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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #70 – [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 $11.2 M.

Major Scope of Work Identified:

- Supply and install one 138 kV dead-end pole tap structure on line 1L251
- Supply and install up to three BC Hydro 152 kV disconnect switches and steel pole structures on line 1L251
- Acquire additional Right-of-Way
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 12 months of construction is considered
- Execution of early Engineering and Procurement Agreement
- No construction during winter season
- Impact Benefit Agreements with First Nations are not considered

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 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_IR70_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 70

Prepared for: [redacted]

Prepared by: [redacted]

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Accepted by: [redacted]

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300-APR-00045
2025 Nov 21

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Reviewed by:	[redacted]
Title:	Principal Engineer, Transmission Planning
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Revision	Date	Description
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5.4 — Transmission Lines Engineering

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Sr. Engineer, Transmission Lines Engineering

Executive Summary

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] 2025 CEAP IR # 70 - to the BC Hydro (BCH) system. [redacted] includes thirty (30) [redacted] type 3 wind turbine generators, adding a maximum power injection of 198.6 MW into the BCH system at the proposed Point of Interconnection (POI). The proposed POI is on the radially connected 138 kV transmission line 1L251, about 71.2 km from Nicola Substation (NIC). The IC's station is interconnected to the POI via a 9.9 km, 138 kV customer-owned transmission line. The IC's total rated plant capacity is 204 MW and its proposed commercial operation date (COD) is October 1, 2029.

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

1. A transmission tap connection on 1L251 proposed by the IC is acceptable to interconnect the customer's generating project to the BCH system.

2. The connection of [redacted] [redacted] [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions and various system contingencies.

3. [redacted] is not allowed to operate in an island with BC Hydro loads. An Anti-islanding transfer trip scheme is required to isolate the wind generating facility to avoid potential islanding operations with BC Hydro loads.

4. The [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output 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.

5. The Reactive Power at Standstill 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.

6. 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.

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Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
D	Delta
ERIS	Energy Resource Interconnection Service
FBC	Fortis BC
HS	Heavy Summer
HW	Heavy Winter
IBR	Inverter Based Resource
IC	Interconnection Customer
IR	Interconnection Request
LS	Light Summer
NERC	North American Electric Reliability Corporation
NIC	Nicola Substation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
OOS	Out of Service
POI	Point of Interconnection
PU	Per Unit
SC	Series Capacitor
SSI	Sub-Synchronous Interaction
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
TVC	Transmission Voltage Customer
VIC	Virtual Inertia Control
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator
YG	Solidly Grounded Wye
YZG	Impedance Grounded Wye

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)	A Line Tap on 1L251, at 71.2 km from Nicola Substation	
IC's Proposed COD	1st October 2029	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	198.6 (Summer)	198.6 (Winter)
Number of Turbines	30 x 6.8 MW WTGs	
Plant Fuel	Wind	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] ([redacted]) - 2025 CEAP IR # 70 - to the BC Hydro (BCH) system. [redacted] includes thirty (30) wind turbine generators with a total rated capacity of 204 MW and a maximum power injection of 198.6 MW into the BCH system at the proposed Point of Interconnection (POI). The proposed POI is on the radially connected 138 kV transmission line 1L251, approximately 71.2 km from Nicola Substation (NIC). The IC's proposed commercial operation date (COD) is October 1, 2029.

In the [redacted], there are 30 [redacted] type 3 wind turbines, each rated at 7.7 MVA / 6.8 MW, 0.95 kV. Each wind turbine is connected to a 7.8 MVA, 0.95/34.5 kV YG/D transformer. The total power from all turbines is collected via eight 34.5 kV feeders, four connected to one 34.5 kV bus and four connected to a second 34.5 kV bus at the IC's substation, which is then stepped up to 138 kV via two 250 MVA, 34.5/138 kV YZG/YG main transformers, one connected to each 34.5 kV bus. The IC substation is connected to the 1L251 tap point by a 9.9 km 138 kV customer owned transmission line. Refer to Appendix A for power flow study modeling of the project.

Figure 1-1 show the Nicola-Highland-Savona system that the [redacted] is connected to. There are four third-party owned substations supplied by

1L251 – three TVC customers' substations, Similco (SCO) and Copper Mountain Mine (CUM), and Kingvale (KPS) pump station; and one distribution substation, Princeton (PRI) substation, normally supplied by the BC Hydro system.

1L251 is supplied by Nicola Substation (NIC). NIC is a major BCH transmission system substation with two 500/230 kV transformers and two 230/138 kV transformers. An additional 230/138 kV transformer will be added to NIC in March 2026. NIC supplies the local area through three 138 kV transmission lines 1L243 NIC-Highland (HLD), 1L244 NIC-Westbank (WBK), and 1L251 NIC-SCO.

There are several high-queued generator and load interconnection projects and their associated network upgrades in the study area. The relevant network upgrades being planned in the study region are included in Section 4 "Assumptions and Conditions".

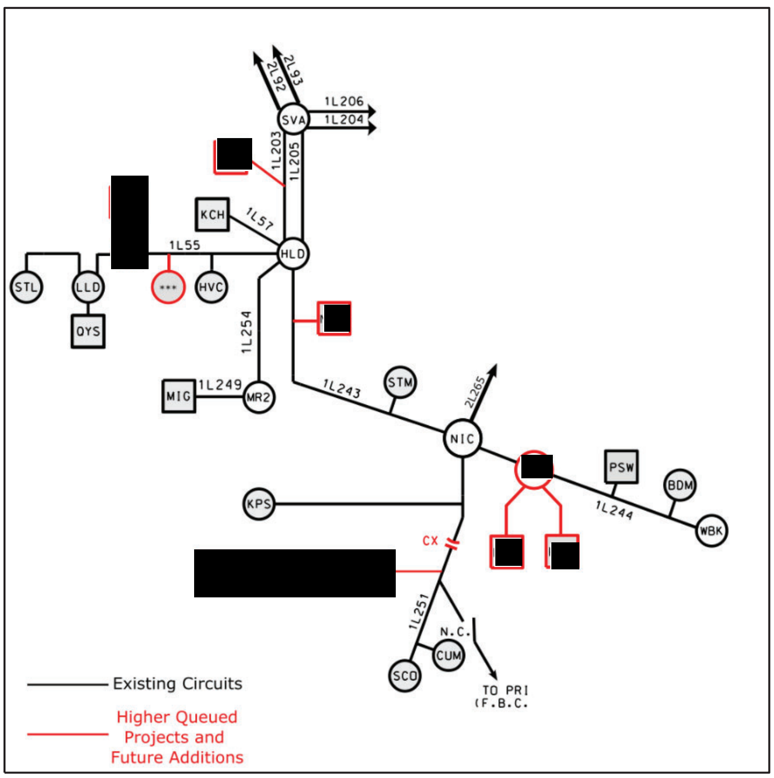

Figure 1-1: 2029/30 Nicola-Highland Region 138 kV Transmission System Diagram

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BC Hydro system based on power flow and short circuit analysis in accordance with BCH's Open Access Transmission Tariff (OATT) and produces the estimated cost of required Network Upgrades and the implementation schedule.

Per OATT, the Feasibility Study is performed individually for each of the participating projects in the CEAP process and focuses specifically on the BC Hydro regional transmission system where the proposed generating project is connected and affects.

This is a "limited scope" study which is restricted to power flow studies of P0, P1 and P2 planning events as defined in TPL-001-4 and short circuit analysis. The study does not address other technical aspects such as transient stability and switching transients and impact of multiple contingencies. These subjects will be addressed in subsequent System Impact Study if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BC Hydro would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed generator project proceeds further.

Please note that, due to the compressed study timeline for CEAP 2025 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 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.

- The regional generation is dispatched in the patterns that most stress the transmission system in the study area. In these patterns, the regional generations are typically set to their maximum power outputs unless otherwise specified.
- The third NIC 230/138 kV transformer (T7), required to interconnect a higher priority queued load project, is scheduled to enter service in March 2026 as planned and has been included in the base cases of this study.
- 1L251 series capacitor (SC) project is included in the study base cases, which is required by a higher-queued load increase project in the 1L251 system. The proposed SC is to be installed between KPS and the PRI tap with 50% compensation provided for 1L251.
- 1L251 (SC – PRI) line rating will be upgraded by December 2026 as planned, which is required by a higher queued load increase project.
- Higher queued transmission generator IR's surrounding the study area are included 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 studies have been conducted with the focus on the 2035 light summer (LS) system condition, taking into considerations of factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system. The 2030 heavy winter (HW) and 2030 heavy summer (HS) cases are also checked to capture any performance violations under high load conditions.

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 Branch Loading Analysis

Appendix B shows a summary of branch loading analysis under system normal and single contingencies (P1) for various load conditions.

For all the studied load conditions (35LS, 30HS, 30HW), there is no branch overload identified under system normal condition (P0) and selected single contingency conditions (P1).

5.1.2 Steady-State Voltage Analysis

For all the studied load conditions (35LS, 30HS, 30HW), the voltage performance under system normal condition (P0) and selected single contingency conditions (P1) is acceptable. Appendix B shows a summery of steady-state voltage performance under various system conditions and contingencies.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires Inverter-Based Resource (IBR) generators have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output 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.

Furthermore, the BCH TIR requires IBR plants to provide reactive power capability at zero MW output level. The IC shall ensure the wind turbines are equipped with the "STATCOM" function such that they provide reactive power at zero output (such as during turbine standstill).

5.1.4 Anti-Islanding Requirements

[redacted] is not allowed to operate in an island with BC Hydro loads. An Anti-islanding transfer trip scheme is required to isolate the wind generating facility to avoid potential islanding operations with BC Hydro 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]. 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 the [redacted] is on the radially connected 138 kV transmission line 1L251, about 71.2 km from NIC. No station work is required.

5.4 Transmission Line Requirements

The Transmission Lines Engineering upgrade scope is as follows.

- At the POI, approx. 7.12 km from NIC on 1L251, BC Hydro will design and build the tap that may include a non-standard tap structure and up to three non-standard switches and structures, two structures adjacent to the switch structures converted to dead-ends, and a dead-end structure as the demarcation point between BC Hydro and the customer. Up to three 152 kV rated disconnect switches may be installed to isolate/ sectionalize the IC's facilities and BC Hydro's system. Additional right-of-way may be required to accommodate the tap.

6 Cost Estimate and Schedule

The non-binding good faith estimated cost and construction schedule for the network upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

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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. Upon a collaborative decision from the BCH study team, a tap connection on 1L251 proposed by the IC is acceptable to interconnect the customer's generating project to the BCH system.
2. The connection of [redacted] [redacted] [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions and various system contingencies.
3. [redacted] is not allowed to operate in an island with BC Hydro loads. An Anti-islanding transfer trip scheme is required to isolate the wind generating facility to avoid potential islanding operations with BC Hydro loads.
4. The [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output 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.
5. 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.
6. 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
Plant Single Line Diagram Used for Power Flow Study

Figure A-1 shows [redacted] single line diagram used for the power flow study.

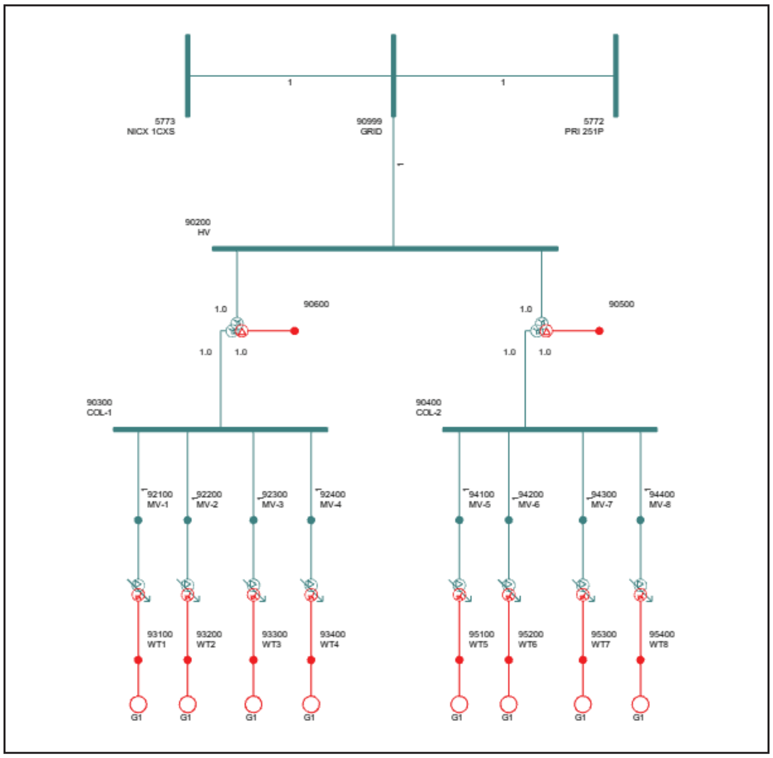

Figure A-1: [redacted] Single Line Diagram for Power Flow Study.

As seen in the diagram, The IC's plant consists of the following major facilities: 30 7.7 MVA, 0.95 kV wind turbines generators, each with an 7.8 MVA, 0.95/34.5 kV step up transformer; 8 – 34.5 kV collector, 4 supplying one 34.5 kV bus and 4 supplying a second 34.5 kV bus; 2 – 250 MVA, 34.5/138 kV main transformers; and a 9.9 km, 138 kV transmission line connecting the plant to the POI in 1L251 NIC-SCO.

Appendix B
Power Flow Study Results

Table B-1: Summary of Branch Loading Analysis Results

Case	IPP's Generator Output	Contingency Identified		Branch Loading		
		Category	Description	NIC_T3	NIC_T5	1L251 (SC-POI)
Winter Rating				1200 MVA	286.8 MVA	188.8 MVA
30HW	204 MW	P0	System Normal	4%	18%	66%
		P1	Loss of [redacted]	4%	7%	N/A
		P1	NIC T2 & NIC T6 OOS[1]	7%	26%	66%
Summer Rating				1200 MVA	286.8 MVA	188.8 MVA
30HS	204 MW	P0	System Normal	12%	14%	68%
		P1	Loss of [redacted]	14%	19%	OOS
		P1	NIC T2 & NIC T6 OOS[1]	22%	19%	68%
35LS	204 MW	P0	System Normal	18%	54%	88%
		P1	Loss of [redacted]	12%	39%	OOS
		P1	NIC T2 & NIC T6 OOS[1]	34%	76%	85%
Note 1: NIC T2 and NIC T6 are in the same protection zone.						

Table B-2: Summary of Steady-State Voltage Study Results

Case	IPP's Generator Output	Contingency		Bus Voltage (PU)		
		Category	Description	NIC_138	POI tap	CUM_138
30HW	204 MW	P0	System Normal	1.02	1.01	1.02
		P1	Loss of [redacted]	1.02	OOS	OOS
		P1	NIC T2 & NIC T6 OOS[1]	1.02	1.01	1.02
30HS	204 MW	P0	System Normal	1.02	1.02	1.02
		P1	Loss of [redacted]	1.02	OOS	OOS
		P1	NIC T2 & NIC T6 OOS[1]	1.02	1.01	1.02
35LS	204 MW	P0	System Normal	1.02	1.02	1.02
		P1	Loss of [redacted]	1.03	OOS	OOS
		P1	NIC T2 & NIC T6 OOS[1]	1.02	1.02	1.02
Note 1: NIC T2 and NIC T6 are in the same protection zone.						