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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #2 – [redacted] Project – Interconnection Feasibility Study

Dear [redacted]:

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR) [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 (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 $92.4 M.

Major Scope of Work Identified:

- Acquire adequate property for a new switching station close to the existing transmission line 2L102
- Construct a new outdoor 287 kV, 3- circuit breaker ring bus switching station.
- Construct a new control building and other required substation facilities and infrastructures.
- Cut the existing 2L102 and loop into the station.
- Terminate 287 kV line of [redacted] at the station
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 36 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Ability to acquire adequate property for a new switching station close to the existing transmission line 2L102
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Cost and ability of obtaining new property for the new switching station may be higher than estimated which may increase the Network Upgrade cost estimate and 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 2033 (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 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_IR2_[redacted] Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR# 2

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Specialist Engineer, Planning Coordinator & Bulk Planning

Reviewed by: [redacted]

Team Lead, Planning Coordinator & Bulk Planning

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

Header:	2025 CEAP IR # 2
Subheader:	Interconnection Feasibility Study
Title:	[redacted]
Subtitle:	2025 CEAP IR# 2
Report Number:	900-APR-00025
Revision:	0
Confidentiality:	Public
Date:	2025 Nov 21
Volume:	1 of 1
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Accepted by:	[redacted] P.Eng.
Title:	Manager, Transmission Planning
Related Facilities:	2L102
Additional Metadata:	Transmission Planning 2025-045 Filing Subcode 1350

Revisions

Revision	Date	Description
0	2025 Nov	Initial release

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Entire report except listed below — Transmission Planning

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[redacted]

Specialist Engineer, Planning Coordinator & Bulk Planning

[redacted]

Section: **Discipline:**

5.2, 5.3 — Stations Planning

Contributed by:

[redacted]

Sr. Engineer, Substation Growth & Sustainment

[redacted]

Executive Summary

[redacted] the interconnection customer (IC), requests to interconnect its [redacted](2025 CEAP IR # 2) to the BC Hydro system. [redacted] has fifty-two (52) [redacted] type-3 wind turbine generators with a maximum power injection of 352 MW into the BC Hydro system at the Point of Interconnection (POI). . The proposed Point of Interconnection (POI) is on BC Hydro's 287 kV line 2L102, approx. 148 km from Skeena substation (SKA). The IC's project will connect to the POI via a 0.5 km 287 kV interconnection line. The IC's proposed commercial operation date (COD) is Oct 1, 2033.

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 287 kV switching substation (referred to as "P02W") on 2L102 is required at the proposed POI for interconnecting the IC's generating project to the BCH system. The new switching station P102W is to be constructed with a 3-breaker ring bus configuration and 2L102 looping in/out. Subsequently, the existing line 2L102 will be segregated into two new circuits, temporarily referred to as: 2L102_A and 2L102_B. The 287KV line between customer and BCH POI will be temporarily named as 2L102_C.
2. The connection of [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions.
3. The connection of [redacted] will trigger thermal overloads on the transformers SKA T1 and SKA T3 under number of contingencies including SKA 5CB3 breaker failures or stuck breaker, and under double contingency SKA T2 OOS & T1 OOS. These overloads are presently not addressed by the North Coast Region generator shedding remedial action scheme (RAS). The [redacted]may need to participate in the generation runback or shedding remedial action scheme (RAS) to secure the system. The RAS function scope will be specified in the System Impact Study (SIS) if the need for RAS is determined.

4. [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.

5. The [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.

6. The "STATCOM option" for proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an inherent limitation—providing only partial reactive power capability during turbine standstill.

7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in proposed wind turbines, is required at the [redacted] The proposed wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

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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Appendices

Appendix A Schematic Diagram of the IC's Project

Appendix B Power Flow Study Results

Appendix C One-Line Sketch for New Switching Station

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
WTG	Wind Turbine Generator

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 2L102 at 148 km from SKA	
IC's Proposed COD	1st October 2033	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	352 MW (Summer)	352 MW (Winter)
Maximum Power installed Capacity (MW)	364 MW (Summer)	364 MW (Winter)
Number of Turbines	52 x 7 MW WTGs	
Plant Fuel	Wind	

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 02) to the BC Hydro system. [redacted] has fifty-two (52) proposed [redacted] type-3 wind turbine generators with total installed capacity of 364 MW. The Point of Interconnection (POI) is on BC Hydro's 287 kV line 2L102, approx.148 km from Skeena substation (SKA). The IC will construct a 287 kV transmission line, about 0.5 km in length, connecting to the proposed POI, where a new switching substation will be built. The temporary name of the new switching station is P02W. The proposed commercial operation date (COD) is Oct 1, 2033.

Figure 1-1 shows the 2L102 region 138/287 kV transmission system diagram. The interconnection point of new switching station P02W is fed from SKA substation. SKA substation is connected to the BC hydro 500kV system. The transmission line between TCT and P02W is temporarily named as 2L102_A and line between P02W and SKA is temporarily named as 2L102_B. The line between P02W and customer site is named 2L102_C. Customer's system topology behind the Point of Interconnection is provided in the Appendix, Figure A-1.

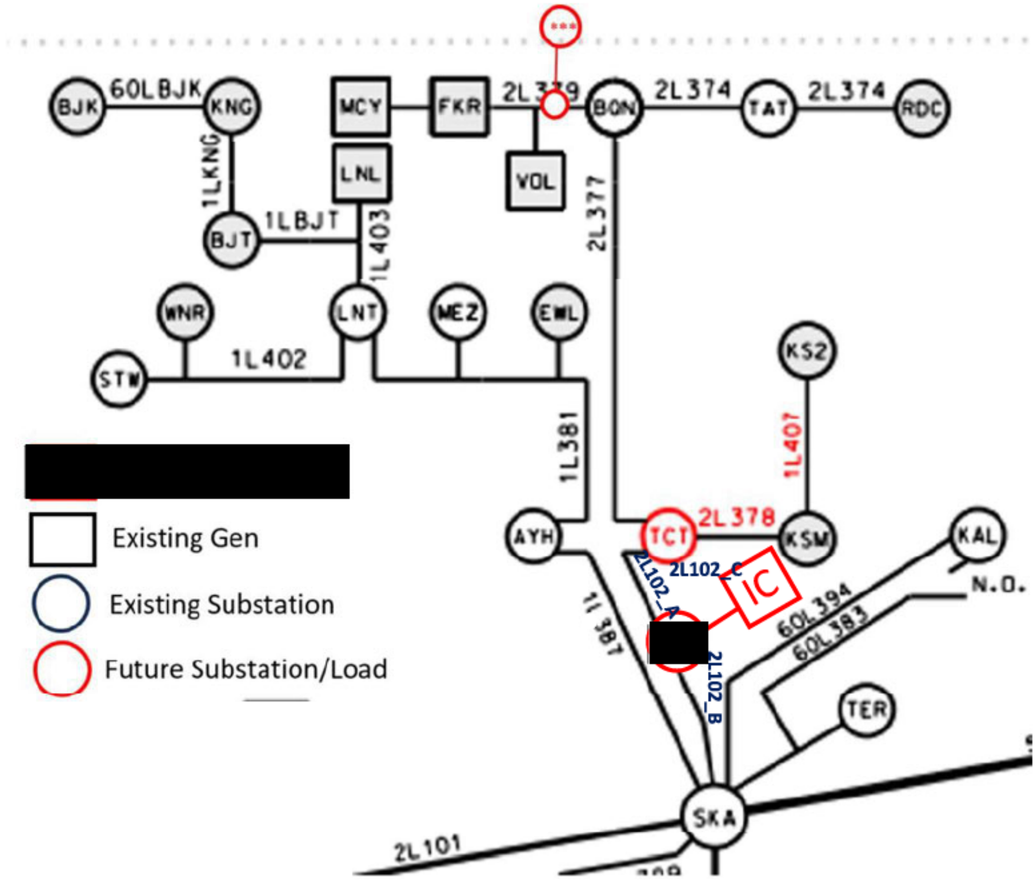

Figure 1-1: 2L102 Region 138/287 kV Transmission System Diagram

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.

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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, October 7, 2025.

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 [redacted] 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) Use of the latest August 2025 distribution load forecast, reference system coincident forecast and reference TVC.
3) Planned transmission reinforcement projects in the study area.
    a. Prince George to Terrace series Capacitor project to be installed in existing lines 5L61, 5L62 and 5L63.
    b. New 500kV lines: 5L64 in PGGT and 5L65& 5L66 (WSN to SKA) in GTTT.
    c. Other system reinforcements in the regional system triggered by future customers are also included in the study model.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new switching station (temporarily referred to as "P02W") at the proposed POI on 2L102 is required to interconnect the IC's generating project to the BCH system. The addition of the new switching station is required to maintain reliability and adequate protection performance to accommodate the new interconnection and serve the existing customers. Details of the study results and reinforcement scopes required to integrate the IC is provided in this section.

5.1 Power Flow Study Results

Steady-state 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 — 33HW/33LS/33HS system conditions that include all the higher-queued interconnection projects in the region and the future proposed reinforcements. 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

The study shows that the addition of 2025 CEAP IR # 2 would not cause any new thermal overloads under N-0 condition or contingency conditions.

The study finds the following facilities overload during the circuit breaker failure or stuck breaker contingencies in 33LS case:

- SKA T1 overloads up to 107% under single contingency 5CB3 breaker failure or stuck breaker and under double contingencies (SKA T2 and SKA T3 OOS)
- SKA T3 overloads up to 105% under single contingency 5CB23 breaker failure or stuck breaker and under double contingencies (SKA T2 and SKA T1 OOS).

The connection of [redacted] will trigger these overloads, which is currently not addressed by North coast Region generator shedding RAS. The [redacted] marginally contributes to these overloads and may need to participate in the generation shedding or runback RAS, which will be determined during the System Impact Study (SIS) stage in future if needed.

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

Table 5-1: Thermal Overload Concerns and Proposed Solutions

Equipment subject to overloads	Conditions observed	Contingencies that result in overloads (Examples)	Solution Proposed
Under contingencies			
SKA T3	LS	P2/P4: Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	Generation Shedding/Runback RAS at [redacted]
SKA T1	LS	P2/P4: Fault at SKA 5CB23 tripping SKA T2 & T3 or, Fault at SKA T2 or T3 with stuck breaker 5CB23	Generation Shedding/Runback RAS at [redacted]

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the stead-state voltage performance under system normal and single contingency conditions is acceptable for all the three load conditions (33LS, 33HS, 33HW). Appendix B, Table B-2 provides the summary of 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 power flow model data submitted by the IC, the proposed [redacted] would be capable of meeting 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 the interconnection process.

In addition, according to the IC-provided reactive capability data, the proposed WTG would provide +1.7 Mvar to -1.7 Mvar reactive capability at the zero MW output if the turbine's "STATCOM" 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 wind farm from the grid when an inadvertent island with the local loads forms.

5.1.5 Other Performance Requirements

Fast Frequency Response, also known as Virtual Inertia Control (VIC) in the proposed wind turbines, is required at the 2025 CEAP IR # 2. The proposed wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

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 287kV, 3-circuit breaker ring bus switching substation (Referred to P02W temporarily) will be built at POI, close to the existing 287kV transmission line 2L102. The existing transmission line 2L102 will be cut and looped into, and 287kV line of [redacted] will be terminated at the new substation. Scope of work at the new switching substation:

- Acquire adequate property for a new switching substation close to the existing transmission line 2L102.
- Construct a new outdoor 287kV, 3-circuit breaker ring bus switching substation. The designation of the new substation and the new line connecting to the customer, as well as two new lines derived from 2L102 are temporarily assigned as P02W, 2L102_C, 2L102_A and 2L102_B. These designations are subject to revision in the next project stage.
- Construct a new control building and other required switching substation facilities and infrastructures.
- Cut the existing 2L102 and loop into the switching substation.
- Terminate 287kV transmission line [redacted] at the switching substation.

Stations planning one-line diagram for the new switching substation P02W is shown in Appendix C, Figure C-1.

5.4 Transmission Line Engineering Requirements

No transmission line engineering scope of work is identified for BC Hydro for this project.

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 287 kV switching substation (referred to as "P02W") on 2L102 is required at the proposed POI for interconnecting the IC's generating project to the BCH system. The new switching substation P102W is to be constructed with a 3-breaker ring bus configuration and 2L102 looping in/out. Subsequently, the existing line 2L102 will be segregated into two new circuits, temporarily referred to as: 2L102_A and 2L102_B. The 287KV line between customer and BCH POI will be temporarily named as 2L102_C.
2. The connection of [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions.
3. The connection of [redacted] will trigger thermal overloads on the transformers SKA T1 and T3 under number of contingencies including breaker failures or stuck breaker conditions. These overloads are presently not addressed by the North coast Region generator shedding remedial action scheme (RAS). The [redacted] will need to participate in the generation runback or shedding remedial action scheme (RAS) to secure the system. The RAS function scope will be specified in the System Impact Study (SIS) if the need for RAS is determined.
4. [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.
5. The [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.

6. The "STATCOM option" for the proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an inherent limitation—providing only partial reactive power capability during turbine standstill.

7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in the proposed wind turbines, is required at the [redacted] The proposed wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

Appendix A
Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [redacted]. Note that the proposed plant configuration includes a total of 25.5 Mvar switchable shunt capacitors – one capacitor bank (8.5 Mvar) on collector bus #1 and the other two (8.5X2 Mvar) on collector bus #2.

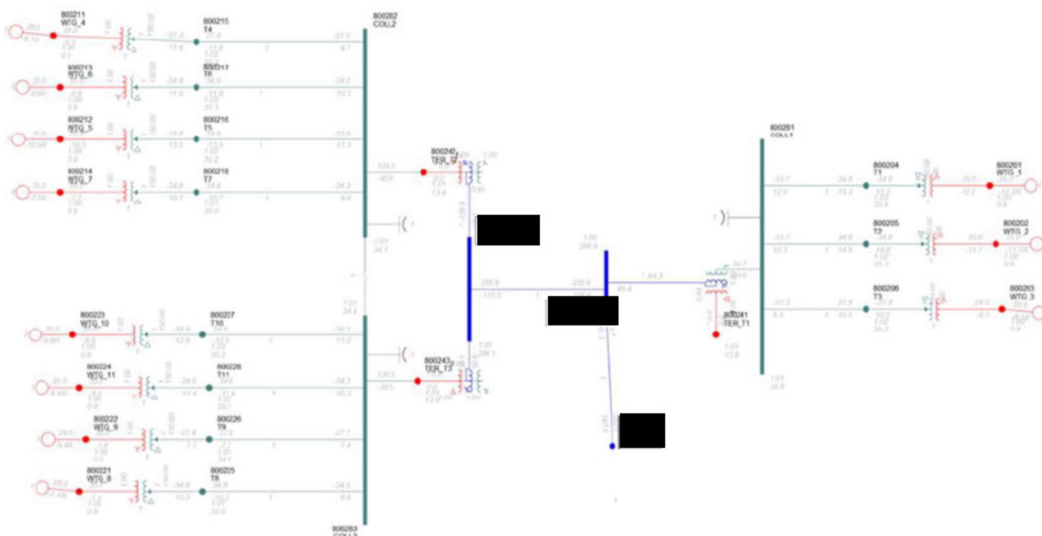

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (32HW/33HS/33LS)

Table B-1: Thermal Overload Study Results

Case	NC+NW Regional Generation/ Load	Contingency Identified		Branch Loading			
				2L102	2L377	SKA T1	SKA T3
		Category	Description	TCT-SKA	TCT-BQN	Winding1/Winding2	Winding1/Winding2
Winter Rating				734.2 MVA	734.2 MVA	798MVA/798 MVA	798MVA/798 MVA
33HW	389.9 MW / 653.8MW	P0	System Normal	65.8%	21.6%	21.7%/21.3%	31.5%/30.5%
		P1	2L374 OOS	81.0%	34.5%	26.1%/25.6%	35.1%/33.9%
		P2/P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	66%	22%	OOS	69%/66%
		P2/P4	Fault at SKA 5CB23 tripping SKA T2 & T3 or, Fault at SKA T2 or T3 with stuck breaker 5CB23	66%	22%	67%/65%	OOS
Summer Rating				734.2 MVA	734.2 MVA	672MVA/672 MVA	672 MVA/672 MVA
33HS	389.9MW / 572.4 MW	P0	System Normal	69.2%	24.5%	29.8%/29.4%	40.8%/39.5%
		P1	2L374 OOS	81.3%	34.7%	33.9/33.4%	44.2/42.8%
		P2/P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	69%	25 %	OOS	94 %/91%
		P2/P4	Fault at SKA 5CB23 tripping SKA T2 & T3 or, Fault at SKA T2 or T3 with stuck breaker 5CB23	69%	25%	92%/88%	OOS
33LS	389.9MW / 572.4 MW	P0	System Normal	77.0%	30.3%	34.1%/33.7	44.1%/42.7
		P1	2L374 OOS	81.8%	35.0%	36.1%/35.3	46.9%/45.3
		P2/P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	77%	30%	OOS	107 %/103%

		P2/P4	Fault at SKA 5CB23 tripping SKA T2 & T3 or, Fault at SKA T2 or T3 with stuck breaker 5CB23	77%	30%	105%/101%	OOS

Table B-2: Steady-State Voltage Study Results

Case	IC's Plant Output	Contingency		Bus Voltage (PU)							
		Cat.	Description	SKA 500	TKW 500	GLN 500	RUP 287	P02W (POI)	TCT 287	MIN 287	BQN 287
33H W	Max	P0	System normal	1.04	1.05	1.05	1.00	1.00	0.99	0.99	1.01
	Max	P1	TKW 500 one shunt OOS	1.06	1.06	1.06	1.01	1.00	0.99	0.99	1.01
	Max	P2/ P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	1.05	1.06	1.06	1.01	1.00	0.99	0.99	1.01
33H S	Max	P0	System normal	1.04	1.05	1.05	1.01	1.00	1.00	0.99	1.02
	Max	P1	TKW 500 one shunt OOS	1.05	1.06	1.06	1.01	1.00	1.00	0.99	1.02
	Max	P2/ P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	1.05	1.05	1.05	1.01	1.00	1.00	0.99	1.02
33LS	Max	P0	System normal	1.04	1.05	1.05	1.01	1.00	1.01	0.99	1.02
	Max	P1	TKW 500 one shunt OOS	1.05	1.06	1.06	1.02	1.00	1.01	0,99	1.02
	Max	P2/ P4	Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3	1.04	1.05	1.05	1.01	1.00	1.01	0.99	1.02

Appendix C

One-Line Sketch for New Switching Substation

Figure C-1 shows the Stations Planning One-Line Sketch for the New Switching Substation P02W.

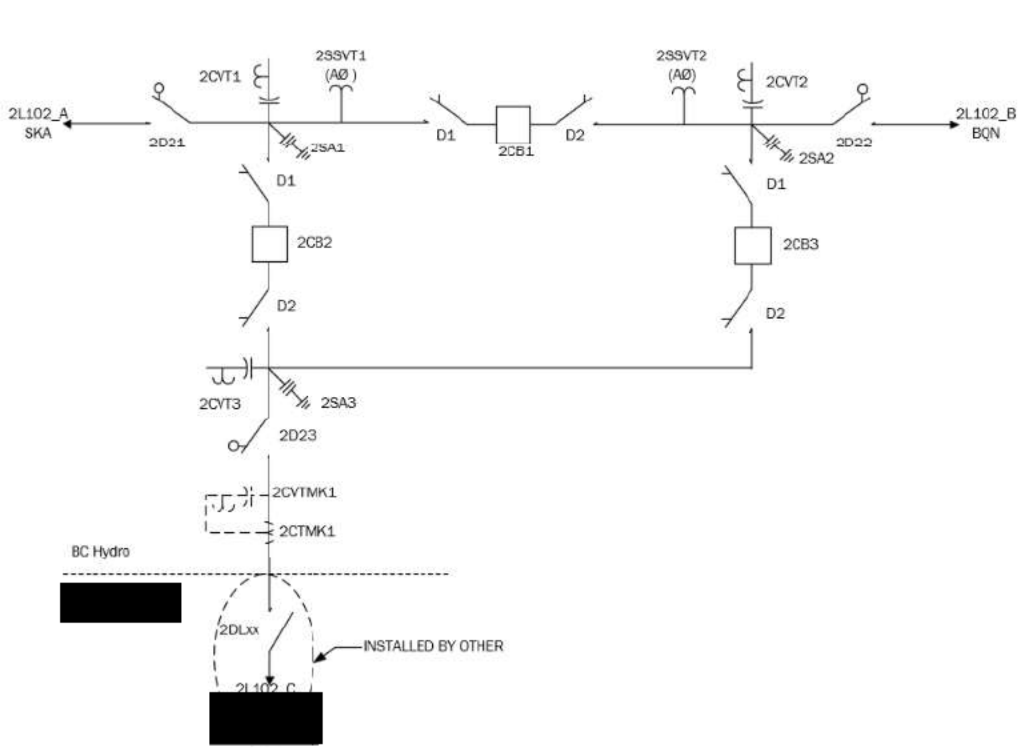

Figure C-1: Stations Planning One-Line Sketch for the New Switching Substation P02W.