SPECIAL TOPICS ON GROUND FAULT PROTECTION AND PROTECTION COORDINATION IN INDUSTRIAL AND COMMERCIAL POWER SYSTEMS

Claudio S. Mardegan
claudio.mardegan@engepower.com
www.engepower.com
Phone: 55 11 3579-8777

Claudio S. Mardegan – Is a Senior Member (2013) of the IEEE. He is an Electrical Power System Engineer graduating in 1980 from the Itajuba´s Federal University (UNIFEI), in Brazil. He is a Director of the EngePower Company. He is the author of the book “Proteção e Seletividade em Sistemas Elétricos Industriais” (Protection and Coordination in Electrical Power Systems). He is also the co-author of the Guide for LV and MV, Brazilian Standards NBR-5410, NBR-14039. He is consulting engineer for Brazilian and multinational companies and instructor of protection training, harmonic training and substation training . He has written over 15 papers on power system analysis. Mr. Mardegan participates in the Generator Grounding, Surge Protecttion, Forensics, DC, 3003-series and 3004-series working groups. He is chair of 3004.8 (Ground Fault Protection) and 3004.13 (Overcurrent Coordination). He has extensive experience in design, assembling, commissioning, maintenance, consulting and power system analysis.

Abstract

This presentation intends to show some special topics on Ground Fault Protection (GFP) and Protection Coordination.

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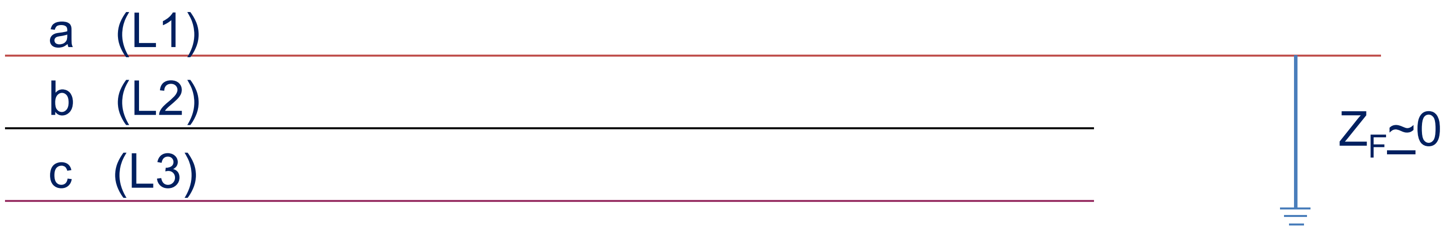
1 GROUND FAULT CURRENT

1.1 – Bolted Single line-to-ground Fault
1.2 – Bolted line-to-ground fault for solidly grounded systems
1.3 – Single-phase arcing fault
1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation
1.5 - Generator Special Issues - Single line-to-ground Fault in Parallel Operation
1.6 – Generator Special Issues – Avoid mixing different system grounding types

1

1.1 - Bolted Single Line-to-Ground Fault (I_{SLGBF})



Conditions: $V_a = 0$ and $I_b = 0$; $I_c = 0$

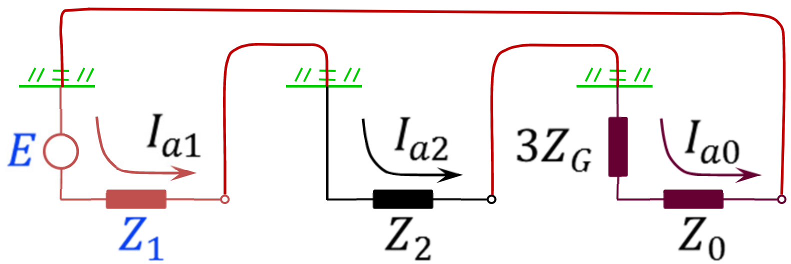
$$I_{a0} = \frac{1}{3} \times (I_a + I_b + I_c) = \frac{1}{3} \times I_a$$

$$I_{a1} = \frac{1}{3} \times (I_a + aI_b + a^2 I_c) = \frac{1}{3} \times I_a$$

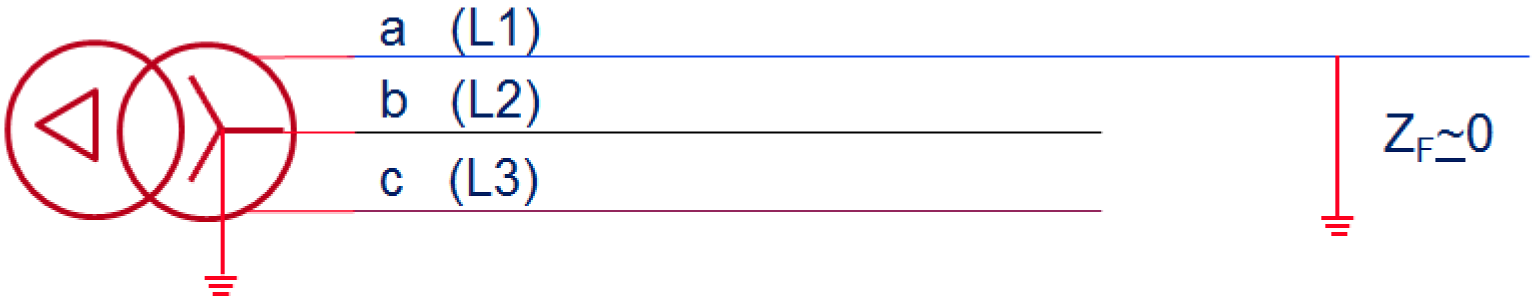
$$I_{a2} = \frac{1}{3} \times (I_a + a^2 I_b + aI_c) = \frac{1}{3} \times I_a$$

$$I_{a0} = I_{a1} = I_{a2} = \frac{E}{Z_0 + Z_1 + Z_2 + 3Z_G}$$

$$\boxed{I_{SLGBG} = 3I_{a0} = \frac{3E}{Z_0 + Z_1 + Z_2 + 3Z_G}}$$



1.2- Bolted Single Line-to-Ground Fault for Solidly Grounded Systems



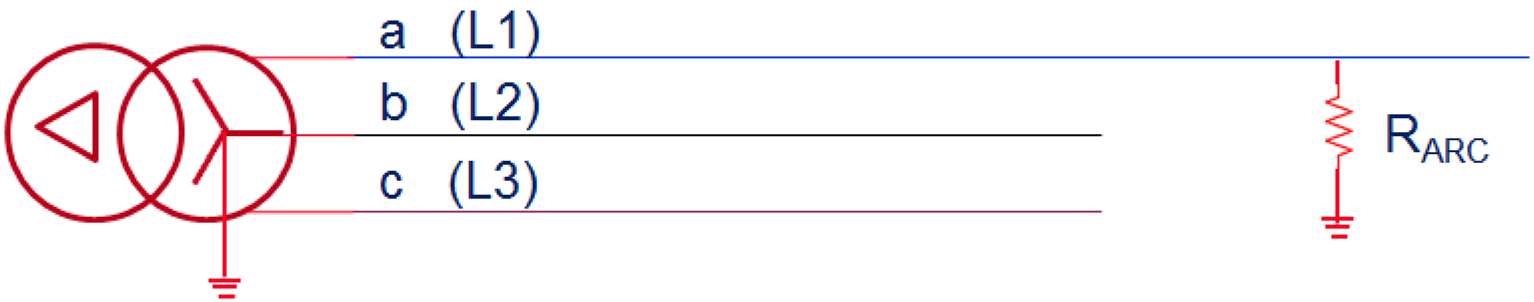
For solidly grounded systems supplied by delta-wye transformers, Z_G is negligible with respect to Z_0. Meanwhile, Z_0 equals Z_1 and Z_2. Thus,

$$Z_1 = Z_2 = Z_0 >> Z_G$$

$$\boxed{I_{SLGBF} = \frac{3E}{Z_1 + Z_1 + Z_1} = \frac{3E}{3Z_1} = \frac{E}{Z_1} = I_{3PHBF}}$$

1.3 - Single-Phase Arcing Fault

Arcing Fault Calculation based on IEEE Std 1584 is explicitly valid for three-phase arcing fault. So, is not valid for line-to-ground arcing fault.



Usually,

$$I_{SLGAF} = (0.3 - 0.9) \times I_{SLGBF}$$

Some papers use:

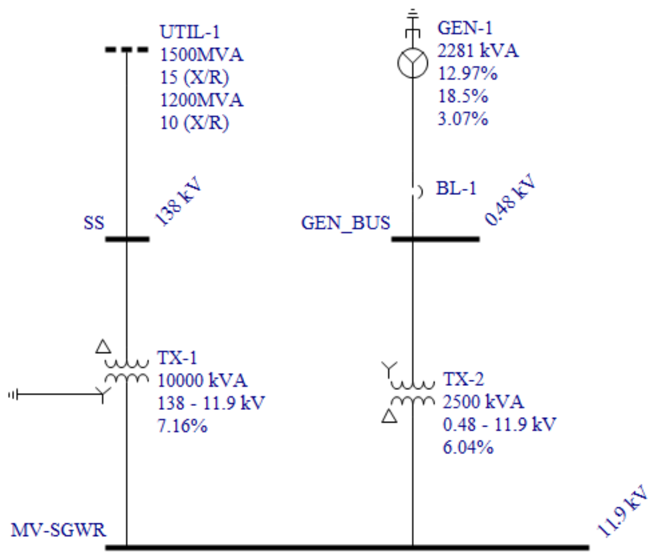
0.38 x I_{BOLTED_FAULT} (Dunki-Jacobs)
(0.47 to 0.52) x I_{BOLTED_FAULT} (Gammon & Matthews)

For Protection Engineer the most import is to provide a setting lower than the actual value. Normally a value of 35% of bolted fault will solve most of the systems.

1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation

1

Consider the one-line diagram presented below.



Assumptions:

<u>Generator</u>

X"d = 12.97%

X'd = 18.50%

X0 = 3.07%

X2 = X"d

X/R = 26.1

<u>Transformer TX-1</u>

Z0 = 0.85xZ1

X/R = 16.1804

<u>Transformer TX-2</u>

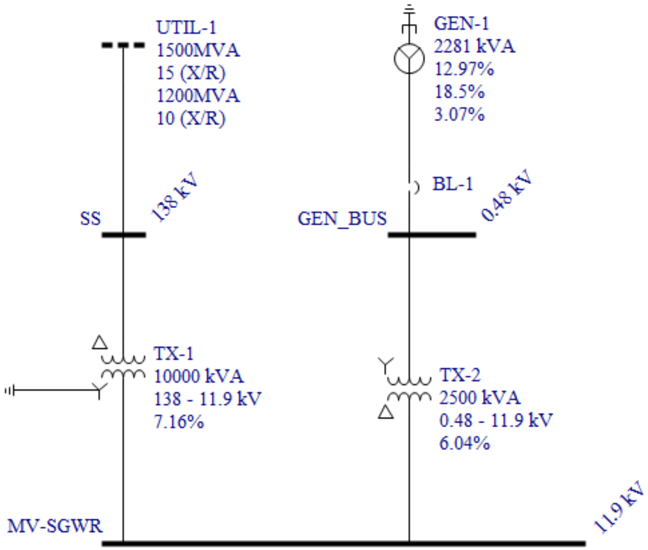
Z0 = Z1

X/R = 8.5

1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation

1

Conversion of the impedances to per unit values to the 100 MVA base.



$$Z_{1S} = \frac{100}{1500} \angle tg^{-1}(15) = 0.0667 \angle 86.19° \; pu$$

$$Z_{1_{TX-1}} = \frac{7.16}{10} \angle tg^{-1}(16.1804) = 0.7160 \angle 86.46° \; pu$$

$$Z_{1_{TX-2}} = \frac{6.04}{2.5} \angle tg^{-1}(8.5) = 2.416 \angle 83.29° \; pu$$

$$X_{1_G} = \frac{12.97}{2.281} = 5.6861 \angle 90° \; pu \qquad R_{1_G} = \frac{5.6861}{26.1} = 0.2179 \angle 0° \; pu$$

$$Z_{1_G} = 5.6903 \angle 87.81° \; pu$$

$$Z_{2G} = 5.6903 \angle 87.81° \; pu$$

$$Z_{0G} = 1.3459 \angle 87.81° \; pu$$

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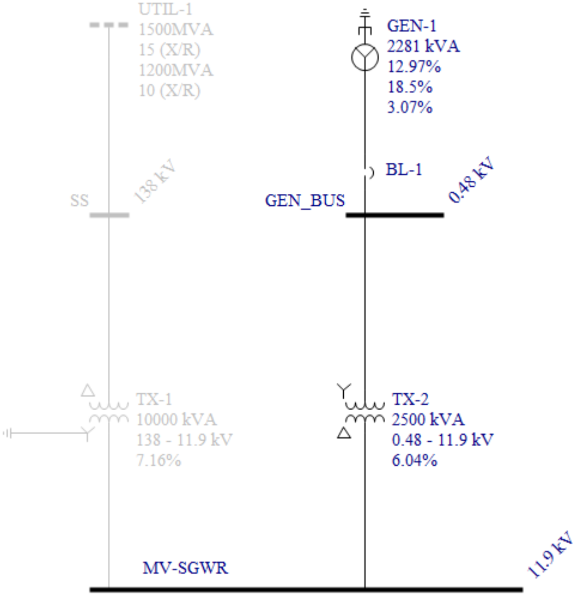
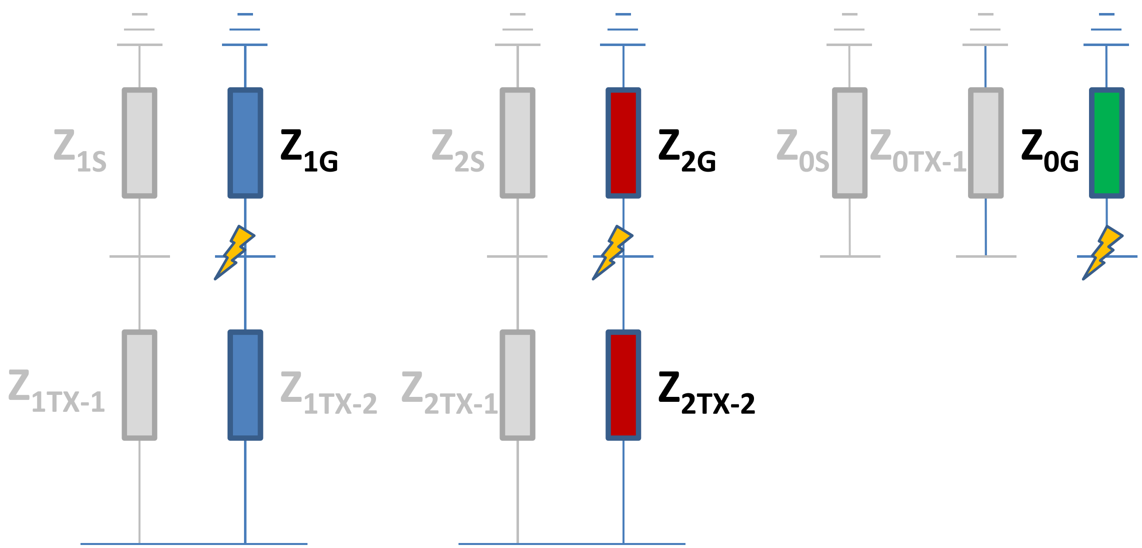
1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation

1

Sequence Diagrams.





Thevenin Equivalent Impedances

$Z_{1EQ} = Z_{1G}$

$Z_{1EQ} = 5.6903\ \angle 87.81°\ pu$

$Z_{2EQ} = Z_{2G}$

$Z_{2EQ} = 5.6903\ \angle 87.81°\ pu$

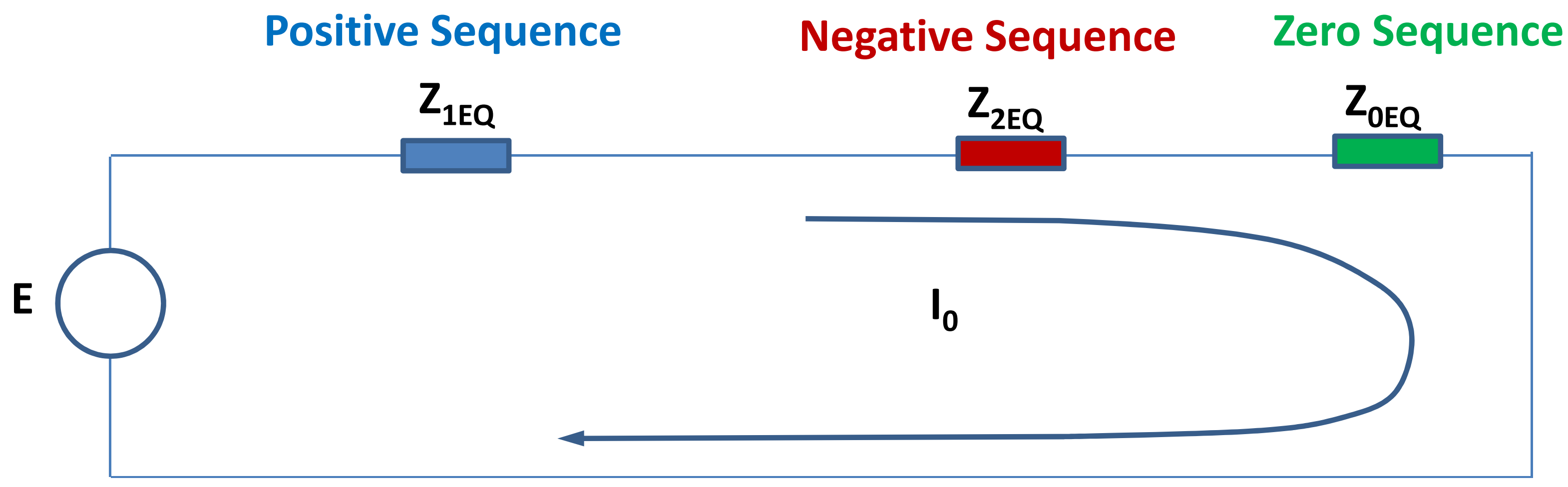
$Z_{0EQ} = Z_{0G}$

$Z_{0EQ} = 1.3459\angle 87.81°\ pu$

1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation

1

Fault Sequence Circuit.



$$I_{SLG} = 3I_0 = \frac{3E}{Z_{1EQ} + Z_{2EQ} + Z_{0EQ}} = 0.2351\angle - 87.81°pu$$

$$I_{BASE} = \frac{100000}{\sqrt{3} \times 0.48} = 120281\ A$$

$$I_{SLG} = 28352\ A$$

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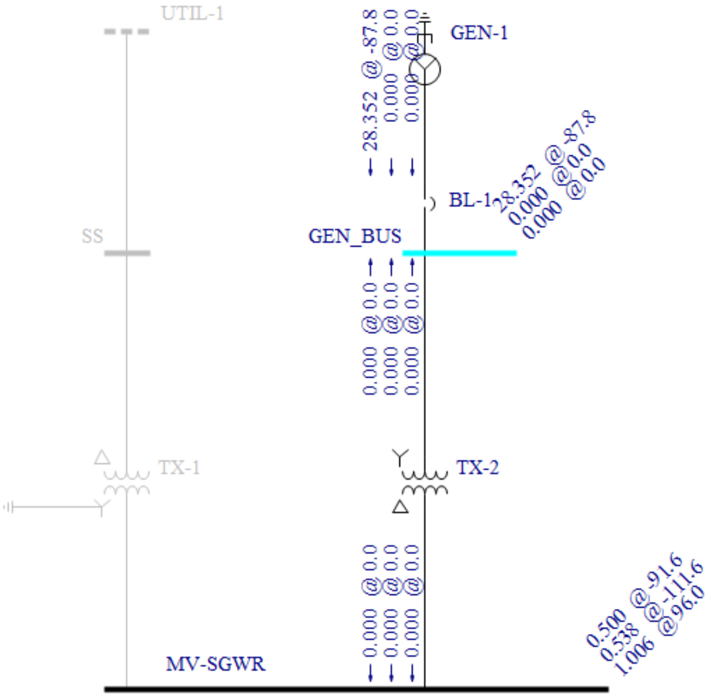
1.4 – Generator Special Issues - Single line-to-ground Fault in Islanding Operation

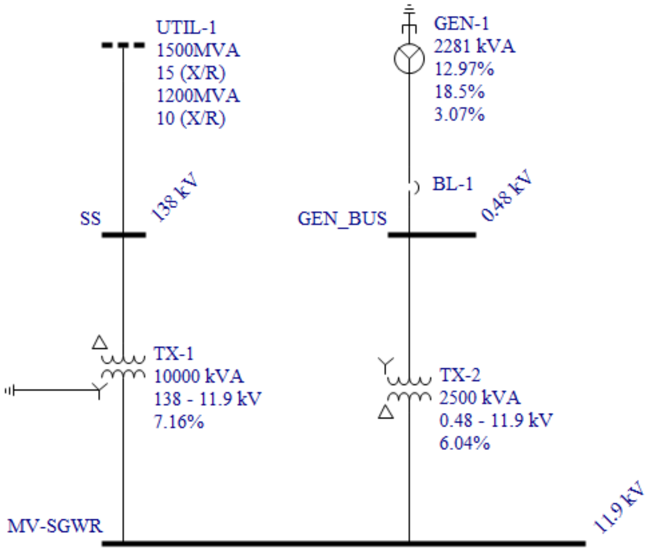
Simulations Results.

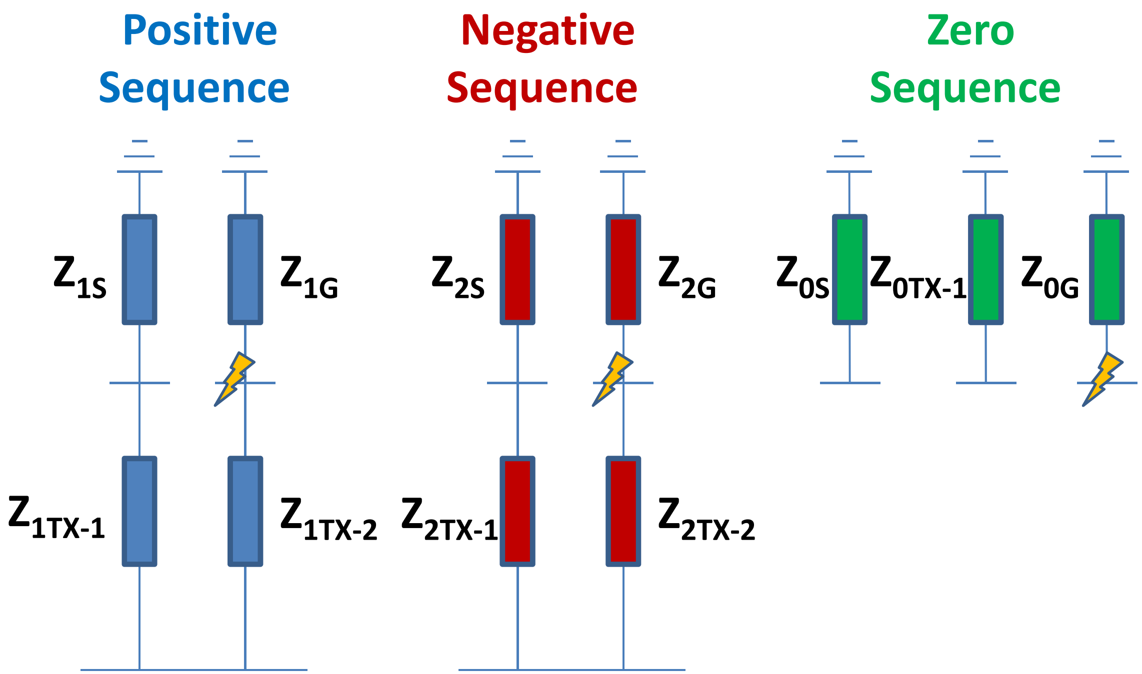


1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

1

Sequence Diagrams.





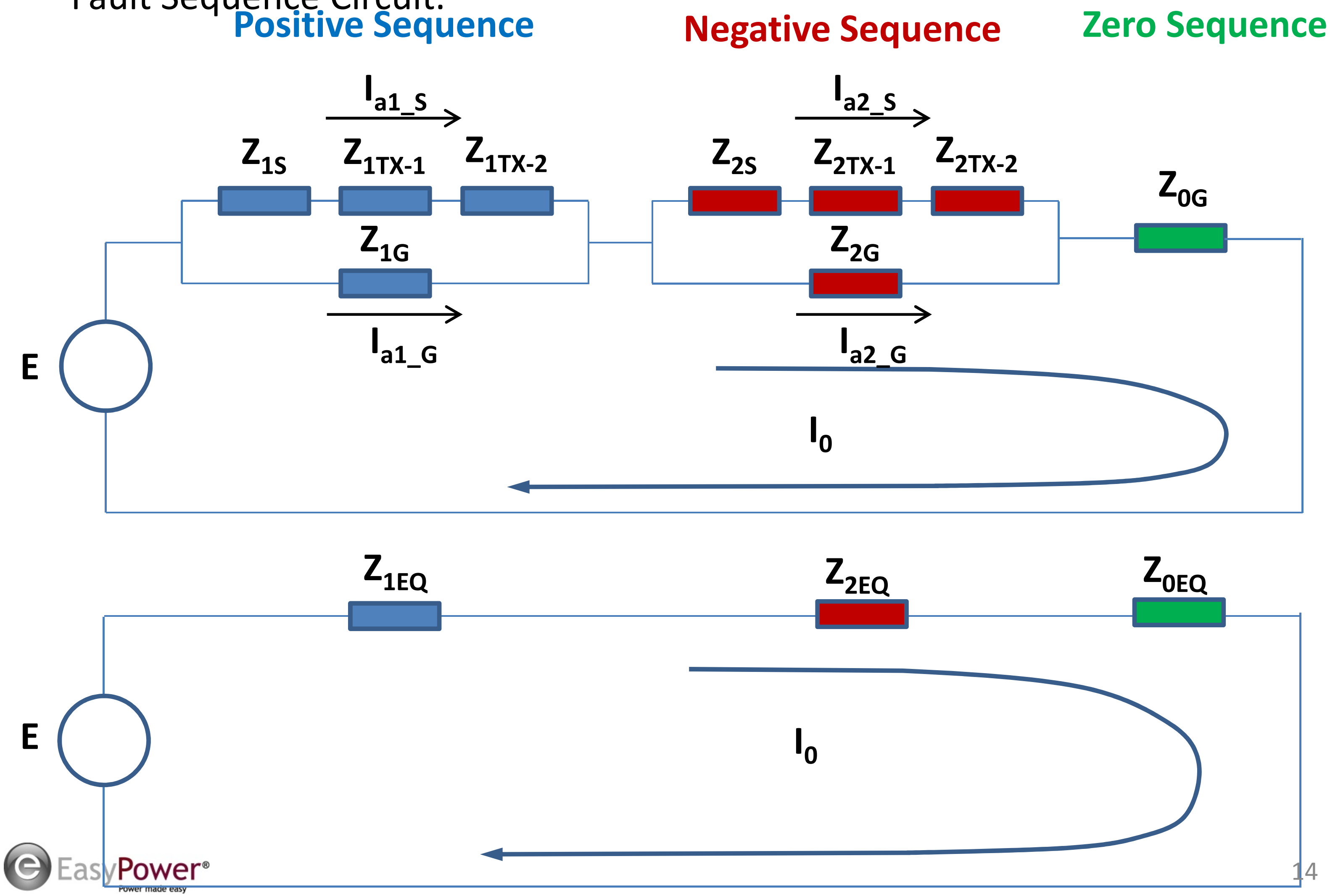
Thevenin Equivalent Impedances

$Z_{1EQ} = (Z_{1S} + Z_{1TX-1} + Z_{1TX-2})\ //\ Z_{1G}$ $Z_{2EQ} = (Z_{2S} + Z_{2TX-1} + Z_{2TX-2})\ //\ Z_{2G}$ $Z_{0EQ} = Z_{0G}$

1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

1

Fault Sequence Circuit.



1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

1

Fault Sequence Impedances.

$(Z_{1S} + Z_{1TX-1} + Z_{1TX-2}) = 3.1978\angle 84.06°$

$(Z_{2S} + Z_{2TX-1} + Z_{2TX-2}) = 3.1978\angle 84.06°$

$Z_{1G} = 5.6903\angle 87.81°$

$Z_{2G} = 5.6903\angle 87.81°$

$Z_{0G} = 1.3469\angle 87.81°$

$Z_{1EQ} = 2.0483\angle 85.41°$

$Z_{2EQ} = 2.0483\angle 85.41°$

$Z_{0EQ} = 1.3469\angle 87.81°$

$$I_{SLG} = 3I_0 = \frac{3E}{Z_{1EQ}+Z_{2EQ}+Z_{0EQ}} = 66301\ A$$

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1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

1

Total Fault Current.

$$I_{SLG} = 3I_0 = \frac{3E}{Z_{1EQ}+Z_{2EQ}+Z_{0EQ}} = 66301\ A$$

Current Contributions - System Contribution

$$I_{a1\_S} = \frac{Z_{1G}}{Z_{1S}+Z_{1TX-1}+Z_{1TX-2}+Z_{1G}} \times I_0 \qquad I_{a2\_S} = \frac{Z_{2G}}{Z_{2S}+Z_{2TX-1}+Z_{2TX-2}+Z_{2G}} \times I_0$$

$I_{a0\_S} = 0$ $\quad I_{a1\_S} = 0.11769\angle-84.65°pu$ $\quad I_{a2\_S} = 0.11769\angle-84.65°pu$

$I_{a\_S} = 0.23538\angle-84.65°pu$ $\quad I_{a\_S} = 28311.7\angle-84.65°\ A$

Current Contributions - Generator Contribution

$$I_{a1\_G} = \frac{Z_{1S}+Z_{1TX-1}+Z_{1TX-2}}{Z_{1S}+Z_{1TX-1}+Z_{1TX-2}+Z_{1G}} \times I_0 \qquad I_{a2\_G} = \frac{Z_{2S}+Z_{2TX-1}+Z_{2TX-2}}{Z_{2S}+Z_{2TX-1}+Z_{2TX-2}+Z_{2G}} \times I_0$$

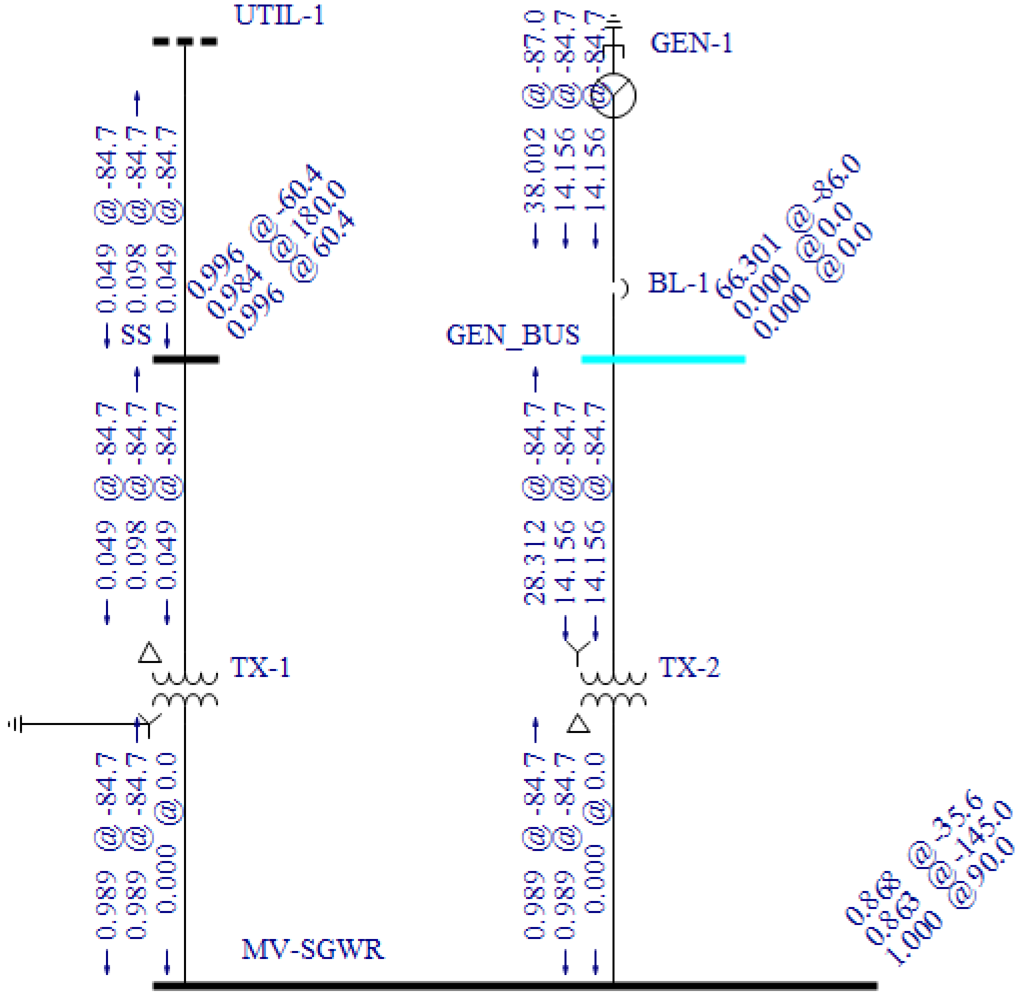
$I_{a1\_G} = 0.06614\angle-88.4°pu$ $\quad I_{a2\_G} = 0.06614\angle-88.4°pu$

$I_{a0\_G} = I_0 = 0.1838\angle-86.00°pu$ $\quad I_{a\_G} = 0.31595\angle-87°pu$

$$I_{a\_G} = 38002\angle-87°\ A$$

1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

Simulation Results.



1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

Simulations	**Calculated**	**Simulated**
Bus Total Fault	66301 A	66301 A
Current Contributions		
System Contribution	28312 A	28312 A
Positive Sequence		
Negative Sequence		
Generator Contribution	38002 A	38002 A
Positive Sequence		
Negative Sequence		
Zero Sequence		

1.5 – Generator Special Issues - Single line-to-ground Fault in Parallel Operation

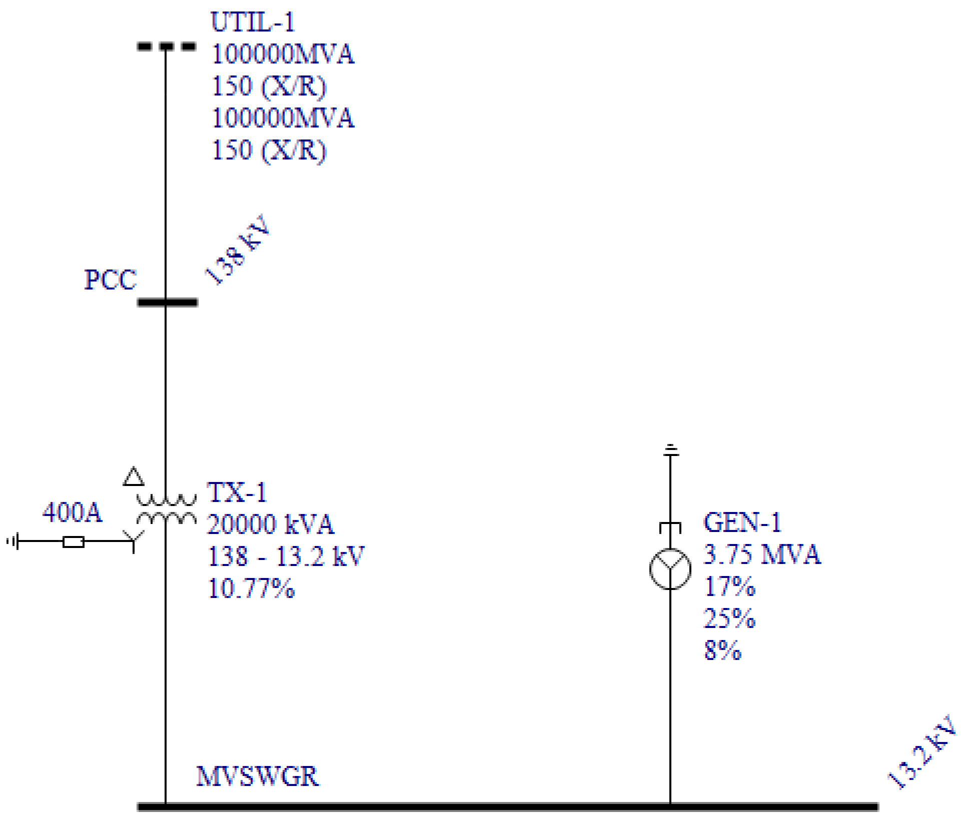
Conclusions

When connecting utility and generator in parallel with the utility, for a ground fault at generator´s terminals:

a) The ground fault current may be greater than the three-phase short circuit current.
b) The ground fault current with generator operating in parallel with the utility may be greater than the single line-to-ground fault of generator in island operation.
c) The current in the generator neutral for the parallel operation between generator and utility is greater than single line-to-ground fault current for the condition of generator island operation.
d) Engineer has to be aware when sizing neutral conductors for generators.
e) Protection Engineer has to be aware with current they are taking into account when setting ground elements.

1.6 – Generator Special Issues – Avoid Mixing Different System Grounding Type

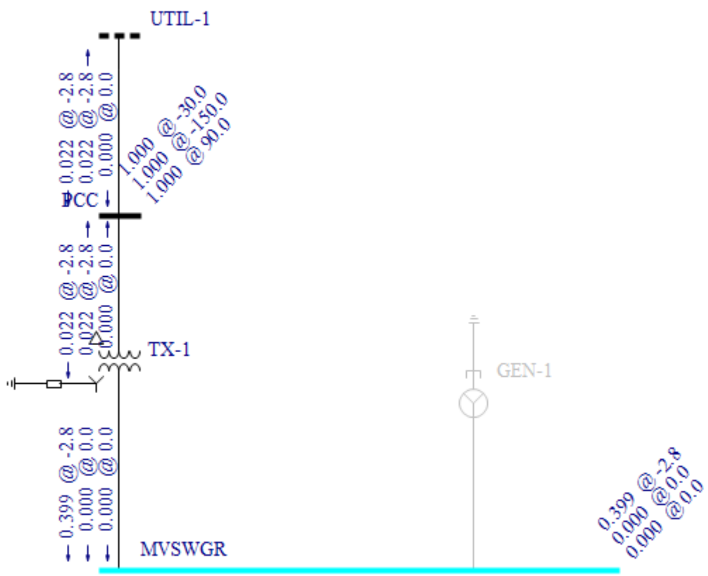
The example below shows us why we shall not mix different types of system grounding.



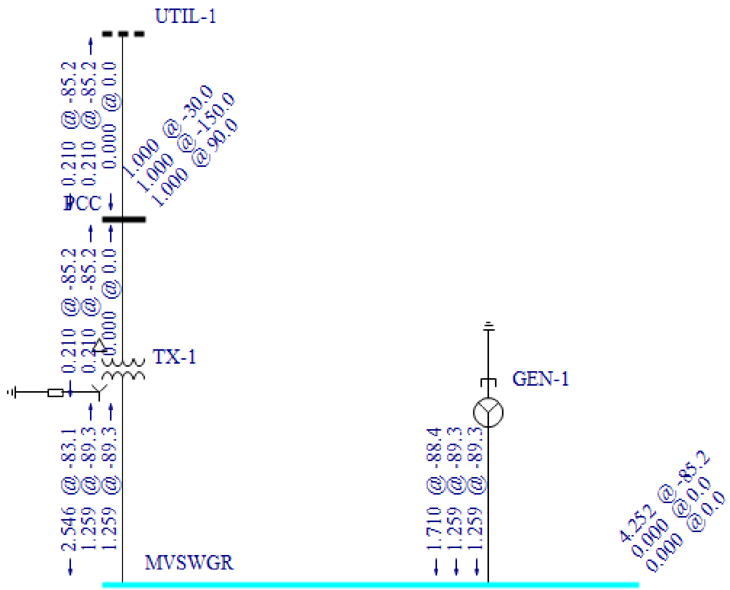
1.6 – Generator Special Issues – Never Mix Different System Grounding Type

Line-to-ground Fault

Only Utility



Utility in Parallel with Generator

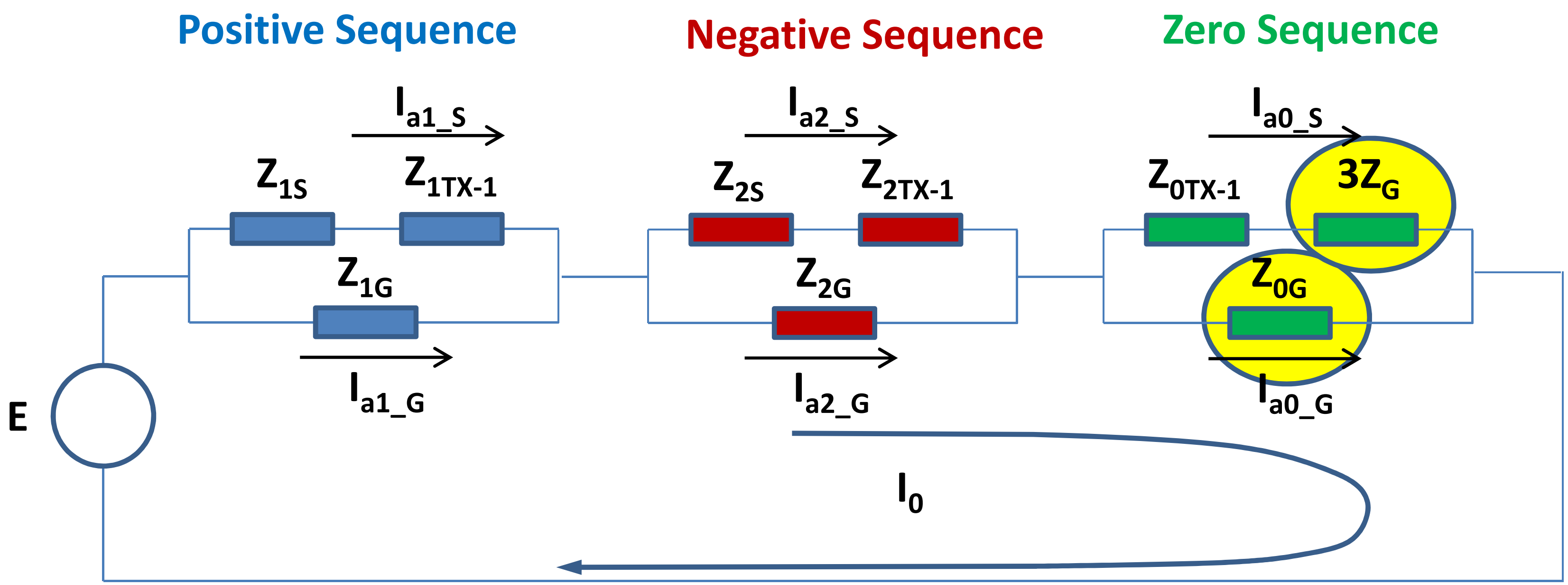


As showed above the line-to-ground current increases; in this case more than 10 times.

1.6 – Generator Special Issues – Never Mix Different System Grounding Type

1

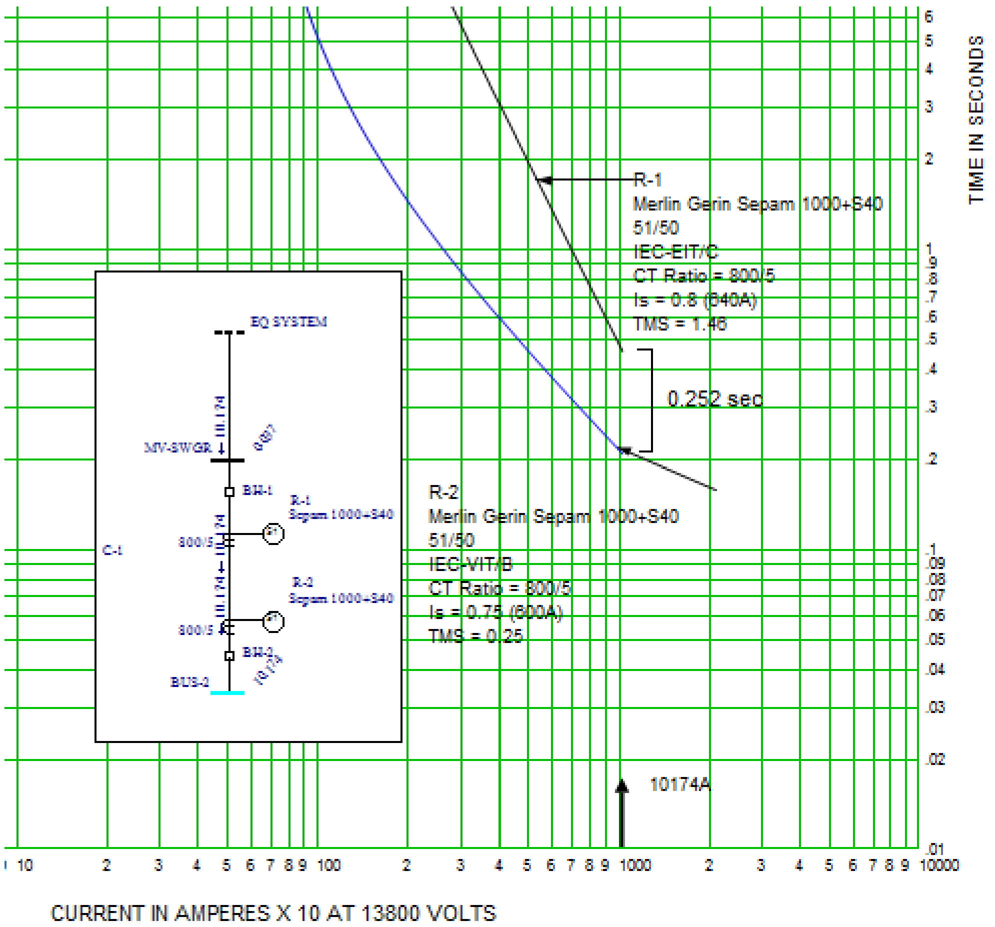
The reason why this happens is presented in sequence impedance circuit below.



The reason for the increase of current is because the grounding current limiting resistor is in parallel with generator zero sequence impedance which is almost always much smaller than resistor.

IMPORTANCE OF USING THE CORRECT VALUE OF FAULT CURRENT

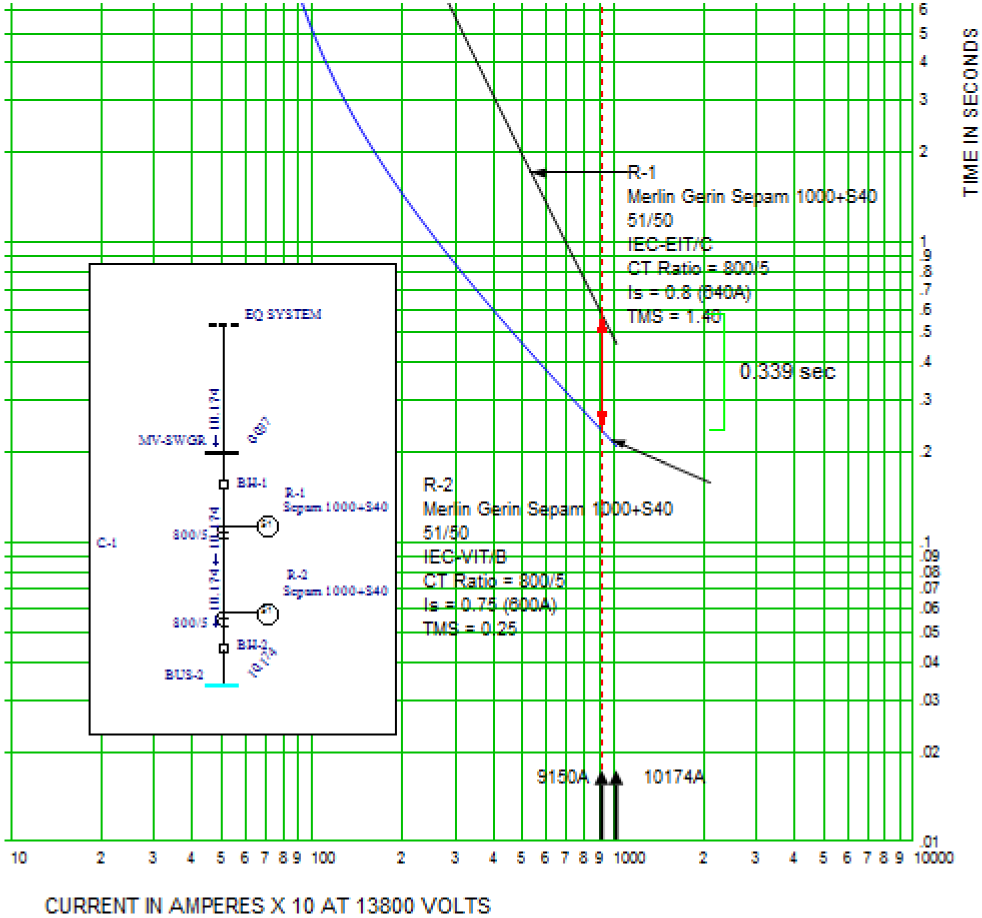
Overcurrent Protection Coordination has a general rule : Coordination is performed at short circuit currents.



2 IMPORTANCE OF USING THE CORRECT VALUE OF FAULT CURRENT

When using inverse time relays :

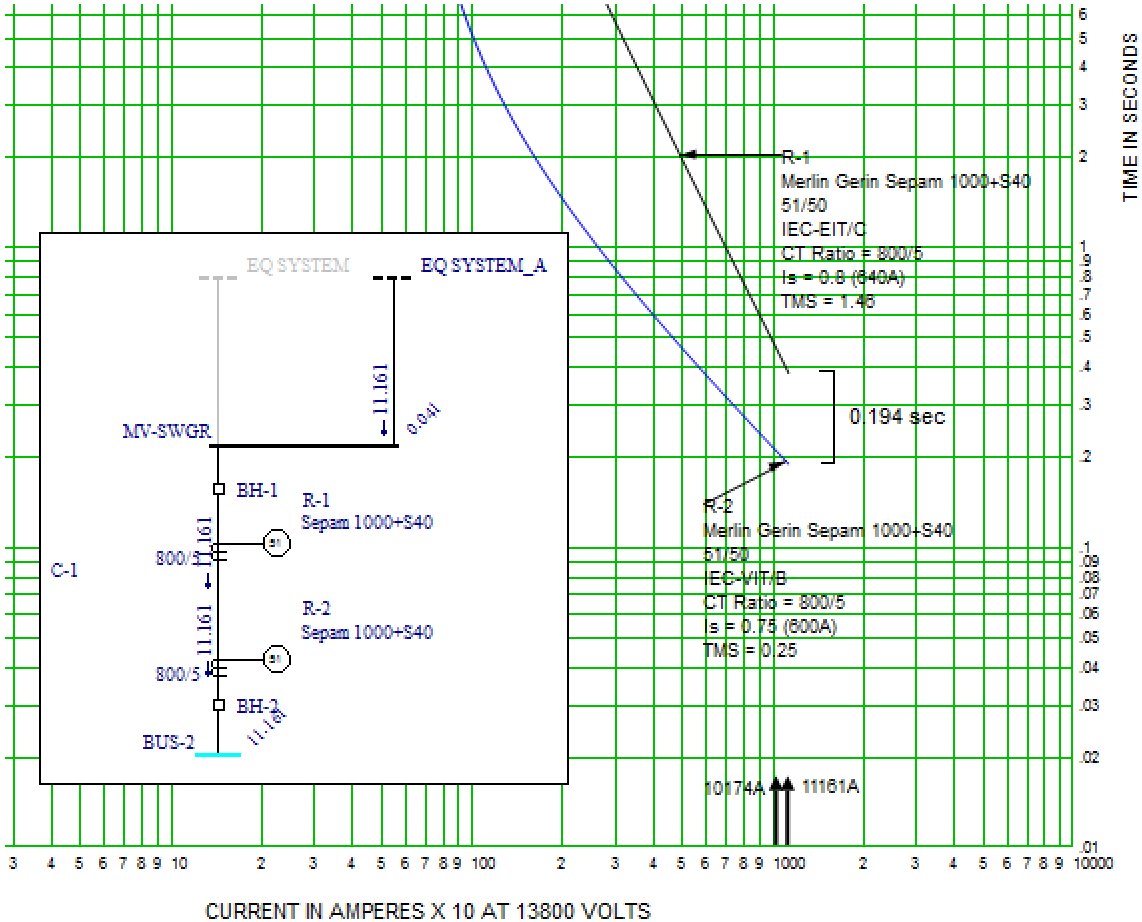
If you use a calculated short circuit current value (10174) higher than the actual value (9150 A) the relay is going to take longer to trip. This means more damage and more time to return system to operation.



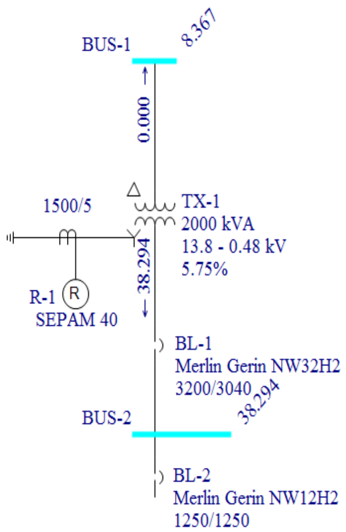
2 IMPORTANCE OF USING THE CORRECT VALUE OF FAULT CURRENT

When using inverse time relays :

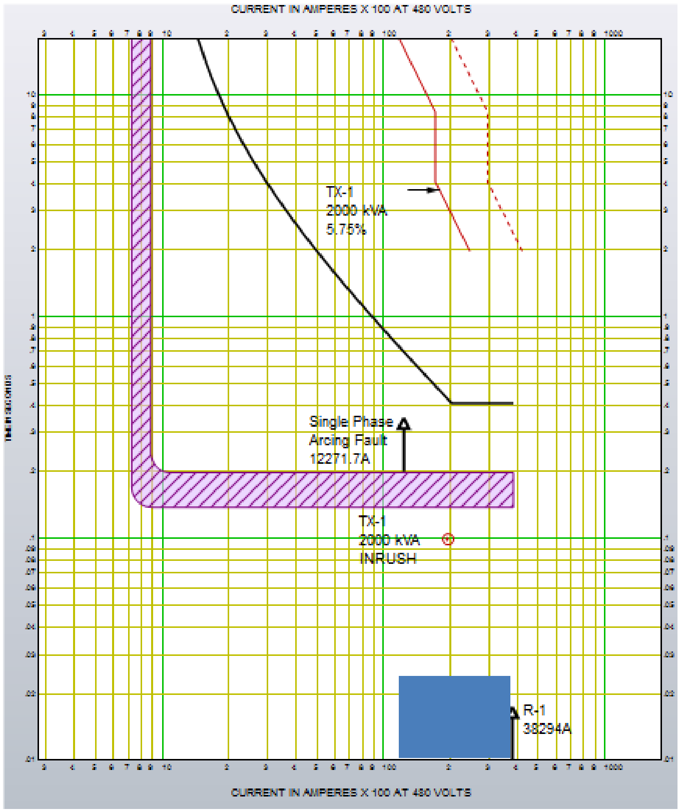
If you use a calculated short circuit current value (10174 A) lower than the actual value (11161A) the relay may miscoordinate with the downstream relay.



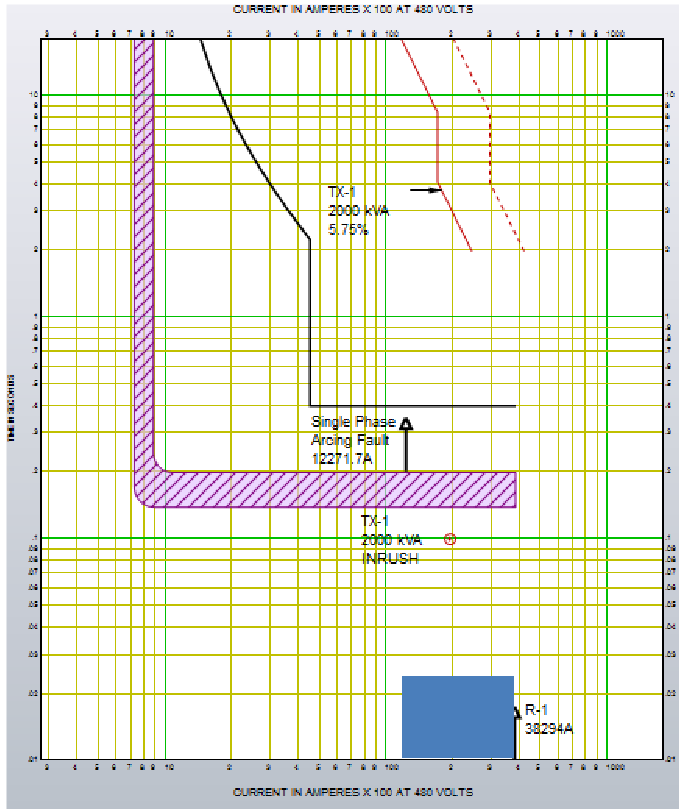
Why is so important to consider the single line-to-ground arcing fault current in the ground coordination ?



As a general rule the TCI (Time Coordination Interval) is applied on the TCCs at the Bolted Short Circuit Value (there some exceptions). What happens if an Arcing Ground Fault occurs ?



Inverse Time Elements



Definite Time Elements

Relay

Trip for Bolted Fault :0.400 s
Trip for Arcing Fault :0.698 s

Trip for Bolted Fault :0.400 s
Trip for Arcing Fault :0.400 s

3 SYSTEM BEHAVIOR AS FUNCTION OF SYSTEM GROUNDING

Electrical Power System voltage are becoming higher in the last years because the consumed energy are increasing and the industrial plants are also becoming bigger (more cable lengths).

Normally, the Project Engineer may choose a LRG, a HRG or even a HHRG as a way to determine the system grounding. But, the system may have an unexpectable behavior.

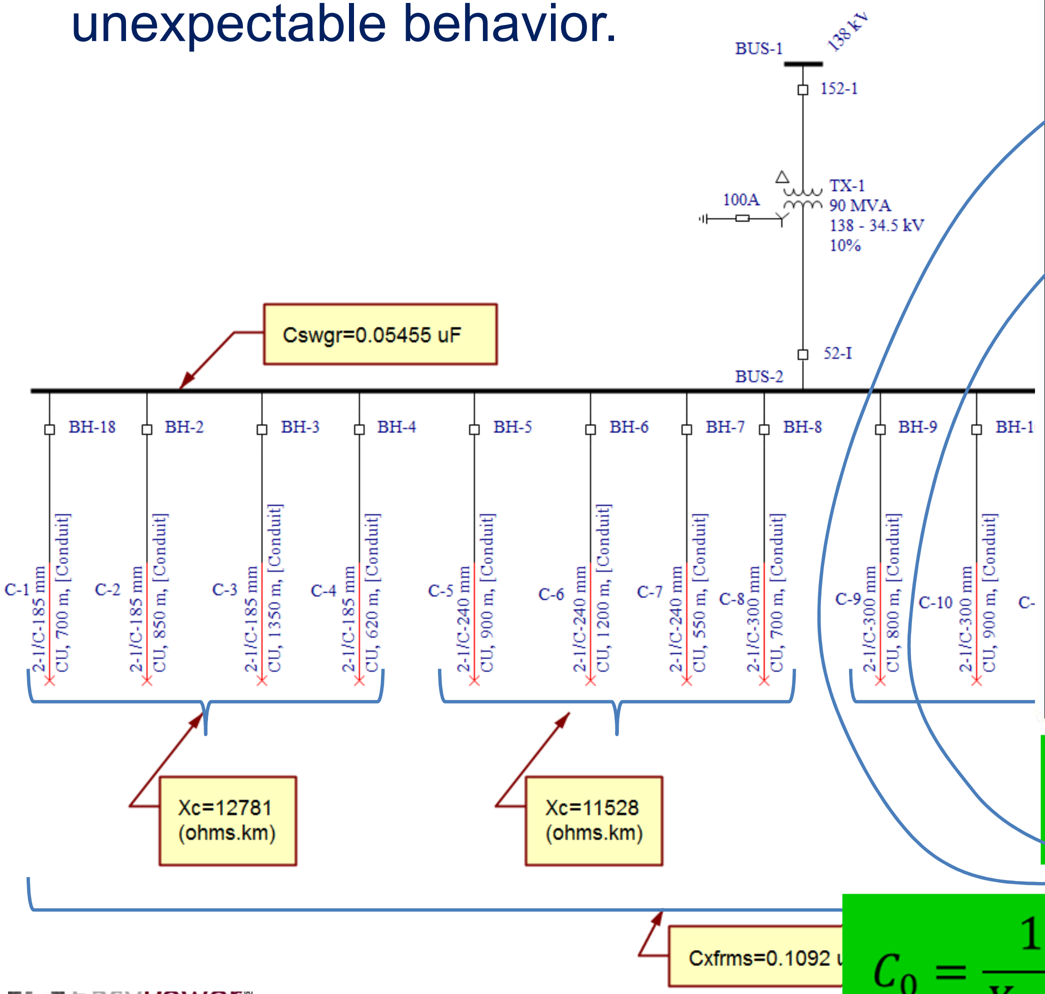
The example prepared in the next slide shows a single-line diagram based on a real case of a paper mill plant in Brazil.

The threshold of a system be considered grounded or not is defined by system stray capacitances. In terms of current the relationship between our neutral resistor current (I_R) and stray capacitances current (I_{C0}) is given by the below equation:

$$I_R = 3I_{C0}$$

System Grounding Type Determines System Behavior

Normally, you may choose a LRG, a HRG or even a UHRG as a way to determine the system grounding. But, the ... unexpectable behavior.



Circ	Nr/ph	S [mm²]	Compr (m)	Xc (Ohmsxkm)	Xc (Ohms)	Co [uF]
1	2	185	700	12781	9129.3	0.2906
2	2	185	850	12781	7518.2	0.3528
3	2	185	1350	12781	4733.7	0.5604
4	2	185	620	12781	10307.3	0.2574
5	2	240	900	11528	6404.4	0.4142
6	2	240	1200	11528	4803.3	0.5522
7	2	240	550	11528	10480.0	0.2531
8	2	300	700	10665	7617.9	0.3482
9	2	300	800	10665	6665.6	0.3979
10	2	300	900	10665	5925.0	0.4477
11	2	300	1100	10665	4847.7	0.5472
12	2	300	1700	10665	3136.8	0.8456
13	2	300	770	10665	6925.3	0.383
14	2	300	680	10665	7841.9	0.3383
15	2	300	520	10665	10254.8	0.2587
16	2	300	430	10665	12401.2	0.2139
17	1	300	930	10665	11467.7	0.2313
Cable total charging Capacitance [uF]						6.6924

$$X_C = \frac{12781}{0.7 \times 2} = 9129.3\ [Ohms]$$

$$C_0 = \frac{10^6}{X_C \times \omega} = \frac{10^6}{9129.3 \times 376.99} = 0.2906\ [\mu F]$$

System Grounding Type Determines System Behavior

3

The total capacitance at this level of voltage (34.5 kV) is given by:

$$\begin{array}{r} 6.69240 \\ +\ 0.10920 \\ \underline{0.05455} \\ 6.85615 \end{array}$$

$$X_C = \frac{1}{\omega \times C} = \frac{1}{376.99 \times 6.85615} = \frac{1}{0.002585} = 386.89\ [Ohms]$$

$$I_{C0} = \frac{\frac{V_{PH-PH}}{\sqrt{3}}}{X_C} = \frac{\frac{34500}{\sqrt{3}}}{386.89} = \frac{19918.58}{386.89} = 51.5\ [A]$$

$$3I_{C0} = 154.5\ [A]$$

As can be seen, the $3I_{C0}$ is greater than the resistor current. This means that this system will have a behavior of an ungrounded system when an unbalanced condition happens. At least a 200 A resistor is required.

The Project Engineer has to take into account, protect the cable shields when a ground fault occurs, but also have to take care when sizing the resistor short time amps for not be less than $3I_{C0}$.

4 ESCALATION OF SINGLE-PHASE ARCING FAULTS

There are few papers about single phase arcing fault escalation. Mr. Dunki-Jacobs´s paper is one of these.

Low Voltage Systems

In low voltage switchgears and motor control centers (MCCs), bus bars are not normally insulated and in these situations there are real possibilities of arcing ground fault escalation into a phase-to-phase fault or three-phase fault.

Medium Voltage Systems from 2.4 kV to 7.2 kV

When the bus bars are insulated at medium-voltage levels from 2.4 kV to 7.2 kV, the probability of escalation is low. The greatest number of cases of arcing ground-fault escalation are when the bus bars are uninsulated.

Medium Voltage Systems from 13.8 kV to 34.5 kV

The switchgears bus bars in these 13.8–kV to 34.5-kV levels are normally insulated and the probability of the arcing ground fault escalating into a phase-to-phase fault and into a three-phase fault is low. However, in solidly grounded aerial-line distribution systems, escalation occurs in 1 to 2 cycles [6]

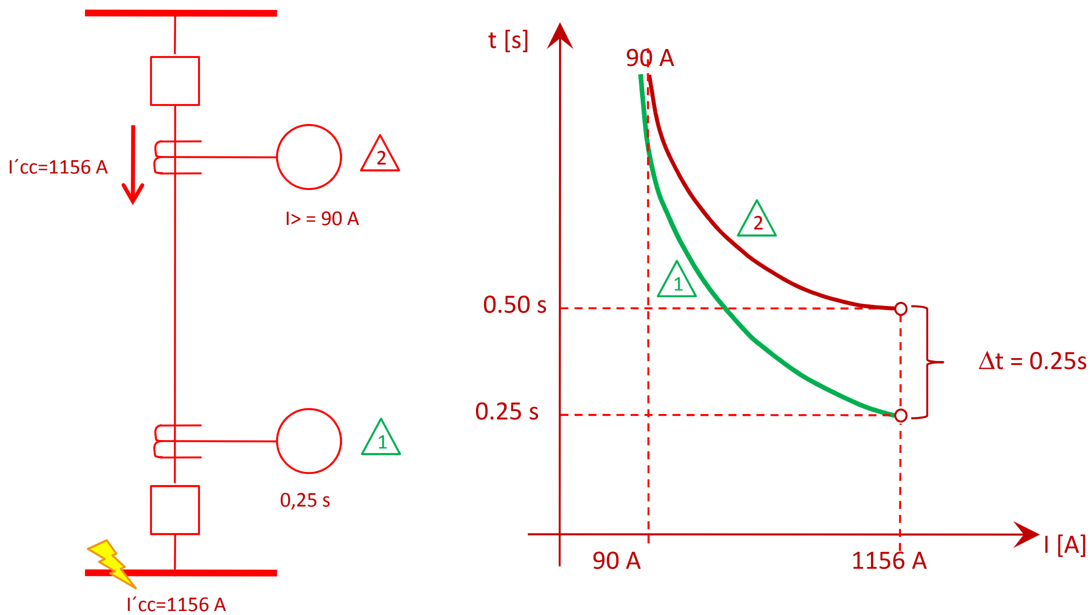
5 TYPES OF COORDINATION

Three main types of coordination are usually used in Protection Coordination Studies:

☑ Chronological Coordination
☑ Current Coordination
☑ ZSI (Zone Selective Interlocking) Coordination

Chronological Coordination

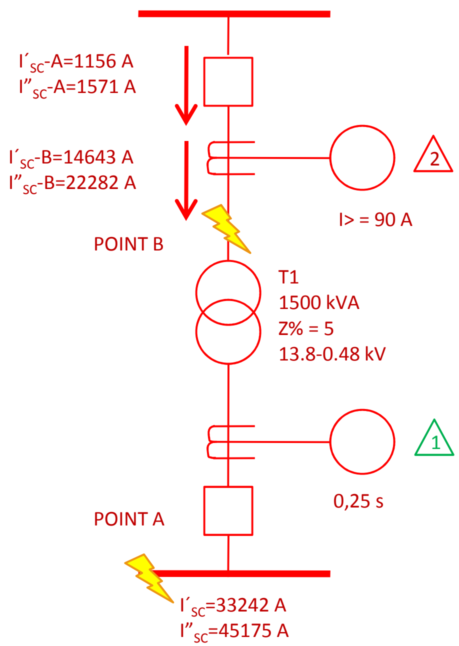
Is that one where the time interval coordination is applied between the downstream and upstream protective device.

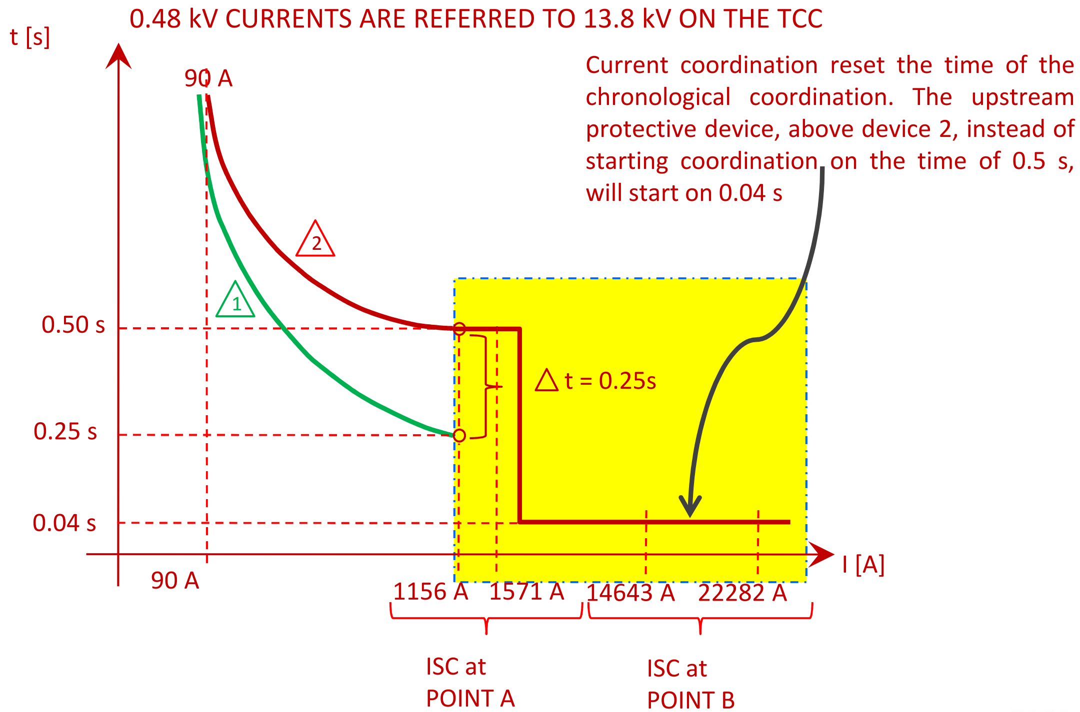


5 TYPES OF COORDINATION

Current Coordination

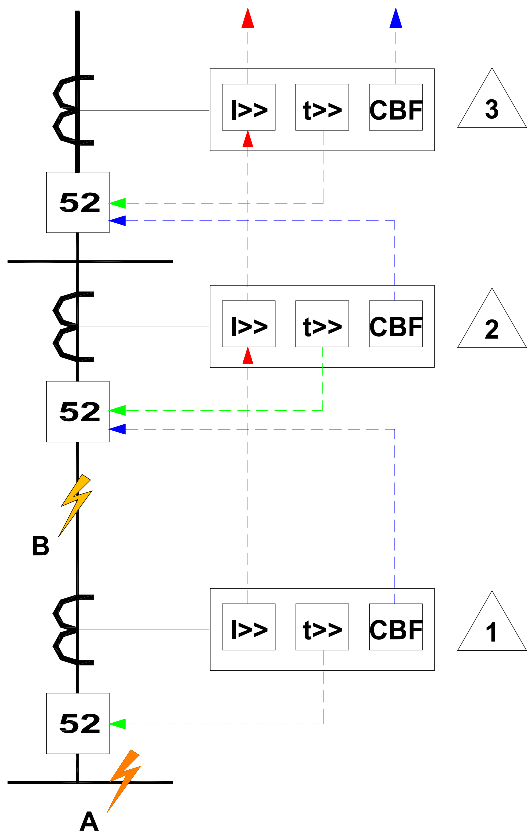
When a big impedance value exist between the downstream and upstream protective device current coordination may be applied. The advantage of this type of coordination is that instantaneous element can be set.





5

Zone Selective Interlocking (ZSI)



ZSI is applied between the downstream and upstream protective device with the main target of reducing trip time delay.

Signals Convention	
TRIP	
BLOCKING	
BREAK FAILURE	

6

COORDINATION TIME INTERVAL (CTI) DETERMINATION

CTI is fundamental to guarantee that downstream protective device is going to trip before the upstream protective device.

It is determination depends on many factors:

- ☑ CT errors
- ☑ Circuit breaker interrupting time
- ☑ Protective device pickup error
- ☑ Protective device delay error
- ☑ Protective devices time x current characteristics

IEEE Std 242-2001™ - Buff Book suggested CTI table is presented below:

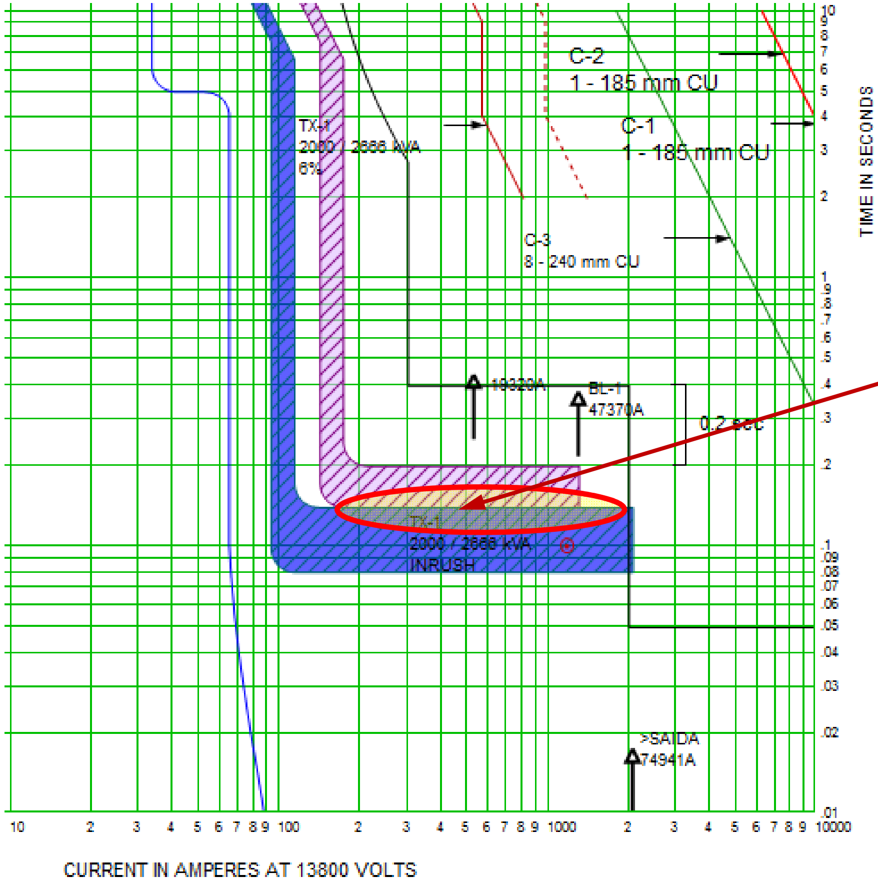
Table 15-3—Minimum CTIs[a]

Downstream	Upstream			
	Fuse	Low-voltage breaker	Electro-mechanical relay	Static relay
Fuse	CS[b,c]	CS	0.22 s	0.12 s
Low-voltage circuit breaker	CS[c]	CS	0.22 s	0.12 s
Electromechanical relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s
Static relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s

[a]Relay settings assumed to be field-tested and -calibrated.
[b]CS = Clear space between curves with upstream minimum-melting curve adjusted for pre-load.
[c]Some manufacturers may also recommend a safety factor. Consult manufacturers' time-current curves.

COORDINATION TIME INTERVAL (CTI) DETERMINATION

The CS used by IEEE Std 242-2001 means Clear Space between curves. During 34 years working with these types of protective devices, most of the manufacturers even with the downstream breaker curve touching the upstream breaker curve may ensure full coordination. So, my suggestion is always consult the respective manufacturer. Some of them have specific software that automatically tells you if you have coordination or not. You will have a big issue if the breakers are from different manufacturers.

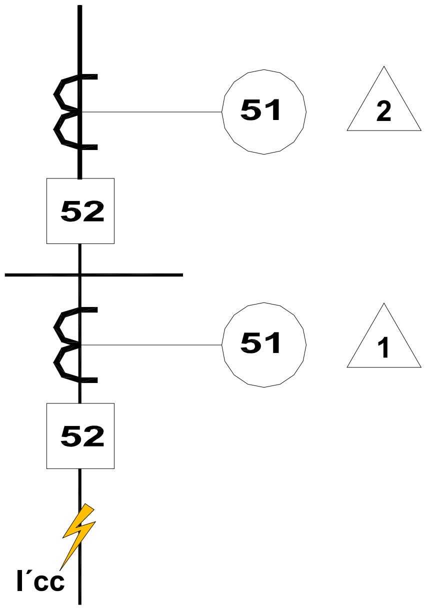


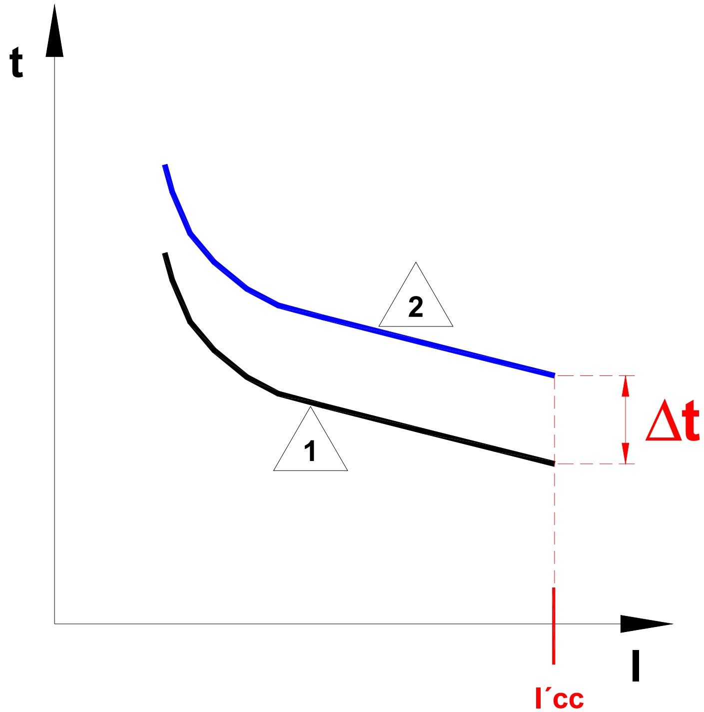
Curves are touching themselves and for this specific breaker the manufacturer ensures full coordination.

WHERE TO APPLY CTI GENERAL RULE AND PARTICULARITIES

7

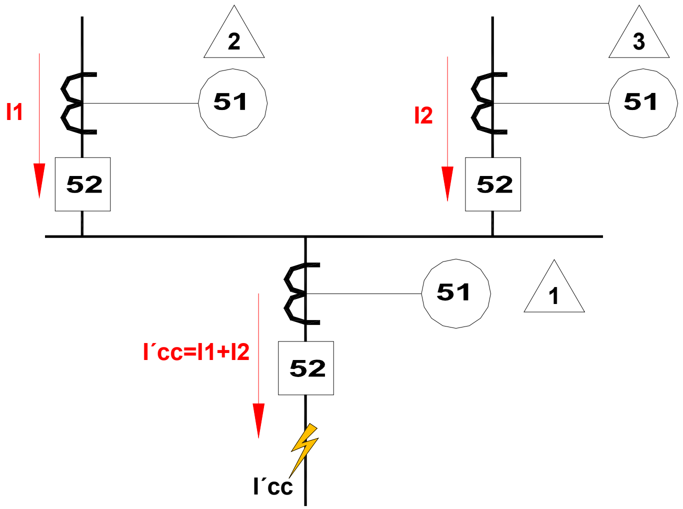
Main Rule – CTI is applied at short-circuit current value.

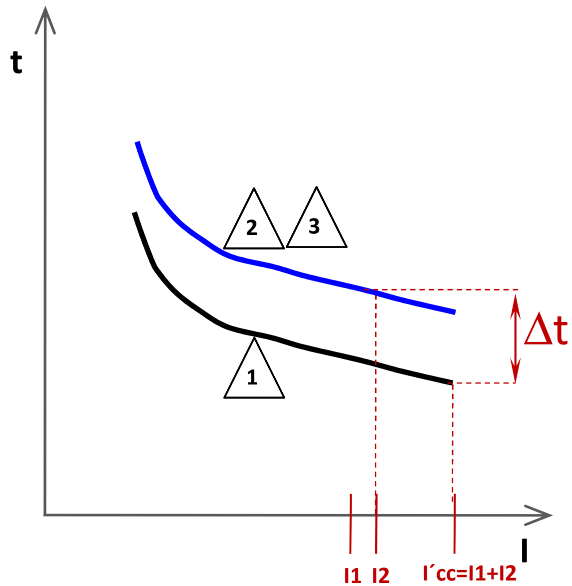




7 WHERE TO APPLY CTI GENERAL RULE AND PARTICULARITIES

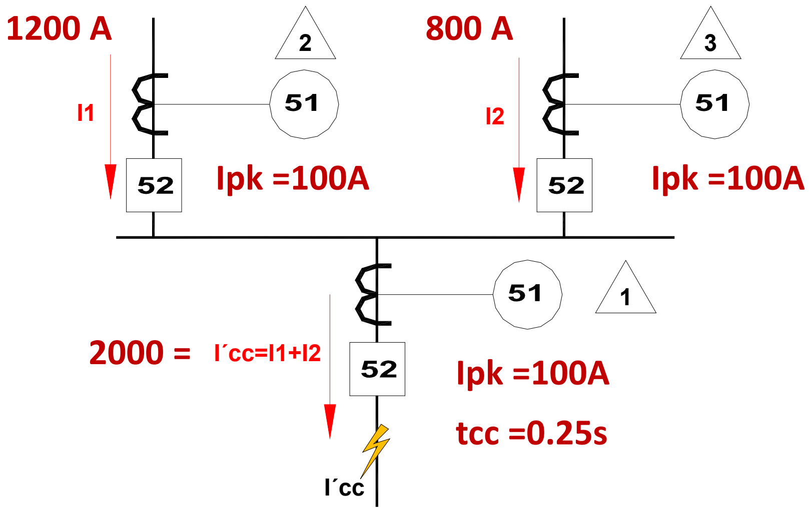
Particularities – Two incoming feeders in parallel with one outgoing feeder.





7 WHERE TO APPLY CTI GENERAL RULE AND PARTICULARITIES

Particularities – Two incoming feeders in parallel with one outgoing feeder.



Relay 1 - Curve : Very Inverse

$$t = \frac{13.5}{M-1} \cdot DT \Rightarrow DT = t \cdot \frac{(M-1)}{13.5} \qquad M = \frac{Icc}{Ipk} = \frac{2000}{100} = 20$$

$$DT = 0.25 \cdot \frac{(20-1)}{13.5} = 0.35$$

Relay 2 - Curve : Very Inverse

$$t = \frac{13.5}{M-1} \cdot DT \Rightarrow DT = t \cdot \frac{(M-1)}{13.5} \qquad M = \frac{Icc}{Ipk} = \frac{1200}{100} = 12$$

$$DT = 0.50 \cdot \frac{(12-1)}{13.5} = 0.41$$

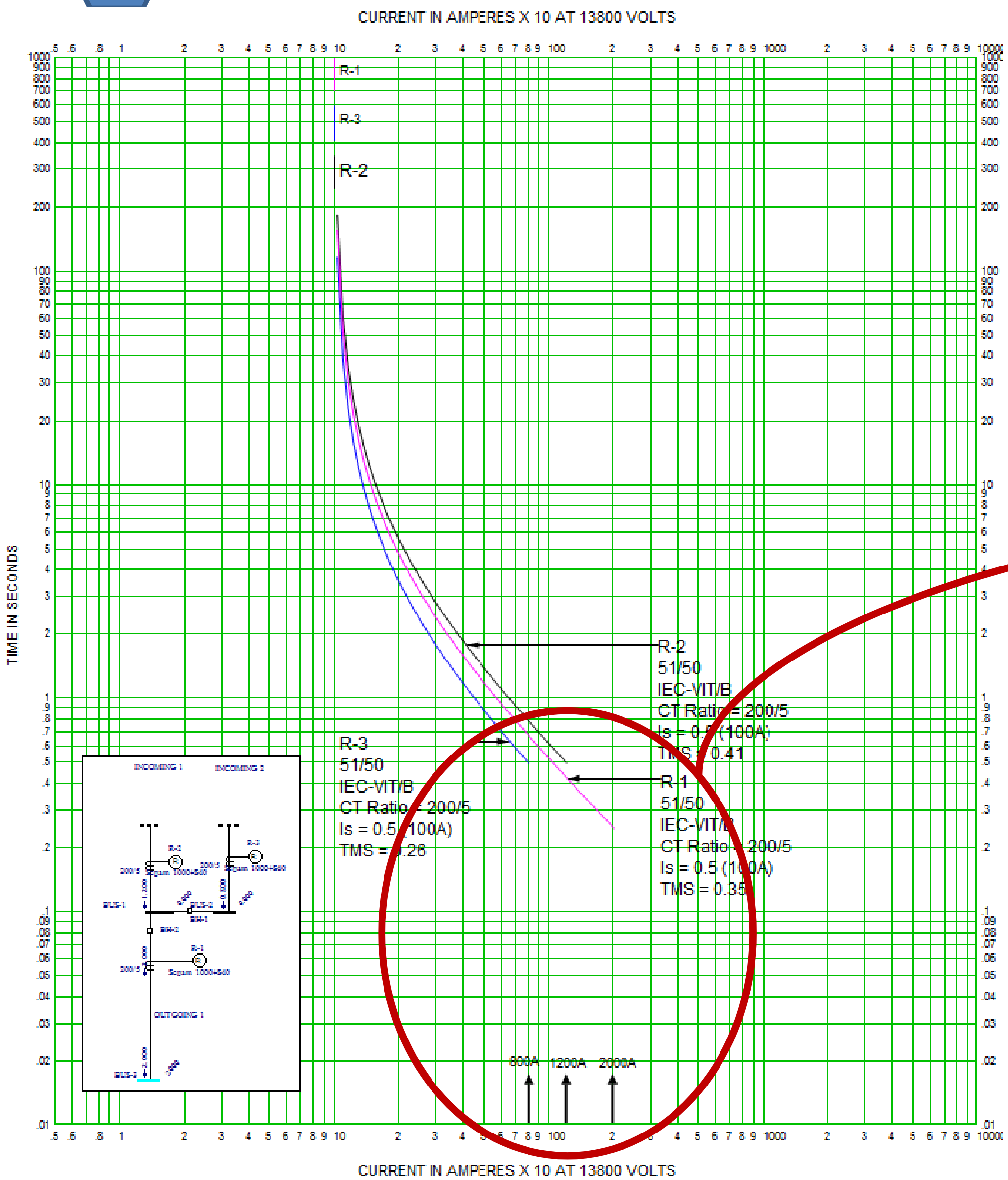
Relay 3 - Curve : Very Inverse

$$t = \frac{13.5}{M-1} \cdot DT \Rightarrow DT = t \cdot \frac{(M-1)}{13.5} \qquad M = \frac{Icc}{Ipk} = \frac{800}{100} = 8$$

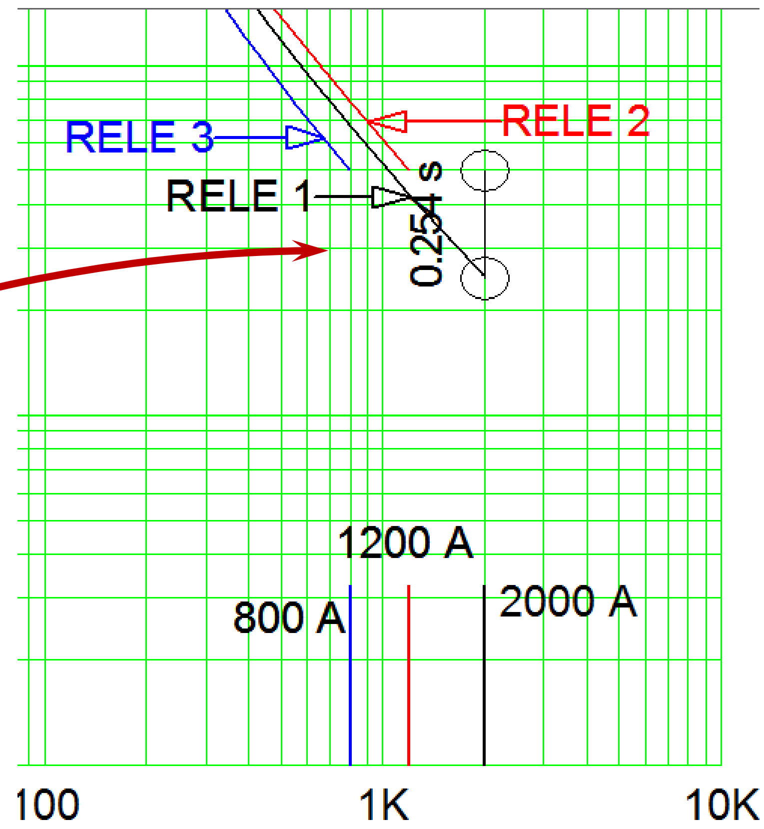
$$DT = 0.50 \cdot \frac{(8-1)}{13.5} = 0.26$$

WHERE TO APPLY CTI GENERAL RULE AND PARTICULARITIES

7



Particularities – Two incoming feeders in parallel with one outgoing feeder.

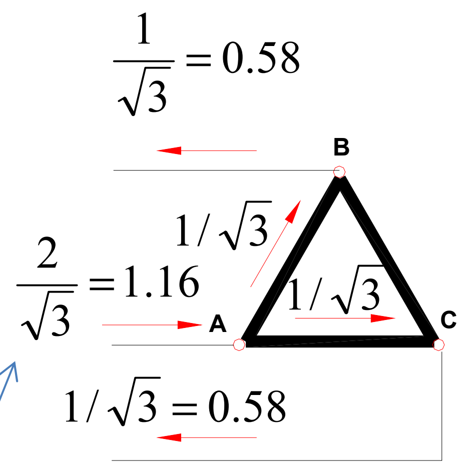


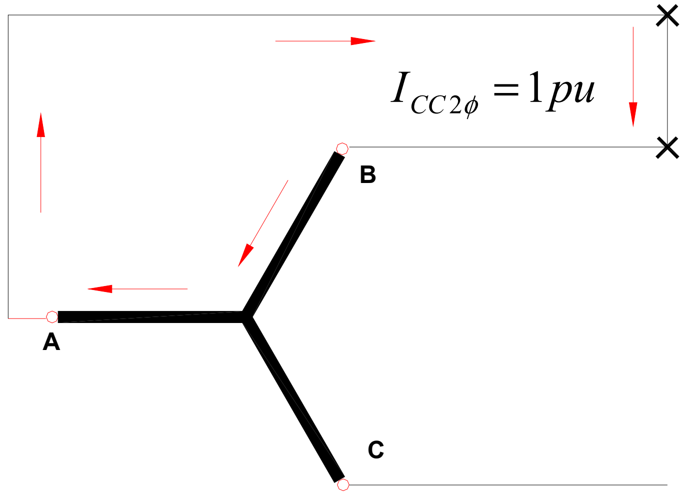
WHERE TO APPLY CTI GENERAL RULE AND PARTICULARITIES

7

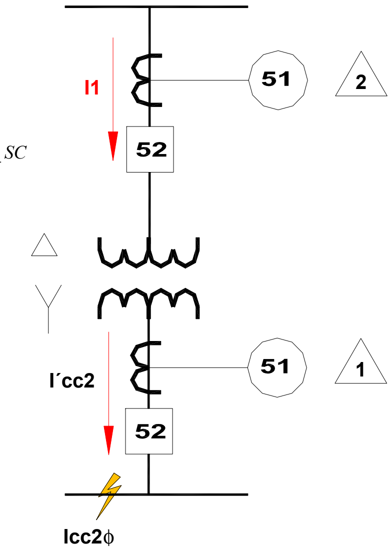
Particularities – Line-to-line short circuit on secondary side of DY Transformer.

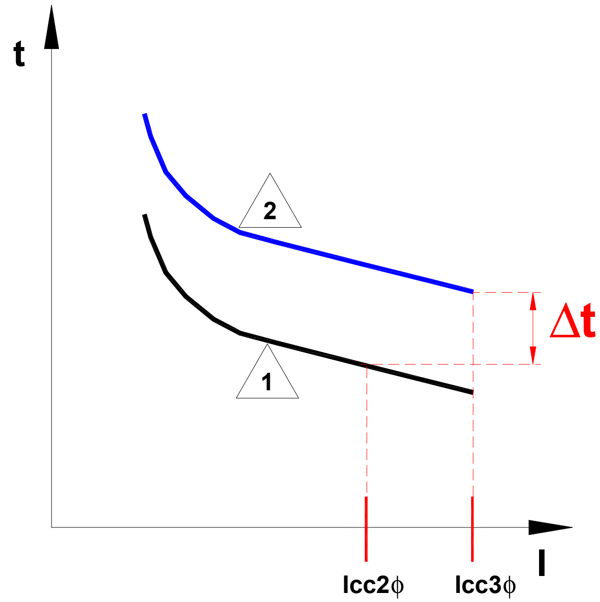
In one of the three phases of primary side will circulate three-phase short circuit.





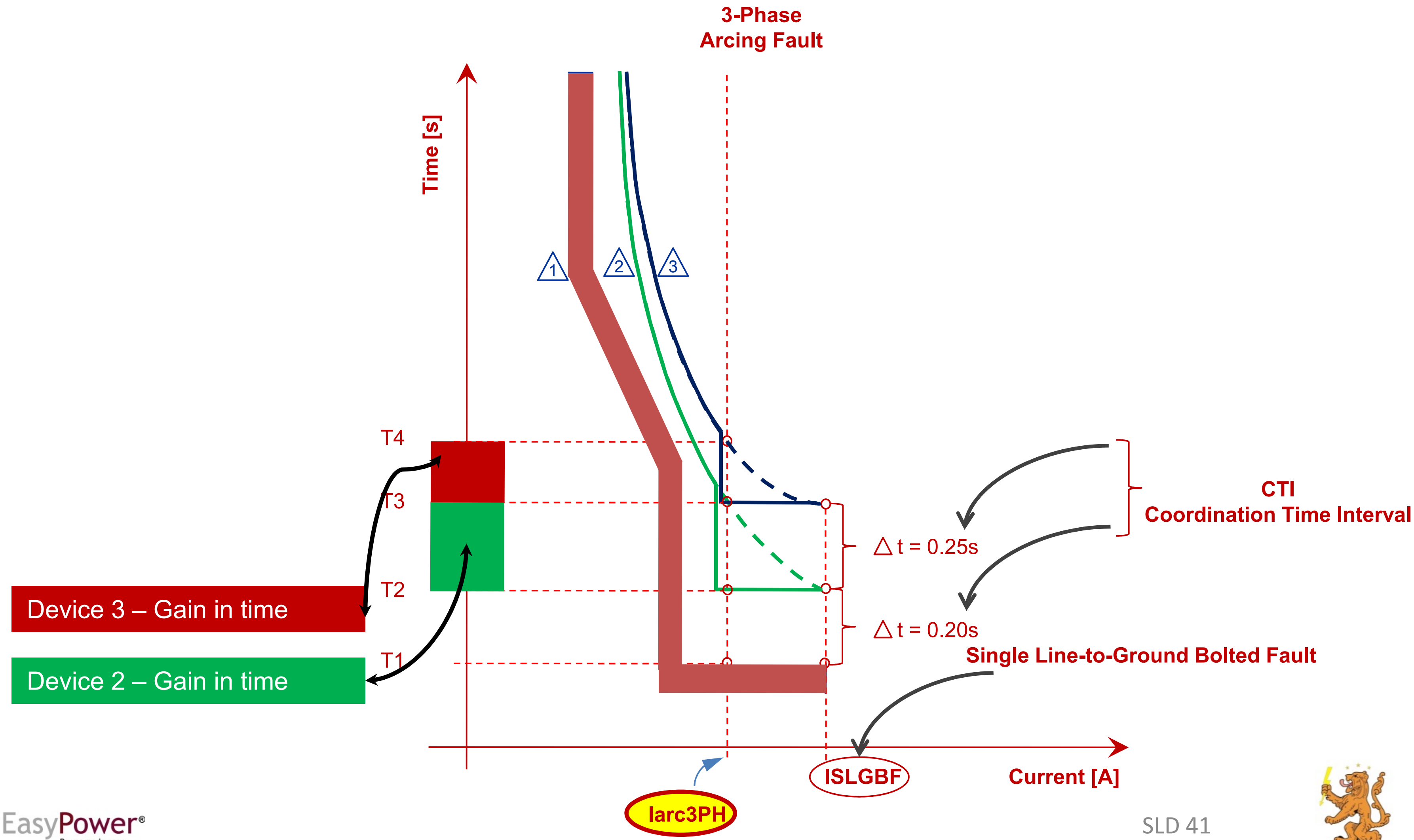
$$\frac{2}{\sqrt{3}} \cdot I_{L-L\_SC} = \frac{2}{\sqrt{3}} \cdot \frac{\sqrt{3}}{2} \cdot I_{3PH\_SC} = I_{3PH\_SC}$$





OVERCURRENT RELAYS – OPTIMIZED SETTINGS

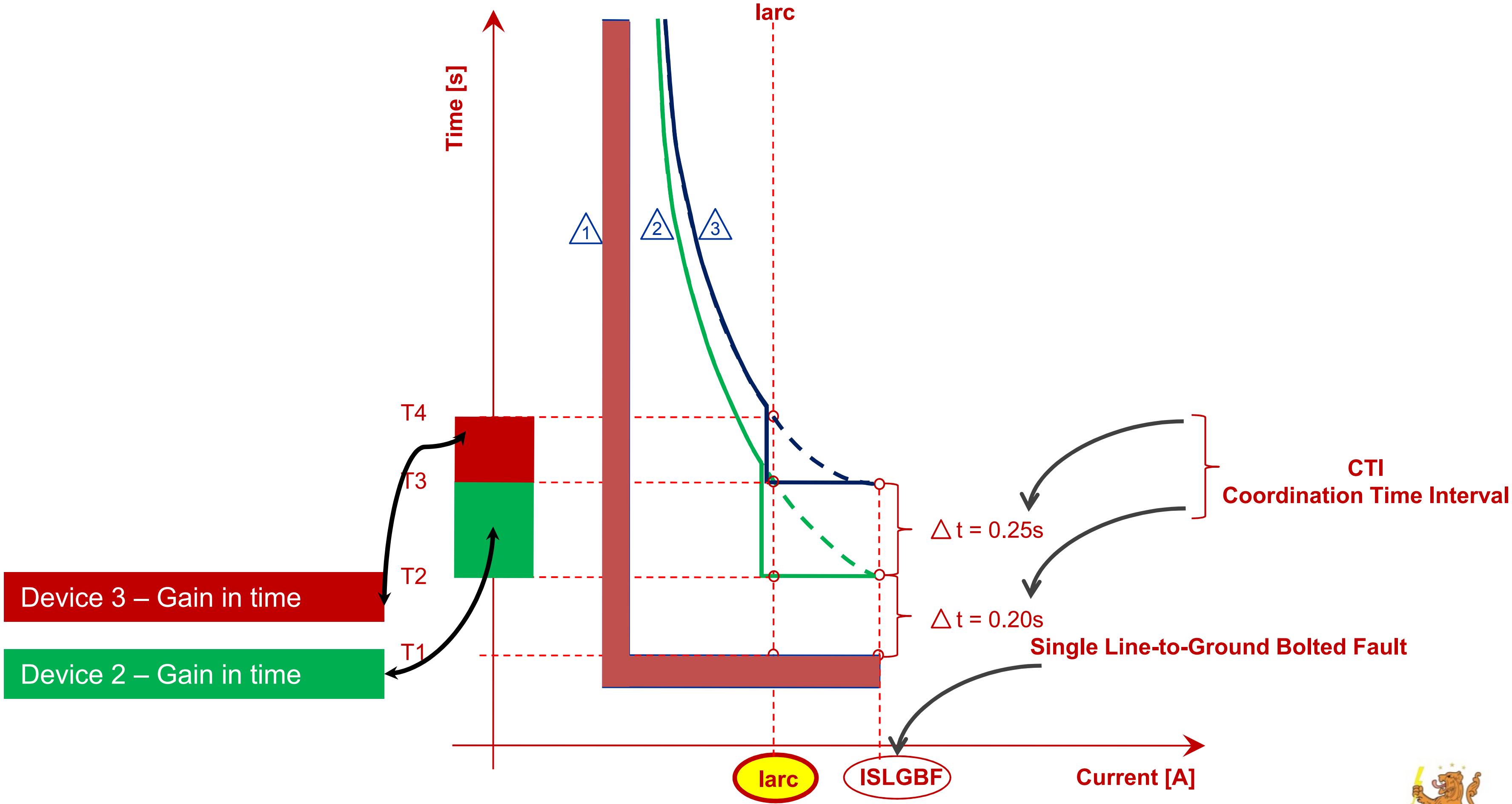
Phase-Protective Devices



OVERCURRENT RELAYS – OPTIMIZED SETTINGS

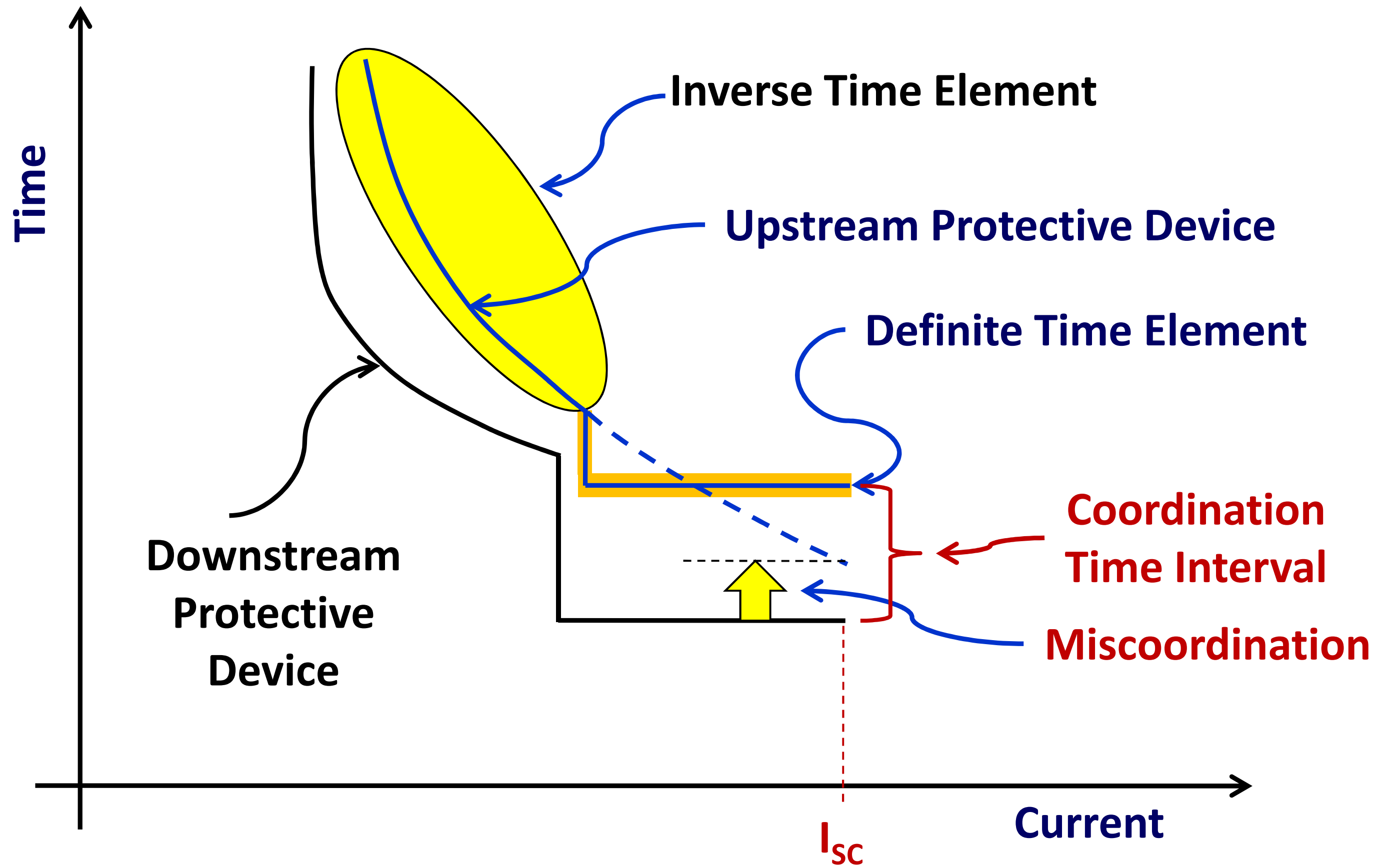
8

Ground-Protective Devices



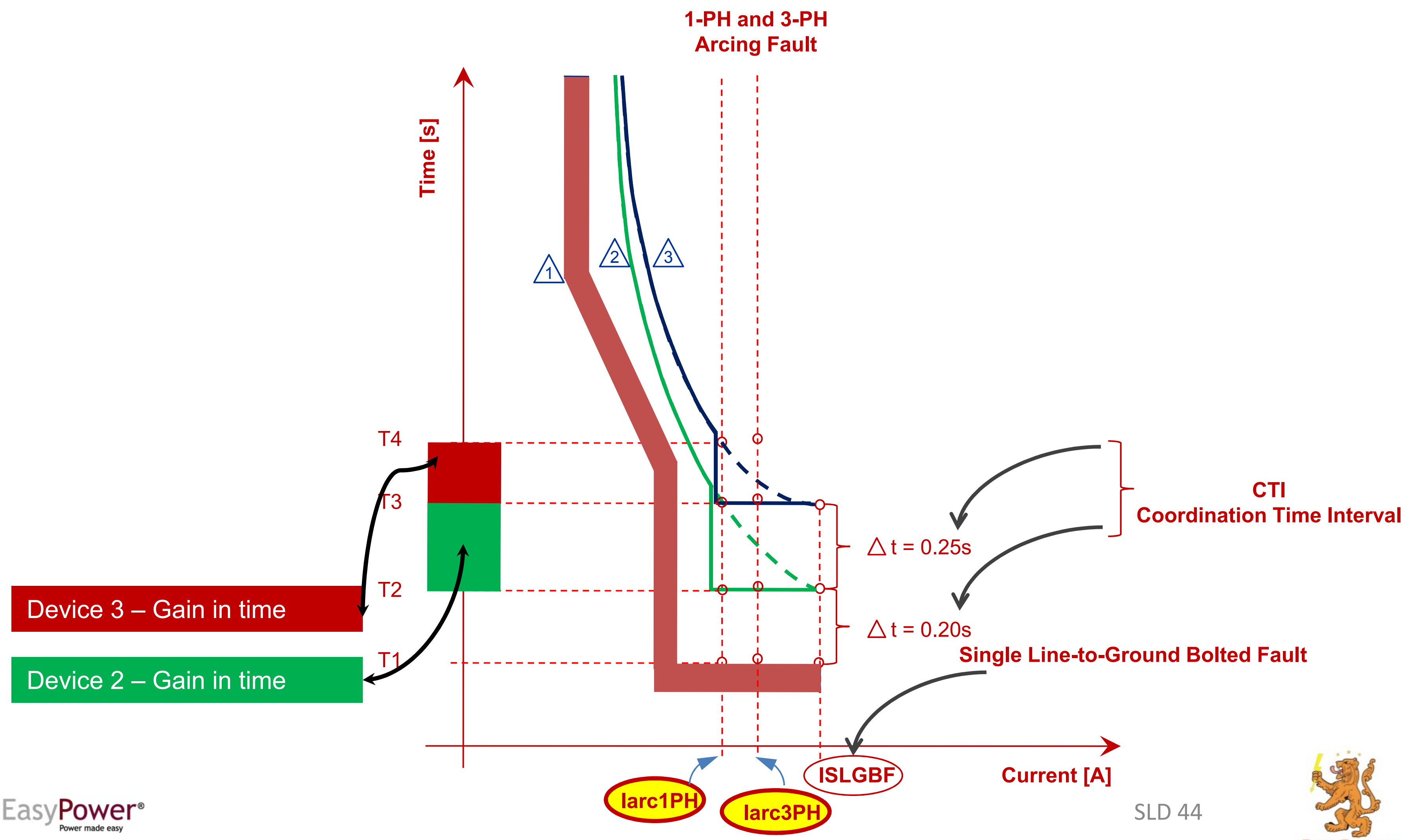
OVERCURRENT RELAYS – OPTIMIZED SETTINGS

Special care when optimizing settings



PHASE PROTECTION AS BACKUP OF GROUND SINGLE LINE-TO-GROUND PROTECTION

Phase-Protective Devices



10 COORDINATION BETWEEN VOLTAGE AND OVERCURRENT ELEMENTS

For single line-to-ground faults, when system grounding is not solidly grounded, voltage elements have to coordinate with overcurrent elements. The reason is because when a line-to-ground fault happens in these systems, at the healthy phases the voltage increases and may cause overvoltage elements to trip. This condition is even critical for the operator´s safety, because looking at alarm annunciator may think that the only problem he has it is an overvoltage and in fact the problem is a short circuit.

Warning! Overvoltage elements can never be set instantaneous in impedance grounded or insulated systems.

Typical settings are:

U> = 115% Un	U>> = 120% Un
U> Delay = 3 s	U>> Delay = 2 s

If the system is solidly grounded the settings may be:

U> = 115% Un	U>> = 120% Un
U> Delay = 2 s	U>> Delay = 0.0 s

THANKS !!!

QUESTIONS

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