Generation Protection Calculations and Settings

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Power Plant Protection Track
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- **27TN – Third Harmonic Neutral Undervoltage**
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Ground Fault Protection (Low-Impedance Grounded Gens)

- 87GD – Ground Differential Current
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System Backup Protection for Phase Faults

- 21 – Phase Distance
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TOC – Calcs & Settings (continued)

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49 – Stator Thermal Overload

Isync Trip

50BF – Breaker Failure

61BF – Breaker Pole Flashover

59X (3Vo) – Bus Gnd Overvoltage

64F/B – Field Ground Protection

Blocking Inputs

Information required for relay calculations

- Gather as much of the following information as possible.
  - If some of this information is not available from mfg, may refer to specific industry guidance, standards, etc.

- **Gen/Turbine Nameplate, Data Sheets, Capability Curves**
  - ✓ *GCC (for 40 & 21 coordination, PRC evaluations, etc)*
  - ✓ *V/Hz withstand capability curve (24, 59 @ 60 Hz)*
  - ✓ *Stator winding pitch diagram and factor (27TN, 59D)*
  - ✓ *friction, windage, iron, rotor, excitation, turbine losses (32)*
  - ✓ *motoring withstand time (32)*
  - ✓ *continuous and short time I_2 rating/curves (46)*
  - ✓ *mechanical thermal overload curve and time constant (49)*
  - ✓ *Off-nominal frequency capability curve (81O/U)*
  - ✓ *mechanical overspeed device (12) settings (off-line 81O)*

- **Excitation Control System settings/curves (PRC-019 coord)**
  - ✓ *24EX, 40EX, 59EX, VPFL, UEL, OEL, Field I*t*

- **GSU Nameplate, Data Sheets**
  - ✓ *V/Hz withstand capability curve (24, 59 @ 60 Hz)*
  - ✓ *GIC withstand capability curve (NERC TPL-007)*

- **Gen Breaker Nameplate**
  - ✓ *Speed Test, rated interrupt time (50BF)*
  - ✓ *out-of-phase interrupt rating (78)*

- **Run as synch condenser? (32, 40, 46, 24)**
- **Round Rotor – Directly or Indirectly cooled? (46)**
- **Salient Pole – Connected Damper windings? (46)**
- **Black start capable? (Isync trip, 25)**
- **NGT and NGR information (59N, 64S)**
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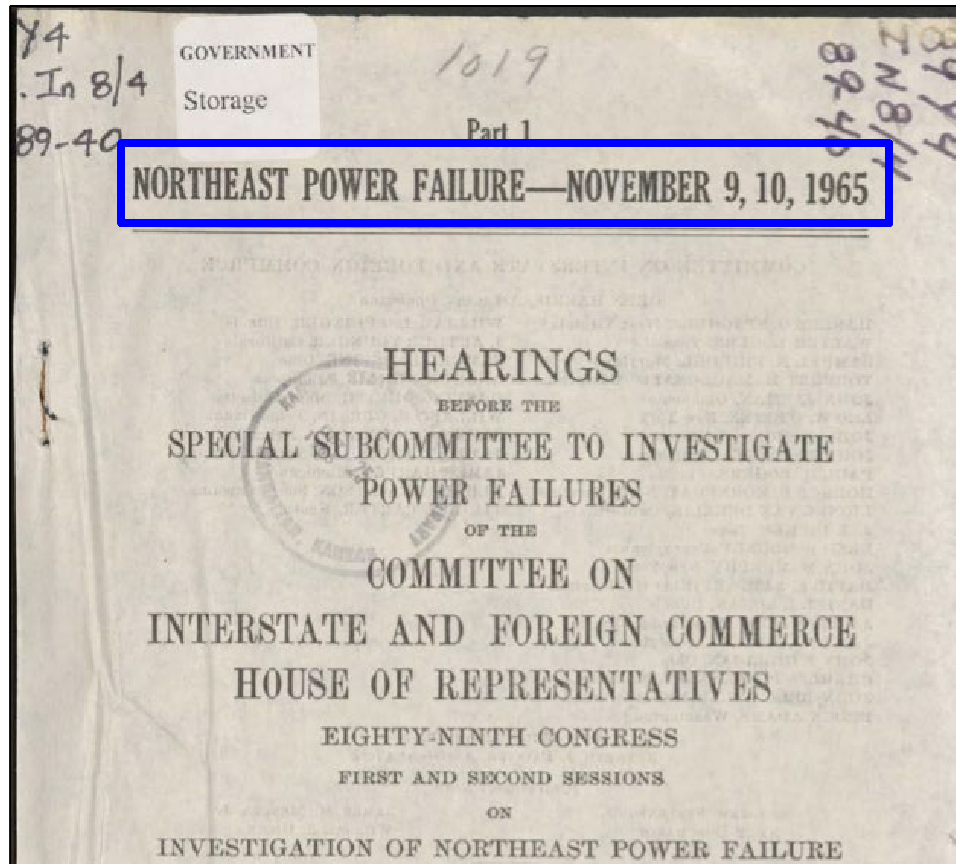
- **CT Saturation Curves (87)**
- **Drawings: 1-line, 3-lines, DC Schematics, relay I/O**
- **System Thevenin equivalent impedances on GSU HS w/o gen**
- **Fault Study**
- **Transient Stability Study (21 with PSB, 40, 50BF for CCT, 78)**
- **Tripping mode requirements: simultaneous, sequential, etc.**

NERC (North American Electric Reliability Corporation)

- FERC (Federal Energy Regulatory Commission) oversees NERC.
- NERC develops standards for the reliable operation of the bulk power system.
- NERC covers the continental United States, Canada, and the northern portion of Baja California, Mexico.
- NERC was first created in 1968 after investigating the 1965 NE blackout:

30 million people out-of-service

- ✓ Initial cause was a transmission line 21 zone 3 setting that picked up on load, which could have been avoided if the relay engineer had checked the "MVA to Trip" ($S=V^2/Z$) of the 21 zone 3 setting.
- ✓ Initially, NERC did issue some general reliability guidelines, but there was no mandatory compliance as it was all voluntary and many utilities did not follow the guidelines.
- ✓ Now, the "MVA to Trip" security check is covered in NERC Relay Loadability Standards PRC-023 (Transmission) and PRC-025 (Generation).



Part 1

NORTHEAST POWER FAILURE—NOVEMBER 9, 10, 1965

HEARINGS

BEFORE THE

SPECIAL SUBCOMMITTEE TO INVESTIGATE POWER FAILURES

OF THE

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

HOUSE OF REPRESENTATIVES

EIGHTY-NINTH CONGRESS

FIRST AND SECOND SESSIONS

ON

INVESTIGATION OF NORTHEAST POWER FAILURE

Transmission – Generator System Coordination

Why is NERC so concerned about Transmission – Generator system coordination?

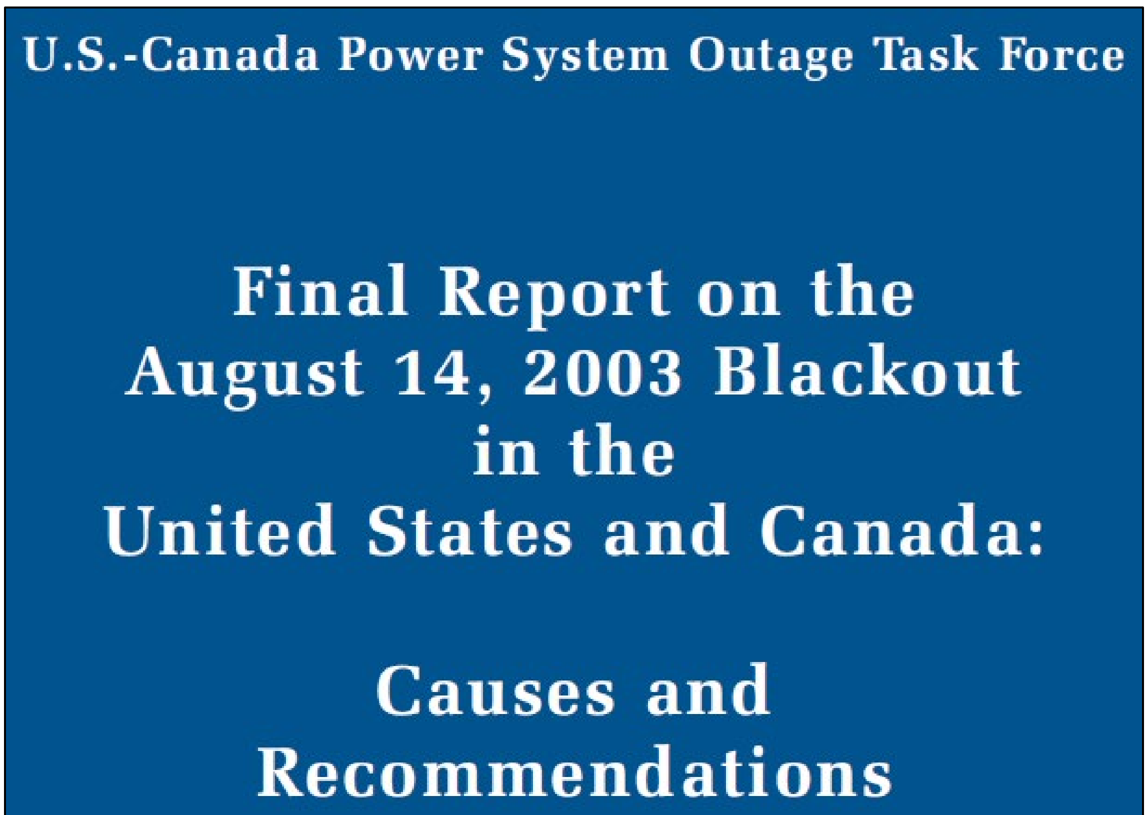
THE 2003 East Coast Blackout:

- Biggest Blackout in North American History
- Largest Area Ever Involved in a Blackout
- 290 Generator Trips – Most Tripped Improperly
- 52,743 MW Lost

50 million people out-of-service

2003 North East Blackout – how it happened

- First, system voltage was depressed from faults and transmission line trips.
- Then, generators gave VAR support via field forcing to help the system voltage.
- Some gens tripped before they needed to (relays set too sensitive or just wrong).
- Therefore, the tripped gens were no longer available to provide voltage support.
- This resulted in cascading system voltage collapse and a much wider outage.
- This outage was studied in detail and documented in report:


U.S.-Canada Power System Outage Task Force

Final Report on the
August 14, 2003 Blackout
in the
United States and Canada:

Causes and
Recommendations

2003 North East Blackout

- Which relay elements tripped during this outage?

Table 1: 2003 Blackout Generation Protection Trips															
Function Type	21	24	27	32	40	46	50/27	50 BF	51V	59	78	81	87T	Unknown	Total
Number of Units	8	1	35	8	13	5	7	1	20	26	7	59	4	96	290

- Were some correct trips? Yes.
- Were some trips due to incorrect relay settings or settings that were overly and unnecessarily sensitive? Yes.

- After thoroughly studying this outage, NERC created standards with specific relay setting criteria to maintain system reliability.
- In 2007, FERC approved these NERC relay setting standards where compliance became mandatory and legally enforceable.
- **What are these new NERC PRC gen relay settings standards?**

NERC PRC standards for BES plants

NERC Standard	Gen Relay Settings
PRC-019	24, 40, 59
PRC-024	24 at 60 Hz, 27, 59, 81
PRC-025	21, 51V, 50, 50DT
PRC-026	21, 40, 78, 50, 50DT
PRC-027	various

- This list may not include all settings requiring evaluation.
- Gen relay settings compliance will be shown.
- GSU relay settings compliance will not be shown in this presentation.
- UAT & export line relay settings compliance will not be shown.

- **Next several slides are just a brief introduction to these standards.**
- **Detailed calculations, coordination plots, and evaluation against the criteria as outlined in the standards will be presented at the end of each relay element's section (when applicable).**

These standards outline criteria for gens to stay on-line (without damaging equipment) to provide system support and avoid a wider outage i.e. they require secure relay settings, so the generators do not trip unless they need to, as opposed to being set overly sensitive.

PRC-019

Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Purpose: To verify coordination of generating unit Facility or synchronous Condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

- in-service limiters are set to operate prior to the protection elements tripping
- protective elements will trip prior to equipment damage or stability limits

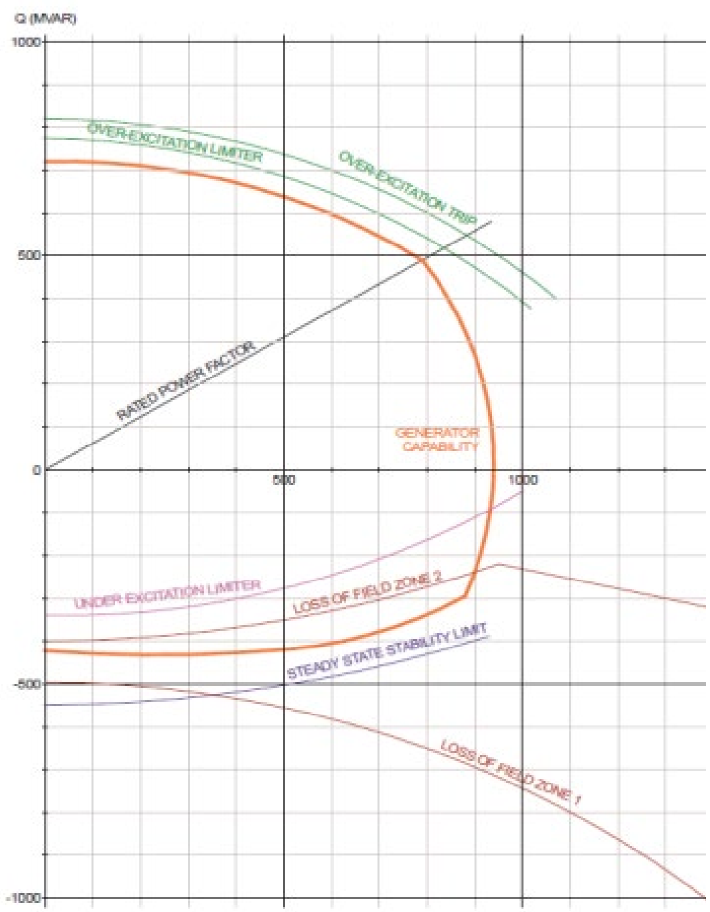
Limiters < Protection < GCC/SSSL

First, the Limiter (UEL, OEL, V/Hz Limiter, etc) should be given a chance to address the issue; however, if the Limiter cannot fix it within a certain time, then the relay (40, 24, etc) should trip to protect the generator and ensure stability.

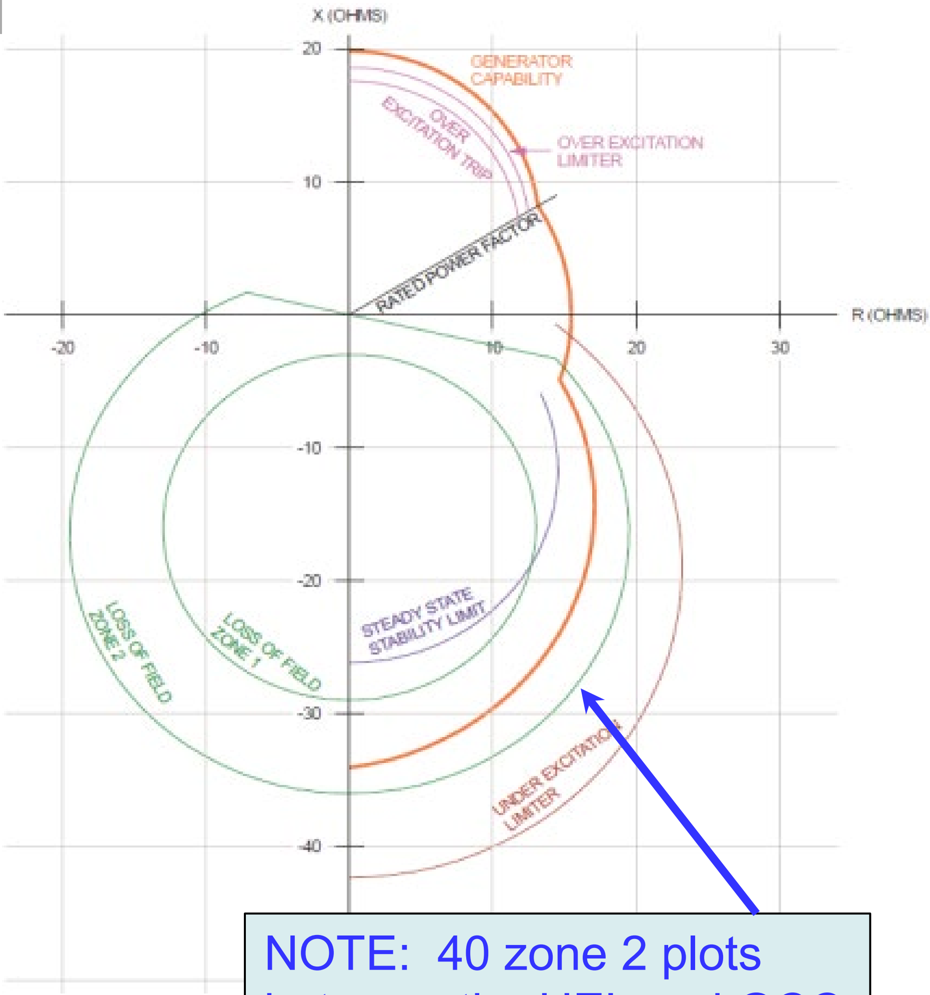
PRC-019

PQ and RX diagram examples

Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal v frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal frequency



NOTE: 40 zone 2 plots between the UEL and GCC

PRC-019

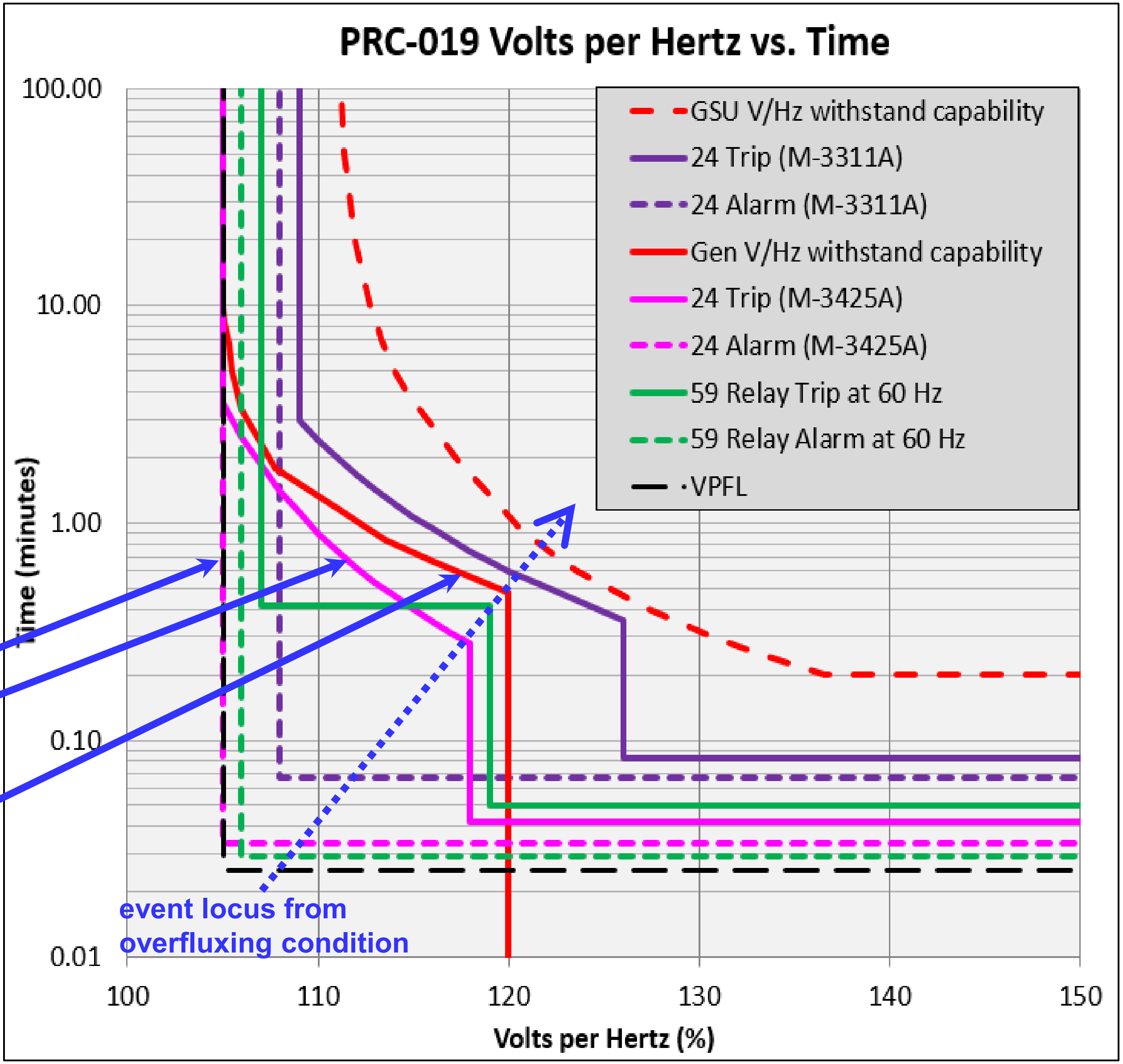
As V/Hz and/or Time increase, the V/Hz operating locus will travel to the right and upward traversing, in order:

1st – VPFL (Limiter)

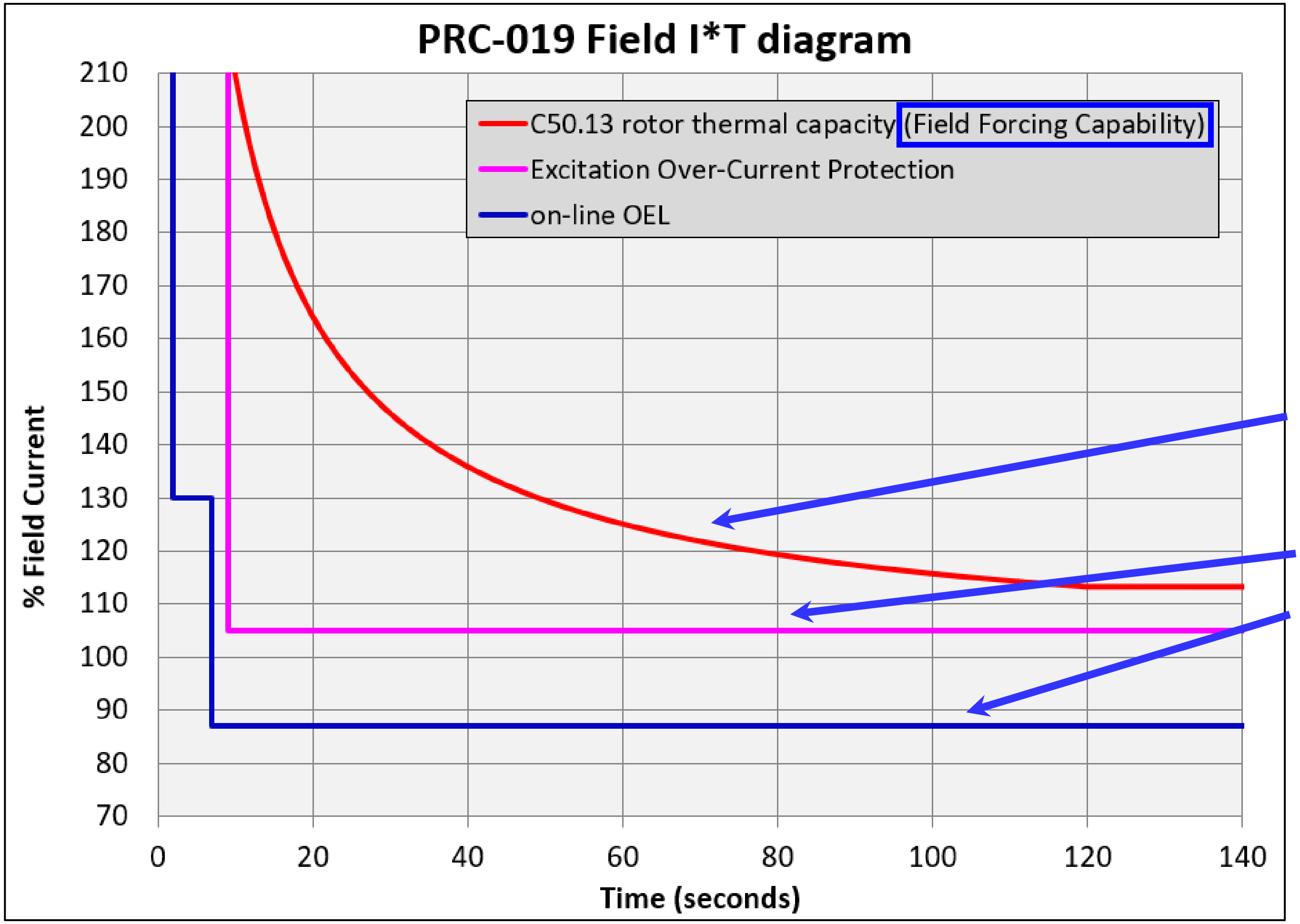
2nd – 24 trip

3rd – V/Hz withstand

Therefore, these 24 & 59 settings are shown to comply.



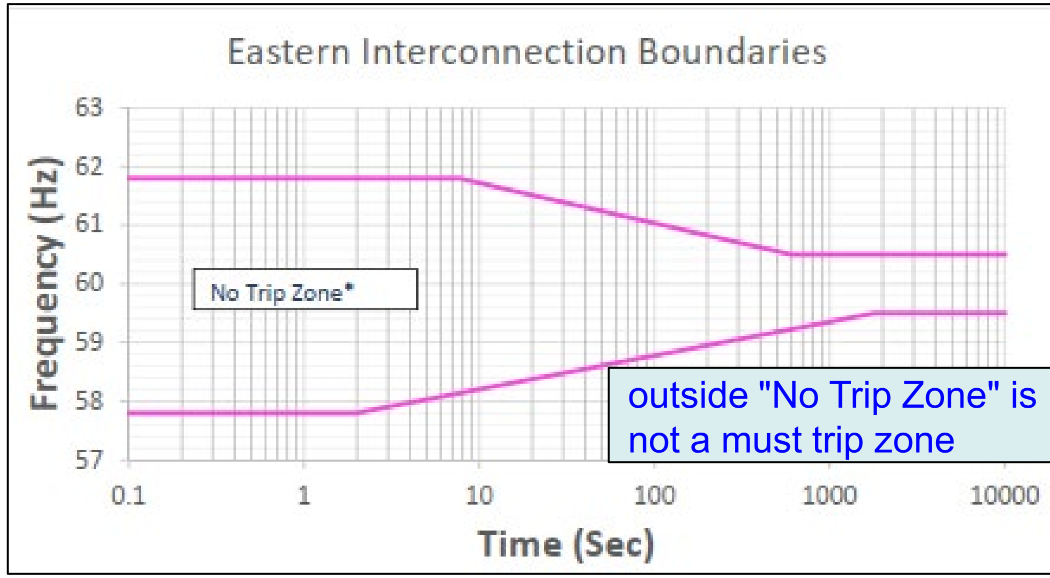
PRC-019



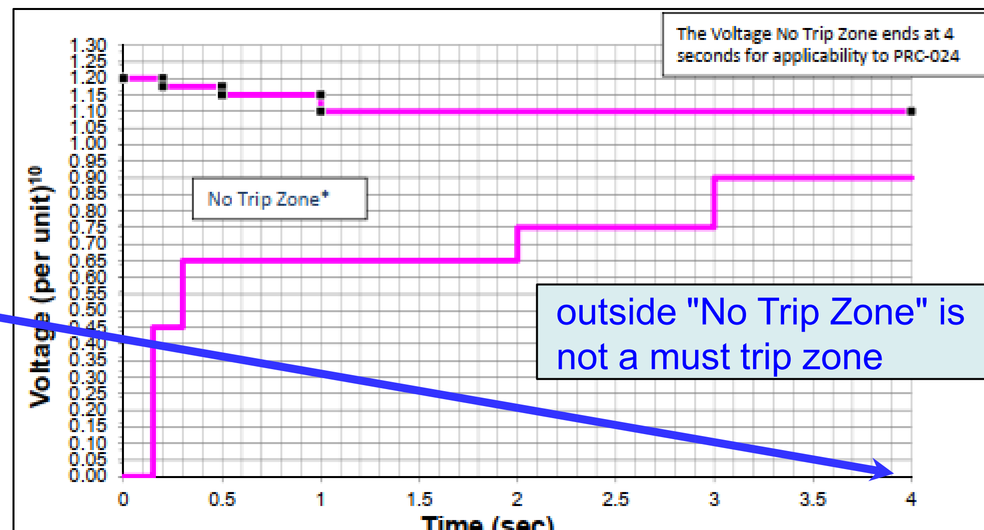
Yes, it complies:

- 3rd – rotor thermal capacity per C50.13
- 2nd – Field I*T trip
- 1st – OEL

PRC-024: Generator Frequency and Voltage Protective Relay Settings



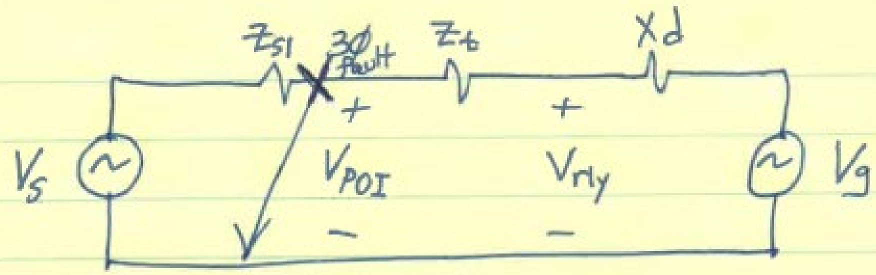
Purpose: Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.



NOTE: The requirements in this standard for the voltage coordination go up to **4 seconds** only, i.e. any relay settings or excitation settings that are inside the "No Trip Zone" but have time delays greater than 4 seconds, are not in violation.

PRC-024

- PRC-024 voltage no trip zone points are given at POI (Point of Interconnect).
- POI is on the HS of the GSU.
- Gen VTs feeding 27, 59, 24 @ 60 Hz protection are on LS of GSU.
- Must transfer PRC-024 points from GSU HS to GSU LS to compare apples to apples.
- NERC also has an **Implementation Guide** available on the NERC website, where they transfer the GSU LS relay setting to the GSU HS POI instead of the way I have done it here.



$$V_{rly} = Z_t I_d + V_{POI}$$

where:

$V_{POI} = 1.2, 1.175, 1.15, 1.10, 0.45, 0.65, 0.75, 0.90$

$$I_d = \frac{(P + jQ)^*}{\sqrt{3}\, V_{gen}}$$

where: $P = P_{rated} = PF_{rated} * S_{base}$

$$Q = S_{base} * \sin(\cos^{-1}(0.95))$$

↑ from PRC-024-2 pg 11 of 12 section I.C

$$V_{gen} = V_{LS} \left(\frac{V_{HS}}{V_{gsuHStap}} \right)$$

PRC-025

Generator Relay Loadability

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system Disturbance for conditions that do not pose a risk of damage to the associated Equipment.

PRC-025

PRC-025-2 One-Line

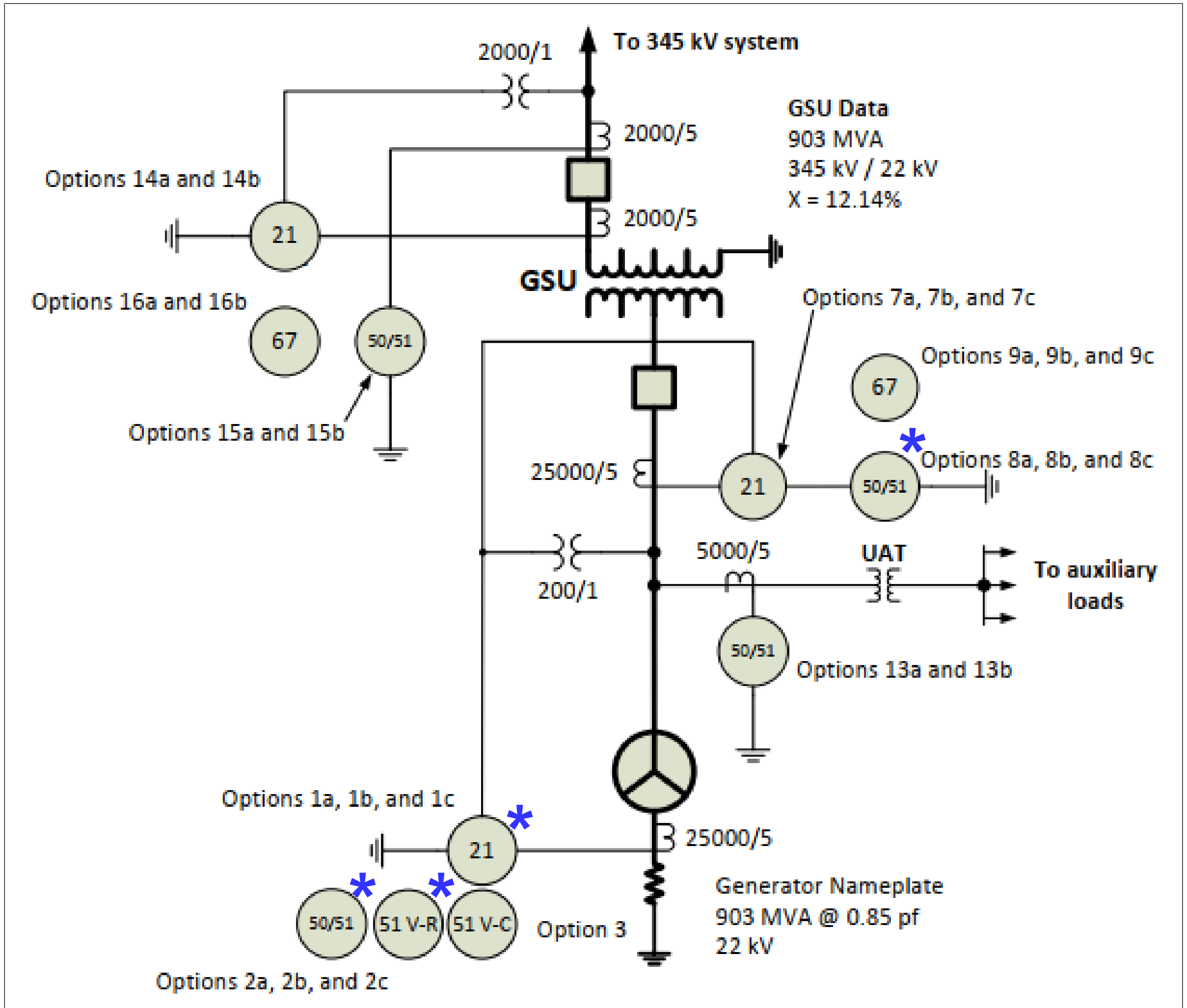


Figure 5: Relay Connection for corresponding synchronous options

*** specific protective functions to be set and evaluated against the PRC-025 criteria in this presentation.**

PRC-025-2 Exclusions:

- Isync Trip (OOPS protection)
- 50/27, Breaker Flashover
- 50FD with 21
- LOP armed 50
- RAS
- 49 (50/51)
- 50 O.L. > 15 minutes
- Non-adjustable LV devices

Beware of this gotcha:

Per PRC-025-2 Guidelines and Technical Basis:

- ***Use Gross MW as reported to the Transmission Planner***
- ***This can be different than the MW at rated PF***

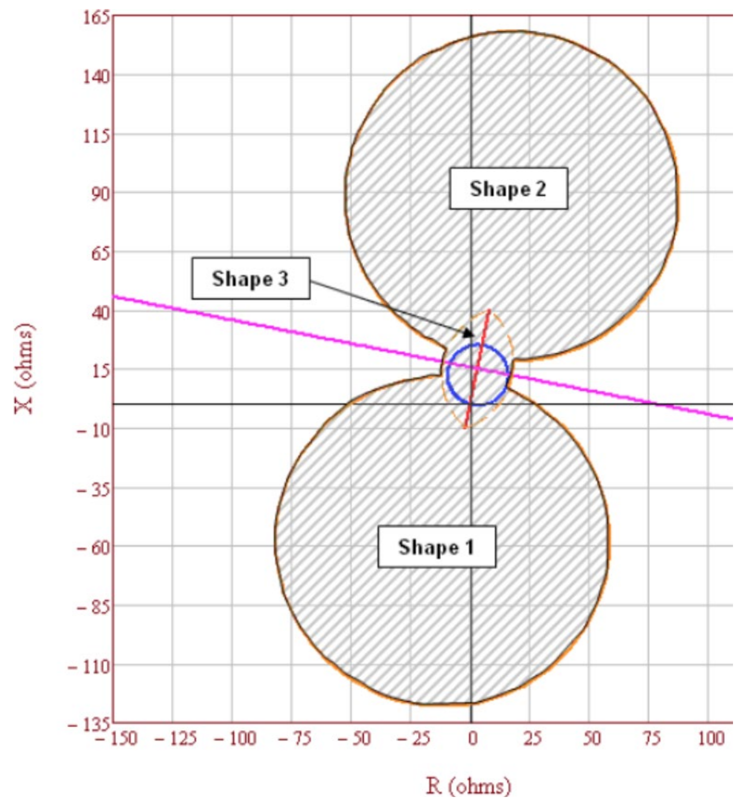
For example, for these sample calculations:

- ***P = S * PF = 700 MVA * 0.85 = 595 MW***
- ***However, 591.77 MW was used as MW reported to TP***

PRC-026

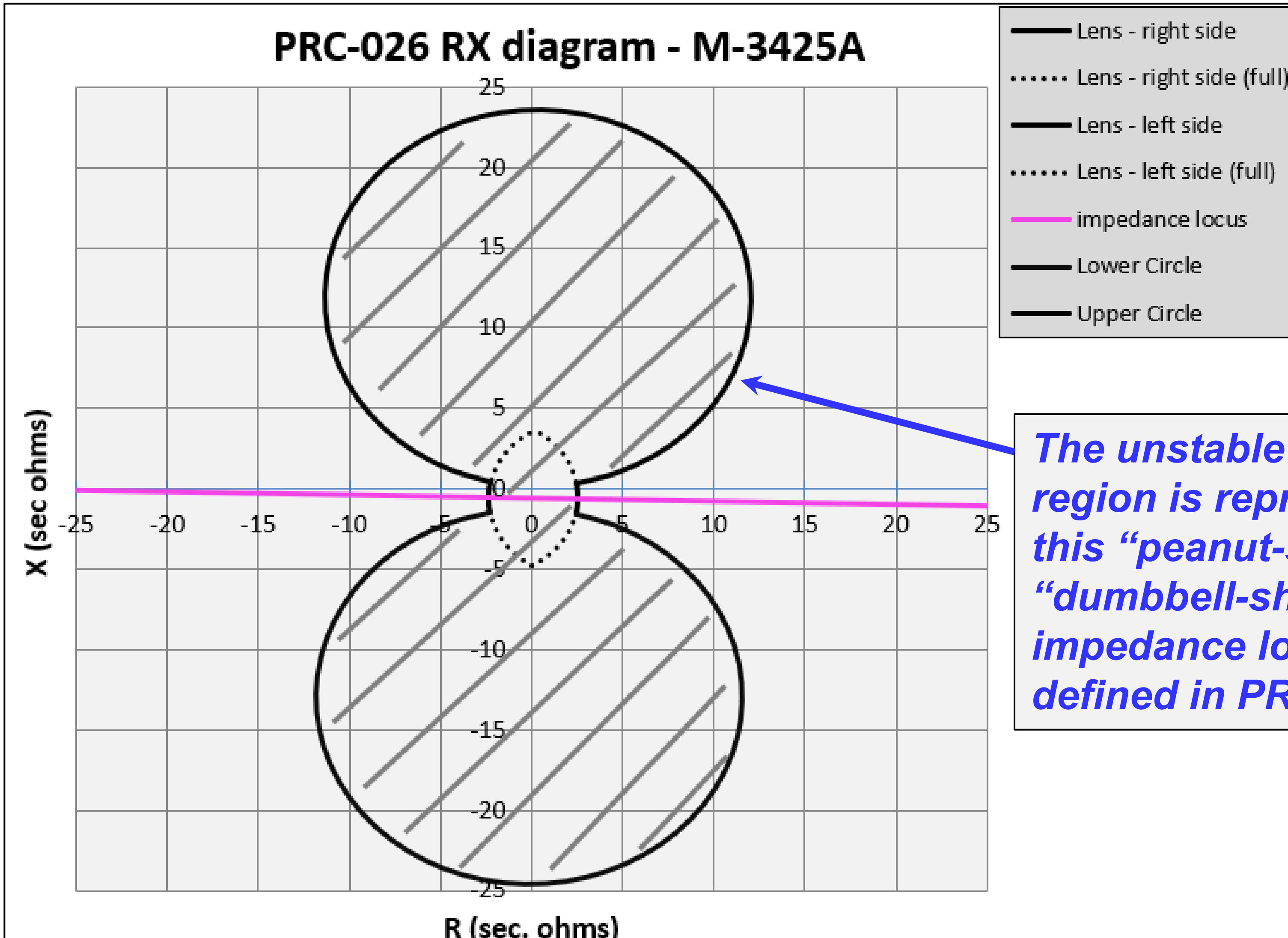
Relay Performance During Stable Power Swings

Purpose: To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.



PRC-026

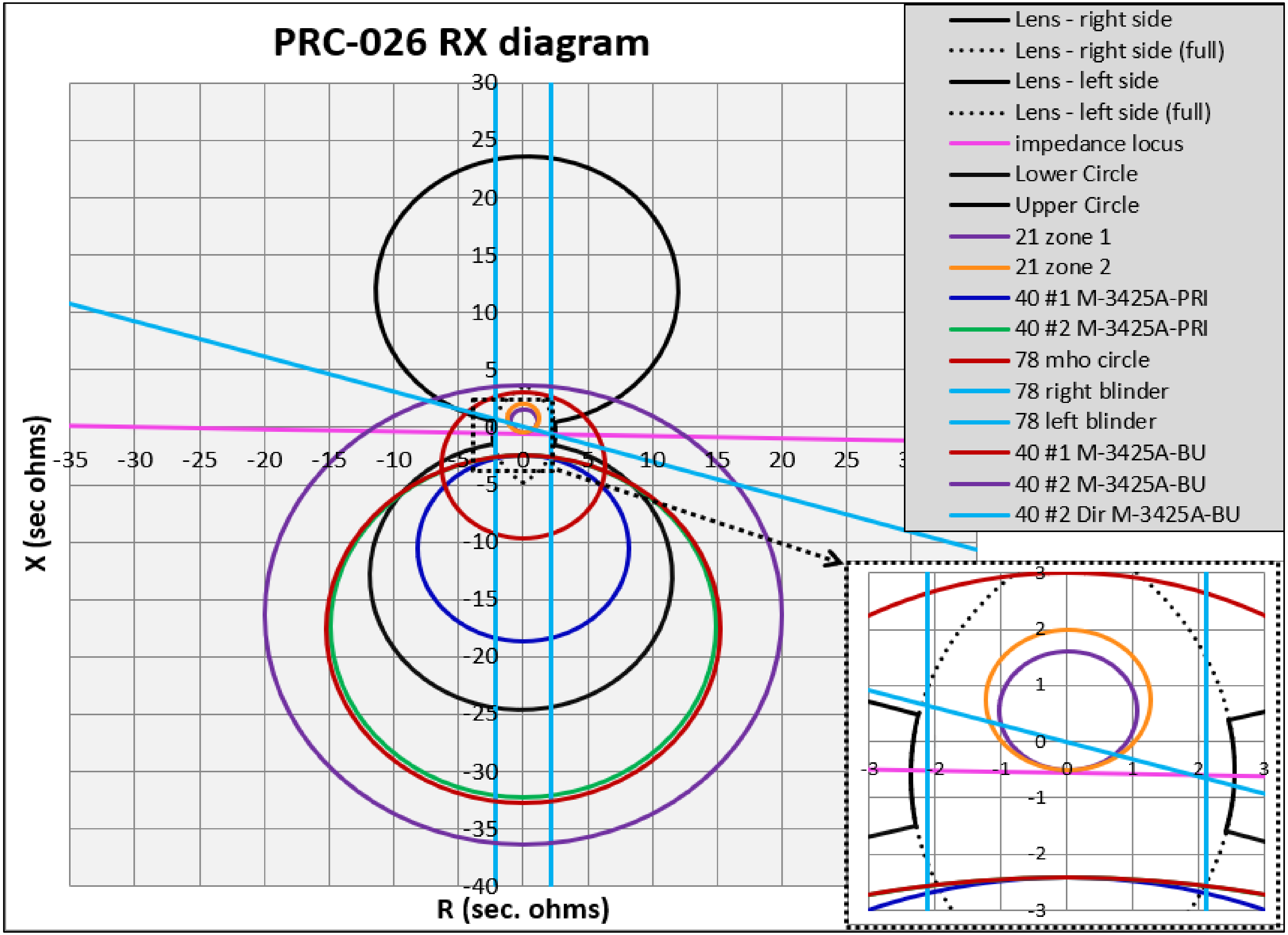
Criterion A: 21, 40, and 78 (within blinders) must be completely contained within the unstable power swing regions or have time delay ≥ 15 cycles.



The unstable power swing region is represented by this "peanut-shaped" or "dumbbell-shaped" impedance locus which is defined in PRC-026.

PRC-026

Yes, complies as 21, 40, 78 plot inside peanut or have time delays ≥ 15 cycles.

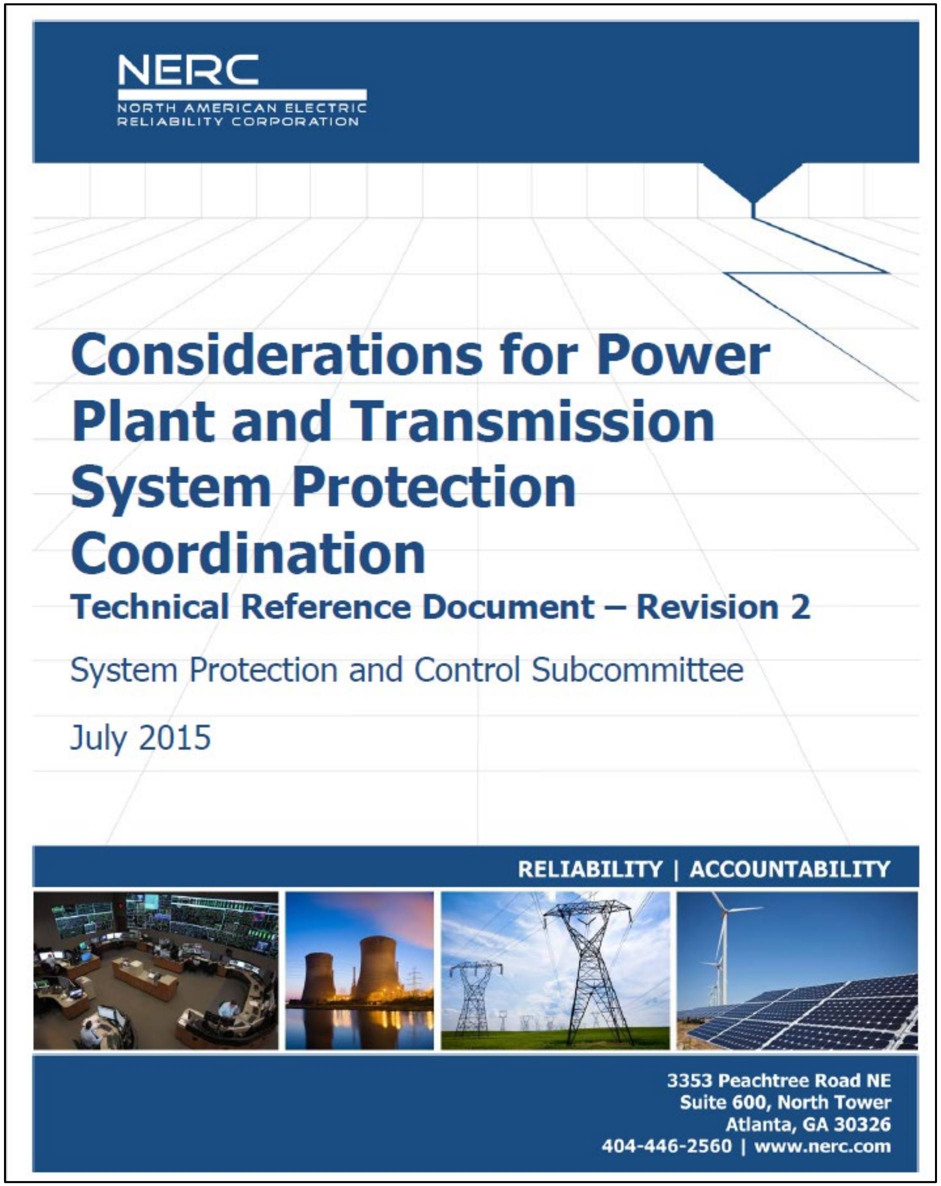


PRC-027

Coordination of Protection Systems for Performance During Faults

Purpose: To maintain the coordination of Protection Systems installed to detect and isolate Faults on BES elements, such that those Protection Systems operate in the intended sequence during Faults.

Guidance/Reference:


NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Considerations for Power Plant and Transmission System Protection Coordination

Technical Reference Document – Revision 2

System Protection and Control Subcommittee

July 2015

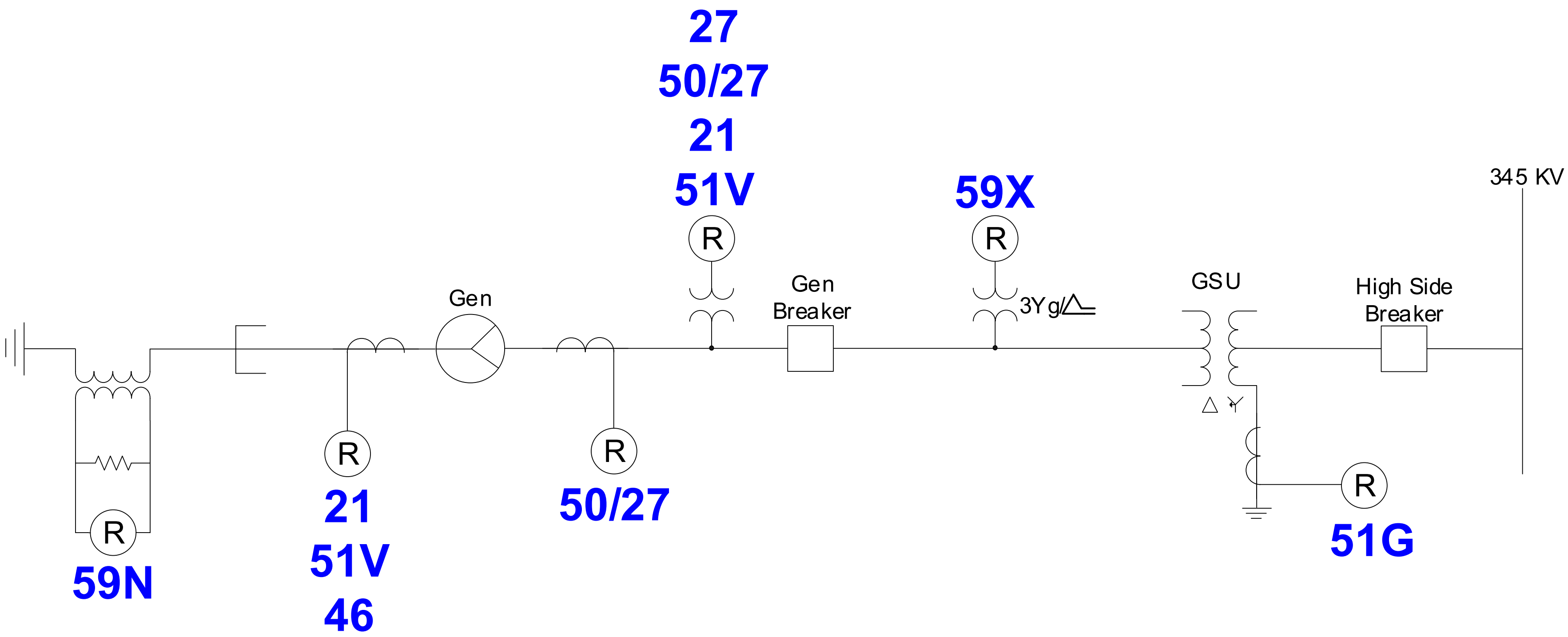
RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

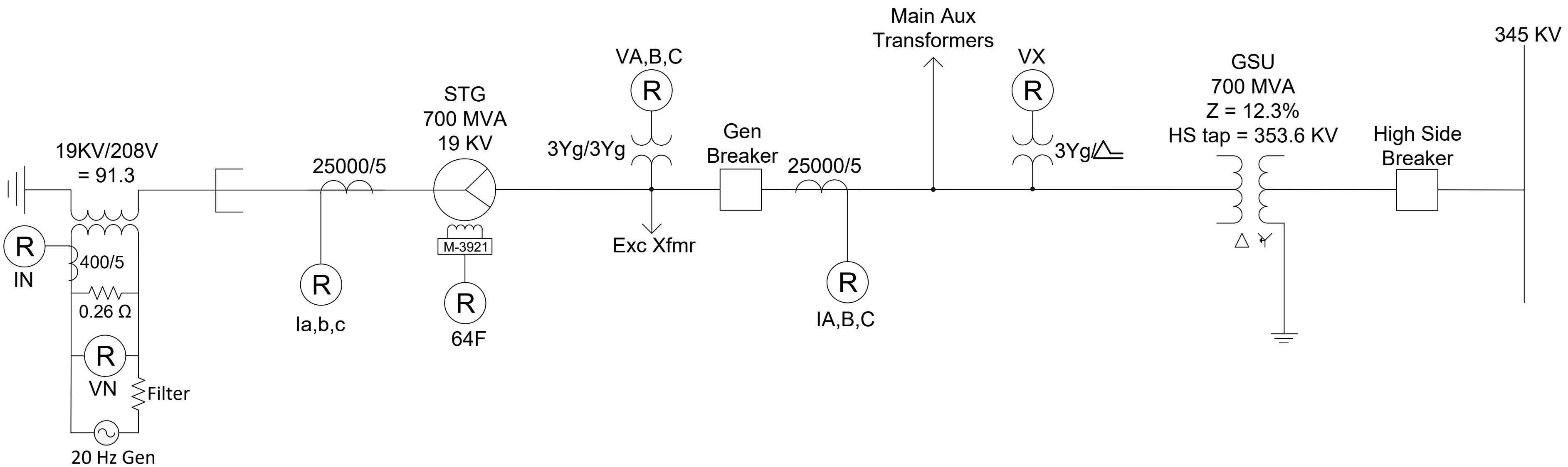
PRC-027

- Coordinate Generation/Transmission protection ≤ every 6 years, or if fault current changes by ≥ 15% in ≤ 6 years then perform coordination study.
  - Share/Coordinate with GO/TO/DP

- Here are some (not all) Generator/GSU protection relay elements that may require coordination with Transmission protection:



Sample application – 700 MVA Steam Turbine Generator



- Most of the relay setting calculations, coordination, and NERC compliance evaluations will be demonstrated using the parameters from this sample application.

- The exception will be for the functions 50N, 51N, 67N, 87GD that are typically used on low impedance or solidly grounded generators. For these functions a sample, small hydro will be used.

Generator Nameplate

A.C.GENERATOR

PHASE	3	TYPE	TAKS	FORM	LCH
POLES	2	kVA	700000	RPM	3600
VOLTS	19000	AMPERES	21271	Hz	60
RATING	CONT.	GAS PRESS.	65psig		

POWER FACTOR	0.85	INLET COOLANT TEMP.	122°F
EXCITATION VOLTS	580	FIELD AMPERES	5080
STATOR TEMP. RISE	90°F	FIELD TEMP. RISE	108°F
STATOR CONNECTION	Y		
STATOR INSULATION CLASS	F	ROTOR INSULATION CLASS	F
STANDARD SPECIFICATION		ANSI C50.13-1989	
SERIAL No.		MANUFACTURED IN	2005

1. 1 REACTANCES

DATA		Design value	
		Saturated	Unsaturated
DIRECT–AXIS SYNCHRONOUS REACTANCE	(x d)	166%	183%
DIRECT–AXIS TRANSIENT REACTANCE	(X d')	29. 6%	32. 4%
DIRECT–AXIS SUBTRANSIENT REACTANCE	(X d")	22. 4%	26. 0%
QUADRATURE–AXIS SYNCHRONOUS REACTANCE	(X q)	164%	181%
QUADRATURE–AXIS TRANSIENT REACTANCE	(X q')	44. 8%	52. 0%
QUADRATURE–AXIS SUBTRANSIENT REACTANCE	(X q")	22. 4%	26. 0%
ARMATURE REACTANCE		0. 193% (at 75℃)	
NEGATIVE PHASE REACTANCE	(X 2)	22. 4%	26. 0%
LEAKAGE REACTANCE	(X 1)	17. 8%	21. 7%
ZERO PHASE REACTANCE	(X 0)	–	12. 8%

1. 2 TIME CONSTANT

DATA		Design value
DIRECT–AXIS TRANSIENT TIME CONSTANT	(T d' #)	1. 6sec (line to neutral) #1
		1. 4sec (line to line) #2
		0. 9sec (three-phase) #3
DIRECT–AXIS SUBTRANSIENT TIME CONSTANT	(T d")	0. 025sec
DIRECT–AXIS TRANSIENT OPEN-CIRCUIT TIME CONSTANT	(T d o')	5. 1 sec
DIRECT–AXIS SUBTRANSIENT OPEN-CIRCUIT TIME CONSTANT	(T d o")	0. 031sec
QUADRATURE–AXIS TRANSIENT TIME CONSTANT	(T q')	0. 32sec
QUADRATURE–AXIS SUBTRANSIENT TIME CONSTANT	(T q")	0. 025sec
QUADRATURE–AXIS SUBTRANSIENT OPEN-CIRCUIT TIME CONSTANT	(T q o")	0. 050sec
ARMATURE TIME CONSTANT	(T a #)	0. 22sec (line to neutral) #1
		0. 26sec (line to line) #2
		0. 26sec (three-phase) #3
QUADRATURE–AXIS TRANSIENT OPEN-CIRCUIT TIME CONSTANT	(T q o')	1. 1 sec

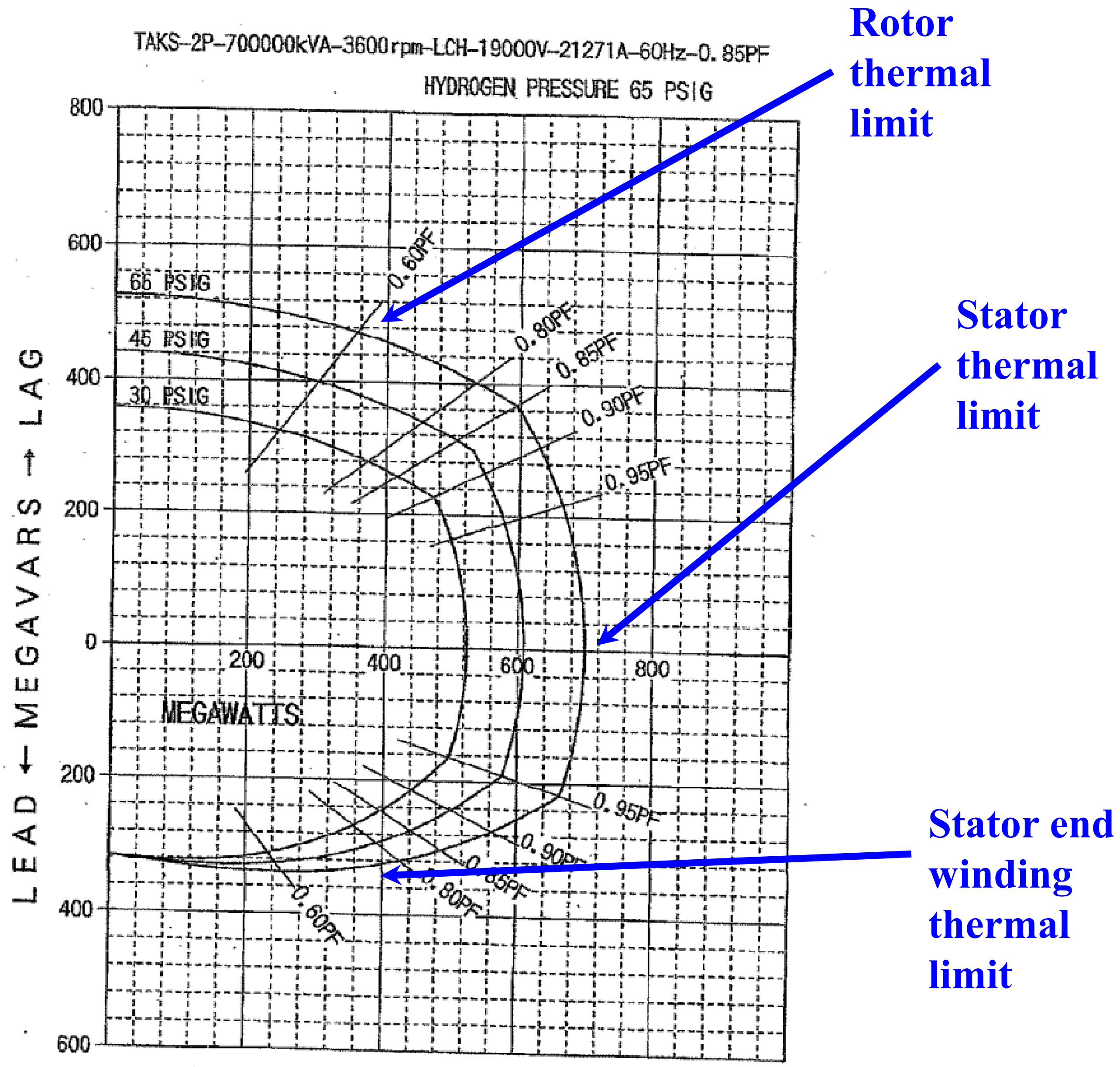
Typically, use Saturated reactances for calculations e.g. to get the max fault current. Saturated reactances are < the unsaturated values and therefore will provide higher fault currents and more conservative settings in general:

- **Xd"sat < Xd"unsat**
- **Id"sat > Id"unsat**

However, in some cases, the unsaturated reactances are used:

- **For the 40 function mho circle diameters to get greater coverage**
- **If the minimum fault current is required**

Generator Capability Curve

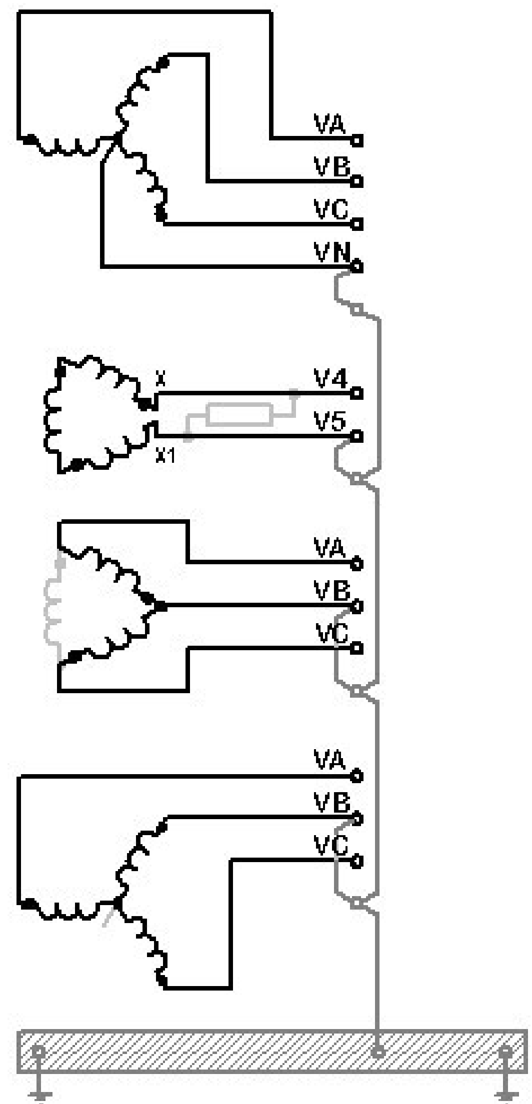


Nominal Voltage and Nominal Current settings in the relay:

- **Voltages and currents that are present at the relay input terminals when the generator is operating at <u>rated</u> voltage and current.**

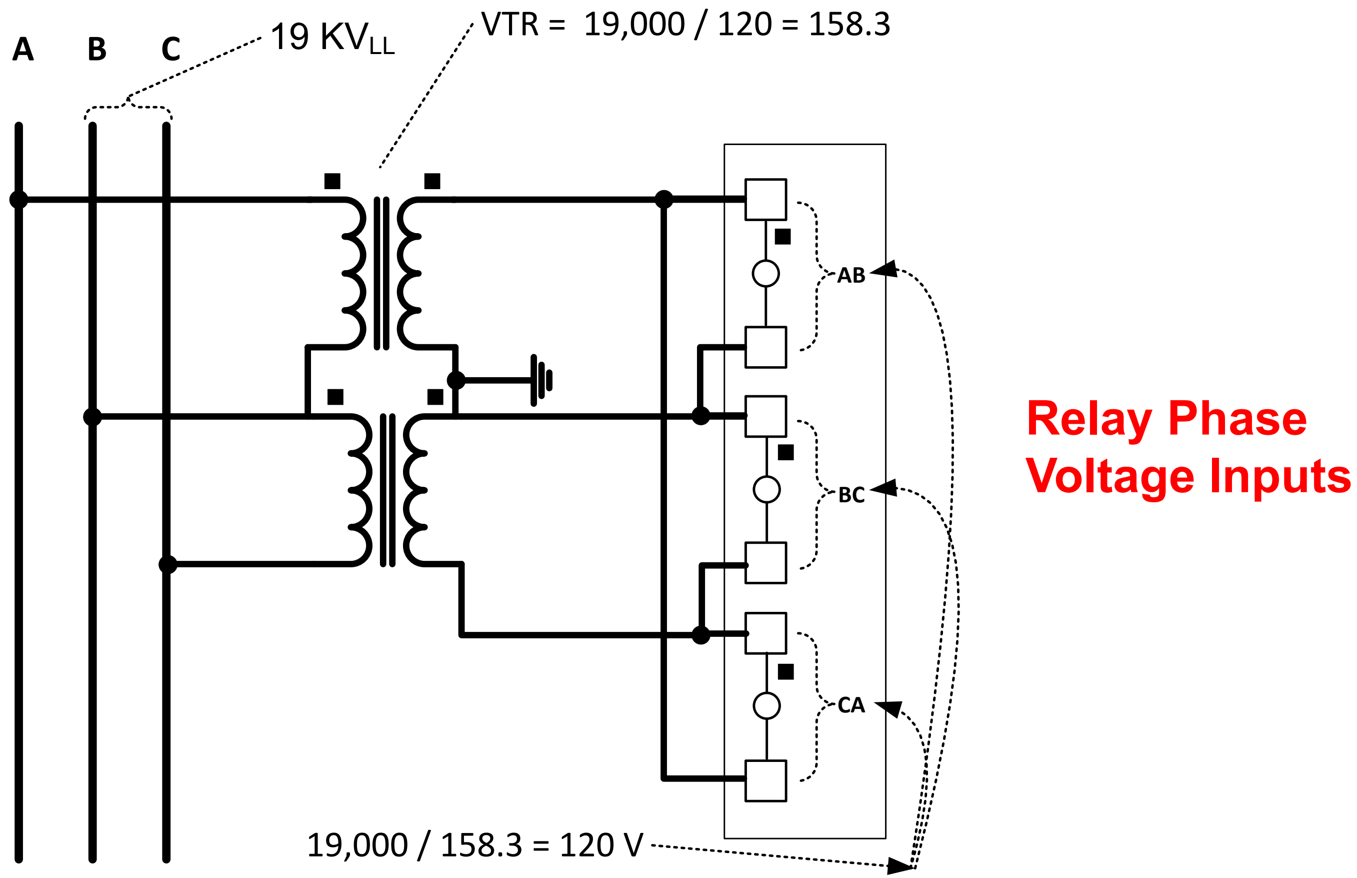
Different types of VT to relay connections

	VT primary	VT secondary	at relay
Yg/Yg	(3) Yg		LN – 3Φ4w
Broken Delta	(3) Yg		3Vo
Open Delta	(2) ΦΦ		LL – 3Φ3w
Closed Delta	(3) Yg or (3) ΦΦ		LL – 3Φ3w



(2) Open Delta VTs, VT Configuration = LL

VT primary connected LL, VT secondary wired LL to relay



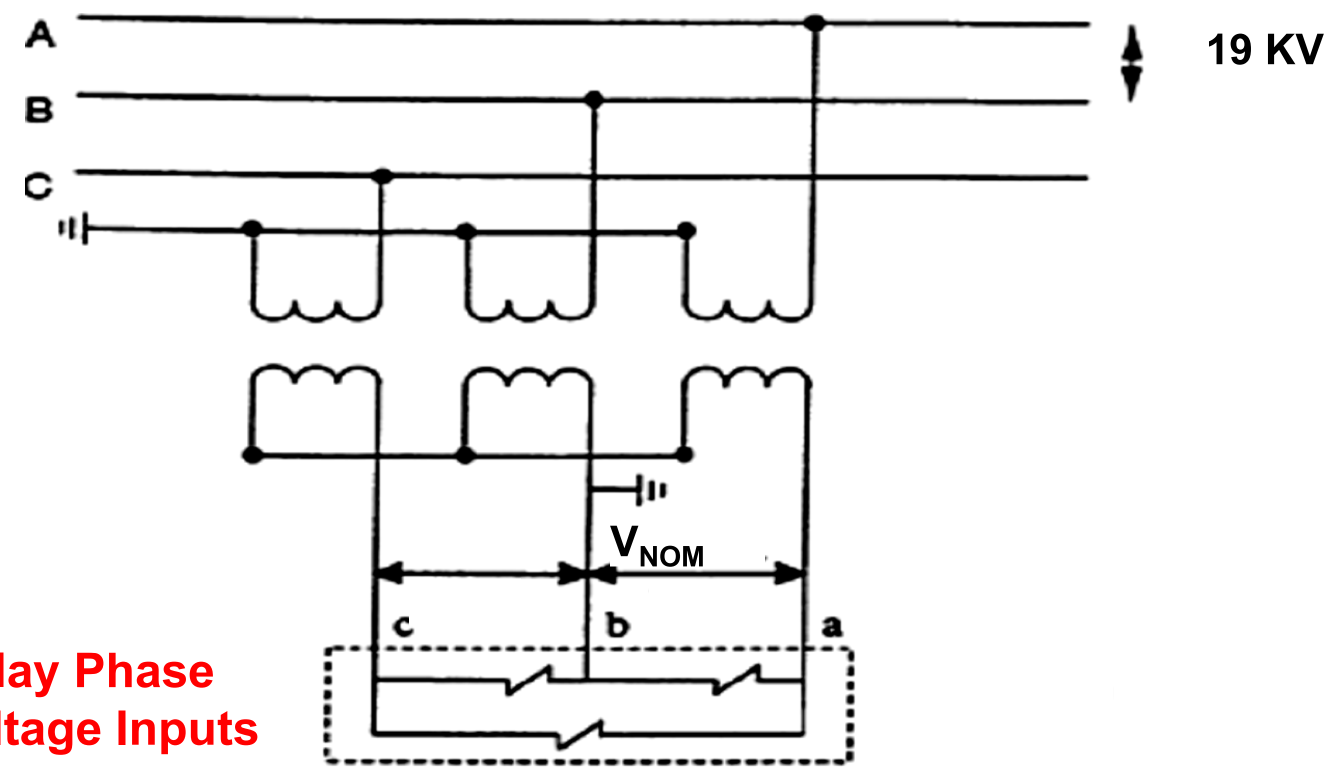
VT Configuration = Line-to-Line

V_{NOM} = 120 V

(3) Closed Delta VTs, *VT Configuration = LL*

VT primary connected LG, VT secondary wired LN, but LL to relay

Example: VTR = (19,000/√3)/69.3 = 158.3
Generator rating V_{LL} = 19 KV
Secondary V_{LL} = 19,000/158.3 = 120 V



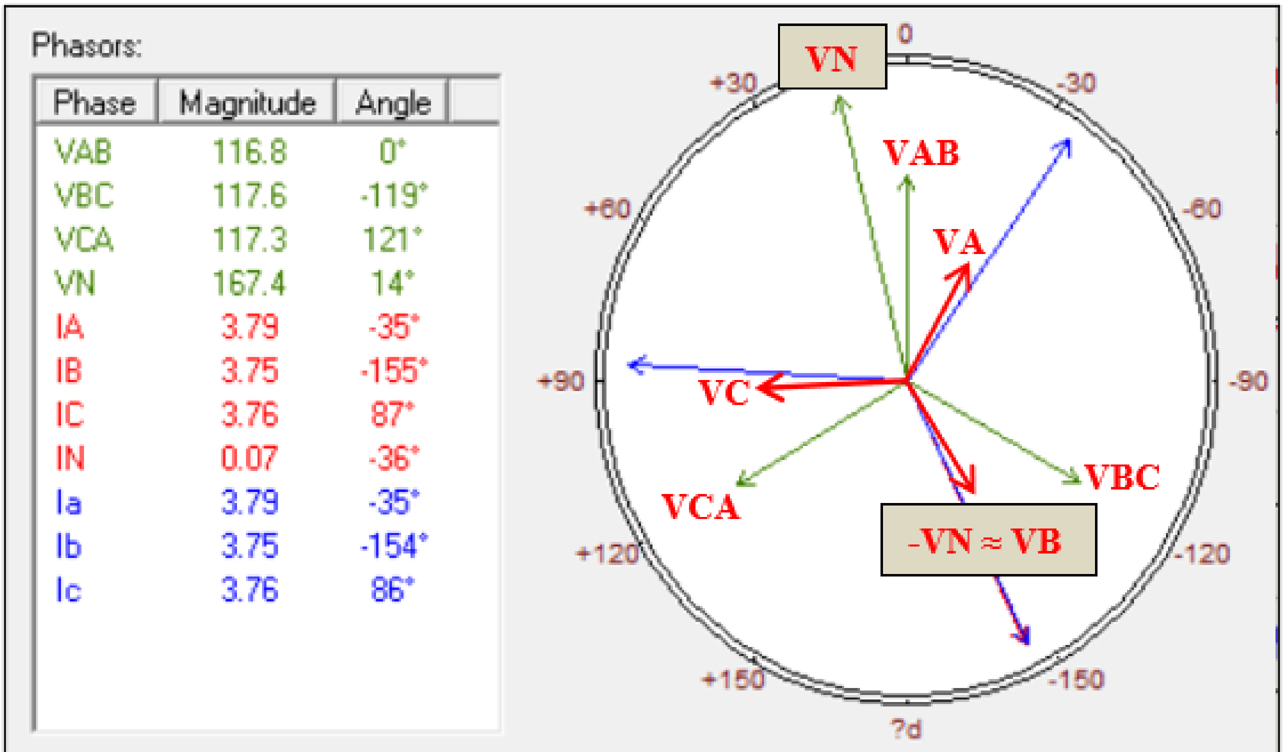
Relay Phase Voltage Inputs

VT Configuration = Line-to-Line
V_{NOM} = 120 V

SIDEBAR:

How to identify the faulted phase from a ΦG fault when VT Config = LL

- VN (or 3Vo) will be 180° from the faulted phase of a ΦG fault.
- Therefore, rotate the VN vector by 180° and that position should approximately match the phase angle of the faulted phase.



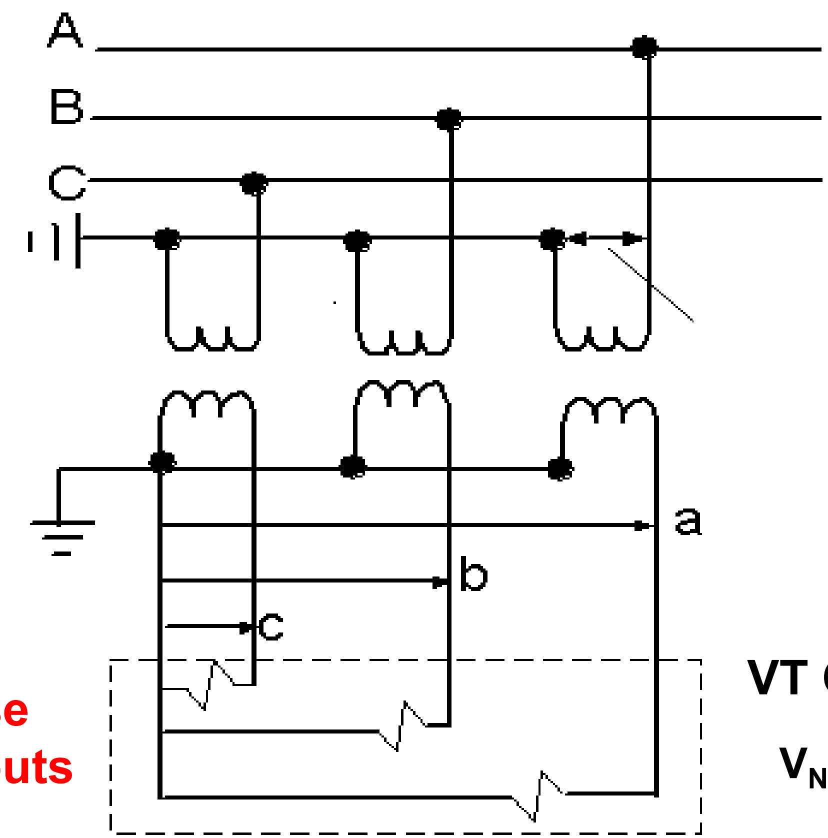
Phasors:

Phase	Magnitude	Angle
VAB	116.8	0°
VBC	117.6	-119°
VCA	117.3	121°
VN	167.4	14°
IA	3.79	-35°
IB	3.75	-155°
IC	3.76	87°
IN	0.07	-36°
Ia	3.79	-35°
Ib	3.75	-154°
Ic	3.76	86°

(3) Yg VTs, *VT Configuration = LG*

VT primary connected LG, VT secondary wired LG to relay

Example: **VTR = (19,000/√3)/69.3 = 158.3**
Generator rating V_{LL} = 19 KV, V_{LG} = 19,000/√3
Secondary V_{LG} = (19,000/√3)/158.3 = 69.3 V



Relay Phase Voltage Inputs

If VT Configuration = LG, this allows the relay to calculate a 3Vo quantity that can be used by the following functions:

- 59D
- 59N (Zero Sequence Voltage Inhibit)
- 67N (Polarizing Quantity)

VT Configuration = Line-to-Ground

V_{NOM}= (19,000/√3)/158.3 = 69.3 V

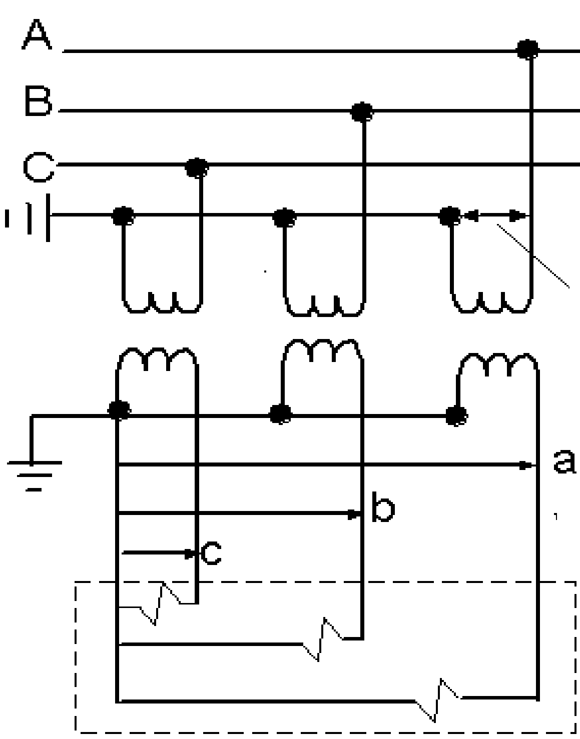
Phase Voltage Inputs (*VT Configuration = LG-LL)*

✓ **This LG-LL selection is used for these sample settings.**

VT primary connected LG, VT secondary wired LG to relay

- **relay measures LG voltage, but then internally converts it to LL voltage**

Example: VTR = (19,000/√3)/69.3 = 158.3
Generator rating V_{LL} = 19 KV
V_{LG} = (19,000/√3)/158.3 = 69.3 V, relay converts to 69.3*√3 = 120 V



Relay Phase Voltage Inputs

VT Config = LG-LL
V_{NOM} = **120 V**

Vnom used in:

- 24
- 32
- 59N V2 and Vo inhibits
- power metering

SIDEBAR:

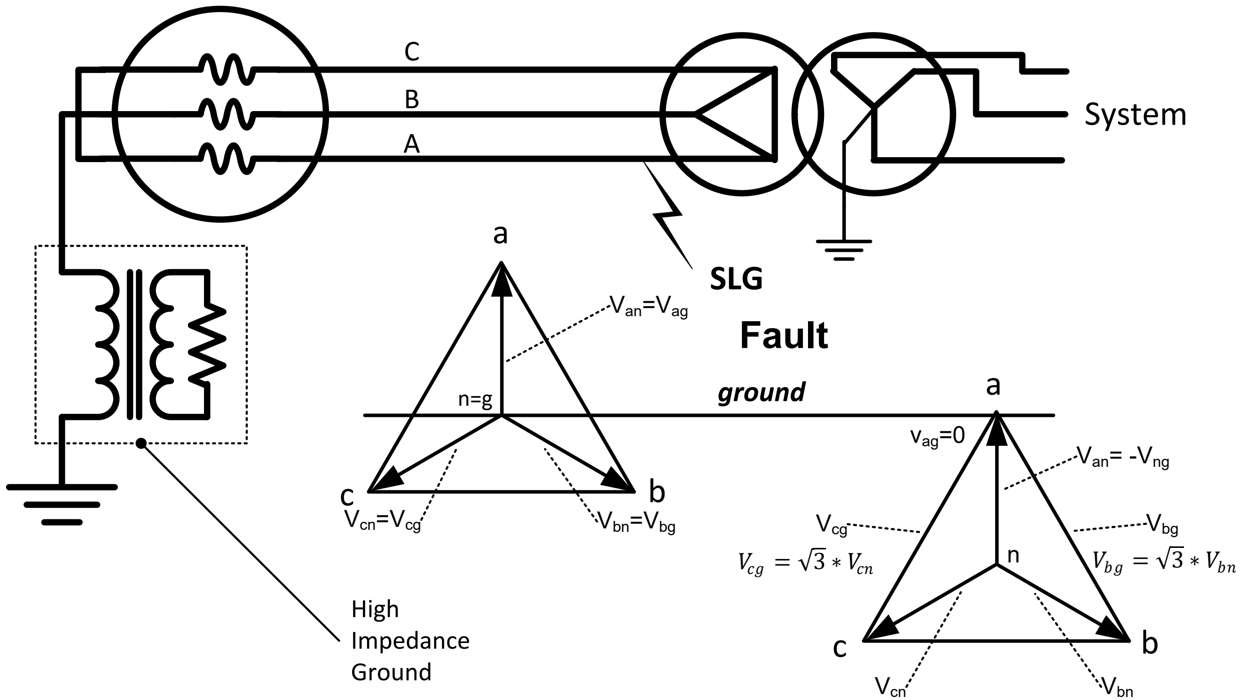
details of selection VT Configuration = LG-LL

- ✓ 3 VTs connected Yg
- ✓ secondary is wired LG, so the relay is measuring LG voltages, but with VT Configuration = LG-LL, the relay internally converts the LG voltages to LL voltages
- ✓ Therefore, all voltage-based settings/elements will use LL voltages i.e. Nominal Voltage, 24, 27, 59, and parts of 25, 27TN, 40, 50/27, 51V, 59D).
  - The LG-LL selection avoids possible false assertions of voltage-based elements due to the neutral shift for a ground fault on a high-impedance grounded machine.
  - The oscillograph in the relay will still show LG voltages for phase identification purposes for stator ground faults.
  - And LG values will also still be used for the 25 function.

SIDEBAR:

Neutral Shift on Ground Fault:

High Impedance Grounded Generator



- **A ground fault will cause neutral shift (n≠g) such that LG connected phase elements through a 3Y-3Y VT may have under/overvoltage elements pickup and/or trip, e.g. if AG fault, then a 27 element may pick up on A-phase and 59 and/or 24 elements may pick up on B and C phases.**

SIDEBAR:

real world event – stator ground fault on a high impedance grounded machine:

- ***The 59N function correctly tripped.***
- ***The 24 and 59 functions also picked up. Why?***
- ***Answer: because the VT Configuration was set to LG (3Y-3Y VTs).***
- ***Remedy: Set VT Configuration to LG-LL.***
- ***Therefore, will not get functions to pickup or trip that could misrepresent the actual event, which could increase the time required for post-fault analysis, the fixing of the problem, and getting the unit back on-line as quickly as possible.***
- ***This is the advantage of using VT Configuration = LG-LL for LG VTs.***

TopTargets - Notepad

File Edit Format View Help

```
                    Target List
IPScom: Version V2.8.0
Relay: M3430/V02.00.21
Comments:


No.    Date          Time                       Event(s)
----------------------------------------------------------------------------------------------------
1      14-Mar-2017   08:22:10.000              (24) Volts/Hz - Definite Time Picked Up
                                               (24) Volts/Hz - Inverse Time Picked Up
                                               (59) RMS Overvoltage #1 - Phase A Picked Up
                                               (59N) RMS Overvoltage #1 - Phase Neutral Timed Out
          INPUTS:                          OUTPUTS: 1,2
          Line Currents:   3.08 A  (A),    3.11 A  (B),    3.10 A  (C),    0.00 A  (N)
```

Current Inputs

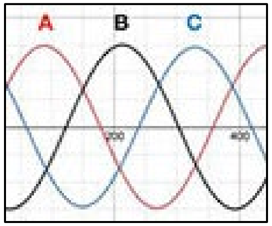
- Determine primary current at rated power
  - $I_{pri\ nom} = MVA*10^6 / \sqrt{3}*V_{LL}$
  - $I_{pri\ nom} = 700*10^6/(1.732*19000)$
  - $I_{pri\ nom} = 21{,}271\ A$

- Convert to secondary value
  - CT ratio (R_C)= 25000/5 = 5000
  - $I_{sec\ nom} = I_{pri\ nom}/R_C$
  - $I_{sec\ nom} = 21{,}271/5000$
  - $I_{sec\ nom} = 4.254\ A$

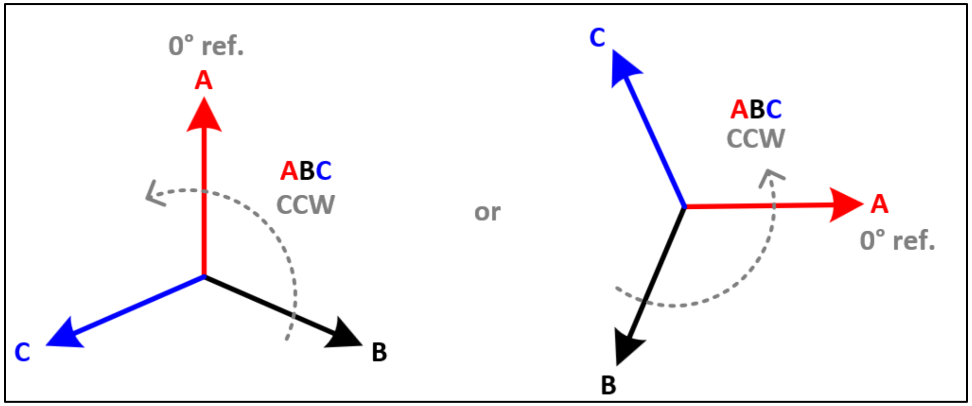
$I_{NOM} = 4.25A$

Phase Rotation = ABC *(used in 32, 46, 81 algorithms)*

- order in which the waveforms reach positive peaks:



- order in which phasors pass ref.:



- "Phase Sequence" or "Electrical Phasor Rotation" may be more technically correct than "Phase Rotation".
- Nothing to do with the physical direction of rotation of the rotor and turbine shaft i.e. either CW or CCW depending on which end it is being viewing.
- By convention, electrical phasors rotate CCW unless specified otherwise.

50DT Split phase Differential = Disable

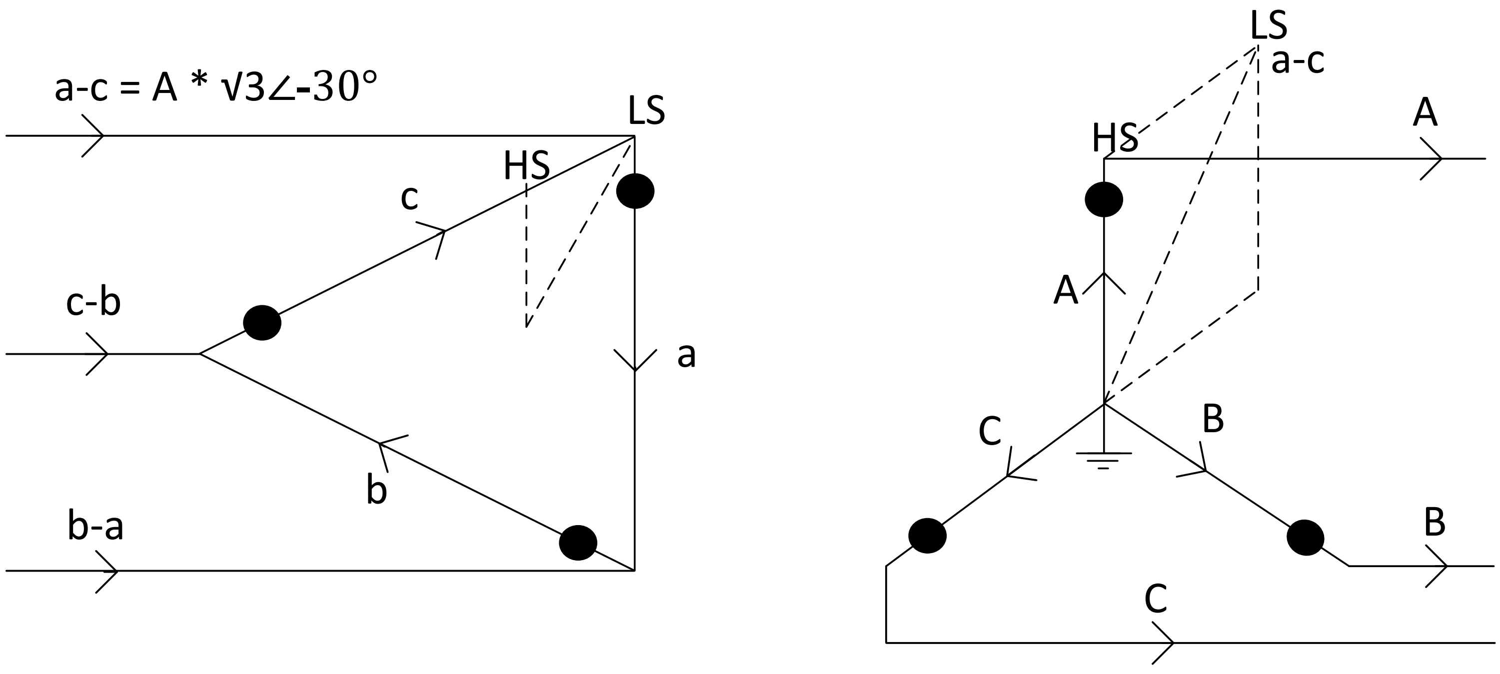
- **Typically used for split phase hydro machine applications.**

Delta-Y transform setting (used with 21, 51V)

This setting Determines calculation used for 21 and 51V functions (*calculates the impedances from the measured voltages and currents for a ΦΦ fault on the GSU HS***)**

- **Disable:** Used for YY and Delta/Delta connected transformers
- **Delta-AB:** Used for Delta-AB/Y connected transformers
- **Delta-AC:** Used for Delta-AC/Y connected transformers

Delta-Y Transform = Delta-AC, because the GSU Delta winding has the polarity of A winding connected to the non-polarity of the C winding:



LS = Dac

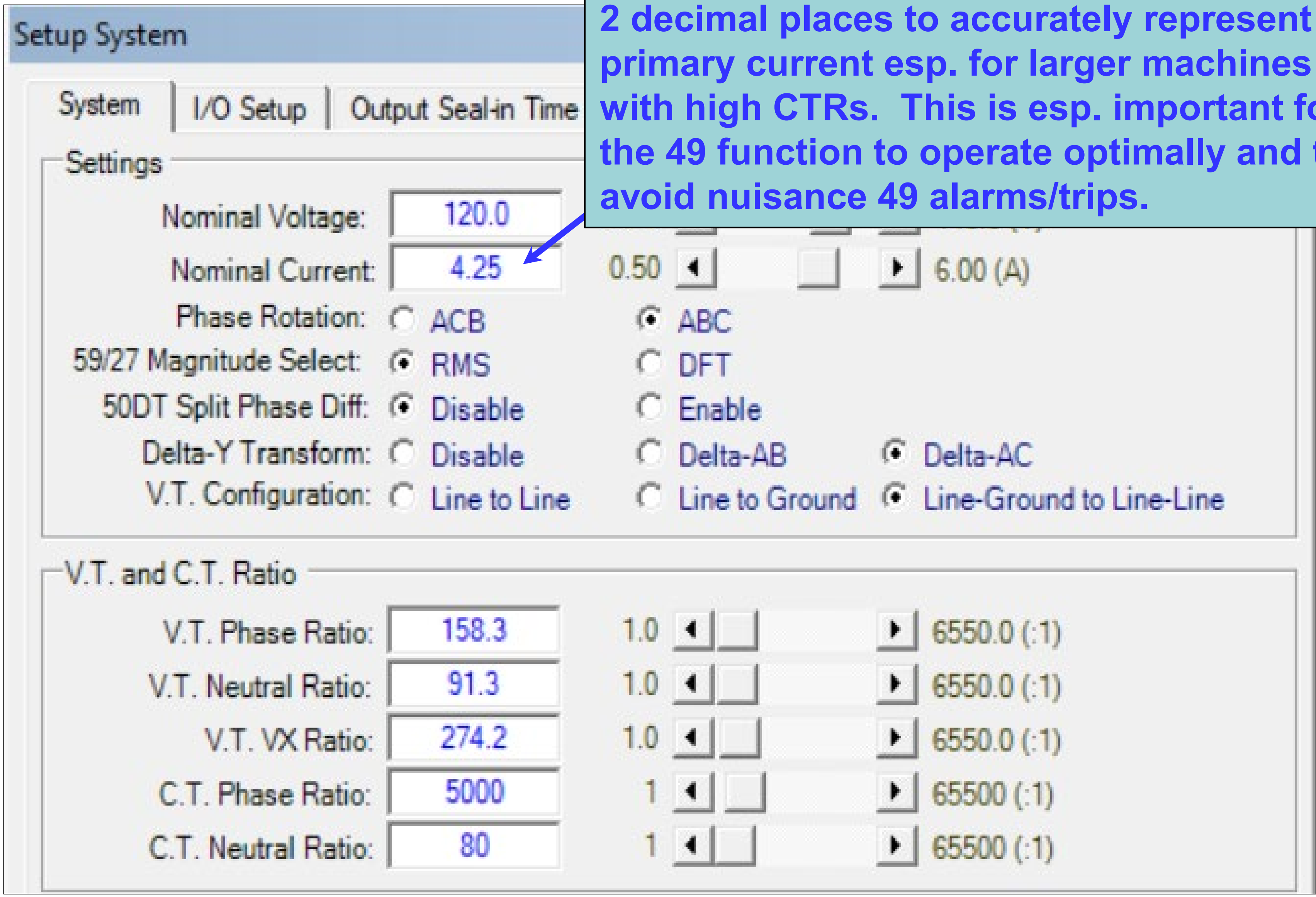
HS = Y

59/27 Magnitude Select = RMS (RMS, DFT)

- RMS uses the total waveform (including harmonics).
- DFT uses the RMS value of the 60 Hz fundamental component of the waveform, so the magnitude calculation is accurate at 60 Hz, but the accuracy degrades quickly.
- Different relay elements have different frequency ranges in which they will operate (this table is specifically for the M-3425A relay whereas other mfg's relay may be different):

	frequency response	DFT	RMS	59/27 Magnitude Select (RMS/DFT)	DFT (f ≤ ±5 Hz of fnom) RMS (f > ±5 Hz of fnom)
21		x			
24	2-80 Hz		X		
25		x			
27	10-80 Hz RMS			X	
27TN *		x			
32		x			
40	50-70 Hz	x			
46		x			
49		x			
50	2-80 Hz				x
50BF		x			
50DT	2-80 Hz				x
50/27	10-80 Hz RMS	50		27	
50N/51N	2-80 Hz				x
51V	3.75-80 Hz				x
59	10-160 Hz RMS			X	
59D *		x			
59N		x			
59X		x			
60FL		x			
64F/B	15 V, 1 Hz squarewave				
64S **		x			
67N		x			
78	50-70 Hz	x			
81/81A/81R					x
87 #	10-80 Hz				x
87GD		x			

It is best for the Inom setting to have at least 2 decimal places to accurately represent primary current esp. for larger machines with high CTRs. This is esp. important for the 49 function to operate optimally and to avoid nuisance 49 alarms/trips.



approx. 30 different protection functions

“Over” vs “Under” categorization of gen protection functions

“Over” functions

- 24 – Over V/Hz
- 46 – Negative Sequence Overcurrent
- 49 – Thermal Overload
- 50/50DT – Overcurrent
- 50/27 – Inadvertent Energization
- 50BF – Breaker Failure
- 50N/51N/67N – Neutral Overcurrent
- 51V – Voltage Control/Restraint O/C
- 59 – Overvoltage
- 59D – 3rd Harmonic Overvoltage Ratio
- 59N – Neutral Overvoltage
- 59X – 3Vo Overvoltage
- 64B – Brush Lift Off
- 64S – 20 Hz Overcurrent
- 81O – Overfrequency
- 87 – Differential Overcurrent
- 87GD – Ground Differential Overcurrent

“Under” functions

- 21 – Distance, Under Impedance
- 27 – Undervoltage
- 27TN – 3rd Harmonic Undervoltage
- 32 – Reverse Power, Under Power
- 40 – LOF, Under Excitation/Field
- 50/27 – Inadvertent Energization
- 64F – Field Ground, Under Resistance
- 78 – OOS, Under Impedance
- 81U – Underfrequency

Bookend "big picture" settings concept

Over-functions

(24,46,49,50/50DT,50/27,50BF,51V,59,59D,59N,59X,64B,64S,81O,87,87GD)

$$\text{good} < \textbf{Pickup} < \text{bad}$$
$$\text{normal conditions} < \textbf{Pickup} < \text{abnormal condition}$$
$$\text{what don't you want it to trip for?} < \textbf{Pickup} < \text{what do you want it to trip for?}$$
$$\text{max load or equipment rating} * \text{SF} < \textbf{Pickup} < \text{SM} * \text{min fault}$$

- $\text{SF} = \text{Security Factor is} > 1 \text{ pu}$
- $\text{SM} = \text{Sensitivity Margin is} < 1 \text{ pu}$

Under-functions

(21,27,27TN,32,40,50/27,64F,78,87U)

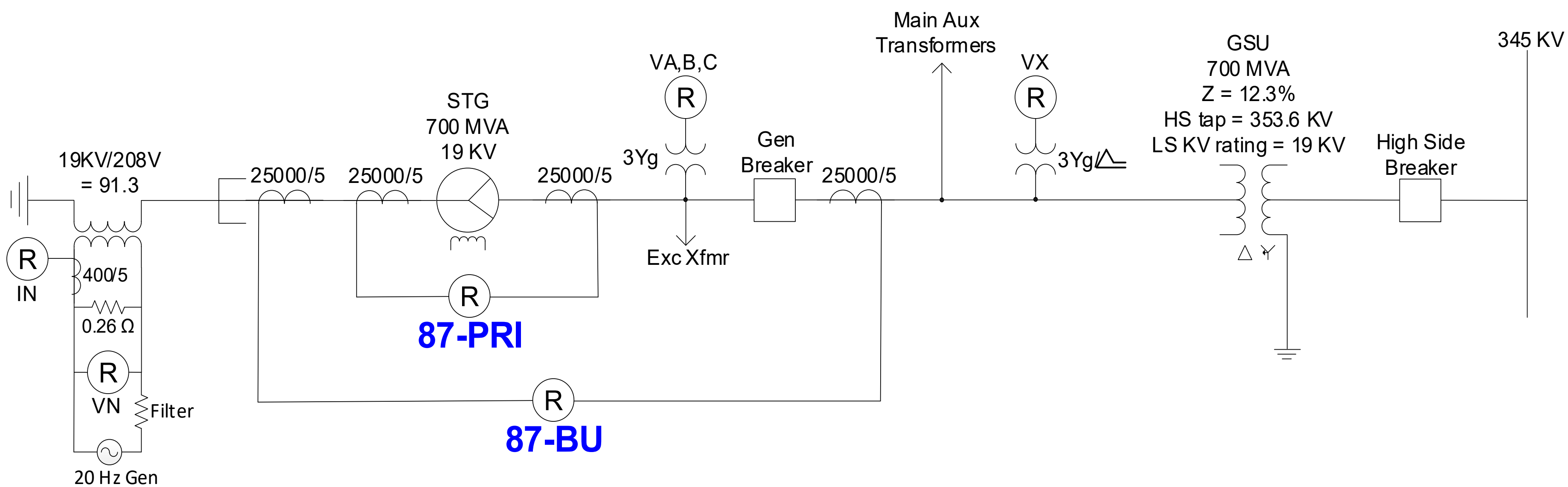
$$\text{what don't you want it to trip for?} > \textbf{Pickup} > \text{what do you want it to trip for?}$$

May use this criteria to hone-in on any setting i.e. Pickup, Time Delay, etc.

Phase Fault Protection

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

87 – Phase Differential



Blocking Inputs = none

(or if LCI starting application, may block a sensitive 87 element with LCI mode or open breaker and not block the other less sensitive 87 element)

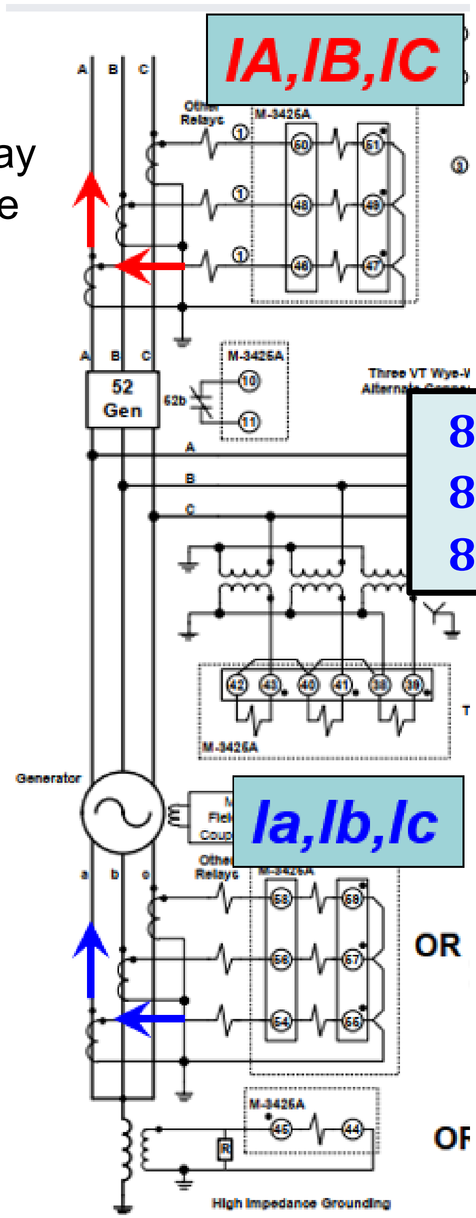
3-line for M-3425A relay

Differences between relay mfgs on how to wire the relay current input polarities to the CTs on each side of the generator:

Some mfg's relays should be wired such that thru current is 180° out-of-phase.

However, the M-3425A relay's current input polarities should be wired such that thru currents are in-phase with each other.

This is because the 87 algorithm operate current equation in the M-3425A relay subtracts the currents from each side.

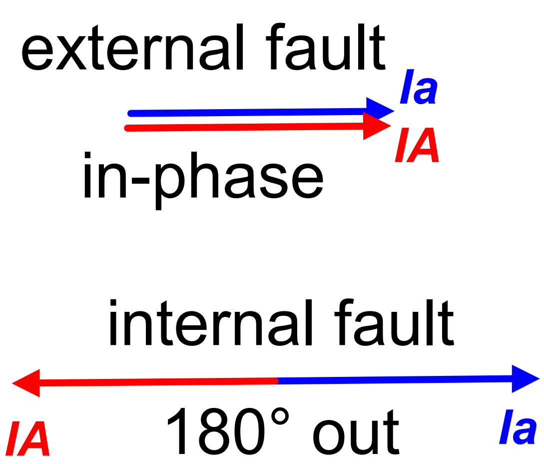


M-3425A 87 equations:

$$87A\_operate = |(\overline{IA} * CTC) - \overline{Ia}|$$
$$87B\_operate = |(\overline{IB} * CTC) - \overline{Ib}|$$
$$87C\_operate = |(\overline{IC} * CTC) - \overline{Ic}|$$

$$87A\_restraint = 0.50 * |\overline{IA} * CTC + \overline{Ia}|$$
$$87B\_restraint = 0.50 * |\overline{IB} * CTC + \overline{Ib}|$$
$$87C\_restraint = 0.50 * |\overline{IC} * CTC + \overline{Ic}|$$

$$CTC = \frac{Line\ side\ CTR}{Neutral\ side\ CTR}$$



87 – Phase Differential

87 Pickup setting criteria:

- The 87 #1 Pickup or minimum operate current should not respond to differential currents caused by performance differences between the phase CTs on the neutral side and the terminal side during non-fault conditions.
- Also, ensure it is set sensitive enough to see a minimum internal phase fault current with plenty of sensitivity margin.
- Assume the unit is up to speed with the field applied but the gen breaker has not yet synched closed so only the generator contribution to an internal phase fault will be factored in for the most conservative operational scenario.
- The 87 function should respond during the subtransient period of the fault current generator decrement curve, therefore Xd" will be used to calculate the minimum internal phase fault current contribution from the generator.
- A quick "rule of thumb" method to derive an appropriate 87 Pickup setting is to set it to 10% (to account for CT error) of the Nominal Current setting. In this case, that would suggest a setting of 0.10 * 4.25 = 0.43 A.
- This is typically sufficiently secure and sensitive for most cases; however, may use more detailed bookend criteria to develop the 87 Pickup setting. →

87 – Phase Differential

87 Pickup setting selection using the bookend criteria method:

$$Excitation\ transformer\ ;\ [(\text{Inom} * 2 * \text{CT error} * \text{SF}) + \text{RA}] \leq 87\ Pickup < \text{SM} * Ifault$$

$$5.5\text{M}/(1.732 * 19\text{K} * 5000);\quad [(4.25 * 2 * 0.05 * 1.2) + 0.10] \leq 87\ Pickup < 0.50 * 0.866 * 18.97$$

$$0.0334\quad ;\quad 0.61 \leq 87\ Pickup < 8.2$$

- Excitation transformer is inside the BU relay's 87 zone, therefore the Pickup must be > this xfmr's max rating
- Inom = Nominal Current setting = 700M/(1.732*19K*5000) = 4.25 A
- CT error = ± 5% (this is very conservative at low load current levels e.g. at nominal current)
- SF (Security Factor) = 1.2 (to account for proximity effect, unmatched CT performance, etc)
- RA (Relay Accuracy) = ± 0.10 A for 5A relay (± 0.02 A for 1A relay) or ± 5%, whichever value is greater:
  - With chosen Pickup, the ± 0.10 A rating in terms of percentage is (0.10/0.61) * 100 = 16%.
  - With chosen Pickup, the ± 5% rating in terms of Amps is 0.05*0.61 = 0.03 A.
  - Therefore, use the ± 0.10 A accuracy rating for this application as 0.10 A > 0.03 A (or 16% > 5%).
- SM (Sensitivity Margin) = 0.50 (use 50% margin to account for ΦΦ faults with fault resistance)
- 0.866 factor = convert from a 3Φ fault to a ΦΦ fault to get the minimum internal phase fault current
- Ifault = min pre-synch internal phase fault current = Ibase * Ipu = Inom * V/Xd" = 4.25 * 1/0.224 = 18.97 A

Set 87 #1 Pickup = 0.61 A

✓ more secure than "rule of thumb" method and still plenty sensitive

✓ in terms of per unit: pu = actual/base = Pickup/Inom = 0.61/4.25 = 0.14 pu

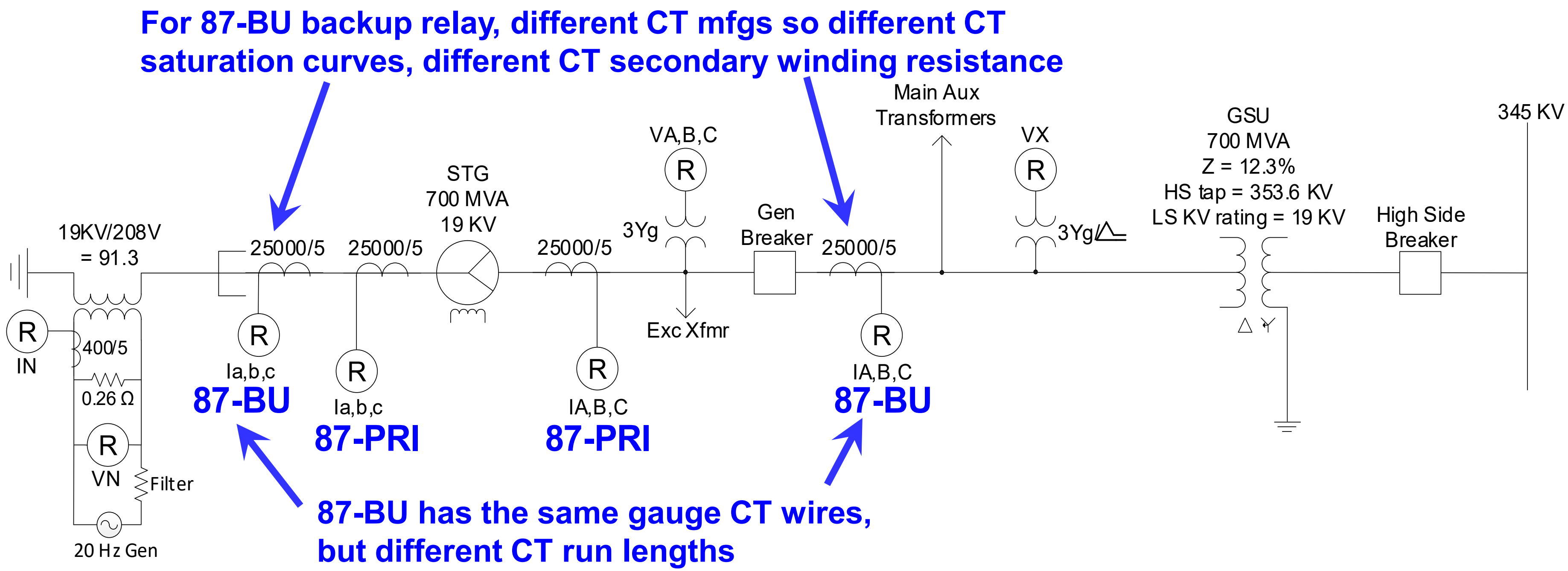
87 – Phase Differential

Choose 87 Time Delay:

- A time delay setting of 1 cycle is optimal from a protection standpoint, but ensure it is secure for external faults, which is primarily dependent upon CT saturation performance matching i.e., CT saturation calculations and modelling can help inform an appropriate time delay setting.
- For this relay mfg, a time delay setting of 1 cycle may operate in as little as 1/16 of a cycle for high magnitude internal faults because of the way the algorithm is designed.
- Other relay mfgs may not have a time delay setting for the 87 function; however, there may be some inherent time introduced for extra security when an event is signatured as an external fault for example.

- **CT Saturation calcs (optimal to have matched CT performance from both sides):**
  - same CT relay class on each side and higher class is better e.g., C800 and C800; however, better to have C100s on each side, rather than C800 on one side and C100 on other
  - same CTR and use full tap
  - same CT secondary winding resistance
  - same CT saturation curves
  - same CT mfg
  - same CT wire gauge
  - same CT wire run length
  - same burden – better to have both sides with only this relay element, rather than one side with only the relay element and the other side with other current elements, metering, etc; however, if there are other current elements in one side then best to have equal burden in other side too.

87 – Phase Differential



CT Saturation spot check equation (also check how each side's CTs saturate with respect to time to ensure CTs enter and exit saturation together):

$$Vsaturation = \frac{\dfrac{\left(\left|\frac{X}{R}\right|+1\right) * \dfrac{Ifmax}{CT\ connected\ tap} * (Zrelay + Zctwdg + 2 * Zleads)}{Zctburden * \dfrac{CT\ connected\ tap}{CT\ max\ tap}}}{1 - remanence}$$

87 – Phase Differential

- Here for this application, use a time delay setting of 1 cycle for 87-PRI and 2 cycles for 87-BU. would have likely been perfectly secure, a time delay setting of 2 cycles was chosen as some of the CT information was unknown and thorough CT saturation calculations and modelling was not completed:

- 87-PRI: 87 #1 Time Delay = 1 cycle
- 87-BU: 87 #1 Time Delay = 2 cycles

- For Black Start units, CT matching performance takes on even greater importance. Detailed CT saturation calculations and if possible, some black start test energization cases may help inform appropriate settings and design (e.g., an increased time delay/pickup/slope settings may be necessary, or a blocking input during black start mode could be needed, or even introducing additional burden on one side of the CT secondary circuit to even-out the saturation performance characteristics may be another option to consider).

87 – Phase Differential

Choose 87 Slope:

The 87 function for this relay mfg has only one slope setting; however, it is still a 2-slope characteristic as the second slope is automatically changed to 4 times the Percent Slope setting at 2 times the Nominal Current setting or when there is sufficient harmonic content or DC offset present in the currents even at low current levels indicating high levels of CT saturation.

Therefore, set the "first" slope more sensitive to detect low level fault currents and then the second slope will automatically be less sensitive to increase security in the high current region to correctly restrain for heavy external faults where the CT error is higher due to CT saturation.

Look at the possible error currents to develop a secure and sensitive slope setting. For this "first" slope in the low current region, assume a CT error of $\pm 1\%$ and a min relay accuracy of 5%. Then calculate the worst-case theoretical differential current:

$$\text{Slope} > 2 * \text{CT error} + \text{min relay accuracy}$$

$$> 2 * 1\% + 5\%$$

$$> 7\%$$

Set 87 #1 Percent Slope = 15% (secure for CT errors up to (15-5)/2 = 5%)

87 – Phase Differential

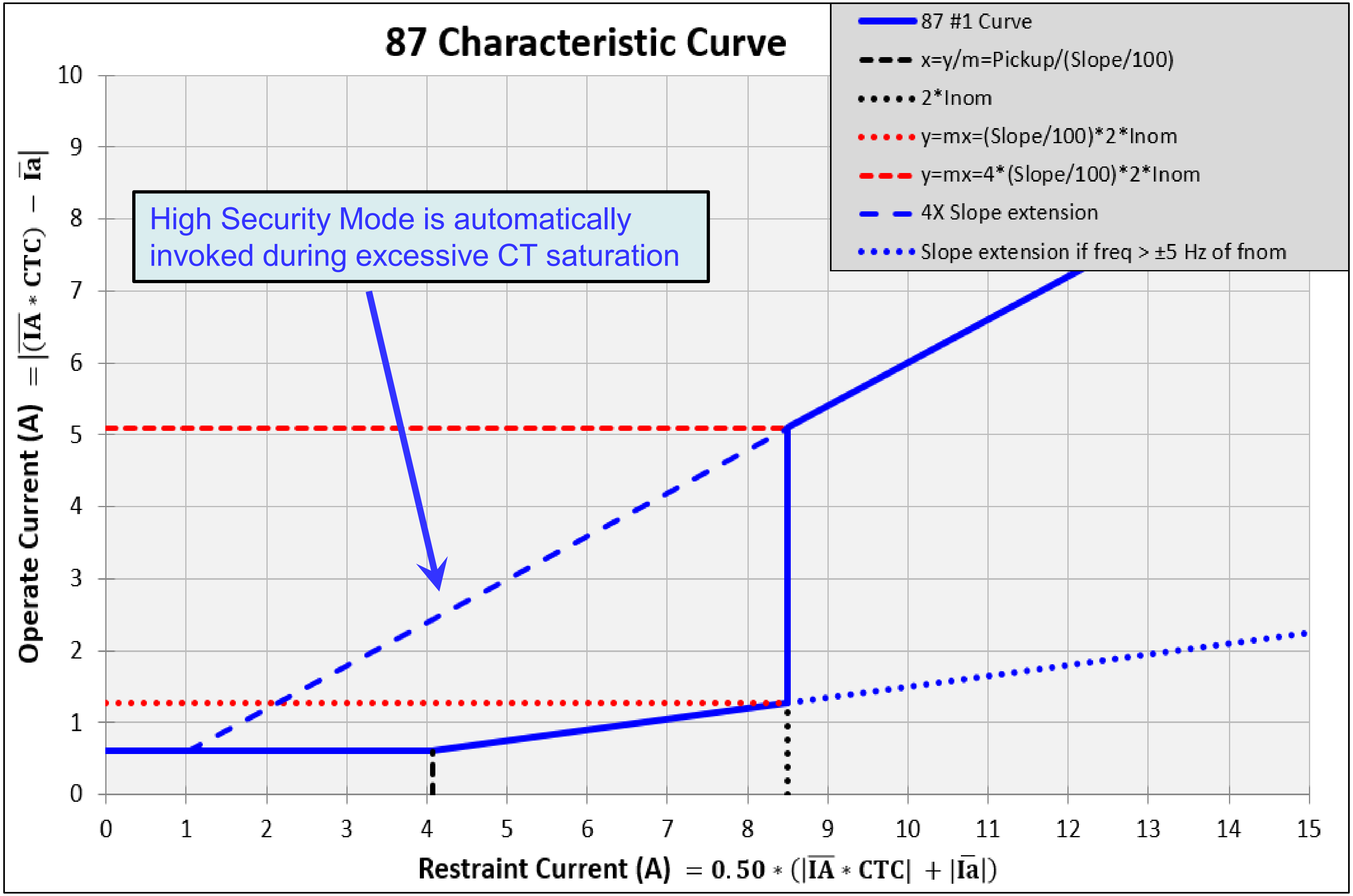
The second slope (4X Slope) is automatically invoked at 2 times the Nominal Current setting i.e., the operational slope used in the algorithm is changed to 4 times the Percent Slope setting (4*15 = 60%) at 2X Inom or when the RMS to fundamental current indicates CT saturation.

This second slope value of 60% is secure for CT errors up to (60-5)/2 = 27.5%.

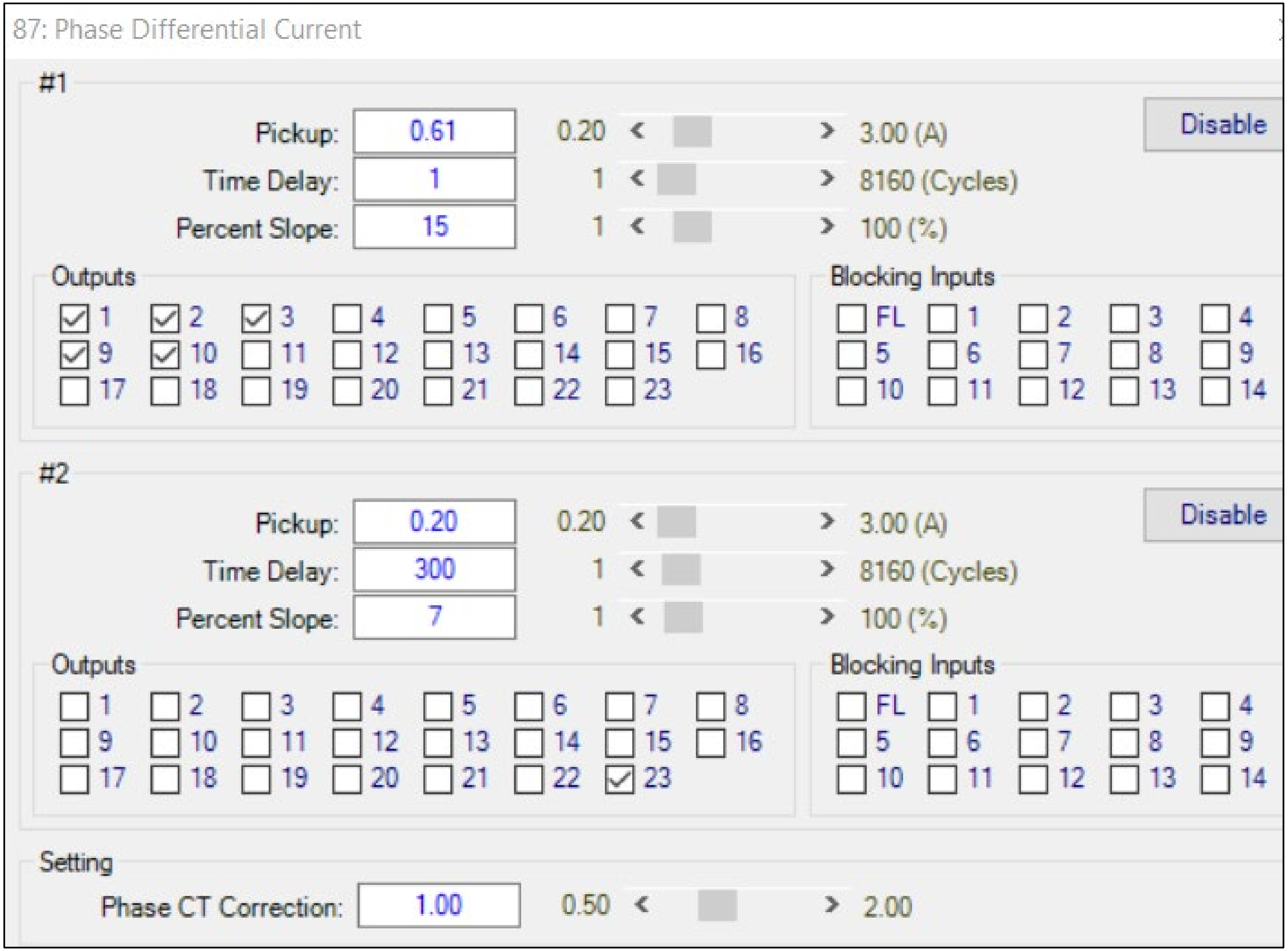
NOTE: To get a more secure 4X second slope, then the first slope (Percent Slope setting) must be increased accordingly e.g., a Percent Slope setting of 20% to 25% may be required to give a more secure 4X second slope of 80% to 100%.

NOTE: For badly unmatched CT saturation performance, may consider increasing the Pickup, Time Delay, and/or Slope to increase security.

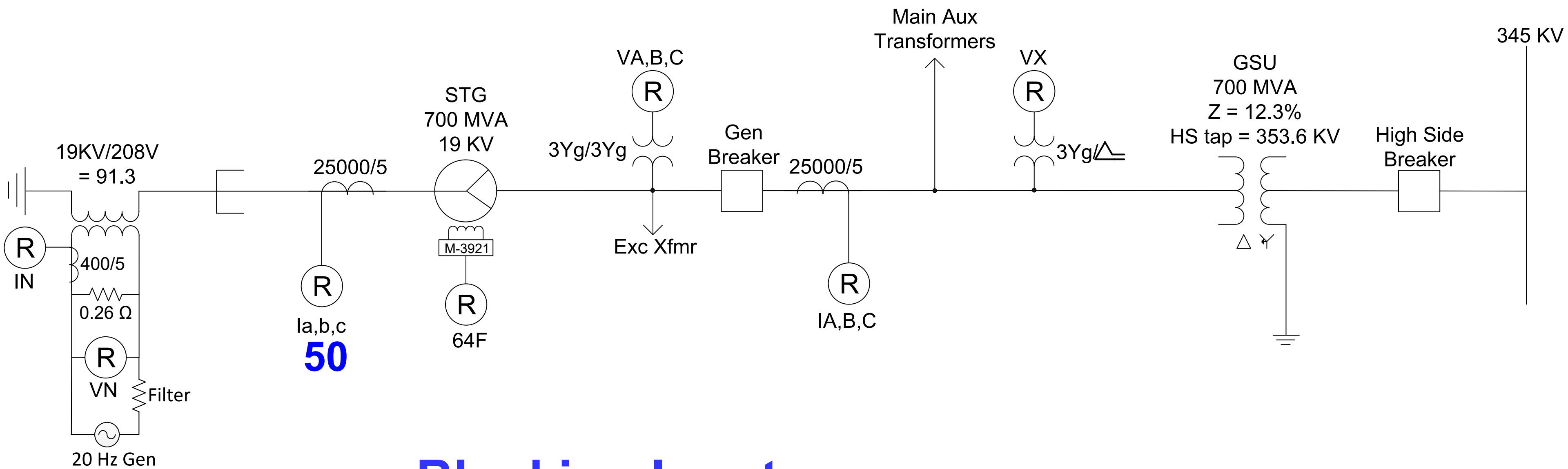
87 Characteristic



87 – Phase Differential



50 – Instantaneous Phase Overcurrent



Blocking Inputs = none

Backup Phase Fault Protection to 87 element:

- *Off-line protection provided due to 2-80 Hz frequency response (for M-3425A), although setting criteria will be created assuming on-line protection.*

50 #1 – Instantaneous Phase Overcurrent

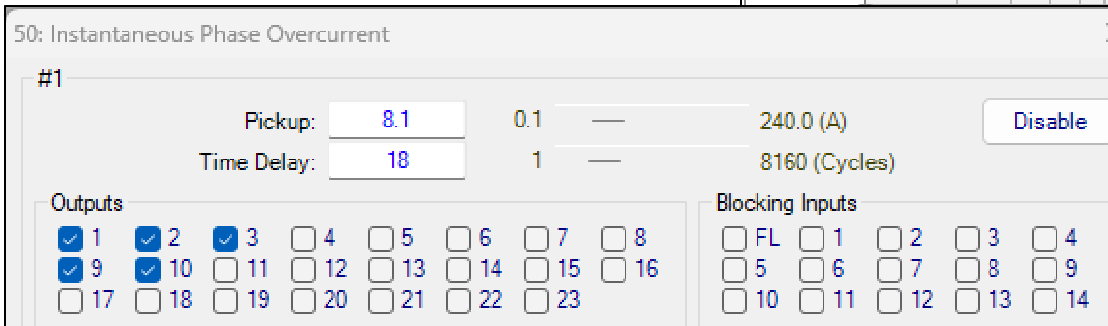
- **"on-line" backup to the 87 function for phase faults on the GSU LS.**
- **Set a short time delay to give preference to the 87 protection. Here, choose 0.30 seconds for extra security (could decrease if desired).**
- **Set the pickup > max output of the generator and > the PRC-025 criteria.**
- **Also, set it > what this relay will see for faults on the GSU HS @ 0.30 seconds using the gen decrement curve equation:**
- $Iac(t) = (|Id''| - |Id'|) * e^{-\frac{t}{Td''}} + (|Id'| - |Id|) * e^{-\frac{t}{Td'}} + |Id|$
- **Set the pickup < the minimum phase fault current that the generator can produce at 0.30 seconds for a LS ΦΦ fault.**
- **Max load, PRC-025, HS 3Φ fault < 50 #1 Pickup < LS ΦΦ fault**

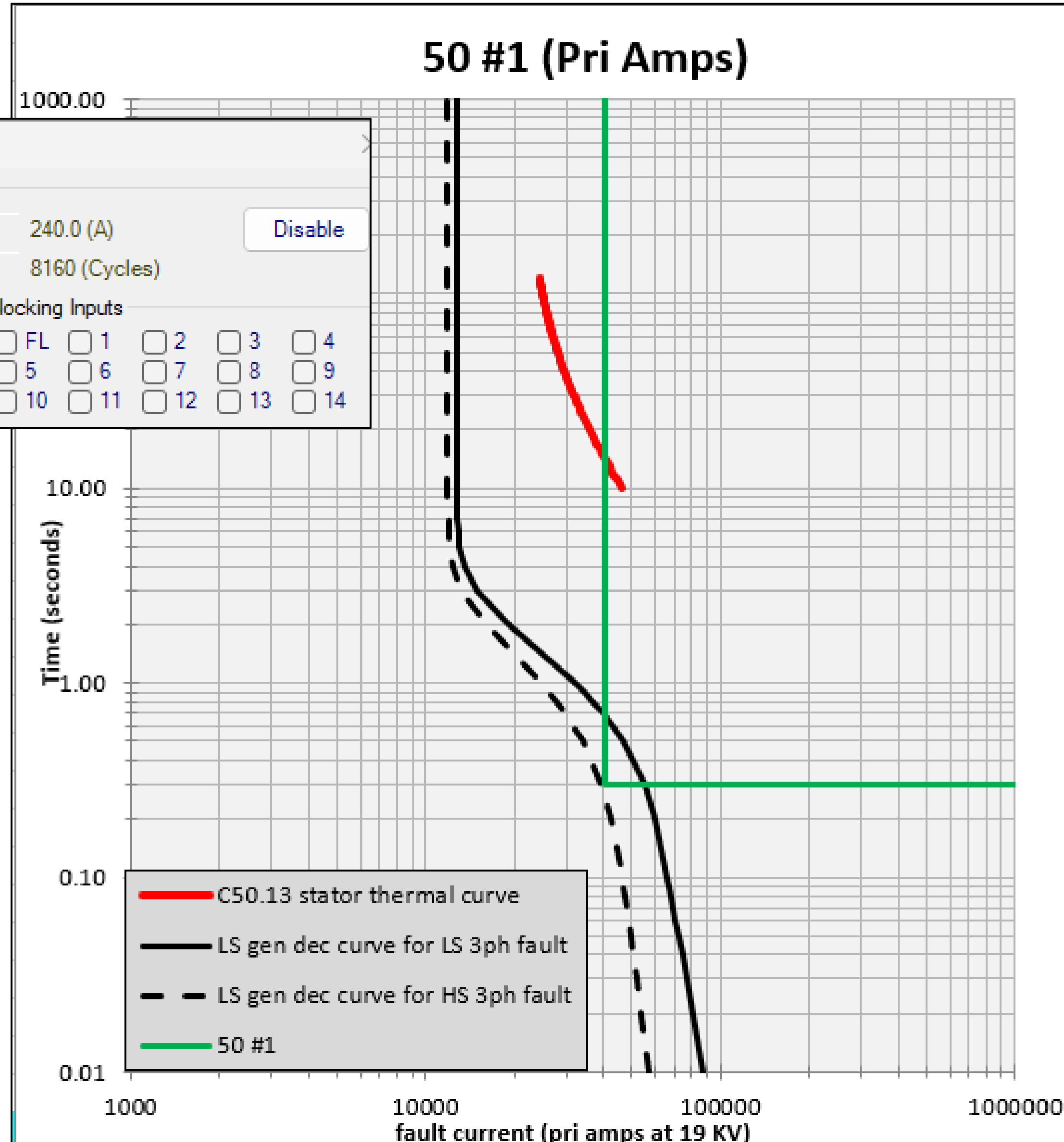
4.25, 8.075, 2174/5000 < 50 #1 Pickup < 0.866*55297/5000

4.25, 8.075, 0.43 < 50 #1 Pickup < 9.6

- **50 #1 Pickup = 8.1 sec amps (191% of max gen output – security check)**
- **50 #1 Time Delay = 18 cycles (0.30 seconds)**

50 #1 – Instantaneous Phase Overcurrent





Plotting the 50 settings with the generator decrement curves and stator thermal overload curve shows that this element will protect for GSU LS phase faults (but not HS) and can also partially protect for thermal overload.

50 #1 – Instantaneous Phase Overcurrent

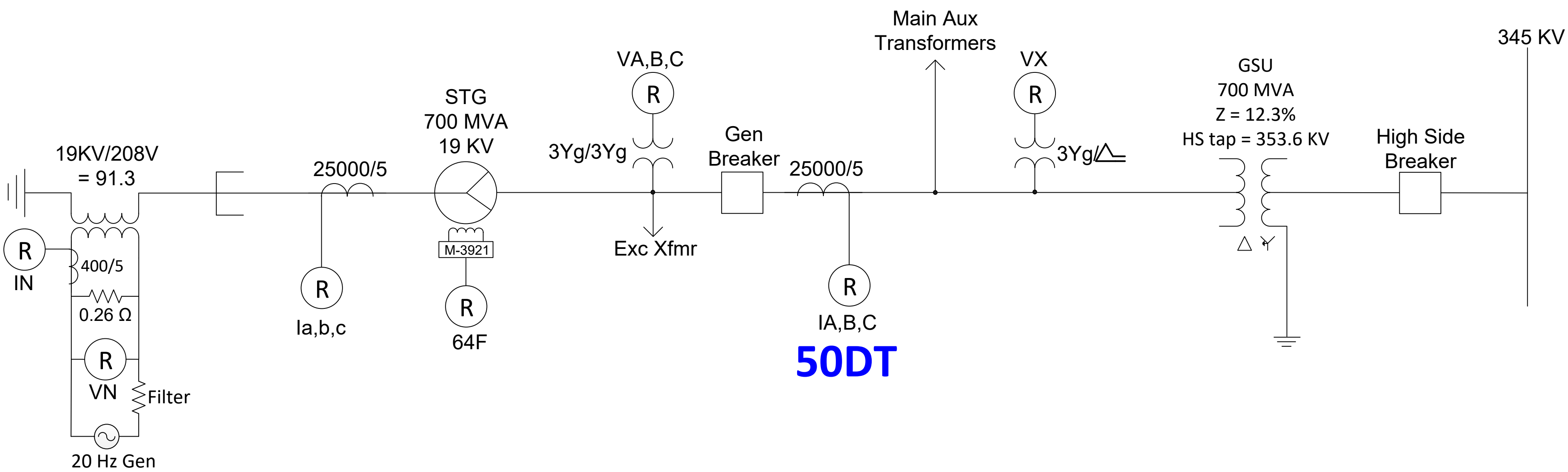
PRC-025: Table 1 Option 2a - M-3425A 50 function		
50 #1 Pickup =	8.1	sec amps
Ipri =	35107	pri amps
Isec =	7.021	sec ohms
1.15*Isec =	8.075	sec ohms
50 #1 Pickup > 1.15*Isec	TRUE	therefore, yes this complies with standard
50 function is from neutral side CTs		

PRC-026: 50 Phase Overcurrent from M-3425A			
50 #1 Pickup	8.1	sec amps	50 function is from neutral side CTs
50 #1 Time Delay	0.30	seconds	
ES at 120 deg =	-0.5+0.866	pu	
1.05*ES at 120 deg =	-0.525+0.9	pu	
ER at 0 deg =	1	pu	
1.05*ER at 0 deg =	1.05	pu	
ES - ER =	-1.575+0.9	pu	
Isys =	1.6804777	pu	
Ibase =	21270.8	pri amps	
Isys =	74043.37	pri amps	
Isys =	14.80867	sec amps	
50 #1 Pickup > Isys	FALSE	however, it complies via time delay criterion	

PRC-026 Criterion B: 50,51 pickup must be > criteria or have time delay ≥ 15 cycles.

Does not comply via Pickup, but Time Delay = 18 cycles which is > then the PRC-026 time delay criterion of 15 cycles, so YES it still complies.

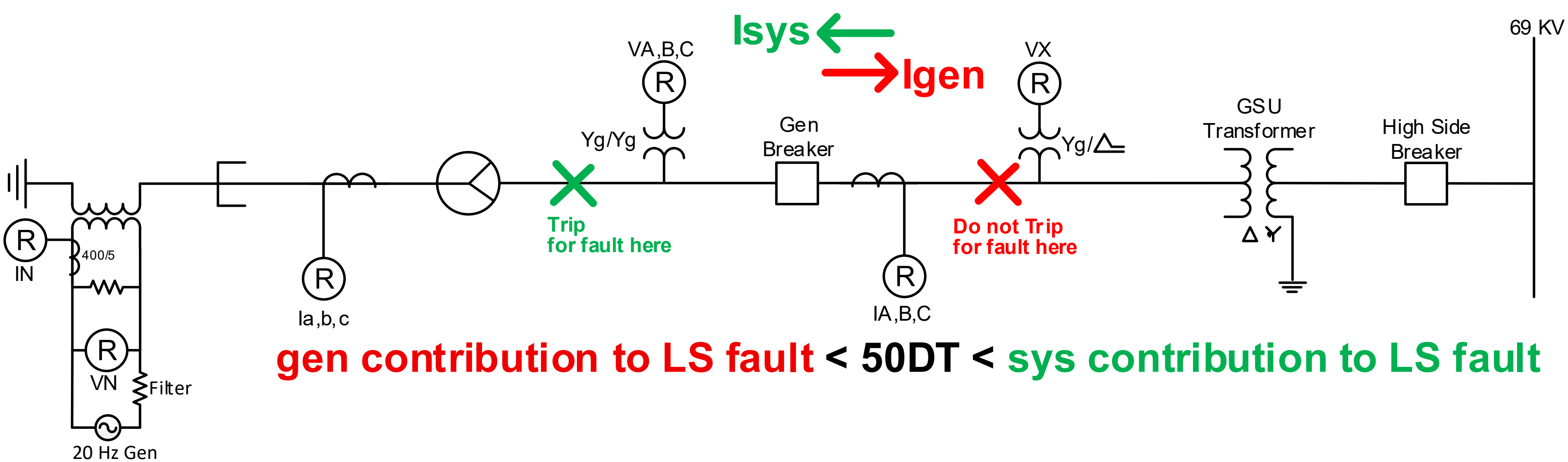
50DT – Definite Time Overcurrent



Blocking Inputs = none

50DT – Definite Time Overcurrent

- Backup to the 87 function for phase faults in the generator.
- Can set shorter time delay than 50 function because of added security provided by CT location and chosen pickup setting which can make it de-facto "directional" in nature (although not technically "directional" in the same manner as a "directional" overcurrent relay):



- So only time delay you may still want to employ is to let the 87 function have dibs which is not necessary but may assist post-event investigations.

50DT – Definite Time Overcurrent

- **Here choose 0.25 seconds for extra security and to abide by PRC-026 (even though it is technically unnecessary due to its in-effect, quasi-directionality).**
- **Set the pickup > max output of the generator at 0.25 seconds to LS fault.**
- $\mathbf{Iac(t) = (|Id''| - |Id'|) * e^{-\frac{t}{Td''}} + (|Id'| - |Id|) * e^{-\frac{t}{Td'}} + |Id|}$
- **Set the pickup < the minimum internal phase fault as fed from system.**

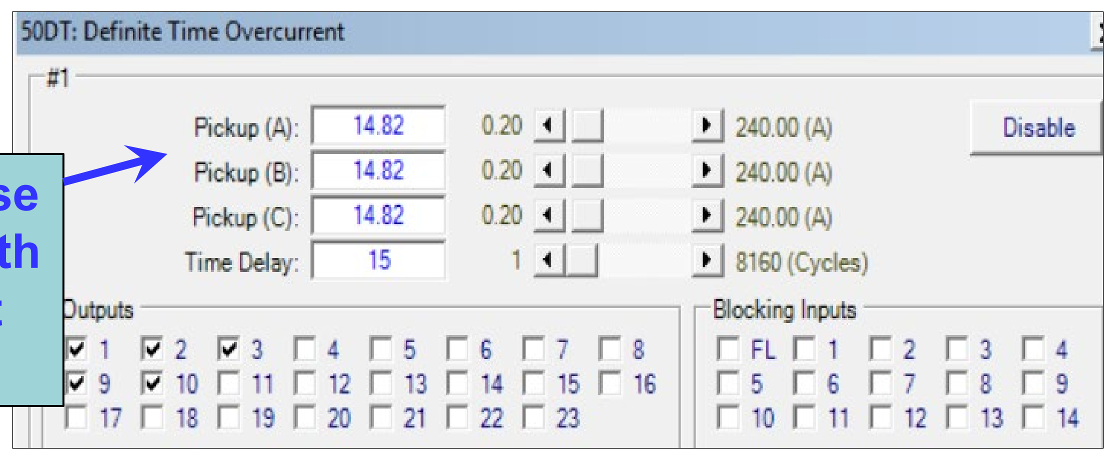
PRC-025,026, LS fault at 0.25 sec < 50DT #1 Pickup < sys contribution to LS fault

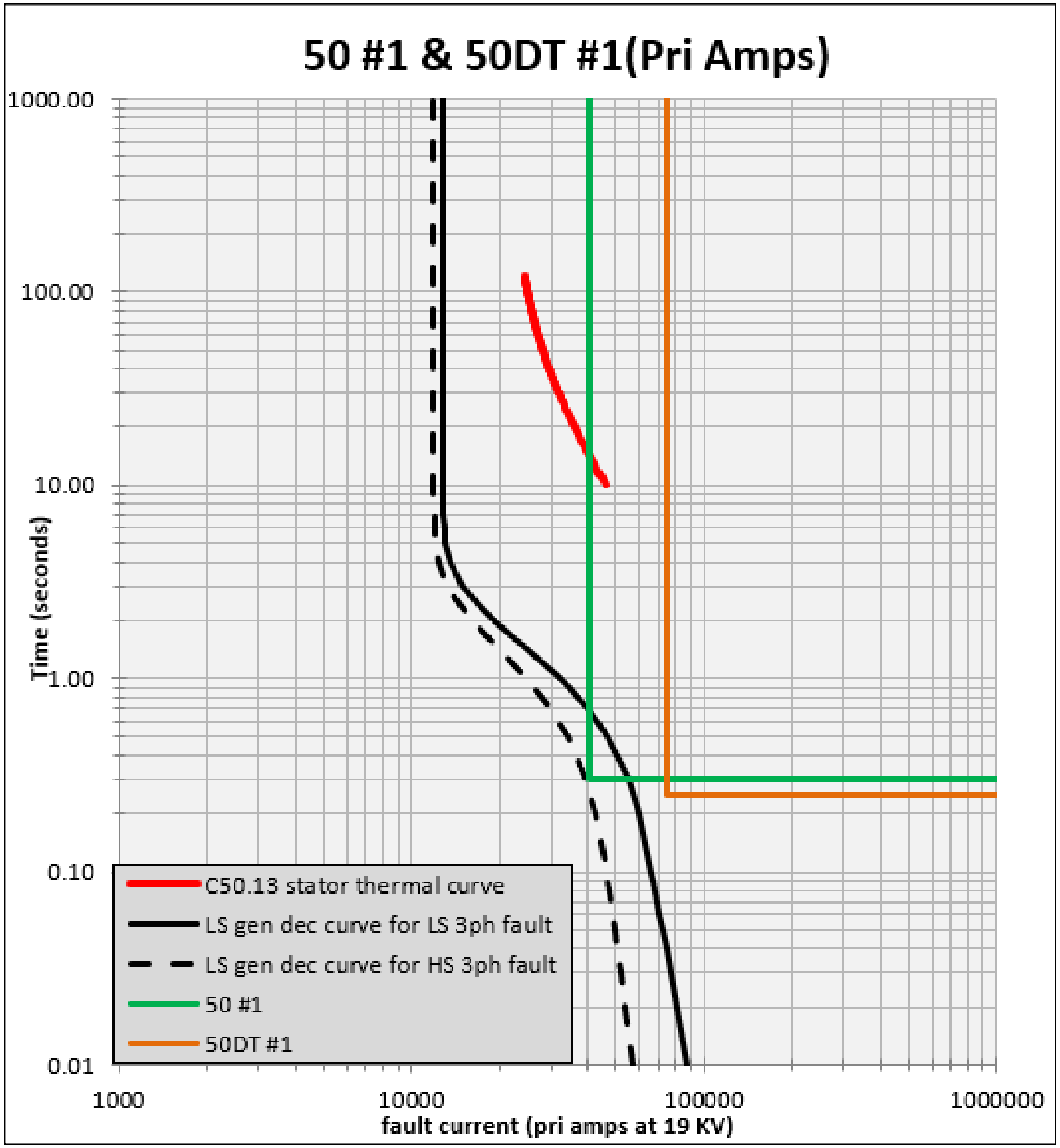
8.075, 14.81, 57725/5000 < 50DT #1 Pickup < 0.866*93462/5000

8.075, 14.81, 11.5 < 50DT #1 Pickup < 16.2

Set 50DT #1 = 14.82 A, 15 cyc

Individual phase elements in case unit needs to run temporarily with shorted turns or cut coils until it can be repaired.





50 #1 & 50DT #1(Pri Amps)
1000.00
100.00
10.00
1.00
0.10
0.01
Time (seconds)
1000
10000
100000
1000000
fault current (pri amps at 19 KV)
C50.13 stator thermal curve
LS gen dec curve for LS 3ph fault
LS gen dec curve for HS 3ph fault
50 #1
50DT #1

PRC-025: Table 1 Option 2a - M-3425A 50DT function

50DT #1 Pickup =	14.82	sec amps
Ipri =	35107	pri amps
Isec =	7.021	sec ohms
1.15*Isec =	8.075	sec ohms
50DT #1 Pickup > 1.15*Isec	TRUE	therefore, yes this complies with standard
		50DT funciton is from terminal side CTs

PRC-026: 50DT Phase Overcurrent from M-3425A

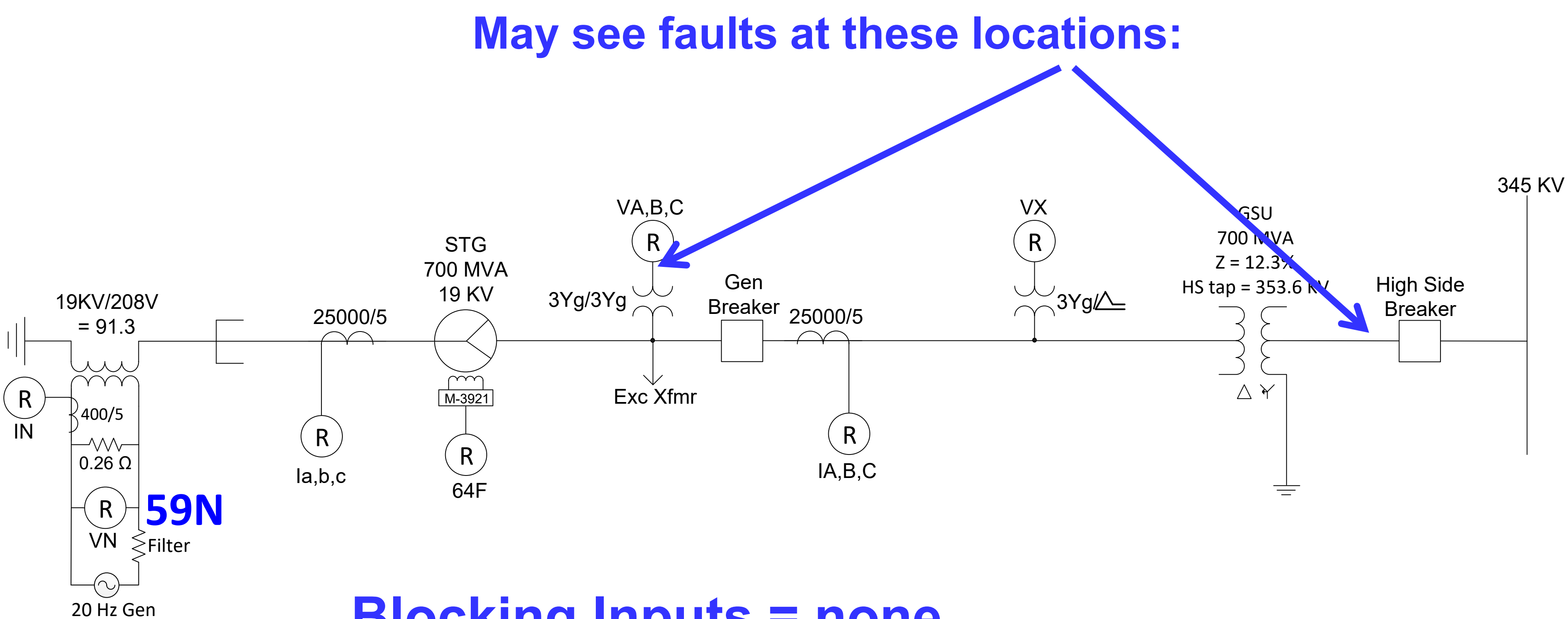
50DT #1 Pickup	14.82	sec amps	50DT funciton is from terminal side CTs
50DT #1 Time Delay	0.25	seconds	
Es at 120 deg =	-0.5+0.8660	pu	
1.05*Es at 120 deg =	-0.525+0.90	pu	
ER at 0 deg =	1	pu	
1.05*ER at 0 deg =	1.05	pu	
Es - ER =	-1.575+0.90	pu	
Isys =	1.68047775	pu	
Ibase =	21270.799	pri amps	
Isys =	74043.374	pri amps	
Isys =	14.808675	sec amps	
50DT #1 Pickup > Isys	TRUE	and it also complies via time delay criterion	

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

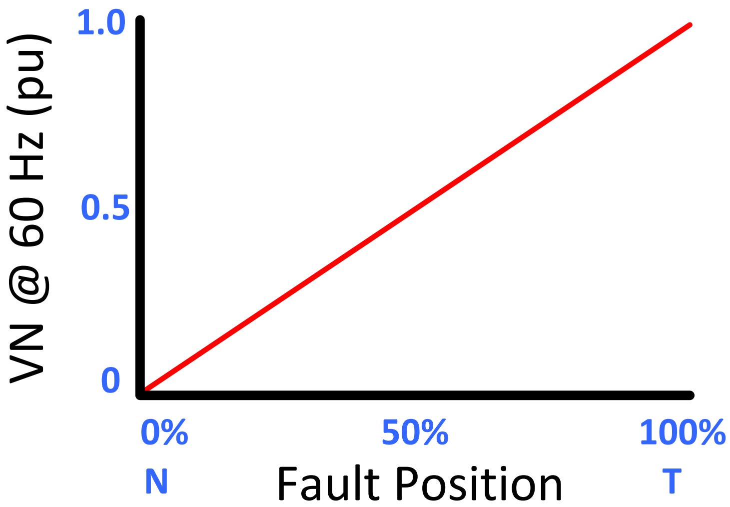
59N – Neutral Overvoltage (aka 64G, 59G)



Blocking Inputs = none
(or use FL blocking if using V2/Vo inhibits)

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

59N Element



VN will measure the following for a fault at the terminal end:

$$V_N = \frac{V_{LG}}{N} = \frac{19000}{\sqrt{3} * 91.3} = 120.1 \text{ sec volts}$$

Fault location is proportional to the measured VN. For faults at various percentages of the stator winding, VN will be that same % of the full, 100% measured voltage from a fault at the terminal end. For example, if a stator ground fault occurs and VN = 90 V, then the fault is located 90/120.1 = 0.75 pu or 75% from the neutral end of the stator winding.

Several factors could make this calculated fault location inaccurate:

- Ignoring NGT impedance
- Fault resistance
- Startup/Shutdown

59N Element

Typical 59N Pickup setting is for 95% coverage, which equates to a 59N Pickup setting of (1-0.95)*120.1=0.05 * 120.1 = 6.0 V.

Typical 59N Pickup bookend criteria:

$$\mathbf{min\ pickup;\ max\ unbalance\ <\ 59N\ \#1\ Pickup\ \leq\ desired\ coverage}$$

$$\mathbf{4.2\%\ ;\ 3\%\ <\ 59N\ \#1\ Pickup\ \leq\ 5\%}$$

$$\mathbf{5\ V\ ;\ 3.6\ V\ <\ 59N\ \#1\ Pickup\ \leq\ 6.0\ V}$$

$$\mathbf{set\ 59N\ \#1\ Pickup = 6.0\ V}$$

$$\mathbf{\left(1-\frac{6.0}{120.1}\right)*100 = 95\%}\quad \textbf{(upper 95\% of the stator winding is protected)}$$

59N Element

The time delay setting needs to coordinate with ground faults on the high side of the GSU and on the secondary of Yg/Yg generator VTs (in this case, only for faults on the neutral cable from the VT to the relay because the ground reference is moved to B-phase). If no accelerated ground fault protection schemes are employed, then it may be appropriate to set a lower time delay, such as the following:

- ***18 cycles = 21 zone 2 time delay of the GSU HS transmission line relays***
- ***5 cycles = breaker interrupt time***
- ***1 cycle = relay operate time***
- ***10 cycles = BF timer***
- ***<u>12 cycles</u> = coordination margin***

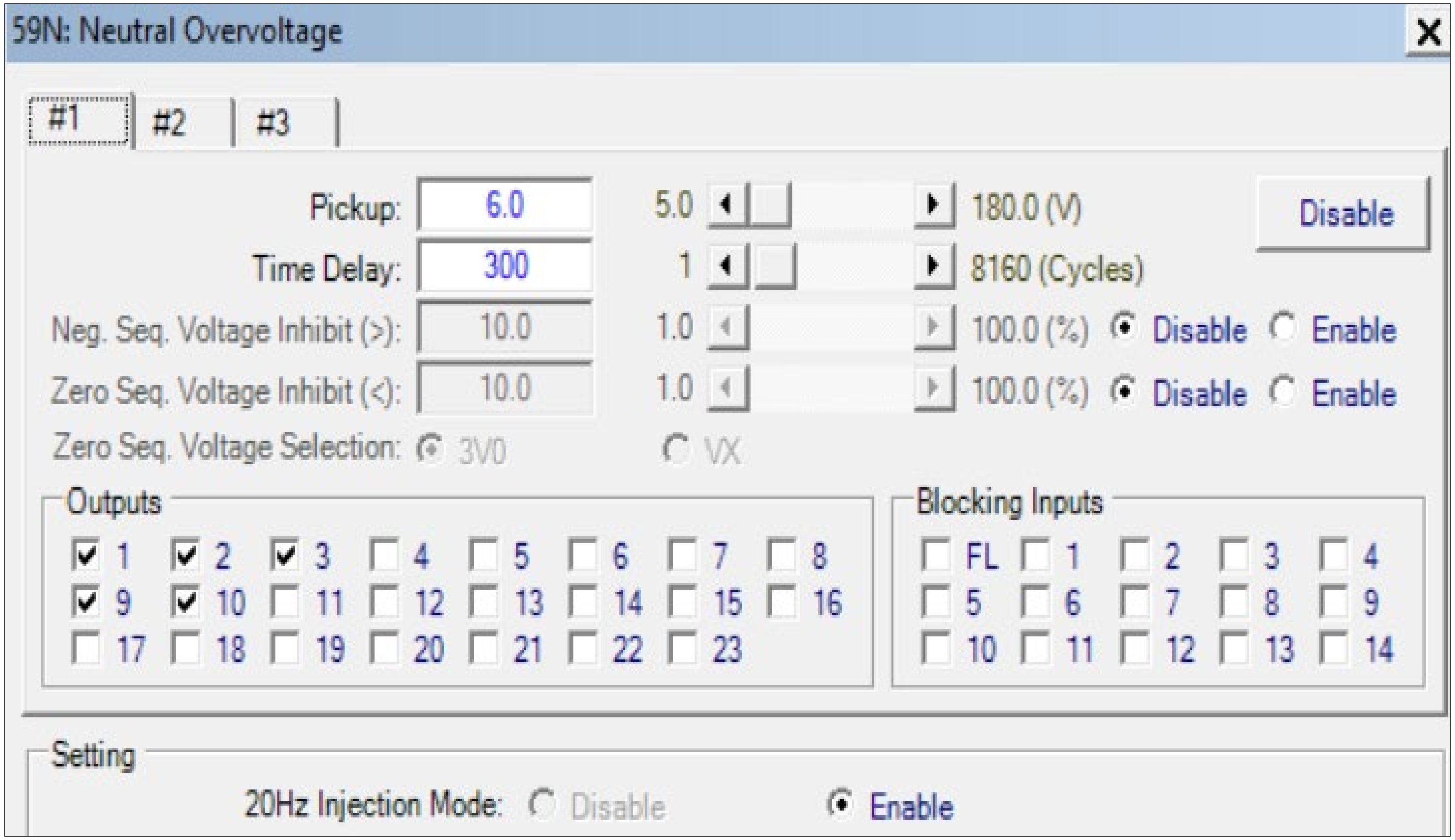
46 cycles = Total (59N #1 time delay setting if no accelerated ground fault protection schemes are used)

However, because accelerated ground fault protection schemes are employed here and to give extra security because the specific protection and clearing times for faults on the transmission system is unknown here, choose a time delay setting of 5 seconds as system ground faults should be cleared by system relaying in well less than 5 seconds.

59N #1 Time Delay = 300 cycles (5 seconds)

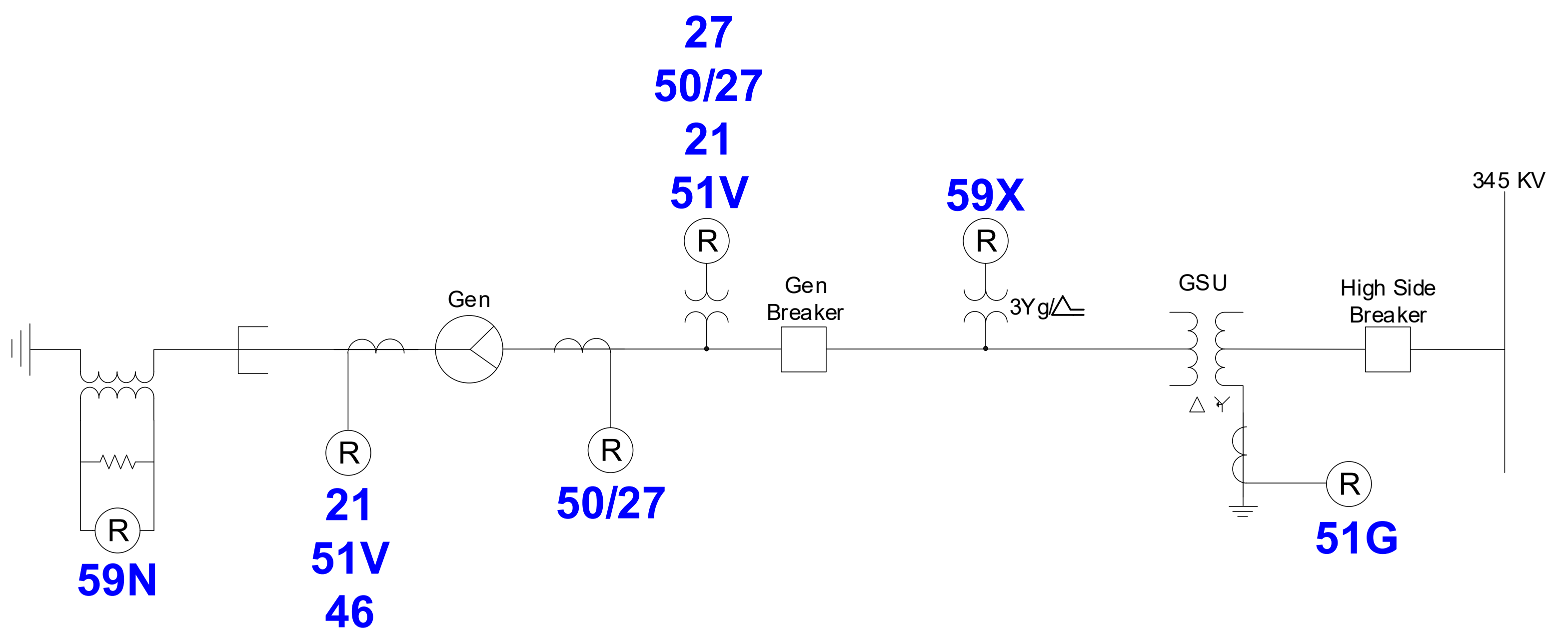
59N – Neutral Overvoltage (Gen)

Set 59N #1 = 6 V and 5 seconds



PRC-027

- Coord 59N with transmission line ground faults.



- 59N time delay = 5 seconds.
- All transmission line relaying clears grounds faults well before this.
- Therefore **YES, complies**

59N – Neutral Overvoltage (Gen)

- **For Yg/Yg gen VTs, must coordinate 59N settings with VT fuses.**

$$\mathrm{I} = \frac{\mathrm{Vpri}}{\mathrm{R_{Npri}}} = \frac{\mathrm{59N\ \#1\ Pickup} * \mathrm{N}}{\mathrm{R_{Npri}}} = \frac{6.0 * 91.3}{2169.47} = 0.25\ \mathrm{pri\ amps}$$

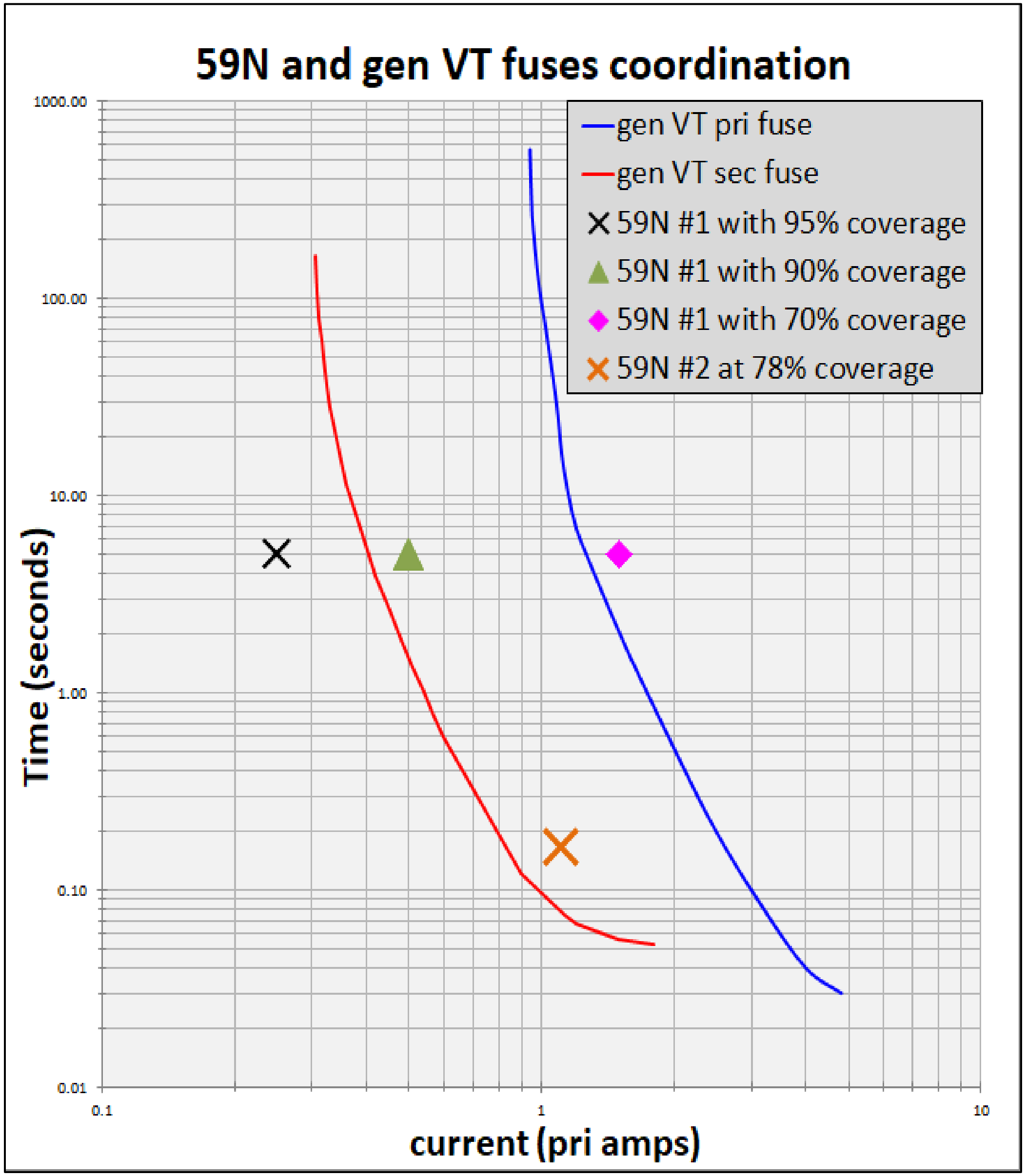
- **Plot 0.25 A at 5 seconds with VT fuses – does not coordinate with primary or secondary fuses.**
- **At 0.5 A and 5 seconds, it coordinates with secondary fuses but not primary and provides 90% coverage:**

$$VN = \mathrm{Ifuse} * VTNR * \mathrm{RN}sec = 0.5 * 91.3 * 0.26 = 11.9\ \mathrm{Vsec}, \left(1 - \frac{11.9}{120.1}\right) * 100 = 90\%$$

- **At 1.5 A and 5 seconds, it coords with both fuses, but only 70% coverage:**

$$VN = \mathrm{Ifuse} * VTNR * \mathrm{RN}sec = 1.5 * 91.3 * 0.26 = 35.6\ \mathrm{Vsec}, \left(1 - \frac{35.6}{120.1}\right) * 100 = 70\%$$

59N – Neutral Overvoltage (Gen)



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

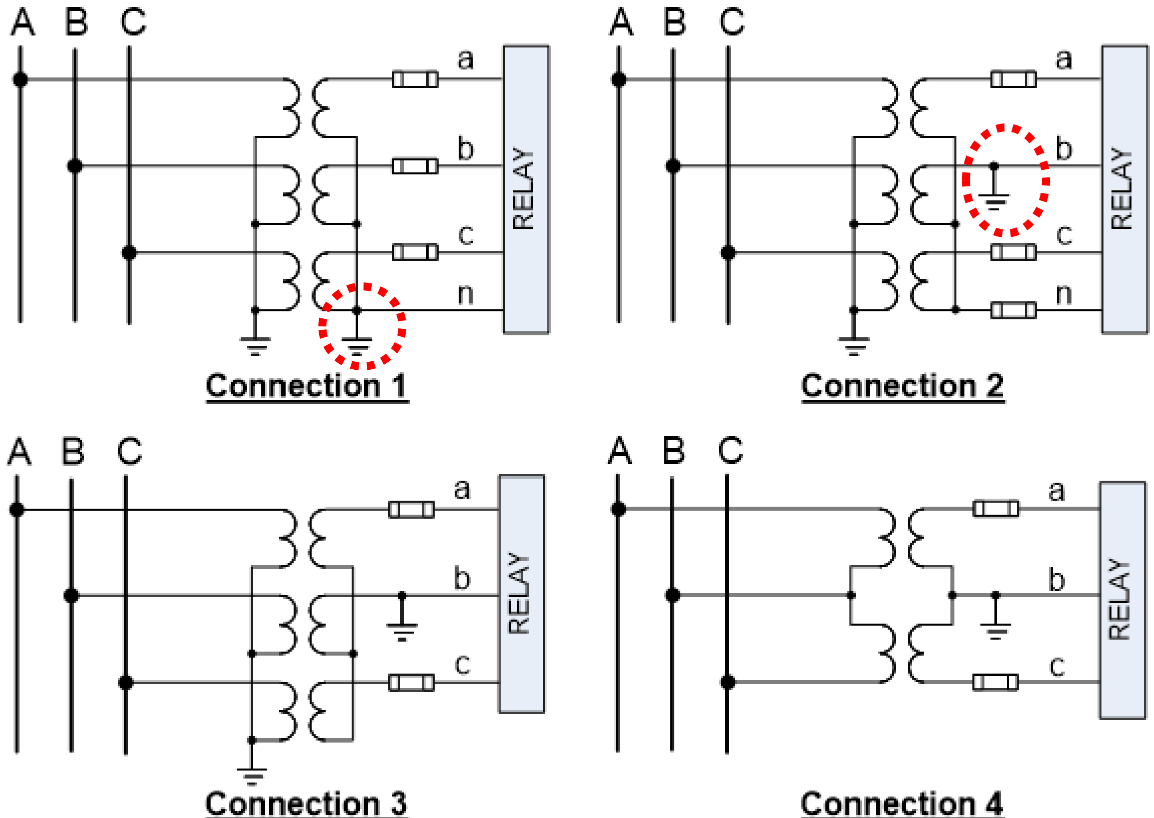
- ***But may decide to accept the 90% coverage and bump the Pickup setting up to 11.9 V to coordinate with secondary VT fuses***

OR -------->>>>

59N – Neutral Overvoltage (Gen)

- ***Keep the 95% coverage (6 V) and move the secondary VT ground safety connection from the neutral to the B-phase to break the zero-sequence path***
  - ***Therefore, coordination with VT fuses is not necessary***

IEEE PSRC J12 report on improved generator ground fault protection discusses pros/cons of different VT arrangements:



59N – Accelerated Ground Fault Protection Schemes

2) **59N #2 – GSU HS fault coord accelerated ground fault protection**
3) **59N #3 – V2/V0 supervised accelerated ground fault protection**
4) **I2 supervised accelerated ground fault protection**
5) **Open gen breaker accelerated ground fault protection**
6) **Intermittent arcing accelerated ground fault protection**

- **These schemes do trip faster, but they still do not provide ground fault protection to the last 5% of the stator winding near the neutral end.**
- **Therefore, still need 27TN, 59D, and/or 64S to see faults at neutral.**
- **The exception may be scheme 5 if initiating that scheme via pickup of 100% elements.**

59N – Accelerated Ground Fault Protection Schemes

2) GSU high side fault coordinated

- ***If the GSU interwinding capacitance is known (and it is here, 0.01182 µF), calculate the voltage that will develop across the NGR for a ground fault on the high side of the GSU:***

$$Xc = \frac{1}{2\pi f C} = \frac{1}{2\pi * 60 * 0.01182\mu} = 224{,}415\ \Omega pri$$

$$\text{Icoupled} = \frac{\text{high side V}_{\text{LG}}}{\text{Xc}} = \frac{345\ K}{\sqrt{3} * 224{,}415} = 0.888\ \text{Apri}$$

$$\text{VN} = RNsec * Icoupled * VTNR = 0.26 * 0.888 * 91.3 = 21.1\ \text{Vsec}$$

- ***Set the pickup > this value (with a 125% security factor) so it will not see faults on the high side of the GSU:***

$$Set\ 59N\ \#2\ Pickup\ = 1.25 * 21.1 = 26.4\ V$$

$$\left(1 - \frac{26.4}{120.1}\right) * 100 = 78\%$$

59N – Accelerated Ground Fault Protection Schemes

2) GSU high side fault coordinated

- ***Determine the corresponding primary amps to check for coordination with the gen VT fuses:***

$$I = \frac{59N\ \#2\ Pickup}{RNsec * VTNR} = \frac{26.4}{0.26 * 91.3} = 1.11\ pri\ amps$$

- ***And since this element will not see ground faults on the high side of the GSU, a shorter time delay setting can be implemented.***

Set 59N #2 Time Delay = 10 cycles (choose 10 cycles to coord with VT sec fuses)

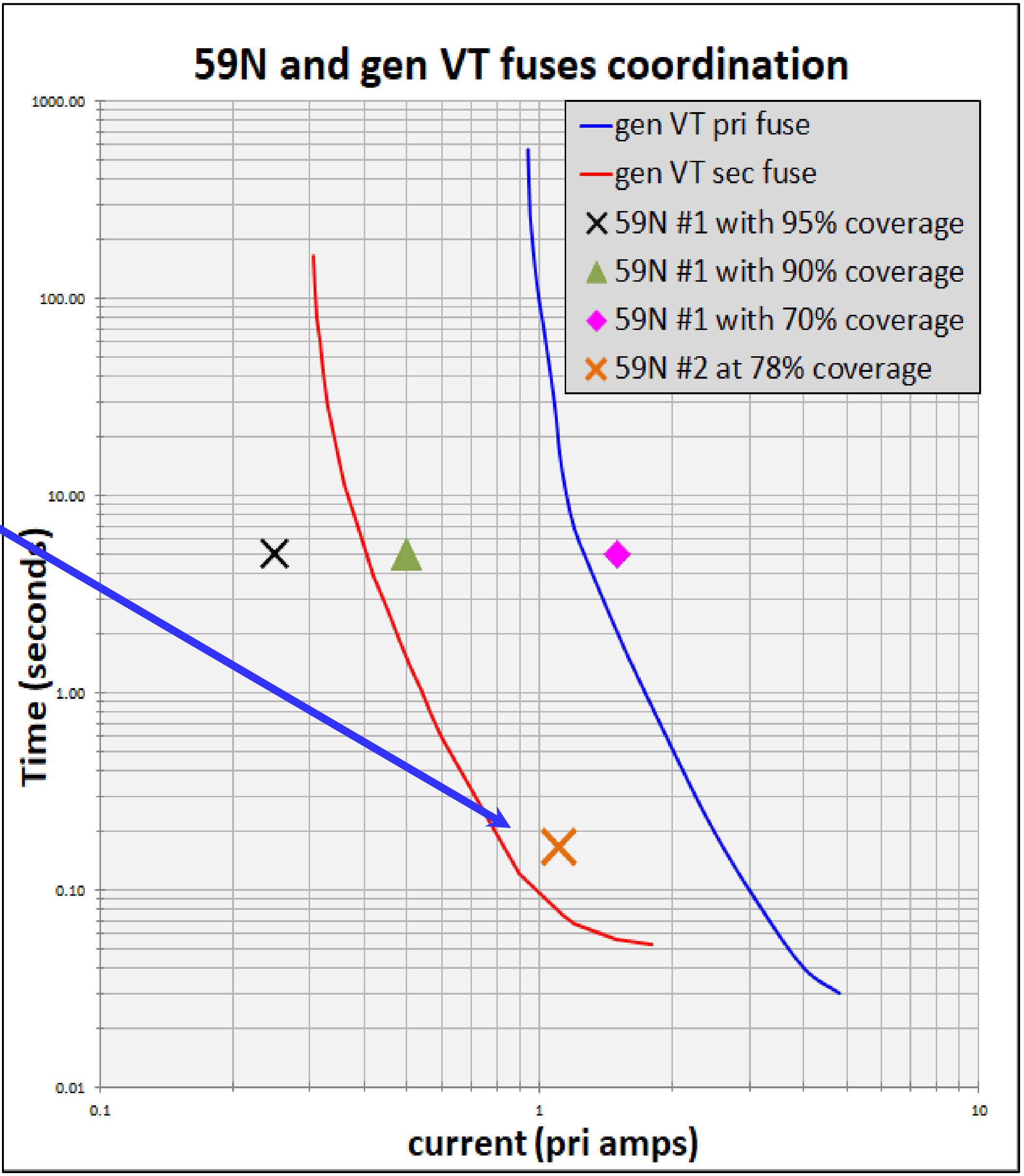
- ***Plotting 1.11 A at 10 cycles with the VT fuses shows that this element would coordinate with the secondary fuses but not the primary fuses; although it is not necessary to coordinate with either of the fuses if the VT secondary safety ground was moved from neutral to B-phase.***

- ***If the GSU interwinding capacitance is not known, then this element could instead be used as an Alarm (set at 5 V and 30 cycles).***

59N – Accelerated Ground Fault Protection Schemes

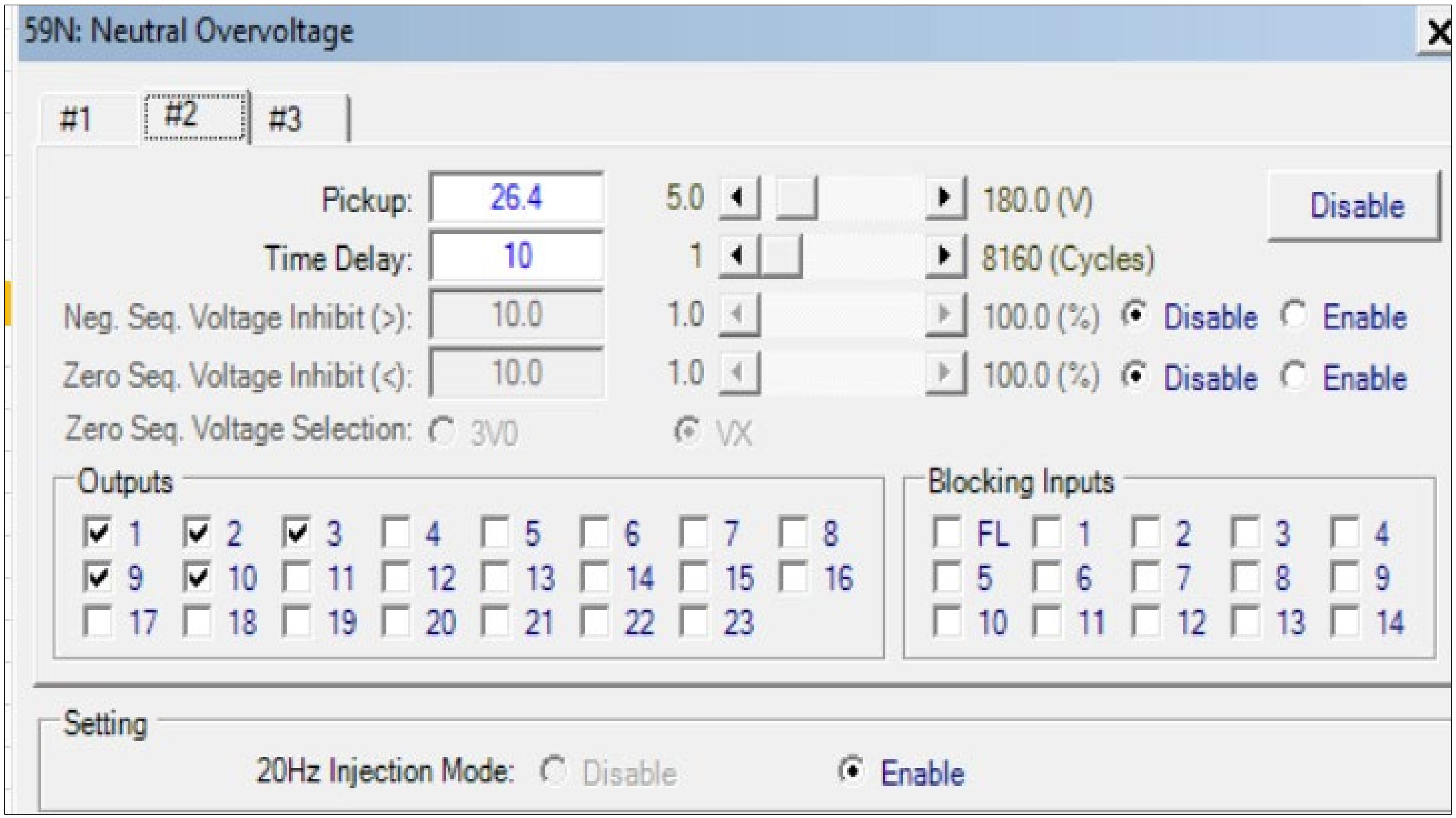
2) **GSU HS fault coordinated**

1.11 A (26.4 V) and 10 cycles or 0.167 seconds



59N – Accelerated Ground Fault Protection Schemes

2) GSU high side fault coordinated

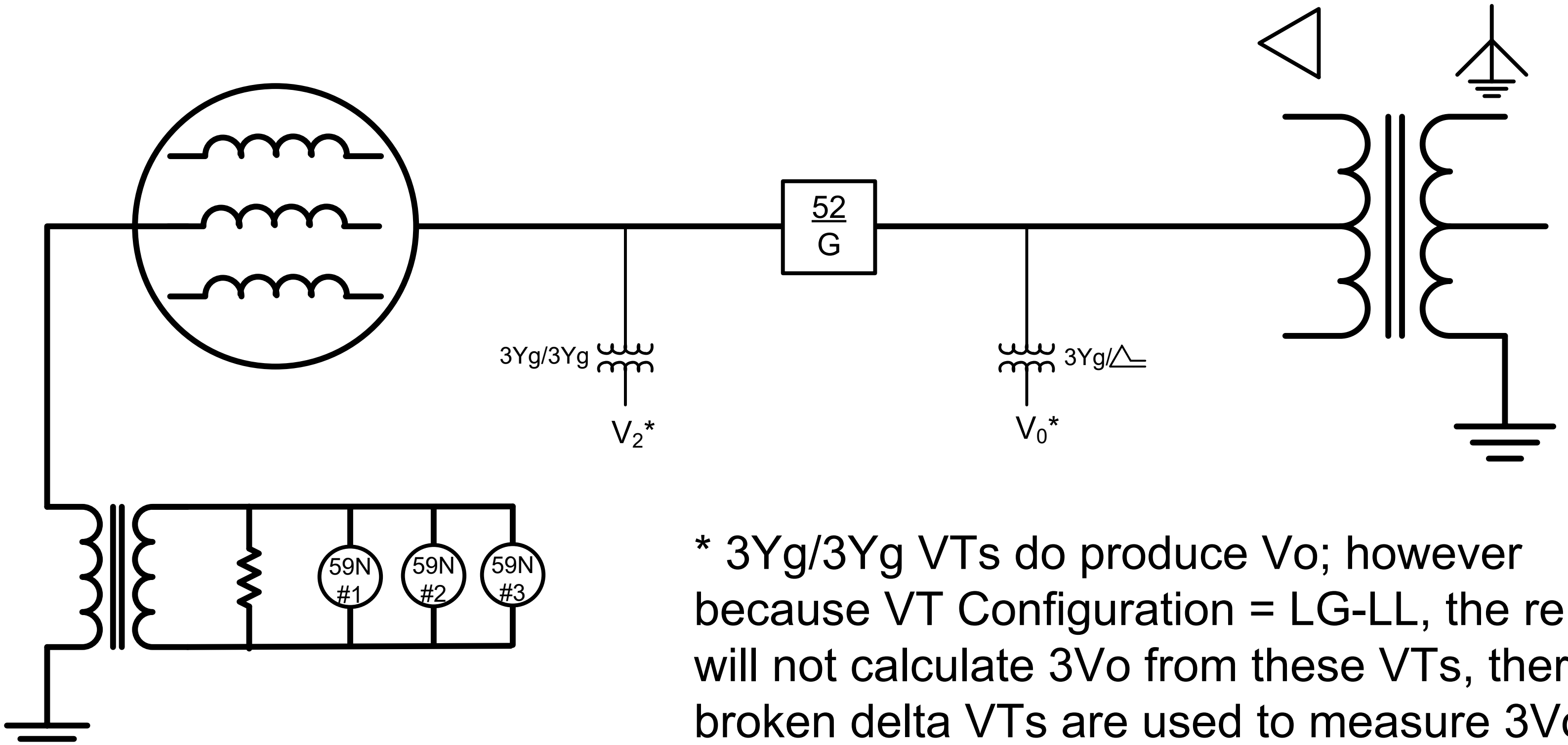


59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

Because there is very little V2 for ΦG fault on GSU LS and there will be some V2 for a ΦG fault on GSU HS or VT secondary, trip can be accelerated:

- Vo > V2 for GSU low side ground faults, accelerate trip
- Vo < V2 for GSU high side ground faults, block trip



* 3Yg/3Yg VTs do produce Vo; however because VT Configuration = LG-LL, the relay will not calculate 3Vo from these VTs, therefore broken delta VTs are used to measure 3Vo

59N – Accelerated Ground Fault Protection Schemes

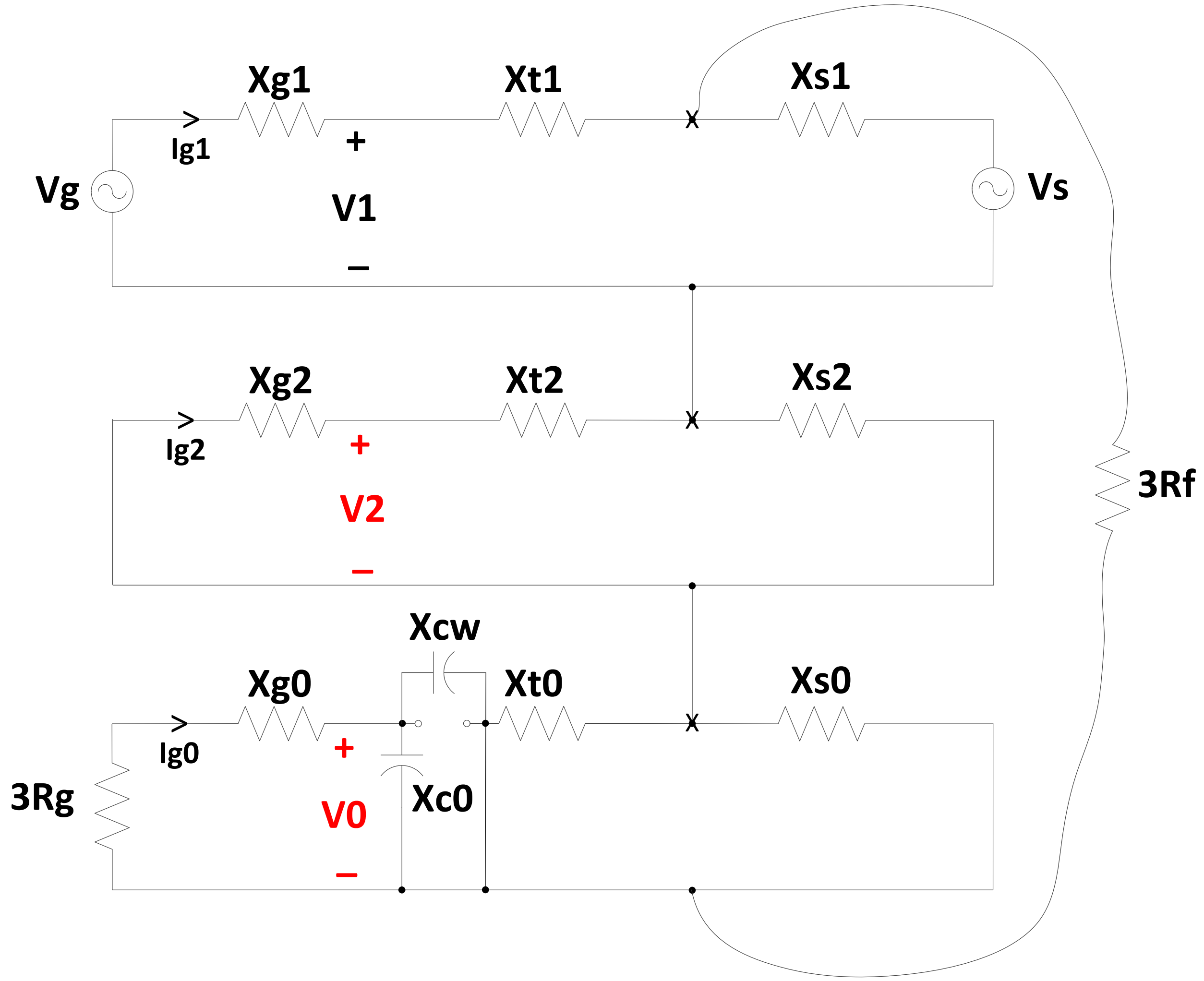
3) V2/V0 supervised

- 59N #3 Pickup = 6.0 V (same as 59N #1)
- Time Delay = 10 cycles as no coord is necessary for system or VT secondary faults
- Calculate V_2 and V_0 that relay will see for ΦG HS and LS GSU faults (need to calculate for VT secondary faults as well if Yg/Yg VTs with ground reference on common – not shown here as n/a for these sample calcs).
- Typical values are if $V_2 > 5\%$ or $V_0 < 7\%$ then block this element.
- **PRO TIP: just use 5% & 7%**
- **Why? Because:**
  - ✓ **Calculations can be quite involved.**
  - ✓ **And I have found that the 5% and 7% are good values to use in all the cases for which I have done the calculations.**

59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

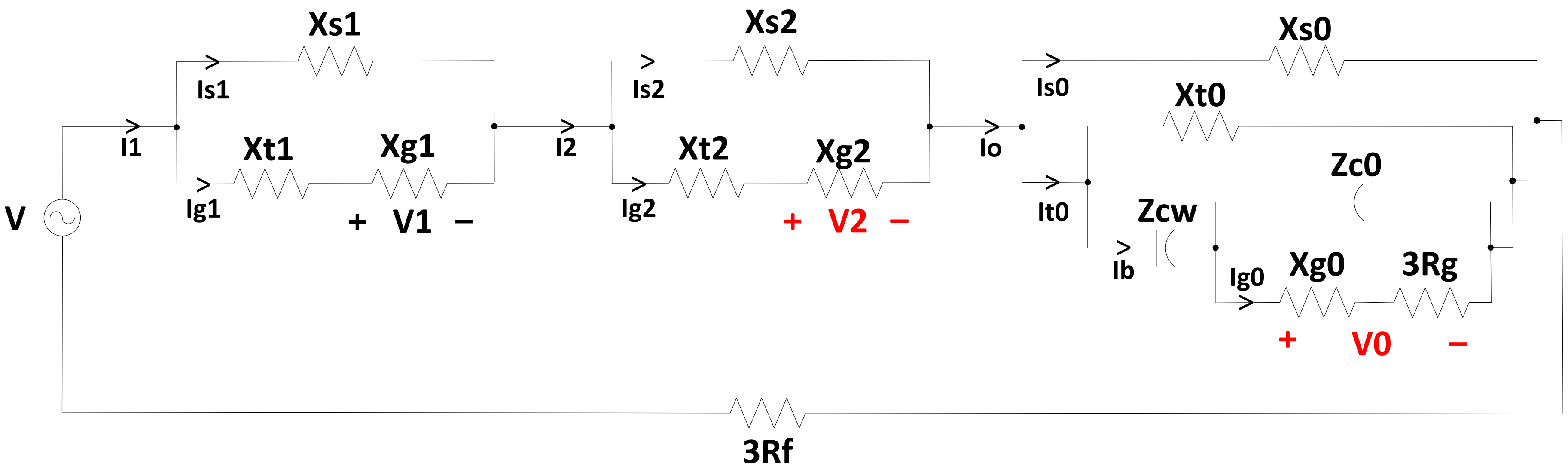
ΦG fault on the HS of the GSU using subtransient reactance:



59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

Network reduction:



59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

$$Z1 := \frac{Zs1 \cdot (Zt + Xg1sub)}{Zs1 + Zt + Xg1sub} \quad Z2 := \frac{Zs2 \cdot (Zt + Xg2)}{Zs2 + Zt + Xg2} \quad Za := \frac{ZCo \cdot (Xg0 + 3 \cdot Rg)}{ZCo + Xg0 + 3 \cdot Rg} \quad Zb := Za + ZCw \quad Zc := \frac{Zt \cdot Zb}{Zt + Zb} \quad Z0 := \frac{Zs0 \cdot Zc}{Zs0 + Zc}$$

$$Io := \frac{1}{Z1 + Z2 + Z0 + 3 \cdot RfHS} \quad Ip := Io \quad In := Io$$

$$Ig1 := Ip \cdot \left(\frac{Zs1}{Zs1 + Zt + Xg1sub}\right) \quad Is1 := Ip - Ig1$$

$$Ig2 := In \cdot \left(\frac{Zs2}{Zs2 + Zt + Xg2}\right) \quad Is2 := In - Ig2 \quad |Ig2 \cdot 100| = 293 \quad \%$$

$$It0 := Io \cdot \left(\frac{Zs0}{Zs0 + Zc}\right) \quad Is0 := Io - It0 \quad Ib := It0 \cdot \left(\frac{Zto}{Zto + Zb}\right) \quad Ig0 := Ib \cdot \left(\frac{ZCo}{ZCo + Xg0 + 3\ Rg}\right)$$

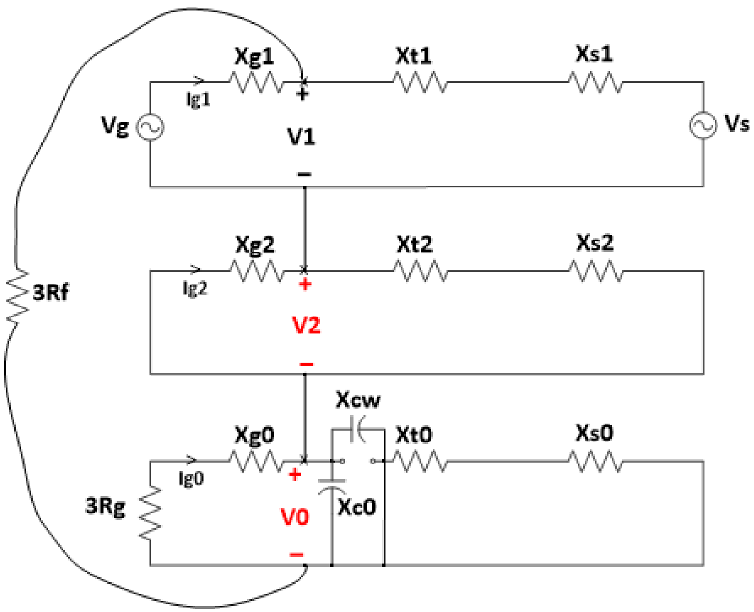
$V2 := Ig2 \cdot Xg2$ $\quad |V2 \cdot 100| = 66$ %, which is > the 5% V2 inhibit setting, so it will correctly block for GSU HS fault

$V0 := Ig0 \cdot Za$ $\quad |V0 \cdot 100| = 3$ %, which is < the 7% V0 inhibit setting, so it will correctly block for GSU HS fault

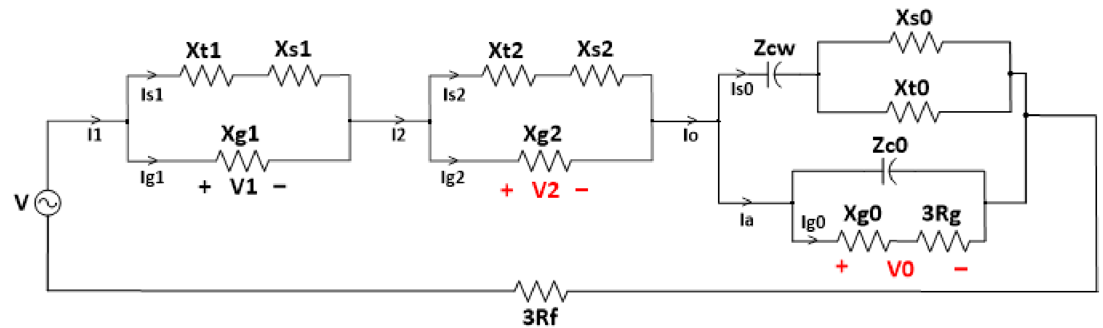
59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

Then do same calcs for GSU LS ΦG faults:



Network reduction:



$Z1 := \frac{(Zs1+Zt)\cdot Xg1sub}{Zs1+Zt+Xg1sub}$ $\quad Z2 := \frac{(Zs2+Zt)\cdot Xg2}{Zs2+Zt+Xg2}$ $\quad Za := \frac{ZCo\cdot(Xg0+3\cdot Rg)}{ZCo+Xg0+3\cdot Rg}$ $\quad Zb := \frac{Zt\cdot Zs0}{Zt+Zs0}$ $\quad Zc := Zb+ZCw$ $\quad Z0 := \frac{Za\cdot Zc}{Za+Zc}$

$Io := \frac{1}{Z1+Z2+Z0+3\cdot RfLS}$ $\quad Ip := Io$ $\quad In := Io$

$Ig1 := Ip\cdot\left(\frac{Zs1+Zt}{Zs1+Zt+Xg1sub}\right)$ $\quad Is1 := Ip - Ig1$

$Ig2 := In\cdot\left(\frac{Zs2+Zt}{Zs2+Zt+Xg2}\right)$ $\quad Is2 := In - Ig2$ $\quad |Ig2\cdot 100| = 0.01$ %

$Ia := Io\cdot\left(\frac{Zc}{Za+Zc}\right)$ $\quad Is0 := Io - Ia$ $\quad Ig0 := Ia\cdot\left(\frac{ZCo}{ZCo+Xg0+3\ Rg}\right)$

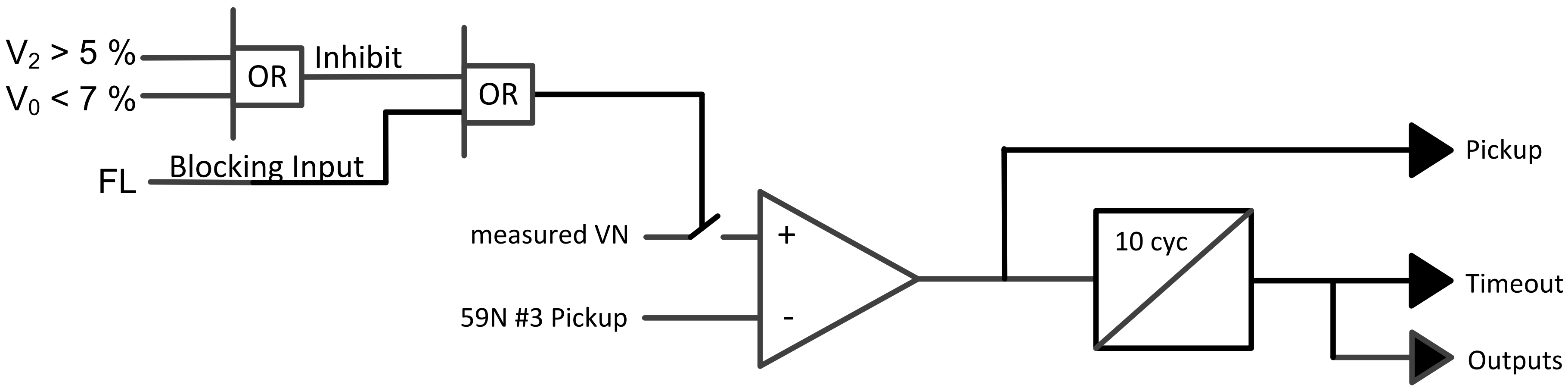
$V2 := Ig2\cdot Xg2$ $\quad |V2\cdot 100| = 0.002$ %, which is **not** > the 5% V2 inhibit setting, so it will allow a trip for GSU LS fault

$V0 := Ig0\cdot Za$ $\quad |V0\cdot 100| = 46$ %, which is **not** < the 7% V0 inhibit setting, so it will allow a trip for GSU LS fault

You will find that the 5% & 7% values are OK to use for all, or at least most, high impedance grounded machines with GSUs that are configured with delta on LS and wye grounded on the HS.

59N – Accelerated Ground Fault Protection Schemes

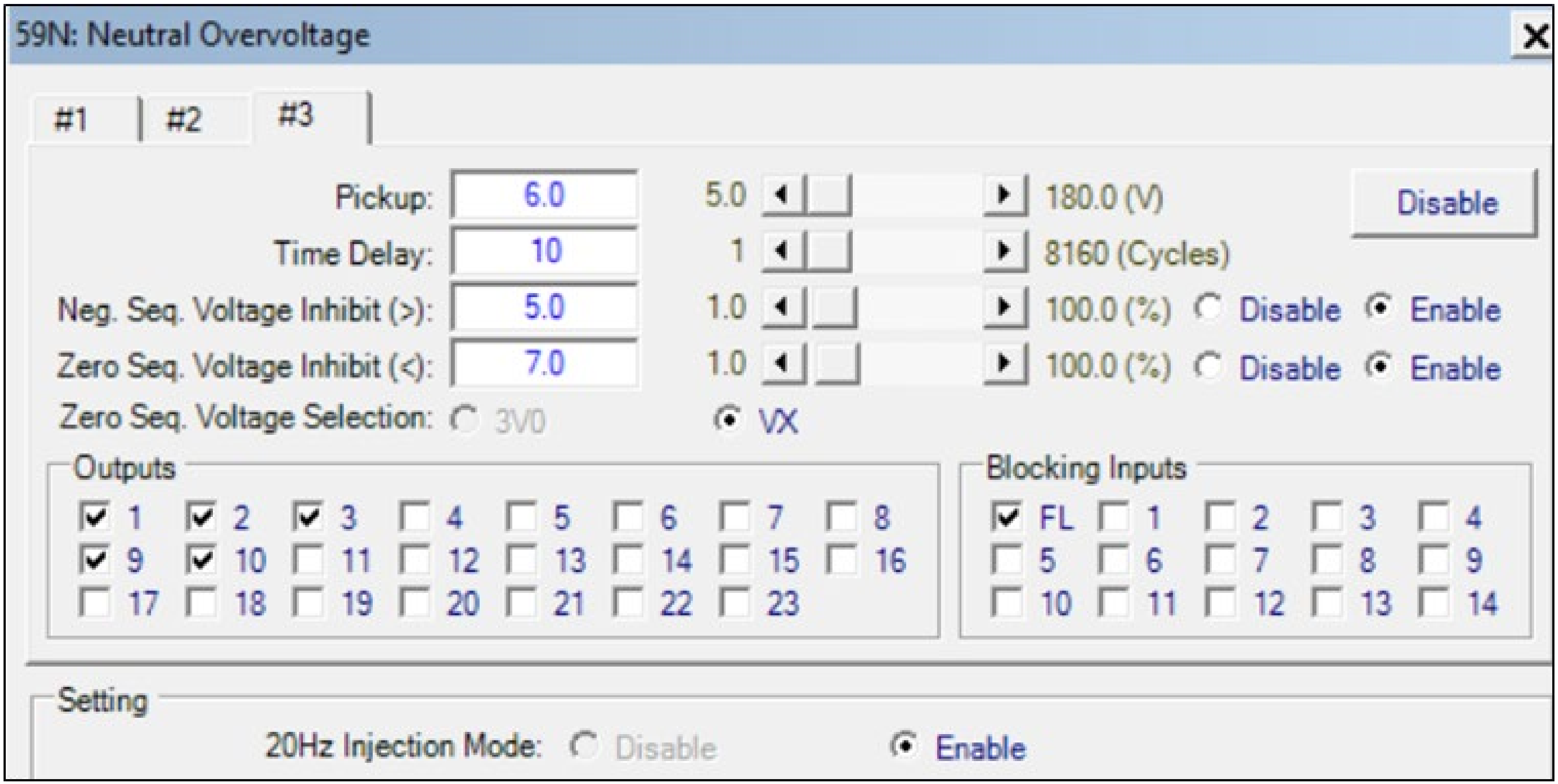
3) V2/V0 supervised



59N – Accelerated Ground Fault Protection Schemes

3) V2/V0 supervised

Built into setting screen already i.e. do not need special logic like some other mfgs may require.



59N – Accelerated Ground Fault Protection Schemes

4) I2 supervised

- **Much like V_2 and V_0 59N supervision, I_2 can also be used to distinguish between ground faults on the HS and LS of the GSU.**

- **For ground faults on the HS of the GSU, the generator relay will measure some I_2.**

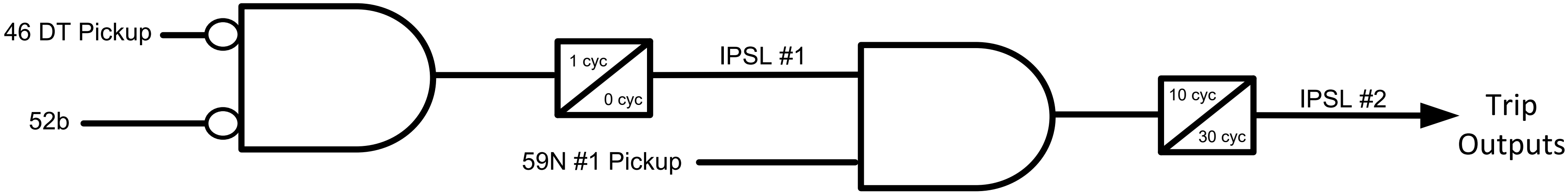
- **For ground faults on the low side of the GSU, the generator relay will measure negligible I_2.**

- **Allow trip if $I_2 < 5\%$ (use 46DT Pickup which is set at 5%) and 59N #1 Pickup is exceeded for > time delay setting.**

- **For this example, set time delay to 10 cycles.**

59N – Accelerated Ground Fault Protection Schemes

4) I2 supervised

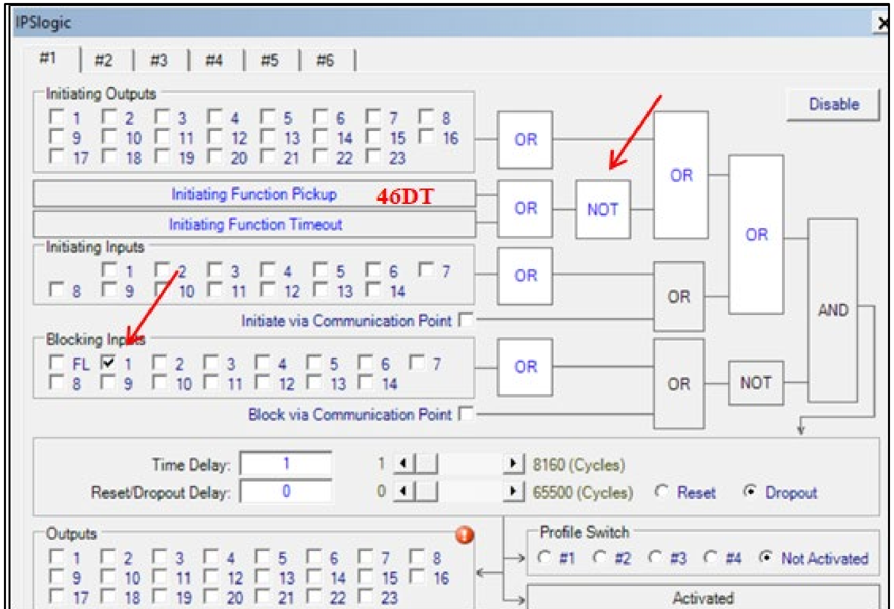


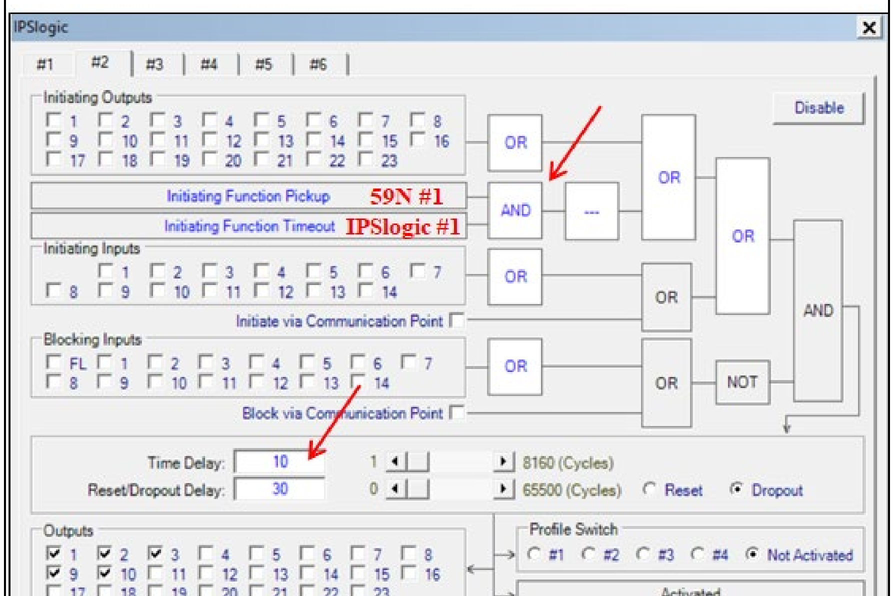
NOTE: If the 52b contact is not used in this scheme as shown, then because IPSL #1 = NOT 46DT would be normally asserted it will block resetting of targets.

59N – Accelerated Ground Fault Protection Schemes

4) I2 supervised

- **Now need IPSlogic, but easy to develop**

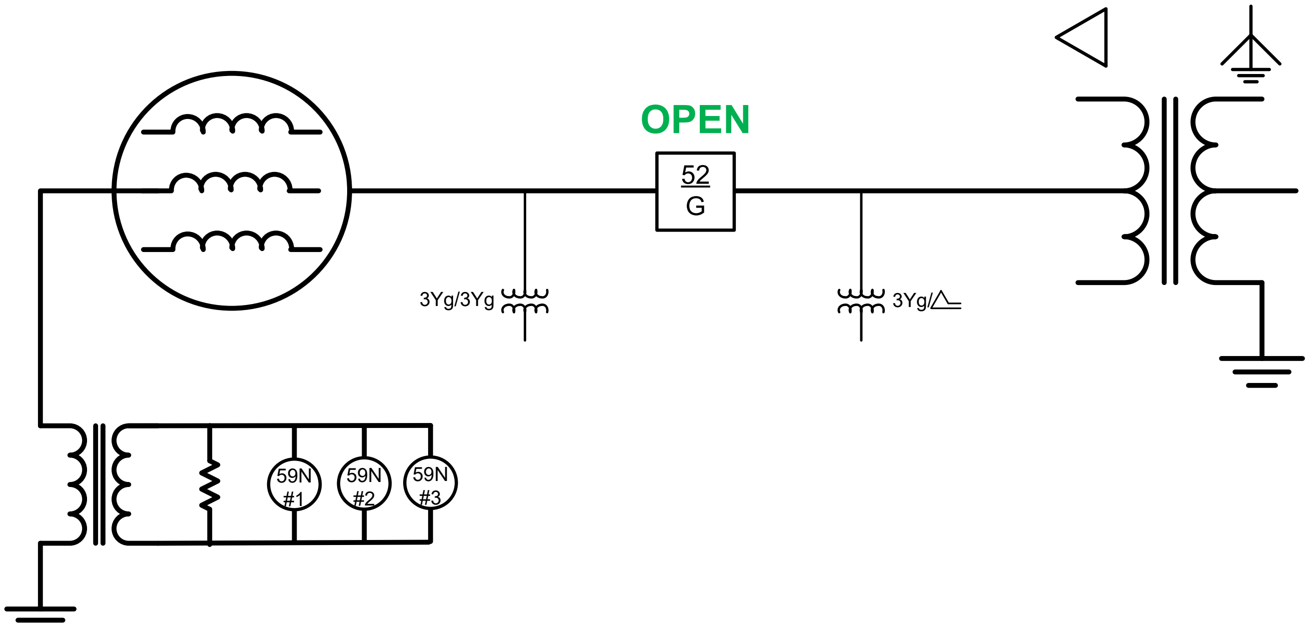




59N – Accelerated Ground Fault Protection Schemes

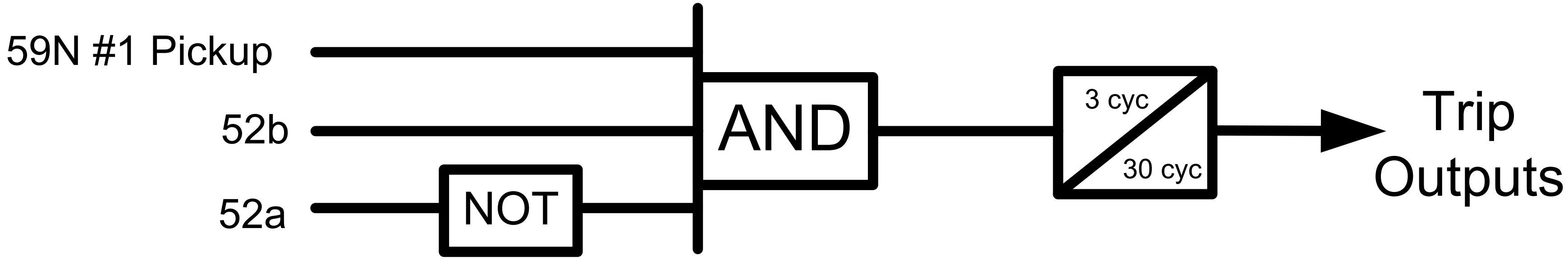
5) Open gen breaker

- 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, etc) if pickup is exceeded.
- If time delay is set too short (3 cycles), this scheme may not coord with VT fuses, but this may be acceptable under this operational scenario.



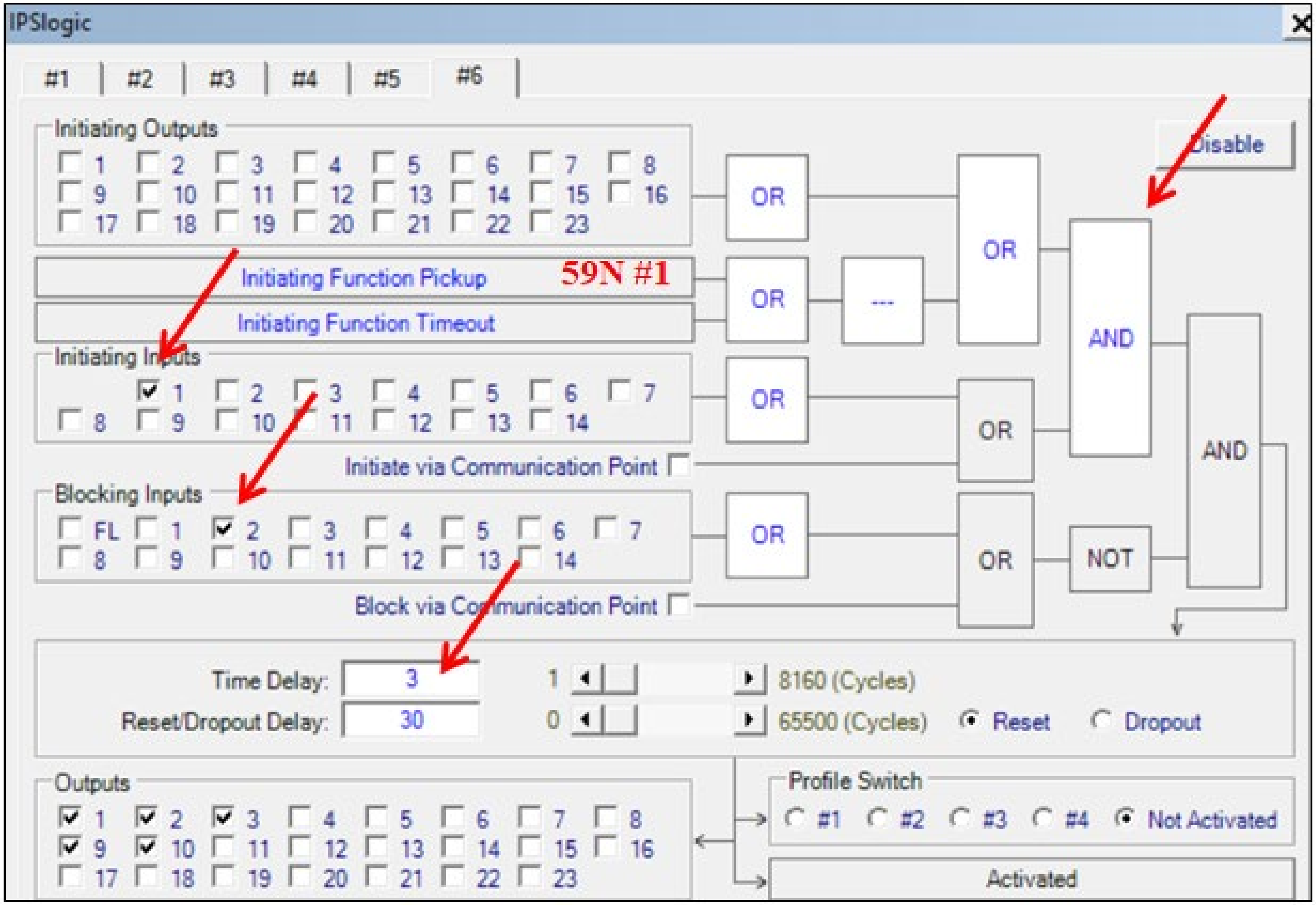
59N – Accelerated Ground Fault Protection Schemes

5) Open gen breaker



59N – Accelerated Ground Fault Protection Schemes

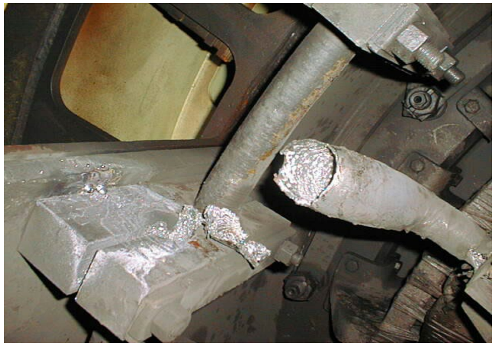
5) Open gen breaker



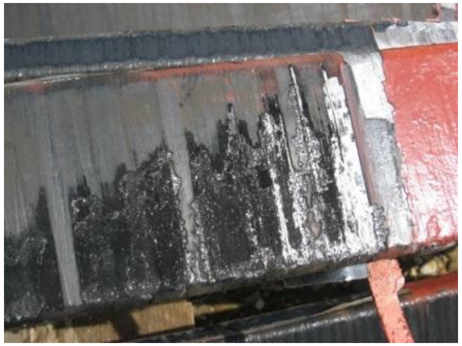
59N – Accelerated Ground Fault Protection Schemes

6) Intermittent arcing

- Can be very destructive, especially at neutral
- At neutral, even though AC current is very low, arcing fault develops a high voltage DC transient
- If enough arcs occur in a short time, destructive insulation damage can occur
- 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

59N – Accelerated Ground Fault Protection Schemes

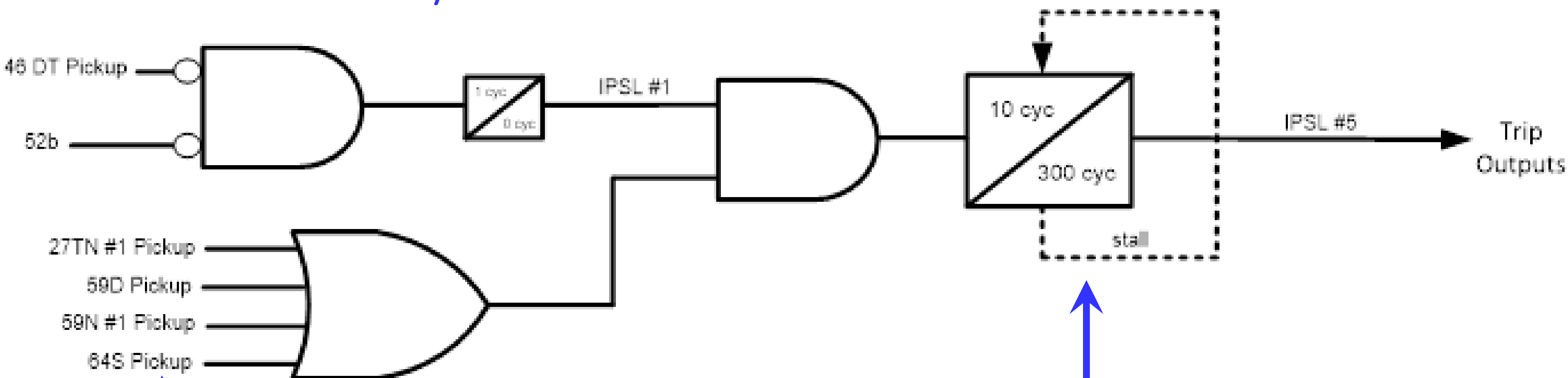
6) Intermittent arcing

- Solution: Create an integrated stall timer that incorporates memory of previous arcing events.
- Accomplished by stalling the timing of the pickup timer when it drops out intermittently as is the case for arcing faults.
- For this example, a pickup timer (Time Delay) of **10 cycles** is used and a stall timer (Reset Delay) of **300 cycles** is used.
- Trip for an arcing fault with an accumulated 10 cycles worth of arcing where the total time between arcs is < 5 seconds.

59N – Accelerated Ground Fault Protection Schemes

6) Intermittent arcing

IPSlogic #1, NOT 46DT AND NOT 52b, is ANDed with the ground pickups to improve the security to ensure it is not falsely asserting from a GSU HS ΦG event. However, this then blocks the element when the breaker is open. So, if an arcing event occurs with an open breaker or if the arcing continues after the breaker is tripped open then this scheme will not provide protection. Alternatively, IPSlogic #1 could be removed from this scheme to provide additional dependability at the cost of the extra security.



The logic could be initiated by any of the ground fault functions (e.g. 59N, 27TN, 59D, 64S, or even 50N/51N if used in some applications).

Integrated stall timer that incorporates memory of previous arcing events

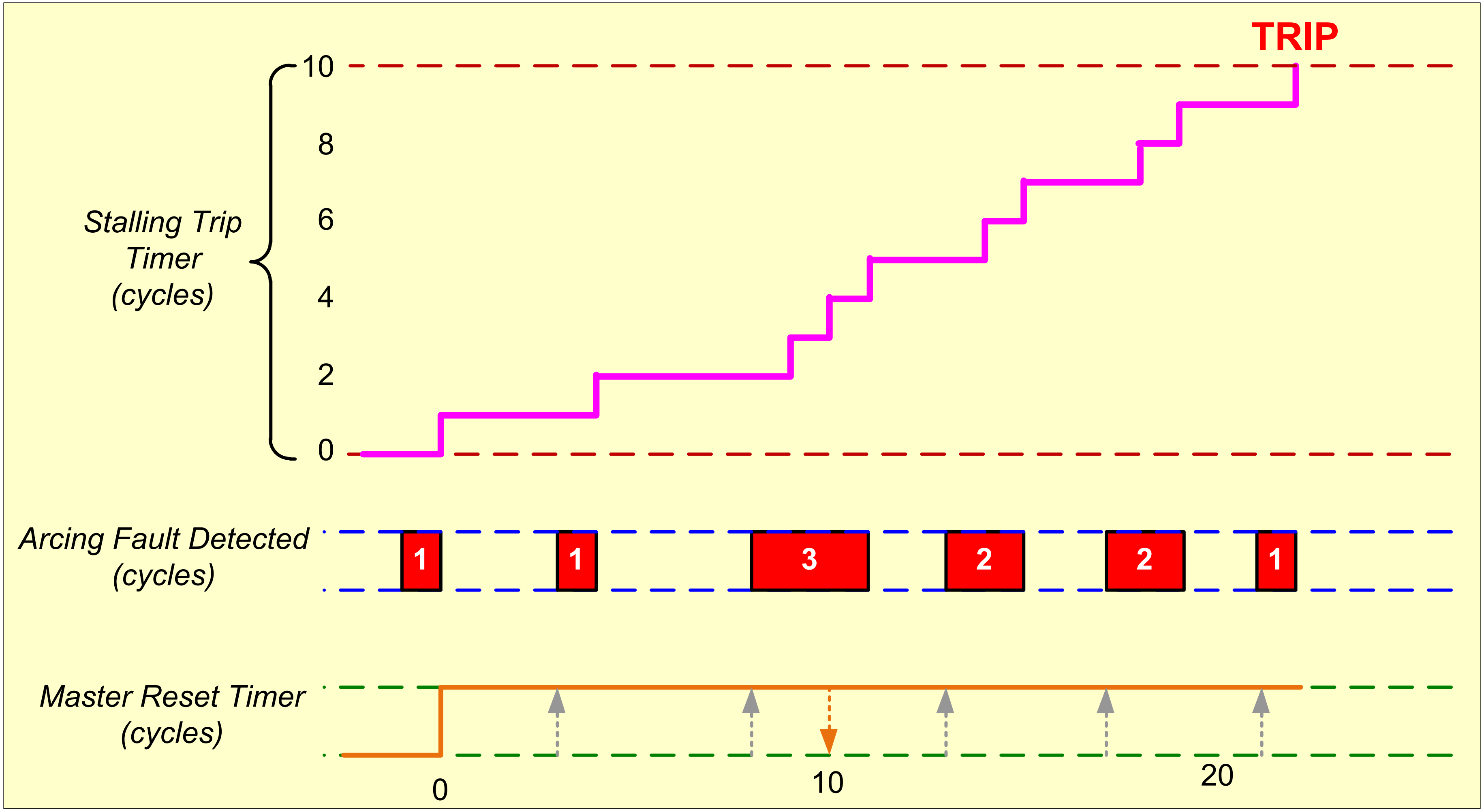
59N – Accelerated Ground Fault Protection Schemes

6) Intermittent arcing

Real world event waveform

59N – Accelerated Ground Fault Protection Schemes

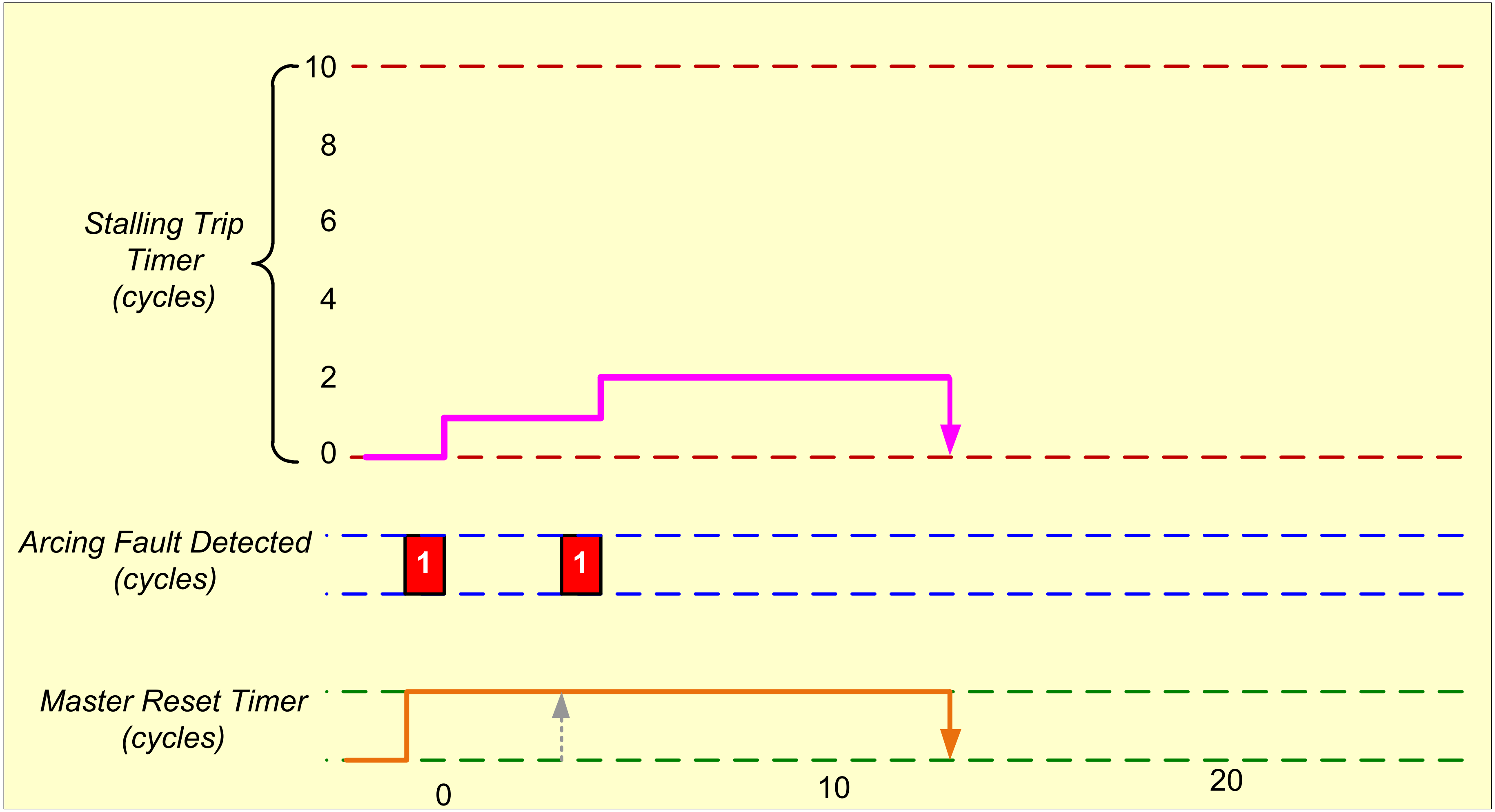
6) Intermittent arcing



Arcing and Trip

59N – Accelerated Ground Fault Protection Schemes

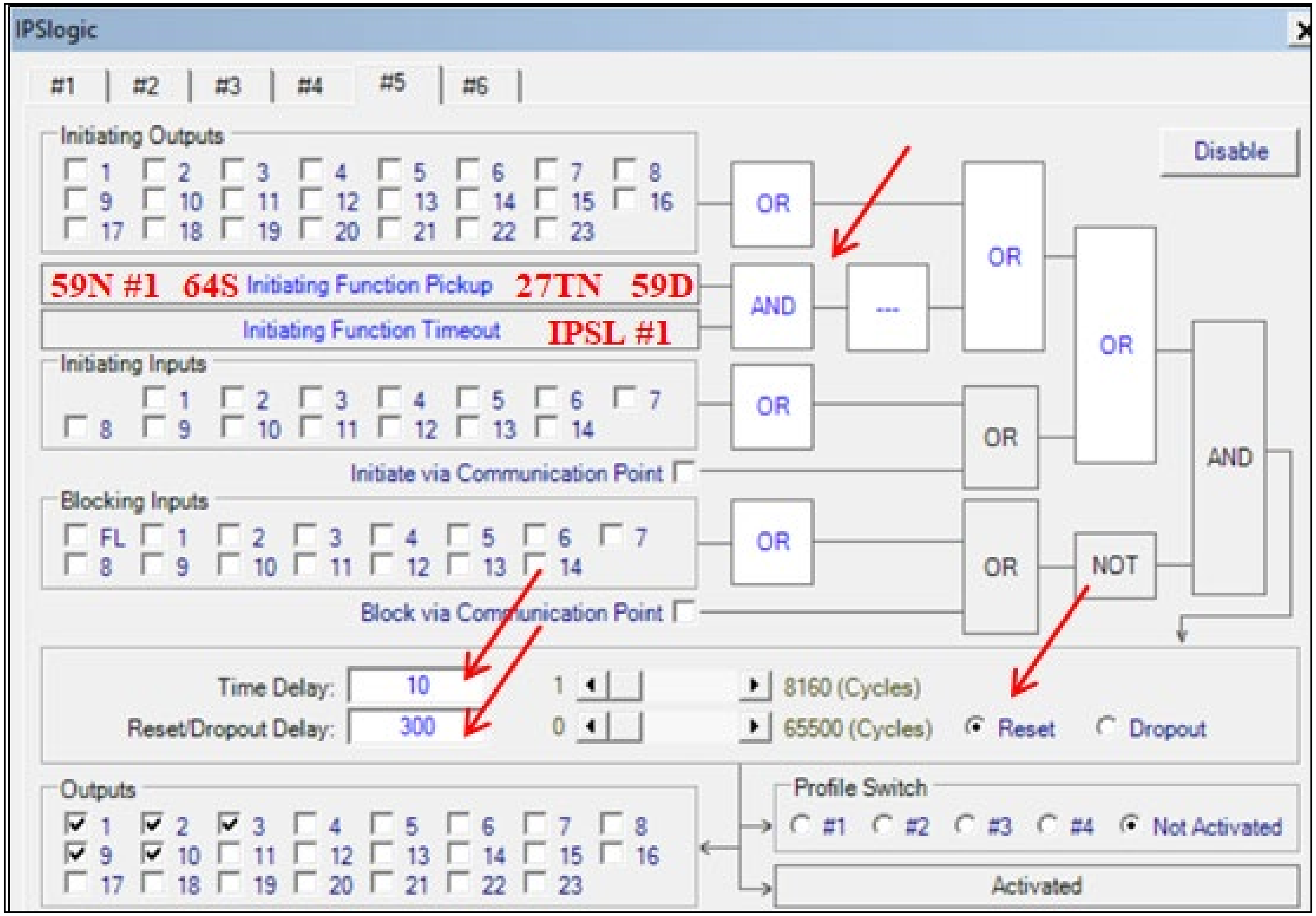
6) Intermittent arcing



Arcing and Reset (No Trip)

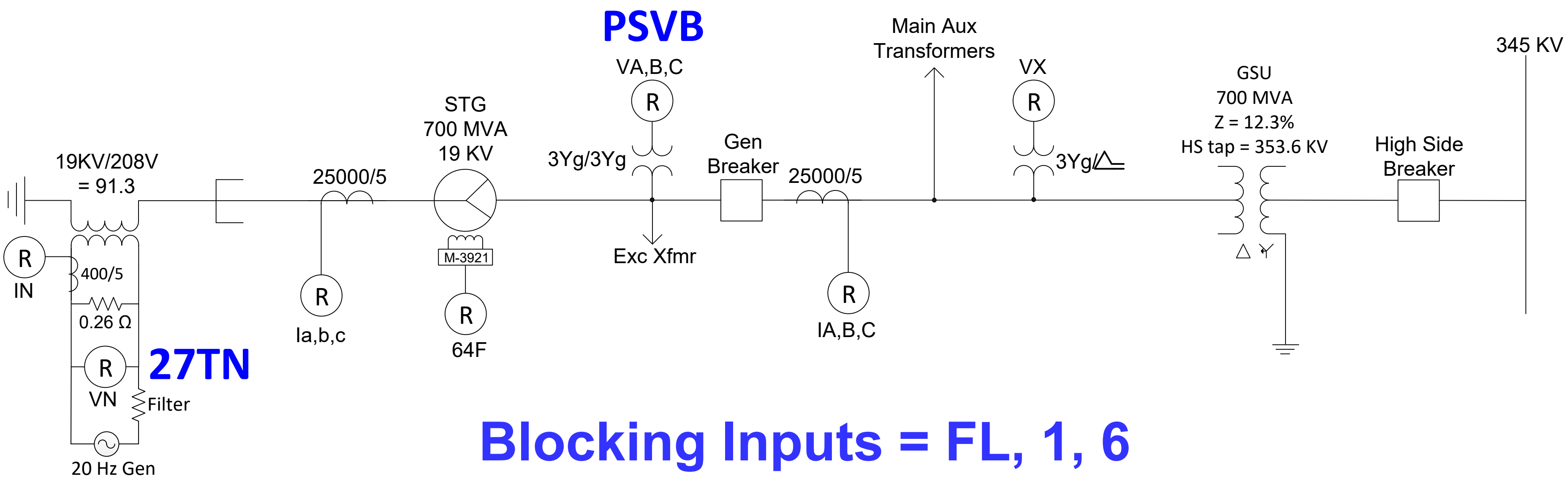
59N – Accelerated Ground Fault Protection Schemes

6) Intermittent arcing



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%***



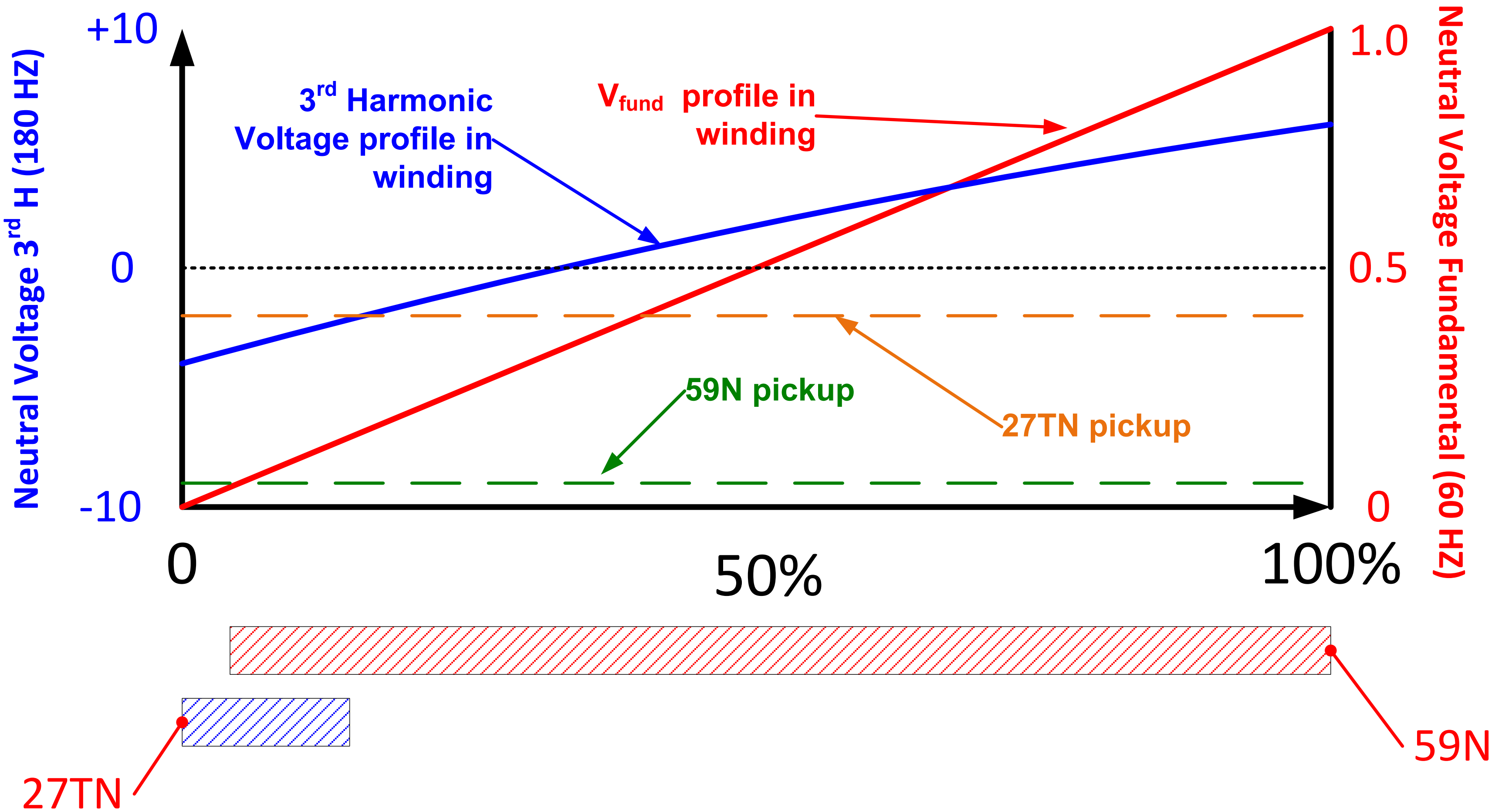
Blocking Inputs = FL, 1, 6

- If using 27TN with 64S, third harmonic survey will inform whether 27TN is secure in presence of 20 Hz source or if 27TN needs to be blocked.
- Input 6 is from 64S 20 Hz generator self-diagnostic alarm such that 27TN will be armed only when the 20 Hz gen has failed or is OFF.

27TN – Third Harmonic Neutral Undervoltage

- Used on high impedance grounded machines.
- Because of the low ground fault current, one ground by itself will not cause damage; however, since the first ground can cause second ground, it is important to trip for this condition rather than just alarm.
- 59N is the 60 Hz neutral overvoltage function that measures the 60 Hz neutral voltage at the grounding transformer. It protects 90%-95% of the stator winding for ground faults.
- The third harmonic functions (27TN and 59D) can be used along with 59N to provide 100% stator ground protection.

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



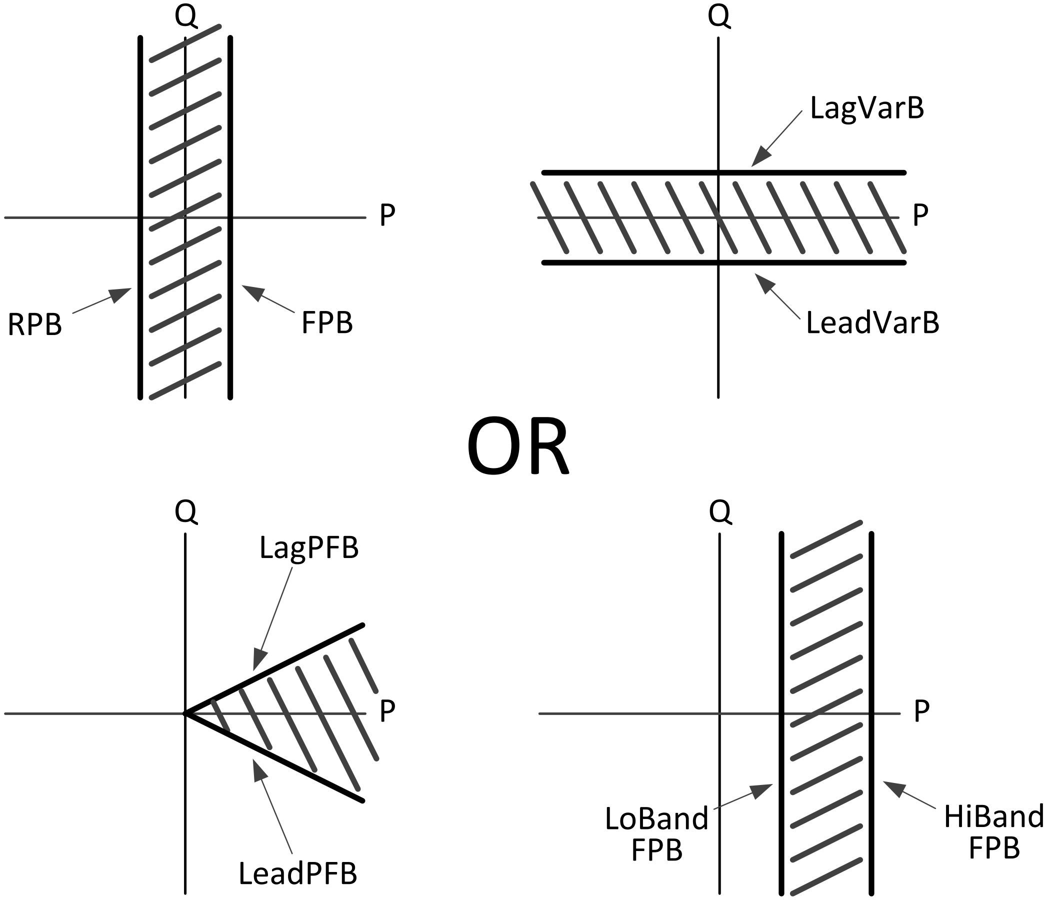
Overlap of Third Harmonic (27TN) with 59N Relay

27TN – 3rd Harmonic Neutral Undervoltage

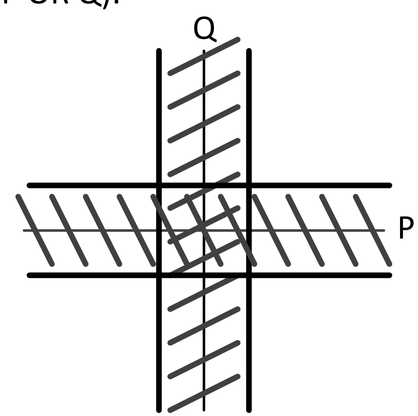
- Provides 0-15% stator winding coverage at the neutral end (typically)
- Tuned to 3rd harmonic frequency (180 Hz)
- Provides two levels of setpoints
- Supervisions for increased security under various loading conditions. Any or all may be applied simultaneously:
  - Phase Overvoltage Supervision
  - Underpower Block
  - Forward & Reverse
  - Under VAr Block; Lead & Lag
  - Power Factor Block; Lead & Lag
  - Definable Power Band Block

Loading/operating variables may be Sync Condenser, VAr Sink, Pumped Storage, CT Starting, Power Output Reduction

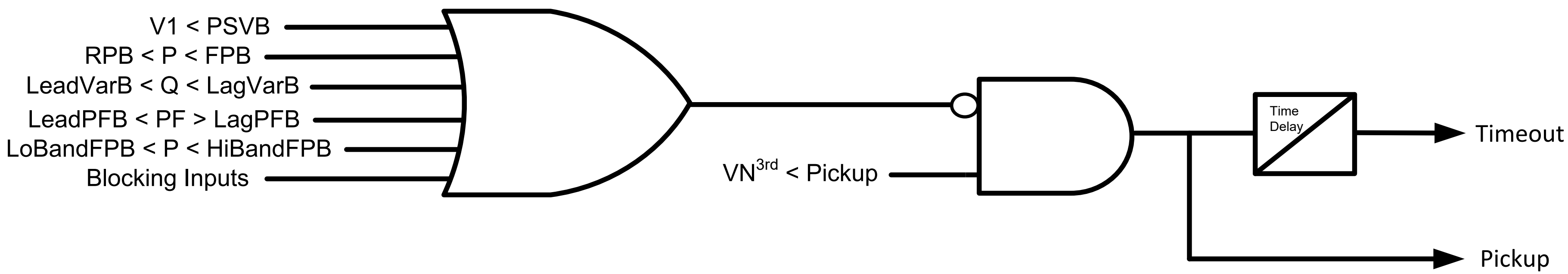
27TN – 3rd Harmonic Neutral Undervoltage



For example, if P and Q blocking are both enabled, it would appear as such (i.e. P OR Q):



27TN – 3rd Harmonic Neutral Undervoltage

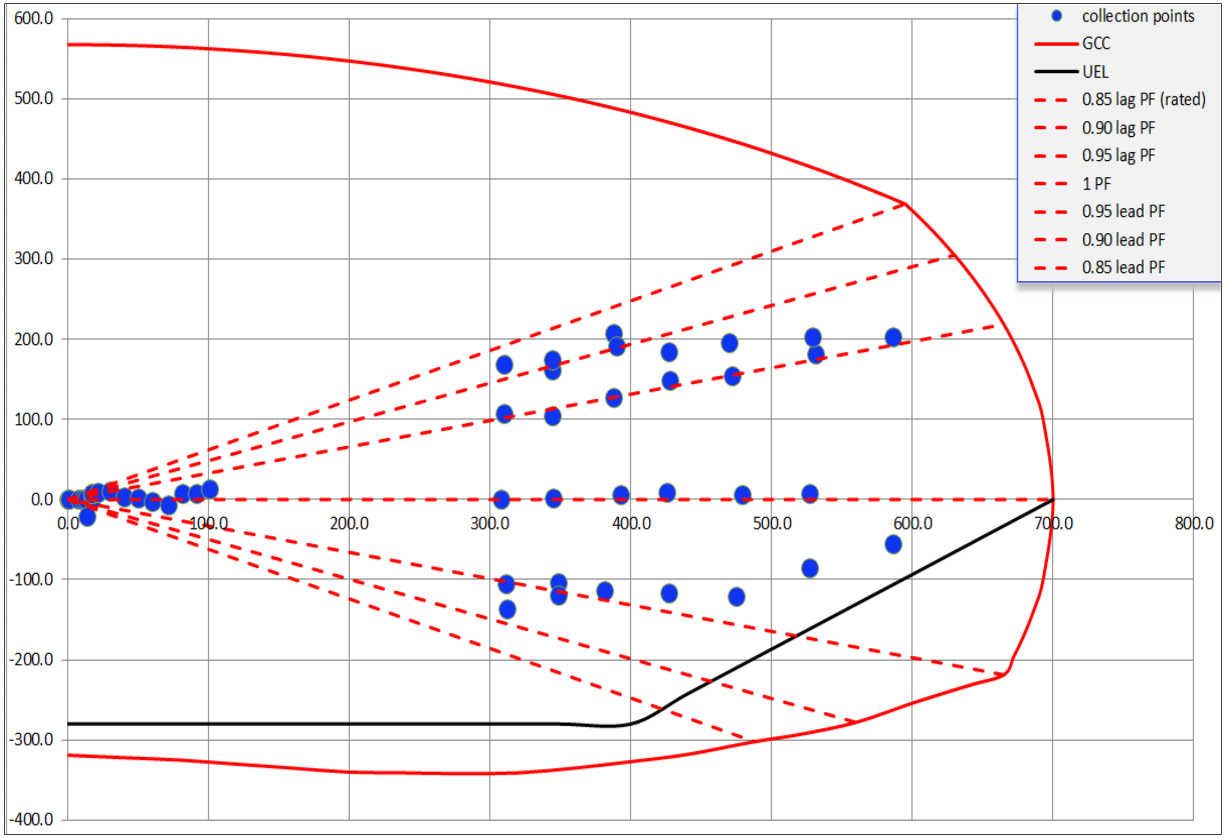


3rd Harmonic Survey – voltages measurements

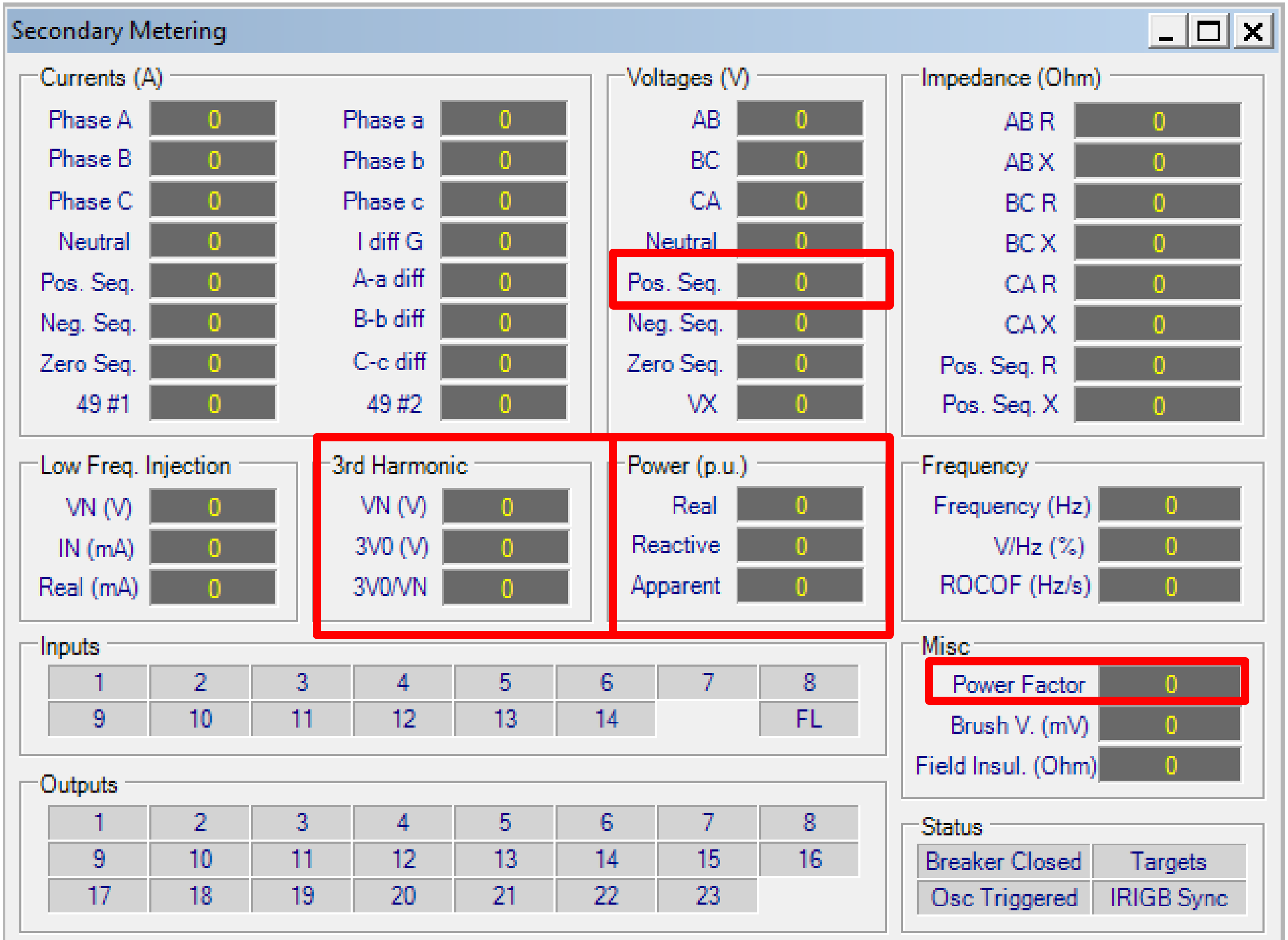
- **Difficult to set without getting real data via field measurements during commissioning:**
- The third harmonic voltage at the neutral end of the stator winding should be recorded throughout the full GCC (Generator Capability Curve), ideally.
- May not be able to get all values inside the GCC, so try to at least get values from 0.85 lagging PF to 0.85 leading PF thru the entire range of the machine, e.g.:

For some applications may not even be able to get this many points.

At least, record it at full load and no load, and as many other points as possible.



3rd Harmonic Survey – voltages measurements



3rd Harmonic Survey – voltages measurements

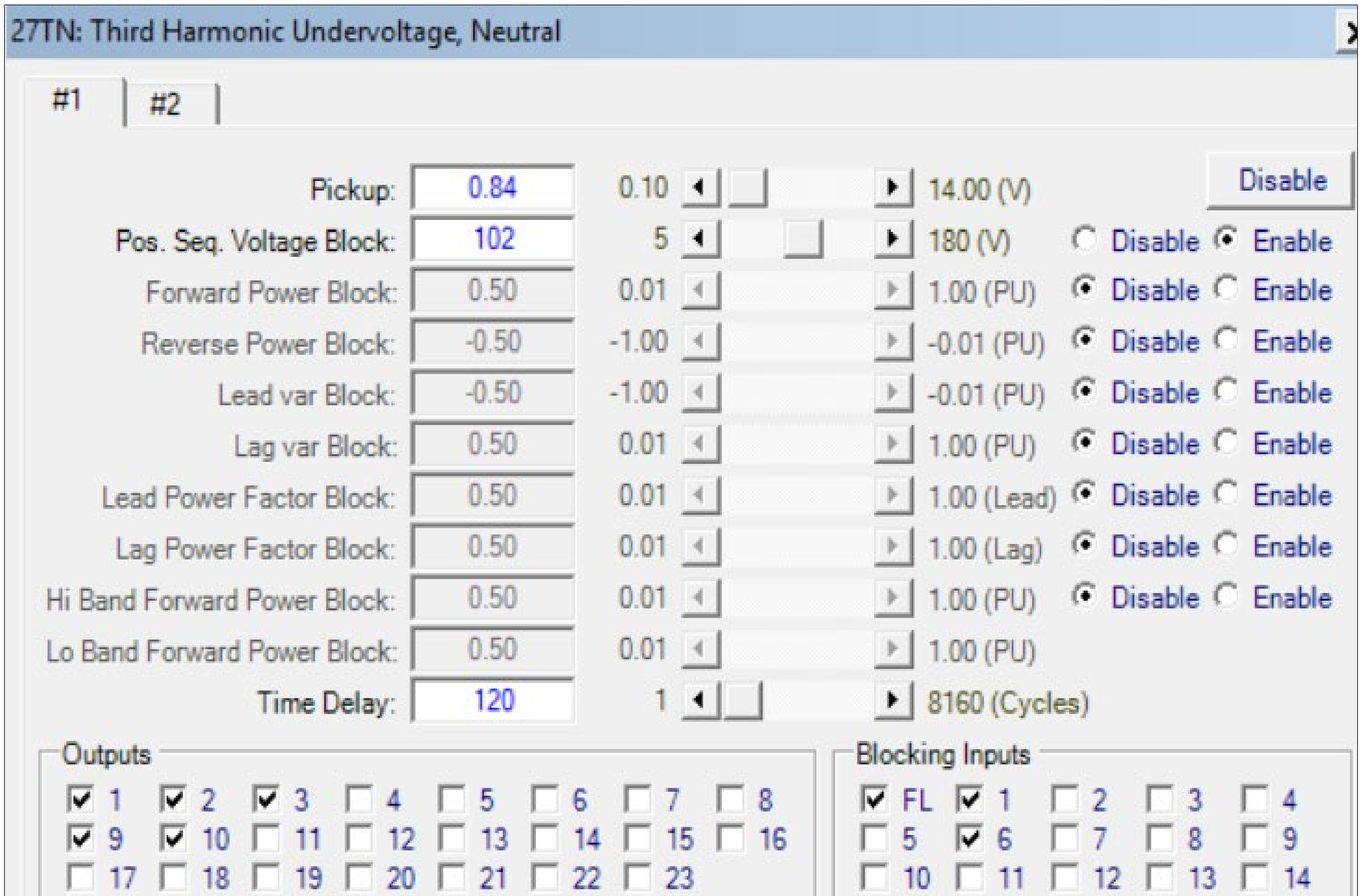
	27TN	
min 3rd Harmonic VN =	1.69	Vsec
27TN #1 Pickup = 50% of min 3rd Harmonic VN =	0.84	Vsec
PSVB = 0.85*Vnom =	102	Vsec

Positive Sequence Voltage Block = 85% of Vnom for security from voltage dips.

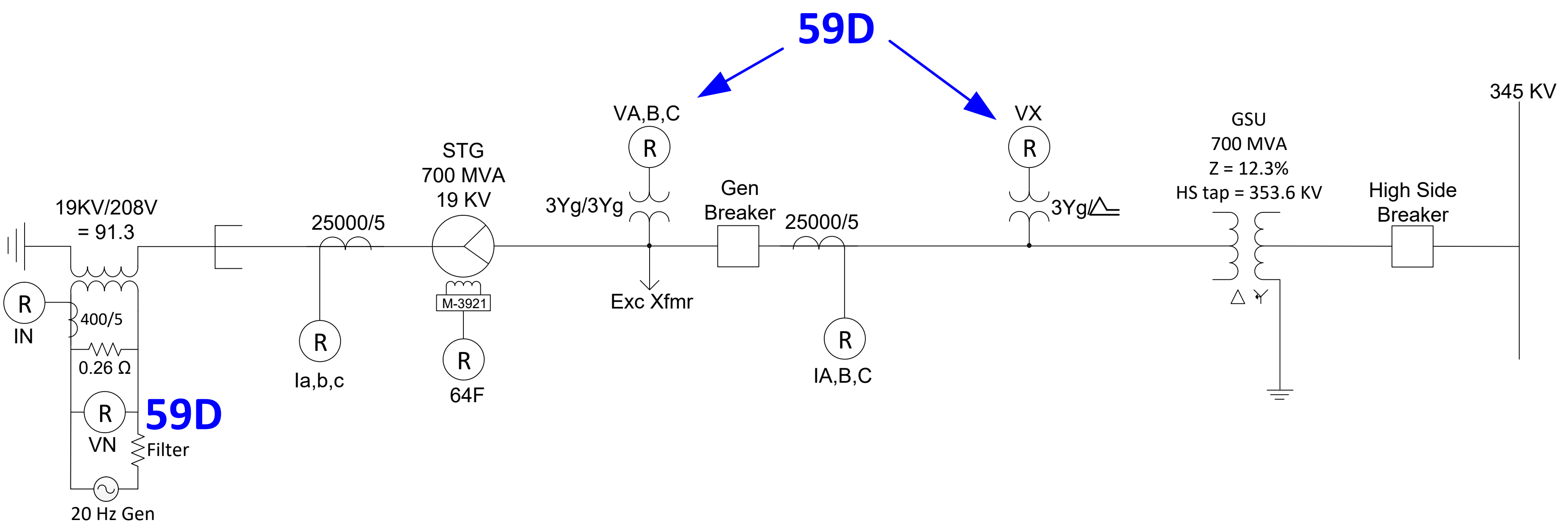
	Target collection points				3rd Harmonic			Pos. Seq.	Power			
Point	MW	MVAR	PF	lag/lead	VN (Vsec)	VX (Vsec)	VX/VN	(Vsec)	Real (pu)	Reactive (pu)	PF	lag/lead
0 *												
1 **	0.0	0.0			1.69	0.04	0.02	118.6	0.0000	0.0000		
2	1.3	0.1	1.00	lag	1.93	0.52	0.26	118.4	0.0019	0.0000	1.00	lag
3	8.5	0.1	1.00	lag	1.91	0.53	0.27	118.9	0.0122	0.0000	1.00	lag
4	11.3	0.2	1.00	lag	1.91	0.53	0.27	119.2	0.0162	0.0000	1.00	lag
5	13.2	0.2	1.00	lag	1.93	0.52	0.26	118.5	0.0189	0.0000	1.00	lag
6	17.3	0.3	1.00	lag	1.90	0.51	0.26	118.6	0.0247	0.0000	1.00	lag
7	17.6	8.0	0.91	lag	1.94	0.53	0.27	118.7	0.0252	0.0114	0.91	lag
8	17.5	7.5	0.92	lag	1.94	0.53	0.27	118.7	0.0250	0.0107	0.92	lag
9	22.0	9.0	0.93	lag	1.94	0.54	0.27	118.8	0.0315	0.0129	0.93	lag
10	30.0	10.0	0.95	lag	1.97	0.54	0.27	118.5	0.0429	0.0143	0.95	lag
11	40.0	4.0	1.00	lag	1.99	0.55	0.27	119.2	0.0572	0.0057	1.00	lag
12	50.0	1.7	1.00	lag	2.03	0.55	0.27	118.7	0.0715	0.0024	1.00	lag
13	60.0	-2.0	1.00	lead	2.07	0.55	0.26	118.6	0.0858	-0.0029	1.00	lead
14	72.0	-6.0	1.00	lead	2.12	0.57	0.26	119.2	0.1030	-0.0086	1.00	lead
15	14.0	-21.0	0.55	lead	1.88	0.52	0.27	118.9	0.0200	-0.0300	0.55	lead
16	82.0	8.0	1.00	lag	2.20	0.58	0.26	118.5	0.1173	0.0114	1.00	lag
17	92.0	7.0	1.00	lag	2.25	0.61	0.27	119.6	0.1316	0.0100	1.00	lag
18	101.0	14.0	0.99	lag	2.32	0.62	0.26	119.3	0.1445	0.0200	0.99	lag
19	310	169	0.88	lag	3.52	0.90	0.25	125.4	0.4437	0.2421	0.88	lag

27TN Settings and Supervision

- **Could be disabled upon initial energization of generator.**
- **If so, may want to temporarily set 59N more sensitive, e.g. 5 V, 0.50 seconds.**
- **Or can enable with estimated or calculated values with understanding that nuisance trips may occur until readings can be taken and settings adjusted.**



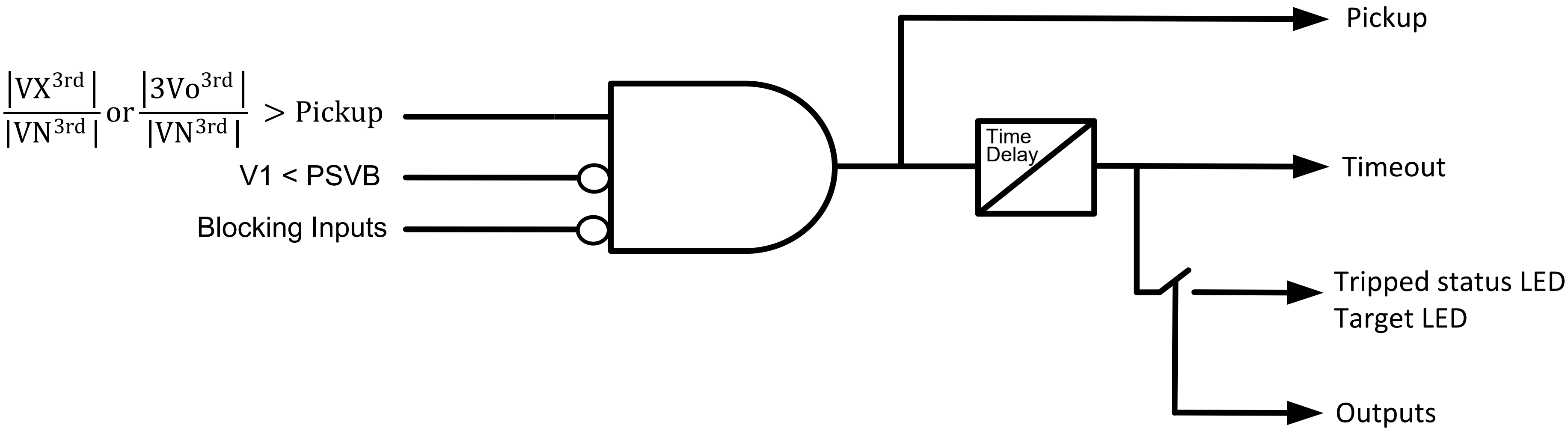
59D – Third Harmonic Voltage Differential (Ratio)



Blocking Inputs = FL, 1, 6

- Input 6 arms 59D when 64S is out of service.

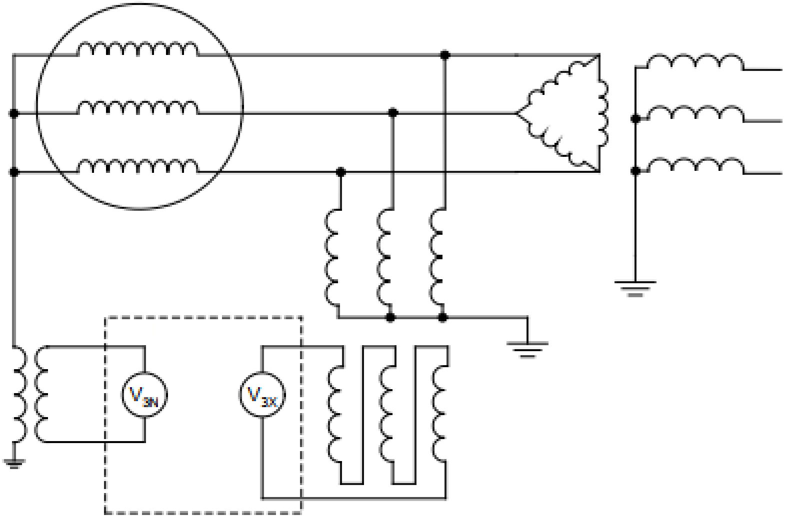
59D (59THD) – Third Harmonic Voltage Differential (Ratio)



59D (59THD) – Third Harmonic Voltage Differential (Ratio)

- 59D has a blind spot in the middle of the stator winding, so it should be used with the 59N function for 100% stator ground fault protection.

- Compares the third harmonic voltage at the terminal side and the neutral side of the stator winding.



- This ratio (V_{3X}/V_{3N}) may be relatively constant at different loading levels, so 59D may not be as load restrictive as the 27TN function.
  - However, field commissioning readings should still be taken at different loadings as this ratio may vary for some machines.

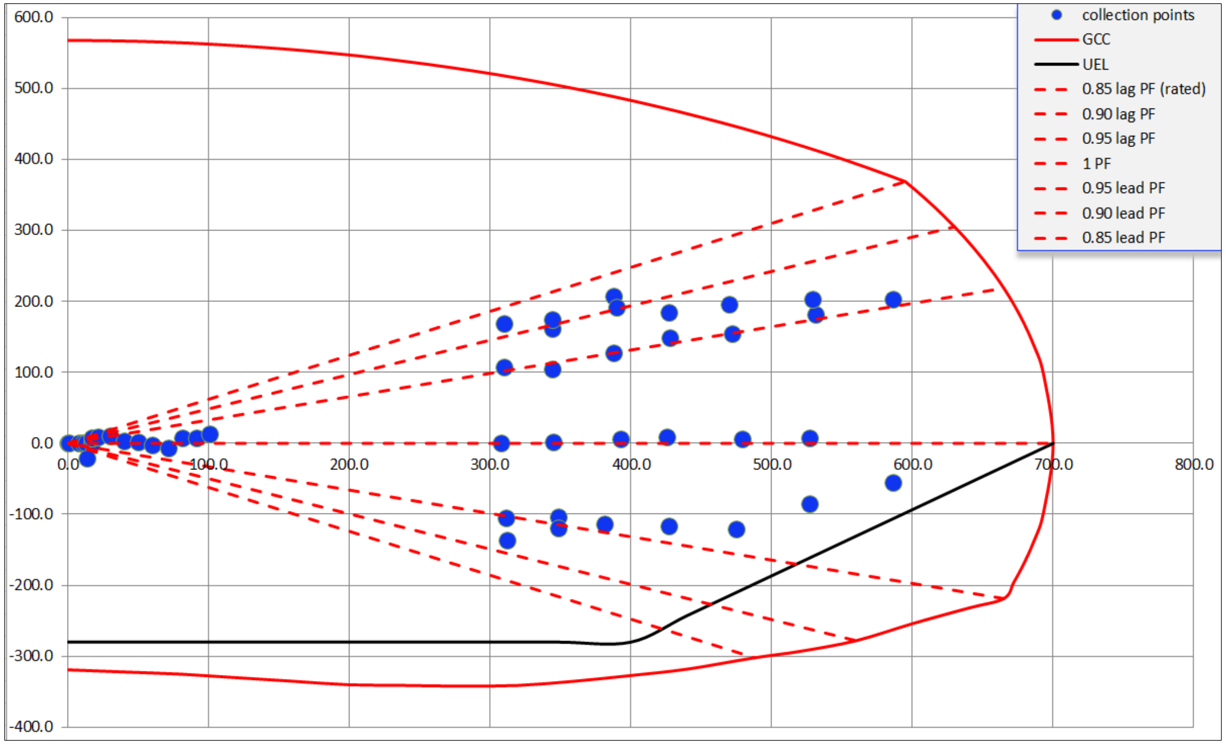
- This ratio will increase for a stator ΦG fault at either end of the stator winding.

59D – Third Harmonic Voltage Differential (Ratio)

Field measurements during commissioning:

- The third harmonic voltage at the terminal and neutral ends of the stator winding should be recorded throughout the full GCC (Generator Capability Curve), ideally.

- However, this may not be practical so a compromise may be to record these values from 0.85 lagging PF to 0.85 leading PF throughout the entire output range of the machine, e.g.:



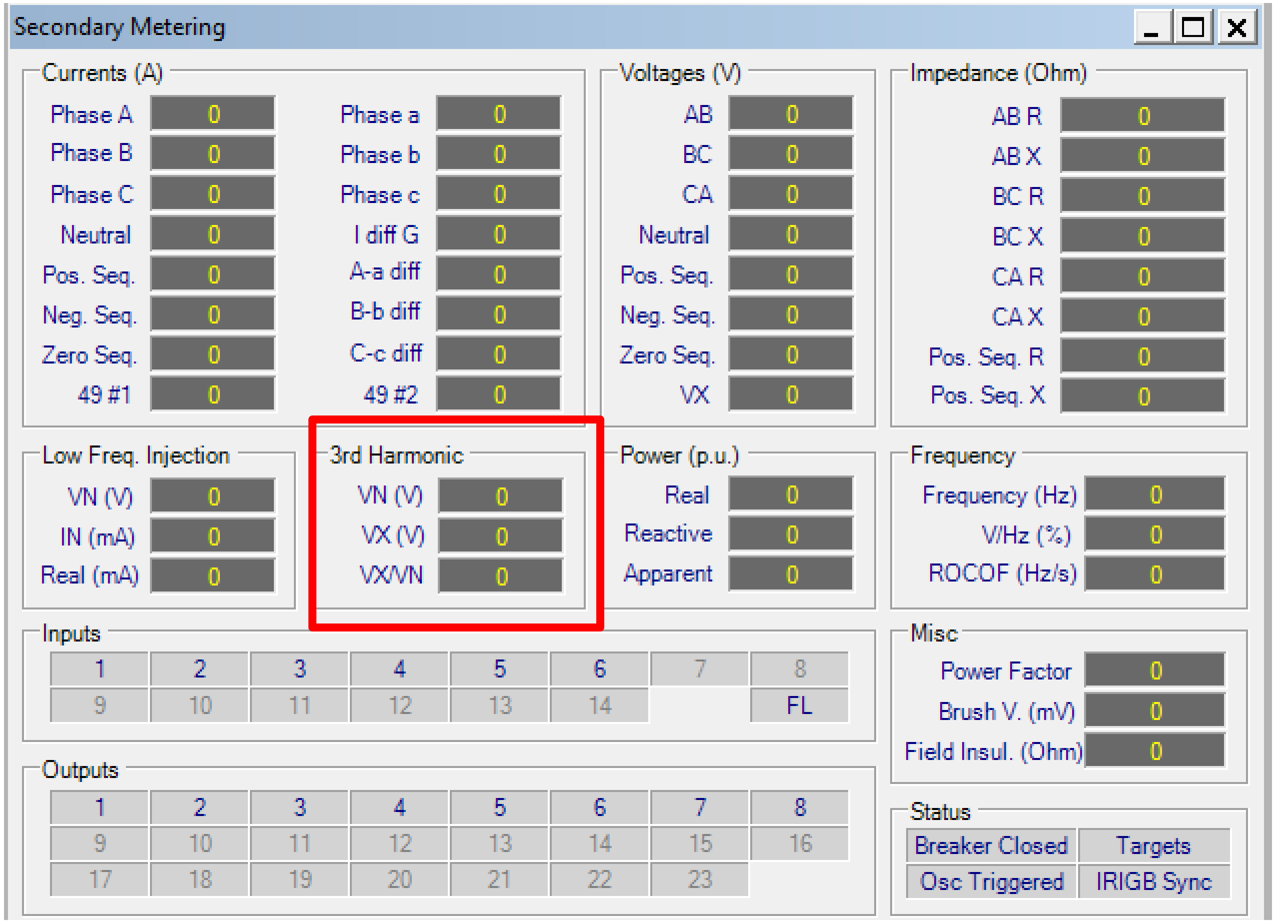
For some applications may not be able to get this many data points.

At least, record it at full load and no load, and as many other points as possible.

59D – Third Harmonic Voltage Differential (Ratio)

Field measurements during commissioning:

- Use Relay software to take the third harmonic readings or may log with comms:



59D – Third Harmonic Voltage Differential (Ratio)

<u>Settings:</u>

- After field data is collected, choose a pickup above the highest ratio measured with some margin (typically 150%):

$$59D\ \text{Ratio Pickup} = 1.5 \times \left(\frac{VX^{3rd}}{V_N^{3rd}}\right) \text{ or } \left(\frac{3V_O^{3rd}}{V_N^{3rd}}\right)$$

- For the "Line Side Voltage" selection, choose either:
  - the calculated 3Vo value from the measured 3 phase voltages from wye connected gen VTs (with VT Configuration = LG).
  - or the measured 3Vo value (VX) from a broken delta VT.
    - The measured 3Vo (VX) will give better accuracy.

- Positive Sequence Undervoltage Blocking may be enabled to avoid mis-operations while the unit is off-line and/or could block with an open breaker.

59D – Third Harmonic Voltage Differential (Ratio)

	59D	
max 3rd Harmonic VX/VN =	0.27	Vsec
59D Pickup = 150% of max 3rd Harmonic VX/VN =	0.4	Vsec
PSVB = 0.85*Vnom =	102	Vsec
Line Side Voltage =	VX	

Positive Sequence Voltage Block = 85% of Vnom for security from voltage dips.

	Target collection points				3rd Harmonic			Pos. Seq.	Power			
Point	MW	MVAR	PF	lag/lead	VN (Vsec)	VX (Vsec)	VX/VN	(Vsec)	Real (pu)	Reactive (pu)	PF	lag/lead
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2	1.3	0.1	1.00	lag	1.93	0.52	0.26	118.4	0.0019	0.0000	1.00	lag
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6	17.3	0.3	1.00	lag	1.90	0.51	0.26	118.6	0.0247	0.0000	1.00	lag
7	17.6	8.0	0.91	lag	1.94	0.53	0.27	118.7	0.0252	0.0114	0.91	lag
8	17.5	7.5	0.92	lag	1.94	0.53	0.27	118.7	0.0250	0.0107	0.92	lag
9	22.0	9.0	0.93	lag	1.94	0.54	0.27	118.8	0.0315	0.0129	0.93	lag
10	30.0	10.0	0.95	lag	1.97	0.54	0.27	118.5	0.0429	0.0143	0.95	lag
11	40.0	4.0	1.00	lag	1.99	0.55	0.27	119.2	0.0572	0.0057	1.00	lag
12	50.0	1.7	1.00	lag	2.03	0.55	0.27	118.7	0.0715	0.0024	1.00	lag
13	60.0	-2.0	1.00	lead	2.07	0.55	0.26	118.6	0.0858	-0.0029	1.00	lead
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15	14.0	-21.0	0.55	lead	1.88	0.52	0.27	118.9	0.0200	-0.0300	0.55	lead
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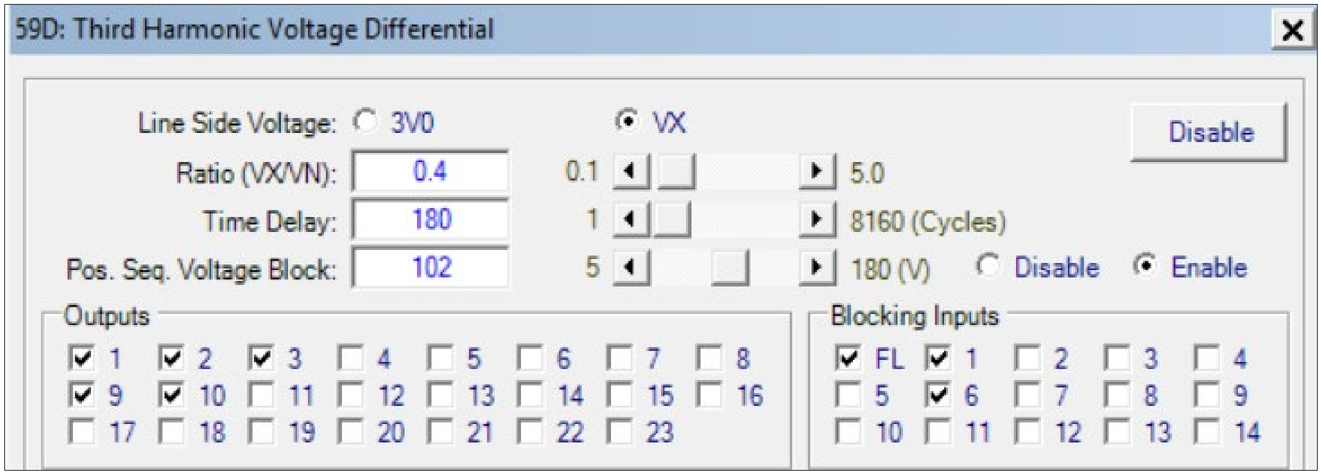
17	92.0	7.0	1.00	lag	2.25	0.61	0.27	119.6	0.1316	0.0100	1.00	lag
18	101.0	14.0	0.99	lag	2.32	0.62	0.26	119.3	0.1445	0.0200	0.99	lag
19	310	169	0.88	lag	3.52	0.90	0.25	125.4	0.4437	0.2421	0.88	lag

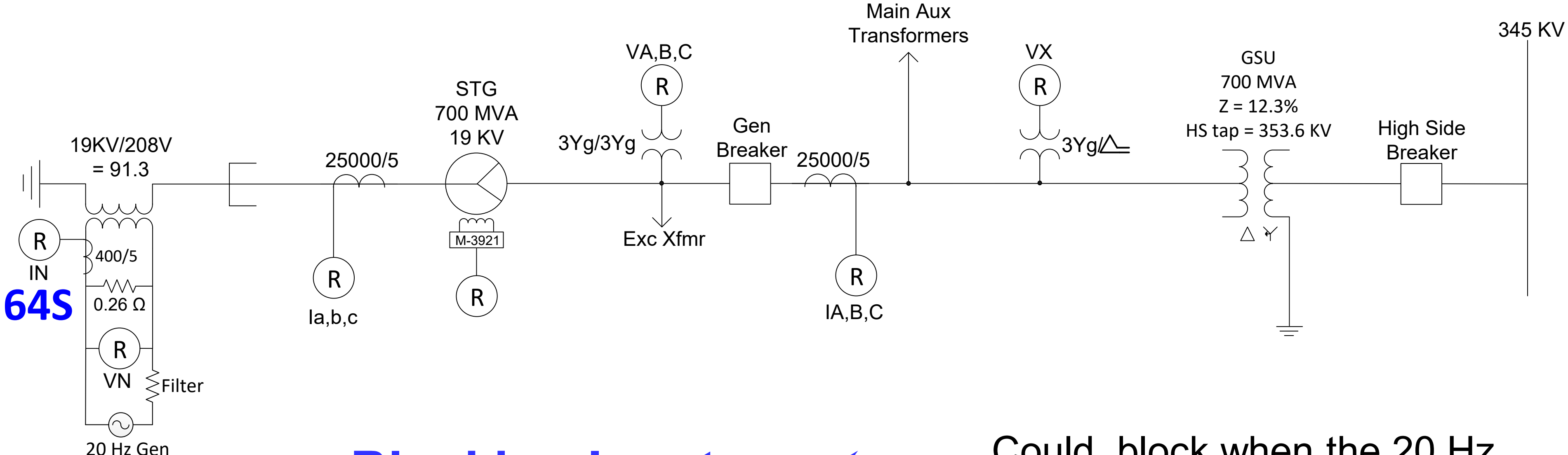
59D – Third Harmonic Voltage Differential (Ratio)

Settings:



- For applications with a LS gen breaker, the third harmonic ratio of VX/VN will be different when the breaker is open vs when the breaker is closed.
    - The GSU will introduce an additional source of third harmonic voltage.
- May block one 59D relay when off-line and set another 59D on the redundant relay for after gen breaker is closed.
- Or different setting profiles could be used, driven by breaker status.

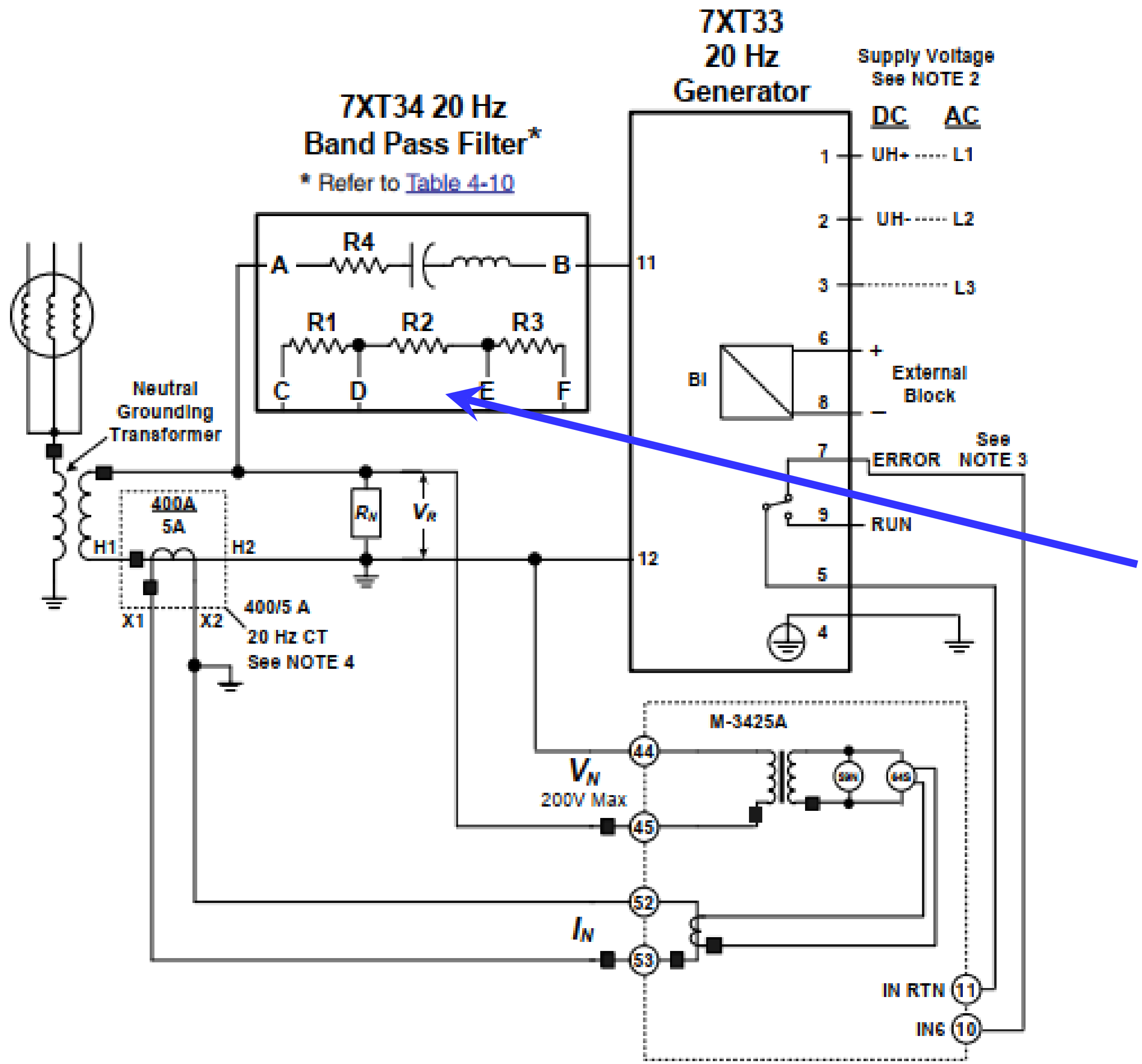
64S – 100% Stator Ground Protection



Blocking Inputs = ← Could block when the 20 Hz gen fails for extra security although it should fail secure.

- 20 Hz gen injects signal into stator winding to detect stator ground faults via changes in the stator winding insulation resistance and the resulting changes in the measured 20 Hz current.

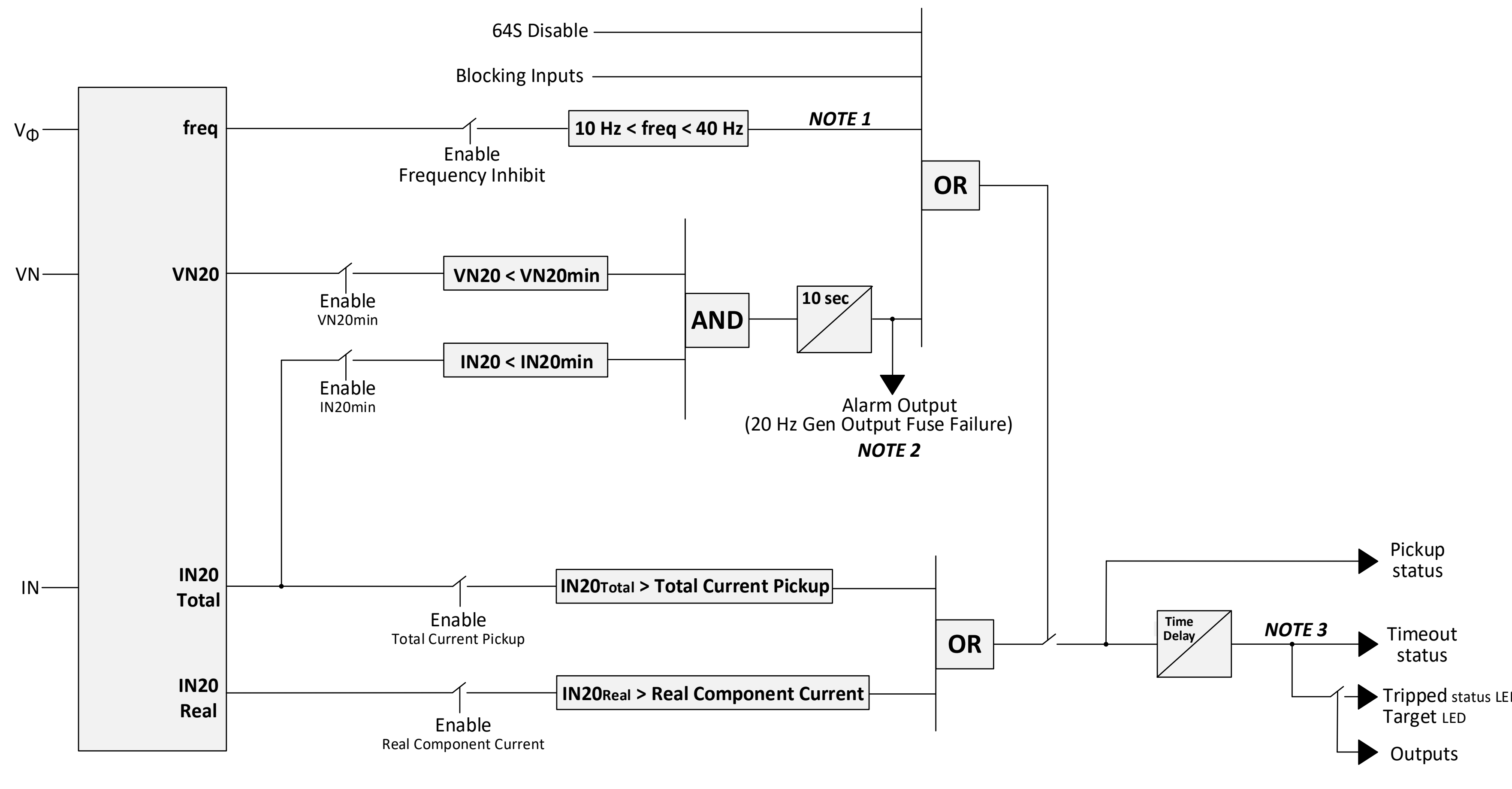
64S – 100% Stator Ground Protection



If the max VN for a ground fault at the terminal end of the stator winding is > 240 V, then can use voltage divider network in the bandpass filter. If used, then should proportion 59N Pickup settings as well.

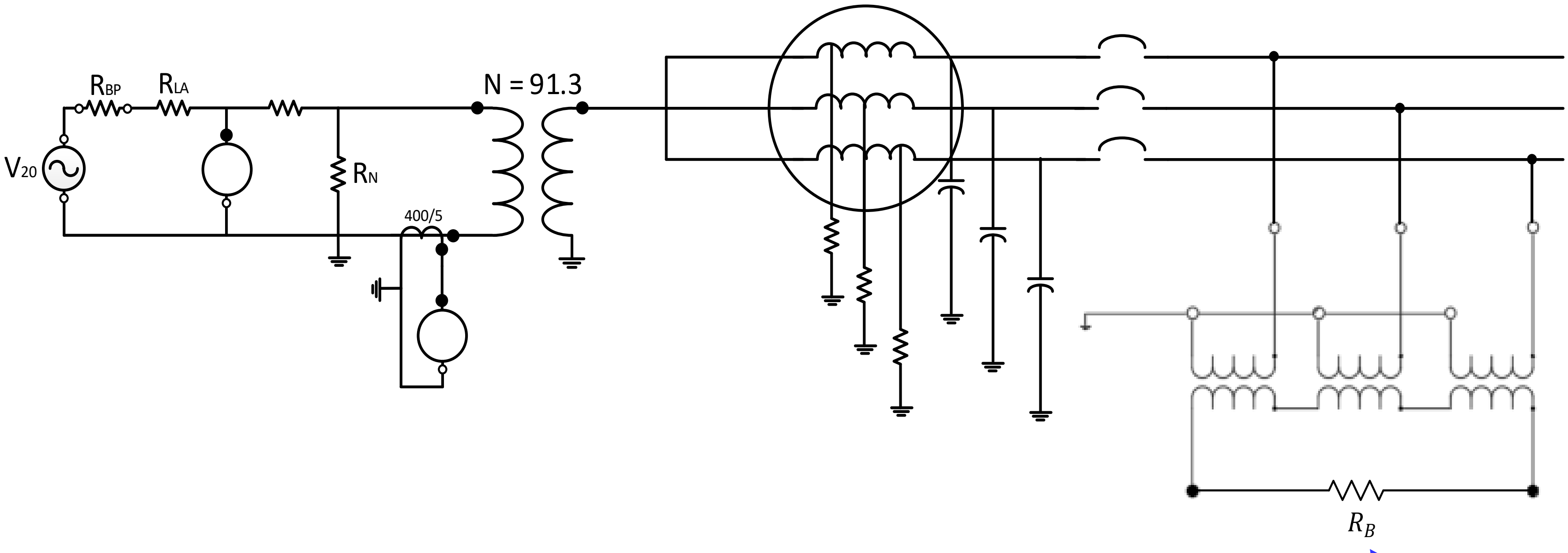
64S – 100% Stator Ground Protection

- How the 64S algorithm works in the M-3425A relay (other mfgs may be different):



64S – 100% Stator Ground Protection

- Reflect the **stator winding insulation resistance**, the **total capacitance** to ground (stator winding, iso-phase bus, surge equipment, GSU, UAT, and VTs), and the broken delta VT **ballast resistor** to the secondary of the NGT for circuit analysis:

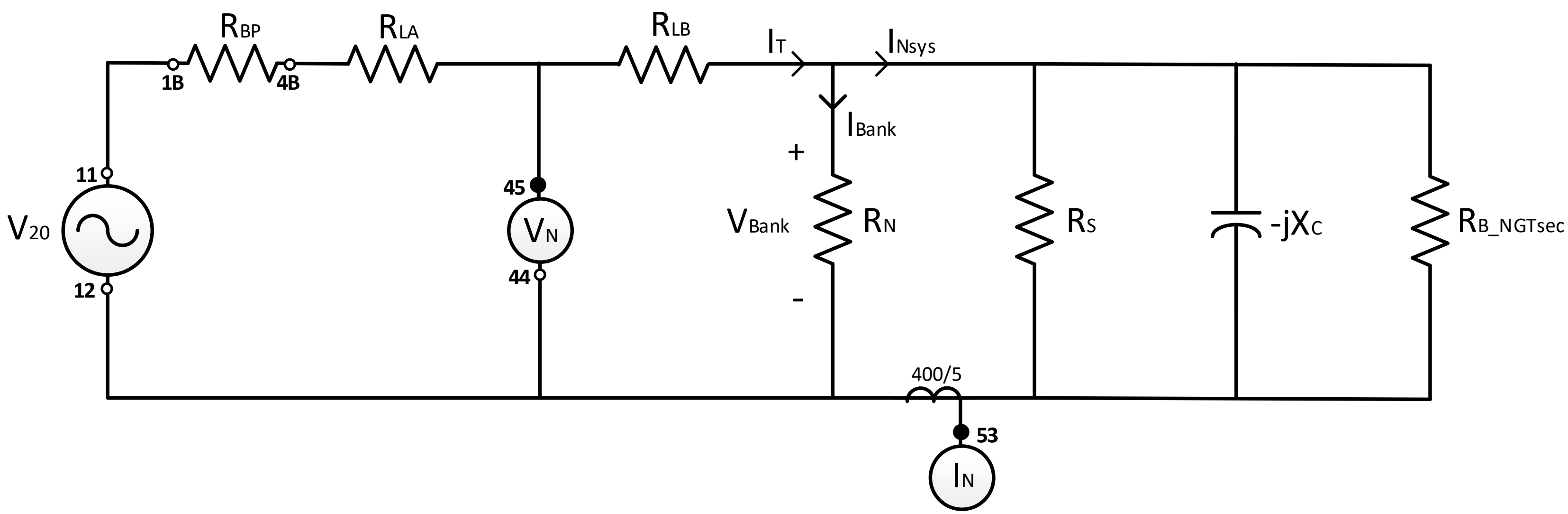


PRO TIP: ensure 400/5 CT is installed between NGT and NGR

this application has a ballast resistor across some broken delta VTs for 3Vo bus ground fault protection, which can be accounted for it in the analysis

64S – 100% Stator Ground Protection

- Derived circuit after parameters have been reflected to the secondary of the NGT:



$x = 1$ ($x = 1$ *for straight thru connection*; $x = 0.80, 0.60, 0.40,$ *or* 0.20 *for voltage divider*)

$V_{20} = 26\ V$ (20 *Hz signal generator*)

$R_{BP} = 8\ \Omega$ (20 *Hz bandpass filter*)

$$R_{LA} = 0' * 2 * \frac{1.588\ \Omega}{1000'} = 0\ \Omega$$ (#12 *gauge wire between relay and* 20 *Hz equip.* – *mounted together*)

$$R_{LB} = 50' * 2 * \frac{1.588\ \Omega}{1000'} = 0.159\ \Omega$$ (#12 *gauge wire between relay and NGR*)

$R_N = 0.26\ \Omega$ (*NGR – Neutral Grounding Resistor*)

R_S – stator winding insulation resistance
$-jX_C$ – total capacitive reactance
R_{B_NGTsec} – ballast resistor

Need to calculate or derive these values yet.

64S – 100% Stator Ground Protection

- Reflect the broken delta ballast resistor to the primary of the VTs and then to the secondary of the NGT via the following derived equation:

$$R_{B\_NGTsec} = \frac{R_B * VTRX^2}{9 * N^2} = = 90\ \Omega \quad \text{(ballast resistor as it appears to the NGT sec. circuit)}$$

Relatively high ballast resistor ohmic sizes like this value of 90 Ω cause very little to no interference to the measured 20 Hz current; however, if the ballast resistor is much smaller (closer to the NGR value) then it can cause some interference to the measured 20 Hz current in which case, the settings may need to be desensitized or 2 setting groups could be used w/ and w/o R_B in the circuit (via gen breaker status) or attempt to resize R_B if application allows such.

Set $R_{B\_NGTsec} = 9999\ \Omega$ if subject application does not have a ballast resistor or just remove it altogether from the circuit and equations.

- Model a healthy stator winding insulation resistance at 100 KΩ and 50 KΩ and model faults at 5 KΩ, 1 KΩ, and 0 KΩ:

$$Rs = \frac{Rstator}{N^2} = \frac{100K, 50K, 5K, 1K, 0K}{91.3^2} = 12, 6, 0.6, 0.12, 0\ \Omega\ \text{sec}$$

64S – 100% Stator Ground Protection

If the per phase total capacitance to ground is known (it is here, $C_{TOTAL} = 0.40797\ \mu F$) then may directly use that to calculate the capacitive reactance at 20 Hz:

$$Xcpri = \frac{1}{2\pi f * C_{TOTAL}} = \frac{1}{2\pi * 20 * 0.40797\mu} = 19506\ \Omega pri$$

$$Xc = \frac{Xcpri}{N^2} = \frac{19506}{91.3^2} = 2.34\ \Omega\ sec \qquad \text{(reflected to secondary of NGT)}$$

- If the total capacitance is not known (may often be the case esp. for older plants), then assume R_N was sized appropriately from knowing the total capacitance i.e., the NGR value on a primary basis should have been designed to equal 1/3 of the ohmic value of the per-phase capacitive reactance to ground ($R_{Npri} = \frac{Xcpri}{3}$) so that equal zero-sequence current will flow through the $3R_N$ and the Xc branches to limit transient overvoltages.

64S – 100% Stator Ground Protection

Therefore, the value of the capacitive reactance can be reverse engineered from this NGR value as such (must first calculate the capacitance reactance at 60 Hz from the NGR value, then calculate the capacitance, then calculate the capacitive reactance at 20 Hz):

$$R_{Npri} = R_N * N^2 = 0.26 * 91.3^2 = 2167\ \ \Omega pri$$

$$Xcpri@60Hz = 3 * R_{Npri} = 3 * 2167 = 6502\ \ \Omega pri$$

$$C_{TOTAL} = \frac{1}{2\pi f * Xcpri@60Hz} = \frac{1}{2\pi * 60 * 6502} = 0.40797\ \mu F \qquad (matches\ mfg\ data)$$

$$Xcpri@20Hz = \frac{1}{2\pi f * C_{TOTAL}} = \frac{1}{2\pi * 20 * 0.40797\mu} = 19506\ \Omega pri$$

$$Xc = \frac{Xcpri@20Hz}{N^2} = \frac{19506}{91.3^2} = 2.34\ \Omega\ sec \qquad (\text{reflected to secondary of NGT})$$

$$Zc = -j2.34\ \ \Omega sec$$

64S – 100% Stator Ground Protection

- For small values of the neutral grounding resistor (< 0.3 Ω) and/or high total capacitance (> 1.5μF), there may not be a satisfactory margin for the total current between the non-fault conditions and the fault conditions.
- For these cases, the “Real Component Current” can be used.
- The real component of the 20 Hz current is based on the angle between V_N and I_N i.e. the angle between the measured 20 Hz voltage across the NGR and the measured 20 Hz current flowing back into the stator winding.
- Regardless whether the real current setting is shown to be required or not, it can be utilized as a backup to the total current setting.
- **PRO TIP: Always use both Total and Real Component together.**
- Calculate both the total and the real component of 20 Hz currents for non-fault and fault conditions to determine how to set each.

64S – 100% Stator Ground Protection

- Now that all the variables in the circuit have been defined and starting off with calculating the values during non-fault conditions with 100 Ω stator winding insulation resistance, therefore, the equations derived from circuit analysis produces the following results:

$$I_T = \frac{V_{20}}{R_{BP} + R_{LA} + R_{LB} + R_N||R_S||Z_C||R_{B_{NGTsec}}} = 3.092 + j0.010\ A \qquad (total\ circuit\ 20\ Hz\ current)$$

$$I_{Nsys} = I_T * \frac{R_N}{R_N + R_S||Z_C||R_{B_{NGTsec}}} = 0.108 + j0.324 = 0.342\ @\ 71.6°\ A \qquad (primary\ value\ of\ 20\ Hz\ IN)$$

$$I_N = |I_{Nsys}| * \frac{1000}{CTR} = 4.3\ mA \qquad (20\ Hz\ Total\ IN\ displayed\ on\ IPScom)$$

$$I_{Bank} = I_T - I_{Nsys} = 2.984 - j0.314\ A \qquad (20\ Hz\ current\ thru\ the\ NGR)$$

$$V_{Bank} = I_{Bank} * R_N = 0.776 - j0.082\ V \qquad (20\ Hz\ voltage\ across\ NGR)$$

$$V_N = x * (R_{LB} * I_T + V_{Bank}) = 1.267 - j0.080 = 1.270\ @ - 3.6°\ V \qquad (20\ Hz\ VN)$$

$$|V_N| = 1.3\ V \qquad (20\ Hz\ VN\ displayed\ via\ IPScom)$$

$$I_{Real} = I_N * cos(\Theta_{VN} - \Theta_{INsys}) = 1.1\ mA \qquad (20\ Hz\ Real\ IN\ displayed\ via\ IPScom)$$

64S – 100% Stator Ground Protection

Next calculate another non-fault condition for a healthy stator winding again but for an older generator where the stator winding insulation resistance has degraded to 50 KΩ. Then also calculate the results for several fault conditions with stator winding insulation resistances of 5 KΩ, 1 KΩ, and 0 KΩ. The results for all 5 cases are summarized here:

64S calculations summary table				
conditions	Rs	IN (Total)	IN (Real)	VN
	kΩ	mA	mA	V
non-fault	100	4.3	1.1	1.3
	50	4.4	1.9	1.3
fault	5	12.2	11.9	1.1
	1	27.0	27.0	0.8
	0	39.8	39.8	0.5

64S – 100% Stator Ground Protection

non-fault < Total Current Pickup < fault

100 KΩ, 50 KΩ < Total Current Pickup < 5 KΩ, 1 KΩ, 0 KΩ

4.3, 4.4 < Total Current Pickup < 12.2, 27.0, 39.8

$$\frac{4.4 + 27.0}{2} = 15.7\ \text{mA} \quad \text{(set Total for 1 K}\Omega\text{ as the Real Component will see 5 k}\Omega\text{ fault)}$$

Total Current Pickup = 15.7 mA

non-fault < Real Component Current < fault

100 KΩ, 50 KΩ < Real Component Current < 5 KΩ, 1 KΩ, 0 KΩ

1.1, 1.9 < Real Component Current < 11.9, 27.0, 39.8

$$\frac{1.9+11.9}{2} = 6.9\ \text{mA}$$

Real Component Current = 6.9 mA

64S – 100% Stator Ground Protection

Set Time Delay = 10 cycles (the time delay may typically be set at 5 to 30 cycles as no coordination is necessary for GSU high side faults)

However, coordination for VT faults may still be necessary as 64S may be able to see ground faults in the VT windings or on the secondary of wye connected VTs with the VT secondary safety ground reference on the neutral common point and the neutral cable brought back to the relay.

Coordination for VT faults may be achieved via time delay or the pickup setting where the pickup may be able to be set above a VT secondary fault depending on the system and VT parameters of the specific application.

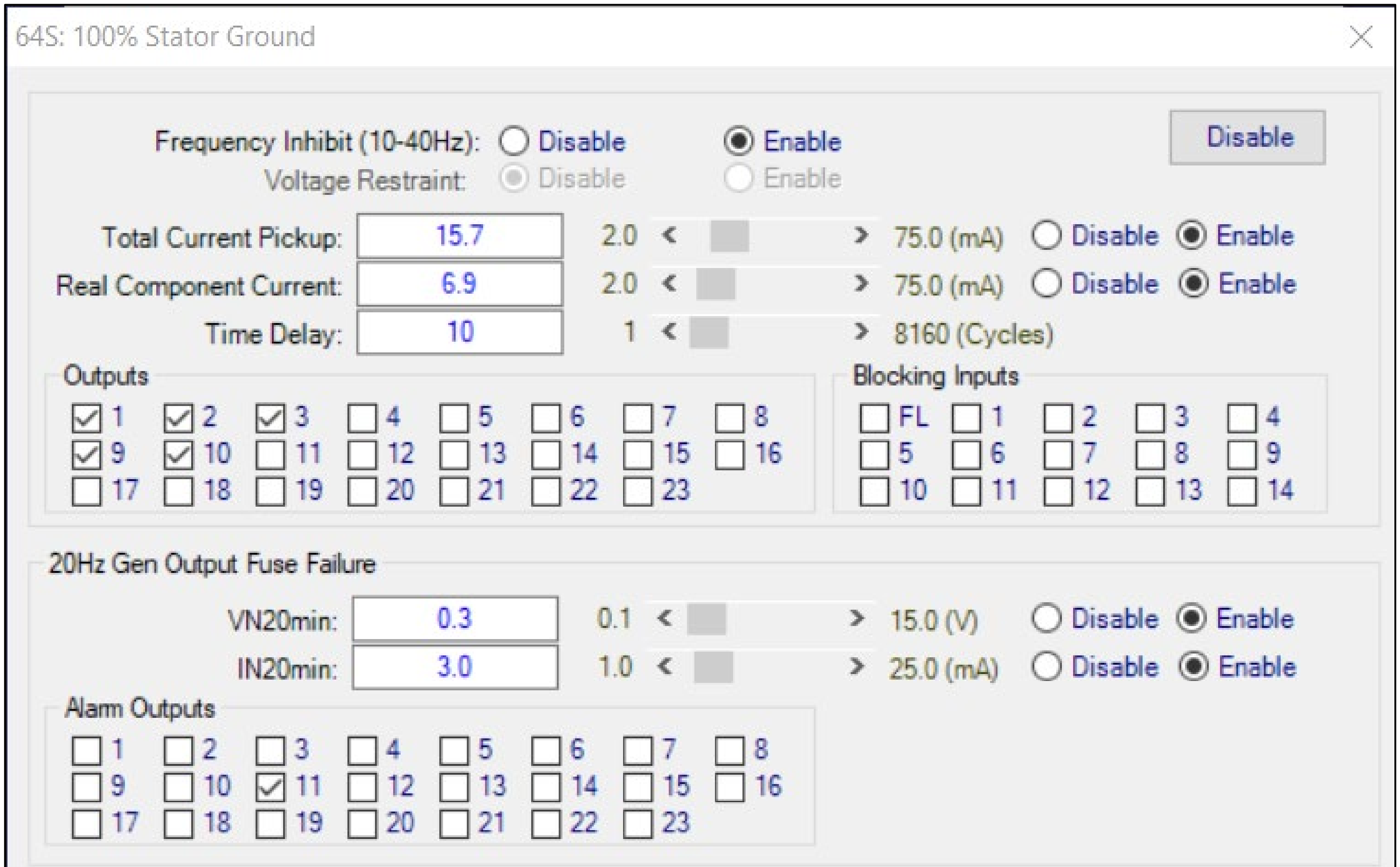
Alternatively, for Yg/Yg VTs if coordination with VT fuses is undesirable, the zero-sequence path can be broken by moving the secondary ground reference from the neutral to one of the phases.

Then if the neutral cable is still brought back to the relay, exposure is reduced by two-thirds (such is the case for this application).

Alternatively, if the neutral cable is not brought back to the relay and the relay is wired LL with VT Configuration = LL, then no VT secondary fuse coordination is necessary however the relay cannot calculate 3Vo if that is needed for any functions.

64S – 100% Stator Ground Protection

- enter preliminary settings into relay



64S – 100% Stator Ground Protection

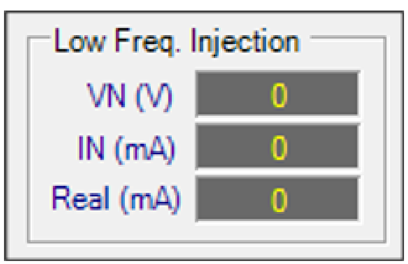
- Collect non-fault and fault commissioning values with unit off-line (system intact up to GSU LS and proper isolation on GSU HS, UAT LS, etc) and during startup and on-line, then adjust preliminary settings, as necessary.

WARNING: When the 20 Hz generator is energized, a dangerous voltage may appear on the primary of the NGT so all the proper personnel safety precautions should be in place. The approximate voltage that will appear on the primary of the NGT for this application with the unit off-line and with the 20 Hz generator energized is the following:

$$V_{Npri} = N * V_{20} * \frac{R_N}{R_N + R_{BP} + R_{LA} + R_{LB}} = 91.3 * 26 * \frac{0.26}{0.26 + 8 + 0 + 0.159} = 73\ V$$

$$or\ V_{Npri} = N * V_{20} = 91.3 * 26 = 2374\ V\ \ (if\ the\ NGR\ should\ open\ circuit\ in\ this\ scenario)$$

During this commissioning, the Secondary Metering screen via the S-3400 IPScom software can be used to monitor and document the 20 Hz values for the different test cases:



- *VN (V) = 20 Hz voltage measured across the NGR*
- *IN (mA) = Total 20 Hz current*
- *Real (mA) = Real Component of the 20 Hz current*

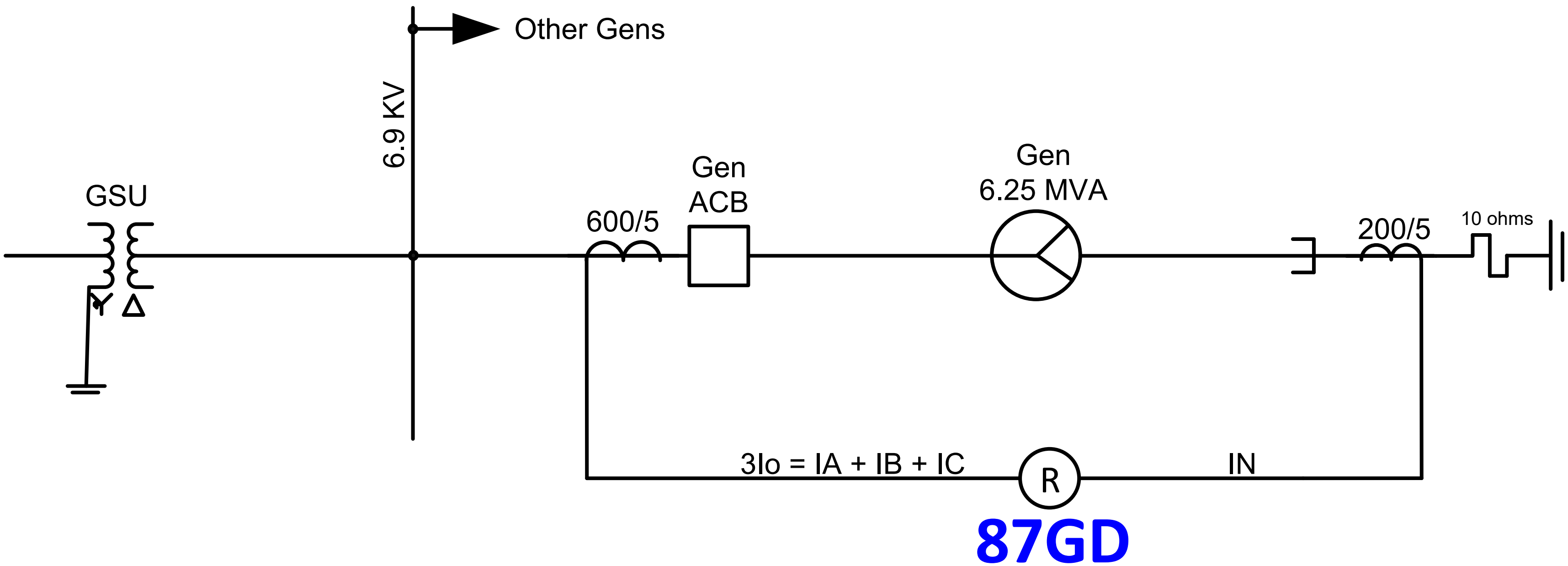
Ground Fault Protection

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

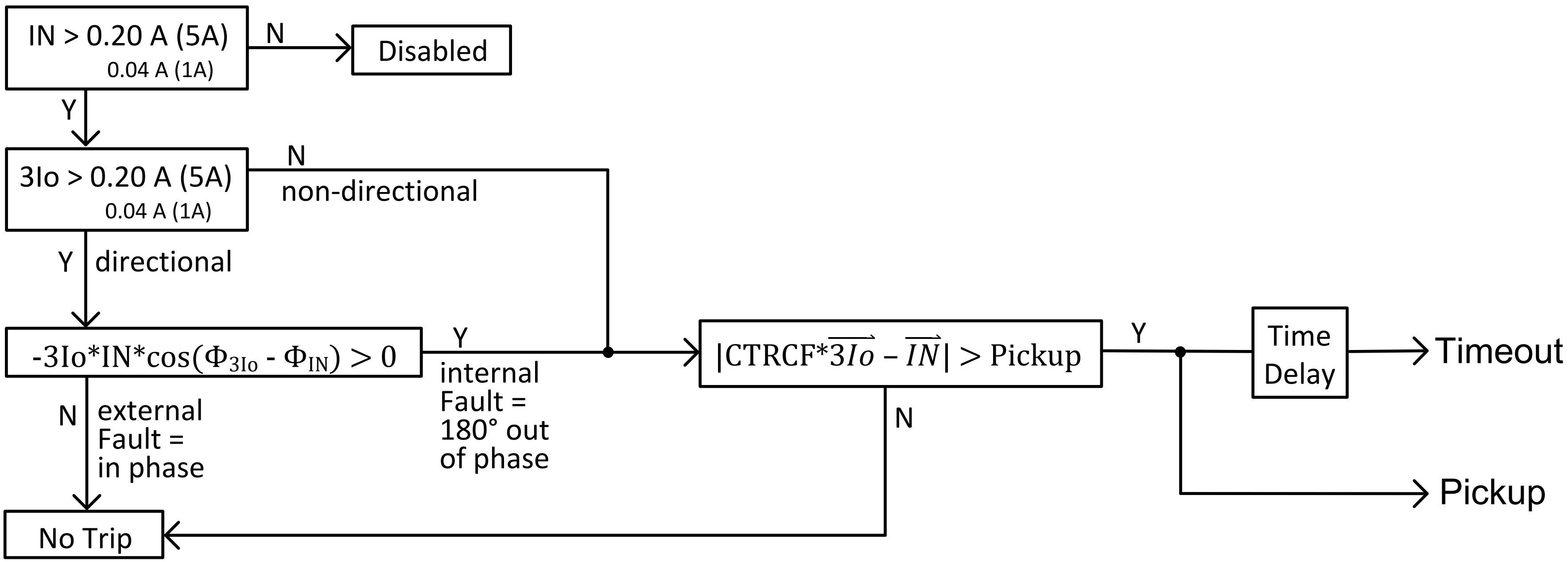
- The Zero Sequence Differential function provides ground fault protection for low impedance or solidly grounded machines.



Blocking Inputs = none

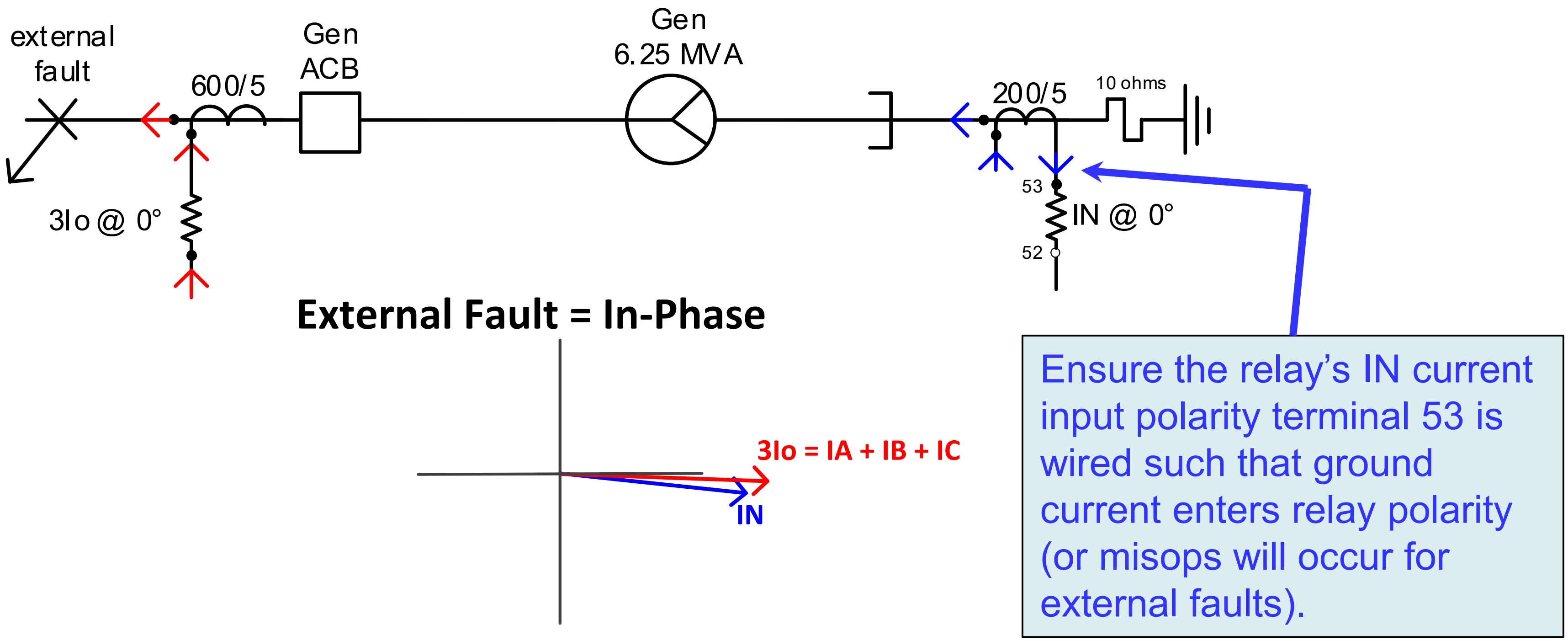
87GD – Ground Directional Overcurrent

- When system can supply zero sequence current to the ground fault (such as when several gens are bussed together), 87GD operates directionally.



87GD – Ground Directional Overcurrent

- For external faults, currents are in phase:

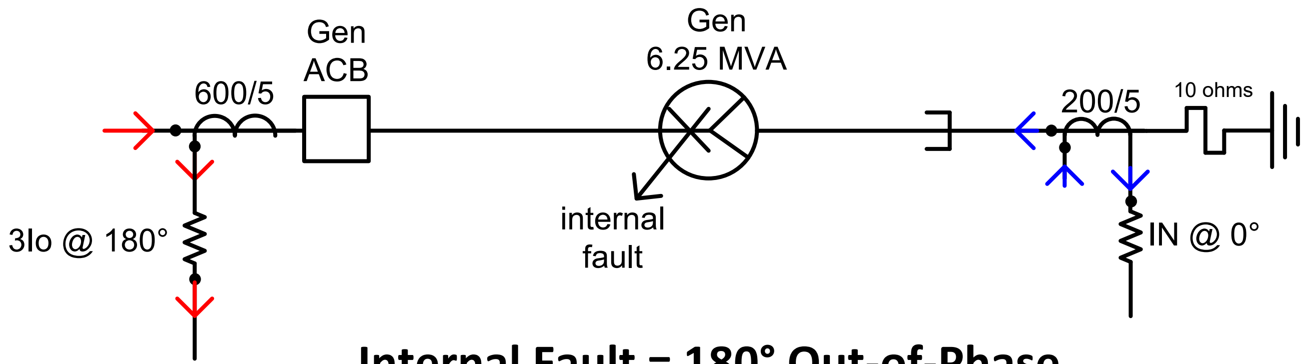


✓ Using Directional element (3Io > 0.20 A):

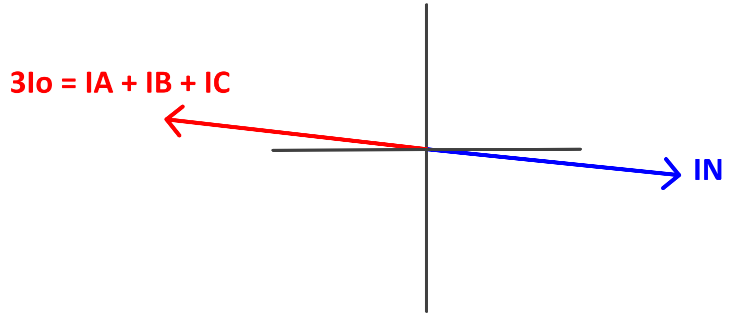
✓ -3Io*IN*cos(0°- 0°) = -3Io*IN*1 < 0, so external fault, no Trip.

87GD – Ground Directional Overcurrent

- For internal faults, currents are 180° out of phase:



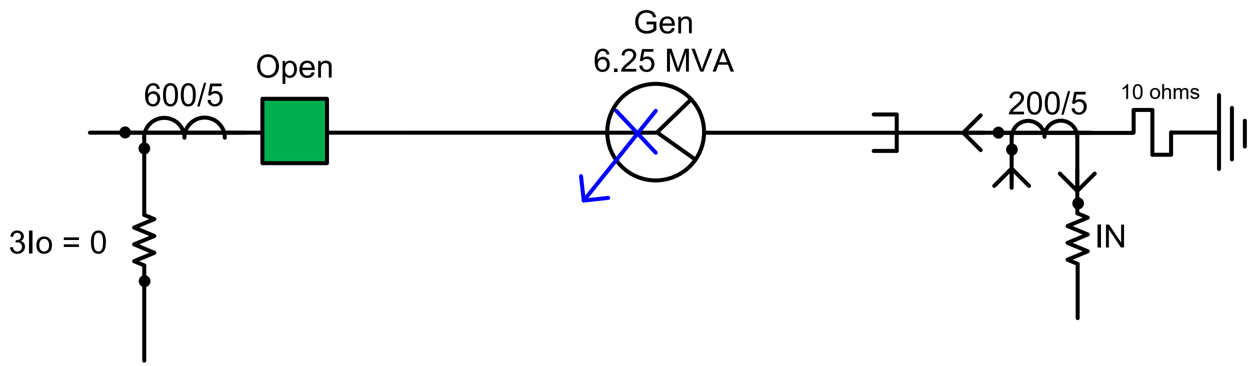
Internal Fault = 180° Out-of-Phase



- ✓ Using Directional element (3Io > 0.20 A):
- ✓ -3Io*IN*cos(180°- 0°) = -3Io*IN*-1 > 0, so internal fault.
- ✓ If |CTRCF*3Io – IN| > 87GD Pickup setting, then start 87GD timer,
- ✓ If 87GD timer expires with 87GD pickup still exceeded, then Trip.

87GD – Ground Directional Overcurrent

- For internal faults, with gen breaker open:



✓ 3Io < 0.20 A, therefore directional element disabled, only do 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.

87GD – Ground Directional Overcurrent

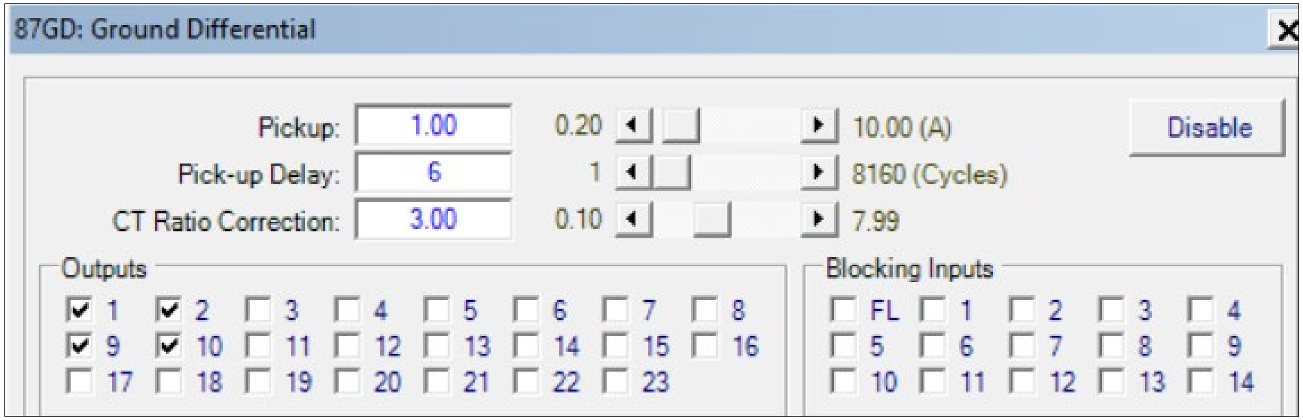
Example Settings (use typical bookend ground pickup setting criteria):

$$Max\ unbalance\ (5\%) \quad < \quad 87GD\ Pickup \quad < \quad ground\ fault\ (30\%\ margin)$$

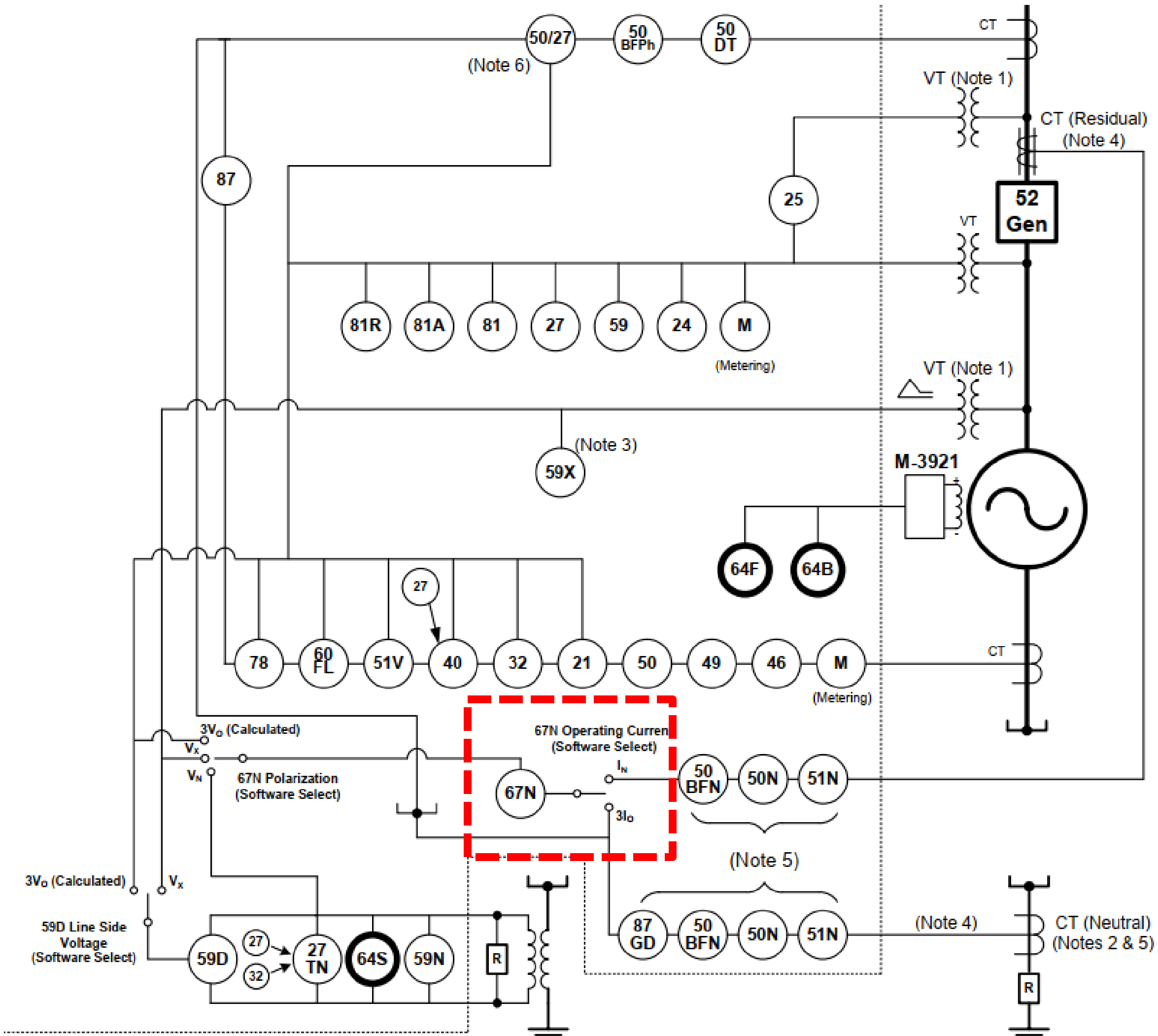
$$0.05 * \frac{6.25M}{\sqrt{3} * 6.9K} * \frac{5}{200} \quad < \quad 87GD\ Pickup \quad < \quad 0.30 * \frac{6.9K}{\sqrt{3} * 10} * \frac{5}{200}$$

$$0.65\ A \quad < \quad 87GD\ Pickup \quad < \quad 3\ A$$

- Choose Pickup = 1 A
- Choose Time Delay = 2 to 6 cycles depending if CT saturation is possible
- $CTR\ Correction\ Factor = \frac{phase\ CTR}{neutral\ CTR} = \frac{120}{40} = 3$



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

67N – Residual Directional Overcurrent

- Provides protection for ground faults on low impedance or solidly grounded generators.

- **Operating Current = 3Io or IN**
  - ✓ 3Io = IA + IB + IC, calculated from terminal-side phase current inputs
  - ✓ IN = measured from IN current input
    - ➢ via a core balance CT
    - ➢ via a single neutral/ground CT

- **Polarizing Quantity = 3Vo or VN or VX**
  - ✓ 3Vo = VA + VB + VC, calculated from phase voltage inputs via Yg/Yg VTs with VT Configuration = LG
  - ✓ VN = measured from VN voltage input
  - ✓ VX = measured 3Vo from VX voltage input via broken delta VTs

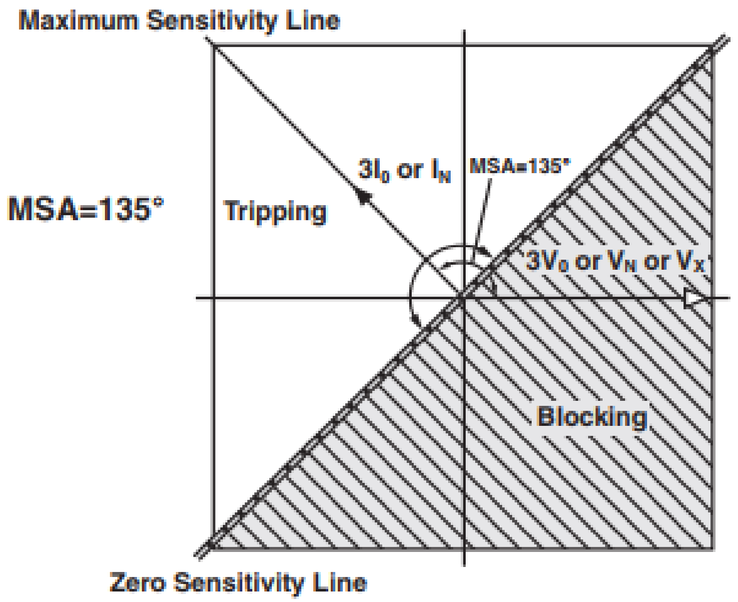
67N – Residual Directional Overcurrent

- To provide maximum sensitivity for fault currents, the directional element is provided with a Maximum Sensitivity Angle (MSA).
- The Pickup sensitivity remains constant for 90° on either side of MSA.
- At current angles > ±90° from the MSA, the function is blocked.
- 67N provides directional discrimination (selectivity) when multiple generators are bussed together.

67N – Residual Directional Overcurrent

- If the ground fault current **enters relay polarity** for a fault in the tripping direction:

  - ✓ MSA = 100° for a solidly grounded generator. Assume AG fault, IA phase angle lags VA phase angle by 80° and 3Vo phase angle is 180° from VA. After rotating 3Vo and IA by 180° to get 3Vo at 0° reference, IA will be at the 100° position.
  - ✓ MSA = 170° for a high-impedance grounded generator. Assume AG fault, IA phase angle lags VA phase angle by 10° and 3Vo phase angle is 180° from VA. After rotating 3Vo and IA by 180° to get 3Vo at 0° reference, IA will be at the 170° position.



Compromise:

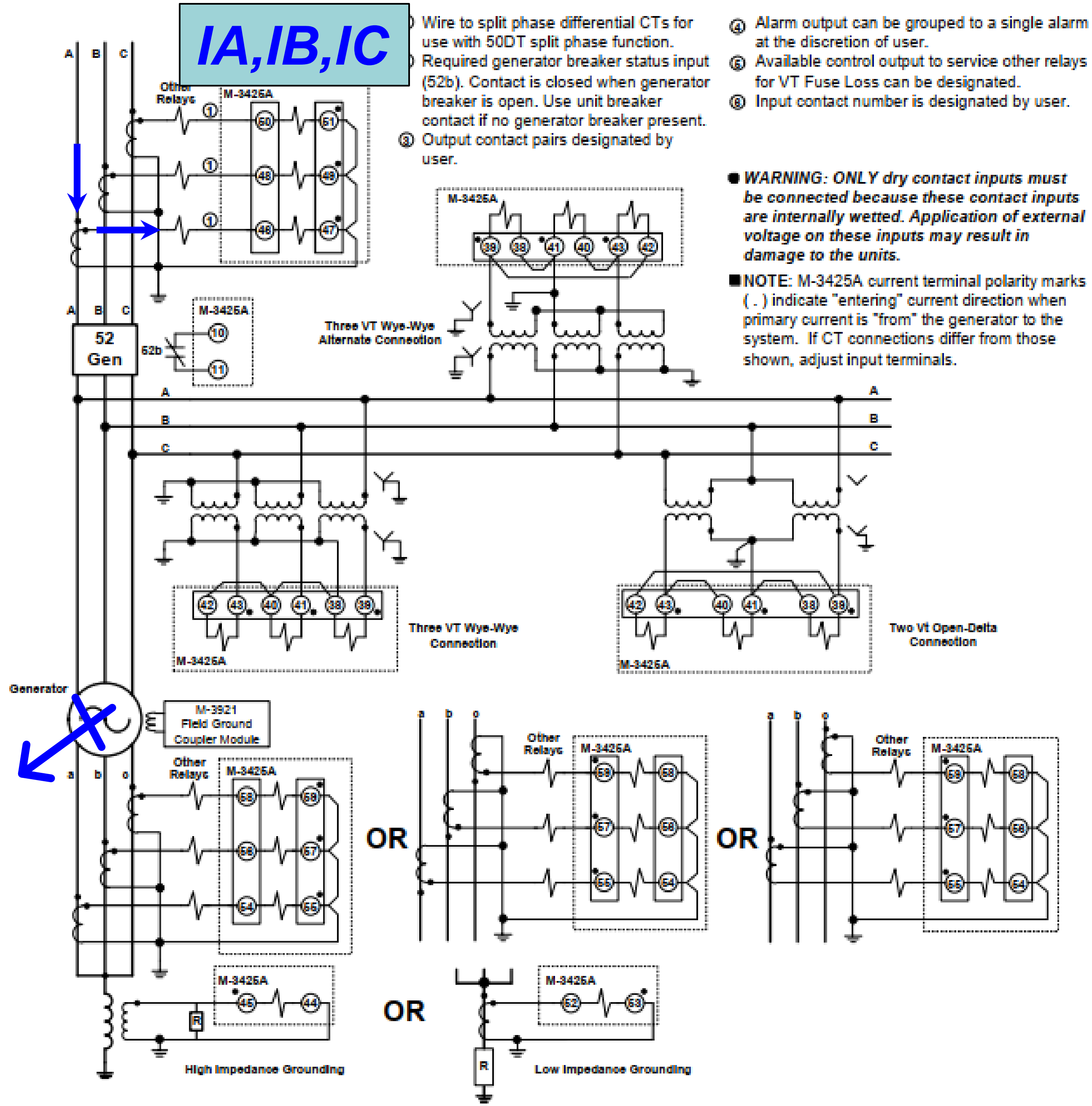
- **MSA = 135°** is the average and with the ± 90° sensitivity, this is typically sufficient for different types of gen grounding applications when current enters relay polarity in the tripping direction for internal generator ground faults.

67N – Residual Directional Overcurrent

- If current is **exiting relay polarity** (180° out) from the relay current inputs that are sourcing the operating current selection for a fault in the desired tripping direction, then an MSA setting of approx. 315° or so may be more appropriate.

- For example, if using an operating current of 3Io that is being calculated from the measured IA, IB, IC current inputs, and if wired per typical and if desired tripping is in the generator direction, then because current exits relay polarity (of IA, IB, IC or at least from the faulted phase for a ΦG fault) for a fault in the tripping direction, therefore the current would be 180° from the 135° position (for cases where current enters relay polarity in tripping direction).

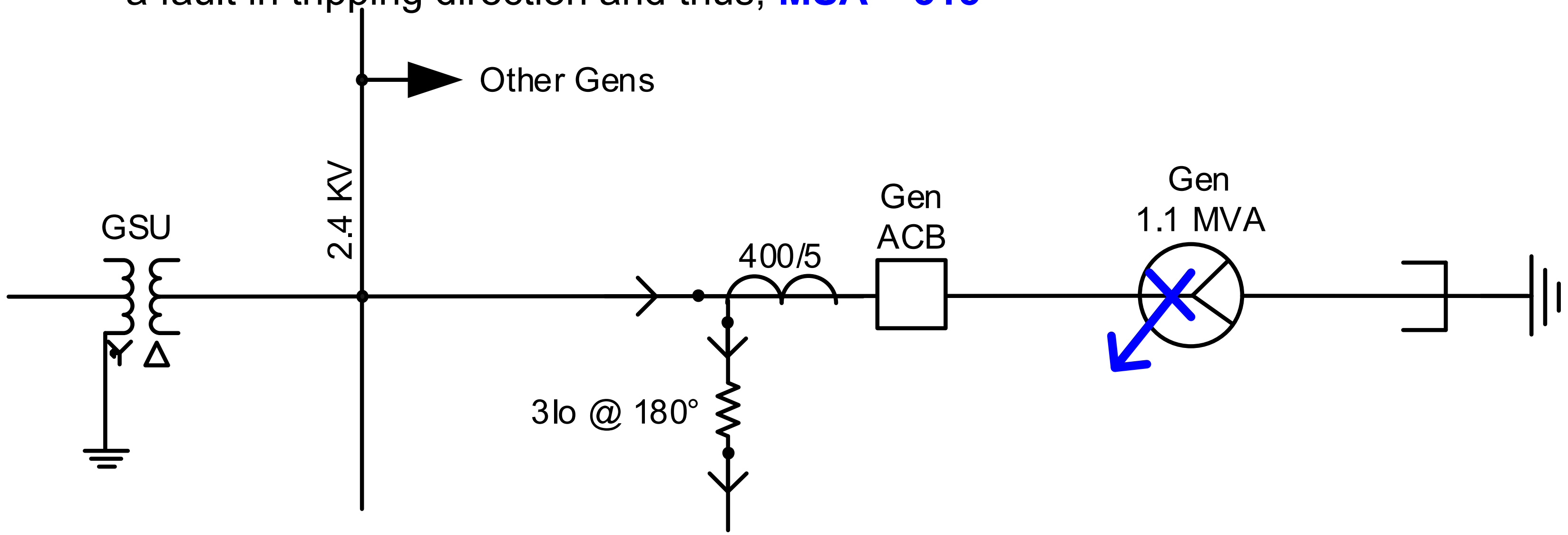
- Thus: **MSA = 135° + 180° = 315°**


IA,IB,IC
Wire to split phase differential CTs for use with 50DT split phase function.
Required generator breaker status input (52b). Contact is closed when generator breaker is open. Use unit breaker contact if no generator breaker present.
③ Output contact pairs designated by user.
④ Alarm output can be grouped to a single alarm at the discretion of user.
⑤ Available control output to service other relays for VT Fuse Loss can be designated.
⑥ Input contact number is designated by user.
WARNING: ONLY dry contact inputs must be connected because these contact inputs are internally wetted. Application of external voltage on these inputs may result in damage to the units.
NOTE: M-3425A current terminal polarity marks (.) indicate "entering" current direction when primary current is "from" the generator to the system. If CT connections differ from those shown, adjust input terminals.
Other Relays
M-3425A
52 Gen
52b
Three VT Wye-Wye Alternate Connection
Three VT Wye-Wye Connection
Two Vt Open-Delta Connection
Generator
M-3921 Field Ground Coupler Module
OR
OR
OR
High Impedance Grounding
Low Impedance Grounding

67N – Residual Directional Overcurrent

Example Settings:

- Solidly Grounded hydro with multiple gens off the same bus
- 1.1 MVA
- 2.4 KV
- Phase CTR = 400/5
- For the "Operating Current" selection, use the calculated 3Io value from the terminal side phase current inputs (3Io = IA + IB + IC); therefore, current exits relay polarity for a fault in tripping direction and thus, **MSA = 315°**



67N – Residual Directional Overcurrent

Example Settings continued:

- Use typical bookending ground pickup setting criteria:

Max normal unbalance < 67NIT Pickup < min ground fault (30% margin)

- Normal unbalance at gen is small (typically < 3%), here assume worst-case of 10% (but this is directional and the normal 3Io flowing into the gen from the system should be practically zero, so this is conservative):

$$\max normal\ unbalance\ 3Io = 0.10 * \frac{1.1 * 1000}{\sqrt{3} * 2.4} * \frac{1}{80} = 0.33\ A$$

- Calculate minimum internal generator ground fault as fed from the system and other parallel generators (assume other generators off-line, assume Xt = 11%):

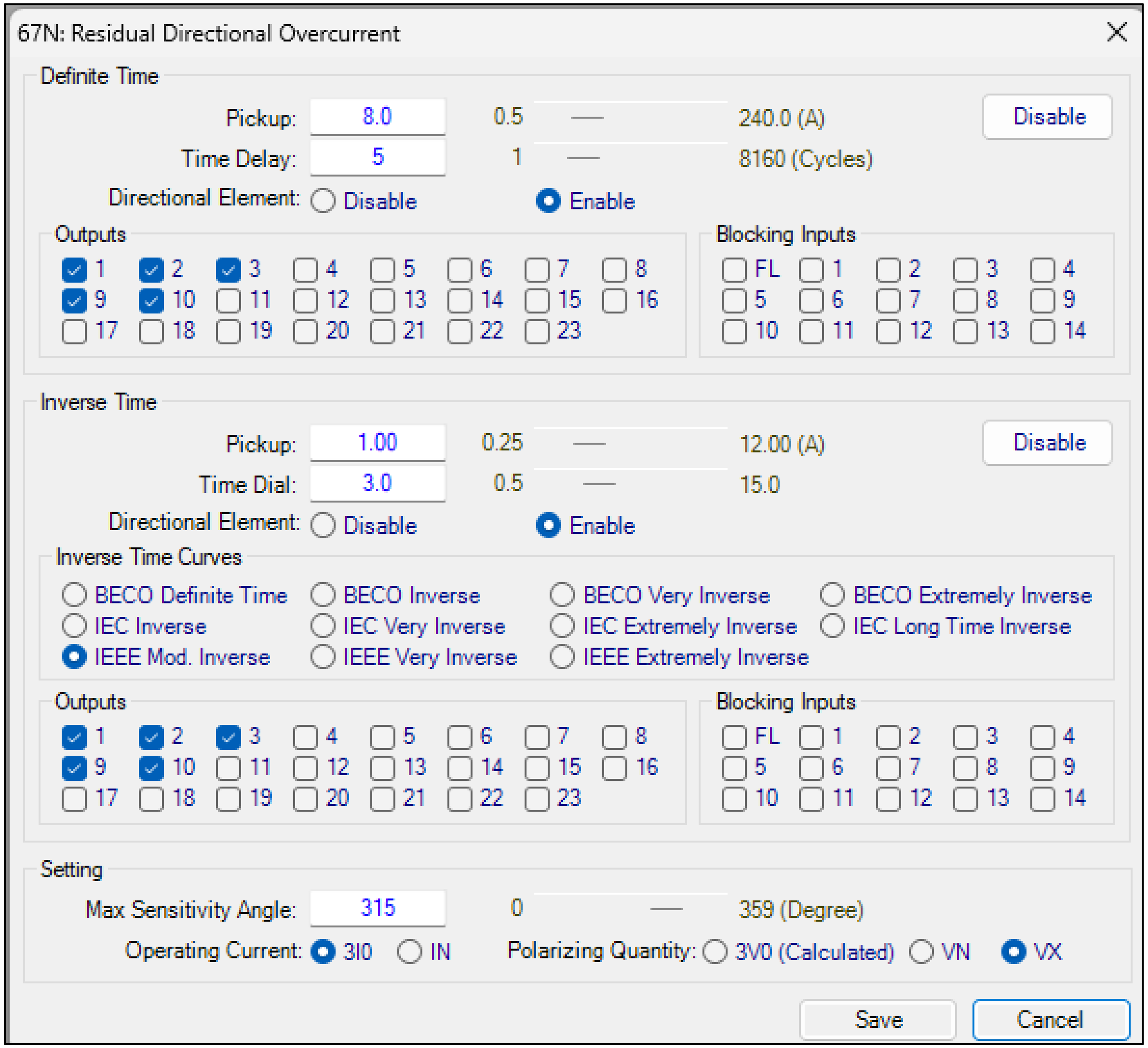
0.33 A < 67NIT Pickup < $0.30 * \frac{1}{0.11} * \frac{1.1*1000}{\sqrt{3}*2.4} * \frac{1}{80}$

0.33 A < 67NIT Pickup < 0.30 * 30

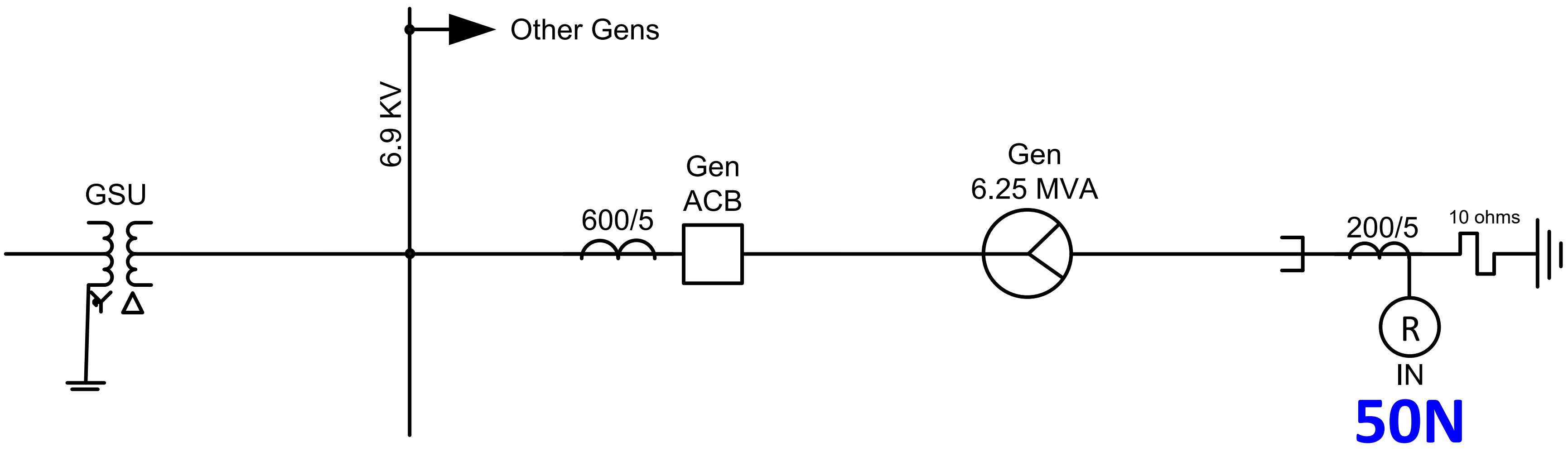
0.33 A < 67NIT Pickup < 9 A

- Set 67NIT Pickup = 1 A, choose U1 flat curve, calculate TD and plot.

67N – Residual Directional Overcurrent



50N – Instantaneous Neutral Overcurrent

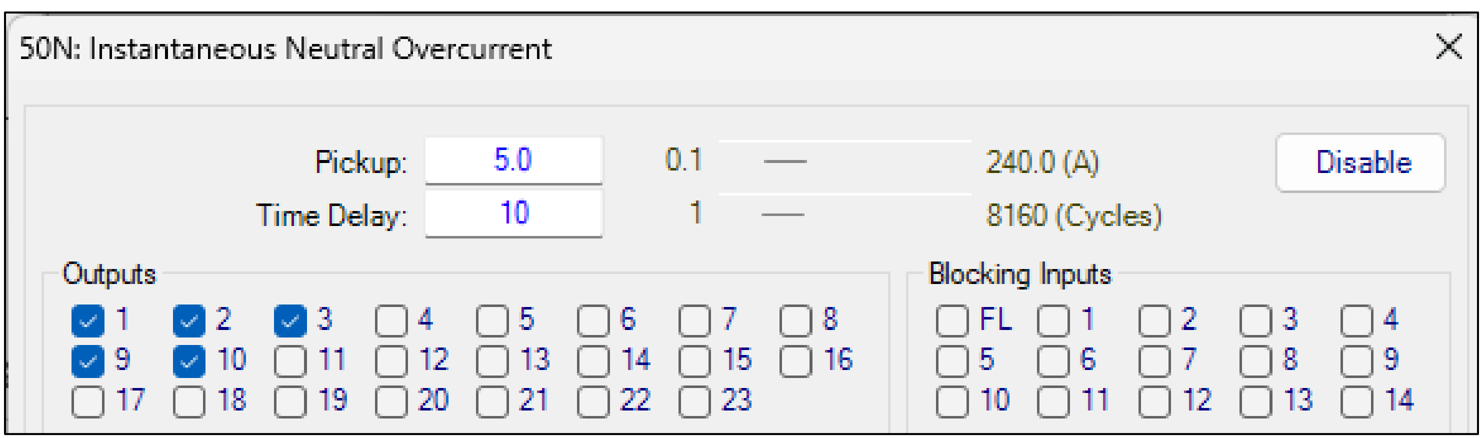


Blocking Inputs = none

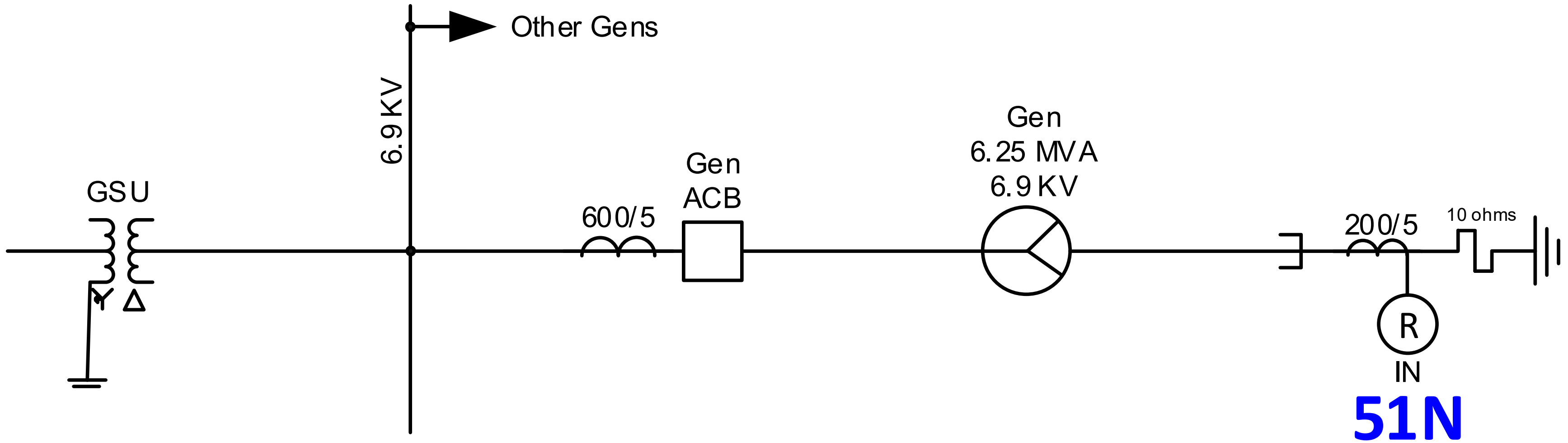
For low impedance or solidly grounded generator applications

50N – Instantaneous Neutral Overcurrent

- **May use 50N along with 51N to cut off the 51N curve at the higher ground fault current levels.**
- **Max available ground fault current:**
  - $$3Io = \frac{V_{LG}}{Rg * CTRN} = \frac{\frac{6.9K}{\sqrt{3}}}{10 * 40} = 10\ Asec$$
- **With 51N Pickup = 1 A (see next section), decide to set 50N Pickup = 5 A.**
- **This is 50% of the max available ground fault current.**
- **For 50N time delay, may need to coordinate with 67N DT time delay if 67N is sourced from currents at the terminal end and set to protect for ground faults located back in the direction of the subject generator. With 67N DT Time Delay = 5 cycles, decide to set 50N Time Delay = 10 cycles.**



51N – Inverse Time Neutral Overcurrent



Blocking Inputs = none

For low impedance or solidly grounded generator applications

51N – Inverse Time Neutral Overcurrent

- **Set sensitive and relatively fast depending on coordination requirements e.g. may need to coordinate with 67N on terminal side looking back into gen.**
- **Choose flat curve (IEEE U1 Moderately Inverse) and choose a TD such that it flattens out above what you need to coord with (e.g. 67N Inverse Time curve).**

- **Choose 51N Pickup to satisfy 2 criteria:**
  1) **Set > max 3Io with machine at full load output**
  2) **Set < min ground fault current * some SM (Sensitivity Margin)**

- **<u>1st criteria:</u> For the max loading 3Io, measure, meter, or poll over time what the relay's IN current input sees with gen running at full output.**
- **Or, if not available, may assume max loading 3Io is some % of gen full output:**
- ***Calculate generator's full load output:*** $I_{FL} = \frac{6.25M}{\sqrt{3} * 6.9K} = 523\ Apri$
- ***Choose 5% of this, seen by IN current input:*** $3Io = 0.05 * \frac{523}{40} = 0.65\ Asec$

51N – Inverse Time Neutral Overcurrent

- **<u>2nd criteria:</u>** **Calculate the minimum ground fault current (times some sensitivity margin to account for fault resistance in the ground fault) as seen by the relay's IN current input.**

- **With a primary connected 10 Ω grounding resistor at 6.9 KV, and assuming a ground fault is located at the terminal end of the gen:**

- ***Max available ground fault current:*** $3Io = a * \frac{V_{LG}}{Rg} = 1 * \frac{\frac{6.9K}{\sqrt{3}}}{10} = 400\ Apri$
  - a *is the per unit distance from the neutral end of the generator*

- ***As seen at the relay's IN (or IG) current input:*** $3Io = \frac{max\ 3Io}{CTRN} = \frac{400}{40} = 10\ Asec$

- ***Try using 25% sensitivity margin:*** $3Io = 0.25 * 10 = 2.5\ Asec$

51N – Inverse Time Neutral Overcurrent

- **51N Pickup bookend criteria:**

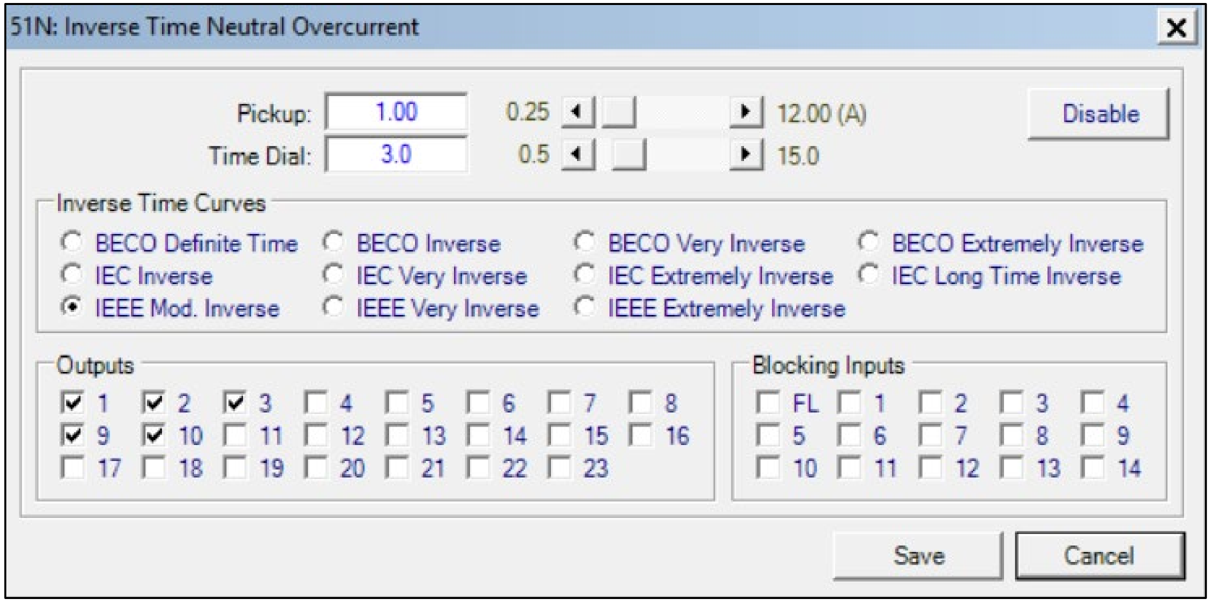
Max normal unbalance < 51N Pickup < min ground fault (25% margin)

0.05*(6.25M/(1.732*6.9K*40)) < 51N Pickup < 0.25*((6.9K/1.732)/10)/40

0.65 A < 51N Pickup < 2.5 A

- **Choose 51N Pickup = 1 A**
- **QUESTION: How much of the generator stator winding will be protected from ground faults with this setting?**
- **Rearrange** $3Io = a * \frac{V_{LG}}{Rg}$ **equation, and solve for a:**
- $a = 51N\ Pickup * CTRN * \frac{Rg}{V_{LG}} = 1A * \frac{200}{5} * \frac{10}{\frac{6.9K}{\sqrt{3}}} = 0.10\ pu, \quad 0.10 * 100\% = 10\%$
- **Therefore, with 51N Pickup = 1A, 51N will detect ground faults from the terminal end down to 10% from the neutral end i.e. it will not see ground faults in the last 10% of the stator winding closest to the neutral**
- **Or it will protect 90% of the stator winding from ground faults i.e. from the terminal end down to 90% from the terminal end or to the neutral end.**

51N – Inverse Time Neutral Overcurrent

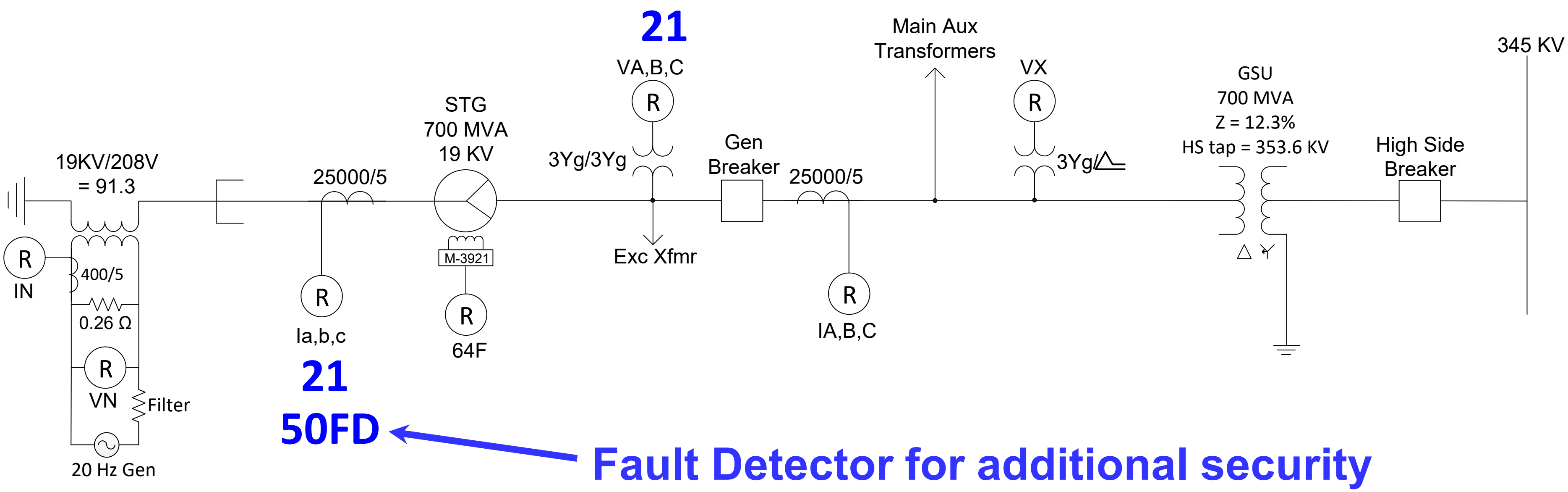


- **If it is desired to protect more than 90% of the stator winding from ground faults with the 51N element, choose a lower 51N Pickup:**
- **for 95% coverage, set 51N Pickup = 0.50 A**
- **Or if set 51N Pickup to its minimum 0.25 A, then 97.5% coverage is achieved.**
- **Just ensure more sensitive setting is secure i.e. > the max 3Io seen during max full load output, where 5% of full load output 3Io was 0.65 A and both a 0.50 A or a 0.25 A Pickup setting are < than that.**

System Backup Protection for Phase faults

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

21 – Phase Distance



Fault Detector for additional security

Blocking Inputs = FL, 1

(block for blown fuse and open breaker)

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

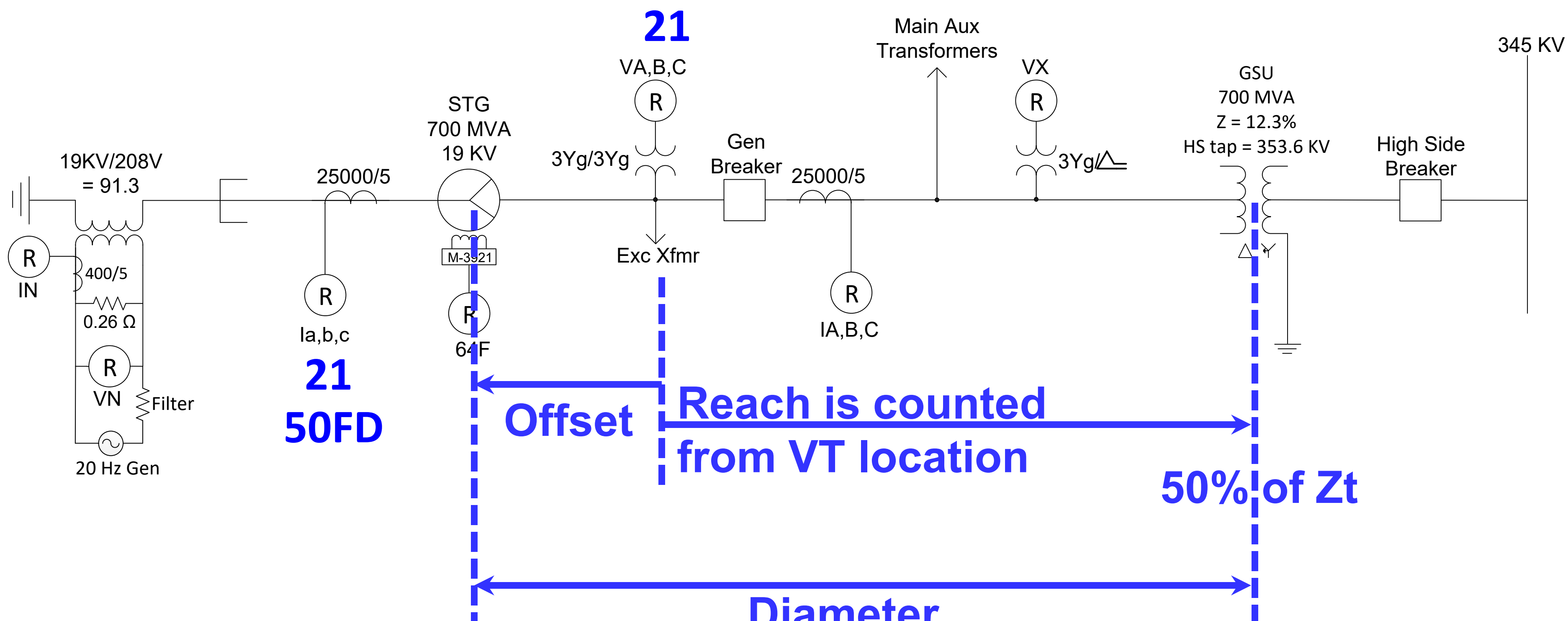
Typically used for system backup phase fault protection.

System Phase Fault Backup (21 zone 1)

Set Zone 1 Reach to 50% of the GSU and 30 cycles:

- Choose 50% (instead of a more typical zone 1 reach of 80% or so) to give plenty of security margin against seeing GSU HS phase faults as the Delta-Y Transform = Delta-AC setting is applied to the calculated impedance regardless of the actual fault location.

- May be set quicker esp. if there is not overlapping 87G and 87T (GSU) zones. Just want to set it long enough to give precedence to 87G, 87T, and 87B (Gen Bus Diff, if present) to optimize fault locating.



(21 zone 1) – Phase Distance

What value to use for the GSU impedance, Zt?

The GSU nameplate and test report shows Zt = 12.306% at max 700 MVA.

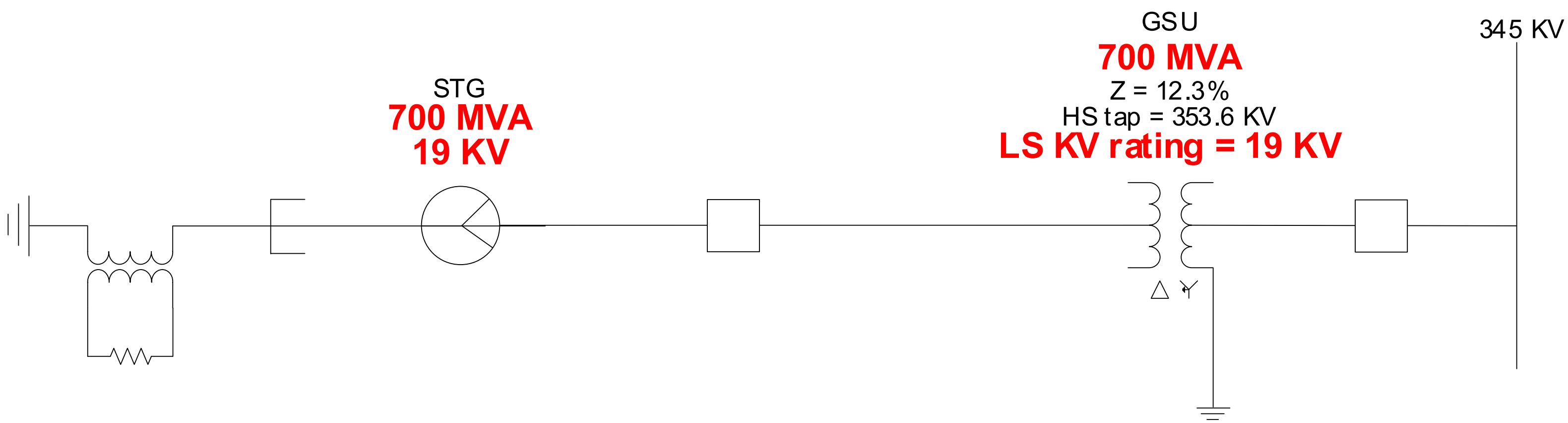
Typically, it is sufficient to estimate that this is all reactance and no resistance (i.e. all "jX" or at 90°); however, to calculate the resistance portion, the copper load loss in watts from the test report may be used as such:

$Zt = 0.123060\ pu$	*GSU impedance at 700 MVA max rating*
$Pt\ act = 1{,}134{,}708\ watts$	*GSU copper load loss at max MVA rating*
$Pt\ pu = i^2 * R = 1^2 * R = Rt\ pu$	*GSU copper load loss in per unit at 1 pu amps*
$Rt = Pt = Pt\ act/St = 1{,}134{,}708/700M = 0.001621\ pu$	*GSU resistance*
$Xt = \sqrt{Zt^2 - Rt^2} = \sqrt{0.123060^2 - 0.001621^2} = 0.123049\ pu$	*GSU reactance*
$Zt = Rt + jXt = 0.001621 + j0.123049 = 0.123060\ pu\ at\ 89.25°$	*GSU impedance*

(21 zone 1) – Phase Distance

If GSU LS voltage rating and/or GSU max MVA rating are different than gen's voltage and MVA ratings, use this eqn:

$$Z_{GSU\_on\_gen\_base} = Z_{GSU} * \frac{V_{GSU}^2}{V_{gen}^2} * \frac{S_{gen}}{S_{GSU}}$$



- *GSU LS voltage rating = gen voltage rating = 19 KV*
- *GSU max MVA rating = gen MVA rating = 700 MVA*

Thus, this eqn is not required as it gives the same result as original:

$$Z_{GSU\_on\_gen\_base} = (0.001621 + j0.123049) * \frac{19^2}{19^2} * \frac{700}{700} = 0.001621 + j0.123049\, pu$$

(21 zone 1) – Phase Distance

$$\mathbf{Z1reach = 50\ \%\ of\ Zt}$$

$$Zbase = \frac{\mathbf{Vbase^2}}{\mathbf{Sbase}} = \frac{19K^2}{700M}$$

$$CTR = \frac{25,000}{5} = 5000$$

$$= 0.50 * Ztpu * Zbase * \frac{CTR}{VTR}$$

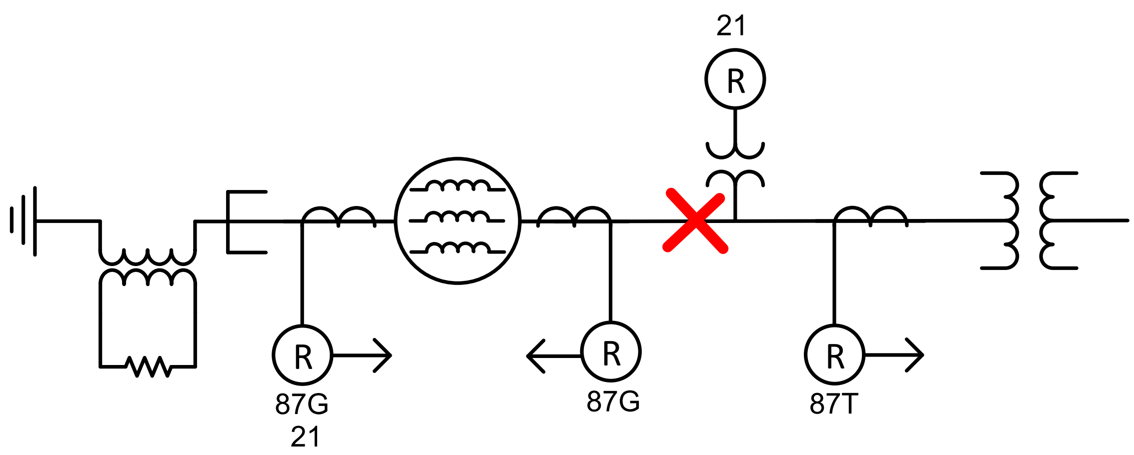
$$VTR = \frac{19,000}{120} = 158.3$$

$$= 0.50 * (0.001621 + j0.123049) * \frac{19^2}{700} * \frac{5000}{158.3}$$

$$= 0.0132 + j1.0022\ \Omega sec$$

Phase Distance (21 zone 1)

- Set a small offset (reverse reach) equal to 10% of the generator transient reactance, therefore:
  - Offset = 10% of Xd'
- This provides coverage for bolted, zero voltage, 3Φ faults right at or near the VT location.
- If the gen VTs are located outside the gen diff zone terminal side CTs, this offset will also provide protection in that area, which can be helpful especially for applications that do not have overlapping diff zones or an 87O overall diff:



(21 zone 1) – Phase Distance

$$Z1offset = -0.10 * jXd' * Zbase * \frac{CTR}{VTR} = -0.10 * j0.295 * \frac{19^2}{700} * \frac{5000}{158.3} = -j0.4805\ \Omega$$

$$Z1offset = -0.5\ \Omega$$

NOTE: This mfg's relay enters 21 settings in terms of Diameter (where Diameter = Reach + |Offset|). Other relays may set it in terms of Reach.

$$Z1dia = Z1reach + |offset| = (0.0132 + j1.0022) + |-j0.4805|$$
$$= 0.0132 + j1.4827\ \Omega$$

$$|Z1dia| = |0.0132 + j1.4827| = 1.5\ \Omega$$

$$Z1angle = arg(Z1dia) = arg(0.0132 + j1.4827) = 89\ degrees$$

Load Encroachment = Disable as zone 1 does not reach past GSU.

(21 zone 1) – Phase Distance

Enable OverCurrent Supervision i.e. 50FD Fault Detector for added security.

If all three of the measured neutral-side phase currents (Ia AND Ib AND Ic) are < this 50FD Pickup setting, then the 21 element will be blocked. This may be set very low for extra sensitivity or for increased security, it may be set above max load current (with a security factor), but it can be picked up on load if necessary. And it should be set well below the minimum phase fault current (with some sensitivity margin) for all fault locations that this zone can reach.

Here, use a GSU LS ΦΦ fault to calculate the fault current as zone 1 will not reach past the GSU. So, for a GSU LS ΦΦ fault, the generator can produce 47,022 A at 30 cycles (from the gen decrement curve assuming a flat start or 1pu voltage i.e. nominal voltage).

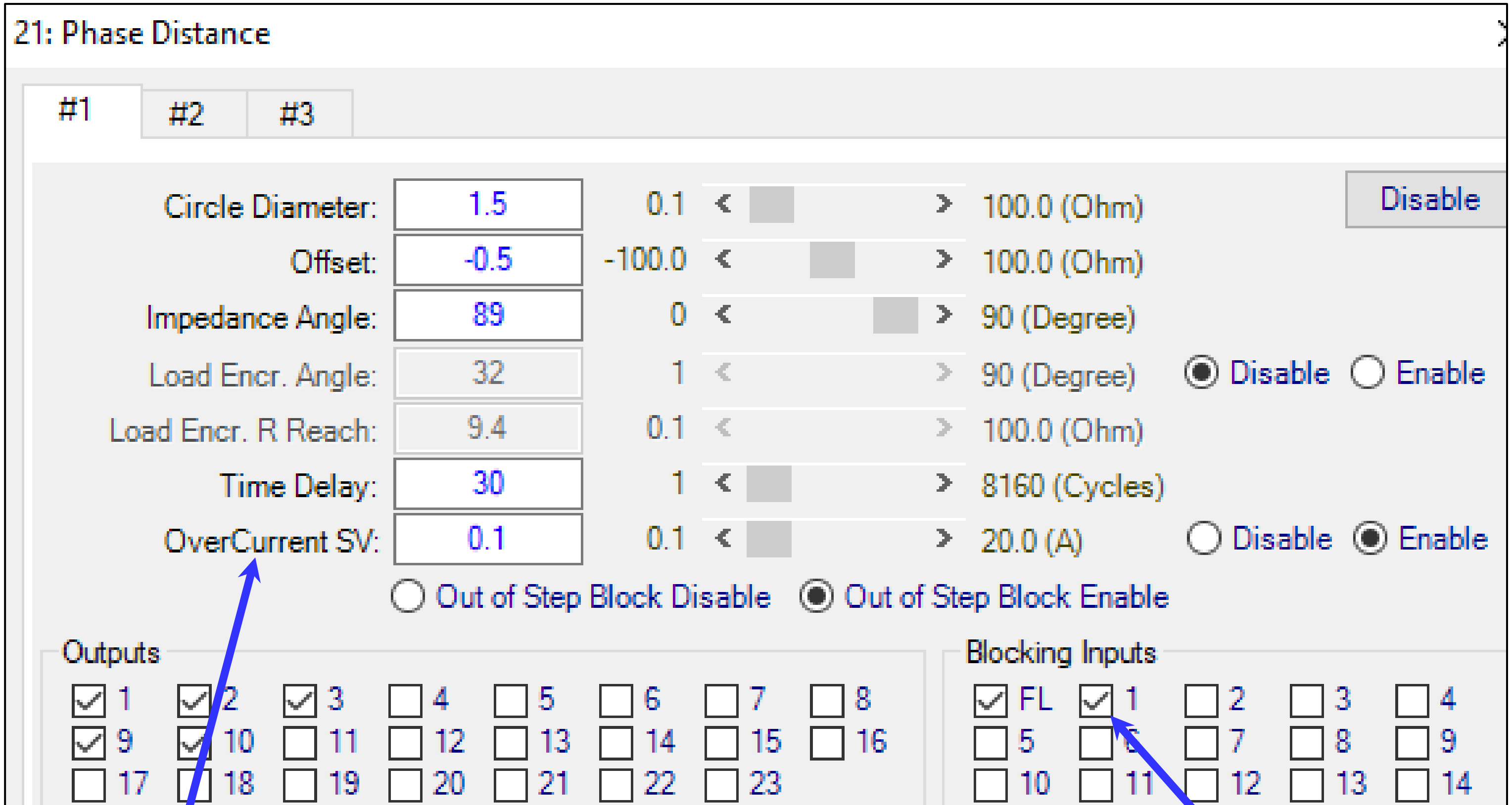
$$\mathrm{Iac(t)} = (|\mathrm{Id}''| - |\mathrm{Id}'|) * e^{-\frac{t}{\mathrm{Td}''}} + (|\mathrm{Id}'| - |\mathrm{Id}|) * e^{-\frac{t}{\mathrm{Td}'}} + |\mathrm{Id}| = 47{,}022\ \mathrm{Apri\ or}\ \frac{47{,}022}{5000} = 9.4\ \mathrm{Asec}$$

$$\mathrm{SF} * \mathrm{Inom} \leq \mathrm{Overcurrent\ SV} < \mathrm{SM} * \mathrm{min\ phase\ fault\ current}$$
$$1.06 * 4.25 \leq \mathrm{Overcurrent\ SV} < 0.50 * 9.4$$
$$4.5 \leq \mathrm{Overcurrent\ SV} < 4.7$$

Overcurrent SV = 0.1 A

(could set it to 4.6 A for added security, but decided to set it at minimum for max sensitivity)

(21 zone 1) – Phase Distance



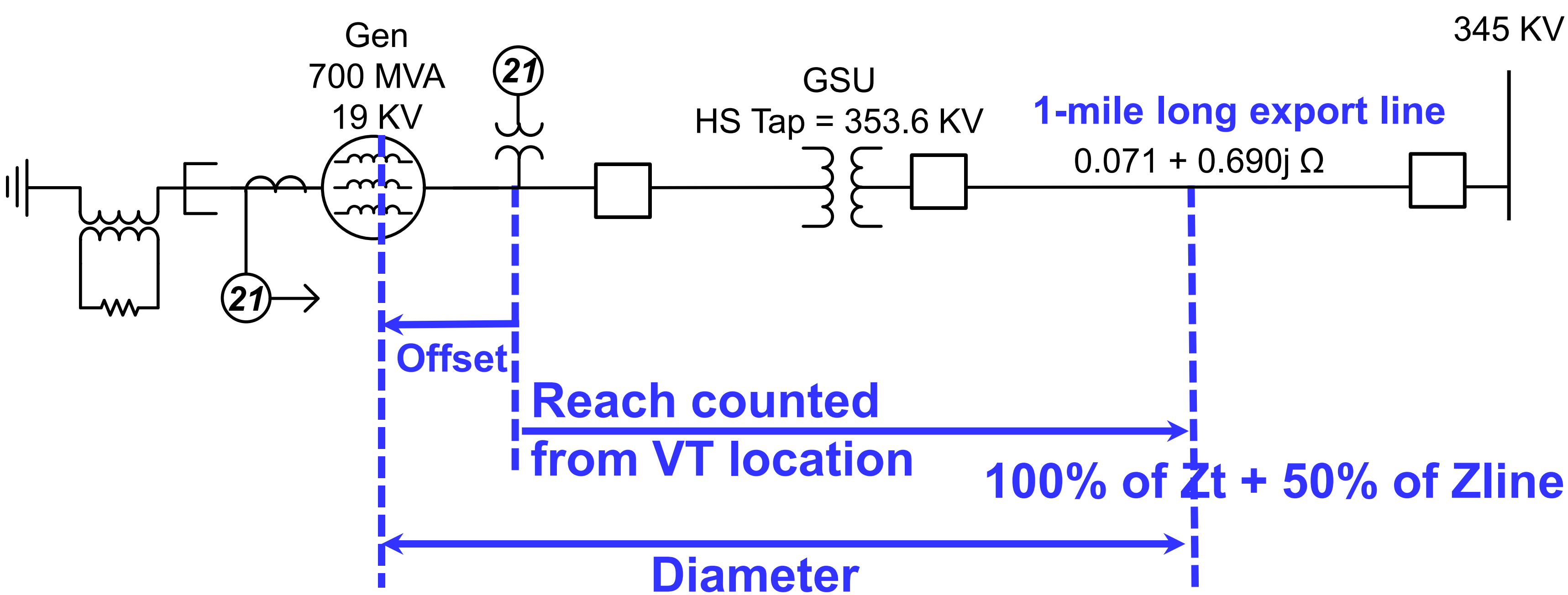
Set 50FD to min for additional security

Block for open breaker for added security unless pre-synch protection is required

System Phase Fault Backup (21 zone 2)

Set Zone 2 Reach to 100% of the GSU plus 50% of next shortest line and 60 cyc:

- For time delay, assume step distance protection is used on the transmission relays that have 21 zone 2 time delays set at 18 cycles (at 50%, this should not see into zone 2 but just assume so to make more conservative).
- 5 cycle breaker
- 1 cycle relay operate time
- 10 cycle BF timer
- 12 cycles of coordination margin
- Total = 18+5+1+10+12 = 46 cycles, which was rounded up to 60 cycles for additional security.



(21 zone 2) – Phase Distance

Z2 Diameter = Z2reach + Z2offset
= 100% of GSU + 50% of the next shortest line + Z2offset

$$Z2reach = \left[(1.00 * Zt * Zbase) + \left(0.50 * Zline * \left(\frac{Vg}{Vgsuhstap}\right)^2\right)\right] * \frac{CTR}{VTR}$$
$$= \left[\left(1.00 * (0.001621 + j0.123049) * \frac{19K^2}{700M}\right) + \left(0.50 * (0.071 + j0.690) * \left(\frac{19K}{353.6K}\right)^2\right)\right] * \frac{5000}{158.3}$$
$$= 0.0296 + j2.0358\ \Omega$$

- Zt is in pu, therefore multiply by Zbase to get Zactual in Ωpri.
- Zline is already in Ωpri, however it is on the GSU HS therefore it must first be transferred to the GSU LS so it can be added to Zt (that is in Ωpri). If instead, Zline is first converted to pu, then it can be added directly with Zt (if left in pu) i.e. there is then no need to first transfer it thru the GSU. Then the per unit combination of Zt and Zline must be multiplied by Zbase to get Zactual in Ωpri.
- Then the Ωpri value is multiplied by CTR/VTR to get Ωsec which are the units the 21 zone 2 reach is set in.

$$Z2offset = -0.10 * jXd' * Zbase * \frac{CTR}{VTR} = -0.10 * j0.295 * \frac{19^2}{700} * \frac{5000}{158.3} = -j0.4805\ \Omega = -0.5\ \Omega$$

$$Z2dia = Z2reach + |offset| = (0.0296 + j2.0358) + |-j0.4805| = 0.0296 + j2.5164 = 2.5\ \Omega$$

$$Z2angle = argument(Z2dia) = argument(0.0296 + j2.5164) = 89\,°$$

(21 zone 2) – Phase Distance

Load Encroachment = Enable for zone 2 as it does reach past the GSU, however the reach is short enough that Load Encroachment is not required. Nonetheless, it will be Enabled here to demonstrate criteria that may be used for cases where it may be required. For example, if any 21 zones are set to reach past the end of a very long transmission line (e.g. SIR < 0.5) off the high side of the GSU, then Load Encroachment can be useful so the mho circles can be set without regard for loading levels. But here, as the calculated Load Encroachment blinder will plot well outside the 21 zone 2 mho circle, it will not block or cutout any portion of the mho circle and therefore will have no effect on the operation of the 21 algorithm. A simple load encroachment blinder setting of 115% of the machine full rated output at rated PF will allow some machine overloading without tripping, for example:

$$Load\ Encr.Angle = \mathrm{acos}(PF) = \mathrm{acos}(0.85) = 32\,°$$

$$Load\ Encr.R\ Reach = Zpu * Zbase * \frac{CTR}{VTR} = \frac{Vpu^2}{Spu} * \frac{Vbase^2}{Sbase} * \frac{CTR}{VTR} = \frac{1^2}{1.15} * \frac{19K^2}{700M} * \frac{5000}{158.3} = 14.2\ \Omega$$

However, to account for the field forcing that may occur during events that cause a depressed voltage and the corresponding increased level of VAR output to support the dip in the generator terminal voltage, PRC-025 Table 1 Relay Loadability Evaluation Criteria Option 1a may be used to calculate a more secure load encroachment reach (which will still not cut out any portion of the 21 zone 2 mho circle in this case):

$$LE = \frac{\left|\frac{\left(0.95 * Vhs\ nom * \frac{Vgen\ nom}{Vgsu\ hs\ tap}\right)^2}{1.15 * [(1.00 * Preport) + j(1.50 * PF * S)]}\right|}{cos(MTA - TLA)} = \frac{\left|\frac{\left(0.95 * 345K * \frac{19K}{353.6K}\right)^2}{1.15 * [(1.00 * 591.77M) + j(1.50 * 0.85 * 700M)]}\right|}{cos(89° - 46.5°)} = 9.4\ \Omega$$

(21 zone 2) – Phase Distance

Enable OverCurrent Supervision i.e. 50FD Fault Detector for zone 2 as well and set it to minimum as well for maximum sensitivity.

Set well below the minimum phase fault current (with some sensitivity margin) for all fault locations that this zone can reach. Here, use a GSU HS ΦΦ fault to calculate the fault current as this zone can reach past the GSU. So for a GSU HS ΦΦ fault, the generator can produce 26,844 A at 60 cycles (from the gen decrement curve assuming a flat start or 1pu voltage i.e. nominal voltage).

$$Iac(t) = (|Id"| - |Id'|) * e^{-\frac{t}{Td''}} + (|Id'| - |Id|) * e^{-\frac{t}{Td'}} + |Id| = 26{,}844\ Apri\ or\ \frac{26{,}844}{5000} = 5.4\ Asec$$

$$SF * Inom \leq Overcurrent\ SV < SM * min\, phase\ fault\ current$$
$$1.06 * 4.25 \leq Overcurrent\ SV < 0.50 * 5.4$$
$$4.5 \leq Overcurrent\ SV < 2.7$$

Overcurrent SV = 0.1 A (could set it to 4.5 A for added security, but decided to set it at minimum for max sensitivity)

(21 zone 2) – Phase Distance

To prevent false trips on recoverable swings: set 21 Z > 200% of gen MVA rating:

$$2 * Sg < MVA\ to\ trip$$

$$2 * Sg < \frac{Vg^2}{Z2reach * \frac{VTR}{CTR}}$$

$$2 * 700 < \frac{19^2}{2.0 * \frac{158.3}{5000}}$$

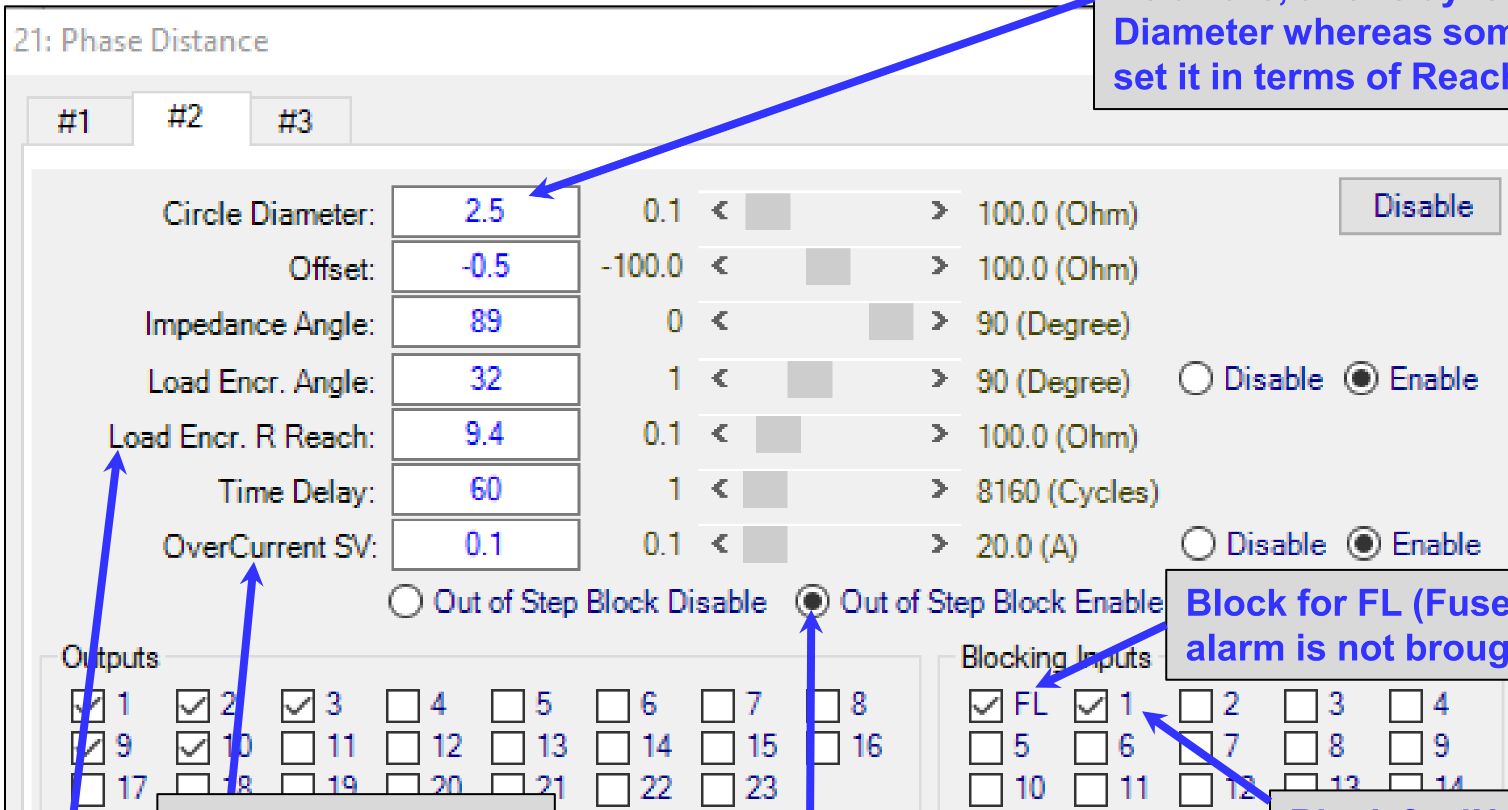
$1400\ MVA < 5701\ MVA$ Therefore, yes the selected Z2reach does abide by this criterion.

Calculate the % of the stator winding that is protected by this reach (use the transient reactance considering that the generator subtransient time constant period will have expired before the Z2 time delay is reached):

$$\frac{\frac{Z2reach}{Zbase} * \frac{VTR}{CTR}}{Xd'} * 100 = \frac{\left(\frac{2.0}{\frac{19^2}{700}}\right) * \frac{158.3}{5000}}{0.295} * 100 = 42\%, Z2\ sees\ this\ percentage\ into\ the\ gen\ transient\ reactance$$

The zone 2 reach will actually see < this percentage as the generator reactance will act like a value > Xd' at 1 second. Solving the generator decrement curve equation at 1 second for a HS 3Φ fault as seen by a relay on the LS, gives a reactance of 24752/21271 = 1.16 pu which in fact only sees 11% into the stator winding.

(21 zone 2) – Phase Distance



Be aware, this relay is set in terms of Diameter whereas some other mfgs may set it in terms of Reach (from origin).

Block for FL (Fuse Loss) unless 60FL alarm is not brought back to dispatch

Set 50FD for additional security

Block for IN1 (open breaker) for added security unless pre-synch protection is required

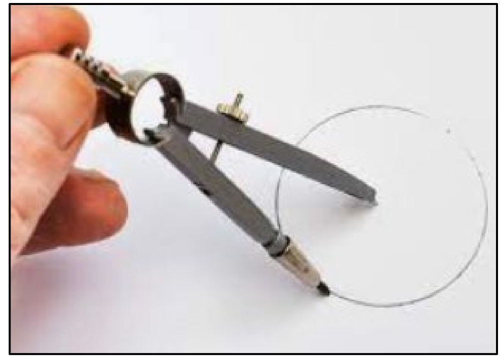
May need Load Encroachment Blinder for long lines

Enable Out Of Step Block to block zone 2 for power swings if using zone 3 for 68/OSB

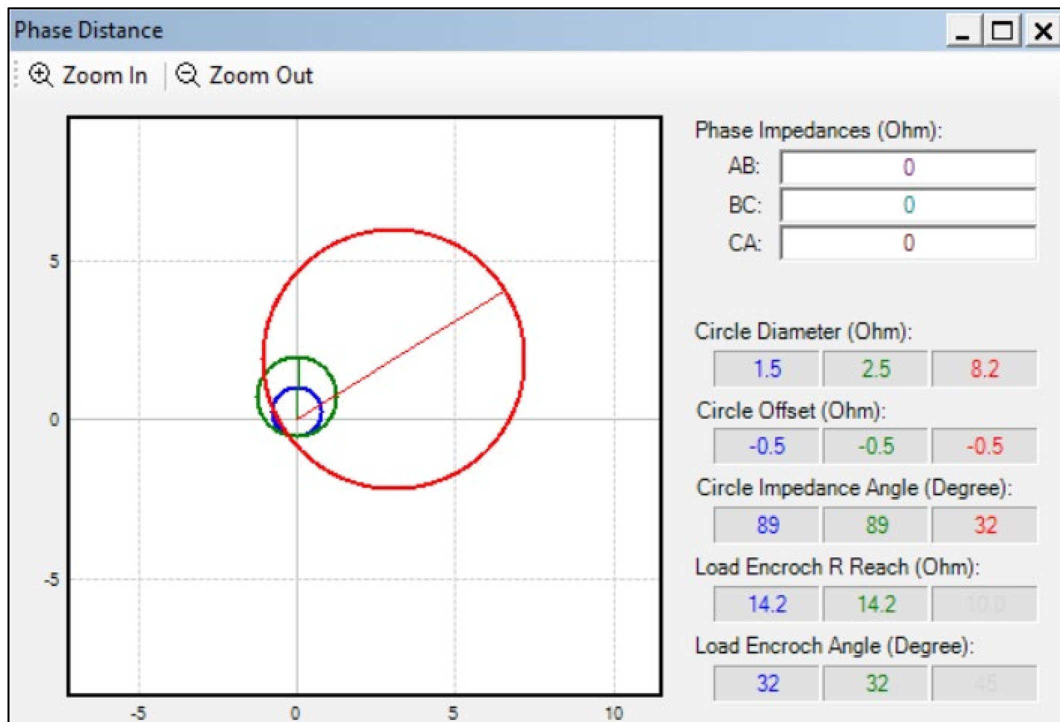
21 – Phase Distance

SIDEBAR: How can we plot these 21 MHO circles?

- Old school method:



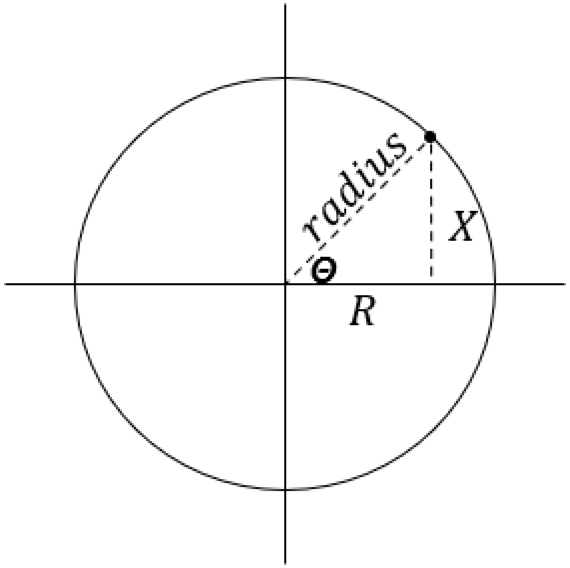
- Some relay mfg software shows a plot of the mho circle settings on an RX diagram as well:



21 – Phase Distance

SIDEBAR continued:

- Or can plot it via Mathcad or Excel or some other tool.
- Here, an example **using Excel** will be demonstrated for the Zone 2 MHO circle:



Use equations:

- $R = radius * Cos(\Theta) + R\ circle\ center$
- $X = radius * Sin(\Theta) + X\ circle\ center$
- $radius = \frac{Diameter}{2} = \frac{2.5}{2} = 1.25\ \Omega\text{sec}$
- $\Theta = 0° \text{ thru } 360°$
- $R\ circle\ center = radius * Cos(\text{Z2ANG}) = 1.25 * Cos(89°) = 0.021816\ \Omega\text{sec}$
- $X\ circle\ center = radius * Sin(\text{Z2ANG}) + Offset = 1.25 * Sin(89°) + -0.5 = 0.74981\ \Omega\text{sec}$

21 – Phase Distance

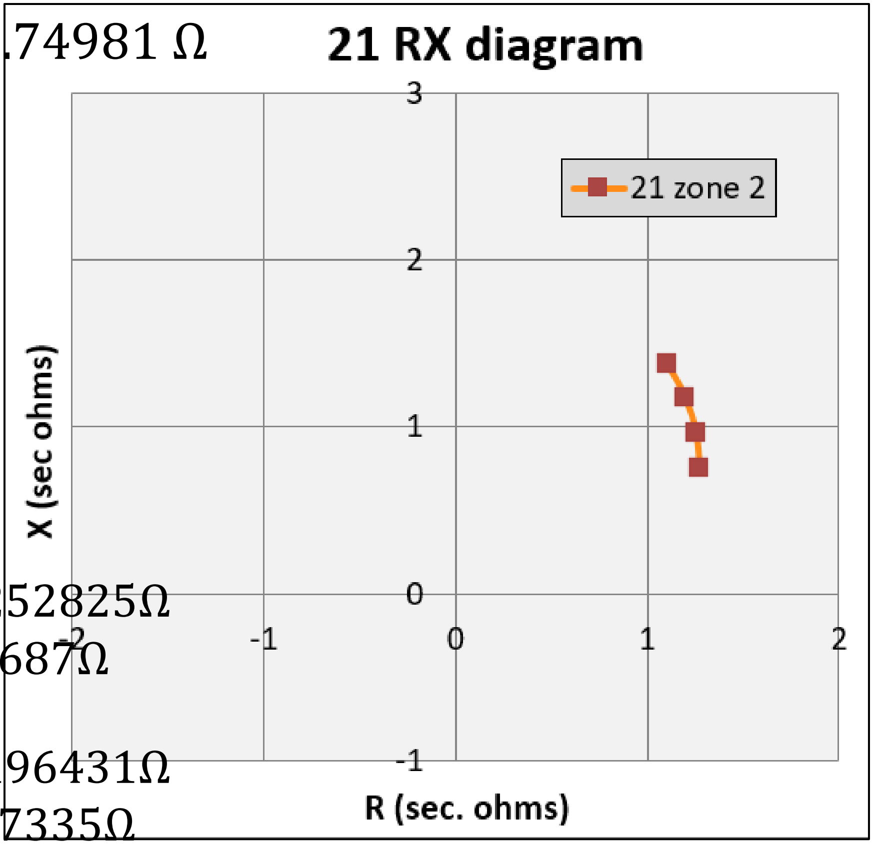
SIDEBAR continued:

- $Rpoint1 \ = 1.25 * Cos(0°) + 0.021816 = 1.271816\ \Omega$
- $Xpoint1 \ = 1.25 * Sin(0°) + 0.74981 = 0.74981\ \Omega$

- As entered in Excel:

- $R = \$G\$7 * COS(RADIANS(A16)) + \$J\$7$
- $X = \$G\$7 * SIN(RADIANS(A16)) + \$J\$8$

- Then just redo this up to 360° to make a complete circle.

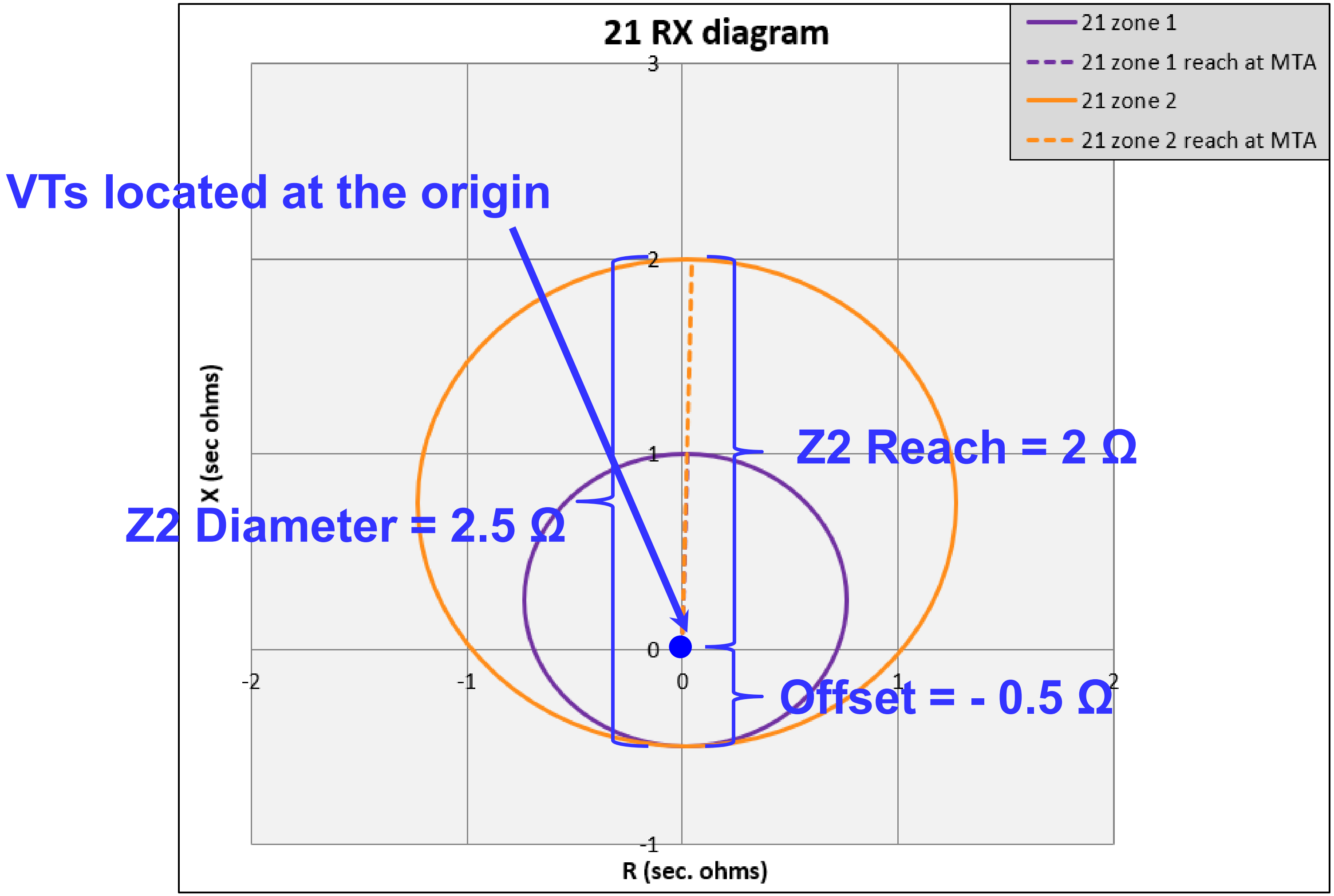


- $Rpoint2 \ = 1.25 * Cos(10°) + 0.021816 = 1.252825\Omega$
- $Xpoint2 \ = 1.25 * Sin(10°) + 0.74981 = 0.96687\Omega$

- $Rpoint3 \ = 1.25 * Cos(20°) + 0.021816 = 1.196431\Omega$
- $Xpoint3 \ = 1.25 * Sin(20°) + 0.74981 = 1.177335\Omega$

- $Rpoint4 \ = 1.25 * Cos(30°) + 0.021816 = 1.104347\Omega$
- $Xpoint4 \ = 1.25 * Sin(30°) + 0.74981 = 1.37481\Omega$

Now plot both 21 zone 1 and zone 2 MHO circles and MTAs:



But why do the 21 MHO circles need to be plotted? To check security and coordination with GCC and verify compliance with PRC-025 & 026.

21 Zone 3 – example if using zone 3 for 68 OSB

- Could use zone 3 as an additional tripping zone or an out of step blocking zone if zone 2 sees into the transmission system.
- Here, OSB is set for demonstration purposes.
- OSB is used to discriminate between power swings and faults when the electrical center of a swing could enter zone 2.
- This will prevent unwanted zone 2 trips for power swings.
- OSB Delay is the transit time of the swing locus between zone 3 and zone 2.
- The OSB Delay timer starts timing when the swing locus enters zone 3. If it expires before the locus enters zone 2, the relay qualifies it as a power swing condition and therefore blocks the zone 2 trip.

21 Zone 3 – use for 68 OSB

- OSB settings should be informed by a transient stability study.
- Absent that, here for these sample settings, set the zone 3 diameter equal to half the Z of a max load current of 4.25 A at 120 V_{LL} rated voltage at a load angle of the PF of 0.85 or 32°.

$$\text{Zone 3 Circle Diameter} = 0.50 * \frac{\text{VLG}}{\text{I}} = 0.50 * \frac{69.3}{4.25} = 8.2 \text{ sec ohms}$$

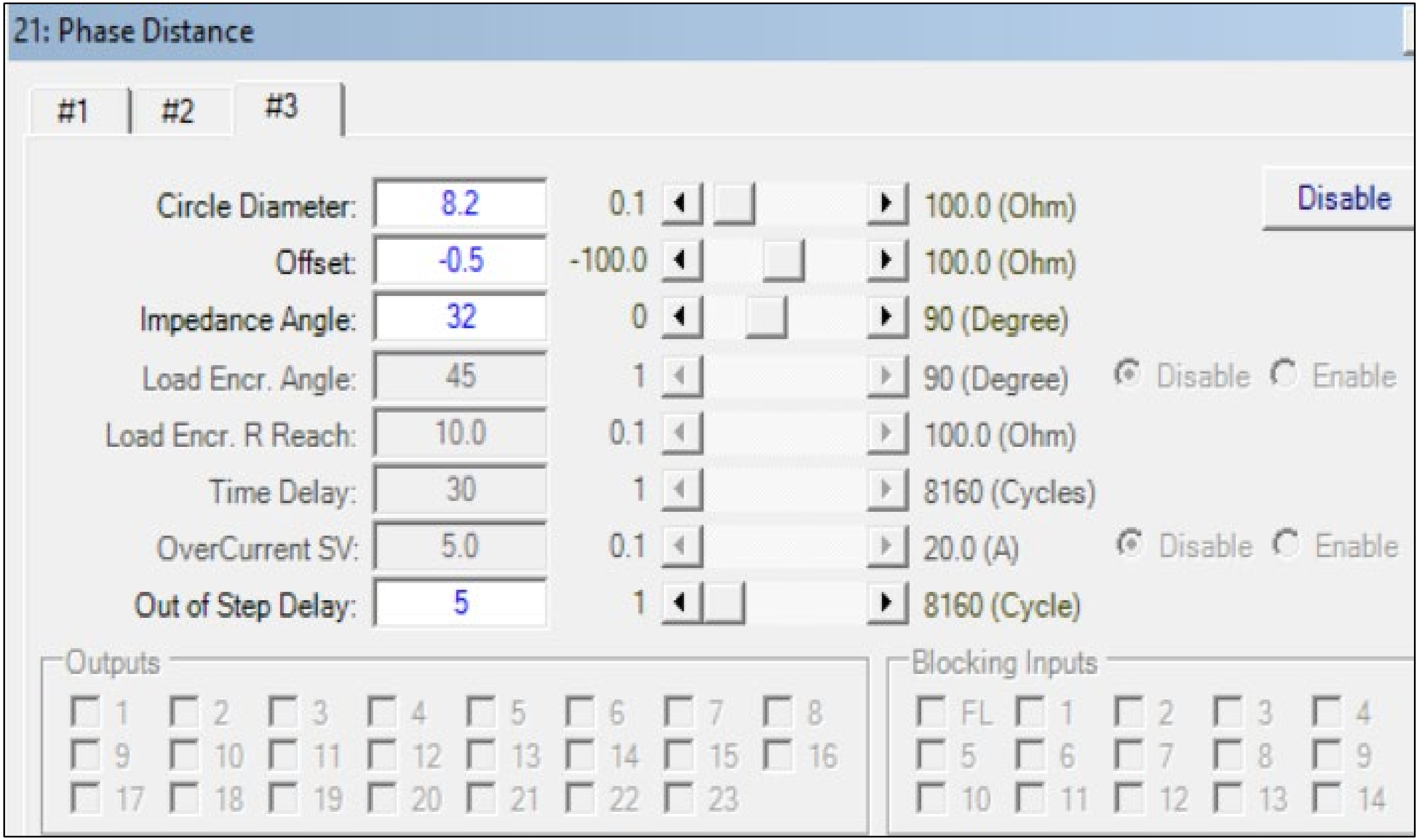
$$\text{Impedance Angle } = \cos^{-1} \text{PF} = \cos^{-1} 0.85 = 32°$$

Assume a stable swing freq of 2 Hz and approximating the transfer impedance angles:

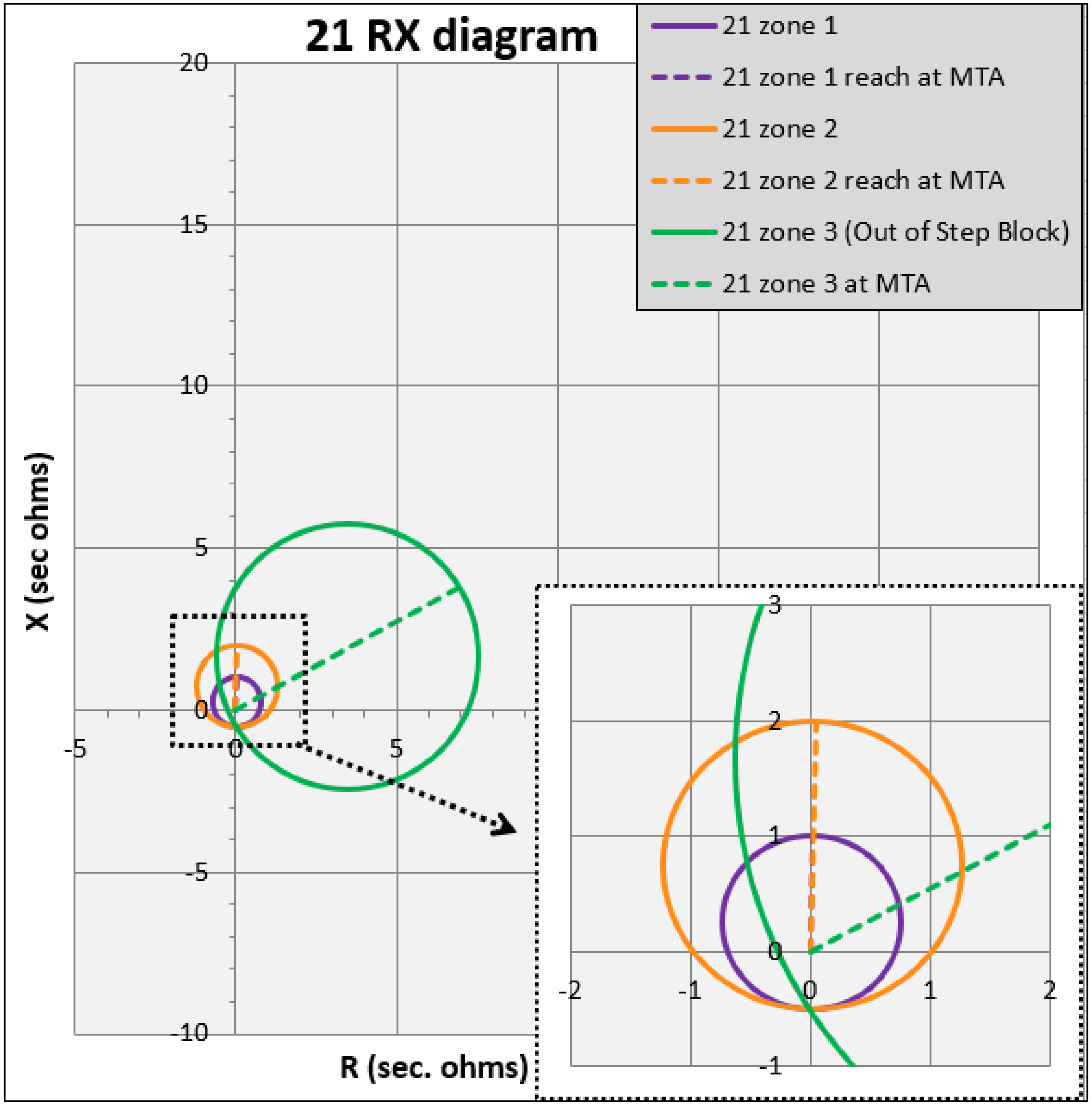
$$\text{OSB Delay} =$$

$$\frac{(\text{Z2 xfr impedance angle} - \text{Z3 xfr impedance angle}) * \text{fnom}}{\frac{360°}{\text{cycle}} * \text{fslip}} = \frac{(120° - 60°) * 60}{\frac{360°}{\text{cycle}} * 2} = 5 \text{ cyc}$$

(21 zone 3) – Phase Distance – set as OSB



Plot all 3 zones



21 Phase Distance

Evaluate settings against PRC-025 and PRC-026

PRC-025-2

Generator Relay Loadability

Check load responsive relay settings against criteria:

- Generator Protection
  - **21**
  - 51V
  - 50
  - 50DT

- ***21 is a load dependent function***
- ***As load increases, if 21 is set too sensitive or fast, a nuisance trip may result***

- GSU Transformer Protection
  - high side 50
  - high side 51

Load Dependent Relays

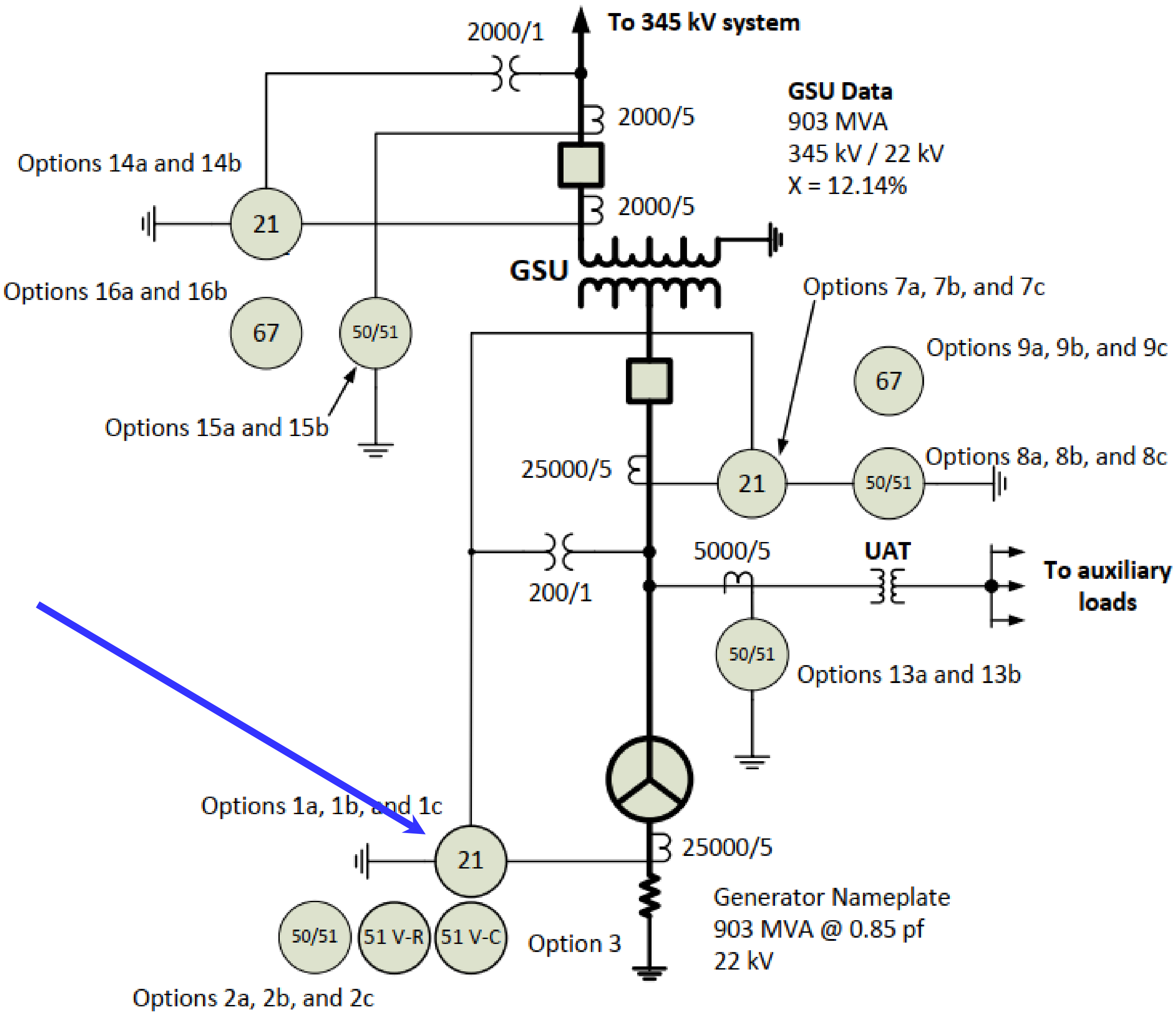


Figure 5: Relay Connection for corresponding synchronous options

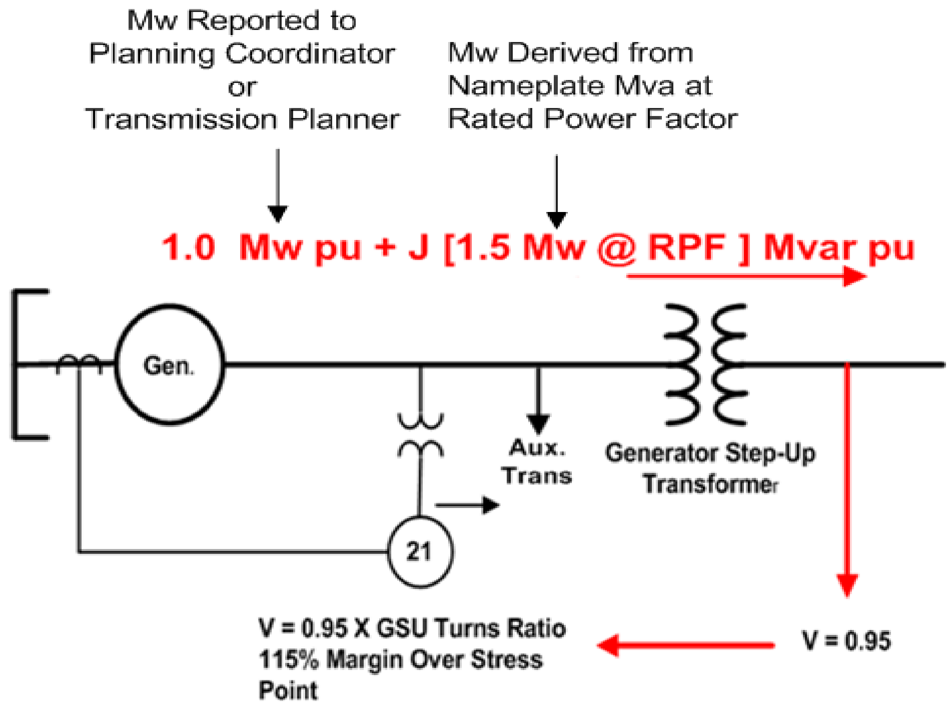
PHASE BACKUP (21) SETTING CRITERIA: OPTIONS – PRC -025-2

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation

PRC-025 Option 1a – 21 Settings Loadability Criteria:

1-Line representation of criteria 1a



Inequality Equation representation of criteria 1a

$$Z_{2\ reach} < \frac{\left| \frac{\left(0.95 * Vhs_{nom} * \frac{V_{gen\ nom}}{V_{gsu\ hs\ tap}}\right)^2}{1.15 * [(1.00 * P_{reported}) + j(1.50 * PFrated * S)]} \right|}{\cos(MTA - TLA)}$$

$2.0\ \Omega < 9.4\ \Omega$, therefore yes compliance is verified

21 settings compliance check against PRC-025-02:

Using Inequality Equation:

Table 1 Option 1a - M-3425A 21 function

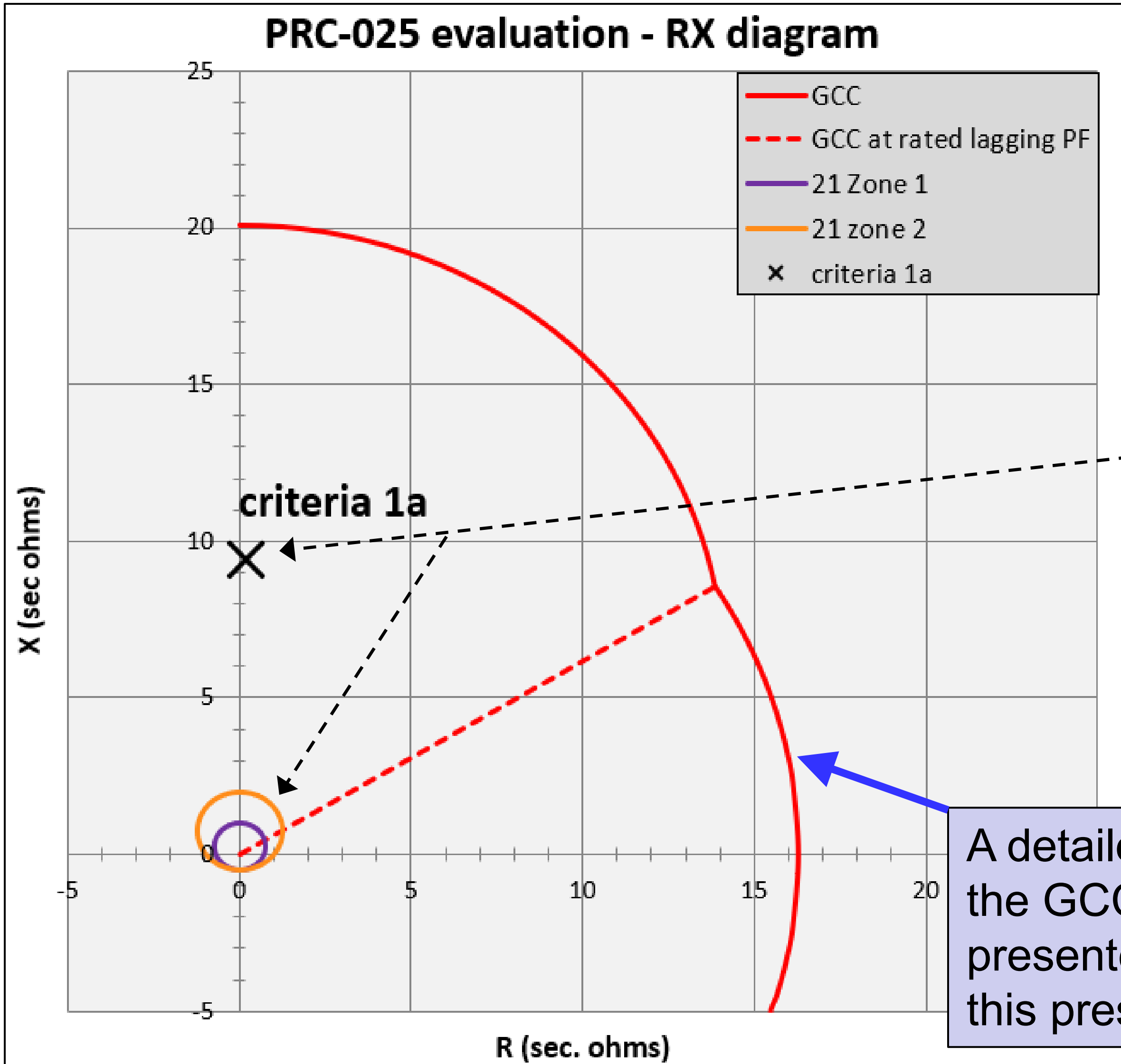
Z2dia	2.5	sec ohms	Z2offset	-0.5	sec ohms
Z2ANG	89	degrees	Z2reach =	2.0	
Zpri =	0.1600490312	pri ohms			
Zsec =	5.0552441954	sec ohms			
|Zsec| =	9.148	sec ohms			
arg(Zsec) =	56.45	degrees			
Zseclimit =	4.3958645178	sec ohms			
|Zseclimit| =	7.955	sec ohms			
arg(Zseclimit) =	56.45373	degrees, transient load angle			
Zmax =	9.437	sec ohms			
Z2reach < Zmax	TRUE	therefore, yes this complies with standard			

NOTE:

- ***setting is in diameter***
- ***Criteria check is against the reach***

21 settings compliance check against PRC-025-02:

plotted on RX Diagram with GCC for visual verification:



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

Yes

- Therefore, 21 Zone-1 and Zone-2 settings comply with PRC-025-02

A detailed description of how to plot the GCC on an RX diagram will be presented in the 40 settings section of this presentation.

PRC-026-1

Relay Performance during Stable Power Swings.

Criterion A: 21, 40, and 78 (within blinders) must be completely contained within the unstable power swing region (lens, upper and lower loss of synchronism circles, shaded area) or have time delay ≥ 15 cycles.

Criterion B: 50,51 pickup must be > criteria or have time delay ≥ 15 cycles.

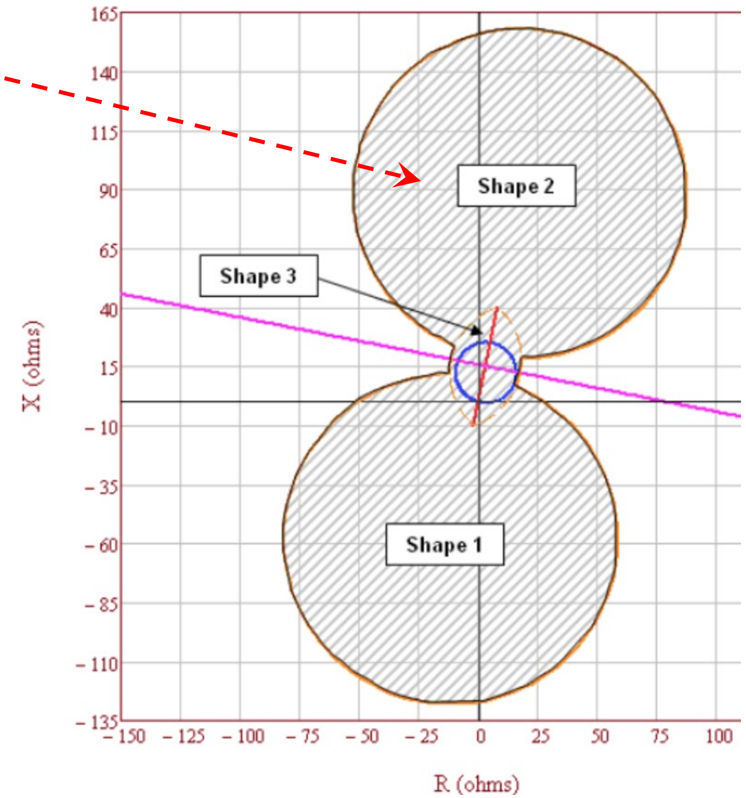
Evaluate the relay settings against criterion:

Generator Protection

- **21**
- 40
- 78
- 50
- 50DT

GSU Transformer Protection

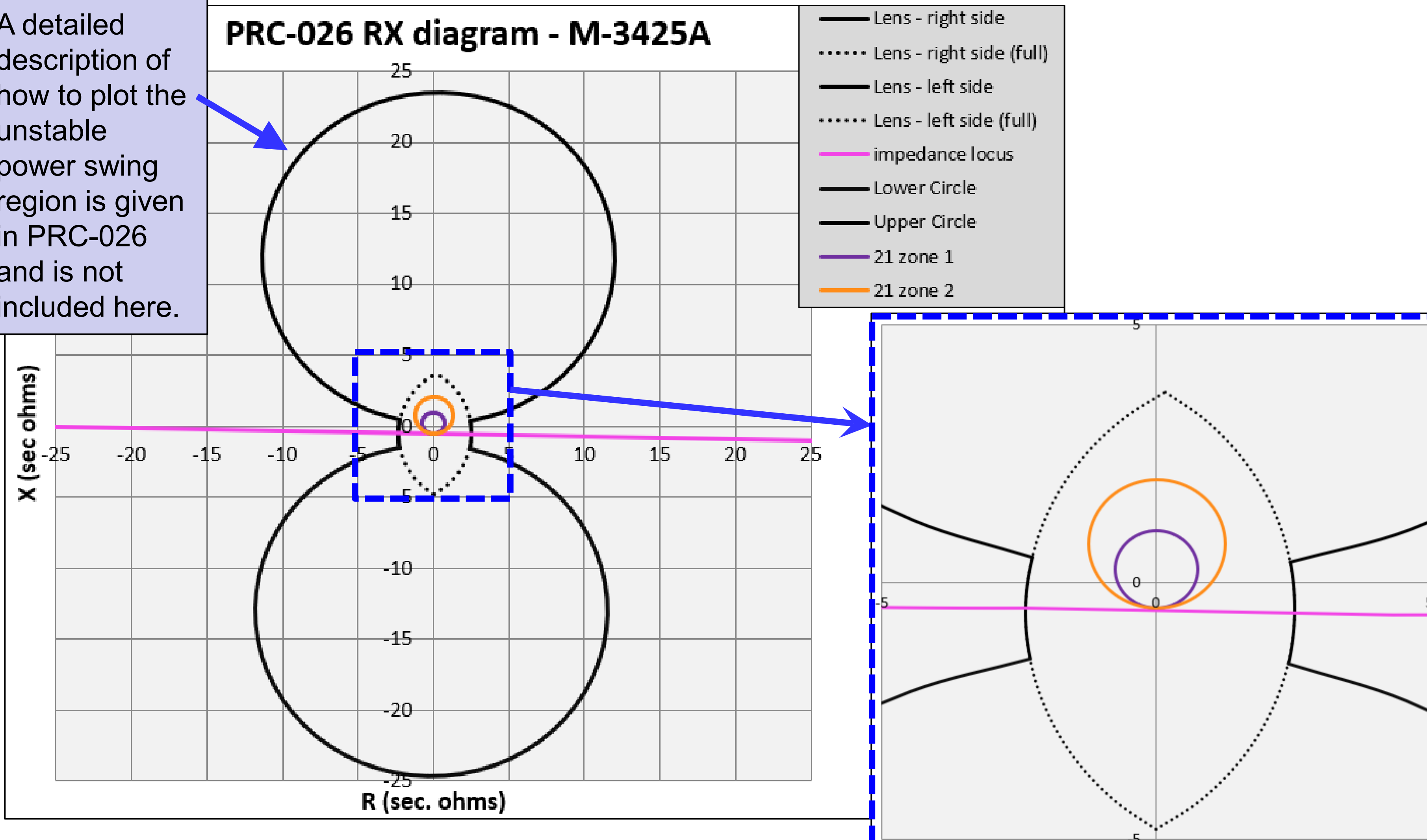
- high side 50
- high side 51



PRC-026-1

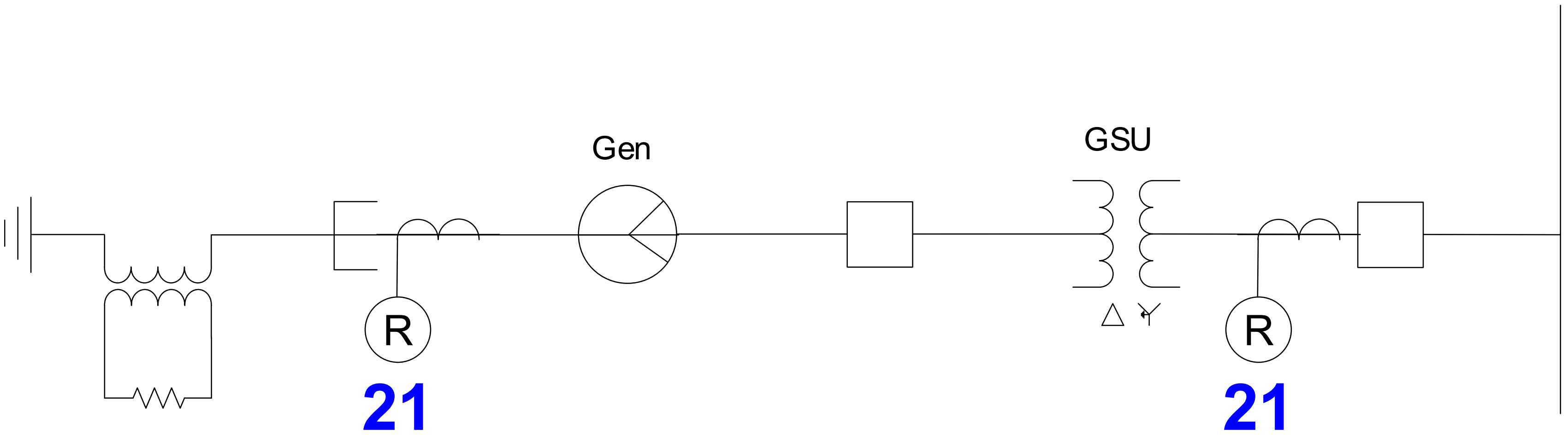
Plot of the 21 mho circles on an RX diagram along with the unstable power swing region impedance locus criteria for this application shows the Zone 1 and Zone 2 mho circles are inside the unstable region and the time delay settings of 21 are ≥ 15 cycles. Complies with PRC-026-1.

A detailed description of how to plot the unstable power swing region is given in PRC-026 and is not included here.



PRC-027

- Coord gen 21 with transmission line 21.



- Gen 21 zone 2 can reach 50% into the one-mile-long export transmission line.
- Export line has 87L and 21 mirrored bits via fiber, both with 21 backup w/o comms.
- For a phase fault at end of export line w/o comms, check:

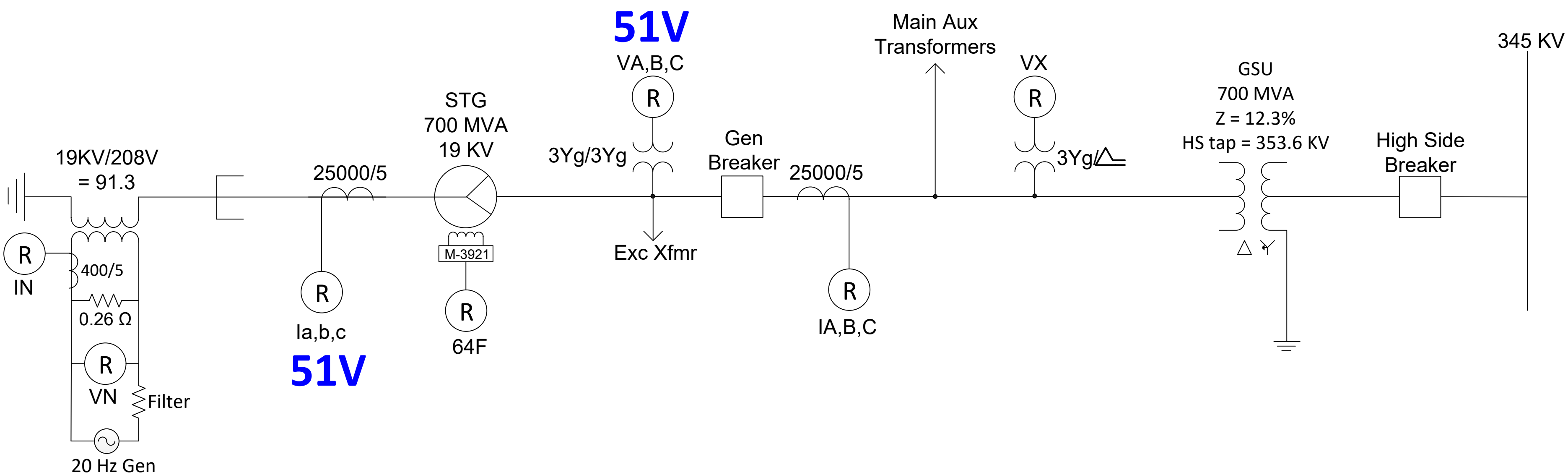
is transmission line relaying clearing time < gen 21 clearing time

is line 21 zone 2 time + HS breaker BF time < Gen 21 zone 2 time delay?

18 cycles + 5 cycles < 60 cycles

23 cycles < 60 cycles **YES, complies**

51V – Voltage R/C Inverse Time Overcurrent



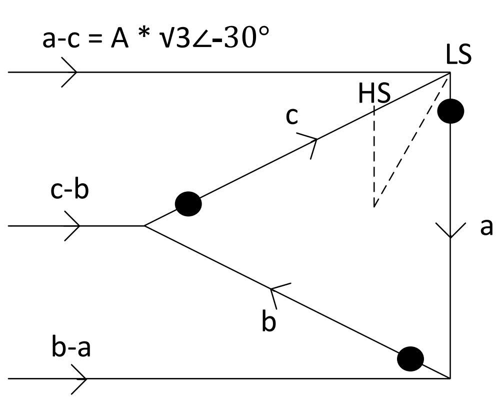
Blocking Inputs = 1

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

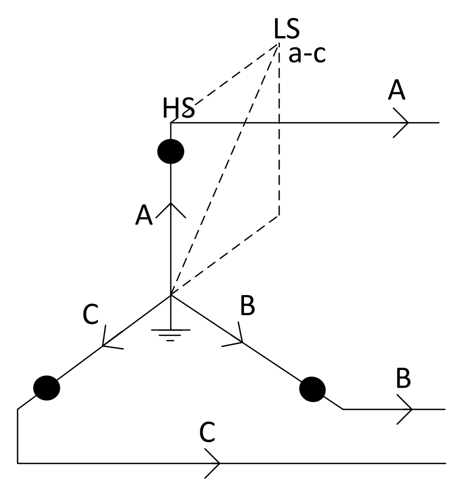
51V – Voltage R/C Inverse Time Overcurrent

51V will see faults on the HS of the GSU (even though the currents and voltages used in the 51V algorithm are measured on the low side of the GSU) as such:

Generator Directly Connected			Generator Connected Through Delta AB/Wye or Delta AC/Wye Transformer		
Current	Voltage Control or Restraint		Current	Voltage Control or Restraint	
	L-G	L-L or L-G to L-L		L-G	L-L or L-G to L-L
I_a	$(V_A - V_C)/\sqrt{3}$	V_{AB}	I_a	V_A	$(V_{AB} - V_{CA})/\sqrt{3}$
I_b	$(V_B - V_A)/\sqrt{3}$	V_{BC}	I_b	V_B	$(V_{BC} - V_{AB})/\sqrt{3}$
I_c	$(V_C - V_B)/\sqrt{3}$	V_{CA}	I_c	V_C	$(V_{CA} - V_{BC})/\sqrt{3}$



LS = Dac



HS = Y

51V – Voltage R/C Inverse Time Overcurrent

51V has (3) options for its method of Voltage Control:

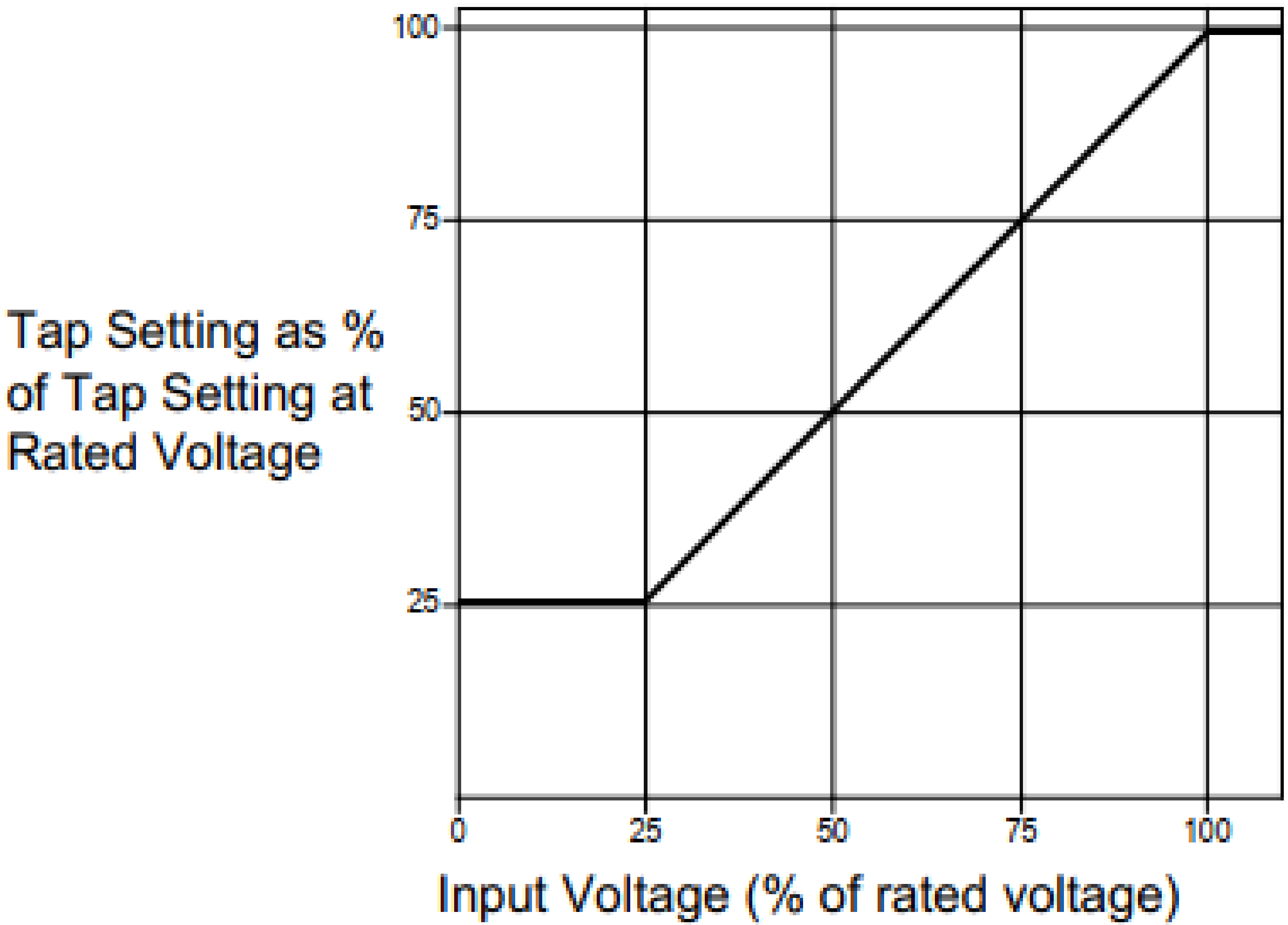
1. Disable
   - No voltage supervision of the 51V function.
   - Functions as a normal 51 relay.

2. Voltage Control
   - Armed when the measured voltage drops below the Voltage Control setpoint.
   - Typically, set VC Pickup to 75% of Vnom.
   - Set Current Pickup < Inom (e.g., if Id < Inom, set to approx. 50% of Id).
   - May block for blown fuse.

3. Voltage Restraint
   - Set Current Pickup > Inom (150% to 300%) – must abide by PRC-025 criteria.
   - No need to block for FL as current pickup remains at 100% for a FL condition.
   - The Pickup of the current element decreases in proportion to measured voltage.

51V – Voltage R/C Inverse Time Overcurrent

Here for these sample settings, use Voltage Restraint:



51V – Voltage R/C Inverse Time Overcurrent

Choose 51V Pickup per PRC-025 criteria Table 1 Option 2a (as shown later):

Set 51V Pickup = 8.10 Asec at 100% voltage (191% of Nominal Current)

*8.10 * 5000 = 40,500 Apri at 100% voltage*

*0.25 * 40500 = 10,125 Apri at 25% voltage*

10,125/5000 = 2.025 Asec at 25 % voltage

51V – Voltage R/C Inverse Time Overcurrent

Choose a flat curve (IEEE U1 Moderately Inverse) and select a TD such that it will trip in 1 second for a ΦΦ fault on the HS of the GSU assuming 25% depressed voltage. The generator contribution into a ΦΦ fault on the HS of the GSU at 1 second from the generator decrement curve equation is the following:

$$\mathrm{Iac(t)} = 0.866 * \left[(|\mathrm{Id}''| - |\mathrm{Id}'|) * e^{-\frac{t}{\mathrm{Td}''}} + (|\mathrm{Id}'| - |\mathrm{Id}|) * e^{-\frac{t}{\mathrm{Td}'}} + |\mathrm{Id}|\right] = 0.866 * 24{,}752 = 21{,}435\ \mathrm{Apri}$$

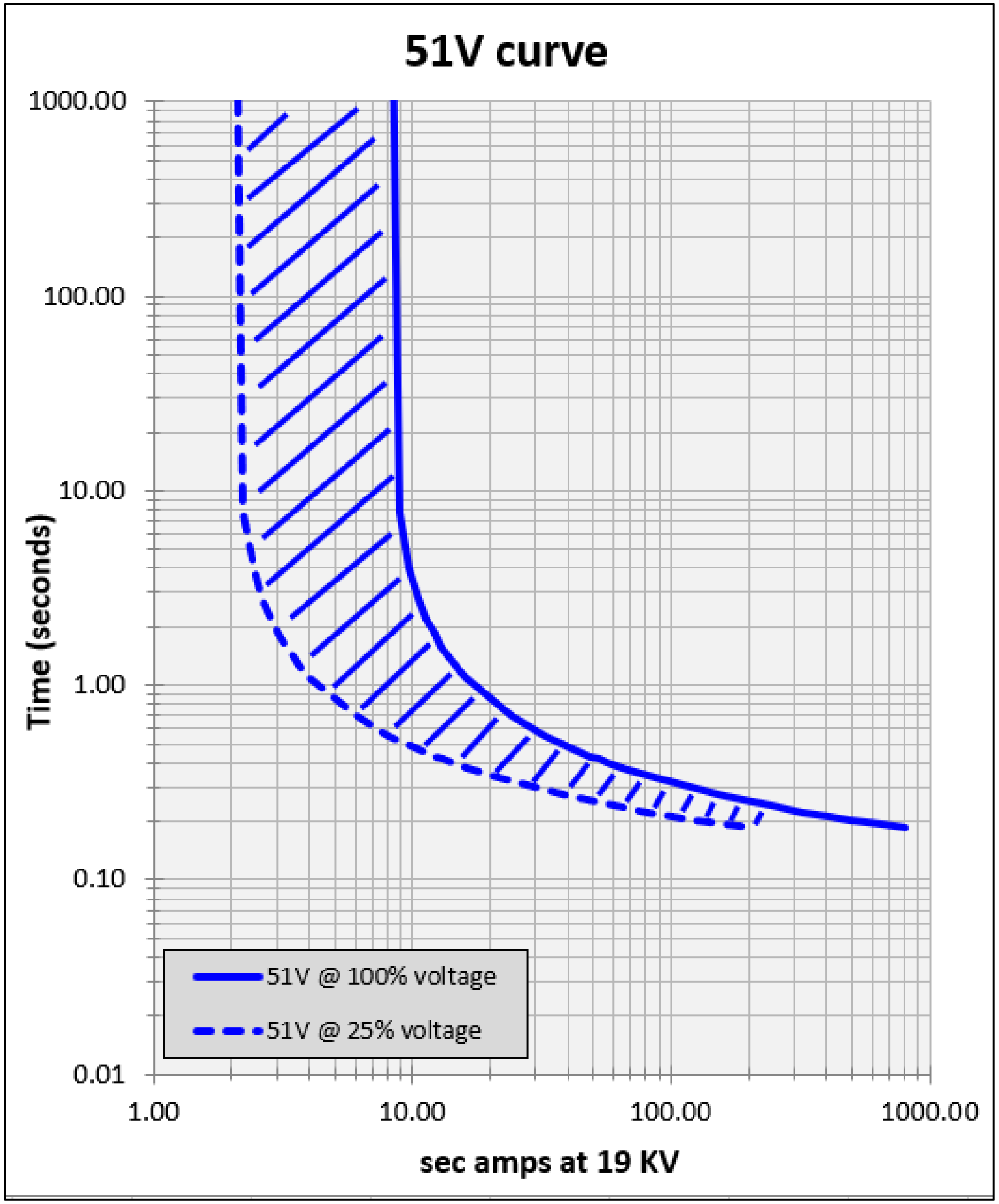
Using the IEEE Moderately Inverse curve equation and solving for the TD at 1 second:

$$\mathrm{TD} = \frac{5 * t}{\frac{0.0515}{M^{0.02} - 1} + 0.114} = \frac{5 * 1}{\frac{0.0515}{\left(\frac{21435}{10125}\right)^{0.02} - 1} + 0.114} = 1.4$$

- $M = \frac{\text{gen contribution into a ΦΦ fault on the HS of the GSU}}{\text{51V Pickup at 25\% voltage}}$

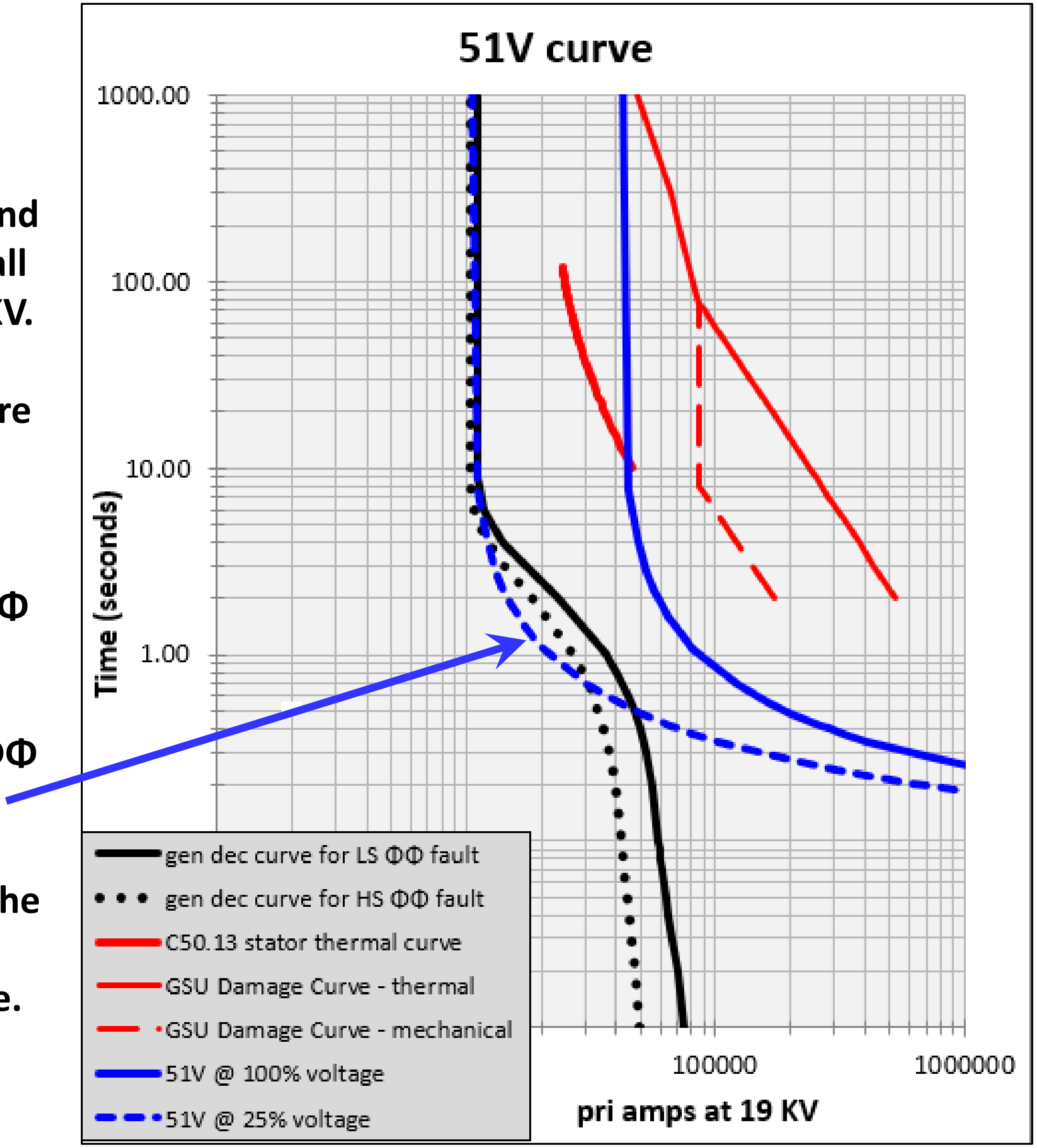
Voltage Control/Restraint Overcurrent (51V)

- **Plot these calculated 51V settings at 100% voltage and 25% voltage, where 51V can operate anywhere in-between i.e. in the cross-hatched area.**

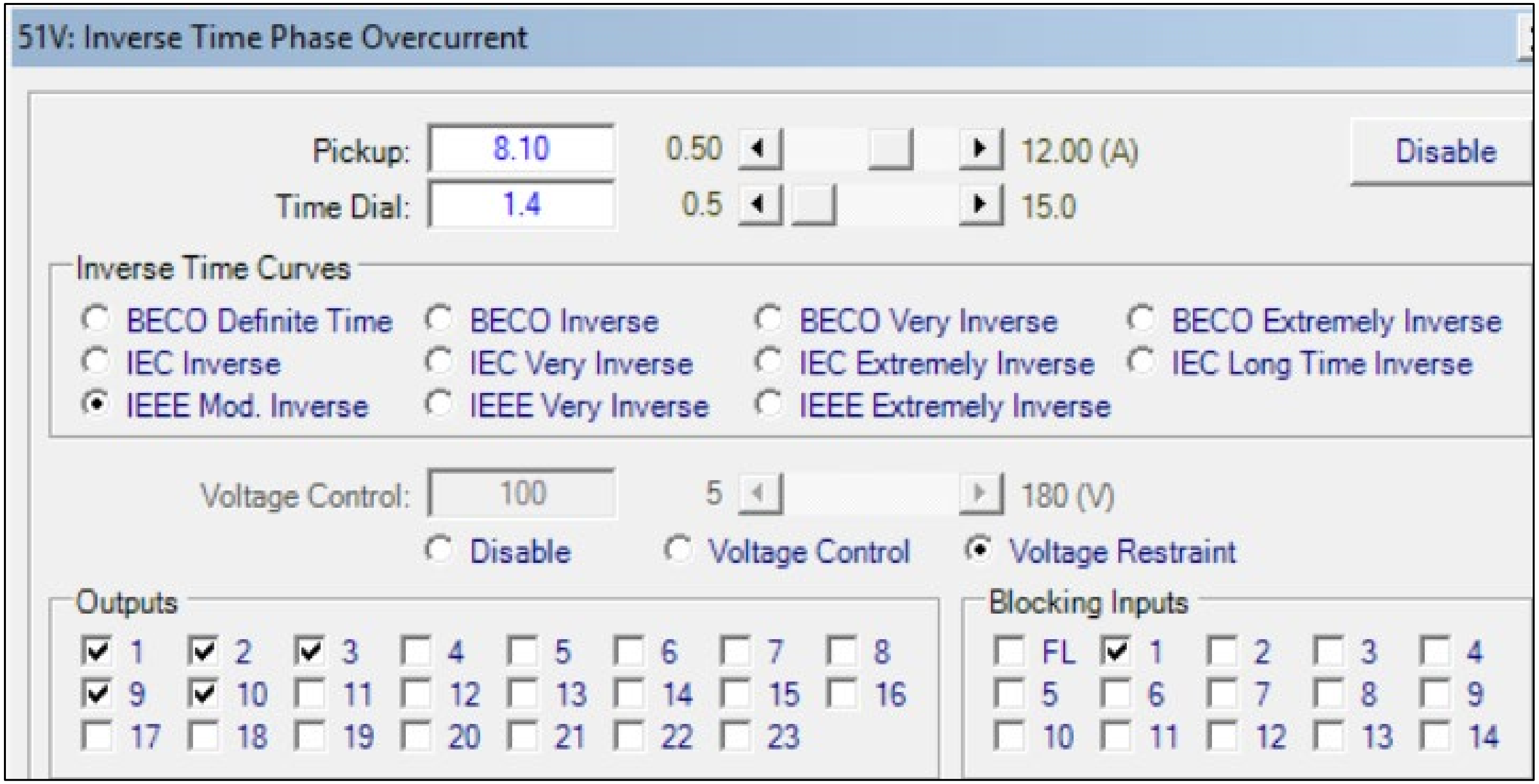


Voltage Control/Restraint Overcurrent (51V)

- Now plot the 51V curves along with the GSU damage curve, the stator thermal overload curve, and the generator decrement curve all in terms of primary amps at 19 KV.
- 51V at 100% voltage is very secure and it will not see any faults but protects the GSU damage curve.
- 51V at 25% voltage will see LS ΦΦ faults at times > 0.48 seconds.
- 51V at 25% voltage will see HS ΦΦ faults between 0.7 to 4 seconds.
- 51V at 25% voltage will protect the C50.13 stator thermal overload curve and the GSU damage curve.



Voltage Control/Restraint Overcurrent (51V)



- Enable Voltage Restraint
- Do not need to select blocking on VT fuse loss when Voltage Restraint is selected as the relay will keep the 51V pickup at 100% during a blown fuse.
- This is specific to Beckwith relays. Other mfgs may require blocking.
- FL blocking is however required if Voltage Control is selected.

51V Voltage Restrained/Controlled Inverse Time Phase Overcurrent

Evaluate settings against PRC-025

PRC-025-2

Generator Relay Loadability

Check load responsive relay settings against criteria:

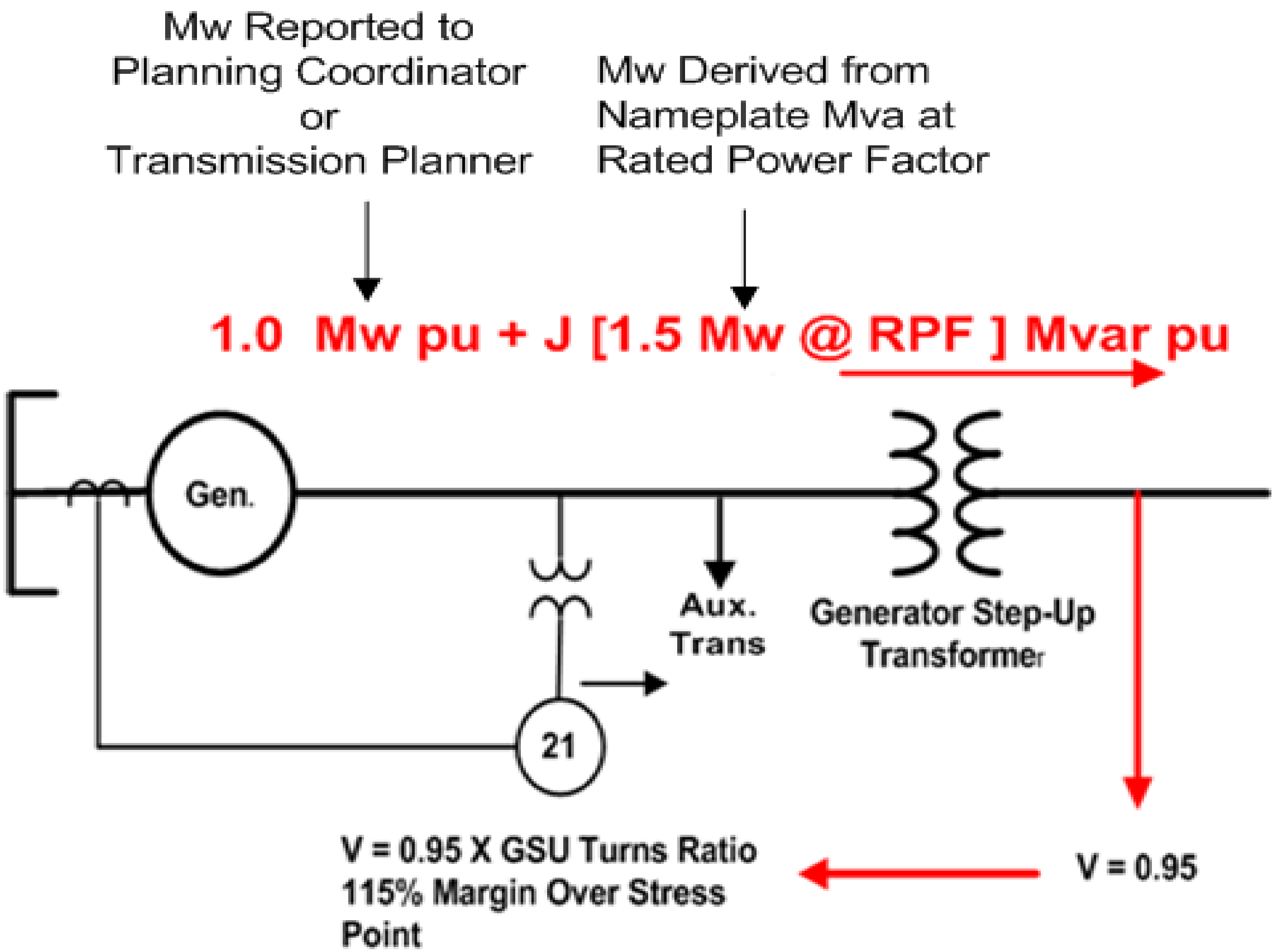
- Generator Protection
    - 21
    - **51V**
    - 50
    - 50DT
- GSU Transformer Protection
    - high side 50
    - high side 51

51VR/51VC SETTING CRITERIA: PRC-025-2

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

PHASE BACKUP (51VR) SETTING CRITERIA: OPTIONS # 2a – PRC-025-2



PHASE BACKUP (51VR) SETTING CRITERIA: OPTIONS # 2a – PRC-025-2

Input Data

Sbase	700	MVA, Gen Nameplate Rating
PF	0.85	
Psynch_reported	591.77	MW (typically different than just S*PF)
CTRgen	5000	
PTRgen	158.3	
Vgen_nom	19	KV
Vhs_nom	345	KV
Vgsuhstap	353.6	KV
CTRgsuhs	240	

Common Calculations

P =	595	MW
Q =	892.5	MVAR
Vgen =	17.611	KV
S =	591.77+892.5j	MVA
|S| =	1070.86	MVA
arg(S) =	56.45	degrees

$$set\ 51V\ Pickup > \text{PRC 025 Table 1 Option 2a} = \frac{1.15 * |\vec{S}|}{\sqrt{3} * Vgen * CTR} = 8.075\ A$$

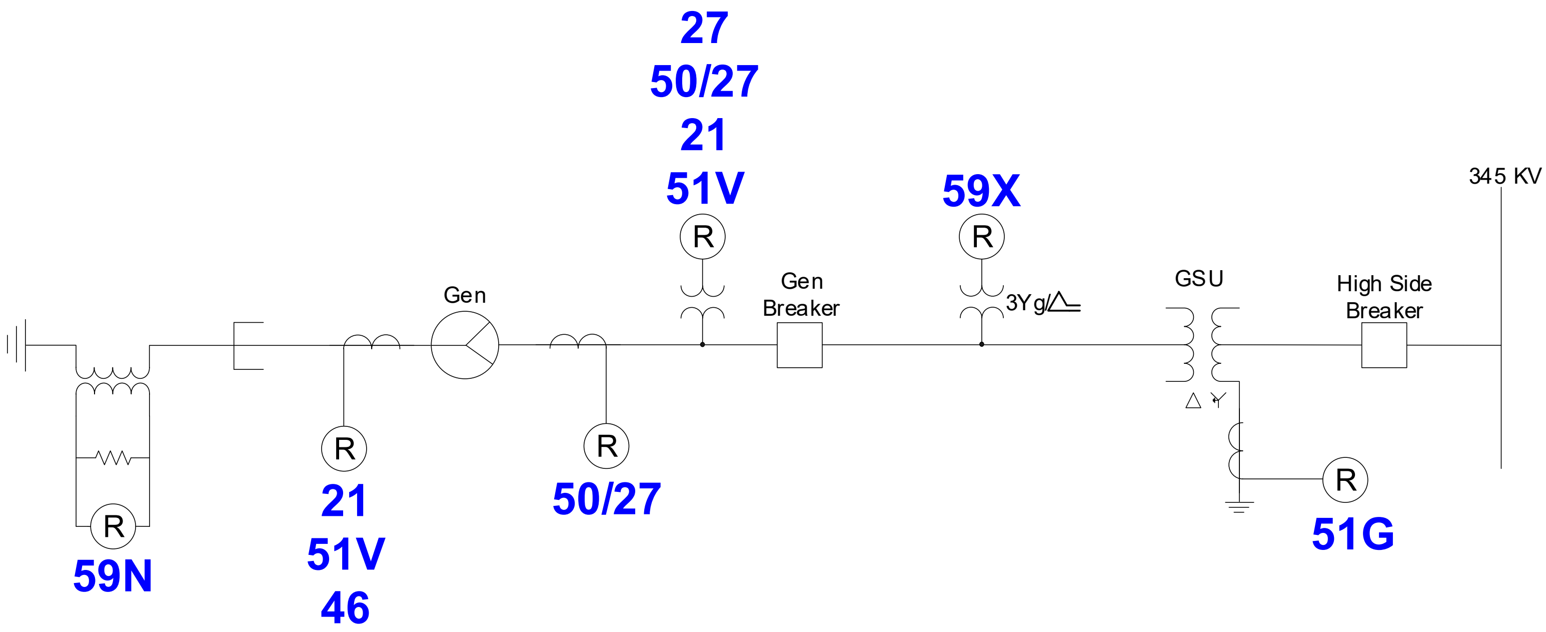
- $|\vec{S}| = |Psynch_{reported} + jQ| = 1070.86\ MVA$
  - ✓ $Psynch_{reported} = 591.77\ MW$
  - ✓ $Q = 1.50 * Prated = 1.50 * (Sbase * PF) = 1.50 * (700 * 0.85) = 892.5\ MVAR$
- $Vgen = 0.95 * VbaseHS * \frac{Vbasegen}{VgsuHStap} = 0.95 * 345\ K * \frac{19\ K}{353.6\ K} = 17.611\ KV$

PRC-025: Table 1 Option 2a - M-3425A 51V function

51V Pickup =	8.10	sec amps
Ipri =	35107	pri amps
Isec =	7.021	sec ohms
1.15*Isec =	8.075	sec ohms
51V Pickup > 1.15*Isec	TRUE	therefore, yes this complies with standard

PRC-027

- Coord 51V with voltage dips from transmission line faults.



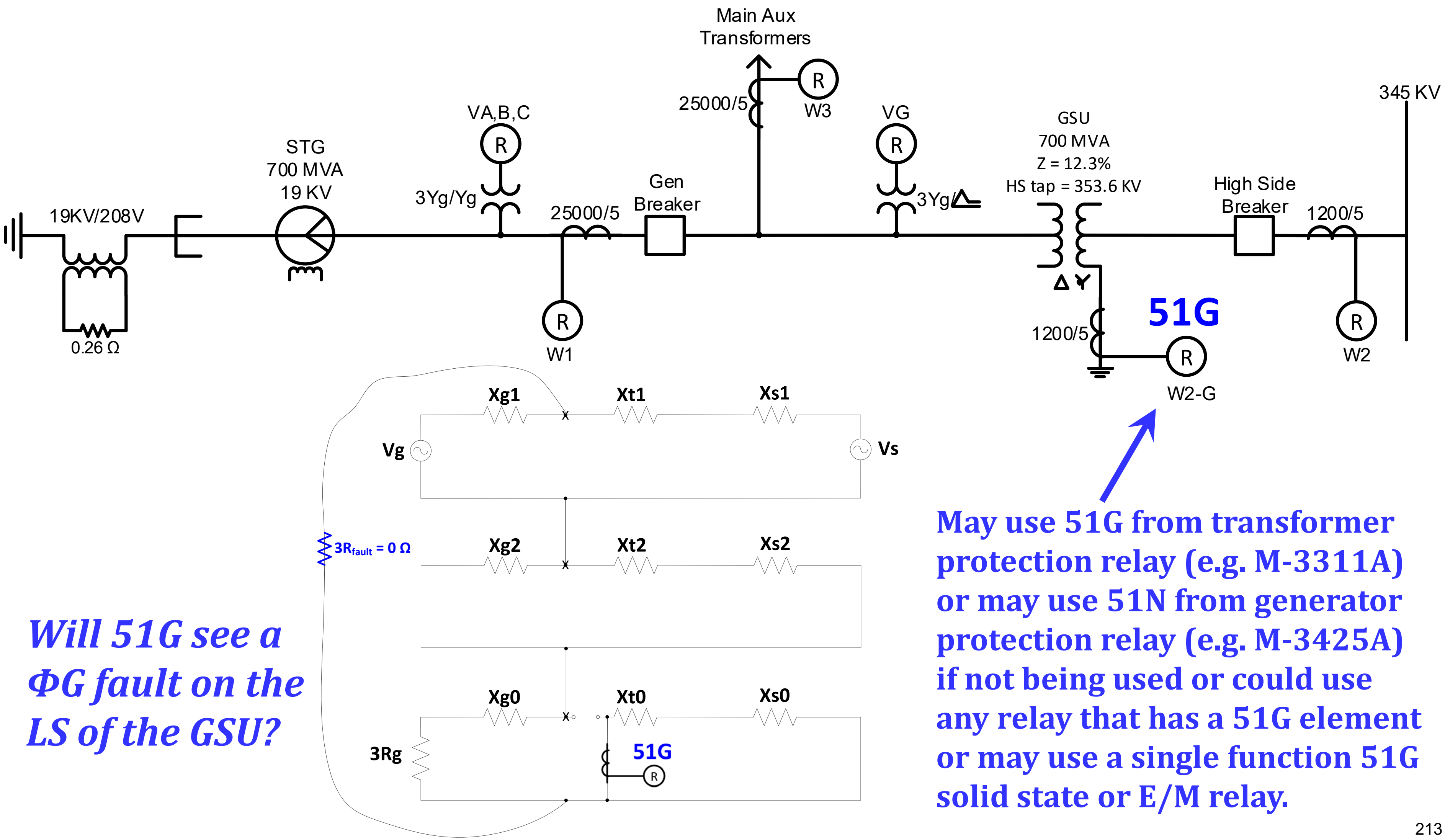
- 51V at 25% voltage will see HS ΦΦ faults between 0.7 to 4 seconds.
- All transmission line relaying clears well before this (longest is 23 cycles).
- Therefore YES, complies

System Backup Protection for Ground faults

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

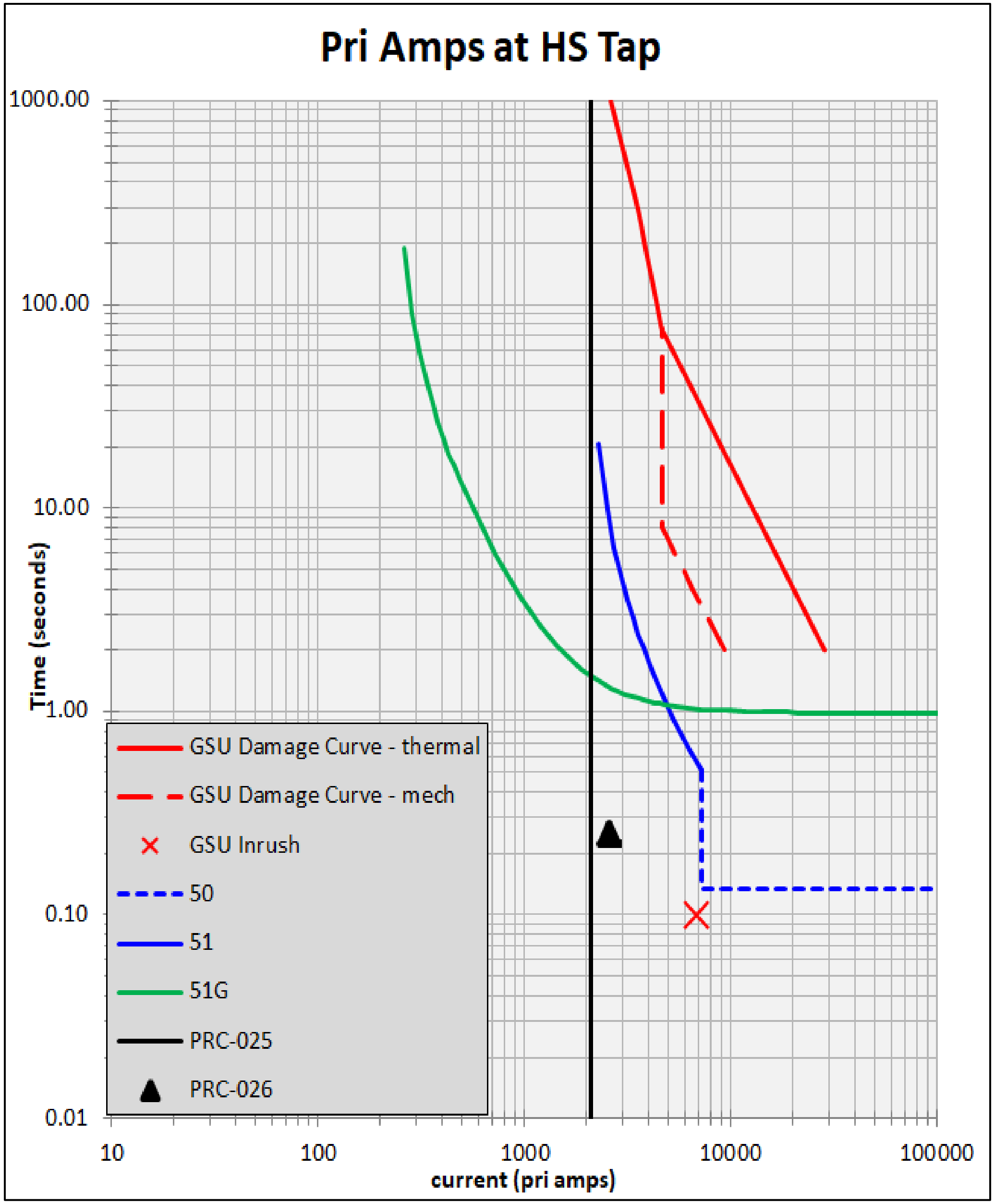
51G – Inverse Time Ground Overcurrent

- *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.



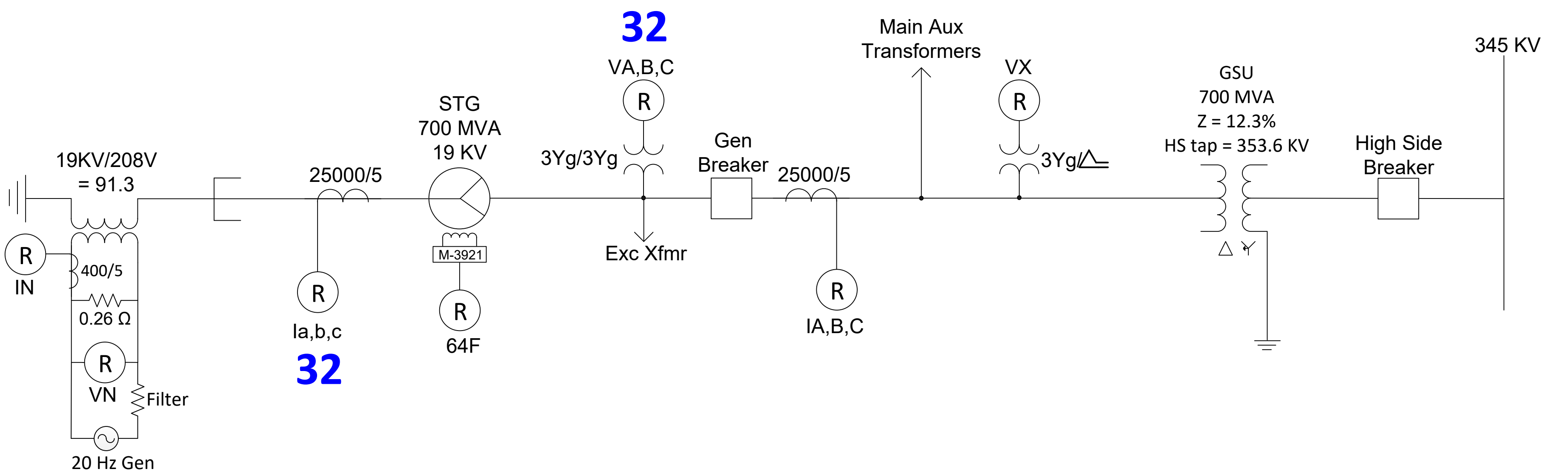
Choose a 51G curve that flattens out at about 1 second to coordinate with transmission line ground fault protection.

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



Blocking Inputs = FL, 1

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

32 – Reverse Power

Typical motoring power in percent of unit's MW rating (not MVA rating):

- Condensing Steam Turbine under zero steam input: 0.5% 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%

Set (3) 32 elements for this sample STG application

1) Set 32 #1 for sequential tripping/normal shutdown (typical for steam turbines)
2) Set 32 #2 for traditional reverse power protection
3) Set 32 #3 as an overexcitation alarm

32 – Reverse Power

FOR REFERENCE: If the total losses is unknown then a typical motoring power value may be used to derive an appropriate 32 pickup setting. Or, if allowed, the losses or motoring power may be measured during initial commissioning after all off-line commissioning is completed and right after the first sync. For example, for this STG application, here are some possible "live" testing steps to use (NOTE: this may not be a stable operating scenario, so the testing steps should be well understood, coordinated, and studied prior to starting this procedure so this testing can be conducted post-haste):

- Temporarily disable 32 settings to ensure sufficient time for the unit to settle into satisfying all its losses.
- Or may enable 32 element(s) with preliminary settings based on typical motoring power.
- Temporarily set OSC Partitions = 2, Post Trigger Delay = 95, Trigger on IN2 only (for the breaker closing).
- Therefore, when breaker closes, OSC record will show measured power for 280*0.95/60=4.43 seconds.
- Have the Primary and Secondary metering screens open side-by-side via S-3400 IPScom.
- Synchronize the generator onto the system (i.e. the generator breaker syncs closed).
- Do not allow the unit to begin to ramp up i.e. ensure control system is not calling for any MW output, etc.
- The steam valves should remain closed.
- The unit should start to drift into reverse power to cover its losses (both generator and turbine).
- Take a screenshot of the Primary and Secondary metering screens (i.e. log the measured reverse power).
- Manually trigger an OSC record (gives additional data if the unit takes > 4.43 seconds to satisfy losses).
- The unit may be taken back off-line (e.g. via the normal shutdown sequential tripping mode) until the final 32 settings can be calculated and applied to the relay or the unit may be allowed to start ramping back up while the 32 element(s) are re-enabled and then with the unit on-line, the 32 settings can be adjusted as required based on the measured MWs which should be equivalent to the total losses.
- NOTE: The trip should be issued shortly after the breaker closes (< approximately 30 seconds).
- Ensure 32 #1 is re-enabled and saved to the relay (if it was disabled at the beginning).
- Reset the original OSC Setup settings.
- Study the collected data and adjust the preliminary reverse power settings as required.

32 – Reverse Power

Prating = S * PF = 700 * 0.85 = 595 MW

<u>Losses information from mfg:</u>

- **Turbine losses = 5.83 MW (1% of Prated, 5.83/595)**
- **Generator losses = 1.49 MW (0.2% of Prated, 1.49/595)**
- **Total losses = 7.32 MW (1.2% of Prated, 7.32/595)**

✓ The Sequential Tripping (32 #1) Pickup is sometimes set to half or even less than the Reverse Power (32 #2) Pickup; however, for this sample application set them both to 70% of total losses.

32 – Reverse Power

70% Sensitivity Margin

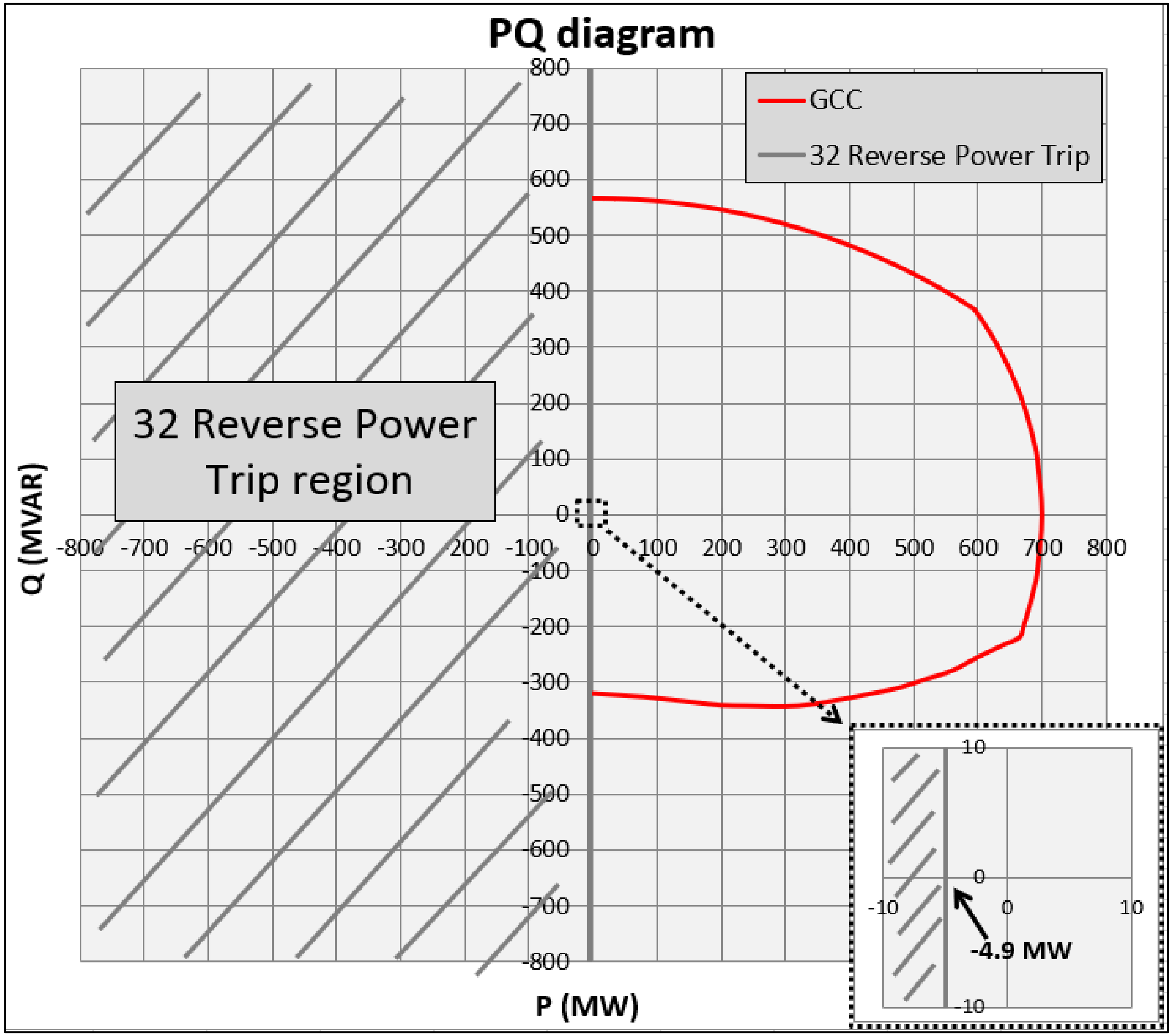
$$\text{Pickup} = \text{Ppu} = \frac{\text{Pactual}}{\text{Sbase}} = \frac{\text{SM} * \text{total losses}}{700\ \text{MVA}} = \frac{0.70 * 7.32\ \text{MW}}{\sqrt{3} * 120 * 4.25 * 5000 * 158.3}$$

$$= -\ 0.007\ \text{pu}$$

- **if VT Configuration = LL or LG-LL, $\text{Sbase} = \sqrt{3} * \text{Vnom} * \text{Inom}$**
- **if VT Configuration = LG, $\text{Sbase} = 3 * \text{Vnom} * \text{Inom}$**

- Apply negative sign to the pickup setting as this should trip when the generator is taking in watts from the system:
- The Pickup setting is in per unit of the rated MVA rather than the rated MW as the relay does not know what the rated MW is as there is no PF setting for the relay. Therefore, Sbase is used in the calculations rather than Pbase; however, it is insignificant as Sbase will cancel out when the algorithm compares the measured value vs the Pickup setting.

32 – Reverse Power



32 #1 Pickup = -0.007 pu

32 #2 Pickup = -0.007 pu

$$\mathbf{Pactual = Ppu * Sbase = -0.007 * \sqrt{3} * 120 * 4.25 * 5000 * 158.3 = -4.9\ MW}$$

32 – Reverse Power

The 32 algorithm operates by calculating the actual Power from the measured individual phase voltage and current magnitudes and phase angles via the following equation:

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

The algorithm then converts this actual measured quantity to a per unit quantity:

$$\text{Ppu\_measured} = \frac{\text{Pactual\_measured}}{\text{Sbase}}$$

The algorithm uses Sbase rather than Pbase in the Ppu_measured calculation as the relay does not know the generator's rated lagging PF.

It then compares this Ppu_measured value against the 32 Pickup setting which also used Sbase rather than Pbase in its derivation so in the end the Sbase has no effect i.e., it cancels out.

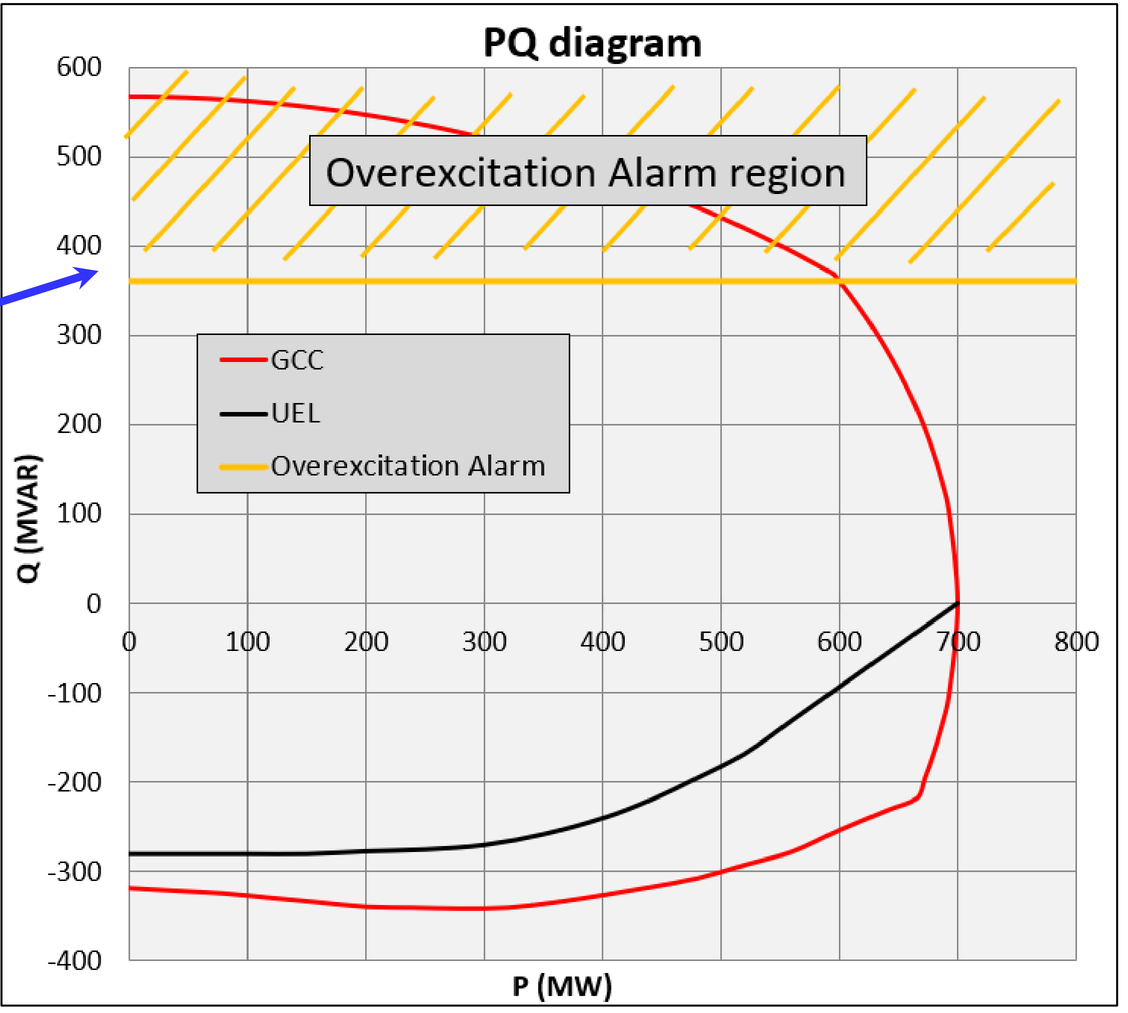
32 – Reverse Power

✓ Set 32 #3 for "Reactive" as an Overexcitation Alarm which also takes the excitation controller to manual mode but still allows the operator to increase voltage if necessary.

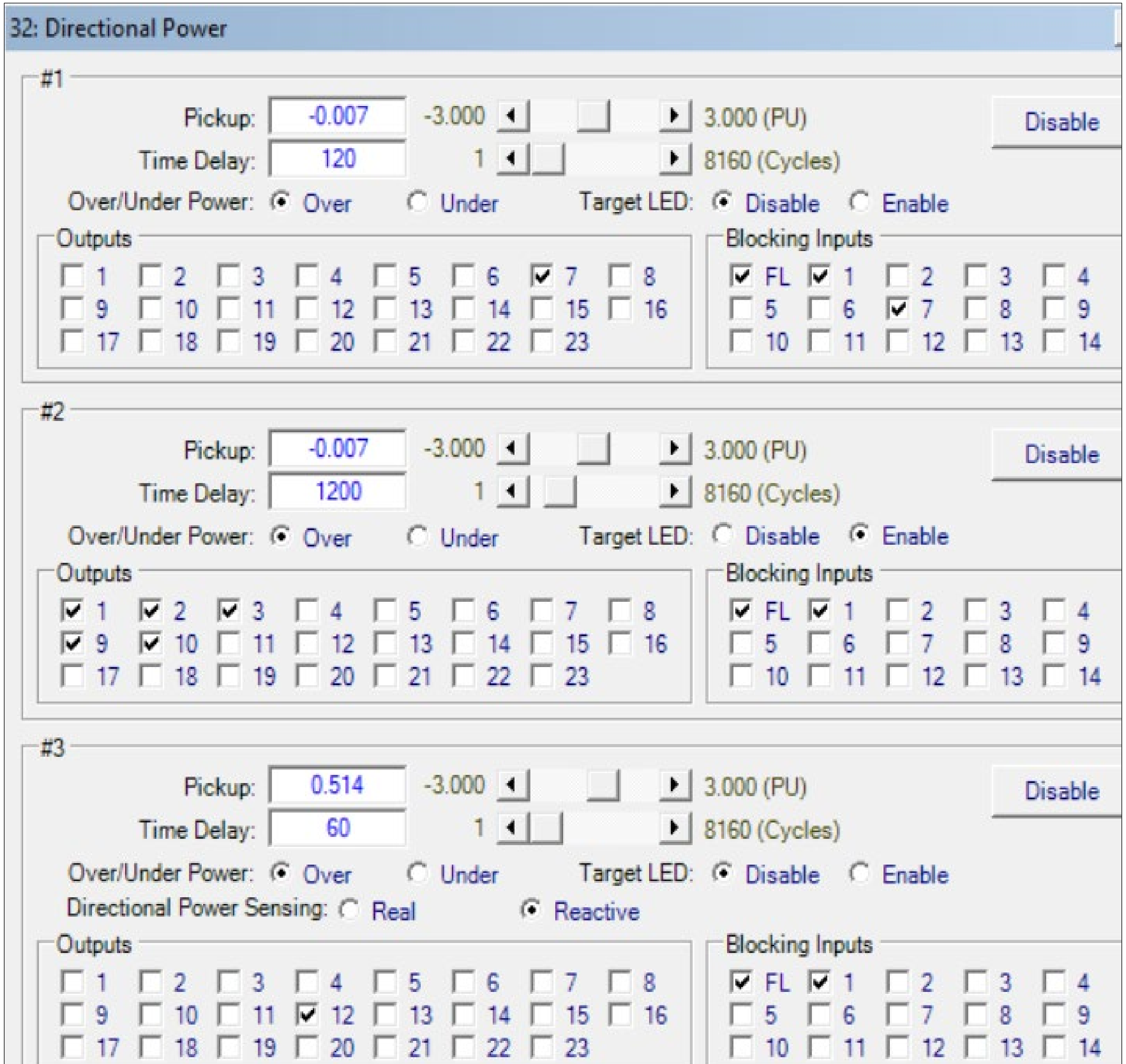
Setpoint of 360 MVAR:

$$\text{Pickup} = \frac{360\text{ MVAR}}{700\text{ MVA}} = 0.514\text{ pu}$$

32 #3 Pickup = 0.514 pu

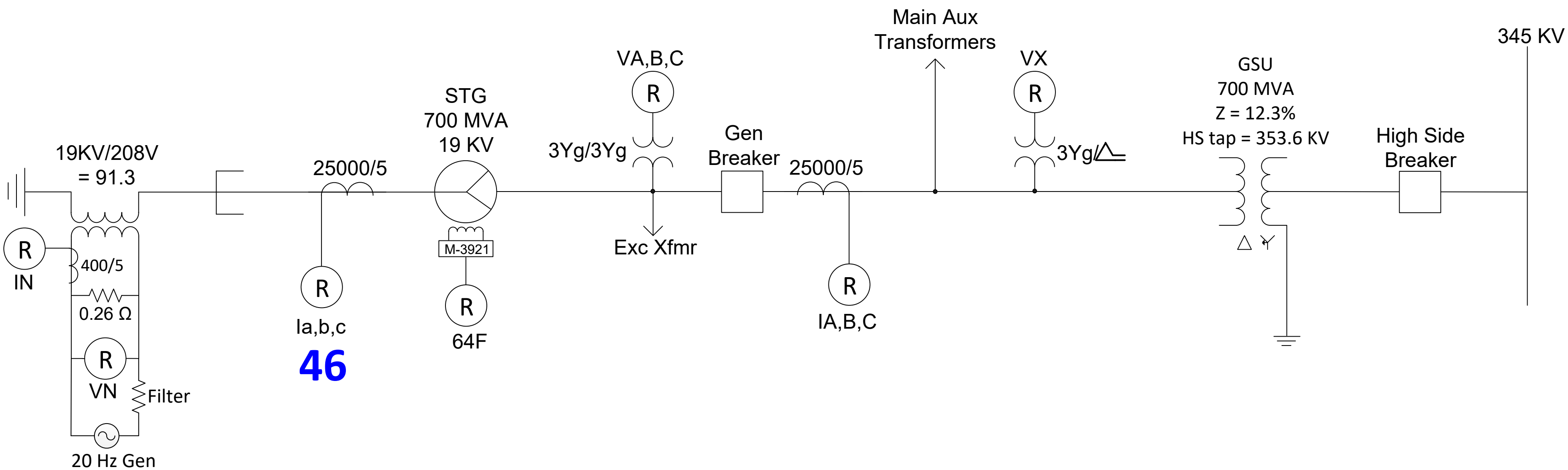


32 – Reverse Power



- **32 #1**
  - **seq trip**
  - **set at 2 seconds**
  - **Disable Target LED**
- **32 #2**
  - **reverse power trip**
  - **set at 20 seconds**
- **32 #3**
  - **Over-excitation alarm**
  - **set at 1 second**

46 – Negative Sequence Overcurrent



Blocking Inputs = none

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

46 – Negative Sequence Overcurrent

- Use 46DT for Alarm.
- Use 46IT to Trip.

- Set the 46 IT Trip Pickup setting per the following criteria:
  1) Set > max expected load unbalance with machine at full output.
  2) Set < machine continuous I_2 rating.
  3) Set < min I_2 caused by unbalanced conditions.

1) Measure I_2 at a single point in time with machine at full output or track it over time. Here, 3% was used per tracking method with added margin.

2) This gen is a directly cooled, cylindrical rotor type; therefore, per IEEE C50.13 the permissible continuous I_2 rating is the following:

$$\text{cont. gen } I_2 \text{ rating} = 8 - \frac{700 - 350}{300} = 6.8\ \%$$

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

46 – Negative Sequence Overcurrent

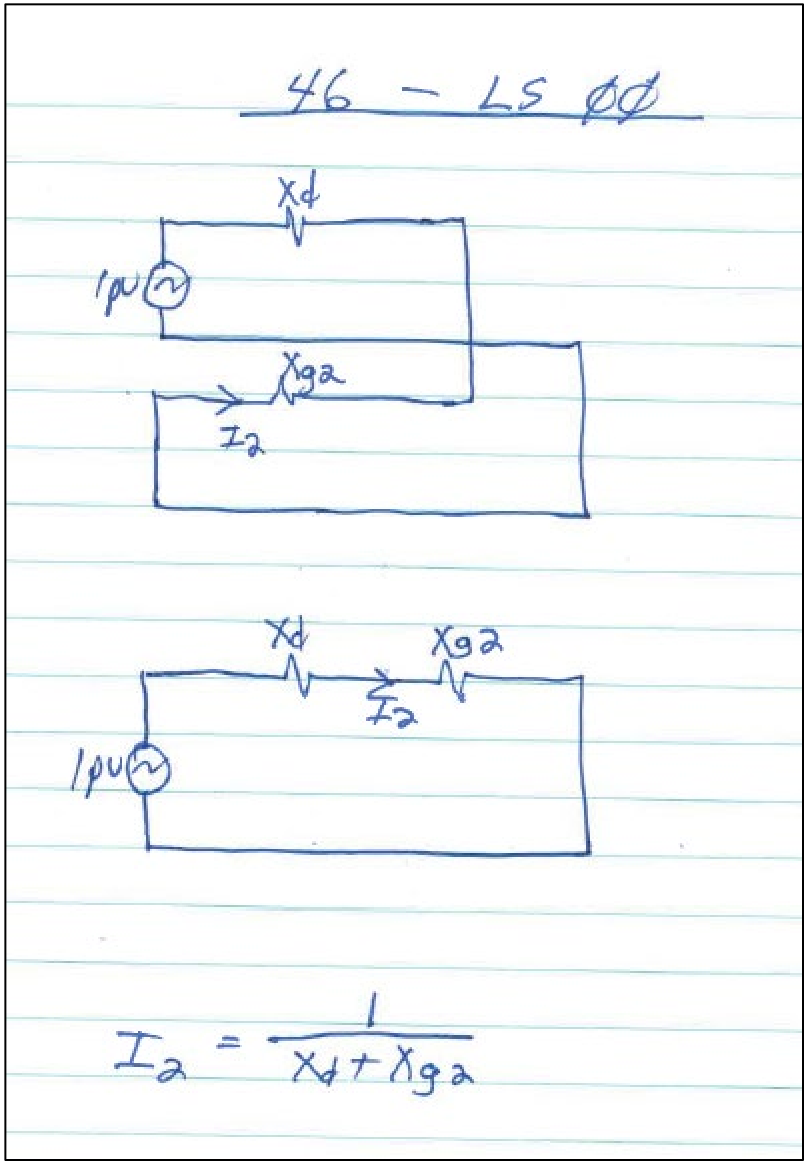
3) Calculate I_2 from various unbalanced conditions assuming infinite bus on GSU HS:

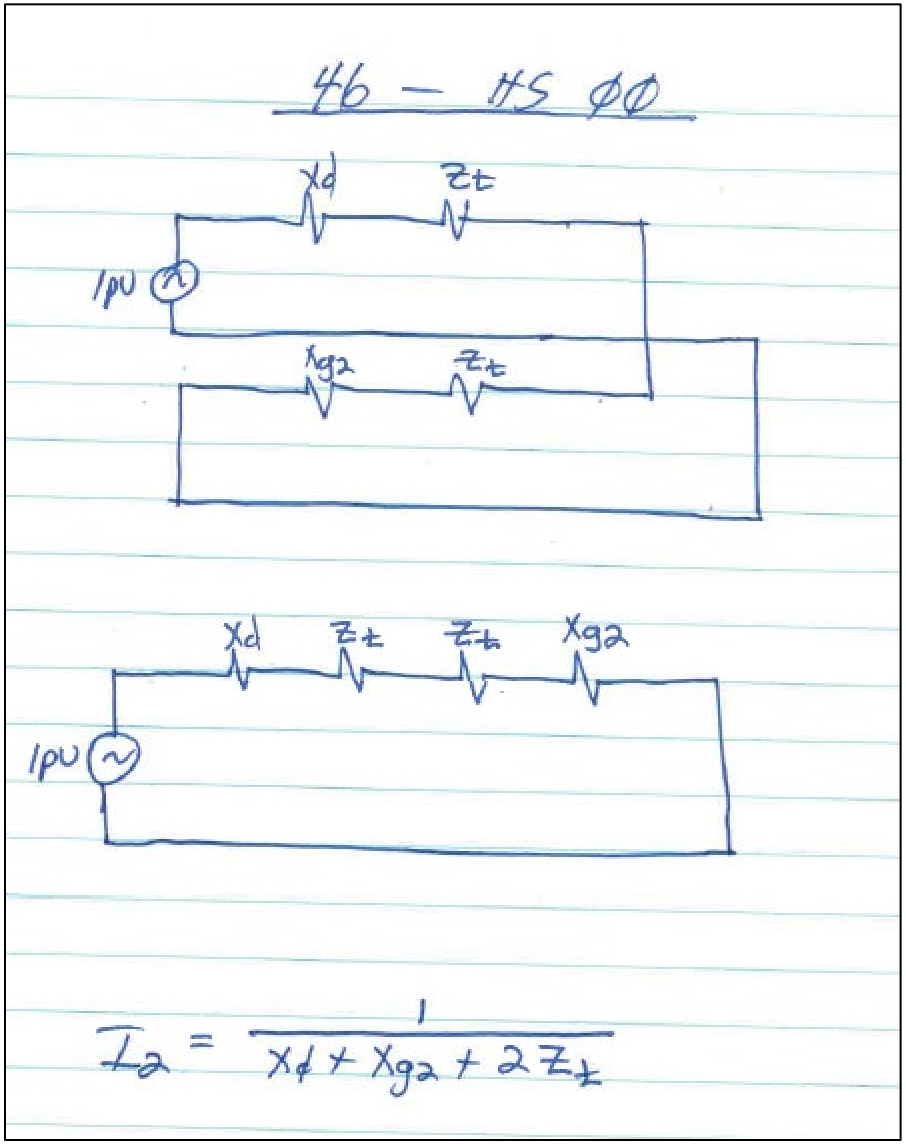
- ΦΦ fault on LS of GSU
- ΦΦ fault on HS of GSU
- ΦΦG fault on LS of GSU, same as LS ΦΦ fault
- ΦΦG fault on HS of GSU
- ΦG fault on LS of GSU
- ΦG fault on HS of GSU
- Open phase on LS of GSU
- Open phase on HS of GSU

All 8 unbalance cases are calculated here for thoroughness; however, the typical max and min cases may instead just be calculated. For most high-impedance grounded gens, the typical max I_2 case will be from a LS ΦΦ fault which should equal the LS ΦΦG fault case. The typical min I_2 will be from a HS ΦΦG fault (excluding the LS ΦG fault as the 46 element will not pick up for this case as the I2 fault current is too small).

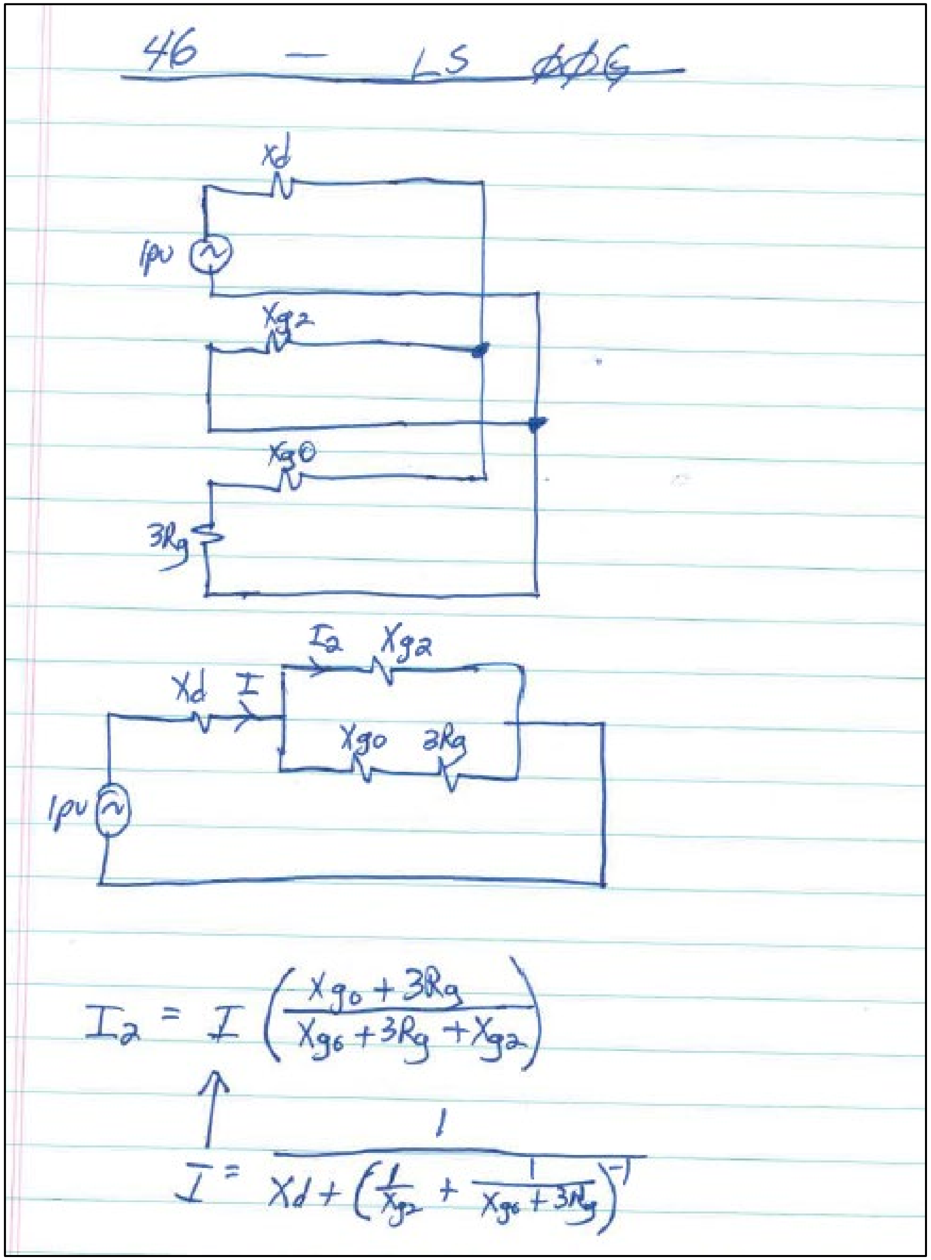
Now, let's take a pause for the next several slides to draw out the sequence networks for each of these cases and solve for I_2:

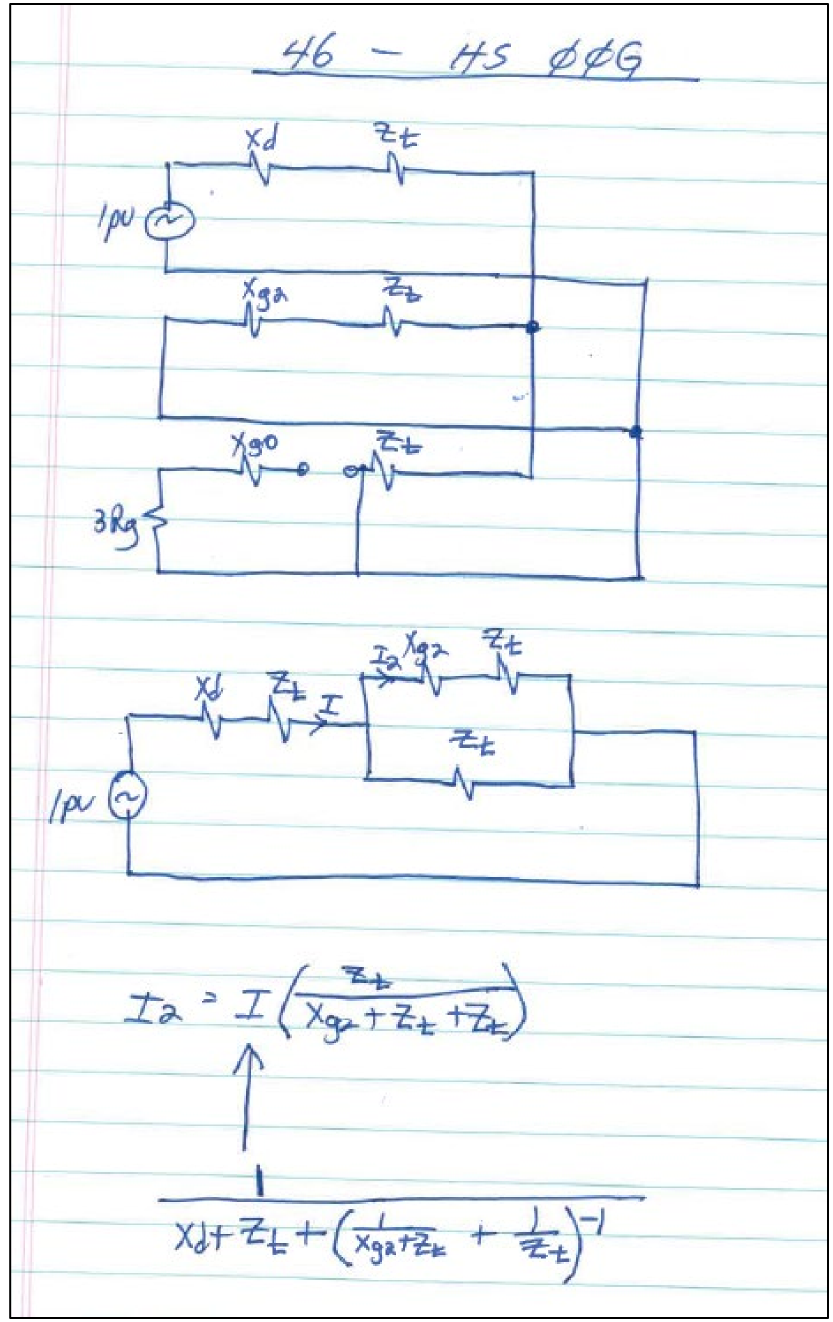
46 – Negative Sequence Overcurrent



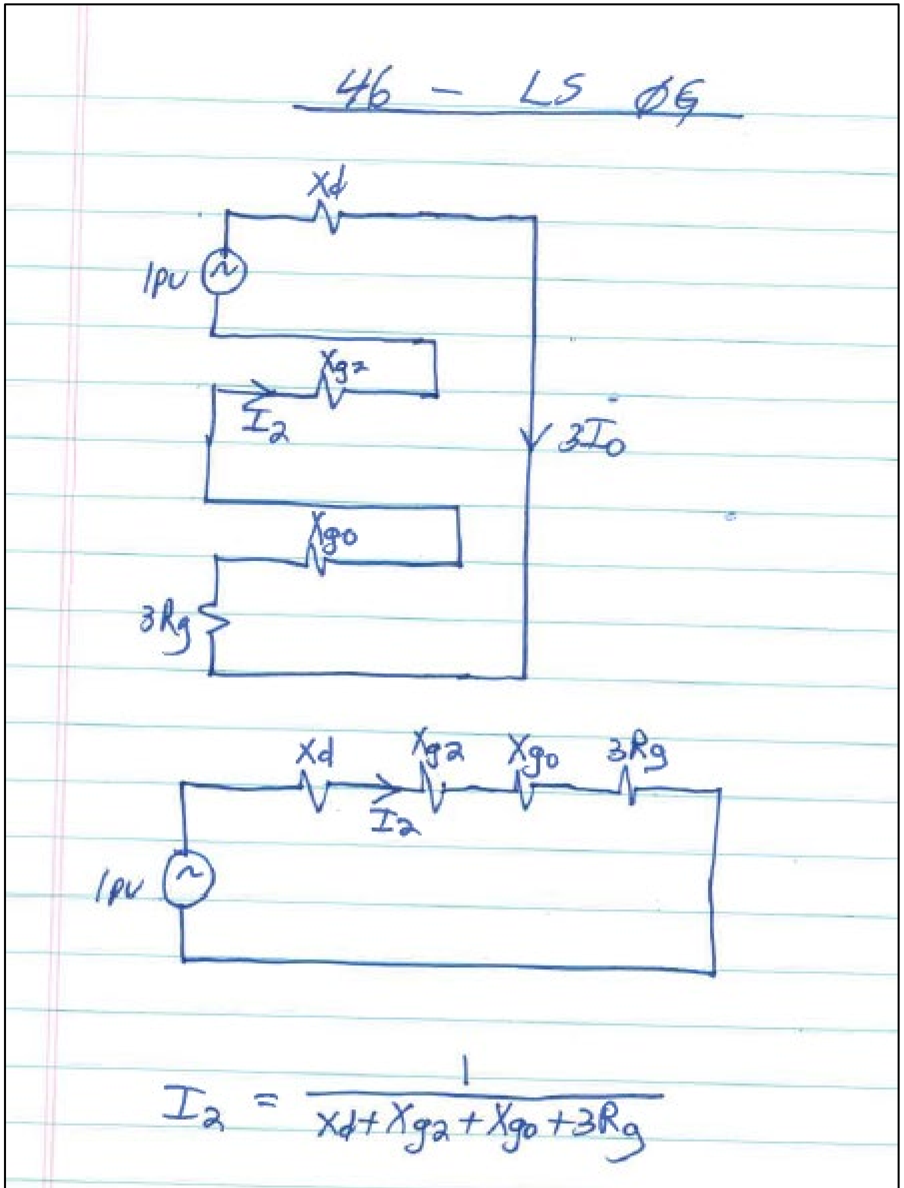


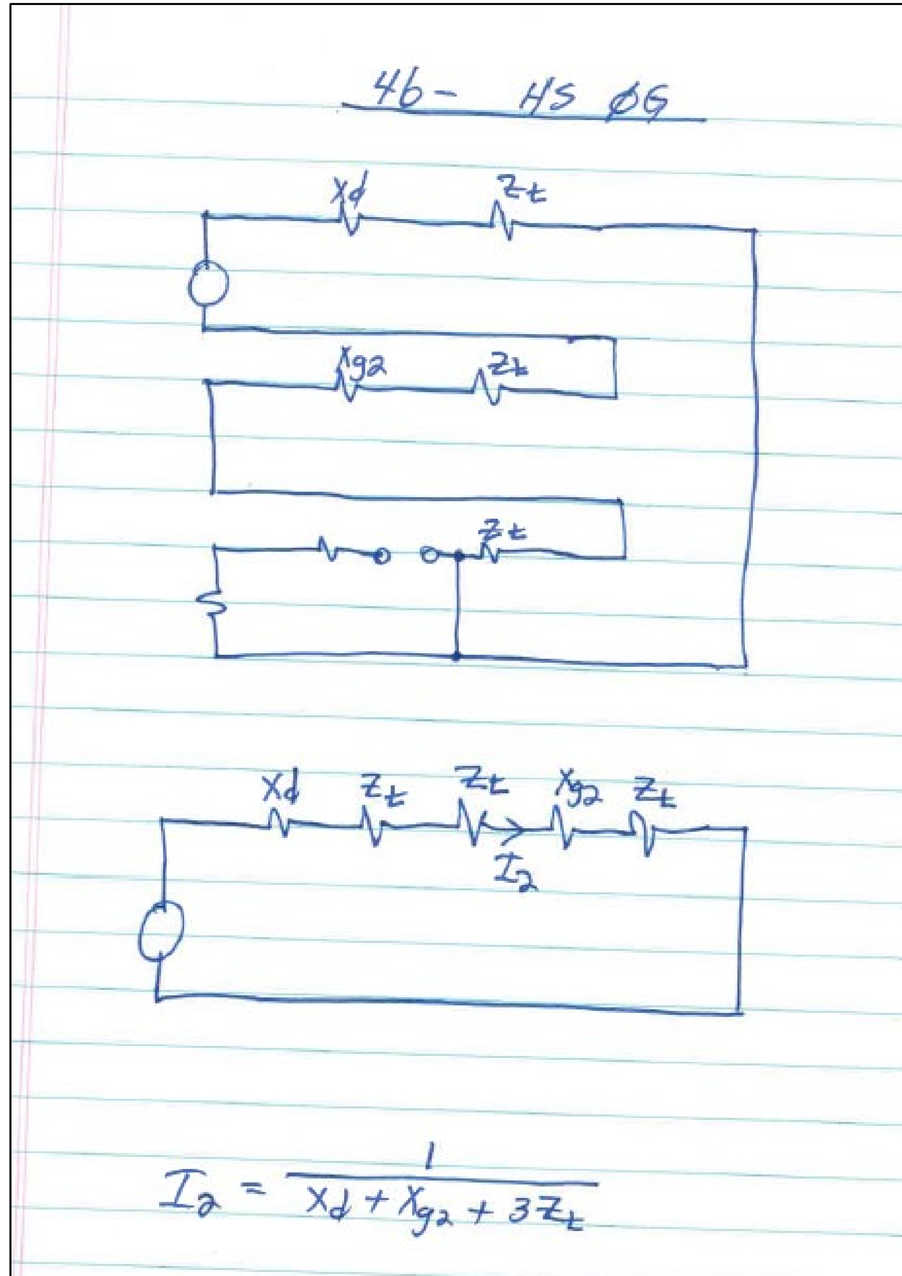
46 – Negative Sequence Overcurrent





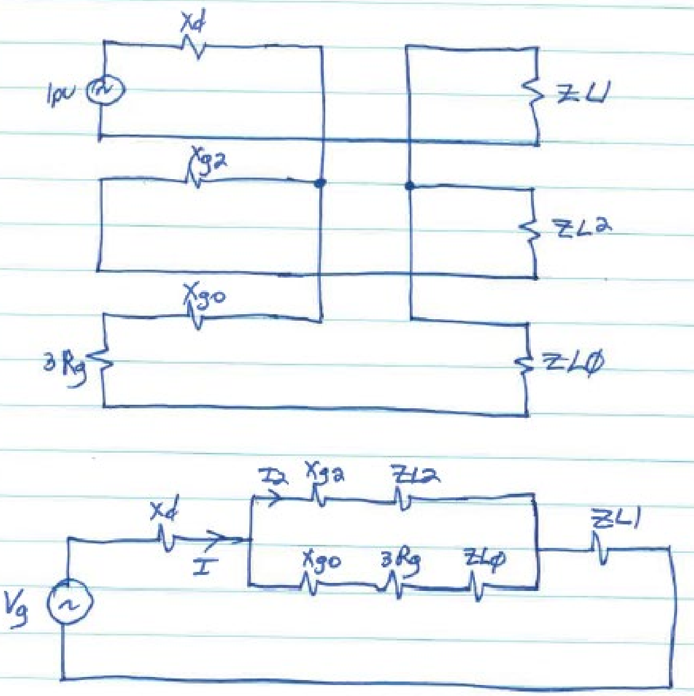
46 – Negative Sequence Overcurrent





46 – Negative Sequence Overcurrent

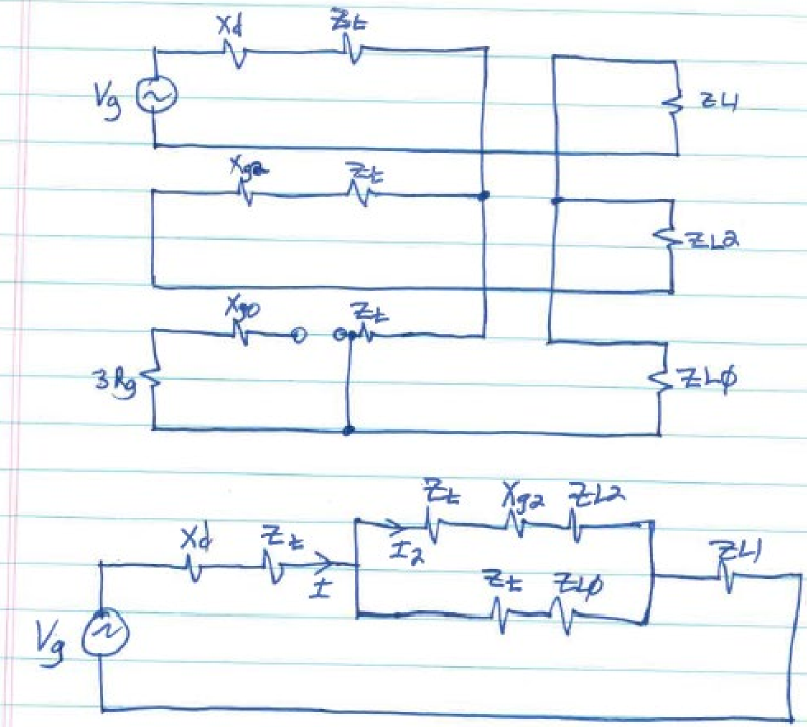
46 – LS open phase



$$I_2 = I\left(\frac{X_{g0}+3R_g+Z_{L\phi}}{X_{g0}+3R_g+Z_{L\phi}+X_{g2}+Z_{L2}}\right)$$

$$I = \frac{1}{X_d + Z_{L1} + \left(\frac{1}{X_{g2}+Z_{L2}} + \frac{1}{X_{g0}+3R_g+Z_{L\phi}}\right)^{-1}}$$

46 – HS open phase



$$I_2 = I\left(\frac{Z_t+Z_{L\phi}}{Z_t+Z_{L\phi}+Z_t+X_{g2}+Z_{L2}}\right)$$

$$I = \frac{1}{X_d + Z_t + Z_{L1} + \left(\frac{1}{Z_t+X_{g2}+Z_{L2}} + \frac{1}{Z_t+Z_{L\phi}}\right)^{-1}}$$

46 – Negative Sequence Overcurrent

Here are the solved equations from the different unbalanced conditions:

$$I_2 = \left|\frac{1}{Xd + Xg2}\right| * 100 = 53\,\% \qquad (\Phi\Phi\ fault\ on\ LS\ of\ GSU)$$

$$I_2 = \left|\frac{1}{Xd + Xg2 + 2Zt}\right| * 100 = 47\,\% \qquad (\Phi\Phi\ fault\ on\ HS\ of\ GSU)$$

$$I_2 = \left|\frac{1}{Xd + \left(\frac{1}{Xg2} + \frac{1}{Xg0 + 3Rg}\right)^{-1}} * \frac{Xg0 + 3Rg}{Xg0 + 3Rg + Xg2}\right| * 100 = 53\,\% \qquad (\Phi\Phi G\ fault\ on\ LS\ of\ GSU, same\ as\ \Phi\Phi)$$

$$I_2 = \left|\frac{1}{Xd + Zt + \left(\frac{1}{Zt} + \frac{1}{Xg2 + Zt}\right)^{-1}} * \frac{Zt}{Xg2 + Zt + Zt}\right| * 100 = 14\,\% \qquad (\Phi\Phi G\ fault\ on\ HS\ of\ GSU)$$

$$I_2 = \left|\frac{1}{Xd + Xg2 + Xg0 + 3Rg}\right| * 100 = 0.01\,\% \qquad (\Phi G\ fault\ on\ LS\ of\ GSU)$$

$$I_2 = \left|\frac{1}{Xd + Xg2 + 3Zt}\right| * 100 = 44\,\% \qquad (\Phi G\ fault\ on\ HS\ of\ GSU)$$

$$I_2 = \left|\frac{1}{Xd + ZL1 + \left(\frac{1}{Xg2 + ZL2} + \frac{1}{Xg0 + 3Rg + ZL0}\right)^{-1}} * \frac{Xg0 + 3Rg + ZL0}{Xg0 + 3Rg + ZL0 + Xg2 + ZL2}\right| * 100 = 53\,\% \qquad (open\ LS)$$

$$I_2 = \left|\frac{1}{Xd + Zt + ZL1 + \left(\frac{1}{Xg2 + Zt + ZL2} + \frac{1}{Zt + ZL0}\right)^{-1}} * \frac{Zt + ZL0}{2Zt + ZL0 + Xg2 + ZL2}\right| * 100 = 28\,\% \qquad (open\ HS)$$

46 – Negative Sequence Overcurrent

And here is a summary table of all the calculated I_2 values:

fault	46 function will see in neg seq amps			
	LS of GSU		HS of GSU	
	pri amps	% of Inom	pri amps	% of Inom
ΦΦ	11290	53	9986	47
ΦΦG	11290	53	2971	14
ΦG	2	0.01	9440	44
Open Phase	11248	53	5969	28

- Now, bookend the 46IT Pickup setting criteria:

I_2 at full output ≤ 46IT Pickup ≤ cont. I_2 rating; min I_2 from unbalanced conditions
3% ≤ 46IT Pickup ≤ 6.8% ; 14%

Choose the Inverse Time Pickup = 6%

Set Alarm Pickup < Trip Pickup (typically half – or more to avoid nuisance alarms)

Set the Alarm 46DT Pickup at 5% and 5 seconds

46 – Negative Sequence Overcurrent

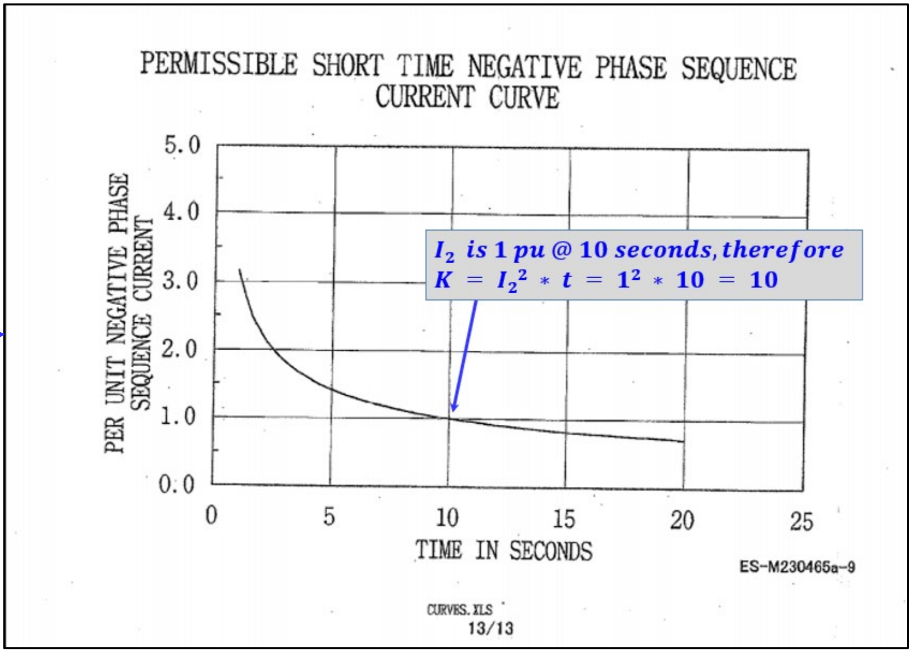
Now, must decide what to set the 46IT Time Dial setting. To do so, need to know the machine's "K" rating or short-time unbalance current capability, which is given in C50.13:

Short-Time Unbalance Current Capability	
Generator Type	*K Permissible* I_2^2t *(I_2 in pu)*
Salient Pole	40
Synchronous Condenser	30
Cylindrical Rotor	
Indirectly Cooled	30
Directly Cooled	
0–800 MVA	10
801–1600 MVA	10–(0.00625)(MVA–800)

Here, $K = I_2^2t = 10$ where K is a machine constant representing the max permissible thermal capacity of the rotor (K rating indicates the machine can withstand K seconds worth of negative sequence current equal to 100% of the generator rated current)

In this case, the mfg also did provide a permissible short-time I_2 curve

This concurs with the K = 10 machine rating as given in IEEE C50.13:



46 – Negative Sequence Overcurrent

- Set the 46IT TD below the machine's K rating to protect the generator from thermal damage.
- Using KISS principle: choose a TD right below the K rating e.g., with K=10, could just choose TD = 9.
- However, if the max negative sequence current from an unbalanced condition is considered, then could choose a TD from the time to trip for this condition e.g., 10 seconds and this typically plots well below the TD of 9 for this example i.e., there is no need to expose the unit to these currents for any longer than necessary if it is determined to be an undesirable condition.

The maximum calculated I_2 that this relay will see is from a GSU LS ΦΦ fault (11290 pri amps or 53% of Nominal Current). Calculate the TD required for the 46IT element to operate in 10 seconds for this ΦΦ fault on the GSU LS:

$$\mathrm{TD} \geq I_{2pu}^2 * t = \left(\frac{\frac{\mathrm{I2pri}}{\mathrm{CTR}}}{\mathrm{Inom}}\right)^2 * t = \left(\frac{\frac{11290}{5000}}{4.25}\right)^2 * 10 = (0.53)^2 * 10 = 2.8 \quad \text{(TD setting is whole number)}$$

46 – Negative Sequence Overcurrent

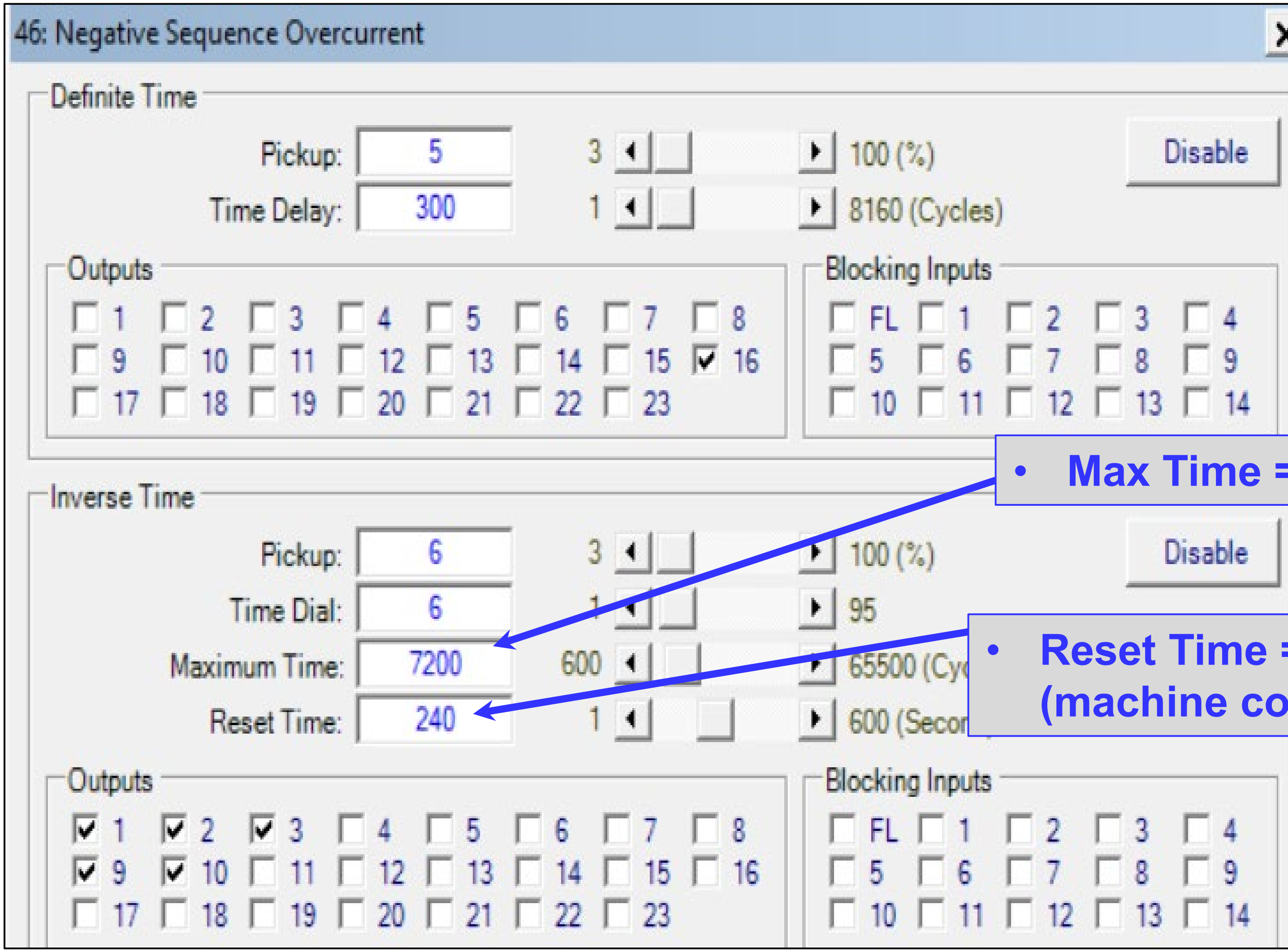
The current will be higher during the subtransient and transient periods of the generator's output contribution to the unbalanced condition but will decay quickly. Therefore, the 46IT algorithm will accumulate "thermal capacity" faster than during the synchronous period.

Because the TD portion of the 46IT algorithm is not adaptive (i.e. the TD setting cannot be set high in the beginning and then decay with respect to time in proportion to the generator decrement curve), therefore the bookend criteria for the TD setting could be represented as such (using an SF i.e. Security Factor of 2 to account for faster heat accumulation during the subtransient and transient periods):

SF * TD at 10 sec using Xd	$\leq$ 46IT TD $\leq$	K rating of the machine
2 * 2.8	$\leq$ 46IT TD $\leq$	10
5.6	$\leq$ 46IT TD $\leq$	10

Set TD = 6 (gives an actual operate time of $6/0.53^2 = 21.4$ seconds)

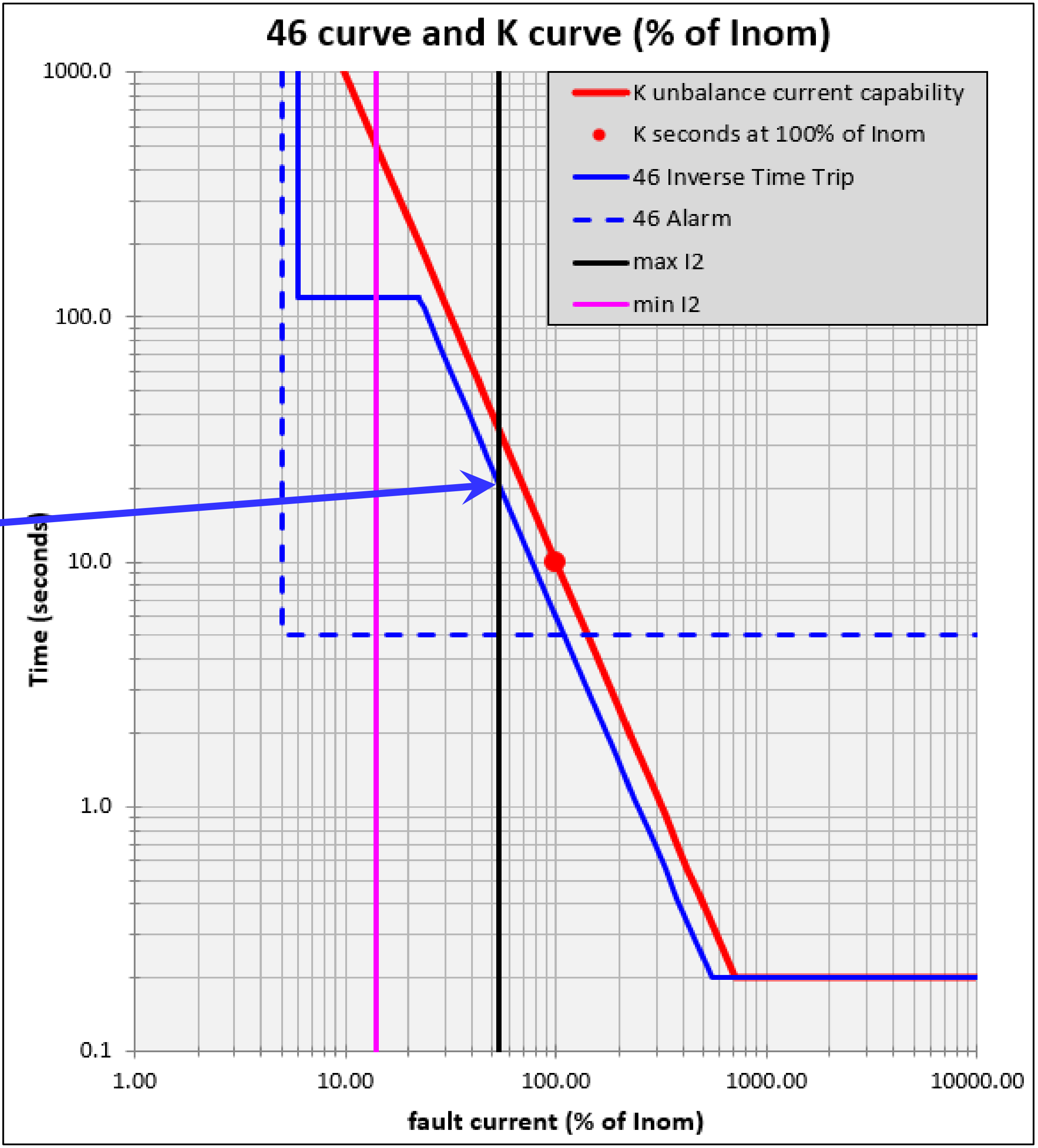
46 – Negative Sequence



- **Max Time = 2 minutes.**

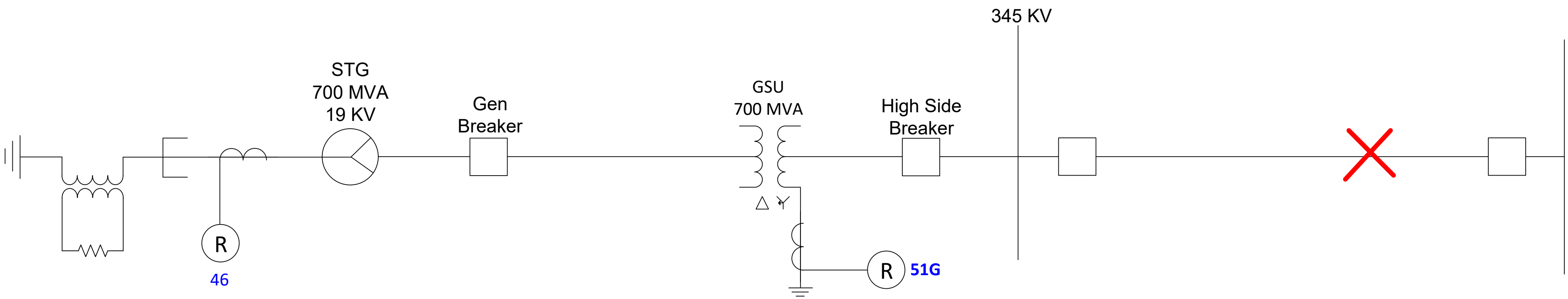
- **Reset Time = 4 minutes (machine cool down time).**

46 – Negative Sequence



Will trip in $6/0.53^2 = 21.4$ seconds for a ΦΦ fault on the LS of the GSU

PRC-027 compliance verification



For faults on the GSU HS that produce both negative sequence current and zero sequence current (ΦG and ΦΦG), must verify that 51G relay wired off CTs from the GSU HS wye-grounded leg coordinate with (trip prior to) this 46 function.

46IT with a TD of 6 will trip in $6/0.44^2$ = 31 seconds for a GSU HS ΦG fault and will trip in $6/0.14^2$ = 306 seconds (hits max time limit of 120 seconds) for a GSU HS ΦΦG fault.

Where 51G will trip in 1 second for a GSU HS ΦG fault and it will also trip in 1 second for a GSU HS ΦΦG fault.

So, coordination is verified to be OK. **YES, complies**

46 – Negative Sequence - testing

Calculate a coordinating point for relay testing:

Choose the same point on the 46 curve as calculated above from a GSU LS ΦΦ fault:

I_2 = 11290 pri amps, 11290/5000 = 2.26 negative sequence sec amps will trip in 10.7 seconds.

What does this look like in terms of phase currents into the relay test set?

$I_2 = 1/3(Ia + a^2Ib + aIc)$

$2.26*3 = Ia \angle 0° + 1 \angle 240° * 4.25 \angle -120° + 1 \angle 120° * 4.25 \angle 120°$

$6.78 = Ia \angle 0° + 4.25 \angle 120° + 4.25 \angle 240°$

Solve for Ia:

$Ia = 11 \angle 0°$ sec amps

Coordinating Point = 11 amps in 10.7 seconds

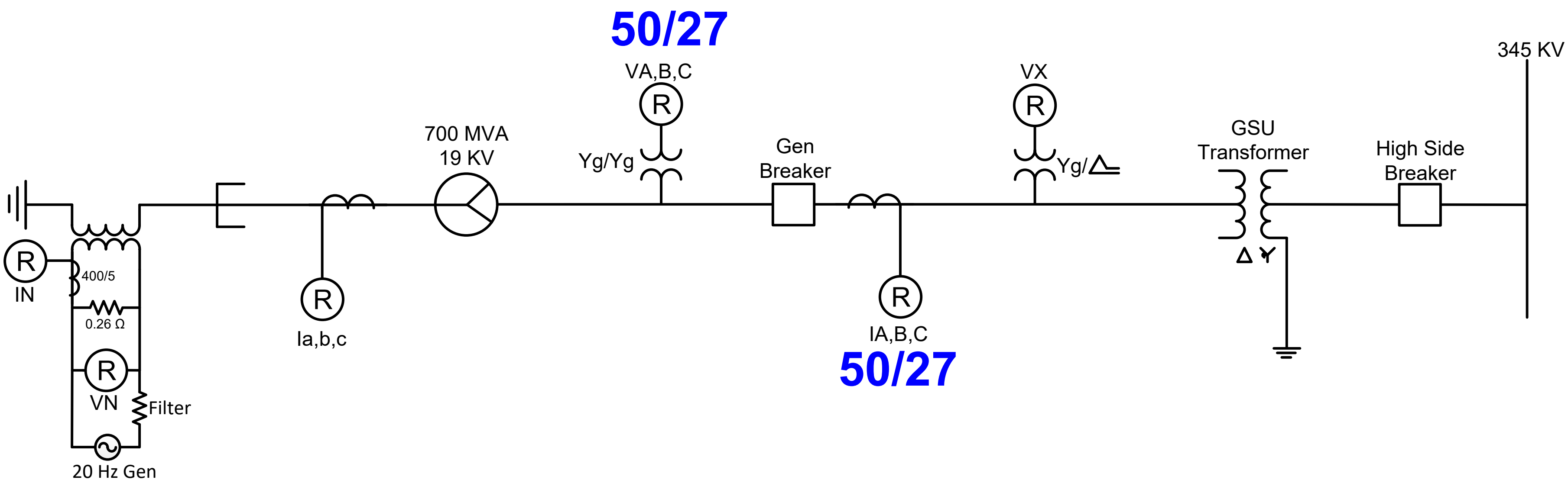
Hook up all 3 phases of current from relay test set with:

$Ia = 11 \angle 0°$ sec amps

$Ib = 4.25 \angle -120°$ sec amps

$Ic = 4.25 \angle 120°$ sec amps

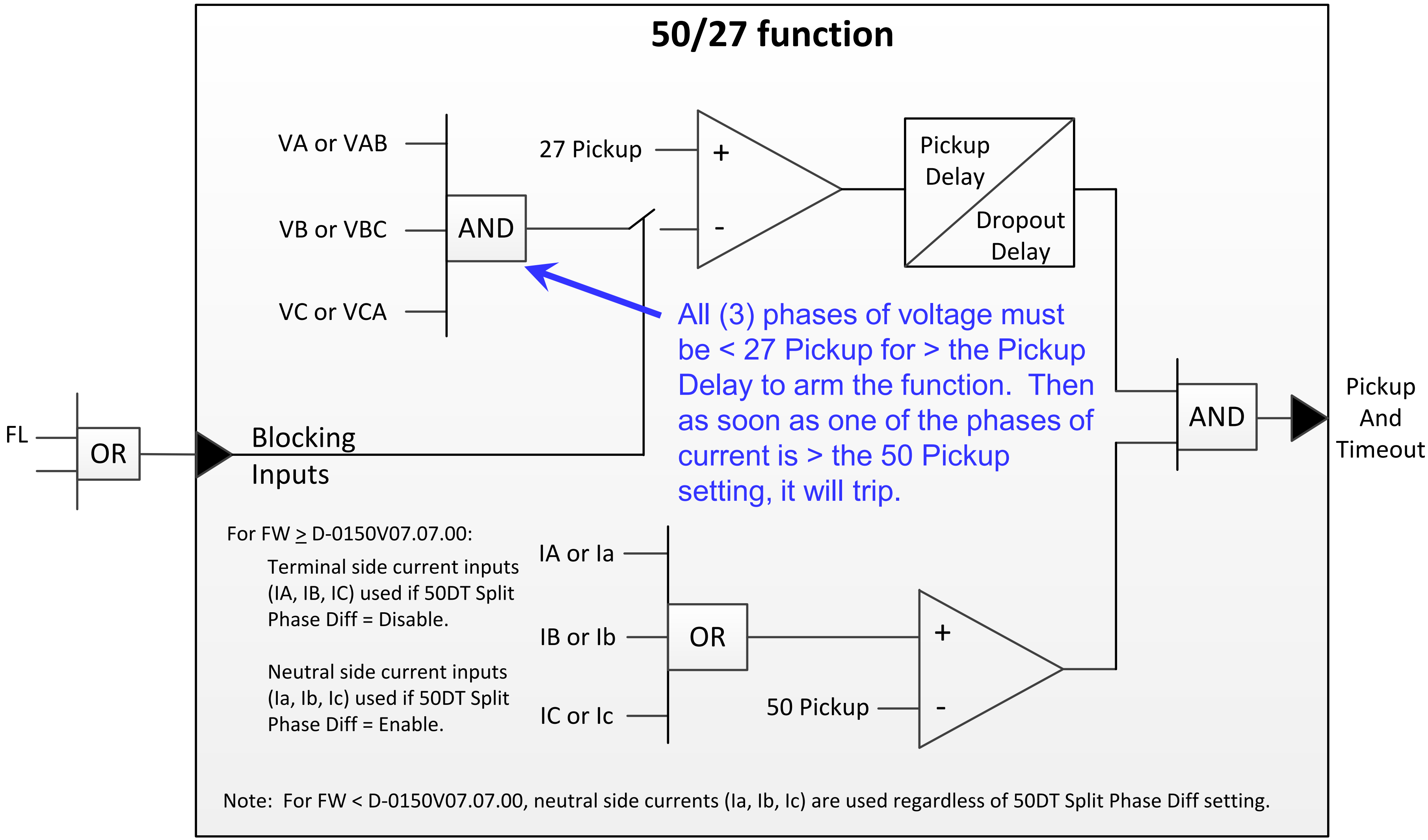
50/27 – Inadvertent Energizing



Blocking Inputs = FL

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

50/27 – Inadvertent Energizing



50/27 – Inadvertent Energizing

- Set Current Pickup per the following criteria (**don't just set at min as that may not be secure, e.g. for unit breaker applications**):

Gen response to 3Φ inadvertent energizing from the GSU HS (worst case) while at standstill:

$$\text{I3ph} = \frac{1}{\text{Zs1} + \text{Zt} + \text{Xg2}} * \text{IbaseLS} * \frac{1}{\text{CTR}} = 9.51\ \text{A}$$

- **Xg2 approximates the gen impedance at standstill and at values of high slip**

Generator response to 1Φ inadvertent energizing from the GSU HS while at standstill:

$$\text{I1ph} = \frac{1}{\text{Zs1} + \text{Zs2} + \text{Zs0} + 3 * \text{Zt} + \text{Xd}'' + \text{Xg2}} * \text{IbaseLS} * \frac{1}{\text{CTR}} = 4.54\ \text{sec amps}$$

50/27 – Inadvertent Energizing

- If system thevenin impedances on the HS of the GSU are not available, may calculate assuming infinite bus (Zs1 = Zs2 = Zs0 = 0):

$$\mathrm{I3ph} = \frac{1}{\mathrm{Zt} + \mathrm{Xg2}} * \mathrm{IbaseLS} * \frac{1}{\mathrm{CTR}} = 12.26\ \sec \mathrm{amps}$$

$$\mathrm{I1ph} = \frac{1}{3 * \mathrm{Zt} + \mathrm{Xd''} + \mathrm{Xg2}} * \mathrm{IbaseLS} * \frac{1}{\mathrm{CTR}} = 5.21\ \sec \mathrm{amps}$$

- For this application, the calculated values using system thevenin impedances vs. an infinite bus are 78% for 3Φ and 87% for 1Φ.

- With a typical sensitivity margin of 50%, using an infinite bus may be acceptable or could add more sensitivity margin when infinite bus is used.

50/27 – Inadvertent Energizing

- The Current Pickup bookend criteria can be displayed as such:

$$1.25 * \text{Inom} < 50\ \text{Pickup} < 0.50 * 3\text{ph inad}; 0.50 * 1\text{ph inad}$$

$$1.25 * 4.25 < 50\ \text{Pickup} < 0.50 * 9.51; 0.50 * 4.54$$

$$5.31 \qquad < 50\ \text{Pickup} < 4.76; 2.27$$

- Set 50 Pickup = 2.27 A (choose additional sensitivity over additional security as it is inherently secure via the 27 portion of the algorithm.)

- If LCI Start may need to set Pickup above LCI starting current.

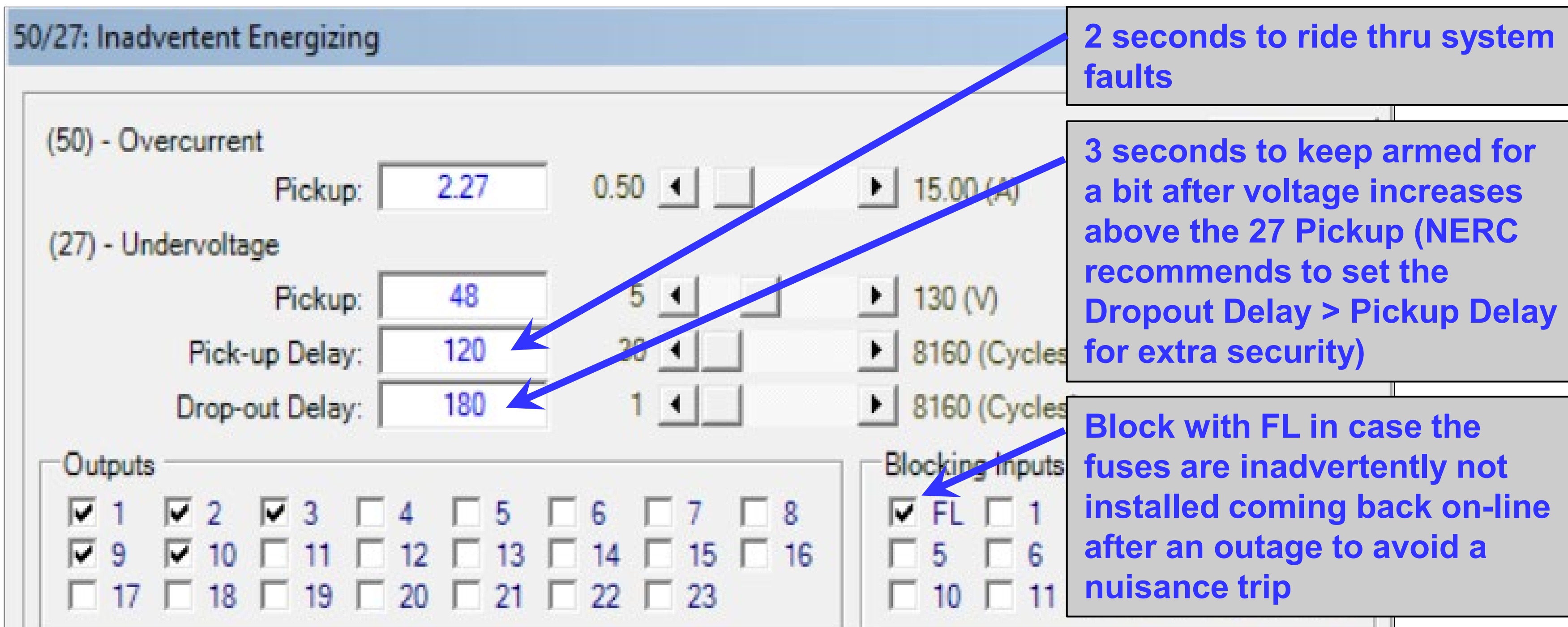
- If energizing from Main Aux is a concern, may need to decrease Pickup considerably e.g. down to 10% of Inom or at minimum.

50/27 – Inadvertent Energizing

- Some of the 50/27 trips during the 2003 NE Blackout were due to the 27 Pickup portion of the 50/27 function being set too high.

- Recommend to set it to 20% to 50% of the Nominal Voltage for security against system voltage dips.

- Set 27 Pickup = 48 V   (40% of Vnom, 0.40 * 120 = 48 V)



50/27 – Inadvertent Energizing

- **Do not have to verify that these settings comply with PRC-025-2 because it is only armed when the generator is off-line as stated in Exclusion 2 of the PRC-025-2 Standard:**

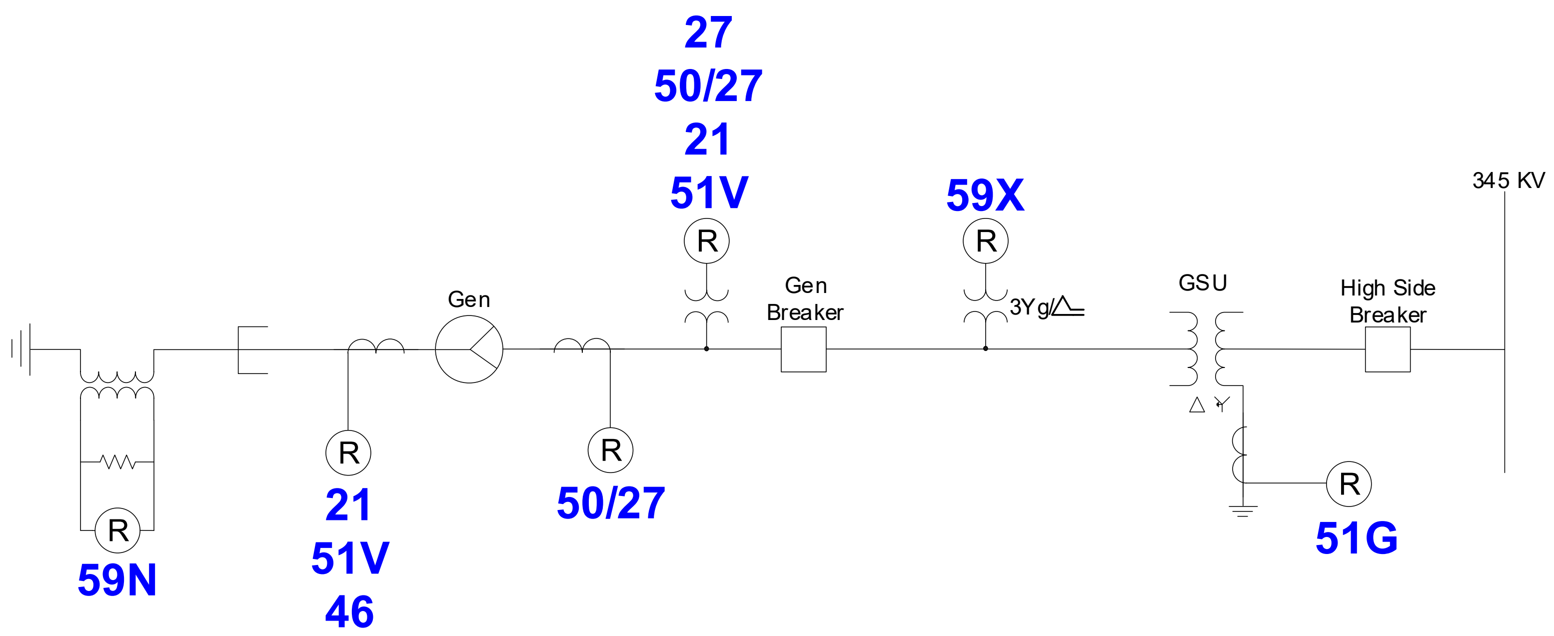
Exclusions

The following protection systems are excluded from the requirements of this standard:

2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).

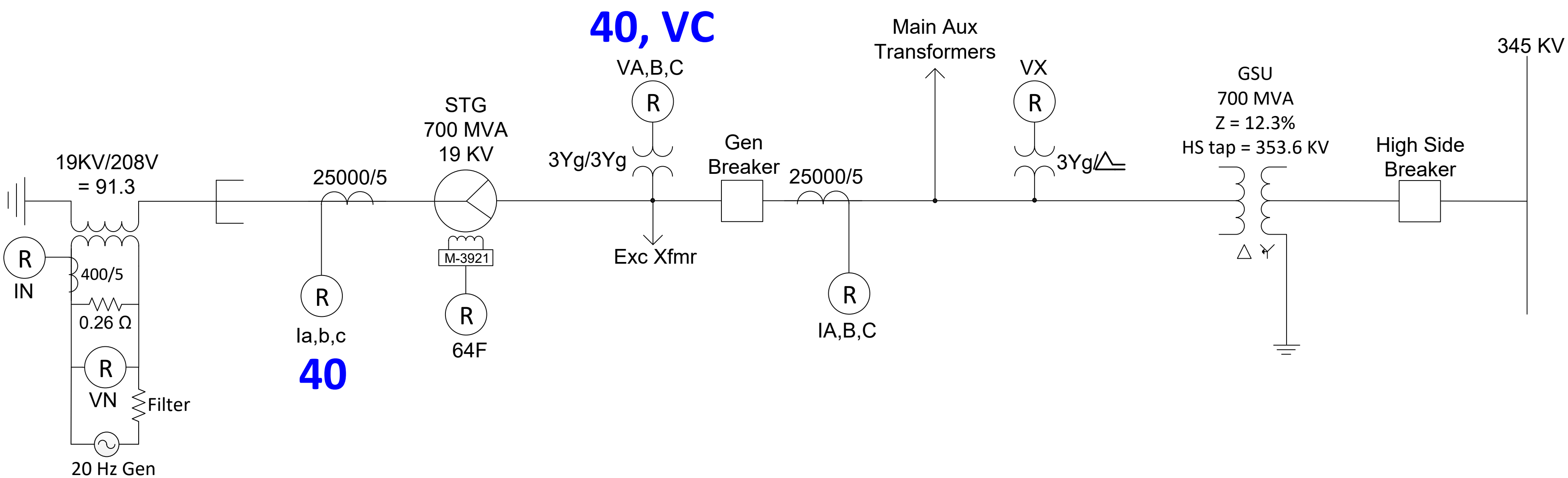
PRC-027

- Coord 50/27 with voltage dips from transmission line faults.



- Gen 50/27, 27 arming delay = 2 seconds.
- All transmission line relaying clears well before this (longest is 23 cycles).
- Therefore **YES, complies**

40 – Loss of Field



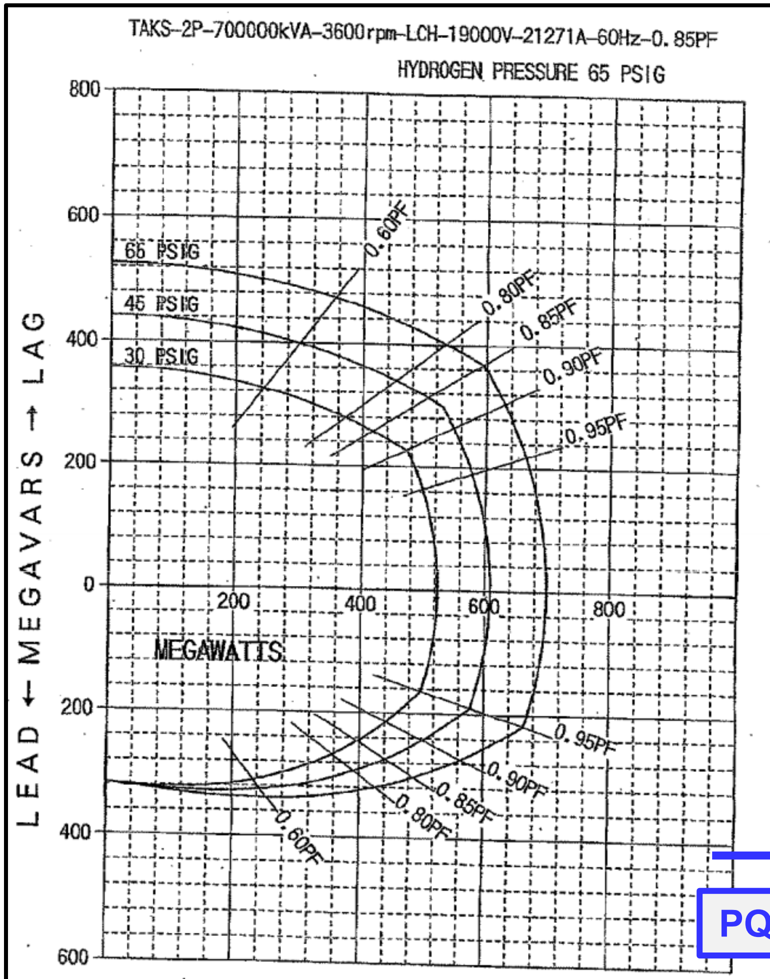
Blocking Inputs = FL, 1

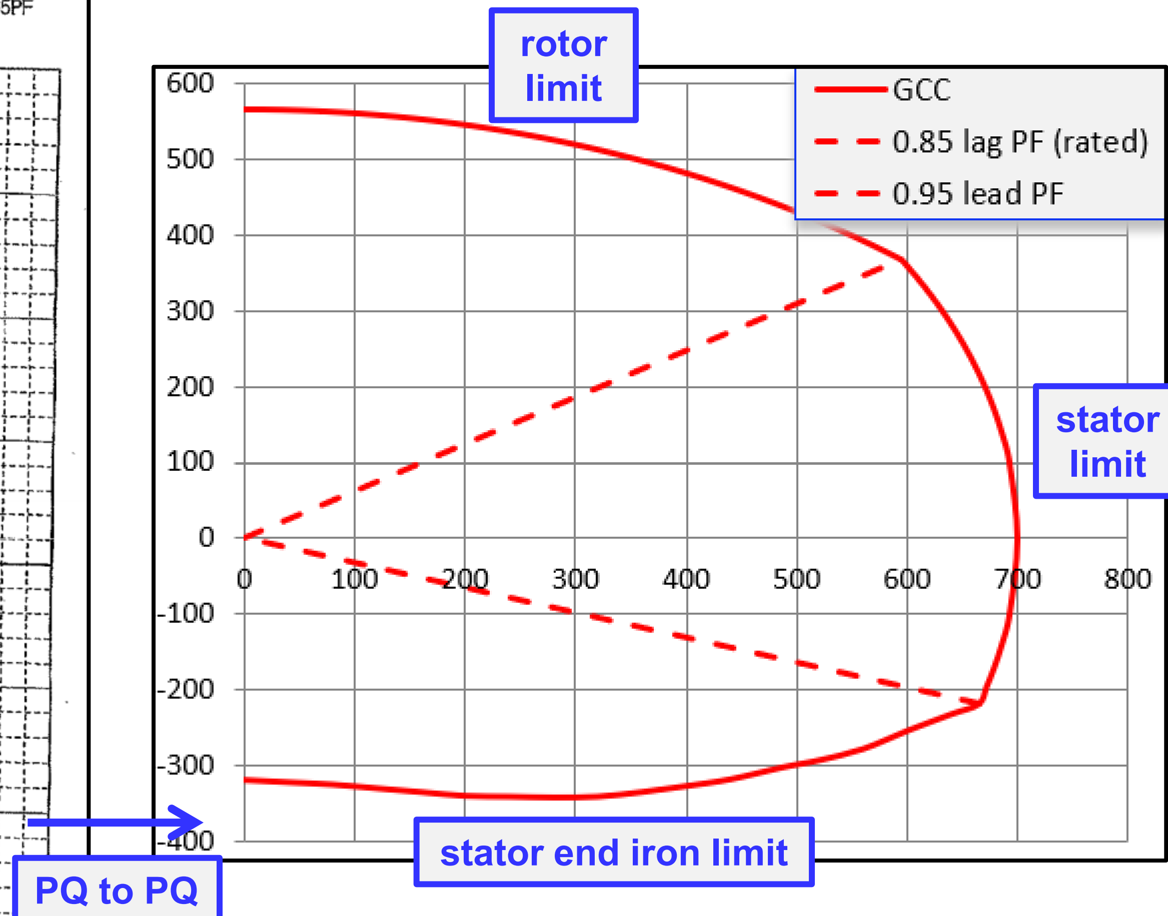
$$Z1 = \frac{V1}{I1}$$

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

40 (LOF) – plot GCC

- First, plot mfg GCC on PQ diagram in software used to show coordination with 40 settings.
- Use plot digitizer app or manually get PQ points from GCC or calculate PQ points to plot GCC:
  - ✓ rotor limit region: circle center at (P,Q) = (0, - jV^2/Xd)
  - ✓ stator limit region: P = S*cosΘ, Q = S*sinΘ
  - ✓ stator end iron limit region: manually translated several PQ points from GCC





40 (LOF) – convert GCC from PQ to RX

Generator Reactive Capability Curve					
Primary Values			Secondary Ohms		
MW	MVAR	Zpri = V²/S*	Zsec = Zpri*CTR/PTR	R	X

all vector quantities:

$S = VI^*$ I^* *by convention*

$$S = V\frac{V^*}{Z^*}$$

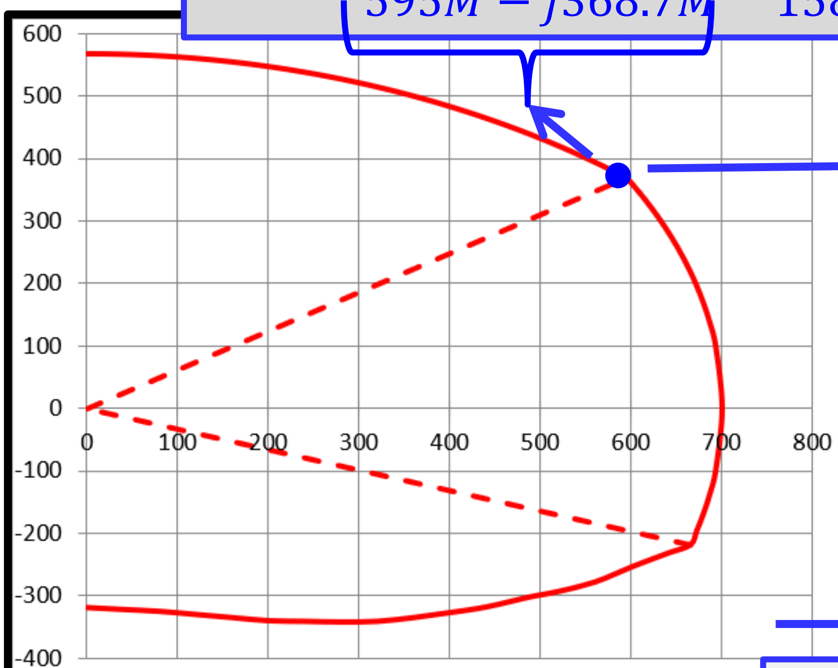
$$\frac{S}{V} = \frac{V^*}{Z^*}$$

$$\frac{S^*}{V^*} = \frac{V}{Z}$$

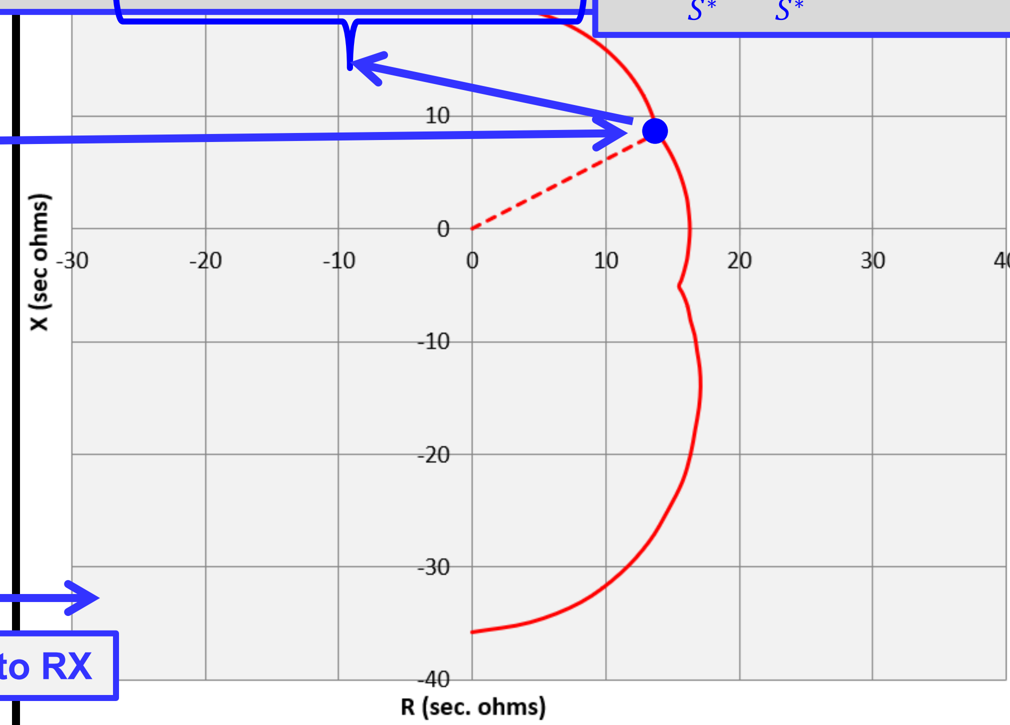
$$Z = \frac{VV^*}{S^*} = \frac{V^2}{S^*}$$

Complex Conjugate

$$Zsec = \frac{19K^2}{595M - j368.7M} \times \frac{5000}{158.3} = 13.85 + j8.58\ \Omega sec$$



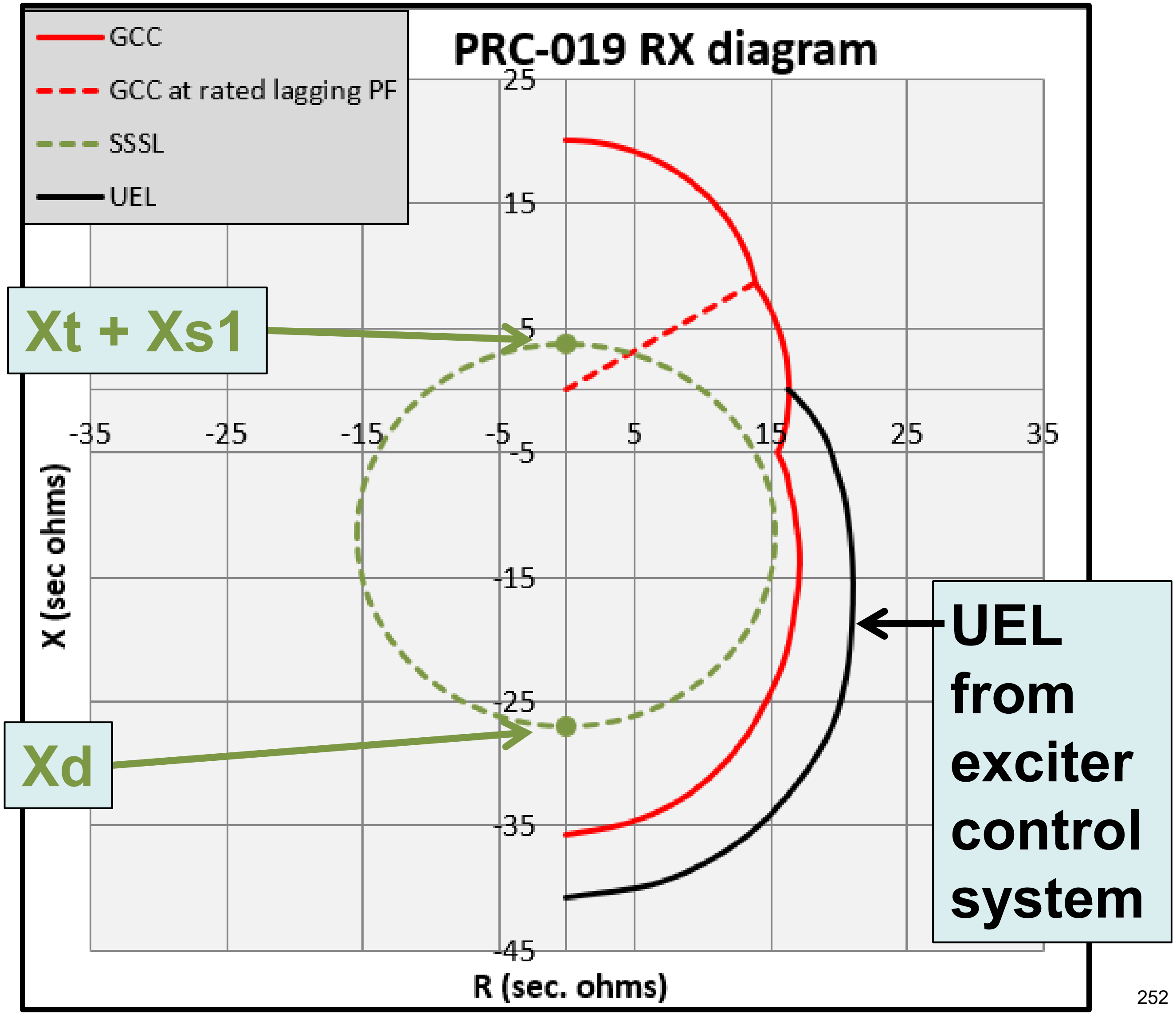
PQ to RX



40 – Loss of Field

- Now, add the UEL and SSSL to the RX diagram:

- SSSL drawn with AVR in manual mode.
- SSSL is a function of the generator and the system to which it is connected.



40 – Loss of Field

- Next, calculate appropriate 40 settings per typical criteria.
- Then plot those 40 settings on the RX diagram with GCC, SSSL, and UEL to check for compliance with PRC-019.
- Also, plot on an RX diagram against the PRC-026 unstable power swing region criteria to check for compliance.
- Adjust settings if necessary to comply with these standards or request waiver.
- **Use Negative Offset Zone 2 Method for primary relay.**
- **Use Positive Offset Zone 2 Method for backup relay.**
  - Provides optimal coordination while still providing full redundancy.

40 #1 – Primary Relay (Negative Offset Zone 2 Method)

Set #1 Circle Diameter = 1 pu if Xd > 1 pu **(or 70% of Xd if Xd < 1 pu)**:

$$\#1\ \text{Circle Diameter} = 1.0 * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 1.0 * \frac{19\text{K}^2}{700\text{M}} * \frac{5000}{158.3} = 16.3\ \text{sec ohms}$$

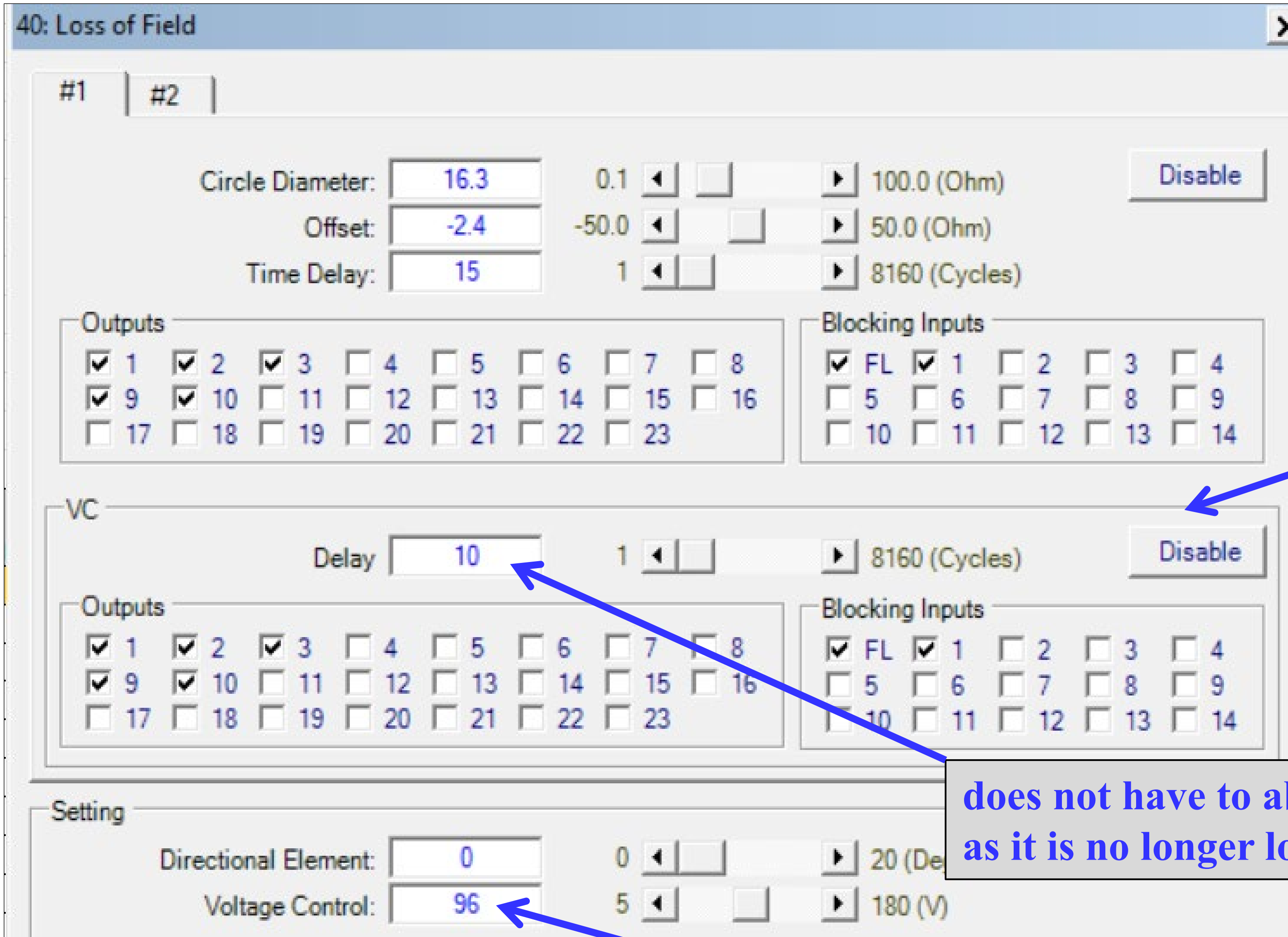
Set #1 Offset = - Xd’/2 (half of the saturated direct axis transient reactance)

$$\#1\ \text{Offset} = -\frac{\text{Xd}'}{2} * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = -\frac{0.295}{2} * \frac{19\text{K}^2}{700\text{M}} * \frac{5000}{158.3} = -2.4\ \text{sec ohms}$$

Per transient stability study results, set the Time Delay to prevent mis-operation during switching transients and stable power swings:

Set #1 Time Delay = 15 cycles (to abide by PRC-026 time criteria, no stability study available)

40 #1 – Primary Relay (Negative Offset Zone 2 Method)



Enable VC to give another, unique element that can trip quicker if accompanied by voltage dip.

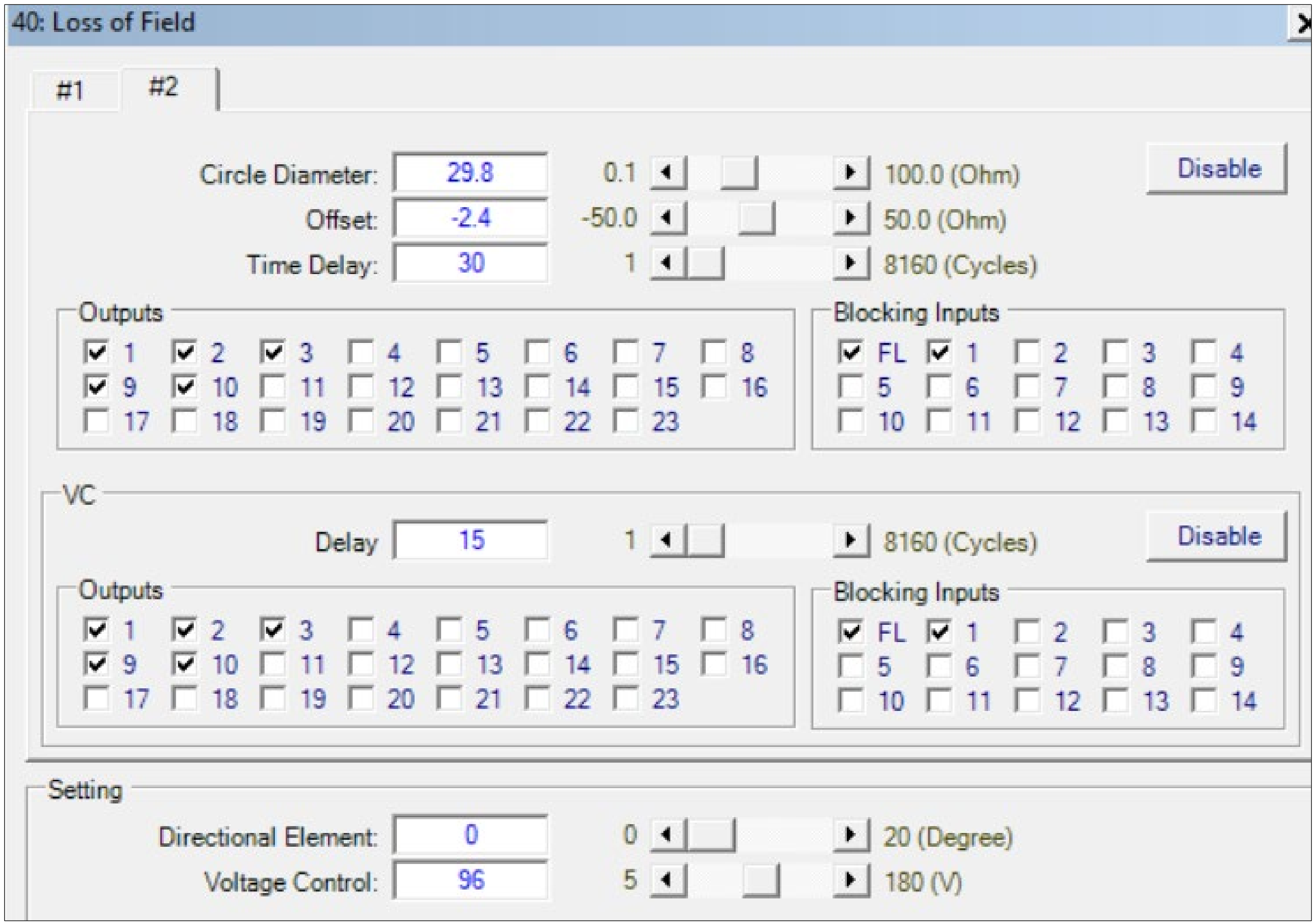
does not have to abide by PRC-026 as it is no longer load responsive

80% of 120 V nominal voltage

40 #2 – Primary Relay (Negative Offset Zone 2 Method)

$$\#2\ \text{Circle Diameter} = \text{Xd} * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 1.83 * \frac{19\text{K}^2}{700\text{M}} * \frac{5000}{158.3} = 29.8\ \text{sec ohms}$$

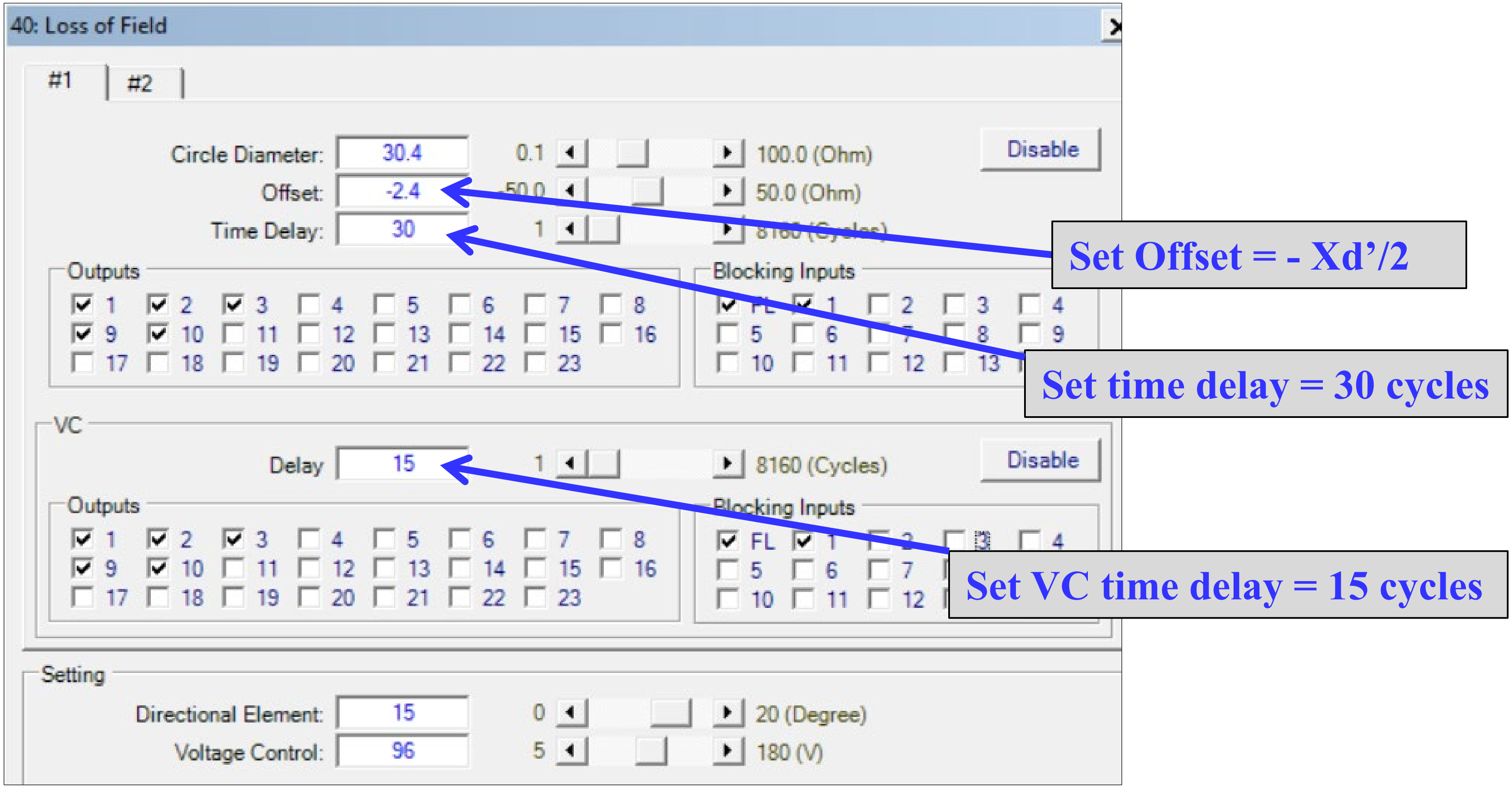
Set same offset as zone 1 with a 30 cycle time delay, and VC Delay of 15 cycles.



40 #1 – Backup Relay (Positive Offset Zone 2 Method)

$$40\ \#1 = (1.1 * Xd - \frac{Xd'}{2}) * \frac{Vbase^2}{Sbase} * \frac{CTR}{VTR} = (1.1 * 1.83 - \frac{0.295}{2}) * \frac{19K^2}{700M} * \frac{5000}{158.3} = 30.4\ \Omega$$

use Unsaturated value for greater coverage



40 #2 – Backup Relay (Positive Offset Zone 2 Method)

Now calculate the zone 2 positive offset mho circle using typical equations:

Set #2 Circle Diameter = Xd + Xt + Xs (unsaturated direct axis synchronous reactance plus the GSU impedance plus the weak system thevenin impedance)

$$\#2\ \text{Circle Diameter} = (\text{Xd} + \text{Xt} + \text{Xs}) * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 33.5\ \ \text{sec ohms}$$

Set #2 Offset = Xt + Xs (GSU impedance plus the weak system thevenin impedance)

$$\#2\ \text{Offset} = (\text{Xt} + \text{Xs}) * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 3.7\ \ \text{sec ohms}$$

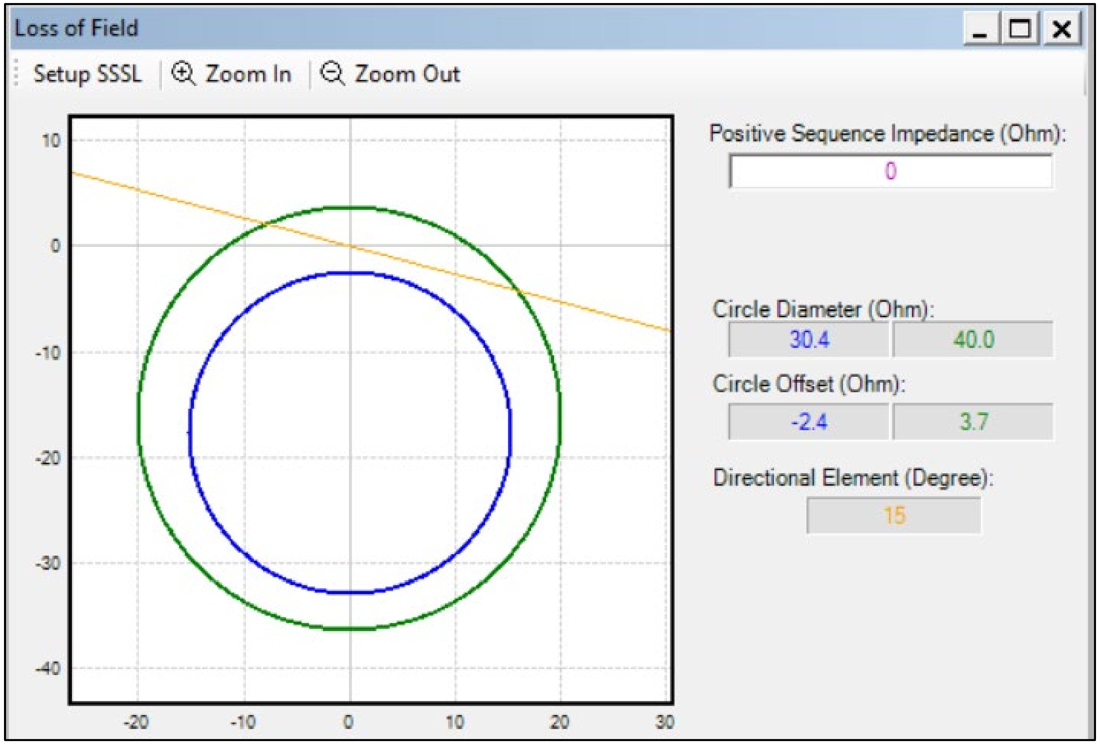
Let's take a PAUSE here to review how to plot these MHO circles.

40 – Loss of Field (plotting the mho circle)

SIDEBAR: How can we plot these 40 MHO circles?

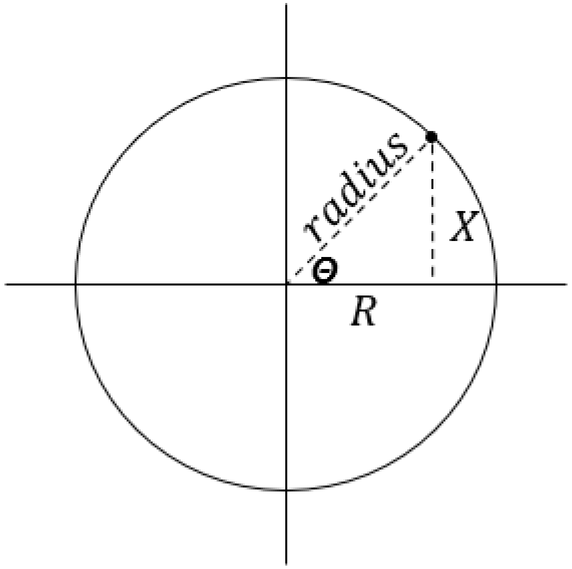
- Old school:

- Some relay mfg software plot the 40 mho circle settings on an RX diagram:



40 – Loss of Field (plotting the mho circle)

- Or can plot it via Mathcad or Excel or some other tool.
- Here, an example using Excel will be demonstrated for the positive offset Zone 2 MHO circle:
- Use equations:
- $R = radius * Cos(\Theta) + R\ circle\ center$
- $X = radius * Sin(\Theta) + X\ circle\ center$
- $radius = \frac{Diameter}{2} = \frac{40.0}{2} = 20.0\ \Omega sec$
- $\Theta = 0° \text{ thru } 360°$
- $R\ circle\ center = 0\ \Omega sec$
- $X\ circle\ center = Offset - radius = 3.7 - 20.0 = -16.3\ \Omega sec$



40 – Loss of Field (plotting the mho circle)

- $R \; = 20.0 * Cos(0°) + 0 = 20.0 \; \Omega$
- $X \; = 20.0 * Sin(0°) - 16.3 = -16.3 \; \Omega$

- Or as entered in Excel:

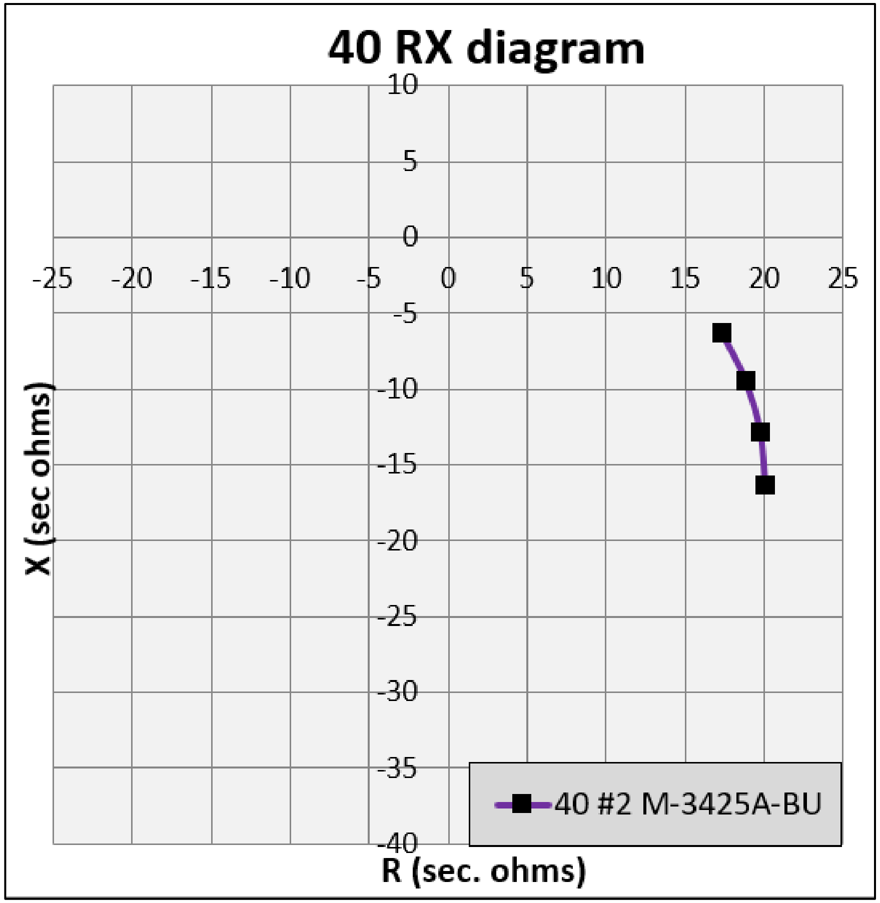
- $R = \$G\$7 * COS(RADIANS(A16)) + \$J\$7$
- $X = \$G\$7 * SIN(RADIANS(A16)) + \$J\$8$

- Then just redo this up to 360° to make a complete circle.

- $R \; = 20.0 * Cos(10°) + 0 = 19.70 \; \Omega$
- $X \; = 20.0 * Sin(10°) - 16.3 = -12.83 \; \Omega$

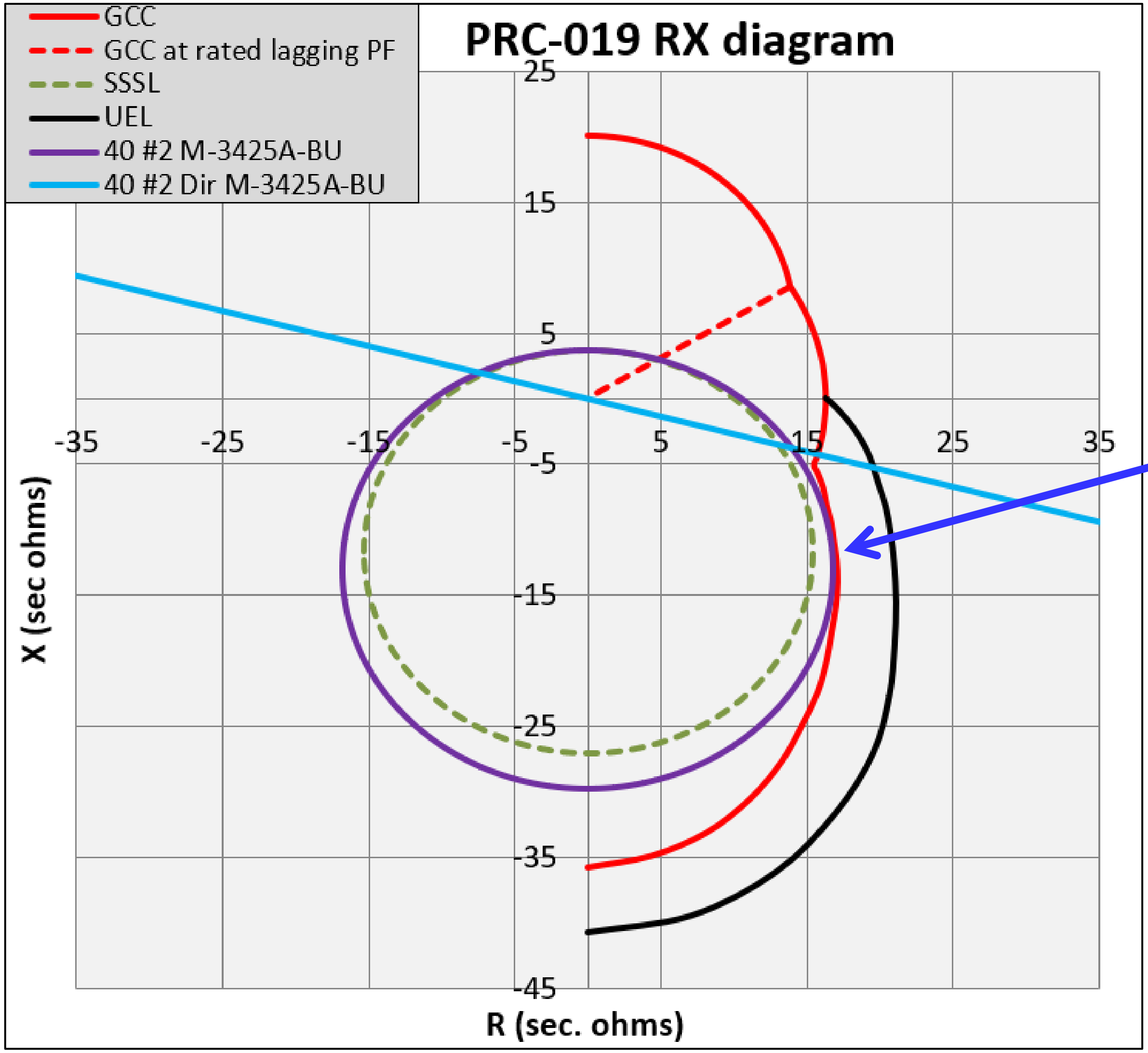
- $R \; = 20.0 * Cos(20°) + 0 = 18.79 \; \Omega$
- $X \; = 20.0 * Sin(20°) - 16.3 = -9.46 \; \Omega$

- $R \; = 20.0 * Cos(30°) + 0 = 17.32 \; \Omega$
- $X \; = 20.0 * Sin(30°) - 16.3 = -6.3 \; \Omega$



40 #2 – Backup Relay (Positive Offset Zone 2 Method)

Plot these settings on the RX diagram with GCC, SSSL, and UEL:

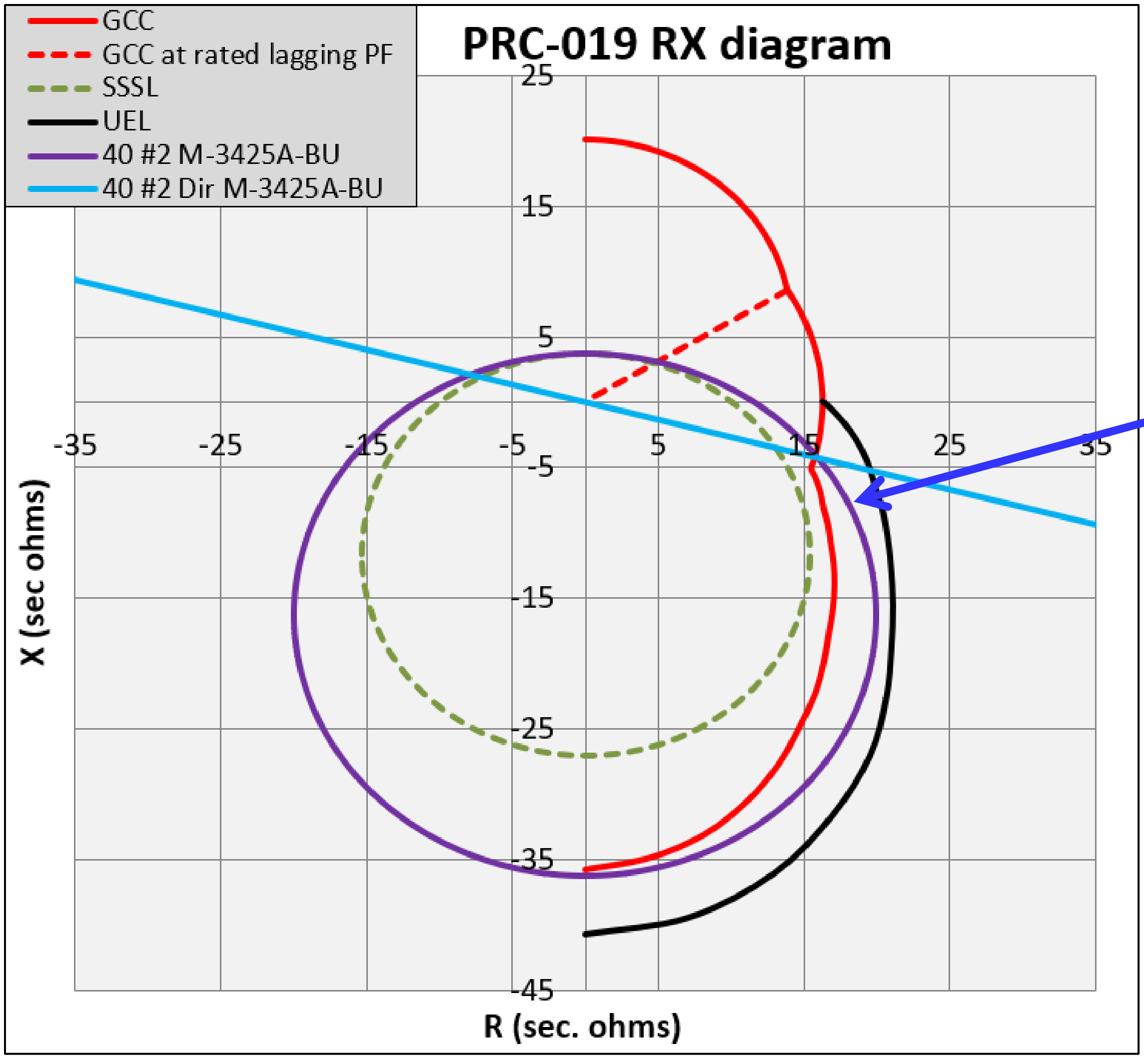


Note, that the zone 2 mho circle plots inside the GCC.

PRC-019 requires it to plot outside the GCC.

40 #2 – Backup Relay (Positive Offset Zone 2 Method)

The resolution is to adjust the zone 2 Diameter and/or Offset settings until the zone 2 mho circle plots outside the SSSL and GCC, but inside the UEL:



Here, the zone 2 Diameter was increased to 40 Ω in order to get it to plot outside the GCC and SSSL, but still inside the UEL.

The Offset was left at 3.7 Ω in this case, however some applications may require adjustment of that setting as well.

40 #2 – Backup Relay (Positive Offset Zone 2 Method)

For representation with the original positive offset zone 2 Diameter and Offset equations, incorporate some adjustment factors (B and D) into the equations:

Set #2 Circle Diameter = B*Xd + Xt + Xs
Set #2 Offset = D*(Xt + Xs)

Start with B = D = 1 to see how it plots.
Adjust Diameter and/or Offset as necessary to get it to plot as required.

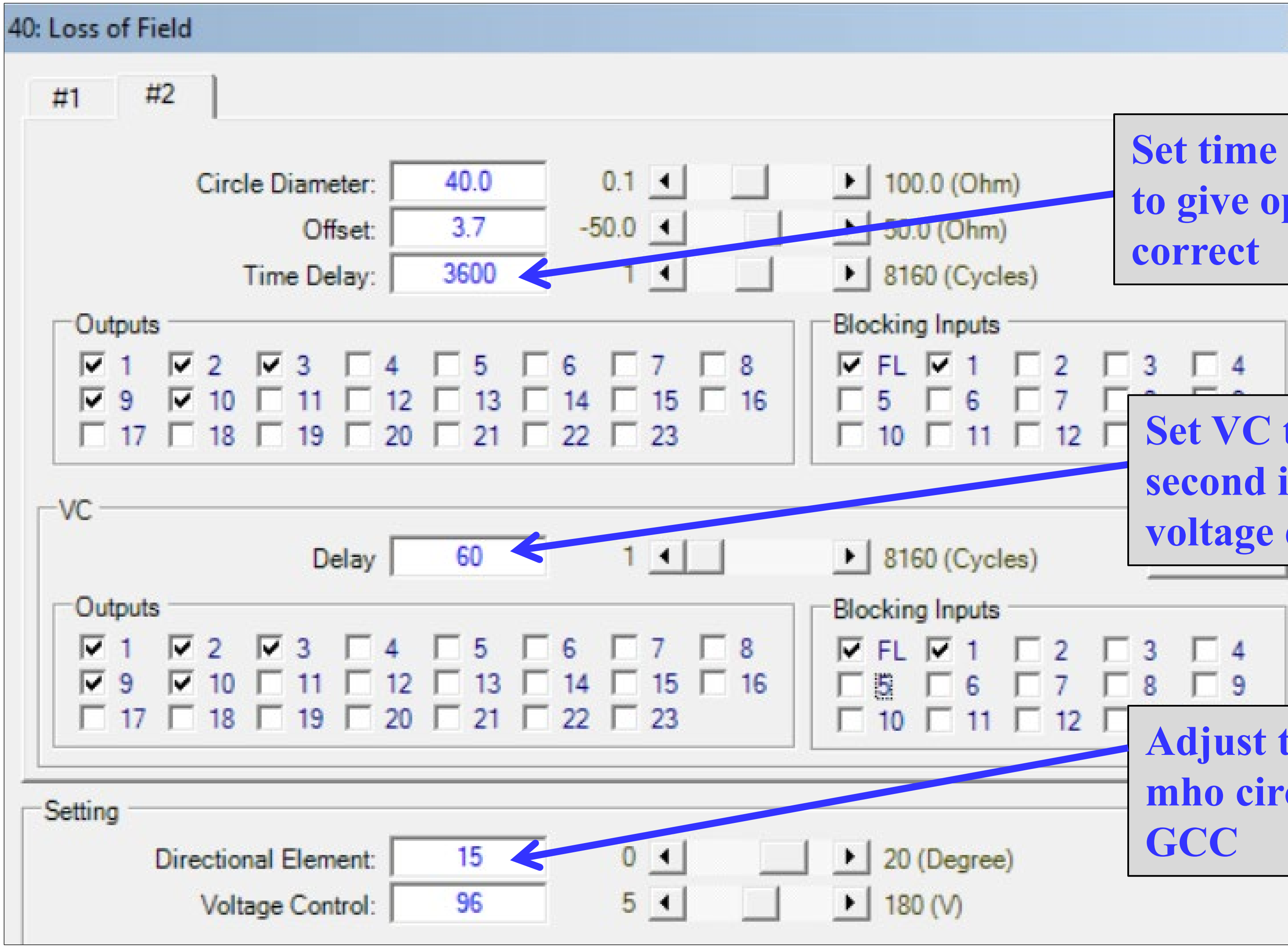
Solve equations for B and D using the new adjusted Diameter and Offset settings:

- **B = 1.2176**
- **D = 1.0000** **(the Offset was not adjusted in this case)**

$$\#2\ \text{Circle Diameter} = (\text{B} * \text{Xd} + \text{Xt} + \text{Xs}) * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 40.0\ \text{sec ohms}$$

$$\#2\ \text{Offset} = \text{D} * (\text{Xt} + \text{Xs}) * \frac{\text{Vbase}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = 3.7\ \text{sec ohms}$$

40 zone 2 – Loss of Field (Positive Offset Zone 2 Method)



Set time delay = 60 seconds to give operator time to correct

Set VC time delay = 1 second if accompanied by voltage dip

Adjust to where the zone 2 mho circle intersects with GCC

40 Loss of Field

Evaluate settings against PRC-019 and PRC-026

PRC-019-2

Verify coordination of generator voltage regulating controls with protective relays and equipment capabilities

Coordinate

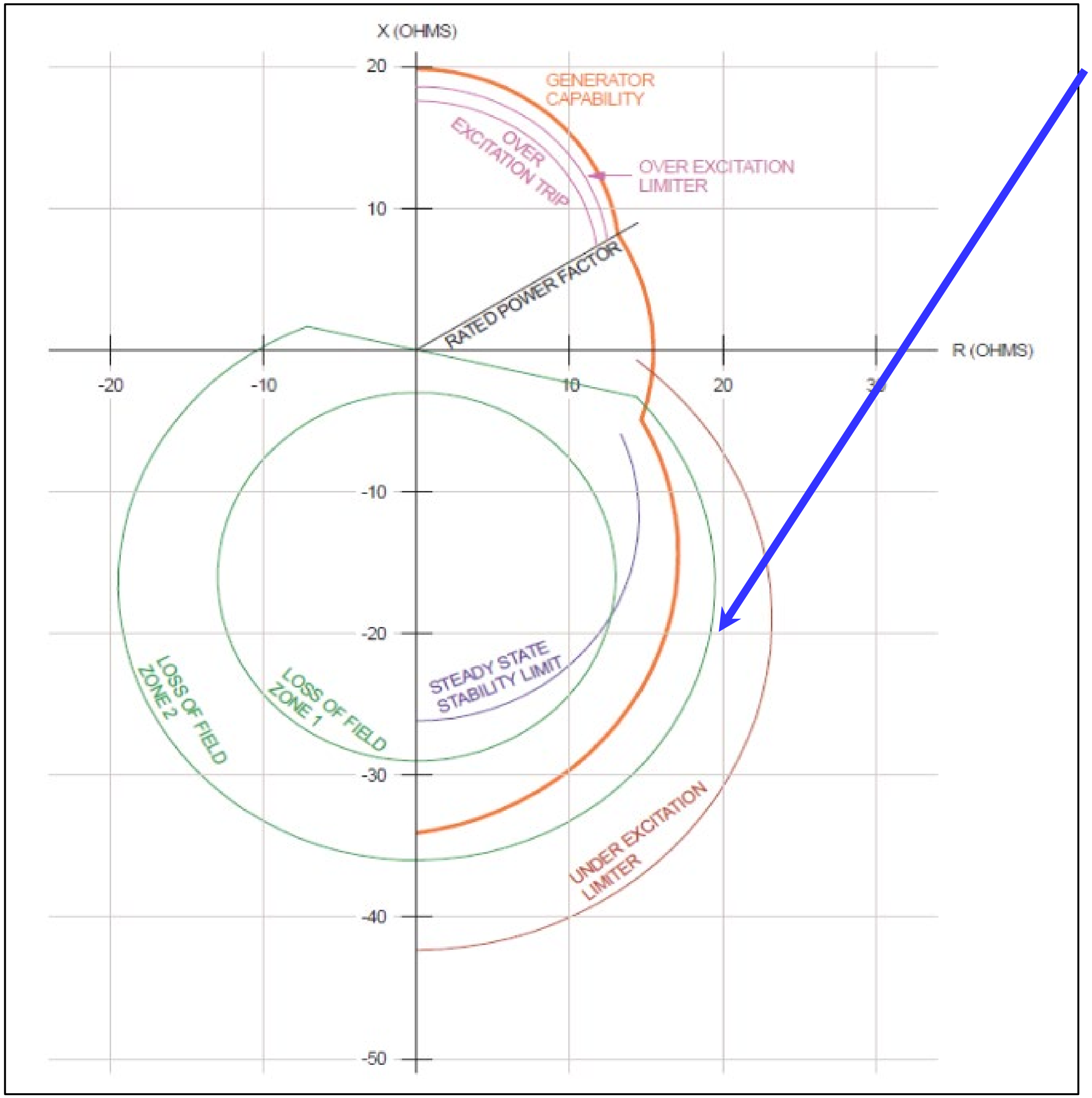
- Voltage Regulating Controls
  - 24EX, VPFL, 40EX, 59EX, OEL, UEL, Field I*T trip
- Protection
  - 24, **40**, 59
- Generating Unit or Plant Capabilities
  - GCC, SSSL

Per section B.R1-1.1.1, the in-service limiters are set to operate prior to the protection elements tripping.

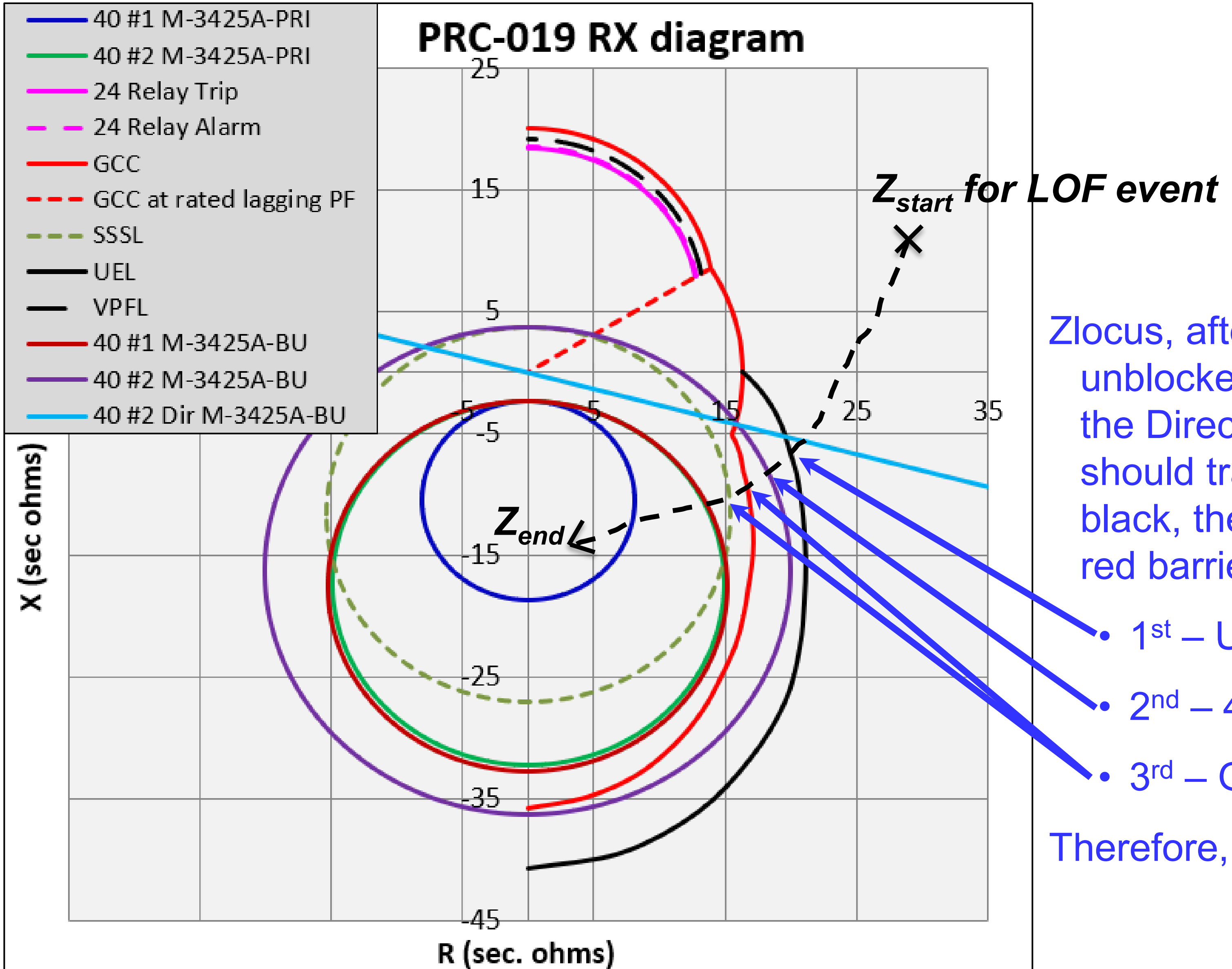
Per section B.R1-1.1.2, the protective elements will trip prior to equipment damage or stability limits (SSSL).

PRC-019-2

Example curve set from PRC-019-2 Section G, Attachment 2



- **Notice that this example coordination curve set shows the 40 zone 2 mho circle plotted between the UEL and the GCC/SSSL.**
- **And a strict interpretation of section B.R1-1.1.2 does require that the LOF protection plot outside the GCC and SSSL on an RX diagram.**
- **This is typically only achievable using the positive offset zone 2 method.**

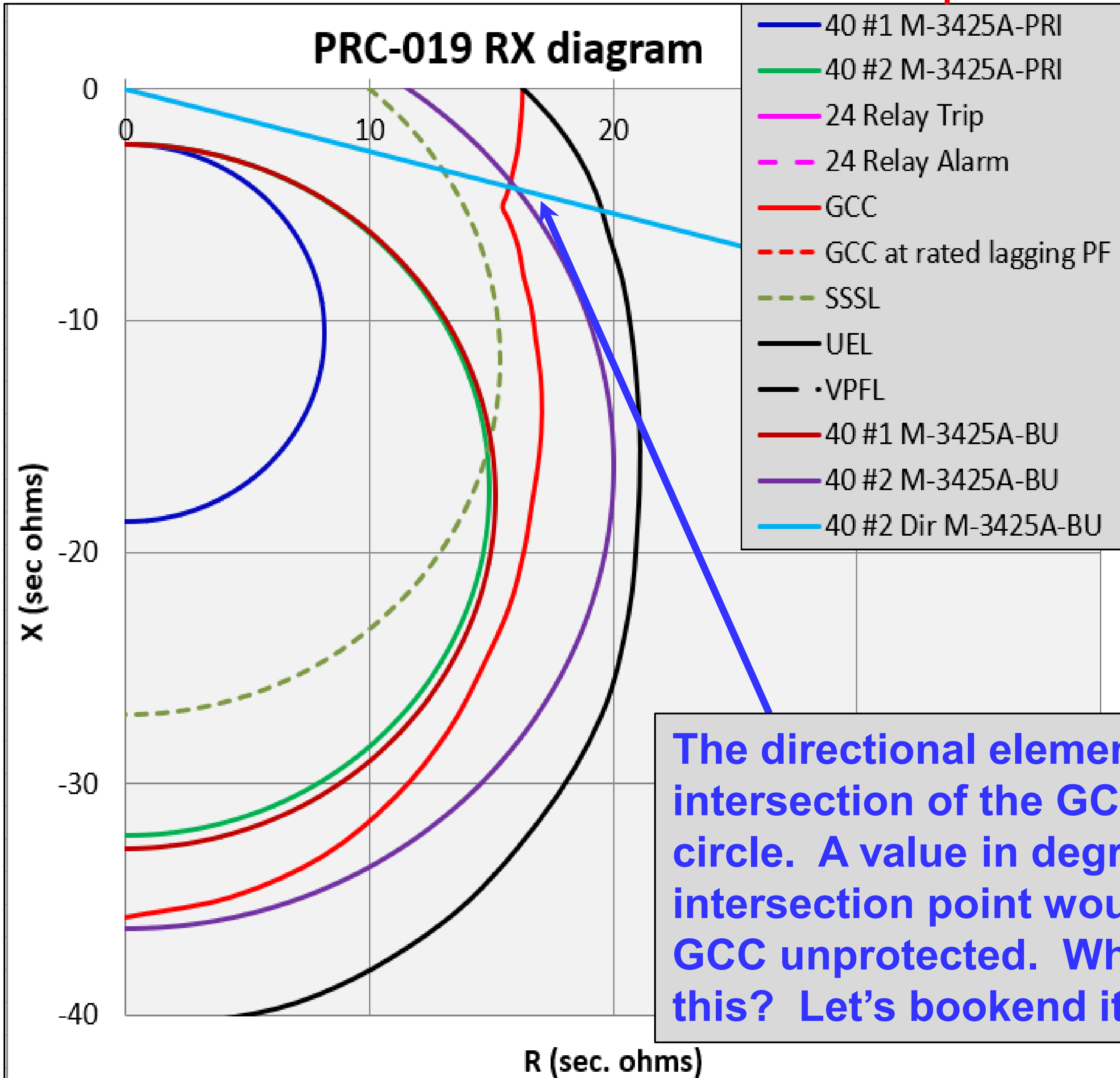


Zlocus, after becoming unblocked by crossing the Directional Line, should traverse the black, then purple, then red barriers i.e.:

- 1st – UEL
- 2nd – 40 trip
- 3rd – GCC and SSSL

Therefore, Yes, complies.

PRC-019-2: Zoomed-in to the 4th quadrant



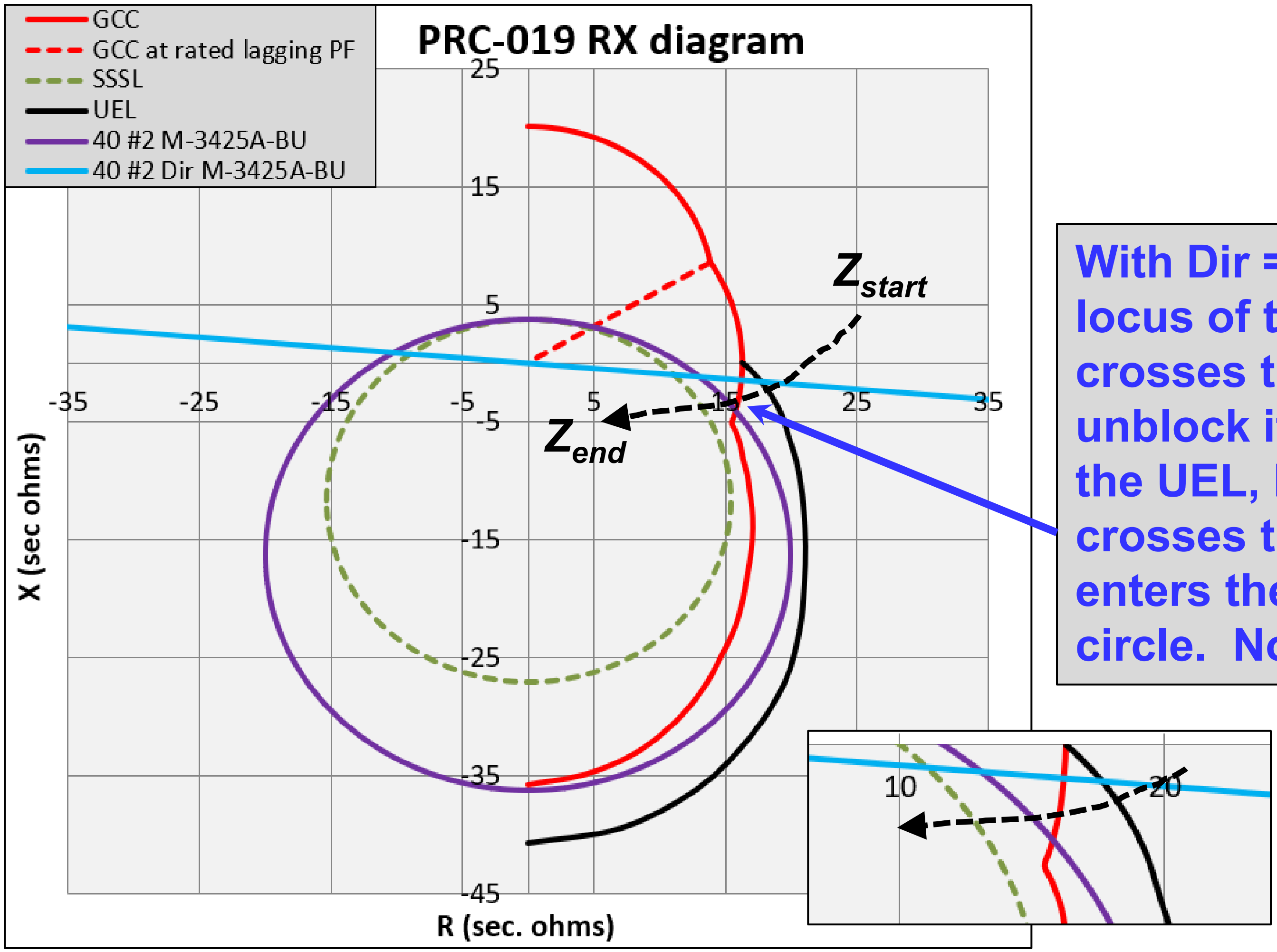
40 #1 & #2 PRI and 40 #1 BU mho circles do not comply with PRC-019 as they plot inside the GCC.

However, 40 #2 BU using the positive offset zone 2 method allows full coverage of the GCC and SSSL and plots inside the UEL; therefore **Yes**, these settings do comply with standard.

The directional element should be set at the intersection of the GCC and the 40 zone 2 mho circle. A value in degrees that is less than this intersection point would leave a portion of the GCC unprotected. What exactly is meant by this? Let's bookend it --------------→

PRC-019-2

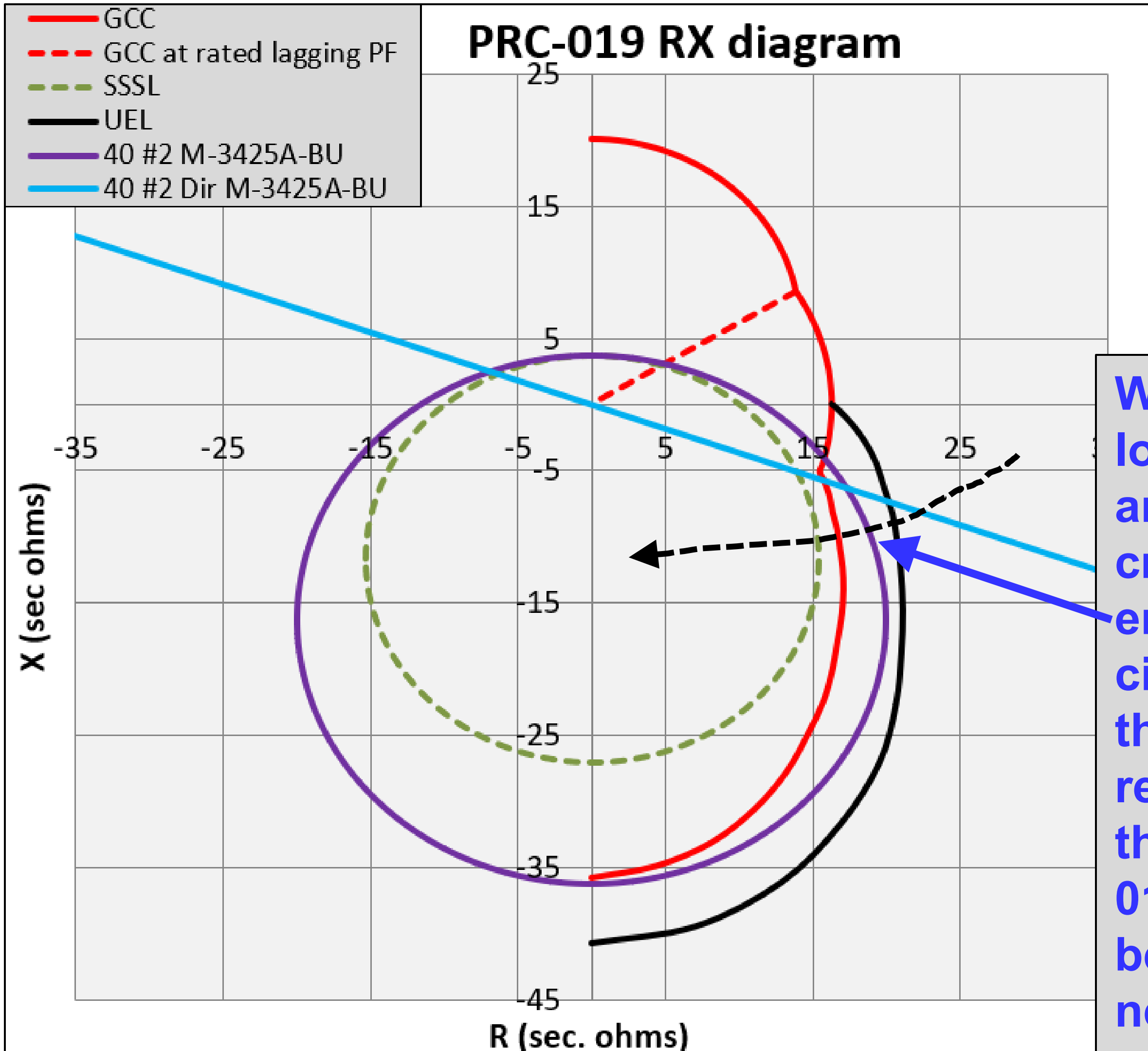
The Directional element must block the mho circle in the first quadrant as that is normal operating region, however the question is what portion of the 4th quadrant should be blocked as well? Let's first look if the Directional element were set to 5°:



With Dir = 5°, notice how the locus of the LOF event first crosses the Dir line to unblock it, then it crosses the UEL, however then it crosses the GCC before it enters the zone 2 mho circle. Not Cool!

PRC-019-2

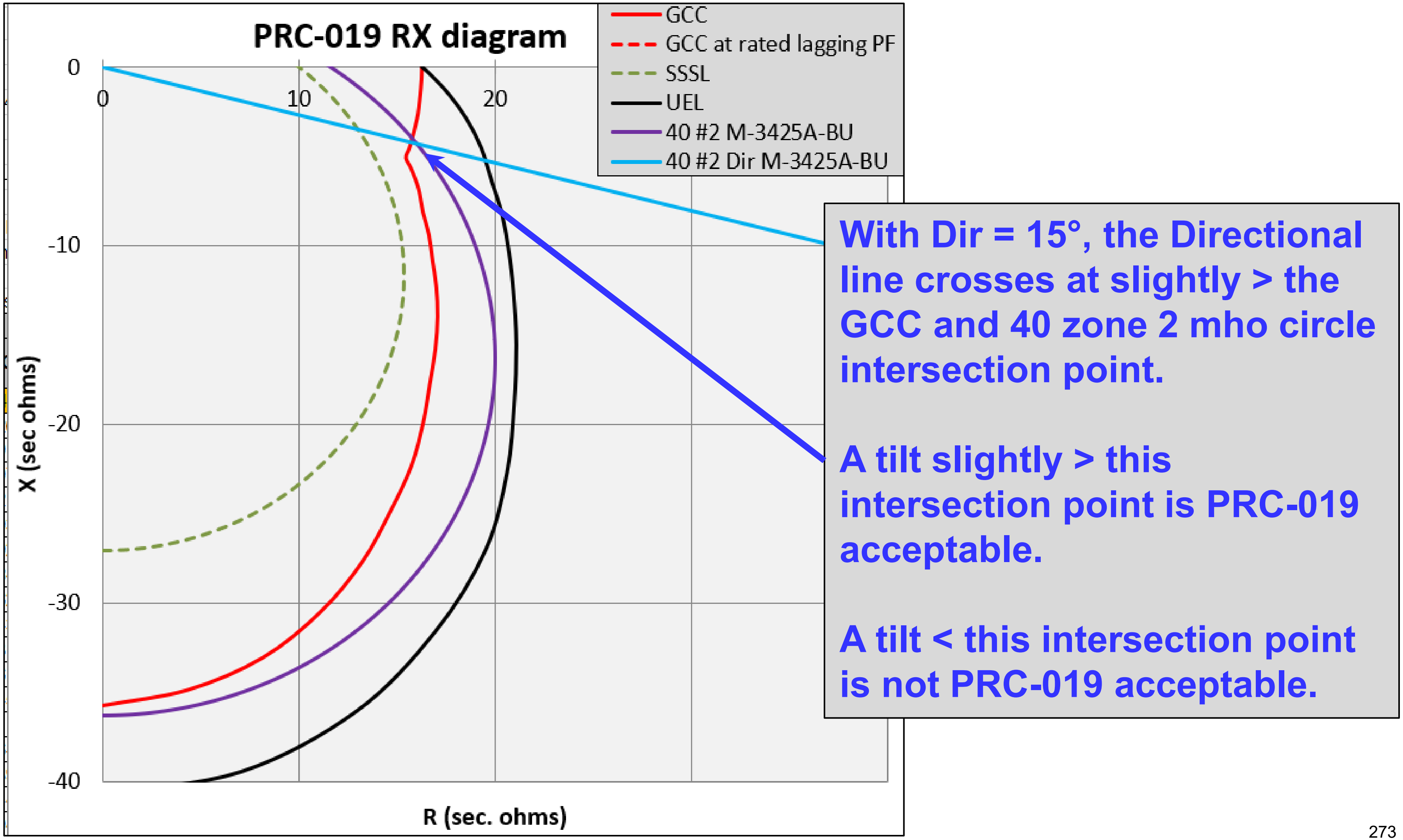
How about if the Directional element were set to 20°:



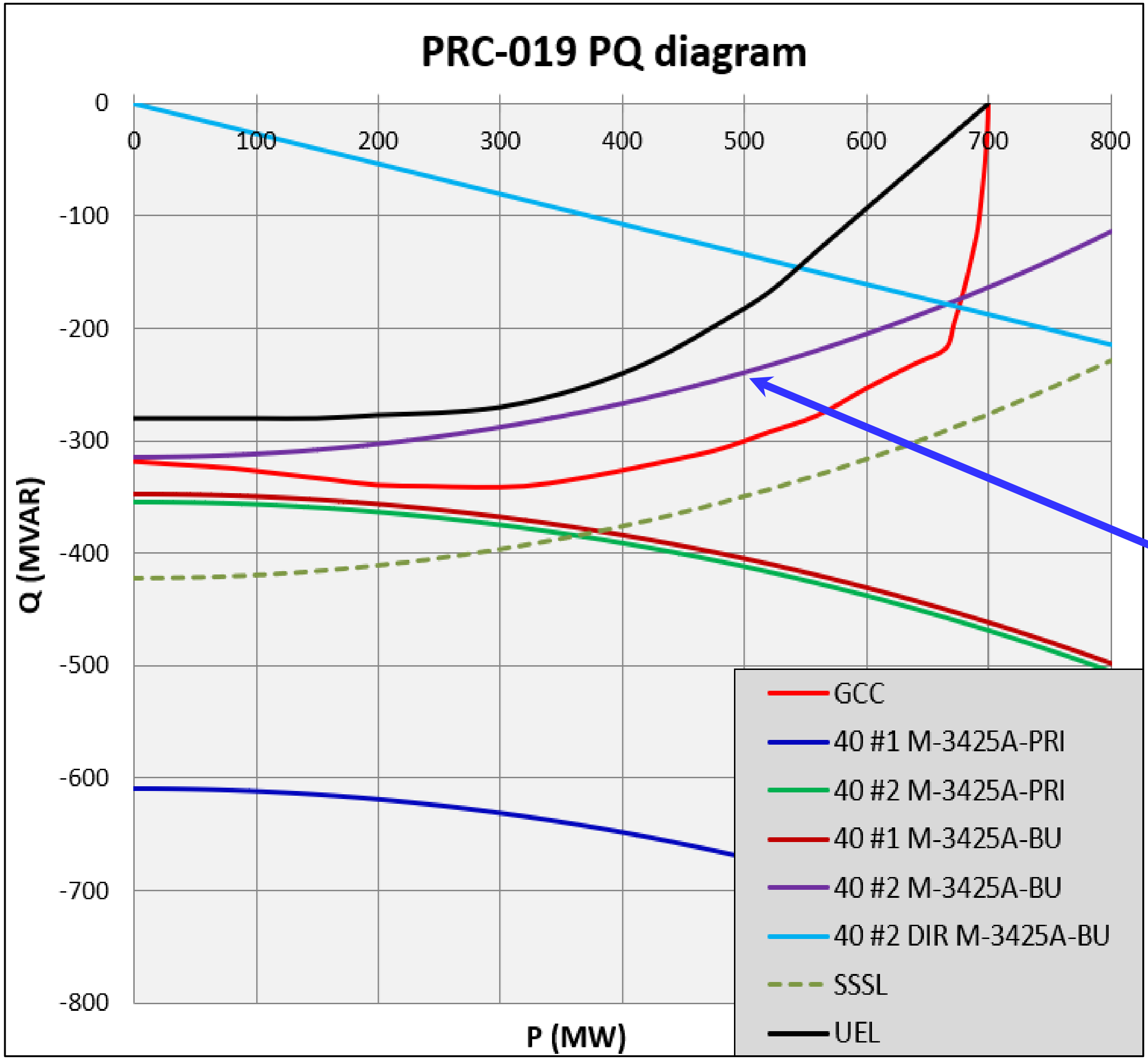
With Dir = 20°, now after the locus crosses the Dir line and becomes armed, it then crosses the UEL, then it enters the 40 zone 2 mho circle and then it crosses the GCC and SSSL as required by PRC-019. So, this is acceptable per PRC-019 but is the mho circle being blocked more than it needs to be blocked? Yep.

PRC-019-2

Therefore, an optimal Directional element setting would be ≥ the GCC and mho circle intersection point, which in this case came out to be Directional = 15°:



PRC-019-2



- Or can plot on a PQ diagram instead, where the order of the curves are flipped as compared to the RX diagram because the operating point on a PQ diagram goes outward from the origin, whereas on an RX diagram the operating point goes inward towards the origin.
- Therefore, on this PQ diagram, the 40 zone 2 mho circle with positive offset plots outside the UEL, but inside the GCC and SSSL.

PRC-026-1

Relay Performance during Stable Power Swings.

Criterion A: 21, 40, and 78 (within blinders) must be completely contained within the unstable power swing region (lens, upper and lower loss of synchronism circles) or have time delay ≥ 15 cycles.

Criterion B: 50,51 pickup must be > criteria or have time delay ≥ 15 cycles.

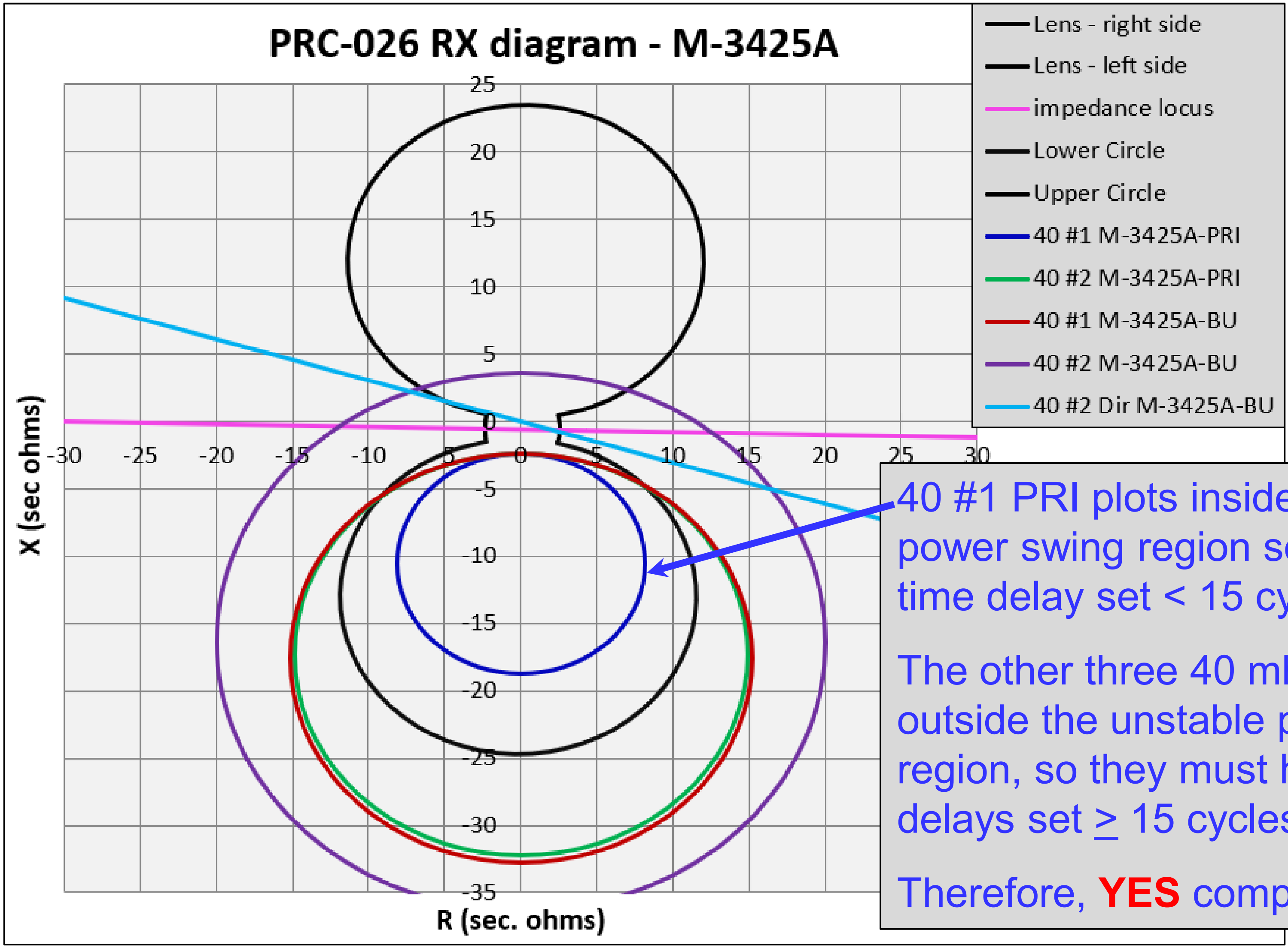
<u>Evaluate the following relay settings against criterion:</u>

- Generator Protection
    - 21
    - **40**
    - 78
    - 50
    - 50DT

- GSU Transformer Protection
    - high side 50
    - high side 51

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.

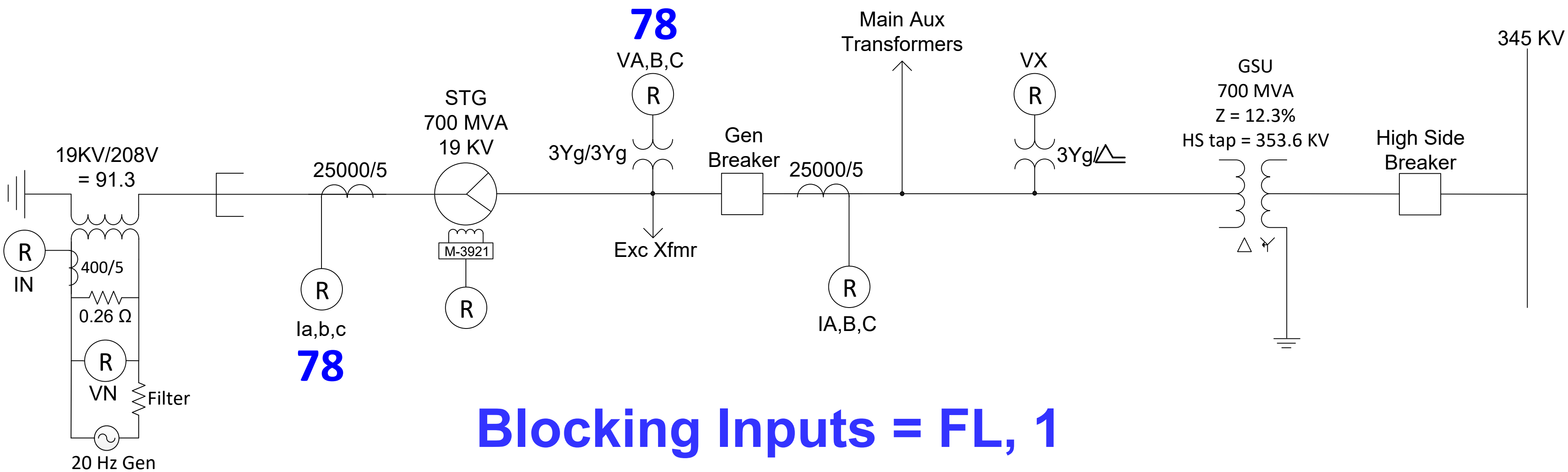


40 #1 PRI plots inside the unstable power swing region so it may have its time delay set < 15 cycles.

The other three 40 mho circles plot outside the unstable power swing region, so they must have their time delays set ≥ 15 cycles, which they do.

Therefore, **YES** complies.

78 – Out of Step



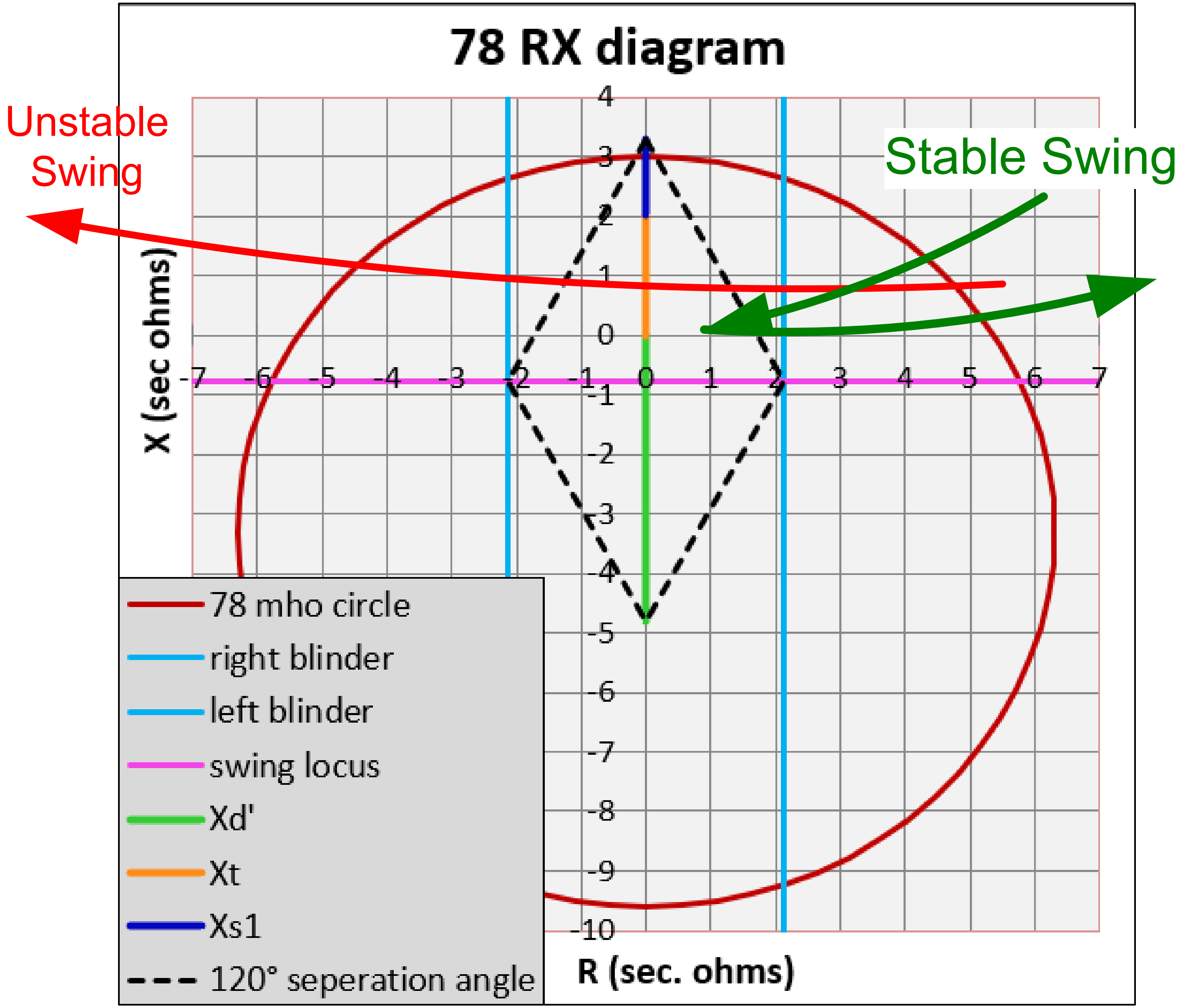
Blocking Inputs = FL, 1

$$Z1 = \frac{V1}{I1} = \frac{\frac{1}{3} * (V_A + aV_B + a^2V_C)}{\frac{1}{3} * (I_a + aV_b + a^2V_c)} = \frac{V_1 \angle \theta_{V1}}{I_1 \angle \theta_{I1}} = \frac{V_1}{I_1} \angle (\theta_{V1} - \theta_{I1})$$

$V_1 = V_{LG}$ *with VT Configuration = LG*

$V_1 = \frac{V_{LL}}{\sqrt{3}} \angle -30°$ *with VT Configuration = LL or LG-LL*

78 – Out of Step



78 – Out-of-Step Protection Characteristic

First, calculate the supervisory MHO element for the 78 function so that only power swings within the gen/GSU zone will arm this function. NOTE: The impedance measurement for the 78 function starts at the generator VT location which is the origin of the RX diagram.

Relay mfgs may express the 78 function's MHO element using different approaches:

- Diameter and Offset
- Forward Reach and Reverse Reach

The different approaches are related as such:

- Diameter = Forward Reach + Reverse Reach
- Offset = Forward Reach

The Forward Reach or Offset is typically set to 2 * Xd' with a negative sign so it is looking into the generator or down into the third and fourth quadrants of the RX diagram.

The Reverse Reach is typically set to 1.5 * Xt with a positive sign so it is looking towards the GSU and out onto the system or up into the first and second quadrants of the RX diagram.

Therefore, the supervisory MHO element is defined as such:

- $\boldsymbol{Diameter = 2Xd' + 1.5Xt}$
- $\boldsymbol{Offset = -2Xd'}$

78 – Out of Step

- Use the **<u>Saturated</u>** Xd' value for the 78 calculations as it is used to derive the unstable power swing region as designated in PRC-026.
- For graphical simplicity and to be more conservative:
  - model Zt as all Xt
  - model Zs1 as all Xs1

Using per unit math and converting to secondary ohms:

- $\text{Zactual} = \text{Zpu} * \text{Zbase} * \frac{\text{CTR}}{\text{VTR}}$

$$\text{Circle Diameter} = (2 * \text{Xd}' + 1.5 * \text{Xt}) * \frac{\text{VbaseLS}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}}$$

$$= (2 * 0.295 + 1.5 * 0.123049) * \frac{19\text{K}^2}{700\text{M}} * \frac{5000}{158.3} = 12.6 \text{ sec ohms}$$

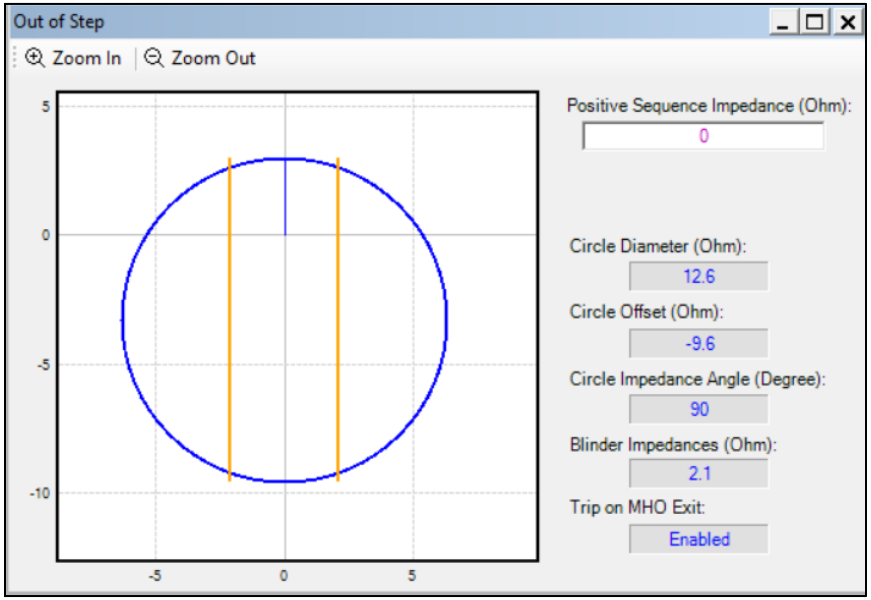
$$\text{Offset} = (-2 * \text{Xd}') * \frac{\text{VbaseLS}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}} = (-2 * 0.295) * \frac{19\text{K}^2}{700\text{M}} * \frac{5000}{158.3} = -9.6 \text{ sec ohms}$$

78 – Out of Step

SIDEBAR: How can we plot this 78 function's supervisory MHO element with the calculated Diameter and Offset?

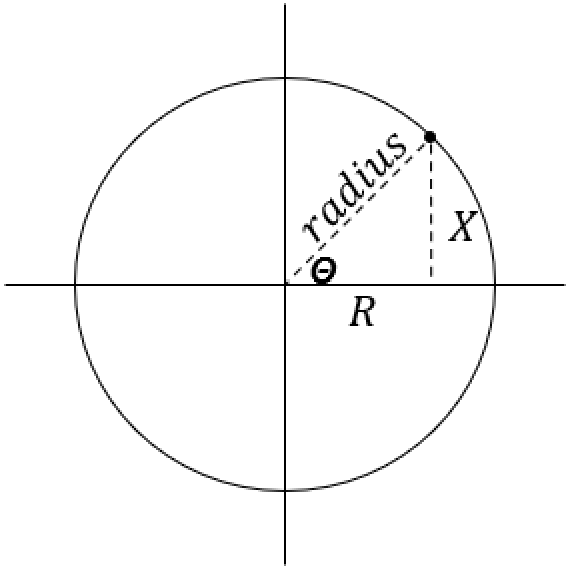
- Old school:

- Some relay mfg software shows a plot of the mho circle on an RX diagram as well:



78 – Out of Step

- Or can plot it via Mathcad or Excel or some other tool.
- Here, an example using Excel will be demonstrated:
- Use equations:
- $R = radius * Cos(\Theta) + R\ circle\ center$
- $X = radius * Sin(\Theta) + X\ circle\ center$
- $radius = \frac{Diameter}{2} = \frac{12.6}{2} = 6.3\ \Omega\text{sec}$
- $\Theta = 0°$ thru $360°$
- $R\ circle\ center = 0\ \Omega\text{sec}$ (as the circle is centered with respect to X axis)
- $X\ circle\ center = radius + Offset = 6.3 + -9.6 = -3.3\ \Omega\text{sec}$



78 – Out of Step

- $R \ = 6.3 * Cos(0°) + 0 = 6.3\ \Omega sec$
- $X \ = 6.3 * Sin(0°) - 3.3 = -3.3\ \Omega sec$

- Or as entered in Excel:

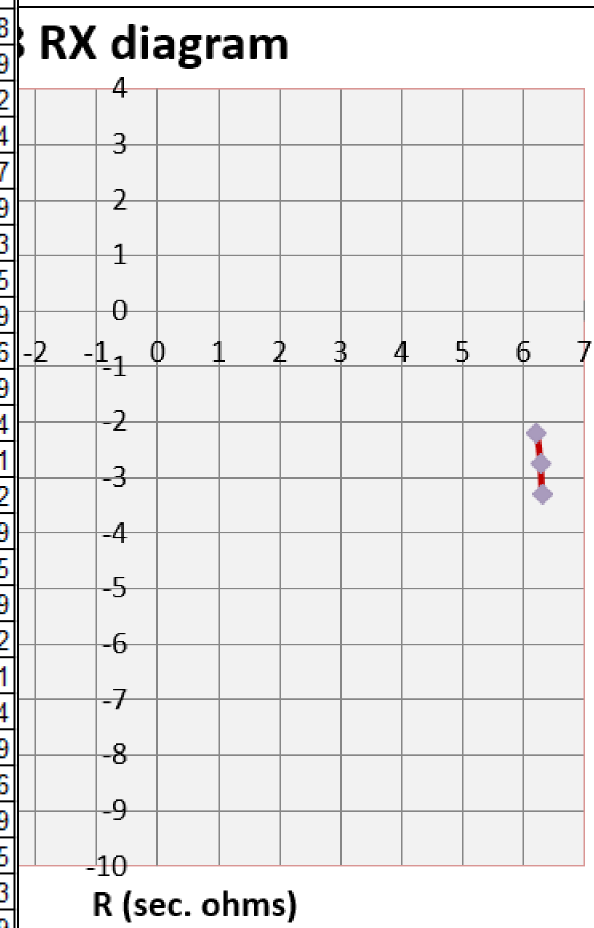
- $R = \$G\$4 * COS(RADIANS(A14)) + \$J\$4$
- $X = \$G\$4 * SIN(RADIANS(A14)) + \$J\$5$

- Then just redo this up to 360°
  to make a complete circle.

- $R \ = 6.3 * Cos(5°) + 0 = 6.28\ \Omega sec$
- $X \ = \ 6.3 * Sin(5°) - 3.3 = -2.75\ \Omega sec$

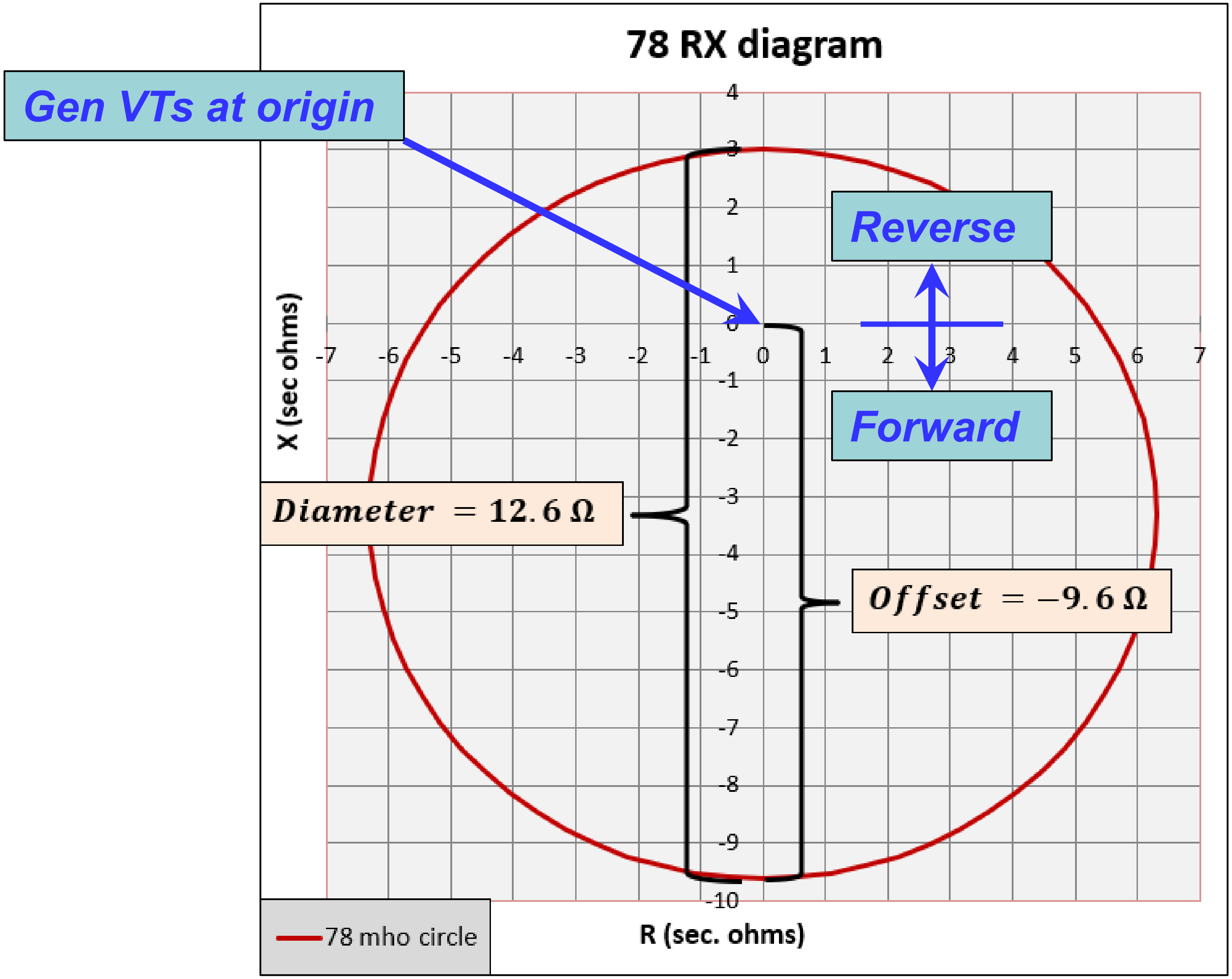
- $R \ = 6.3 * Cos(10°) + 0 = 6.21\ \Omega sec$
- $X \ = \ 6.3 * Sin(10°) - 3.3 = -2.21\ \Omega sec$

angle	78 mho circle	
	R78	X78
0	6.3087	-3.30189
5	6.284693	-2.75206
10	6.212857	-2.2064
15	6.093736	-1.66908
20	5.928239	-1.14419
25	5.717624	-0.63572
30	5.463494	-0.14754
35	5.167784	0.316627
40	4.832745	0.753259
45	4.460924	1.15903
50	4.055154	1.53085
55	3.618522	1.86589
60	3.15435	2.1616
65	2.666172	2.415729
70	2.157702	2.626344
75	1.632812	2.791841
80	1.095494	2.910962
85	0.549839	2.982799
90	3.86E-16	3.006805
95	-0.54984	2.982799
100	-1.09549	2.910962
105	-1.63281	2.791841
110	-2.1577	2.626344
115	-2.66617	2.415729
120	-3.15435	2.1616
125	-3.61852	1.86589
130	-4.05515	1.53085
135	-4.46092	1.15903
140	-4.83274	0.753259
145	-5.16778	0.316627
150	-5.46349	-0.14754
155	-5.71762	-0.63572
160	-5.92824	-1.14419
165	-6.09374	-1.66908
170	-6.21286	-2.2064



78 – Out of Step

- Now, plot the entire circle for the 78 function's supervisory MHO element:



78 – Out of Step

- Next, calculate the Blinder assuming a separation angle δ of 120° (as specified in PRC-026). 120° would typically prevent the system from returning to a stable equilibrium. Start by converting Xd', Xt, and Xs1 to Ωsec and summing:

Once again, use pu math and convert to secondary ohms: $Xactual = Xpu * Xbase * \frac{CTR}{VTR}$

- $Xd' = 0.295 * \frac{19K^2}{700M} * \frac{5000}{158.3} = 4.81\ \Omega$

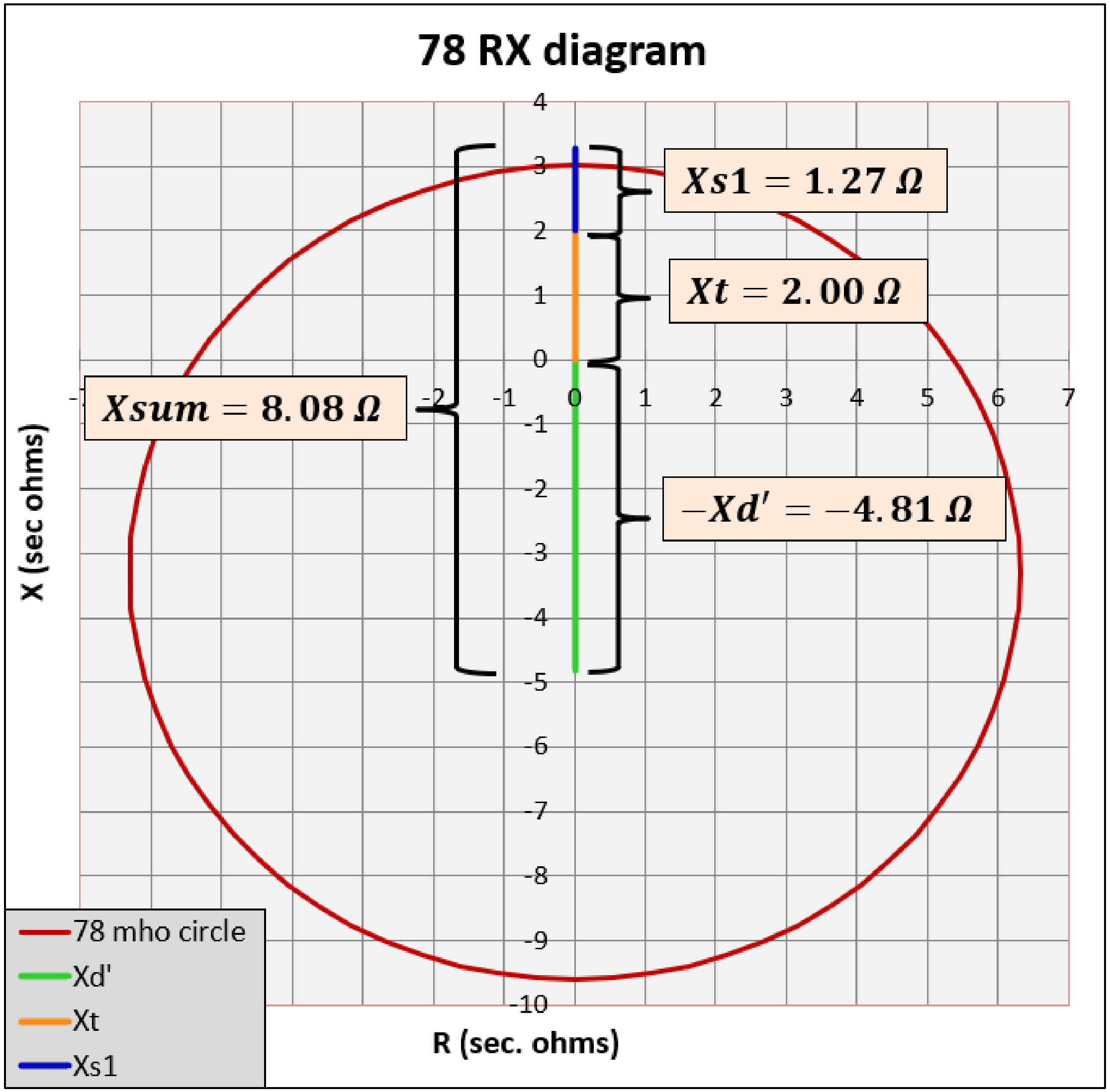
- $Xt = 0.123049 * \frac{19K^2}{700M} * \frac{5000}{158.3} = 2.00\ \Omega$

- $Xs1 = 0.078060 * \frac{19K^2}{700M} * \frac{5000}{158.3} = 1.27\ \Omega$

- $Xsum = Xd' + Xt + Xs1 = 4.81 + 2.00 + 1.27 = 8.08\ \Omega$

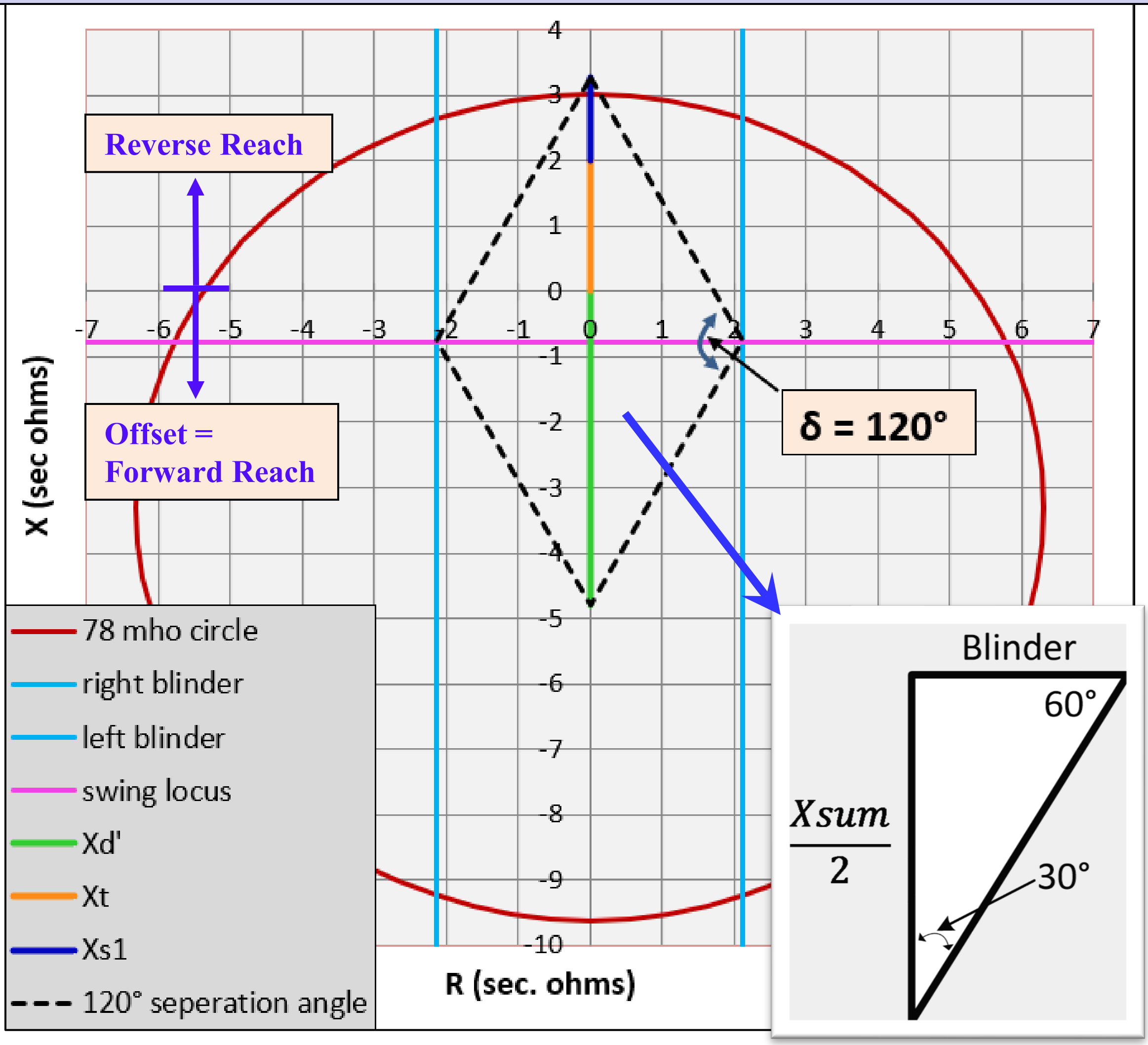
78 – Out of Step

- Now, add this to the RX diagram with the MHO circle:



78 – Out of Step

- Next, add a swing locus (per GER-3180, GE paper "Application of Out-of-Step Blocking and Tripping Relays“) that bisects Xsum and add 120° separation angle:



$$\tan 30° = \frac{opp}{adj} = \frac{Blinder}{\frac{Xsum}{2}}$$

$$Blinder = \frac{Xsum}{2} * \tan 30°$$

$$\tan 30° = \frac{1}{\sqrt{3}}$$

$$Blinder = \frac{Xsum}{2 * \sqrt{3}}$$

78 – Out of Step

$$\text{Blinder} = A * \frac{(Xd' + Xt + Xs1)}{2 * \sqrt{3}} * \frac{\text{VbaseLS}^2}{\text{Sbase}} * \frac{\text{CTR}}{\text{VTR}}$$

$$= 0.91 * \frac{(0.295 + 0.123049 + 0.078060)}{2 * \sqrt{3}} * \frac{19K^2}{700M} * \frac{5000}{158.3} = 2.1 \text{ sec ohms}$$

The A multiplication factor was chosen to comply with PRC-026 (gets the blinders inside the unstable power swing region). This has the effect of increasing the separation angle greater than the 120 degrees which is allowed by PRC-026.

NOTE: If the Unsaturated Xd’ is used in PRC-026 instead of the Saturated value to calculate the unstable power swing region, it is possible that this multiplication factor “A” may not be required; however, the Saturated values were used to calculate the blinder and used in PRC-026 to calculate the unstable power swing region as PRC-026 designates such.

NOTE: Xs1 with subject gen was used for the blinder calculation rather than w/o subject gen which should be used, because the PRC-026 evaluation locus criteria uses Xs1 w/o subject gen. However, this will just magnify the “error” even more, so will just have decrease the “A” factor even more.

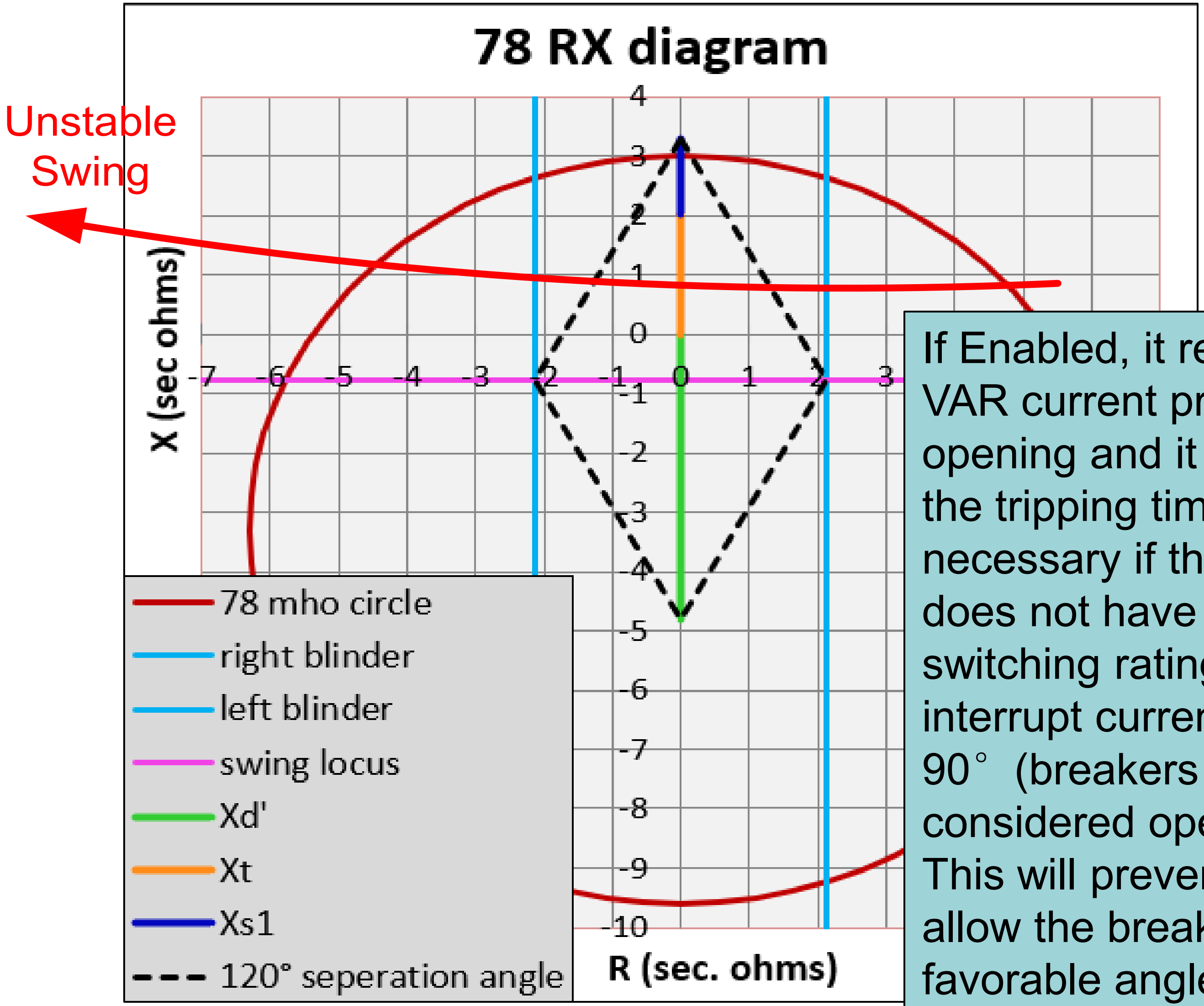
78 – Out of Step

- What to choose for the time delay setting?
- Best to be informed from **transient stability study**.
- The time delay setting is meant to help distinguish between an unstable swing and a fault. If the swing locus is between the blinders for > the time delay setting, then a trip is issued.
- Here set Time Delay = 3 cycles (typically 2 to 6 cycles)
- 3 cycles corresponds to the following swing rate:

$$\text{swing rate} = \frac{(180° - ß) + (180° - \alpha)}{78 \text{ time delay} * 360°} = \frac{360° - (120° + 120°)}{\frac{3}{60} * 360°} = 6.67 \text{ Hz}$$

78 – Out of Step

Should "Trip on MHO Exit" be Enabled?



If Enabled, it reduces the amount of VAR current present at breaker opening and it will slightly increase the tripping time, but it may be necessary if the generator breaker does not have an out-of-phase switching rating and if it must interrupt current at an angle > 90° (breakers are generally considered operable at up to 90°). This will prevent breaker flashover to allow the breaker to open at a more favorable angle.

78 – Out of Step

- Check with breaker mfg or nameplate/data sheet to determine if an out-of-phase switching rating is specified.
- Here, this breaker does have an out-of-phase switching rating but go thru these calculations to demonstrate the method:
- The dynamic swing data from the stability study can be checked to confirm that the breaker does not have to trip at an angle > 90° .
- Absent the stability study, if a particular breaker does not have an out-of-phase switching rating, the breaker will be capable of interrupting 50% rated current at an angular displacement of 90° between the generator and system voltage.
- This LS gen breaker must be rated to interrupt a 3Φ fault on the gen side of the breaker:

$$\mathrm{I} = 0.50 * \frac{1}{\mathrm{Xs1} + \mathrm{Xt}} = 2.2 \text{ pu at } 90$$

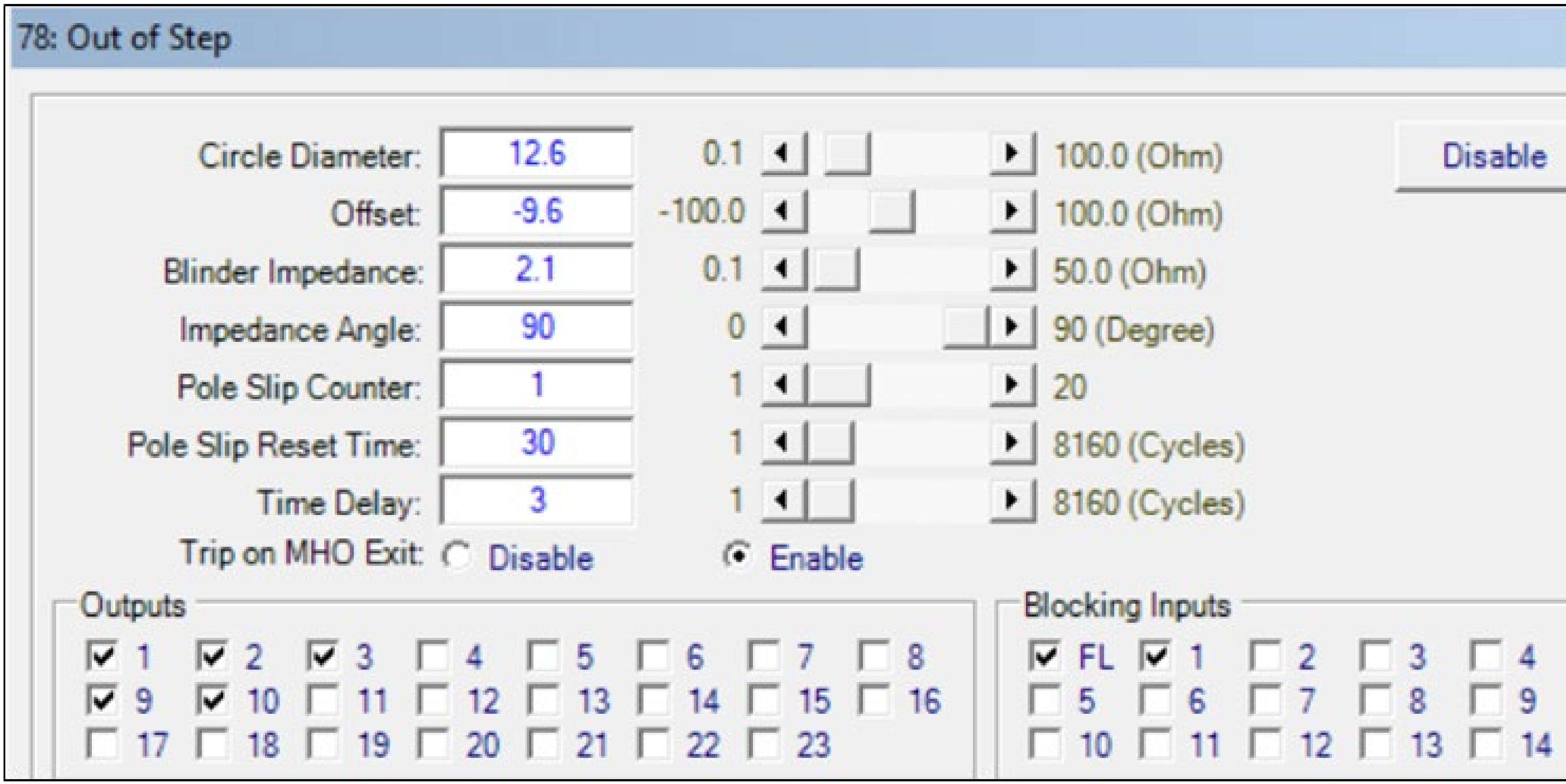
78 – Out of Step

- The minimum impedance during an out-of-step event is (Xd’+Xt+Xs1).
- The resulting out-of-phase switching current at 90° separation is then:

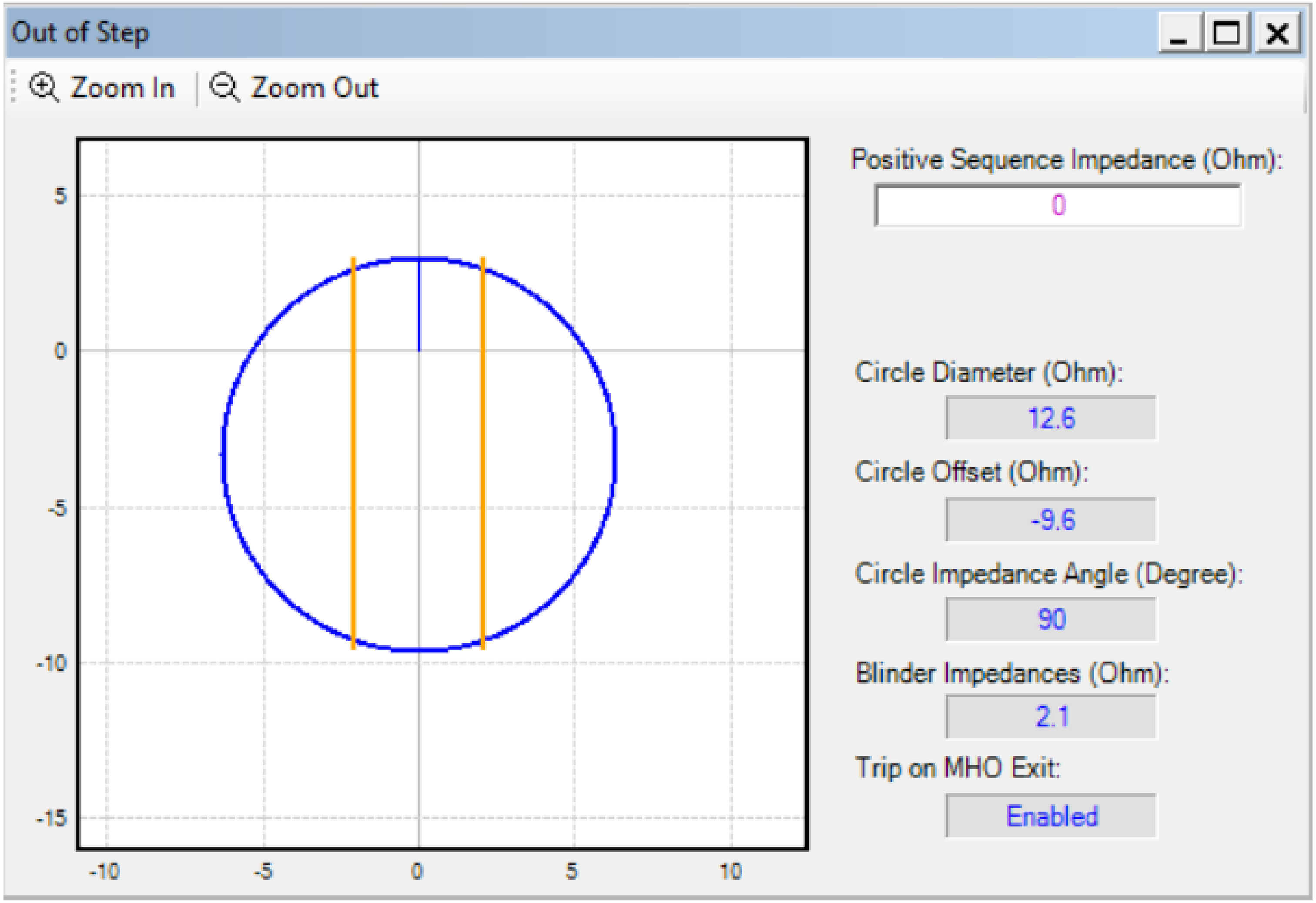
$$I = \frac{\sqrt{2}}{(Xd' + Xt + Xs1)} = 2.7 \text{ pu}$$

- Since 2.7 pu is > 2.2 pu (90° switching rating), this breaker should have an out-of-phase switching rating, which it does, or at least “Trip on MHO Exit” should be Enabled, which it also is.
- But specifically for this sample application, the “Trip on MHO Exit” does not necessarily have to be Enabled, but still Enabled it here as I would typically do as I thought the small amount of increased trip time is worth the possible extra wear it could take on a breaker, in general.

Generator Out-of-Step Protection (78)



Generator Out-of-Step Protection (78)



78 Out of Step

Evaluate settings against PRC-026

PRC-026-1

Relay Performance during Stable Power Swings.

Criterion A: 21, 40, and 78 (within blinders) must be completely contained within the unstable power swing region (lens, upper and lower loss of synchronism circles) or have time delay ≥ 15 cycles.

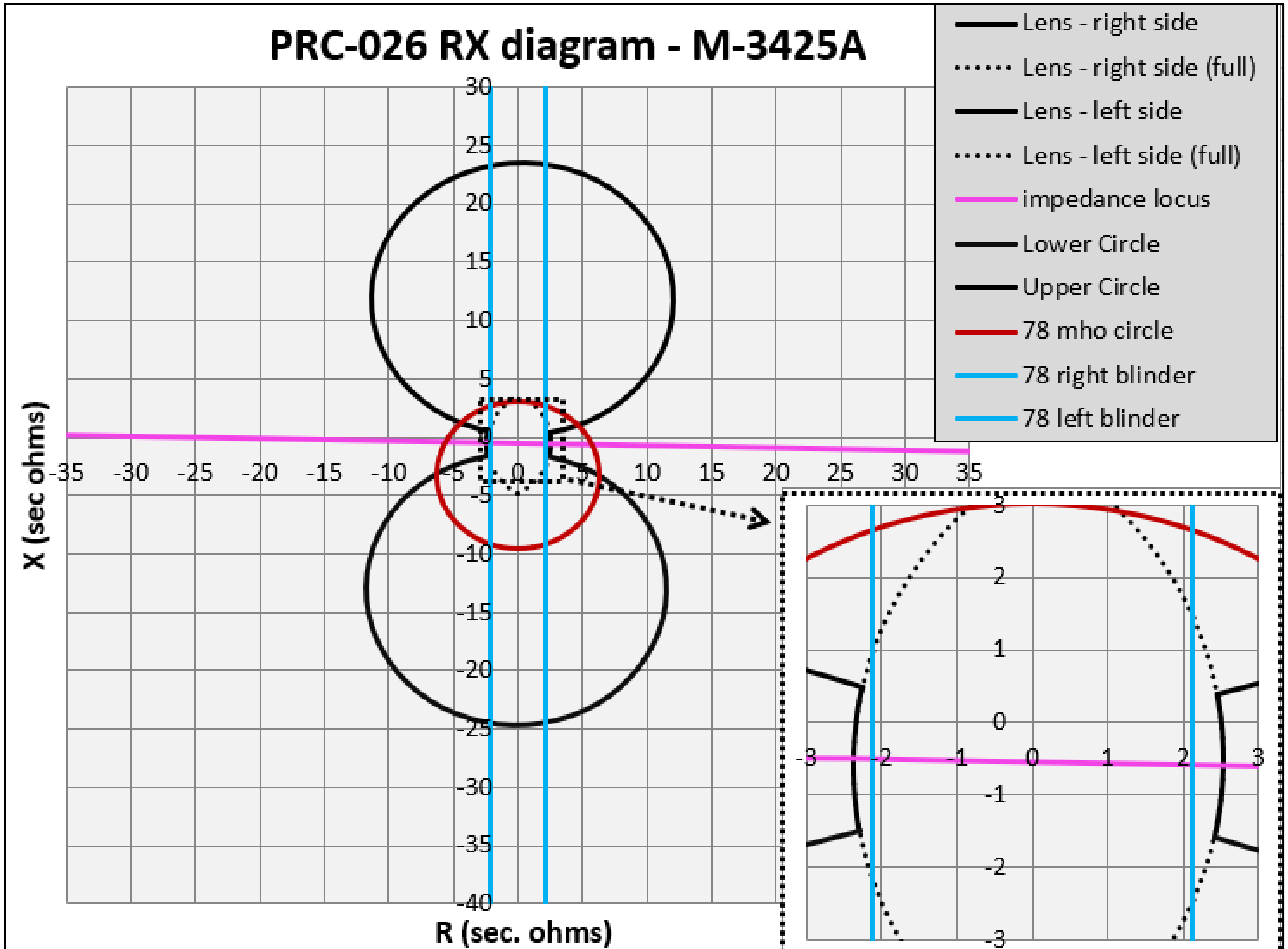
Criterion B: 50,51 pickup must be > criteria or have time delay ≥ 15 cycles.

Evaluate the following relay settings against criterion:

- Generator Protection
  - 21
  - 40
  - **78**
  - 50
  - 50DT
- GSU Transformer Protection
  - high side 50
  - high side 51

PRC-026-1

Plot the 78 settings on an RX diagram along with the unstable power swing region impedance locus criteria for this application:

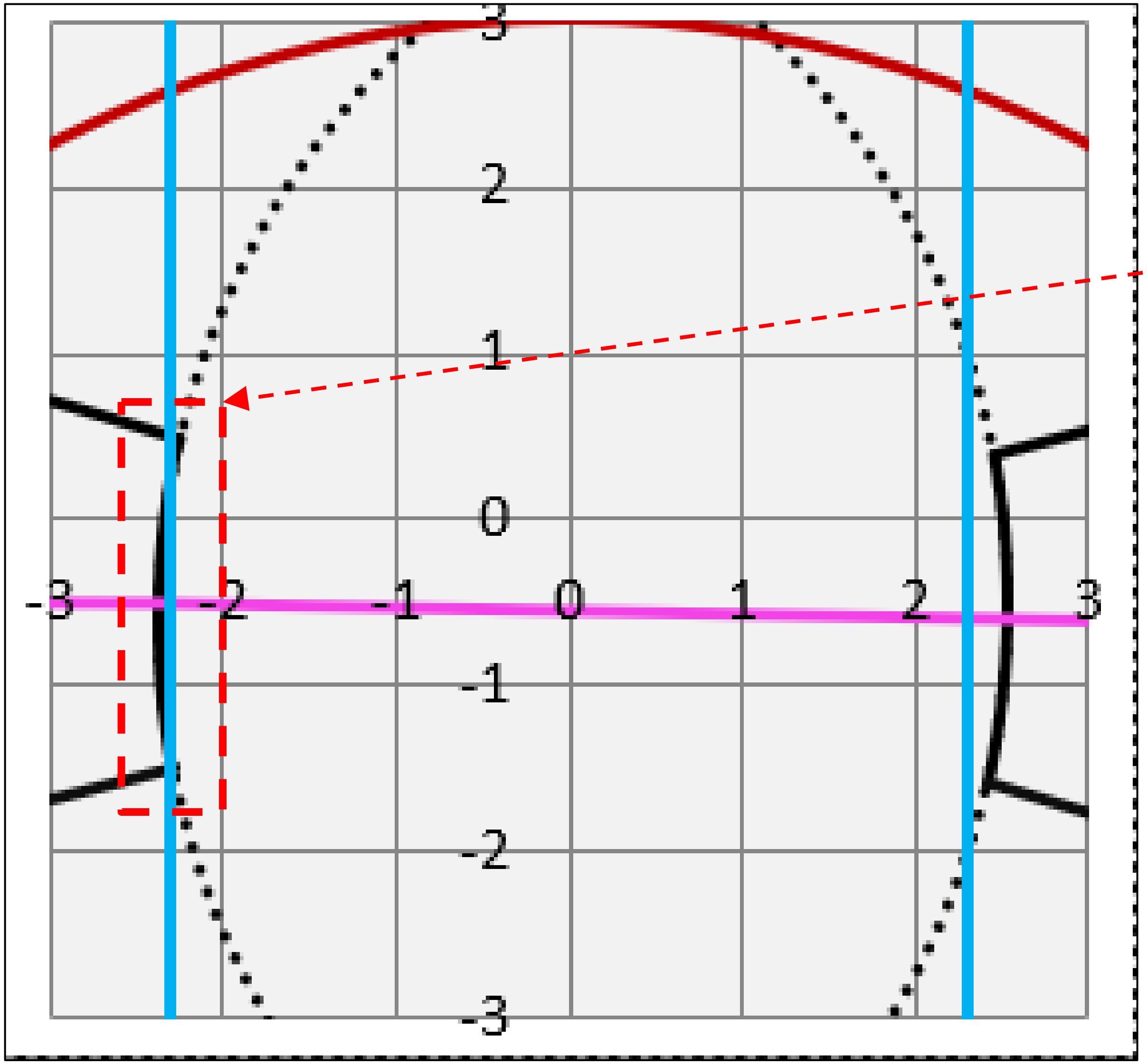


- 78 mho circle within blinders must be completely contained within the unstable power swing region.

- I have found that if I use the **unsaturated Xd'** for the blinder calculation, the blinders will typically plot inside the unstable power swing region.
- But if I use the **saturated Xd'** for the blinder calculation, the blinders will typically just barely plot outside the unstable power swing region, so I end up having to pull them in i.e. I have to use a cheat factor i.e. the "A" multiplication factor.
- PRC-026-1 does say to use Saturated values and that may be the logical value to use, however, then must typically pull in your blinders if using the typical blinder equation.

PRC-026-1

With blinder = 2.3 Ω:



Notice, if Xd'satuated value is used in the blinder calcs **(with no cheat factor)** 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.

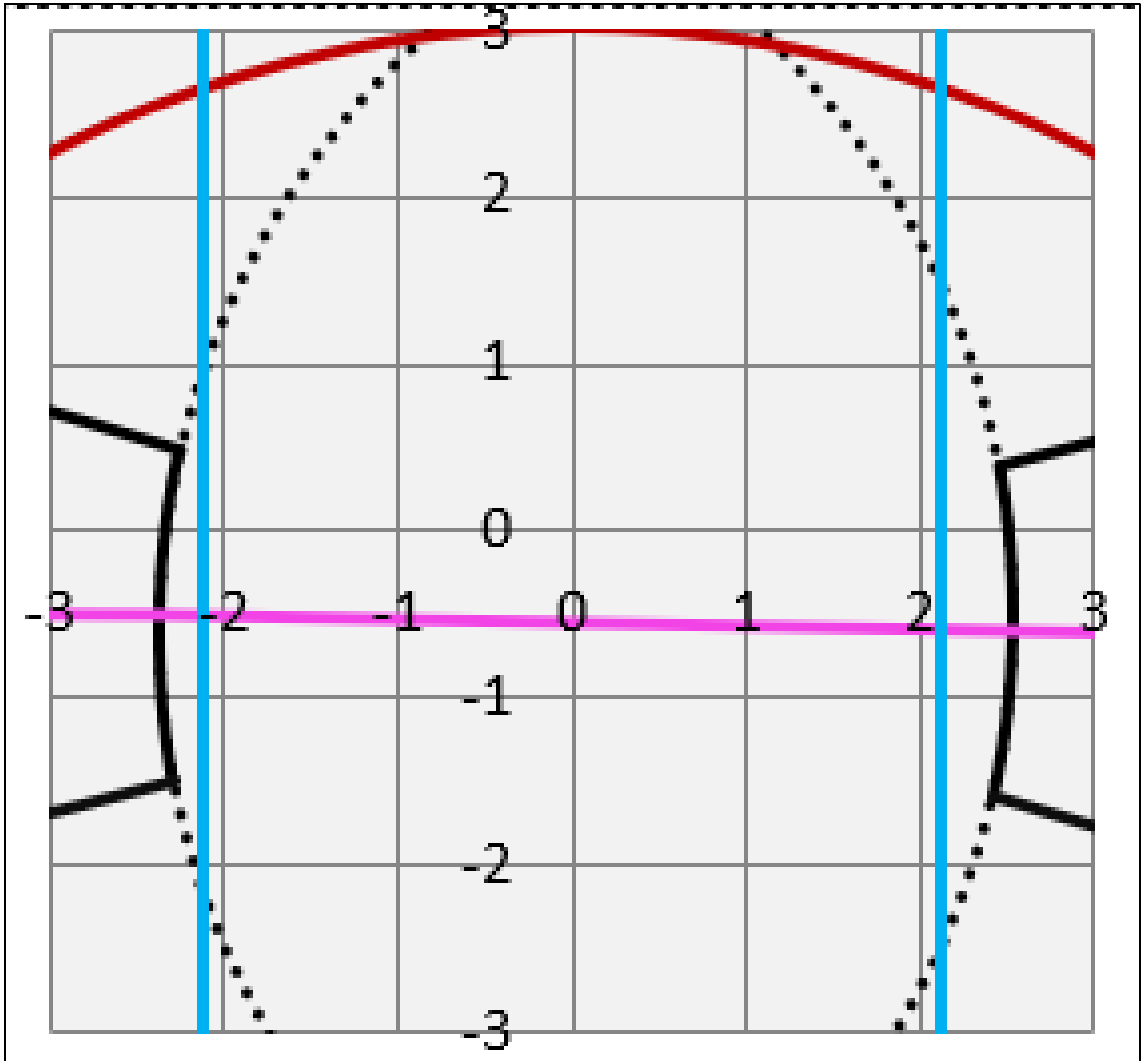
So must apply a cheat factor or use Unsaturated Xd' in blinder equation, although PRC-026 says to use Saturated value.

PRC-026-1

- In order to comply with PRC-026-1 the blinders must be adjusted so they plot inside the lens portion of the unstable power swing locus.
- The blinders are pulled in by a factor of 0.91 to be inside the lens portion (blinders decreased in steps of 0.1 until it visually plots inside lens, then the cheat factor is reverse engineered from the new blinder value.
- The blinder distance without the cheat factor is 2.3 Ω.
- The new blinder is 2.3 x 0.91 = 2.1 sec ohms
- This has the effect of increasing the separation angle to greater than 120 degrees which is allowed by PRC-026.

PRC-026-1

Changed blinder from 2.3 Ω to 2.1 Ω:



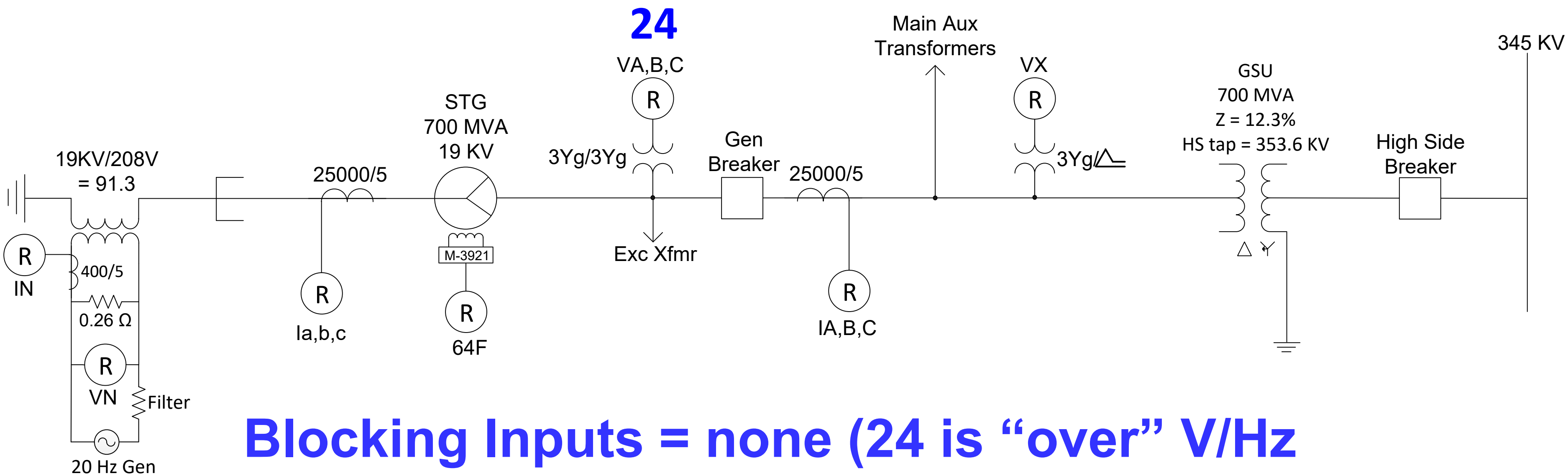
- Now the 78 blinders are fully inside the unstable power swing region, therefore these blinders settings do allow compliance with this standard.

PRC-026-1

Summary of PRC-26-1 compliance

- If typical criteria is used to calculate the 78 blinders, then the blinders may plot outside the unstable power swing region; thus, violating the standard
- Therefore, the blinders may have to be pulled in a bit in order to get them inside the unstable power swing region
- Multiplication factor (< 1) was inserted to typical criteria to get the blinders to plot inside the unstable power swing region

24 – Volts/Hz (Overexcitation)



Blocking Inputs = none (24 is "over" V/Hz protection while FL results in decreased voltage)

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

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

24 – Volts/Hertz (Overexcitation)

- First, locate the mfg Gen and GSU V/Hz withstand capability curves.
- If no mfg curves can be found, use “typical” curves.
- For this sample application, both the Gen and GSU mfg curves were available.

- Here is the **mfg gen V/Hz withstand capability curve**:

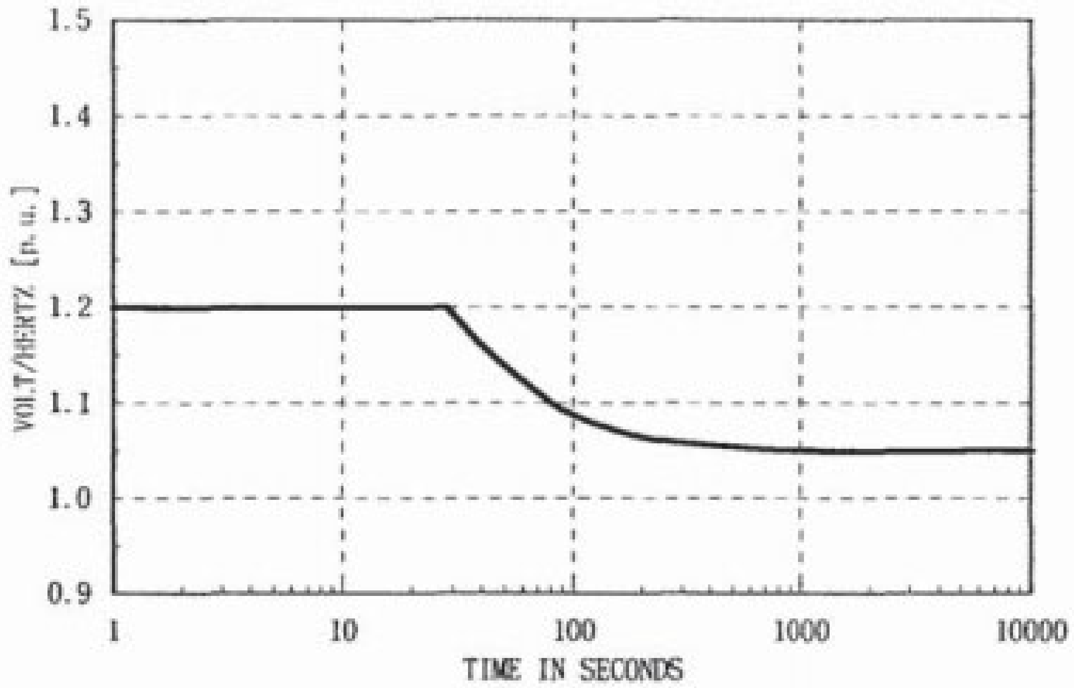
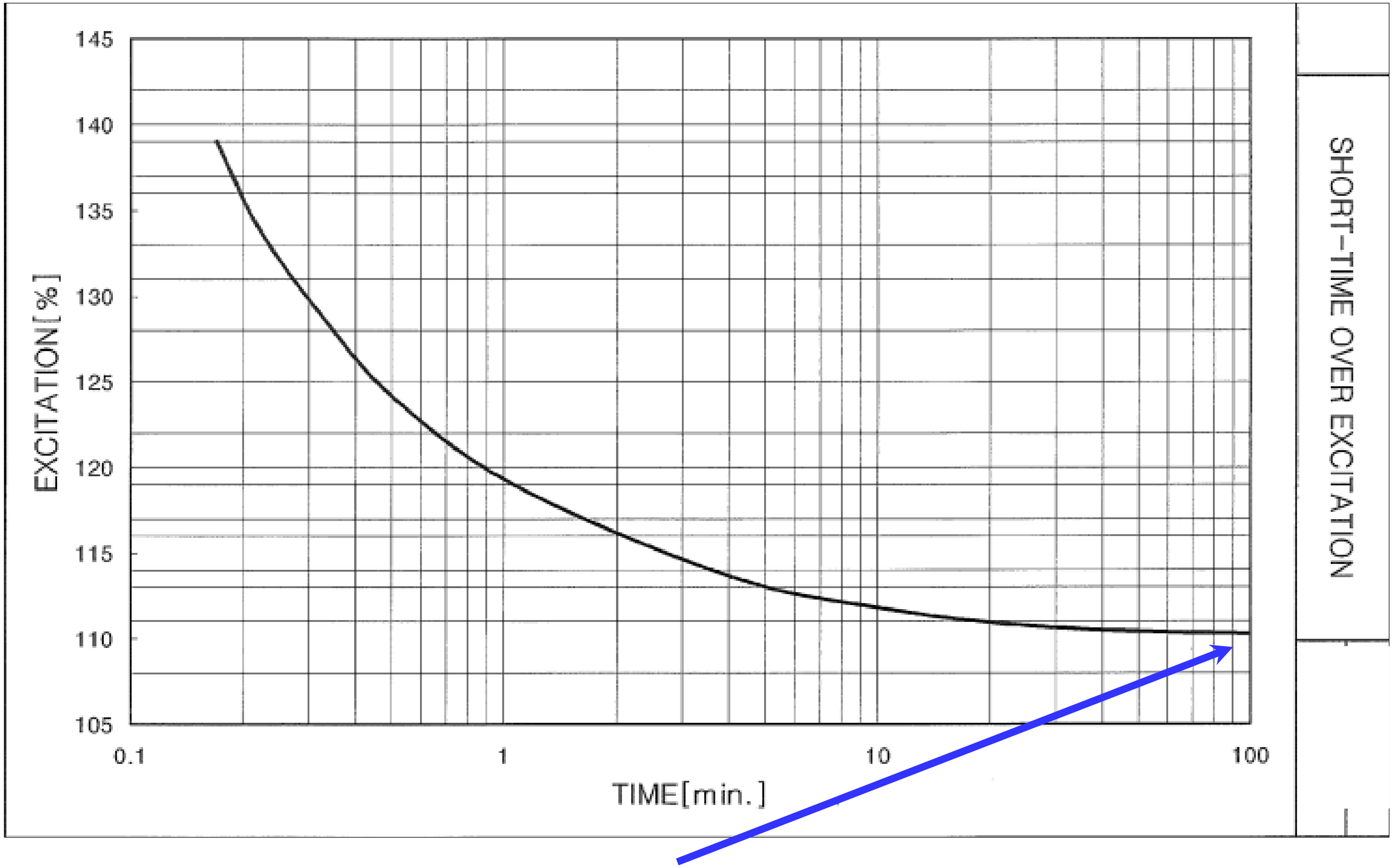


Fig. 2 : PERMISSIBLE SHORT TIME ARMATURE VOLT/HERTZ CURVE

24 – Volts/Hertz (Overexcitation)

- And here is the **mfg GSU V/Hz withstand capability curve**:



The asymptote of the curve is 110%, so assume this curve is given at "No Load" and per C57.12, this curve is at the GSU HV terminals.

24 – Volts/Hertz (Overexcitation)

SIDEBAR – how to calc the GSU FL V/Hz damage curve:

- May plot NL and FL curves, if provided, or just the more restrictive curve.
- If only one provided, likely the NL curve – confirm via curve's asymptote.
- IEEE C57.12 designates 110% NL curve and 105% FL curve at 0.8 PF on the HS of the GSU.
- The VTs are on the LS while the FL curve is defined on the HS, therefore must consider voltage crop across GSU to calculate the FL curve. First, calc the amps with 1 pu load at 0.80 lagging PF with a 105% HS voltage:

$$\mathrm{I} = \frac{\mathrm{S}^*}{\mathrm{V_{HS-FL}}^*} = \frac{(1 \cos^{-1} 0.8)^*}{(1.05\,\angle 0°)^*} = 0.952 \text{ pu} \angle -36.9°$$

- LS voltage during FL may be calculated via KVL:

$$\mathrm{V_{LS-FL}} = |\mathrm{V_{HS-FL}} + \mathrm{IZt}| = |1.05\angle 0° + (0.952 \text{ pu} \angle -36.9°) * (0.001621 + j0.123049)| = 1.13 \text{ pu}$$

- The 110% NL limit on the HS is the same on the LS because I = 0 at NL:

$$\mathrm{V_{LS-NL}} = |\mathrm{V_{HS-NL}} + \mathrm{IZt}| = |1.10\angle 0° + 0 * (0.001621 + j0.123049)| = 1.10 \text{ pu}$$

24 – Volts/Hertz (Overexcitation)

SIDEBAR – plot mfg gen and GSU V/Hz damage curves on same voltage base:

- In some applications, the GSU LS voltage rating < the gen voltage rating to compensate for the voltage drop across the GSU. However, this reduces the overfluxing capability and increases GSU core losses when operating at a higher than rated voltage.

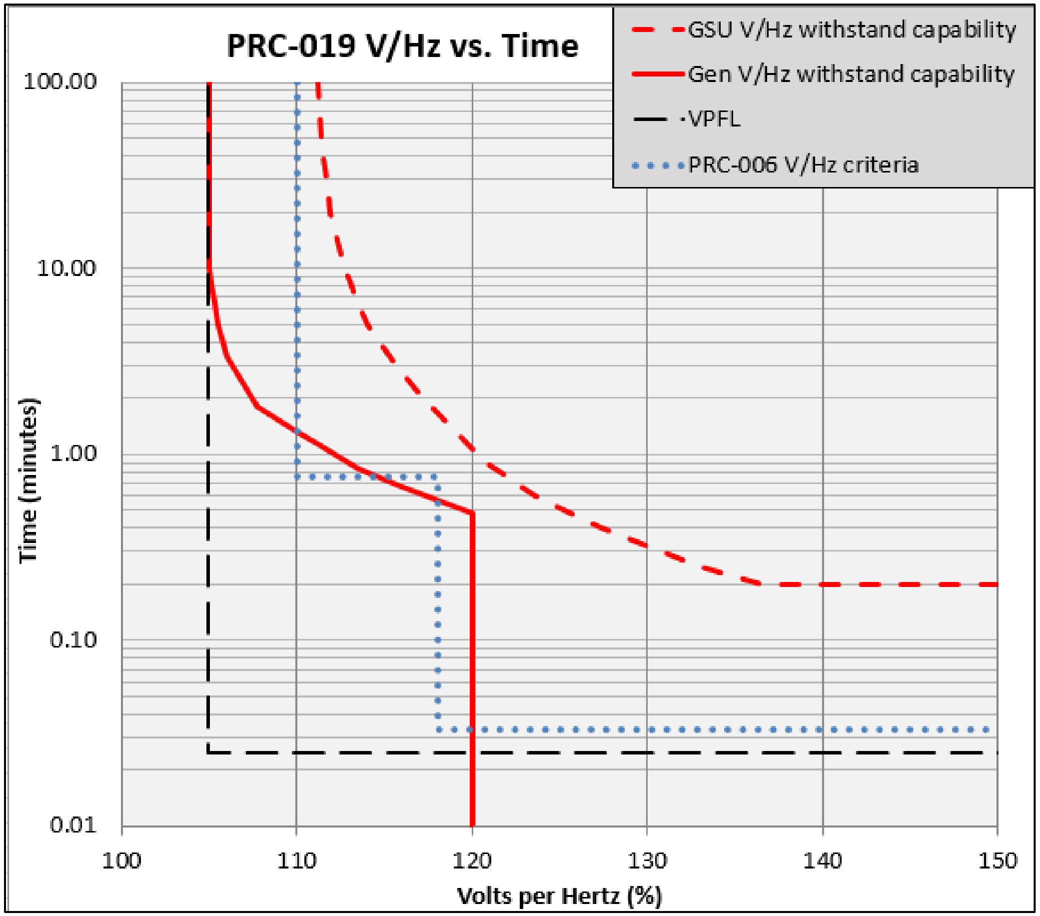
- Another method to account for the voltage drop across the GSU is to place the GSU HS Tap on a higher than nominal Tap. However, many factors are considered when specifying the GSU LS voltage rating and the GSU HS Tap setting

- Here, the GSU LS voltage rating = 19 KV (same as gen voltage rating); however, to demonstrate how to get the GSU curve on the same gen base, assume the GSU LS voltage rating = 18 KV and show how to convert a point of 110% to the gen base:

$$VHz_{GSU\ new} = \frac{V_{GSU\ LS\ rating}}{V_{gen\ rating}} * VHz_{GSU\ old} = \frac{18\ K}{19\ K} * 110 = 104.2\ \%$$

24 – Volts/Hertz (Overexcitation)

- Now, we can plot the mfg Gen and GSU V/Hz withstand capability curves:



- Also plot VPFL (Volts Per Frequency Limiter) aka V/Hz Limiter (if used) which is sometimes located within the excitation control system or overall gen PLC.

- Also plot the NERC PRC-006 V/Hz "shall not exceed" criteria as Transmission Planning can compel compliance, if within the machine's capability, thus it is best to verify compliance up front just in case.

- Notice, the gen damage curve is more restrictive than the GSU damage curve.

24 – Volts/Hertz (Overexcitation)

How to choose the Pickup setting for the 24 Inverse Time (24IT) Trip curve:

- What is the minimum V/Hz continuous capability from the more restrictive of the gen and GSU mfg V/Hz damage curves?
- The gen mfg curve at 105% is the more restrictive.

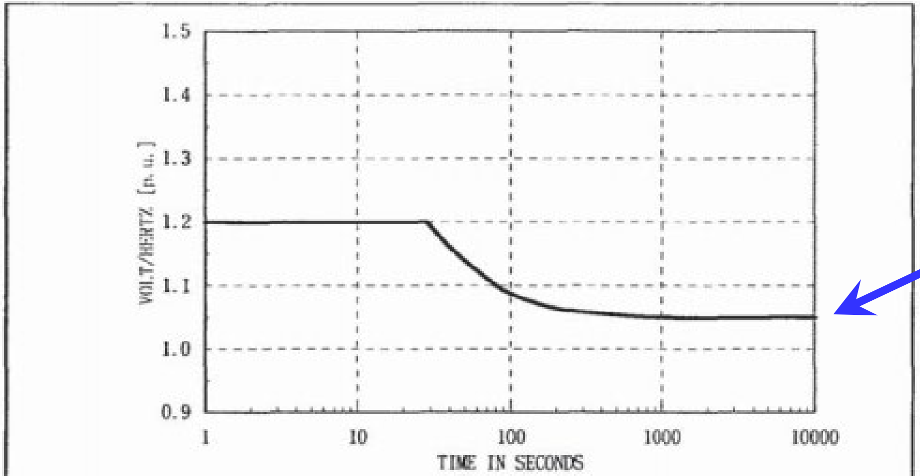
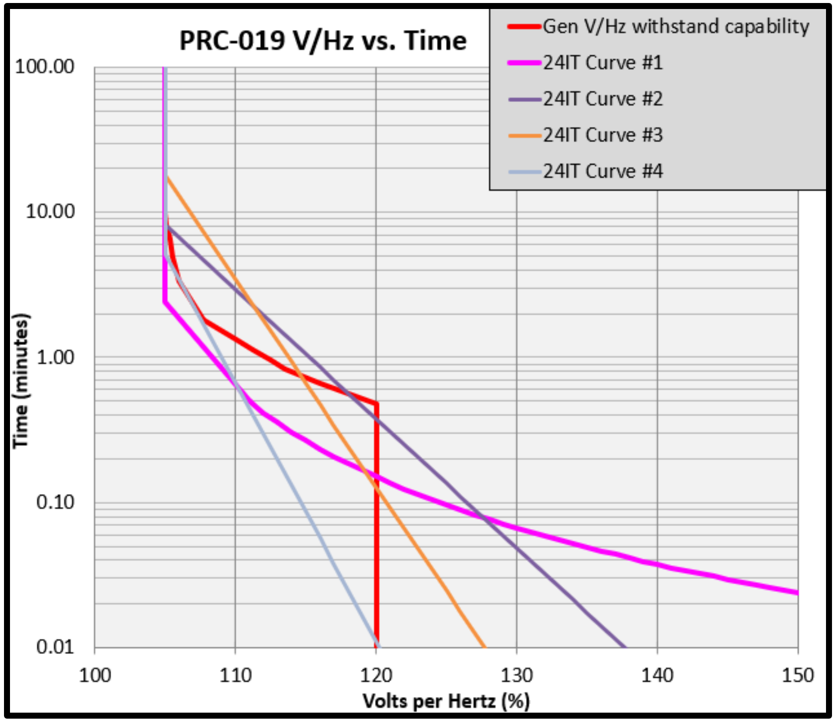


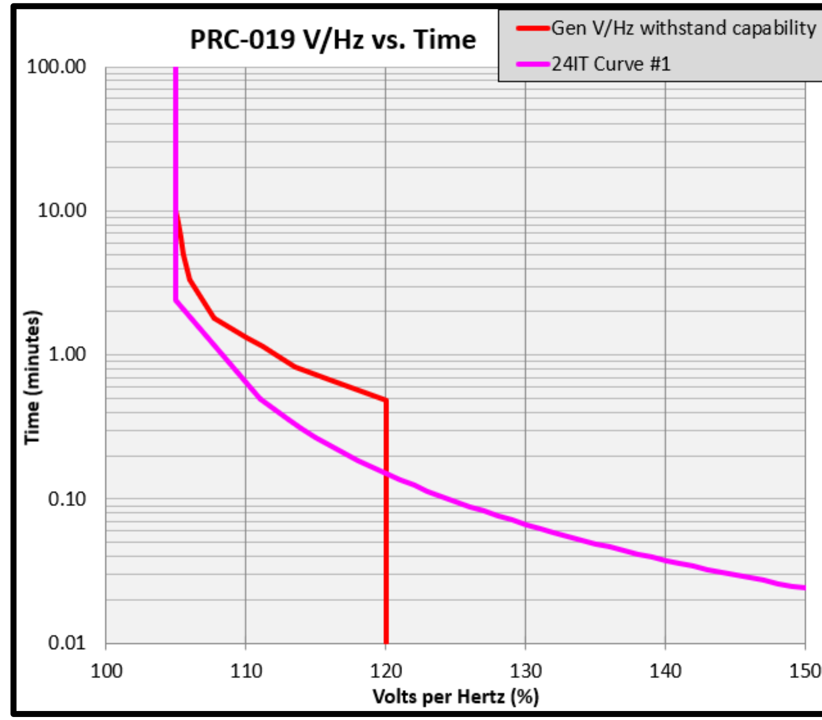
Fig. 2 : PERMISSIBLE SHORT TIME ARMATURE VOLT/HERTZ CURVE

Set **24IT Pickup = 105%** as that is the minimum generator continuous V/Hz capability before damage will eventually occur.

24 – Volts/Hertz (Overexcitation)

Process of elimination method to choose optimal 24IT (Inverse Time) curve type:



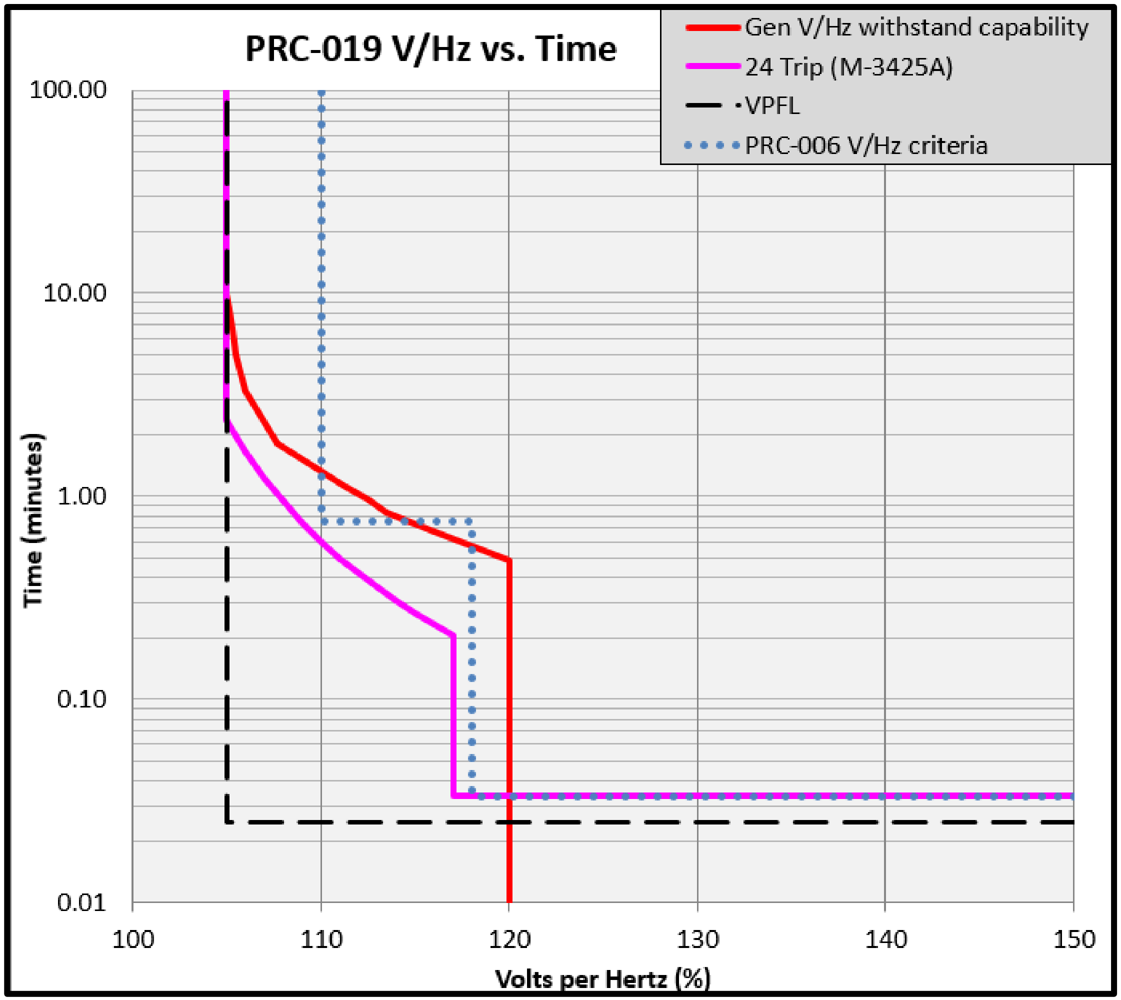


- First, plot all 24IT curves that are available in the specific relay being used along with the more restrictive of the gen and GSU V/Hz damage curve.

- Select **24IT Curve = Curve #1** as it best matches the shape of the inverse portion of the gen V/Hz damage curve.
- Delete the other unused curves.
- Set **24IT TD = 2** so the 24IT curve plots below the V/Hz damage curve.

24 – Volts/Hertz (Overexcitation)

Now add a Definite Time element (24DT#2) to cut off or take over for the 24IT curve at higher, more severe overfluxing levels to trip quicker than if only the 24IT were used:



<u>24DT#2 Pickup = 117%</u> to protect and plot below the gen V/Hz damage curve and the PRC-006 “shall not exceed” criteria.

<u>24DT#2 Time Delay = 2 seconds</u> to plot above the VPFL.

24 – Volts/Hertz (Overexcitation)

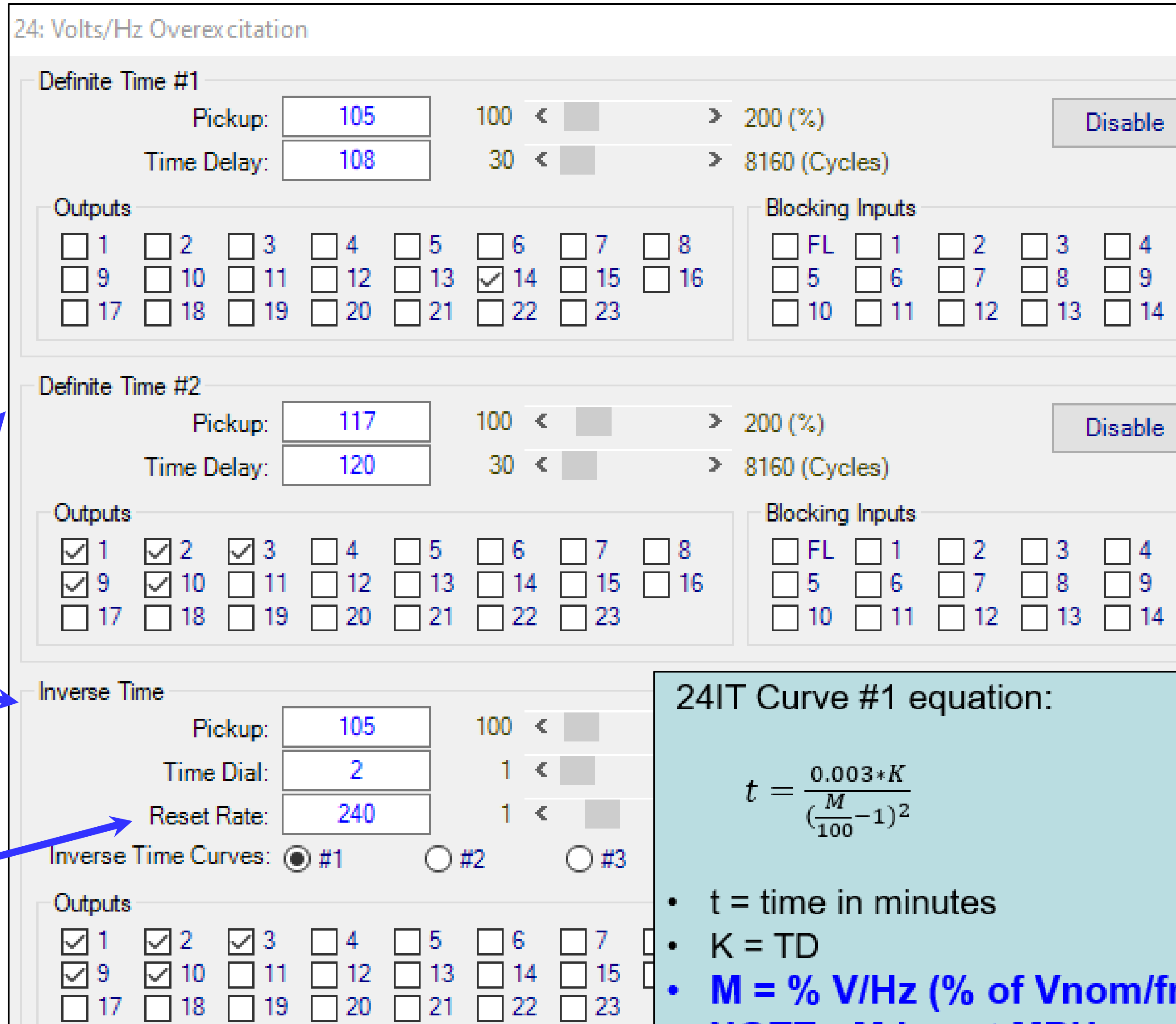
- Set **<u>24IT Reset Rate = 240 seconds</u>**.
- Reset Rate gives 24IT a thermal memory where the accumulated heat in the stator core from overfluxing and the rate of heat dissipation is emulated in the algorithm.
- Different machines have different rates for cooling down – consult mfg.
- The 24IT Delay Timer can be monitored via relay HMI: ENTER, right arrow to STATUS, ENTER, right arrow to TIMER STATUS, ENTER, right arrow to 24IT DELAY TIMER.
- This timer starts at 100% when 24IT is fully reset.
- It then starts decreasing in % if the V/Hz exceeds the curve and when it reaches 0%, it will assert selected outputs.
- The reset characteristic is linear, so if 24IT times 60% towards a trip (i.e. the 24IT DELAY TIMER has decremented from 100% down to 40%), then the V/Hz drops below the 24IT curve, it will fully reset in 0.60 * Reset Rate = 0.60 * 240 = 144 seconds.
- The Reset Rate is not used by the 24DT elements.

24 – Volts/Hertz (Overexcitation)

Set Alarm at the gen continuous V/Hz capability of 105%.

Trip

Reset Rate = 4 min



24IT Curve #1 equation:

$$t = \frac{0.003 * K}{(\frac{M}{100} - 1)^2}$$

- t = time in minutes
- K = TD
- **M = % V/Hz (% of Vnom/fnom)**
  NOTE: M is not MPU

24 Volts/Hz (Overexcitation)

Evaluate settings against PRC-019 and PRC-024

PRC-019-2

Verify coordination of generator voltage regulating controls with protective relays and equipment capabilities.

Coordinate

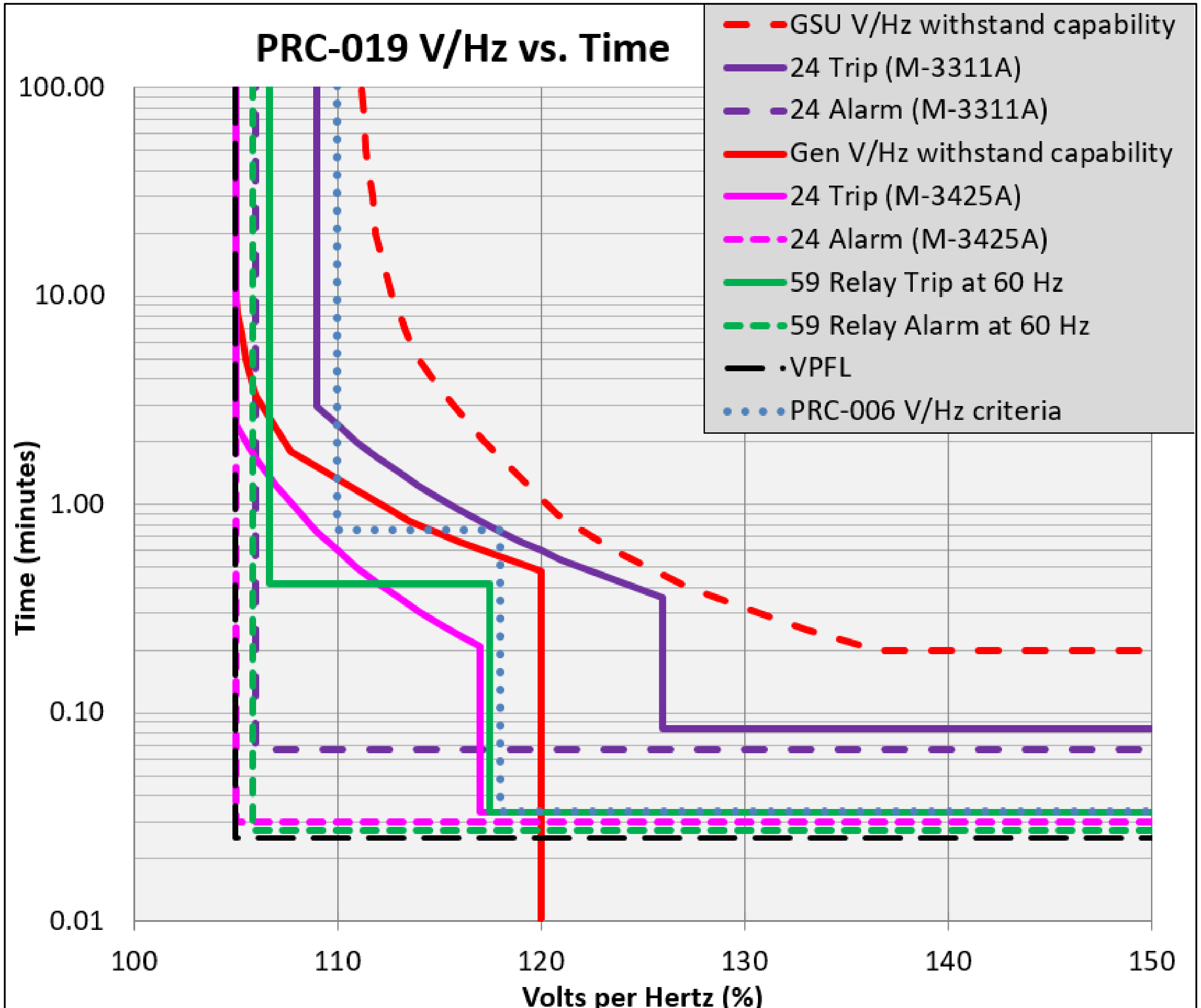
- Voltage Regulating Controls
  - **VPFL**, 24EX, 40EX, 59EX, OEL, UEL, Field I*T trip
- Protection
  - **24**, 40, 59
- Generating Unit or Plant Capabilities
  - GCC, SSSL
  - **V/Hz withstand capability curve**

Per section B.R1-1.1.1, the in-service limiters are set to operate prior to the protection elements tripping.

Per section B.R1-1.1.2, the protective elements will trip prior to equipment damage or stability limits.

PRC-019-2 coordination

24 Relay settings along with the Gen V/Hz capability curve and V/Hz Limiter (VPFL)



- Standard requires Limiter (VPFL) to operate prior to protection (24):

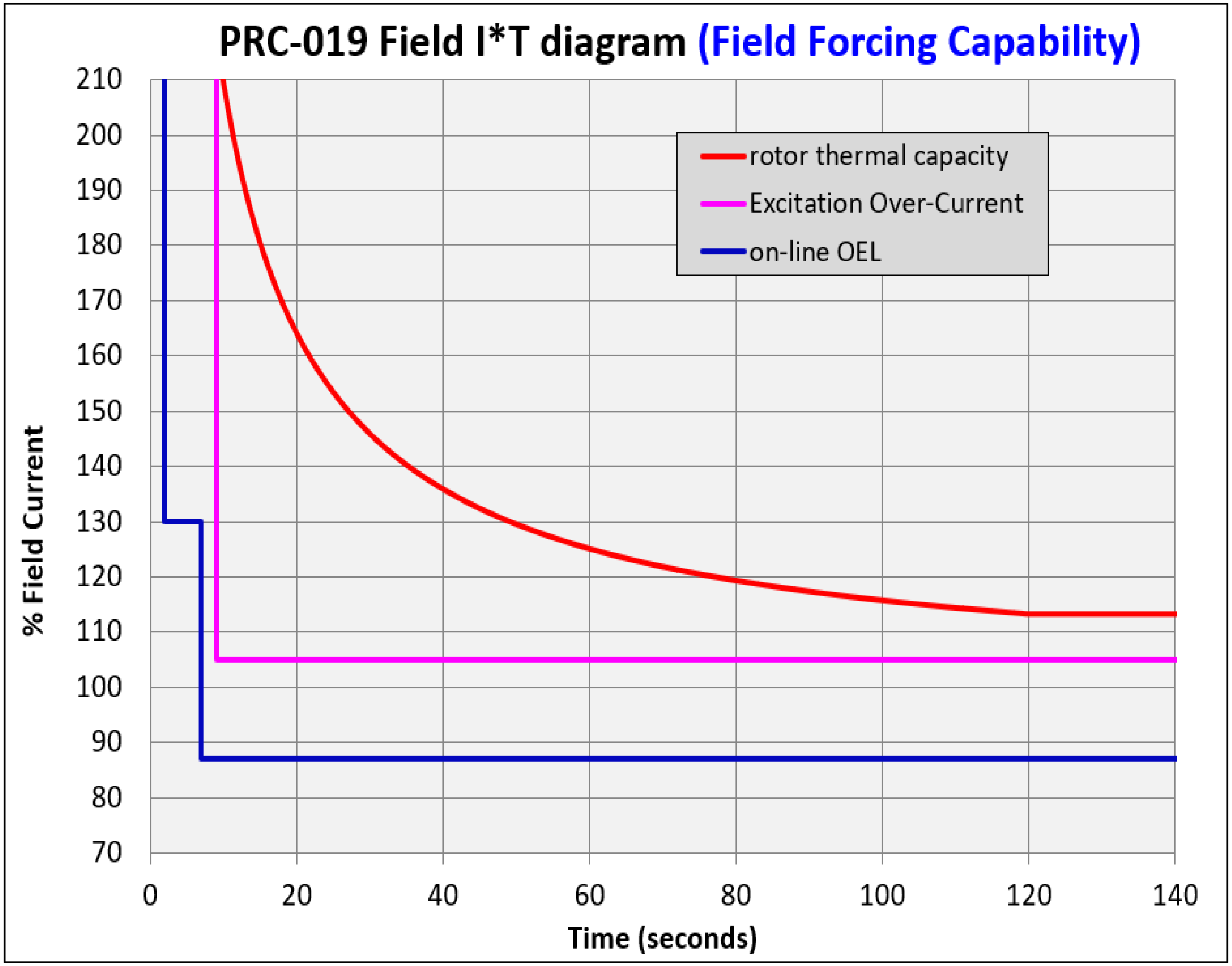
  Yes

- Standard requires protection (24) to operate before damage (V/Hz withstand) occurs:

  Yes

PRC-019-2

OEL and Field Overcurrent Protection Coordination



Standard requires Limiter to operate prior to protection:

Yes

Standard requires protection to operate before damage occurs:

Yes

PRC-024

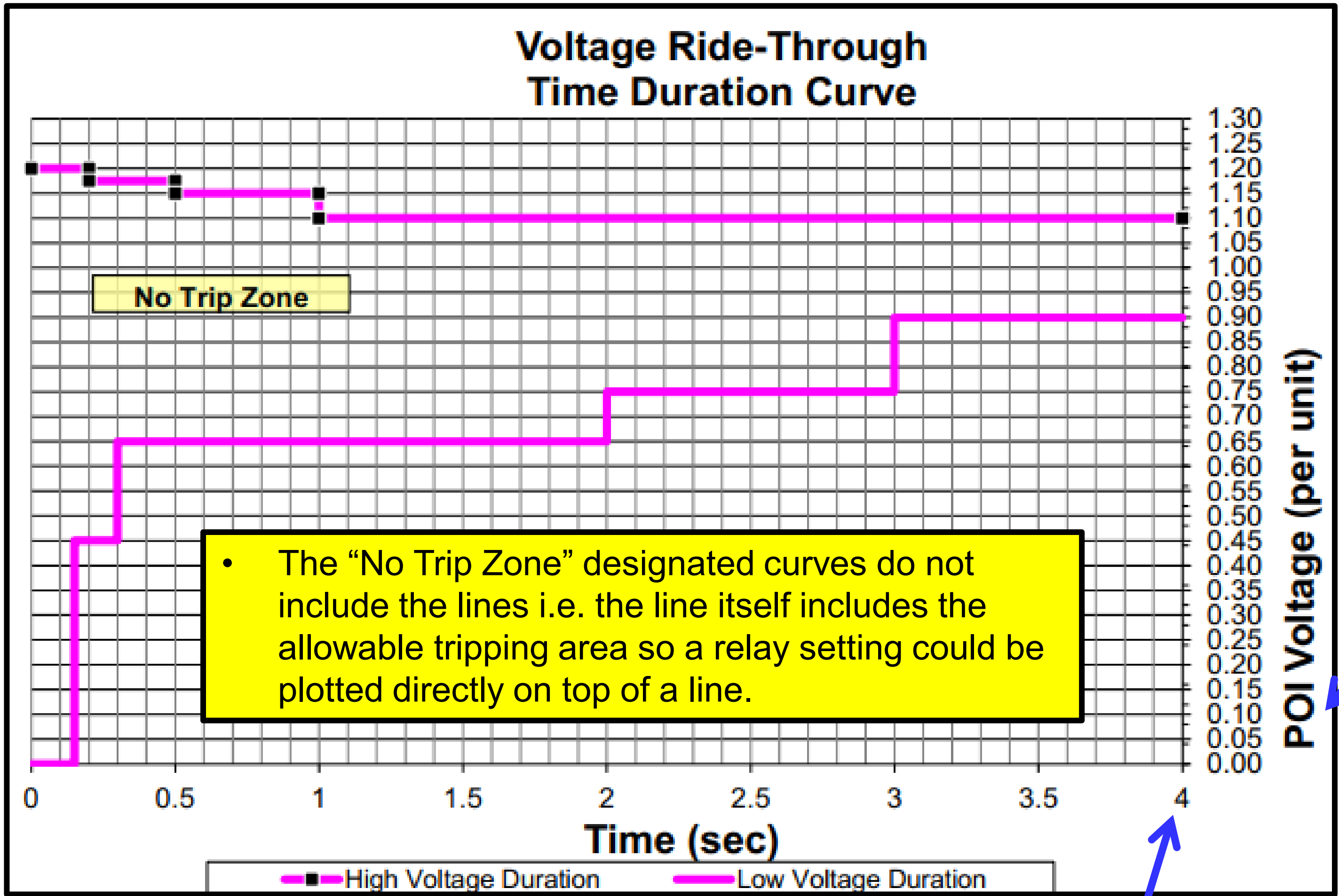
Verify generators remain connected during frequency and voltage excursions

Coordinate

- Protection
  - **24 at 60 Hz**, 27, 59, 81
- Voltage Regulating Controls
  - 24EX, 59EX
- Defined ride thru curves
  - frequency
  - voltage

Aux systems are out of scope of this standard.

Voltage Ride-Through (PRC-024)



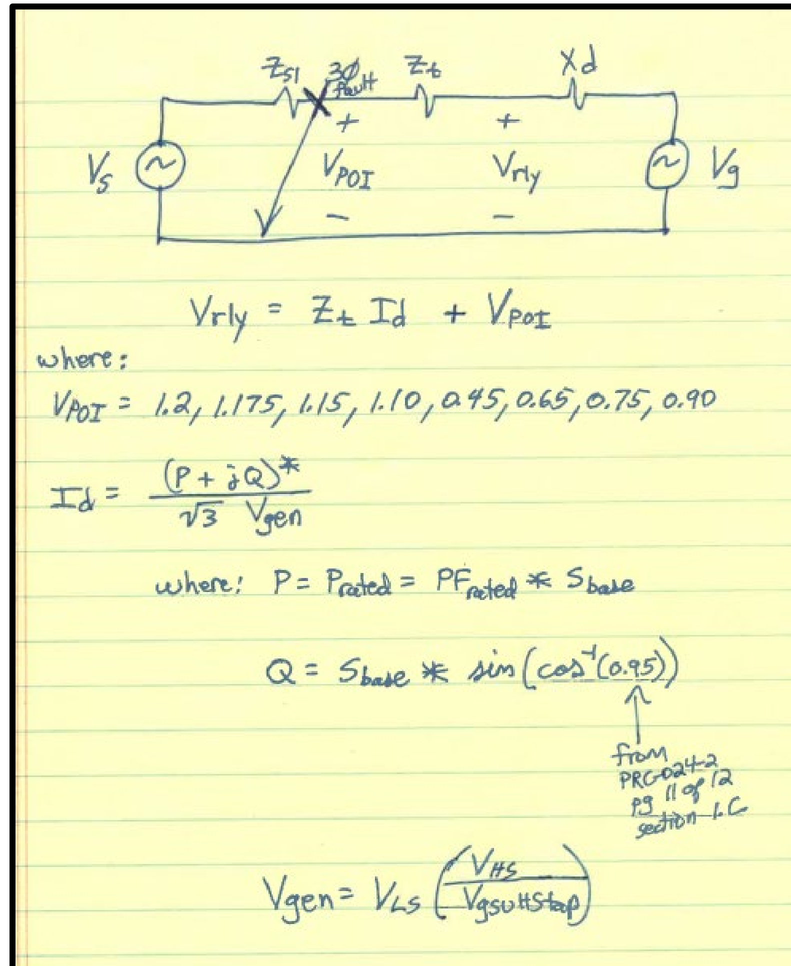
- The "No Trip Zone" designated curves do not include the lines i.e. the line itself includes the allowable tripping area so a relay setting could be plotted directly on top of a line.

Voltage ride-thru at POI (Point of Interconnect), typically, on GSU HS

only need to comply for the first 4 seconds of a voltage excursion event

Voltage Ride-Through (PRC-024)

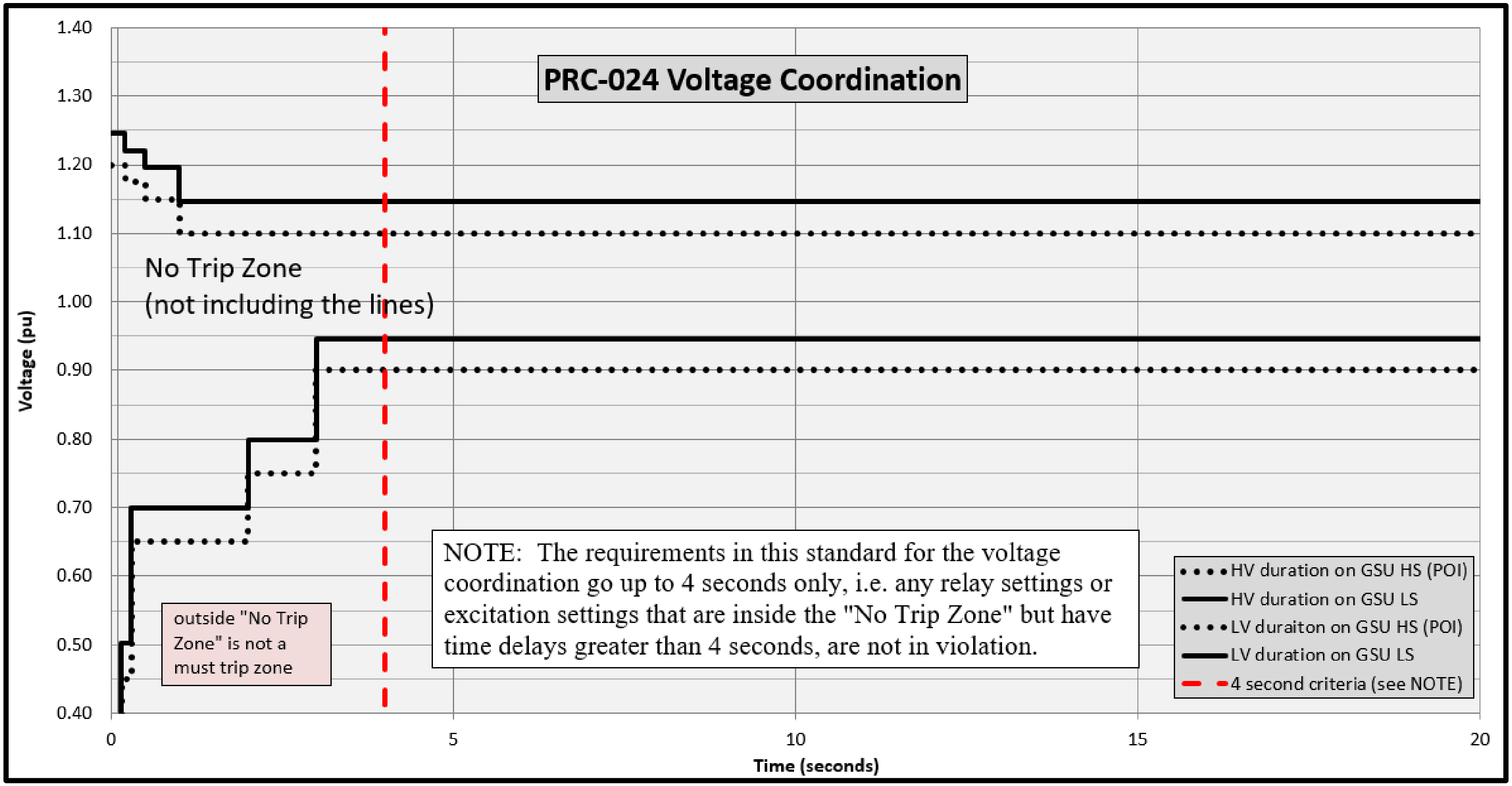
- The Voltage Ride-Through curves are at the POI (Point of Interconnect), which typically will be on the high side of the GSU; however, the 24 relay is sourced from VTs on the low side of the GSU. Therefore, to coordinate may take the POI voltage ride-through curves to the low side of the GSU as shown here:



- Or may instead take the 24 relay settings from the GSU LS to the GSU HS (POI) to coordinate as explained in NERC PRC-024 Implementation Guide.

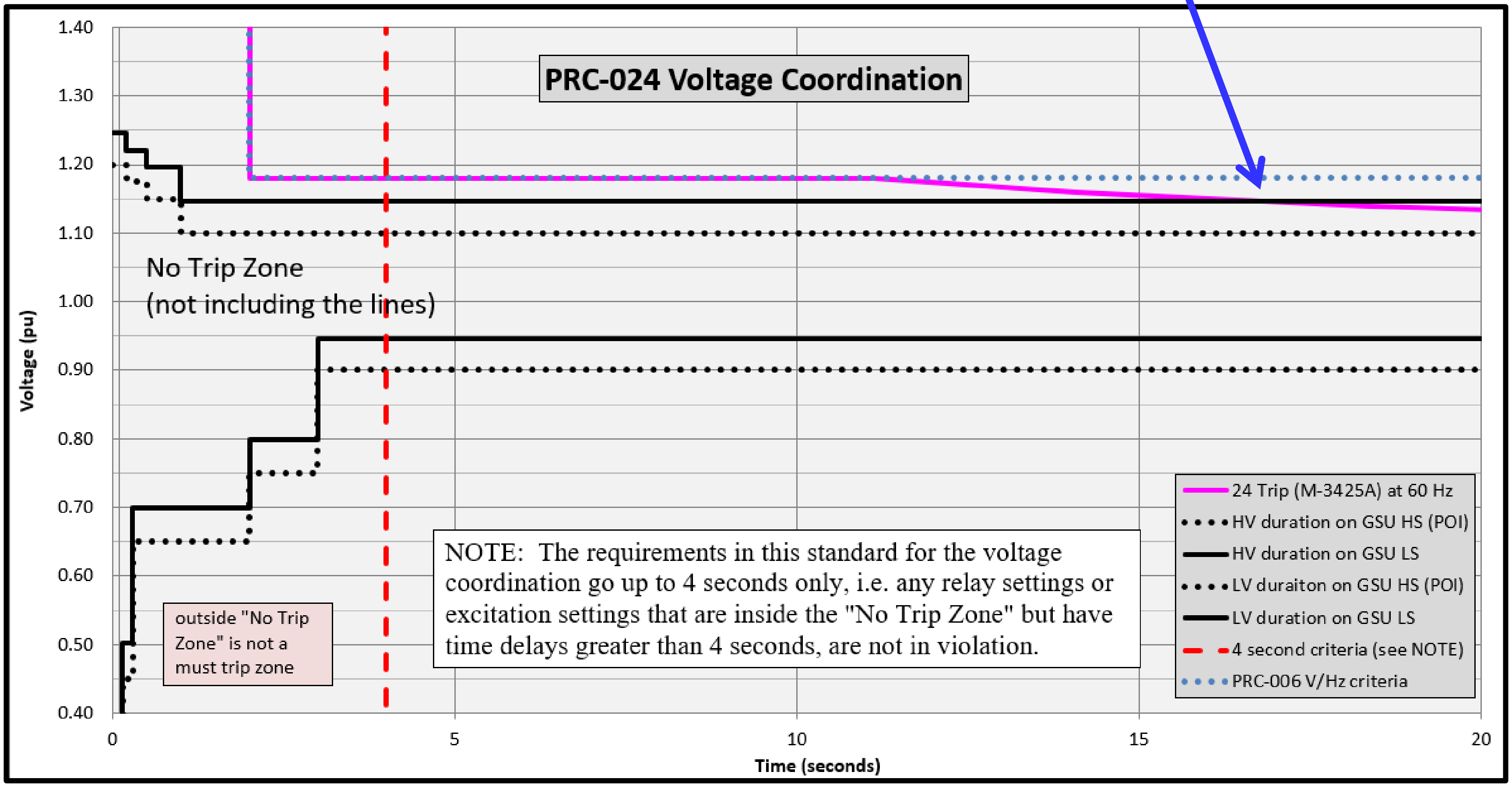
Voltage Ride-Through (PRC-024)

- Now, plot the PRC-024 Voltage Ride-Through criteria at the GSU HS POI (dotted black lines) and as translated to the GSU LS (solid black lines) to directly compare with the 24 settings:



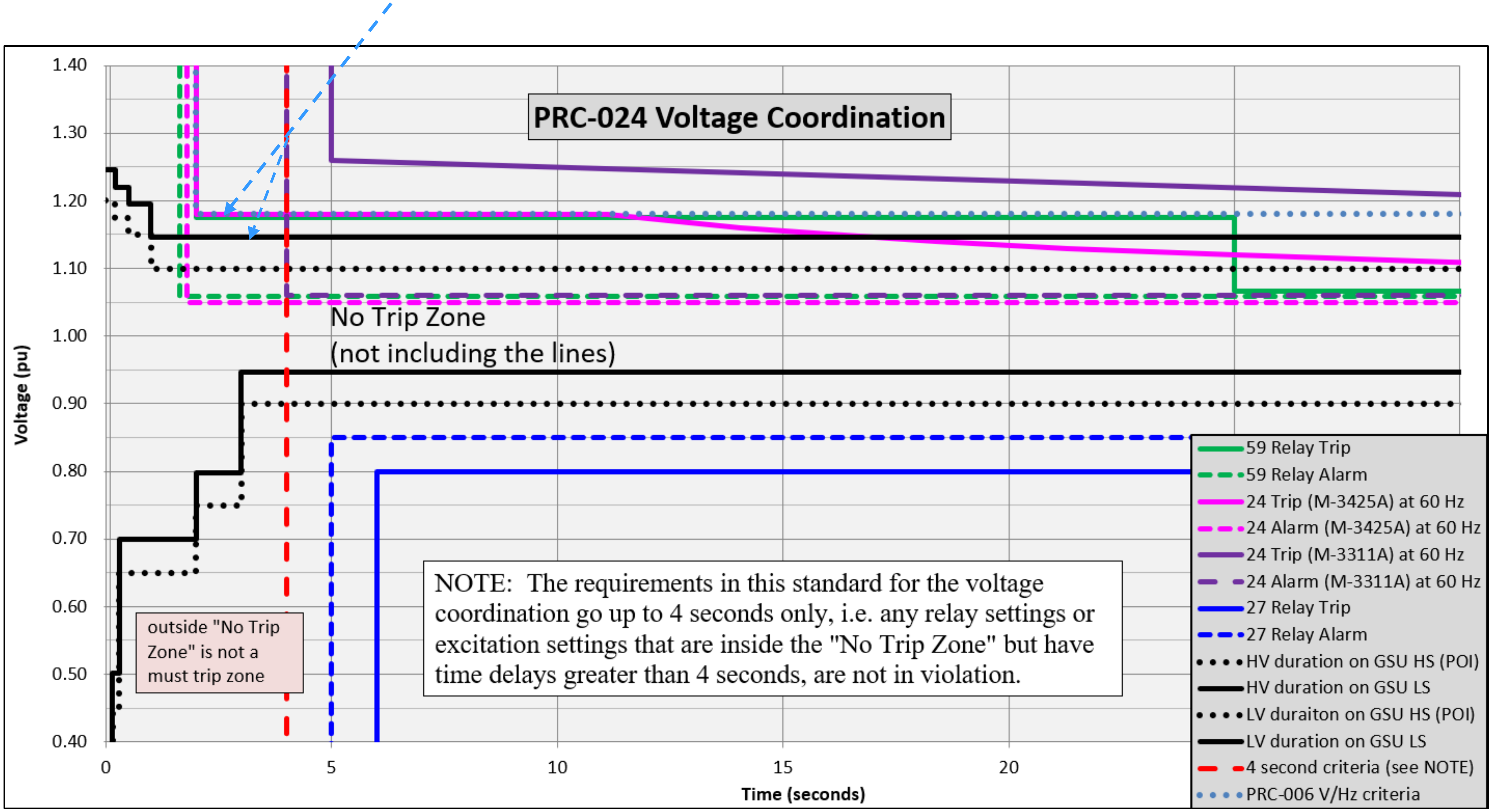
Voltage Ride-Through (PRC-024)

- Add 24 relay Trip settings and the PRC-006 "shall not exceed" criteria.
- Notice, the 24IT curve eventually goes inside the "No Trip Zone" criteria but it is well outside of the first 4 seconds, so it does not violate compliance.

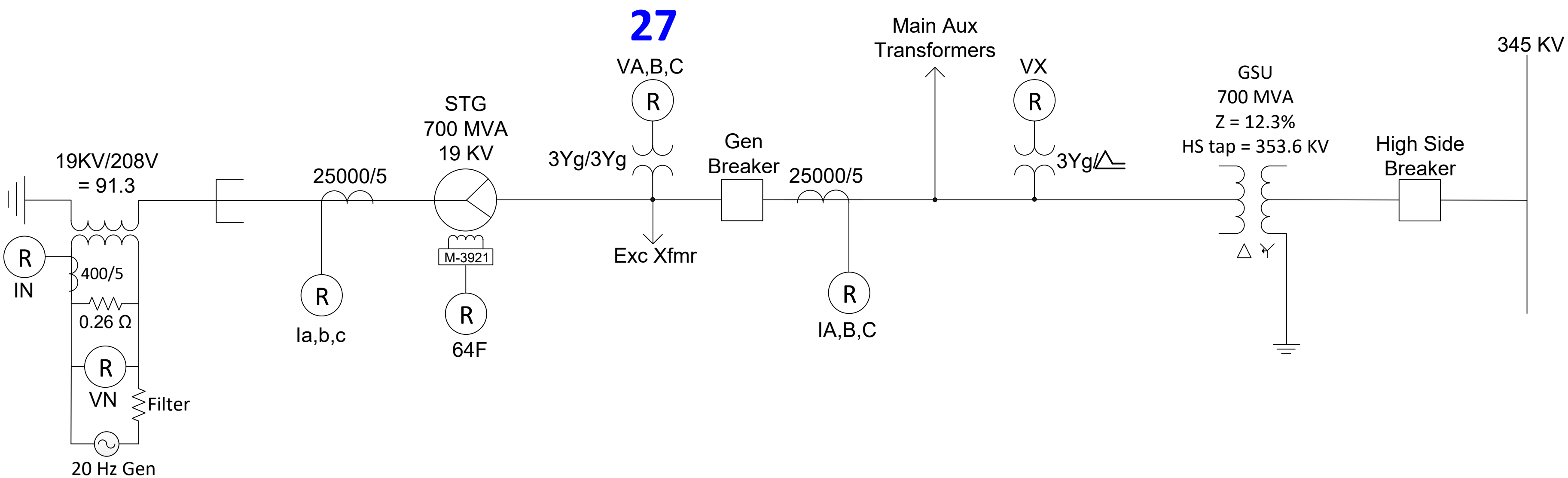


PRC 024-2 Verify that the 24 settings at 60 Hz plot outside the No Trip Zone criteria

Finally, plot all applicable relay settings together to demonstrate overall coordination and specifically that the 24 relay settings do comply with PRC-024 i.e. Yes, compliance is verified as the 24 Trip (solid Pink) characteristic plots outside the solid black line No Trip Zone inside of 4 seconds.

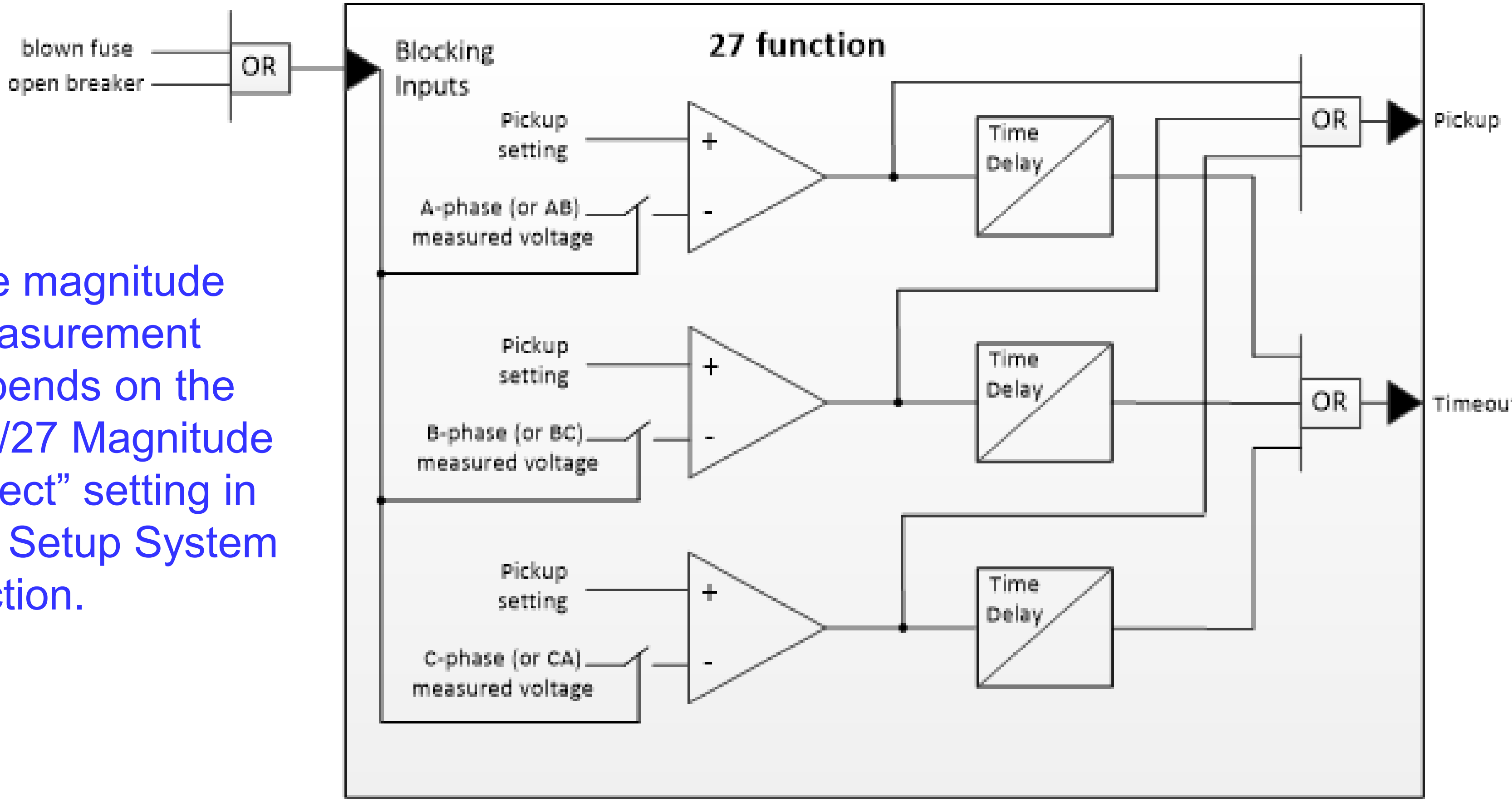


27 – Phase Undervoltage



Blocking Inputs = FL, 1

27 – Phase Undervoltage



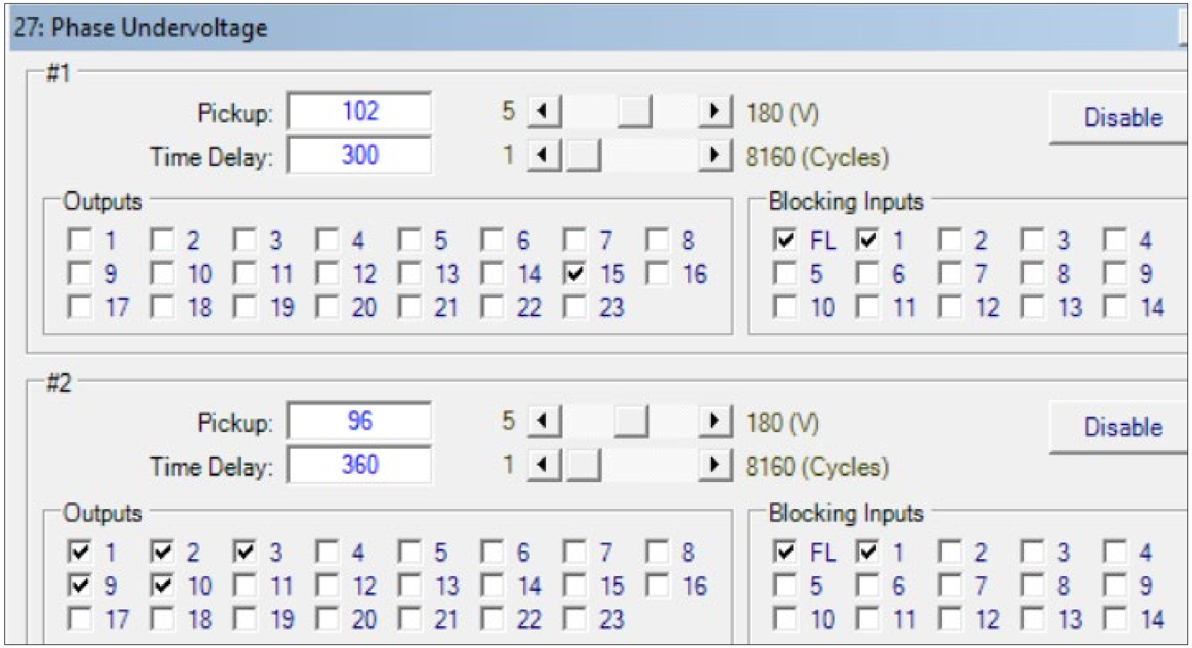
- The magnitude measurement depends on the “59/27 Magnitude Select” setting in the Setup System section.

- ***each phase has an independent timing element***

27 – Phase Undervoltage

- Use #1 as an Alarm and set it at 85% of Nominal Voltage and a time delay longer than any voltage transients and to ride thru depressed voltage from system faults:
  - #1 Pickup = 0.85*120 = 102 V (Line-Line)
  - #1 Time Delay = 300 cycles

- Use #2 as a Trip and set it at 80% of Nominal Voltage and a time delay longer than any voltage transients and to ride thru depressed voltage from system faults:
  - #2 Pickup = 0.80*120 = 96 V (Line-Line)
  - #2 Time Delay = 360 cycles



27 Phase Undervoltage

Evaluate settings against PRC-024

PRC-024

Verify generators remain connected during frequency and voltage excursions.

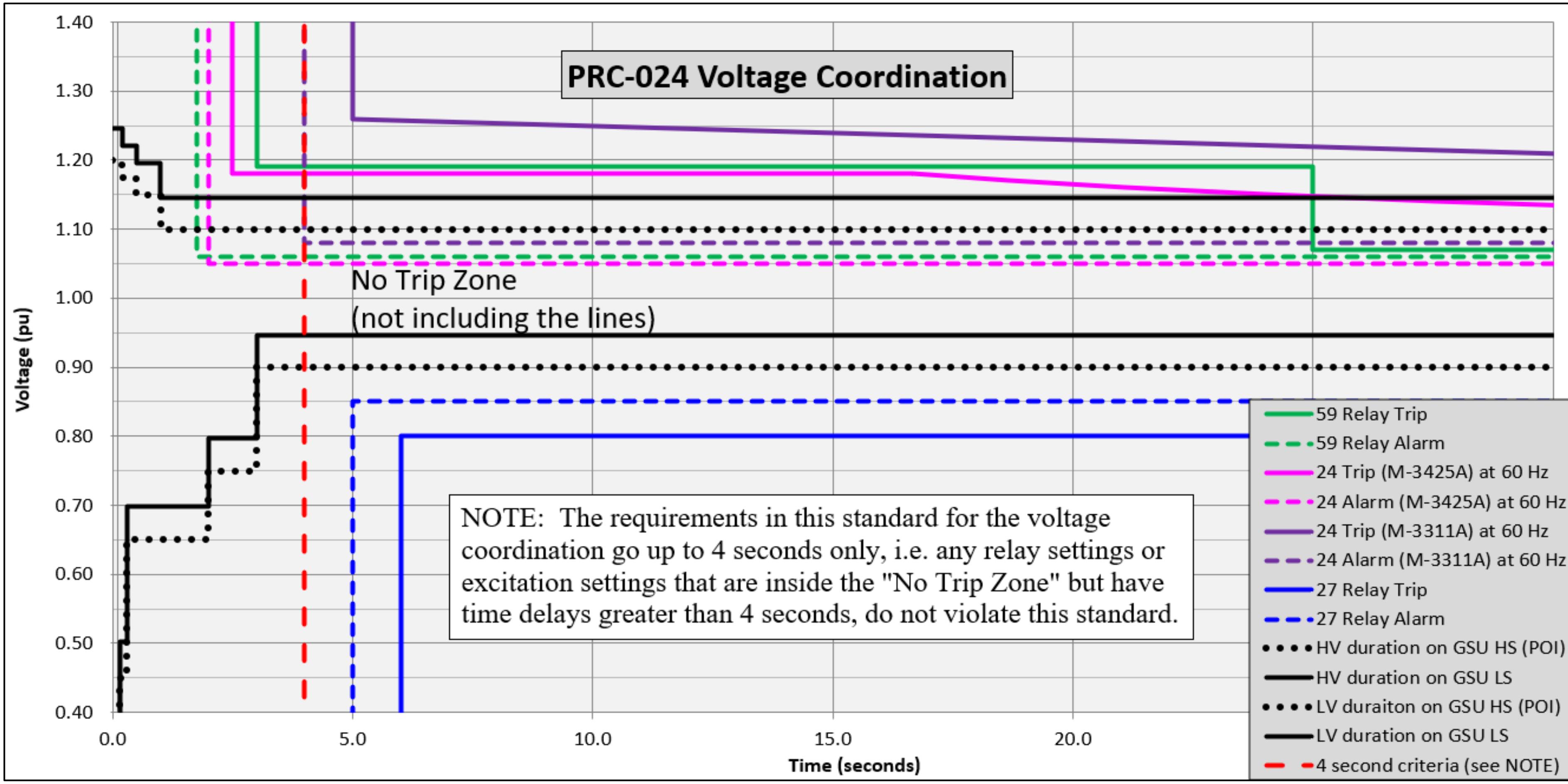
Coordinate

- Protection
    - 24 at 60 Hz, **27**, 59, 81
- Voltage Regulating Controls
    - 24EX, 59EX
- Defined ride thru curves
    - frequency
    - voltage

Aux systems are out of scope of this standard.

PRC-024

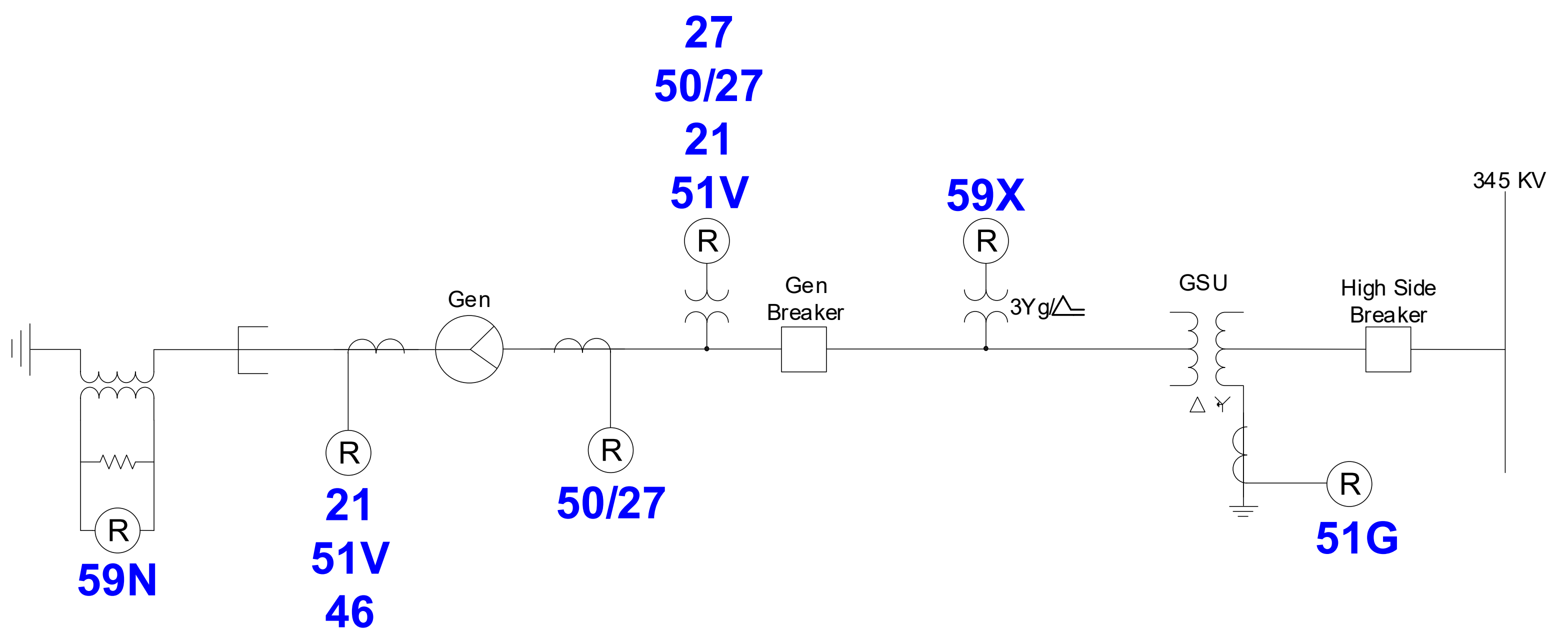
Plot the 27 settings versus the voltage duration criteria:



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

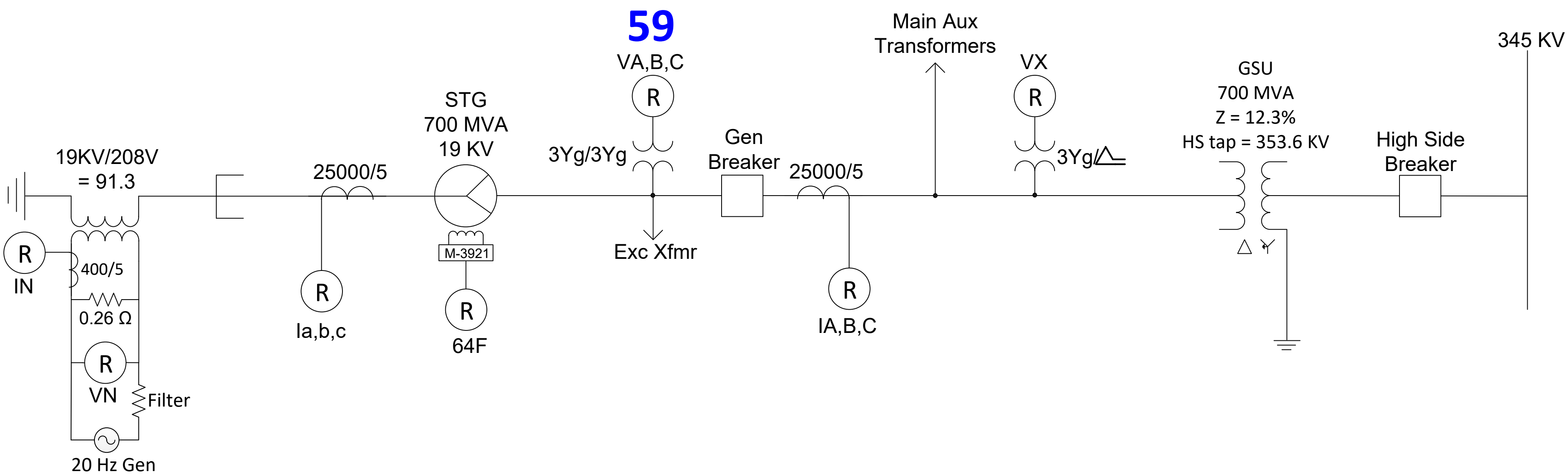
PRC-027

- Coord gen 27 with voltage dips from transmission line faults.



- Gen 27 Trip time delay = 6 seconds.
- All transmission line relaying clears in well before this.
- Therefore **YES, complies**

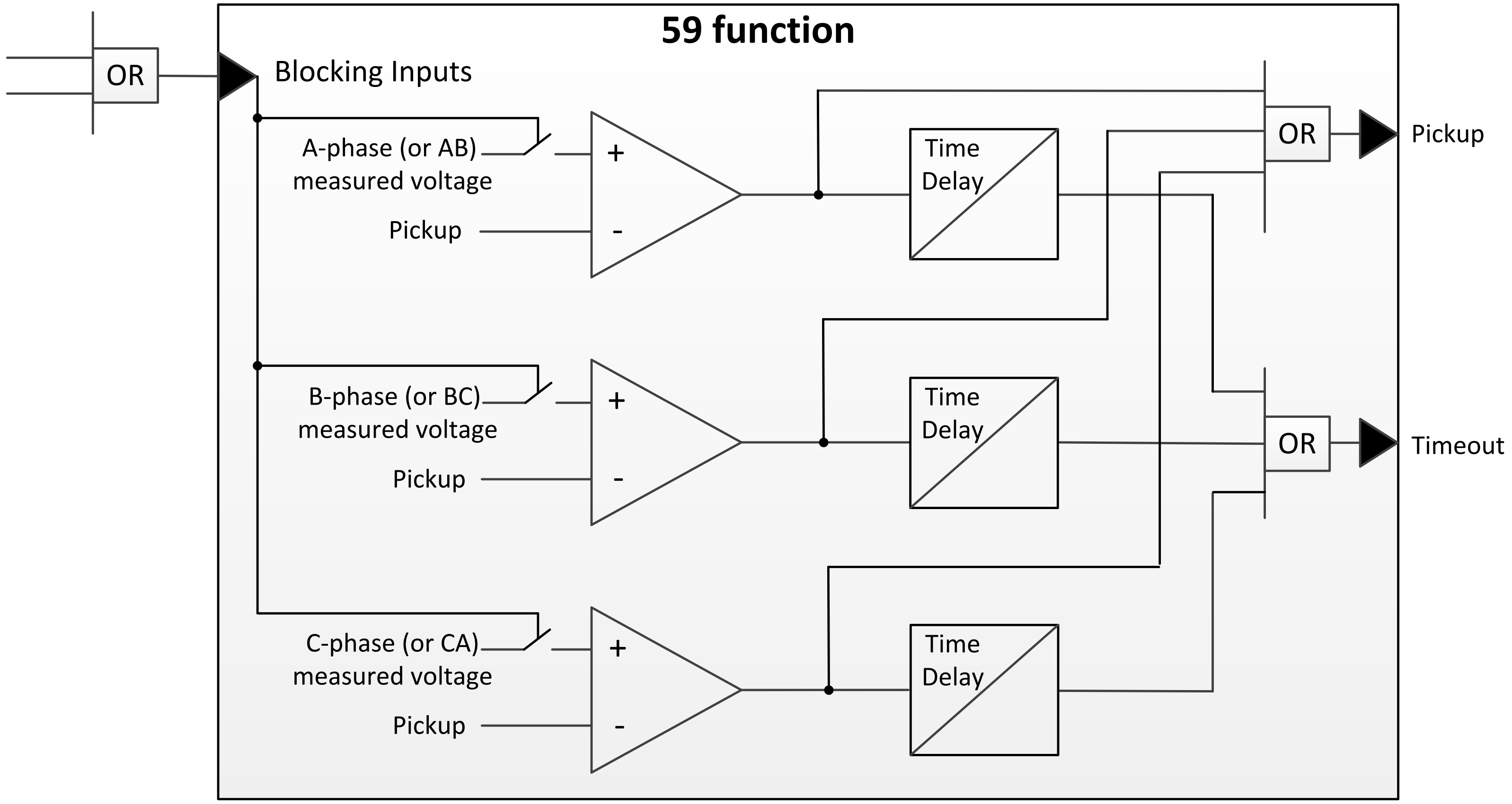
59 – Phase Overvoltage



Blocking Inputs = none

Recommend to set both 24 and 59 functions.

59 – Phase Overvoltage



Phase Overvoltage (59)

59 Pickup bookend criteria may be represented as such:

PRC-019, PRC-024 < 59 Pickup < overvoltage damage curve

May request the overvoltage damage curves from the Gen and GSU mfg, but typically such information is not provided. Different resources may provide some general guidance, but here is a summary from the JL Blackburn book "Protective Relaying, Principles and Applications" 4th edition, where it is stated that typical permissible overvoltages at No Load are the following:

Gen	GSU
105% continuous	110% continuous
110%, 30 minutes	115%, 30 minutes
115%, 5 minutes	120%, 5 minutes
125%, 2 minutes	130%, 3 minutes

Phase Overvoltage (59)

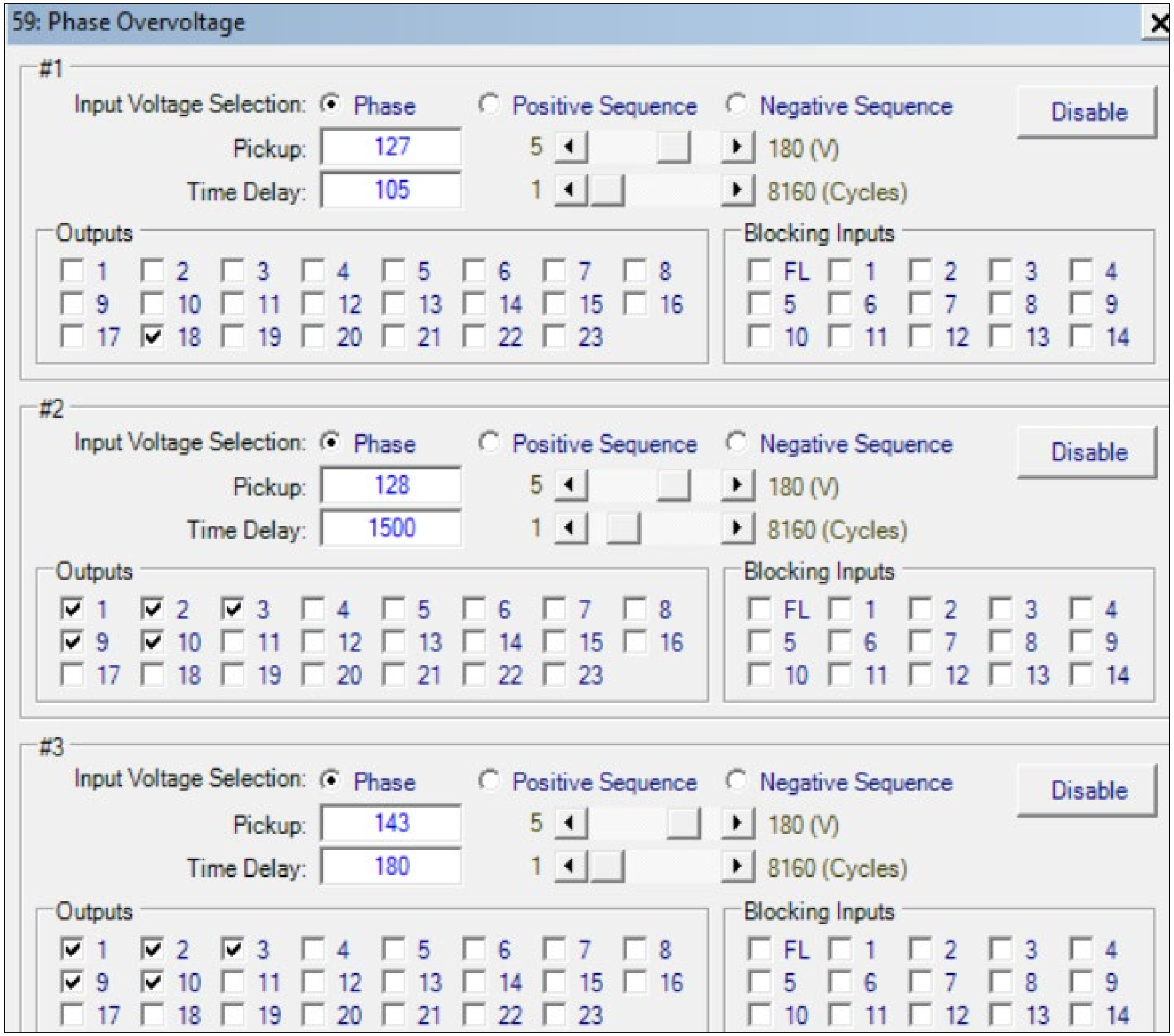
- The following 59 settings were chosen based on PRC-019 and PRC-024 compliance:

Set 59 #1 to Alarm at 106% (1.06*120=127 V) and 1.75 seconds (105 cycles)

Set 59 #2 to Trip at 107% (1.07*120=128 V) and 25 seconds (1500 cycles)

Set 59 #3 to Trip at 119% (1.19*120=143 V) and 3 seconds (180 cycles)

Some of the values may seem odd, but I would always like to achieve clear space between plotted curves to easily show compliance to NERC auditors.



59 Phase Overvoltage

Evaluate settings against PRC-019 and PRC-024

PRC-019-2

Verify coordination of generator voltage regulating controls with protective relays and equipment capabilities.

Coordinate

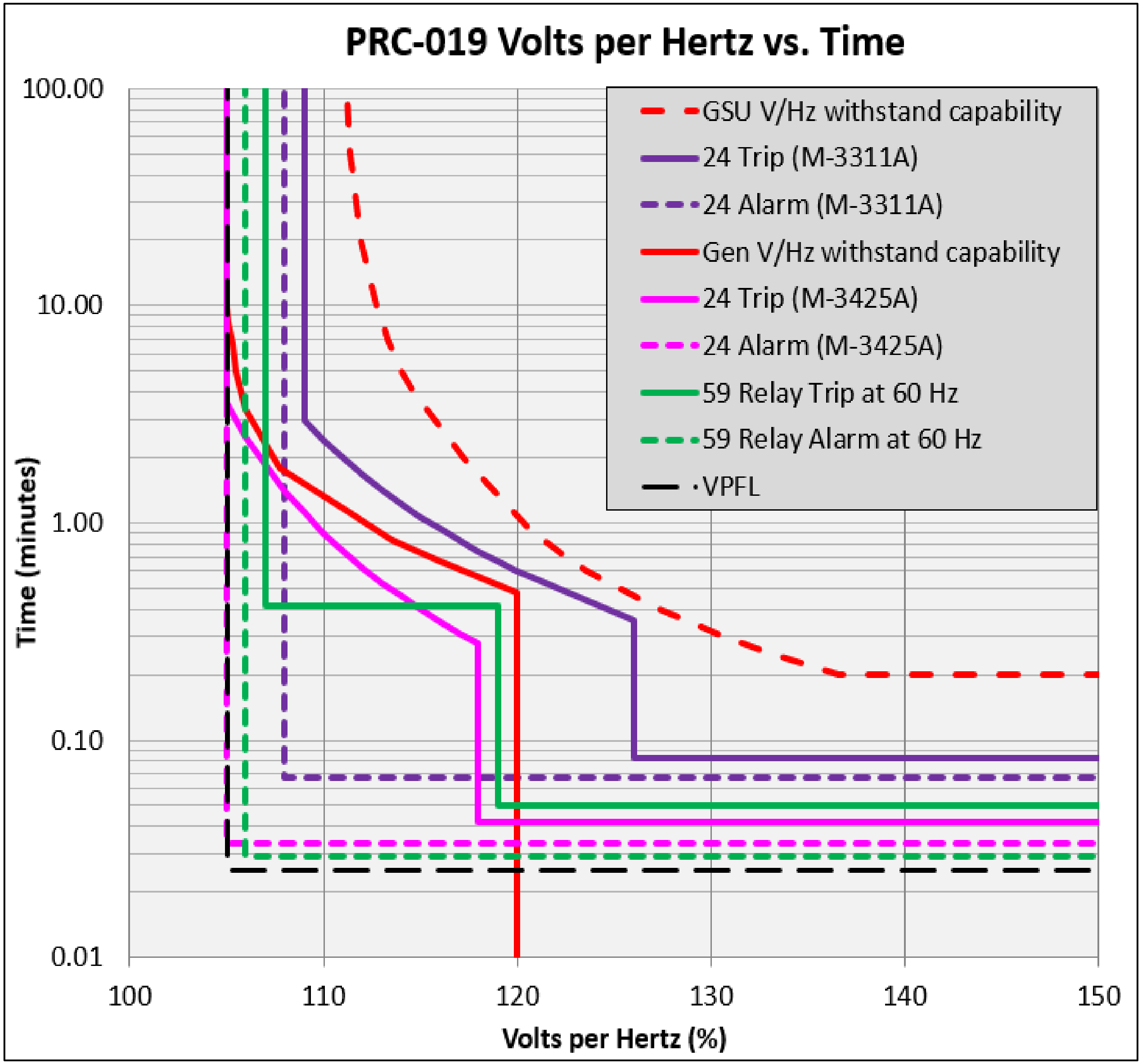
- Voltage Regulating Controls
  - 24EX, VPFL, 40EX, 59EX, OEL, UEL, Field I*T trip
- Protection
  - 24, 40, **59**
- Generating Unit or Plant Capabilities
  - GCC, SSSL

Per section B.R1-1.1.1, the in-service limiters are set to operate prior to the protection elements tripping.

Per section B.R1-1.1.2, the protective elements will trip prior to equipment damage or stability limits.

PRC-019-2

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



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

PRC-024

Verify generators remain connected during frequency and voltage excursions

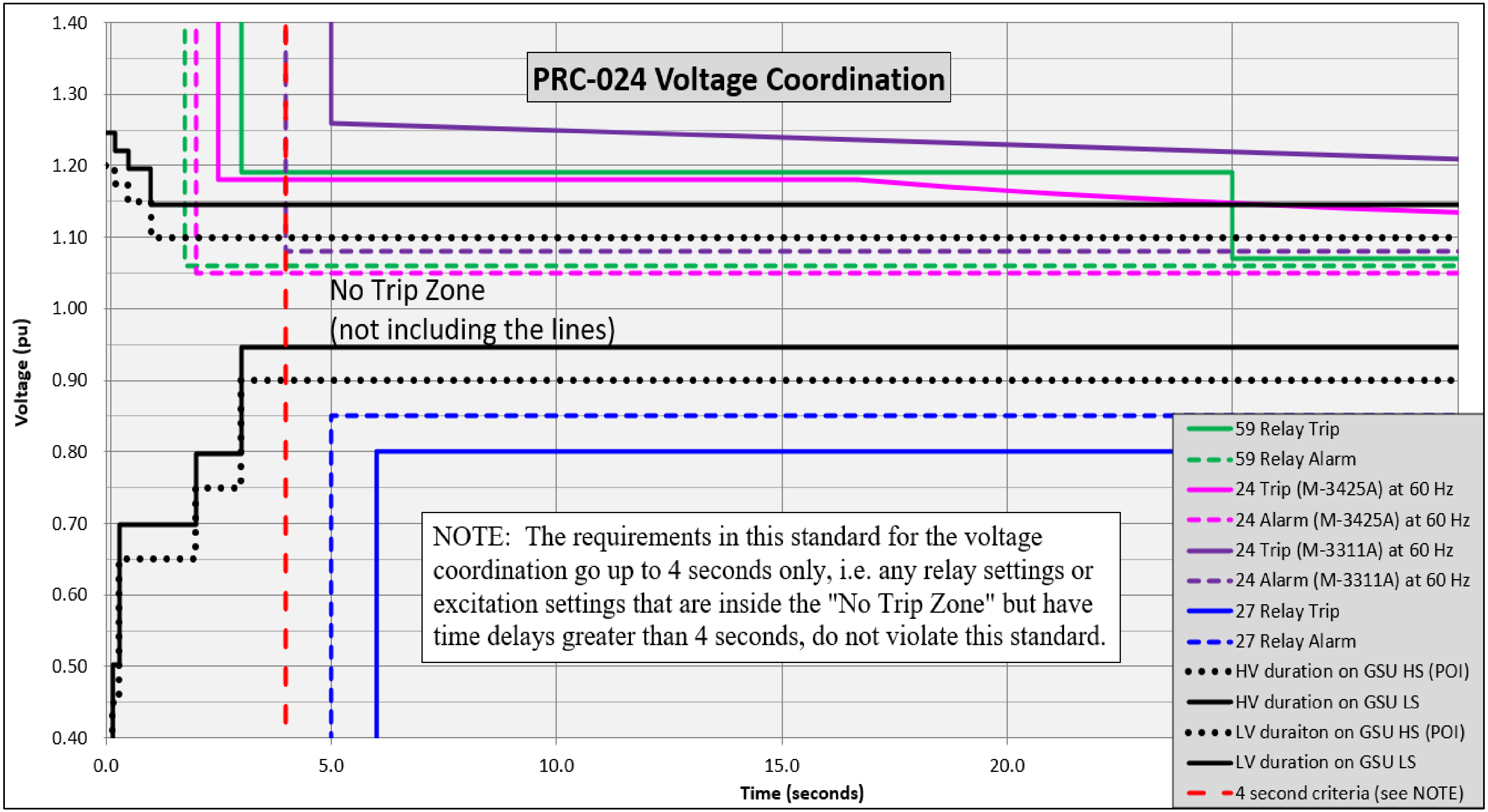
Coordinate

- Protection
  - 24 at 60 Hz, 27, **59**, 81
- Voltage Regulating Controls
  - 24EX, 59EX
- Defined ride thru curves
  - frequency
  - voltage

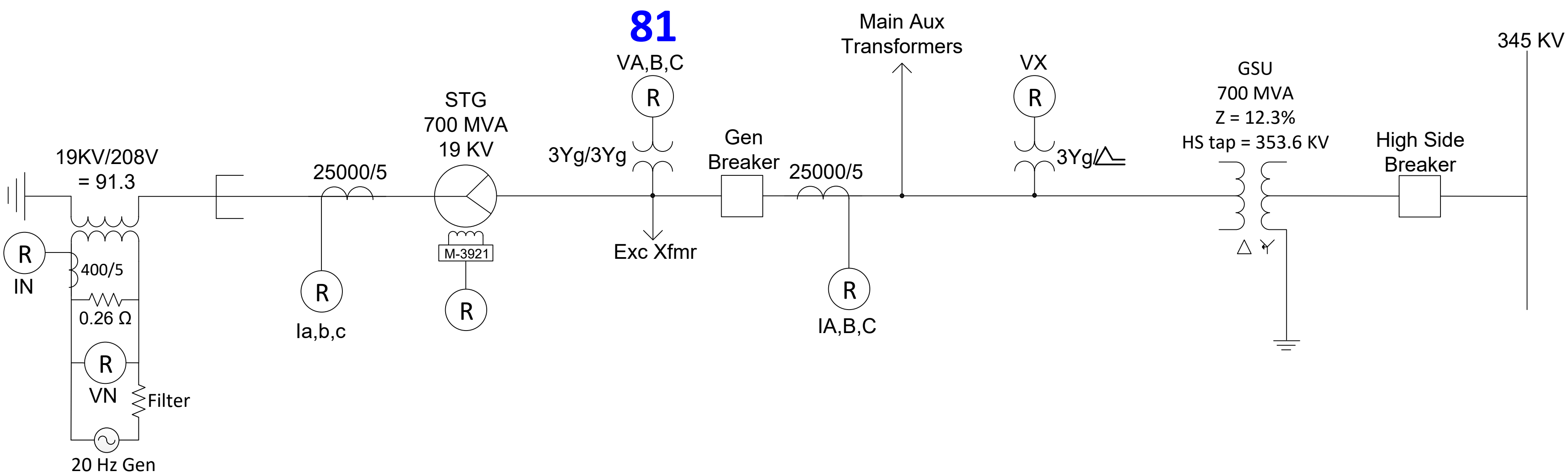
Aux systems are out of scope of this standard.

PRC-024

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



81 – Over/Under Frequency



Blocking Inputs = FL, 1 (for on-line 81O/U)

Blocking Inputs = FL (for off-line 81O)

Frequency derived from measured voltage waveforms

81 – Over/Under Frequency

- **81 – the relay type used in this example has (4) frequency elements**
  - Each element may be applied for over- or underfrequency
  - Use Primary and Backup relays in tandem to give (8) unique frequency elements for optimal protection and security but choose settings such that if either relay is out of service, that adequate protection is still provided.
  - High accuracy – $1/100^{th}$ Hz (0.01 Hz)
  - Coordination with System Load Shedding.
  - **Let PRC-024 criteria along with mfg off-nominal frequency withstand capability curve drive chosen settings.**

NOTE: Set an off-line 81O element (if enough elements are available) to back up the "12" mechanical overspeed device, which is typically set to 110% of the rated rpm (1.10 * 3600 = 3960 rpm):

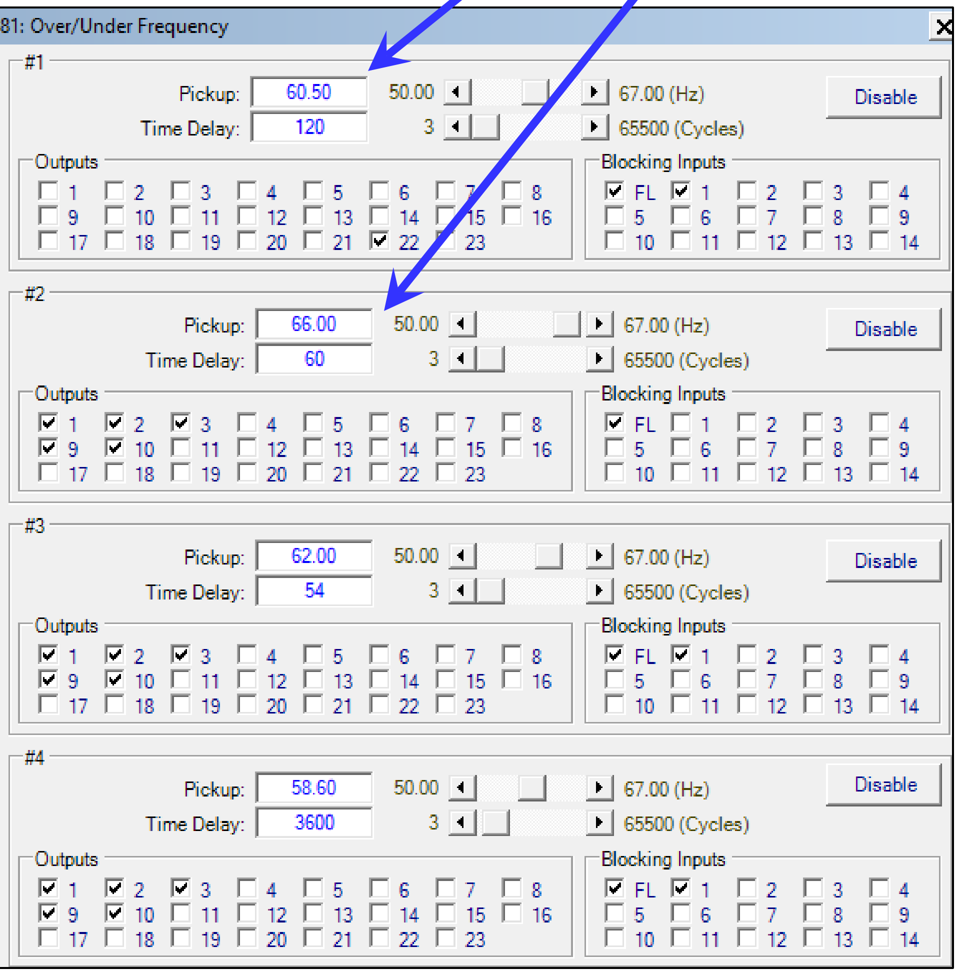
- $$f = \frac{110\%\ of\ rated\ RPM * \#\ of\ Poles}{120} = \frac{3960 * 2}{120} = 66\ Hz$$

81 Frequency Protection

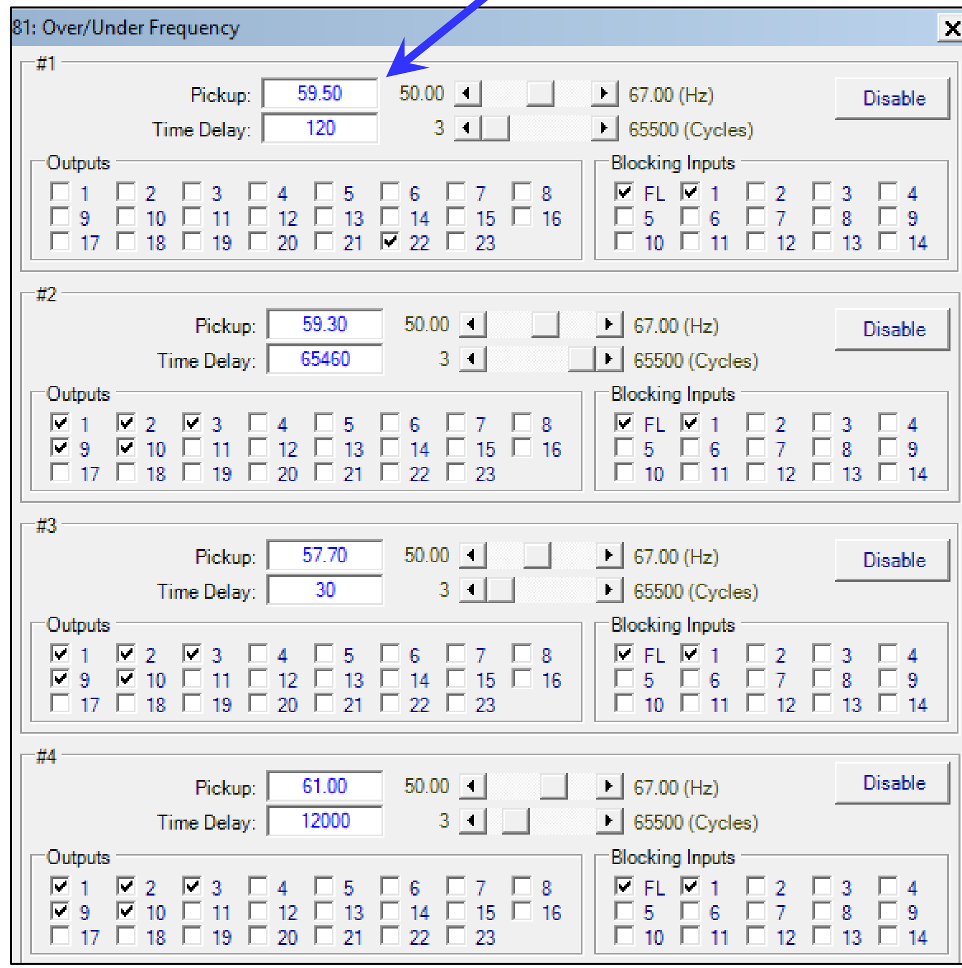
81O Alarm

Off-line 81O

81U Alarm



Primary relay



Backup relay

81 Over/Under Frequency

Evaluate settings against PRC-024

PRC-024

Verify generators remain connected during frequency and voltage excursions

Coordinate

- Protection
  - 24 at 60 Hz, 27, 59, **81**
- Voltage Regulating Controls
  - 24EX, 59EX
- Defined ride thru curves
  - frequency
  - voltage

Aux systems are out of scope of this standard.

PRC-024

- Choose the interconnection boundary where plant is located.
- This sample application is in the Eastern area.

NOTE: the area outside the "No Trip Zone" is not a must trip zone.

PRC-024-3 —Frequency and Voltage Protection Settings for Generating Resources

Attachment 1

(Frequency No Trip Boundaries by Interconnection[8])

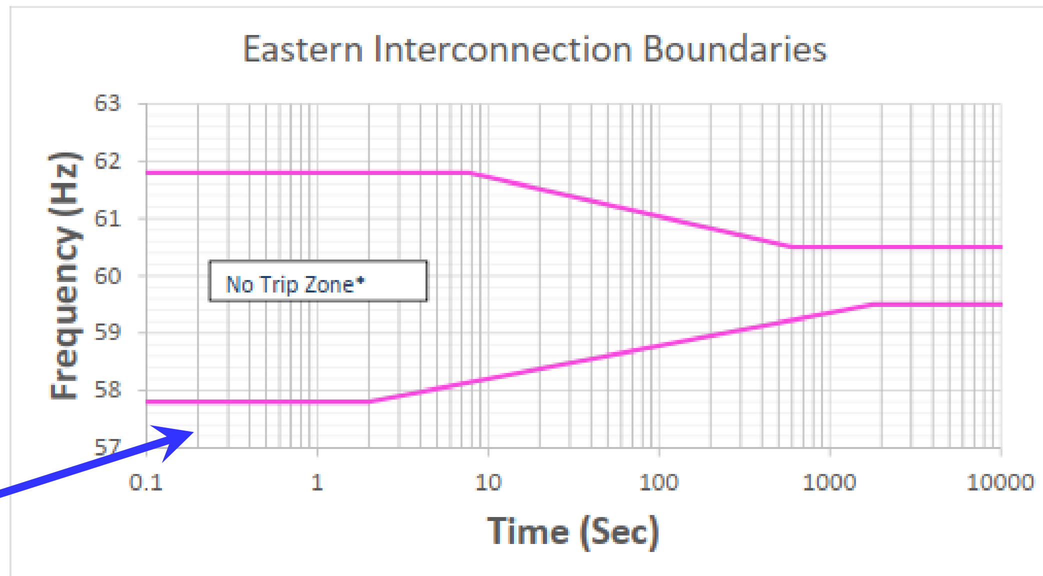


Figure 1

** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

PRC-024

Off-nominal frequency damage curves:

- from mfg – specific to these sample calcs
- typical – from pg 1142, IEEE transactions Vol. PAS-99, No. 3, 1980

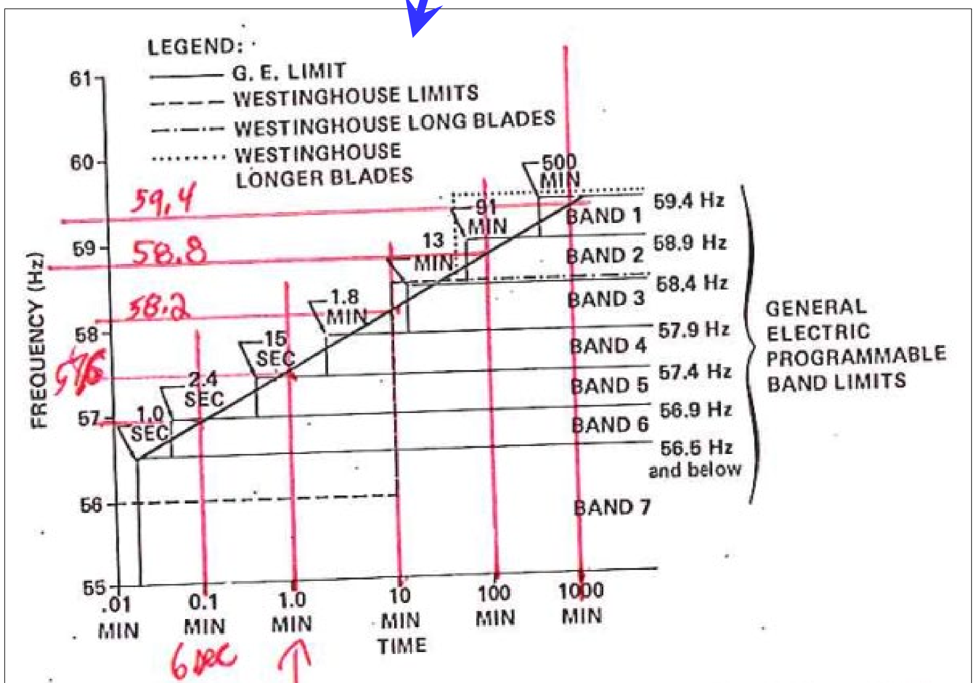
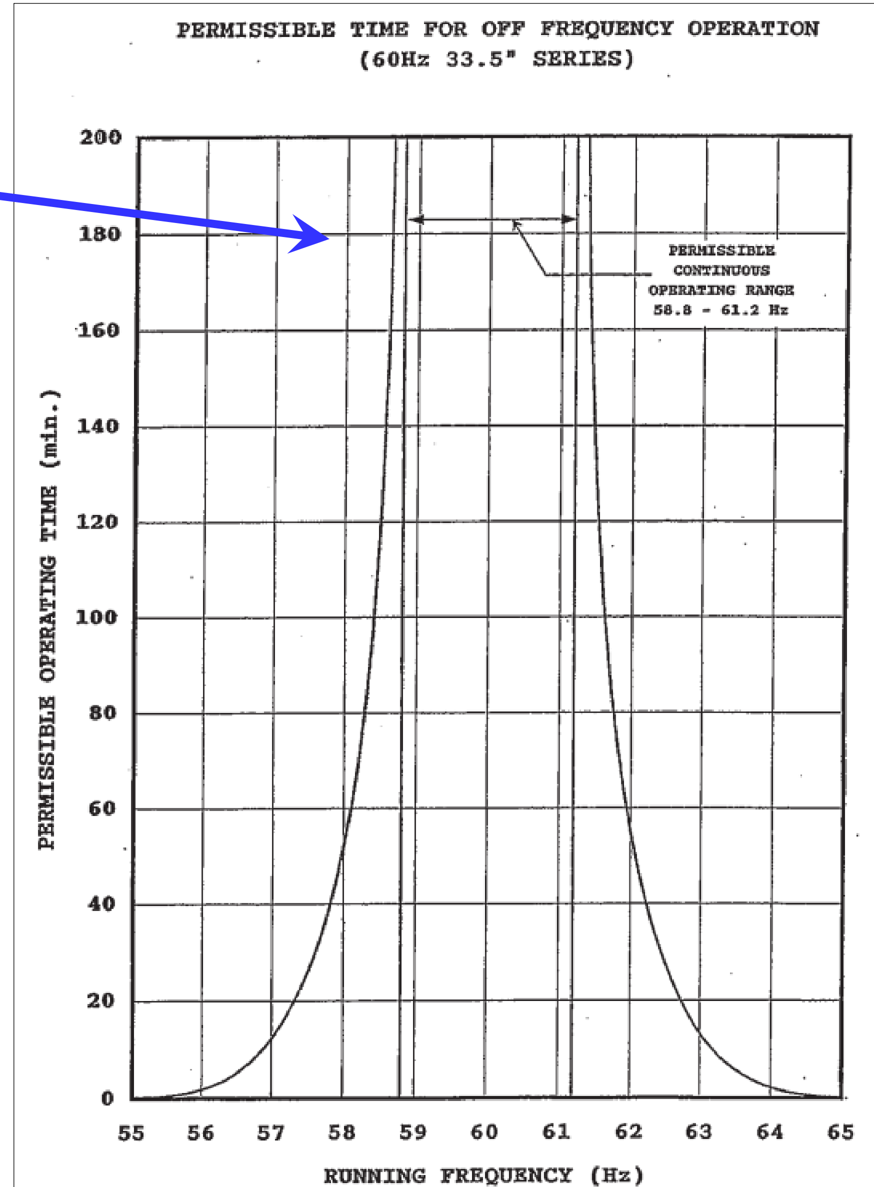
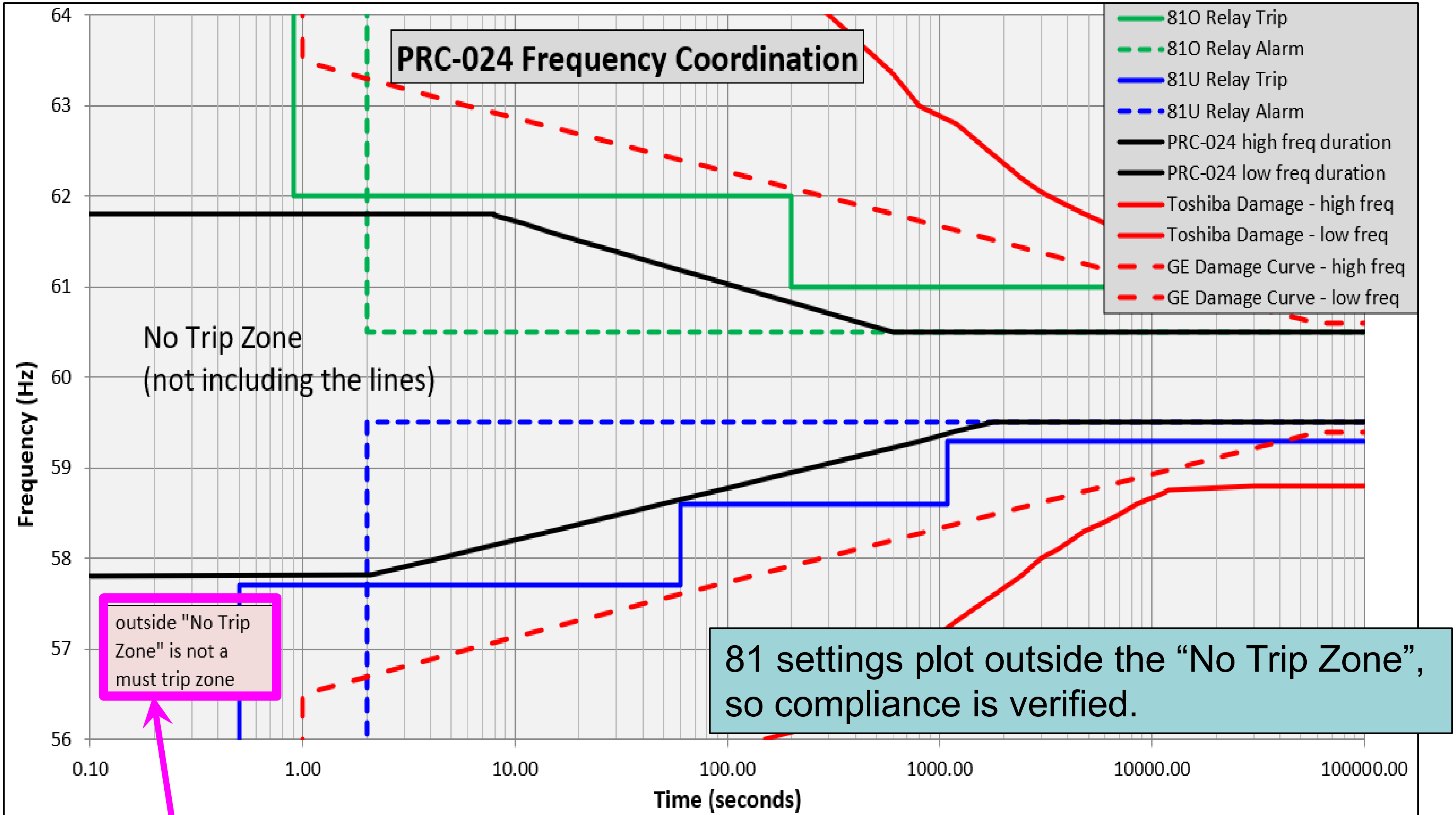


Figure 6 - General Electric and Westinghouse Underfrequency Limits For Steam Turbines

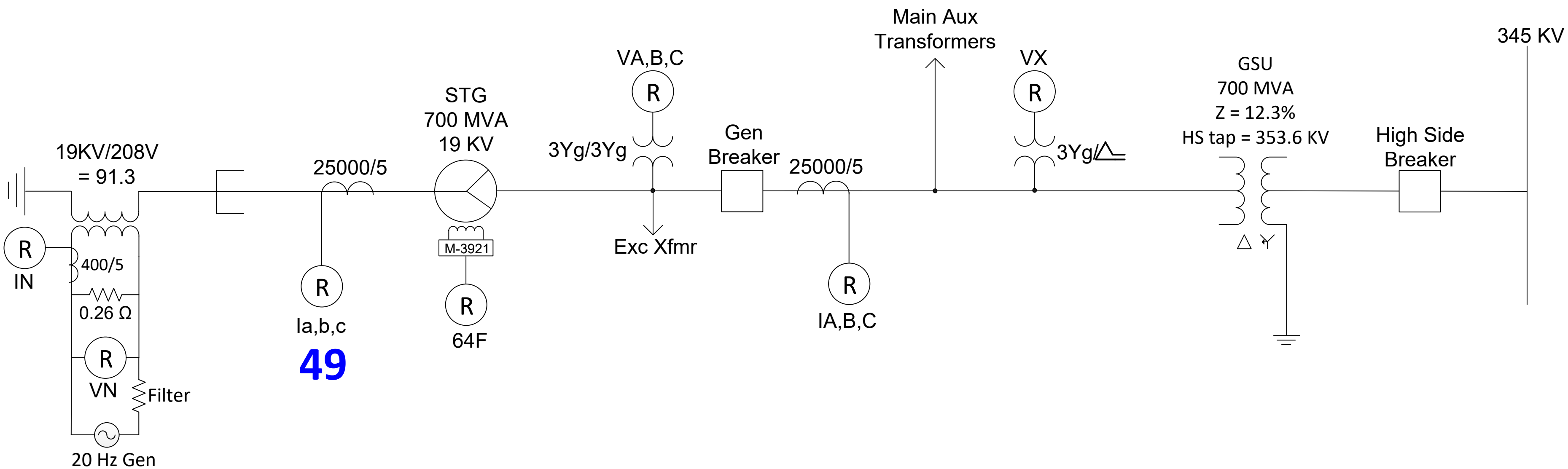


PRC-024 Plot 81 settings, frequency duration criteria, and damage curves:



- Some folks misinterpret this criteria and set their 81 settings so fast and end up mis-operating on transients.

49 – Stator Thermal Overload

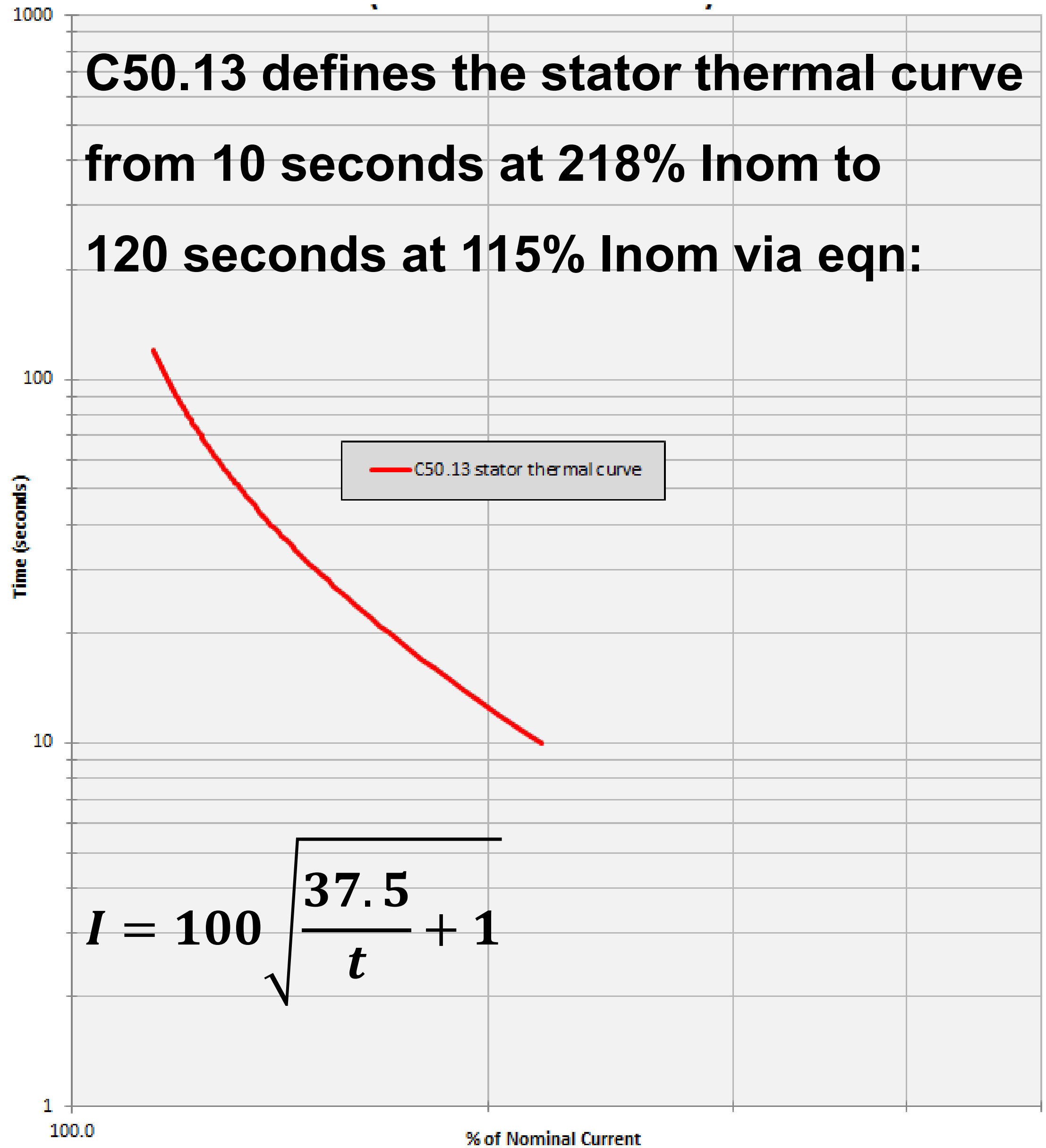


Blocking Inputs = none

$$time = TC * ln(\frac{M^2 - preload^2}{M^2 - pickup^2})$$

49 – Stator Thermal Overload

- If the gen mfg provides a stator thermal overload curve, then plot a 49 protection curve under that mfg provided thermal damage curve.
- If no information is provided by mfg, then may use this curve from C50.13:



C50.13 defines the stator thermal curve from 10 seconds at 218% Inom to 120 seconds at 115% Inom via eqn:

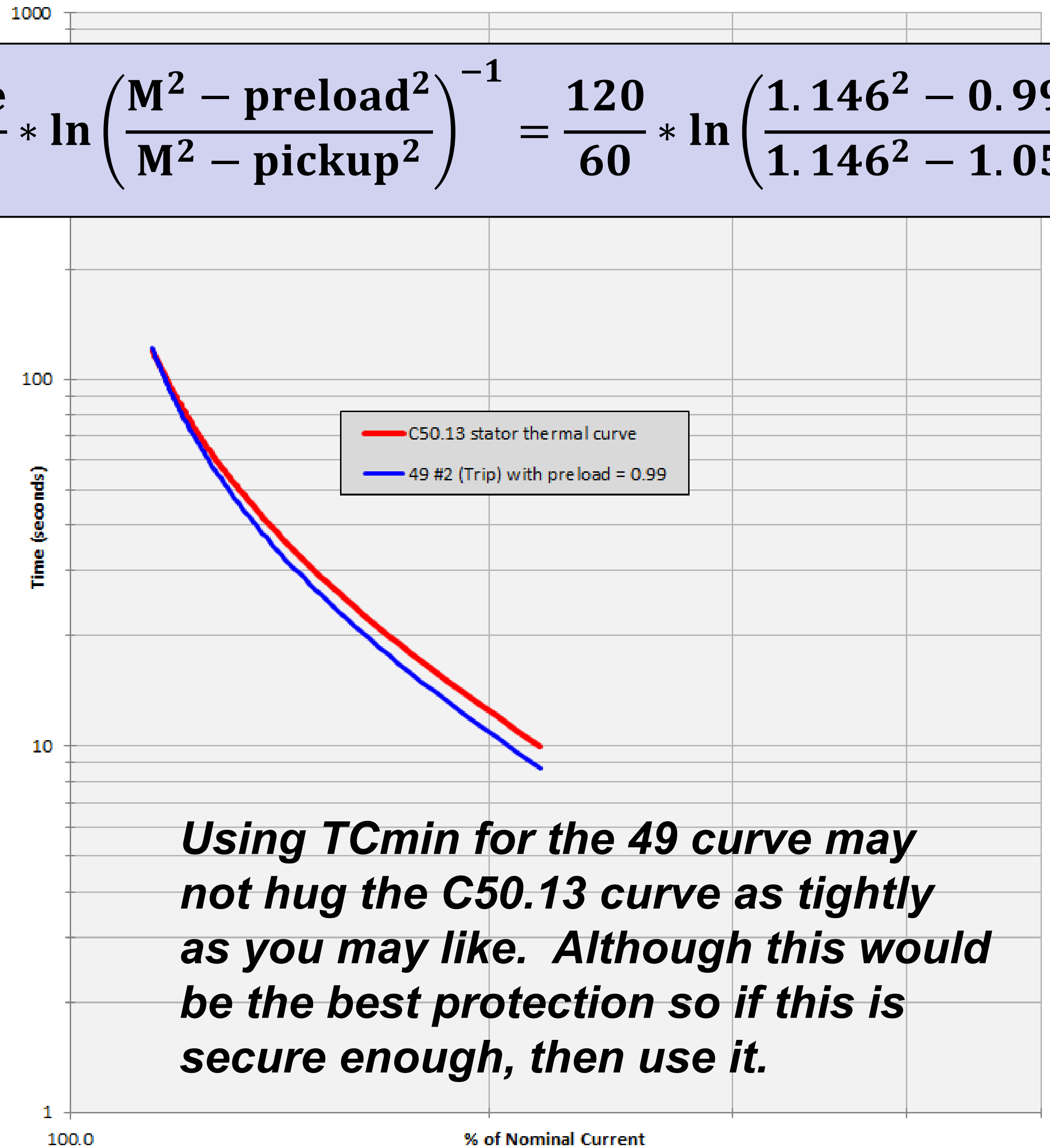
$$I = 100\sqrt{\frac{37.5}{t} + 1}$$

49 – Stator Thermal Overload

- The best method to protect this generator stator thermal overload/damage curve is typically with a 49 function (not 50/51).
- Use 49 #1 to Alarm and 49 #2 to Trip.
- First, choose the Pickup setting: here choose Pickup = 105%.
- PRO TIP: Plot the 49 trip curve as closely as possible under the C50.13 stator thermal overload curve to avoid nuisance trips.
- Next, solve the 49 equation for the thermal time constant (unless the TC is known from the mfg or from doing heat runs) to protect the C50.13 curve assuming a worst-case preload of 0.99 pu.
  - Most relay mfg's use IEC 60255-8 equation for 49 algorithm
  - Use "Goldilocks" strategy to develop time constant setting i.e. calculate TC at both ends of the C50.13 curve:
    - @ 10 seconds and 218%
    - @ 120 seconds and 115%

49 – Stator Thermal Overload

$$TCmin = \frac{time}{60} * \ln\left(\frac{M^2 - preload^2}{M^2 - pickup^2}\right)^{-1} = \frac{120}{60} * \ln\left(\frac{1.146^2 - 0.99^2}{1.146^2 - 1.05^2}\right)^{-1} = 4.4 \text{ minutes}$$

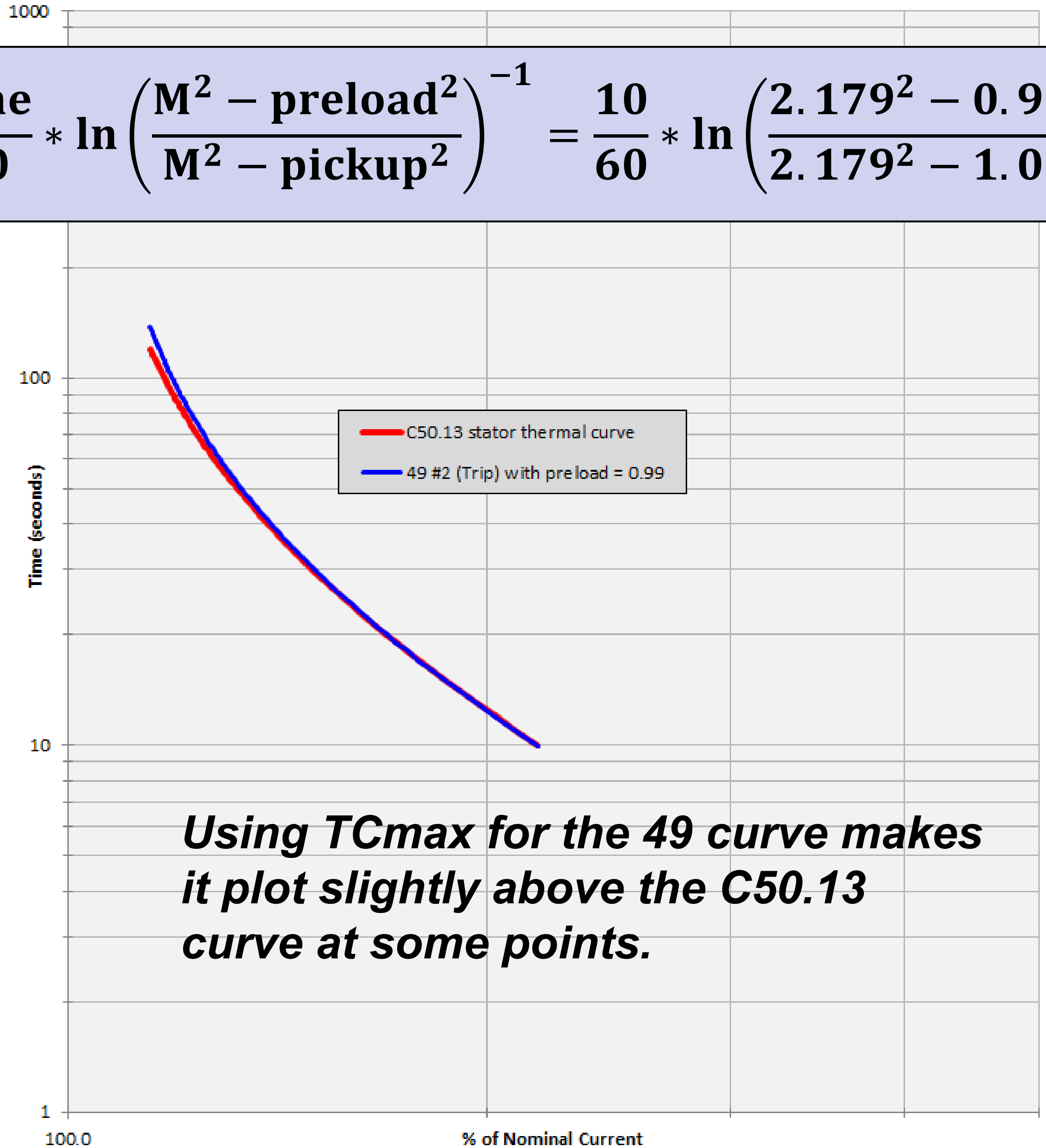


Too cold

Using TCmin for the 49 curve may not hug the C50.13 curve as tightly as you may like. Although this would be the best protection so if this is secure enough, then use it.

49 – Stator Thermal Overload

$$\text{TCmax} = \frac{\text{time}}{60} * \ln\left(\frac{M^2 - \text{preload}^2}{M^2 - \text{pickup}^2}\right)^{-1} = \frac{10}{60} * \ln\left(\frac{2.179^2 - 0.99^2}{2.179^2 - 1.05^2}\right)^{-1} = 5.0 \text{ minutes}$$

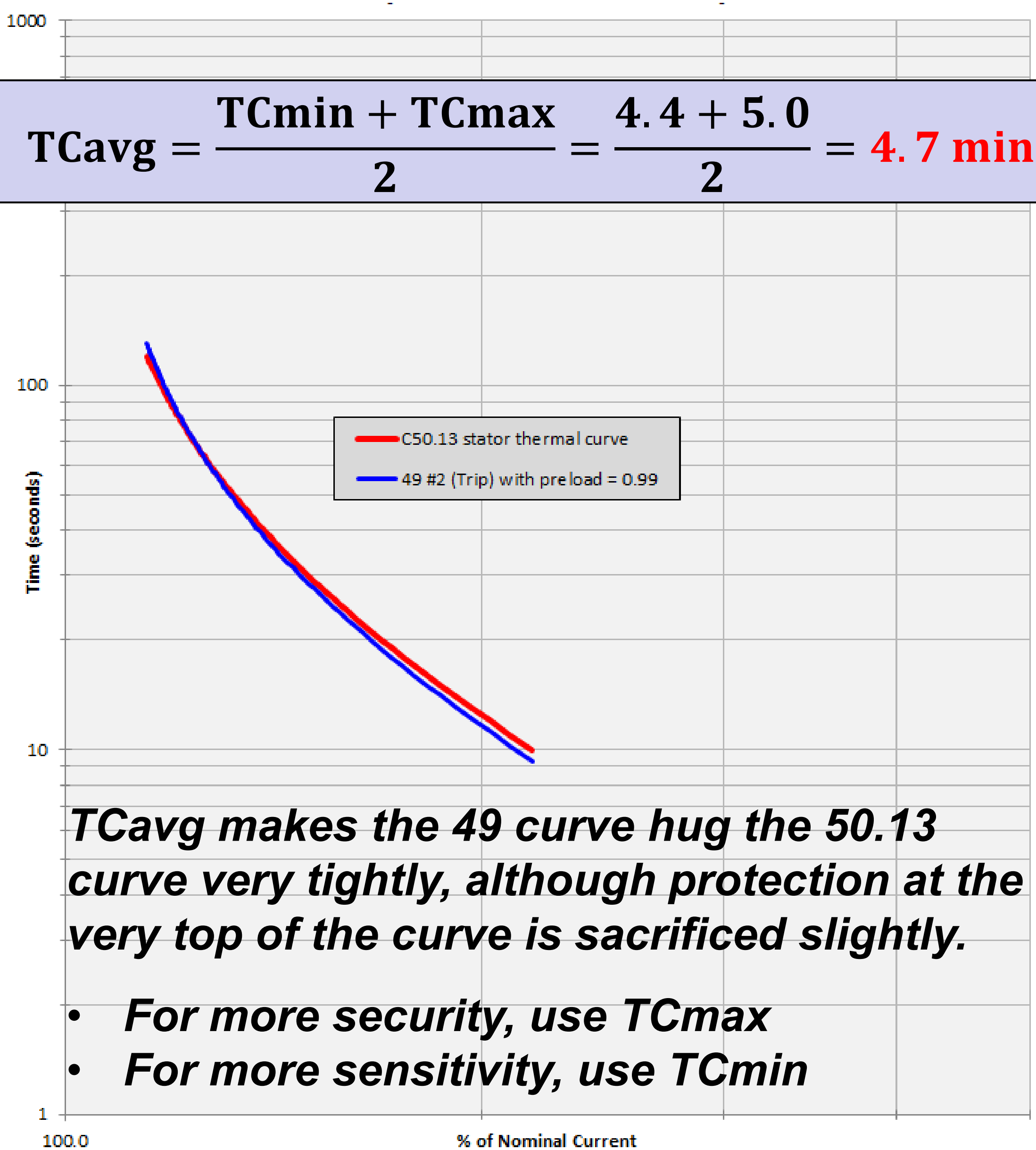


Too hot

Using TCmax for the 49 curve makes it plot slightly above the C50.13 curve at some points.

49 – Stator Thermal Overload

$$\text{TCavg} = \frac{\text{TCmin} + \text{TCmax}}{2} = \frac{4.4 + 5.0}{2} = 4.7\ \text{minutes}$$



Just right …

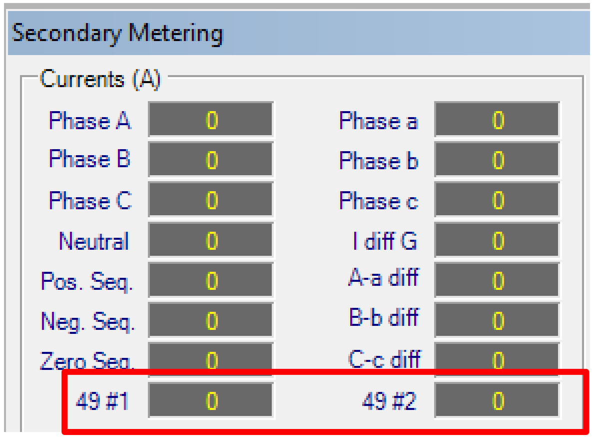
almost

TCavg makes the 49 curve hug the 50.13 curve very tightly, although protection at the very top of the curve is sacrificed slightly.

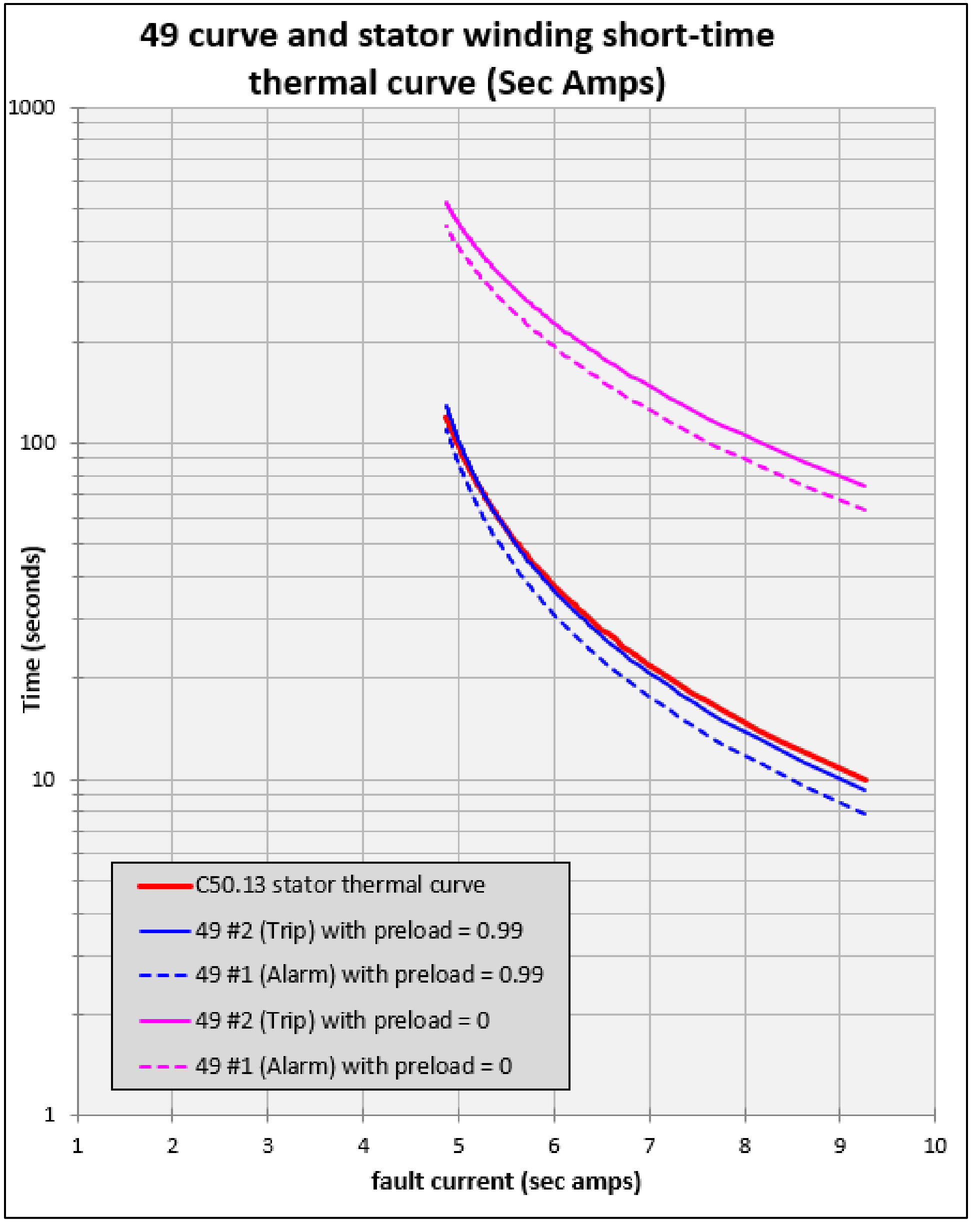
- ***For more security, use TCmax***
- ***For more sensitivity, use TCmin***

49 – Stator Thermal Overload

- **PRO TIP: The relay's Nominal Current setting must be set at the absolute, maximum generator output (which may differ from nameplate).**
- **Track the unit max loading over time or ask operator to run the unit up to max to see if the machine is running above the Nominal Current setting (because this algorithm uses the Nominal Current setting).**
- **The 49 function's real time metering values can be monitored via the relay software or HMI as well to determine if the settings are acceptable.**
- **If it is running hot, then may consider adjusting the 49 settings and/or the Nominal Current setting.**
- **Another option is to initially enable the 49 function but do not program it to activate any outputs.**
- **Or just use the 49 Alarm initially and not the Trip.**



49 – Stator Thermal Overload

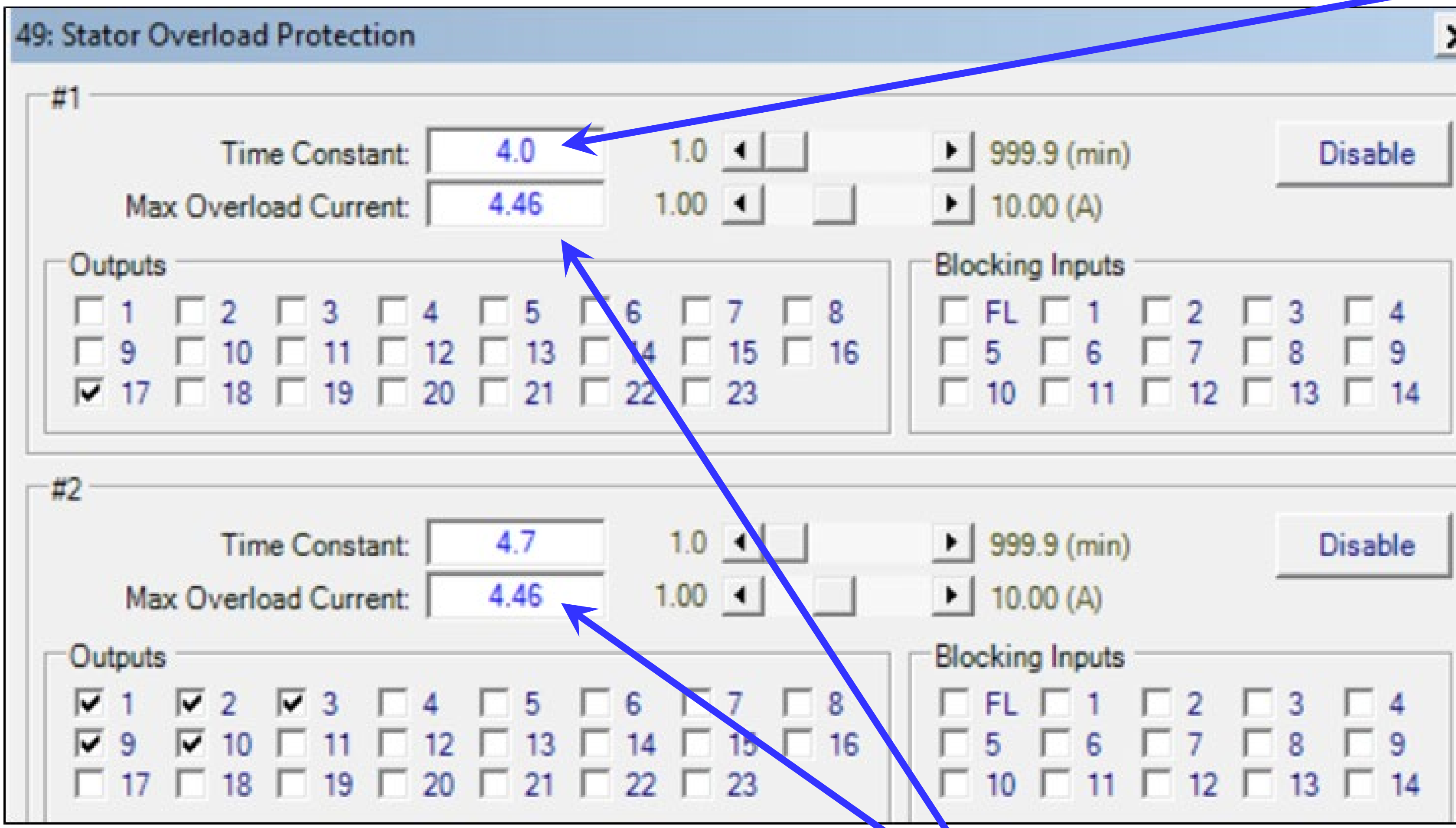


Test Values		
	49 #1 (Alarm)	49 #2 (Trip)
	Preload = 0	Preload = 0
I (sec amps)	t (sec)	t (sec)
9.26	63	75
6.38	162	190
5.42	273	321
4.87	441	518

For testing with preload = 0 erase thermal memory between successive tests.

49 – Stator Thermal Overload

Set 49 Alarm Time Constant at 85% of the Trip Time Constant, 0.85 * 4.7 = 4 min



Set 49 Pickup to 105% of Inom: 1.05 * 4.25 = 4.46 A

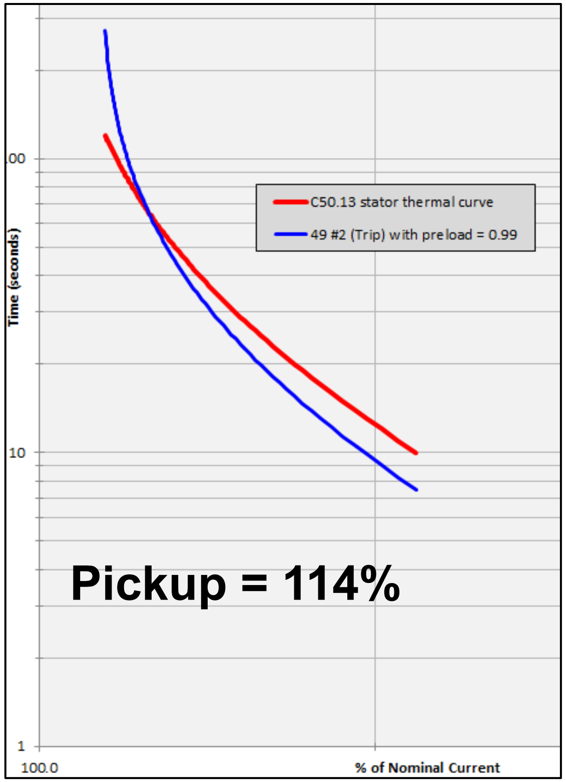
49 – Stator Thermal Overload

- **PRC-025-2 (Generator Relay Loadability) exclusion 6 states:**

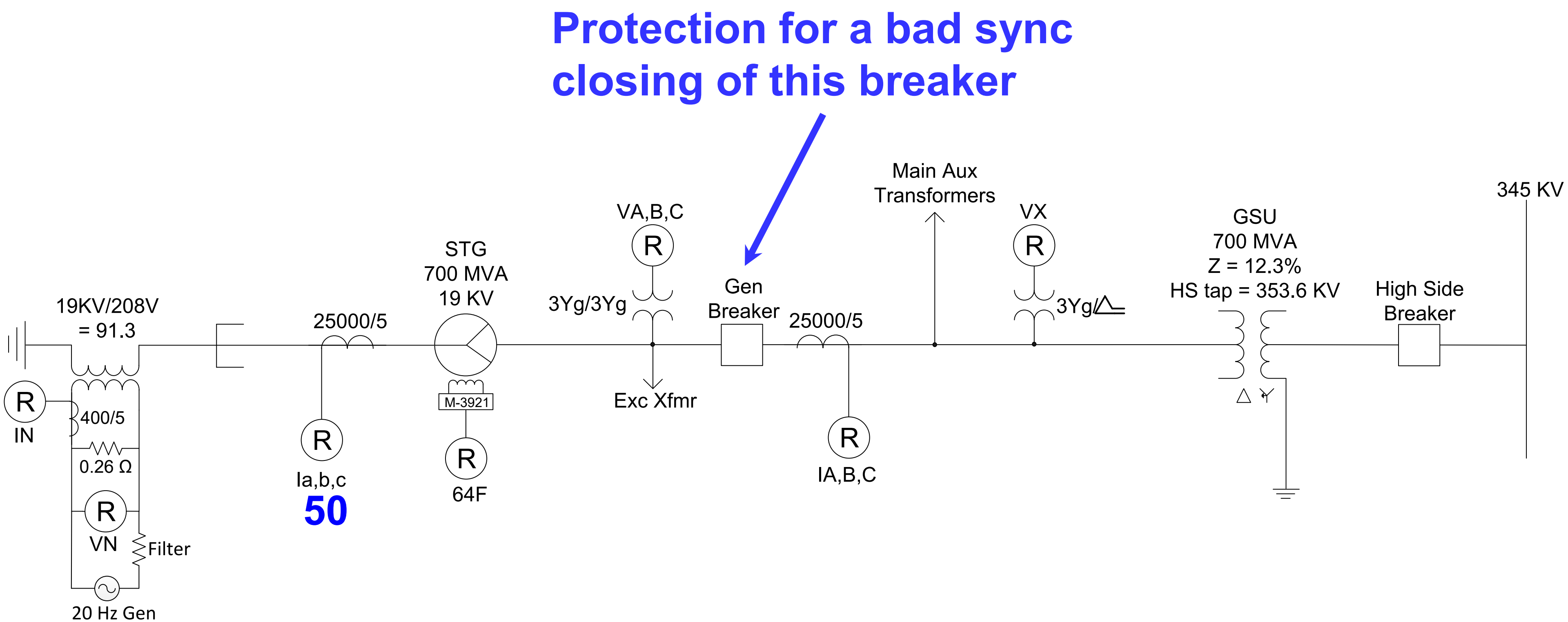
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

- **49 trip time at 218% is 9 sec, so OK at curve bottom.**
- **However, does not prevent operation below 115% (pickup is 105%).**
- **49 eqn will not allow pickup ≥ 115% (divide by zero).**
- **Can set it to 114%, but curve fit is not good, and at 114% the TC approaches 1 min – is that secure?**
- **So cannot technically exclude these 49 settings from PRC-025, but these settings provide better and more secure protection.**
  - **request exemption/waiver or request clarification from NERC?**



50 – Instantaneous Phase Overcurrent

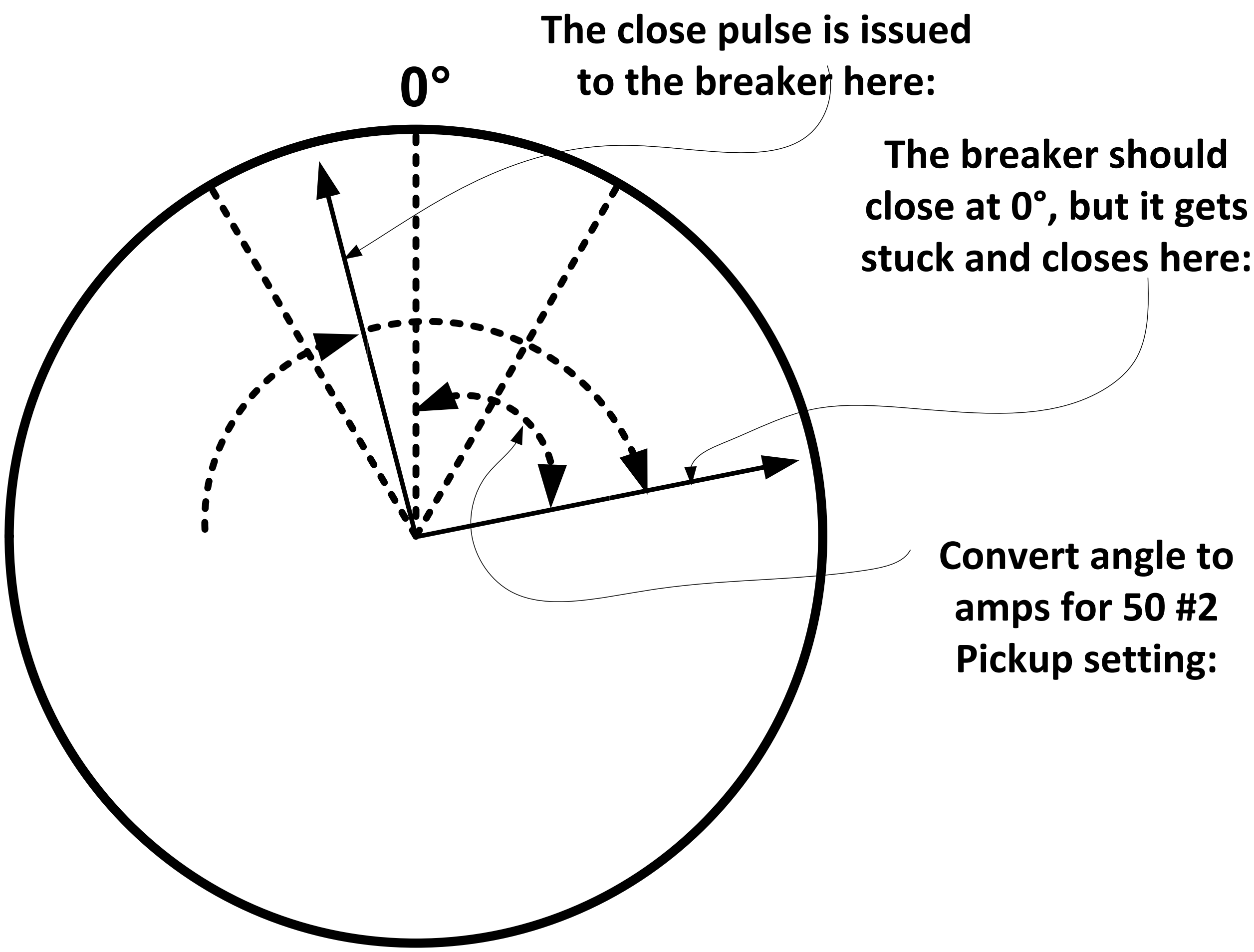


Blocking Inputs = none

50 #2 with IPSlogic – Isync trip

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.



50 #2 with IPSlogic – Isync Trip

Calculate pickup setting:

- Engage logic when the breaker is open and for 15 cycles after breaker is closed.
- Look at the current instead of the angle as angle supervision won’t do any good now because the close pulse has already been sent to the breaker.
- Convert from the damage angle to pickup amps using equation from reference [1].
- What to use for damage angle to use? Check with mfg. For this example, use 60°, but could increase for more security:

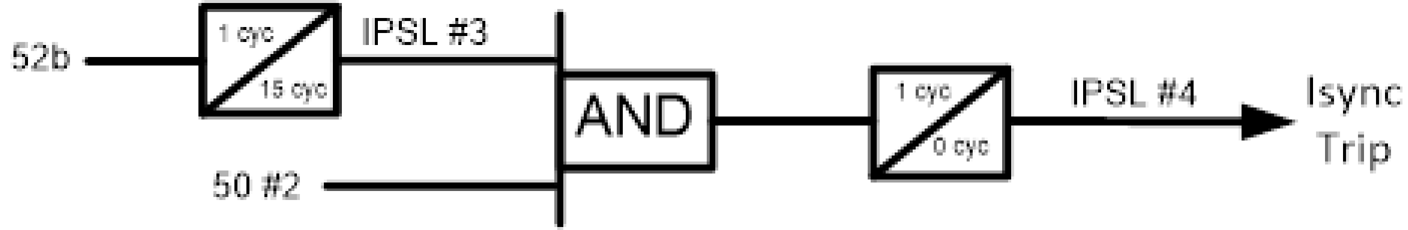
$$\delta s := 60 \cdot \frac{\pi}{180} \qquad Iac := \frac{\sqrt{Es^2 + Eg^2 - 2 \cdot Es \cdot Eg \cdot \cos(\delta s)}}{Xg1subunsat + Zt + Zs1} \cdot \frac{Sbase \cdot 1000}{\sqrt{3} \cdot VbaseLS} \qquad |Iac| = 44003 \quad pri\_amps$$

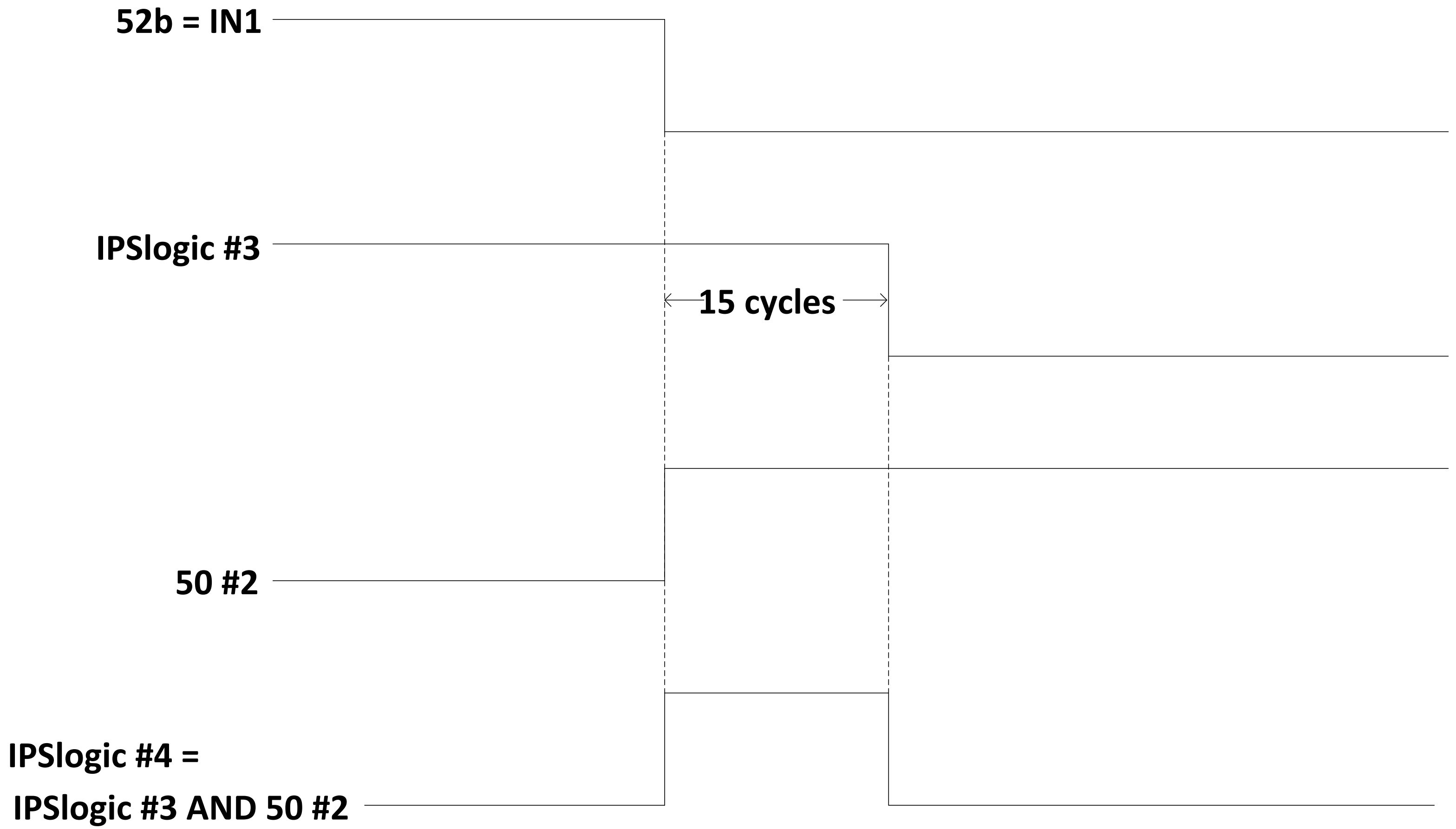
Max gen output * SF	≤	50 #2 Pickup	<	Isync at 60°, Isync at 120°
4.25 * 2	≤	50 #2 Pickup	<	44003/5000, 76215/5000
8.5	≤	50 #2 Pickup	<	8.8, 15.2

- Set 50 #2 Pickup = 8.5 A

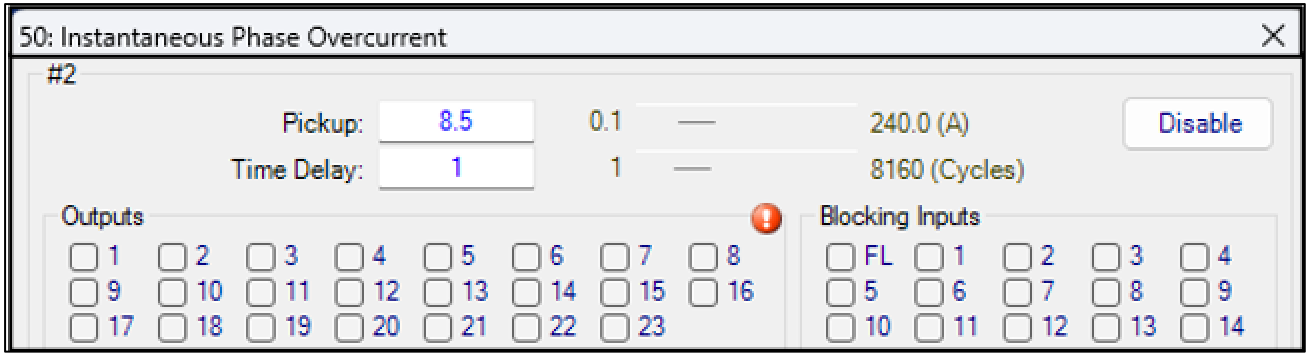
[1] “Protective Relaying for Power Generation Systems” by Donald Reimert, Page 359, Equation 14.3

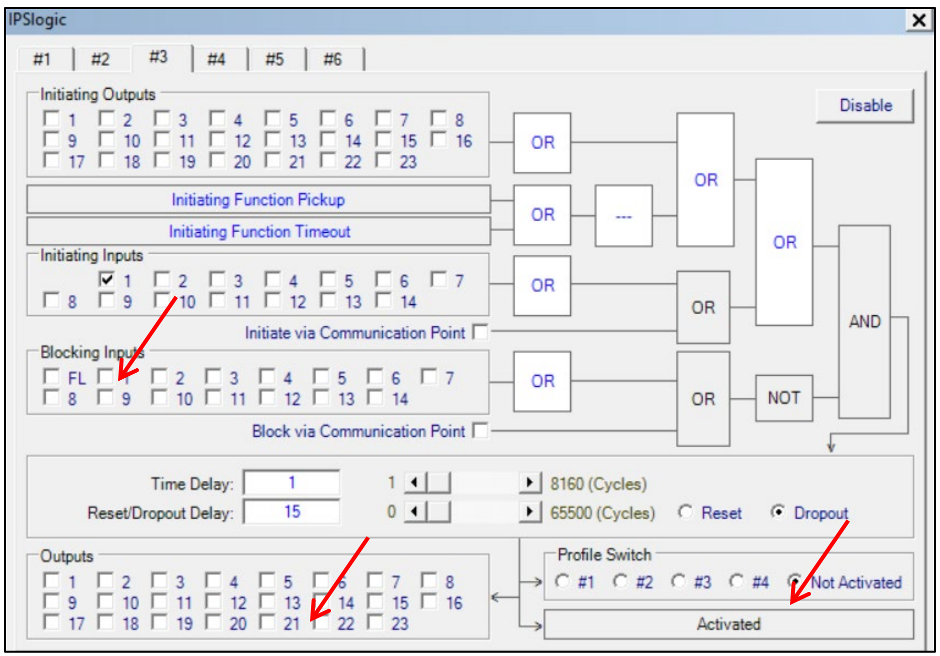
50 #2 with IPSlogic – Isync Trip

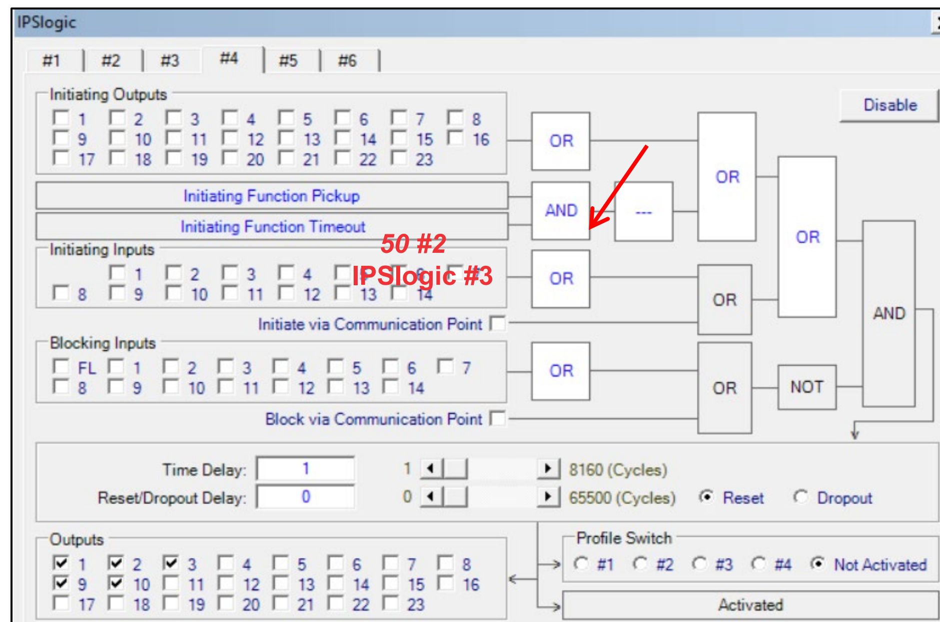




50 #2 with IPSlogic







50 #2 with IPSlogic – Isync Trip

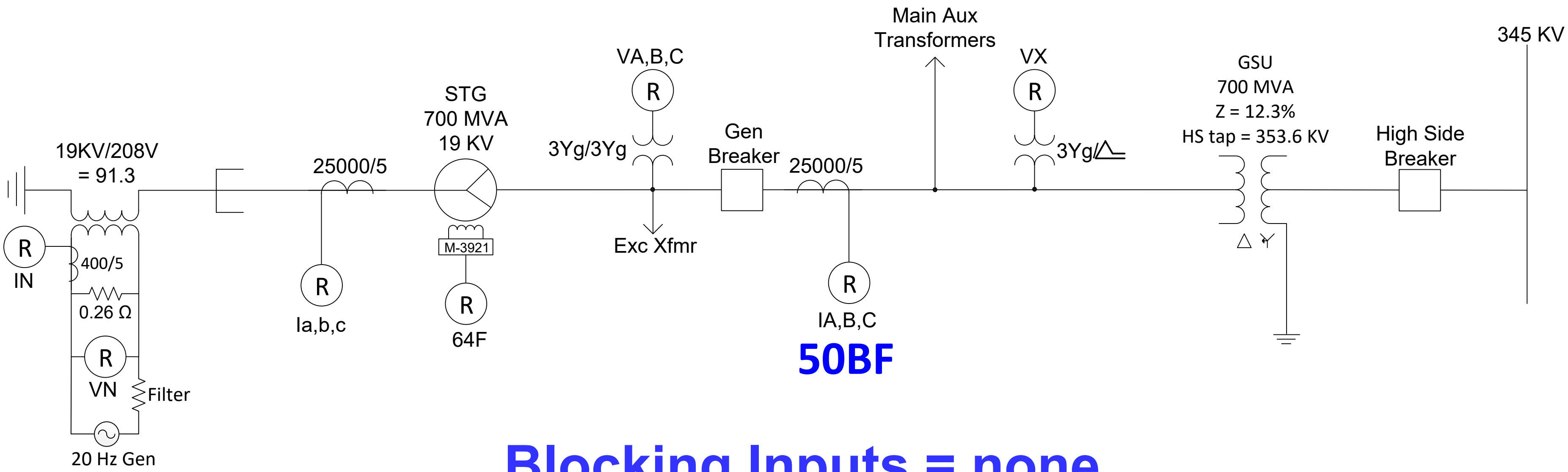
- **Do not have to verify that these settings comply with PRC-025-2 because they are only armed for 15 cycles after the generator breaker is synched closed as stated in Exclusion 1 of the PRC-025-2 Standard:**

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.

50BF – Breaker Failure



Blocking Inputs = none

When the relay (or another device e.g. LOR) sends a trip signal to the breaker but current continues to flow OR the breaker “52” contact continues to indicate closed, then trip the upstream breaker, along with the excitation, turbine, fuel, etc.

50BF – Breaker Failure

- Phase Pickup may be set low for max sensitivity or for increased security, it may be set above max load.
- But it should always be set well below the min phase fault current.
- For a GSU LS ΦΦ fault, from the generator decrement curve at the chosen BF Time Delay setting of 7 cycles:

$$\mathrm{Iac(t)} = 0.866 * \mathrm{Ipu} * \mathrm{Ibase}$$

$$\mathrm{Iac(t)} = 0.866 * \left[(|\mathrm{Id''}| - |\mathrm{Id'}|) * e^{-\frac{t}{\mathrm{Td''}}} + (|\mathrm{Id'}| - |\mathrm{Id}|) * e^{-\frac{t}{\mathrm{Td'}}} + |\mathrm{Id}| \right] * \mathrm{Ibase}$$

$$\mathrm{Iac(t)} = 0.866 * \left[\left(\left|\frac{1}{\mathrm{Xd''}}\right| - \left|\frac{1}{\mathrm{Xd'}}\right| \right) * e^{-\frac{t}{\mathrm{Td''}}} + \left(\left|\frac{1}{\mathrm{Xd'}}\right| - \left|\frac{1}{\mathrm{Xd}}\right| \right) * e^{-\frac{t}{\mathrm{Td'}}} + \left|\frac{1}{\mathrm{Xd}}\right| \right] * \frac{\mathrm{Sgen}}{\sqrt{3} * \mathrm{VLL}}$$

$$\mathrm{Iac(t)} = 0.866 * \left[\left(\left|\frac{1}{0.224}\right| - \left|\frac{1}{0.295}\right| \right) * e^{-\frac{0.1167}{0.025}} + \left(\left|\frac{1}{0.295}\right| - \left|\frac{1}{1.66}\right| \right) * e^{-\frac{0.1167}{1.4}} + \left|\frac{1}{1.66}\right| \right] * \frac{700\ \mathrm{M}}{\sqrt{3} * 19\ \mathrm{K}}$$

$$\mathrm{Iac(t)} = 0.866 * 3.177 * 21{,}271$$

$$\mathrm{Iac(t)} = 58{,}523\ \text{pri amps}$$

$$\mathrm{Iac(t)} = \frac{58{,}523}{5000} = 11.7\ \text{sec amps @ 7 cycles}$$

$$SF * Inom < Phase\ Current < SM * \min phase\ fault\ current\ at\ BF\ Time\ Delay$$

$$1.10 * 4.25 < Phase\ Current < 0.50 * 11.7$$

$$4.68 < Phase\ Current < 5.85$$

- Phase Current = 0.10 A   (decided to set at minimum for max sensitivity)

50BF – Breaker Failure

- Set BF Timer per the following criteria from IEEE C37.119:

(8) BF Timer = (3)DIT – (2)62BF PU + (4)FD DO + (5)SM
= 3 – 0 + 1.5 + 2.5
= 7 cycles

(1) The BFI (relay operate time plus fault detector pick up time) is 1 + 1.5 = 2.5 cyc
(2) The Gen Breaker does not have 62BF in its circuit.
(3) The Device Interrupt Time (DIT) of the Gen Breaker is 3 cycles.
(4) Use 1.5 cycles for the Fault Detector Drop Out (FD DO) time.
(5) For the Security Margin (SM), use 2.5 cycles.
(6) GSU HS breaker is tripped from this 50BF output, so LOR operate time is 0 cyc.
(7) The GSU HS breaker has a 2 cycle interrupt time.

Total BF clearing time = (1)BFI + (8)BF Timer + (6)LOR + (7)backup breaker time

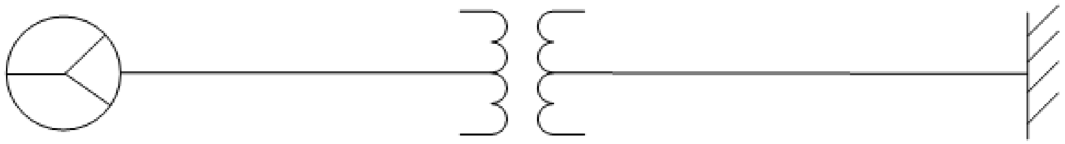
Total BF clearing time = 2.5 + 7 + 0 + 2 = 11.5 cycles

Check: **Is the Total BF clearing time < Critical Clearing Time (CCT) to maintain stability?**

50BF – sidebar to derive CCT

If a transient stability study is not available to find the worst-case, minimum CCT for a particular application, then it may be manually calculated as such:

CCT (Critical Clearing Time) calculation



All values are in per unit at 700 MVA base.

$$Gen\ operating\ at\ S = 1\ pu\ @\ 0.85\ PF\ lagging, PF\ angle = \Theta = \cos^{-1} 0.85 = 31.8^\circ$$

$$P = S * PF = 1 * 0.85 = 0.85\ pu$$

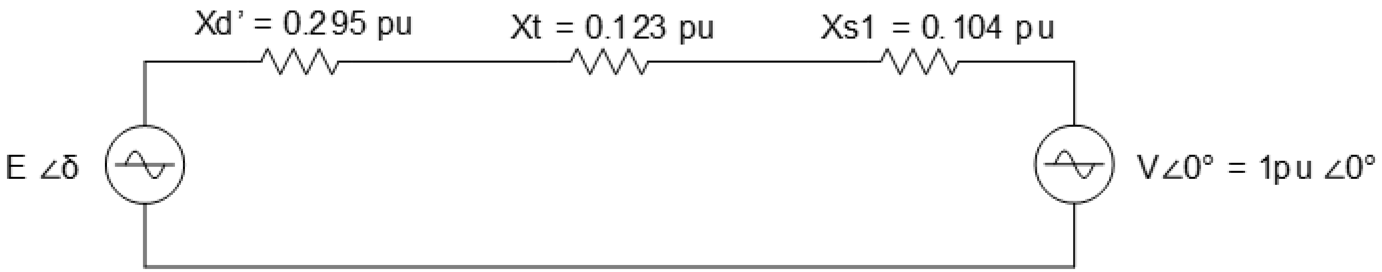
$$Q = \sqrt{S^2 - P^2} = \sqrt{1^2 - 0.85^2} = 0.5268$$

$$S = P + jQ = 0.85 + j0.5268$$

$$S = VI^*$$

$$I = \frac{S^*}{V^*} = \frac{(0.85 + j0.5268)^*}{(1\angle 0^\circ)^*} = 0.85 - j0.5268 = 1\angle -31.8^\circ$$

50BF – sidebar to derive CCT (continued)



$$X_{TOT} = j(Xd' + Xt + Xs1) = j(0.295 + 0.123 + 0.104) = j0.522\ pu$$

$$V_{drop} = jX_{TOT} * I = j0.522 * (0.85 - j0.5268) = 0.522\ pu\ \angle 58.2°$$

$$KVL: \quad E\angle\delta = V_{drop} + V = 0.522\angle 58.2° + 1\angle 0° = 1.35\ pu\ \angle 19.2°$$

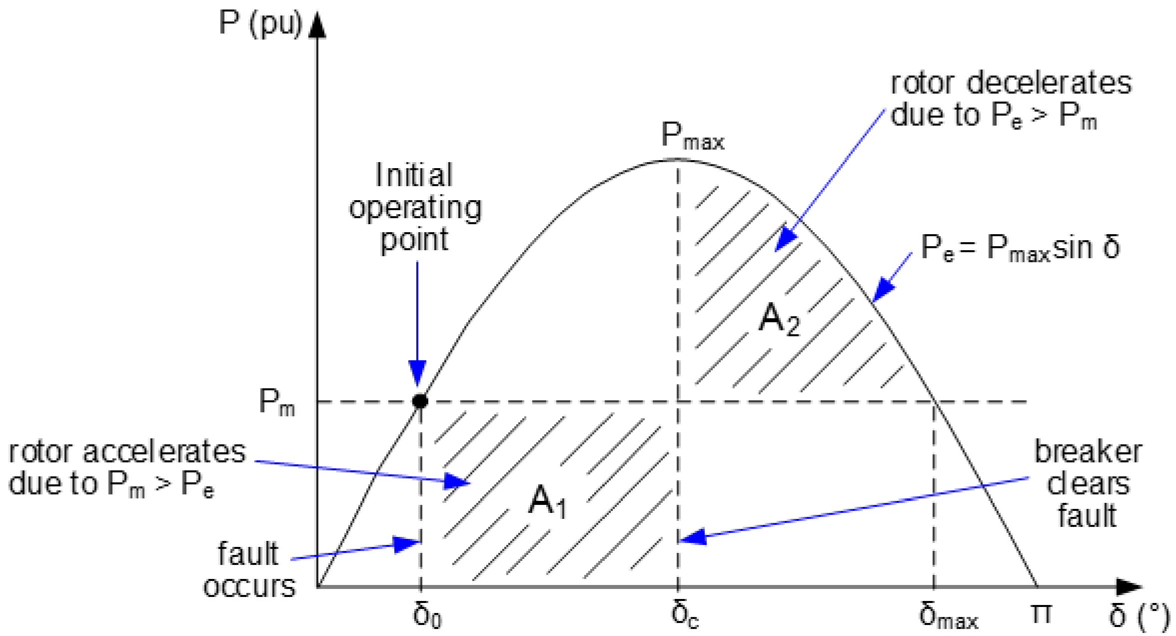
$$\delta_0 = 19.2°$$

$$\delta_{max} = \pi - \delta_0 = 180° - 19.2° = 160.8°$$

$$P_{max} = \frac{E * V}{X_{TOT}} * \sin 90° = \frac{1.35 * 1}{0.522} * 1 = 2.6\ pu$$

$$\delta_c = \cos^{-1}\left[\frac{P_m(\delta_{max} - \delta_0)}{P_{max}} + \cos\delta_{max}\right] = \cos^{-1}\left[\frac{0.85 * (160.8° - 19.2°)\frac{\pi}{180°}}{2.6} + \cos 160.8°\right] = 97.8°$$

50BF – sidebar to derive CCT (continued)



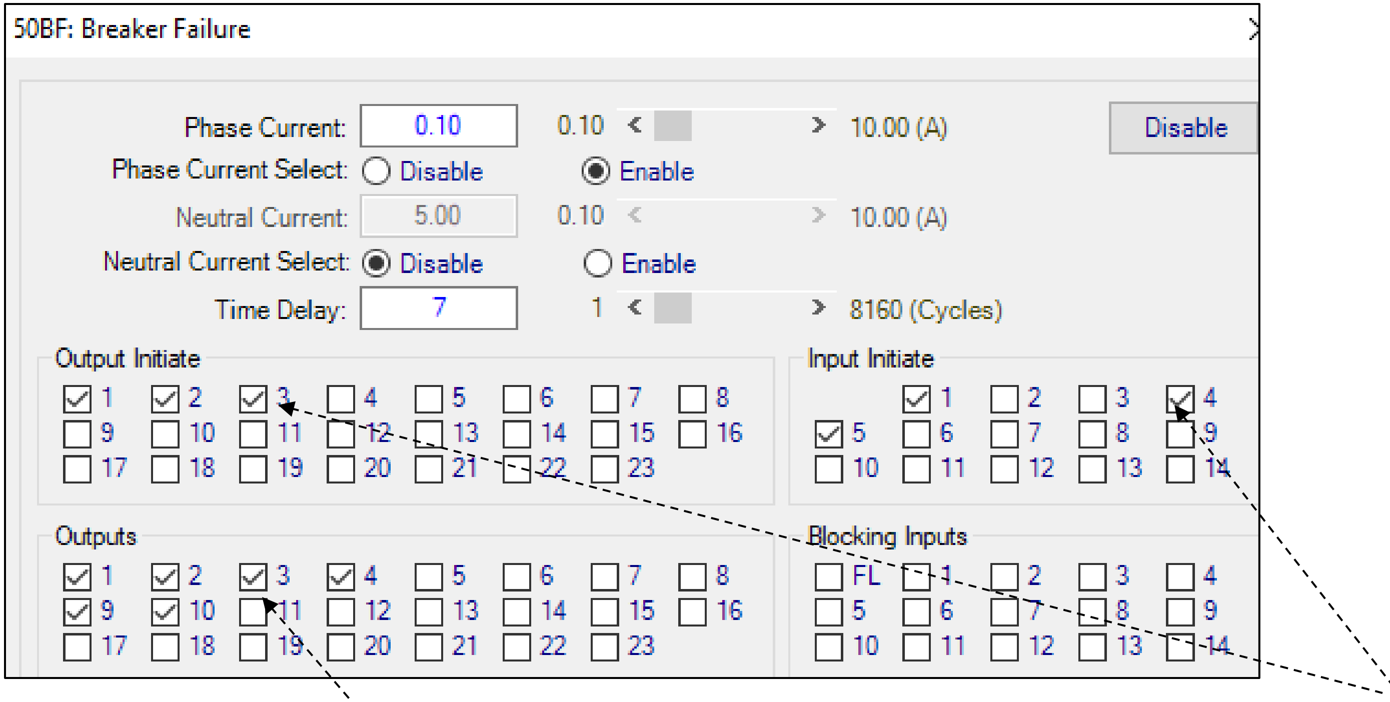
$$H = \frac{0.231 * 10^{-6} n^2 J}{SgenKVA} = \frac{0.231 * 10^{-6} * 3600^2 * 683 * 10^3}{700 * 10^3} = 2.92\ seconds$$

$$CCT = t_c = \sqrt{\frac{4H(\delta_c - \delta_0)}{\omega P_m}} = \sqrt{\frac{4 * 2.92 * (97.8° - 19.2°) * \frac{\pi}{180°}}{2\pi * 60 * 0.85}} = 0.2236\ seconds; \quad 0.2236 * 60 = 13.4\ cycles$$

<u>Check:</u> Total BF clearing time < CCT

11.5 cycles < 13.4 cycles, therefore with a 7 cycle BF Time Delay setting, stability is maintained.

50BF – Breaker Failure



Breaker Failure Trip Outputs

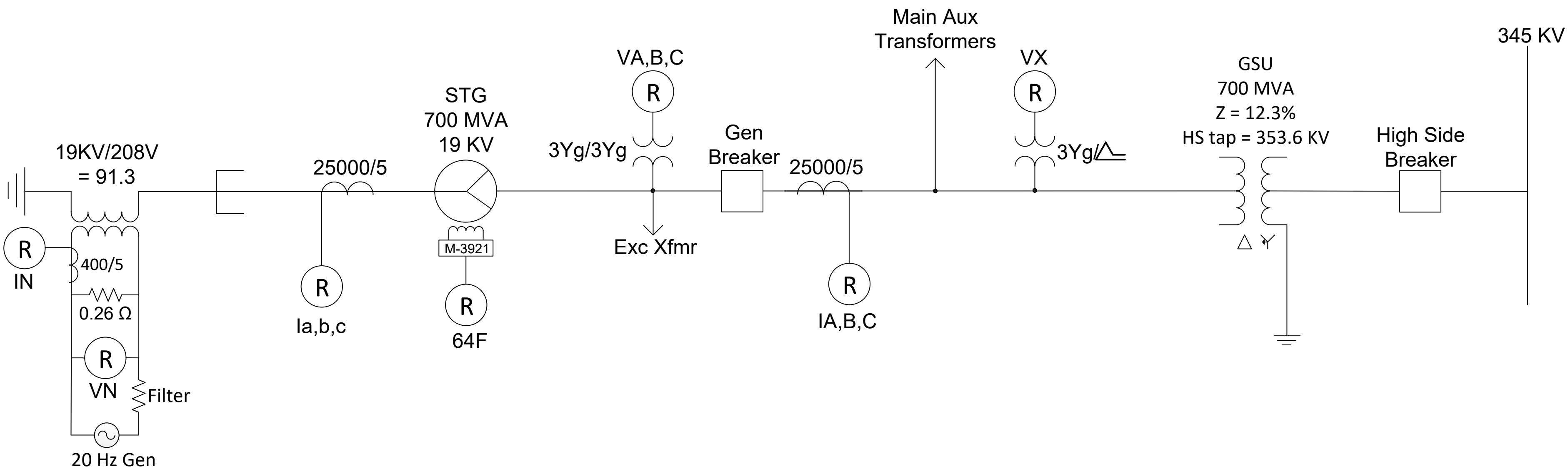
BFI

BFI

Output Initiate – Output contacts from this same relay that trip generator breaker.

Input Initiate – Input into breaker failure logic tripping of generator breaker of other trip device – i.e., turbine trip, LORs, other relays.

61BF – Breaker Flashover



Blocking Inputs = 2

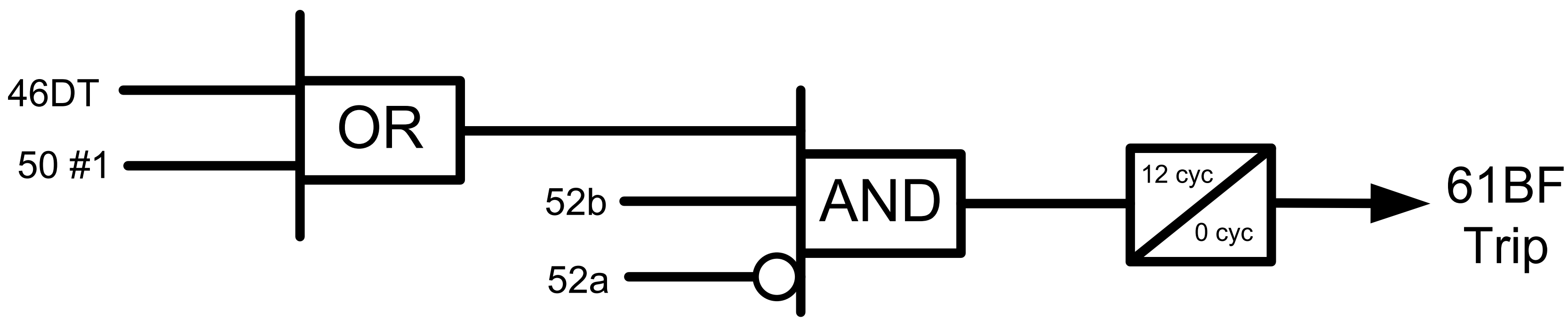
- Input 2 is gen breaker “52a” contact

61BF – Breaker Flashover

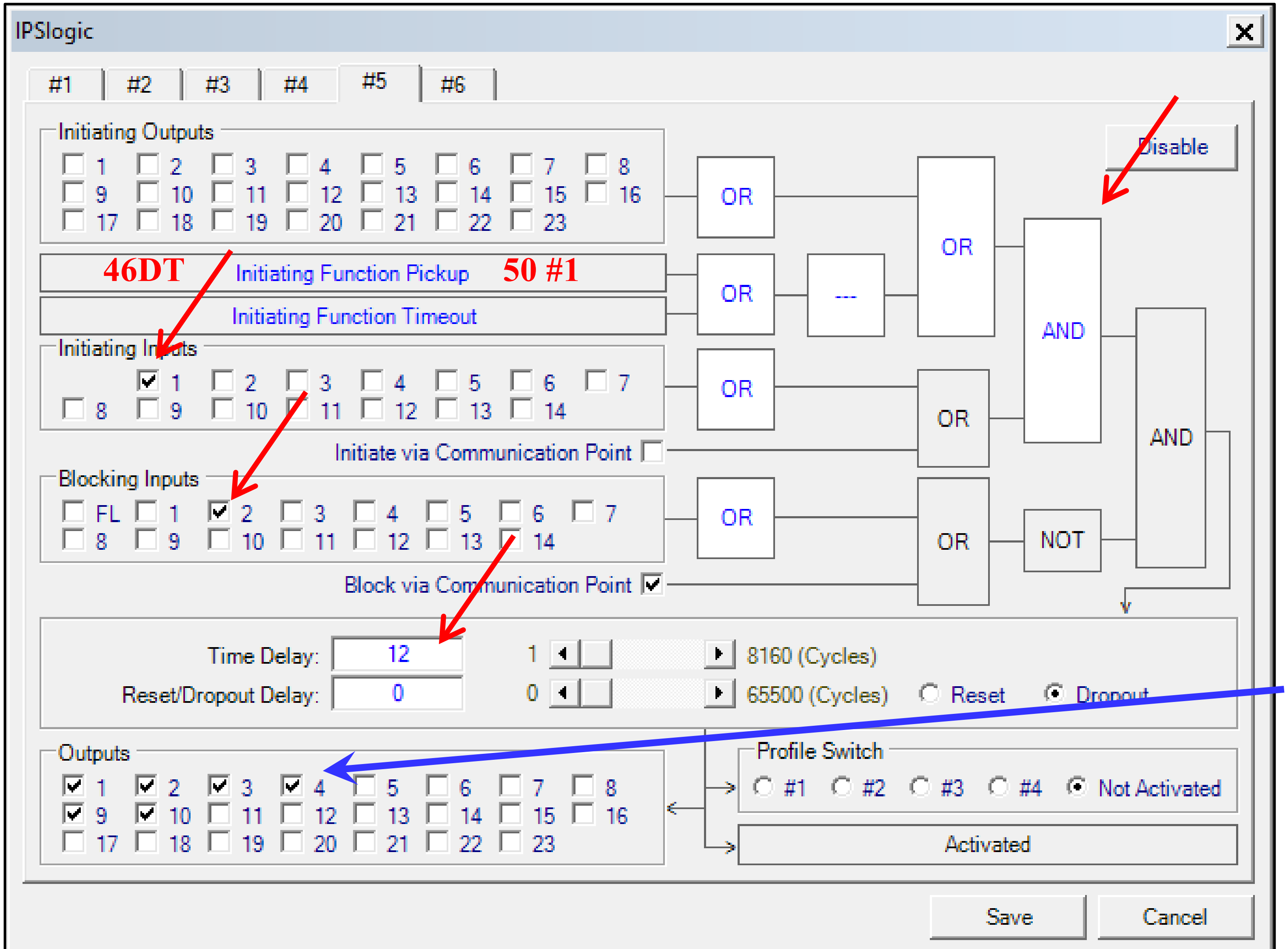
- **In most cases, 50/27 will not see this as V is still OK.**
- **46IT may respond, but with too long of a time delay, plus it only trips the breaker it does not BF trip back a zone.**
- **Many methods to develop this protection, use KISS:**
  - **Is the breaker Open? If Yes, there should be no current. If there is current, that is a problem.**
- **Since the breaker is already open, must trip back a zone i.e. BF trip.**
- **Although can try to re-trip the breaker itself as well.**

61BF – Breaker Flashover

- **Which currents to use?**
  - ✓ **Phase**
  - ✓ **Negative Sequence**
  - ✓ **3Io**
- **Set current pick ups very low.**
- **I2 will see 1 or 2 pole flashover, which are most common.**
- **Additional security can be introduced by looking if the breaker is open and also if the breaker is not closed (52b and NOT 52a).**
- **Time delay setting could be set > the normal breaker close time.**



61BF – Breaker Flashover protection



If breaker is open (and not closed for added security) and current is measured, then after 12 cycles trip back a zone or in this case trip the GSU HS breaker (Output 4) i.e. BF trip along with the 86G LORs which will trip the excitation, turbine, etc.

61BF – Breaker Flashover

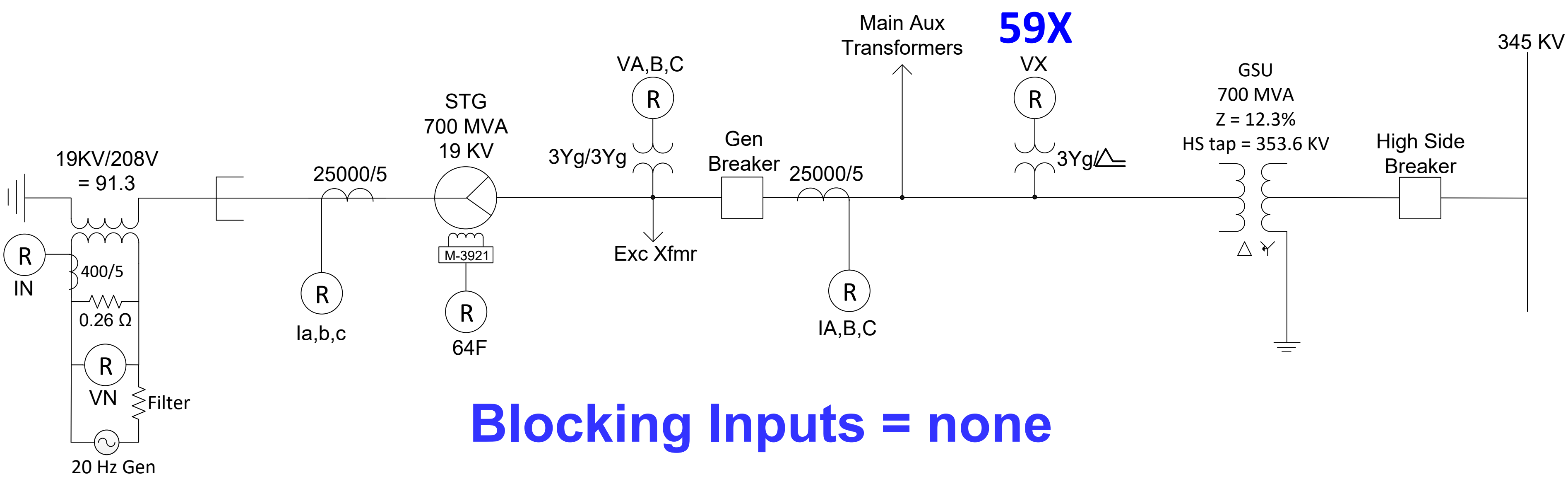
- **Do not have to verify that these settings comply with PRC-025-2 because it is only armed when the generator breaker is open as stated in Exclusion 2 of the PRC-025-2 Standard:**

Exclusions

The following protection systems are excluded from the requirements of this standard:

2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).

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



Blocking Inputs = none

- **VX is wired across broken delta VTs.**
- **Provides bus ground fault protection during backfeed scenarios.**
- **Must trip HS breaker to clear system fault contribution into a bus ground fault.**

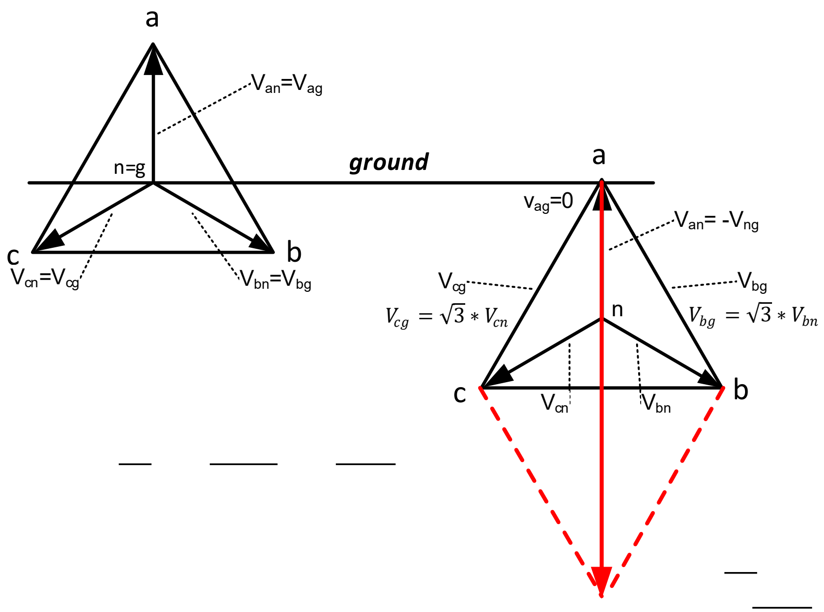
59X – Residual (3Vo) Overvoltage (Bus)

For a ground fault on a high impedance grounded generator, Io approaches zero and Vo approaches the phase-ground value of the nominal voltage:

$$\text{Vo} = \text{sec LG Nominal Voltage} = \frac{\frac{\text{pri LL Nominal Voltage}}{\sqrt{3}}}{\text{VTRX}} = \frac{\frac{19\text{ K}}{\sqrt{3}}}{274.2} = 40\text{ Vsec}$$

$$\frac{19000/\sqrt{3}}{120/3}$$

The broken delta VT on the gen bus VTs is measuring 3Vo, not Vo, therefore, $3\text{Vo} = 3 * 40 = 120\text{ V}$



AG fault on the 19 KV bus, the voltage across each of the two unfaulted VT secondaries will approach a phase-phase value (40*1.732 = 69.3 V) due to the neutral shift on high-impedance grounded systems. Then the total measured voltage across the broken delta will be the vector addition of those 2 secondary voltages.

59X – Residual (3Vo) Overvoltage (Bus)

Here is the pickup setting criterion (% is listed as a % of the 120 V max 3Vo for a ΦG fault):

$$\text{SF} * \text{max unbalace}; \;\; \text{min pickup} \;\leq\; \text{59X Pickup} \;\leq\; \text{SM} * \text{3Vo from ΦG fault}; \;\; \text{VT pri fuse loss}$$

$$2 * 2.3\% \text{ or } 4.6\%; \;\; 4.2\% \;\leq\; \text{59X Pickup} \;\leq\; 0.25 * 100\% \text{ or } 25\%; \;\; 33\%$$

$$5.5 \text{ V}; \;\; 5 \text{ V} \;\leq\; \text{59X Pickup} \;\leq\; 30 \text{ V}; \;\; 40 \text{ V}$$

- SF = Security Factor ≥ 2
- SM = Sensitivity Margin ≤ 0.25
- Max unbalance during backfeed, pre-synchronizing period, and on-line was measured to be 2.3%
- Min pickup range for this setting is 5 V
- VT primary fuse loss is calculated as follows:
  - $3V_0$ = VA + VB + VC = 40 /0° + 40 /-120° + 40 /120° = 0 V under normal conditions with all fuses intact
  - $3V_0$ = VA + VB + VC = 0 + 40 /-120° + 40 /120° = 40 /180° V for 1 blown fuse
  - $3V_0$ = VA + VB + VC = 40 /0° + 0 + 0 = 40 /0° V for 2 blown fuses
  - $3V_0$ = VA + VB + VC = 0 + 0 + 0 = 0 V for 3 blown fuses

Set 2 trips at 5% and 4 seconds and 15% and 2 seconds of the max 3Vo for a ground fault:

59X #1 = 0.05 * 120 = 6 Vsec
59X #1 Time Delay = 240 cycles (4 seconds)

59X #2 = 0.15 * 120 = 18 Vsec
59X #2 Time Delay = 120 cycles (2 seconds)

59X – Residual (3Vo) Overvoltage (Bus)

NOTE: 59X must trip the high side breaker as it is providing bus ground fault protection under backfeed scenarios and during the pre-synchronizing period. However, because 59X will also provide on-line ground fault protection, ensure it is a backup and coordinated with 59N i.e. let 59N go first as it does not trip the high side breaker. To coordinate 59N and 59X, the setpoints must be compared on a primary basis, rather than secondary, because of the different VT ratios:

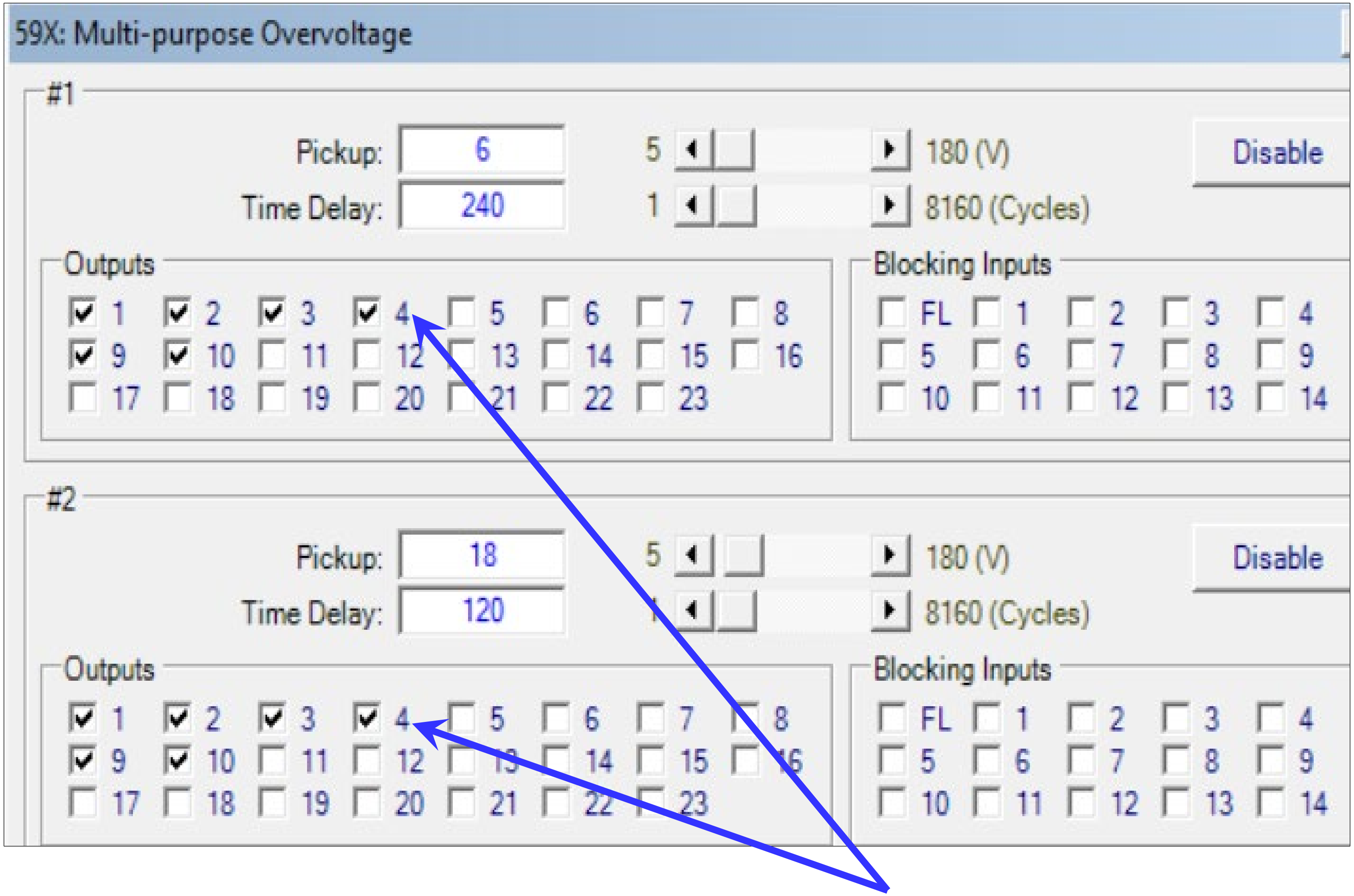
59N trip = 59N pickup * VTNR = 6.0 * 91.3 = 548 pri volts, 5 seconds or 10 cycles

59X #1 trip = 59X #1 pickup * VTRX = 6 * 274.2 = 1645 pri volts, 4 seconds

59X #2 trip = 59X #2 pickup * VTRX = 18 * 274.2 = 4936 pri volts, 2 seconds

Here, with the accelerated 59N schemes it is not necessary to coordinate with the 5 second 59N #1 time delay. However, if accelerated schemes are not used, then may consider coordinating e.g. could set 59N #1 at 2 seconds (instead of the 5 seconds) and then set the 59X elements at 3 and 4 seconds.

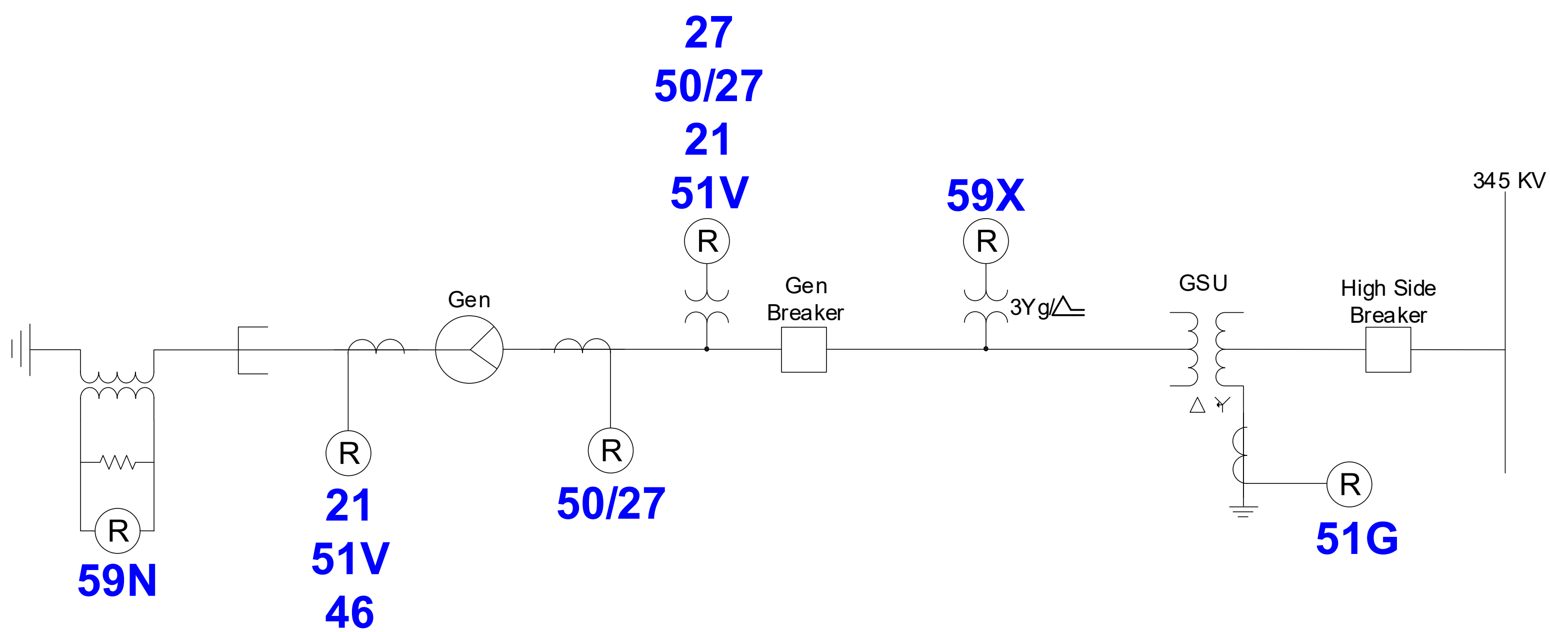
59X – Residual (3Vo) Overvoltage (Bus)



Output 4 is wired to trip the GSU HS Breaker.

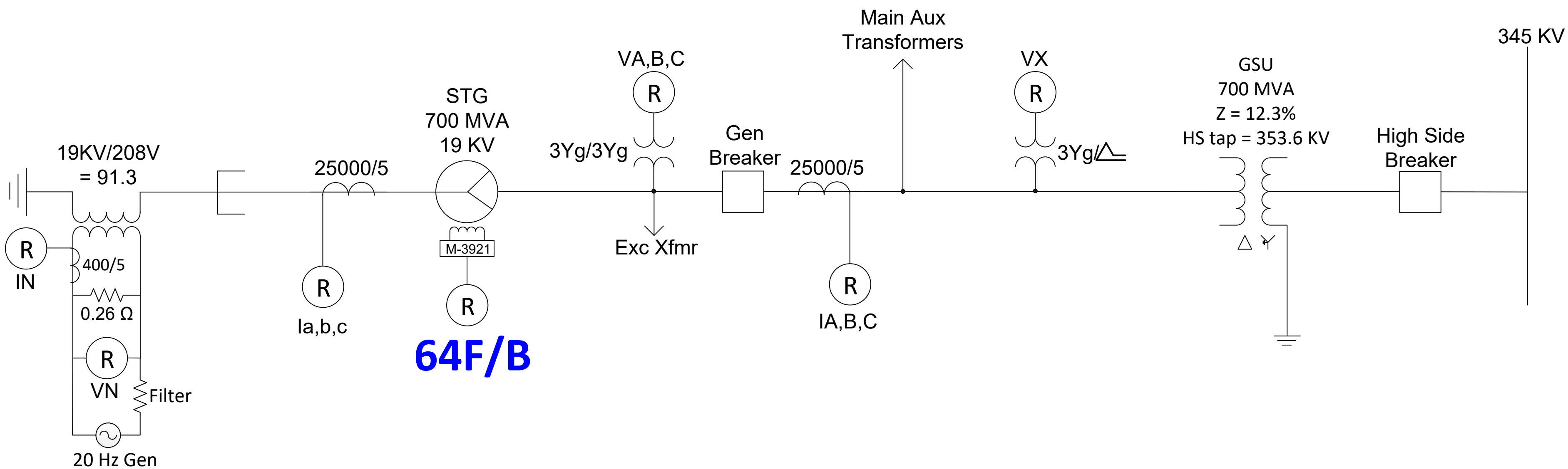
PRC-027

- Coord 59X with transmission line ground faults.



- 59X time delays are 2 seconds and 4 seconds.
- All transmission line relaying clears grounds faults well before this.
- Therefore **YES, complies**

64F/B – Field Ground Protection



Blocking Inputs = none

64F/B – Field Ground Protection

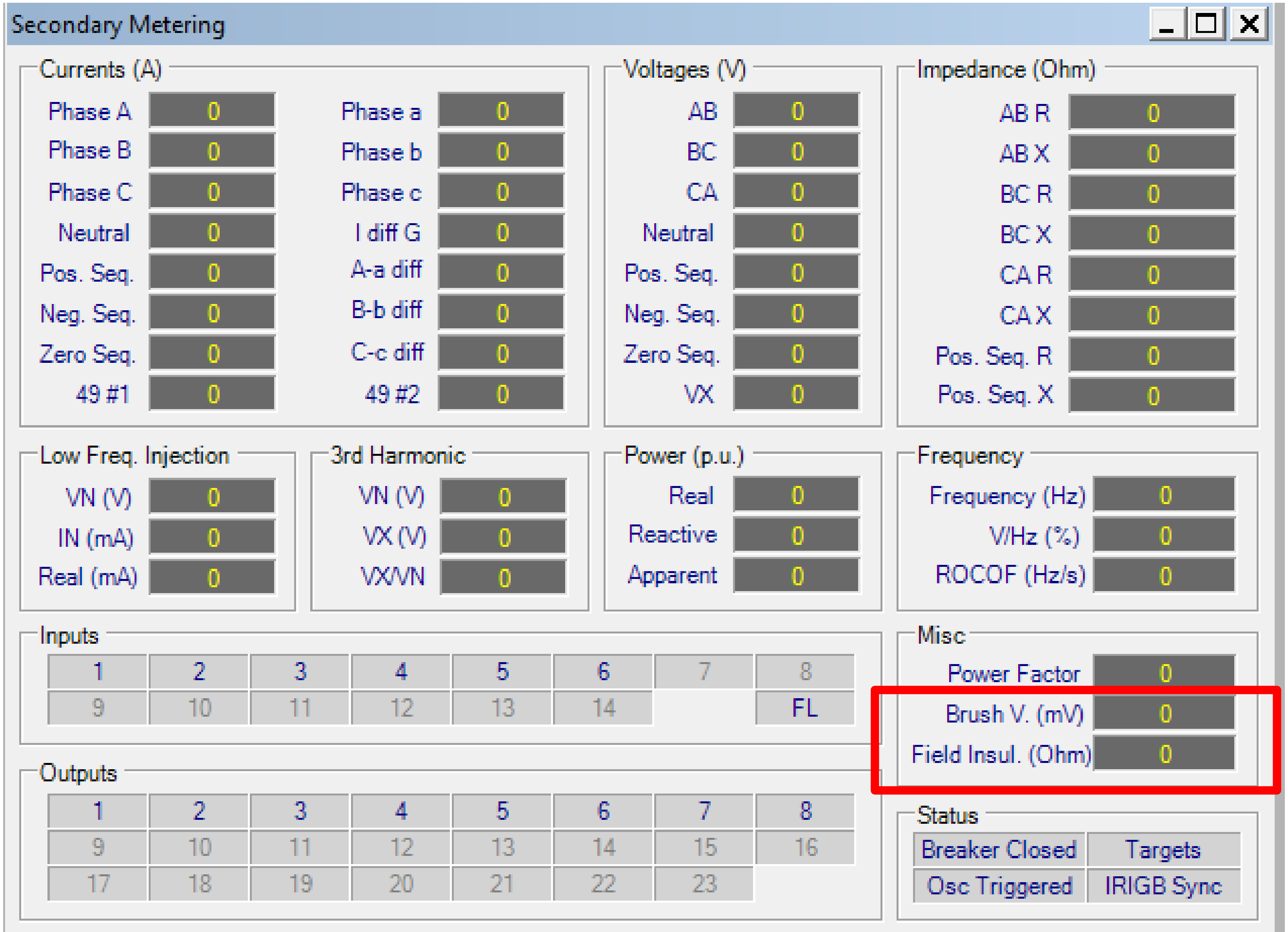
- **Set 64F Alarm = 20 KΩ**
- **Set 64F Trip = 5 KΩ**

- **Rotor capacitance was measured as 7.5 µF**

Field Winding to Ground Capacitance (uF)	Typical Frequency Setting (Hz)	Minimum ALARM Time Delay (sec)	Minimum ALARM Time Delay (cyc)	Minimum TRIP Time Delay (sec)	Minimum TRIP Time Delay (cyc)
1 to 2	0.52	4.85	291	11.85	711
2 to 3	0.49	5.08	305	12.08	725
3 to 4	0.46	5.35	321	12.35	741
4 to 5	0.43	5.65	339	12.65	759
5 to 6	0.39	6.13	368	13.13	788
6 to 7	0.35	6.71	403	13.71	823
7 to 8	0.32	7.25	435	14.25	855
8 to 9	0.3	7.67	460	14.67	880
9 to 10	0.28	8.14	489	15.14	909
>10	0.26	8.69	522	15.69	942
		T_{min} (sec) = $2/f_1 + 1$ for each Typical Frequency Setting		T_{min} (sec) = $2/f_1 + 1 + 7$ for each Typical Frequency Setting	

Table 4-8 Typical Frequency Settings

64F: Field/Rotor Ground Faults

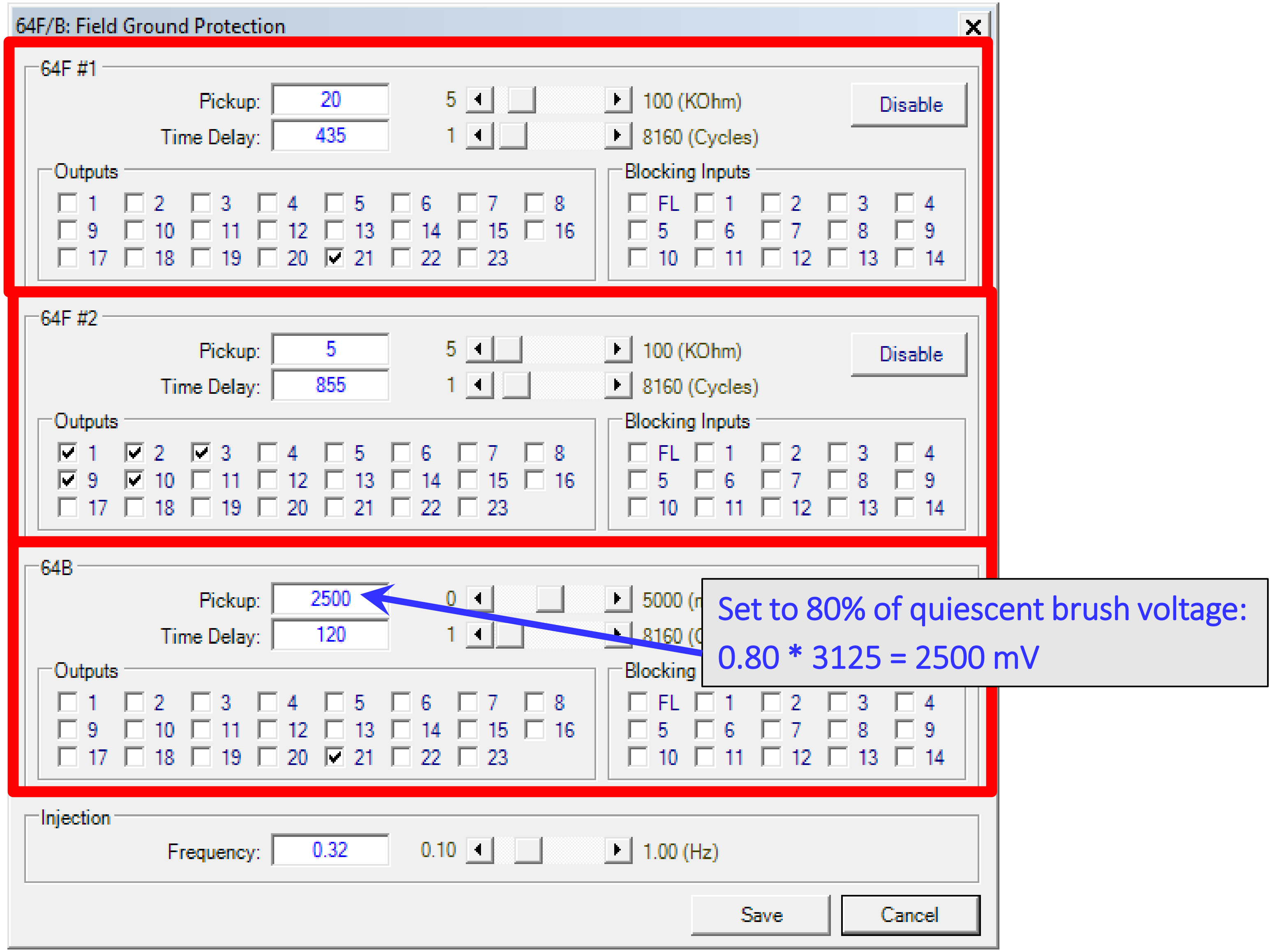


64F: Field/Rotor Ground Faults

64F ALARM

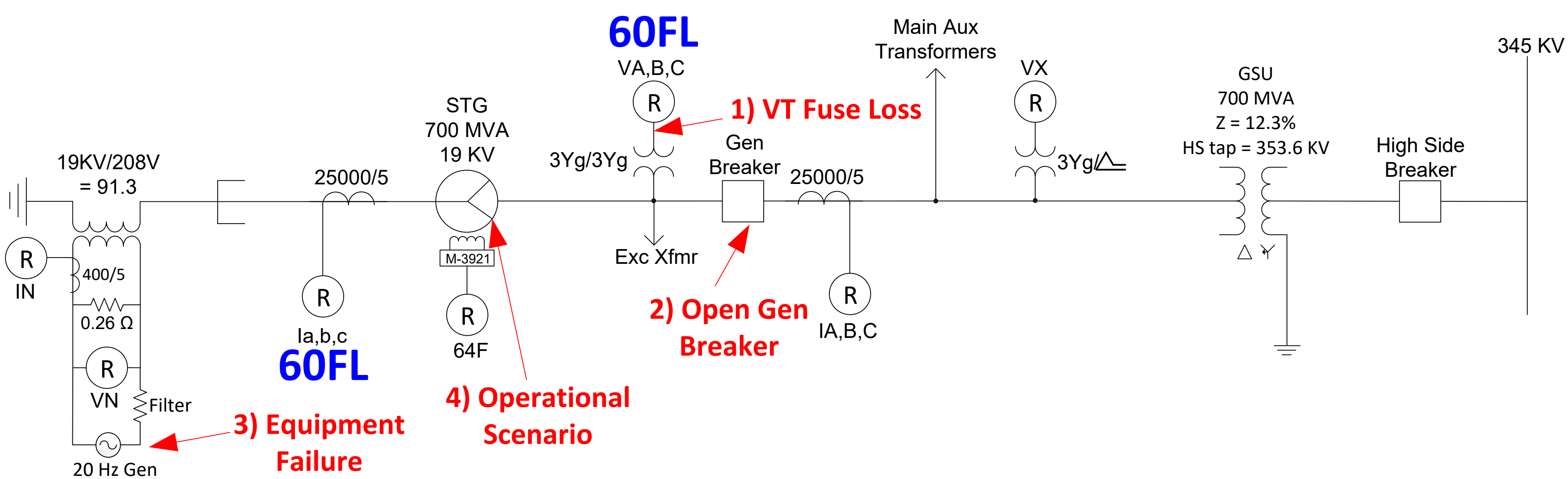
64F TRIP

64B Alarm



Blocking Inputs (aka Inhibit, Torque Control, Arming)

- Should all protection functions be allowed to operate all the time?
- If not, for what conditions should you block the function?
- And which functions should you block for which conditions?
- Typical conditions to consider for blocking:
  1) 60FL/VT Fuse Loss
  2) Open Gen Breaker
  3) Equipment Failure
  4) Operational Scenarios



Blocking Inputs

1) Blocking for VT Fuse Loss

- **FL will cause the measured voltage to be reduced in magnitude and shifted in phase angle.**
  - ✓ **Therefore, the calculated V/Hz, Z, P will be reduced as well.**
- **Consider (not necessarily implement) FL blocking for all functions that use voltages in their algorithms:**
  - ✓ **21, 24, 25, 27, 27TN, 32, 40, 50/27, 51V, 59, 59D, 59N, 59X, 67N, 78, 81, 81A, 81R**
- **Each of these functions should be "considered" individually for if they should be blocked with FL, e.g.:**
  - ✓ **21 = Yes: V reduced, Z also reduced and could enter mho circle**
  - ✓ **24 = No: "Over" V/Hz function, V will not increase for FL**
  - ✓ **27 = Yes: V decreases for FL so block 27 with FL**
  - ✓ **27TN = Yes: Already blocks with PSVB (if enabled), but doesn't sacrifice any dependability if also block for FL**
  - ✓ **Go thru this justification for each function**

Blocking Inputs

- If FL Alarm is not brought back to the control center, then may want to consider not blocking (certain or all functions) with FL.
  - ✓ And if it is Alarmed, how quickly is it dispatched, etc?
- If blocking with FL does not add any security, then do not use it e.g. current-only based functions i.e. 50, 87, etc.
- If blocking with FL does add security, then even if it is brought back as an alarm to control center, then decide on if the reduction in availability is worth the increase in security:
  - ✓ Do you have redundant protection?
  - ✓ Does the redundant protection have their own VTs?
  - ✓ If using the same VTs, are there main VT secondary fuses or are the relays individually branch fused or both?

FL Blocking Input – VT Fuse Loss Detection

- Justify each function that is blocked for a blown fuse condition, e.g. 50/27:

CAUTION: When the unit is off-line during an outage, typically the 50/27 element should remain in-service on at least one of a set of redundant relays i.e. ensure that the relay's TCOs (Trip Cut Out switches) are not opened and that the relay's power supply source is not removed and that the VT fuses are not pulled, etc.

Block the 50/27 function for a fuse loss condition. This 50/27 protection is primarily intended to be armed when the unit is off-line, therefore it should not be blocked by anything at this time. And it will not be blocked even if FL blocking is used. This is because the FL relay word bit will not be asserted when the unit is off-line with no voltage present due to how the FL logic is built where it requires a small amount of current to be present to qualify as an FL condition.

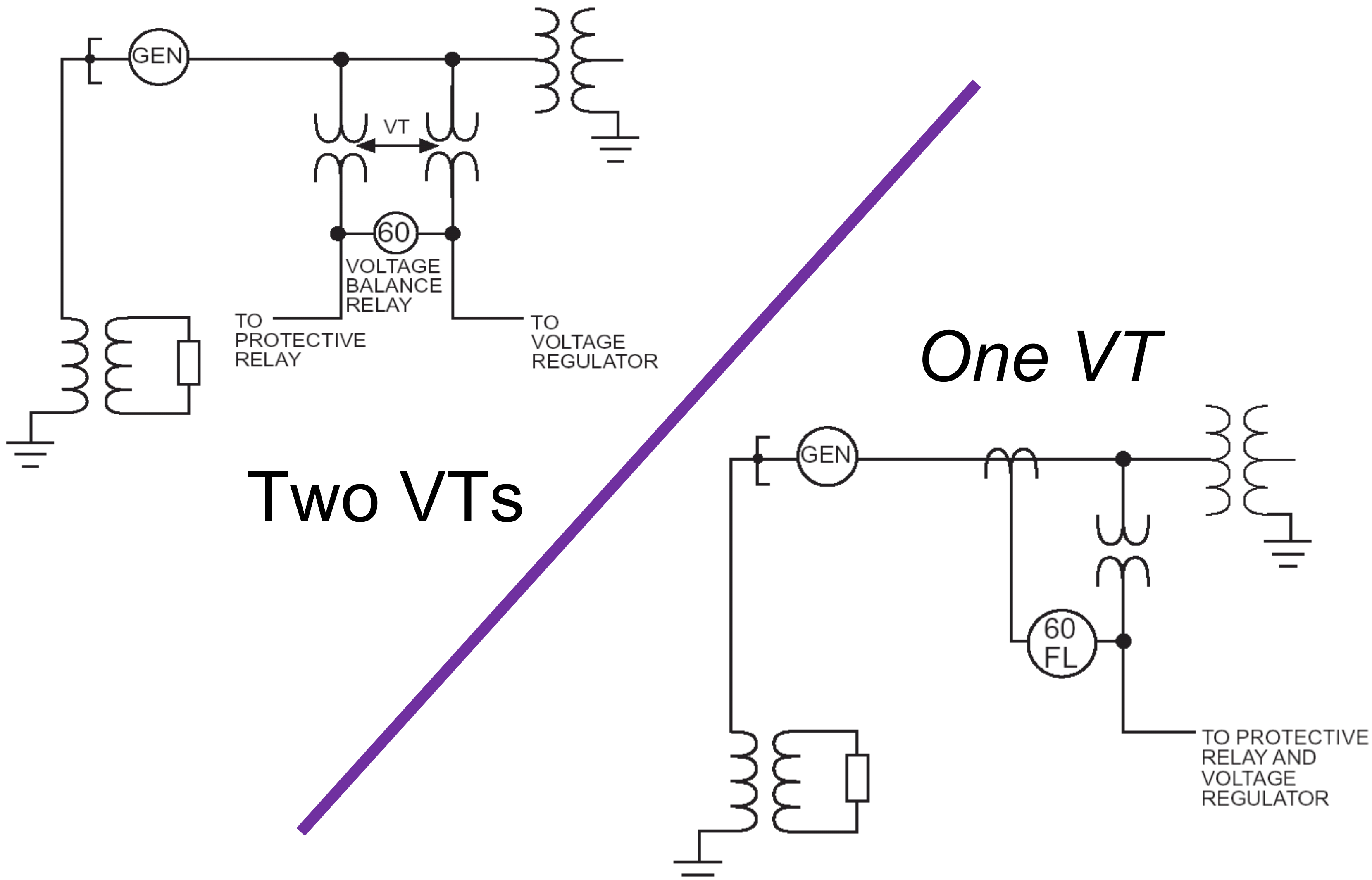
Therefore, blocking with FL will not reduce the availability and dependability of the 50/27 function when the unit is off-line. However, FL blocking is also not required when off-line so blocking for FL is inconsequential at that time. This is the case with the 50/27 algorithm in this M-3425A relay due to how it is designed (as shown in logic diagram above) where the blocking input enters the 50/27 logic at the start of the voltage portion of the logic. Conversely, if a different relay mfg has their 50/27 algorithm designed differently with the FL blocking input instead at the end of algorithm, then it may be best not to block for FL as the protection needs to be in-service when the unit is off-line with fuses removed. The 27 Pickup portion of this function is driven from the generator VT phase voltage inputs so a blown fuse on those VTs will decrease 1 or more of the phases of voltage magnitudes. Although this 50/27 function requires all 3 phases of the voltages to drop below the 27 pickup setting for longer than the pickup delay to arm this function, it is still OK to block for FL as it will not sacrifice any dependability because of the location that the blocking input enters this algorithm.

Blocking with FL will give extra security (no nuisance trip will occur) in the scenario where all 3 fuses blow (or a VT secondary 3-phase fused breaker is opened or the voltage test switches are opened or a VT primary current limiting resistor is temporarily opened i.e. loose connection, etc) while the unit is on-line, which should be a very rare occurrence. However, blocking with FL will primarily provide security for the situation where the unit is coming back on-line after an outage and the fuses are inadvertently left out (or the voltage test switches are left open), then by blocking for FL it will avoid a nuisance trip during the startup so the VT secondary fuses can be installed (or the voltage test switches can be closed) depending on the plant's policies and procedures and depending on where the unit is at during the startup process and the type of starting being used in the application (e.g. LCI starting). To ensure avoidance of a nuisance 50/27 trip, it may be best to halt the startup process and fully shut the unit back down so the fuses can be installed, or the voltage test switches can be closed.

Regardless, ensure that the 60FL alarm is brought to DCS and is actively monitored so the plant operator realizes that the fuses are not installed (or the voltage test switches are left open) so it can be dispatched and remedied. Also, ensure the 60FL settings have the "Three Phase Fuse Loss Detection" Enabled to detect the scenario where all the fuses are left out or all the voltage test switches are left open. If the blown fuse alarm is not brought back to the dispatch center, then may consider not blocking this function for a blown fuse condition.

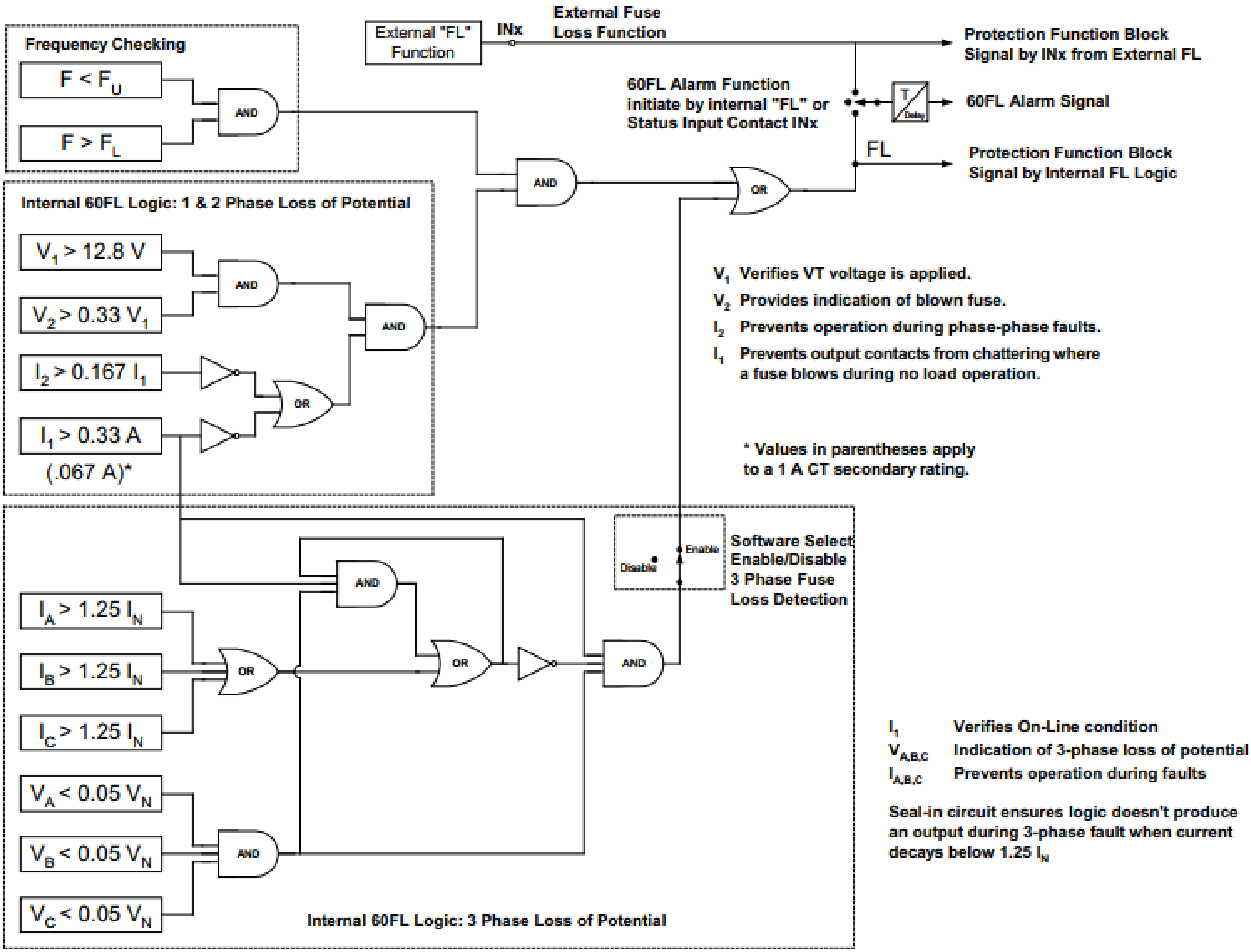
Blocking Inputs

1) Blocking for VT Fuse Loss

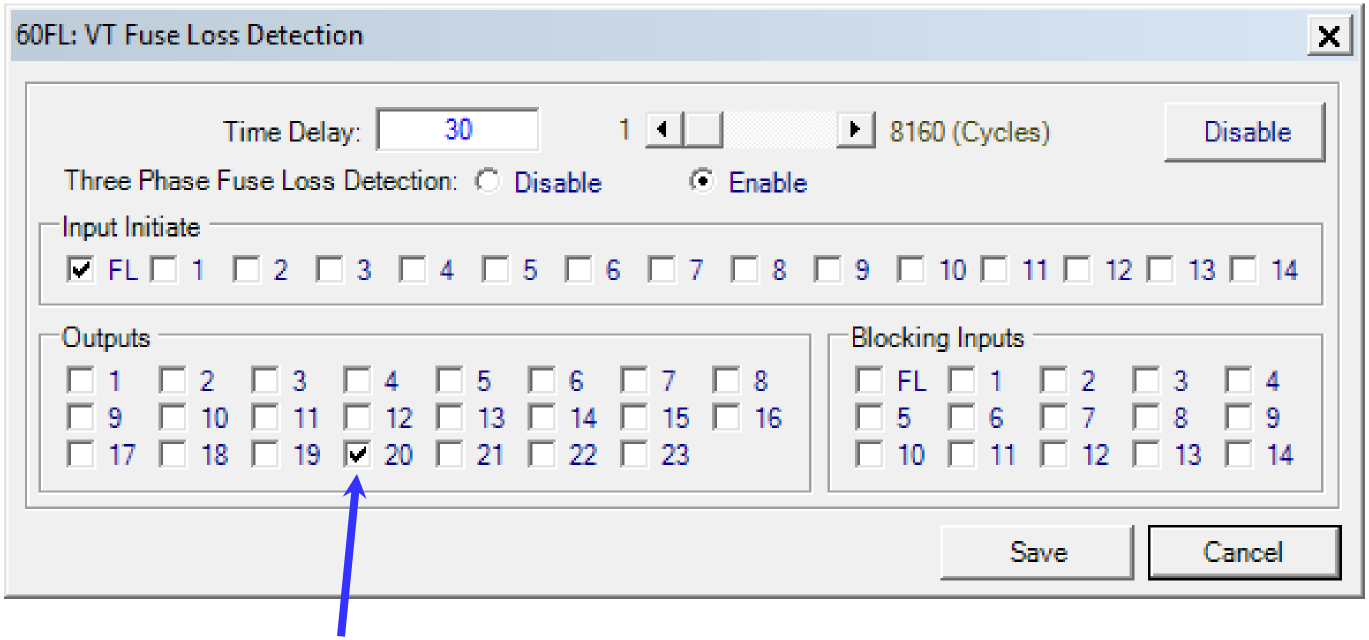


60FL – VT Fuse Loss Detection

- ***1 or 2 phase FL detection: V2 w/o I2 with min V1.***
- ***3 phase FL detection: All 3 voltages < 0.05*Vnom, and all 3 currents < 1.25*Inom and I1 > 0.33 A.***



60FL – VT Fuse Loss Detection



- ***Wire Output 20 to DCS as 60FL alarm.***
- ***Set the Time Delay at 30 cycles to coordinate with secondary VT faults that are cleared by local low voltage fuses/breakers.***
- ***60FL function does not have to be enabled to use FL as a Blocking Input.***

Blocking Inputs

Protective functions typically considered for Blocking for Blown Fuse:

- ***21***
- ***27***
- ***27TN***
- ***32***
- ***40***
- ***50/27***
- ***59D***
- ***78***
- ***81***

Blocking Inputs

2) Blocking for Open Generator Breaker

- Is protection needed when the breaker is open? NOTE: Breaker open is not the same as unit being off-line, as the pre-synchronizing period should be considered as well.
- If not, then consider blocking for an open breaker for extra security.
- Is any dependability sacrificed?
- Each function should be "considered" individually for whether or not they should be blocked for an open breaker, e.g.:
  - ✓ 21 = Yes: not required when unit is off-line (unless off-line stator thermal overload backup protection is desired)
  - ✓ 24 = No: may be needed even before gen breaker is closed, but some applications (e.g. PMG) may require blocking (e.g. PMG)
  - ✓ 81 = mostly Yes, but may use one off-line 81O to back up "12" so for that one, would not block with an open gen breaker
  - ✓ Go thru this justification for each function

Blocking Inputs

3) Blocking for Equipment Failure

- **27TN – Block 27TN when the 20 Hz generator has not failed i.e. arm the 27TN function when 64S is out of service.**

4) Operational Scenarios

- **32 – Block sequential tripping (normal shutdown mode) with an input from the position of the steam valves (i.e. unblock it after the steam valves are fully closed).**
- **40 – For LCI units, may want to block when in the LCI mode (if LCI mode not wired into relay, then could block with open gen breaker)**
- **64S – may need to block during starting for some applications (may be inherent in algorithm or have an inhibit option)**
- **87 – may want to consider blocking one sensitive set 87 element during LCI starting with no blocking on higher set 87 (> LCI current)**

Blocking Inputs

- **Here are some "typical" blocking inputs used for a high impedance grounded generator application (may not be appropriate for all applications):**

Available	21	24	25	27	27TN	32	40	46	49	50	50BF	61BF	50DT	50N	50/27	51N	51V
Used	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓		✓
Blocking	FL,1			FL,1	FL,1,6	FL,1	FL,1					2			FL		1
Available	59	59D	59N	59X	60FL	64F/B	64S	67N	78	81	81A	81R	87	87GD	IPS logic	BM	TC
Used	✓		✓	✓	✓	✓	✓		✓	✓			✓		✓		✓
Blocking									FL,1	FL,1							1

- **25 – if using, typically block after the breaker closes and for FL**
- **59D – may block for FL if using calculated 3Vo**
- **59N – may want to block for FL if using V2/Vo supervision**
- **59X – FL is off gen VTs, whereas this is from broken delta VTs, so ideally would block with external FL if brought into relay, could also add a bit of extra security by blocking for closed breaker if backup on-line stator ground fault protection is not desired**

Questions?