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

July 30, 2024

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

RE: CEAP IR 17 - [redacted] Project - Interconnection Feasibility Study Report

Enclosed is the Interconnection Feasibility study report for the proposed [redacted] Project submitted under Attachment M-2: Transmission Service and Interconnection Service Procedures for Competitive Electricity Acquisition Process (CEAP) of the Open Access Transmission Tariff (OATT). This letter provides a non-binding good faith estimate of the cost and time to construct the facilities required to interconnect your project to BC Hydro's Transmission System, being the Network Upgrades, based on the findings of the Interconnection Feasibility 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's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Cost Estimate

Based on the Interconnection Feasibility study, the non-binding good faith estimated cost (typical accuracy range of +150%/-50%) for Network Upgrades required to interconnect your project is $134.7 M.

Major Scope of Work Identified:

- Acquire adequate property for a new substation
- Construct a new outdoor 138 kV, 3- circuit breaker ring bus switching station
- Thermal upgrade (reconductor) section between HVC Tap and new switching station (~19km) on 1L055
- Assume 90% structure replacement (105 structures) from single pole to 138kV H-frame on 1L055
- Supply and install telecom towers, racks, waveguides and antennas
- Supply and install protection relays and other required protection equipment
- Other Telecom and Protection work, as required

Exclusions:

- GST
- Right-of-Way
- Permits

Key Assumptions:

- Construction will be done by contractor
- Early Engineering and Procurement
- 3 years of construction
- No ground improvements for crossing towers will be required
- A Certificate of Public Convenience and Necessity (CPCN) requirement will not impact the schedule

Key Risks:

- Cost of obtaining new property for the new switching station may be higher than estimated which may significantly increase the project cost
- No defined supply chain strategy, construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased costs
- Costs may be affected by market conditions and escalation
- A CPCN requirement may delay the project schedule and increase costs

Please note that the Revenue Metering requirements and associated costs required to interconnect your project have not been determined at this stage and, therefore, not included in the above estimate. 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 Feasibility study, the non-binding good faith estimated in-service date for your project's Network Upgrades is Quarter 3, 2031 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

Timely actions required from you to minimize risks to the schedule:

- Submission of additional technical data required for the System Impact Study and Facilities Study
- Submission of any required information or document such as demonstration of Site Control
- Execution of Combined Study Agreement and Standard Generator Interconnection Agreement
- Financial commitments and securities

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 September 2024, we will issue a final invoice for the Feasibility Study costs. This invoice will reflect the total amount due, taking into account the $15,000 Feasibility Study deposit you have already paid and any remaining amount on the non-refundable $15,000 Interconnection request deposit that we did not spend in reviewing and validating your interconnection request.

If you have any questions, please contact the BC Hydro CEAP Team at ceap2024@bchydro.com.

Sincerely,

[redacted]

Senior Manager, Transmission Interconnections

BC Hydro

Encl.: CEAP2024_IR_17_[redacted]_FeS_Report_final.pdf

[redacted]

[redacted] Project

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2024 CEAP IR # 17

Prepared for: [redacted]

[redacted]

300-APR-00008
2024 Jul 30

[redacted]

Report Metadata

Header:	[redacted] Project
Subheader:	Interconnection Feasibility Study
Title:	[redacted] Project
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Report Number:	300-APR-00008
Revision:	0
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Date:	2024 Jul 30
Volume:	1 of 1

Prepared for:	[redacted]
[redacted]	[redacted]

Related Facilities:	1L55
Additional Metadata:	Transmission Planning 2024-041 Filing Subcode 1350

Revisions

Revision	Date	Description
0	2024 Jul	Initial release

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[redacted]

Executive Summary

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] Project (2024 CEAP IR # 17) to the BC Hydro (BCH) system. [redacted] Project has forty-one (41) [redacted] solar PV inverters, and thirty-one (31) [redacted] BESS inverters with the installed capacity of 129 MW and 132 MW, respectively. The proposed Point of Interconnection (POI) is on BC Hydro's 138 kV line 1L55, approx. 37 km from [redacted] substation (HLD). The IC's project will connect to the POI via a 1.16 km 138 kV interconnection line. The proposed commercial operation date (COD) is July 31, 2026.

To interconnect the [redacted] Project and its facilities to the BCH Transmission System at the proposed POI, this Feasibility Study has identified the following conclusions and requirements:

1. A new 138 kV switching station (referred to as "P17T") on 1L55 is required at the proposed POI for interconnecting the IC's generating project to the BCH system. With the new switching station P17T at the POI, 1L55 will be segregated into two segments, and three new lines are temporarily referred to as: 1L55_A (HLD-P17T), 1L55_B (P17T-STL) and 1L55_C (P17T-P17).

2. The interconnection of [redacted] Project will cause 1L55 line thermal overload on the section from HVC tap to the proposed switching station, under system normal (N-0) condition. It is required to thermally upgrade the overhead circuit 1L55 (HVC Tap to P17T, 17.57 km in length) from existing 254 Amps to 851 Amps with structure replacements. It is required to furnish and install 48-strand single mode fibre cable on 1L55 from P17T to QYS for telecommunication. The length is approximately 17km.

3. A direct transfer trip (DTT) from HLD to P17T is required to isolate the solar farm from the system for protective and unintentional tripping of 1L55_A. In addition, the IC is required to install anti-islanding protection within their facility to disconnect the IC's solar farm from the grid when an inadvertent island with the local loads forms.

4. The line 1L55_A will become part of BC Hydro BES and need to be compliant with applicable NERC MRS requirements. The line 1L55_B (P17T-STL) will remain as a non-BES line.

5. BC Hydro will provide line protections for 1L55_A, 1L55_B and 1L55_C (BC Hydro end only) protections. As part of the line protection replacements for each of the three lines, 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 to accommodate the new protection schemes.

The above conclusions are made based on the IC's input data and study assumptions listed in Section 4, which represent the best available information on May 22, 2024.

A non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
BESS	Battery Energy Storage System
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
FeS	Feasibility Study
IBR	Inverter-Based Resources
IC	Interconnection Customer
LAPS	Local Area Protection Schemes
MPO	Maximum Power Output
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
POI	Point of Interconnection
RAS	Remedial Action Scheme
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
WECC	Western Electricity Coordinating Council
EDM	Edmonds Office
FVO	Fraser Valley Office
SIC	South Interior Control
SIO	South Interior Office

1 Introduction

Table 1-1 below summarizes the project reviewed in this Feasibility Study.

Table 1-1 Summary of Project Information

Project Name	[redacted] Project	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	on 1L55 at 37 km from HLD	
IC's Proposed COD	31st July 2026	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	125 MW (Summer)	125 MW (Winter)
Number of Generator Units	41 x 3.15 MW Solar PV inverters 31 x 4.25 MW BESS inverters	
Plant Fuel	Solar	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] Project (2024 CEAP IR # 17) to the BC Hydro system. [redacted] Project has forty-one (41) [redacted] solar PV inverters, and thirty-one (31) [redacted] BESS inverters with the installed capacity of 129 MW and 132 MW, respectively. The IC's proposed Point of Interconnection (POI) is on BC Hydro's 138 kV line 1L55, approx. 37 km from [redacted] substation (HLD). The IC's project will connect to the POI via a 1.16 km 138 kV interconnection line. The proposed commercial operation date (COD) is July 31, 2026.

Figure 1-1 shows the Nicola-[redacted] region transmission system diagram. [redacted] substation (HLD) is a 138/60 kV substation in the Merritt area. In addition to supplying the industrial customer of [redacted] Valley Copper and interconnecting a high-queued generating station via 1L55, HLD connects to BC Hydro's Savona (SVA) substation via 1L203 and 1L205, and Nicola (NIC) substation via 1L243.

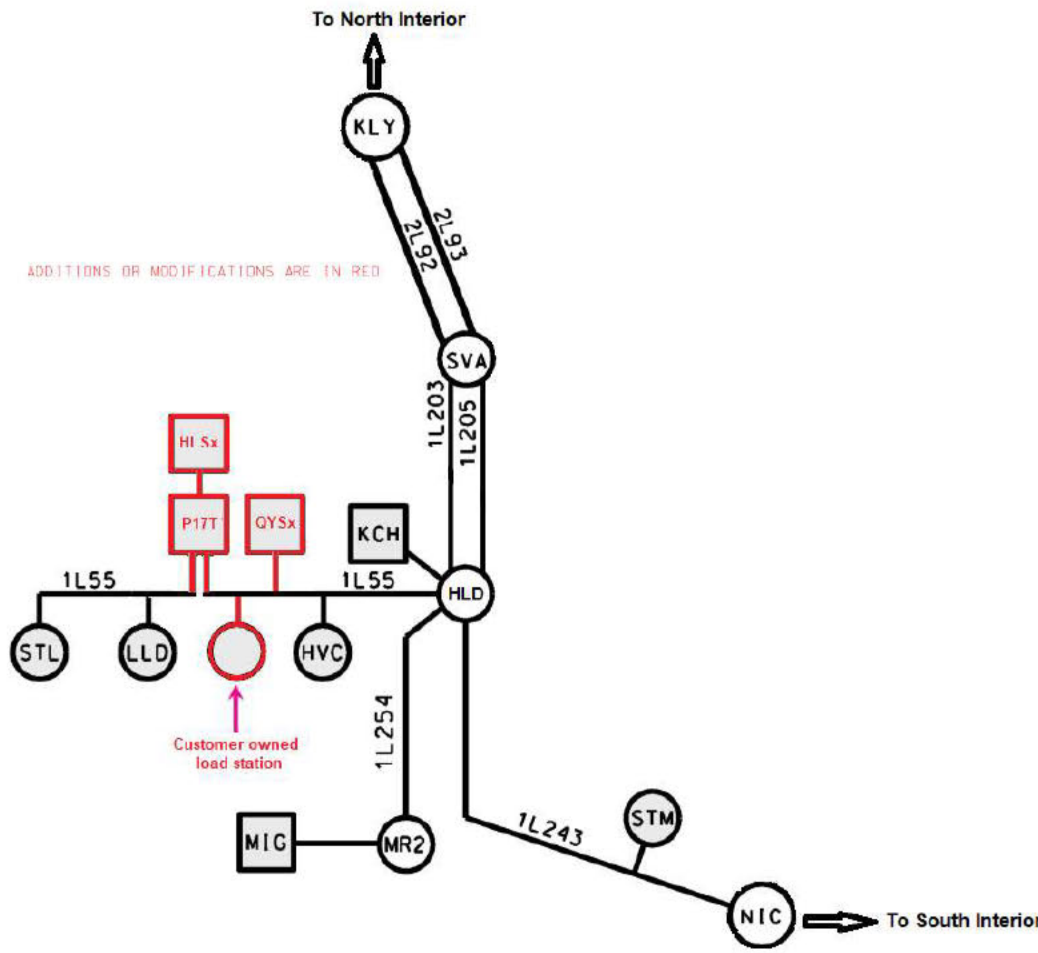

Figure 1-1: Nicola-[redacted] region 138/230 kV Transmission System Diagram

The existing line 1L55 is a radial circuit. There are three industrial facilities fed by circuit 1L55: [redacted] Valley Copper station (HVC), Lower Level Dam station (LLD) and Spatsum station (STL). The three load stations are owned by the same customer: [redacted] Valley Copper.

There are three other customers' owned power plants in the study region.

- Kwoiek Creek Generating Station (KCH) has a total capacity of 60 MW and is connected to HLD via the line 1L57.
- Merritt Green Energy Project Generating Station (MIG) has a total capacity of 40 MW and is connected to Merritt 2 Substation (MR2) via 1L249.
- quA-ymn Solar farm (QYS) is a 15 MW IPP generating project currently under construction. It is connected to 1L55 via a tap.

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BC Hydro system based on power flow and short circuit analysis in accordance with BCH's Open Access Transmission Tariff (OATT). A non-binding good faith estimated cost of required Network Upgrades and estimated time to construct will be provided.

Per OATT, the feasibility study is performed individually for each of the participating projects in the CEAP process and focuses specifically on the BC Hydro regional transmission system where the proposed generating project is proposed to be constructed. An assessment of the incremental effect on the 500kV bulk transmission system is beyond this study scope.

This is a "limited scope" study which is restricted to power flow studies of P0, P1 and P2 planning events as defined in TPL-001-4 and short circuit analysis. The study does not address other technical aspects such as transient stability and switching transients and impact of multiple contingencies. These subjects would be addressed in subsequent System Impact Study if the project is a Successful Participant of the CEAP.

In case impact to the adjacent external systems to BC Hydro is observed, such impact would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed interconnection proceeds further.

3 Standard and Criteria

The Feasibility Study is performed in compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards, and the BCH interconnection requirements in the TIR, and upon the ratings of the existing BCH transmission facilities described in Operating Orders, specifically:

- NERC standards: TPL-001-4 and FAC-002-3 relevant to the scope of this Feasibility Study.
- WECC criteria TPL-001-WECC-CRT-4 Transmission System Planning Performance, July 1, 2023.
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, April 16, 2024.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, November 8, 2022.
- BC Hydro System Operating Order 7T-22 System Voltage Control, September 19, 2023.

4 Assumptions and Conditions

This Feasibility Study is performed based on the IC's submitted data and information available to BC Hydro on May 22, 2024 for the study purpose. Appendix A shows the plant single line diagram for the IC's project used in the study model. Certain assumptions were, as set out below, made to the extent required.

The power flow study cases used in this Feasibility Study are established based upon the BC Hydro's base resource plan and load forecasts available at the time of performing the study, which includes existing and future generations, transmission facilities, and loads in addition to the subject interconnection project in this study. Applicable seasonal conditions and the appropriate study years for the study planning horizon are also incorporated.

Additional assumptions are listed as follows.

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

2) quA-ymn solar project is under construction and is included in the Feasibility Study model. This new solar generation site is to be connected to 1L55 via a line tap.

3) A higher queued load interconnection project near HVC, along with the addition of new customer owned substation are included in the Feasibility Study model.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new switching station (referred to as "P17T") at the proposed POI on 1L55 is required to interconnect the IC's generating project to the BCH system. There are multiple terminals and multiple sources on the existing line 1L55. The addition of the new switching station would help to maintain reliability and adequate protection performance to serve the existing customers and the new addition.

With the new switching station P17T, the existing line 1L55 will be segregated into two segments, and three new lines are temporarily referred to as: 1L55_A (HLD-P17T), 1L55_B (P17T-STL) and 1L55_C (P17T-P17).

The existing line 1L55 does not meet BES criteria and is excluded from the Bulk Electric System (BES) list. The line 1L55_A will become part of BC Hydro BES and need to be compliant with applicable MRS requirements. The line 1L55_B will remain as a non-BES line.

5.1 Power Flow Study Results

Power flow studies were performed to evaluate whether the IC's generating project would cause any unacceptable system performance (e.g. equipment overloads, steady-state voltage violation and voltage instability) and to determine the reinforcement requirement based on steady state performance analysis.

In corresponding to the power call schedule, the study focuses on the 2029 light summer (29LS) system load condition which is typically a stressed condition for a generation interconnection project, taking into considerations of factors such as load conditions, seasons and generation patterns. The 2029 heavy summer (29HS) and 2028 heavy winter (28HW) cases are also checked at a high level to capture any possibility of performance violations under high load conditions.

5.1.1 Branch Loading Analysis

Table 5-1 shows a summary of branch loading analysis under system normal and single contingencies (P1) for various load conditions.

For all the studied load conditions (29LS, 29HS, 28HW), 1L55 line thermal overloading for the section from HVC tap to the proposed switching station was observed in the transmission system under system normal (P0) and single contingency (P1) conditions. The overloading section of 1L55 line is approximately 17.57 kilometers, and the rating for this section is 254 A Summer (30°C) and 488 A Winter (0°C) at maximum conductor temperature of 49°C. Upgrades of transmission line 1L55 are needed from HVC tap to POI to achieve the same thermal rating of 1L55 from HLD to HVC tap.

Table 5-1: Summary of Branch Loading Study Results

Case	IPP's Generator Output	Contingency Identified		Branch Loading				
				1L55	1L55	1L55	1L55	
		Cat.	Description	POI-QYS	QYS-Substaton*	Substation*-HVC	HVC-HLD	QYS-Substaton*
Winter Rating				116.6 MVA	116.6 MVA	116.6 MVA	260.8 MVA	260.8 MVA **
28HW	Max	P0	System Normal	97 %	110 %	107 %	24 %	49 %
	Max	P1	1L243 OOS	96 %	109 %	106 %	23 %	49 %
	Max	P1	1L203 or 1L205 OOS	96 %	109 %	106 %	22 %	49 %
	Max	P1	Loss of HVC load	102 %	115 %	112 %	50 %	51 %
Summer Rating				60.7 MVA	60.7 MVA	60.7 MVA	203.4 MVA	203.4 MVA **
29HS	Max	P0	System Normal	189 %	214 %	210 %	32 %	64%
	Max	P1	1L243 OOS	188 %	213 %	208 %	29 %	64%
	Max	P1	1L203 or 1L205 OOS	188 %	213 %	208 %	29 %	64%
	Max	P1	Loss of HVC load	199 %	223 %	219 %	65 %	67%
29LS	Max	P0	System Normal	191 %	215 %	211 %	34 %	64%
	Max	P1	1L243 OOS	189 %	214 %	209 %	32 %	64%
	Max	P1	1L203 or 1L205 OOS	189 %	213 %	209 %	32 %	64%
	Max	P1	Loss of HVC load	200 %	224 %	220 %	66 %	67%

Note: * This is the customer owned load substation on 1L55.
Note: ** Study based on upgraded rating to demonstrate the performance adequacy after the 1L55 line section upgrade.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the voltage performance under system normal condition and single contingencies is acceptable for all the three load conditions (29ls, 29hs, 28hw). Table 5-2 shows a summery of steady-state voltage performance under various system conditions and contingencies.

Table 5-2: Summary of Steady-State Voltage Study Results

Case	IPP's Generator Output	Contingency		Bus Voltage (PU)			
		Cat.	Description	HLD 138	SVA 138	NIC 138	POI 138
28HW	Max	P0	System Normal	1.01	1.02	1.02	1.0
	Max	P1	1L243 OOS	1.01	1.02	1.02	1.0
	Max	P1	1L203 or 1L205 OOS	1.0	1.03	1.02	1.0
29HS	Max	P0	System Normal	1.01	1.02	1.02	1.0
	Max	P1	1L243 OOS	1.01	1.02	1.02	1.0
	Max	P1	1L203 or 1L205 OOS	1.0	1.02	1.02	1.0
29LS	Max	P0	System Normal	1.01	1.02	1.03	1.0
	Max	P1	1L243 OOS	1.01	1.02	1.03	1.0
	Max	P1	1L203 or 1L205 OOS	1.01	1.03	1.03	1.0

5.1.3 Reactive Power Capability Evaluation

The BC Hydro TIR requires an IBR power plant to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO at the high voltage side of the IC's switchyard over the full MW operating range.

Based on the PSS/E power flow data submitted by the IC, the proposed generating project would be capable of to meet the BC Hydro's reactive capability requirement at the plant's maximum MW output, which is subjected to further verification in the next stage of interconnection study.

Furthermore, the BCH TIR requires the IC's project to provide sufficient reactive power capability over full MW operating range including at zero MW output level. According to the IC-provided reactive capability curve, the proposed [redacted] solar PV inverter has +2.16 / -2.16 Mvar reactive capability at zero MW output and [redacted] BESS inverter has +5.0 / -5.0 Mvar reactive capability at zero MW output, which means the solar farm can meet the reactive power requirement at 0 MW. This will need to be re-confirmed if the IC's project proceeds further.

5.1.4 Anti-Islanding Requirements

If 1L55_A between HLD and P17T is open at either end, the IC's project may be inadvertently islanded with the existing generators and BC Hydro loads, which is not allowed. A direct transfer trip (DTT) from HLD to P17T is required to isolate the solar farm from the system for protective and unintentional tripping of 1L55_A.

In addition, the IC is required to install anti-islanding protection within its facility to disconnect the IC's solar farm from the grid when an inadvertent island with the local load forms.

5.2 Fault Analysis

The short circuit analysis in the FeS is based upon the latest BC Hydro system model, which includes the generating facility information and associated impedance data provided by the IC. A more detailed study will be performed at the system impact study stage if needed.

5.3 Stations Requirements

A new outdoor 138 kV, 3-circuit breaker ring bus switching substation (Referred to P17T temporarily) will be built at POI, close to the existing 138 kV transmission line 1L55. The existing transmission line 1L55 will be cut and looped in to, and 138 kV line from [redacted] Project (1L55_C) will be terminated at the new substation.

Scope of substation work at the new switching station:

- Acquire adequate property for a new substation close to the existing transmission line 1L55.
- Construct a new outdoor 138 kV, 3- circuit breaker ring bus switching substation. Refer to the one-line sketch in Appendix B for details.

Notes:

- The designation of the new station and the new line connecting to the customer and the two new lines derived from 1L55 will be assigned in later stage.
- The Installation location of the metering kits will be decided in later stage.

5.4 Transmission Line Requirements

It is required to thermally upgrade the overhead circuit 1L55 (HVC Tap to P17T, Str 12-09 to Str 23-10, 17.57 km) from existing 254 Amps to required 851 Amps (30°C ambient summer Temperature) by changing from the existing Partridge/Merlin ACSR to new Goose ACSR (at 90°C conductor temperature), with structure replacements required.

It is required to furnish and install 48-strand single mode fibre cable on 1L55 from P17T to QYS for telecommunication. The length is approximately 17km.

5.5 Protection & Control Requirements

BC Hydro will provide line protections for the BC Hydro owned terminals 1L55_A, 1L55_B and 1L55_C (BC Hydro end only) protections. As part of the line protection replacements for each of the three lines, telecommunication facilities will be required to accommodate the new protection schemes.

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

- Entrance protection that complies with the latest version of the “60 kV to 500 kV BC Hydro Technical Interconnection Requirements for Power Generators.”
- Provide two SEL-411L-1 relays (firmware and options specified by BC Hydro) at the entrance of P17 HV to provide protection coverage for 1L55_C. BC Hydro P&C Planning will provide core protection settings for these relays to protect transmission line 1L55_C during a transmission line fault. Non-core protection such as local breaker failure, auto-reclosing, backup protection for station elements will not be provided by BC Hydro P&C Planning.
- The IC is responsible for NERC PRC-related tasks, settings to compliance standards within their facilities.
- The IC is responsible for providing a communications link for remote interrogation of the PPIS equipment by BCH servers.
- Provide anti-islanding protection as stated in Section 5.1.

5.6 Telecommunications Requirements

BC Hydro performed a high-level feasibility assessment of a telecom solution to meet the following requirements.

Teleprotection Requirements for Telecom

- WECC Level 3 PY & SY, HLD – P17T, with C37.94 interfaces.
- WECC Level 3 PY & SY, HLD – QYS, with C37.94 interfaces.
- WECC Level 3 PY & SY, P17T – QYS, with C37.94 interfaces.
- WECC Level 3 PY & SY, P17T – P17 (HV), with C37.94 interfaces.

Telecontrol Requirements for Telecom

- Two P17T SCADA circuit off FVO & SIO.

- One P17 SCADA circuits off FVO & SIO.
- One P17T REMACC circuit off EDM.

Other Requirements for Telecom

- None identified

Certain assumptions were made for determining a potential telecom solution. Details of the telecom solution (e.g. assumptions made, alternatives investigated and work required for BCH and the IC) would be provided at the next study stage.

6 Cost Estimate and Schedule

The non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

7 Conclusions

To interconnect the [redacted] Project and its facilities to the BCH Transmission System at the POI, this Feasibility Study has identified the following conclusions and requirements:

1. A new 138 kV switching station (referred to as "P17T") on 1L55 is required at the proposed POI for interconnecting the IC's generating project to the BCH system.

2. The interconnection of [redacted] Project will cause 1L55 line thermal overload on the section from HVC tap to the proposed switching station, under system normal (N-0) condition. It is required to thermally upgrade the overhead circuit 1L55 (HVC Tap to P17T) from existing 254 Amps to 851 Amps with structure replacements. It is required to furnish and install 48-strand single mode fibre cable on 1L55 from P17T to QYS for telecommunication. The length is approximately 17km.

3. A direct transfer trip (DTT) from HLD to P17T is required to isolate the solar farm from the system for protective and unintentional tripping of 1L55_A. In addition, the IC is required to install anti-islanding protection within their facility to disconnect the IC's solar farm from the grid when an inadvertent island with the local loads forms.

4. The line 1L55_A will become part of BC Hydro BES and need to be compliant with applicable NERC MRS requirements. The line 1L55_B (P17T-STL) will remain as a non-BES line.

5. BC Hydro will provide line protections for 1L55_A, 1L55_B and 1L55_C (BC Hydro end only) protections. As part of the line protection replacements for each of the three lines, 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 to accommodate the new protection schemes.

Appendix A
Plant Single Line Diagram Used for Power Flow Study

Figure A-1 shows [redacted] Project single line diagram used for power flow study.

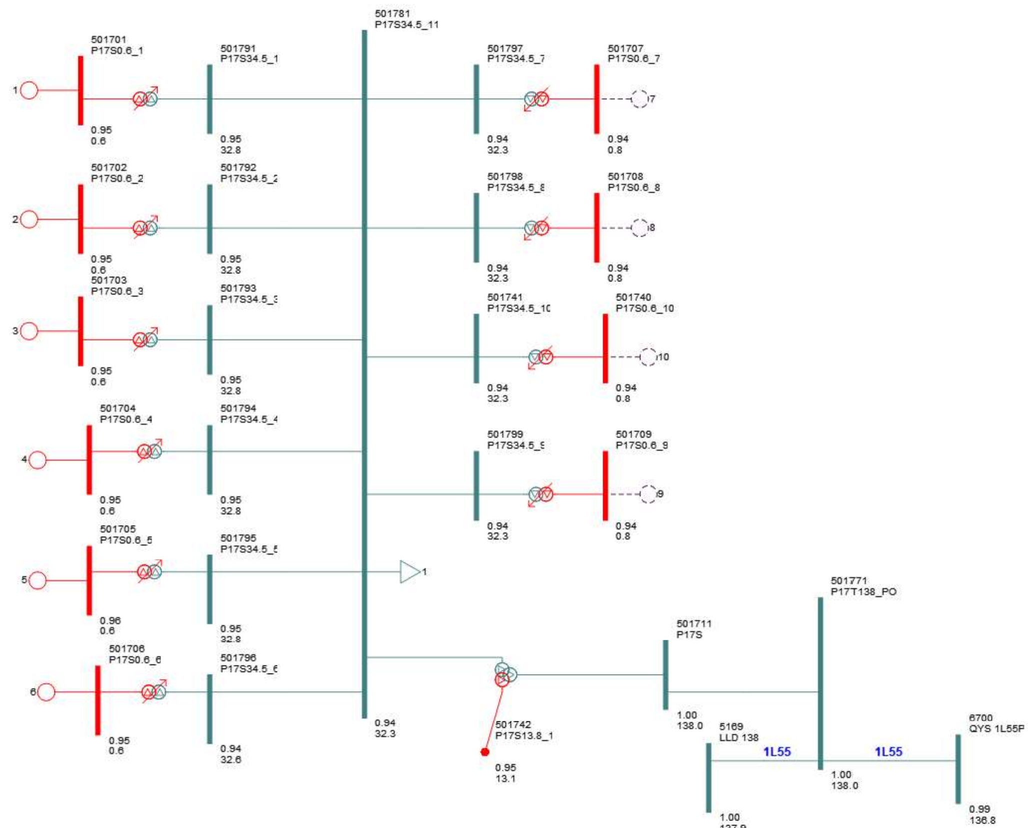

Figure A-1: [redacted] Project Single Line Diagram for Power Flow Study.

As seen in the diagram, [redacted] Project has one main power transformer.

- There are six (6) feeders connecting 41 solar PV inverters to the collector station.

- There are four (4) feeders connecting 31 BESS inverter to the collector station.

Appendix B
One-Line Sketch for New Switching Station

Figure B-1 shows the Stations Planning One-Line Sketch for the New Switching Station P17T.

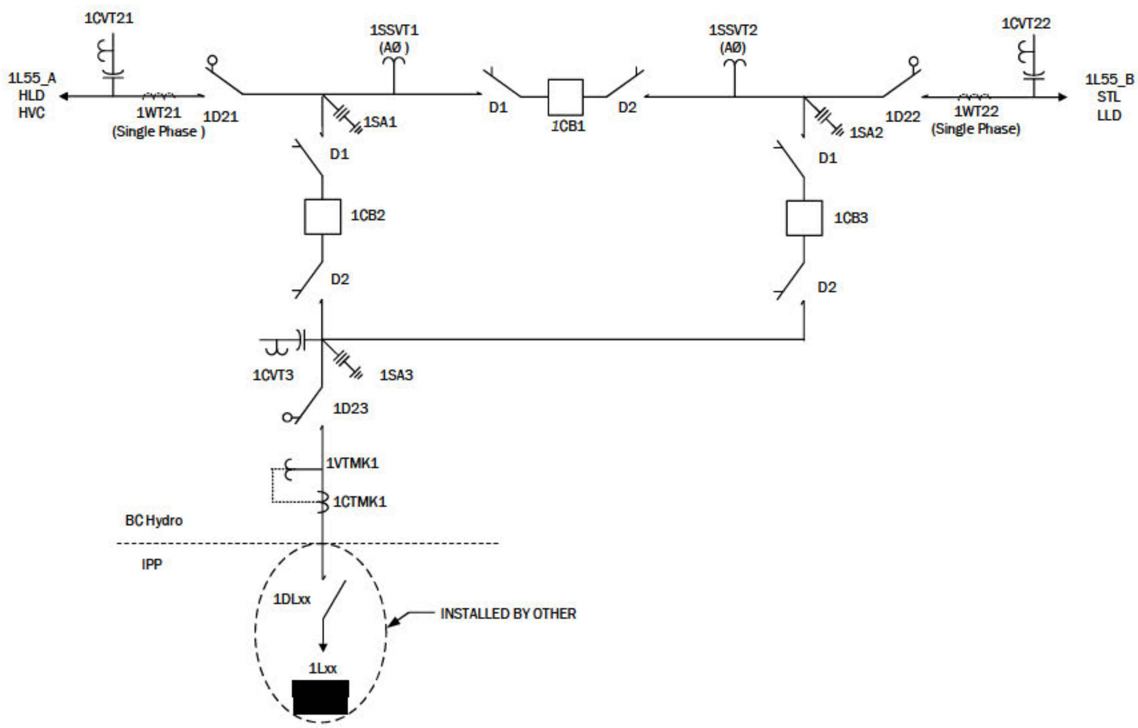

Figure B-1: Stations Planning One-Line Sketch for the New Switching Station P17T.