

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

November 24, 2025

[REDACTED]

via email: [REDACTED]

RE: CEAP IR #17 – [REDACTED] 153MW – Interconnection Feasibility Study

Dear [REDACTED]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [REDACTED] 153MW, 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 \$218.8 M.

Major Scope of Work Identified:

- Supply and install a 138 kV non-standard tap structure, up to three switch structures with total up to three disconnect switches on line 1L377
- Convert two adjacent structures of disconnect switches to dead-end structures
- Acquire additional Right-of-Way

- Thermal upgrades involving reconductoring of, and structure replacements of 138 kV line 1L377 from Taylor substation (TAY) to proposed POI
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 24 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Impact Benefit Agreements with First Nations are not considered
- Full line thermal upgrade to replace existing structures along 18.5km section of 1L377, which includes 17 new 3 pole dead-end and 100 new tangent/angle structures

Key Risks:

- Transmission scope may be different than assumed, including number of disconnect switches and structure types
- 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

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 signature]

[Redacted name]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR17_ [Redacted] 153MW_Feasibility_Study.pdf

[Redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 17

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

Report Metadata

Header: 2025 CEAP IR # 17
Subheader: Interconnection Feasibility Study
Title: [REDACTED] 153MW
Subtitle: 2025 CEAP IR # 17
Report Number: 1000-APR-00050
Revision: 0
Confidentiality: Public
Date: 2025 Nov 21
Volume: 1 of 1

Prepared for: [REDACTED]
Prepared by: [REDACTED]
Title: Specialist Engineer, Transmission Planning
Checked by: [REDACTED]
Title: Senior Engineer, Transmission Planning
Reviewed by: [REDACTED]
Title: Technical Strategic Principle, Transmission Planning

Related Facilities: TAY, 1L377, 1L367
Additional Metadata: Transmission Planning 2025-058
Filing Subcode 1350

Revisions

Revision	Date	Description
0	2025 Nov	Initial release

Disclaimer of Warranty, Limitation of Liability

This report was prepared solely for internal purposes. All parties other than BC Hydro are third parties.

BC Hydro does not represent, guarantee or warrant to any third party, either expressly or by implication:

any information, product or process disclosed, described or recommended in this report.

BC Hydro does not accept any liability of any kind arising in any way out of the use by a third party of any information, product or process disclosed, described or recommended in this report, nor does BC Hydro accept any liability arising out of reliance by a third party upon any information, statements or recommendations contained in this report. Should third parties use or rely on any information, product or process disclosed, described or recommended in this report, they do so entirely at their own risk.

This report was prepared by the British Columbia Hydro And Power Authority ("BCH") or, as the case may be, on behalf of BCH by persons or entities including, without limitation, persons or entities who are or were employees, agents, consultants, contractors, subcontractors, professional advisers or representatives of, or to, BCH (individually and collectively, "BCH Personnel").

This report is to be read in the context of the methodology, procedures and techniques used, BCH's or BCH's Personnel's assumptions, and the circumstances and constraints under which BCH's mandate to prepare this report was performed. This report is written solely for the purpose expressly stated in this report, and for the sole and exclusive benefit of the person or entity who directly engaged BCH to prepare this report. Accordingly, this report is suitable only for such purpose, and is subject to any changes arising after the date of this report. This report is meant to be read as a whole, and accordingly no section or part of it should be read or relied upon out of context.

Unless otherwise expressly agreed by BCH:

- (a) any assumption, data or information (whether embodied in tangible or electronic form) supplied by, or gathered from, any source (including, without limitation, any consultant, contractor or subcontractor, testing laboratory and equipment suppliers, etc.) upon which BCH's opinion or conclusion as set out in this report is based (individually and collectively, "Information") has not been verified by BCH or BCH's Personnel; BCH makes no representation as to its accuracy or completeness and disclaims all liability with respect to the Information;
- (b) except as expressly set out in this report, all terms, conditions, warranties, representations and statements (whether express, implied, written, oral, collateral, statutory or otherwise) are excluded to the maximum extent permitted by law and, to the extent they cannot be excluded, BCH disclaims all liability in relation to them to the maximum extent permitted by law;
- (c) BCH does not represent or warrant the accuracy, completeness, merchantability, fitness for purpose or usefulness of this report, or any information contained in this report, for use or consideration by any person or entity. In addition, BCH does not accept any liability arising out of reliance by a person or entity on this report, or any information contained in this report, or for any errors or omissions in this report. Any use, reliance or publication by any person or entity of this report or any part of it is at their own risk; and
- (d) In no event will BCH or BCH's Personnel be liable to any recipient of this report for any damage, loss, cost, expense, injury or other liability that arises out of or in connection with this report including, without limitation, any indirect, special, incidental, punitive or consequential loss, liability or damage of any kind.

Copyright Notice

Copyright and all other intellectual property rights in, and to, this report are the property of, and are expressly reserved to, BCH. Without the prior written approval of BCH, no part of this report may be reproduced, used or distributed in any manner or form whatsoever.

Contributors

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

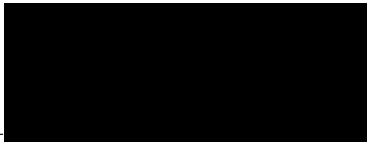
Section:

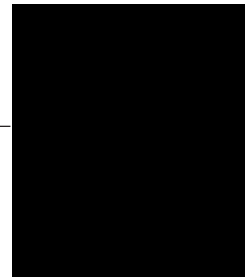
Entire report
except listed
below

Contributed by:

Discipline:

Transmission Planning


Specialist Engineer, Transmission
Planning



Section:

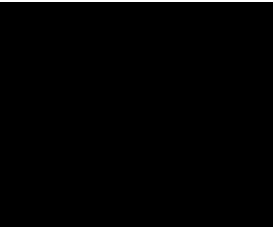
5.2, 5.3

Contributed by:

Discipline:

Stations Planning


Specialist Engineer, Station Plannin



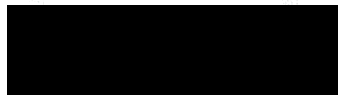
Section:

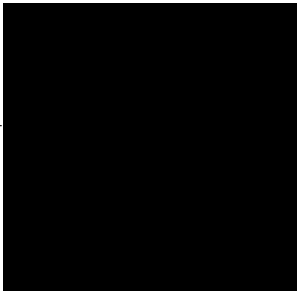
5.4

Contributed by:

Discipline:

Transmission Line Engineering


Senior Engineer, Transmission Line
Engineering



5. Anti-islanding protection is required for the [REDACTED] and shall be configured in the manner that does not compromise the required ride-through performance.
6. [REDACTED] would be islanded with the Transmission Voltage Customer (TVC) load in the event of no-fault opening 1L377 at TAY or 1L377 fault. A Direct Transfer Trip (DTT) protection scheme is required to isolate the [REDACTED] at the IC's entrance circuit breaker to avoid potential islanding operations with the existing and future loads.
7. 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, per BC Hydro's TIR Section 6.4.2.
8. The "STATCOM option" for the proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. It is understood that, due to inherent limitation, type-3 WTGs with "STATCOM option" enabled can provide only partial reactive capability when the turbine is at standstill.
9. 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 interconnection studies.

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

Executive Summary	vi
1 Introduction	1
2 Purpose and Scopes of Study	3
3 Standard and Criteria	4
4 Assumptions and Conditions	5
5 System Studies and Results	6
5.1 Power Flow Study Results	6
5.1.1 Thermal Overload Analysis	6
5.1.2 Steady-State Voltage Analysis	7
5.1.3 Reactive Power Capability Evaluation	7
5.1.4 Anti-Islanding Requirements	7
5.1.5 Other Performance Requirements	8
5.2 Fault Analysis	8
5.3 Stations Requirements	8
6 Cost Estimate and Schedule	9
7 Conclusions	10

Appendices

Appendix A	Schematic Diagram of the IC's Project
Appendix B	Power Flow Study Results

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
GMS	Gordan M. Shrum
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

Error! Reference source not found. 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)	Line Tap on 1L377	
IC's Proposed COD	5th February 2031	
Type of Interconnection Service	NRIS <input checked="" type="checkbox"/>	ERIS <input type="checkbox"/>
Maximum Power Injection (MW)	149.1 MW (Summer)	149.1 MW (Winter)
Number of Generator Units	26 x 5.9 MW WTGs	
Plant Fuel	Wind	

[REDACTED] the interconnection customer (IC), requests to interconnect its [REDACTED] 2025 CEAP IR # 17) to the BC Hydro system. The Project has twenty-six (26) [REDACTED] type-3 wind turbine generators, adding a total capacity of 153.4 MW with a maximum power injection of 149.1 MW into the BC Hydro system at the Point of Interconnection (POI). The proposed POI is a 138 kV tap structure on the BC Hydro's transmission line 1L377, located at 18.5 km from BC Hydro's Taylor Substation (TAY). The IC's project will be connected to the POI via a new 22.55 km customer-built 138 kV line.

Figure 1-1 shows the Peace region 138/230/500 kV transmission system diagram including IC's wind project (P17) interconnection. The Peace Region transmission system consists of 230 kV and 138 kV transmission infrastructures supplied from Gordan M. Shrum Generation Station (GMS) and Southbank (SBK) substations, which are the major source of supply to the Peace Region transmission system. Wind power projects such as Bear Mountain Wind, Dokie Wind, Quality Wind, Meikle Wind, Moose Lake Wind, Quality Wind, and Zonnebeke Wind, have been successfully integrated into the Peace Region transmission system.

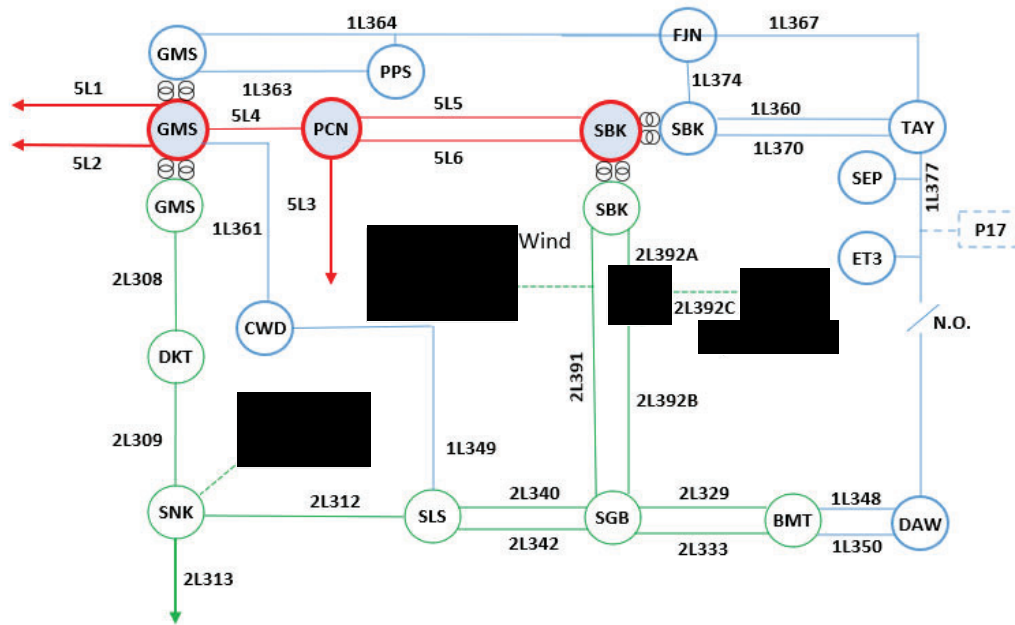


Figure 1-1: Peace Region 138/230/500 kV Transmission System Single Line Diagram.

In addition to the existing generators, there are three future generating projects with higher queue priority in the Peace region. Two of them — [redacted] wind and [redacted] with installed capacity of 200 MW each are successful projects from the 2024 CEAP. Moreover, one non-CEAP wind farm with 56 MW installed capacity will also be added in the Peace region. The three wind farms and the connections are shown in Figure 1-1.

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 generations, transmission facilities, and loads in addition to the subject interconnection project in this study. Applicable seasonal conditions and the appropriate study years for the study planning horizon are also incorporated. Additional assumptions are listed as follows.

- 1) The 2024 Distribution Substation Load Forecast, 2025 Transmission Voltage Customer (TVC) Load Forecast and 2025 System Peak Forecast are used.
- 2) September 2024 Base Resource Plan.
- 3) Two successful projects from the 2024 CEAP, [REDACTED] and [REDACTED] with installed capacity of 200 MW each, are considered in this study. [REDACTED] will be in service on September 30, 2031, and [REDACTED] will be in service on October 1, 2030.
- 4) A future 56 MW wind generation interconnection in the Peace region will be in service on October 31, 2028.
- 5) Fort St. John Transmission Reinforcement project will be in-service in October 2029 when the McMahon Cogeneration Plant (MCM) EPA is expected to be terminated as planned. This project builds a new 138 kV transmission line from SBK to TAY substation.
- 6) All BCH TVC loads by October 14, 2025, with its associated system reinforcement are modeled in this study.
- 7) 1L377 normally open between PLD and ET3.

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/31LS/31HS system conditions. These base cases were prepared based on factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system.

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

5.1.1 Thermal Overload Analysis

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

Table 5-1: Thermal Overload Concerns and Proposed Solutions

Equipment subject to overloads	Conditions observed	Contingencies that result in overloads	Solution Proposed
Under system normal conditions			
1L377 (TAY – P17 POI)	LS	System Normal	Thermal upgrade of 1L377 from TAY to P17 POI with an ampacity of 710 amperes minimum continuous summer rating
Under contingencies			
1L367	LS	P2.3: TAY 1CB31 internal breaker fault	A new Generation Shedding RAS to trip [REDACTED] at IC’s site station.

In addition, the interconnection of [REDACTED] exacerbates the existing thermal overloads on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies of loss of one of the 500 kV lines 5L3, 5L4, or 5L7. These existing

overloads are currently mitigated by the G.M. Shrum Area Gen Shedding remedial action scheme (RAS). The [REDACTED] is required to participate in the existing GMS Area Gen Shedding RAS and details of RAS will be studied under System Impact Study (SIS) stage.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the steady-state voltage performance under system normal (P0) and single contingencies (P1 & P2) are acceptable for all the three scenarios (31LS, 31HS, 31HW).

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 PSS/E power flow data submitted by the IC, the proposed [REDACTED] would be capable of meeting 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 load forms.

[REDACTED] would be islanded with the Transmission Voltage Customer (TVC) loads in the event of no-fault opening 1L377 at TAY or 1L377 fault. A Direct Transfer Trip (DTT) protection scheme is required to isolate the [REDACTED] at the IC's entrance circuit breaker to avoid potential islanding operations with the existing and future loads.

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] Project. 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 Feasibility Study is based upon the latest BC Hydro system model, which includes the generating facility information and associated impedance data provided by the IC. A more detailed study will be performed at the System Impact Study stage if needed.

5.3 Stations Requirements

The POI of [REDACTED] 153 MW is a 138 kV tap connection on 1L377. No station work is required.

5.4 Transmission Line Requirements

At the POI, BCH will design and build the tap on 1L377 that will include a tap structure and up to three switch structures. A 152 kV rated disconnect switch will be installed to isolate the IC's facilities from the BCH system. Up to two 152 kV rated disconnect switches will be installed to isolate the trunk circuit on both sides. Additional Right-of-Way (ROW) may be required to accommodate the tap.

Thermal upgrade the overhead circuit 1L377 (TAY – P17 tap) from existing 575 Amps (30°C ambient summer Temperature) to required 710 Amps by changing from the existing “Merlin” and “Linnet” ACSR to new “Goose” ACSR (at 90°C conductor temperature, 40°C ambient summer Temperature) is required. Structure replacements may be 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, a new tap structure at the 138 kV line 1L377 with tap connection is acceptable to interconnect the customer's generating project to the BCH system.
2. The connection of the [REDACTED] causes thermal overload on the 138 kV transmission line 1L377 between TAY and P17 POI during light load periods under system normal conditions. To mitigate this, a thermal upgrade of approximately 18.5 km of the 1L377 line section between TAY and P17 POI is required, with a minimum summer continuous ampacity rating of 710 amperes.
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. 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. Thermal overload is identified on the line 1L367 under single contingency TAY 1CB31 internal breaker fault (P2.3). A new generation shedding RAS is required to trip IC's wind generators at the IC's entrance circuit breaker and mitigate the potential thermal overloads.
5. Anti-islanding protection is required for the [REDACTED] and shall be configured in the manner that does not compromise the required ride-through performance.
6. [REDACTED] would be islanded with the TVC loads in the event of no-fault opening 1L377 at TAY or 1L377 fault. A Direct Transfer Trip protection scheme is required to isolate the [REDACTED] at the

IC's entrance circuit breaker to avoid potential islanding operations with the existing and future loads.

7. 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, per BC Hydro's TIR Section 6.4.2.
8. The "STATCOM option" for the proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. It is understood that, due to inherent limitation, type-3 WTGs with "STATCOM option" enabled can provide only partial reactive capability when the turbine is at standstill.
9. Fast Frequency Response, also known as Virtual Inertia Control 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 interconnection studies.

Appendix A

Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [REDACTED]

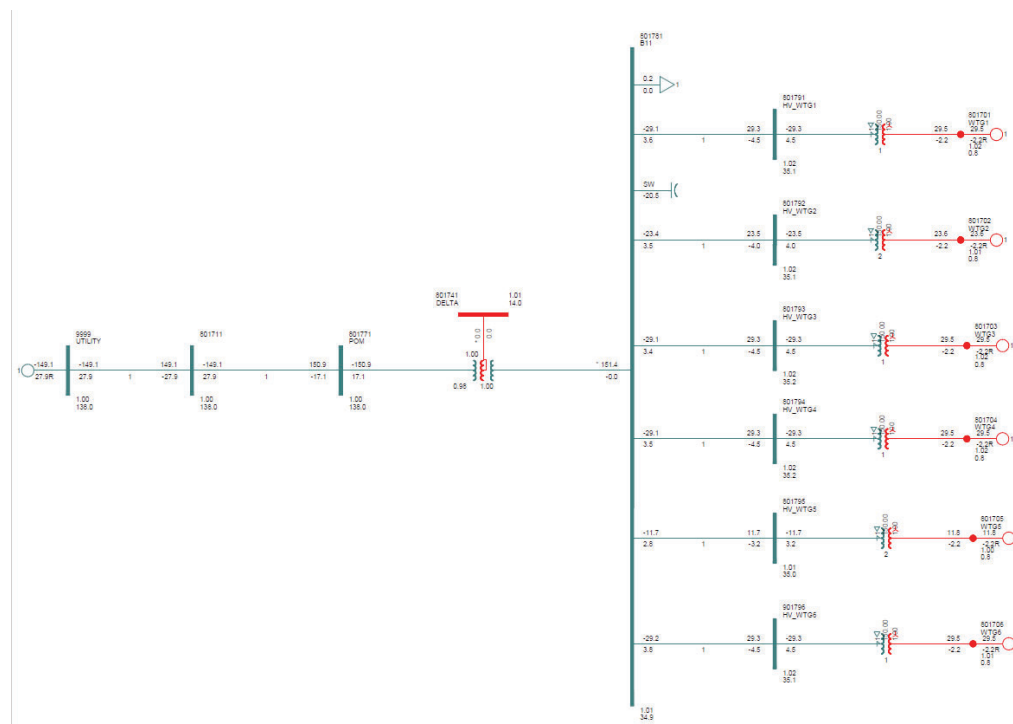


Figure A-1: [REDACTED] Plant Schematic Diagram.

Appendix B

Power Flow Study Results

Base Scenario (31HW/31HS/31LS)

Table B-1: Thermal Overload Study Results

Case	IC's Generator Output (MW)	Contingency Identified		Branch Loading ((% of its seasonal normal MVA rating))					
		Cate-gory	Description	1L377.ET3 SEP 377P- P17 POI	1L377.SEP TAY-SEP 377P	1L370/1L360 TAY-SBK	1L374 FJN-SBK	1L367.TAY TAY- SLO367P	1L367.SLO SLO 367P- FJN
Winter rating in MVA				171.6	171.6	171.1	169.9	169.9	169.9
31hw	Max	P0	System Normal	126 74%	111 63%	27 16%	65 38%	64 37%	60 35%
		P1	1L360/1L370	126 74%	111 63%	40 23%	69 41%	66 39%	63 37%
		P1	1L374	126 74%	111 63%	45 26%	NA	117 69%	111 66%
		P1	1L367	126 74%	111 63%	46 26%	114 67%	NA	NA
		P2	TAY_1CB31	125 73%	109 64%	NA	NA	107 63%	104 61%
Summer rating in MVA				137.4	137.4	139.4	137.9	135	135
31hs	Max	P0	System Normal	127 92%	111 80%	24 17%	39 28%	52 38%	49 36%
		P1	1L360/1L370	127 92%	111 80%	37 26%	40 29%	58 43%	55 41%
		P1	1L374	127 92%	111 80%	18 13%	NA	90 65%	87 63%
		P1	1L367	127 92%	111 80%	45 32%	77 56%	NA	NA
		P2	TAY_1CB31	126 92%	110 80%	NA	NA	108 80%	105 78%
Summer rating in MVA				137.4	137.4	139.4	137.9	135	135
31ls	Max	P0	System Normal	155 113%	145 106%	35 25%	23 16%	60 44%	58 43%
		P1	1L360/1L370	155 113%	145 106%	54 39%	25 18%	74 55%	72 53%
		P1	1L374	155 113%	145 106%	35 24%	NA	73 54%	71 52%
		P1	1L367	155 113%	145 106%	64 46%	49 49%	NA	NA
		P2	TAY_1CB31	155 113%	145 106%	NA	NA	144 107%	142 106%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output (MW)	Contingency		Bus Voltage (PU)		
		Cate.	Description	FJN 138	TAY 138	SBK138
31hw	Max	P0	System Normal	1.007	1.009	1.020
		P1	1L367	1.003	1.010	1.019
		P1	1L374	0.999	1.004	1.022
31hs	Max	P0	System Normal	1.003	1.004	1.011
		P1	1L367	1.002	1.004	1.011
		P1	1L374	1.004	1.007	1.017
31ls	Max	P0	System Normal	1.007	1.008	1.012
		P1	1L367	1.005	1.007	1.011
		P1	1L374	0.999	1.005	1.013