# [redacted] Project

## Interconnection System Impact Study

BC Hydro Permit to Practice #: 1002449

[redacted]

Prepared for: [redacted] Project Limited Partnership

Prepared by: [redacted]

[redacted]

Sr. Engineer, Interconnection Planning

[redacted]

Reviewed by: [redacted]

[redacted]

Manager, Interconnection Planning

Accepted by: [redacted]

[redacted]

Manager, Transmission Assets Planning

2024 Apr 04

300-APR-00003

# Contributors

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

**Section:** Entire report except sections listed below
**Discipline:** Transmission Planning

Contributed by: [redacted]

[redacted]
Sr. Engineer, Interconnection Planning

[redacted]

**Section:** **5.4**
**Discipline:** Station Planning

Contributed by: [redacted]

[redacted]
Specialist Engineer, Station Planning

[redacted]

**Section:** **5.5 5.7**
**Discipline:** Station Planning

Contributed by: [redacted]

[redacted]
Sr. Engineer, Station Planning

[redacted]

**Section:** **5.6**
**Discipline:** Transmission Operations Services

Contributed by: [redacted]

[redacted]
Sr. Engineer, Transmission Operations Services

[redacted]

| **Section:** | **Discipline:** | |
|---|---|---|
| **5.8** | Transmission Line Engineering | |
| Contributed by: | [redacted]<br>[redacted]<br>Sr. Engineer, Transmission Line Enginering | [redacted] |

| **Section:** | **Discipline:** | |
|---|---|---|
| **5.5, 5.9.1, 5.9.2** | P&C Planning | |
| Contributed by: | [redacted]<br>[redacted]<br>Sr. Engineer, P&C Planning | [redacted] |

| **Section:** | **Discipline:** | |
|---|---|---|
| **5.9.3** | Telecom Planning | |
| Contributed by: | [redacted]<br>[redacted]<br>Specialist Engineer, Telecom Planning | [redacted] |

| **Section:** | **Discipline:** | |
|---|---|---|
| **5.10** | Revenue Metering System Mgmt | |
| Contributed by: | [redacted]<br>[redacted]<br>Sr. Engineer, Revenue Metering System Mgmt | [redacted] |

The following accept responsiblity for the content in Section 6 Cost Estimate and Schedule, but the cost/schedule information is not covered by any of the P.Eng seals/stamps.

| **Section:** | **Discipline:** |
|---|---|
| **6** | Cost Estimate and Schedule |

Contributed by:

[redacted] 4-APR-24

[redacted]
Interconnection Manager,
Interconnections

# Report Metadata

| | |
|---|---|
| Header: | [redacted] Project |
| Subheader: | Interconnection System Impact Study |
| Title: | BC Hydro Permit to Practice #: 1002449 |
| Subtitle: | [redacted] |
| Report Number: | 300-APR-00003 |
| Revision: | 0 |
| Confidentiality: | Public |
| Date: | 2024 Apr 04 |
| Volume: | 1 of 1 |
| | |
| Prepared for: | [redacted] Project Limited Partnership |
| Prepared by: | [redacted] |
| Title: | Sr. Engineer, Interconnection Planning |
| Checked by: | [redacted] |
| Title: | Sr. Engineer, Interconnection Planning |
| Reviewed by: | [redacted] |
| Title: | Manager, Interconnection Planning |
| | |
| Related Facilities: | 1L251, NIC substation |
| Additional Metadata: | 300-APR-00003 |

# Revisions

| Revision | Date | Description |
|---|---|---|
| 0 | 2024 Apr | Initial release |

# Disclaimer of Warranty, Limitation of Liability

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

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

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

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

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

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

Unless otherwise expressly agreed by BCH:

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

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

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

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

# Copyright Notice

# Table of Contents

## Tables



## Figures

## Acronyms

The following are acronyms used in this report.

| | |
|---|---|
| ASPx | [redacted] Generating Station |
| ASTx | [redacted] Terminal Substation |
| BES | Bulk Electric System |
| COD | Commercial Operation Date |
| CUM | Copper Mountain Substation |
| EMS | Energy Management System |
| ERIS | Energy Resource Interconnection Service |
| FBC | FortisBC |
| FRT | Fault Ride Through |
| FVO | Fraser Valley Office |
| HAM | Hamilton Mountain Microwave Repeater Station |
| IC | Interconnection Customer |
| NERC | North American Electric Reliability Corporation |
| NIC | Nicola Substation |
| NRIS | Network Resource Interconnection Service |
| OATT | Open Access Transmission Tariff |
| OO | Operating Order |
| POI | Point of Interconnection |
| POW | Point on Wave |
| PPIS | Power Plant Information System |
| PY | Premery Relay |
| RAS | Remedial Action Scheme |
| SCADA | Supervision Control and Data Aquicition |
| SCB | 1L251 Series Capacitor |
| SIS | System Impact Study |
| SY | Standby Relay |
| TYN | Thynne Mountain Microwave Repeater Station |
| TIR | BC Hydro 60 kV to 500 kV Technical Interconnection Requirements for Power Generators |
| WECC | Western Electricity Coordinating Council |

# Executive Summary

[redacted] Project Limited Partnership, the Interconnection Customer (IC), requested a System Impact Study (SIS) for the [redacted] project. This project is a hybrid resource installation, which includes 115.2 MVA solar inverter facilities collecting the output from the PV blocks and 115 MVA battery inverter facilities that connect 400 MWh battery banks. The maximum power injection into the BCH system is 100 MW, and the battery will be charged from their own solar generation only. The IC proposed Point of Interconnection (POI) is on the radially connected 138 kV transmission line 1L251, about 44.75 km from Nicola Substation (NIC). The proposed Commercial Operation Date (COD) is July 31, 2026. The details of the project information can be found in the Introduction section.

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

1 A three-circuit-breaker-ring switching station is required for interconnecting the [redacted] project. The switching station would be collocated with an 1L251 series capacitor station, which is proposed for a higher queued load interconnection project. The collocated station would be located near the proposed [redacted] POI in coordination with the [redacted] project.

2 With the proposed switching station, the system performance after the [redacted] project interconnection is acceptable under system normal and contingence conditions.

3 The [redacted] project inverters are required to have fault ride through (FRT) capabilities per the BC Hydro 60 kV to 500 kV Technical Interconnection Requirements for Power Generators (TIR). With the models and settings provided, the FRT performance of the inverters is satisfactory.

4 The [redacted] project inverters are required to have primary frequency response capability per the TIR. With the models and settings provided, the frequency response performance of the inverters is satisfactory.

5 The [redacted] project is not arranged for islanded operation. The IC is required to install anti-islanding protection within their facility to disconnect the [redacted] project from the grid when an inadvertent island with the local loads forms.

6 Voltage sags caused by energization of the IC's station transformers are expected to exceed the limits specified in the TIR. Point-On-Wave (POW) controlled closing of the 138 kV circuit breaker of the station transformer is required to control the magnetizing inrush current and the associated voltage sag.

7 A direct transfer tripping (DTT) scheme is required to disconnect the [redacted] project from the BC Hydro system if there is a protective operation or no-fault

opening of the transmission line 1L251 between the BC Hydro NIC substation and the new switching station ASTx.

8 The 138 kV circuit breakers are required to have the out-of-phase current interrupting capability to trip the [redacted] project at the new switching station ASTx.

9 The IC is required to meet the harmonic limitations that are specified in IEEE 519-2022 standard. Harmonic studies will be required when the associated data becomes available.

10 BC Hydro will provide a new control system for the new switching station ASTx, including remote and local control and indication for the new devices that will be installed at ASTx.

11 The IC is required to install a 48-strand single mode fibre optic cable from ASPx to ASTx.

The cost estimate provided for the Interconnection Network Upgrades is a non-binding good-faith cost estimate based on a Class 5, conceptual level estimate. The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to the BC Hydro transmission system is $50.55 million (+100%/-35%). The cost estimate includes a 24% contingency. The non-binding good faith estimated time to construct the required Network Upgrades is 4 to 5 years after completion of the Interconnection Facilities Study and execution of a Standard Generator Interconnection Agreement (SGIA), which suggests that the IC's proposed COD of July 31, 2026 would not be achievable.

The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.

# 1 Introduction

[redacted] Project Limited Partnership, the Interconnection Customer (IC), requested a System Impact Study (SIS) for [redacted] project. The proposed [redacted] project is located in the South Interior region, BC. This project is a hybrid resource installation, which includes 115.2 MVA solar inverter facilities collecting the output from the PV blocks and 115 MVA battery inverter facilities that connect 400 MWh battery banks. The maximum power injection into the system is 100 MW. The IC proposed Point of Interconnection (POI) is on the existing radial 138 kV transmission line 1L251, about 44.75 km from Nicola Substation (NIC). The proposed Commercial Operation Date (COD) is July 31, 2026. The IC confirmed that they will only use their own generation to charge the Bettary Energy Storage System (BESS). The IC also indicated that the [redacted] project does not have black start capability.

The project reviewed in this SIS is summarized in Table 1-1 below.

Table 1-1: Project Information

| | | |
|---|---|---|
| Project Name | [redacted] | |
| Interconnection Customer | [redacted] Project Limited Partnership | |
| Point of Interconnection | On 1L251, about 44.75 km from Nicola Substation | |
| IC Proposed COD | July 31 2026 | |
| Type of Interconnection Service | NRIS ☒ | ERIS ☐ |
| Maximum Power Injection (MW) | 100 (Summer) | 100 (Winter) |
| Number of PV Inverters | 32 PV Inverters, total 115.2 MVA capacity | |
| Number of Battery Inverters | 23 Battery Inverter, total 115 MVA capacity | |
| Battery Bank Capacity | 400 MWh | |
| Plant Fuel | Solar & Battery | |

In the [redacted] project, there are 32 Sungrow SG3600 PV inverters, each rated at 3.6 MVA and 0.868 power factor. Each PV inverter is connected to a 630 V/34.5 kV wye/delta transformer. There are also 23 Sungrow SC5000 battery inverters, each rated at 5 MVA and 0.87 power factor. Each battery inverter is connected to a 900 V / 34.5 kV wye /delta transformer. The total power from all inverters is collected via eight 34.5 kV equivalent feeders, and then stepped up to the 138 kV system through one 115 MVA, 138/34.5 kV (high side Y-gnd/Delta) station transformer. The IC owned station ASPx is connected into the system through an IC owned 5.8 km line at the required switching station (ASTx) near the IC proposed POI on line 1L251. Refer to Figure 1 below for details.

In Figure 1, four equivalent PV feeders and four equivalent battery feeders are connected to ASPx 34.5 kV bus(es). On each of equivalent solar feeders, 8 individual solar inverters and 8 individual step-up transformers are represented.

Similarly, 5-6 individual battery inverters and 5-6 individual step-up transformers are represented on each of the equivalent battery feeders.

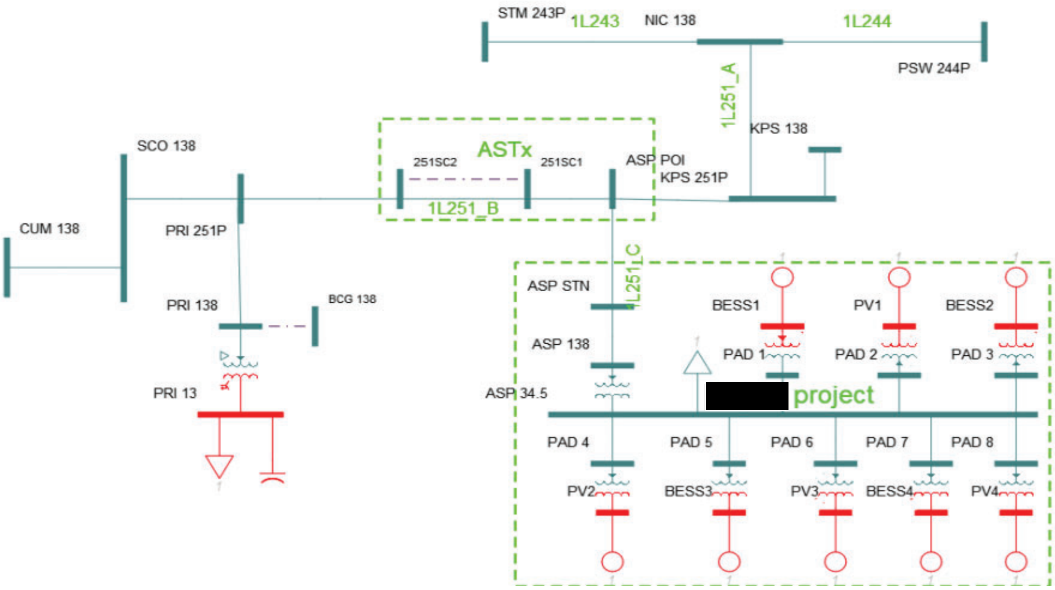



Figure 1: [redacted] Project and Adjacent Transmission System

Figure 2 below illustrates the local system discussed in the following paragraphs.

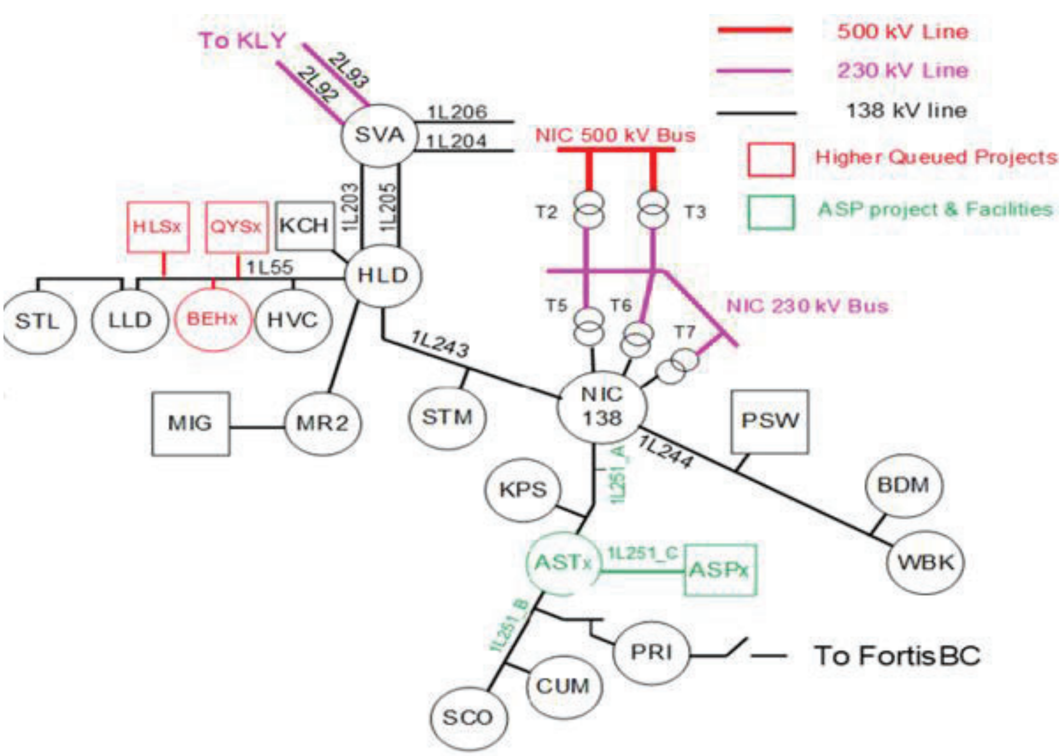



Figure 2: [redacted] Project and HLD-NIC-Okanagan Reginal Transmission System

A three-circuit-breaker-ring switching station near the [redacted] project POI is needed for interconnecting [redacted] project. The switching station would be collocated with the 1L251 series capacitor station that is required for a higher queued load interconnection project.

Due to the addition of the three-circuit-breaker-ring station, line 1L251 (NIC-SCO/CUM) will be sectionalized into two 138 kV lines. One between NIC and ASTx is tentatively designated as 1L251_A in this SIS report, and the other between ASTx and SCO/CUM as 1L251_B. The [redacted] collector station is designated as ASPx in this report. The IC's 5.8 km, 138 kV line from ASPx to ASTx is tentatively designated as 1L251_C. With the switching station in place, the POI will be the [redacted] project's 138 kV line disconnect at ASTx.

There are three industrial facilities currently fed by circuit 1L251. The industrial facilities are Copper Mountain Substation (CUM), Similco Substation (SCO), Kingsvale substation (KPS). Fortis BC's Princeton substation (PRI) serves the distribution loads. PRI may be supplied from either the 1L251 tap point or Fortis BC's line 43L. Paralell operation of 1L251 with the FBC system through PRI is not permitted, except for a short period of load transfer. In this SIS, PRI is supplied from 1L251. The two load stations CUM and SCO are owned by the same customer, Copper Mountain Mine BC Ltd.

NIC is one of the BC Hydro major transmission substations, and presently has two 500/230 kV transformers, and two 230/138/12 kV transformers. An additional 230/138 kV transformer will be added in NIC in March 2026 as planned, which is required by a higher queued load interconnection project.

# 2 Purpose of Study

The purpose of this SIS is to assess the impact of the interconnection of the proposed project on the BC Hydro transmission system per BC Hydro's Open Access Transmission Tariff (OATT). This study is to identify any constraints and suggest network upgrade options to obtain adequate performance for reliable operation of the transmission system.

The SIS is performed in compliance with the North American Electric Reliability Corporation (NERC) reliability standards and Western Electricity Coordinating Council (WECC) transmission planning criteria, as well as the BC Hydro transmission planning criteria, specifically:

- NERC standards: FAC-002-3 and TPL-001-4;
- WECC criteria: TPL-001-WECC-CRT-3.2;
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators per FAC-001-3;
- BC Hydro's TAP FAC-002-3 Study Guide.

# 3 Scope of Study

This SIS investigates and addresses the voltage and overloading issues of the transmission system in the vicinity of the [redacted] project for the long term planning horizon as a result of the proposed [redacted] project. Studies completed include steady-state studies, dynamics studies and short circuit analysis to evaluate system performance, as well as protection coordination, operation flexibility, telecom requirements and high level remedial action scheme (RAS) requirements. BC Hydro planning methodology and criteria are used in the studies as stated in Purpose of Study.

Pursuant to FAC-002-3, BC Hydro has taken the necessary measures to assess the potential reliability impact on the FBC system, including monitoring the part of FBC system that is adjacent to the proposed [redacted] project. The study result pertaining to the FBC system, will be shared and coordinated with FBC upon completion of this SIS.

# 4 Assumptions and Conditions

The study cases are established based upon the IC's submission completed on March 08, 2023. Reasonable assumptions have been made to complete this study. The key assumptions and study conditions used in this SIS are listed below.

- BC Hydro 2026 light summer, heavy summer and heavy winter load base cases are selected in performing this study as with the local load growth, the 2026 base cases represent more constrained system conditions in the local systems than those in other future years. In the three base cases, the intertie exchanges are set within their long-term firm transfers.

- The nearby higher queued load interconnection project is included in the base cases. The identified system upgrades for this load project, i.e.,1L251 line thermal rating upgrade and addition of a series capacitor (SCB) on 1L251 to provide 50% series compensation, are also included.

- NIC T7 that is required for interconnecting another higher queued load project in the Highland area will be in service in March 2026 as planned and is included in this study base cases.

- The PRI load of 15 MW is supplied from 1L251 in this SIS although normally supplied by FBC in real time operatrion.

- The Highland project of 150 MW PV inverters and 150 MW battery inverters is included in this study, but is studied separately with another project.

- 1L251 is supplied from NIC only, with the FBC side open, which means whenever the NIC end of 1L251 is open, the [redacted] project will need to be off-line.

- Acheivable fault clearing time for the selected contingences are listed in Table 5-2.

# 5 System Studies and Results

## 5.1 Steady State Study

Power flow analyses under system normal (N-0 or P0) and contingency conditions were performed to evaluate whether the [redacted] project would cause any adverse impact on the transmission system.

Before the [redacted] addition, Line 1L251 thermal rating is required to be uprated for the higher queued Load project. No thermal overload concern due to interconnection of the [redacted] project is identified since the [redacted] project's power injection will be largely offset and consumed locally.

With the [redacted] project in service, the impact of different [redacted] project generation outputs to the local system is demonstrated in case 1 to case 3 of Table 5-1. No concerns have been identified.

With the [redacted] project in service, if the 1L251 SCB is bypassed or two CUM & SCO shunt capacitors are out-of-service (OOS), CUM & SCO voltage can be maintained within the required level, see case 4 and case 5 of Table 5-1.

For certain critical contingency condition, such as with 1L251 SCB already bypassed, forced outage of the [redacted] project could result in CUM & SCO 138 kV bus voltage dip below 0.9 pu. In such an event, load tripping at CUM&SCO is required, see case 6 of Table 5-1. The load tripping could be initiated by the existing under voltage load shedding protection at CUM & SCO.

In Table 5-1, case 7 to case 9 demonstrate the impact of the [redacted] project generation outputs to the local system voltage and to the loadings of NIC 230/138 transformers under P6 contingence conditions.

This study has concluded that with the [redacted] project connected to the system, under system normal (N-0 or P0) and with contingency conditions there is no overloading or unaccepted voltage profiles observed in the transmission system under the studied load and generation conditions.

Table 5-1: Power Flow Results

| Base Cases and System condition | | | [redacted] output | 138 kV bus voltage (pu) | | | | | equipment loading (percentage of the equipment rating) | | | Load Shedding Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base Cases | TPL-01-004 Categories | Case Number and System Condition | | NIC 138 kV bus | [redacted] POI | PRI 138 kV bus | SCO 138 kV bus | CUM 138 kV bus | NIC T5 | NIC T6 | NIC T7 | |
| 2026 Heavy Summer | P0 | 1. System normal | 100 MW | 1.02 | 1.04 | 1.0 | 0.99 | 0.99 | 20 | 20 | 15 | |
| | | 2. System normal | 50 MW | 1.02 | 1.04 | 1.0 | 0.99 | 0.99 | 25 | 25 | 19 | |
| | | 3. System normal | 0 MW | 1.02 | 1.04 | 1.0 | 0.99 | 0.99 | 31 | 31 | 24 | |
| | P1 | 4. 1L251_B SCB bypassed | 100 MW | 1.02 | 1.04 | 0.97 | 0.95 | 0.95 | 17 | 17 | 13 | |
| | | 5. 1L251_B SCB bypassed | 0 MW | 1.02 | 1.04 | 0.96 | 0.95 | 0.94 | 31 | 31 | 24 | |
| | P6 | 6. 1L251_C, with 1L251_B SCB already bypassed | N/A, ([redacted] is tripped) | 1.02 | 0.98 | 0.96 | 0.95 | 0.95 | 27 | 27 | 21 | Required at CUM & SCO. |
| | | 7. 1L251_B tripped with NIC T5 already OOS | 100 MW | 1.05 | 1.04 | N/A | N/A | N/A | N/A | 7 | 5 | |
| | | 8. NIC T6 (isolates T2), with NIC T5 already OOS | 100 MW | 1.02 | 1.04 | 1.0 | 0.99 | 0.98 | N/A | N/A | 45 | |
| | | 9. NIC T6 (isolates T2), with NIC T5 already OOS | 0 MW | 1.02 | 1.04 | 1.01 | 0.99 | 0.99 | N/A | N/A | 73 | |
| 2026 Light Summer | P0 | 10. System normal | N/A (Before [redacted] is connected) | 1.02 | 1.0 | 0.97 | 0.95 | 0.95 | 23 | 23 | 18 | |
| | | 11. System normal | 100 MW | 1.02 | 1.04 | 1.01 | 0.99 | 0.99 | 12 | 12 | 9 | |
| 2026 Heavy Winter | P0 | 12. System normal | N/A (Before [redacted] is connected) | 1.02 | 0.99 | 0.96 | 0.94 | 0.94 | 29 | 29 | 22 | |
| | | 13. System normal | 100 MW | 1.03 | 1.04 | 1.01 | 0.99 | 0.99 | 18 | 18 | 13 | |

## 5.2 Transient Stability Study

Transient stability simulations were performed on the 2026 heavy summer load scenario for single and multiple contingencies.

The study results have demonstrated that with the [redacted] project in service any single contingence in the local system will not result in unacceptable performance, see case 1 to case 6 of Table 5-2, including losing of the [redacted] project, see case 7 of Table 5-2. In Table 5-2, case 8 demonstrates a P3 contingency, case 9 demonstrate a SLG fault on 1L243 with a line circuit breaker stuck (P4) event and Case 10 demonstrate a N-1-1 (P6) event. The results show the performances of the events are all acceptable.

For a critical event, case 11, e.g., with the 1L251_B SCB already bypassed, a contingency on 1L251_C will cause a disconnection of the [redacted] project. This contingency would result in voltage dip below 0.9 pu but above 0.85 pu at CUM & SCO and PRI. The dynamic performance is acceptable although some load tripping at CUM and SCO can be expected during the later stage of voltage recovery.

The [redacted] project inverters are required to have fault ride-through (FRT) capabilities per the BC Hydro's TIR. The [redacted] project inverters are expected to remain connected to the system and continue to inject reactive current after a voltage disturbance occured in the transmission system with normal fault clearing. With the models and settings provided, the FRT performance of the inverters is satisfactory and does not result in inverters tripping or entering momentary ceasation in dynamic simulations. The [redacted] project inverters are required to have primary frequency response. With the models and settings provided, the frequency response performance of the inverters is satisfactory.

The stability performance with the [redacted] project was shown to be acceptable.

A few selected transient stability study results are listed in Table 5-2 below.

Table 5-2: Transient stability study results

| NERC TPL-001-4 Category | Cases | [redacted] generation output | Contingencies | Fault Locations | Fault Clearing Time (Cycles) | | Transient Stability Performance |
|---|---|---|---|---|---|---|---|
| | | | | | Close End | Far End | |
| P1 | 1 | 100 MW from PV | 1L243 | 3-phase fault at NIC end | 8 | 9 | Acceptable |
| | 2 | 100 MW from BESS | 1L243 | 3-phase fault at NIC end | 8 | 9 | Acceptable |
| | 3 | 40 MW from PV and 60 MW from BESS | 1L243 | 3-phase fault at NIC end | 8 | 9 | Acceptable |
| | 4 | Same as case 3 | 1L251_B | 3-phase fault at ASPT end | 6 | N/A | Acceptable |
| | 5 | Same as case 3 | NIC T5 (also isolates T3) | at 138 kV side | 8 | N/A | Acceptable |
| | 6 | Same as case 3 | PRI 138 kV Transformer | at 138 kV bus | 8 | N/A | Acceptable |
| | 7 | Same as case 3 | 1L251_C | 3-phase fault at ASPT end | 6 | N/A | Acceptable |
| P3 | 8 | One [redacted] PV Inverter OOS | 1L251 SCB bypass | No Fault | | | Acceptable |
| P4 | 9 | Same as case 3 | 1L243 with NIC 1CB17 stuck, tripping 1L243, T5 and T3 | SLG fault at NIC end | 15 | 9 | Acceptable |
| P6 | 10 | Same as case 3 | 1L251_C (with NIC T5 already out of service) | at POI end | 6 | N/A | Acceptable |
| Extreme Event | 11 | Same as case 3 | 1L251_C (with 1L251 SCB already by-passed) | at POI end | 6 | N/A | Acceptable |

## 5.3 Reliability Impact to Adjacent Utilities

The reliability impact of the proposed interconnection to the adjacent part of FBC was monitored in accordance with FAC-002-3. No unacceptable performance is observed in the monitored part of the FBC system.

## 5.4 Analytical Studies

The impact of the 100 MW [redacted] project was assessed based on the models and data provided by the IC. The study identified the following key findings and requirements:

- Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by BC Hydro's TIR. Point-On-Wave (POW) controlled closing of the transformer 138kV circuit breaker is required to control the magnetizing inrush current and the associated voltage sag.
- A direct transfer tripping (DTT) scheme is required to disconnect the [redacted] project if there is a protective operation or no-fault opening of transmission line 1L251 between the BC Hydro NIC substation and the new switching station ASTx.
- Temporary Over Voltages (TOV) are being mitigated with DTT to ring bus at BC Hydro owned the new switching station ASTx.
- The 138kV circuit breakers are required to have the out-of-phase current interrupting capability to trip the [redacted] project at the new switching station ASTx.
- The IC is required to meet the harmonic limitations that are specified in IEEE 519-2022 standard. Harmonic studies will be required when the associated data becomes available.
- The Power Parameter Information System (PPIS) meter is required within the Power Generating Facility to provide electrical parameters including but not limited to kW, kVAR, kVA, Voltage, Current, Power Factor, Power Frequency and Harmonics.

For the [redacted] project as an Inverter-Based-Resource plant, detailed EMT models of the interconnecting facilities should be submitted to BC Hydro at the Facilities Study stage. These models shall provide an accurate representation of the controls and protection features of the plant. The model will be used to demonstrate plant compliance with the requirements specified in BC Hydro's TIR.

## 5.5 Fault Analysis

The short circuit analysis for the SIS is based upon the latest BC Hydro system model, which includes project equipment and impedances provided by the IC.

Thevenin impedances, including the near term and 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 Scheme

The interconnection of [redacted] project has no material impact on the BC Hydro bulk system performance, and therefore no additional RAS function is required for interconnecting the [redacted] project.

## 5.7 Station Upgrade Requirements

As stated in Section 1, a three circuit breaker ring switching station (tentatively named as ASTx) is needed to interconnect the [redacted] project. Details of the station configuration and equipment disgnations can be found in the ASTx one line diagram shown in Appendix A.

## 5.8 Transmission Line Requirements

- Re-terminate line 1L251 at approximately structure 25-03 to the new switching station ASTx. This will form a new section designated as 1L251_A from NIC substation to ASTx. The exact circuit number will be determined at a later stage.
- Re-terminate the other portion of line 1L251 at approximately structure 25-04 to ASTx. This will form a new section designated as 1L251_B from SCO substation to ASTx. The exact circuit number will be determined at a later stage.
- Installe two new dead-end structures in-line to re-terminate the existing line 1L251.
- New right-of-way may be required to build ASTx and complete the ingress/egress of line 1L251.
- The last span of the IC's line 1L251_C from the IC's substation ASPx into ASTx, should have the owners engineer review (if design build by the IC) by BC Hydro.

## 5.9 Protection, Control and Telecommunications

### 5.9.1 Protection Upgrade Requirement

A new line protection system for the line, 1L251_C, which extends from the new switching station ASTx to IC's station ASPx is required. The scheme will be a line current differential protection system using SEL 411L relaying. Protection systems for the other line terminals at ASTx will be required. The existing NIC 1L251 line protection system will be retained but revised to account for the new ASTx switching station as well as the addition of DTT logic to trip ASPx as required to mitigate TOV concerns due to interconnection of [redacted] project.

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

- Entrance protection that complies with the latest version of the BC Hydro TIR.
- Two SEL-411L relays at the entrance of ASTx to provide protection coverage for 1L251_C. Appropriate telecom facilities to support the SEL-411L relaying scheme. BC Hydro P&C Planning will provide settings for these relays.
- The full model of the generation sources in a table format which includes current output, angle and power factor at a variety of voltage levels. If the inverter is programmed to output negative sequence current this information will be required as well. This will have to be provided to BC Hydro P&C Planning prior to P&C Planning begins work on the P&C Application.
- Anti-islanding protection to prevent [redacted] project from operating in islanded condition.

In addition, the following SIGNED and SEALED documents must be submitted by the IC to BC Hydro P&C Planning for review at least 8 weeks prior to the target Interconnection date.

- Issued for construction Protection one-line diagram.
- Relevant DC schematics of protection relay(s) and wiring diagram
- Transformer nameplate drawings
- Generating Resource specifications that is usable by BC Hydro for protection studies
- Entrance HV interrupting device(s) nameplate with interruption time rating indicated.
- Relevant Protection relay(s) settings

### 5.9.2 Control Upgrade Requirement

- BC Hydro will provide a new control system for the new switching station ASTx, including remote and local control and indication for the new devices that will be installed at ASTx.The BC Hydro Control Center will update the Energy Management System (EMS) to add ASTx and ASPx to the network model.

- The IC is required to report telemetry, and status information in real-time by exception using a remote terminal unit (RTU) with DNP3 reporting to a Data Concentration Point per the BC Hydro TIR. The IC is responsible to provide a dedicated (always on) telecommunication to the closest BC Hydro station with appropriate telecom facilities (station to be determined by BC Hydro Telecom).
- The IC is responsible for providing a power plant information system (PPIS) meter, connected to a suitable high voltage source for harmonics and power quality metering. The selection of the PPIS meter is subject to BC Hydro approval.
- The IC is also responsible for providing a communications link for remote interrogation of the line protection relays and PPIS equipment by BC Hydro servers. As a minimum it can be a dial-up telephone line. Alternative communications include IP cellular modem, IP satellite, BC Hydro WAN (where appropriate), and is subject to BC Hydro review and approval.
- Communications and equipment selection is subject to BC Hydro review and approval.

In addition, the IC may be asked to provide 1L251_C protection event records from 1L251_C protection relays to BC Hydro under the following circumstances (in the circumstance where remote data access is not working).

- Fault on 1L251_C
- Relay mis-operation for fault outside 1L251_C
- Relay operation due to Power Quality Protection elements

The exchange of event reports will assist BC Hydro in analyzing system disturbances. This should improve the protection performance of both BC Hydro and the IC for faults near points of interconnection.

Work by BC Hydro will be required to commission telemetry, alarms of the new DTT telecommunication facilities and remote access at [redacted] project.

### 5.9.3 Telecommunication Upgrade Requirement

At the time of this study, the precise location of ASTx was not yet determined; only its general vicinity. A microwave solution from Thynne Mountain Microwave Repeater Station (TYN) with a back-to-back passive repeater site near ASTx has been assumed for the purpose of this study. Appendix B shows [redacted] project telecom block diagram.

There is a severe bandwidth limitation for the network backbone and for the path into NIC from Hamilton Mountain Microwave Repeater Station (HAM). A microwave capacity addition from TYN to NIC has been assumed for the purpose of this study.

A few assumptions were made when delivering the above telcom upgrade requirements, including ASTx being reachable by microwave from TYN, availability of existing telecom system capacity, availability of commercial telecommunication service, and availability of required equipment, etc, but the details are not included in this report.

The requirements to derive the need for the telecom additions are described bellow.

**Tele-protection Requirements for Telecom:**

- Provide WECC Level 3 PY and SY transfer trip signals, NIC to ASTx.
- Provide WECC Level 3 PY and SY 64 kbps synchronous circuits between ASTx and ASPx. Physical interface shall be V.35.

**Tele-control Requirements for Telecom:**

- Provide ASTx SCADA circuit, minimum speed 9.6 kbps.
- Provide ASTx REMACC circuit.
- Provide ASPx SCADA circuit.

**Other Requirements:**

- ASPx PPIS circuit.
  ASPx Revenue Metering circuit(s).

The detailed telecommunication upgrade works required would be described in the next stage of Facilities study. It is expected that all work would be done by BC Hydro unless otherwise indicated.

The IC is required to install a 48-strand single mode fibre optic cable from HLTx to HLSx.

## 5.10 Revenue Metering Requirements

- The remote read load profile revenue metering installation should be in accordance with Canada federal regulations 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.23-26.

- Primary Metering is required. A 3-element metering scheme with 3 curent transformers (CT) and 3 voltage transformers (VT) connected L-N (Grd) will 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 BC Hydro Billing Group using MV-90; the Point-of-Metering (POM) shall have a dedicated communications line (BC Hydro's approved wireless internet protocol (IP) solution, landline or other approved alternative). It should be used for revenue metering only. If there is digital cell phone coverage for data in the site, BC Hydro can supply the IP Wireless Communications Modem equipment.
- The revenue class meters (main and backup) are Measurement Canada (MC) approved and will be supplied and maintained by BC Hydro. The MC approved revenue class instrument transformers (CTs and VTs units) are supplied by the IC. The IC must submit all technical information for CTs and VTs as Model/Maker/MC Approval under to BC Hydro prior to purchasing it. BC Hydro will analyse it.
- If the impedance and losses between the POM and the Point-of-Delivery/Receipt (PODR) are significant, the meters will be programmed to account for the line and/or transformer losses between the POM and PODR. The IC or the consultant shall provide the line parameters (and/or power transformer) data signed and stamped by a professional engineer.
- During the planning phase, BC Hydro Revenue Metering department should be contacted to discuss the specifics of the project. The applicant should send drawings to BC Hydro Revenue Metering Department showing the one-line diagram (SLD) and informing the planned metering scheme, meter cabinet location, as well as any other related document. BC Hydro's Revenue Metering department can be contacted via email: metering.revenue@bchydro.com.

Here under are some information about CTs and VTs, which are important as reference for guidance.

| | |
|---|---|
| Voltage Transformers (Supplied by IPP) | 3 x VTs (L-Grd) – 80,500-115-115V – To be supplied by PG |
| Current Transformers (Supplied by IPP) | 3 x CTs- 600:5-5 A – Ratio – To be supplied by PG |

# 6 Cost Estimate and Schedule

The cost estimate provided for the Interconnection Network Upgrades is a non-binding good-faith cost estimate based on a Class 5, conceptual level estimate. The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BC Hydro transmission system is $50.55 million (+100%/-35%). The cost estimate includes a 24% contingency.

The estimate excludes:

- GST
- Book value of decommissioned equipment
- Outage costs (lost revenue)
- Any work at the customer substation
- Any thermal upgrade work of 1L251
- Transmission line from Customer's station (ASPx) to BC Hydro's new switching station (ASTx)

The non-binding good faith estimated time to construct is 4 to 5 years after completion of the Interconnection Facilities Study stage and execution of a Standard Generator Interconnection Agreement. The estimated time to construct assumes that the transmission line reinforcement work and new series capacitor bank station work required for a higher queued project does not delay the [redacted] project schedule.

The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.

# 7 Conclusions

To interconnect the [redacted] project to the BC Hydro Transmission System at the POI, this SIS has identified the following conclusions and requirements:

- A three-circuit-breaker-ring switching station is required for interconnecting the [redacted] project. The switching station would be collocated with an 1L251 series capacitor station, which is required for a higher queued load interconnection project. The collocated station would be located near the proposed [redacted] project's POI in coordination with the [redacted] project. The series capacitor should be on the down stream side to CUM & SCO.

- With the proposed switching station, the system performance after the [redacted] project interconnection is acceptable under system normal and contingence conditions.

- The [redacted] project is not arranged for islanded operation. The IC is required to install anti-islanding protection within their facility to disconnect the [redacted] project from the grid when an inadvertent island with the local loads forms.

- A DTT scheme is required to disconnect the 100 MW [redacted] project if there is a protective operation or no-fault opening of the transmission line 1L251 between the BC Hydro NIC substation and the new switching station ASTx.

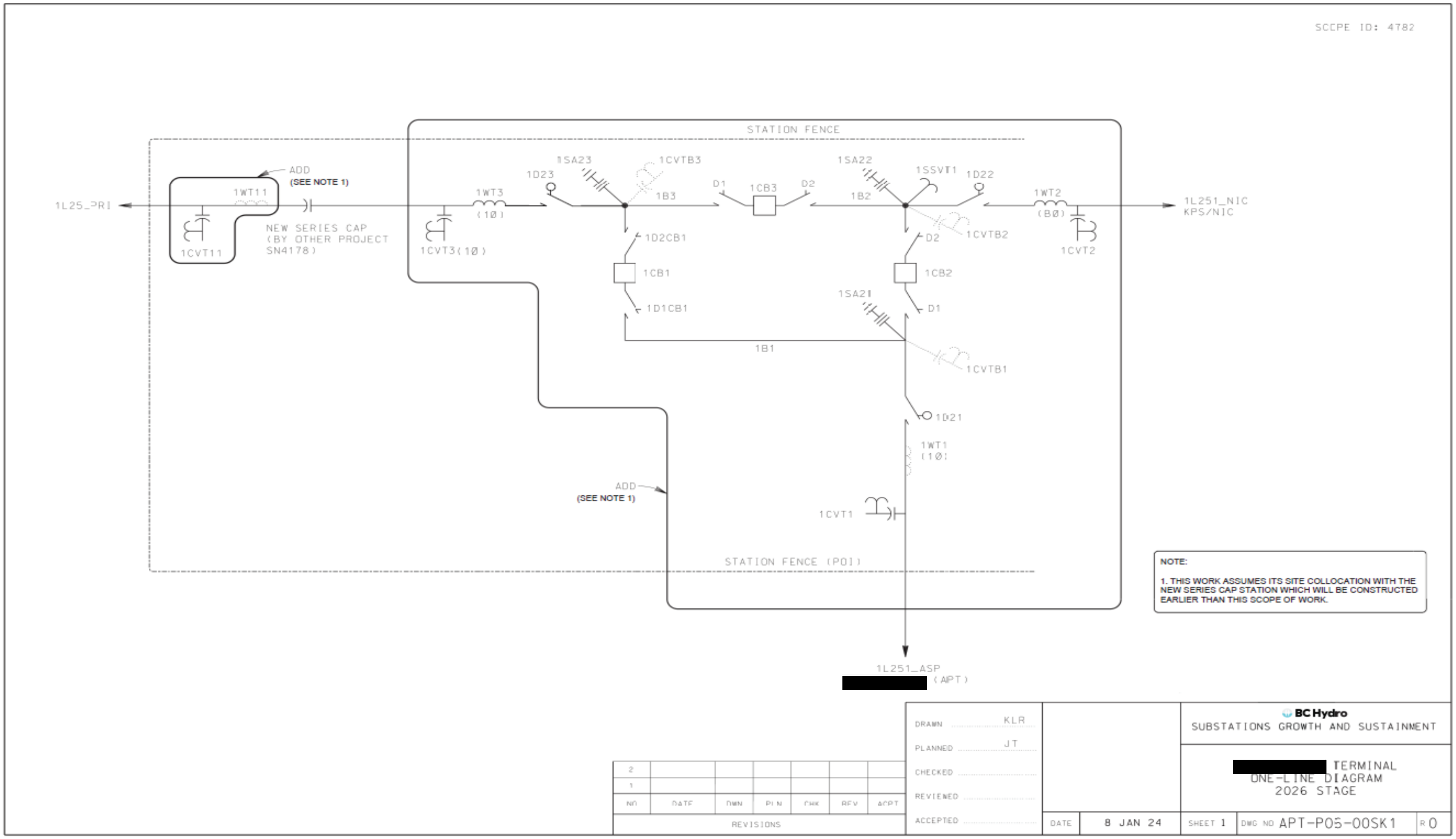
- BC Hydro will provide a new control system for the new switching station ASTx, including remote and local control and indication for the new devices that will be installed at ASTx.

- The IC is required to install a 48-strand single mode fibre optic cable from ASPx to ASTx.

- The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BC Hydro transmission system is $50.55 million (+100%/-35%). The cost estimate includes a 24% contingency. The non-binding good faith estimated time to construct is 4 to 5 years after completion of the Interconnection Facilities Study stage and execution of a Standard Generator Interconnection Agreement, which suggests that the IC's proposed COD of July 31, 2026 would not be achievable.

- The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.

# Appendix A: Draft of ASTx One Line Diagram



# Appendix B: [redacted] Project Telecom Block Diagram