BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #85 – [redacted] Interconnection Feasibility Study

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted] 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 (POI) to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Interconnection Study Costs

The Interconnection Customer is responsible for paying the full cost of all Interconnection Studies in cash. Interconnection Study costs vary depending on the scope, complexity, and other factors such as whether any scope is shared with another Interconnection Customer (not applicable to this Interconnection Feasibility Study). The deposit amounts specified in the OATT are not proxy Interconnection Study costs. If actual Interconnection Study costs exceed the deposit amount, the Interconnection Customer must pay the remaining balance in cash. Please refer to the answer for question no. 53 in the posted Questions & Answers for 2025 Call for Power for typical study cost ranges.

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 $90.7 M.

Major Scope of Work Identified:

- Add one 60 kV line position with associated substation equipment at BC Hydro Tachick substation (TAC)
- Upgrade TAC 230 kV bus support increasing transformation capacity of TAC

- Replace Transformer 2 with a new transformer the same rating, impedance and tap range/steps of the existing Transformer 3 at TAC
- Remove Transformer 5 at TAC
- Upgrade required substation facilities, infrastructures, and bus work to support new station(s) equipment, including expansion of the station footprint
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

- GST
- Permits
- Right-of-Way & property costs

Key Assumptions:

- Construction by contractor
- 24 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- No expansion of station and control buildings to accommodate new equipment
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Expansion of the existing station and/or control building may be required leading to increased costs and/or a longer project schedule
- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

Study Limitations and Exclusions

Protection, Control, and Telecommunications

The Interconnection Feasibility Study does not include a detailed review of the protection, control, and telecommunications system requirements specific to your Interconnection Request. Based on a high-level review, we have identified proxy costs for protection, control, and telecom Network Upgrades drawn from comparable interconnection projects with similar scope and complexity; these proxy costs have been included solely for indicative budgeting purposes. The relative interconnection cost determined by the Interconnection Feasibility Study includes a telecommunications component based on an assumed solution to deliver teleprotection and telecontrol circuit requirements necessary for the Interconnection Request. Protection, control, and telecommunications system requirements will be reviewed in detail in the System Impact Study if you are a successful participant of the CEAP and meet applicable requirements.

For Interconnection Feasibility Study purposes, it is assumed that any applicant-proposed works that could obstruct or impair the performance of existing BC Hydro microwave systems or new links from the proposed Interconnection Customer Interconnection Facilities (ICIF) to the BC Hydro microwave system would be identified and either relocated or repositioned as determined in a System Impact Study if you are a successful participant of the CEAP and meet applicable requirements. Such works may include, but are not limited to, towers, turbines, dams, support structures, panels, surface materials deposited or redistributed, water surface changes, or vegetation.

Generation Shedding/Curtailment Scheme and Electromagnetic Transient (EMT) Studies

The generation shedding/curtailment scheme reviews (e.g., Remedial Action Scheme (RAS), and a direct transfer trip for anti-islanding scheme) and EMT studies are completed in a System Impact Study. The outcomes of these studies may result in additional requirements, which could include Network Upgrades or ICIF. Any costs associated with completion of these studies, and resulting requirements, are not included in the Interconnection Feasibility Study cost estimate.

Revenue Metering

Please note that revenue metering requirements have not been determined with the Interconnection Feasibility Study. As such, any costs associated with revenue metering and other interconnection components are not included in the cost estimate provided above. Once these requirements are defined, 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 Interconnection Request's Network Upgrades is Quarter 3 2032 (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

Since your proposed POI is located within the North Coast Transmission Line Region, the interconnection of your IR has been determined, at this time, to be dependent upon the completion of the North Coast Transmission Line (NCTL) project.

Accordingly, please note the 2025 Call for Power Addendum 5 and revised Specimen EPA specify that the Guaranteed Commercial Operation Date for a project which is dependent upon the completion of NCTL will be October 1, 2033, notwithstanding that the Interconnection Feasibility Study report may indicate an earlier date.

Please note that changes to your IR or delays in data submission or financial commitments may also impact the target in-service date. Please note that changes to your Interconnection Request or delays in data submission or financial commitments may also impact the target in-service date.

If you have any questions, please contact the BC Hydro CEAP team at ceap2025@bchydro.com.

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR85_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 85

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Specialist Engineer, Transmission Operations Services

Reviewed by: [redacted]

Principal Engineer, Transmission Operations Services

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

Header:	2025 CEAP IR # 85
Subheader:	Interconnection Feasibility Study
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Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Specialist Engineer, Transmission Operations Services
Checked by:	[redacted]
Title:	Specialist Engineer, Transmission Operations Services
Reviewed by:	[redacted]
Title:	Principal Engineer, Transmission Operations Services
Related Facilities:	Tachick Substation (TAC)
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Revisions

Revision	Date	Description
0	2025 Nov	Initial release

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The following accept responsibility for the content in the specified sections. Professionals apply their signature and/or seal as appropriate.

Section: **Discipline:**

Entire report except listed below — Transmission Planning

Contributed by:

[redacted]

Specialist Engineer, Transmission Operations Services

[redacted]

Section: **Discipline:**

5.2, 5.3 — Stations Planning

Contributed by:

[redacted]

Sr. Engineer, Stations Growth and Sustainment

[redacted]

Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] project (2025 CEAP IR# 85) to the BC Hydro system. [redacted] has twenty-four (24) [redacted] inverters with 204000 panels, adding a total capacity of 100.32 MW with maximum power injection of 97.82 MW into the BC Hydro system at the Point of Interconnection (POI). The POI is on BC Hydro's Tachick Substation (TAC). The IC's proposed commercial operation date (COD) is April 1st, 2032.

To interconnect the [redacted] and its facilities to the BCH Transmission System at the proposed POI, this Feasibility Study has made the recommendations and conclusions as follow:

1. A new 66 kV line position is required at Tachick substation (TAC) to facilitate the interconnection of [redacted]
2. The study identified thermal overload on TAC 230/69 kV transformer T3 under system normal condition in all heavy summer, light summer, and heavy winter loading scenarios. Increasing transformation capacity of TAC substation to 150 MVA under system normal condition is required to accommodate [redacted] interconnection.
3. Existing TAC T2 and T5 are hot-standby transformers. Replacing T2 by a new transformer and removing T5 is required. In addition, the new T2 replacement transformer shall be normally in service, have the same rating, impedance and tap range/steps of the existing T3 so that it can be operated in parallel with T3 to meet the increasing TAC transformation capacity need. TAC 230 kV bus requires modification to accommodate this change.
4. [redacted] needs to be shed or runback in response to a TAC T2 or T3 transformer contingency to mitigate the thermal overloads on the remaining transformer.
5. [redacted] is required to be integrated in the existing BC Hydro RAS to maintain system reliability for 500 kV contingencies. The exact RAS functional requirements will be determined in subsequent studies if the project proceeds.

6. [redacted] is required to install anti-islanding protection within its facility to disconnect the IC's generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.

7. [redacted] is required 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, per BC Hydro's TIR Section 6.4.2.

8. The “Reactive Power at Night” function for the [redacted] solar inverter is required so that each inverter can provide reactive power capability at zero MW output including during nighttime.

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 October 14, 2025.

A non-binding good faith cost for required network upgrades and estimated schedule for construction are included in a separate letter to the IC.

Please note that, this Feasibility Study report does not include the descriptions of Protection, Control, and Telecommunications requirements and the associated upgrade scopes; however, as discussed in Section 2 “Purpose and Scopes of Study, the associated cost implications are captured and delivered in the cover letter to the IC”.

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Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
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
IR	Interconnection Request
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

1 Introduction

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

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	on Tachick substation (TAC)	
IC's Proposed COD	1st April 2032	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	97.82 MW (Summer)	97.82 MW (Winter)
Number of Solar Inverters	24 x 4.18 MW Inverters	
Plant Fuel	Solar	

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR# 85) to the BC Hydro system. [redacted] twenty-four (24) [redacted] inverters with 204000 panels, adding a total capacity of 100.32 MW with maximum power injection of 97.82 MW into the BC Hydro system at the Point of Interconnection (POI). The POI is on BC Hydro's Tachick Substation (TAC). The IC's proposed commercial operation date (COD) is April 1st, 2032.

Figure 1-1 shows the Glenannan region transmission system diagram. Glenannan substation (GLN) is a major substation in this area connecting to Williston substation (WSN) via 500 kV line 5L61, and Telkwa substation (TKW) via 500 kV line 5L62. GLN has two existing 500/230 kV transformers (GLN T1 & T2), two 230/138 kV transformers (GLN T5 & T11), and three 138/69 kV transformers (GLN T3, T4 & T6). GLN presently supplies two 230 kV transmission lines — 2L353 to the Tachick substation (TAC) and 2L355 to Blackwater Mine substation (BWM), one 138 kV lines — 1L384 to Burns Lake substation (BRN), and two 66 kV lines — 60L341 to Fraser Lake substation (FSR) and 60L352 to Endako Mines [redacted] (EKO).

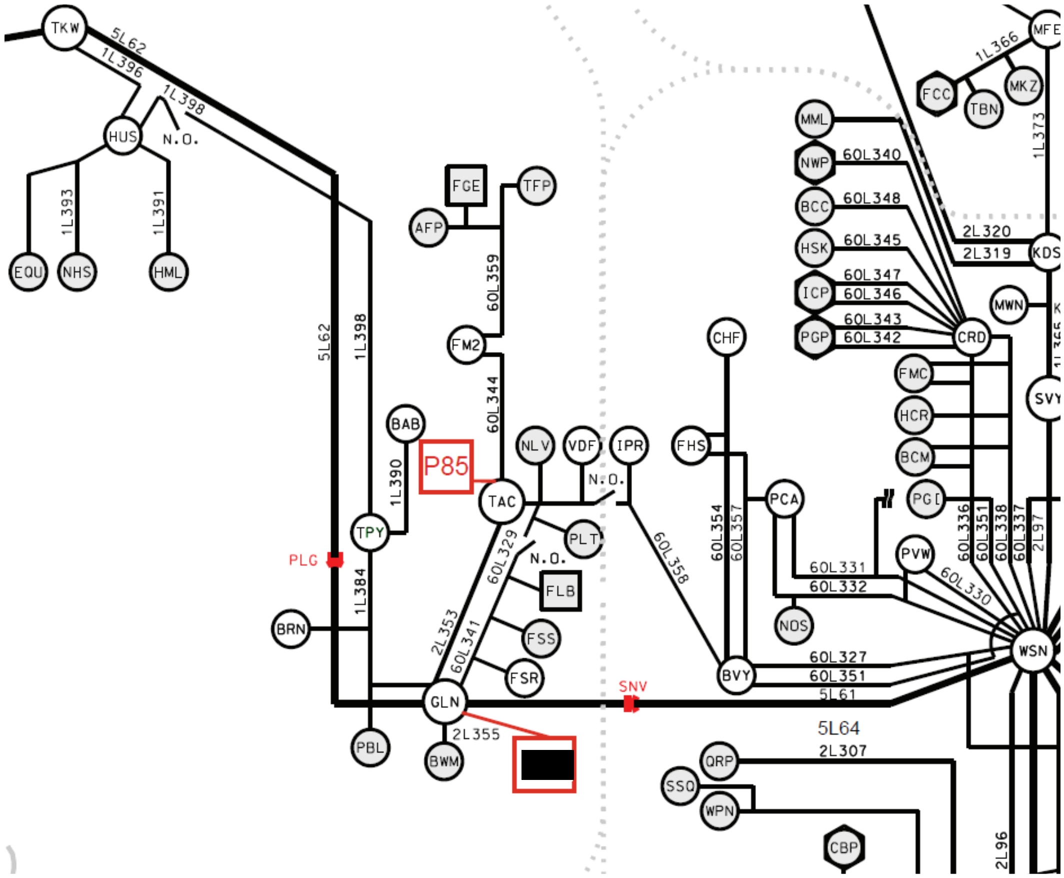


Figure 1-1: Glenannan region Transmission System Diagram

Tachick substation (TAC) has three existing 230/69 kV transformers (TAC T2, T3, and T5). Only TAC T3 is normally in service and supplies two 66 kV lines — 60L329 to Vanderhoof substation (VDF), Nechako Lumber substation (NLV), Canfor Plateau substation (PLT), and 60L344 to Fort St. James #2 substation (FM2), Fort St. James Forest Product substation, (TFP), and Fort St. James Green Energy Generating station (FGE). TAC T2 and T5 are hot standby transformers. The combined capacity of both transformers is less than T3 and they are equipped with off-load tap changers, and therefore can not provide voltage regulation. They are allowed to be in service only when TAC T3 is out of service to supply the regional load.

There are two existing customers' owned power plants in the study region.

- Fort St. James Green Energy Generating Station (FGE) has a total capacity of 40 MW and is connected to TAC substation via the line 60L344.

- Fraser Lake Biomass Generating Station (FLB) has a total capacity of 7.2 MW and is connected to GLN substation via 60L329.

In addition to the existing generators, the North Coast region has a new generator interconnection project - [redacted] project with installed capacity of 205.2 MW and POI at GLN 230 kV.

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) and produces the estimated cost of required Network Upgrades and the implementation schedule.

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 connected and affects.

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 will be addressed in subsequent System Impact Study if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BC Hydro would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed generator project proceeds further.

Please note that, due to the compressed study timeline for 2025 CEAP Feasibility Study, this report does not include the descriptions of the Protection, Control, and Telecommunication requirements and the associated upgrade scopes. Instead, the network upgrades associated with Protections, Controls and Telecommunications are incorporated with cost estimates in a separate cover letter to the IC.

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, Rev 2.1.1, Effective: Sept 22, 2025.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, Sept 17, 2025.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, Sept 22, 2025.
- BC Hydro System Operating Order 7T-22 System Voltage Control, Sept 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 Oct 14, 2025 for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the schematic diagram of the IC's Project IC's project used in the study model.

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

2) BC Hydro Prince George Capacitor Bank Project (PGTC) project, Prince George to Glenannan Transmission Project (PGGT), and Glenannan to Terrace Transmission Project (GTTT) are included in the study. PGTC project will add series compensation for 5L61, 5L62, and 5L63, and a new 500KV/230KV transformer SKA T3. PGGT Project will construct 500 kV line - 5L64 from Williston to Glenannan substation. GTTT project will construct two 500 kV lines - 5L65 and 5L66 from Glenannan to Skeena substation. Based on the schedule available at the time of study, the PGTC project will be completed by October 2027, PGGT project will be completed by October 2030, and GTTT project will be completed by May 2032.

3) [redacted] project, [redacted], with installed capacity of 205.2 MW will be added in the Glenannan region and is included in the study. Its commercial operation date is November 2029.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, the existing 230 kV bus of TAC substation is required to be converted to three (3) circuit breaker ring to accommodate a normally in-service T2 operating in parallel with the existing T3. Additional circuit breakers are also required on existing 66 kV ring bus to interconnect the IC's generating project to the BCH system.

A new 66 kV interconnecting line, to be built by the IC, is temporarily referred to as 60LXXX (TAC-P85). The temporary line designation will be replaced by permanent designation at a later stage of interconnection study.

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 system reinforcement requirement based on steady state performance analysis.

The study focuses on the base scenario — 32HW/32LS/32HS system conditions that include all the higher-queued generating projects [redacted] the future proposed North Coast 500 kV transmission lines. These base cases were prepared based on factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system.

The studies are performed for system normal conditions and under critical system contingencies specified in the P1 and P2 events by NERC TPL-001-4. Study results are summarized below.

5.1.1 Thermal Overload Analysis

Table 5-1 summarizes the thermal overload concerns identified in the study and the proposed solutions. Appendix B contains the details of thermal overload analysis results.

Table 5-1: Thermal Overload Concerns and Proposed Solutions

Equipment subject to overloads	Conditions observed	Contingencies that result in overloads	Solution Proposed
Under system normal conditions			
TAC T3	LS, HS, HW	P0: system normal	Remove existing TAC T5, replace TAC T2 by a new transformer with the same size as T3 to achieve a continuous transformer capacity of 150 MVA.
Under contingencies			
TAC T2 (new)	LS, HS, HW	P1.3: TAC T3	Generation Shed or Runback RAS at [redacted]
TAC T3	LS, HS, HW	P1.3: TAC T2 (new)	Generation Shed or Runback RAS at [redacted]

The study identified thermal overload on TAC 230/69 kV transformer T3 under system normal condition in all heavy summer, light summer, and heavy winter loading scenarios. Therefore, increasing transformation capacity of TAC substation to 150 MVA under system normal condition is required to accommodate [redacted] interconnection.

Existing TAC T2 and T5 are hot-standby transformers and not suitable to operate in parallel with TAC T3. The combined capacity of TAC T2 and T5 are smaller than TAC T3. Replacing T2 by a new transformer and removing T5 is required. In addition, the new T2 replacement transformer shall be normally in service, have the same rating, impedance and tap range/steps of T3 so that it can be operated in parallel with T3 to meet the increasing TAC transformation capacity need.

In addition, [redacted] needs to be shed or runback in response to a TAC T2 or T3 transformer contingency to mitigate the thermal overloads on the remaining transformer.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the steady-state voltage performance under system normal and single contingency conditions is acceptable for all the three load conditions (32LS, 32HS, 32HW). Appendix B shows the details in the steady-state voltage study results.

5.1.3 Reactive Power Capability Evaluation

The BC Hydro TIR requires 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 IC-submitted PSS/E model data, the proposed [redacted] project **does not** meet the requirement above, which needs to be addressed if the project proceeds to the next stage of the interconnection process.

In addition, according to the IC-provided reactive capability data, the proposed Solar Inverter would provide +2.64 Mvar to -2.64 Mvar reactive capability at the zero MW output if the inverter's "Night" function is enabled. This function needs to be re-confirmed if the IC's project proceeds to next stage of the interconnection process.

5.1.4 Anti-Islanding Requirements

[redacted] is not arranged for islanded operation. 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 loads forms.

5.2 Fault Analysis

The short circuit analysis in the Feasibility Study 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

The station upgrade scope at the Tachick substation (TAC) is as follows.

- Add two new 60 kV circuit breakers and the associated disconnect switches as shown in the attached one-line diagram.
- Add one line terminal 60LXXX for [redacted] project including a motor operated disconnect switch, surge arrester, and capacitor voltage transformer.

- Remove transformer T5 (three phase 236/69 kV, 20/26/33.3MVA), and the associated substation equipment.
- Replace the transformer T2 (three phase 236/69 kV, 20/26/33.3MVA) with a new three phase 230/64 kV, 45/60/75 MVA unit.
- No addition or changes of transformer-associated equipment is required, which will need to be confirmed by analytical study if the project proceeds to System Impact Study.
- Add three 230 kV dead tank circuit breakers together with associated substation equipment including six 230 kV manual operated disconnect switches, and one 230 kV surge arrester.
- Remove the temporary connection and a section of the 230 kV busbar as shown in Appendix C.
- To facilitate the addition of one 60 kV line position and connect 230 kV equipment, extend the existing 60 kV and 230 kV busbars within the limits of the current property boundaries to accommodate the above-mentioned facilities.
- Install associated P&C, station service and other equipment in the existing control building.
- Other associated station work.

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

1. A new 66 kV line position is required at Tachick substation (TAC) to facilitate the interconnection of [redacted] project.
2. The study identified thermal overload on TAC 230/69 kV transformer T3 under system normal condition in all heavy summer, light summer, and heavy winter loading scenarios. Increasing transformation capacity of TAC substation to 150 MVA under system normal condition is required to accommodate [redacted] interconnection.
3. Existing TAC T2 and T5 are hot-standby transformers. Replacing T2 by a new transformer and removing T5 is required. In addition, the new T2 replacement transformer shall be normally in service, have the same rating, impedance and tap range/steps of the existing T3 so that it can be operated in parallel with T3 to meet the increasing TAC transformation capacity need. TAC 230 kV bus requires modification to accommodate this change.
4. [redacted] needs to be shed or runback in response to a TAC T2 or T3 transformer contingency to mitigate the thermal overloads on the remaining transformer.
5. [redacted] is required to be integrated in the existing BC Hydro RAS to maintain system reliability for 500 kV contingencies. The exact RAS functional requirements will be determined in subsequent studies if the project proceeds.
6. [redacted] is required to install anti-islanding protection within its facility to disconnect the IC's generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.
7. [redacted] is required 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, per BC Hydro’s TIR Section 6.4.2.

8. The “Reactive Power at Night” function for the [redacted] solar inverter is required so that each inverter can provide reactive power capability at zero MW output including during nighttime.

Appendix A
Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [redacted] Project.

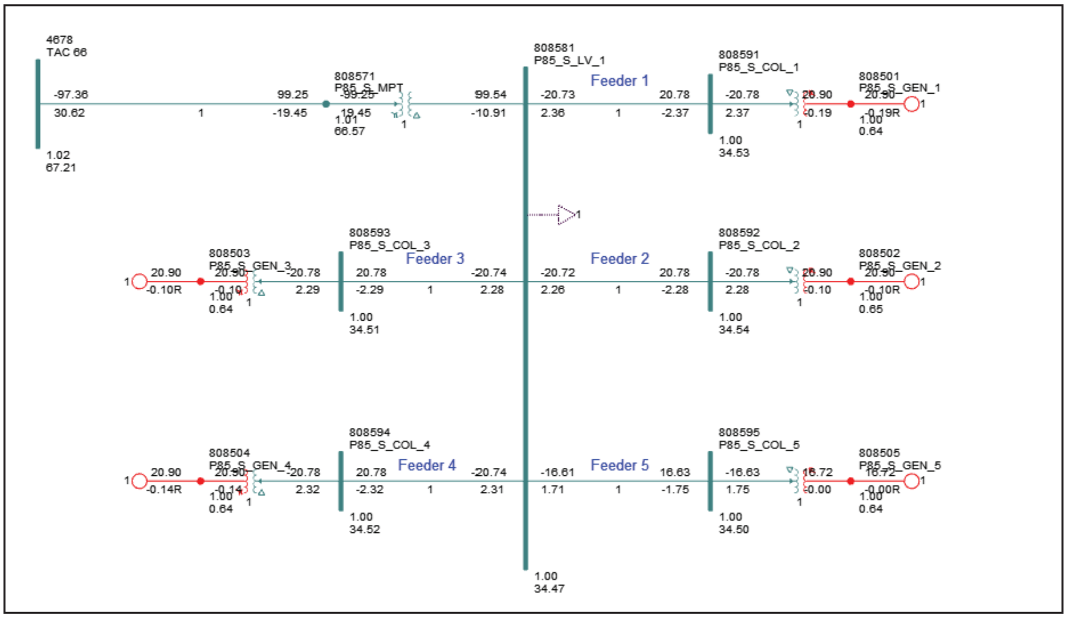


Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (32HW/32HS/32LS)

Table B-1: Thermal Overload Study Results

Case	NC Regional Generation	Contingency		Branch Loading (% of its seasonal normal rating)			
				TAC T3	TAC T2 or T5	GLN T1	GLN T2
		Cat.	Description	TAC	TAC	GLN	GLN
Winter Rating in MVA				89.1	39.5	714	714
32HW	Max	P0	System Normal	135%	-	15%	15%
	Max	P1.3	GLN T1/T11[1]	-	-	-	31%
	Max	P1.3	GLN T2/T5[1]	-	-	31%	-
	Max	P1.3	TAC T3 OOS	-	128%	-	-
Summer Rating in MVA				75	33	600	600
32HS	Max	P0	System Normal	178%	-	21%	21%
	Max	P1.3	GLN T1/T11[1]	-	-	-	41%
	Max	P1.3	GLN T2/T5[1]	-	-	41%	-
	Max	P1.3	TAC T3 OOS	-	177%	-	-
Summer Rating in MVA				75	33	600	600
32LS	Max	P0	System Normal	191%	-	22%	21%
	Max	P1.3	GLN T1/T11[1]	-	-	-	43%
	Max	P1.3	GLN T2/T5[1]	-	-	43%	-
	Max	P1.3	TAC T3 OOS	-	190%	-	-
Note 1: T1 and T11 share the same tripping zone, T2 and T5 share the same tripping zone							

Table B-2: Steady-State Voltage Study Results

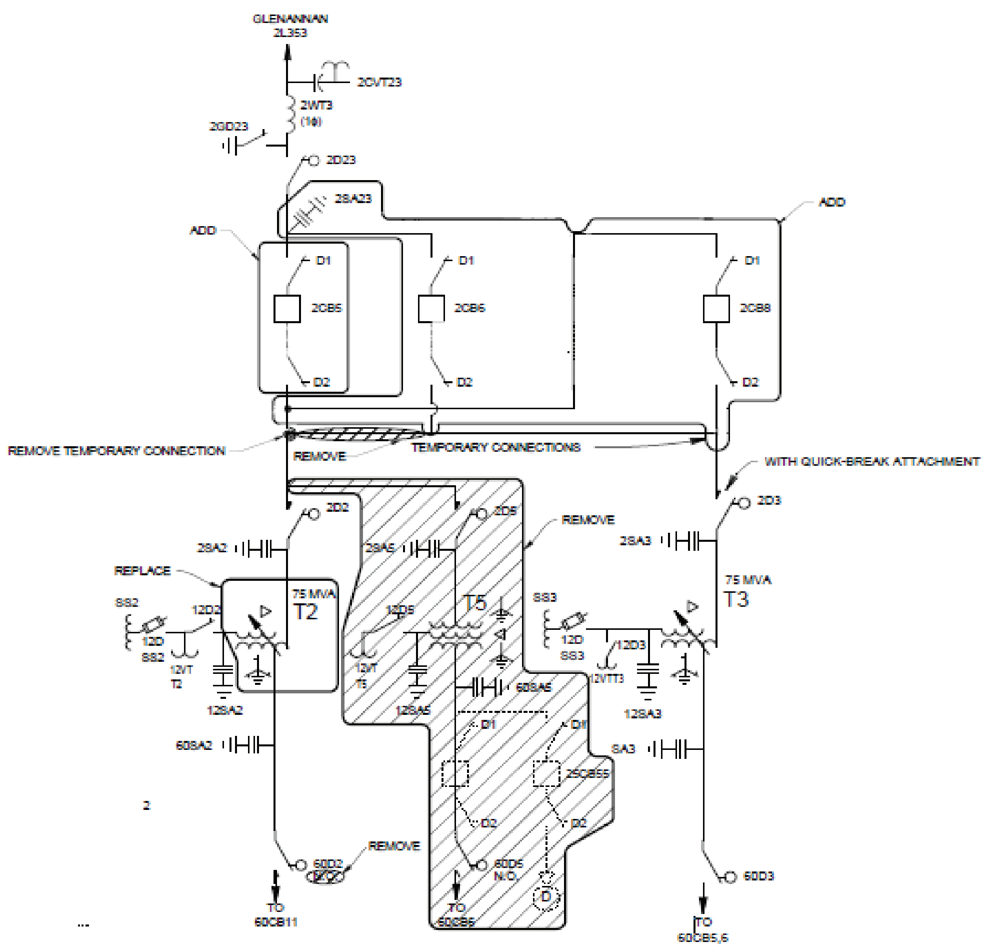
Case	IC's Plant Output	Contingency		Bus Voltage (PU)		
		Cat.	Description	GLN 230	TAC 230	TAC 60
32HW	Max	P0	System Normal	1.030	0.990	1.018
	Max	P1.3	GLN T2/T5[1]	1.024	0.982	1.016
32HS	Max	P0	System Normal	1.022	0.985	1.025
	Max	P1.3	GLN T2/T5[1]	1.018	0.981	1.023
32LS	Max	P0	System Normal	1.020	0.980	1.017
	Max	P1.3	GLN T2/T5[1]	1.016	0.976	1.015
Note 1: T1 and T11 share the same tripping zone, T2 and T5 share the same tripping zone						

Table B-3: Thermal Overload Study Results after T2 Replacement

Case	NC Regional Generation	Contingency		Branch Loading (% of its seasonal normal rating)			
				TAC T3	TAC T2	GLN T1	GLN T2
		Cat.	Description	TAC	TAC	GLN	GLN
Winter Rating in MVA				89.1	89.1	714	714
32HW	Max	P0	System Normal	60%	60%	15%	15%
	Max	P1.3	TAC T3	-	128%	-	-
Summer Rating in MVA				75	75	600	600
32HS	Max	P0	System Normal	84%	84%	21%	21%
	Max	P1.3	TAC T3	-	177%	-	-
Summer Rating in MVA				75	75	600	600
32LS	Max	P0	System Normal	88%	88%	22%	21%
	Max	P1.3	TAC T3	-	191%	-	-
Note 1: After T2 is replaced. Forced outage of either T2 or T3 result in overload of the remaining transformer. Generation runback of [redacted] is required in response to the contingency. The detailed RAS function will be specified in the subsequent studies if the project proceeds.							

Appendix C
One-Line Sketch for Tachick Substation (TAC)

Figure C-1 shows the Stations Planning One-Line Sketch for the revised TAC substation.



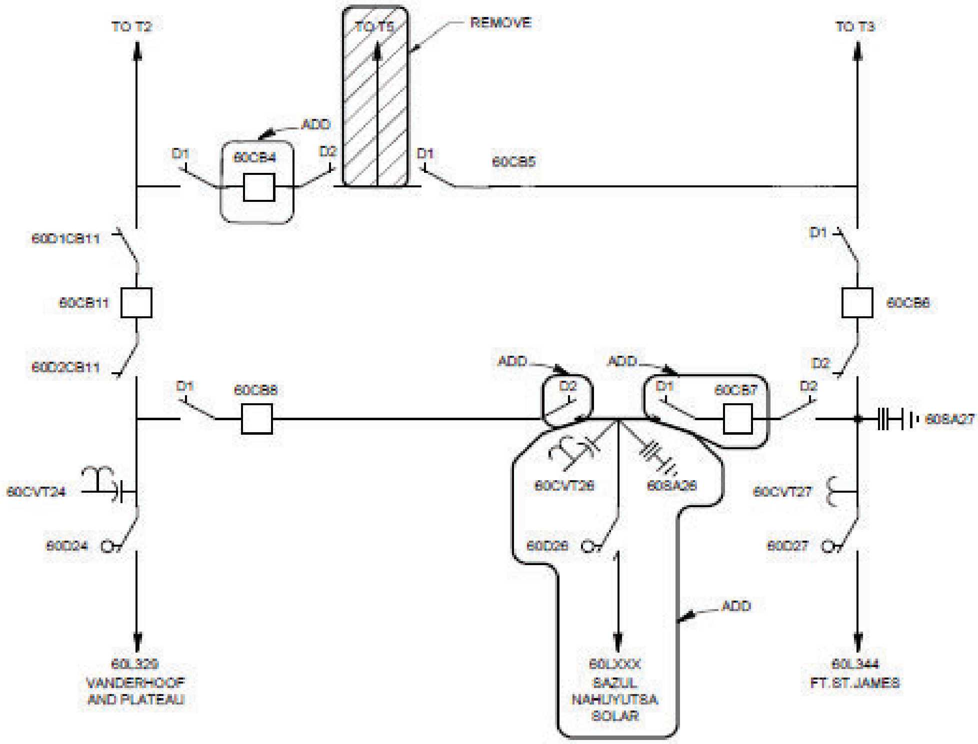


Figure C-1: Stations Planning One-Line Sketch for the TAC substation.