BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #27 – [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 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 $50.5 M.

Major Scope of Work Identified:

- Supply and install one motor-operated disconnect switch, one 12 kV circuit breaker, and one 12 kV, 35 MVAR switched shunt reactor with AutoVar control scheme at the tertiary winding of the T1 transformer of the 230 kV bus at Kennedy substation (KDS)

- Upgrade required substation facilities, infrastructures, and bus work to support new station equipment
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 6 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Impact Benefit Agreements with First Nations are not considered
- No station or control room expansion

Key Risks:

- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- If station or control room expansion is required, it may present project cost and schedule risks
- 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

Indirect Interconnection

Your IR involves an indirect interconnection to the BC Hydro Transmission System. Under the OATT Attachment M-1: Standard Generator Interconnection Procedures (SGIP) and the Standard Generator Interconnection Agreement (SGIA), the party executing the SGIA must be the owner of the Interconnection Customer Interconnection Facilities up to the Point of Interconnection. Depending on the scope of required Network Upgrades, this execution may occur years before the Commercial Operation Date.

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 2030 (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 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_IR27_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 27

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Specialist Engineer, Transmission

Reviewed by: [redacted]

Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

Division Manager, Transmission Planning

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Title:	Specialist Engineer, Transmission Planning
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Title:	Technical Strategic Principle, Transmission Planning
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Revisions

Revision	Date	Description
0	2025 Nov	Initial release

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Section: **Discipline:**

Entire report except listed below — Transmission Planning

Contributed by:

[redacted] [redacted]

Specialist Engineer, Transmission Planning

Section: **Discipline:**

5.2, 5.3 — Stations Planning

Contributed by:

[redacted] [redacted]

Sr. Engineer, Station Planning

Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (2025 IR # 27) to the BC Hydro system. [redacted] has thirty-six (36) [redacted] type-3 wind turbine generators, adding a total capacity of 197.9 MW into the BC Hydro system. The IC proposes an indirect tap connection on 2L319, a third-party owned 230 kV transmission line, located at approximately 42 km from Kennedy substation (KDS). 2L319 currently radially serves a Transmission Voltage Customer (TVC) at Mount Milligan substation (MML). The Point of Interconnection (POI) for this study is the KDS 230 kV bus. The IC will construct a 230 kV transmission line with two segments, totalling approximately 9.7 km in length, connecting to the proposed tapping structure.

The proposed Commercial Operation Date (COD) of this project is 1 November 2029.

To interconnect [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. An indirect, T-tap connection on a third-party owned transmission line, 2L319, is acceptable for interconnecting the IC's generating project to the BCH system. However, the POI to the BC Hydro system shall be considered at the KDS 230 kV bus.
2. The connection of [redacted] may contribute towards high voltage conditions on the 230 kV system when the generators are outaged in System Normal operating condition. A 35 MVAr switched shunt reactor with AutoVar control scheme at the tertiary winding of the KDS T1 transformer is required. The size and exact location of the reactor on the KDS bus will be explored in the later stages of the interconnection of this project.
3. For single contingency operating conditions, potential thermal overloads of 500 kV series capacitors at Kennedy Series Capacitor Station (KDY) and McLeese Series Capacitor Station (MLS) and 500 kV transmission lines are observed. These violations can be addressed by the existing GMS Area Gen Shedding remedial action scheme (RAS). The new wind generators

at [redacted] may need to participate in the existing GMS Area Gen Shedding RAS. 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. [redacted] would be islanded with the TVC load or BCH loads for certain fault and no-fault contingencies at KDS. A Direct Transfer Trip (DTT) protection scheme is required to isolate the IC's wind project at the IC's entrance circuit breaker to avoid potential islanding operations with the existing loads.

6. [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.

7. The "STATCOM option" for [redacted] 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.

8. Fast Frequency Response (FFR), as per BCH TIR Section 6.4.5, is required at the [redacted]. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of 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”.

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
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)	Tap on 2L319 (third-party owned) at 42 km from KDS	
IC's Proposed COD	1 November 2029	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	197.9 MW (Summer)	197.9 MW (Winter)
Number of Turbines	36 x 5.7 MW WTGs	
Plant Fuel	Wind	

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 27) to the BC Hydro system. [redacted] has thirty-six (36) [redacted] type-3 wind turbine generators, adding a total capacity of 197.9 MW into the BC Hydro system. A 34.5 kV collector system transmits the energy from the wind turbines to two on-site 34.5/230 kV substations, that are interconnected via a 9.5 km 230 kV intertie line. One of these substations is adjacent to 2L319, a third-party owned 230 kV line. The IC proposes an indirect tap interconnection on 2L319, located at approximately 42 km from Kennedy substation (KDS). 2L319 currently radially serves a Transmission Voltage Customer (TVC) at Mount Milligan substation (MML). The Point of Interconnection (POI) for this study is the KDS 230 kV bus. The IC will construct a 230 kV transmission line with two segments, totalling approximately 9.7 km in length, connecting to the tap structure on 2L319.

During the Data Review phase of the IR submission, the IC clarified that the maximum injection of 197.9 MW into the BC Hydro system is considered when the TVC at MML is completely offline/out-of-service and the IBR Plant is generating at MPO.

Figure 1-1 shows the Mackenzie and CI region 138/230/500 kV transmission system diagram. The Mackenzie electric system is supplied via three single-phase 500/230 kV transformers at KDS. The 230 kV voltage level is stepped down to 138 kV via two transformers operated in parallel to further supply additional transmission and distribution customers. There is also an Independent Power Producer (IPP) in the region. The IC is interconnecting on 2L319 that radially supplies a TVC at MML substation.

There are no existing branch overload or voltage stability concerns for single or multiple contingencies in the Mackenzie region. There is, however, the GMS Area Gen Shedding RAS that is relied on to address any overload or transient stability concerns on the 500 kV system from which the Mackenzie region is supplied.

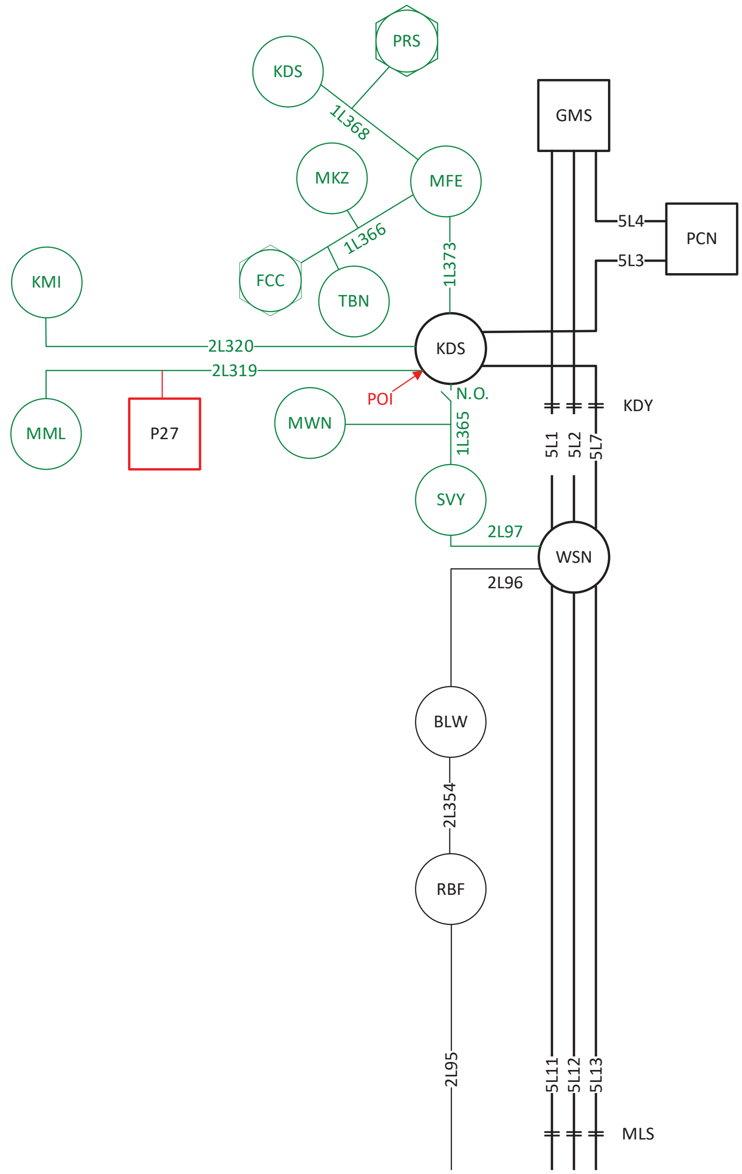

Figure 1-1: Mackenzie and CI Region 138/230/500 kV Transmission System Diagram. [redacted] and POI are shown in red.

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, 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) 1L365 will be normal opened at KDS. Only normal operating condition has been studied i.e. supply from Salmon Valley (SVY) substation is not considered in this study.
3) Assume 2L319 has sufficient capacity to accommodate the IC's wind project.

5 System Studies and Results

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 — 29HW/30HS/30LS – system conditions that include all the higher-queued generation projects in the region. 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 [redacted] would not cause thermal overloads under System Normal condition (P0).

For single contingency operating conditions, the study finds overloads of 500 kV series capacitors at Kennedy Series Capacitor Station (KDY) and McLeese Series Capacitor Station (MLS) and 500 kV transmission lines from Peace Canyon Generating Station (PCN) to KDS, which is mostly associated with the existing generation in the Peace Region. These overloads are addressed by the existing GMS Area Gen Shedding RAS.

The [redacted] marginally contributes to these overloads and may need to participate in the existing generation shedding RAS, which will be determined during the System Impact Study (SIS) stage in future, if needed.

Appendix B contains the details of thermal overload analysis results.

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 heavy winter and summer conditions (30HS, 29HW).

However, for light summer condition (30LS), the IBR plant may contribute towards high voltage conditions on the 230 kV system when the generators are outaged, but the plant remains connected to BC Hydro system.

A 35 MVAr switched shunt reactor with AutoVar control scheme at the tertiary winding of the KDS T1 transformer is required to address these overvoltage conditions. The size and exact location of the reactor on the KDS bus will be determined during the SIS stage in future, if needed.

Appendix B contains the details of 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 -1.9 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.

[redacted] would be islanded with the TVC load or BCH loads for certain fault and no-fault contingencies at KDS. A Direct Transfer Trip (DTT) protection scheme is required to isolate the IC's wind project at the IC's entrance circuit breaker to avoid potential islanding operations with the existing loads.

5.1.5 Other Performance Requirements

Fast Frequency Response (FFR), as per BCH TIR Section 4.6.5, is required at the [redacted] The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of 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

It is assumed that a 35 MVAR switched shunt reactor with AutoVar control scheme at the tertiary winding of the KDS T1 transformer is required as per Transmission Planning. If the size or exact location of the reactor changes, the Station Scope of Work may also change.

The scope of work at the KDS substation is as follows.

- Add one 12 kV motor-operated disconnect, one 12 kV circuit breaker, and one 12 kV, 35 MVAR switched shunt reactor with AutoVar control scheme at the tertiary winding of the KDS T1 transformer.
- Other associated station work.

Refer to the one-line diagram in Appendix C for details.

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. An indirect, T-tap connection on a third-party owned transmission line, 2L319, is acceptable for interconnecting the IC's generating project to the BCH system. However, the POI to the BC Hydro system shall be considered at the KDS 230 kV bus.

2. The connection of [redacted] may contribute towards high voltage conditions on the 230 kV system when the generators are outaged in System Normal operating condition. A 35 MVAr switched shunt reactor with AutoVar control scheme at the tertiary winding of the KDS T1 transformer is required. The size and exact location of the reactor on the KDS bus will be determined in the SIS stage of the interconnection of this project.

3. For single contingency operating conditions, potential thermal overloads of 500 kV series capacitors at KDY and MLS substations and 500 kV transmission lines are observed. These violations can be addressed by the existing GMS Area Gen Shedding remedial action scheme. The new wind generators at [redacted] may need to participate in the existing GMS Area Gen Shedding RAS. The RAS function scope will be specified in the 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. [redacted] would be islanded with the TVC load or BCH loads for certain fault and no-fault contingencies at KDS. A DTT protection scheme is required to isolate the IC's wind project at the IC's entrance circuit breaker to avoid potential islanding operations with the existing loads.

6. [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.

7. The "STATCOM option" for [redacted] 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.

8. Fast Frequency Response (FFR), as per BCH TIR Section 6.4.5, is required at [redacted]. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

Appendix A
Schematic Diagram of the IC’s Project

Figure A-1 shows the schematic diagram for [redacted] (205MW 2L319 POI).

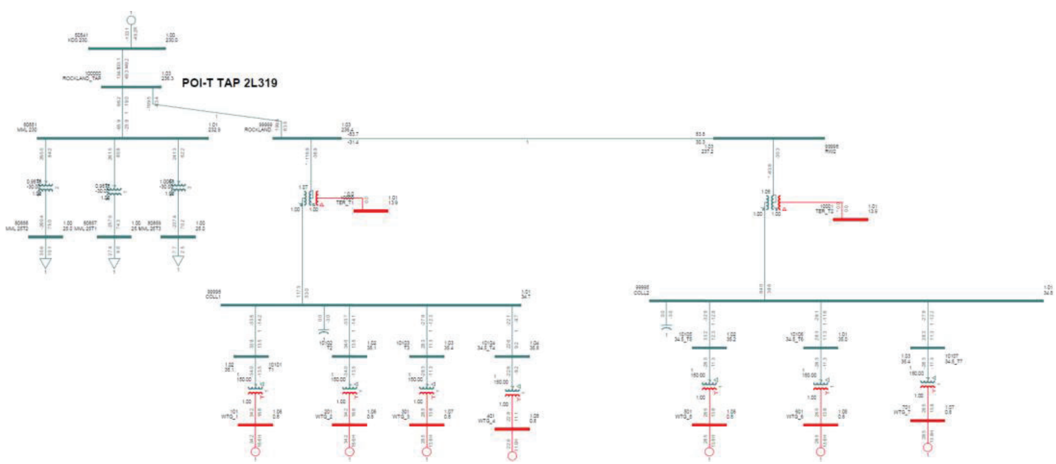

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

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

Table B-1: Thermal Overload Study Results

Case	Peace Regional Generation	Contingency Identified		Branch Loading (A/MVA/% of its seasonal normal rating)			
				2L319	KDS T1	KDY CX 500 kV	MLS CX 500 kV
	(MW)	Category	Description	MML-KDS	KDS 230/500 kV		
Winter Rating in MVA/A				-	356 MVA	2300 A	1950 A
29HW	Max	P0	System Normal	492.1 A	168.3 MVA	1614.6 A	1144 A
				43.80%	47.30%	70.20%	58.70%
		P1	1L366 OOS	494.7 A	217.3 MVA	1662.9 A	1156.8001 A
				44.00%	61.00%	72.30%	59.30%
		P1	5L2 OOS w/o RAS	500 A	169.5 MVA	2350.6 A	1161.1 A
				44.50%	47.60%	102.2%	59.50%
		P1	5L13 OOS w/o RAS	505.1 A	169.7 MVA	1636.8 A	1746.1999 A
				45.00%	47.70%	71.20%	89.50%
Summer Rating in MVA/A				-	300 MVA	2300 A	1950 A
30HS	Max	P0	System Normal	494.9 A	176.2 MVA	1657.8 A	1279 A
				51.90%	58.70%	72.10%	65.60%
		P1	1L366 OOS	497.1 A	224.4 MVA	1704.8 A	1291.1 A
				52.10%	74.80%	74.10%	66.20%
		P1	5L2 OOS w/o RAS	500.1 A	176.6 MVA	2412.2 A	1294 A
				52.40%	58.90%	104.9%	66.40%
		P1	5L13 OOS w/o RAS	504.9 A	177.3 MVA	1680 A	1941.9 A
				53.00%	59.10%	73.00%	100%
30LS	Max	P0	System Normal	494.8 A	202.4 MVA	1696.8001 A	1353.5 A
				51.90%	67.50%	73.80%	69.40%
		P1	1L366 OOS	494.9 A	227 MVA	1719.1 A	1358.1999 A
				51.90%	75.70%	74.70%	69.70%
		P1	5L2 OOS w/o RAS	499.6 A	202.8 MVA	2457 A	1368.1 A
				52.40%	67.60%	106.80%	70.20%
		P1	5L13 OOS w/o RAS	521.5 A	204.8 MVA	1762.2 A	2135.5 A
				54.70%	68.20%	76.60%	109.50%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output	Contingency		Bus Voltage (PU)		
		Category	Description	KDS 230 kV	KDS 500 kV	P27 Tap on 2L319
29HW	Max	P0	System Normal	1.0372	1.0697	1.0344
		P1	1L373 OOS	1.0386	1.07	1.0354
		P1	5L13 OOS	1.0124	1.047	1.0088
30HS	Max	P0	System Normal	1.0308	1.0644	1.0281
		P1	1L373 OOS	1.0329	1.0647	1.0296
		P1	5L13 OOS	1.0142	1.0494	1.0101
30LS	Max	P0	System Normal	1.0321	1.0656	1.029
	0 MW	P0	System Normal (IBR Generators OFF)	1.0725	1.0800	1.0830
	Max	P1	1L373 OOS	1.0338	1.0658	1.0303
		P1	5L13 OOS	0.9816	1.0186	0.9775

Appendix C

One-Line Sketch for Work at KDS Substation

Figure C-1 shows the Stations Planning One-Line Sketch for the substation work required at KDS.

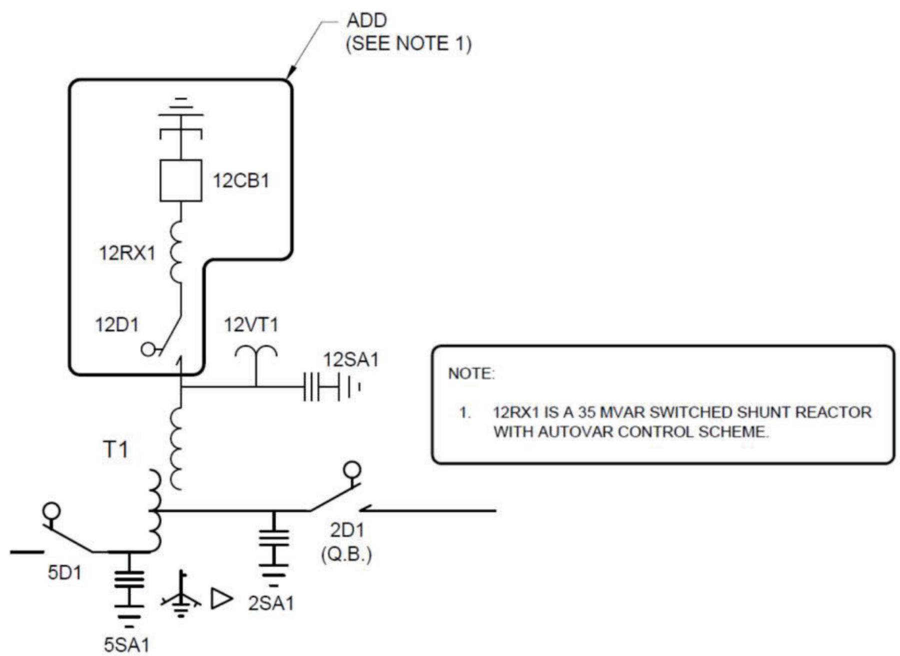

Figure C-1: Stations Planning One-Line Sketch for the substation work required at KDS.