TRANSFORMER PROTECTION THEORY

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Combined Track
Wednesday, August 6, 2025
Day 3 – Session 2

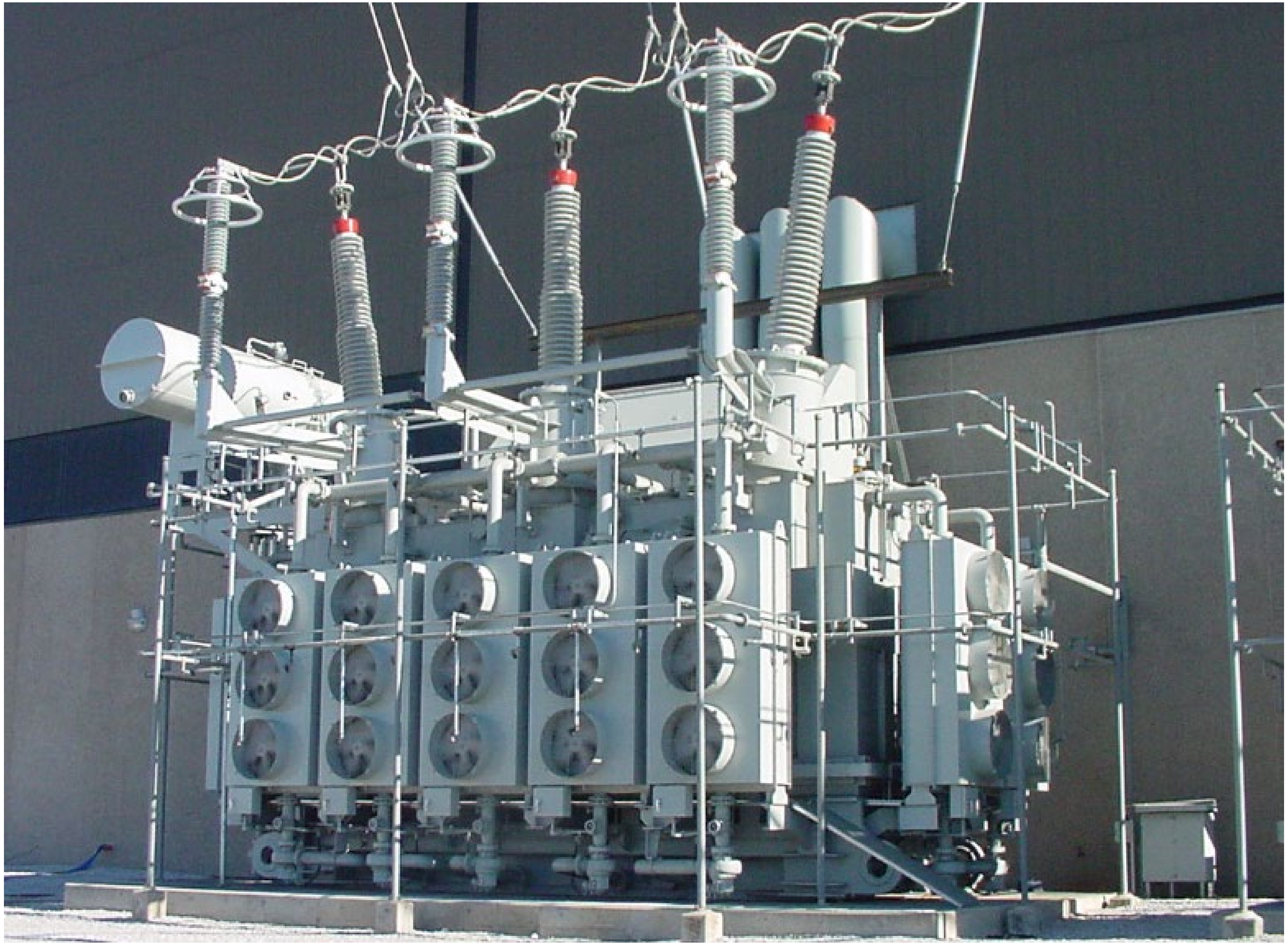
Objectives

- Why Transformers Fail
- The Cost of Failure
- IEEE C37.91, "Guide for Power Transformer Protection"
- Electrical Protection
  - Overexcitation
  - Differential
    - CT performance issue
    - Transformer protection challenges
    - Percentage differential characteristic
    - Restraints for inrush and overexcitation
  - Through-fault protection
  - Overcurrent based
- Non-Electrical Protections
- Realization of Settings
- Analysis Tools to View Protection Operation

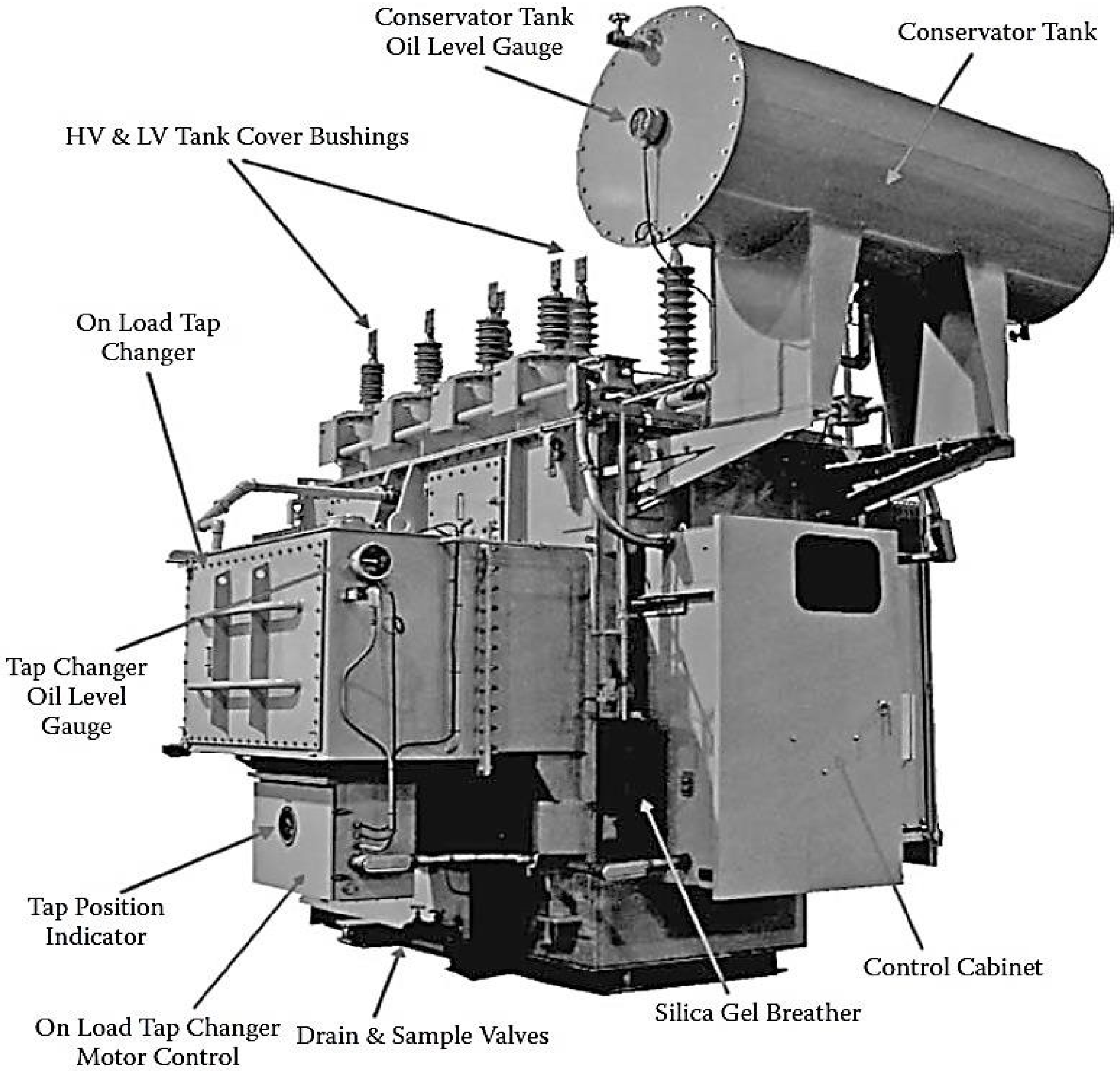
Transformers: T&D

Transformers: T&D

Transformer: GSU Step Up



Key Components



Conservator design 15/20 MVA 72kV–25kV

Failure!

Failure!

Failure!

Why Do Transformers Fail?

The electrical windings and the magnetic core in a transformer are subject to a number of different forces during operation:

- Voltage stresses due to lightning and other surges
- Expansion and contraction due to thermal cycling
- Vibration
- Local heating due to magnetic flux
- Impact forces due to through-fault current
- Excessive heating due to overloading or inadequate cooli

Causes of Transformer Failures

1. Lightning (32%) - Lightning strikes can induce high voltage surges, leading to insulation breakdown and damage to windings and other components. Proper surge protection is essential to mitigate this risk.
2. Through faults (14%) - External short circuits, often caused by faults in connected electrical systems, can result in excessive current flow, overheating, and damage to transformer windings and insulation.
3. Manufacturing error (11%) - Manufacturing errors, including defects in materials or assembly processes, can lead to premature component failures. Quality control and rigorous testing are crucial to prevent such issues.
4. Insulation deterioration (10%) - Over time, the insulating materials within transformers degrade due to thermal, electrical, and environmental stresses. This deterioration can lead to electrical faults and component failures.
5. Overloading (8%) - Operating transformers beyond their rated capacity can cause excessive heating and stress, leading to accelerated aging and failure of windings and other critical components.

Courtesy of "Trafo Design and Services"

Costs and Other Factors To Be Considered

- Cost of repairing damage
- Cost of lost production
- Adverse effects on the balance of the system
- The spread of damage to adjacent equipment
- The period of unavailability of the damaged equipment

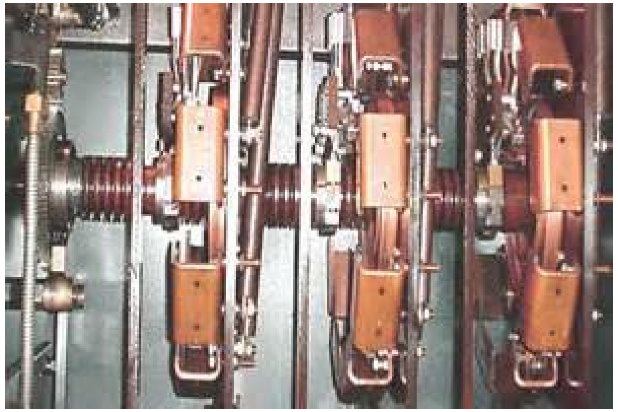
What Fails in Transformers?

Windings

- Insulation deterioration from:
  - Moisture
  - Overheating
  - Vibration
  - Voltage surges
  - Mechanical stress from through-faults

LTCs

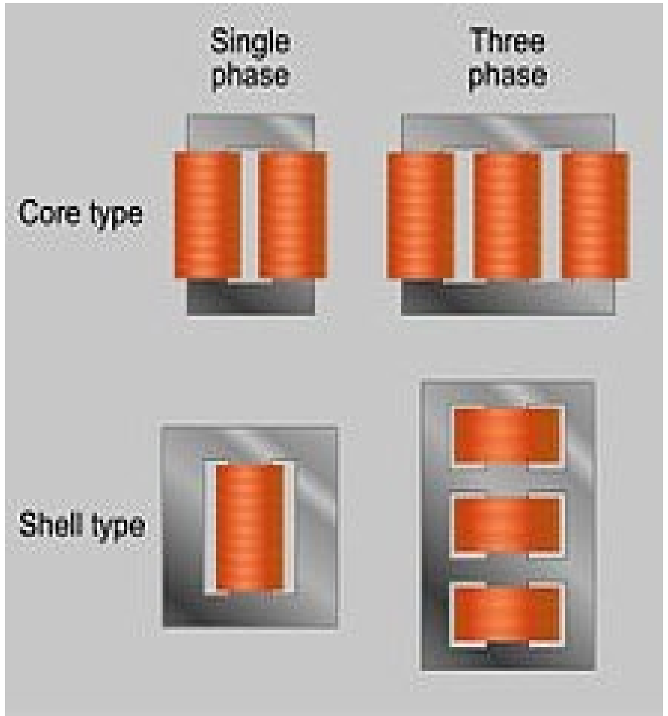
- Malfunction of mechanical switching mechanism
- High resistance contacts
- Overheating
- Contamination of insulating oil



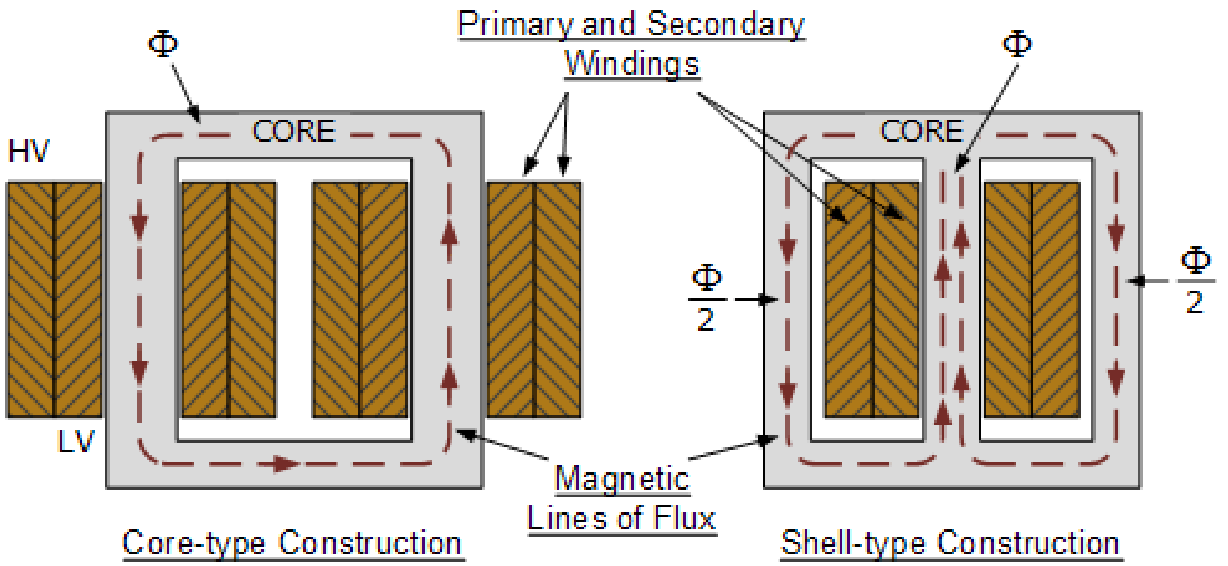
What Fails in Transformers? (continued)

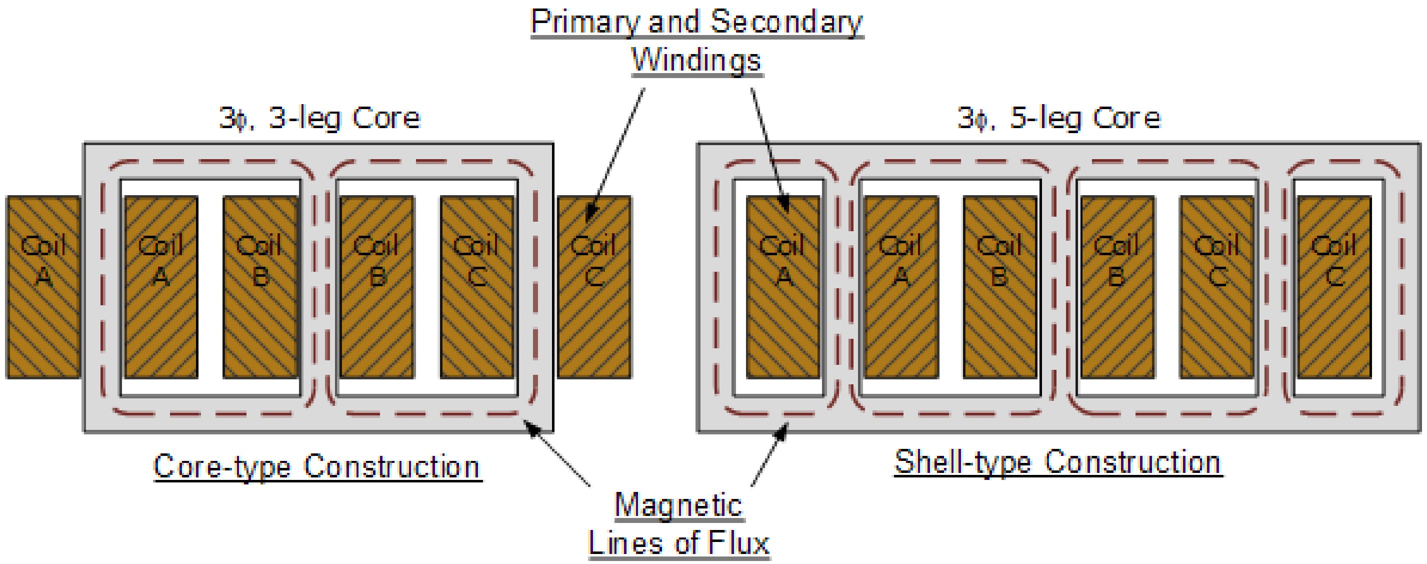
- Bushings
  - General aging
  - Contamination
  - Cracking
  - Internal moisture
- Core Problems
  - Core insulation failure
  - Open ground strap
  - Shorted laminations
  - Core overheating

Core Construction



- Shell construction is lighter than core construction

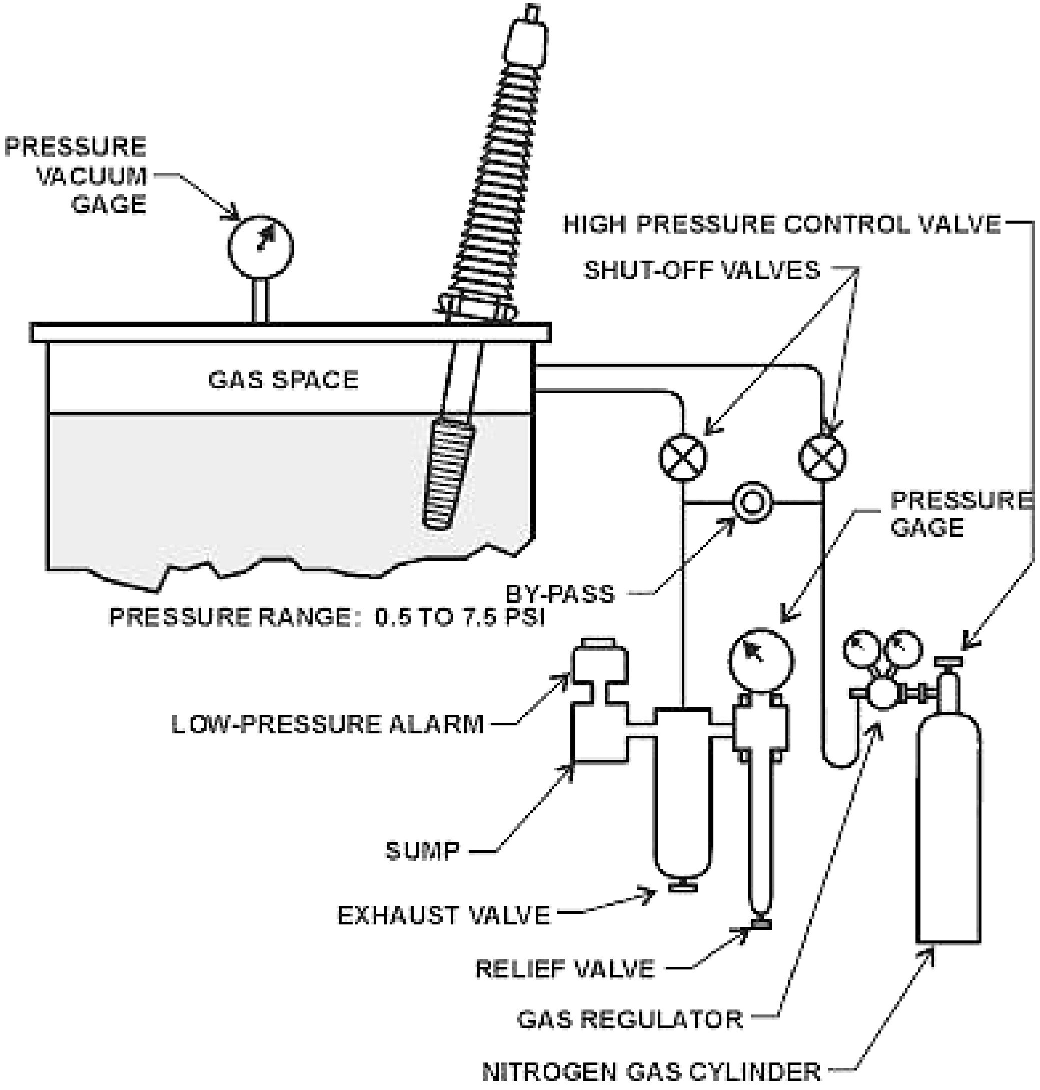




What Fails in Transformers?

Miscellaneous

- CT Issues
- Oil leakage
- Oil contamination
  - Metal particles
  - Moisture



Failure Statistics of Transformers

	1955 - 1965		1975 - 1982		1983 - 1988	
	Number	% of Total	Number	% of Total	Number	% of Total
Winding failures	134	51	615	55	144	37
Tap changer failures	49	19	231	21	85	22
Bushing failures	41	15	114	10	42	11
Terminal board failures	19	7	71	6	13	3
Core failures	7	3	24	2	4	1
Miscellaneous	12	4	72	6	101	26
Total	262	100	1127	100	389	100

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Failure Statistics of Transformers: 110 kV-149 kV

Table B.2—Transformer bank analysis by subcomponents for operating voltages from 110 kV to 149 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
9302	Bushings including CTs	93	0.0100	22 144	238.1	14.58	226.3
	Windings	31	0.0033	24 876	802.5	10.35	130.1
	On-load tap changer	187	0.0201	51 806	277.0	26.78	274.5
	Core	15	0.0016	493	32.9	1.27	32.9
	Leads	2	0.0002	17	8.6	8.56	8.6
	Cooling equipment	28	0.0030	1 590	56.8	17.61	56.8
	Auxiliary equipment	24	0.0026	6 166	256.9	18.76	256.9
	Other	162	0.0174	37 455	231.2	24.80	231.2
	All integral components	542	0.0583	144 547	266.7	22.82	225.3
	Control and protection equipment	323	0.0347	23 407	72.5	1.78	72.5
	Surge arrester	31	0.0033	3 104	100.1	14.33	100.1
	Bus	61	0.0066	14 132	231.7	1.18	231.7
	Disconnect	157	0.0169	28 664	182.6	24.00	182.6
	Circuit switcher	3	0.0003	71	23.6	4.85	23.6
	CT (free standing)	11	0.0012	1 585	144.1	4.23	144.1
	Potential devices	27	0.0029	6 971	258.2	73.95	258.2
	Motor-operated ground switch	31	0.0033	7 661	247.1	22.58	247.1
	Other	64	0.0069	1 977	30.9	2.94	30.9
	Unknown	220	0.0237	34 341	156.1	14.03	156.1
	All terminal equipment	928	0.0998	121 911	131.4	6.66	131.4

IEEE 37.91

Failure Statistics of Transformers: 150 kV-199 kV

Table B.3—Transformer bank analysis by subcomponents for operating voltages from 150 kV to 199 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
594	Bushings including CTs	18	0.0303	11 143	619.1	4.88	619.1
	Windings	2	0.0034	6 678	3 339.2	3 339.24	3 339.2
	On-load tap changer	28	0.0471	16 109	575.3	57.76	575.3
	Core	0					
	Leads	0					
	Cooling equipment	6	0.0101	2 151	358.5	239.53	358.5
	Auxiliary equipment	18	0.0303	955	53.0	12.00	53.0
	Other	16	0.0269	12 493	780.8	248.86	780.8
	All integral components	88	0.1481	49 529	562.8	32.00	562.8
	Control and protection equipment	19	0.0320	6 439	338.9	23.90	338.9
	Surge arrester	7	0.0118	973	139.0	37.10	139.0
	Bus	4	0.0067	3	0.6	0.62	0.6
	Disconnect	26	0.0438	27 024	1 039.4	127.53	1 039.4
	Circuit switcher	0					
	CT (free standing)	1	0.0017	4 626	4 625.6	4 625.63	4 625.6
	Potential devices	8	0.0135	3 350	418.7	122.70	418.7
	Motor-operated ground switch	3	0.0051	688	229.3	104.43	229.3
	Other	1	0.0017	1	0.7	0.68	0.7
	Unknown	9	0.0152	628	69.8	0.70	69.8
	All terminal equipment	78	0.1313	43 730	560.6	28.04	560.6

IEEE 37.91

Failure Statistics of Transformers: 200 kV-299 kV

Table B.4—Transformer bank analysis by subcomponents for operating voltages from 200 kV to 299 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
5940.0	Bushings including CTs	32	0.0054	6 283	196.3	13.83	196.3
	Windings	19	0.0032	23 225	1222.4	68.97	891.0
	On-load tap changer	90	0.0152	25 148	279.4	12.81	279.4
	Core	5	0.0008	557	111.5	30.18	111.5
	Leads	5	0.0008	140	28.0	2.58	28.0
	Cooling equipment	34	0.0057	2 187	64.3	3.64	64.3
	Auxiliary equipment	35	0.0059	9 024	257.8	9.25	257.8
	Other	90	0.0152	21 719	241.3	29.14	241.3
	All integral components	310	0.0522	88 284	284.8	16.92	264.5
	Control and protection equipment	207	0.0348	8 280	40.0	2.70	40.0
	Surge arrester	27	0.0045	1 491	55.2	23.55	55.2
	Bus	15	0.0025	282	18.8	6.13	18.8
	Disconnect	59	0.0099	14 469	245.2	31.40	245.2
	Circuit switcher	1	0.0002	3	3.2	3.23	3.2
	CT (free standing)	3	0.0005	401	133.8	68.17	133.8
	Potential devices	9	0.0015	106	11.8	8.52	11.8
	Motor-operated ground switch	6	0.0010	1 059	176.4	9.03	176.4
	Other	41	0.0069	1 224	29.9	3.45	29.9
	Unknown	120	0.0202	5 990	49.9	18.23	49.9
	All terminal equipment	488	0.0822	33 305	68.2	9.03	68.2

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Analysis of Transformer Failures*

Table 1 – Number and Amounts of Losses by Year

Table 1	Total # of Losses	Total Loss	Total Property Damage	Total Business Interruption
1997	19	$ 40,779,507	$ 25,036,673	$ 15,742,834
1998	25	$ 24,932,235	$ 24,897,114	$ 35,121
1999	15	$ 37,391,591	$ 36,994,202	$ 397,389
2000	20	$ 150,181,779	$ 56,858,084	$ 93,323,695
2001	15	$ 33,343,700	$ 19,453,016	$ 13,890,684
Grand Total	94	$ 286,628,811	$ 163,239,089	$ 123,389,722

** Total losses in 2000 includes one claim with a business interruption portion of over $86 million US*

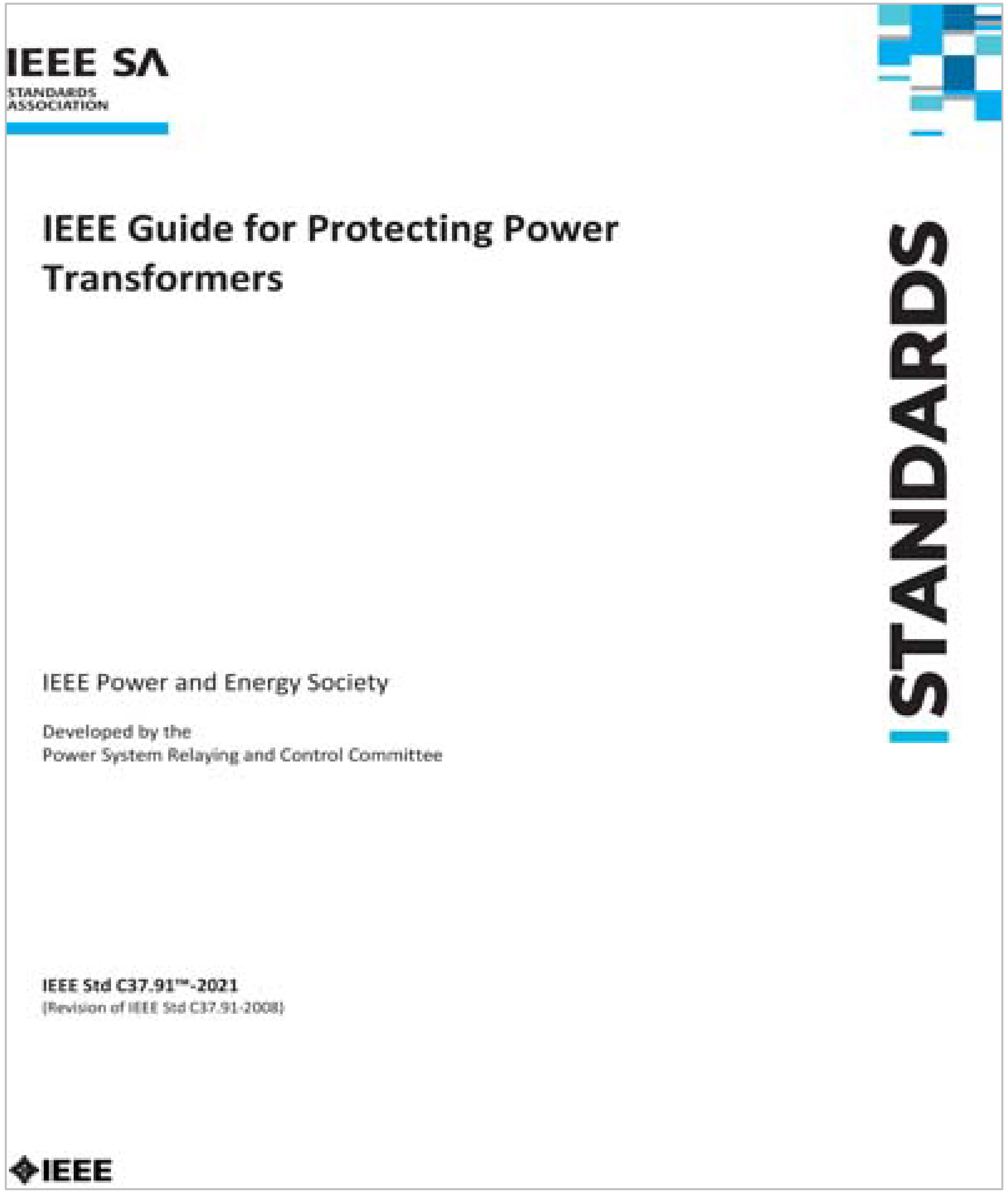
Table 1A – Number and Amounts of Losses by MVA and Year

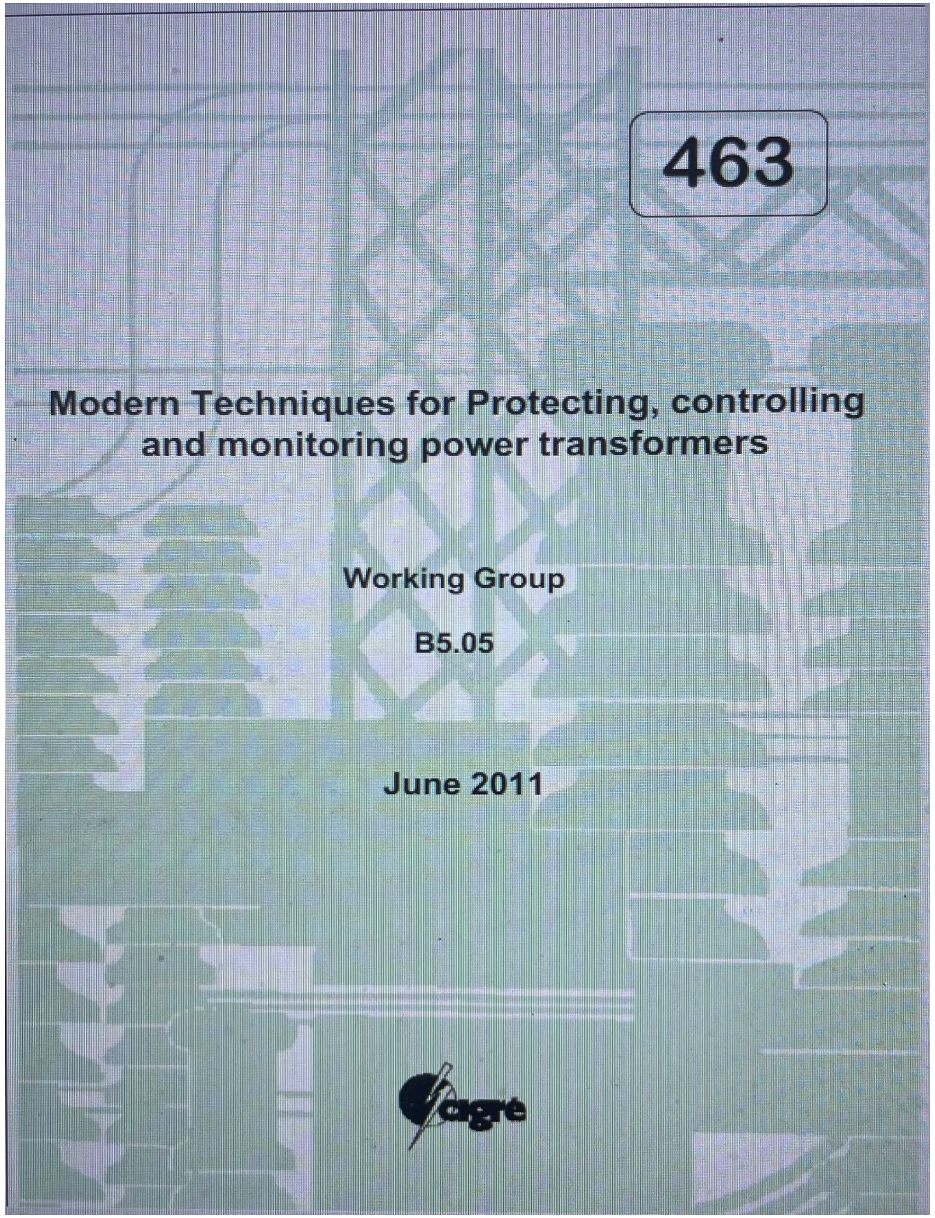
Table 1 A	Total # of Losses	Losses w/data	Total MVA reported	Total PD (with size data)	Cost /MVA
1997	19	9	2567	$20,456,741	$7969
1998	25	25	5685	$24,897,114	$4379
1999	15	13	2433	$36,415,806	$14967
2000	20	19	4386	$56,354,689	$12849
2001	15	12	2128	$16,487,058	$7748
Total	94	78	17,199	$15,4611,408	

During this five year period, the average cost is $8,990 per MVA, or about $9 per kVA.

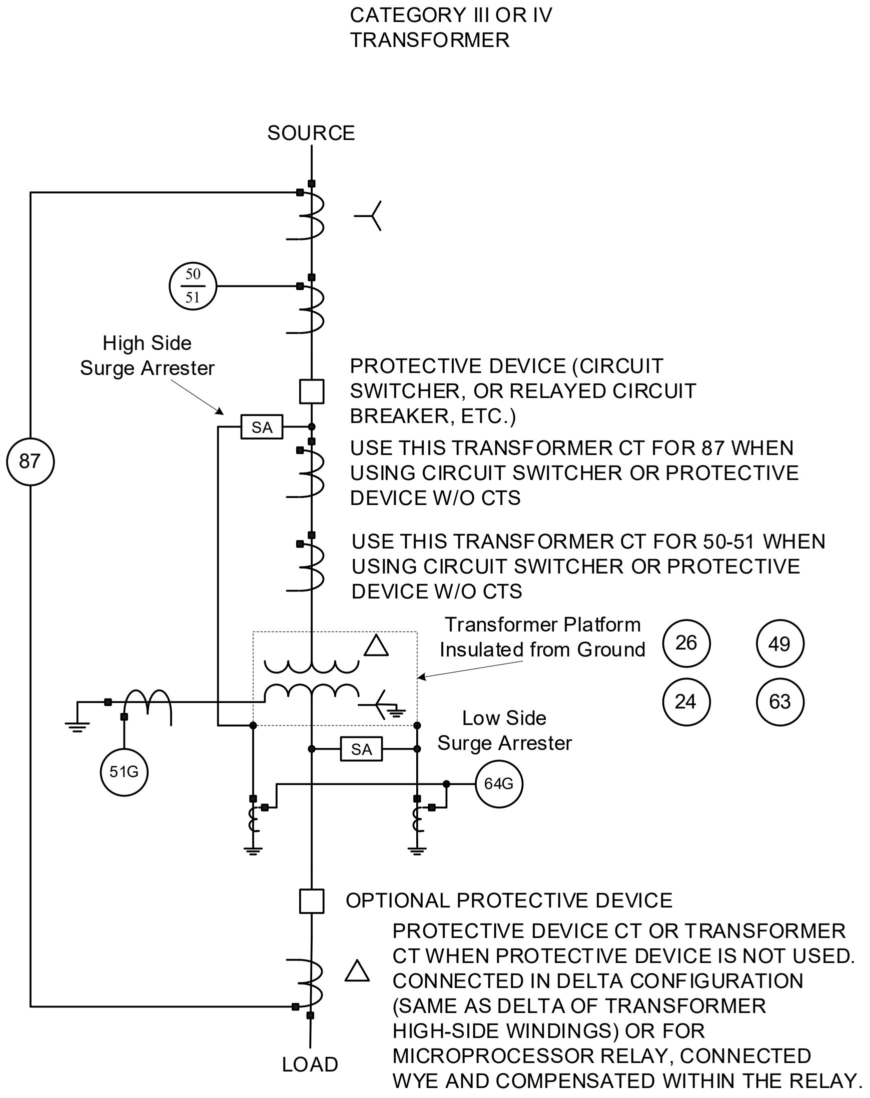
*Data taken from “Analysis of Transformer Failures” by William H Bartley, Presented at the International Association of Engineering Insurers 36th Annual Conference – Stockholm, 2003

Industry Standards & Guides





ANSI / IEEE C37.91-2021



From IEEE C37.91, 2021

"Guide for Protective Relay Applications for Power Transformers"

- 87 = Phase Diff
- 51G = Ground Overcurrent
- 50/51 = Phase Overcurrent
- 64G = Transformer Tank Ground Overcurrent
- 26 = Thermal Device
- 49 = Thermal Overload
- 24 = Overexcitation
- 63 = Gas Relay (SPR, Buccholtz)

Class III and IV Transformers (>= 5MVA)

IEEE Devices Used in Transformer Protection

24: Overexcitation (V/Hz)

26: Thermal Device

46: Negative Sequence Overcurrent

49: Thermal Overload

50: Instantaneous Phase Overcurrent

50G: Instantaneous Ground Overcurrent

50N: Instantaneous Residual Overcurrent

50BF: Breaker Failure

51G: Ground Inverse Time Overcurrent

51N: Residual Inverse Time Overcurrent

63: Sudden Pressure Relay (Buccholtz Relay)

64G: Transformer Tank Ground Overcurrent

81U: Underfrequency

87H: Unrestrained Phase Differential

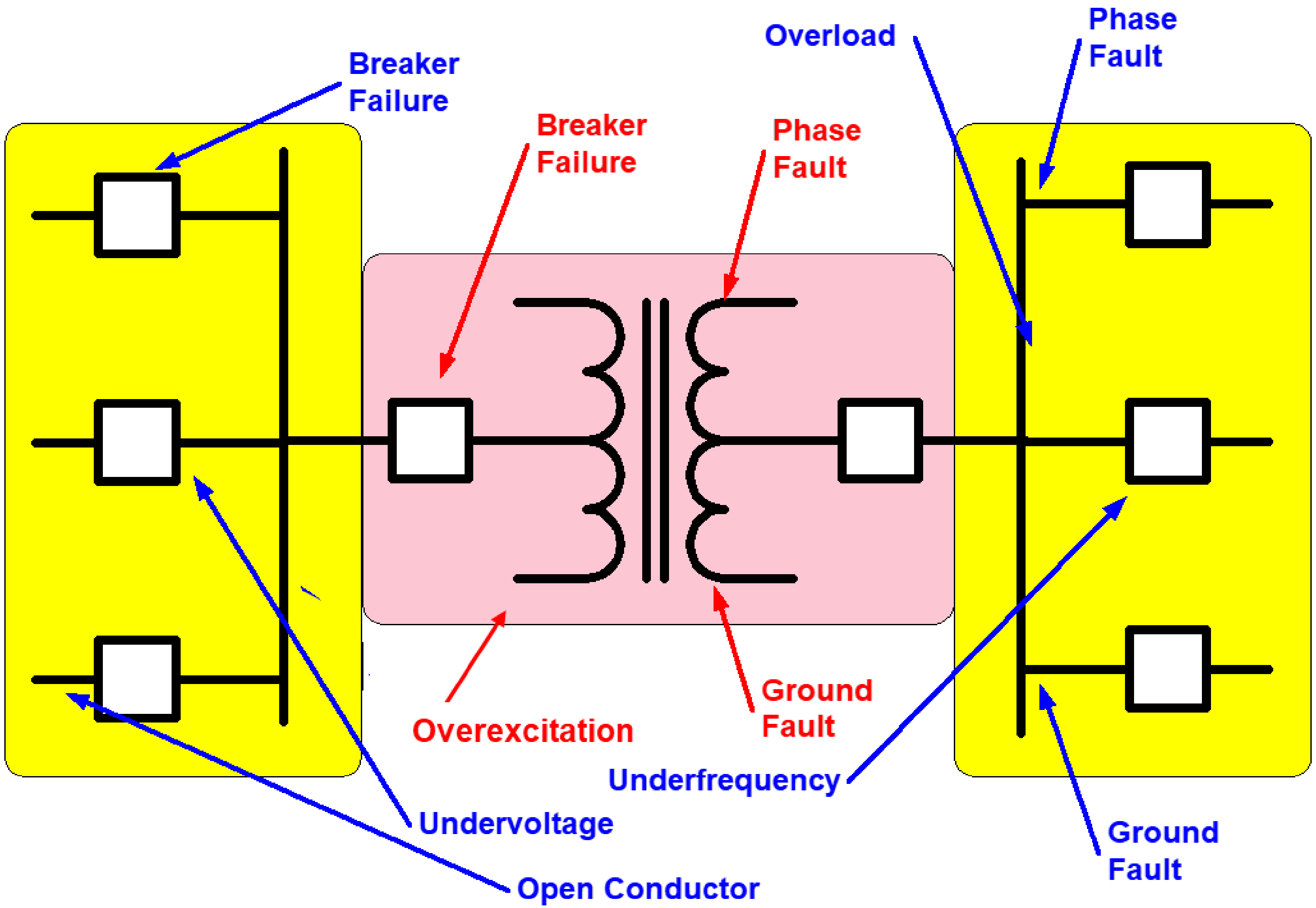
87T: Transformer Phase Differential with Restraints

87GD: Ground Differential (also known as "restricted earth fault")

Transformer Protection Review

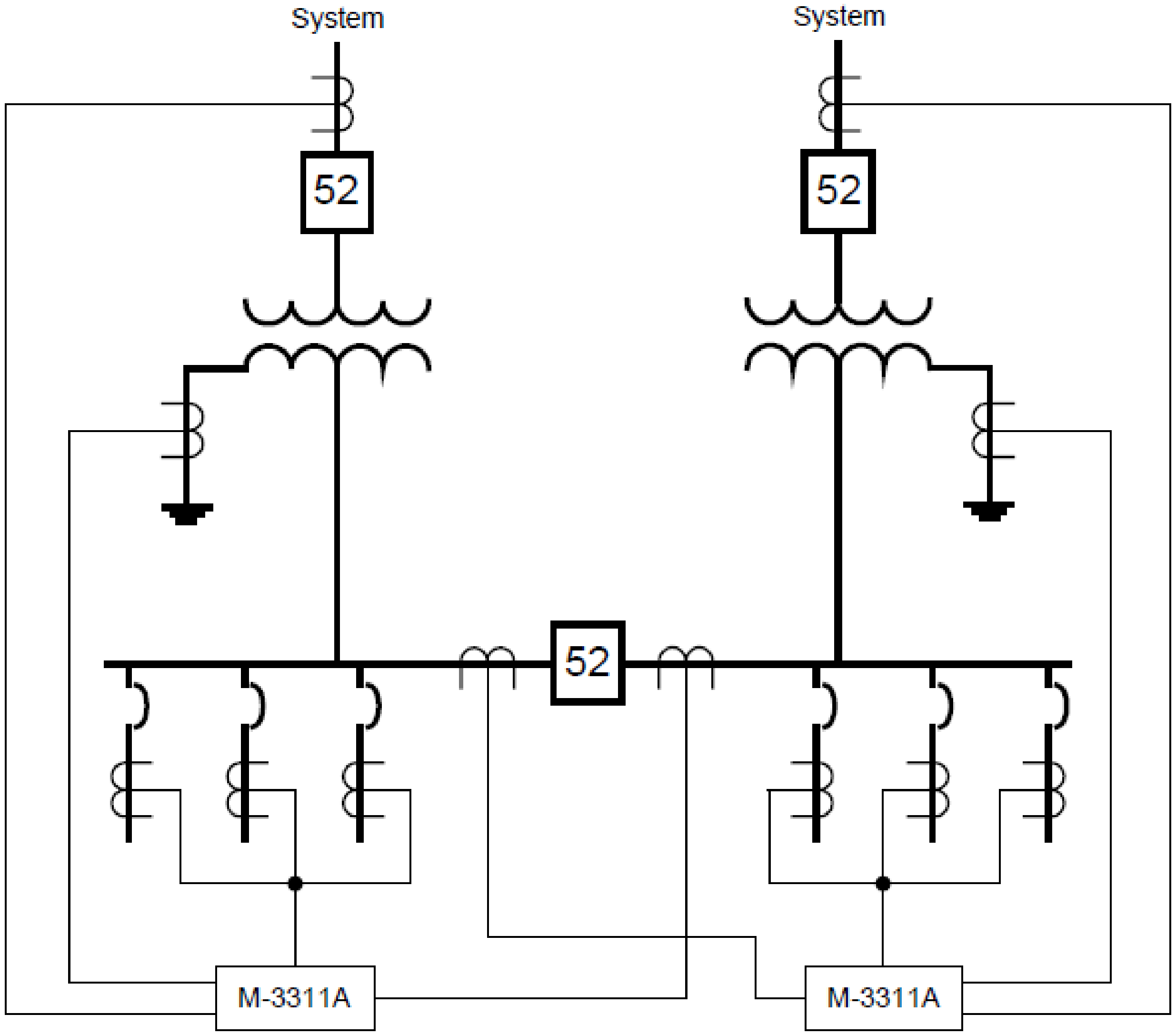
- Internal Short Circuits
  - Phase Faults
  - Ground Faults
- System Short Circuits (Back Up Protection)
  - Buses and Lines
    - Phase Faults
    - Ground Faults
- Abnormal Conditions
  - Open Circuits
  - Overexcitation
  - Abnormal Frequency
  - Abnormal Voltage
  - Breaker Failure
  - Overload
  - Geo-magnetically induced current (GIC)

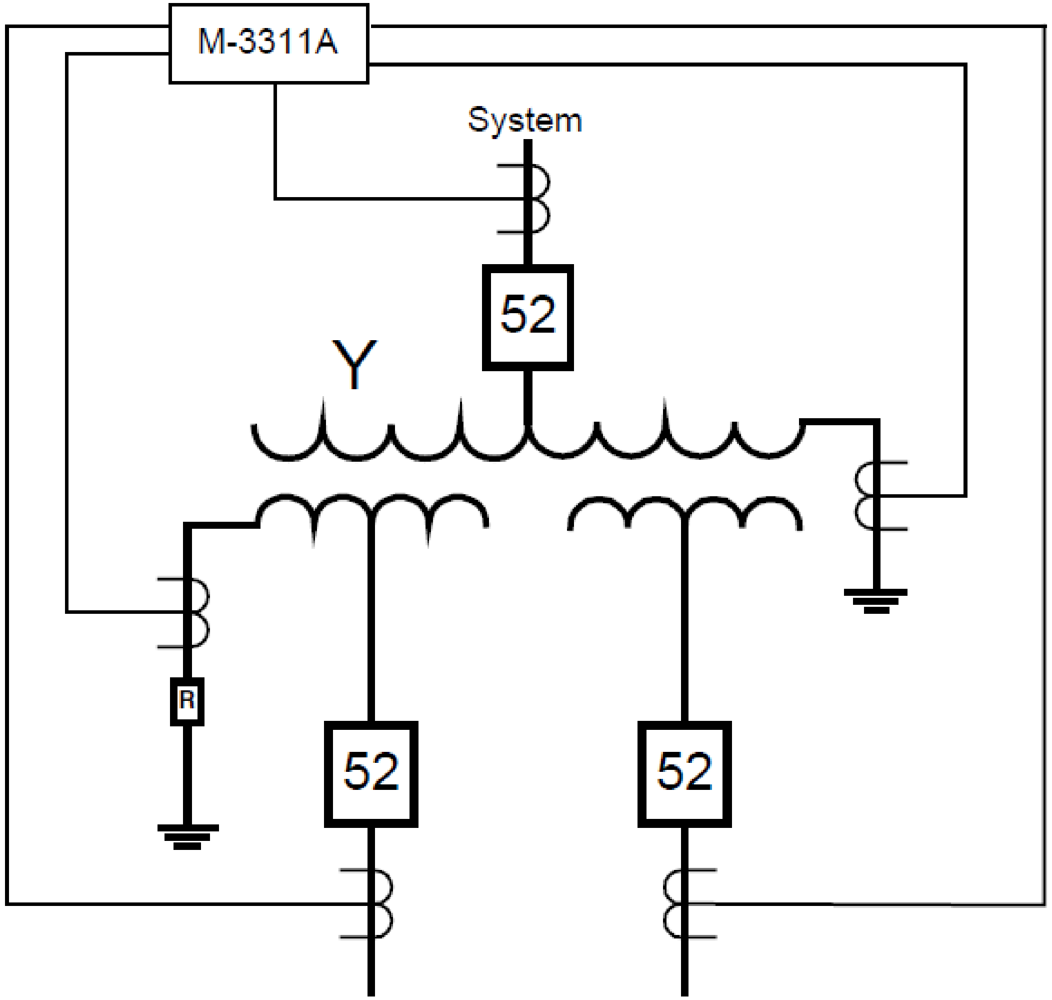
Transformer Electrical Protection Issues



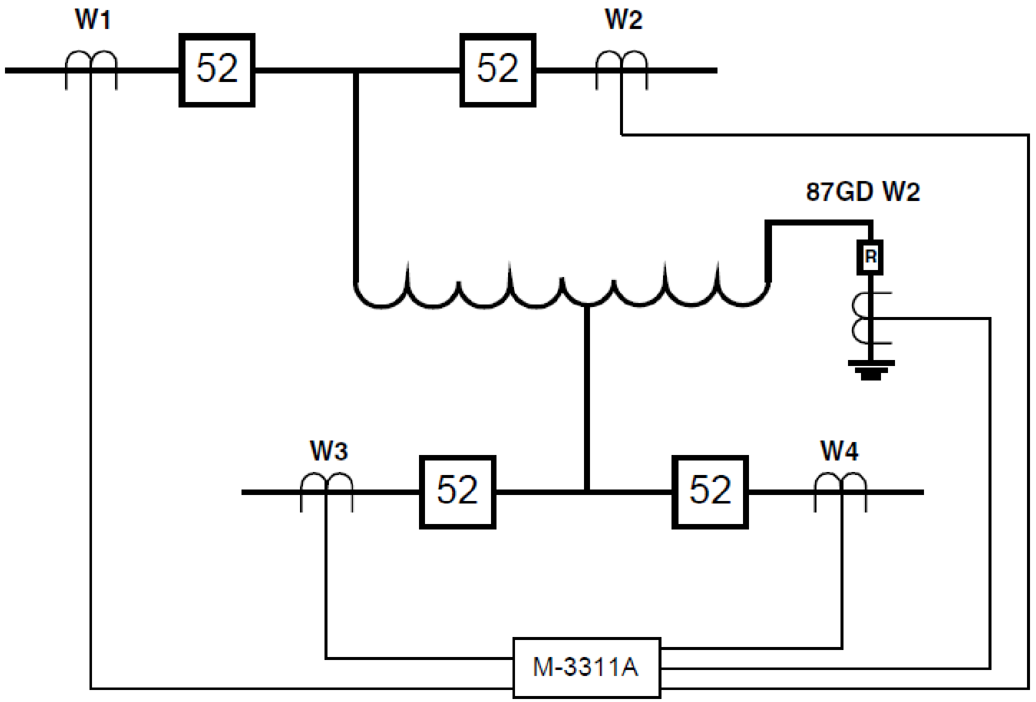
In and Out of Zone

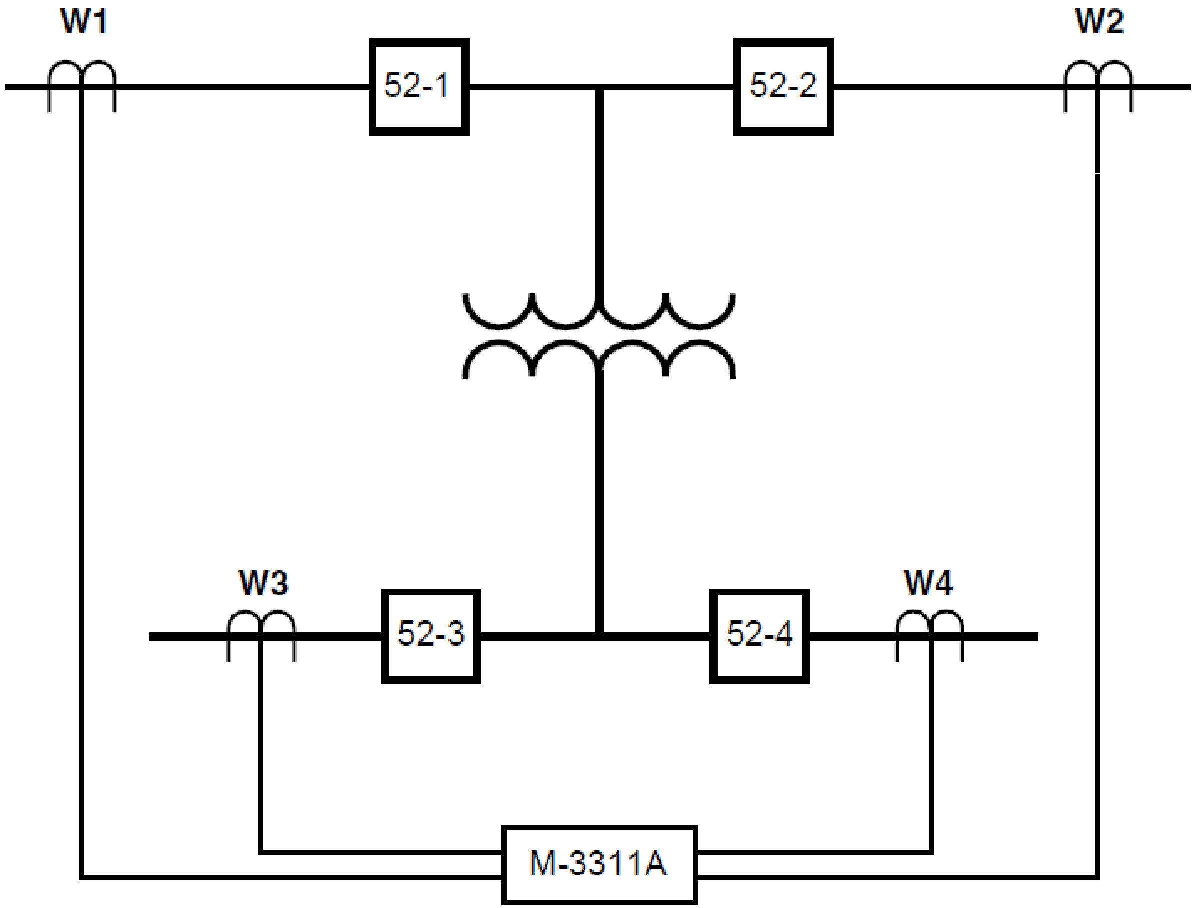
Complex Applications



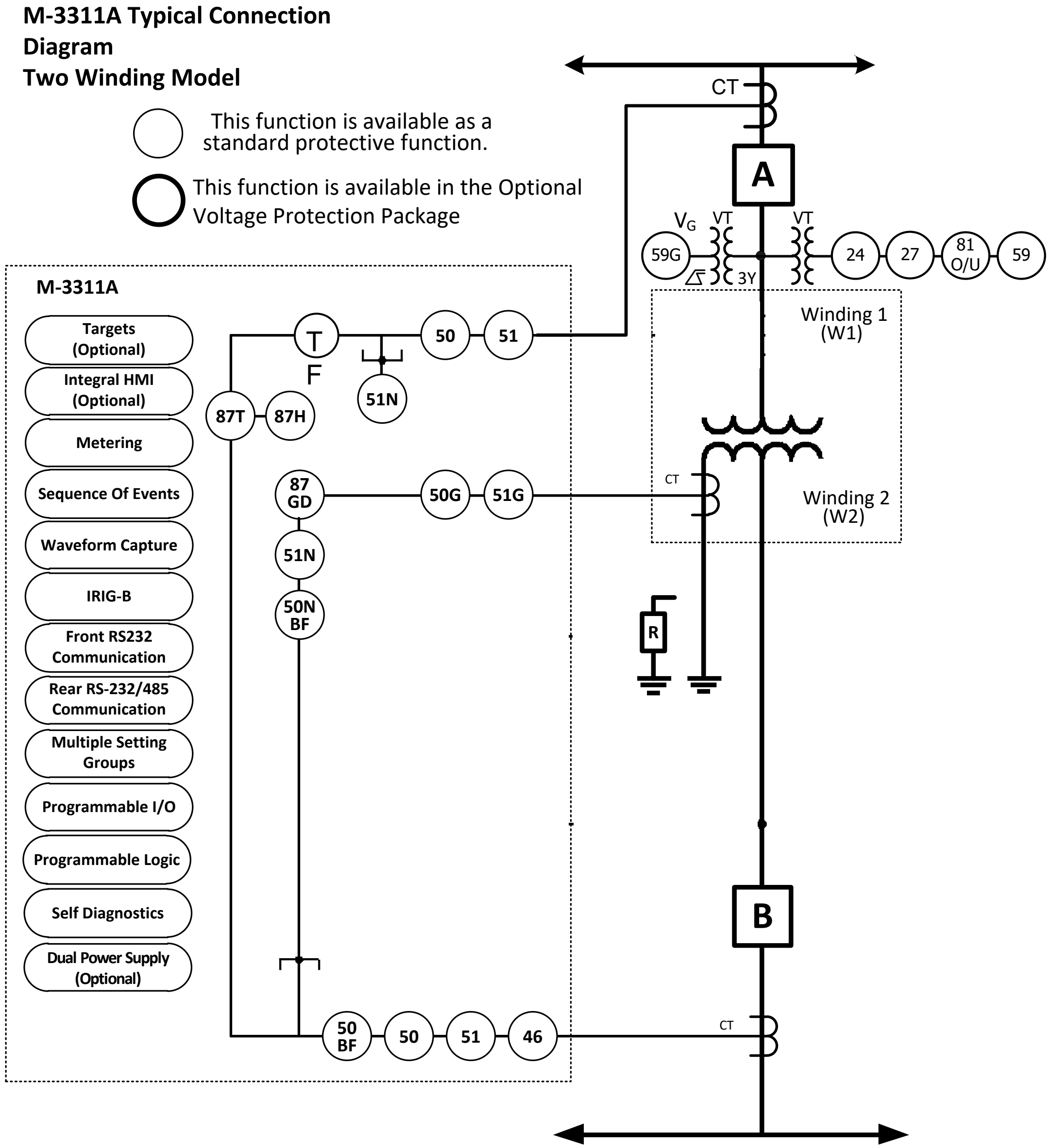


Complex Applications

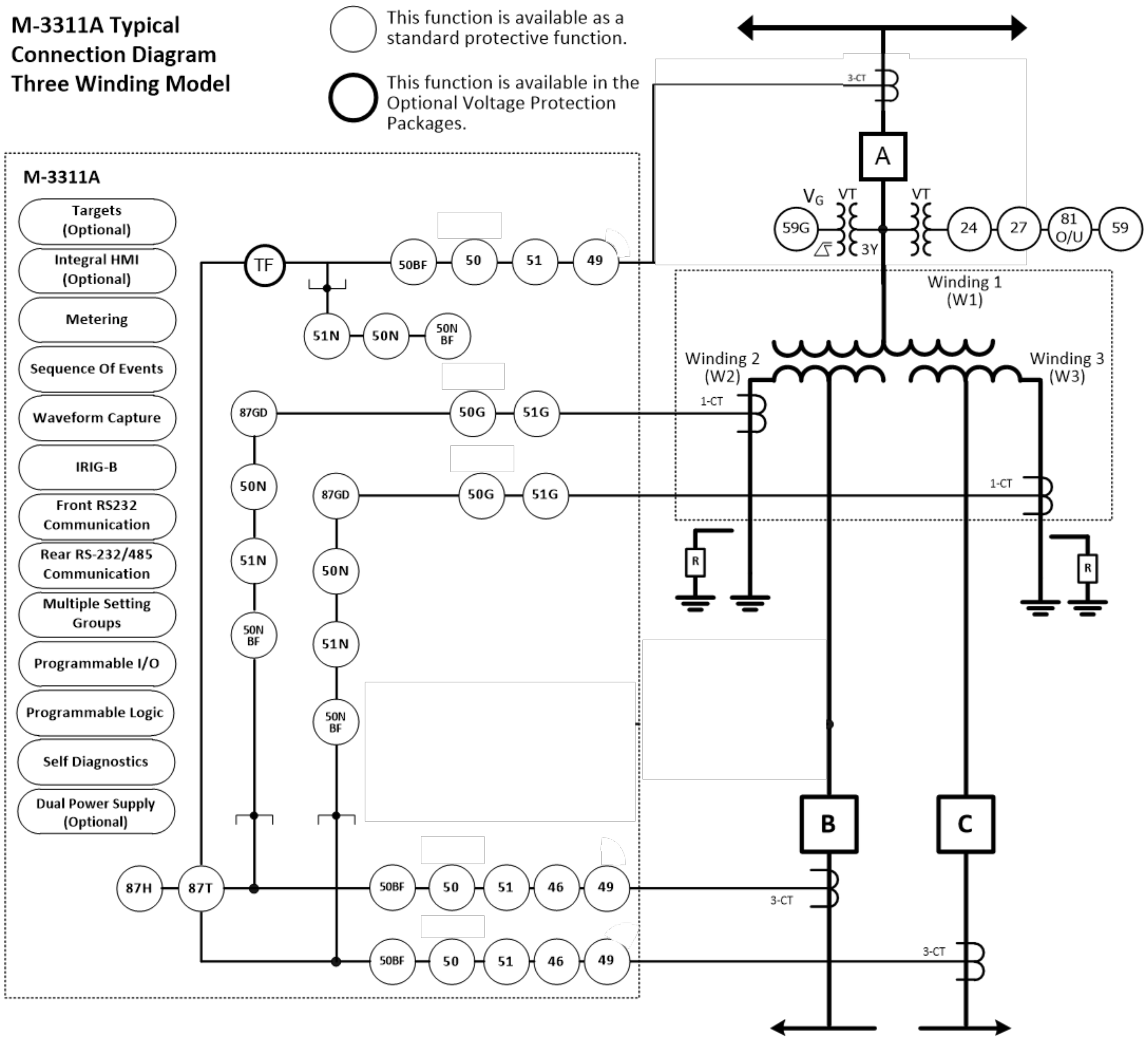




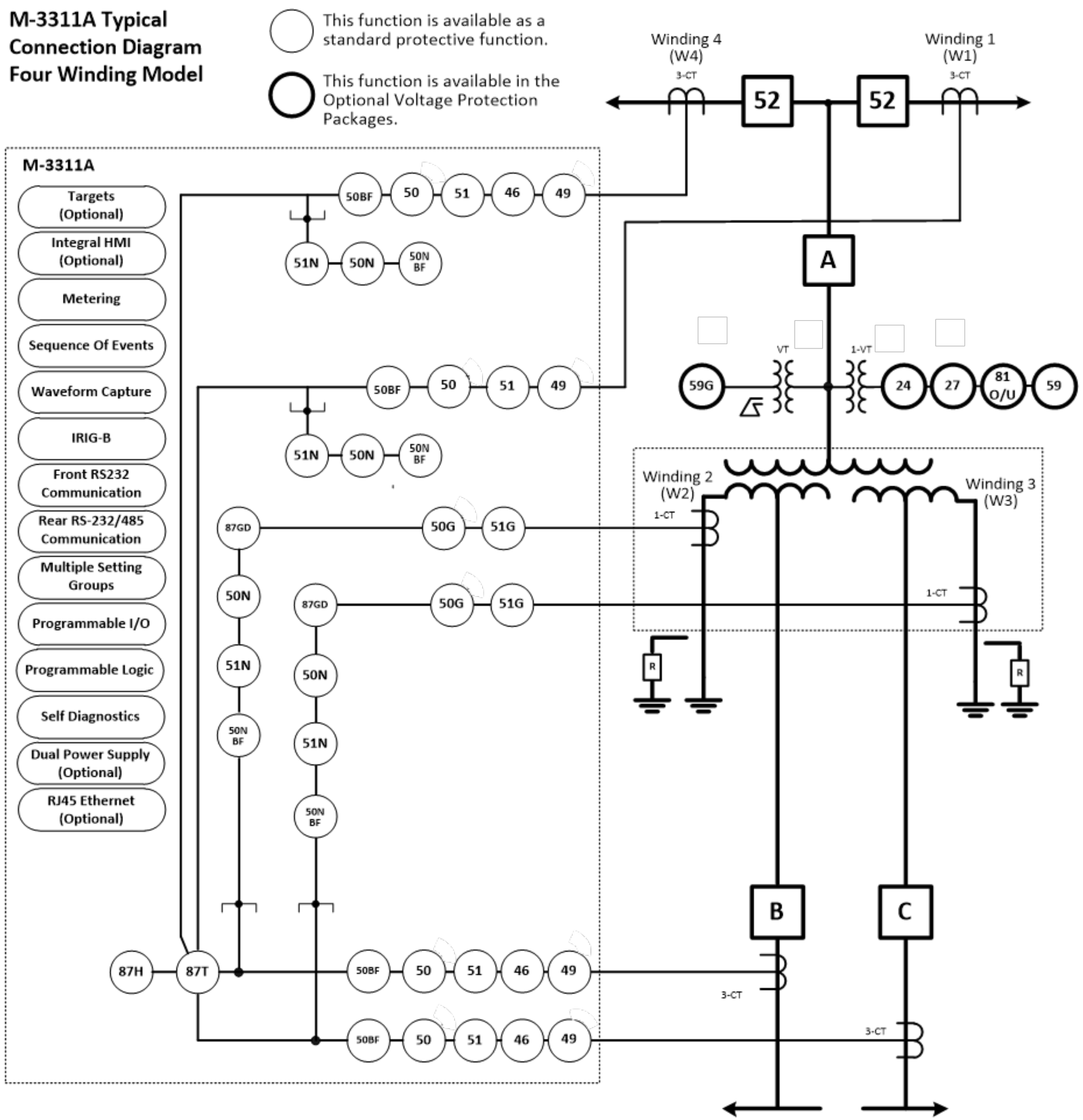
2 Winding


M-3311A Typical Connection Diagram
Two Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Package
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
T
F
50
51
51N
87T
87H
87 GD
50G
51G
51N
50N BF
50 BF
50
51
46
CT
A
VG
VT
VT
59G
3Y
24
27
81 O/U
59
Winding 1 (W1)
Winding 2 (W2)
CT
R
B
CT

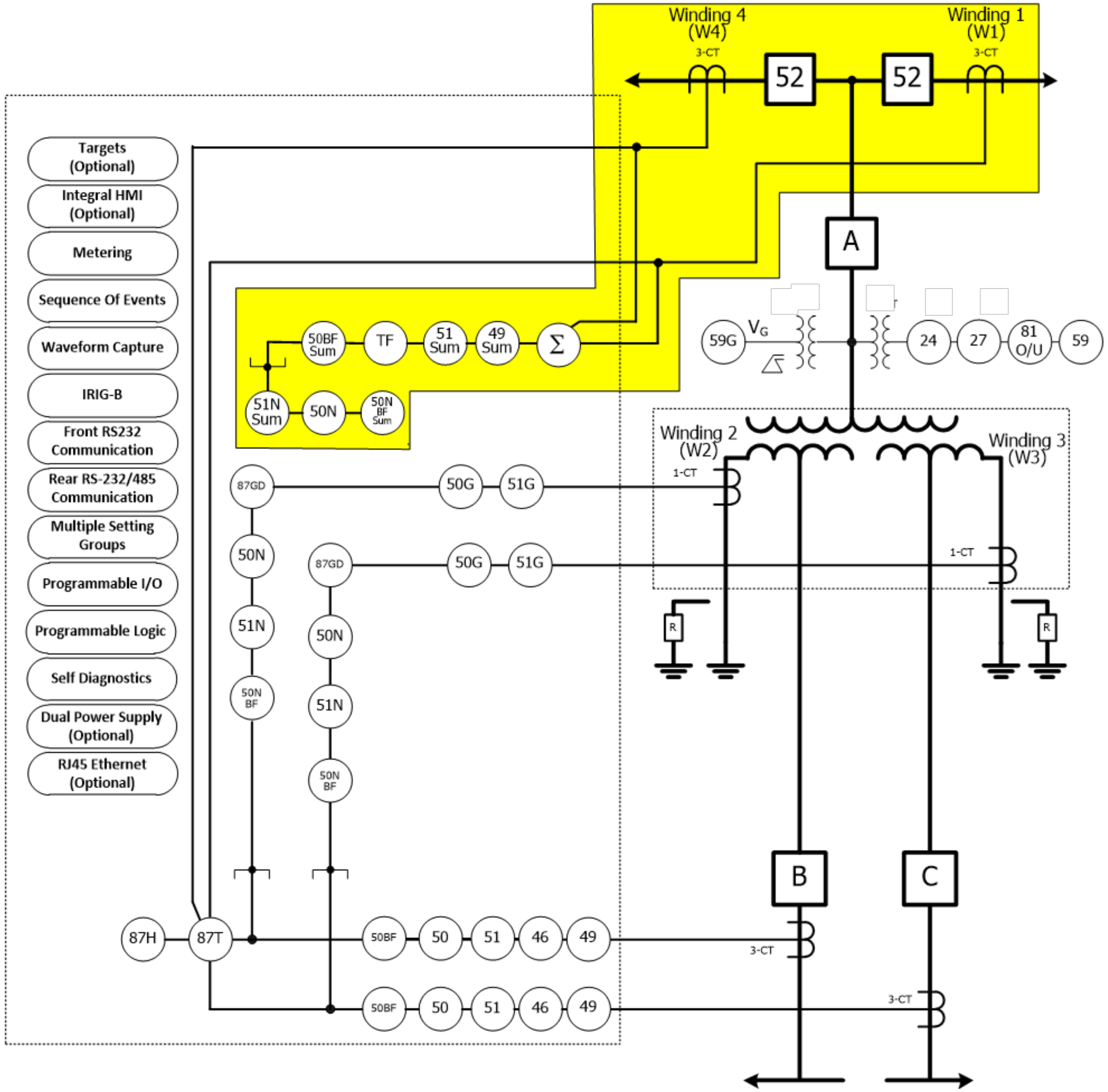
3 Winding


M-3311A Typical
Connection Diagram
Three Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Packages.
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
TF
50BF
50
51
49
51N
50N
50N BF
87GD
50G
51G
87H
87T
46
3-CT
1-CT
A
B
C
VG
VT
59G
3Y
24
27
81 O/U
59
Winding 1 (W1)
Winding 2 (W2)
Winding 3 (W3)
R

4 Winding


M-3311A Typical Connection Diagram Four Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Packages.
Winding 4 (W4)
Winding 1 (W1)
3-CT
52
52
A
B
C
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
RJ45 Ethernet (Optional)
50BF
50
51
46
49
51N
50N
50N BF
87GD
50G
51G
87H
87T
VT
1-VT
59G
24
27
81 O/U
59
Winding 2 (W2)
Winding 3 (W3)
1-CT
R

4 Winding with Current Summing



Desirable Sensing Possibilities

M-3311A Configuration Options		
Windings	**Ground Inputs**	**Voltage Inputs**
Two	One	Zero
		Two
		Four
Three	Two	Zero
		Two
		Four
Four	Three	Zero
		Two

- Many ground Inputs available for 87GD (REF), 51G
- Many voltage inputs available for 24, 59, 59N, 27, 81-0, 81-U
- Current Summing available on two sets of current inputs
  - Useful for through-fault on dual high side CB applications

Types of Protection

Electrical

Fuses

- Small transformers (typ. <10 MVA)
- Short circuit protection only

Overcurrent protection

- High side
  - Through-fault protection
  - Differential back-up protection for high side faults
- Low side
  - System back up protection
  - Unbalanced load protection

Transformer Protection Functions

Internal Faults:

- 87T Phase Differential with Restraints
- 87H Unrestrained Phase Differential
- 87GD Three Ground Differential elements (Restricted Earth Fault)
- 64G Tank Ground Overcurrent

Through-Faults:

- 50/51 Phase Overcurrent
- 50G/51G Ground Overcurrent
- 50N/51N Instantaneous Residual Overcurrent
- 46 Negative Sequence Overcurrent

Transformer Protection Functions

Abnormal Operating Conditions:

- 27 Undervoltage
- 24 Overexcitation (V/Hz)
- 49 Thermal Overload
- 81U Underfrequency
- 50BF Breaker Failure

Asset Management Functions:

- TF Through-Fault Monitoring
- BM Breaker Monitoring
- TCM Trip Circuit Monitoring

Overexcitation

- Responds to overfluxing; excessive V/Hz
  - 120V/60Hz = 2 = 1pu
- Constant operational limits
  - ANSI C37.106 & C57.12
    - 1.05 loaded, 1.10 unloaded
  - Inverse time curves typically available for values over the constant allowable level
- Overfluxing is a voltage and frequency based issue
- Overfluxing protection needs to be voltage and frequency based (V/Hz)
- Although 5th harmonic is generated during an overfluxing event, there is no correlation between levels of 5th harmonic and severity of overfluxing
- Apparatus (transformers and generators) is rated with V/Hz withstand curves and limits – not 5th harmonic withstand limits

Overexcitation vs. Overvoltage

Overvoltage protection reacts to dielectric limits.

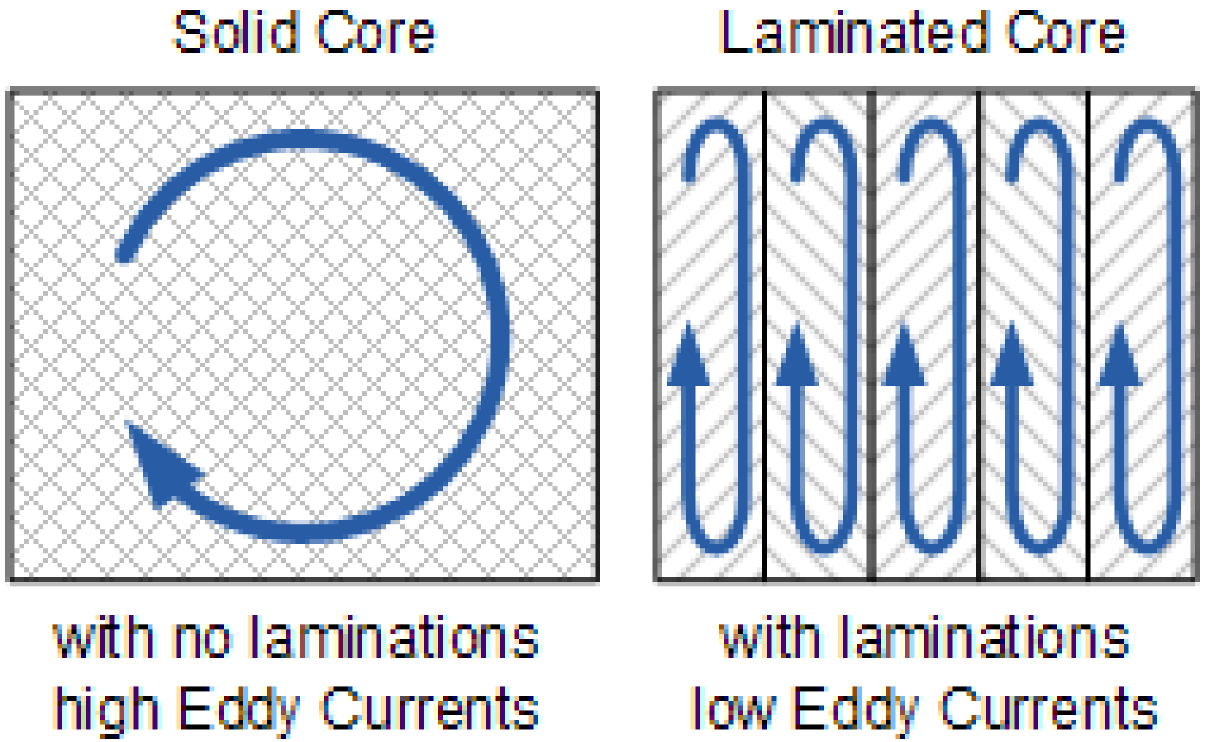
- Exceed those limits and risk punching a hole in the insulation
- Time is not negotiable

Overexcitation protection reacts to overfluxing

- Overfluxing causes heating
- The voltage excursion may be less than the prohibited dielectric limits (overvoltage limit)
- The excess current causes excess heating which will cumulatively damage the asset, and if left long enough, will result in catastrophic failure

Coping with Transformer Overexcitation

- Non-laminated components at the ends of the cores begin to heat up because of the higher losses induced in them
- This can cause severe localized overheating in the transformer and eventual breakdown in the core assembly or winding insulation



Causes of Overexcitation

Generating Plants

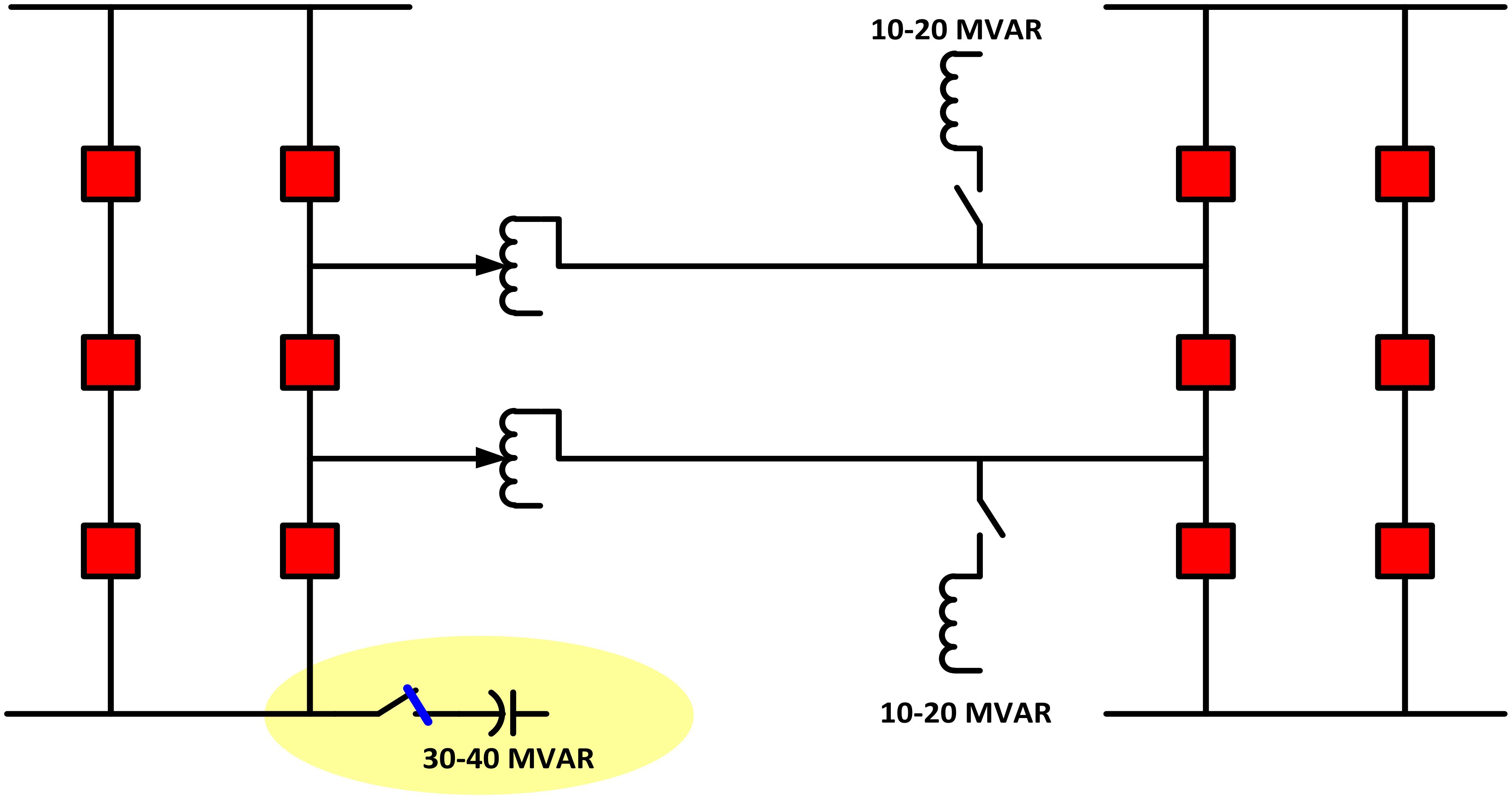
- Excitation system runaway
- Sudden loss of load
- Operational issues (reduced frequency)
  - Static starts
  - Pumped hydro starting
  - Rotor warming

Transmission Systems

- Voltage and Reactive Support Control Failures
  - Capacitor banks ON when they should be OFF
  - Shunt reactors OFF when they should be ON
  - Runaway LTCs
  - Load Loss on Long Lines (Capacitive Charging Voltage Rise)

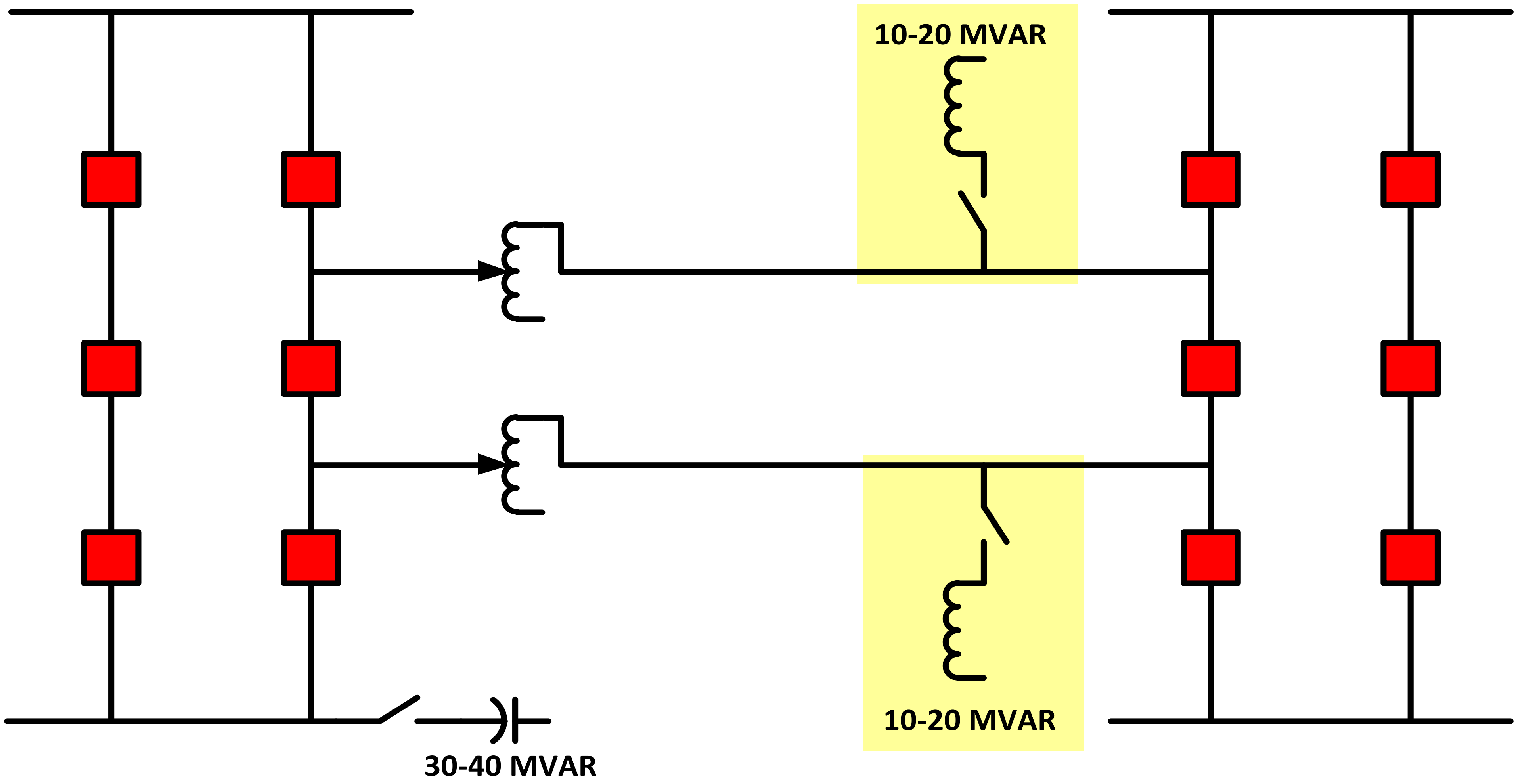
    -- Ferranti effect

System Control Issues: Overvoltage and Overexcitation



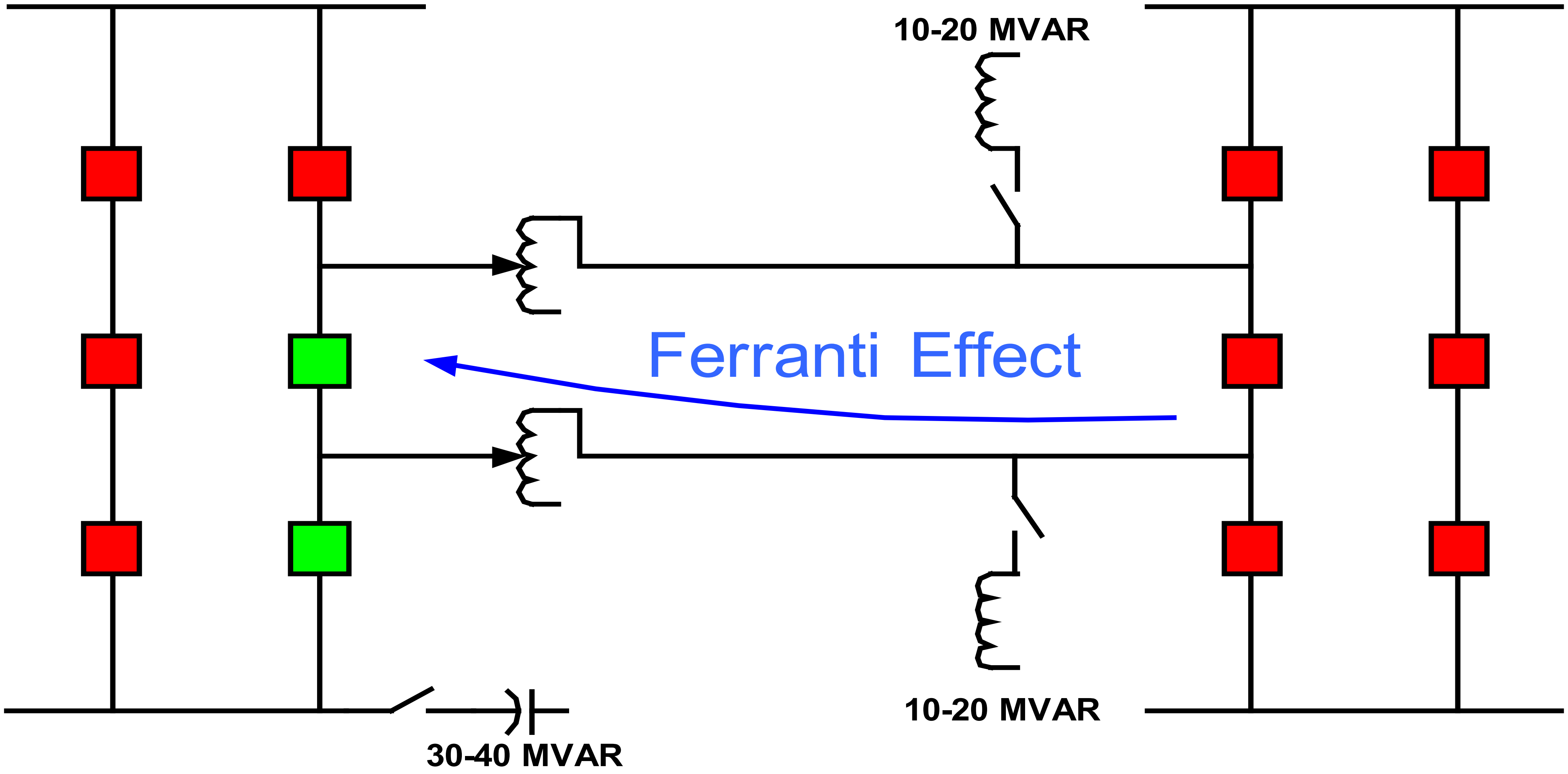
Caps ON When They Should Be Off

System Control Issues: Overvoltage and Overexcitation

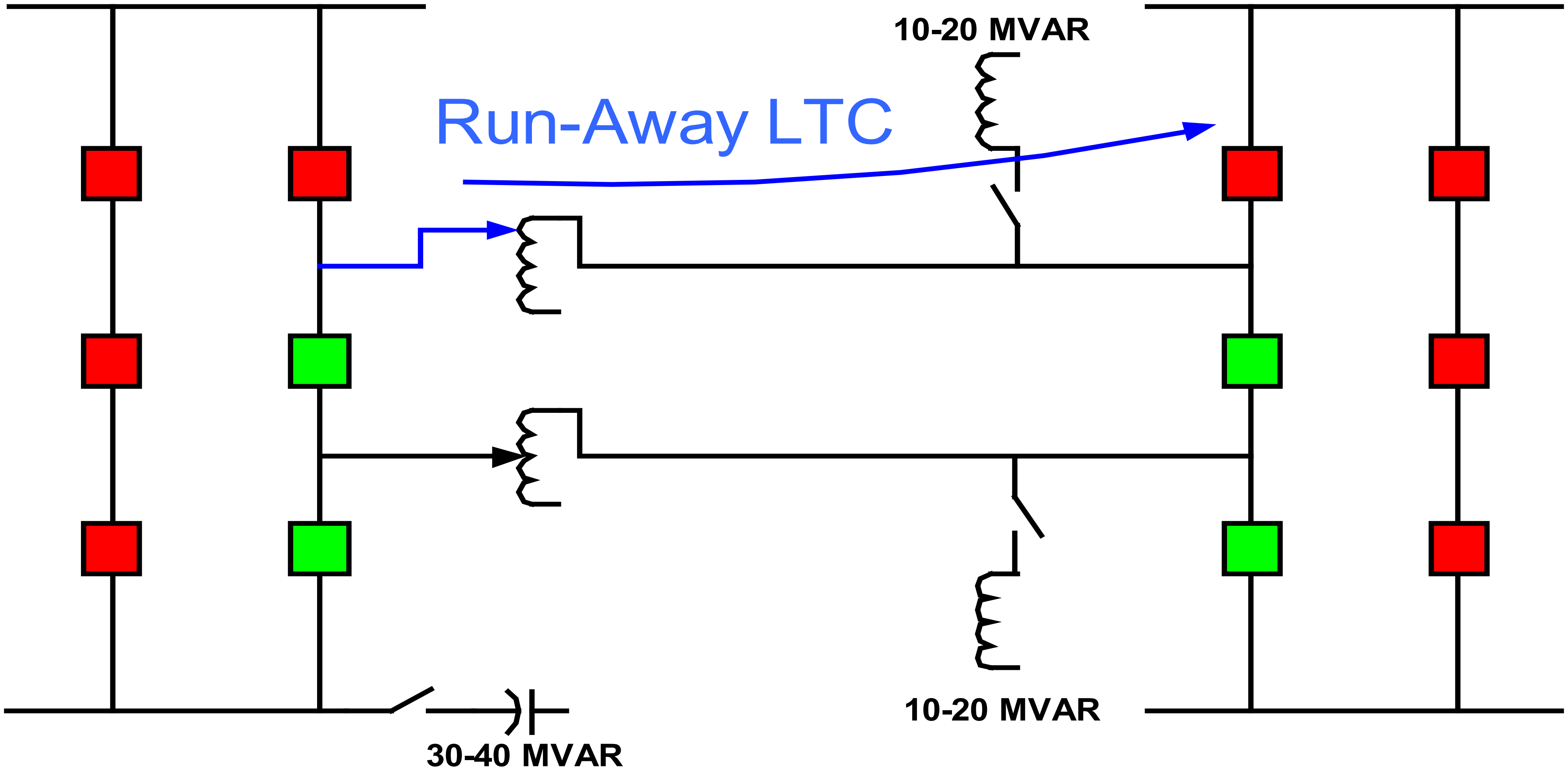


Reactors OFF When They Should Be On

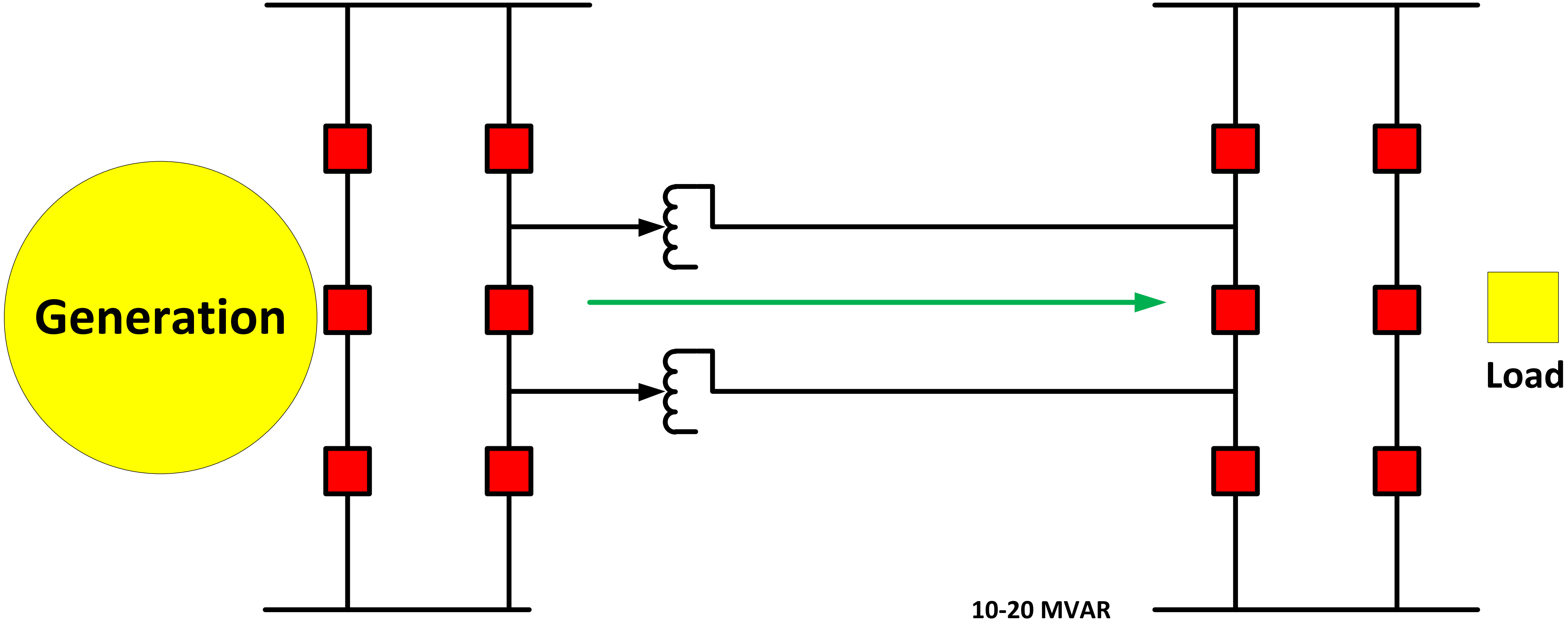
System Control Issues: Overvoltage and Overexcitation



System Control Issues: Overvoltage and Overexcitation



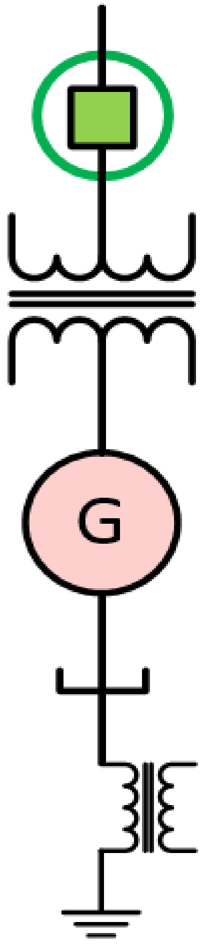
System Control Issues: Overvoltage and Overexcitation

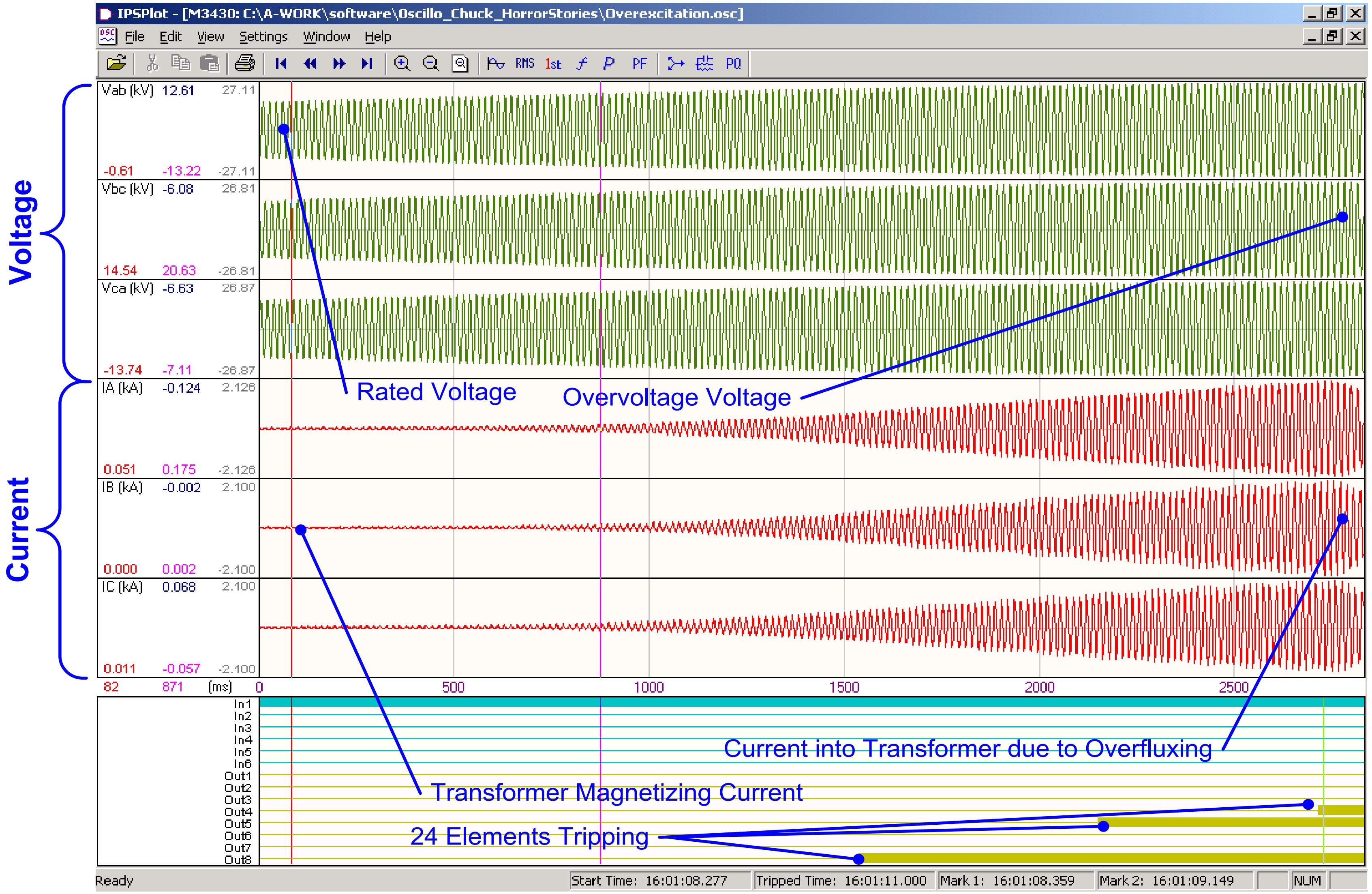


Small Load Trasport (Load Rejection at Remote Area)

1996 WECC Load Rejection Event

Increased V/Hz = Overexcitation Event = Excess Current

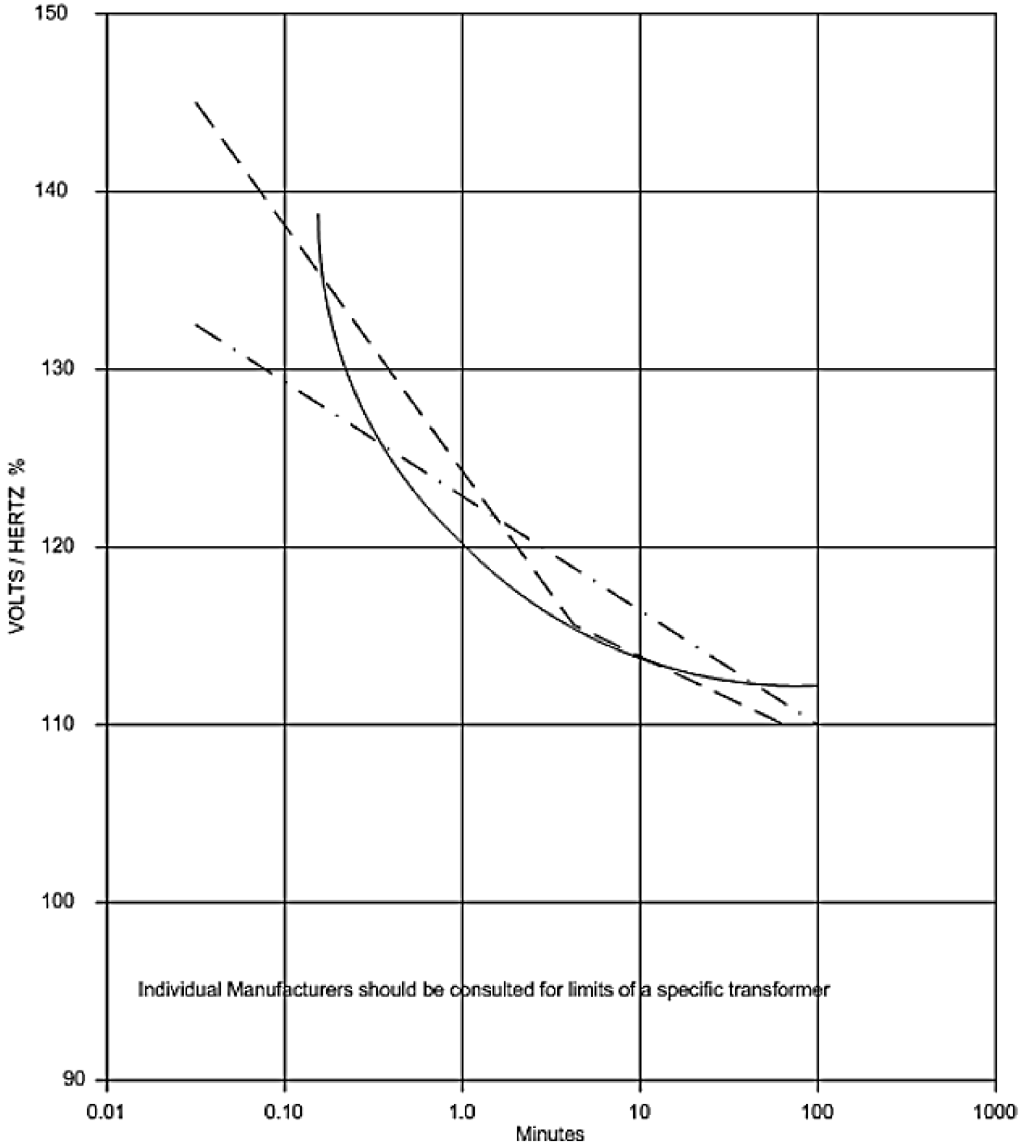




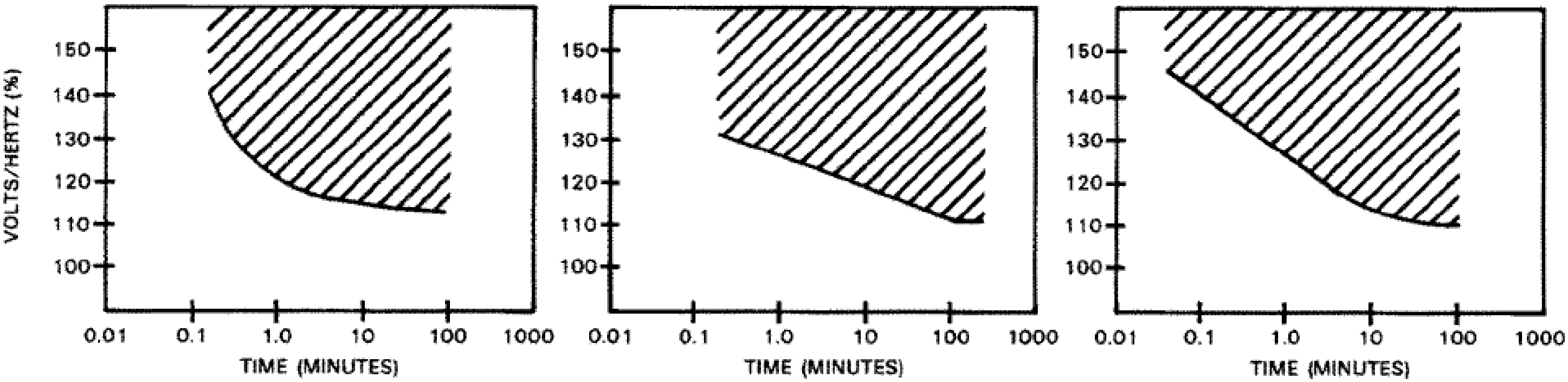
Overexcitation Event Oscillograph

Overexcitation Curves

This is typically how the apparatus manufacturer specifies the V/Hz curves



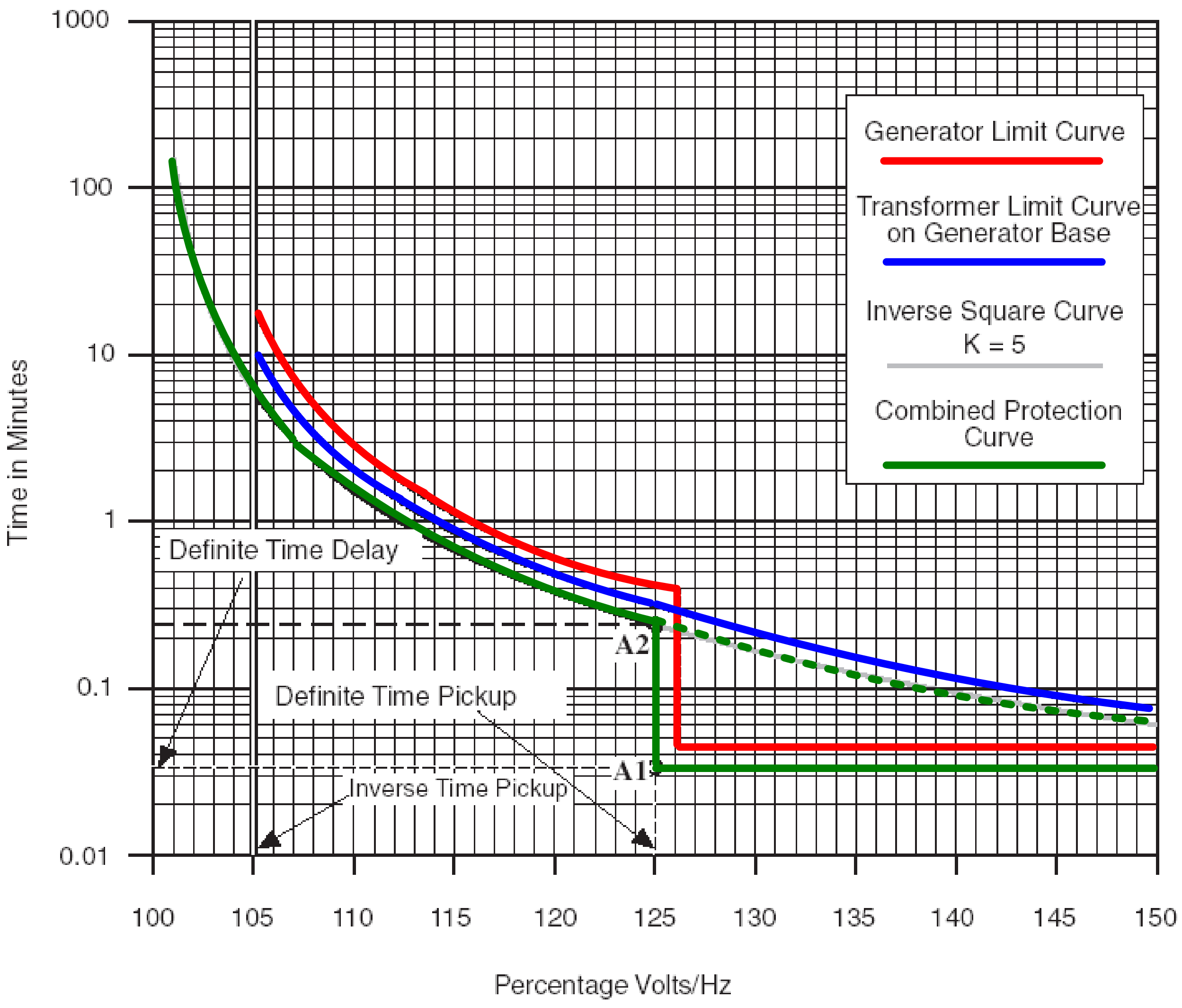
Overexcitation Curves



This is typically how the apparatus manufacturer specifies the V/Hz curves

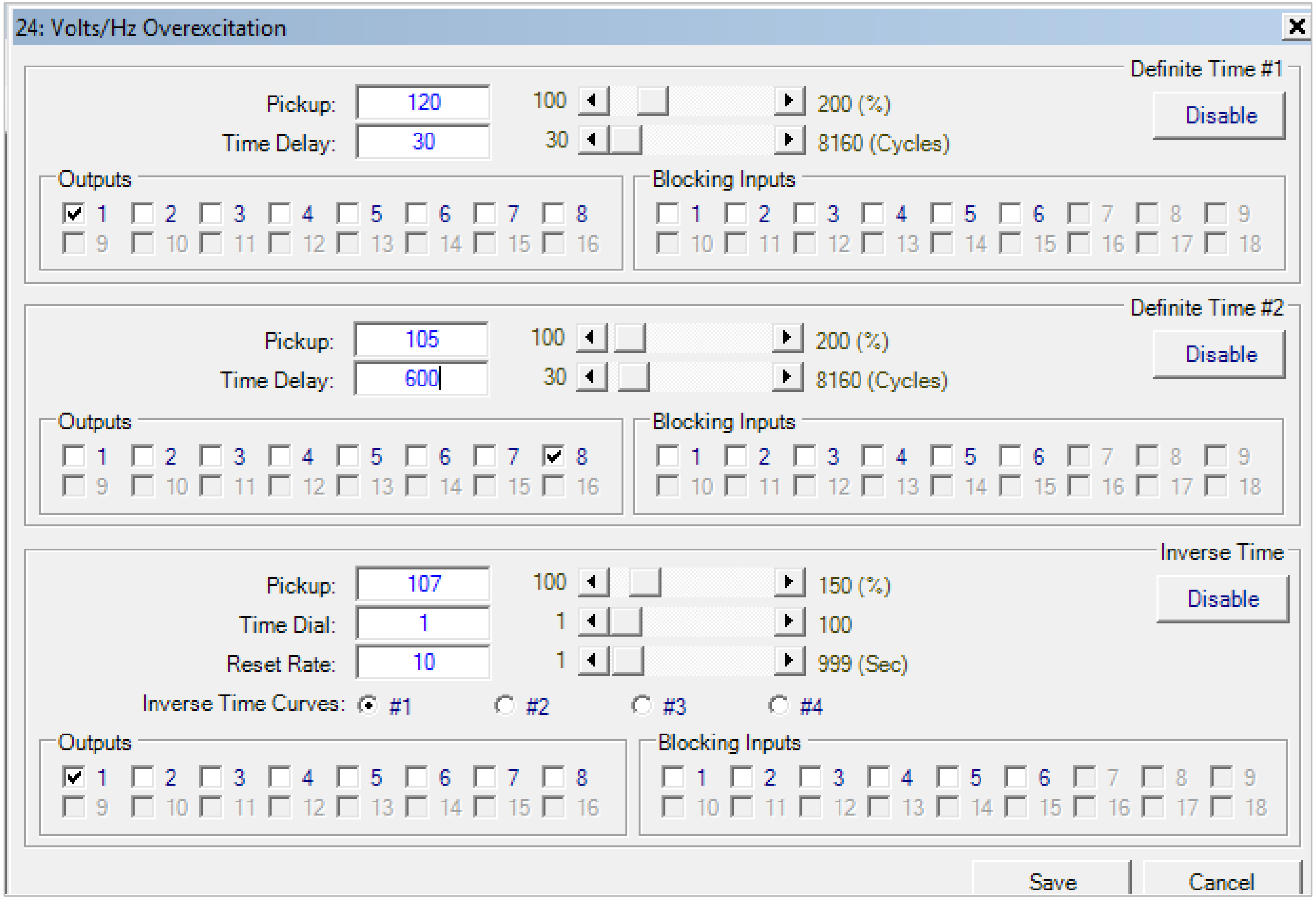
Protect Against Overexcitation

- V / Hz levels indicate flux
- V / Hz elements for alarming and tripping
- Based on transformer manufacturer's V/Hz withstand curves
- Reset timer waits for cooling



Typical Overexcitation Protection Curves

Overexcitation (24)



Types of Protection: Differential

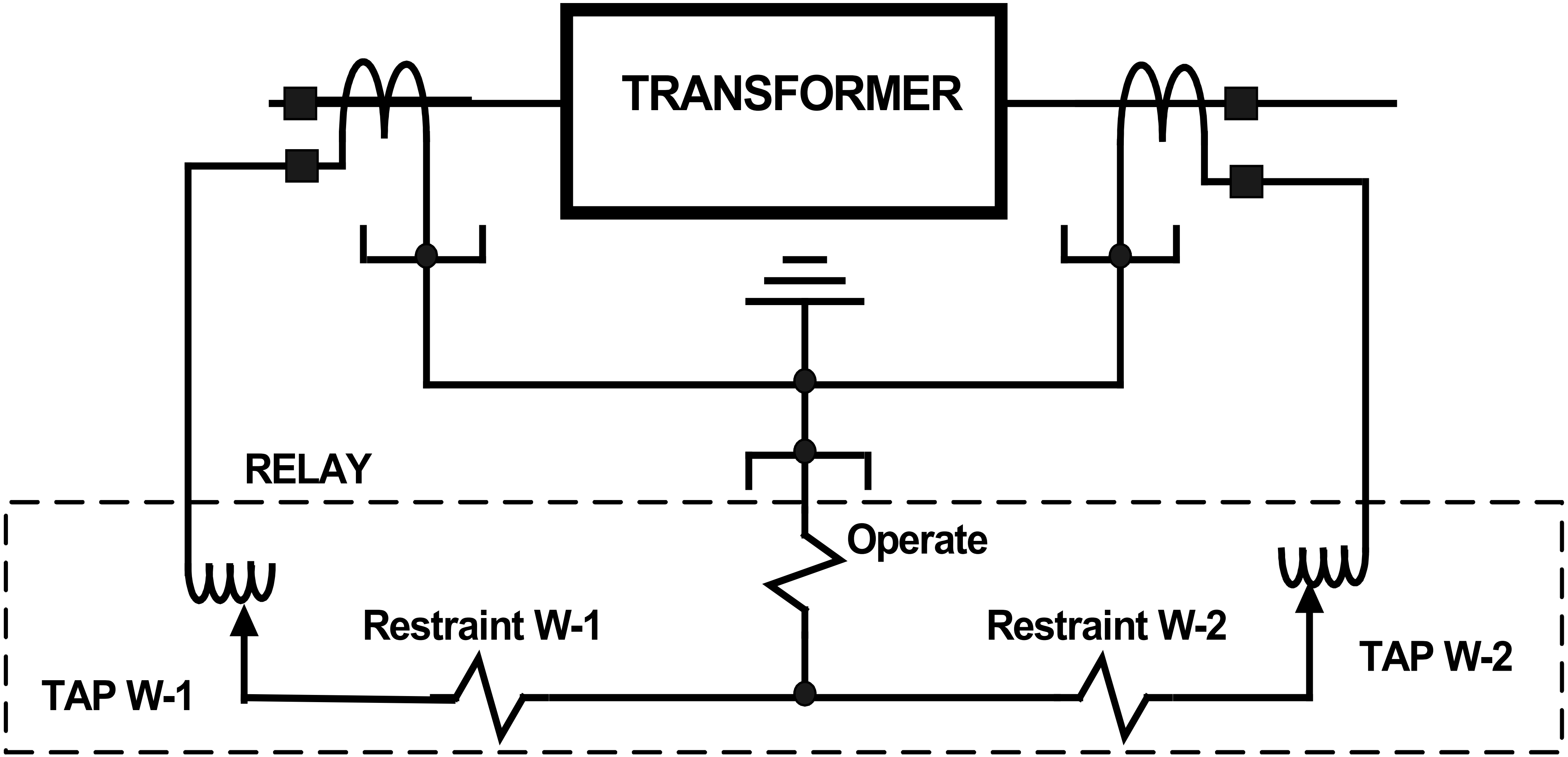
Advantages

- Provides high speed detection of faults that can reduce damage due to the flow of fault currents
- Offers high speed isolation of the faulted transformer, preserving stability and decreasing momentary sag duration
- No need to coordinate with other protections
- The location of the fault is determined more precisely
  - Within the zone of differential protection as demarked by CT location

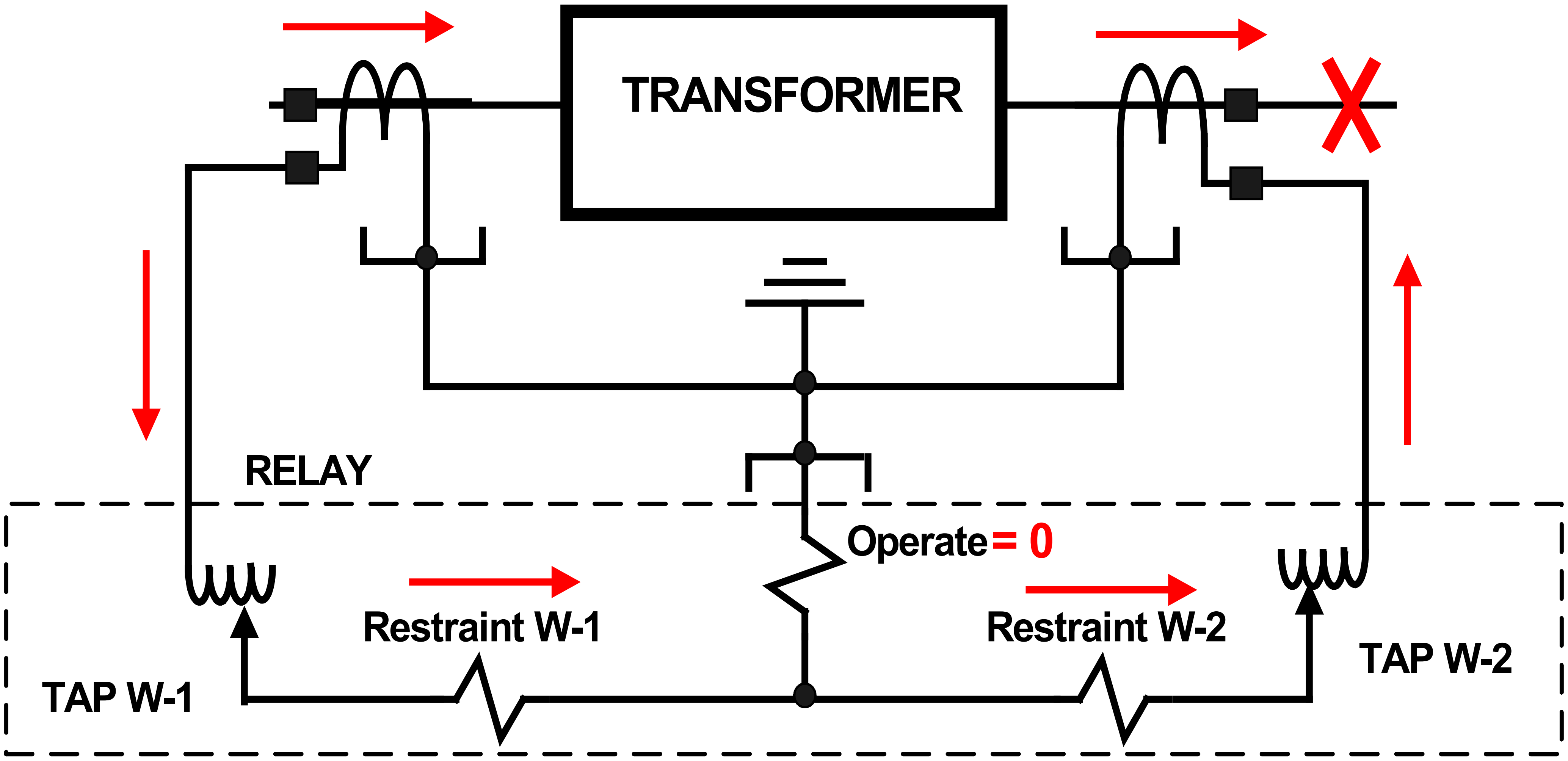
Types of Protection: Phase Differential

- Applied with variable percentage slopes to accommodate CT saturation and CT ratio errors
- Applied with inrush and overexcitation restraints
- Pickup/slope setting should consider magnetizing current, turns ratio errors due to fixed taps and +/-10% variation due to LTC
- May not be sensitive enough for all faults (low level, ground faults near neutral)

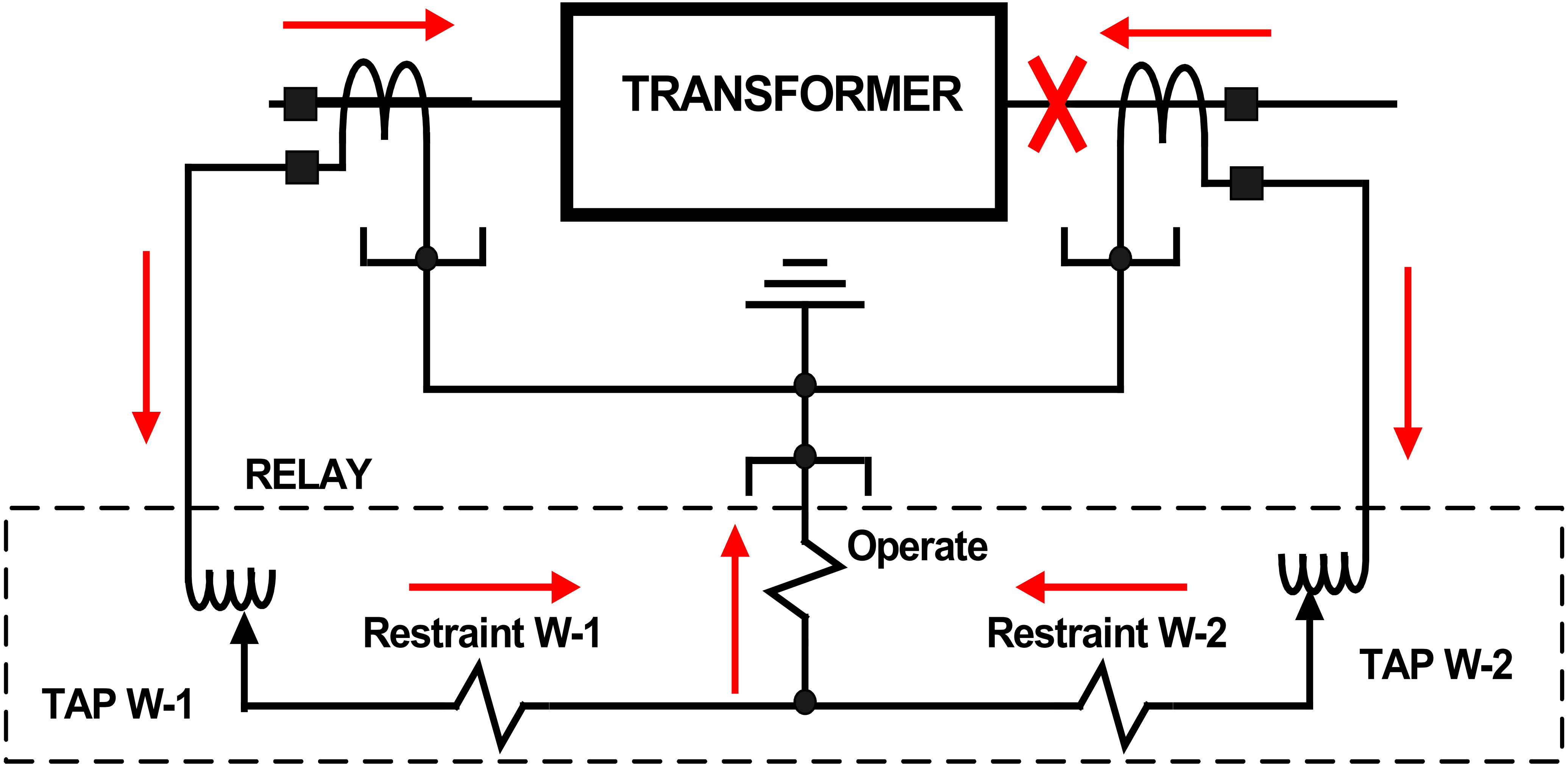
Phase Differential: Basic Differential Relay



Basic Differential Relay - External Fault



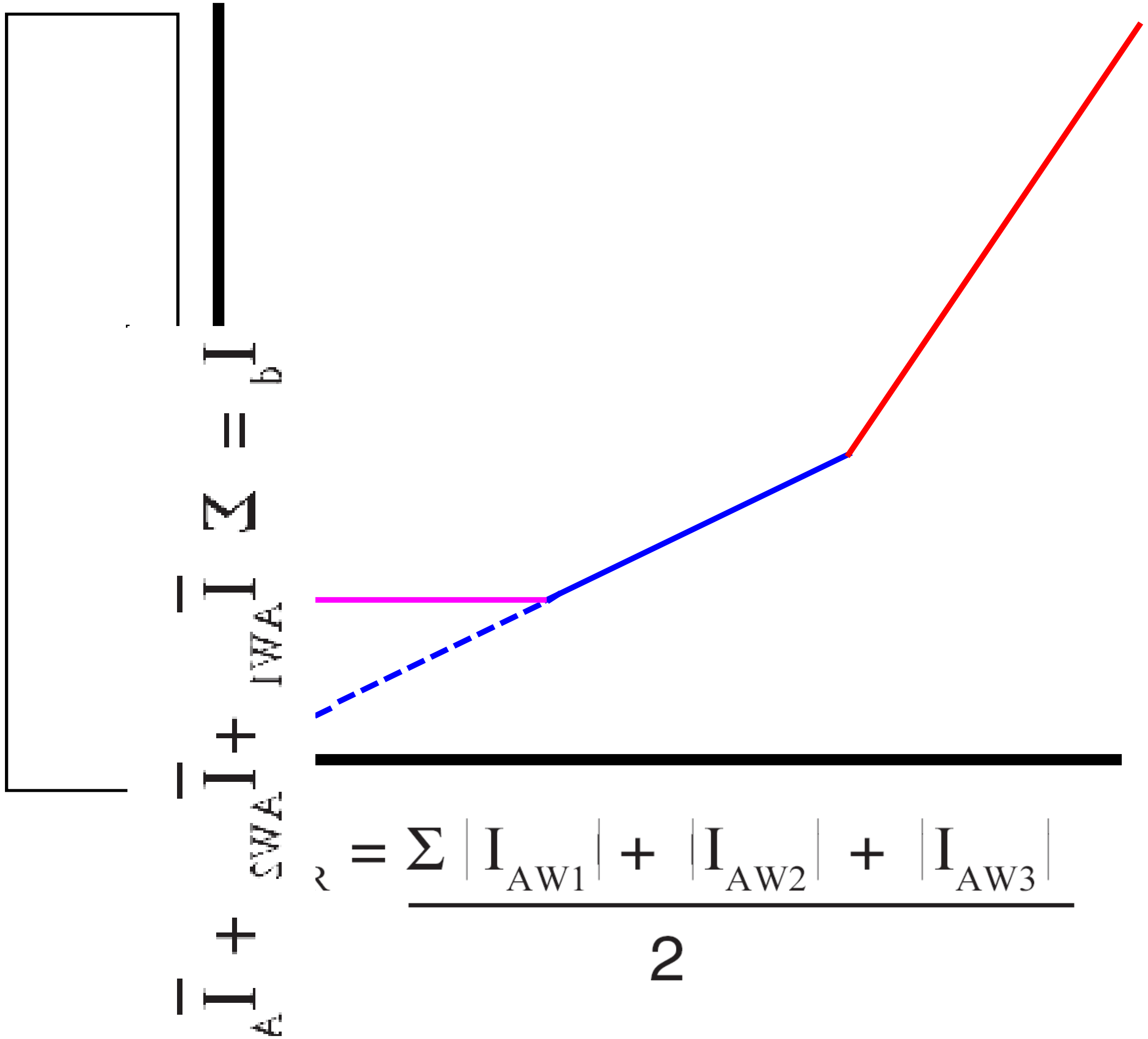
Basic Differential Relay - Internal Fault



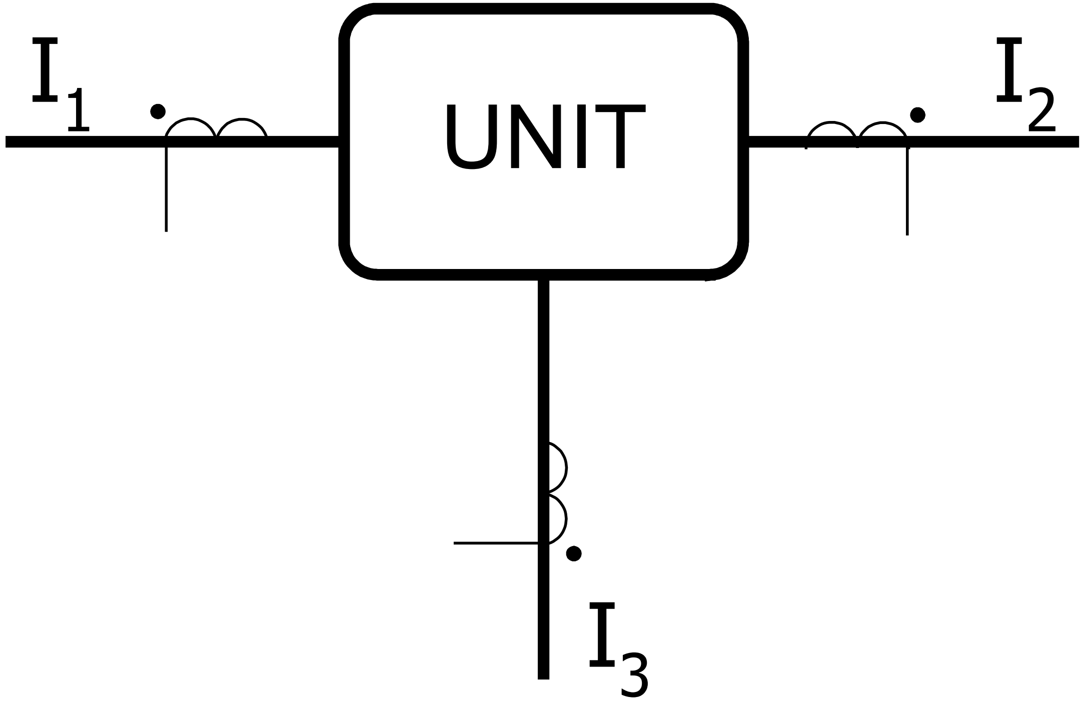
Differential Protection

- What goes into a “unit” comes out of a “unit”
- Kirchoff’s Law: The sum of the currents entering and leaving a junction is zero
- Straight forward concept, but not that simple in practice with transformers
- A host of issues challenges security and reliability of transformer differential protection

Typical Phase Differential Characteristic



$$I_1 + I_2 + I_3 = 0$$



Unique Issues Applying to Transformer Differential Protection

- CT ratio caused current mismatch
- Transformation ratio caused current mismatch (fixed taps)
- LTC induced current mismatch
- Delta-wye transformation of currents
  - Vector group and current derivation issues
- Zero-sequence current elimination for external ground faults on wye windings
- Inrush phenomena and its resultant current mismatch

Unique Issues Applying to Transformer Differential Protection

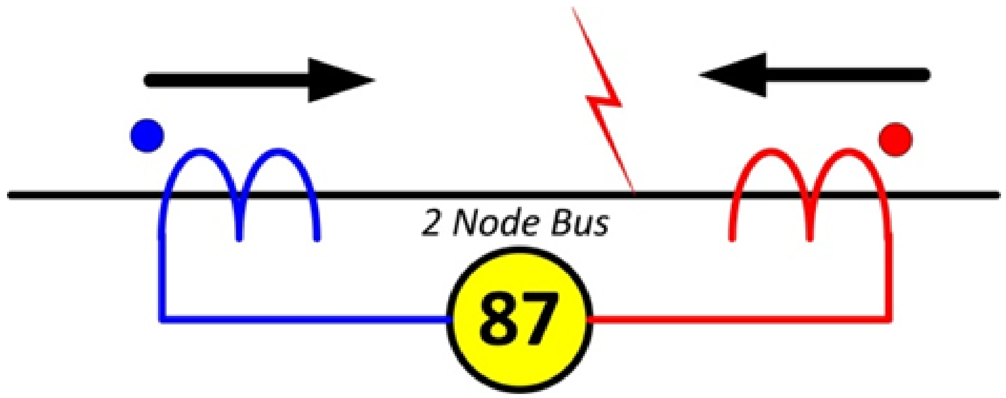
- Harmonic content available during inrush period due to point-on-wave switching
  - Especially with newer transformers with step-lap core construction
- Overexcitation phenomena and its resultant current mismatch
- Internal ground fault sensitivity concerns
- Switch onto fault concerns
- CT saturation, remanence, and tolerance

Remanence & X/R Ratio: CT Saturation

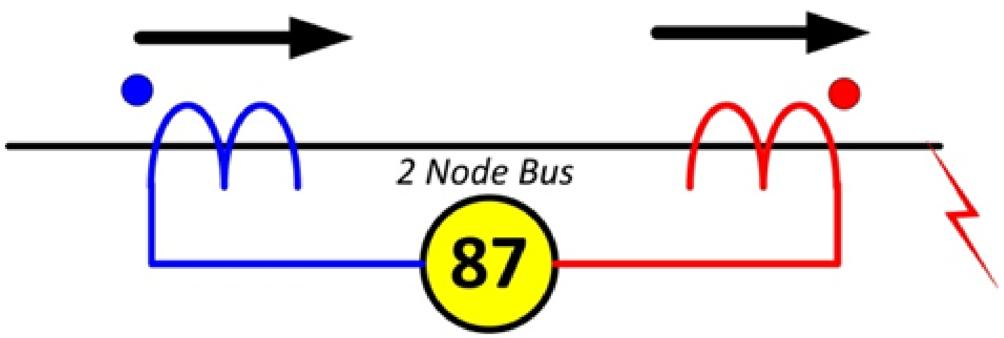
- Remnant Flux
  - Magnetization left behind in CT iron after an external magnetic field is removed
  - Caused by current interruption with DC offset
- High X/R Ratio
  - Increases the time constant of the CT saturation period
- CT saturation is increased by the above factors working alone or in combination with:
  - Large fault or through-fault current (causes high secondary CT voltage)

IEEE CT Saturation Calculator

- The IEEE Power System Relaying & Control Committee (PSRCC) developed a simplified model for CT saturation
  - Includes the major parameters that should be considered.
- Examples of saturation with a 2-node bus



Internal Fault

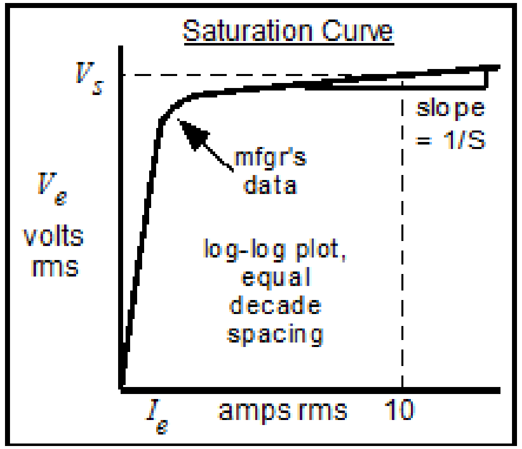


External Fault

CT Performance

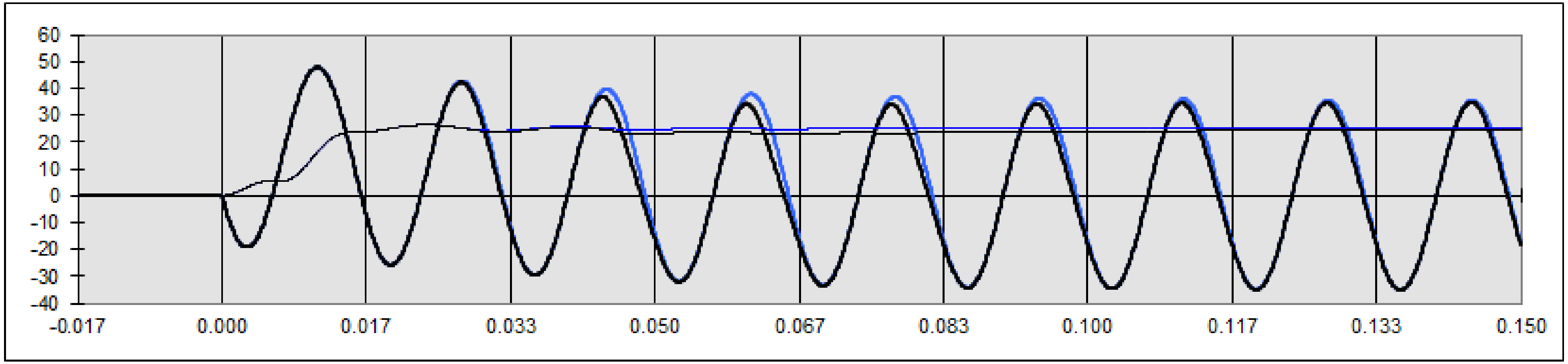
200:5, C200, R=0.5, Offset = 0.5, 1000A

INPUT PARAMETERS:		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	200	volts rms
Turns ratio = n2/1=	N =	40	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	1,000	amps rms



CALCULATED:			
Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	0.750	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	1.61E+04	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

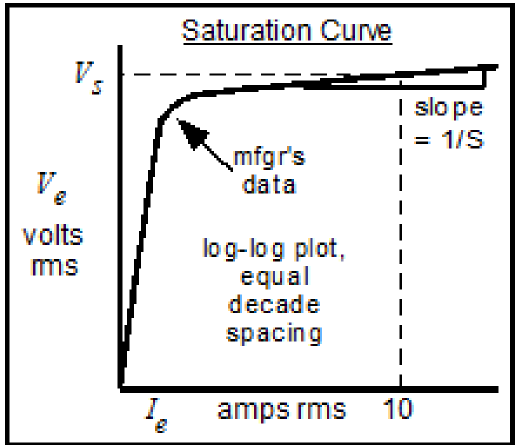
Thick lines: **Ideal (blue)** and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: **Ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



CT Performance

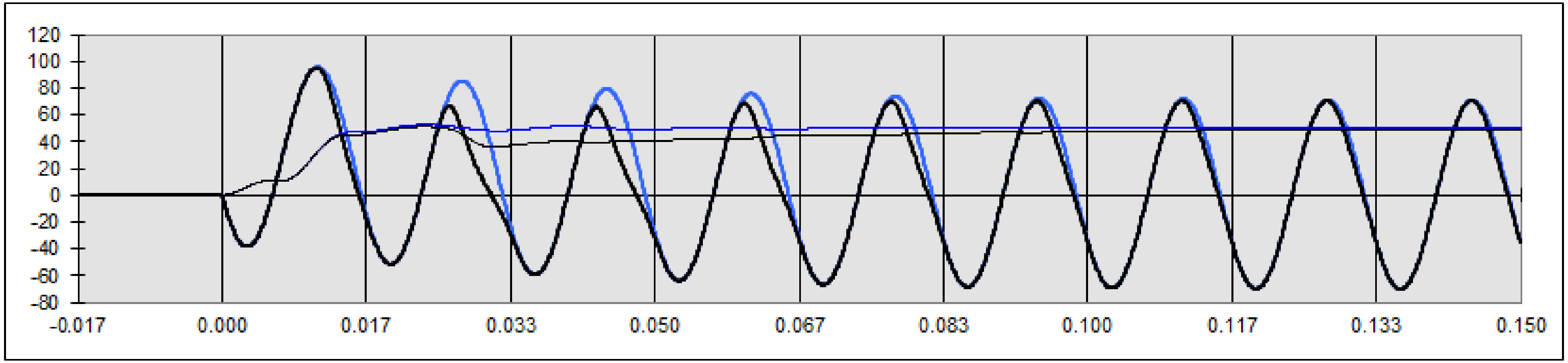
200:5, C200, R=0.5, Offset = 0.5, 2000A

INPUT PARAMETERS:		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	200	volts rms
Turns ratio = n2/1=	N =	40	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	2,000	amps rms



CALCULATED:			
Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	0.750	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	1.61E+04	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

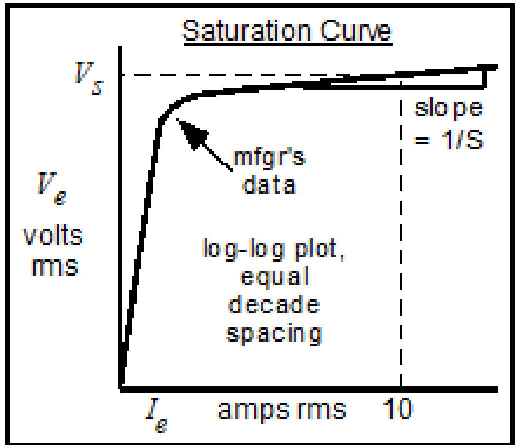
Thick lines: **Ideal (blue)** and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: **Ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



CT Performance

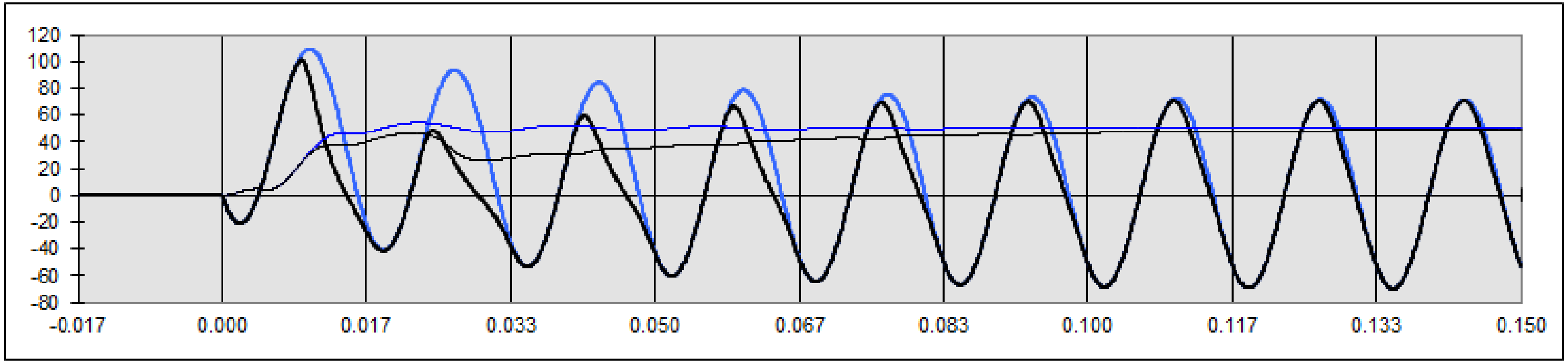
200:5, C200, R=0.5, Offset = 0.75, 2000A

INPUT PARAMETERS:		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	200	volts rms
Turns ratio = n2/1=	N =	40	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	2,000	amps rms



CALCULATED:			
Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	0.750	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	1.61E+04	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

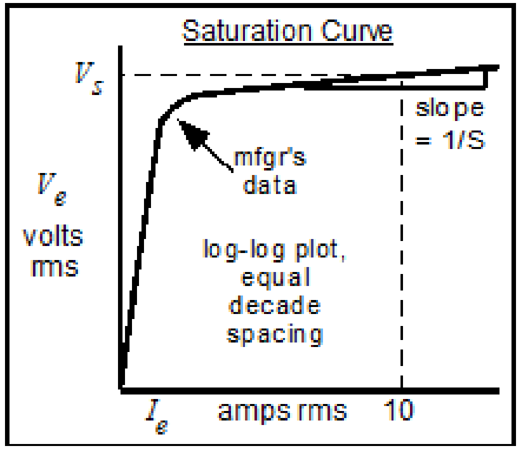
Thick lines: **Ideal (blue)** and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: **Ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



CT Performance

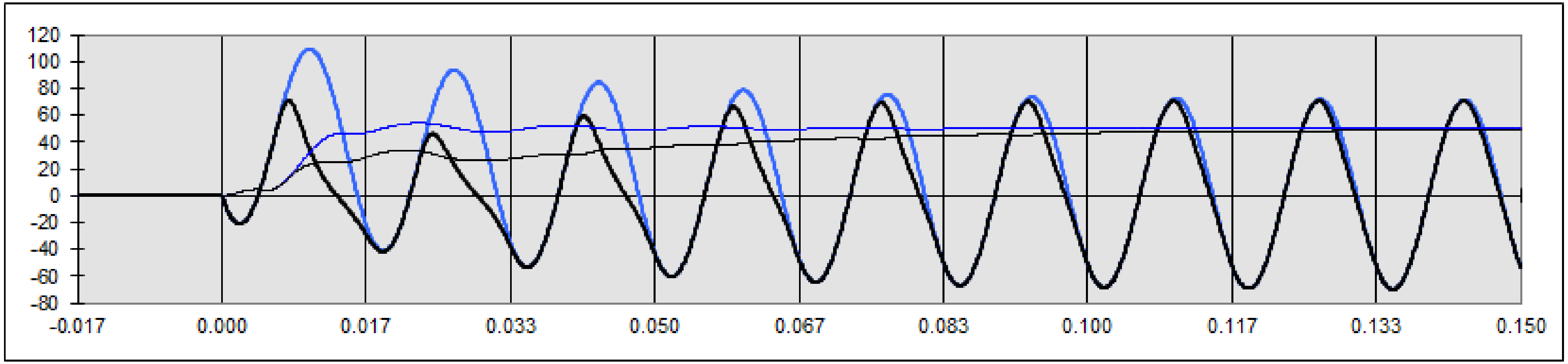
200:5, C200, R=0.75, Offset = 0.75, 2000A

INPUT PARAMETERS:		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	200	volts rms
Turns ratio = n2/1=	N =	40	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.75	---
Symmetrical primary fault current =	Ip =	2,000	amps rms



CALCULATED:			
Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	0.750	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	1.61E+04	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

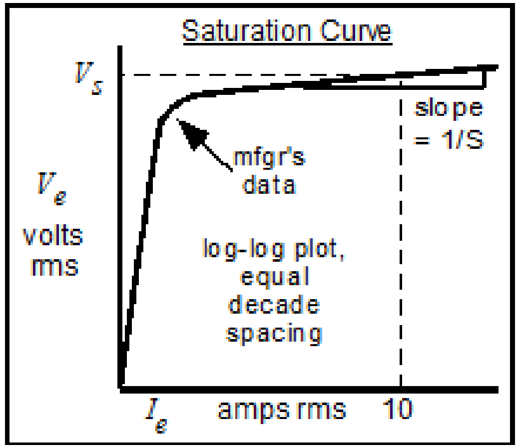
Thick lines: Ideal (blue) and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



CT Performance

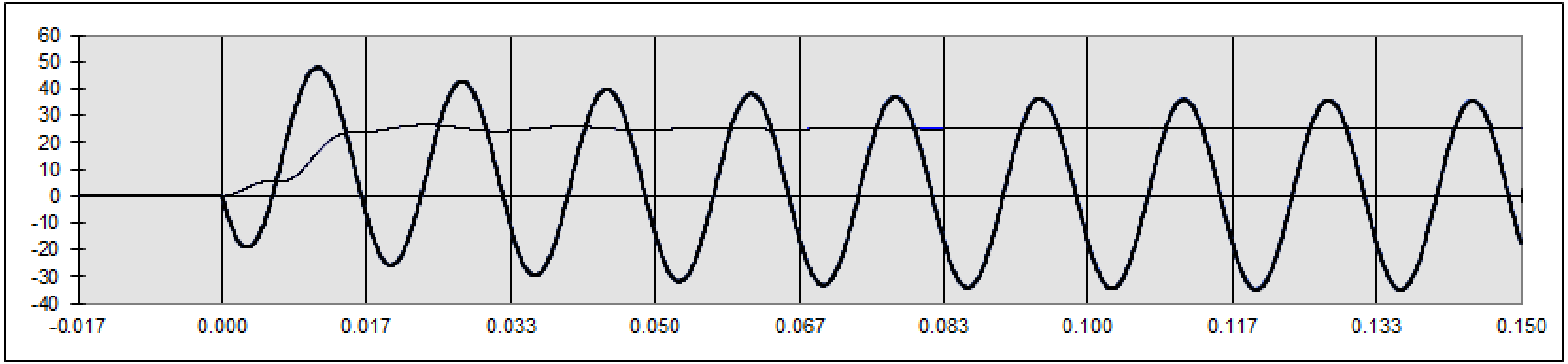
400:5, C400, R=0.5, Offset = 0.5, 2000A

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



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

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

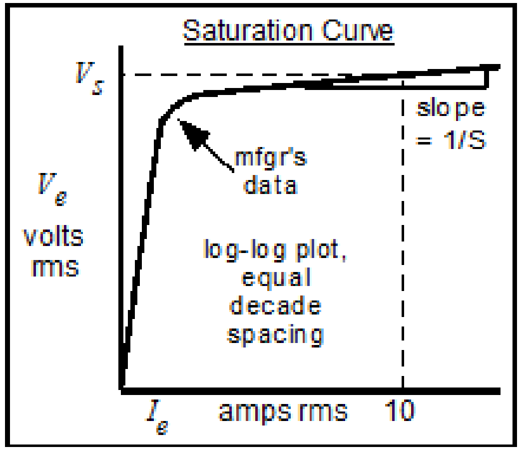


CT Performance

400:5, C400, R=0.5, Offset = 0.5, 4000A

INPUT PARAMETERS:

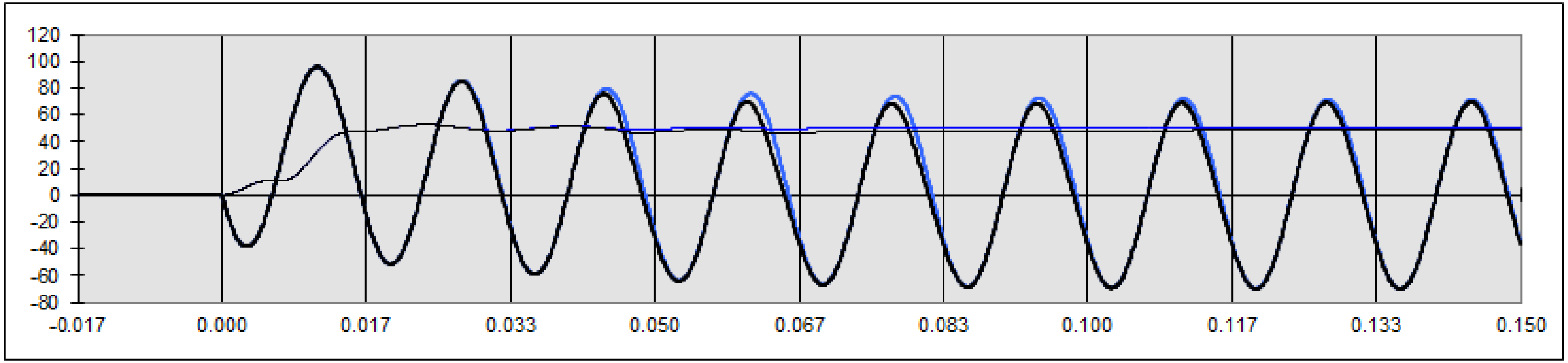
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	4,000	amps rms



CALCULATED:

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

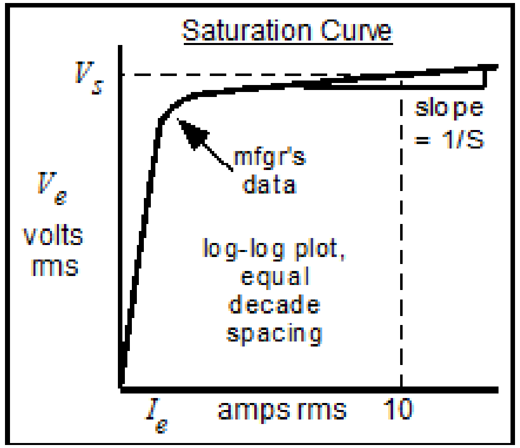
Thick lines: Ideal (blue) and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



CT Performance

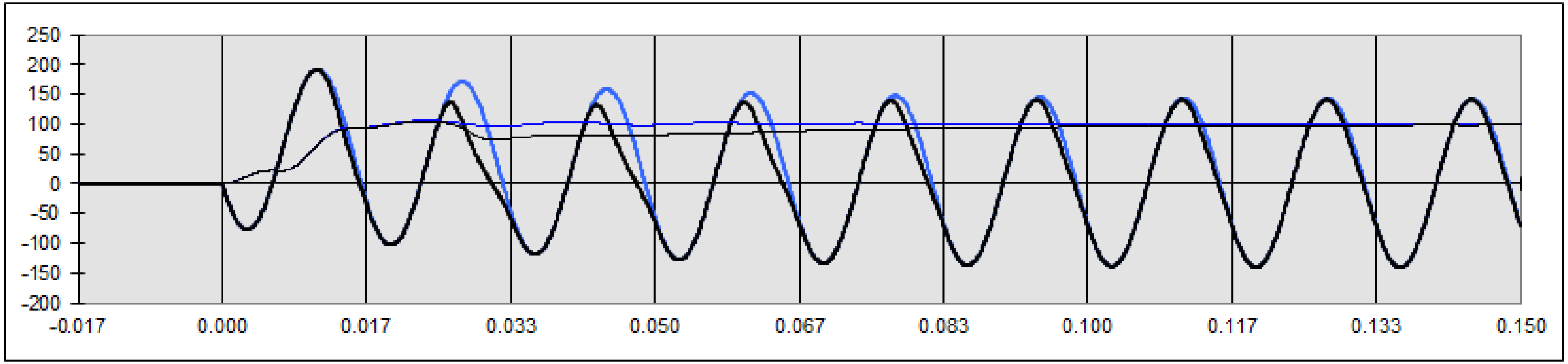
400:5, C400, R=0.5, Offset = 0.5, 8000A

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



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

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

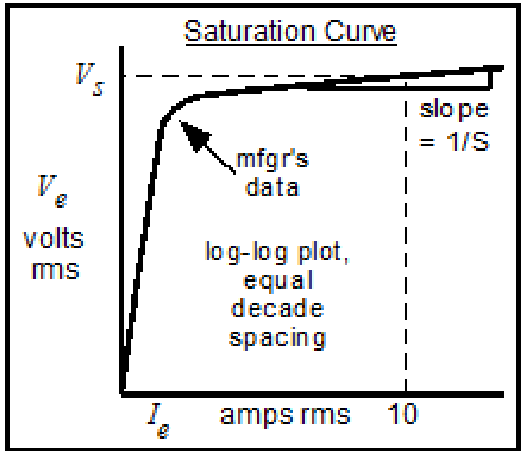


CT Performance

400:5, C400, R=0.5, Offset = 0.75, 8000A

INPUT PARAMETERS:

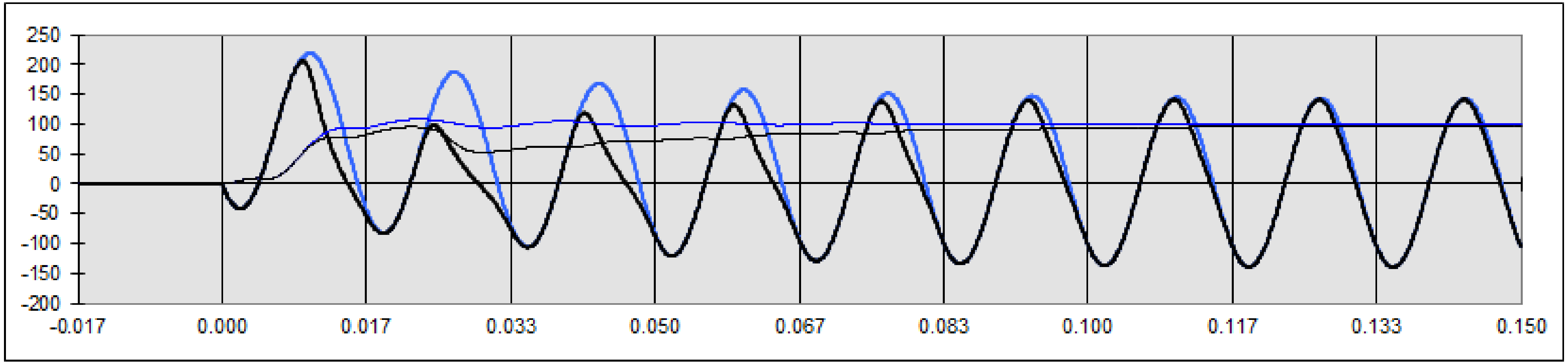
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	8,000	amps rms



CALCULATED:

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

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

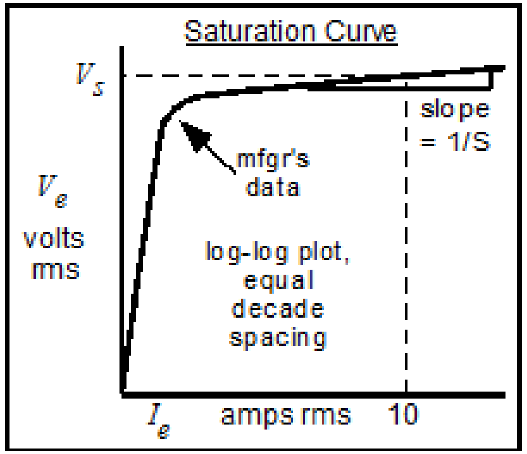


CT Performance

400:5, C400, R=0.75, Offset = 0.75, 8000A

INPUT PARAMETERS:

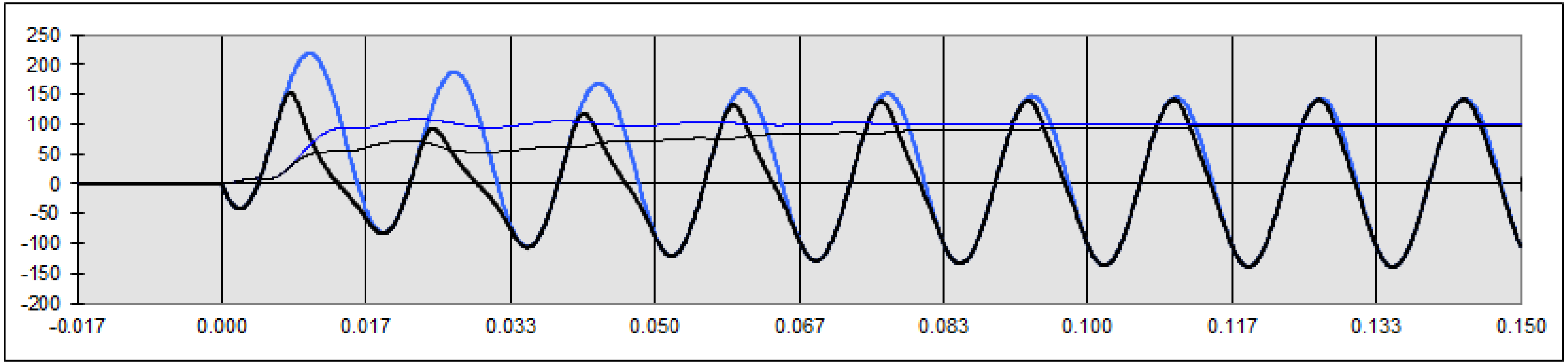
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.75	---
Symmetrical primary fault current =	Ip =	8,000	amps rms



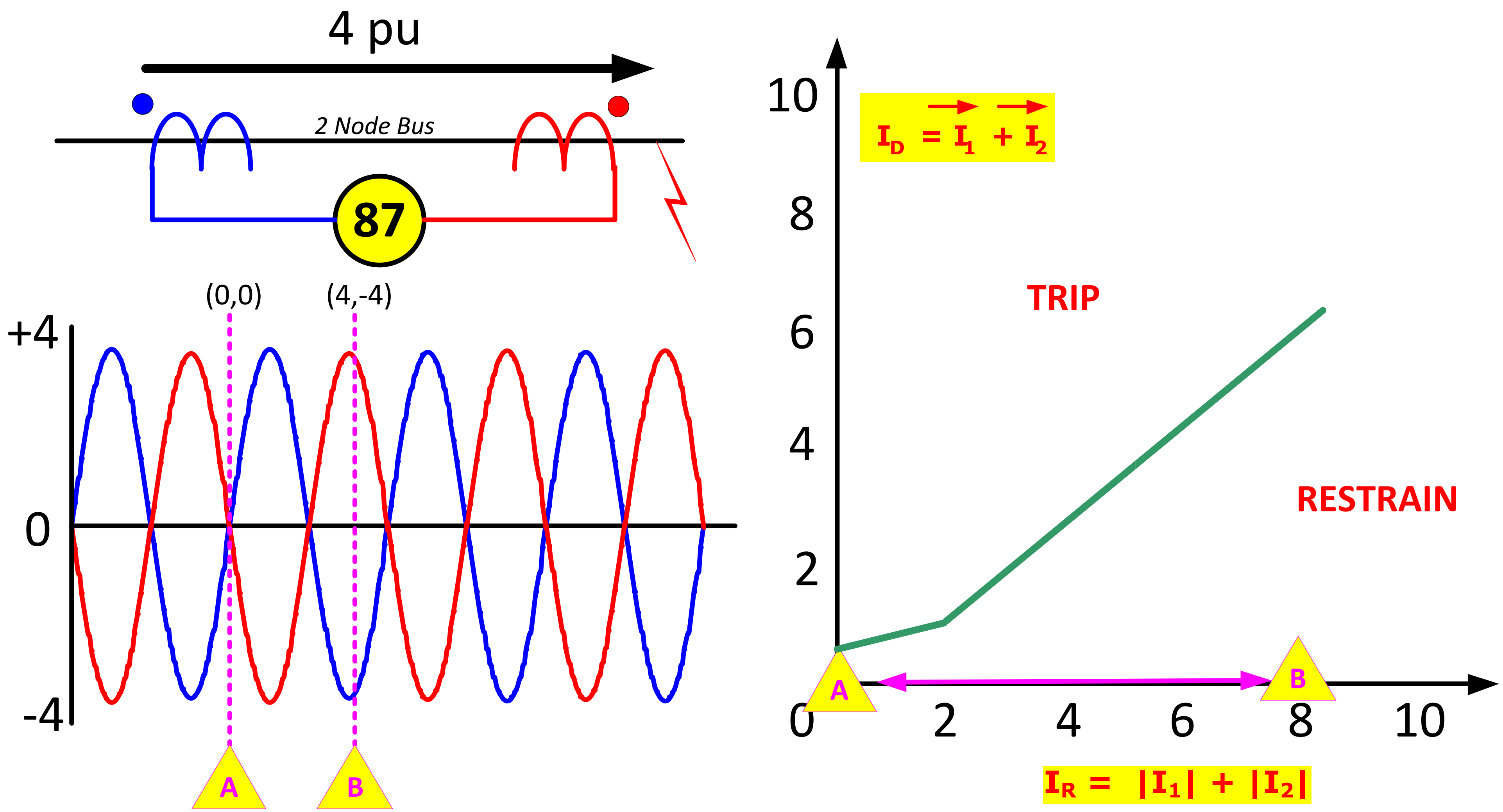
CALCULATED:

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

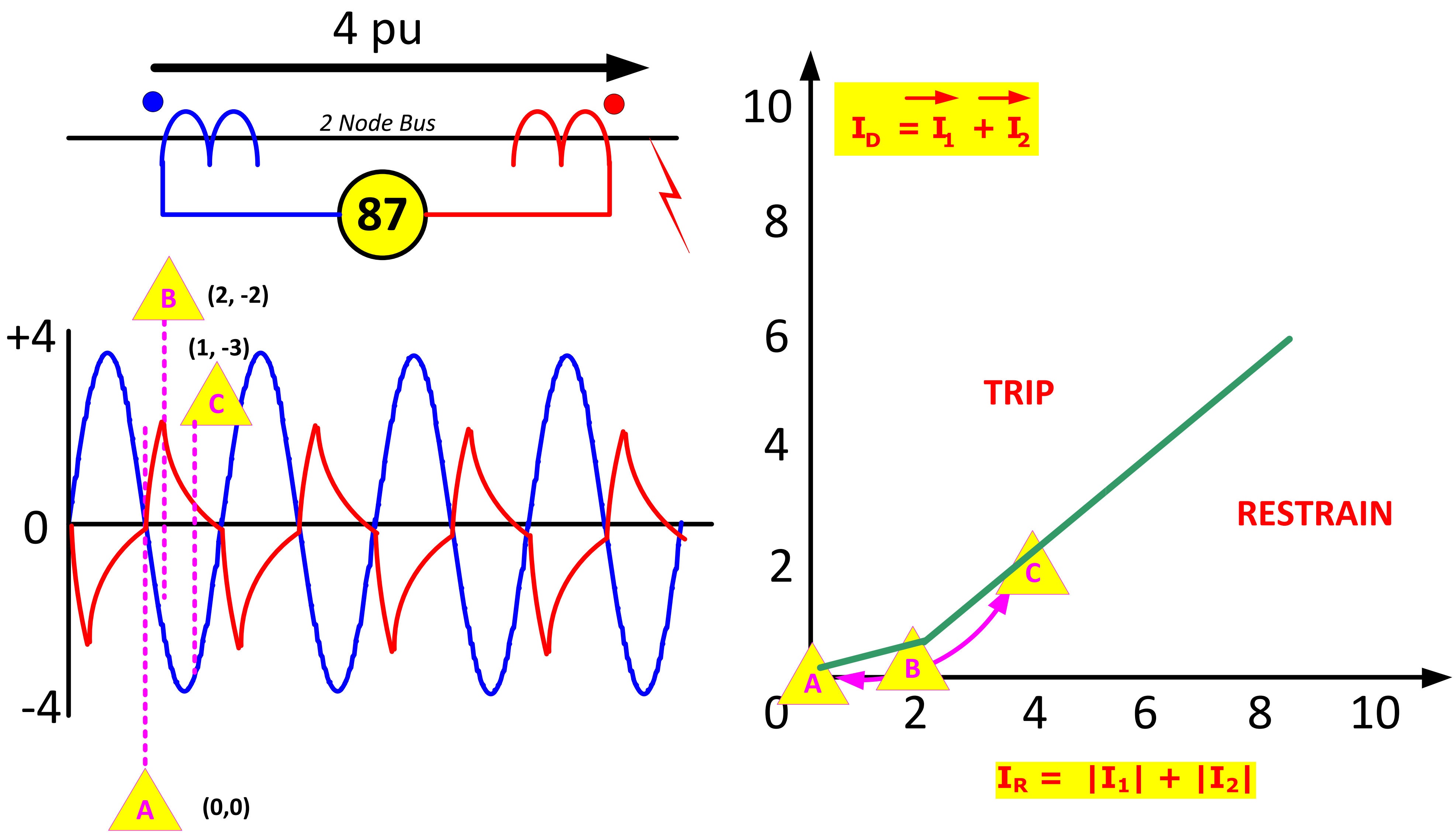
Thick lines: Ideal (blue) and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



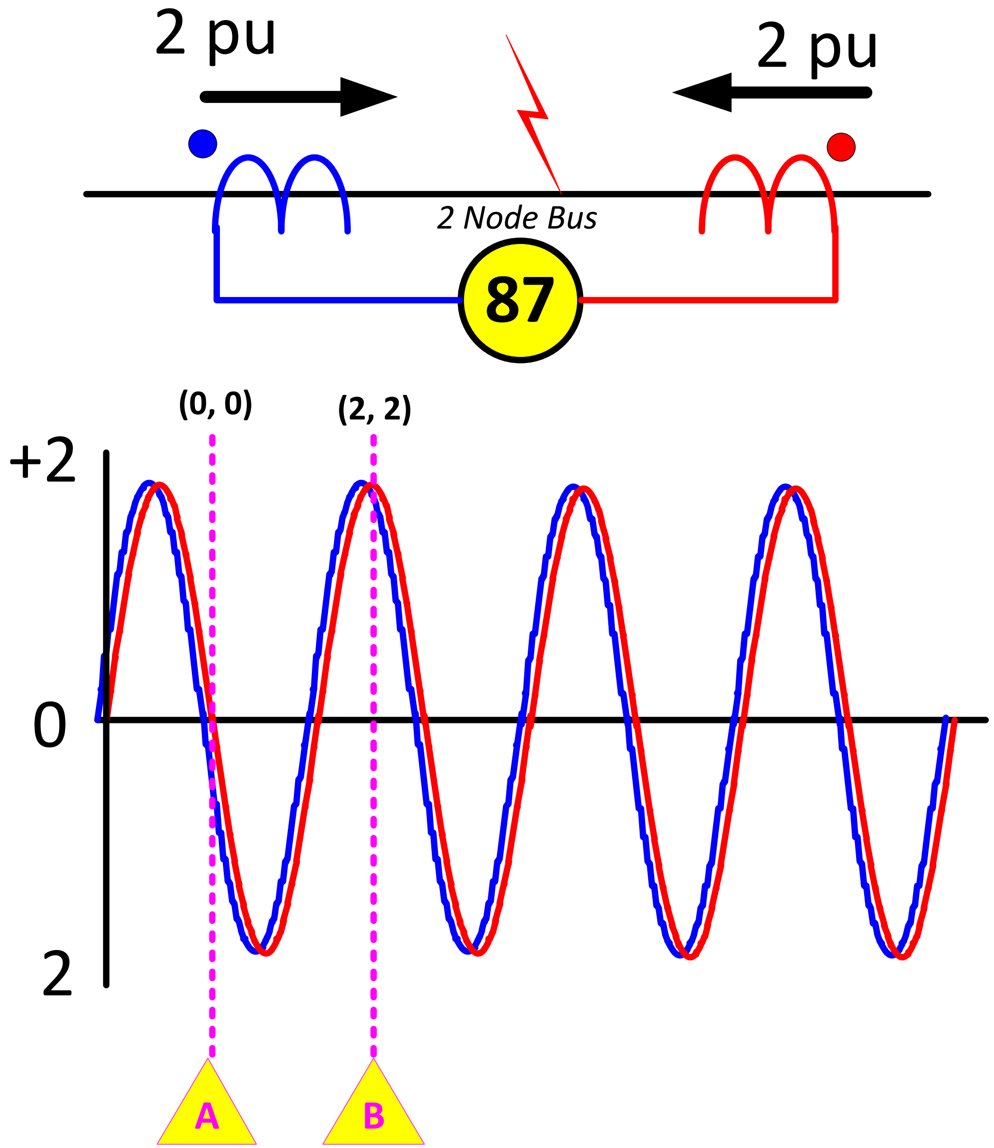
Through Current: Perfect Replication

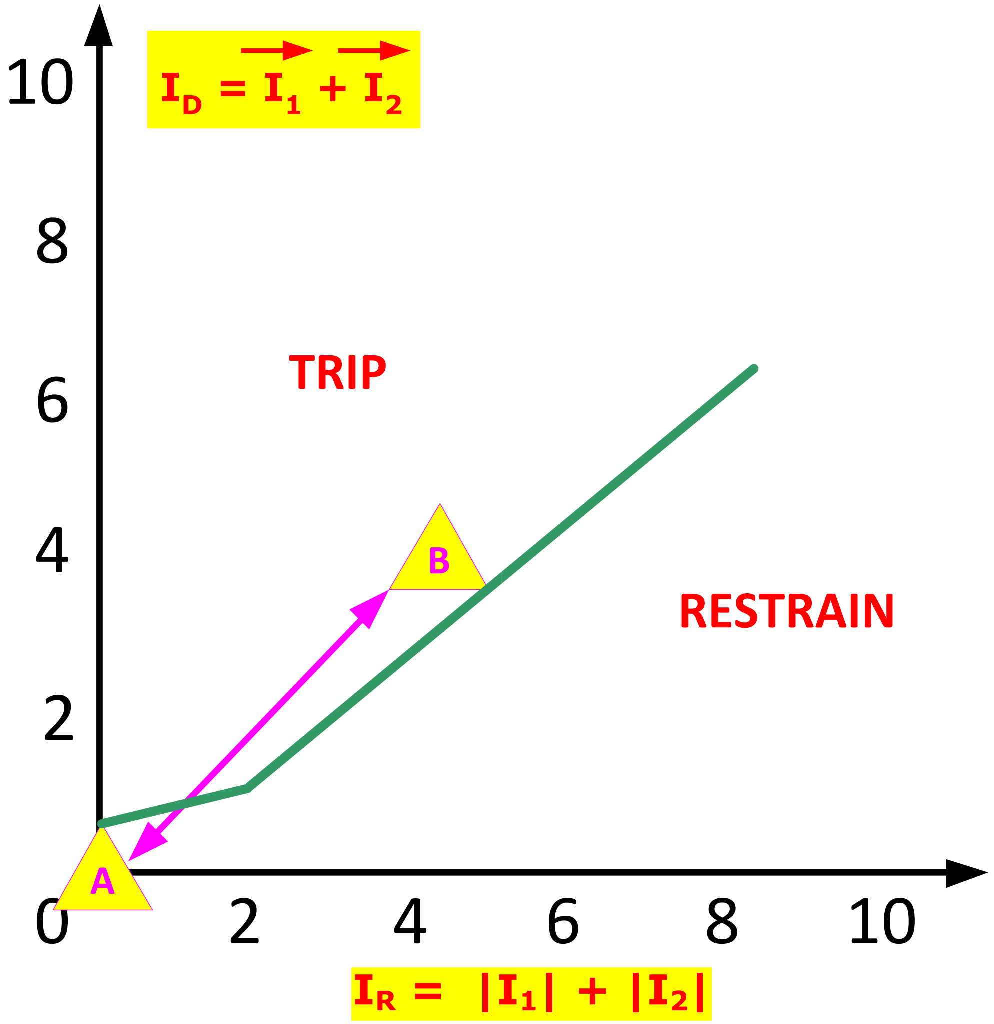


Through Current: Imperfect Replication

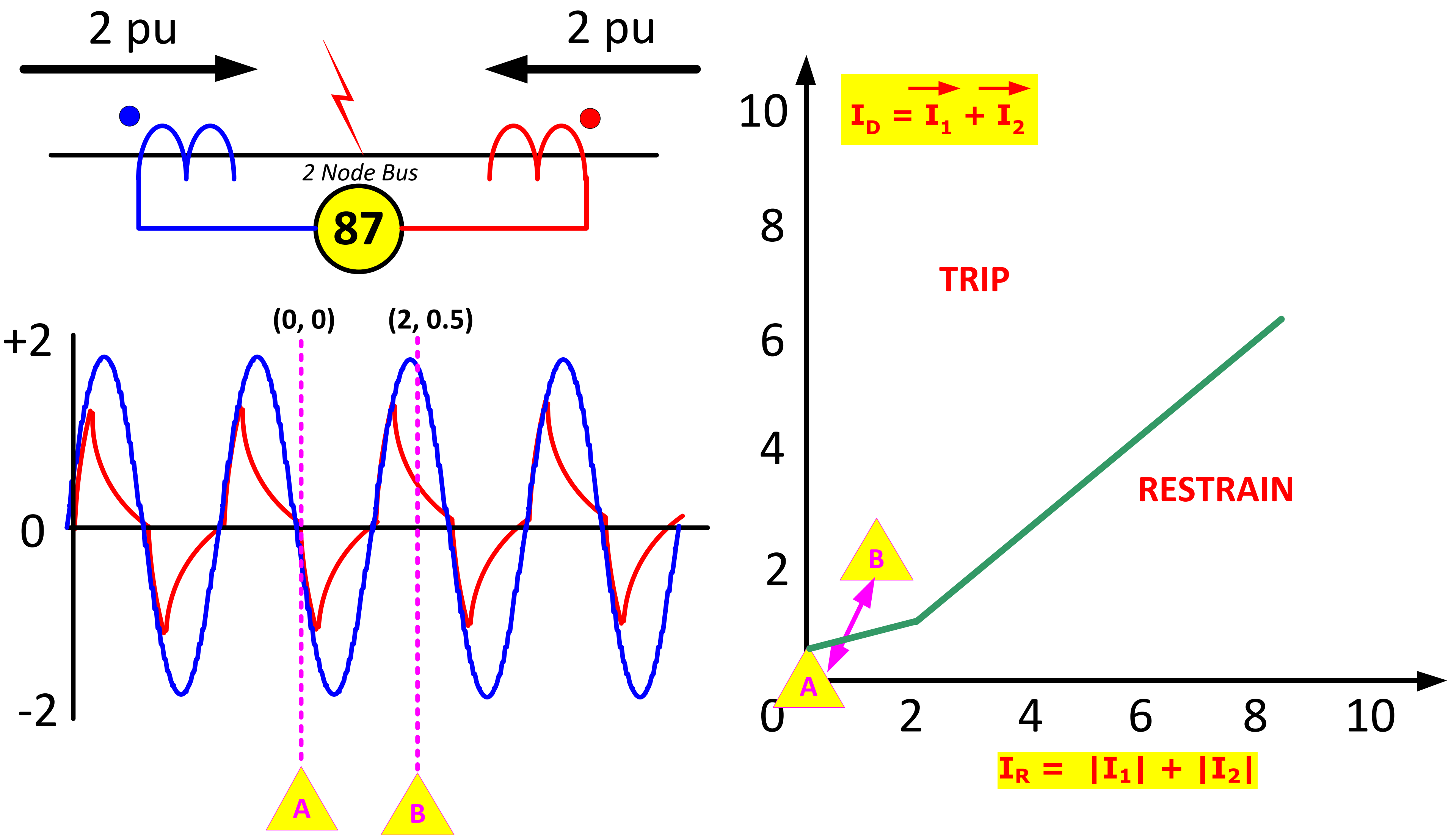


Internal Fault: Perfect Replication





Internal Fault: Imperfect Replication



CT Issues

- Best defense is to use high “Class C” voltage levels
  - C400, C800
  - These have superior characteristics against saturation and relay/wiring burden
- Use low burden relays
  - Digital systems are typically 0.020 ohms
- Use a variable percentage slope characteristic to desensitize the differential element when challenged by high currents that may cause replication errors

Differential Element Quantities

- Restraining versus Operating

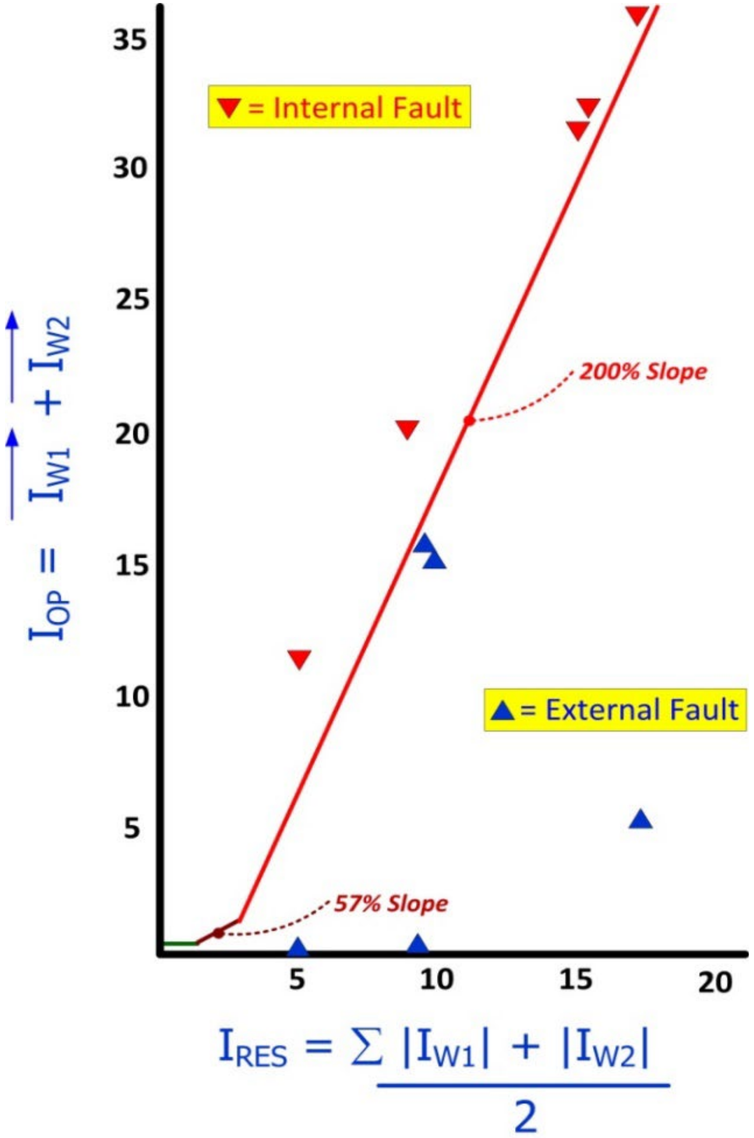
$$I_{RES} = \frac{\sum |I_{W1}| + |I_{W2}|}{2} \qquad I_{OP} = \overrightarrow{I_{W1}} + \overrightarrow{I_{W2}}$$

- Assumptions
  - Rated current (full load): 400A = 1 pu
  - Maximum through or internal fault current = 20X rated = 20pu

Fig	Rated I	Test I	Rated/Test (pu)	% Diff (max)	EXT Op	EXT Res	INT Op	INT Res
2	400	2000	5	0	0	5	11	5
3	400	4000	10	5	0.5	9.75	20.5	9.75
4	400	8000	20	25	5	17.5	36	17.5
5	400	8000	20	45	9	15.5	32	15.5
6	400	8000	20	50	10	15	31	15

Characteristic & Values Plot

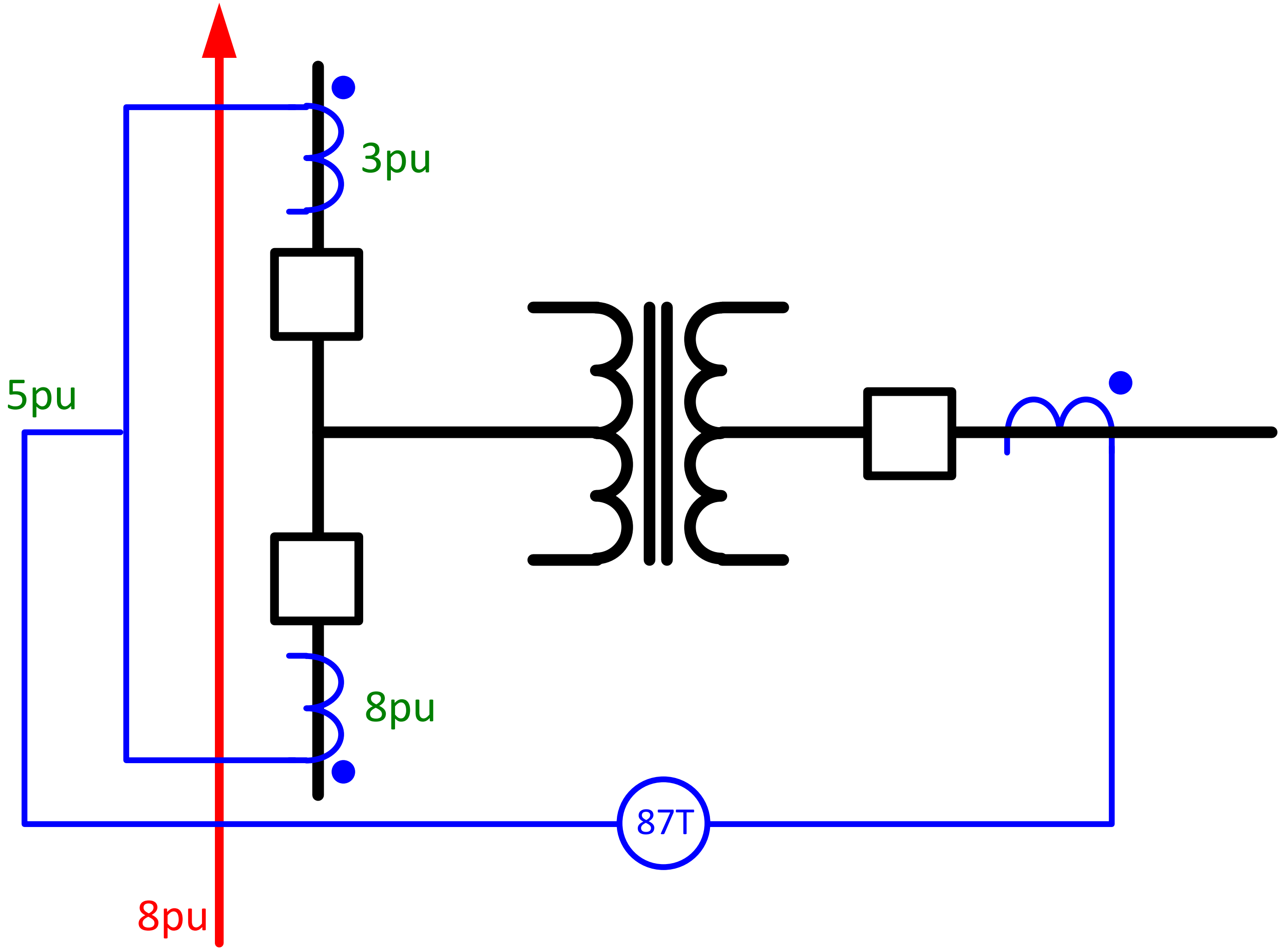
- Pick Up: 0.35pu
- Slope 1 Breakpoint: 1.5pu
- Slope 1: 57%
- Slope 2 Breakpoint: 3.0pu
- Slope 2: 200%
- Relay elements from different manufacturers use different restraining and operating calculations
- Careful evaluation is recommended



Modeled Test Plots

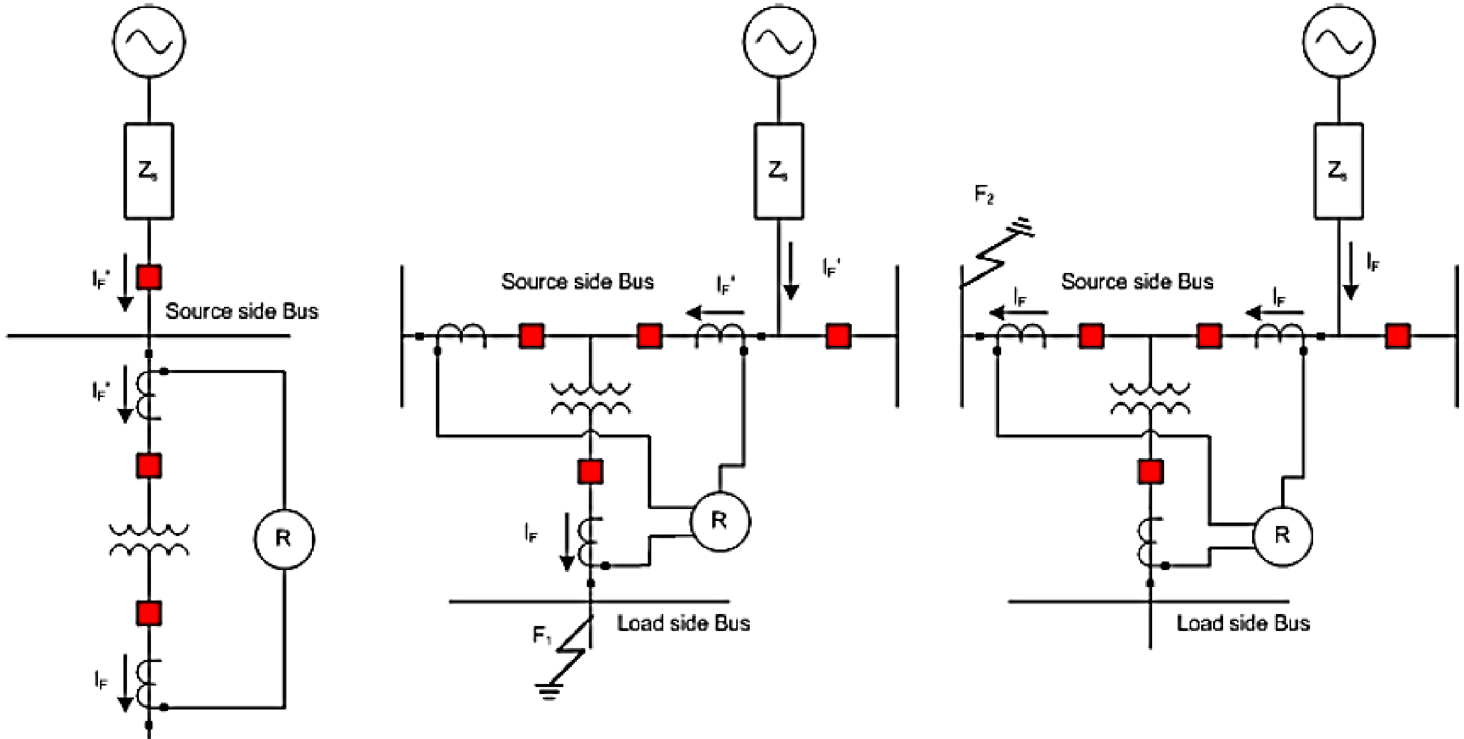
Application Considerations: Paralleling Sources

- When paralleling sources for differential protection, beware!
- Paralleled sources (not loads, specifically sources) have different saturation characteristics and present the differential element input with corrupt values
  - Consider through-fault on bus section
  - One CT saturates, the other does not
  - Result: Input is presented with "false difference" due to combining of CTs from different sources outside of relay



Differential Element Security Challenge

- The problem with external faults is the possibility of CT saturation making an external fault “look” internal to the differential relay element



(a) Source side and load side buses are single bus arrangements

(b) Source side bus is a breaker and a half scheme and the load side bus is a single bus arrangements

Note 1: CTs for the transformer differential only are shown in this figure

Note 2: Load currents are ignored in this figure

(c) Source side bus is a breaker and a half scheme and the load side bus is a single bus arrangements

Note 1: CTs for the transformer differential only are shown in this figure

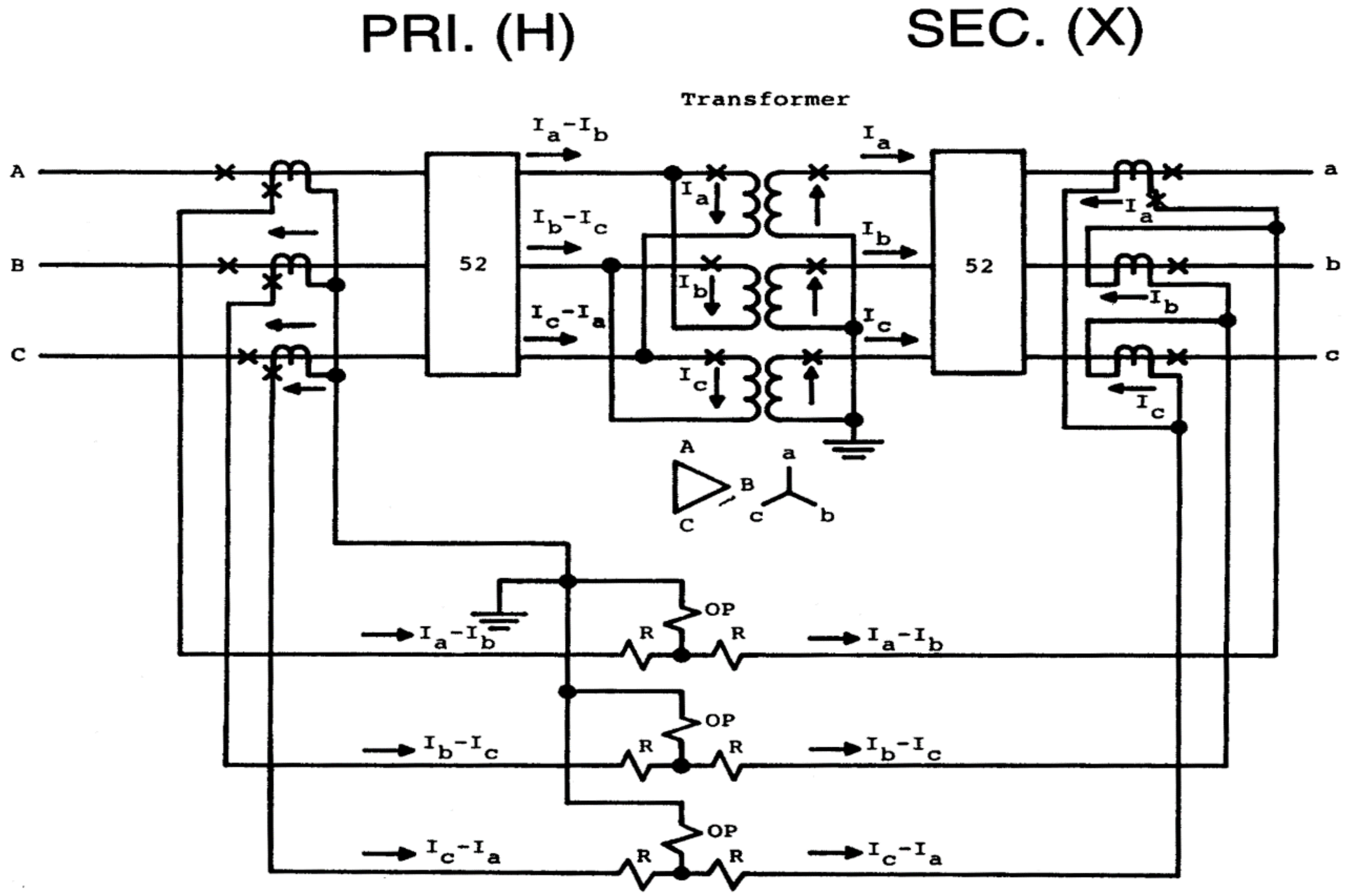
Note 2: Load currents are ignored in this figure

R This may be a differential or overcurrent relay

Classical Differential Compensation

- CT ratios must be selected to account for:
  - Transformer ratios
  - If delta or wye connected CTs are applied
  - Delta increases ratio by 1.73
- Delta CTs must be used to filter zero-sequence current on wye transformer windings

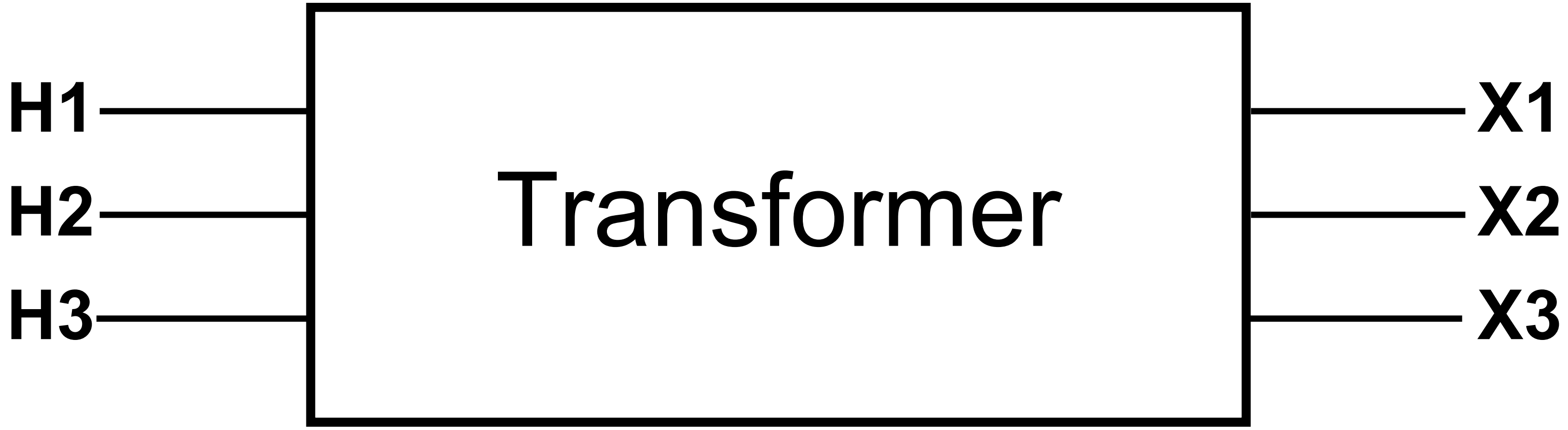
Classical Differential Compensation



“Dab” as polarity of “A” connected to non-polarity of “B”

Bushing Nomenclature

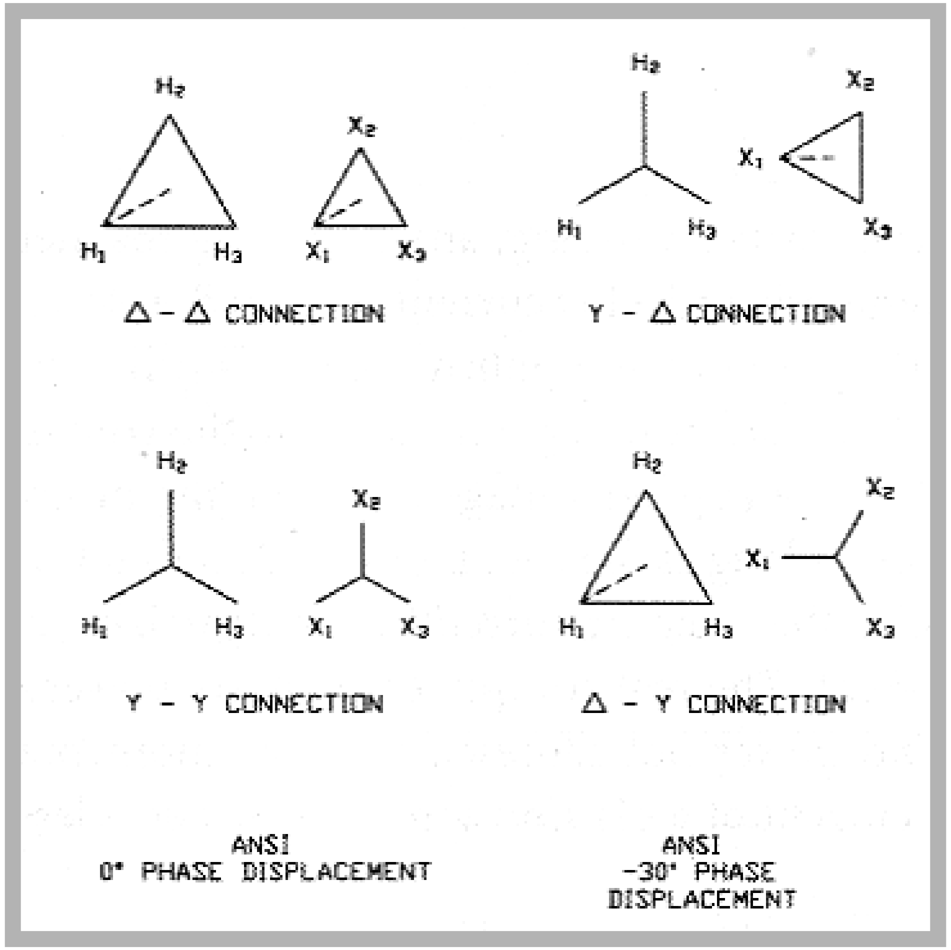
- H1, H2, H3
  - Primary Bushings
- X1, X2, X3
  - Secondary Bushings



Wye-Wye	H1 and X1 at zero degrees
Delta-Delta	H1 and X1 at zero degrees
Delta-Wye	H1 lead X1 by 30 degrees
Wye-Delta	H1 lead X1 by 30 degrees

ANSI Standard

Angular Displacement



- ANSI Y-Y & Δ-Δ @ 0°
- ANSI Y-Δ & Δ-Y @ H1 lead X1 by 30° ***or*** X1 lag H1 by 30°

Winding Types and Impacts

Wye-Wye

- Cheaper than 2 winding if autobank
- Conduct zero-sequence between circuits
- Provides ground source for secondary circuit

Delta-Delta

- Blocks zero-sequence between circuits
- Does not provide a ground source

Delta-Wye

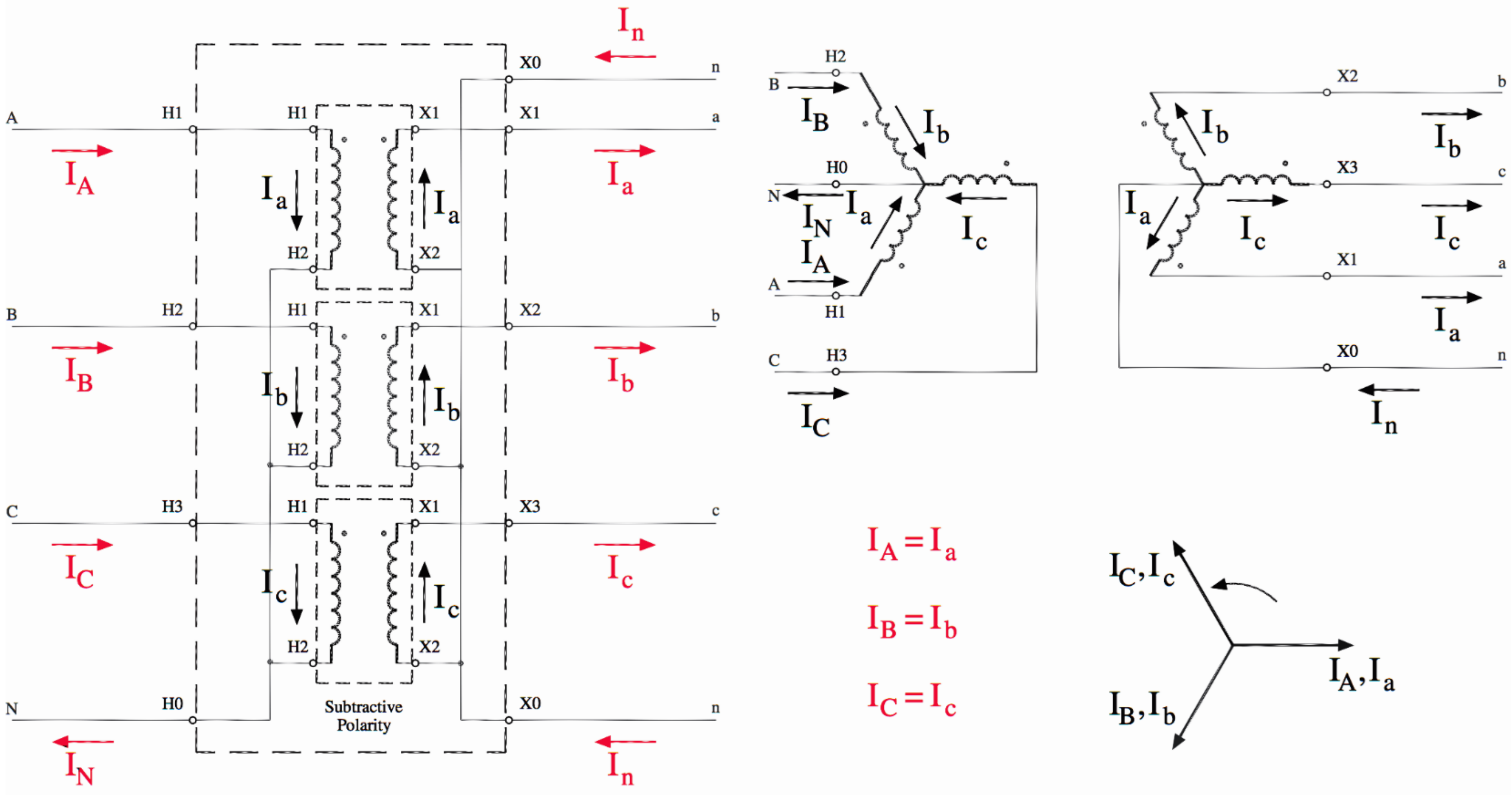
- Blocks zero-sequence between circuits
- Provides ground source for secondary circuit

Wye-Delta

- Blocks zero-sequence between circuits
- Does not provide a ground source for secondary circuit

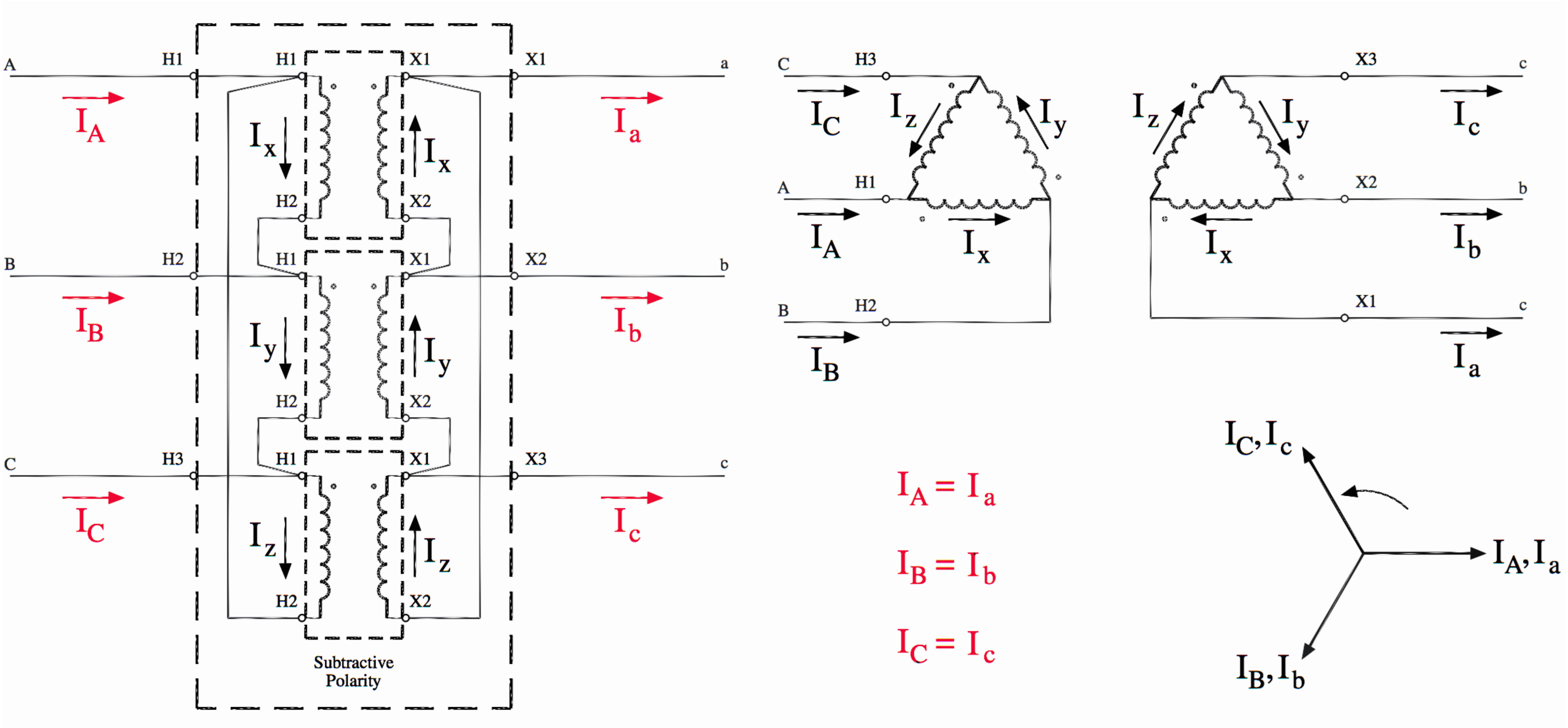
Winding Types

- Wye-Wve



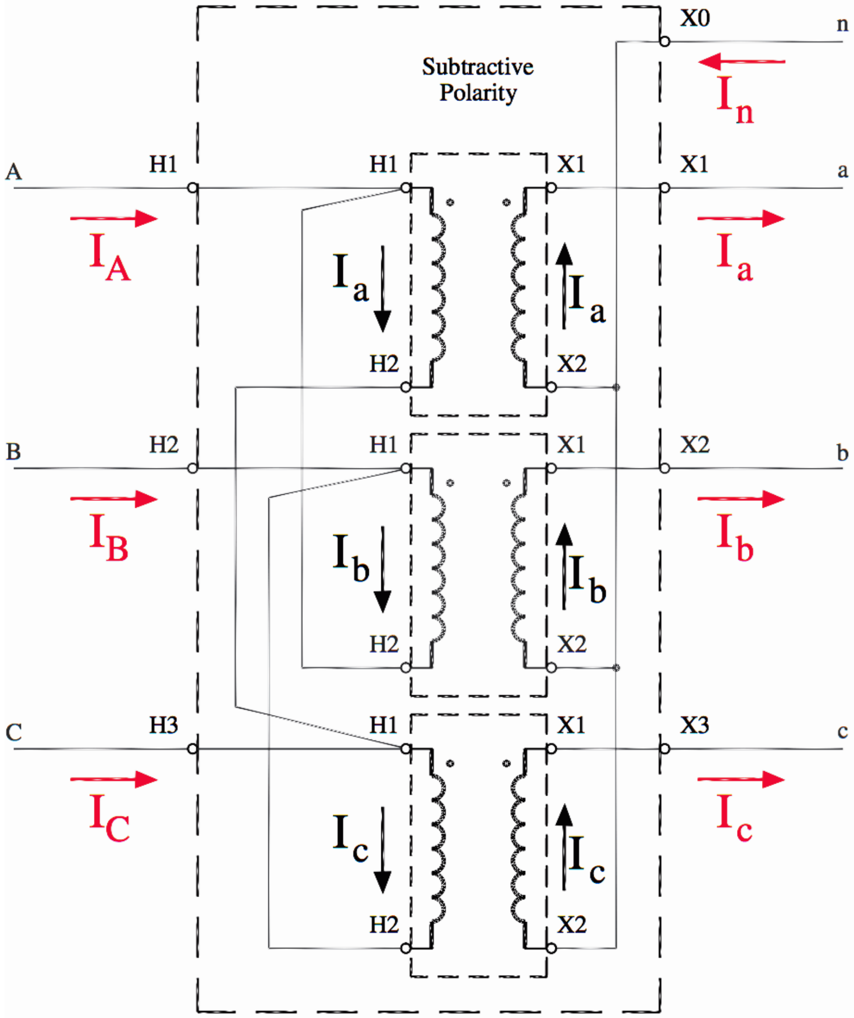
Winding Types

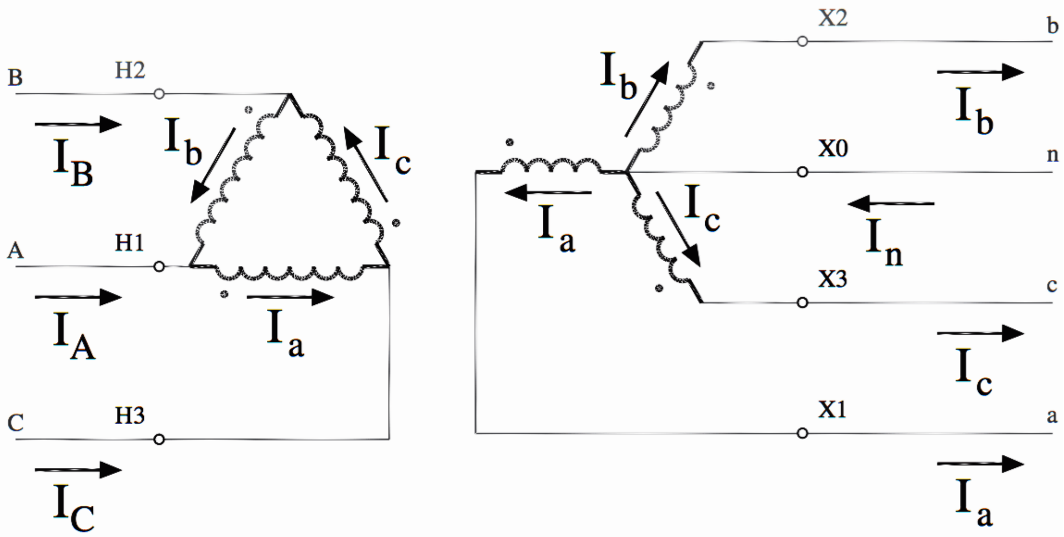
- Delta-Delta



Winding Types

- Delta-Wye

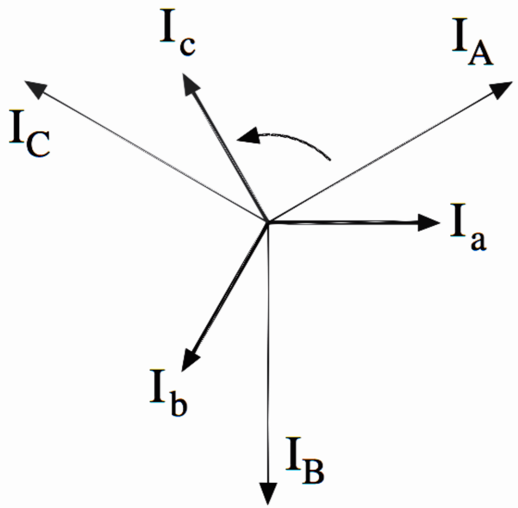




$$I_A = I_a - I_b = I_a \times \sqrt{3} \angle 30°$$

$$I_B = I_b - I_c = I_b \times \sqrt{3} \angle 30°$$

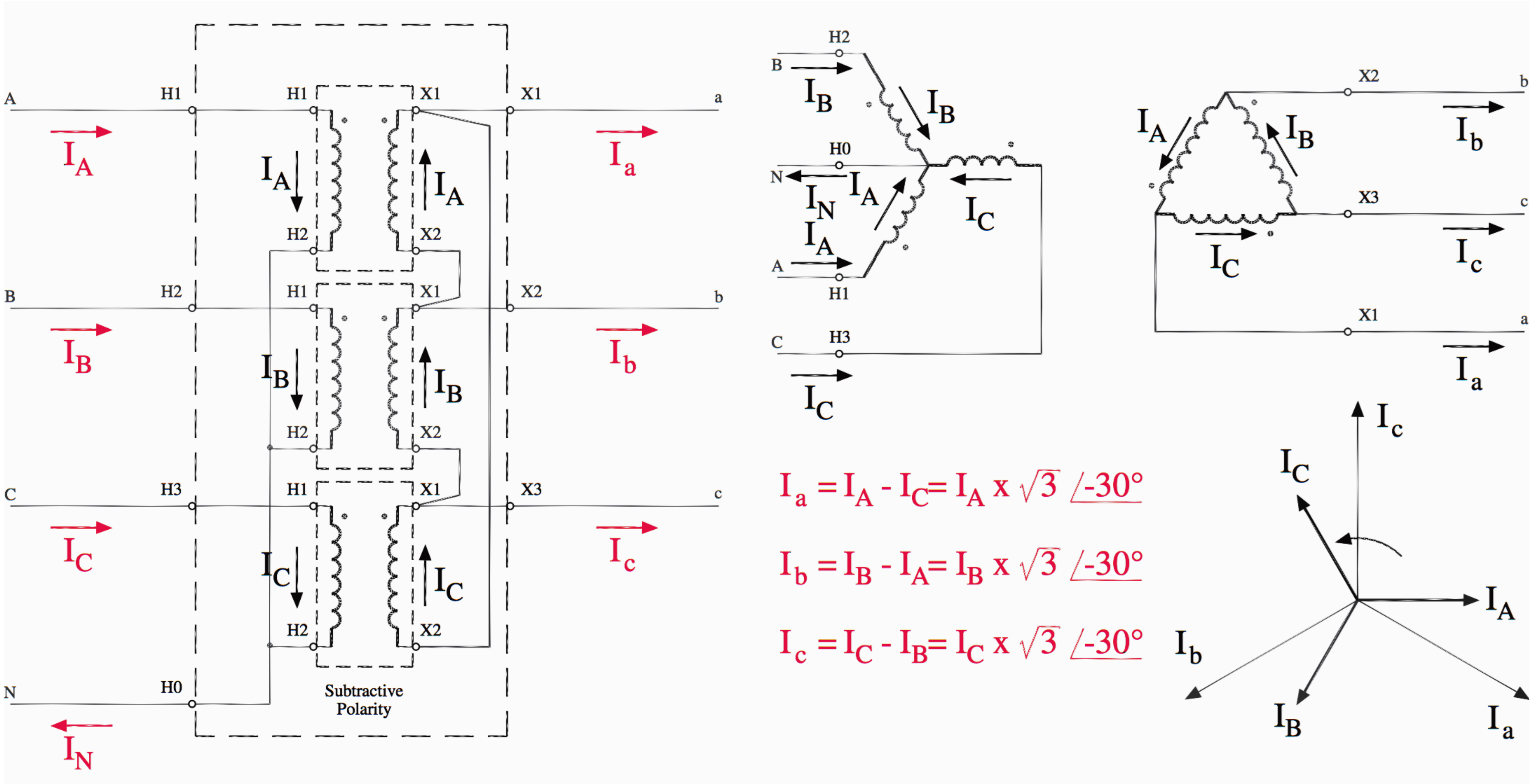
$$I_C = I_c - I_a = I_c \times \sqrt{3} \angle 30°$$



Industrial Power Distribution

Winding Types

- Wye-Delta



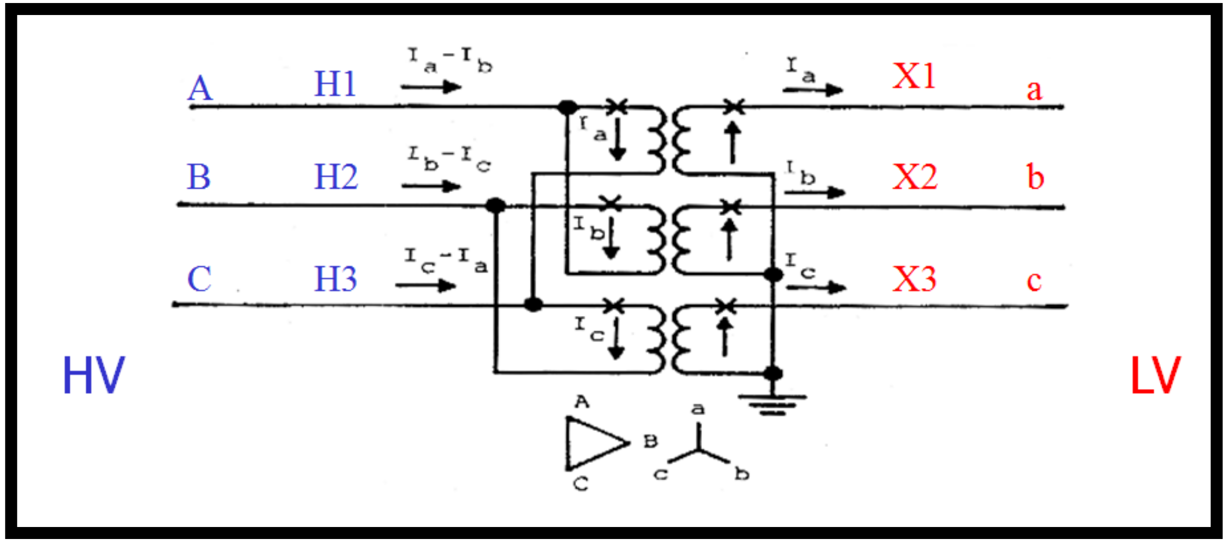
Industrial Power Distribution

Compensation in Digital Relays

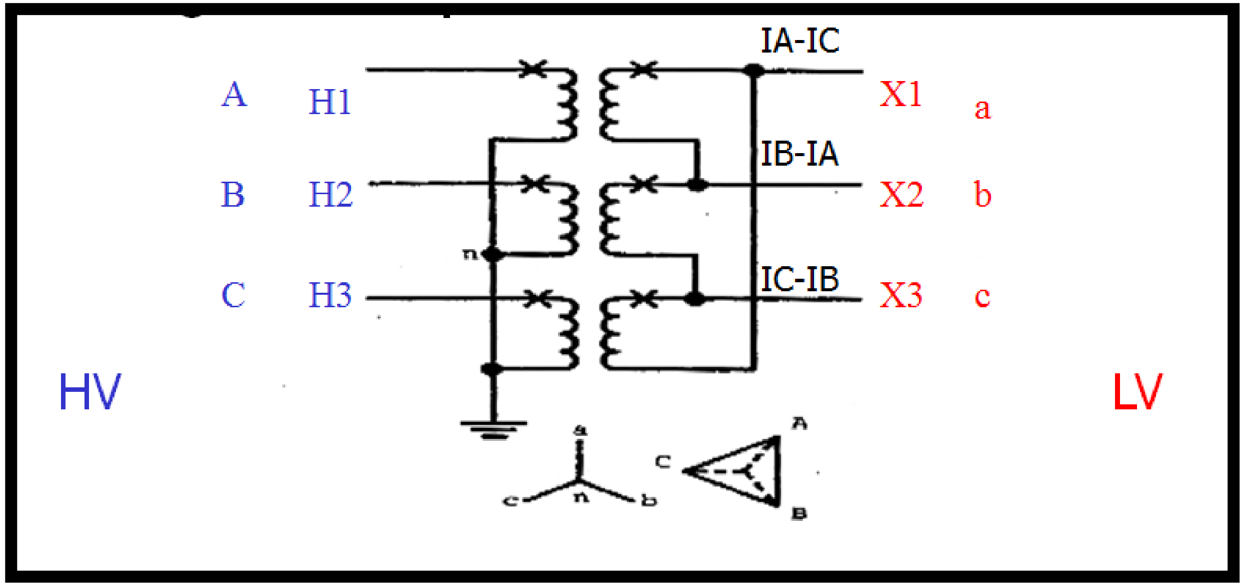
- Transformer ratio
- CT ratio
- Phase angle shift and √3 factor due to delta/wye connection
- Zero-sequence current filtering for wye windings so the differential quantities do not occur from external ground faults

Phase Angle Compensation in Numerical Relays

- Phase angle shift due to transformer connection in electromechanical and static relays is accomplished using appropriate connection of the CTs
- The phase angle shift in Numerical Relays can be compensated in software for any transformer with zero or 30° increments
- All CTs may be connected in WYE which allows the same CTs to be used for both metering and backup overcurrent functions
- Some numerical relays will allow for delta CTs to accommodate legacy upgrade applications



- Delta High Side, Wye Low Side
- High Lead Low by 30°
- Delta-Wye
- Delta (ab)
- Dy1
  - Dyn1



- Wye High Side, Delta Low Side
- High Lead Low by 30°
- Wye-Delta
- Delta (ac)
- Yd1
  - YNd1

Transformer Connection Bushing Nomenclature

IEC Connection Description	Symbol	Description	Symbol	Input Value	Symbol
Yy0		YY		Y Y 0 0	
Dd0		Dac Dac		Dac Dac 1 1	
Yd1		Y Dac		Y Dac 0 1	
Yd11		Y Dab		Y Dab 0 11	
Dy1		Dab Y		Dab Y 11 0	
Dy11		Dac Y		Dac Y 1 0	
Yd5		Y Inverse Dab		Y Inverse Dab 0 5	
Dy5		Dac Inverse Y		Dac Inverse Y 1 5	
Dd10		Dac Dab		Dac Dab 1 11	
Dz2		Dab Custom		Dab Wye 11 1	

Y-Y ANSI

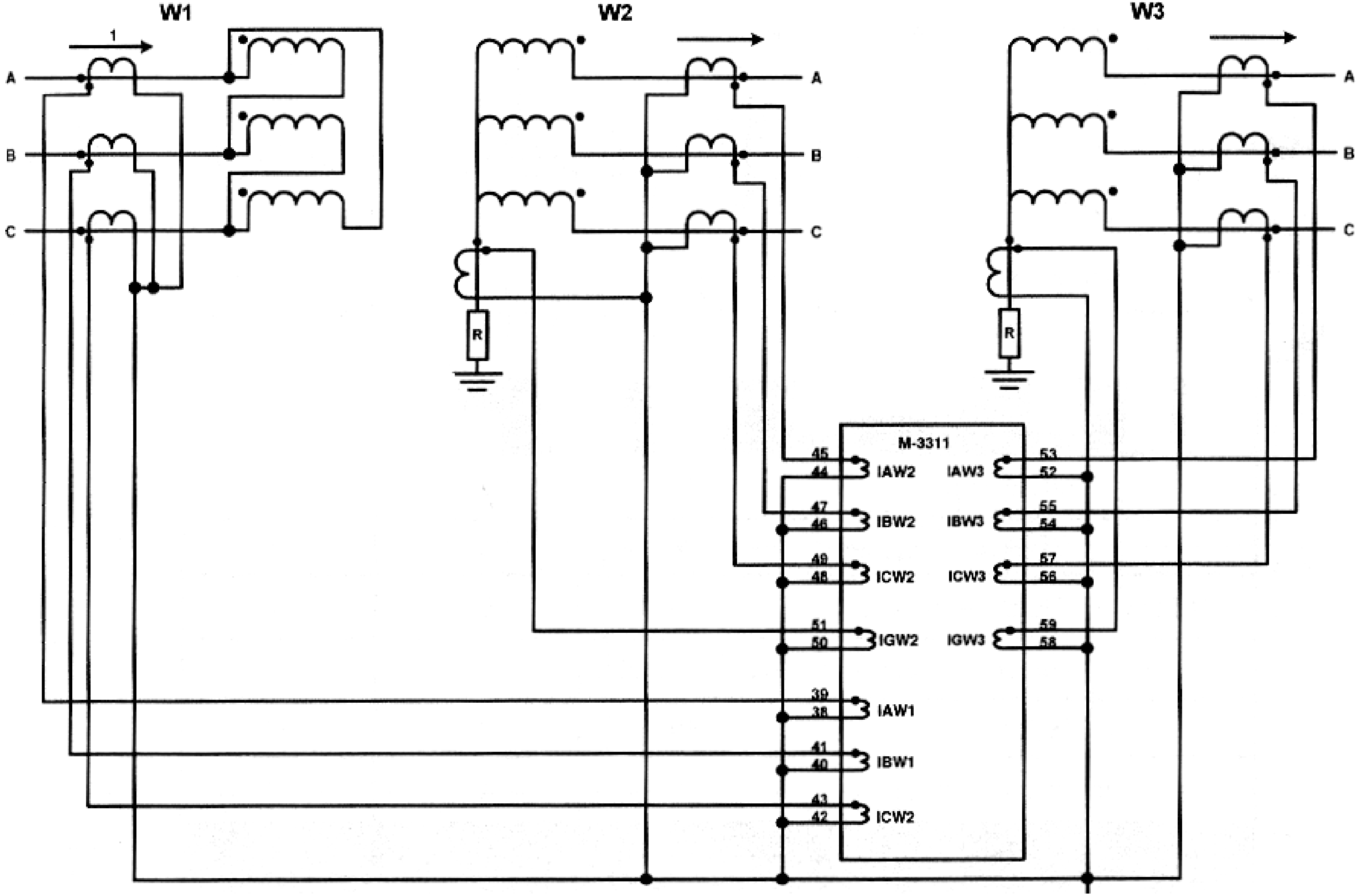
Δ-Δ ANSI

Y-Δ ANSI

Δ-Y ANSI

- ANSI follows “zero phase shift”, or “high lead low by 30°”
- IEC designations use “low lags high by increments of 30° phase shift
- IEC uses various phase shifts in 30 increments
  - 30, 60, 90, 180, etc.

Digital Relay Application



All WYE CTs shown

Benefits of Wye CTs

Phase segregated line currents

- Individual line current oscillography
- Currents may be easily used for overcurrent protection and metering
- Easier to commission and troubleshoot
- Zero sequence elimination performed by calculation

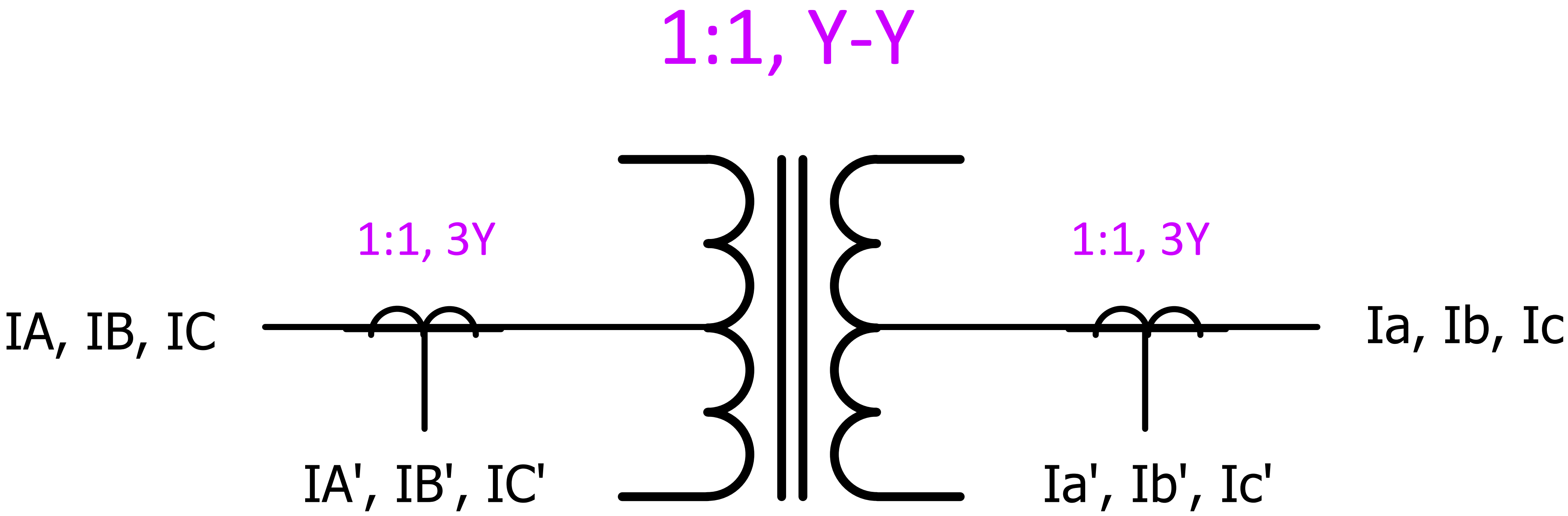
NOTE:

- For protection upgrade applications where one wants to keep the existing wiring, the relay must:
  - Accept either delta or wye CTs
  - For delta CTs, recalculate the phase currents for overcurrent functions

Application Adaptation

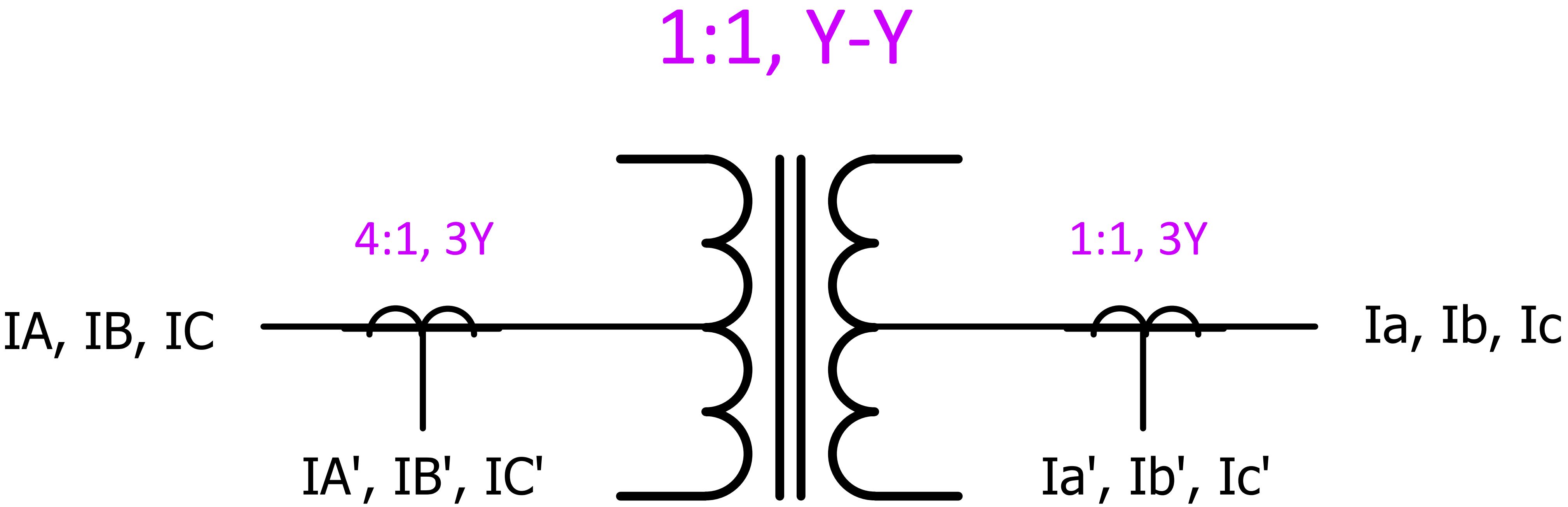
- Challenge: To be able to handle ANY combination of transformer winding arrangements and CT connection arrangements
- Strategy: Use a menu that contains EVERY possible combination
  - Set W1's transformer winding configuration and CT configuration
  - Set W2's transformer winding configuration and CT configuration
  - Set W3's transformer winding configuration and CT configuration
  - Set W4's transformer winding configuration and CT configuration
  - Standard or Custom Selection
    - Standard handles most arrangements, including all ANSI standard type
    - Custom allows any possible connections to be accommodated (Non-ANSI and legacy delta CTs)
  - Relay selects the proper currents to use, directly or by vector subtraction
  - Relay applies √3 factor if required
  - Relay applies zero sequence filtering if required

Compensation: Base Model



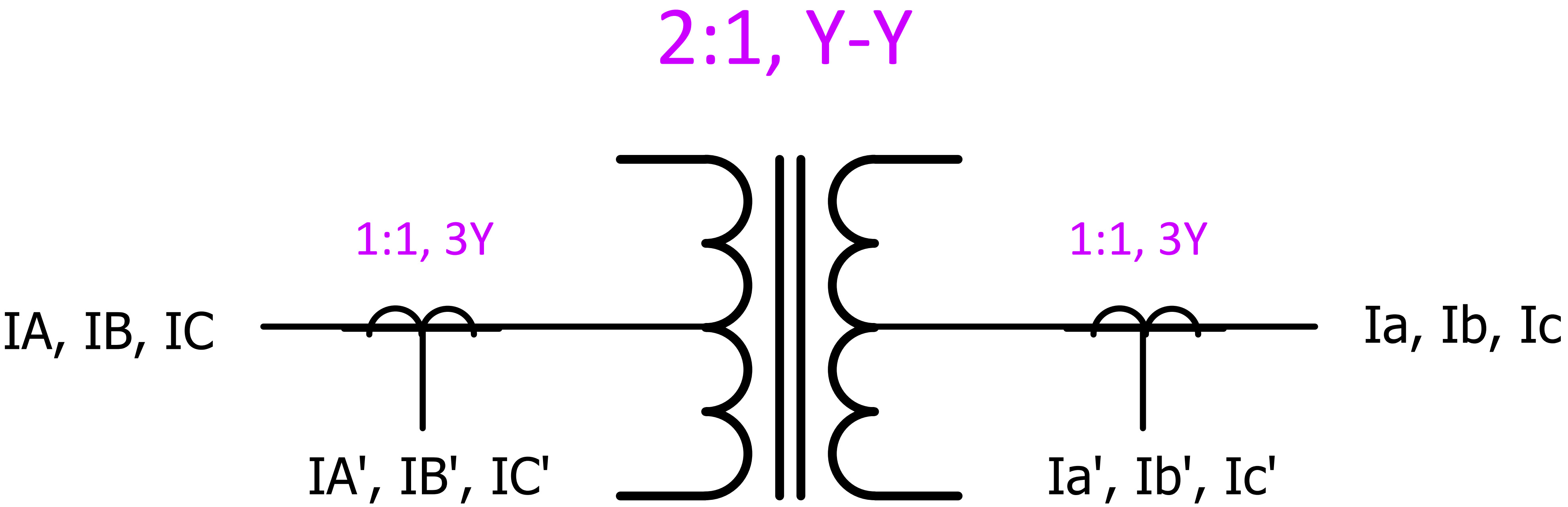
IA' = Ia'
IB' = Ib'
IC' = Ic'

Compensation: Change in CT Ratio



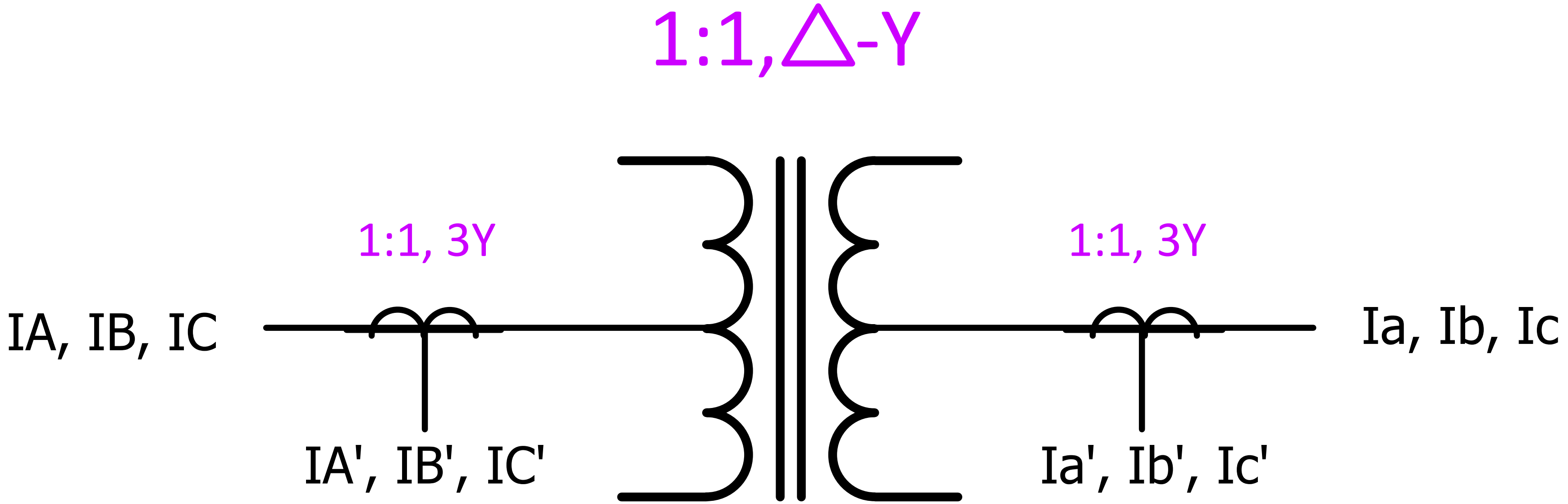
IA' = Ia' / 4
IB' = Ib' / 4
IC' = Ic' / 4

Compensation: Transformer Ratio



$$IA' = Ia' / 2$$
$$IB' = Ib' / 2$$
$$IC' = Ic' / 2$$

Compensation: Delta – Wye Transformation



ANSI standard, high lead low by 30,
Current pairs are: IA-IB, IB-IC, IC-IA

IA' = Ia' * 1.73
IB' = Ib' * 1.73
IC' = Ic' * 1.73

Compensation: Zero-Sequence Elimination

$$3I_0 = [I_a + I_b + I_c]$$

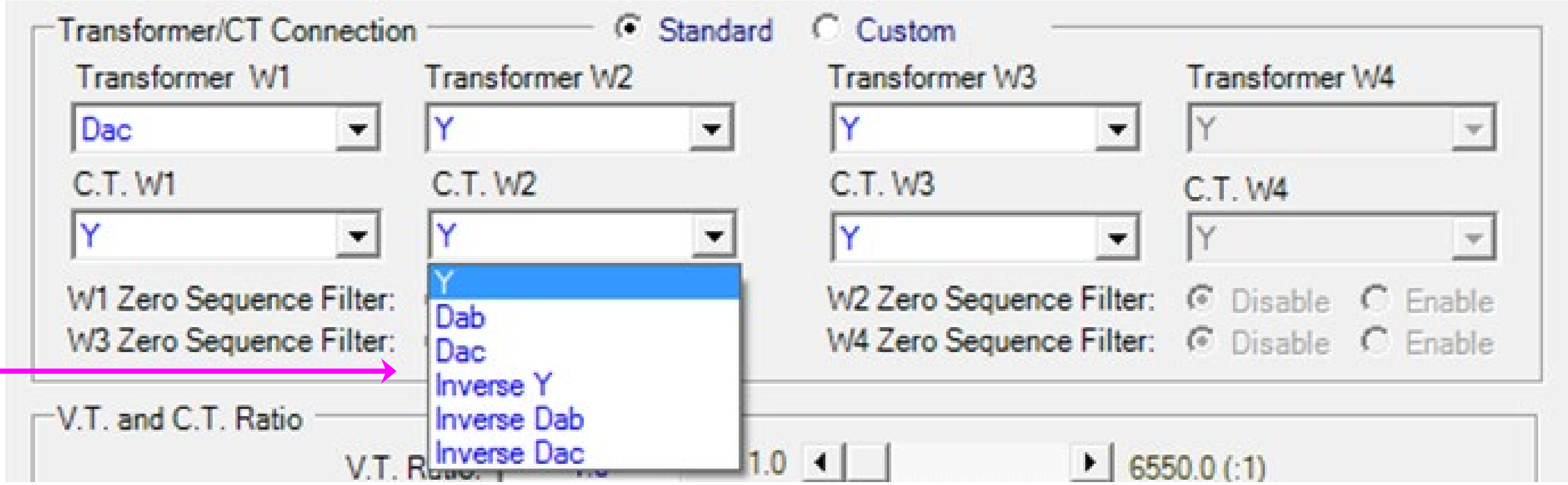
$$I_0 = 1/3 *[I_a + I_b + I_c]$$

Used where filtering is required (Ex: Y/Y transformer).

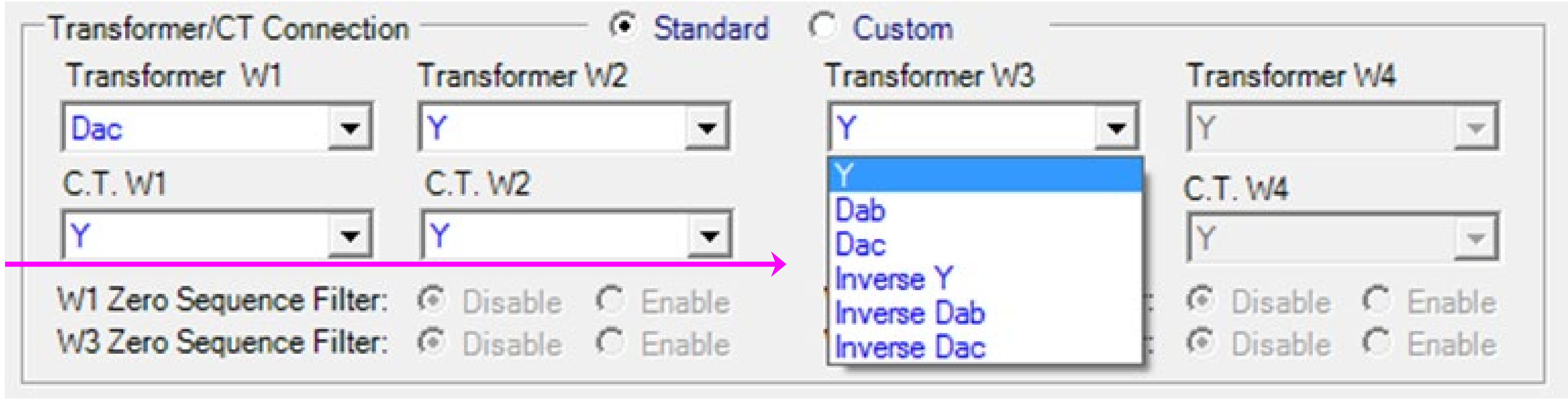
Standard Application

- Set winding types
- 6 choices of configuration for windings and CTs

CT

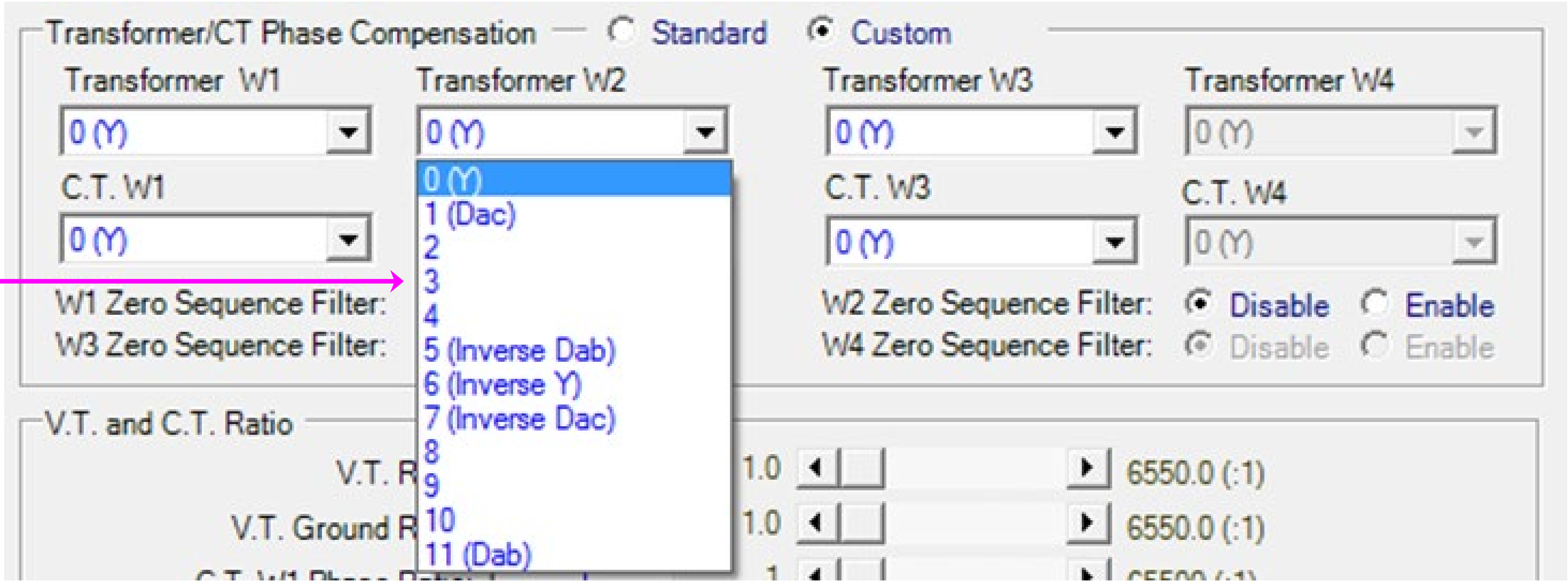


Winding

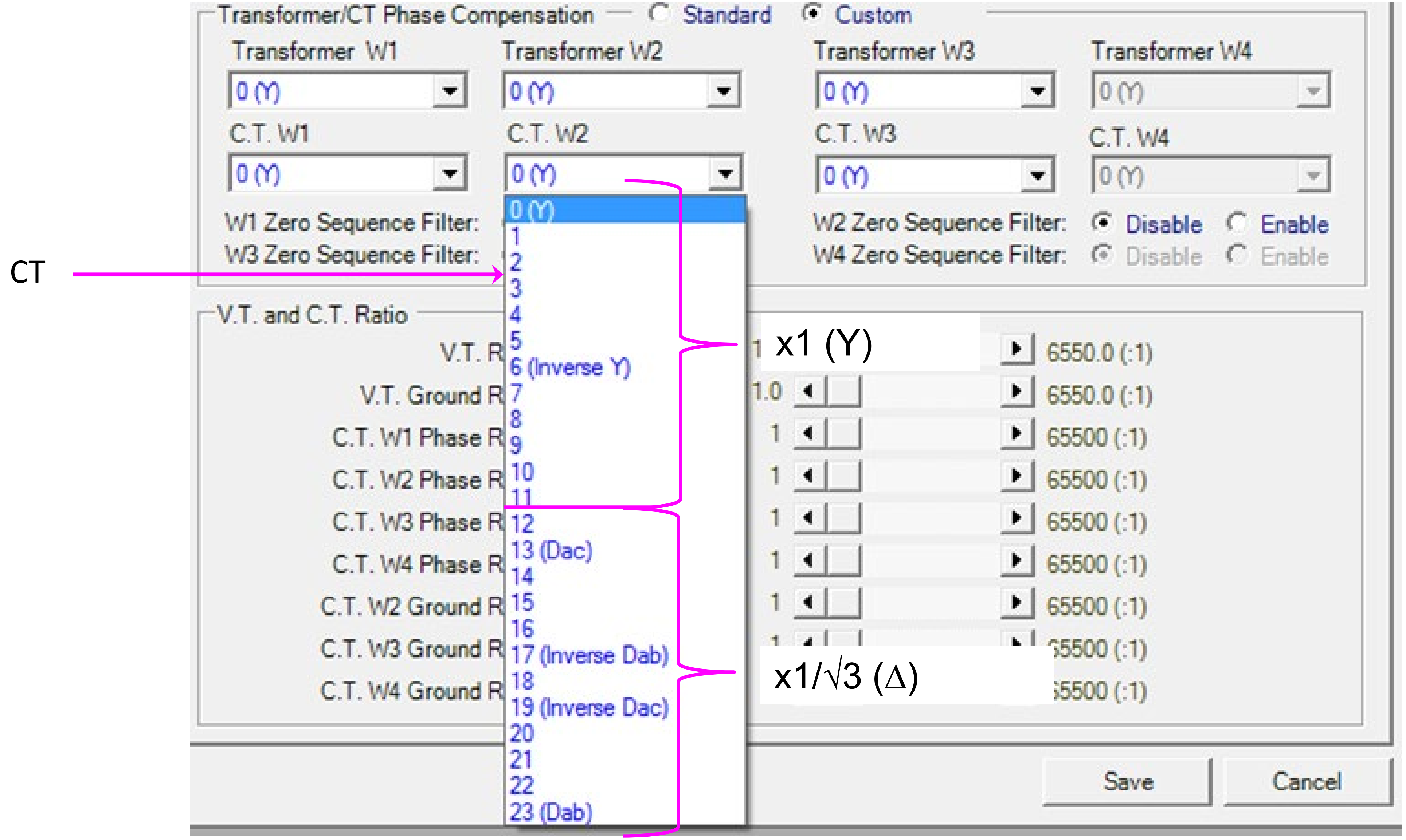


Custom Application: Accommodates any CTs and Windings

Winding

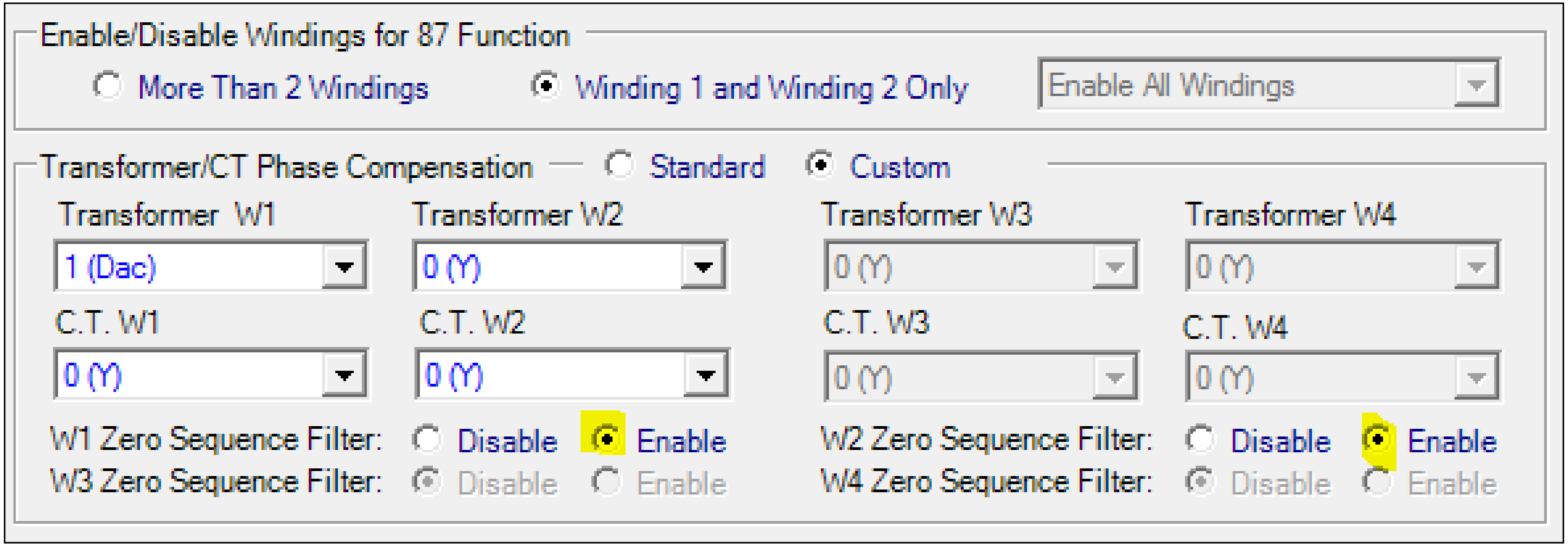


Custom Application: Accommodates any CTs and Windings



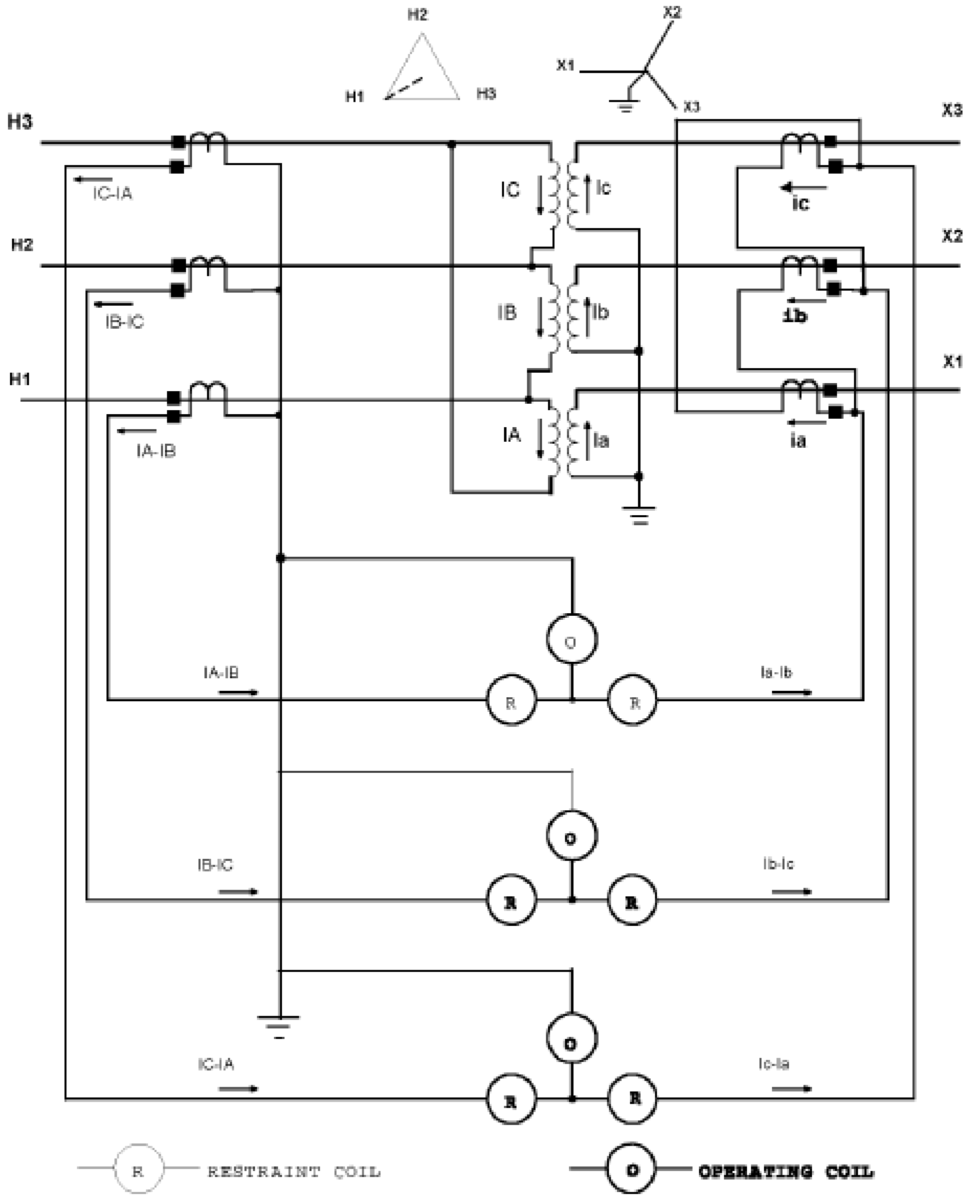
Core Construction and $3I_0$ Current

- Unit transformer with Three-Legged Core
- With a 3-legged core, the zero-sequence current contribution of the transformer case may contribute as much as 20% to 25% zero-sequence current.
- This is true regardless if there is delta winding involved
- Use $3I_0$ restraint on wye CTs even on the delta CT winding!!!
- Use $3I_0$ restraint on wye CTs with wye windings!!!



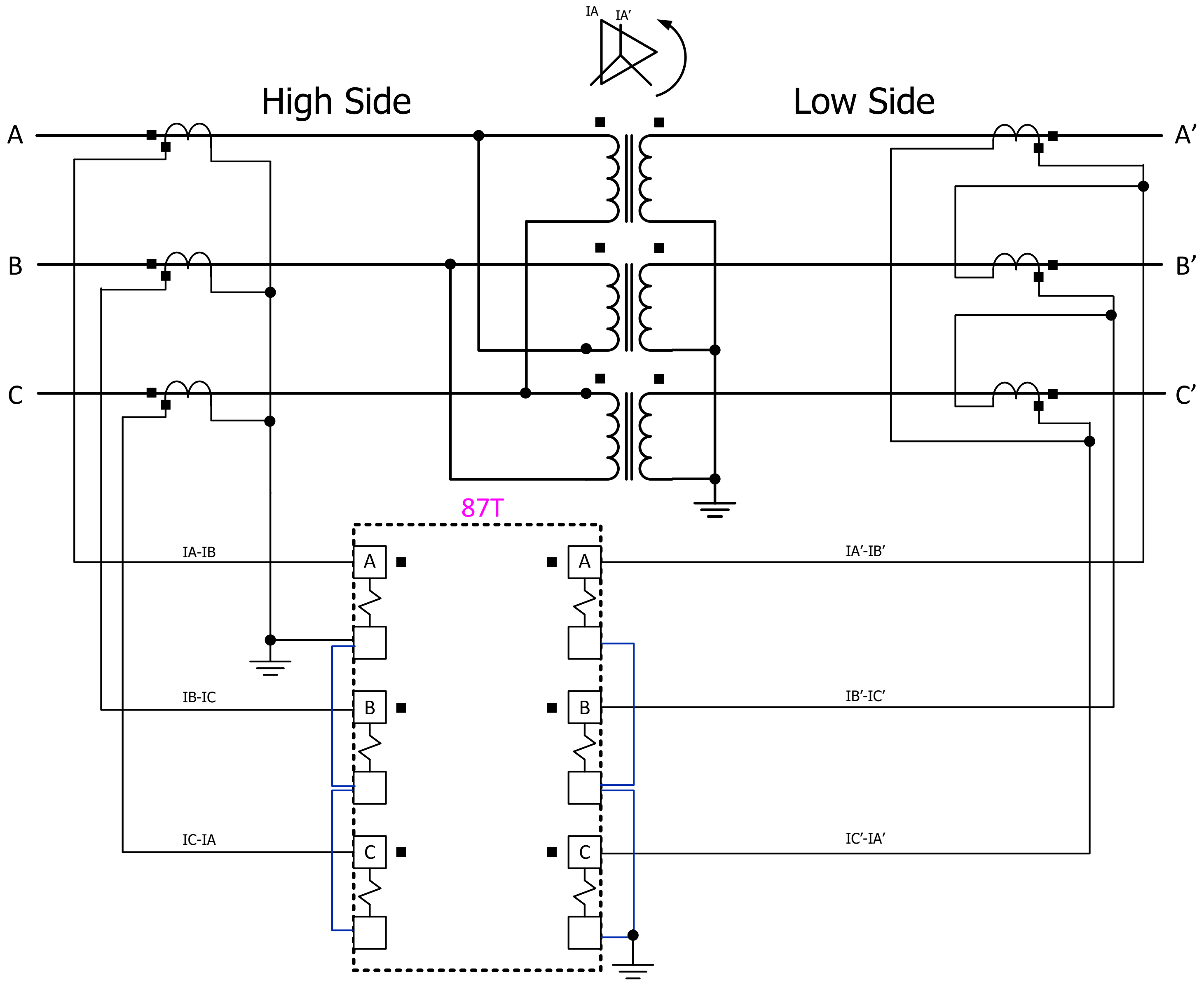
Custom Application: Accommod

- Legacy application
- Need to keep Delta CTs on WYE side of transformer

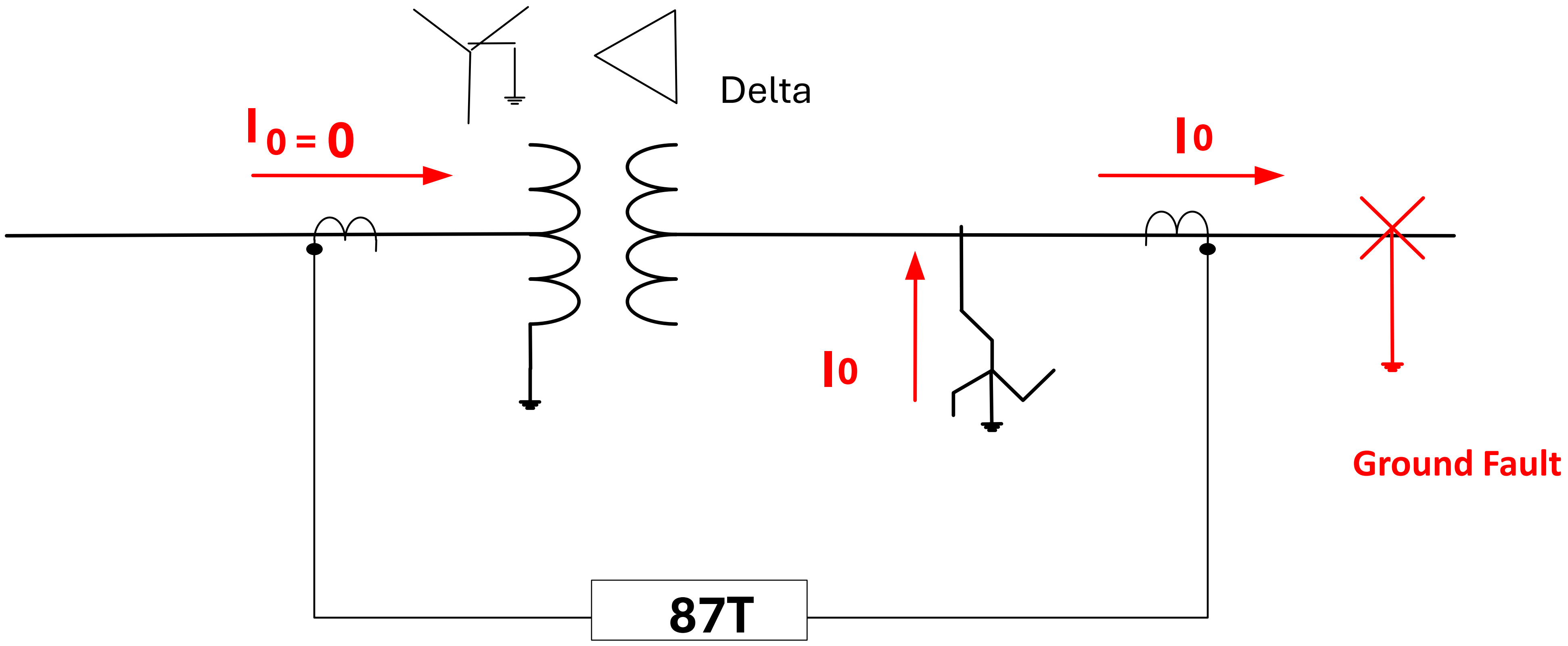


Custom Application: Accommodates any CTs

- Legacy application
- Need to keep Delta CTs on WYE side of transformer



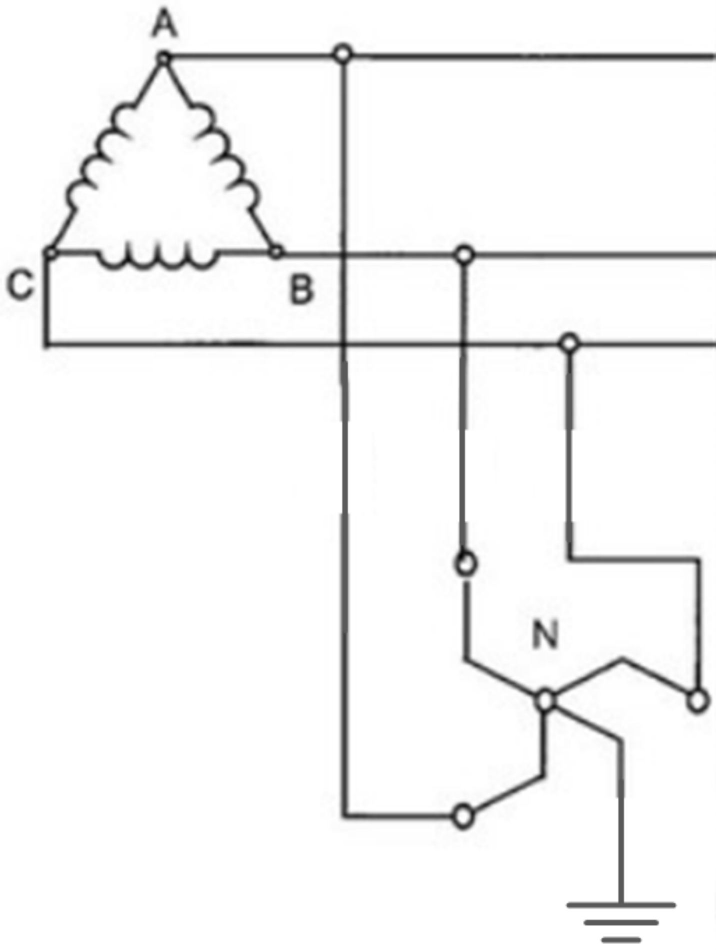
Relay Custom Application

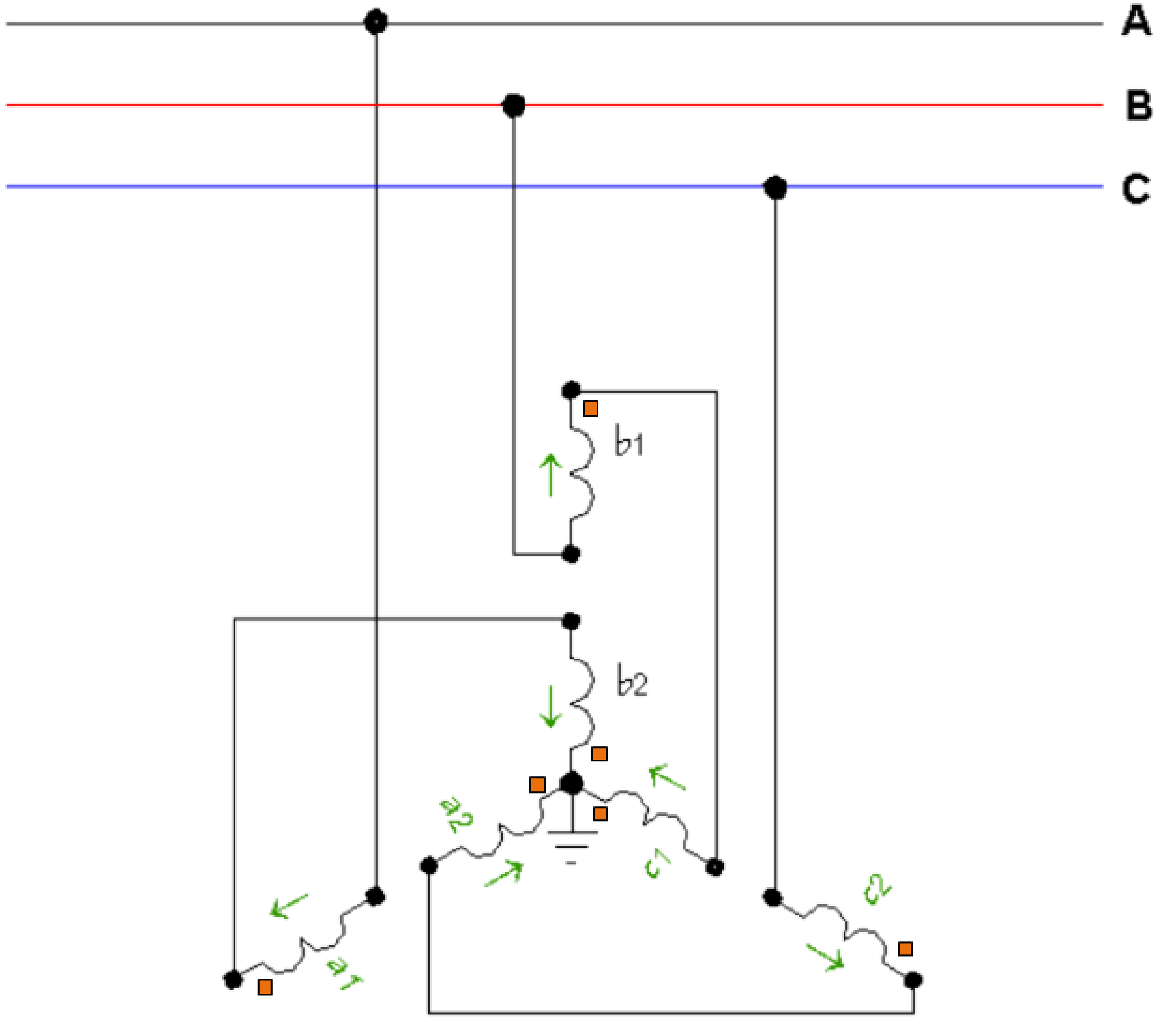


Winding Types

Zig-Zag

- Provides Ground source for Ungrounded systems

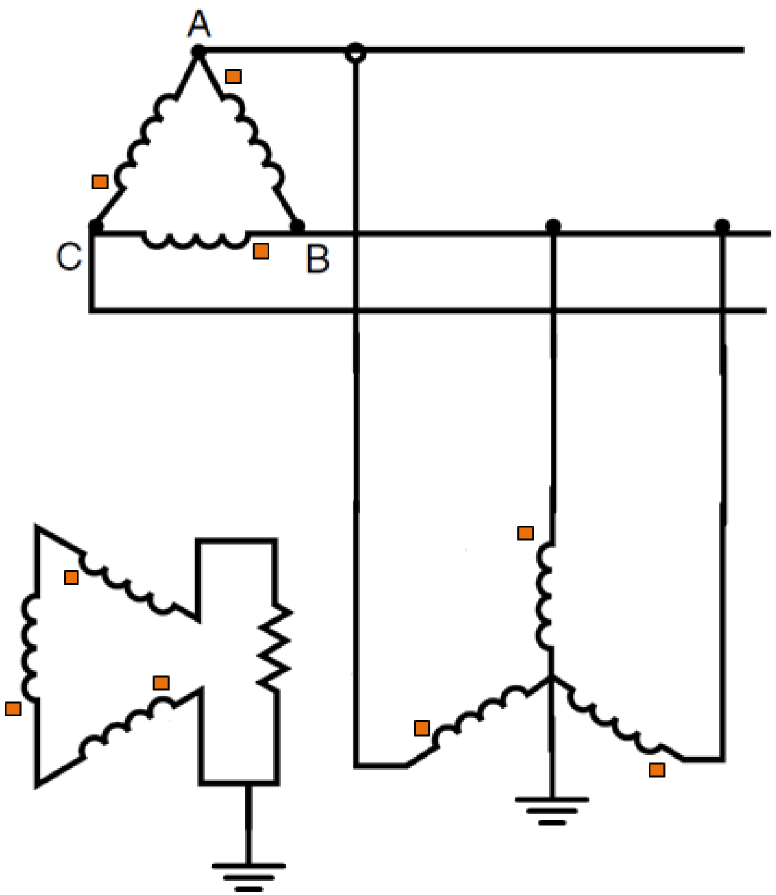


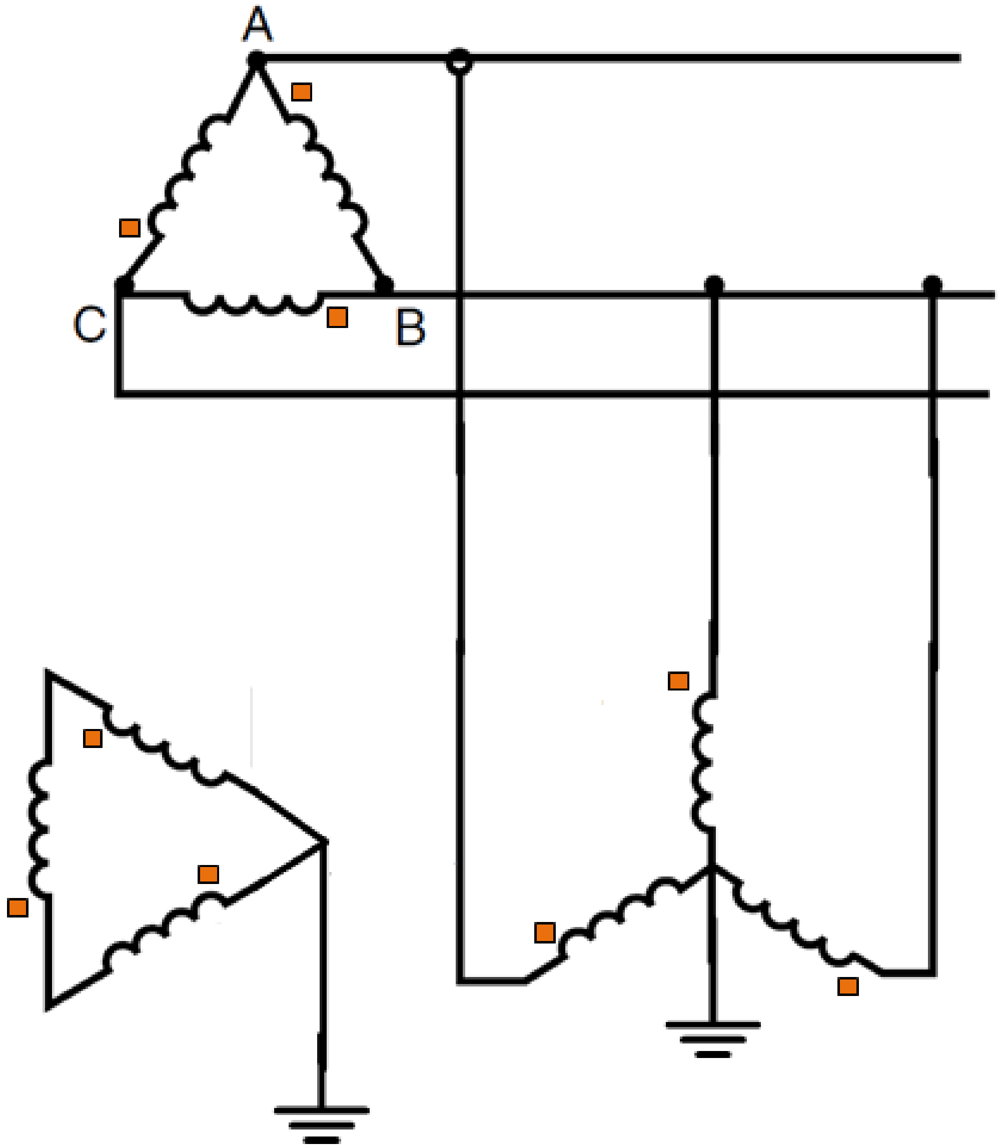


Winding Types

Wye-Delta Ground Bank

- Provides Ground Source for Ungrounded Systen





Inrush Detection and Restraint

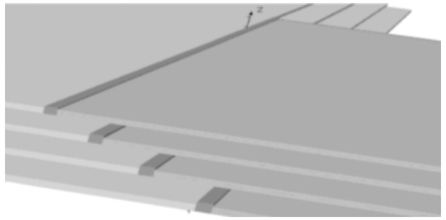
- Characterized by current into one winding of transformer, and not out of the other winding(s)
  - This causes a differential element to pickup
- Use **inrush restraint** to block differential element during inrush period
  - **Initial inrush** occurs during transformer energizing as the core magnetizes
  - **Sympathy inrush** occurs from adjacent transformer(s) energizing, fault removal, and allowing the transformer to undergo a low level inrush
  - **Recovery Inrush** occurs after an out-of-zone fault is cleared and the fault induced depressed voltage suddenly rises to rated.

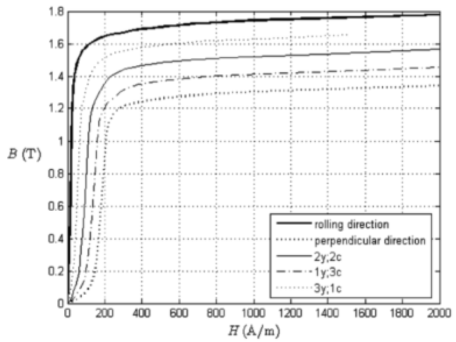
Classical Inrush Detection

- Inrush current is distinguishable from fault current by the inclusion of harmonic components
- 2nd harmonic restraint has traditionally been applied to prevent undesired tripping of differential elements
- 2nd harmonic quantity depends upon the magnetizing characteristics of the transformer core and residual magnetism present in the core
- If 2nd harmonic restraint level is set too low, differential element may be blocked for internal faults with CT saturation (with associated harmonics generated)

Coping with Transformer Inrush

- Modern transformers tend to have:
  - Low core losses
  - Step lap construction
  - Very steep magnetizing characteristics
  - Lower values of 2nd harmonic on inrush
- Fortunately, even order harmonics are generated during inrush, not only 2nd harmonic
- Use 2nd and 4th harmonic as a restraining quantity for inrush.



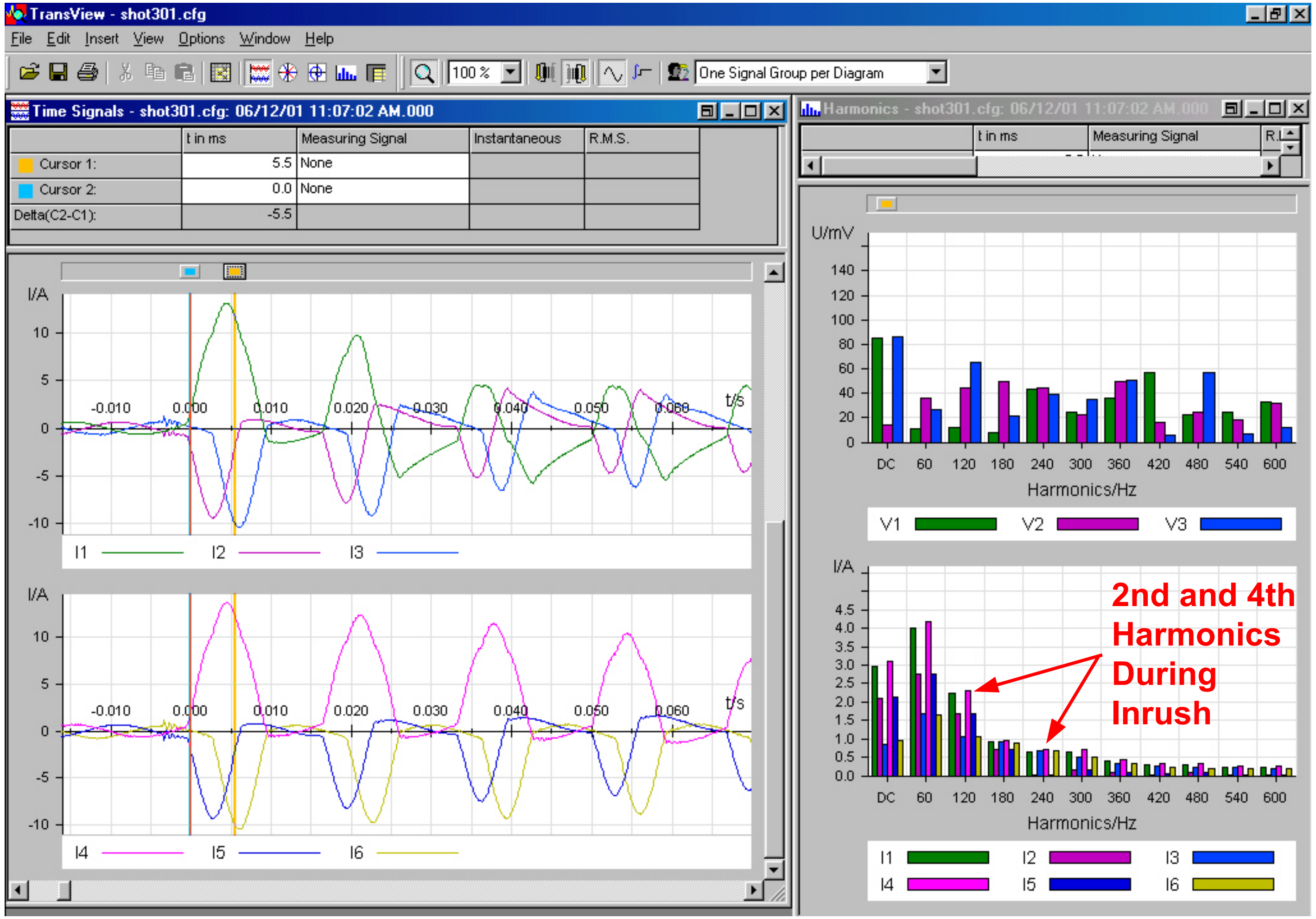


$$I_{RES:2nd\text{-}4th} = \sqrt{(I_{RES:2nd}^2 + I_{RES:4th}^2)}$$

Advanced Inrush Detection

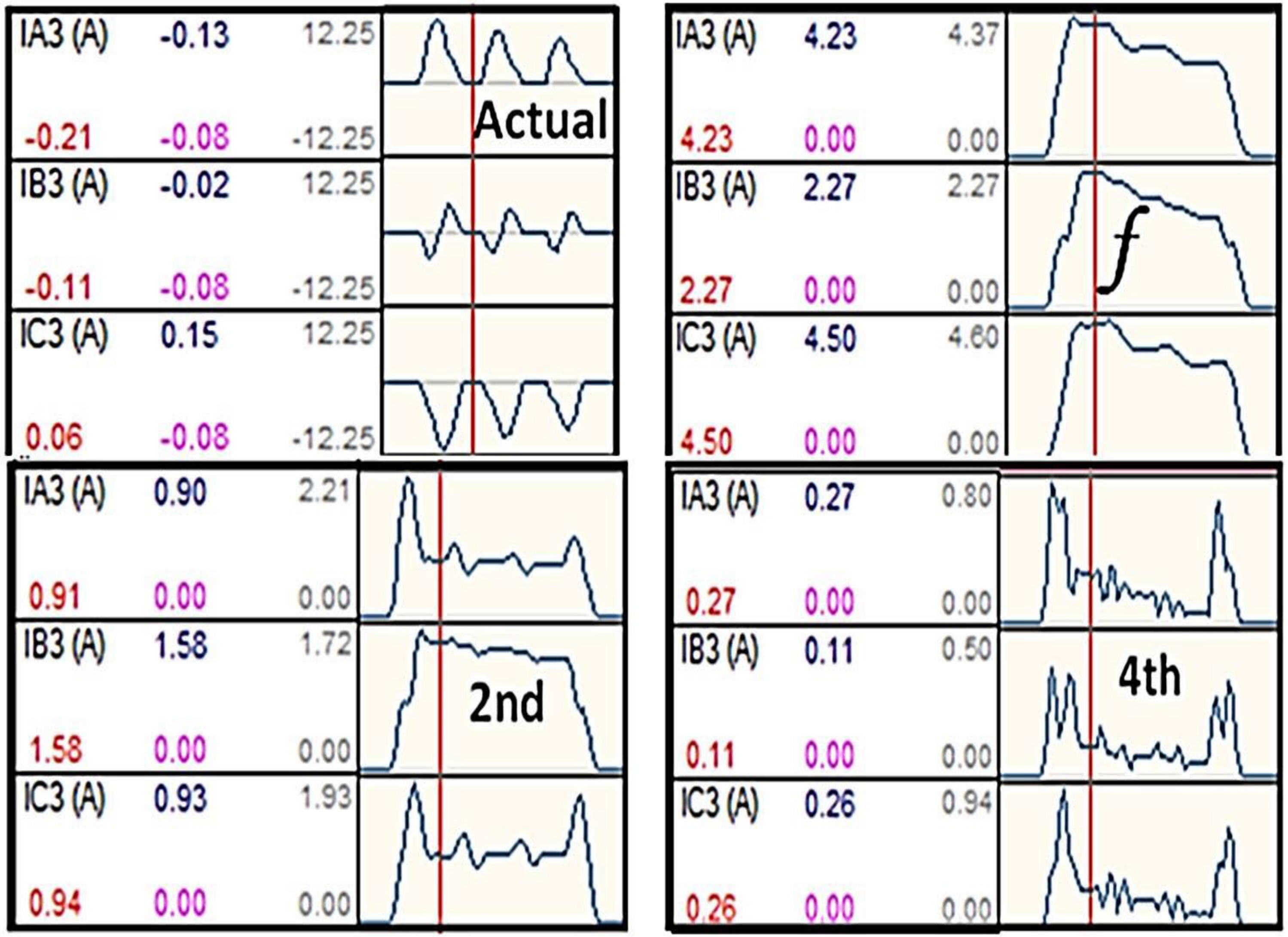
- 4th harmonic is also generated during inrush
  - Even harmonics are more prevalent than odd harmonics during inrush
  - Odd harmonics are more prevalent during CT saturation
- Use 4th harmonic and 2nd harmonic together
  - Use RMS sum of the 2nd and 4th harmonic as inrush restraint
- Result: Improved security while not sacrificing reliability

Inrush Oscillograph



Typical Transformer Inrush Waveform

Inrush Oscillograph



Typical Transformer Inrush Waveform

Point-on-Wave Considerations During Switch On

- As most circuit breakers are ganged three-pole, one phase will be near voltage zero at the moment of transformer energization
- When a phase of a transformer is switched on near zero voltage, the inrush is increased and so is the resultant harmonics
- Low levels of harmonics (especially modern transformers) may not provide inrush restraint for affected phase – security risk!
- Employ cross-phase averaging to compensate for this issue

Cross Phase Averaging

- Provides security if a phase(s) has low harmonic content during inrush
- Cross phase averaging uses the sum of harmonics on all three phases as the restraint value

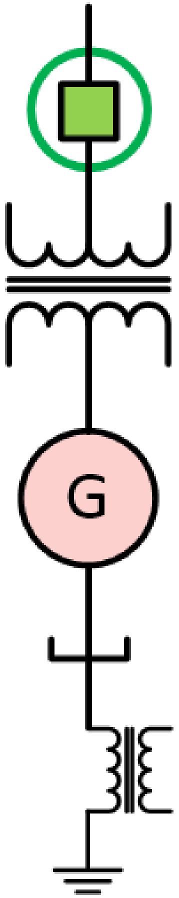
$$Id_{CPA24} = \sqrt{IAd_{24}^{\ 2} + IBd_{24}^{\ 2} + ICd_{24}^{\ 2}}$$

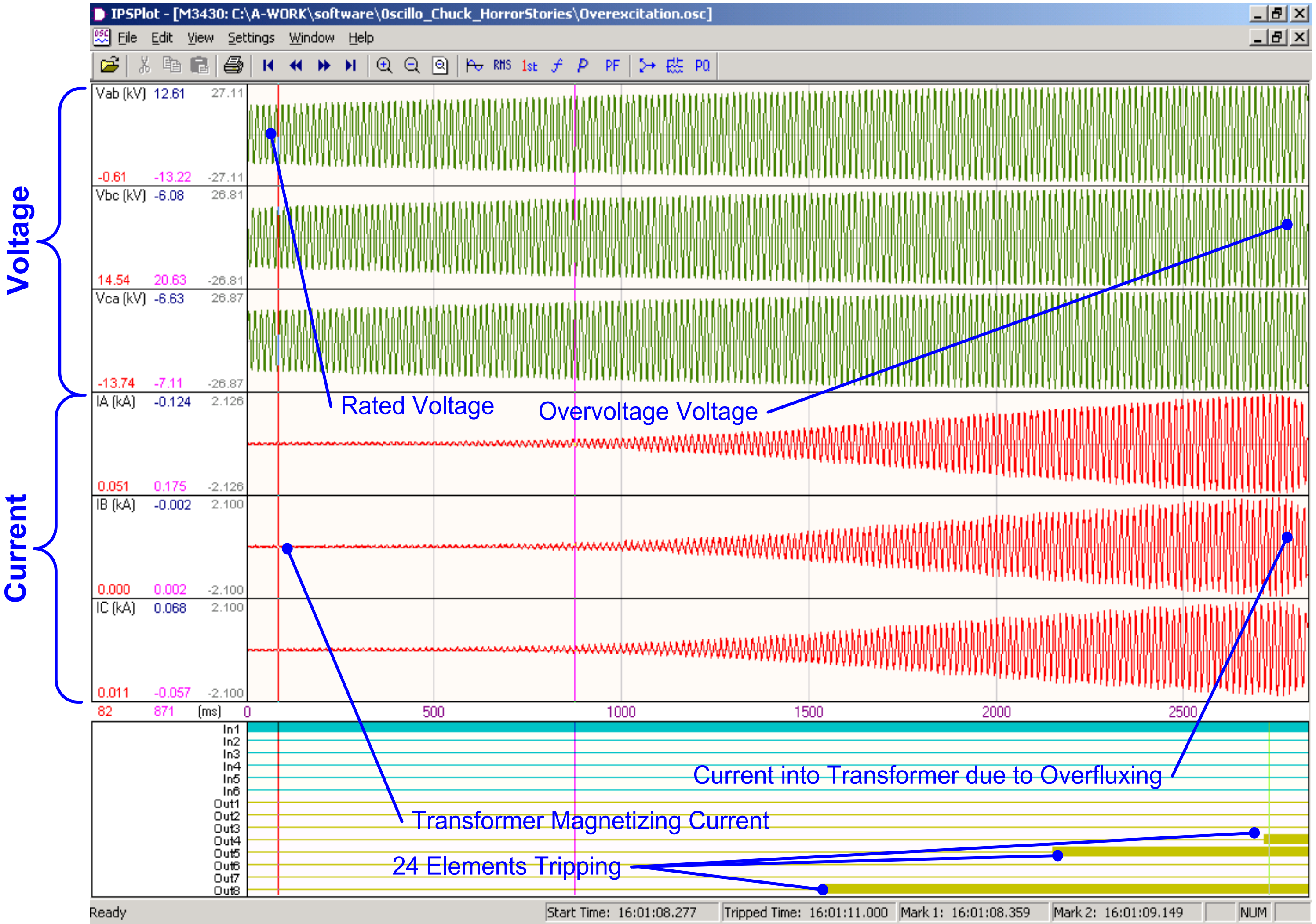
- Cross Phase Averaging (harmonic sharing) is a modification of the harmonic blocking technique
- The harmonic content of all three phases is summed before checking the ratio of the fundamental to harmonic
- This approach adds security to applications in which harmonic content on one or two phases is not sufficient to block the operation of the relay

Overexcitation Restraint

- Overexcitation occurs when volts per hertz level rises (V/Hz) above the rated value
- This may occur from:
  - Load rejection (generator transformers)
  - Malfunctioning of voltage and reactive support elements
  - Malfunctioning of breakers and line protection (including transfer trip communication equipment schemes)
  - Malfunctioning of generator AVRs
- The voltage rise at nominal frequency causes the V/Hz to rise
- This causes the transformer core to saturate and thereby increase the magnetizing current.
- The increased magnetizing current contains 5th harmonic component
- This magnetizing current causes the differential element to pickup
  - Current into transformer that does not come out

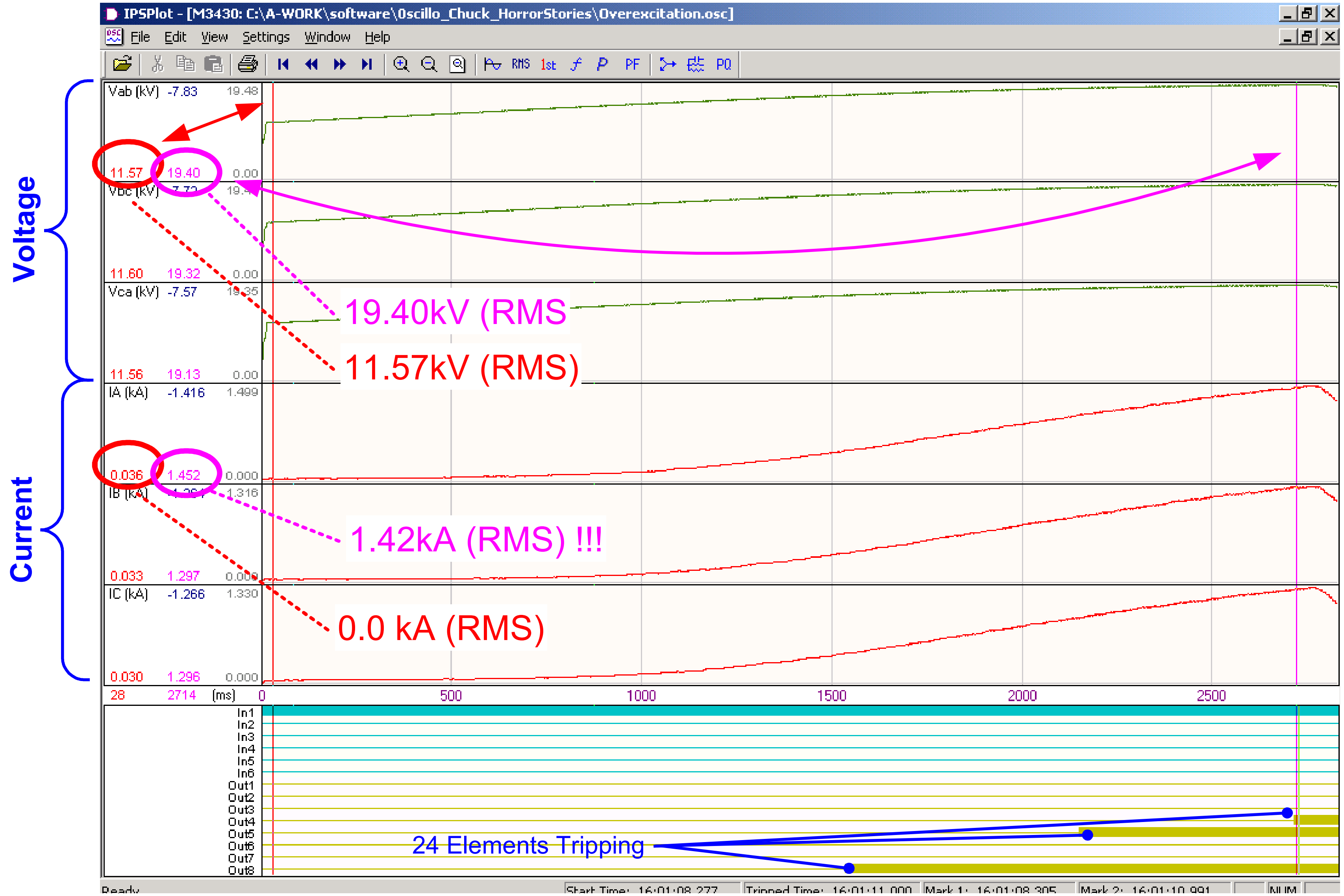
Increased V/Hz = Overexcitation Event = Excess Current



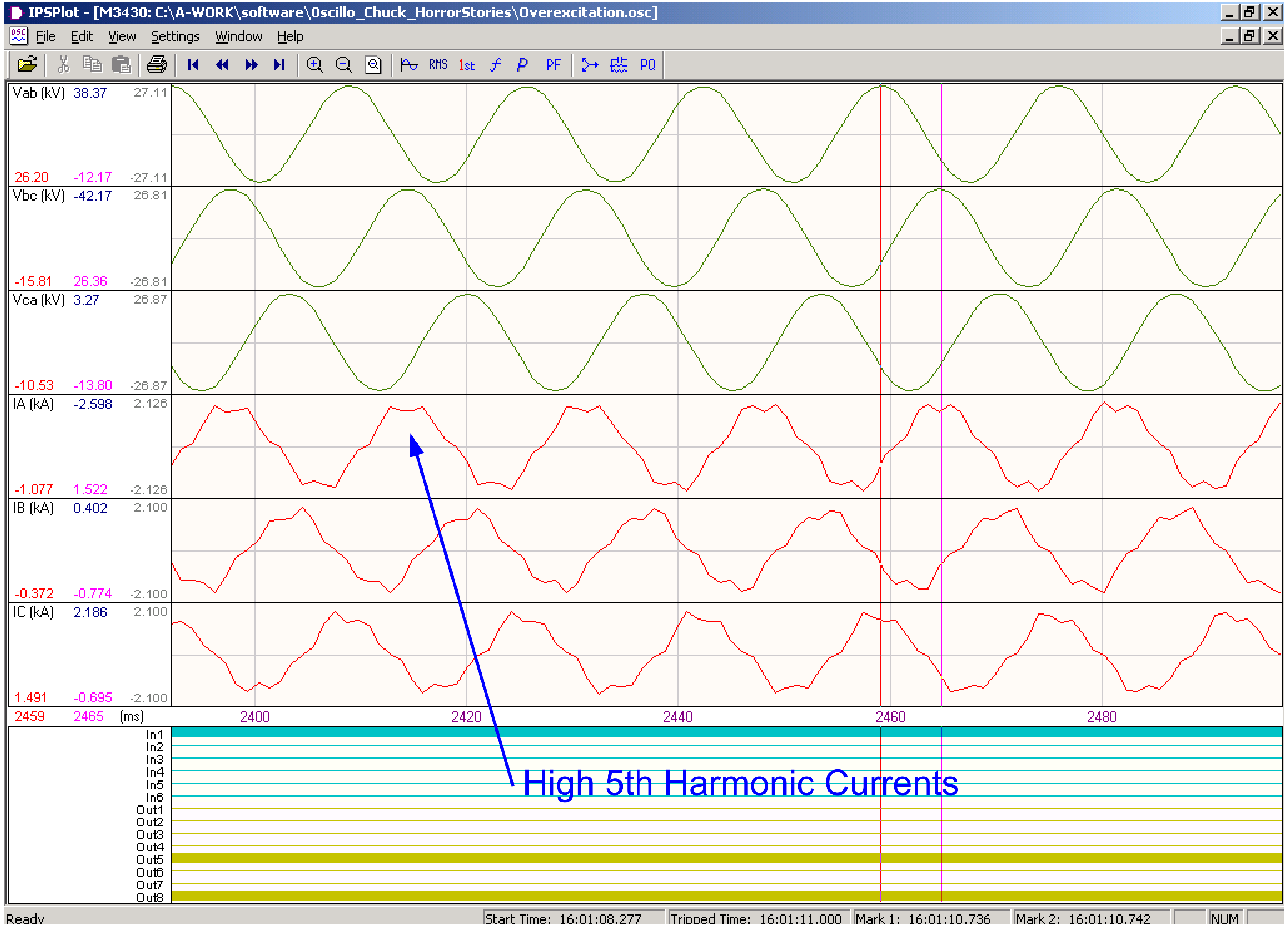


Overexcitation Event Oscillograph

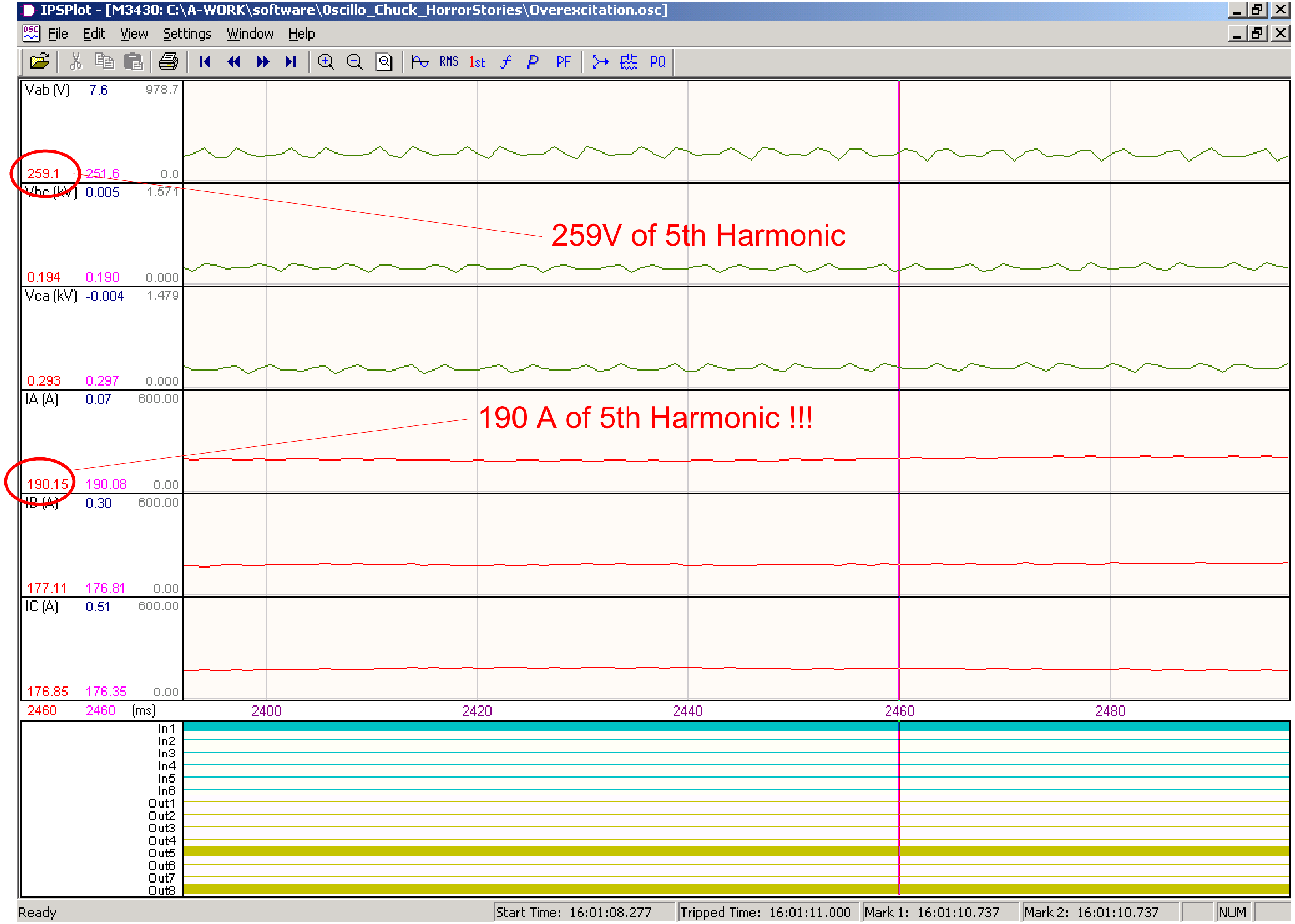
Overexcitation Event



Overexcitation Event



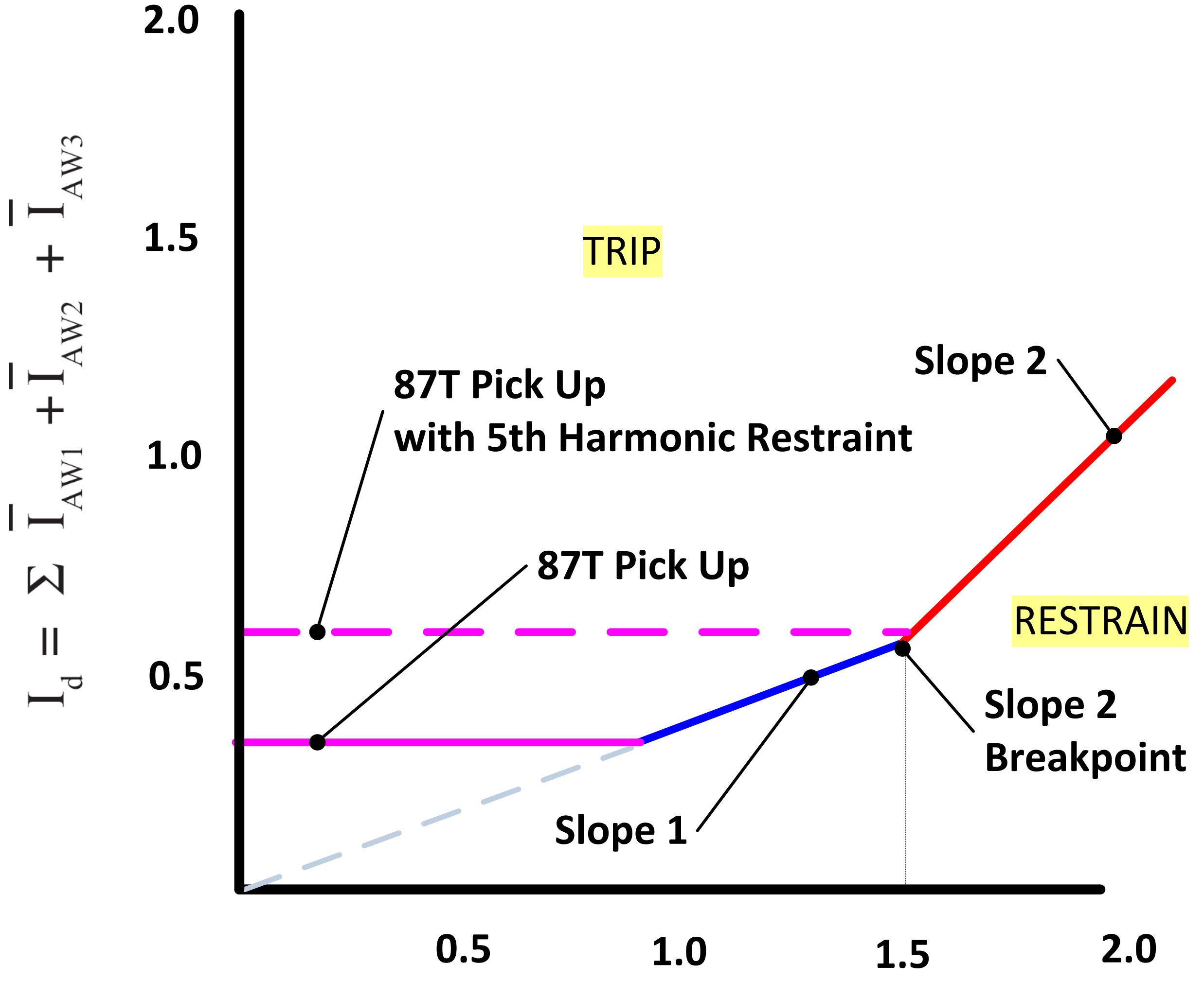
Overexcitation Event



Overexcitation Restraint

- Use 5th harmonic level to detect overexcitation
- Most relays block the differential element from functioning during transformer overexcitation
  - If the transformer internally faults (1 or 2 Phase), the unfaulted phases(s) remain overexcited blocking the differential element
  - Faulting during overexcitation is more likely if the voltage is greater than rated, as it will cause increased dielectric stress
- An improved strategy is to raise the pickup level of the differential element to accommodate the increased difference currents caused by the transformer saturation
  - This allows the differential element to rapidly trip if an internal fault occurs during the overexcitation period
- Result: Improved reliability while not sacrificing security

Trip Characteristic – 87T



$$I_R = \frac{\Sigma\ |I_{AW1}| + |I_{AW2}| + |I_{AW3}|}{2}$$

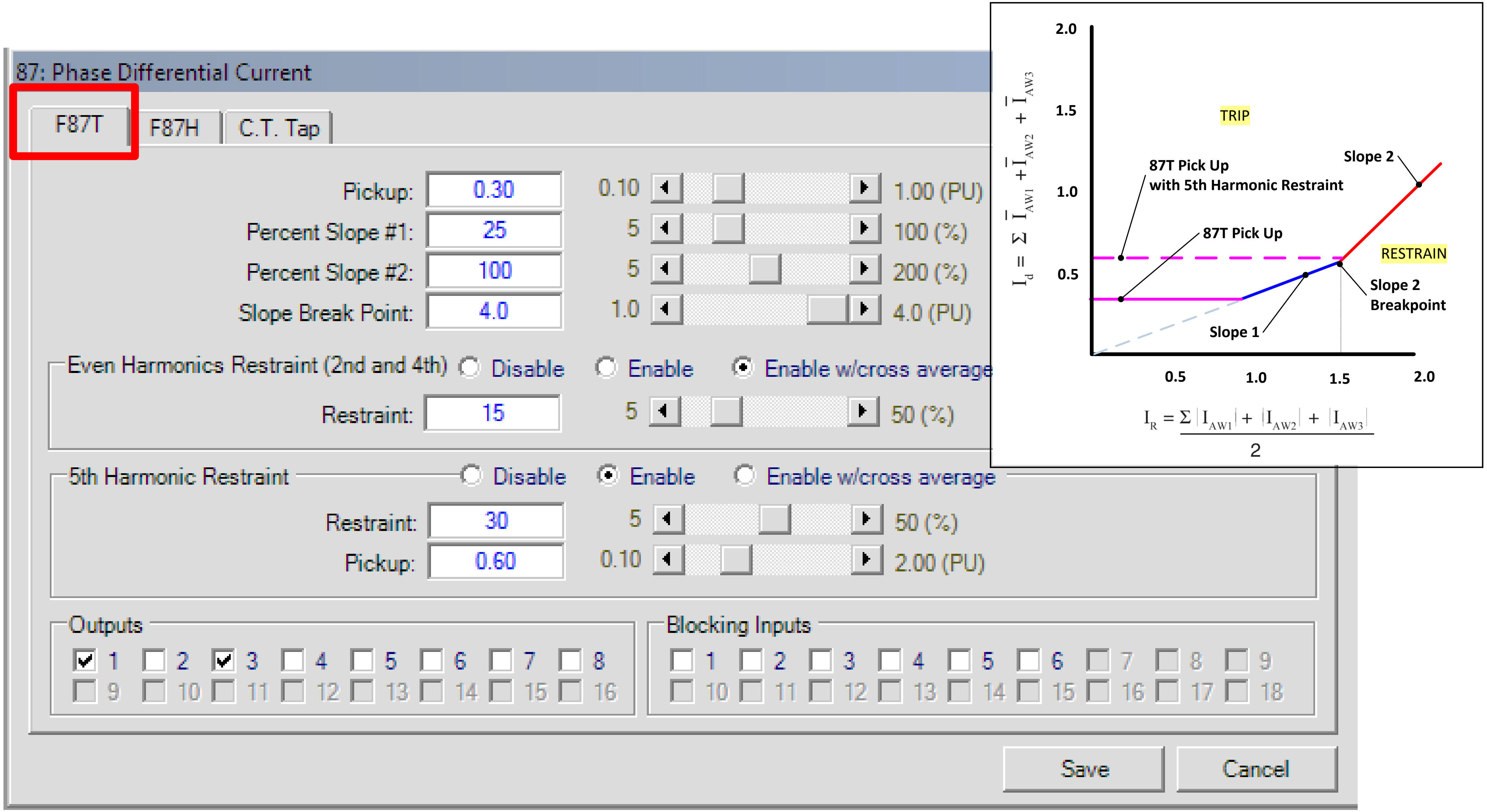
Switch-onto-Fault

- Transformer is faulted on energizing
- Harmonic restraint on unfaulted phases may work against trip decision if cross phase averaging is used
  - This may delay tripping until the inrush current is reduced
- 87H and 87GD can be used to provide high speed protection for this condition
  - If fault is close to bushings current may be greater than 6-8pu
  - High set element 87H can provide high speed protection for severe faults as this function is not restrained by harmonics
  - 87H is set above the worst case inrush current
  - 87GD function can provide fast protection during switching onto ground faults as this element is not restrained using harmonics

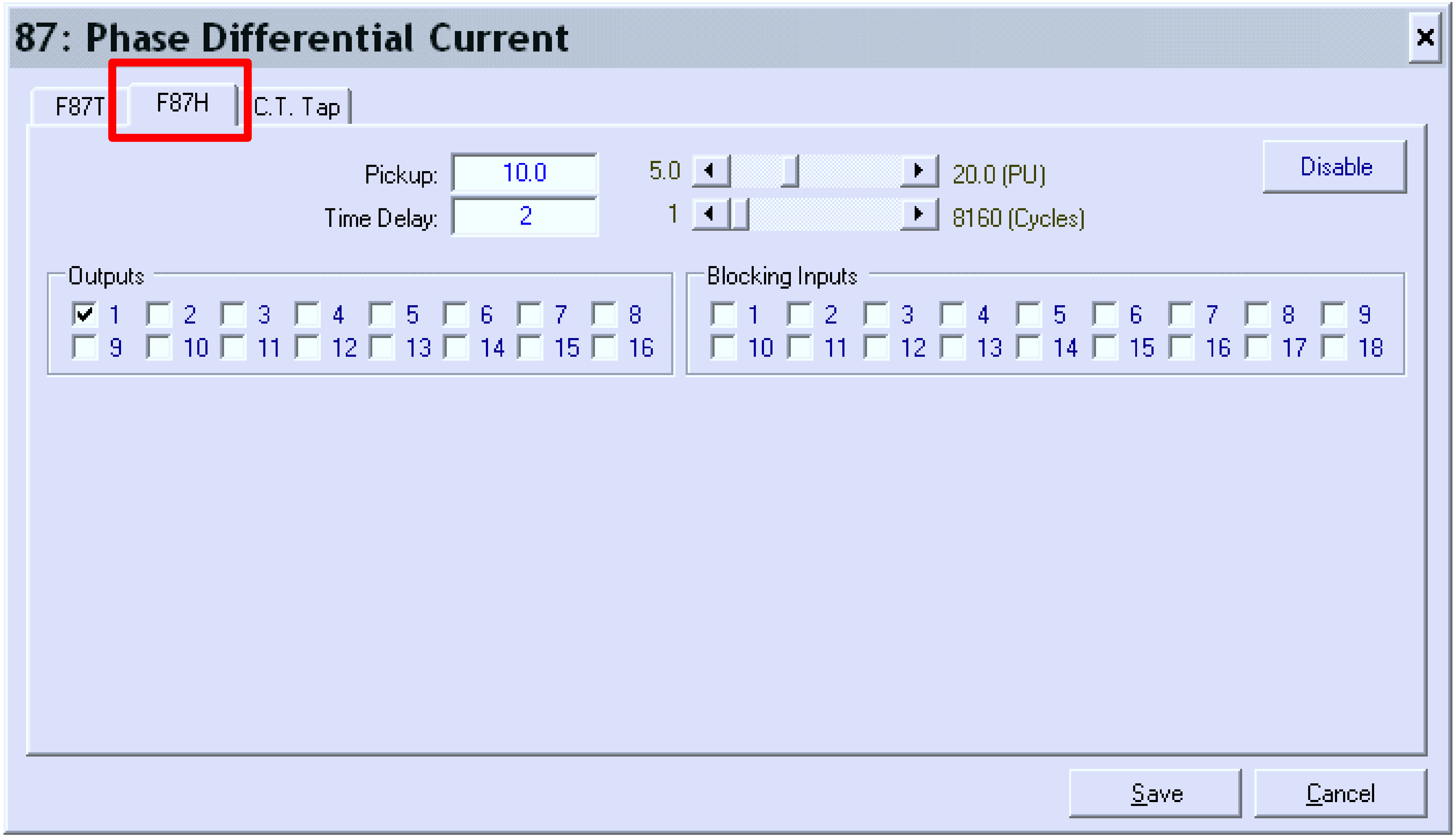
Phase Differential

- 87T element is typically set with 30-40% pickup
  - This is to accommodate:
  - Class "C" CT accuracy (+/- 10%, x20 nominal current)
  - Effects of LTCs (+/- 10%)
- 87HS set to 9-12x rated current
  - Inrush does not exceed 6-8x rated current
- That leaves a portion of the winding not covered for a ground fault (near the neutral)
- Employ a ground differential element to improve sensitivity (87GD)

Phase Differential (87)

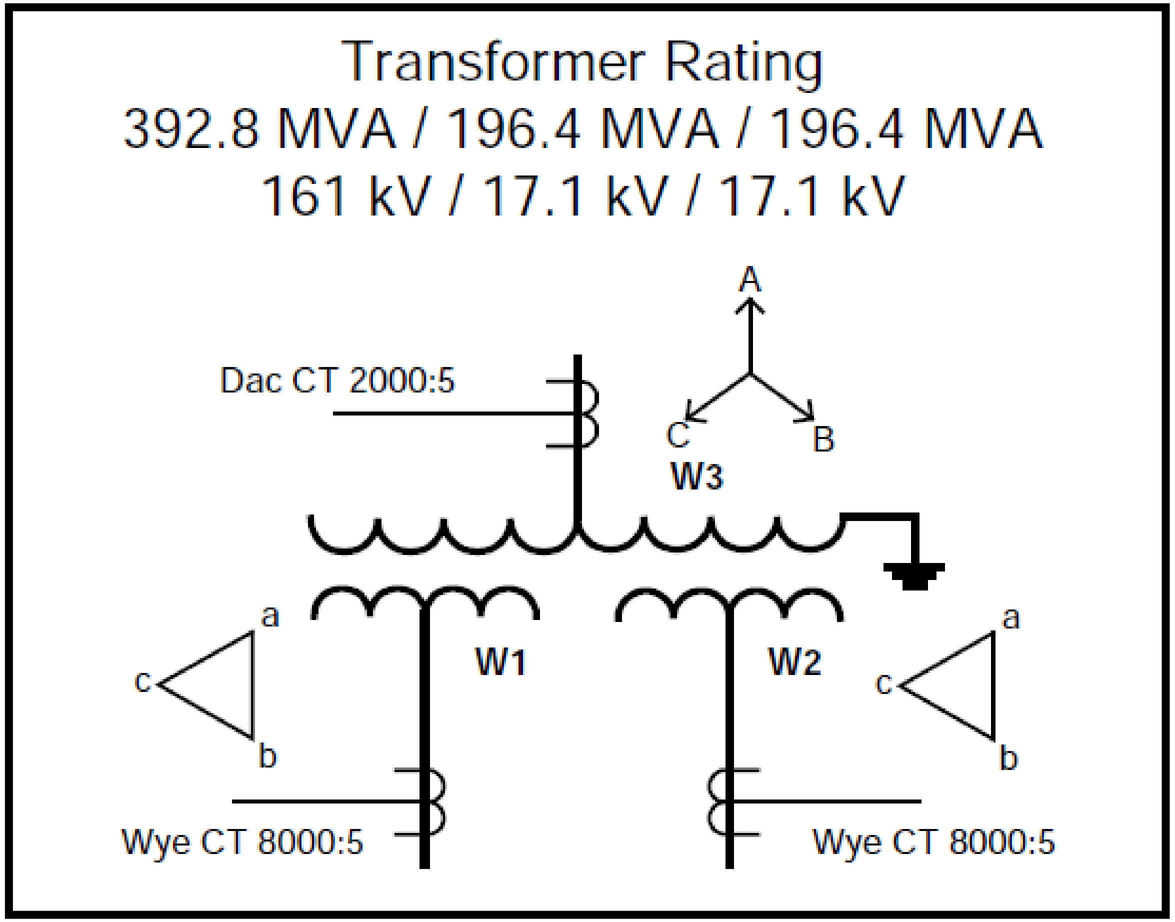


Phase Differential (87)



Phase Differential (87)

- Setting “tap” is a method used to nominalize the winding currents with respect to MVA, kV, and CT ratio

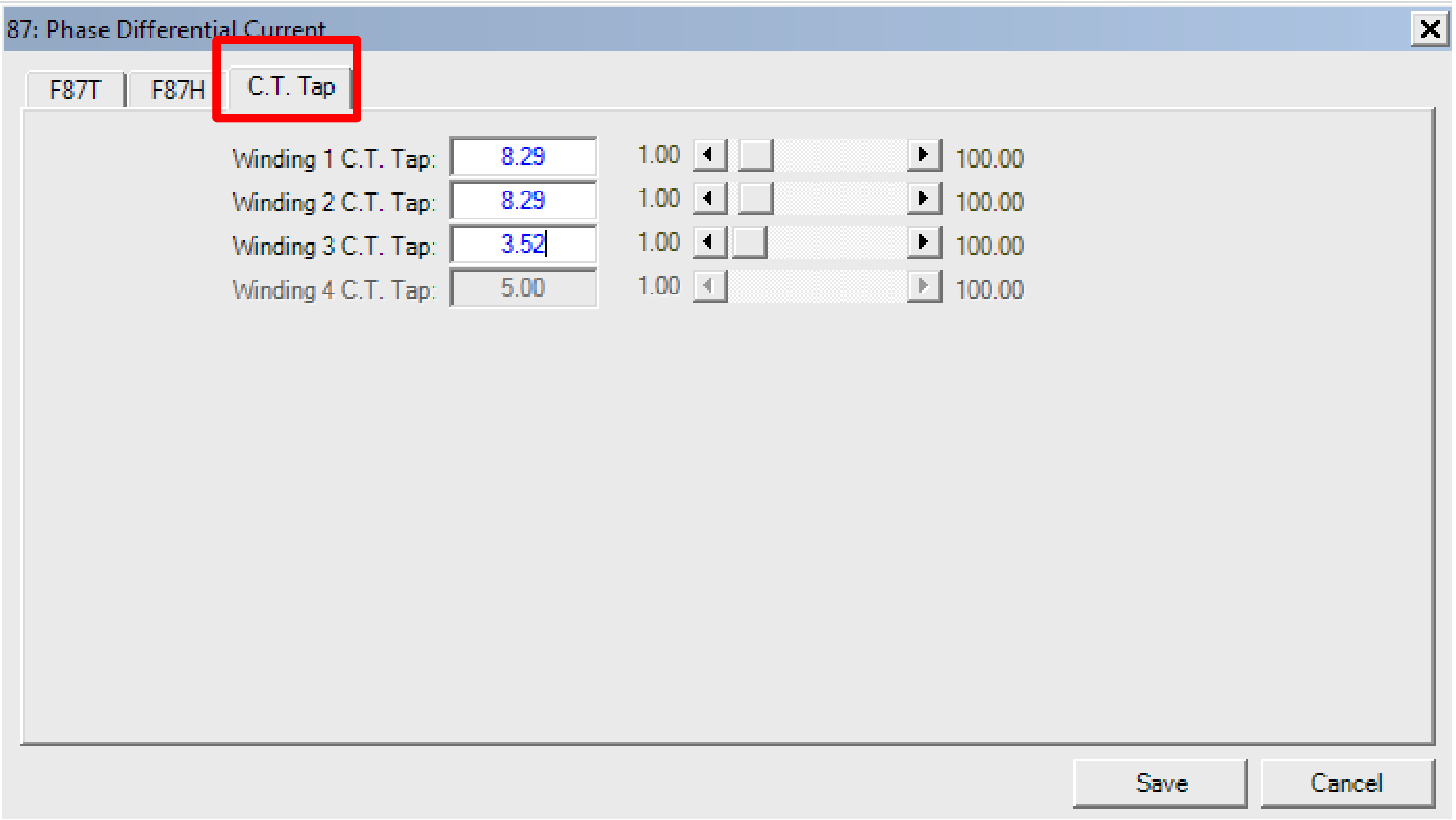


$$87\ \text{CT Tap}_{W1} = \frac{392.8\ \text{MVA} \times 10^3}{\sqrt{3} \times 17.1\ \text{kV} \times 1600} = 8.29$$

$$87\ \text{CT Tap}_{W2} = \frac{392.8\ \text{MVA} \times 10^3}{\sqrt{3} \times 17.1\ \text{kV} \times 1600} = 8.29$$

$$87\ \text{CT Tap}_{W3} = \frac{392.8\ \text{MVA} \times 10^3}{\sqrt{3} \times 161\ \text{kV} \times 400} = 3.52$$

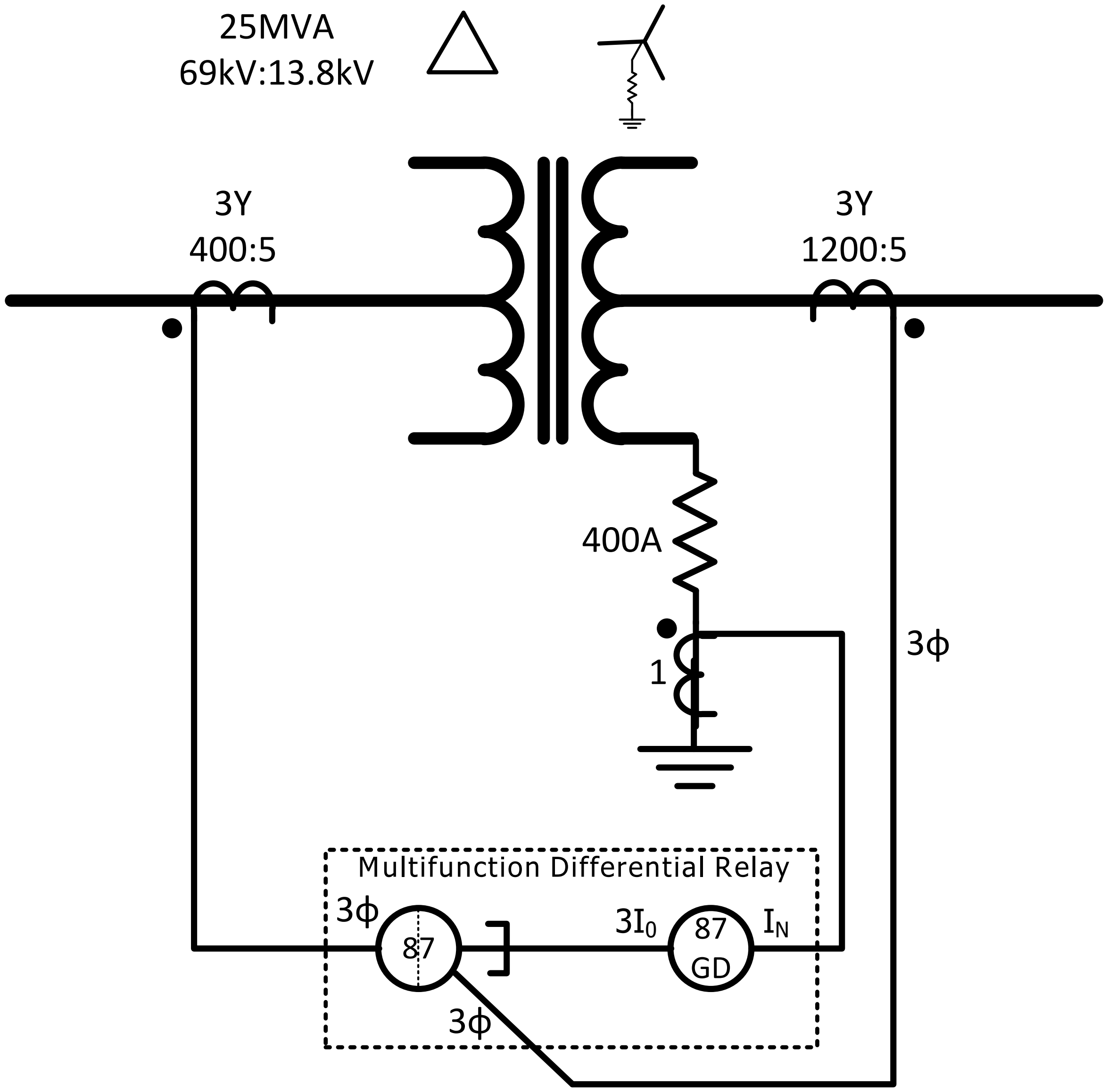
Phase Differential (87)



Types of Protection: Ground Differential (87GD; REF)

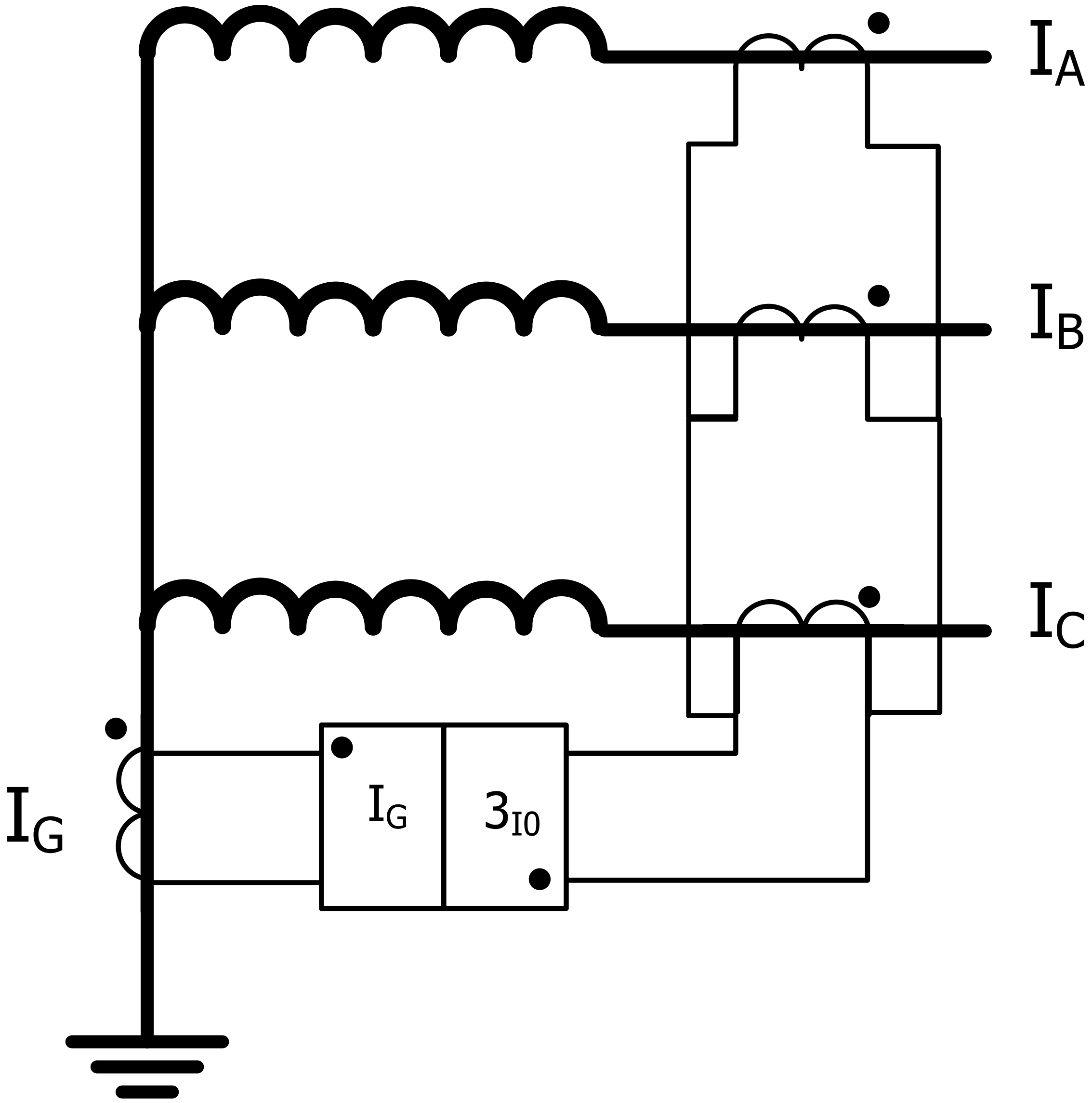
- Sensitive detection of ground faults, including those near the neutral
- Does not require inrush or overexcitation restraint
- Low impedance grounded systems use directional signal for added stability
- Low impedance grounded systems do not require dedicated CTs
  - Same set of CTs can be used for phase differential, phase overcurrent, ground differential and ground overcurrent protection

Types of Protection: Ground Differential (87GD; REF)

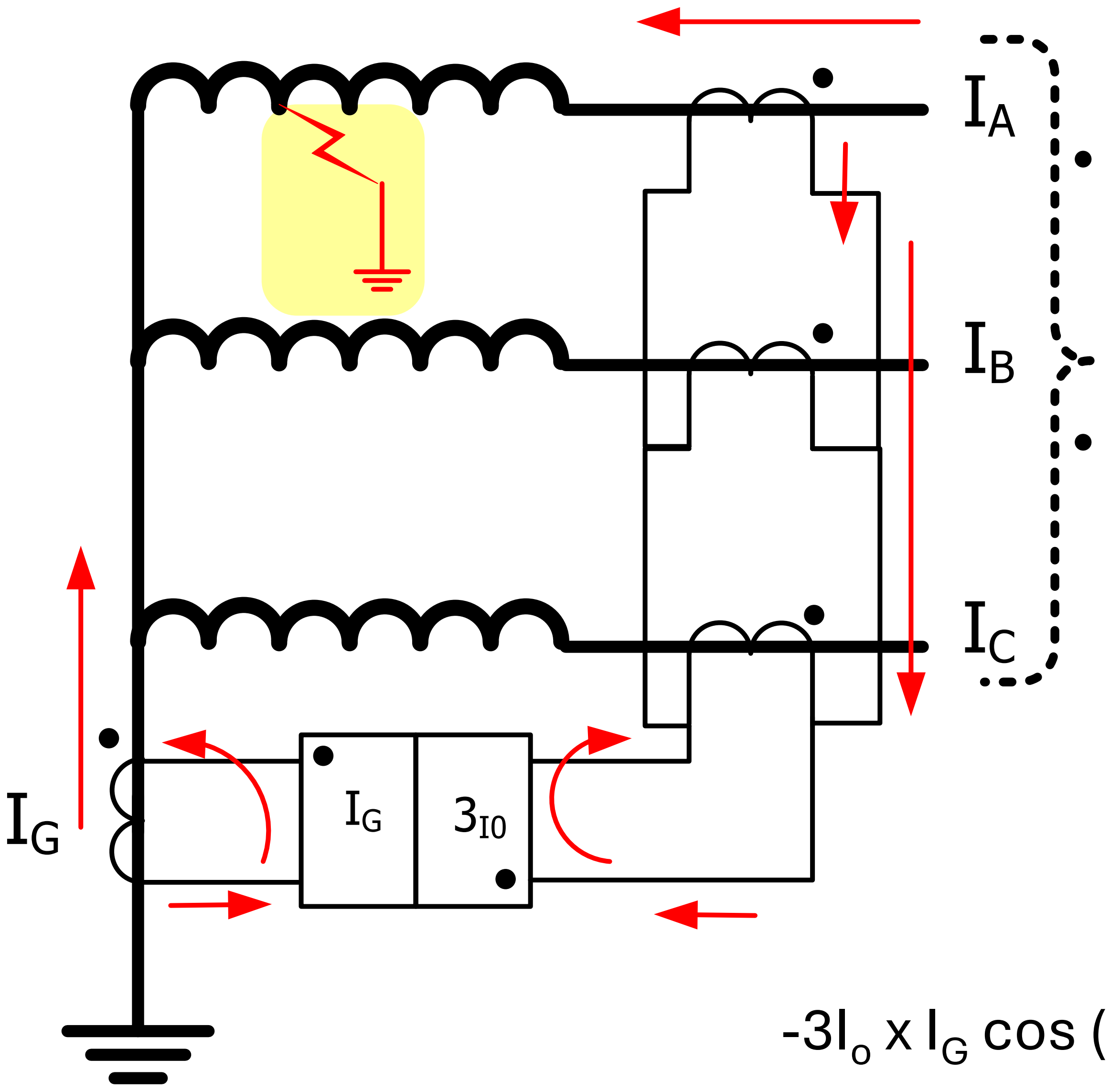


Improved Ground Fault Sensitivity

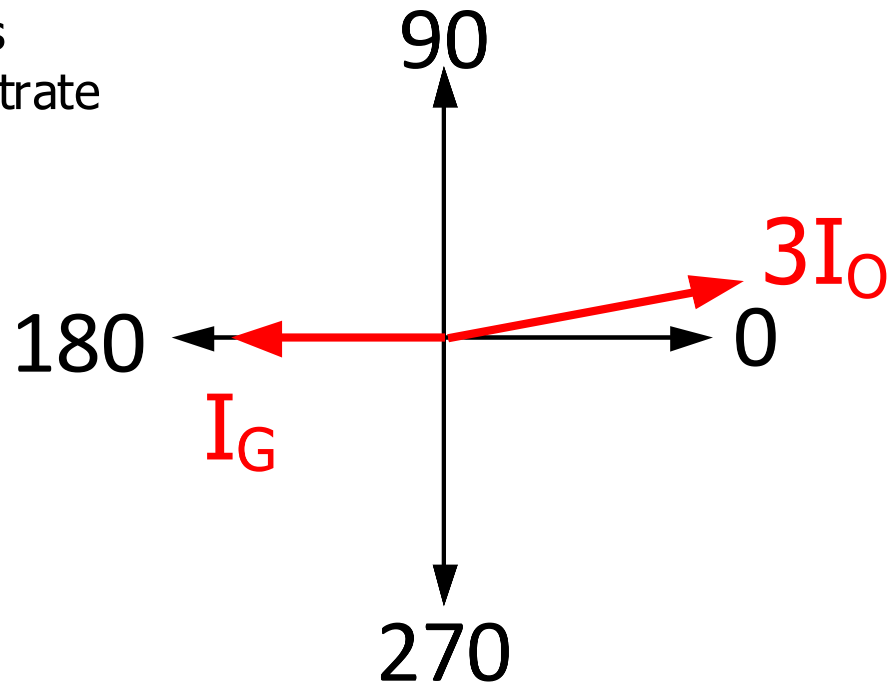
- Use 87GD
- $I_A + I_B + I_C = 3I_0$
- If fault is internal, opposite polarity
- If fault is external, same polarity



87GD with Internal Fault, Double Fed

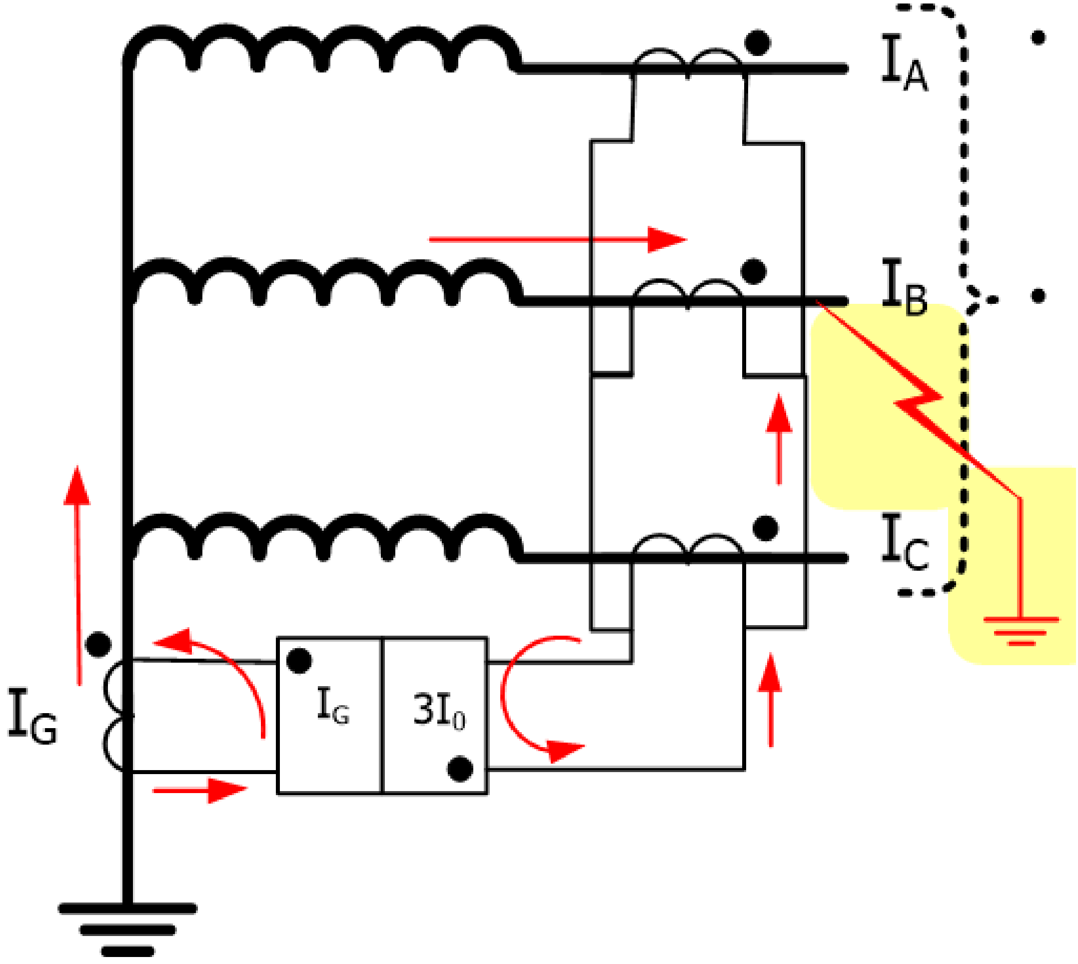


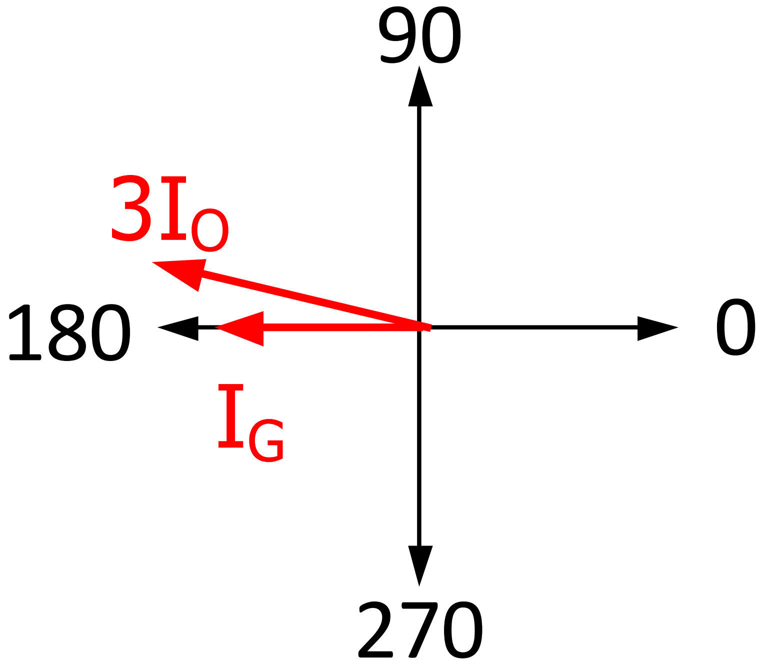
- Residual current ($3I_0$) calculated from individual phase currents
- Paralleled CTs shown to illustrate principle



$$-3I_o \times I_G \cos(180) = 3I_oI_G$$

87GD with External Through-Fault



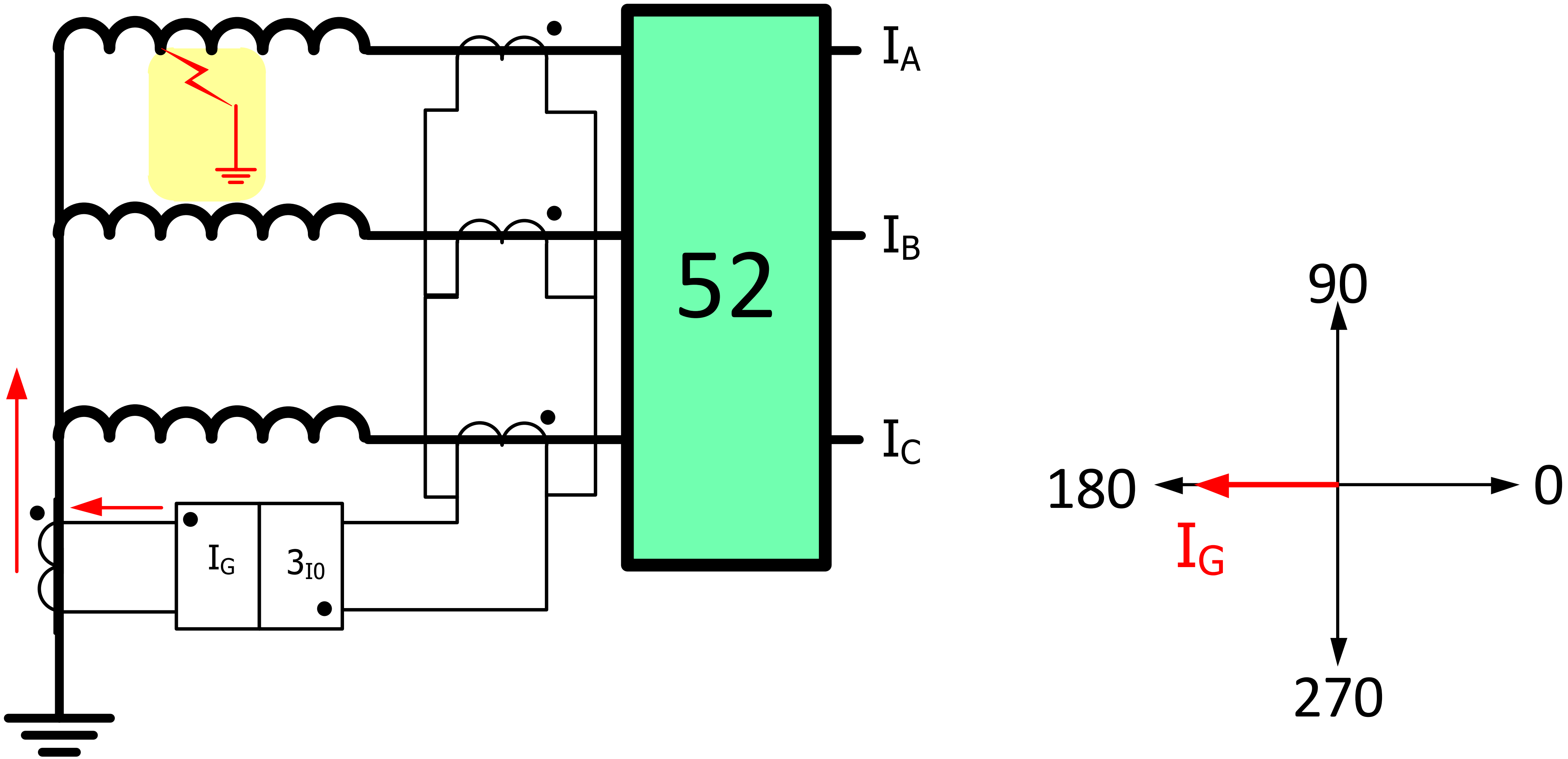


$$-3I_o \times I_G \cos(0) = -3I_oI_G$$

Improved Ground Fault Sensitivity (87GD)

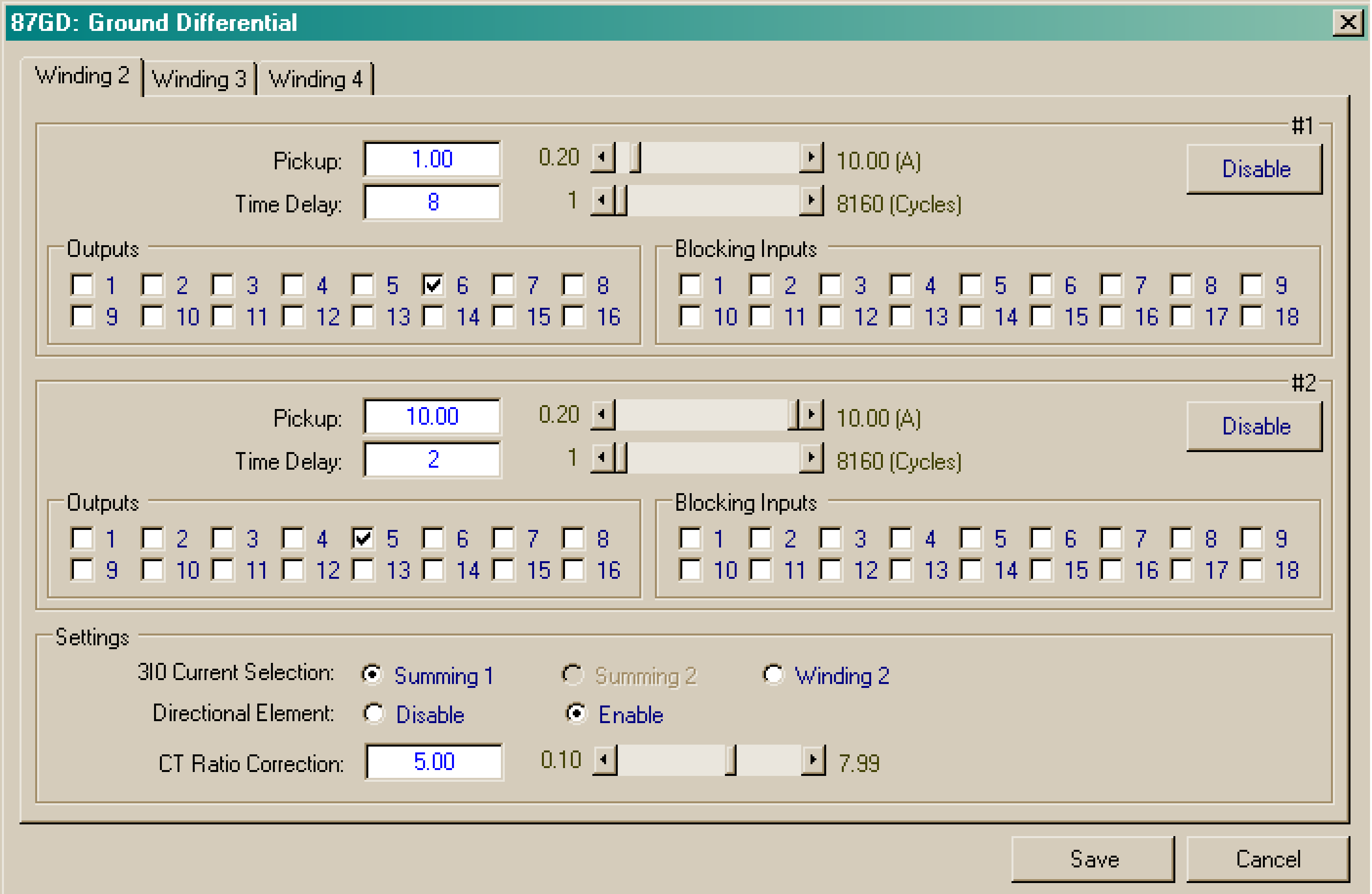
- Direction calculation used with currents over 140mA on both sets of CTs (3_{I0} and I_G)
- Directional element used to improve security for heavy external phase to phase faults that cause saturation
- When current >140mA, element uses current setting and directional signal
- When current <= 140mA, element uses straight differential current (Tsetting only)
  - Saturation will not occur at such low current levels
  - Directional signal not required for security
  - Allows element to function for internal faults without phase output current (open low side breaker, transformer energized) operating current = $I_A + I_B + I_C + I_G$

87GD with Internal Fault, Single Feed

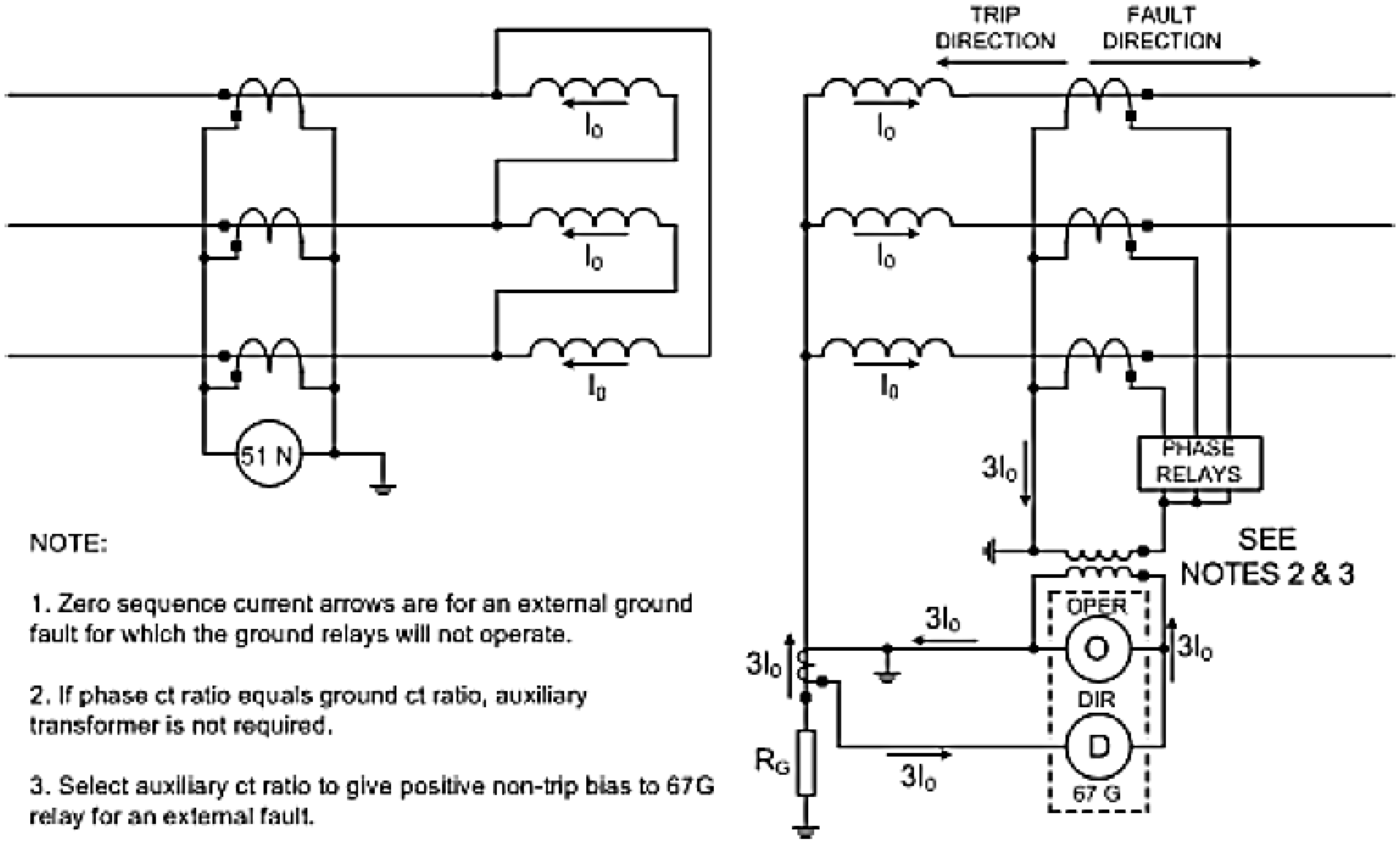


$I_A + I_B + I_C + I_G >$ setting

87GD Function: May be used with Current Summing



Ground Fault Protection for Delta-Wye Transformer

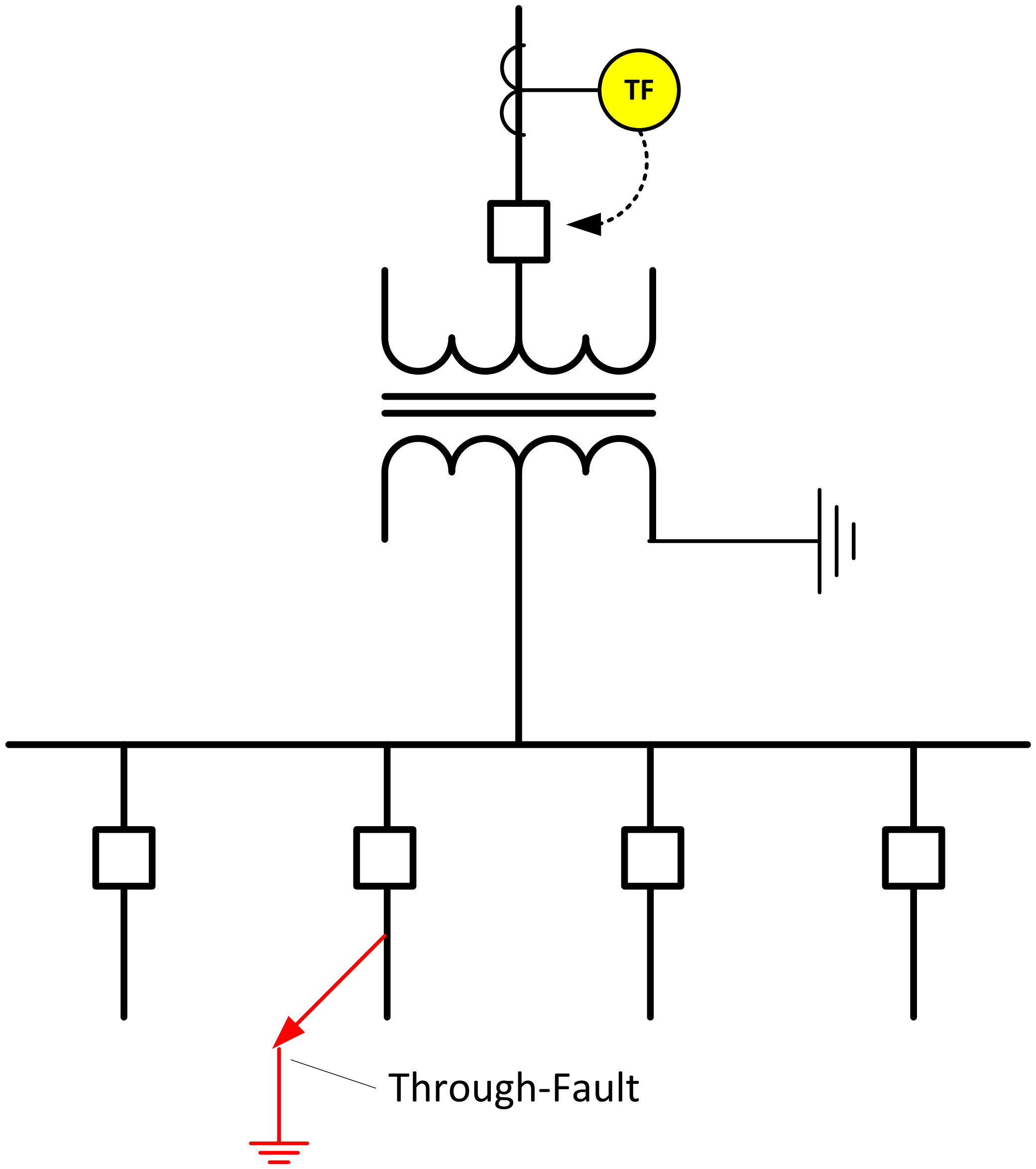


System must supply zero sequence current for this scheme to work

From IEEE C37.91

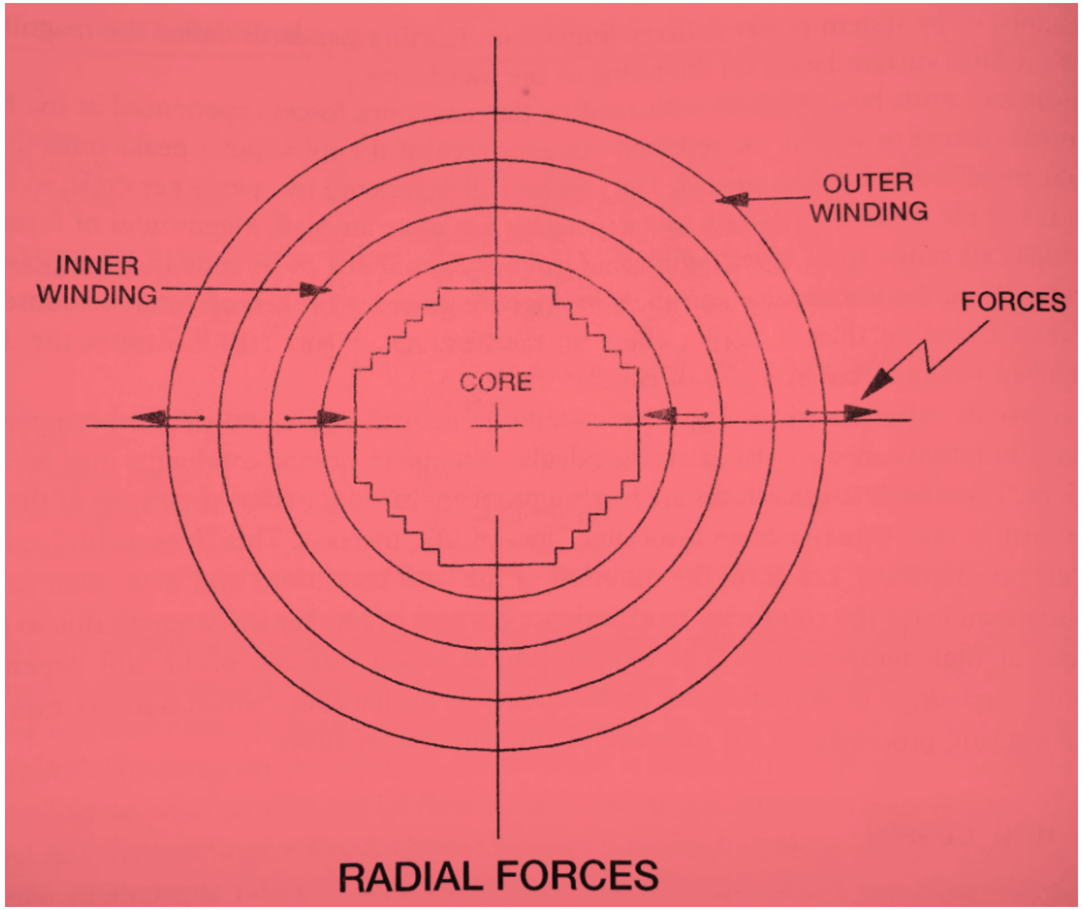
Through-Fault

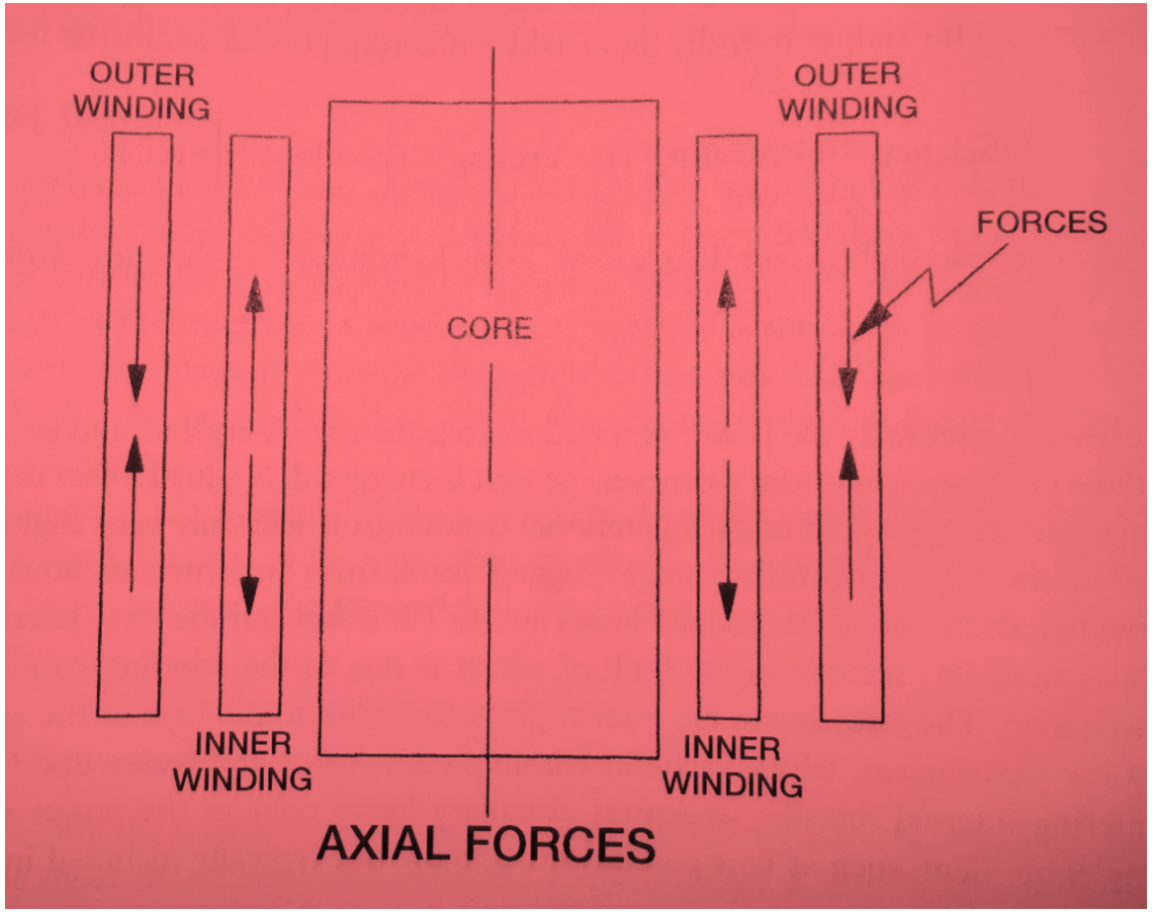
- Provides protection against cumulative through-fault damage
- Typically alarm function



Through-Fault

- A transformer is like a motor that does not spin
- There are still forces acting in it
- That is why we care about limiting through-faults

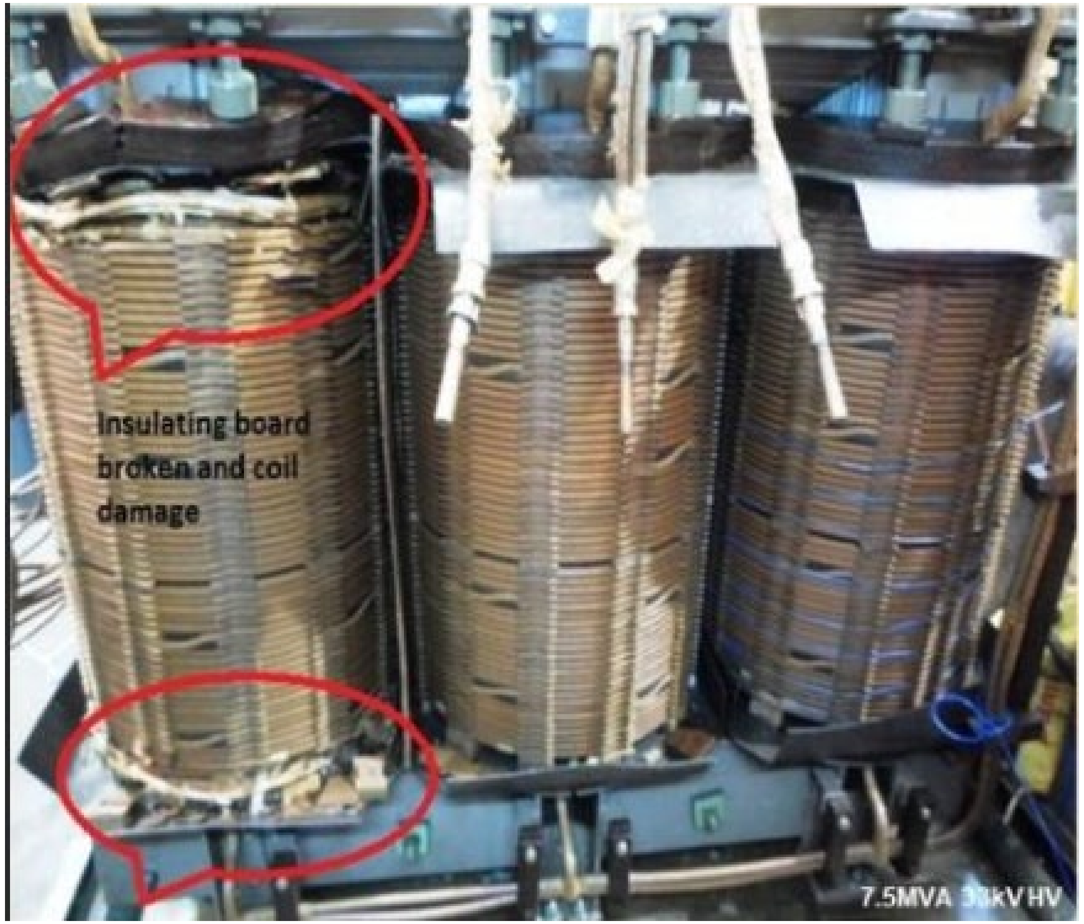




Electric Power Engineering Handbook

Through-Fault

- A transformer is like a motor that does not spin
- There are still forces acting in it
  - An example of what through-fault damage looks like



Source: EnconEngineers

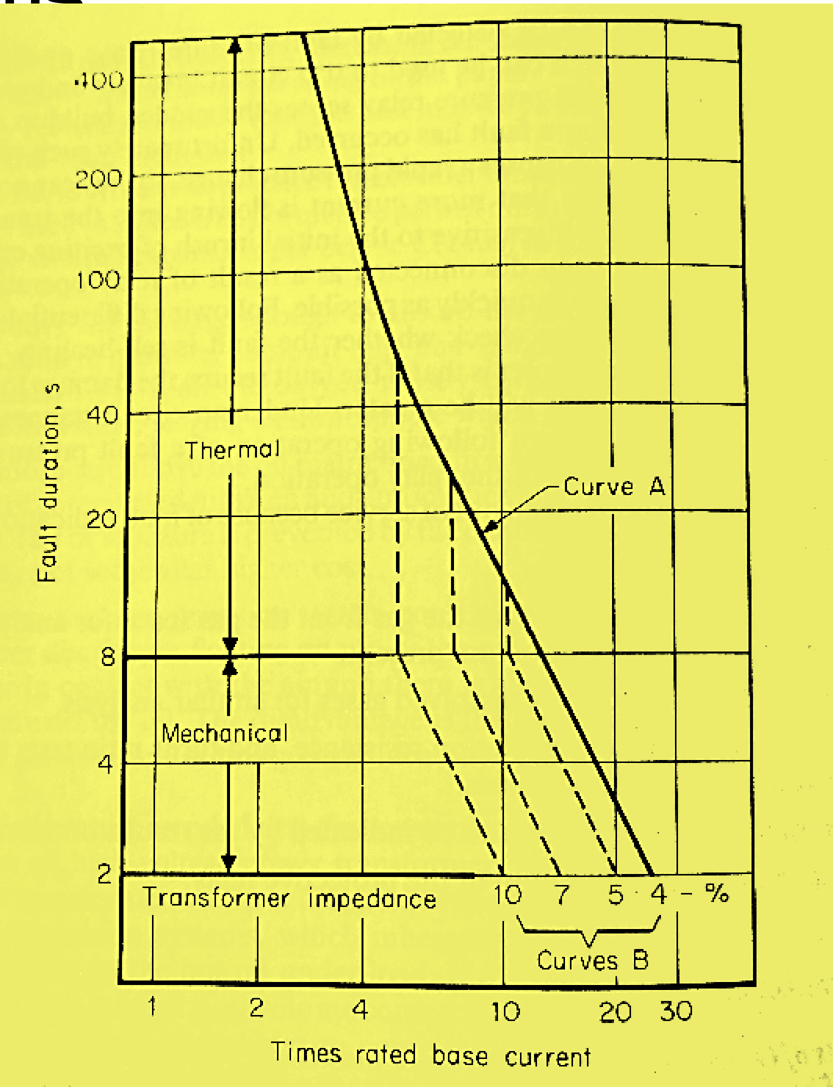
Through-Fault Monitoring

- Protection against heavy prolonged through-faults
- Transformer Category
  - IEEE Std. C57.109-1985 Curves

	Minimum nameplate (kVA)	
Category	**Single-Phase**	**Three-Phase**
I	5-500	15-500
II	501-1667	501-5000
III	1668-10,000	5001-30,000
IV	Above 10,000	Above 30,000

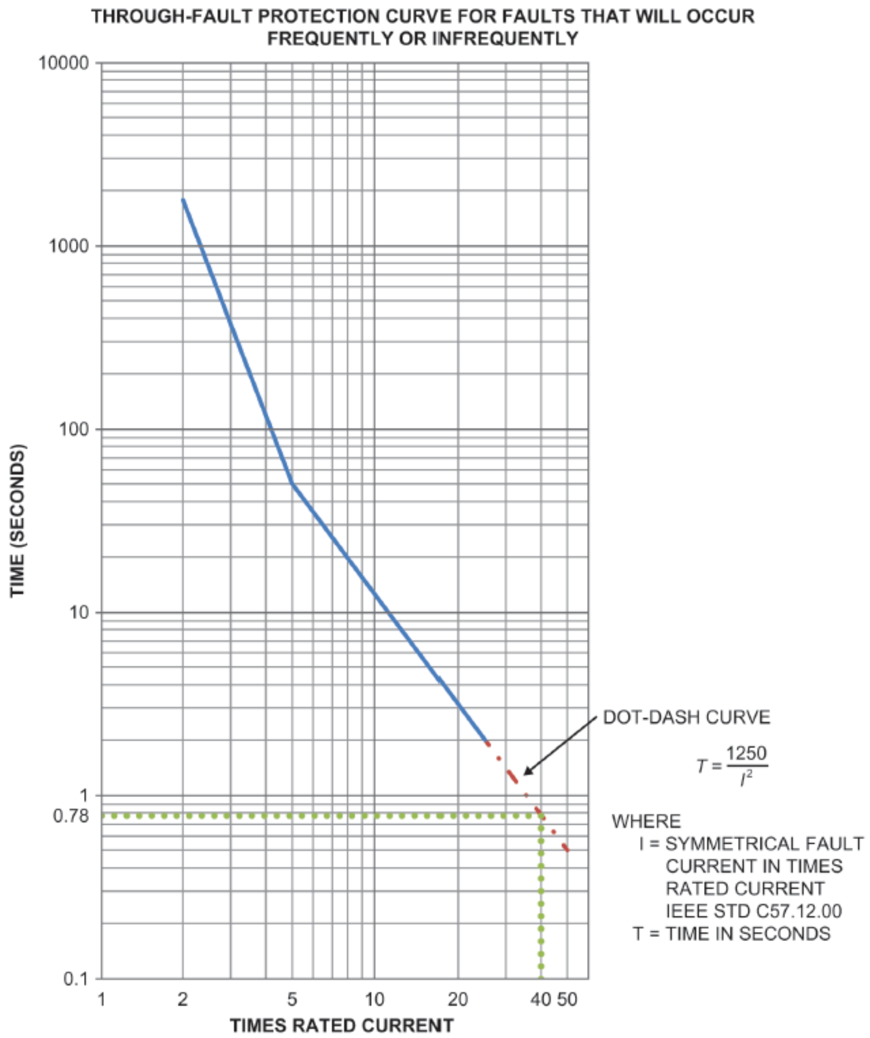
Through-Fault Damage Mechanisms

- Thermal Limits for prolonged through-faults typically 1-5X rated
  - Time limit of many seconds
- Mechanical Limits for shorter duration through-faults typically greater than 5X rated
  - Time limit of few seconds
- NOTE: Occurrence limits on each Transformer Class Graph



Standard Handbook for Electrical Engineers

Through-Fault Category 1 (15 kVA – 500 kVA)

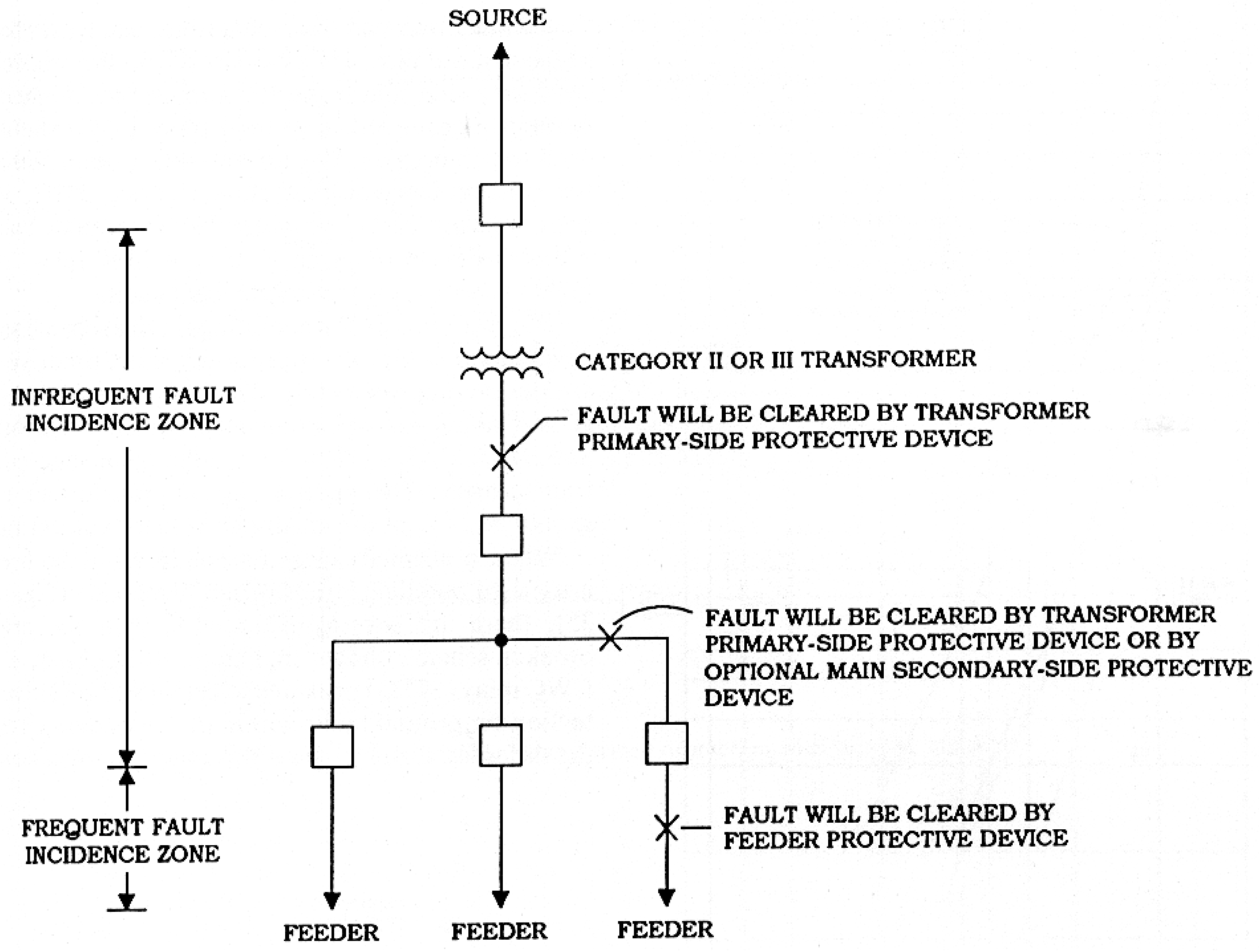


NOTE—Low current values of less than or equal to five times rated current do not follow the function $T = 1250/I^2$, rather the duration comes from Table 2.

Figure 1—Category I transformers: 5 kVA to 500 kVA single phase and 15 kVA to 500 kVA three phase

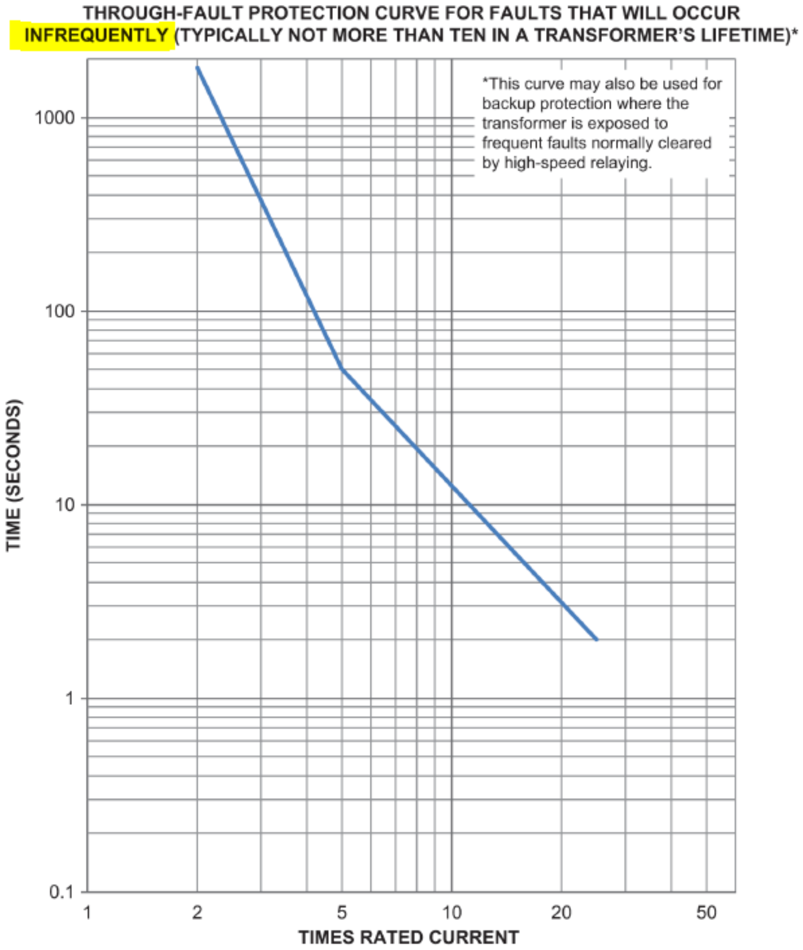
From IEEE C57.109-2018

Cat. 2 & 3 Fault Frequency Zones (501 kVA - 30 MVA)



From IEEE C37.91

Through-Fault Category 2 (501 kVA – 5 MVA)



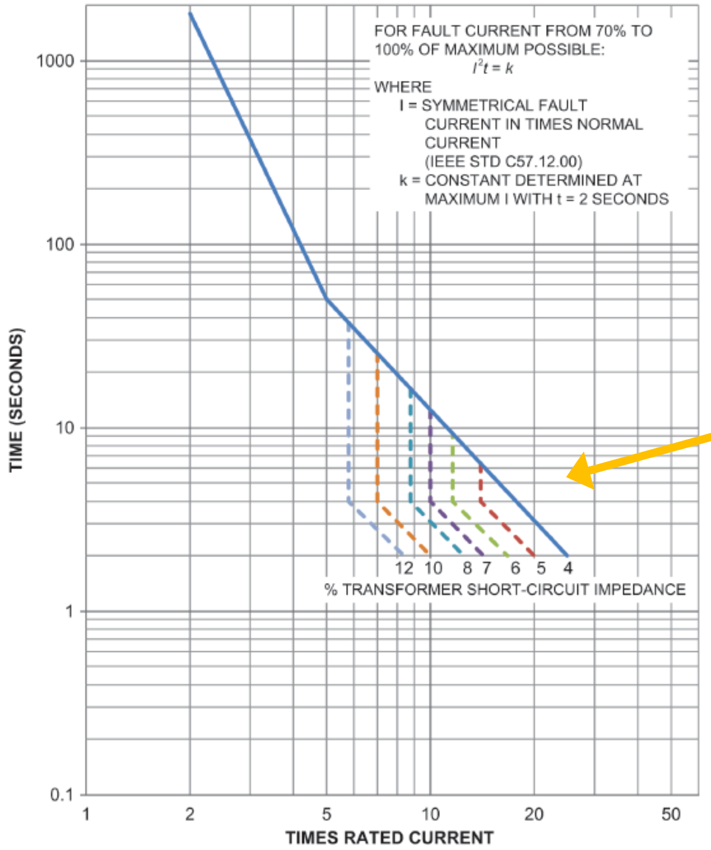
NOTE—Low current values of less than or equal to five times rated current may result from overloads rather than faults. An appropriate loading guide should be referred to for specific allowable time durations.

Figure 3—Category II transformers: 501 kVA to 1667 kVA single-phase and 501 kVA to 5000 kVA three phase

From IEEE C57.109-2018

Through-Fault Category 2 (501 kVA – 5 MVA)

THROUGH-FAULT PROTECTION CURVE FOR FAULTS THAT WILL OCCUR FREQUENTLY
(TYPICALLY MORE THAN TEN IN A TRANSFORMER'S LIFETIME)



NOTE 1—Sample $I^2t = k$ curves have been plotted for selected transformer short circuit impedances.

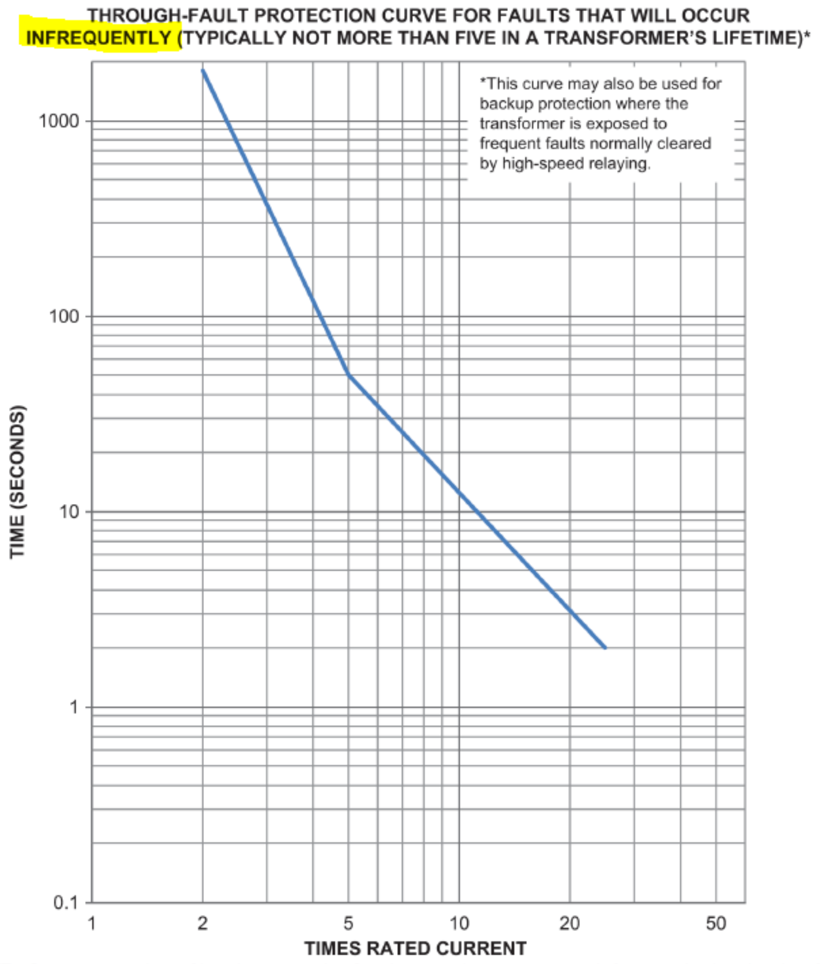
NOTE 2—Low current values of less than or equal to five times rated current may result from overloads rather than faults. An appropriate loading guide should be referred to for specific allowable time durations.

Figure 2—Category II transformers: 501 kVA to 1667 kVA single-phase and 501 kVA to 5000 kVA three phase

Through-Fault damage increases for a given amount of transformer Z%, as more I (I^2) through the Z results in higher energy (forces)

From IEEE C57.109-2018

Through-Fault Category 3 5.001 MVA – 30 MVA

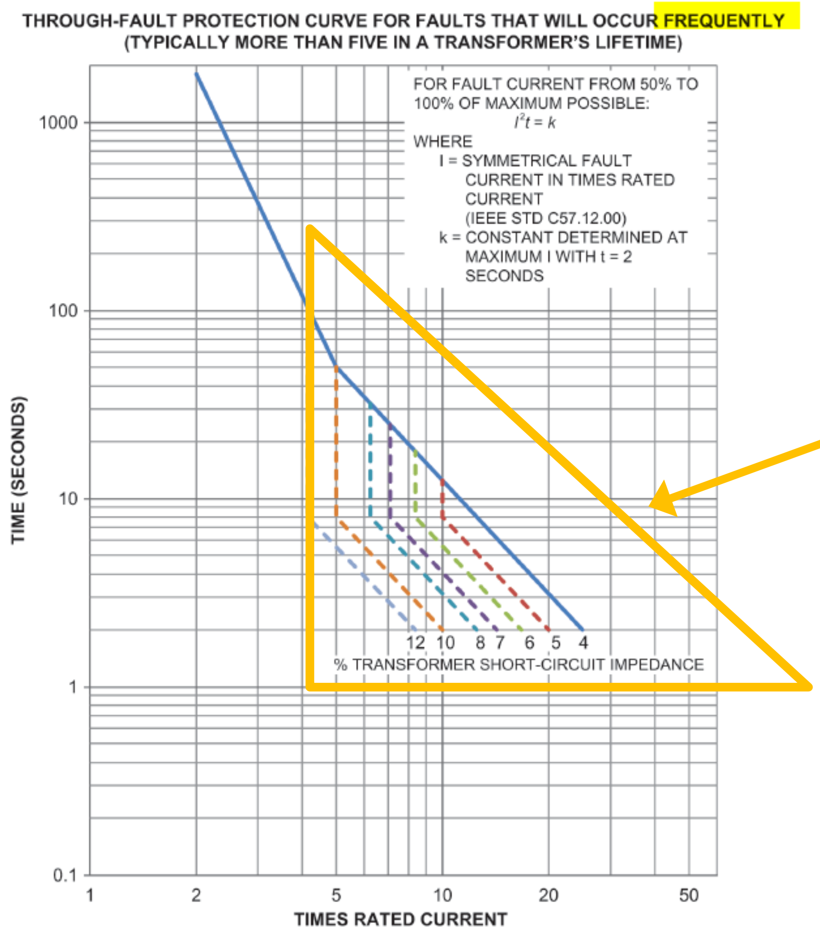


NOTE—Low current values of less than or equal to five times rated current may result from overloads rather than faults. An appropriate loading guide should be referred to for specific allowable time durations.

Figure 5—Category III transformers: 1668 kVA to 10 000 kVA single phase and 5001 kVA to 30 000 kVA three phase

From IEEE C57.109-2018

Through-Fault Category 3 5.001 MVA – 30 MVA



NOTE 1—Sample $I^2t = k$ curves have been plotted for selected transformer short circuit impedances.

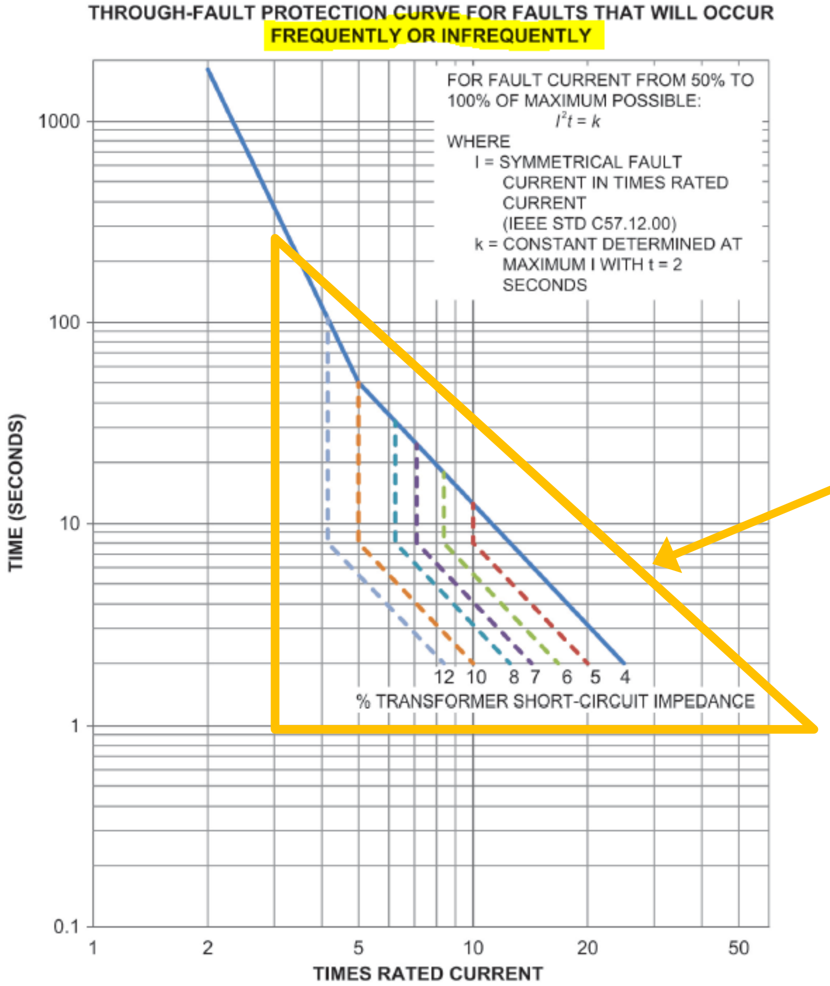
NOTE 2—Low current values of less than or equal to five times rated current may result from overloads rather than faults. An appropriate loading guide should be referred to for specific allowable time durations.

Figure 4—Category III transformers: 1668 kVA to 10 000 kVA single phase and 5001 kVA to 30 000 kVA three phase

Through-Fault damage increases for a given amount of transformer Z%, as more I (I^2) through the Z results in higher energy (forces)

From IEEE C57.109-2018

Through-Fault Category 4 (>30 MVA)



NOTE 1—Sample $I^2t = k$ curves have been plotted for selected transformer short circuit impedances as noted.

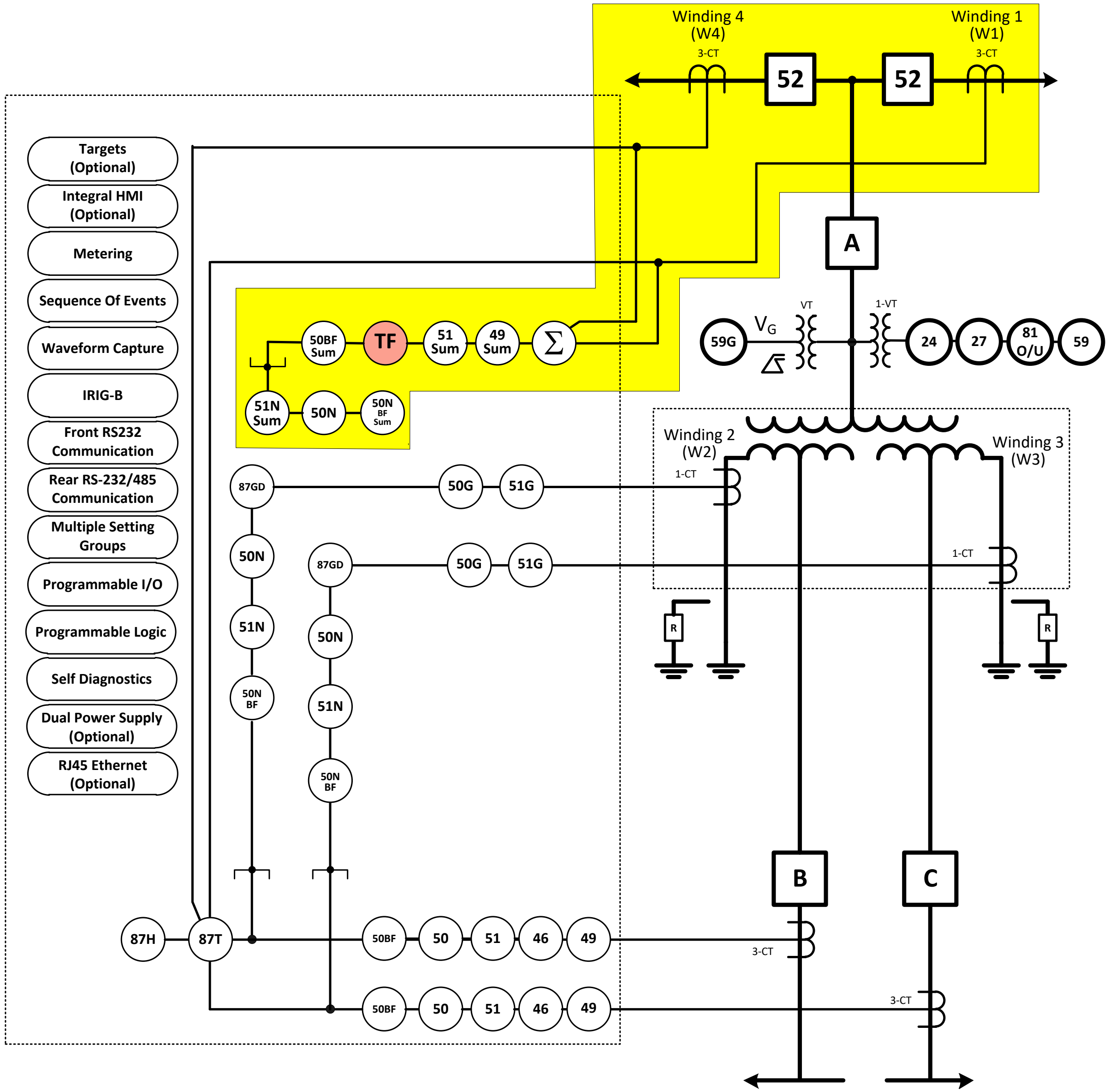
NOTE 2—Low current values of less than or equal to five times rated current may result from overloads rather than faults. An appropriate loading guide should be referred to for specific allowable time durations.

Figure 6—Category IV transformers: above 10 000 kVA single-phase and above 30 000 kVA three-phase

Through-Fault damage increases for a given amount of transformer Z%, as more I (I^2) through the Z results in higher energy (forces)

From IEEE C57.109-2018

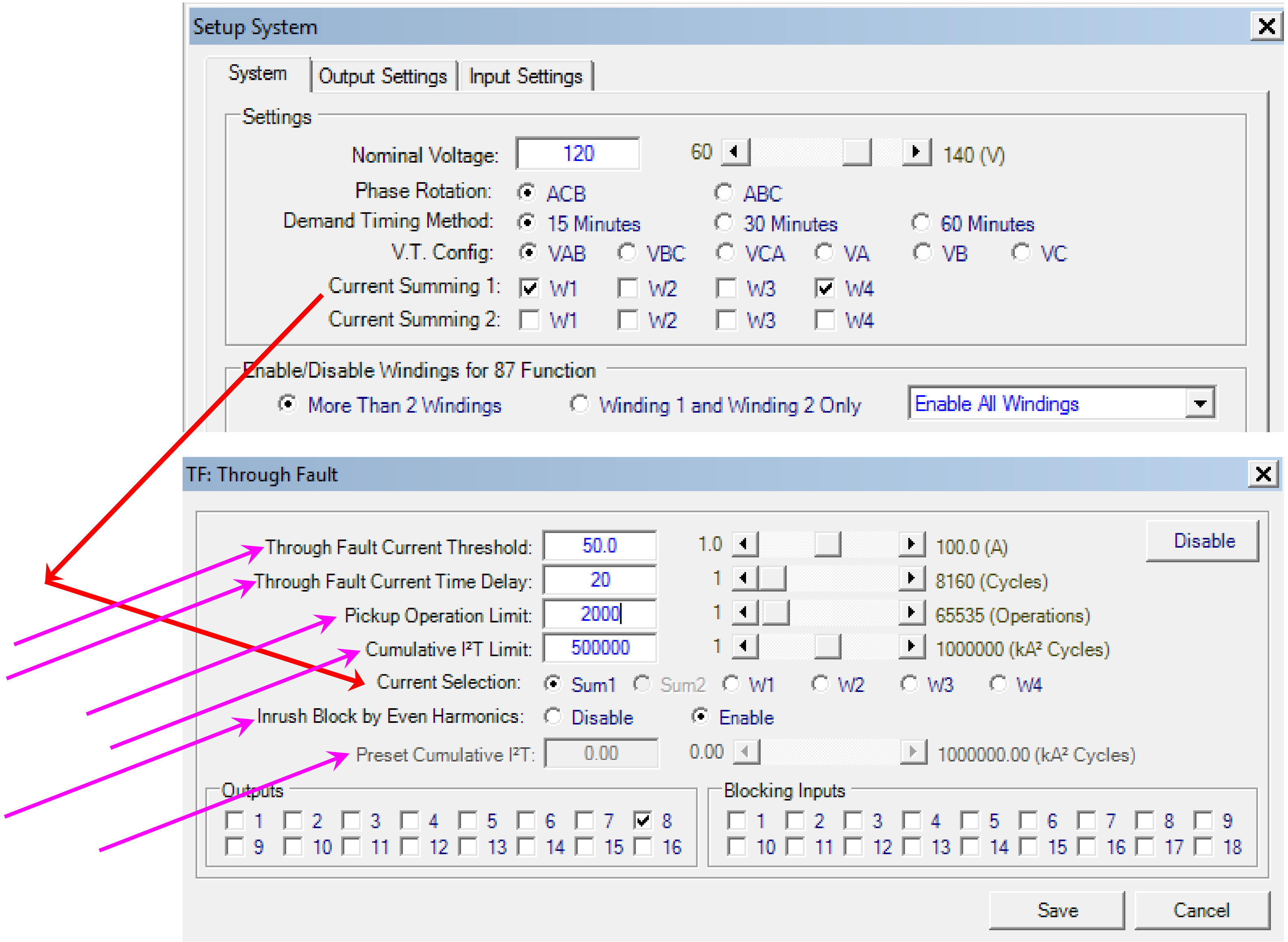
4 Winding with Current Summing & Through-Fault



Through-fault Function Settings (TF)

- Should have a **current threshold** to discriminate between mechanical and thermal damage areas
  - May ignore through-faults in the thermal damage zone that fails to meet recording criteria
- Should have a **minimum through-fault event time delay** to ignore short transient through-faults
- Should have a **through-fault operations counter**
  - Any through-fault that meets recording criteria increments counter
- Should have a **preset** for application on existing assets with through-fault history
- Should have **cumulative I^2t setting**
  - How total damage is tracked
- Should use **inrush restraint** to not record inrush periods
- Inrush does not place the mechanical forces to the transformer as does a through-fault

Through-fault Function Settings (TF)



49 Thermal Overcurrent

- The Transformer Overload function (49) provides protection against possible damage during overload conditions
- IEC-255-8 standard (presently under revision), provides both cold and hot curves
- The function uses the thermal time constant of the transformer and the maximum allowable continuous overload current (Imax) in implementing the inverse time characteristic

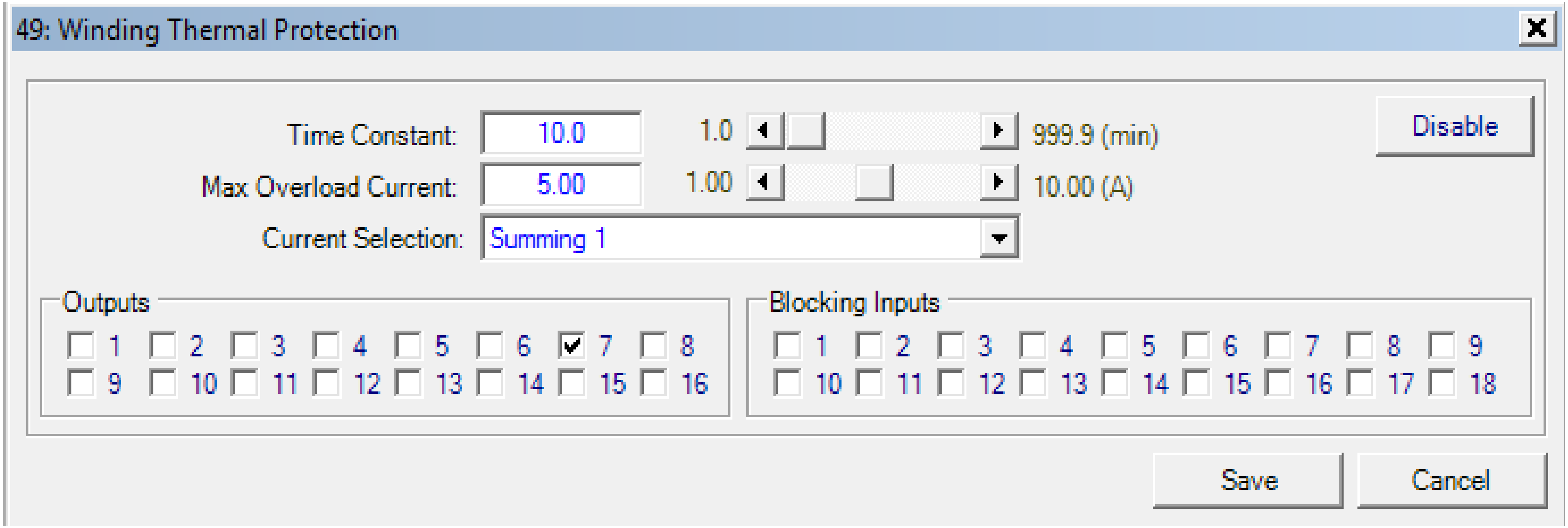
49 Thermal Overcurrent

The operating time is defined according to the standard

IEC 60255-8 (superseded by IEC 60255-149):

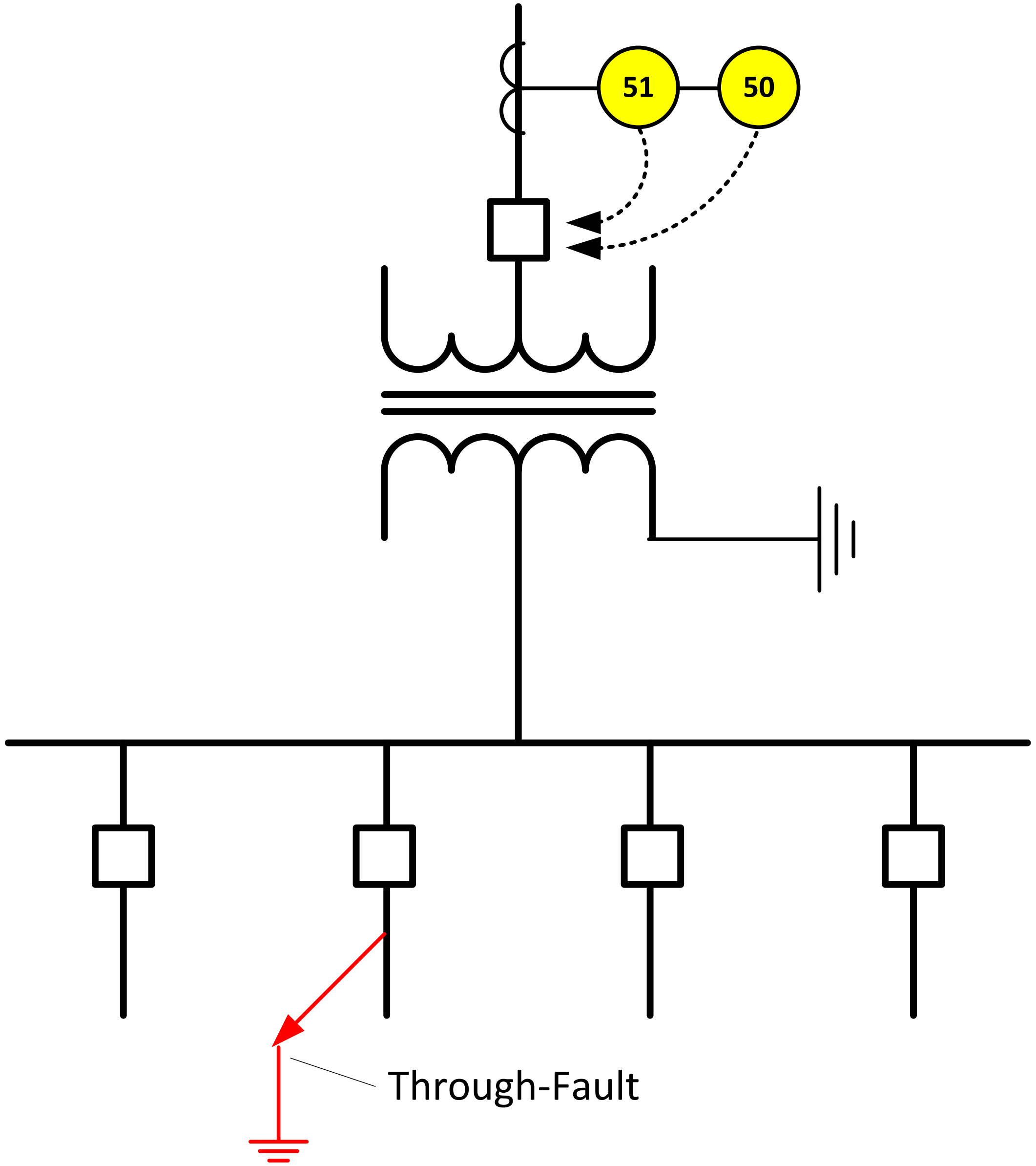
$$t = \tau \times \ln \left(\frac{I_L^2 - I_{PL}^2}{I_L^2 - I_{max}^2} \right)$$

49 Thermal Overcurrent



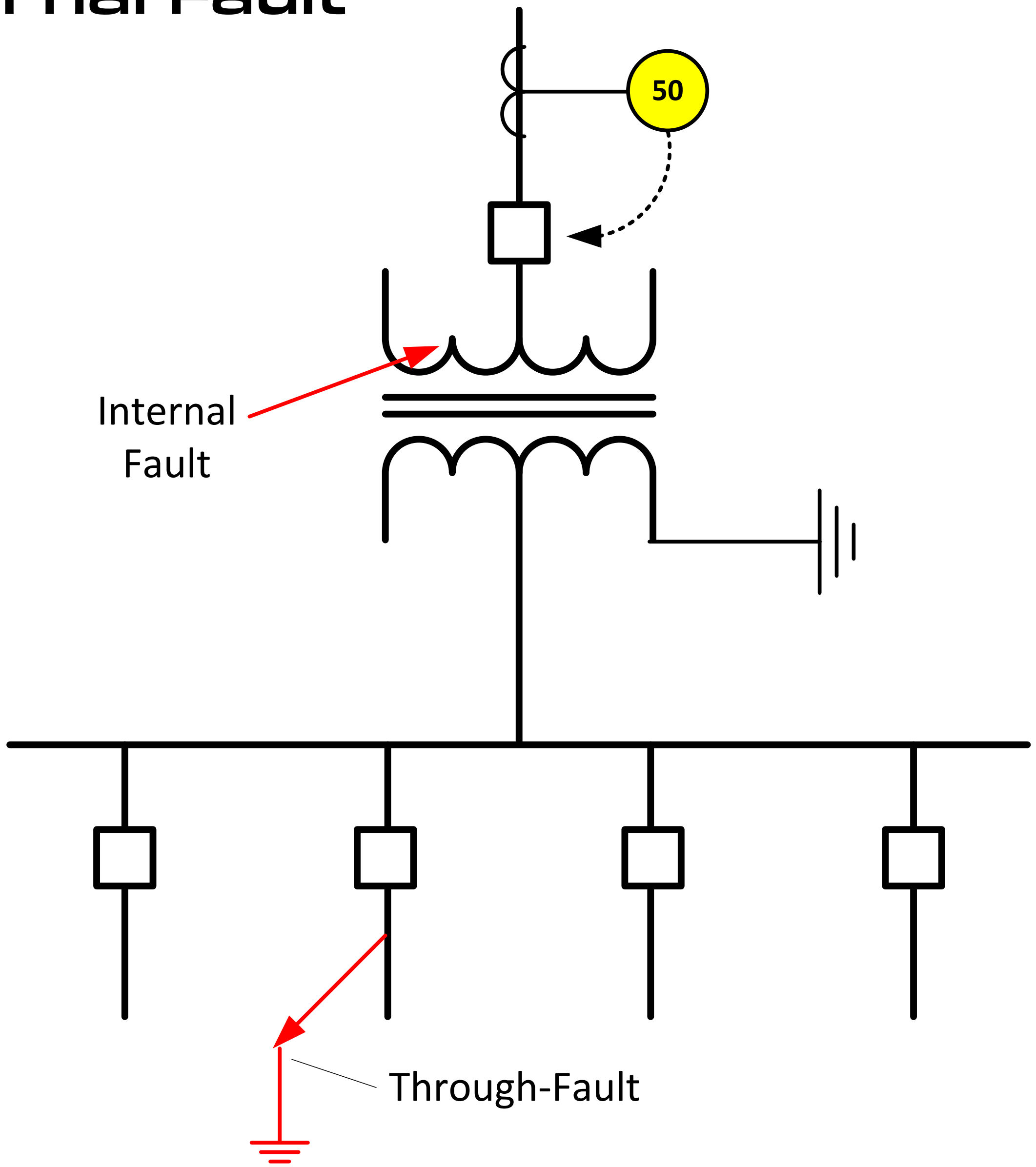
High Side Overcurrent

- Back up to differential, sudden pressure
- Coordinated with line protection off the bus
  - Do not want to trip for low-side external faults

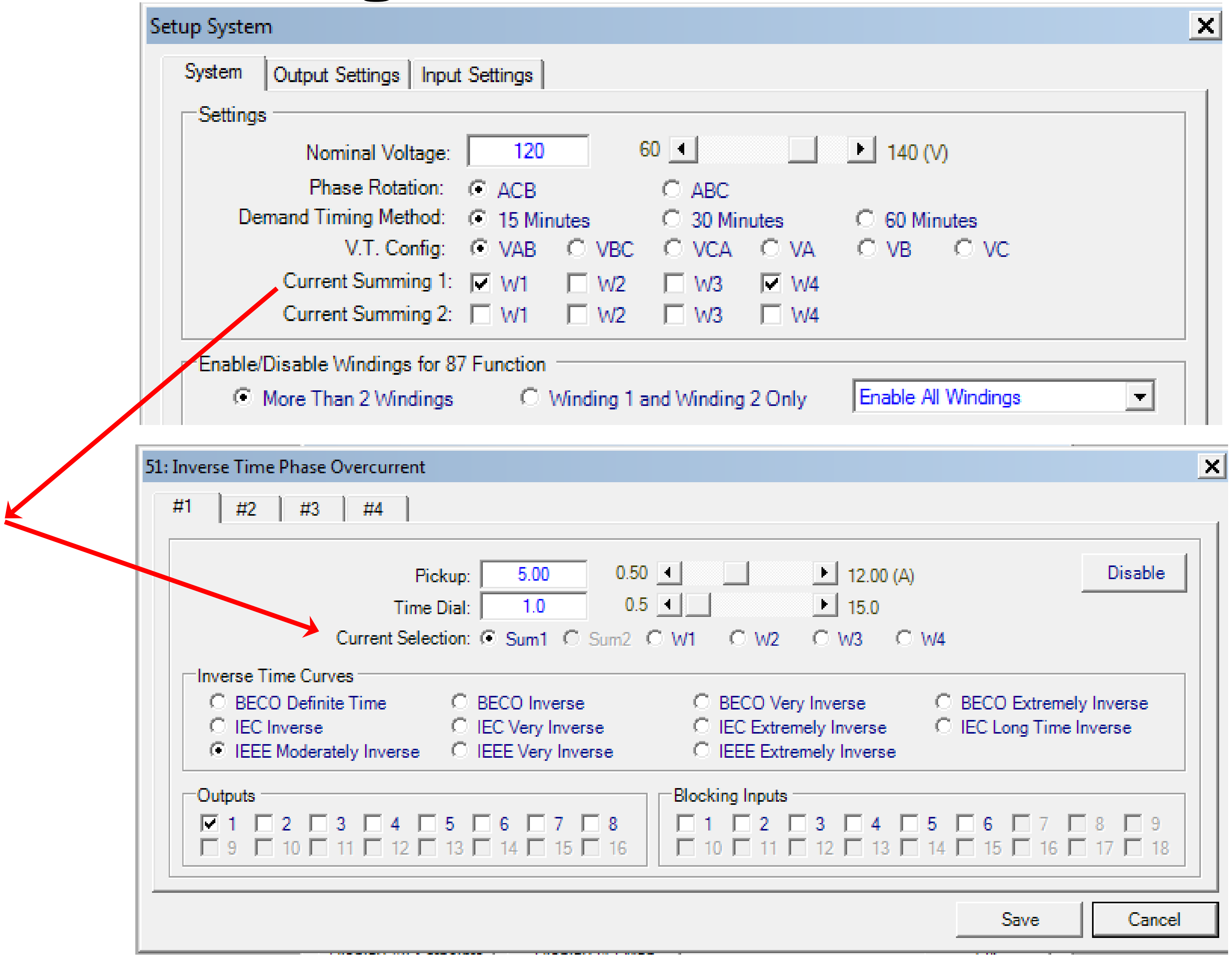


High Side Overcurrent for Internal Fault

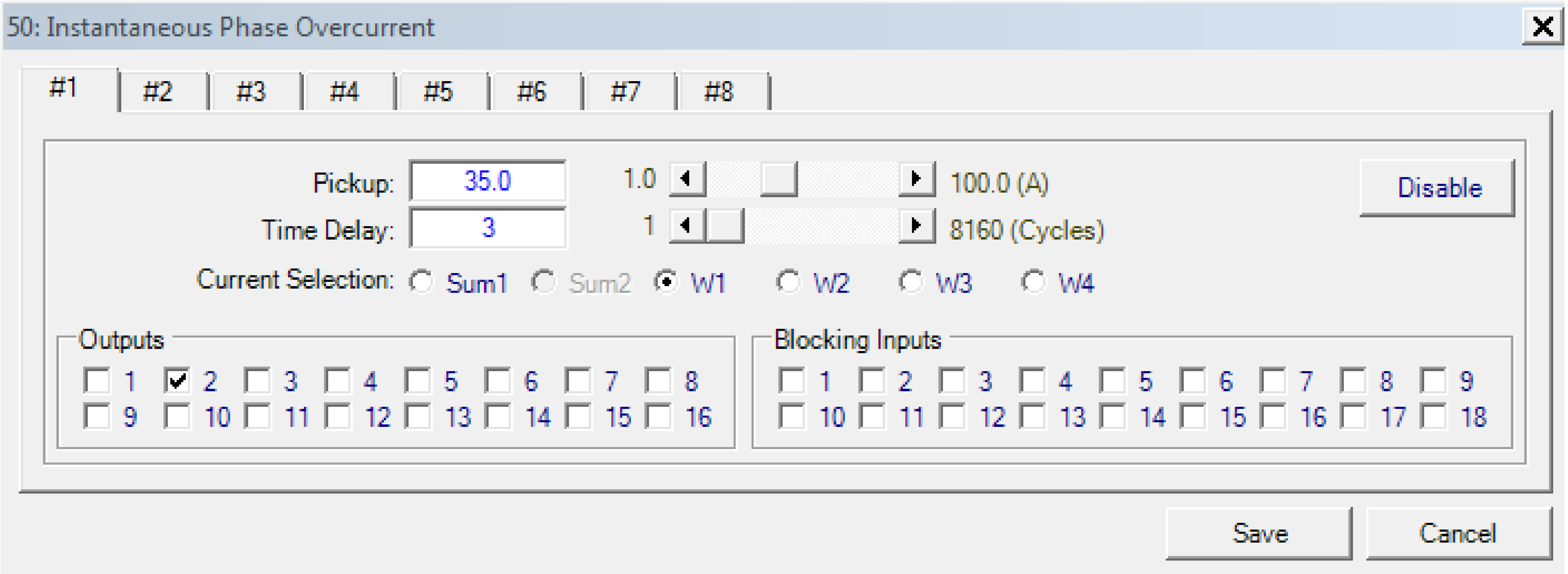
- Set to pick up at a value higher than the maximum asymmetrical through-fault current.
  - This is usually the fault current through the transformer for a low-side three-phase short circuit.
- Instantaneous units that are subject to transient overreach are set for pickup in the range of 125% to 200%.



51 Function Settings

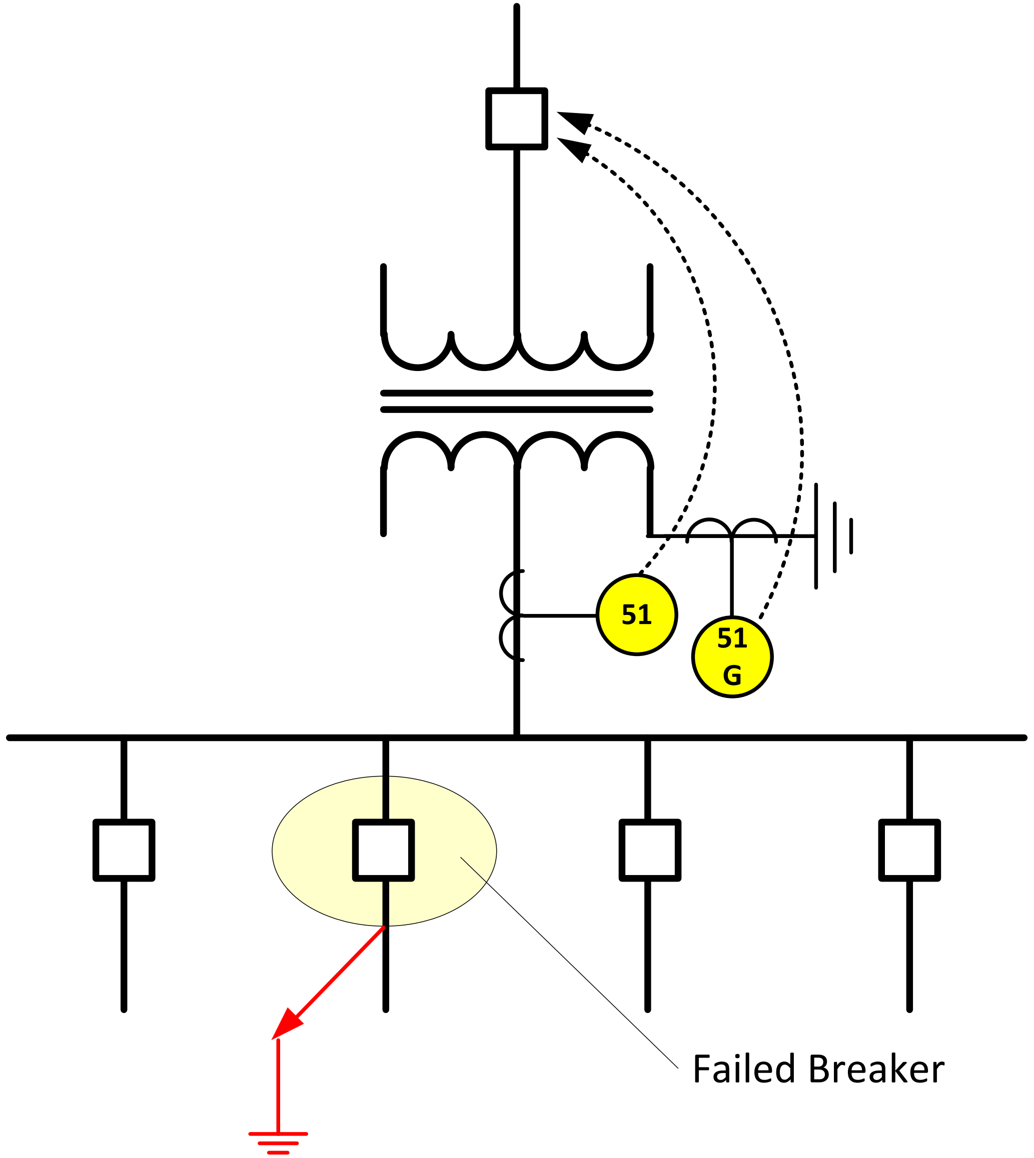


50 Function Settings



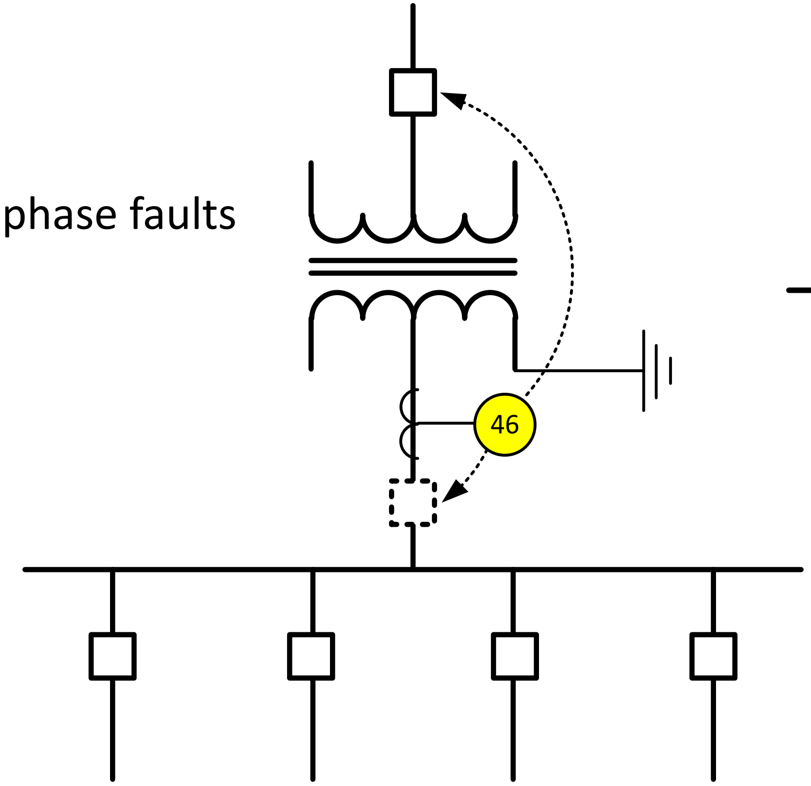
Low Side Overcurrent

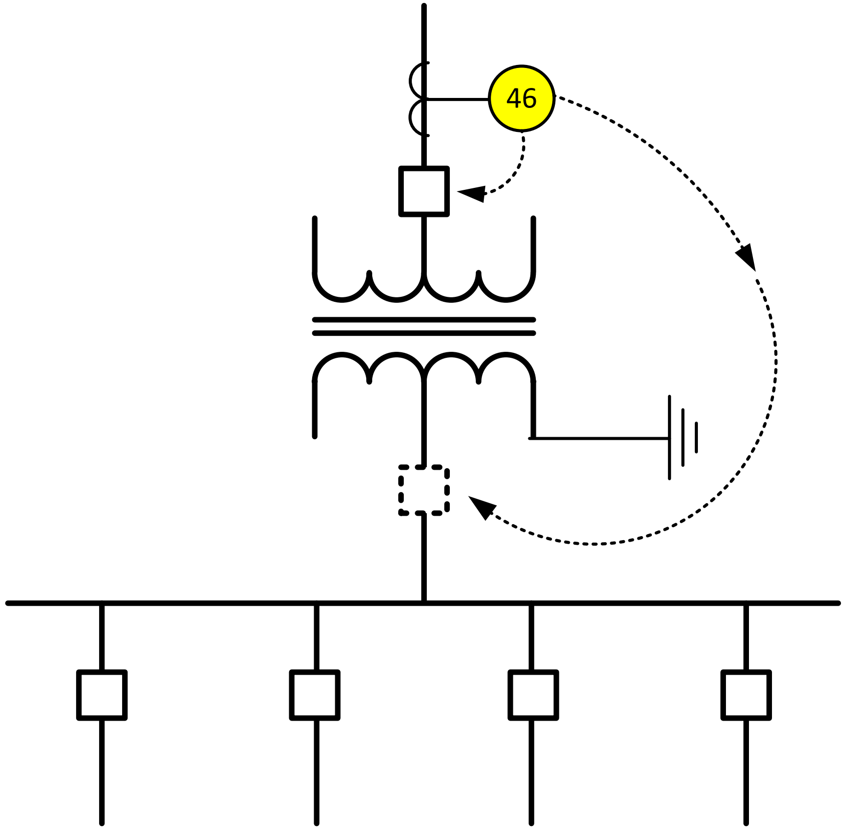
- Provides protection against uncleared faults downstream of the transformer
- May consist of phase and ground elements
- Coordinated with downline protection off the bus



Negative Sequence Overcurrent

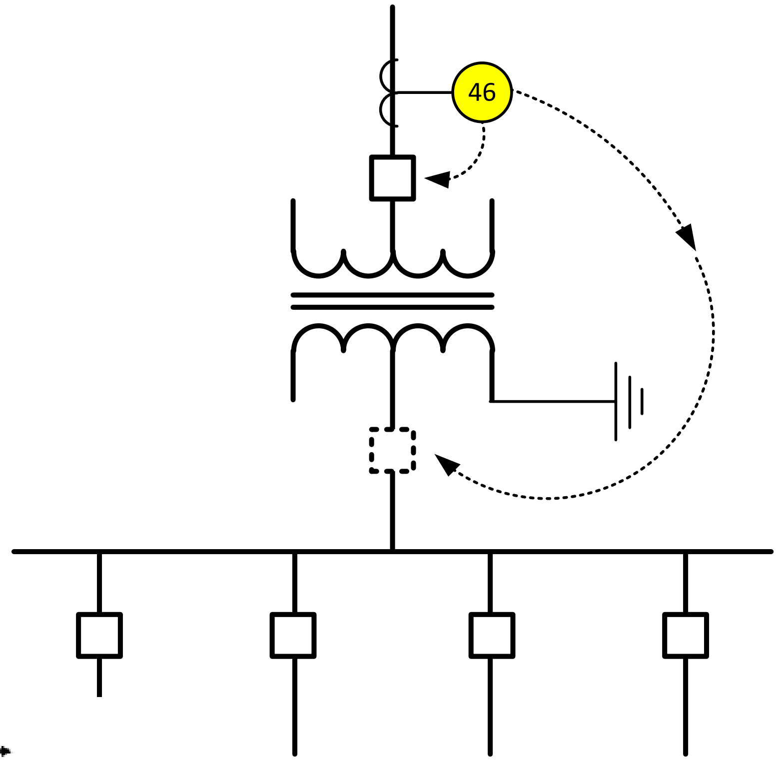
- Negative sequence overcurrent provides protection against:
  - Unbalanced loads
  - Open conductors
  - Phase-to-phase faults
  - Ground faults
    - Does not protect against 3-phase faults

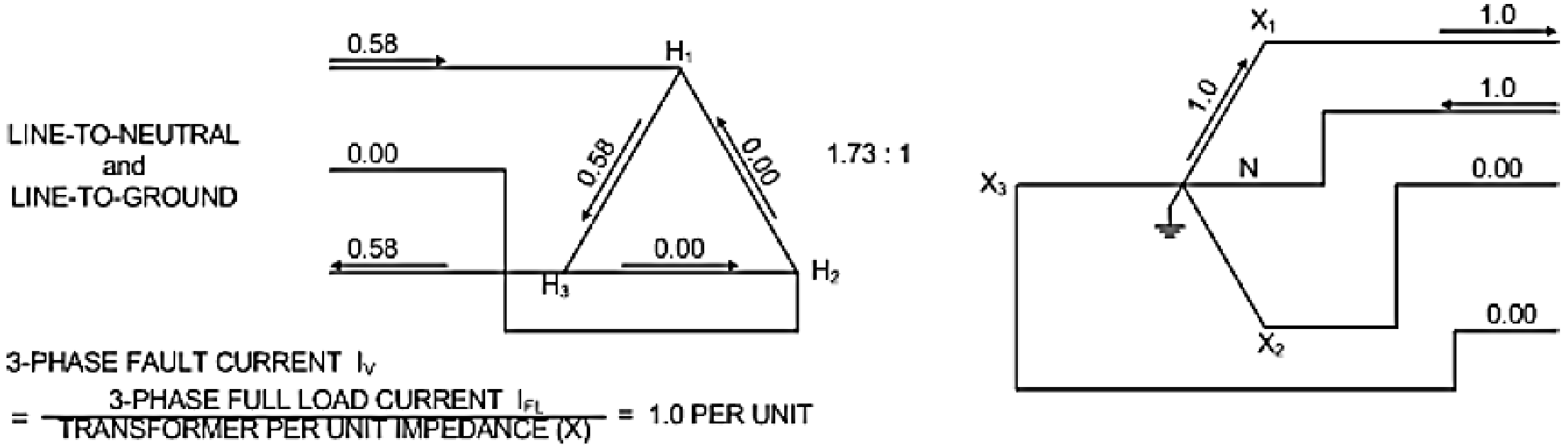




Negative Sequence Overcurrent

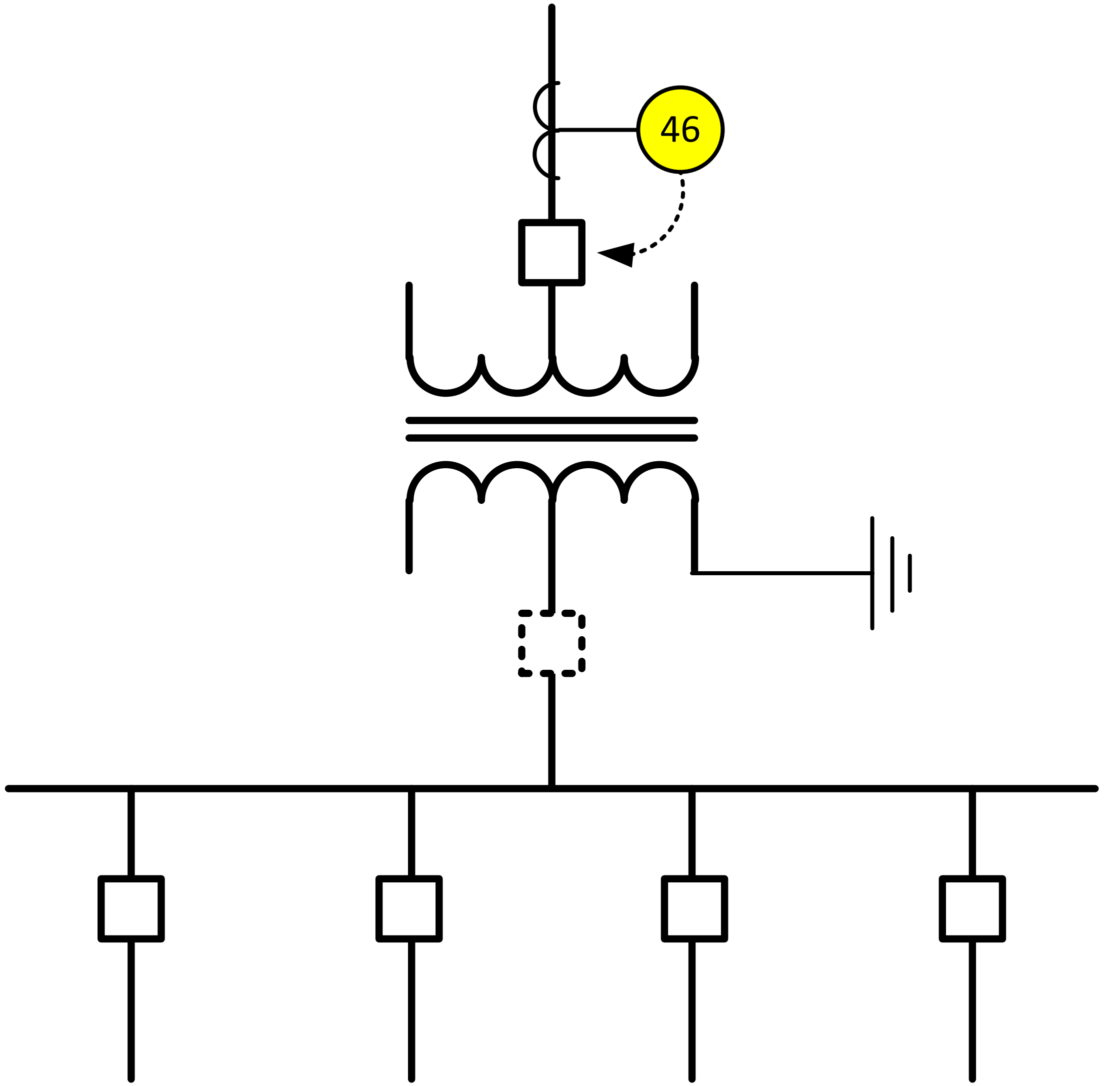
- Can be connected in the primary supply to protect for secondary phase-to-ground or phase-to-phase faults
- Helpful on delta-wye grounded transformers where only 58% of the secondary p.u. phase-to-ground fault current appears in any one primary phase conductor





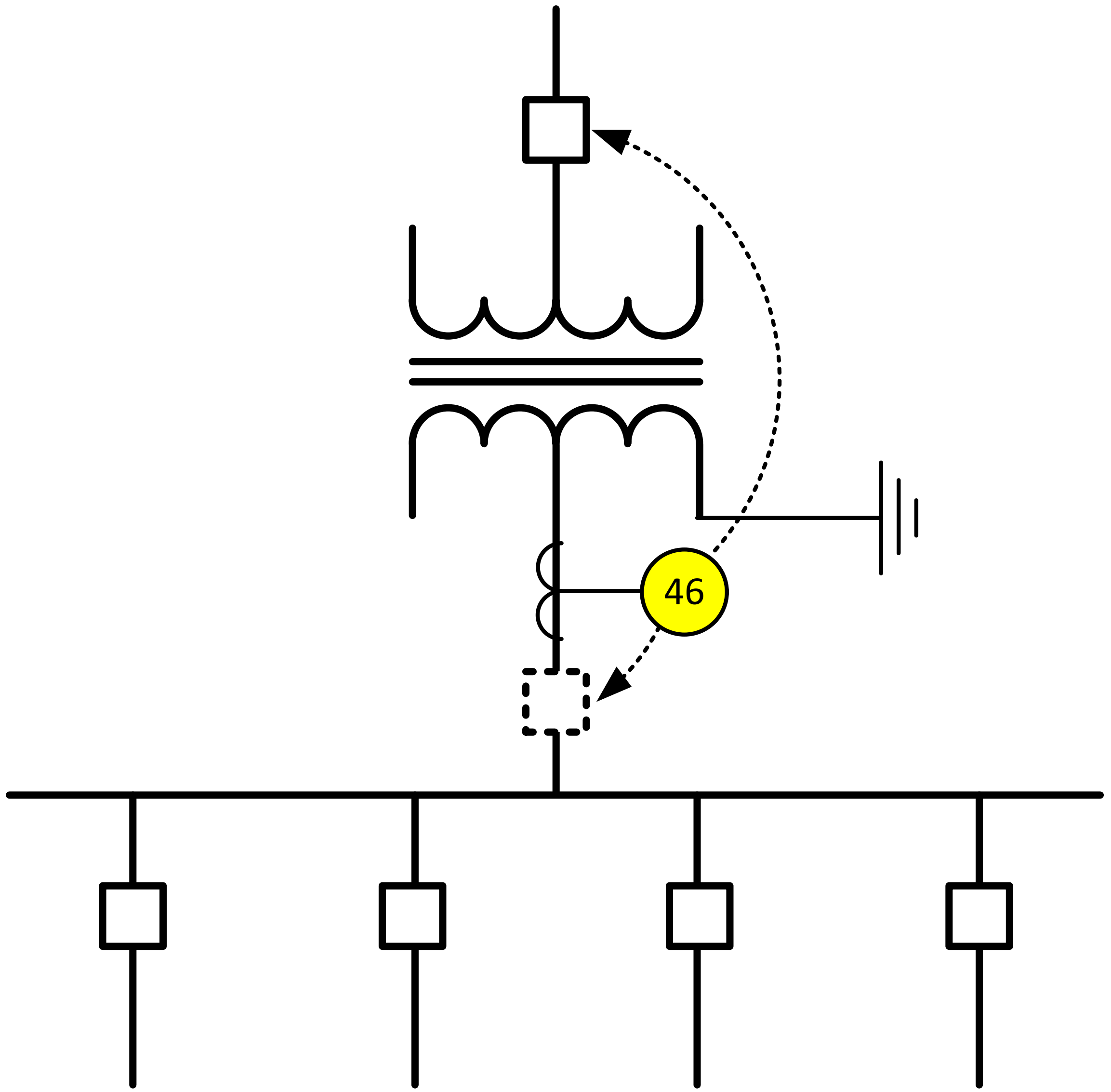
Negative Sequence Overcurrent

- Provides better protection than phase overcurrent relays for internal transformer faults
- The relay must also be set higher than the negative-sequence current due to unbalanced loads
- The relay should be set to coordinate with the low-side phase and ground relays for phase-to-ground and phase-to-phase faults

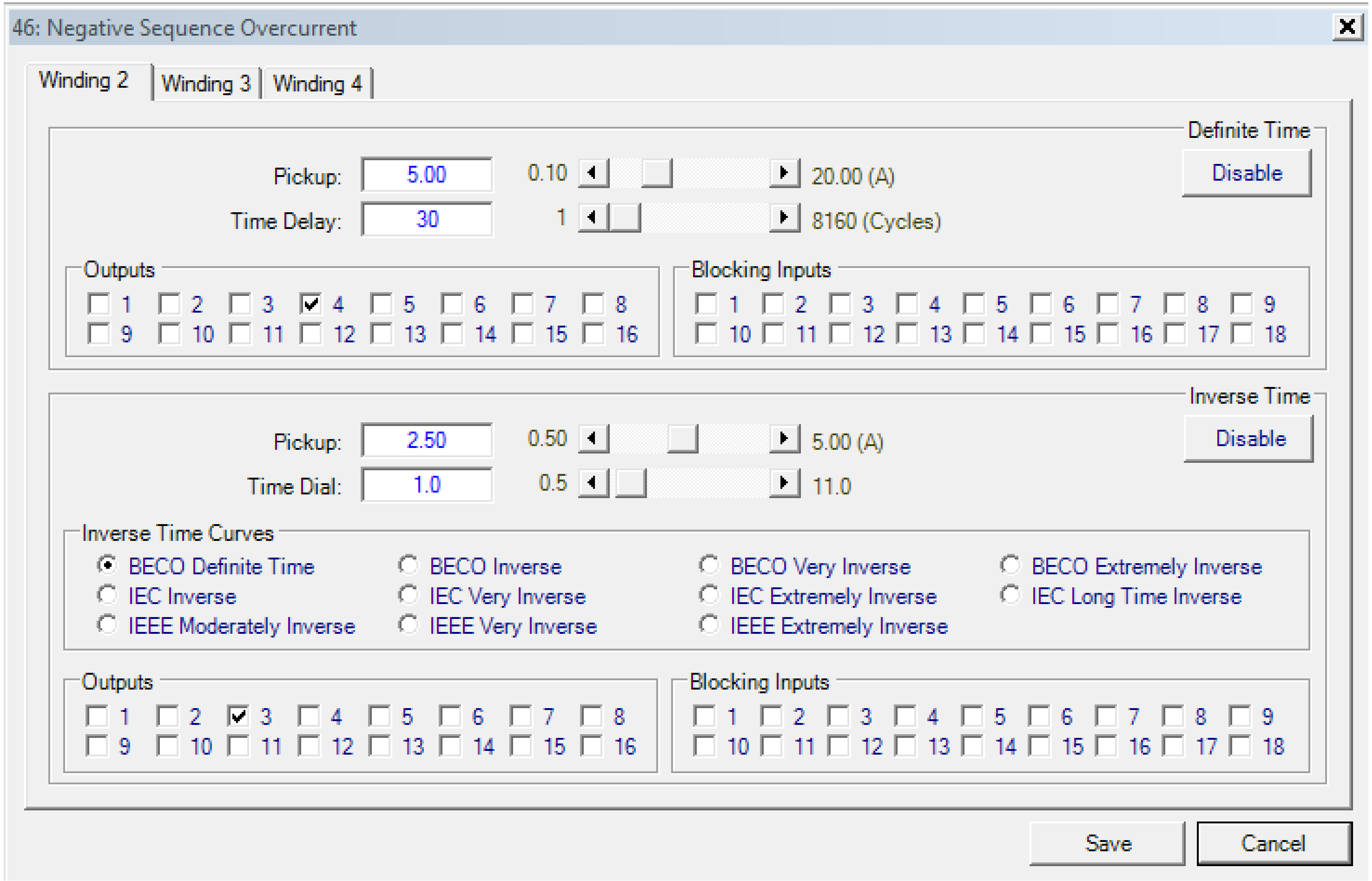


Negative Sequence Overcurrent

- Negative sequence relays can be set below load current levels and can be set more sensitively than phase overcurrent relays for phase-to-phase fault detection.
- In many applications, phase overcurrent relay pickup settings can be higher, allowing more feeder load capability.



46 Function Settings



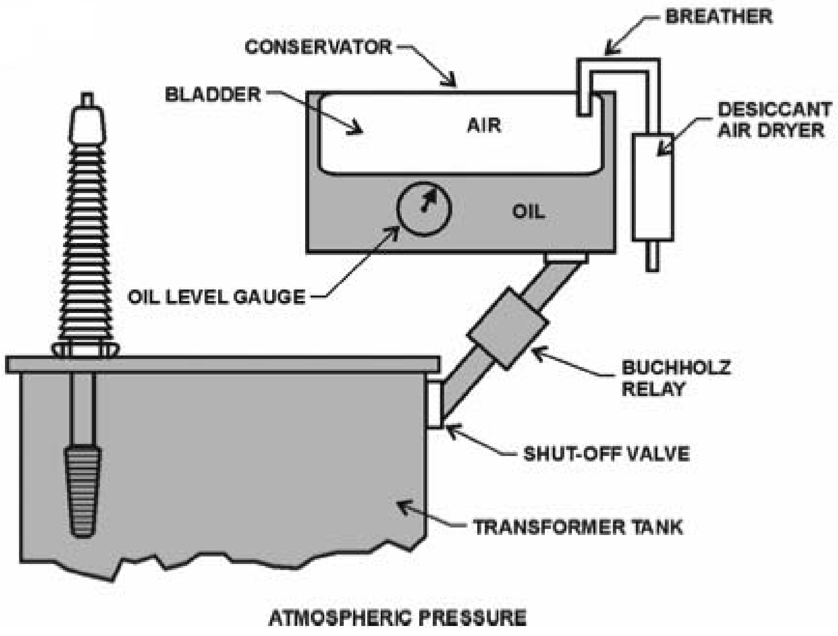
Types of Protection

Mechanical

- Accumulated Gases
  - Arcing by-products (Buchholz Relay)
- Pressure Relays
  - Arcing causing pressure waves in oil or gas space (Sudden Pressure Relay)
- Thermal
  - Caused by overload, overexcitation, harmonics and Geo-magnetically induced currents (GIC)
    - Hot spot temperature
    - Top Oil
    - LTC Overheating

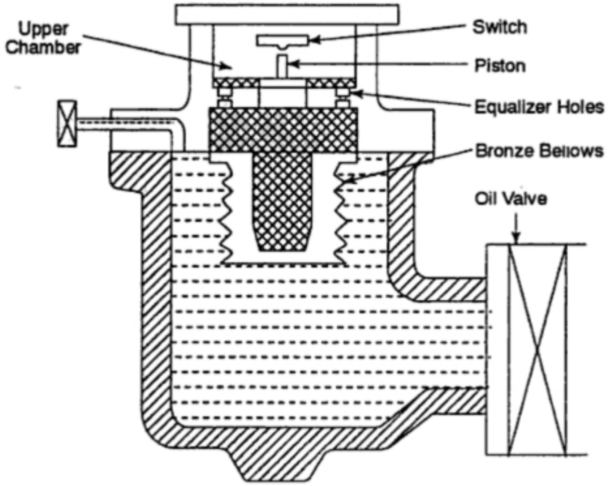
Buchholz Relay

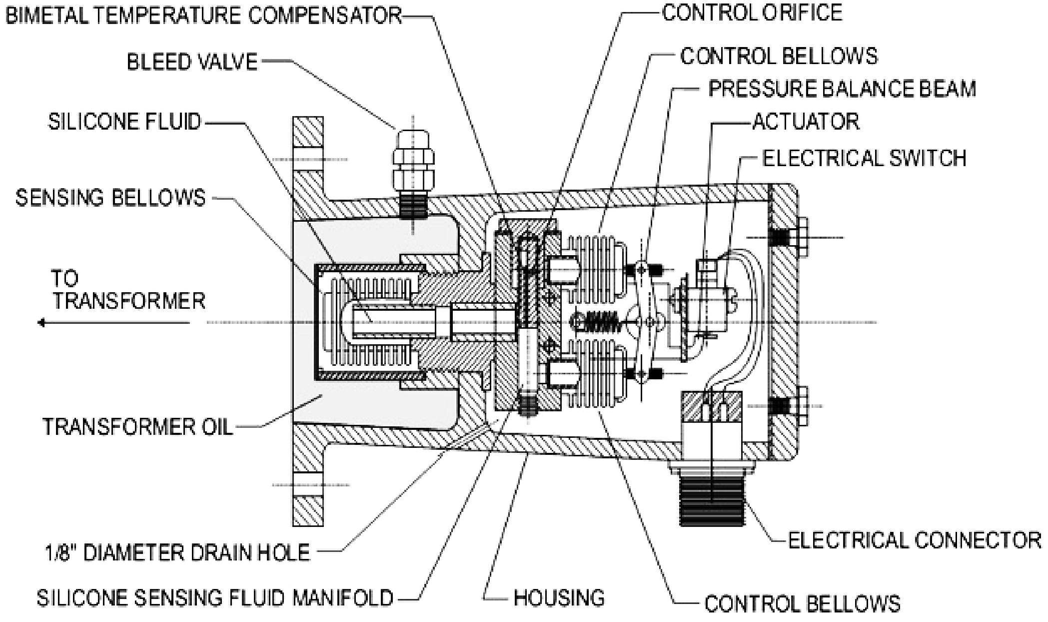
- Gas accumulator relay
- Applicable to conservator tanks equipped
- Operates for repeat, low-level faults by accumulating the gas over a period of time
  - Typically used for alarming only
- Operates or for large faults that force the oil through the relay at a high velocity
  - Used to trip
  - Able to detect a small volume of gas and accordingly can detect arcs of low energy
- Detects
  - High-resistance joints
  - High eddy currents between laminations
  - Low- and high-energy arcing
  - Accelerated aging caused by overloading



Sudden Pressure Relay

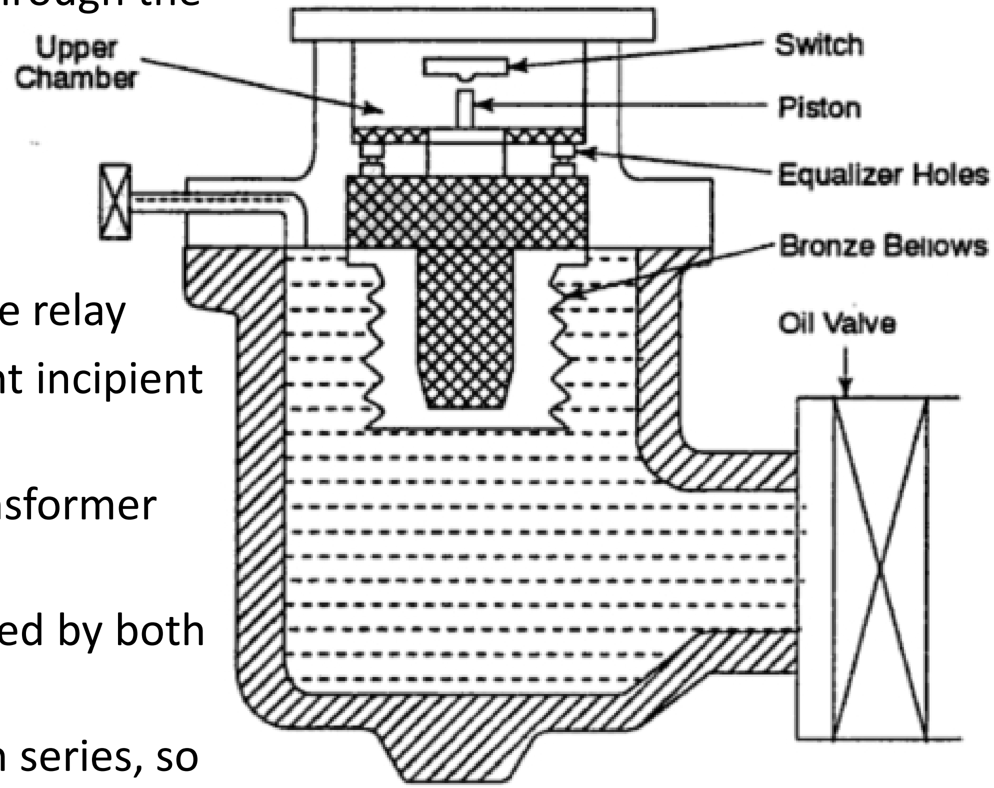
- When high current passes through a shorted turn, a great deal of heat is generated
  - Detect large and small faults
- This heat, along with the accompanying arcing, breaks down the oil into combustible gases
- Gas generation increases pressure within the tank
- A sudden increase in gas pressure can be detected by a sudden-pressure relay located either in the gas space or under the oil
- The sudden-pressure can operate before relays sensing electrical quantities, thus limiting damage to the transformer





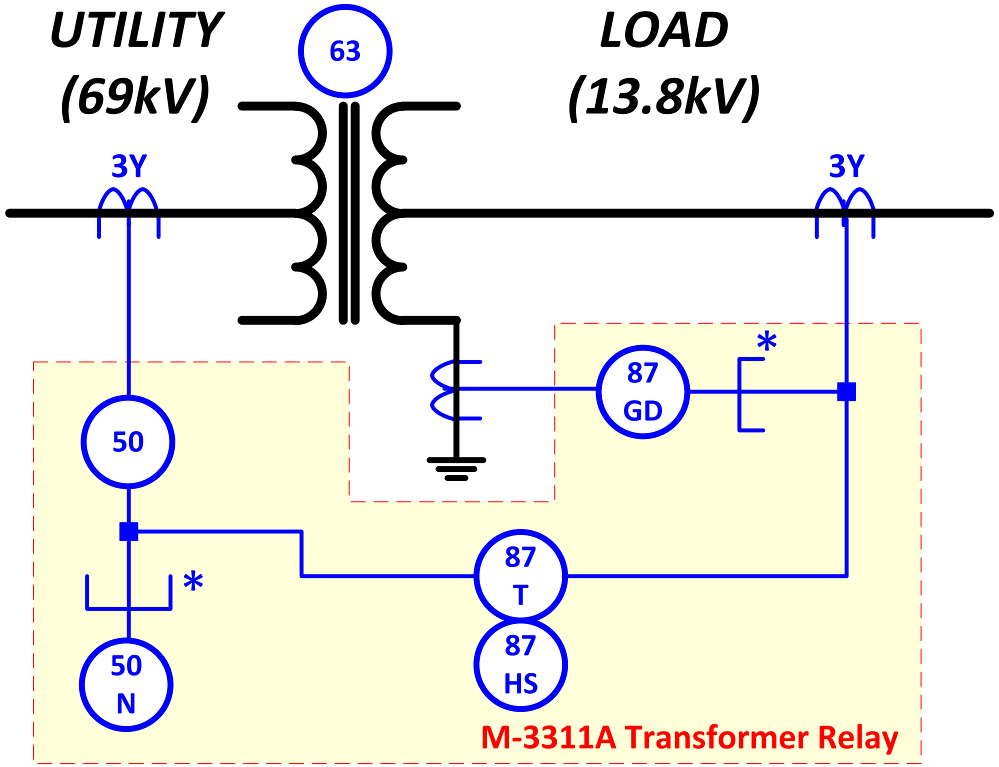
Sudden Pressure Relay

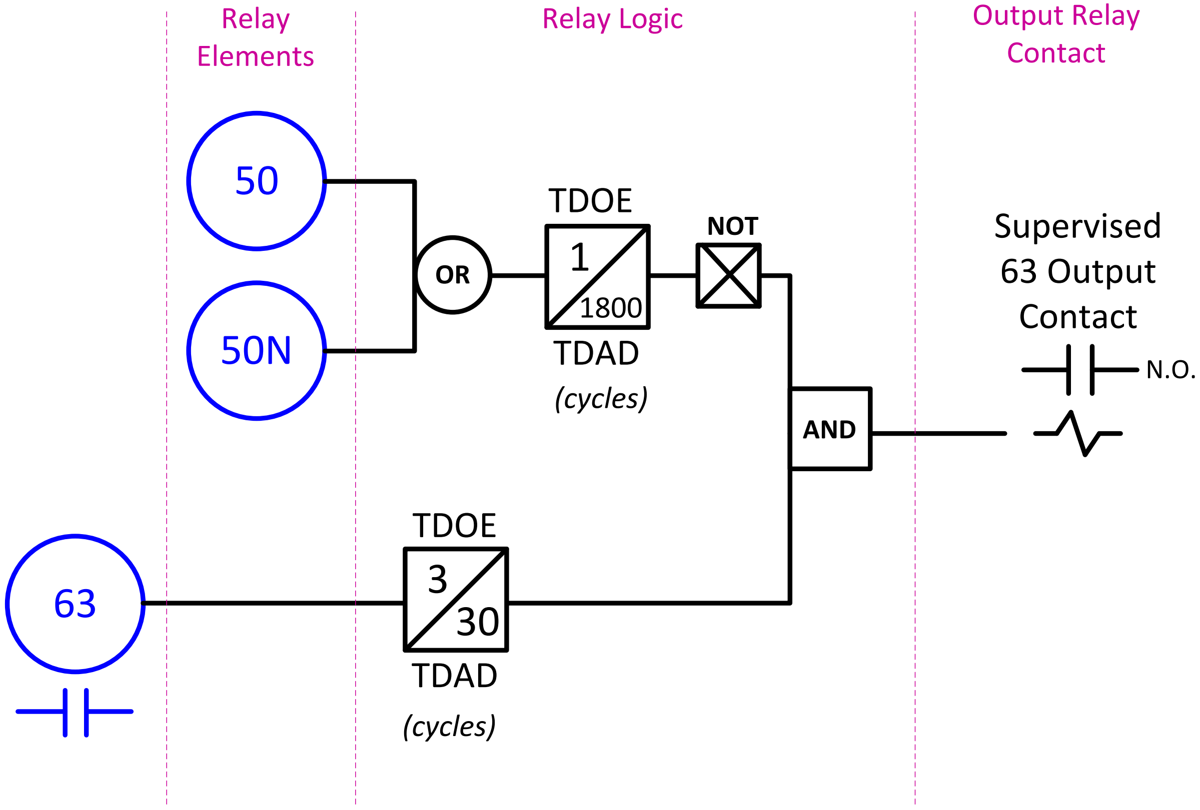
- Drawback of using sudden-pressure relays is tendency to operate on high-current through-faults
  - The sudden high current experienced from a close-in through-fault causes windings of the transformer to move.
  - This movement causes a pressure wave that is transmitted through the oil
- Countermeasures:
  - Overcurrent relay supervision
    - Any high-current condition detected by the instantaneous overcurrent relay blocks the sudden-pressure relay
    - This method limits the sudden-pressure relay to low-current incipient fault detection.
  - Place sudden-pressure relays on opposite corners of the transformer tank.
    - Any pressure wave due to through-faults will not be detected by both sudden-pressure relays.
    - The contacts of the sudden-pressure relay are connected in series, so both must operate before tripping.



Sudden Pressure Relay Supervision Scheme

- Phase and Ground Overcurrent supervises SPR (63)
- SPR (63) employs:
  - Pickup delay for overcurrent supervision
  - Drop out delay to allow SPR (63) to reset





Causes of Transformer Overheating

- Transformers may overheat due to the following reasons:
  - High ambient temperatures
  - Failure of cooling system
  - External fault not cleared promptly
  - Overload
  - Abnormal system conditions such as low frequency, high voltage, non-sinusoidal load current, or phase-voltage unbalance

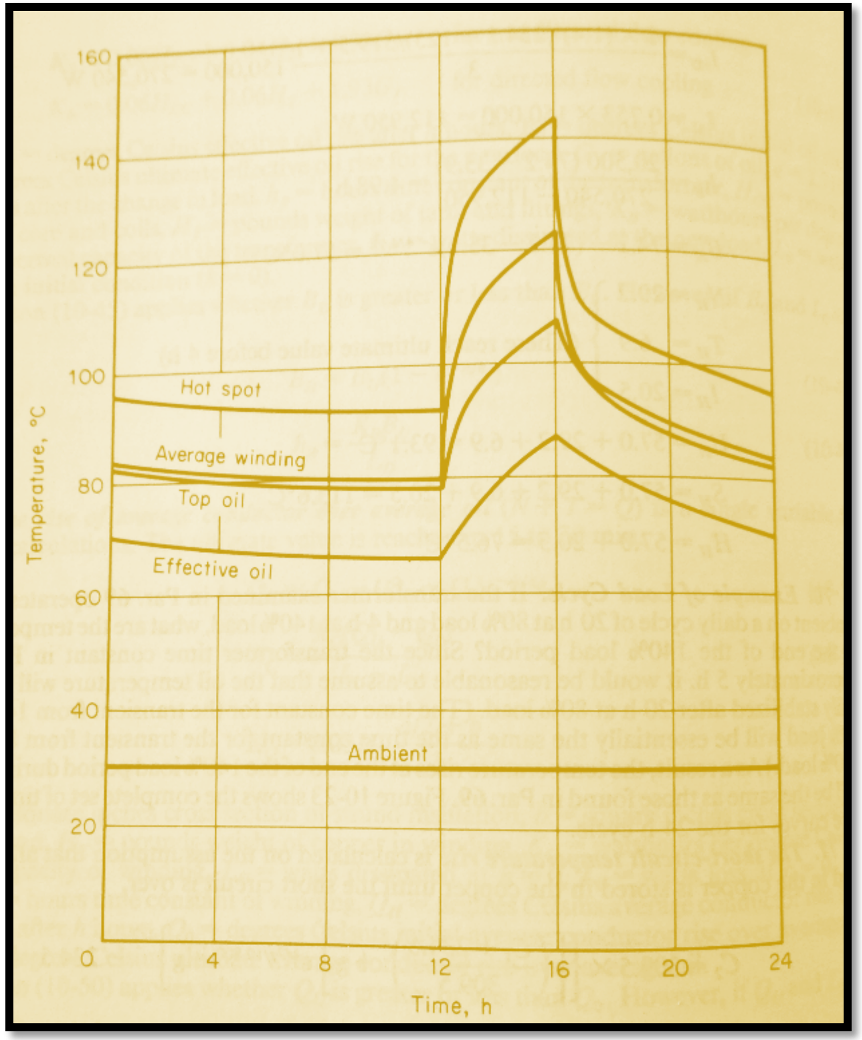
Transformer Overheating

Undesirable results of overheating

- Overheating shortens the life of the transformer insulation in proportion to the duration of the high temperature, and in proportion to the degree of the high temperature.
- Severe over temperature may result in an immediate insulation failure (fault).
- Overheating can generate gases that could result in an electrical failure (fault). Severe over temperature may result in the transformer coolant heated above its flash temperature, with a resultant fire (fault and a bang!).

Heating and Relative Transformer Temperatures

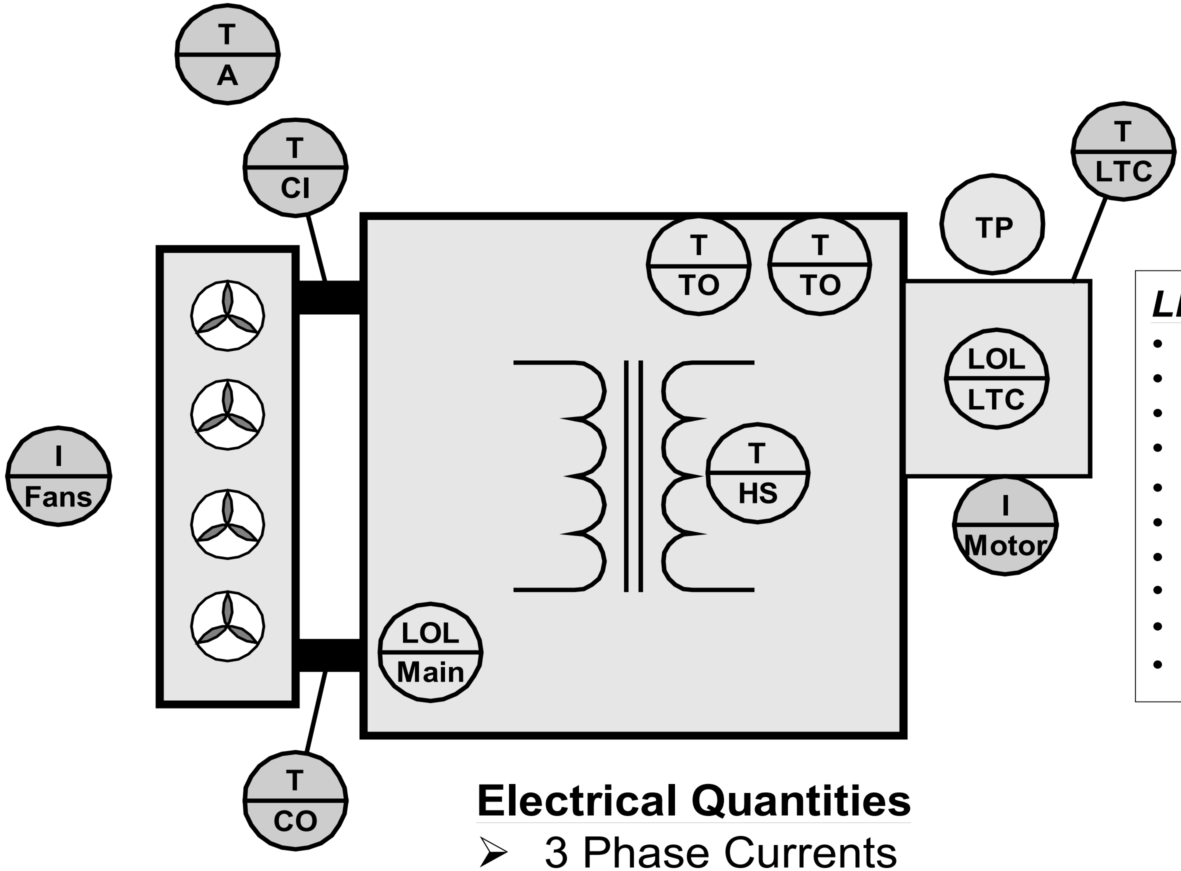
- Temperature may be monitored multiple places
  - Hot Spot
  - Top Oil
  - Bottom Oil
  - LTC Tank
  - Delta of the above
- The “hot spot” is, as the name indicates, the hottest spot
- Other temperatures are lower



Standard Handbook for Electrical Engineers

Transformer Temperature Monitoring

Transformer Sensing Inputs (Typical)



LEGEND:

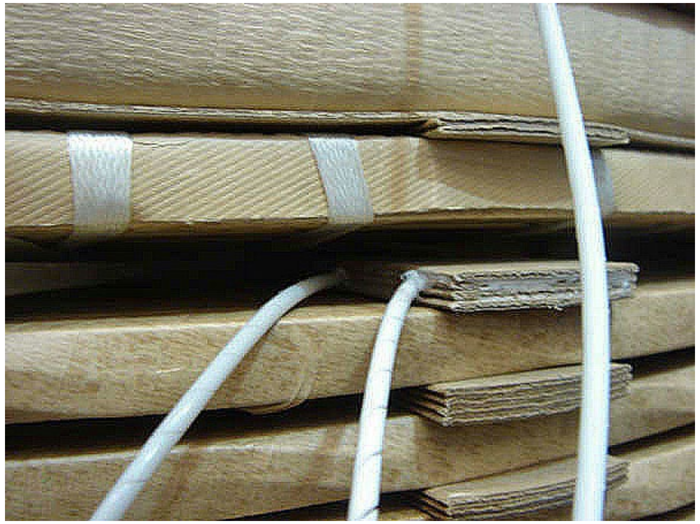
- T = Temperature
- TO = Top Oil
- Wind = Winding
- LOL = Low Oil Level
- I = Current
- CO = Cooler Outlet
- CI = Cooler Inlet
- A = Ambient
- LTC = Load tap changer
- TP = Tap Position

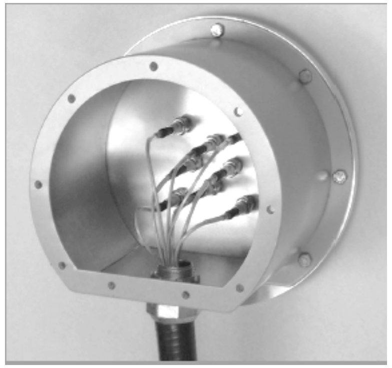
Electrical Quantities

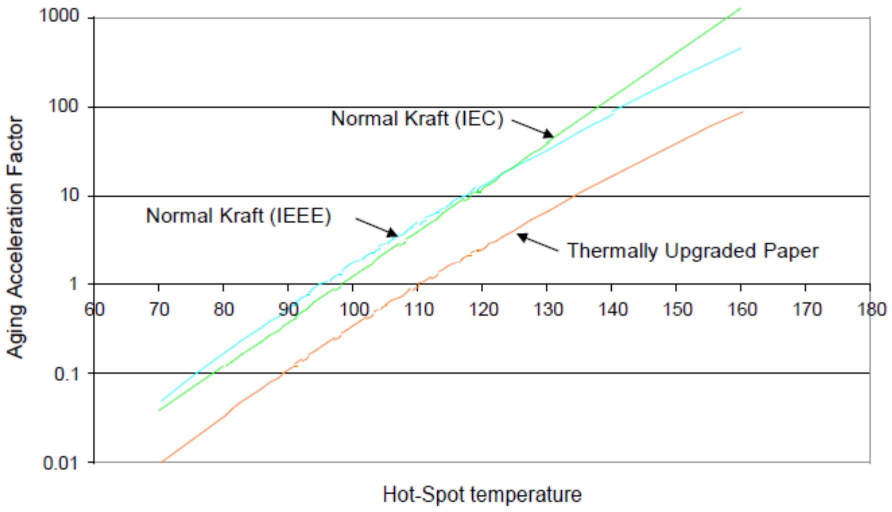
- 3 Phase Currents
- 1 Neutral Current
- 3 Phase Voltages

Hot Spot Detection

- Fiberoptic sensors
  - Use Gallium Arsenic (GaAs) based spectrophotometric module
  - Measures the spectrum a temperature-dependent GaAs crystal affixed on optical fiber
- Typical on newly constructed transformers
- Difficult to retrofit
- More precise than IEEE calculation approximations
  - “Aging Factor” = multiples of 1 hour of normal temperature use

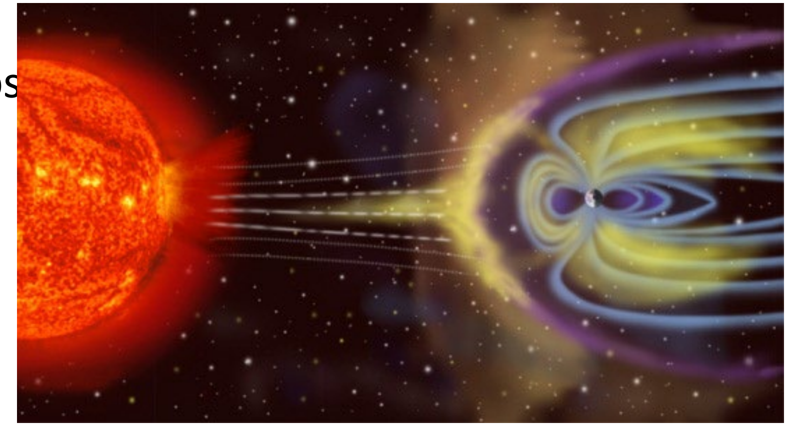


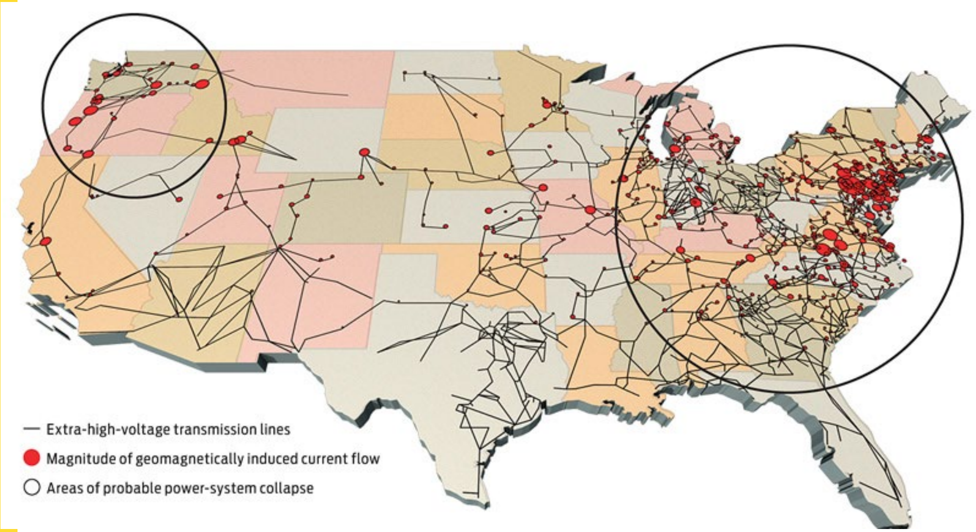


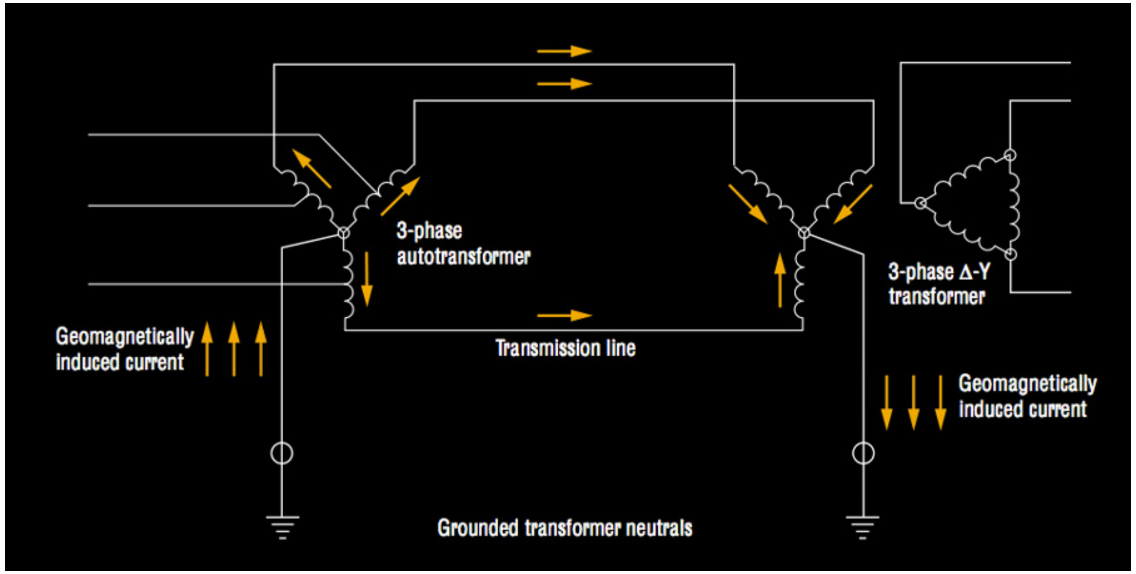


Special Subject: GIC

- Occurs in near polar and polar latitudes
- Result of solar storms impacting earth and causing induction and current loops
- Currents are DC and cause saturation of power transformers
- Proactive protection consists of:
  - Deliberate system compartmentalizing or transformer isolation
  - Use of capacitors on transformer grounds to block DC path







Interface and Analysis Software: Desirable Attributes

- NERC "State of Reliability 2017"
- 37% of Relay Misoperations are due to human error
  - Programming too complex
  - Commissioning difficult
  - Period Testing difficult

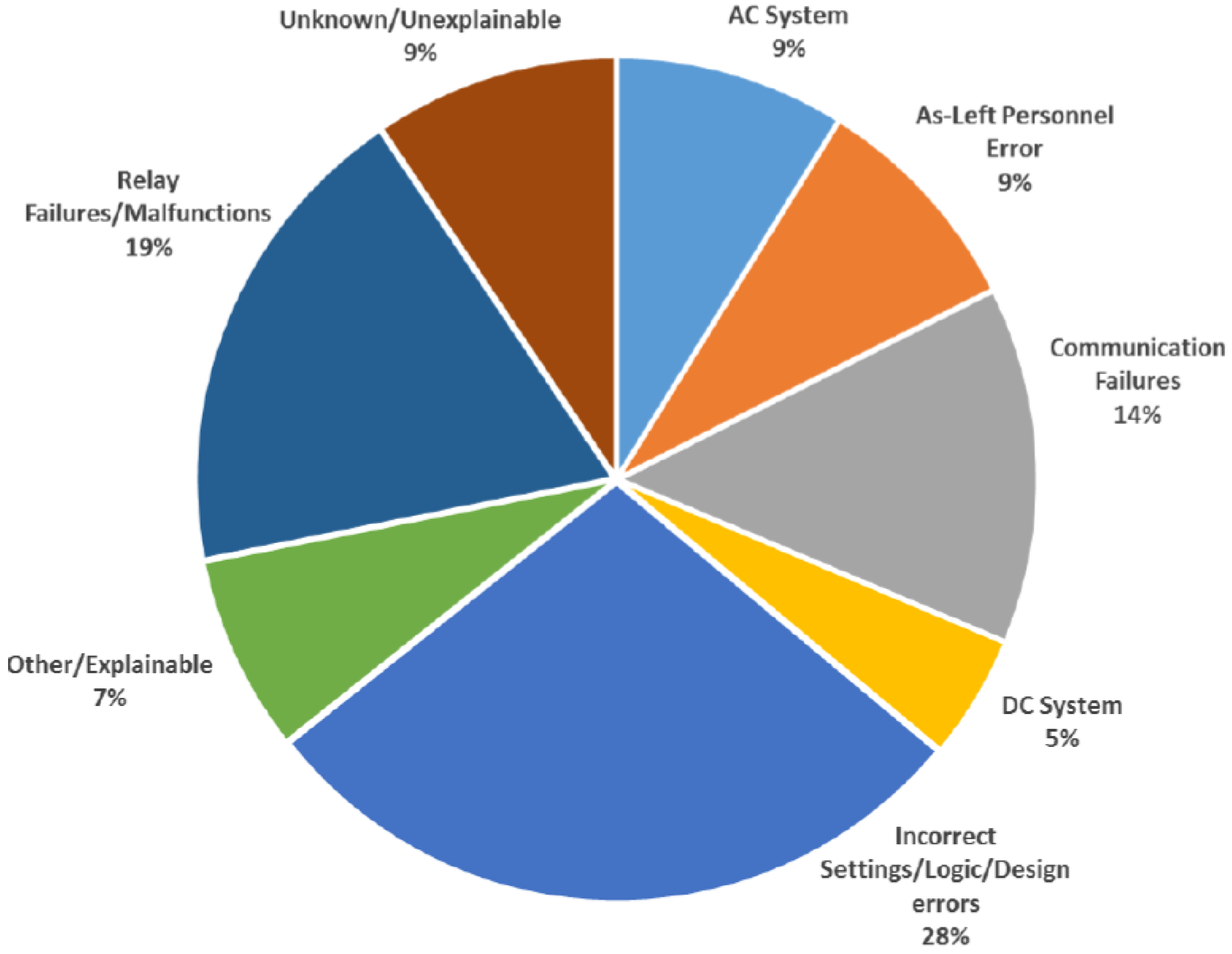


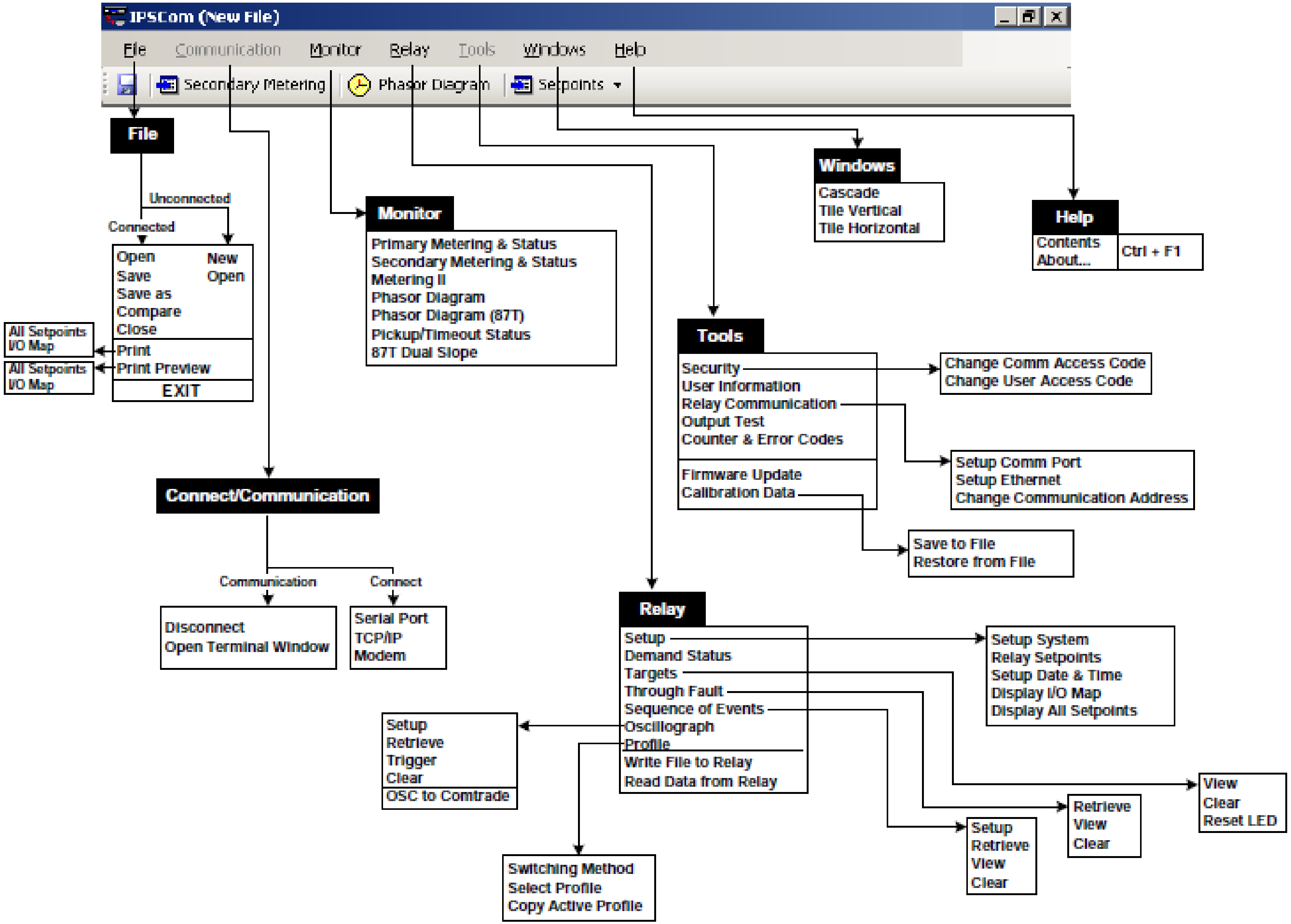
Figure E.21: NERC Misoperations by Cause Code (2Q 2012–3Q 2016)

Interface and Analysis Software: Desirable Attributes

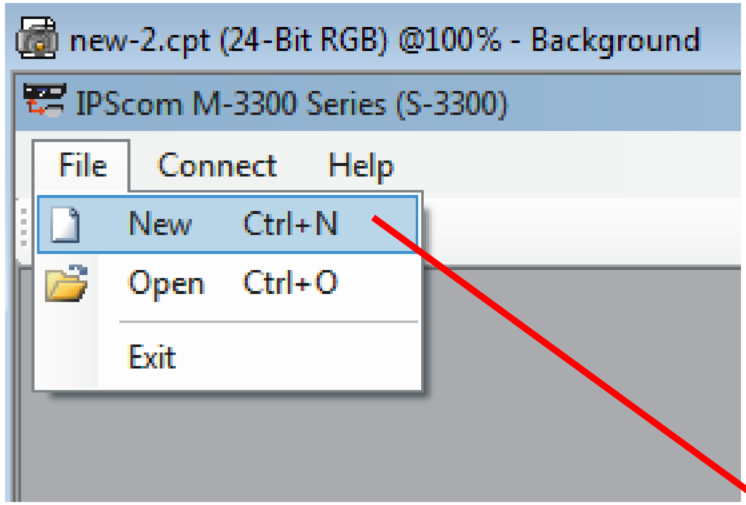
- PC software package for setpoint interrogation and modification, metering, monitoring, and downloading oscillography records
- Oscillography Analysis Software package graphically displays to facilitate analysis, and print captured waveforms
- Be menu-driven, graphical, simple to use
- Auto-documentation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

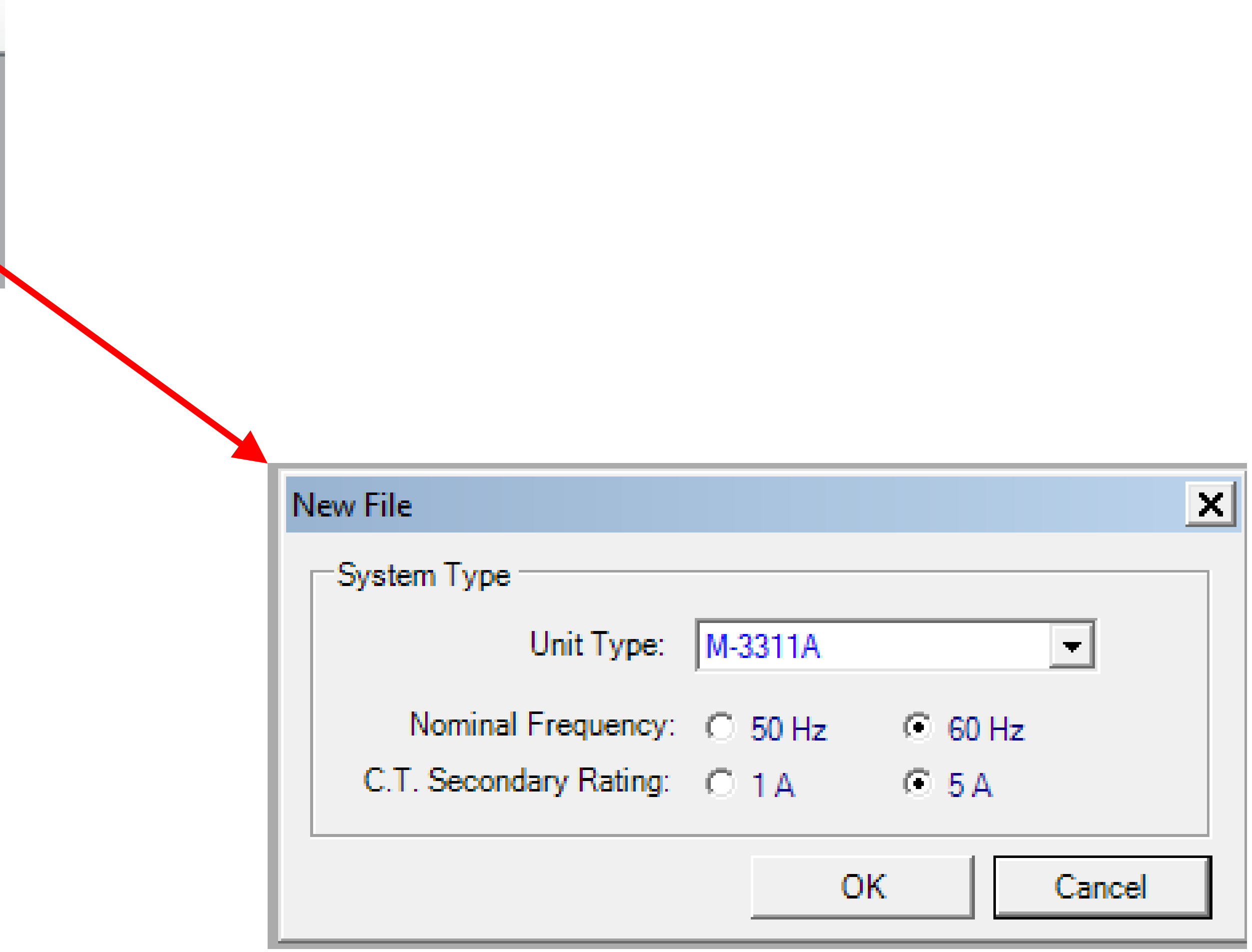
How Do You Set a Relay?

- Set the configuration (relay environment)
- Set elements
- Define tripping and blocking assignments
- Review/print summary

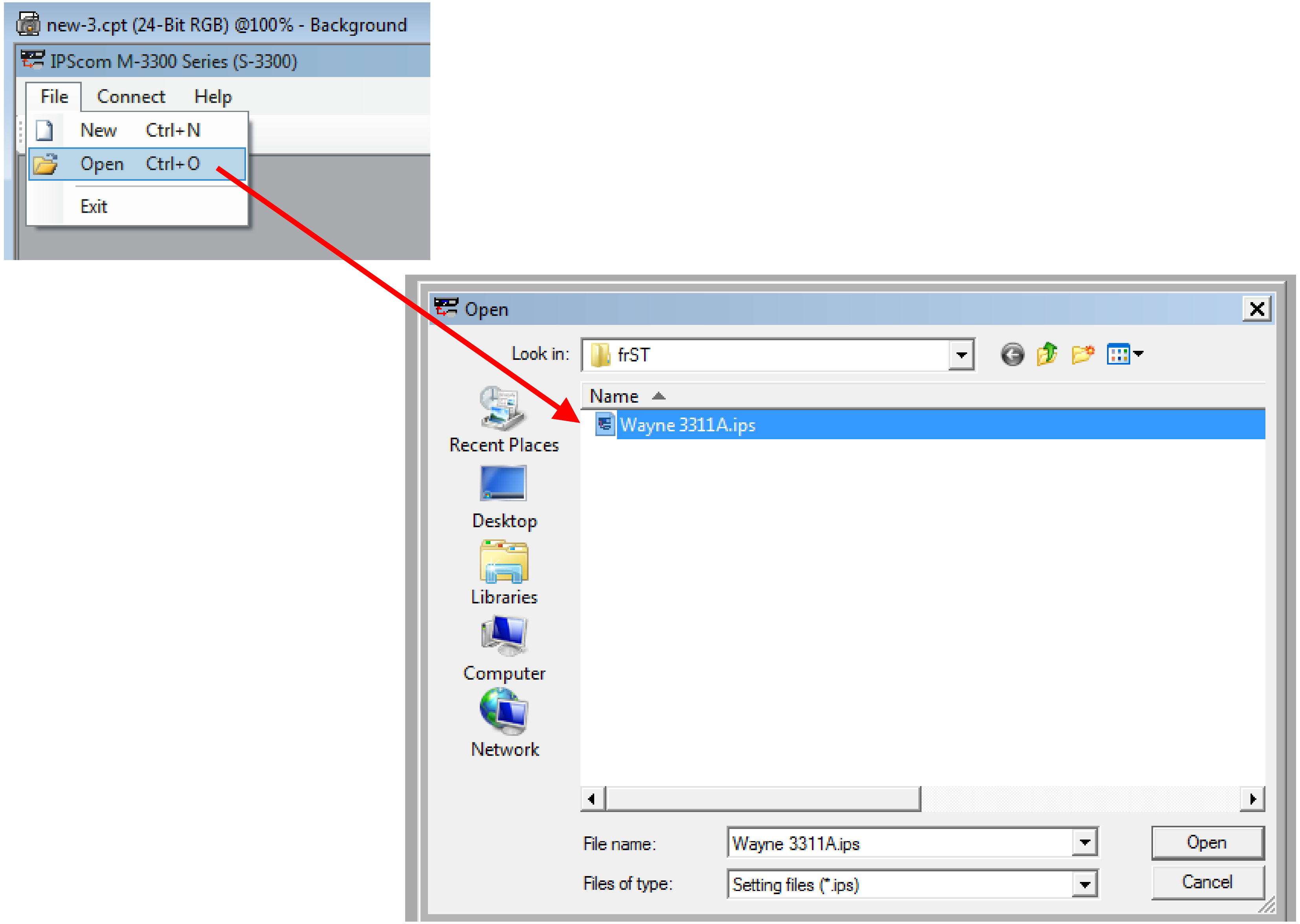

IPSCom (New File)
File
Communication
Monitor
Relay
Tools
Windows
Help
Secondary Metering
Phasor Diagram
Setpoints
File
Unconnected
Connected
Open
Save
Save as
Compare
Close
New
Open
Print
Print Preview
EXIT
All Setpoints
I/O Map
All Setpoints
I/O Map
Monitor
Primary Metering & Status
Secondary Metering & Status
Metering II
Phasor Diagram
Phasor Diagram (87T)
Pickup/Timeout Status
87T Dual Slope
Windows
Cascade
Tile Vertical
Tile Horizontal
Help
Contents
About...
Ctrl + F1
Tools
Security
User Information
Relay Communication
Output Test
Counter & Error Codes
Firmware Update
Calibration Data
Change Comm Access Code
Change User Access Code
Setup Comm Port
Setup Ethernet
Change Communication Address
Save to File
Restore from File
Connect/Communication
Communication
Connect
Disconnect
Open Terminal Window
Serial Port
TCP/IP
Modem
Relay
Setup
Demand Status
Targets
Through Fault
Sequence of Events
Oscillograph
Profile
Write File to Relay
Read Data from Relay
Setup System
Relay Setpoints
Setup Date & Time
Display I/O Map
Display All Setpoints
Setup
Retrieve
Trigger
Clear
OSC to Comtrade
Switching Method
Select Profile
Copy Active Profile
View
Clear
Reset LED
Retrieve
View
Clear
Setup
Retrieve
View
Clear

Creating NEW File

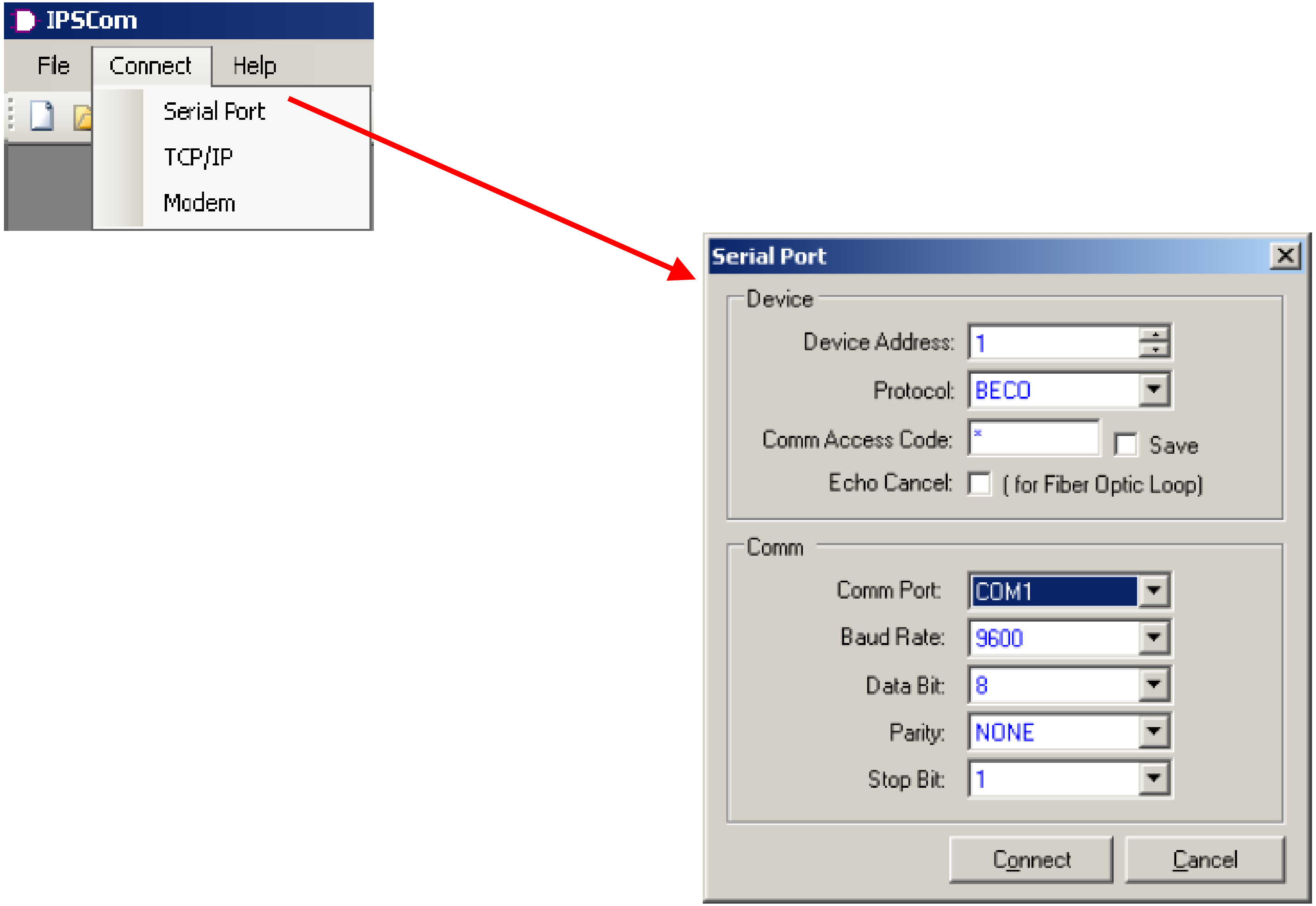




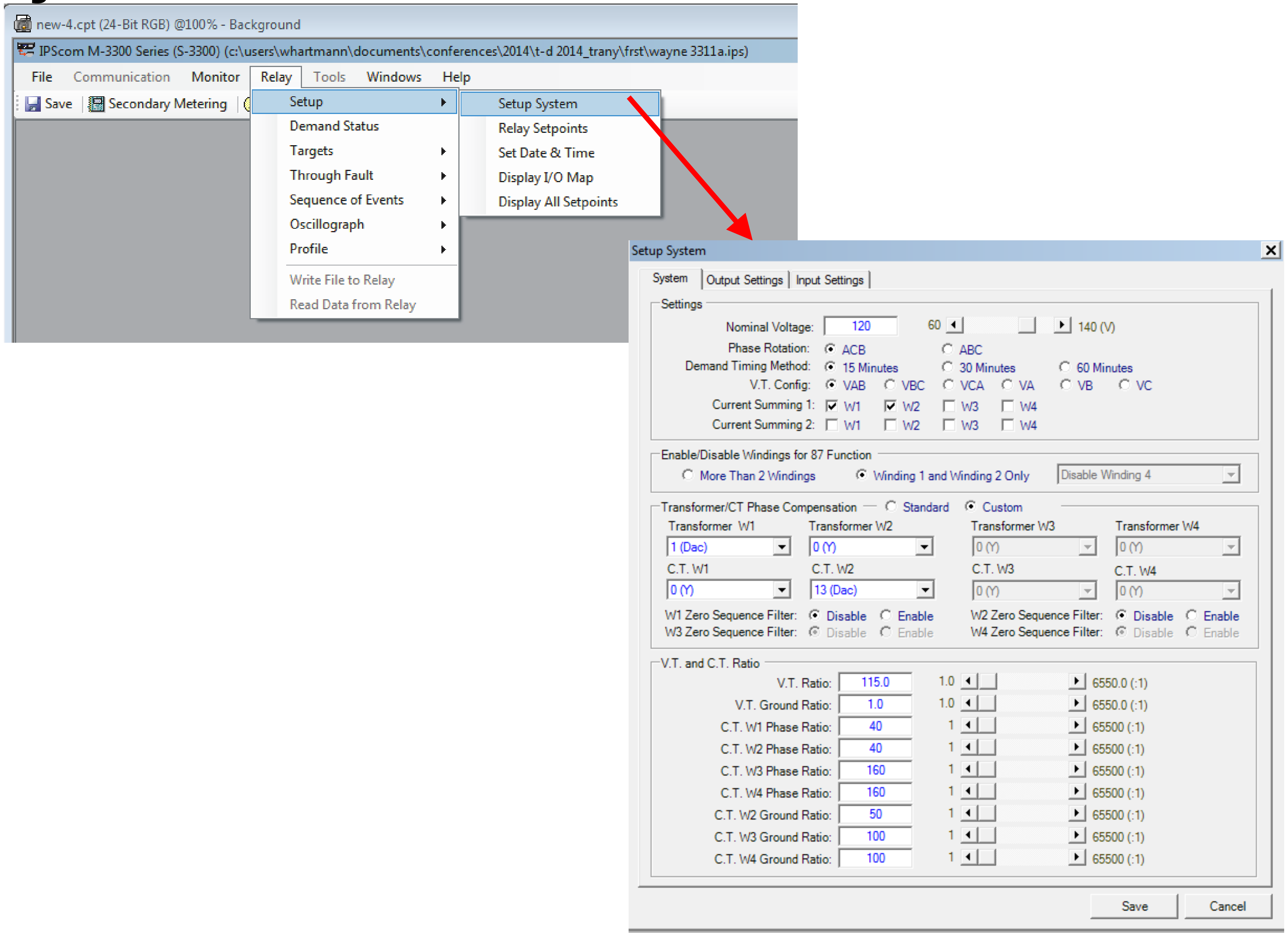
Opening EXISTING File



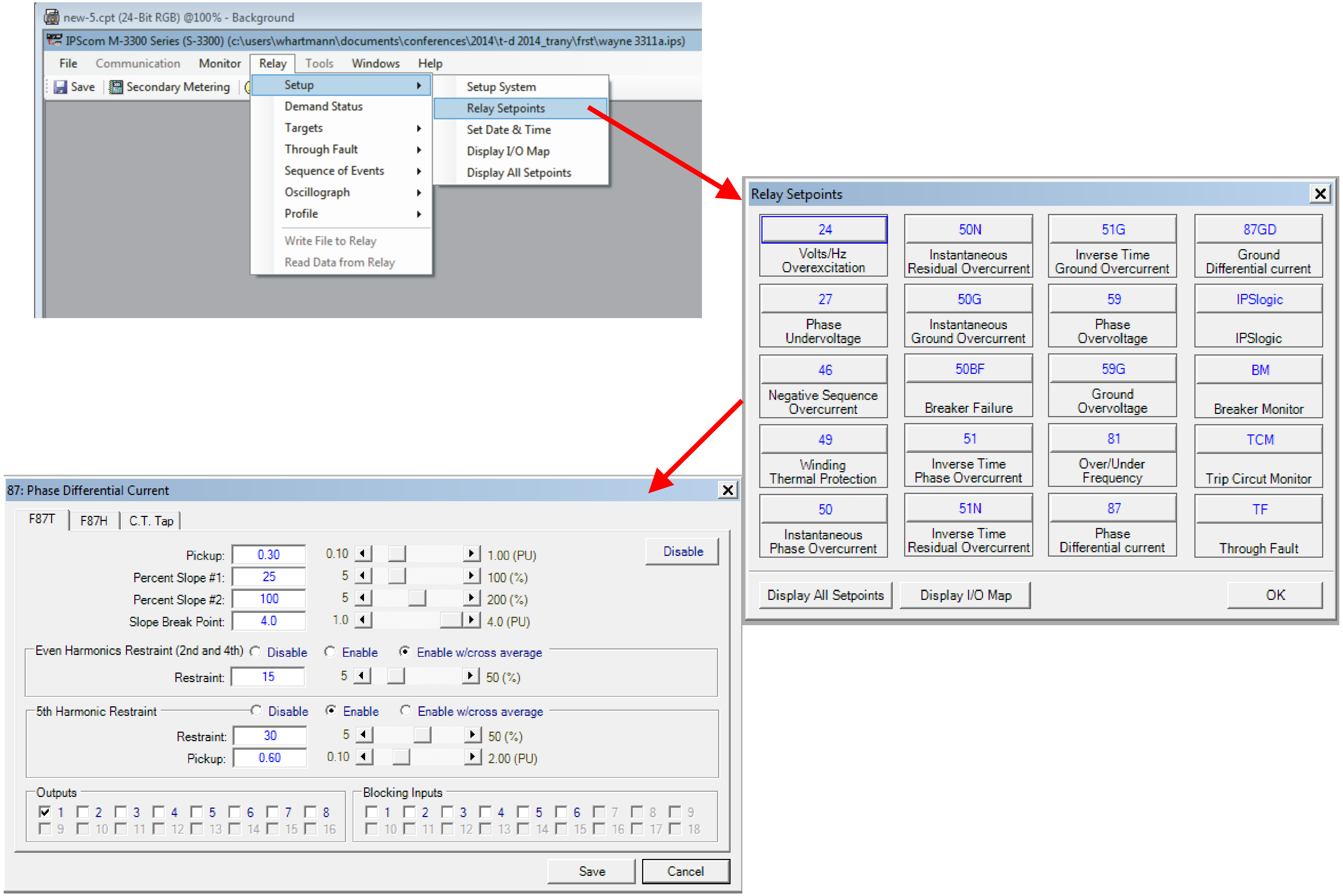
Connect to the Relay



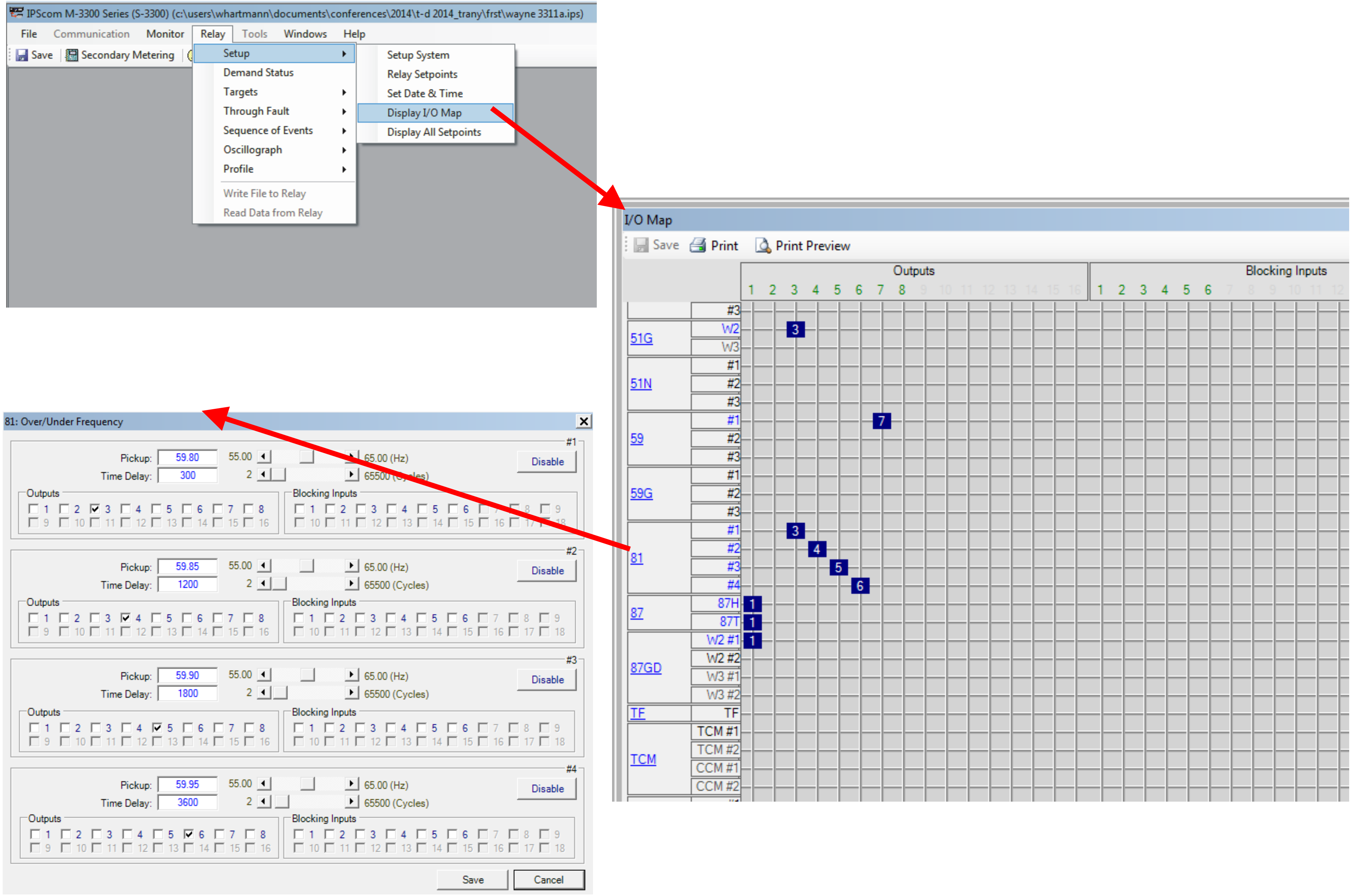
Set Up System



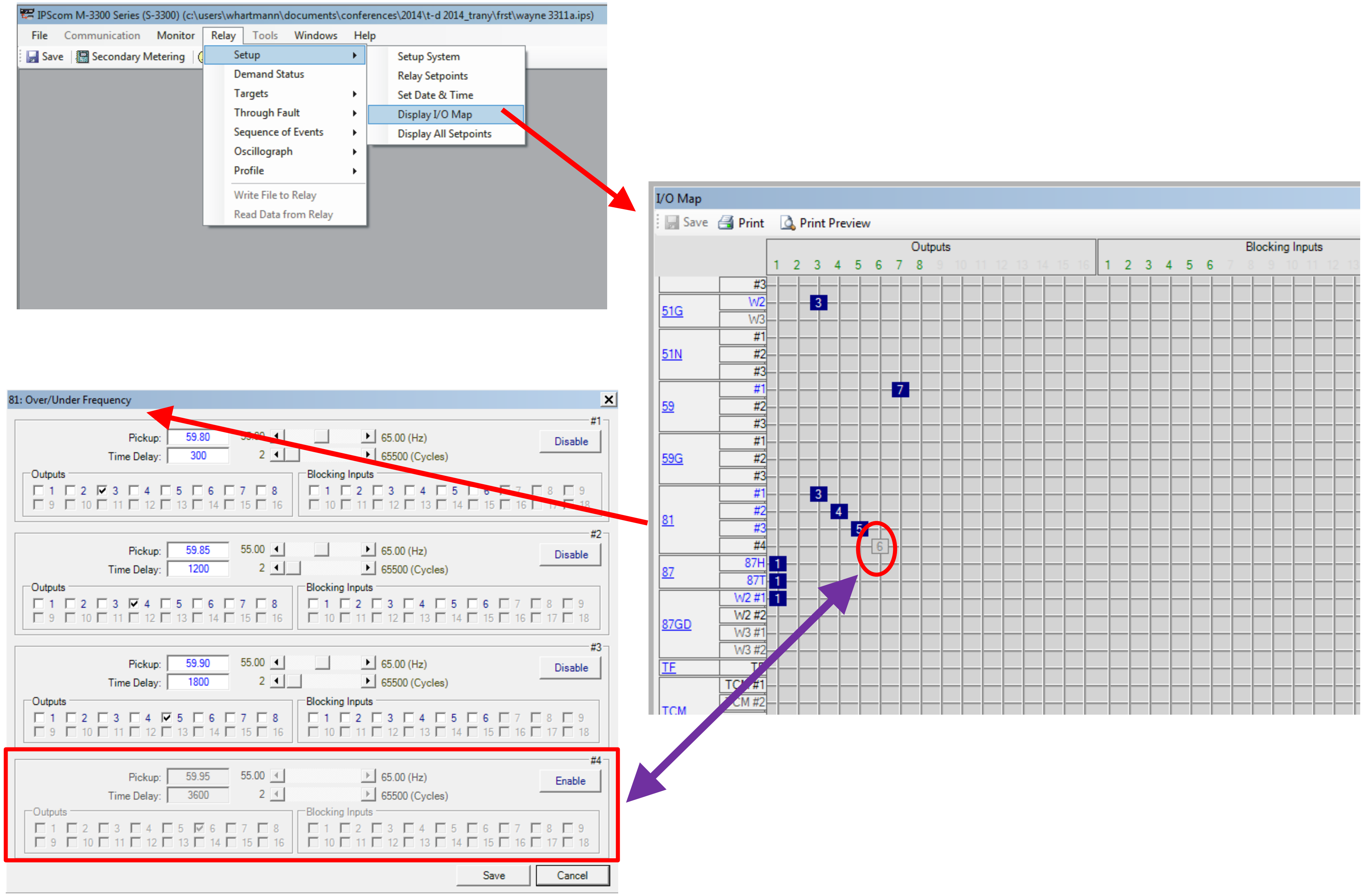
Relay Setpoints



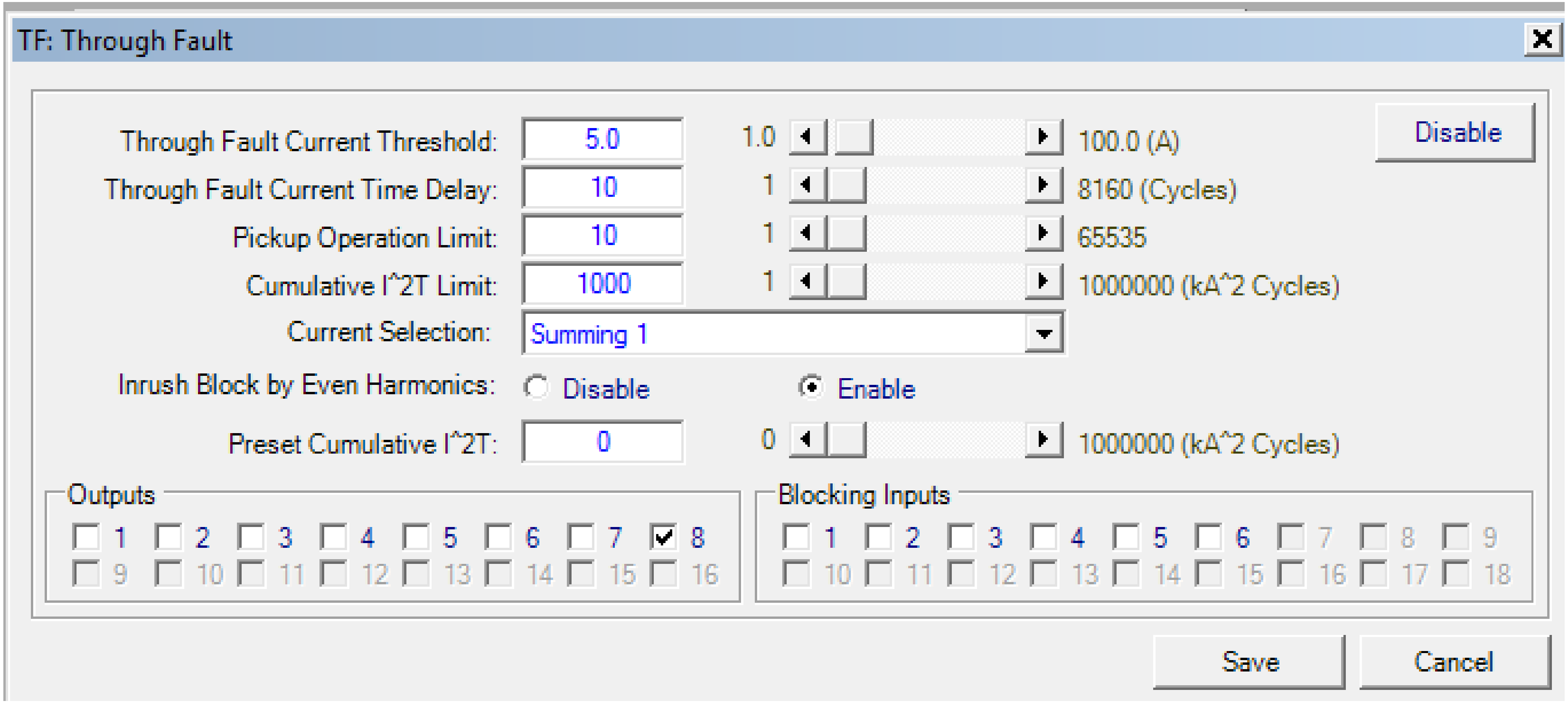
Display I/O Map



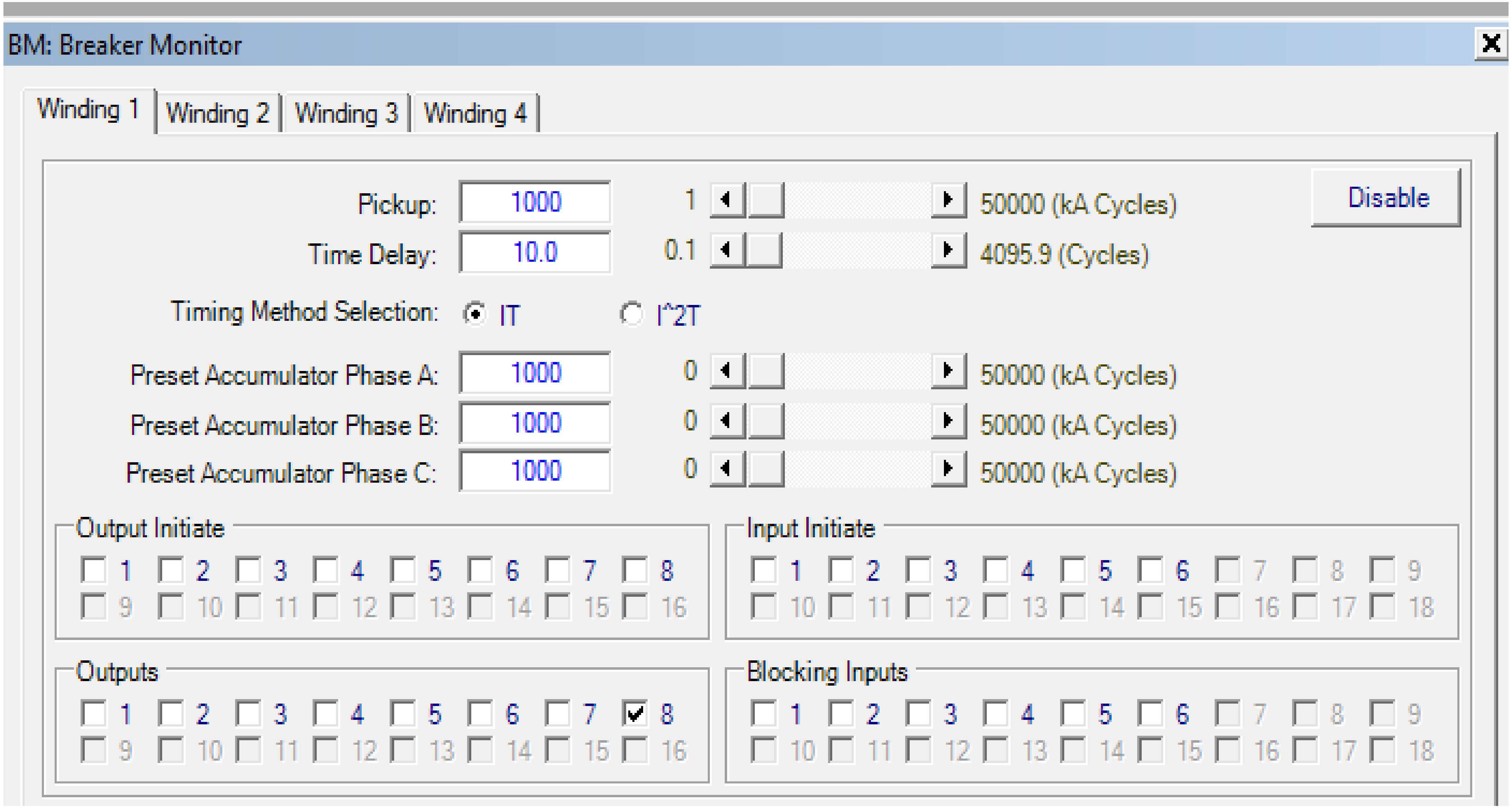
Display I/O Map: Element Disabled



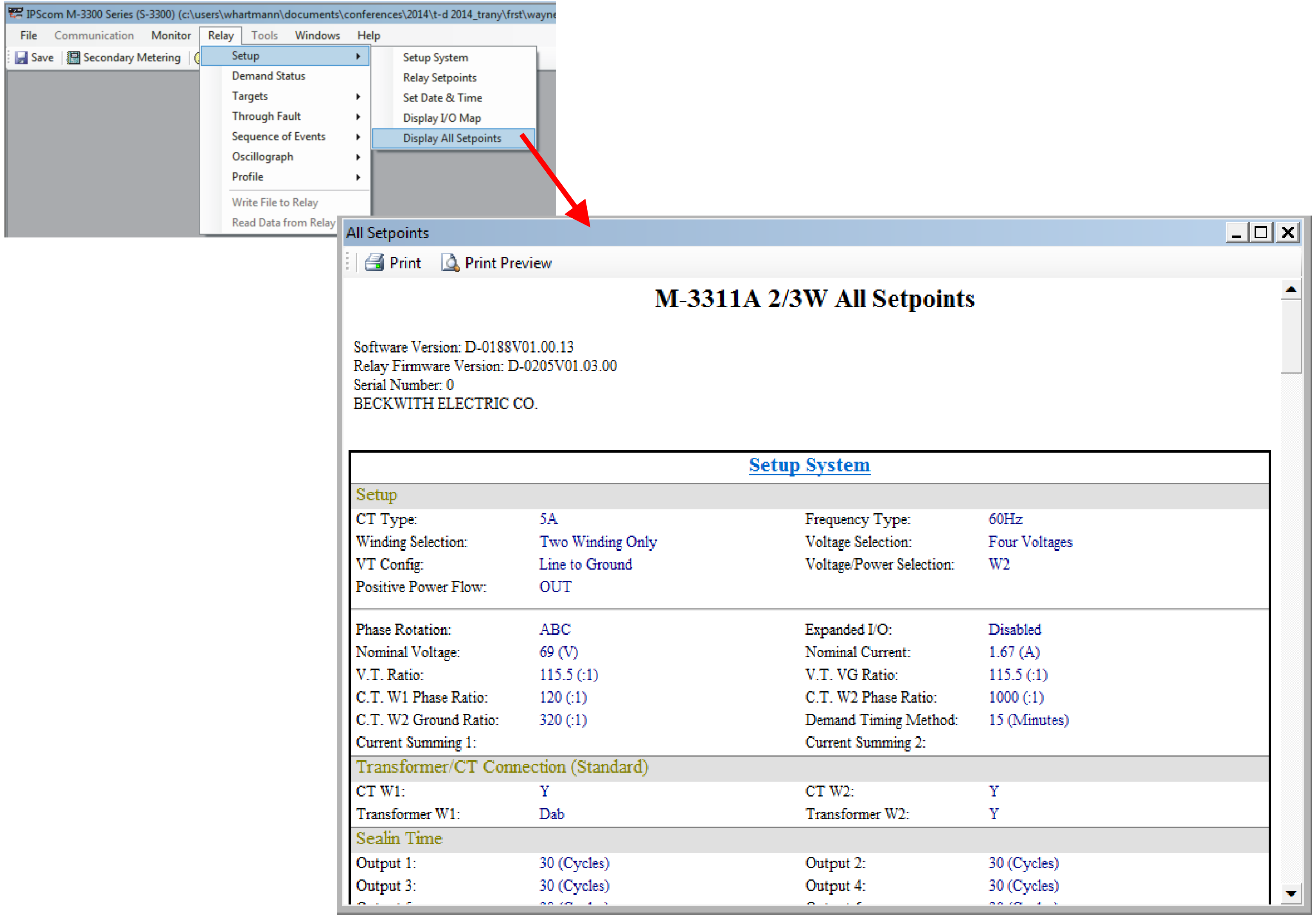
Through-Fault Recorder



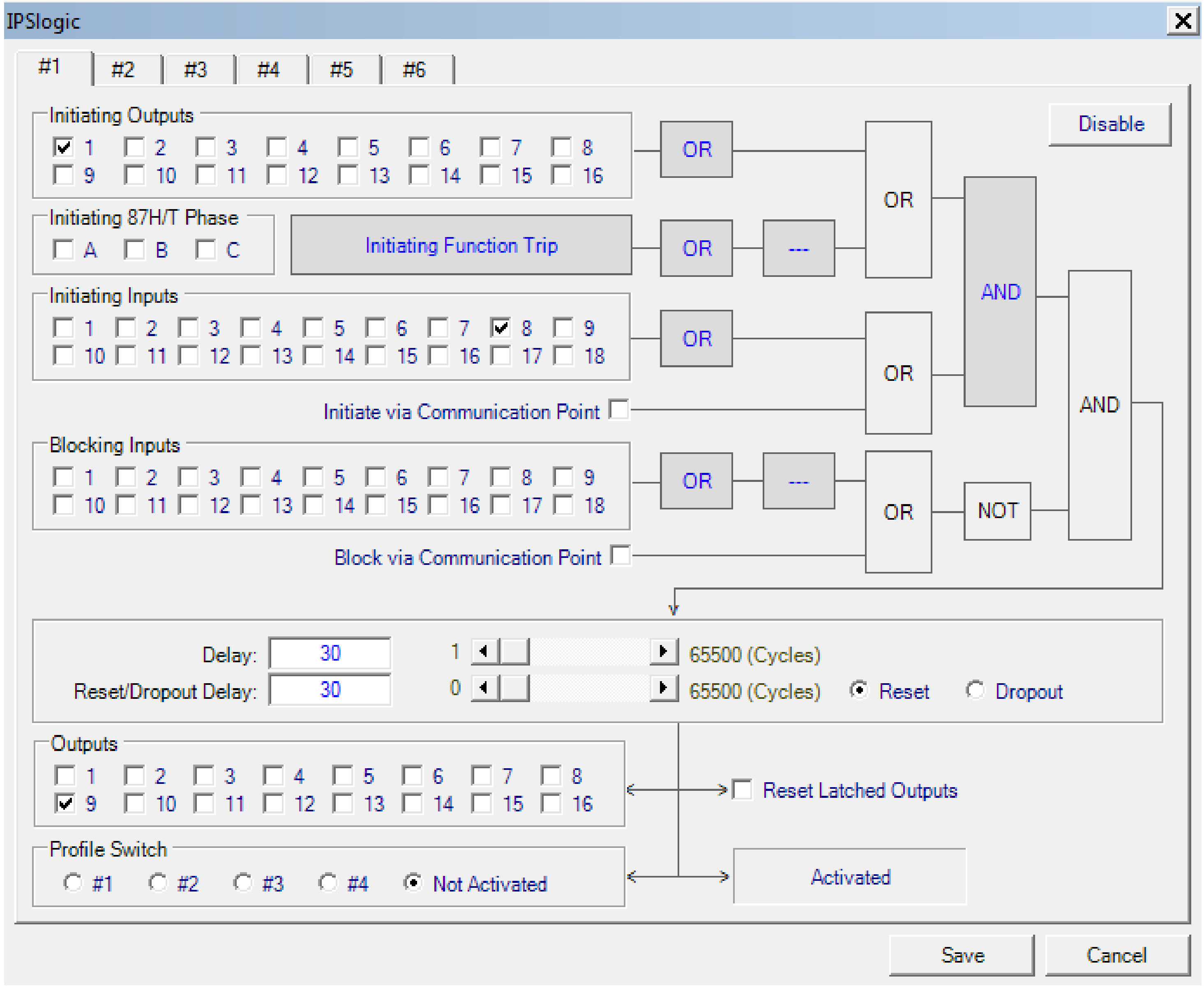
Breaker Monitor



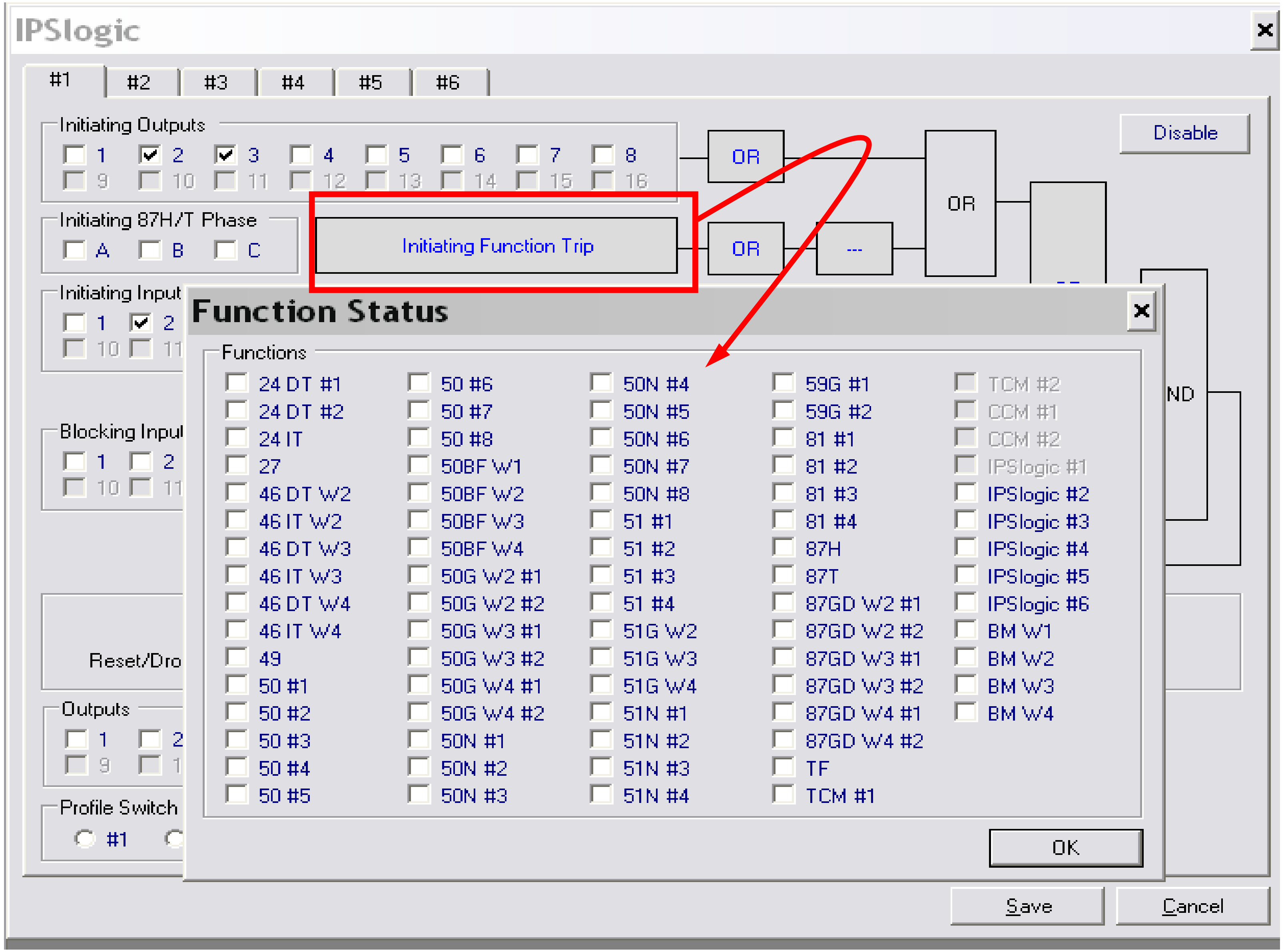
Setpoint Summary



Example: Programmable Logic



Example: Programmable Logic



Graphic Metering and Monitoring

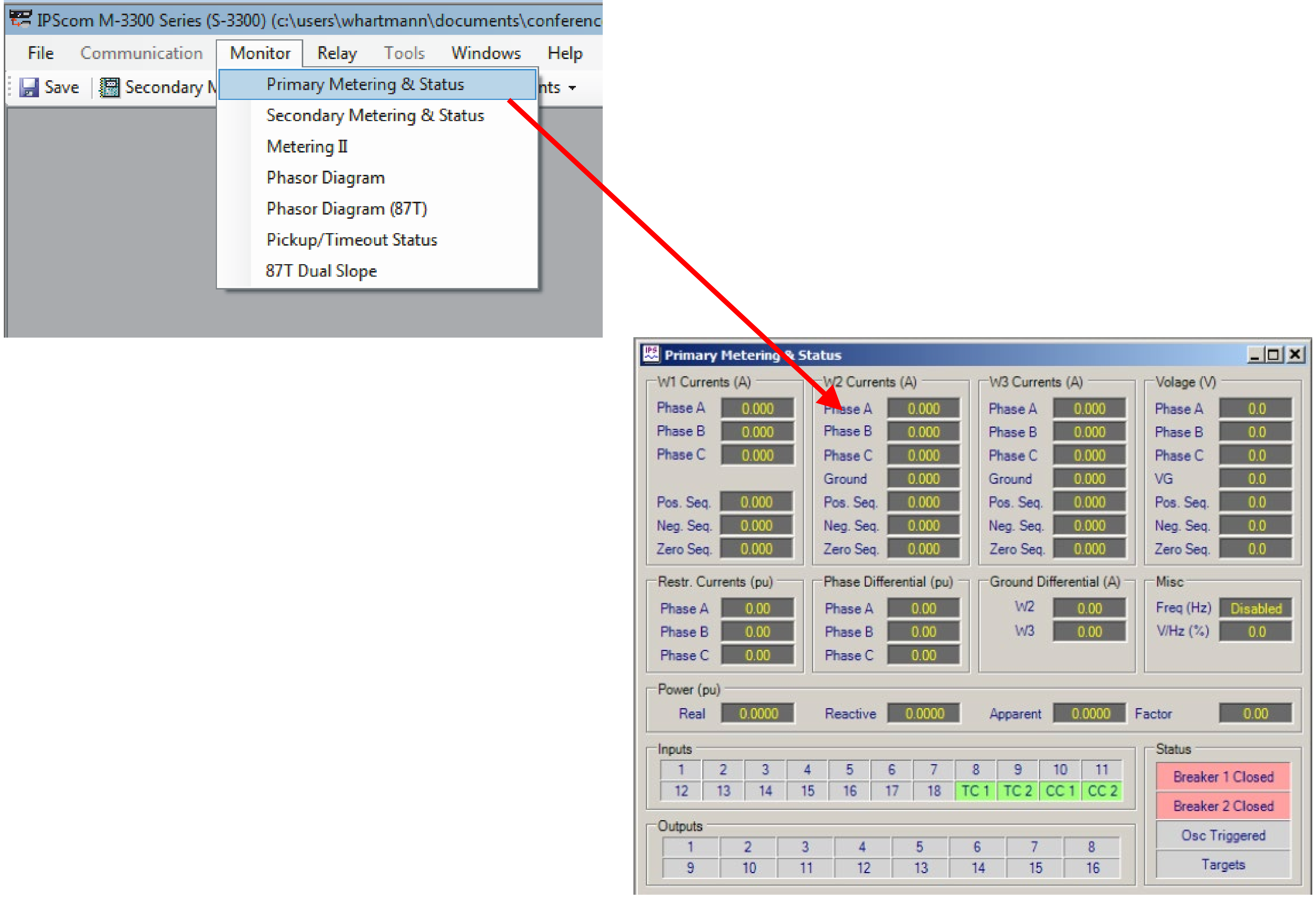
Metering of all measured inputs

- Measured and calculated quantities
- Instrumentation grade

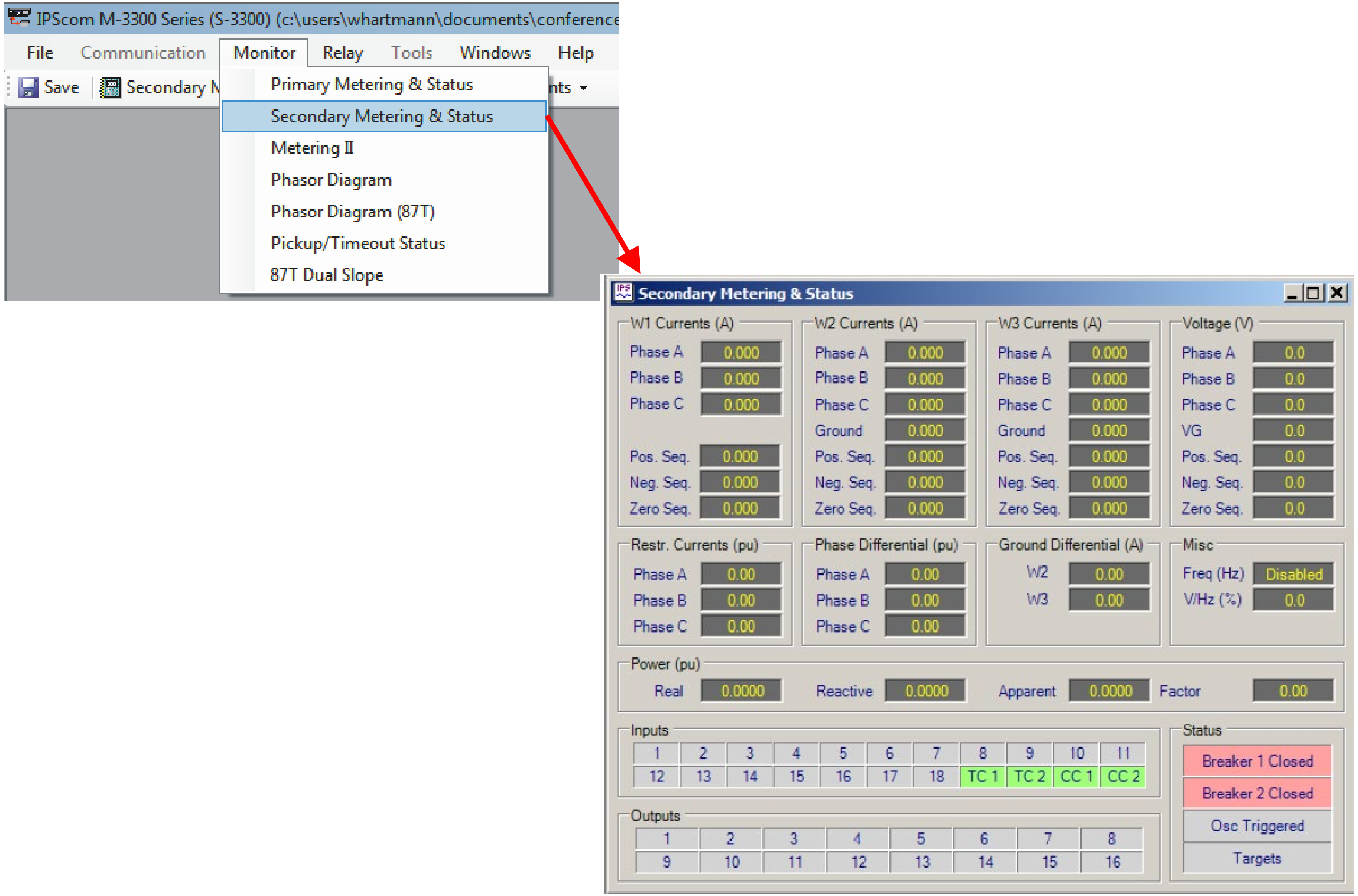
Commissioning and Analysis Tools

- Advanced metering
- Event logs
- Vector meters
- R-X Graphics
- Oscillograph recording

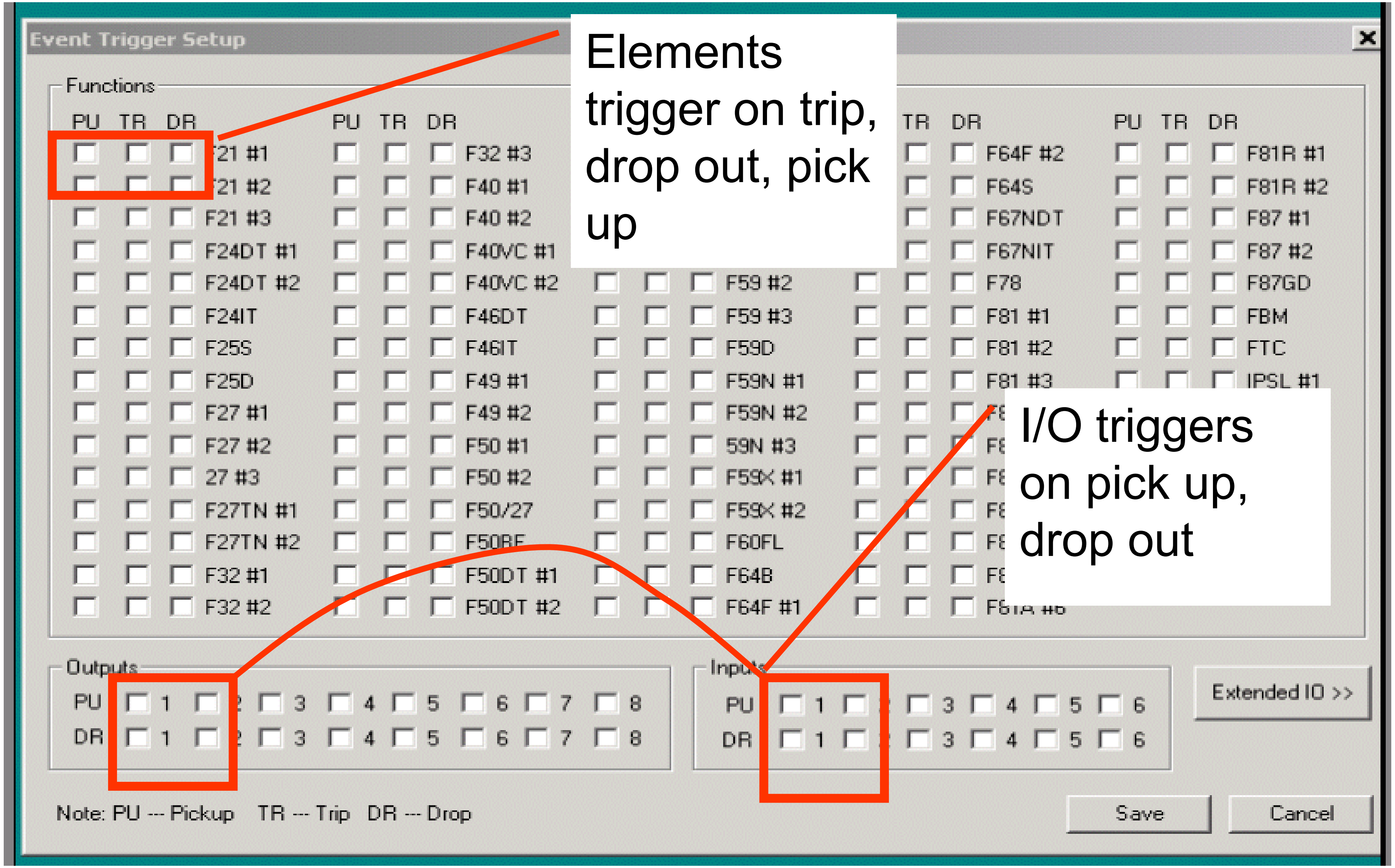
Primary Metering And Component Metering



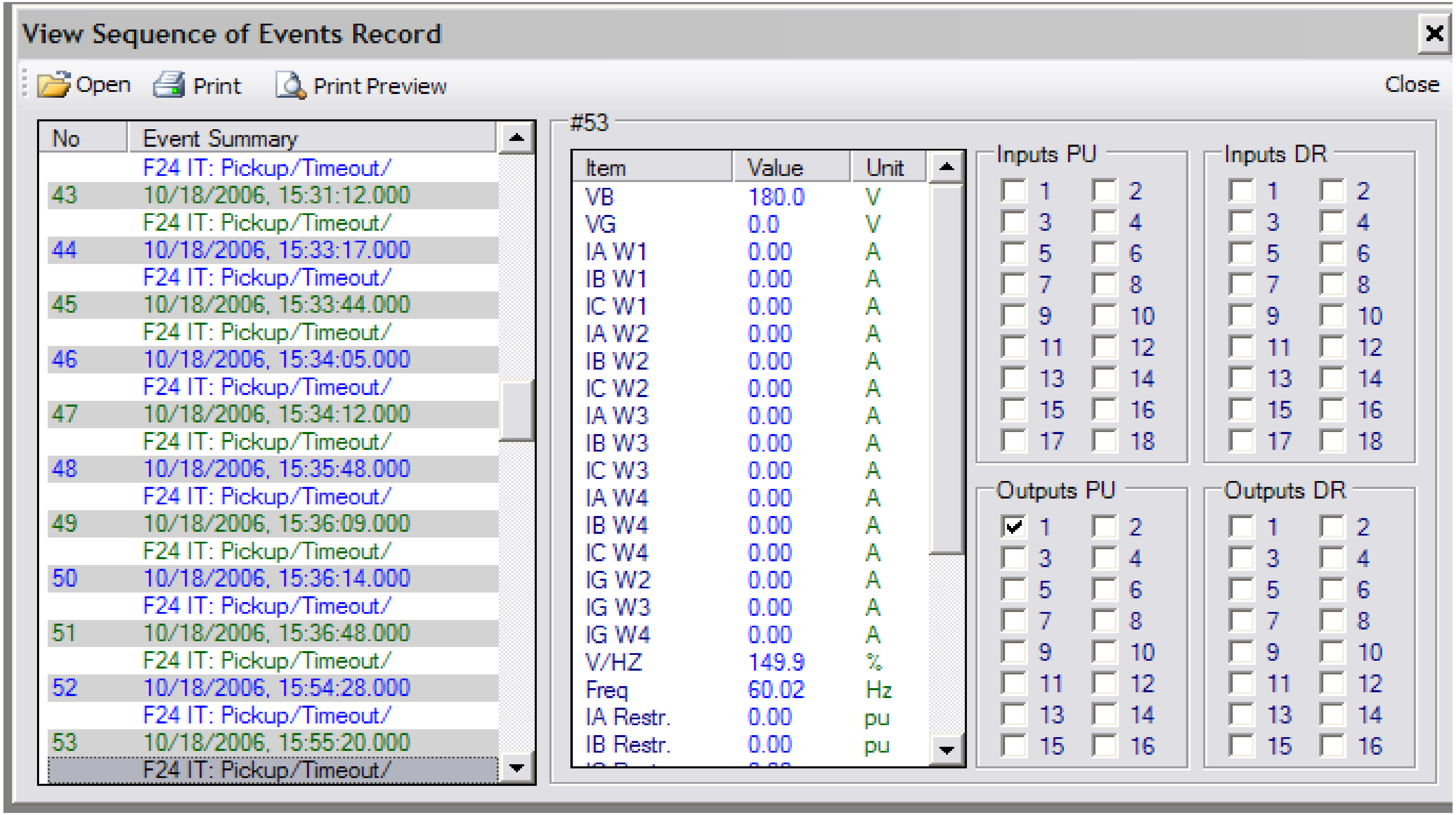
Secondary Metering, Components Metering, and Status



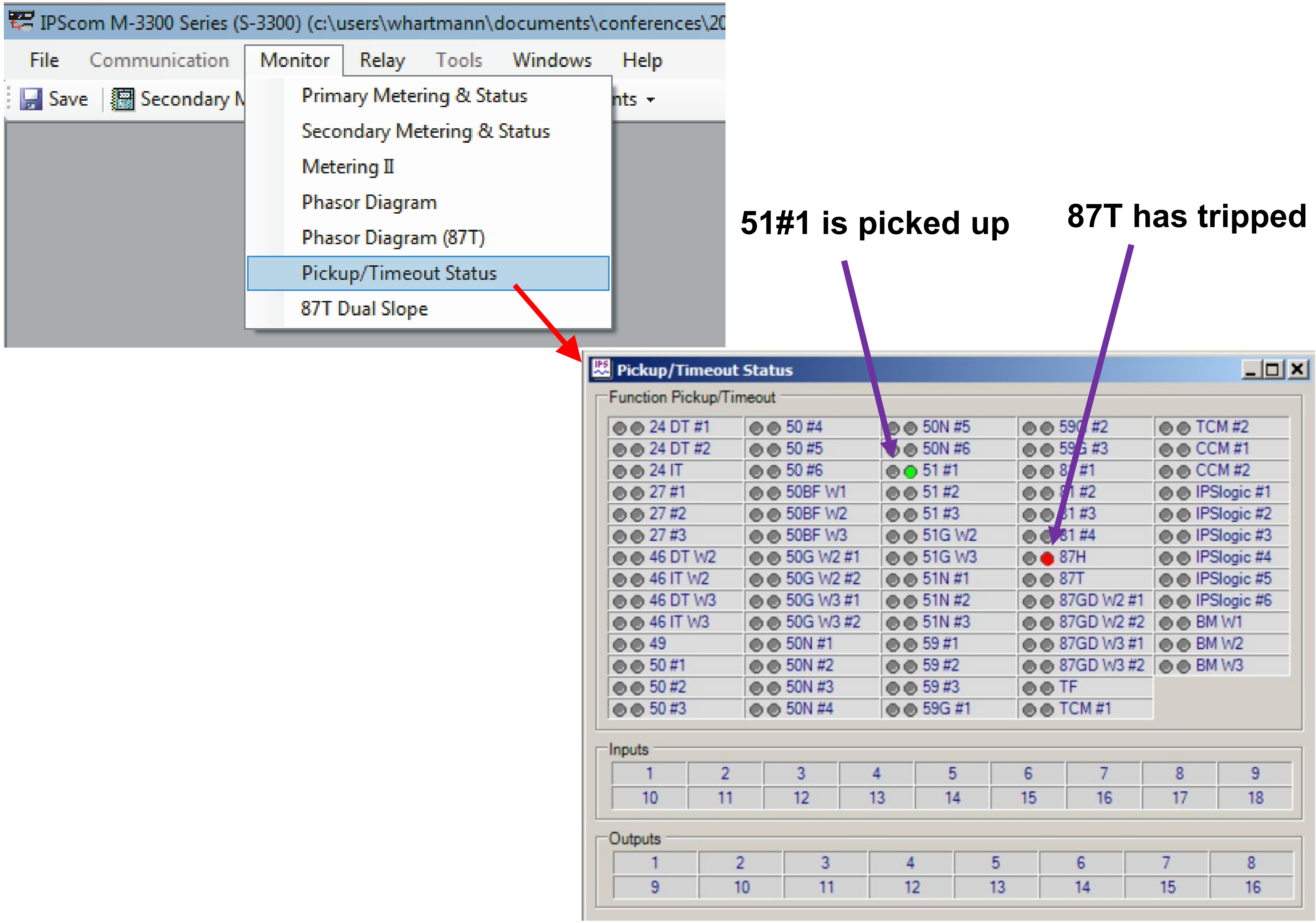
Event Log Trigger



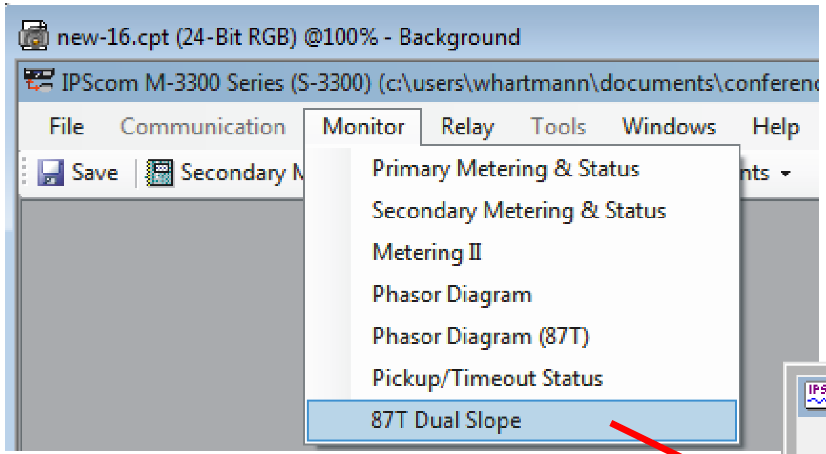
Sequence of Events Recorder (total 512 Events are stored)

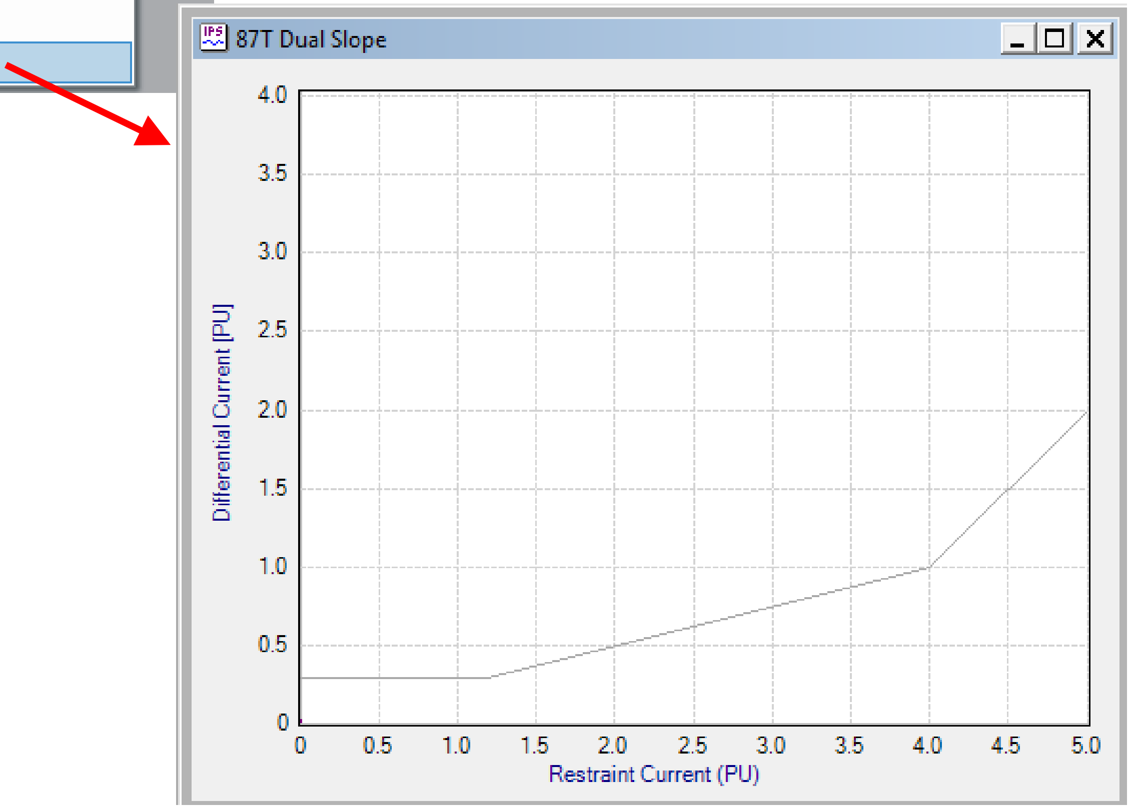


Function Status (Targets)

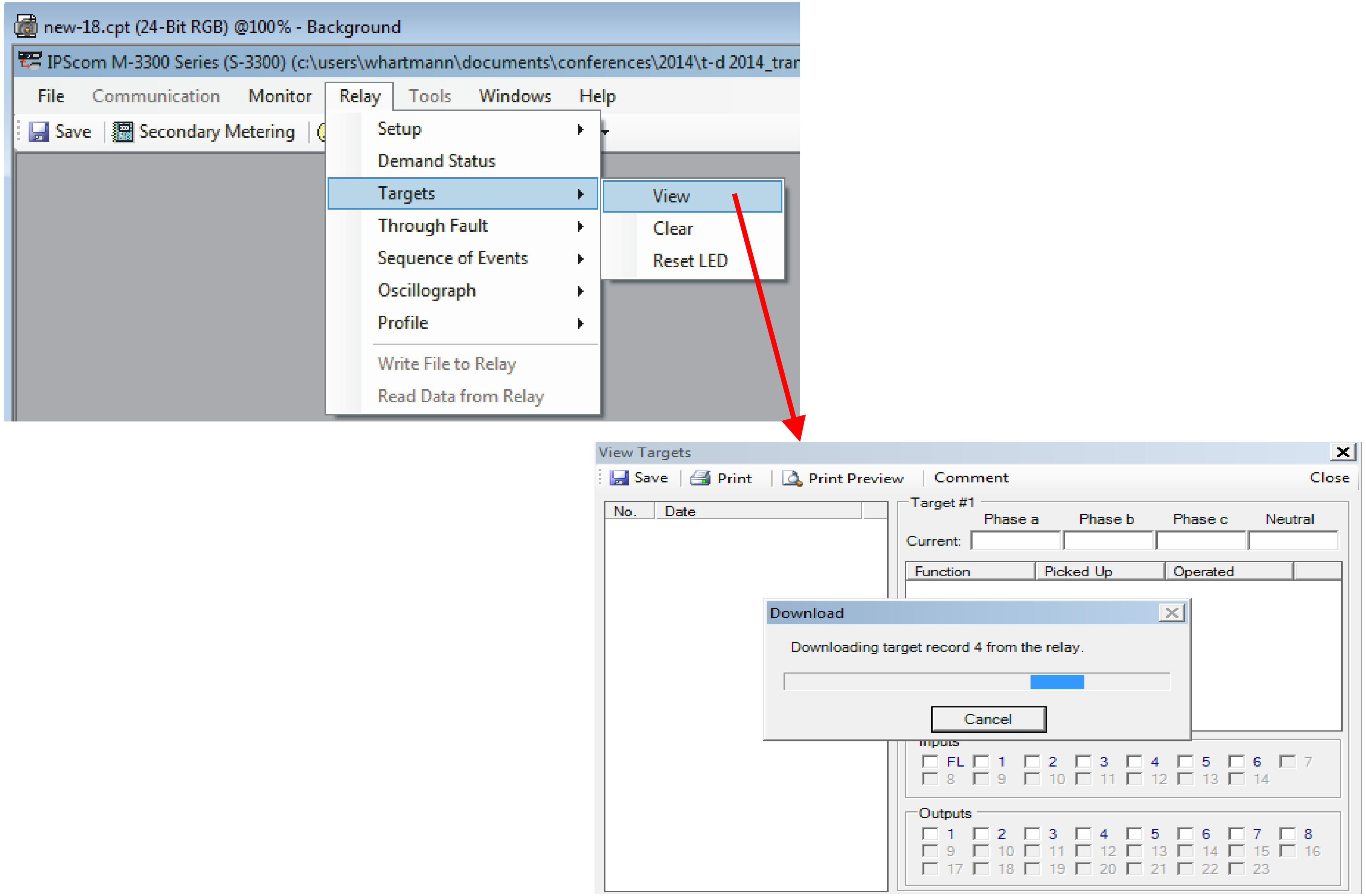


Differential Plot





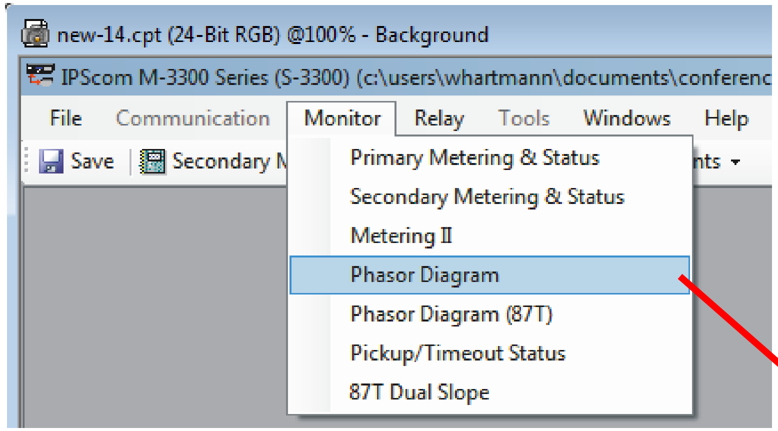
Retrieve Target Log

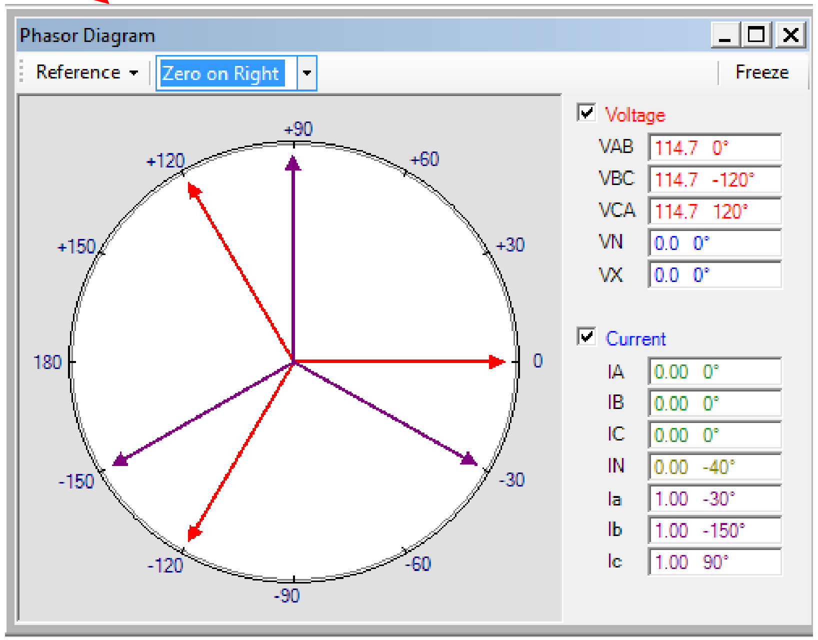


Phasor Displays

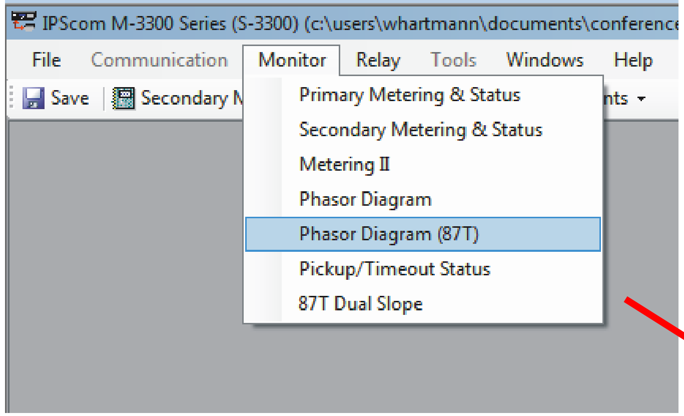
- A very useful commissioning tool for viewing selected vectors
  - Differential
  - Displays uncompensated currents
    - You can see the phase shift and relative magnitudes
  - Displays compensated currents
    - If they are equal in magnitude, and W2 and W3 are 180 degrees out from W1, the field wiring and relay settings are in agreement
- All Currents and Voltages
  - Displays all values

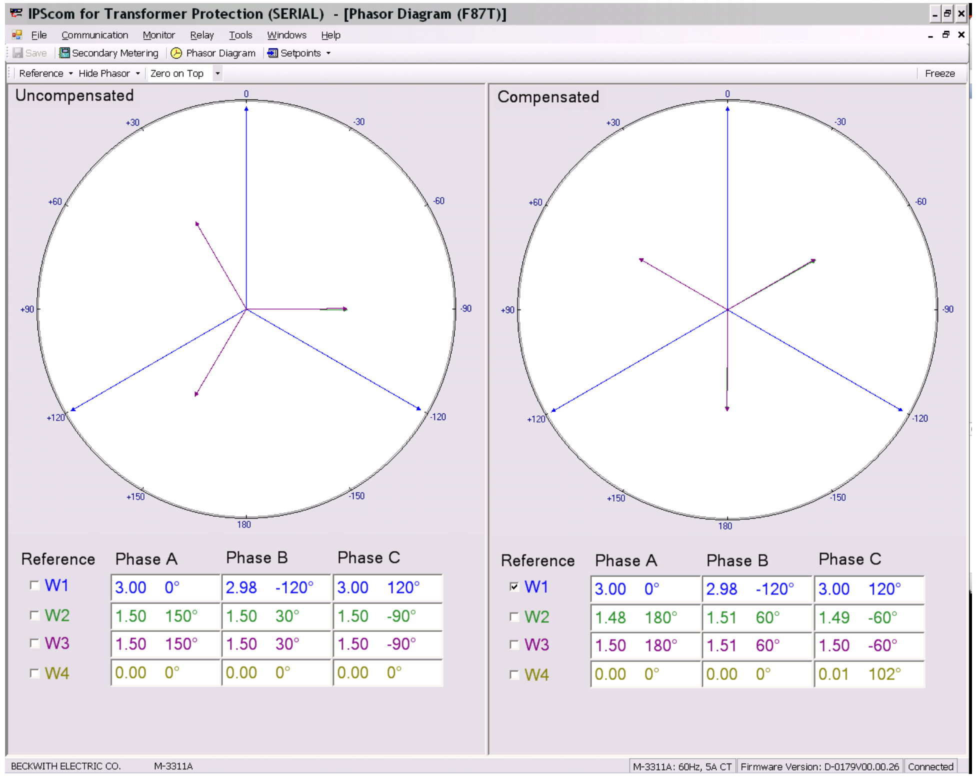
Phasor Diagram



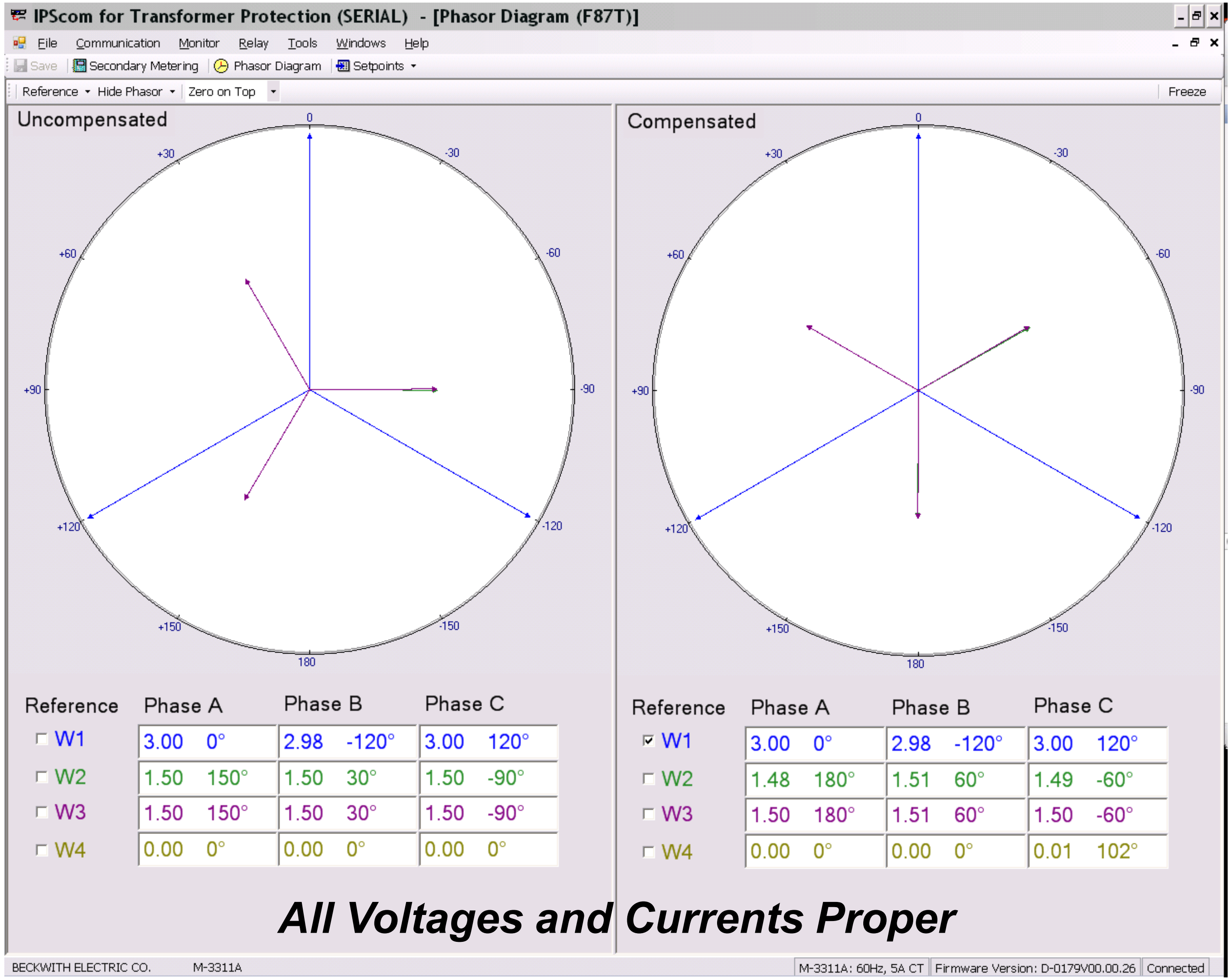


Phasor Diagram





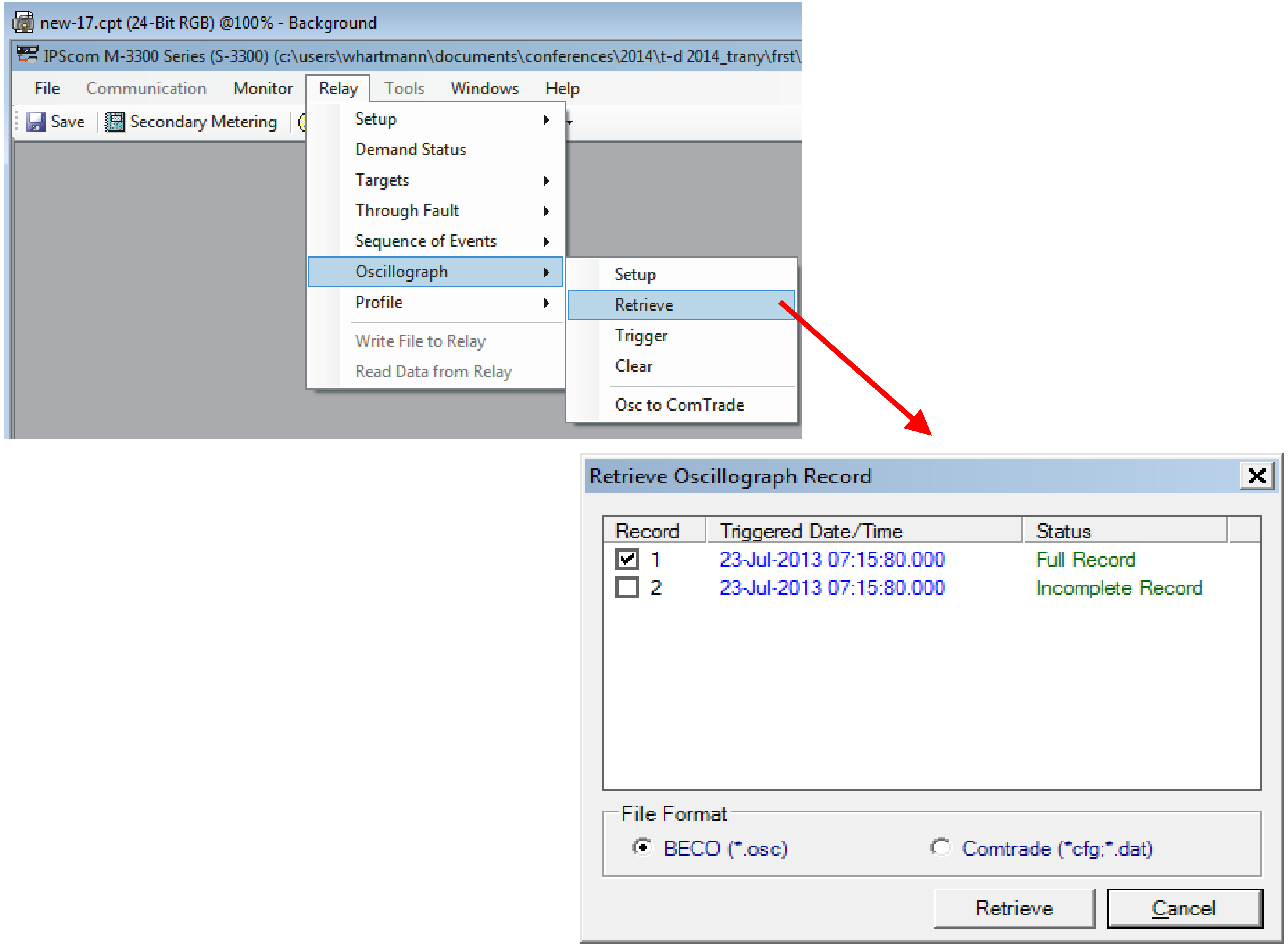
Phasor Display (Vectors)



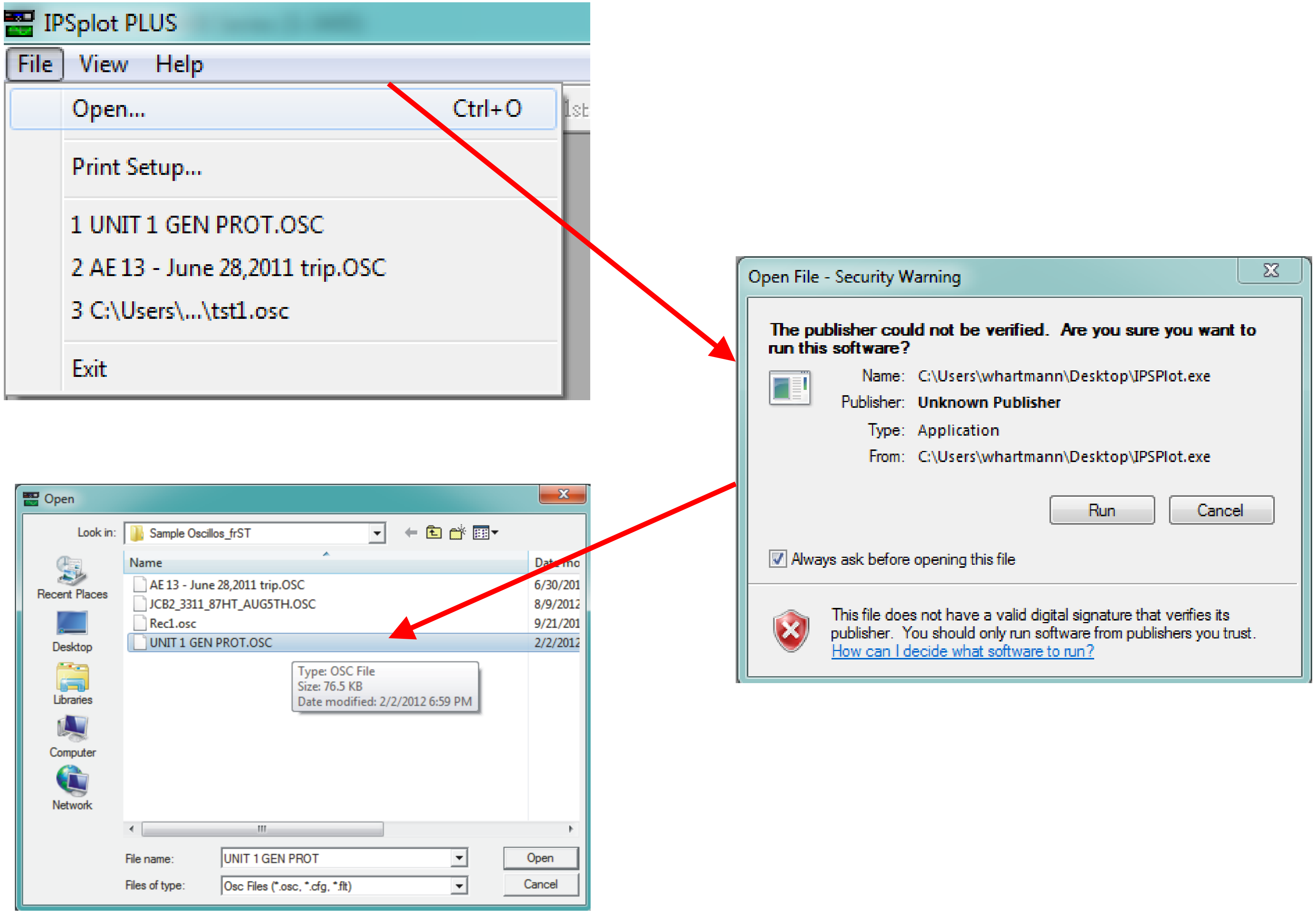
Oscillography Uses

- Speed transformer's return to service if event is not an internal fault
  - Identify type of testing needed
  - In the transformer or system?
  - Provide data to transformer manufacturer if asset health is in question
- Determine if relay and circuit breaker operated properly
  - Identify relay, control or breaker problem
- Uncovers unexpected problems
  - Settings
- Comtrade Oscillographs (*.cfg)

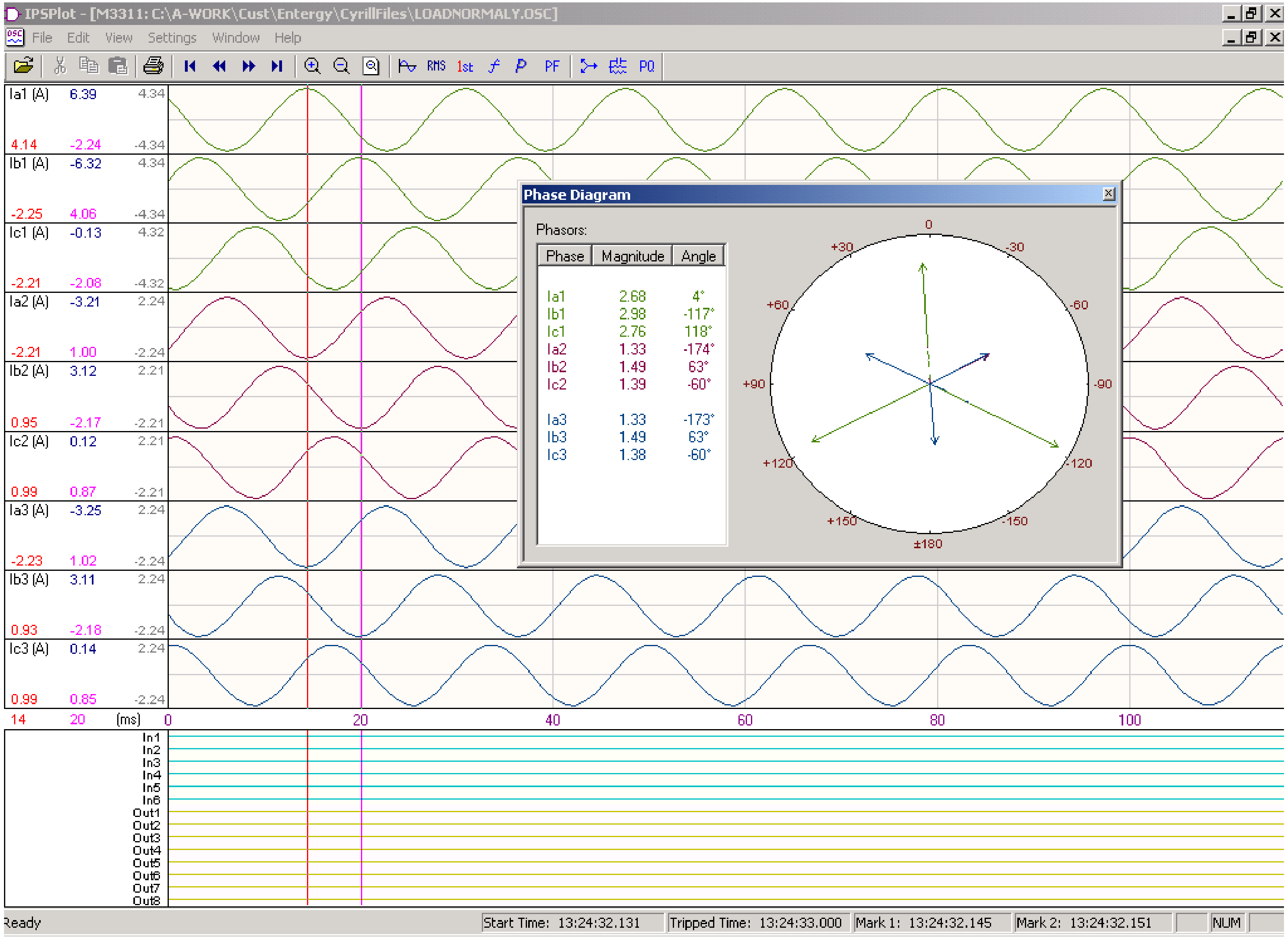
Retrieve Oscillographic Record



Opening an Oscillographic File (*.cfg or *.ocs)



Waveform Capture



Commissioning Tasks

- PAT
  - Panel Acceptance Test
  - Test from the panel terminal blocks to the relay
    - Includes test switches
- SAT
  - Site Acceptance Test
  - Take successful PAT panel, and test with:
    - Secondary injection from CT termination cabinet at transformer/switchyard
    - Load pick up on transformer

Commissioning Tools

- Advanced Metering
  - Sequence components for all windings
    - Positive, negative and zero
- Restraint and differential currents
- Vector Metering
  - Uncompensated
    - Raw signal
  - Compensated
    - Post vector and ratio corrections
- Digital Oscillography
  - All winding currents

Commissioning Examples

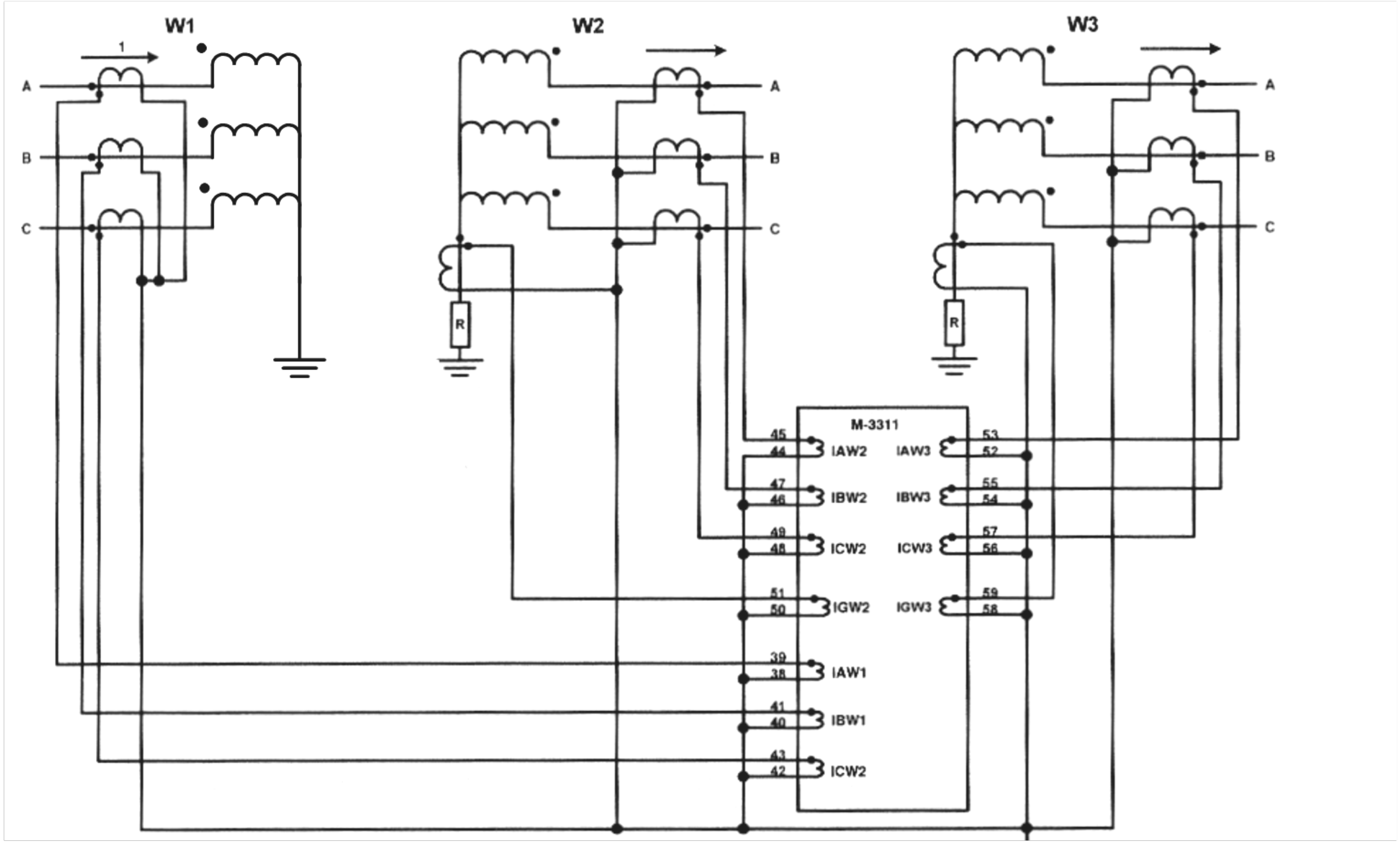
- Y-Y-Y, yyy, normal load flow
- Y-Y-Y, yyy, rolled A-phase on W2
- Δ-Y-Y, yyy, normal load flow
- Δ-Y-Y, yyy, rolled A-phase on W1
- Δ-Y-Y, yyy, rolled C-phase on W1

Details

- Used test equipment to simulate 3 winding transformers of various winding and CT configurations
- Injected 3A into W1, injected 1.5A into W2 and W3 to simulate load flow
- Assumed 1:1 transformer and 1:1 CTs for easy viewing of principles
- Created correct “base case”
- Created incorrect case
- Used advanced protection system tools to “diagnose” the incorrect issue

Y:Y:Y, yyy, 1:1 Ratio, 1:1 CTs, Normal

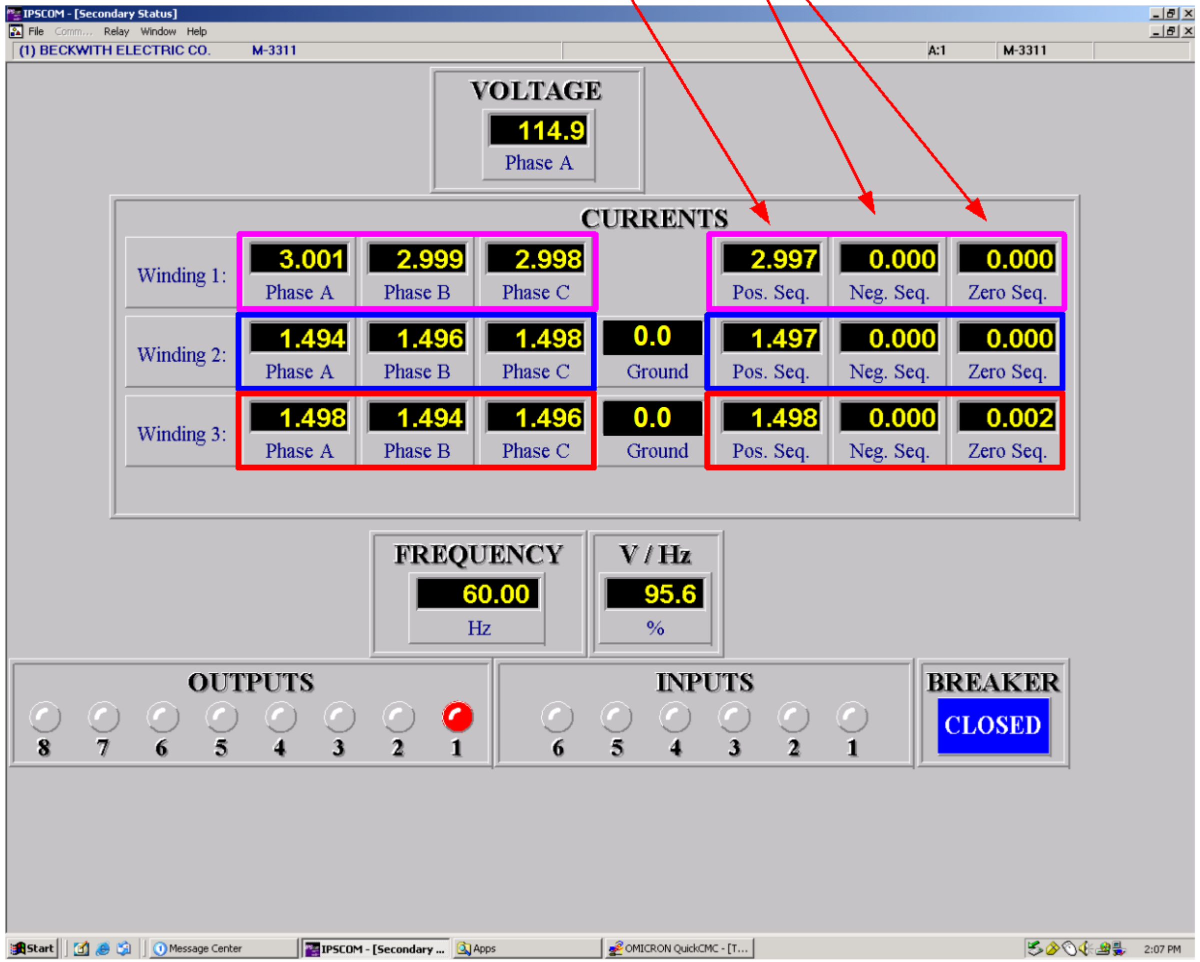
Three Line: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Normal



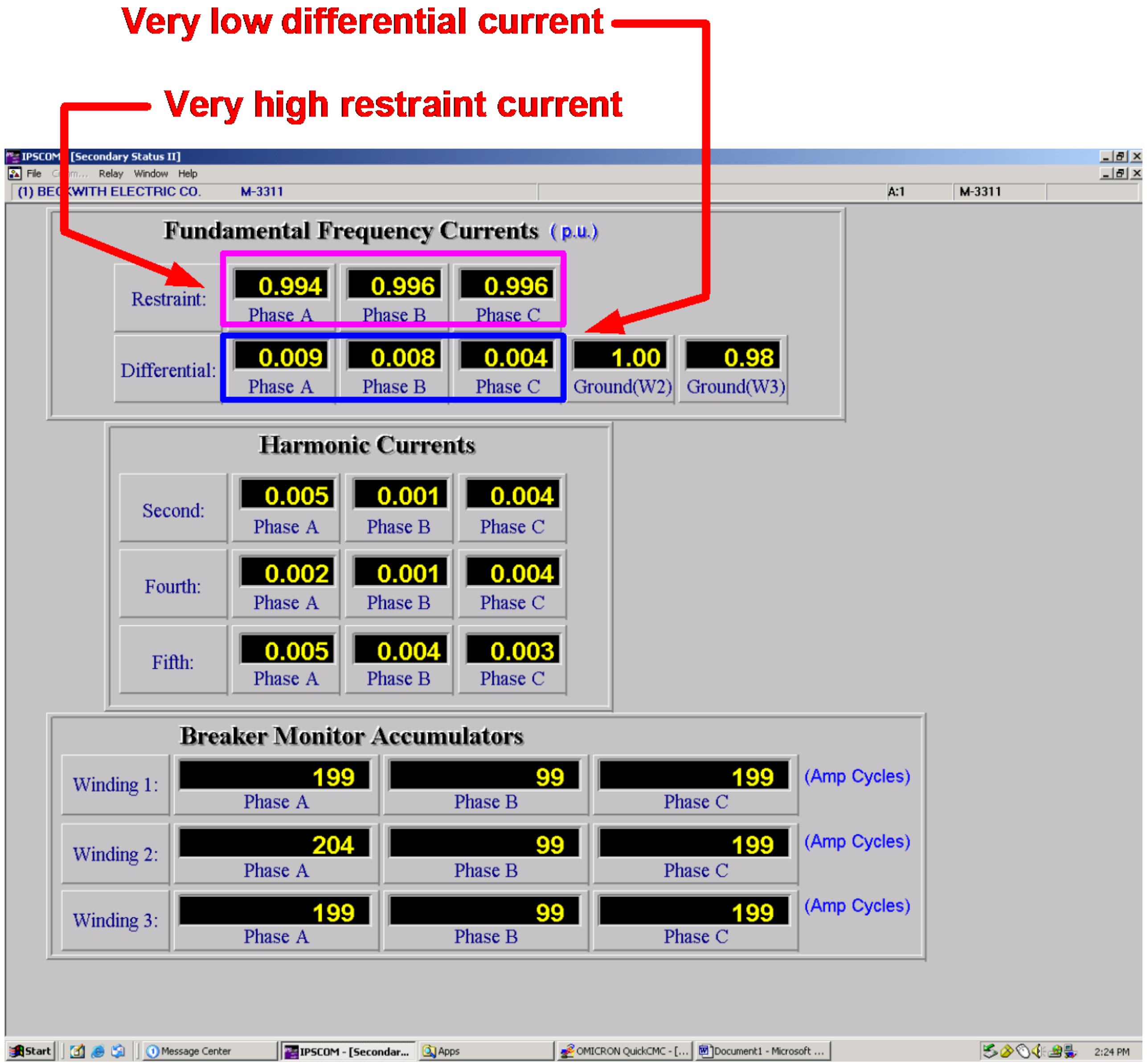
Advanced Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Normal

Low levels of negative and zero sequence current

High level of positive sequence current

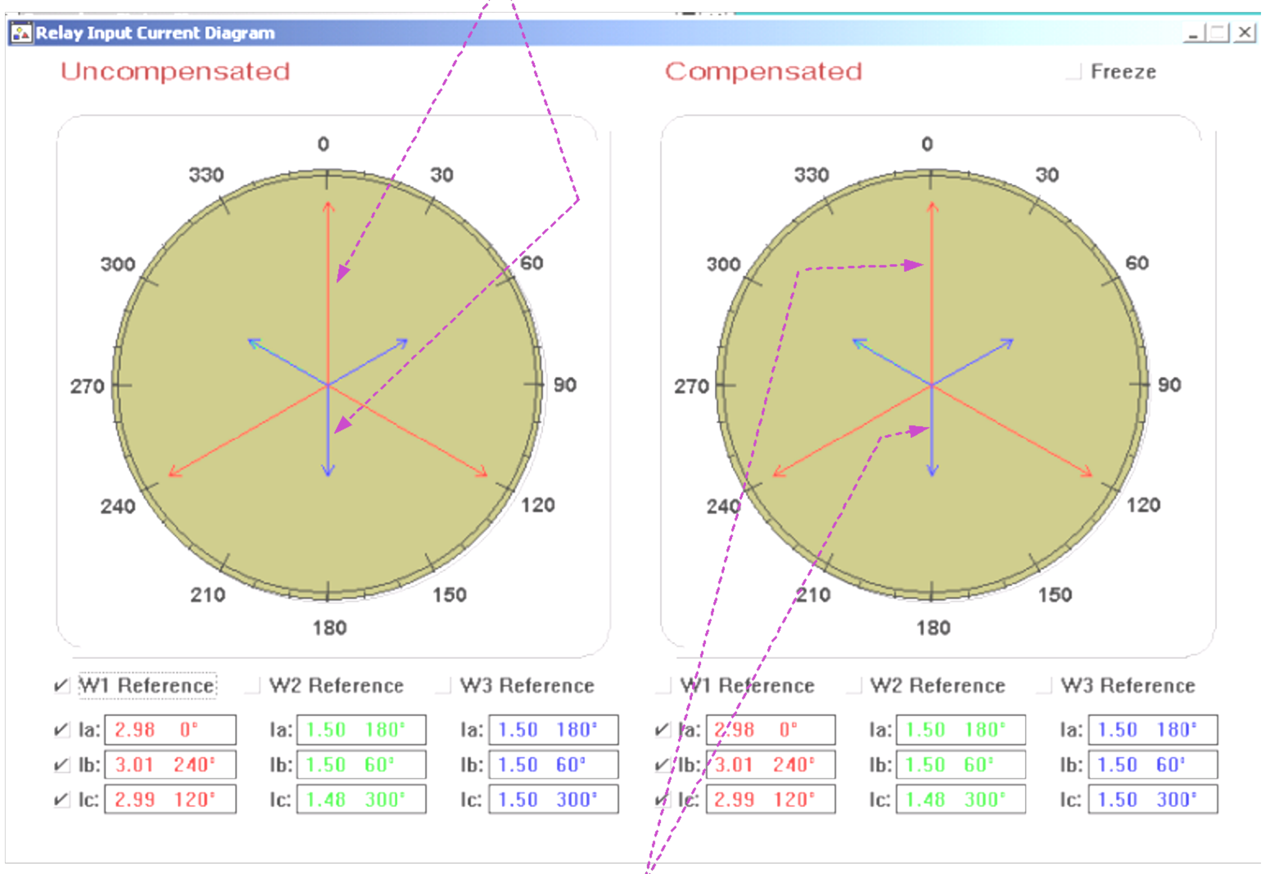


Advanced Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Normal



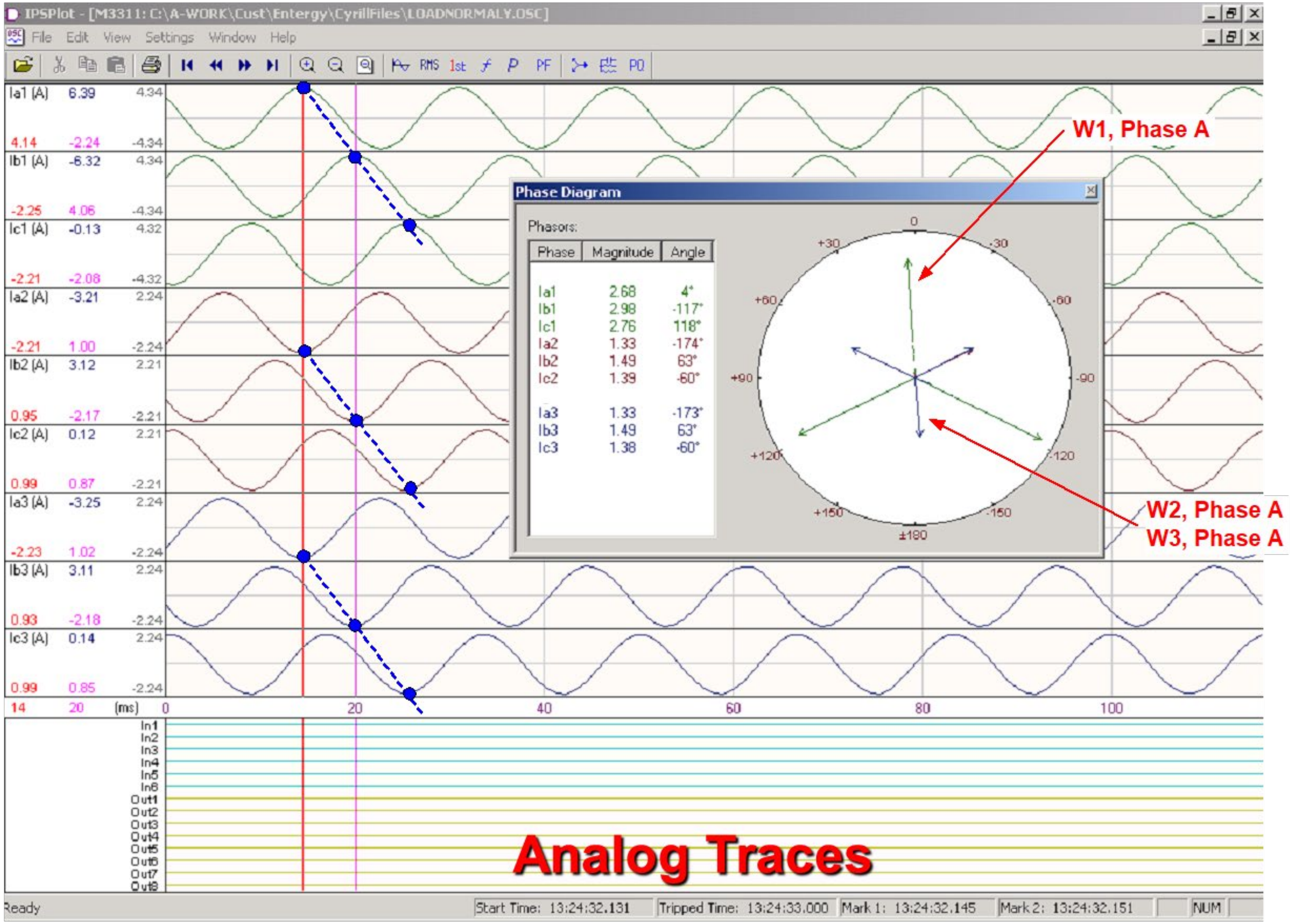
Vector Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Normal

W1, Phase A at 0 degrees
W2, Phase A at 180 degrees
W3, Phase A at 180 degrees



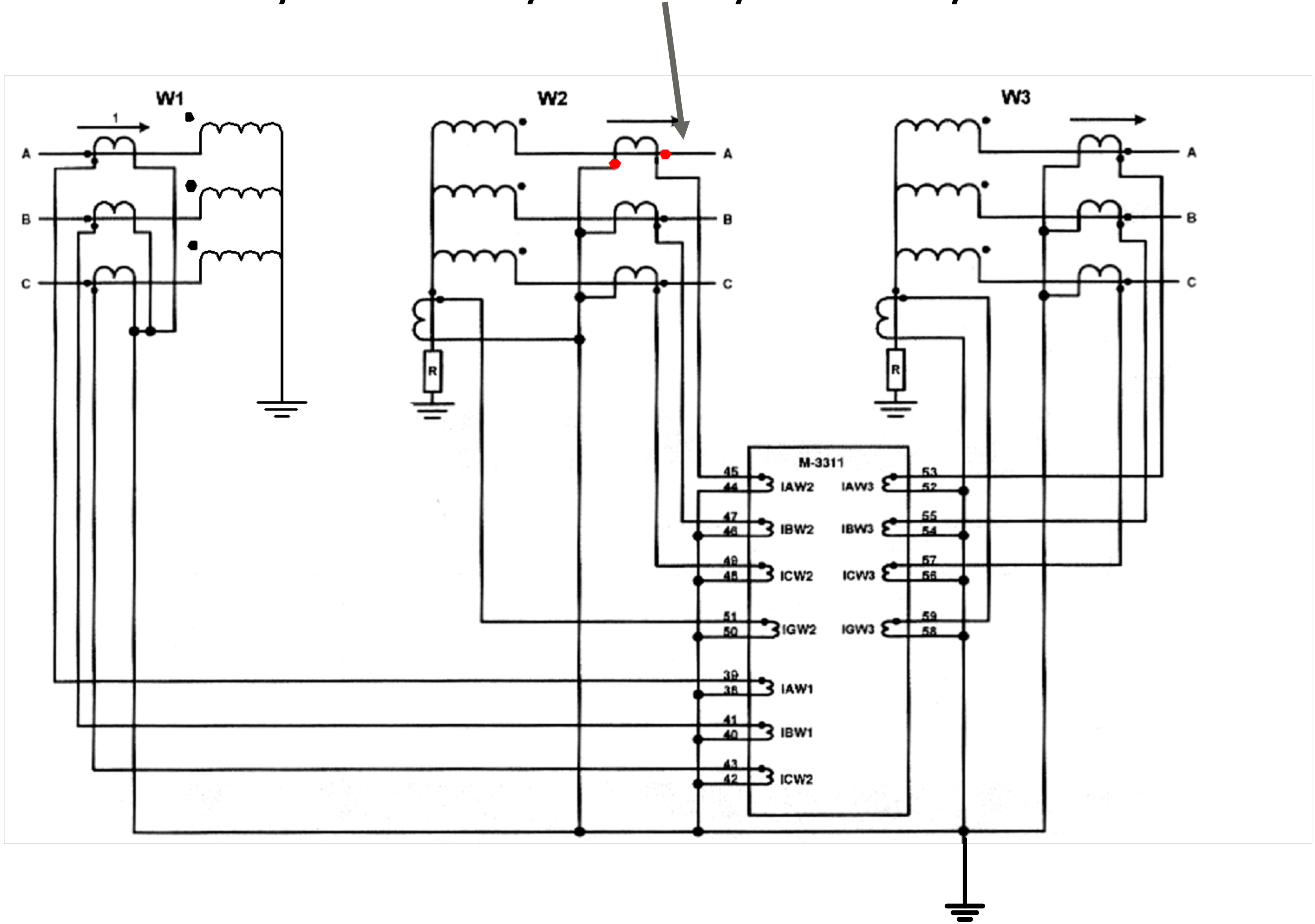
W1, Phase A at 0 degrees
W2, Phase A at 180 degrees
W3, Phase A at 180 degrees

Digital Oscillography: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Normal

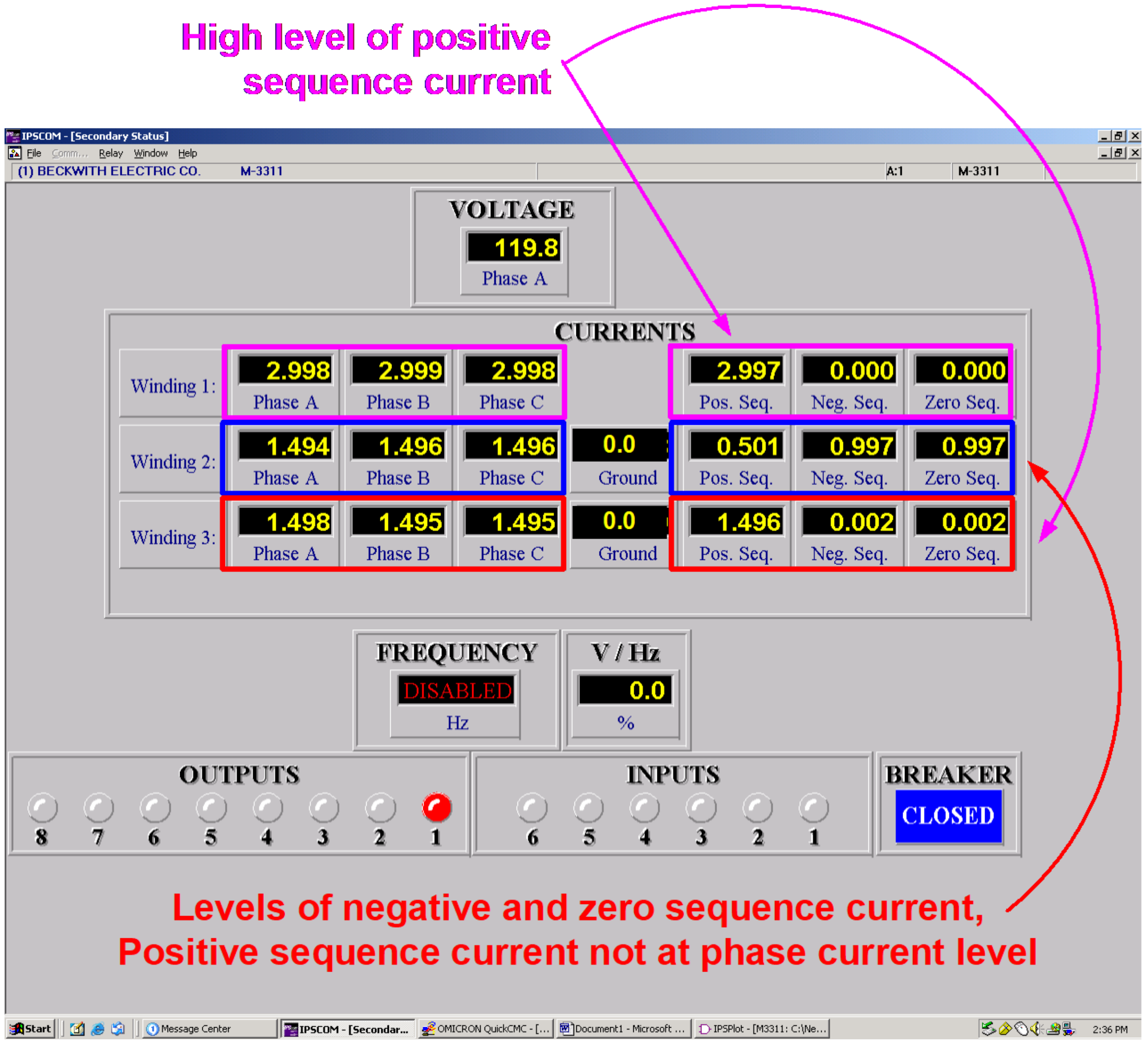


Y:Y:Y, yyy, 1:1 Ratio, 1:1 CTs, Roll W2, ØA

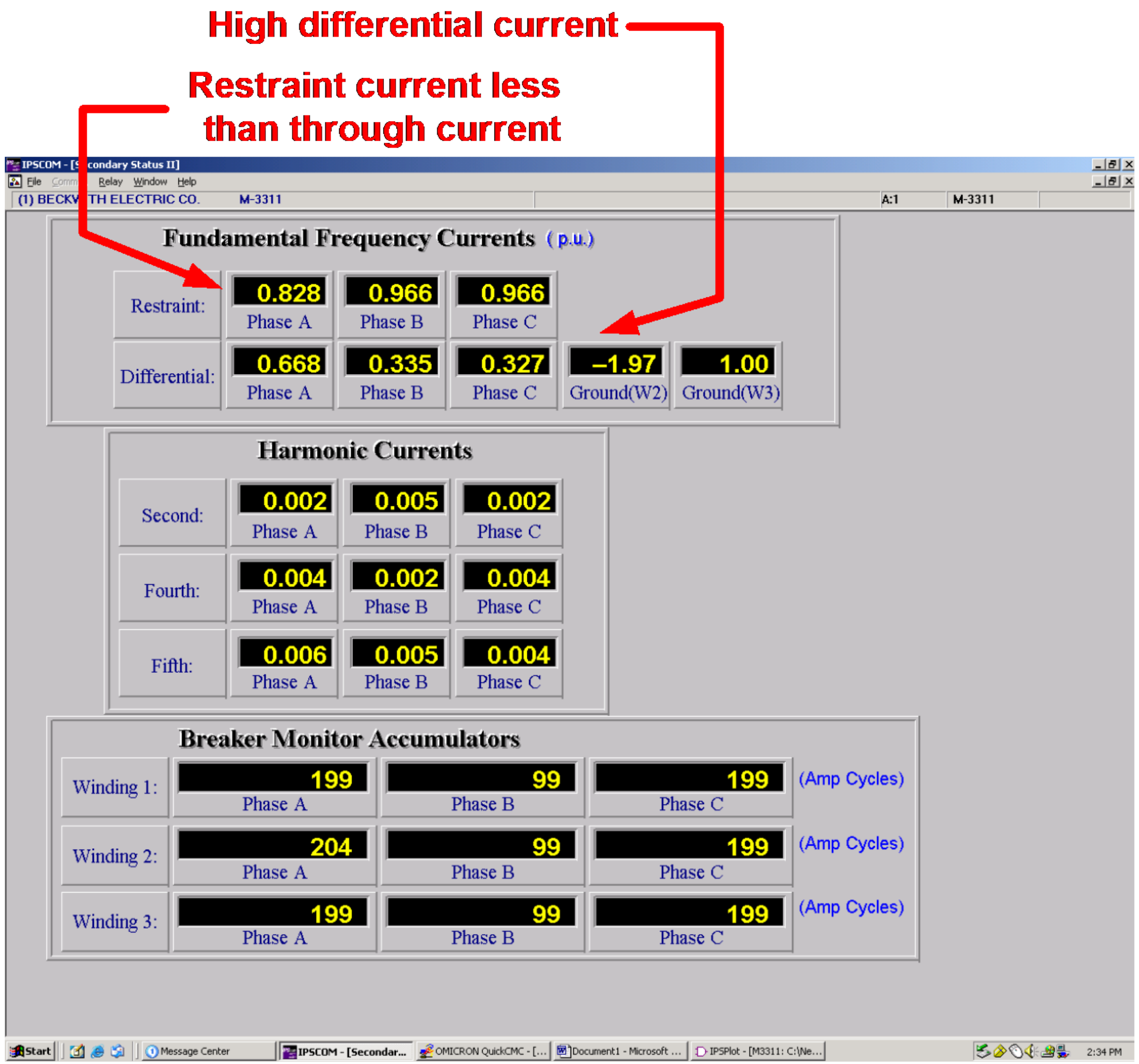
Three Line: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Roll ØA, W2



Advanced Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Roll ØA, W2

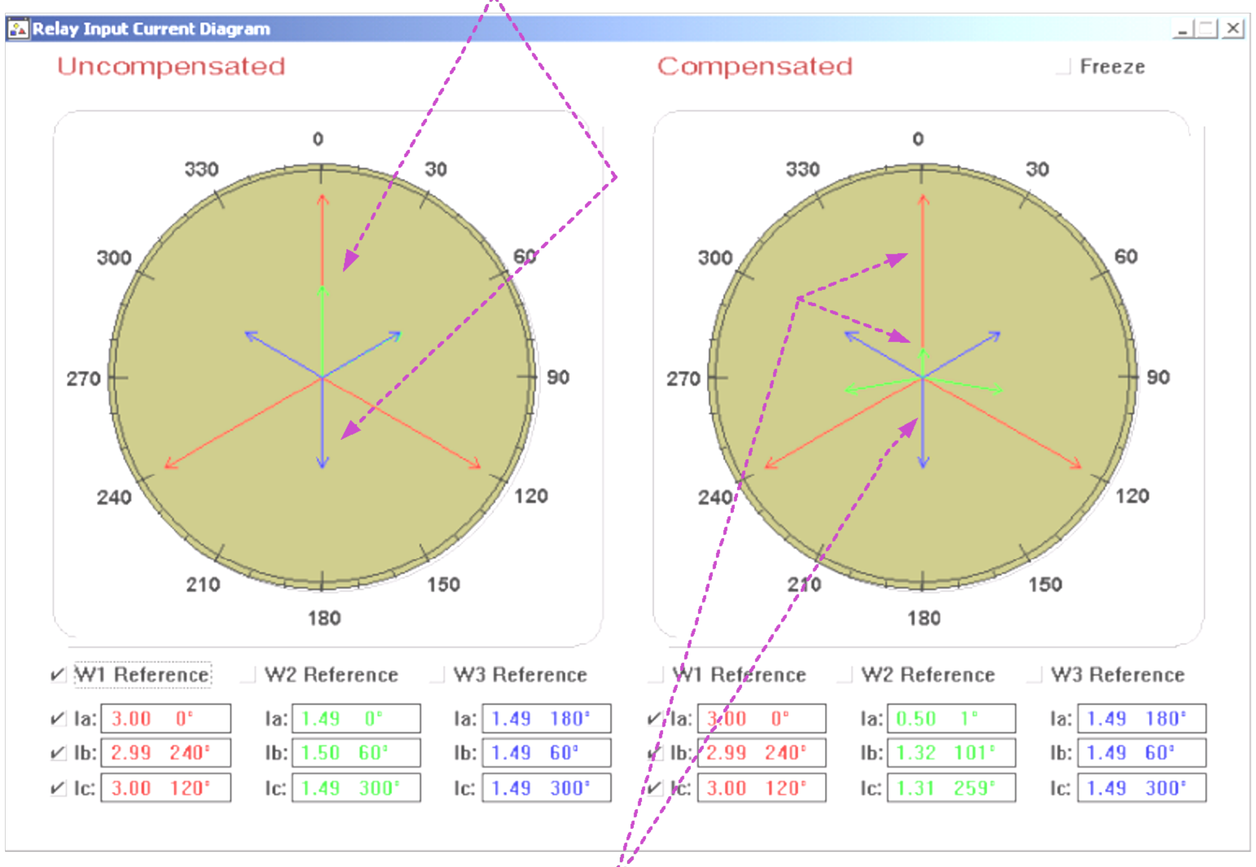


Advanced Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Roll ØA, W2



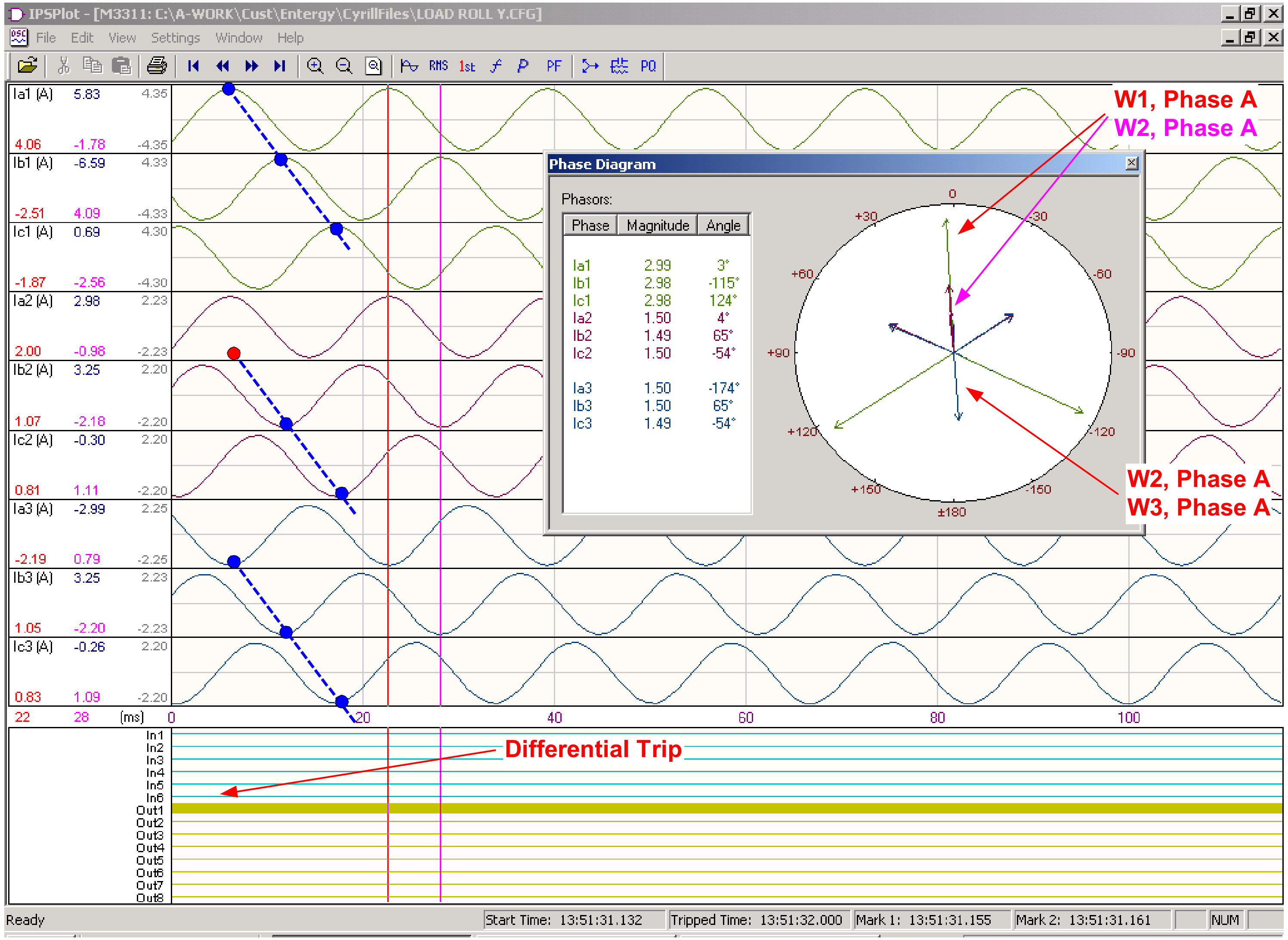
Vector Metering: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Roll ØA, W2

W1, Phase A at 0 degrees
W2, Phase A at 0 degrees (180)
W3, Phase A at 180 degrees



W1, Phase A at 0 degrees
W2, Phase A at 0 degrees (180)
W3, Phase A at 180 degrees

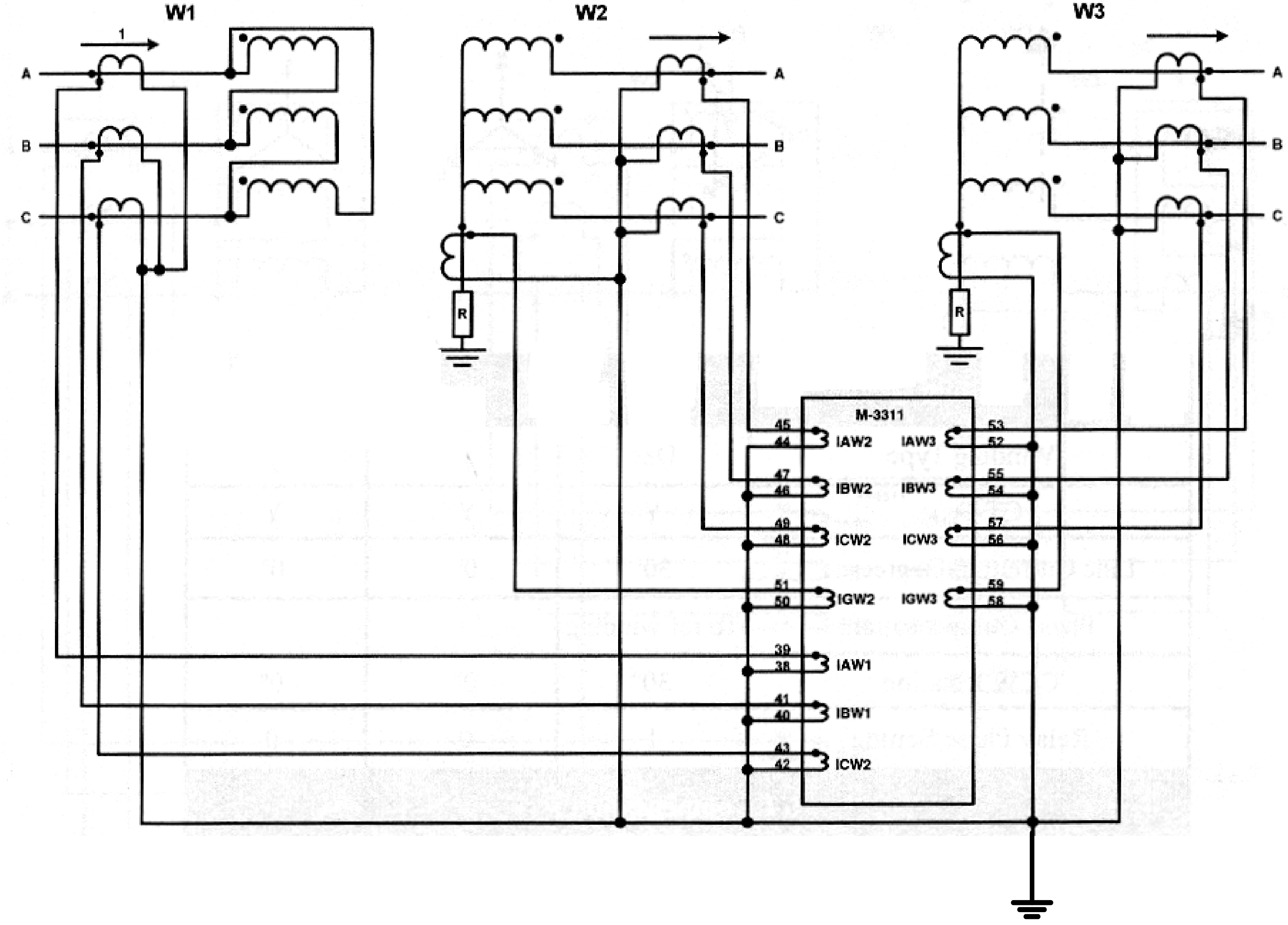
Digital Oscillography: Y:Y:Y, 1:1 Ratio, 1:1 CTs, Roll ØA, W2



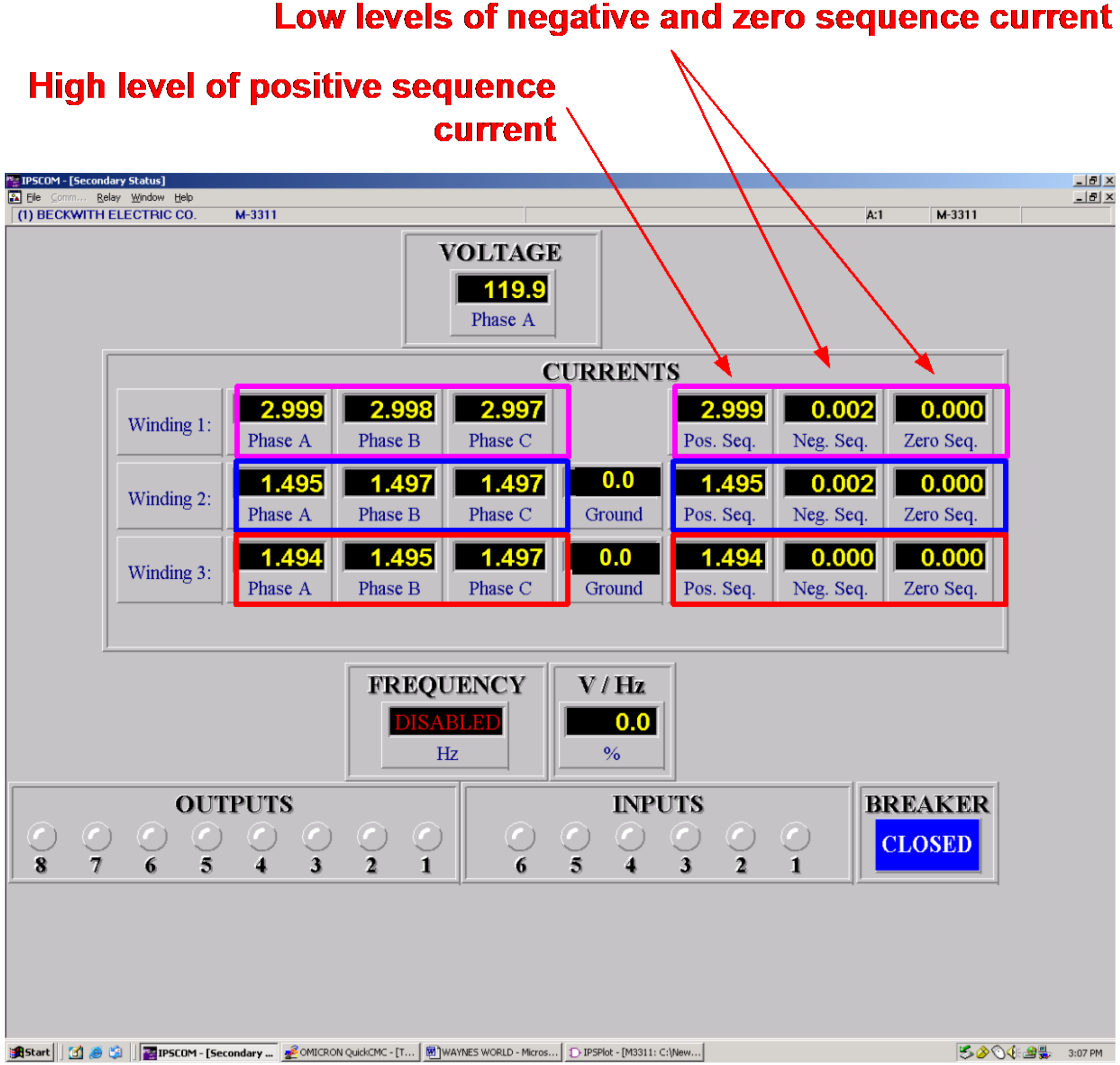
Analog Traces

∆ :Y:Y, yyy, 1:1 Ratio, 1:1 CTs, Normal

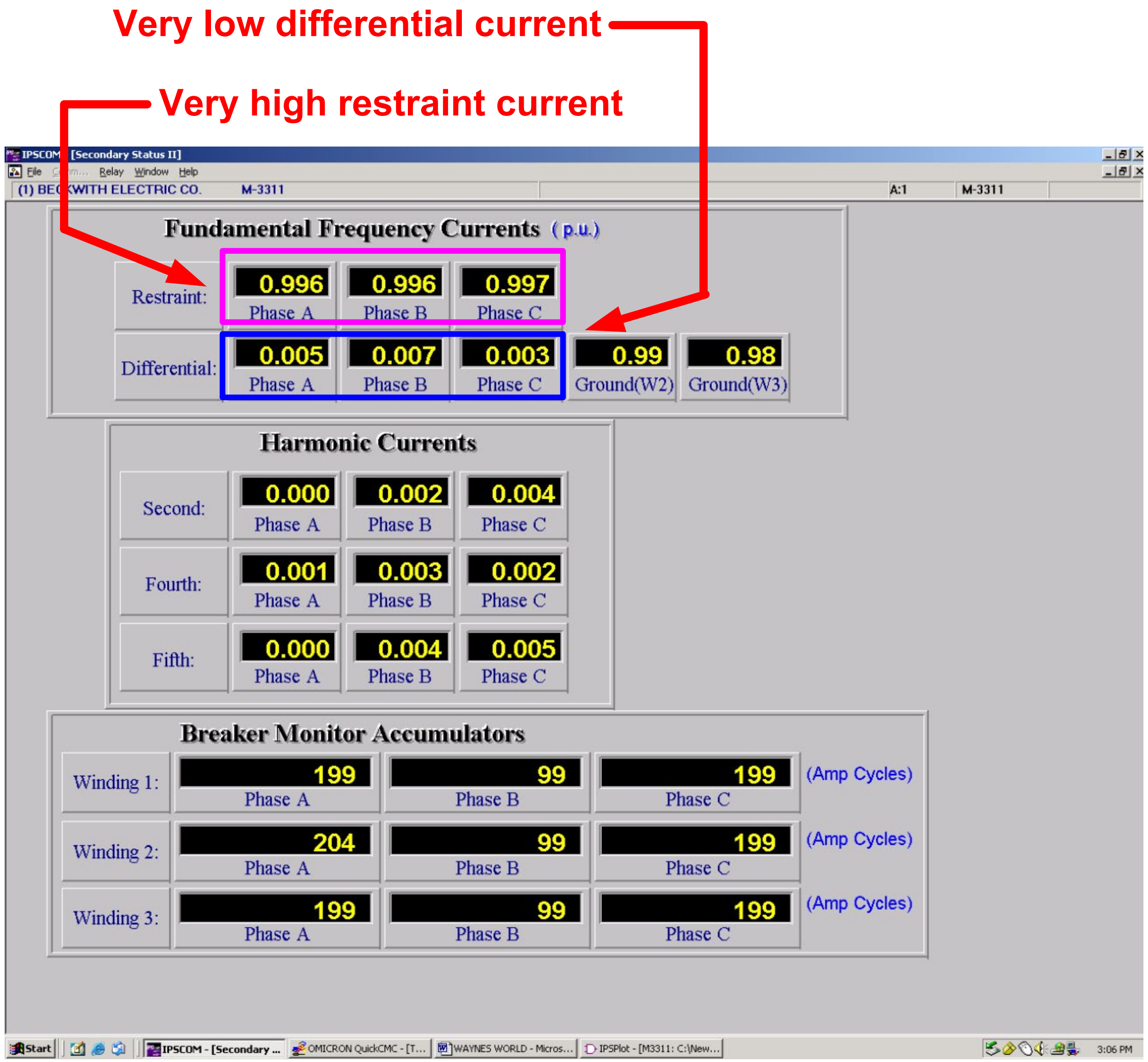
Three Line: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, Normal



Advanced Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, Normal

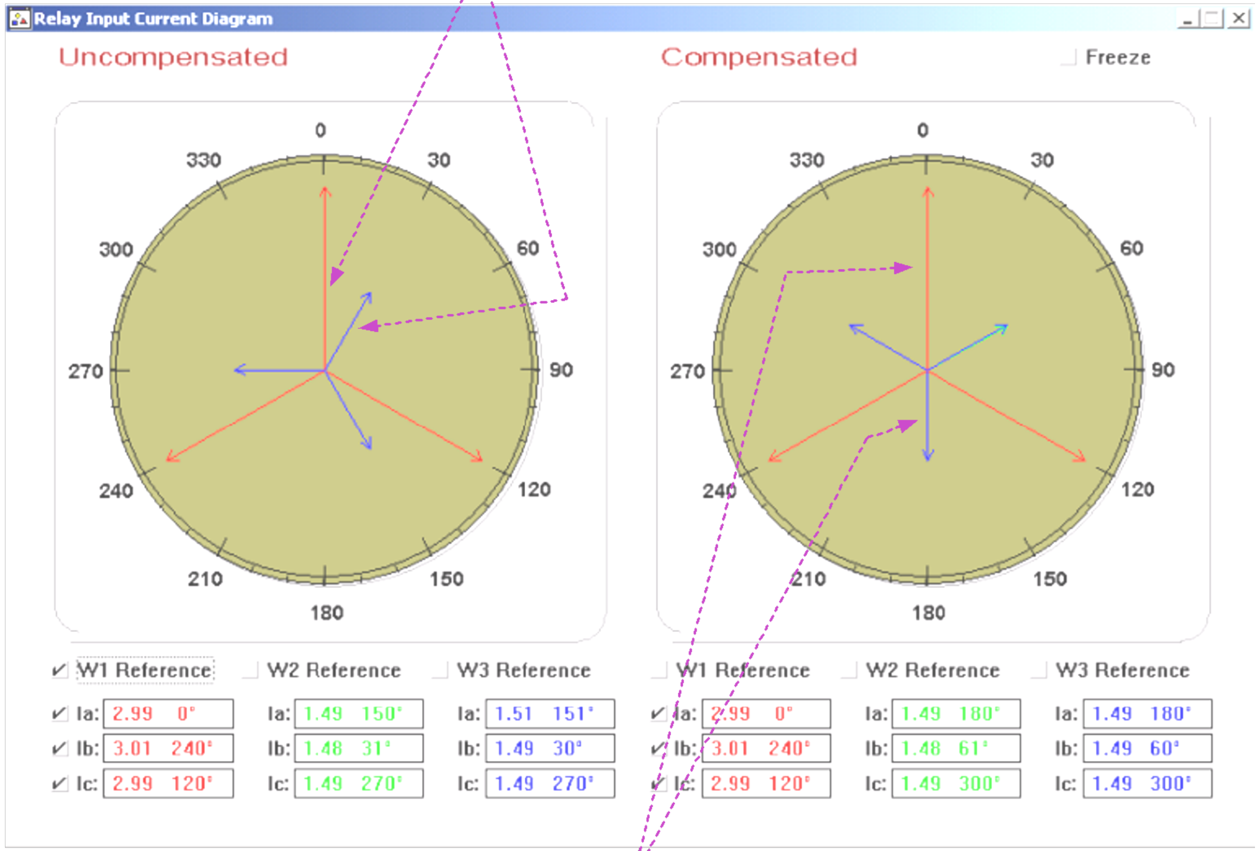


Advanced Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, Normal



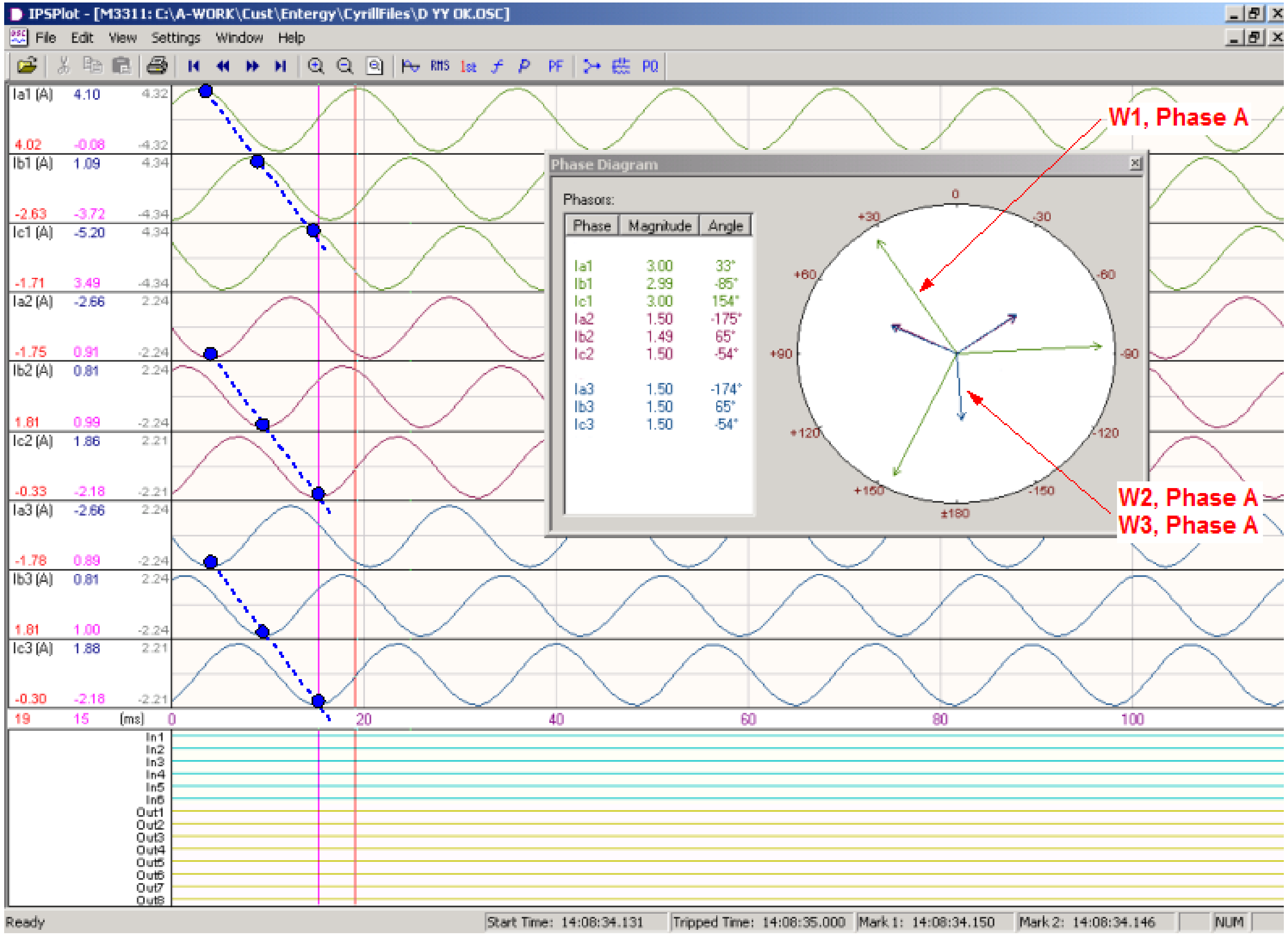
Vector Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, Normal

W1, Phase A at 0 degrees
W2, Phase A at 30 degrees
W3, Phase A at 30 degrees



W1, Phase A at 0 degrees
W2, Phase A at 180 degrees
W3, Phase A at 180 degrees

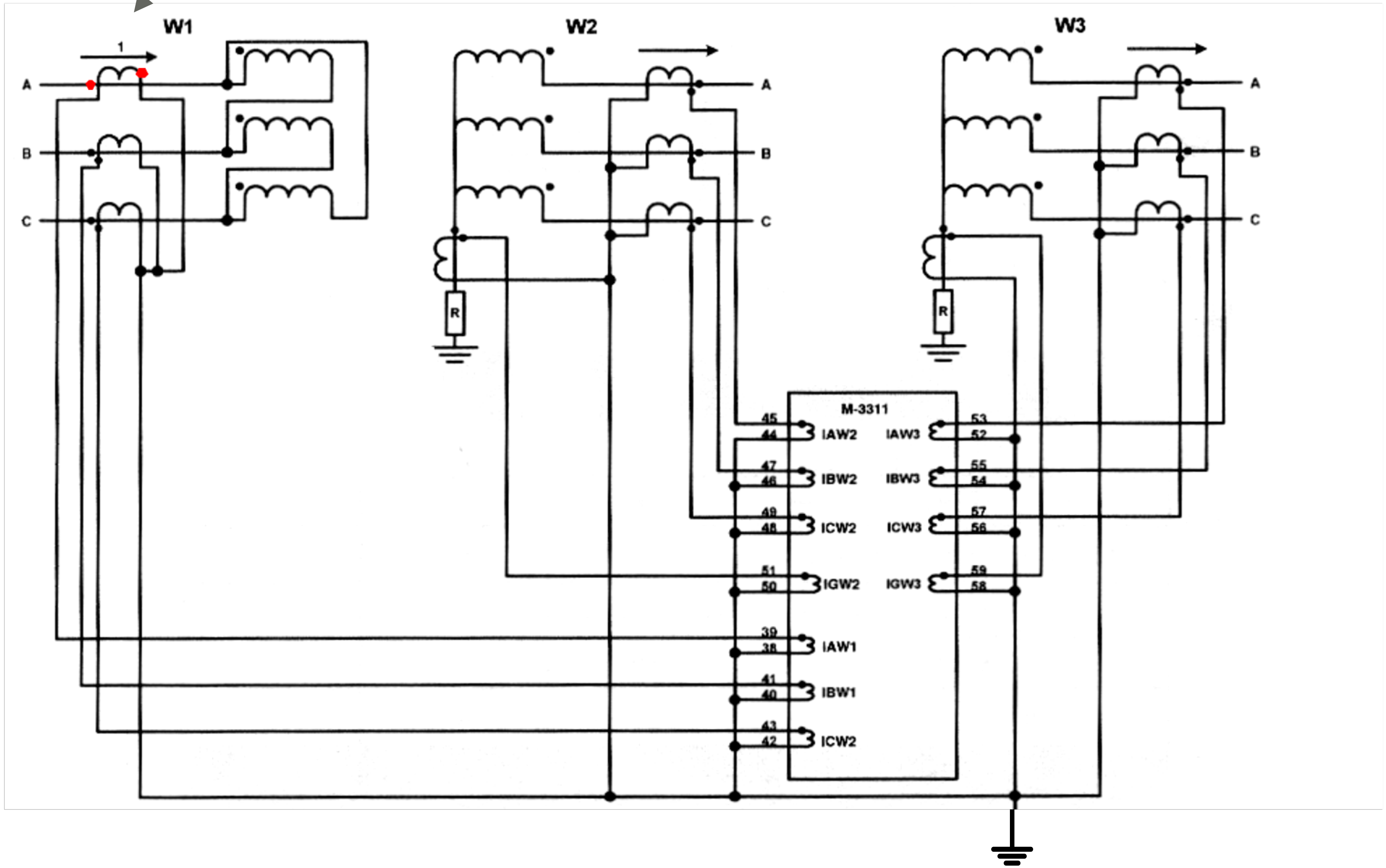
Digital Oscillography: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, Normal



Analog Traces

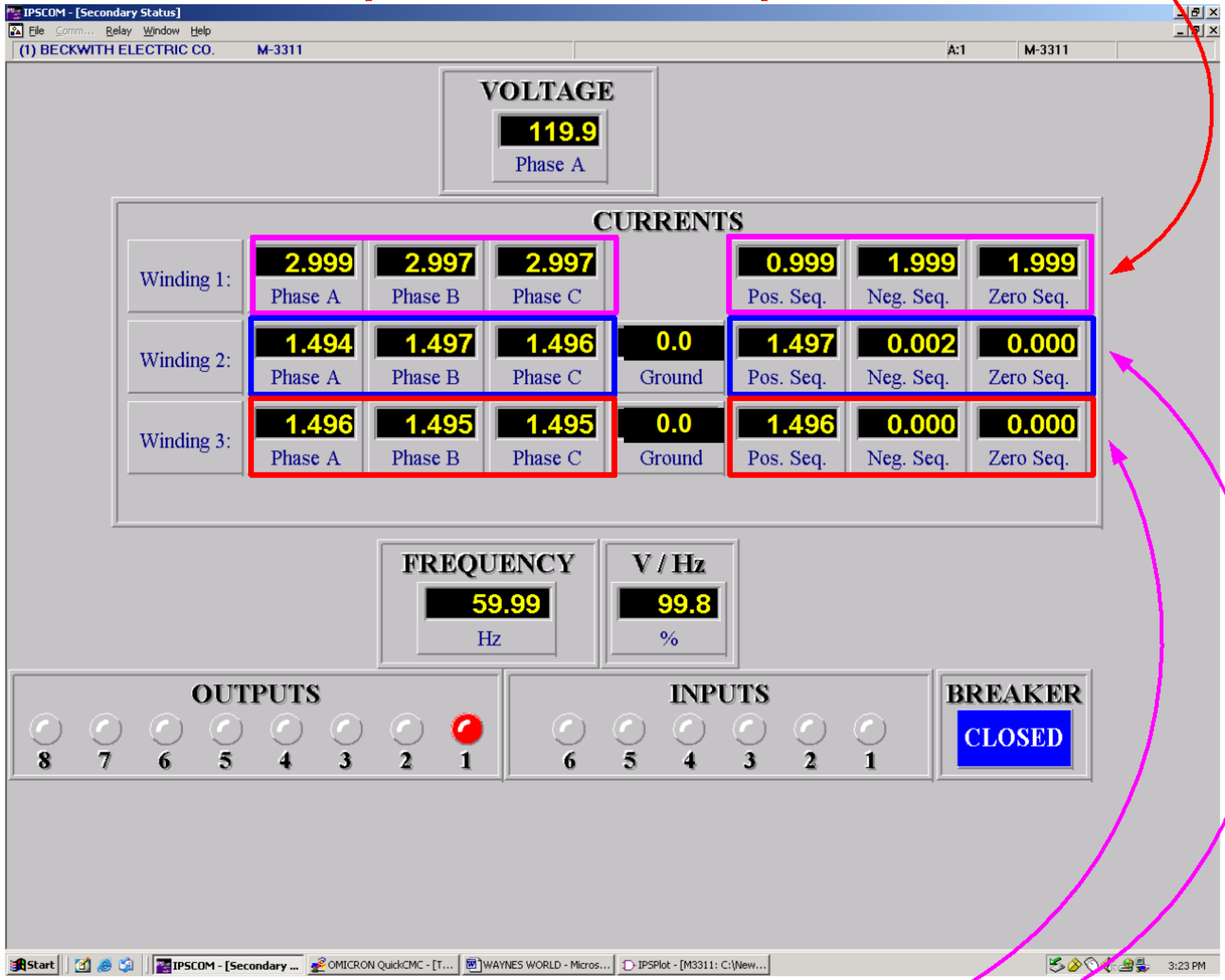
∆:Y:Y, yyy, 1:1 Ratio, 1:1 CTs, Roll W1, ØA

Three Line: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØA



Advanced Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØA

Levels of negative and zero sequence current,
Positive sequence current not at phase current level

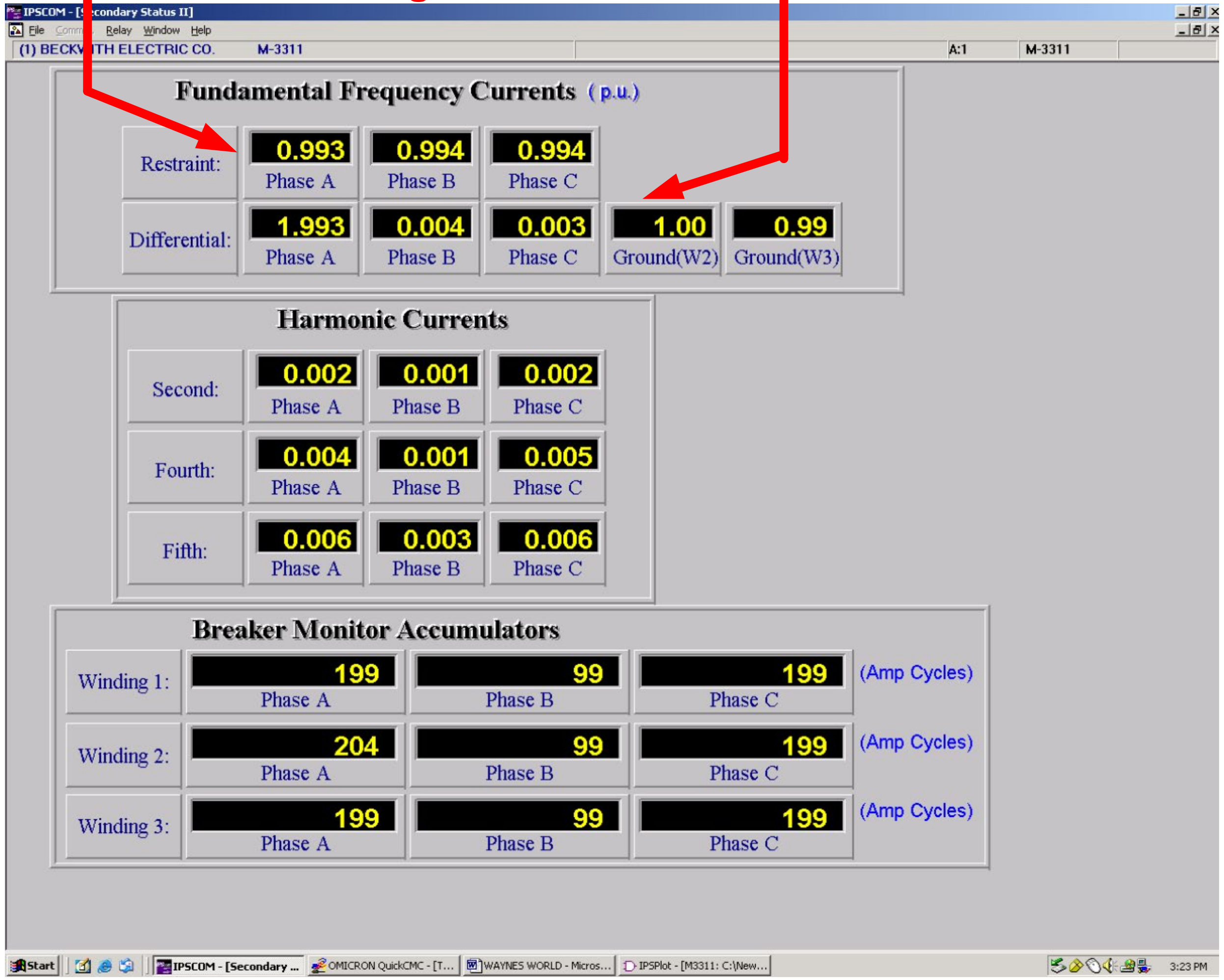


High level of positive sequence current

Advanced Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØA

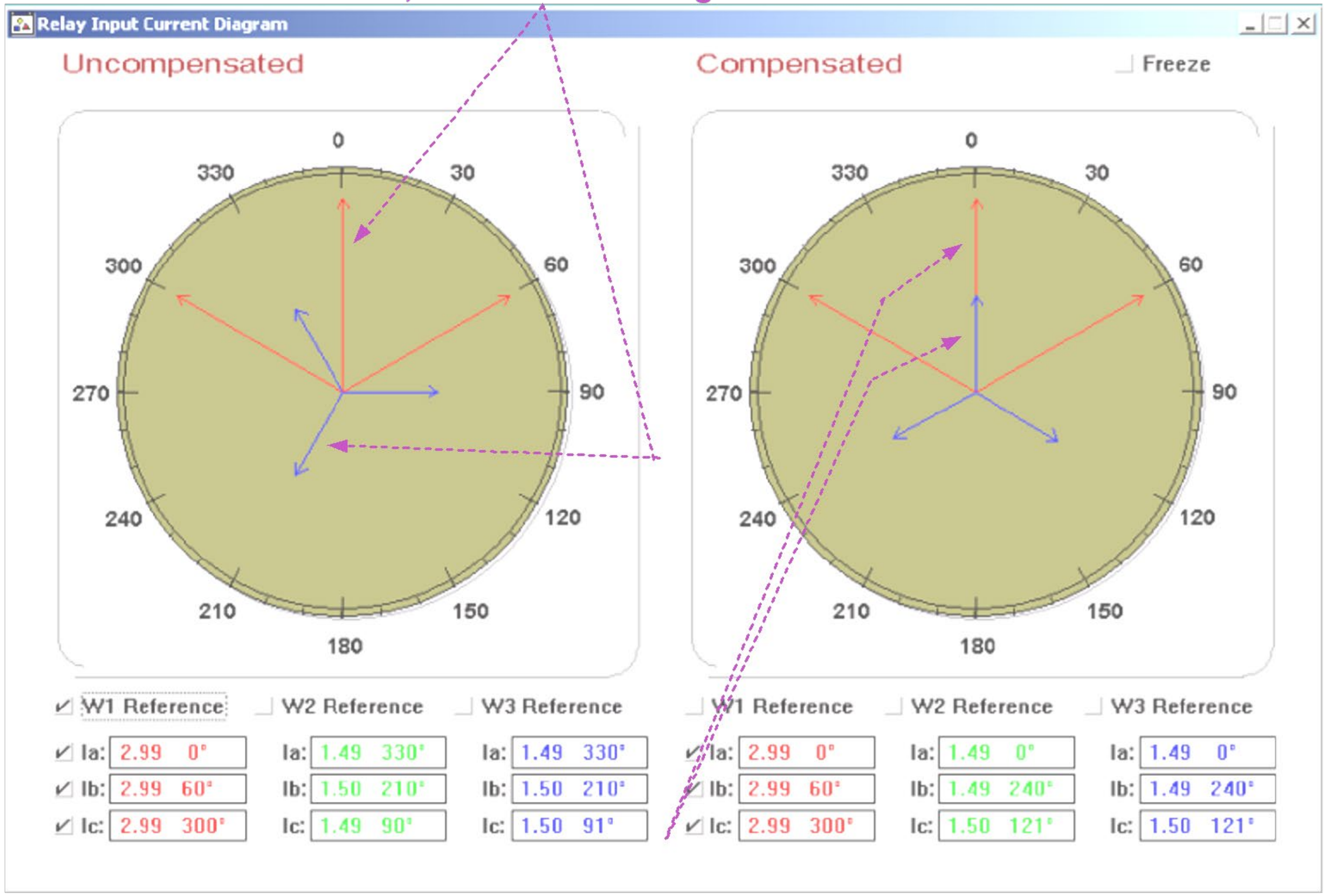
High differential current

Restraint current less than through current



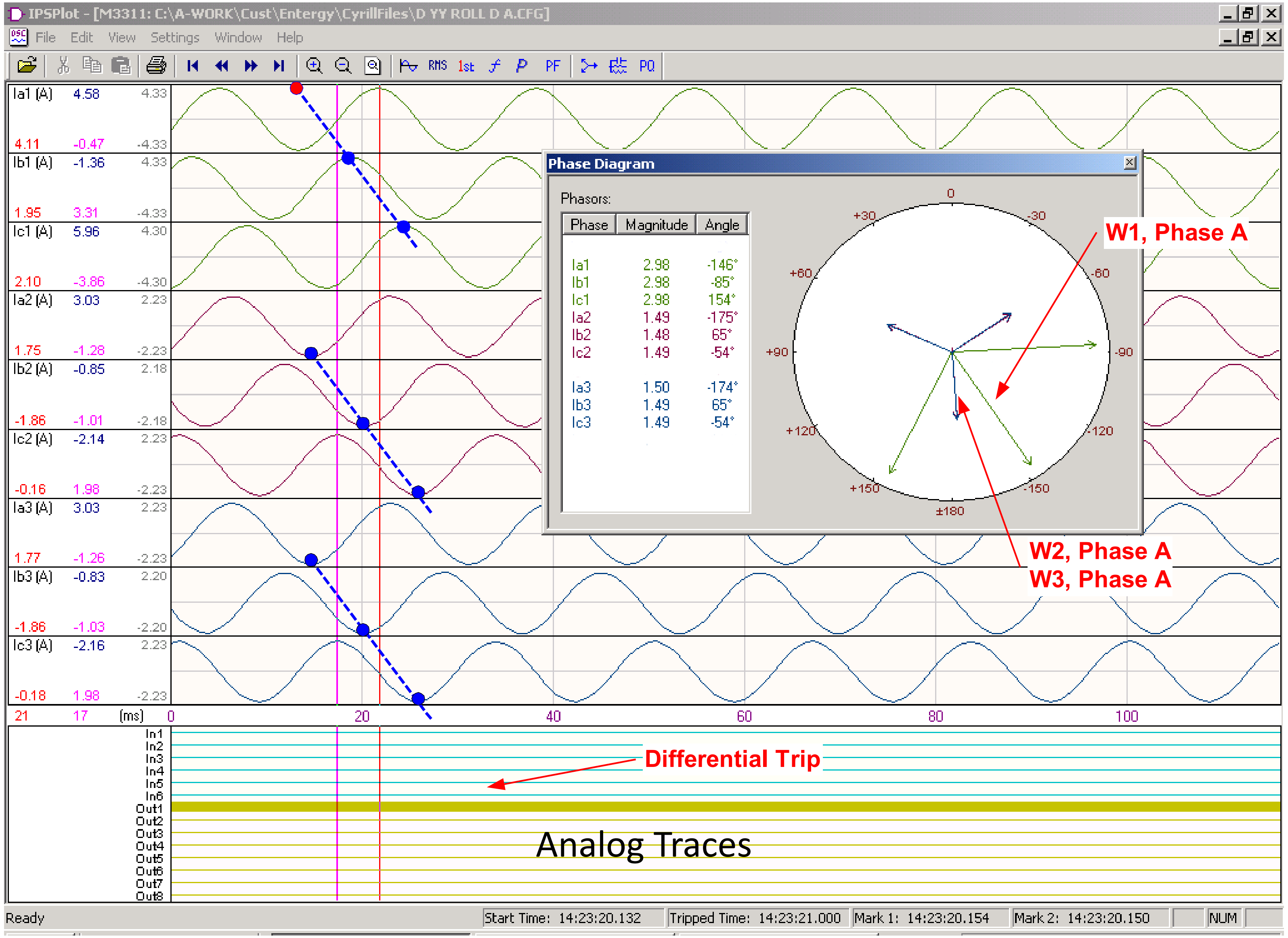
Vector Metering: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØA

W1, Phase A at 0 degrees (180)
W2, Phase A at 210 degrees
W3, Phase A at 210 degrees



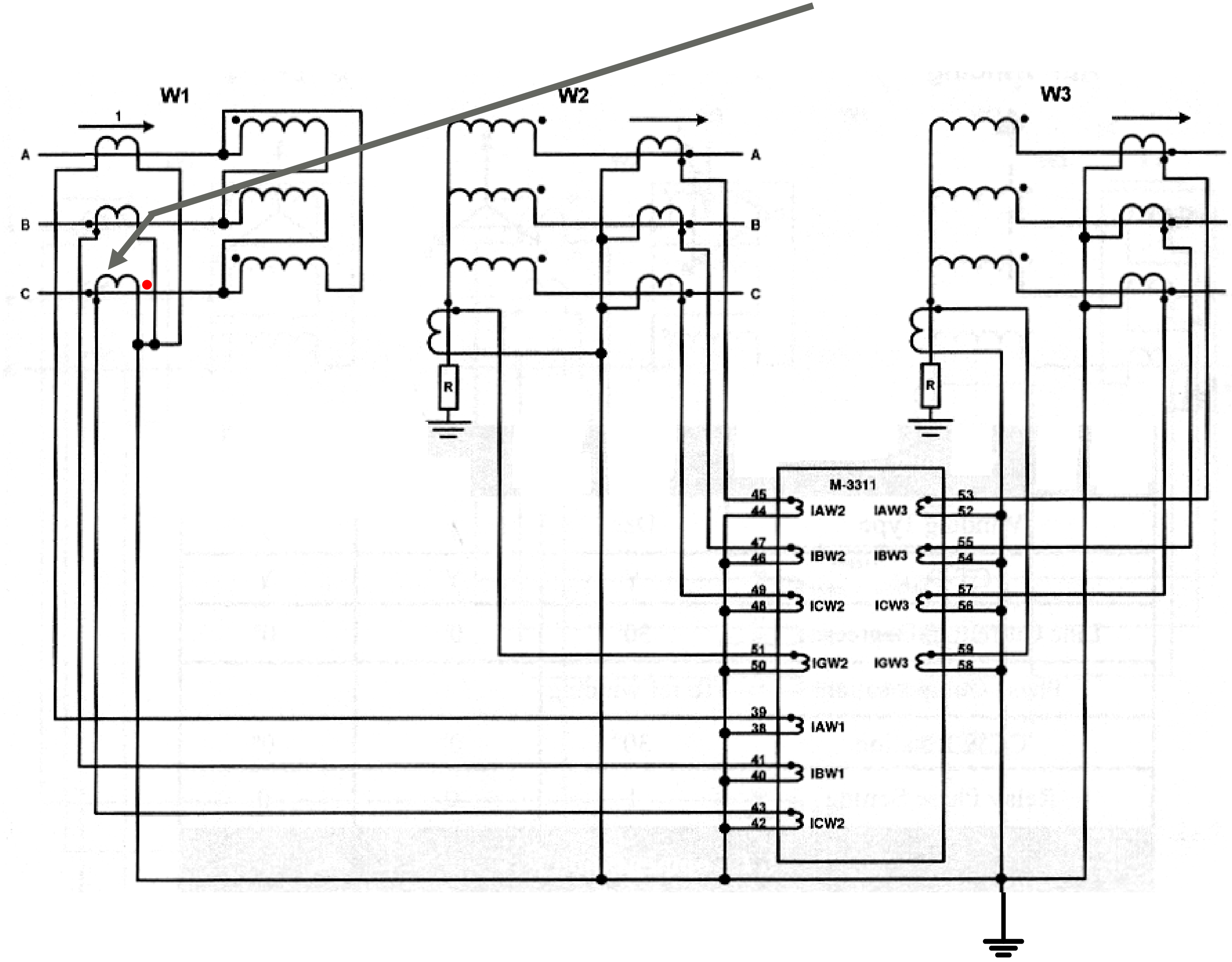
W1, Phase A at 0 degrees (180)
W2, Phase A at 0 degrees
W3, Phase A at 0 degrees

Digital Oscillography: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØA

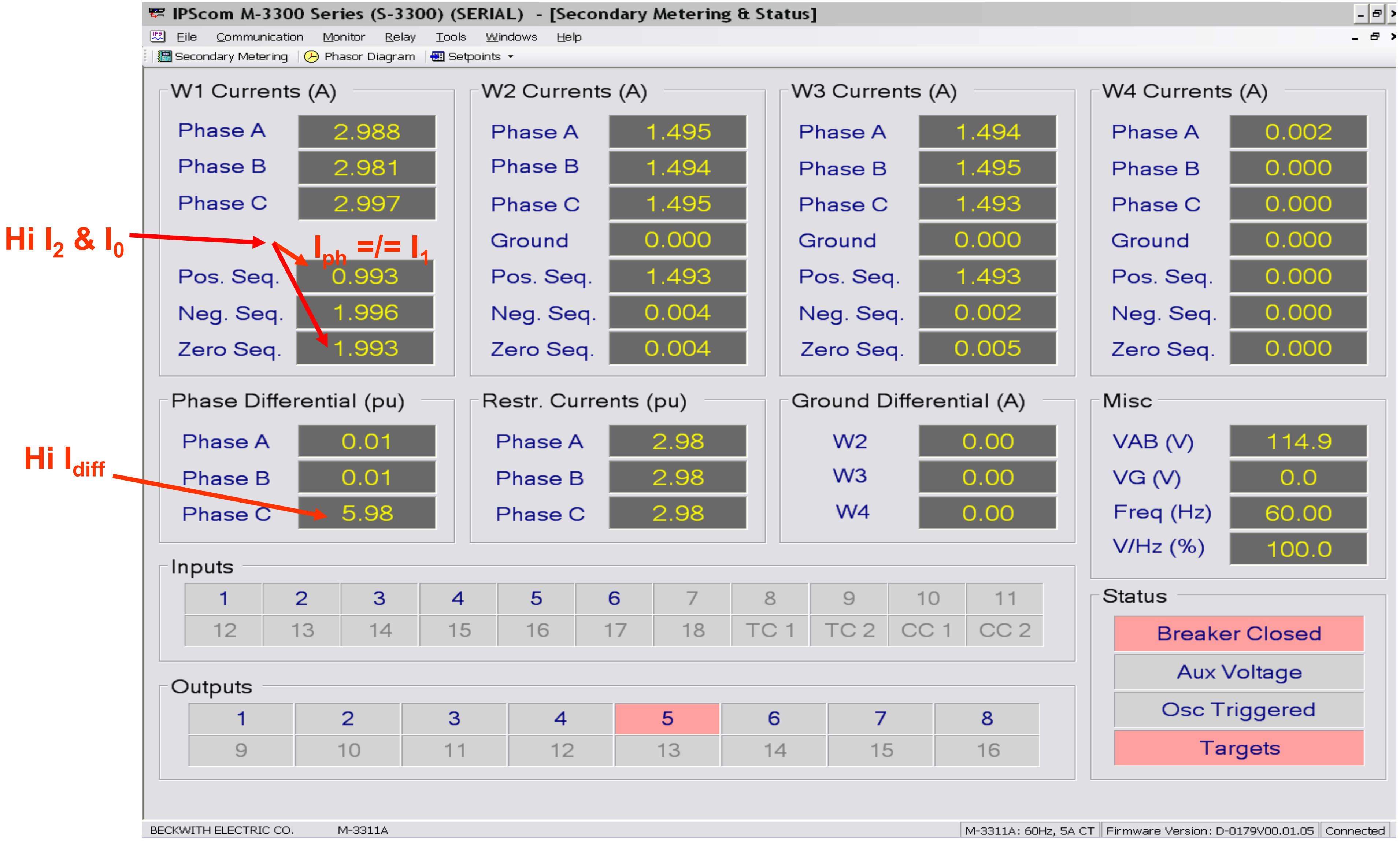


Δ:Y:Y, yyy, 1:1 Ratio, 1:1 CTs, W1, Roll ØC

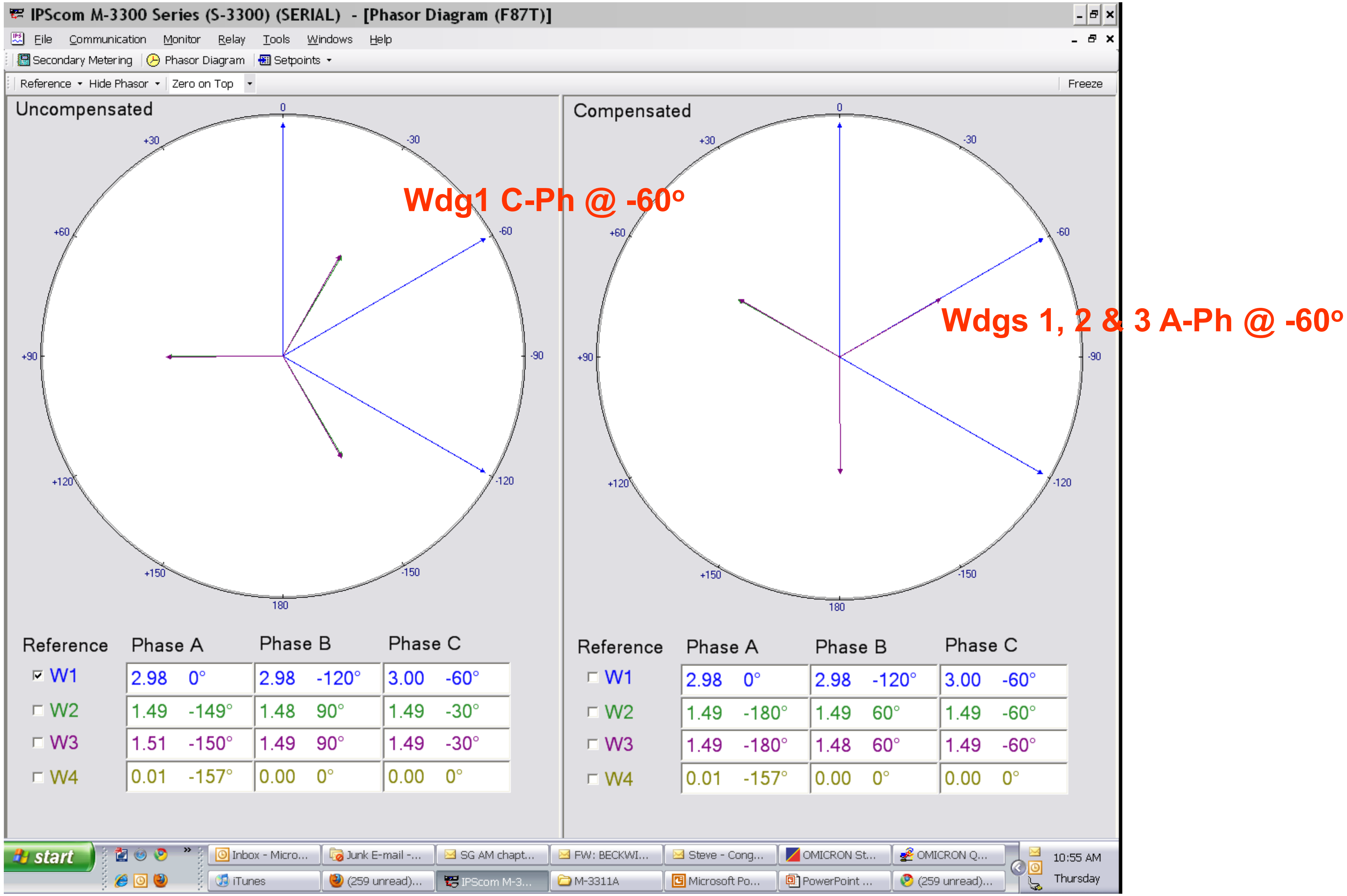
Three Line: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØC



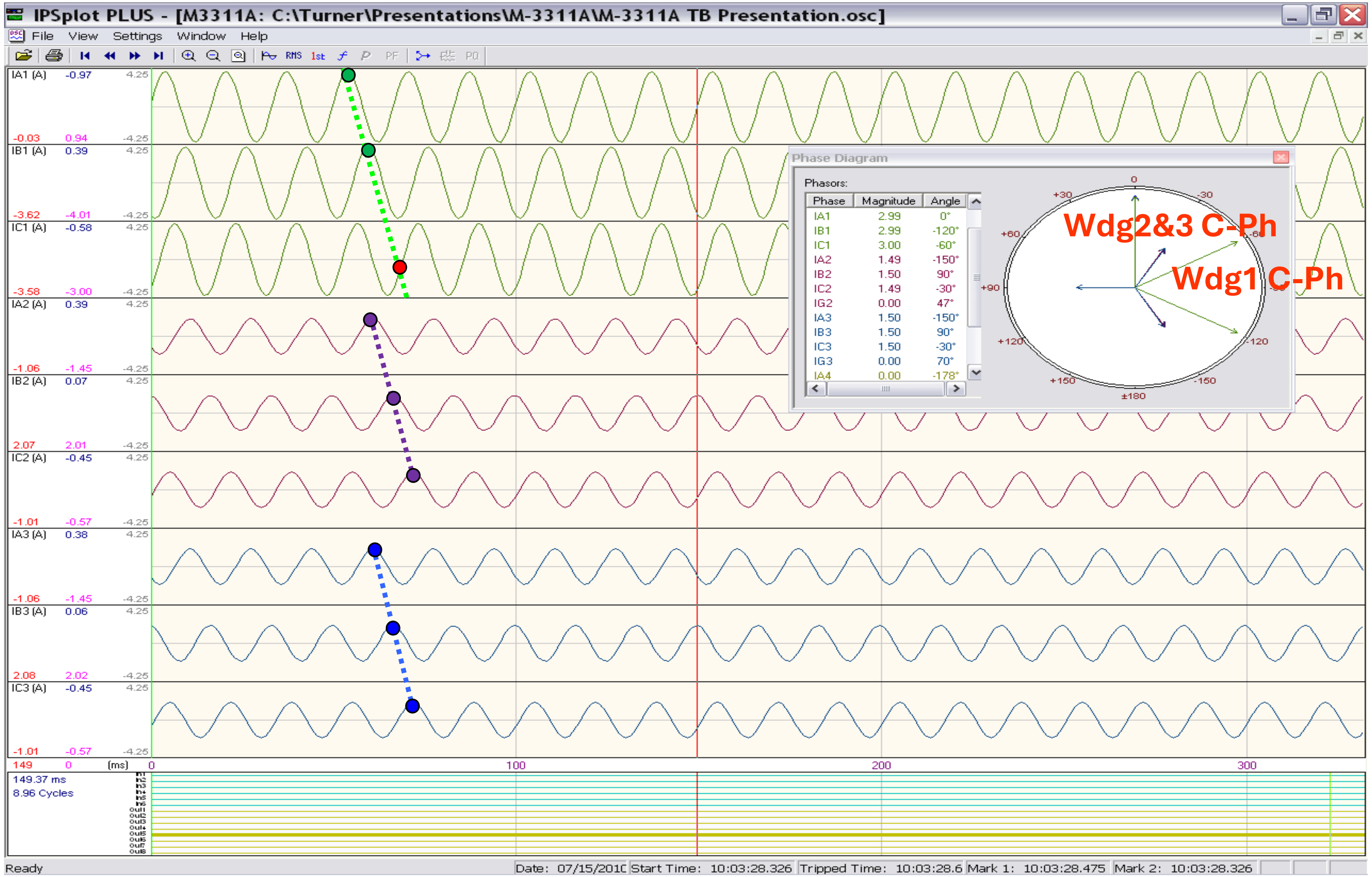
Advanced Metering: ∆:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØC



Vector Metering: ∆:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØC



Digital Oscillography: Δ:Y:Y, 1:1 Ratio, 1:1 CTs, W1, Roll ØC

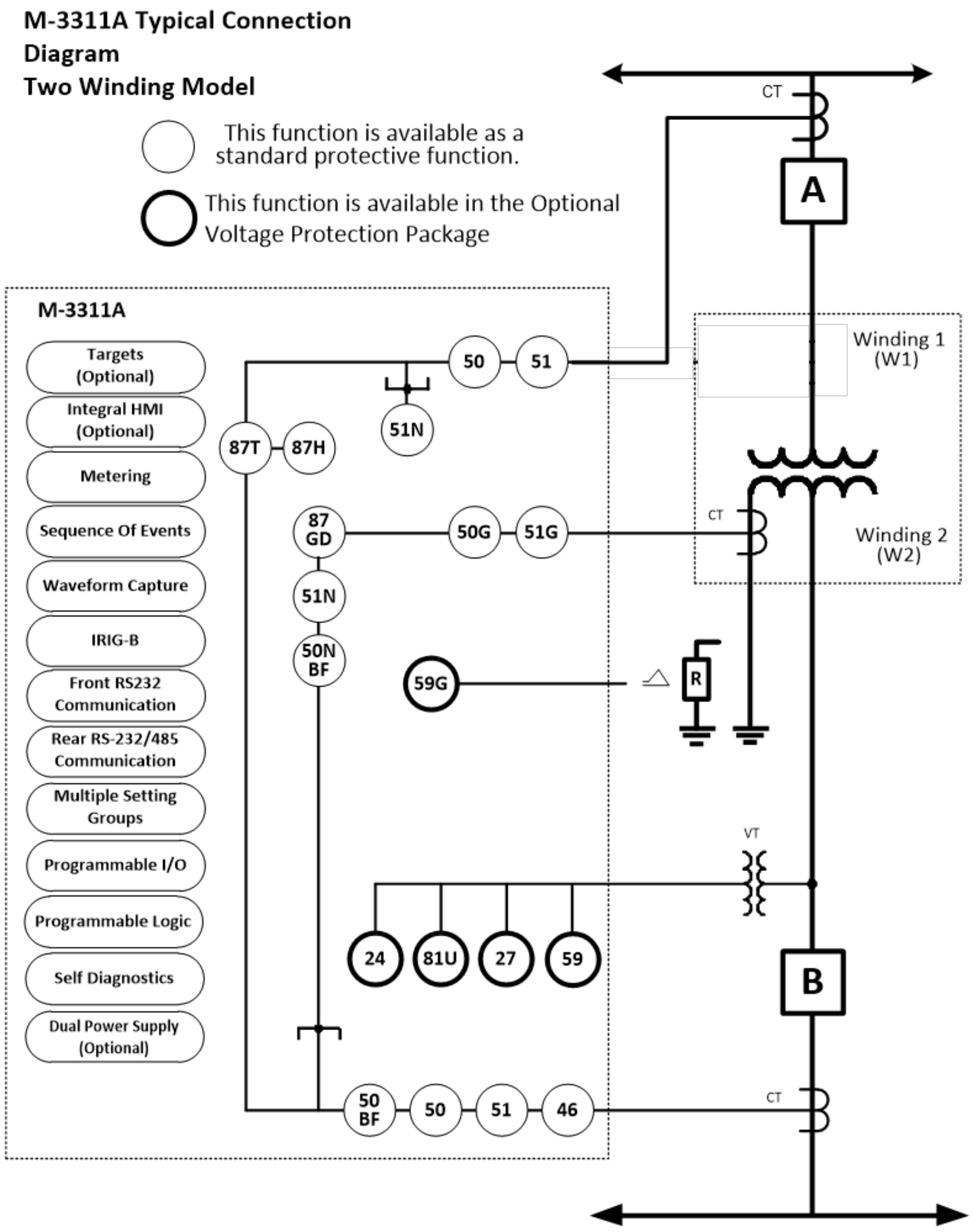


Analog Traces

Commissioning Tools Make Your Life Easier!

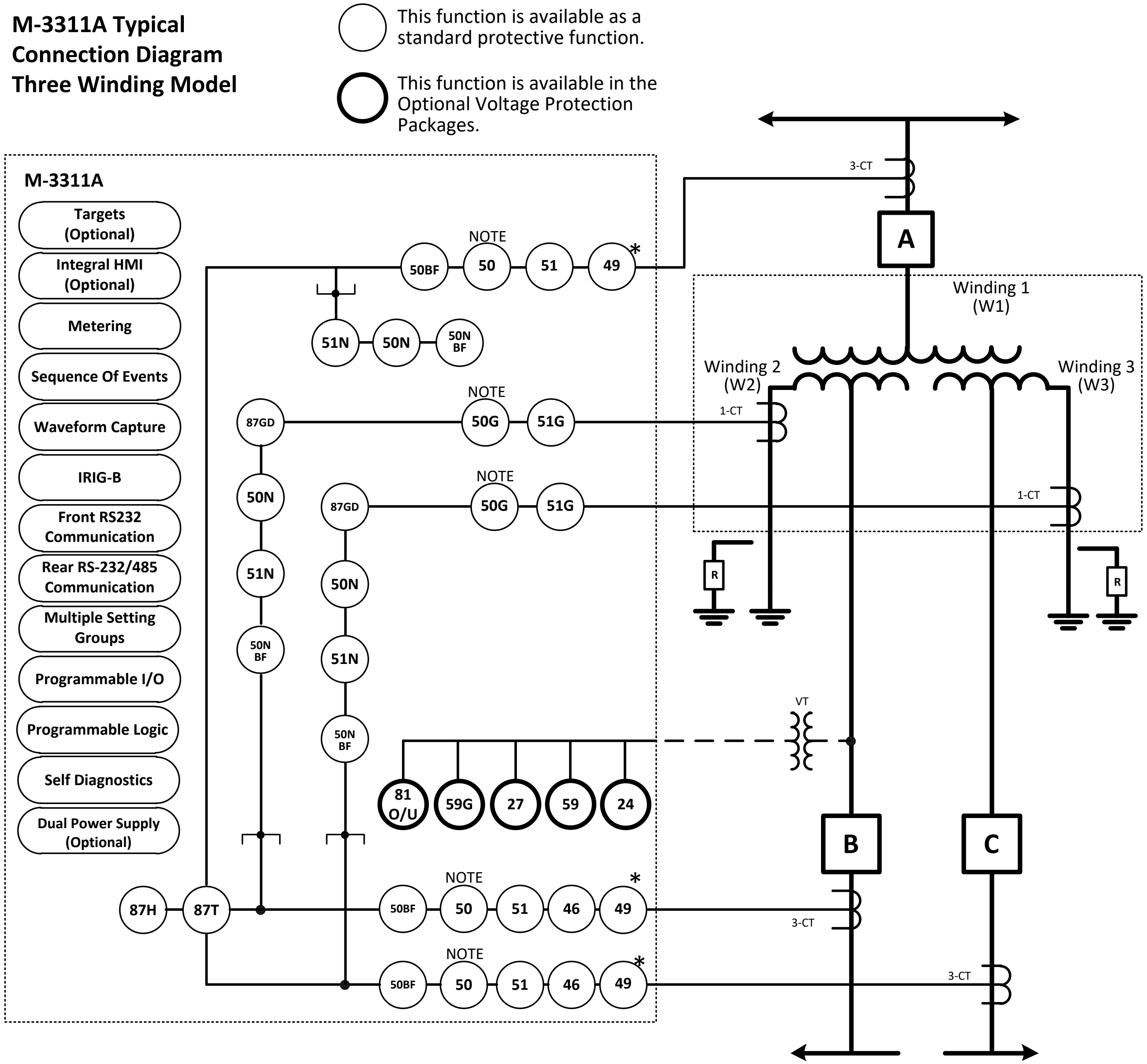
- Advanced Metering
  - Sequence components for all windings
    - Positive, negative and zero
- Restraint and differential currents
- Vector Metering
  - Uncompensated
    - Raw signal
  - Compensated
    - Post vector and ratio corrections
- Digital Oscillography
  - All winding currents

2 Winding

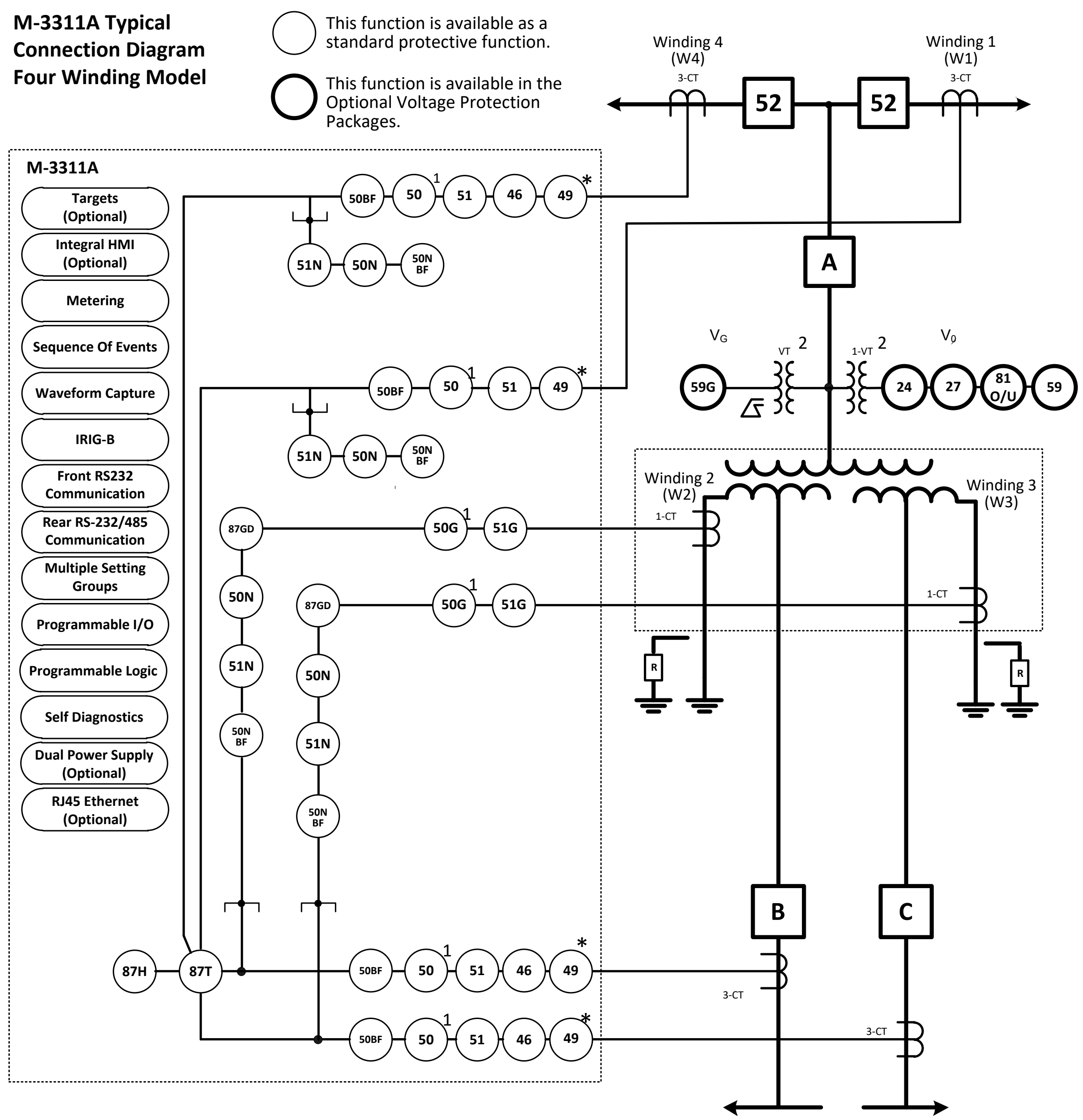


M-3311A Typical Connection Diagram
Two Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Package
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
50
51
51N
87T
87H
87 GD
50G
51G
51N
50N BF
59G
24
81U
27
59
50 BF
50
51
46
CT
A
Winding 1 (W1)
Winding 2 (W2)
CT
R
VT
B
CT

3 Winding

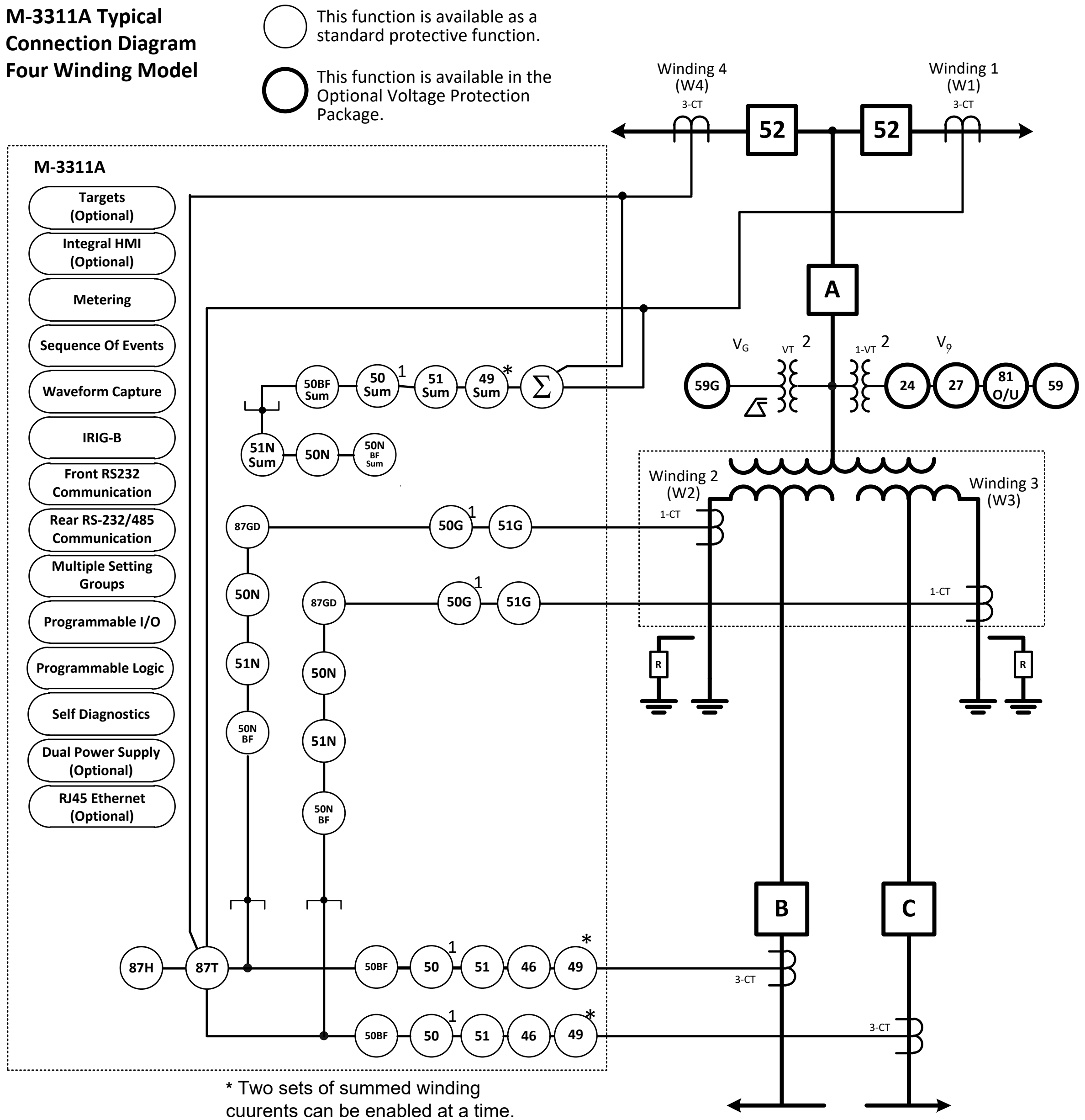

M-3311A Typical
Connection Diagram
Three Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Packages.
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
NOTE
50BF
50
51
49
*
51N
50N
50N BF
87GD
50G
51G
81 O/U
59G
27
59
24
87H
87T
46
3-CT
1-CT
VT
R
A
B
C
Winding 1 (W1)
Winding 2 (W2)
Winding 3 (W3)

4 Winding



M-3311A Typical Connection Diagram Four Winding Model
This function is available as a standard protective function.
This function is available in the Optional Voltage Protection Packages.
Winding 4 (W4)
Winding 1 (W1)
3-CT
52
52
A
B
C
M-3311A
Targets (Optional)
Integral HMI (Optional)
Metering
Sequence Of Events
Waveform Capture
IRIG-B
Front RS232 Communication
Rear RS-232/485 Communication
Multiple Setting Groups
Programmable I/O
Programmable Logic
Self Diagnostics
Dual Power Supply (Optional)
RJ45 Ethernet (Optional)
50BF
50
51
46
49
51N
50N
50N BF
87GD
50G
51G
87H
87T
59G
24
27
81 O/U
59
VT
1-VT
1-CT
Winding 2 (W2)
Winding 3 (W3)
R

4 Winding with Current Summing



* Two sets of summed winding cuurents can be enabled at a time.

Unique Features of Beckwith Transformer Protection Relays

- Voltage inputs with overexcitation protection
- Adaptive overexcitation restraint based on 5th harmonic
- Use of 2nd and 4th harmonic for inrush restraint
- Up to three ground directional differential elements
- Current summing for 51 and 87GD functions to be used with dual breaker configurations (ring bus, breaker-and-one half)
- Through-fault monitoring to schedule early maintenance and prevent transformer failures
- Graphical display of uncompensated and compensated phasors for each winding to help with test and commissioning
- Easy to access metering screens for test and commissioning
- User friendly setting of transformer/CT connection configurations

References

- IEEE Guide for Transformer Protection, ANSI/IEEE C37.91-2008.
- IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems, IEEE Std. 142-1991.
- Protective Relaying: Principles and Applications, 3rd Ed.; Lew Blackburn and Thomas Domin, CRC Press 2007; ISBN# 978-1-57444-716-3
- Protective Relaying for Power Generation Systems; Donald Reimert, CRC Press 2006; ISBN#0-8247-0700-1.
- Industrial Power Distribution; Dr. Ralph E. Fehr III, Wiley – IEEE Press 2016; ISBN# 978-1-119-06334-6
- Optimizing Transformer Protection, Wayne Hartmann, presented at the Doble Conference 2016

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