GE Digital Energy Multilin

Fundamentals of Modern Protective Relaying
Your Presenters

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Course Agenda

• Generator Protection
  • Generator basics
  • Types of generator grounding
  • Stator differential
  • Ground faults
  • Ground directional
  • Negative sequence unbalance
  • Low forward power and reverse power
  • Accidental energization
  • Loss of excitation
  • Volts/Hz
  • Under and overfrequency

• Fundamentals of Industrial Communications
  • Distance protection theory
  • Step distance and pilot aided schemes
  • Line current differential protection
Course Agenda

• Arc Flash Protection
  • Introduction
  • Relay based techniques
  • Light based technique
Generator Protection
Single Phase AC Generator:

- Exciter – electromagnet rotating about its axis
- Stator – 2 electromagnets or poles wired in series to a load
Single Phase AC Generator Theory of Operation:

![Diagram of Single Phase AC Generator Theory of Operation](image-url)
Three-Phase AC Generator Theory of Operation:
Three-Phase AC Generator Theory of Operation:
Review of Grounding Techniques

Grounding Provides:

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

Low Impedance

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

High Impedance

- System ground source obtained from generator step-up transformer
- Uses principle of reflected impedance
  - Eq: $R_R = R_P \times \left(\frac{V_{sec}}{V_{pri}}\right)^2$
  - Where $R_R$ = Resistance Reflected and $R_P$ = Resistance Primary
- Generator damage minimized or prevented from ground fault
  - Ground fault current typically $\leq 10A$
Burning Stator Iron

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

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

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

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

Generator connected to system with multiple lines
System consists of load and other generation
System voltage varies with loading
  > Excitation control will adjust to system voltage/VAr requirements within machine capability

Output will normally be near full rating for best efficiency
  > Prime mover control will adjust to system frequency requirements within machine capability
Machine Limits

- Rotor Limited (Heat) Limited by OEL
- Stator Limited (Heat) Limited by SCL
- Stator End Core Limited (Heat) Limited by MEL

Increasing pressure (cooling)

- Overexcited
- Underexcited

Real Power

Reactive Power
Excitation Control

Control for off-line operation (synchronizing) and on-line (grid interconnected)
Over- and under-excitation limiters control when power system is in abnormal state
Turbine Control

\[
\frac{d\omega}{dt} = \frac{1}{J} \cdot (T_m - T_e)
\]

Steam / Water

Valve

Turbine

Governor

Transfer Function

Speed

Speed Reference

\[\Delta F\]

\[\Delta P\]

Speed - Droop
Generator Protection
Overview

Internal and External Short Circuits

Exciter

Abnormal Operating Conditions

Short Circuits

System Faults

Internal and External Short Circuits
Electrical Failures

Stator ground faults: 59G, 51G, 87G
Stator phase faults: 87
Interturn faults: 50SP
Rotor ground faults: 64F
Abnormal Conditions

Loss of Excitation: 40
Loss of Prime Mover: 32
Overexcitation: 24
Overvoltage: 59
Off-nominal Frequency: 81
Accidental Energization: 50-27
Out-of-Step: 78
System Backup
Generator Unbalance: 46
System Phase Faults: 21P, 51V
System Ground Faults: 51TG
Generator Breaker Failure: 50BF
ANSI/IEEE Standards

Std. 242:  Buff Book

C37.102: IEEE Guide for Generator Protection

C37.101: IEEE Guide for AC Generator Ground Protection

C37.106: IEEE Guide for Abnormal Frequency Protection for Power Generating Plants

C37.110: IEEE Guide for the application of current transformers used for protective relaying purposes
Small – up to 1 MW to 600V, 500 kVA if >600V
IEEE Buff Book

Medium – up to 12.5 MW
Large – up to 50 MW
Electrical Failures
Stator Ground Fault: High-Z, Unit Connected Machines

59N
> 95% coverage of winding from terminal end
> Tuned to the fundamental frequency

27TN
> 5-15% coverage from the neutral end
> Responds to the Neutral 3\textsuperscript{rd} Harmonic

59D
> 5-15% coverage from the neutral end
> Responds to the ratio of the Neutral and Terminal 3\textsuperscript{rd} Harmonic

Combine 59N and 27TN or 59D for 100% coverage
Neutral grounding transformer (NGT) ratio selected that provides 120 to 240V for ground fault at machine terminals

- Max L-G volts = $13.8kV / 1.73 = 7995V$
- Max NGT volts sec. = $7995V / 120V = 66.39$ VTR
Use of Multiple Setpoints

> **1\textsuperscript{st} level** set sensitive to cover 95% of stator winding
  > - Delayed to coordinate with close-in system ground faults capacitively coupled across GSU

> **2\textsuperscript{nd} level** set higher than the capacitively coupled voltage so coordination from system ground faults is not necessary
  > - May cover from 85% of the stator winding
  > - Need to calculate influence of system fault with GSU capacitive coupling and pickup above the coupled value
  > - Allows higher speed tripping
  > - Only need to coordinate with VT fuses
3rd Harmonic in Generators

3rd harmonic present in terminal and neutral ends
Varies with loading
Useful for ground fault detection near neutral

> If 3rd harmonic goes away, conclude a ground fault near neutral
27TN: 3rd Harmonic Neutral Undervoltage

Primary $3^{rd}$ harmonic voltage may be small, ex., 0.5-8 volts
Element must be sensitive
$3^{rd}$ Harmonic Field Measurements

Neutral Voltage Field Measurements

Voltage

Megawatts

- PF=1
- PF=0.95
- PF=0.9
- PF=-0.9
- PF=-0.95
27TN: 3rd Harmonic Neutral Undervoltage

Use supervisions for increased security under various loading conditions

> Any or All May be Applied Simultaneously
  – Positive Sequence Undervoltage Block
  – Definable Power Band Block
  – Under VAr Block; Lead & Lag
  – Power Factor Block; Lead & Lag
27TN Supervision

Phase voltage
- No phase voltage, machine dead
- Cannot generate $3^{rd}$ harmonic voltage

Power
- $3^{rd}$ harmonic typically increases as power output increases

VAr, PF, I, Power Band
- Additional supervisions for cases where $3^{rd}$ harmonic levels vary with modes of operation (sync condenser, pumping, VAr sink)
59D: 3rd Harmonic Ratio Voltage

\[ |V_n(3rd)| + |V_o(3rd)| \]

and

\[ |V_n(3rd)| + |V_o(3rd)| < 1 - \text{Pickup} \]

\[ R_n = X_{oc} \text{ at } 3 \cdot F_n \]
### Typical 3rd Harmonic Values

<table>
<thead>
<tr>
<th>Real Power</th>
<th>Reactive Power</th>
<th>Neutral Voltage</th>
<th>Terminal Voltage</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>4.2</td>
<td>4.05</td>
<td>1.0</td>
</tr>
<tr>
<td>2</td>
<td>0</td>
<td>3.75</td>
<td>4.95</td>
<td>1.0</td>
</tr>
<tr>
<td>12</td>
<td>1</td>
<td>4.05</td>
<td>5.7</td>
<td>1.3</td>
</tr>
<tr>
<td>32</td>
<td>1</td>
<td>6.3</td>
<td>7.95</td>
<td>1.4</td>
</tr>
<tr>
<td>56</td>
<td>7</td>
<td>8.25</td>
<td>9</td>
<td>1.3</td>
</tr>
<tr>
<td>100</td>
<td>7</td>
<td>12</td>
<td>12.3</td>
<td>1.1</td>
</tr>
</tbody>
</table>

3rd harmonic values tend to increase with power and VAr loading. Fault at neutral causes 3rd harmonic voltage at neutral to go to zero volts.
59D – 3rd Harmonic Ratio Voltage

Examines 3rd harmonic at terminal and neutral ends of generator

> 59D trips when:
  – \[\frac{V_{N,3rd}}{V_{N,3rd} + V_{30,3rd}}\] > pick up

Uses undervoltage supervision
  – \(V_{N,3rd} + V_{30,3rd}\) > pick up

Provides 0-20 stator winding coverage and 80-100% (typ.)

Does not have a security issue with loading, as can a 27TN

> May be less reliable than 27TN
  – Not enough difference to trip

“Null spot” at mid-winding protected by 59N

Needs wye phase VTs; cannot use delta VTs to obtain \(3V_0\) voltage at terminals
100% Stator Ground Fault coverage afforded by overlap by 59N and either the 27TN or 59D elements
Grounding Fault Calculations

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

- **System**
  - 13.8:230 kV
  - 0.006uf Interwind
  - \( V_{\text{nom}} = 13.8 \text{kV} \)
  - 33:1

- **GSU**
  - 0.01uf to GND
  - 0.12uf to GND
  - 0.24uf to GND

- **Aux Load**
  - 1.27uf to GND
  - 1.71 ohm

- **UAT**
  - 0.24uf to GND
Ground Fault Calculations

1) Calculate Generator Line-Neutral Voltage
   • \( V_{LN} = V_{LL \text{ nom}} / \sqrt{3} \)
   • \( V_{LN} = 13,800V / 1.73 = 7977 \text{ V} \)

2) Calculate Total Capacitance
   • \( C_T = C_{\text{gen}} + C_{\text{lead}} + C_{\text{GSU}} + C_{\text{UAT}} + C_{\text{surge}} \)
   • \( C_T = 1.27 \text{ uf} + 0.12 \text{ uf} + 0.01 \text{ uf} + 0.24 \text{ uf} = 1.424 \text{ uf} \)

3) Calculate Total Capacitive Reactance
   • \( X_{CT} = \frac{1}{2\pi f C} = \frac{1}{(6.28) \times (60) \times (1.424 \times 10^{-6})} \)
   • \( X_{CT} = 1,864\Omega \)

4) Pick NGT ratio for 240V\(_{\text{sec}}\) on full ground fault
   • NGT Ratio = \( V_{LG} / V_{\text{sec max}} \)
   • NGT Ratio = \( 7977\text{V} / 240\text{V} = 33 \)
5) Calculate 95% 59N Setting
- $59N_{(95\%)} = V_{sec\ max} \times [100\% - \% \text{Desired Coverage}]$
- $59N_{(95\%)} = 240V \times [100\% - 95\%]$
- $59N_{(95\%)} = 240V \times [0.05] = 12V$
- Use timer set greater then system ground fault back up

6) Select $R_{\text{ground pri}}$ to equal $X_{CT}$ to limit transient overvoltages
- $R_{\text{ground pri}} = 1,864\Omega$

7) Calculate NGR based on desired $R_{\text{ground pri}}$
- $NGR = R_{\text{ground pri}} / [\text{NGT ratio}]^2$
- $NGR = 1,864\Omega / 33^2 = 1.71\Omega$
Ground Fault Calculations

8) Calculate Maximum Primary Ground Fault Current
   - \( GFC_{pri\ max} = \frac{VLN}{R_{ground\ pri}} \)
   - \( GFC_{pri\ max} = \frac{7977\ V}{1,864\ \Omega} = 4.28\ A \)

9) Calculate Maximum Secondary Ground Fault Current
   - \( GFC_{sec\ max} = \frac{V_{sec\ max}}{NGR} \)
   - \( GFC_{sec\ max} = \frac{240\ V}{1.71\ \Omega} = 140\ A \)

10) Calculate NGT/NGR Power Dissipation
    - \( W = V_{sec\ max} \times GFC_{sec\ max} \)
    - \( W = 240\ V \times 140\ A = 33.6\ KW \)
Ground Fault Calculations

11) Calculate Worse Case Coupling Voltage

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

51N: Neutral Overcurrent
67N: Neutral Directional
87GD: Ground Differential
51N

Typically set to 5% of available fault ground fault current

Coordination with system ground fault protection

Blocking by system ground fault protection
67N: Neutral Directional

Provides selective ground fault detection for multi-generator bus connected arrangements
Set to operate faster than 51N

-may have short time delay
67 N: Neutral Directional

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

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

67N is set faster than 51N
> May be short definite time delay

Requires $3V_0$ polarizing signal

Core balance CT recommended for sensitive fault detection
Neutral Directional : Low-Z Generator

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

- Ground fault in machine is detected by 67N & 51N
- 51N picks up in unfaulted machine
- 67N trips fast in faulted machine
- 51N resets on unfaulted machine
Employed 87GD to selectively clear machine ground fault for multi-generator bus connected arrangements

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

Ground switches on all machines can all be closed
87GD: Ground Differential

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

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

- Single generator, with system supplying ground current, or multiple generators as ground current sources
- Protection down to last 5% near neutral using 51N, 67N or 87GD

In Low-Z schemes, you cannot provide 100% stator ground fault protection.
Stator Phase Faults

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

Sensitive detection of phase and ground faults
No coordination issues
Difficult to install on large machines
No need to coordinate with other zones
High speed (typ. 0.75-2.5 cycles)
Main issue is security during CT saturation
Biased Differential: 87G

Fast, selective

Used to clear multiphase faults

> Can detect ground faults to a degree in low-Z grounded machines

> Cannot detect ground faults in high-Z grounded machines
  – Too little ground fault current at <= 10A

Uses differential principle

> Current in should equal current out
Biased Differential Characteristic

Minimum Pickup: 5% of Inominal
Slope 1 for “normal” CT errors: 10%
Slope 2 for large errors: 50-80%
Through Current: Ideal CTs

4 pu

Differential Current

TRIP

Restraint Current

4 pu

A

B

A

B

0

+4

-4
Through Current: CT Error

4 pu

Differential Current

Restraint Current

TRIP

A

B

C
Internal Fault: Ideal CTs

2 pu → 4 pu

87

Differential Current

Restraint Current

TRIP

A

B

A

B
Internal Fault: CT Error

2 pu → 4 pu

Differential Current

Restraint Current

TRIP

A → B

A → B

A

B
CT Calculations for Differential

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

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

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

Long runs of thin wire raise burden
C37.110 Recommendations

The following requirements apply to CTs used for generator differential applications:
  a) Select CT current rating to 120%-150% of generator rating
  b) Utilize full-winding ratio
  c) Use CTs with the highest practical secondary voltage capability
  d) Use CTs that have fully distributed secondary windings

The differential CTs on both sides of a generator should be of the same ratio, rating, connected burden, and preferably have the same manufacturer, so that the excitation characteristics are well matched.
C37.110 Recommendations

If the generator differential zone must include a generator breaker it is not always possible to use CTs with the same excitation characteristics, especially knee point voltage. The mismatch of the CTs should be checked.

In order of preference, the goal is to:

a) Avoid CT saturation for asymmetrical currents, if possible
b) Prevent saturation on symmetrical currents
c) Go into saturation at the same current if avoiding dc saturation is not possible
d) Minimize the difference in time to saturation for asymmetrical currents (dc saturation)
CT Saturation for DC

\[ I \cdot e^{-t/T_s} \]

Current

Flux

[Diagram of electrical circuit with symbols and annotations]
DC Saturation: Fundamental Relations

\[ V_E = I_S \cdot (R_S + Z_B) \]

\[ K_S = \frac{V_X}{I_S \cdot Z_T} \]

\[ K_S > 1 + X/R \]

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

Voltage across the magnetizing branch

Saturation factor

Saturation-free operation

Time to saturation
CT Calculations for AC Saturation

Gather Burden Information

CT = 0.3 Ω
Leads = 0.6 Ω
Relay = 0.040 Ω

\[ Z_{total} = CT + Leads + Relays \]
\[ = 0.3\Omega + 0.6\Omega + 0.04\Omega = 0.94\Omega \]

Use \( X''_d \) for maximum Fault Current

\[ X''_d = 0.136 \text{ pu} \]
\[ If = \frac{1}{X''_d} = 7.35 \text{ pu} \]

Determine Rated Current

\[ I_{rated} = \frac{\text{MVA}_{\text{nom}}}{\sqrt{3} \cdot V_{\text{nom}}} \]
\[ = \frac{212 \text{ MVA}}{\sqrt{3} \cdot 18 \text{ kV}} \]
\[ = 6808 \text{ A}_{\text{PRI}} \]

\[ X''_d = 0.136 \text{ pu} \]
\[ If_{PRI} = 7.35 \cdot 6808 = 50309 \text{ A}_{\text{PRI}} \]
\[ If_{SEC} = \frac{50309 \cdot 5}{8000} = 31 \text{ A}_{\text{SEC}} \]
CT Calculations for AC Saturation

INPUT PARAMETERS:
- Inverse of sat. curve slope = S
- RMS voltage at 10A exc. current = Vs
- Turns ratio = n2/1=n
- Winding resistance = Rw
- Burden resistance = Rb
- Burden reactance = Xb
- System X/R ratio = XoverR
- Per unit offset in primary current = Off
- Per unit remanence (based on Vs) = \lambda_{rem}
- Symmetrical primary fault current = Ip

ENTER:
- 16
- 450
- 1600
- 0.300
- 0.640
- 0.004
- 20.0
- 1.00
- 0.00
- 50,309

CALCULATED:
- Voltages rms: Vs
- Currents rms: Ie

C400 OK
CT Calculations for AC Saturation

Set Breakpoint @ 35KA
Abnormal Operation Protection
Abnormal Operation
Loss of Excitation: 40

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

> Block function for VT Fuse Failure
Loss of Excitation: 40

Heavy Load

Light Load
Loss of Excitation: Method 1

212 MVA, 18 kV
X'd=0.216 pu
Xd=1.967

18.9 kV:120 V
8000:5A

\[ VT = \frac{18900}{120} = 157.5 \]

\[ CT = \frac{8000}{5} = 1600 \]

\[ Z_{base}(sec) = \frac{\text{base } kV^2}{\text{base MVA}} \cdot \frac{CTR}{VTR} = \frac{(18kV)^2}{211MVA} \cdot \frac{1600}{157.5} = 15.54 \Omega \]

\[ X_d'(sec) = X_d' \cdot Z_{base}(sec) = 0.216 \cdot 15.54 = 3.36 \Omega \]

\[ X_d(sec) = X_d \cdot Z_{base}(sec) = 1.967 \cdot 15.54 = 30.57 \Omega \]
PQ vs. R-X

\[
Z_{\text{relay}} = \frac{kV^2 \ast \text{CTR}}{\text{MVA} \ast \text{VTR}}
\]

\[
Z_{\text{relay}} = \frac{V^2 \ast \text{CTR}}{\text{VA} \ast \text{VTR}}
\]
Reverse Power (32)

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

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

Trips to prevent damage to mechanical parts
Reverse Power (32)

> The reverse power element should be set at \( \frac{1}{2} \) the rated motoring power

> Pickup is calculated as follows:

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

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

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

> Block function when the generator is offline
Reverse Power (32)

212 MVA, 18 kV
X’d=0.216 pu
Xd=1.967

18.9 kV:120 V

8000:5A

(a) Q
OPERATE RESTRAN
P
RCA = 180° SMIN > 0

(b) Q
OPERATE RESTRAN
P
RCA = 180° SMIN < 0
Voltz Per Hertz (24)

> Protect directly and indirectly connected generators from excessive voltage and/or low frequency
Voltz Per Hertz (24)

> Coordinate with manufacturers excitation capability curves. The combined generator/GSU limit curve is shown below:
Voltz Per Hertz (24)

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

- Protect stator windings and rotor from very high induced currents (in case the Gen. is connected on line, before being ready - V and f )
Generator Protection – Inadvertent Energization:

I_{phase} > O/C Level

V_{phase} < U/V Level
Breaker Status = Offline

Arming Signal = U/V or Offline
**Power Swing Block/Trip (78)**

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

1. Loss of generation with load remaining constant
2. Load increases substantially on a weak system
Out-of-Step Relaying

Out-of-step blocking relays

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

Out-of-step tripping relays

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

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

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

Must move and stay between the middle and inner characteristics.
Power Swing Blocking

Applications:

• Establish a blocking signal for stable power swings (Power Swing Blocking)

• Establish a tripping signal for unstable power swings (Out-of-Step Tripping)

Responds to:

• Positive-sequence voltage and current

Block when:

• Generator off-line or VTFF
Power Swing Block/Trip (78)

Voltage = High
Current = Low

Voltage = Low
Current = High

Voltage = High
Current = Low

\[ Z = \frac{V}{I} \]

Movement through Zone 1

End (System Re-synchronized & Stable)

Start
Power Swing Block/Trip (78) – No Fault

Timer Starts

Additional Impedance Zones

R
Power Swing Block/Trip - Internal Fault

Operating Impedance Zones

Timer Starts

R
Underfrequency (81U)

- Under-frequency occurs when power system load exceeds prime mover capabilities of generator
- Protect turbine from under-speed
- Pickup and delay settings are dependent on operating practices and system characteristics
- Block underfrequency when offline
Overfrequency (81O)

• Over-frequency occurs when mechanical input to prime mover exceeds electrical load (loss of load due to transmission / feeders disconnection)
• Protect turbine from over-speed or damage due to over-speeding
• Pickup and delay settings are dependent on operating practices and system characteristics
• Block overfrequency when offline
Phase Undervoltage (27)
Phase Overvoltage (59)

- Configured to alarm
- Set undervoltage to 90% with time delay
- Block undervoltage when generator breaker open or VTFF
- Set overvoltage to 110% with time delay
Generator Protection – **Negative Sequence**:

- Protect rotor from heating due to negative sequence currents
Generator Protection – Negative Sequence:

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

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

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

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

Simultaneous Trip

87
59G
32-1
51N
64F

OR

Trip Gen BKR
Trip Turbine
Trip Exciter
Aux Transfer

Gen Alarm

49
27/59

OR

Alarm

Unit Separation

81
21/51V
46
78
40
24

OR

Trip Gen BKR
Aux Transfer

Sequential Trip

32-2

AND

Trip Gen BKR

Turbine FLT
Arc Flash Solutions
A Study of a Fault…….

**Total Clearing Time**

- Relaying (2 Cycles)
- Mech Time (1 Cycle)
- Arcing Time (2 Cycles)

ARC Extinguished in Five Cycles

SHORT CIRCUIT OCCURS HERE
Fault Interruption and Arcing

Arc Characteristics

Contacts Closed
Heat $I^2R$

Current

Contacts Opening
Enlarged View of Contact Surface
AIR

Contacts Fully Open

Heated Air

Air at Room Temp = Good Insulator
Air at 4000°C = Conductor

ArCs can reach temperatures of over 35,000°F (19,427°C)
Arc Flash Mitigation: Problem Description

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

- Arc flash energy may be expressed in $I^2t$ terms, so you can decrease the $I$ or decrease the $t$ to lessen the energy.
- Protective relays can help lessen the $t$ by optimizing sensitivity and decreasing clearing time.
  - Protective Relay Techniques
- Other means can lessen the $I$ by limiting fault current.
  - “Non-Protective Relay Techniques”
Non-Protective Relaying Methods of Reducing Arc Flash Hazard

- System design modifications increase power transformer impedance
  - Addition of phase reactors
  - Faster operating breakers
  - Splitting of buses
- Current limiting fuses (provides partial protection only for a limited current range)

- Electronic current limiters (these devices sense overcurrent and interrupt very high currents with replaceable conductor links (explosive charge)
- Arc-resistant switchgear (this really doesn't reduce arc flash energy; it deflects the energy away from personnel)
- Optical arc flash protection via fiber sensors
- Optical arc flash protection via lens sensors
Protective Relaying Methods of Reducing Arc Flash Hazard

- Bus differential protection (this reduces the arc flash energy by reducing the clearing time)
- Zone interlock schemes where bus relay selectively is allowed to trip or block depending on location of faults as identified from feeder relays
- Temporary setting changes to reduce clearing time during maintenance
  - Sacrifices coordination

- FlexCurve for improved coordination opportunities
- Employ 51VC/VR on feeders fed from small generation to improve sensitivity and coordination
- Employ UV light detectors with current disturbance detectors for selective gear tripping
Fuses vs. Relayed Breakers

- **Current**
- **Peak available current (Ip)**
- **Fuses**
- **Breakers**
- **Normal load current**
- **Point of fault**
- **Breaker operates here**
- **Fuse opens within 1/4 to 1/2 cycle**
- **Heat Energy**
# Arc Flash Hazards

<table>
<thead>
<tr>
<th>Skin Temperature</th>
<th>Time of Skin Temp.</th>
<th>Damage Caused</th>
</tr>
</thead>
<tbody>
<tr>
<td>110 °F</td>
<td>6 Hours</td>
<td>Cell breakdown starts</td>
</tr>
<tr>
<td>158 °F</td>
<td>1 sec.</td>
<td>Total cell destruction</td>
</tr>
<tr>
<td>176 °F</td>
<td>0.1 sec</td>
<td>Curable burn</td>
</tr>
<tr>
<td>200 °F</td>
<td>0.1 sec</td>
<td>Incurable burn</td>
</tr>
</tbody>
</table>

## NFPA-70E 2004 Equipment Requirements

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

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

\[ P = 11.65 \times \frac{(kA)}{R^{0.9}} \]

Where:
- \( P \) = Pressure developed by arc in lbs./ft.²
- \( kA \) = Short circuit current \(_{\text{rms}}\) in kiloamps
- \( R \) = Distance in feet from arc center to area of interest

Available Short Circuit Current (Amps - RMS) 1kA 2.5kA 5kA 10kA 25kA 50kA 100kA
Arc Flash Warning Example 1

Arc-Flash Hazard and Shock Hazard

<table>
<thead>
<tr>
<th>0' - 11&quot;</th>
<th>Arc-Flash Protection Boundary</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.8 cal/cm²</td>
<td>Incident Energy Flash Hazard at 18 inches</td>
</tr>
</tbody>
</table>

Appropriate PPE Required for both Arc-Flash and Shock Hazards:

Safety Glasses, Class 1 Voltage Gloves, Voltage Rated Tools, Non-melting, flammable clothing

2400 V<sub>ac</sub> - Shock Hazard with covers/doors open

5' - 0" - Limited Approach Boundary

2' - 2" - Restricted Approach Boundary

0' - 7" - Prohibited Approach Boundary

1106-MCC 2-1
STARTER DOOR OF AIR COMPRESSOR #1
### Arc-Flash Hazard and Shock Hazard

| 3' - 7" | Arc-Flash Protection Boundary |
| 4.4 cal/cm² | Incident Energy Flash Hazard at 18 inches |

**CLASS 2 Arc-Flash Hazard Risk Category**

**Appropriate PPE Required for both Arc-Flash and Shock Hazards:**


| 480 V<sub>ac</sub> | Shock Hazard with covers/doors open |
| 3' - 6" | Limited Approach Boundary |
| 1' - 0" | Restricted Approach Boundary |
| 0' - 1" | Prohibited Approach Boundary |

**1806-MCC G**

**AHU #2**
### Arc Flash Warning Example 3

#### Arc-Flash Hazard and Shock Hazard

| 44' - 0" | Arc-Flash Protection Boundary |
| 32.1 cal/cm² | Incident Energy Flash Hazard at 18 inches |

| CLASS 4 | Arc-Flash Hazard Risk Category |

#### Appropriate PPE Required for both Arc-Flash and Shock Hazards:

- Safety Glasses/Goggles
- Hard Hat
- Flash Suit Hood
- Hearing Protection
- Class 2 Voltage Gloves
- Leather Gloves/Protectors
- Voltage Rated Tools
- Leather Shoes
- Cotton Underwear
- FR Long Sleeve Shirt
- FR Long Pants
- Multi-layer flash suit

| $12470 \text{ V}_{ac}$ | Shock Hazard with covers/doors open |
| 5' - 0" | Limited Approach Boundary |
| 2' - 2" | Restricted Approach Boundary |
| 0' - 7" | Prohibited Approach Boundary |

**1020-SUB2 BUS B2**
**REAR OF 2-12A CUBICLE**
Arc Flash Solutions
Relaying Techniques to Reduce Arc Flash Energy

1-2 ms  Install discrete Arc Flash Detection device

1 cycle  Implement low impedance bus protection

1.5 to 2 cycles  Implement instantaneous overcurrent tripping using maintenance setting group in relay. Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary

1.5 to 2 cycles  Implement high impedance bus protection

3-4 cycles  Implement bus zone interlocking scheme

20.0 cycles  Breaker failure protection

Seconds  Reduce coordination intervals of existing time-overcurrent relays

Time to clear saves lives
Arc Flash Solutions
Bus Interlock Scheme

3-4 Cycles Detection
Arc Flash Solutions
High Impedance Bus Differential

1.5 to 2 Cycles Detection
Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary.

Replacement Relays: 2\textsuperscript{nd} 50 element
Multifunction Relays: setting groups
Multifunction Relays: multiple 50’s
Arc Flash Solutions

2nd Instantaneous Overcurrent Element

1.5 to 2 Cycles Detection
Arc Flash Solutions
Low Impedance Bus Differential

1 Cycle Detection
Arc Flash Solutions

Time Current Coordination

A = Downstream feeder relay with the highest settings

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

Transformer damage

Select Relay B Instantaneous Pickup (if possible)
Arc Flash Solutions
Fault Current and Operate Time
ARC FLASH DETECTION METHODS
Traditional Arc Flash Detection Methods

Light Sensing

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

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

> Cons:
  - High susceptibility to false triggers if light sensing threshold not set high enough
  - Fiber loops can be easily damaged due to bending or pinching
  - Difficult to install or re-install if fiber loop is damaged
Traditional Arc Flash Detection Methods
Light and Current Sensing

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

> Cons:
  – Requires the use of CT’s and overcurrent protection device
  – Comparatively more cost and complexity
A Novel Approach: Light And Sound Sensing based Detection
A Unique Light and Sound Signature

- In an arc flash condition, every millisecond counts...

- Known and standard time relationship from the difference between a light signal (3x$10^8$m/s) and an associated pressurized sound wave (343 m/s) generated unique time delay signature

Figure 1: light and pressure wave signal during the Arc Flash event
Light & Sound Sensor – US Patent

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

- Jacket of the light fiber inside the sensor head is removed which provides better sensitivity to the light from all angles through transparent head cover. Mirror reflects the light for testing.

- The Light Fiber picks up the flash of light from the Bare Fiber in the sensor head and transmits that to the unit

- The Sound/Pressure Fiber emits light which gets reflected back by the diaphragm, then collected by the same sound/pressure fiber and sent back to the unit

- During an arc flash event, the diaphragm vibrates from the pressurized sound wave creating a signature which is detected by the sensor head
Continuous System Self-testing

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

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

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

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

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