Overcurrent Protection & Coordination for Industrial Applications

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Agenda

- Introduction
- Using Log-Log Paper & TCCs
- Types of Fault Current
- Protective Devices & Characteristic Curves
- Coordination Time Intervals (CTIs)
- Effect of Fault Current Variations
- Multiple Source Buses
- Partial Differential Relaying
- Directional Overcurrent Coordination
- Transformer Overcurrent Protection
- Motor Overcurrent Protection
- Conductor Overcurrent Protection
- Generator Overcurrent Protection
- Coordinating a System
- Supplemental Material
- Coordination Quizzes
- Hands-On Demonstration
- References
Introduction
Protection Objectives

• Personnel Safety
Protection Objectives

• Equipment Protection
Protection Objectives

• Service Continuity & Selective Fault Isolation

- Faults should be quickly detected and cleared with a minimum disruption of service.

- Protective devices perform this function and must be adequately specified and coordinated.

- Errors in either specification or setting can cause nuisance outages.
Types of Protection

Protective devices can provide the following assortment of protection, many of which can be coordinated. We’ll focus primarily on the last one, overcurrent.

• Distance
• High-Impedance Differential
• Current Differential
• Under/Overfrequency
• Under/Overvoltage
• Over Temperature
• Overload
• Overcurrent
Coordinating Overcurrent Devices

• Tools of the trade “in the good old days…”
Coordinating Overcurrent Devices

• Tools of the trade “in the good old days…”
Coordinating Overcurrent Devices

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• Tools of the trade “in the good old days…”
Coordinating Overcurrent Devices

• Tools of the trade today…
Using Log-Log Paper & TCCs
Log-Log Plots

Time-Current Characteristic Curve (TCC)

Why log-log paper?

- Log-Log scale compresses values to a more manageable range.
- $I^2t$ withstand curves plot as straight lines.

Current in Amperes

Time in Seconds

0.01 0.1 1 10 100 1000 10000

0.1 1 10 100

1 cycle (momentary)

5 cycles (interrupting)

Typical fault clearing

Typical motor acceleration

1 minute

$I^2t$ withstand curves plot as straight lines

effectively steady state

FLC = 1 pu

Fs = 13.9 pu

Fp = 577 pu

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Plotting A Curve

5000 hp Motor TCC

FLC = 598.9 A

Accel. Time = 2 s

LRC = 3593.5 A

Current in Amperes

Time in Seconds

1000
100
10
1
0.1
0.01
0.001
0.5
1
10
100
1000
10000

4 kV 5000 hp
90% PF, 96% η, 598.9 A
3593.5 LRC, 2 s start

13.8 kV

13.8/4.16 kV
10 MVA
6.5%

4.16 kV

M

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Plotting Fault Current & Scale Adjustment

5000 hp Motor TCC with Fault on Motor Terminal

- FLC = 598.9 A
- Accel. Time = 2 s
- LRC = 3593.5 A

Current in Amperes \times 10 A

- 13.8 kV
- 13.8/4.16 kV
- 10 MVA
- 4.16 kV
- 6.5%
- 15 kA

4 kV 5000 hp
- 90% PF, 96% \eta, 598.9 A
- 3593.5 LRC, 2 s start

15 kA
Voltage Scales

5000 hp Motor TCC with Fault on Transformer Primary

45 kA @ 13.8 kV
= ? @ 4.16 kV
= (45 \times \frac{13.8}{4.16})
= 149.3 \text{kA} @ 4.16 \text{kV}
Types of Fault Currents
Fault Current Options

ANSI
- Momentary Symmetrical
- Momentary Asymmetrical
- Momentary Crest
- Interrupting Symmetrical
- Adjusted Interrupting Symmetrical

IEC
- Initial Symmetrical ($I_k$)
- Peak ($I_p$)
- Breaking ($I_b$)
- Asymmetrical Breaking ($I_{b,\text{asym}}$)
Fault Current Options

- Symmetrical currents are most appropriate.
- Momentary asymmetrical should be considered when setting instantaneous functions.
- Use of duties not strictly appropriate, but okay.
- Use of momentary/initial symmetrical currents lead to conservative CTIs.
- Use of interrupting currents will lead to lower, but still conservative CTIs.
Protective Devices & Characteristic Curves
Electromechanical Relays (EM)

IFC 53
Very Inverse Time
Time-Current Curves

MULTIPLES OF PICK-UP SETTING

TIME IN SECONDS

0.01 0.1 1 10 100

0.1 1 10 100

1 10

1/2

Overcurrent Coordination for Industrial Applications
Electromechanical Relays

Pickup Calculation

The relay should pick-up for current values above the motor FLC (~ 600 A).

For the IFC53 pictured, the available ampere-tap (AT) settings are 0.5, 0.6, 0.7, 0.8, 1, 1.2, 1.5, 2, 2.5, 3, & 4.

For this type of relay, the primary pickup current was calculated as:

\[ PU = CT \text{ Ratio} \times AT \]

\[ PU = (800/5) \times 3 = 480 \text{ A (too low)} \]
\[ = (800/5) \times 4 = 640 \text{ A (107\%, okay)} \]
Electromechanical Relays

IFC 53 RELAY
Very Inverse Time
Time-Current Curves

IFC 53 Relay Operating Times

<table>
<thead>
<tr>
<th>Fault Current</th>
<th>15 kA</th>
<th>10 kA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multiple of Pick-up</td>
<td>15000/640 = 23.4</td>
<td>10000/640 = 15.6</td>
</tr>
<tr>
<td>Time Dial ½</td>
<td>0.07 s</td>
<td>0.08 s</td>
</tr>
<tr>
<td>Time Dial 3</td>
<td>0.30 s</td>
<td>0.34 s</td>
</tr>
<tr>
<td>Time Dial 10</td>
<td>1.05 s</td>
<td>1.21 s</td>
</tr>
</tbody>
</table>
Solid-State Relays (SS)
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Power CBs

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Insulated & Molded Case CB

Fault current < Inst. Override

Molded Case CB
HKD
Size = 250 A
Terminal Trip = Fixed
Magnetic Trip = 10

Insulated Case MCB
1200 A

0.48 kV

11 kA @ 0.48 kV

Amps X 100 (Plot Ref. kV=0.48)

Seconds

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Insulated & Molded Case CB

- Insulated & Molded Case CB
- 1200 A
- 16-SWGR-02A
- 0.48 kV
- Molded Case CB
- 250 A
- HKD
- Size = 250 A
- Terminal Trip = Fixed
- Magnetic Trip = 10

- Fault current > Inst. Override
- Insulated Case MCB
- 42 kA @ 0.48 kV

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Power Fuses

Overcurrent Coordination for Industrial Applications

MCC 1
4.16 kV

Mtr Fuse
JCL (2/03)
Standard 5.08 kV 5R

Seconds

Minimum Melting

Total Clearing

Amps X 10 (Plot Ref. kV=4.16 kV)

Mtr Fuse
15 kA @ 4.16 kV
Coordination Time Intervals (CTIs)
Coordination Time Intervals (CTIs)

The CTI is the amount of time allowed between a primary device and its upstream backup.

Backup devices wait for sufficient time to allow operation of primary devices.

Primary devices sense, operate & clear the fault first.

When two such devices are coordinated such that the primary device “should” operate first at all fault levels, they are “selectively” coordinated.
In the good old (EM) days,

What typical CTI would we want between the feeder and the main breaker relays?

It depends.
Coordination Time Intervals – EM

On what did it depend?

Remember the TD setting?

It is continuously adjustable and not exact.

So how do you really know where TD = 5?

FIELD TESTING!
(not just hand set)

Pickup = 8 (0.05 - 20 xCT Sec)
Time Dial = 5
3x = 3.3 s, 5x = 1.24 s, 8x = 0.628 s
Coordination Time Intervals – EM

Plotting the field test points.

Pickup = 8 (0.05 - 20 xCT Sec)  
Time Dial = 5

3x = 3.3 s, 5x = 1.24 s, 8x = 0.628 s

“3x” means 3 times pickup  
3 * 8 = 24 A (9.6 kA primary)  
5 * 8 = 40 A (16 kA primary)  
8 * 8 = 64 A (25.6 kA primary)
Coordination Time Intervals – EM

So now, if test points are not provided what should the CTI be?

0.4 s

But, if test points are provided what should the CTI be?

0.3 s
Coordination Time Intervals – EM

Where does the 0.3 s or 0.4 s come from?

1. breaker operating time (Feeder breaker)
2. CT, relay errors (both)
3. disk overtravel (Main relay only)

<table>
<thead>
<tr>
<th></th>
<th>Tested</th>
<th>Hand Set</th>
</tr>
</thead>
<tbody>
<tr>
<td>breaker 5 cycle</td>
<td>0.08 s</td>
<td>0.08 s</td>
</tr>
<tr>
<td>Disk over travel</td>
<td>0.10 s</td>
<td>0.10 s</td>
</tr>
<tr>
<td>CT, relay errors</td>
<td>0.12 s</td>
<td>0.22 s</td>
</tr>
<tr>
<td>TOTAL</td>
<td>0.30 s</td>
<td>0.40 s</td>
</tr>
</tbody>
</table>
Coordination Time Intervals – EM

Obviously, CTIs can be a subjective issue.

### Red Book (per Section 5.7.2.1)

<table>
<thead>
<tr>
<th>Components</th>
<th>Handset</th>
<th>Set using instruments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breaker operating time (5 cycles)</td>
<td>0.083 s</td>
<td>0.083 s</td>
</tr>
<tr>
<td>Relay overtravel (disk inertia)</td>
<td>0.10 s</td>
<td>0.10 s</td>
</tr>
<tr>
<td>Relay tolerance and setting errors</td>
<td>0.217 s</td>
<td>0.117 s</td>
</tr>
<tr>
<td>Allowable time interval</td>
<td>0.40 s</td>
<td>0.30 s</td>
</tr>
</tbody>
</table>

### Buff Book (taken from Tables 15-1 & 15-2)

<table>
<thead>
<tr>
<th>Components</th>
<th>Handset</th>
<th>Field Tested</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breaker operating time (5 cycles)</td>
<td>0.08 s</td>
<td>0.08 s</td>
</tr>
<tr>
<td>Relay overtravel (disk inertia)</td>
<td>0.10 s</td>
<td>0.10 s</td>
</tr>
<tr>
<td>Relay tolerance and setting errors</td>
<td>0.17 s</td>
<td>0.12 s</td>
</tr>
<tr>
<td>Allowable time interval</td>
<td>0.35 s</td>
<td>0.30 s</td>
</tr>
</tbody>
</table>
Coordination Time Intervals
EM & SS

So, let's move forward a few years....

For a modern (static) relay what part of the margin can be dropped?

So if one of the two relays is static, we can use 0.2 s, right?

Disk overtravel

It depends

CTI = 0.3 s
(because disk OT is still in play)

CTI = 0.2 s
Coordination Time Intervals

- Main (EM)
- Main (SS)
- Feeder (SS)
- Feeder (EM)

- Main (EM)
- Feeder (SS)

- Main (EM)
- Feeder (SS)

- Main (SS)
- Feeder (EM)

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Coordination Time Intervals
EM/SS with Banded Devices

OC Relay combinations with banded devices

- EM Relay
  - disk over travel \( \checkmark \) 0.1 s
  - CT, relay errors \( \checkmark \) 0.12 s
  - operating time \( \times \)
  - CTI 0.22 s

- Static Trip or Molded Case Breaker
  - disk over travel \( \times \)
  - CT, relay errors \( \checkmark \) 0.12 s
  - operating time \( \times \)
  - CTI 0.12 s

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CTI – EM/SS with Banded Devices

EM-Banded

EM Relay

PWR MCB

SS-Banded

SS Relay

PWR MCB

EM Relay

0.22 s

25 kA

Amps X 100 (Plot Ref. kV=0.48)

Seconds

Amps X 100 (Plot Ref. kV=0.48)

0.12 s

25 kA

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CTI – Banded Devices

- Banded characteristics include tolerances & operating times.
- There is no intentional/additional time delay needed between two banded devices.
- All that is required is clear space (CS).
CTI – Banded Devices

• Note that areas of mis-coordination may exist even if the TCC looks good.
• Manufacturer of banded devices will typically not provide data below 0.01 sec.
Coordination Time Intervals
Summary

Buff Book (Table 15-3 – Minimum CTIs$^a$)

<table>
<thead>
<tr>
<th>Downstream</th>
<th>Upstream</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fuse</td>
</tr>
<tr>
<td>Fuse</td>
<td>CS$^{b,c}$</td>
</tr>
<tr>
<td>Low-voltage circuit breaker</td>
<td>CS$^c$</td>
</tr>
<tr>
<td>Electromechanical relay (5 cycles)</td>
<td>0.20 s</td>
</tr>
<tr>
<td>Static relay (5 cycles)</td>
<td>0.20 s</td>
</tr>
</tbody>
</table>

$^a$Relay settings assumed to be field-tested and -calibrated.
$^b$CS = Clear space between curves with upstream minimum-melting curve adjusted for pre-load.
$^c$Some manufacturers may also recommend a safety factor. Consult manufacturers’ time-current curves.
Effect of Fault Current Variations
Inverse relay characteristics imply

For a fault current of 10 kA the CTI is 0.2 s.

For a fault current of 20 kA the CTI is 0.06 s.

Consider a main-tie-main arrangement with a N.O. tie breaker
Total Bus Fault versus Branch Currents

- For a typical distribution bus all feeder relays will see a slightly different maximum fault current.
- Years back, the simple approach was to use the total bus fault current as the basis of the CTI, including main incomer.
- Using the same current for the main led to a margin of conservatism.
Using Total Bus Fault Current of 15 kA

Using Actual Maximum Relay Current of 10 kA

Feeder

Main

0.2 s

15 kA

0.8 s

10 kA

15 kA

Total Bus Fault versus Branch Currents

Overcurrent Coordination for Industrial Applications

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Curve Shaping

- Most modern relays include multiple OC Elements.

- Using a definite time characteristic (or delayed instantaneous) can eliminate the affect of varying fault current levels.
Curve Shaping – Danger of Independent OC Units

- Many software programs include the facility to plot integrated overcurrent units, usually a 50/51.
- However, the OC units of many modern relays are independent and remain active at all fault current levels.
- Under certain setting conditions, such as with an extremely inverse characteristic, the intended definite time delay can be undercut and higher fault levels.

Overcurrent Coordination for Industrial Applications

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Multiple Source Buses
Multiple Source Buses

• When a bus includes multiple sources, care must be taken to **not** coordinate all source relays at the total fault current.

• Source relays should be plotted only to their respective fault currents or their “normalized” plots.

• Plotting the source curves to the total bus fault current will lead to much larger than actual CTIs.
Curve Shifting

- Many software packages include the facility to adjust/shift the characteristics of the source relays to line up at the bus maximum fault currents.

- Shifting allows relay operation to be considered on a common current basis (primarily the max).

- The shift factor (SF) is calculated using:

  \[ SF = \frac{\text{Bus Fault}}{\text{Relay Current}} \]

  Source Relay SF = \( \frac{30}{12} = 2.5 \)
  Feeder Relay SF = \( \frac{30}{30} = 1.0 \)
Curve Shifting

Without shift factor both pickups = 3000 A.

With shift factor relay 2 pickup shifts to 7500 A.
Multiple Source Buses

- Different fault locations cause different flows in tie.
  \[ SF_{(Fa)} = \frac{25}{10 + 5} = 1.67 \]
  \[ SF_{(Fb)} = \frac{25}{10} = 2.5 \]

- Preparing a TCC for each unique location can confirm defining case.

- Cases can be done for varying sources out of service & breaker logic used to enable different setting groups.
Partial Differential Relaying
Partial Differential (Bus O.C.) Relaying

- Commonly used on secondary selective systems with normally closed tie breakers.

- CT wiring automatically discriminates between faults on Bus A and Bus B.

- CT wiring ensures that main breaker relay sees the same current as the faulted feeder.

- 51A trips Main A & tie; 51B trips Main B & tie.

- Eliminates need for relay on tie breaker & saves coordination step.
Partial Differential Relaying

- Scheme works with a source or tie breaker open.

- The relay in the open source must remain in operation.

- Relay metering functions can be misleading due to CT summation wiring.

- Separate metering must be provided on dedicated CTs or before the currents are summed.
Partial Differential Relaying

- Scheme will work for any number of sources or bus ties.

- A dedicated relay is needed for each bus section.

- Partial differential schemes simplify the coordination of multiple source buses by ensuring the main relay for each bus always see the same current as the faulted feeder.
Directional Overcurrent Relaying
Directional Current Relaying

- Directional overcurrent (67) relays should be used on double-ended line-ups with normally closed ties and buses with multiple sources.

- Protection is intended to provide more sensitive and faster detection of faults in the upstream supply system.

- Directional device provides backup protection to the transformer differential protection.
Transformer Overcurrent Protection
Transformer Overcurrent Protection

NEC Table 450.3(A) defines overcurrent setting requirements for primary & secondary protection pickup settings.

<table>
<thead>
<tr>
<th>Location Limitations</th>
<th>Transformer Rated Impedance</th>
<th>Primary Protection Over 600 Volts</th>
<th>Secondary Protection (See Note 2.)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Circuit Breaker (See Note 4.)</td>
<td>Fuse Rating</td>
</tr>
<tr>
<td>Any location</td>
<td>Not more than 6%</td>
<td>600% (See Note 1.)</td>
<td>300% (See Note 1.)</td>
</tr>
<tr>
<td></td>
<td>More than 6% and not more than 10%</td>
<td>400% (See Note 1.)</td>
<td>300% (See Note 1.)</td>
</tr>
<tr>
<td>Supervised locations only (See Note 3.)</td>
<td>Any</td>
<td>300% (See Note 1.)</td>
<td>250% (See Note 1.)</td>
</tr>
<tr>
<td></td>
<td>Not more than 6%</td>
<td>600%</td>
<td>300%</td>
</tr>
<tr>
<td></td>
<td>More than 6% and not more than 10%</td>
<td>400%</td>
<td>300%</td>
</tr>
</tbody>
</table>
Transformer Overcurrent Protection

- C37.91 defines the ANSI withstand protection limits.

- Withstand curve defines thermal & mechanical limits of a transformer experiencing a through-fault.

- Requirement to protect for mechanical damage is based on frequency of through faults & transformer size.

- Right-hand side (thermal) used for setting primary protection.

- Left-hand side (mechanical) used for setting secondary protection.
Transformer Overcurrent Protection

Primary
FLC = \(2.4 \text{ MVA} / (\sqrt{3} \times 13.8) = 100.4 \text{ A}\)
Relay PU must be \(\leq 600\% \text{ FLC} = 602.4 \text{ A}\)
Using a relay setting of \(2.0 \times \text{CT}\), the relay PU = \(2 \times 200 = 400 \text{ A}\)
\(400 / 100.4 = 398\% \text{ so okay}\)

Secondary
FLC = \(2.4 \text{ MVA} / (\sqrt{3} \times 0.48) = 2887 \text{ A}\)
MCB Trip must be \(\leq 250\% \text{ FLC} = 7217 \text{ A}\)
Breaker Trip = \(3200 \text{ A per bus rating}\)
\(3200 / 2887 = 111\% \text{ (okay)}\)

Time delay depends on level of protection desired.
Transformer Overcurrent Protection

Δ-Y Connections – Phase-To-Phase Faults

- A phase-phase fault on the secondary appears more severe in one phase on the primary.

- Setting the CTI based on a three-phase fault is not as conservative as for a phase-phase fault.

- The secondary curve could be shifted or a slightly larger CTI used, but can be ignored if primary/secondary selectivity is not critical.

\[30 \times 0.867 = 26 \text{ kA}\]
Transformer Overcurrent Protection

**Δ-Y Connections – Phase-To-Ground Faults**

- A one per unit phase-ground fault on the secondary appears as a 58% \((1/\sqrt{3})\) phase fault on the primary.
- The transformer damage curve is shifted 58% to the left to ensure protection.
Transformer Overcurrent Protection

Inrush Current

- Use of 8-12 times FLC @ 0.1 s is an empirical approach based on EM relays.

- The instantaneous peak value of the inrush current can actually be much higher than 12 times FLC.

- The inrush is not over at 0.1 s, the dot just represents a typical rms equivalent of the inrush from energization to this point in time.
Transformer Overcurrent Protection

Setting the primary inst. protection

- The primary relay instantaneous (50) setting should clear both the inrush & the secondary fault current.

- It was common to use the asymmetrical rms value of secondary fault current (1.6 x sym) to establish the instantaneous pickup, but most modern relays filter out the DC component.
\[\Delta-Y\] Connection & Ground Faults

- A secondary L-G fault is not sensed by the ground (zero sequence) devices on the primary (\(\Delta\)) side.

- Low-resistance and solidly-grounded systems on the secondary of a \(\Delta-Y\) transformer are therefore coordinated separately from the upstream systems.
 transformer overcurrent protection

△-Y Connection & Ground Faults

- The ground resistor size is selected to limit the fault current while still providing sufficient current for coordination.

- The resistor ratings include a maximum continuous current that must be considered.
Motor Overcurrent Protection
Motor Overcurrent Protection

- Fuse provides short-circuit protection.

- 49 or 51 device provide motor overload protection.

- Overload pickup depends on motor FLC and service factor.

- The time delay for the 49/51 protection is based on motor stall time.
Motor Overcurrent Protection

• In the past, instantaneous OC protection was avoided on contactor-fed motors since the contactors could not clear high short-circuits.

• With modern relays, a definite time unit can be used if its setting is coordinated with the contactor interrupting rating.
Motor Overcurrent Protection

- The instantaneous or definite time setting for a breaker-fed motor must be set to pass the motor asymmetrical inrush.

- Can be done with a pickup over the asymmetrical current.

- Can be done using a lower pickup and time delay to allow the DC component to decay out.
Conductor Overcurrent Protection
Conductor Overcurrent Protection

LV Cables

NEC 240.4 Protection of Conductors – conductors shall be protected against overcurrent in accordance with their ampacities

(B) Devices Rated 800 A or Less – the next higher standard device rating shall be permitted

(C) Devices Rated over 800 A – the ampacity of the conductors shall be \( \geq \) the device rating

NEC 240.6 Standard Ampere Ratings

(A) Fuses & Fixed-Trip Circuit Breakers – cites all standard ratings

(B) Adjustable Trip Circuit Breakers – Rating shall be equal to maximum setting

(C) Restricted Access Adjustable-Trip Circuit Breakers – Rating can be equal to setting if access is restricted
Conductor Overcurrent Protection

**MV Feeders & Branch Circuits**

**NEC 240.101 (A) Rating or Setting of Overcurrent Protective Devices**

- Fuse rating \( \leq 3 \times \text{conductor ampacity} \)
- Relay setting \( \leq 6 \times \text{conductor ampacity} \)

**MV Motor Conductors**

**NEC 430.224 Size of Conductors**

Conductors ampacity shall be greater than the overload setting.
Conductor Overcurrent Protection

- The insulation temperature rating is typically used as the operating temperature ($T_o$).

- The final temperature ($T_f$) depends on the insulation type (typically 150 deg. C or 250 deg. C).

- When calculated by hand, you only need one point and then draw in at a -2 slope.

\[
\left( \frac{I}{CM} \right)^2 (tF_{ac}) = 0.0297 \log_{10} \frac{T_f + 234}{T_o + 234} \text{ for copper}
\]
Generator Overcurrent Protection
Generator Overcurrent Protection

- A generator’s fault current contribution decays over time.

- Overcurrent protection must allow both for moderate overloads & be sensitive enough to detect the steady state contribution to a system fault.

- Voltage controlled/ restrained relays (51V) are commonly used.

- The pickup at full restraint is typically \( \geq 150\% \) of Full Load Current (FLC).

- The pickup at no restraint must be \( < \frac{FLC}{X_d} \).
Generator 51V Pickup Setting Example

\[ F_g = \frac{FLC}{X_d} = \frac{903}{2.8} = 322.5 \, A \]

51V pickup (full restraint)  > 150% FLC = 1354 A
51V pickup (no restraint)  < 322.5 A
**Generator 51V Pickup Setting Example**

51V Setting > 1354/1200 = 1.13

Using 1.15, 51V pickup = 1.15 x 1200 A = 1380 A

With old EM relays,

51V pickup (no restraint) = 25% of 1380 A
= 345 A (> 322.5 A, not good)

With new relays a lower MF can be set, such that 51V pickup (no restraint) = 15% of 1380 A
= 207 A (< 322.5, so okay)
• Limited guidance on overcurrent protection (C37.102 Section 4.1.1) with respect to time delay.

• Want to avoid nuisance tripping, especially on islanded systems, so higher TDs are better.
Coordinating a System
Coordinating a System

- TCCs show both protection & coordination.

- Most OC settings should be shown/confirmed on TCCs.

- Showing too much on a single TCC can make it impossible to read.
Coordinating a System

- Showing a vertical slice of the system can reduce crowding, but still be hard to read.

- Upstream equipment is shown on multiple and redundant TCCs.
Coordinating a System

• A set of overlapping TCCs can be used to limit the amount of information on each curve and demonstrate coordination of the system from the bottom up.

• Protection settings should be based on equipment ratings and available spare capacity – not simply on the present operating load and installed equipment.

• Typical TCCs can be used to establish settings for similar installations.

• Device settings defined on a given TCC are used as the starting point in the next upstream TCC.

• The curves can be shown on an overall one-line of the system to illustrate the TCC coverage (Zone Map).
Phase TCC Zone Map

Overcurrent Coordination for Industrial Applications
Coordinating a System: TCC-1

- Motor starting & protection is adequate.
- Cable withstand protection is adequate.
- The MCC main breaker may trip for faults above 11 kA, but this cannot be helped.
- The switchgear feeder breaker is selective with the MCC main breaker, although not necessarily required.

Overcurrent Coordination for Industrial Applications

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Coordinating a System: TCC-2

- The switchgear feeder breaker settings established on TCC-1 set the basis for this curve.
- The main breaker is set to be selective with the feeder at all fault levels.
- A CTI marker is not required since the characteristic curves include all margins and breaker operating times.
- The main breaker curve is clipped at its through-fault current instead of the total bus fault current to allow tighter coordination of the upstream relay. (See TCC-3)
Coordinating a System: TCC-3

- The LV switchgear main breaker settings established on TCC-2 set the basis for this curve.
- The transformer damage curve is based on frequent faults and is not shifted since the transformer is resistance grounded.
- The primary side OC relay is selective with the secondary main and provides adequate transformer and feeder cable protection.
- The OC relay instantaneous high enough to pass the secondary fault current and transformer inrush current.

Overcurrent Coordination for Industrial Applications
Coordinating a System: TCC-307J

**Zone Map**

- This curve sets the basis for the upstream devices since its motor is the largest on the MCC.
- Motor starting and overload protection is acceptable.
- Motor feeder cable protection is acceptable.
- The motor relay includes a definite time unit to provide enhanced protection.
- The definite time function is delay to allow the asymmetrical inrush current to pass.
Coordinating a System: TCC-4

• The 307J motor relay settings established on TCC-307J set the basis for this curve.
• The tie breaker relay curve is plotted to the total bus fault current to be conservative.
• The main breaker relay curve is plotted to its let-through current.
• A coordination step is provided between the tie and main relay although this decision is discretionary.
• All devices are selectively coordinated at all fault current levels.
• The definite time functions insulate the CTIs from minor fault current variations.

- The definite time functions insulate the CTIs from minor fault current variations.

[Diagram of electrical system with labels and connections]

Overcurrent Coordination for Industrial Applications

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Coordinating a System: TCC-5

• The MV MCC main breaker settings established on TCC-4 set the basis for this curve.
• The transformer damage curve is based on frequent faults and is not shifted since the transformer is resistance grounded.
• The primary side OC relay is selective with the secondary main and provides adequate transformer and feeder cable protection.
• The OC relay instantaneous high enough to pass the secondary fault current and transformer inrush current.
Coordinating a System: TCC-Comp

• Due to the compressor size, this curve may set the basis for the MV switchgear main breaker.
• Motor starting and overload protection is acceptable.
• Short-circuit protection is provided by the relay/breaker instead of a fuse as with the 1000 hp motor.
• The short-circuit protection is delayed 50 ms to avoid nuisance tripping.
The feeder breaker settings established on TCC-3, TCC-4, and TCC-Comp are shown as the basis for this curve.

The settings for feeder 52A1 (to the 2.4 MVA) could be omitted since it does not define any requirements.

A coordination step is provided between the tie and main relay although this decision is discretionary.

All devices are selectively coordinated at all fault current levels.

The definite time functions insulate the CTIs from minor fault current variations.
Ground TCC Zone Map
Current Transformer Basics

Don’t let polarity marks fool you!
Current Transformer Basics

Residual CT connection

Zero sequence CT

Bus NOT Protected
Current Transformer Basics

Understand How CTs work!

*IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes - IEEE Std C37.110*
Basic Guides for Protective Relay Settings

Suggested “Rules of Thumb” for MV Equipment

- Transformers
- Bus
- Feeders
- Motors
- Capacitors
Basic Guides for Protective Relay Settings

Suggested “Rules of Thumb” for MV Equipment

• The intent of this section is to provide a range of “typical” settings. It is the engineer’s responsibility to verify the application on an individual basis.

• This section does NOT apply to equipment 600 V and below.

• Care must be taken when coordinating a microprocessor TOC element with an electromechanical relay downstream. The electromechanical relay may respond to a fundamental phasor magnitude, true RMS, or rectified magnitude.
Rules of Thumb...(above 600 V)

Power Transformers
Phase Relays
(delta – wye)

Primary – Phase Settings

• CT Ratio: 200% FLA
• Set pickup to comply with NEC 450-3, but as a rule of thumb setting should be less than 300% of transformer self cooled rating or 150% of transformer maximum rating.
• Try to set the time dial such that pickup time for maximum through fault is in the neighborhood of 1.0 seconds or less. If higher, ensure that ANSI damage points are not exceeded.
• Set instantaneous at between 160% and 200% of maximum through fault (assume infinite bus). Ensure that available system short circuit allows this.
• Time Dial set at 1.0 to 1.5 seconds at maximum fault. Do not exceed 2.0 seconds which is the mechanical damage point.
Primary – Ground Settings

- Set 50G if primary winding is delta connected.
- Provide time delay (approx 20 msec) when setting digital relays with zero sequence CTs. No time delay when using electro-mechanical relays with zero sequence CTs.
- CT considerations:
  - Residually connected neutral. CT mismatch and residual magnetization will not allow the most sensitive setting. Recommend to delay above inrush.
  - Zero sequence CT. Care must be taken to ensure that cables are properly placed and cable shields are properly terminated.

Residual CT connection

Zero sequence CT
Primary Fuse Rating of power transformer:
135% FLA < Fuse < 250% FLA. Try to stay in the range of 150%.

Primary fuse rating of power transformer should be approximately 200% FLA if transformer has a secondary main.

Generally use E-rated fuses. Note that TOC characteristics of fuses are not all the same.
Rules of Thumb...(above 600 V)

Secondary Power Transformers

Secondary Low-Resistance Grounded

• Set pickup for 20% to 50% of maximum ground fault. Note that ground resistors typically have a continuous rating of 25-50% of nominal. This value can be specified when purchasing the equipment.

**Example:** 2000 A main breaker (2000:5 CTs), it may make sense to specify an 400 A ground resistor with a continuous rating of 50% (200 A) such that a 2000:5 residually connected CT input can be used with a minimum pickup (0.1 x CT = 0.5 A secondary, 200 A primary).

• Set the time dial such that at the time to trip is 2.0 seconds at maximum ground fault

• Protect resistor using $I^2t$ curve. Typical resistor is rated for 10 seconds at nominal current (to be specified at time of order).
Rules of Thumb...(above 600 V)

**Secondary Solidly Grounded** (for balanced three phase industrial loads)

- If secondary is solidly grounded and neutral relay is available (using CT on X0 bushing), set pickup at approximately 50% of phase element and ensure transformer 2 second damage point is protected. Coordinate TOC with main breaker (or partial differential) ground relay.

- Decrease the primary phase element by 58% (to account for transformer damage curve shift). This is the equivalent current seen on the primary (delta) for a secondary ground fault (refer to the Symmetrical Components presentation on Oct 5th, 2010 by Dr. Kurt Ederhoff).
Rules of Thumb...( above 600 V)

Protection for Transformer
Secondary Faults on Solidly Grounded Systems

It is certainly preferable to rely on the transformer primary phase overcurrent relay for backup of transformer secondary ground faults. However, downstream coordination does not always afford us that luxury (shifting the transformer damage curve and associated transformer primary relay 58%).

For solidly grounded transformer secondary installations, an argument can be made that the 87T is the primary protection and 51NT is the backup protection for a transformer secondary ground fault. This will allow you to set the 50T/51T relay without consideration of the 58% shift.
Rules of Thumb...(above 600 V)

**Primary Side Wye-Grounded Transformer**

If primary is solidly grounded and neutral relay is available, set pickup at approximately 50% of phase element. This must coordinate with upstream line protection devices (i.e. 21P, 21G, 67, 67G …). If it’s at the utility level, they will review and provide settings.

For generator step-up transformers (GSU), the HV 51NT should typically be the last device to trip for upstream ground faults. Ensure that the GSU damage curve and the H0 grounding conductor is protected.
Rules of Thumb...( above 600 V)

Directional Overcurrent Consideration for transformer secondary fault

*For a fault between the transformer and main breaker, the partial differential bus relays will not detect current (other than motor contribution).*

*Both transformer primary overcurrent relays will detect see the same current. A directional overcurrent relay is required to prevent tripping of both transformers via 50T/51T.*

Set 67 pickup at 40% of transformer FLA. Coordinate with time curve with 50T/51T
Rules of Thumb...( above 600 V)

Directional Overcurrent
Consideration for transformer secondary fault

For a fault between the transformer and main breaker, the main and tie breaker relays will all see the same current (other than motor contribution).

The tie breaker will trip followed by the respective transformer primary overcurrent. A directional overcurrent relay is required to prevent loss of one bus.

Set 67 pickup at 40% of transformer FLA. Coordinate with time curve with 51Tie.
Rules of Thumb...( above 600 V)

**Bus and Feeders**

**Bus Relays (Main Breaker or Partial Differential):**
Pickup set between 100% and 125% FLA (150% FLA maximum)
Set to coordinate with transformer primary protective relaying

*Do not enable the instantaneous overcurrent element on main breaker relays!*

**Feeder Relays:**
Set pickup to comply with NEC 240-100 (limited to 600% of rated ampacity of conductor). Actually, pickup permitted by NEC is slightly higher. Keep it down in the neighborhood of 200%. The intent is **NOT** to provide overload protection. The intent is to provide short-circuit protection.

Set time dial as required to coordinate with downstream devices while protecting conductor against damage.

*Enable instantaneous element only if the load has a notable impedance (i.e. transformer, motor, capacitor, etc) or if the load is the end of a radial circuit.*
Rules of Thumb...( above 600 V)

**Induction Motors**

**Pickup** set at 101% - 120% **Nameplate Rating** depending on Service Factor and normal load.

- Motor < 1,500 hp: Set at 1.15 x FLA
- Motor > 1,500 hp: Set just above FLA x S.F.

**Instantaneous Trip** set at 200% LRC. A higher pickup may be used depending on system available short circuit, however, do not lower below 160% LRC unless you know that the relay filters/removes the DC component. **Ensure that the instantaneous trip setting will not cause a motor starter to attempt interrupting a fault beyond its rating.**

**Ground Overcurrent.** For Zero Sequence CT (BYZ) set ground **Trip** at 10A primary and **Alarm** at 5A primary. Set for instantaneous if using electromechanical and set at 20 msec delay (minimum) if using digital relays. For solidly grounded systems, ensure that the ground trip setting will not cause a motor starter to attempt interrupting a fault beyond its rating.

**Mechanical Jam** set 150% FLA at 2 sec, unless application does not allow this (i.e. grinder, crusher, etc).
Rules of Thumb...( above 600 V)

Capacitors

Capacitor Bank:
For individual protection, the Fuse protecting the capacitor is chosen such that its continuous current capability is greater than or equal to 135% of rated capacitor current. The feeder cable should be sized as such for continuous operation. This over rating is due to 10% for allowable overvoltage conditions, 15% for capacitor kVAR rating tolerance (this correlates to 15% percent deviation from nominal capacitance) and 10% for overcurrent due to harmonics.

For unbalance, set Alarm for loss of one capacitor, set Trip for overvoltage of 110% rated (nameplate).

For feeder protection, set Pickup at 135% of FLA, set Time Dial at 1.0, set 50P element above maximum inrush and include a slight time delay to coordinate with individual fuse clear time. Plot TOC to protect the capacitor case rupture curve.

Note: Systems with high harmonic content require special attention.
Hands-On Demonstration
Coordination Quizzes
Does this TCC look okay??

- There is no need to maintain a coordination interval between feeder breakers.

- The CTI between the main and feeder 2 is appropriate unless all relays are electromechanical and hand set.

- Fix – base the setting of the feeder 2 relay on its downstream equipment and lower the time delay if possible.
Coordination Quiz #2

Does this TCC look okay??

- The CTIs shown between main and both feeders are sufficient.
- Assuming testing EM relays, the 0.62 s CTI cannot be reduced since the 0.30 s CTI is at the limit.
- The main relay time delay is actually too fast since the CTI at 30 kA is less than 0.2 s.

- Fix – raise the time delay setting of the main relay.
Coordination Quiz #3

Does this TCC look okay??

- The marked CTIs are okay, but....

- A main should never include an instantaneous setting.

- Fix – delete the instantaneous on the main relay and raise the time delay to maintain a 0.2s CTI at 50 kA.
Coordination Quiz #4

Does this TCC look okay??

- Primary relay pickup is 525% of transformer FLC, thus okay.

- Transformer frequent fault protection is not provided by the primary relay, but this is okay – adequate protection is provided by the secondary main.

- Cable withstand protection is inadequate.

- Fix – Add instantaneous setting to the primary relay.
Coordination Quiz #5

Does this TCC look okay??

- Selectivity between Relay14 on the transformer primary and CB44 on the secondary is not provided, but this can be acceptable.

- Relay 14 is not, however, selectively coordinated with feeder breaker CB46.

- Fix – raise Relay14 time delay setting and add CTI marker.
Coordination Quiz #6

Does this TCC look okay??

- Crossing of feeder characteristics is no problem.

- There is no need to maintain an intentional time margin between two LV static trip units – clear space is sufficient.

- Fix – lower the main breaker short-time delay band.
Does this TCC look okay??

- The source relays should not be plotted to the full bus fault level unless their plots are shifted based on:
  \[
  SF = \frac{\text{Total fault current}}{\text{relay current}}.
  \]

- Assuming each relay actually sees only half of the total fault current, the CTI is actually much higher than 0.3 s.

- Fix – plot the source relays to their actual fault current or apply \( SF \).
Coordination Quiz #8

Does this TCC look okay??

- There are two curves to be concerned with for a 51V – full restraint and zero restraint.
- Assuming the full restraint curve is shown, it is coordinated too tightly with the feeder.
- The 51V curve will shift left and lose selectivity with the feeder if a close-in fault occurs and the voltage drops.
- Fix – show both 51V curves and raise time delay.
Selected References

- IEEE Std 242 – Buff Book
- IEEE Std 141 – Red Book
- IEEE Std 399 – Brown Book
- IEEE C37.90 – Relays
- IEEE C37.91 – Transformer Protection
- IEEE C37.102 – Guide for AC Generator Protection
- NFPA 70 – National Electrical Code
- Applied Protective Relaying – Westinghouse
- Protective Relaying – Blackburn
- Protective Relaying Theory and Applications – ABB Power T&D Company
- Protective Relaying for Power Systems – IEEE Press
- Protective Relaying for Power Systems II – IEEE Press
- AC Motor Protection – Stanley E. Zocholl
- Industrial and Commercial Power System Applications Series – ABB
- Analyzing and Applying Current Transformers – Stanley E. Zocholl