NBS-AB-7

PART OF BURNS & McDONNELL

DISTRIBUTED GENERATION INTERCONNECTION SYSTEM IMPACT STUDY

VERMONT ELECTRIC COOPERATIVE

NOVUS BUCK 4999 KW SOLAR PV PROJECT

PROJECT NO. 196616

REVISION 0

JUNE 12, 2026

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Revision History

Revision No.	Date	Updates
0	06/12/2026	Initial Draft
1	07/06/2026	Final Report issued

CONTENTS

APPENDICES

Appendix A - Interconnection application

Appendix B - Steady State Load Flow Results

Appendix C - Time Series analysis Results

Appendix D - Harmonics Screening Results

FIGURES

TABLES

Executive Summary

The Novus Buck Solar Project (“Project”; “Interconnecting Customer”) is a 4999 kW (AC) solar project requesting to interconnect to the Vermont Electric Cooperative (“VEC”; “Company”) Irasburg substation 12.47 kV distribution system. The Project is proposed to be located approximately 7 miles from the Irasburg substation, served by a single power transformer, and connected via the 42-1A grounded-Wye distribution circuit. The power transformer has a nameplate rating of 7.5/9.375 MVA. The net peak load on the 42-1A circuit is 1815 kW. Aggregate DER on the 42-1A circuit and Irasburg substation (including the Project) is 5319.23 kW (approximately).

1898 & Co., a part of Burns & McDonnell, was retained by VEC to perform the System Impact Study (“Study”) for the proposed interconnection of the Project to the VEC Irasburg substation 12.47/7.2 kV distribution system and presents the conclusions of the Study herein. The objective of the Study was to determine adverse system impacts, operating restrictions, and required system upgrades on the VEC distribution system to accommodate interconnection of the Project in accordance with Vermont Public Utility Commission (“PUC”) Rules and other applicable codes and standards. The Study also identified the responsible party for the required system upgrades.

Analyses were performed to understand the adverse system impacts and identify mitigation projects to resolve the issues identified. To identify criteria exceptions attributed to the interconnection of the Project, analyses were performed to compare system performance both with and without the interconnection of the Project. Analyses included load flow, short circuit, voltage flicker, and unintentional islanding. The steady state analyses were performed using Milsoft WindMil® (“WindMil”) and the Long-Term Dynamics module of the CYME Power Engineering software suite (“CYME”). For the purposes of the Study, VEC provided an existing distribution planning model, and load allocation was performed using historical data from the Irasburg substation, 42-1A and 42-3A circuits. The steady state analysis was conducted with the Project assuming unity power factor.

To serve the Customer, a three-phase primary overhead line must be extended to the Project location. Additionally, the company will install a three-phase recloser upstream from the Project and at the Project PCC. The Project will have a three-phase pole-mounted primary metering package or other VEC-approved metering package that accounts for transformer loss compensation installed upstream of (or on) a new customer riser pole. All electrical facilities beyond this point will be installed, owned, and operated by the Project.

Following the required upgrades to facilitate the Project interconnection and the recommended mitigations, no thermal criteria violations during minimum or peak load conditions were observed on conductors or equipment due to the interconnection of the Project. After reviewing the Project addition, there are no adverse effects on the voltage for the system. No voltage violations were observed.

During the time series analysis, the CYME Long-Term Dynamics Analysis module was utilized to perform analysis that assists in understanding the impacts of load variations, irradiance variations, wind fluctuations, and ancillary market service signals on equipment such as regulators, load tap changers, and capacitor switching. Control coordination and voltage control settings for regulators, tap changers, shunt caps and their sensitivities were monitored during this analysis. The time series analyses were conducted over a two-hour period with one-second time intervals. The intent was to determine the frequency and magnitude of the voltage changes caused by a varying output from the Project. No flicker violations against the IEEE 1453-2022 standard were observed in all study scenarios, prior to or after the interconnection of the Project.

A short circuit analysis was performed using WindMil to evaluate the incremental impact of the Project on system protection and adequacy of existing circuit breakers, other fault current interrupting devices, and related equipment on the Company EPS. The results indicate fault current contribution exceeding 10% at the project PCC when the project is online. The Project was evaluated using the Sandia National Laboratories risk-of-islanding screening tool. Results of the screening indicate that the Project presents a non-negligible risk of unintentional islanding; therefore, further evaluation is recommended.

Harmonics screening was performed to estimate the incremental impact of the proposed Project on voltage distortion at the Point of Common Coupling ("PCC") of the proposed Project under normal feeder configuration. The assessment used the ENA EREC G5/5[1] Stage 2C methodology as a calculation framework, with final voltage distortion results evaluated against IEEE 519-2022[2] planning criteria. IEEE 1547-2018[3] current distortion requirements were also reviewed as supporting reference criteria for inverter harmonic emissions.

Complete measured PCC background harmonic data for harmonic orders 2 through 50 was not available. Therefore, consistent with the agreed screening approach, background harmonic voltage distortion was assumed to be 75% of the applicable IEEE 519 individual harmonic voltage planning level for each order. Available area background measurements indicate that existing harmonic voltage distortion on the feeder may already be elevated, and in some cases may exceed the selected planning criteria. The harmonic input data for the analysis is based on Test Case 1 from the inverter test report *"250KW-600 Test Data – IEEE 1547.1-2020 Section 5.12 Current Distortion (TRD)"*, which represents the selected worst-case harmonic current injection condition for this study and aggregated at the PCC using IEC power-law summation methods. The results provide an order-by-order evaluation of post-project harmonic distortion relative to applicable limits.

[1] Energy Networks Association, Engineering Recommendation G5 Issue 5 (EREC G5/5), Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom, June 2020.
[2] IEEE Std 519-2022, IEEE Standard for Harmonic Control in Electric Power Systems, Institute of Electrical and Electronics Engineers, 2022.
[3] IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, Institute of Electrical and Electronics Engineers, 2018.

The screening results indicate that the Project does not meet the harmonics criteria under the assumed background conditions. The controlling individual harmonic is the 7th harmonic, with a calculated post-project voltage distortion of approximately 4.02% compared with the IEEE 519 individual harmonic voltage distortion planning limit of 3.0%. As the screening results do not demonstrate harmonic compliance, a detailed harmonic study is recommended prior to final interconnection approval or determination of any required mitigation measure.

In summary, the System Impact Study found that the interconnection of the Project should have no adverse impacts on the Area EPS safety and reliability, provided the following recommended operating conditions and system modifications to the Company's EPS are implemented:

Recommended System Improvements

1. Install approximately 18,300 feet of primary overhead 556 ACSR conductor. Poles will need to be installed and replaced as necessary to meet the Company standards for the primary overhead three-phase configuration.
    a. Reconductor approximately 17,100 feet of existing three-phase overhead 2 ACSR and 4/0 ACSR conductor to three-phase 556 ACSR conductor from Span_48630 to Span_10439.
    b. Upgrade approximately 1,000 feet single-phase overhead 2 ASCR conductor to three-phase overhead 556 ACSR conductor from Span_17410 to Span_47714.
    c. Install a line extension of approximately 200 feet of three-phase overhead 556 ACSR conductor from Span_47714 to the Project PCC recloser.
2. Install a set of three single-phase 328-Amp, 250 kVA line regulators at or near Span_48592 to maintain voltages within ANSI C84.1 limits.
3. Decrease the voltage setpoint of the existing substation regulator from 123.5 V to 122 V to maintain voltages within ANSI C84.1 limits.
4. Install two three-phase 600 kVAR switched capacitor banks, each on feeders 42-1A and 42-3A, at or near Span_48484 and Span_39839, respectively.
5. Fuses for the line extension will be reviewed and evaluated by VEC.
6. The Company will install a three-phase recloser upstream from the Project and at the Project PCC.
7. The Project will have a three-phase pole-mounted primary metering package or other VEC approved metering package that accounts for transformer loss compensation installed upstream of (or on) a new customer riser pole.
8. Installation of real-time (SCADA) communications from the Project to VEC.
9. The Company will perform a detailed harmonic study before final interconnection approval or final determination of harmonic mitigation requirements.

Interconnection Customer Responsibility

The following is a summary of all items that were determined to be the responsibility of the interconnecting Project.

1. Procuring and installing all Customer-owned components associated with the Project.
2. All costs associated with system upgrades required to interconnect the Project as described in Recommended System Improvements, unless specifically noted as the responsibility of the Company.

3. Providing necessary communications for data reporting.
4. Providing inverter model information and specifications and ensuring compliance with UL 1741 SA and IEEE 1547-2018 standards.
5. Providing under- and over-frequency and voltage settings for the inverters prior to the Facilities Study. Inverter settings shall be in compliance with the ISO-NE SRD, IEEE 1547-2018 standard, the NPCC Directory 12 Figure 1 Curve requirements for the Eastern Interconnection.
6. Ensuring that the Project complies with ISO-NE SRD, UL 1741 SA, IEEE 1547-2018, and the Vermont Electric Cooperative Interconnection Guidelines at all times.

If the recommended system modifications are made to the 42-1A circuit and the Project, the Project should not have a negative impact on system thermal capability and voltage of the Area EPS, under normal steady state and dynamic operating conditions.

If an event occurs with a recorded overvoltage at the PCC exceeding ANSI C84.1 Range A limitations and/or any reported damage to customer equipment, the Company reserves the right to disconnect the Project from the EPS. The interconnecting customer will be responsible for all associated claims and for mitigation to prevent recurrence.

The Company reserves the right to disconnect the Project during times of temporary load transfers or if abnormal conditions develop.

This Study has been completed using information provided by the Interconnecting Customer, Novus Buck Solar LLC, who submitted an Interconnection Application Form dated November 25, 2025.

In accordance with the Vermont Public Utility Commission Rule 5.500, the Company has completed a System Impact Study to determine the scope of the required modifications to its EPS to provide the requested interconnection service.

The conclusions and recommendations specified herein are exclusive to the Project and are based upon the information submitted by the Interconnecting Customer at the time the Interconnection Application ("IA") was submitted and 1898 & Co.'s understanding of the VEC system at the time of study. Any subsequent design changes made by the Interconnecting Customer without 1898 & Co.'s and/or VEC's knowledge, review, and/or approval may render the findings of this report null and void.

1.0 Introduction

1.1 Project Background

The Novus Buck Solar Project ("Project"; "Interconnection Customer") is proposed at a size of 4999 kW (AC) PV and is requesting to interconnect to the Vermont Electric Cooperative ("VEC") Irasburg substation and the 42-1A 12.47/7.20 kV grounded-wye distribution circuit. The Project is proposed to be located approximately 7 miles from the Irasburg substation, served by a single power transformer, and connected via the 42-1A grounded-Wye distribution circuit. The power transformer has a nameplate rating of 7.5/9.375 MVA. The net peak load on the 42-1A circuit is 1815 kW. Aggregate DER on the 42-1A circuit and Irasburg substation (including the Project) is 5319.23 kW (approximately).

1.2 Study Scope

1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (hereinafter called "1898 & Co."), was retained by VEC to complete a System Impact Study that will provide the Company with an understanding of any adverse impacts or operating restrictions related to the interconnection of the Project to the Irasburg substation and 42-1A 12.47/7.20 kV grounded-wye distribution circuit.

1.3 Objectives

The overall objective of the study is to identify adverse system impacts, operating restrictions, and required system upgrades on the VEC distribution system to accommodate interconnection of the Project in accordance with Vermont Public Utility Commission ("PUC") Rules and other applicable codes and standards. The system impact study will also identify the responsible party for the required system upgrades.

1.4 Study Criteria

1.4.1 Voltage Criteria

As required by VEC, the following voltage criteria were utilized during the Study analysis.

1. Steady State: Within ANSI C84.1 distribution voltage limits
2. Reconnection: Within ANSI C84.1 distribution voltage limits
3. Voltage Imbalance: All three phases are less than three (3) percent before and after the project
4. Sag, swell, flicker criteria: Flicker shall be in compliance with IEEE 1547-2018, Section 7.2.3 based upon IEEE 1453-2022.

1.4.2 Thermal Criteria

As required by VEC, the following thermal criteria were utilized during the Study analysis.

With the aggregate generation on circuit 42-1A, including the Project, with generation output at 100 percent and minimum load, thermal conditions shall not exceed:

1. 80 percent of the phase pickup of an electronic recloser
2. 90 percent of the conductor ampacity rating;
3. 100 percent of a sectionalizing fuse continuous rating;
4. 100 percent of the load tap changer or regulator continuous rating;
5. 100 percent of a hydraulic recloser continuous rating

1.4.3 Standards Criteria

The Project shall be compliant with the following applicable codes, standards, and guidelines:

1. Vermont Public Utility Commission Rule 5.500, Section 5.510 Codes and Standards
2. Vermont Electric Cooperative Distributed Resource Interconnection Guidelines
3. ISO-NE Source Requirement Document ("SRD")
4. IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
5. IEEE 1547.3-2007 - IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected to Power Systems
6. IEEE 1453-2022 - IEEE Standard for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems
7. ANSI C84.1-2020 - American National Standard for Power Systems and Equipment Voltage Ratings (60 Hz)
8. IEEE Standard C37.90.1-2012 - IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus

1.4.4 Harmonics Screening Criteria

The Project shall comply with IEEE 519-2022[4] voltage distortion limits at the Point of Common Coupling (PCC) as the governing acceptance criteria. For systems within the 1 kV to 69 kV voltage range, the applicable limits are 3.0% for individual harmonic voltage distortion and 5.0% for total harmonic voltage distortion (THDV). IEEE 1547-2018[5] harmonic current distortion requirements are also considered as supporting reference criteria for the Project's inverter harmonic current emissions.

1.5 Steady State Analyses

To identify criteria exceptions attributed to the interconnection of the Project, load flow, short circuit, voltage flicker, and unintentional islanding analyses were performed to compare system performance both with and without the interconnection of the Project. The results of the analyses were evaluated using the applicable standards and industry best practices listed in Standards Criteria.

1.6 Time Series Analyses

DERs, such as photovoltaic ("PV") systems and battery energy storage systems ("BESS") that act as variable generation sources, introduce complexity to the distribution system. Within CYME, the Long-Term Dynamics Analysis module is capable of performing analysis that assists in understanding the impacts of load variations, irradiance variations, and ancillary market service signals on equipment such as regulators, load tap changers, and capacitor switching. Generation and load curves were developed to assess how the distribution circuit and its components would respond and perform under these scenarios. Control coordination and voltage control settings for regulators, tap changers, shunt caps and their sensitivities were monitored during this analysis. The results of the analyses were evaluated using the applicable standards and industry best practices listed in Standards Criteria.

[4] IEEE Std 519-2022, IEEE Standard for Harmonic Control in Electric Power Systems, Institute of Electrical and Electronics Engineers, 2022.

[5] IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, Institute of Electrical and Electronics Engineers, 2018.

Flicker may arise due to variable loads and distributed energy resources. The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE 1453-2022 provides guidance on flicker and voltage fluctuations. Flicker values were assessed for compliance with the GE Flicker Visibility curve throughout the duration of the simulation. Statistical methods and probabilities are utilized in IEEE 1453-2022 to analyze flicker performance. For the Study, using the CYME Long-Term Dynamics Analysis module, rolling 10-minute windows were applied when evaluating the frequency of voltage flicker measured against the GE Visibility Flicker curve. The 10-minute averaging windows helped to identify persistent flicker violations during the Long-Term Dynamics analysis.

The existing and proposed DERs on the circuit were evaluated following two-hour generator curves developed using historical measured data from existing facilities. The PV generation curve for existing PV system sites represented a period of high output variability, simulating the impacts of fast-moving cloud cover.

1.7 Short Circuit Analyses

The purpose of the short circuit analysis is to evaluate the fault current levels against the interrupting capability of existing equipment, as well as evaluating the fault current contribution of the Project.

1.8 Harmonic Screening Analyses

The harmonic screening analysis was conducted to evaluate the potential impact of the proposed Novus Buck Solar project on voltage distortion levels at the Point of Common Coupling ("PCC") and to ensure alignment with applicable industry standards. As a screening-level assessment, the analysis provides an initial, order-by-order estimation of the project's incremental harmonic contribution under normal operating conditions, while considering conservative assumptions for background distortion. This approach enables the identification of potential compliance concerns at an early stage and supports the determination of whether the project is likely acceptable as screened or if a more detailed harmonic study is warranted for refined assessment.

2.0 Inputs and Assumptions

2.1 Irasburg Substation and Area Electric Power System

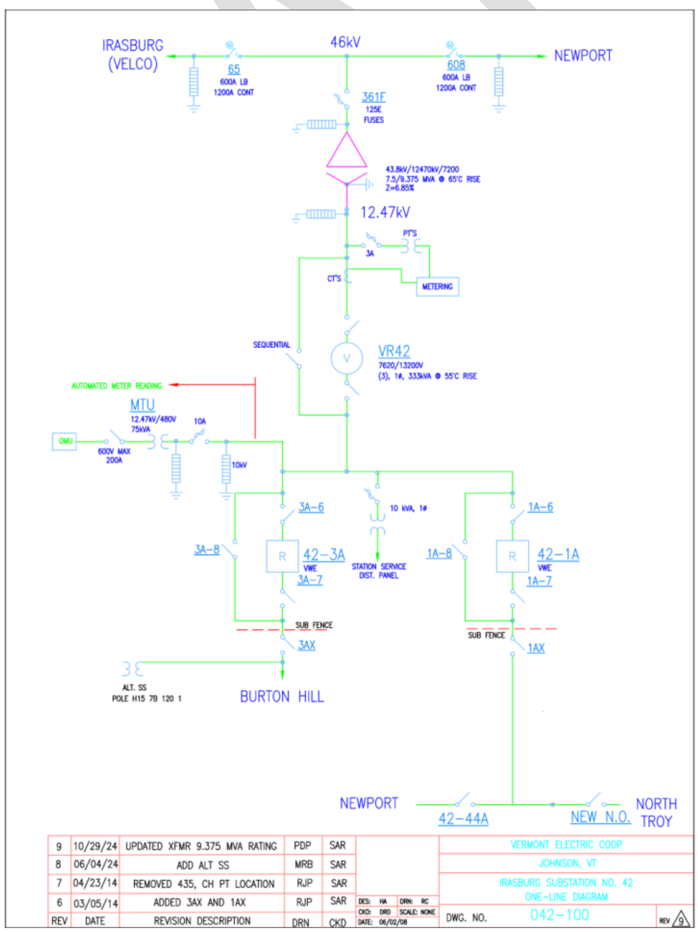
The Irasburg substation is a distribution substation supplied from a 46 kV sub-transmission system. It serves two (2) circuits: 42-1A and 42-3A via one 46 kV/12.47 kV power transformer. The existing power transformer has a base and maximum nameplate rating of 7.5 MVA and 9.375 MVA, respectively.

At the time of the Study, aggregate DER (including the Project) on the 42-1A and 42-3A circuits are 5,319.23 kW and 995.26 kW, respectively, corresponding to an aggregate DER capacity of 6,314.5 kW at the Irasburg substation.

Additionally, the characteristics of the 42-1A distribution circuit are as follows:

- The peak and minimum load data used in the Study are provided in Table 2-2.
- The 42-1A circuit voltage at the Irasburg 12.47 kV substation is regulated by three (3) 333 kVA 439-Amp substation regulators. In addition, the circuit includes two sets of single-phase line regulators rated at 167 kVA, 219-Amp and 250 kVA, 328-Amp, respectively. The regulator settings are provided in Table 2-4.

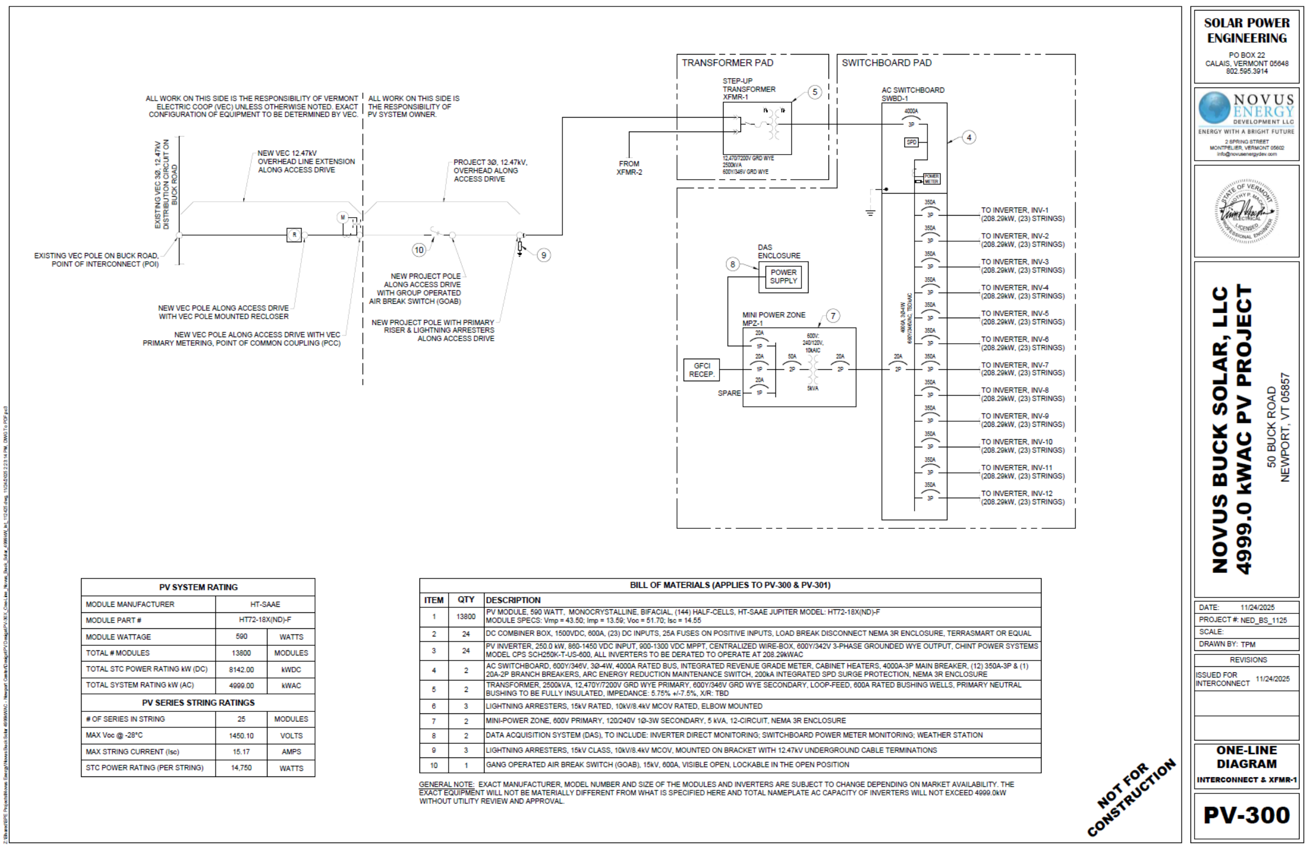
Figure 2-1: Substation Single-Line Diagram

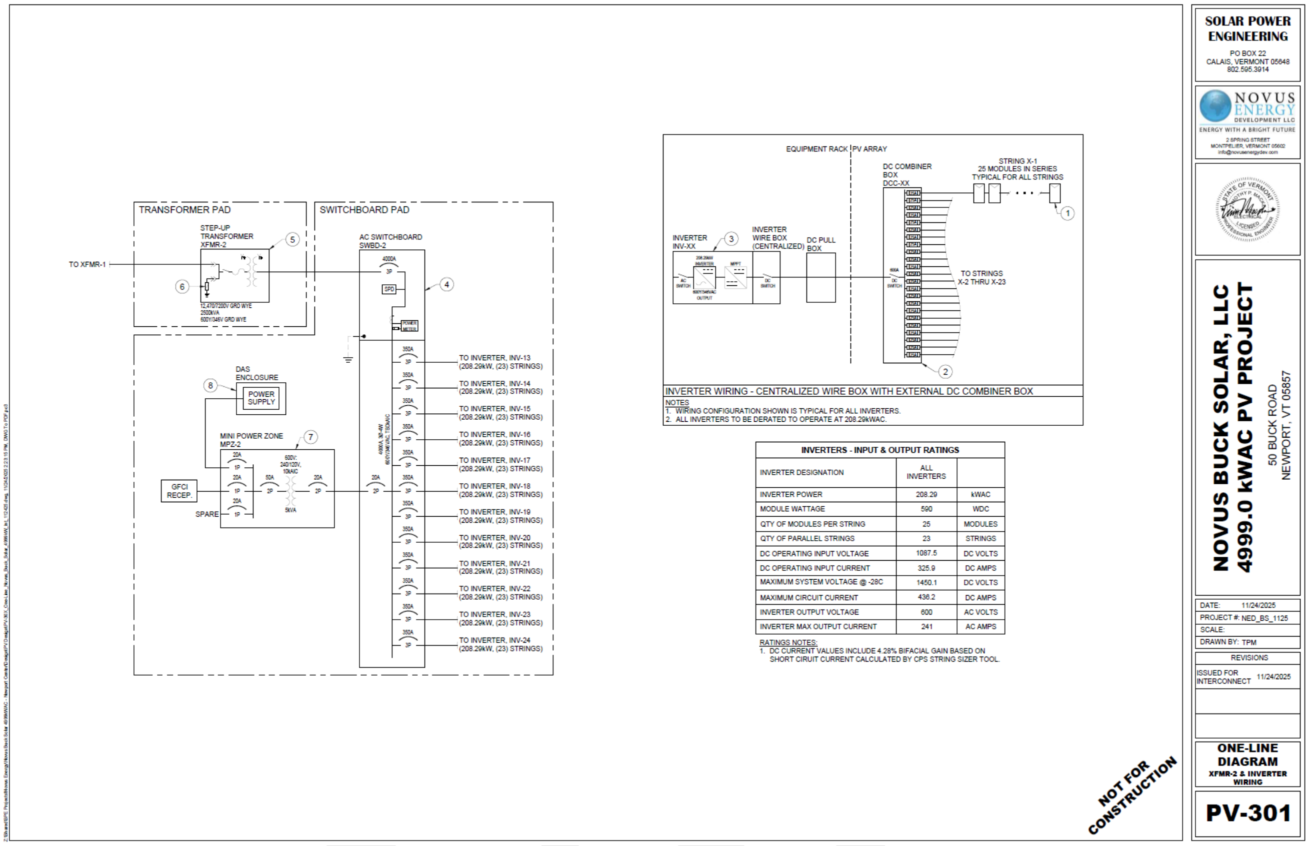


2.2 Project Background

The Project will interconnect to the VEC Irasburg substation via the 46/12.47 kV grounded-wye distribution circuit, 42-1A. The Project-owned and operated equipment is an inverter-based facility consisting of a 4999 kW-AC PV project, described in the Project Interconnection Application (Appendix A) and as depicted in the Interconnection Customer's Site One Line Diagram (Figure 2-2). As described in the Project Interconnection Application, the PV project is expected to operate with a maximum export limit of 4999 kW. A Company-owned and operated recloser shall be installed upstream from the PCC. The PCC is the point of connection between the Area EPS and the Local EPS and will be designated as the Project-side of the Company-installed primary meter.

Figure 2-2: Project Single Line Diagram





2.3 Project Generator

The Project is proposed to be located at 50 Buck Road, Newport Center, Vermont. The Project will be normally served from the Irasburg substation transformer, via the 42-1A 46/12.47 kV grounded-wye distribution circuit. The Project is proposed to be located approximately 7 miles from the Irasburg substation. Table 2-1: shows details of the Project generator, including general information, PCC details, and inverter specifications.

2.4 Service Configuration

In accordance with VEC requirements, all inverter-based projects exceeding 500 kW require the installation of a dedicated three-phase recloser at the PCC. Additionally, the Company requires the interconnection GSU transformers to be equipped with manual tap changing capability. The manual tap changing capability of the interconnection GSU transformers could not be confirmed because transformer data sheets were not provided by the Project with the interconnection application.

The PCC will be designated as the Project side of the Company-installed primary meter. The point of DER connection ("PoC") is the point where a DER unit is electrically connected in a Local EPS and meets the requirements of IEEE 1547-2018.

To serve the Customer, a three-phase primary overhead line must be extended to the Project location. Additionally, the company will install a three-phase recloser upstream from the Project and at the Project PCC. The Project will have a three-phase pole-mounted primary metering package or other VEC-approved metering package that accounts for transformer loss compensation installed upstream of (or on) a new customer riser pole. All electrical facilities beyond this point will be installed, owned, and operated by the Project.

Table 2-1: Project Generator Information

Project Information	
Name	Novus Buck Solar
Developer	Novus Energy Development LLC
Generation Type	Photovoltaic (Solar)
Maximum Export Capability Requested (kW)	4999 kW (AC)
Auxiliary Power Requirement (kW)	None
Interconnecting Voltage	12.47 kV
Point of Common Coupling	
Description	3-phase 12.47 kV Line
GPS Coordinates	44.9194, -72.2868
Location	50 Buck Rd, Newport Center, VT 05857
Substation	Irasburg
Circuit	42-1A
Generator Step Up Transformer	
Transformer Size	2-2500 kVA
Impedance	5.75 % (Assumed)
kVA Base	2500 kVA
Primary Voltage (LV Winding)	600 V
Configuration	Wye-grounded
Secondary Voltage (HV Winding)	12.47 kV
Configuration	Wye-grounded
X/R Ratio	4 (Assumed)
Tap Changer (Yes/No)	No
Primary-Side AC Load Break Disconnect and Fuses	Yes
Inverters	
Manufacturer	Chint Power Systems (CPS)
Model Name	CPS SCH250K-T-US-600
Capacity	250 kVA (each)*
Quantity	24
Output Rating (AC)	600 V, 3Ø, 60 Hz

* Inverters derated to operate at 208.29 kWAC as indicated in Figure 2-2

2.5 Monitoring Information

Per IEEE 1547-2018, Section 10.5, the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability and shall include at a minimum: active power, reactive power, voltage, frequency, operational state of the DER, connection status, and alarm status.

The Project will be considered an Independent Power Producer, planning to install 4999 kW PV; therefore, bi-directional metering provisions are required. The Company intends to meet this requirement through bi-directional metering installed at the PCC. Real-time monitoring via a SCADA feed will also be required for this Project due to its significant impact on the dynamic loading condition of the distribution system.

2.6 Steady State Analyses Assumptions

The steady-state analyses were performed using Milsoft Engineering Analysis software, WindMil® 25.1. For the purposes of the Study, VEC provided an existing distribution planning model, and load allocation was performed using historical data for the Irasburg substation and 42-1A & 42-3A circuits from VEC's Supervisory Control and Data Acquisition ("SCADA") system. The analysis was conducted with the 4999 kW PV project assuming unity power factor.

The study models were created by adding the Project to the 42-1A distribution circuit of Irasburg Substation. The SCADA system recorded peak and minimum load values on the 42-1A and 42-3A distribution circuits used for the study are shown in Table 2-2. The aggregate existing and proposed DERs on the 42-1A and 42-3A circuits and Irasburg substation transformer (including the Project) are summarized in Table 2-3.

Table 2-2: Loading Scenarios (Non-coincident)

Load Profile	Element	SCADA System Recorded Load	
		kW	kVAr
Peak	Irasburg #42 XFMR	3776	1027
	42-1A	1495	-10
	42-3A	2281	1037
Minimum	Irasburg #42 XFMR	630	-437
	42-1A	425	-547
	42-3A	205	110

Table 2-3: Aggregated DER on Electrical Power System

Element	Existing DER (kW)	Project DER (kW)	Aggregate DER Existing & Proposed w/ Project (kW)
Irasburg #42 XFMR	1315	4999	6314
42-1A	320	4999	5319
42-3A	995	0	955

The transformer at Irasburg substation is not equipped with a Load Tap Changer ("LTC"). Voltage is regulated on the 42-1A and 42-3A circuits via three (3) 333 kVA 439-Amp regulators (one per phase) installed at the substation. In addition, the 42-1A circuit includes two sets of single-phase line regulators rated at 167 kVA, 219-Amp and 250 kVA, 328-Amp respectively, with the settings shown below in Table 2-4. The 42-1A circuit also includes two (2) fixed three-phase 300 kVAr shunt capacitors, with capacitor Cap-42226, located near the proposed PCC, disconnected due to pre-existing power quality issues identified by VEC.

Table 2-4: Existing Station and Line Regulator Settings

Substation Regulator				
Control Settings				
Operating Mode		Regulator Terminal		
Reverse Sensing Mode		Locked Forward		
Forward & Reverse Tap Settings				
Phase	**Voltage**	**Bandwidth**	**R**	**X**
Phase A	123.5	3.0	0	0
Phase B	123.5	3.0	0	0
Phase C	123.5	3.0	0	0
Line Regulator-167 kVA				
Control Settings				
Operating Mode		Regulator Terminal		
Reverse Sensing Mode		Bi-Directional		
Forward & Reverse Tap Settings				
Phase	**Voltage**	**Bandwidth**	**R**	**X**
Phase A	122	2.0	0	0
Phase B	122	2.0	0	0
Phase C	122	2.0	0	0
Line Regulator-250 kVA				
Control Settings				
Operating Mode		Regulator Terminal		
Reverse Sensing Mode		Bi-Directional		
Forward & Reverse Tap Settings				
Phase	**Voltage**	**Bandwidth**	**R**	**X**
Phase A	122	2.0	0	0
Phase B	122	2.0	0	0
Phase C	122	2.0	0	0

2.7 Long-Term Dynamics Analyses Assumptions

The Long-Term Dynamics analyses were conducted over a two-hour period with one-second time intervals utilizing the CYME Long-Term Dynamics Analysis module. The intent was to determine the frequency and magnitude of the voltage changes caused by a varying output from the Project. A typical load curve was used for peak and minimum loads to represent fluctuating loads for the relevant circuit(s). A generation curve for existing PV system sites that represented a period of high variability in output was used to simulate the impacts of fast-moving cloud cover. The purpose was to simulate worst-case conditions by modeling existing PV systems under high output variability associated with fast-moving cloud cover using a high-variability generation curve.

2.8 Background Harmonic Measurements and Screening Assumptions

2.8.1 Background Harmonic Measurements

Background harmonic voltage measurements were provided for a location on the 42-1A circuit under normal feeder configuration. The measurement location is approximately 2 miles from the Project point of interconnection (“POI”) and is not the Project PCC. The available measurements were recorded from a three-phase, 4-wire, 480Y/277 V class service location and include Total Harmonic voltage Distortion (“THD_V”) and selected individual voltage harmonic orders.

The available dataset consists of 35,825 measurement records recorded at a 5-minute timestep. The measurement period spans from November 7, 2025 through March 11, 2026, representing approximately 124 days of monitoring. The measurement duration is considered sufficient to provide useful context regarding existing feeder harmonic conditions; however, the measurements were not collected at the Project PCC and do not include all harmonic orders from the 2nd through the 50th harmonic. A summary of the available measurement dataset is provided in Table 2-5.

The available background measurements indicate that harmonic voltage distortion on the feeder is already elevated. Some measured individual harmonic values (3rd, 5th, and 7th) exceed the selected IEEE 519-2022 planning criteria used for this screening assessment. Therefore, the concern about harmonic distortion is not solely attributable to the proposed Project, and the feeder already has limited or no available harmonic margin for certain harmonic orders.

Table 2-5: Summary of Background Harmonic Measurement Dataset

Item	Description
Measurement location	On the normal 42-1A feeder configuration, approximately 2 miles from the Project POI
Voltage class	480Y/277 V class, three-phase, 4-wire service location
Measurement period	November 7, 2025 at 00:00 EST through March 11, 2026 at 10:35 EDT
Approximate monitoring duration	Approximately 124 days
Measurement timestep	5 minutes
Number of records	35,825
Available harmonic quantities	Voltage THD and selected individual voltage harmonics through the 21st harmonic
Limitation	Measurements are not PCC-specific and do not include all harmonic orders from the 2nd through the 50th harmonic

In addition, the available measurements do not provide a complete PCC-specific background harmonic spectrum for all harmonic orders from the 2nd through the 50th harmonic. The individual harmonic measurements available in the dataset are limited to selected odd harmonic orders through the 21st harmonic. As a result, the measured data were not used directly as the background input for each harmonic order in the screening calculation. Instead, the measurements were used to provide context regarding existing feeder power quality conditions. A summary of the available background harmonic measurements is provided in Table 2-6.

Table 2-6: Summary of Available Background Harmonic Measurements

Quantity	Measured Peak (%)	99th Percentile (%)
Voltage THD	5.966	3.377
3rd Harmonic	9.266	5.700
5th Harmonic	13.918	7.641
7th Harmonic	10.080	6.779
9th Harmonic	2.430	1.682
11th Harmonic	1.666	1.082
13th Harmonic	1.222	0.776
15th Harmonic	0.236	0.186
17th Harmonic	0.424	0.228
19th Harmonic	0.200	0.124
21st Harmonic	0.106	0.062

2.8.2 Harmonics Screening Analyses Assumptions

The harmonic screening assessment is based on the following assumptions:

- Complete measured background harmonic voltage data at the PCC was not available for harmonic orders 2 through 50. Therefore, background harmonic voltage distortion is assumed to be 75% of the applicable IEEE 519 individual harmonic voltage planning limit for each harmonic order, consistent with the agreed screening approach.
- The assumed 75% background harmonic voltage spectrum is intended to provide a screening basis and does not represent a measured PCC harmonic spectrum.
- The ENA EREC G5/5[6] Stage 2C method is used solely as a computational framework for harmonic impedance and voltage calculations. G5/5 planning levels are not used as the final compliance criteria.
- IEEE 519-2022 voltage distortion planning criteria are used as the final voltage distortion screening criteria at the PCC. For systems within the 1 kV to 69 kV voltage range, the applicable limits are 3.0% for individual harmonic voltage distortion and 5.0% for THD_V.
- IEEE 1547-2018 harmonic current distortion requirements are reviewed as supporting reference criteria for the Project's inverter harmonic current emissions.

[6] Energy Networks Association, Engineering Recommendation G5 Issue 5 (EREC G5/5), Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom, June 2020.

- The harmonic input data for the analysis is based on Test Case 1 from the inverter test report “250KW-600 Test Data – IEEE 1547.1-2020 Section 5.12 Current Distortion (TRD)”, which represents the selected worst-case harmonic current injection condition for this study.
- The project consists of 24 inverters, arranged into two transformer groups. Harmonic currents are:
    - Aggregated arithmetically within each transformer group
    - Combined at the PCC using IEC/TR 61000-3-6 power-law summation
- The analysis assumes normal feeder configuration only. Abnormal, contingency, or switching conditions are not considered in this screening assessment.
- Harmonic analysis is performed for orders h = 2 through 50.
- The upstream network is represented by a Thevenin equivalent at the PCC, derived from available short-circuit strength and X/R ratio. The network is assumed to behave linearly for harmonic calculations.
- Harmonic impedance is derived from fundamental values using Stage 2C relationships, with frequency scaling applied consistently for all harmonic orders.

3.0 Steady State Analysis

To identify criteria exceptions attributed to the interconnection of the Project, load flow, short circuit, and voltage flicker analyses were performed to compare system performance with and without the interconnection of the Project.

3.1 Load Flow Analysis

The purpose of the load flow analysis was to evaluate thermal loading (current flow), voltage profiles, voltage drop, and power factor with and without the interconnection of the Project. Impacts associated with the Project were evaluated for peak and minimum load conditions. Under normal operating conditions, it is expected that VEC meets its obligations for ANSI C84.1 with the Project interconnected and the interconnecting circuit in its normal configuration.

3.1.1 Criteria

The load flow analysis was evaluated against the following criteria to identify the violations.

1. **Thermal**
    a. With the aggregate generation on the 17-4A, including the Project, with generation output at 100 percent and the circuit at minimum load:
        i. None of the following equipment shall exceed 100 percent of the manufacturer recommended continuous rating:
            (1) Sectionalizing fuse
            (2) Load tap changer
            (3) Hydraulic recloser
            (4) Regulator (without load bonus)
        ii. No conductor shall exceed 90 percent of the conductor ampacity rating.
    b. Under no-load condition with aggregate generation at 100 percent output, the per-phase rating of the windings of the substation transformer shall not be exceeded.
2. **Voltage**
    a. During steady state and reconnection conditions, service voltages must be between the range of 114 V and 126 V (± 5 percent) on a 120 V scale (ANSI C84.1 Range A).
    b. All three phases are less than three (3) percent unbalanced before and after interconnection of the Project.
    c. Sag, swell, flicker criteria: Flicker shall be in compliance with IEEE 1547-2018, Section 7.2.3 based upon IEEE 1453-2022.

The power factor at the substation recloser was also monitored to evaluate any severe degradation from base case results.

3.1.2 Scenarios

Table 3-1 outlines the Load Flow Analysis Scenarios that were considered for evaluation with the regulators and capacitor unlocked for the simulations, and thus able to react to system changes. Each scenario was studied on the 42-1A circuit with existing DER operating at 100 percent output. Alternate sources were not considered in this study. If the Project desires to generate while sourced from an alternate circuit, additional analysis should be performed to understand and address the impacts on the alternate circuit.

Table 3-1: Load Flow Analysis Scenarios

Scenario #	Base/Study Case	Load Model	Switched Devices	Existing DER Status	Project Status
1	Base	Peak	Unlocked	On	Offline
2	Study	Peak	Unlocked	On	Online
3	Base	Minimum	Unlocked	On	Offline
4	Study	Minimum	Unlocked	On	Online

3.1.3 Methodology

The steady state analyses were performed using Milsoft Engineering Analysis software, WindMil® 25.1.6. For the purpose of the Study, VEC provided an existing distribution planning model loaded with a Peak Load Profile and a Minimum Load Profile. The steady state analysis was conducted with the 4999 kW PV Project assuming unity power factor.

Prior to the commencement of the Study, a Base Case analysis was conducted to understand and evaluate existing conditions on the system. Any pre-existing conditions were documented and are not considered to be a result of the Project.

To serve the Customer, a three-phase primary overhead line extension is required from Span_47714 to the Project Point of Common Coupling (PCC). The existing section at Span_47714 is a single-phase 2 ACSR conductor, which is inadequate to support the projected 4,999 kW generation export due to capacity limitations. Accordingly, it is proposed to reconfigure the feeder segment from Span_17410 to Span_47714 from single-phase to three-phase construction and upgrade the conductor from Span_10438 to Span_47714 to 556 ACSR to meet thermal and operational requirements. The upgraded 556 ACSR three-phase conductor will then be extended to the Project PCC to ensure reliable and compliant interconnection.

3.1.4 Load Flow Analysis Results

Tables Table 3-2, Table 3-3 and Table 3-4 present a summary of the load flow results (thermal loadings, voltages, current, real and reactive power, and power factor) during peak and minimum loading.

3.1.4.1 Peak Load Scenario

- **Thermal Analysis**
  During the base case analysis, pre-existing thermal concerns were observed on conductors or equipment during peak loading as summarized in Table 3-2. No additional thermal violations except for span_1482 were observed during peak loading as a result of the interconnection of the Project.
- **Voltage Analysis**
  No pre-existing voltage concerns were observed during the base case analysis. Following the interconnection of the Project, voltage violations were observed upstream of the 167 kVA line regulators on circuit 42-1A as shown in Table 3-3 and Figure 3-2.

- **Substation and Feeder Power Factor**
  During the base case analysis, power factors at the substation and feeder 42-1A are above 95% lagging. Following the interconnection of the Project, the power factors decrease to less than 95% leading as shown in Table 3-3. The power factor on the adjacent feeder, 42-3A, remains below 95% lagging in both cases.

Table 3-2: Thermal Concerns (Base Case and Post-Project)

Element Name	Equipment Type	Base Case Loading	Post-interconnection Loading	Rating
Peak Loading				
42-3-1BA	Fuse	112.97%	111.78%	40 A
42-1-3L8C1	Fuse	323.19%	325.18%	6 A
42-3-3A13A	Fuse	104.57%	104.47%	6 A
42-3-3A5A1B	Fuse	114.07%	113.97%	6 A
42-3-1B	Recloser	102.99%	101.97%	70 A
Span_1482	Overhead Conductor*	5.81%	94.14%	230 A
Minimum Loading				
42-1-3L8C1	Fuse	313.44%	314.16%	6 A
Span_1482	Overhead Conductor*	3.00%	96.24%	230 A

*Note: The overloaded conductor on Span_1482 is specified as three-phase overhead 1/0 ACSR in the WindMil model and GIS, in contrast to three-phase overhead 4/0 ACSR in both downstream and upstream sections, suggesting a possible conductor size inconsistency.

Table 3-3: Peak Load Results

Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
Peak Load - Project Idle												
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	KW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	3765.64	3649.89	926.50	47.44	96.93	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	119.05	3734.59	3649.89	790.89	174.86	97.73	-	-	-	39.84
42100	42-7-1A	12.47	123.42	1481.35	1480.52	-49.62	67.33	-99.94	320.23	115.66	123.97	112.97
42300	42-7-3A	12.47	123.42	2326.50	2169.37	840.51	105.08	93.25	995.26	114.68	123.38	323.19
PCC	Novus Buck POI RECL	12.47	0.00	0.00	0.00	0.00	0.00	100.00	-	-	-	-
Peak Load - Project Full Output												
Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	KW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	1871.03	-1039.04	1556.00	-23.78	-55.53	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	118.30	1839.95	-1039.04	1518.48	-93.72	-56.47	-	-	-	19.63
42100	42-7-1A	12.47	123.44	3279.25	-3208.60	677.04	-148.27	-97.85	5319.23*	116.71	127.20	111.78
42300	42-7-3A	12.47	123.44	2327.02	2169.56	841.45	105.08	93.23	995.26	114.79	123.40	325.18
PCC	Novus Buck POI RECL	12.47	124.36	4942.05	-4935.54	253.66	-220.77	-99.87	4999.00	-	-	-

Note: *This includes 4999 kW of generation by the Project.

Figure 3-1: Peak Load Network (Base Case)

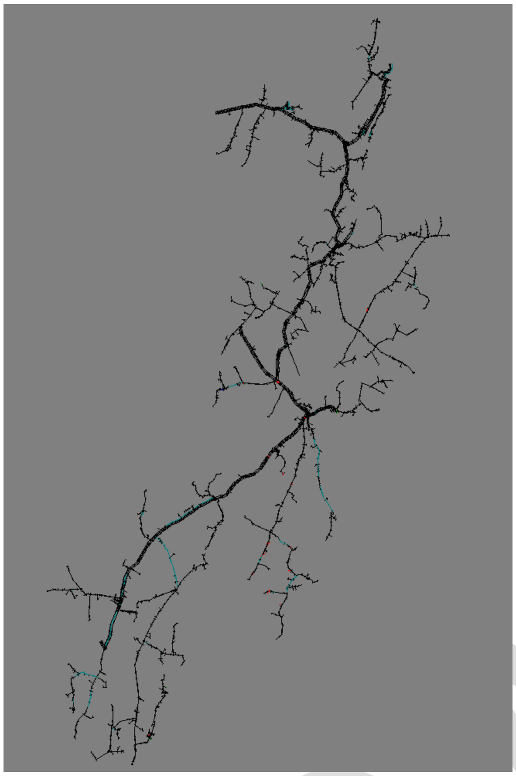
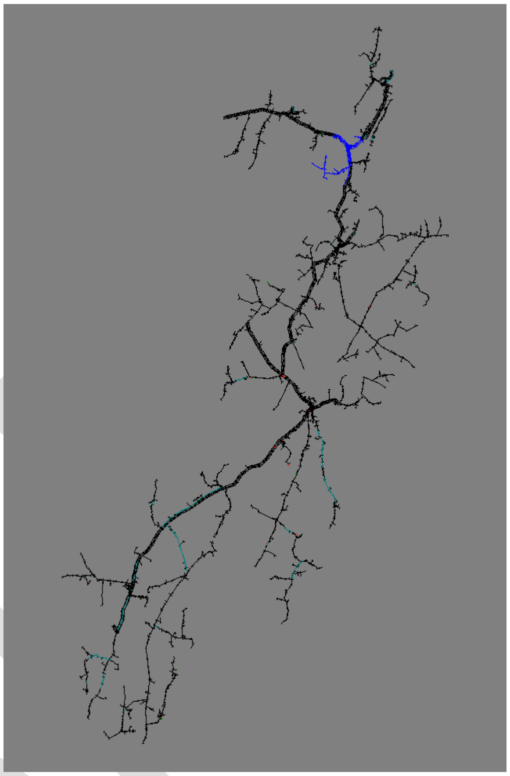


Figure 3-2: Peak Load Network (Post-Project)



3.1.4.2 Minimum Load Scenario

- **Thermal Analysis**
  During the base case analysis, pre-existing thermal concerns were observed on conductors or equipment during loading as summarized in Table 3-2. No additional thermal violations except for span_1482 were observed during Min loading as a result of the interconnection of the Project.
- **Voltage Analysis**
  Pre-existing voltage concerns and power factor violations were observed during the base case analysis as shown in Figure 3-3. Following the interconnection of the Project, additional voltage violations were observed upstream of the 167 kVA line regulators on circuit 42-1A as shown in Table 3-4 and Figure 3-4. In addition, reverse power flow of 4024.24 kW, through the Irasburg Substation Transformer onto VEC's transmission system, is observed.
- **Substation and Feeder Power Factor**
  During the base case analysis, leading power factors less than 95% were observed at the substation and the 42-1A and 42-3A reclosers. Following the interconnection of the project at full output, the power factors at the substation and feeder reclosers increase above 95% as shown in Table 3-4.

Table 3-4: Minimum Load Results

Min Load - Project Idle

Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	KW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	786.31	611.59	-494.21	10.10	-77.78	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	120.54	791.67	611.59	-502.69	42.45	-77.25	-	-	-	8.44
42100	42-7-1A	12.47	123.64	698.97	422.07	-557.15	-33.20	-60.39	320.23	121.54	125.04	36.96
42300	42-7-3A	12.47	123.64	197.18	189.52	54.45	19.68	96.11	995.26	118.53	126.66	313.44
PCC	Novus Buck POI RECL	12.47	0.00	0.00	0.00	0.00	0.00	100.00	-	-	-	-

Min Load - Project Full Output

Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	KW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	4054.59	-4024.24	495.18	-50.94	-99.25	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	119.54	4038.76	-4024.24	342.23	-187.89	-99.64	-	-	-	43.08
42100	42-7-1A	12.47	123.40	4223.58	-4213.90	285.79	-190.18	-99.77	5319.23*	121.37	128.22	96.24
42300	42-7-3A	12.47	123.40	197.88	189.66	56.44	19.72	95.85	995.26	118.22	127.20	314.16
PCC	Novus Buck POI RECL	12.47	123.98	4941.79	-4935.19	255.25	-221.44	-99.87	4999.00	-	-	-

Note: *This includes 4999 kW of generation by the Project.

Figure 3-3: Minimum Load Network (Base Case)

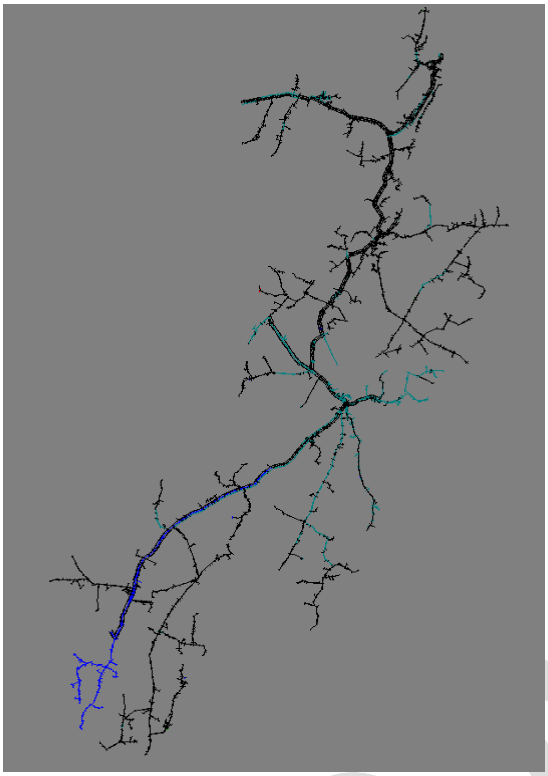
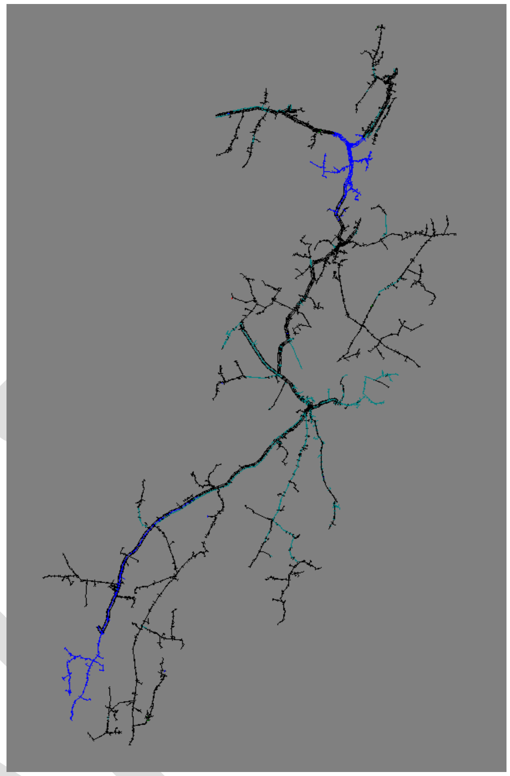


Figure 3-4: Minimum Load Network (Post-Project)



3.1.4.3 Load Flow Violations and Proposed Mitigation

1. **Voltage Violations:**
   As noted in Sections 3.1.4.1 and 3.1.4.2, following the interconnection of the Project, voltages greater than 126 V were observed upstream of the 167 kVA line regulators on the 42-1A feeder during peak and minimum loading.

   Proposed Mitigations:

   - Decrease the voltage setpoint of the existing substation regulator from 123.5 V to 122 V to maintain voltages within ANSI C84.1 limits.
   - Install a set of three single-phase 328-Amp, 250 kVA line regulators at or near Span_48592 to maintain voltages within ANSI C84.1 limits.
   - Reconductor approximately 17,100 feet of existing three-phase overhead 2 ACSR and 4/0 ACSR conductor to three-phase overhead 556 ACSR conductor from Span_48630 to the Project PCC to mitigate voltage flicker concerns.

2. **Substation and Feeder Power Factor**
   Following the interconnection of the Project at full output, the power factors at the substation and feeder 42-1A decrease to less than 60% leading during peak load conditions, indicating substantial reactive power demand. This condition increases system losses, reduces available capacity, and can adversely impact the feeder voltage profile.

   Proposed Mitigation:

   - Install two three-phase 600 kVAR switched capacitor banks, each on feeders 42-1A and 42-3A, at or near Span_48484 and Span_39839, respectively.

3.1.4.4 Peak Load Scenario (Post-Mitigation)

Post-mitigation, the identified thermal, voltage and power factor violations, following the interconnection of the Project, were resolved as shown in Table 3-5 and Figure 3-5. The analysis showed reverse power flow of 1135.24 kW through the Irasburg Substation Transformer onto VEC's transmission system.

Table 3-5: Peak Load Results (Post-mitigation)

Peak Load - Project Full Output (Post-mitigation)												
Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	kW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	1166.54	-1135.24	268.43	-14.99	-97.32	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	119.71	1162.57	-1135.24	250.61	-61.12	-97.65	-	-	-	12.40
42100	42-7-1A	12.47	123.05	3299.47	-3299.34	29.49	-149.22	-100.00	5319.23	116.95	125.11	111.52
42300	42-7-3A	12.47	123.05	2175.37	2164.10	221.12	98.82	99.48	995.26	115.63	123.28	323.03
PCC	Novus Buck POI RECL	12.47	122.86	4940.84	-4934.00	259.81	-223.42	-99.86	4999.00	-	-	-

3.1.4.5 Minimum Load Scenario (Post-Mitigation)

Post-mitigation, all system parameters, including thermal loading, voltage profile, and power flow conditions, were within acceptable limits as shown in Table 3-6 and Figure 3-6. The analysis showed reverse power flow of 4118.21 kW through the Irasburg Substation Transformer onto VEC's transmission system.

Table 3-6: Minimum Load Results (Post-mitigation)

Min Load - Project Full Output (Post-mitigation)*												
Substation/ Feeder Name	Monitored Element	Voltage		Feeder Demand					Total Generation	Min. Voltage	Max. Voltage	Max. Loading
		kVLL	V	kVA	kW	kVAR	Amps	PF (%)	KW	V	V	%
Substation XFMR Primary	span_214423	46.00	120.00	4119.57	-4118.21	-105.71	-51.75	99.97	-	-	-	-
Substation XFMR Secondary	span_214424	12.47	120.20	4126.63	-4118.21	-263.52	-190.91	99.80	-	-	-	44.02
42100	42-7-1A	12.47	121.21	4321.06	-4308.20	-333.18	-198.03	99.70	5319.23	119.99	123.88	99.87
42300	42-7-3A	12.47	121.21	202.35	189.99	69.65	20.25	93.89	995.26	118.50	124.69	311.14
PCC	Novus Buck POI RECL	12.47	122.29	4940.42	-4933.46	262.18	-224.44	-99.86	4999.00	-	-	-

*Note: This scenario assumes that both of the proposed switched capacitor banks are turned off to maintain the substation and feeder power factor within the required limits.

Figure 3-5: Peak Load Network (Post-mitigation)

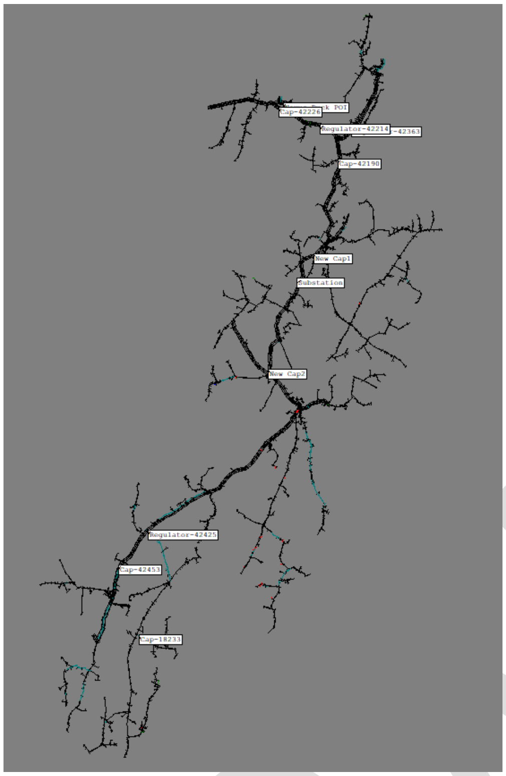
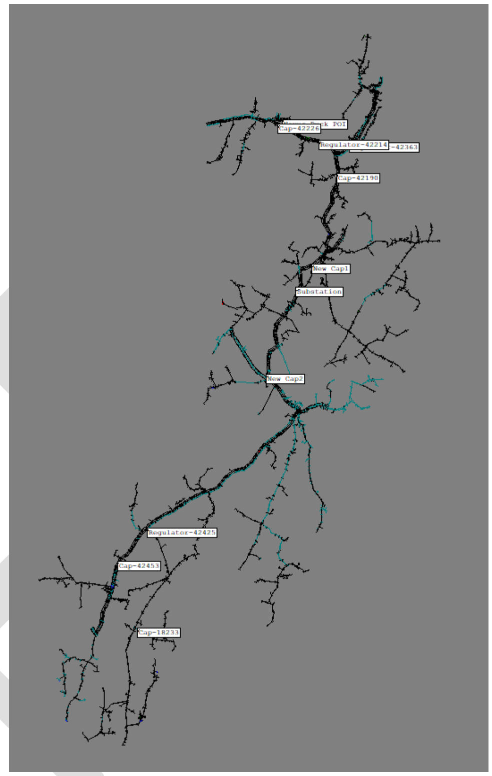


Figure 3-6: Minimum Load Network (Post-Mitigation)



3.1.5 Reverse Power Flow

As part of the analysis, the potential for the Project to cause reverse power flow was evaluated. Under full-export conditions, the Project, in addition to existing DER projects, could result in reverse power flow through the 42-1A recloser and the substation transformer to the 46 kV system. The maximum reverse power from the 42-1A circuit through the Irasburg substation transformer and 42-1A recloser was determined to be 4.118 MVA, during the minimum load scenario, with distributed resources operating at 100 percent output. Hence, substation equipment and regulator controls must be properly equipped for reverse power flow. VEC should consider further evaluation of impacts on the sub-transmission system.

3.1.6 Recommendations

The Steady State Analysis found that the interconnection of the Project should have no adverse impacts on the Area EPS safety and reliability, provided the following recommended operating conditions and system modifications to the Company's EPS are implemented:

Recommended System Improvements

1. Install approximately 18,300 feet of primary overhead 556 ACSR conductor. Poles will need to be installed and replaced as necessary to meet the Company standards for the primary overhead three-phase configuration
   a. Reconductor approximately 17,100 feet of existing three-phase overhead 2 ACSR and 4/0 ACSR conductor to three-phase 556 ACSR conductor from Span_48630 to Span_10439.

   b. Upgrade approximately 1,000 feet single-phase overhead 2 ASCR conductor to three-phase overhead 556 ACSR conductor from Span_17410 to Span_47714.
   c. Install a line extension of approximately 200 feet of three-phase overhead 556 ACSR conductor from Span_47714 to the Project PCC recloser.
2. Install a set of three single-phase 328-Amp, 250 kVA line regulators at or near Span_48592 to maintain voltages within ANSI C84.1 limits.
3. Decrease the voltage setpoint of the existing substation regulator from 123.5 V to 122 V to maintain voltages within ANSI C84.1 limits.
4. Install two three-phase 600 kVAR switched capacitor banks, each on feeders 42-1A and 42-3A, at or near Span_48484 and Span_39839, respectively.
5. Fuses for the line extension will be reviewed and evaluated by VEC.
6. The Company will install a three-phase recloser upstream from the Project and at the Project PCC.
7. The Project will have a three-phase pole-mounted primary metering package or other VEC-approved metering package that accounts for transformer loss compensation installed upstream of (or on) a new customer riser pole.
8. Installation of real-time (SCADA) communications from the Project to VEC.

3.2 Voltage Flicker Analysis

Voltage flicker analysis was conducted under steady state conditions. IEEE defines voltage flicker as subjective impression of fluctuating luminance caused by voltage fluctuations. The IEEE recommended practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2022 provides guidance on flicker and voltage fluctuations. To compute the voltage degradation that could cause a voltage flicker due to the new PV generator interconnection, the Project output was modeled at 100% of the rated capacity to assess the impact of this output on voltages at the PCC.

3.2.1 Criteria

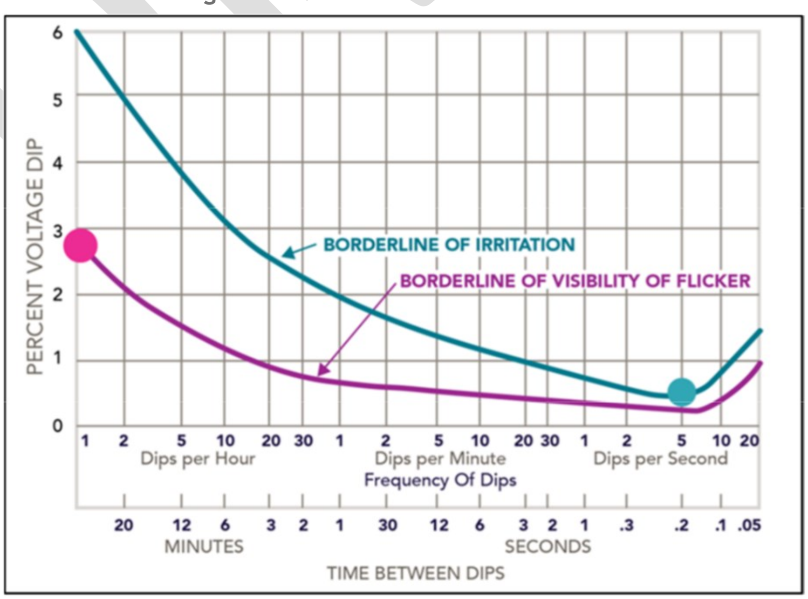
The voltage flicker analysis is performed using peak and minimum load scenarios to test the impacts of interconnecting the Project with the VEC distribution system. The modeling assumptions utilized in the voltage flicker analysis included locking of any capacitor banks and regulators to simulate a conservative response to variability in the output of the Project. A percentage change of greater than 3 percent is considered a violation.

The Project shall comply with the voltage flicker criterion of IEEE 519™, IEEE Std. 1453™, IEEE 1453.1™, IEEE 1547.7™, and section 4.3.2 of IEEE 1547™, including Table 3-7 shown below.

Table 3-7: IEEE 1453-2022 Voltage Fluctuations producing Pst=0.9 and Pst=1.0

Changes per Minute	Changes per Second	IEEE 1453 Pst=0.9	IEEE 1453 Pst=1.0
1	0.0167	2.3166	3.1660
2	0.0333	1.8790	2.5680
3	0.0500	1.6463	2.2500
5	0.0833	1.3895	1.8990
7	0.1167	1.2402	1.6950
10	0.1667	1.0968	1.4990
22	0.3667	0.8678	1.1860
39	0.6500	0.7639	1.0440
48	0.8000	0.7317	1.0000
68	1.1333	0.6871	0.9390
110	1.8333	0.6154	0.8410
176	2.9333	0.5407	0.7390
273	4.5500	0.4756	0.6500
375	6.2500	0.4346	0.5940
480	8.0000	0.4090	0.5590
585	9.7500	0.3666	0.5010
682	11.3667	0.3256	0.4450
796	13.2667	0.2876	0.3930
1020	17.000	0.2561	0.3500
1055	17.5833	0.2568	0.3510
1200	20.000	0.2715	0.3710
1390	23.1667	0.3205	0.4380

Figure 3-7: IEEE 519 GE Flicker Curve



3.2.2 Scenarios

Table 3-8 outlines the scenarios that were evaluated during the voltage flicker analysis with LTCs, regulators and capacitors locked for the simulations and therefore unable to react to system changes.

Table 3-8: Voltage Flicker Analysis Scenarios

Scenario	Base/Study Case	Load Model	Switched Devices
Scenario 1	Project Offline	Peak	Unlocked
Scenario 2	Project at 100% output	Peak	Locked
Scenario 3	Project at 100% output	Peak	Unlocked
Scenario 4	Project Offline	Peak	Locked
Scenario 5	Project Offline	Min	Unlocked
Scenario 6	Project at 100% output	Min	Locked
Scenario 7	Project at 100% output	Min	Unlocked
Scenario 8	Project Offline	Min	Locked

3.2.3 Results

The following tables show the results from voltage flicker analysis during peak and minimum load conditions.

Table 3-9: Voltage Flicker - Peak Load (Project Output Change: 0% to 100%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 1	Scenario 2		Scenario 1	Scenario 2		Scenario 1	Scenario 2	
42-1A	123.49	122.71	-0.63%	123.65	122.82	-0.67%	123.14	122.434	-0.57%
PCC	122.31	128.16	4.78%	122.21	127.86	4.63%	122.51	128.56	4.94%

Table 3-10: Voltage Flicker - Peak Load (Project Output Change: 100% to 0%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 3	Scenario 4		Scenario 3	Scenario 4		Scenario 3	Scenario 4	
42-1A	123.51	124.31	0.65%	123.61	124.47	0.70%	124.06	124.80	0.59%
PCC	124.35	118.68	-4.57%	124.04	118.61	-4.38%	124.03	118.27	-4.64%

Table 3-11: Voltage Flicker - Minimum Load (Project Output Change: 0% to 100%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 5	Scenario 6		Scenario 5	Scenario 6		Scenario 5	Scenario 6	
42-1A	123.87	122.89	-0.79%	123.62	122.52	-0.89%	123.42	122.43	-0.80%
PCC	121.99	127.49	4.51%	121.69	126.81	4.20%	121.96	127.38	4.44%

Table 3-12: Voltage Flicker - Minimum Load (Project Output Change:100% to 0%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 7	Scenario 8		Scenario 7	Scenario 8		Scenario 7	Scenario 8	
42-1A	123.68	124.69	0.81%	124.13	125.24	0.90%	123.21	124.23	0.83%
PCC	124.46	119.15	-4.26%	123.88	118.93	-4.00%	124.38	119.09	-4.25%

3.2.4 Observations

The maximum voltage flicker observed at the PCC is 4.94 % during the Peak load scenario when the project output changes from 0% to 100%.

3.2.5 Recommendations/Mitigations

Implement the recommended system improvements provided in Section 3.1.6 to mitigate identified voltage flicker violations.

3.2.6 Post-Mitigation Results

The following tables show the results from voltage flicker analysis during peak and minimum load conditions after implementing the mitigations listed in Section 3.1.6.

Table 3-13: Voltage Flicker - Peak Load Post-Mitigation (Project Output Change: 0% to 100%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 1	Scenario 2		Scenario 1	Scenario 2		Scenario 1	Scenario 2	
42-1A	121.71	120.98	-0.60%	121.86	121.08	-0.64%	122.17	121.53	-0.52%
PCC	121.90	125.19	2.70%	122.43	125.52	2.53%	121.93	125.43	2.87%

Table 3-14: Voltage Flicker - Peak Load Post-Mitigation (Project Output Change: 100% to 0%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 3	Scenario 4		Scenario 3	Scenario 4		Scenario 3	Scenario 4	
42-1A	121.75	122.51	0.62%	122.67	123.47	0.65%	123.12	123.80	0.55%
PCC	122.81	119.64	-2.58%	123.24	120.26	-2.42%	122.43	119.06	-2.76%

Table 3-15: Voltage Flicker - Minimum Load Post-Mitigation (Project Output Change: 0% to 100%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 5	Scenario 6		Scenario 5	Scenario 6		Scenario 5	Scenario 6	
42-1A	122.09	121.15	-0.77%	121.85	120.81	-0.86%	121.65	120.71	-0.77%
PCC	122.05	125.08	2.48%	121.67	124.30	2.16%	122.01	124.97	2.44%

Table 3-16: Voltage Flicker - Minimum Load Post-Mitigation (Project Output Change:100% to 0%)

Monitored Element	Va		% Change	Vb		% Change	Vc		% Change
	Scenario 7	Scenario 8		Scenario 7	Scenario 8		Scenario 7	Scenario 8	
42-1A	121.92	122.88	0.79%	122.37	123.43	0.87%	121.47	122.43	0.79%
PCC	122.73	119.83	-2.36%	122.81	120.24	-2.09%	122.68	119.78	-2.37%

3.2.7 Observations

With the proposed mitigations, the maximum voltage flicker observed at the PCC decreases to 2.87 % during Peak load scenario, when the project output changes from 0% to 100%. A thorough time series analysis was completed to further evaluate voltage flicker concerns and is provided in the succeeding section.

4.0 Time Series Analysis

DERs, such as PV systems and wind turbine generators, that act as variable generation sources introduce complexity to the distribution system. Within CYME, the Long-Term Dynamics Analysis module is capable of performing analysis that assists in understanding the impacts of load variations, irradiance variations, wind fluctuations, and ancillary market service signals on equipment such as regulators, load tap changers, and capacitor switching. Curves were developed to assess how the distribution circuit and its components would respond and perform under these scenarios. Control coordination and voltage control settings for regulators, tap changers, shunt caps and their sensitivities were monitored during this analysis.

4.1 Time Series Analysis Scenarios

Time series analysis was completed for the combinations of load conditions and generation profiles described in Table 4-1, utilizing the CYME Long-Term Dynamics Analysis module, to quantify the voltage flicker magnitudes and frequencies at the PCC.

Table 4-1: Long-Term Dynamics Analysis Scenarios

Scenario #	Load Model	Switched Devices	Existing DER Status	Project Status	Description
LTD1	Peak	Unlocked	Online	Online	High PV Variability
LTD2	Min	Unlocked	Online	Online	
LTD3	Peak	Unlocked	Online	Online	0% to 100% with (2% per second) soft-start ramp rate per ISO-NE SRD
LTD4	Min	Unlocked	Online	Online	

4.2 Voltage Flicker Analysis

Flicker may arise due to variable loads and distributed energy resources. The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2022 provides guidance on flicker and voltage fluctuations. Flicker values were assessed for compliance with the GE Flicker Visibility curve throughout the duration of the simulation. Statistical methods and probabilities are utilized in IEEE 1453-2022 to analyze flicker performance. For the Study, using the CYME Long-Term Dynamics Analysis module, rolling 10-minute windows were applied when evaluating the frequency of voltage flicker measured against the GE Visibility Flicker curve. 10-minute averaging windows helped to identify persistent flicker violations during this analysis.

4.2.1 Criteria

VEC requires that the Project shall not exceed flicker limits defined in IEEE 1453-2022 at the PCC. The flicker values were assessed for compliance with the recommended short-term flicker severity (Pst) planning threshold of 0.9 (applicable for medium voltage systems). The time step / voltage change frequency limits for Pst=0.9 were conservatively estimated utilizing the Pst=1 value in IEEE Std. 1453-2022, Table 4 and associated shape factors for square wave periodic changes in IEEE Std. 1453-2022, Annex C, Figure C.1.

4.2.2 Voltage Flicker Results

The results of the Voltage Flicker Analysis are provided in Table 4-2 and evaluated against the Maximum Allowable Voltage Fluctuation at the given frequency. The existing load of the circuit was evaluated following a two-hour trend from the maximum load day and a minimum load day.

The existing and proposed PV DERs on the circuit were evaluated following a generator curve that was developed using historical measured data from an existing PV facility. A generation curve for existing PV system sites within VEC territory was developed that represented a period of high variability in output, simulating the impacts of fast-moving cloud cover. The purpose was to simulate worst-case conditions by modeling existing PV systems under high output variability associated with fast-moving cloud cover using a high-variability generation curve. The Project was incorporated into the analysis with existing DER at high variability output to evaluate the contributing impacts of the Project.

The results of the Voltage Flicker Analysis are provided in Table 4-2.

Table 4-2: Voltage Flicker Analysis

BASELINE	0.1 CHANGES PER MINUTE	0.2 CHANGES PER MINUTE	0.4 CHANGES PER MINUTE	0.6 CHANGES PER MINUTE	1 CHANGES PER MINUTE	2 CHANGES PER MINUTE	3 CHANGES PER MINUTE	5 CHANGES PER MINUTE	7 CHANGES PER MINUTE	10 CHANGES PER MINUTE
Maximum Allowable Voltage Fluctuation	6.001	3.828	2.972	2.667	2.317	1.879	1.646	1.390	1.240	1.097
LTD 1	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS
LTD 2	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS
LTD 3	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS
LTD 4	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS	PASS

4.2.3 Voltage Flicker - Observations

The following observations are based on the scenarios described in Table 4-1.

- **No objectionable voltage flicker was observed for existing system conditions.**

4.2.4 Switched Device Analysis

Control coordination and voltage control settings for regulators, tap changers, shunt capacitors and their sensitivities were monitored during this analysis.

4.2.4.1 Criteria

Analysis was conducted for the operation of switched devices in the scenarios described in Table 4-1 with a target of reducing operations to approximately 50 changes or less within the 2-hour study period. The analysis focuses on the operations of the regulators and the recommended switched capacitor banks on the circuit. Existing capacitor banks on the circuit are fixed and are not included in this analysis.

4.2.4.2 Switched Device Results Discussion

Based on the results of the analysis, all switched devices on the 42-1A circuit are operating within the criteria following the proposed recommendations in the Steady State Analysis. The results for the Project operating under normal conditions are provided in Table 4-3 and Table 4-4.

Table 4-3: Regulator Tap Changing Summary (2-hour period)

Scenarios	Regulator	Phase	Tap Change Count	Minimum Tap	Maximum Tap	Average Tap	Load Model
LTD1	REG-42001	A	11	4	9	5	Peak Load
		B	5	4	7	5	
		C	27	4	10	6	
	REG-42363	A	19	-16	-1	-15	
	REG-42364	B	23	-16	-1	-14	
	REG-42365	C	0	0	0	0	
	REG-42216	A	0	0	0	0	
	REG-42214	B	0	0	0	0	
	REG-42215	C	0	0	0	0	
	NEW_VEC_REG	A	16	1	16	15	
		B	15	2	16	15	
		C	31	0	16	12	
	REG-42425*	A	58	-1	14	4	
LTD2	REG-42001	A	3	4	6	5	Min Load
		B	1	1	2	2	
		C	5	1	6	5	
	REG-42363	A	18	-16	2	-13	
	REG-42364	B	16	-16	0	-14	
	REG-42365	C	0	0	0	0	
	REG-42216	A	0	0	0	0	
	REG-42214	B	0	0	0	0	
	REG-42215	C	0	0	0	0	
	NEW_VEC_REG	A	18	-2	16	14	
		B	16	0	16	14	
		C	20	-3	16	14	
	REG-42425	A	66	-8	6	-3	
LTD3	REG-42001	A	0	0	0	0	Peak Load
		B	0	0	0	0	
		C	1	0	1	1	
	REG-42363	A	0	-16	-16	-16	
	REG-42364	B	13	-16	-3	-7	
	REG-42365	C	0	0	0	0	
	REG-42216	A	0	0	0	0	
	REG-42214	B	0	0	0	0	
	REG-42215	C	0	0	0	0	
	NEW_VEC_REG	A	0	16	16	16	
		B	15	1	16	6	
		C	1	0	1	0	
	REG-42425	A	1	2	3	3	

Scenarios	Regulator	Phase	Tap Change Count	Minimum Tap	Maximum Tap	Average Tap	Load Model
LTD4	REG-42001	A	0	8	8	8	Min Load
		B	0	2	2	2	
		C	1	2	7	7	
	REG-42363	A	0	-1	-1	-1	
	REG-42364	B	16	-16	0	-16	
	REG-42365	C	0	0	0	0	
	REG-42216	A	0	0	0	0	
	REG-42214	B	0	0	0	0	
	REG-42215	A	0	0	0	0	
	NEW_VEC_REG	A	15	1	16	16	
		B	15	1	16	16	
		C	14	1	16	16	
	REG-42425	A	20	-12	8	-11	

Note: REG-42425 is located on the adjacent feeder 42-3. The rest of the regulators listed in Table 4-3 are located on the study feeder, 42-1A.

Table 4-4: Capacitor Bank Switching Summary (2-hour period)

Scenario	Device Number	Phase	Switching Count	ON time (s)	OFF time (s)	Load Model
LTD1	NEW_CAP2	ABC	0	7200	0	Peak
	NEW_CAP1	ABC	1	596	6604	
LTD2	NEW_CAP2	ABC	1	601	6599	Min
	NEW_CAP1	ABC	1	596	6604	
LTD3	NEW_CAP2	ABC	0	7200	0	Peak
	NEW_CAP1	ABC	0	7200	0	
LTD4	NEW_CAP2	ABC	0	7200	0	Min
	NEW_CAP1	ABC	1	596	6604	

4.2.4.3 Recommendations

Assuming the recommended system modifications identified in the steady state analysis are implemented, no additional system improvements are required resulting from time series analysis.

5.0 Short Circuit Analysis

5.1 Short Circuit Analysis

The purpose of the short circuit analysis was to evaluate the impact of the Project on fault current levels on VEC's distribution system. A short circuit analysis using WindMil was performed to evaluate the incremental impact of the Project on system protection and adequacy of existing circuit breakers, other fault current interrupting devices, and related equipment on the Company EPS. Short circuit analysis was conducted for the case with the Project offline and with the Project online to evaluate the impact of the Project on fault currents on the 42-1A circuit and the VEC Irasburg Substation.

5.1.1 Criteria

The short circuit analysis was evaluated against the following criteria to identify violations:

- Change in available fault current at the PCC less than 10%.
- No protection device either over-sensitized or desensitized by more than 10%.
- No protection device over 100% of its duty rating.

5.1.2 Results

A short circuit analysis was performed to evaluate the incremental impact of the Project on system protection and adequacy of existing circuit breakers, fault current interrupting devices, and related equipment on the Company EPS. Short circuit analysis was conducted for the case with the Project offline and with the Project online to evaluate the impact of the Project on fault currents on the 42-1A circuit and Irasburg substation. Following the interconnection of the Project, the available fault current at the PCC increases by more 10 percent, as shown in the results summary in Table 5-1 below.

Table 5-1: Short Circuit Study Results (Post-Mitigation)

Equipment/Location	Feeder Id	Pre-Project Case		Post-Project Case		% Increase LLL	% Increase LG
		Max LLL (A)	Max LG (A)	Max LLL (A)	Max LG (A)		
Substation XFMR	–	3,921	4,244	4,133	4,408	5.41%	3.85%
42-1A Recloser	42-1A	3,921	4,244	4,133	4,408	5.41%	3.85%
42-3A Recloser	42-3A	3,921	4,244	4,133	4,408	5.41%	3.85%
PCC	42-1A	1,131	828	1,276	816	12.76%	-1.47%

5.1.3 Short Circuit - Observations

- The only overcurrent device upstream of the Project on VEC's distribution system is the 42-1A recloser.
- Fault current contribution greater than 10% was observed at the project PCC when the project is online.

5.1.4 Recommended System Improvements

Due to the Project's fault current contribution exceeding 10% at the PCC, a system protection coordination review is recommended to address identified short circuit concerns.

5.2 Temporary Overvoltage on Distribution System

Reverse power flow was observed in the analysis due to the aggregate generation exceeding the minimum load on the 42-1A circuit. This condition can cause a temporary overvoltage (TOV) as a result of:

- Ground Fault Over Voltage ("GFOV"): Should a line-to-ground fault occur on the 42-1A that causes the circuit breaker or line reclosers to open, the distribution system downstream of these devices loses its reference to the system neutral. The Project itself is considered as ineffectively grounded with three-phase inverter sources. Thus, the neutral can shift, and the inverter may not detect and operate in sufficient time to prevent damaging overvoltage to the system.
- Load Rejection Over Voltage ("LROV"): The inverters act as a constant current source, which can create a transient overvoltage event when a switch opens and forces all of the inverter current through a fixed load impedance.

The Company may require installation of a G&W Viper ST recloser to mitigate EPS impacts associated with load rejection and ground fault overvoltage, unless the Customer provides sufficient test data to show that the project inverters will not cause TGFOV outside of the CBEMA and ITIC acceptable ranges. Additionally, the Company requires all inverter-based projects to meet the settings requirements of the ISO-NE SRD.

5.3 Temporary Overvoltage on Transmission Supply

The Company requires that the minimum load-to-generation ratio on transmission systems be greater than 2 (i.e., total generation excluding direct transfer trip) for all distributed resources. Due to the reverse power flow condition identified in the study, the Company will require Direct Transfer Trip (DTT) for this Project to address TGFOV on the transmission system.

5.4 Effective Grounding

Effective grounding equivalency is defined as providing adequate protection to limit over-voltages to 125% of rated phase to neutral voltage. VEC requires all interconnecting distributed resources to be designed to support the effective grounding of its distribution circuits. To meet this requirement, inverter-based generators are required to be UL-certified. In addition, VEC requires the use of grounded wye primary winding in the generator step up (GSU) transformer to ensure that the distribution system voltage remains within acceptable during the brief interval required for the Project's main breaker to clear a fault.

The Project's GSU transformer uses a grounded wye primary winding as indicated in Table 2-1: and on the Interconnection Application Form submitted by the Customer. Based on the inverter datasheet, the Project inverters, CPS SCH250K-T-US-600, are compliant with UL1741 and UL1741 SA.

5.5 Inverter Protection Settings

The Company requires that all inverter-based DER, including this Project, be compliant with IEEE 1547-2018 and be certified per the requirements of UL 1741 SA. Specifically, the voltage and frequency settings, including the abnormal performance capabilities (ride through) and other grid support inverter functions, shall comply with the ISO-NE SRD.

The Customer is proposing the installation of twenty-four (24) CPS SCH250K-T-US-600 inverters rated at 250 kVA[7]. Based on the inverter datasheet, the CPS SCH250K-T-US-600 is compliant with UL1741, UL1741 SA, IEEE 1547-2018 AND ISO-NE SRD.

5.5.1 Voltage Setting Requirements / Ride Through

For three-phase inverters, the Company requires specific modifications to the overvoltage condition setting of the inverters. As part of ISO-NE SRD requirements, the Company requires the inverters to enter "momentary cessation" for overvoltage conditions while operating in the "Permissive Operation" mode (Table III: Inverters Voltage Ride through Capability and Operational Requirements of ISO-NE SRD). The Company requires the inverters to enter "Permissive Operation with Momentary Cessation" with a Maximum Response Time of 0.1s. If the proposed inverters are not capable of this Maximum Response time, a Category III inverter shall be used instead, which can comply with this requirement. For reference, see IEEE 1547-2018 6.4.2 Table 16.

Inverter responses to under voltages while operating in the "Permissive Operation" mode is specified and can be found in ISO-NE SRD document footnotes A and B.

5.5.2 Frequency Setting Requirements / Ride Through

In the event of abnormal frequencies, the Project shall cease to energize the area EPS according to *Table II: Inverter's Frequency Trip Settings* of the ISO-NE SRD document requirements.

5.6 Disconnect Switch

Per IEEE 1547-2018 Section 4.8 Isolation device, when required by the Area EPS operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the PCC. The Company requires a 600 A load break switch (or a Viper ST recloser) to be installed as a sectionalizing device for the line extension to the PCC.

5.7 Unintentional Islanding

The Project was screened using the Sandia National Laboratories risk-of-islanding screening tool. Results of the screening indicate that the Project presents a non-neglibible risk of unintentional islanding. Further evaluation is recommended to determine if additional anti-islanding protection is required.

Per IEEE 1547-2018 Section 8.1 Unintentional Islanding, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

If the Project is unable to detect an unintentional island and cease energizing the Company's distribution or transmission system within two seconds, the Company may require installation of a Direct Transfer Trip (DTT) system or equivalent anti-islanding protection to mitigate any islanding risks.

5.8 Direct Transfer Trip

Due to the size of the proposed Project and the resulting low minimum load-to-generation ratio at the Irasburg substation following interconnection, DTT will be required for this Project. The installation of the DTT scheme will be evaluated by VEC to come from the 42-1A recloser.

[7] Inverters derated to operate at 208.29 kWAC

5.9 Frequency

The Project will consist of twenty-four (24) CPS SCH250K-T-US-600 inverters rated at 250 kVA[8]. The Project inverter system is compliant with UL 1741 and IEEE 1547 standards. The ISO-NE SRD requires inverters to have settings that will address any abnormal (over and under) frequency conditions. The Project must meet the ISO-NE SRD requirements.

[8] Inverters derated to operate at 208.29 kWAC

6.0 Harmonics Screening

6.1 Harmonics Screening

A screening-level harmonic assessment was conducted to evaluate the potential impact of the proposed Project on voltage distortion at the Point of Common Coupling (PCC) under normal operating conditions. The analysis provides an order-by-order estimate of the Project's incremental harmonic contribution and compares post-project distortion levels against applicable industry standards to determine compliance and identify the need for further detailed evaluation.

6.1.1 Criteria

Harmonic distortion at the PCC was assessed against IEEE 519-2022 voltage limits, with thresholds of 3.0% for individual harmonic distortion and 5.0% for total harmonic voltage distortion ("THD_V") applicable for systems in the 1 kV to 69 kV range. The ENA EREC G5/5 Stage 2C framework was used to calculate harmonic voltages and impedance, while compliance determination was based solely on IEEE 519 limits. An IEEE 1547 current distortion benchmark was also included as a supporting reference.

6.1.2 Scenarios

The harmonic screening analysis was performed considering the normal feeder configuration, representing the expected steady-state operating condition of the system. Abnormal system configurations, switching conditions, and contingency scenarios were not included as part of this screening-level study.

6.1.3 Methodology

The harmonic screening analysis was performed using the ENA EREC G5/5 Stage 2C methodology as a computational framework to estimate the project's incremental harmonic impact at the Point of Common Coupling (PCC). Inverter harmonic current inputs were derived from the OEM test report, specifically Test Case 1, which represents a bounding worst-case emission condition. The harmonic current spectrum (orders h = 2 through 50) was first established on a consistent current base and referred to a common electrical reference, the transformer high-side or PCC basis. The plant configuration, consisting of two transformer groups with 12 inverters each, was represented by aggregating inverter currents arithmetically within each group, followed by combination at the PCC using IEC/TR 61000-3-6 power-law summation, applying order-dependent exponents to account for diversity effects.

The upstream network was represented by an equivalent Thevenin impedance at the PCC, derived from available short-circuit strength and X/R ratio data. Harmonic impedance for each order was obtained by scaling the fundamental impedance in accordance with ENA EREC G5/5 Stage 2C formulations, ensuring consistent treatment of frequency dependency and network characteristics. The incremental harmonic voltage contribution of the project was calculated on an order-by-order basis as the product of aggregated harmonic current and corresponding harmonic impedance, and expressed as a percentage of the nominal PCC voltage.

Complete measured background harmonic voltage data at the PCC for all harmonic orders from the 2nd through the 50th harmonic were not available. Therefore, background harmonic voltage distortion was assumed to be 75% of the applicable IEEE 519 individual harmonic voltage planning limit for each harmonic order. These assumed background values were combined with the project incremental contributions using consistent summation techniques to determine post-project harmonic voltage levels. Total harmonic voltage distortion (“THD_V”) was subsequently calculated using a root-sum-square (“RSS”) approach across all considered harmonic orders. The resulting post-project harmonic distortion levels were then compared against IEEE 519 voltage limits to evaluate compliance margins and identify any controlling harmonic orders that may warrant further detailed investigation.

6.1.4 Results

The detailed order-by-order harmonic screening results, including background, project incremental, and post-project voltage distortion levels, are provided in Appendix D. The results indicate that the Project does not screen as acceptable for harmonics under the assumed background conditions. The controlling individual harmonic is the 7th harmonic. The calculated post-project 7th harmonic voltage distortion is approximately 4.02%, compared with the selected IEEE 519 individual harmonic voltage distortion planning limit of 3.0%.

The calculated THD_V also exceeds the selected 5.0% planning criterion. This THD_V exceedance is primarily driven by the conservative assumption that background distortion is equal to 75% of the individual harmonic planning limit at every harmonic order from the 2nd through the 50th. Since the assumed spectrum is not based on complete PCC measurements, the THD_V result should be re-evaluated using measured PCC background harmonic data.

6.1.5 Recommendation

A detailed harmonic study is recommended before final interconnection approval or final determination of harmonic mitigation requirements. The study should include:

- PCC-specific background harmonic measurements for at least two weeks, including voltage THD and individual voltage harmonics from the 2nd through the 50th harmonic.
- EMT (PSCAD) modeling of the feeder, source system, Project step-up transformers, inverter harmonic emissions, and shunt capacitor banks.
- Evaluation of potential resonance conditions, including the effect of shunt capacitor banks.
- Evaluation of mitigation options if required, including inverter harmonic control settings, harmonic filtering, capacitor bank detuning or control modifications, operating restrictions, or other VEC-approved measures.

The detailed study should distinguish between pre-existing background harmonic distortion and the Project’s incremental contribution. The Project should not be assigned responsibility for correcting pre-existing harmonic exceedances that are not caused by the Project; however, the Project should demonstrate that it will not materially worsen existing harmonic distortion or provide mitigation for its incremental contribution if required by VEC.

7.0 System Impact Study Recommendations

7.1 Recommended System Improvements

- Install approximately 18,300 feet of primary overhead 556 ACSR conductor. Poles will need to be installed and replaced as necessary to meet the Company standards for the primary overhead three-phase configuration
    - Reconductor approximately 17,100 feet of existing three-phase overhead 2 ACSR and 4/0 ACSR conductor to three-phase 556 ACSR conductor from Span_48630 to Span_10439.
    - Upgrade approximately 1,000 feet single-phase overhead 2 ASCR conductor to three-phase overhead 556 ACSR conductor from Span_17410 to Span_47714.
    - Install a line extension of approximately 200 feet of three-phase overhead 556 ACSR conductor from Span_47714 to the Project PCC recloser.
- Install a set of three single-phase 328-Amp, 250 kVA line regulators at or near Span_48592 to maintain voltages within ANSI C84.1 limits.
- Decrease the voltage setpoint of the existing substation regulator from 123.5 V to 122 V to maintain voltages within ANSI C84.1 limits.
- Install two (2) three-phase 600 kVAR switched capacitor banks, each on feeders 42-1A and 42-3A, at or near Span_48484 and Span_39839, respectively.
- Fuses for the line extension will be reviewed and evaluated by VEC.
- The Company will install a three-phase recloser upstream from the Project and at the Project PCC.
- The Project will have a three-phase pole-mounted primary metering package or other VEC-approved metering package that accounts for transformer loss compensation installed upstream of (or on) a new customer riser pole.
- Installation of real-time (SCADA) communications from the Project to VEC.
- The Company will perform a detailed harmonic study before final interconnection approval or final determination of harmonic mitigation requirements.

7.2 Interconnection Customer Responsibility

The following is a summary of all items that were determined to be the responsibility of the interconnecting Project.

- Procuring and installing all Customer-owned components associated with the Project.
- All costs associated with system upgrades required to interconnect the Project as described in Recommended System Improvements, unless specifically noted as the responsibility of the Company.
- Providing necessary communications for data reporting.
- Providing inverter model information and specifications and ensuring compliance with UL 1741 SA and IEEE 1547-2018 standards.
- Providing under- and over-frequency and voltage settings for the inverters prior to the Facilities Study as determined by the Company. Inverter settings shall be in compliance with the ISO-NE SRD, IEEE 1547-2018 standard, and the NPCC Directory 12 Figure 1 Curve requirements for the Eastern Interconnection.

- Ensuring that the Project complies with ISO-NE SRD, UL 1741 SA, IEEE 1547-2018, and the Vermont Electric Cooperative Interconnection Guidelines at all times.
- Participating in and, as applicable, funding the detailed harmonic study required to evaluate the Project's incremental harmonic contribution at the PCC.
- Implementing VEC-approved harmonic mitigation measures, if required, to address the Project's incremental harmonic contribution.
- Providing post-installation or commissioning harmonic measurements at the PCC, if required by VEC, to verify harmonic performance following interconnection.

7.3 Conclusion

If the recommended system modifications are made to the 42-1A circuit and the Project, the Project should not have a negative impact on system thermal capability and voltage of the Area EPS under normal steady state and dynamic operating conditions.

If an event occurs with a recorded overvoltage at the PCC exceeding ANSI C84.1 Range A limitations and/or any reported damage to customer equipment, the Company reserves the right to disconnect the Project from the EPS. The developer will be responsible for all associated claims and for mitigation to prevent recurrence.

This study has been completed using information provided by the Interconnecting Customer, Novus Buck Solar, who submitted an Interconnection Application Form dated November 25, 2025.

In accordance with the Vermont Public Utility Commission Rule 5.500, the Company has completed a System Impact Study to determine the scope of the required modifications to its EPS to provide the requested interconnection service.

APPENDIX A – INTERCONNECTION APPLICATION

Date and Time Received:
Unique Application Number :

Certificate of Public Good Case No.

Rule 5.500 Application for Interconnection of Distributed Energy Resources Greater than 150 kW

This form may be made available in an electronically fillable format and it is permissible to submit the form with electronic signatures.

Preamble and Instructions:
An owner of a distributed energy resource who requests interconnection to a State-regulated distribution or transmission facility must submit an application to the Interconnecting Utility. An application is accepted as complete when it provides all applicable information required along with the required Application fee. A site plan and one-line diagram must be supplied with the Application. Additional information to evaluate a request for interconnection may be required after an Application is deemed complete.

1. Applicant Information:

Name: Novus Buck Solar LLC
Address [eSITE ID]: 50 Buck Road
City: Newport Center State: VT Zip: 05857
Telephone (Day): 347-891-0296 (Alternate): 802-242-1229
Email: alex@novusenergydev.com
Utility Consumption Meter Number (if applicable):
Name of Utility: Vermont Electric Coop

Representative: (e.g., System installation contractor or coordinating company, if appropriate)
Name: Alex Bravakis - Novus Energy Development
Address: 250 Main Street
City: Montpelier State: VT Zip: 05602
Telephone (Day): 347-891-0296 (Alternate):
Email: alex@novusenergydev.com

Will the Generation Resource be used for any of the following? Check all that apply

Net-Metering?	Yes☐	No☐
Group Net-Metering? (If yes, please provide group information directly to your utility)	Yes☐	No☐
Non-Exporting?	Yes☐	No☐
To participate in the Standard Offer Program?	Yes☐	No☐
Participate in the wholesale electricity market?	Yes☐	No☐
Qualifying Facility[1] where 100% of output will be sold to Interconnecting Utility?	Yes☐	No☐
Qualifying Facility[1] intending to sell power at wholesale to an entity other than Interconnecting Utility?	Yes☐	No☐

Other (describe):

[1] Evidence of FERC QF Certification will be required prior to commercial operation.

For an energy storage system, check the mode of operation below: (Check all that apply)

- ☐ Peak Shaving
- ☐ Retail Demand Management
- ☐ Emergency/Back-up
- ☐ Frequency Regulation
- ☐ Wholesale market participation(describe)_____
- ☐ Other (describe)_____

2. Project Specifications:

All power ratings should be listed in AC throughout unless otherwise noted

Physical Address [eSITE ID] : ☐ Same as above

_____

City:_____ State:_____ Zip:_____

Is this an amendment to an existing system? Check One Yes☐ No☐

If YES, what is existing CPG# _____

Please describe the proposed amendment: _____

_____

Requested Point of Interconnection (Include on site plan)_____

Requested in-service date: _____

Energy Source: Check all that apply

■ Solar ☐ Wind ☐ Hydro

☐ Energy Storage ☐ Other: _____

Interconnection Configuration? Check One

■ Generation Meter ☐ Behind Consumption Meter

Total number of inverters to be interconnected pursuant to this Application:_____
(24) CPS 250 kWAC, CPS SCH250K-T-US-600

Total Aggregate Nameplate Rating for all generators (kW): 4999 kWAC

Generating Export Capacity [2] (kW): 4999 kWAC

Individual Generator Data:

Provide for each Generator, use additional sheets if needed.

Type of Generator: Check One

■ DC Generator or Solar ☐ Synchronous ☐ Induction ☐ Other_____ Generator Manufacturer, Model Name & Number: CPS 250kWAC, CPS SCH250K-T-US-600

Power Rating per generator 250 kWAC Nameplate*

[2] As limited by any export controls.

*Inverters to be derated to operate at 208.29kWAC.

Photovoltaic (PV) Data

Panel Manufacturer HT-SAAE Jupiter 590 WDC Model HT72-18X(ND)-F

Quantity of PV panels 13,800 Power Rating per panel (DC Watts) 590 WDC

Total Power Rating (DC Watts) 8142.0 kWDC

☐ Roof Mount

■ Ground Mount

☐ Other

System Orientation: ■ fixed mount ☐ 1-axis tracking ☐ 2-axis tracking

Individual Inverter Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter Manufacturer: Chint Power Systems (CPS)

Model Name & Number: CPS SCH250K-T-US-600

Version Number:

Nameplate Rating: (kW) 250 kWAC* (kVA) 250 kVA (AC Volts) 600 VAC

Quantity of units installed: (24) *Inverters to be derated to operate at 208.29kWAC.

If Power Factor not Unity: Inverters to be operated at unity power factor.

Rated Power Factor: (Underexcited) N.A. (Overexcited) N.A.

Minimum Power Factor: (Underexcited) N.A. (Overexcited) N.A.

Do export controls apply to this inverter? (Check one) Yes ☐ No ■

- Is the inverter UL 1741 / IEEE 1547.1 Compliant?

  Yes ■ * No ☐

- Is the inverter certified per UL 1741-SA and compliant with ISO-NE's Inverter Source Requirements Document (ISO-NE SRD)?

  Yes ■ * No ☐

- Is the inverter certified per UL 1741-SB and compliant with ISO-NE's Default IEEE 1547-2018 Setting Requirements?

  Yes ■ * No ☐

If Yes to any of above bullets, include testing certificate or manufacturer a data sheet describing the inverter's UL 1741/IEEE 1547.1 listing.

*Please refer to attached inverter datasheet and Certificate of Compliance.

Induction Generators

Motoring Power (kW): ______

I22t or K (Heating Time Constant): ______

Rotor Resistance, Rr: ______ P.U.   Rotor Reactance, Xr: ______ P.U.

Stator Resistance, Rs: ______ P.U.   Stator Reactance, Xs: ______ P.U.

Magnetizing Reactance, Xm: ______ P.U.

Short Circuit Reactance, Xd: ______ P.U.

Exciting Current: ______ Amps

Temperature Rise: ______

Frame Size: ______

Design Letter: ______

Reactive Power Required in Vars (No Load): ______

Reactive Power Required in Vars (Full Load): ______

Total Rotating Inertia, H: ______ Per Unit on kVA Base

3. Transformer and Protective Relay Specifications

Will a transformer be used between the generator and the Point of Common Coupling?

Yes ☐ No ☐

Will the transformer be provided by the Interconnection Customer? Yes ■ No ☐

(a) Transformer Data: (if applicable, for Interconnection Customer-Owned Transformer)

Is the transformer? ☐ Single phase ■ Three phase (check one)

Size: (2) 2500 kVA kVA

Transformer Impedance: TBD* percent on TBD kVA Base *5.75% Assumed

If Three Phase:

Transformer Primary	12.47kV	Volts	☐ Delta	☐ Wye	■ Grounded Wye
Transformer Secondary	600 V	Volts	☐ Delta	☐ Wye	■ Grounded Wye
Transformer Tertiary	N.A.	Volts	☐ Delta	☐ Wye	☐ Grounded Wye

(b) Transformer Fuse Data: (if applicable, for Interconnection Customer-Owned Fuse)

Enclose/Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves

Manufacturer: TBD Type: TBD

Size: TBD Speed: TBD

APPENDIX B - STEADY STATE LOAD FLOW RESULTS

Steady State Load Flow Results

Provided as Microsoft Excel file attachments

APPENDIX C – TIME SERIES ANALYSIS RESULTS

Time Series Analysis Results

Scenario	0.1 CHANGES PER MINUTE	0.2 CHANGES PER MINUTE	0.4 CHANGES PER MINUTE	0.6 CHANGES PER MINUTE	1 CHANGES PER MINUTE	2 CHANGES PER MINUTE	3 CHANGES PER MINUTE	5 CHANGES PER MINUTE	7 CHANGES PER MINUTE	10 CHANGES PER MINUTE	Maximum Flicker %
	6.001	3.828	2.972	2.667	2.317	1.879	1.646	1.39	1.24	1.097	
LTD1	0	0	0	0	0	0	0	1	2	3	1.490%
LTD2	0	0	0	0	0	0	0	0	2	2	1.359%
LTD3	0	0	0	0	0	0	0	0	0	0	0.233%
LTD4	0	0	0	0	0	0	0	0	0	0	0.290%

Table C-1: Detailed Long Term Dynamic Results

Table C-1 shows the maximum number of flicker violations for a given rolling time frame. There were no voltage flicker violations greater than allowed number of changes for the given time. Also shown is the maximum voltage flicker measured during each analysis to verify that voltage flicker above 3% would not be seen at the Novus Buck Solar PCC. Figures C-1 to C-2 below show voltage plots at the Project PCC for the long-term dynamics scenarios listed in Table 4-1.

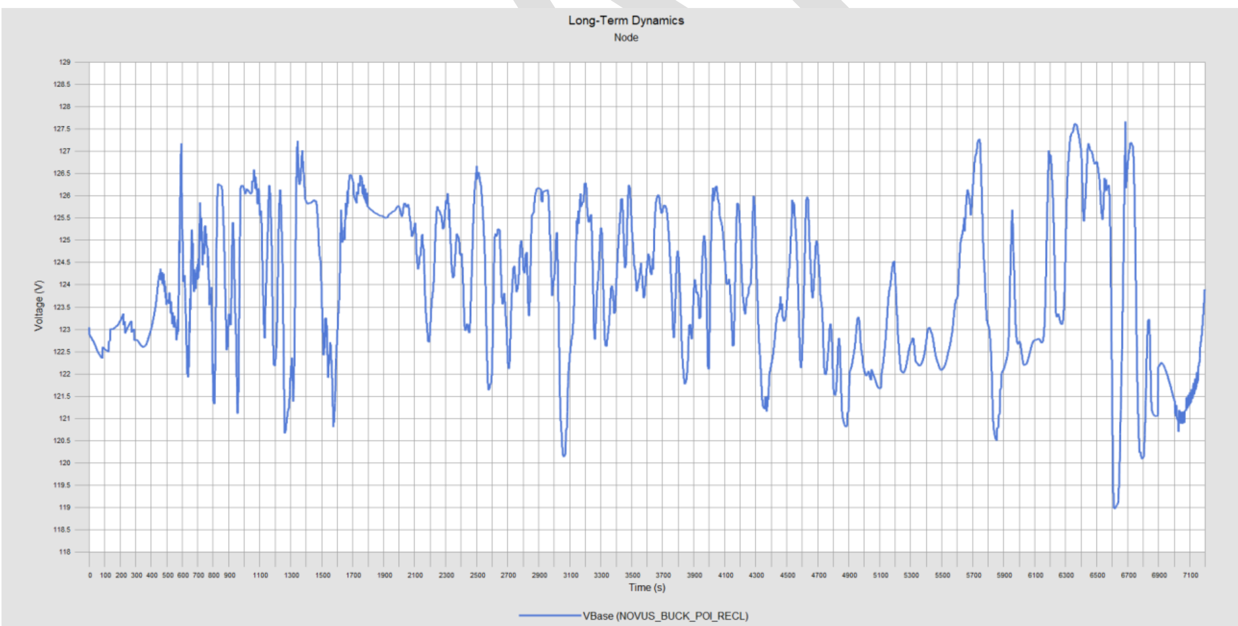


Figure C-3: Peak Load High Variability (Scenario 1)

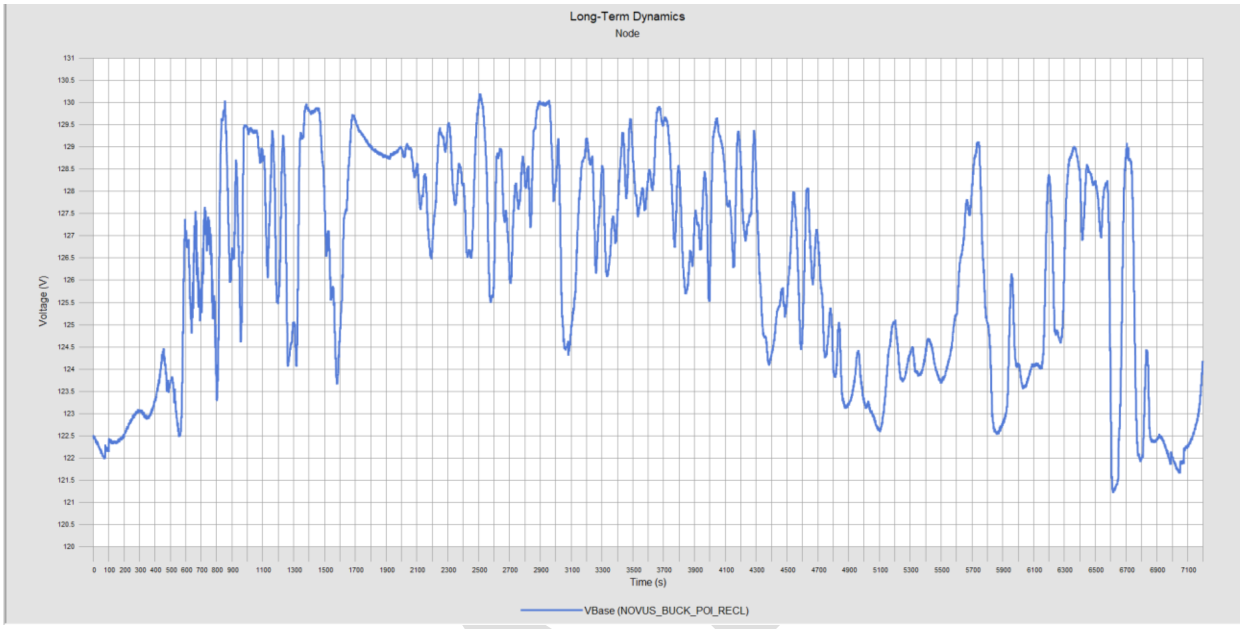


Figure C-4: Minimum Load High Variability (Scenario 2)

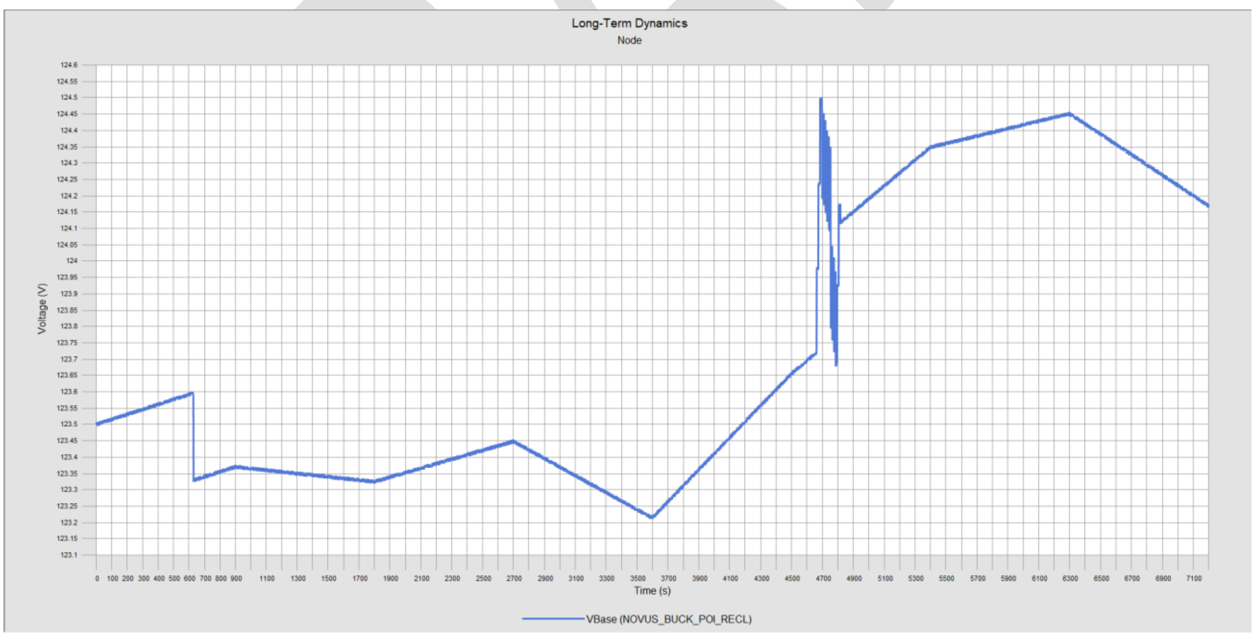


Figure C-5: Peak Load 2 PCT (Scenario 3)

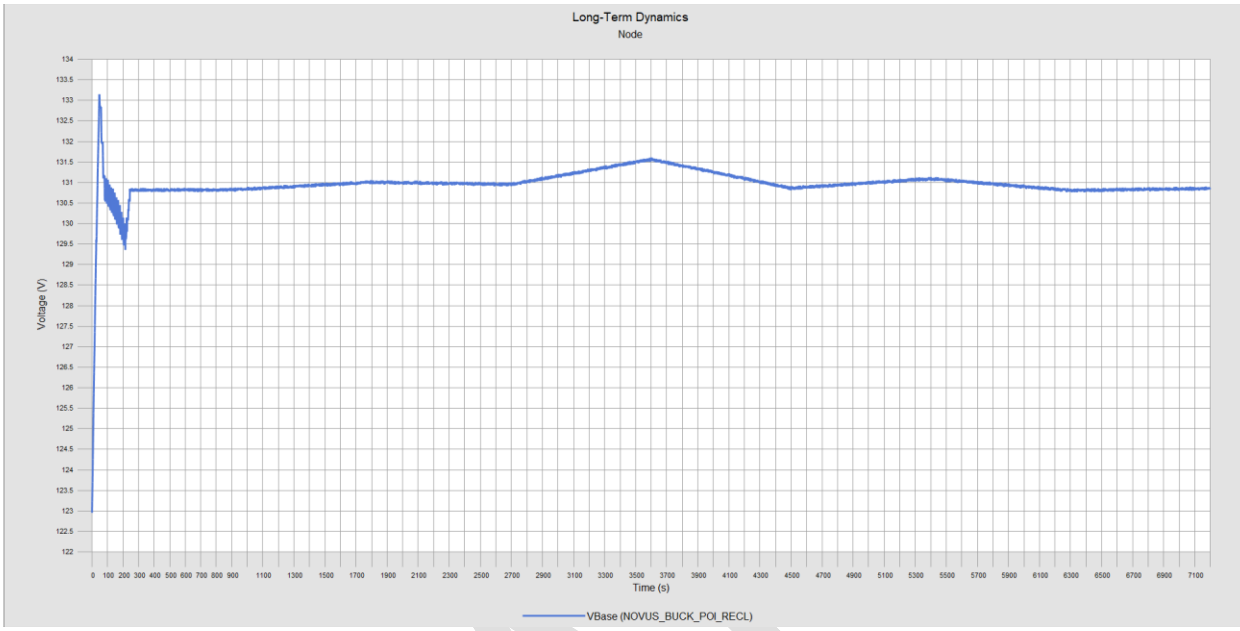


Figure C-6: Minimum Load 2 PCT (Scenario 4)

APPENDIX D – HARMONICS SCREENING RESULTS

Table D-1: IEEE 519 Harmonic Screening Results

h	Vbg(h) (%)	I_PCC_worst (A)	Z_h (ohm)	Vproj_worst (%)	Vpost_worst (%)	IEEE limit (%)	Margin (%)	Status
2	2.25	0.14	24.73	0.05	2.30	3	0.70	PASS
3	2.25	0.18	37.05	0.09	2.34	3	0.66	PASS
4	2.25	0.13	49.36	0.09	2.34	3	0.66	PASS
5	2.25	0.86	61.67	0.74	2.58	3	0.42	PASS
6	2.25	0.14	73.99	0.14	2.28	3	0.72	PASS
7	2.25	2.21	86.30	2.64	4.02	3	-1.02	FAIL
8	2.25	0.16	98.62	0.22	2.31	3	0.69	PASS
9	2.25	0.28	55.62	0.22	2.31	3	0.69	PASS
10	2.25	0.13	61.78	0.11	2.27	3	0.73	PASS
11	2.25	1.27	67.94	1.20	2.55	3	0.45	PASS
12	2.25	0.12	74.10	0.13	2.25	3	0.75	PASS
13	2.25	0.77	80.25	0.86	2.41	3	0.59	PASS
14	2.25	0.13	86.41	0.15	2.26	3	0.74	PASS
15	2.25	0.20	92.57	0.26	2.26	3	0.74	PASS
16	2.25	0.09	98.72	0.13	2.25	3	0.75	PASS
17	2.25	1.23	104.88	1.79	2.88	3	0.12	PASS
18	2.25	0.09	111.04	0.13	2.25	3	0.75	PASS
19	2.25	0.62	117.19	1.01	2.47	3	0.53	PASS
20	2.25	0.09	123.35	0.15	2.25	3	0.75	PASS
21	2.25	0.13	129.51	0.23	2.26	3	0.74	PASS
22	2.25	0.07	135.66	0.14	2.25	3	0.75	PASS
23	2.25	0.36	141.82	0.71	2.36	3	0.64	PASS
24	2.25	0.06	147.98	0.12	2.25	3	0.75	PASS
25	2.25	0.26	154.13	0.55	2.32	3	0.68	PASS
26	2.25	0.05	160.29	0.12	2.25	3	0.75	PASS
27	2.25	0.07	166.45	0.16	2.26	3	0.74	PASS
28	2.25	0.05	172.60	0.12	2.25	3	0.75	PASS
29	2.25	0.57	178.76	1.43	2.66	3	0.34	PASS
30	2.25	0.04	184.92	0.11	2.25	3	0.75	PASS
31	2.25	0.50	191.07	1.33	2.61	3	0.39	PASS
32	2.25	0.04	197.23	0.11	2.25	3	0.75	PASS
33	2.25	0.06	203.39	0.17	2.26	3	0.74	PASS
34	2.25	0.04	209.54	0.11	2.25	3	0.75	PASS
35	2.25	0.11	215.70	0.32	2.27	3	0.73	PASS
36	2.25	0.03	221.86	0.11	2.25	3	0.75	PASS
37	2.25	0.39	228.01	1.24	2.57	3	0.43	PASS
38	2.25	0.03	234.17	0.10	2.25	3	0.75	PASS
39	2.25	0.05	240.33	0.17	2.26	3	0.74	PASS
40	2.25	0.03	246.48	0.11	2.25	3	0.75	PASS
41	2.25	0.35	252.64	1.23	2.56	3	0.44	PASS
42	2.25	0.03	258.80	0.10	2.25	3	0.75	PASS

h	Vbg(h) (%)	I_PCC_worst (A)	Z_h (ohm)	Vproj_worst (%)	Vpost_worst (%)	IEEE limit (%)	Margin (%)	Status
43	2.25	0.21	264.95	0.78	2.38	3	0.62	PASS
44	2.25	0.02	271.11	0.09	2.25	3	0.75	PASS
45	2.25	0.05	277.27	0.18	2.26	3	0.74	PASS
46	2.25	0.02	283.42	0.09	2.25	3	0.75	PASS
47	2.25	0.16	289.58	0.64	2.34	3	0.66	PASS
48	2.25	0.02	295.74	0.08	2.25	3	0.75	PASS
49	2.25	0.19	301.89	0.80	2.39	3	0.61	PASS
50	2.25	0.02	308.05	0.07	2.25	3	0.75	PASS

Table D-2: Column Header Descriptions for Table D-1: IEEE 519 Harmonic Screening Results

Parameter	Description
h	Harmonic number
Vbg(h)	Background harmonics (assumed)
I_PCC_worst	Worst phase harmonic current at the PCC
Z_h (ohm)	Harmonic impedance at PCC
Vproj_worst	Project-induced harmonic voltage
Vpost_worst	Total post-project harmonic voltage
IEEE limit	Applicable harmonic distortion limit at PCC (IEEE 519)
Margin	Difference between IEEE limit and calculated value
Status	Compliance result (Pass / Fail against IEEE limit)

Table D-3: IEEE 1547 Benchmark Results

h	I_PCC_A (A)	I_PCC_B (A)	I_PCC_C (A)	I1_rated (A)	Ih_A (% of I1)	Ih_B (% of I1)	Ih_C (% of I1)	Benchmark limit (%)	Worst Ih (% of I1)	Margin (worst) (%)	Status (worst)
2	0.12	0.14	0.12	231.50	0.05	0.06	0.05	1	0.06	0.94	PASS
3	0.13	0.14	0.18	231.50	0.06	0.06	0.08	4	0.08	3.92	PASS
4	0.12	0.13	0.13	231.50	0.05	0.06	0.06	2	0.06	1.94	PASS
5	0.86	0.84	0.86	231.50	0.37	0.36	0.37	4	0.37	3.63	PASS
6	0.11	0.11	0.14	231.50	0.05	0.05	0.06	3	0.06	2.94	PASS
7	2.19	2.21	2.17	231.50	0.95	0.95	0.94	4	0.95	3.05	PASS
8	0.16	0.16	0.14	231.50	0.07	0.07	0.06	4	0.07	3.93	PASS
9	0.26	0.24	0.28	231.50	0.11	0.11	0.12	4	0.12	3.88	PASS
10	0.13	0.12	0.13	231.50	0.06	0.05	0.06	4	0.06	3.94	PASS
11	1.26	1.27	1.27	231.50	0.55	0.55	0.55	2	0.55	1.45	PASS
12	0.12	0.11	0.12	231.50	0.05	0.05	0.05	2	0.05	1.95	PASS
13	0.76	0.76	0.77	231.50	0.33	0.33	0.33	2	0.33	1.67	PASS
14	0.13	0.13	0.10	231.50	0.05	0.05	0.05	2	0.05	1.95	PASS
15	0.18	0.18	0.20	231.50	0.08	0.08	0.09	2	0.09	1.91	PASS
16	0.09	0.09	0.09	231.50	0.04	0.04	0.04	2	0.04	1.96	PASS
17	1.23	1.21	1.22	231.50	0.53	0.52	0.52	1.5	0.53	0.97	PASS
18	0.09	0.08	0.08	231.50	0.04	0.04	0.04	1.5	0.04	1.46	PASS
19	0.62	0.58	0.62	231.50	0.27	0.25	0.27	1.5	0.27	1.23	PASS
20	0.08	0.09	0.08	231.50	0.04	0.04	0.03	1.5	0.04	1.46	PASS
21	0.10	0.11	0.13	231.50	0.04	0.05	0.06	1.5	0.06	1.44	PASS
22	0.06	0.07	0.07	231.50	0.03	0.03	0.03	1.5	0.03	1.47	PASS
23	0.36	0.34	0.35	231.50	0.16	0.15	0.15	0.6	0.16	0.44	PASS
24	0.05	0.05	0.06	231.50	0.02	0.02	0.03	0.6	0.03	0.57	PASS
25	0.26	0.18	0.24	231.50	0.11	0.08	0.11	0.6	0.11	0.49	PASS
26	0.05	0.05	0.05	231.50	0.02	0.02	0.02	0.6	0.02	0.58	PASS
27	0.06	0.05	0.07	231.50	0.03	0.02	0.03	0.6	0.03	0.57	PASS
28	0.04	0.05	0.05	231.50	0.02	0.02	0.02	0.6	0.02	0.58	PASS
29	0.57	0.55	0.57	231.50	0.25	0.24	0.25	0.6	0.25	0.35	PASS
30	0.03	0.04	0.04	231.50	0.01	0.02	0.02	0.6	0.02	0.58	PASS
31	0.50	0.50	0.50	231.50	0.22	0.22	0.22	0.6	0.22	0.38	PASS
32	0.03	0.04	0.04	231.50	0.01	0.02	0.02	0.6	0.02	0.58	PASS
33	0.06	0.04	0.06	231.50	0.03	0.02	0.03	0.6	0.03	0.57	PASS
34	0.03	0.04	0.04	231.50	0.01	0.02	0.02	0.6	0.02	0.58	PASS
35	0.11	0.07	0.10	231.50	0.05	0.03	0.04	0.3	0.05	0.25	PASS
36	0.03	0.03	0.03	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
37	0.36	0.37	0.39	231.50	0.16	0.16	0.17	0.3	0.17	0.13	PASS
38	0.03	0.03	0.03	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
39	0.05	0.03	0.05	231.50	0.02	0.01	0.02	0.3	0.02	0.28	PASS
40	0.03	0.03	0.03	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
41	0.32	0.29	0.35	231.50	0.14	0.12	0.15	0.3	0.15	0.15	PASS

h	I_PCC_A (A)	I_PCC_B (A)	I_PCC_C (A)	I1_rated (A)	Ih_A (% of I1)	Ih_B (% of I1)	Ih_C (% of I1)	Benchmark limit (%)	Worst Ih (% of I1)	Margin (worst) (%)	Status (worst)
42	0.02	0.03	0.03	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
43	0.21	0.21	0.20	231.50	0.09	0.09	0.09	0.3	0.09	0.21	PASS
44	0.02	0.02	0.02	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
45	0.05	0.03	0.04	231.50	0.02	0.01	0.02	0.3	0.02	0.28	PASS
46	0.02	0.02	0.02	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
47	0.16	0.10	0.15	231.50	0.07	0.04	0.06	0.3	0.07	0.23	PASS
48	0.01	0.02	0.02	231.50	0.01	0.01	0.01	0.3	0.01	0.29	PASS
49	0.19	0.18	0.18	231.50	0.08	0.08	0.08	0.3	0.08	0.22	PASS

Table D-4: Column Header Descriptions for Table D-3: IEEE 1547 Benchmark Results

Parameter	Description
I_PCC_A, I_PCC_B, I_PCC_C	Phase harmonic current at PCC
I1_rated	Rated fundamental current
Ih_A, Ih_B, Ih_C	Phase harmonic current (% of fundamental)
Benchmark limit	Applicable harmonic current limit (IEEE 1547 reference)
Worst Ih	Maximum harmonic current among phases
Margin (worst)	Remaining margin to limit (based on worst phase)
Status (worst)	Compliance result based on worst phase (Pass/Fail)

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