Clements Gap BESS
132/33 kV Substation Project – Protection Settings Report

PSD1834-100-007

Prepared for

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A	Issued for Review	31/01/2025	S. Francis	S.K. Hards
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Table of Contents

Table of Figures

Table of Tables

1. Introduction

1.1. Purpose

PSD Energy Australia (PSD) has been awarded a contract for the primary and secondary design for the Clements Gap BESS, an inverter-based Battery Energy Storage System.

This document describes the settings of the protection IEDs to be installed at Clements Gap BESS. PSD Energy is responsible for the complete settings design of the new 132 kV and 33 kV protection IEDs at Clements Gap BESS Substation.

1.2. References

Table 1 – References

Drawing / Document Number	Rev	Description
PSD1834-110-001-001 to -004	0	132/33kV Substation Overall Simplified Single Line Diagram
PSD1834-110-002-001 to -004	0	132/33kV Substation Protection & Control Single Line Diagram
PSD1834-110-003-001 to -002	0	132/33kV Substation Metering Single Line Diagram
PSD1834-100-009	B	Protection Tripping Matrix
PSD1834-100-010	B	Protection Interlocking matrix
PSD1834-100-001	A	Clements Gap Battery Energy Storage System - Functional Design Specification – Secondary Plant
PSD1834-100-004	0	Cubicle, Relays, Part no, Firmware & Serial no Matrix
PSD1834-100-008	0	Clements Gap BESS Substation CT & VT Adequacy Calculations
PSD1834-100-006	A	400V AC Sizing Aux Board Report
PSD1834-100-012	A	400V AC Sizing Mini Substation
PSD1834-REP-500-002	0	Clements Gap BESS MV Cable Calculations
C53000-G5040-C016-G	V8.83	Siprotec 5 Transformer Differential Protection 7UT82/85/86/87 V8.83 and higher Manual
C53000-G5040-C017-F	V8.80	Siprotec 5 Overcurrent Protection 7SJ82/7SJ85 V8.80 and higher Manual
PCS-978S Transformer Relay	17/01/2022	PCS-978S Transformer Relay Technical Manual
PCS-9611S Feeder Relay	23/02/2023	PCS-9611S Feeder Relay Technical Manual
Clements Gap BESS GPS	07/09/2023	Clements Gap BESS Generator Performance Standards
EG.31018 - CG BESS TCA	1.0	Transmission Connection Agreement - Clements Gap Battery Energy Storage System Project
SW-AU-CGB-GEN-E-RPT-014	A	Clements Gap BESS Short Circuit Study Report

J25-0335-EL-RPT-001	A	Clement Gap BESS Power Study
MVPS Skid Protection Settings	04/11/2024	Email "MVPS Skid Protection Settings" from Krunal Soni
SieyaunTAL33-3000-BLW	v.10	3MVAr C-Type Harmonic Filter specification (Preliminary)
SieyaunTAL33-12000-BLW	v.10	12MVAr C-Type Harmonic Filter specification (Preliminary)
Sieyaun SY-2024-09-1019	0	NEC Design drawings
GRV240724(002)	24/07/2024	EEMC 70MVA Power Transformer Technical Data sheets
GRV240724(002) Annexure	07/02/2025	EEMC 70MVA Power Transformer Technical Data sheets – Overexcitation characteristics

1.3. Acronyms and Abbreviations

Table 2 – Acronyms and Abbreviations

AR	Automatic Reclose
BESS	Battery Energy Storage System
BU	Backup
CB	Circuit Breaker
CT	Current Transformer
CGBESS	Clements Gap Battery Energy Storage System,
DT	Definite Time
EF	Earth fault
EI	Extremely Inverse IEC curve
GPS	Generator Performance Standards
HV	High Voltage
IDMT	Inverse Definite Minimum Time (refers to IEC time/current curves)
IED	Intelligent Electronic Device (protection relay, DRMCC, RTU)
LV	Low Votlage
MV	Medium Voltage
MVPS	Medium Voltage Power Transformer
NEC	Neutral Earth Connection

NER	Neutral Earthing Resistor
NI/SI	Normal / Standard Inverse IEC curve
NPS	Negative Phase Sequence
NR	NARI
OC	Over-current
OF	Over Frequency
ONAN	Oil Natural, Air Natural (cooling, as related to power transformer rating)
ONAF	Oil Natural, Air Forced (cooling, as related to power transformer rating)
ODAF	Oil Directed, Air Forced (cooling, as related to power transformer rating)
OV	Overvoltage
POC	Point Of Connection
PSD	Power System Design (PSD Energy)
REF	Restricted Earth Fault
RMU	Ring Main Unit
ROCOF	Rate of Change of Frequency
TCC	Time Current Curve
UF	Under Frequency
UV	Undervoltage
VI	Very Inverse IEC curve

2. Network Information

2.1. Overview

2.1.1. Transmission System

The Clements Gap BESS (CGBESS) connects into the into the 132 kV transmission network via the new ElectraNet Clements Gap North (CGN) 132 kV Substation. The Clements Gap North 132kV Substation interconnects the Clements Gap Windfarm (CGWF) and Clements Gap BESS via on OHL to Red Hill (RH) 132kV Substation to dispatch energy to the grid.

2.1.2. 33 kV Distribution System

Clements Gap BESS is a Battery Energy Storage Farm consists of 25 inverters, each with a maximum output power of 3.62 MW, 25 2-winding 33/0.69 kV transformers, one medium voltage busbar (Busbar 1) and a 2-winding 132/33 kV transformer.

2.2. Plant Ratings

2.2.1. 132/33 kV Transformer

Table 3 – 132/33 kV Transformer Data

Manufacturer	Dong Anh Electrical Equipment Corporation - JSC	
Rated Voltage	**HV**	132 kV
	LV	33 kV
Rating	**ONAN**	**ONAF**
Rated Power	45 MVA	70 MVA
Rated Current (HV)	197 A	306 A
Rated Current (LV)	787 A	1225 A
Vector Group	YNyn0	
% Impedance	13 % @ 70 MVA (IEC tolerance ±7.5%)	
Frequency	50 Hz	
Tap Range	132 (-15.75 to +12.25) x 1.75% (17 Taps)	
No load losses	≤ 39.9kW	
Copper losses	≤ 260kW @ 75°C	

2.2.2. 33/0.4 kV Auxiliary Transformer

Table 4 – 33/0.4 kV Auxiliary Transformer Data

Manufacturer	Dong Anh Electrical Equipment Corporation - JSC	
Rated Voltage	**HV**	33 kV
	LV	0.4 kV
Rated Power (ONAN)	315 kVA	
Rated Current (HV)	5.5 A	
Rated Current (LV)	455 A	
Vector Group	Dyn11	
% Impedance	5 % @ 315 kVA (Nominal Tap)	
Frequency	50 Hz	
Zero sequence Short-circuit impedance	5 %	

2.2.3. 33/0.4 kV MVPS Auxiliary Transformer

Table 5 – 33/0.4 kV MVPS Auxiliary Transformer Data

Manufacturer	Dong Anh Electrical Equipment Corporation - JSC	
Rated Voltage	**HV**	33 kV
	LV	0.4 kV
Rated Power (ONAN)	500 kVA	
Rated Current (HV)	8.75 A	
Rated Current (LV)	722 A	
Vector Group	Dyn11	
% Impedance	4 % @ 500 kVA (Nominal Tap)	
Frequency	50 Hz	
Zero sequence Short-circuit impedance	5 %	

2.2.4. 33 kV Neutral Earthing Resistor

Table 6 – 33 kV Neutral Earthing Resistor Data

Manufacturer	Sieyuan Electrical
Rated Voltage	33 / √3 kV
Rated Current	1000 A / 10 s
Resistance (at 20°C)	19.05 Ω
Frequency	50 Hz

2.2.5. 33 kV Harmonic Filter Bank

Table 7 – 33 kV Harmonic Filter Bank Data – 12 Mvar

Manufacturer	Sieyuan
Harmonic Filter	1 x 12 Mvar Harmonic Filters (C-type)
Rated Voltage	33 kV
Reactive Power at System Voltage	12 Mvar
Capacitance C1	35.1 µF
Capacitance C2	774.1 µF
Resistance	11.8 Ω
Inductance	13.1 mH
Frequency	50 Hz

Table 8 – 33 kV Harmonic Filter Bank Data – 3 Mvar

Manufacturer	Sieyuan
Harmonic Filter	1 x 3 Mvar Harmonic Filters (C-type)
Rated Voltage	33 kV
Reactive Power at System Voltage	3 Mvar
Capacitance C1	8.78 µF
Capacitance C2	8147.7 µF
Resistance	89.3 Ω
Inductance	1.24 mH
Frequency	50 Hz

2.2.6. 33 kV Switchgear

Table 9 – 33 kV Circuit Breaker Data

Manufacturer	Ormazabal Velatia	
Type	cpg.0 (Incomers)	cpg.0 (Feeders)
Rated Voltage	36 kV	36 kV
Rated Current	2000 A	630 A
Rated short circuit time withstand current	25 kA / 3 s	25 kA / 3 s
Frequency	50 Hz	50 Hz

2.3. Fault Level Summary

Fault level data is based on the information provided in the Clements Gap BESS Power Study Report (J25-0035-EL-RPT-001 of August 2024). A summary of the information provided in this report is in Table 10 and Table 11.

Table 10 – Maximum Fault Levels

Location	LLL (A)	LL (A)	LLG (A)	LG (A)
132 kV POC	7,047	5,906	6,671	6,834
33 kV Main Switchboard	8,824	6,651	6,925	976
33 kV MPVS	8,802	6,636	6,910	975 *
0.69 kV Inverter	40,062	32,344	32,346	0 *

(*) Worst case of all MVPS's

Table 11 – Minimum Fault Levels

Location	LLL (A)	LL (A)	LLG (A)	LG (A)
132 kV POC	3,282	2,692	3,068	3,112
33 kV Main Switchboard	6,447	4,945	5,211	970
33 kV MPVS	6,382	4,904	5,168	966 *
0.69 kV Inverter	39,214	32,266	32,262	0 *

(*) Worst case of all MVPS's

2.4. Maximum 33 kV Cable Loading

As per the Clements Gap BESS MV Cable Calculations report (PSD1834-REP-500-002), the cable cyclic ratings can be summarised in Table 12.

Table 12 – Cable Ratings

Cable	Calculated Cyclic Rating (A)	Required Cyclic Rating (A)
Power Transformer Cables 19/33kV (36kV) - 2 x single core 630 mm2 Al XLPE PVC HDPE per phase	1,442	1,225
5 x Inverter Transformer Feeders 19/33kV (36kV) - 1 x three core 300 mm2 Al XLPE PVC HDPE	360	338.75
Auxiliary Transformer Cables 19/33kV (36kV) - 1 x three core 120 mm2 Al XLPE PVC HDPE	161.6 (continuous)	N/A
Harmonic Filter Cables * 19/33kV (36kV) - 1 x three core 300 mm2 Al XLPE PVC HDPE	309.1	286.8

Note (*) only cable from 33kV Feeder switchgear to first Harmonic Filter need be shown.

3. 132/33 kV Transformer Protection

Transformer biased differential protection is duplicated in the Transformer X (Siemens 7UT85) and Transformer Y (NR PCS-978S) relays. The protection functions to be implemented in these relays are highlighted in Table 13.

Table 13 – Protection Functions

Siemens 7UT85	NR PCS-978S
Transformer Differential Protection (87T)	Transformer Differential Protection (87T)
Transformer HV REF (87NH)	Transformer HV REF (87NH)
Transformer LV REF (87NL)	Transformer LV REF (87NL)
Transformer HV side Overcurrent (51H)	Transformer HV side OC (51H)
Transformer LV side Overcurrent (51L)	Transformer LV side Overcurrent (51L)
Transformer LV Neutral Overcurrent (51NL)	Transformer LV Neutral Overcurrent (51NL)
Volts/Hertz Overexcitation (24)	Volts/Hertz Overexcitation (24)
132kV Breaker Failure (50BF1) *	132kV Breaker Failure (50BF1) *
33kV Breaker Failure (50BF2)	33kV Breaker Failure (50BF2)
Over/Under Frequency (81O/U)	Over/Under Frequency (81O/U)
Under/Over Voltage (27/59)	Under/Over Voltage (27/59)
Rate of Change of Frequency (81R)	Disturbance Fault Recorder (DFR)
Disturbance Fault Recorder (DFR)	
BCU Control (CTRL)	

(*) Logical inter trip received from Electranet only.

The part number and Firmware for these relays are summarised in Table 14.

Table 14 – Protection Relays

Transformer ID	Protection	Relay Part Number	Relay Firmware Number
Transformer 1	Siemens 7UT85	P1F1076066	v9.71
	NR PCS-978S	PCS-978S-A-AA-RX.XX-ACAA-CAAAC-A-BXAXAXLEDEIXXXX-R1	Latest

3.1.1. Set X – Siemens 7UT85

Siemens 7UT85 provides differential protection in the form of operate / restraint plane characteristic as per Figure 1 below.

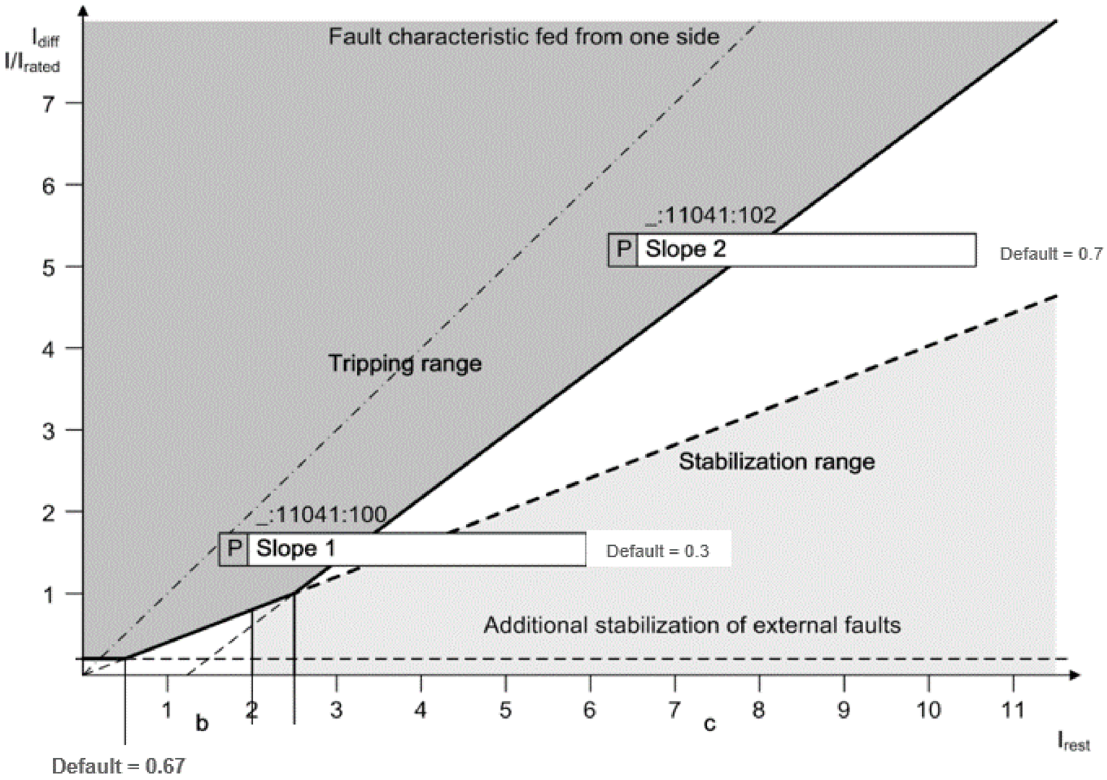


Figure 1 - Siemens 7UT85 Differential Characteristic

Biased Differential Pickup

As per the manufacturer recommendation the pickup can be set sensitive since a relatively small magnetizing current flows into the transformer as a constant differential current. To include errors which may arise from tap change errors, the pickup value should be increased to a higher value. The manufacturer recommends satisfying the following equation when no tap changers are present.

$$\mathrm{I_{pickup}} = 0.2$$

As per the manufacturer requirement, when including a tap changer, the setting should be increased with the following relationship.

$$\mathrm{I_{pickup}} = 0.2 + k_{StS} \times \text{Intersection } 1, \mathrm{I_{rest}}$$

$$k_{StS} = \frac{(100\% + St_{max}) - (100\% - St_{min})}{(100\% + St_{max}) + (100\% - St_{min})} = \frac{(100\% + 12.25\%) - (100\% - 15.75\%)}{(100\% + 12.25\%) + (100\% - 15.75\%)}$$

$$k_{sts} = 0.142$$

$$\text{Intersection 1, } I_{rest} = 0.67 \quad \text{(recommended default setting)}$$

Thus:

$$I_{pickup} = 0.2 + 0.142 \times 0.67 = 0.30$$

Set differential pickups to manufacturer's recommendations,

$$I_{pickup} = 0.30 \times I_{rated}$$

The differential pickups of 0.30 will operate on the HV and LV side of the transformer as follow.

$$I_{pickup\ HV} = 0.30 \times \frac{70\ \text{MVA}}{\sqrt{3} \times 132\ \text{kV}} = 90\ \text{A}$$

$$I_{pickup\ LV} = 0.30 \times \frac{70\ \text{MVA}}{\sqrt{3} \times 33\ \text{kV}} = 362\ \text{A}$$

The selected Diff MinOp (362 A) detects the minimum in-zone fault (LG = 0.97 kA) by an operating factor of 2.7.

Slope 1

For multi-slope biased differential, the first slope must accommodate all possible errors that may cause mismatch in the transformer HV to LV current transfer. The error sources in the following table are worst-case scenario values, calculated as a percentage differential current for load or fault current flowing through the transformer.

$$I_{d\ Max} = (1 + \text{CT error}) - \frac{1 - \text{CT error}}{1 + \text{TF ratio variation}}$$

$$I_{d\ Max} = (1 + 0.1\ \%) - \frac{1 - 0.1\ \%}{1 + 15.75\ \%} = 13.79\ \%$$

Table 15 – Possible errors for load currents up to 2.5 times nominal current

Error Source	No.1, 2 & 3 Trans Value
CT error (up to ~ 2.5 x INominal)	0.1 %
Transformer ratio variation (maximum)	15.75 %
Maximum Differential Current error	13.79 %
Transformer excitation current (maximum)	3 %
Relay measurement error (maximum)	5 %
Total Error (E)	21.79 %

The operate and restraint calculations for the SIEMENS 7UT85 relay is as follows:

Differential current: $\mathrm{I_{diff}} = |\mathrm{I_1} + \mathrm{I_2}|$ Restraint current: $\mathrm{I_{res}} = \mathrm{Max}(|\mathrm{I_1}|, |\mathrm{I_2}|)$

With full load current and error as calculated above, the differential current is calculated as follows.

$$\mathrm{I_1} = 1.00\ \mathrm{pu}$$

$$\mathrm{I_2} = \frac{-1.00\ \mathrm{pu}}{1 + \mathrm{E}} = \frac{-1.00\ \mathrm{pu}}{1 + 21.79\ \%} = -0.82\ \mathrm{pu}$$

$$\mathrm{I_{diff}} = |\mathrm{I_1} + \mathrm{I_2}| = |1.00\ \mathrm{pu} - 0.82\ \mathrm{pu}| = 0.18\ \mathrm{pu}$$

The restraint is calculated as follows.

$$\mathrm{I_{res}} = \mathrm{Max}(|\mathrm{I_1}|, |\mathrm{I_2}|) = \mathrm{Max}(1.00\ \mathrm{pu}, 0.82\ \mathrm{pu}) = 1.00\ \mathrm{pu}$$

Therefore, the minimum corresponding slope is

$$\mathrm{Slope\ 1} = \frac{\mathrm{I_{diff}}}{\mathrm{I_{res}}} = 17.89\ \%$$

The Slope 1 setting should be greater than the calculated total error of 21.79 % and greater than the calculated minimum corresponding slope of 17.9 %.

Therefore, set the slope as follows:

$$\mathrm{Slope\ 1} = 0.25$$

Siemens recommends keeping $\mathrm{Intersection\ 1}, \mathrm{I_{rest\ 1}}$ the default setting of 0.67.

Therefore, set $\mathrm{I_{rest\ 1}}$ as per manufacturer's recommendation:

$$\mathrm{I_{rest\ 1}} = 0.67$$

Slope 2

The second slope is utilised to accommodate the increasing errors which occur as current increases beyond 2.5 × nominal current, without loss of sensitivity for small internal fault currents. Therefore, set the second slope to start at 250 % of transformer maximum rated current. In the following table are worst-case scenario values, calculated as a percentage differential current for load or fault current flowing through the transformer.

$$I_{d\,Max} = (1 + \text{CT error}) - \frac{1 - \text{CT error}}{1 + \text{TF ratio variation}}$$

$$I_{d\,Max} = (1 + 20\,\%) - \frac{1 - 20\,\%}{1 + 15.75\,\%} = 50.89\,\%$$

Table 16 - Possible errors for load currents over 2.5 times nominal current

Error Source	No.1, 2 & 3 Trans Value
CT error (worst case – partial saturation)	20 %
Transformer ratio variation (maximum)	15.75 %
Maximum Differential Current error	50.89 %
Transformer excitation current (maximum)	3 %
Relay measurement error (maximum)	10 %
Total Error (E)	63.89 %

With 5 x full load current and error as calculated above:

$$I_1 = 5.00 \text{ pu}$$

$$I_2 = \frac{-5.00 \text{ pu}}{1 + E} = \frac{-5.00 \text{ pu}}{1 + 63.89\,\%} = -3.05 \text{ pu}$$

$$I_{diff} = |I_1 + I_2| = |5.00 \text{ pu} - 3.05 \text{ pu}| = 1.95 \text{ pu}$$

The restraint is calculated as follows:

$$I_{res} = \text{Max}(|I_1|, |I_2|) = \text{Max}(5.00 \text{ pu}, 3.05 \text{ pu}) = 5.00 \text{ pu}$$

Therefore, the minimum corresponding slopes are:

$$\text{Slope 2} = \frac{I_{diff}}{I_{res}} = 38.98\,\%$$

Therefore, set Slope 2 at least 2 times of Slope 1 as per Siemen’s recommendation and greater than the calculated total error of 63.89 %:

$$\text{Slope 2} = 0.70$$

Siemens recommends keeping $\text{Intersection 2}, I_{rest\,2}$ the default setting of 2.50.

Therefore, set $I_{rest\,2}$ as per manufacturer’s recommendation:

$$I_{rest\,2} = 2.50$$

Unrestrained Differential

An un-restrained operating element is set to react quickly to very heavy current levels that clearly indicate an internal fault. This element only responds to fundamental frequency component of the differential operating current. It must be set high enough, so it does not operate for large inrush currents. Industry standard sets the pickup level to about 10 times transformer rated current. Note however that the setting needs to also be below the minimum fault level where the instantaneous differential setting is used to obtain fast clearance of high fault current internal faults.

Siemens recommends setting the unrestrained differential element using the following equation.

$$\mathrm{I_{diff\ unrest}} = \frac{1}{\mathrm{U_T}} \times \mathrm{I_n}$$

Where

$$\mathrm{U_T} = \text{Transformer \%Z}$$

$$\mathrm{I_{diff\ unrest}} = \frac{1}{0.13} \times \mathrm{I_n} = 7.69\ \mathrm{I_n}$$

Therefore, set

$$\mathrm{I_{diff\ unrest}} = 8.00\ \mathrm{p.u.}$$

Second Harmonic Restraint

The second harmonic restraint level should not be set too low, as it may incorrectly inhibit the differential relay from detecting a real internal transformer fault during energisation.

Generally, the ratio of second harmonic current to fundamental current in transformer inrush exceeds 30 %. Setting the detection level to 15% is considered safe and is the normal recommended setting. This setting generally only needs to be lowered if the transformer has a long cable connected to the secondary terminals (which would reduce the second harmonic content).

Therefore, set

$$\text{2nd harmonic}_{\text{pickup}} = 15\ \%$$

Fifth Harmonic Restraint

Fifth harmonic restraint shall be set according to the manufacturer’s recommendations to prevent maloperation during transformer overvoltage or over flux conditions.

Therefore, set

$$\text{5th harmonic}_{\text{pickup}} = 30\ \%$$

3.1.2. Set Y – NARI PCS978S

The NR PCS-978S provides differential protection in the form of operate / restraint plane characteristic as per Figure 2 below.

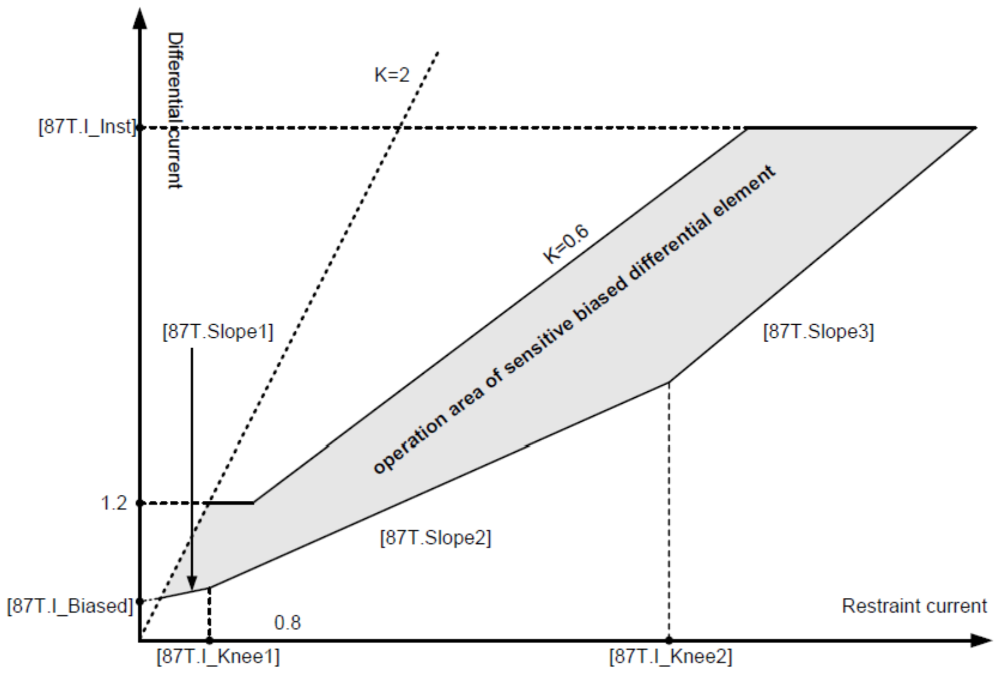


Figure 2 - NR PSC-987S Sensitive Differential Characteristic

Sensitive Biased Differential Knee Point

The following Knee values are recommended by NARI:

$$87T.I_{Knee1} = 0.5$$

$$87T.I_{Knee2} = 6.0$$

Sensitive Biased Differential Pickup

The transformer biased differential setting should be set at a minimum to ensure sensitivity however it should be set high enough to ensure the differential element will not operate for currents caused by errors from to CT inaccuracies and current variations due to transformer magnetizing current and relay measurement errors. To set similar to the Set X Siemens Relay as per Section 3.1.1, the pickup shall be selected as

$$\mathrm{87T.I\ Biased\ (PCS978S)} = I_{\mathrm{Pickup}}\ \mathrm{(7UT86)} = 0.3 \times \mathrm{I_{Base}} = 0.3 \times \frac{70\ \mathrm{MVA}}{\sqrt{3} \times 33\ \mathrm{kV}} = 362\ \mathrm{A_P}$$

Therefore set

$$\mathrm{87T.I}\ Biased = 0.30 \times \mathrm{I_B}$$

The selected Diff MinOp (362 A) detects the minimum in-zone fault (LG = 0.97 kA) by an operating factor of 2.7.

Slope 1 & 2

As per Set X, for multi-slope biased differential, the first slope must accommodate all possible errors that may cause mismatch in the transformer HV to LV current transfer. The operate and restraint calculations for the NARI PCS-978S are as follows:

Differential current: $\mathrm{I_{diff}} = |\mathrm{I_1} + \mathrm{I_2}|$ Restraint current: $\mathrm{I_{res}} = \frac{|\mathrm{I_1}|+|\mathrm{I_2}|}{2}$

With full load current and error as per Table 15, the differential current is calculated as follows.

$$\mathrm{I_1} = 1.00\ \mathrm{pu}$$

$$\mathrm{I_2} = \frac{-1.00\ \mathrm{pu}}{1 + \mathrm{E}} = \frac{-1.00\ \mathrm{pu}}{1 + 21.79\ \%} = -0.82\ \mathrm{pu}$$

$$\mathrm{I_{diff}} = |\mathrm{I_1} + \mathrm{I_2}| = |1.00\ \mathrm{pu} - 0.82\ \mathrm{pu}| = 0.18\ \mathrm{pu}$$

The restraint is calculated as follows.

$$\mathrm{I_{res}} = \frac{|\mathrm{I_1}| + |\mathrm{I_2}|}{2} = \frac{|1.00\ \mathrm{pu}| + |-0.82\ \mathrm{pu}|}{2} = 0.91\ \mathrm{pu}$$

Therefore, the minimum corresponding slope is

$$\mathrm{Slope\ 1} = \frac{\mathrm{I_{diff}}}{\mathrm{I_{res}}} = 19.65\ \%$$

Therefore, set the slope as follows:

$$87T.Slope1 = 0.20$$

$$87T.Slope2 = 0.50$$

Slope 3

The third slope is utilised to accommodate the increasing errors which occur as current increases beyond 2.5 × nominal current, without loss of sensitivity for small internal fault currents.

With 5 x full load current and error as per Table 16, the differential current is calculated as follows.

$$I_1 = 5.00\ \mathrm{pu}$$

$$I_2 = \frac{-5.00\ \mathrm{pu}}{(1 + E)} = \frac{-5.00\ \mathrm{pu}}{(1 + 63.89\ \%)} = -3.05\ \mathrm{pu}$$

$$\mathrm{I_{diff}} = |I_1 + I_2| = |5.00\ \mathrm{pu} - 3.05\ \mathrm{pu}| = 1.95\ \mathrm{pu}$$

The restraint is calculated as follows.

$$I_{res} = \frac{|I_1| + |I_2|}{2} = \frac{|5.00\ pu| + |1.95\ pu|}{2} = 4.03\ pu$$

Therefore, the minimum corresponding slope is

$$Slope\ 1 = \frac{I_{diff}}{I_{res}} = 48.42\ \%$$

Therefore, set the slope as follows:

$$87T.Slope3 = 0.75$$

Unrestrained Differential

An un-restrained operating element is set to react quickly to very heavy current levels that clearly indicate an internal fault. The settings shall be set as per the Set X relay, hence as per Section 3.1.1 set

$$87T.I\_Inst = 8.00\ p.u.$$

Second Harmonic Restraint

The second harmonic restraint will be set to match the Set X protection, hence

$$87T.K_H m2_I nrush = 15\ \%$$

Fifth Harmonic Restraint

The fifth harmonic restraint will be set to match the Set X protection, hence

$$87T.K\_Hm3/Hm5\_OvExc = 30\ \%$$

3.2. Transformer REF (87NH & 87NL)

3.2.1. Set X – Siemens 7UT85

Siemens 7UT85 provides REF protection in the form of operate / restraint plane characteristic as per Figure 3 below.

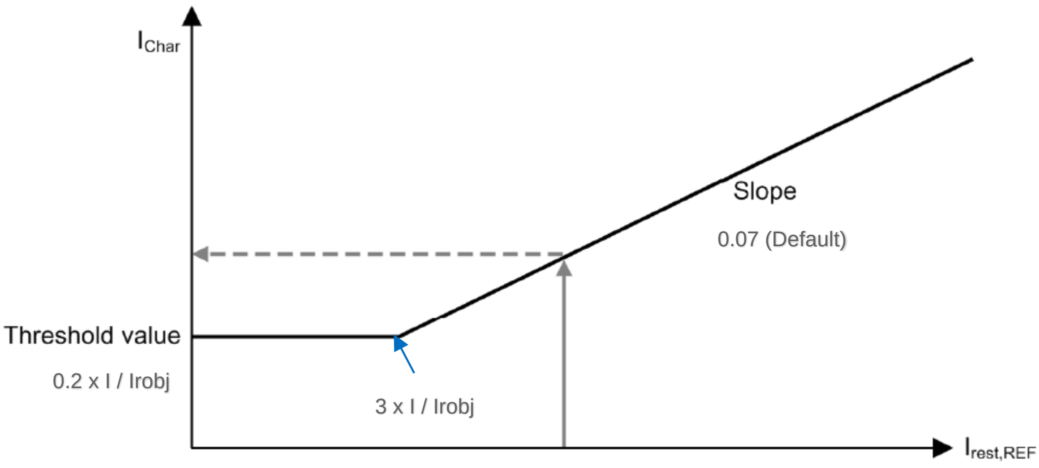


Figure 3 - Siemens 7UT86 REF Characteristic

3.2.1.1. HV REF (87NH)

The setting in the 7UT85 is selected as I/Irobj where:

$$\mathrm{I_{robj}} = \frac{S_{rated}}{\sqrt{3} \times V_{rated}} = \frac{70\ MVA}{\sqrt{3} \times 132\ kV}$$

$$\mathrm{I_{robj}} = 306.53\ \mathrm{A}$$

The 7UT85 is limited by a minimum setting of 0.05 I/Irobj, thus the setting needs to satisfy the following:

$$\mathrm{Threshold}_{min} \geq 0.05 \times \frac{CTR}{I_{robj}}$$

$$\mathrm{Threshold}_{min} \geq 0.05 \times \frac{800}{306.53}$$

$$\mathrm{Threshold}_{min} \geq 0.13$$

Therefore, element can be set to the manufacturer's recommended default setting for added stability:

$$\mathrm{Threshold} = 0.20\ \mathrm{I/Irobj}$$

With this setting the element shall detect fault current down to 61.3 Ap.

The protection function with external multiphase short-circuits to ground can be stabilize with the parameter Slope. Calculate the gradient as follows:

$$\text{Slope} = \frac{\text{Threshold}}{\text{I\_rest}_{\text{REF}}}$$

$$\text{I}_{\text{rest}_{\text{REF}}} = |\text{I}_0| + |\text{I}_1| + |\text{I}_2| + |\text{I}_3| = 3\ \text{I/Irobj}$$

$$\text{Slope} = \frac{0.20}{3} = 0.07$$

Therefore, set to the manufacturer's recommended setting:

$$\text{Slope} = 0.07$$

3.2.1.2. LV REF (87NL)

The setting in the 7UT85 is selected as I/Irobj where:

$$\text{I}_{\text{robj}} = \frac{S_{rated}}{\sqrt{3} \times V_{rated}} = \frac{70\ MVA}{\sqrt{3} \times\ 33\ kV}$$

$$\text{I}_{\text{robj}} = 1226.13\ \text{A}$$

The 7UT85 is limited by a minimum setting of 0.05 I/Irobj, thus the setting needs to satisfy the following:

$$\text{Threshold}_{min} \geq 0.05 \times \frac{CTR}{I_{robj}}$$

$$\text{Threshold}_{min} \geq 0.05 \times \frac{1600}{1226.13}$$

$$\text{Threshold}_{min} \geq 0.06$$

Therefore, element can be set to the manufacturer's recommended default setting for added stability:

$$\text{Threshold} = 0.20\ \text{I/Irobj}$$

With this setting the element shall detect fault current down to 245 Ap.

The protection function with external multiphase short-circuits to ground can be stabilize with the parameter Slope. Calculate the gradient as follows:

$$\text{Slope} = \frac{\text{Threshold}}{\text{I\_rest}_{\text{REF}}}$$

$$\text{I}_{\text{rest}_{\text{REF}}} = |\text{I}_0| + |\text{I}_1| + |\text{I}_2| + |\text{I}_3| = 3\ \text{I/Irobj}$$

$$\text{Slope} = \frac{0.20}{3} = 0.07$$

Therefore, set to the manufacturer's recommended setting:

$$\text{Slope} = 0.07$$

3.2.2. Set Y – NARI PCS978S

The NR PCS-978S provides REF protection in the form of operate / restraint plane characteristic as per Figure 4 below.

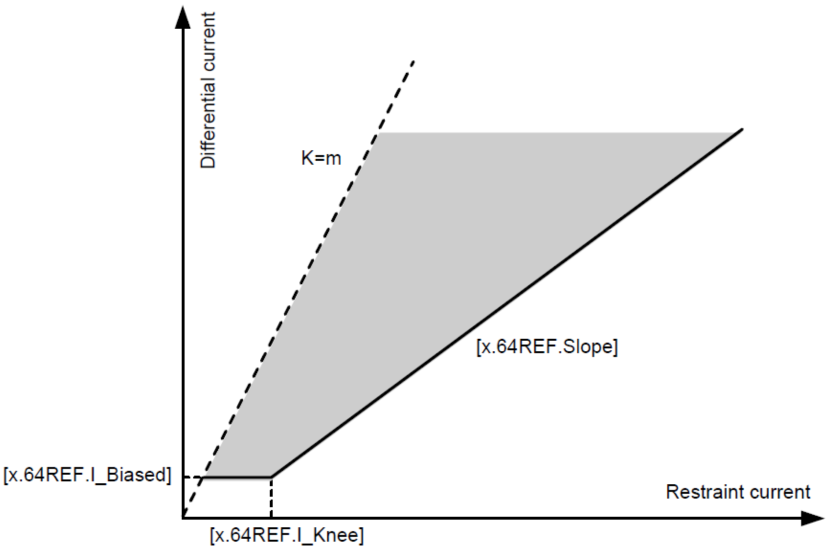


Figure 4 - NR PSC-987S REF Characteristic

3.2.2.1. HV REF (87NH)

The following Knee value is recommended by NARI:

$$64\text{REF}.\,I_{Knee1} = 0.5$$

To set the REF similar to the Set X Siemens Relay as per Section 3.2.1, the pickup shall be selected as

$$87\text{T.I Biased (PCS978S)} = I_{\text{Pickup}}\ (7\text{UT}85) = 0.2 \times \text{I}_{\text{Base}} = 0.2 \times \frac{70\ \text{MVA}}{\sqrt{3} \times 132\ \text{kV}} = 61\ \text{A}_{\text{P}}$$

Therefore set

$$64\text{REF}.\,\text{I\_}Biased\ = 0.20 \times \text{I}_{\text{B}}$$

The minimum slope setting in the PCS-978S relay is 0.2 hence set:

$$64\text{REF}.\,Slope = 0.20$$

3.2.2.2. LV REF (87NL)

The following Knee value is recommended by NARI:

$$64\text{REF}.\,I_{Knee1} = 0.5$$

To set the REF similar to the Set X Siemens Relay as per Section 3.2.1, the pickup shall be selected as

$$87\text{T.I Biased (PCS978S)} = I_{\text{Pickup}}\ (7\text{UT}86) = 0.2 \times \text{I}_{\text{Base}} = 0.2 \times \frac{70\ \text{MVA}}{\sqrt{3} \times 33\ \text{kV}} = 245\ \text{A}_{\text{P}}$$

Therefore set

$$64\text{REF}.\,\text{I}\_Biased\ = 0.20 \times \text{I}_{\text{B}}$$

The minimum slope setting in the PCS-978S relay is 0.2 hence set:

$$64\text{REF}.\,Slope = 0.20$$

3.3. Transformer HV side Overcurrent (51H)

Transformer 132 kV Side OC protection is implemented in the Set X and Set Y relays. The intension of this element is to provide back-up OC protection to the transformer primary protection being the differential protection element. The element shall be graded with the downstream and upstream protection and shall not operate before the primary and back-up protection on the Electranet Clements Gap North substation has operated.

Time Delayed Overcurrent

Inverse time pick-up shall be ≥ 1.15 x transformer MVA rating.

The maximum transformer rating is 70 MVA, hence

$$\text{MinOp}_{(\text{pri})} \geq 1.15 \times \frac{70\ \text{MVA}}{\sqrt{3} \times 132\ kV} = 352\ \text{A}$$

Given a HV CT ratio of 800/1 A, set

$$\text{I}_{\text{pickup}} = 0.44\ A$$

The inverse time OC characteristic curve shall generally be normal inverse time to coordinate with the downstream transformer LV OC protection.

IDMT and highset overcurrent shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Grading with downstream protection can be seen in Appendix B.1

Set

$$\text{TMS} = 0.20$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

High-Set Time Overcurrent

An instantaneous element will be set to ensure fast tripping for bus fault levels to provide back-up protection for the busbar protection relays. The pickup will be less than 80% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(\text{pri})} < 0.8 \times 4.9\ \text{kA} \times \left(\frac{33\ kV}{132\ kV}\right) = 980\ \text{A}$$

Therefore, set

$$\text{I}_{\text{pickup}} = 1.23\ A$$

$$\text{TD}{=}0.95\ \text{s}$$

Overcurrent Grading can be seen in Appendix B.1

3.4. Transformer LV side Overcurrent (51L)

Transformer 33 kV Side OC protection is implemented in the Set X and Set Y relays as backup protection for the transformer primary differential protection as well as the 33 kV Busbar protection. The intension is that this element shall operate only after the primary differential or 33kV busbar protection has failed to clear faults in their respective zones. Operation of the Transformer LV OC element shall trip and initiate CB Fail for the 33 kV incomer circuit breaker only.

Time Delayed Overcurrent

Inverse time pick-up shall be ≥ 1.15 x transformer MVA rating.

The maximum transformer rating is 70 MVA, hence

$$\mathrm{MinOp}_{(\mathrm{pri})} \geq 1.15 \times \frac{70\ \mathrm{MVA}}{\sqrt{3} \times 33\ kV} = 1408\ \mathrm{A}$$

Given a HV CT ratio of 1600/1 A, set

$$\mathrm{I}_{\mathrm{pickup}} = 0.88\ A$$

The inverse time OC characteristic curve shall generally be normal inverse time to coordinate with the upstream transformer HV OC protection and downstream Harmonic Filter and Collector Group feeder OC protection.

IDMT and highset overcurrent shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Grading with upstream and downstream protection can be seen in Appendix B.1

Set

$$\mathrm{TMS} = 0.20$$

$$\mathrm{Curve} = \mathrm{IEC\ Normal\ Inverse}$$

High-Set Time Overcurrent

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 80% of the minimum 33 kV Fault level.

$$\mathrm{MinOp}_{(\mathrm{pri})} < 0.8 \times 4.9\ \mathrm{kA} = 3.92\ \mathrm{kA}$$

Therefore, set

$$\mathrm{I}_{\mathrm{pickup}} = 2.45\ A$$

$$\mathrm{TD}{=}0.65\ \mathrm{s}$$

Overcurrent Grading can be seen in Appendix B.1

3.5. Transformer LV Neutral Overcurrent (51NL)

This element shall measure the neutral current in the Starpoint of the main power transformer. The intension of this element is to provide a long-time back-up protection of the NER unit, should the current duration exceed the thermal capability of the unit. Operation of this protection will trip the 33kV incomer breaker.

This element must not operate before all downstream earth fault protection elements have operated and must not operate for any faults on the HV network, which may be reflected through the Y-Y configuration of the transformer.

Time Delayed Earth Fault

Definite time pick-up shall be in the order of 60-120 A or minimum 10% of CTR unless grading with downstream protection requires a higher pickup setting.

The earth fault pickup at Clements Gap BESS is proposed to be set at 160A_P as the LV CT ratio is 1600/1A, which is well below the minimum expect fault current of 966 Ap. Therefore, set

$$\mathrm{I}_{\mathrm{pickup}} = 0.10\,A$$

IDMT and highset earth fault shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Set,

$$\mathrm{TMS} = 10\ \mathrm{sec}$$

$$\mathrm{Curve} = \mathrm{Definite\ Time\ (DTL)}$$

The long time setting of this element will ensure that it does not operate for earth faults on the HV network.

Grading with downstream protection can be seen in Appendix B.2

3.6. Volts/Hertz Overexcitation (24)

Overexcitation protection is implemented to prevent overexcitation of the transformer due to excessive applied voltage, possibly in combination with below-normal frequency. The custom V/Hz characteristic is determined from transformer manufacturer data and recommendations.

Operation of this element shall trip the 33kV Incomer.

Curve data to be configured based on this characteristic is as per Table 17.

Table 17 – Overexcitation Curve Data

Point No.	U/f ratio	Time (min)
0	105%	Continuous
1	108%	360
2	110%	30
3	115%	1.5 (90s)
4	120%	0.5 (30s)
5	125%	0.3 (18s)
6	130%	0.2 (12s)
7	135%	0.15 (9s)
8	140%	0.12 (7.2s)

3.7. Transformer Guard Protection

In addition to the configured protection, the transformer will be equipped with the following mechanical guard protection. These trips shall be connected to the transformer Set X and Y inputs to initiate tripping of the 132 kV HV and 33 kV LV circuit breakers and initiate circuit breaker failure for these trips.

- Gas Relay (Buchholz Device) (63B)
- Oil Temperature (49O)
- Winding Temperature (49W)
- Pressure Relief Device (PRD)

3.8. Breaker Failure (50BF1 & 50BF2)

3.8.1. 132kV Breaker Failure (50BF1)

The 132kV breaker (CB7088) is located in the Electranet substation and is managed by the Electranet ADM standard schemes. As such CB failure protection of this breaker is done by Electranet, with a tripping signal received via the SEL-2506 X & Y devices.

On receiving this signal from Electranet, the 33kV Incomer breaker shall be tripped.

3.8.2. 33kV Incomer Breaker Failure (50BF2)

CB Fail protection for the 33 kV Incomer breaker is implemented in each of the Transformer X & Y relays.

Operation of the CB Fail protection shall result in a direct intertrip being sent to the 132 kV breaker CB7088 at Clements Gap North Substation via Set X and Set Y SEL 2506 intertrip devices, and tripping of the breakers on the 33 kV bus via the 33 kV Busbar protection.

Current Check CB Fail

The Current Checked CB Fail timer will be initiated by the operation of current based protection elements such as transformer differential operation and shall use current checking to establish operation of the breaker. If the CB Fail current check limit remains exceeded beyond expiration of the CB Fail timer, then a CB Fail trip will be issued.

The following guidelines will be utilized in setting the current pick-up values and the delay timer:

The CB Fail current check pick-up setting shall be set at 10% of CT Ratio.

The time delay setting should be long enough to allow for the breaker to clear the fault under normal conditions with a safety margin.

Given a CT ratio of 1600/1A

$$MinOp = 0.1 \times \frac{1600}{1} = 160\ A_{pri}$$

Therefore, Set

$$\mathrm{I}_{\mathrm{pickup}} = 0.1\ A$$

A time delay of 200 ms will be implemented to allow for the circuit breaker to operate.

CB Auxiliary Contact Check

An additional auxiliary contact check CB Fail will be implemented for the detection of CB Fail conditions for non-current based transformer protection trips and external trips.

The auxiliary contact check CB Fail timer shall be configured with a slower time delay than the current check CB Fail element, hence a 250 ms time delay will be applied to the contact check CB Fail element.

4. Grid Connection Protection

GPS required generator ride through settings shall be applied such that the plant is capable of operating within certain network disturbances and parameters. The transformer protection Set X and Set Y relays and will contain, over and under frequency, over and under voltage and rate of change of frequency protection and ensure generator ride through as defined in the GPS is not affected. But will provide and overarching protection function that shall disconnect the plant of operation is sustained outside of these parameters.

4.1. Rate of Change of Frequency (81R) (Anti-islanding)

As per GPS Clause S5.2.5.3, ROCOF settings are based on the following statement:

> *Unless the rate of change of frequency is outside the range of ±4 Hz/s for more than 0.25 s, ±3 Hz/s for more than 1.00 s…*

The function is only applied in the X Protection relay.

The siemens relay recommends a measurement window of 5 periods, with a minimum setting of 2 periods. Siemens recommends a setting of 5 periods for maximum measurement accuracy however reducing this setting will result in less measurement accuracy however faster operating time. To account for a balance between the two, a margin of 0.25 Hz/s, with a measurement window of 3 periods (60 ms) the following settings are proposed:

Minimum operating voltage = 0.65 x Un (Siemens recommended default)

Stage 1:

df/dt (trigger rising) = +4.25 Hz/s, Time delay = 0.31 s

df/dt (trigger falling) = -4.25 Hz/s, Time delay = 0.31 s

Stage 2:

df/dt (trigger rising) = +3.25 Hz/s, Time delay = 1.06 s

df/dt (trigger falling) = -3.25 Hz/s, Time delay = 1.06 s

4.2. Over/Under Frequency (81O/U)

As per GPS Clause S5.2.5.3, Over and Under voltage settings are based on the following statement:

> *the generating system and each of its generating units is capable of continuous uninterrupted operation for frequencies in the ranges indicated in Table 2.4:*

Table 2.4: Frequency Limits for Continuous Uninterrupted Operation

Frequency range(1) (Hz)	**Duration(1)**
47 to 48	*2 min*
48 to 49.5	*10 min(2)*
49.5 to 50.5	*continuous*
50.5 to 52	*10 min(3)*

Notes: (1) Based on the frequency operating standard effective 1 January 2020.
(2) 10 min, including any time spent in the range 47–48 Hz.

Over and under frequency settings required in the GPS will be set in the inverters by the inverter manufacturer. Over and under frequency settings will therefore be configured in the protection relays to grade with those implemented in the inverters with a 1 sec margin.

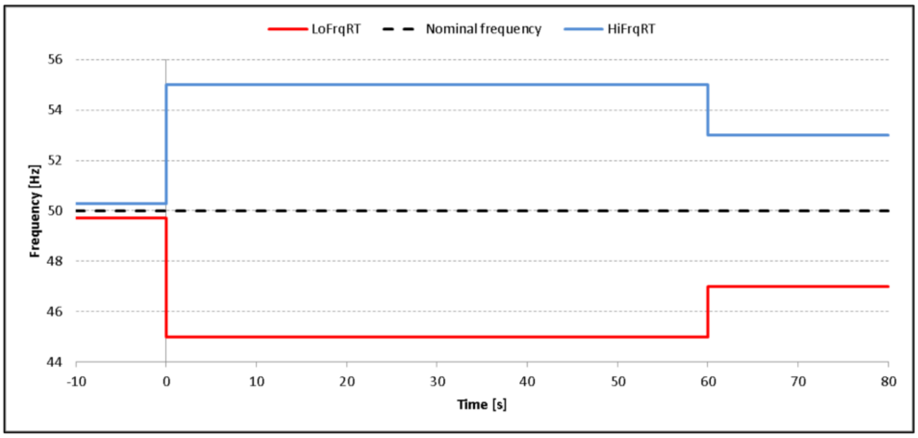


Figure 5 - Inverter Frequency Capabilities

Under frequency settings in Inverters (as per figure 5 from SMA settings):

UF Stage 1 = 47 Hz, Time delay = 60.0 s

UF Stage 2 = 45 Hz, Time delay = 0.0 s

Over frequency settings in Inverters (as per figure 5 from SMA settings):

OF Stage 1 = 53 Hz, Time delay = 60.0 s

OF Stage 2 = 55 Hz, Time delay = 0.0 s

The settings the be applied in the protection relays will be as follows:

Under frequency setting in X & Y Protection relays:

UF Stage 1 = 46.5 Hz, Time delay = 121.0 s

UF Stage 2 = 44.5 Hz, Time delay = 1.0 s

Over frequency setting in X & Y Protection relays:

OF Stage 1 = 53.5 Hz, Time delay = 61.0 s

OF Stage 2 = 55.5 Hz, Time delay = 1.0 s

4.3. Under/Over Voltage (27/59)

As per GPS Clause S5.2.5.4, Over and Under voltage settings are based on the following statement:

The generating system and each of its generating units is capable of continuous uninterrupted operation where a power system disturbance causes the voltage at the Connection Point to vary within the ranges indicated in Table 2.5:

Table 2.5: Voltage Limits for Continuous Uninterrupted Operation

Voltage range (% of Normal Voltage)	***Duration***
> 130%	*0.02 s*[(1)]
125% to 130%	*0.2 s*[(1)]
120% to 125%	*2.0 s*[(1)]
115% to 120%	*20 s*[(1)]
110% to 115%	*20 min*[(1)]
90% to 110%	*continuous*
80% to 90%	*10 s*[(2)]
70% to 80%	*2 s*[(2)]

Notes: [(1)] After the Connection Point voltage first varied above 110% of Normal Voltage before returning to between 90% and 110% of Normal Voltage.

[(2)] After the Connection Point voltage first varied below 90% of Normal Voltage before returning to between 90% and 110% of Normal Voltage.

Over and under voltage settings required to meet the GPS will be set in the inverters by the inverter manufacturer. Over and under voltage settings will therefore be configured the POC protection relays to grade with those implemented in the inverters.

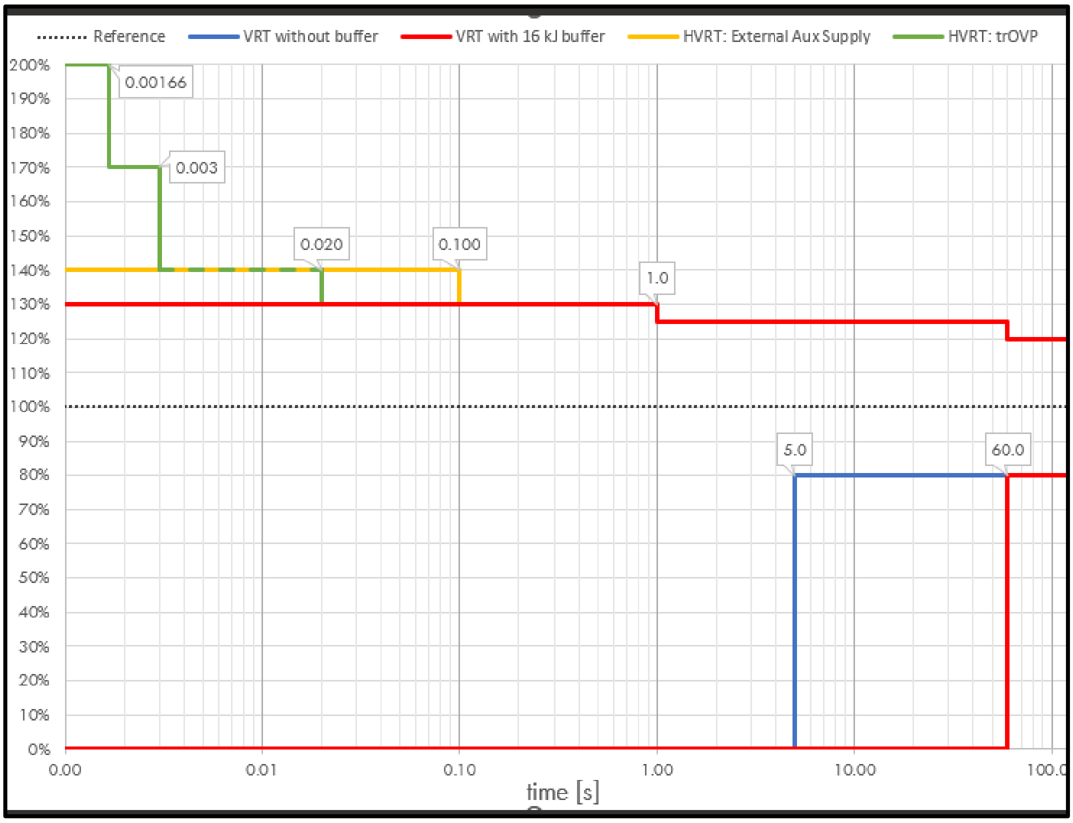


Figure 6 - Inverter Voltage Capabilities

The SMA inverters have been ordered with the optional 16kJ buffer for extended LV ride through (LVRT) capabilities. The high voltage ride through (HVRT) has been specified to include the "trOVP" option. As such based on the supplied capability curves in figure 6:

Under Voltage setting in Inverters:

UV Stage 1 = 0.80 pu, Time delay = 60.0 s (LVRT - Red Curve)

Over Voltage settings in Inverters:

OV Stage 1 = 1.20 pu, Time delay = 60.0 s (HVRT – Red Curve Step 1)

OV Stage 2 = 1.25 pu, Time delay = 1.0 s (HVRT – Red Curve Step 2)

OV Stage 3 = 1.40 pu, Time delay = 0.02 s (HVRT – Green Curve Step 1)

OV Stage 4 = 1.70 pu Time delay = 0.003 s (HVRT – Green Curve Step 2)

OV Stage 5 = 2.00 pu Time delay = 0.00166 (HVRT – Green Curve Step 3)

The settings applied to the X & Y Transformer protection relays shall be set to operate just outside those of the inverter as a back-up function as follows:

Under Voltage setting in Inverters:

UV Stage 1 = 0.75 pu, Time delay = 61.0 s

Over Voltage settings in Inverters:

OV Stage 1 = 1.25 pu, Time delay = 61.0 s

OV Stage 2 = 1.35 pu, Time delay = 1.3 s

As the above protection is only a back-up function to the inverters, any trip times faster than 1 sec are not considered, with the minimum trip time graded with a 300ms margin for the OV Stage 2 element.

5. 33 kV Bus Protection

33 kV high impedance bus differential protection is performed by a set of NR-9611S relays. One each for the “X” Busbar protection and one for the “Y” Busbar protection schemes. The protection functions to be implemented in these relays are highlighted in Table 18.

Table 18 – Protection Functions

NR PCS-9611	**NR PCS-9611**
X - Busbar Differential Protection (87B)	Y – Busbar Differential Protection (87B)
X - CB Failure Trip Repeat Logics	Y – CB Failure Trip Repeat Logics

The part number and Firmware for these relays are summarised in Table 19.

Table 19 – Protection Relays

Bus ID	**Protection**	**Relay Part Number**	**Relay Firmware Number**
BUSBAR 1 X Protection	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-ACXBXFNN-R1	Latest
BUSBAR 1 Y Protection	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-ACXBXFNN-R1	Latest

5.1. Busbar Differential Protection (87B)

High impedance busbar differential protection operates by comparing the current entering and leaving the busbar. Under normal conditions, the currents should balance, but in the event of a fault, the differential current will increase. The system uses a high impedance relay to detect this imbalance, minimizing the impact of external disturbances. This method ultimately ensures rapid isolation of faults while being less sensitive to external faults and CT saturation.

The selected CT for bus zone protection is 0.1PX 450 R10 class with a ratio of 1600/1A.

A voltage pickup is to be set to at least 120% of the maximum expected secondary voltage, and below 50% of the CT kneepoint voltage. Therefore,

$$V_s = 1.2 \times \frac{I_{maxfault}}{CTR} \times (R_{CT} + R_L)$$

Where R_L is

$$R_L = \frac{9.01\Omega}{1000m} \times 10m = 0.09\Omega$$

Hence,

$$V_s = 1.2 \times \frac{8.83kA}{1600/1} \times (10\Omega + 0.09\Omega) = 66.8V$$

The selected voltage setting provides is only 15% of the CT rated kneepoint voltage.

The high impendance bus protection shall be configured to ensure detection of less than 50% of the minimum fault level (LG = 0.97 kA). Therefore

$$I_{req} = 0.5 \times 970\ A = 485\ A_{pri}$$

Considering a CT magnetising current of 100 mA at the kneepoint voltage, the magnetising current at the voltage setting is

$$I_{mag} = I_e \times \frac{V_s}{V_k} = 0.1\ A \times \frac{67\ V}{450\ V} = 15\ mA$$

Therefore, a relay pickup should be selected to account for magnetising current of the 7 current transformers

$$I_s = \frac{I_{req}}{CTR} - n \times I_{mag} = \frac{485\ A}{1600} - 7 \times 0.015\ A = 0.199\ A$$

Set relay pickup to,

$$\mathrm{I_{pickup}} = 0.15\ \mathrm{A_s} = 240\ A_p$$

To achieve this current the following stabilising resistor will be required

$$R_{stab} = \frac{V_s}{I_{pickup}} = \frac{67\ V}{0.15\ A} = 445\ \Omega$$

Therefore, select stabilising resistor of

$$\mathrm{R_{stab}} = 500\ \Omega$$

With the selected pickup and resistor, the equivalent pickup will therefore be

$$I_{op} = CTR \times \left(I_{pickup} + n \times I_{mag}\right) = 1600 \times (0.15 + 7 \times 0.015) = 406\ A_{pri}$$

Non-linear resistors are required to limit peak AC voltages within the cubicle to less than 3kV. Peak voltages can be calculated as

$$V_{peak} = 2 \times \sqrt{2 \times V_k \times \left(I_{maxsec_{fault_{level}}} \times R_{stab} - V_k\right)}$$

$$= 2 \times \sqrt{2 \times 450\ V \times \left(\frac{8.83\ kA}{1600} \times 500\ \Omega - 450\ V\right)}$$

$$= 2.69\ kV$$

As the expected peak voltage is less than 3 kV, a non-linear resistor is not required. However, for safety reasons one 3-phase unit shall be provided per busbar protection device, to limit the voltage rise during fault trips.

6. 33 kV Collector Group Feeder Protection

The 33 kV Collector groups are protected by a NR PCS-9611S relay. The protection functions to be implemented in these relays are highlighted in Table 20.

Table 20 – Protection Functions

NR PCS-9611S
Phase Overcurrent High-Set and Time Delayed (50/51)
Residual Overcurrent High-Set and Time Delayed (50N/51N)
Sensitive Time Delayed Earth Fault (50SG/51SG)
Neutral Overvoltage / Neutral Displacement (59N)
Negative Sequence Backup Overcurrent (51Q)
Breaker Failure (50BF)
Measurement (MEAS)
Control (CTRL)

The part number and Firmware for these relays are summarised in Table 21.

Table 21 – Protection Relays

Feeder ID	**Protection**	**Relay Part Number**	**Relay Firmware Number**
Collector Group 1	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-A-CXBXFNN-R1	Latest
Collector Group 2	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-A-CXBXFNN-R1	Latest
Collector Group 3	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-A-CXBXFNN-R1	Latest
Collector Group 4	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-A-CXBXFNN-R1	Latest
Collector Group 5	NR PCS-9611S	PCS-9611S-A-AA-RX.XX-ACAA-BAAAC-A-CXBXFNN-R1	Latest

Note: the inverter downstream protection settings have not yet been confirmed. Overcurrent and Earth fault grading with downstream inverter protection has therefore been assessed based on the following assumptions:

Protection settings for the MVPS RMU's

Each MVPS has a transformer rated 3.78 MVA connecting the inverters to the 33 kV network via an RMU. These RMU's will be supplied with Ormazabal ekorRP protection relays as per production option MVPS-K2.

Product	Short circuit protection		Overload protection			Earth fault current protection		Earth overcurrent protection		
	I>>	ti>>	I>/Is	K	Curve	Io>>	To>>	Io>	Ko	Curve
MVPS xxxSC MVPS 2200SC - 3000SC-EV MVPS 4400SC – 6000SC-EV MVB 2200SC / 2500SC-EV MVPS 2500 - 3000-S-AU MVPS 5000 - 6000-S-AU MVPS-K2	10	0,05	1,3	0,1	EI	Dy: 5 YNd: 5	$\boxed{\text{Dy: 0,5}}$ YNd: 0,2	Dy: 0,2*In YNd: 0,7*In	0,2	NI
MVS xxxSTP	10	0,05	1,2	0,1	EI	Dy: 5 YNd: 5	Dy: 0,5 YNd: 0,2	Dy: 0,2*In YNd: 0,7*In	0,2	NI

The above table supplied by SMA defines the standard settings applied to the RMUs as factory default. However, these settings allow for no grading with the upstream feeder protection for heavy earth faults since settings To>> = 0.5 DTL. (See above table).

The value of In has been defined by SMA as follows:

Hello Kisan,

On the first point, In used in the relay settings is the nominal current of MVPS 4200 (4200kVA at 25 deg) at 33kV: 73.48 A

Thanks & Regards,
Cyriac

Therefore the following:

$$I_n = \frac{4.2 \text{ MVA}}{\sqrt{3} \times 33 \ kV} = 73.48 \text{ A}$$

The following settings are recommended:

- I> is set to 1.3x In = 95.52 A_P, K =0.1, Curve = EI
- I>> is set to 10x In = 734.80 A_P , Ti>> =0.05, Curve = DTL
- Io> is set to 0.2x In = 14.70 A_P , Ko =0.2, Curve = NI
- Io>> is set to 5x In = 367.40 A_P, **To>> =0.05**, Curve = DTL

Final settings to be confirmed during site testing of the units to align with the above recommendation to insure correct grading of the protection.

Protection settings for the Auxiliary Supply KIOSK RMU's (+MS01 through +MS05)

Each collector string has a single auxiliary supply Kiosk which has a transformer rated 500 kVA connecting to the 33kV network via an RMU. These RMU's are supplied with FANOX SIA-B self-powered protection relays, with the settings applied as calculated in Section 8 of this report.

6.2. Phase Overcurrent High-Set and Time Delayed (50/51)

Overcurrent protection is provided to clear faults downstream of the 33 kV Busbar on the collector group 33 kV cable Network. This protection is required to grade with both the downstream 33/0.4 kV Auxiliary Kiosk transformer and MVPS Inverter 33/0.69 kV Transformer overcurrent and earth fault protection setting as detailed above.

Time Delayed Overcurrent

Inverse time pick-up shall be ≥ 1.2 x feeder rating.

There are five 3.78 MVA inverters and one 500 kVA inverter auxiliary supply transformer connected on each feeder. The maximum collector group load is therefore considered as

$$I_{CG} = \frac{n \times S_{inv} + S_{aux_{TF}}}{\sqrt{3} \times V_{nom}} = \frac{5 \times 3.78\ MVA + 0.5\ MVA}{\sqrt{3} \times 33\ kV} = 339\ A_{pri}$$

Thefore, set the IDMT overcurrent pickup as

$$\text{MinOp}_{(\text{pri})} \geq 1.2 \times 339\ A = 390\ \text{A}$$

Given a HV CT ratio of 600/1 A, set

$$\text{I}_{\text{pickup}} = 0.65\ A$$

The inverse time OC characteristic curve shall generally be normal inverse time to coordinate with the upstream transformer LV OC protection and downstream inverter and auxiliary supplies transformer OC protection.

IDMT and highset overcurrent shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Grading with upstream and downstream protection can be seen in Appendix B.1

Set

$$\text{TMS} = 0.20$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

High-Set Time Overcurrent

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(pri)} < 0.5 \times 4.9\ \text{kA} = 2.45\ \text{kA}$$

Therefore, set

$$\text{I}_{\text{pickup}} = 4.08\ A$$

$$\text{TD}=0.35\ \text{s}$$

Overcurrent Grading can be seen in Appendix B.

6.3. Residual Overcurrent High-Set and Time Delayed (50N/51N)

Time Delayed Earth Fault

Inverse time pick-up shall be in the order of 60-120 A unless grading with downstream protection requires a higher pickup setting.

The inverse time earth fault pickup at Clements Gap BESS is proposed to be set at $100A_P$. Therefore, set

$$\text{I}_{\text{pickup}} = 0.17\ A$$

IDMT and highset earth fault shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Set,

$$\text{TMS} = 0.20$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

Grading with upstream and downstream protection can be seen in Appendix B.2

High-Set Time Earth Fault

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(pri)} < 0.5 \times 966\ \text{A} = 480\ \text{A}$$

Therefore, set

$$\text{I}_{\text{pickup}} = 0.8\ A$$

$$\text{TD}=0.35\ \text{s}$$

Earth Fault Grading can be seen in Appendix B.2

6.4. Sensitive DTL Earth Fault (50SG/51SG)

Although called for in Section 8.3.1 of the BOP Substation specifications, the Sensitive Earth fault will not be applied as the entire 33kV collector reticulation network consists of underground cable. There is no instance where overhead line conductors are used, so the likelihood of high impedance ground fault is extremely low.

The element shall be disabled in all the collector group NR relays.

6.5. Neutral Overvoltage / Neutral Displacement (59N)

The 59N element measures the residual voltage at the broken-delta winding. The measured voltage represents to the zero-sequence voltage V_0. The neutral over voltage (59N) elements shall be enabled on the feeder protection relays to allow disconnection of the 33 kV Collector Group Feeders during abnormal voltage conditions. The intention of the neutral displacement element is to detect floating neutral should the NEC be disconnected from the network.

Set the pickup to 20 % of the nominal secondary voltage,

$$\begin{aligned}&\text{59N Pickup Threshold} = 20\%\ \text{V}_\text{n} = 20\%\ \text{x}\ 110\ \text{V} = 22.00\ \text{V}\ and\\ &\text{Pickup delay} = 0.0\ \text{s}\\ &\text{Operate delay} = 5.0\ \text{s}\end{aligned}$$

The Operate delay allows ample time to prevent transient residual voltages from initiating a trip. The operation of this element will send a trip signal to the associated feeders.

6.6. Negative Sequence Backup Overcurrent (51Q)

Negative Sequence OC shall be implemented to provide backup protection for faults on the 690 V side of the inverter transformer.

A phase-to-phase fault on the 690V side of the inverter transformer will result in a 2-1-1 split between phases on the 33 kV side. This equates to a 33.333% negative sequence current component. The relay shall be set to detect this current unbalance and provide a long-time back-up trip should the inverter protection fail to clear this condition. The element must not operate for any transient unbalances cause by 33kV network ground faults, or those on the 132kV network that may be reflected through the main power transformer star-star connection.

Therefore, with a minimum 690 V L-L phase fault level of 32,266 A_P, the negative sequence fault current will be:

$$I_2 = \frac{I_{FL}}{\sqrt{3}} = \frac{32.27\ kA}{\sqrt{3}} = 18.63\ kA$$

Seen at 33 kV is therefore:

$$I_{2\_33kV} = 18.63\ kA \times \frac{0.69\ kV}{33\ kV} = 390\ A$$

Therefore, set to below 50% of the minimum fault current:

$$\text{MinOp}_{(\text{pri})} < 0.5 \times 390 \text{ A} = 195 \text{ A}$$

Therefore, set,

$$\mathrm{I}_{2 \text{ pickup}} = 0.32\ A$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

$$\text{TD}=1.0 \text{ s}$$

6.7. 33kV Breaker Failure (50BF)

CB Fail protection for the 33 kV feeder breaker is implemented in the Collector Group Feeder relays.

Operation of the CB Fail protection shall result in tripping of all the Collector group feeder breakers, 33kV Incomers and the Harmonic Filter breakers on the 33 kV bus via the 33 kV Busbar protection trip logic.

Current Check CB Fail

The CB Fail timer will be initiated by the operation of current based protection elements and shall use current checking to establish operation of the breaker. If the CB Fail current check limit remains exceeded beyond expiration of the CB Fail timer, then a CB Fail trip will be issued.

The following guidelines will be utilized in setting the current pick-up values and the delay timer:

The CB Fail current check pick-up setting shall be set at 10% of CT Ratio.

The time delay setting should be long enough to allow for the breaker to clear the fault under normal conditions with a safety margin.

Given a CT ratio of 600/1A

$$MinOp = 0.1 \times \frac{600}{1} = 60\ A_{pri}$$

Therefore, Set

$$\mathrm{I}_{\text{pickup}} = 0.1\ A$$

A time delay of 200 ms will be implemented to allow for the circuit breaker to operate.

CB Auxiliary Contact Check

An additional auxiliary contact check CB Fail will be implemented for the detection of CB Fail conditions for non-current based external trips.

The auxiliary contact check CB Fail timer shall be configured with a slower time delay than the current check CB Fail element, hence a 250 ms time delay will be applied to the contact check CB Fail element.

7. 33 kV Harmonic Filter Bank Protection

The 33 kV Harmonic Filter Bank is protected by a Siemens 7SJ85 relay. This relay shall include the protection of the 33kV Feeder breaker at the switchgear in the control room, the cables from this switchgear to the 12MVAr and 3MVAr filter bank installations, as well as the protection functions associated with the protection of each of the filter banks.

The equipment is defined as follows:

- 33kV Switchgear Feeder Breaker +1F07-Q10
- 33kV Filter Bank No.1A Breaker +F01A-Q20
- 33kV Filter Bank No.1B Breaker +F01B-Q20

The protection functions to be implemented in this relay are highlighted in Table 22.

Table 22 – Protection Functions

Siemens 7SJ85
33kV Feeder Phase Overcurrent High-Set and Time Delayed (50/51)
33kV Feeder Residual Overcurrent High-Set and Time Delayed (50N/51N)
Neutral Overvoltage / Neutral Displacement (59N)
Harmonic Filter 1A Unbalance / Discharge Delay (60N-1/68-1)
Harmonic Filter 1B Unbalance / Discharge Delay (60N-2/68-2)
Under/Over Voltage (27/59)
33kV Feeder Breaker Failure (50BF-1)
Harmonic Filter 1A Breaker Failure (50BF-2)
Harmonic Filter 1B Breaker Failure (50BF-3)
Measurement (MEAS)
Control (CTRL)

The part number and Firmware for these relays are summarised in Table 23.

Table 23 – Protection Relays

Feeder ID	Protection	Relay Part Number	Relay Firmware Number
Harmonic Filter Bank 1	Siemens 7SJ85	P1J1998986	v9.71

7.1. Phase Overcurrent High-Set and Time Delayed (50/51)

Overcurrent protection is provided to clear faults downstream of the 33 kV Busbar on the Hamonic Filter Bank 33 kV Network. That said the 33kV Ormazabal breaker in the feeder switchgear is not rated for capacitive switching. As such the operation of the overcurrent elements shall trip directly to the two Harmonic Filter breakers, with the trip to the Feeder breaker blocked by the closed status of either of the two filter breakers. Once both Harmonic Filter breakers have opened, will trip to the Feeder breaker be released. It is envisaged that if the fault is on either of the filter banks.

Time Delayed Overcurrent

Inverse time overcurrent pick-up setting shall be ≥ 1.5 × Filter bank nominal current rating. The higher protection current setting is in recognition of the following:

- *Bus voltage is always set higher than the nominal bus voltage - can be up to 4% higher than nominal.*
- *Manufacturing tolerance in filter bank ratings.*
- *Filter banks tend to be sink for harmonic currents.*

Inverse time overcurrent pick-up setting shall be less than 50% of the minimum Filter bank fault current.

The minimum grading margin with upstream overcurrent elements will be 300ms.

Harmonic Filter bank sizing is confirmed, and the current proposed solution is a 15 Mvar filter bank consisting of a12 Mvar and 3 Mvar unit.

Therefore, set the IDMT overcurrent pickup as

$$\text{MinOp}_{(\text{pri})} \geq 1.5 \times \frac{S_{HF}}{\sqrt{3} \times V_{nom}} = 1.5 \times \frac{15\ Mvar}{\sqrt{3} \times 33\ kV} = 394\ A$$

Given a HV CT ratio of 600/1 A, set

$$\mathrm{I}_{\text{pickup}} = 0.66\ A$$

The inverse time OC characteristic curve shall generally be normal inverse time to coordinate with the upstream transformer LV OC protection and downstream inverter and auxiliary supplies transformer OC protection.

IDMT and highset overcurrent shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Grading with upstream and downstream protection can be seen in Appendix B.3

Set

$$\text{TMS} = 0.20$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

High-Set Time Overcurrent

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(\text{pri})} < 0.5 \times 4.9\ \text{kA} = 2.45\ \text{kA}$$

Therefore, set

$$I_{\text{pickup}} = 4.08\ A$$

$$\text{TD}=0.35\ \text{s}$$

Overcurrent Grading can be seen in Appendix B.3

7.2. Residual Overcurrent High-Set and Time Delayed (50N/51N)

The same tripping philosophy shall apply as detailed in Section 7.1

Time Delayed Earth Fault

Inverse time pick-up shall be in the order of 60-120 A or minimum 10% of CTR unless grading with downstream protection requires a higher pickup setting.

The inverse time earth fault pickup at Clements Gap BESS is proposed to be set at $100A_P$. Therefore, set

$$I_{\text{pickup}} = 0.17\ A$$

IDMT and highset earth fault shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Set,

$$\text{TMS} = 0.20$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

Grading with upstream and downstream protection can be seen in Appendix B.3

High-Set Time Earth Fault

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(\text{pri})} < 0.5 \times 966\ \text{A} = 480\ \text{A}$$

Therefore, set

$$I_{\text{pickup}} = 0.8\ A$$

$$\text{TD}=0.35\ \text{s}$$

Earth Fault Grading can be seen in Appendix B.4

7.3. Neutral Overvoltage / Neutral Displacement (59N)

The 59N element measures the residual voltage at the broken-delta winding. The measured voltage represents to the zero-sequence voltage V_0. The neutral over voltage (59N) elements shall be enabled on the feeder protection relays to allow disconnection of the 33 kV Collector Group Feeders during abnormal voltage conditions. The intention of the neutral displacement element is to detect floating neutral should the NEC be disconnected from the network.

Tripping shall be routed to trip the two Harmonic Filter breakers.

Set the pickup to 20 % of the nominal secondary voltage,

$$\text{59N Pickup Threshold} = 20\%\ \mathrm{V_n} = 20\%\ \mathrm{x}\ 110\ \mathrm{V} = 22.00\ \mathrm{V}\ and$$
$$\text{Pickup delay} = 0.0\ \mathrm{s}$$
$$\text{Operate delay} = 5.0\ \mathrm{s}$$

The Operate delay allows ample time to prevent transient residual voltages from initiating a trip. The operation of this element will send a trip signal to the associated feeders.

7.4. Harmonic Filter Unbalance (60N-1/60N-2)

Any internal fault in the capacitor C-elements inside Harmonic filter bank leads to unbalance in the single-phase current which can be due to open or short circuit of the capacitor elements. An unbalance CT is installed in each of the Harmonic Filter banks to detect these unbalance currents.

The protection relay shall have two elements, each tripping the respective Harmonic Filter breaker, in which the fault has been detected.

There will be two unbalance stages, one alarm and one trip. Given a 5/1 A CT ratio, set the alarm to

$$\mathrm{I_{pickup}} = 0.06\ A_S\ (0.3\ A_P)$$

$$\mathrm{TD}{=}0.1\ \mathrm{s}$$

set the trip to

$$\mathrm{I_{pickup}} = 0.16\ A_S\ (0.8\ A_P)$$

$$\mathrm{TD}{=}0.1\ \mathrm{s}$$

7.5. Discharge Delay (68-1/68-2)

To allow sufficient time for the capacitors to discharge after de-energisation of the Harmonic Filter Bank, a discharge timer shall be applied in the Harmonic Filter protection relay. This time shall start after opening of the Harmonic Filter Breaker and be set as per manufactures recommendations. An optional gate interlocking solenoid can be installed in the YMK which shall protect release of the access key before this timer times out.

An industry standard time delay of 10 min shall be applied unless advised by the filter bank manufacturer.

Two elements shall be provided in the relay, one per Harmonic Filter Bank designated 68-1 and 68-2 respectively. Depending on the final fencing and access requirements, the bay releases shall be individual or a combination of both timers. This will be updated during detailed design.

7.6. Under/Over Voltage (27/59)

Under and over voltage protection shall be implemented on the Feeder protection relay. Voltage settings will be configured in line with the generator ride through requirements in the GPS however will operate 0.5 s faster to ensure grading.

Operation of these elements shall trip the Harmonic Filter breakers directly.

Under Voltage:

UV = 0.75 pu, Time delay = 24.5 s

Over Voltage:

OV = 1.35 pu, Time delay = 4.5 s

7.7. Breaker Failure (50BF-1/50BF-2/50BF-3)

CB Fail protection shall be provided for the three breakers associated with the Harmonic Filter protection scheme. That is as follows:

- 33kV Feeder Breaker +1F07-Q10 Failure (50BF-1)
- 33kV Harmonic Filter 1A Breaker +F01A-Q20 Failure (50BF-2)
- 33kV Harmonic Filter 1B Breaker +F01B-Q20 Failure (50BF-3)

33kV Feeder breaker failure (50BF-1) operation, shall result in a trip issued all the 33kV breakers on the 33kV busbar via repeat trip logic in the 33kV busbar protection panel.

Any 33kV Harmonic Filter breaker failure (50BF-2 / 50BF-3) operation shall result in the issuing of a trip to the 132kV CB7088, via repeat trip logic in the 33kV busbar protection relay to the Transformer X & Y protection schemes.

Current Check CB Fail

The CB Fail timer will be initiated by the operation of current based protection elements and shall use current checking to establish operation of the breaker. If the CB Fail current check limit remains exceeded beyond expiration of the CB Fail timer, then a CB Fail trip will be issued.

The following guidelines will be utilized in setting the current pick-up values and the delay timer:

The CB Fail current check pick-up setting shall be set at 10% of CT Ratio.

The time delay setting should be long enough to allow for the breaker to clear the fault under normal conditions with a safety margin.

Given a CT ratio of 600/1A

$$MinOp = 0.1 \times \frac{600}{1} = 60\ A_{pri}$$

Therefore, Set

$$\mathrm{I}_{\mathrm{pickup}} = 0.1\ A$$

A time delay of 200 ms will be implemented to allow for the circuit breaker to operate.

CB Auxiliary Contact Check

An additional auxiliary contact check CB Fail will be implemented for the detection of CB Fail conditions for non-current based external trips.

The auxiliary contact check CB Fail timer shall be configured with a slower time delay than the current check CB Fail element, hence a 250 ms time delay will be applied to the contact check CB Fail element.

8. 33/0.4 kV Collector Group Auxiliary Transformer Protection

Clements Gap BESS has 5 x 33/0.4 kV Kiosk for feeding the "Normal non-critical Supply" to all the TRINA Battery Containers. Each of the KIOSKs are fed from 33 kV Busbar via a piggy-back connection to the first MVPS RMU in each of the Collector group strings.

The 33/0.4 kV Collector Group Auxiliary Transformers are protected by a 33 kV FANOX SIA-B relay and 400 V MCCB on the LV side.

The protection functions to be implemented in these relays are highlighted in Table 24.

Table 24 – Protection Functions

Fanox SIA-B	400 V MCCB
Phase Overcurrent High-Set and Time Delayed (50/51)	Phase Overcurrent High-Set and Time Delayed (50/51)
Residual Overcurrent High-Set and Time Delayed (50N/51N)	Residual Overcurrent High-Set and Time Delayed (50N/51N)
Measurement (MEAS)	

8.1. 33 kV Phase Overcurrent High-Set and Time Delayed (50/51)

Time Delayed Overcurrent

Inverse time pick-up shall be ≥ 1.2 x transformer rating.

The auxiliary transformer rating is 500 kVA, hence:

$$\text{MinOp}_{(\text{pri})} \geq 1.2 \times \frac{0.5 \text{ MVA}}{\sqrt{3} \times 33\, kV} = 10 \text{ A}$$

Given a HV CT ratio of 100/1 A, a pickup of at least 10 A_P (0.1 A_s) is required. The minimum available setting in this relay is however 0.2 x In, hence:

$$\text{I}_{\text{pickup}} = 0.20\, A$$

The inverse time OC characteristic curve shall generally be normal inverse time to coordinate with the upstream collector group feeder protection.

Given a pickup of 10 A, typical relay IDMT curves only operate up to 30x the pickup setting before flattening, which in this case be 300 A_p. The expected operate time with the minimum TMS setting of 0.05 is therefore:

$$\text{Trip Time} = \text{TMS} \times \left(\frac{0.14}{\left(\frac{I_{\text{PhMin}}}{I_{\text{pickup}}}\right)^{0.02} - 1} \right) = 0.1 \times \left(\frac{0.14}{\left(\frac{600\ A}{20\ A}\right)^{0.02} - 1} \right)$$
$$= 0.10\ s$$

The IDMT element will therefore be set as

Therefore, set

$$\text{TMS} = 0.05$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

High-Set Time Overcurrent

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(\text{pri})} < 0.5 \times 4.9\ \text{kA} = 2.45\ \text{kA}$$

Given a maximum setting of 20x nominal with a CT ratio of 100/1, the primary current setting will be 2 kA.

$$I_{\text{pickup}} = 20\ A$$

$$\text{TD}{=}0.05\ \text{s}$$

Overcurrent Grading can be seen in Appendix B.1

8.2. 33 kV Residual Overcurrent High-Set and Time Delayed (50N/51N)

Inverse time pick-up shall be in the order of 60-120 A unless grading with downstream protection requires a higher pickup setting.

The inverse time earth fault pickup at is proposed to be set at $80A_P$ to grade with the upstream feeder protection. Therefore, set

$$I_{\text{pickup}} = 0.8\ A$$

IDMT and highset earth fault shall discriminate with downstream protection. The minimum grading margin shall generally be in the range of 0.3 seconds (for digital and numerical relays) to 0.4 seconds (for electromechanical relays). A grading margin of 0.2 seconds is generally acceptable between definite time elements.

Set,

$$\text{TMS} = 0.10$$

$$\text{Curve} = \text{IEC Normal Inverse}$$

Grading with downstream protection can be seen in Appendix B.2

High-Set Time Earth Fault

An instantaneous element will be set to ensure fast tripping for bus fault levels. The pickup will be less than 50% of the minimum 33 kV Fault level.

$$\text{MinOp}_{(\text{pri})} < 0.5 \times 966\ \text{A} = 480\ \text{A}$$

Therefore, set

$$\text{I}_{\text{pickup}} = 4.5\ A$$

$$\text{TD}{=}0.05\ \text{s}$$

Earth Fault Grading can be seen in Appendix B.

8.3. 400 V Circuit Breaker Settings

The following are the settings for 400V LV side of the 33kV/0.4 V auxiliary transformer. The LV protection is provided by a Siemens 3WJ1112 3P 1250 A ACB.

The auxiliary transformer rating is 500 kVA, hence

$$\text{MinOp}_{(\text{pri})} \geq 1.2 \times \frac{0.5\ \text{MVA}}{\sqrt{3} \times 0.4\ kV} = 866\ \text{A}$$

The maximum expected short circuit fault current (assuming an infinite bus is) with a transformer impedance of 4%±10%

$$\text{MinOp}_{(\text{pri})} \leq 0.8 \times \frac{0.5\ \text{MVA}}{\sqrt{3} \times 0.4\ kV \times 3.6\ \%} = 16.0\ \text{kA}$$

To grade with the downstream 100 A MCB, settings will be as follows:

$$I_n = 1250\ A$$

$$I_r = 0.7 \times \text{I}_\text{n} = 0.7\ \times 1250\ \text{A} = 875\ A$$

$$TD = 0.75\ \text{s}$$

$$I_{Instantaneous} = 1.5.I_n = 1.5\ \times 1250\ A = 1875\ A$$

Grading can be seen in Appendix B.5

9. 33/0.4 kV Station Auxiliary Transformer Protection

The Substation 33/0.4 kV Auxiliary transformer (+TF02) is connected directly to the 70MVA Power Transformers, by a 33kV cable. This cable as well as the transformer itself are within the transformer differential protection zone. Thus there is no need for a 33kV breaker or fuses on the HV side of the auxiliary transformer.

9.1. 400 V Circuit Breaker Settings

The following are the settings for 400V LV side of the 33kV/0.4 V auxiliary transformer. The LV protection is provided by a Schneider ComPacT NS630bN 3P 630 A MCB.

The auxiliary transformer rating is 315 kVA, hence:

$$\text{MinOp}_{(\text{pri})} \geq 1.2 \times \frac{0.315\ \text{MVA}}{\sqrt{3} \times 0.4\ kV} = 546\ \text{A}$$

The maximum expected short circuit fault current (assuming an infinite bus is) with a transformer impedance of 4%±10%

$$\text{MinOp}_{(\text{pri})} \leq 0.8 \times \frac{0.315\ \text{MVA}}{\sqrt{3} \times 0.4\ kV \times 3.6\ \%} = 10.1\ \text{kA}$$

To grade with the downstream 250 A MCB, settings will be as follows:

$$I_n = 630\ A$$

$$I_r = 0.9 \times I_n = 0.9 \times 630\ \text{A} = 567\ A$$

$$TD = 16\ \text{s}$$

$$I_{Instantaneous} = 6.I_n = 1.5\ \times 630\ \text{A} = 3780\ A$$

Grading can be seen in Appendix B.6

Appendix A Fault Level Studies

Fault data referenced from the Clement Gap BESS Power Study produced by Beyond Electrical Engineering are as per the following exports.

A.1. Source Data

Parameter	Ultimate Fault Level	Maximum Fault Level	Minimum Fault Level
Short Circuit Power (MVA)	9145.229	1384.13	510
Short Circuit Current (kA)	40	6.054	2.231
X/R value	15	4.34	4.34

A.2. System Data

System Component	Make/Model/Parameters	Remark
132/33kV Power Transformer	YNyn0 70 MVA (ONAF) Z% HV-LV=13% @ 70MVA X/R= 38.66 OLTC Tap range [+12.25%, -15.75%], step 1.75% Zero-sequence impedance values assumed NER modelled on TX LV to achieve Earth fault limit of 1kA	Inputs taken from Overall SLD and existing PF Model
33kV/690V Inverter Transformer	Dy11 3600kVA 33/.69kV Z=7.5% @3.6MVA X/R=7.8 Zero-sequence impedance values assumed	Inputs taken from existing PF Model and SLD -0002
33/0.4 kV Aux TX	315kVA ONAN, Dyn11 Z% HV-LV=5% @ 0.315MVA X/R= 8	Assumed 200kVA load with 0.8 (lagging) PF
MV Kiosk TX	500kVA ONAN, Dyn11 Z% HV-LV=6% @ 0.5MVA X/R = 10	Assumed impedance and X/R based on typical values.
33kV Collector Cables	Olex Single Core 630mm2 19/33kV, Al Olex 3C 300mm2, 185mm2, 120mm2 19/33kV, Al -120mm2 3C: Z+ = 0.325+j0.124 Ohm/km 1 cable per phase	Modelled as Nexans 1C and 3C MV AL cables as seen in Appendix C.

System Component	Make/Model/Parameters	Remark
	-185mm2 3C: Z+= 0.211+j0.117 Ohm/km 1 cable per phase -300mm2 3C: Z+= 0.13+j0.108 Ohm/km 1 cable per phase -630mm2 1C: Z+= 0.063+j0.108 Ohm/km 6 cable per phase	
SMA Inverters	Modelled as Static generator with: Rated size: 3.62 MVA Modelled as dynamic votlage support X/R = 0.76 / K factor = 1 Ik'' = 5.144 kA	Operational Power limits taken from provided PF model SC3600-UP PQ Curve A power frequency and station controller were used to control the active and reactive power output of the inverters. The inverter SC behaviour is described in Appendix C.
Harmonic filer	R-L-C1-C2,Rp Shunt Filter / Y connected C1 = 977 uF C2 = 43.82 uF L = 10.37 mH R = 0 Rp = 12.5 Fixed tap	Details taken from existing PF model

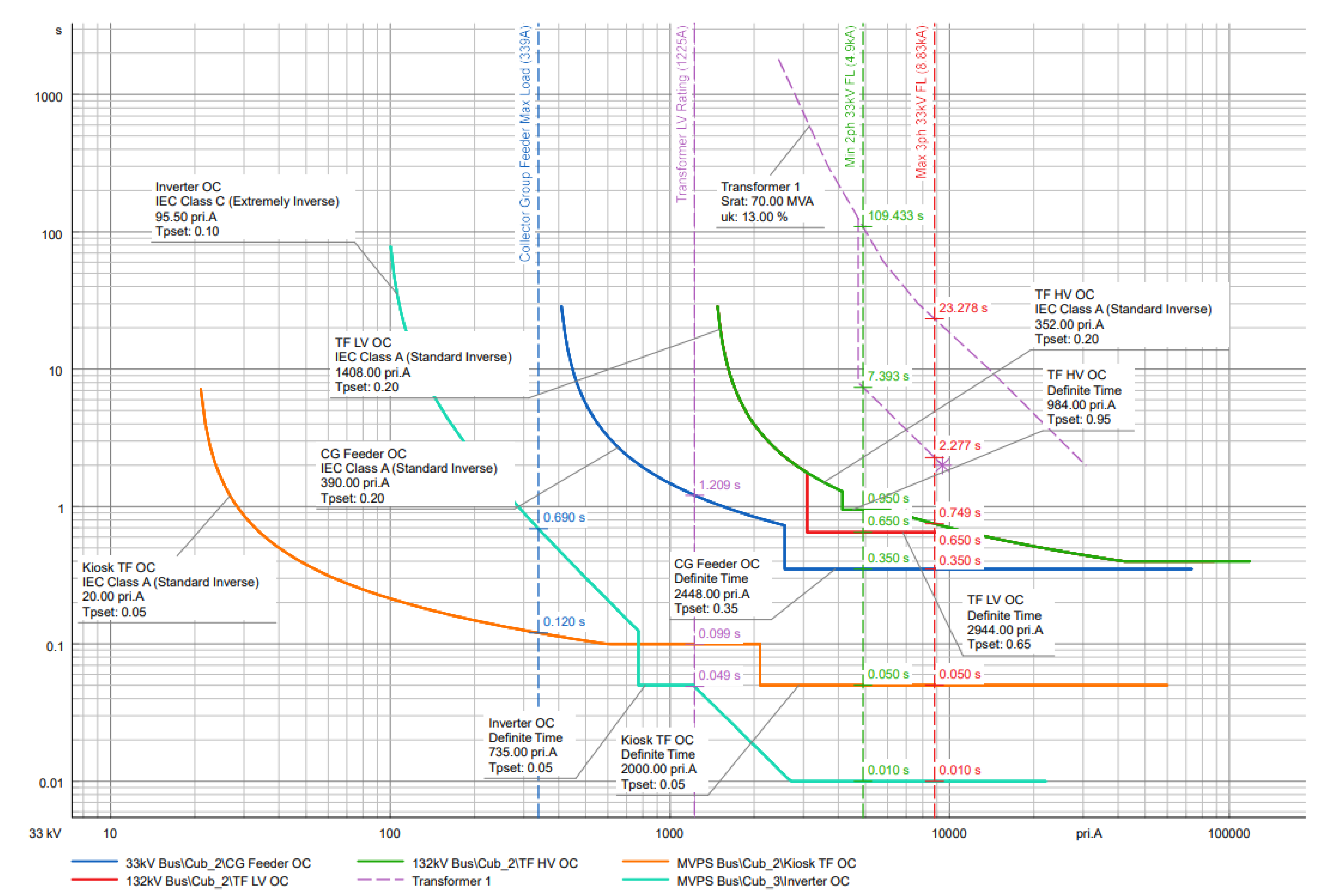
A.3. Maximum Fault Levels

Location	3ph Ik'' (kA)	LL Ik'' (kA)	LLG Ik'' (kA)	SLG Ik'' (KA)	Comments
132kV Bus	7.047	5.906	6.671	6.834	
33kV Main Switchboard	8.824	6.651	6.925	0.976	
33kV MVPS	8.802	6.636	6.91	0.975	Largest fault at any MVPS
690VAC Inverter Terminals	40.062	32.344	32.346	0	Largest fault at any inverter

A.4. Minimum Fault Levels

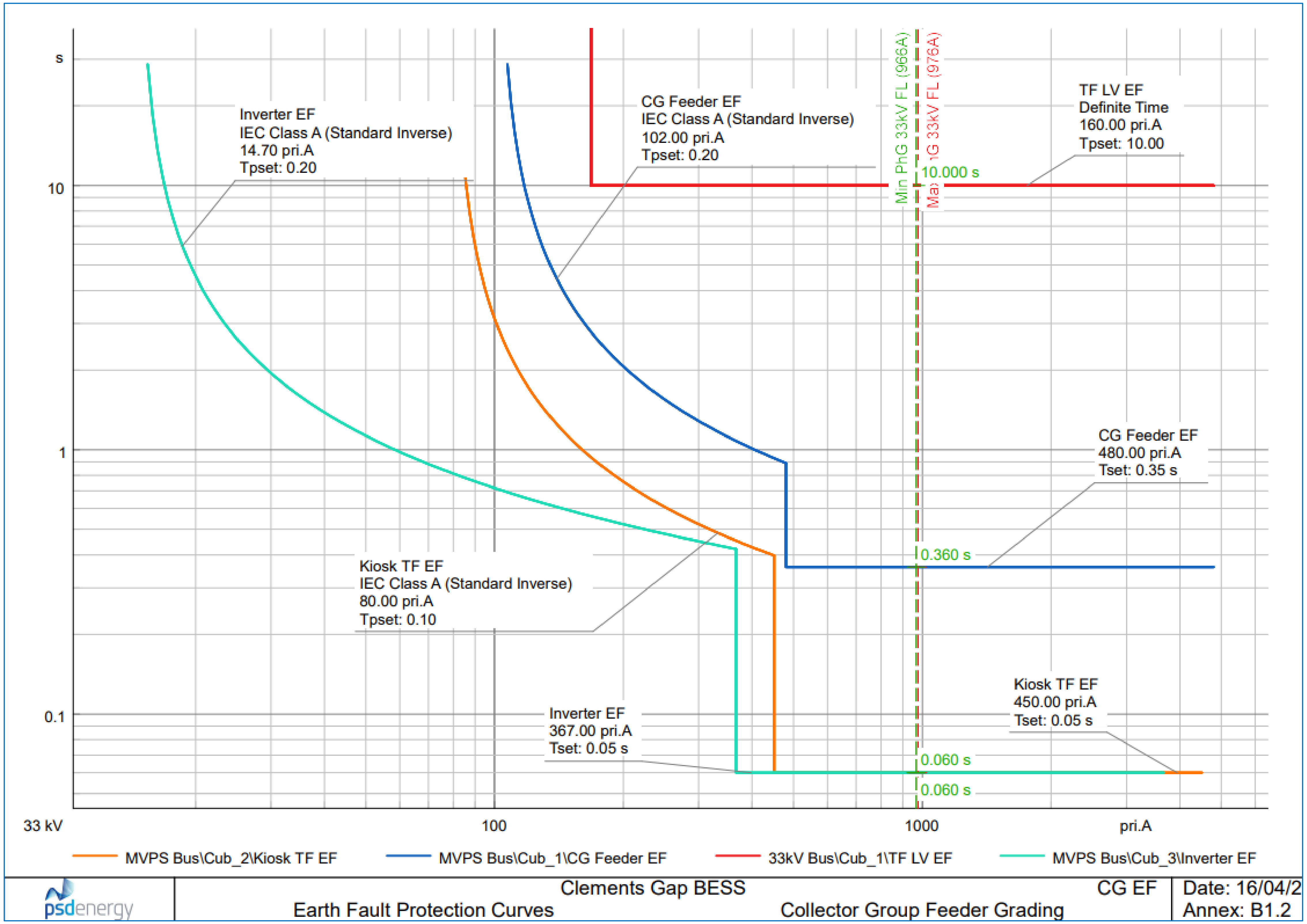
Location	3ph Ik'' (kA)	LL Ik'' (kA)	LLG Ik'' (kA)	SLG Ik'' (KA)	Comments
132kV Bus	3.282	2.692	3.068	3.112	
33kV Control Building Bus	6.447	4.945	5.211	0.97	
33kV MVPS	6.382	4.904	5.168	0.966	Lowest fault at any MVPS
690VAC Inverter Terminals	39.214	32.266	32.262	0	Lowest fault at any Inverter

B.1. Collector Group Feeder OC Grading

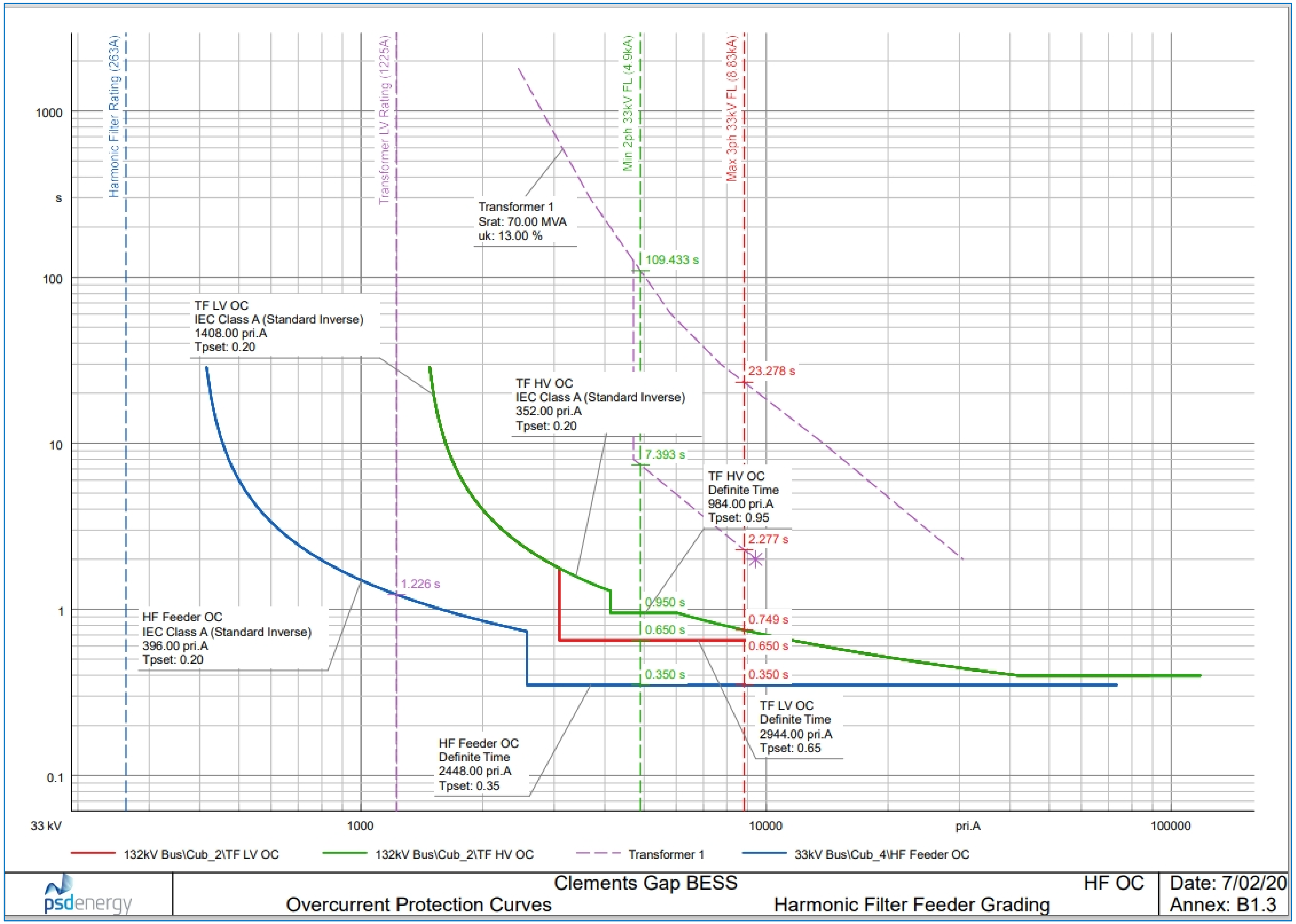


psdenergy	Clements Gap BESS Overcurrent Protection Curves	CG OC Collector Group Feeder Grading	Date: 16/04/2 Annex: B1.1

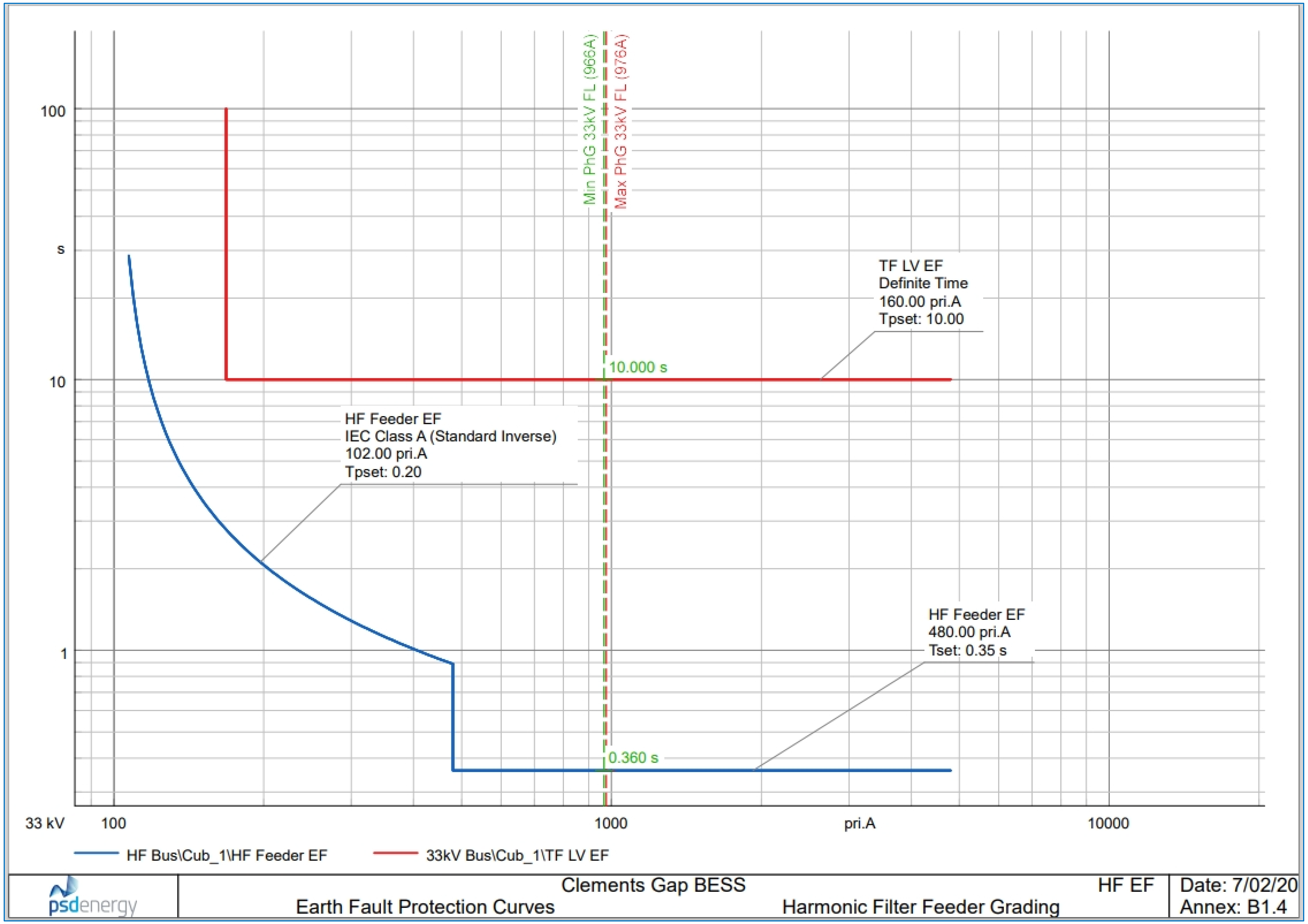
B.2. Collector Group Feeder EF Grading



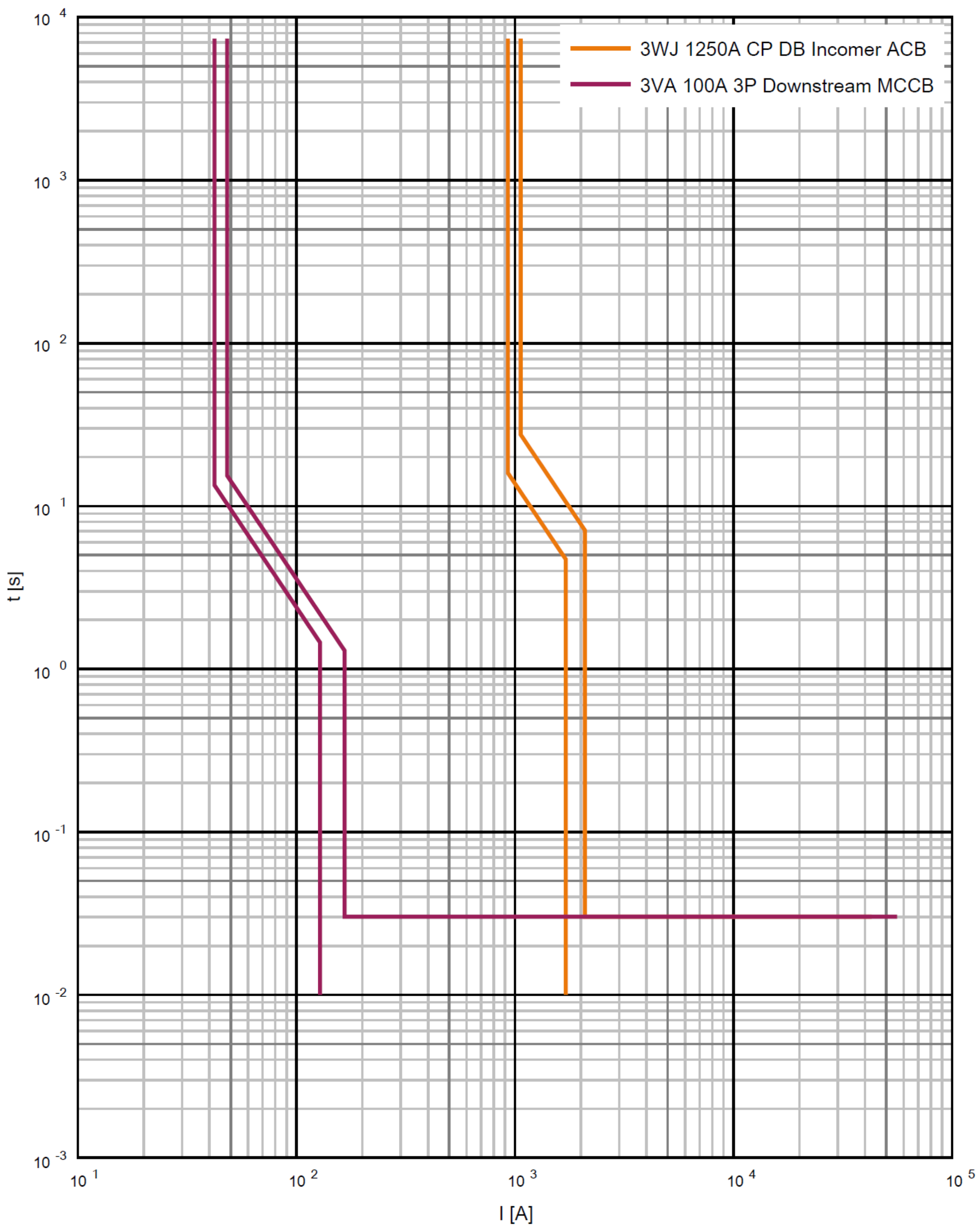
B.3. Harmonic Filter Feeder OC Grading



B.4. Harmonic Filter Feeder EF Grading



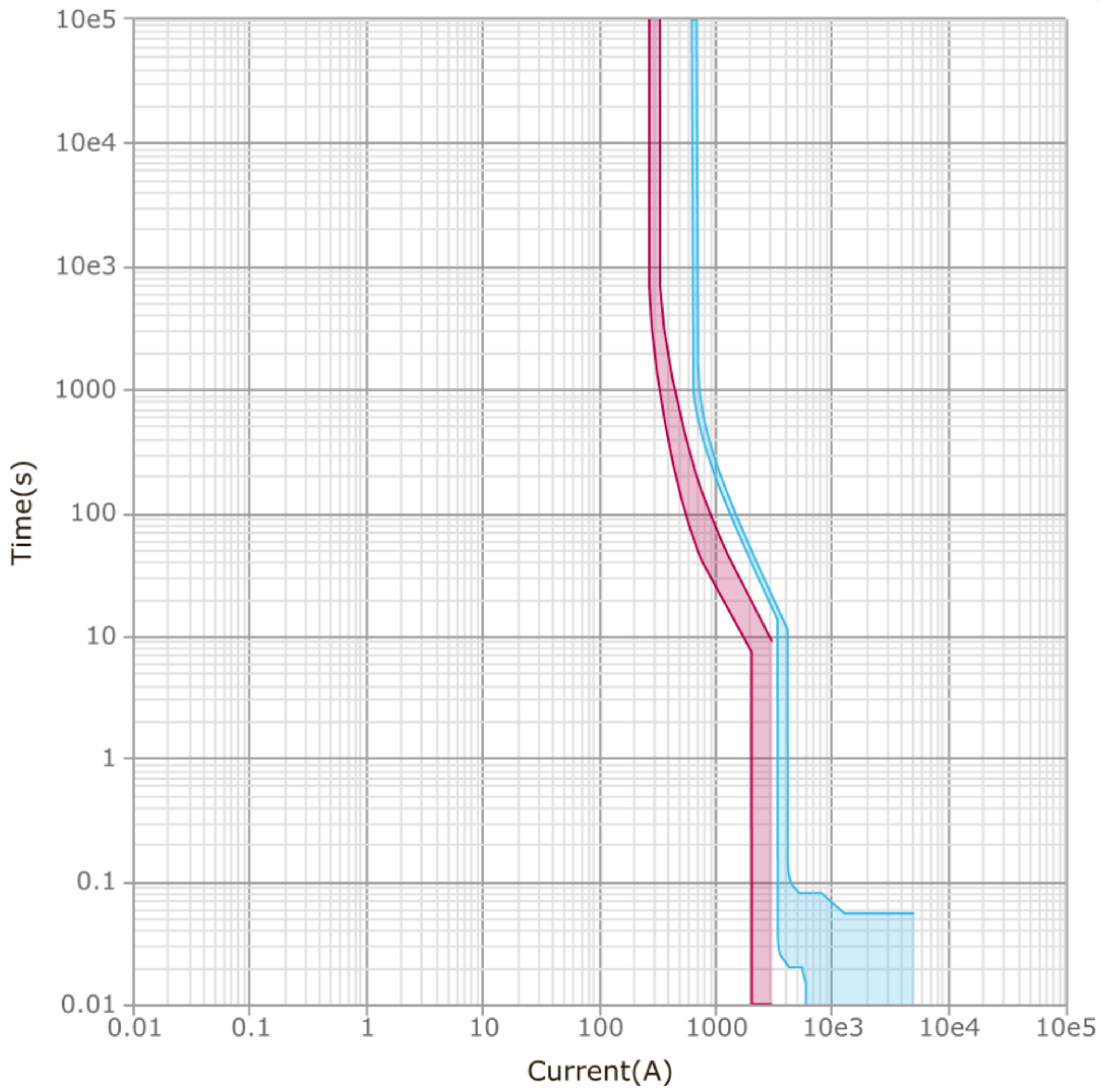
B.5. MVPS Kiosk Transformer 400 V Distribution Grading



Low voltage

Designation		L		I	
	In [A]	Ir [A]	tr [s]	Ii [A]	on
3WJ 1250A CP DB Incomer ACB	1,250	875	0.75	1,875	yes
3VA 100A 3P Downstream MCCB	100	40	0.5	150	-

Time current curve



	Circuit breaker
Name	NSX630N Micrologic 7.3 E - 570
Range	ComPacT NSX
Designation	NSX630N
Circuit breaker rating	630 A
Trip unit	Micrologic 7.3 E
Trip unit rating	570 A
Long delay settings	
Ir	570 A
Tr	16 s
Short delay settings	
Isd	3705 A
Tsd	0 s
Instantaneous tripping	
Ii	6270 A

	Circuit breaker
Name	CVS250F TM-D - 250
Range	EasyPact CVS
Designation	CVS250F
Circuit breaker rating	250 A
Trip unit	TM-D
Trip unit rating	250 A
Long delay settings	
Ir	250 A
Tr	NA
Short delay settings	
Isd	2500 A
Tsd	NA
Instantaneous tripping	
Ii	NA