GE Digital Energy Multilin

Fundamentals of Modern Protective Relaying

Your Presenters

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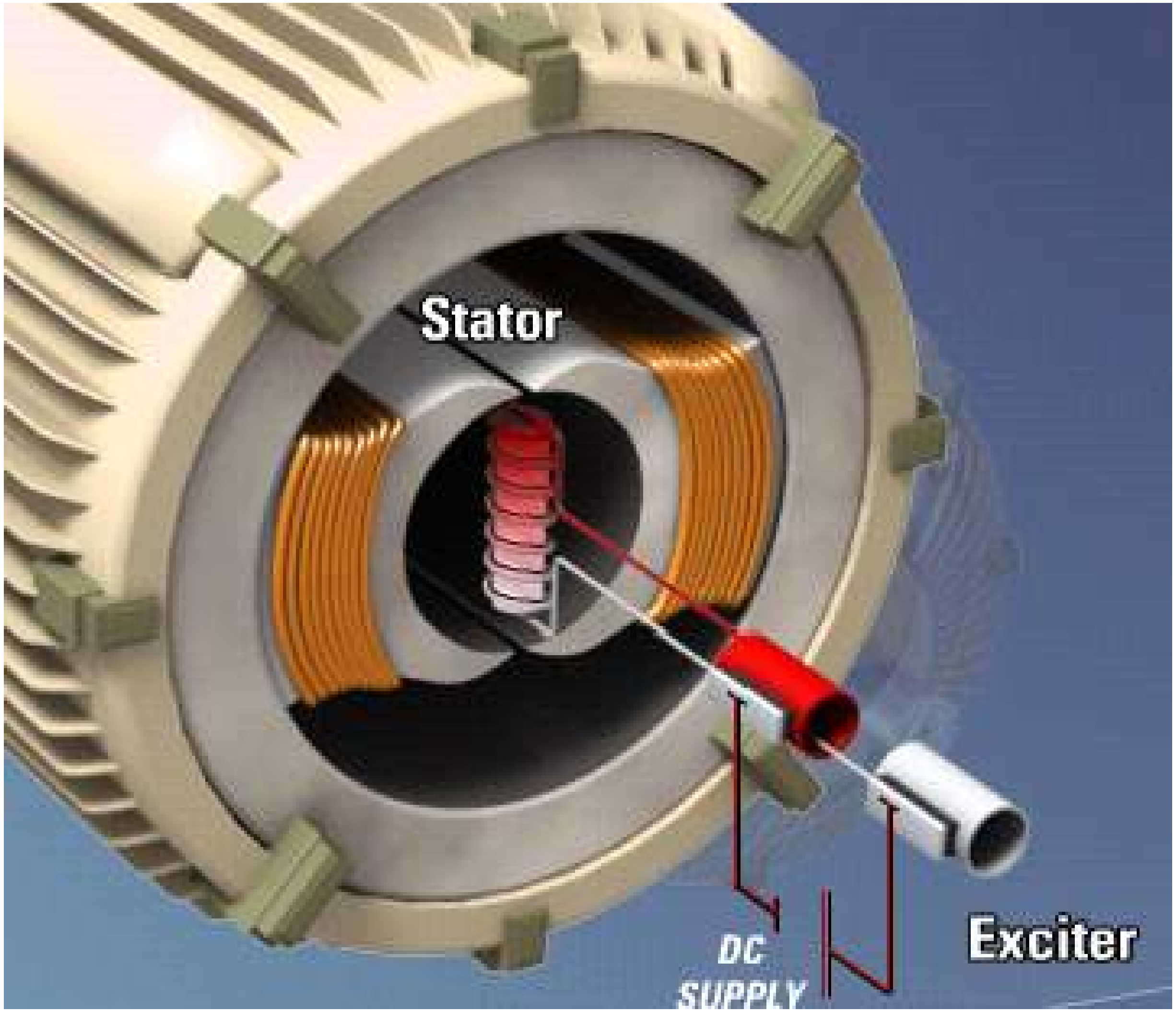
Course Agenda

- Generator Protection
  - Generator basics
  - Types of generator grounding
  - Stator differential
  - Ground faults
  - Ground directional
  - Negative sequence unbalance
  - Low forward power and reverse power
  - Accidental energization
  - Loss of excitation
  - Volts/Hz
  - Under and overfrequency
- Fundamentals of Industrial Communications
  - Distance protection theory
  - Step distance and pilot aided schemes
  - Line current differential protection

Course Agenda

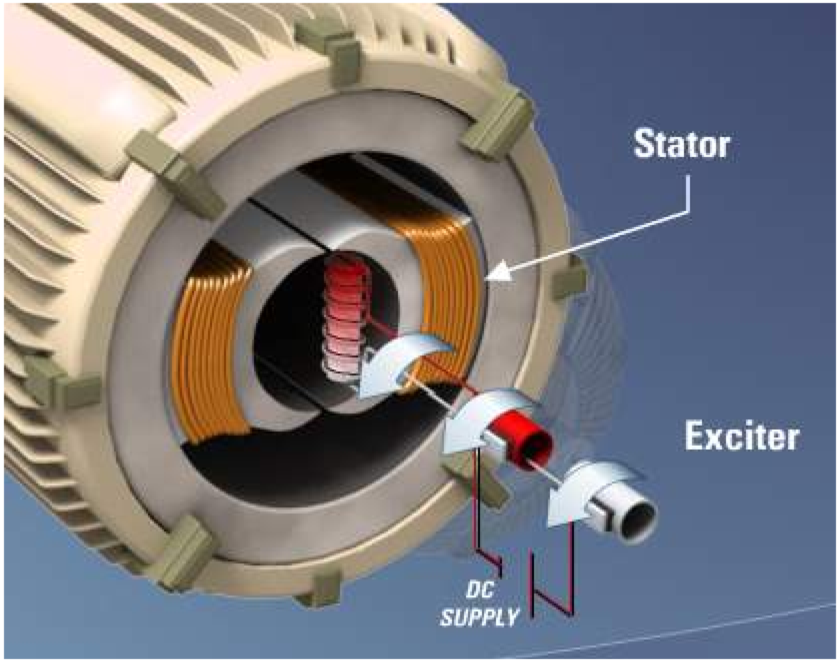
- Arc Flash Protection
  - Introduction
  - Relay based techniques
  - Light based technique

Generator Protection

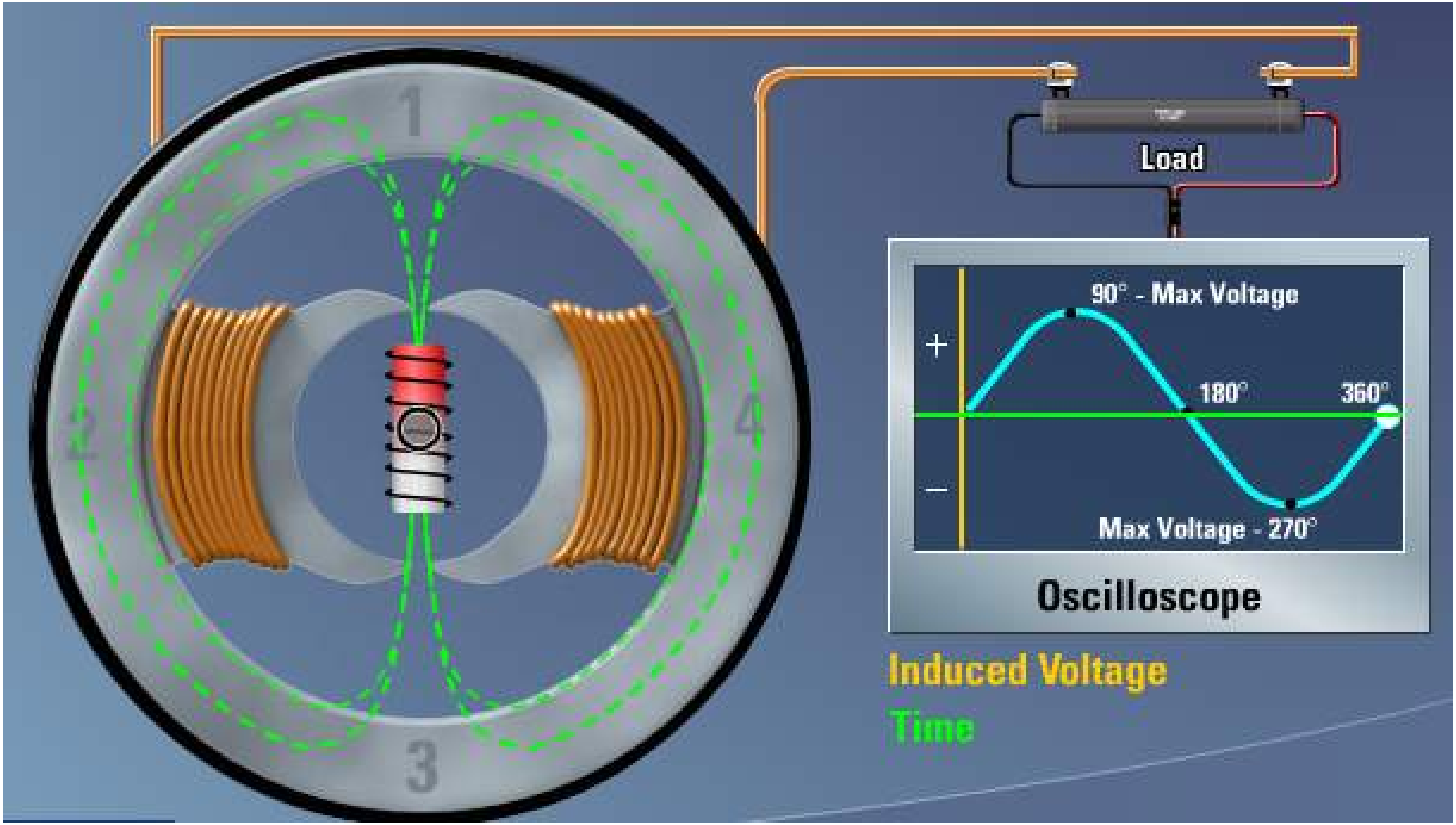


Single Phase AC Generator:

- Exciter – electromagnet rotating about its axis
- Stator – 2 electromagnets or poles wired in series to a load

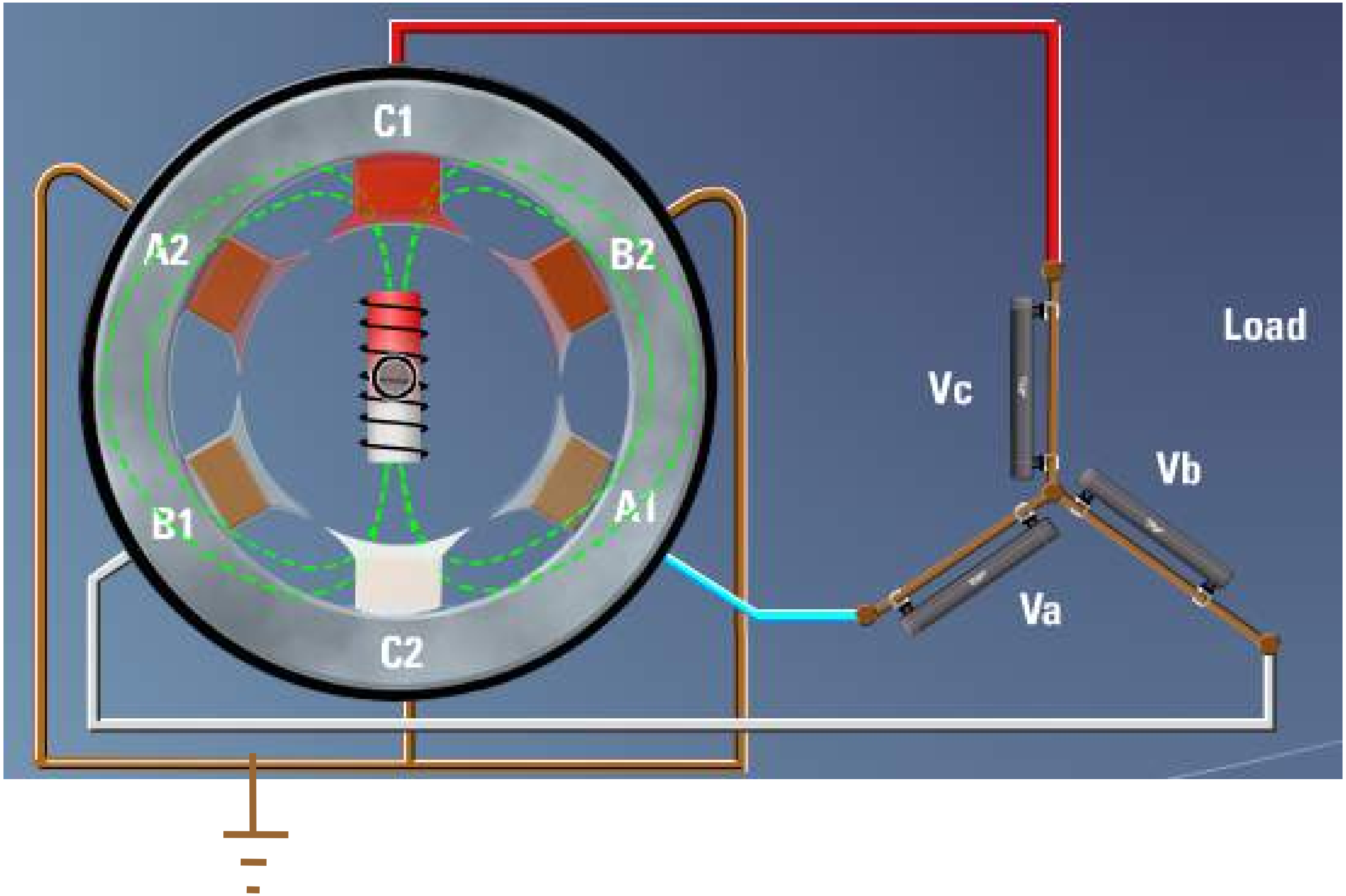


Single Phase AC Generator Theory of Operation:



Three-Phase AC Generator Theory of Operation:

Three-Phase AC Generator Theory of Operation:

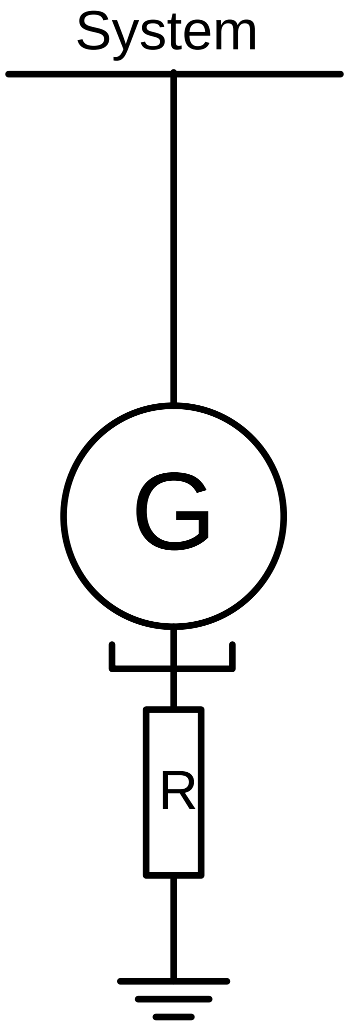


Review of Grounding Techniques

Grounding Provides:

- Improved safety by allowing detection of faulted equipment
- Stop transient overvoltages
  - Notorious in ungrounded systems
- Ability to detect a ground fault before a multiphase to ground fault evolves
- If impedance is introduced, limit ground fault current and associated damage faults
- Provide ground source for other system protection (other zones supplied from generator)

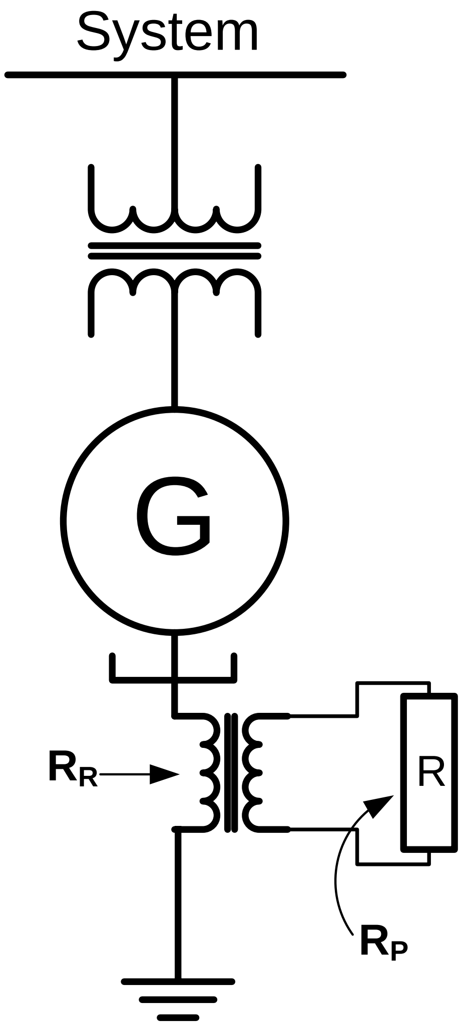
Types of Generator Grounding



Low Impedance

- Provides a ground source for the system
- Can get expensive as resistor rating goes up
- Generator will be damaged on internal ground fault
  - Ground fault current typically 200-400 A

Types of Generator Grounding

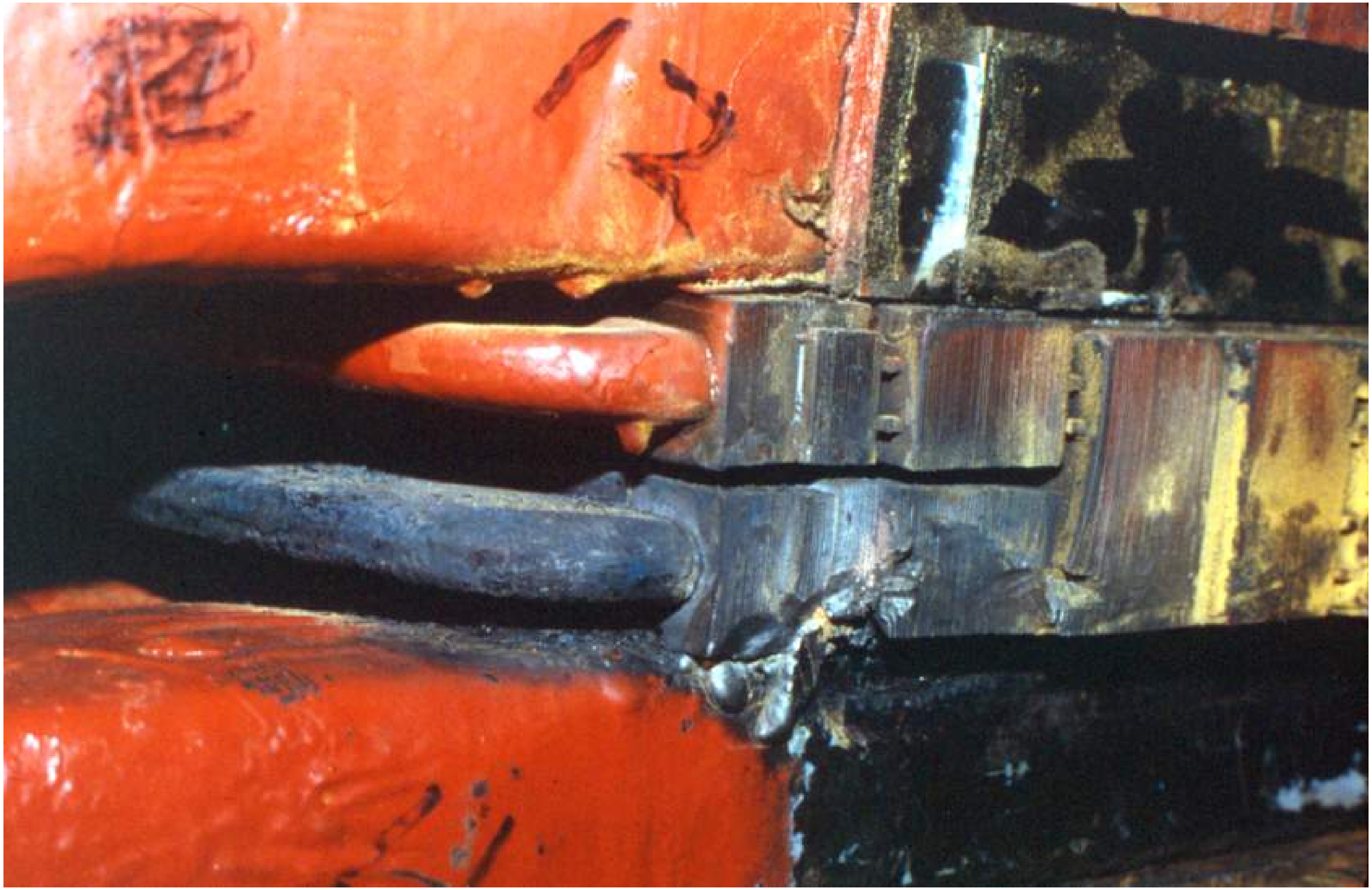


High Impedance

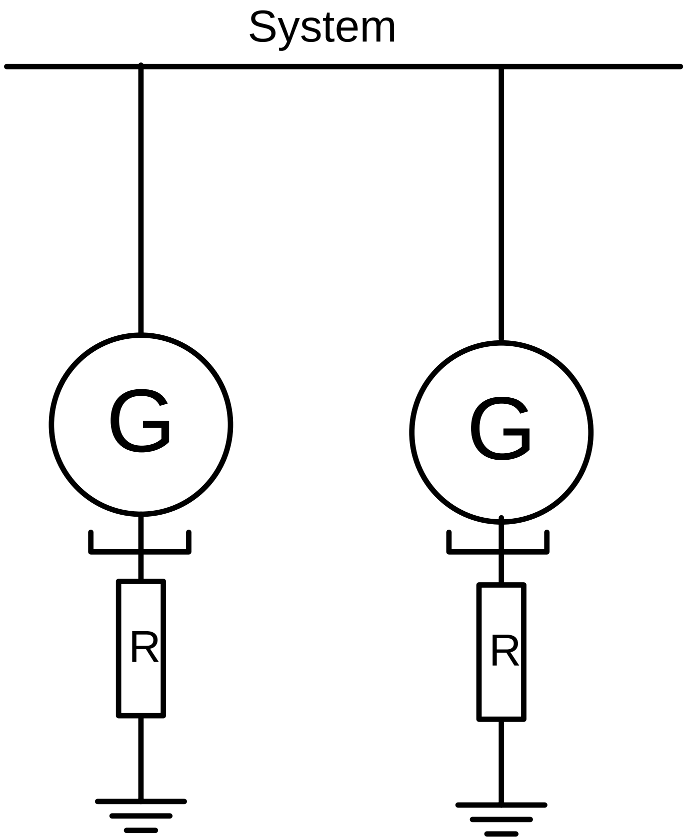
- System ground source obtained from generator step-up transformer
- Uses principle of reflected impedance
  - Eq: $R_R = R_P * [V_{sec}/V_{pri}]^2$
    - Where R_R = Resistance Reflected and R_P = Resistance Primary
- Generator damage minimized or prevented from ground fault
  - Ground fault current typically <=10A

Burning Stator Iron

- Following pictures show stator damage after an internal ground fault
- This generator was high impedance grounded, with the fault current less than 10A
- Some iron burning occurred, but the damage was repairable
- With low impedance grounded machines the damage is more severe

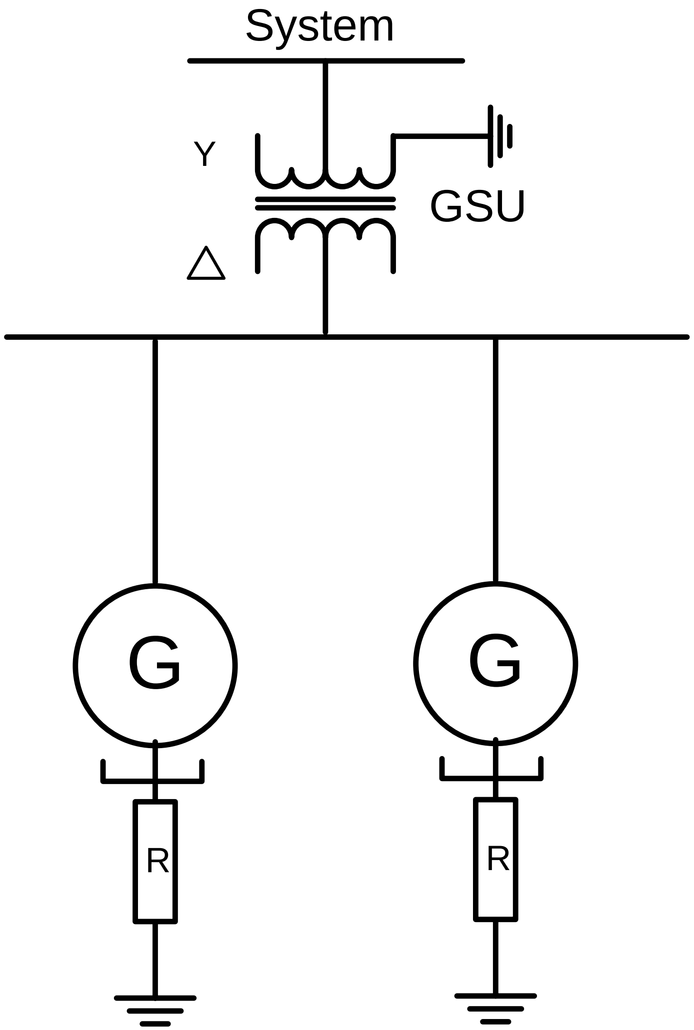


Bus Connected



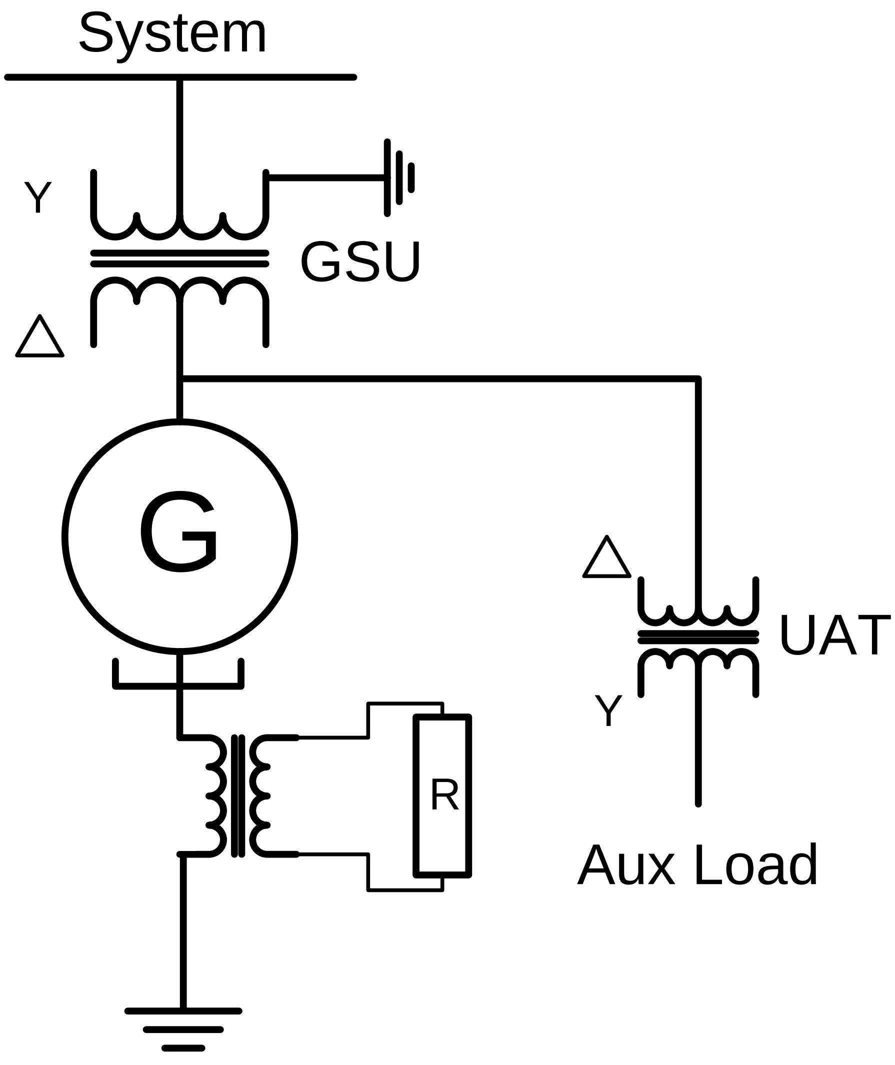
- No transformer between generator and power system bus
- Typically low impedance grounded for selectivity on internal ground faults

Connections: Sharing Transformer



- Transformer between paralleled generators and system
- Typically low impedance grounded for selectivity on internal ground faults

Connections: Unit Connected



- Transformer between generators and system
- Typically high impedance grounded for damage minimization
- Delta GSU (generator step-up) and UAT (unit auxiliary transformer) windings are used on the generator output to isolate from system ground

Normal Generator Operation & Power System Interaction

Normal Operation

Generator connected to system with multiple lines

System consists of load and other generation

System voltage varies with loading

> Excitation control will adjust to system voltage/VAr requirements within machine capability

Output will normally be near full rating for best efficiency

> Prime mover control will adjust to system frequency requirements within machine capability

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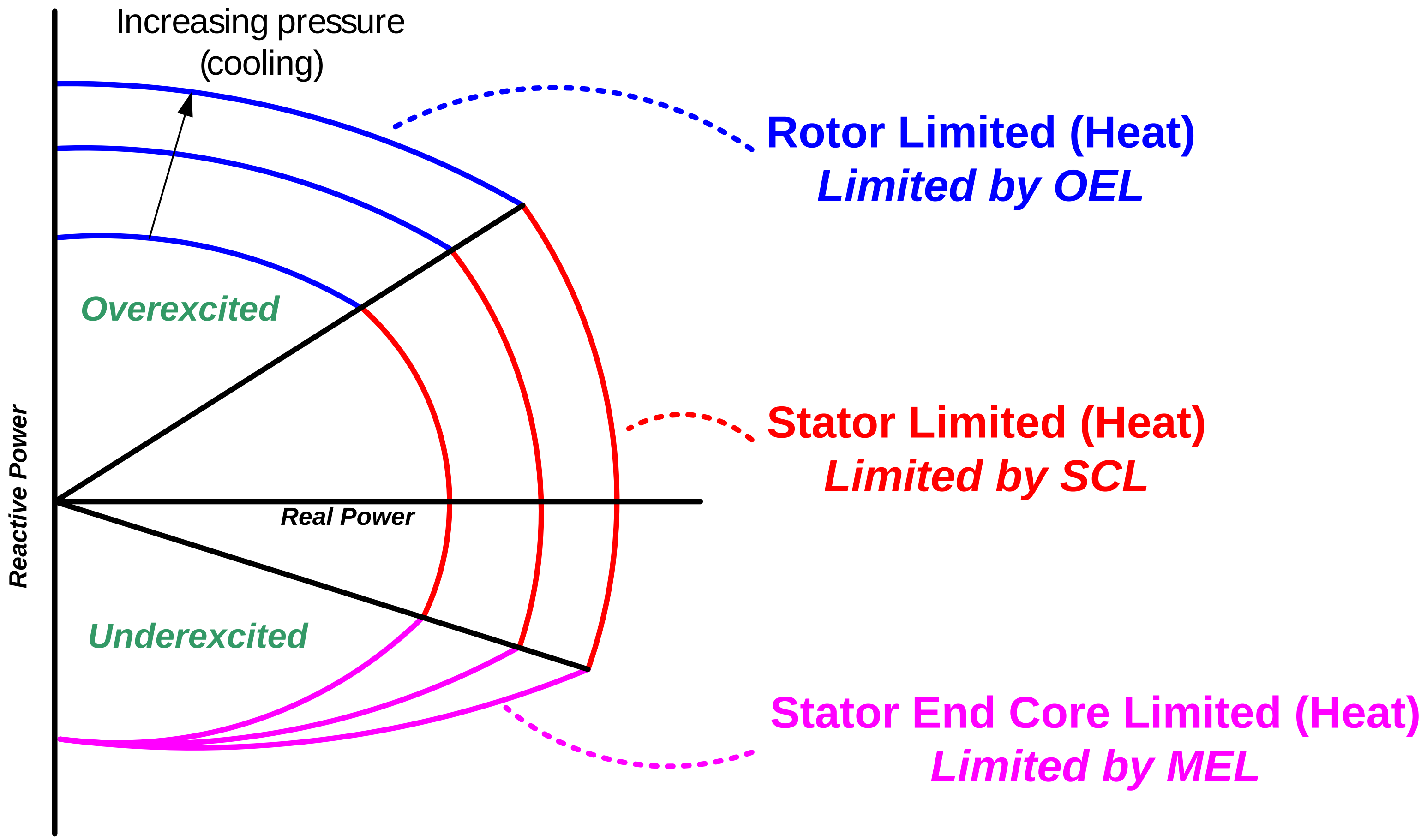
Machine Limits



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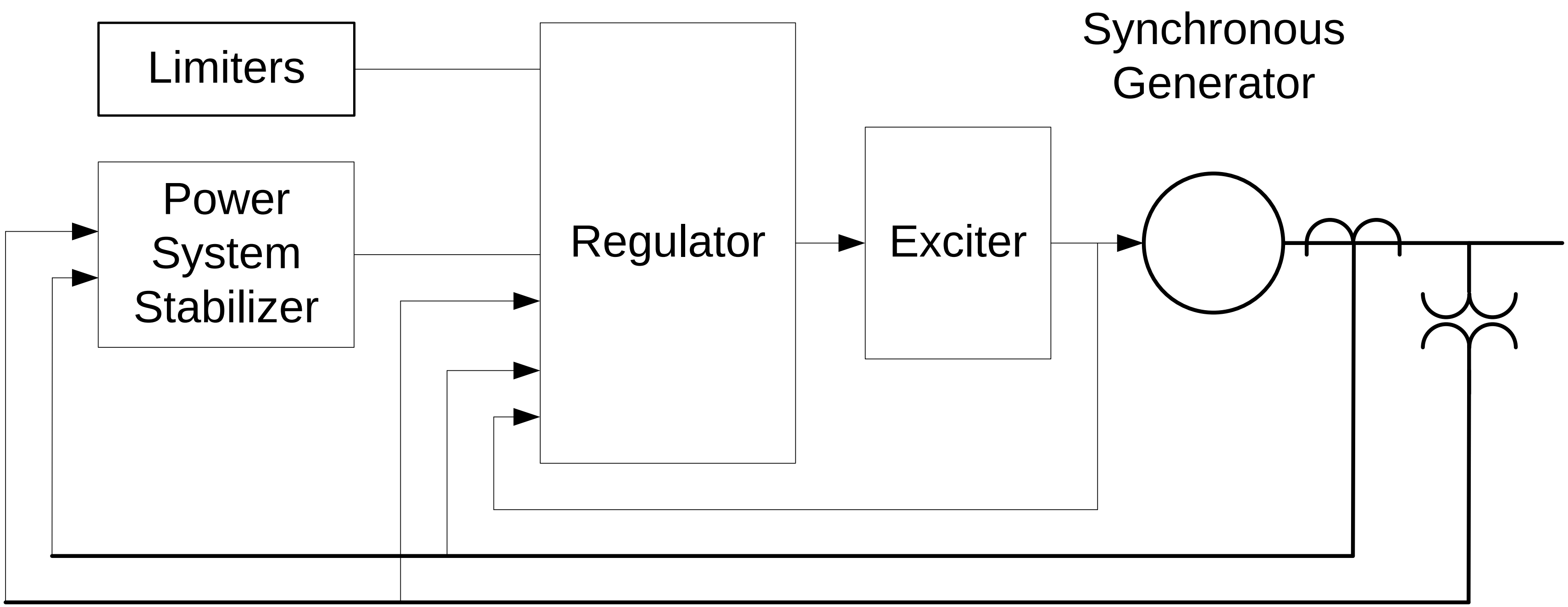
Excitation Control



Control for off-line operation (synchronizing) and on-line (grid interconnected)

Over- and under-excitation limiters control when power system is in abnormal state

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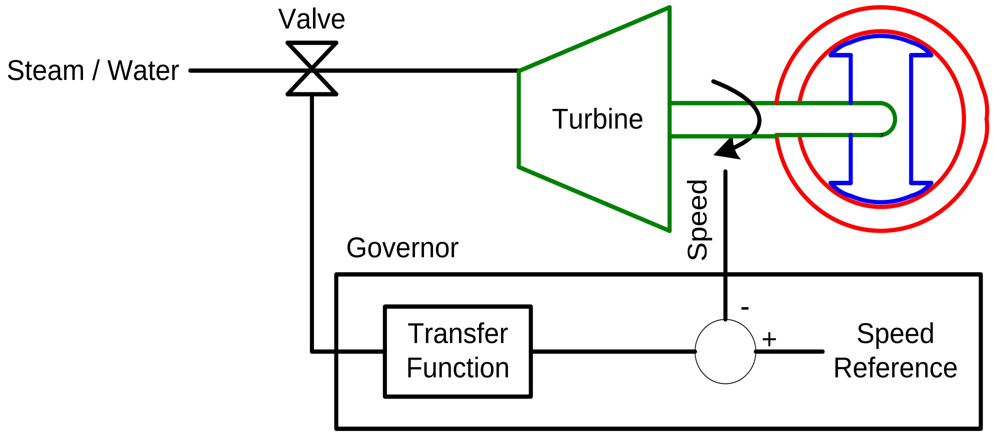
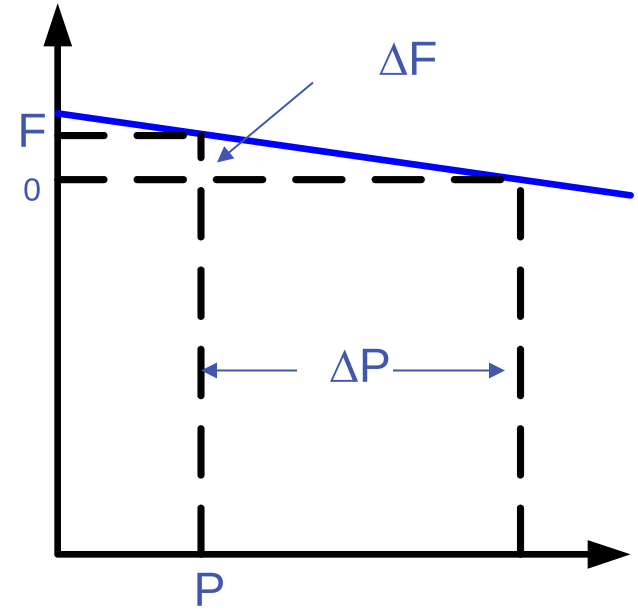
Turbine Control



$$\frac{d\omega}{dt} = \frac{1}{J} \cdot \left(T_m - T_e\right)$$



Speed - Droop

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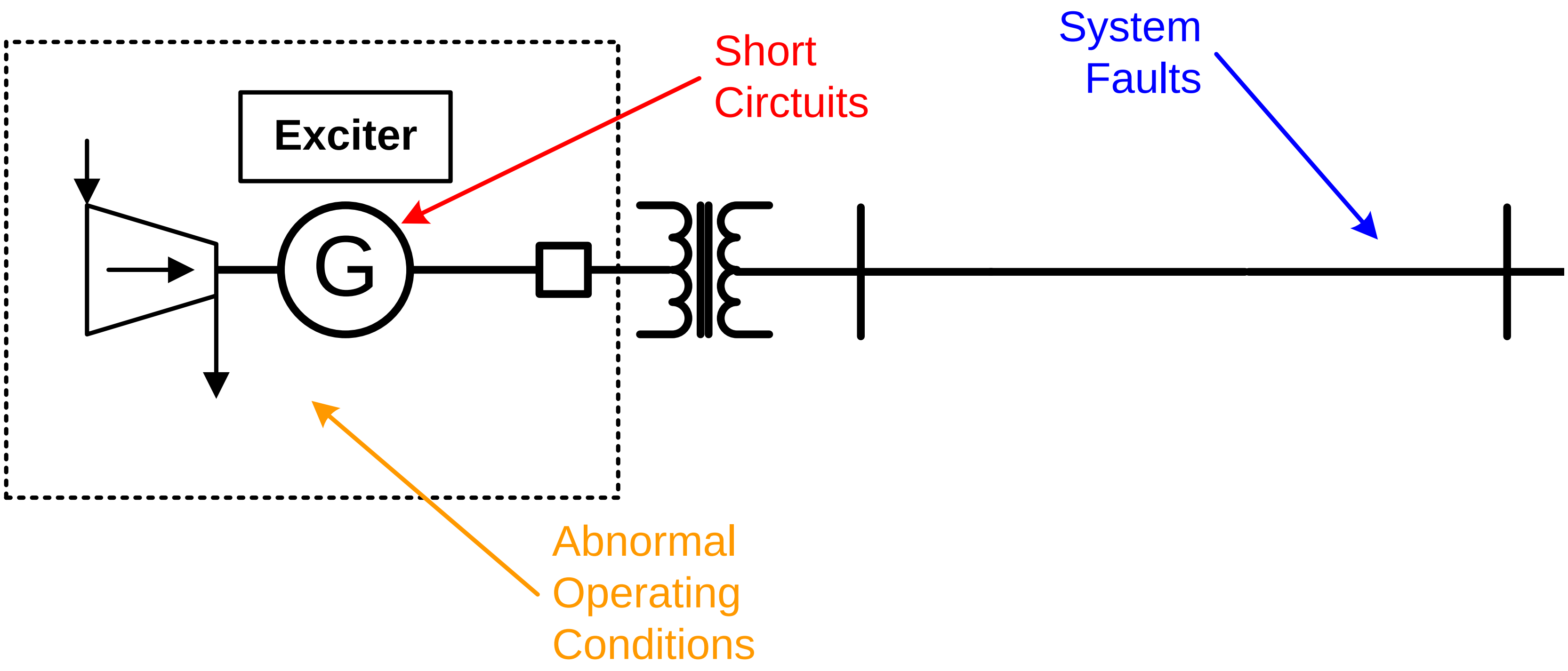
Generator Protection

Overview



Internal and External Short Circuits

Electrical Failures

Stator ground faults: 59G, 51G, 87G

Stator phase faults: 87

Interturn faults: 50SP

Rotor ground faults: 64F

Abnormal Conditions

Loss of Excitation: 40

Loss of Prime Mover: 32

Overexcitation: 24

Overvoltage: 59

Off-nominal Frequency: 81

Accidental Energization: 50-27

Out-of-Step: 78

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System Backup

Generator Unbalance: 46

System Phase Faults: 21P, 51V

System Ground Faults: 51TG

Generator Breaker Failure: 50BF

ANSI/IEEE Standards

- Std. 242: Buff Book
- C37.102: IEEE Guide for Generator Protection
- C37.101: IEEE Guide for AC Generator Ground Protection
- C37.106: IEEE Guide for Abnormal Frequency Protection for Power Generating Plants
- C37.110: IEEE Guide for the application of current transformers used for protective relaying purposes

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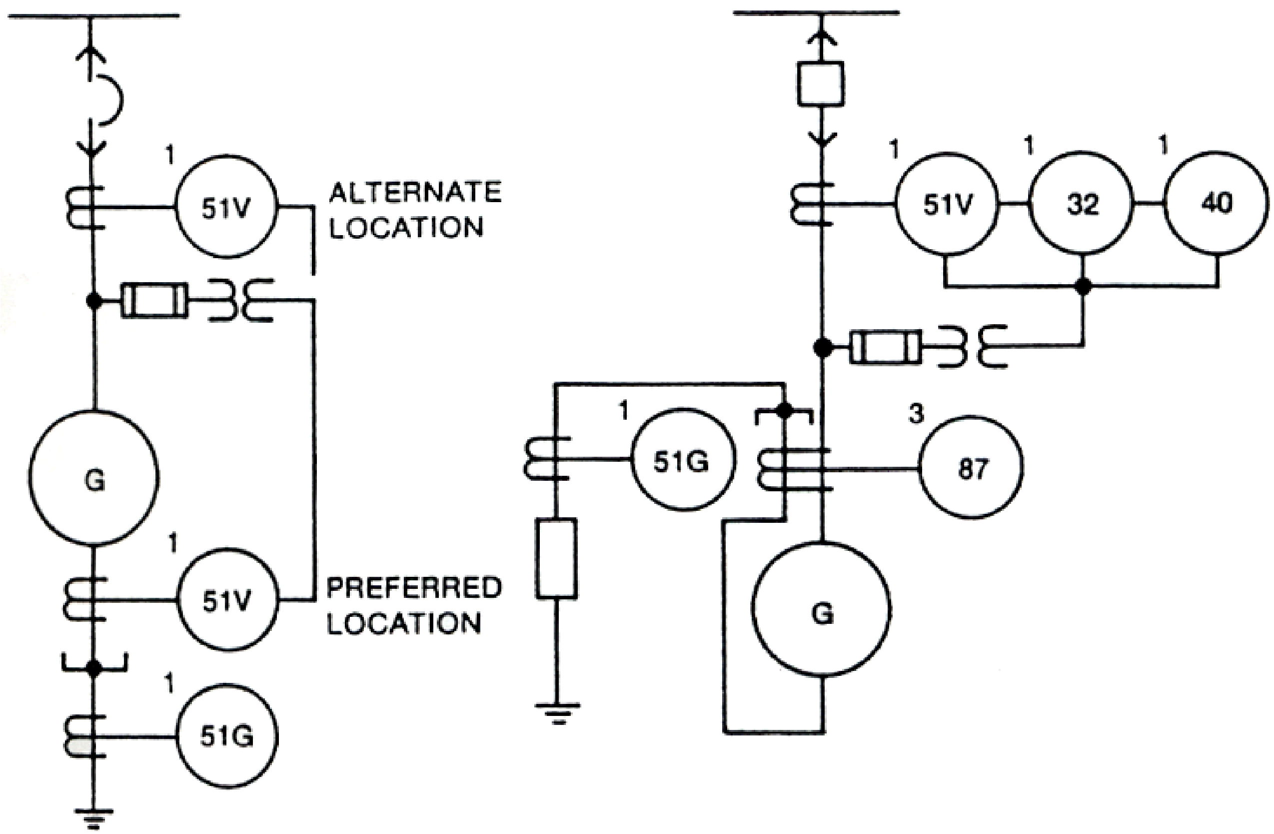
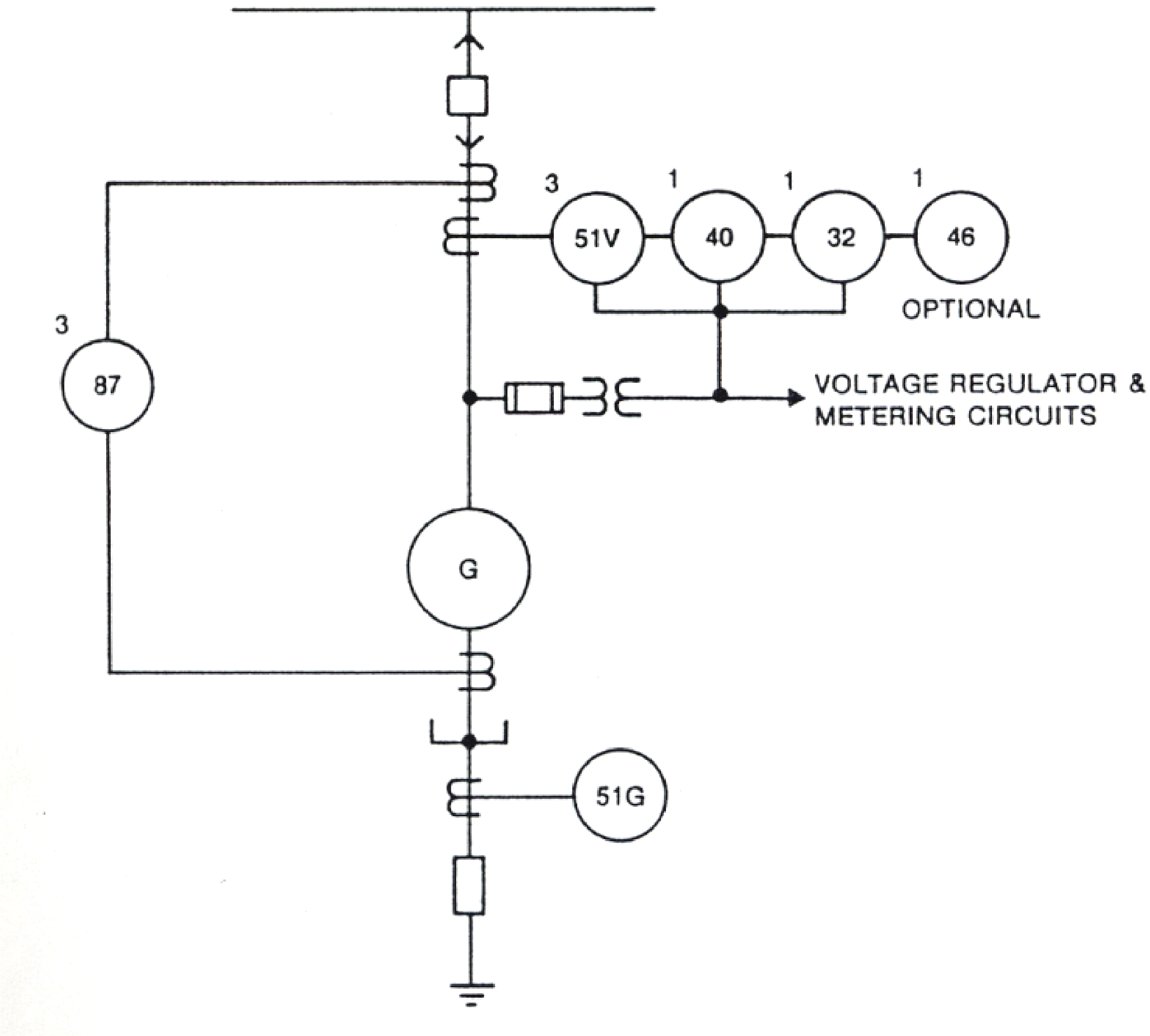
IEEE Buff Book



Small – up to 1 MW to 600V, 500 kVA if >600V

IEEE Buff Book



Medium – up to 12.5 MW

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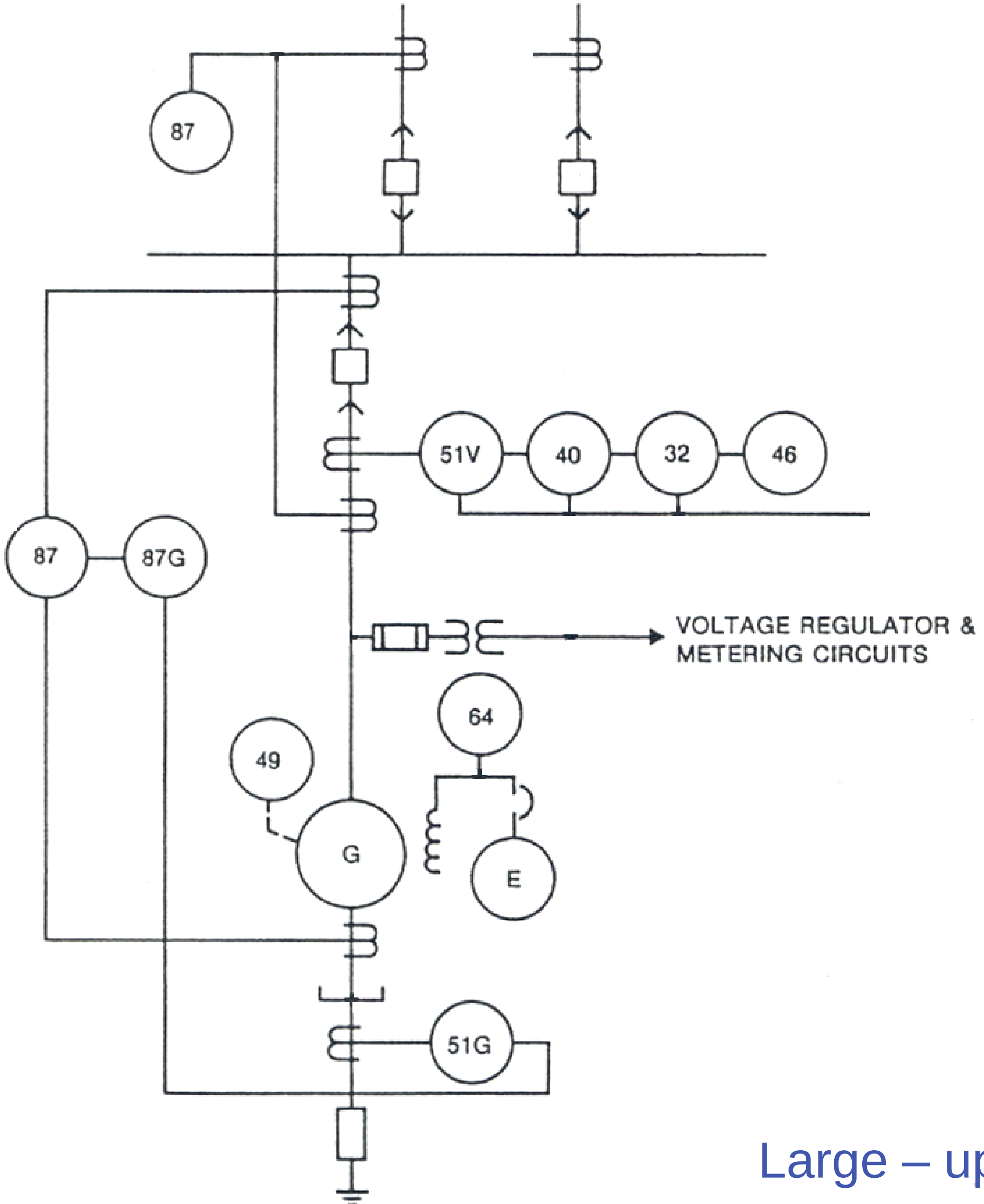
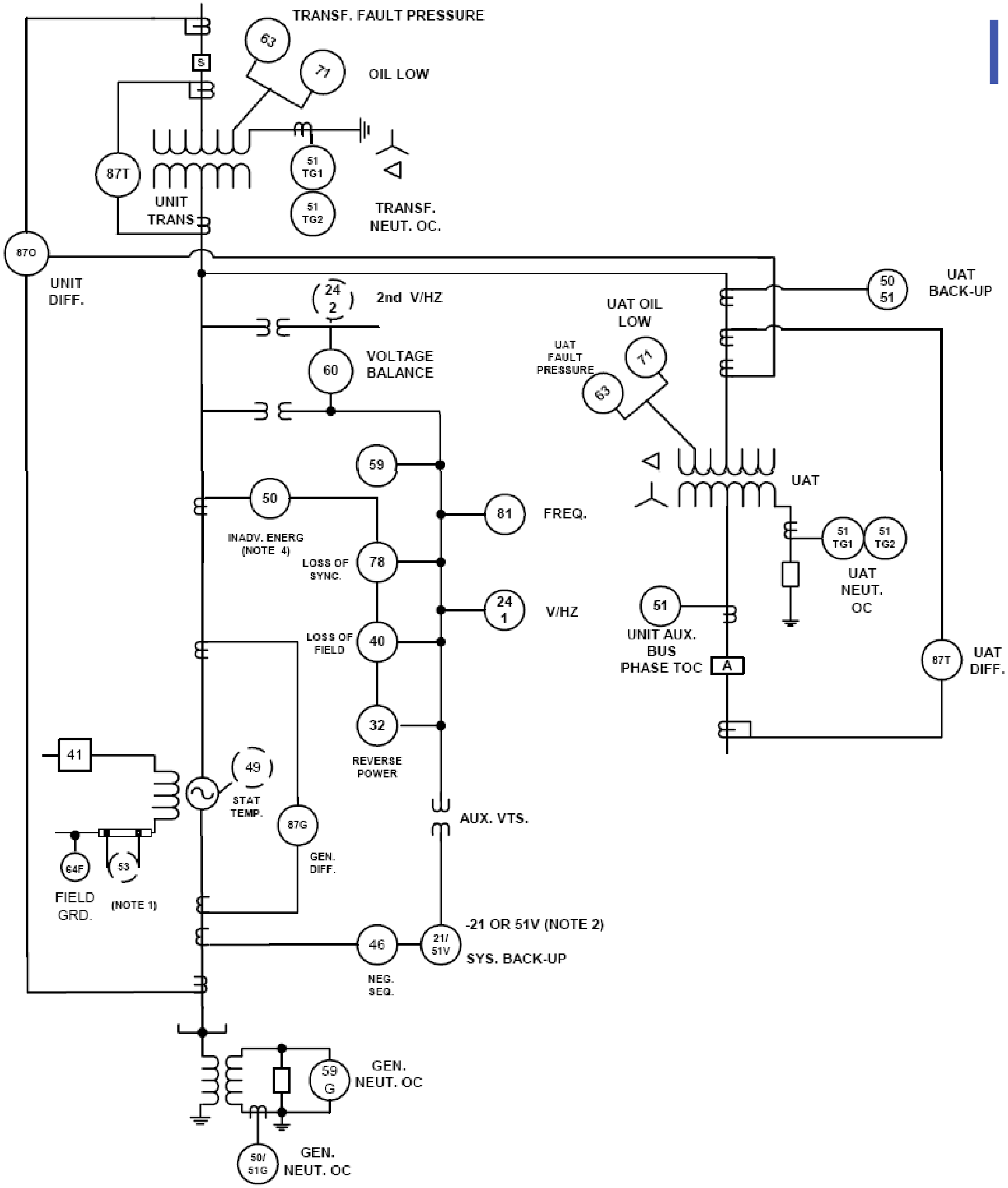
IEEE Buff Book

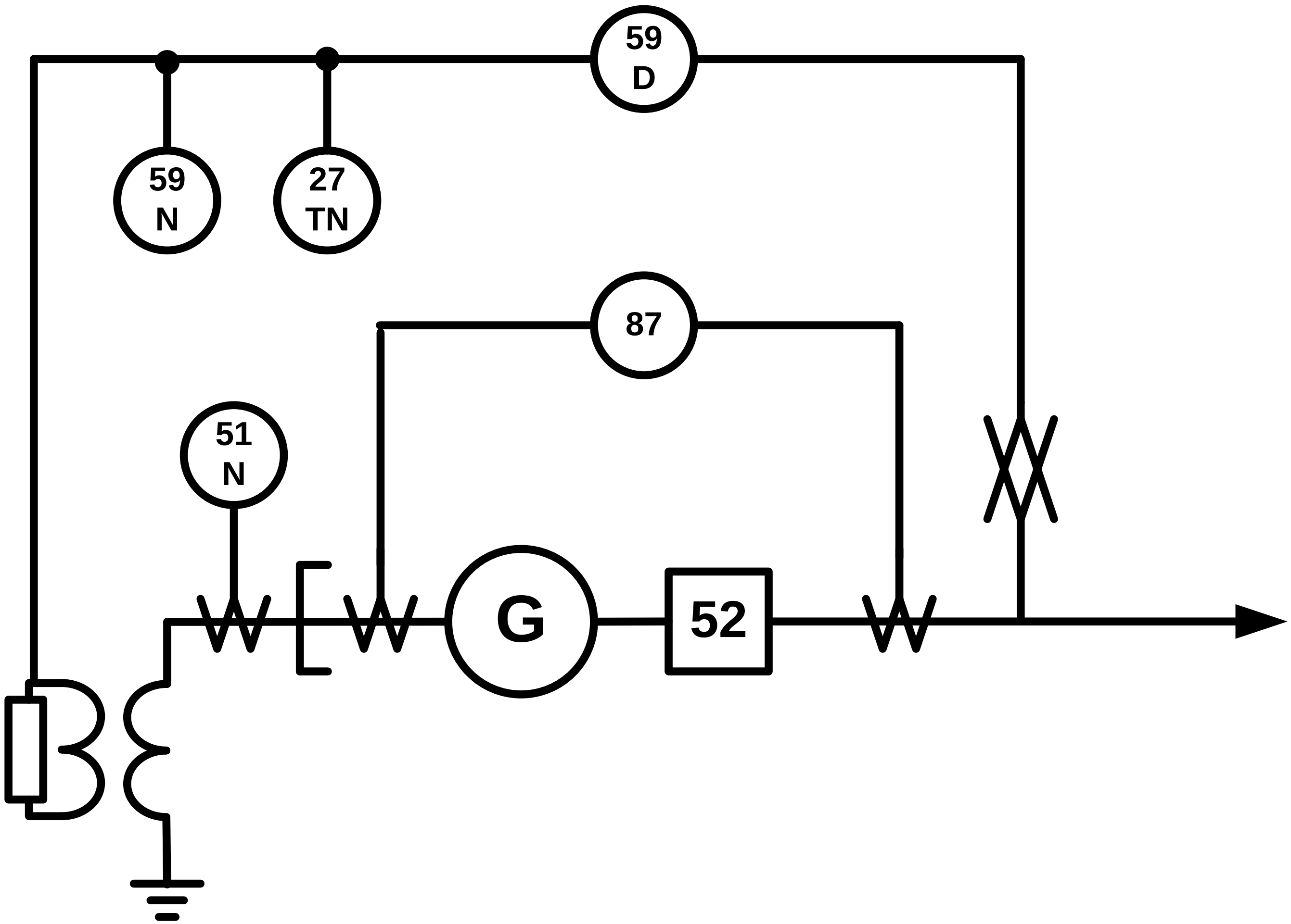


Large – up to 50 MW

IEEE C37.102


TRANSF. FAULT PRESSURE
63
71
OIL LOW
S
87T
UNIT
TRANS
51
TG1
51
TG2
TRANSF.
NEUT. OC.
87O
UNIT
DIFF.
24
2
2nd V/HZ
60
VOLTAGE
BALANCE
UAT OIL
LOW
UAT
FAULT
PRESSURE
71
63
50
51
UAT
BACK-UP
UAT
59
50
INADV. ENERG
(NOTE 4)
81
FREQ.
78
LOSS OF
SYNC.
24
1
V/HZ
40
LOSS OF
FIELD
32
REVERSE
POWER
51
TG1
51
TG2
UAT
NEUT.
OC
51
UNIT AUX.
BUS
PHASE TOC
A
87T
UAT
DIFF.
41
49
STAT
TEMP.
87G
GEN.
DIFF.
AUX. VTS.
64F
53
FIELD
GRD.
(NOTE 1)
-21 OR 51V (NOTE 2)
46
NEG.
SEQ.
21/
51V
SYS. BACK-UP
59
G
GEN.
NEUT. OC
50/
51G
GEN.
NEUT. OC

Electrical Failures



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Stator Ground Fault: High-Z, Unit Connected Machines

59N

- 95% coverage of winding from terminal end
- Tuned to the fundamental frequency

27TN

- 5-15% coverage from the neutral end
- Responds to the Neutral 3rd Harmonic

59D

- 5-15% coverage from the neutral end
- Responds to the ratio of the Neutral and Terminal 3rd Harmonic

Combine 59N and 27TN or 59D for 100% coverage

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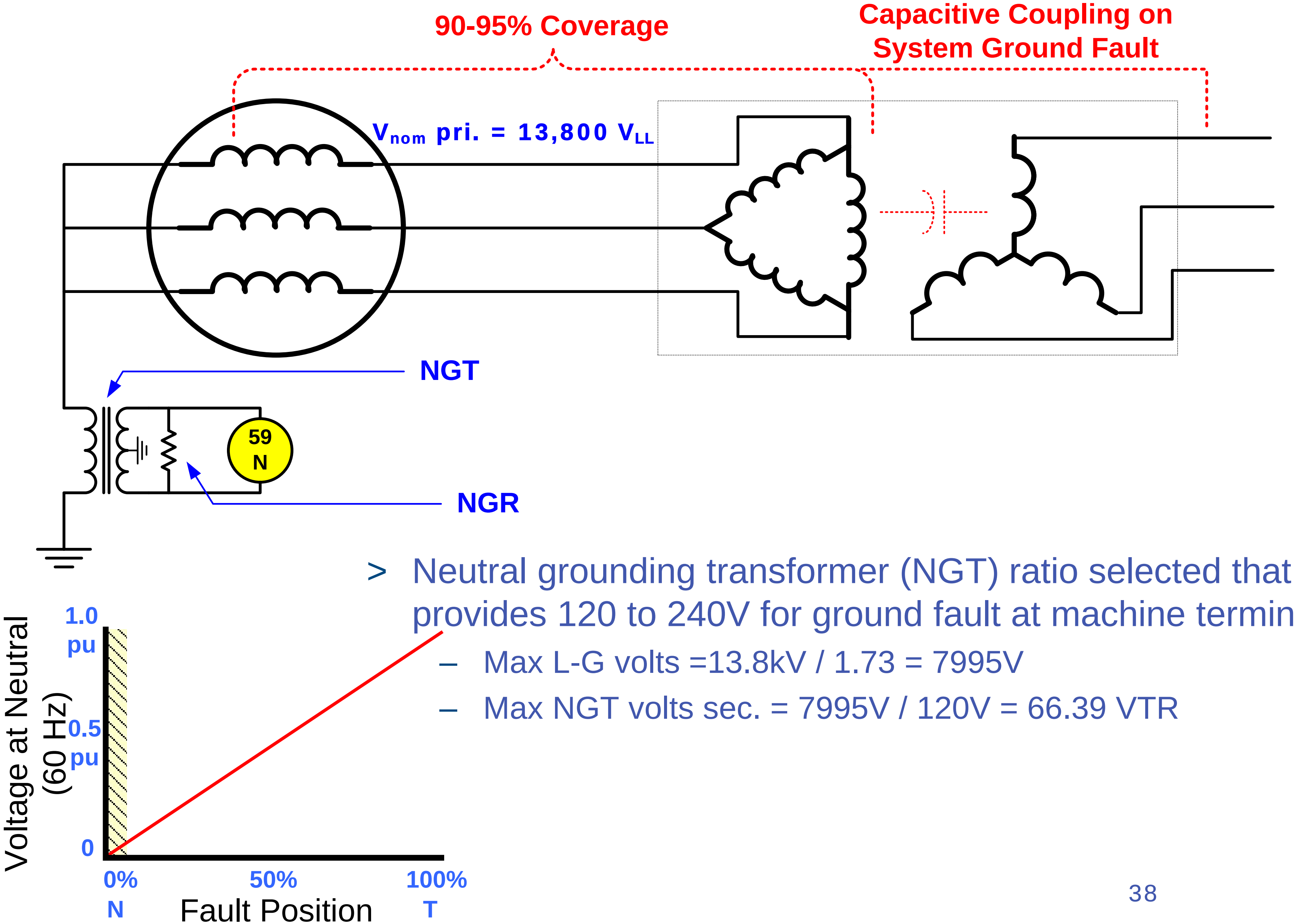
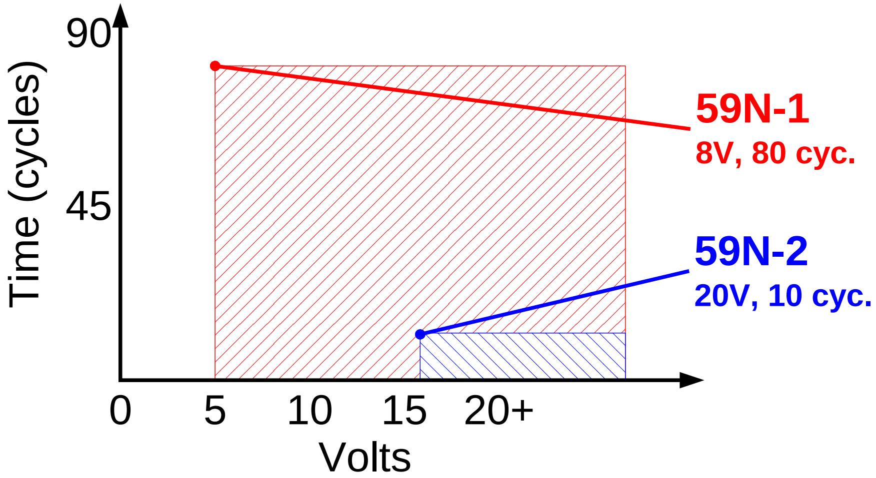
59N Element



> Neutral grounding transformer (NGT) ratio selected that provides 120 to 240V for ground fault at machine terminals
  – Max L-G volts =13.8kV / 1.73 = 7995V
  – Max NGT volts sec. = 7995V / 120V = 66.39 VTR

59N Element

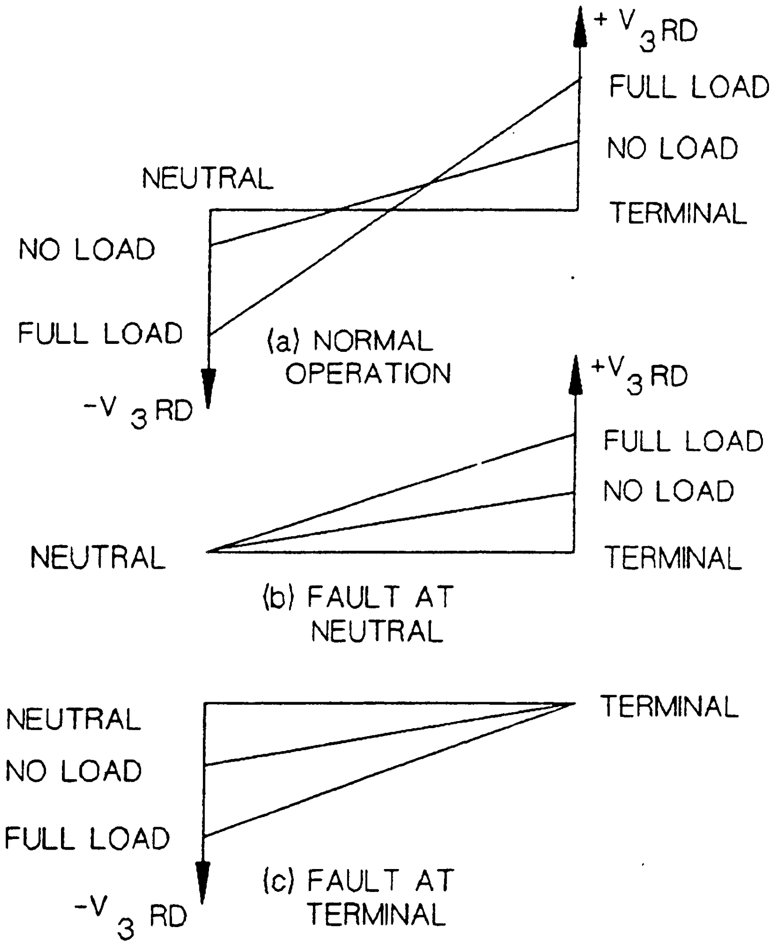


Use of Multiple Setpoints

- 1st level set sensitive to cover 95% of stator winding
  - Delayed to coordinate with close-in system ground faults capacitively coupled across GSU
- 2nd level set higher than the capacitively coupled voltage so coordination from system ground faults is not necessary
  - May cover from 85% of the stator winding
  - Need to calculate influence of system fault with GSU capacitive coupling and pickup above the coupled value
  - Allows higher speed tripping
  - Only need to coordinate with VT fuses

3rd Harmonic in Generators

- 3rd harmonic present in terminal and neutral ends
- Varies with loading
- Useful for ground fault detection near neutral
  - If 3rd harmonic goes away, conclude a ground fault near neutral



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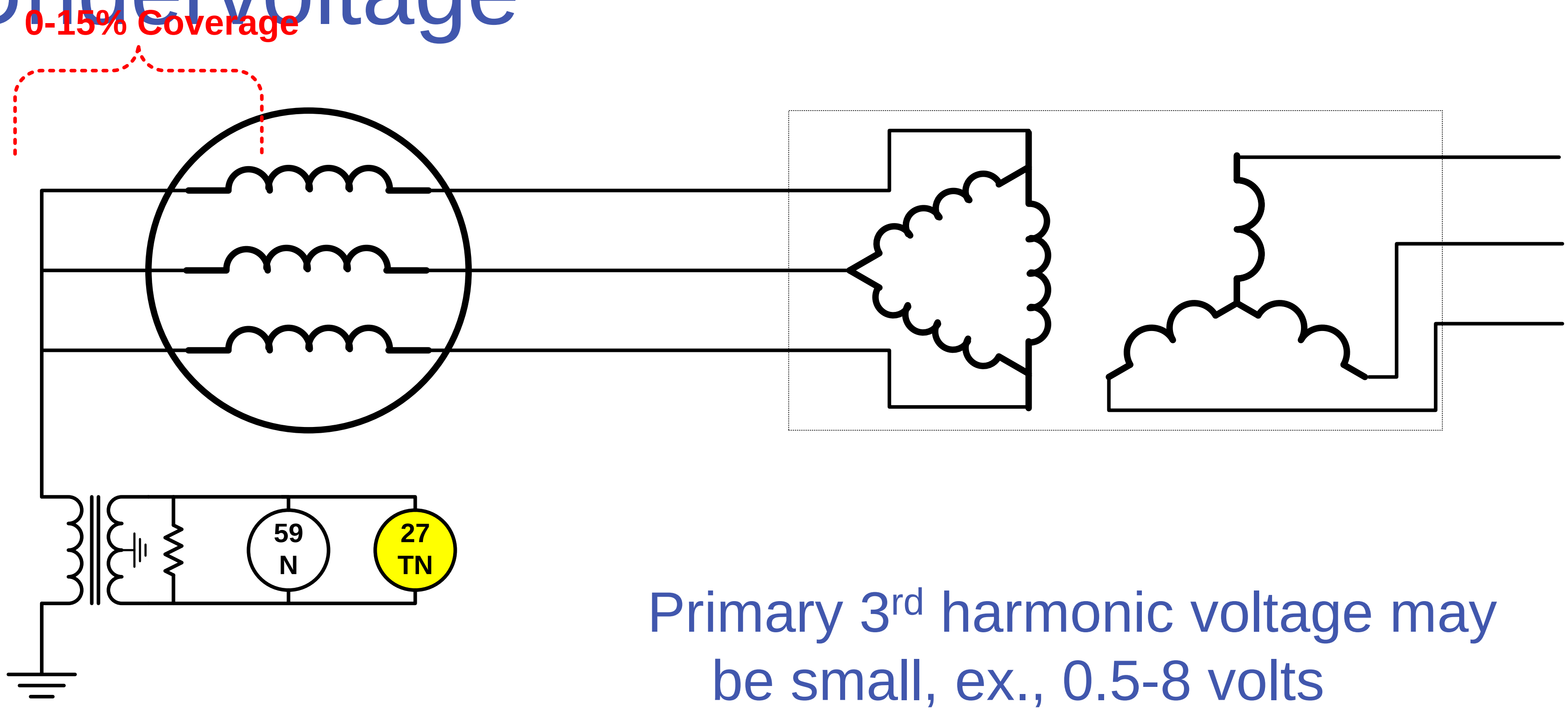
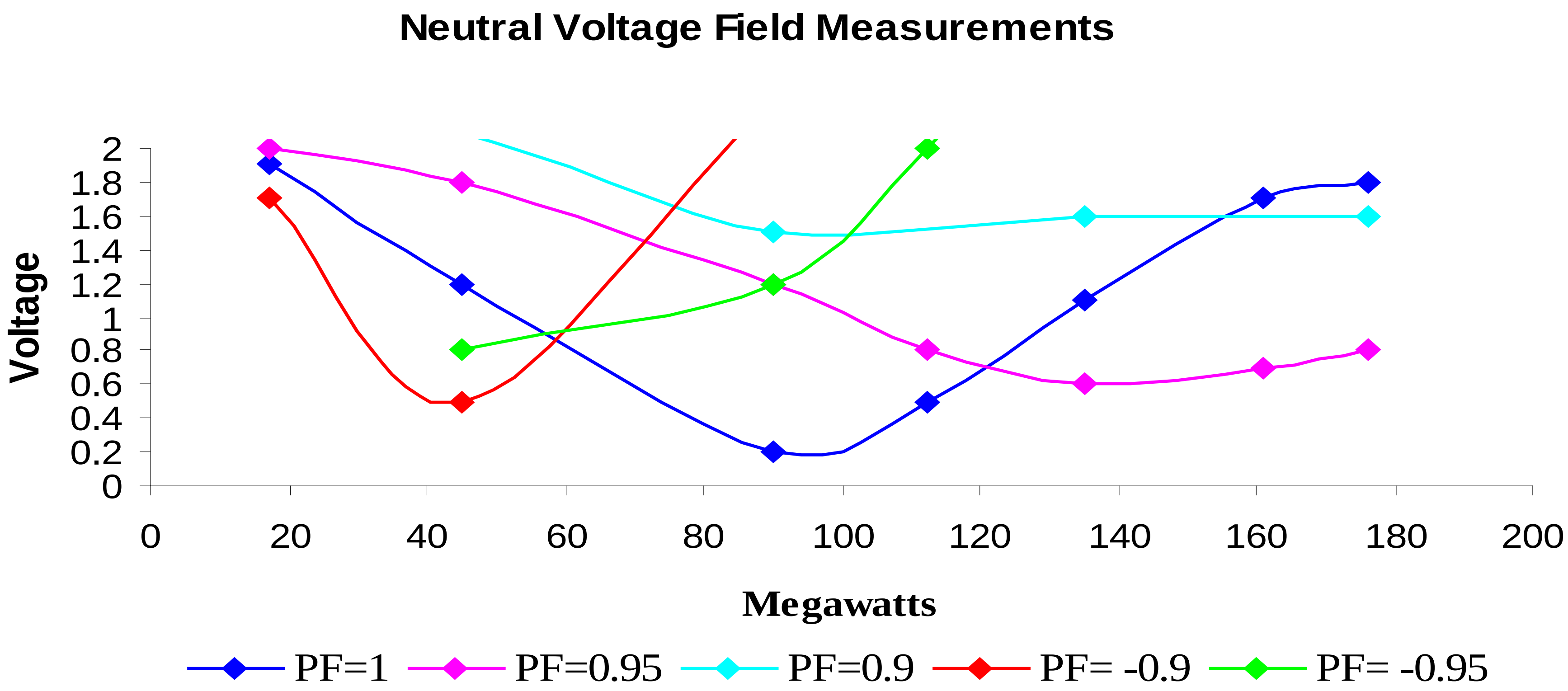
27TN: 3rd Harmonic Neutral Undervoltage



Primary 3rd harmonic voltage may be small, ex., 0.5-8 volts

Element must be sensitive

3rd Harmonic Field Measurements



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27TN: 3rd Harmonic Neutral Undervoltage

Use supervisions for increased security under various loading conditions

> Any or All May be Applied Simultaneously

- Positive Sequence Undervoltage Block
- Definable Power Band Block
- Under VAr Block; Lead & Lag
- Power Factor Block; Lead & Lag

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27TN Supervision

Phase voltage

- No phase voltage, machine dead
- Cannot generate 3rd harmonic voltage

Power

- 3rd harmonic typically increases as power output increases

VAr, PF, I, Power Band

- Additional supervisions for cases where 3rd harmonic levels vary with modes of operation (sync condenser, pumping, VAr sink)

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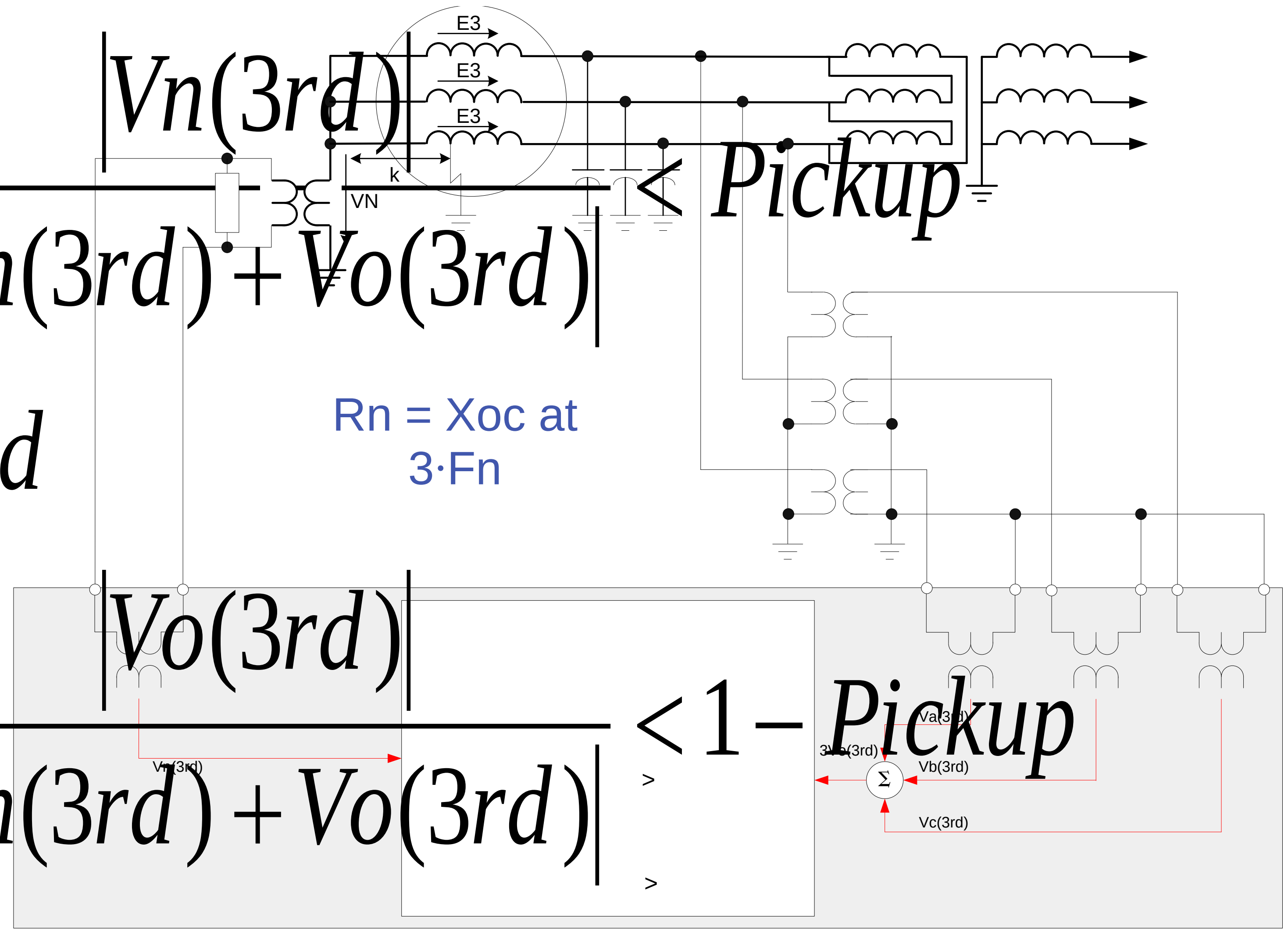
59D: 3rd Harmonic Ratio Voltage

$$\frac{|Vn(3rd)|}{|Vn(3rd)+Vo(3rd)|} < Pickup$$

and

$$\frac{|Vo(3rd)|}{|Vn(3rd)+Vo(3rd)|} < 1-Pickup$$



Rn = Xoc at 3·Fn

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Typical 3rd Harmonic Values

Real Power	Reactive Power	Neutral Voltage	Terminal Voltage	Ratio
0	0	4.2	4.05	1.0
2	0	3.75	4.95	1.0
12	1	4.05	5.7	1.3
32	1	6.3	7.95	1.4
56	7	8.25	9	1.3
100	7	12	12.3	1.1

3rd harmonic values tend to increase with power and VAr loading

Fault at neutral causes 3rd harmonic voltage at neutral to go to zero volts

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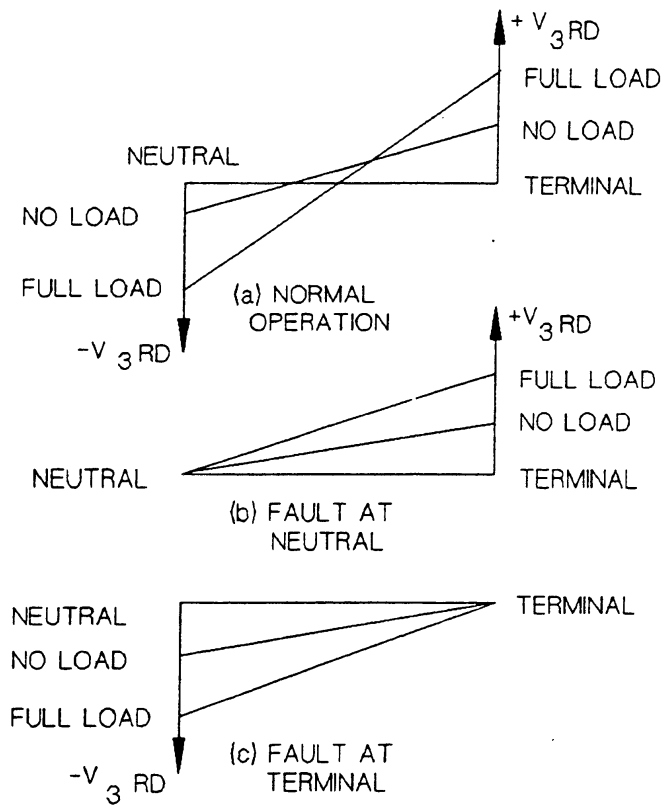
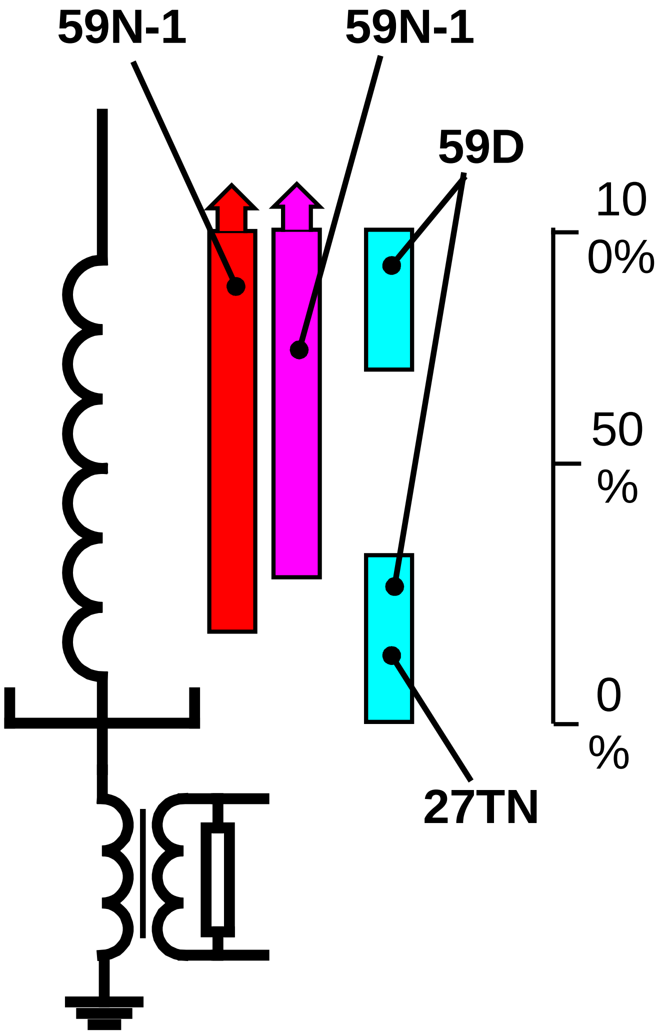
59D – 3rd Harmonic Ratio Voltage

- Examines 3rd harmonic at terminal and neutral ends of generator
  - 59D trips when:
    - $[V_N 3rd / V_N 3rd + V3_0 3rd] >$ pick up
- Uses undervoltage supervision
    - $V_N 3rd + V3_0 3rd >$ pick up
- Provides 0-20 stator winding coverage and 80-100% (typ.)
- Does not have a security issue with loading, as can a 27TN
  - May be less reliable than 27TN
    - Not enough difference to trip
- "Null spot" at mid-winding protected by 59N
- Needs wye phase VTs; cannot use delta VTs to obtain $3V_0$ voltage at terminals



Stator Ground Faults: High-Z Element Coverage

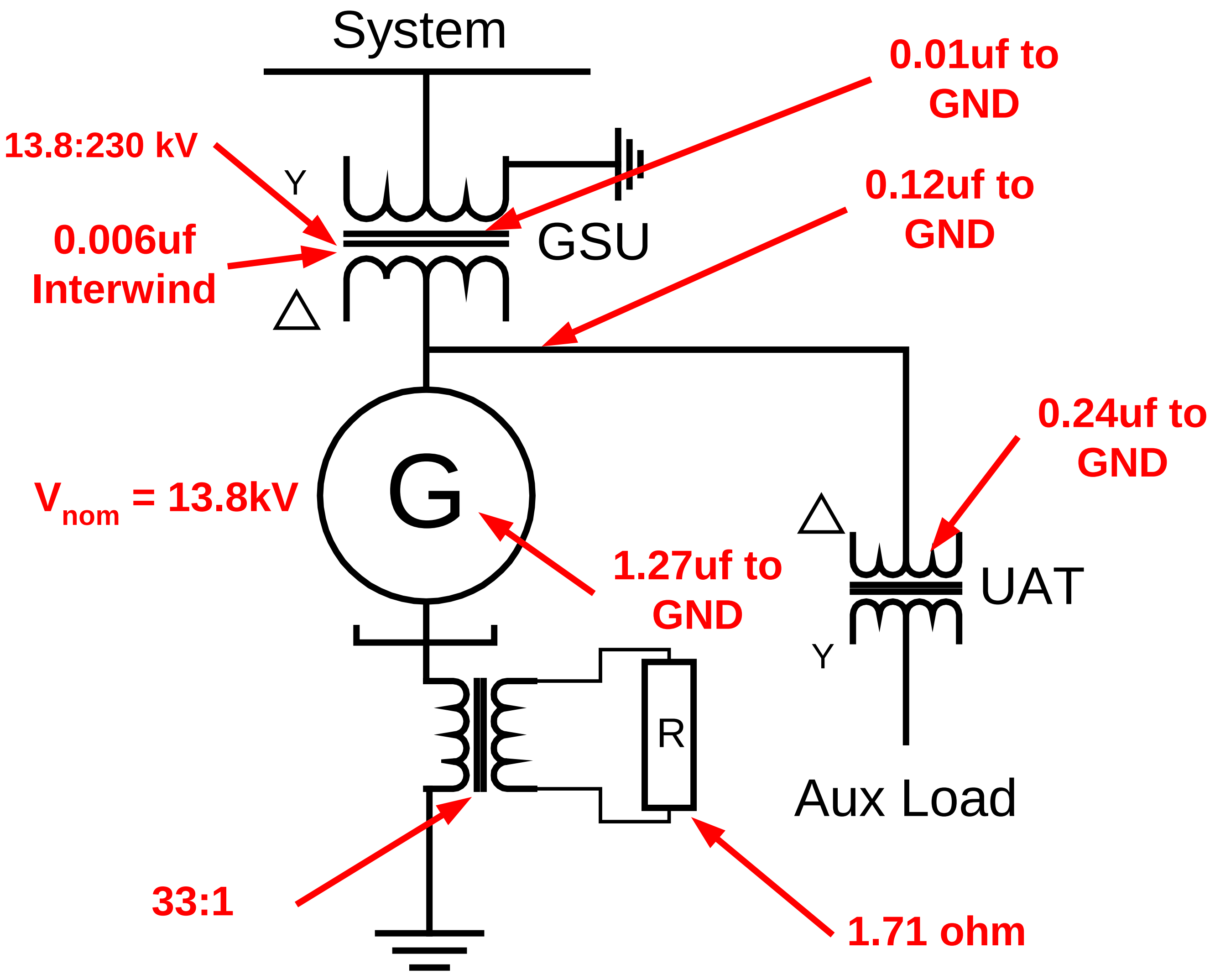


100% Stator Ground Fault coverage afforded by overlap by 59N and either the 27TN or 59D elements

Grounding Fault Calculations

- Size the NGT to obtain 120 to 240V for a full winding ground fault
- Size the NGR to limit ground fault currents
- Calculate 5%-100% ground fault setting
- Calculate optional high speed 15%+ ground fault setting

Ground Fault Calculation



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Ground Fault Calculations

1) Calculate Generator Line-Neutral Voltage

- $V_{LN} = V_{LL}$ nom / √3
- V_{LN} = 13,800V / 1.73 = 7977 V

2) Calculate Total Capacitance

- $C_T = C_{gen} + C_{lead} + C_{GSU} + C_{UAT} + C_{surge}$
- C_T = 1.27 uf + 0.12 uf + 0.01 uf + 0.24 uf = 1.424 uf

3) Calculate Total Capacitive Reactance

- $X_{CT} = 1/2\pi fC = 1/(6.28) * (60) * (1.424 * 10\text{-}6)$
- $X_{CT} = 1{,}864\Omega$

4) Pick NGT ratio for $240V_{sec}$ on full ground fault

- NGT Ratio = $V_{LG} / V_{sec\,max}$
- NGT Ratio = 7977V / 240V = 33

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Ground Fault Calculations

5) Calculate 95% 59N Setting

- $59N_{(95\%)} = V_{sec\ max} * [100\% - \%\ \text{Desired Coverage}]$
- $59N_{(95\%)} = 240V * [100\% - 95\%]$
- $59N_{(95\%)} = 240V * [0.05] = 12V$
- Use timer set greater then system ground fault back up

6) Select $R_{ground\ pri}$ to equal X_{CT} to limit transient overvoltages

- $R_{ground\ pri} = 1{,}864\Omega$

7) Calculate NGR based on desired $R_{ground\ pri}$

- $NGR = R_{ground\ pri} / [\text{NGT ratio}]^2$
- $NGR = 1{,}864\Omega / 33^2 = 1.71\Omega$

Ground Fault Calculations

8) Calculate Maximum Primary Ground Fault Current

- $GFC_{pri\ max} = VLN / R_{ground\ pri}$
- $GFC_{pri\ max} = 7977V / 1{,}864\Omega = 4.28\ A$

9) Calculate Maximum Secondary Ground Fault Current

- $GFC_{sec\ max} = V_{sec\ max} / NGR$
- $GFC_{sec\ max} = 240V / 1.71\Omega = 140\ A$

10) Calculate NGT/NGR Power Dissipation

- $W = V_{sec\ max} * GFC_{sec\ max}$
- $W = 240V * 140\ A = 33.6KW$

Ground Fault Calculations

11) Calculate Worse Case Coupling Voltage

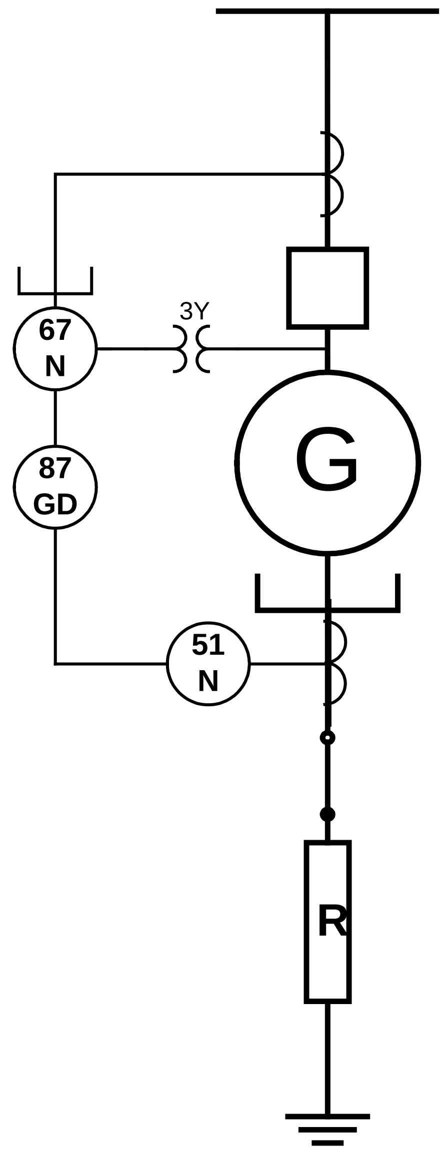
- $GFC_{pri\ coupled} = V_{LN\ High\ Side}\ /\ [1/2\pi fC]$
- $GFC_{pri\ coupled} = [230{,}000\ V\ /\ \sqrt{3}]\ /\ [1/376 * 0.006uf \times 10^{-6}]$
- $GFC_{pri\ coupled} = 132{,}948\ V\ /\ 443262\Omega$
- $GFC_{pri\ coupled} = 0.2999 = 0.3\ A$
- $59N_{(max\ coupled)} = [GFC_{pri\ coupled} * R_{ground\ pri}]\ /\ NGT\ ratio$
- $59N_{(max\ coupled)} = [0.3\ A * 1{,}864\Omega]\ /\ 33$
- $59N_{(max\ coupled)} = 16\ V$
- Set time to coordinate with phase VT fuses

Stator Ground Fault: Low Z Machines

51N: Neutral Overcurrent

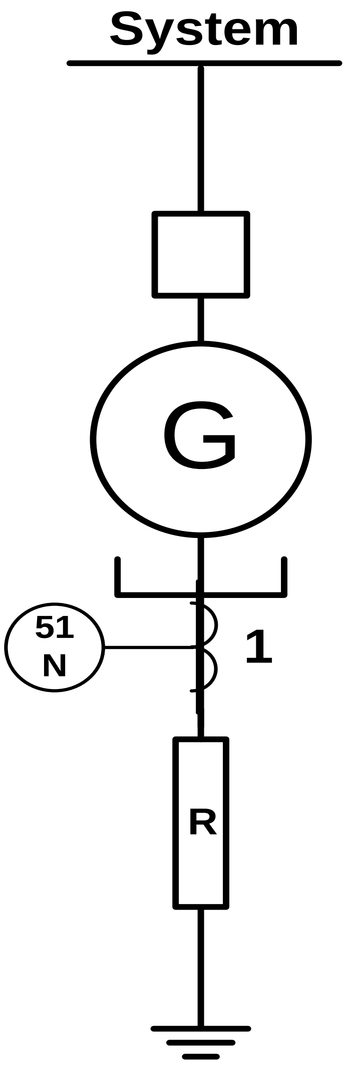
67N: Neutral Directional

87GD: Ground Differential



51N

- Typically set to 5% of available fault ground fault current
- Coordination with system ground fault protection
- Blocking by system ground fault protection



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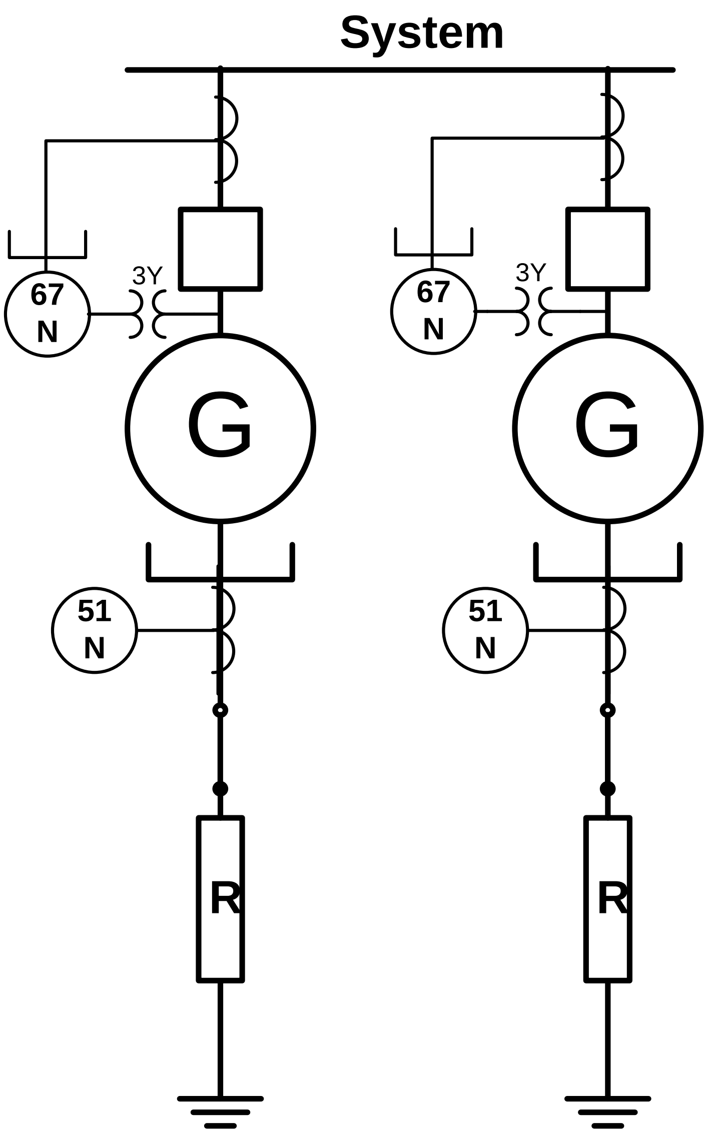
67N: Neutral Directional



Provides selective ground fault detection for multi-generator bus connected arrangements

Set to operate faster than 51N

-may have short time delay

67 N: Neutral Directional

67N directionalized to trip for zero-sequence (ground) current flowing toward a generator

- Complements 51N
- Open circuit neutral resistor or open grounding switch
- Ground switch supervision (becomes non directional)

67N is set faster than 51N

- May be short definite time delay

Requires $3V_0$ polarizing signal

Core balance CT recommended for sensitive fault detection

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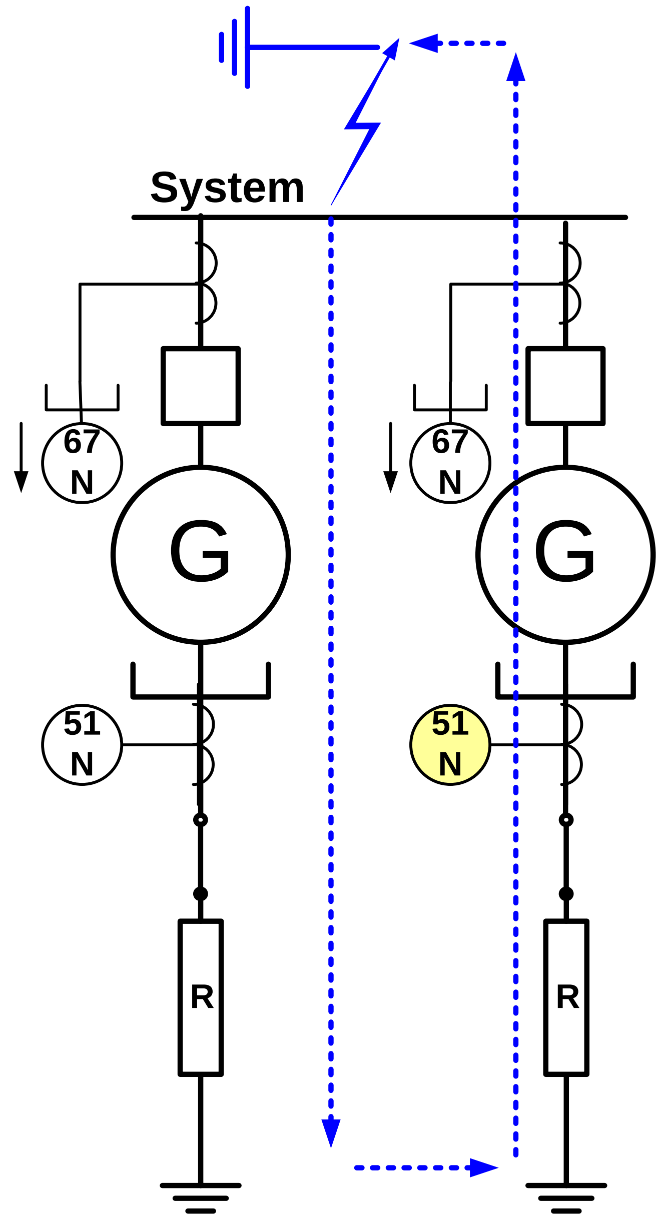
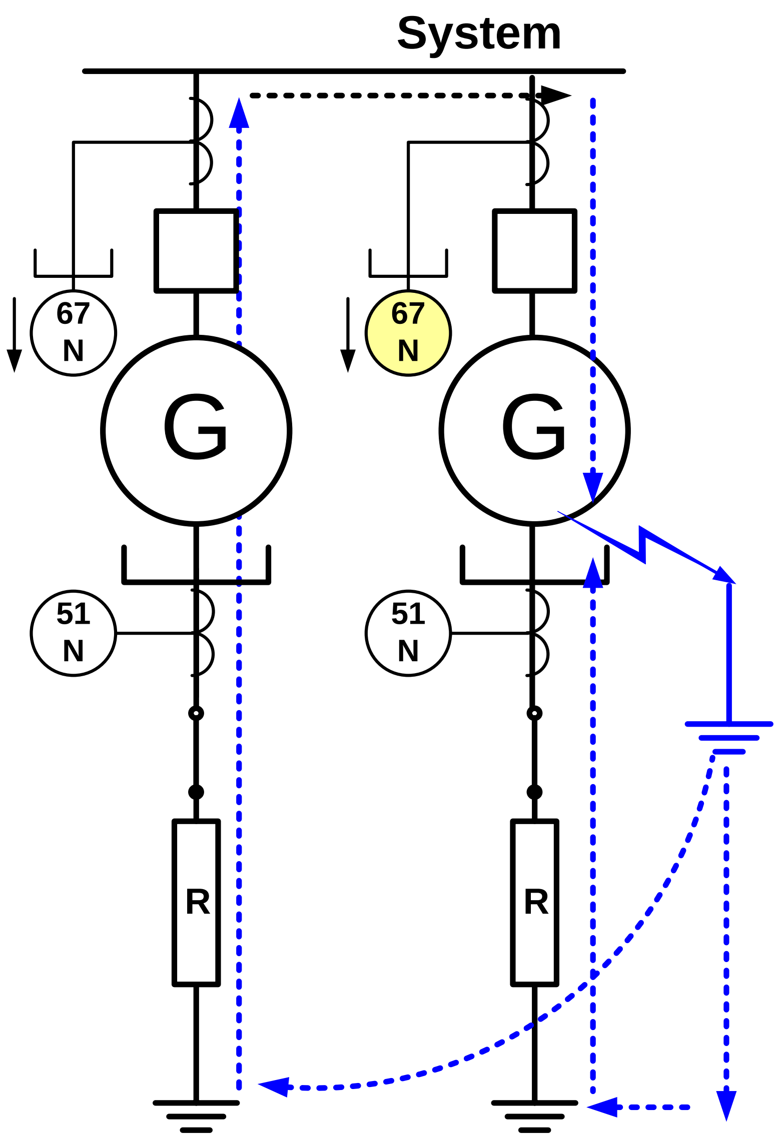
Neutral Directional : Low-Z Generator



- Ground fault on system is detected by grounded generator's 51N element
- Coordinated with system relays, they should trip before 51N
- 67N sees fault current in the reverse direction and does not trip

Neutral Directional : Low-Z Generator



- Ground fault in machine is detected by 67N & 51N
- 51N picks up in unfaulted machine
- 67N trips fast in faulted machine
- 51N resets on unfaulted machine

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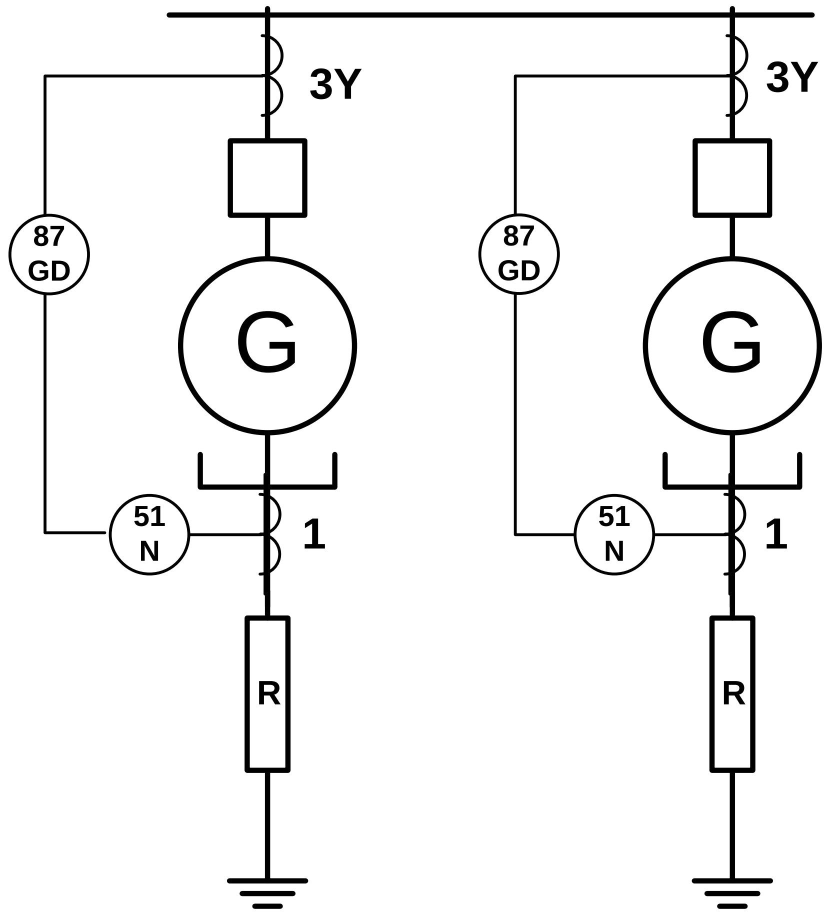
87GD: Ground Differential

Employed 87GD to selectively clear machine ground fault for multi-generator bus connected arrangements

Use with 51N on grounded machine(s) for internal fault and system back up

Ground switches on all machines can all be closed



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87GD: Ground Differential

- 87GD element provides selectivity on multiple bused machine applications
- Requires phase CTs, or terminal side zero-sequence CT, and a ground CT
- 87GD uses currents with directionalization for security and selectivity
- 87GD is set faster than 51N

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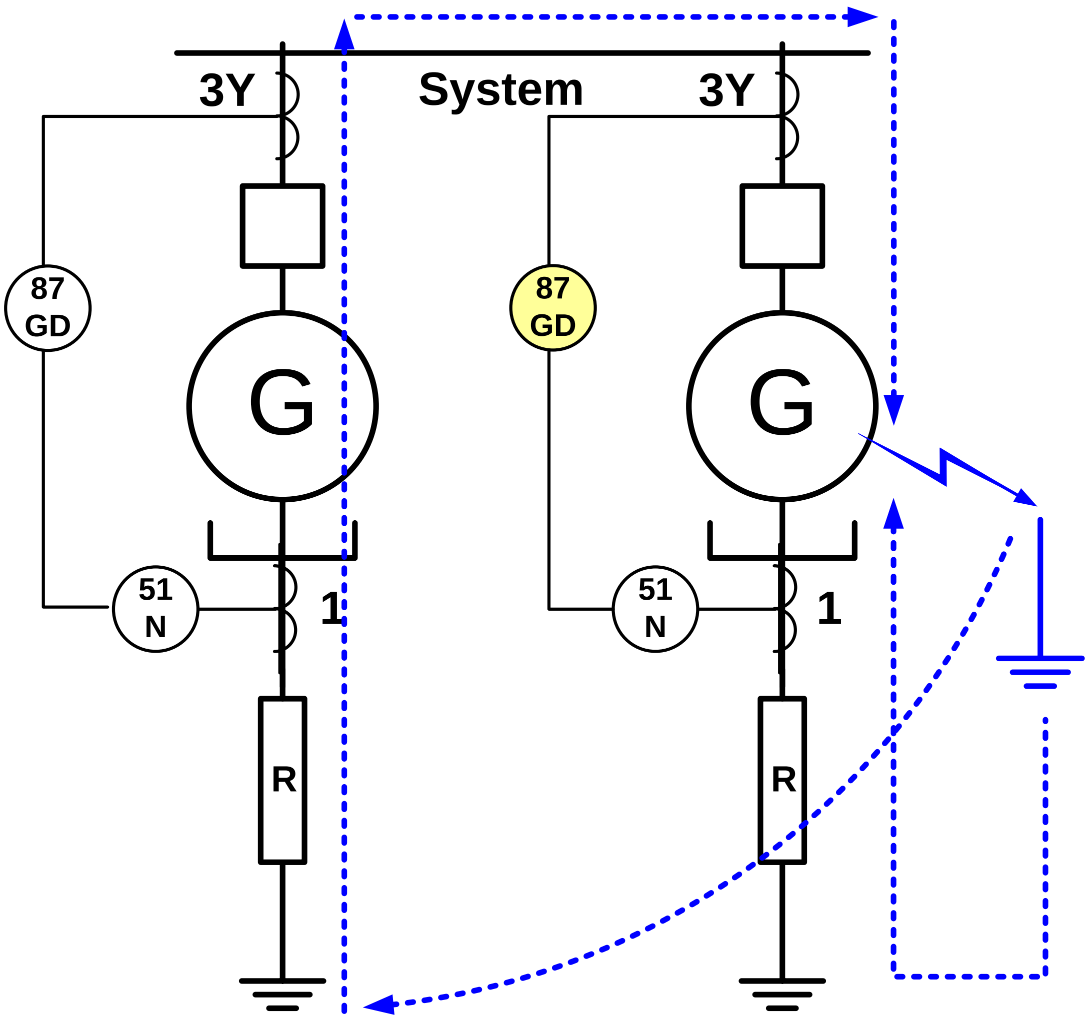
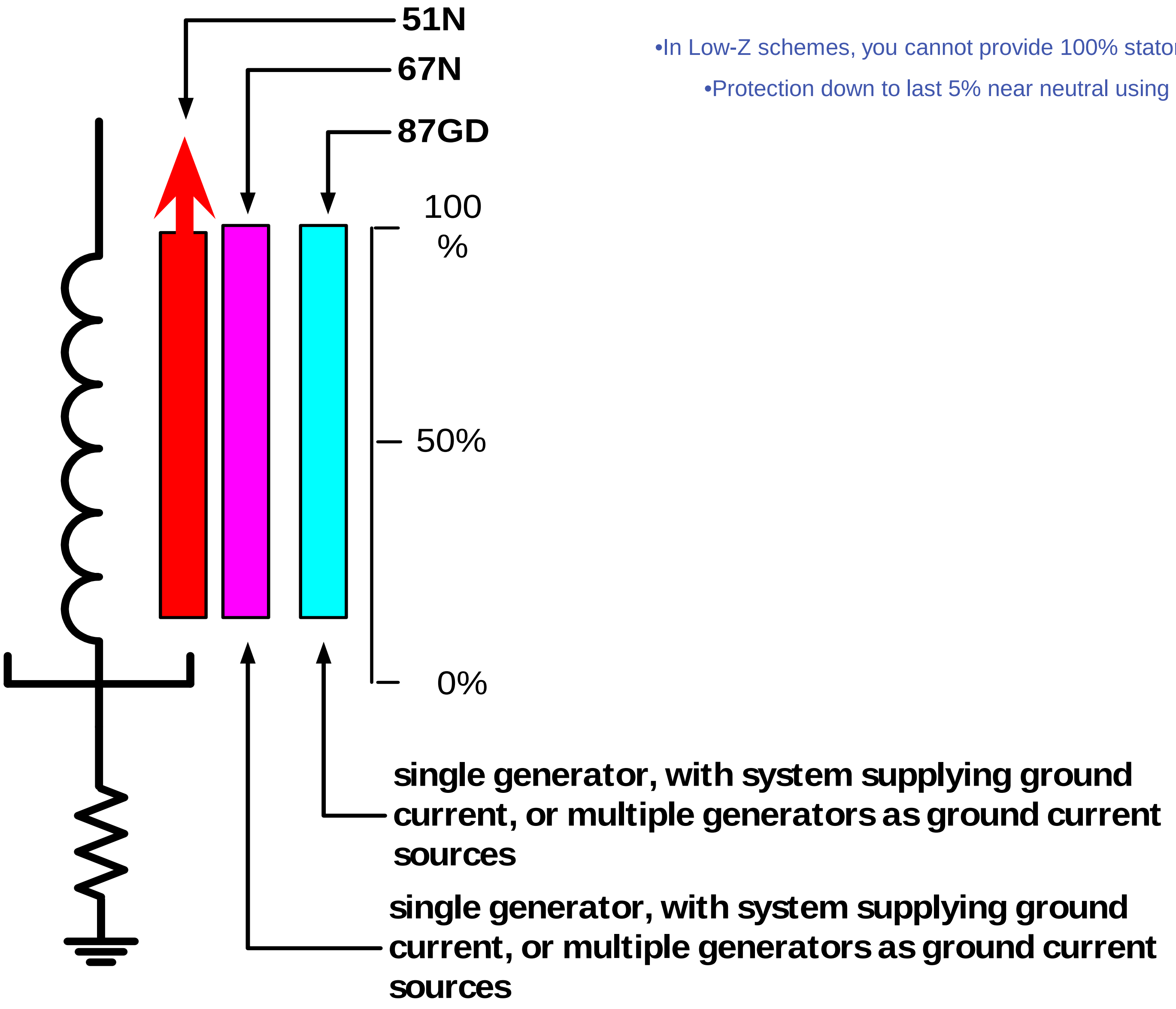
Ground Differential



- Ground fault in machine is detected by 87GD & 51N
- 51N picks up in unfaulted machine
- 87GD trips fast in faulted machine
- 51N resets on unfaulted machine

Stator Ground Faults: Coverage



- In Low-Z schemes, you cannot provide 100% stator ground fault protection
  - Protection down to last 5% near neutral using 51N, 67N or 87GD

Stator Phase Faults

- Elements responding to zero sequence quantities will not operate
- Fault current not limited by grounding impedance
- Overcurrent protection would require coordination

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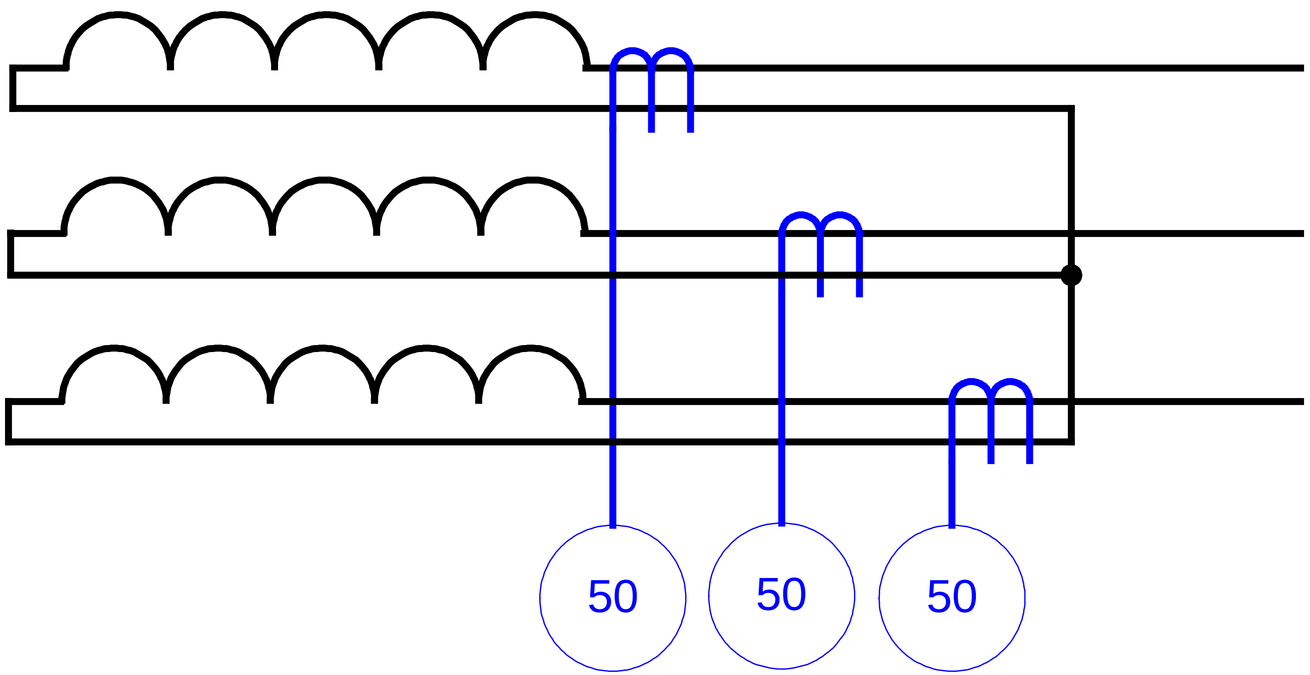
Balanced Differential

- Sensitive detection of phase and ground faults
- No coordination issues
- Difficult to install on large machines



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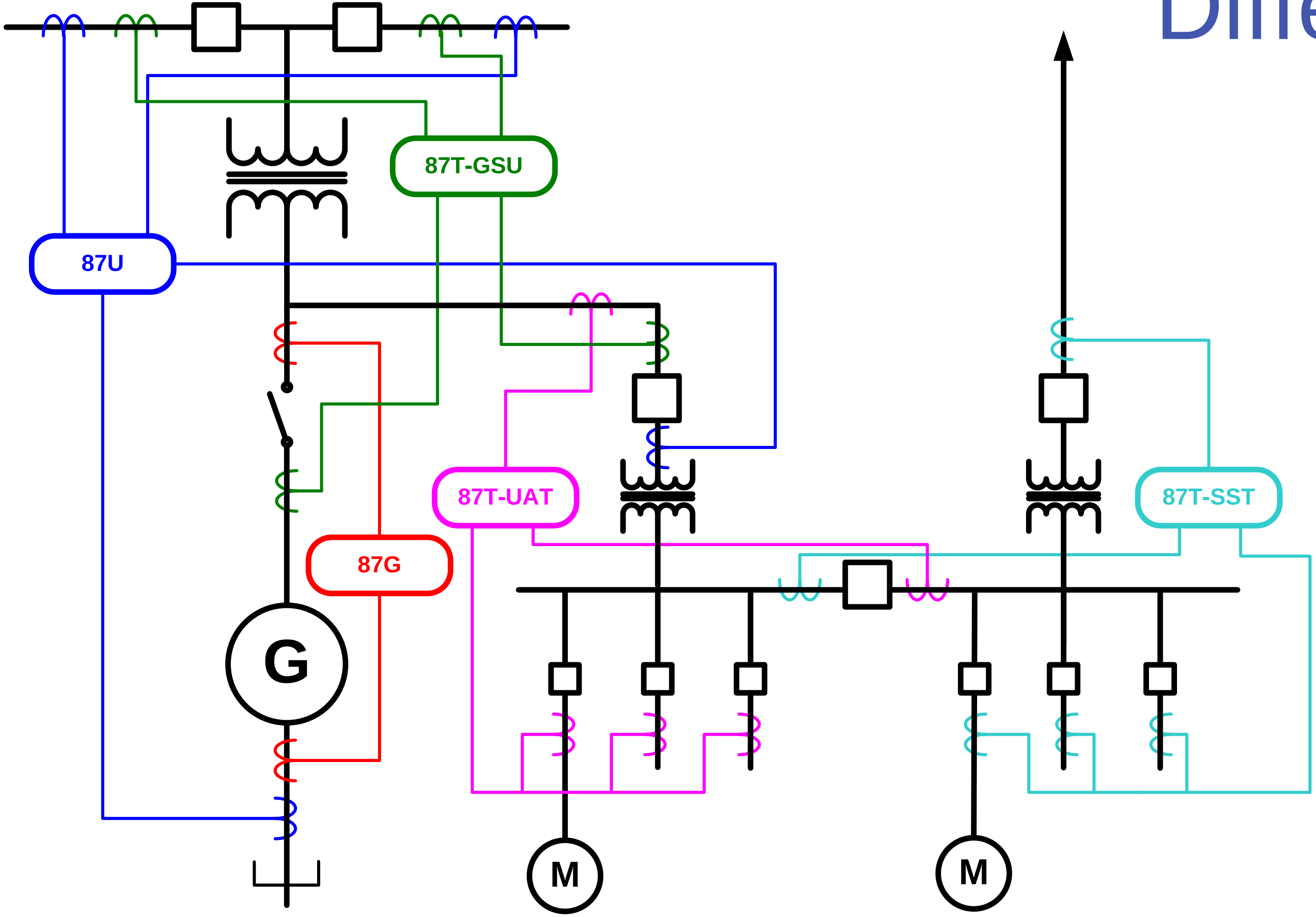
Differential



No need to coordinate with other zones

High speed (typ. 0.75-2.5 cycles)

Main issue is security during CT saturation

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Biased Differential: 87G

- Fast, selective
- Used to clear multiphase faults
  - Can detect ground faults to a degree in low-Z grounded machines
  - Cannot detect ground faults in high-Z grounded machines
    - Too little ground fault current at <= 10A
- Uses differential principle
  - Current in should equal current out

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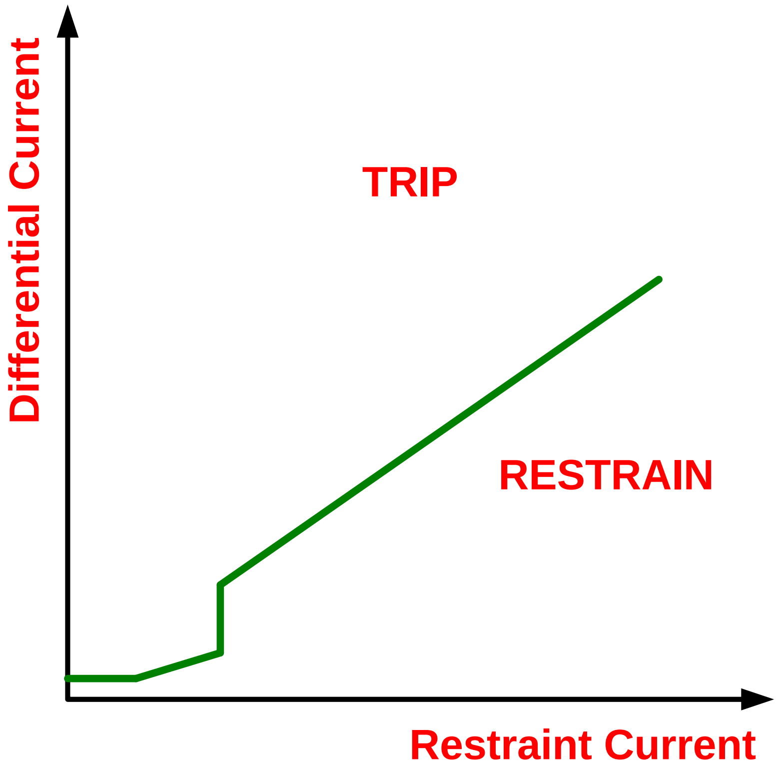
Biased Differential Characteristic



Minimum Pickup: 5% of Inominal

Slope 1 for “normal” CT errors: 10%

Slope 2 for large errors: 50-80%

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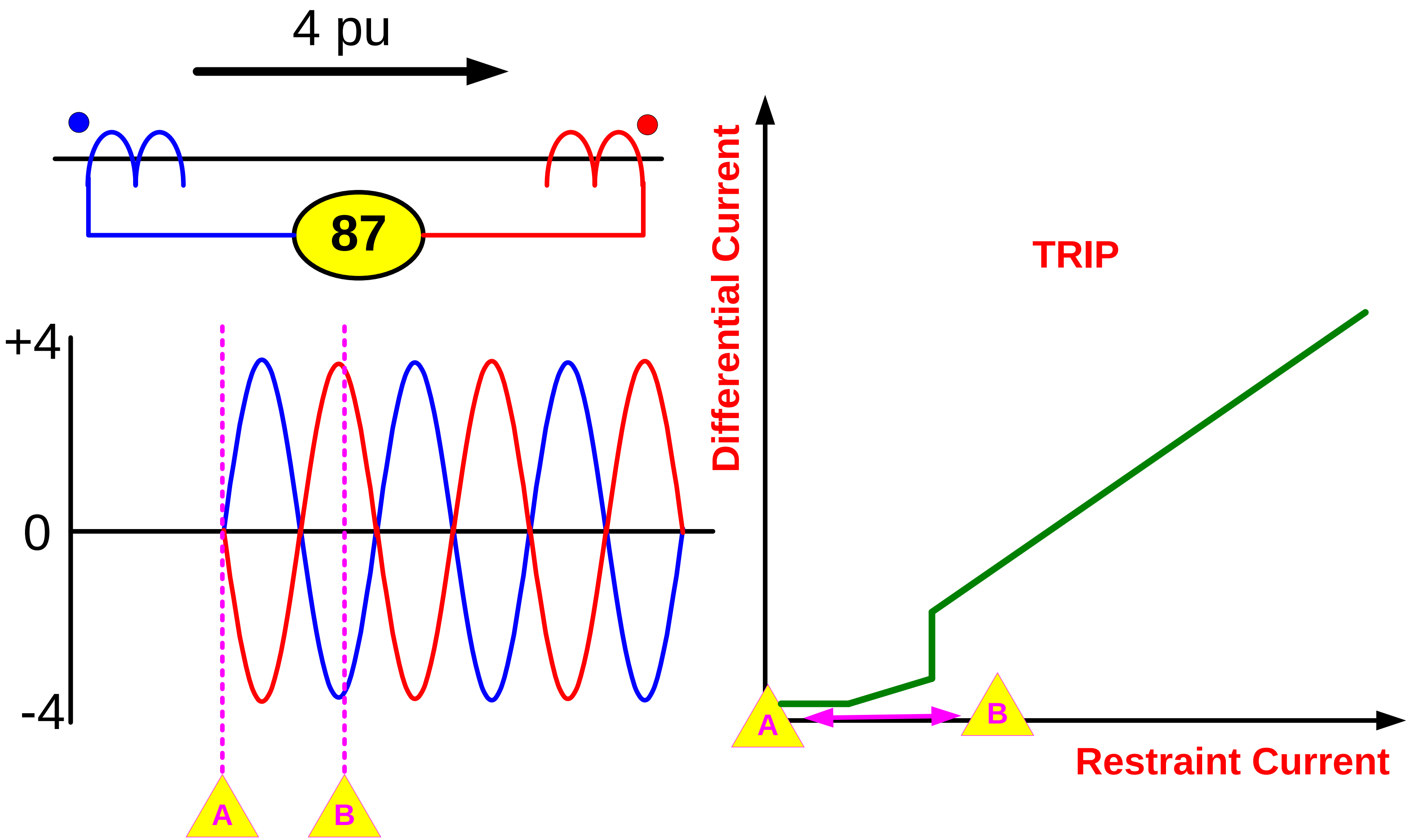
Through Current: Ideal CTs



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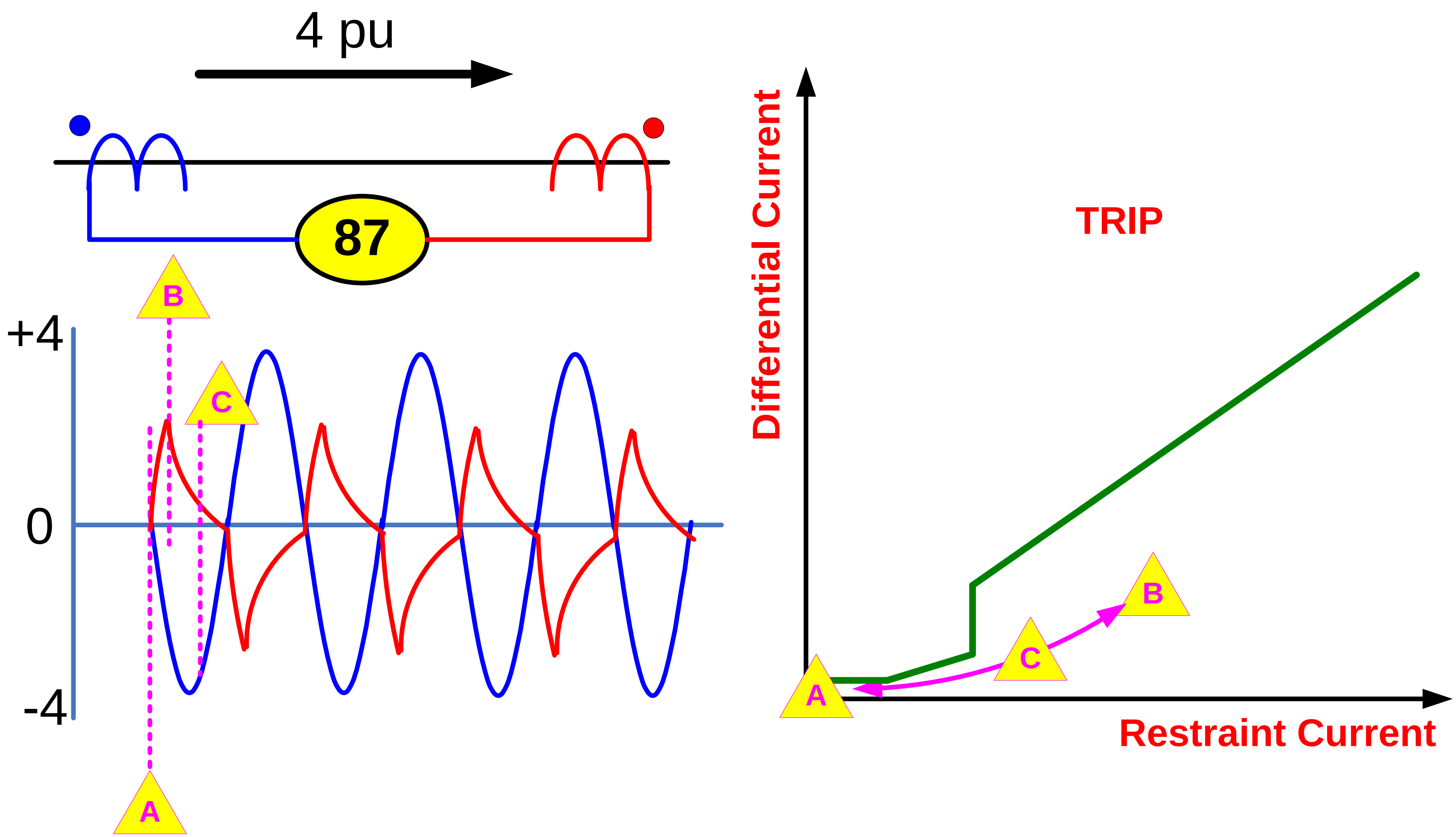
Through Current: CT Error



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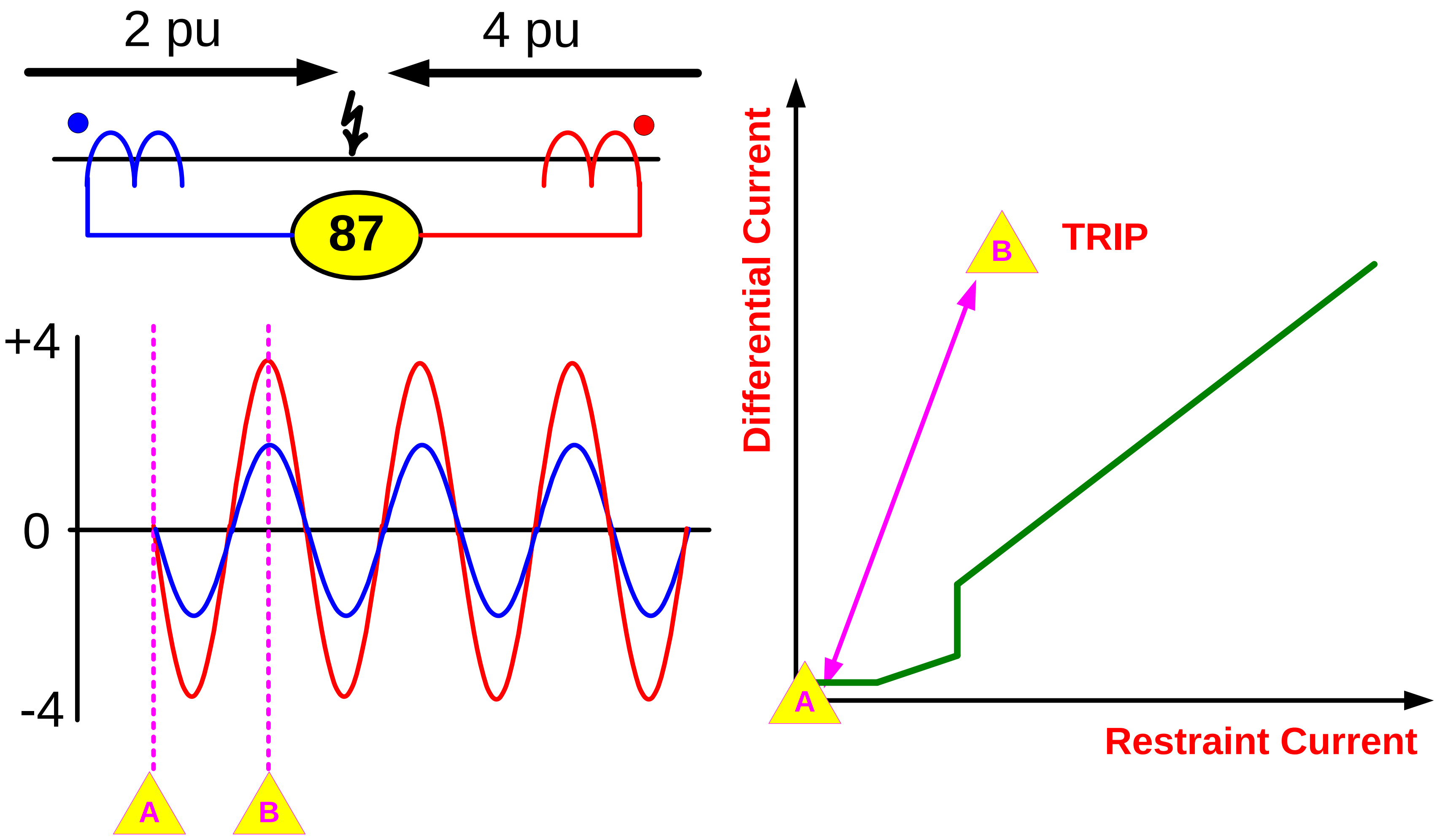
Internal Fault: Ideal CTs



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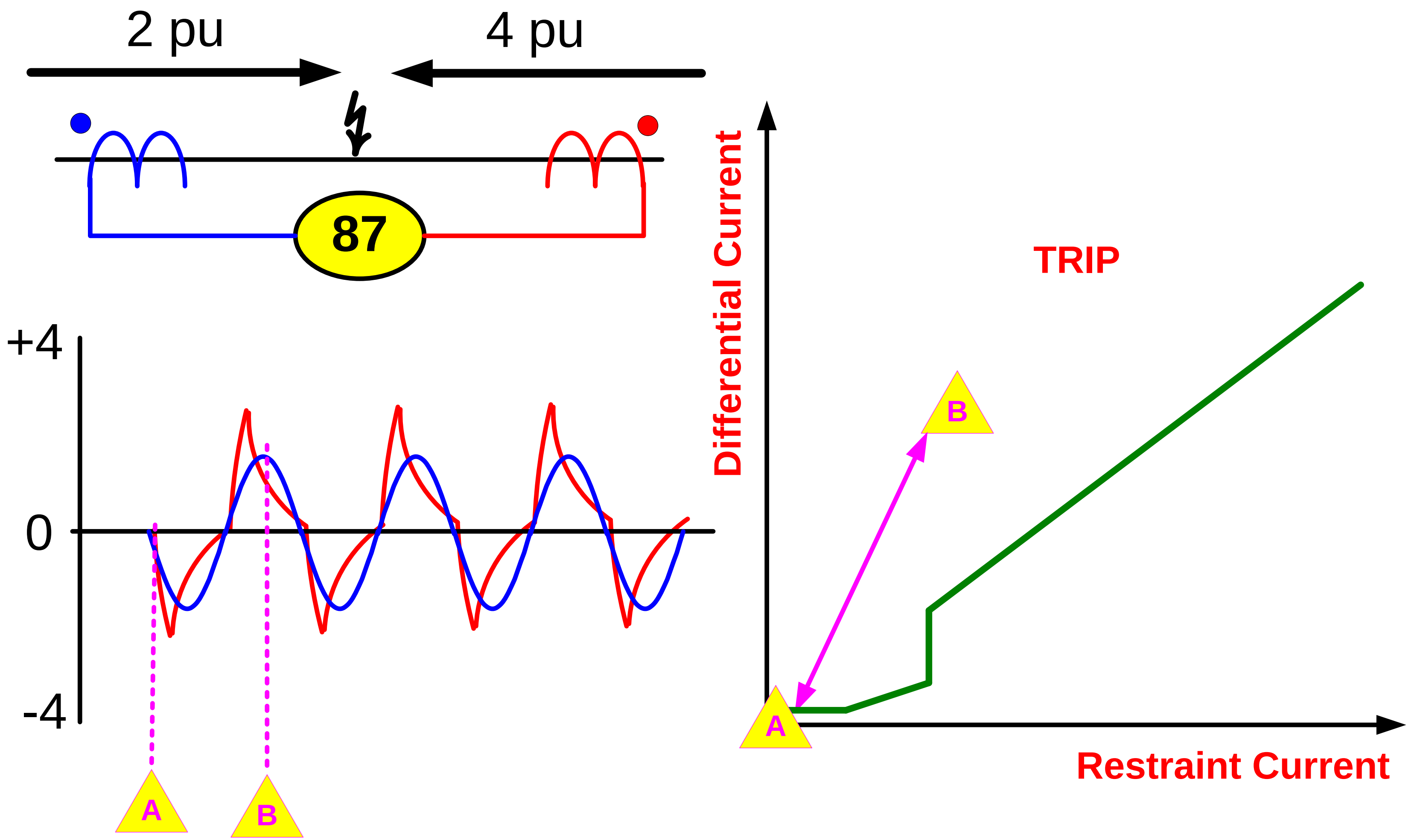
Internal Fault: CT Error



CT Calculations for Differential

Intent is to size CTs for fault current and burden to avoid saturation

Modern protection has very low burden which is helpful (0.020 ohm typ.)

Old E/M protection may have high burden (0.3-0.8 ohm typ.)

Long runs of thin wire raise burden

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C37.110 Recommendations

The following requirements apply to CTs used for generator differential applications:

- a) Select CT current rating to 120%-150% of generator rating
- b) Utilize full-winding ratio
- c) Use CTs with the highest practical secondary voltage capability
- d) Use CTs that have fully distributed secondary windings

The differential CTs on both sides of a generator should be of the same ratio, rating, connected burden, and preferably have the same manufacturer, so that the excitation characteristics are well matched

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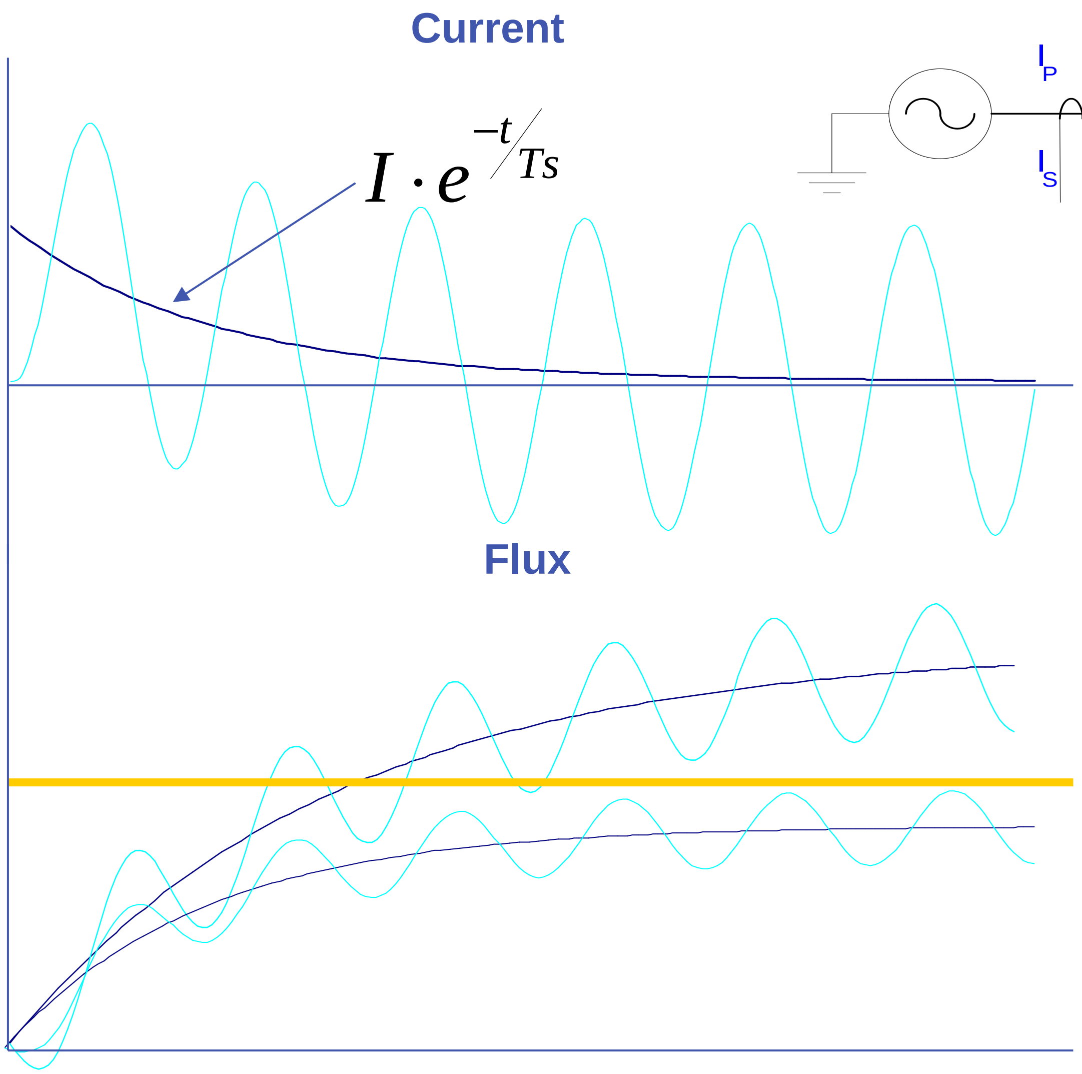
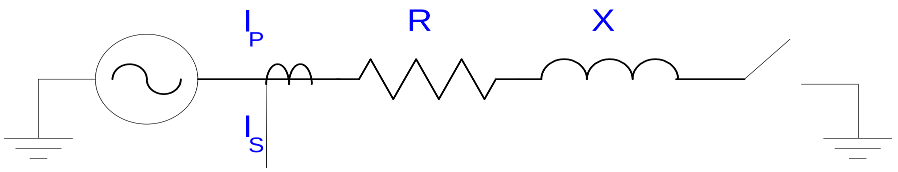
C37.110 Recommendations

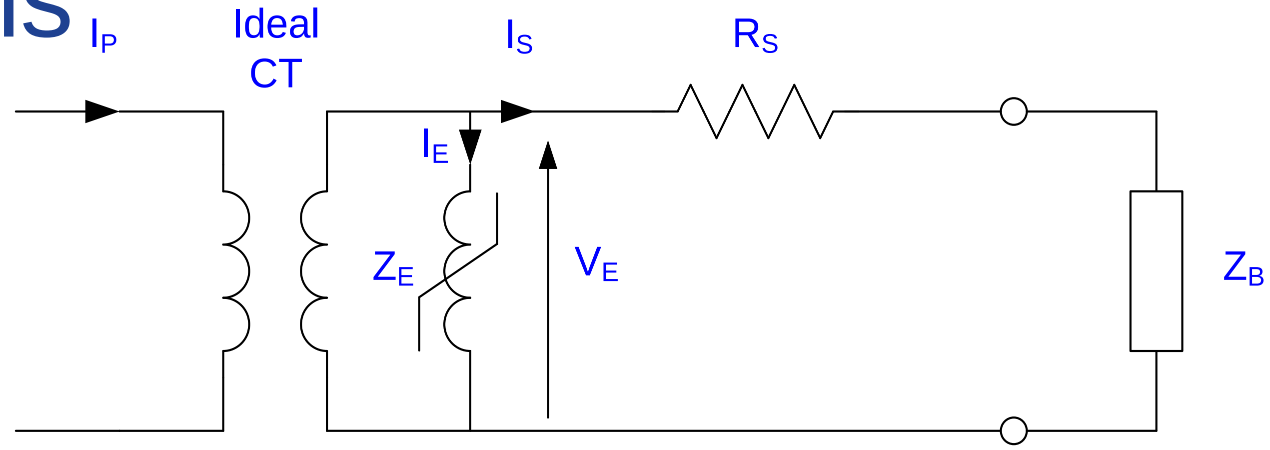
- If the generator differential zone must include a generator breaker it is not always possible to use CTs with the same excitation characteristics, especially knee point voltage. The mismatch of the CTs should be checked
- In order of preference, the goal is to:
  - a) Avoid CT saturation for asymmetrical currents, if possible
  - b) Prevent saturation on symmetrical currents
  - c) Go into saturation at the same current if avoiding dc saturation is not possible
  - d) Minimize the difference in time to saturation for asymmetrical currents (dc saturation)

CT Saturation for DC





DC Saturation: Fundamental Relations



$$V_E = I_S \cdot (R_S + Z_B)$$

Voltage across the magnetizing branch

$$K_S = \frac{V_X}{I_S \cdot Z_T}$$

Saturation factor

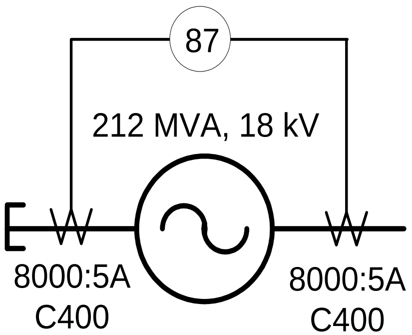
$$K_S > 1 + X/R$$

Saturation-free operation

$$T_S = \frac{-X/R}{2 \cdot \pi \cdot \mathrm{f}} \cdot \ln\left(1 - \frac{K_S - 1}{X/R}\right)$$

Time to saturation

CT Calculations for AC Saturation



Gather Burden Information

CT = 0.3 Ω

Leads = 0.6 Ω

Relay = 0.040 Ω

Z_{total} = CT + Leads + Relays

= 0.3Ω + 0.6Ω + 0.04Ω = 0.94 Ω

Determine Rated Current

$I_{rated} = MVA_{NOM}/\sqrt{3} \cdot V_{NOM}$

$= 212 MVA/\sqrt{3} \cdot 18\ kV$

$= 6808\ A_{PRI}$

Use X''_d for maximum Fault Current

X"d=0.136 pu

$If = 1/X''_d = 7.35$ pu

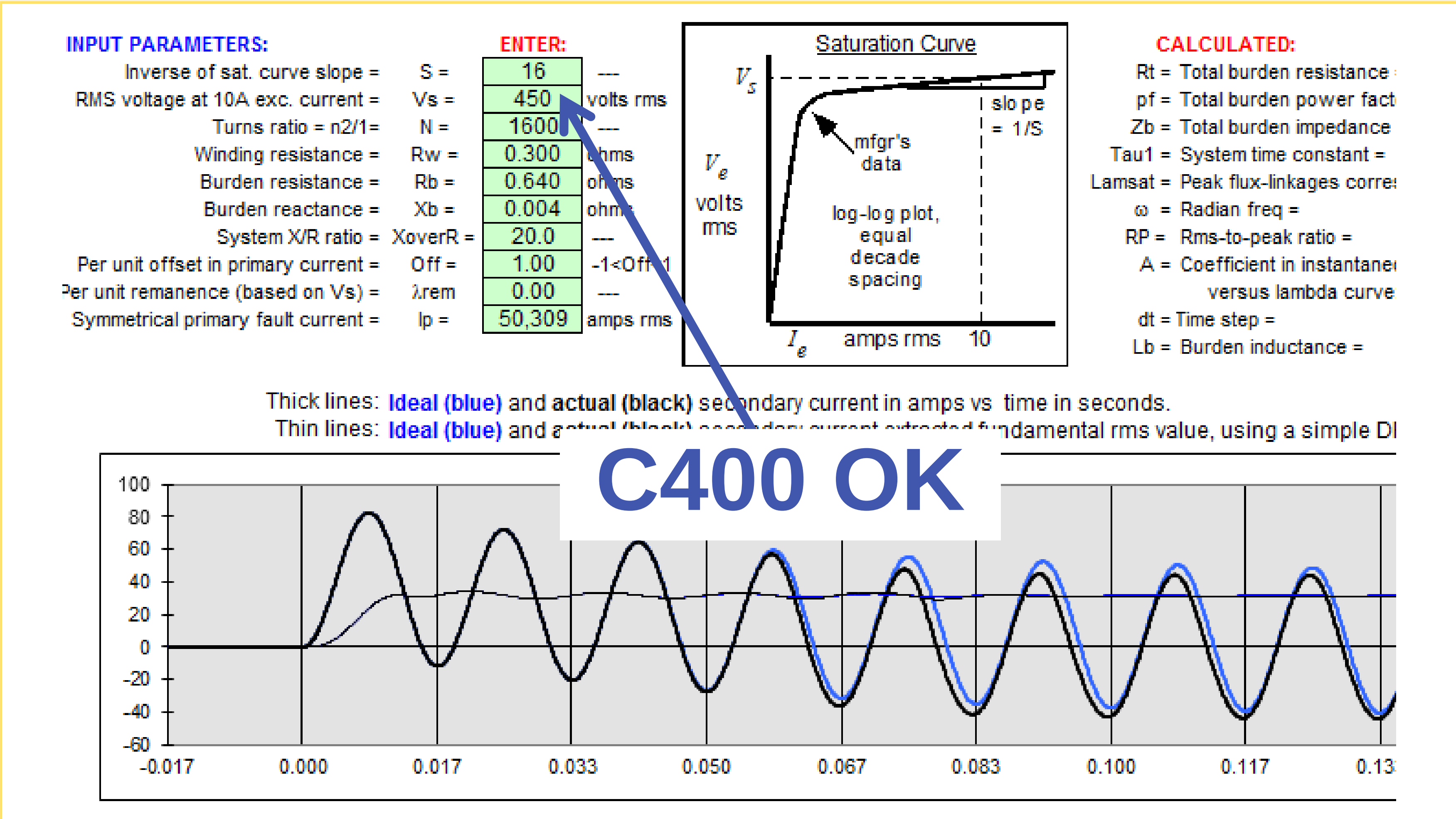
$If_{PRI} = 7.35 * 6808$

$= 50309\ A_{PRI}$

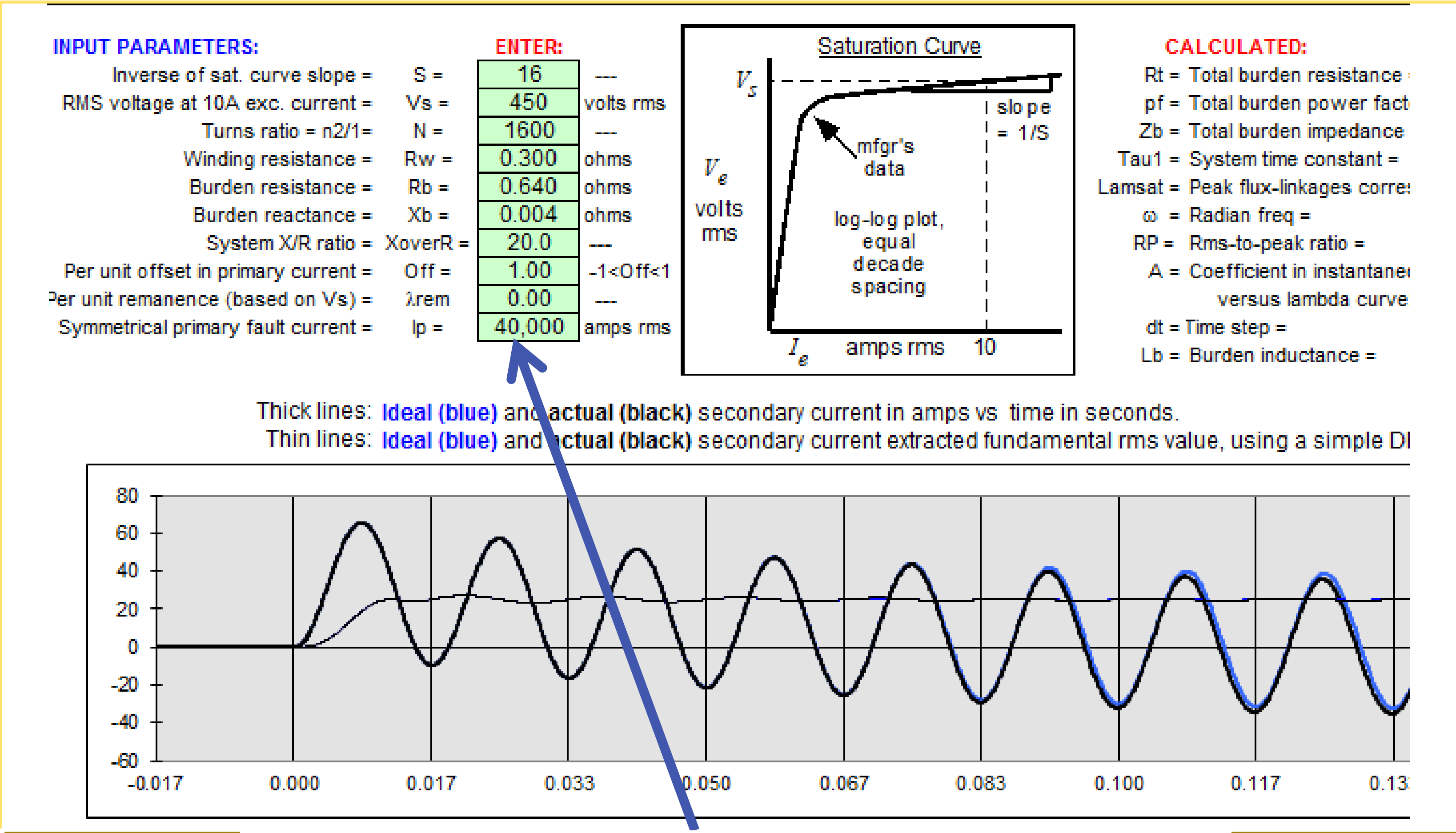
$If_{SEC} = 50309 * 5/8000$

$= 31\ A_{SEC}$

CT Calculations for AC Saturation



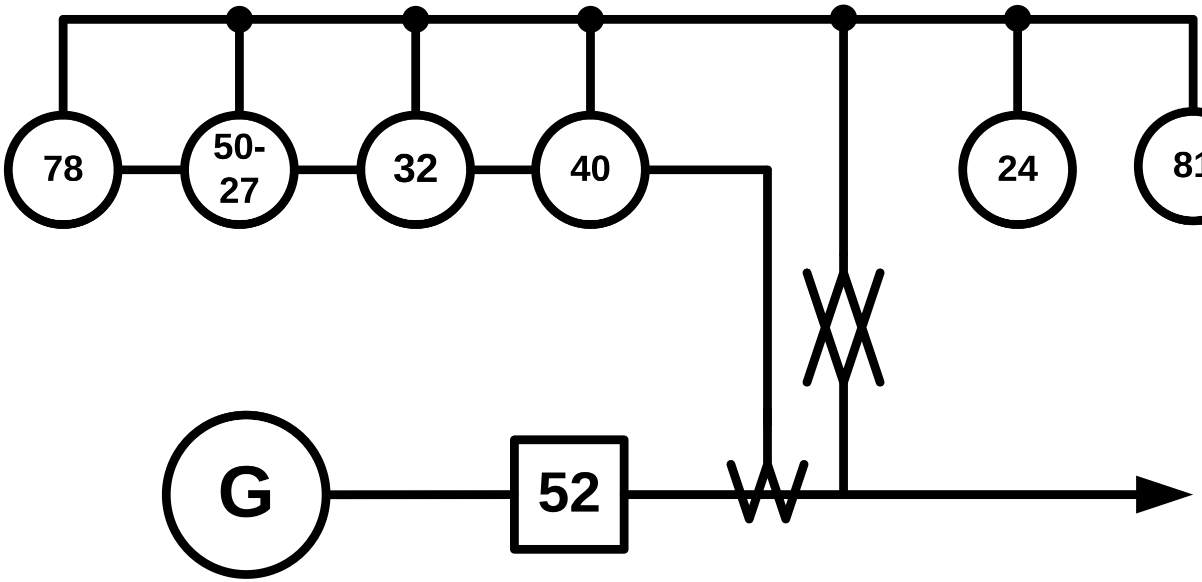
CT Calculations for AC Saturation



Set Breakpoint @ 35KA

Abnormal Operation Protection

Abnormal Operation

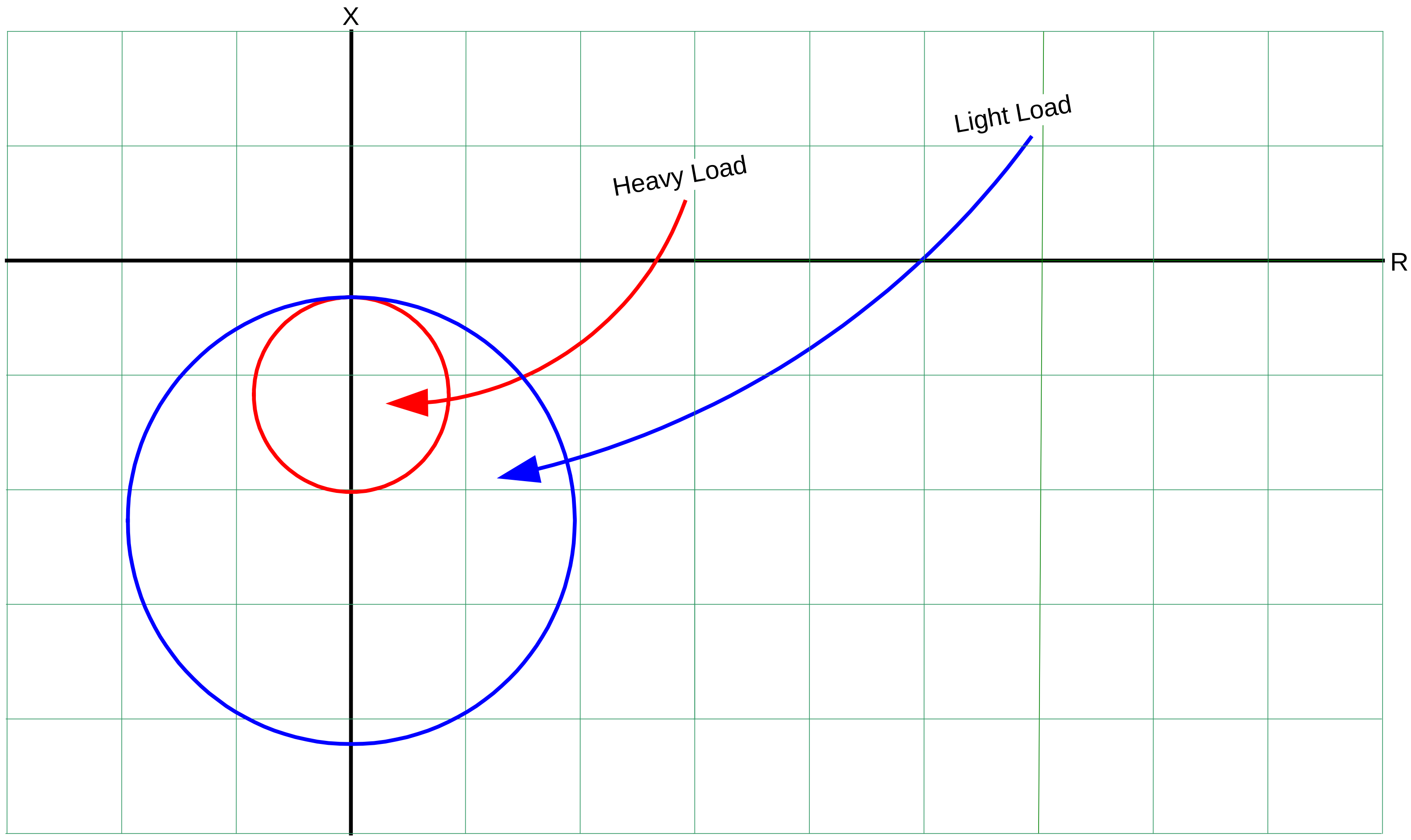


Loss of Excitation: 40

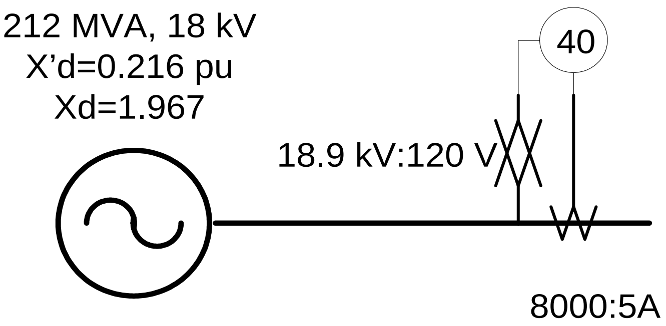
- After field loss, generator acts like an induction machine
- Takes reactive (VAr) support from the system
  - Bad for machine as rotor surface heats due to slip induced currents
  - Bad for the system, as stability is compromised, plus it can take down local area voltage
- Damage can take place quickly or over time based on severity of field loss
  - Complete: fast, seconds
  - Incomplete (low field): longer, 10 sec to minutes

> Block function for VT Fuse Failure

Loss of Excitation: 40



Loss of Excitation: Method 1



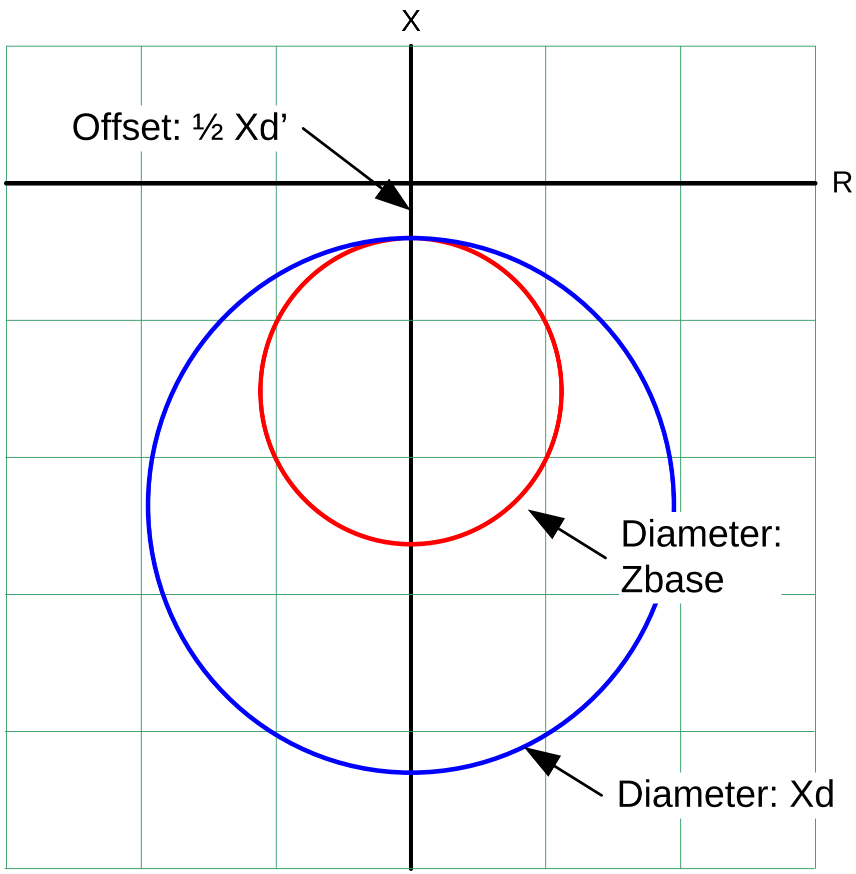
$$VT = \frac{18900}{120} = 157.5$$

$$CT = \frac{8000}{5} = 1600$$

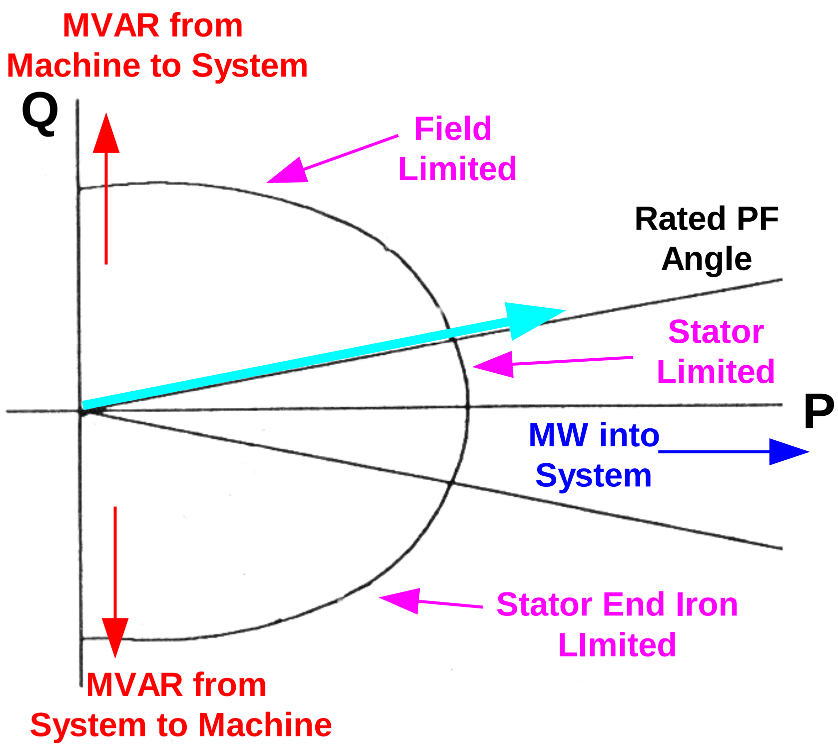
$$Zbase(\sec) = \frac{base\ kV^2}{base\ MVA} \cdot \frac{CTR}{VTR} = \frac{(18kV)^2}{211MVA} \cdot \frac{1600}{157.5} = 15.54\Omega$$

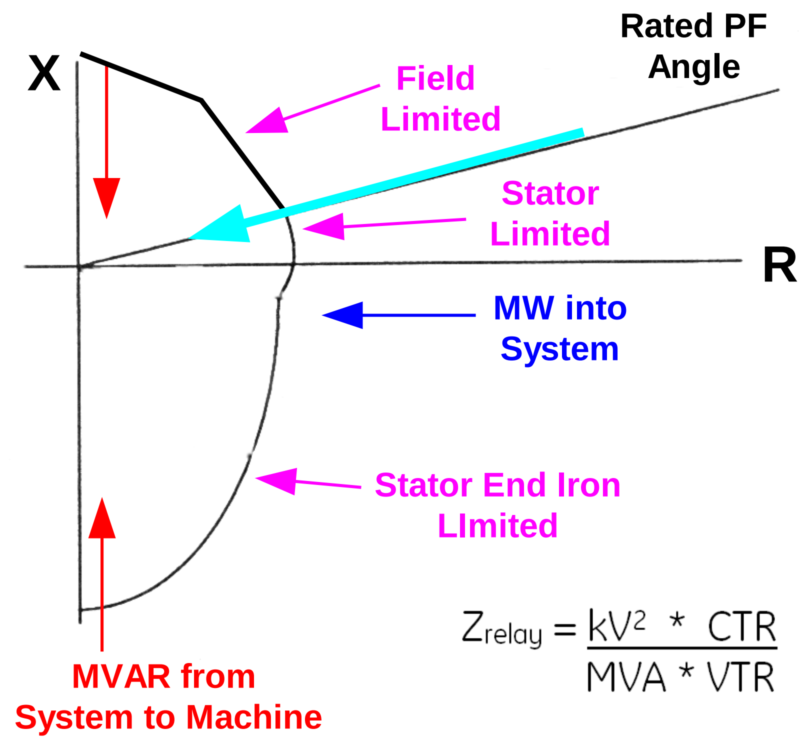
$$X'_d(\sec) = X'_d \cdot Zbase(\sec) = 0.216 \cdot 15.54 = 3.36\Omega$$

$$X_d(\sec) = X_d \cdot Zbase(\sec) = 1.967 \cdot 15.54 = 30.57\Omega$$



PQ vs. R-X





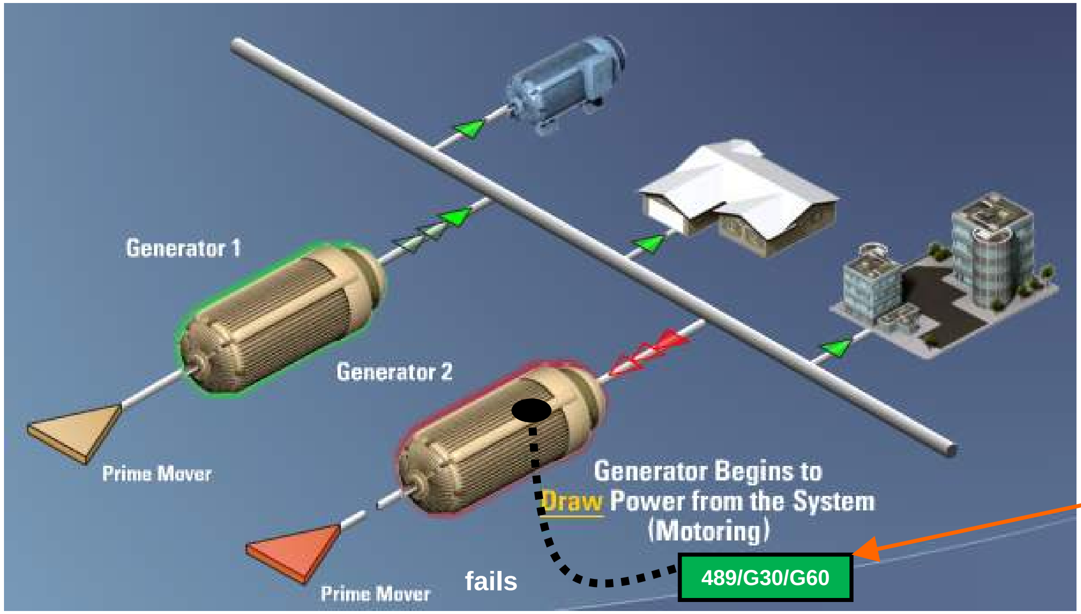
$$Z_{relay} = \frac{kV^2 * CTR}{MVA * VTR}$$

$$Z_{relay} = \frac{V^2 * CTR}{VA * VTR}$$

Reverse Power (32)

> Prevent turbine blade heating and/or damage to mechanical parts from “motoring” (in case the Generator is connected on line, before being ready)

> “Motoring” can happen where the Prime Mover (source of mechanical energy) of the generator fails



Trips to prevent damage to mechanical parts

Reverse Power (32)

> The reverse power element should be set at ½ the rated motoring power

> Pickup is calculated as follows:

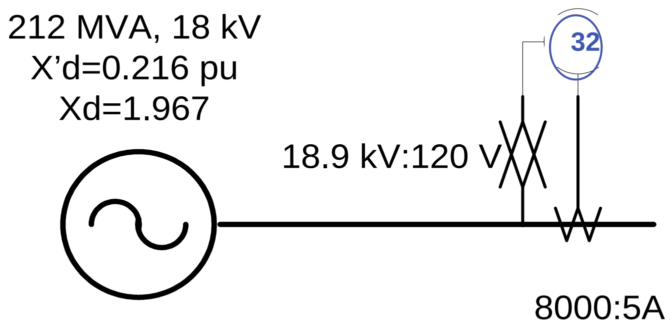
$$S_{min} = \frac{1}{2} \times \frac{\text{Rated Motoring Power (primary watts)}}{3 \times \text{Phase CT Primary} \times \text{Phase VT Ratio} \times \text{Phase VT Secondary}}$$

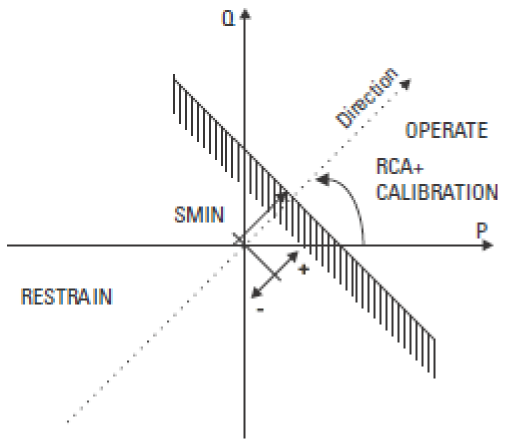
> To prevent mis-operation for power swings, use typical delay of 20 to 30 seconds

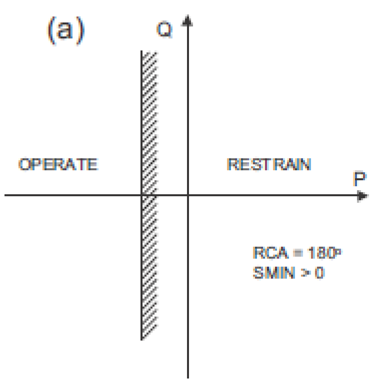
> For sequential tripping applications, time delay will be 2 to 3 seconds

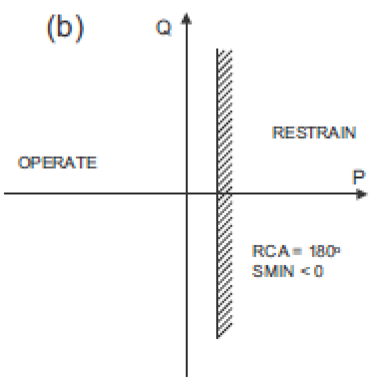
> Block function when the generator is offline

Reverse Power (32)



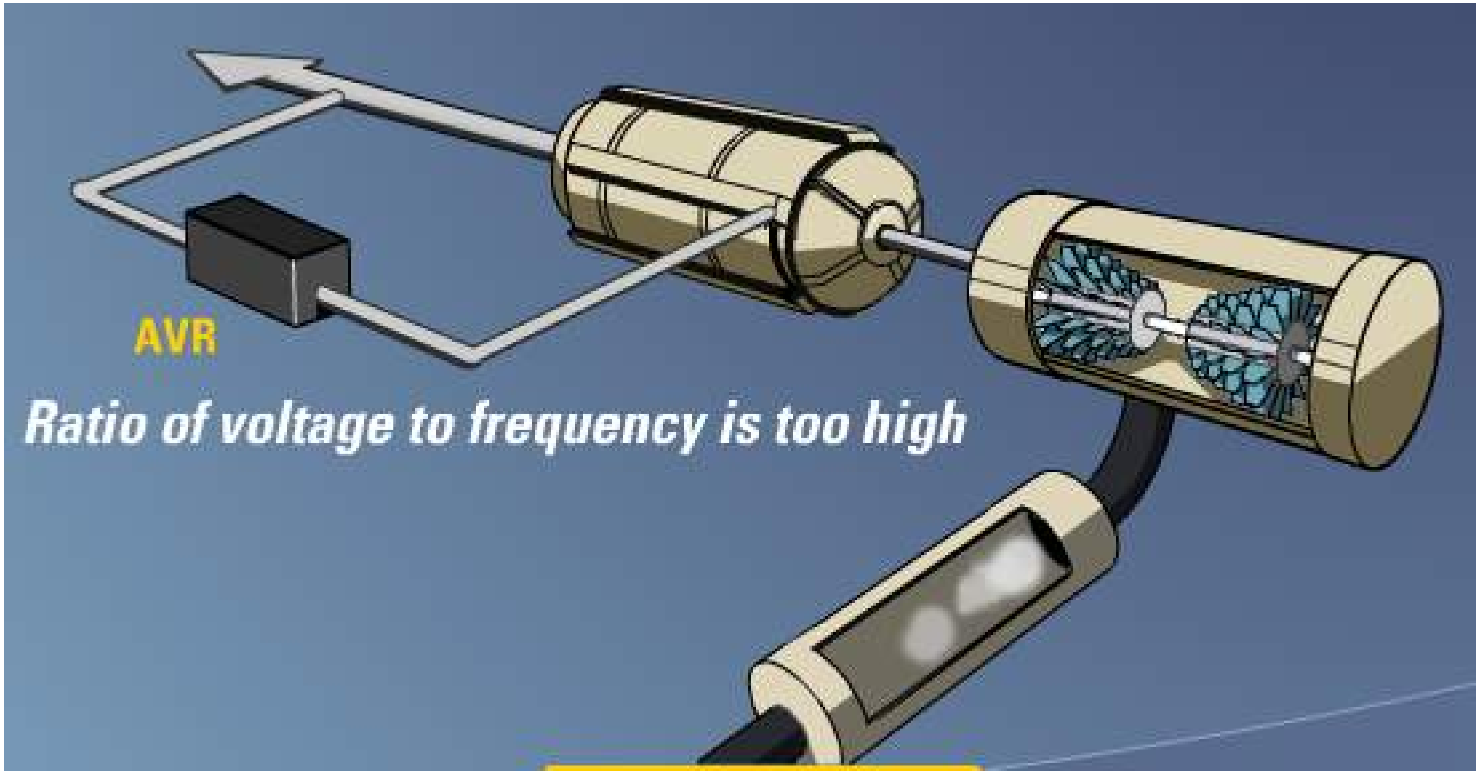






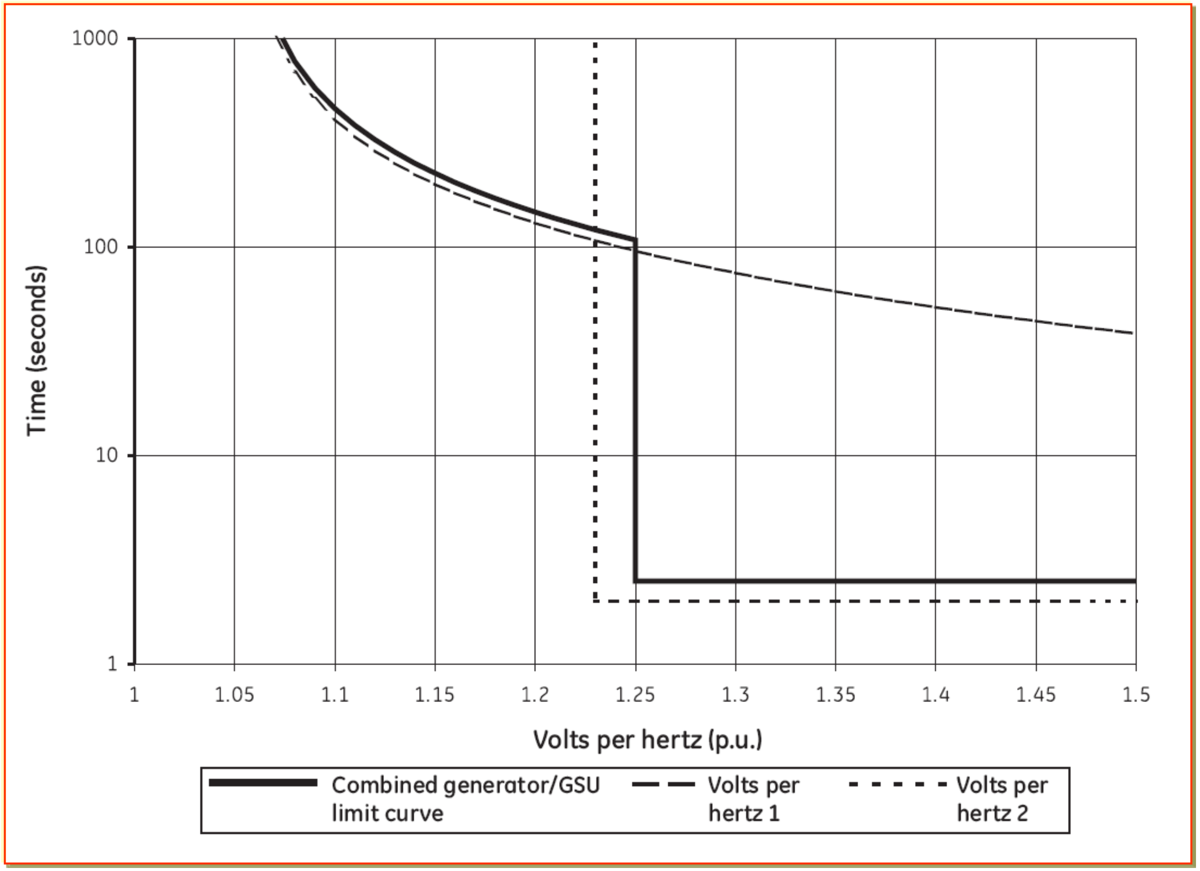
Voltz Per Hertz (24)

> Protect directly and indirectly connected generators from excessive voltage and/or low frequency



Voltz Per Hertz (24)

> Coordinate with manufacturers excitation capability curves. The combined generator/GSU limit curve is shown below:

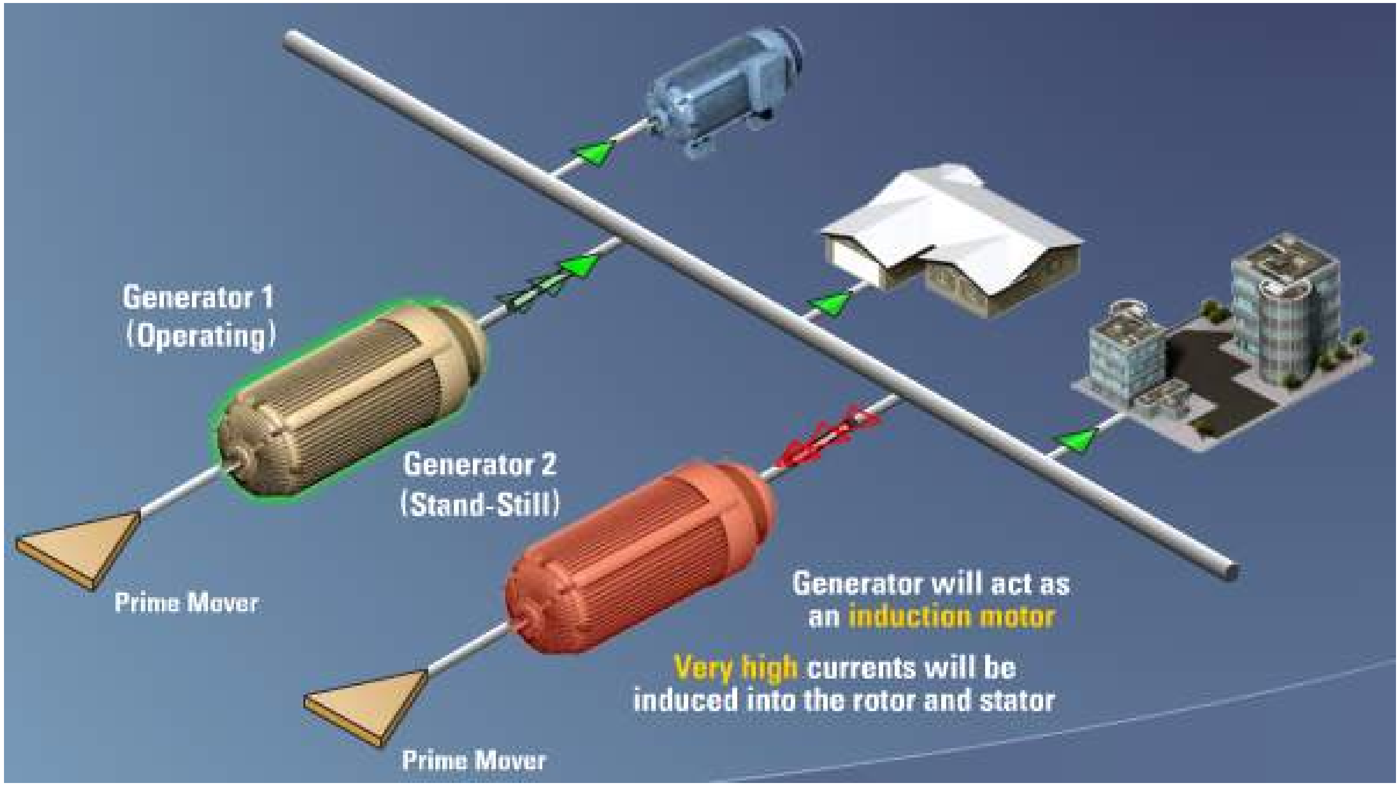


Voltz Per Hertz (24)

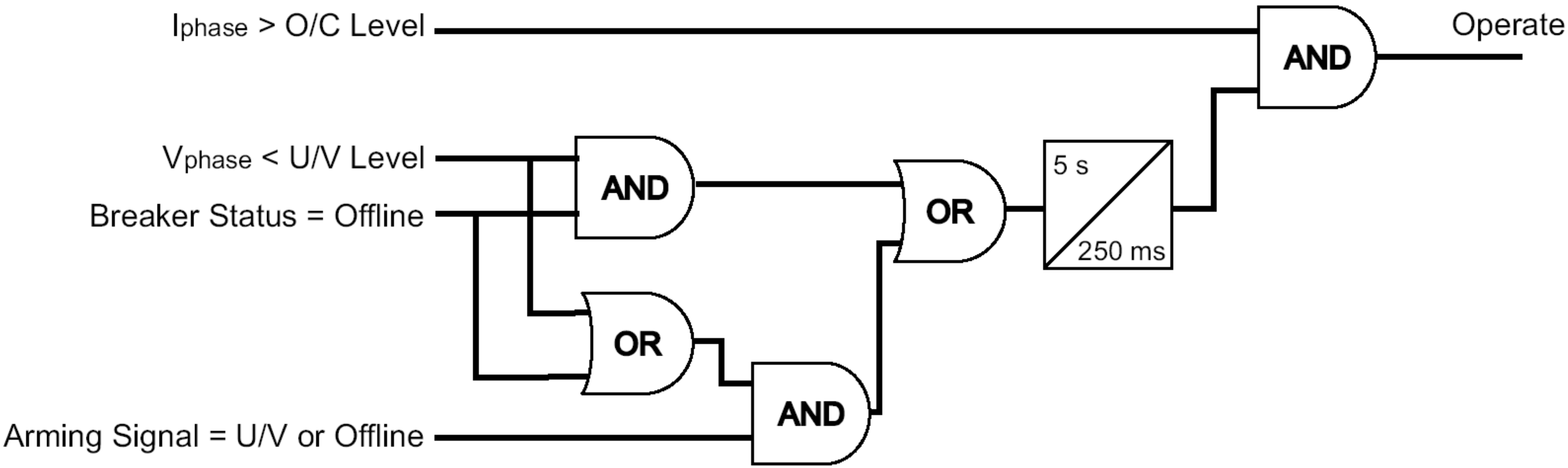
- The measurement of V/Hz will be accurate through a frequency range of 5 to 90 Hz
- Program volts per hertz element 1 with an inverse characteristic (for example: curve A, 1.05 pu pickup, TDM=40)
- Program volts per hertz element 2 with a definite time characteristic (for example: 1.23pu pickup, 2 second time delay)
- Both elements 24-1 and 24-2 issue a trip
- Volts per hertz 1 pickup used to generate an alarm

Generator Protection – Inadvertent Energization:

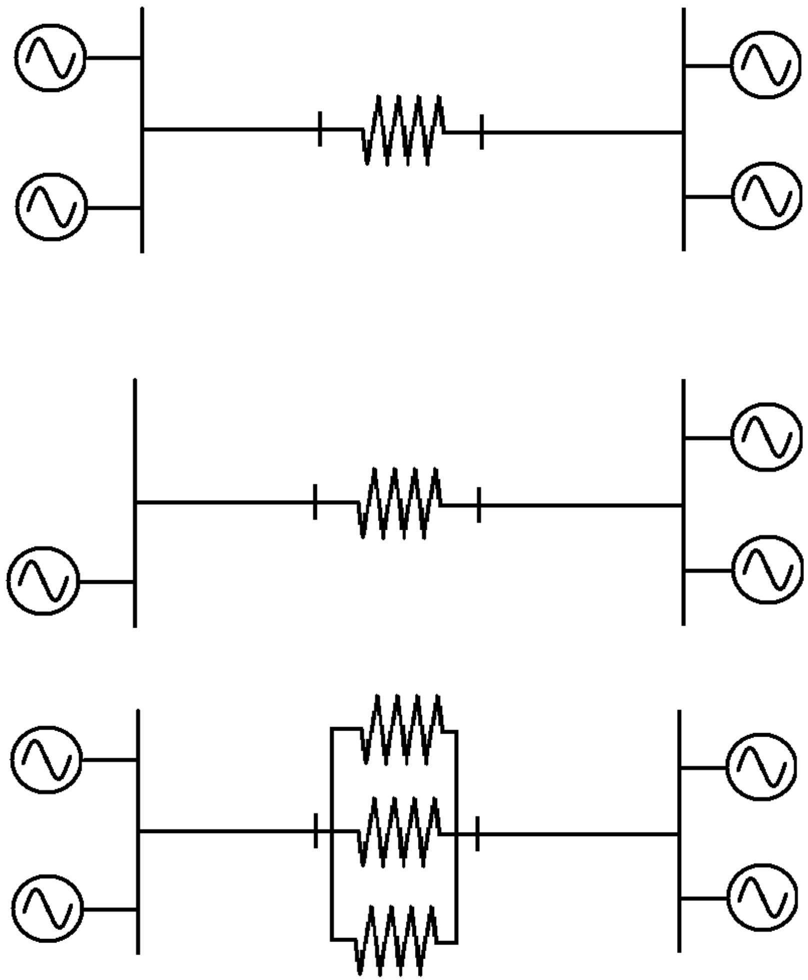
- Protect stator windings and rotor from very high induced currents (in case the Gen. Is connected on line, before being ready- V and f)



Generator Protection – Inadvertent Energization:



Power Swing Block/Trip (78)



Power Swing, which causes a lost of synchronism between neighboring systems for a short time, can occur in the following conditions:

1. Loss of generation with load remaining constant

2. Load increases substantially on a weak system

Out-of-Step Relaying

<u>Out-of-step blocking relays</u>

- Operate in conjunction with mho tripping relays to prevent a terminal from tripping during severe system swings & out-of-step conditions.
- Prevent system from separating in an indiscriminate manner.

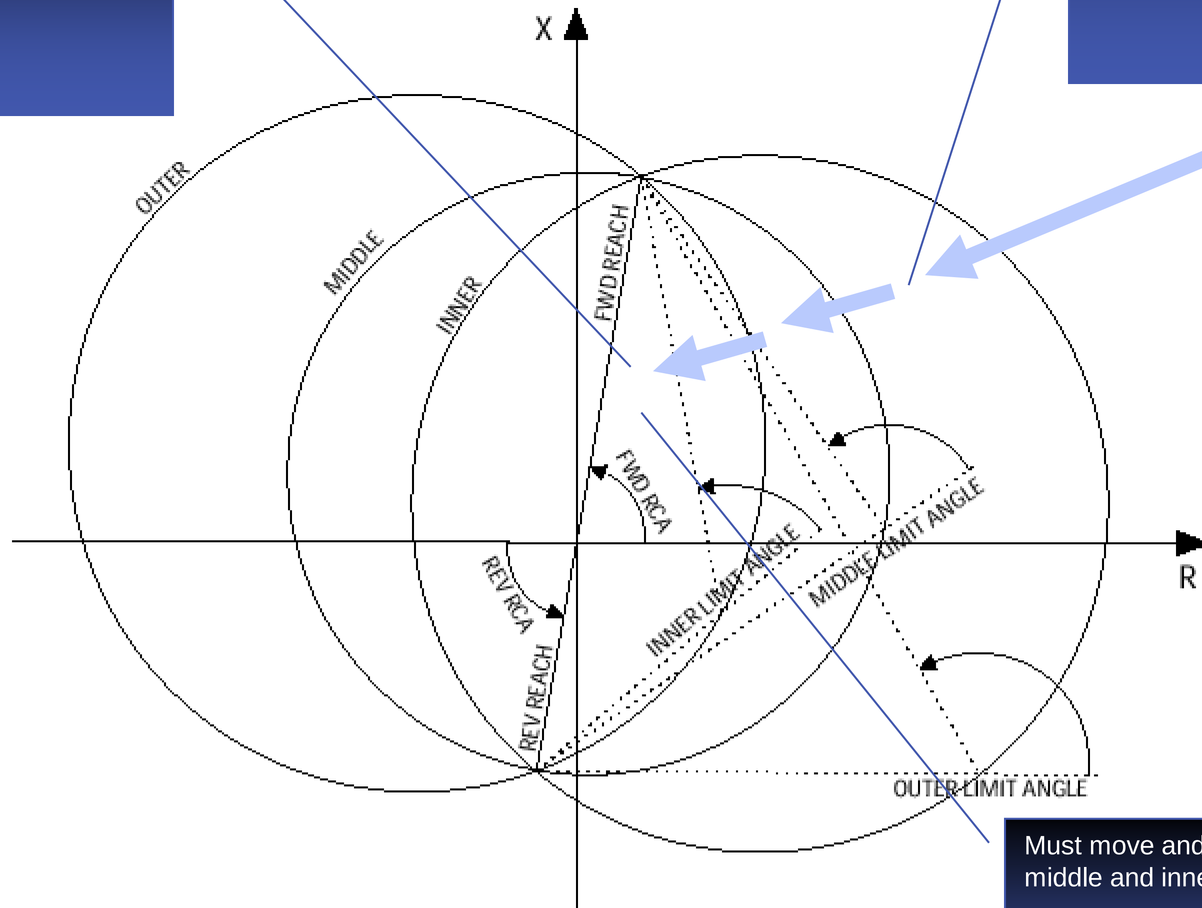
<u>Out-of-step tripping relays</u>

- Operate independently of other devices to detect out-of-step condition during the first pole slip.
- Initiate tripping of breakers that separate system in order to balance load with available generation on any isolated part of the system.

Out-of-Step Tripping

When the inner characteristic is entered the element is ready to trip

The locus must stay for some time between the outer and middle characteristics



Must move and stay between the middle and inner characteristics

Power Swing Blocking

Applications:

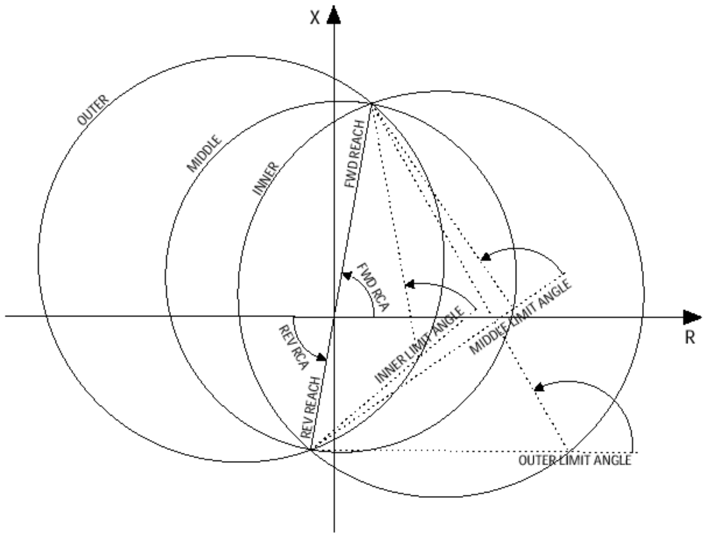
- Establish a blocking signal for stable power swings (Power Swing Blocking)
- Establish a tripping signal for unstable power swings (Out-of-Step Tripping)

Responds to:

- Positive-sequence voltage and current

Block when:

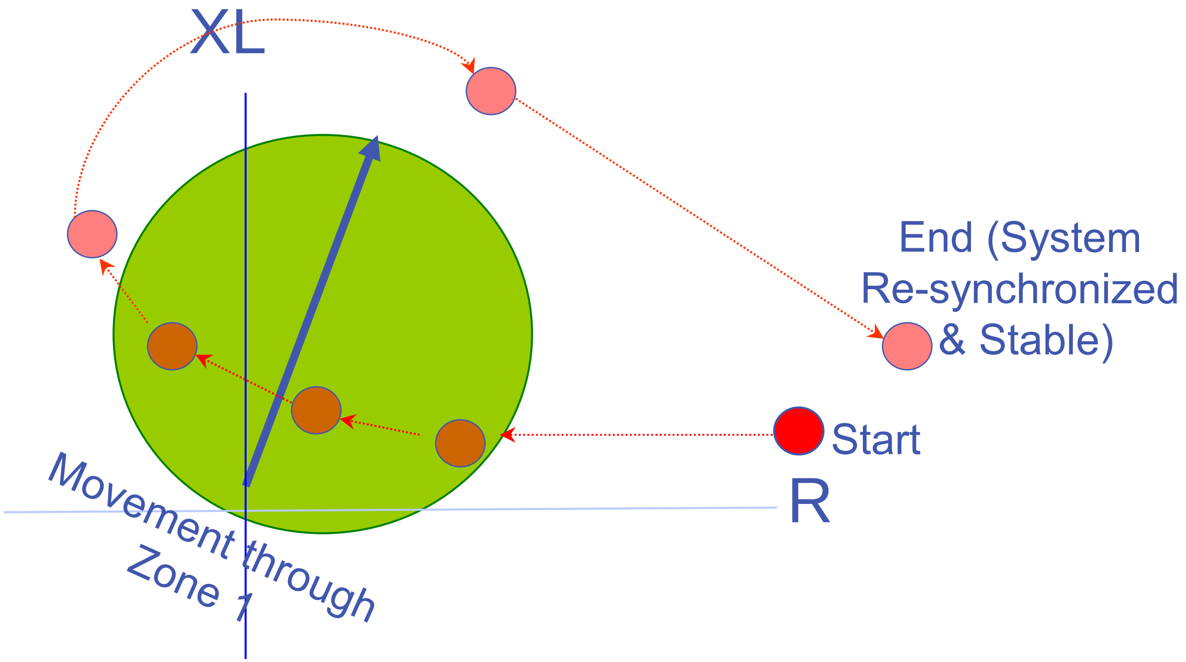
- Generator off-line or VTFF



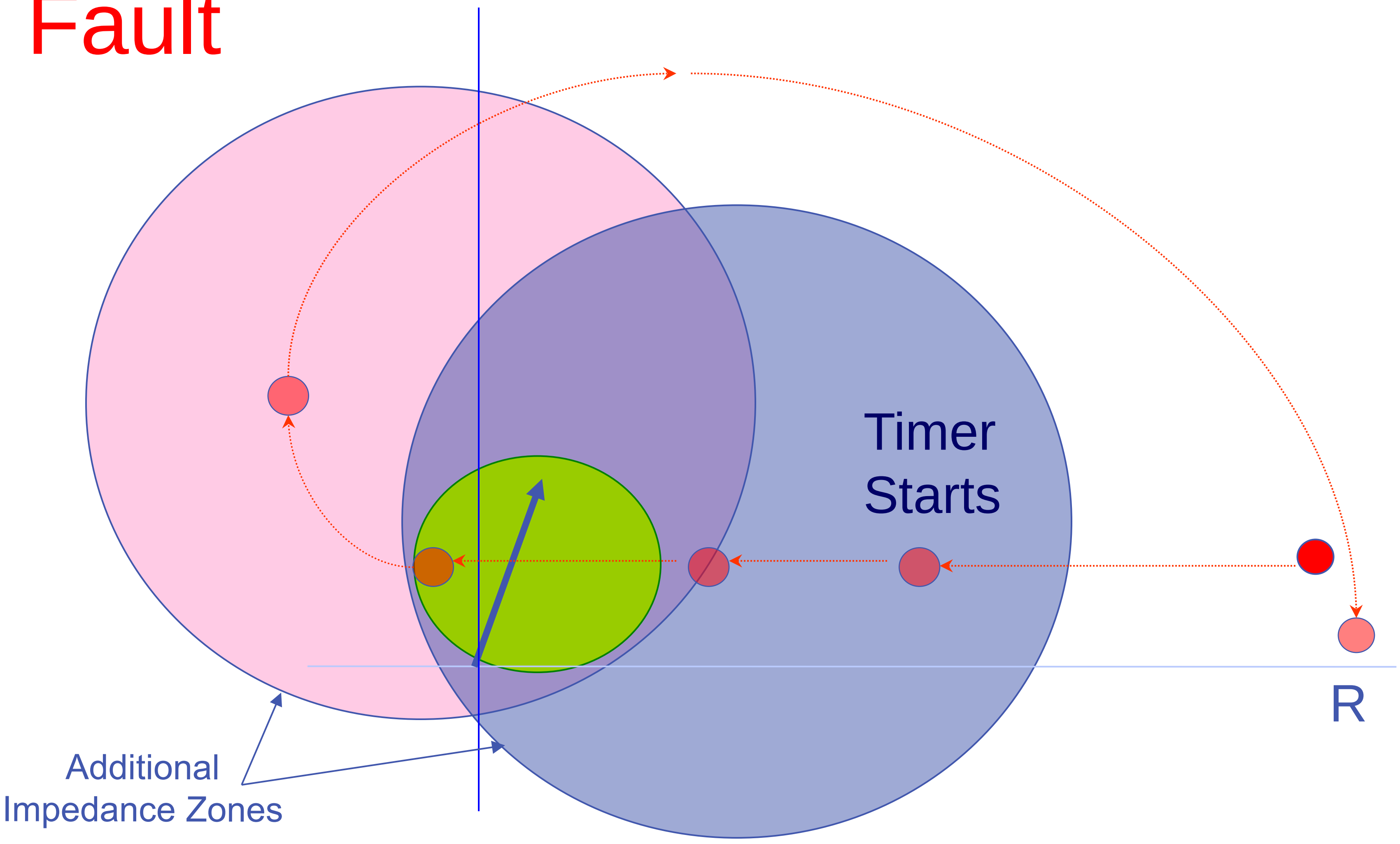
Power Swing Block/Trip (78)

Voltage = High Current = Low	→	Voltage = Low Current = High	→	Voltage = High Current = Low

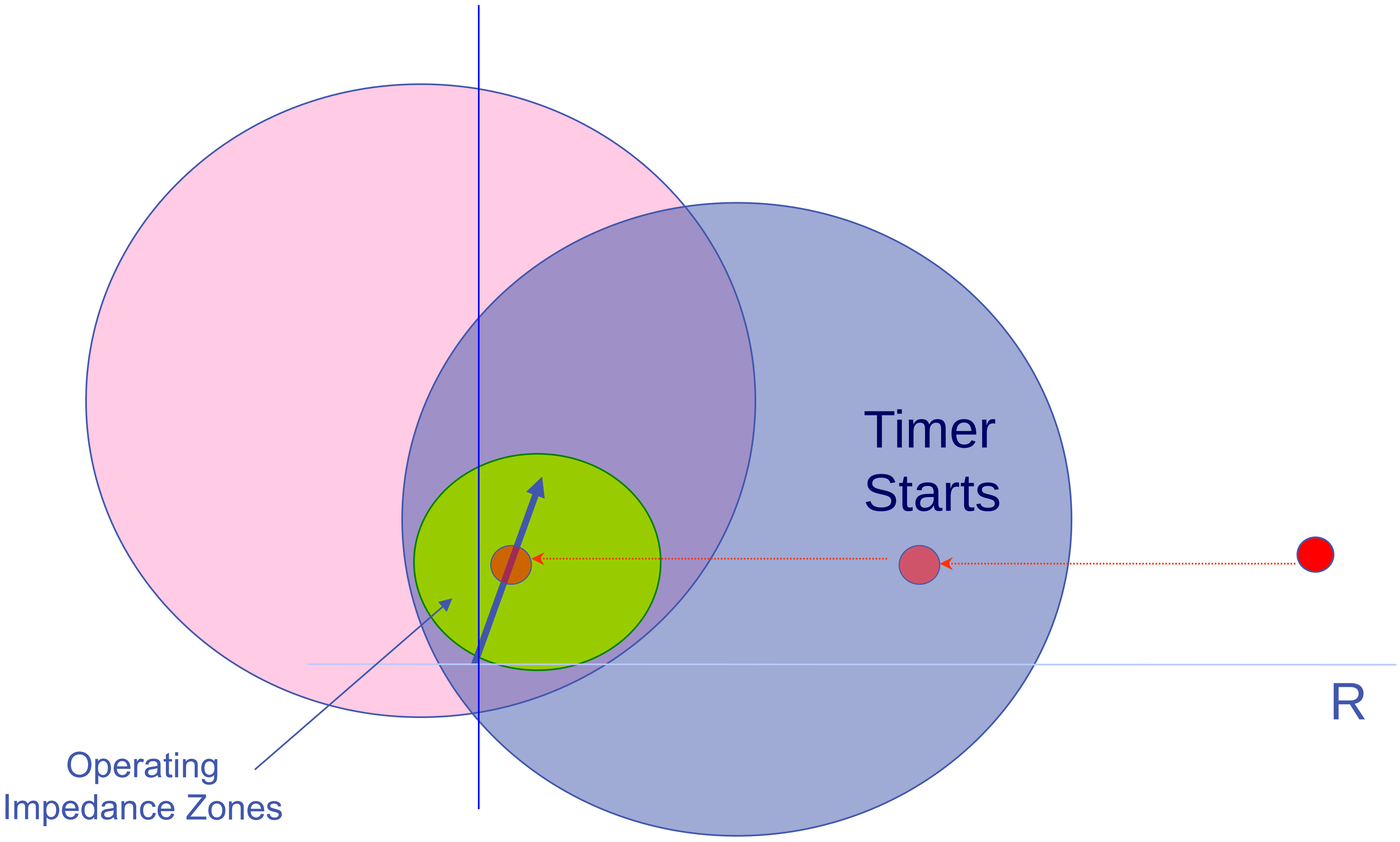
$$Z = \frac{V}{I}$$



Power Swing Block/Trip (78) – No Fault

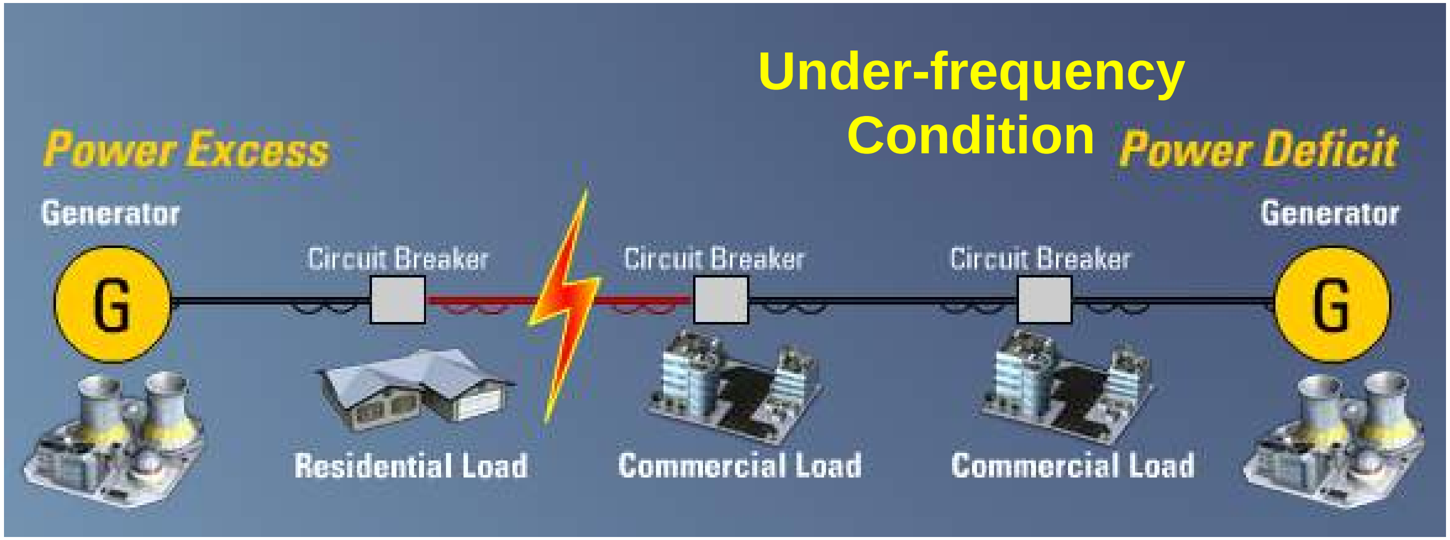


Power Swing Block/Trip - Internal Fault



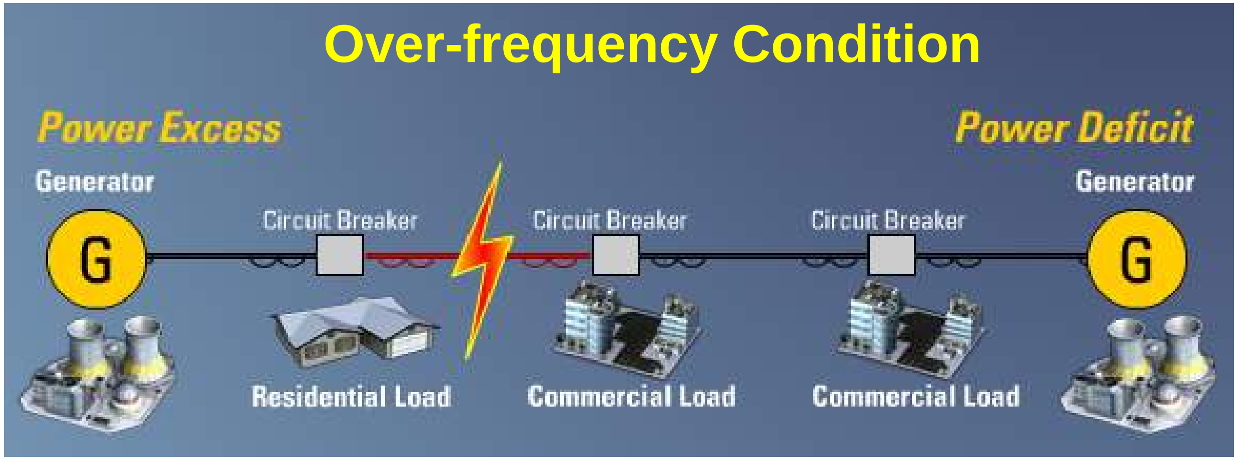
Underfrequency (81U)

- Under-frequency occurs when power system load exceeds prime mover capabilities of generator
- Protect turbine from under-speed
- Pickup and delay settings are dependent on operating practices and system characteristics
- Block underfrequency when offline



Overfrequency (81O)

- Over-frequency occurs when mechanical input to prime mover exceeds electrical load (loss of load due to transmission / feeders disconnection)
- Protect turbine from over-speed or damage due to over-speeding
- Pickup and delay settings are dependent on operating practices and system characteristics
- Block overfrequency when offline



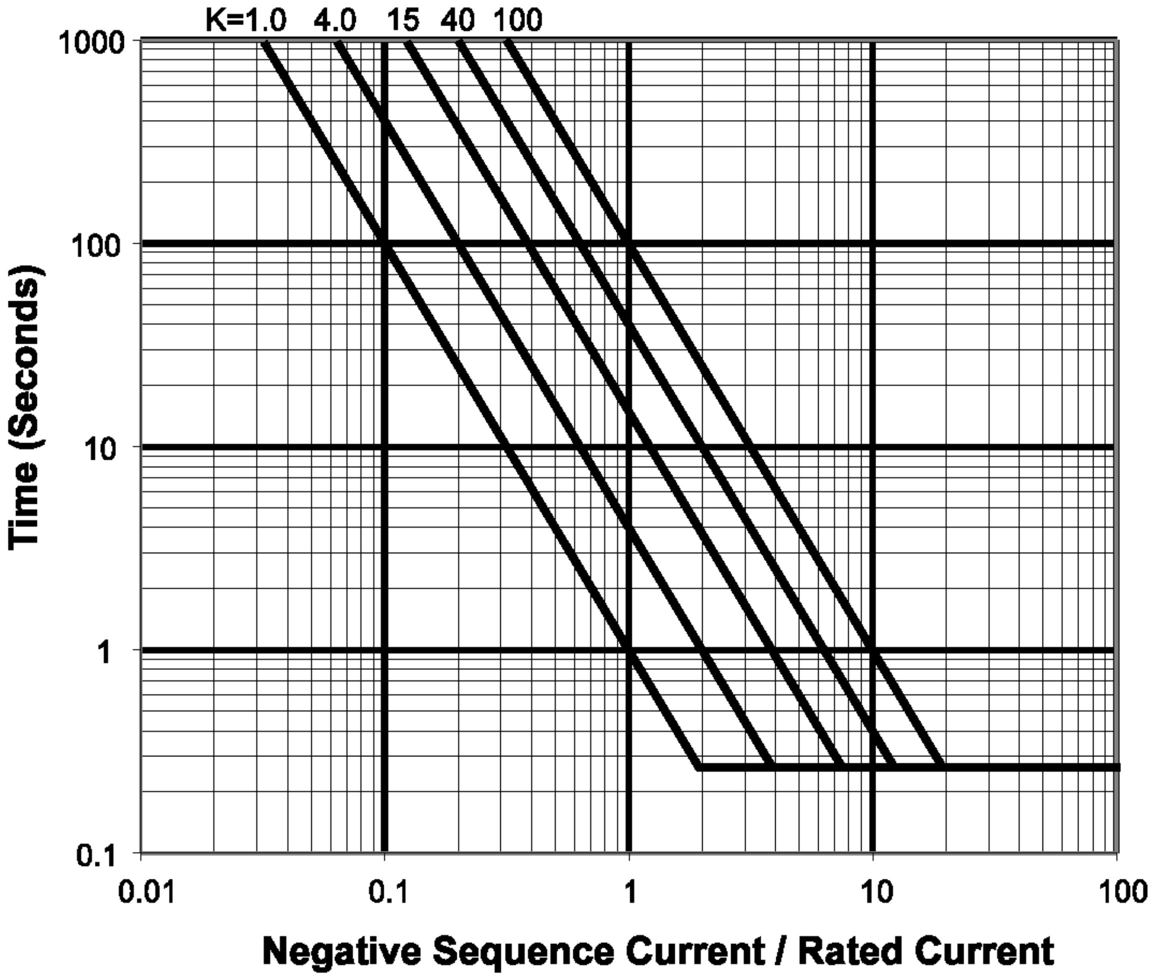
Phase Undervoltage (27)
Phase Overvoltage (59)

- Configured to alarm
- Set undervoltage to 90% with time delay
- Block undervoltage when generator breaker open or VTFF
- Set overvoltage to 110% with time delay

Generator Protection – Negative Sequence:

- Protect rotor from heating due to negative sequence currents

Generator Protection – Negative Sequence:



- The K curve that is selected must match the generator curve (From the family of biased curves and K.
- K is proportional to the Gen. TC Thermo-Capacity)

Tripping Philosophy & Sequential Tripping

- Machines may be shutdown for faults, abnormal operating conditions or for a scheduled off-line period
- Shutdowns may be whole or partial
- Shutdowns may lock out (LOR) or be self resetting (94)

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Tripping Philosophy & Sequential Tripping

- Unit separation
  - Used when machine is to be isolated from system, but machine is left operating so it can be synced back to the system after separating event is cleared
  - Only generator breaker(s) are tripped
- Generator Trip
  - Used when machine is isolated and overexcitation trip occurs
  - Exciter breaker is tripped (LOR) with generator breakers already opened

Tripping Philosophy & Sequential Tripping

- Simultaneous Trip (Complete Shutdown)
  - Used when internal (in-zone) protection asserts
  - Generator and exciter breakers are tripped (LOR)
  - Prime mover shutdown initiated (LOR)
  - Auxiliary transfer (if used) is initiated
- Sequential Trip
  - Used for taking machine off-line (unfaulted)
    - Generator and exciter breakers are tripped (94)
    - Prime mover shutdown initiated (94)
    - Auxiliary transfer (if used) is initiated

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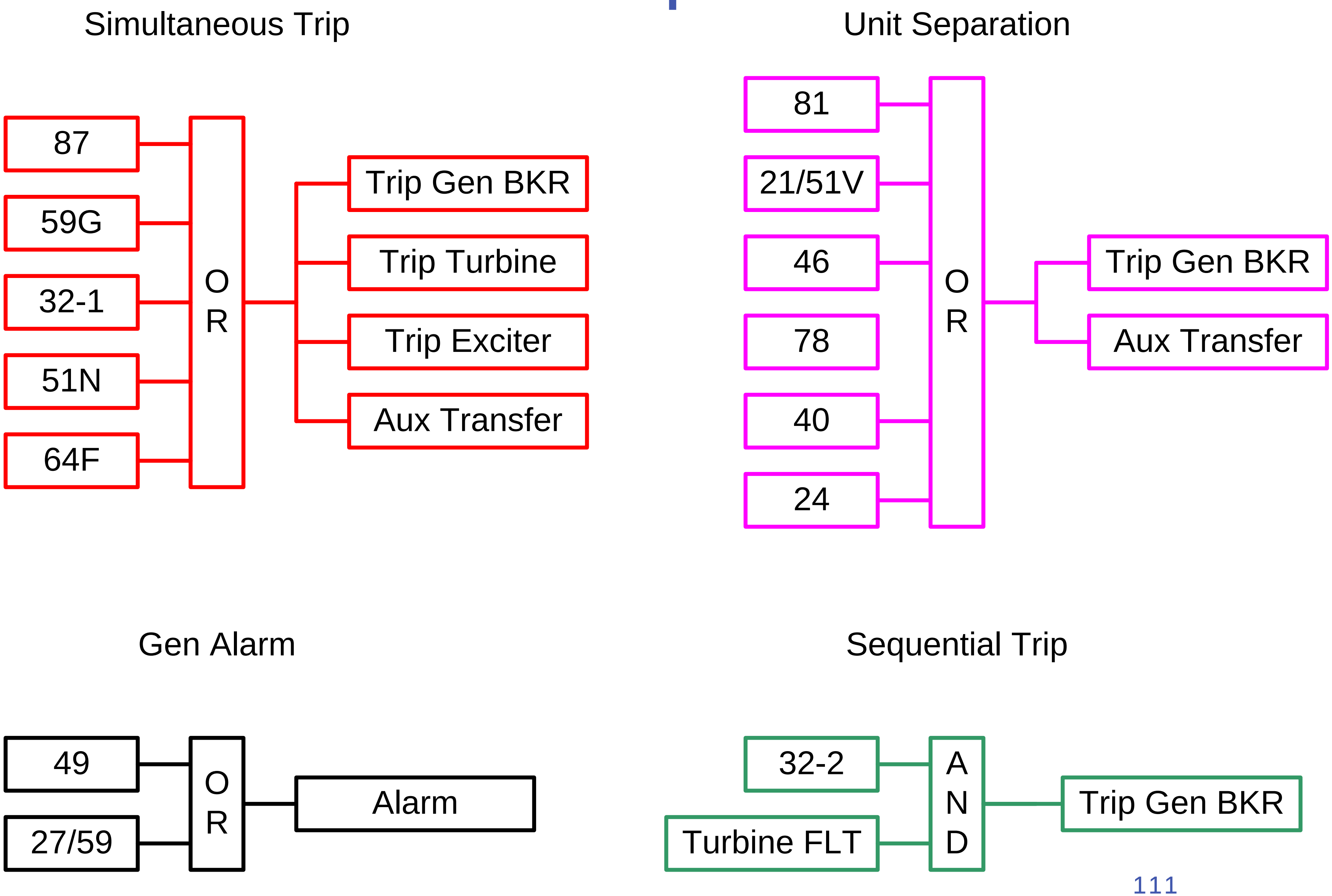
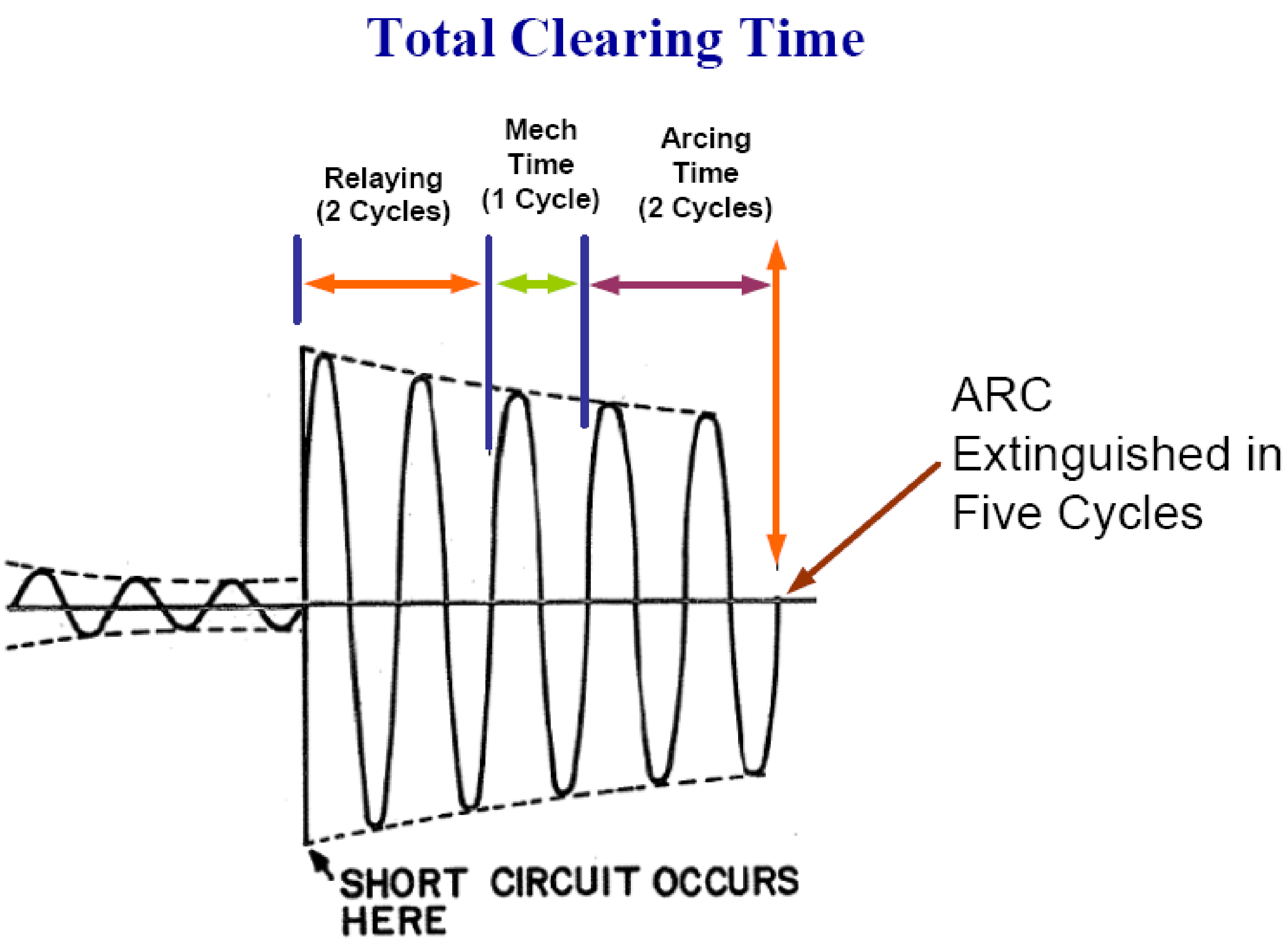
Trip Outputs Example

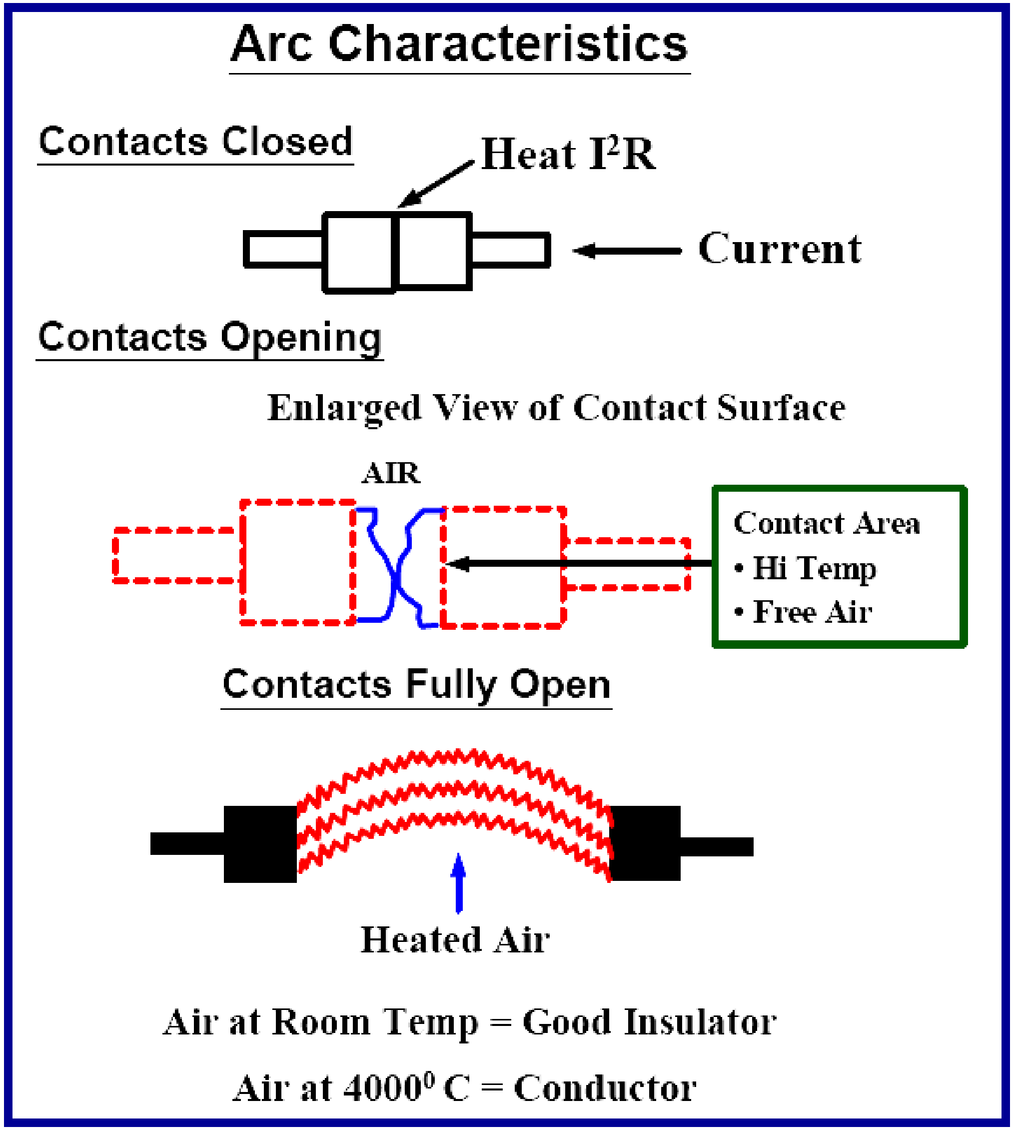


Arc Flash Solutions

A Study of a Fault…….



Fault Interruption and Arcing



Arcs can reach temperatures of over 35,000°F (19,427°C)

Arc Flash Mitigation: Problem Description

- An electric arc flash can occur if a conductive object gets too close to a high-amp current source or by equipment failure (ex., while opening or closing disconnects, racking out)
  – The arc can heat the air to temperatures as high as 35,000 F, and vaporize metal in equipment
  – The arc flash can cause severe skin burns by direct heat exposure and by igniting clothing
  – The heating of the air and vaporization of metal creates a pressure wave (arc blast) that can damage hearing and cause memory loss (from concussion) and other injuries.
  – Flying metal parts are also a hazard.

Methods to Reduce Arc Flash Hazard

- Arc flash energy may be expressed in I^2t terms, so you can decrease the I or decrease the t to lessen the energy
- Protective relays can help lessen the t by optimizing sensitivity and decreasing clearing time
  - Protective Relay Techniques
- Other means can lessen the I by limiting fault current
  - "Non-Protective Relay Techniques"

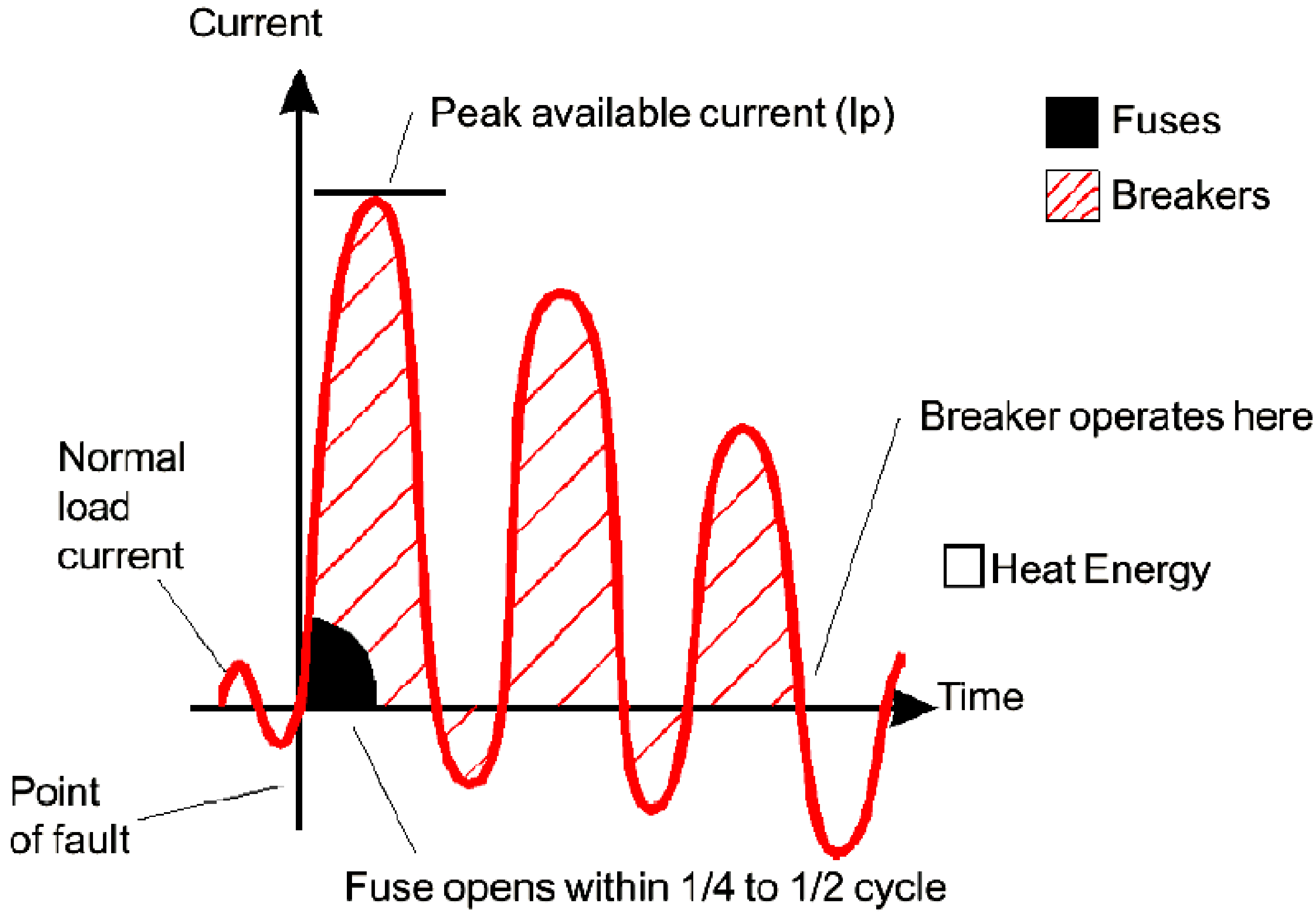
Non-Protective Relaying Methods of Reducing Arc Flash Hazard

- System design modifications increase power transformer impedance
  - Addition of phase reactors
  - Faster operating breakers
  - Splitting of buses
- Current limiting fuses (provides partial protection only for a limited current range)
- Electronic current limiters (these devices sense overcurrent and interrupt very high currents with replaceable conductor links (explosive charge)
- Arc-resistant switchgear (this really doesn't reduce arc flash energy; it deflects the energy away from personnel)
- Optical arc flash protection via fiber sensors
- Optical arc flash protection via lens sensors

Protective Relaying Methods of Reducing Arc Flash Hazard

- Bus differential protection (this reduces the arc flash energy by reducing the clearing time
- Zone interlock schemes where bus relay selectively is allowed to trip or block depending on location of faults as identified from feeder relays
- Temporary setting changes to reduce clearing time during maintenance
  - **Sacrifices coordination**
- FlexCurve for improved coordination opportunities
- Employ 51VC/VR on feeders fed from small generation to improve sensitivity and coordination
- Employ UV light detectors with current disturbance detectors for selective gear tripping

Fuses vs. Relayed Breakers



Arc Flash Hazards

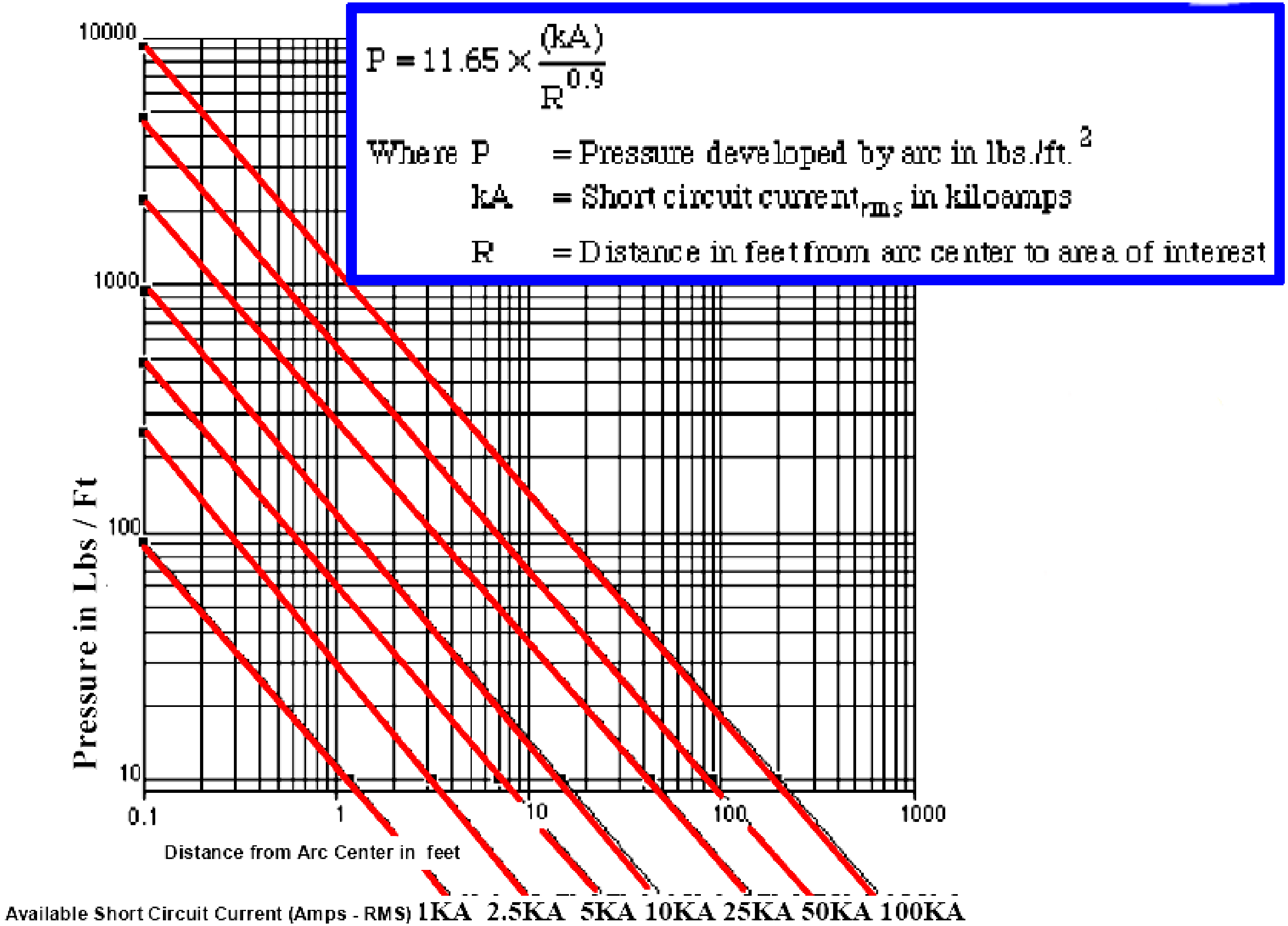
Skin Temperature	Time of Skin Temp.	Damage Caused
110 °F	6 Hours	Cell breakdown starts
158 °F	1 sec.	Total cell destruction
176 °F	0.1 sec	Curable burn
200 °F	0.1 sec	Incurable burn

NFPA-70E 2004 Equipment Requirements

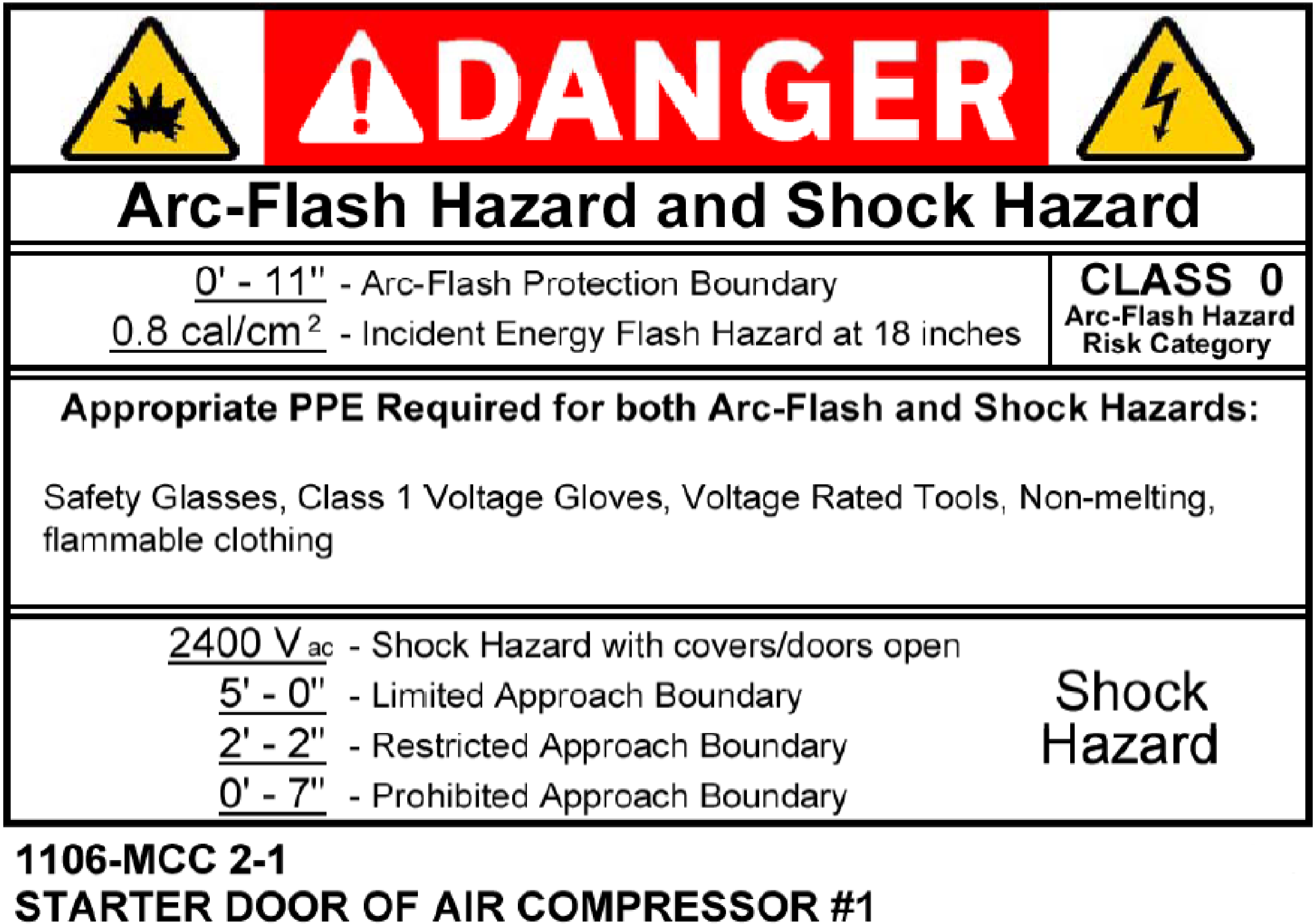
Category	Energy Level	Typical Personal Protective Equipment required
0	1.2 cal/cm²	Non-melting flammable materials
1	5 cal/cm²	Fire Resistant (FR) shirt and FR pants
2	8 cal/cm²	FR shirt, FR pants, cotton underwear
3	25 cal/cm²	Two layers FR clothing, cotton underwear
4	40 cal/cm²	FR shirt, FR pants, multilayer flash suit, cotton underwear

Other:
Face Protection Face Shield and/or safety glasses
Hand Protection Leather over rubber for arc flash protection
Leather work boots above 5 cal/cm²

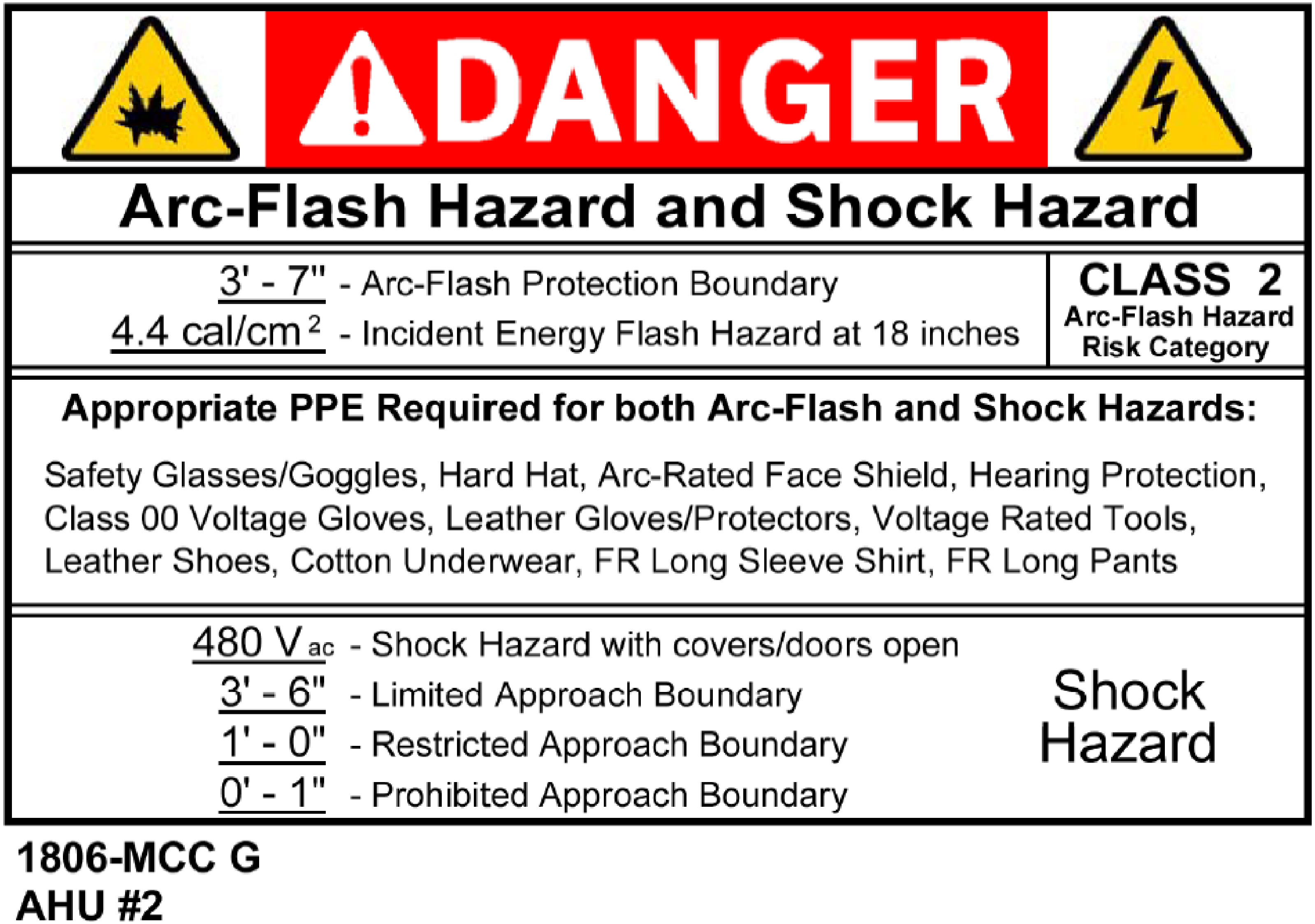
Arc Pressure Wave



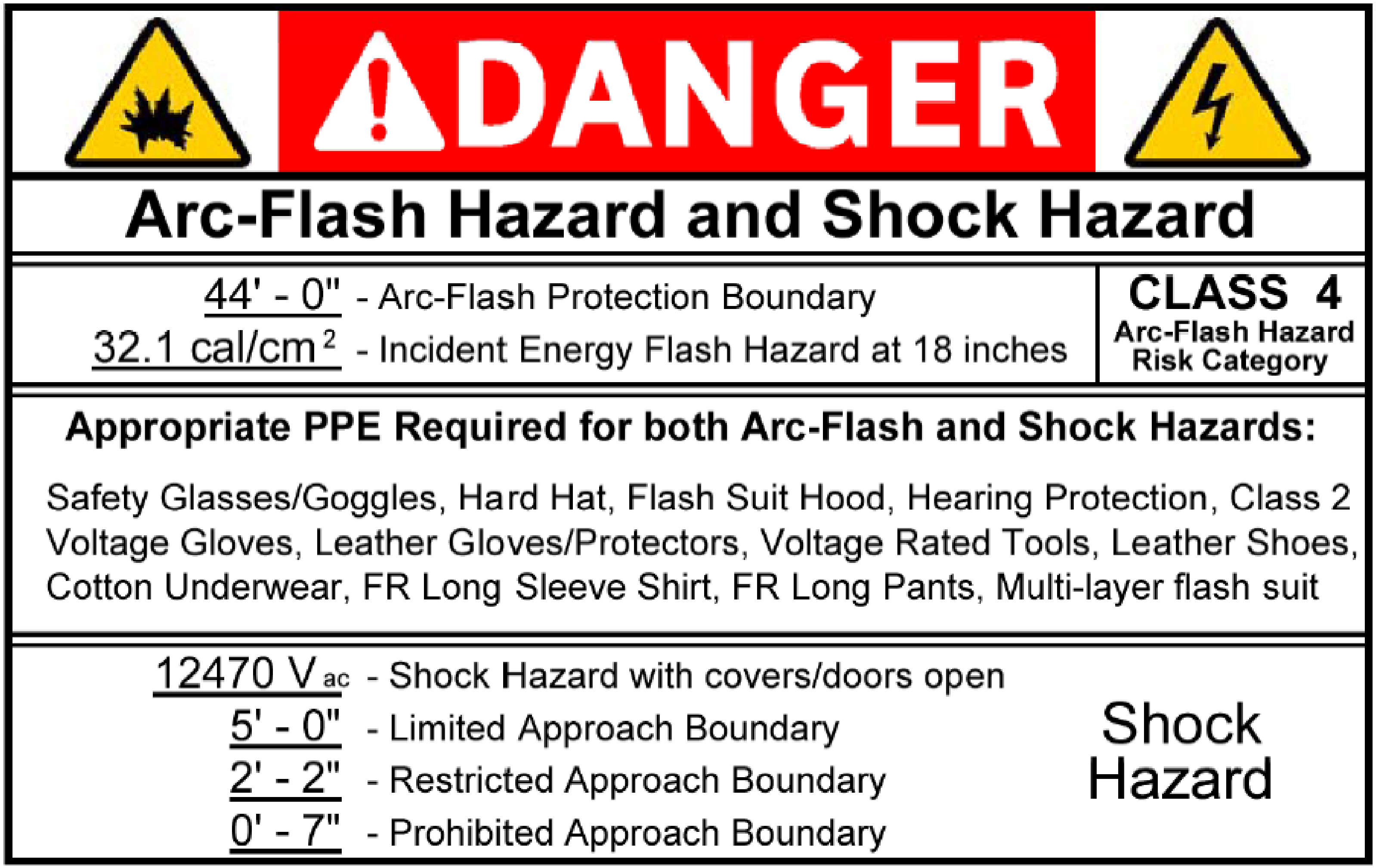
Arc Flash Warning Example 1



Arc Flash Warning Example 2



Arc Flash Warning Example 3



1020-SUB2 BUS B2
REAR OF 2-12A CUBICLE

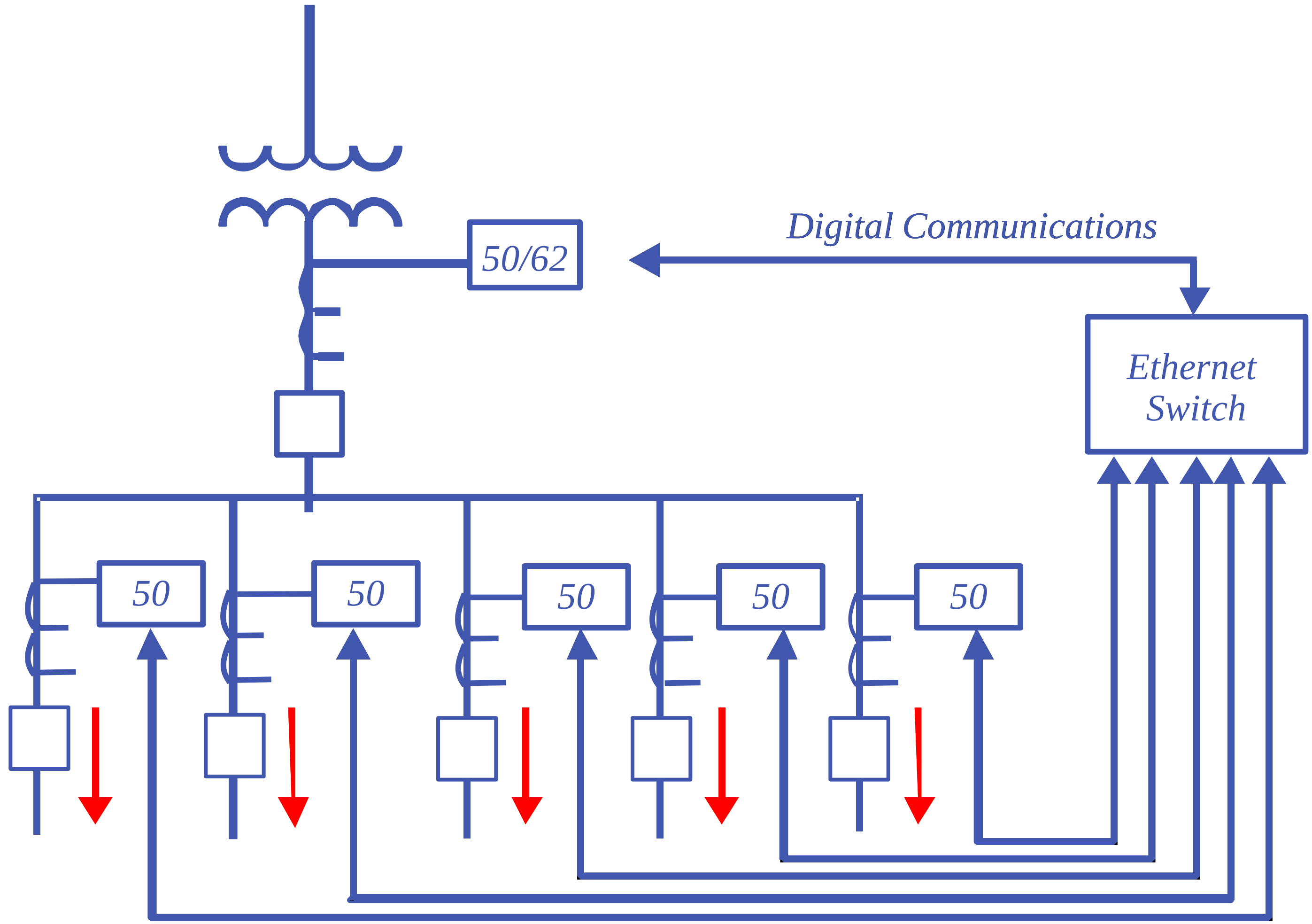
Arc Flash Solutions

Relaying Techniques to Reduce Arc Flash Energy

1-2 ms	Install discrete Arc Flash Detection device
1 cycle	Implement low impedance bus protection
1.5 to 2 cycles	Implement instantaneous overcurrent tripping using maintenance setting group in relay. Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary
1.5 to 2 cycles	Implement high impedance bus protection
3-4 cycles	Implement bus zone interlocking scheme
20.0 cycles	Breaker failure protection
Seconds	Reduce coordination intervals of existing time-overcurrent relays

Time to clear saves lives

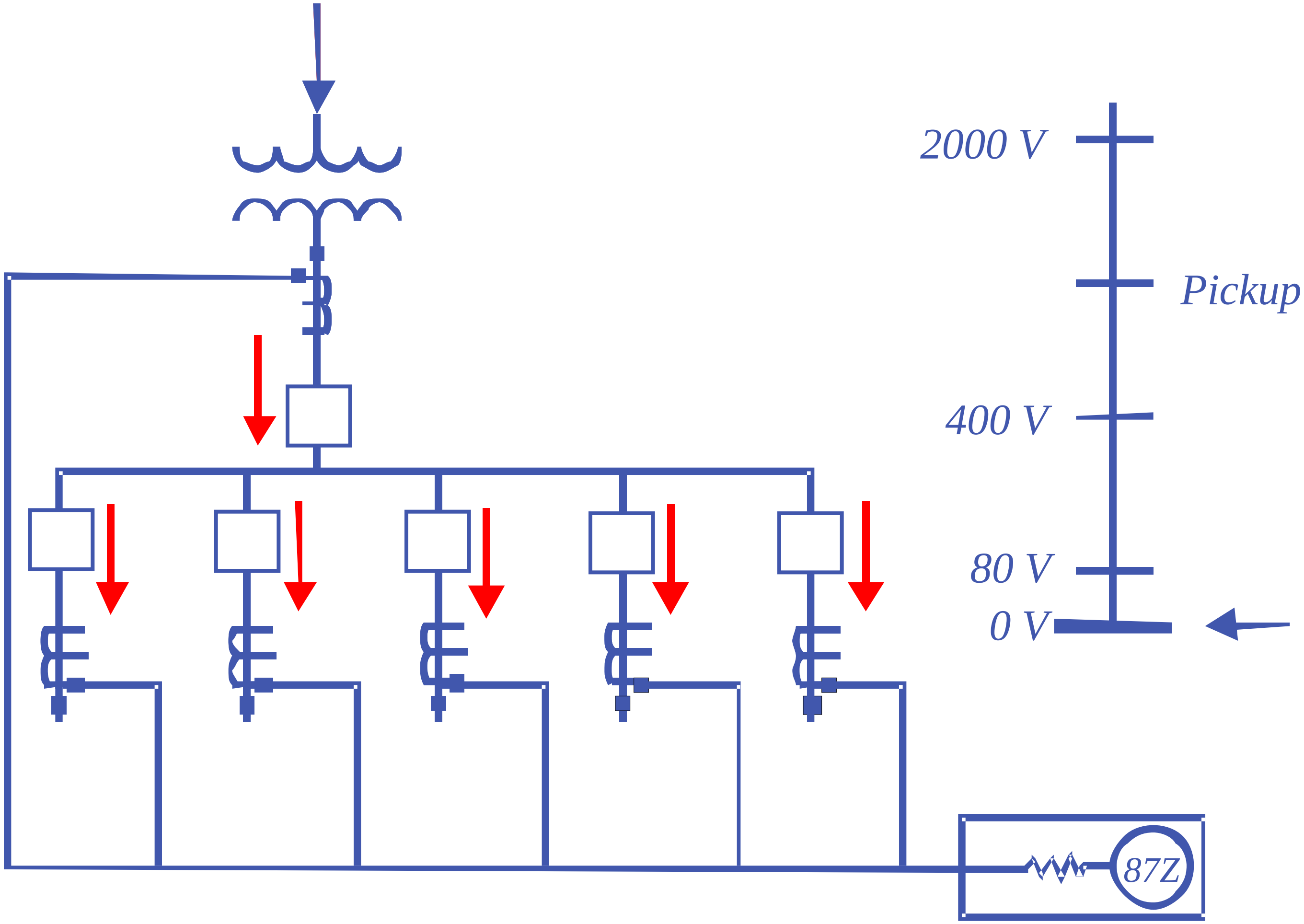
Arc Flash Solutions
Bus Interlock Scheme



3-4 Cycles Detection

Arc Flash Solutions

High Impedance Bus Differential



1.5 to 2 Cycles Detection

Arc Flash Solutions

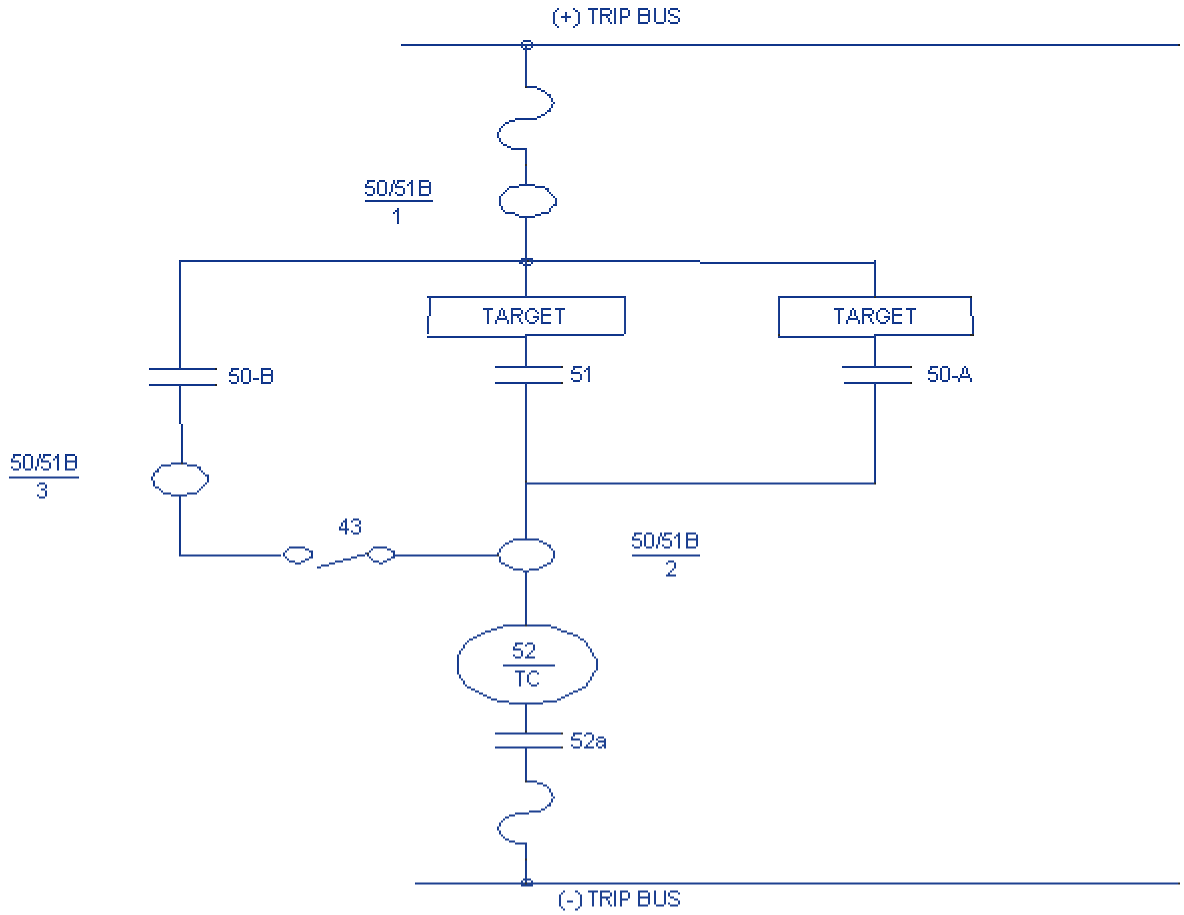
Enable Maintenance Mode

Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary.

Replacement Relays: 2nd 50 element
Multifunction Relays: setting groups
Multifunction Relays: multiple 50's

Arc Flash Solutions

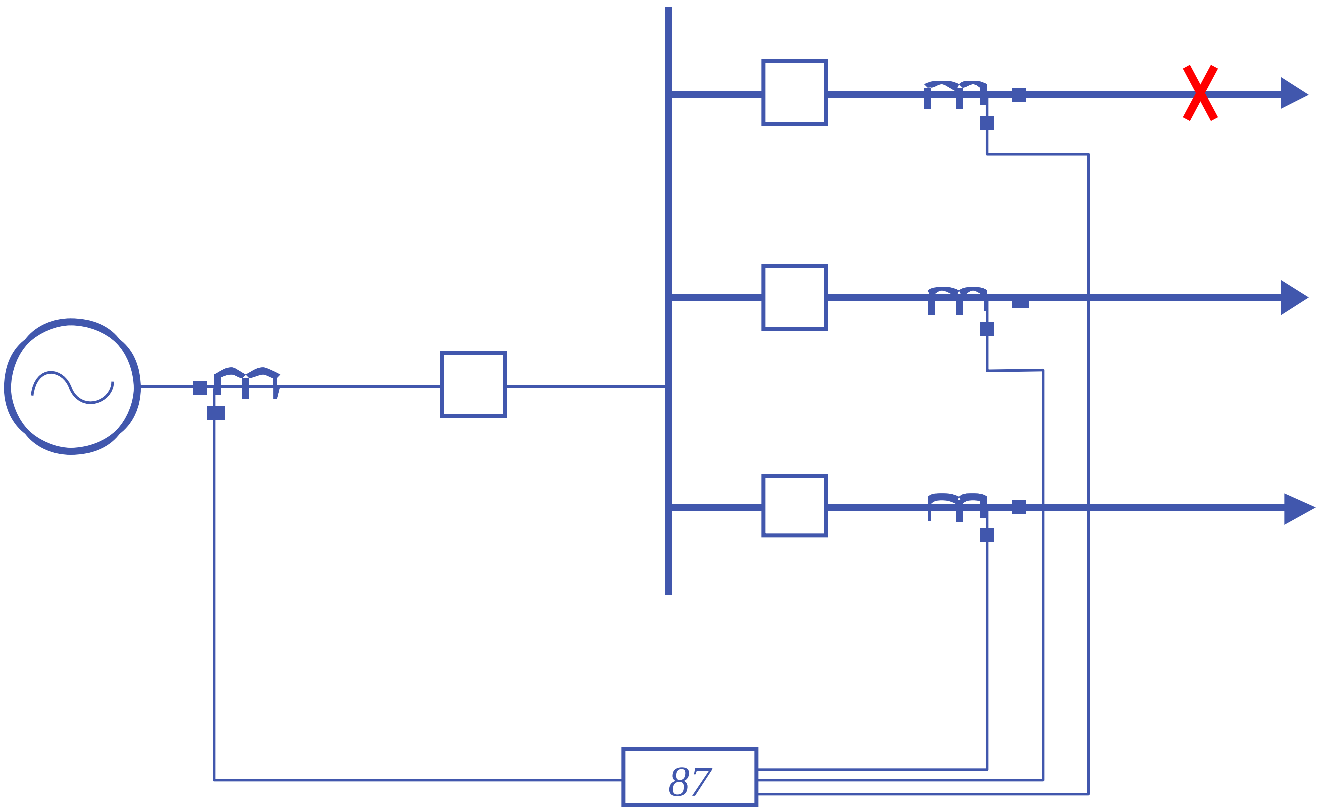
2nd Instantaneous Overcurrent Element



1.5 to 2 Cycles Detection

Arc Flash Solutions

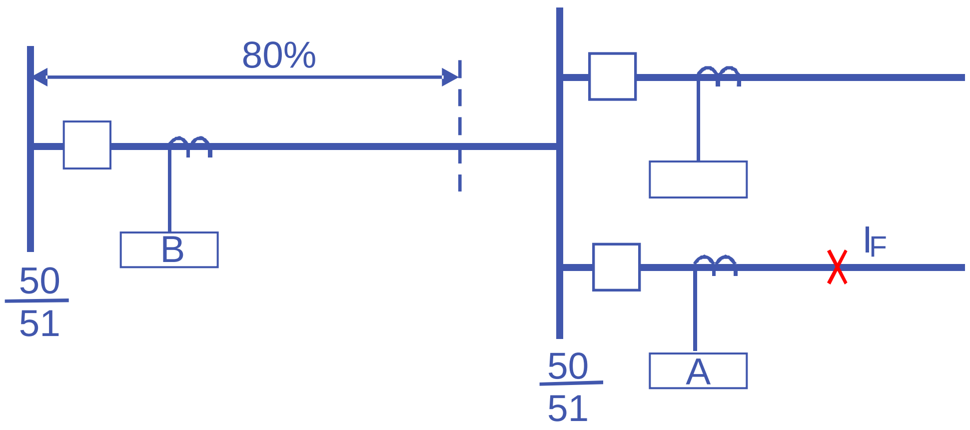
Low Impedance Bus Differential



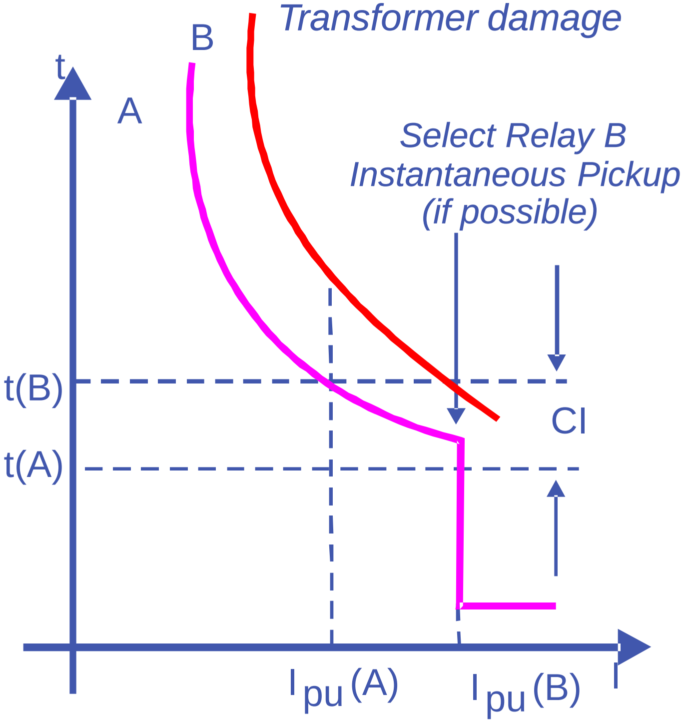
1 Cycle Detection

Arc Flash Solutions

Time Current Coordination



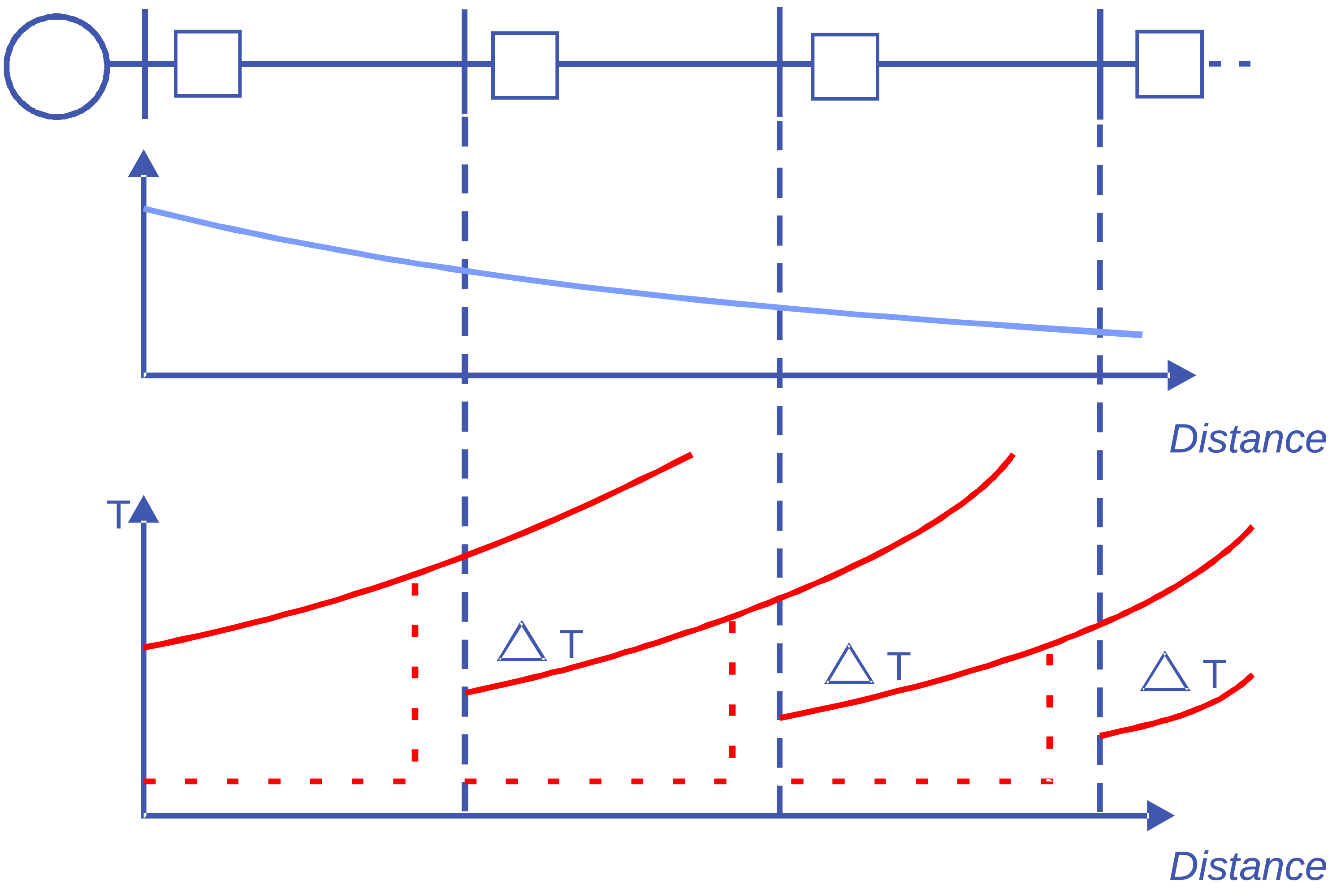
A = *Downstream feeder relay with the highest settings*



Use I_{pu} (A) *for coordination*

Arc Flash Solutions

Fault Current and Operate Time



ARC FLASH DETECTION METHODS

Traditional Arc Flash Detection Methods

Light Sensing

- Why Light Sensors?
  - Accelerate the trip time during arc flash events

- Two types of light sensors:
  - Point sensors – provides a focused view, which minimize susceptibility to external light noise, but has limited range
  - Loop sensors – provides ability to collect light and channel it to a sensor along the fiber to the end of the fiber, but can be challenging to install and troubleshoot

- Cons:
  - High susceptibility to false triggers if light sensing threshold not set high enough
  - Fiber loops can be easily damaged due to bending or pinching
  - Difficult to install or re-install if fiber loop is damaged

Traditional Arc Flash Detection Methods

Light and Current Sensing

- Pros:
  - Additional Current input minimizes the probability of a false trigger

- Cons:
  - Requires the use of CT’s and overcurrent protection device
  - Comparatively more cost and complexity

A Novel Approach : Light And Sound Sensing based Detection

A Unique Light and Sound Signature

Light & Pressure Wave Detection

- In an arc flash condition, every millisecond counts…
- Known and standard time relationship from the difference between a light signal ($3x10^8$m/s) and an associated pressurized sound wave (343 m/s) generated unique time delay signature

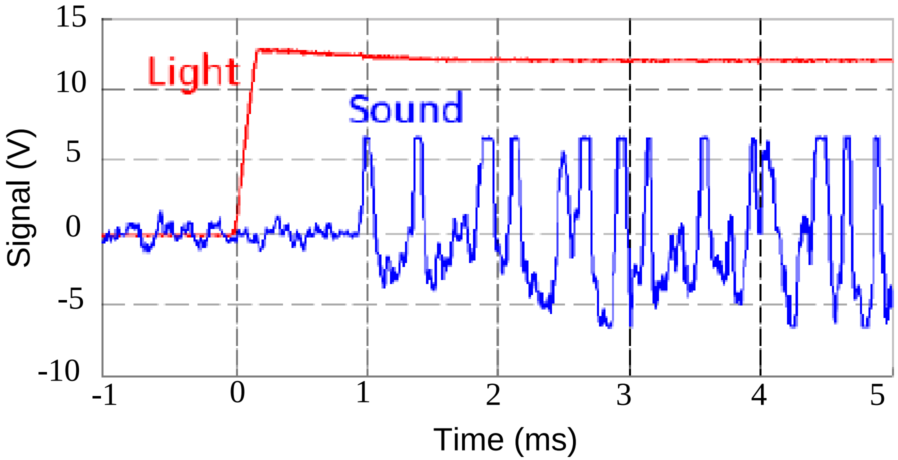
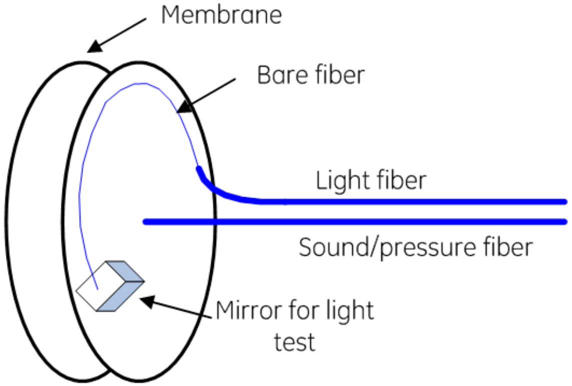


Figure 1: light and pressure wave signal during the Arc Flash event

Light & Sound Sensor – US Patent

- US Patent 8040517- novel sensor technology to detect both arc flash induced light and sound



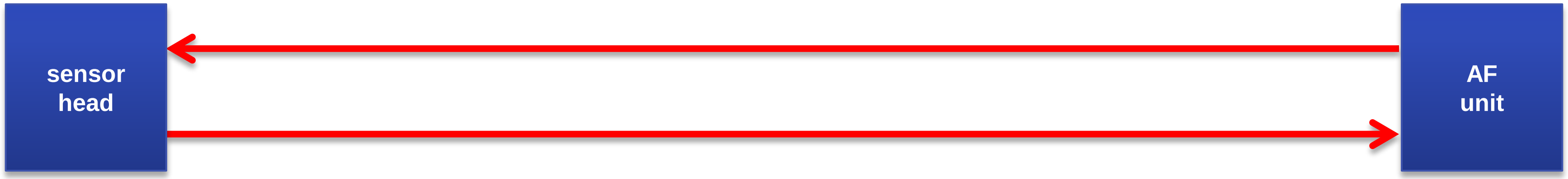
- Jacket of the light fiber inside the sensor head is removed which provides better sensitivity to the light from all angles through transparent head cover. Mirror reflects the light for testing.
- The Light Fiber picks up the flash of light from the Bare Fiber in the sensor head and transmits that to the unit
- The Sound/Pressure Fiber emits light which gets reflected back by the diaphragm, then collected by the same sound/pressure fiber and sent back to the unit
- During an arc flash event, the diaphragm vibrates from the pressurized sound wave creating a signature which is detected by the sensor head

Continuous System Self-testing

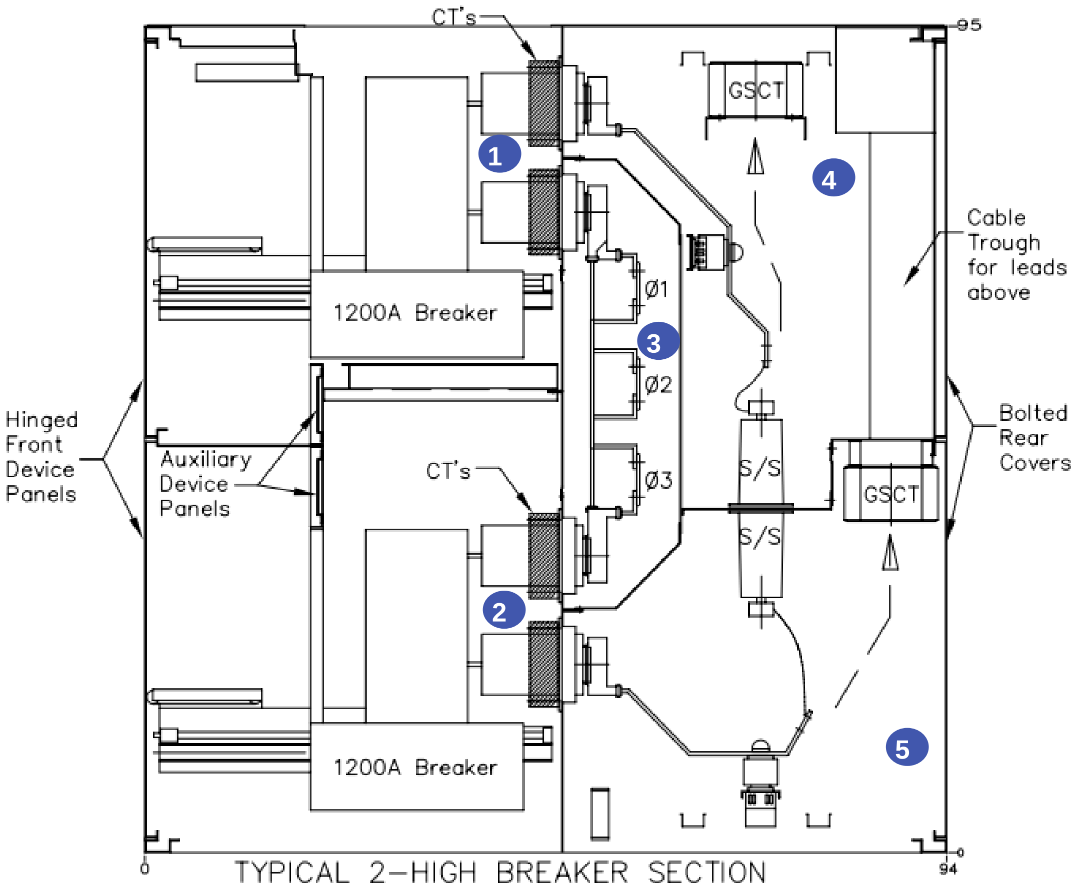
To ensure high reliability of the system all sensor heads and fiber are continuously tested.

For the “light path fiber every second short duration light pulse is sent from the laser diode: once reflected in the small mirror installed in the head and received by the photo detector, path is considered healthy.

For the “sound” path the light is sent continuously from the laser diode to be reflected by the shiny membrane and received by the photo detector which confirms health of the sensor path.



Sensor Placement



The above is a representation of a Two-High design with Arc-Flash Sensors:

- 1 – Breaker 1 Compartment
- 2 – Breaker 2 Compartment
- 3 – Main Bus Bar Section
- 4 – Upper Cable Exit Section
- 5 – Lower Cable Exit Section