (DTT) anti-islanding scheme is required in accordance with IEEE Std 2800-2022. This DTT

scheme will initiate a trip to the [redacted] for any protection tripping or manual opening of the line 1L243.

8. The connection of the [redacted] together with other 2024 Call for Power projects in the area does not cause any system performance violations (i.e. thermal overload, voltage violation, voltage instability, etc.) 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]. To address those concerns under contingencies, the [redacted] is required to participate in generation runback remedial action schemes (RAS). No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

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

Appendix A

Schematic Diagram of the IC's Project

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

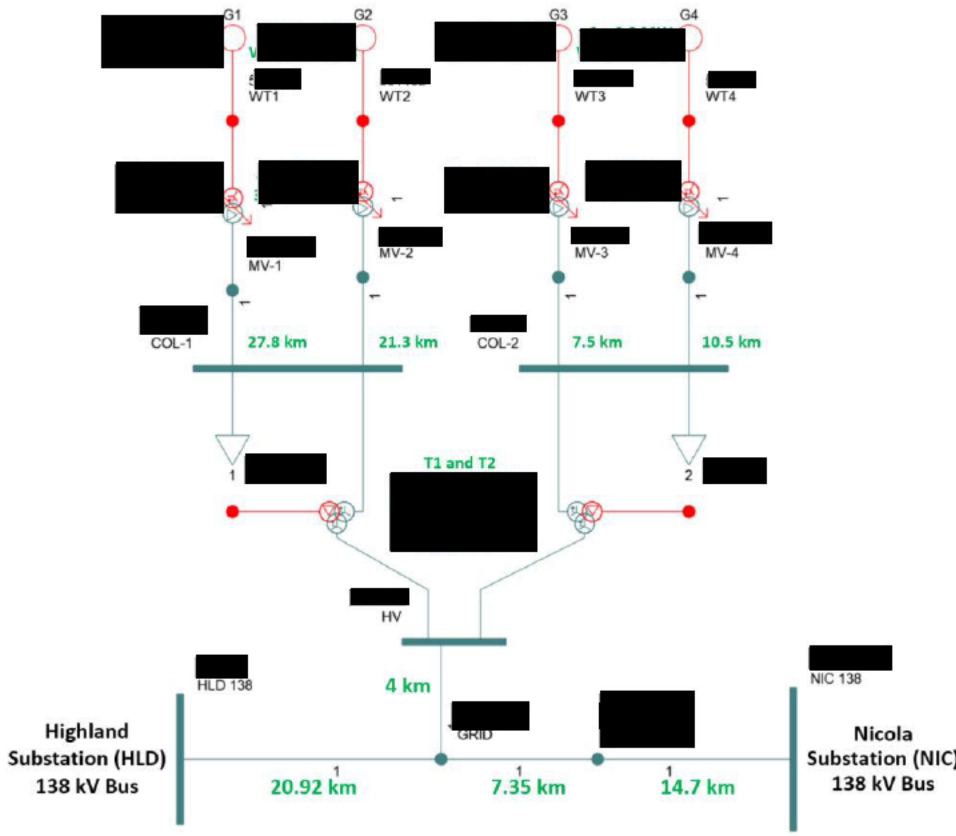


Figure A-1: Schematic Diagram of [redacted]

Appendix B
Steady-State Power Flow Study Results

Base Scenario

The base case scenario considered a northbound power flow on the 5L87 line, corresponding to conditions with elevated power output from Columbia generation sources and reduced output from Peace region facilities.

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

[redacted]

[redacted]

Additional Scenario

As stated in Section 5.1, the Additional Scenario reflects the high generation outputs from the Peace River system. In this study, 1L204 and 1L206 could be overloaded under the following single contingencies.

[redacted]

In addition, the study also reviewed the study result of pre- and post- West Kelowna Transmission Project (WKTP) scenarios and finds no obvious impact of WKTP on the interconnection of [redacted].

Appendix C
Transient Stability Study Results

Table C-1: Transient Stability Study Results

Cat.	Contingency	3-Ph Fault Location	Fault Clearing Time (Cycles)		Dynamic Performance	
			Close End	Far End	[redacted]	Other Generators in Study Area
P1.2	1L203	Close to SVA	8	9	Acceptable	Acceptable
P1.2	1L203	Close to [redacted]	8	9	Acceptable	Acceptable
P1.2	1L203	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L205	Close to SVA	8	9	Acceptable	Acceptable
P1.2	1L205	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L243	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L243	Close to NIC	8	9	Acceptable	Acceptable
P1.2	1L243	Close to [redacted]	8	9	Acceptable	Acceptable
P1.2	2L92	Close to KLY	6	8	Acceptable	Acceptable
P1.2	2L92	Close to SAV or SVA 12T3	6	8	Acceptable	Acceptable
P1.2	2L93	Close to KLY	6	7	Acceptable	Acceptable
P1.2	2L93	Close to SVA or SVA 12T1	6	7	Acceptable	Acceptable
P1.3	NIC T5 + T3	-	6	-	Acceptable	Acceptable
P1.3	NIC T6 + T2	-	6	-	Acceptable	Acceptable
P2-3	SVA 2CB5	-	15	-	Acceptable	Acceptable
P2-2	HVC TN HV BUS	-	8	-	Acceptable	Acceptable

Appendix D

Power Flow and Dynamic Models and Data

Each feeder is represented by an equivalent generator in power flow case with the following data:

- G1: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.9 kV
- G2: MBASE: 30.8 MVA, P_{max}: 27.2 MW, V_{nom}: 0.9 kV
- G3: MBASE: 30.8 MVA, P_{max}: 27.2 MW, V_{nom}: 0.9 kV
- G4: MBASE: 30.8 MVA, P_{max}: 40.8 MW, V_{nom}: 0.9 kV

In dynamic simulation, each equivalent generator is represented by a user-defined WTG model [redacted], which is proprietary and parameterized with vendor support. Table D-1 shows a selection of model parameters used in this SIS.

Table D-1: Selected Model Parameters in WTG [redacted]

Parameter #	Value	Description
[redacted]	1	[redacted]
	1	
	1	

In addition, the [redacted] package includes a user-defined [redacted] controller model [redacted], which is proprietary and parameterized with vendor support. Table D-2 shows a selection of model parameters used in this SIS.

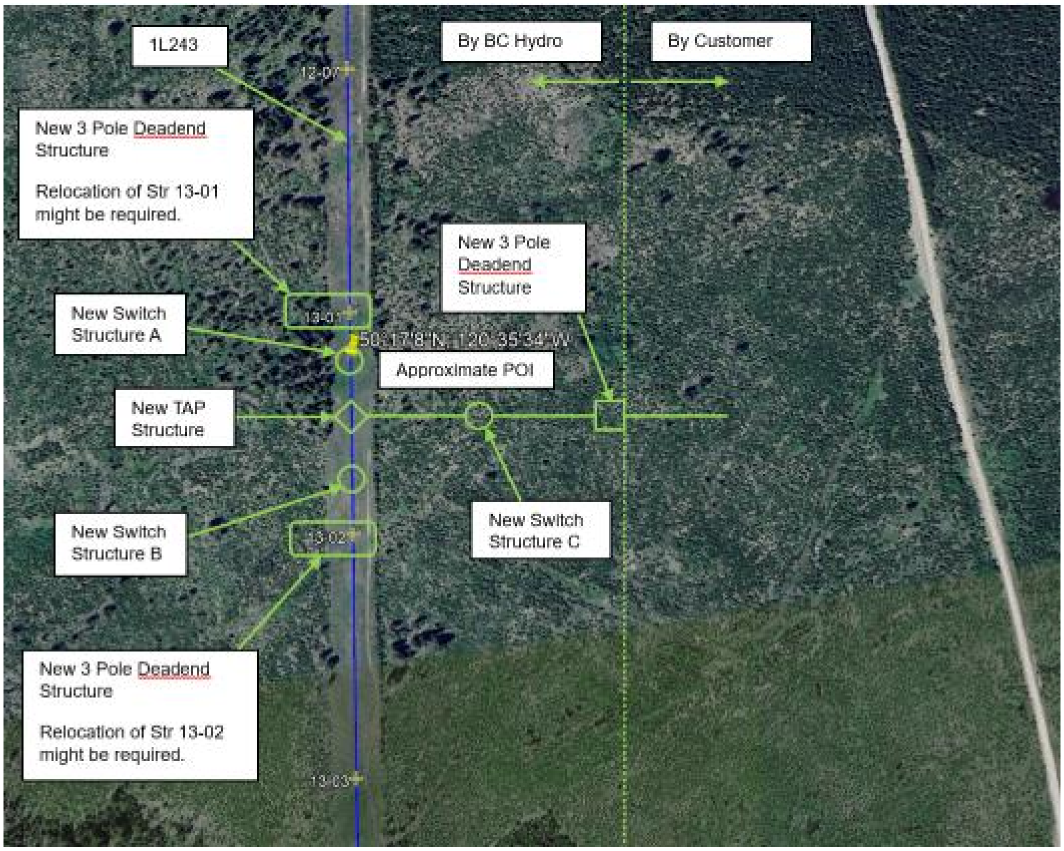
Table D-2: Selected Parameters in user-defined wind park controller model “NXWFC_4184”

Parameter #	Value	Description
[redacted]	[redacted]	[redacted]

Appendix E
T-Line Diagram

The diagram below shows the POI Location and Transmission Line Scope of Work.

Figure E-1: POI (approx. 22 km from NIC) on 1L243



Appendix F
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 NIC and HLD for "NIC-HLD 1L243 PY/SY Digital Teleprotection". Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 3 64 kbps synchronous circuits between HLD and [redacted] for "NIC-[redacted] 1L243 PY/SY Digital Teleprotection". Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 3 64 kbps synchronous circuits between HLD and [redacted] for "HLD-[redacted] 1L243 PY/SY Digital Teleprotection". Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 1 transfer trip facilities from NIC to [redacted] for "NIC 500 kV Contingency PY/SY G/S (Runback) TT TO [redacted]".
- Provide WECC Level 1 transfer trip facilities from NIC to [redacted] for "NIC 1L243 PY/SY G/S (Runback) TT TO [redacted]".
- Provide WECC Level 1 transfer trip facilities from SVA to [redacted] for "SVA 138 kV PY/SY G/S (Runback) TT TO [redacted]".

Telecontrol Requirements for Telecom

- [redacted] SCADA circuit off FVO & SIO.

Other Requirements for Telecom

- Provide corporate Virtual Private Routed Network (VPRN) circuits at HLD and MSA.
- See assumption d) in Section 5.9.3.

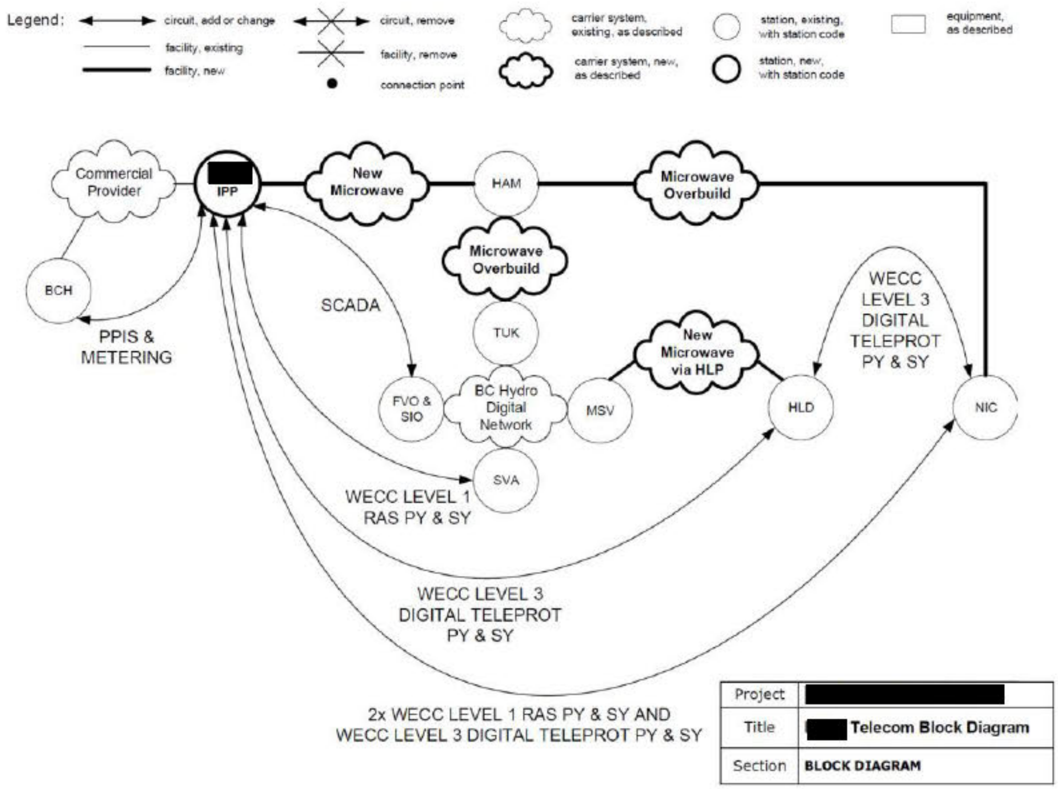


Figure F-1: Telecom Block Diagram Identified in the SIS of [redacted]

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.