Generator Protection Theory

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Power Plant Protection Track
Monday, August 4, 2025

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81 – Over/Under Frequency

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Isync Trip

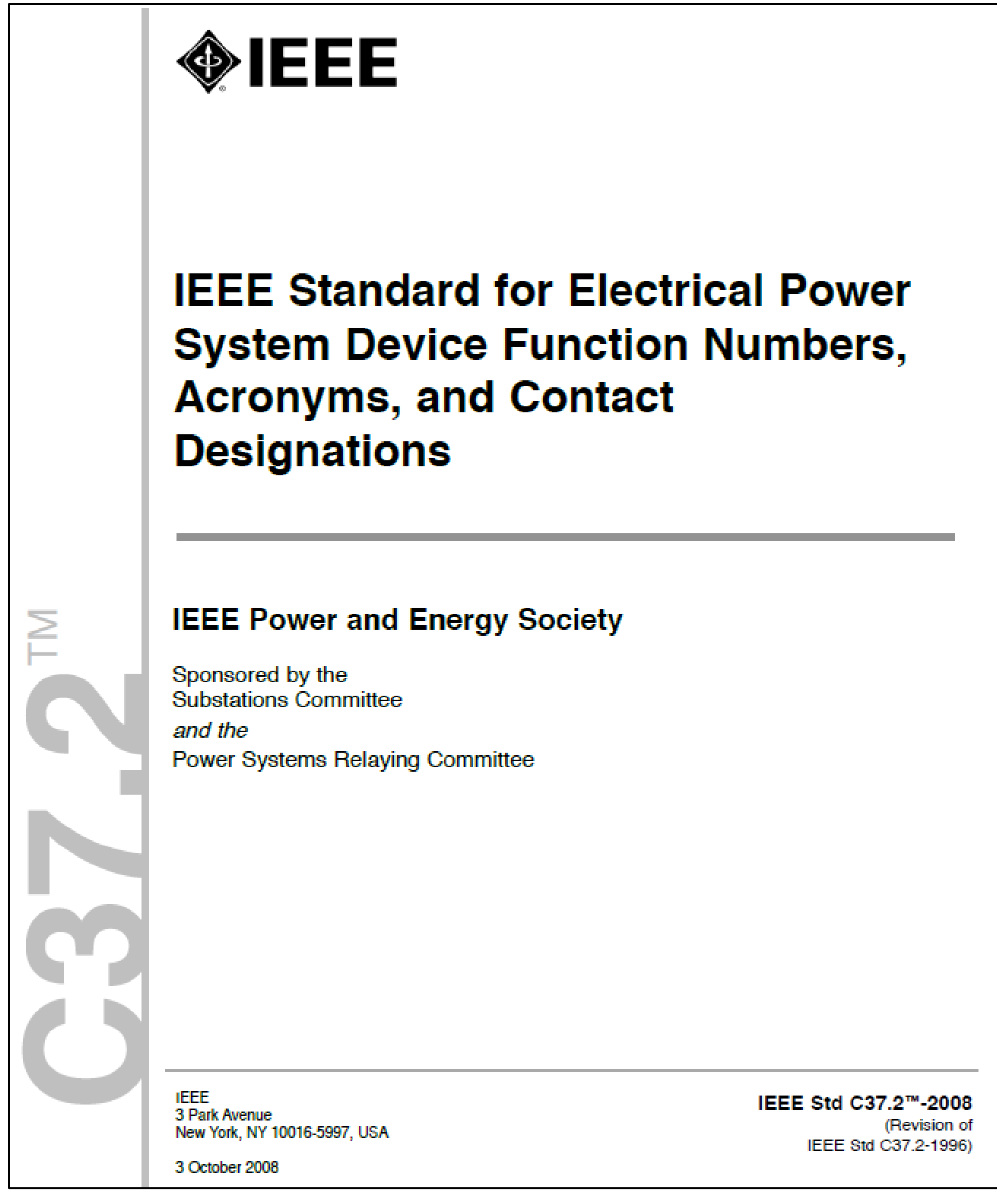
50BF – Breaker Failure
61BF – Breaker Pole Flashover

59X (3Vo) – Bus Gnd Overvoltage

64F/B – Field Ground Protection

Tripping Modes
Protection Upgrades

- IEEE C37.2 defines the IEEE "numerical" function designation for all protective relay functions.
- Different relay mfgs may use different designations for some functions.
- This presentation primarily uses the designations from the Beckwith M-3425A relay, which in most cases follows IEEE C37.2 however there are a few exceptions which will be pointed out.
- The TOC has embedded hyperlinks for each protective function that will work as a pdf file, so may go directly to specific section.
- Less time may be spent on certain functions or may skip ahead, depending on time.


IEEE

C37.2™

IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations

IEEE Power and Energy Society

Sponsored by the
Substations Committee
and the
Power Systems Relaying Committee

IEEE
3 Park Avenue
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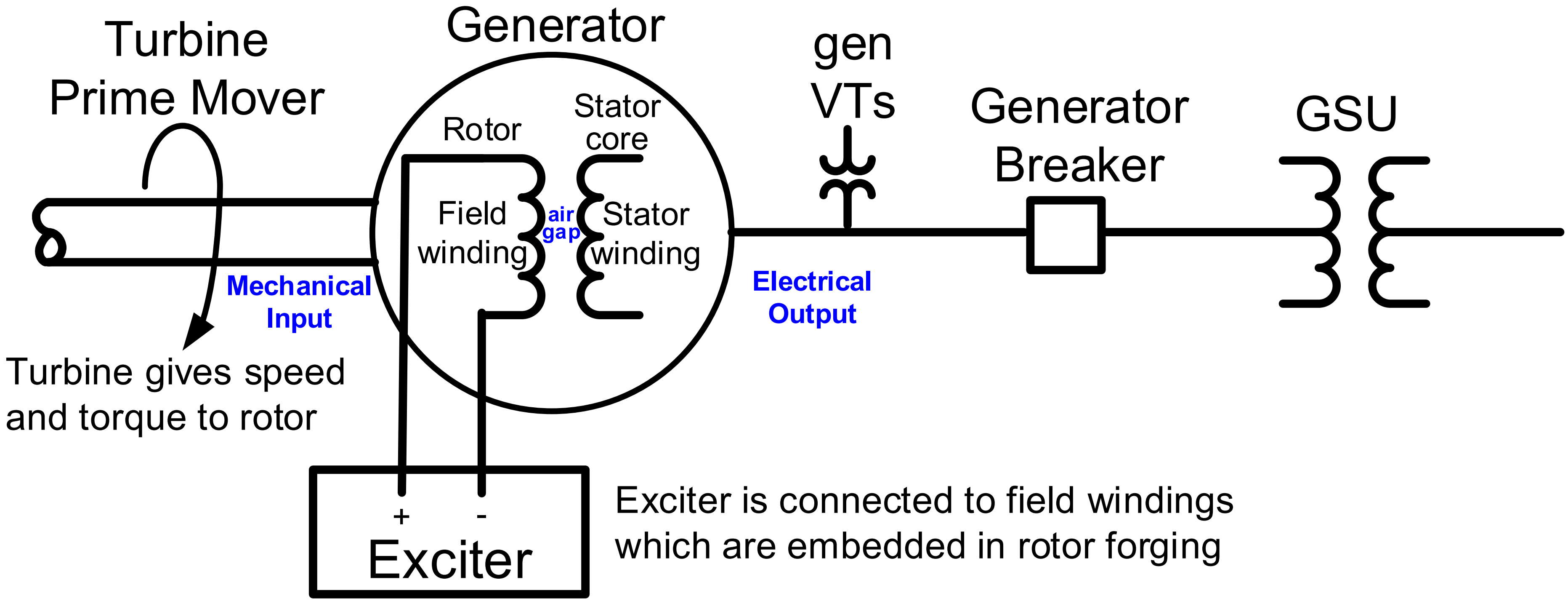
3 October 2008

IEEE Std C37.2™-2008
(Revision of
IEEE Std C37.2-1996)

Synchronous Generators 101



Exciter is connected to field windings which are embedded in rotor forging

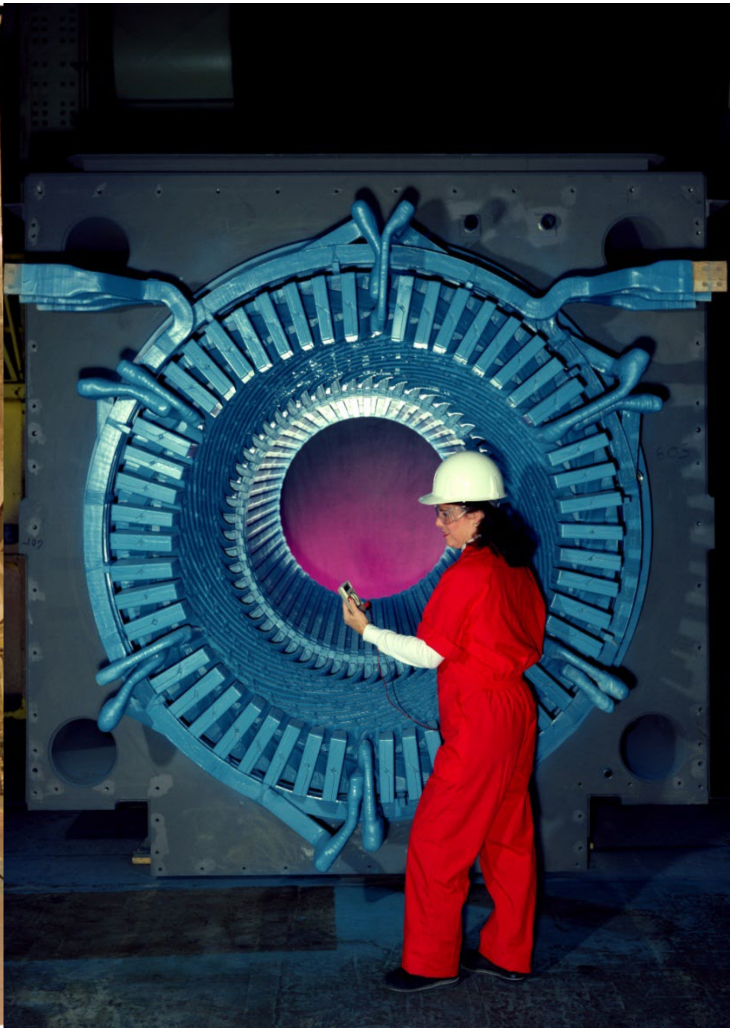
1) Excitation creates a **rotor magnetic field (Br)** in the air gap between rotor and stator.
2) When turbine rotates rotor, Br rotates in air gap.
3) The rotating Br induces **voltage (V)** onto the stator winding which energizes the gen VTs.
4) When gen breaker is sync closed, load **current (I)** flows thru the stator winding to load.
5) The stator winding current creates a **stator magnetic field (Bs)** in the air gap.
6) Br and Bs interact in the air gap to transform mechanical energy into electrical energy.
7) Maxwell's equations describe the behavior of the Electric & Magnetic Fields and how they interact in the air gap to become Voltage and Current to make Power.

Maxwell's equations

$$\nabla . E = \frac{\rho}{\epsilon_0}$$
$$\nabla . B = 0$$
$$\nabla \times E = -\frac{\partial B}{\partial t}$$
$$\nabla \times H = J + \frac{\partial D}{\partial t}$$

Rotor

Stator



Different possible gen protection functions

Categorized by operating quantity:

Measured by relay

Voltage
- 27
- 59
- 59N
- 59X
- 27TN (180 Hz)
- 59D (180 Hz)
- 24
- 50/27
- 51V
- 64B

Current
- 50/50DT
- 50BF
- 46
- 49
- 50/27
- 51V
- 64S (20 Hz)
- 87
- 50N
- 51N
- 67N
- 87GD

Calculated by relay

Impedance
- 21
- 40
- 78

Power
- 32

frequency
- 81O/U
- 81A
- 81R
- 24

V/Hz
- 24

R_{field}
- 64F

Which relay elements and what settings criteria should be used? It depends on the type of application.

Different types of generator applications

Some of the generator protection elements are set using the same criteria while other elements may be set using different criteria:

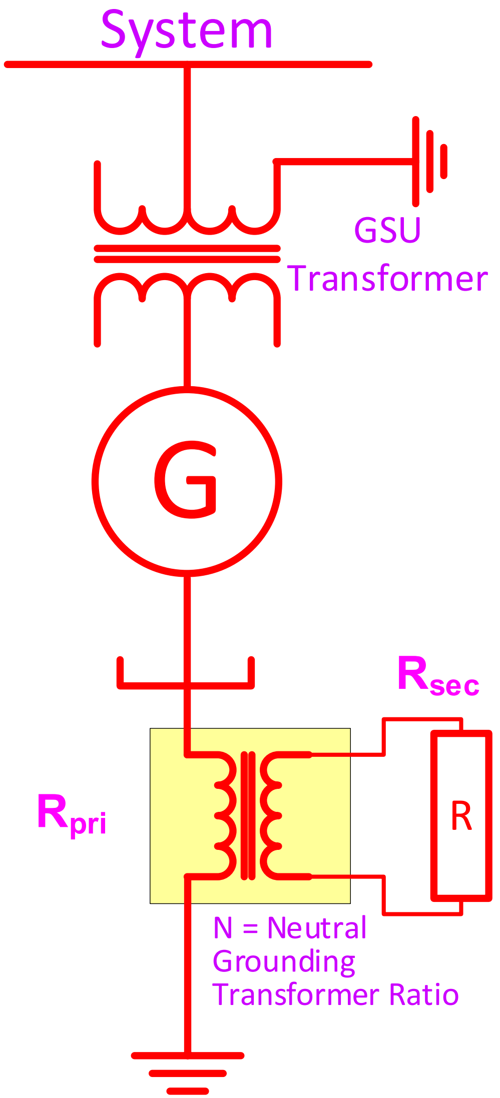
1) Grounding Type
2) Rotor Type
   - Round rotor: Directly vs Indirectly Cooled
   - Salient pole: Connected vs Nonconnected Damper Windings
3) Turbine Type (STG, CTG, RICE, Hydro)
   - STG: Condensing vs Non-Condensing
   - Hydro: blades above vs below tail race water level
4) Excitation Type
5) Connection Type (Direct vs Unit Connected)
6) LS gen breaker vs HS unit breaker only
7) Pre-Synch vs. Interconnected
8) Generator Winding Configuration Types
9) Operation mode (sync condenser, pumped storage, etc)
10) Stator winding pitch factors
11) Black Start Capable

1) Types of Generator Grounding

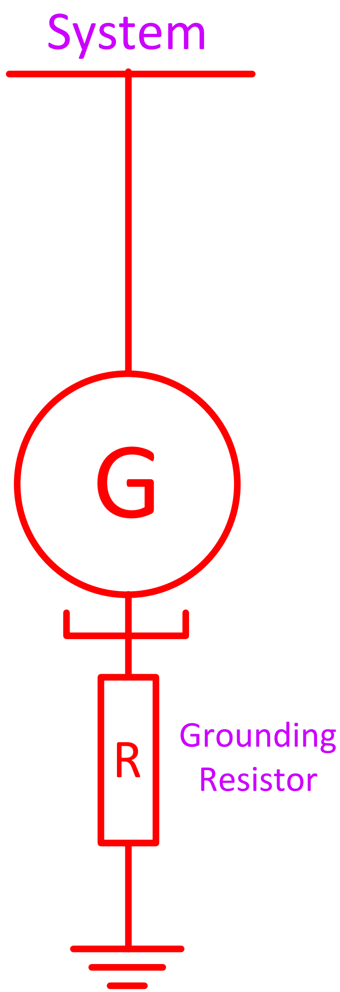
✓ High Impedance Grounded

- Used for larger generators
- Most of the sample cases discussed will be high impedance grounded, although many of the protection elements are set similarly regardless of grounding method.

  - Uses reflected resistance:
    - $R_{pri} = R_{sec} * N^2$
      - ✓ R_{sec} typically < 1 Ω
      - ✓ R_{pri} typically in KΩs
    - 3Io typically 3A to 25A



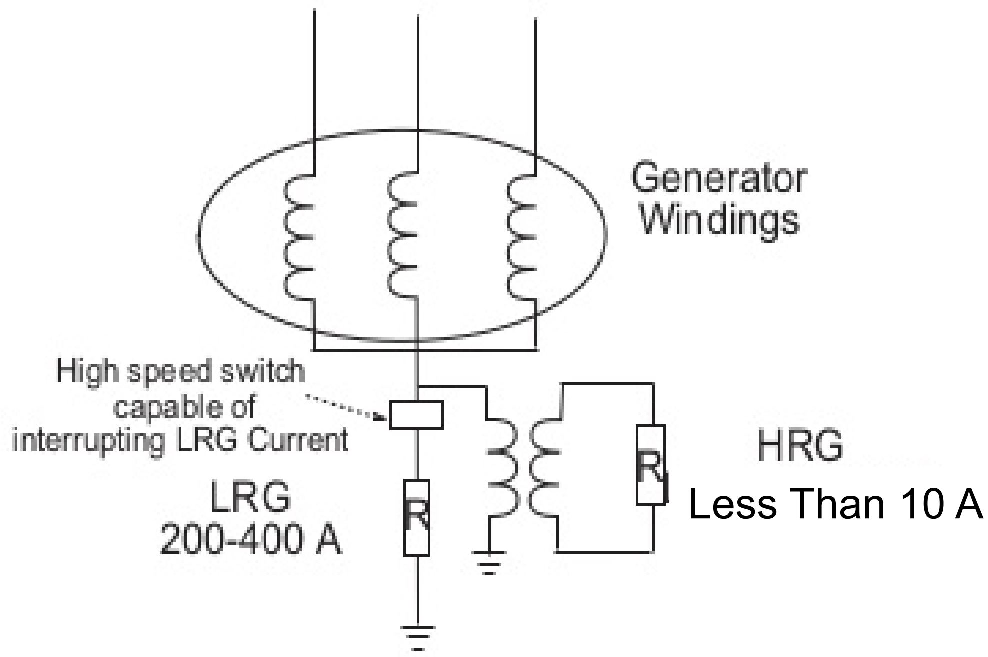
Types of Generator Grounding



- Low Resistance or Solidly Grounded
  - Used for smaller generators
  - Good ground source
    - The lower the R, the better the ground
    - The lower the R, the more damage to the generator for an internal ground fault
  - Lowest R is solid ground case
  - Can get expensive as resistor voltage rating goes up
  - Generator will be damaged for an internal ground fault
    - Ground fault current typically 200-400 A

Types of Generator Grounding

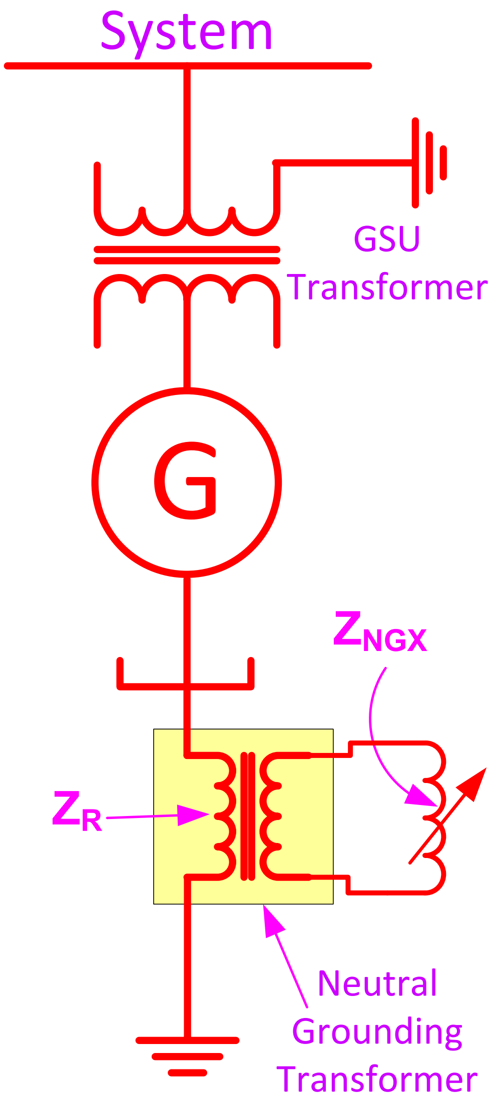
Dual (Hybrid) Grounding



Hybrid

- Low Z and High Z in parallel
- After trip, reverts to High Z

Types of Generator Grounding

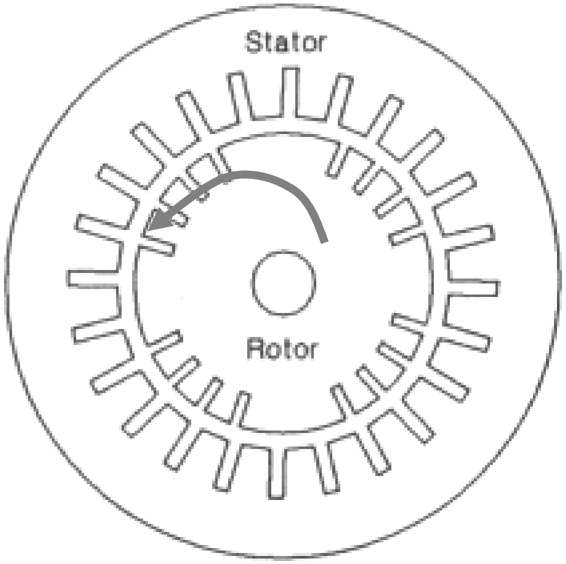


- Compensated
  - Most expensive
    - Tuned reactor
    - aka Peterson Coil
  - System ground source obtained from GSU
  - Uses reflected impedance from grounding transformer, same as high impedance grounded system does
  - Gen damage mitigated from ground fault
  - Reactor tuned against generator capacitance to ground to limit ground fault current to very low value (can be less than 1A)

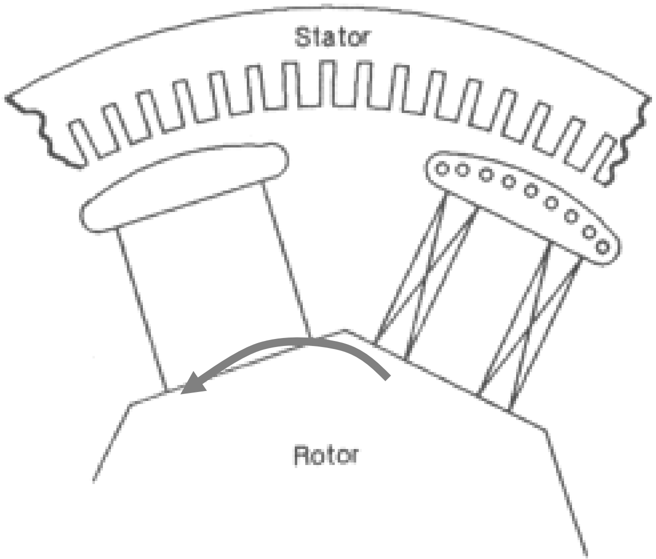
Stator Ground Fault Damage

- This generator was high impedance grounded.
- Some iron burning occurred, but the damage was repairable.
- If 59N accelerated scheme and/or 64S had been used, the damage may have been less.
- With low impedance grounded machines, the damage could be more severe.

2) Rotor Styles



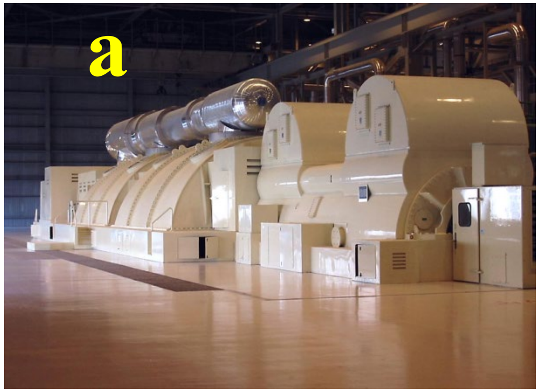
Cylindrical/Round Rotor – IEEE C50.13

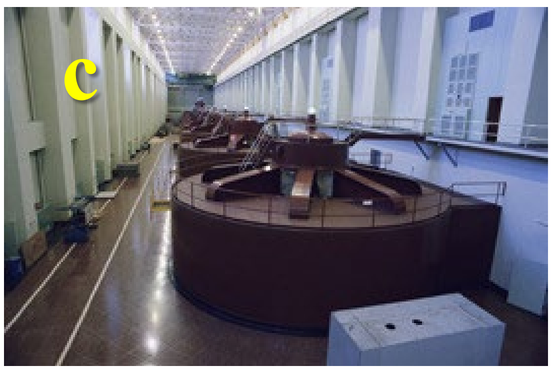


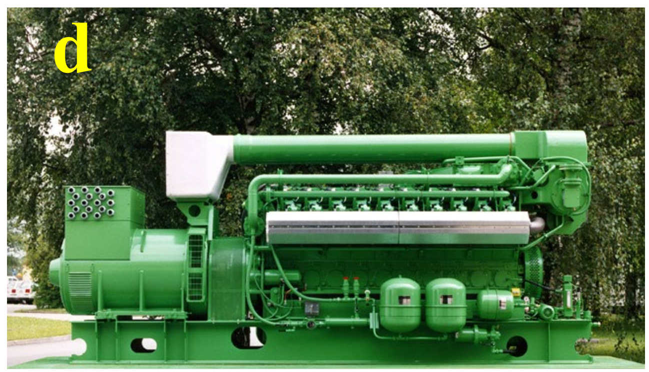
Salient pole – IEEE C50.12

- Cylindrical rotor seen in STG, CTG, RICE
  - Typically, 2 or 4 pole
  - For 2 poles: $N_{rotor} = 120*f_{stator}/P_{rotor} = 120*60/2 = 3600$ rpm
- Salient pole rotor seen in Hydros
  - More poles to obtain nominal frequency at low RPM
  - For 24 poles: $N = 120*60/24 = 300$ rpm

3) Turbine Types







a) Steam Turbine

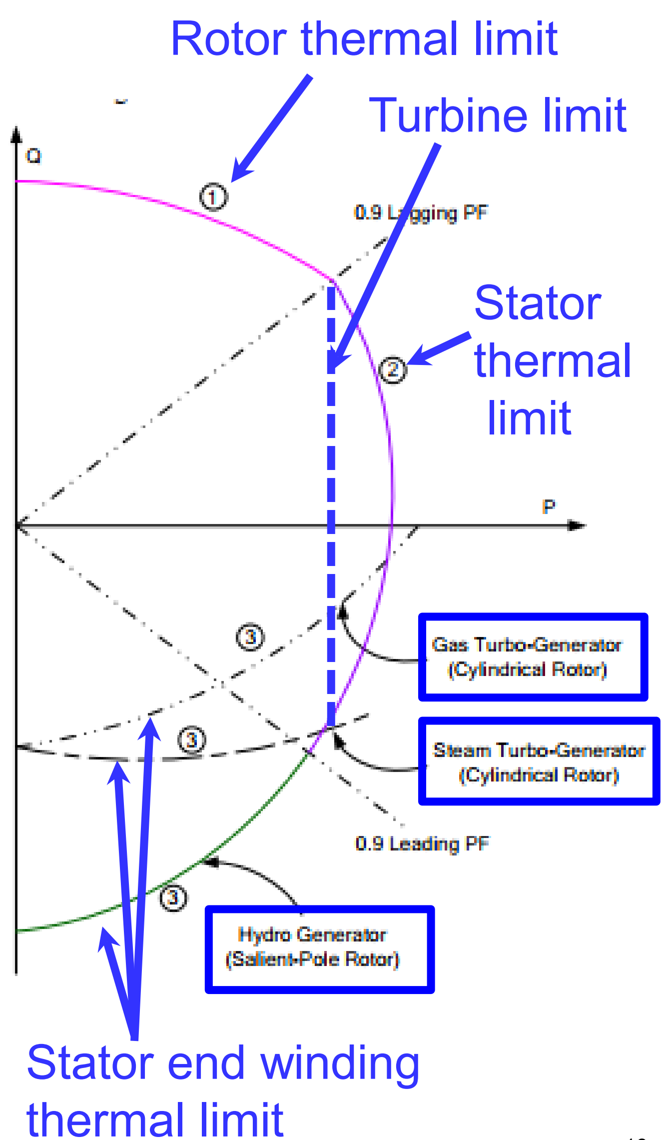
b) Combustion Gas Turbine

c) Hydraulic Turbine (Hydro)

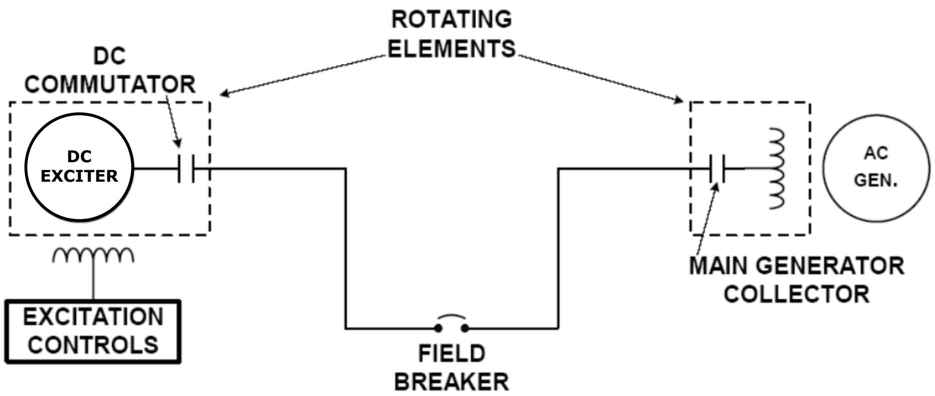
d) RICE (Reciprocating Internal Combustion Engine)

GCC

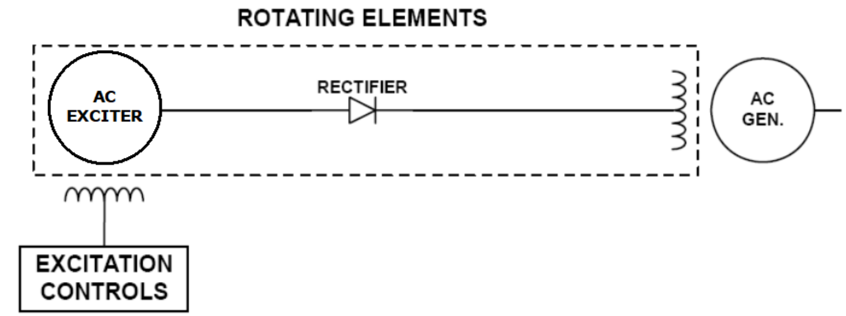
Generator Capability Curve



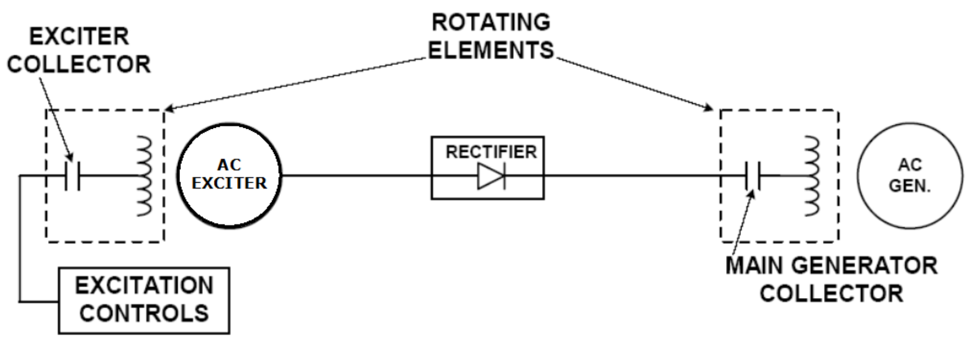
4) Exciter Types



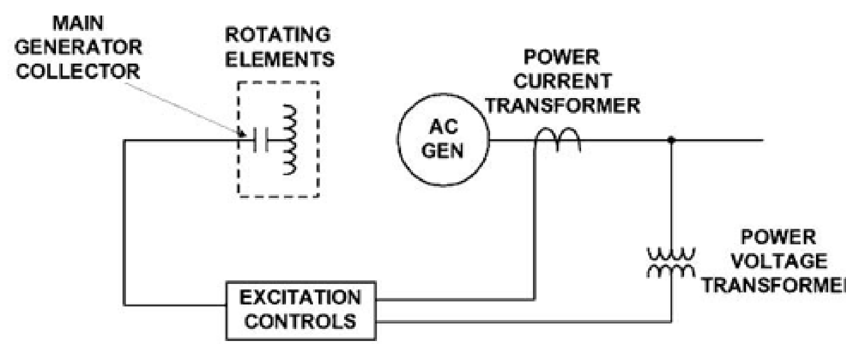
System with dc generator commutator exciter



System with alternator rectifier exciter and rectifiers (brushless exciters)



System with alternator, rectifier, stationary exciter and stationary rectifier

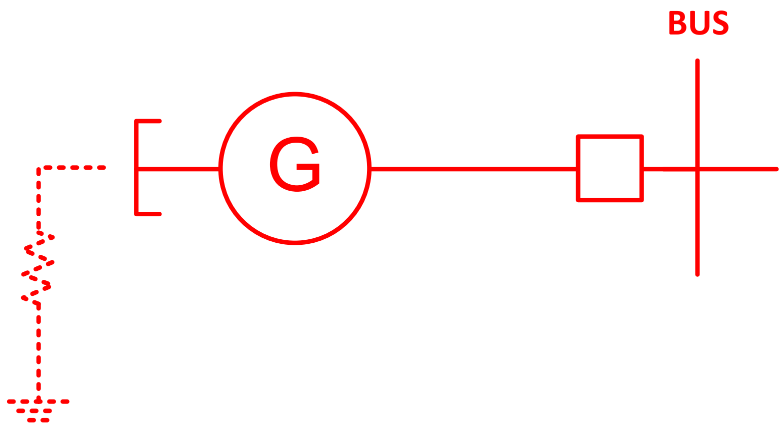


System with static exciter

Courtesy of IEEE C37.102

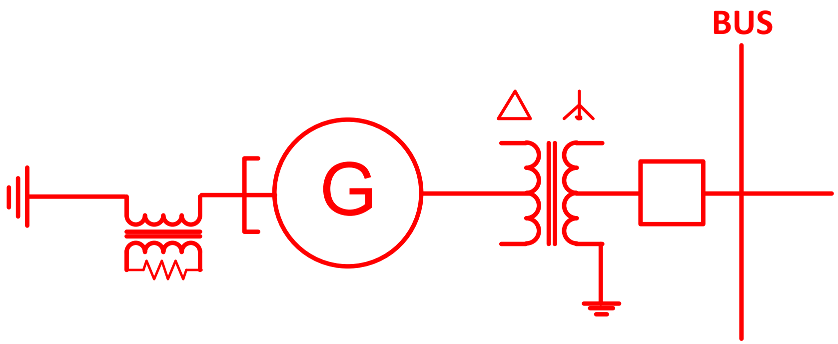
5) Types of Generator Connections

- **Direct Connected**



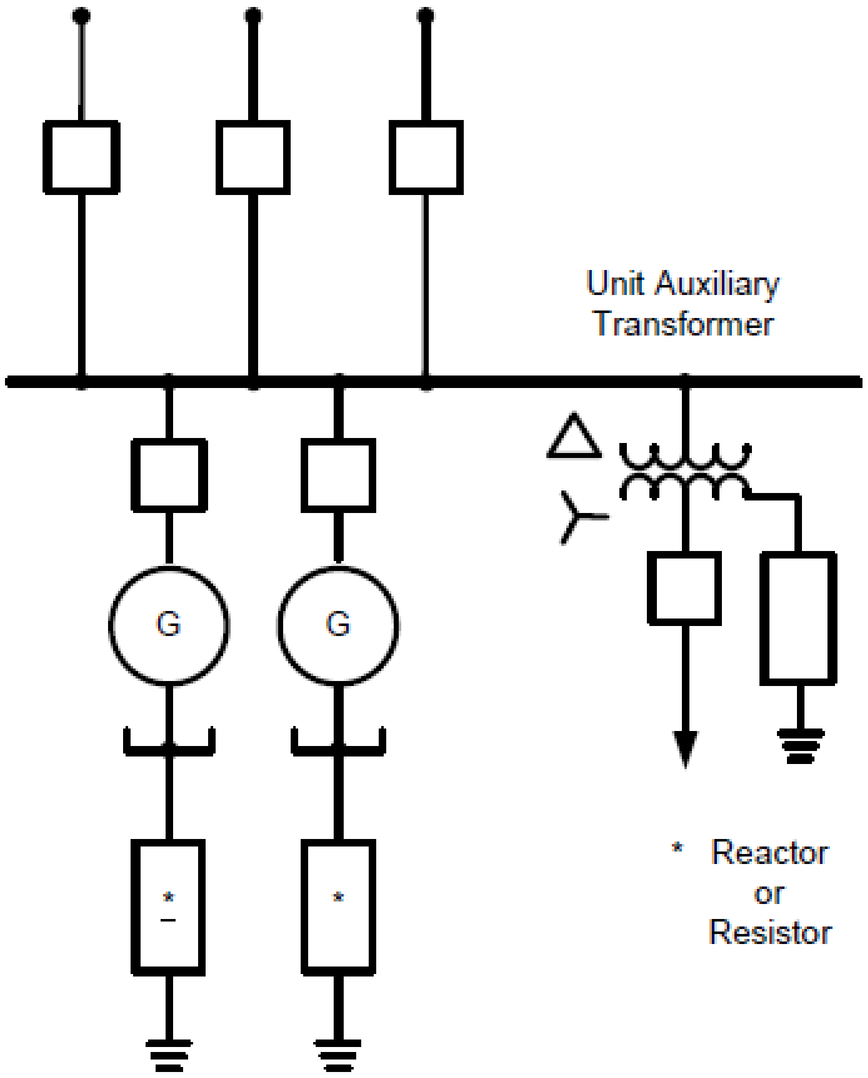
- Smaller gens
- no GSU
- Low Z or solidly grounded
- directly connected to load bus
- hydros, industrial, commercial

- **Unit Connected**



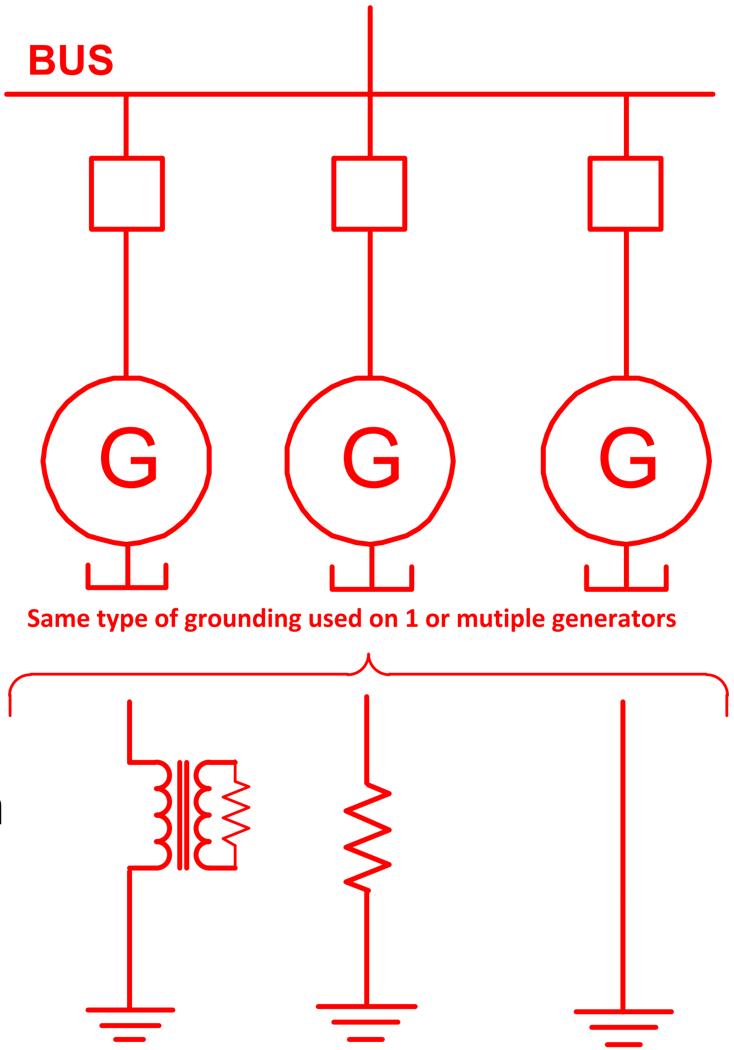
- Larger gens
- dedicated GSU
- High Z grounded
- Utility, industrial

Bus (Direct) Connected – no GSU



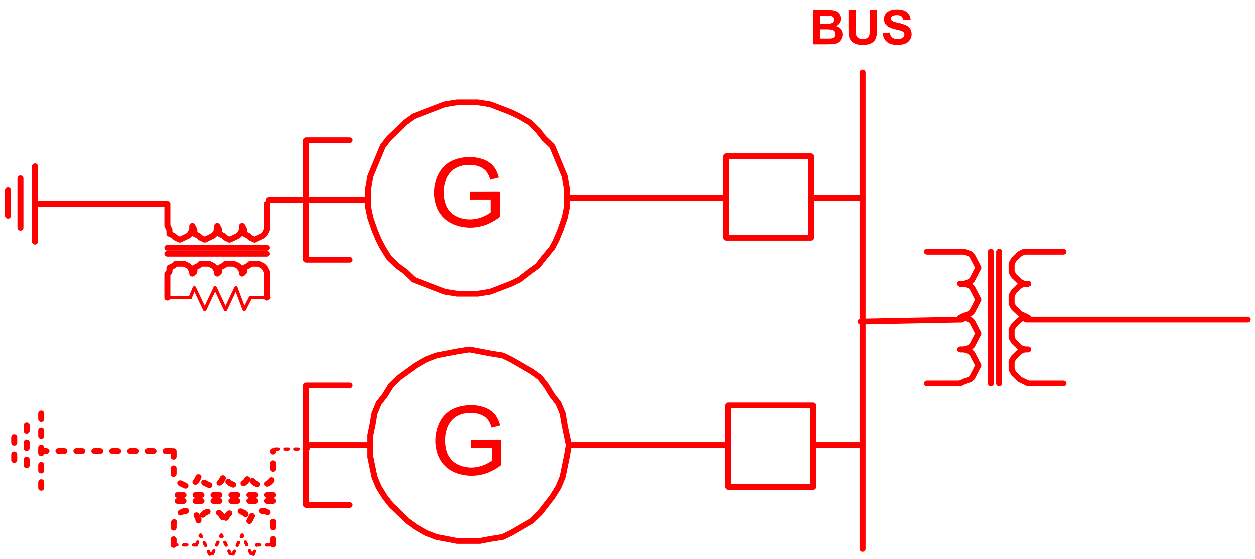
Types of Generator Connections

- **Multiple Direct or Bus Connected (solidly grounded, Low Z, High Z)**
  - Directly connected to bus
  - Likely in hydros, RICE, industrial, commercial, and isolated systems
  - Simple
  - May have problems with circulating current
    - Use of single grounded machine can help
  - Adds complexity to discriminate ground fault source for high Z



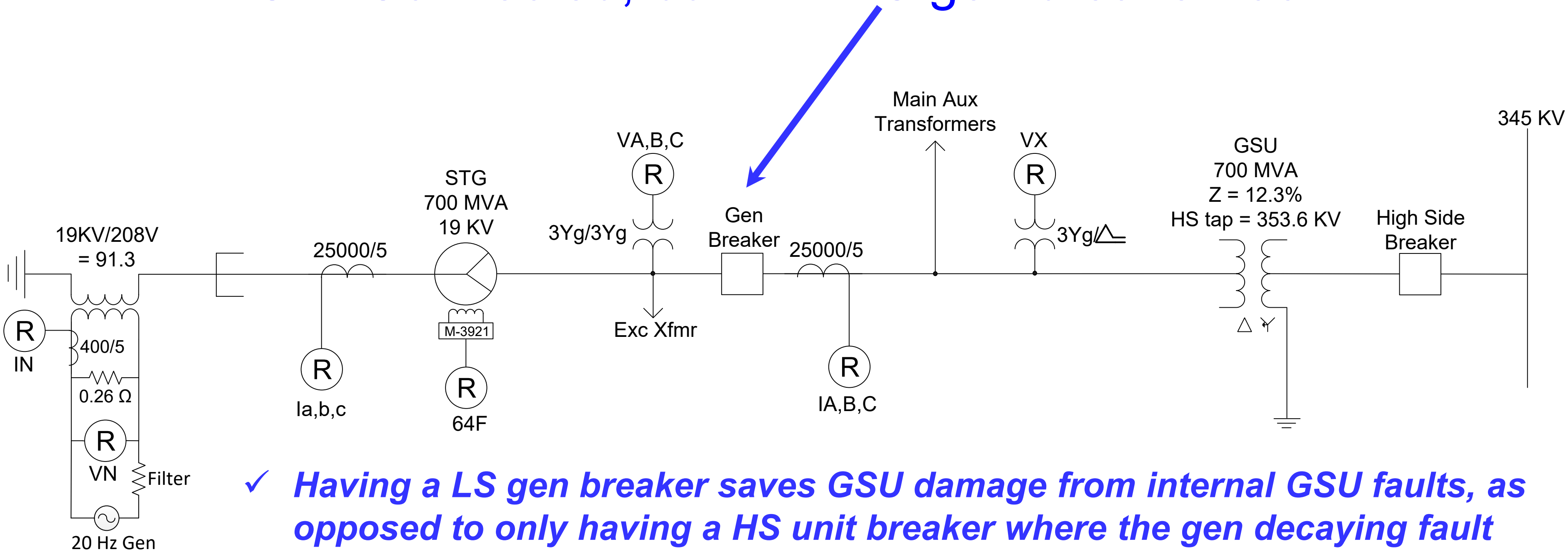
Types of Generator Connections

- **Multiple Bus (High Z), 1 or Multiple Generators**
  - Does not neatly fit into Direct or Unit connected definition
  - Multiple units connected through one GSU
  - Likely in large industrial and utility systems
  - No circulating current issue, but third harmonic voltage discrimination may be an issue.
  - Adds complexity to discriminate ground fault source
    - Special CTs needed for sensitivity, and directional ground overcurrent elements



6) LS gen breaker or only HS unit breaker

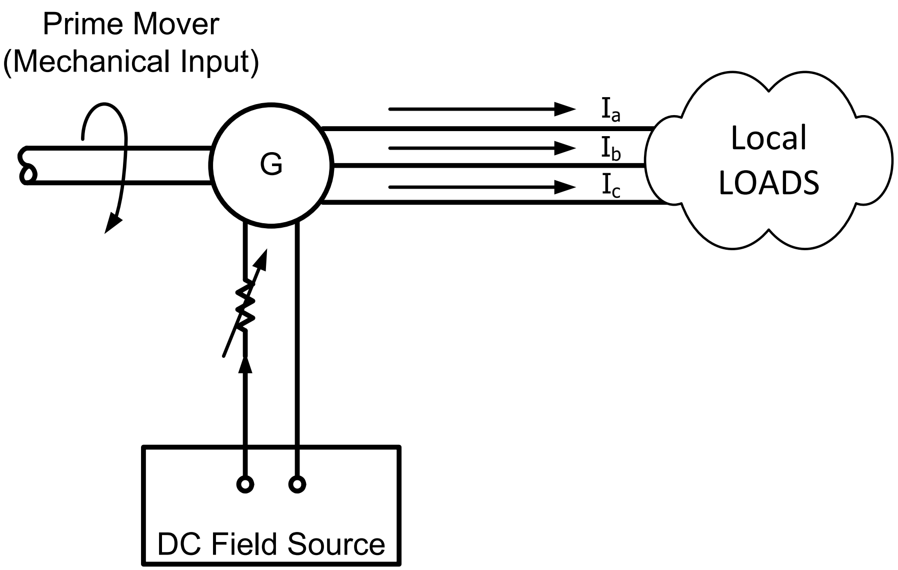
Unit Connected, but with LS gen breaker too



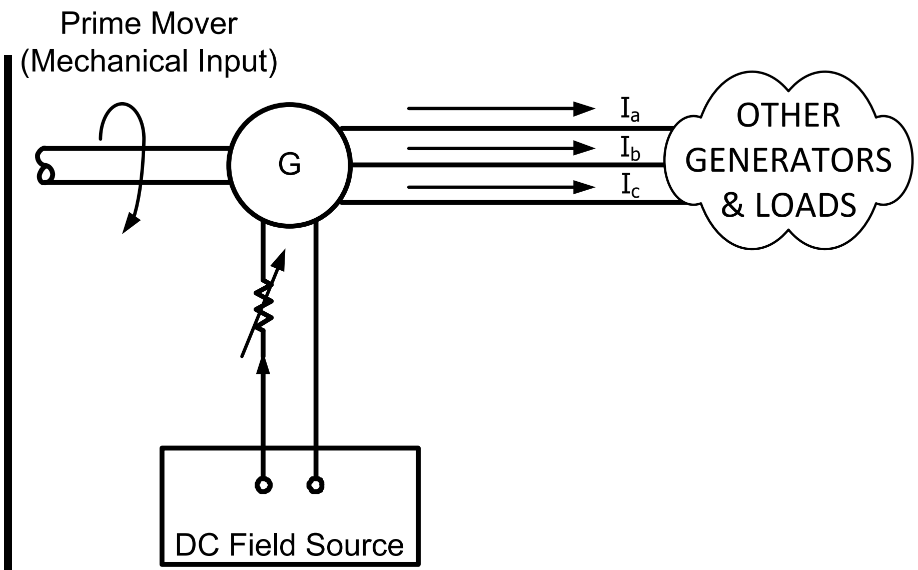
✓ ***Having a LS gen breaker saves GSU damage from internal GSU faults, as opposed to only having a HS unit breaker where the gen decaying fault current can continue to feed into a GSU internal fault for some time.***

- A gen breaker on the LS (Low Side) of the GSU for larger gens was not as common in the past, but now much larger gen breakers are available that can interrupt much more fault current than in the past. For example, at one utility:
  - ✓ In 1980, a 400 MVA generator was installed with only a HS Unit Breaker.
  - ✓ In 2010, a 700 MVA generator was installed with a LS Gen Breaker as well.

7) Pre-Sync vs. Interconnected

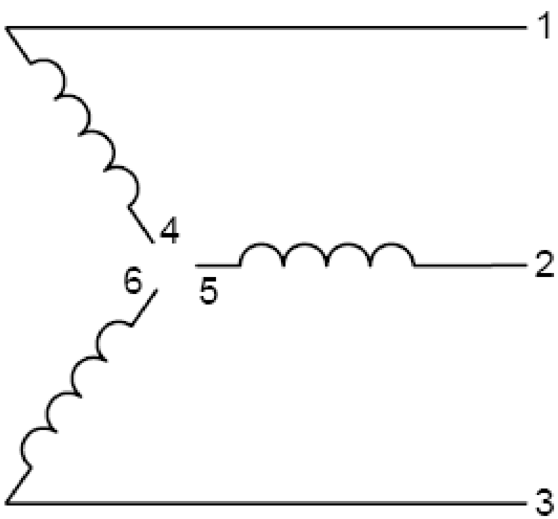


- Islanded or pre-sync
  - Exciter
    - Regulates voltage
  - Turbine
    - Regulates frequency



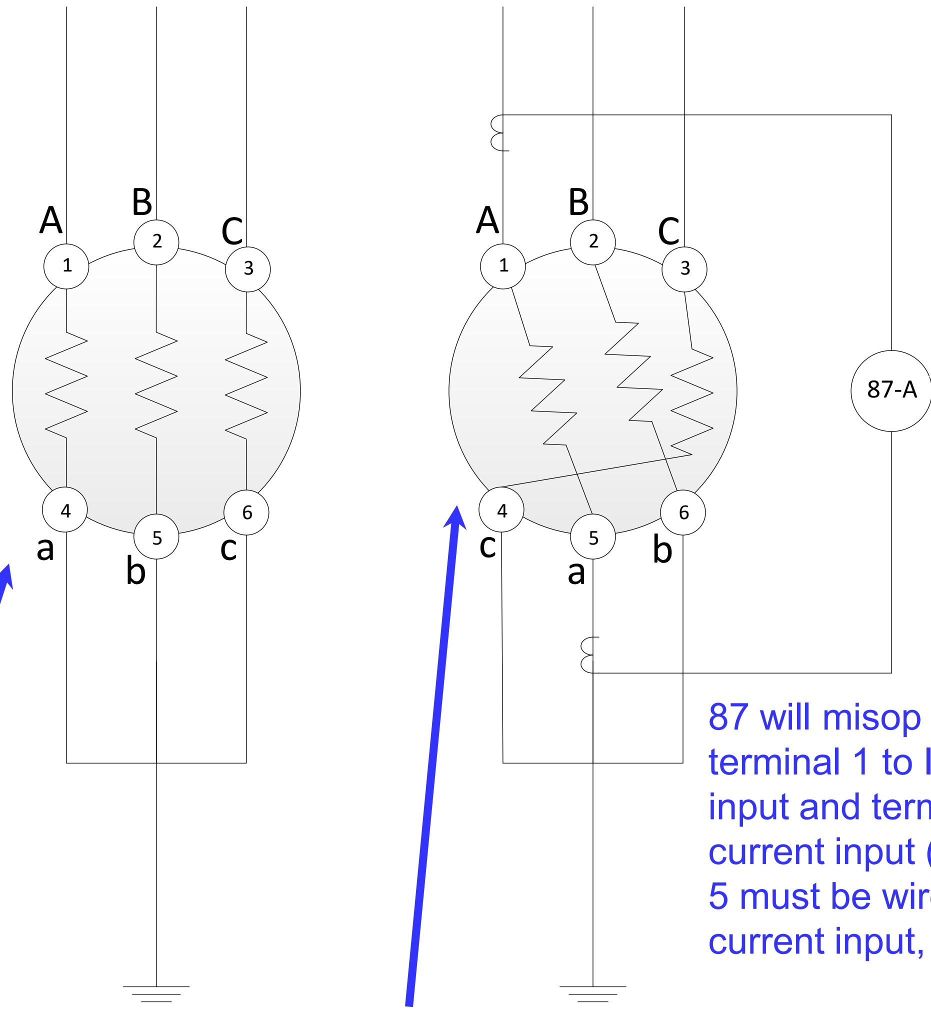
- Interconnected
  - Exciter
    - Controls MVAR
  - Turbine
    - Controls MW

8) Generator Winding Styles



Wye

- 3 Phase
- 6 Bushings
- Most common

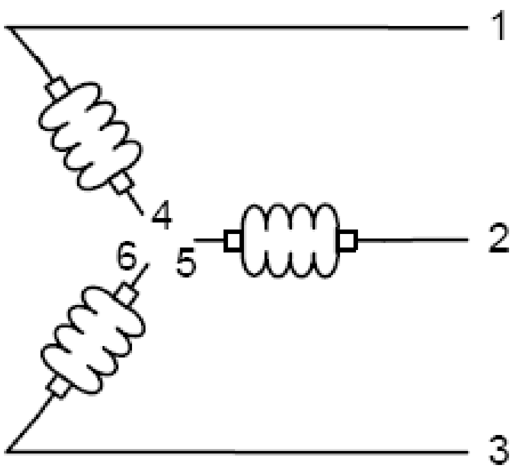


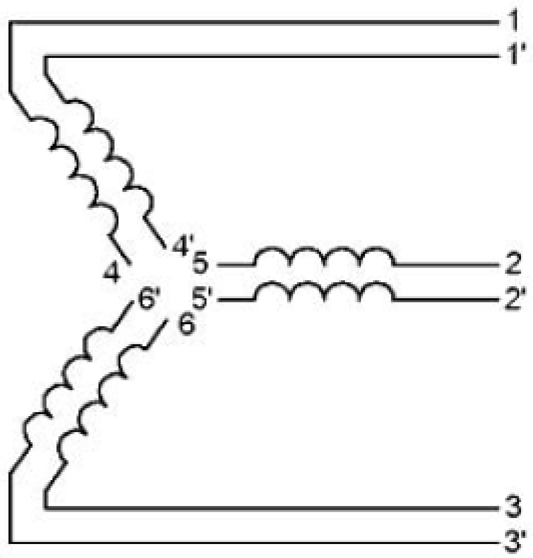
87 will misop if wire terminal 1 to I_A current input and terminal 4 to I_C current input (i.e. terminal 5 must be wired to I_a current input, etc)

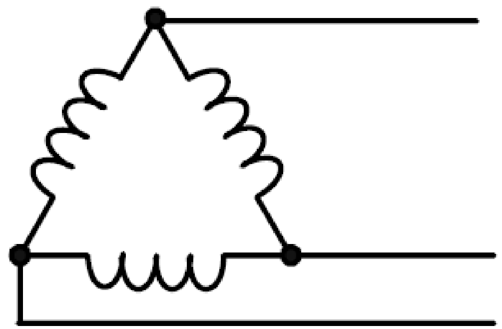
Standard straight-thru connections

Be aware of possible non-standard, non-straight thru connections e.g. at very old hydro plants

Winding Styles and Connections







Wye
- 3 Phase
- 6 Bushings

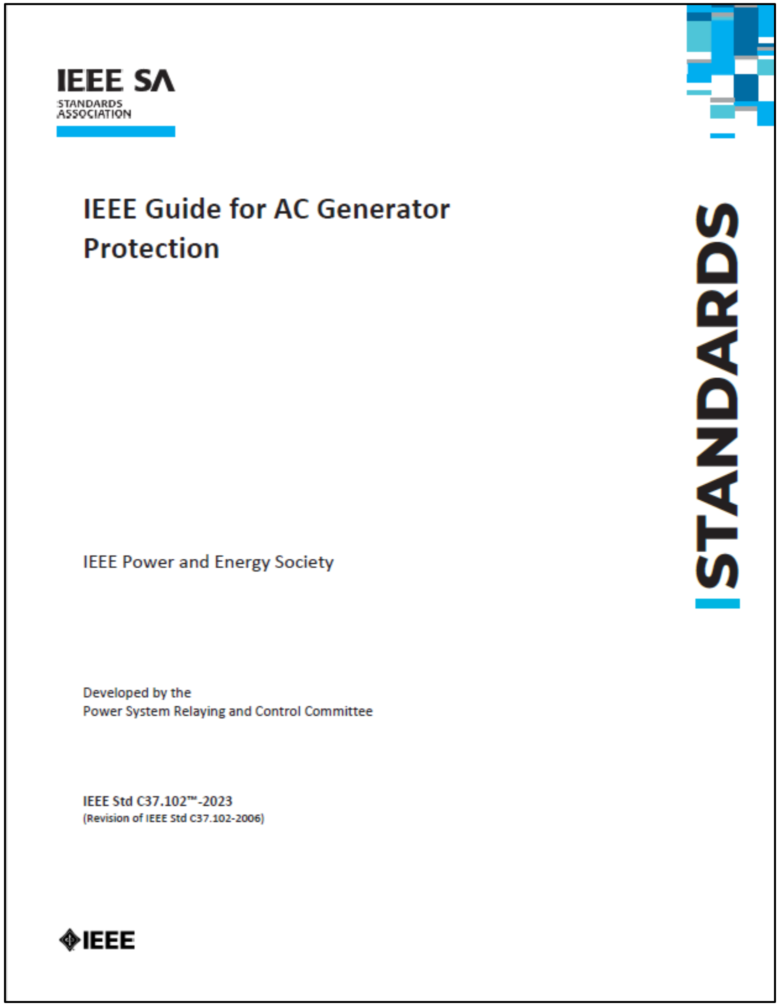
Double Winding
- 3 Phase
- 12 Bushings

Delta
- 3 Phase
- 3 Bushings

reference Standards

Created and maintained by the IEEE PES PSRC, EM, IAS and IEC TC 2 committees

- ✓ C37.102-2023: IEEE Guide for Generator Protection
- ✓ C37.101-2006: IEEE Guide for AC Generator Ground Protection *(currently under revision)*
- ✓ C37.106-2022: IEEE Guide for Abnormal Frequency Protection for Power Generating Plants
- ✓ Std. 242-2001: IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (IEEE Buff Book)
- ✓ C50.13-2014 - IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above
- ✓ C50.12-2005 - IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators *(in revision)*
- ✓ IEC 60034-3: 2007 Rotating electrical machines - Part 3: Specific requirements for synchronous generators driven by steam turbines or combustion gas turbines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IEEE Guide for AC Generator Protection

IEEE Power and Energy Society

Developed by the
Power System Relaying and Control Committee

IEEE Std C37.102™-2023
(Revision of IEEE Std C37.102-2006)

IEEE

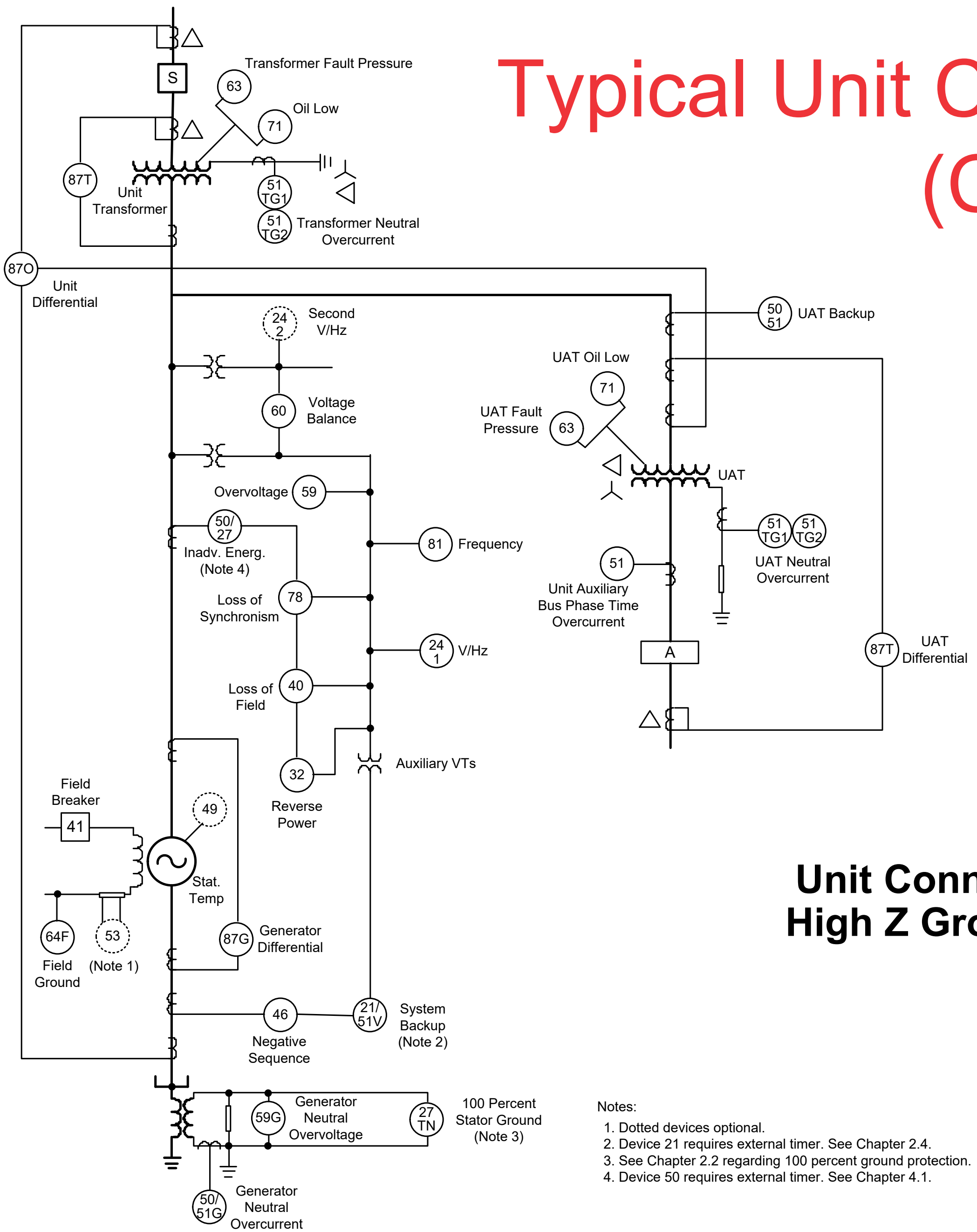
STANDARDS

IEEE TUTORIAL ON THE PROTECTION OF SYNCHRONOUS GENERATORS

Second Edition, 2011

Special Publication of the IEEE Power System Relaying Committee

Typical Unit Connected Generator (C37.102)



Unit Connected, High Z Grounded

Notes:

1. Dotted devices optional.
2. Device 21 requires external timer. See Chapter 2.4.
3. See Chapter 2.2 regarding 100 percent ground protection.
4. Device 50 requires external timer. See Chapter 4.1.

Generator Protection Overview

<u>main categories of generator protection:</u>

1) **Faults**
   - Internal – Shorts circuits in the generator
   - External – Uncleared faults on the system
2) **Abnormal operating conditions**
   - Abnormal electrical conditions may be caused by the generator or the system
   - System disturbances and operational hazards

- Proper protection mitigates or **reduces** damage
- Proper protection enhances generation security

➢ **Faults** (Phase Faults vs Ground Faults):

- Phase faults in generators are rare, but they should be detected and cleared as fast as possible due to their very high magnitude fault currents.
- Phase faults can develop in the winding end turns, where all three phase windings are in close proximity, or in slots if there are two coils in the same slot.
- Phase faults may evolve into ground faults (or vice-versa), but either way, faults should be detected and cleared as quickly as possible to avoid more extensive damage.

- **Internal faults** (in generator, or within the gen 87 zone)
  - ✓ Phase Faults (3Φ, ΦΦ) – 87, 50, 50DT, 21, 51V
  - ✓ Ground Faults (ΦG, ΦΦG) – 59N, 27TN, 59D, 64S
- **External faults** (on system, or outside the gen 87 zone)
  - ✓ Phase Faults (3Φ, ΦΦ) – 21, 51V
  - ✓ Ground Faults (ΦG, ΦΦG) – 51G on GSU HS ground leg

Generator Protection Overview

Generator Internal Phase vs Ground Fault protection for high impedance vs low impedance grounded machines

Phase faults – protection is the **same** for internal phase faults:

- Low impedance grounded machine
  - ✓ *87 (backup 50, 50DT, 21, 51V)*
- High impedance grounded machine
  - ✓ *87 (backup 50, 50DT, 21, 51V)*

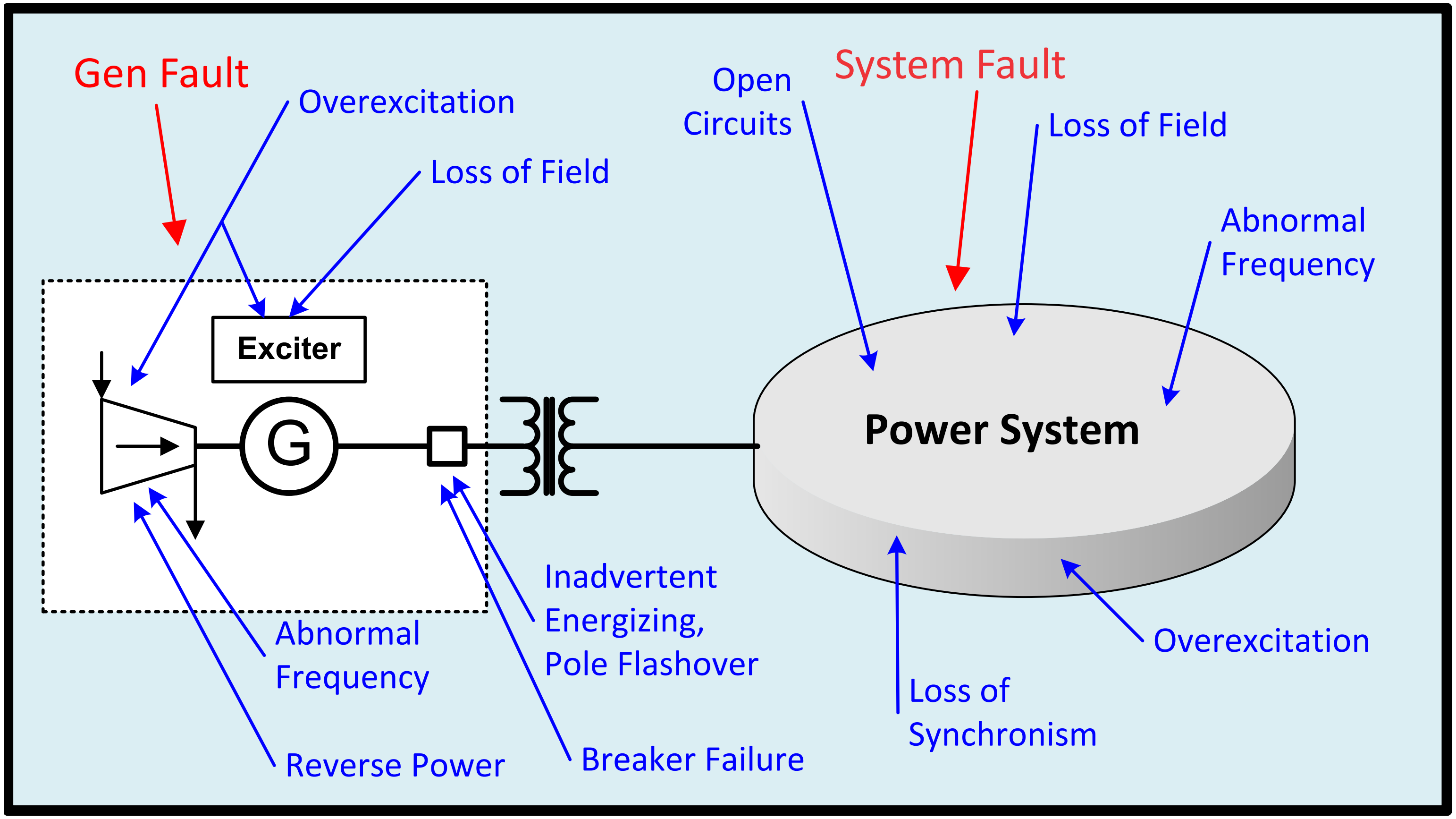
Ground faults – protection is **different** for internal ground faults:

- Low impedance grounded machine
  - ✓ *Use current-based protection (3Io, IN, IG).*
    - ✓ *87GD, 50N, 51N, 67N*
- High impedance grounded machine
  - ✓ *Use voltage-based protection (3Vo, VN, VG, VN^{3rd}) as ground fault current is too low to use current-based protection.*
    - ✓ *59N, 27TN, 59D, 64S (uses VN_{20} & IN_{20}), 59X (uses 3Vo)*

➢ Abnormal Operating Conditions

- 24 – Overexcitation
- 27 – Under Voltage
- 32 – Loss of Prime Mover (motoring)
- 40 – Field Loss
- 46 – Unbalanced Currents
- 49 – Thermal Overload
- Isync Trip – Out of Phase Synchronizing
- 50/27 – Inadvertent Energizing
- 50BF – Breaker Failure
- 59 – Over Voltage
- 60FL – Blown VT Fuses
- 78 – Out-of-step (Loss of Synchronism)
- 81 – Abnormal Frequency

Generator Protection Overview



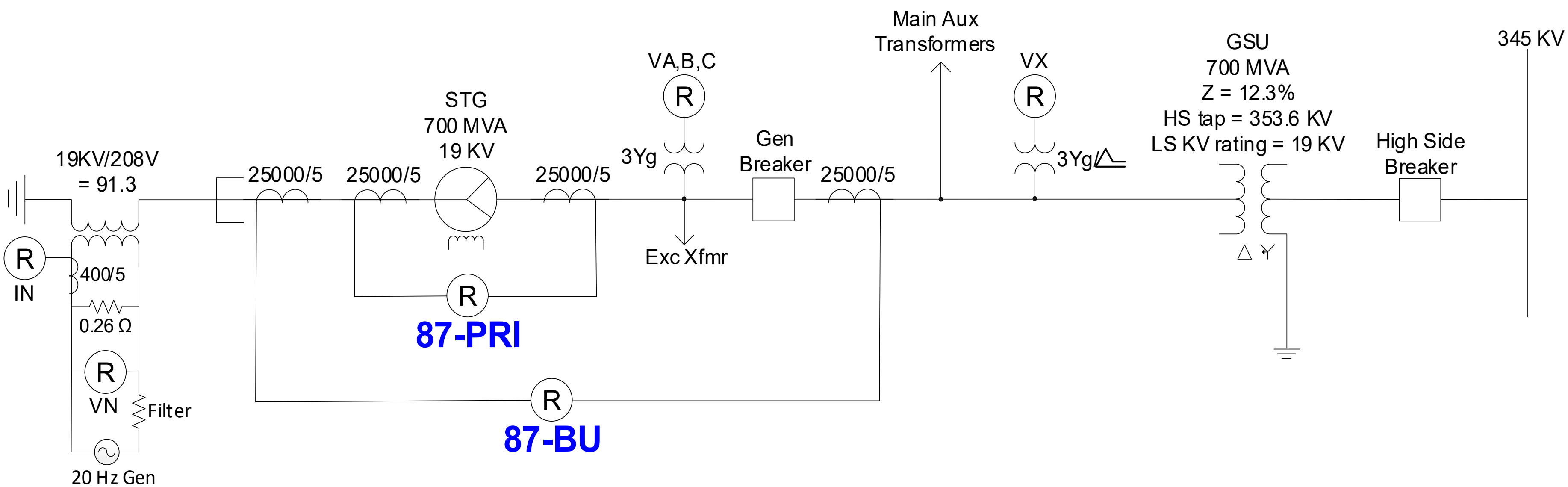
Internal vs. External Short Circuits

Abnormal Operating Conditions

Phase Fault Protection

- 87 – Phase Differential Current
- 50 – Instantaneous Phase Overcurrent
- 50DT – Definite Time Overcurrent

87 – Phase Differential



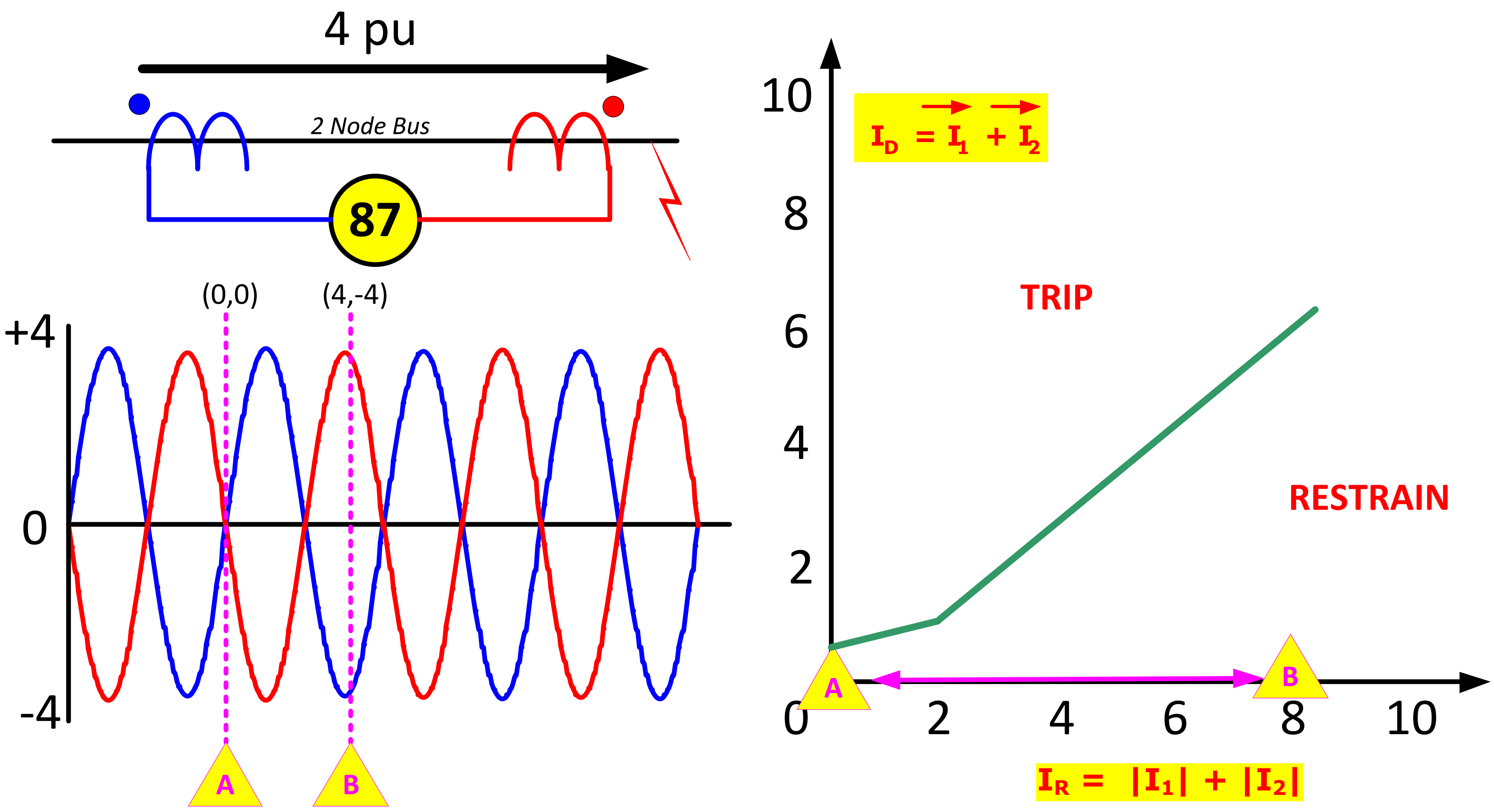
Differential Phase Overcurrent Fault Protection

- Protects for internal phase faults
- Protects the generator stator windings and everything enclosed within the (2) sets of CTs

Stator Phase Faults

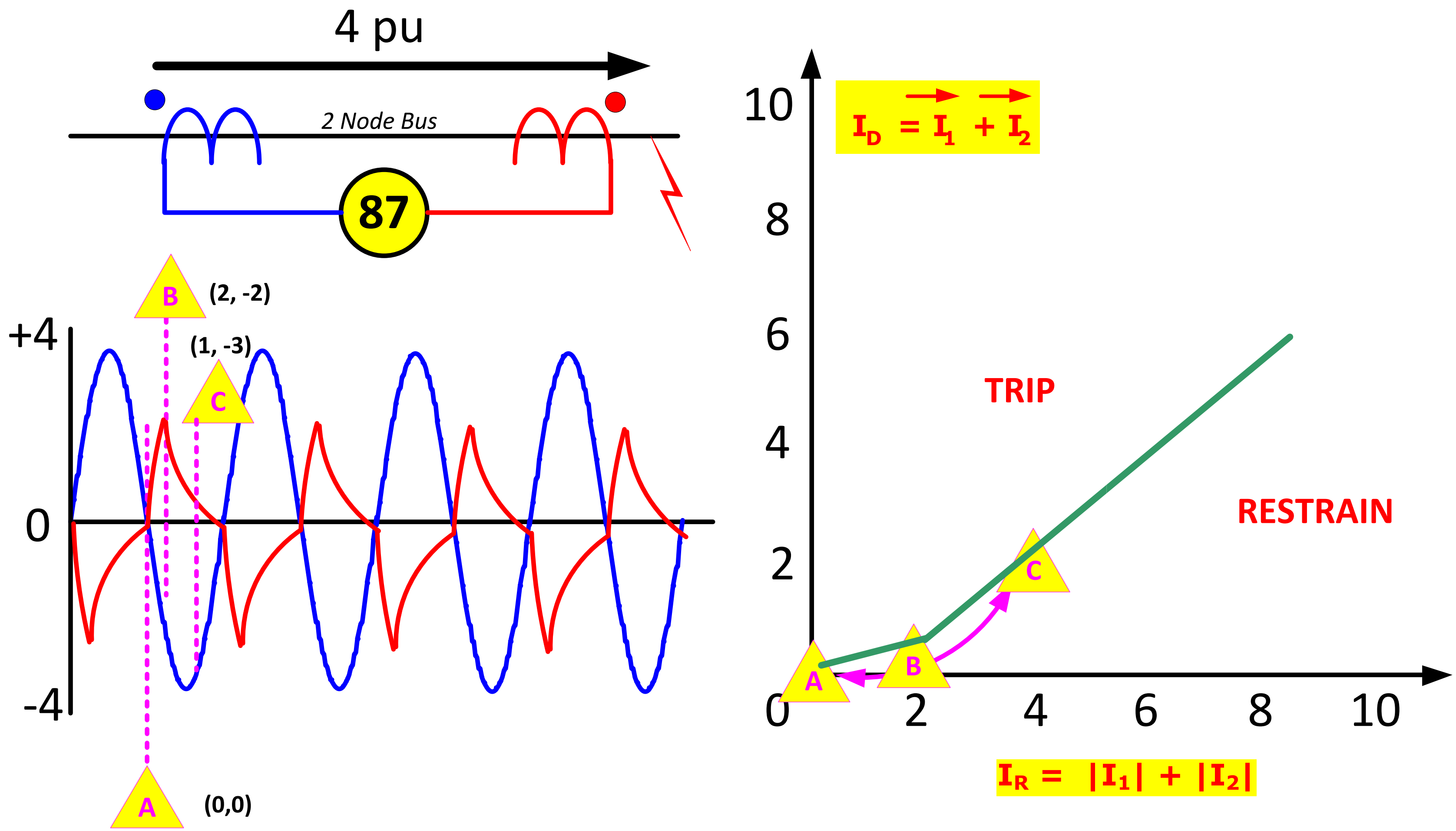
- 87 – Phase Differential (primary for in-zone phase faults)
  - What goes into zone must come out
  - For low impedance units, may see some ground faults as well
  - Challenges to Differential
    - CT replication issues: Remnant flux causing saturation
    - DC offset causing CT saturation from energizing transformers and large, sudden load pick up
    - Must work properly from 10 Hz to 80 Hz so it operates correctly at off-nominal frequencies from internal faults during startup/shutdown
    - May require multiple elements for CGT static start
  - Tactics:
    - Use variable percentage slope
    - Operate over wide frequency range
    - Use some type of high security mode technique to adaptively desensitize element when challenged by DC offset for security
      - DC offset can also occur from black plant starting and close-in faults

Through Current: no CT saturation



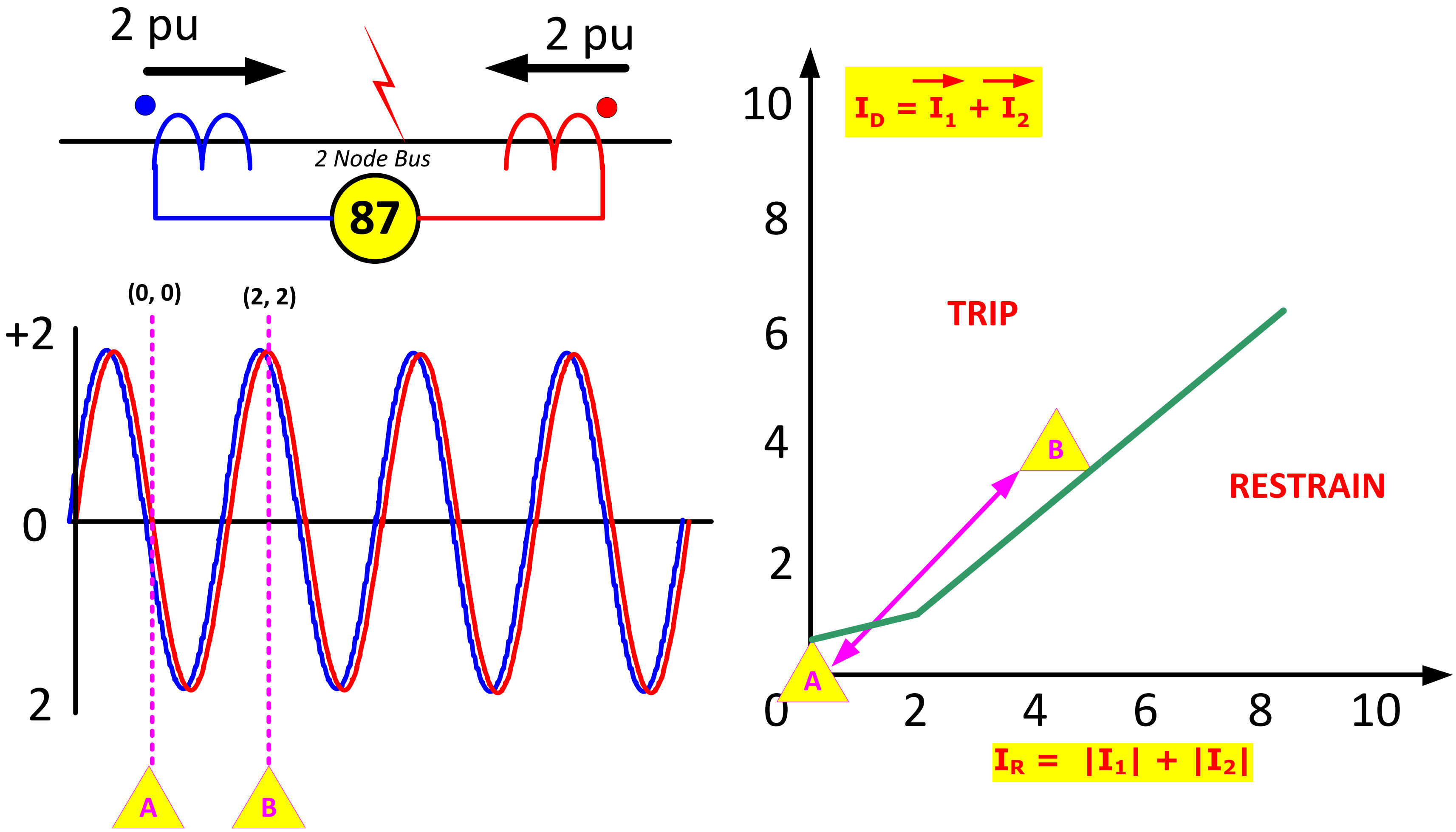
Current waveforms shown as thru current being 180° out-of-phase or in-phase for internal faults (opposite of the M-3425A relay).

Through Current: with CT saturation



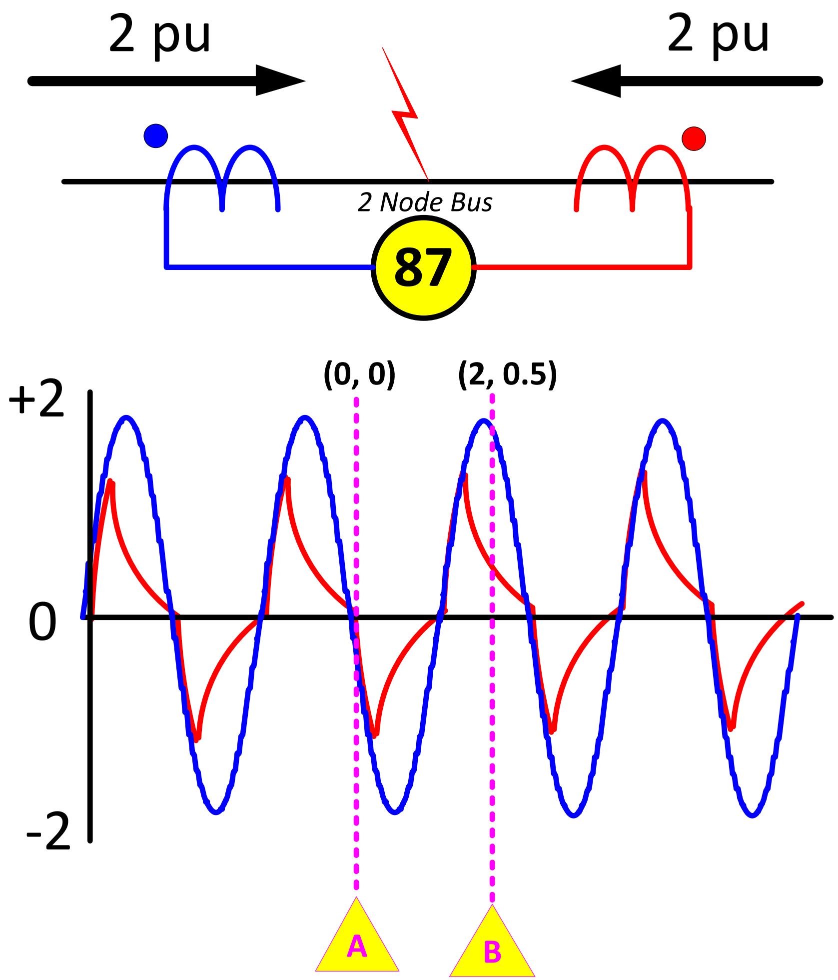
Current waveforms shown as thru current being 180° out-of-phase or in-phase for internal faults (opposite of the M-3425A relay).

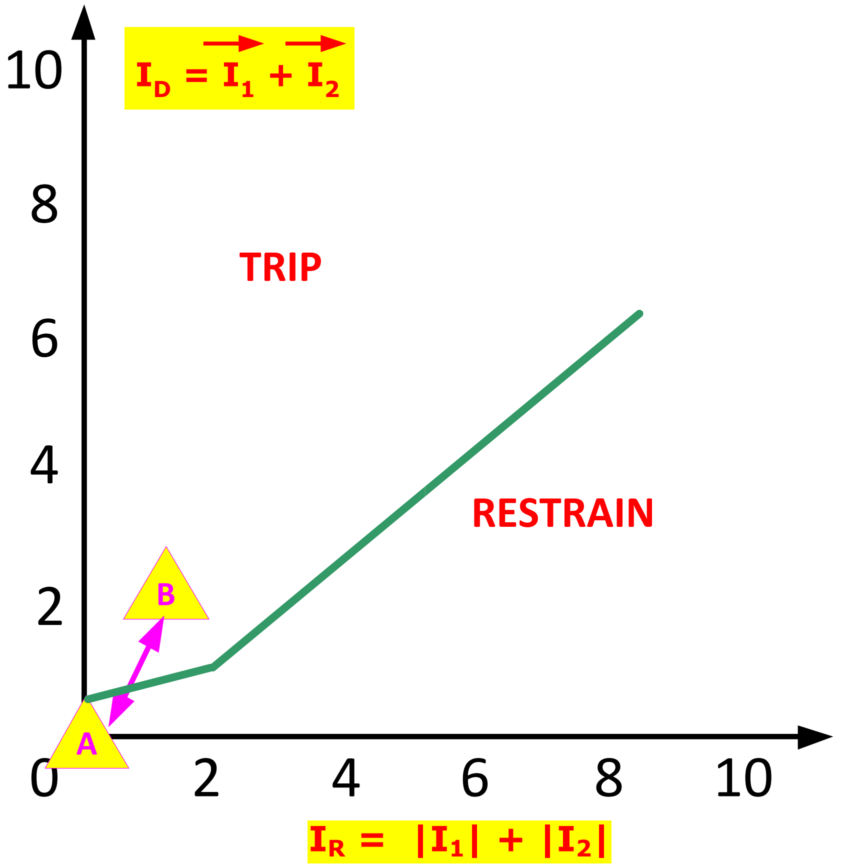
Internal Fault: no CT saturation



Current waveforms shown as thru current being 180° out-of-phase or in-phase for internal faults (opposite of the M-3425A relay).

Internal Fault: with CT saturation





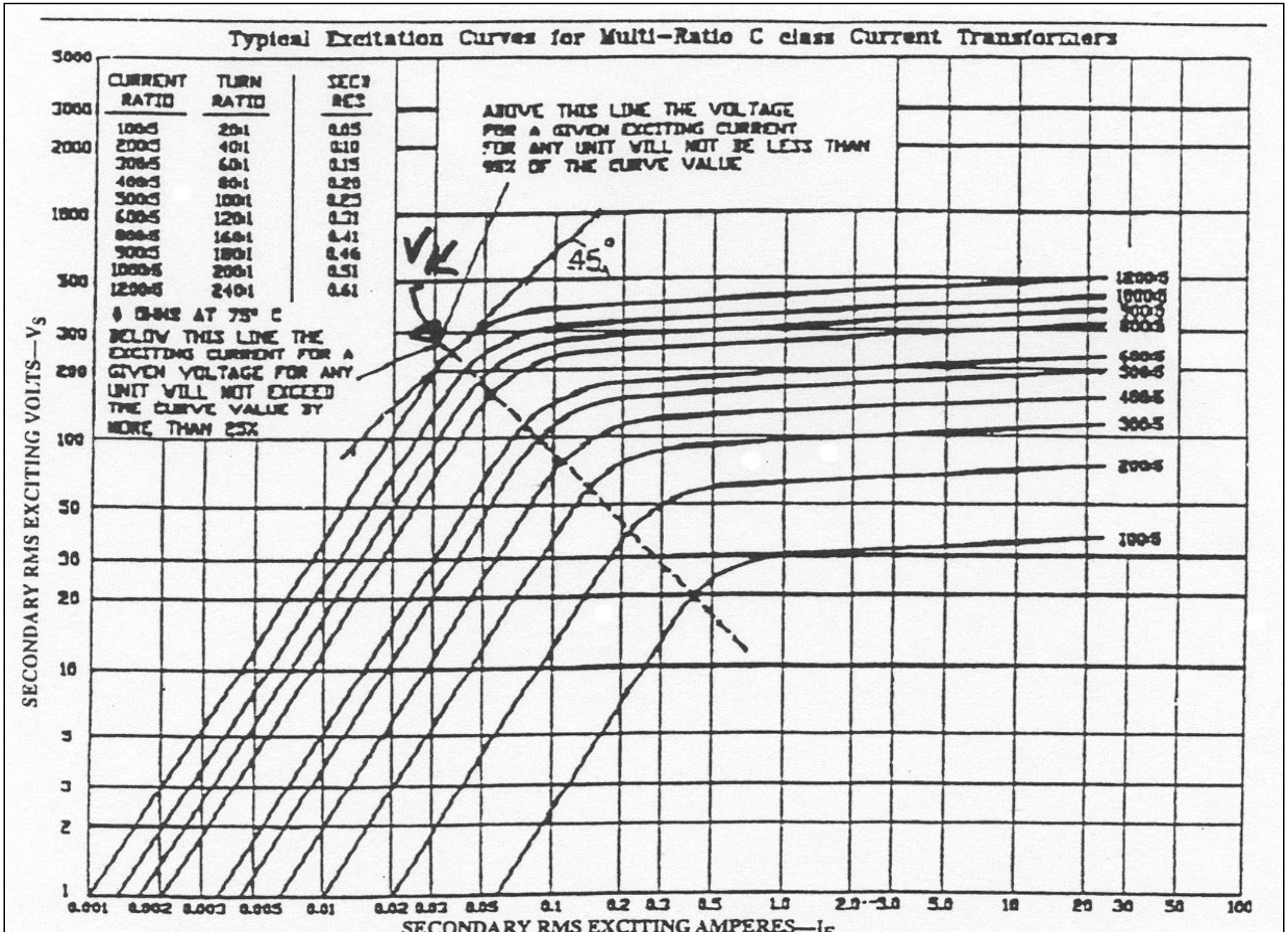
Current waveforms shown as thru current being 180° out-of-phase or in-phase for internal faults (opposite of the M-3425A relay).

CT Remanence and Performance

- Magnetization left behind in CT iron after an external magnetic field is removed
- Caused by current interruption with DC offset
- CT saturation is increased by other factors working alone or in combination:
  - High system X/R ratio which increases time constant of the CT saturation period
  - CT secondary circuit burden which causes high CT secondary voltage
  - High primary fault or through-fault current which causes high secondary CT voltage

CT Saturation performance matching for CTs on each side

CTR, CT class, CT saturation curve knee points, CT secondary wdg resistance and other burdens, CT wire gauge, CT cable run length

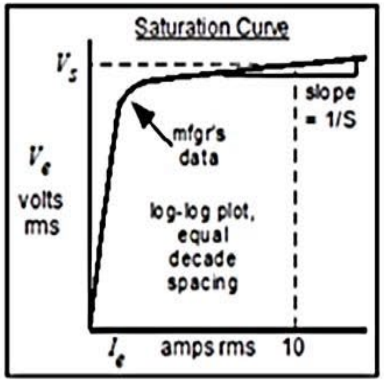


CT Saturation calculator from IEEE PSRC

CT Saturation example 1

INPUT PARAMETERS:

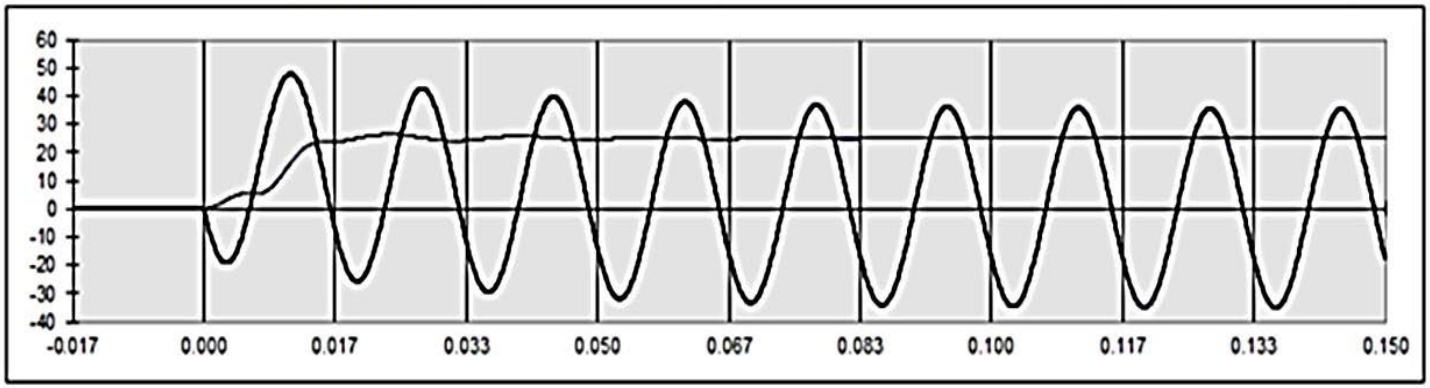
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	2,000	amps rms



CALCULATED:

Rt = Total burden resistance = Rw + Rb =	0.800	ohms
pf = Total burden power factor =	0.848	---
Zb = Total burden impedance =	0.943	ohms
Tau1 = System time constant =	0.032	seconds
Lamsat = Peak flux-linkages corresponding to Vs	1.501	Wb-turns
ω = Radian freq =	376.99	rad/s
RP = Rms-to-peak ratio =	0.34584	
A = Coefficient in instantaneous ie versus lambda curve: ie = A * λ^S :	3.83E-03	---
dt = Time step =	0.000083	seconds
Lb = Burden inductance =	0.00133	henries

Thick lines: Ideal (blue) and actual (black) secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and actual (black) secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.

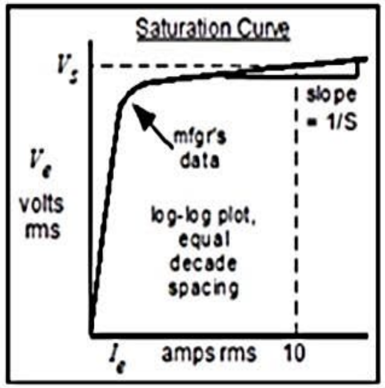


400:5, C400, R=0.5, Offset = 0.5, **Fault Current = 2000A**

CT Saturation example 2

INPUT PARAMETERS:

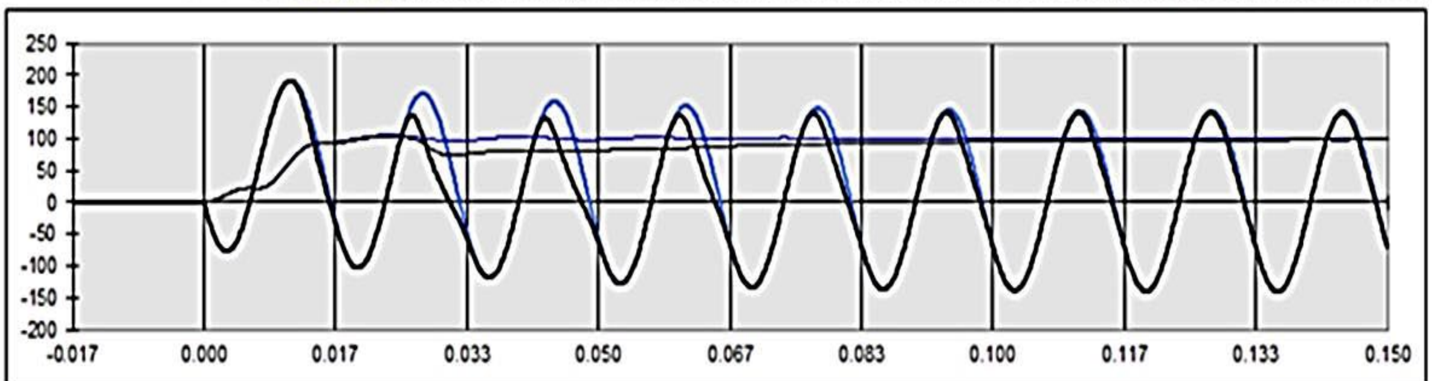
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	8,000	amps rms



CALCULATED:

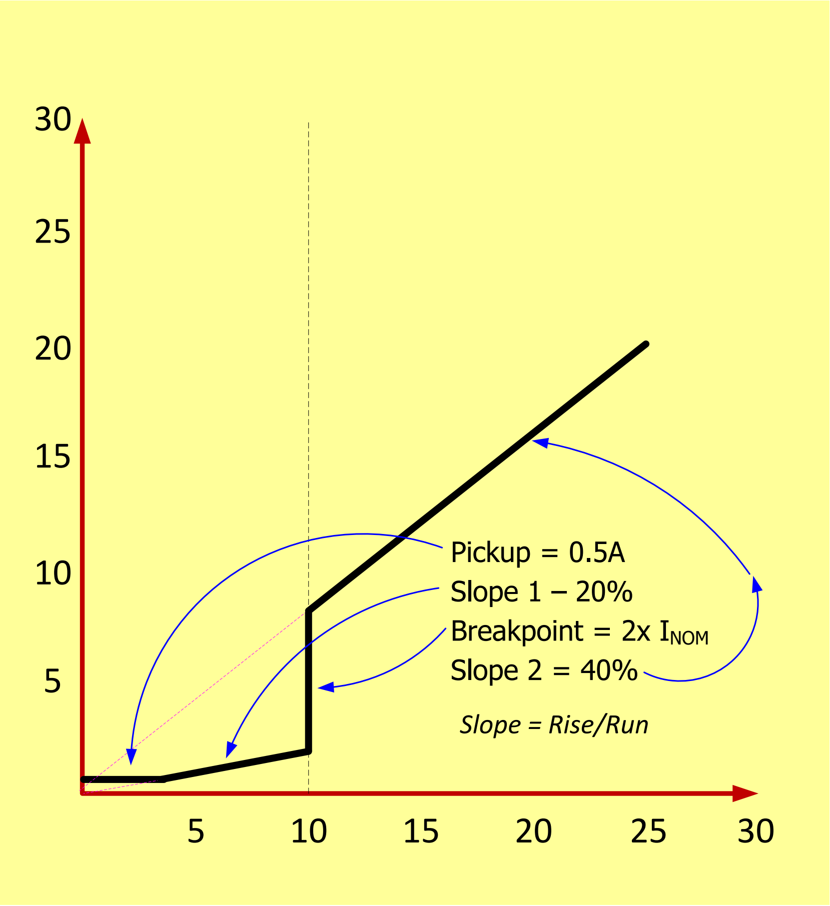
Rt = Total burden resistance = Rw + Rb =	0.800	ohms
pf = Total burden power factor =	0.848	---
Zb = Total burden impedance =	0.943	ohms
Tau1 = System time constant =	0.032	seconds
Lamsat = Peak flux-linkages corresponding to Vs	1.501	Wb-turns
ω = Radian freq =	376.99	rad/s
RP = Rms-to-peak ratio =	0.34584	
A = Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	3.83E-03	---
dt = Time step =	0.000083	seconds
Lb = Burden inductance =	0.00133	henries

Thick lines: Ideal (blue) and actual (black) secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and actual (black) secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.

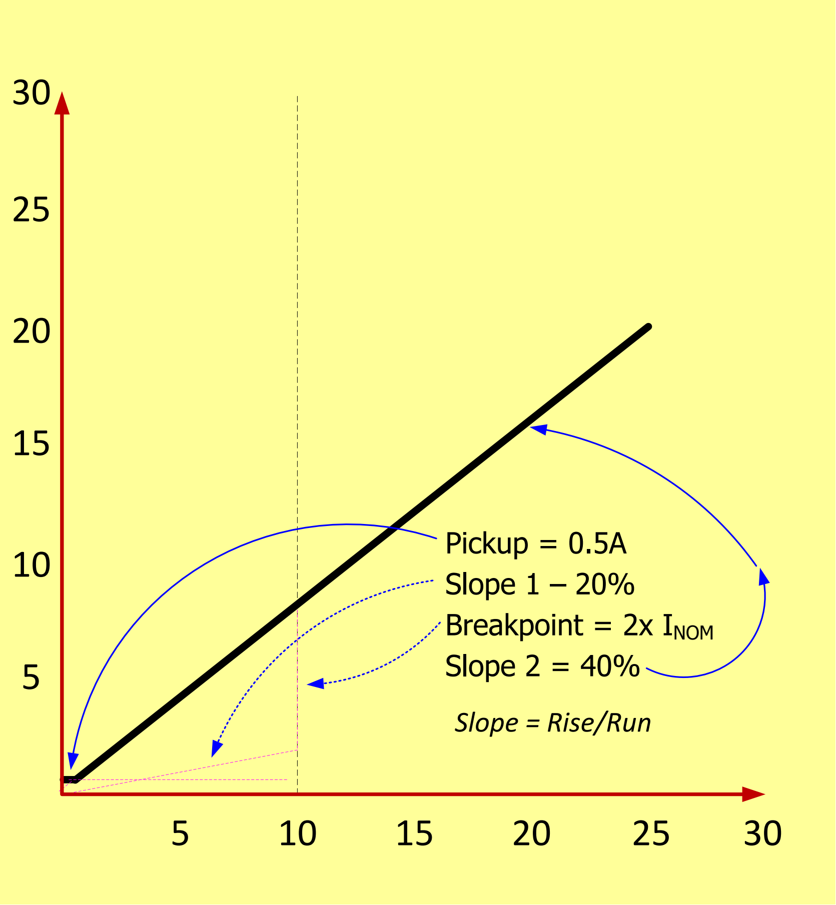


400:5, C400, R=0.5, Offset = 0.5, **Fault Current = 8000A**

87 Characteristic Curves

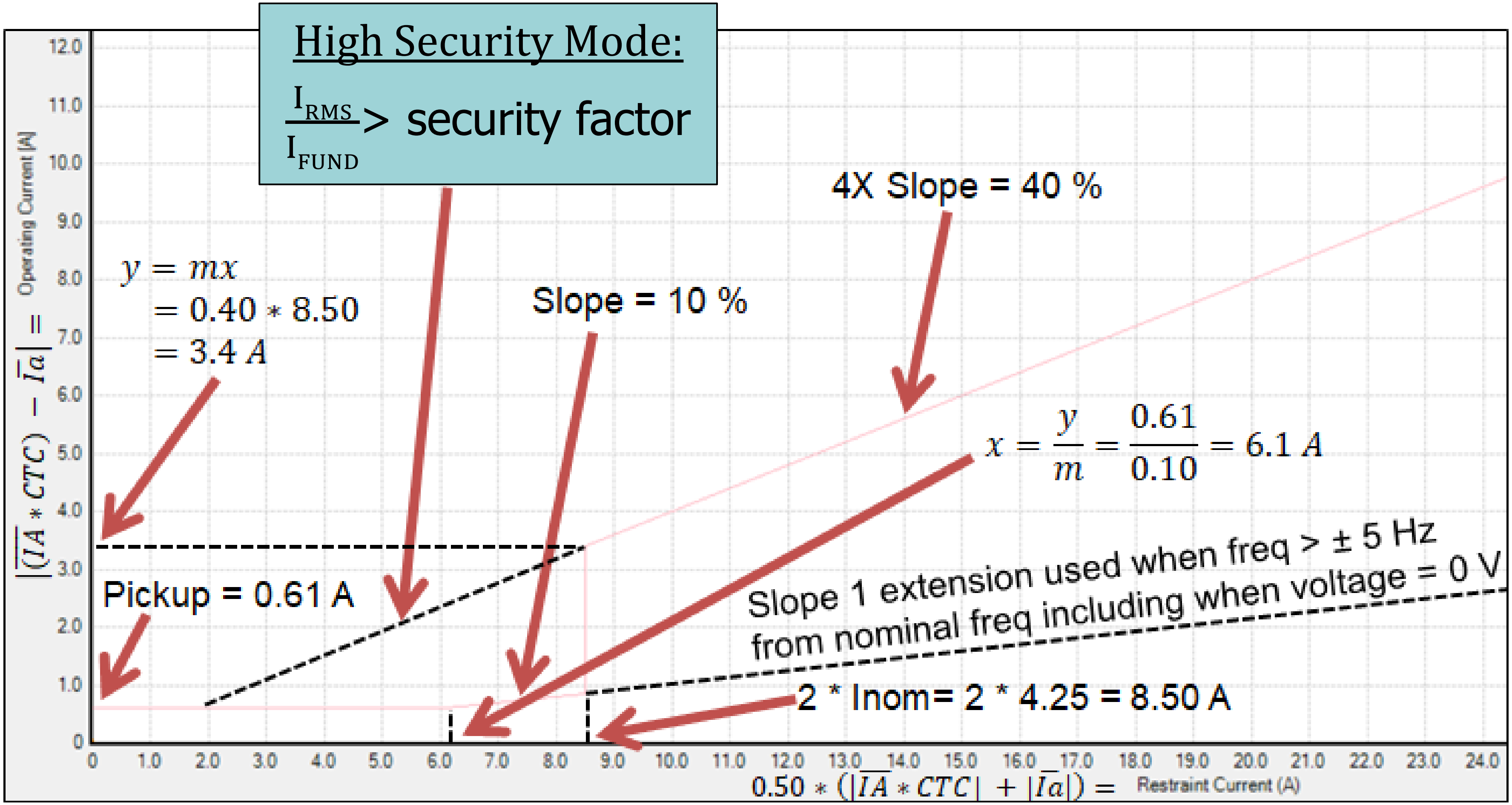


Normal 87 Characteristic Curve

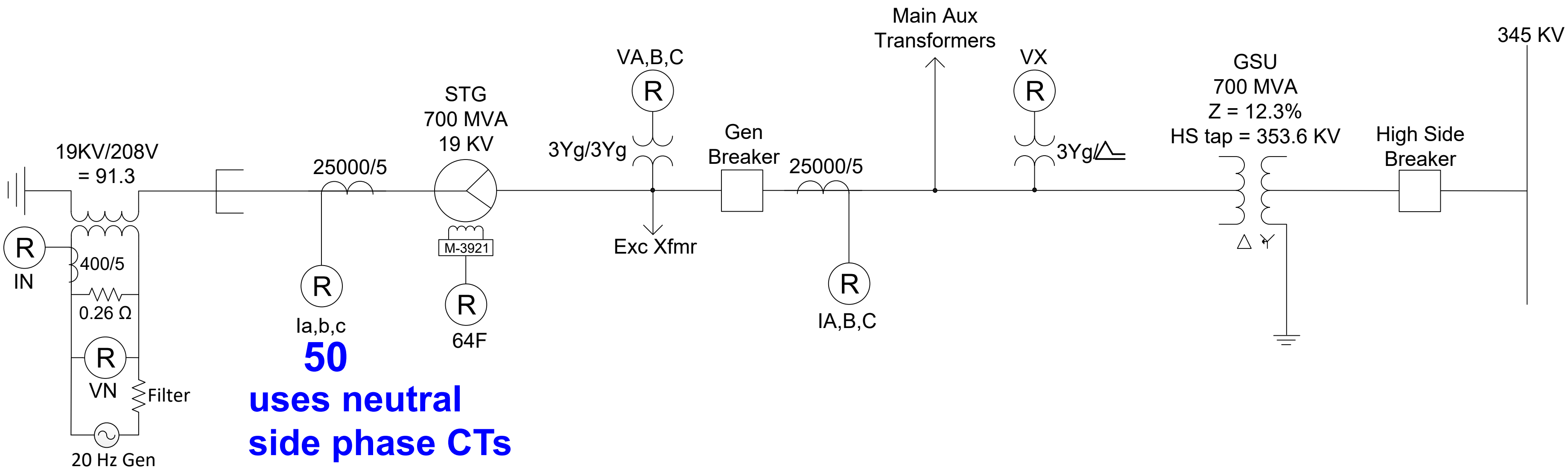


87 Characteristic Curve when DC offset current is present and high security mode is invoked

87 Characteristic Curve in M-3425A



50 – Instantaneous Phase Overcurrent



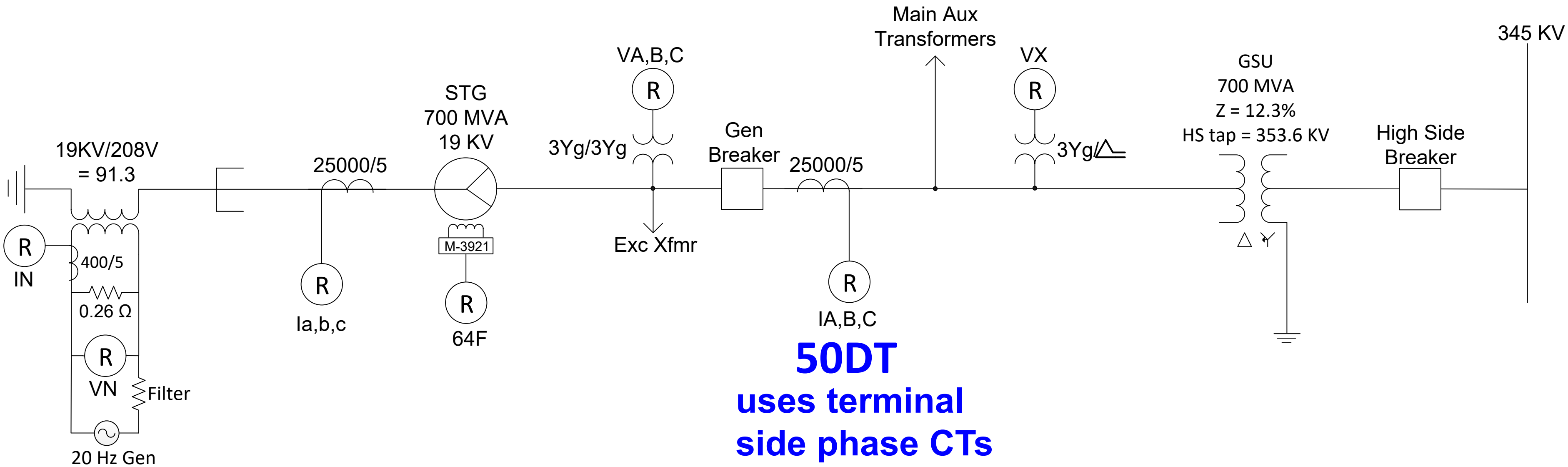
Backup Phase Fault Protection to 87 element:

- *The 50 function in the M-3425A relay provides protection from 2-80 Hz, (other mfgs may vary).*
- *This can provide protection while off-line or during startup in the pre-synchronizing period and during shutdown.*

50 – Instantaneous Phase Overcurrent

- Primary purpose may be for “off-line” 87 backup protection; however, if also using this element for “on-line” protection, then the generator decrement curve can be used to select a pickup and time delay setting that complies with NERC PRC-025 and PRC-026:
  - $Iac(t) = (|Id''| - |Id'|) * e^{-\frac{t}{Td''}} + (|Id'| - |Id|) * e^{-\frac{t}{Td'}} + |Id|$
- **PRC-025:**
  - For “off-line” protection, there is no need to comply.
  - For “on-line” protection, it may be more difficult to comply using 50 elements that are sourced by neutral side CTs vs terminal side CTs (which source 50DT elements in M-3425A relay), so could just use 50DT as an 87 backup for additional security.
- **PRC-026:**
  - For “off-line” protection, there is no need to comply.
  - For “on-line” protection, if set the time delay $\geq$ 15 cycles, then do not need to worry about the selected pickup setting.

50DT – Definite Time Overcurrent

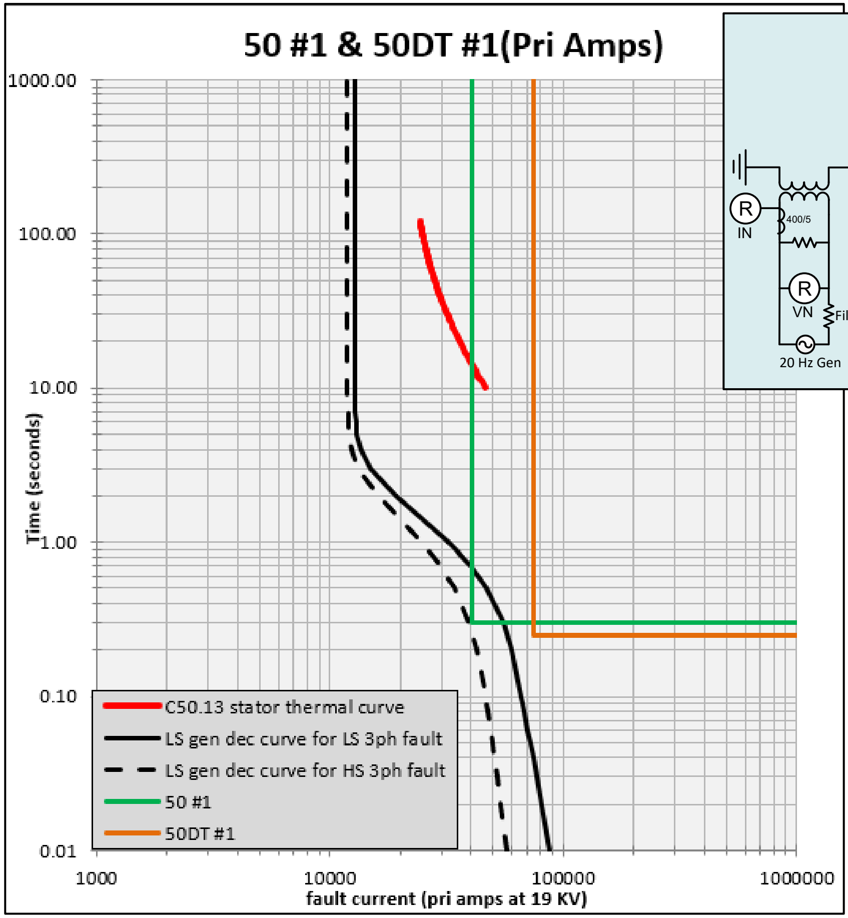


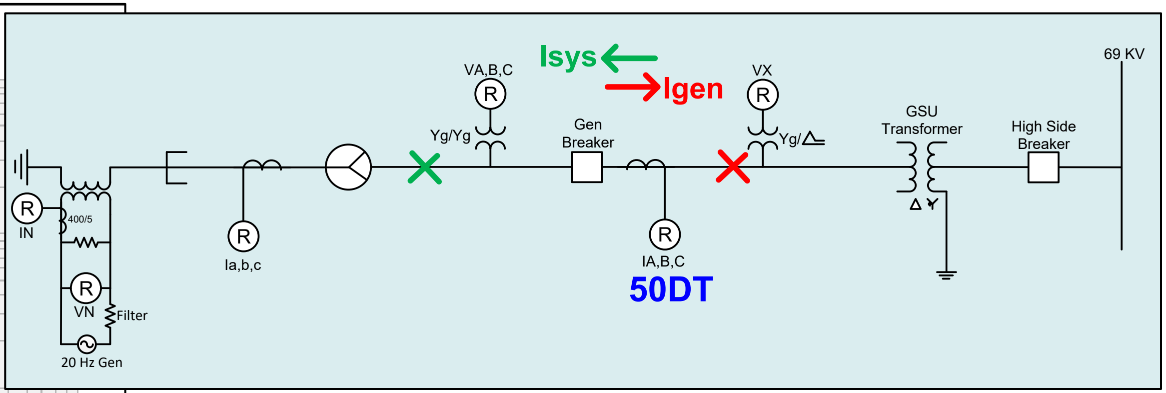
50DT
uses terminal side phase CTs

- May also (in addition to 50 element) be used for "on-line" 87 backup
- May provide "off-line" protection as well depending on the element's frequency response (which is also 2-80 Hz for M-3425A relay)
- Or may use for Split Phase Differential Protection (specifically in reference to the M-3425A relay)

50DT – Definite Time Overcurrent

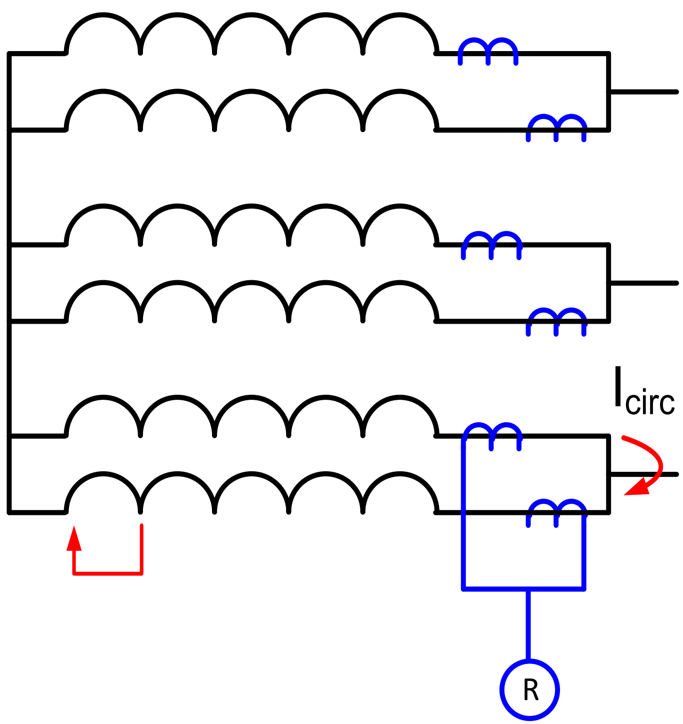
- Use “on-line” criteria to develop secure and sensitive settings.
- Must comply with NERC PRC-025 and PRC-026 when “on-line”.
- For security, set Pickup > the generator contribution to a GSU LS phase fault using the generator decrement curve at the chosen time delay.

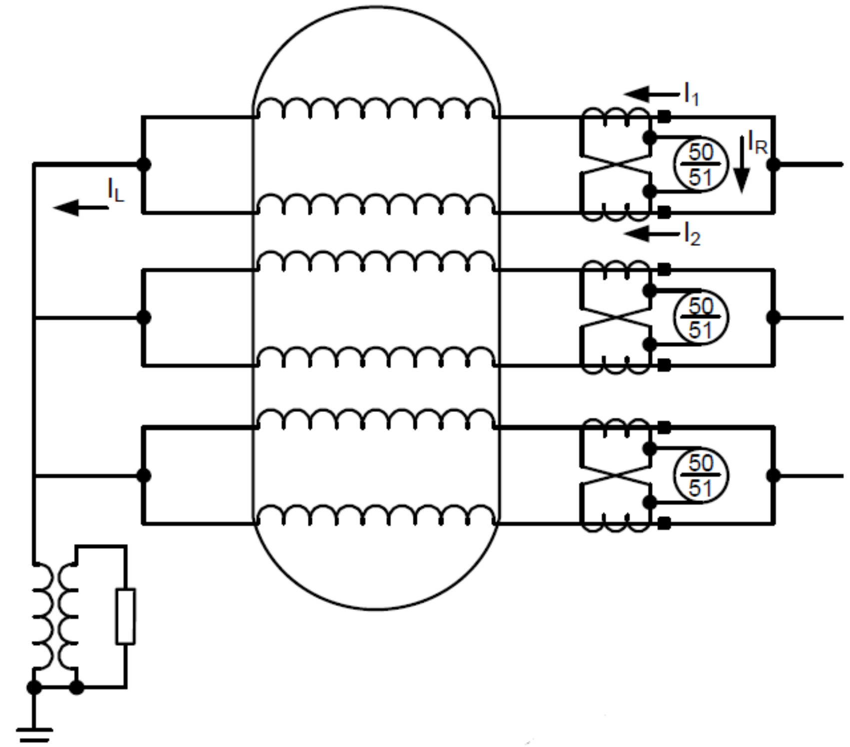




- 50DT is inherently more secure than 50 element due to sourcing CT location, which allows discrimination between faults in front of CTs (towards generator) vs faults behind CTs (towards GSU/system).
- Therefore, if only using one of them, may prefer to use 50DT.

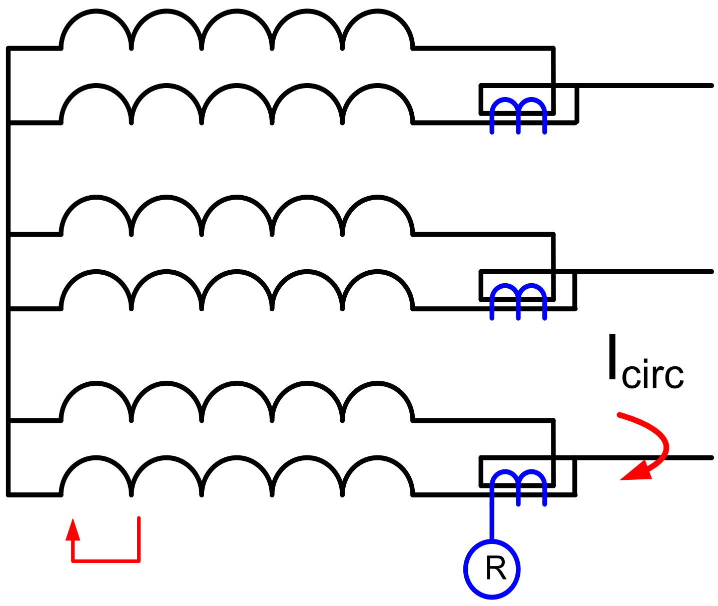
Split Phase Diff protection

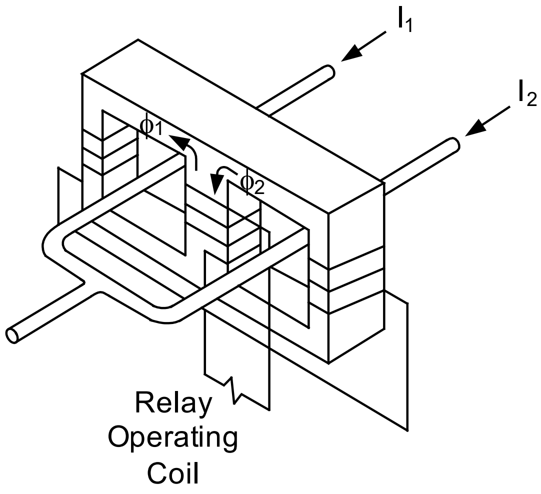


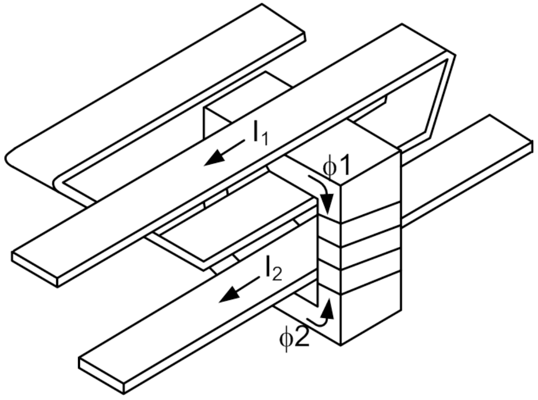


Separate CTs may have slightly different replication characteristics, therefore may require a desensitized setting

Split Phase Using Core Balance CTs







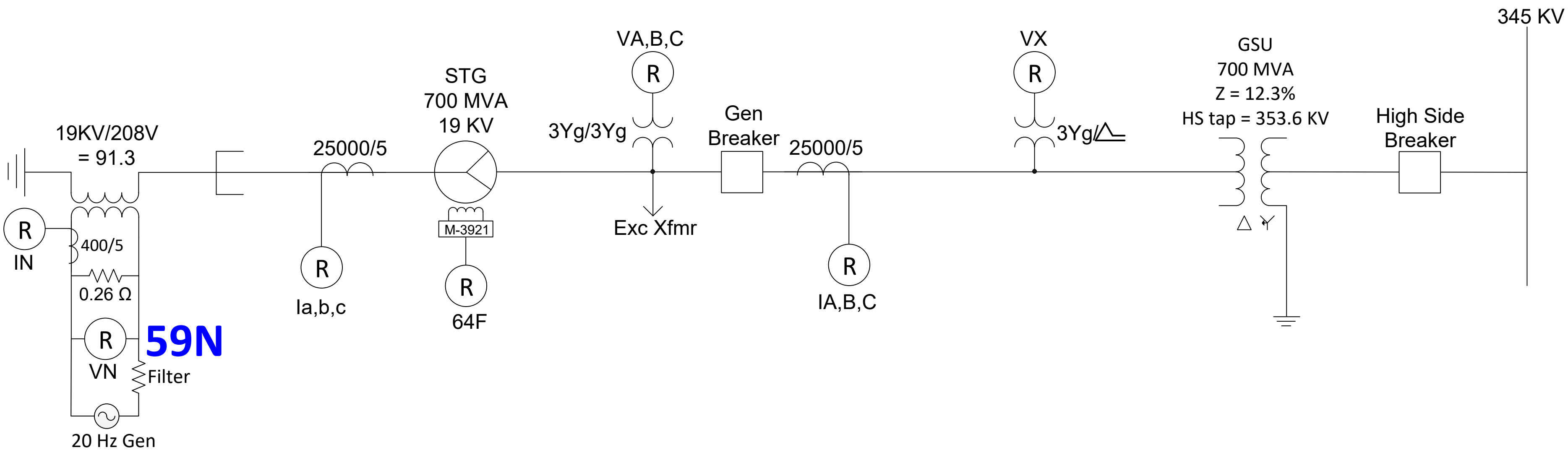
Balance CTs allow greater sensitivity

Ground Fault Protection

High-Impedance Grounded Generators

- 59N – Neutral Overvoltage
- 27TN – Third Harmonic Neutral Undervoltage
- 59D – Third Harmonic Voltage Differential (Ratio)
- 64S – 100% Stator Ground Protection

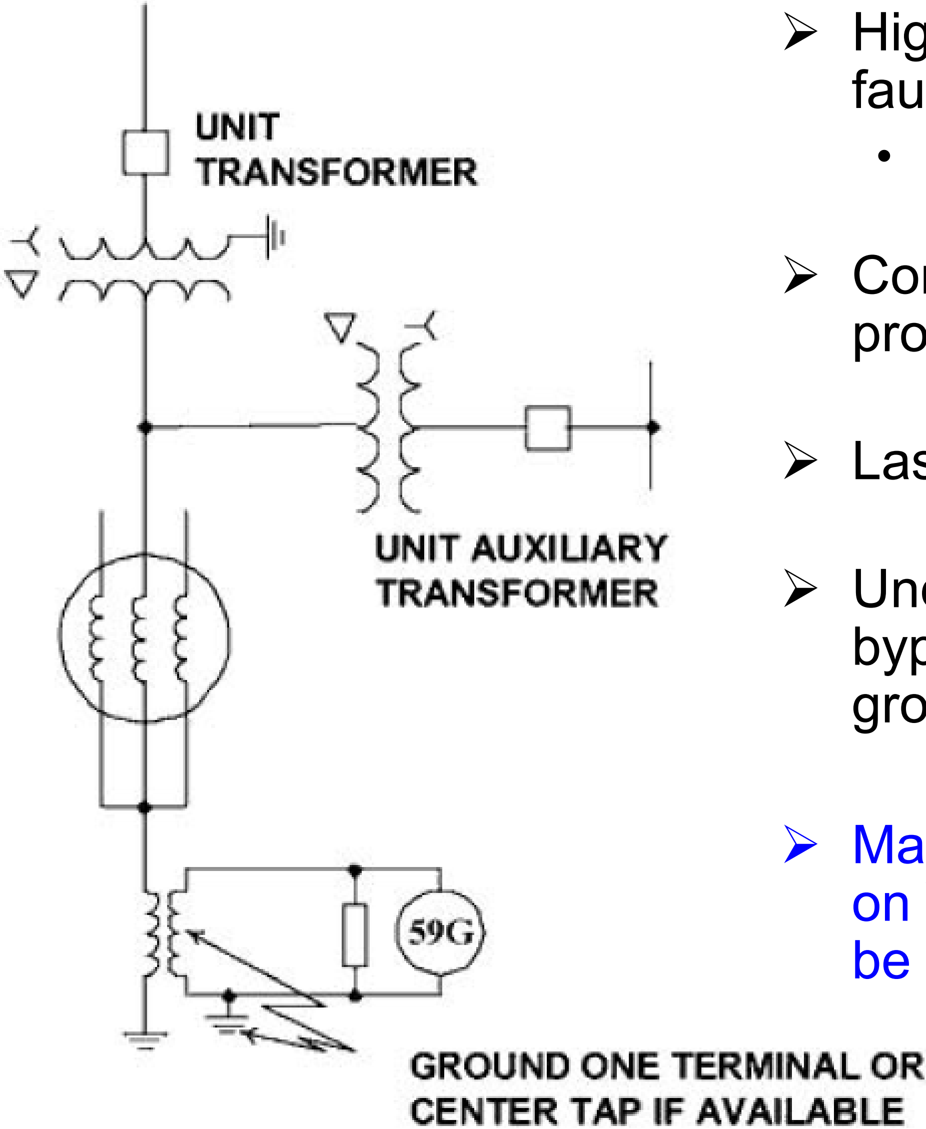
59N – Neutral Overvoltage (aka 59G, 64G)



Scheme 1) 59N #1 – 95% stator ground fault protection

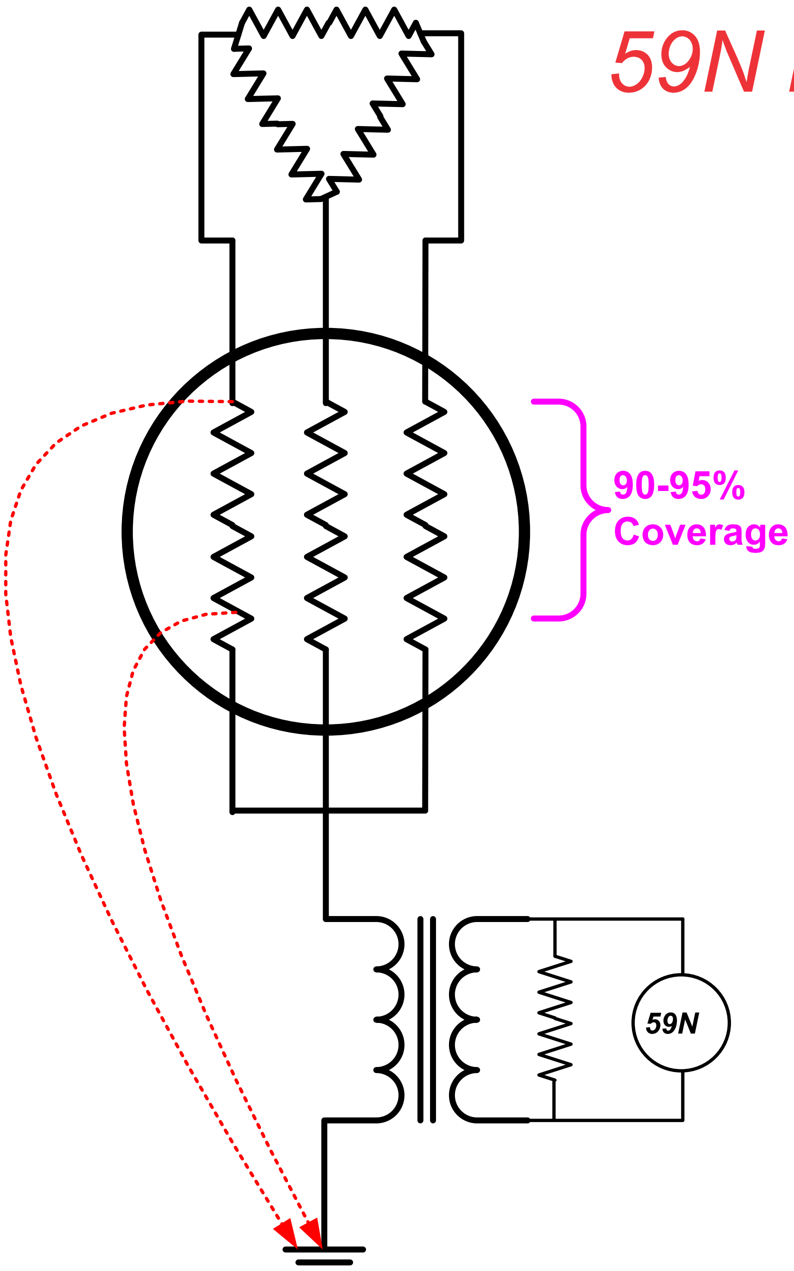
- **Operates on the fundamental frequency component (± 5 Hz) of the VN voltage (it filters out the third harmonic voltage).**

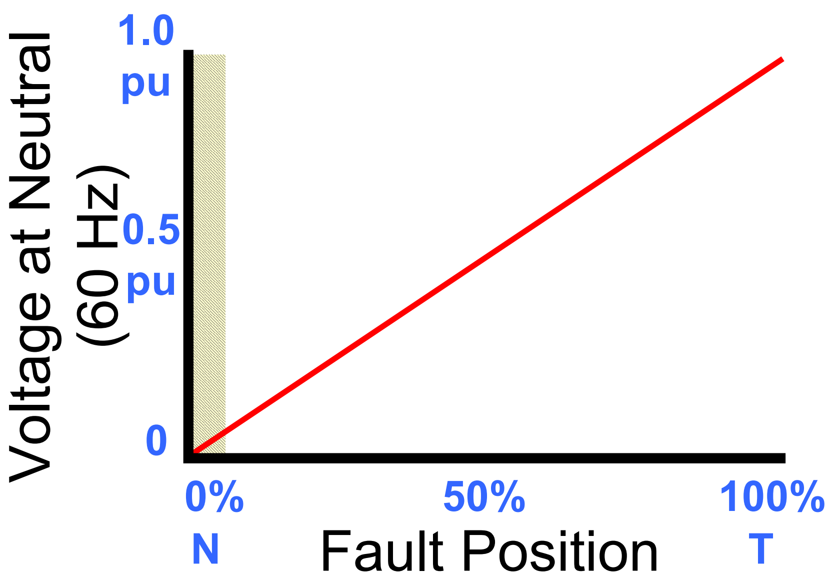
59N – Neutral Overvoltage



- High impedance ground limits ground fault current to about 10A
  - Limits damage on internal ground fault
- Conventional neutral overvoltage relay provides 90-95% stator coverage
- Last 5-10% near neutral not covered
- Undetected grounds in this region bypass grounding transformer, solidly grounding the machine!
- May see ground faults on GSU HS and on VT secondary so coordination may be necessary.

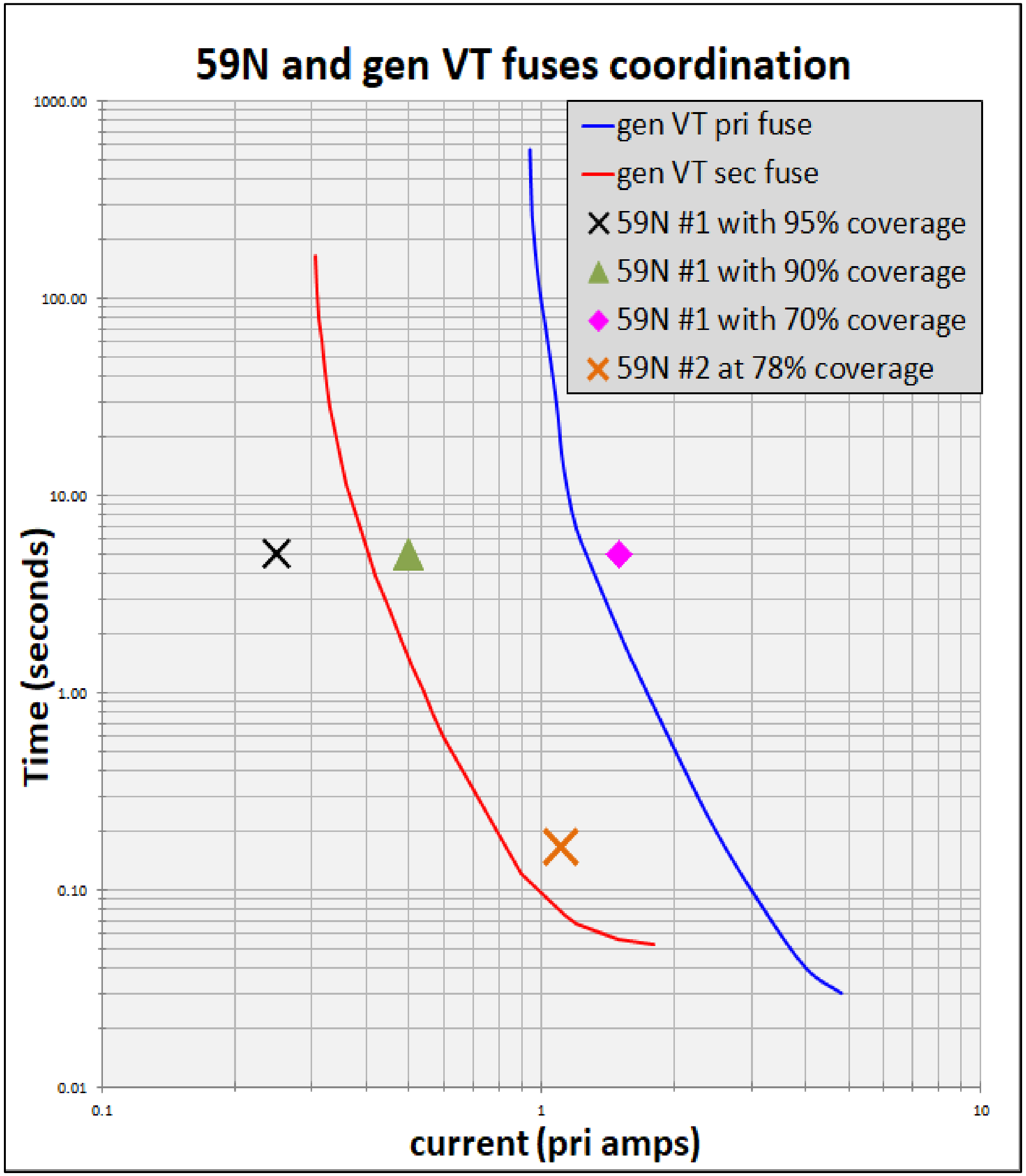
59N Element





- ***Fault position is proportional to the measured VN voltage across the NGR.***

59N – Neutral Overvoltage (Gen)



- ***Probably do not want to accept 70% coverage and coordination with the primary VT fuse may not be as important.***

- ***But may decide to accept the 90% coverage and bump the Pickup setting up to coordinate with secondary VT fuses***

  OR

- ***move the secondary VT ground safety connection from the neutral to one of the phases.***

59N – Accelerated Ground Fault Protection Schemes

Scheme 2) 59N #2 – GSU HS fault coord

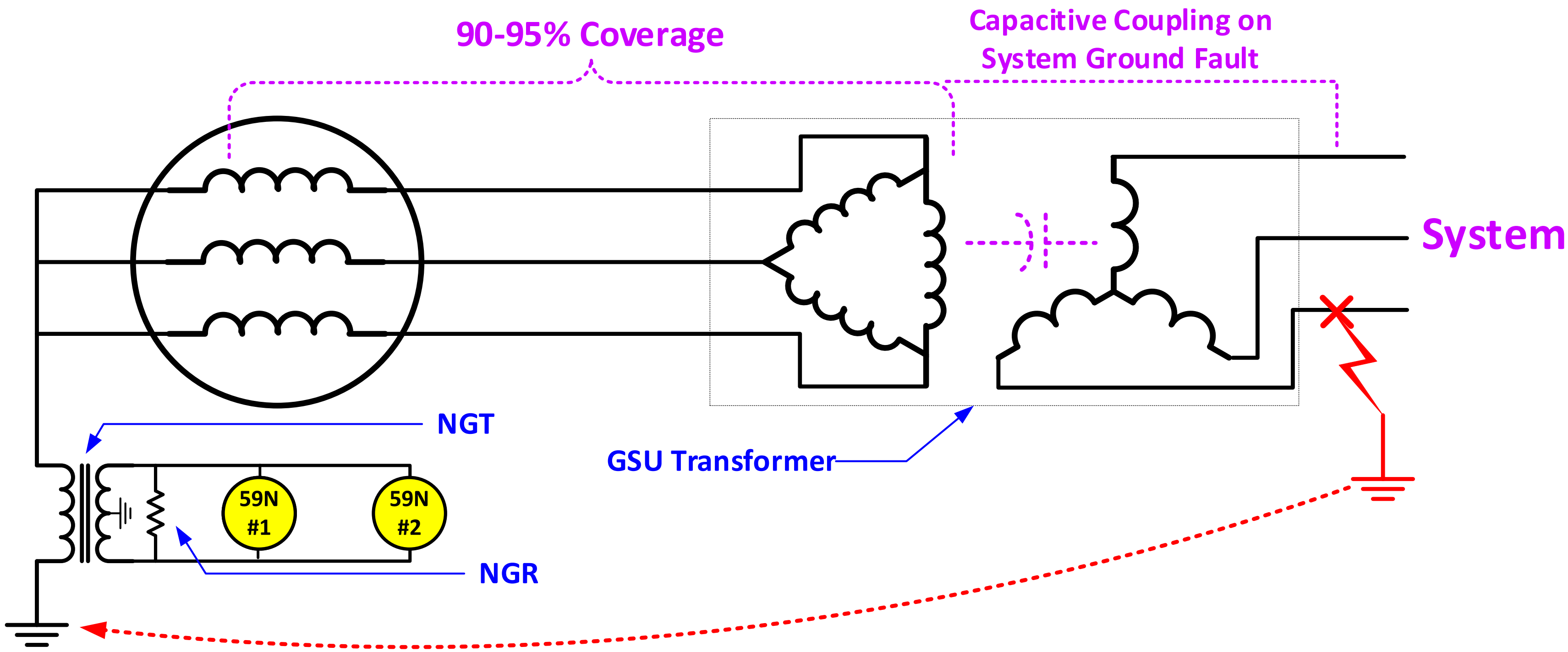
Scheme 3) 59N #3 – V2/V0 supervised

Scheme 4) I2 supervised

Scheme 5) Open gen breaker

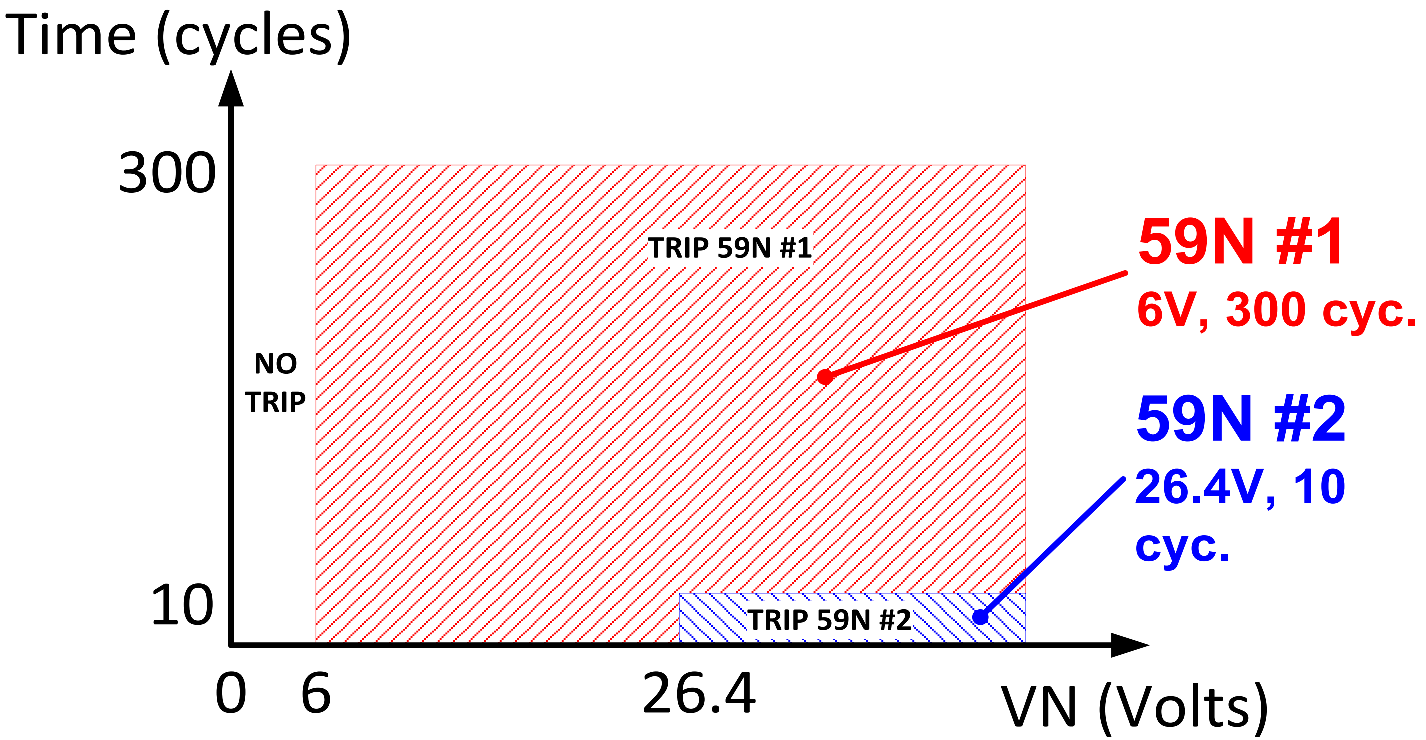
Scheme 6) Intermittent arcing

Scheme 2) GSU HS fault coordinated



- Measured VN voltage across NGR will see GSU HS ground faults due to the GSU interwinding capacitance.
- Therefore, set 59N #2 Pickup > the measured VN for a GSU HS ground fault.
- May accelerate the trip, but it still <u>cannot</u> detect ground faults at/near the neutral.

Schemes 1 & 2) Multiple 59N Element Application



- **59N #1:** set to 95% coverage with long time delay as it may sense capacitance-coupled out-of-zone ground fault
- ***59N #2:*** *set to short time delay and 78% coverage to set above capacitance-coupled out-of-zone ground fault*

Schemes 3 & 4) use symmetrical component values to supervise and accelerate tripping

- A ground fault in the generator zone produces primarily <u>zero</u> sequence voltage.
  - ✓ Very small, negligible V_2, I_2 and I_0
- A fault in the VT secondary or system (GSU coupled) generates <u>negative</u> sequence quantities in addition to zero sequence voltage.
- The V_2/V_0 method may be employed to control 59N for system and VT secondary ground faults.
- The I_2 method may be employed to control 59N for system ground faults.

Schemes 1 & 3) use V_2/V_0 to accelerate 59N tripping

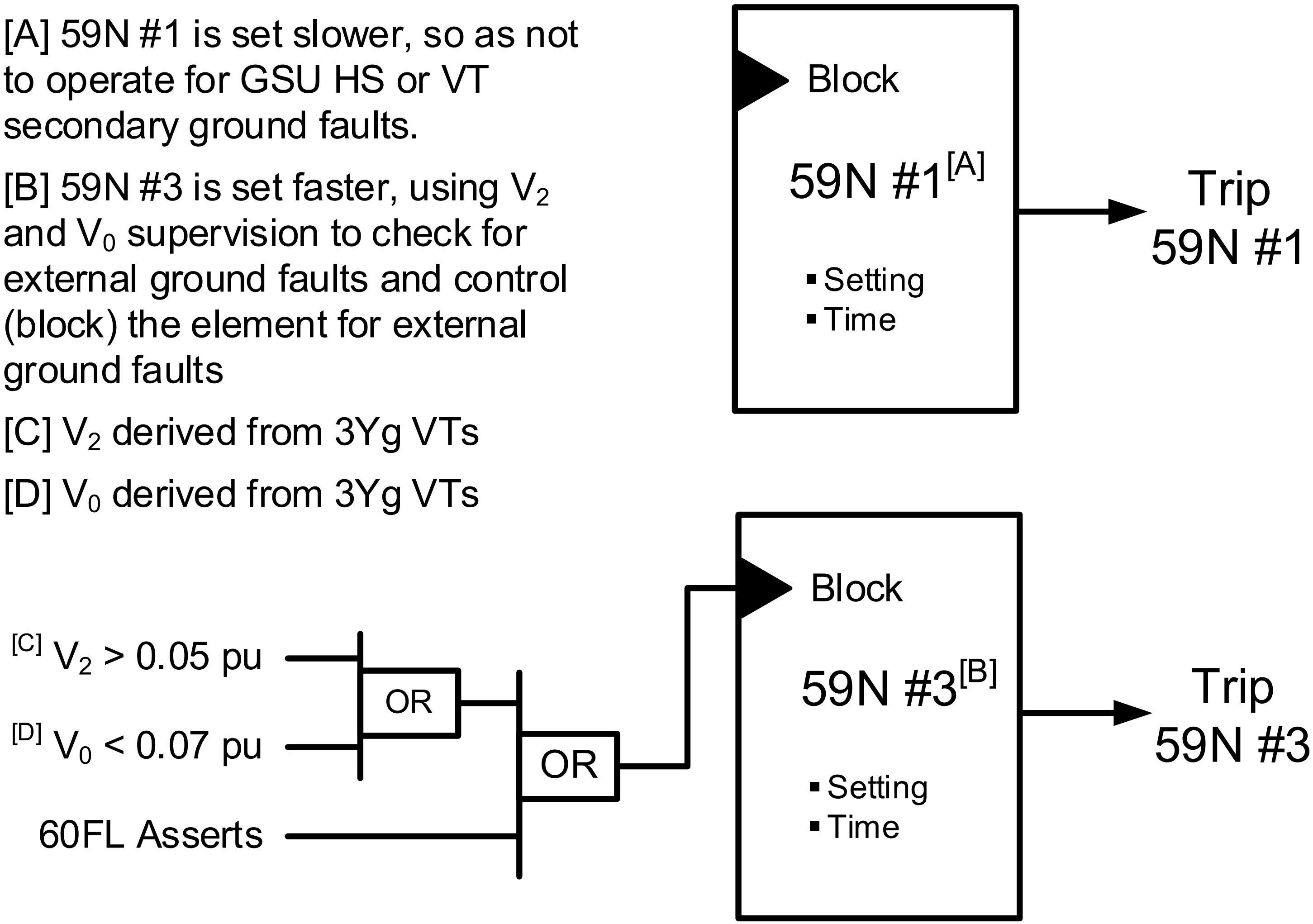
<u>NOTES:</u>

[A] 59N #1 is set slower, so as not to operate for GSU HS or VT secondary ground faults.

[B] 59N #3 is set faster, using V_2 and V_0 supervision to check for external ground faults and control (block) the element for external ground faults

[C] V_2 derived from 3Yg VTs

[D] V_0 derived from 3Yg VTs

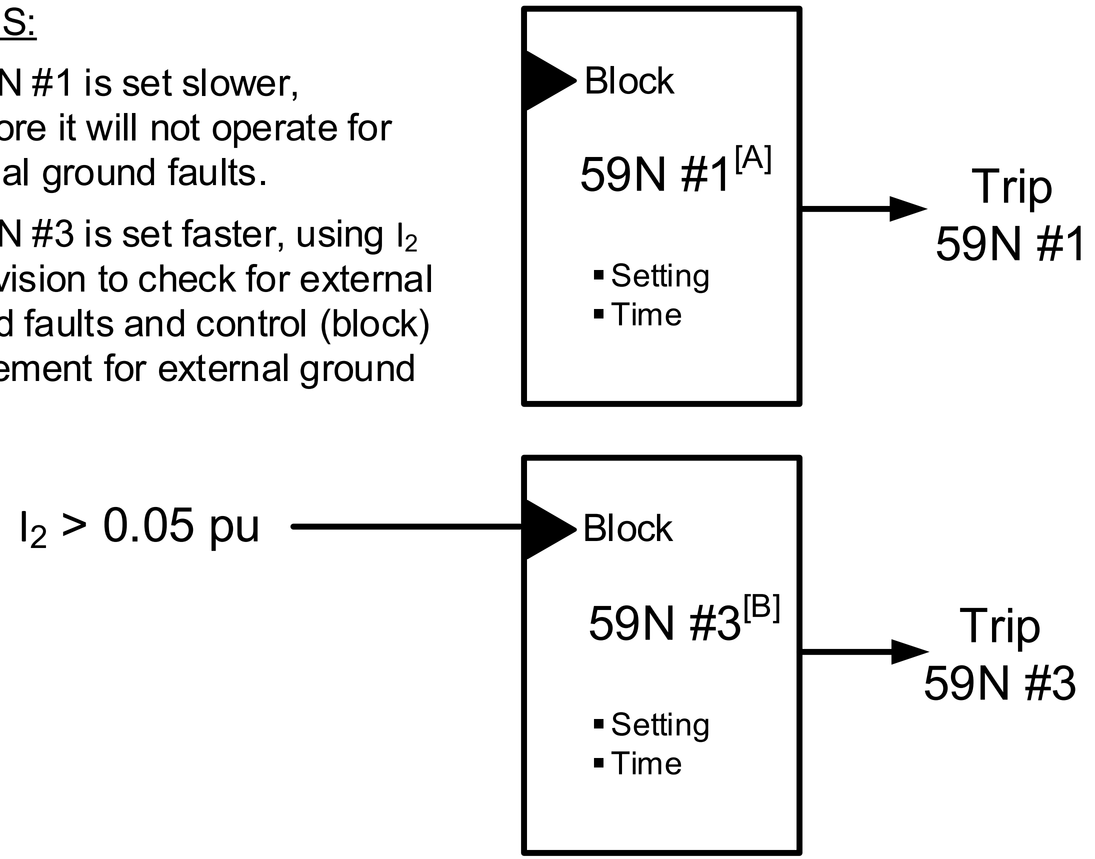


Schemes 1 & 4) use I_2 to accelerate 59N tripping

NOTES:

[A] 59N #1 is set slower, therefore it will not operate for external ground faults.

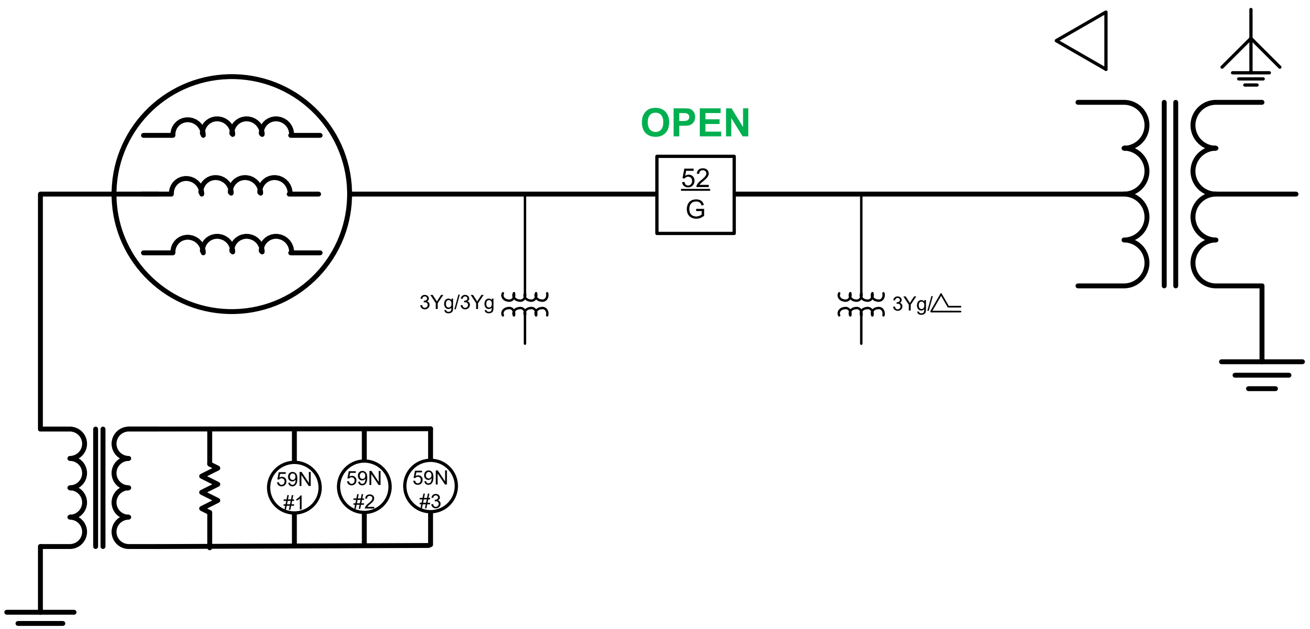
[B] 59N #3 is set faster, using I_2 supervision to check for external ground faults and control (block) the element for external ground faults.



I_2 is used to control 59N for ground faults on the high voltage side of the GSU

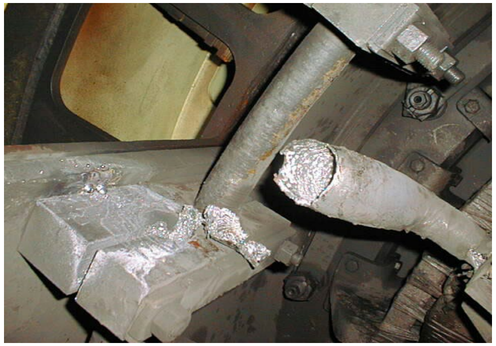
Scheme 5) Open gen breaker accelerated tripping

- For ground faults when the generator breaker is open, there is no need for time coordination for external faults.
- Therefore, the gen LOR can be tripped very quickly (tripping excitation, turbine, and send trip to open breaker, etc) if pickup is exceeded.

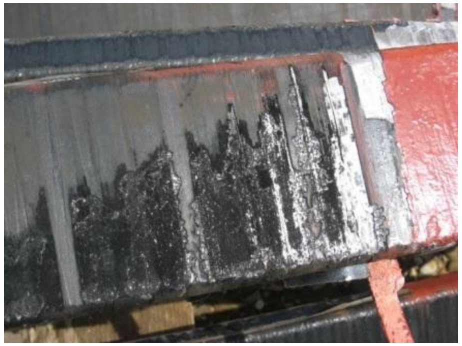


Scheme 6) Intermittent Arcing Ground Faults

- Conventional time delayed ground fault protection cannot protect for these events



Burned away copper of a fractured connection ring



Side of a bar deeply damaged by vibration sparking

Premature Failure of Modern Generators, Clyde V. Maughan

Typical winding damage resulting from broken stator winding conductor

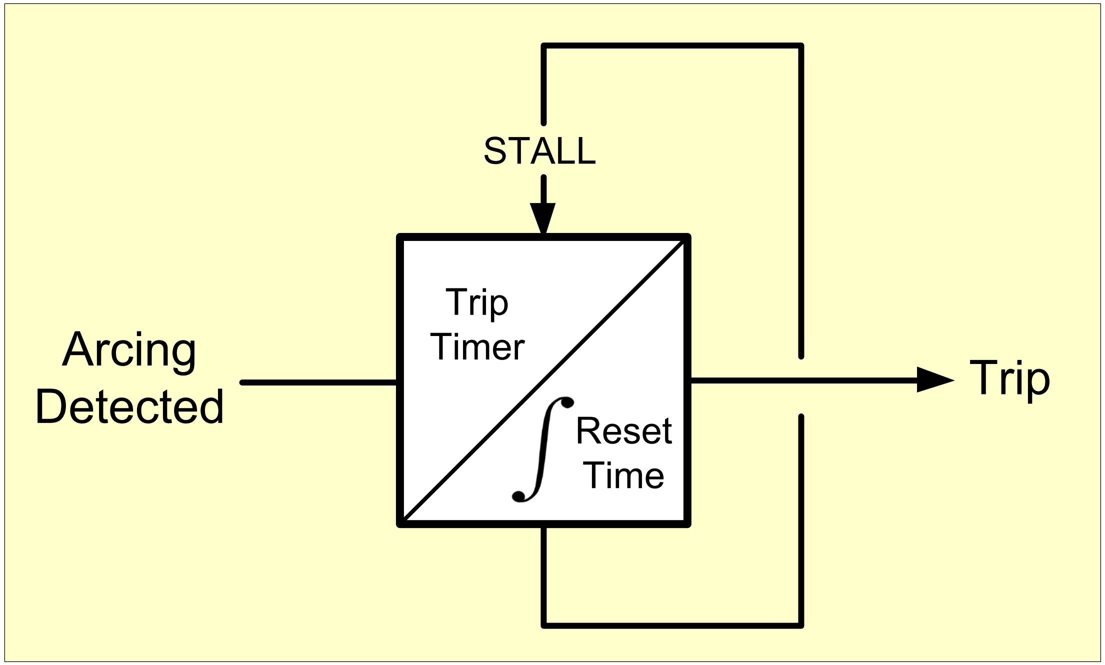
Typical core and winding damage resulting from a burned open bar in a slot

Typical winding damage resulting from broken stator winding conductor

Clyde V. Maughan; "Stator Winding Ground Protection Failures," ASME Power 2013

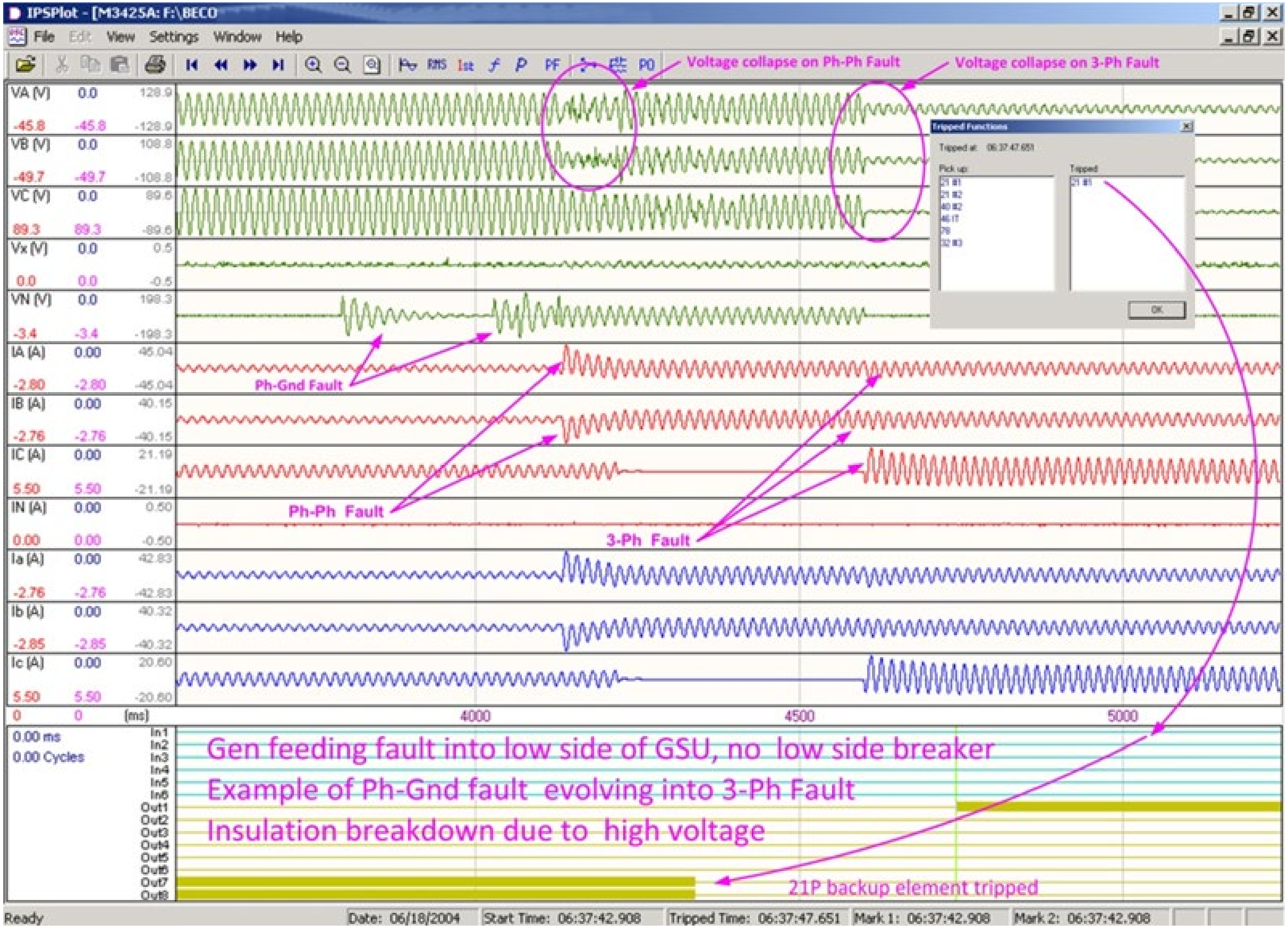
May be able to save much of the stator ground fault damage if trip in the very early, incipient stages as some intermittent arcing will typically occur prior to the sustained ground fault.

Intermittent Arcing Fault Timer Logic



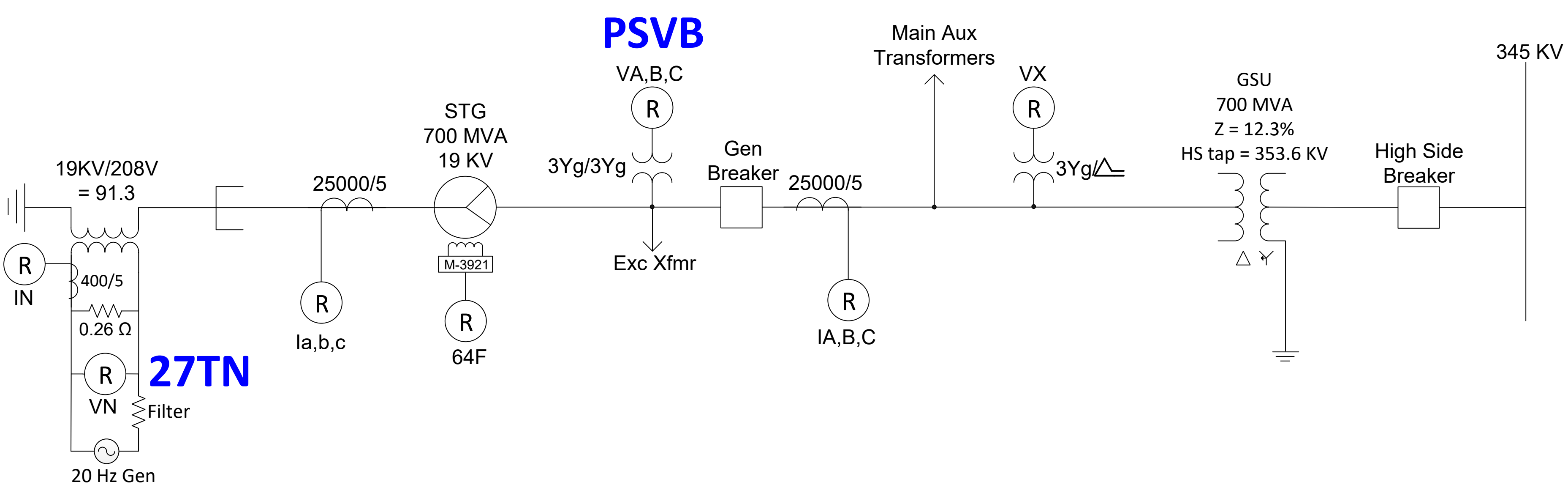
Stallable Trip Timer: Times Out to Trip
Integrating Reset Time: Delays Reset for Interval

Intermittent Arcing Ground Fault Turned Multiphase



27TN – Third Harmonic Neutral Undervoltage

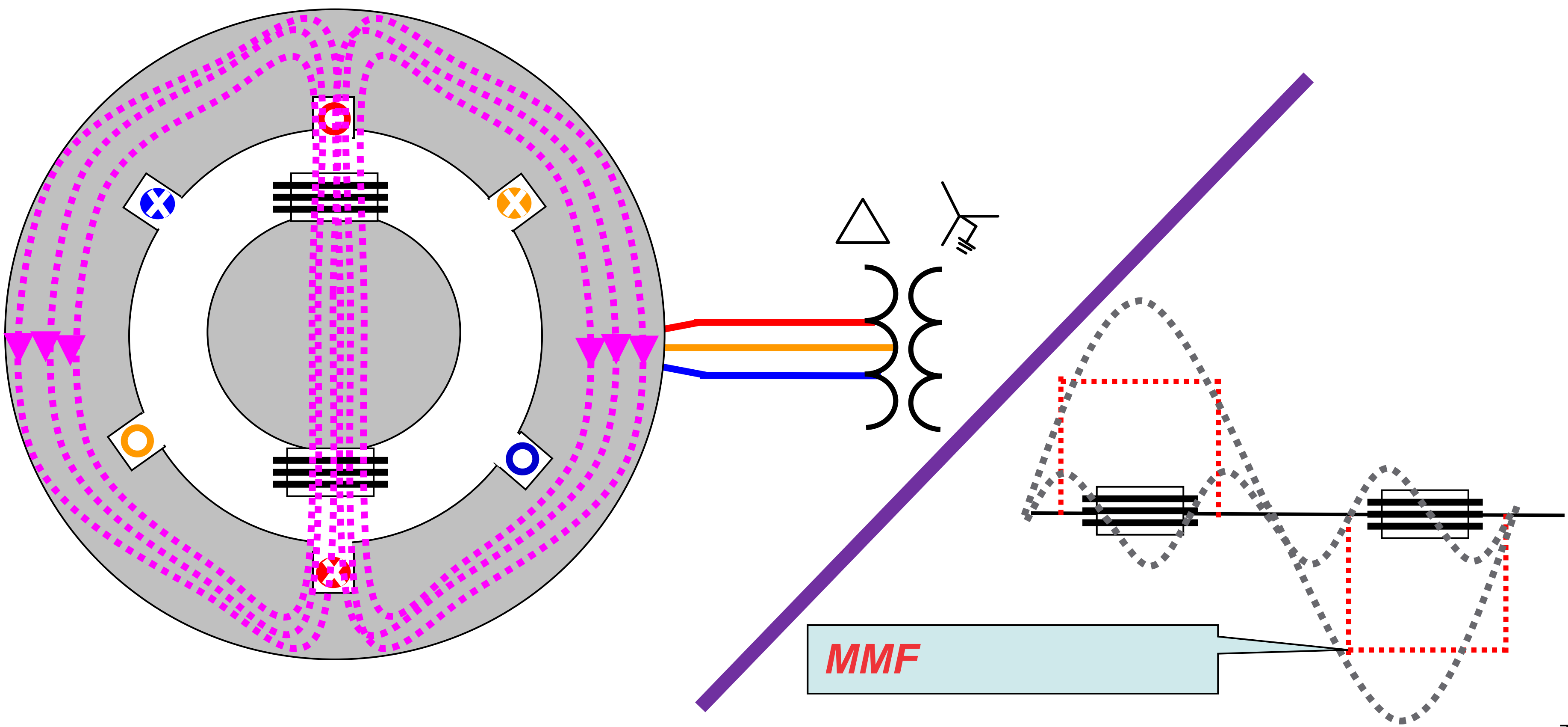
- **IEEE identifies as 27TH**
- **may be referred to as 100% Stator Ground Protection**
  - ***Not technically true, but with 59N then yes 100%***



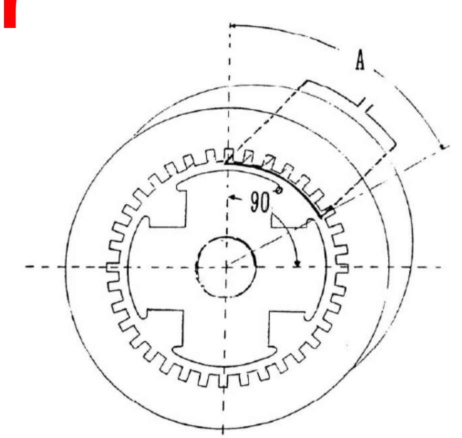
PSVB = Positive Sequence Voltage Block

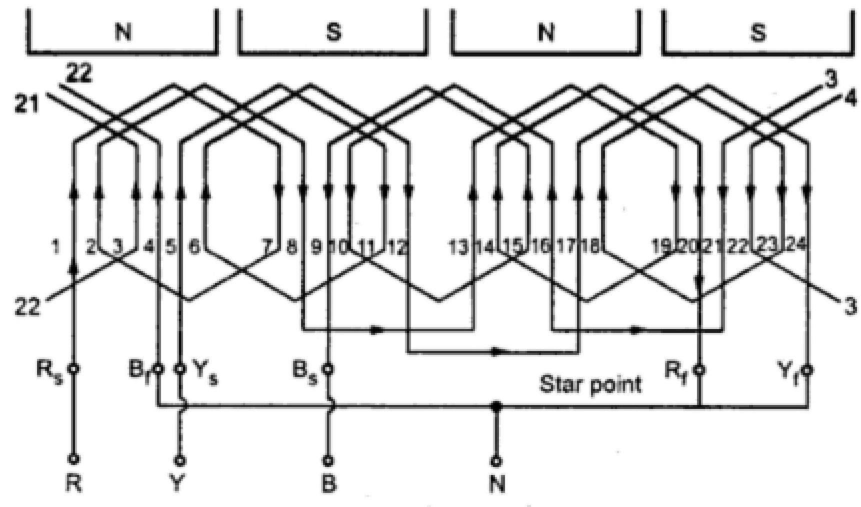
Third-Harmonic Flux

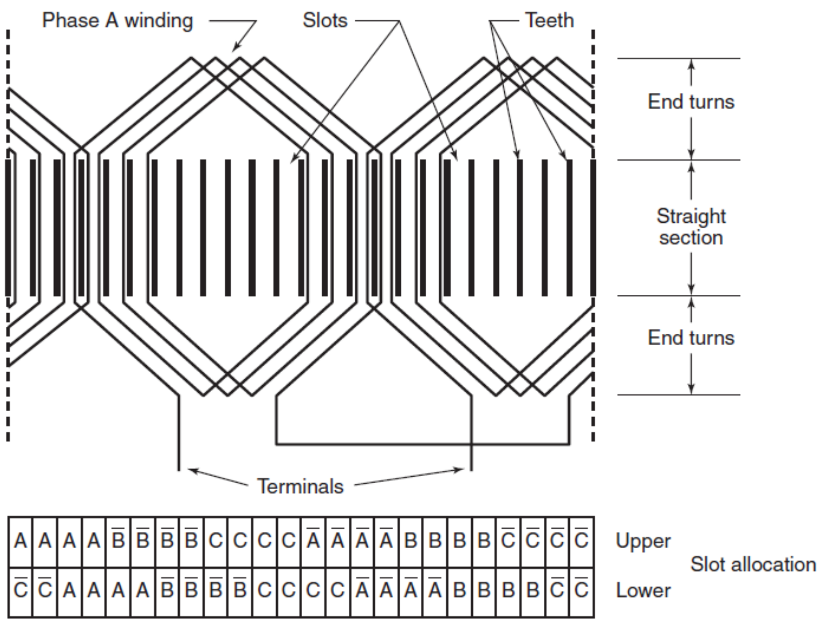
- *Develops in stator due to imperfections in winding and system connections*
- *Unpredictable amount requiring field observation at various operating conditions*
- *Dependent on* ***stator winding and other capacitances*** *and the* ***winding pitch****, which is a method to define the way stator windings are placed in the stator slots*



Generator Stator Winding Pitch Factor







Example:

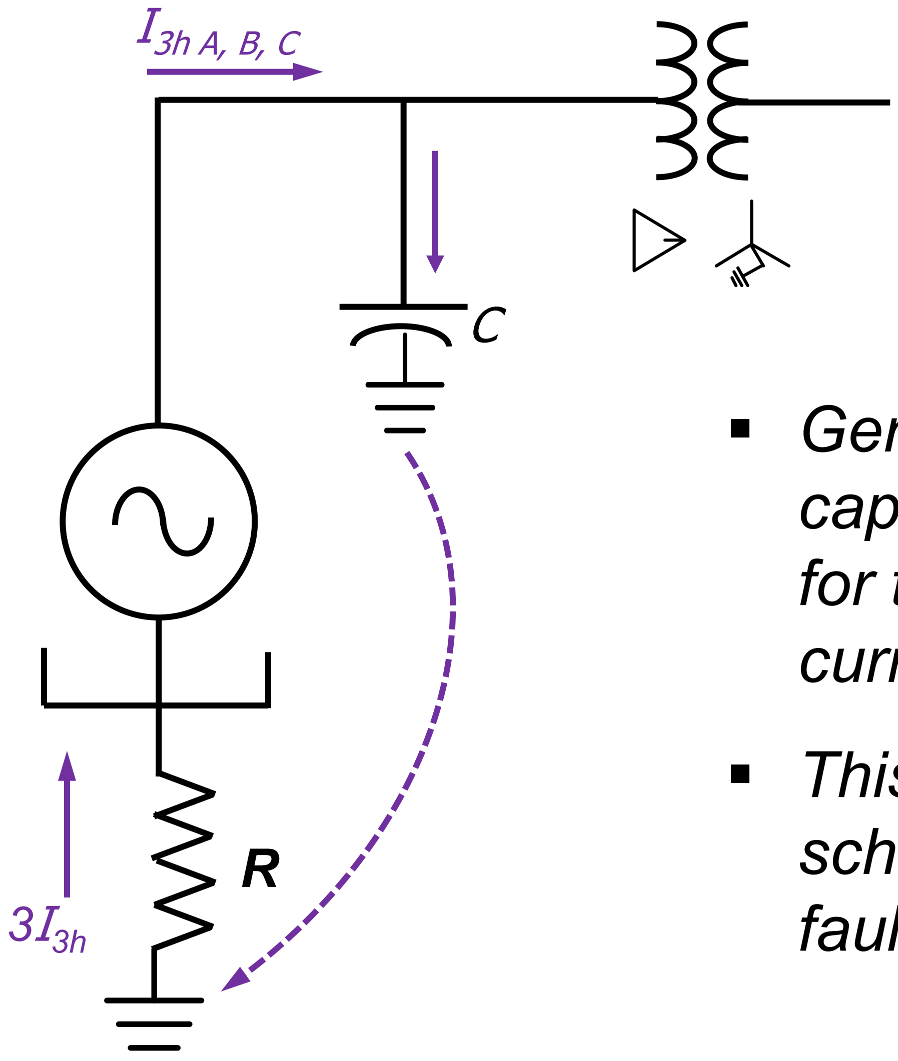
$$full\ pitch = \frac{total\ slots}{poles} = \frac{216\ slots}{18\ poles} = 12\ slots$$

$$pitch = \frac{span}{full\ pitch} = \frac{slot\ 128 - slot\ 120}{12\ slots} = \frac{8}{12} = \frac{2}{3}\ pitch$$

2/3 pitch machines typically do not have much of a third harmonic voltage signature making it difficult to use 27TN or 59D

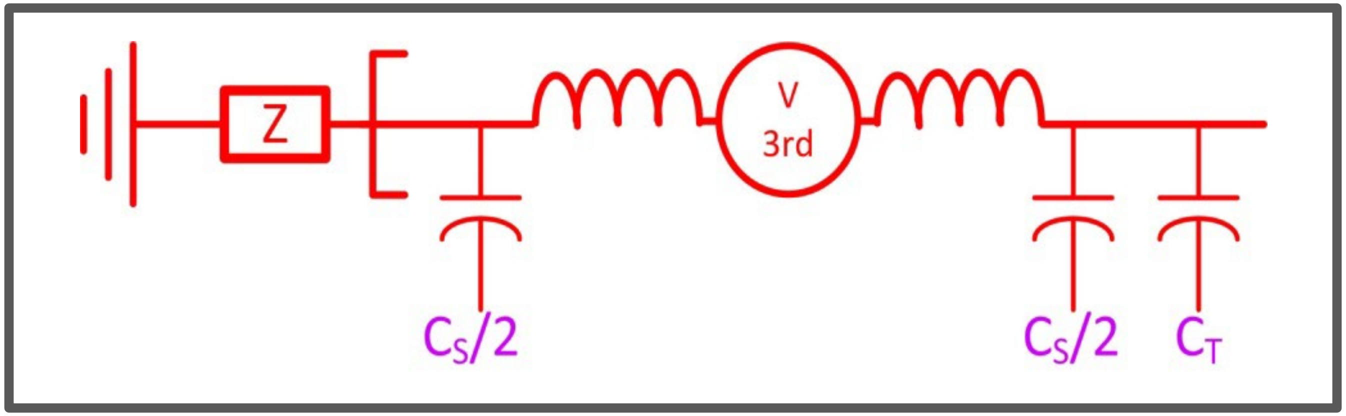
Stator Winding Diagram Illustrating "Pitch" In Winding Construction

Using Third Harmonic in Generators



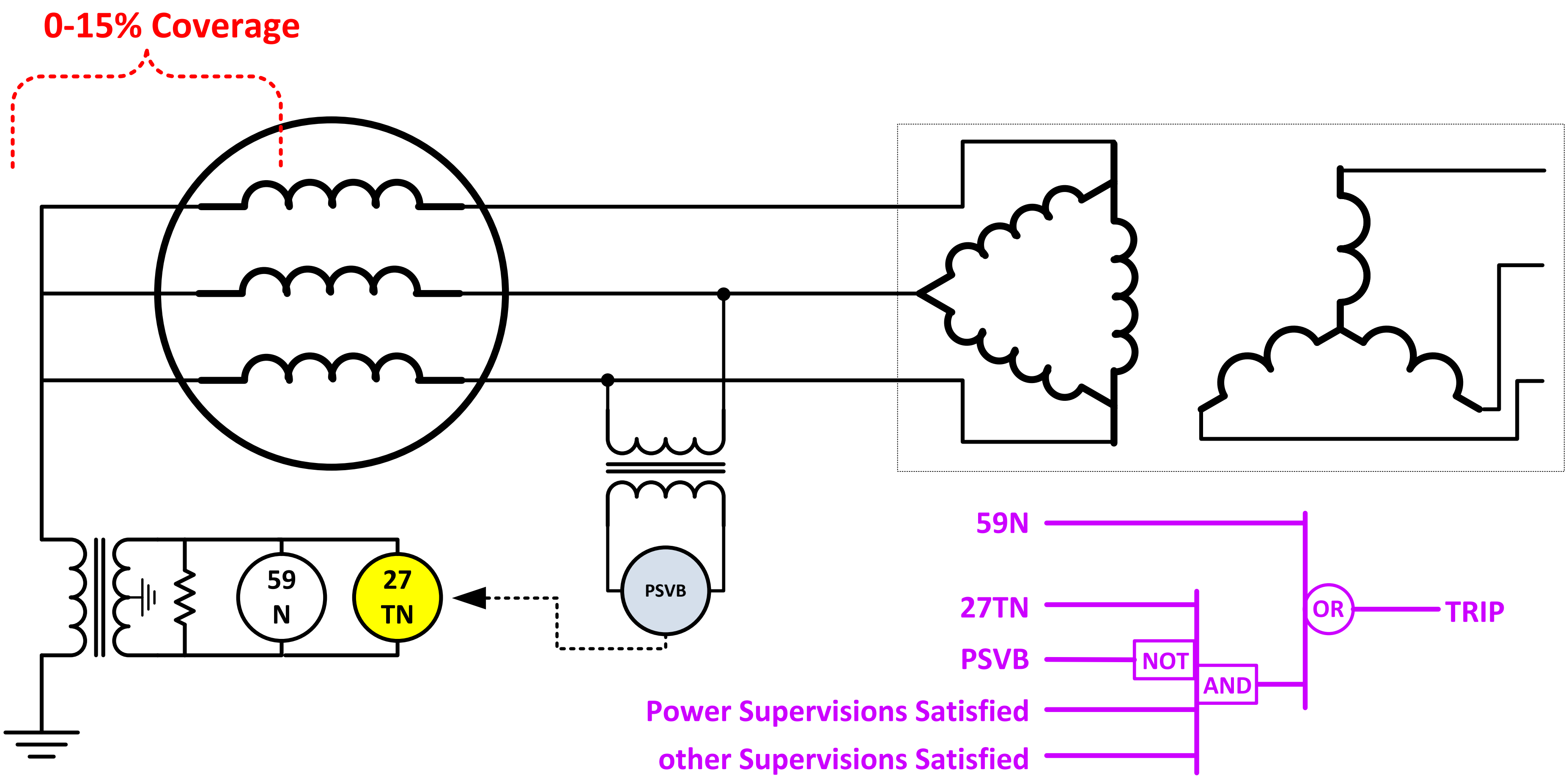
- *Generator winding and terminal capacitances (C) provide path for the third-harmonic stator current via grounding resistor*
- *This can be applied in protection schemes for enhanced ground fault protection coverage*

Generator Capacitance and 3rd Harmonics



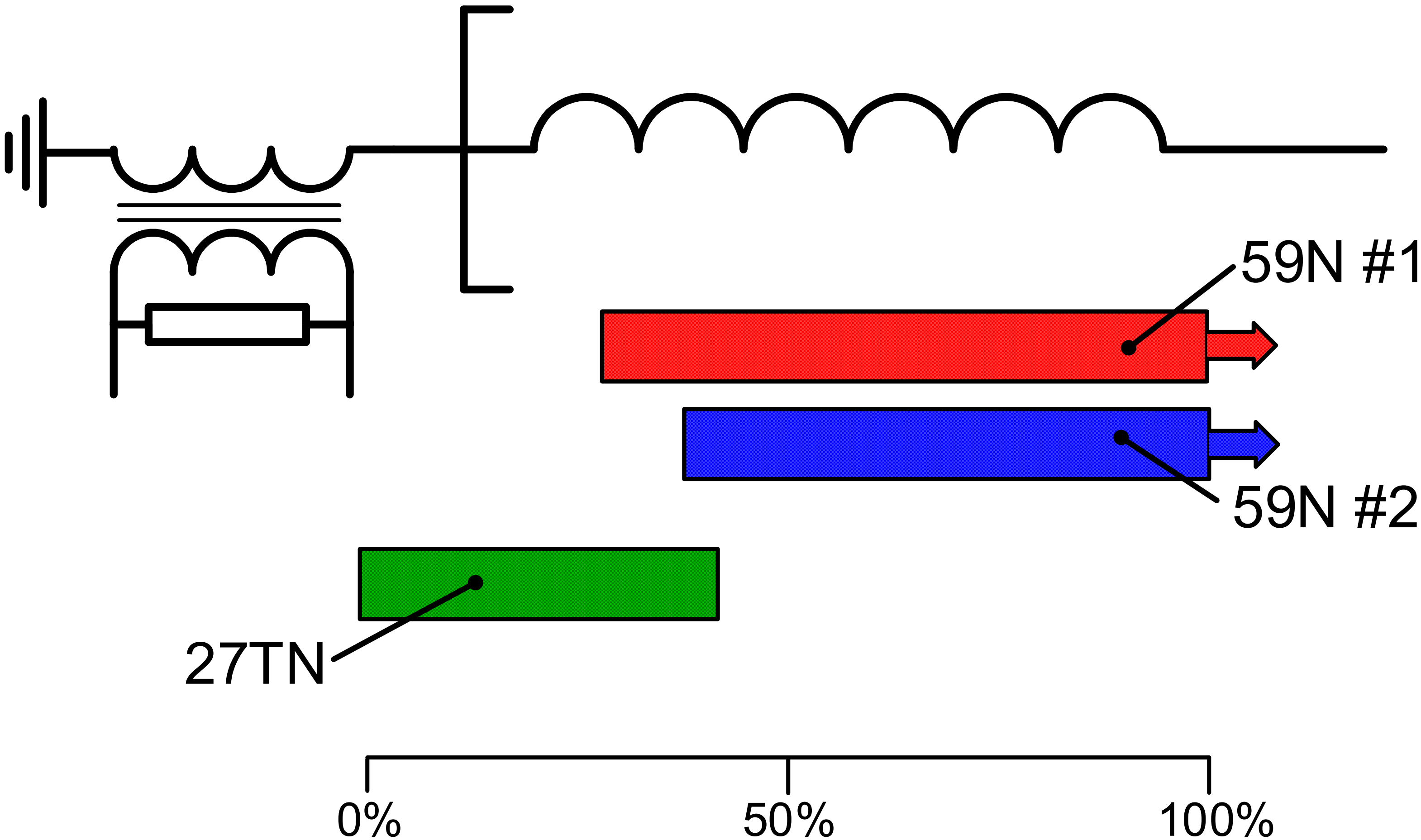
- 3rd harmonics are produced by some generators
  - Amount typically small
    - Lumped capacitance on each stator end is $C_S/2$.
  - C_T is added at terminal end due to surge caps and isophase bus
  - Effect is 3rd harmonic null point is shifted toward terminal end and not balanced

100% Stator Ground Fault (59N/27TN)



Third-Harmonic Undervoltage Ground-Fault Protection Scheme

coverage/reach for stator ground faults



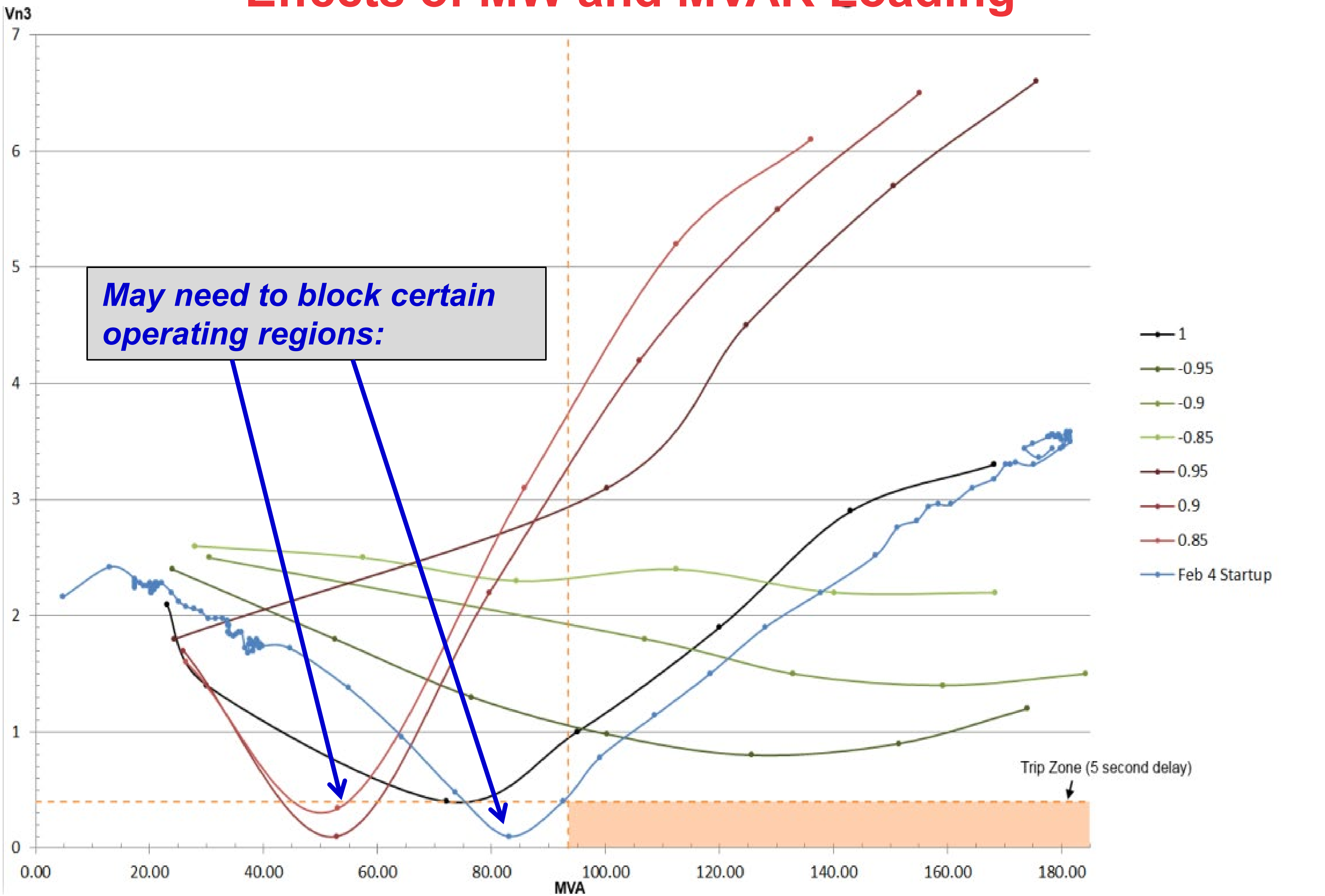
3rd Harmonic in Generators: Sample 3rd Harmonic Values

UNIT LOAD		180 HZ RMS VOLTAGE		VOLTAGE RATIO
MW	MVAR	NEUTRAL	TERMINAL	TERMINAL/NEUTRAL
0	0	2.8	2.7	1.08
7	0	2.5	3.7	1.48
35	5	2.7	3.8	1.41
105	5	4.2	5.0	1.19
175	25	5.5	6.2	1.13
340	25	8.0	8.0	1.00

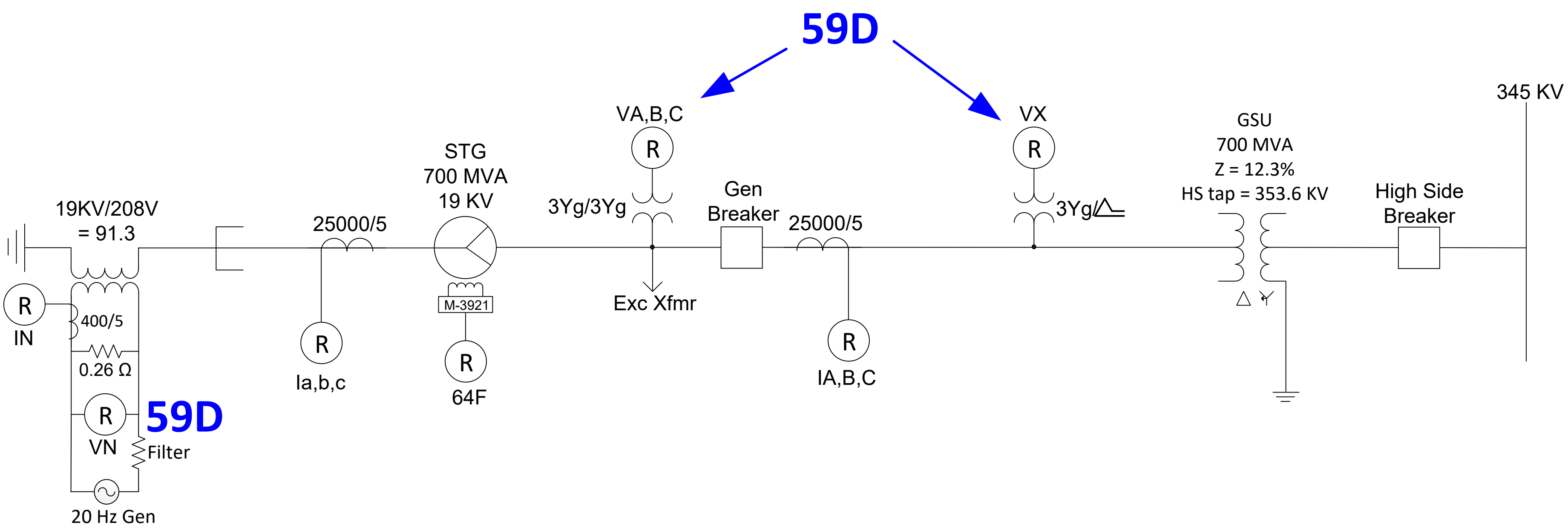
Magnitudes of Third Harmonic Voltages
for a Typical Generator

- **3rd harmonic values tend to increase with power (not always) and VAr loading**
- **Fault near neutral causes 3rd harmonic voltage at neutral to go to zero volts**

Example 3rd Harmonic Plot: Effects of MW and MVAR Loading

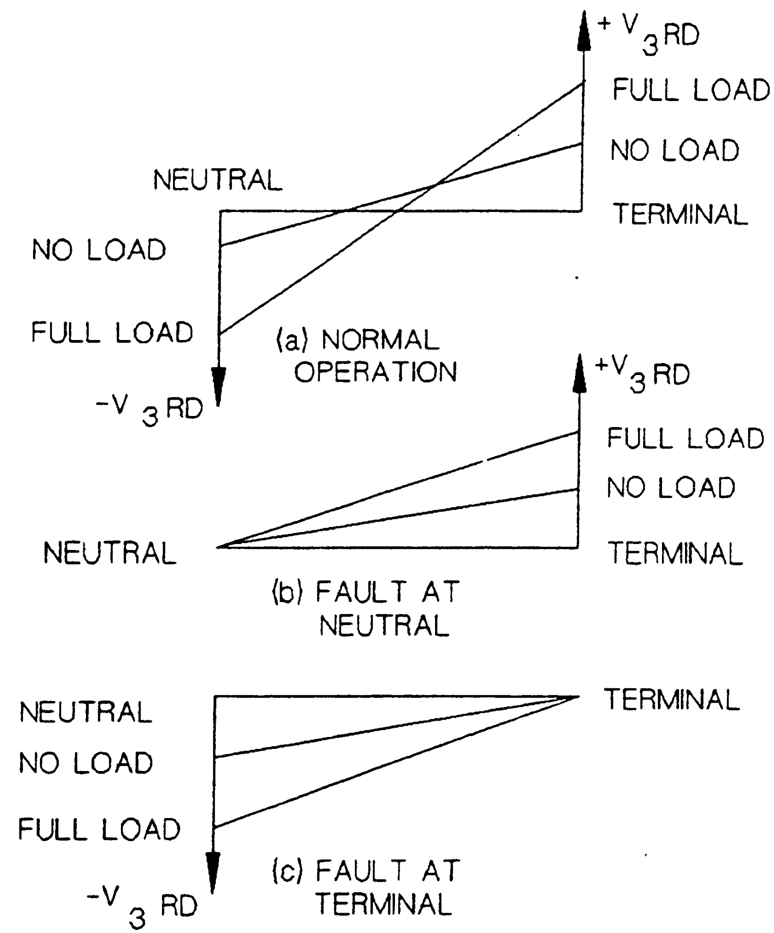


59D – Third Harmonic Voltage Differential (Ratio)

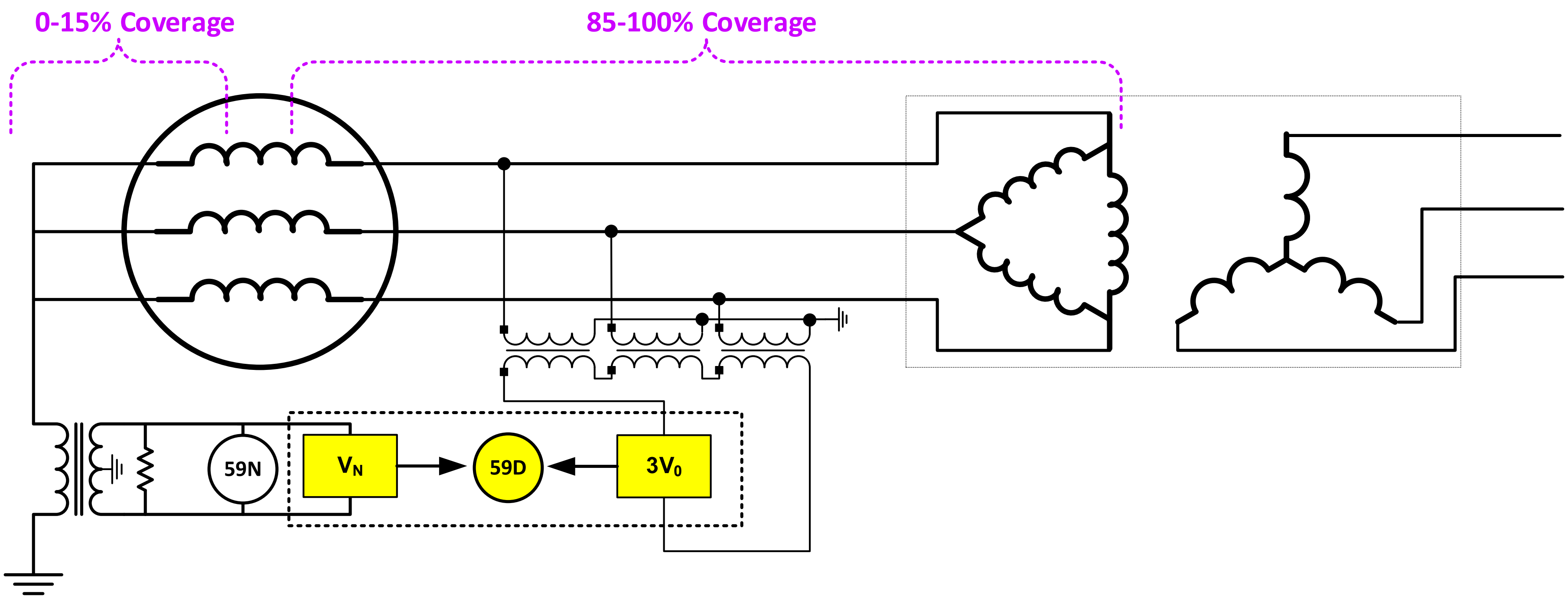


59D – 3rd Harmonic Ratio Voltage

- **Examines 3rd harmonic at line and neutral ends of generator**
- **Provides 0-15% and 85-100% stator winding coverage (typ.)**
- **Does not have a security issue with loading, as can a 27TN**
  - May be less reliable than 27TN (not enough difference to trip)
- **"Blind spot" at mid-winding protected by 59N (aka 59G, 64G)**
- **Needs wye VTs for calculated 3Vo or broken delta VTs for measured 3Vo; cannot use open delta VTs**

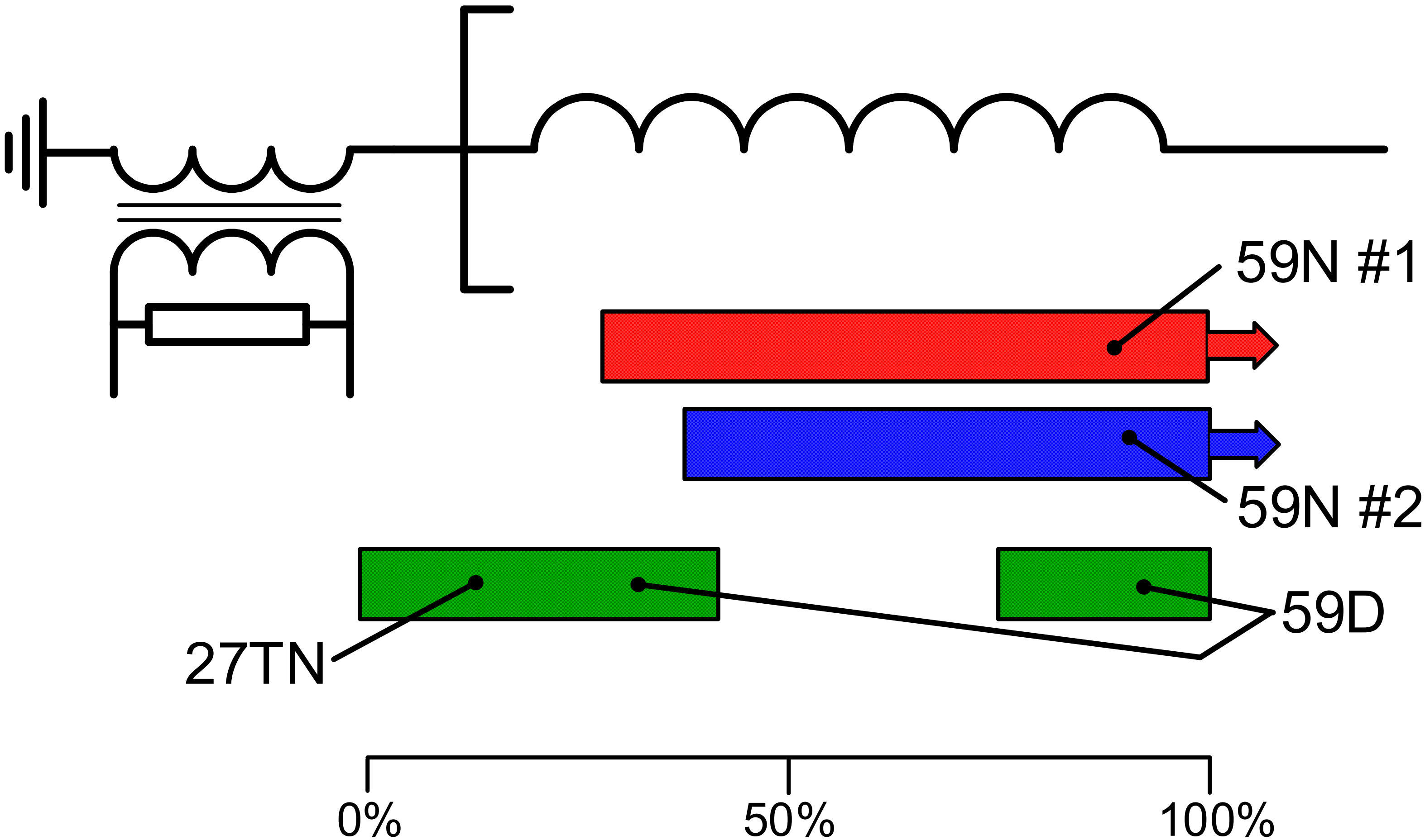


59D – 3rd Harmonic Ratio Voltage

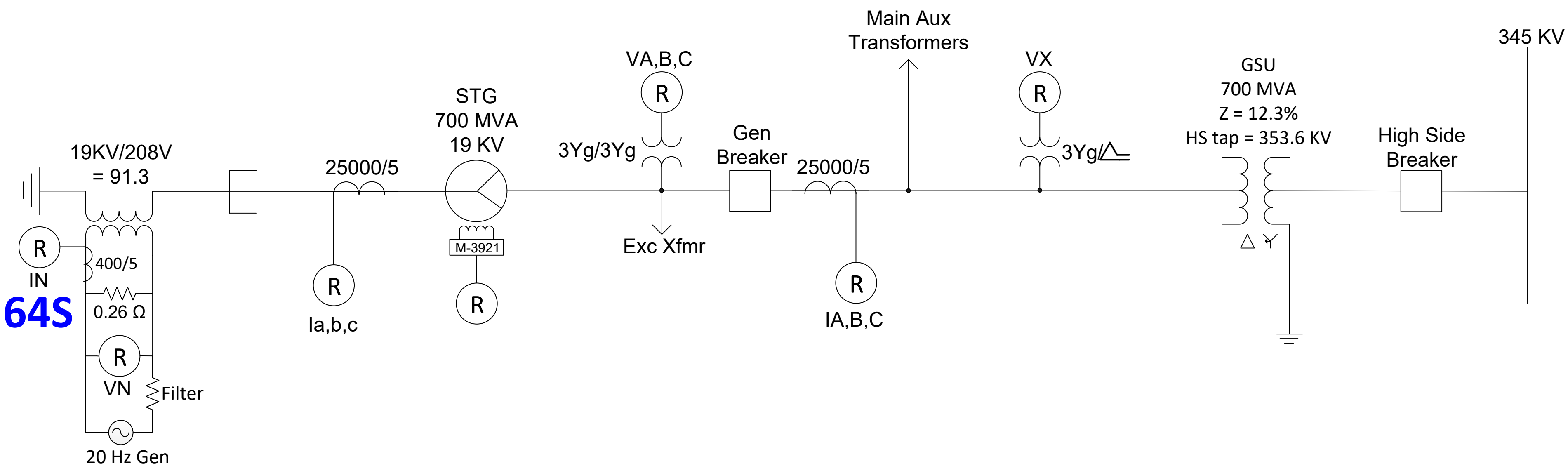


- Employs comparison of 3rd harmonic voltages at terminal and neutral ends
- These voltages may be fairly close to each other
- One goes very low if a ground fault occurs at either end of the winding

Stator Ground Fault coverage:



64S – 100% Stator Ground Protection



- **100% stator ground fault protection via subharmonic frequency injection**

64S – 100% Stator Ground Protection

- 20 Hz signal injection scheme provides 100% stator ground protection on high impedance grounded machines when off-line and on-line regardless of:
  - ✓ third harmonic signature of unit
  - ✓ loading levels
  - ✓ operating mode

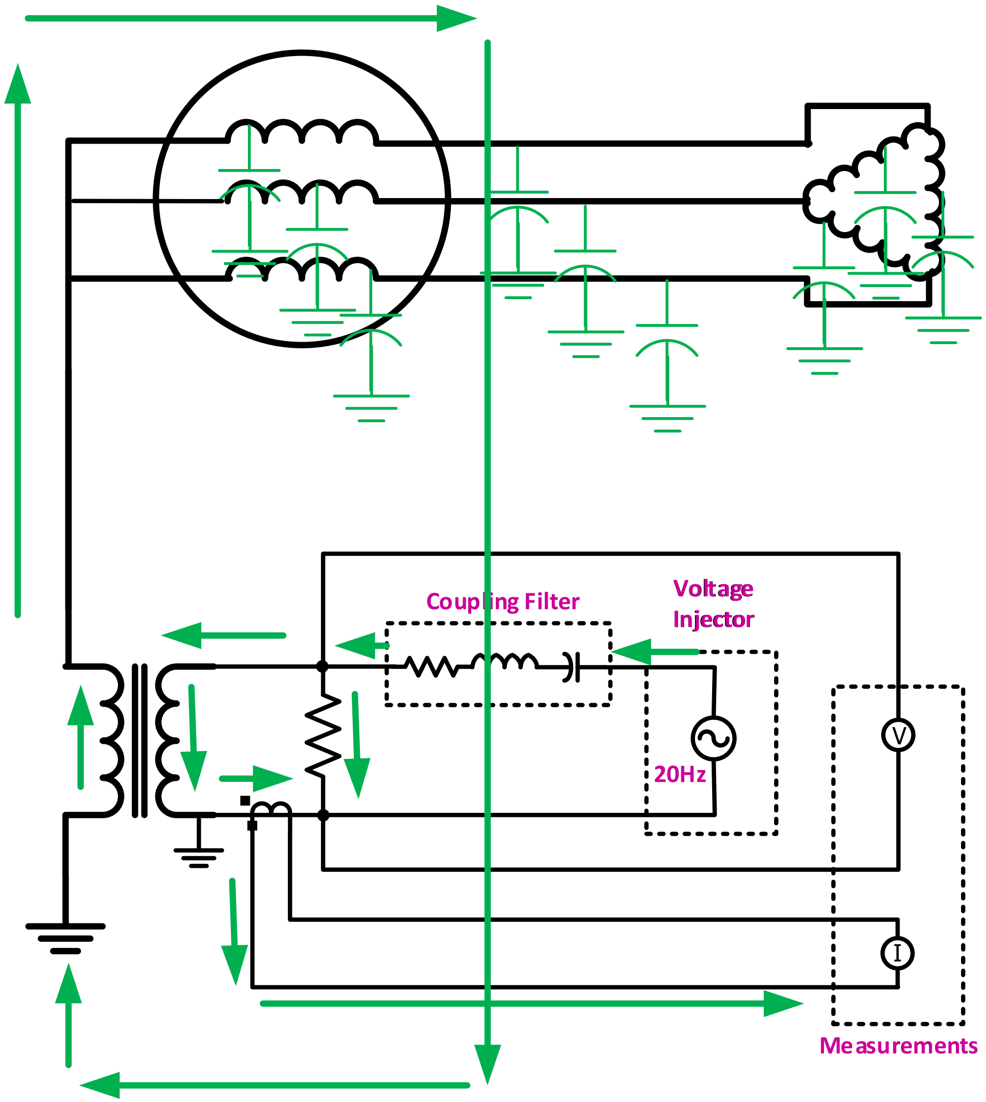
- Detects change in stator winding insulation resistance and operates based on the measured 20 Hz current.

- With no ground fault, a small amount of 20 Hz current will flow as a result of the stator capacitance to ground.

- When a ground fault occurs anywhere in the stator winding the 20 Hz current will increase and if the pickup is exceeded for longer than the time delay setting, the function will operate.

Subharmonic Injection: 64S

- 20Hz injected into grounding transformer secondary circuit
- An increase in the 20 Hz IN current and decrease in the 20 Hz VN voltage suggests a ground fault.



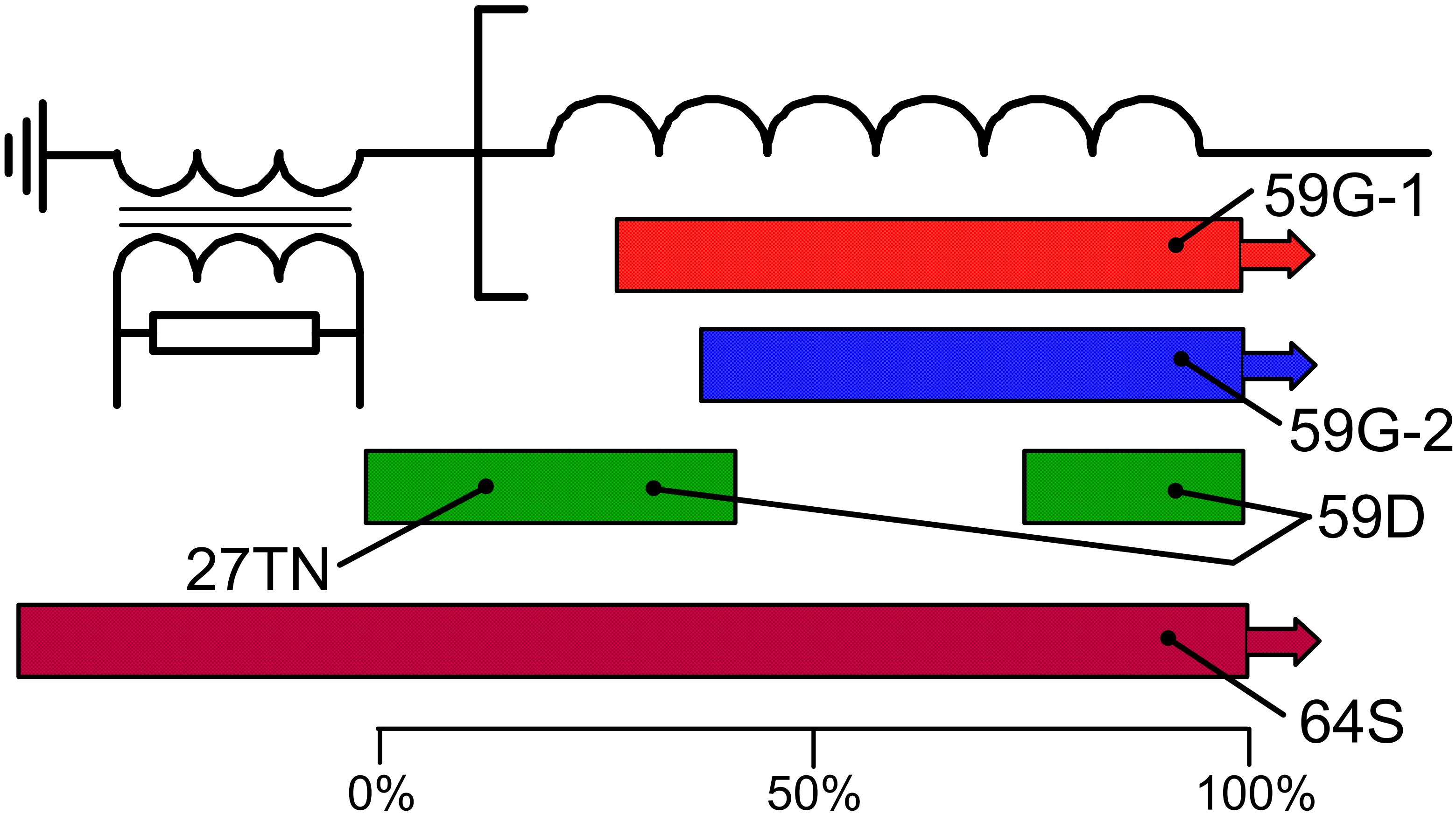
Notes:

- Subharmonic injection frequency = 20 Hz
- Coupling filter tuned for subharmonic frequency
- Measurement inputs tuned to respond to subharmonic frequency

64S: Stator Ground Faults – Subharmonic Injection

- *Injects subharmonic frequency into generator neutral*
  - *Does not rely on third harmonic signature of generator*
- *Frequency independent*
  - *Indifferent to generator's operating frequency*
- *Provides full coverage protection*
- *Provides on and offline protection, prevents serious damage upon application of excitation if a ground fault exists*

Stator Ground Faults: High Z Element Coverage



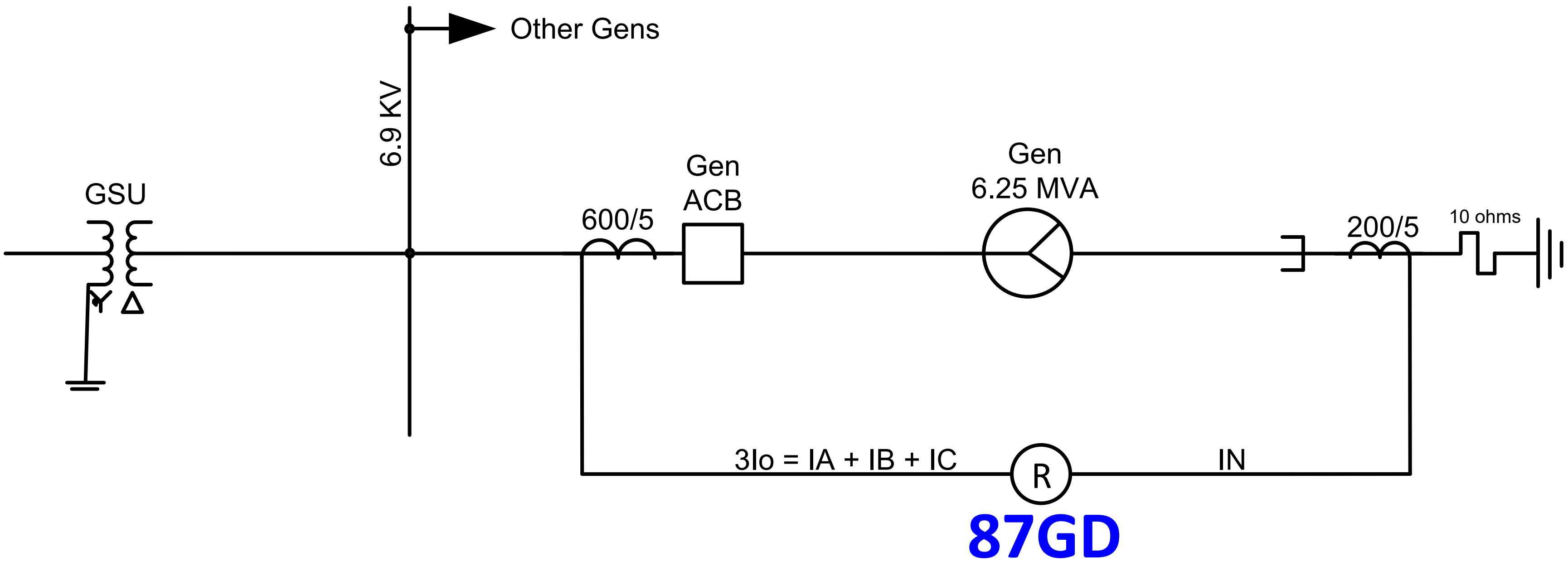
Ground Fault Protection

Low-Impedance Grounded Generators

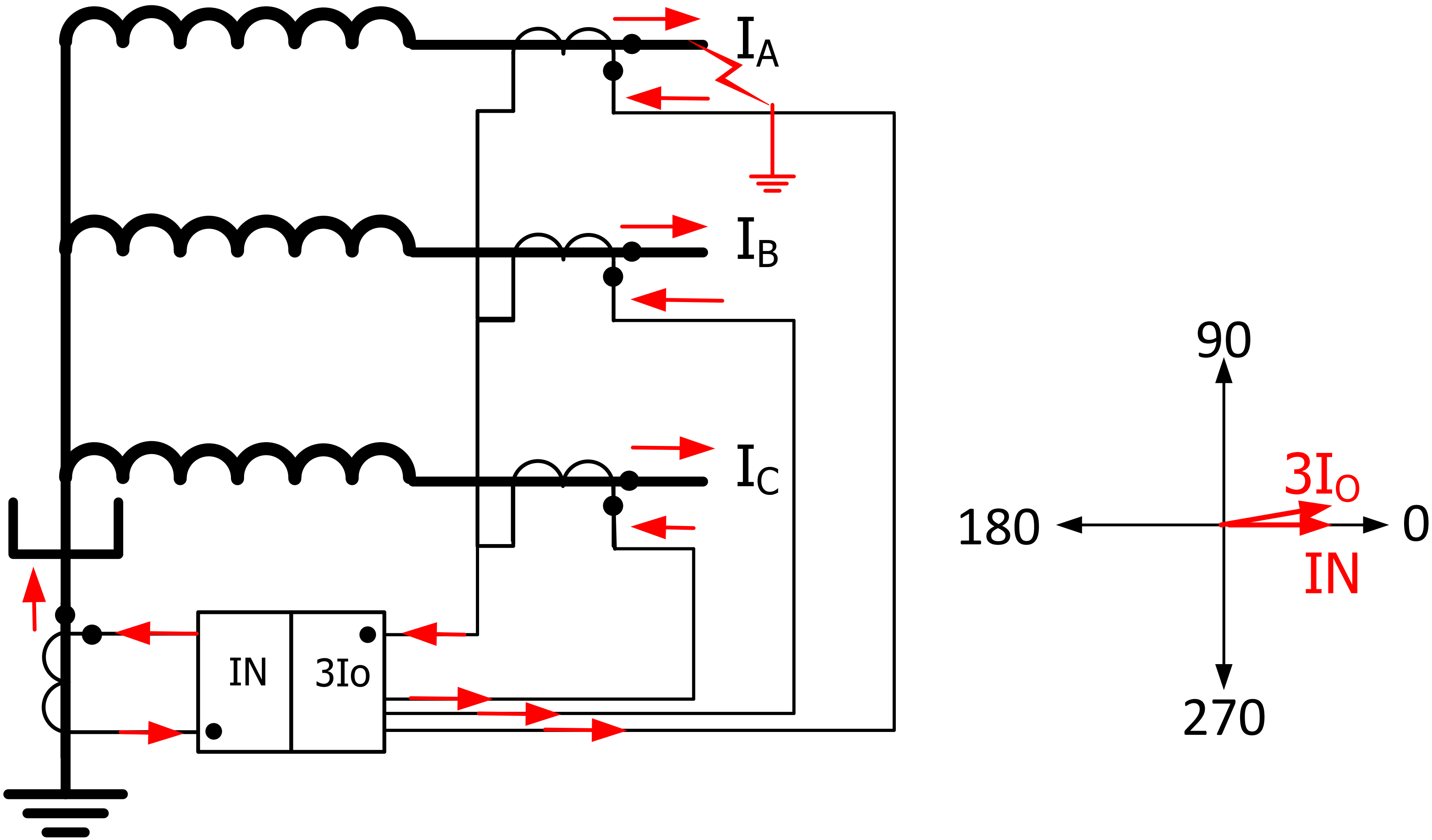
- 87GD – Ground Differential Current
- 67N – Residual Directional Overcurrent
- 50N – Instantaneous Neutral Overcurrent
- 51N – Inverse Time Neutral Overcurrent

87GD – Ground Directional Overcurrent

- The Zero Sequence Differential function provides ground fault protection for low impedance or solidly grounded machines.

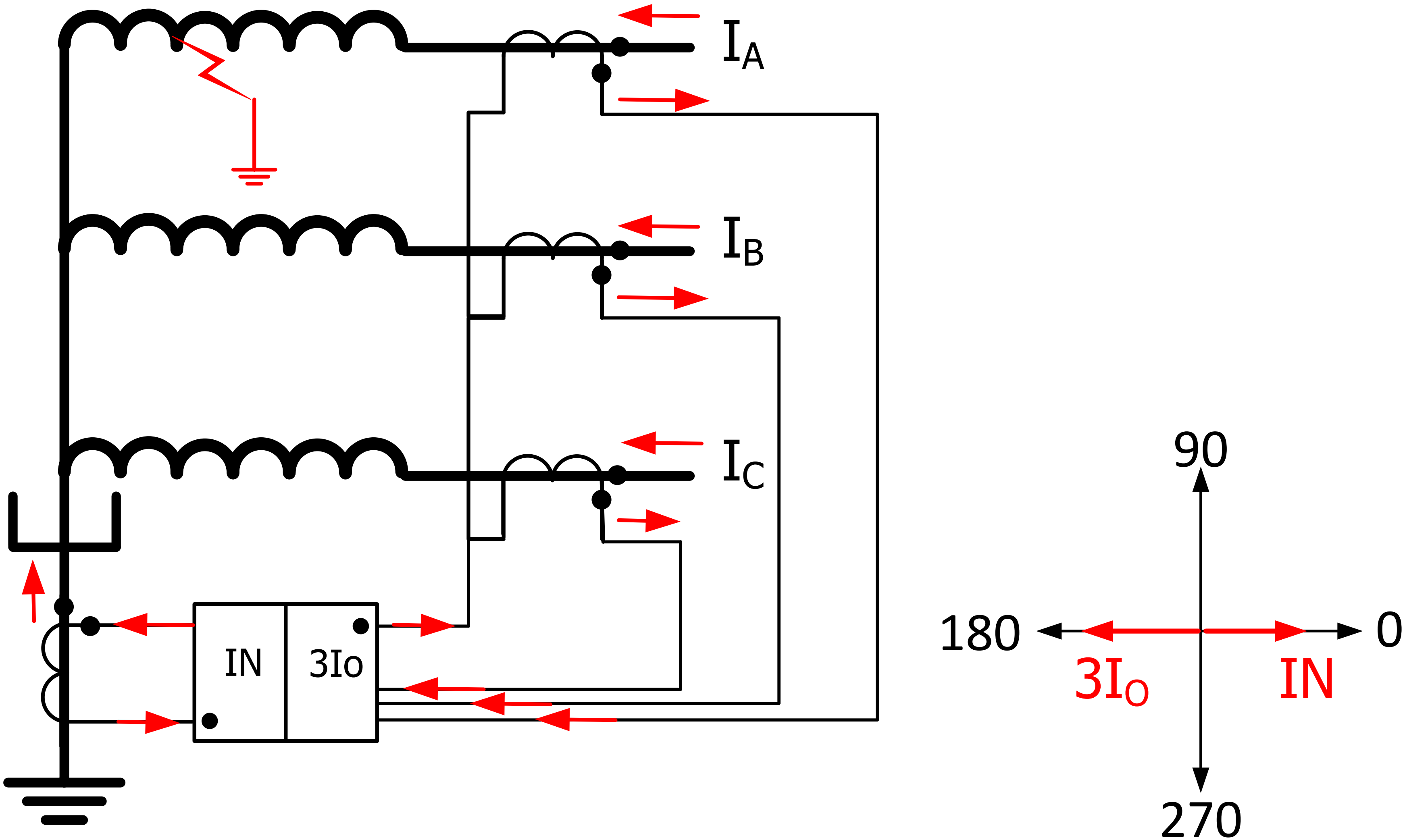


87GD with External Fault



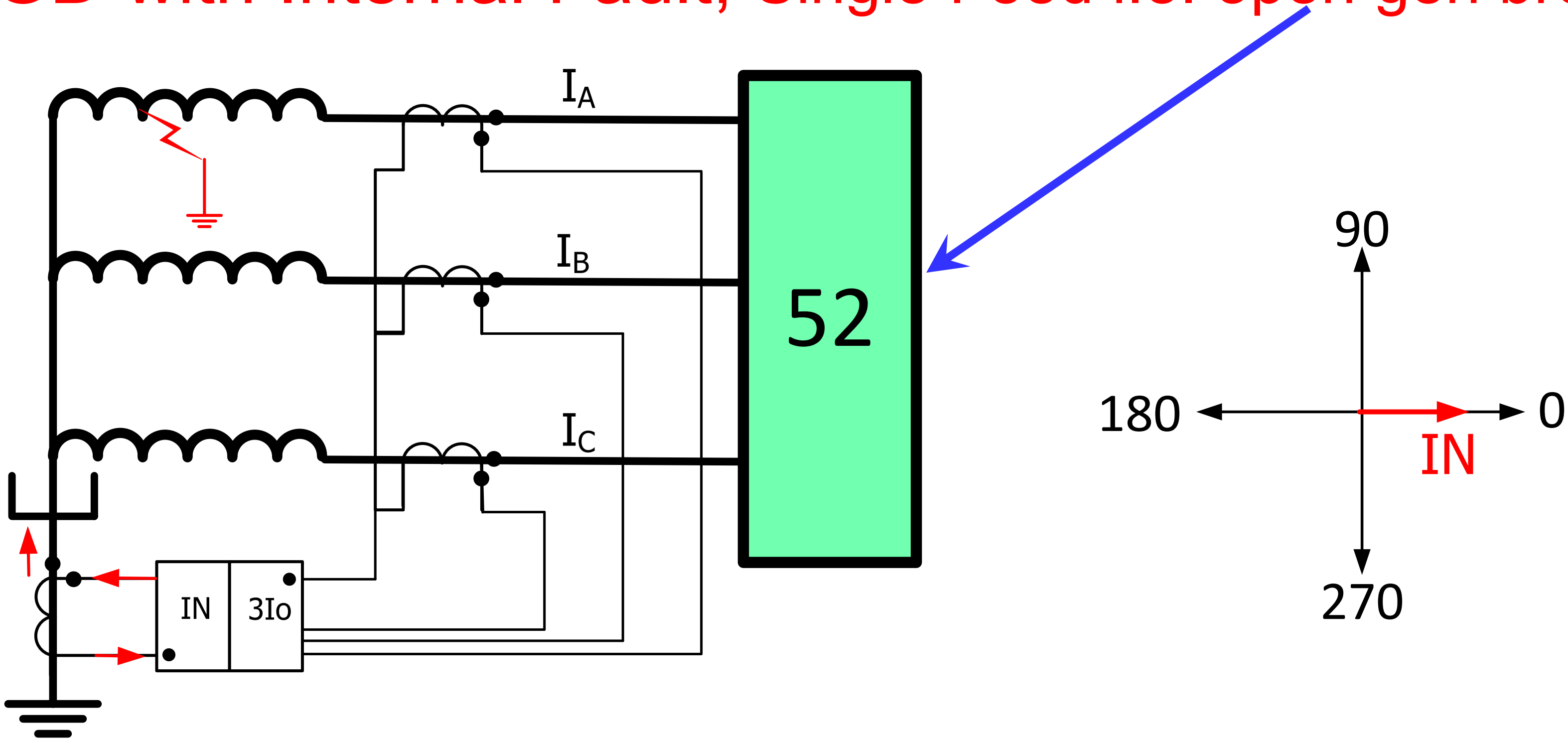
$-3I_o$ x IN cos (0°) = $-3I_o$ IN < 0, so external fault

87GD with Internal Fault, Double Fed



- $3I_o$ x IN cos (180) = $3I_oI_G$ > 0, so internal fault

87GD with Internal Fault, Single Feed i.e. open gen breaker



- ✓ 3Io < 0.20 A, therefore directional element is disabled, only does a comparison of IN measured current vs the 87GD Pickup setting:
- ✓ If |CTRCF*3Io – IN| > 87GD Pickup setting, then start 87GD timer,

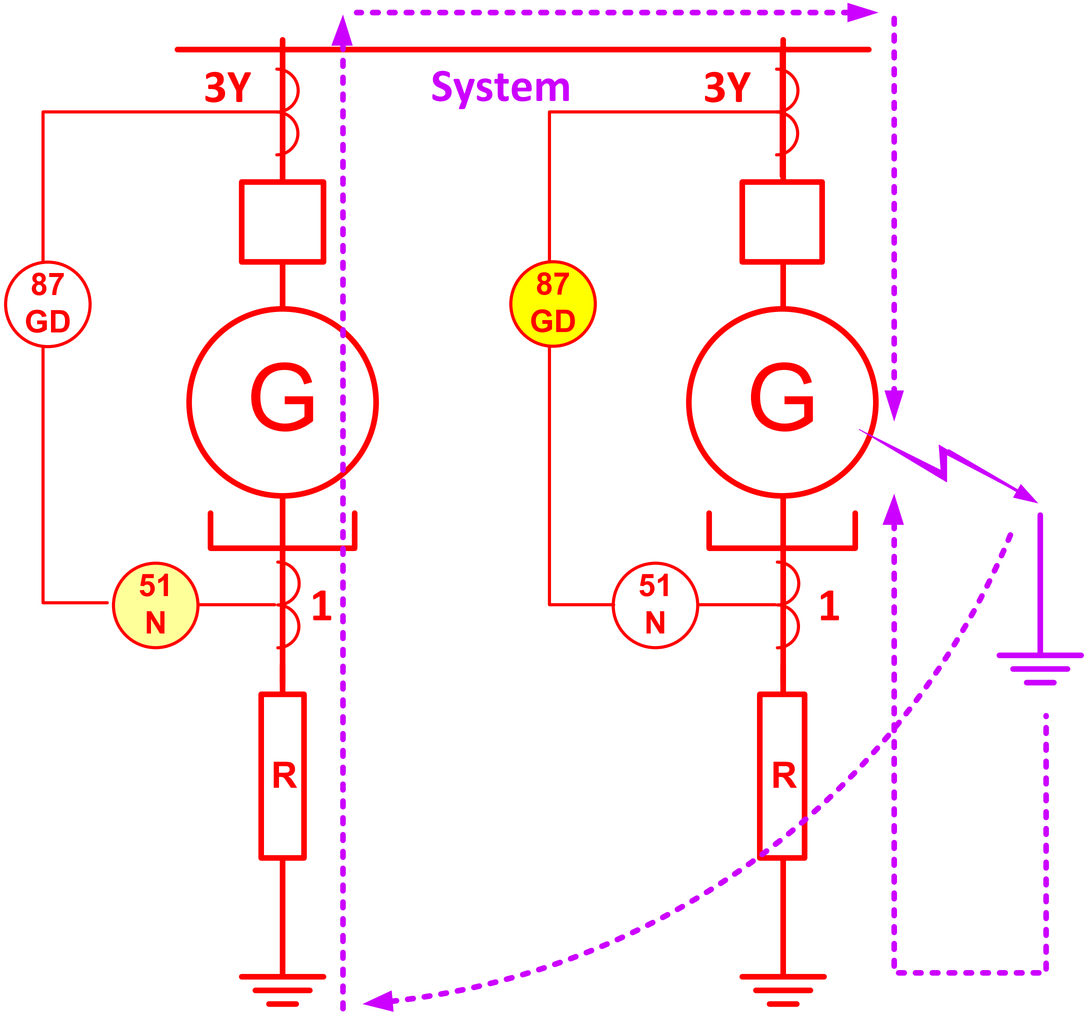
  |0 – IN| > 87GD Pickup setting, then start 87GD timer,

  If 87GD timer expires with 87GD pickup still exceeded, then Trip.

Directional Neutral Overcurrent: 87GD
Low-Z Grounded Generator

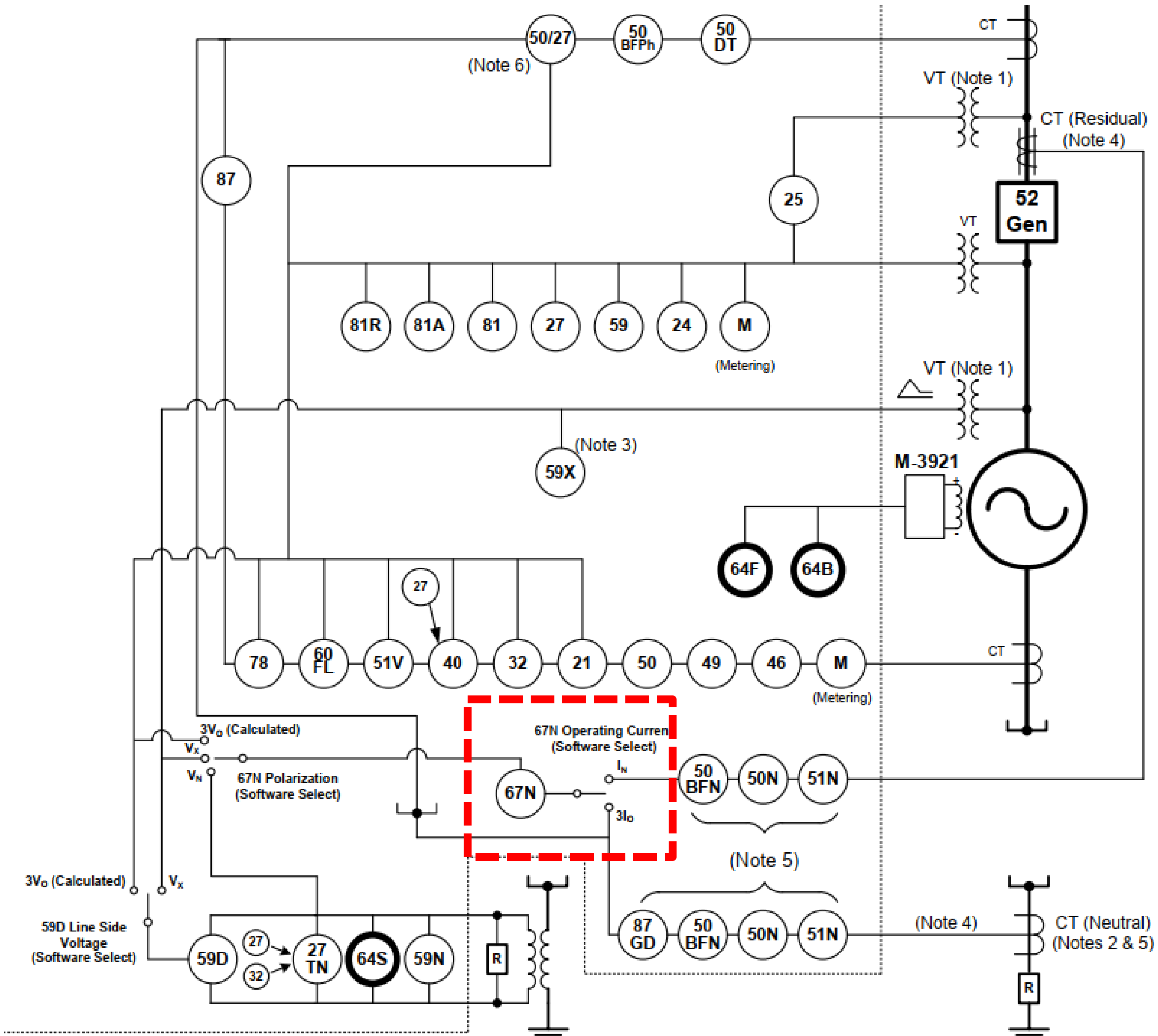
- 87GD element provides selectivity on multiple bused machine applications
- Requires phase CTs, or terminal side zero-sequence CT, and a ground CT
- 87GD uses currents with directionalization for security and selectivity
- 87GD is set faster than 51N
  - May use short definite time delay
- Ground current should not flow into a generator from terminal end under normal operating conditions
- Ground current should not flow unchallenged into machine

Directional Neutral Overcurrent: 87GD
Low-Z Grounded Generator



- *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*

67N – Residual Directional Overcurrent



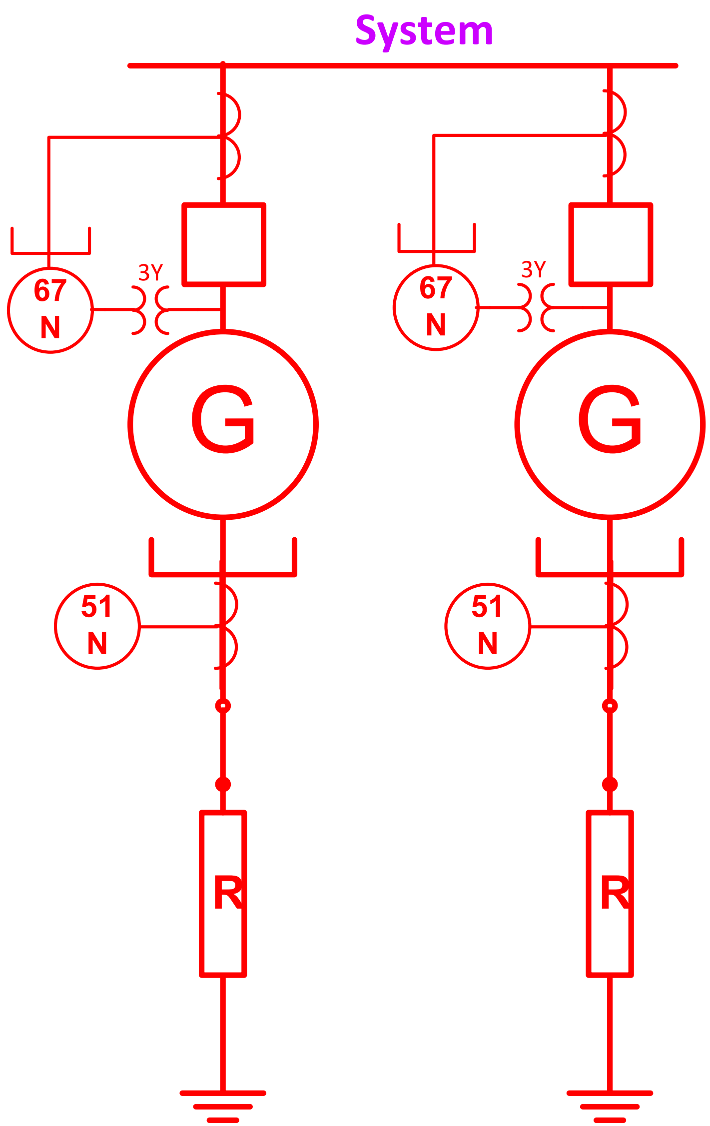
High-impedance Grounding with Third Harmonic 100% Ground Fault Protection

Low-impedance Grounding with Ground Differential and Overcurrent Stator Ground Fault Protection

Directional Neutral Overcurrent: 67N
Low-Z Grounded Generator

- 67N element typically used to provide gen ground fault protection selectivity for multiple parallel bussed gens.
- For operate current, may use a calculated 3Io = IA + IB + IC from terminal-side phase CTs.
- OR may use a measured 3Io from a core-balance (zero-sequence) CT located on terminal side, typically.
- OR may use a measured IN current from a single ground CT.
- 67N polarizing is typically set to trip for zero-sequence (ground) current in the direction of the generator.
- 67N DT and/or 67N IT can be set to trip faster than 51N.
  - Ground current should not flow into a generator under normal operating conditions.
- May be applied on ungrounded machines for ground fault protection if the bus has a ground source e.g. zig-zag or grounding transformer, etc (or if parallel gen is grounded).

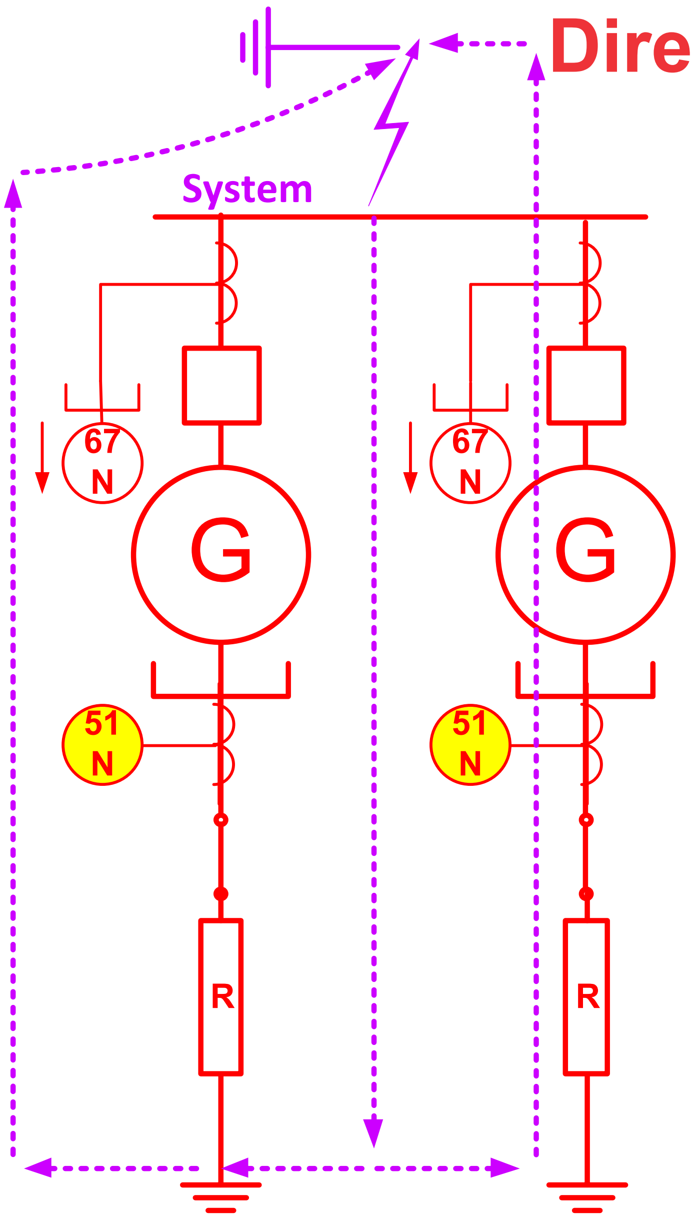
Directional Neutral Overcurrent: 67N
Low-Z Grounded Generator



- *Employ 67N 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*

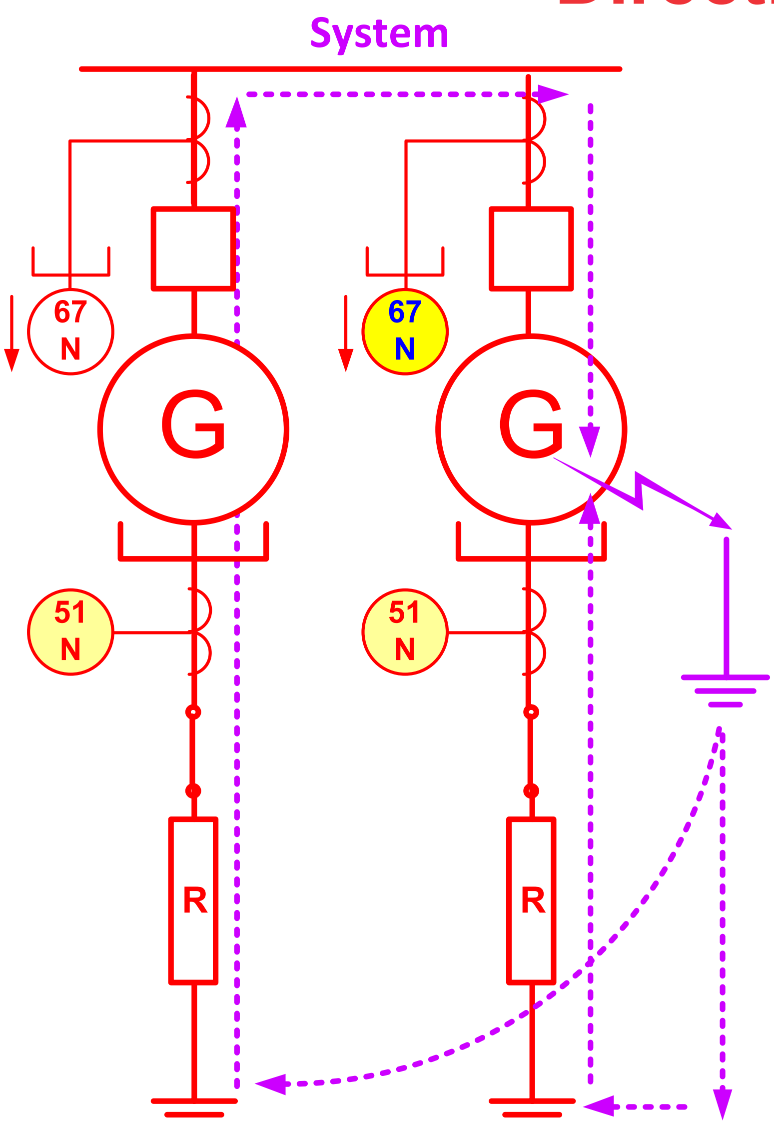
Directional Neutral Overcurrent: 67N

Low-Z Grounded 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*

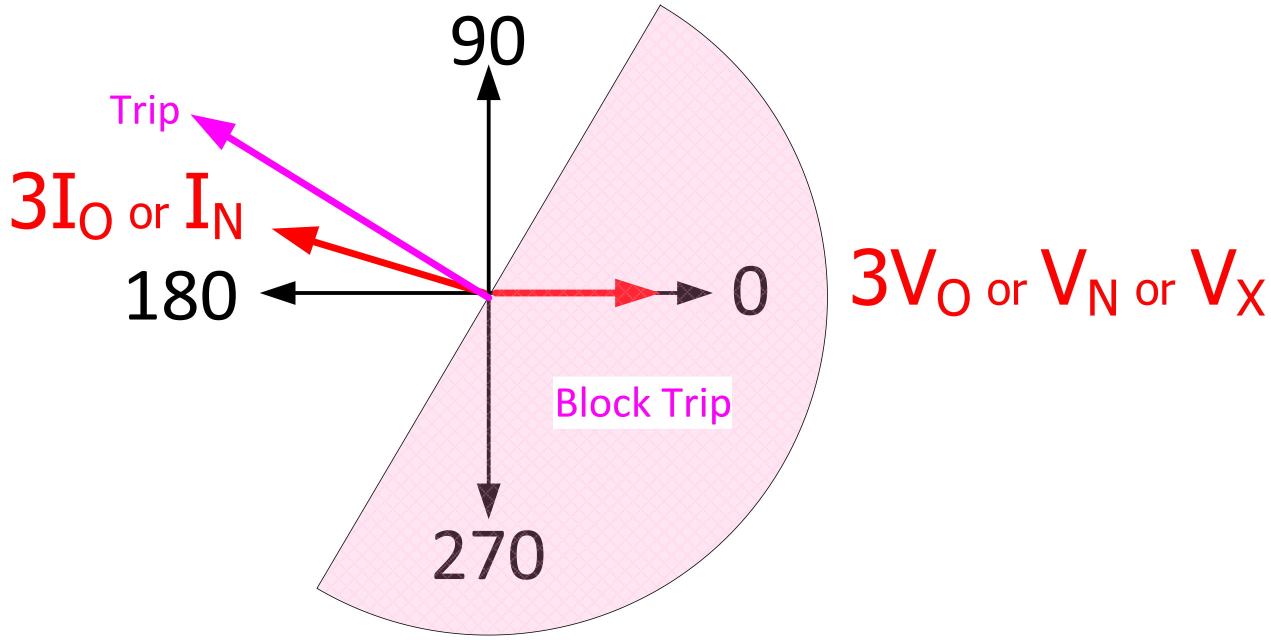
Directional Neutral Overcurrent: 67N
Low-Z Grounded Generator



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

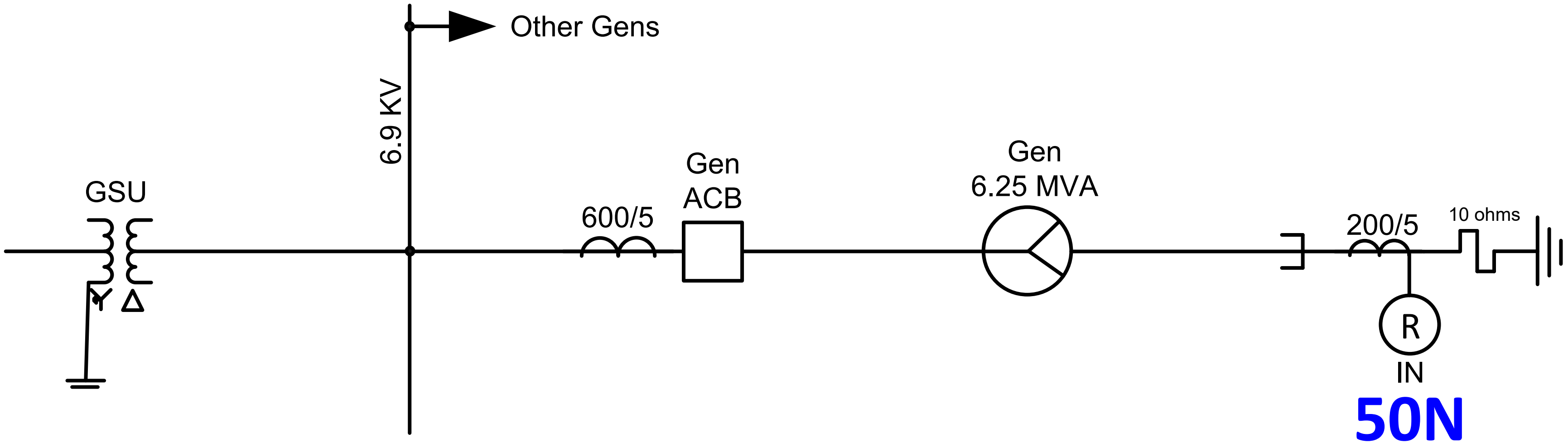
Directional Neutral Overcurrent: 67N

Internal Fault

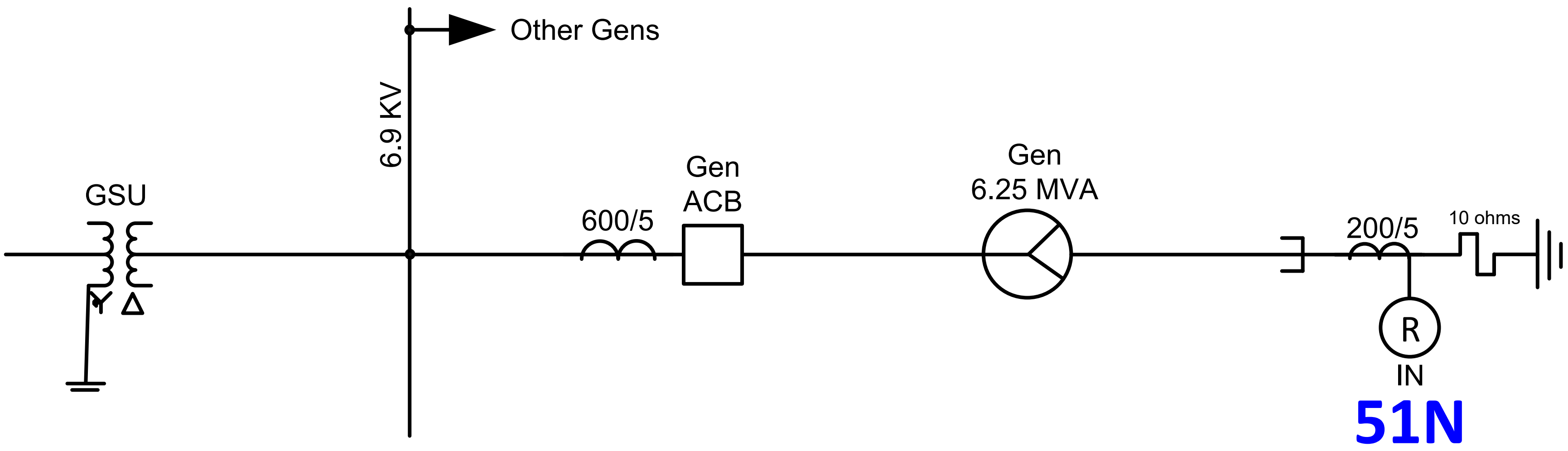


- Internal faults create angles of $3I_0$ or I_N current flow into generator from system that are approximately 150 degrees from $3V_0$ if polarities are wired so current in tripping direction enters relay polarity (if exiting relay polarity in tripping direction, then 315° may be more appropriate for an MSA setting)

50N – Instantaneous Neutral Overcurrent

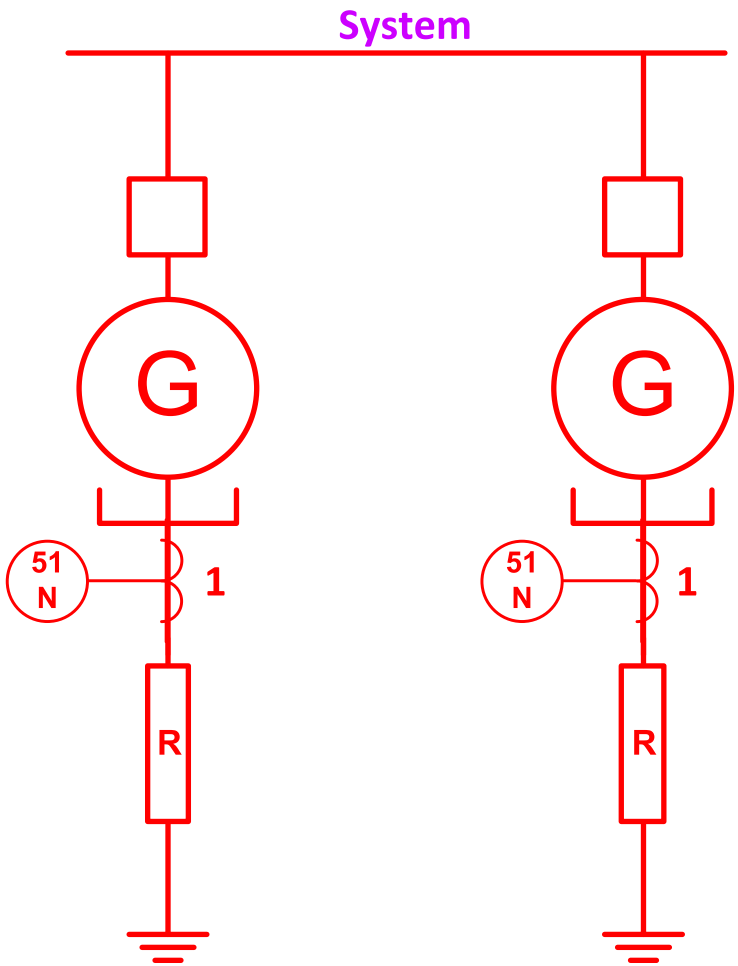


51N – Inverse Time Neutral Overcurrent



Stator Ground Fault: Low Z Grounded Machines

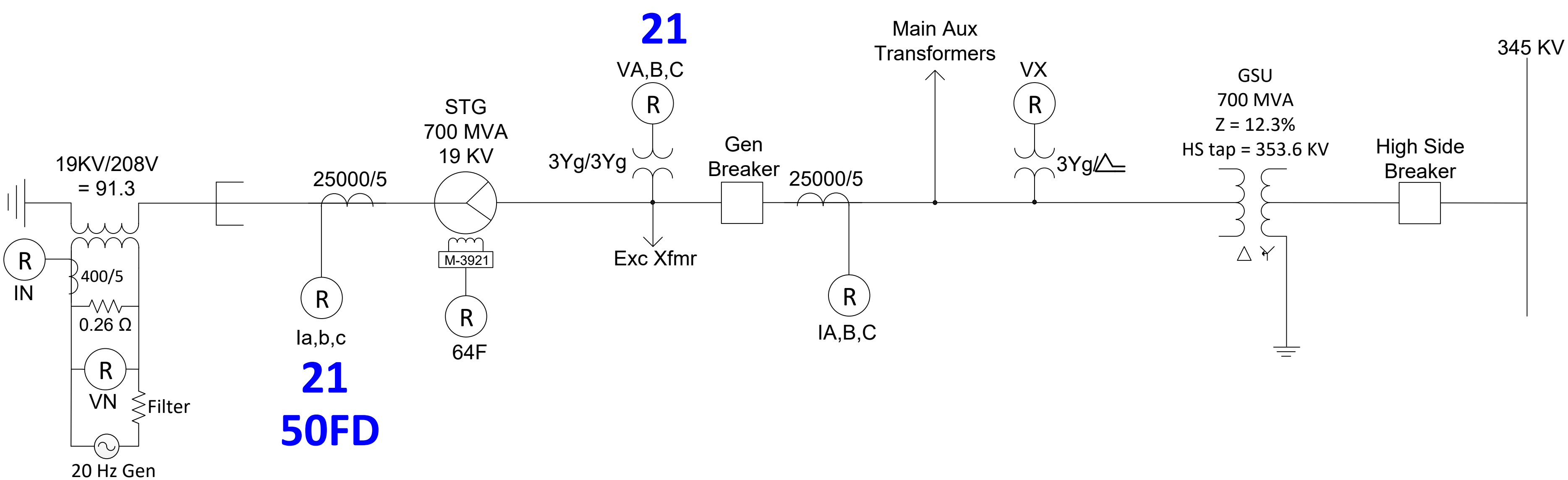
- 50N/51N element typically applied
  - Coordinate with system ground fault protection for security and selectivity
  - Results in long clearing time for internal machine ground fault
  - Selectivity issues with bused machines
  - One solution is to add 67N from core balance CTs on terminal side of generator



System Backup Protection for Phase faults

- 21 – Phase Distance
- 51V – Voltage R/C Inverse Time Phase Overcurrent

21 – Phase Distance



- *Under-impedance (Z=V/I), step-distance phase fault protection.*
- ***Provides protection against uncleared system faults (due to transmission relaying failure) to avoid contribution from this generator to any phase faults on the high side of the GSU.***
- ***May also see phase faults on the low side of the GSU and partially into the generator stator winding.***

21 – Phase Distance

Different Distance protection methods:

- **Mho circle (this presentation will focus on this method)**
- Quadrilateral
- Lens
- Elliptical
- Time domain
- Travelling wave

There are pros and cons for each method.

The 21 Mho circle characteristic was used for E/M relay design due to its simplicity, reliability, and due to some mechanical limitations.

For digital relays, mho circles are still widely used as it became a de factor standard for distance protection.

21 – Phase Distance

The distance function is typically set using one of two approaches:

1) Thermal protection for uncleared transmission faults, which will also provide protection for the following:
    - Partial gen stator winding phase fault protection
    - Generator bus phase fault protection (faults between the gen and GSU)
    - GSU phase fault protection (faults inside the GSU)
    - Partial transmission line phase fault protection (just past the GSU)

2) Full Backup transmission line phase fault protection to see all phase faults at the end of the longest transmission line off the high side of the GSU considering infeed effects (this approach also provides protection as designated in approach 1).

21 – Phase Distance

- 21 or 51V – backup for system **phase** faults
  - 51G – on GSU high side Wye-grounded leg is used as a backup for system **ground** faults

- If transmission system relays are distance based, generally the 21 function is used for backup.

- If transmission/distribution system relays were overcurrent based, then the 51V may be used for backup.

- IEEE/NERC recommend to <u>only set either the 21 or 51V</u> for system backup protection, not both (21 is preferred).

21 – Phase Distance

- CT location determines directional sensing:
  - ✓ If CTs on neutral side, may provide backup protection for at least a portion of the generator stator winding.
  - ✓ If CTs on terminal side, then the generator stator winding would not receive any backup protection (unless by offset).

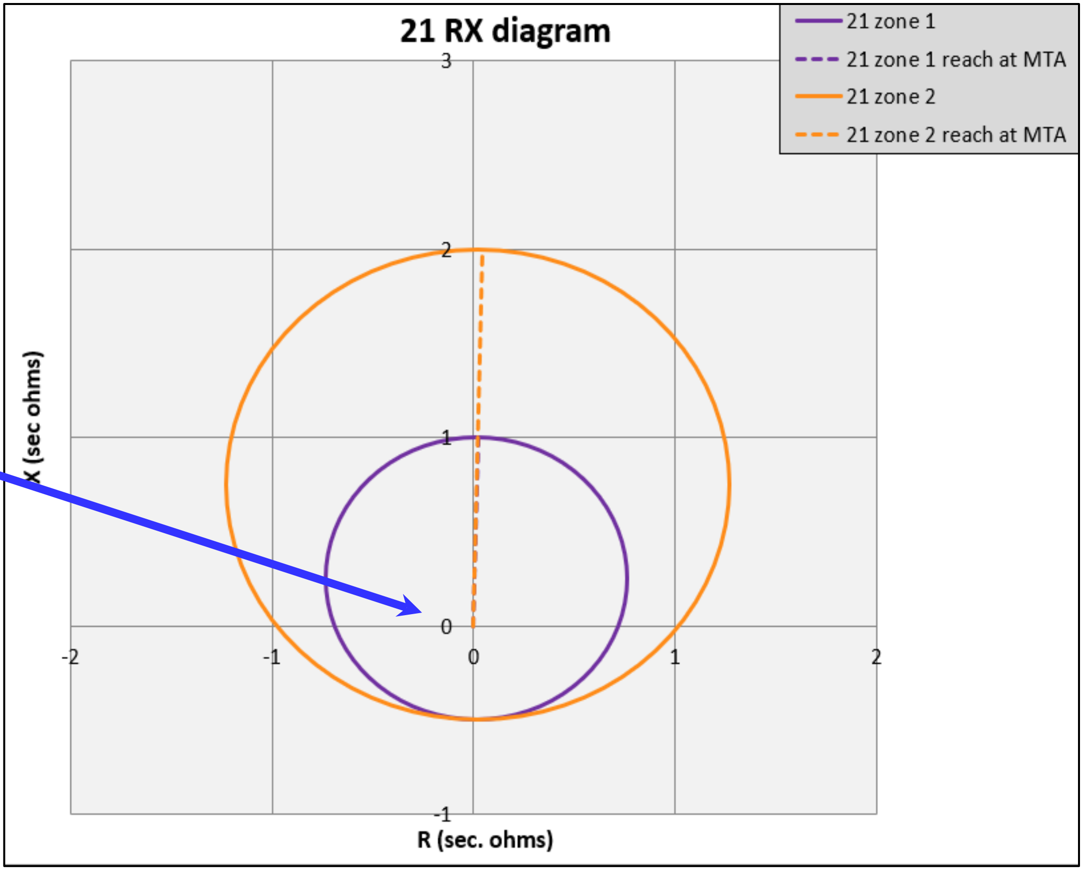
21 – Phase Distance

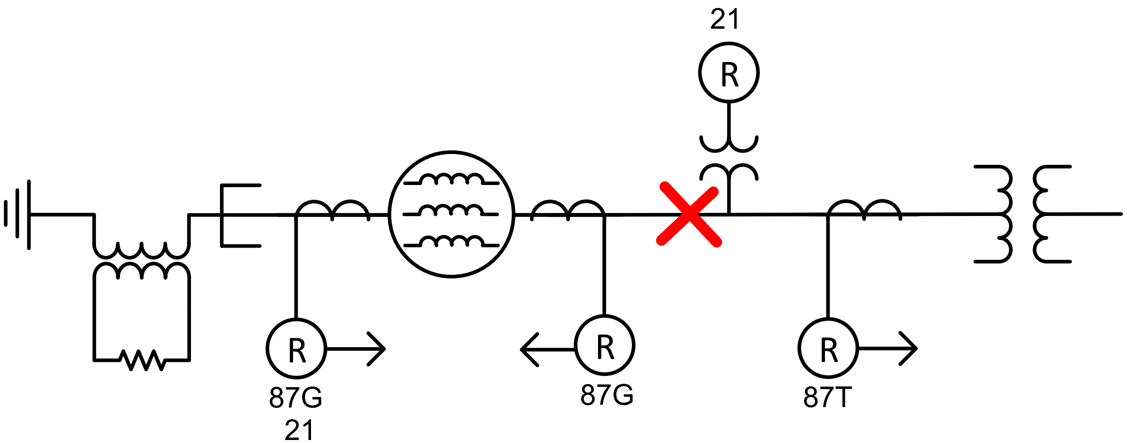
VT location determines distance:

VT is origin on the RX diagram

If VTs between gen and GSU, the reach is counted from this location independent of CT location

Therefore, in-effect "forward" reach in both directions





21 – Phase Distance

This is how a non-compensator distance 21 function sees thru a Delta/Wye GSU:

	Transformer Direct Connected		Transformer Delta-AC Connected		Transformer Delta-AB Connected	
	VT Connection		VT Connection		VT Connection	
	L-L or L-G to L-L	L-G	L-L or L-G to L-L	L-G	L-L or L-G to L-L	L-G
AB Fault	$\frac{V_{AB}}{I_a - I_b}$	$\frac{V_A - V_B}{I_a - I_b}$	$\frac{V_{BC} - V_{AB}}{(3)I_b}$	$\frac{V_B - V_O}{I_b}$	$\frac{V_{AB} - V_{CA}}{(3)I_a}$	$\frac{V_a - V_o}{I_a}$
BC Fault	$\frac{V_{BC}}{I_b - I_c}$	$\frac{V_B - V_C}{I_b - I_c}$	$\frac{V_{CA} - V_{BC}}{(3)I_c}$	$\frac{V_C - V_O}{I_c}$	$\frac{V_{BC} - V_{AB}}{(3)I_b}$	$\frac{V_b - V_o}{I_b}$
CA Fault	$\frac{V_{CA}}{I_c - I_a}$	$\frac{V_C - V_A}{I_c - I_a}$	$\frac{V_{AB} - V_{CA}}{(3)I_a}$	$\frac{V_A - V_O}{I_a}$	$\frac{V_{CA} - V_{BC}}{(3)I_c}$	$\frac{V_c - V_o}{I_c}$

21 – Phase Distance

- **Phase distance backup protection may be prone to tripping on stable swings and/or load encroachment if approach 2 is used.**
  - May employ up to three zones:
    - Z1 can be set to reach 50%-80% of GSU impedance for 87 back-up and bit of a time delay just to give the 87 precedence.
    - Z2 can be set to reach 120% of GSU for station bus backup (or 100% of GSU plus 50% of the next shortest line) and a longer time delay, **or** to overreach remote bus for system fault back up protection. Load encroachment blinder provides security against high loads with long reach settings.
    - Z3 may be used in conjunction with Z2 to form out-of-step blocking logic for security on power swings **or** to overreach remote bus for system fault back up protection. Load encroachment blinder provides security against high loads with long reach settings.
  - Security: 50FD, FL, “52b” gen breaker

21 – Phase Distance

The zone is shown as starting here, rather than at VT, therefore it indicates that some offset is used in these modelled settings.

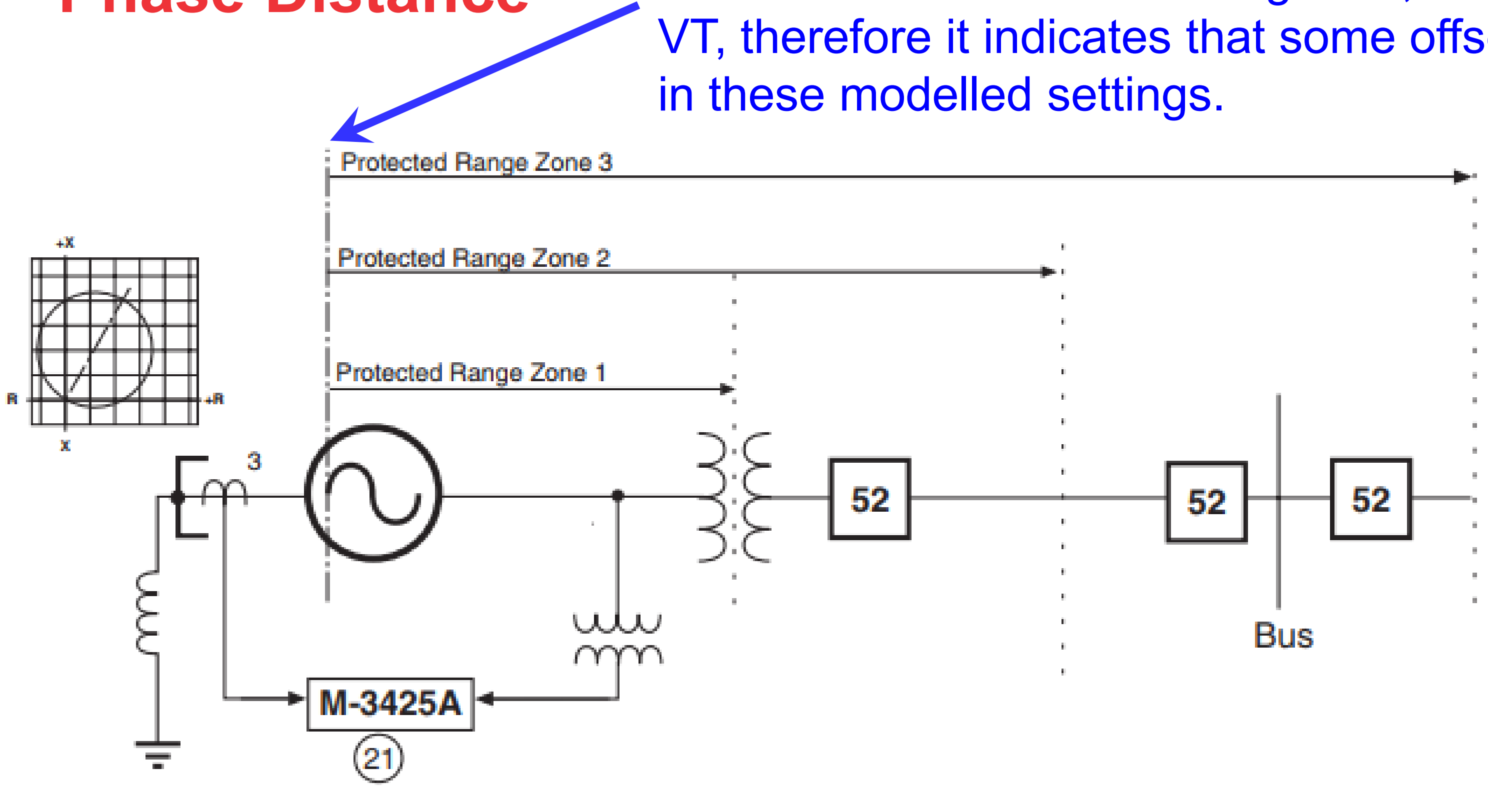
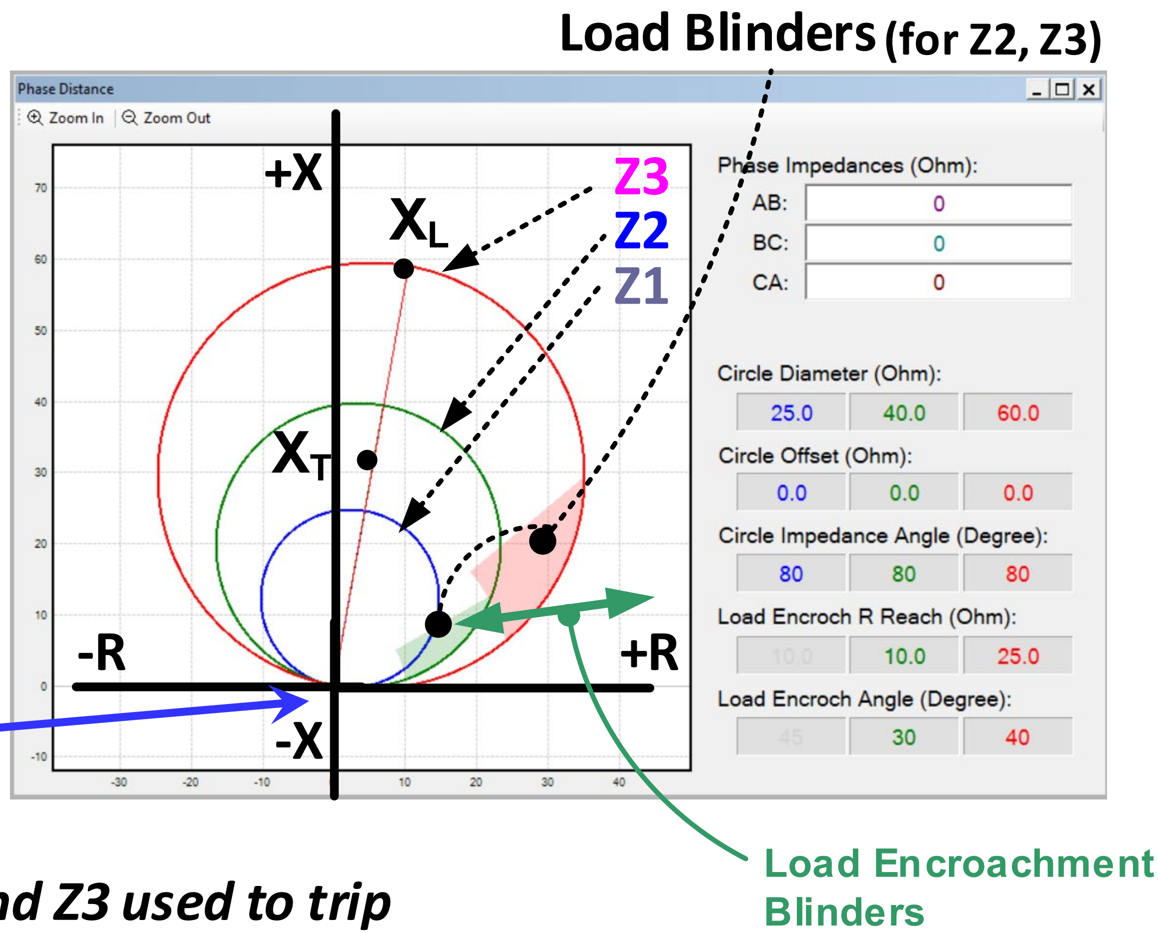


Figure 4-29 Phase Distance (21) Coverage

■ **NOTE:** The reach settings of the distance elements (21) should not include generator impedance since the distance measurement starts at the VT location. However, since the neutral side CTs are used for this function, backup protection for generator Phase-to-Phase faults is also provided.

21 – Phase Distance

With Load Encroachment Blinders



Here, no offset is set for these displayed settings.

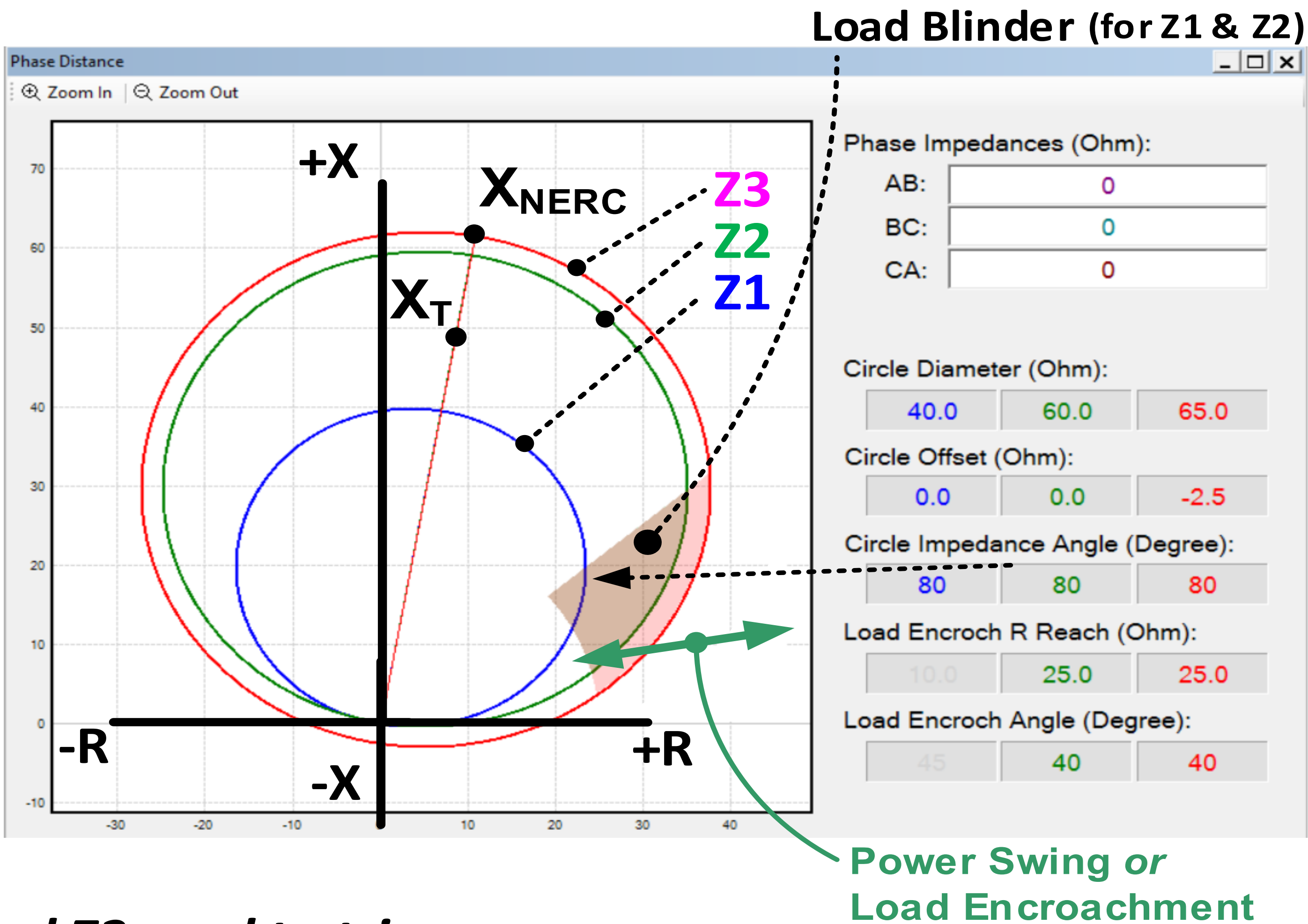
Z1, Z2 and Z3 used to trip

Z1 set to 80% of GSU, Z2 set to 120% of GSU

Z3 set to overreach remote bus if compliant with NERC PRC-025

21 – Phase Distance

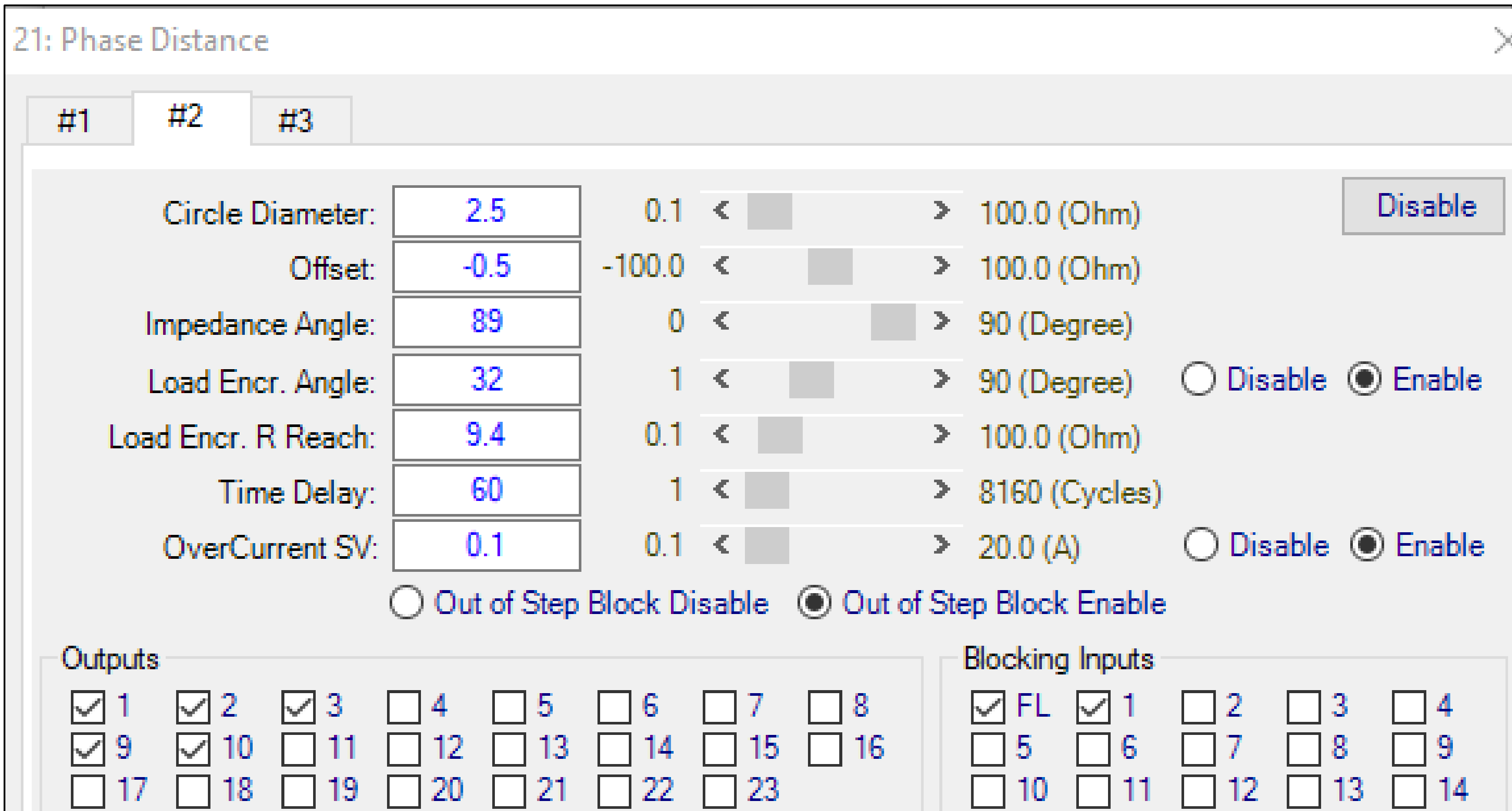
With 68 (OSB/Out-of-Step Blocking aka PSB/Power Swing Blocking) & Load Encroachment Blinders



Z1 and Z2 used to trip
Z1 set to 80% of GSU, Z2 set to overreach remote bus
Z3 used for 68 (power swing blocking)

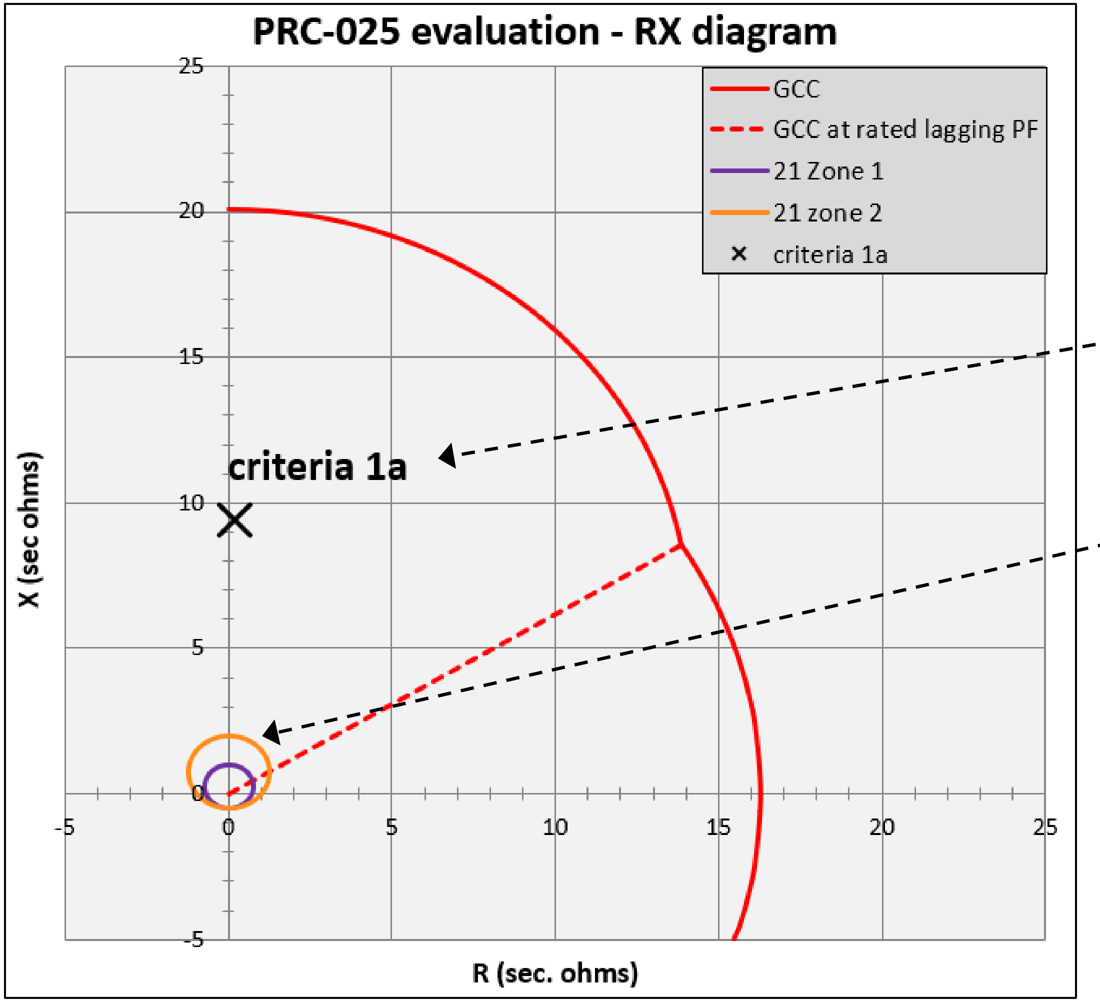
21 – Phase Distance

Here is one sample relay setting input screen. To avoid duplication, no other relay element's specific relay setting input screen will be shown today in this "Generator Protection Theory" presentation as all settings will be calculated, discussed, and displayed in the "Generator Protection Relay Calcs & Settings" training.



21 – Phase Distance compliance with PRC-025

NOTE: Here, in this "Generator Protection Theory" presentation, at the end of each relay element's section, if a particular NERC PRC generator protection relay setting coordination standard (PRC-019, 024, 025, or 026) applies, then the final coordination plot that proves compliance may be shown and briefly discussed. However, the in-depth analysis and calculations behind the coordination plots will be presented in the "Generator Protection Relay Calcs & Settings" training.



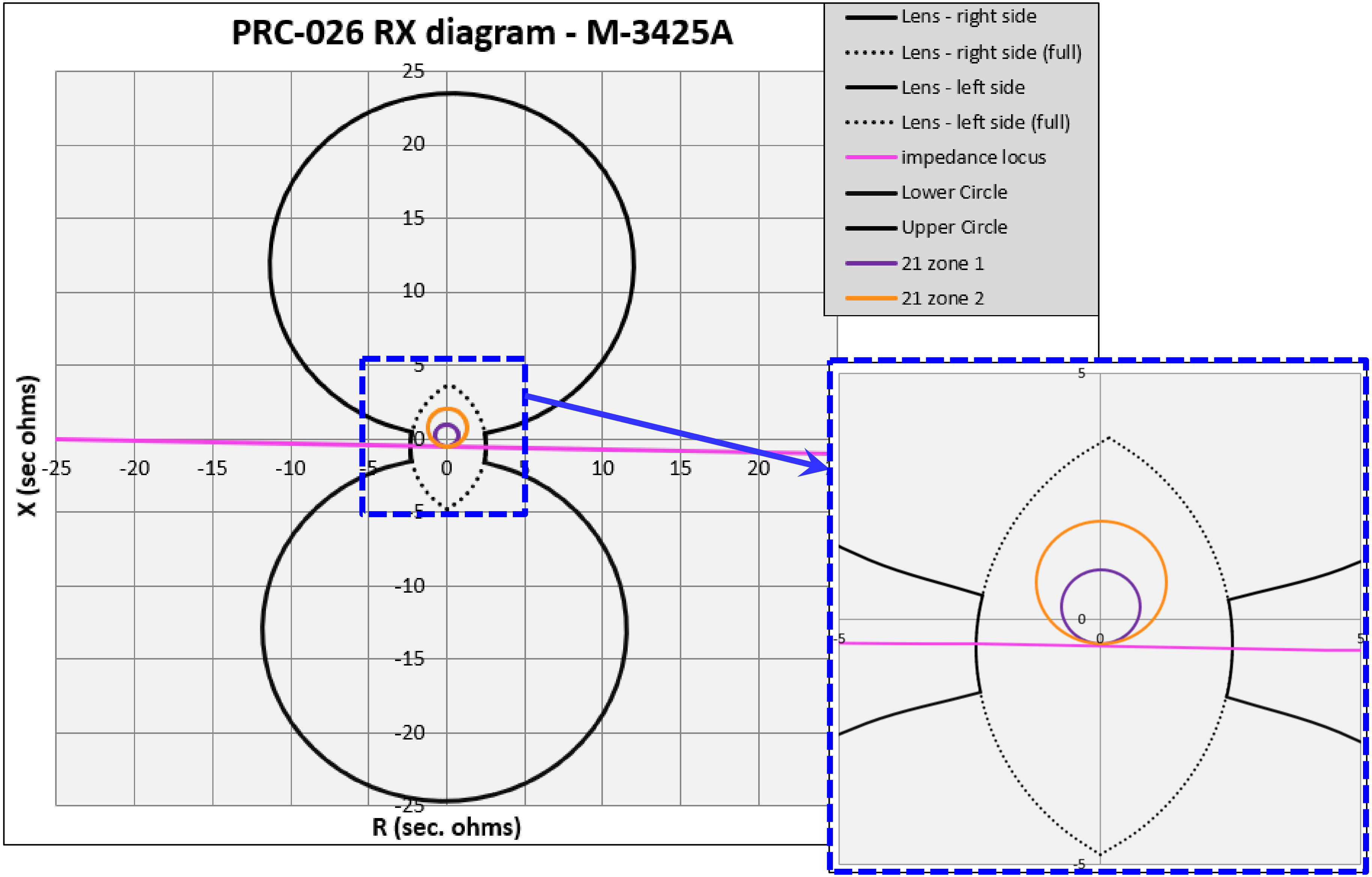
Is the stressed system operating point ("X Criteria 1a" point) of PRC-025 outside both Zone-1 and Zone-2 of the 21 relay mho circles?

Yes

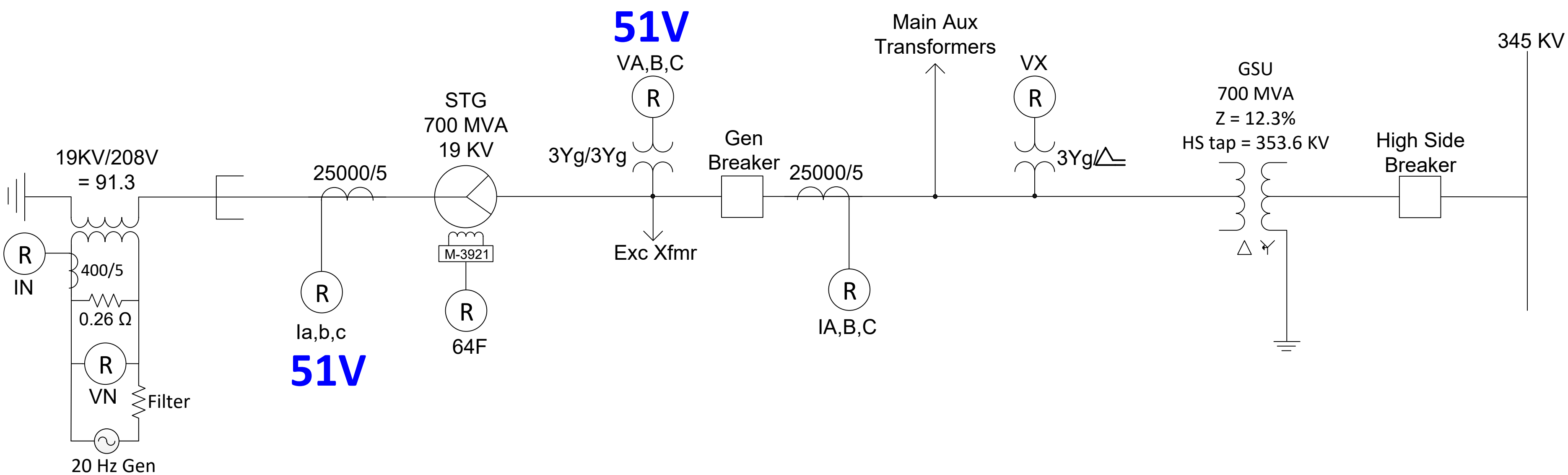
Therefore, 21 Zone-1 and Zone-2 settings comply with PRC-025

21 – Phase Distance compliance with PRC-026

The 21 mho circles plot inside the unstable power swing region. Therefore, yes complies with PRC-026



51V – Voltage R/C Inverse Time Overcurrent



- **Block for an open breaker for extra security unless protection is required during the pre-synchronizing period.**
- **System Phase fault Backup protection.**

51V – Voltage R/C Inverse Time Overcurrent

- Similar to 21's purpose, 51V is backup for system phase faults primarily but will also see phase faults on the low side of the GSU and part way into the generator stator.

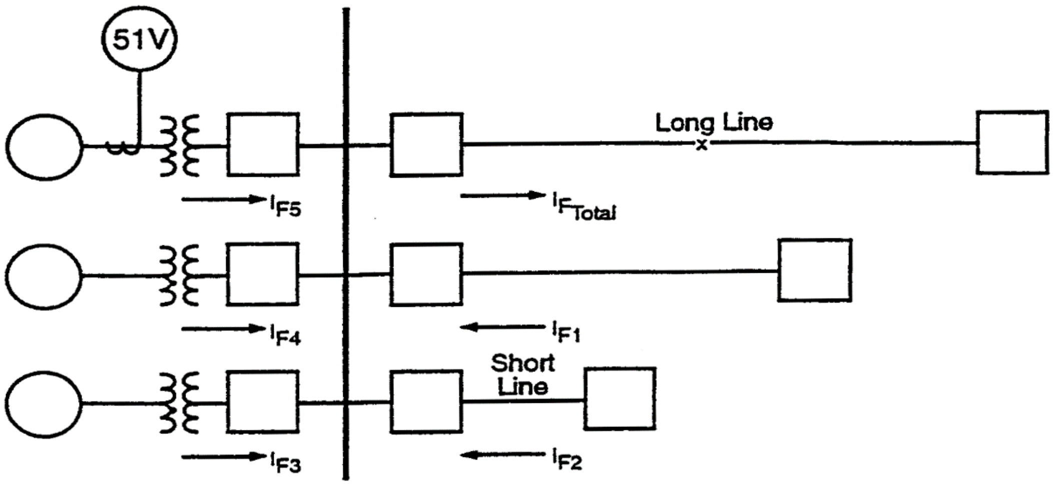
- If transmission system relays are distance based, generally the 21 function is used for backup.

- If transmission system (or distribution system) relays were overcurrent based, then the 51V could be used for backup.

- Recommended to only set either the 21 or 51V for backup protection (2003 blackout saw several 51V trips due to incorrect 51V settings).

- However, both 21 and 51V can be set, as long as they are set correctly and properly coordinated and secure e.g. could ensure the 51V curve trips at > 1 second or so for GSU HS phase faults.

Voltage Control/Restraint Overcurrent (51V)

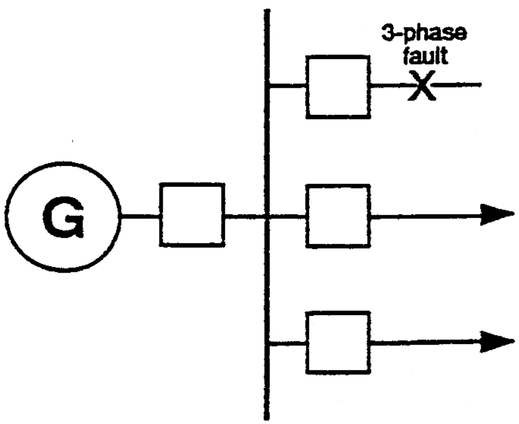


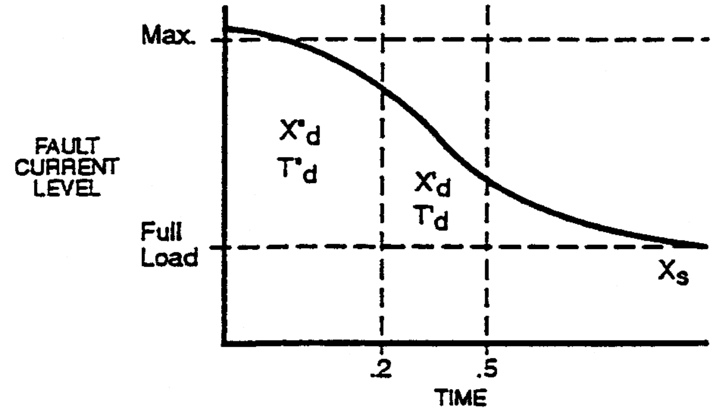
System Configuration with Multiple In-Feeds

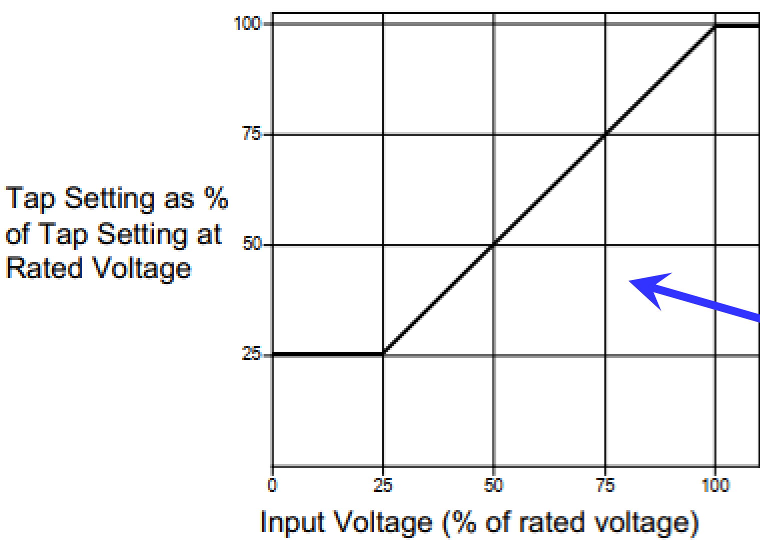
- More difficult to set than 21 function: must coordinate with system backup protection
- Setting coordination criteria
  - System relaying time
  - breaker failure time
  - Consideration should be given to system emergency conditions

Voltage Control/Restraint Overcurrent (51V)

Voltage control/restraint needed because of generator fault current decay (Id < Inom)





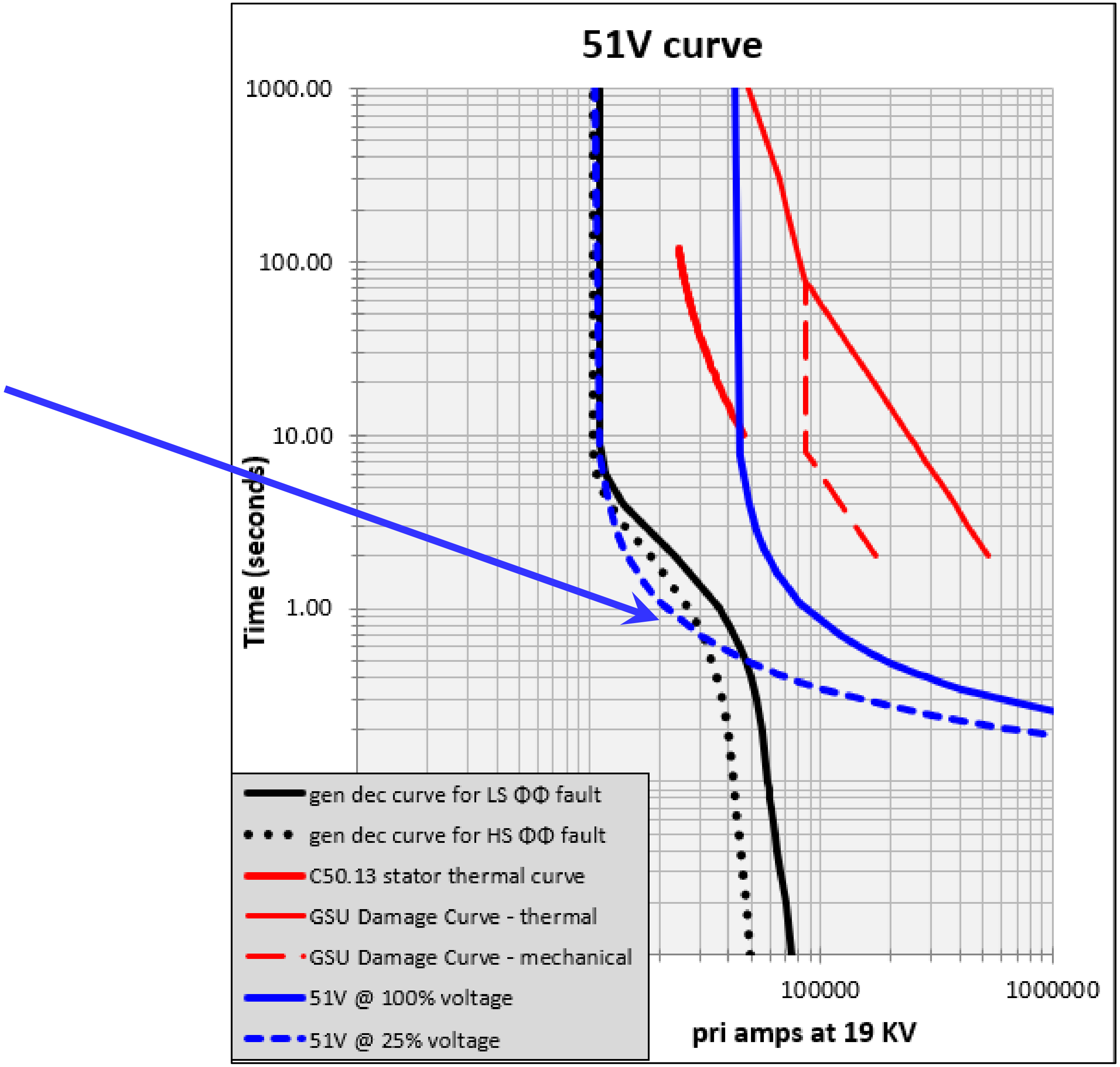


<u>51V Voltage Control Types:</u>

- Voltage Control (VC): set 51V pickup at a percent of full load (40-50%)
- Voltage Restraint (VR): set 51V pickup between 150% and 300% of full load

Voltage Control/Restraint Overcurrent (51V)

Trips in 0.7 seconds for a ΦΦ fault on the HS of the GSU assuming voltage is depressed to 25%.

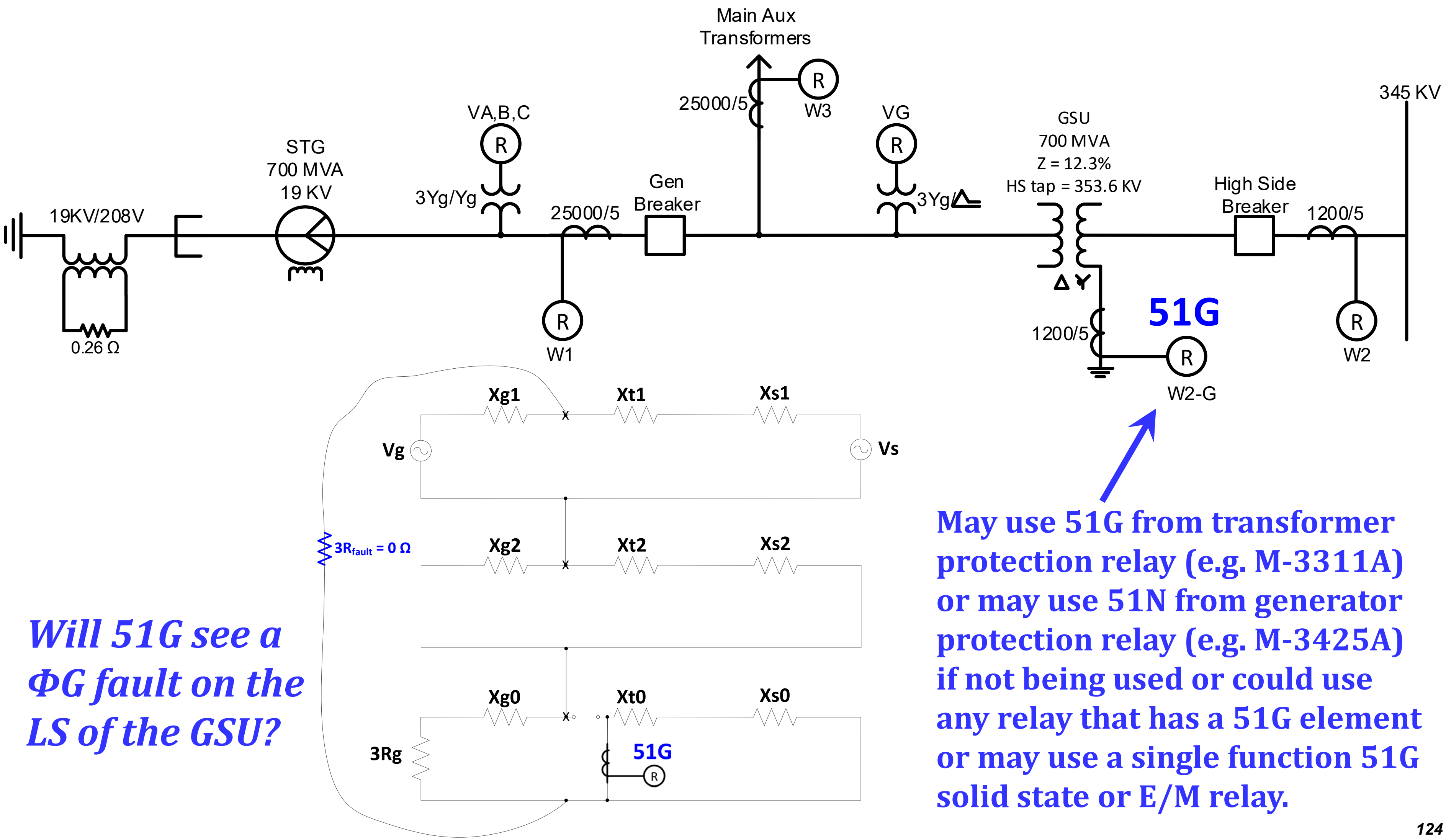


System Backup Protection for Ground faults

- 51G from ground CT on GSU high side wye-grounded leg

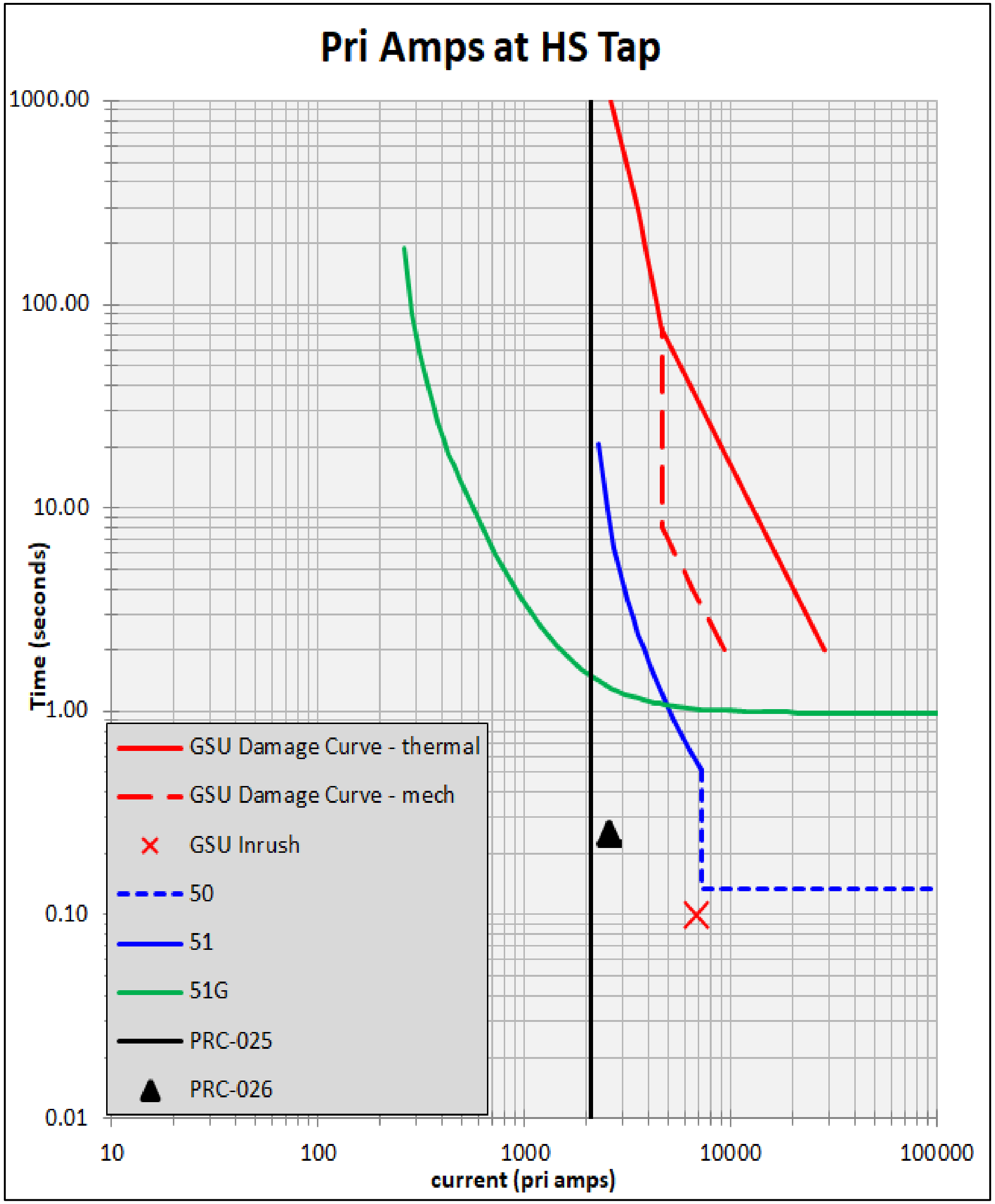
51G – Inverse Time Ground Overcurrent

- *Set 51G as a backup for uncleared system ground faults*



Will 51G see a ΦG fault on the LS of the GSU?

May use 51G from transformer protection relay (e.g. M-3311A) or may use 51N from generator protection relay (e.g. M-3425A) if not being used or could use any relay that has a 51G element or may use a single function 51G solid state or E/M relay.

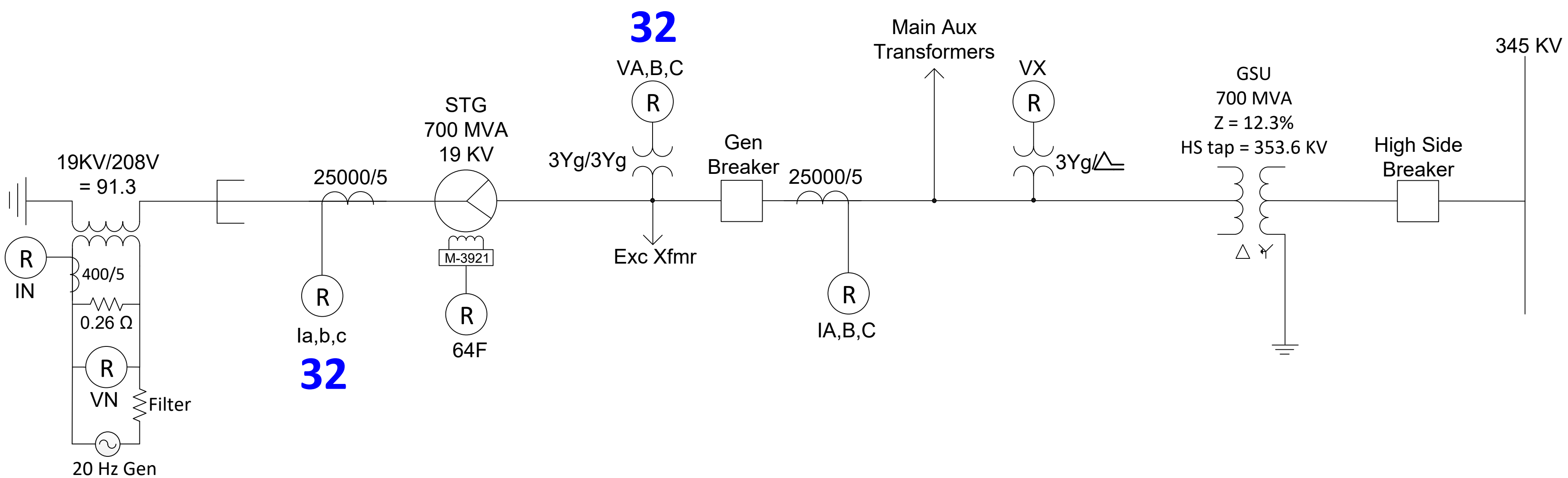


Choose a 51G curve that flattens out at about 1 second to coordinate with transmission line ground fault protection.

Abnormal Operation & Other Protection

- 32 – Reverse Power
- 46 – Negative Sequence O/C
- 50/27 – Inadvertent Energizing
- 40 – Loss of Field
- 78 – Out of Step
- 24 – Volts/Hz (Overexcitation)
- 27 – Phase Undervoltage
- 59 – Phase Overvoltage
- 81 – Over/Under Frequency
- 49 – Stator Thermal Overload
- Isync Trip
- 50BF – Breaker Failure
- 61BF – Breaker Pole Flashover
- 59X (3Vo) – Bus Gnd Overvoltage
- 64F/B – Field Ground Protection

32 – Reverse Power



- The M-3425A relay uses the following for the 32 element's operating quantity:

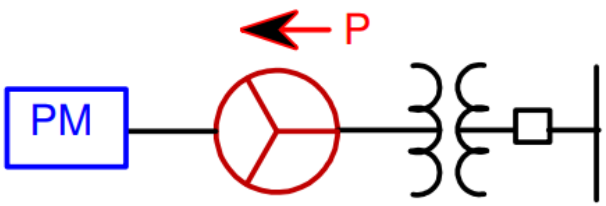
$$P = VA * Ia * \cos(\theta_{VA} - \theta_{Ia}) + VB * Ib * \cos(\theta_{VB} - \theta_{Ib}) + VC * Ic * \cos(\theta_{VC} - \theta_{Ic})$$

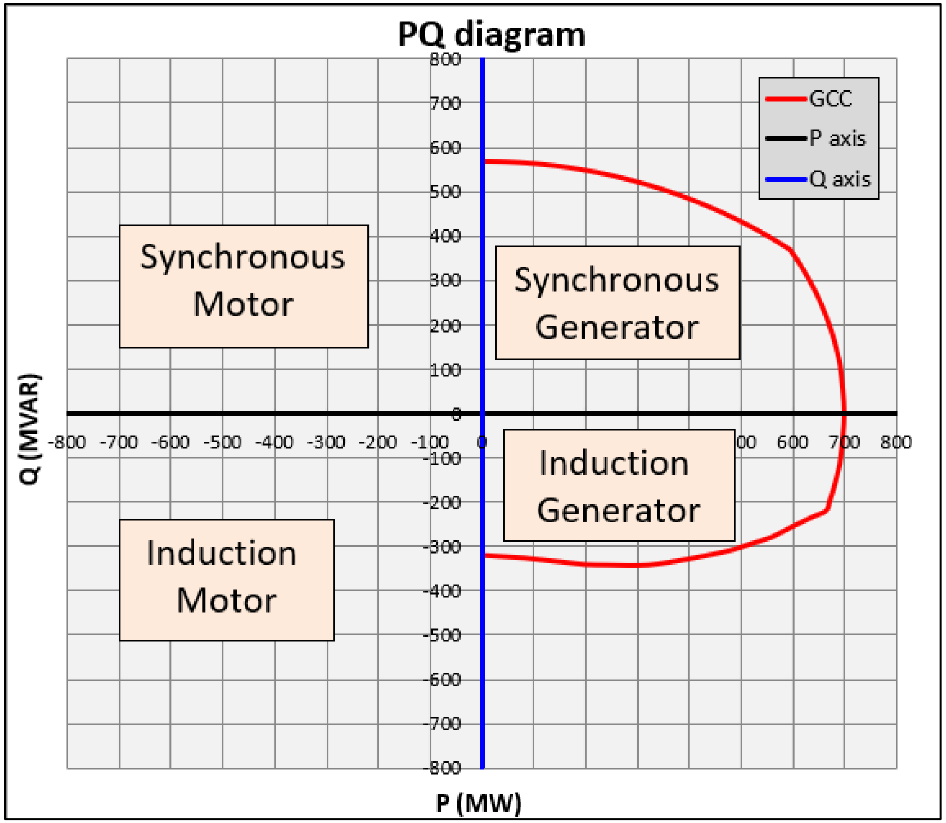
- Other relay mfgs may use other operating quantities.

32 – Reverse Power

- A generator motors when the mechanical input power to its shaft is lost i.e., when the prime mover/turbine is lost or the input to the turbine is lost.
- Operating outside of the turbine mfg recommended back pressure design limits as can occur with loss of turbine input can cause high exhaust temperature due to rotating blade windage friction.
- This windage friction causes the rotating blades to vibrate, increasing the stresses in the blade root area mainly in the last row of rotating blades.
- Typically, it is the vibration from the high back pressure rather than the temperature increase that may cause damage during a motoring event.
- However, the overheating can also be damaging when the generator behaves as a motor and draws real power from the system.

32 – Reverse Power





- If the field is unaffected, the gen becomes a <u>synchronous motor</u> (2nd quadrant) driving the prime mover at synch speed:
  - ✓ The Gen is OK with this, but not the turbine.
  - ✓ 32 element protects for this case where excitation is maintained.
- If field excitation is also lost, the gen may lose synchronism and act like an <u>induction motor</u> (3rd quadrant) – this is protected by the 40 element typically.

32 – Reverse Power

Used to protect turbine and generator from motoring during low or loss of prime mover input (steam, fuel, water supply).

- Motoring:
  - Wastes power from the system that could be sold
  - May cause heating in steam turbines as ventilation is greatly reduced
  - Steam and dewatered hydro can motor with very little power

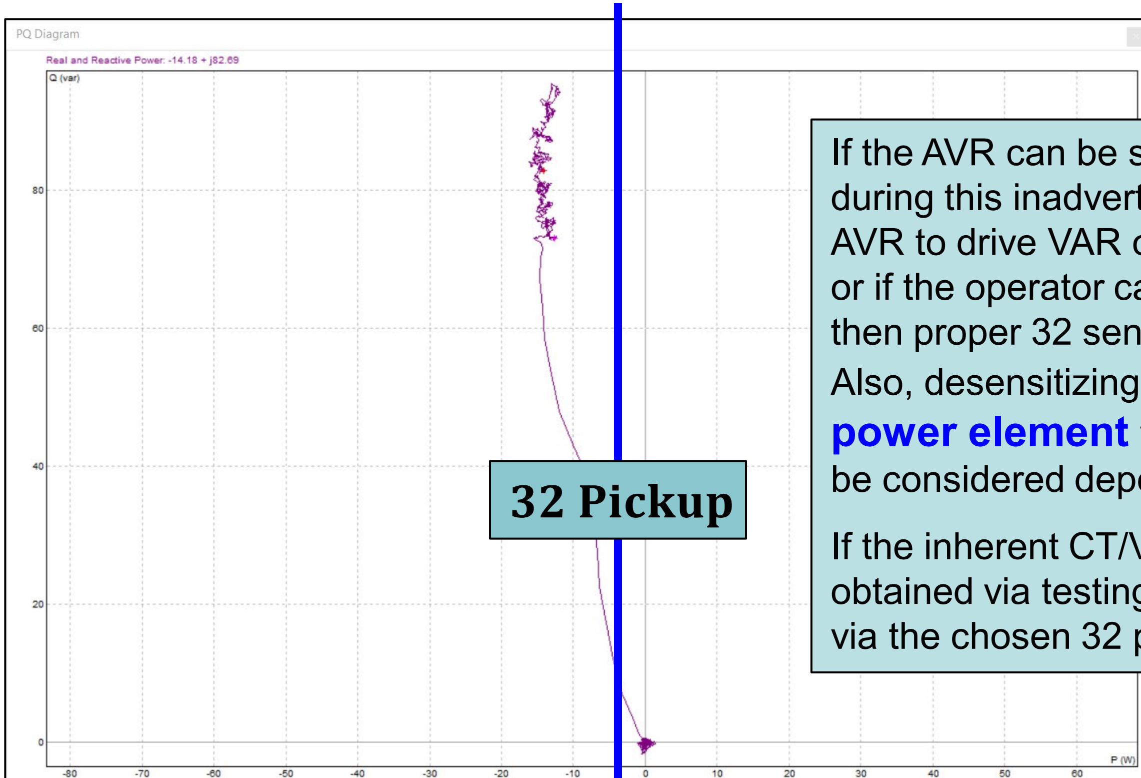
- Some generators are taken off the system by backing off the power until importing MW slightly:
  - This is known as **Sequential Tripping** (See Tripping Mode section).
  - More common for some steam turbines, which may utilize a separate reverse power relay or separate 32 element for normal shutdown.
  - Typical sequence: operator initiates shutdown, turbine trips, steam valves close, reverse power occurs, trip gen breaker, then trip field breaker.

- Two 32 elements may typically be applied for STGs (Steam Turbine Gens):
  1) Normal Shutdown – Sequential Trip with manual or electrical reset LOR
  2) Reverse Power Protection – Simultaneous Trip with manual reset LOR

32 – Reverse Power

During a **normal shutdown sequential trip** that uses a supervising 32 element, both the P and Q are ramped down to zero together keeping the PF near unity and therefore the relay is accurately able to measure the real power component.

Conversely, during an **inadvertent motoring event** with the AVR in auto, the VAR output may initially remain high at near pre-event levels thus resulting in a high MVA output, high VARs, low Watts, and low PF. During these conditions, accurate measurements may be difficult and could result in a loss of dependability for the 32 element as even small CT/VT angle errors can be amplified resulting in relatively large errors in measuring the very small real reverse power.



If the AVR can be set to automatically reduce the VARs during this inadvertent motoring condition (i.e. program the AVR to drive VAR output to zero in the event of a turbine trip) or if the operator can manually and rapidly reduce the VARs, then proper 32 sensitivity and security may be maintained. Also, desensitizing the 32 element or using a **low forward power element** while still retaining proper protection may be considered depending on the specific application.

If the inherent CT/VT angle errors are known or can be obtained via testing, then this can be compensated for as well via the chosen 32 pickup setting.

32 – Reverse Power

Motoring power is different depending on type of prime mover:

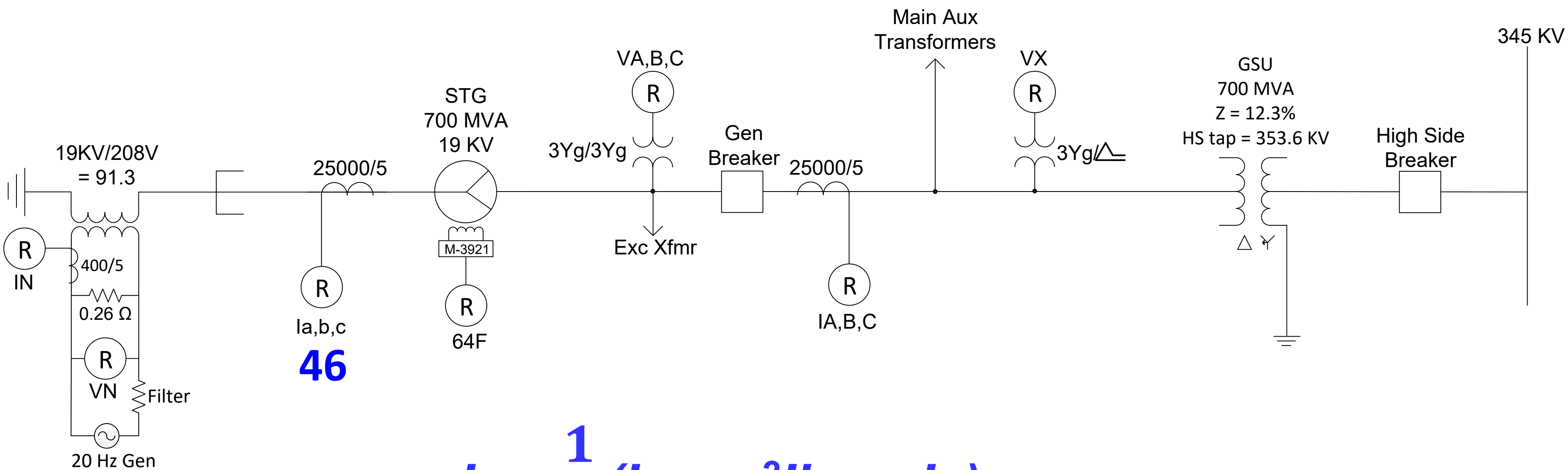
Typical power required in order to motor (in percent of unit rating):

- Condensing Steam Turbine under zero steam input: 0.50 to 3%
- Non-Condensing Steam Turbine: $\geq$ 3%
- Combustion Gas Turbine: 50%
- Diesel Engine: 25%
- Hydraulic Turbine (with blades above the tail-race water level): 0.2 to 2%
- Hydraulic Turbine (with blades below the tail-race water level): 2% to 100%

When the turbine or turbine input is low or lost; the generator draws enough real power from the system to meet its total loss demand (turbine losses plus generator losses e.g. friction windage, load, core, stator I^2R, rotor I^2R, stray, ventilation and cooling, excitation system). Mfg should provide losses information.

Therefore, the total losses determines the reverse power input to the generator while motoring i.e. **losses ≈ motoring power**.

46 – Negative Sequence Overcurrent



$$I_2 = \frac{1}{3}(Ia + a^2Ib + aIc)$$

The Negative Sequence Overcurrent function provides protection against rotor overheating where rotor heating is proportional to the negative sequence current present in the stator windings:

$$\textbf{Rotor heating} \propto I_2 \textbf{ in Stator winding}$$

46 – Negative Sequence Overcurrent

- Unbalanced currents in the stator winding produces a rotating magnetic field in the air gap between the rotor and stator.

- This magnetic field rotates at sync speed but in the opposite direction relative to the direction that the rotor is spinning.

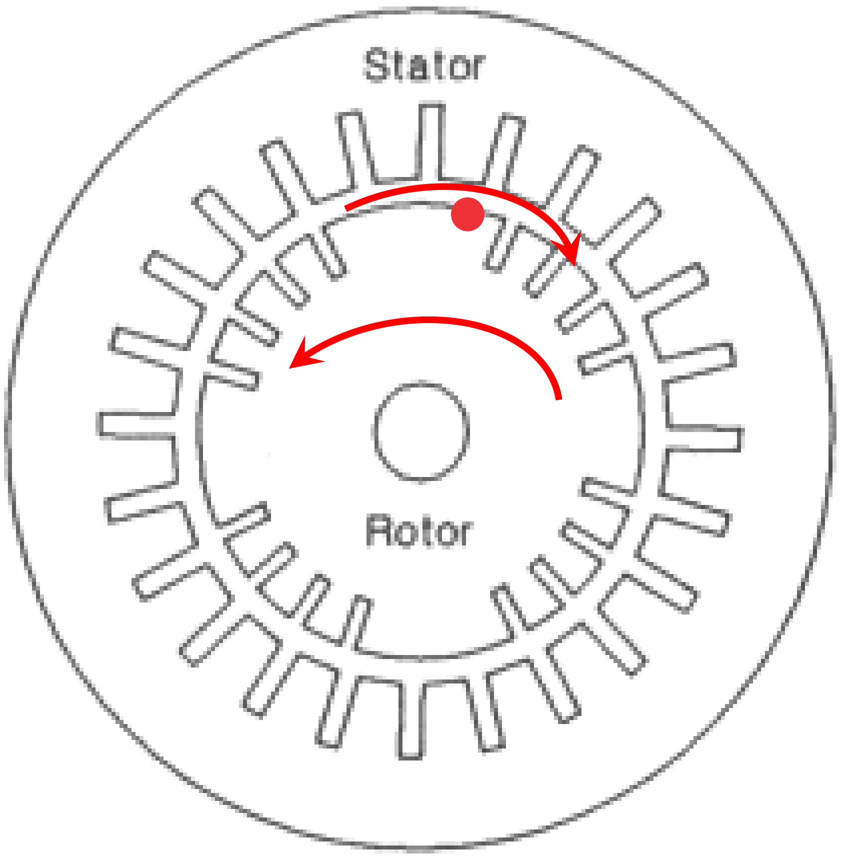
- Therefore, from the perspective of a single point on the rotor this magnetic field will appear to be rotating at **twice** sync speed:

  2*Ns = 2*3600 = 7200 rpm

- Thus, the virtual slip will be equal to:

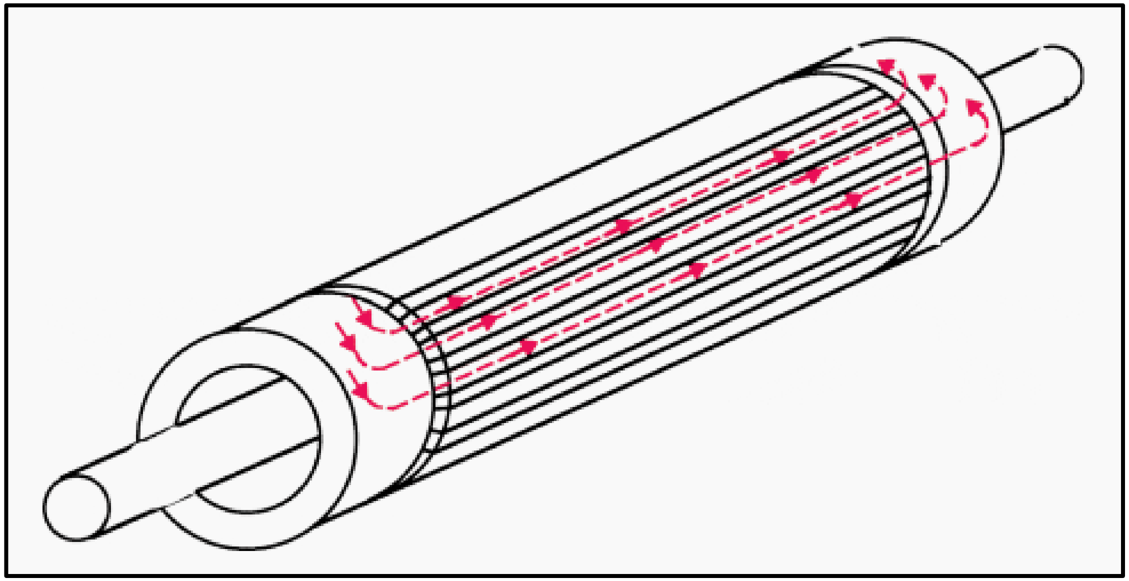
  (Ns-Nr)/Ns = [Ns-(-Ns)]/Ns = 2Ns/Ns = 2

- As the speed and frequency are directly proportional (p = 120f/rpm), the rotating magnetic field induces a double frequency (2*f = 2*60 = 120 Hz) current on the rotor i.e. p = (120***2***f)/(**2***N).



46 – Negative Sequence Overcurrent

- Because these induced 120 Hz currents are not uniform, the current density will migrate to the rotor surface down to a depth of 0.1” to 0.4” due to “skin effect”.
- Portions of the induced current path present a high resistance to the current which results in losses and heating and can result in insulation failure in seconds.



- Gens have continuous and short time ratings for negative sequence current and are different for salient pole (C50.12) and round rotor (C50.13) machines.
- I_2 ratings are dependent on if damper windings are connected at hydros.
- Also dependent on availability of the unit as a synch condenser.

46 – Negative Sequence Overcurrent

Negative sequence current in the stator windings can be caused by:

- Unbalanced faults:
  - ✓ out on the system (can calculate)
  - ✓ in the generator itself (can calculate)
- Open phases (can calculate)
  - ✓ Stuck poles, switches, and breakers
- Un-transposed transmission lines (measure at max gen output)
- Sudden loss or connection of heavy loads
- Unbalanced loads (measure at max gen output)
- Single-phase loads or single-phase generation (e.g. solar)
- Single pole/phase recloser tripping
- Poorly balanced distribution of loads or general unbalanced loading

Some of the most common types of unbalanced loads are single phase railroad loads, induction furnace loads, and three-phase arc furnace loads which produce higher order harmonics that behave like negative sequence quantities.

Also, because negative sequence current coincides with negative sequence harmonics (2, 5, 8, 11, 14, etc), the inrush from the energization of transformers or nonlinear loads such as electronic devices and variable speed drives (VFD) can introduce these harmonics.

46 – Negative Sequence Overcurrent

Electromechanical Relays

- Sensitivity restricted and cannot detect I_2 levels less than ≈ 60% of generator rating
- Fault backup may be provided
- However, generally insensitive to load unbalances or open conductors

46 – Negative Sequence Overcurrent

Digital Relay

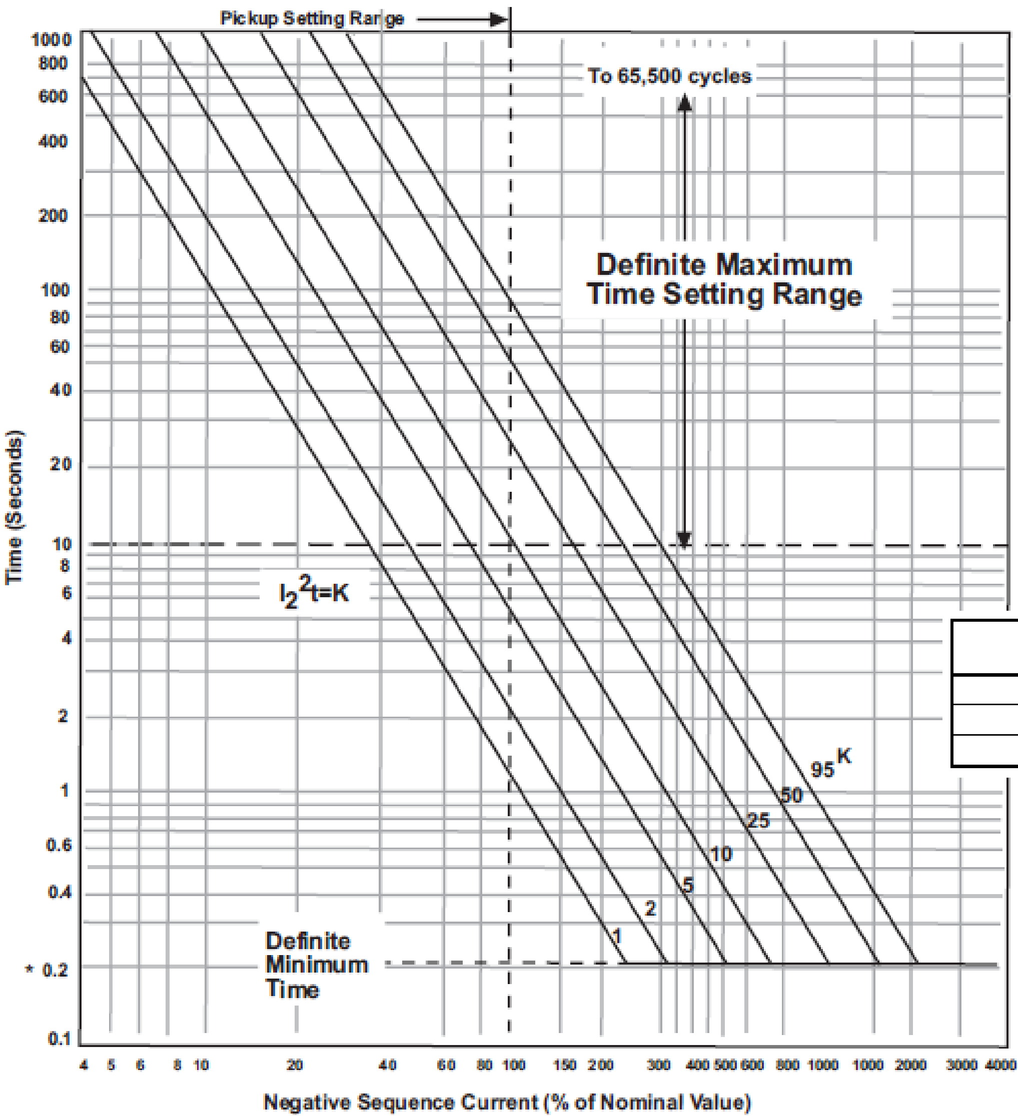
- Protects generator down to its continuous negative sequence current (I_2) rating vs. electromechanical relays that don't detect levels < 60%
- Fault backup provided
- Can detect load unbalances
- Can detect open conductor conditions
- Should provide thermal time reset as I_2 causes heating

Continuous I_2 Generator ratings
per IEEE C50.12 and C50.13:

Continuous Unbalance Current Capability	
Generator Type	*Permissible I_2 Stator Rating Percent*
Salient Pole	
Connected Amortisseur Windings	10
Nonconnected Amortisseur Windings	5
Cylindrical Rotor	
Indirectly Cooled	10
Directly Cooled	
To 350 MVA	8
351–1250 MVA	8 – [(MVA-350)/300)]
1251–1600 MVA	5

Generator Short Time I_2 ratings defined by $I_2^2 T=K$

where K is Time Dial



per IEEE C50.12 and C50.13:

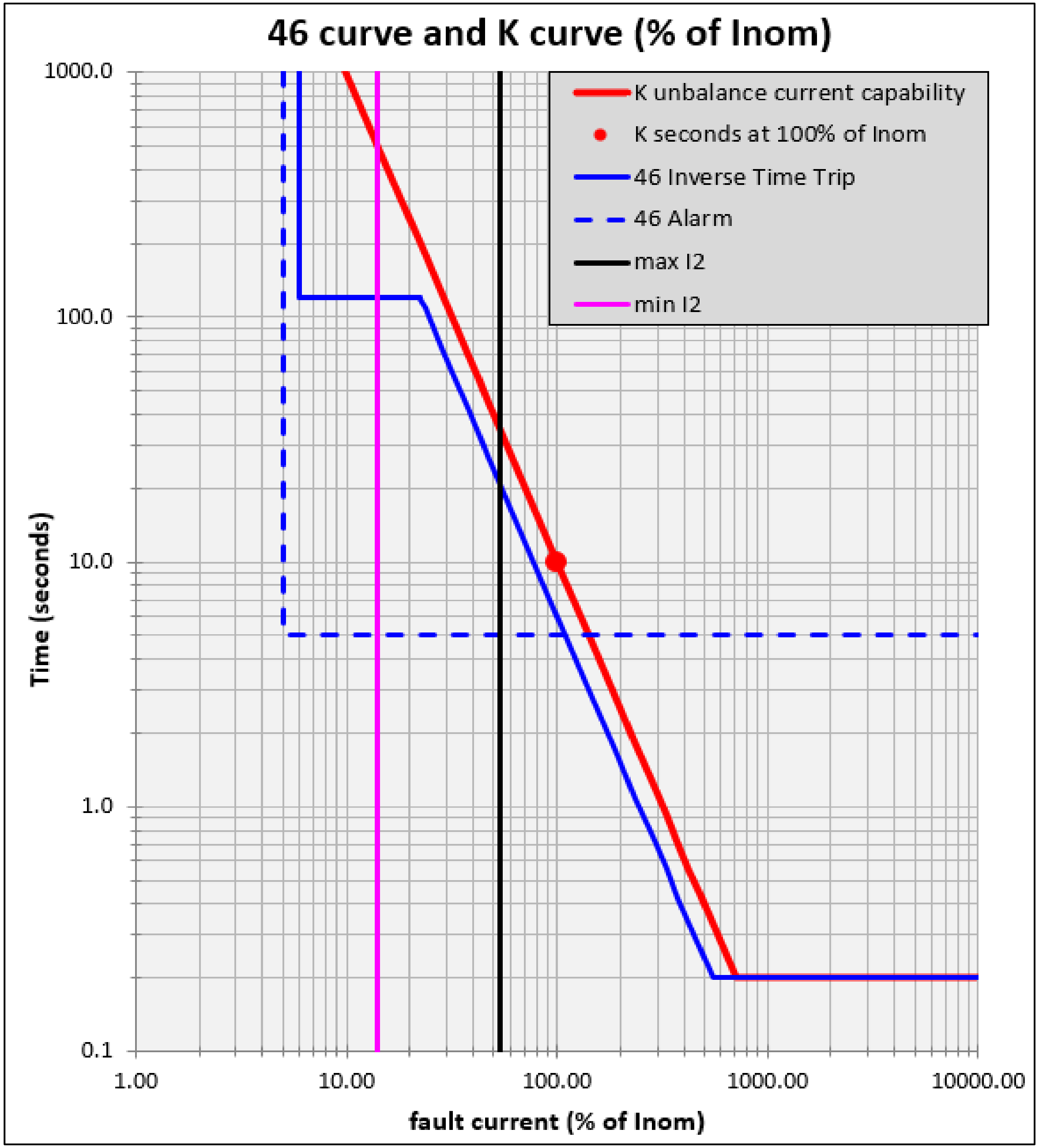
Typical K Values

Salient Pole Generators *40*

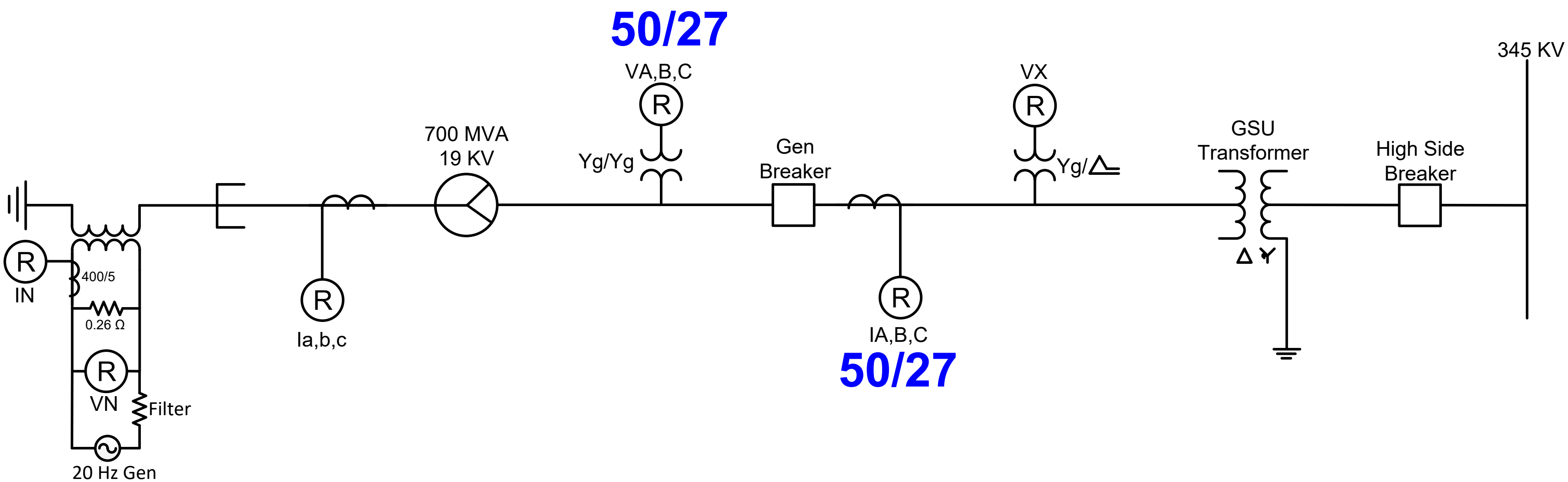
Cylindrical Generators

Type of generator rotor cooling	Minimum generator short-time capability expressed in terms of I_2^2t
Indirectly cooled	30
Directly cooled up to 800 MVA	10
800 MVA to 1600 MVA	10–(0.00625)(MVA–800)

46 – Negative Sequence



50/27 – Inadvertent Energizing



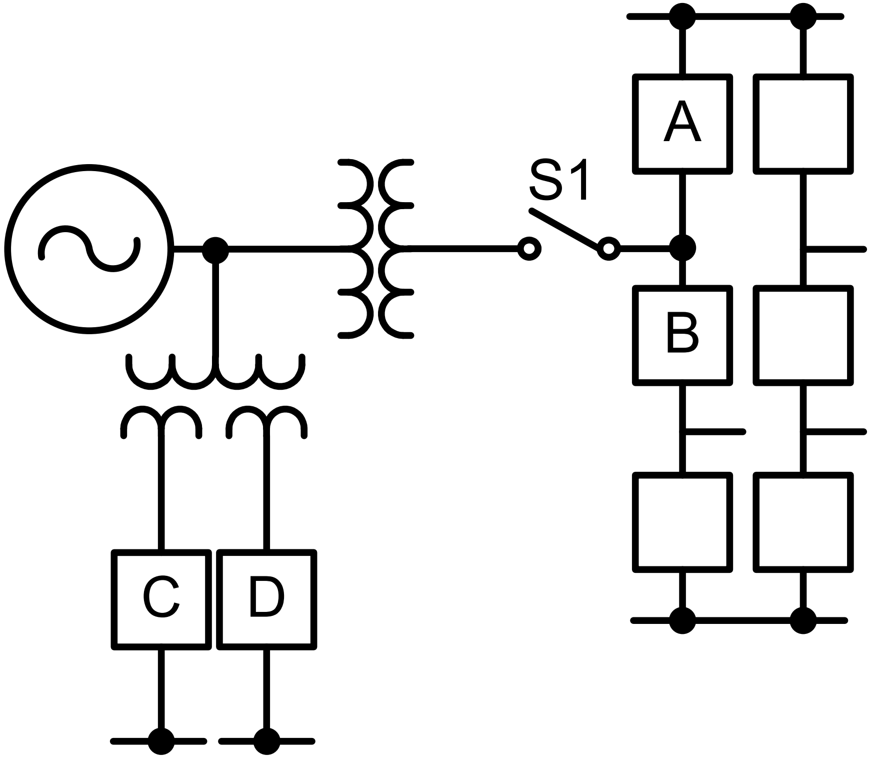
Protection for when the generator is accidently energized when off-line.

50/27 – Inadvertent Energizing

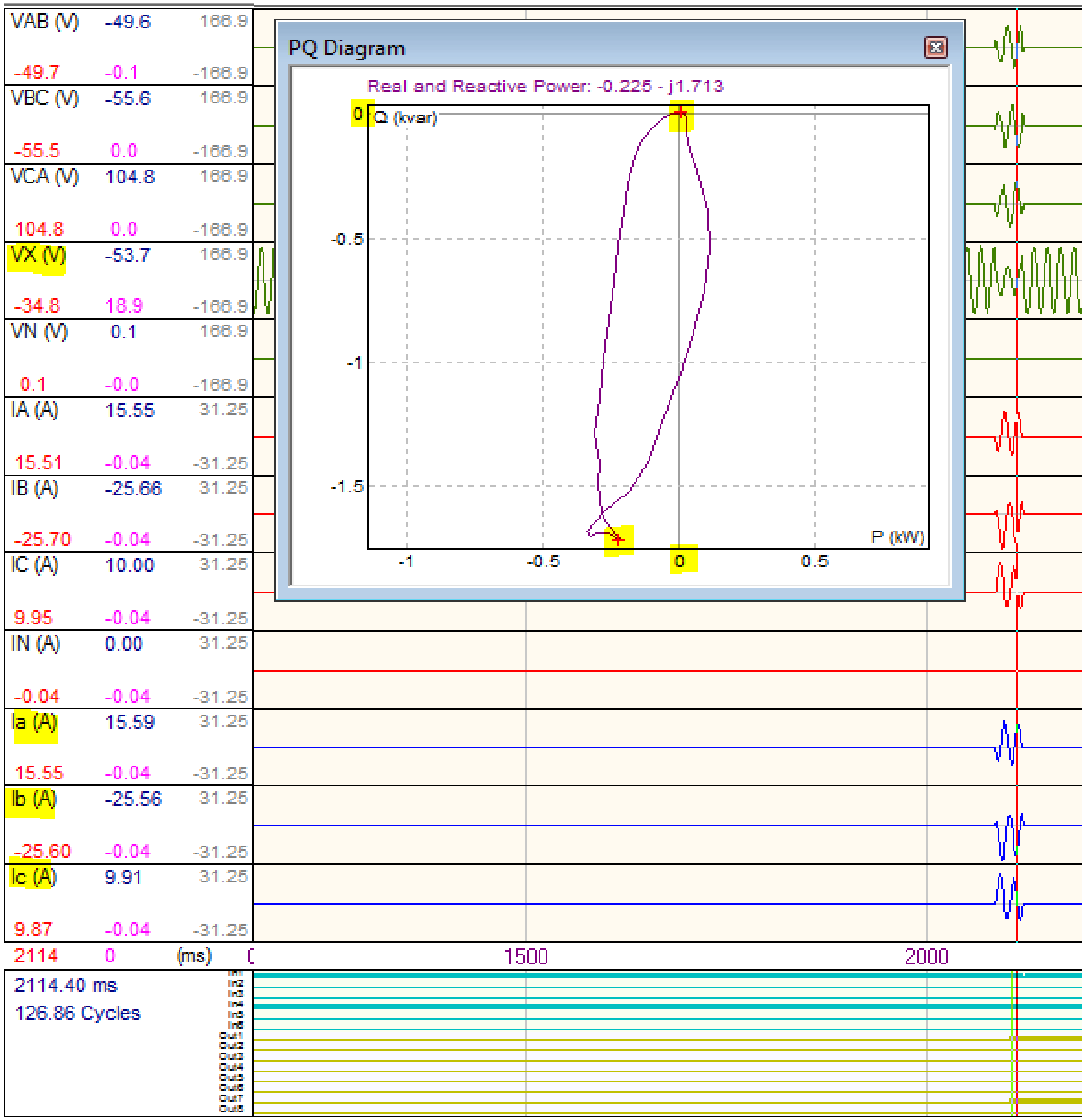
- Inadvertent energization occurs when the generator main circuit breaker or aux transformer circuit breaker is accidently closed to energize the generator while the generator is out of service.

<u>Causes:</u>

- Operating errors
- Breaker head flashovers
- Control circuit malfunctions
- Combination of above



50/27 – Inadvertent Energizing



PRO TIP:

- When machine is off-line do not disable 50/27:
  - ✓ Do not open TCOs
  - ✓ Do not remove fuses
  - ✓ Do not remove DC
- Because this is when the 50/27 function is really needed.
- For this reason, may consider installing a separate, discrete 50/27 relay.

50/27 – Inadvertent Energizing

- When inadvertently energized from a 3Φ source, the generator can act as an induction motor, drawing as much as 4 to 6 times rated stator current from the system.
  - These high stator currents induce high currents in the rotor, quickly damaging the rotor.
  - Rotor heats rapidly (very high I_2 in the rotor)

- Current drawn similar to Locked Rotor Amps for a motor:
  - ✓ Strong system: 4-6x rated
  - ✓ Weak system: 1-2x rated
  - ✓ From Auxiliary System: 0.1-0.2x rated

➢ When inadvertently energized from 1-phase source (pole flashover), the machine does not accelerate

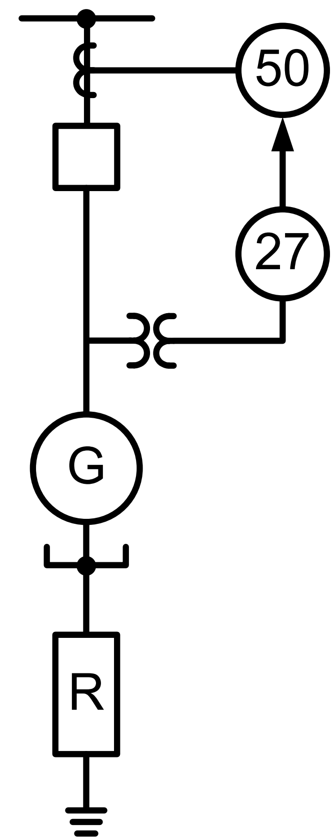
  - No rotating flux is developed, but rotor heats rapidly (high I_2 in rotor)

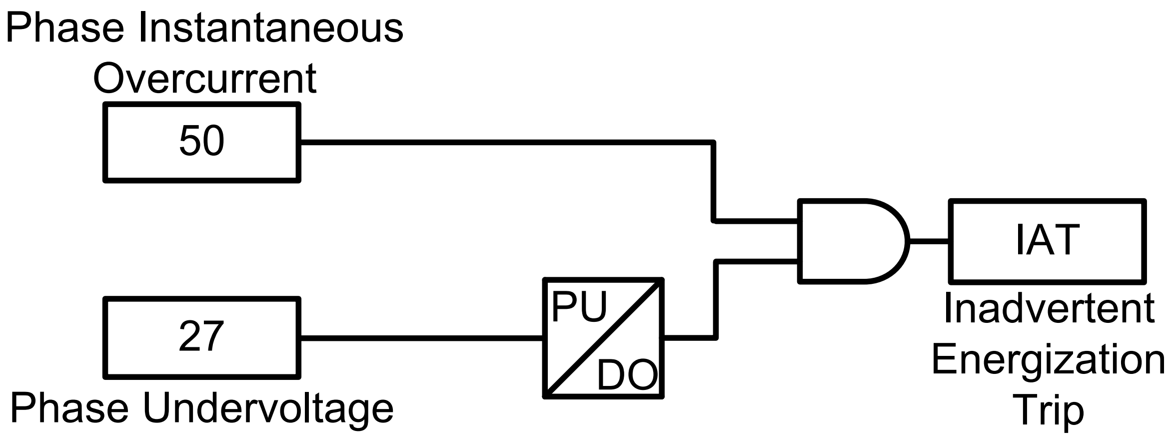
50/27 – Inadvertent Energizing

- This scheme will also protect for the scenario where the unit is off-line with the high side breaker disconnects open for testing:
  - ✓ After the testing is completed, if the breakers are accidently left in the closed position, then when the disconnect(s) are closed, the generator stator windings will be energized from standstill.
  - ✓ The 50/27 function will already be armed, so as soon as that first disconnect is closed it will trip.
- Typically, normal generator relaying is not adequate to detect inadvertent energizing (too slow or not sensitive enough):
  - ✓ 21 – Distance
  - ✓ 46 – Negative sequence
  - ✓ 32 – Reverse power
  - ✓ Some types are complicated and may have reliability issues
    - e.g. Distance relays in switchyard disabled for testing and inadvertent energizing event takes place

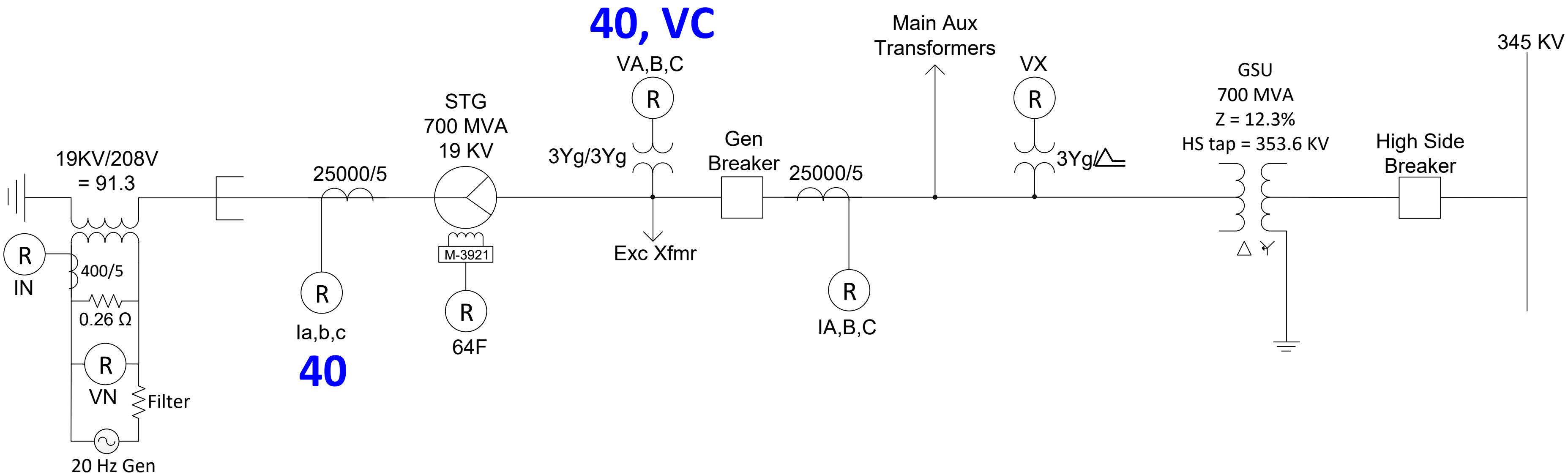
50/27 – Inadvertent Energizing

- Undervoltage (27) supervises low-set, instant overcurrent (50) – recommended 27 setting is 50% or lower of normal voltage
- Pickup timer ensures generator is dead for fixed time to ride through three-phase system faults
- Dropout timer ensures that overcurrent element gets a chance to trip just after synchronizing





40 – Loss of Field



$$Z1 = \frac{V1}{I1}$$

$(uses\ positive\ sequence\ quantities\ for\ security\ during\ power\ swings)$

40 – Loss of Field

- Loss of field current causes the synchronous generator to act as an induction generator (down in 4^{th} quadrant of PQ or RX diagram).
- High currents are induced as the rotor speed increases, active power output decreases, and the generator pulls VARs from the system.
- Operates in under-excited region of the capability curve, which has reduced stability in this area
- Dangerous overheating can occur in a very short time as stator currents can rise as high as 2 pu very quickly.
- LOF may be result of equip failure, opening of field breaker, open ckt or short ckt in excitation system, or slip ring flashover.
- **Sample Settings: Set Primary relay with neg offset zone 2 method and the Backup relay using the pos offset zone 2 method.**
- This gives the maximum coverage while still providing redundancy.

40 – Loss of Field

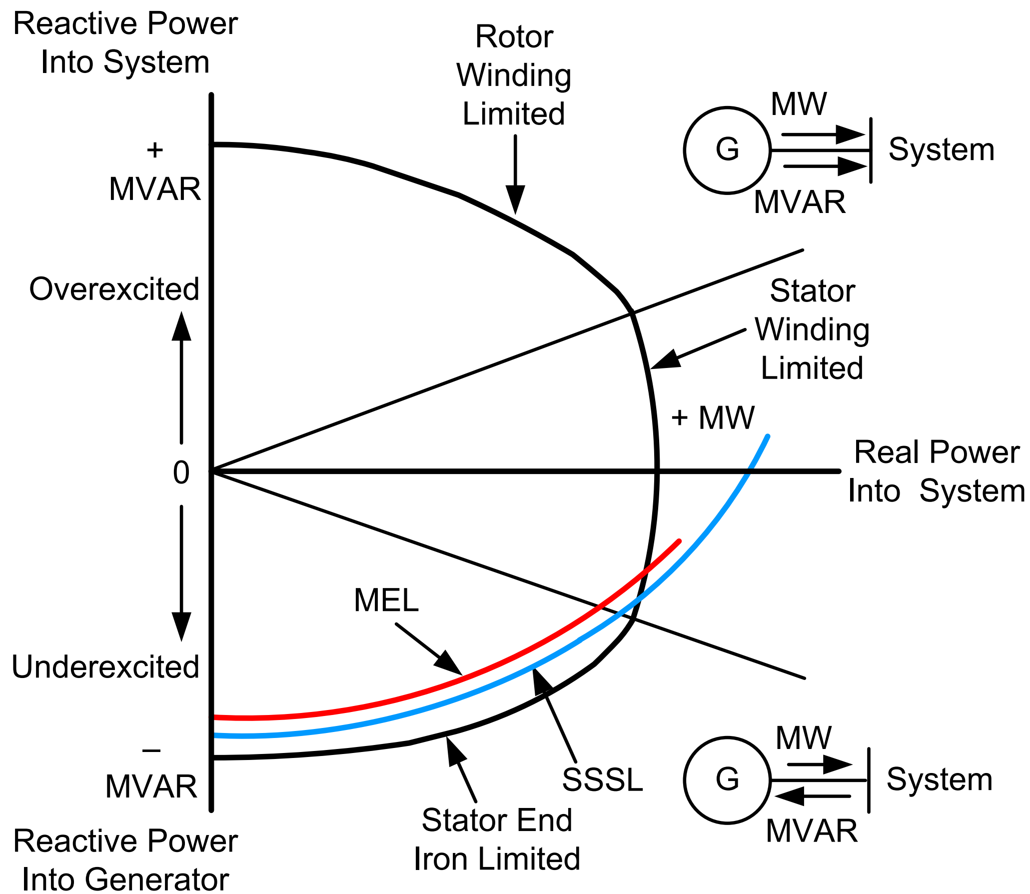
Can adversly affect the generator and the system!!

- Generator effects
  - Synchronous generator becomes induction
  - Slip induced eddy currents heat rotor surface
  - High reactive current drawn by generator
  - overloads stator

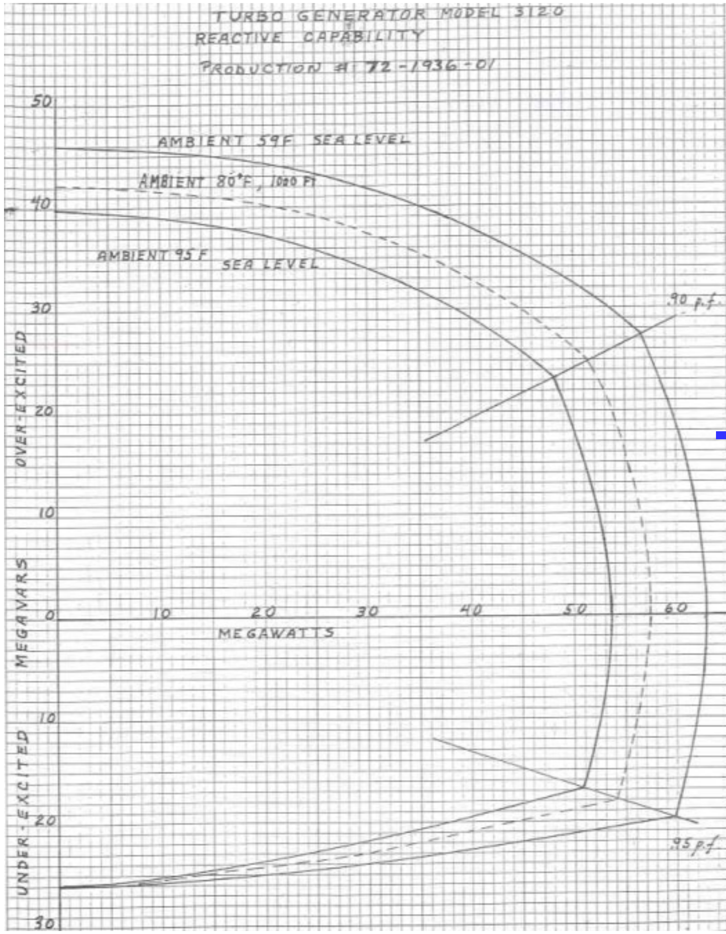
- Power system effects
  - Loss of reactive support
  - Creates a reactive drain
  - Can trigger system/area voltage collapse (2003 NE Blackout)

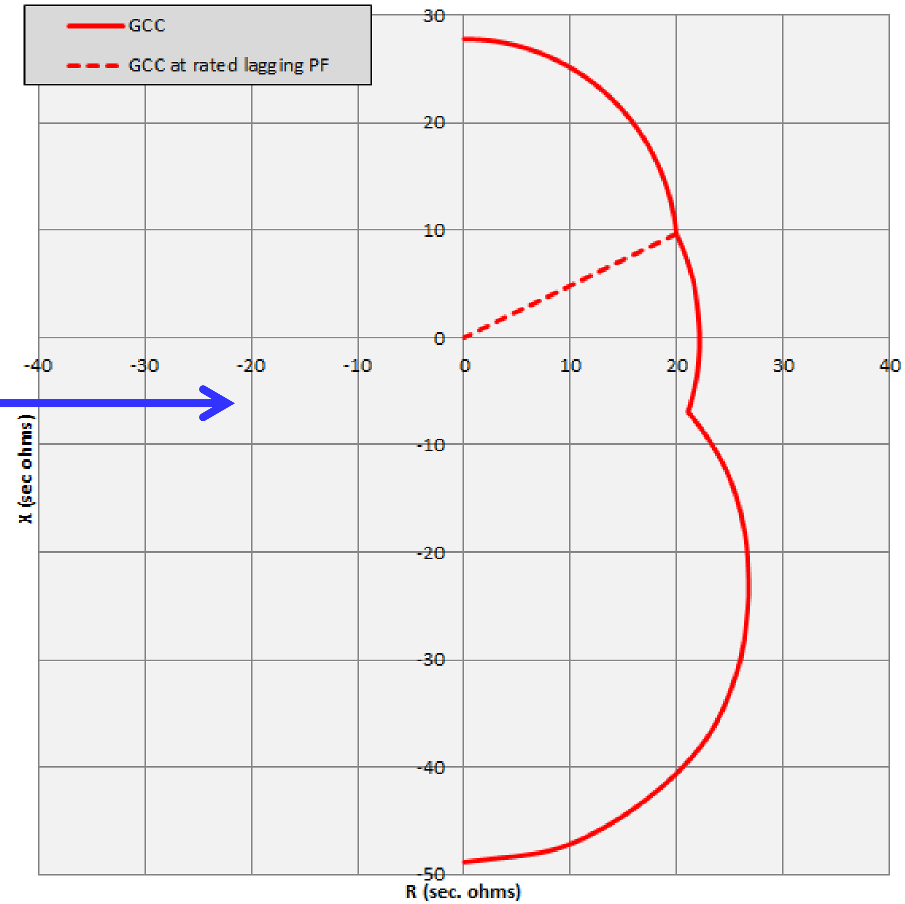
Generator Capability Curve

- Underexcited limiting factor is stator end iron heat
- Minimum excitation limiter (MEL) or UEL prevents exciter from reducing the field below SSSL



Convert GCC from PQ to RX

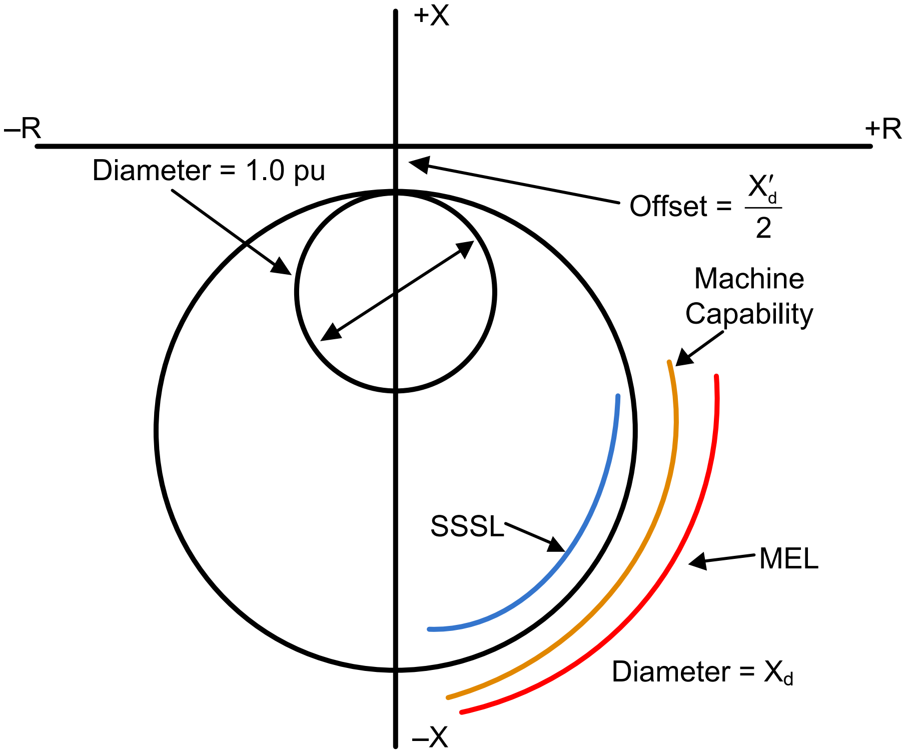


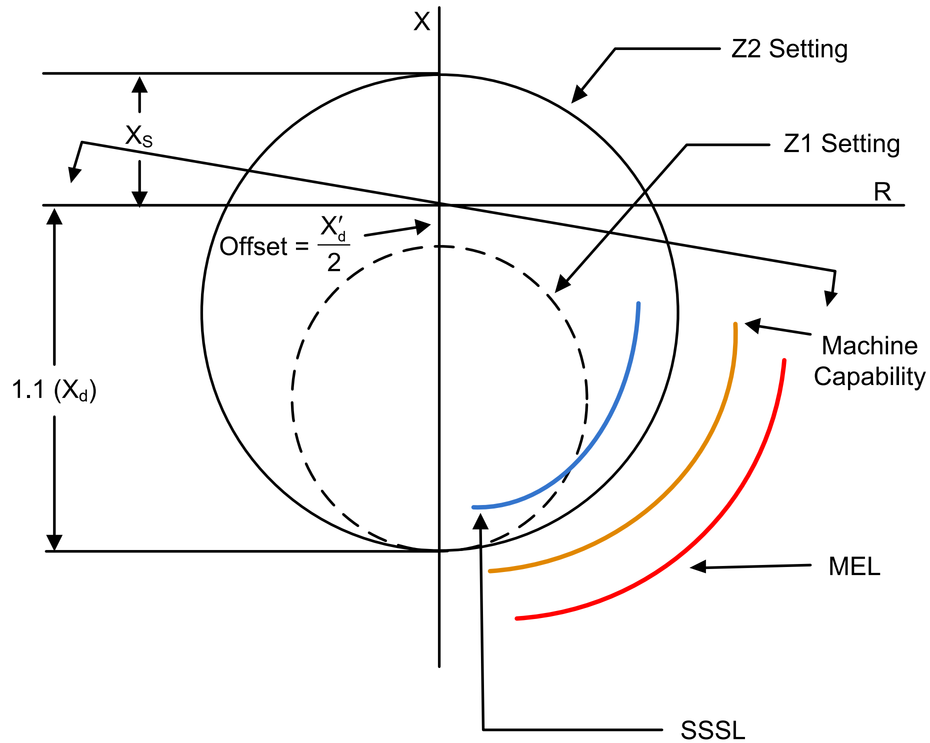


			Generator Reactive Capability Curve						
3									
4			Primary Values			Secondary Ohms			
5			MW	MVAR	Zpri=V^2/S*	Zsec = Zpri*CTR/PTR	R	X	
6	PF	lag/lead							

Loss of Field

Legacy E/M relay GE and Westinghouse approaches



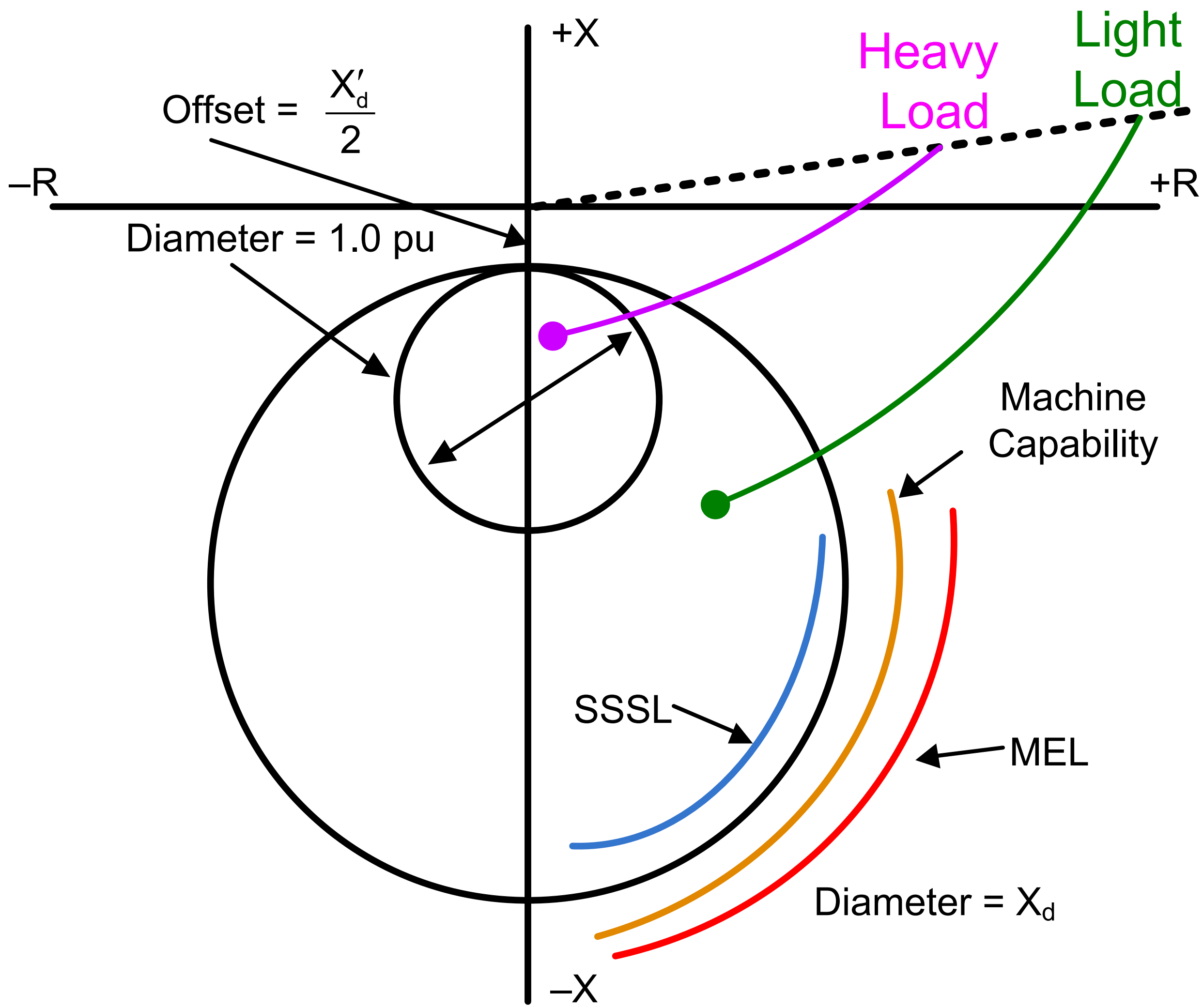


GE – CEH
Approach 1
Negative Offset Zone 2
Two Zone Offset Mho

Westinghouse – KLF
Approach 2
Positive Offset Zone 2
Impedance w/Directional Unit

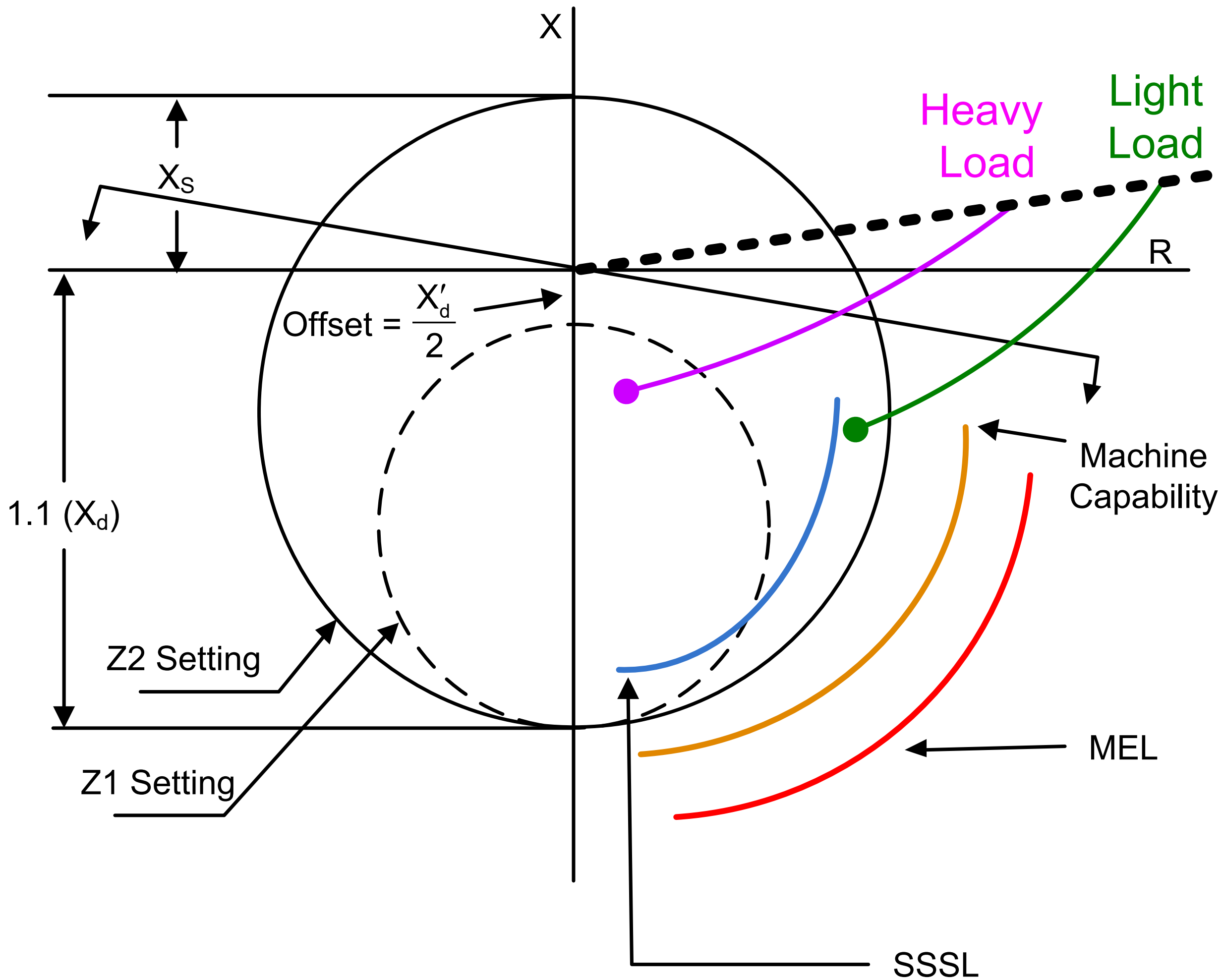
Loss of Field

Negative Offset Zone 2 – GE – Approach 1



Loss of Field

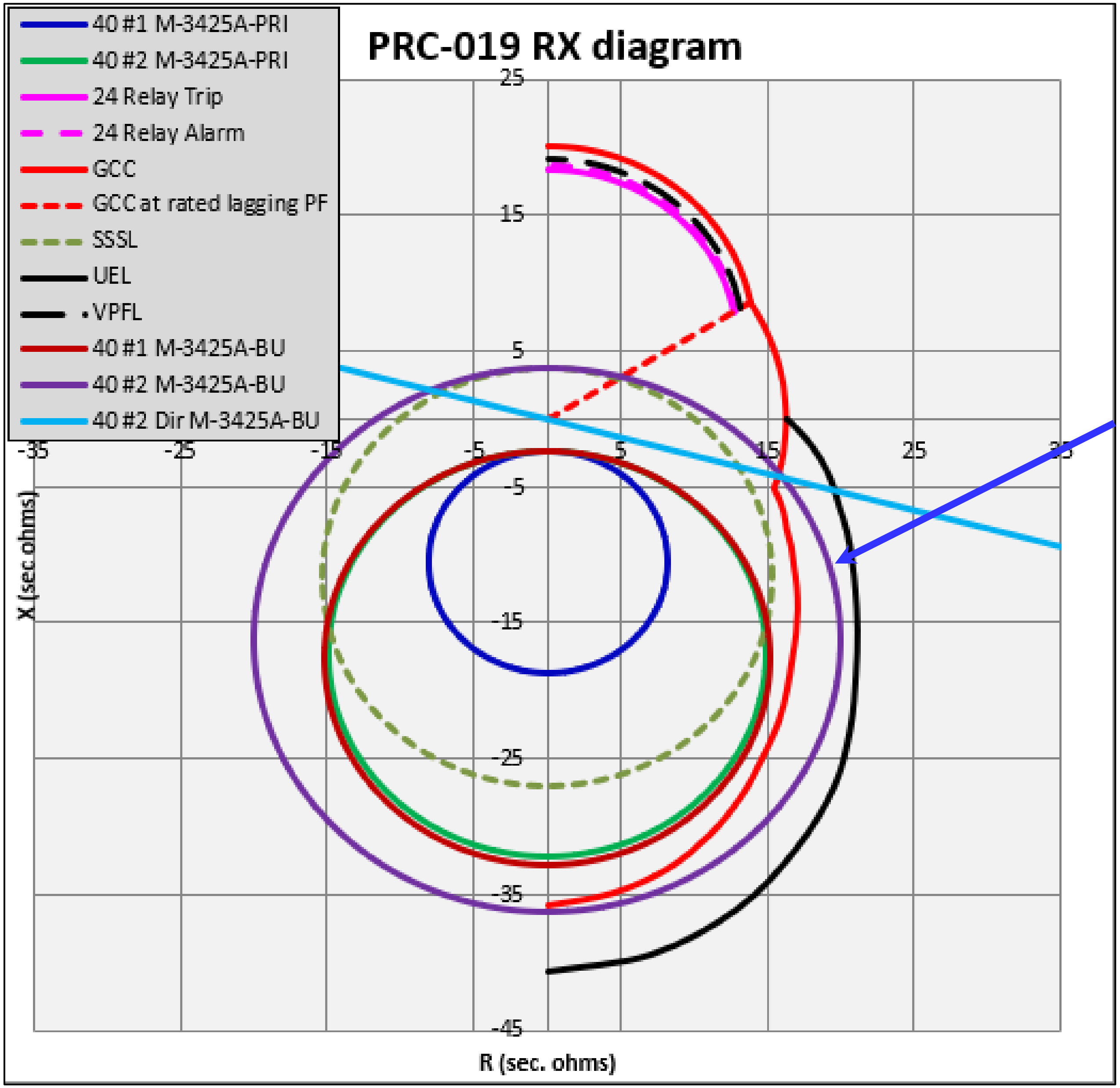
Positive Offset Zone 2 – Westinghouse – Approach 2



40: Loss of Field

- **Positive sequence quantities used to maintain security and accuracy over a wide frequency range.**
- **Must work properly from 50 to 70 Hz (60 Hz systems) Required to operate correctly (and not misoperate) with wide frequency variations possible during power swing conditions.**
- **May employ best of both methods to optimize coordination.**
  - Provide maximum coordination between machine limits, limiters and protection
  - Offset mho for Z1. Fast time for true Loss of Field event.
  - Impedance with directional unit and slower time for Z2. Better match of machine capability curve. Also, able to ride through stable swing.
  - May employ voltage supervision for accelerated tripping of Z2 (slower zone) in cases of voltage collapse where machine is part of the problem, importing VArs.

PRC-019-2



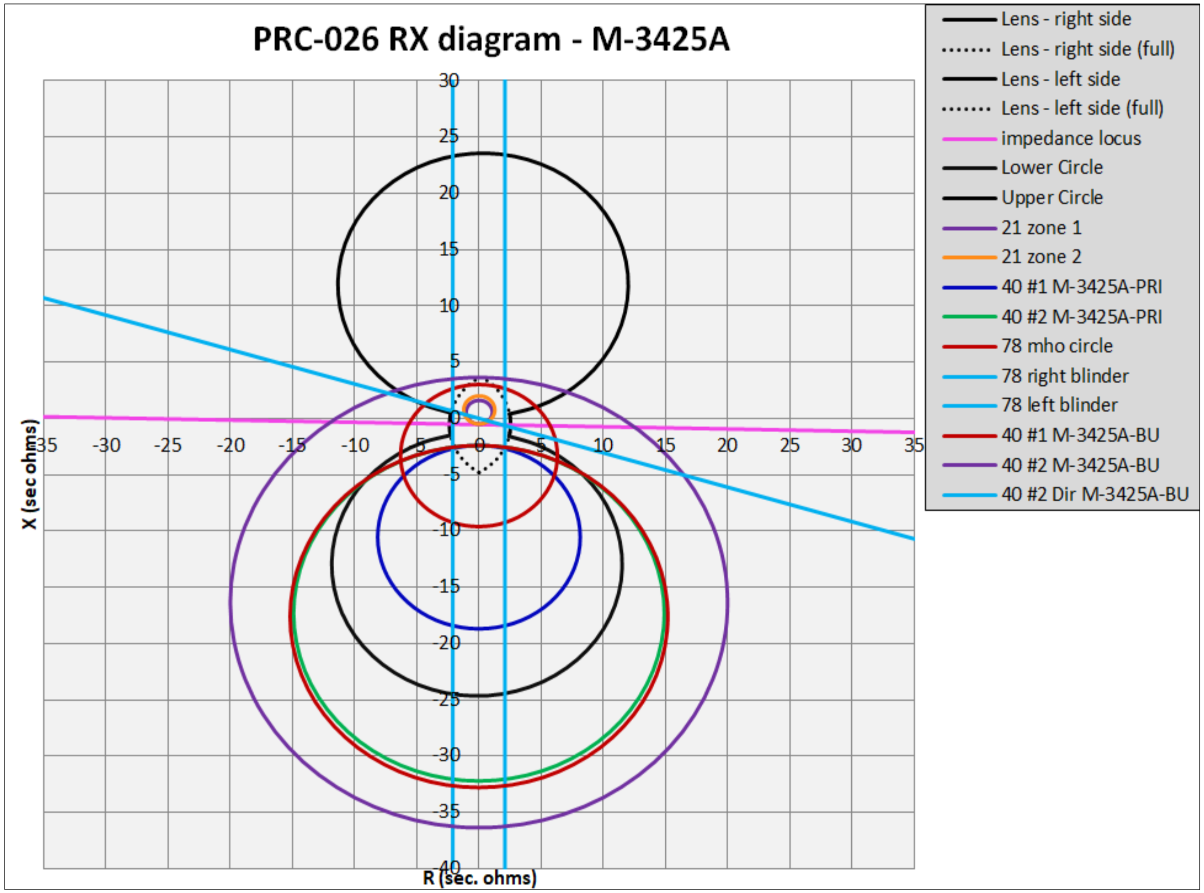
The positive offset zone 2 method allows full coverage or plots outside of the GCC and SSSL, while it plots inside the UEL; therefore,

YES

these settings do comply.

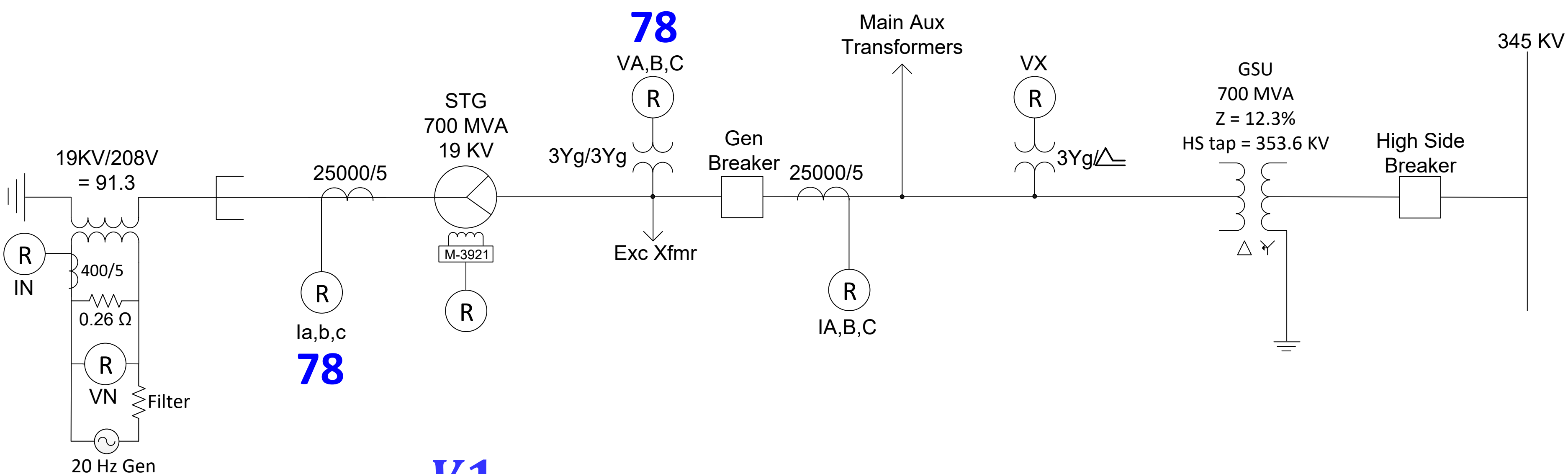
PRC-026-1

Plot the 40 mho circle settings on an RX diagram along with the unstable power swing region impedance locus criteria for this application



- 3 of the 4 LOF mho circles plot outside the unstable power swing region.
- For those must instead comply using time delay criterion i.e. all time delays must be ≥ 15 cycles.
- 40 #1 PRI does plot inside the unstable power swing region so it can be set with a time delay < 15 cycles if required.

78 – Out of Step (Loss of Synchronism, Pole Slipping)



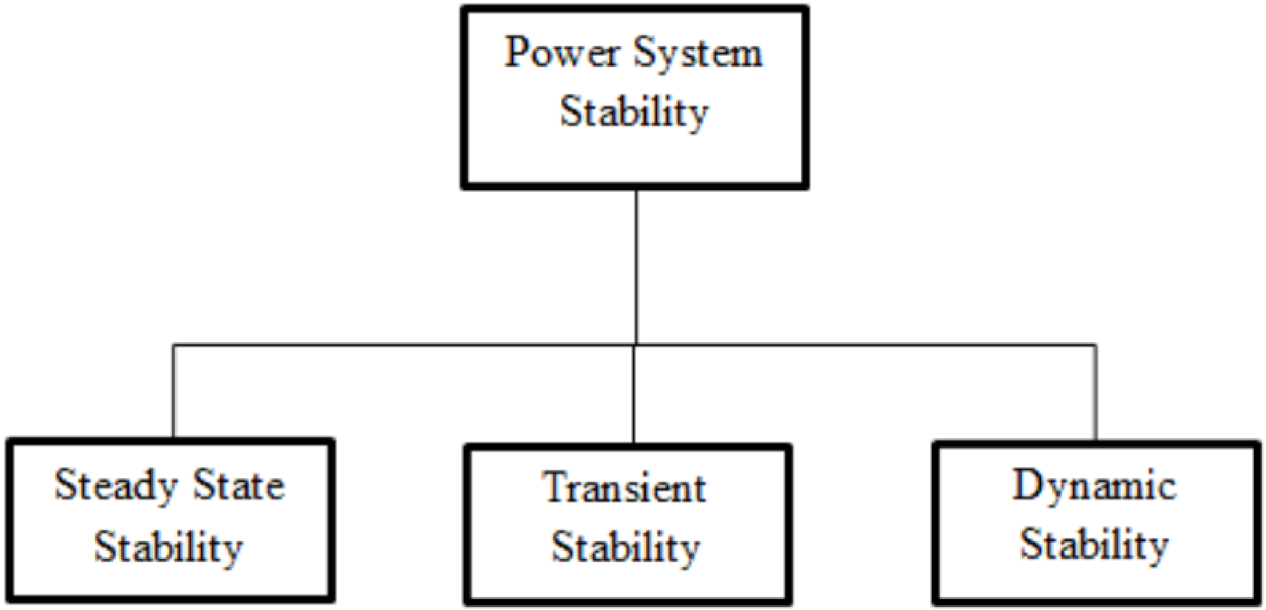
$$Z1 = \frac{V1}{I1}$$ *(uses positive sequence impedance for security)*

- Protection from the generator and system going unstable.
- Operates on the swing path of the impedance locus which represents the voltage angle difference between the gen and system (aka rotor angle, torque angle, load angle, power angle, system separation angle).

Generator Out-of-Step Protection (78)

Types of Stability

(ability of the system to remain stable)



Generator Out-of-Step Protection (78)

1) Steady State:

- Response of generator to gradual load increase.
- SSSL (Steady State Stability Limit), Steady Voltage and Impedance, Load Flow Studies.

2) Transient (used for 78 settings and CCA/CCT):

- Response of generator to large disturbances causing the impedance to swing.
- The system's response to such a disturbance is usually evident in < 1 second.
- The transmission lines must clear the fault in a certain time for the system to remain stable.
- This time is referred to as the Critical Clearing Time (CCT) that informs the 50BF timer setting.
- CCT is derived from the Critical Clearing Angle (CCA), which informs the 78 setting criteria.
- The CCA is the system separation power angle at which point recovery is not possible.
- Transient stability study produces CCA and CCT (although can calculate by hand).

3) Dynamic:

- Response of generator to small oscillations (usually very low frequency).
- Power System Stabilizer (PSS) may be needed to dampen the oscillations.
- If these oscillations decrease in amplitude, the system is considered dynamically stable.
- If oscillations grow in amplitude, the system is dynamically unstable (may take 10-30 seconds).

Generator Out-of-Step Protection (78)

Causes:

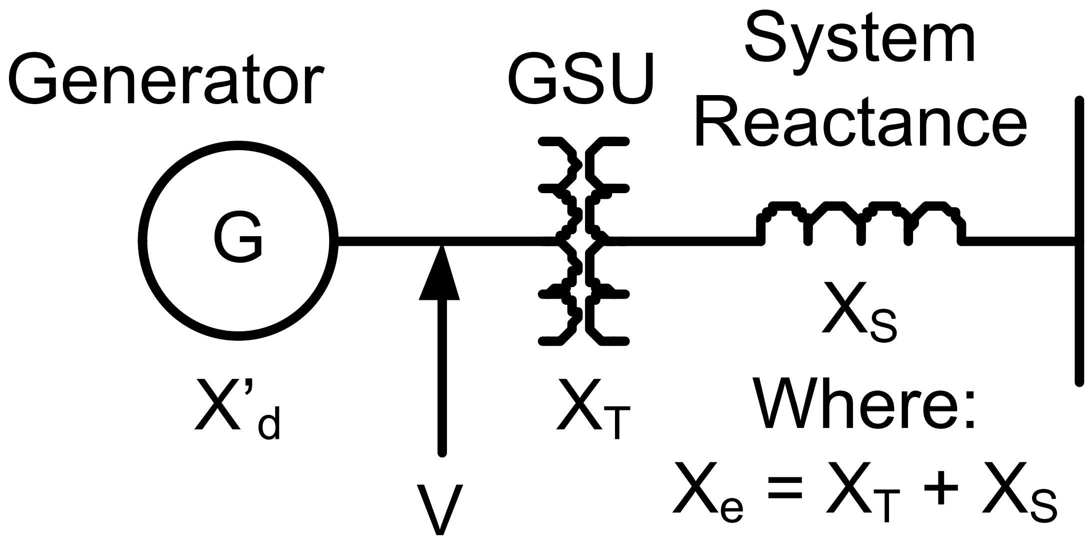
- Faults that are severe and close to the generator
- Switching of nearby transmission lines
- Loss of lines leaving plant (raises impedance of loadflow path)
- Large load losses/gains after the system breaks up to clear fault
- Problems with excitation (open/short ckt, faulty controls, etc)
- Improper synchronizing
- Insufficient transient stability

Generator Out-of-Step Protection (78)

Effect:

- Mechanical input & electrical output power balance is disrupted.
- Rotor accelerates or decelerates, changing the power transferred, rotor speed, and rotor angle.
- Generator and prime mover can experience large transient torques and high currents, damaging shaft, prime mover, stator windings.
- If the pole slip frequency approaches natural shaft resonant frequency, torque can break the shaft.
- High stator core end iron flux can overheat and short the gen stator core.
- GSU also subject to high transient currents and mechanical stresses.
- System instability from power swings can cause cascading outages.

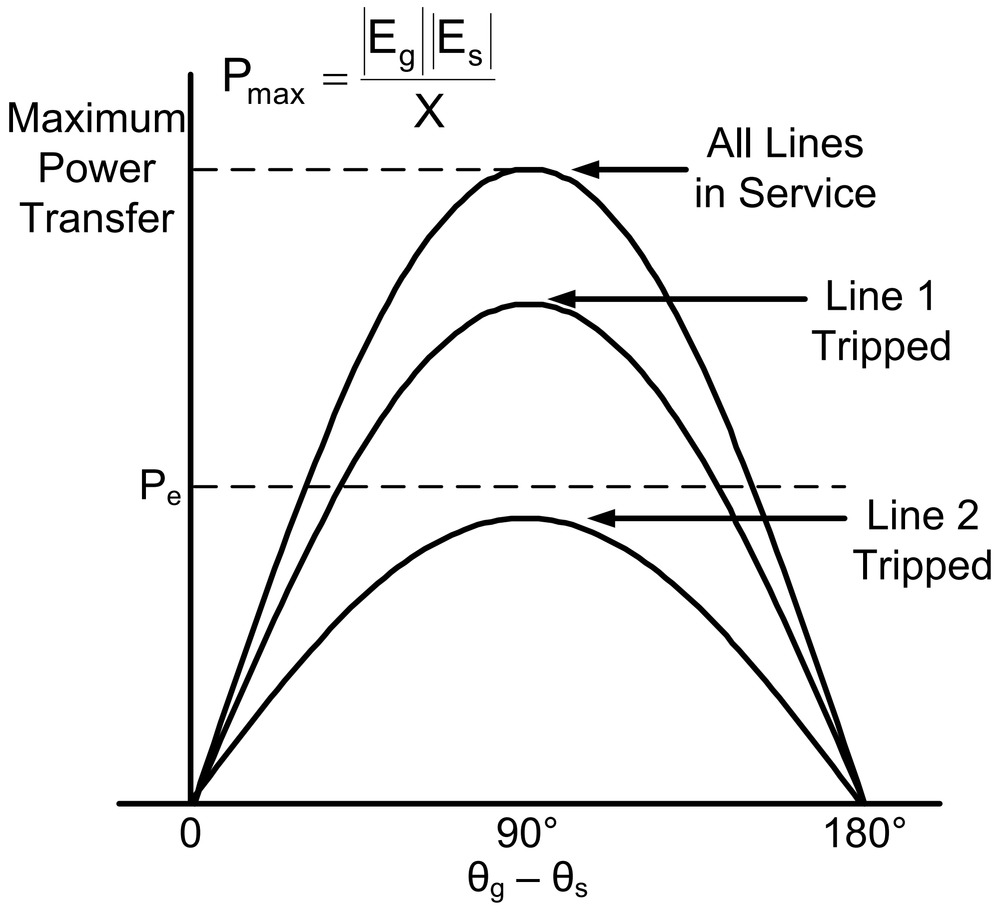
Out of Step:
Generator and System Issue



Power Transfer Equation

$$P_e = \frac{|E_g||E_s|}{X} \sin(\theta_g - \theta_s)$$

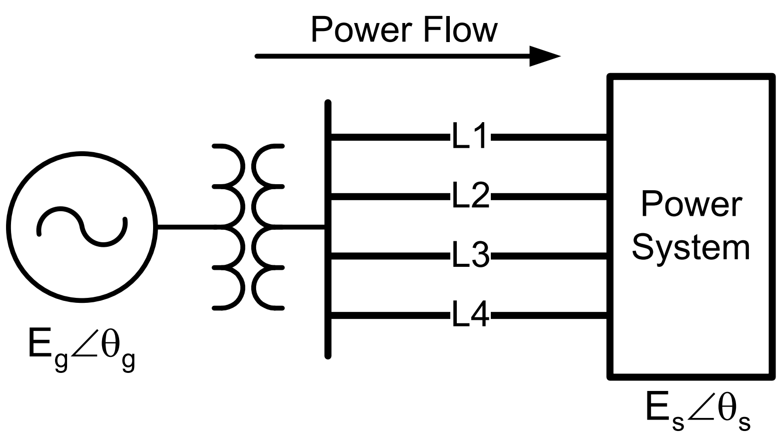
Stability



Power Transfer Equation

$$P_e = \frac{|E_g||E_s|}{X}\sin(\theta_g - \theta_s)$$

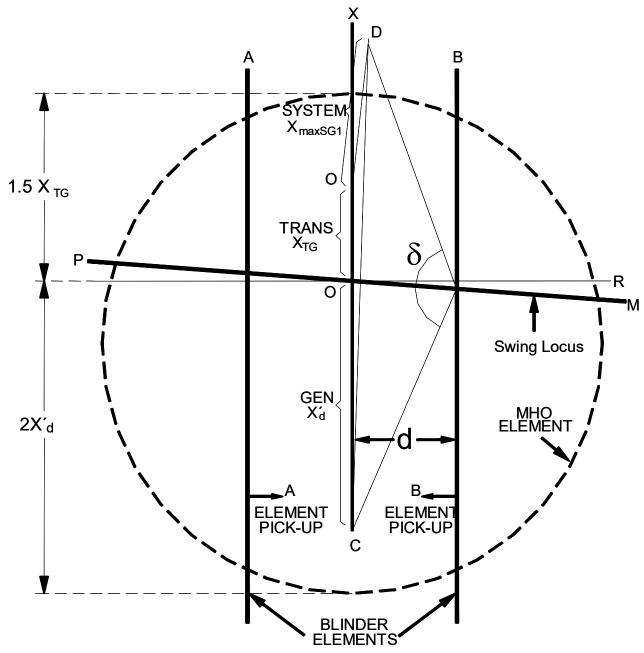
E_s - System Voltage
E_g - Generator Voltage
Θ_s - System Voltage Phase Angle
Θ_g - Generator Voltage Phase Angle
P_e - Electrical Power

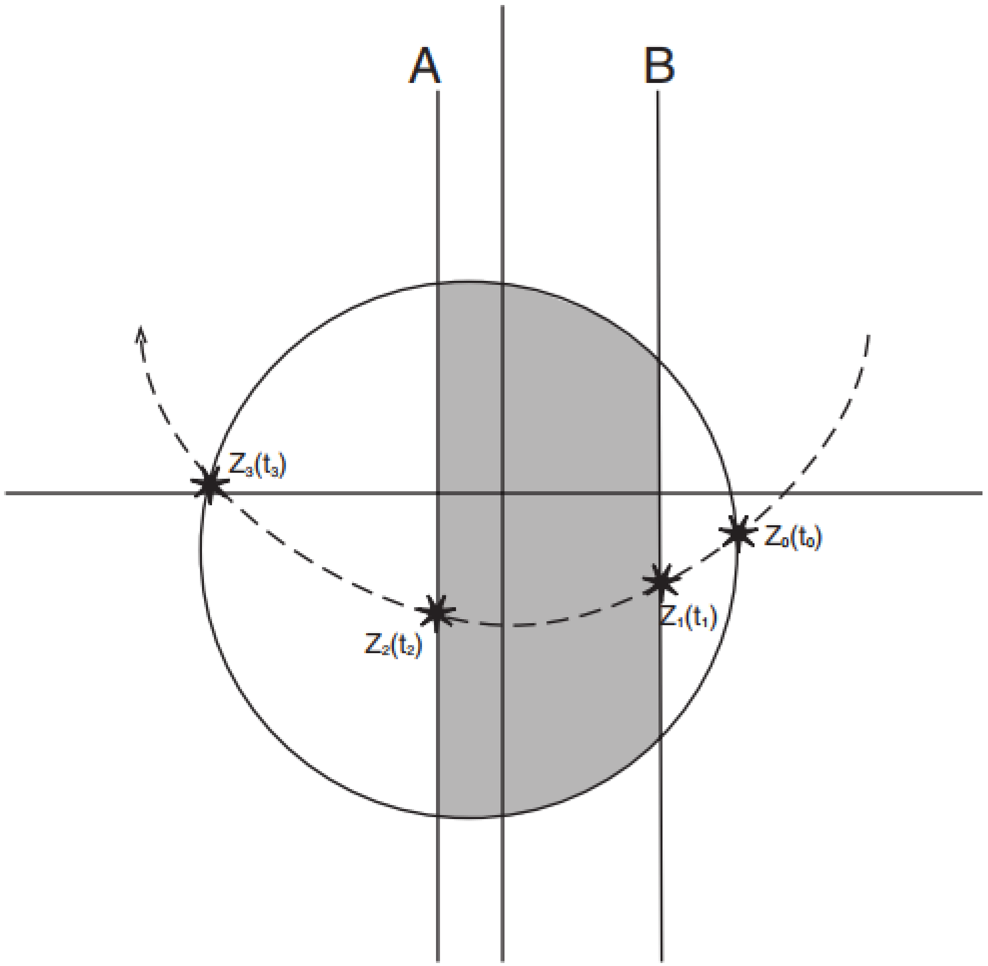


For maximum power transfer:

- *Voltage of GEN and SYSTEM should be nominal – Faults lower voltage*
- *Impedance of lines should be low – lines out raise impedance*

78 – Out-of-Step Protection Characteristic





- Protects for unstable swings with the electrical center of the power system disturbance (represented by the impedance locus) passing through the generator or GSU.

78 – Out of Step

- ***The logic distinguishes between a stable and unstable swing by monitoring the entry and exit path of the swing impedance loci.***

- ***For trip initiation, the swing impedance must first enter the mho function from outside then traverse both blinders in sequence.***

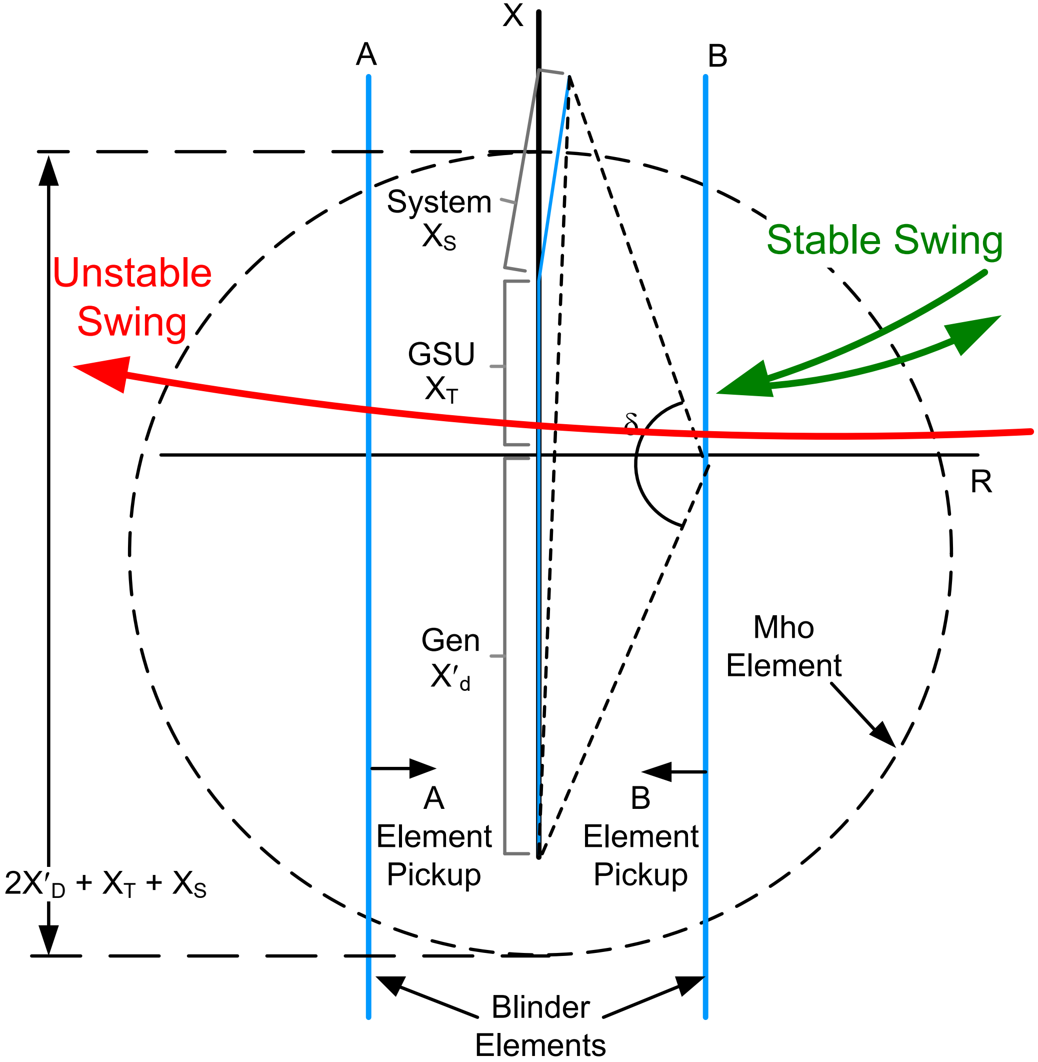
- ***For a gen/GSU fault, the loci will penetrate between the blinders, but never exit the left hand blinder and then the appropriate protective function will quickly trip off the unit.***

- ***The stable swing will cross one blinder, but never the other, then it will exit out the first blinder that it entered.***

78 – Out of Step

- The advantage of this scheme is its security as it will only operate for an unstable swing.
- But because both blinders must operate in sequence (i.e. the impedance path must exceed the 180 degree separation); the scheme ensures that the generator, prime mover, and GSU are exposed to the maximum out-of-phase current of at least one slip cycle i.e. the machine has slipped a pole.
- The impedance measurement starts at the generator VT location (origin of the RX diagram) just as it does in the distance function.
- The forward reach is defined as into the generator (down into the third and fourth quadrants with the generator VT's at the origin).
- The reverse reach is defined as towards the GSU and out onto the system (up into the first and second quadrants).
- This is dictated by the CT and VT polarity marks if wired as shown in the Instruction Book.

Graphical Method: 78



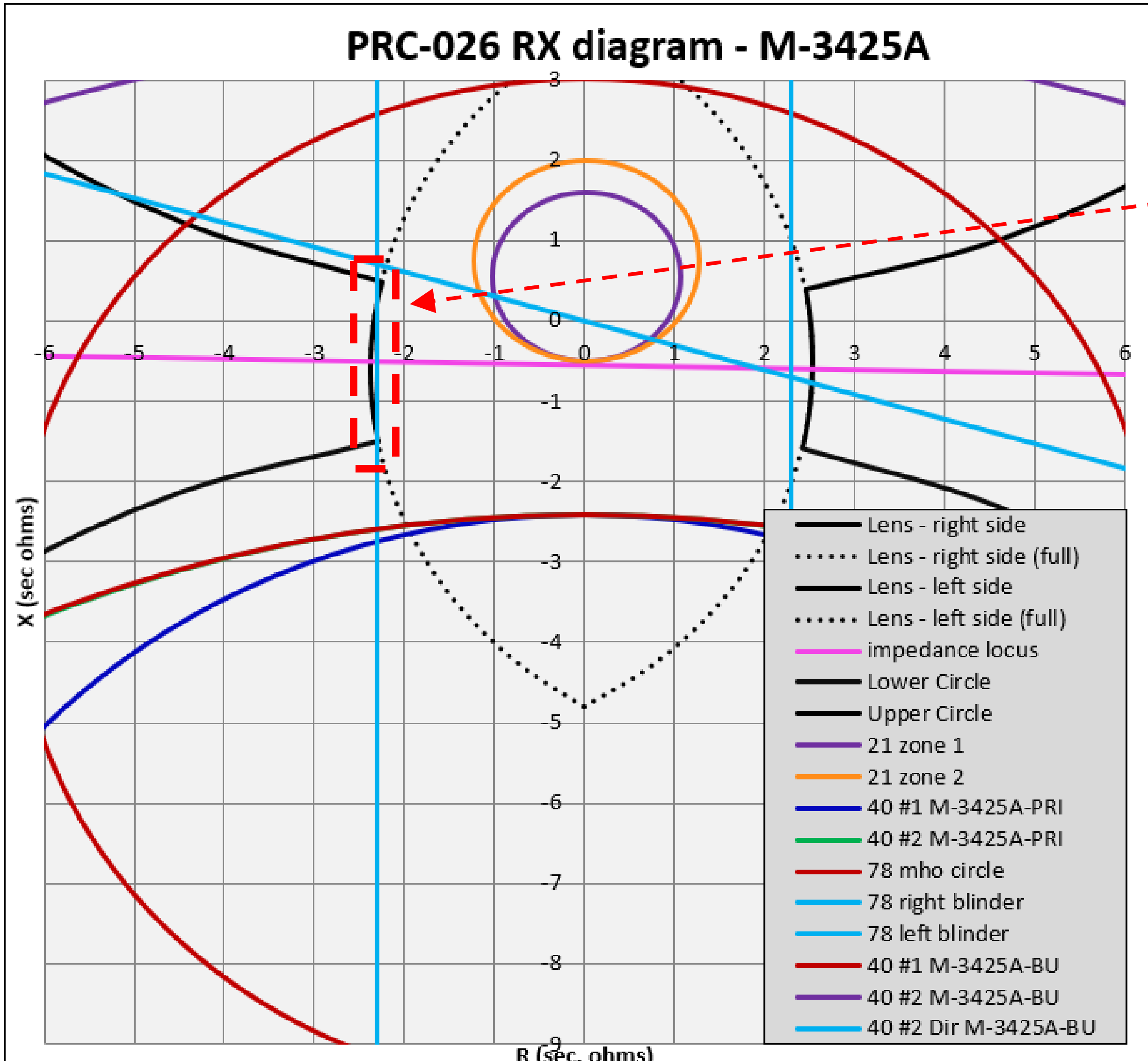
Generator Out-of-Step Protection (78)

Dependability Concerns

- *Positive sequence quantities used to maintain security and accuracy over a wide frequency range.*
- *Required to operate correctly (and not misoperate) with wide frequency variations possible during power swing conditions*
  - *Must work properly from 50 to 70 Hz (60 Hz systems).*

PRC-026-1

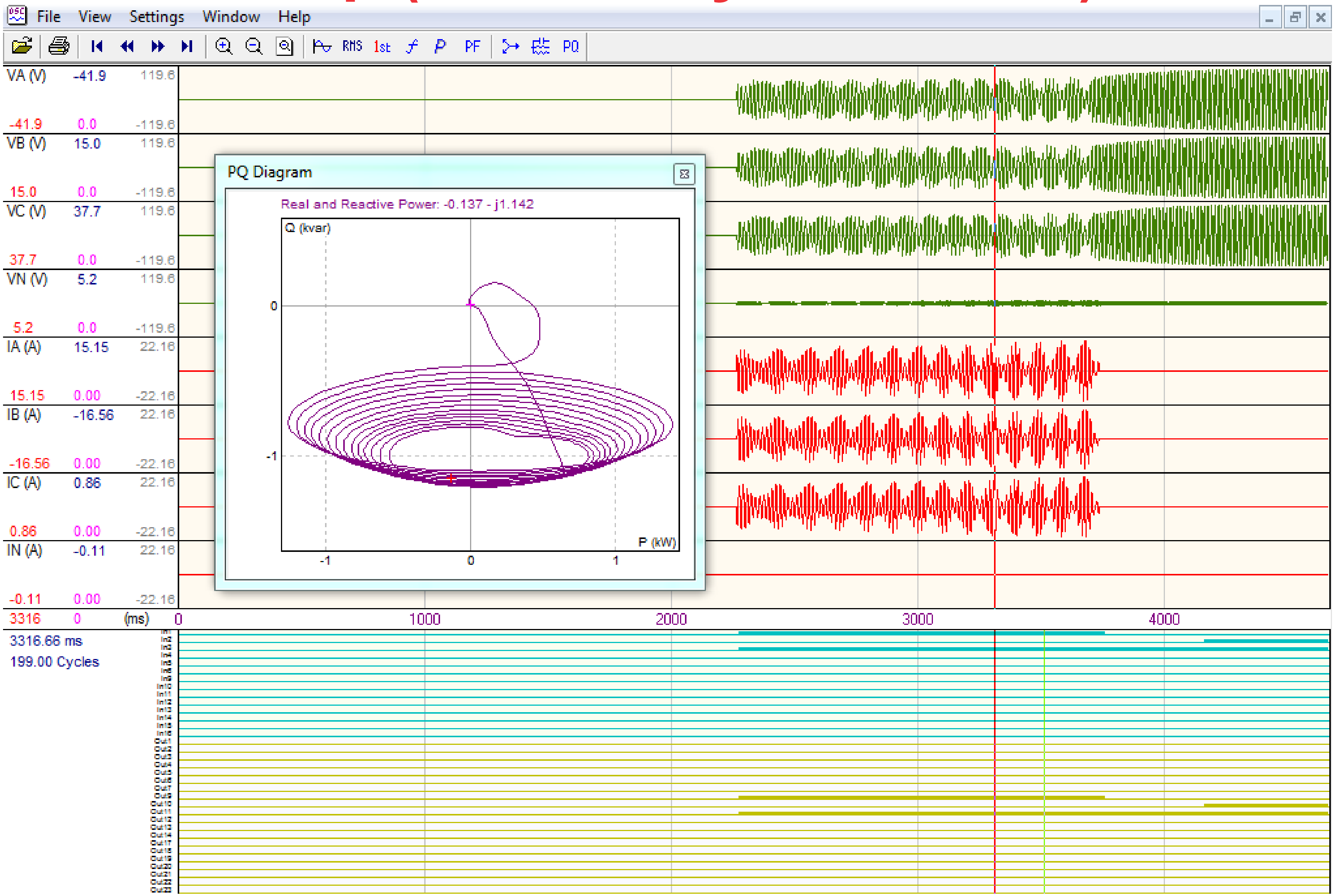
Zoomed in around the origin:



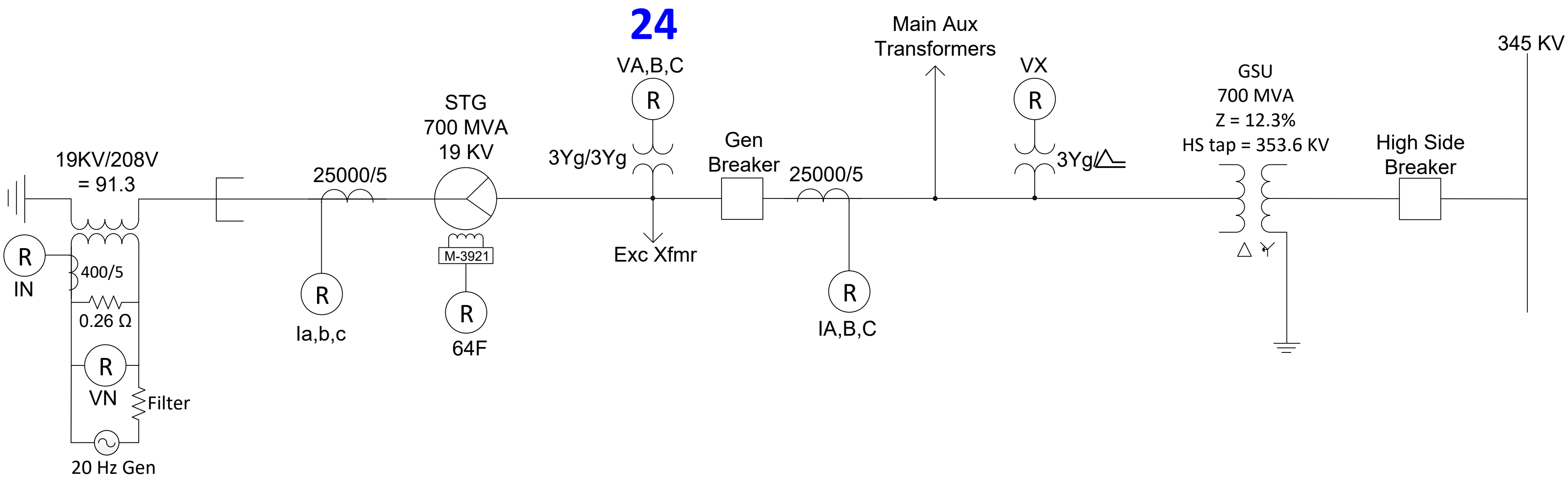
Notice, if Xd'saturated is used in the blinder calcs that the 78 blinders will typically plot slightly outside of the unstable power swing region, therefore these blinders settings would not allow compliance with this standard.

So must pull in the blinders (add cheat factor) or use Unsaturated Xd' in blinder equation, although PRC-026 says to use Saturated value.

Out-of-Step (Loss of Synchronism) Event



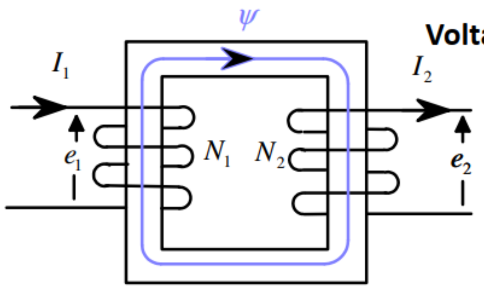
24 – Volts/Hz (Overexcitation)



$$B = \frac{Volts}{Hz}$$

- *Excessive B (magnetic flux density) causes overexcitation*
- *frequency measured from voltage waveform*
- *Recommend to set both 24 and 59 functions.*

24 – Volts/Hz (Overexcitation)



Voltage developed in generator or transformer winding

$$e = N\frac{d\varphi}{dt}$$

$$\varphi_{\max} = \frac{\sqrt{2}E_{RMS}}{N2\pi f}$$

$$\varphi \propto \frac{V}{f}$$

Volts/Hz

$$A = \frac{\varphi_{\max}}{B_M}$$

Why don't we just operate based on the flux density?

- ***It would be difficult to measure.***
- ***Instead, use V/Hz as that is proportional to flux and easy to measure.***

24 – Volts/Hz (Overexcitation)

- Generators require an internal magnetic field to operate.

- An overexcitation condition occurs when the flux levels exceed design limit, and the stator core becomes saturated where stray flux is induced in non-laminated components, causing overheating and heat destroys insulation resulting in a fault.

- Overexcitation can occur with either an increase in voltage or a decrease in frequency or both:
  - e.g. if nominal V/Hz = 120V/60Hz = 2 V/Hz = 1pu, then in terms of per unit:

    ✓ V = 1.1 pu, f = 1.0 pu, V/f = 1.10 pu
    ✓ V = 1.0 pu, f = 0.9 pu, V/f = 1.11 pu
    ✓ V = 1.1 pu, f = 0.9 pu, V/f = 1.22 pu

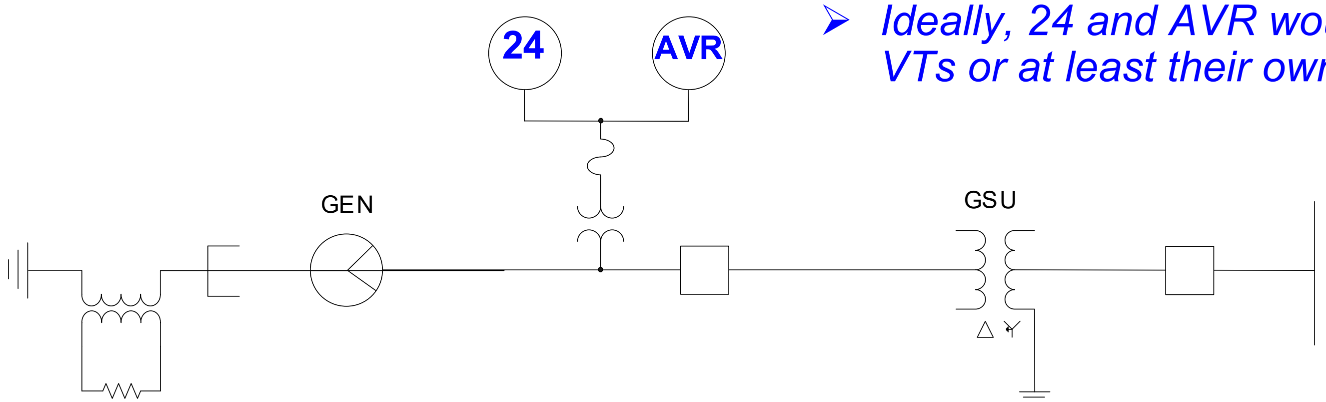
  - If gen running at 132 V at nominal frequency (with Vnom = 120 V):

$$\frac{\text{Volts}}{\text{Hz}}(\text{n}) = \frac{\frac{\text{measured voltage}}{\text{Nominal Voltage}}}{\frac{\text{derived frequency}}{\text{Nominal Frequency}}} * 100 = \frac{\frac{132\text{ V}}{120\text{ V}}}{\frac{60\text{ Hz}}{60\text{ Hz}}} * 100 = 110\ \%$$

24 – Volts/Hz (Overexcitation)

Causes of V/HZ Problems at Generating Plants

- ✓ Operational issues at reduced frequencies during startup
- ✓ Sudden loss of load
- ✓ Operator error with AVR in manual mode
- ✓ Excitation control system failure (AVR runaway)
- ✓ VT fuse loss of the AVR sensing voltage with no AVR FL logic or failure of the AVR FL transfer to backup voltages or switch to manual mode, so the AVR sees 0 V and boosts continuously
  - **Therefore, may not want to block 24 protection for FL if sourced from the same VTs and off the same fuses.**



- *Ideally, 24 and AVR would get their own VTs or at least their own branch fuses*

24 – Volts/Hz (Overexcitation)

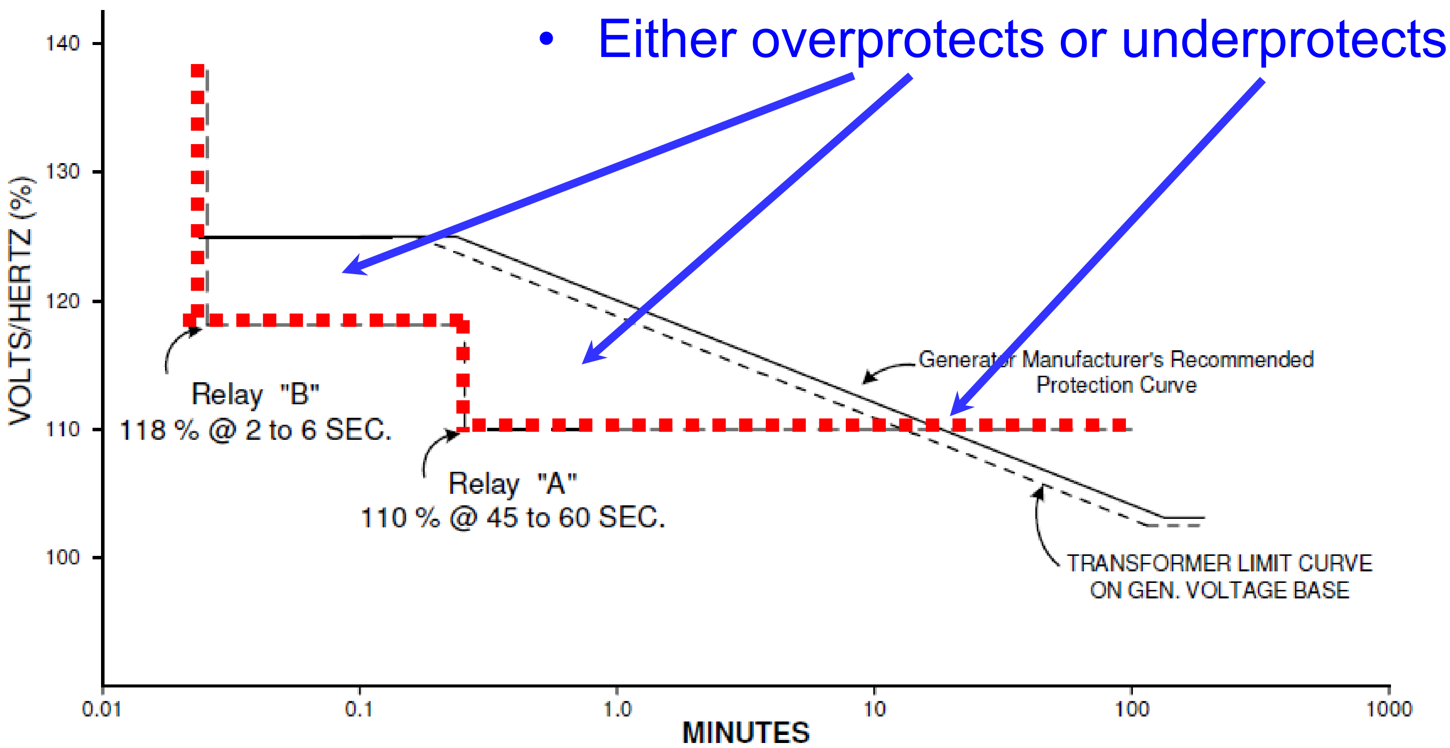
Causes of V/HZ Problems from Transmission Systems

- ✓ Unit load rejection: full load, partial rejection
- ✓ Power system islanding during major disturbances
- ✓ Shunt Reactor out, when it should be in-service
- ✓ Capacitors in-service, when they should be out
- ✓ Runaway LTCs
- ✓ Ferranti Effect – Voltage rise due to the charging current from the distributed capacitance on long transmission lines that are lightly loaded or if the breaker on the remote end opens, while the local breaker remains closed.

24 – Volts/Hz (Overexcitation)

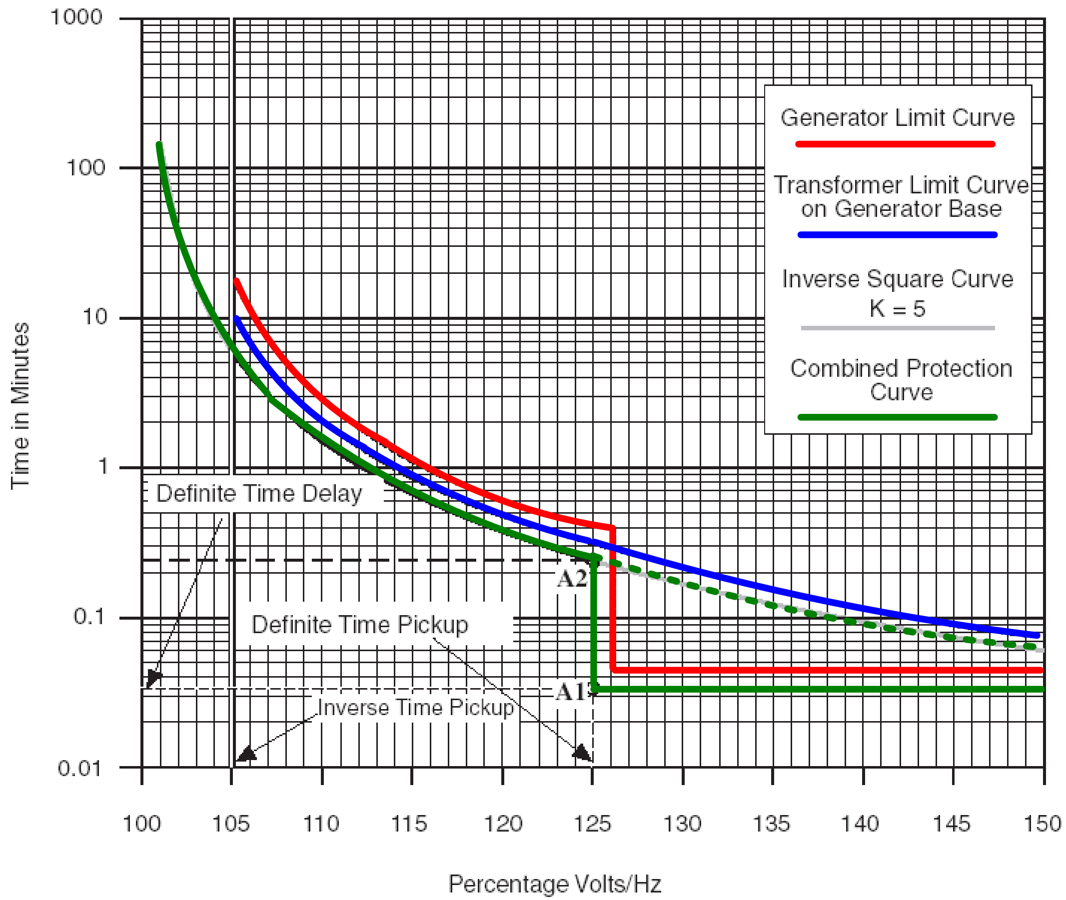
Legacy E/M Relays

- *May use single or dual Definite-Time V/Hz relays with instantaneous reset.*



24 – Volts/Hz (Overexcitation)

- ***Modern digital relays*** *have Inverse Time curves available.*
- *Example using 24 Definite Time along with 24 Inverse Time curve:*



- The **green** 24 Inverse Time curve more closely match the shape of the mfg **blue** GSU V/Hz damage curve and the mfg **red** Gen V/Hz damage curve.
- To protect for more severe overfluxing events, a Definite Time element is used with the Inverse Time element to trip faster or cut off the portion of the Inverse Time curve at higher V/Hz levels.
- Thermal Reset Timer emulates the machine's cool down time.

24 – Volts/Hz (Overexcitation)

- Check the frequency range for which the 24 relay element will provide protection (the 24 element in the M-3425A relay protects from 2-80 Hz) because V/Hz protection may be needed even at low frequencies as the unit is ramping up, e.g.:

  if V = 10 V, f = 2 Hz, then V/f = (10/120)/(2/60) = 2.5 pu **(or 250%)**

  - Frequency can be as low as 2 Hz during startup/shutdown e.g. during rotor pre-warming, LCI starting, converter starting, static starting, etc.

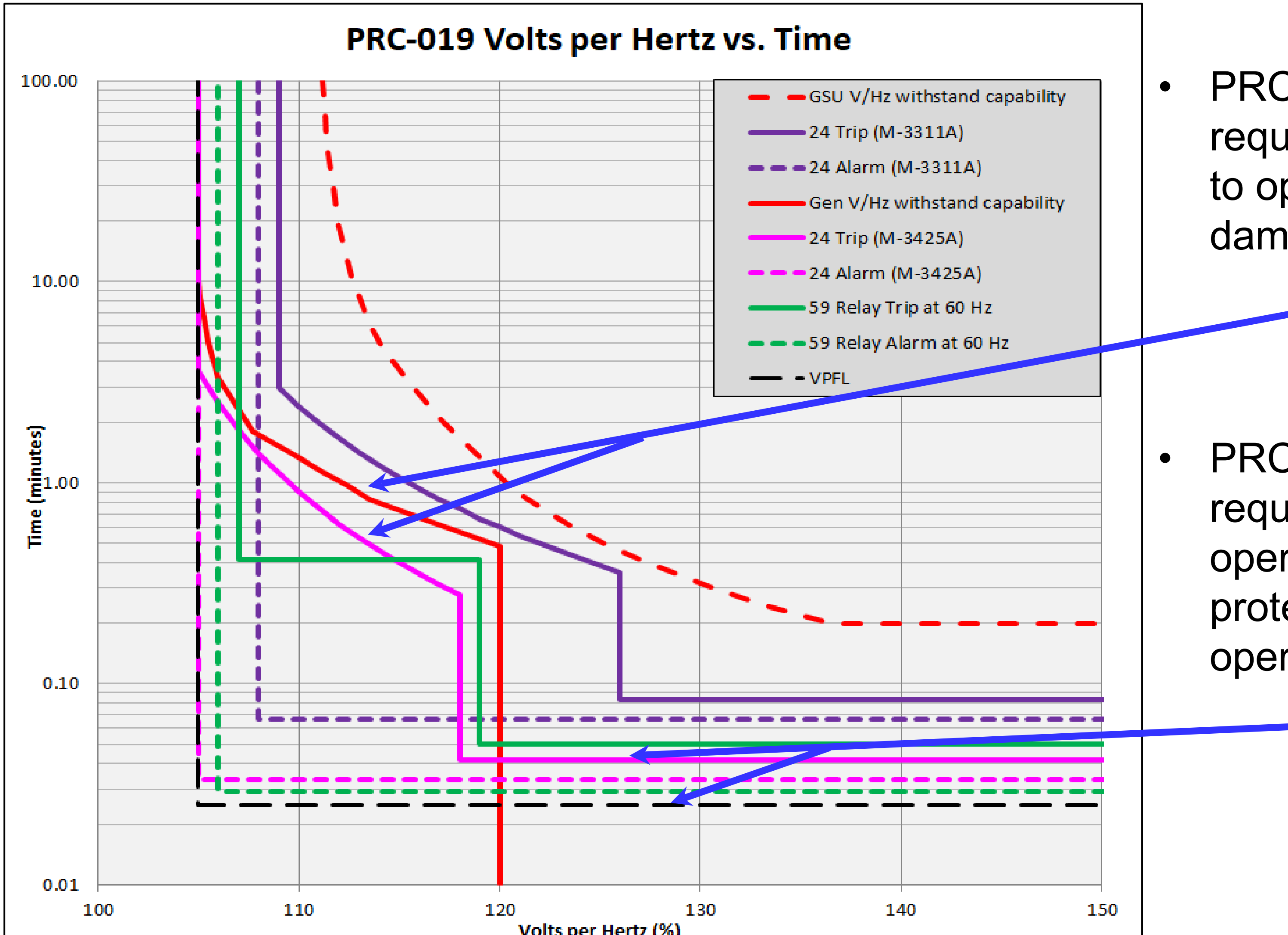
NOTE:

- During full load rejection at a hydro the unit can experience high speed and high frequency up to 120 Hz so the derived V/Hz will be too low (e.g. 50% if V/Hz = 1pu/2pu) for the 24 element to protect.
- Solution: Use 59 overvoltage protection as well as the 24 elements.
- Check that the relay's 59 function is designed to work up to 120 Hz to cover full load rejection scenarios (the 59 element in the M-3425A relay protects from 10-160 Hz.

24 – Volts/Hz (Overexcitation) compliance with PRC-019

even if not a BES plant, still coord 24 curve with V/Hz damage curves and VPFL.

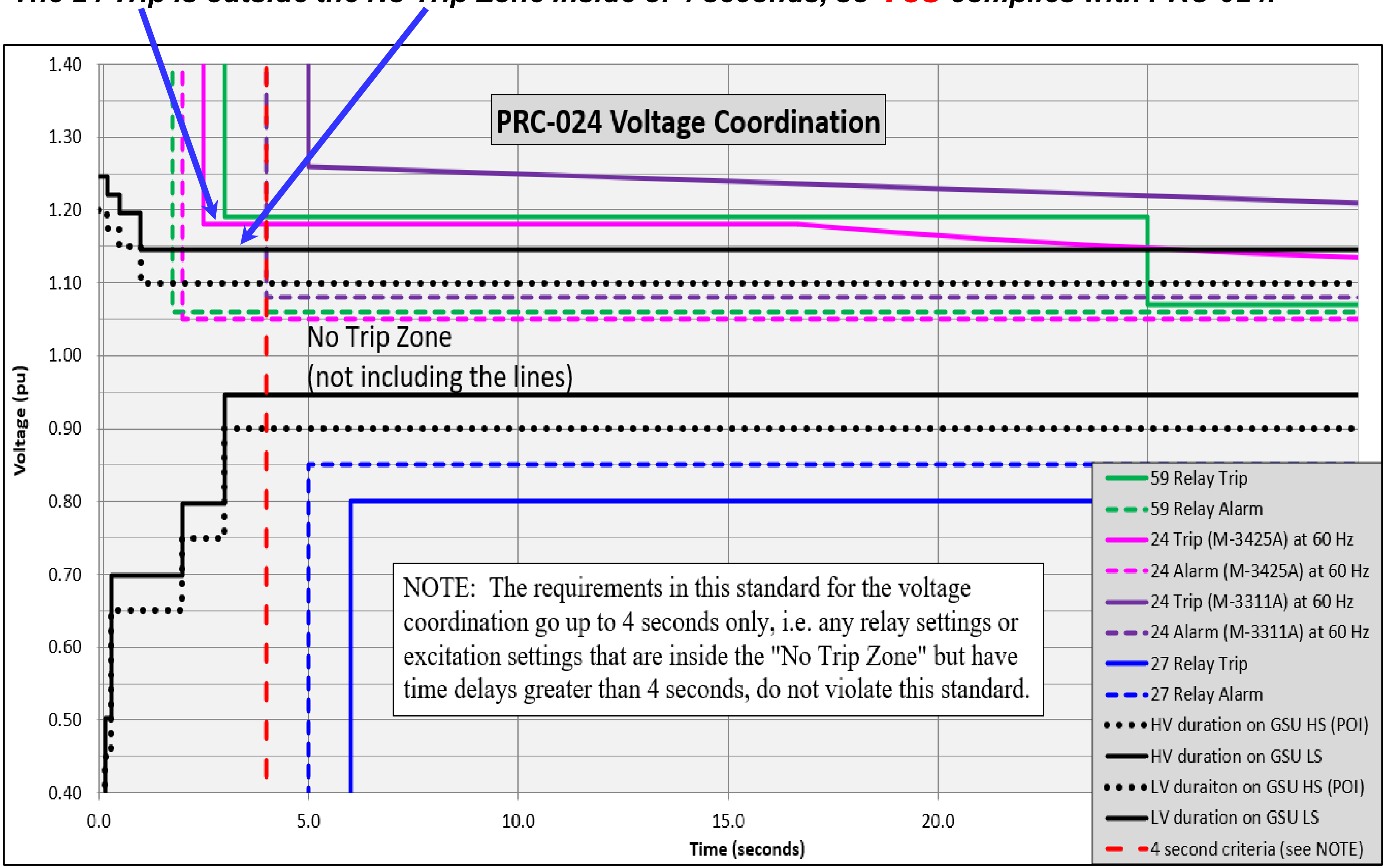
Plot 24 relay settings along with Gen V/Hz capability and V/Hz Limiter (VPFL)



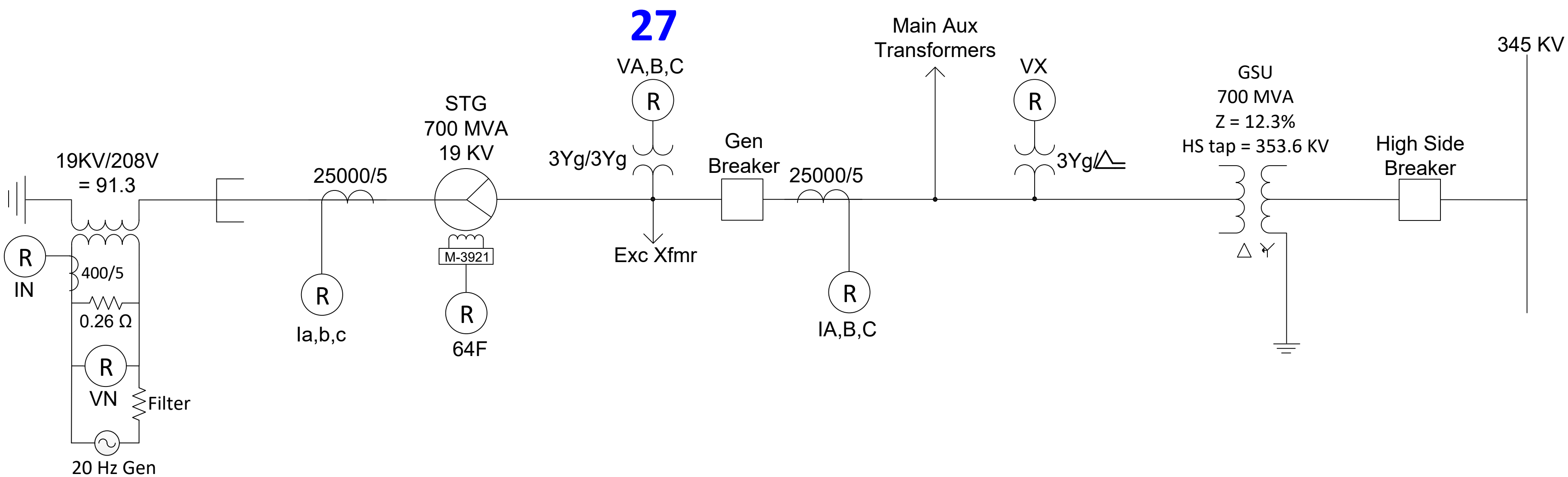
- PRC-019 Standard requires protection to operate before damage occurs:
- PRC-019 Standard requires Limiter to operate prior to protection operation:

24 – Volts/Hz (Overexcitation) compliance with PRC-024

The 24 Trip is outside the No Trip Zone inside of 4 seconds, so Yes complies with PRC-024.

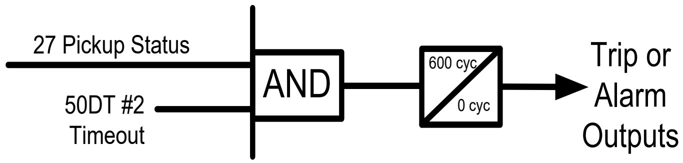


27 – Phase Undervoltage



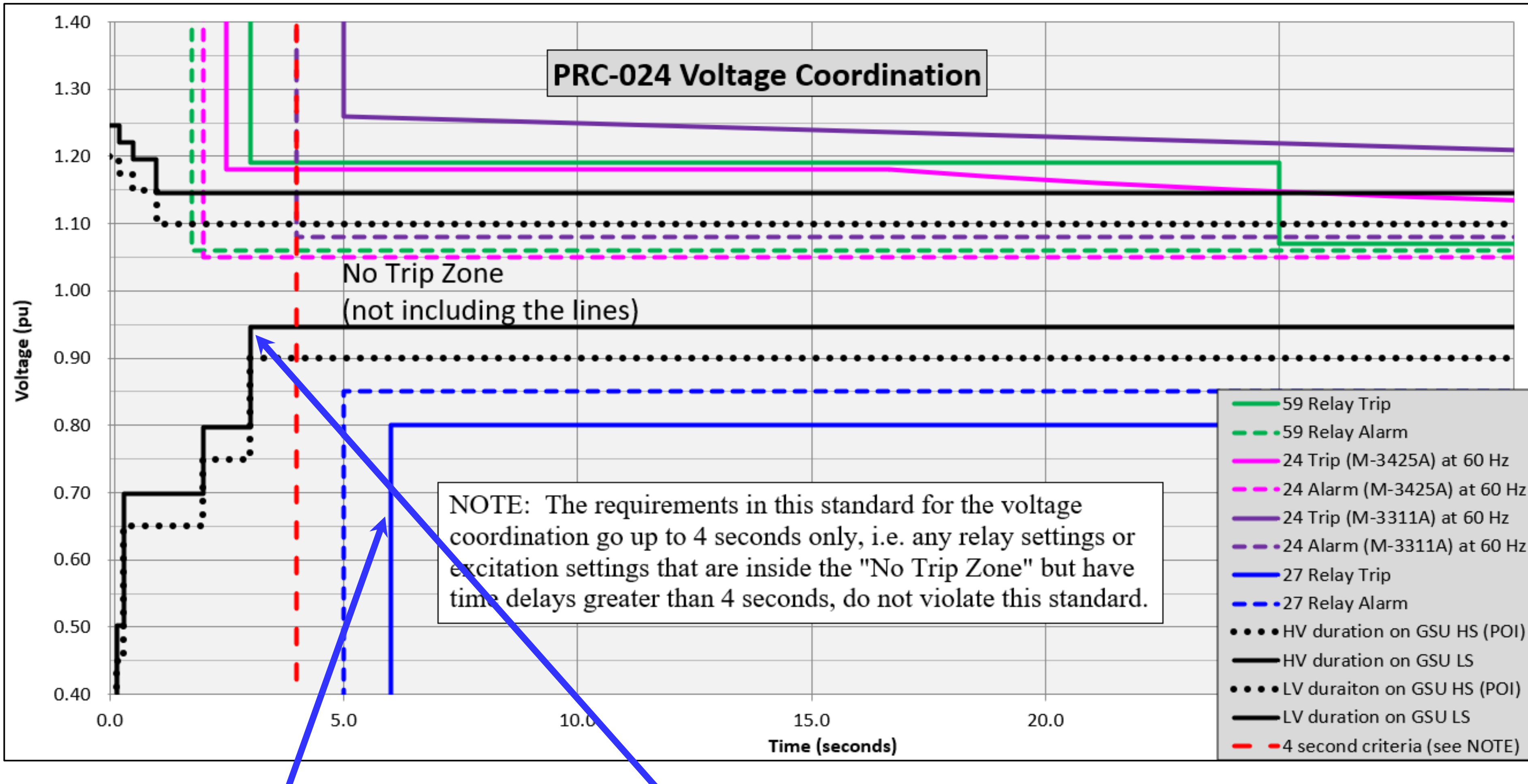
27 – Phase Undervoltage

- Generators are usually designed to operate continuously at a minimum voltage of 95% of its rated voltage, while delivering rated power at rated frequency.
- They will operate at decreasing voltages for decreasing times, but low voltage generally does not cause generator damage as the limitation will be with the dropping of the plant aux loads.
- IEEE C37.102 recommends to only alarm, but can trip as well.
- But must coordinate properly, i.e. set long time delay.
- Security: Set it long enough to ride thru system faults and block for blown fuse and for an open breaker.
- To avoid false trips while doing the cold commissioning (with the unit off-line), supervise with a low set overcurrent element; however then 50 Target will be normally asserted which could be an operational nuisance.



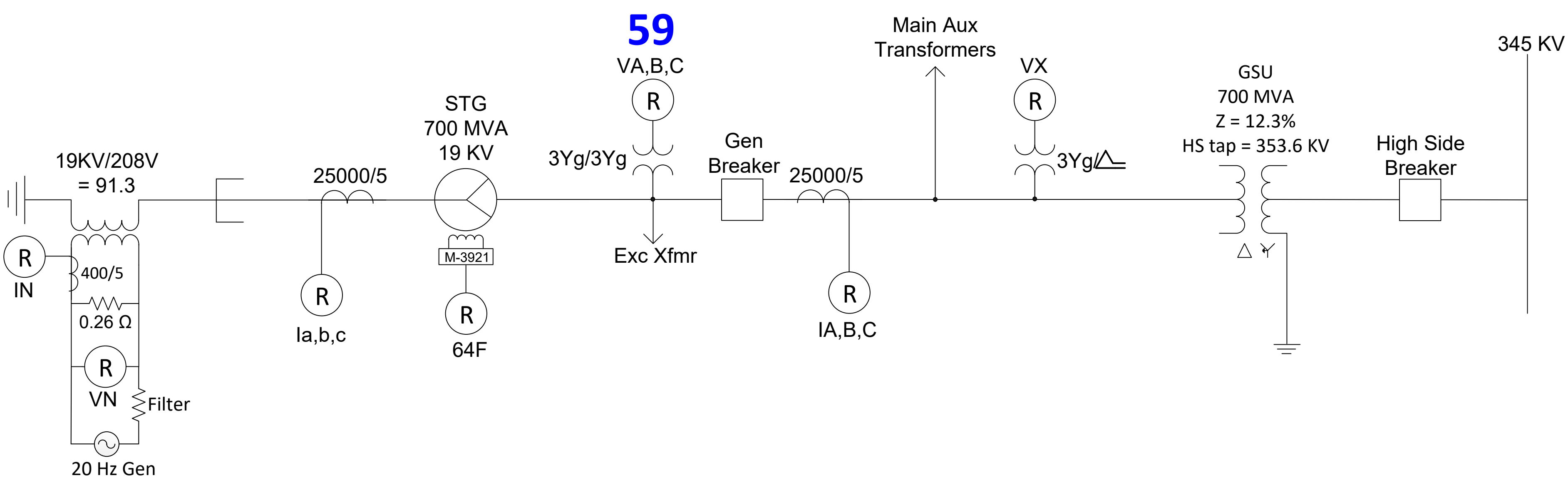
27 – Phase Undervoltage compliance with PRC-024

Plot the 27 settings versus the PRC-024 voltage duration criteria:



As the 27 Trip is outside the "**No Trip Zone**" criteria for the first 4 seconds, the chosen settings are verified to be **OK**

59 – Phase Overvoltage



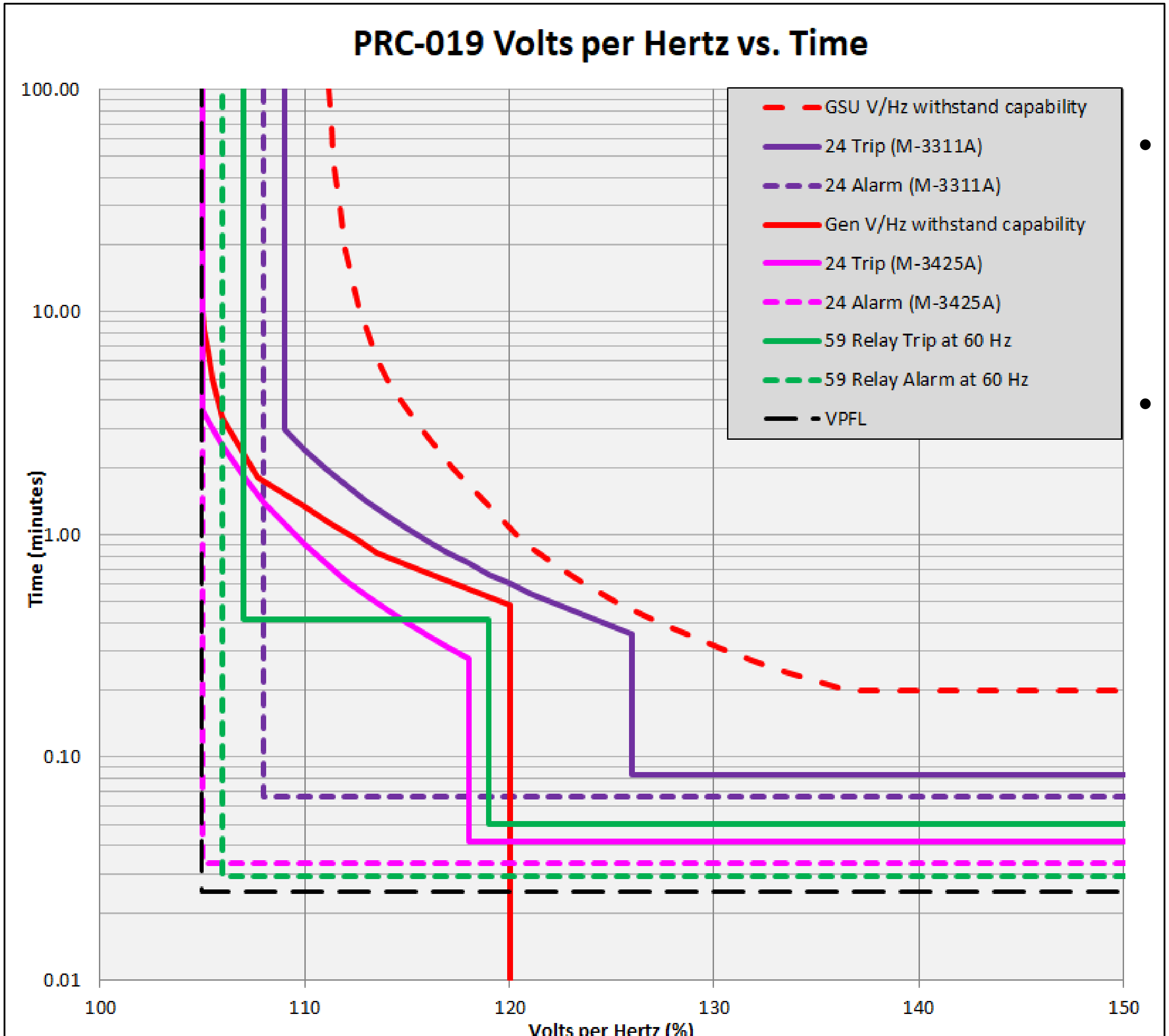
Recommend to set both 24 and 59 functions.

59 – Phase Overvoltage

- Generator overvoltage may occur without necessarily exceeding the V/Hz limits of the machine.
- Overvoltage is usually caused by sudden load rejection or AVR failure.
- For combustion turbines, this problem is typically mitigated by the fast response of the speed control system and the AVR;
- however, this protection is still warranted for the case of the failure of the speed control or AVR.
- This 59 settings should be coordinated with (set above) the volt-time characteristic of the exciter control to give the exciter control a chance to correct the voltage first.
- Generators are designed to operate continuously at 105% of the rated voltage.
- Overvoltage condition can cause over fluxing and also can cause excessive electrical stress.

PRC-019-2

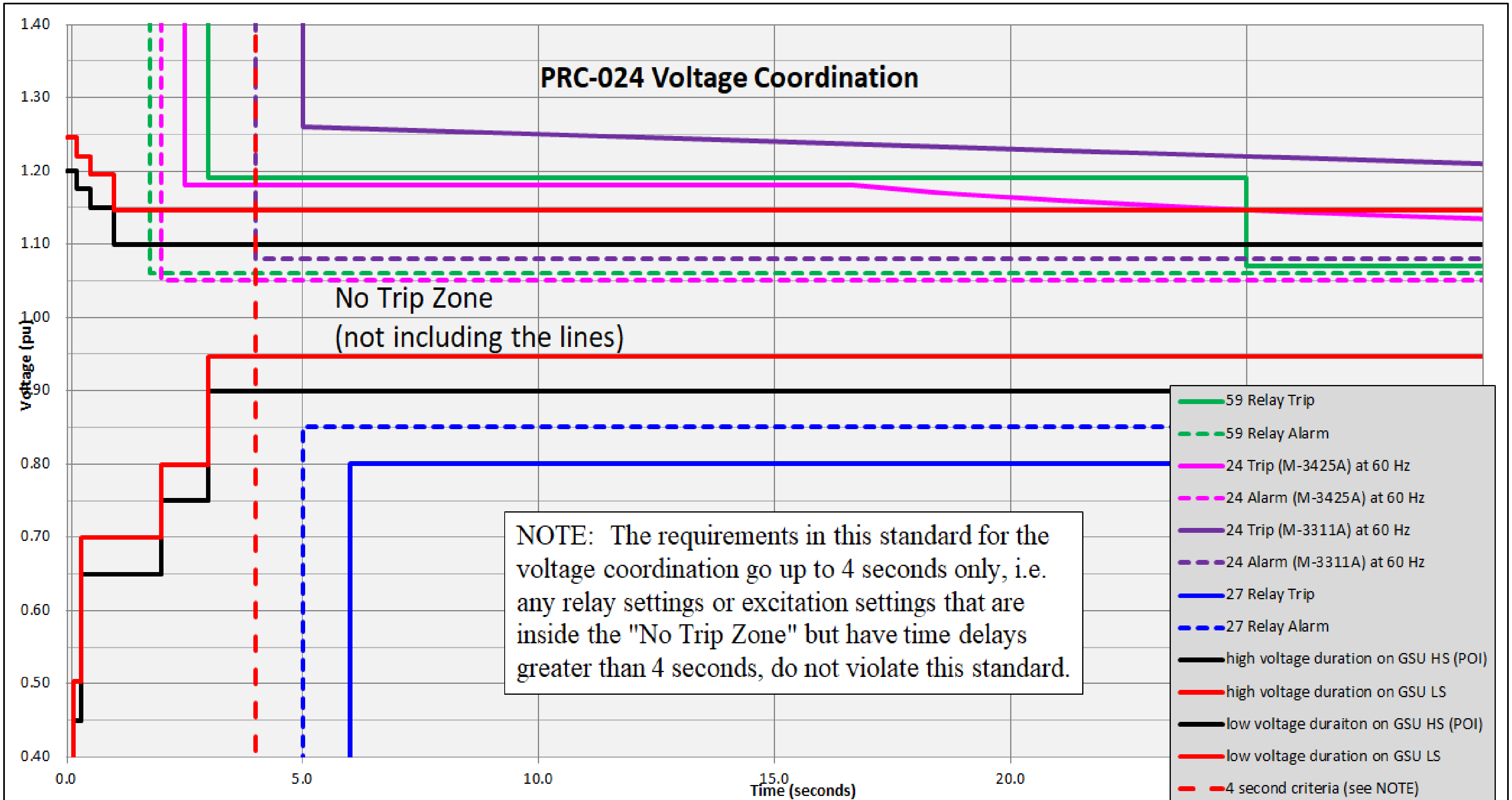
Plot of the 59 settings at 60 Hz with the Gen V/Hz capability curve, VPHL, and 24 settings:



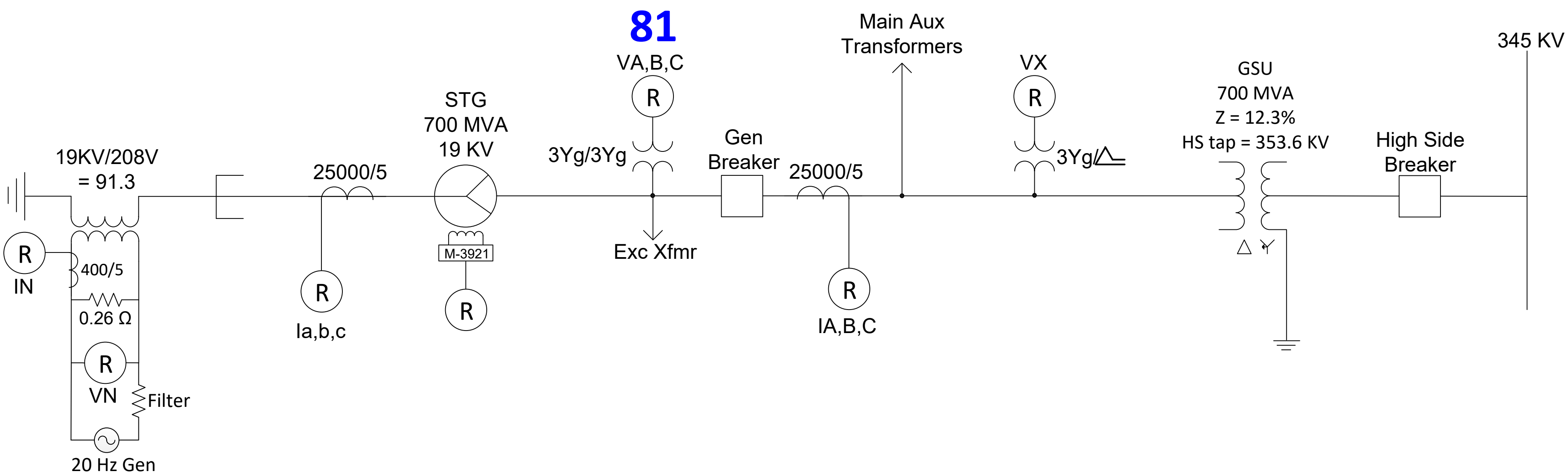
- Standard requires Limiter to operate prior to protection:
  - **YES**
- Standard requires protection to operate before damage occurs:
  - **Yes**

PRC-024-2

- Plot the 59 settings versus the voltage duration criteria
- As the 59 settings **(green curve)** plot above the “No Trip Zone” **(red curve)** criteria for the first 4 seconds, the chosen settings are verified to be **OK**



81 – Over/Under Frequency (also 81A and 81R)



Frequency derived from measured voltage waveforms

81 – Over/Under Frequency

- The intent is to keep generation on as long as possible during frequency excursions without damaging the machine.

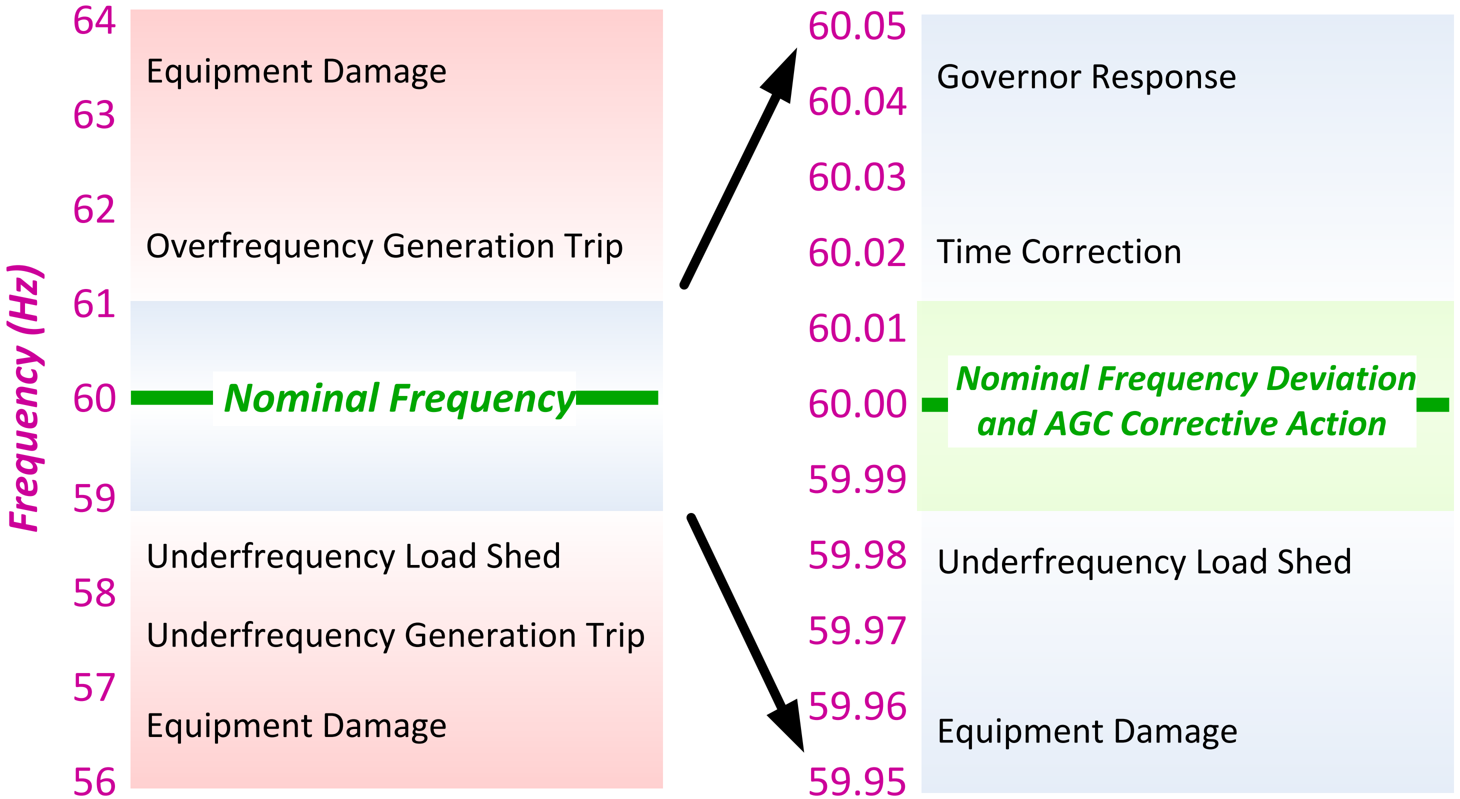
  - Underfrequency may occur from system overloading
    - Loss of generation
    - Loss of tie lines importing power
  - Underfrequency is an issue for the generator
    - Ventilation is decreased
    - Flux density (V/Hz) increases
  - Underfrequency limit is typically dictated by the generator and turbine
    - Generator: V/Hz and loading
    - Turbine: Vibration Issues

81-U

  - Overfrequency may occur from load rejection
  - Overfrequency is typically not an issue with the generator
    - Ventilation is improved
    - Flux density (V/Hz) decreases
  - Overfrequency limit is typically dictated by the turbine (vibration)

81-O

System Frequency Overview

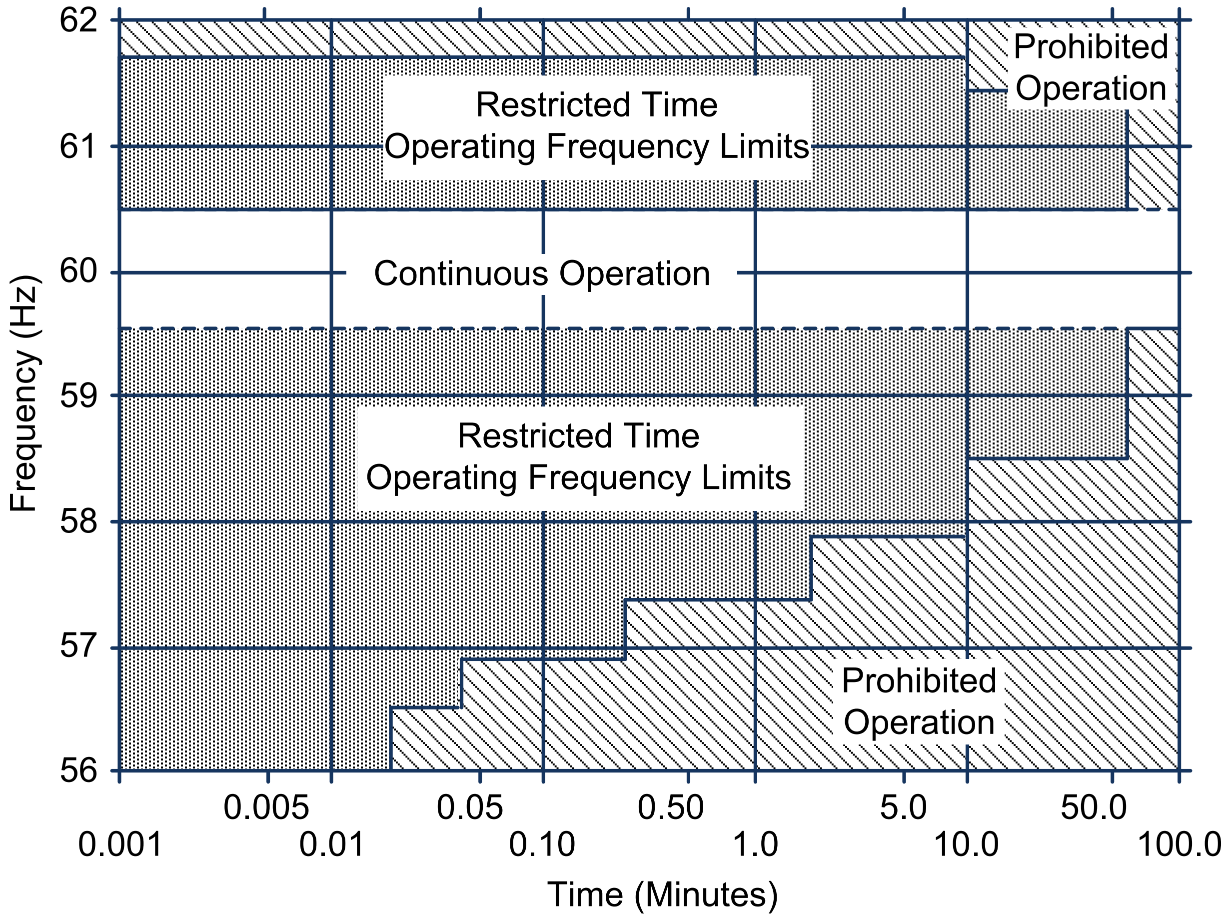


- *For overfrequency events, the generator prime mover power is reduced to bring generation equal to load*
- *For underfrequency events, load shedding is implemented to bring load equal to generation*
  - *It is imperative that underfrequency tripping for a generator be coordinated with system underfrequency load shedding*

Abnormal Operating Conditions

- **81O/U**
  - Coord with gen and turbine mfg off-nominal frequency damage curves.
  - Coord with load shedding schemes.
  - Coord with PRC-024.
- **81A – Underfrequency Accumulator**
  - Time Accumulation in Six Underfrequency Bands
  - Limits Total Damage over Life of Machine
    - Typically used to Alarm
- **81R – Rate of Change of Frequency**
  - Allows tripping on rapid frequency swing (anti-islanding protection)

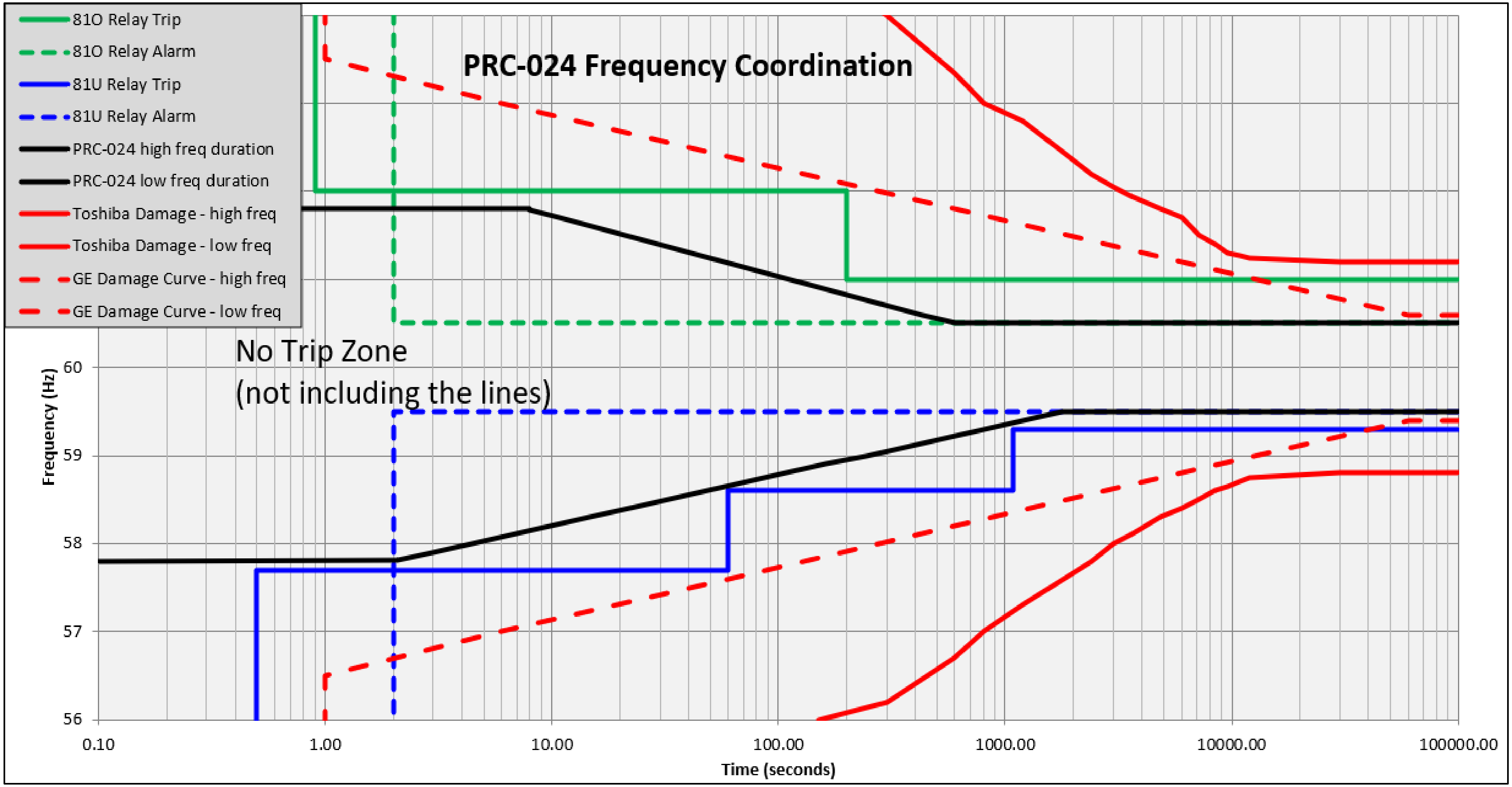
Turbine Over/Underfrequency



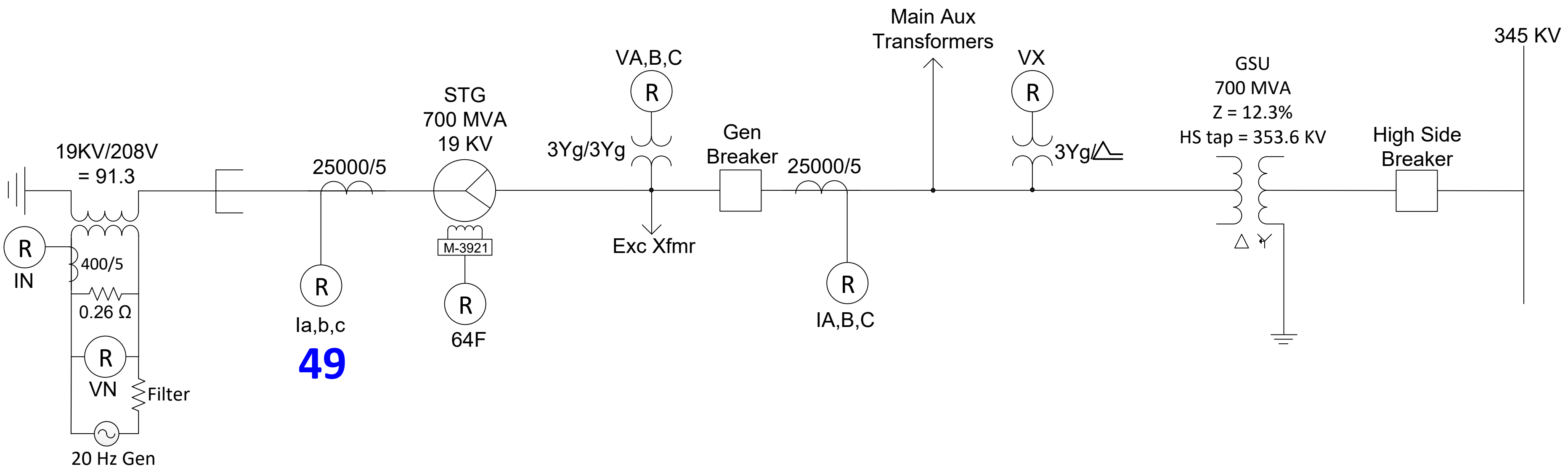
example from C37.106

PRC-024-2

- Plots of 81 settings, frequency duration criteria, and damage curves.
- As the 81 settings plot outside the "No Trip Zone" criteria, the chosen settings are verified to be **OK** per this standard



49 – Stator Thermal Overload



- **This protection may be more common on <u>induction generators</u>, but it can also be used for <u>synchronous generators</u> because no other protection accounts for the stator winding thermal history.**

49 – Stator Thermal Overload

- **The 49 function provides protection against stator winding overheating that can weaken insulation making it more brittle.**

- **Caused by the following:**
  - ✓ **Increased power output**
  - ✓ **Overload condition**
  - ✓ **Generator control system failure**

- **RTDs may be required to detect the following:**
  - ✓ **Cooling system failure**
  - ✓ **High resistance connections**
  - ✓ **Localized hot spots caused by core lamination insulation failures**
  - ✓ **Localized or rapidly developing winding failures**

49 – Stator Thermal Overload

- **If stator winding RTDs are available, then they may provide independent thermal overload protection (or alarming) to detect the overheating conditions that the current-based 49 protection may not be able to detect.**

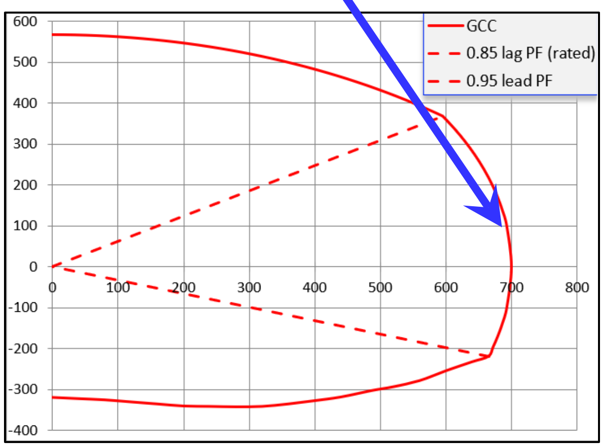
- **Alternatively, the RTDs could be ANDed with a 49 element for extra security at the cost of sensitivity.**

- **In addition, this 49 trip could be supervised by an instantaneous overcurrent element to define a value below which a trip will not occur if for example it is desired to cut off the top portion of the curve at some value above the chosen 49 pickup value.**

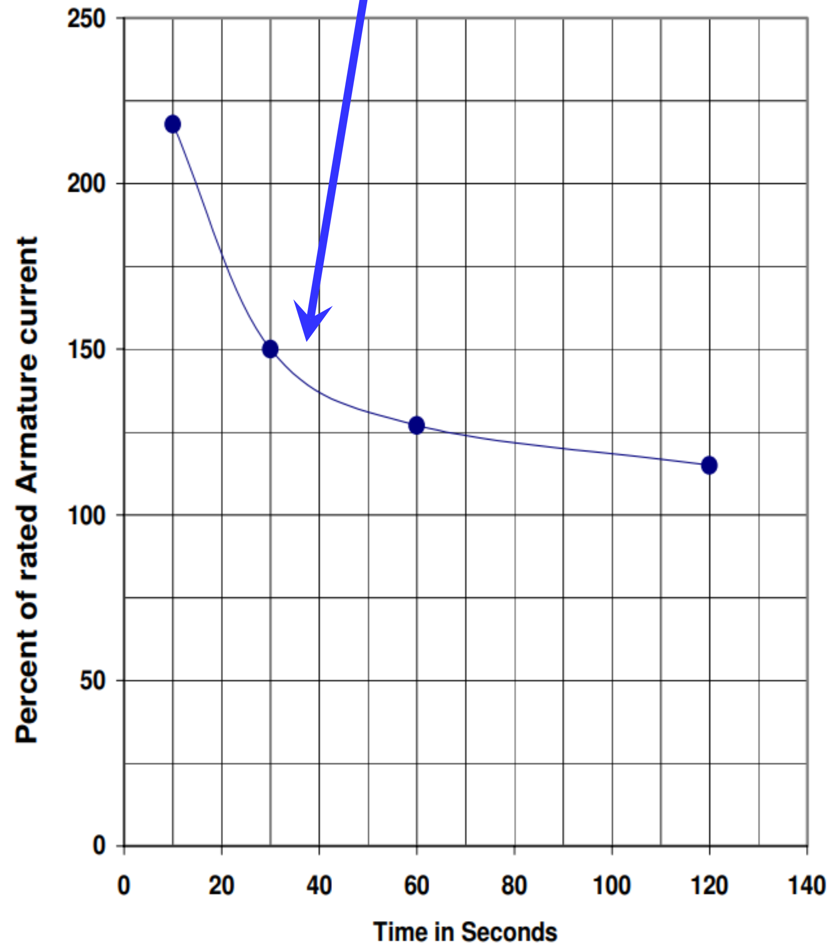
49 – Stator Thermal Overload

- **If no mfg stator thermal overload curve is provided, may use this curve from IEEE C50.13 for cylindrical rotor machines that defines the stator winding short-time thermal overload criteria that mfg should design to meet:**

- **The GCC does have a stator thermal limit section too:**



However, it does not have a time axis, whereas the C50.13 curve does.



- Therefore, plot 49 curve under the C50.13 curve, so will be protecting that curve instead of the actual mfg curve as that was not provided (as is often the case).

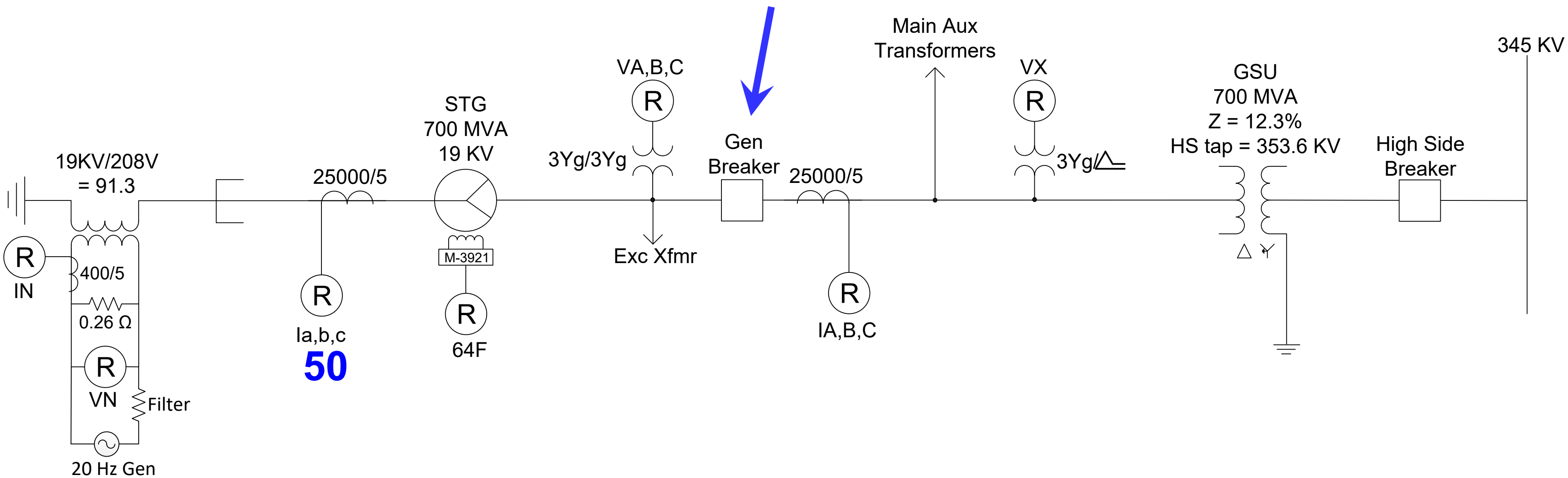
49 – Stator Thermal Overload

- **The C50.13 stator thermal overload curve is required to withstand exposure to transient and emergency duty caused by power system events <u>not more than 2 times per year</u>.**

  ✓ **C50.12 for Salient Pole machines <u>does not</u> define a similar stator winding thermal overload curve.**

  ✓ **PRO TIP: Salient Pole machines have much greater thermal time constants (due to slower speeds) i.e. do not use C50.13 curve for hydros or nuisance trips will likely result.**

Isync Trip

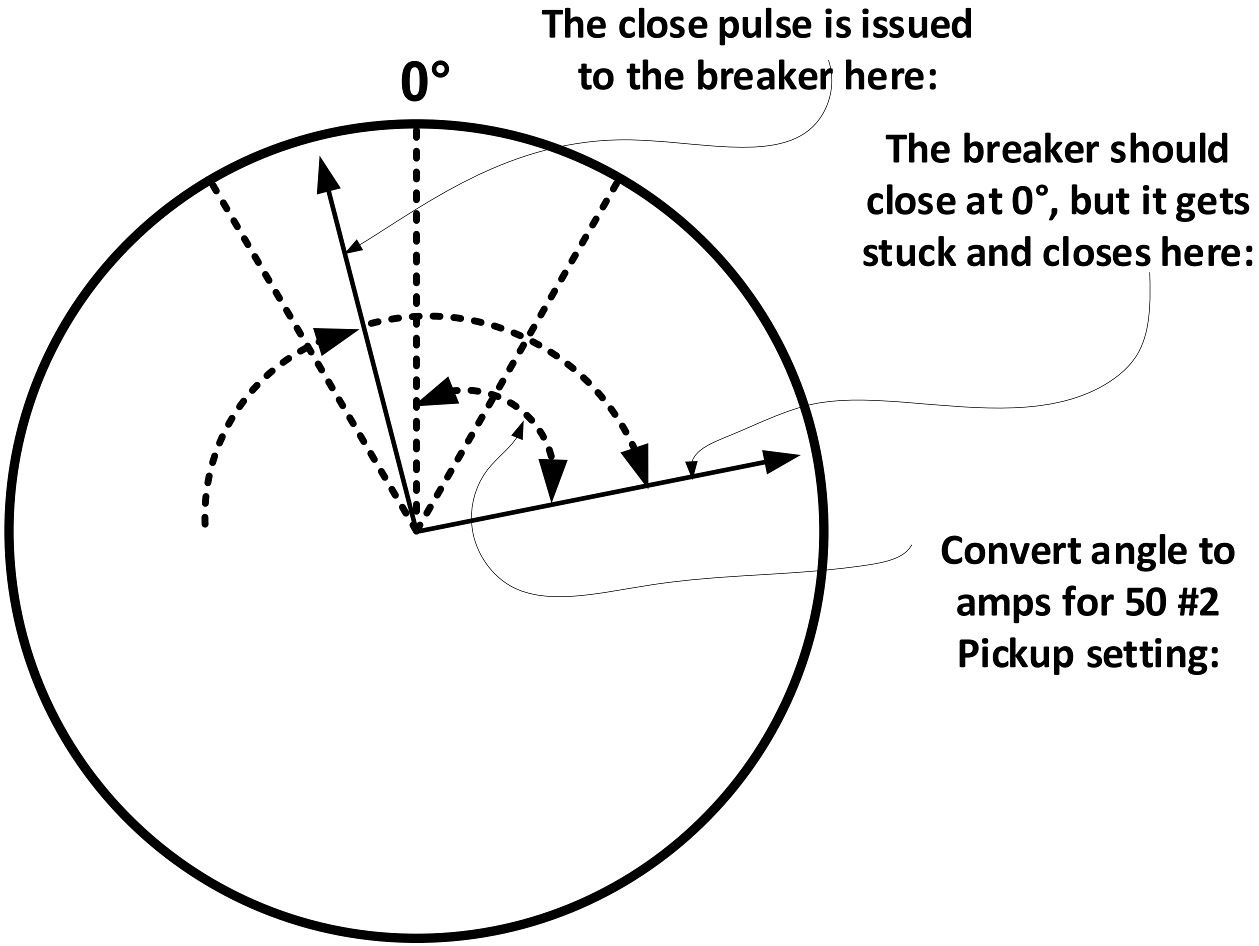


Protection for bad auto or manual synchronizing closures of the generator breaker i.e. closing in the breaker at too large of an angle.

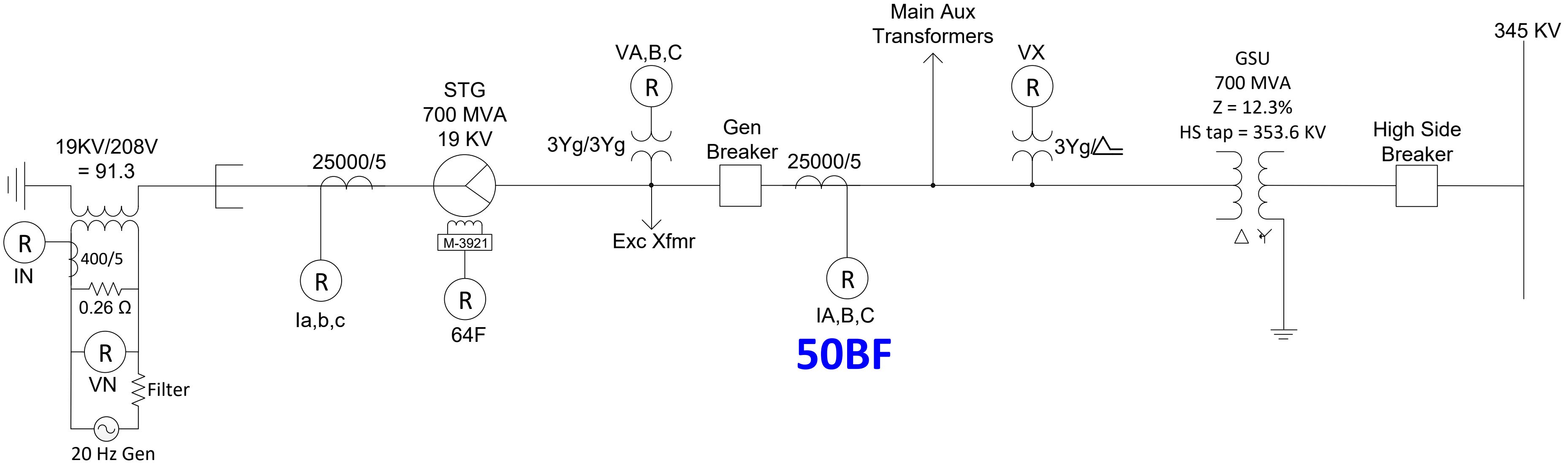
- **aka OOPS (Out-of-Phase Sync Protection)**
- **Use 50 element, breaker status, and flexible logic**

50 #2 with IPSlogic – Isync Trip

For protection against out of phase closures due to slow or stuck breaker, VT mis-wiring, incorrect sync settings, etc.

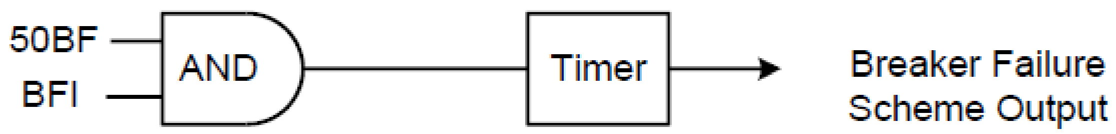


50BF – Breaker Failure

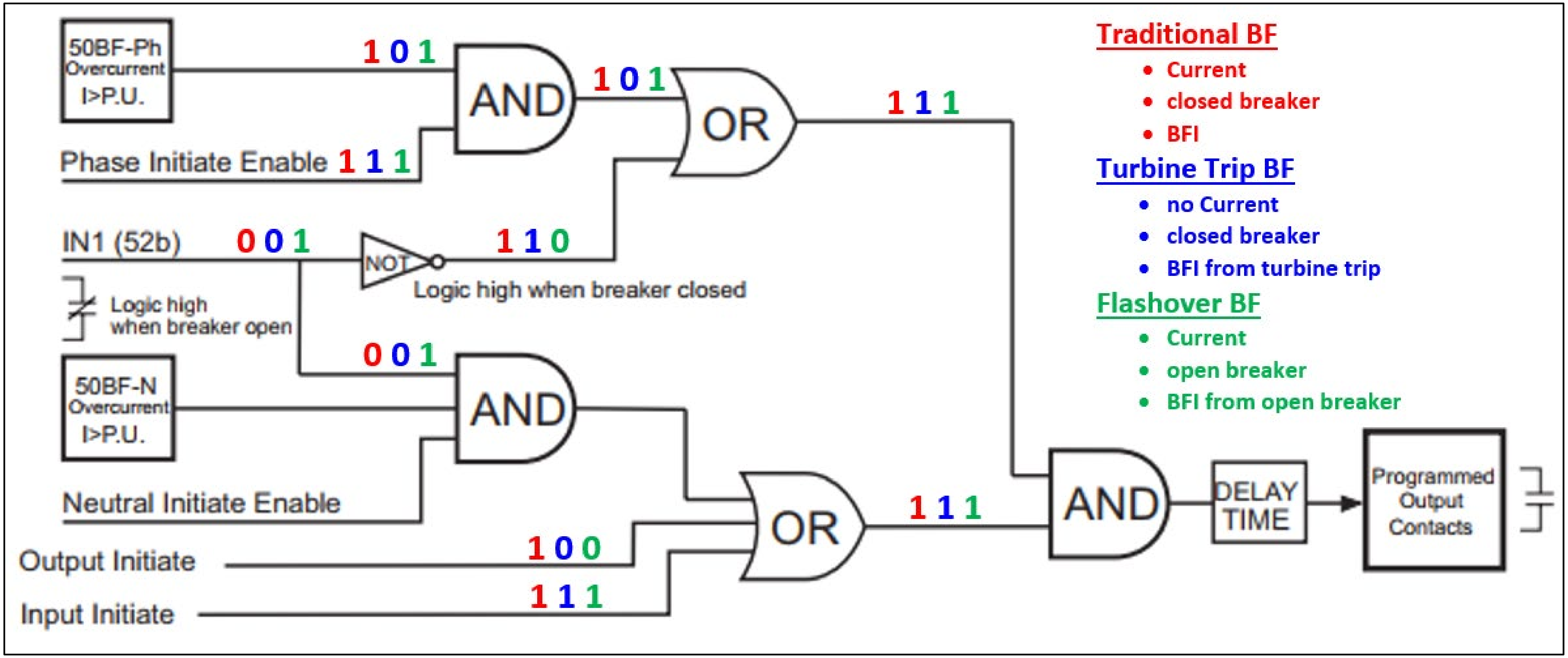


If subject breaker fails to trip, then trip back a zone in each direction (High Side Breaker and 86G LOR).

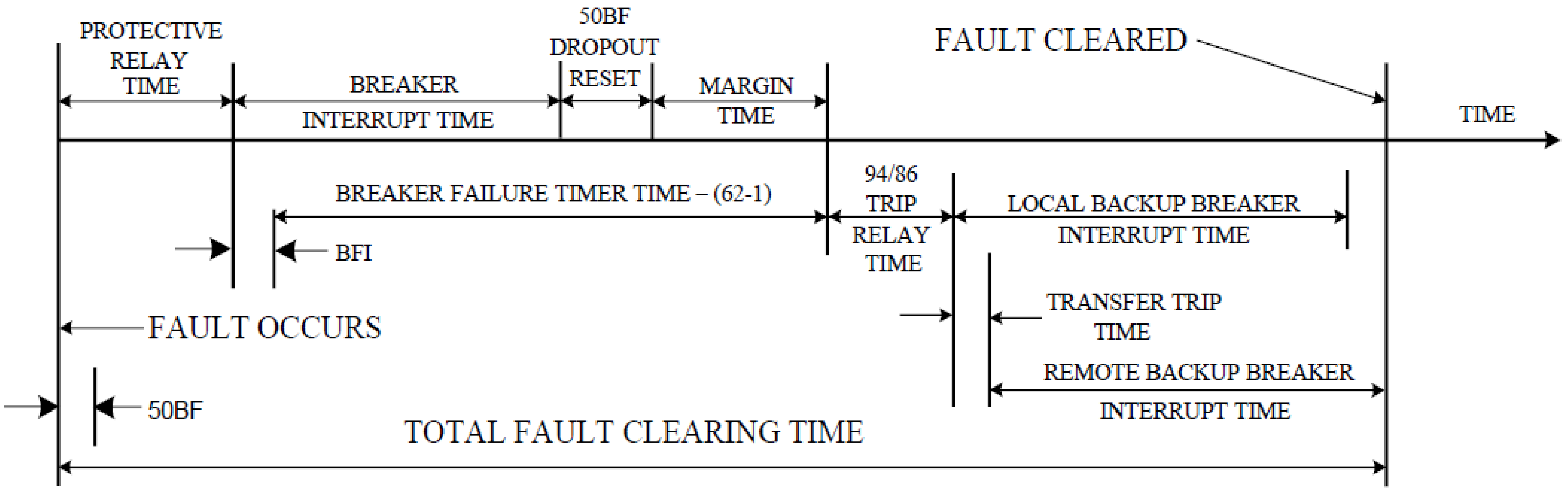
Simple BF Scheme



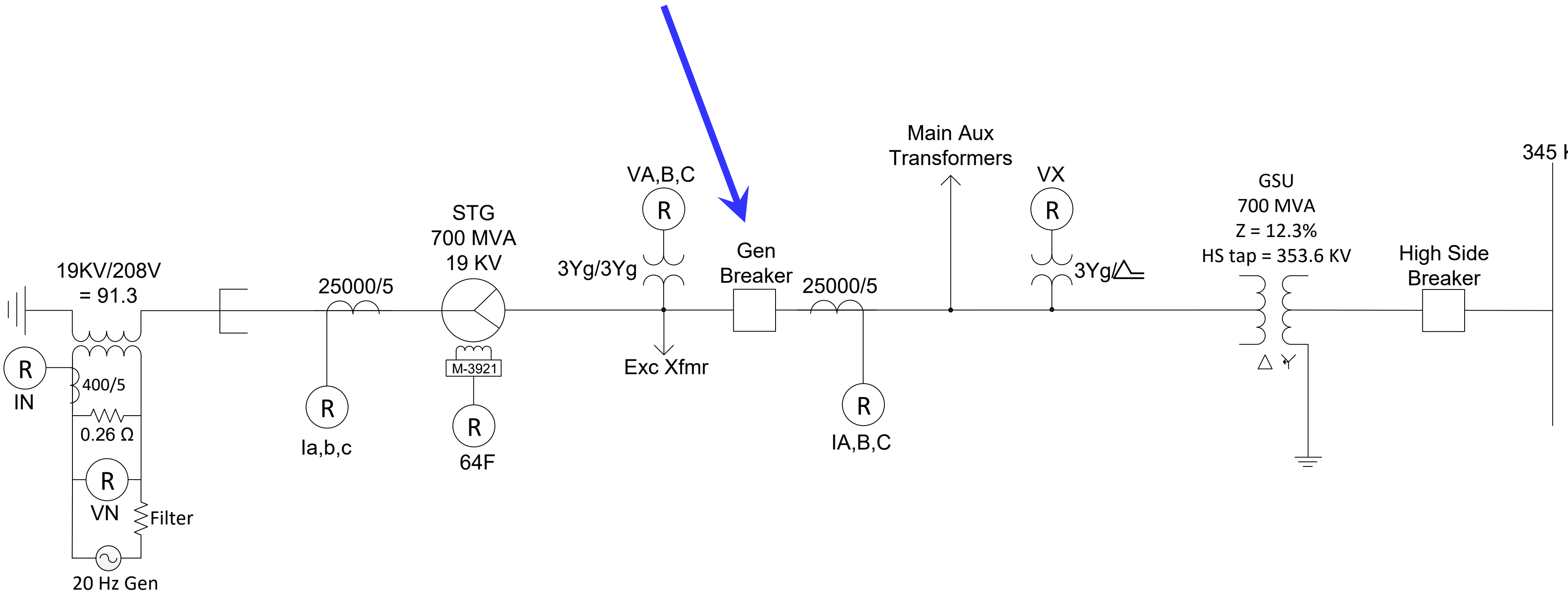
Gen or Unit breaker BF with Turbine Trip and flashover options



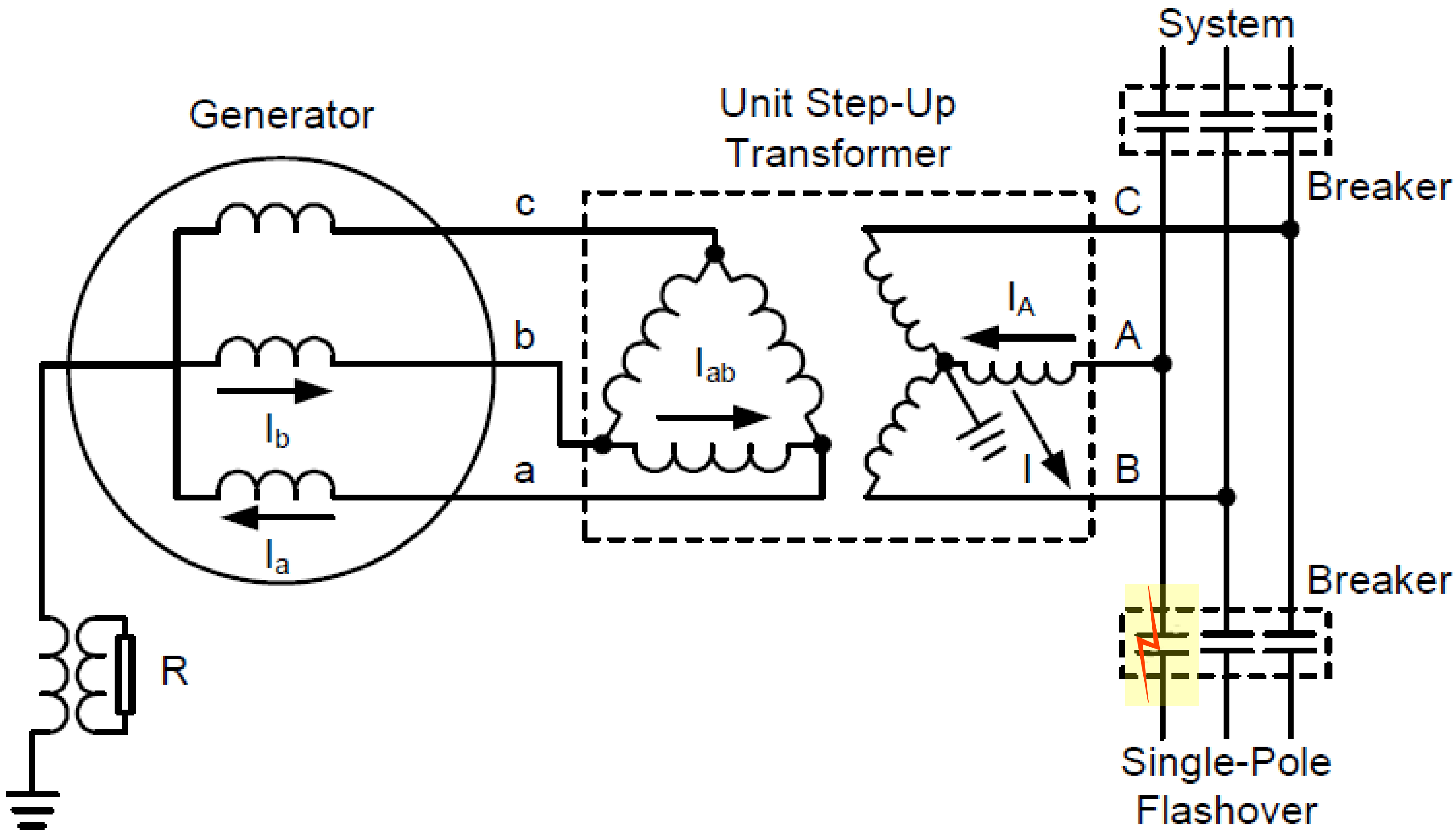
50BF Time Delay setting derivation per IEEE C37.119



61BF Breaker Flashover protection

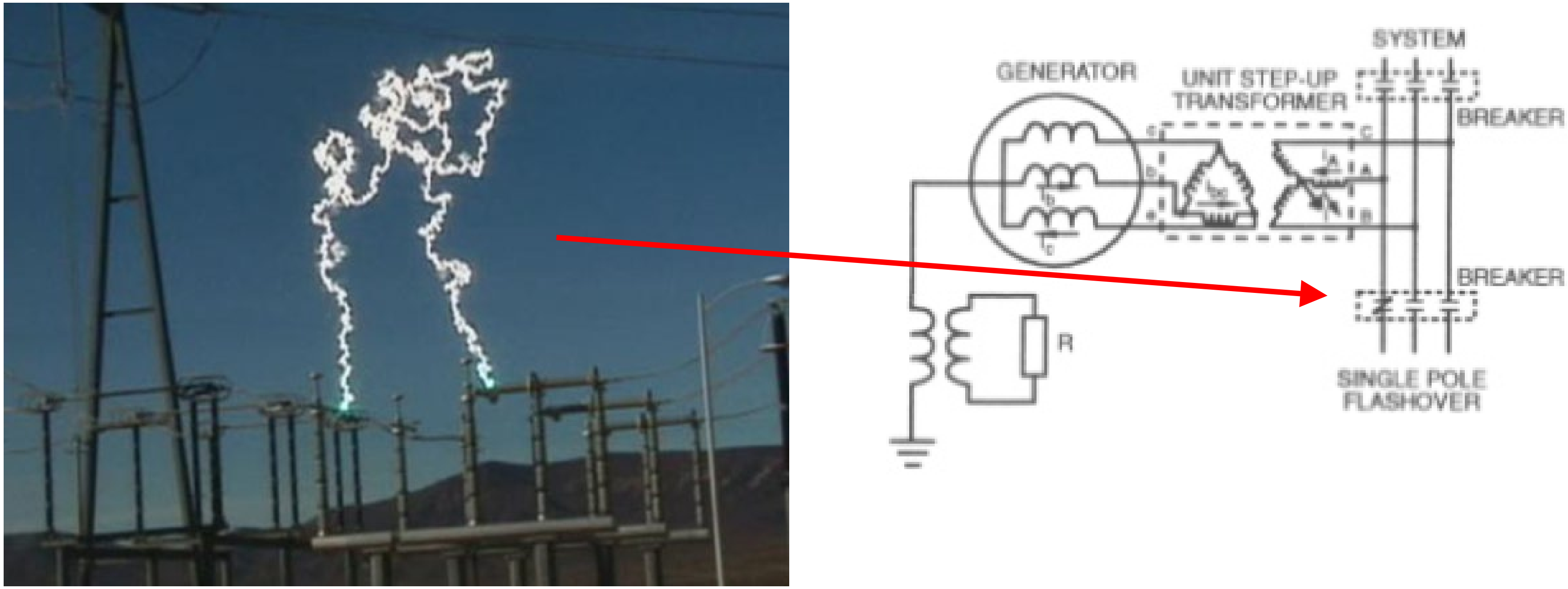


Breaker Flashover protection – **unit breaker on the GSU HS may be more susceptible to possible flashovers as compared to GSU LS gen breakers**



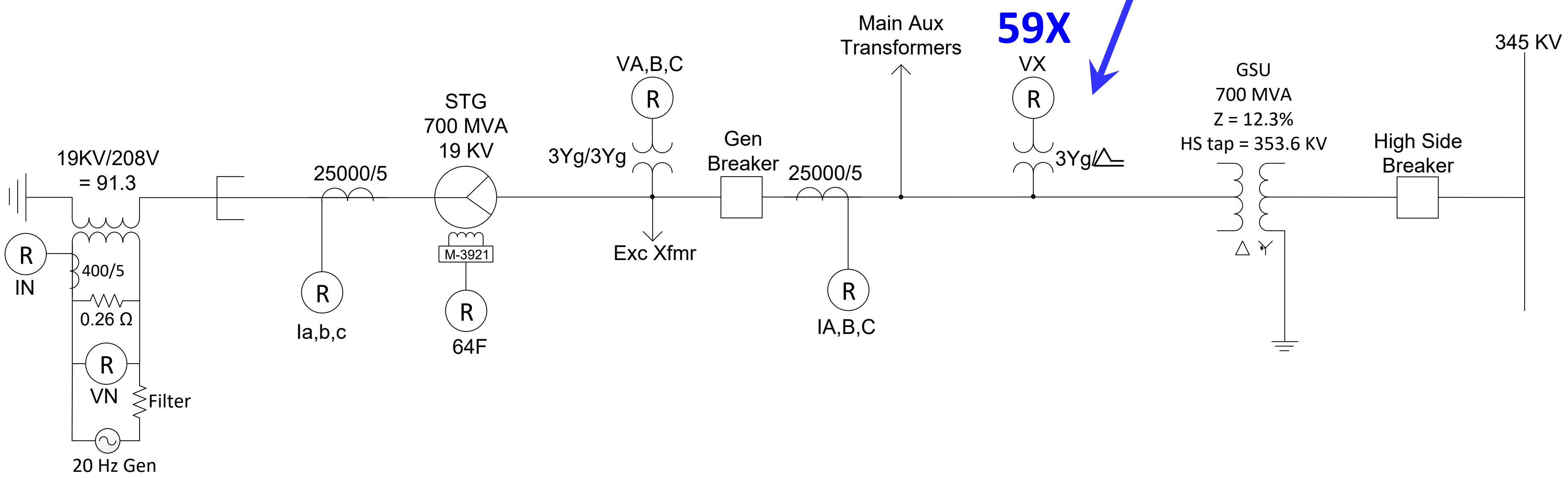
Breaker Flashover protection

- **A breaker head flashover (or breaker pole flashover or stuck pole) may occur as the result of dielectric failure at the contacts of an open generator breaker.**
- **Flashover more likely just prior to synchronizing or just after the gen breaker has tripped as the voltage across contacts approaches twice normal as gen slips in frequency with respect to system.**



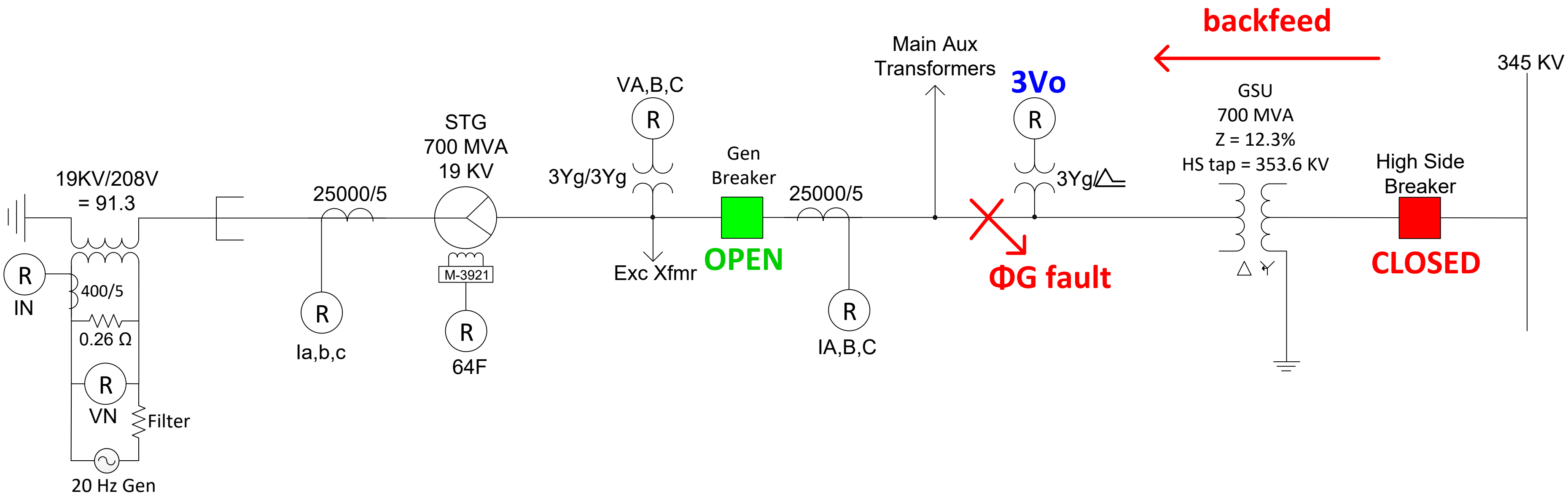
59X (aka 59N, 59G) – measured 3Vo Ground Overvoltage

The relay's VX voltage input is wired across a ballast resistor from broken delta VTs



- ✓ **Bus Ground fault protection**
- ✓ **Turn to Turn fault protection**

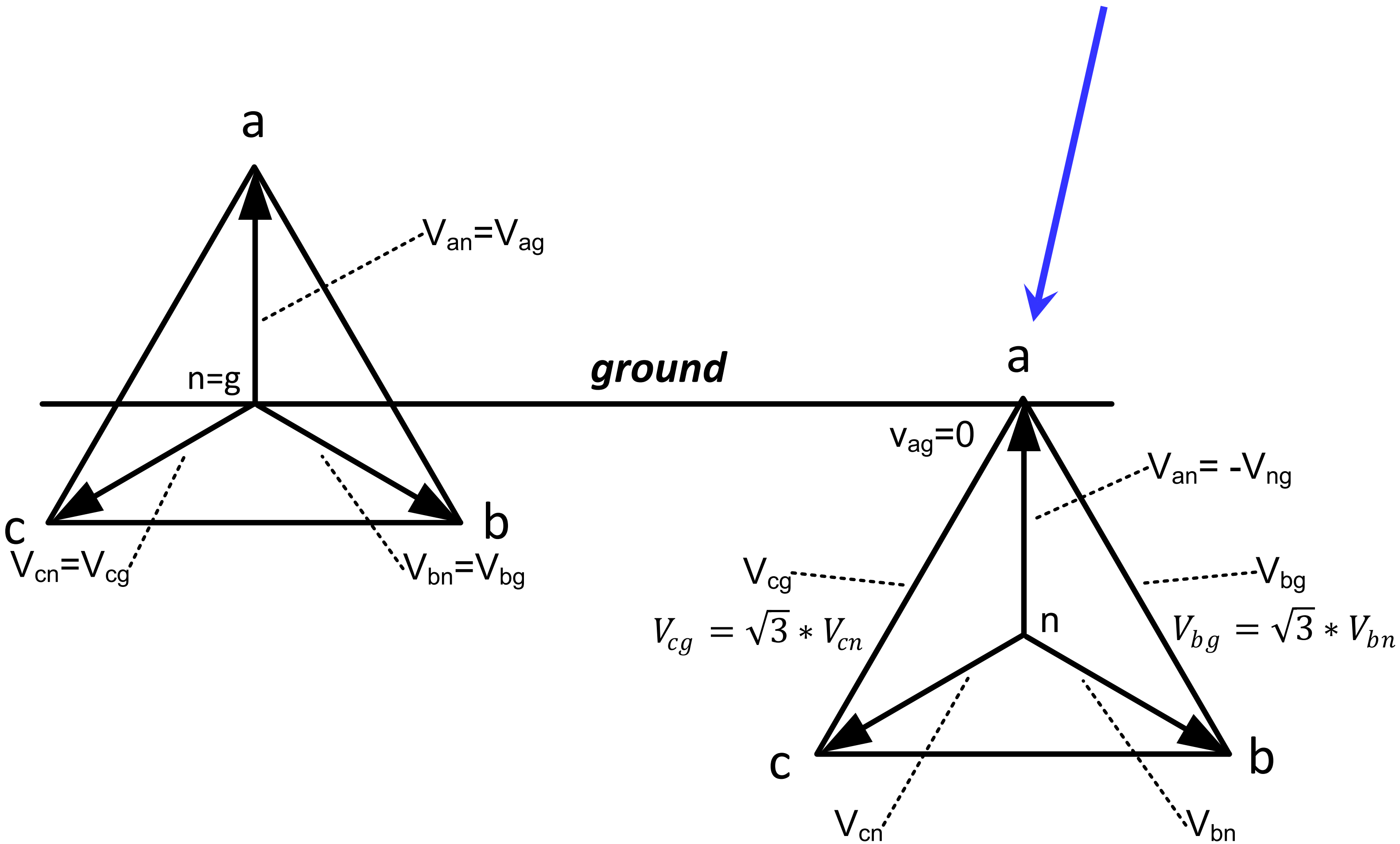
3Vo Bus Ground fault protection



- Provides Gen Bus Ground fault protection prior to the unit being synched on-line and during back-feed scenarios where the generator breaker is open, or the generator links are removed with the GSU back energized from the system.
- Must trip HS breaker to clear system fault contribution into a bus ground fault.

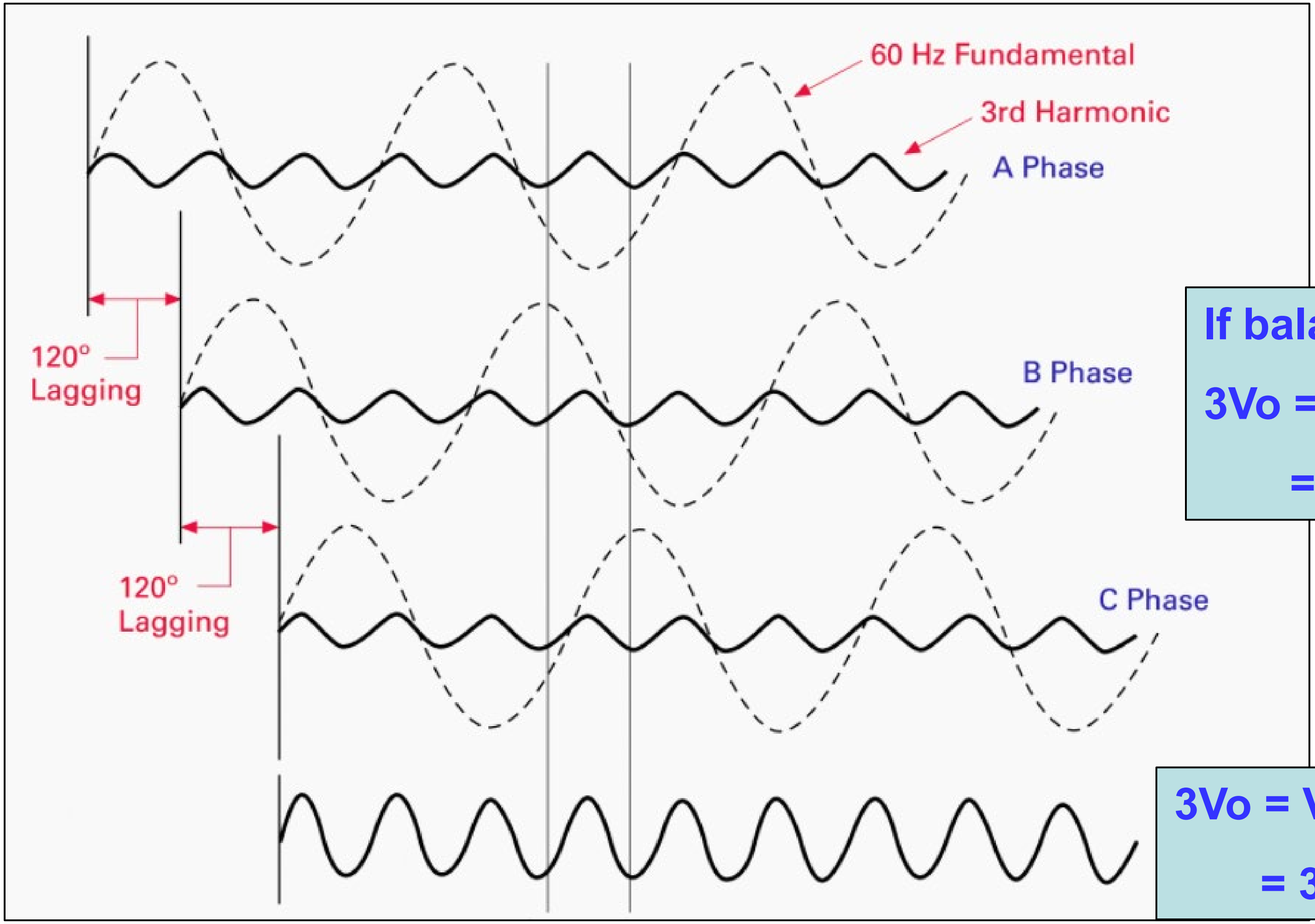
3Vo Bus Ground fault protection

$$unbalance, min\ range \leq 59X\ Pickup \leq 3Vo\ from\ \Phi G\ fault;\ VT\ pri\ FL$$



3Vo Bus Ground fault protection

- **Relationship between zero sequence and third harmonic**
  - **Triplen harmonics (3,9,15,21 …) are in-phase so they are additive and return thru neutral**
  - **Verify specific relay's frequency response of the 3Vo element**
  - **Not an issue for M-3425A relay as it's 59X function uses DFT and operates from 55-65 Hz**



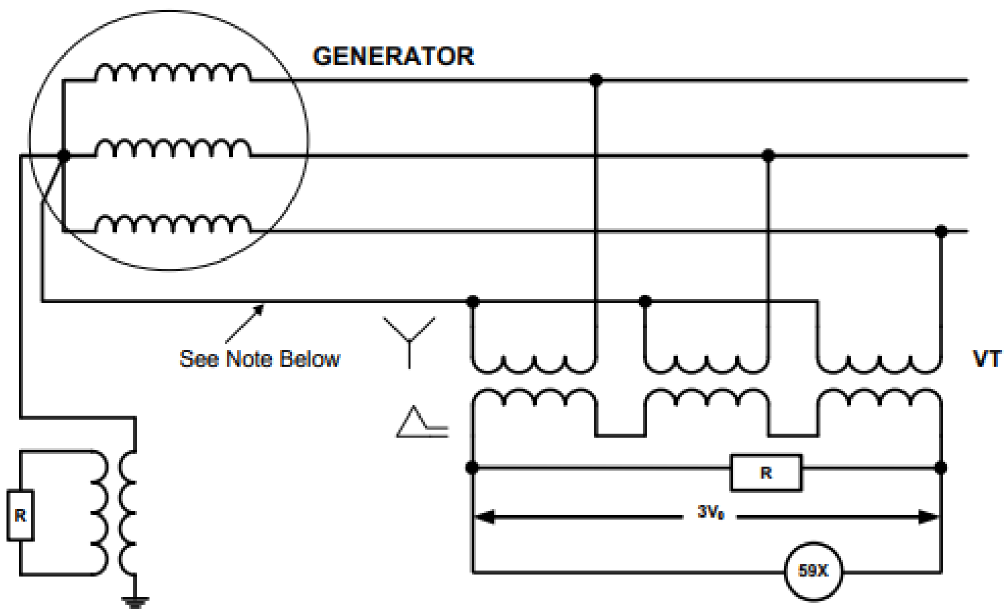
If balanced:

$$3Vo = V_A + V_B + V_C$$
$$= 0 \text{ V @ } 60 \text{ Hz}$$

$$3Vo = V_A + V_B + V_C$$
$$= 3V_A \text{ @ } 180 \text{ Hz}$$

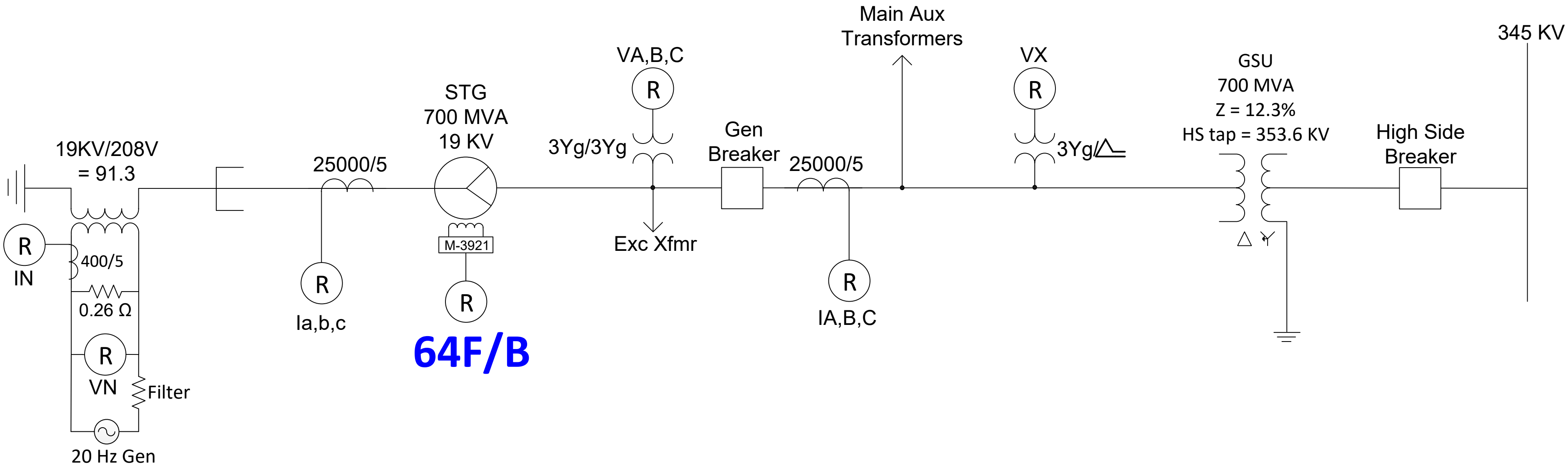
3Vo Turn-to-Turn or inter-Turn Fault Protection

- Some low-speed hydros are constructed with 2 parallel circuits per phase.
- Under normal conditions, the currents in the two parallel circuits are equal.
- When an inter-turn fault occurs, the difference in the voltages that develop causes a current to circulate.
- Stator differential protection does not detect turn-to-turn faults.



■NOTE: Installation requires the cable from the neutral of the VT to generator neutral be insulated for the system line-to-ground voltage.

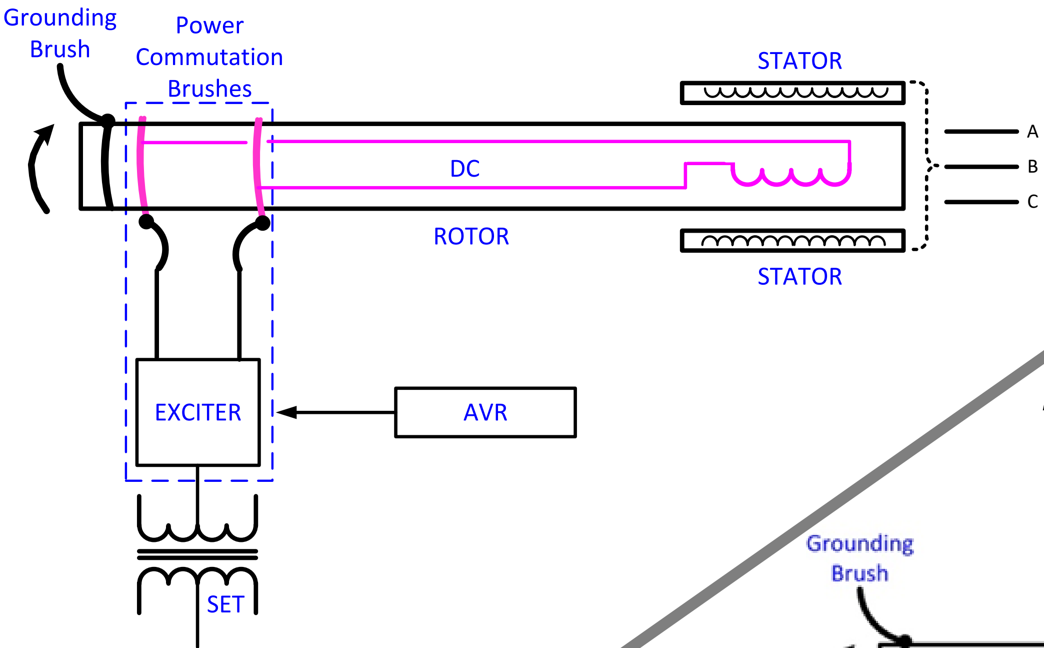
64F/B – Field Ground Protection



64F/B – Field Ground Protection

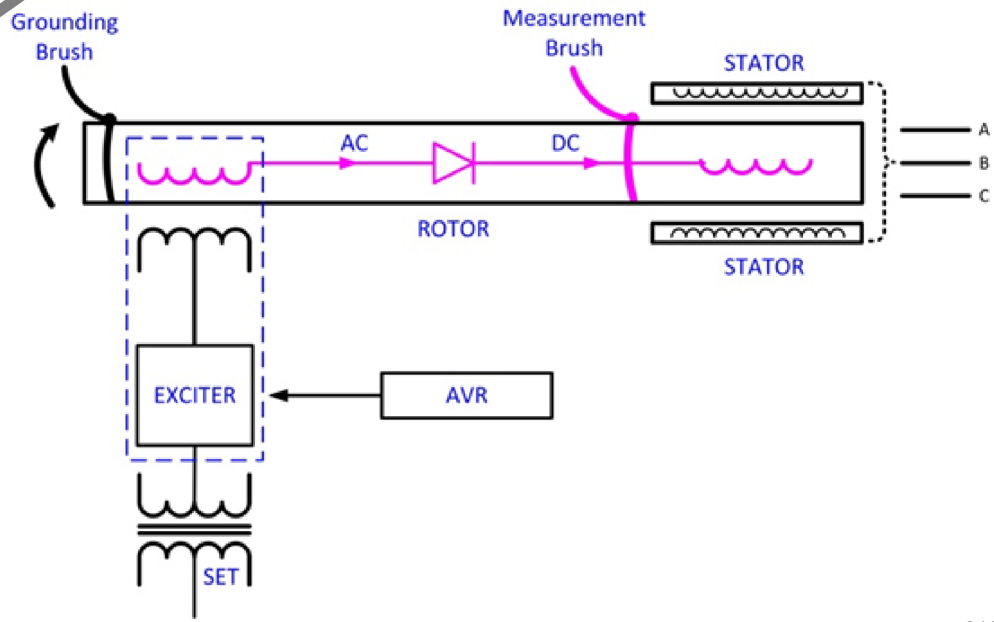
- **64F provides detection of insulation breakdown between the excitation field winding and ground.**
- **The relay internally generates a 15 V, 1 Hz squarewave and injects this back into the field winding thru a coupler.**
  - ✓ **Requires external coupler to provide isolation from dc field voltage transients.**
  - ✓ **Mount coupler close to exciter.**
- **64B detects open brushes of the rotor shaft.**
- **When 64B detects open brush, 64F cannot detect field ground. Usually alarm on 64B.**

Brushed and “Brushless” Excitation

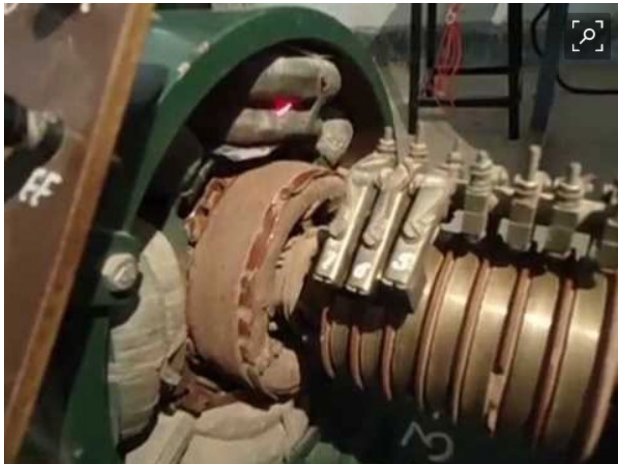


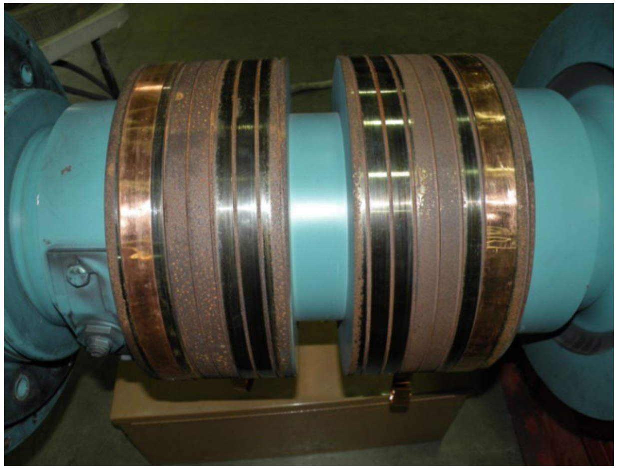
Brushed

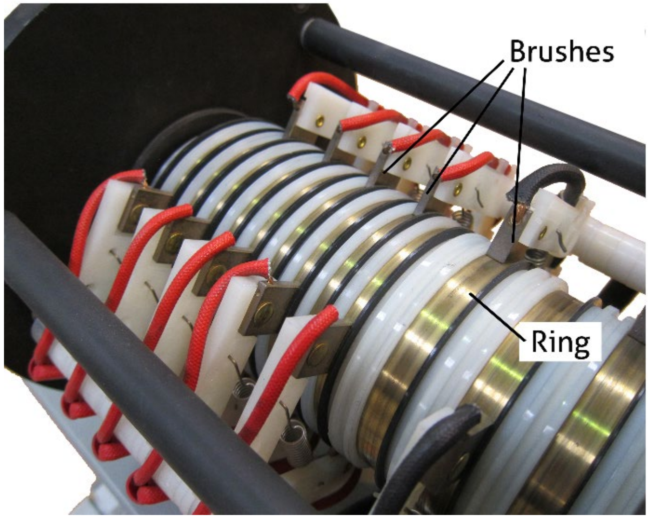
“Brushless”



Brushes and Collector Rings



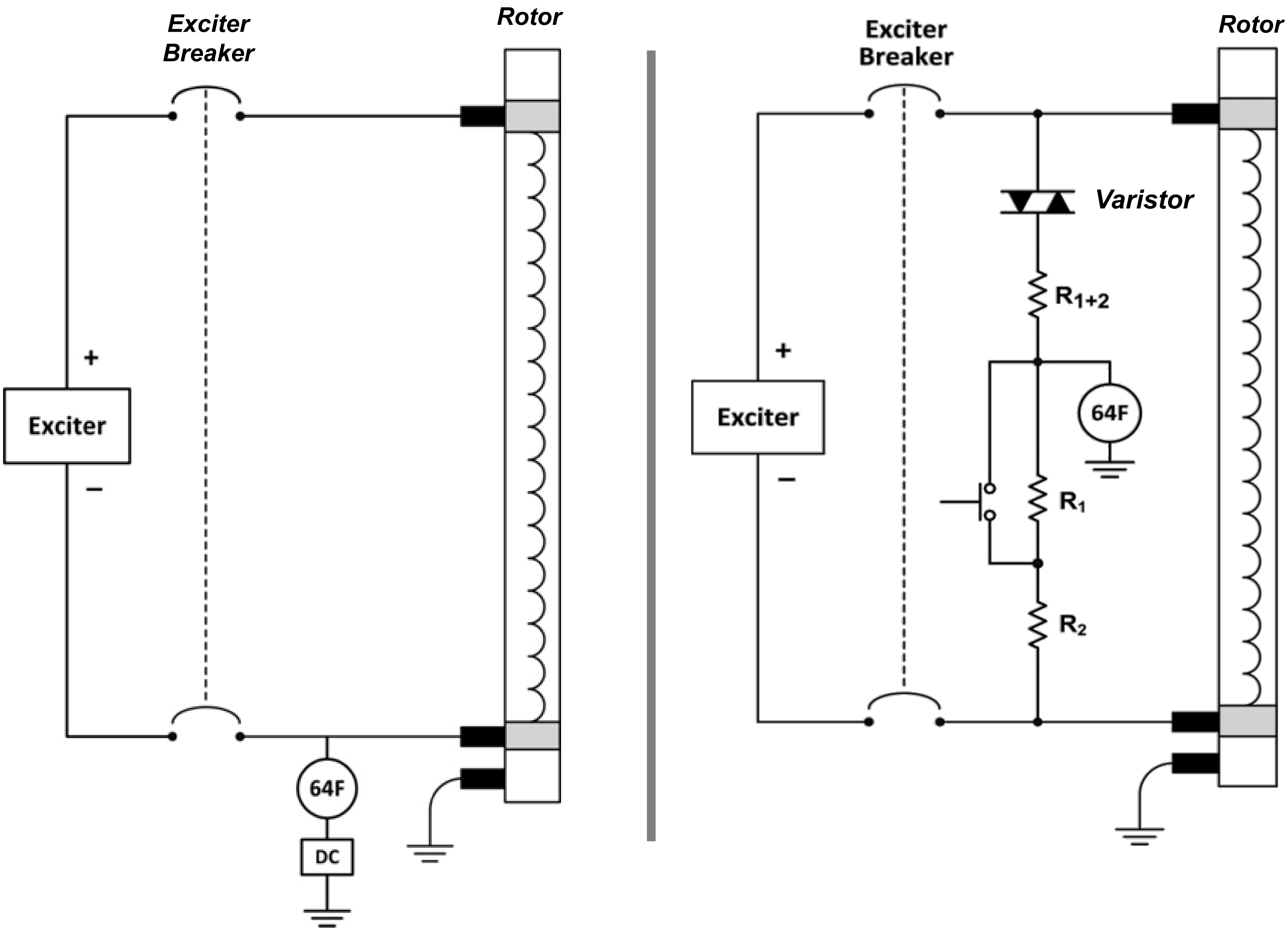




Field/Rotor Ground Fault

- Traditional field/rotor circuit ground fault protection schemes employ DC voltage detection
  - Schemes based on DC principles are subject to security issues during field forcing, other sudden shifts in field current and system transients

DC-Based 64F

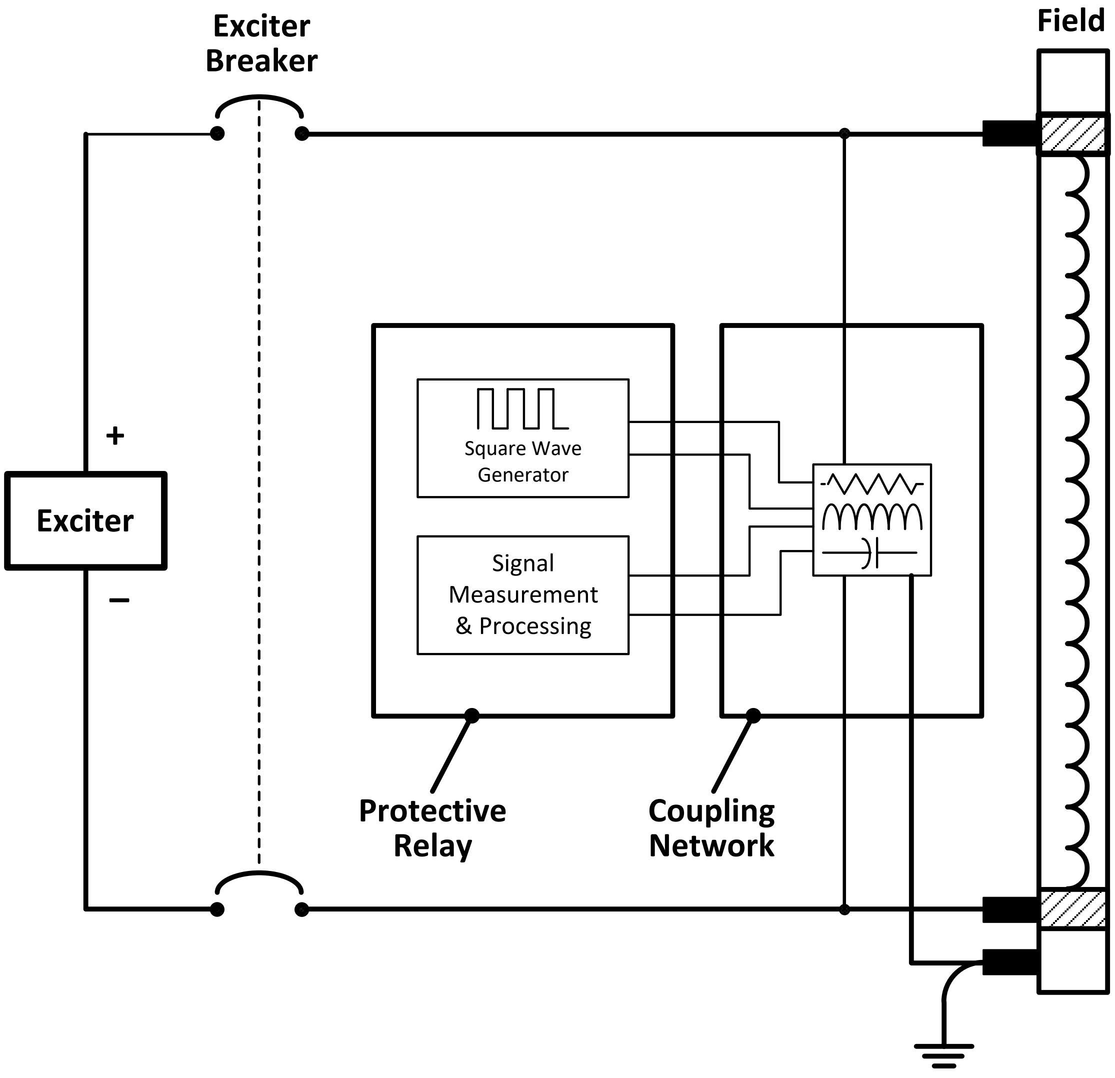


Exciter
Breaker
Rotor
+
Exciter
–
64F
DC
Exciter
Breaker
Rotor
Varistor
R1+2
+
Exciter
–
64F
R1
R2

Field/Rotor Ground Fault (64F)

- To mitigate the security issues of traditional DC-based rotor ground fault protection schemes, AC injection based protection may be used
  - AC injection-based protection ignores the effects of sudden DC current changes in the field/rotor circuits and attendant DC scheme security issues

Advanced AC Injection Method



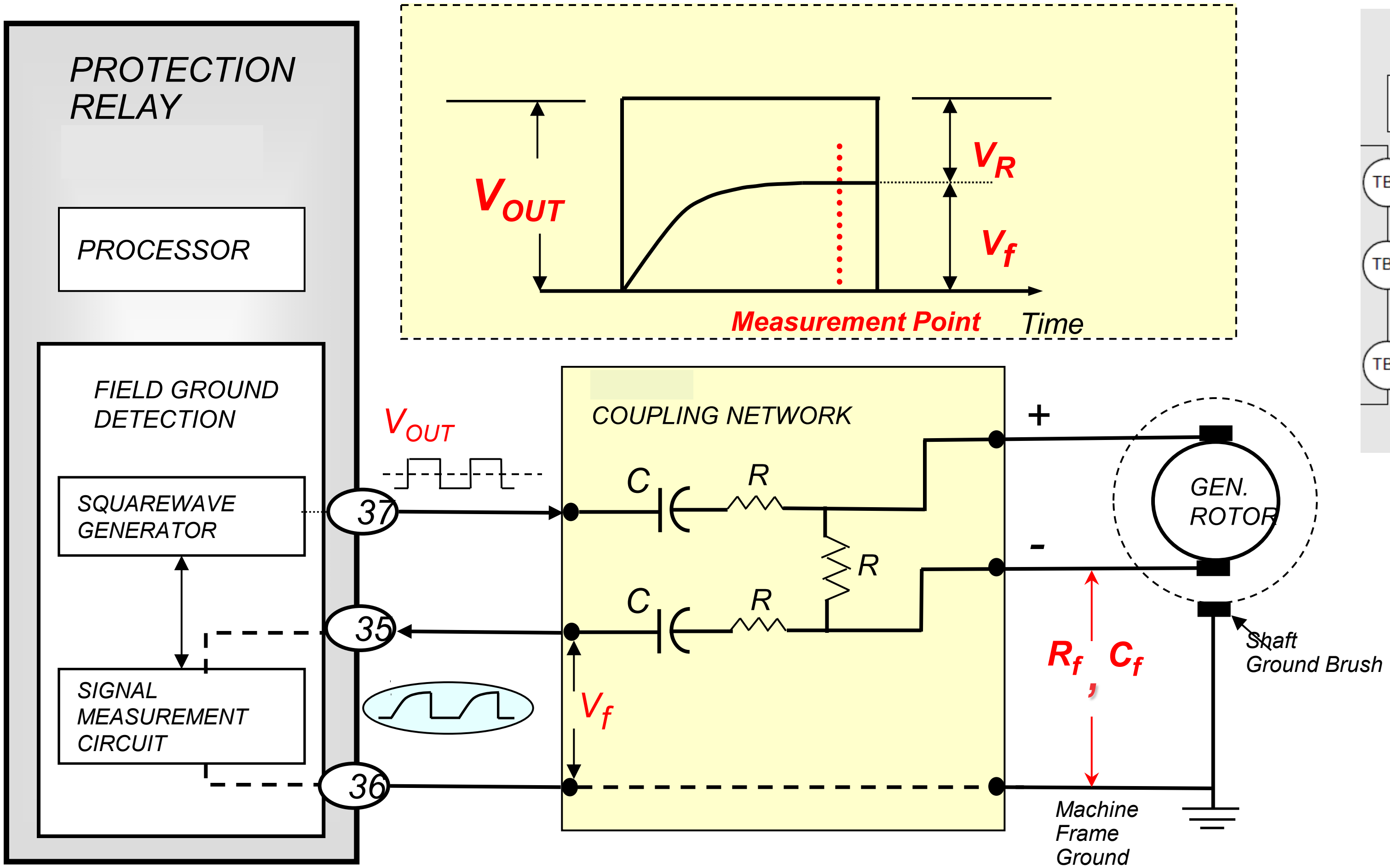
Advanced AC Injection Method: Advantages

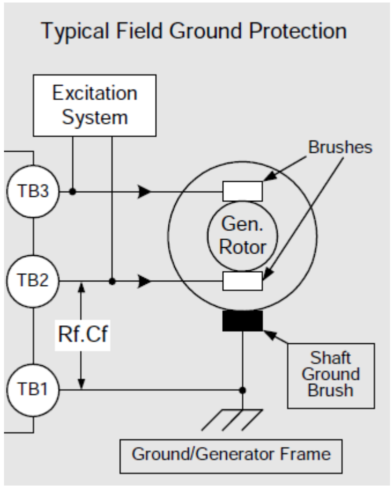
- Scheme is secure against the effects of DC transients in the field/rotor circuit
  - DC systems are prone to false alarms and false trips, so they sometimes are ignored or rendered inoperative, placing the generator at risk
  - The AC system offers greater security so this important protection is not ignored or rendered inoperative

- Scheme can detect a rise in impedance which is characteristic of grounding brush lift-off
  - In brushless systems, the measurement brush may be periodically connected for short time intervals
  - The brush lift-off function must be blocked, during the time interval the measurement brush is disconnected

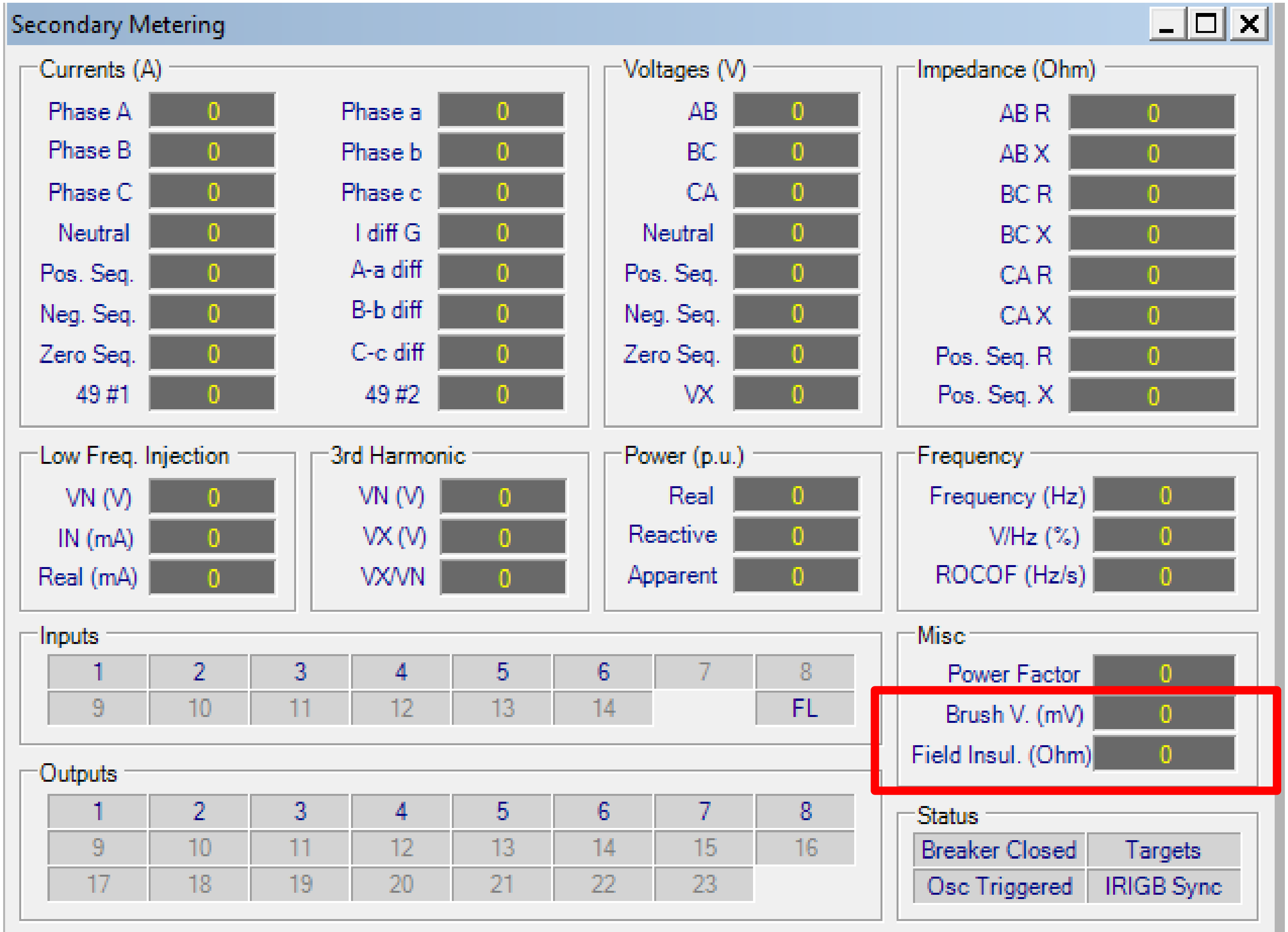
Rotor Ground Fault Measurement

- *Plan a shutdown to determine why impedance is lowering, versus an eventual unplanned trip!*
- *When resistive fault develops, **V_f goes down***



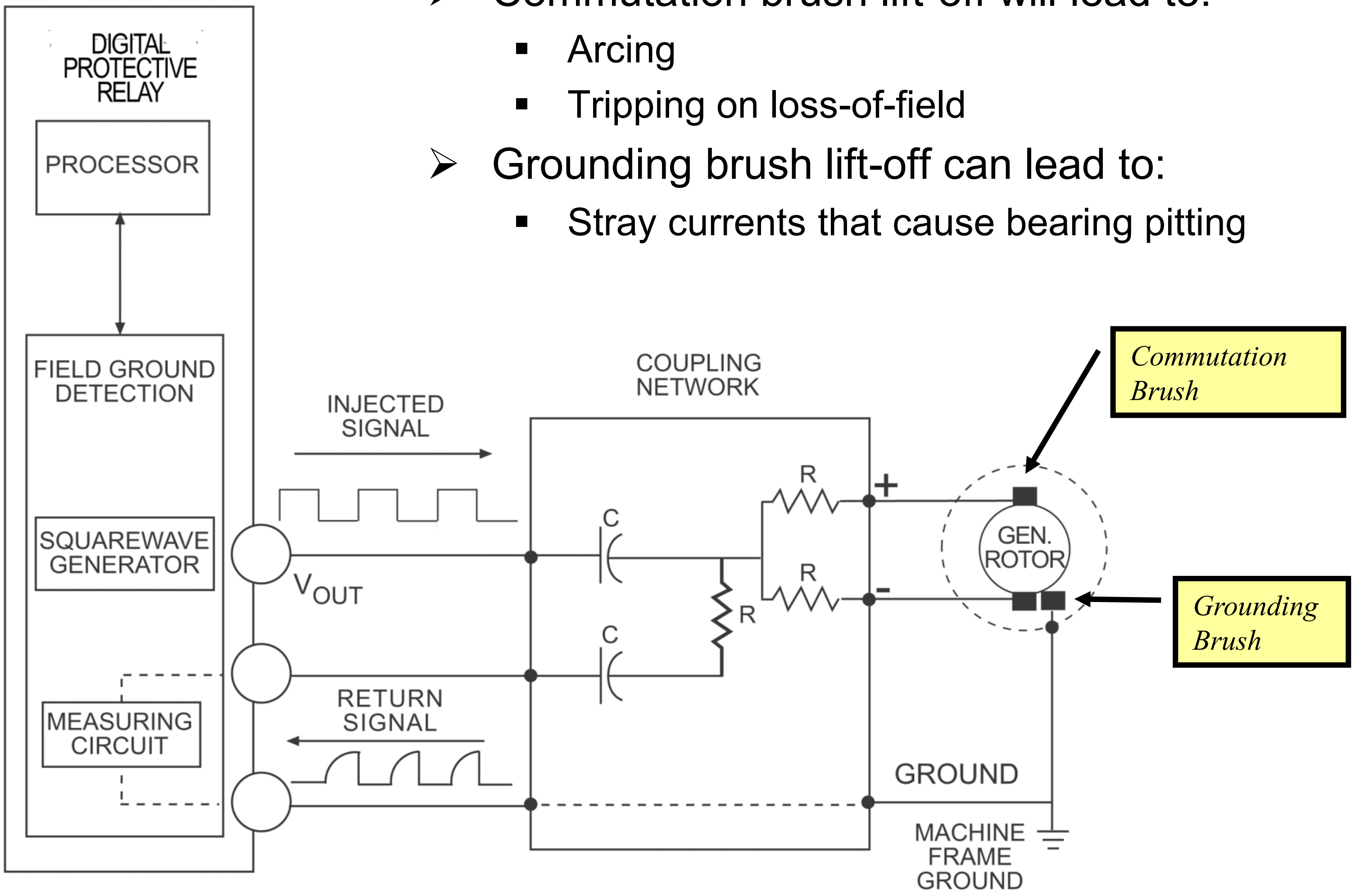


64F: Field/Rotor Ground Faults



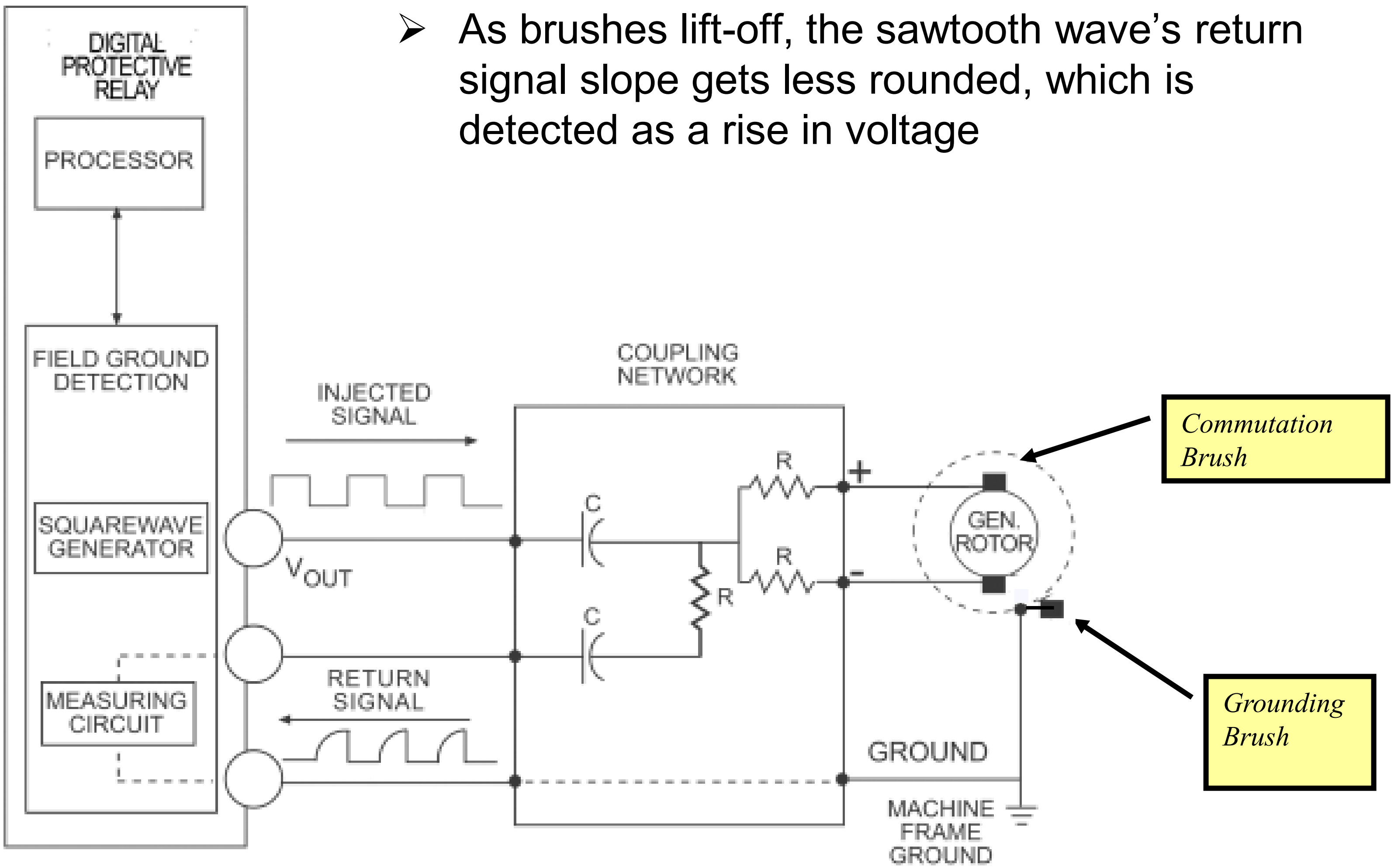
64B: Brush Lift Off

- Commutation brush lift-off will lead to:
  - Arcing
  - Tripping on loss-of-field
- Grounding brush lift-off can lead to:
  - Stray currents that cause bearing pitting



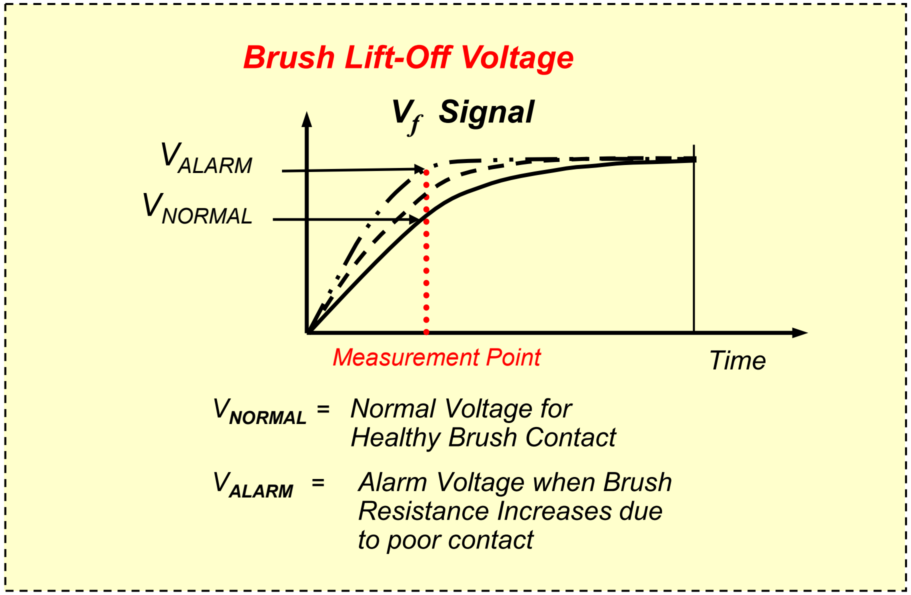
64B: Brush Lift Off

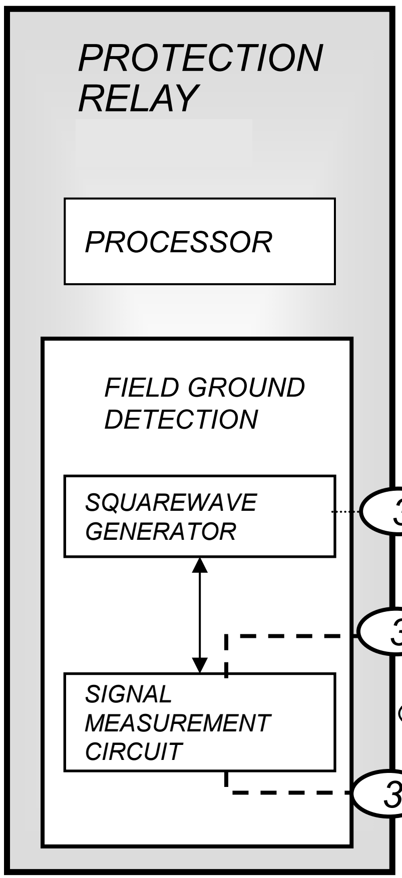
- As brushes lift-off, the sawtooth wave's return signal slope gets less rounded, which is detected as a rise in voltage

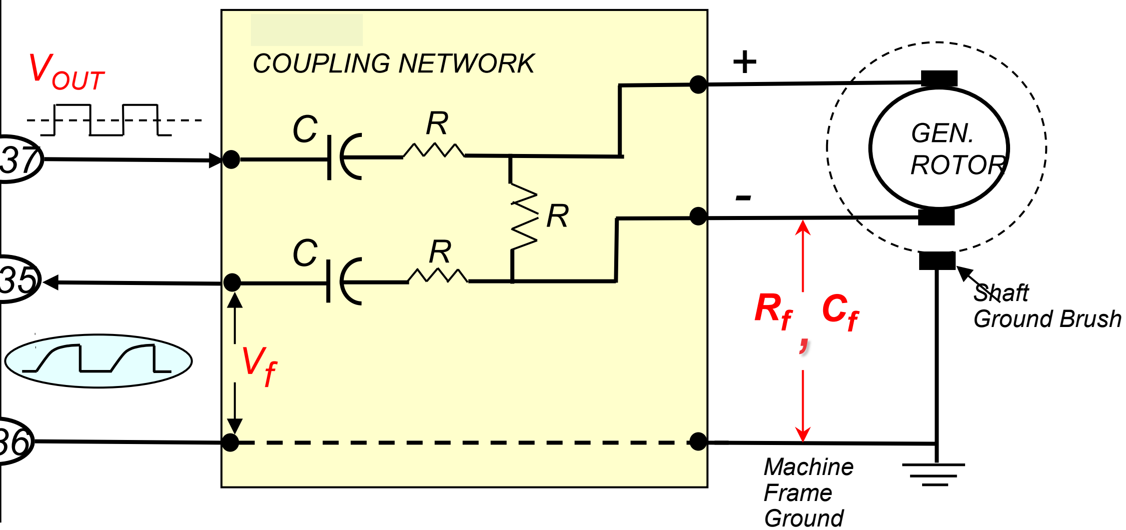


Brush Lift-Off Measurement

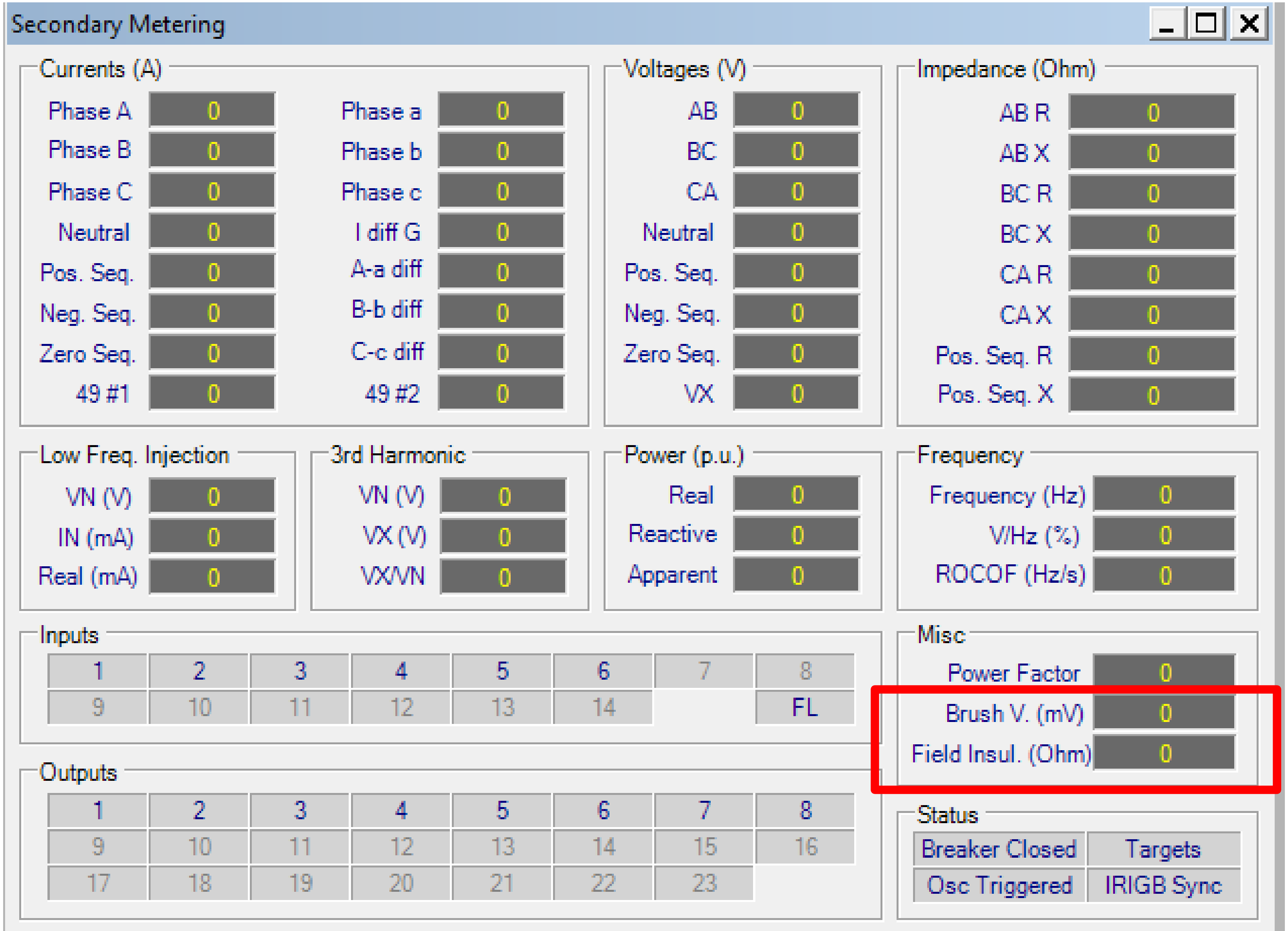
- *When brush lifts off, **V_f goes up***





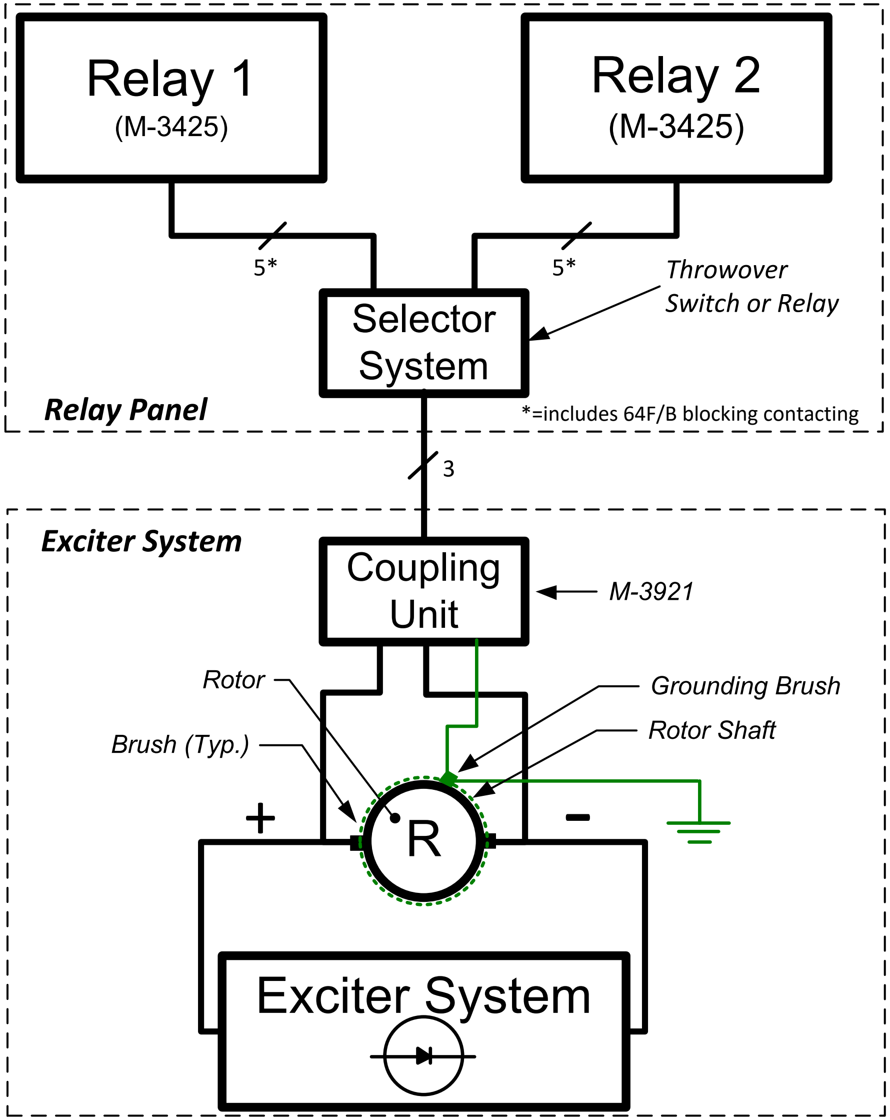


64F: Field/Rotor Ground Faults



Field/Rotor Ground Faults

- 64F/B
  - It is possible to apply two systems and have redundancy
  - The switch system is initiated by manual means or by monitoring relay self diagnostic contacts



Tripping Modes

TABLE I
TRIPPING ACTION

Tripping Mode	Generator Breakers	Field Trip	Prime Mover Trip	Transfer Auxiliaries
Simultaneous Trip	X	X	X	X
Generator Trip	X	X		X
Unit Separation Trip	X			
Sequential Trip	X*	X*	X	X*

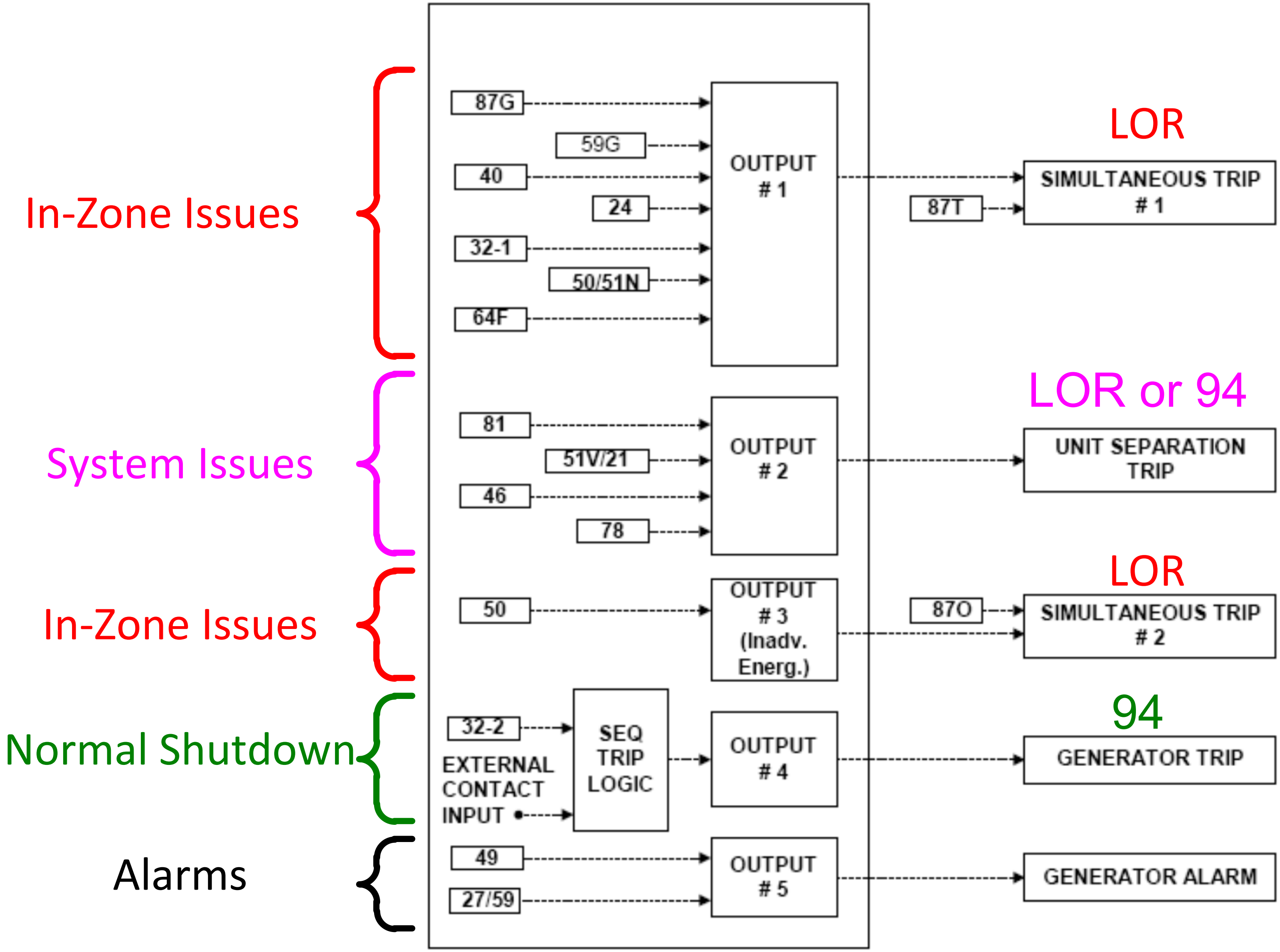
* Generally supervised by turbine valve position switch and reverse power relay

- Sometimes simple is better (KISS principle) so trip everything with everything i.e. use Simultaneous Tripping mode for all protection elements.
- Why? Because using multiple tripping modes means added complexity as different elements are mapped to different relay outputs which in turn trip different equipment, meaning more LORs, etc.
- However, if increased complexity is worth it and if procedures are in place to allow a fast re-synch to system, then may consider implementing different tripping modes with different protection elements.

Tripping Table from C37.102

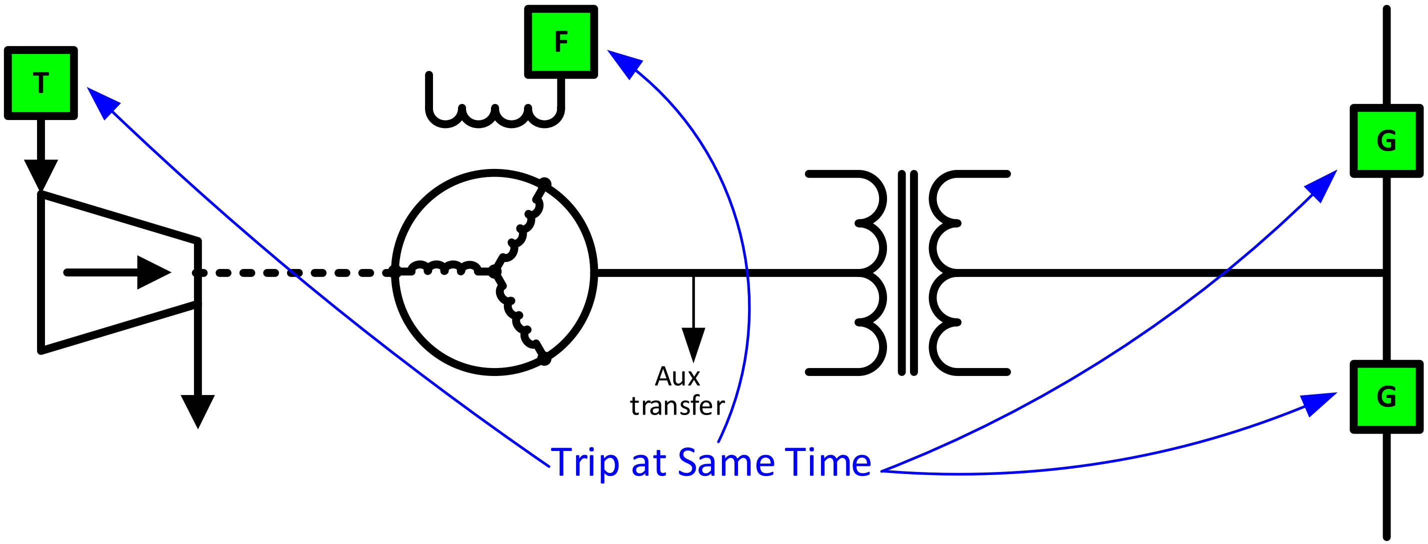
Element	Generator breaker trip	Field breaker trip	Transfer auxiliaries	Prime mover trip	Alarm only	Subclause reference
21	X					4.6.5
24	X	See Note 2	X	See Note 7		4.5.5.6
27					See Note 1	4.5.8.3
27TH	X	X	X	X		4.3.3.2.2
27THR	X	X	X	X		4.3.3.2.2
32	X	X	X	X		4.5.6.6
40	X	X	X	See Note 9		4.5.2.5
46	X	See Note 4	See Note 4	See Note 4		4.5.3.3
49					X	4.1
50/27 (See Note 6)	X	X	X	X		5.4
50BF						4.7.4
50P/52A	X	X	X	X		5.4.4
50P/59S/52A	X	X	X	X		5.4.4
50SP	X	X	X	X		4.3.2.6.2
50/51	X					4.1.2.3
50/51G	X	X	X	X		4.3.3.2.2
51G	X					4.6.5
51TG1	X					4.6.5
51TG2	X	X	X	X		4.6.5
51V	X					4.6.5
59	X	X	X	See Note 8	See Note 1	4.5.7.3
59BN	X	X	X	X		4.3.3.2.2
59G	X	X	X	X		4.3.3.2.2
59N	X	X	X	X		4.3.3.2.2
59TH	X	X	X	X		4.3.3.2.2
59THD	X	X	X	X		4.3.3.2.2
60					X	5.2.2.2
64F	See Note 3	See Note 3			X	4.4.2
64S	X	X	X	X		4.3.3.2.2
67N	X	X	X	X		4.3.3.2.2
67Q	X	X	X	X		4.3.2.6.4, 4.3.2.7
78	X	See Note 5	See Note 5	See Note 5		4.5.4.5
81	X					4.5.9.5
87G	X	X	X	X		4.3.2
87GN	X	X	X	X		4.3.3.3.2
87O	X	X	X	X		4.3.2.8
87SP	X	X	X	X		4.3.2.6.2
87T	X	X	X	X		4.3.2.8

Sample Tripping Scheme Using Different Tripping Modes



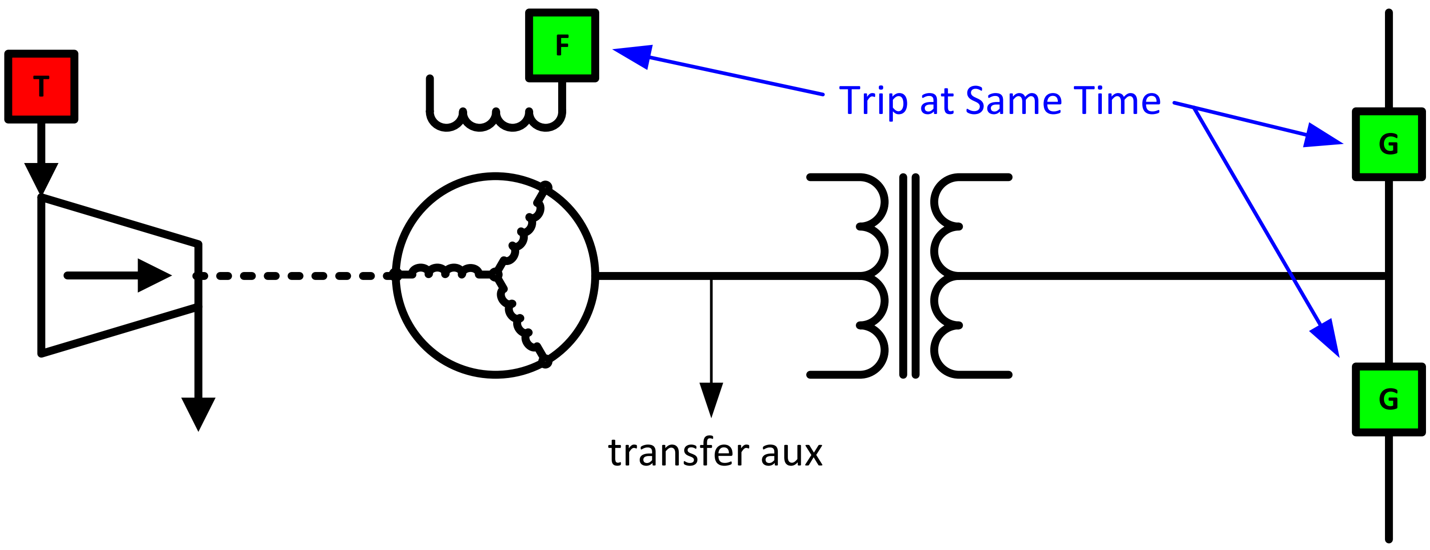
Simultaneous Trip

- *Remove all possible sources of energy feeding into the fault*
- *Provides fastest means of isolating generator*
- *Used for all internal generator faults*
- *Used for severe abnormalities in generator zone*
- *Main to Reserve Aux transfer (if aux is from GSU LS) is initiated*



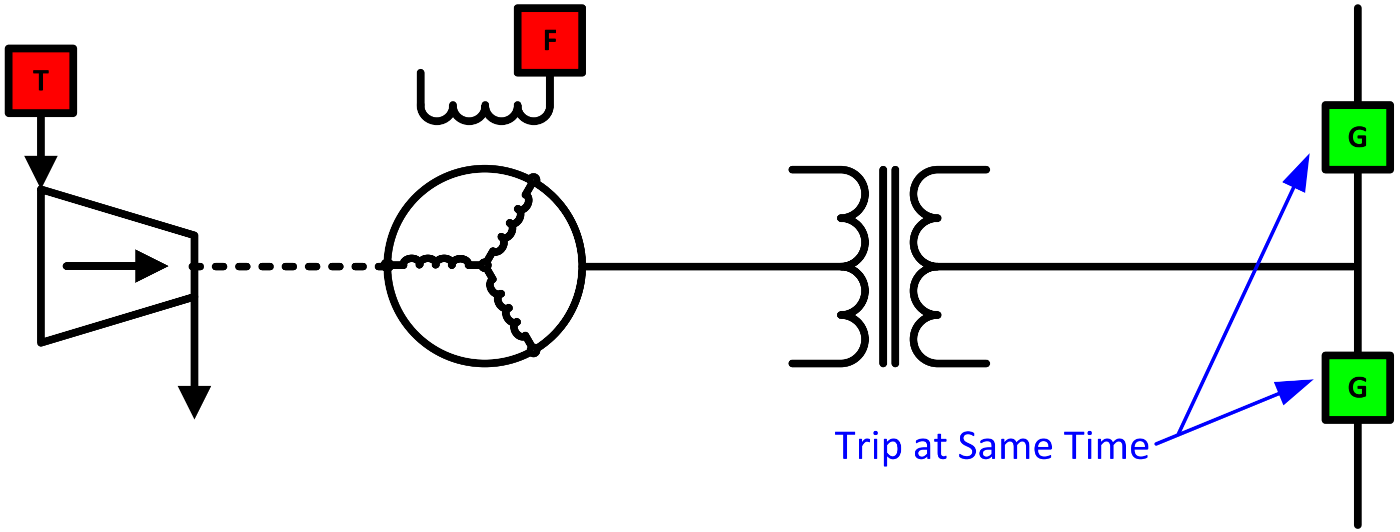
Generator Trip

- *Trip Gen Breaker, Field, and transfer auxiliaries*
- *This scheme does not shut down the prime mover*
- *Used when it may be possible to correct the abnormality quickly, thereby allowing a rapid reconnection of the machine to the system*



Unit Separation Trip

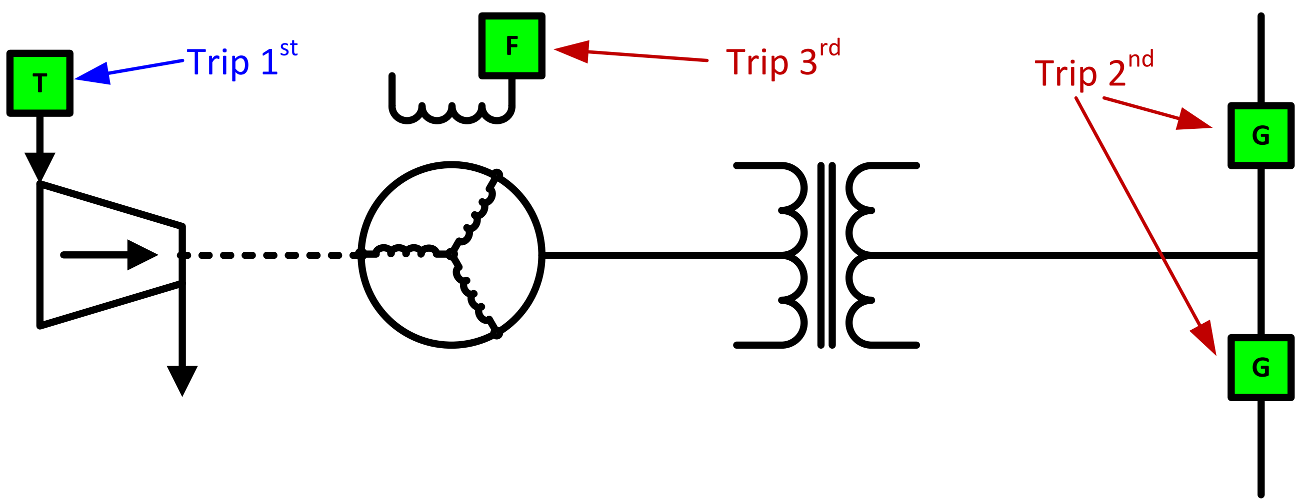
- *Used when machine is to be isolated from system, but machine is left operating so it can be synced back to the system after separating event is cleared (system issue)*
- *System faults and system abnormal operating conditions*
- *Only generator unit breakers are tripped*



Sequential Tripping

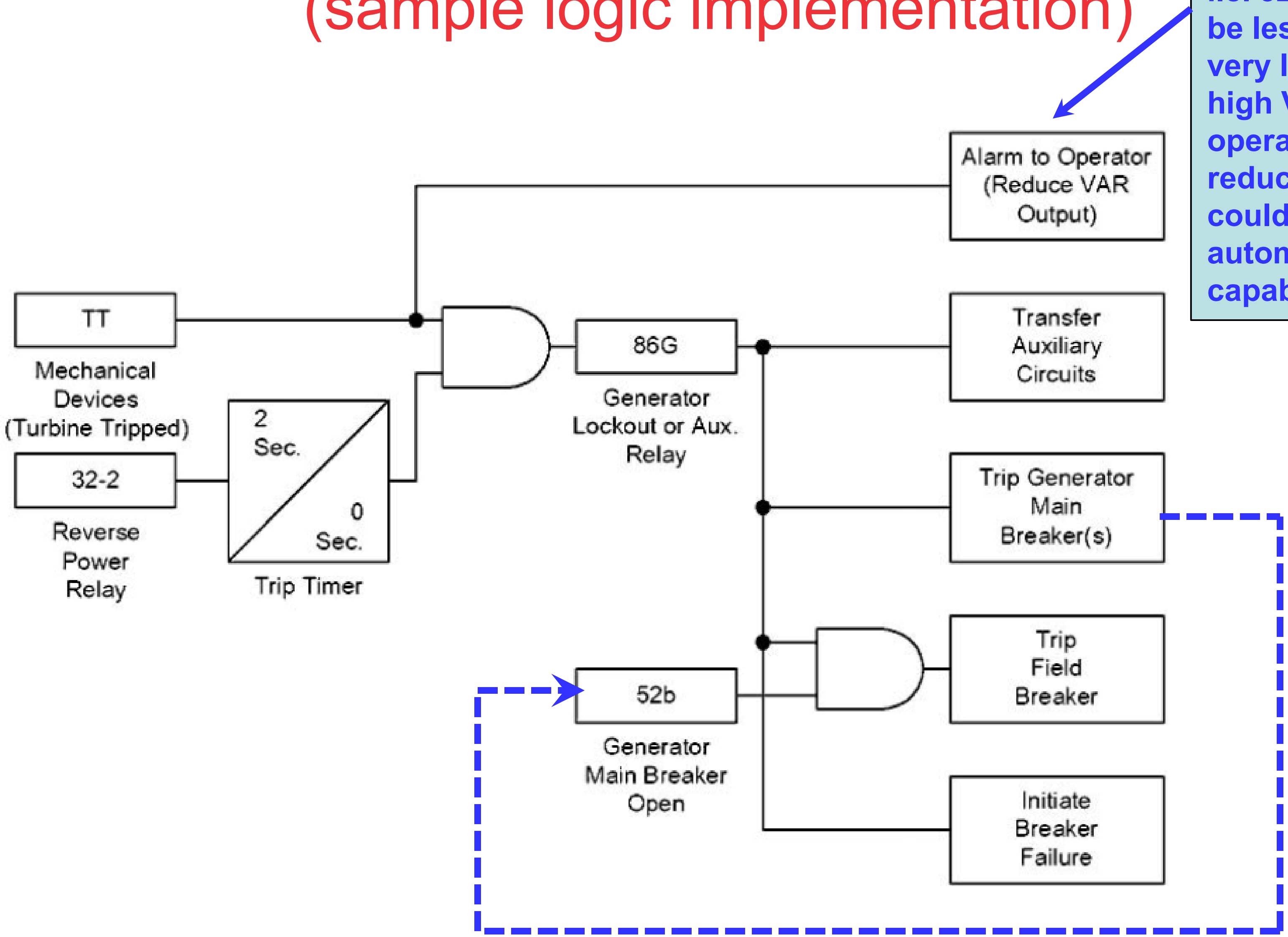
- May typically be used for steam turbines where high-speed tripping for reverse power is not required or (2) separate 32 elements may be used, one for reverse power protection and one for sequential tripping.
- Typically, used for non-electrical issues i.e. prime mover/boiler/reactor/turbine problems such as:
  - ✓ Loss of fuel to the boiler, Boiler flame out, Low lubricating oil pressure, High lubricating oil pressure, High shaft vibration, Thrust bearing wear, Low condenser vacuum, Loss of boiler fans, Loss of generator coolant
  - ✓ When the turbine has been tripped, the 32 element is used to ensure steam valves are shut to prevent overspeed, then gen breaker tripped, then the field is tripped

- May also be used for taking machine off-line (i.e. Normal Shutdown mode), e.g.:
  - ✓ operator hits "Normal Shutdown" DCS HMI button
  - ✓ Turbine is tripped
  - ✓ steam valves close (unit ramps down) and unit drifts slightly into pulling in Watts from system
  - ✓ 32 element trips Gen breaker and transfers plant load from Main to Reserve Aux (if fed from GSU LS)
  - ✓ Field breaker is tripped (supervised by "52b" from gen breaker)



Sequential Tripping scheme (sample logic implementation)

Important for 32 element sensitivity i.e. 32 element may be less accurate at very low Watts with high VARs therefore operator should reduce VARs or AVR could be set to do so automatically if capable.



Why Upgrade protection to digital relay?

- Existing E/M gen and transformer protection may:
  - Require frequent and expensive maintenance
  - Cause coordination issues with plant control (excitation, turbine control)
  - Trip on through-faults (external faults), stable power swings, load encroachment and energizing
  - Not follow NERC PRC Standards
  - Exhibit insensitivity to certain abnormal operating conditions and fault types
  - Not be self-diagnostic
  - Lack comprehensive monitoring and communications capabilities
    - Not provide valuable event information that can lead to rapid restoration
    - Part of NERC Report comments on the August 03 Blackout
  - Not be in compliance with latest ANSI/IEEE Standards
    - Asset Reliability, Insurance, Liability Issues
    - C37-102: Guide for the Protection of Synchronous Generators

Protection Upgrade Opportunities

- **Improved sensitivity**
  - Loss of Field (voltage control, pos. or neg. offset zone 2)
  - 100% stator ground fault (some E/M only covered 95%)
  - Reverse power (multiple elements)
  - Negative sequence
  - Overexcitation
- **Improved Security**
  - Directionally supervised ground differential protection
  - Distance Element Enhancements
    - Load encroachment blinding
    - Power swing blocking (for stable swings)

Protection Upgrade Opportunities

- **New functions generally available in digital relays as opposed to E/M relays:**
  - 50/27
  - 64S
  - 60FL (integrated)
  - TCM
  - Blocking Inputs
  - Isync Trip
  - 59N accelerated schemes
  - Breaker Flashover

Interface and Analysis Software: Desirable Attributes

- NERC "State of Reliability 2017"
- 37% (28% + 9%) of Relay Misoperations are due to human error
  - Programming too complex
  - Commissioning difficult
  - Periodic Testing difficult

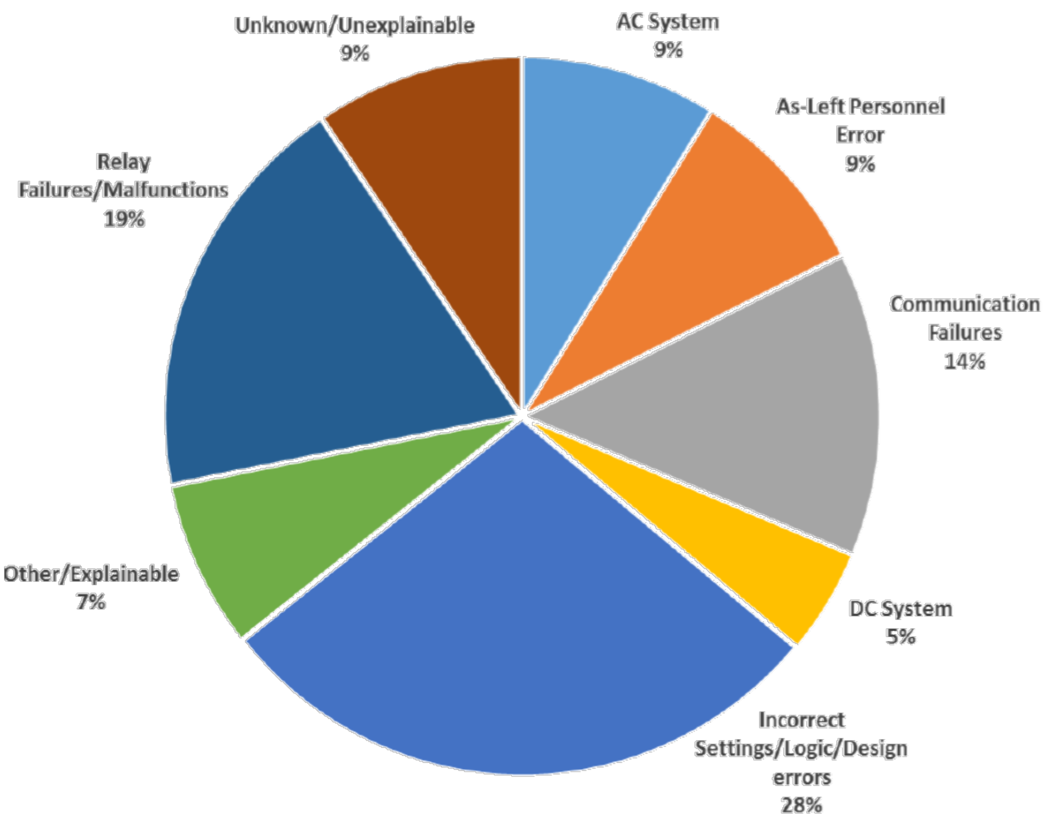


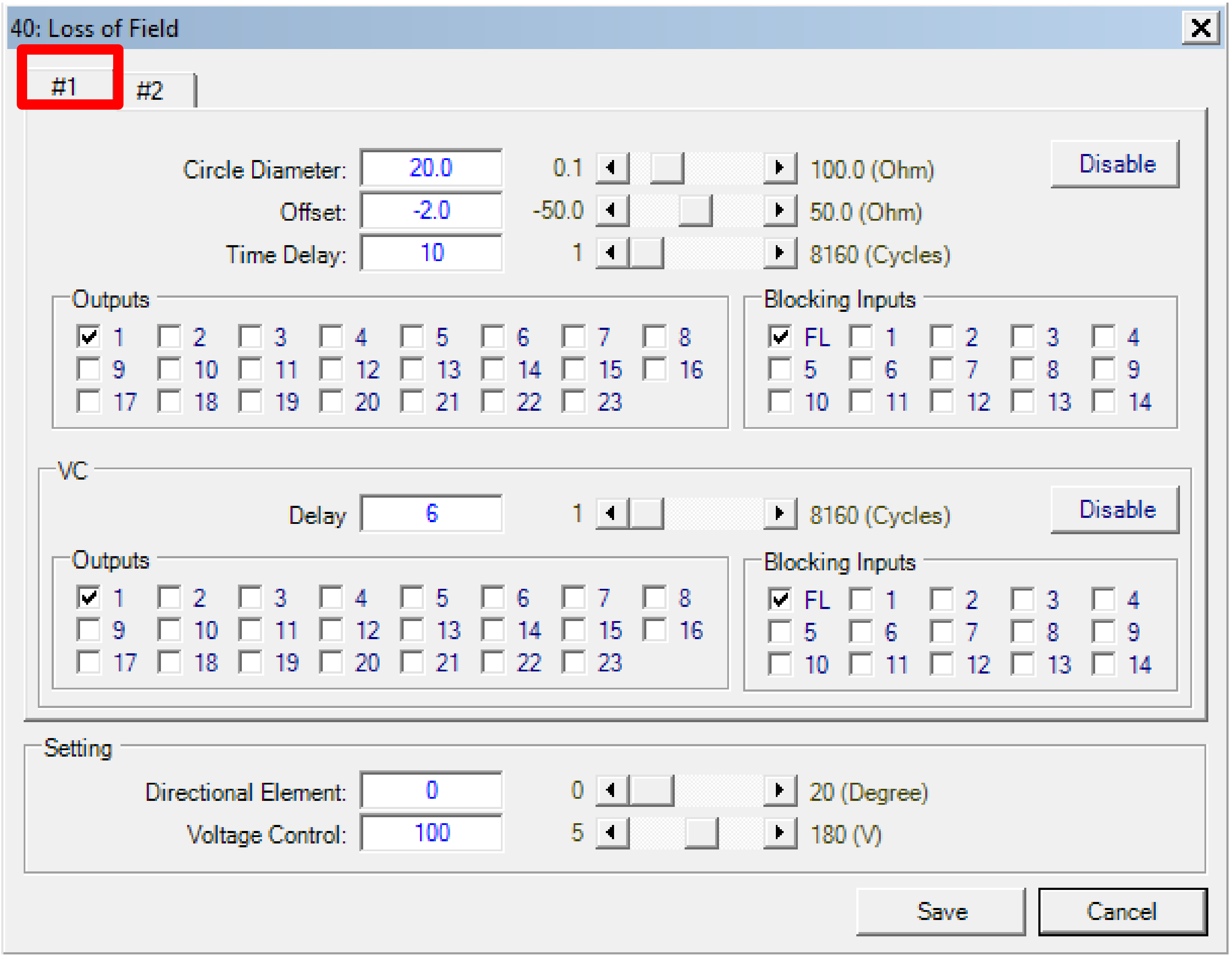
Figure E.21: NERC Misoperations by Cause Code (2Q 2012–3Q 2016)

Interface and Analysis Software: Desirable Attributes

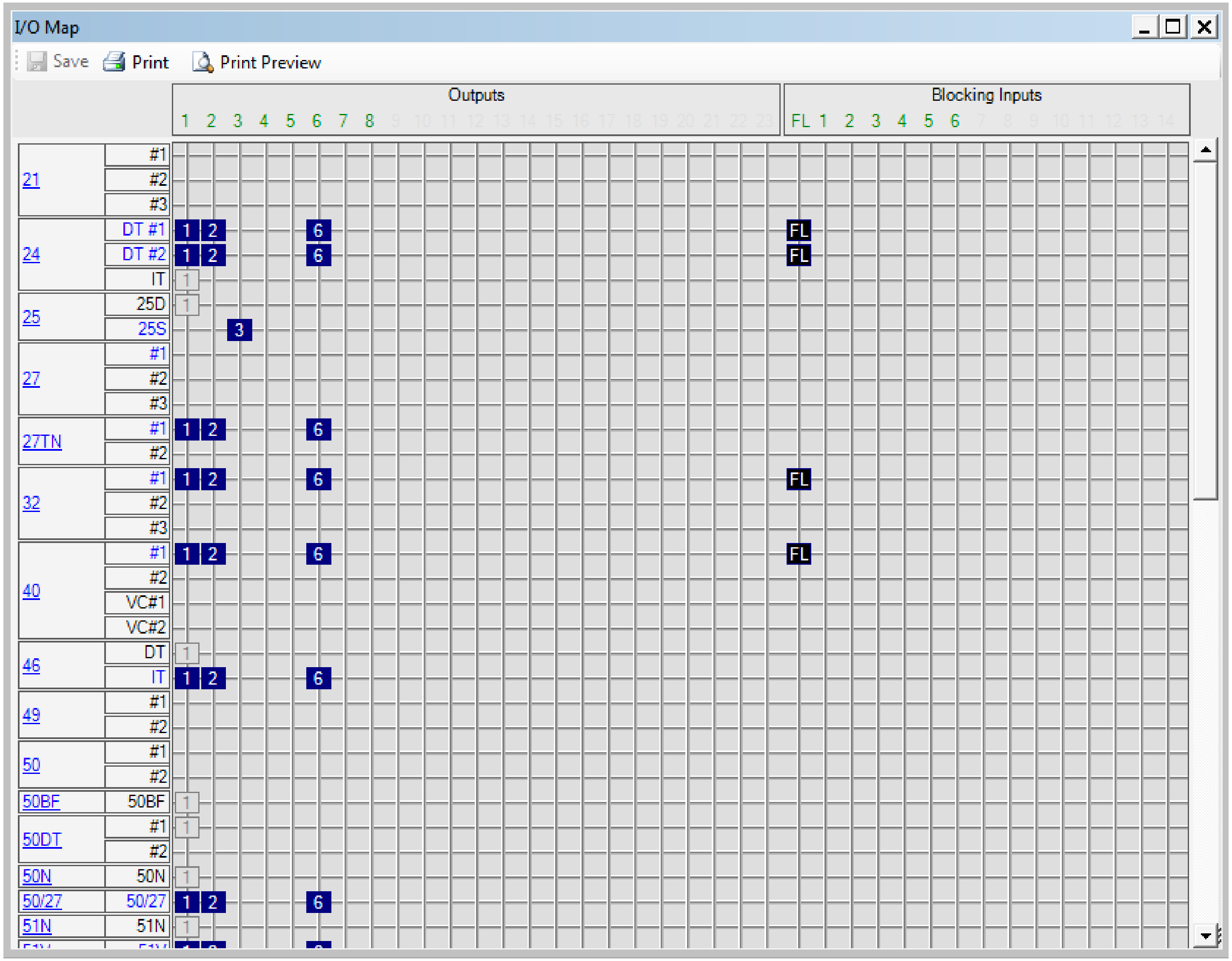
- PC Software package for setpoint interrogation and modification, metering, monitoring, and downloading oscillography records
- Oscillography Analysis Software package employs graphical displays to facilitate analysis, and print captured waveforms
- Be menu-driven, graphical, simple to use
- Autodocumentation to eliminate transcription errors

Example: Element Selection

Example: Element Setting



Example: I/O Assignment



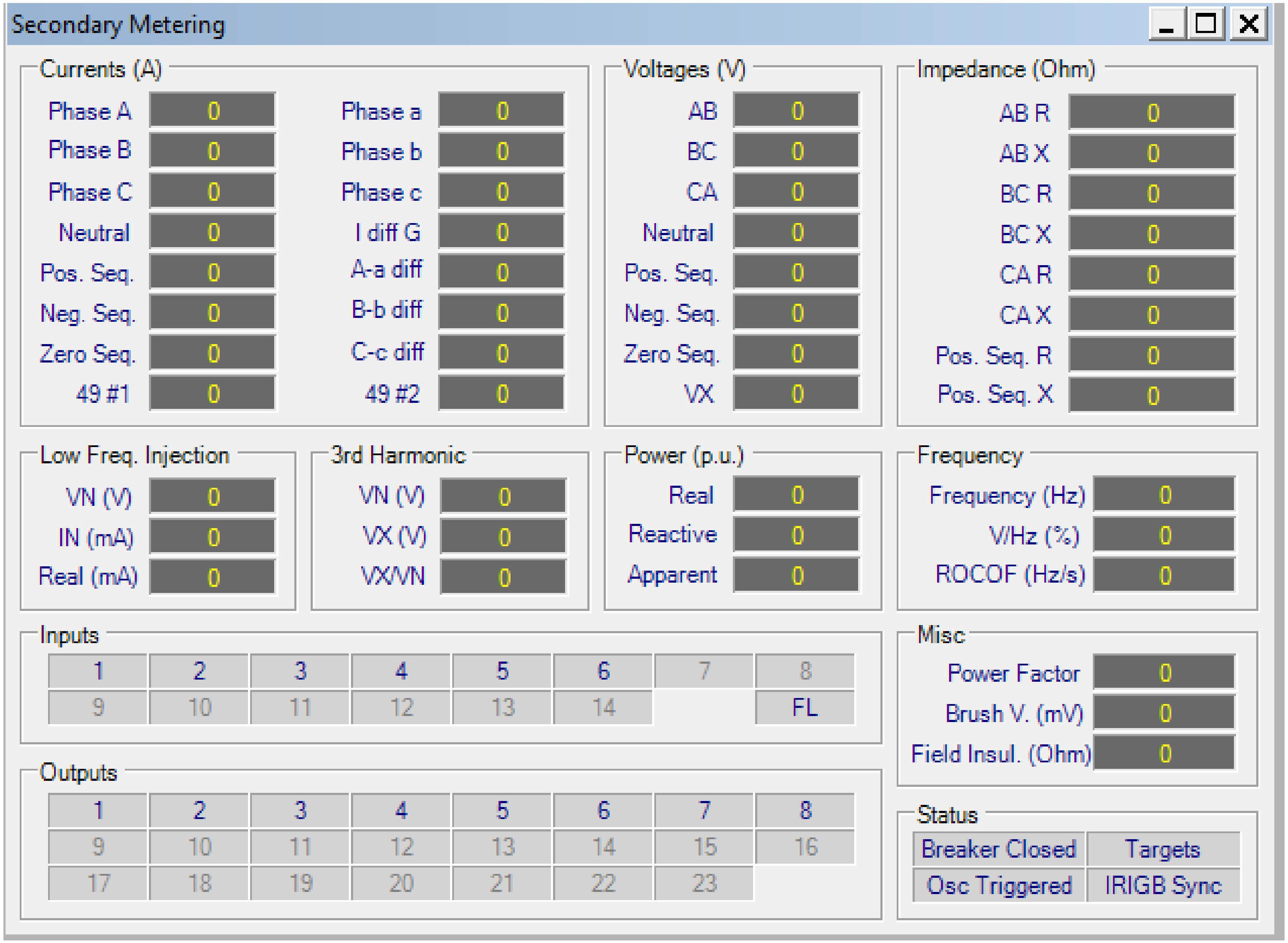
Graphic Metering and Monitoring

- **Metering of all measured inputs**
  - Measured and calculated quantities
    - Instrumentation grade

- **Commissioning and Analysis Tools**
  - Advanced metering
  - Event logs
  - Vector meters
  - R-X Graphics
  - Oscillograph recording

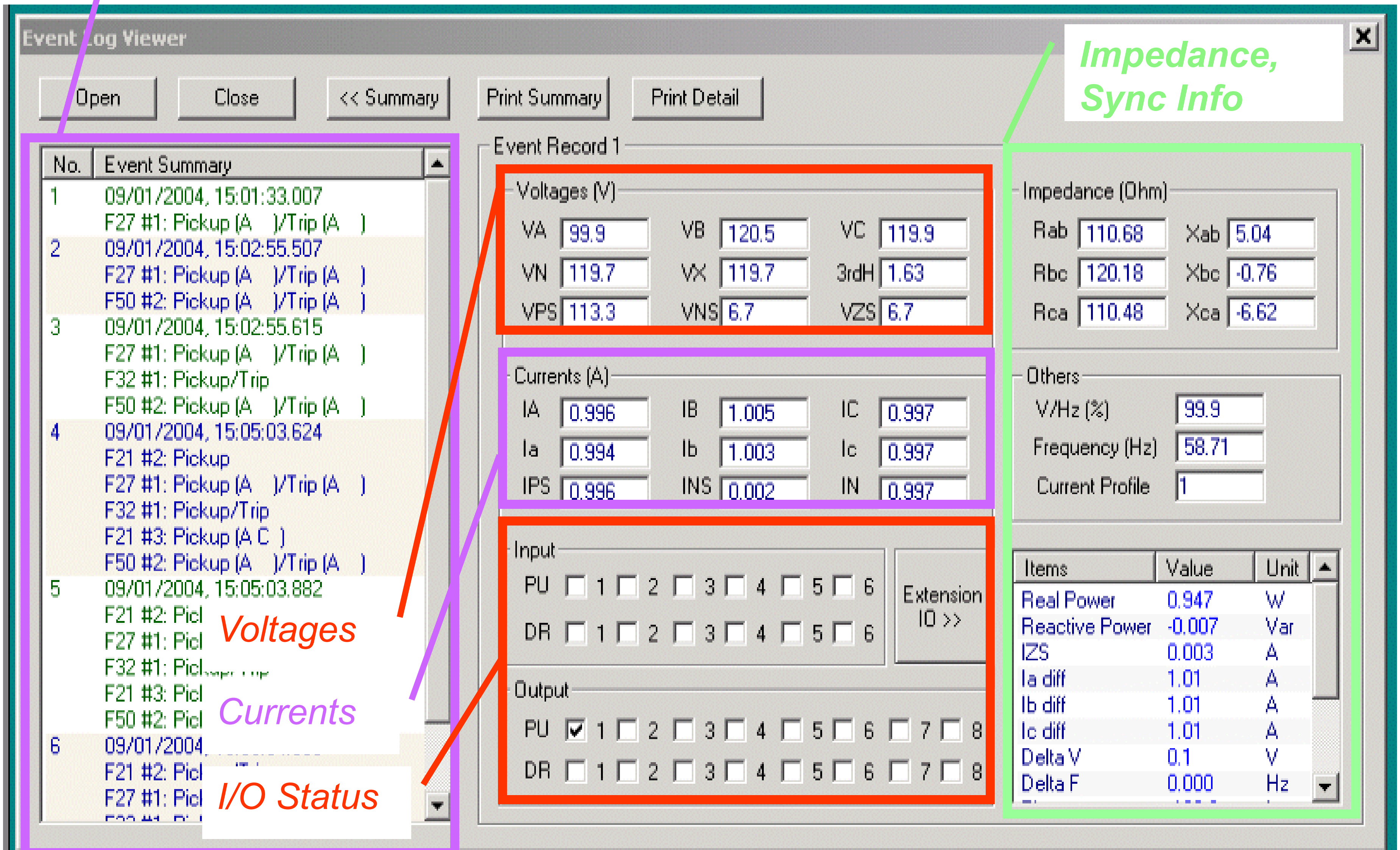
Metering of all measured inputs

- displays measured and calculated quantities

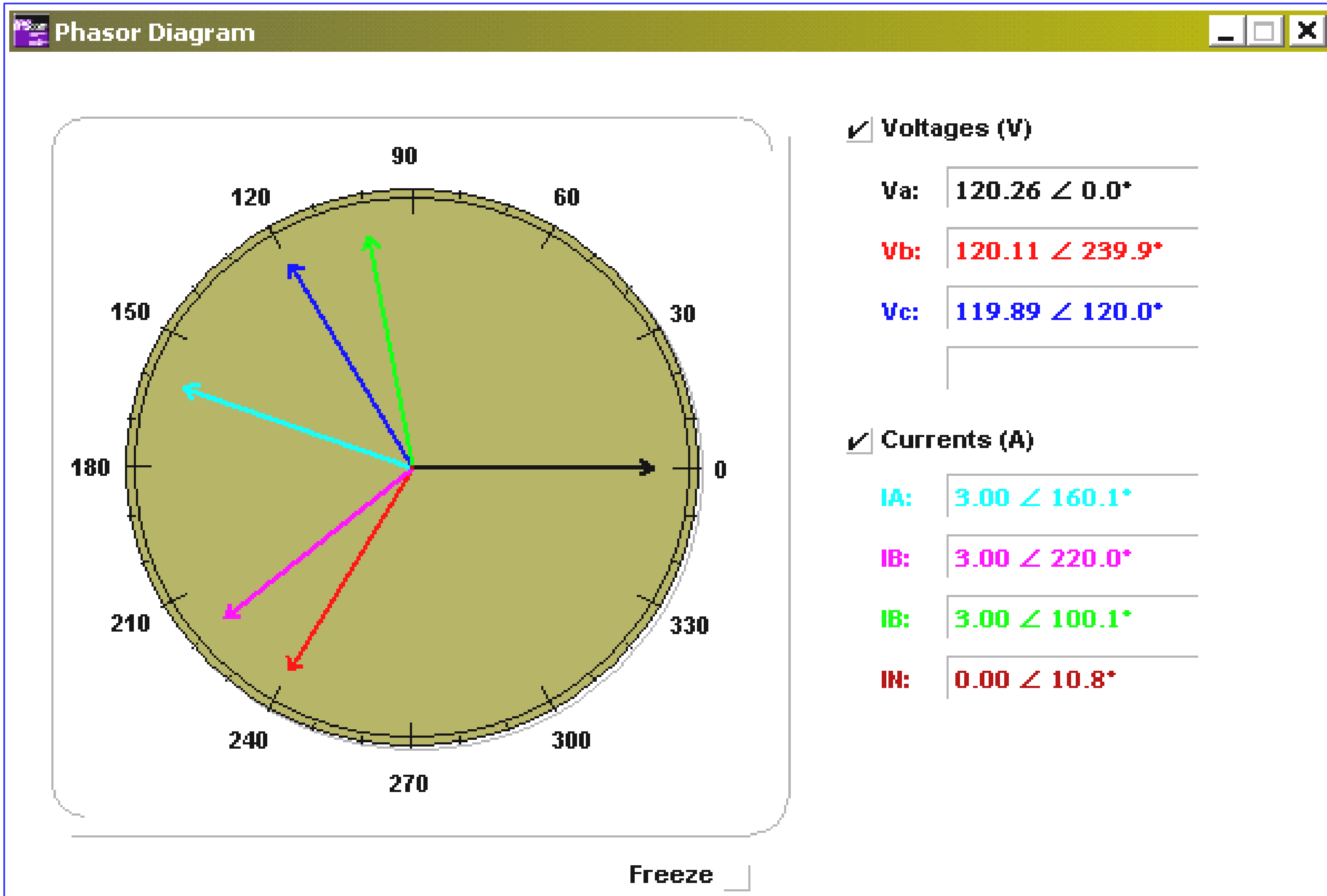


Event Log (512) Events

Pick up, drop out, trip
Event #, Date, Time

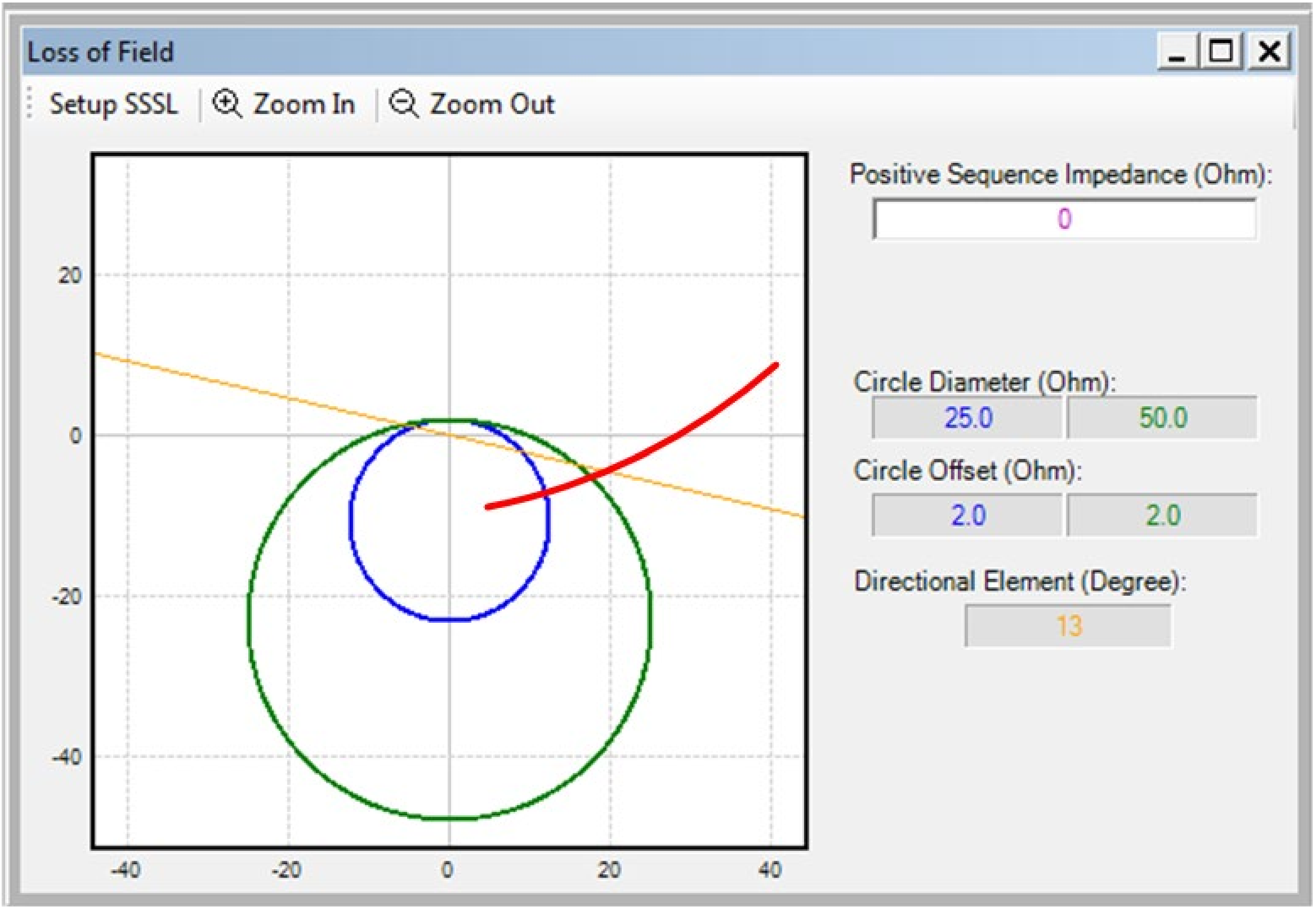


Phasor Display (Vectors)



Phase A Current "Rolled"

R-X Diagram: 40/Loss-of-Field (also 21, 78)



Provides the ability to check settings, view testing, event playback.

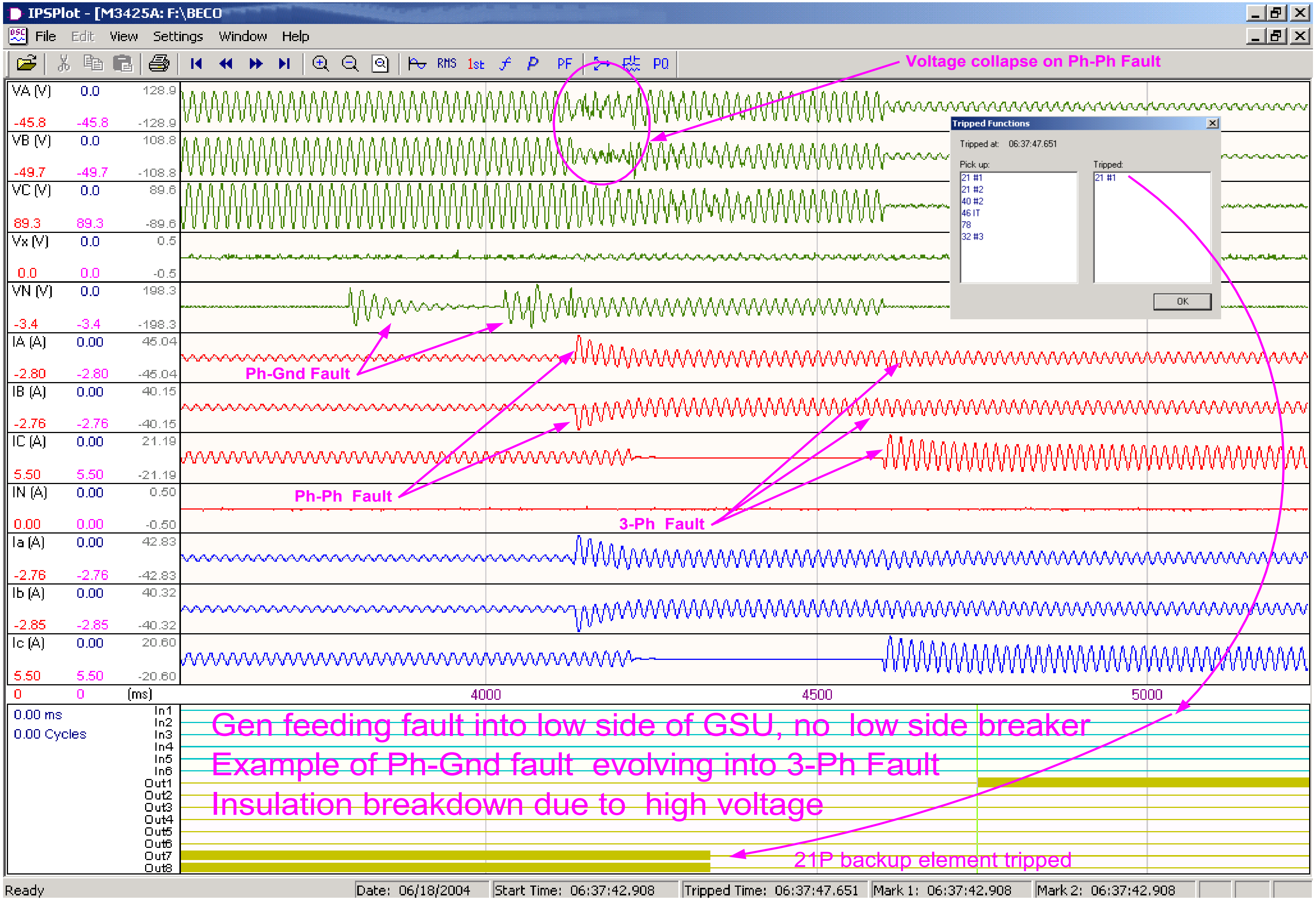
Oscillography

- **Determine if relay and circuit breaker operated properly**
  - Identify relay, control or breaker problem
  - Generators do experience faults / abnormal conditions
    - In the machine or the system?
- **Speed generator's return to service**
  - Identify type of testing needed
  - Provide data to generator manufacturer
- **Gives plant engineer data to recommend inspection/testing**
- **Uncovers unexpected problems**
  - Synchronizing, shutdown

❑ Retrieve oscillograph records via both:

- ✓ BECO format (.osc) – to view elements that picked up and tripped
- ✓ COMTRADE format (.cfg, .dat) – to playback event and to view event with software other than IPSplot PLUS

Long Records Let You See the Issue – 416 cycles



Questions?

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