Event Analysis of 4.16 kV Generato Differential Misoperation

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Agenda

- Introduction
- History of Percentage Differential
- Enhancements to Percentage Differential
- Harmonic Restraint (Blocking) of Percentage Differential
- Securing Percentage Differential using Directionality Check and CT Saturation Detection
- Settings of Percentage Differential
- Analysis of 4.16 kV Generator Differential Incorrect Operation
- Conclusion

Introduction

- Generator Protection Original fuses, later Overcurrent
  - Not very selective; Current/Time used for Coordination – Internal Faults NOT Instantaneous
- Generator Protection Evolved, Schemes can include: (C37.102)

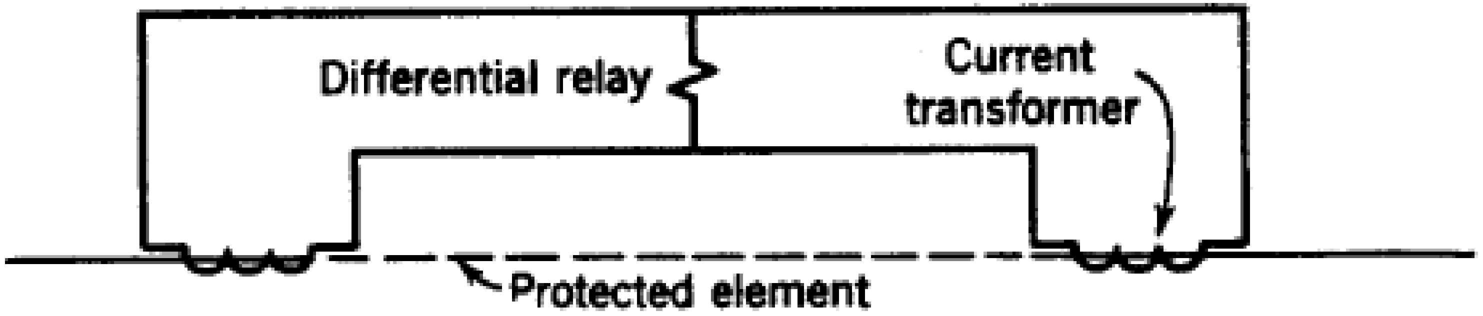
1. Distance (21) (Backup)
2. Volts-per-Hertz (24)
3. Undervoltage (27)
4. Third harmonic undervoltage (27TH)
5. Inadvertent energization (50/27)
6. Reverse power (32)
7. Loss-of-field (40)
8. Stator unbalanced current (46)
9. Stator thermal (49)
10. Breaker failure (50BF)
11. Timed and instantaneous phase overcurrent (50/51)
12. Timed and instantaneous ground overcurrent (50G/51G)
13. Percentage differential (87)
14. Time-overcurrent, detection of turn-to-turn faults (51)
15. Voltage controlled or restrained time-overcurrent (51V) (Backup)
16. Exciter or DC generator relay (53)
17. Overvoltage protection (59)
18. Zero-sequence overvoltage for detection of ground faults in ungrounded generators (59BN)

Introduction (2)

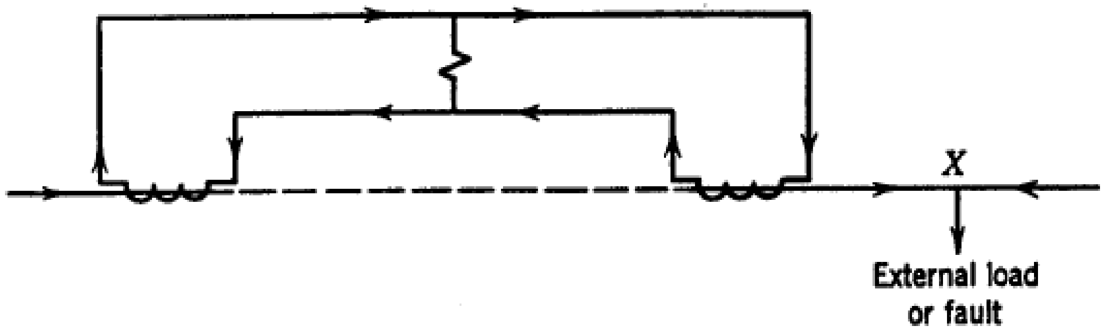
19. Zero-sequence overvoltage for detection of stator turn-to-turn fault protection (59N)
20. Third harmonic instantaneous overvoltage (59TH)
21. Third harmonic instantaneous voltage differential (59THD)
22. Voltage balance or loss of potential (60)
23. Breaker failure timer (62B) or (50BF)
24. Fault pressure for transformer (63)
25. Rotor ground fault voltage (64F)
26. 100% stator ground fault with sub-harmonic injection (64S)
27. Directional ground overcurrent (67N)
28. Transformer oil/gas level (71)
29. Loss of synchronism (78)
30. Frequency, both under and over (81)
31. Hand-reset lockout (86)
32. Differential for bus (87B)
33. Differential for generator stator (87G)
34. Sensitive differential for generator stator (87GN)
35. Differential for generator step-up and/or unit transformers (87T)
36. Differential for overall generator and transformer (87O)
37. Self-reset auxiliary relay (94)

History of Percentage Differential

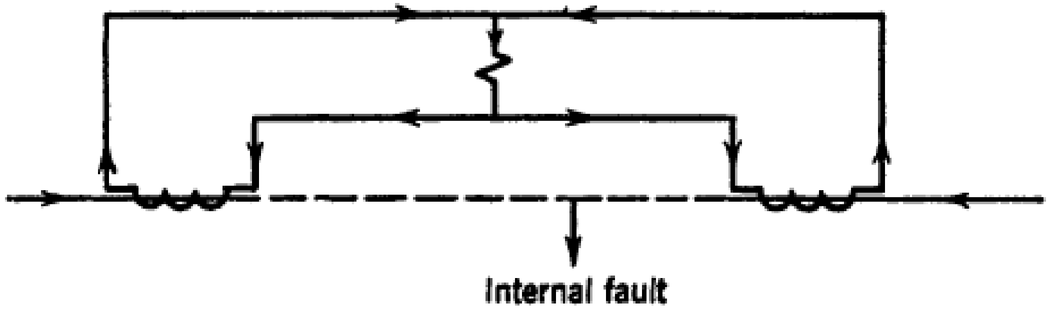
- First Transformer Differential was Overcurrent only



- External Faults

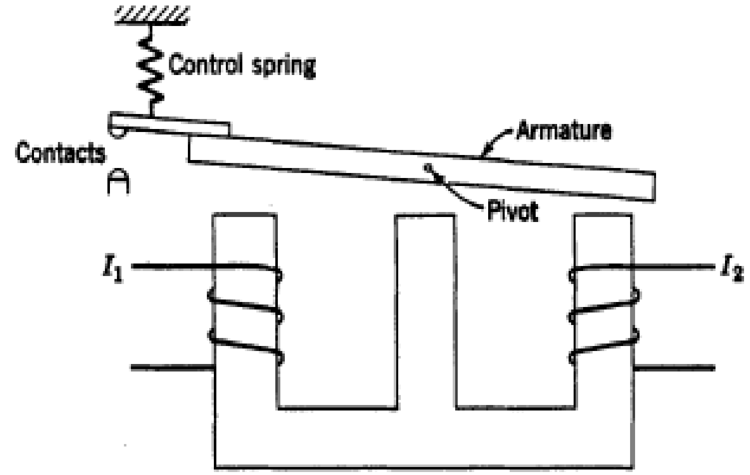


- Internal Faults

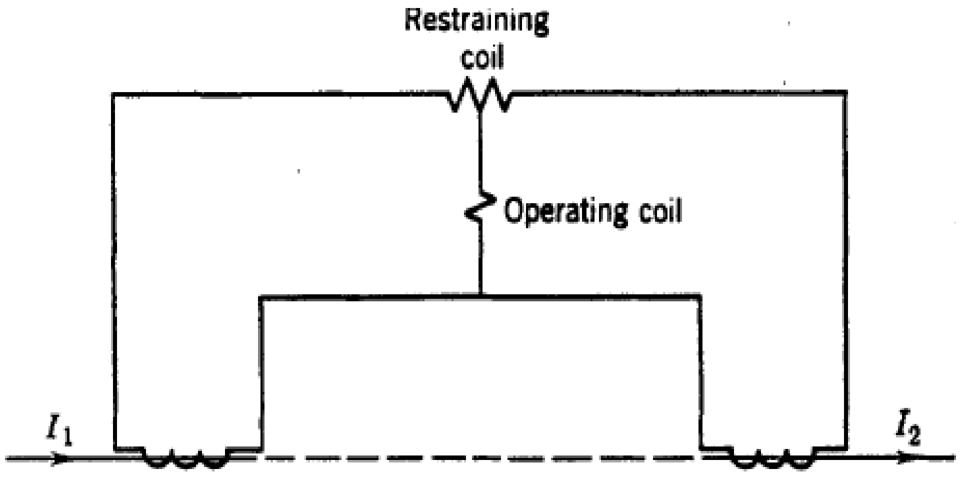


History of Percentage Differential (2)

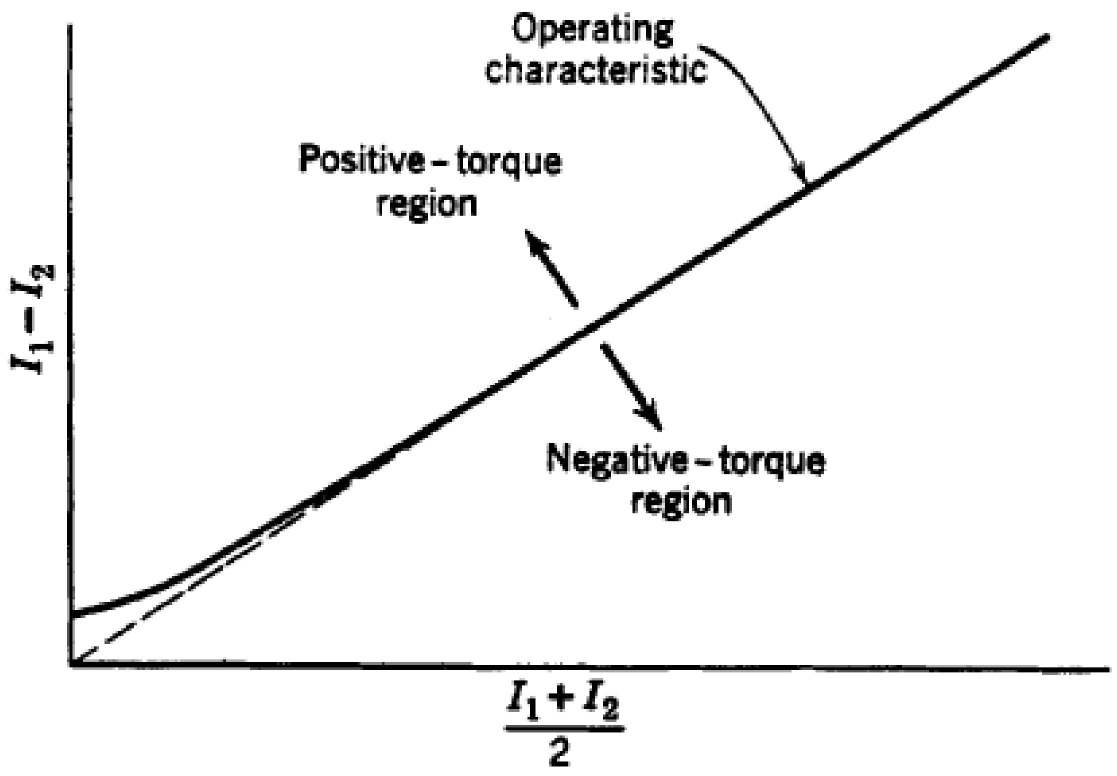
- First Transformer Differential with Restraint:



- Coils Connected

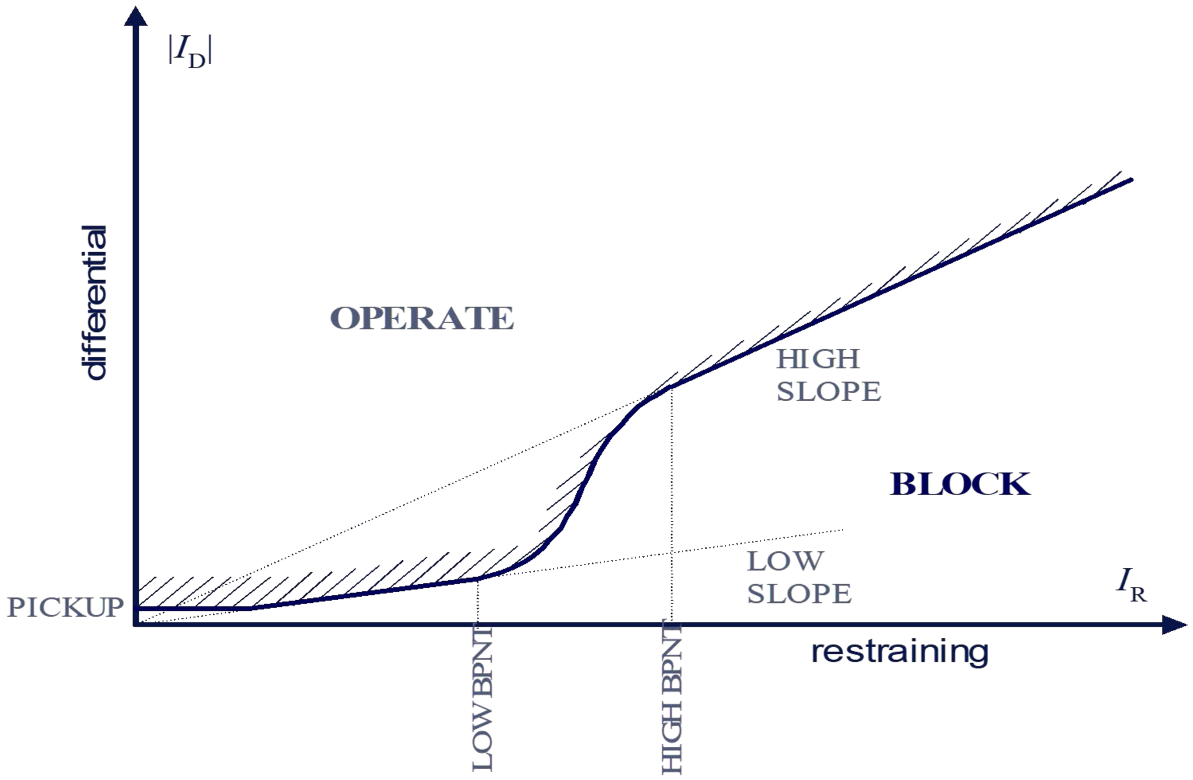


- Operating Characteristic

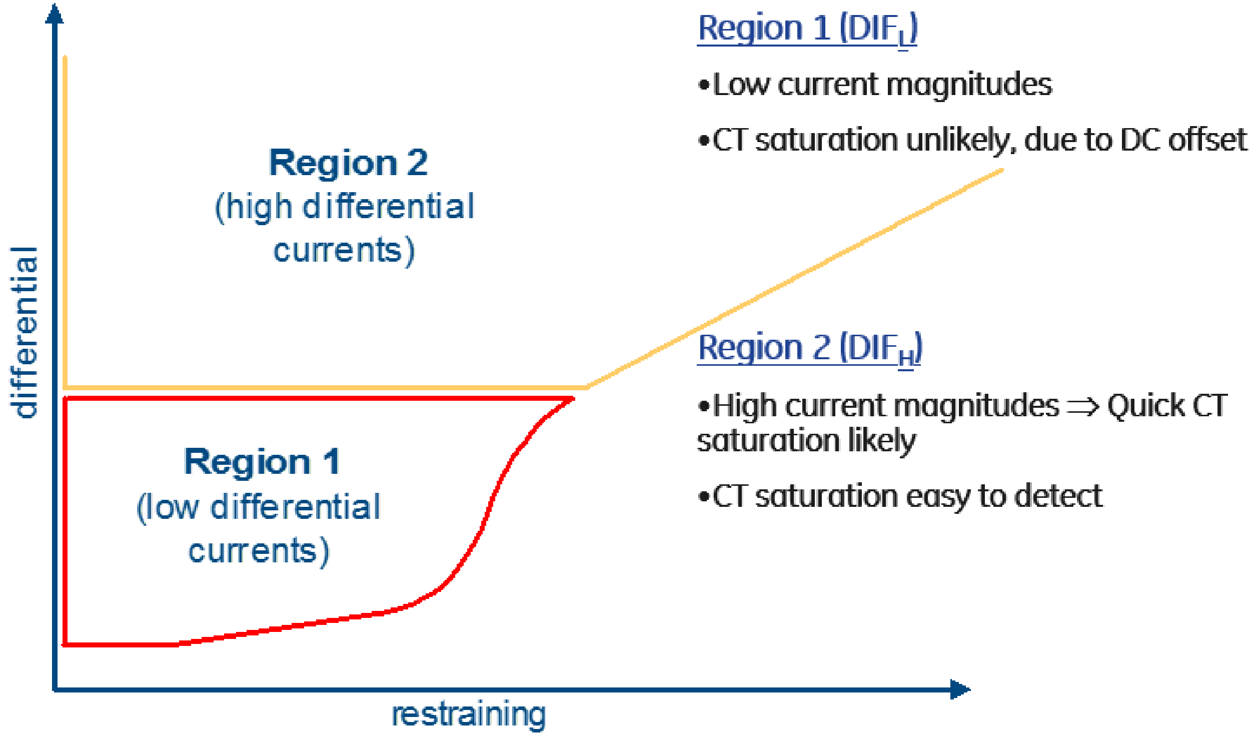


Enhancements to Percentage Differential

- Percentage Differential Enhanced in IEDs for added Sensitivity:



- Two Regions of Percentage Differential

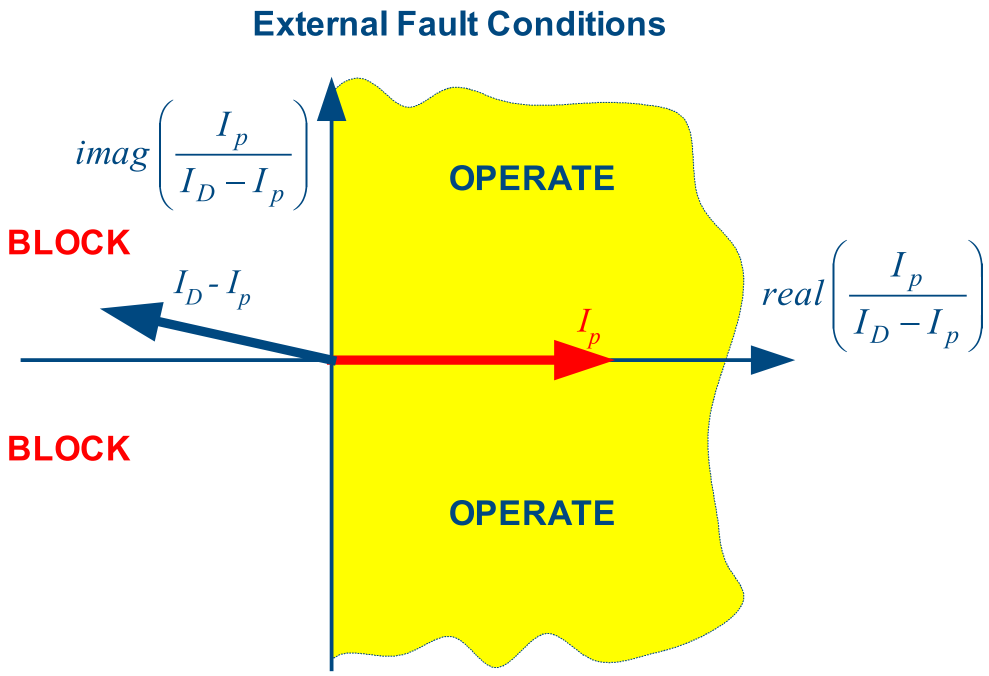


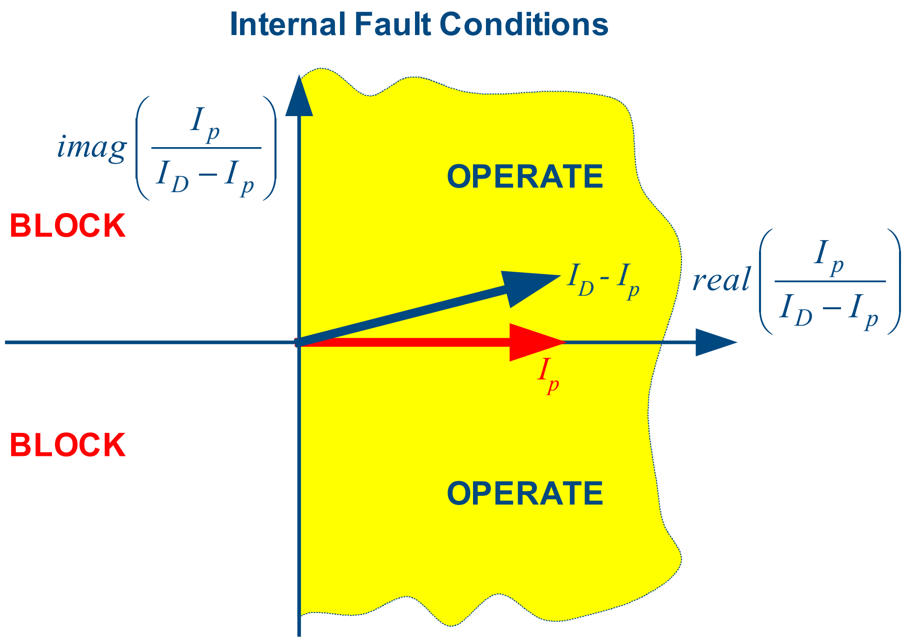
Harmonic Restraint of Percentage Differential

- Percentage Differential still challenged during Transformer Energization
- Multiple event types can cause Inrush/Harmonics:
  1. External Fault
  2. Voltage Recover after Ext Fault
  3. Fault Change eg. PG to PPG
  4. Out-of-phase Gen Synch
  5. CT Saturation during Inrush
  6. Inrush during Fault Removal
  7. Sympathetic Inrush
- Electromechanicals & early IEDs used fixed 20% of 2nd/fundamental magnitude to restrain (block) percentage differential
- Modern Transformers much lower 2nd harmonics (7-10%) – due to improvements
- Improvements to Harmonic Restraint:
  1. Adjustable levels of 2nd Harm
  2. Account for 2nd Harm Phase Angle
  3. 1-of-3, 2-of-3, 3-of-3 Inhibit
  4. 5th Harm Restraint added

Securing Percentage Differential With Dir Chec

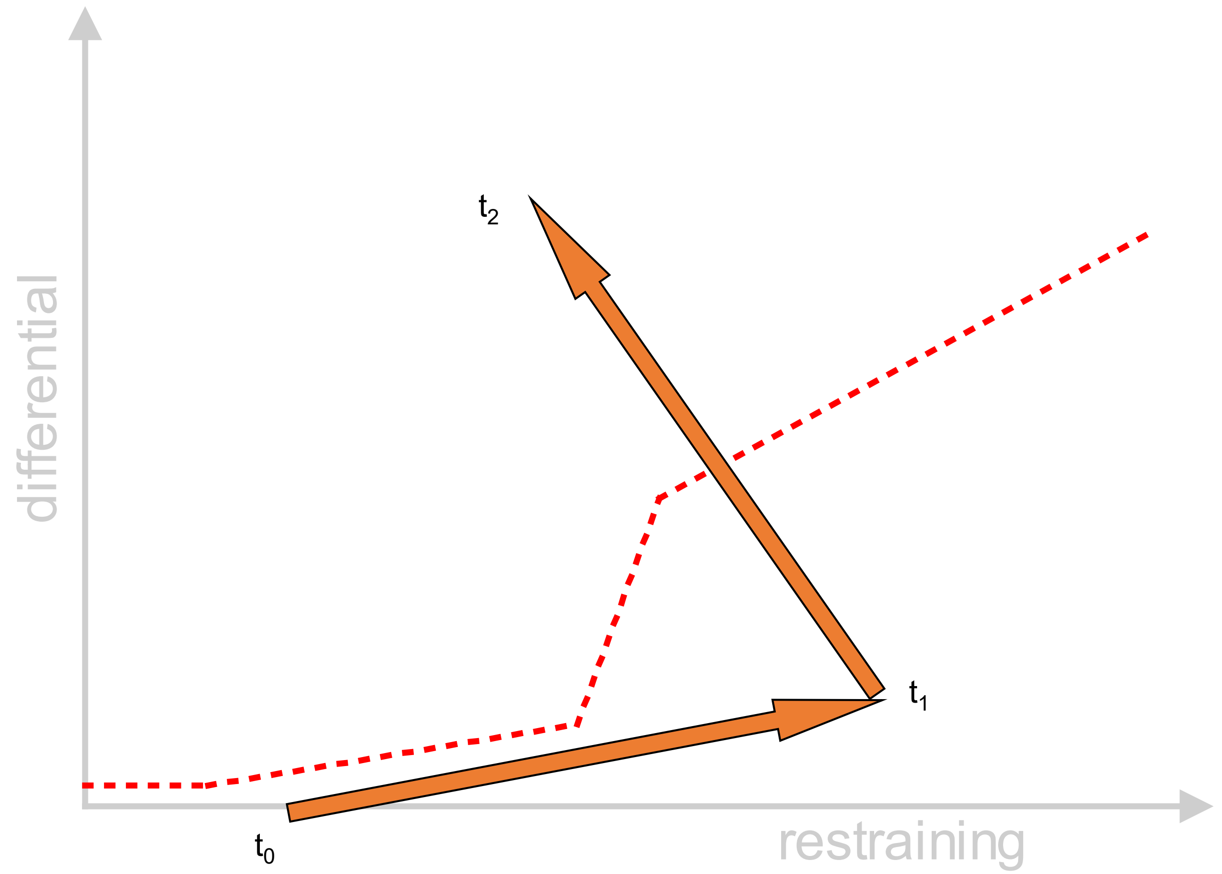
- Directionality Check of Current Phase Angles: (No Voltages Used)





Securing Percentage Differential With CT Satur

- CTs provide typically 2-4 ms unsaturated current
- Fault starts at t_0, CT starts to saturate at t_1, fully saturated at t_2



Settings of Percentage Differential

- Electromechanical relays needed secondary currents to be same phase and magnitude, hence Wye-winding CTs connected in Delta and Aux CTs needed
- All CTs on IEDs Wye-connected; magnitude and phase angle compensated numerically
- Compensated currents calculated based on Magnitude and Phase, eg. for 30deg lag:

$\Phi_{comp}[w]$	Grounding[w] = "Not within zone"	Grounding[w] = "Within zone"
30° lag	$I_A^P[w] = \frac{1}{\sqrt{3}} I_A[w] - \frac{1}{\sqrt{3}} I_C[w]$ $I_B^P[w] = \frac{1}{\sqrt{3}} I_B[w] - \frac{1}{\sqrt{3}} I_A[w]$ $I_C^P[w] = \frac{1}{\sqrt{3}} I_C[w] - \frac{1}{\sqrt{3}} I_B[w]$	$I_A^P[w] = \frac{1}{\sqrt{3}} I_A[w] - \frac{1}{\sqrt{3}} I_C[w]$ $I_B^P[w] = \frac{1}{\sqrt{3}} I_B[w] - \frac{1}{\sqrt{3}} I_A[w]$ $I_C^P[w] = \frac{1}{\sqrt{3}} I_C[w] - \frac{1}{\sqrt{3}} I_B[w]$

- Differential current calculated as: $I_d = \overrightarrow{I_{1(comp)}} + \overrightarrow{I_{2(comp)}}$
- Restraint can be: Sum of, scaled sum of, geometrical average, maximum of
- Most commonly used: "Max Of"

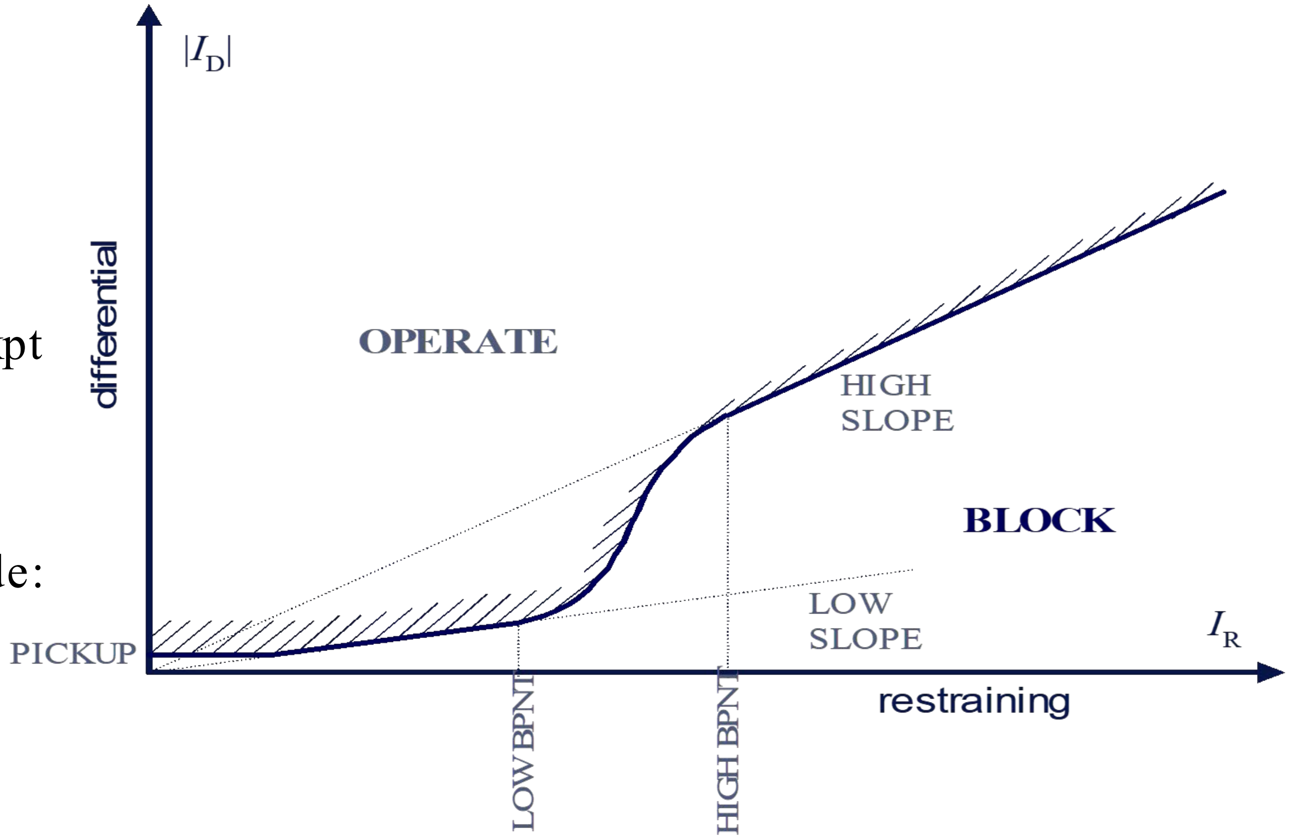
Settings of Percentage Differential (2)

- The Following Setting must be calculated:

- Minimum Pickup
  1. Defines Minimum Differential Pickup at 0 Restraint
  2. Compensates for CT Errors at low currents
  3. Must be above leakage current not zoned

- Low Slope
  1. Defines Percent Bias for Restraint A0 to Low Breakpt
  2. Determines Sensitivity at Low-current Int Faults
  3. Must be above CT errors in Linear Operating Mode
  4. Include errors due to Tap Changers
  5. Based on CT performance in Linear Operating mode:

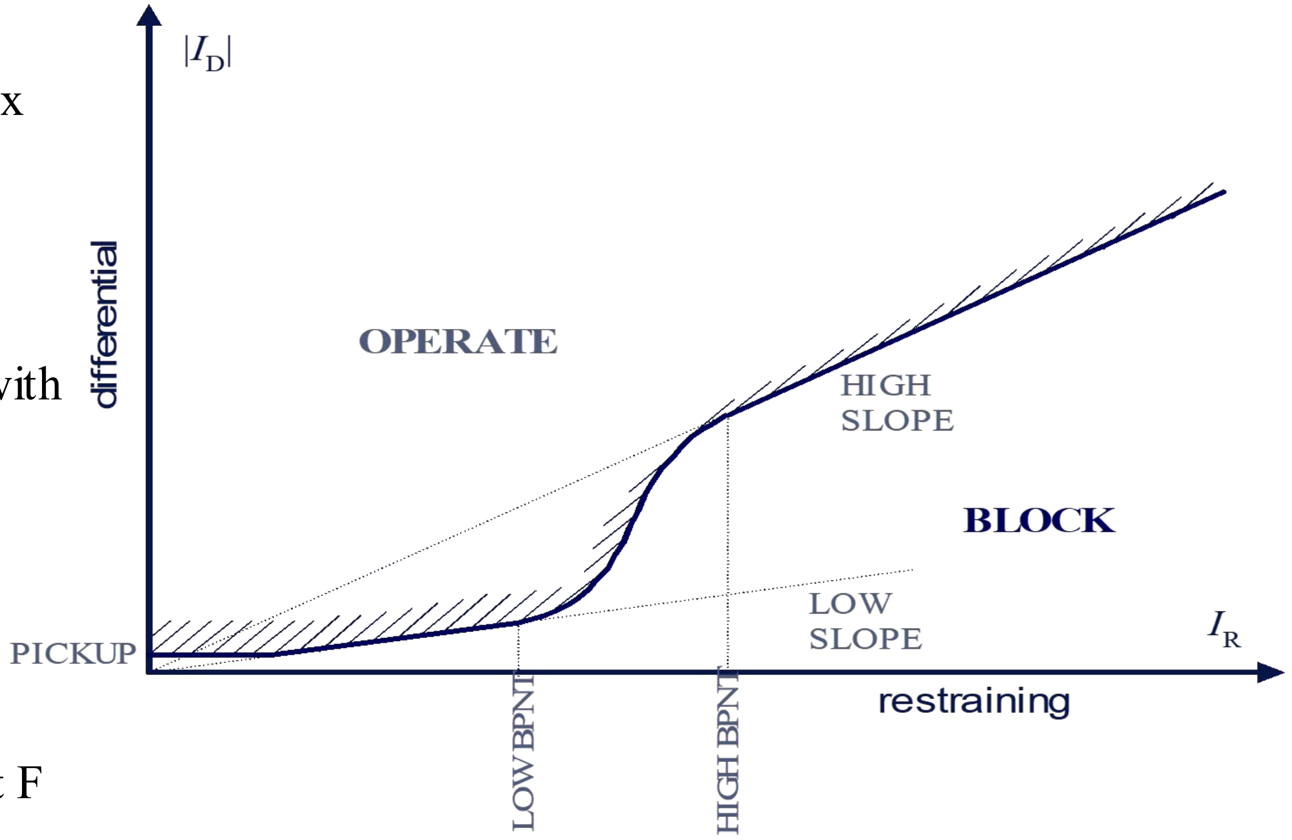
$$\text{Slope} = \frac{\Delta I_d}{\Delta I_r} \times 100\% \text{ (in pu)}$$



- Maximum Differential Current can be calculated based on CT Performance using IEEE PSRC CT Saturation Calculator

Settings of Percentage Differential (3)

- Low Breakpoint
  1. Defines Upper Limit of Diff/Restraint of Low Slope
  2. Must be above Max Load and all CTs still Linear (including Remanence Flux)
  3. CTs Must be Linear with up to 80% Remanence Flux up to Low Breakpoint
- High Breakpoint
  1. Defines Min Limit of Diff/Restraint of High Slope
  2. Must be Minimum A where weakest CT Saturates with no Remanence Flux
- High Slope
  1. Defines Percent Bias for Restraint A above High Breakpoint
  2. Determines Stability of Diff at High External Faults
  3. Must be high to tolerate Spurious Diff CT Sat on Ext F
  4. Can be relaxed if Dir Check and CT Sat Detect used



- Maximum Differential Current can be calculated based on CT Performance using IEEE PSRC CT Saturation Calculator

Settings of Percentage Differential (4)

- CT Saturation Calculator

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Sheet 2: INSTRUCTIONS
Sheet 4: BACKGROUND

CT Saturation Calculator

Excel Spread Sheet
See IEEE publication C37.110: "IEEE Guide for the Application of CurrentTransformers Used for Protective Relaying Purposes"

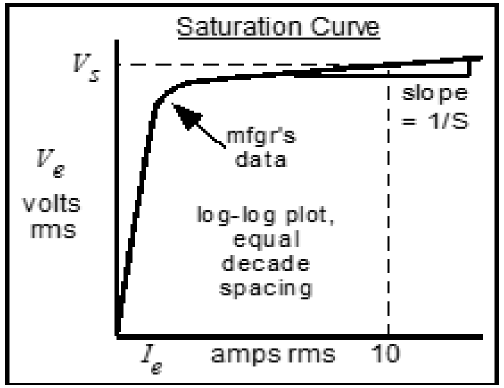
A document of the
IEEE Power Systems Relaying Committee
Contact: gswift@nxtphase.com
Refer also to "CT SAT Theory (PSRC)".

VERSION:
30 Dec 2002

ASSUMPTIONS: CT core losses and sec'y reactance zero (thru-hole primary). Frequency: 60 Hz
CT primary current is zero for t<0. CT is 5 amp nominal. Time step = 1/12,000 second.

INPUT PARAMETERS:

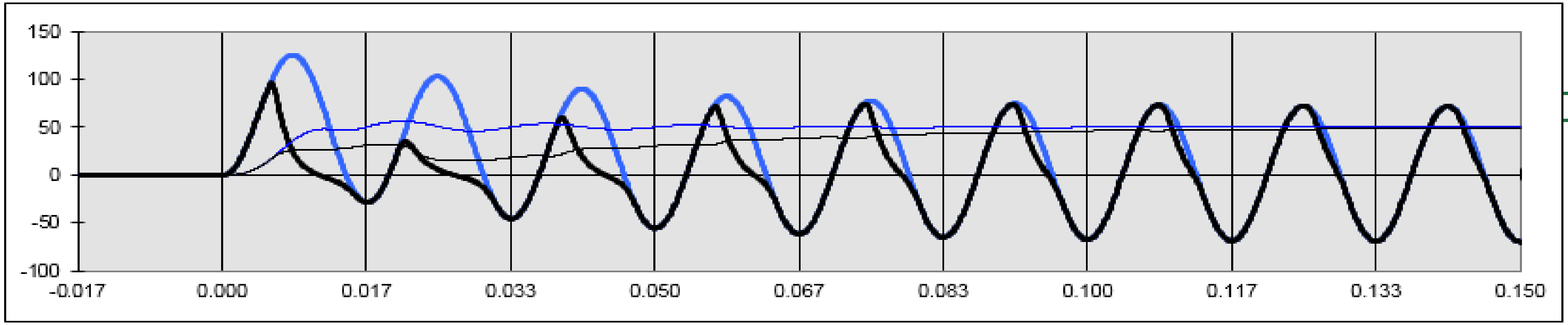
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	240	---
Winding resistance =	Rw =	0.000	ohms
Burden resistance =	Rb =	4.000	ohms
Burden reactance =	Xb =	2.000	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	1.00	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.00	---
Symmetrical primary fault current =	Ip =	12,000	amps rms



CALCULATED:

Rt =	Total burden resistance = Rw + Rb =	4.000	ohms
pf =	Total burden power factor =	0.894	---
Zb =	Total burden impedance =	4.472	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 =	0.00531	henries

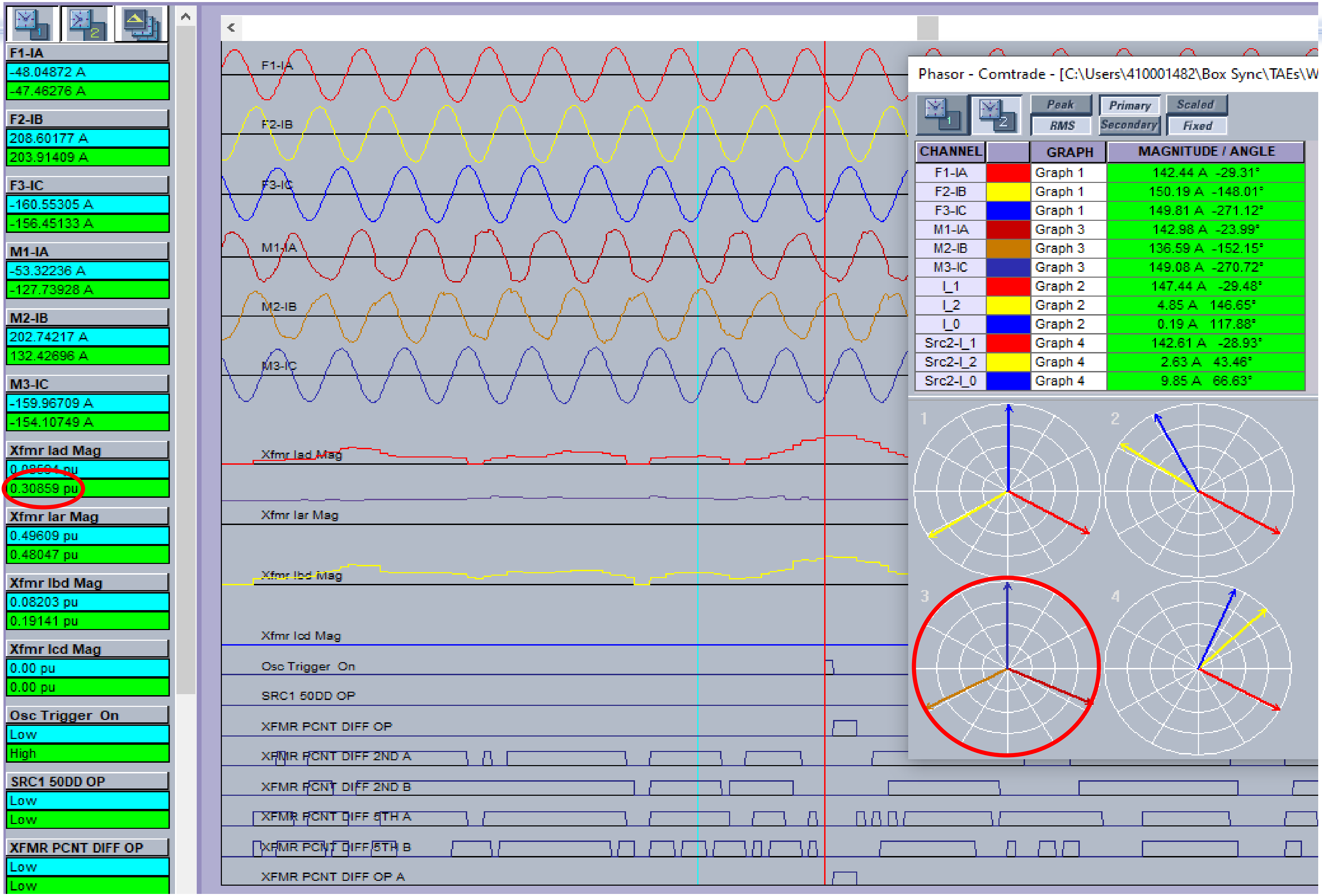
Thick lines: **Ideal (blue)** and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: **Ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



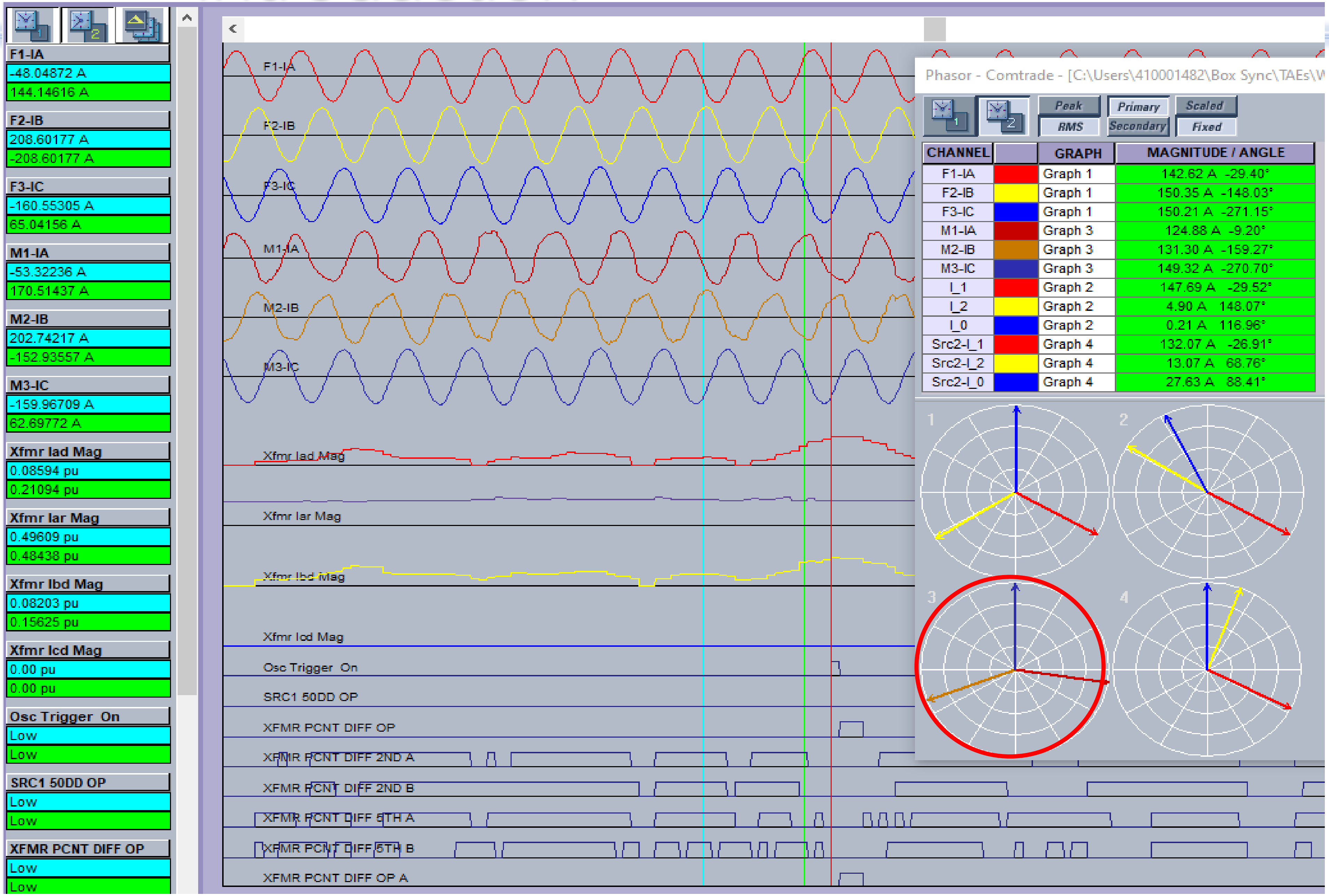
Analysis of 4.16kV Generator Diff Incorrect Ope

- Percentage differential operated incorrectly after the generator was synchronized and loaded to 1.1 MW with no faults on the system.
- This occurred during two incidents
- During both incidents differential currents were observed in both A and B-phases (nothing in C-phase). Diff currents fluctuated until threshold of 0.3p.u. reached.
- Other generator protection relay functions did not pick up or operate.
- Currents well in load region; no CT saturation observed
- Very little negative and zero sequence currents are observed
- Directional Check and CT Saturation Detection NOT used
- Why did it happened and what may be wrong?

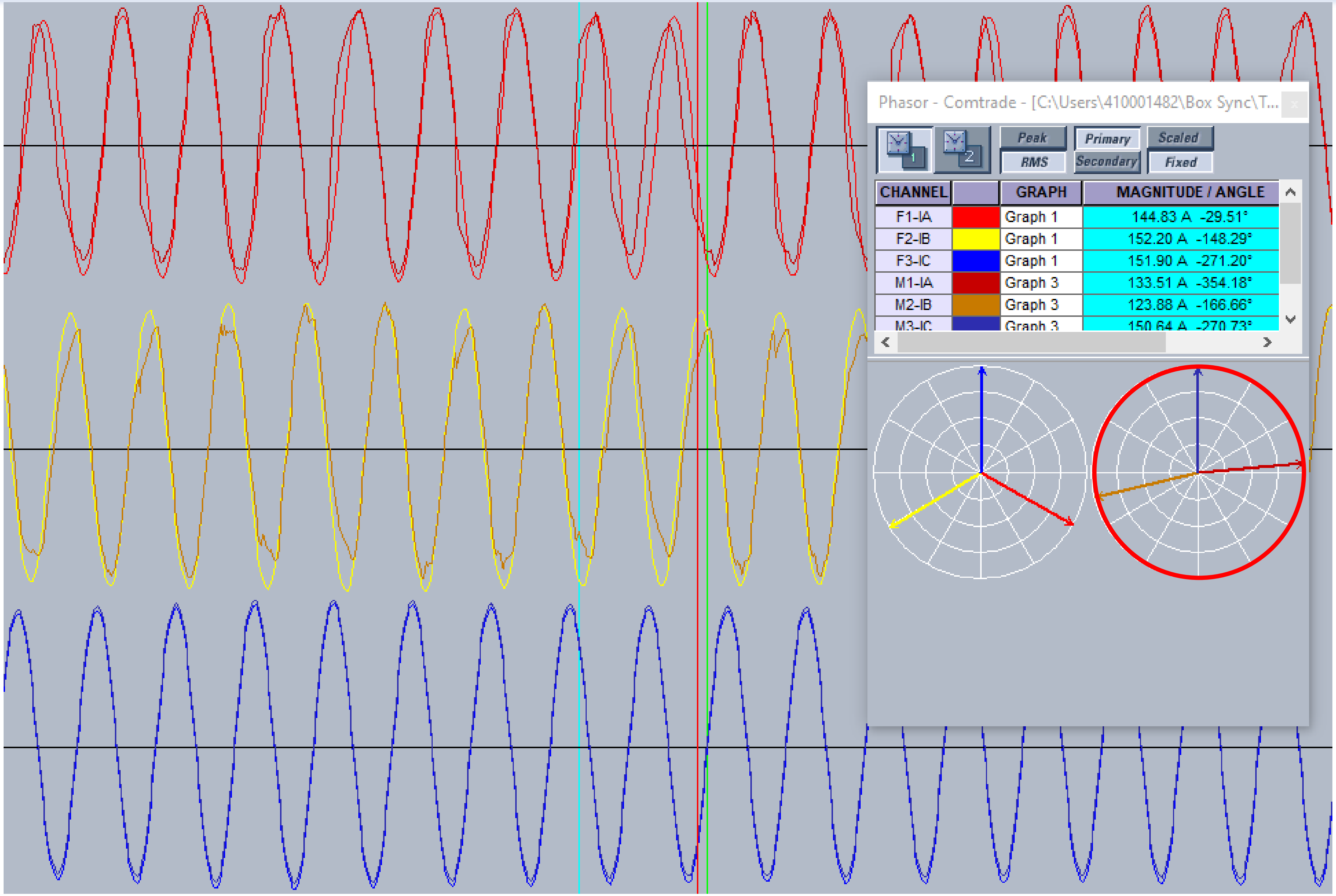
Introduction



Introduction



Introduction



- Why A and B differences?
- Same CT ratios and type
- Neutral A and B currents little distorted with harmonics

Investigation

- Possible internal fault in generator windings?

•In order to rule out internal generator stator winding faults, several electrical tests were done:

i. Insulation Resistance IR, and Polarization Index PI of each stator phase winding and associated medium voltage cabling (PI values were average of 9)

ii. DC winding resistance of each phase winding (average of 84.8mΩ @ 20°C)

- Since generator tested healthy, NTPC decided to increase the differential pickup from 0.2pu to 0.3pu before returning generator online.

•This resulted in the same outcome; unit would trip around 1MW. It was observed that differential current would increase as the load on the unit increases. Around 1MW was when the differential pickpup and trip occurred.

Investigation

- Possible settings error?

Windings // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Users\4100...

Save | Restore | Default | Reset | VIEW ALL mode

PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	2.339 MVA	2.340 MVA
Nominal Phs-phs Voltage	4.160 kV	4.160 kV
Connection	Wye	Wye
Grounding	Not within zone	Not within zone
Angle Wrt Winding 1	0.0 deg	-180.0 deg

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | System Setup: Transformer

Current // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Users\410001...

Save | Restore | Default | Reset | VIEW ALL mode

PARAMETER	CT F1	CT M1
Phase CT Primary	300 A	300 A
Phase CT Secondary	5 A	5 A
Ground CT Primary	1 A	50 A
Ground CT Secondary	1 A	5 A

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | System Setup: AC Inputs

Percent Differential // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Us...

Save | Restore | Default | Reset | VIEW ALL mode

SETTING	PARAMETER
Operating Characteristc Graph	View
Function	Enabled
Pickup	0.300 pu
Slope 1	25 %
Break 1	2.000 pu
Break 2	8.000 pu
Slope 2	90 %
Inrush Inhibit Function	Adapt. 2nd
Inrush Inhibit Mode	Per phase
Inrush Inhibit Level	20.0 % fo
Overexcitation Inhibit Function	5th
Overexcitation Inhibit Level	10.0 % fo
Block	Virt Op 6 On (VO6)
Target	Latched
Events	Enabled

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | Grouped Elements: Group 1: Transfo

Doesn't look like…

Investigation

- Relay algorithm error?

The phasors observed by the relay were as below:

Phase	Trip Point	
	Line Currents	Neutral Currents
A	143.85A∠-29.48°	124.63A∠-348.94°
B	150.94A∠-148.21°	124.33A∠-168.54°
C	150.84A∠-271.08°	149.60A∠-270.61°

Since the CT ratios are the same and no transformer, the magnitude and phase compensation factors = 1.

$$I_d = m_1 \cdot \begin{bmatrix} IA_{1c} \\ IB_{1c} \\ IC_{1c} \end{bmatrix} + m_2 \cdot \begin{bmatrix} IA_{2c} \\ IB_{2c} \\ IC_{2c} \end{bmatrix}$$

Since the A-phase differential current was significantly higher than B-phase, we can calculate:

differential current from above phasors:

$$Id = 94.74A \ or \ 0.31pu$$

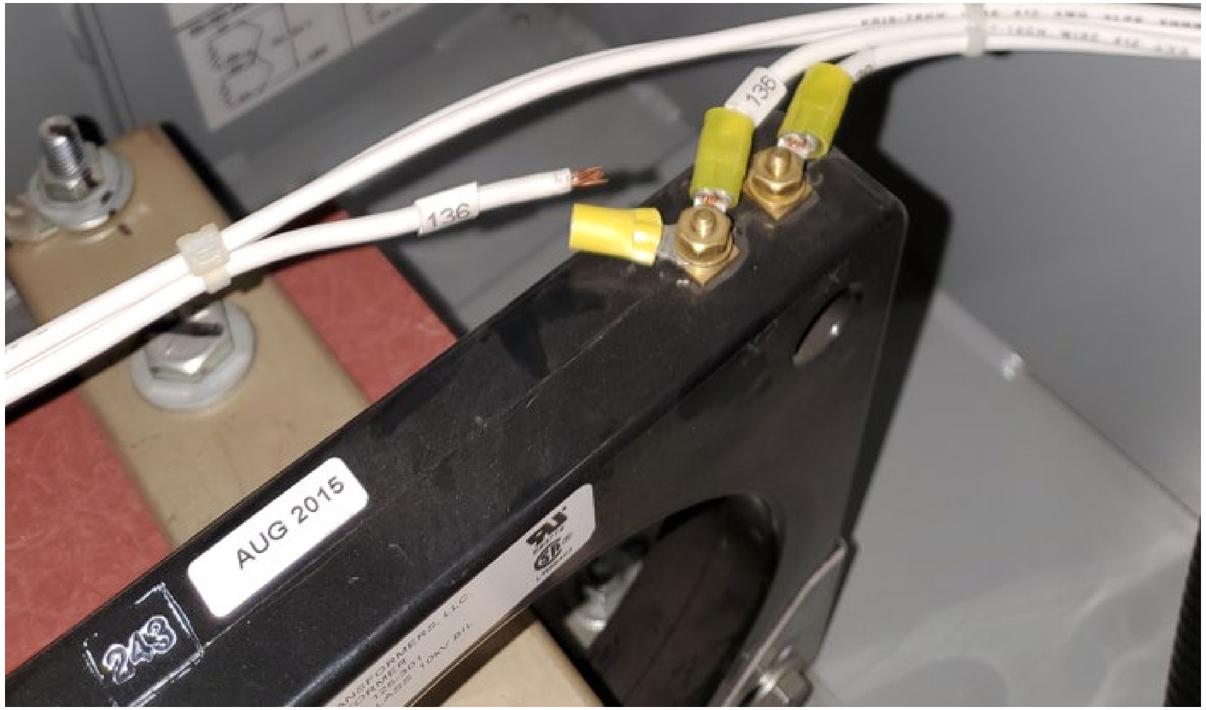
Investigation

- Time out! Time to think where we are…

- Settings seems correct
- Waveforms of A and B-phase line side currents are somewhat distorted without signs of saturation (No CT saturation)
- Differential current relay calculated from waveforms and settings seems correct as well.
- What is abnormal, the A and B-phase differential are higher than expected; C-phase differential currents were very close to 0.
- Possibly a CT or wiring issue, or relay hardware failure?

Investigation

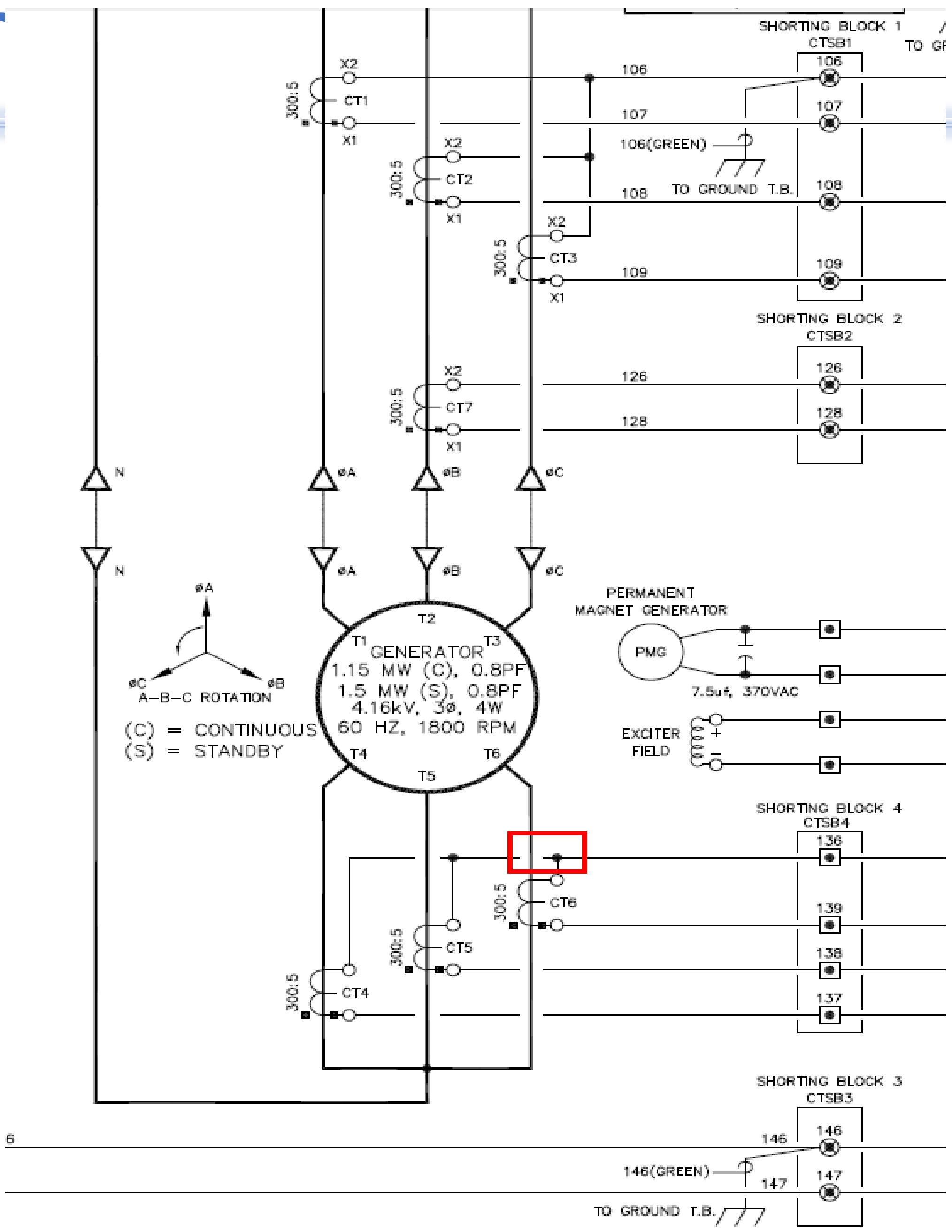
- CT and wiring checks:
  - With generator out of service, measuring resistance of the CT circuit at the relay, phases A and B had a higher resistance than phase C.
  - The same was observed at the preceding shorting block.
  - The CTs wiring were inspected, and the common conductor was found to be loose. This common conductor was made on the C-phase CT so that connection was good, it was the connection to A and B that was loose.



Investigation

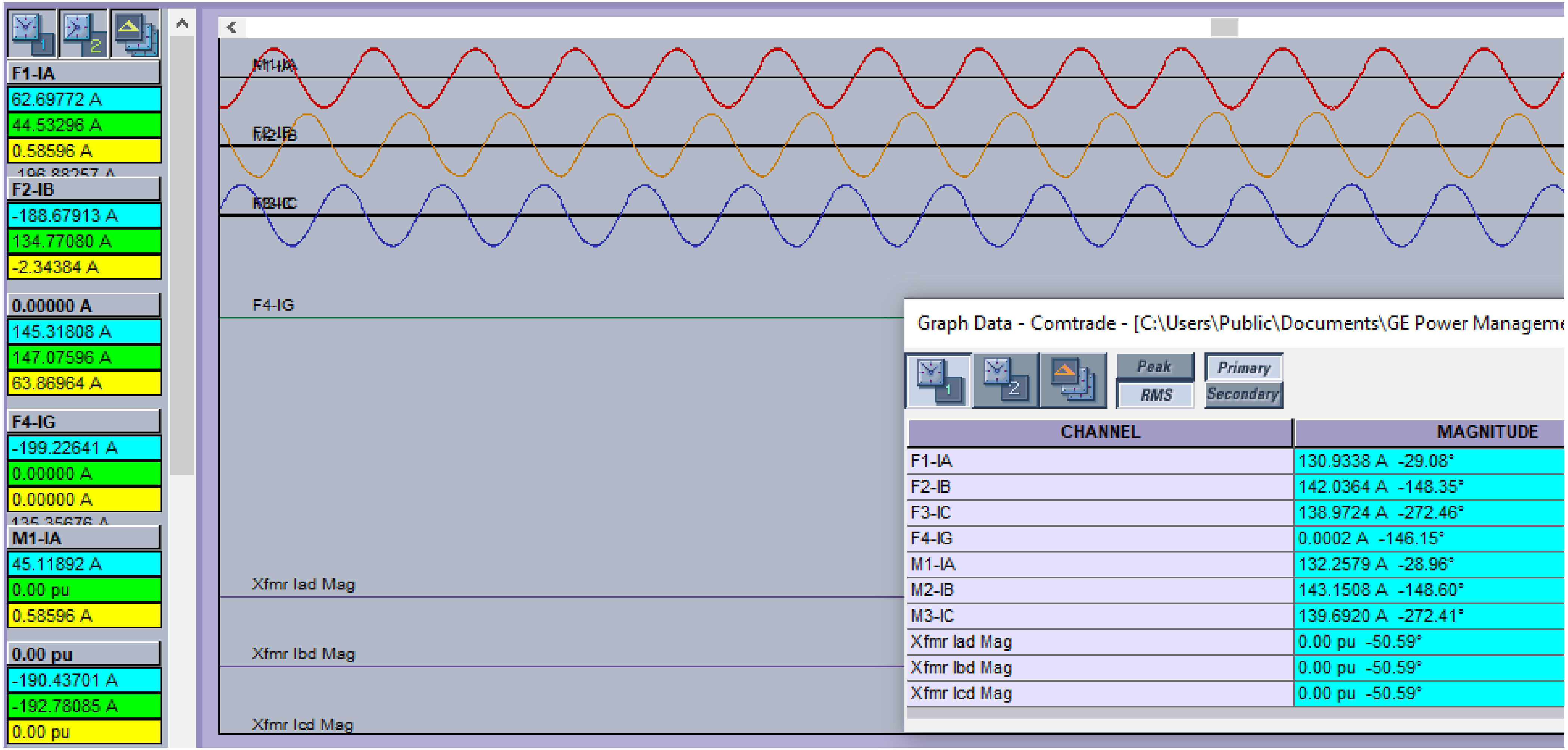
- Arching of CT Wires/lug

Investigatior



Loose connections to A- and B-phase Neutral CTs

Wiring corrected and resynchronization



Generator Differential Currents after correcting CT wiring

Conclusions

- Percentage Differential is fast, dependable and secure; forms important part of Generator and Transformer Protection Schemes
- This function was enhanced with added sensitivity (changes to characteristic) and security (CT saturation detection and Directionality check)
- When investigating suspicious relay operation, don't take anything for granted; consider settings errors, wiring errors, instrument transformers errors and relay h/w or s/w (firmware) issues.
- Use analytical skills, literature, s/w analytical programs to identify possible causes and prove these possible causes right or wrong.
- Consult with colleagues, equipment manufacturers and Industry Experts.
- This event highlights that CT wiring failure is unlikely but can occur.

Thank You

Questions?