BECKWITH ELECTRIC

FEEDER PROTECTION CALCULATIONS & SETTINGS

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Distribution Protection Track

Tuesday, August 5th, 2025

Day 2 - Session 1

HUBBELL

Overcurrent Protection

- Fundamentals and classification
- Protection coordination principles
- Criteria for Setting Instantaneous and time delay units
- Considerations with Distribution Automation and FLISR
- Adaptive Protection
- Reclosing Procedures
- Coordination in a microgrid system

Overcurrent Protection

Overcurrent relays are the most common form of protection used to operate only under fault conditions.

They should not be installed purely as a means of protecting systems against overloads.

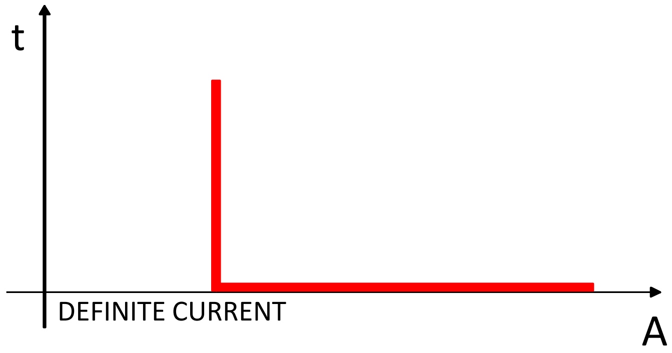
The relay settings that are selected are often a compromise in order to cope with both overload and overcurrent conditions.

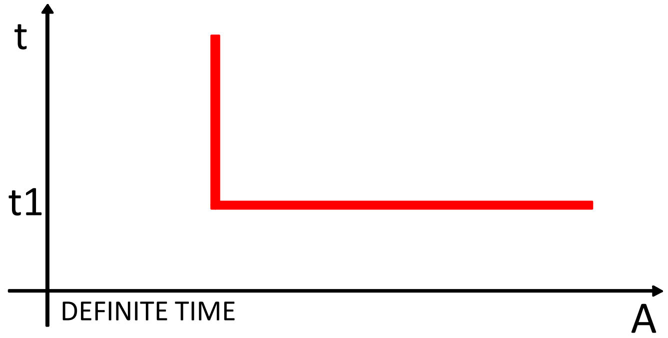
Protection Coordination Principles

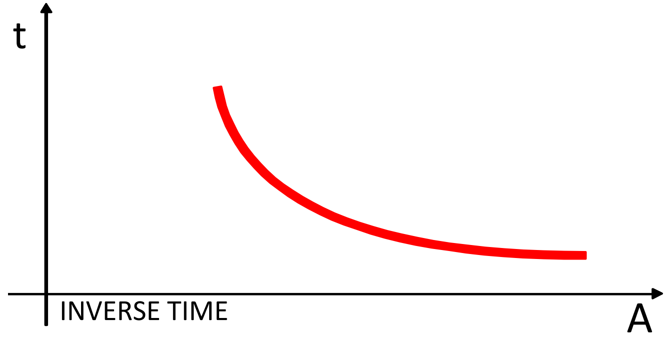
Relay coordination is the process of selecting settings that will assure that the relays will operate in a reliable and selective way.

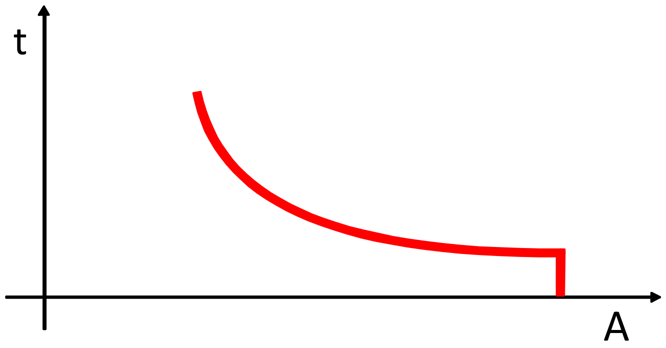
In OC relays the coordination is based on the relay time-current characteristics of instantaneous and/or time delay units.

Classification









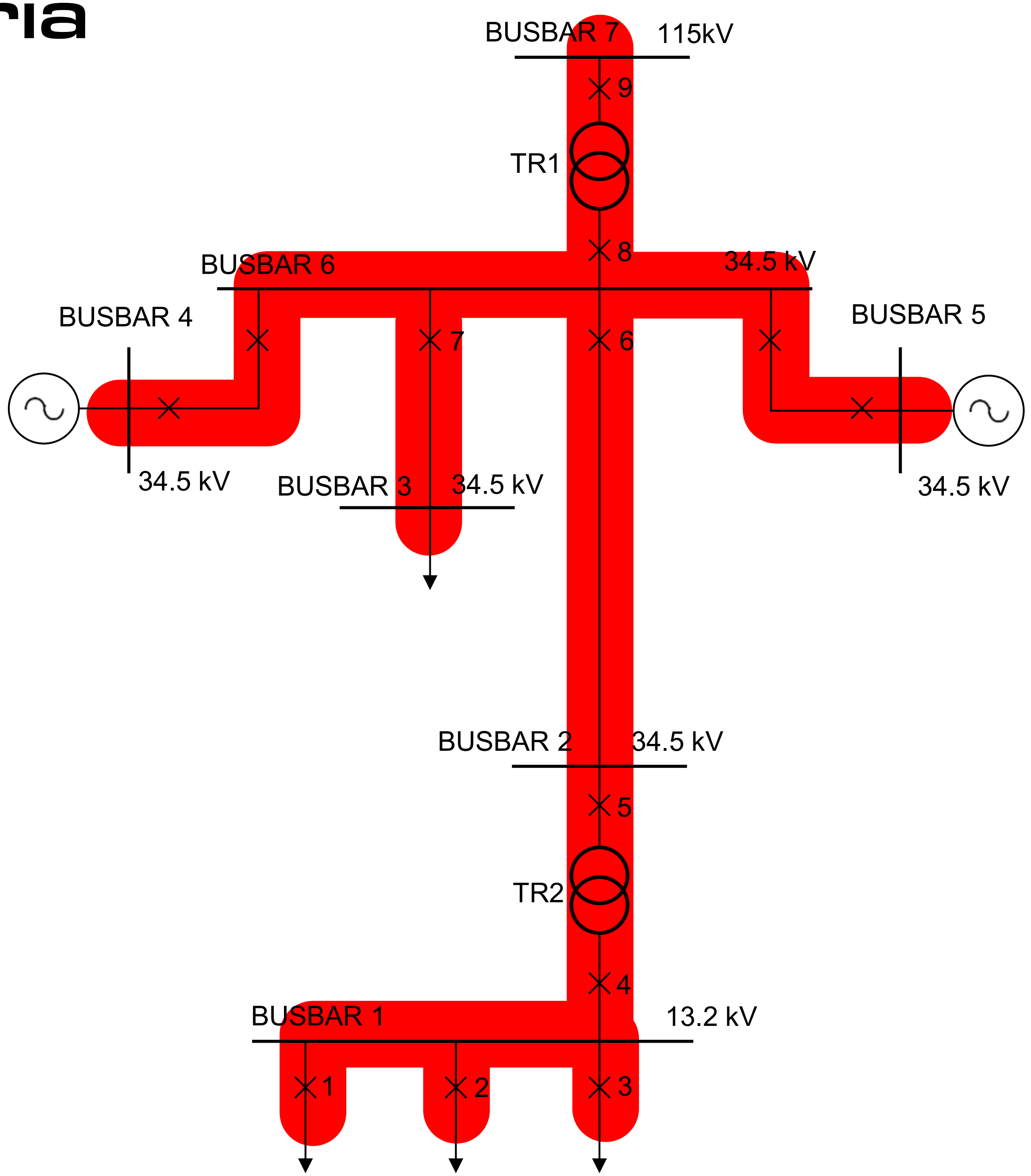
INVERSE TIME WITH INSTANTANEOUS UNIT

Protection Coordination Principles

1. Instantaneous units should be set so they do not trip for fault levels equal or lower to those at busbars or elements protected by downstream instantaneous relays.

2. Time delay units should be set to clear faults in a selective and reliable way, assuring the proper coverage of the thermal limits of the elements protected.

Setting Criteria Illustration



Criteria for Setting Instantaneous Units

Instantaneous units are set by adjusting the pick up level current at which the relays operate.

Most numerical relays now have the possibility of setting an operating time, allowing the relay to behave as a definite time unit.

Criteria for Setting Instantaneous Units

1. Distribution lines

- Between 6 and 10 times the maximum circuit rating
- 50% of the maximum short circuit at the point of connection of the relay

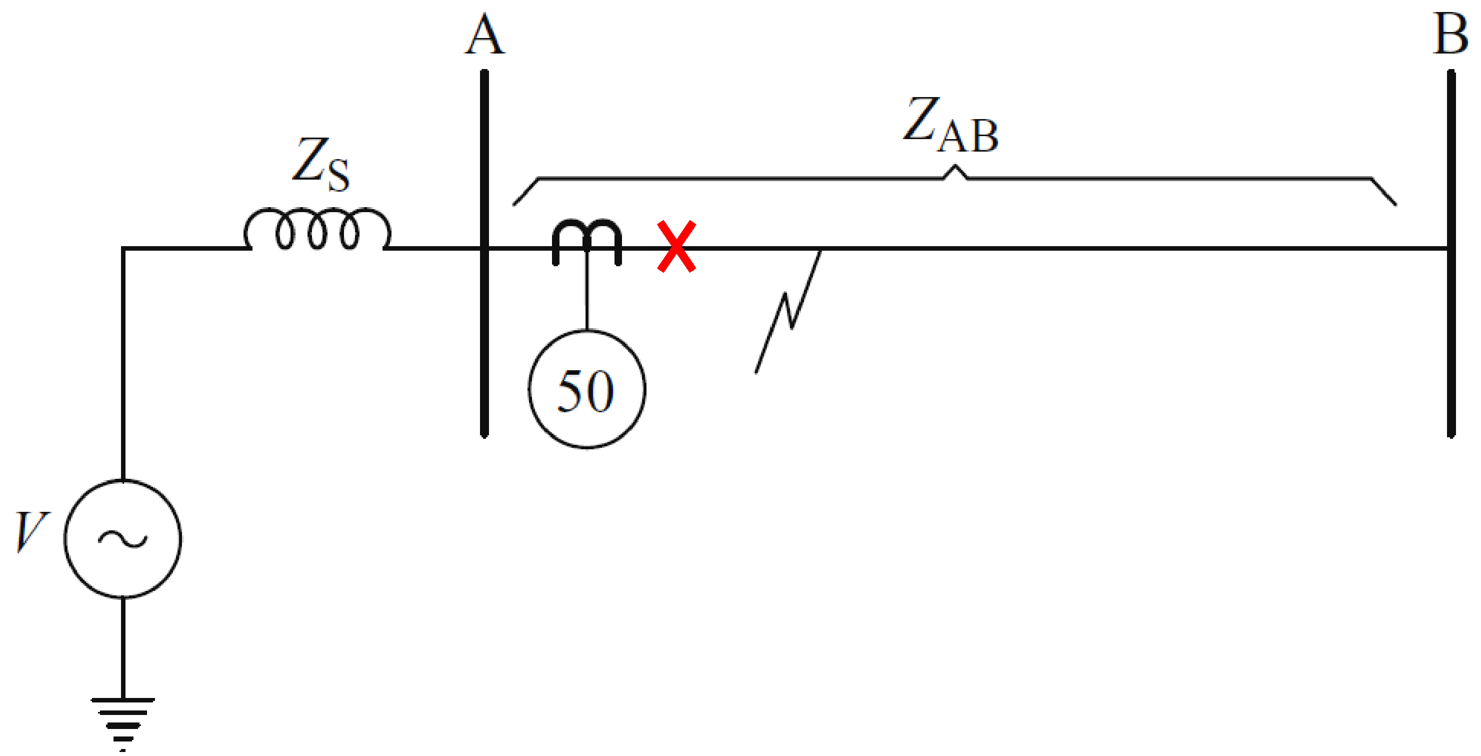
2. Lines between substations

- 125% to 150% of the short circuit current existing on the next substation

3. Transformer units

- 25% to 150% of the short circuit current existing on the LV side
- The units at the LV side are overridden unless there is communication with the relays protecting the feeders.

Coverage of Instantaneous Units



Coverage of Instantaneous Units

Definition of parameters:

$$K_i = \frac{I_{pickup}}{I_{end}} \qquad K_s = \frac{Z_{source}}{Z_{element}}$$

$$I_{end} = \frac{V}{Z_s + Z_{ab}} \qquad I_{pickup} = \frac{V}{Z_s + XZ_{ab}}$$

$$X = \frac{Z_s + Z_{ab} - Z_s K_i}{Z_{ab} K_i} \qquad X = \frac{K_s + 1 - K_s K_i}{K_i}$$

Setting Time Delay Relays

Time delay units are set by selecting the time/curve characteristic that is defined by two parameters:

TAP or PICKUP VALUE:

- A value that defines the pickup current of the relay. Current values are expressed as multiples of this value in the time/current characteristic curves.

DIAL:

- Defines the time curve at which the relay operates for any TAP value. Higher DIAL values represent higher operating times.

Protection Criteria – Reach / Sensitivity

Overcurrent protective devices are set by selecting the time/curve characteristic that is defined by two parameters for any given TCC curve

PICK UP (TAP) VALUE

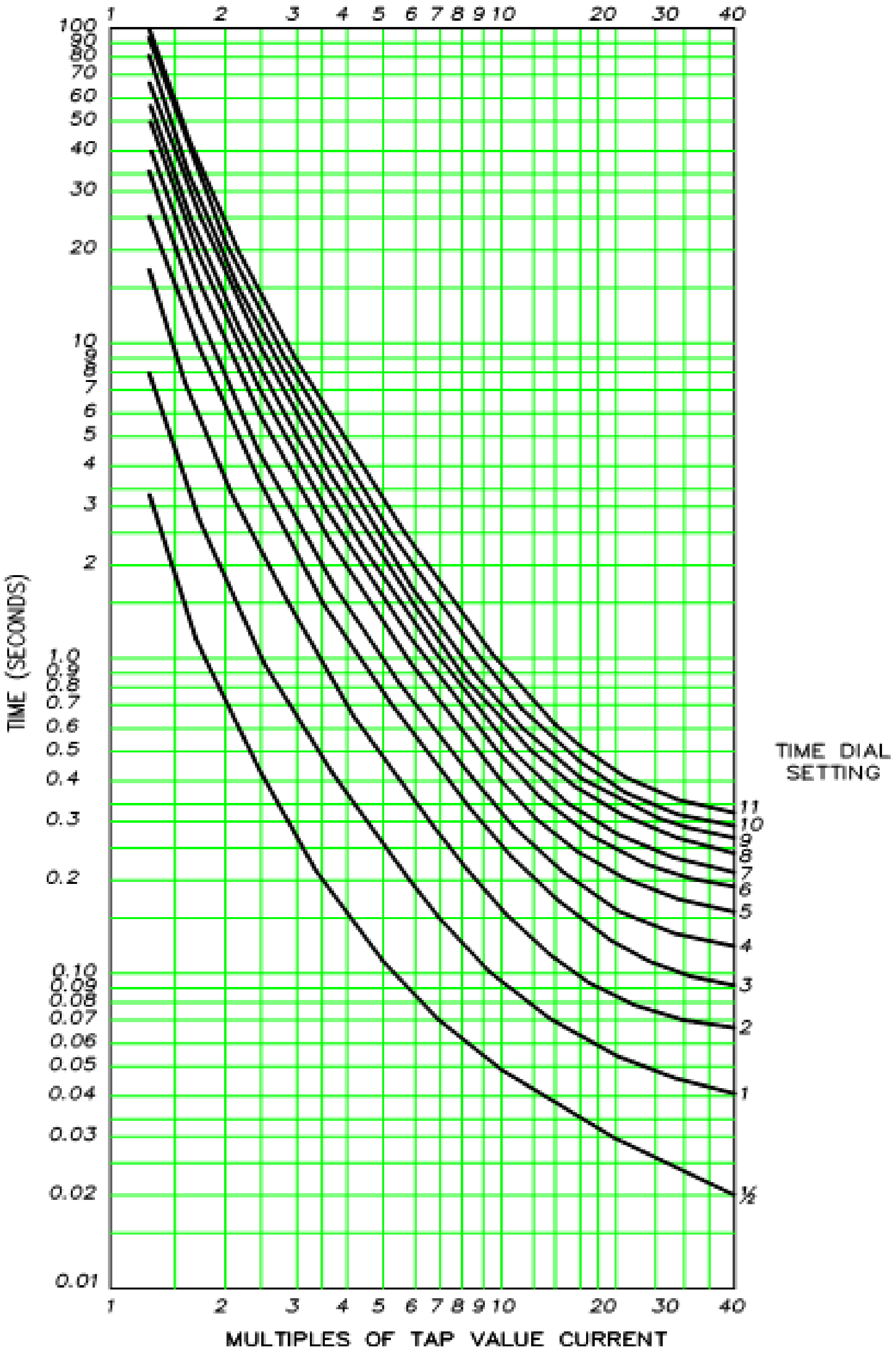
- A value that defines the minimum operating current of the relay
- Current values are expressed as multiples of this value in TCC curves

TIME DIAL (sometimes called Time Lever)

- Defines the time curve at which the relay operates for any Pickup (TAP) value
- Higher values represent higher operating times

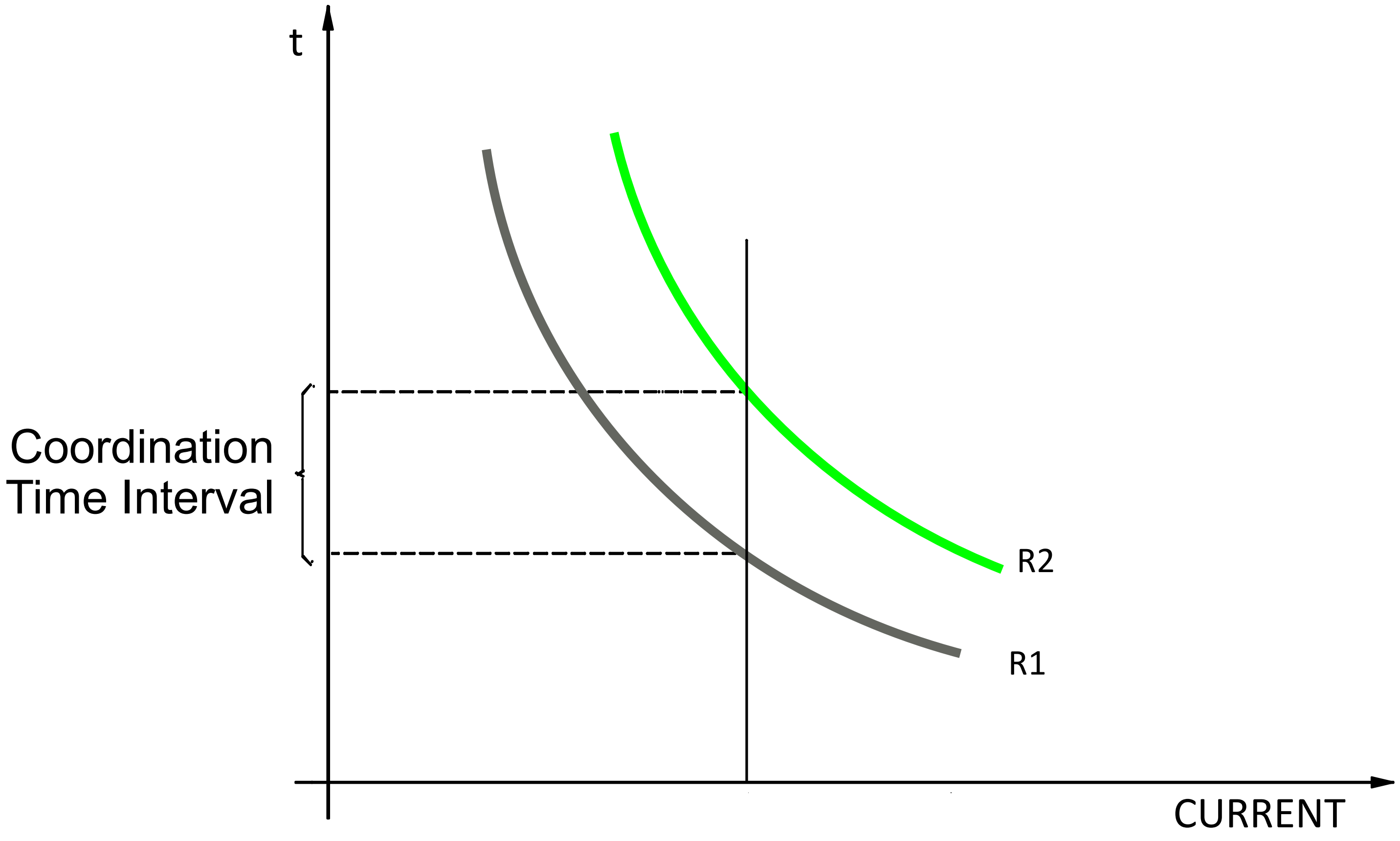
Typical Time/Current Characteristic

CO-11 ABB/Westinghouse



Coordination of OC time delay units

Overcurrent inverse time relay curves associated with two breakers on the same feeder.



Criteria for Setting the TAP

For phase relays, the TAP or PICK UP VALUE is determined by:

$$TAP = (OLF \times I_{nom}) \div CTR$$

For ground fault relays, the TAP value is determined, with the maximum unbalance, typically around 20%:

$$TAP = ((0.2) \times I_{nom}) \div CTR$$

Criteria for Setting the TAP

The overload factor recommended is as follows:

- Motors = 1.05 of the value that considers the service factor
- HV Lines, transformers and generators = 1.25 to 1.5
- Distribution feeders = 1.5

If FLISR has been implemented, a value of 2.0 or higher, should be considered

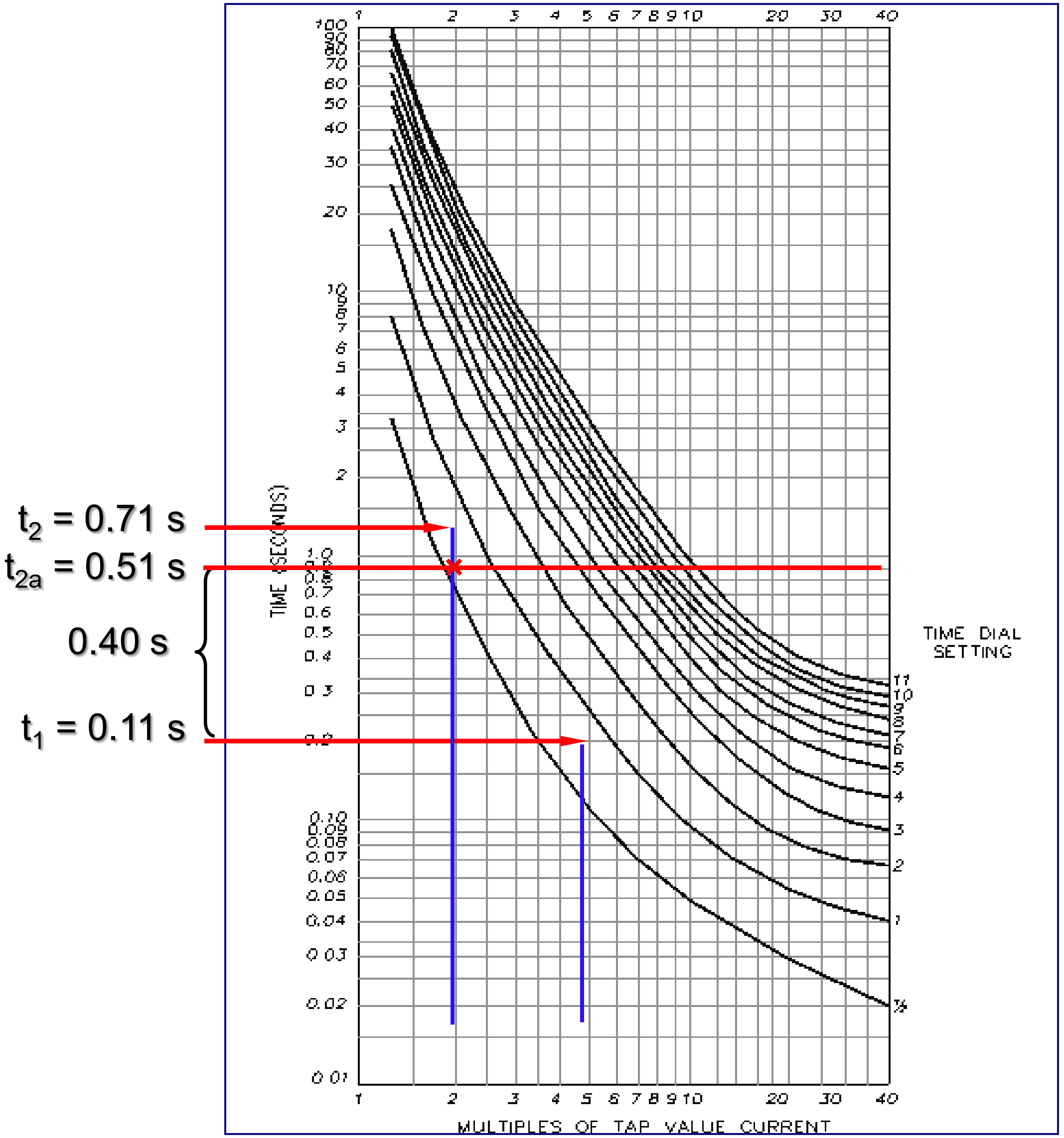
Criteria for Setting the TAP

For phase relays, three phase faults and maximum short time overload should be considered.

For ground relays, line to ground faults and max $3I_o$ should be considered.

Procedure for Time Delay OC Setting

1) Calculate the multiple of Pick Up value for the I_{sc} corresponding to the instantaneous setting.
2) Determine the operating time t_1 of the relay for the given Time Dial.
3) Determine the operating time t_{2a} of the upstream relay with the expression $t_{2a} = t_1 + t_{margin}$.
4) Calculate the multiple of Pick Up value of the upstream relay using the same short circuit current.
5) Select the above nearest TIME DIAL.



Expression for Time Delay Setting

The operating times defined by IEC 60255 and IEEE C37.112 are:

$$t = \frac{k \cdot \beta}{\left(\frac{I}{I_s}\right)^{\alpha} - 1} + L$$

t	=	Relay operating time in seconds
k	=	Time dial, or time multiplier setting
I	=	Fault current level in seconds amps
I_S	=	Tap or pick up current selected
L	=	Constant
a	=	Slope constant
b	=	Slope constant

IEEE and IEC Constants of Standard TCCs of OC Relays

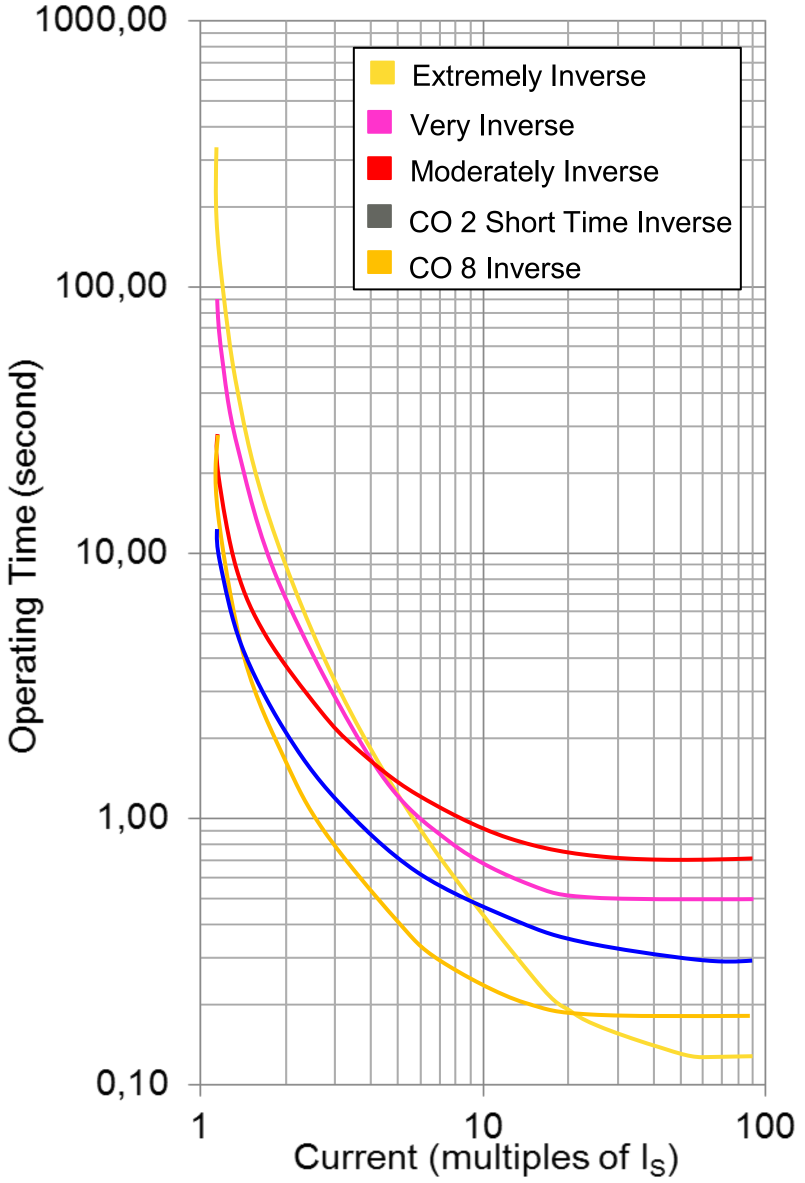
IEEE Constants

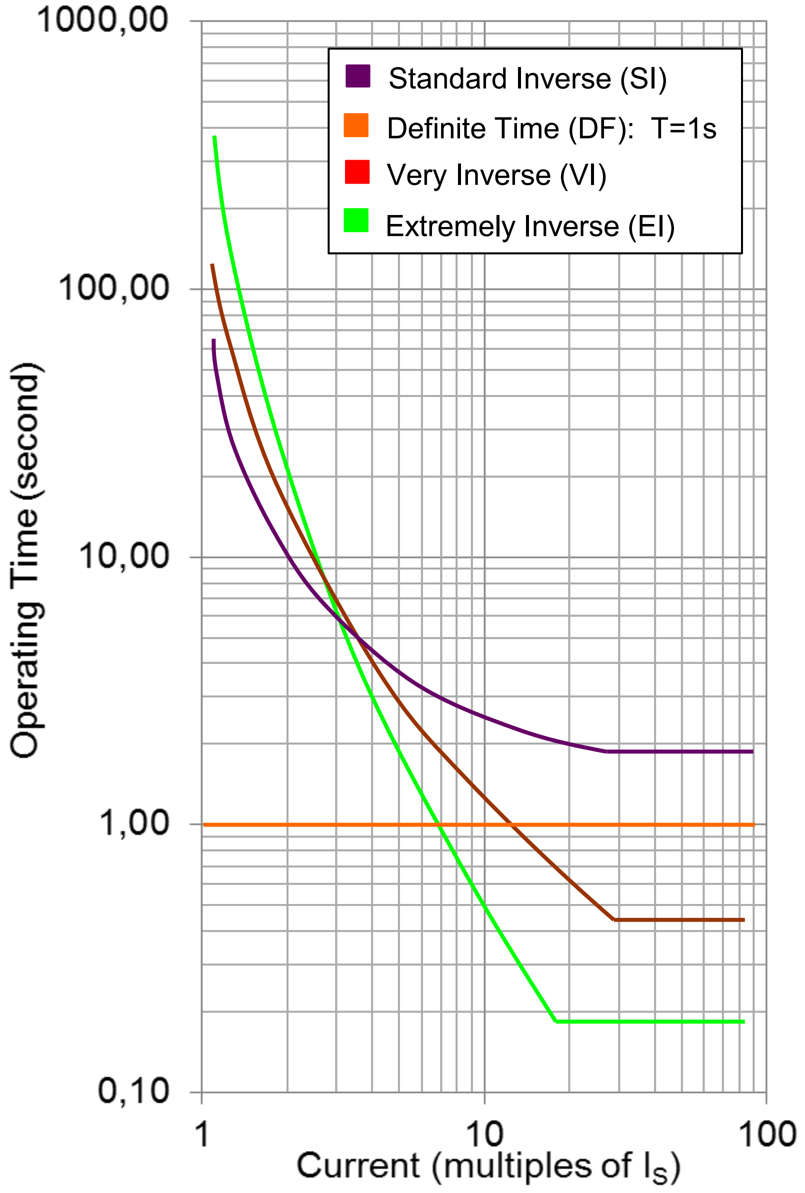
IDMT Curve Description	Standard	α	β	L
Moderately Inverse	IEEE	0.02	0.0515	0.114
Very Inverse	IEEE	2	19.61	0.491
Extremely Inverse	IEEE	2	28.2	0.1217

IEC Constants

Short Time Inverse	US-CO2	0.02	0.02394	0.01694
Standard Inverse	IEC	0.02	0.14	
Very inverse	IEC	1.0	13.5	
Extremely inverse	IEC	2.0	80.0	
Long Time Inverse	IEC	1	120	

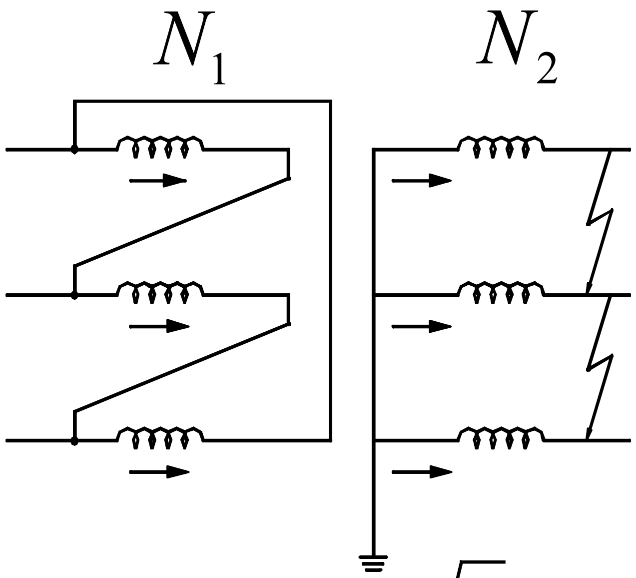
Standards of Time/Current Characteristics





Coordination Across Dy Transformers

Three Phase Fault



$$N_1 = N_2\sqrt{3}$$

$$I_f = \frac{E_{\phi-n}}{X} = I$$

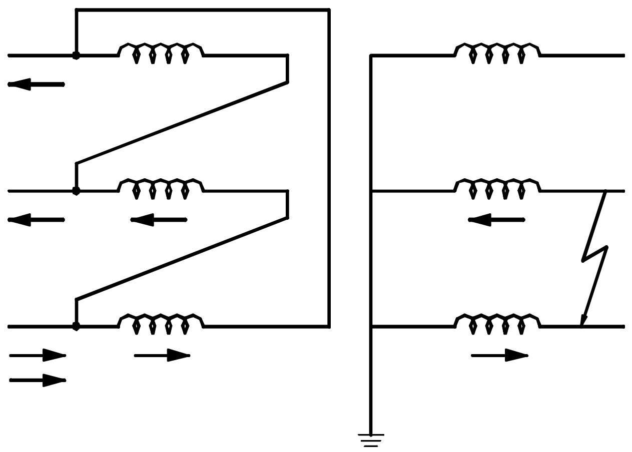
$$I_{delta} = I\frac{N_2}{N_1} = \frac{I}{\sqrt{3}}$$

$$I_{primary} = \sqrt{3}I_{delta} = I$$

Coordination Across Dy Transformers

Phase-to-Phase Fault

N_1 N_2



$$N_1 = N_2\sqrt{3}$$

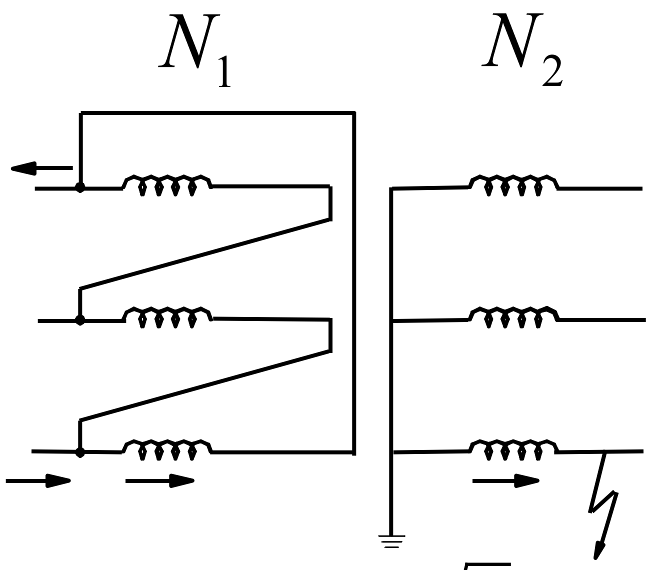
$$I_f = \frac{E_{\phi-\phi}}{2X} = \frac{\sqrt{3}E_{\phi-n}}{2X} = \frac{\sqrt{3}}{2}I$$

$$I_{delta} = I\frac{\sqrt{3}}{2}\frac{N_2}{N_1} = \frac{I}{2}$$

$$I_{primary} = 2I_{delta} = I$$

Coordination Across Dy Transformers

Phase-to-Ground Fault



$$N_1 = N_2\sqrt{3}$$

$$I_{delta} = I\frac{N_2}{N_1} = \frac{I}{\sqrt{3}}$$

$$I_{primary} = \frac{I}{\sqrt{3}}$$

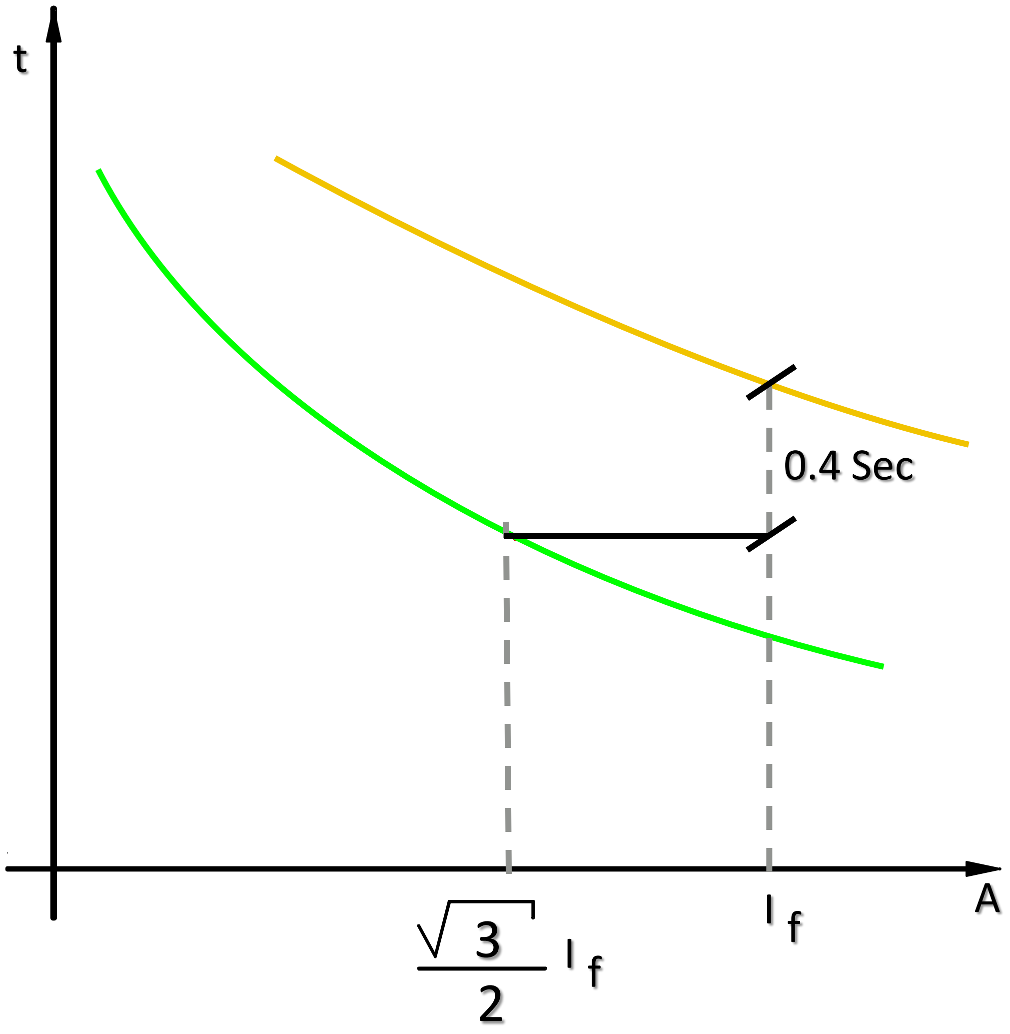
Coordination Across Dy Transformers

Summary of fault conditions

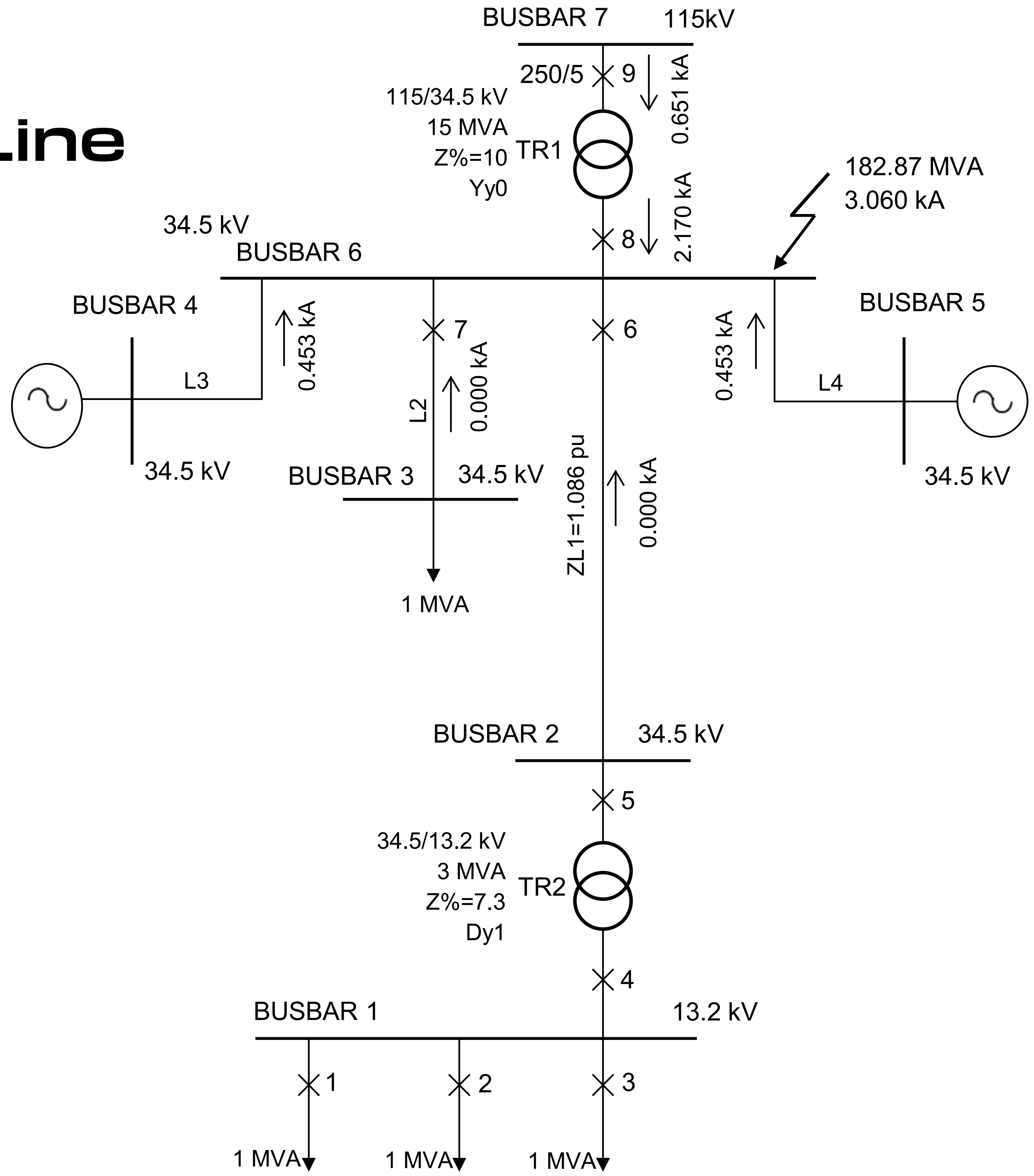
Fault	$I_{primary}$	$I_{secondary}$
Three Phase	I	I
Phase-to-Phase	I	$\sqrt{3}I/2$
Phase-to-Ground	I	$\sqrt{3}I$

Coordination Across Dy Transformers

Coordination of overcurrent relays for a Dy transformer



Example - Single Line



Example - Data

Calculate the following:

1. The three phase short circuit levels on busbars 1 and 2
2. The transformation ratios of the CTs associated with breakers 1 to 8, given that the number of primary turns is a multiple of 100.The CT for breaker number 9 is 250/5
3. The settings of the instantaneous elements, and the TAP and DIAL settings of the relays to guarantee a coordinated protection arrangement, allowing a discrimination margin of 0.4 seconds
4. The percentage of the 34.5 kV line protected by the instantaneous element of the overcurrent relay associated with breaker 6

The p.u. impedances are calculated on the following bases:

V = 34.5 kV,   P = 100 MVA

Example - Data

- All the relays are electromechanical W CO 11 with extremely inverse TCC characteristic type with the following ranges:

TAP = 1 to 12 A, in steps of 1 A

DIAL = as shown in next figure

- The settings of relay 7 are:

TAP = 4 A

DIAL = 5

Instantaneous = 1100 A

Note: in electromechanical relays as this one, it is customary to use the term TAP

Calculation of Short Circuit Levels - Example

$$Z_{THEVENIN} = \frac{V^2}{P_{SC}} = \frac{(34{,}500\,V)^2}{182.87*10^6} = 6.5\,ohms\ referred\ to\ 34.5\,kV$$

$$Z_{transf\,1} = 0.1\frac{(34500)^2}{15*10^6} = 7.93\,ohms,\ referred\ to\ 34.5\,kV$$

$$= 88.17\,ohms,\ referred\ to\ 115\,kV$$

$$Z_{transf\,2} = 0.073\frac{(34500)^2}{3*10^6} = 28.96\,ohms,\ referred\ to\ 34.5\,kV$$

$$Z_{line} = 1.086\frac{(34500)^2}{100*10^6} = 12.93\,ohms,\ referred\ to\ 34.5\,kV$$

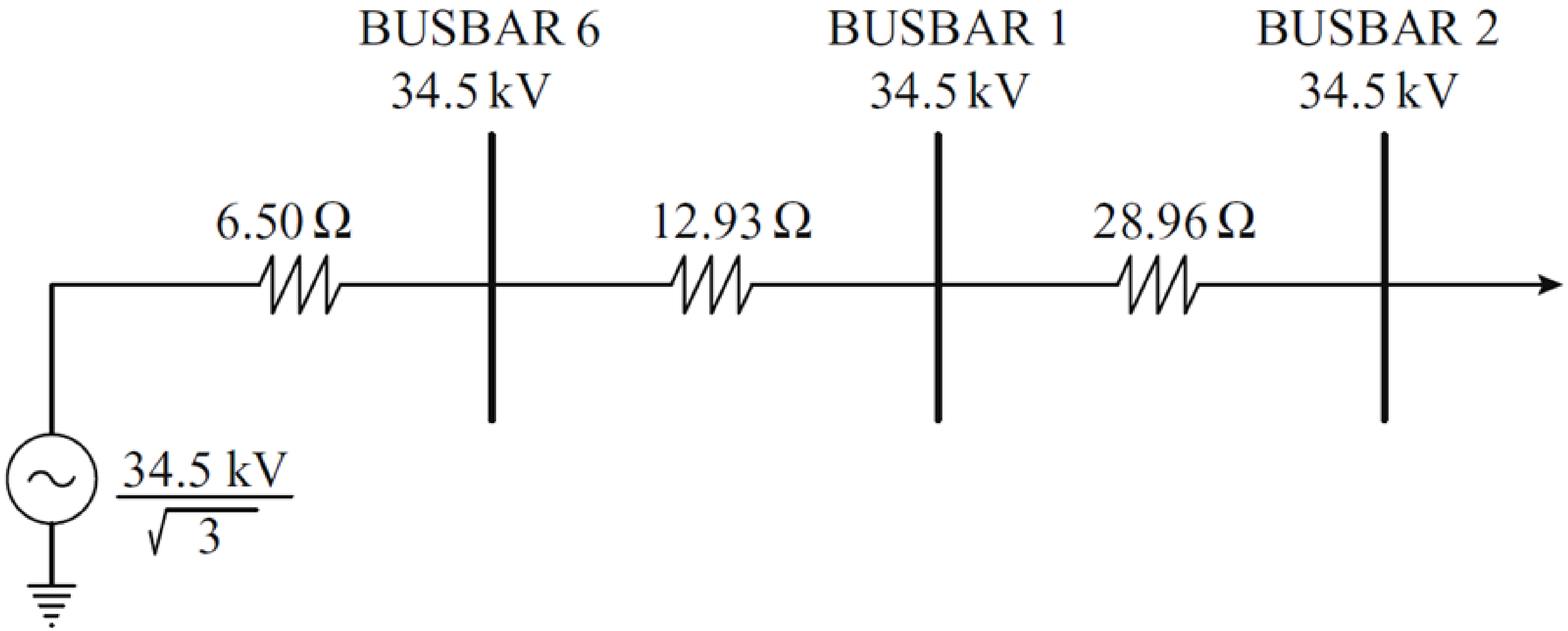
Short Circuit Levels - Example

$$Z_{transf\,1} + Z_{Network} = \frac{(34.5)^2}{129.69} = 9.18\,ohms, referred\ to\ 34.5\,kV$$

$$= 102.0\,ohms, referred\ to\ 115\,kV$$

$$Z_{Network} = 102.0 - 88.16 = 13.84\,ohms, referred\ \ to\ 115\,kV$$

Network Equivalent - Example



Positive Sequence Network

(Impedances are referred to 34.5 kV)

Short Circuit Levels – Example

$$I_{fault1,2,3,4} = \frac{34.5 \cdot 10^3}{\sqrt{3}\left(6.5 + 12.92 + 28.96\right)} = 411.72\,A\,at\,34.5\,kV$$

$$= 1076.06\,A\,at\,13.2\,kV$$

$$I_{fault5} = \frac{34.5 \cdot 10^3}{\sqrt{3}\left(6.5 + 12.92\right)} = 1025.67\,A\,at\,34.5\,kV$$

Short Circuit Levels – Example

$$I_{fault\,6,7} = \frac{34.5 \cdot 10^3}{\sqrt{3}(6.5)} = 3060.34\,A\,at\,34.5\,kV$$

$$I_{fault\,8} = \frac{129.69 \cdot 10^6}{\sqrt{3} \cdot 34.5 \cdot 10^3} = 2170.4\,A\,at\,34.5\,kV$$

$$I_{fault\,9} = \frac{115 \cdot 10^3}{\sqrt{3} \cdot 13.84} = 4797.35\,A\,at\,115\,kV$$

Example – Short Circuit Printout

Fault location		Distance from fault	Element name	Type	Un [kV]	UL-E (RST) [kV]	AU L-E (RST) [°]	Ik" (RST) [kA]
From Node	To Node							
BUSBAR6	Faulted	0			34,5	19,919	180	3,06
BUSBAR6	BUSBAR2		L1	Line				0
BUSBAR6	BUSBAR3		L2	Line				0
BUSBAR6	BUSBAR5		L4	Line				0,453
BUSBAR6	BUSBAR4		L3	Line				0,453
BUSBAR6	BUSBAR7		TR1	2W Transformer				2,17
BUSBAR2		1			34,5	19,919	180	
BUSBAR2	BUSBAR6		L1	Line				0
BUSBAR2	BUSBAR1		TR2	2W Transformer				0
BUSBAR3		1			34,5	19,919	180	
BUSBAR3	BUSBAR6		L2	Line				0
BUSBAR5		1			34,5	8,281	179,94	
BUSBAR5	BUSBAR6		L4	Line				0,453
BUSBAR5	BUSBAR5		G8	Synchronous Machine				0,453
BUSBAR4		1			34,5	8,281	179,94	
BUSBAR4	BUSBAR6		L3	Line				0,453
BUSBAR4	BUSBAR4		G15	Synchronous Machine				0,453
BUSBAR7		1			115	8,988	180	
BUSBAR7	BUSBAR6		TR1	2W Transformer				0,651
BUSBAR7	BUSBAR7		EQUIVALENT	Network Feeder				0,651
BUSBAR1		2			13,2	7,621	180	
BUSBAR1	BUSBAR2		TR2	2W Transformer				0

Nominal Currents – Example

$$I_{nom1,2,3} = \frac{1 \cdot 10^6 VA}{\sqrt{3} \cdot 13.2 \cdot 10^3 V} = 43.74\, A$$

$$I_{nom4} = \frac{3 \cdot 10^6 VA}{\sqrt{3} \cdot 13.2 \cdot 10^3 V} = 131.22\, A$$

$$I_{nom5} = \frac{3 \cdot 10^6 VA}{\sqrt{3} \cdot 34.5 \cdot 10^3 V} = 50.20\, A\, at\, 34.5 kV$$

$$I_{nom6} = 50.20\, A\, at\, 34.5 kV$$

$$I_{nom7} = 16.73\, A\, at\, 34.5 kV$$

$$I_{nom8} = 251.02\, A\, at\, 34.5 kV$$

$$I_{nom9} = \frac{15 \cdot 10^6 VA}{\sqrt{3} \cdot 115 \cdot 10^3 V} = 75.31\, A\, at\, 34.5 kV$$

Selection of current transformers - Example

The two criteria to be fulfilled are:

- The CT withstands the nominal current continuously
- The maximum short circuit current does not saturate the CT. This is verified with the following expression assuming C100 CTs and a burden of 1 Ohm :

$$(Isc \times 5/X) \leq 100 \Rightarrow X \geq (Isc \times 5/100)$$

Summary of Currents and CT Ratios - Example

Breaker No.	Pnom (MVA)	Inom (A)	Isc (A)	5/100 Isc (A)	CT Ratio
9	15	75.31	4797.35	233.12	250/5
8	15	251.02	2170.40	108.51	300/5
7	1	16.73	3060.34	153.01	200/5
6	3	50.20	3060.34	153.01	200/5
5	3	50.20	1025.67	51.28	100/5
4	3	131.22	1076.06	53.80	200/5
1,2,3	1	43.74	1076.06	53.80	100/5

Example - Settings with a Numerical Relay

Now, consider all the relays to be set are Beckwith M-7679, numerical type with the characteristics indicated in the following slide. The relays have an extremely inverse time current characteristic with the following constants:

α = 2.0,
β = 80
L = 0

The TCC is defined by

$$t = \frac{Time\,Dial * 80}{(MULT)^2 - 1}$$

Where *MULT = Fault current (in secondary amps)/TAP*

The following considerations have to be taken into account:

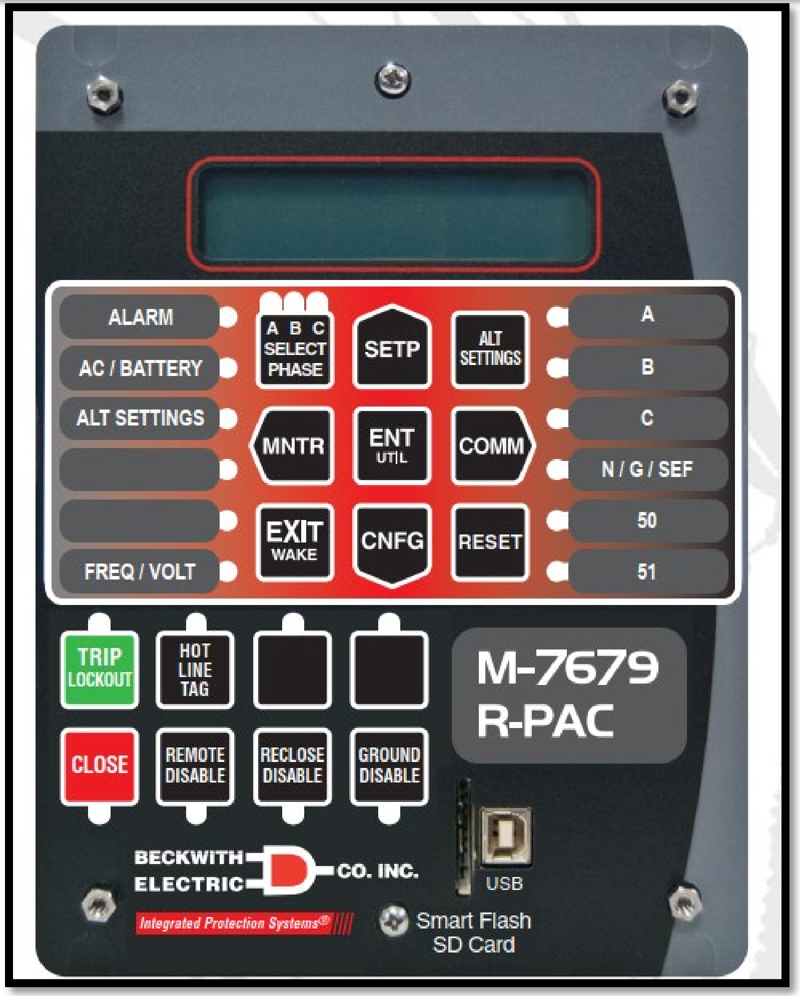
For setting of the instantaneous element a value of ten (10) times the maximum load current is used.

The margin time for this relay can be 0.2 s since it is of numerical type.

Relay 7 is the same W CO 11 with TAP = 4 A, DIAL = 5 and Inst = 1100 A

Example - Settings with a Numerical Relay

M-7679 R-PAC



Characteristics of Relay M-7679

The PICK UP or TAP settings are available in Steps of 0.01

The TIME DIAL settings are available in Steps of 0.01

M-7679 R-PAC – Specification

PROTECTIVE FUNCTIONS (*cont.*)

Device Number	Function	Setpoint Ranges	Increment	Accuracy[†]
	Inverse Time Overcurrent (#1 to #5 Elements)			
51P	**Phase Inverse Time Overcurrent with Voltage Control/Restraint**			
	Pickup			
	1 A CT (or 5 mA CT)	0.02 to 3.20 A	0.01 A	±0.02 A or ±3%
	5 A CT	0.10 to 16.00 A	0.01 A	±0.1 A or ±3%
	Load Encroachment Logic	Use/Do Not Use	–	–
	Voltage Control or Voltage Restraint	4.0 to 150.0 %	0.1 %	
51N	**Residual Inverse Time Overcurrent**			
	Pickup			
	1 A CT (or 5 mA CT)	0.02 to 3.20 A	0.01 A	±0.02 A or ±3%
	5 A CT	0.10 to 16.00 A	0.01 A	±0.1 A or ±3%
51G	**Ground Inverse Time Overcurrent**			
	Pickup			
	1 A Gnd CT	0.02 to 3.20 A	0.01 A	±0.02 A or ±3%
	5 A Gnd CT	0.10 to 16.00 A	0.01 A	±0.1 A or ±3%
	Electromechanical Reset Delay	Yes/No		
	Reset Coefficient	0.001 to 30.000 s	0.001 s	±0.01 s or ±1%
	TCC Modifiers Time Adder	0.00 to 30.00 s	0.01 s	±0.01 s or ±1%
	Minimum Response Time Adder	0.00 to 1.00 s	0.01 s	±0.01 s or ±1%
	IEC Curves Family (IEC 60255-151)	Inverse, Very Inverse Extremely Inverse		
	Time Multiplier	0.05 to 1.00	0.01	±2 cycles or ±5%
	IEEE Curves (C37.112)	Moderately Inverse Very Inverse Extremely Inverse		
	Time Multiplier	0.10 to 25.00	0.01	±2 cycles or ±5%
	US Curves	Moderately Inverse Standard Inverse Very Inverse Extremely Inverse Short Time Inverse		
	Time Multiplier	0.05 to 15.00	0.01	±2 cycles or ±5%

Tap Setting - Example

$I_{load1,2,3} = 43.74\ A$ $Pickup_{1,2,3} = (1.5)(43.74)(5/100) = 3.28\ A \Rightarrow Pickup_{1,2,3} = 3.28\ A$

$I_{load4} = 131{,}22\ A$ $Pickup_{4} = (1.5)(131.22)(5/200) = 4.92\ A \Rightarrow Pickup_{4} = 4.92\ A$

$I_{load5} = 50.20\ A$ $Pickup_{5} = (1.5)(50.20)(5/100) = 3.76\ A \Rightarrow Pickup_{5} = 3.76\ A$

$I_{load6} = 50.20\ A$ $Pickup_{6} = (1.5)(50.20)(5/200) = 1.88\ A \Rightarrow Pickup_{6} = 1.88\ A$

$I_{load8} = 251.02\ A$ $Pickup_{8} = (1.5)(251.02)(5/300) = 6.28\ A \Rightarrow Pickup_{8} = 6.28\ A$

$I_{load9} = 75.31\ A$ $Pickup_{9} = (1.5)(75.31)(5/250) = 2.26\ A \Rightarrow Pickup_{9} = 2.26\ A$

Summary of Currents and CT Ratios - Example

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1,2,3	1	43.74	1076.06	53.80	100/5

Settings with a Numerical Relay

Relays 1, 2 and 3

Iinst. trip = 10 × Inom × (1/CTR)

= 10 × 43.74 × (5/100) = 21.87 A

Iprim. trip = 21.87(100/5) = 437.4 A.

MULT = 21.87/3.28 = 6.668 times

with Time Dial = 0.05,

$$t = \frac{0.05 \cdot 80}{(6.668)^2 - 1} = 0.092s$$

Relay 4

To coordinate with relays 1, 2 and 3 at 437.4 A , relay 4 requires that t_{4a} = *0.092 + 0.2 = 0.292 s.*

Settings with a Numerical Relay

$MULT_{4a}$ = (437.4)(5/200)(1/4.92) = 2.223 times.

At 2.223 times, and t_{4a} = 0.292 s,

$$Time\ Dial = \left(\frac{0.292}{80}\right)\left((2.223)^2 - 1\right) = 0.01$$

However, the dial 0.05 is the minimum that the relay has.

The operating time for a line-to-line fault is determined by taking 86% of the three-phase fault current.

$MULT_{4b}$ = (0.86)(1076.06)(5/200)(1/4.92) = 4.702 times.

$$t_{4b} = \frac{0.05 \cdot 80}{(4.627)^2 - 1} = 0.190s$$

This relay has no setting for the instantaneous

Settings with a Numerical Relay

Relay 5

The back-up to relay 4 is obtained by considering the operating time for a three phase fault of t_{5a} = *0.190 + 0.2 = 0.390 s.*

MULT$_{5a}$ *= 1076.06 (13.2/34.5) (5/100) (1/3.76) = 5.475 times. At 5.475 times and top = 0.390 sec.,*

$$Time\ Dial = \left(\frac{0.390}{80}\right)\left((5.475)^2 - 1\right) = 0.14$$

Iinst. trip = 1.25 (1076.06) (13.2/34.5) (5/100)=25.73

Iprim. trip = 25.73(100/5) = 514.6 A.

MULT$_b$ *= 25.73/3.76 = 6.843 times, with Time Dial = 0.14,*

$$t_{5b} = \frac{0.14 \cdot 80}{(6.843)^2 - 1} = 0.244s$$

Settings with a Numerical Relay

Relay 6

At 514.6 A this relay has to operate in t_{6a} = *0.244 + 0.2 = 0.444 sec.*

$MULT_a$ = 514.6 (5/200) (1/1.88) = 6.843 times. At 6.843 times and top = 0.444 sec.,

$$Time\ Dial = \left(\frac{0.444}{80}\right)\left((6.843)^2 - 1\right) = 0.25$$

Instantaneous setting = 1.25 (1025.67) (5/200) = 32.05A.

$I_{prim\ trip}$ = 32.05 x 200/5 = 1282.09 A

Settings with a Numerical Relay

Relay 8

Relay 8 backs up relays 6 and 7, and should be co-ordinated with the slowest of these two relays. Relay 7 has an instantaneous setting of 1100 A, which is smaller than the setting of relay 6, and so the operating time of both relays is determined by this value.

For relay 7: *MULT = 1100 5/200 1/4 = 6.87 times. At 6.87 times and Time Dial 5, top = 0.71 sec.*

For relay 6: *MULT = 1100 (5/200) (1/1.88) = 14.628 times.*

At 14.628 times and Time Dial 0.25,

$$t = \frac{0.25 \cdot 80}{(14.628)^2 - 1} = 0.094s$$

Therefore the operating time to give correct discrimination with relay 7 is t_{8a} *= 0.71 + 0.2 = 0.91 sec.*

Settings with a Numerical Relay

Relay 8

The contributions from substations G and M are not considered to back up relay 8. Only the currents through the transformer have to be taken into account. Therefore,

$MULT_a$ = 1100 (2170.39/3060.34) (5/300) (1/6.28) = 2.07 times.

At 2.07 times and top = 0.91 sec.,

$$Time\ Dial = \left(\frac{0.91}{80}\right)\left((2.07)^2 - 1\right) = 0.04$$

However, the Time Dial 0.05 is the minimum that the relay has. No instantaneous setting is given to relay 8 for the reasons already given. The maximum short circuit current to be used for this relay is that which flows from the 115 kV to the 34.5 kV busbar for a fault on the latter,

$MULT_b$ = 2170.39 (5/300) (1/6.28) = 5.76 times. At 5.76 times and Time Dial 0.05,

$$t = \frac{0.05 \cdot 80}{(5.76)^2 - 1} = 0.124s$$

Settings with a Numerical Relay

Relay 9

This relay backs up relay number 8 in a time of $t_{9a} = 0.124 + 0.2 = 0.324$ *sec*

$MULT_a$ = 2170.39 (34.5/115) (5/250) (1/2.26) = 5.762 times. At 5.762 times and top = 0.324 s,

$$Time\ Dial = \left(\frac{0.324}{80}\right)\left((5.762)^2 - 1\right) = 0.13$$

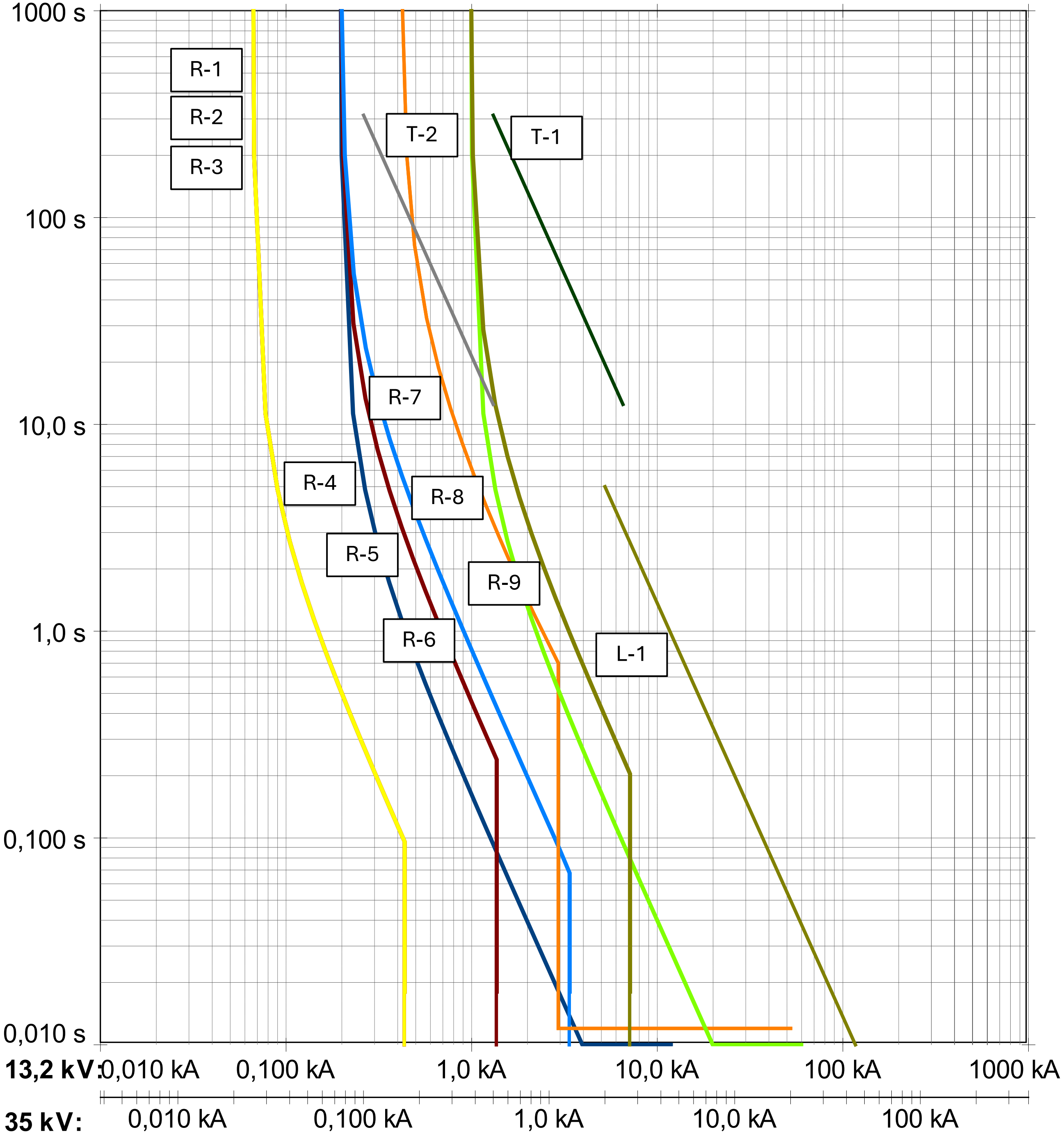
Instantaneous setting = 1.25 (2170.39) (34.5/115) (5/250) = 16.27 A

$I_{prim\ trip}$ = 16.27 (250/5) = 813.5 A referred to 115 kV

Summary of Numerical Relay Settings - Example

Relay No.	CT Ratio	Tap	Dial	Instantaneous
1,2,3	100/5	3.28	0.05	21.87 A
4	200/5	4.92	0.05	—
5	100/5	3.76	0.14	25.73 A
6	200/5	1.88	0.25	32.05 A
7	200/5	4	5	27.5 A
8	300/5	6.28	0.05	—
9	250/5	2.26	0.13	16.27 A

Example - Coordination Curves with NR



Coverage of the instantaneous unit - Example

Percentage of 34.5 kV line protected by the instantaneous element of the overcurrent relay associated with breaker 6.

Given that: $\% = (K_s(1-K_i)+1)/K_i$

where $K_i = I_{sc\ pickup}/I_{sc\ end} = 1282.09/1025.67 = 1.25$

and $K_s = Z_{source}/Z_{element}$

From the computer listing:

$Z_f = V^2/P = 34.5^2/182.87 = 6.5$ and,

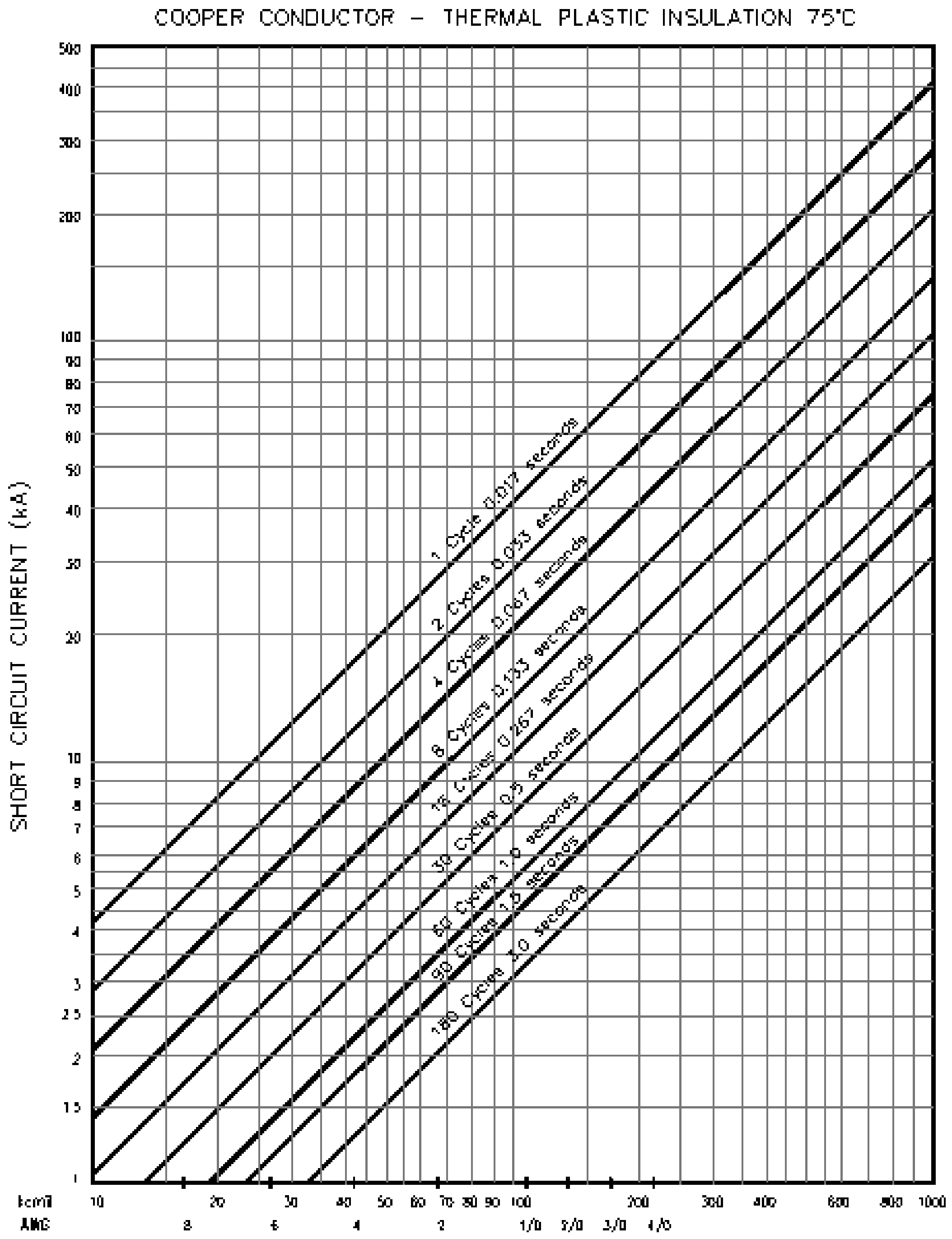
$Ks = 6.50/12.92 = 0.50$

Therefore, $\% = (0.50 \times (1-1.25)+1)/1.25 = 0.70$

This indicates that the instantaneous element covers 70% of the line.

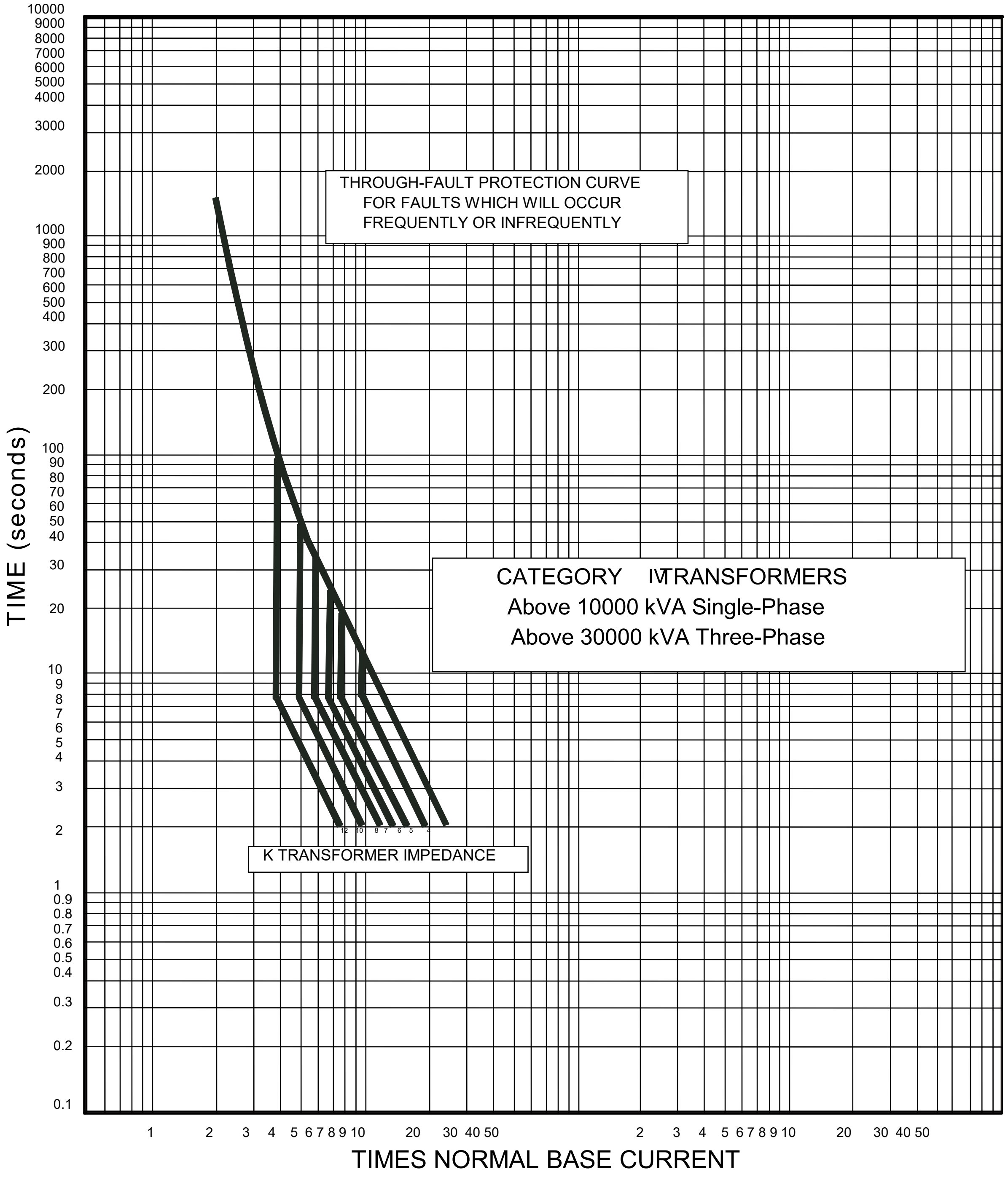
Thermal Limits of Copper Conductors

Thermal Plastic Insulation 75°C



Thermal Capacity of Transformers

Category IV



Checking of Energizing Conditions

It is important to check that the relay settings are not going to present problems when system elements are energized.

In the case of transformers, the initial magnetization inrush current can be expressed as:

$$I_{Inrush} = K \times I_{nom}$$

where

I_{nom} = nominal transformer current

K = 8, from 500 to 2,500 kVA transformer capacity

K = 10 above 2,500 kVA transformer capacity

The inrush point remains during 0.1 seconds.

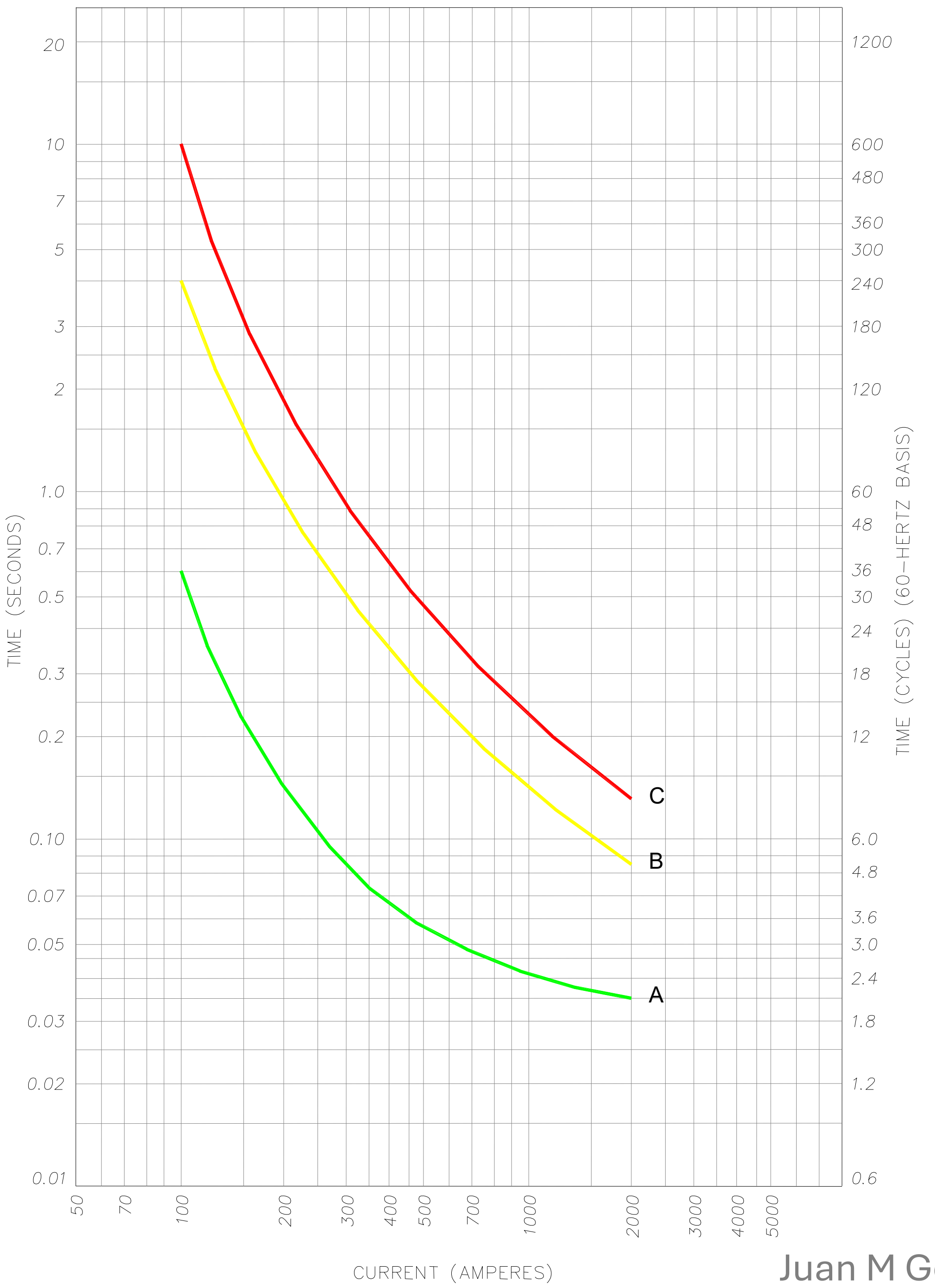
Reclosers - General

Reclosers are devices with the ability to:

- Detect phase and phase-to-ground overcurrent conditions
- Interrupt the circuit if the overcurrent persists after a pre-determined time
- Automatically reclose to re-energize the line

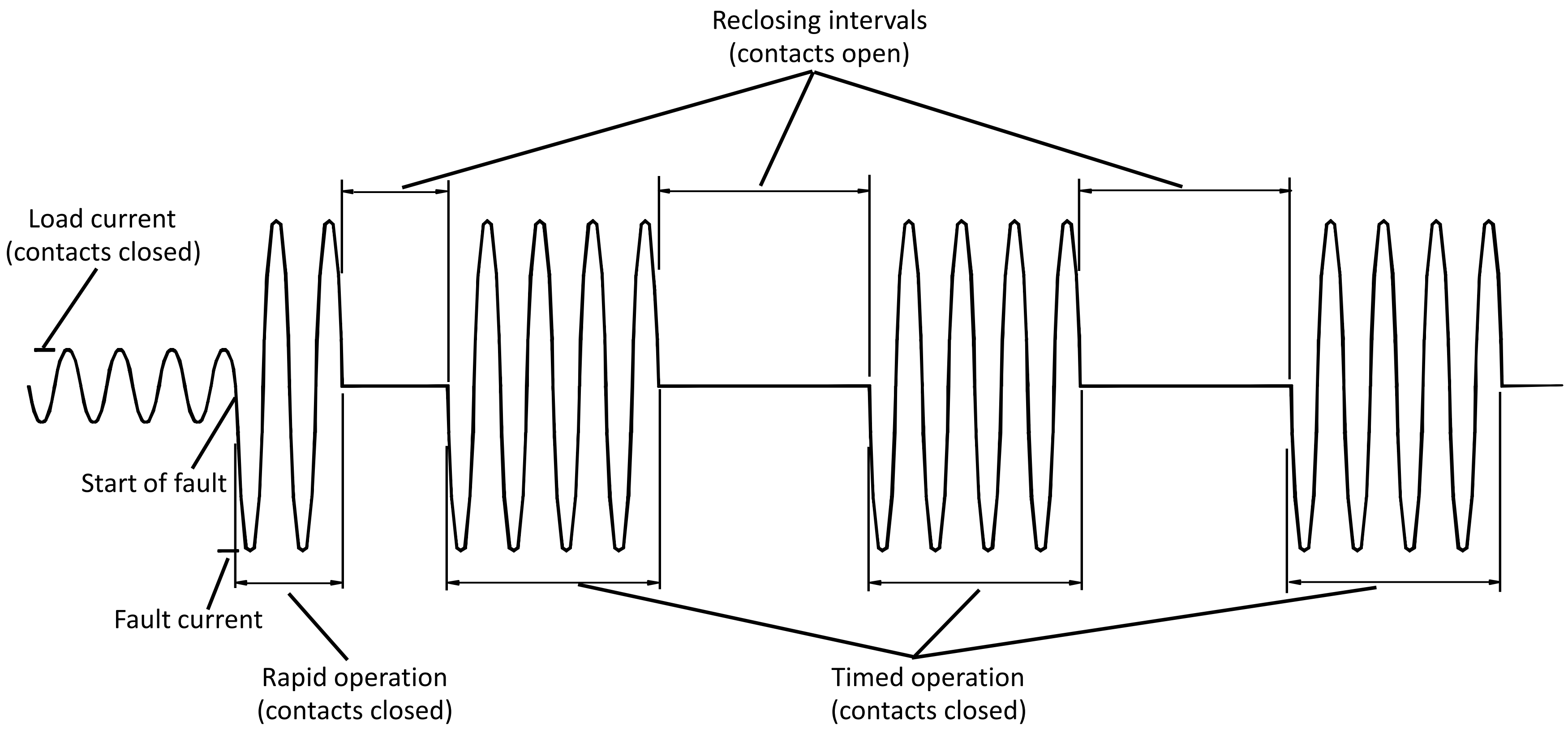
Reclosers - General

TCC for reclosers

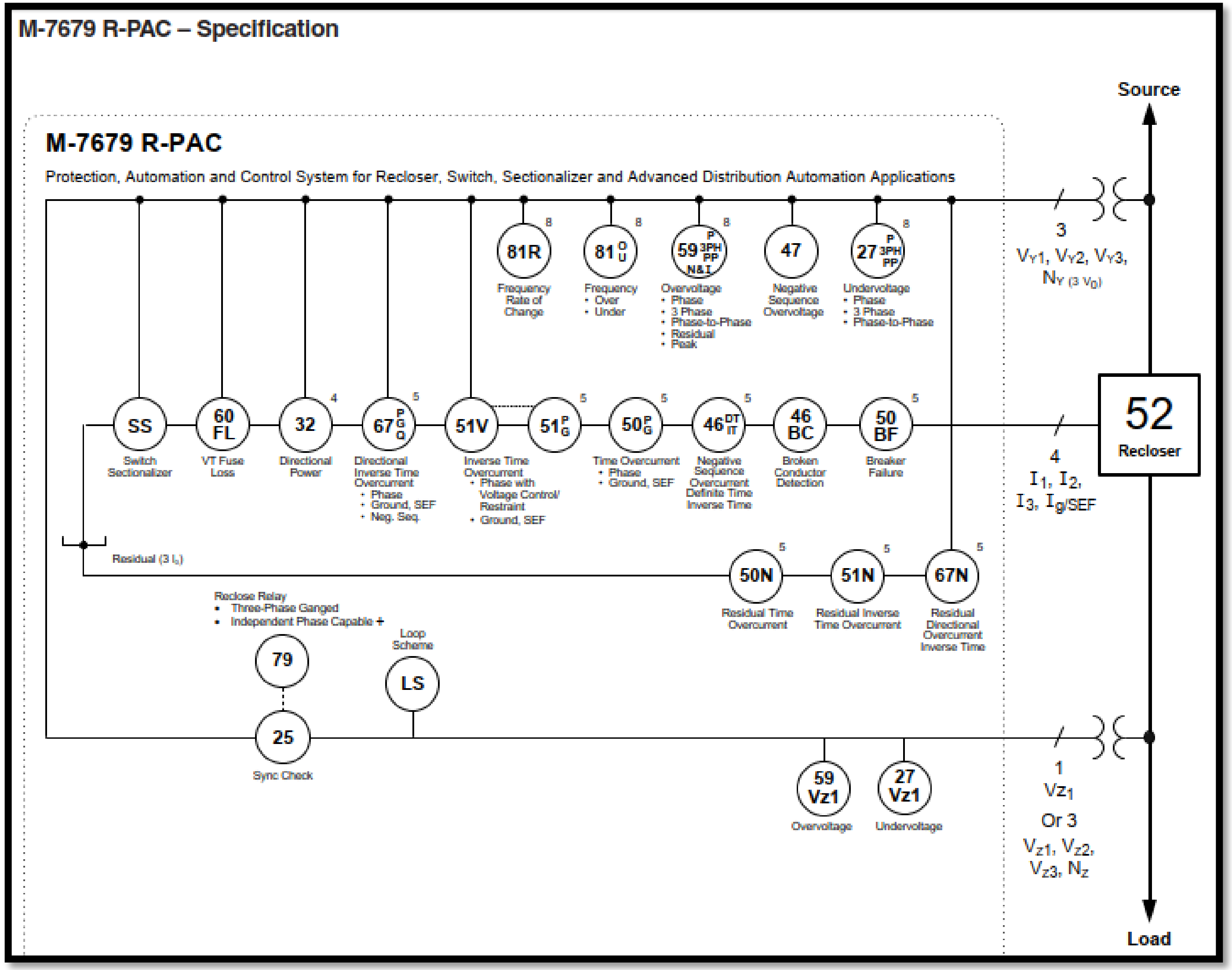


Reclosers - General

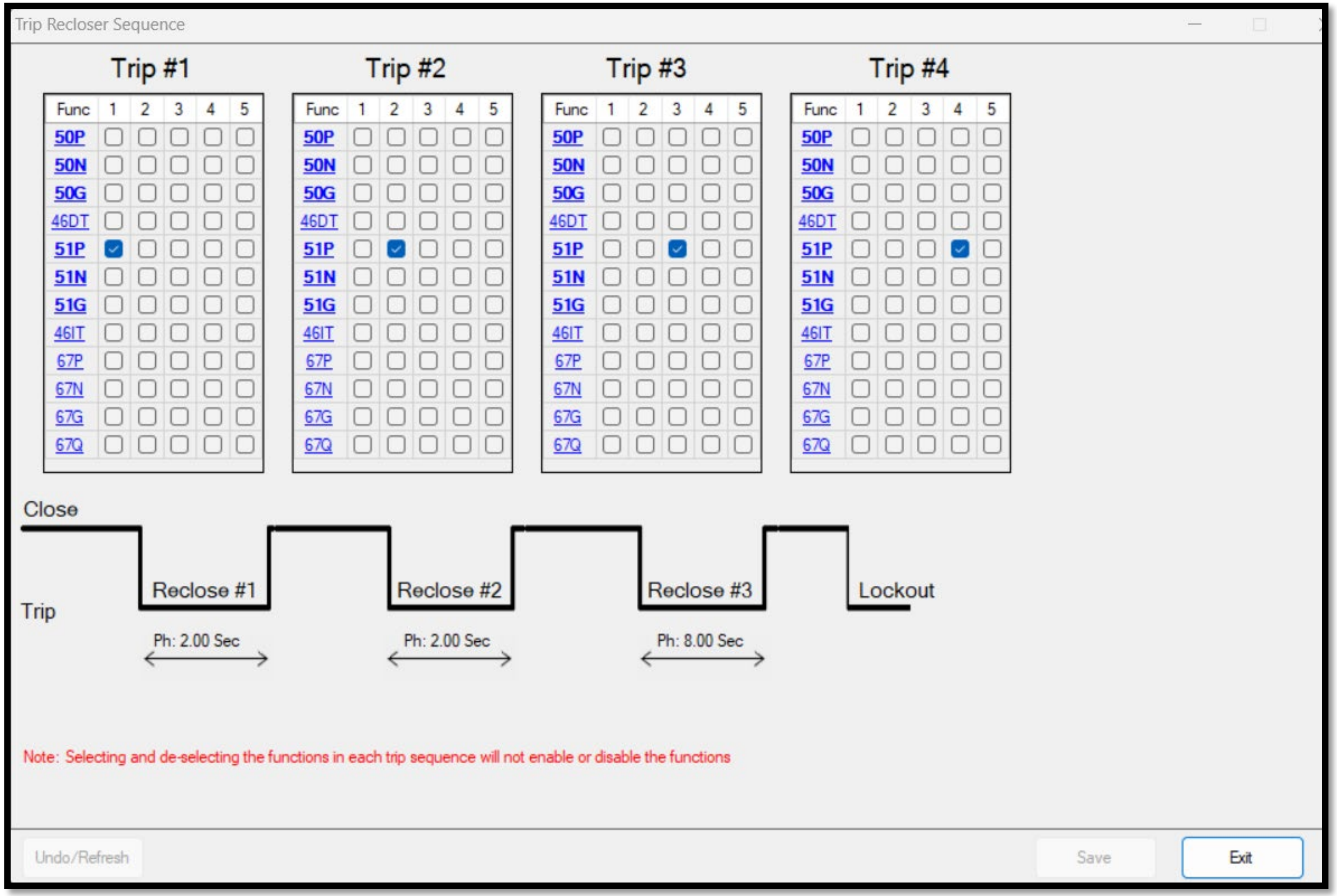
Typical sequence for recloser operation



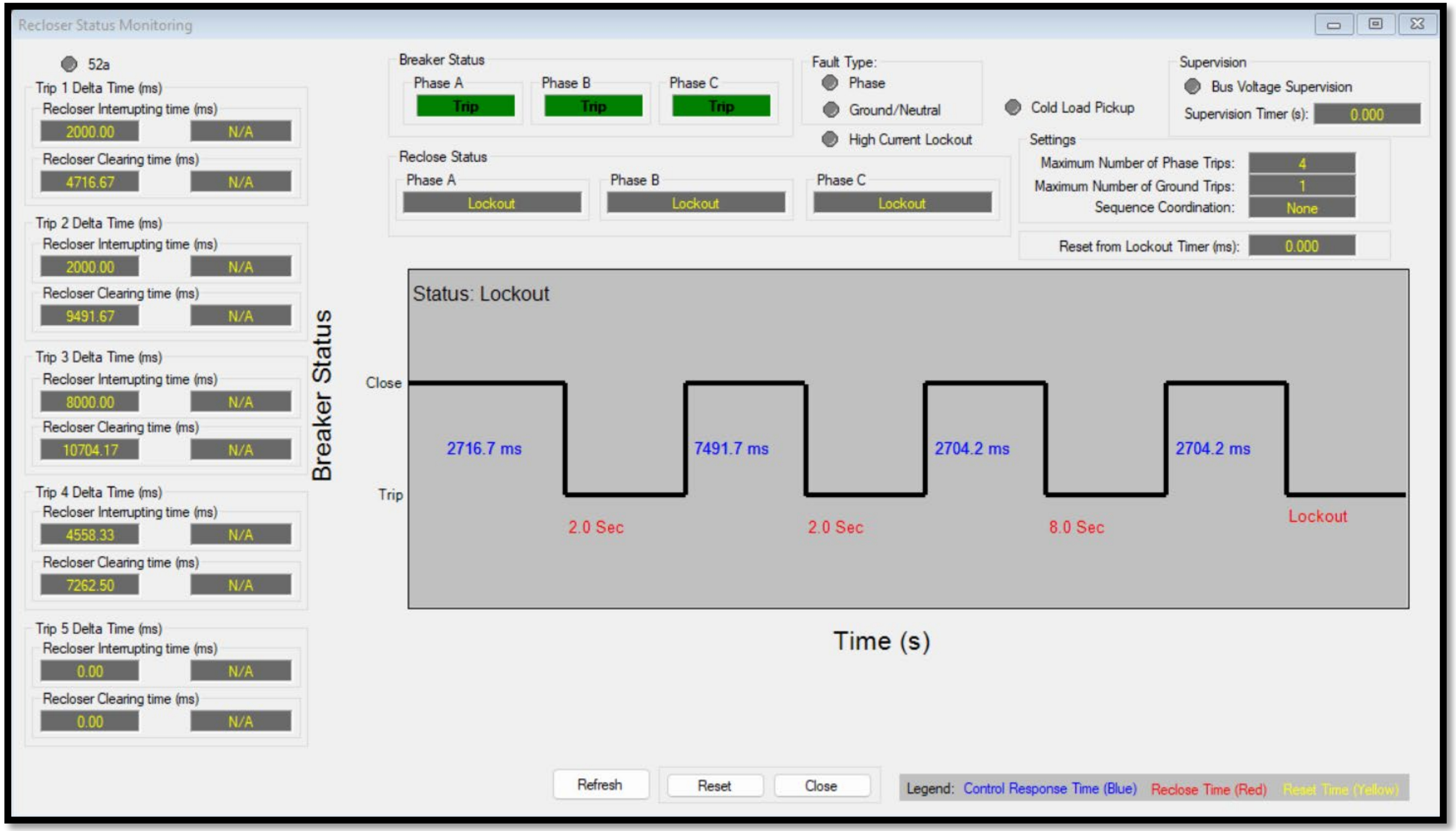
Reclosing Procedures



Reclosing Procedures

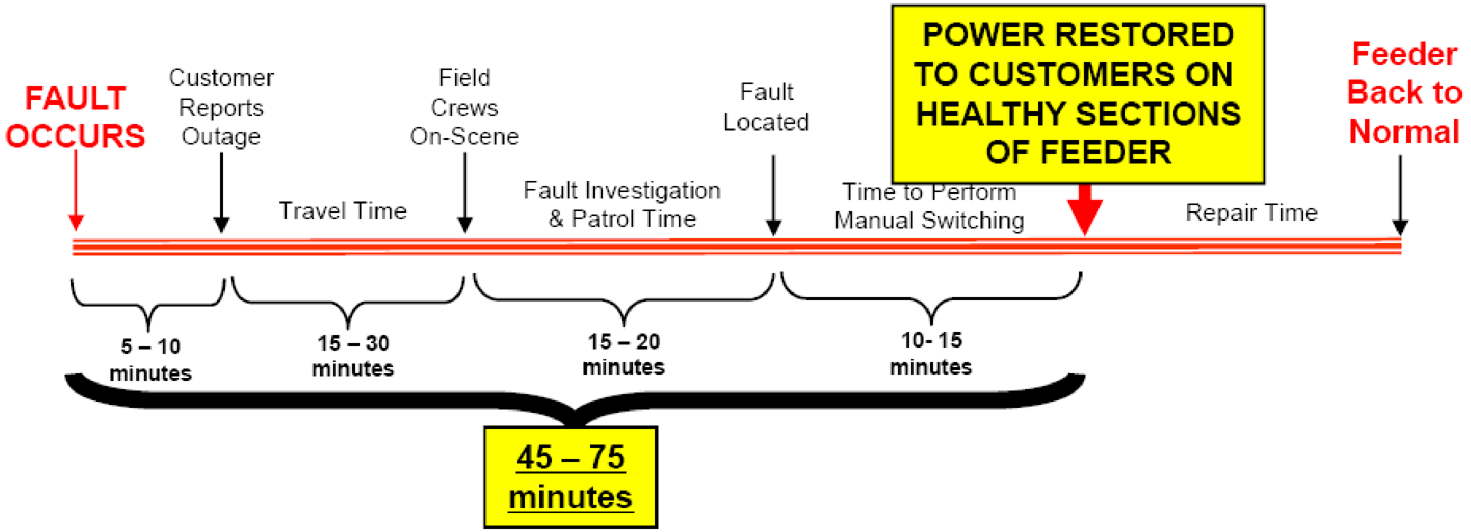


Reclosing Procedures



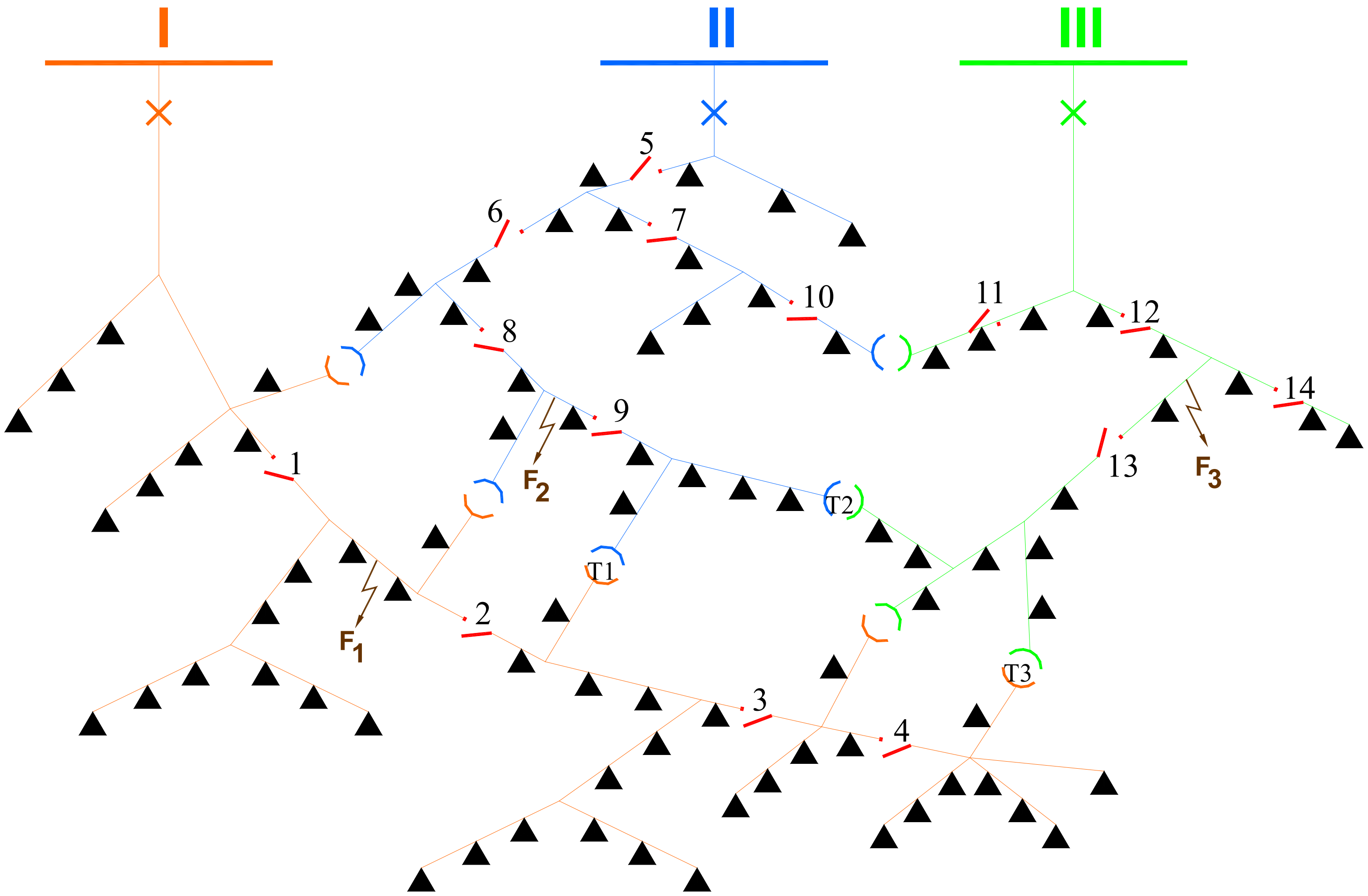
Manual Restoration vs FLISR

When a permanent fault occurs, customers on "healthy" sections of the feeder may experience a lengthy outage.



FLISR provides the means to restore service to some customers before field crews arrive on the scene.

Location of NC and NO Switches in a DS

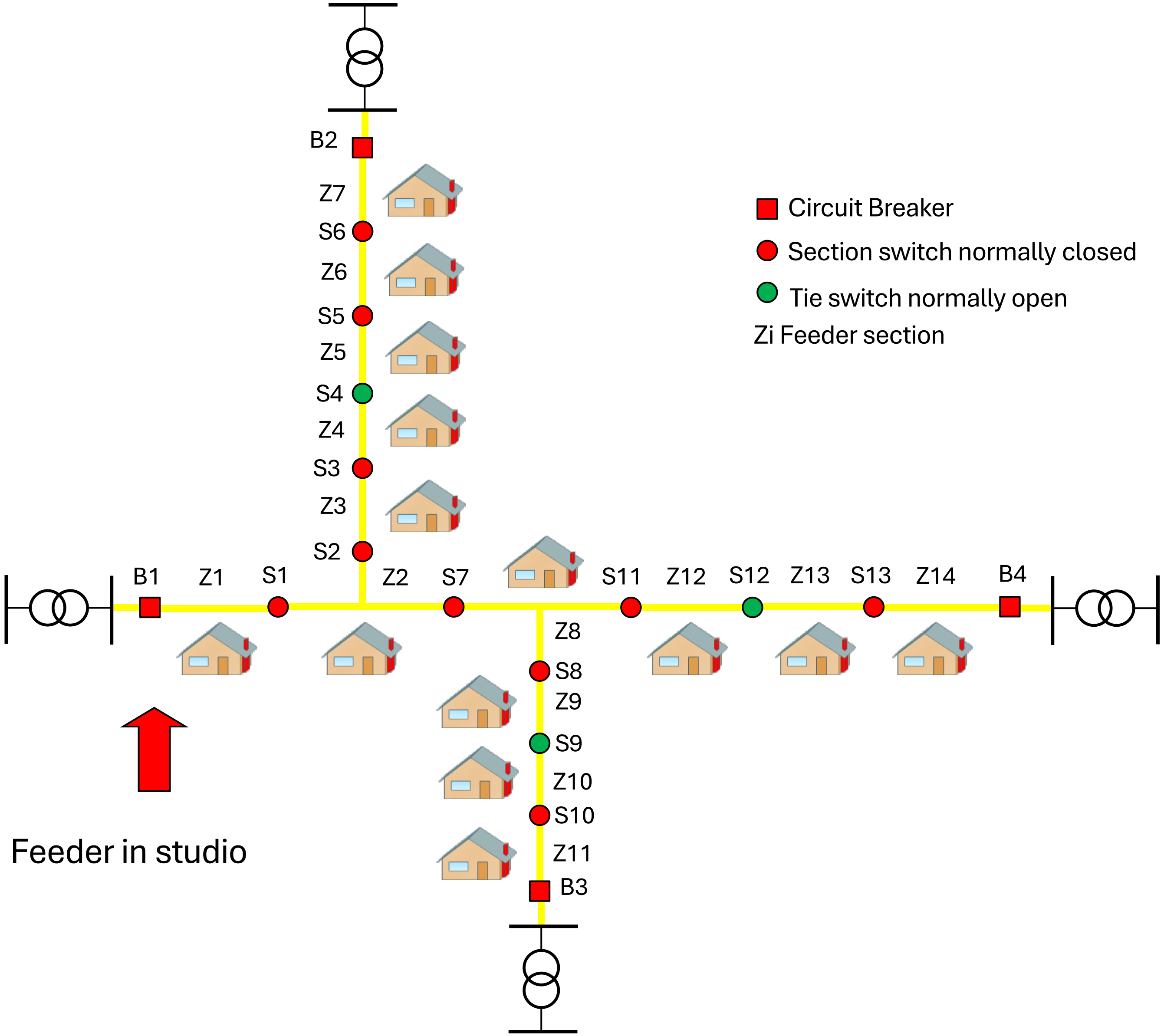


Restrictions for Restoration

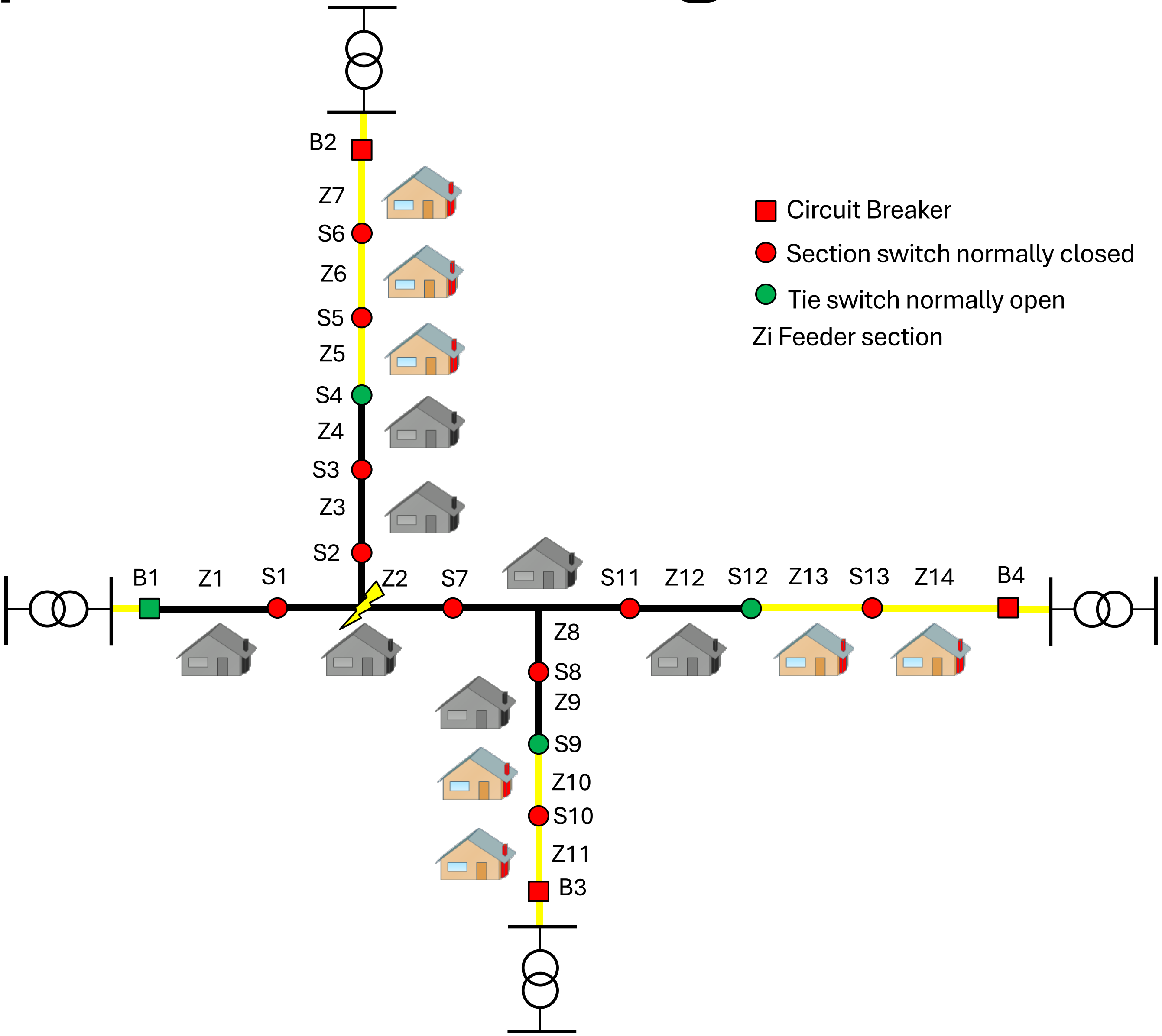
When carrying out the system restoration, the operations that are executed should allow that the system satisfies some restrictions, such as:

- The capacity of current of the transformers and lines should be within specified limits
- The voltage drop should stay inside an established margin.
- System should continue being radial
- The Number of operations of the equipment has limits
- Important customers have priority
- System must be balanced in the best possible way
- The coordination of the protection must be maintained

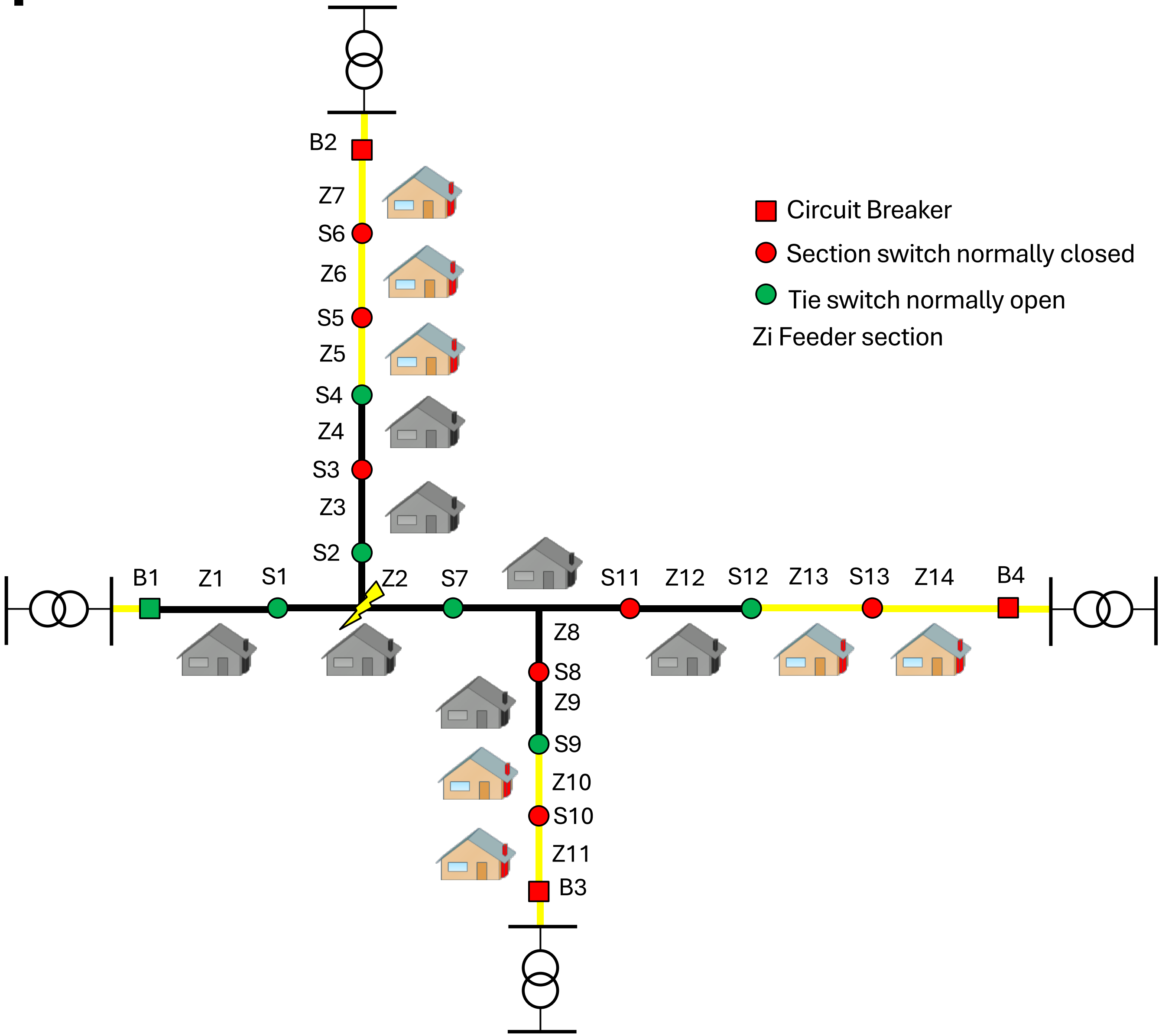
Case Example – Initial Configuration



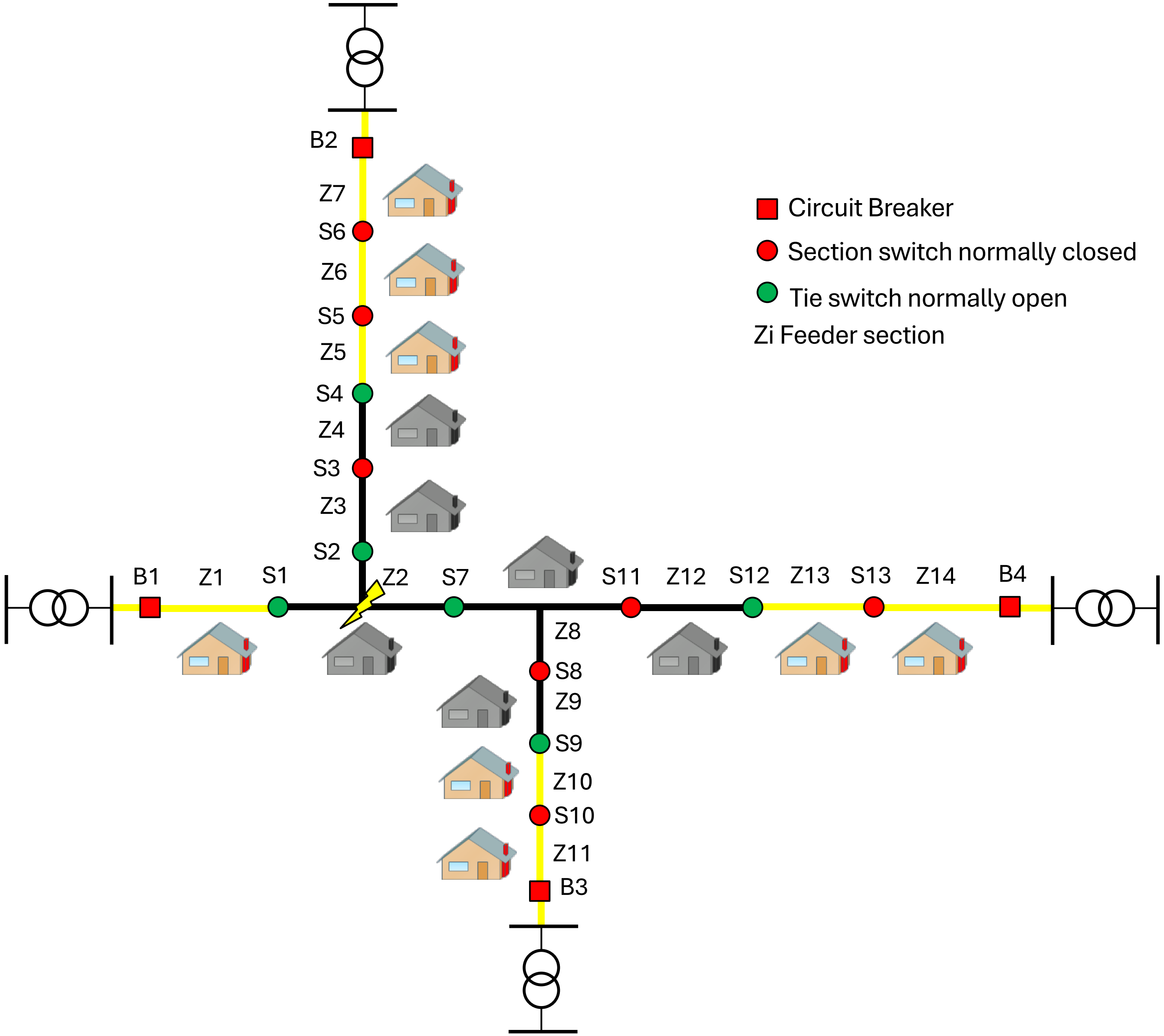
Case Example – Fault Clearing



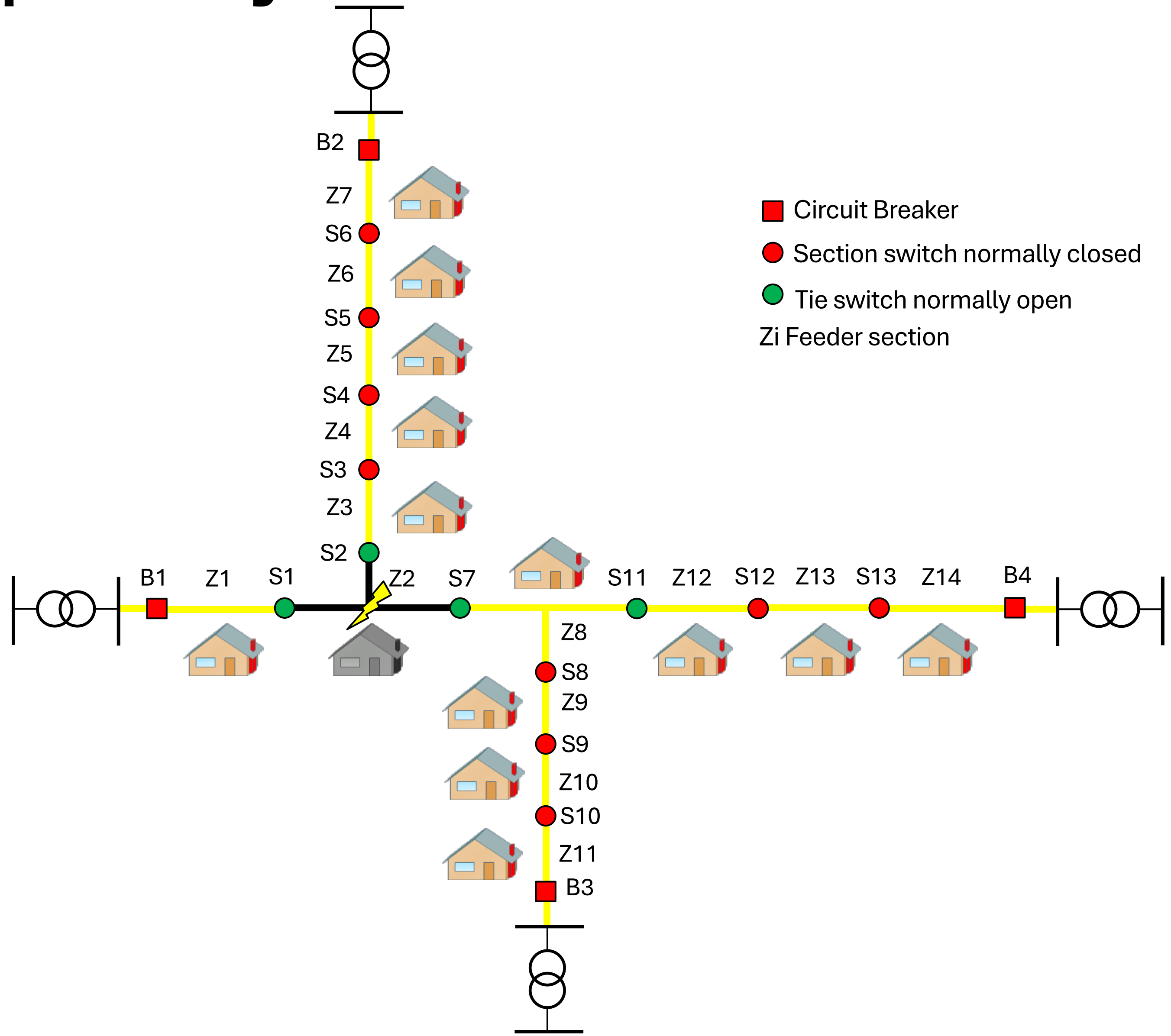
Case Example – Fault Location and Isolation



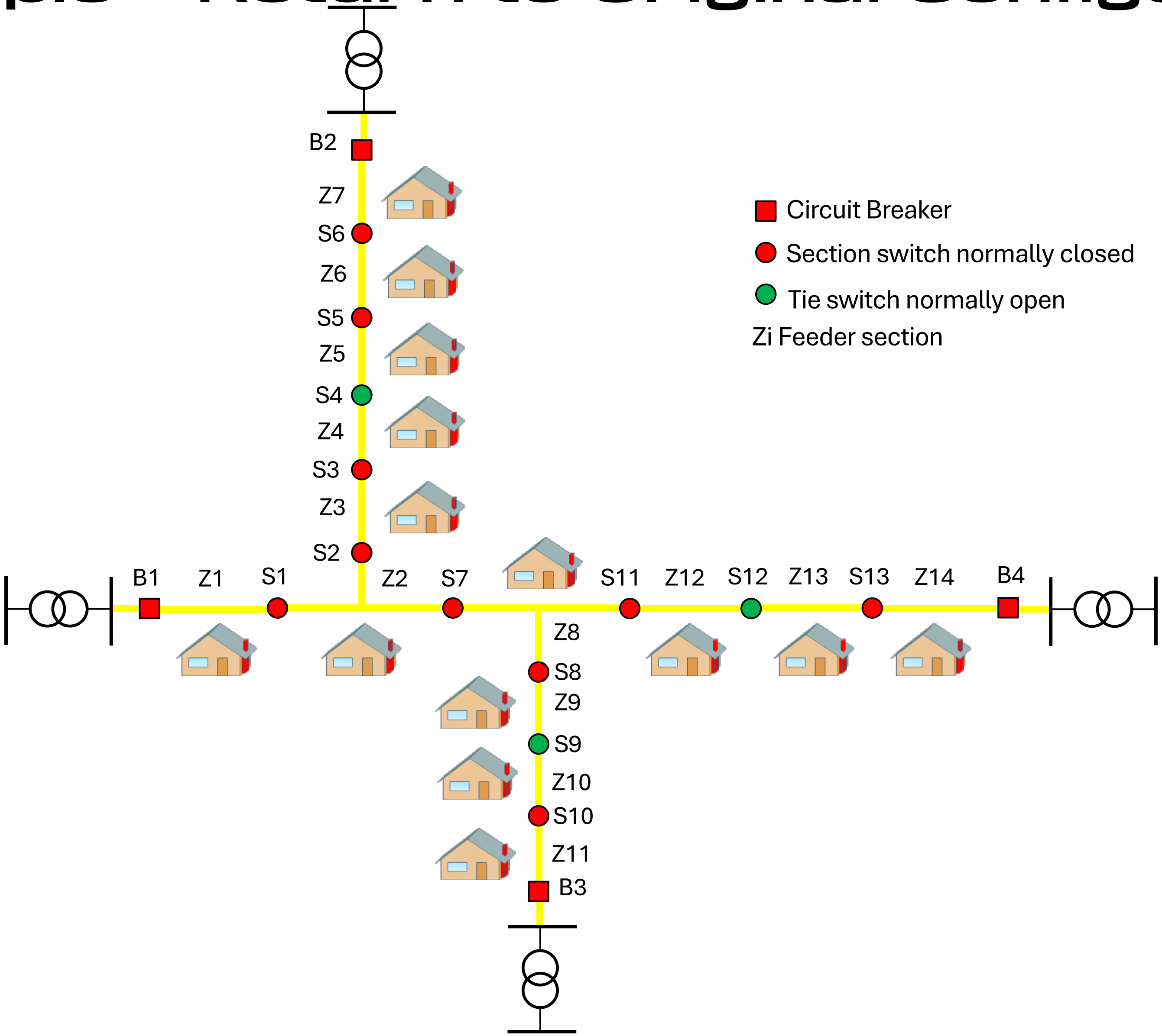
Case Example – Feeder Reenergization



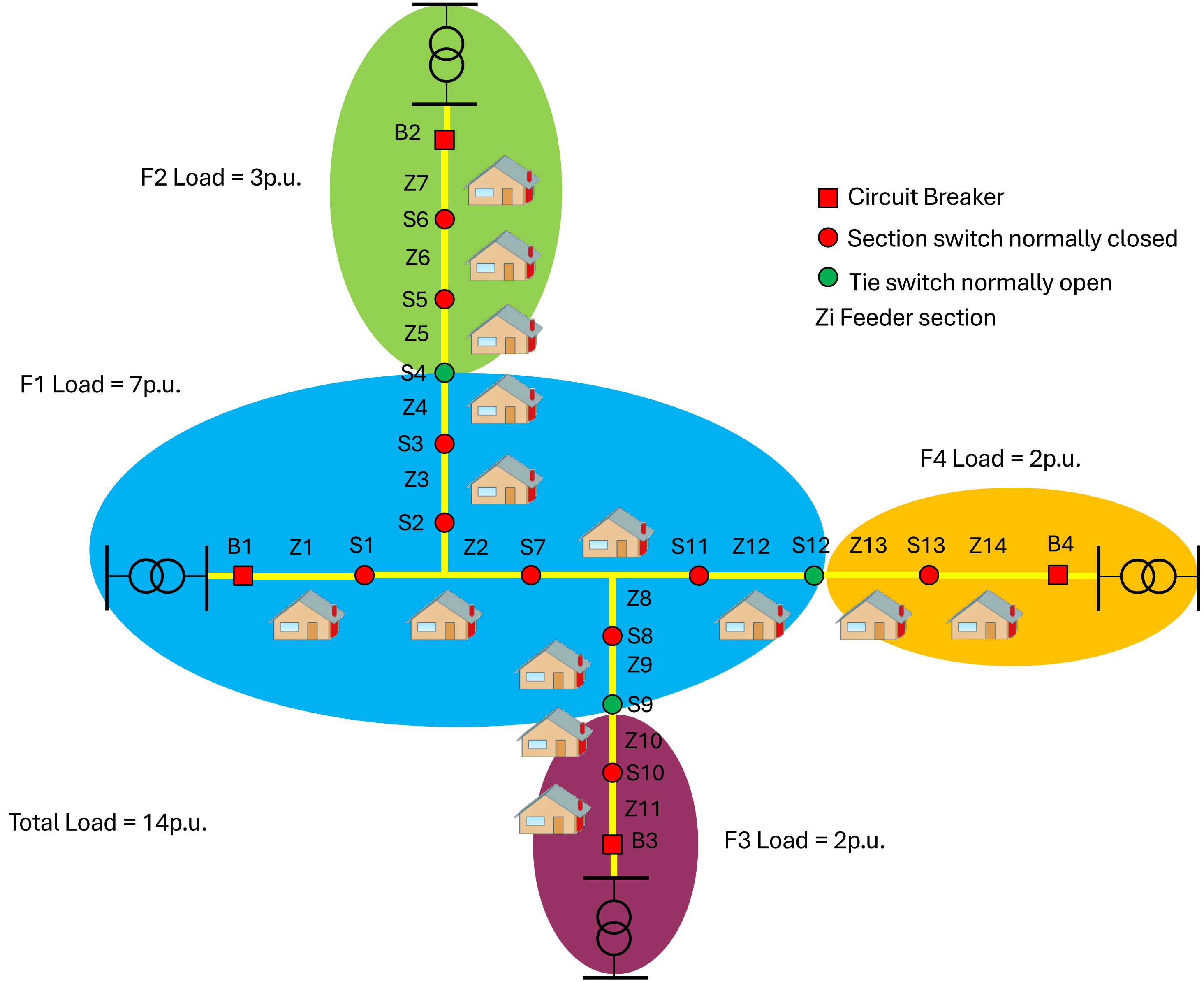
Case Example – System Restoration



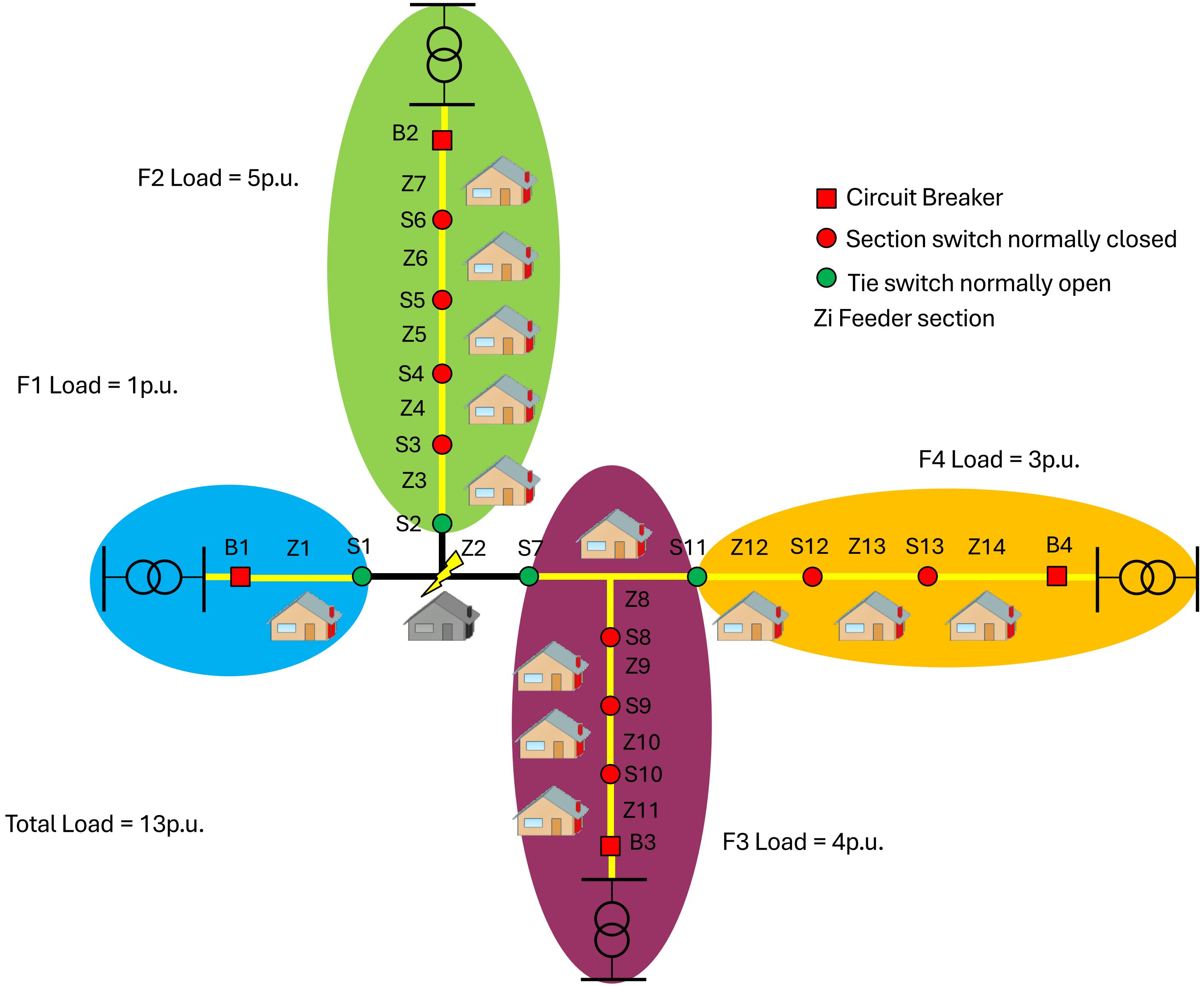
Case Example – Return to Original Configuration



Case Example – Initial Configuration



Case Example – System Reconfigured



Adaptive Protection During Changing System Conditions

There are many other reasons that produce changes in the loading conditions which may result in misoperation of the relays. These reasons could be classified in two main groups:

- Changes in Topology of the Distribution/Transmission System
- Automatic Feeder Reconfiguration of Distribution Systems

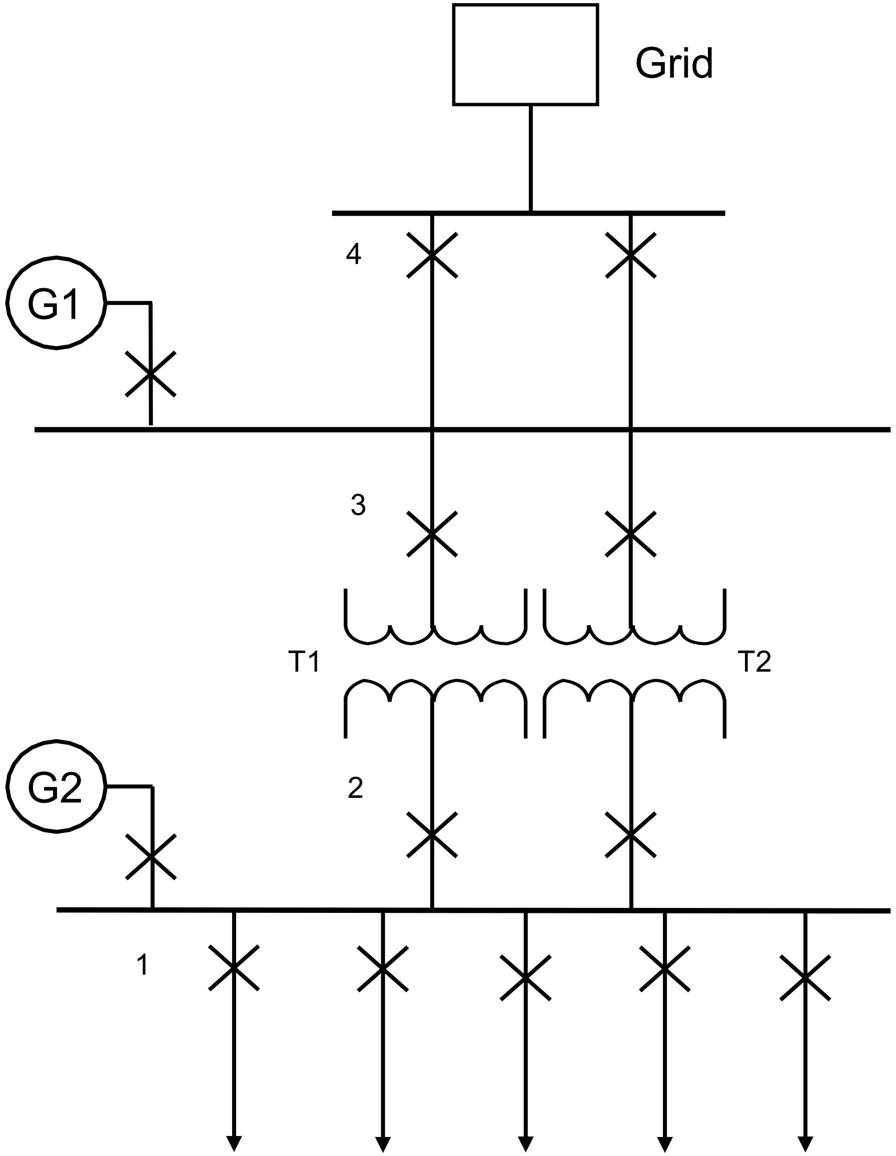
Adaptive Protection During Changing System Conditions

Adaptive protection aims to adjust settings of protective relaying to the prevailing conditions of a power system.

This can be achieved readily nowadays with the multiple group setting that numerical relays have.

Power system operating conditions change continuously.

System integration – Adaptive Protection



System integration – Adaptive Protection

Loss of a Parallel Transformer

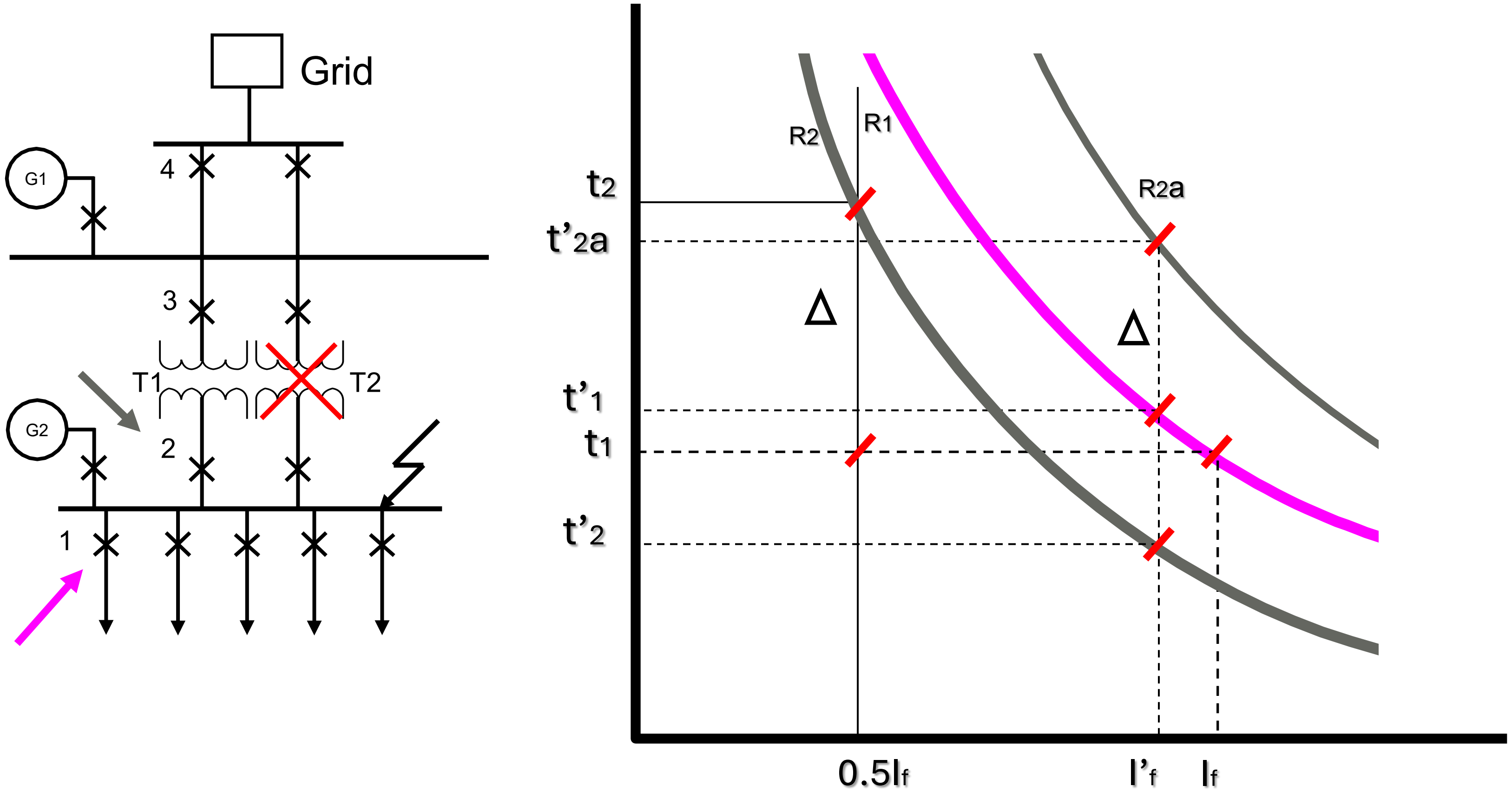
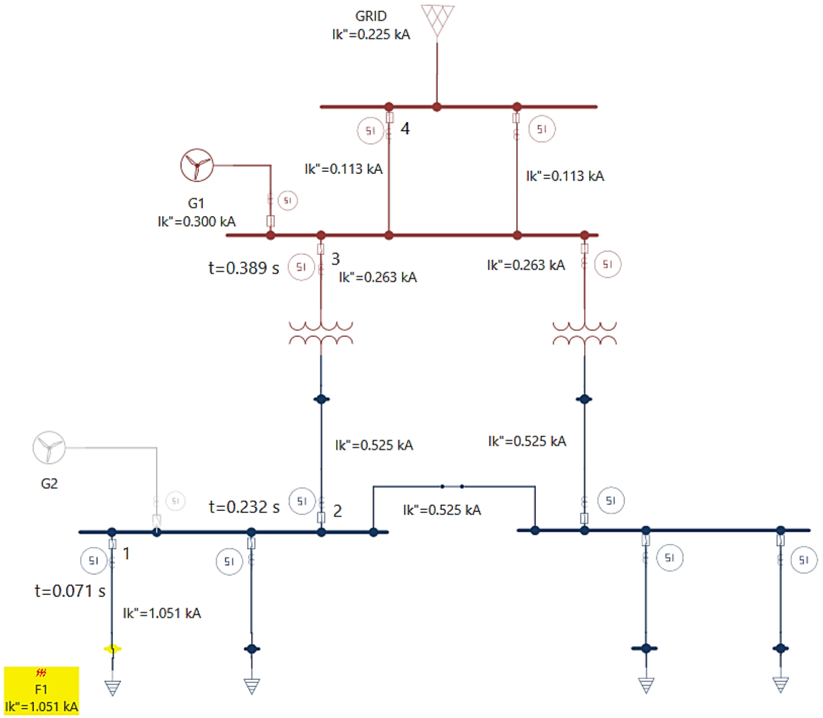
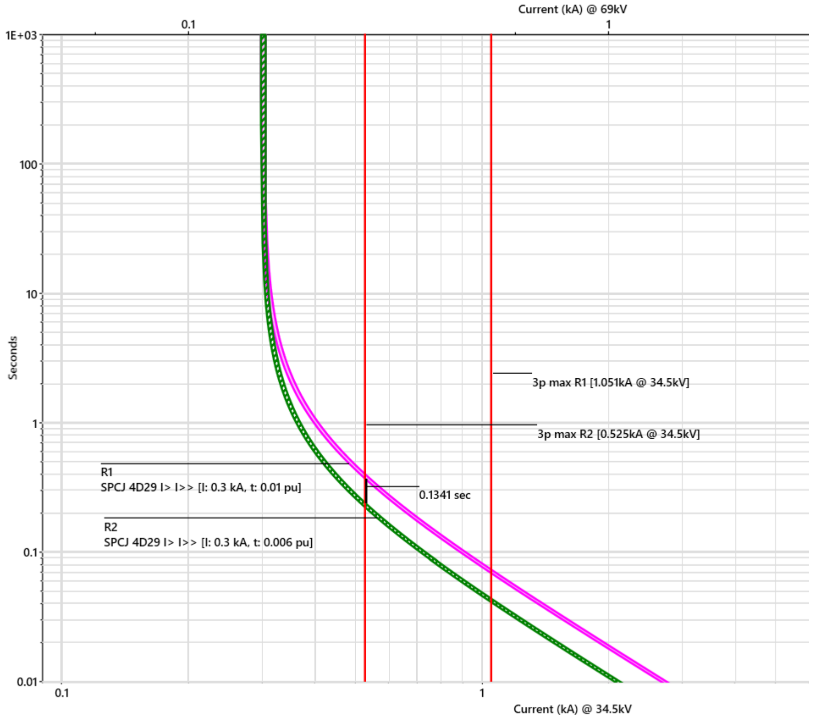


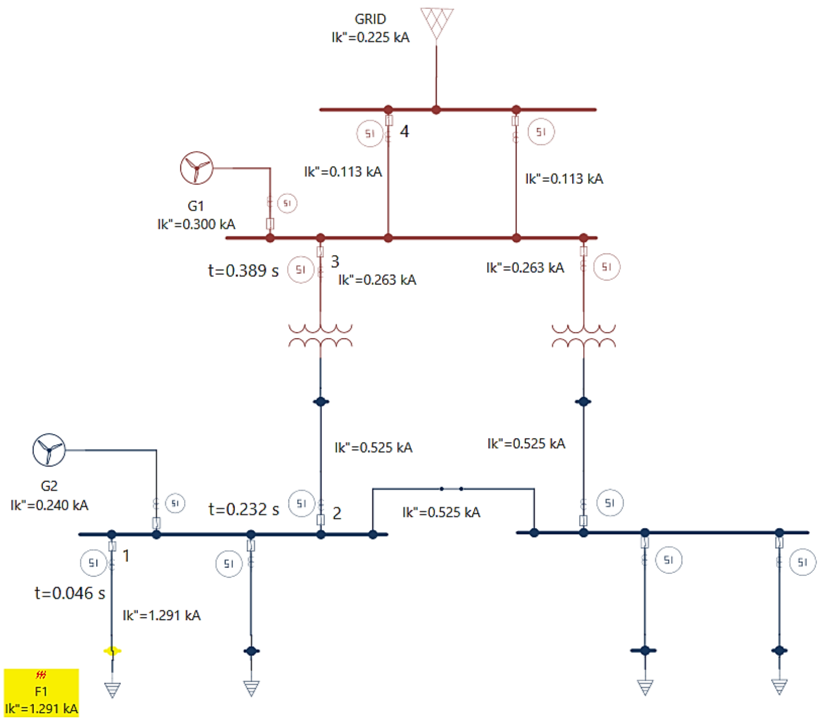
Illustration Case

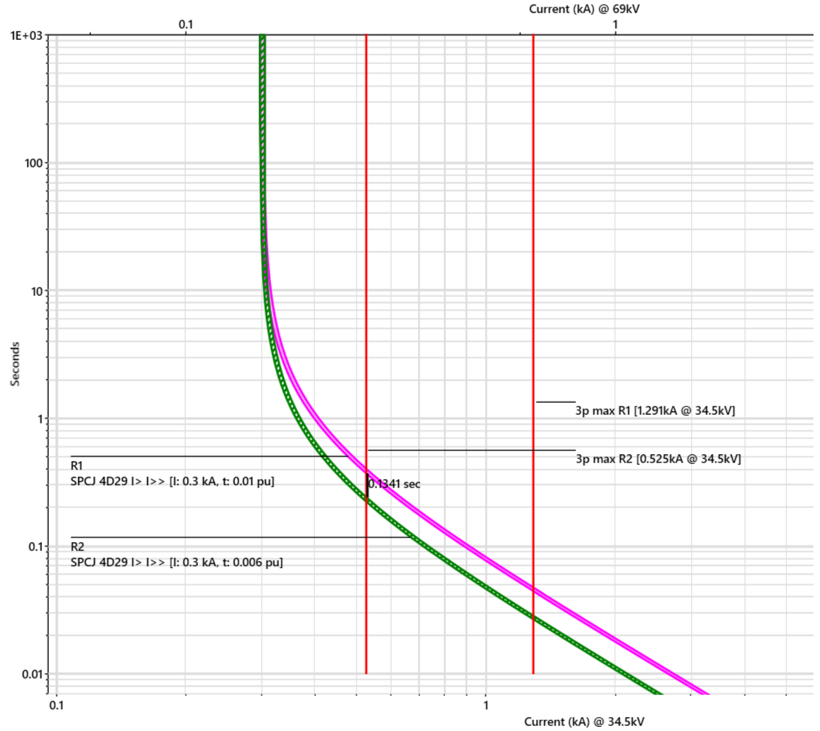




Base Case

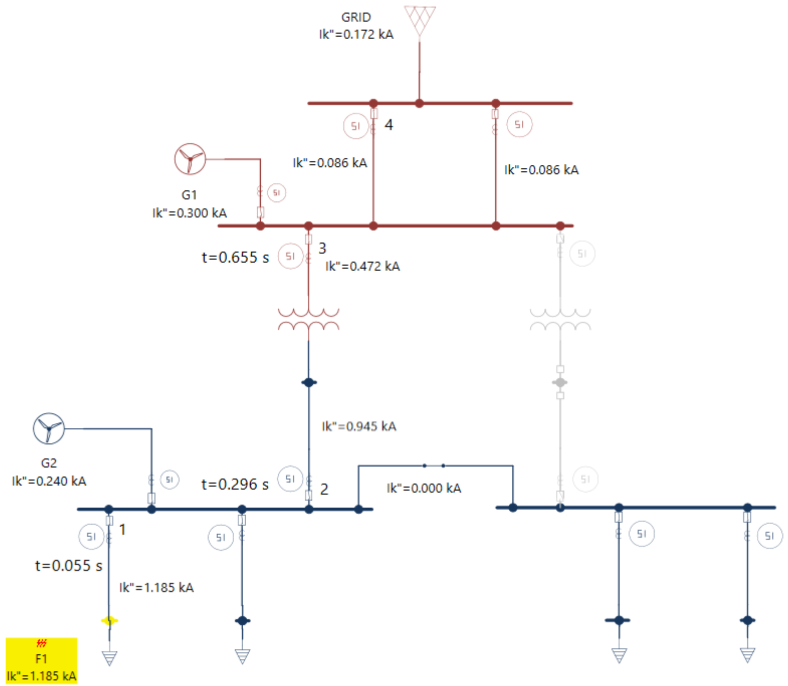
Illustration Case

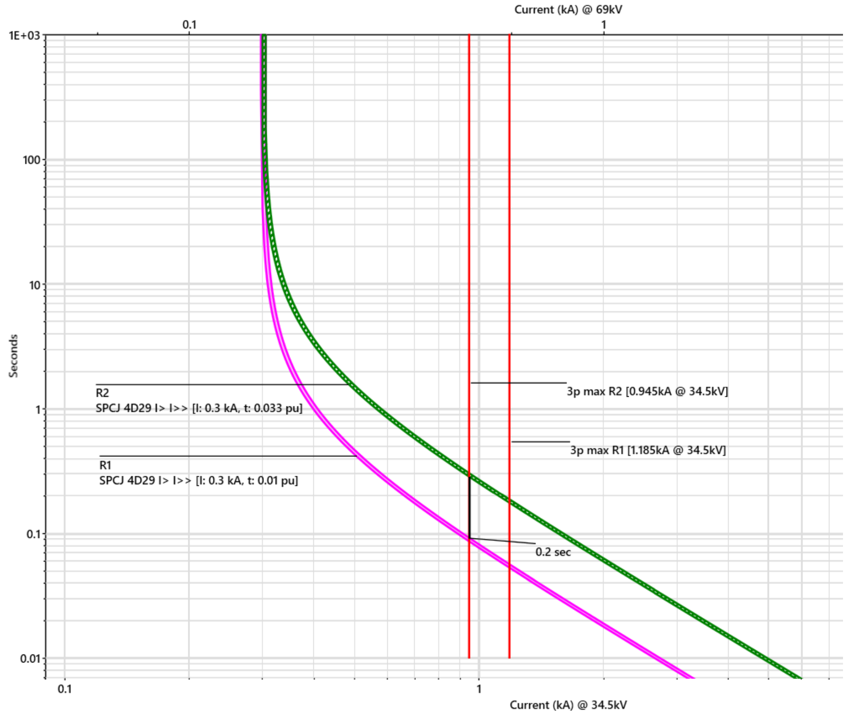




Base Case

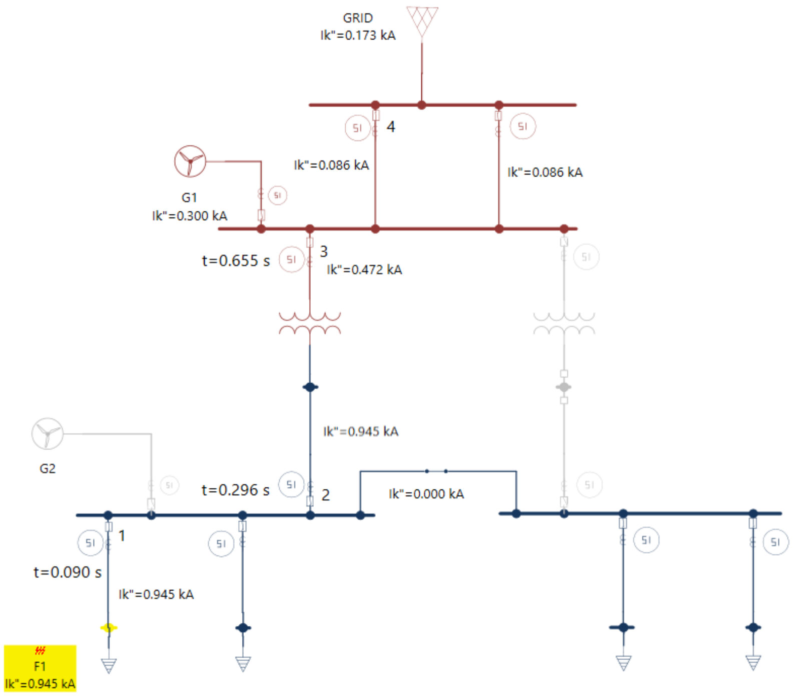
Illustration Case

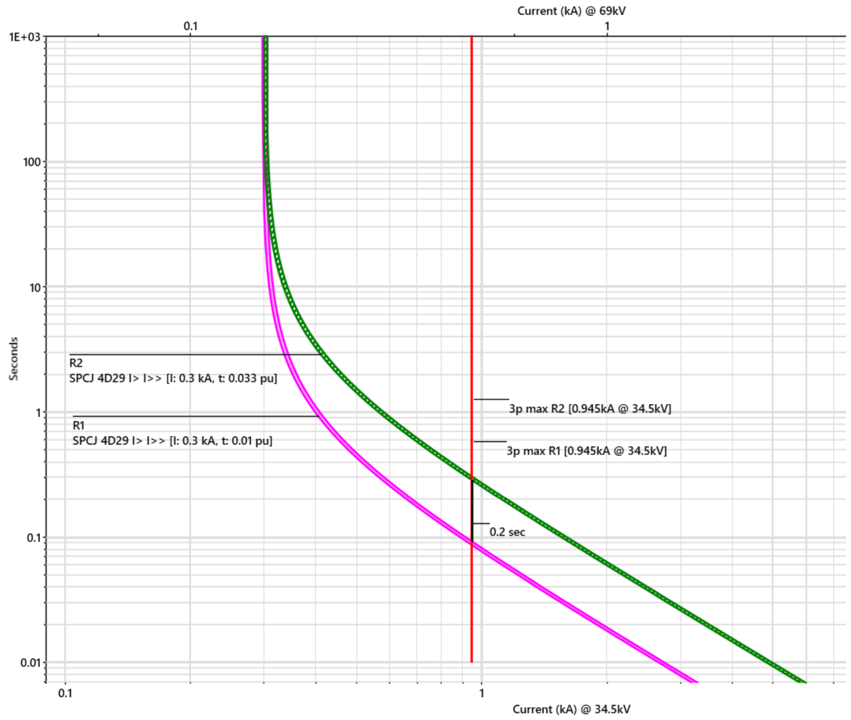




G2 Closed, T2 Open

Illustration Case

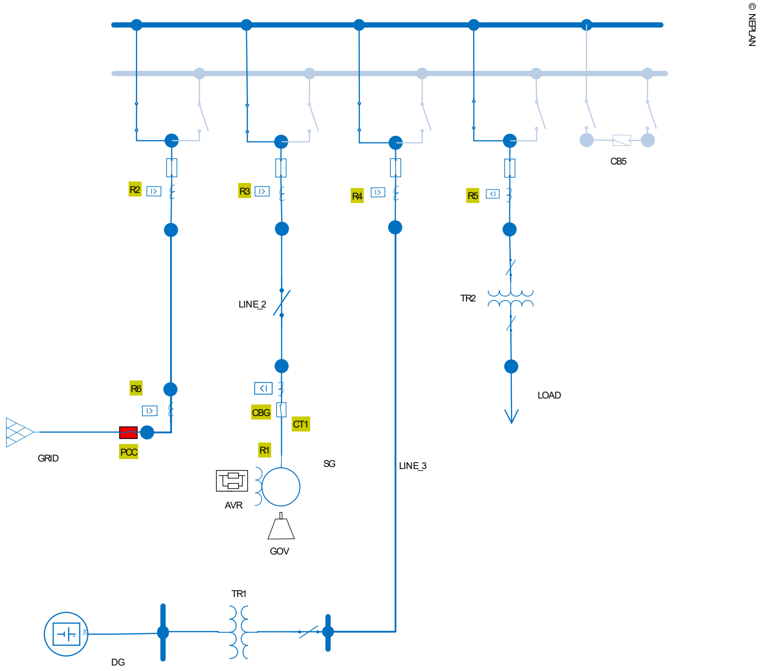




Open G2, Open T2

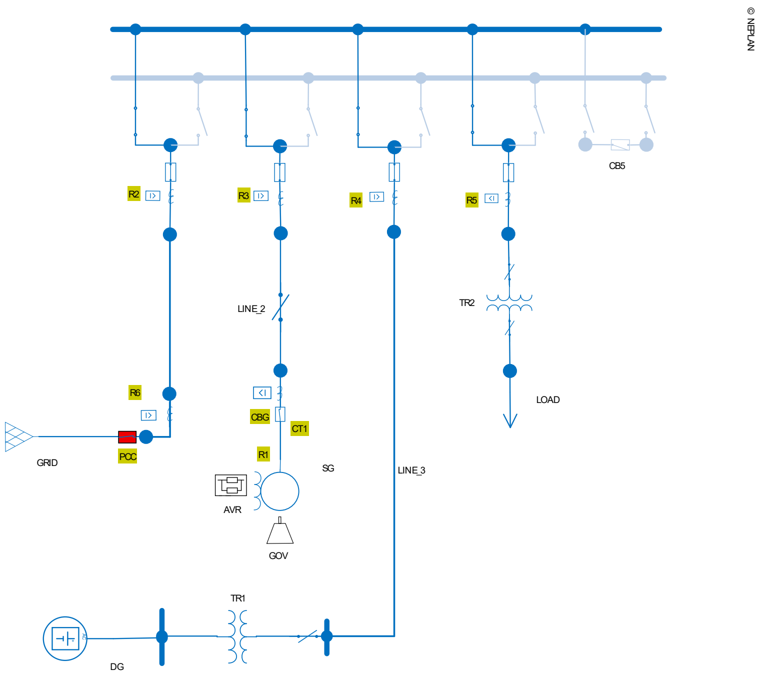
Protection Coordination in a Microgrid System

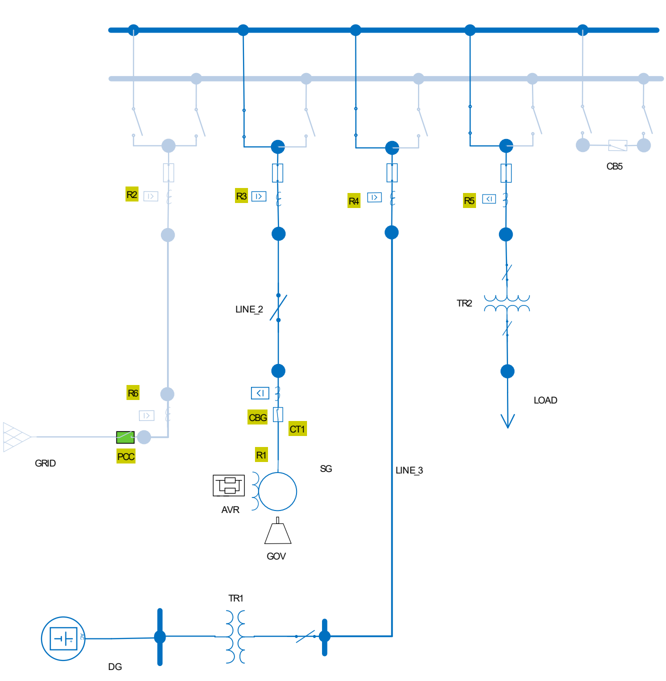
Power Element	Name	Rating Information
Synchronous Generator	SG	Voltage: 120/208 V, Current: 4.85 / 2.8 A, Power: 0.8 kW, RPM: 1800, Excitation System: 7.5 to 200 V_{DC}
Three Phase Inverter	DG	Adjustable power factor from 0.8 capacitive to 0.8 inductive. DC input voltage range: 250-1000V, MPP Voltage: 300 – 800 V, DC current max: 11A, Output voltage: 3x400V, Power output: 3.2 kW
Three Phase Autotransformer	TR1	Power: 2.5 kVA, Voltage: 400 / 208 V, Zcc=3%, Current: 3.608 / 6.939 A
Three Phase Transformer	Tr2	Power: 1 kVA, Voltage: 208V/ 208-120V, Zcc=2.3%, Current 2.776 A
Circuit Breaker	PCC	Remote with Power terminals, 52a and 52b contacts, trip and close coils.



System Description

Protection Coordination in a Microgrid System

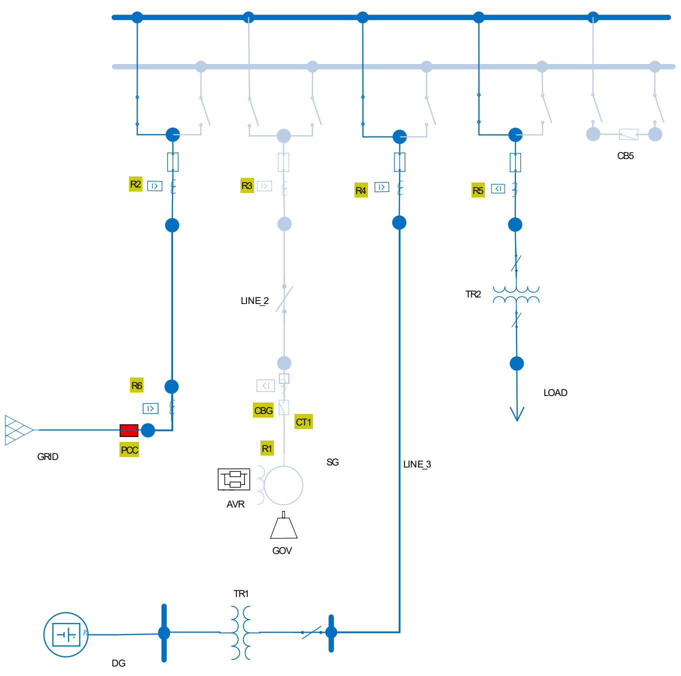




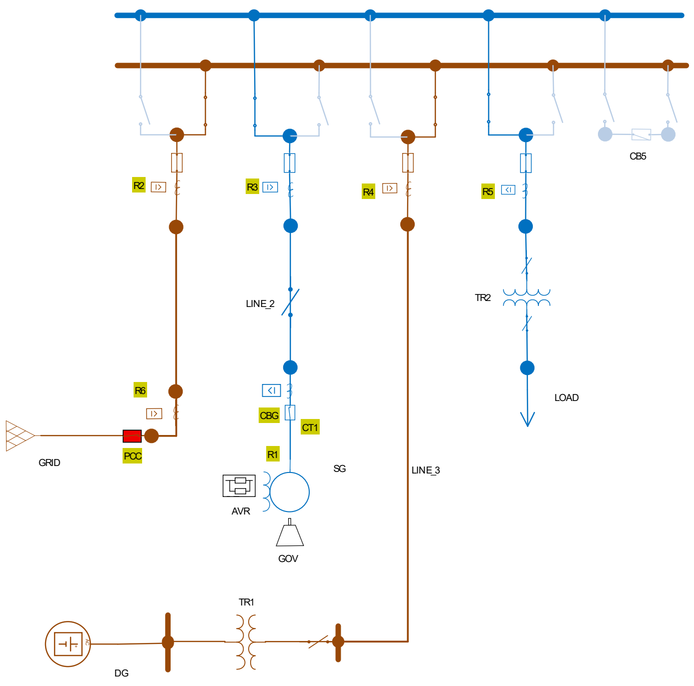
Connected Mode

Island Mode

Protection Coordination in a Microgrid System

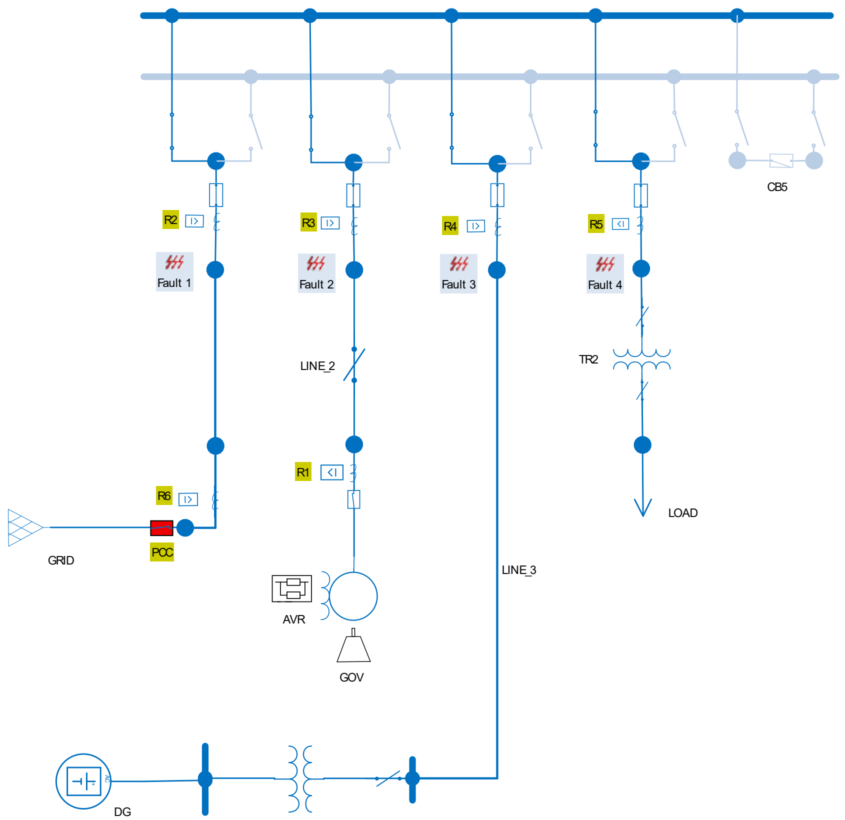


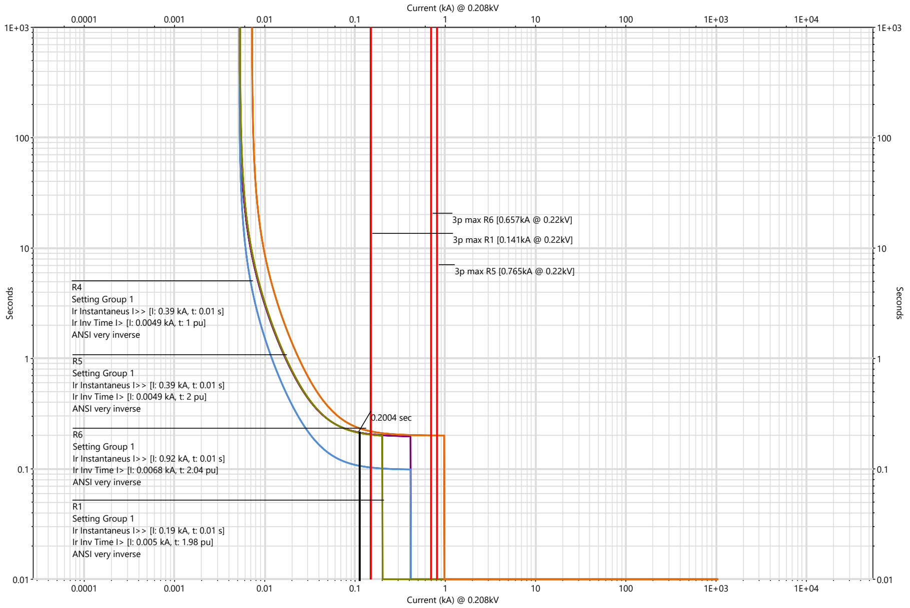
SG Off



Solar Export and Microgrid

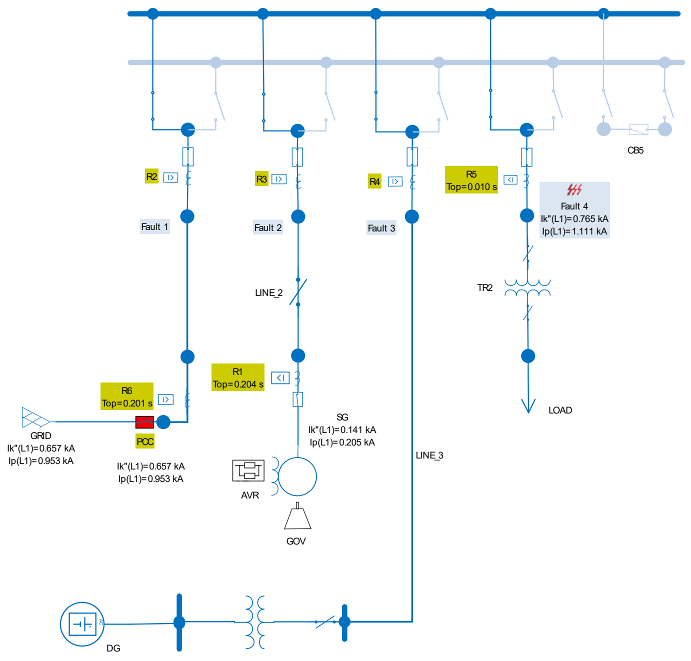
Protection Coordination in a Microgrid System

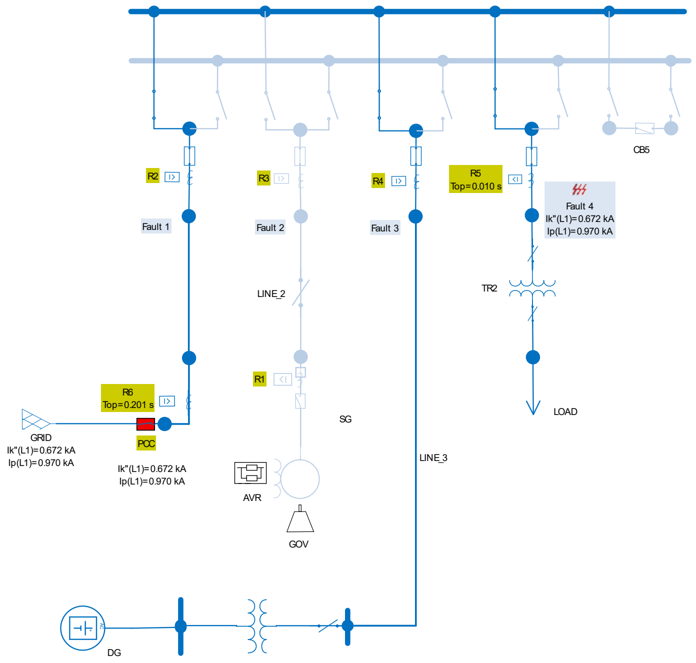




Fault	Primary Relays	Backup Relays
Fault 1	R2 and R6	R1
Fault 2	R3 and R1	R6
Fault 3	R4	R1 and R6
Fault 4	R5	R1 and R6

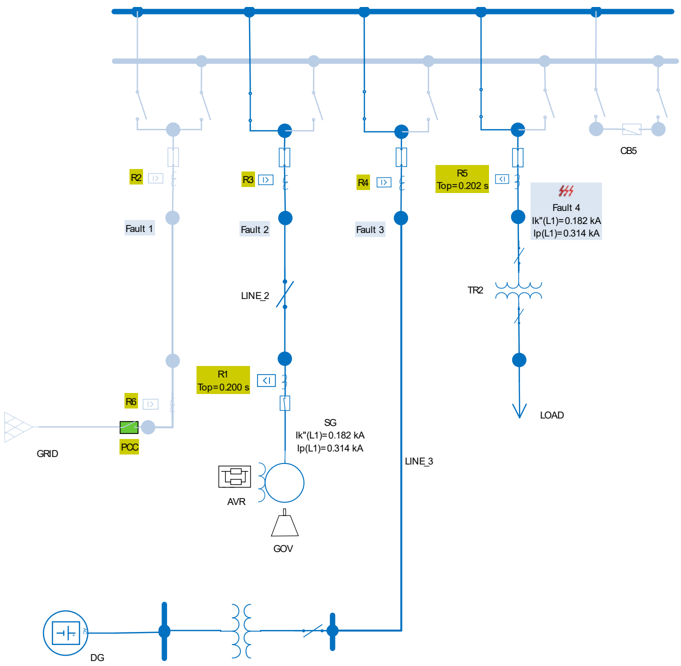
Protection Coordination in a Microgrid System

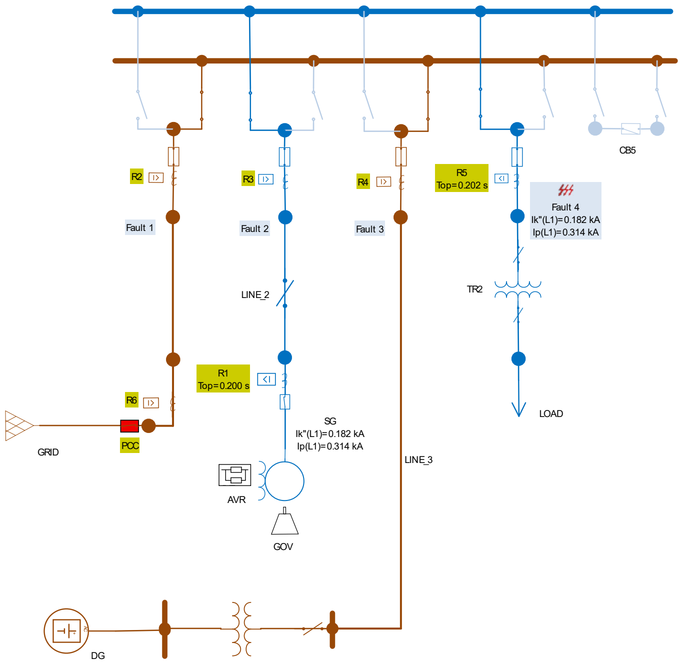




Sequence of operation with the external grid contribution at Fault 4

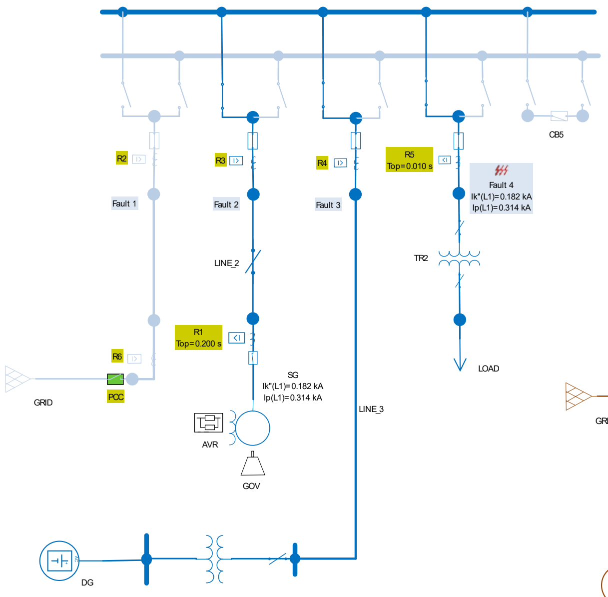
Protection Coordination in a Microgrid System

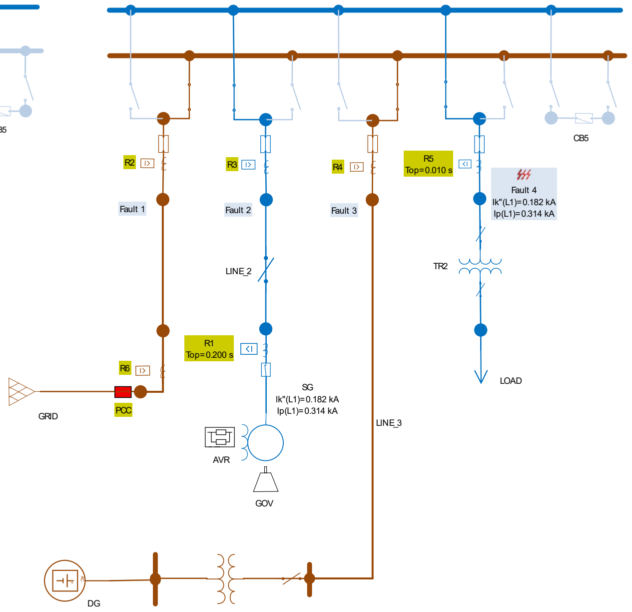


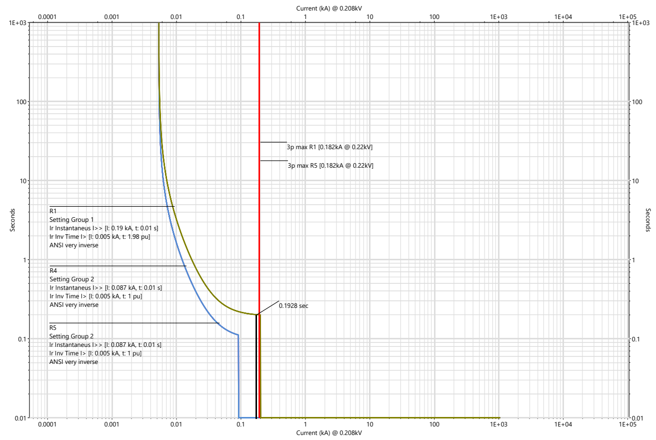


Loss of selectivity without the external grid contribution at Fault 4

Protection Coordination in a Microgrid System



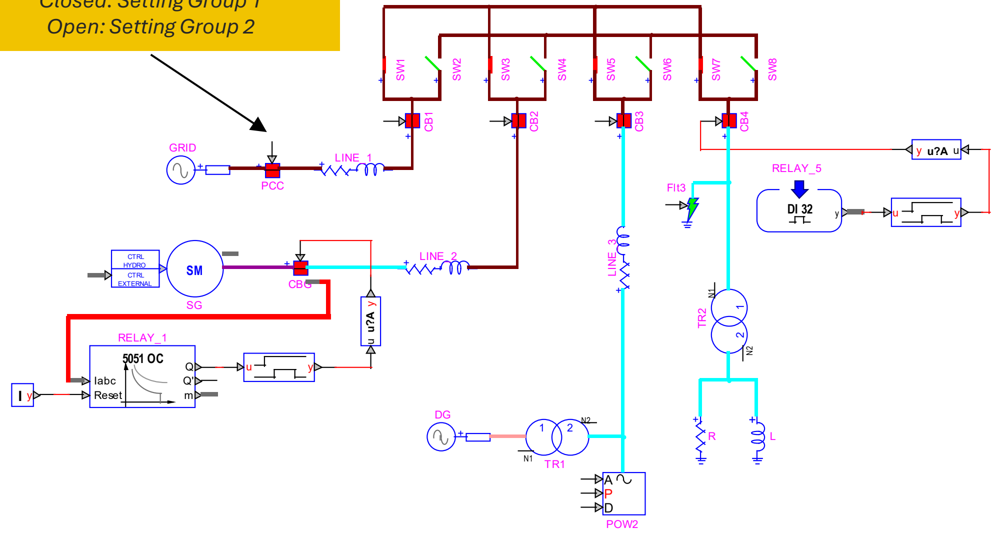




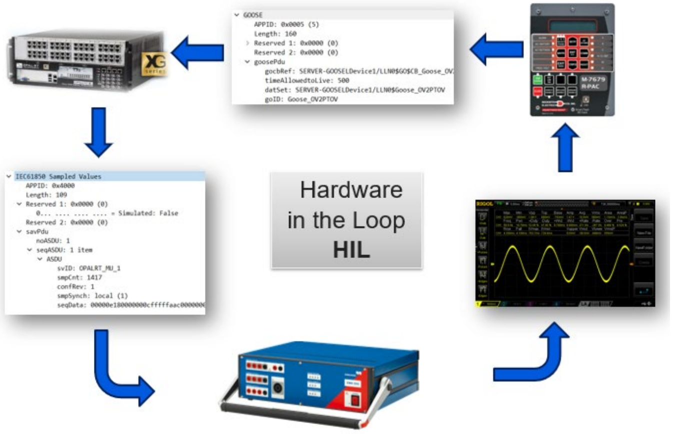
Sequence of operation with Setting Group 2 for Fault 4 without the external grid contribution

Hardware In the Loop Test

Relay 5 will change the setting group depending on the PCC status (GOOSE Subscription).
Closed: Setting Group 1
Open: Setting Group 2



Model in HYPERSIM



HIL Test Configuration

Questions?