BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #115 – [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 (POI) to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Interconnection Study Costs

The Interconnection Customer is responsible for paying the full cost of all Interconnection Studies in cash. Interconnection Study costs vary depending on the scope, complexity, and other factors such as whether any scope is shared with another Interconnection Customer (not applicable to this Interconnection Feasibility Study). The deposit amounts specified in the OATT are not proxy Interconnection Study costs. If actual Interconnection Study costs exceed the deposit amount, the Interconnection Customer must pay the remaining balance in cash. Please refer to the answer for question no. 53 in the posted Questions & Answers for 2025 Call for Power for typical study cost ranges.

Cost Estimate

Based on the Interconnection Feasibility Study, the non-binding good faith estimated cost (typical accuracy range of +150%/-50%) for Network Upgrades required to interconnect your project is $10.1 M.

Major Scope of Work Identified:

- Add one 287 kV line position and a line terminal to terminate the customer's line with associated equipment including a motor-operated disconnect switch, surge arrester and capacitor voltage transformer at BC Hydro's Bob Quinn substation (BQN)
- Extend 287 kV existing switchyard to facilitate new 287 kV line position
- Add one new 287 kV circuit breaker c/w POW controller and associated disconnect, current

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

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 12 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- No expansion of existing other stations or control buildings to accommodate new equipment
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Expansion of the existing other substation and/or control building may be required leading to increased costs and/or a longer project schedule
- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

Study Limitations and Exclusions

Protection, Control, and Telecommunications

The Interconnection Feasibility Study does not include a detailed review of the protection, control, and telecommunications system requirements specific to your Interconnection Request. Based on a high-level review, we have identified proxy costs for protection, control, and telecom Network Upgrades drawn from comparable interconnection projects with similar scope and complexity; these proxy costs have been included solely for indicative budgeting purposes. The relative interconnection cost determined by the Interconnection Feasibility Study includes a telecommunications component based on an assumed solution to deliver teleprotection and telecontrol circuit requirements necessary for the Interconnection Request. Protection, control, and telecommunications system requirements will be reviewed in detail in the System Impact Study if you are a successful participant of the CEAP and meet applicable requirements.

For Interconnection Feasibility Study purposes, it is assumed that any applicant-proposed works that could obstruct or impair the performance of existing BC Hydro microwave systems or new links from the proposed Interconnection Customer Interconnection Facilities (ICIF) to the BC Hydro microwave system would be

identified and either relocated or repositioned as determined in a System Impact Study if you are a successful participant of the CEAP and meet applicable requirements. Such works may include, but are not limited to, towers, turbines, dams, support structures, panels, surface materials deposited or redistributed, water surface changes, or vegetation.

Generation Shedding/Curtailment Scheme and Electromagnetic Transient (EMT) Studies

The generation shedding/curtailment scheme reviews (e.g., Remedial Action Scheme (RAS), and a direct transfer trip for anti-islanding scheme) and EMT studies are completed in a System Impact Study. The outcomes of these studies may result in additional requirements, which could include Network Upgrades or ICIF. Any costs associated with completion of these studies, and resulting requirements, are not included in the Interconnection Feasibility Study cost estimate.

Revenue Metering

Please note that revenue metering requirements have not been determined with the Interconnection Feasibility Study. As such, any costs associated with revenue metering and other interconnection components are not included in the cost estimate provided above. Once these requirements are defined, costs that are attributable to the Interconnection Customer are to be paid in cash. For more details on revenue metering requirements and responsibilities, please refer to:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/distribution/standards/ds-rmr-complex-revenue-metering.pdf.

Schedule

Based on the Interconnection Feasibility Study, the non-binding good faith estimated in-service date for your Interconnection Request's Network Upgrades is Quarter 3 2033 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

Timely actions required from you to minimize risks to the schedule:

- Submission of additional technical data required for the System Impact Study and Facilities Study
- Submission of any required information or document such as demonstration of Site Control
- Execution of Combined Study Agreement and Standard Generator Interconnection Agreement
- Financial commitments and securities

Since your proposed POI is located within the North Coast Transmission Line Region, the interconnection of your IR has been determined, at this time, to be dependent upon the completion of the North Coast Transmission Line (NCTL) project.

Accordingly, please note the 2025 Call for Power Addendum 5 and revised Specimen EPA specify that the Guaranteed Commercial Operation Date for a project which is dependent upon the completion of NCTL will be October 1, 2033, notwithstanding that the Interconnection Feasibility Study report may indicate an earlier date.

Please note that changes to your IR or delays in data submission or financial commitments may also impact the target in-service date. Please note that changes to your Interconnection Request or delays in data submission or financial commitments may also impact the target in-service date.

If you have any questions, please contact the BC Hydro CEAP team at ceap2025@bchydro.com.

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR115_[redacted]_Feasibility_Study.pdf

BC Hydro
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[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 115

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]

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Reviewed by: [redacted]

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Engineering Team Lead, Transmission Planning

Accepted by: [redacted]

[redacted]

Manager, Transmission Planning

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Revision	Date	Description
0	2025 Nov	Initial release

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Entire report except listed below	Transmission Planning
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Section:	**Discipline:**
5.2, 5.3	Stations Planning
Contributed by:	[redacted] Specialist Engineer, Stations Planning [redacted]

Executive Summary

[redacted], the Interconnection Customer (IC), requests to interconnect its [redacted] project to the BC Hydro system. [redacted] has three (3) units of hydro generators – rated 25 MW each – adding a total capacity of 75 MW. The proposed Point of Interconnection (POI) is on a 287kV line position at the BC Hydro's Bob Quinn (BQN) Substation.

Transmission Planning assessed the impact of interconnecting the proposed generating project to the BC Hydro system and identified the system modifications required to obtain acceptable system performance.

Transmission Planning's study has concluded the transmission interconnection requirements as follows:

1. A new 287 kV line position is required at the BQN substation to enable the interconnection of the [redacted] Project. Work at BQN will include installing a 287 kV circuit breaker, associated disconnect switches, protection and control systems, station service equipment, and other components necessary to build the new line position and terminate the incoming customer's line. To accommodate these facilities, the existing 287 kV switchyard will be expanded within the current property boundaries.

2. The study did not find any thermal overload, voltage performance violation or voltage stability concern under system normal, caused by connection of [redacted].

3. The new hydro generators at [redacted] are required to participate in the existing North Coast generator shedding RAS.

4. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

5. The proposed [redacted] project must meet BC Hydro's reactive power requirements for synchronous generators, as outlined in Section 6.4.2 of the Technical Interconnection Requirements. Specifically, each unit must operate continuously within a power factor range of 0.90 over-excited to 0.95 under-excited, measured at the generator terminals.

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

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.

Note that this is a “limited scope” study which is restricted to only power flow and short circuit analysis in accordance with the BC Hydro Open Access Transmission Tariff (OATT). This Feasibility Study report does not include stability analysis, 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”.

A non-binding good faith cost for required network upgrades and estimated schedule for construction are included in a separate letter to the IC.

Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
FeS	Feasibility Study
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
IPP	Independent Power Producer
MPO	Maximum Power Output
MPT	Main Power Transformer
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

1 Introduction

[redacted], the Interconnection Customer (IC), requests to interconnect its [redacted] Project to the BC Hydro system. [redacted] Project has three (3) Hydro units, adding a total capacity of 75 MW. The proposed Point of Interconnection (POI) is a 287kV line position at the BC Hydro's Bob Quinn (BQN) Substation.

Table 1-1 below summarizes the project reviewed in this Feasibility Study.

Table 1-1: Summary Project Information

Project Name	[redacted]	
Proponent Name	[redacted]	
Point of Interconnection	BQN	
Applicant Proposed COD	August 1, 2033	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	74.5	
Number of Generator Units	3	
Plant Fuel	Hydro	

Figure 1 shows the Bob Quinn region 287/138 kV transmission system diagram. The [redacted] Project connects to the interconnection point at BQN 287 kV via a 20 km long 287 kV transmission line. BQN substation is connected to Skeena (SKA) substation through Treaty Creek (TCT) substation with a 287 kV transmission line 2L102, while SKA substation is further connected to the BC Hydro's North Coast 500kV transmission system. Customer's system topology behind the Point of Interconnection is provided in the Appendix, Figure A-1.

The transmission line between BQN and TCT has a 287 kV series capacitor installed at BQN to increase transfer capability. The continuous facility rating of the BQN series capacitor 2CX1 is 650A (323 MVA).

Figure 1 Bob Quinn region Transmission System Diagram

2 Purpose and Scopes of Study

This Feasibility Study (FeS) 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 FeS 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. An assessment of the incremental effect on the 500kV bulk transmission system is beyond this study scope.

This is a "limited scope" study which is restricted to power flow studies of Categories P0, P1, and P2 planning events as defined in TPL-001-4 Table 1 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 would be addressed in subsequent System Impact Study if the project proceeds further.

In case impact to the adjacent external systems to BC Hydro is observed, such impact would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed interconnection 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, October 7, 2025.

4 Assumptions and Conditions

This Feasibility Study is performed based on the IC's submitted data and information available to BC Hydro on October 14, 2025, for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the plant single line diagram for 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 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:

- Use of the latest August 2025 distribution load forecast, reference system coincident forecast and reference TVC.
- The generation in the study area are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the associated generators are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.
- Planned transmission reinforcement projects in the study area.
  - Prince George to Terrace series Capacitor project to be installed in existing lines 5L61, 5L62 and 5L63.
  - New 500kV lines: 5L64 in PGGT and 5L65& 5L66 (WSN to SKA) in GTTT.
  - Other system reinforcements in the regional system triggered by future load customer interconnections are also included in the study model.

5 System Studies and 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 reinforcement requirement based on steady state performance analysis.

5.1 Power Flow Study Results

Steady-state power flow studies have been conducted with the focus on the light summer system condition, taking into considerations the COD of this Hydro Project (August 1, 2033) and factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system. Since the 34LS basecase is not available, the 33LS basecase is used which should closely represent the 2034 LS basecase. 33HW and 33HS cases were also checked to capture any performance violations over other seasons following the ISD.

The studies are performed under system normal conditions and after critical system contingencies in this area as 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 load conditions (33LS, 33HS, 33HW), no thermal overload is identified under system normal condition (P0) in the region.

However, the series capacitors at Bob Quinn substation are observed to get overloaded when the line 2L374 goes out of service (OOS) – in all the three scenarios (33LS, 33HS, 33HW). This marginal overload – as shown in the Table 5-1 below – can be overcome by utilizing the series capacitor overload capacity of 8hr out of 12hr period and implementing an RAS to run-back one unit from among the three new hydro units in the [redacted] project for extended period of outages.

Additional results for the branch loading study are included in Appendix B, Table B-1.

Table 5-1: Summary of Branch Loading Study Results

Case	Contingency Identified		Branch Loading		
	Category	Description	Branch	Load MVA	Loading%
33LS	P1	2L374 OOS	BQN SC	331.8	102.7
33HS	P1	2L374 OOS	BQN SC	330.2	102.2
33HW	P1	2L374 OOS	BQN SC	329.3	101.9

5.1.2 Steady-State Voltage Analysis

For all the studied load conditions (33HW, 33LS, 33HS), the voltage performance under both system normal (P0) and N-1 contingency conditions (P1 and P2) is within acceptable limits. A summary of the results is provided in Appendix B, Table B-2, for reference.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires IBR generators have the dynamic reactive power capability at a minimum of +/- 33% of its Maximum Power Output (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 for this project, the study finds that the proposed generating project can meet the BC Hydro's reactive capability requirement.

5.1.4 Anti-Islanding Requirements

[redacted] Project 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 project from the grid when an inadvertent island forms with the local loads.

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

To accommodate the new 287 kV transmission line proposed by the IC to inject hydro power produced by the [redacted] project into the BCH POI, Bob Quinn substation (BQN) will need to incorporate changes listed below. The station one-line sketch with the marked additions and changes is provided in the Appendix C, Figure C-1.

Scope of substation work:

- Add one new 287 kV circuit breaker with POW controller and associated disconnect, current transformer.
- Add one-line terminal 2LXXX for [redacted] including a motor-operated disconnect switch, surge arrester and capacitor voltage transformer.
- Expand the existing 287kV switchyard within the current property boundaries to accommodate the above-mentioned facilities.
- Install associated P&C, station service and other equipment in the existing control building.
- Other associated station work.

5.4 Transmission Line Engineering Requirements

No requirements from transmission line engineering have been identified for this project.

6 Cost Estimate and Schedule

The non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

7 Conclusions

[redacted], the Interconnection Customer (IC), requests to interconnect its [redacted] project to the BC Hydro system. [redacted] has three (3) units of hydro generators – rated 25 MW each – adding a total capacity of 75 MW. The proposed Point of Interconnection (POI) is on a 287kV line position at the BC Hydro's Bob Quinn (BQN) Substation.

Transmission Planning assessed the impact of interconnecting the proposed generating project to the BC Hydro system and identified the system modifications required to obtain acceptable system performance.

Transmission Planning's study has concluded the transmission interconnection requirements as follows:

1. A new 287 kV line position is required at the BQN substation to enable the interconnection of the [redacted] Project. Work at BQN will include installing a 287 kV circuit breaker, associated disconnect switches, protection and control systems, station service equipment, and other components necessary to build the new line position and terminate the incoming customer's line. To accommodate these facilities, the existing 287 kV switchyard will be expanded within the current property boundaries.
2. The study did not find any thermal overload, voltage performance violation or voltage stability concern under system normal, caused by connection of [redacted]
3. The new hydro generators at [redacted] are required to participate in the existing North Coast generator shedding RAS.
4. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.
5. Based on the IC-submitted PSS/E model, the proposed [redacted] project meets the reactive capability requirement for synchronous generators.

Appendix A
One-Line Sketch for the [redacted]

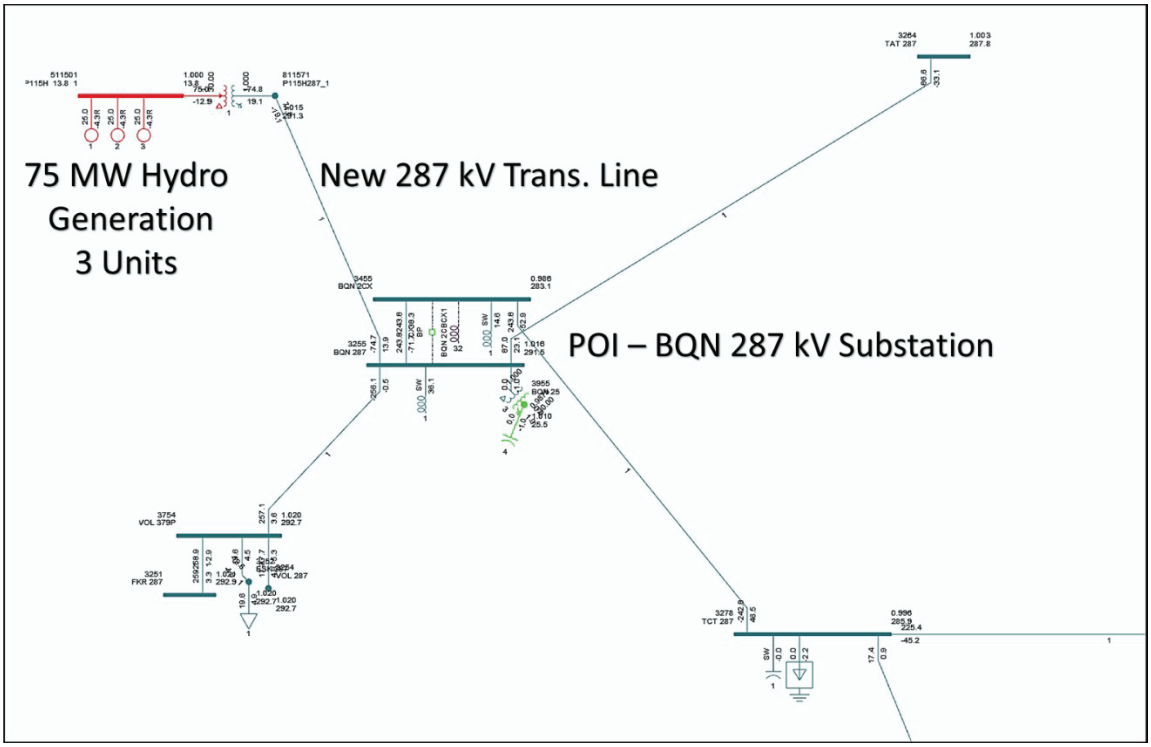

Figure A-1: [redacted] project Single Line Diagram and its interconnection to the BC Hydro POI

Appendix B
Power Flow Study Results

Table B-1: Summary of Branch Loading Study Results

Case	Contingency Identified		Branch Loading		
	Category	Description	Branch	Load MVA	Loading%
33LS	P0	System Normal	SKA T1 SKA T3	138 204	21 30
33HS	P0	System Normal	SKA T1 SKA T3	110 186	16 28
33HW	P0	System Normal	SKA T1 SKA T3	85 172	11 21
33LS	P1	2L374 OOS	BQN SC	**331.8**	**102.7**
	P1	2L99 OOS	SKA T1 SKA T3	116 177	17 26
	P1	5L61 OOS	SKA T1 SKA T3	140 205	21 31
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 with stuck 5CB3), tripping SKA T1, T2 & 5CX1	SKA T3	420	63
	P2/P4	Fault at SKA 5CB23 or (Fault at SKA T2 or T3 with stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	406	60
33HS	P1	2L374 OOS	BQN SC	**330.2**	**102.2**
	P1	2L99 OOS	SKA T1 SKA T3	92 161	14 24
	P1	5L61 OOS	SKA T1 SKA T3	111 189	17 28
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 with stuck 5CB3), tripping SKA T1, T2 & 5CX1	SKA T3	336	50
	P2/P4	Fault at SKA 5CB23 or (Fault at SKA T2 or T3 with stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	318	47
33HW	P1	2L374 OOS	BQN SC	**329.3**	**101.9**
	P1	2L99 OOS	SKA T1 SKA T3	116 177	17 21
	P1	5L61 OOS	SKA T1 SKA T3	87 173	11 21
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 with stuck 5CB3), tripping SKA T1, T2 & 5CX1	SKA T3	262	33
	P2/P4	Fault at SKA 5CB23 or (Fault at SKA T2 or T3 with stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	228	30

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

Case	IPP's Gen Output (MW)	Contingency		Bus Voltage (PU)			
		Cat.	Description	TAT 287	BQN 287	TCT 287	MIN 287
33LS	74.7	P0	System Normal	1.023	1.021	1.006	0.993
		P1	Bypass on BQN Series Capacitor	1.004	1.003	1.006	0.994
			2L374 OOS	-	1.024	1.006	0.993
			2L99 OOS	1.023	1.021	1.006	-
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	1.023	1.021	1.006	0.994
33HS	74.7	P0	System Normal	1.003	1.016	0.996	0.993
		P1	Bypass on BQN Series Capacitor	0.994	1.007	1.006	0.994
			2L374 OOS	-	1.004	0.998	0.993
			2L99 OOS	1.003	1.016	0.996	-
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	1.003	1.016	0.996	0.994
33HW	74.7	P0	System Normal	0.99	1.011	0.99	0.993
		P1	Bypass on BQN Series Capacitor	0.983	1.004	1.033	0.993
			2L374 OOS	-	1.004	0.998	0.993
			2L99 OOS	0.99	1.011	0.99	-
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	0.99	1.011	0.99	0.994

Appendix C
One-Line Sketch for Bob Quinn Substation

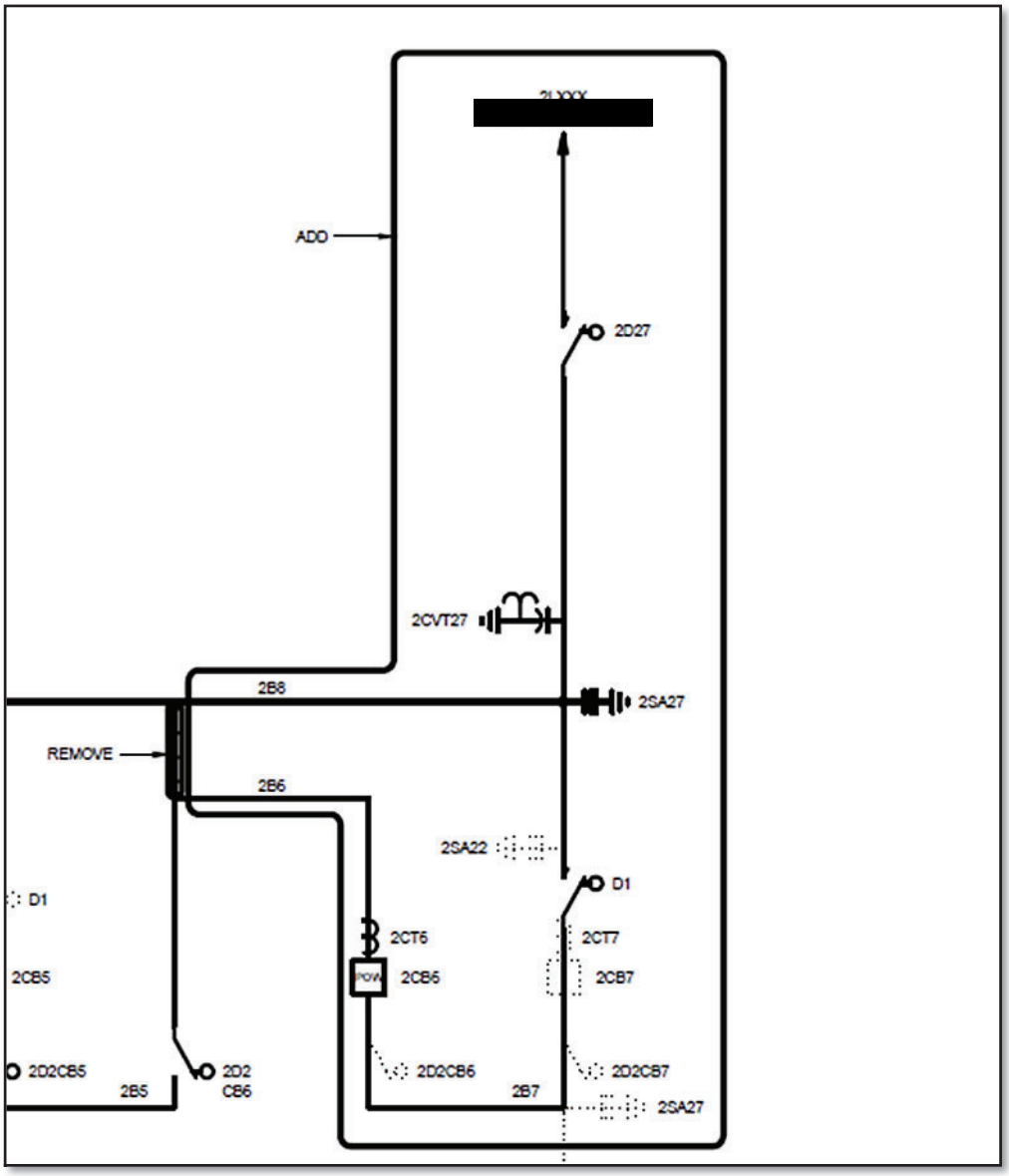

Figure C 1: Stations Planning One-Line Sketch for Bob Quinn substation