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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #14 – [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 $1.2 M.

Major Scope of Work Identified:

- 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
- Taylor Wind Phase 1 project is assumed to be in-service in July 2031.

Key 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 1 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

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_IR14_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 14

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

[redacted]
Sr. Engineer, Transmission Planning

Reviewed by: [redacted]

Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

Division Manager, Transmission Planning

1000-APR-00047
2025 Nov 21

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Revision	Date	Description
0	2025 Nov	Initial release

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Sr. Engineer, Transmission Planning

Section:	**Discipline:**
5.2, 5.3	Stations Planning

Contributed by:

[redacted]

[redacted]

[redacted]

Specialist Engineer, Station Planning

Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (BCH's Unified Study Project Code: # 14) to the BC Hydro system. [redacted] has eighteen (18) [redacted] type-3 wind turbine generators, adding a total capacity of 106.2 MW with a maximum power injection of 104.17 MW into the BC Hydro system at the Point of Interconnection (POI). The IC has proposed to connect their Wind Project to BC Hydro transmission system at the same POI as the [redacted] at the 230 kV bus of the [redacted] [redacted] on the BC Hydro's 230 kV line 2L392, approximately 22.1 km from the South Bank Substation (SBK).

The IC's Wind Project will be connected via a new 230 kV customer-built transmission line from a tap structure on the planned customer-built 230 kV line 2L392C, running from [redacted] to the planned customer-owned [redacted] which will be constructed under the 2024 CEAP [redacted]. The IC's proposed commercial operation date (COD) is Feb 4, 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. The proposed POI at the planned 230 kV switching station [redacted] and tap connection on the planned customer-built connection line 2L392C are acceptable to interconnect the customer's generating project to the BCH system.
2. No thermal overloads or voltage constraints have been identified under system normal condition.
3. The connection of [redacted] will exacerbate the existing thermal overloads on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies. These overloads can be mitigated by the existing G.M. Shrum Area Gen Shedding remedial action scheme (RAS). Therefore, the [redacted] is required to participate in the G.M. Shrum Area Gen Shedding RAS. Further RAS details will be studied under System Impact Study (SIS) stage.

4. The [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. 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 planned TVC load. This will be further assessed in the SIS stage.

6. 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. Based on the IC-submitted PSS/E model, the proposed [redacted] meets the reactive capability requirement above.

7. 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.

8. 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.

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
BMT	Bear Mountain Terminal
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
EGB	East Groundbirch
ERIS	Energy Resource Interconnection Service
ET3	Cutbank Ridge Partnership- Tower 03/07 Substation
FeS	Feasibility Study
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
GMS	Gordon M. Shrum G.S.
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
PRES	Peace Region Electric Supply
PLD	[redacted] Parkland Substation
RAS	Remedial Action Scheme
SGB	Shell Groundbirch Substation
SBK	South Bank Substation
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
[redacted]	[redacted] Terminal Station
[redacted]	[redacted] Station
TVC	Transmission Voltage Customer
VIC	Virtual Inertia Control

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 the [redacted] 230 kV station	
IC's Proposed COD	4th February 2032	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	104.17 MW (Summer)	104.17 MW (Winter)
Number of Turbines	18 x 5.9 MW WTGs	
Plant Fuel	Wind	

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (BC IR # 14) to the BC Hydro system. [redacted] has eighteen (18) the proposed [redacted] type-3 wind turbine generators, adding a total capacity of 106.2 MW with a maximum power injection of 104.17 MW into the BC Hydro system at the Point of Interconnection (POI). The IC has proposed to connect [redacted] to BC Hydro transmission system at the same POI as the planned [redacted], at the 230 kV bus of the planned [redacted] [redacted] on the BC Hydro's 230 kV line 2L392, approximately 22.1 km from the South Bank Substation (SBK).

[redacted] will be connected via a new 230 kV customer-built transmission line from a tap structure on the planned customer-built 230 kV line 2L392C, running from [redacted] to the planned customer-owned [redacted] which will be constructed under the 2024 CEAP [redacted] The IC's proposed commercial operation date (COD) is Feb 4, 2032.

The Peace Region transmission system consists of 230 kV and 138 kV transmission infrastructures supplied from Gordon M. Shrum G.S.(GMS) and South Bank substation, which are the major sources of supply to the Peace Region transmission system. Figure 1-1 shows the Peace region transmission system diagram.

The Dawson Creek-Groundbirch area is supplied from Shell Groundbirch substation (SGB) via two 230 kV lines and multiple radial 138 kV transmission lines, which interconnecting with the two major BC Hydro substations, Bear Mountain Terminal (BMT) and Dawson Creek (DAW) substation, serving major oil and gas customer loads. SGB is fed by 230 kV Peace Region Electric Supply project (PRES) lines from Southbank substation and the other 230 kV lines 2L340 & 2L342 with power sourced from GMS.

There are two new wind farms, [redacted] and [redacted] with installed capacity of 200 MW each, to be added in the Peace region. In addition, one wind farm with 56 MW installed capacity will be added in the Peace Region. [redacted] will be tap connected on the customer-built transmission line 2L392C, located on the southern portion of the Peace Regional System. The wind farms and connection are shown in Figure 1-1 below.

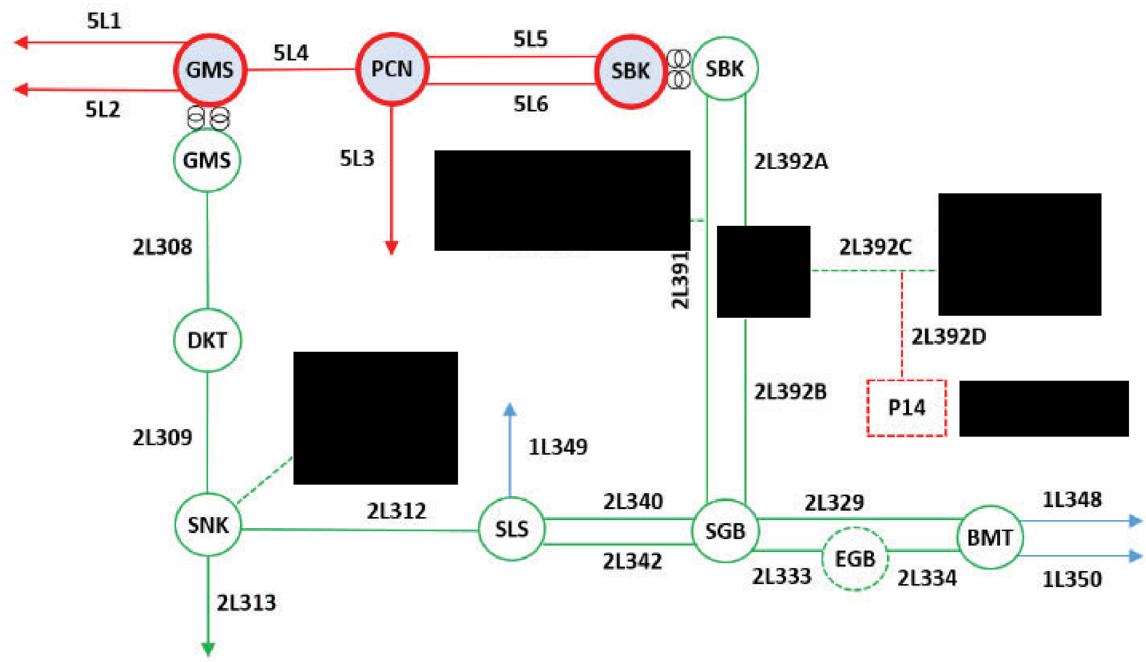

Figure 1-1: Peace Region Transmission System Diagram

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.

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 Peace region 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 Maximum Power Outputs (MPO) unless otherwise specified.

2) The 2024 Distribution Substation Load Forecast, 2025 Transmission Voltage Customer (TVC) Load Forecast and 2025 System Peak Forecast are used.

3) September 2024 Base Resource Plan.

4) [redacted] will be in service on September 30, 2031, and [redacted] [redacted] will be in service on October 1, 2030.

5) A new 56 MW Wind project will be in service on October 31, 2028.

6) 31HW, 32HS and 32LS are used as base case in the study to evaluate system impact after [redacted] plant interconnection.

7) The Bear Mountain Terminal T4 will be in service by March 2027.

8) 1L377 is normally open between [redacted] Parkland Substation (PLD) and [redacted]- Tower 03/07 Substation (ET3).

9) All BCH TVC load interconnection associated system reinforcement are modeled in this study.

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 scenarios — 31HW/32LS/32HS system conditions that includes all the higher-queued generating projects ([redacted]) in the Peace 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 were 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

For all the studied scenarios (31HW, 32LS, and 32HS), the study shows that the addition of [redacted] would not cause any thermal overloads under system normal condition.

Under single contingency conditions, branch overloads were observed on the 500 kV line 5L1, 5L2, and 5L3 following single contingencies on line 5L3, 5L4 or 5L7. The connection of [redacted] will further aggravate these existing overloads, which is currently addressed by the existing G.M. Shrum Area Gen Shedding RAS. So, [redacted] will be required to participate in the G.M. Shrum Area Gen Shedding RAS. The detailed RAS requirements will be confirmed during the System Impact Study (SIS) stage, if necessary.

Details of the thermal overload analysis are provided in Appendix B.

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 study scenarios (32LS, 32HS, 31HW). 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 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. 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 planned TVC load. This will be further assessed in the SIS stage.

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 [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.

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

The POI of the [redacted] is the planned 230 kV switching substation [redacted]. The tap point is located on the customer-built 230 kV line 2L392C ([redacted]), which will be constructed under the 2024 CEAP [redacted].

No station work is required.

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. The proposed POI at the planned 230 kV switching station [redacted] and tap connection on the planned customer-built connection line 2L392C are acceptable to interconnect the customer's generating project to the BCH system.
2. No thermal overloads or voltage constraints have been identified under system normal condition.
3. The connection of [redacted] will exacerbate the existing thermal overload on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies. These overloads can be mitigated by the existing G.M. Shrum Area Gen Shedding RAS. Therefore, the [redacted] is required to participate in the G.M. Shrum Area Gen Shedding RAS. Further RAS details will be studied under System Impact Study stage.
4. The [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. 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 planned TVC load. This will be further assessed in the SIS stage.
6. 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. Based on the IC-submitted PSS/E model, the proposed [redacted] meet the reactive capability requirement above.

7. 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.

8. 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] [redacted]. Note that the proposed plant configuration includes one total of 16 MVAr switchable shunt capacitor on the collector bus.

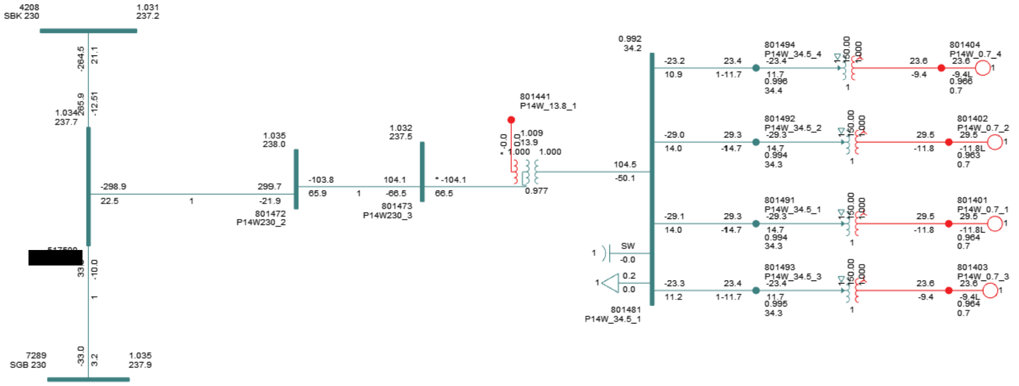

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B

Power Flow Study Results

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

Table B-1: Thermal Overload Study Results

Cases	IC's Gen Output (MW)	Contingency Identified		Branch Loading (Amps/MVA)						
				5L1	2L308	2L391	2L392B	2L392A	GMS_T13	SBK_T21
		Cate.	Description	GMS-WSN	GMS-DKT	SBK-SGB	SGB-[redacted]	SBK-[redacted]	(MVA)	(MVA)
Winter ratings				3444	1359	1667	1667	1667	356	714
31HW	Max	P0	System Normal	1697.5 56.6%	742.7 55 %	322.7 19 %	202.4 12 %	523.7 31 %	128.8 36%	167.9 24%
		P1	2L391	1698.2 56.6%	666.1 49 %	N/A	255.6 15 %	468.8 28 %	113.6 32 %	90.6 13 %
		P1	2L392A_SBK-[redacted]	1698.6 56.6%	866 64 %	673.1 40 %	720.8 72 %	N/A	128.8 43 %	132.5 19 %
		P1	2L392B_SGB-[redacted]	1696.8 56.6%	694.2 51 %	186.8 11 %	N/A	723.5 54 %	119.2 33 %	181.1 25 %
		P1	2L308	1687.4 56.2%	N/A	619.3 37 %	149.7 15 %	848.7 63 %	21.8 6 %	294.6 41%
		P1	5L3	2613.5 87.1%	791.4 58.2%	299.4 18.0%	226.7 13.6%	502.5 30.1%	135.9 38.2%	158.0 22.1%
		P1	GMS_T14	1697.8 56.6%	679.6 50%	349.8 21%	173.8 10%	551 33%	138.1 65%	167.9 25%
		P1	SBK_T22	1698.2 56.6%	789.3 58%	290.8 17%	232.2 14%	492.5 30%	128.8 39%	309.6 43%
		P2	SBK_2CB22	1699.0 56.6%	897.3 66%	632.3 38%	723.6 43%	N/A	159.4 45%	247.1 35%
Summer ratings				2244	1073	1343	1343	1343	300	600
32HS	Max	P0	System Normal	1718.7 76.6%	777.4 72 %	371.3 28 %	151.9 11 %	572.7 43 %	135.9 45 %	167.8 28 %
		P1	2L391	1719.6 76.6%	712.8 63 %	N/A	174.1 13 %	550.4 41 %	123.2 41 %	87.6 15 %
		P1	2L392A_SBK-[redacted]	1719.8 76.6%	911.3 85 %	754.4 56 %	720.6 54 %	N/A	162.6 54 %	129.5 22 %
		P1	2L392B_SGB-[redacted]	1718.1 76.6%	777.4 71 %	268.7 20 %	N/A	723.5 54 %	128.7 43 %	177.8 30 %
		P1	2L308	1707.7 76.1%	N/A	693.9 52 %	182.9 14 %	899.2 67 %	21.6 7.2 %	300.2 50 %

		P1	5L3	2644.1 117.8%	825.9 77.0%	348.3 25.9%	177.9 13.2%	551.6 41.1%	142.9 47.6%	157.5 26.2%
		P1	GMS_T14	1718.9 76.6%	711.1 66%	400 30%	123.7 9%	601.6 45%	244.7 82%	179.6 30%
		P1	SBK_T22	1719.2 76.6%	823.9 88%	339.6 25%	183.4 14%	541.8 40%	145.3 48%	309.2 52%
		P2	SBK_2CB22	1720.1 76.7%	942.8 53%	715.2 53%	723.7 54%	N/A	168.6 56%	241 40%
32LS	Max	P0	System Normal	1769.2 78.8%	829.7 77 %	443.1 33 %	79.9 6 %	644.1 48 %	141.6 50 %	202.6 34 %
		P1	2L391	1770.0 78.9%	782.5 73 %	N/A	53.6 4%	671.1 50%	150.9 47%	117.9 20%
		P1	2L392A_SBK-[redacted]	1770.1 78.9%	981.7 91 %	874.2 65 %	723.8 54 %	N/A	180.7 60%	159.2 27%
		P1	2L392B_SGB-[redacted]	1768.9 78.8%	810.7 76 %	389.6 29 %	N/A	297.8 54 %	147.1 49%	207.9 35%
		P1	2L308	1756.9 78.3%	N/A	790 59%	273.7 20 %	993.2 74 %	17.6 6%	343.8 57%
		P1	5L3	2739.8 122.1%	882.0 82.2%	419.2 31.2%	107.1 8.0%	622.7 46.4%	157.8 52.6%	191.8 32.0%
		P1	GMS_T14	1769.3 78.8%	756.5 71%	474.9 35%	48.8 6%	676.2 50%	271.6 91%	215.7 36%
		P1	SBK_T22	1769.8 78.9%	885.9 83%	404.6 30%	118 9%	606.8 45%	162.1 54%	373.2 62%
		P2	SBK_2CB22	1770.5 78.9%	1019.4 95%	825.2 61%	723,9 54%	N/A	188.1 63%	296.4 49%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output (MW)	Contingency		Bus Voltage (PU)	
		Cate.	Description	SBK 230	SGB 230
31HW	Max	P0	System Normal	1.034	1.034
		P1	SBK_T21	1.034	1.034
		P1	2L391	1.037	1.032
		P1	2L392A_SBK-[redacted]	1.032	1.032
		P1	2L392B_SGB-[redacted]	1.034	1.034
		P2	SBK_2CB12	1.036	1.033
		P2	SBK_2CB22	1.03	1.033
32HS	Max	P0	System Normal	1.034	1.035
		P1	SBK_T21	1.033	1.035
		P1	2L391	1.036	1.034
		P1	2L392A_SBK-[redacted]	1.031	1.034
		P1	2L392B_SGB-[redacted]	1.034	1.035
		P2	SBK_2CB12	1.035	1.034
		P2	SBK_2CB22	1.029	1.033
32LS	Max	P0	System Normal	1.034	1.037

		P1	SBK_T21	1.033	1.037
		P1	2L391	1.037	1.037
		P1	2L392A_SBK-[redacted]	1.031	1.035
		P1	2L392B_SGB-[redacted]	1.034	1.034
		P2	SBK_2CB12	1.035	1.037
		P2	SBK_2CB22	1.028	1.035